Public Version

2012 Wholesale Electricity Market Report for the Minister for Energy

19 April 2013

Economic Regulation Authority

WESTERN AUSTRALIA

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EXECUTIVE SUMMARY

The Wholesale Electricity Market (**WEM**) was 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 efficient investment in the generation and retail sectors, and ultimately to minimise the cost of electricity supplied to consumers.

Overview of the market

The WEM consists of an energy market and a capacity mechanism. The energy market provides for the trading of energy between Market Participants and includes the Short Term Energy Market (**STEM**) and the Balancing Market. The WEM was designed under the assumption that retailers would cover the majority of their electricity requirements through bilateral contracts with generators. The STEM enables Market Participants to adjust their contract positions on the day prior to the trading day. The Balancing Market adjusts for real time deviations from these contract positions.

The Reserve Capacity Mechanism (**RCM**) exists to ensure continued investment in existing and new capacity. It was adopted primarily to provide sufficient capacity to maintain reliability and meet peak summer demand. As an isolated system, the SWIS cannot rely on any interconnections with other systems, and must therefore have sufficient capacity within itself to satisfy demand and deal with emergency situations.

Both the energy market and the RCM are intended to facilitate efficient new entry and hence, to promote competition. Given that wholesale electricity costs comprise roughly half of the total efficient cost of supply for an average residential customer, a well functioning WEM can play an important part in placing downward pressure on electricity prices.

The operation of the WEM is governed by the *Wholesale Electricity Market Rules* (**Market Rules**). Amongst other things, these Market Rules establish the monitoring and reporting regime on the effectiveness of the market.

Specifically, clause 2.16.11 of the Rules requires that the Economic Regulation Authority (**Authority**) must provide a report to the Minister for Energy, at least annually, on the effectiveness of the market in meeting the specified Wholesale Market Objectives. This report fulfils that requirement for the period 1 August 2011 to 30 June 2012.

The Electricity Industry Act 2004 (**Act**) also requires the Authority to report to the Minister on the overall effectiveness of the market, once every three years. To avoid overlap and duplication, the Authority seeks to focus on operational matters in this annual report and strategic matters in the triennial report. The next triennial report is scheduled to be delivered to the Minister in 2013/14.

The Authority is conscious that there may be potential or perceived overlap between its role, the role of the Independent Market Operator (**IMO**) and the Public Utilities Office (**PUO**) in the WEM. Various submissions received in response to the Authority's Discussion Paper highlight the perception of role overlap between these organisations.

The Authority considers that its role differs from the roles of the PUO and the IMO, as follows:

- The role of the Authority is to monitor the market and clearly identify problems or issues that need to be resolved, and to recommend measures to the Minister to improve the effectiveness of the market in achieving the Wholesale Market Objectives.

- The role of the PUO focuses on the development of energy policy, including the policy response to issues or problems identified by the Authority. Major reform changes to the WEM that have wide implications for consumers need to be addressed by the PUO.

- The role of the IMO is primarily operational and involves rule administration and rule development, providing continuous refinements to the market, and finding the most efficient means to implement the solutions or policy responses identified by the PUO.

The Authority recognises that the three organisations must work collaboratively to achieve the best outcome for consumers in the SWIS.

Consistent with the Authority's role, the scope of this report is limited to identifying problems within the WEM and to reporting on the matters that the Market Rules require the Authority to report on.

The Authority notes that the energy market has recently gone through its first significant structural change since its inception. Primarily, the Balancing Market has been reformed to allow for competition in the provision of this service. However, since this Balancing Market change has only recently taken place (effective from 1 July 2012), there is not enough history to undertake a meaningful analysis. The Authority has therefore focussed on the RCM in this report.

Key issues within the Reserve Capacity Mechanism

Investment is occurring in the WEM, with over $2 billion invested since market commencement, and there is robust competition between generators, with ultimate benefits for consumers. However, as with all other markets, there are areas that can be improved upon to achieve more efficient outcomes. The Authority considers that the following issues in the RCM require attention.

Excess Capacity

The Authority considers that the excess capacity being procured through the RCM indicates that there is scope to achieve greater efficiency in the WEM.

Under the RCM the IMO is responsible for determining the capacity requirement two years in advance, in accordance with the Planning Criterion (based on peak demand and energy forecasts and including a reserve margin).[1] This is called the Reserve Capacity Requirement (**RCR**). The RCR is published in the IMO's annual Statement of Opportunities Report in June/July each year and considers capacity requirements and projected shortfalls for the next ten years. As part of the process of determining the RCR the IMO engages a consultant to produce economic forecasts and forecasts for electricity consumption and demand in the South West Interconnected System (**SWIS**) under various scenarios. The one in ten year demand forecast has been used as the basis for setting the RCR, which also includes a reserve margin for system security and reliability purposes.

[1] For further detail on the Planning Criterion for setting the RCR, refer to clause 4.5.9 of the Market Rules.

To ensure sufficient capacity is installed in the SWIS to meet the capacity requirement, the Reserve Capacity Mechanism provides a possible income stream through the trade of Capacity Credits. One Capacity Credit, as defined in the Market Rules, represents one megawatt (**MW**) of capacity. Capacity Credits are allocated by the IMO to capacity that is supplied from both existing and new generators, and Demand Side Management (**DSM**) providers.

To apply for Capacity Credits, a capacity provider (i.e. generator or DSM provider) must go through the capacity certification process whereby the IMO determines the maximum quantity of capacity that can be allocated to a facility. This process involves the IMO conducting a due diligence assessment, including a technical review of the capability of the offered facility.

After the certification process is complete and certified capacity has been granted, capacity providers will need to declare to the IMO the amount of certified capacity they intend to trade bilaterally with other participants.[2]

The IMO assesses the amount of capacity declared to be traded bilaterally between participants, and in the event that insufficient capacity is identified during this process, the IMO is able to procure the shortfall by calling a Reserve Capacity Auction. To date, the capacity requirement has always been met through declarations of capacity for bilateral trading and there has been no capacity auction held.

Declarations of the amount of capacity to be traded bilaterally between participants are not binding. Under the Market Rules, the IMO must allocate Capacity Credits to all certified capacity that has been declared for bilateral trade (unless the capacity provider decides to withdraw prior to the IMO's allocation decision being made). There is no quantity limit to the amount of Capacity Credits that the IMO can allocate (even if the total declared certified capacity for bilateral trading is well above the capacity requirement).

Under the Market Rules, the price for capacity (i.e. one Capacity Credit) is determined by the capacity auction if it is held. In the situation that no capacity auction is held, the Market Rules provide a formula for determining the capacity price, which is set at 85 per cent of the Maximum Reserve Capacity Price (**MRCP**). This value is multiplied by an adjustment factor when there is excess capacity in the market (i.e. the Excess Capacity Adjustment).[3] Given that no capacity auction has ever been held since market commencement, the capacity price (known as the Reserve Capacity Price, **RCP**) has always been determined administratively using the formula defined in the Market Rules.

Capacity Credits are tradable in the WEM, i.e. they can be traded between participants (which include retailers and capacity providers) and with the IMO (as the default buyer of Capacity Credits). Retailers (classified as Market Customers) are assigned an individual obligation for capacity, known as the Individual Reserve Capacity Requirement (**IRCR**). In order to meet the IRCR obligations, retailers can procure Capacity Credits bilaterally from capacity providers, or they can make payments to the IMO (for the purchase of the required Capacity Credits by the IMO from capacity providers to meet the capacity requirement).

[2] As part of the process, a capacity provider may also declare the amount of certified capacity it intends to offer to the capacity auction.

[3] Refer to clause 4.29.1 of the Market Rules.

Capacity Credits are only valid for a particular Capacity Year.[4] Hence, the process of capacity certification and allocation of Capacity Credits is repeated each year.

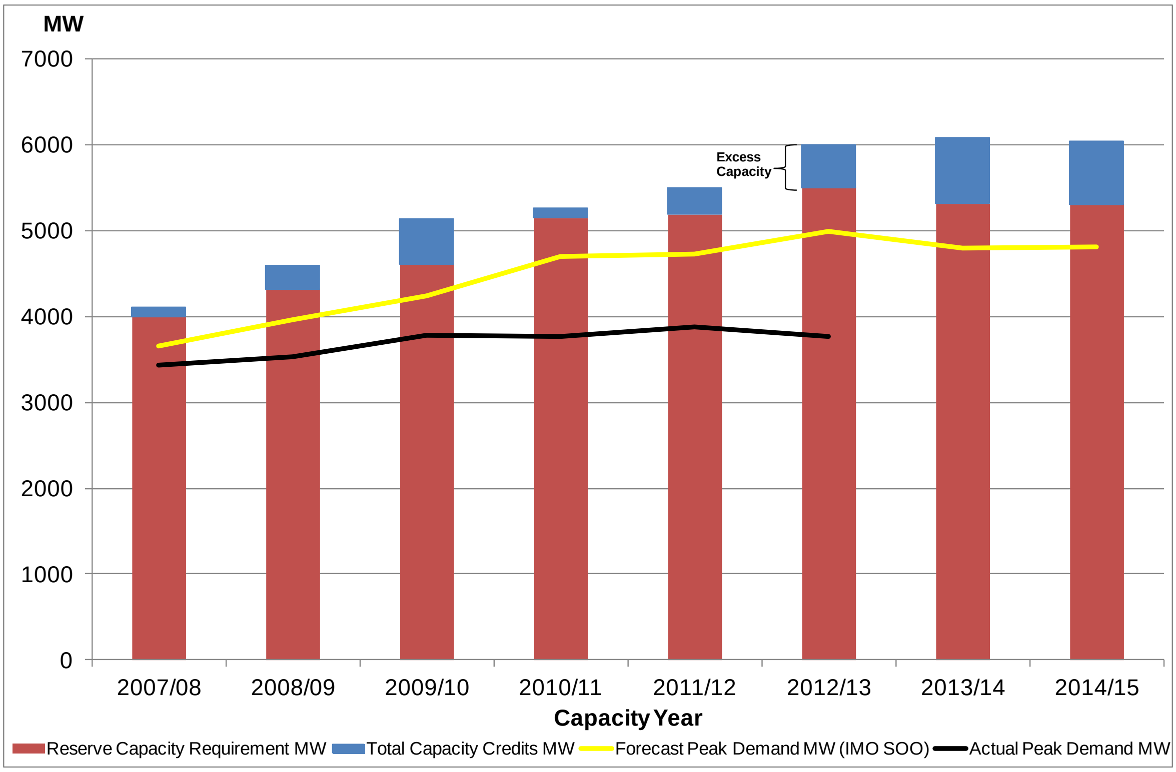
The flow chart below illustrates the process for the allocation of Capacity Credits and the determination of the capacity price.

Figure A1 Flow of Capacity Credits allocation and determination of the capacity price

[4] A Capacity Year is a period of 12 months commencing at the start of the Trading Day on 1 October and ending at the close of the Trading Day on 30 September of the following year.

Although the operation of the Reserve Capacity Mechanism has resulted in the capacity requirement always being met, it has also resulted in the accumulation of a substantial amount of excess capacity over the capacity requirement, i.e. the market has purchased a level of capacity that is in excess of the required amount of capacity, as shown in the figure below.

Figure A2 Actual and forecast peak demand, Reserve Capacity Requirement, and total Capacity Credits allocated (2007/08 to 2014/15 Capacity Years)



The graph above shows:

- the actual peak demand (the black line), which represents the highest level of actual demand for each year that is measured based on the maximum Operational System Load Estimate;[5]
- the forecast peak demand requirement each year based on a one in ten year peak (the yellow line);
- the Reserve Capacity Requirement (red column), which represents the forecast system capacity requirement determined based on the peak demand forecast plus a reserve margin; and
- the excess capacity over and above the Reserve Capacity Requirement that has accumulated in the market (blue column).

This chart demonstrates that there has been excess capacity in the market since its inception and that this has recently increased. Additionally, as can be seen from the

[5] Clause 6.14.4(a) defines the Operational System Load Estimate as the estimate made by System Management of the total loss factor adjusted consumption (in MWh) supplied via the SWIS during a Trading Interval. It is the total loss factor adjusted generator sent out energy as estimated from generator operational meter data and the use of state estimator systems.

chart, up to the 2012/13 Capacity Year, the forecast peak demand (the yellow line) has continually grown ahead of the actual demand (the black line).

There are a number of possible reasons for this excess capacity accumulation in the WEM. For example, the ongoing excess indicates that the price being paid for capacity has been set too high. Additionally, it is noteworthy that there is nothing in the Market Rules that sets a limit on the amount of Capacity Credits that can be issued each year; only a stipulation that sufficient capacity be obtained so as to satisfy the reserve capacity required.

The Authority is aware that the RCM has recently undergone a major review, undertaken by the Reserve Capacity Mechanism Working Group (**RCMWG**).[6] An important outcome of this review has been the proposal by the Lantau Group, the consultant engaged by the IMO, to change the formula for calculating the RCP to make it more responsive to market conditions, such that the price would reduce more rapidly in conditions of excess capacity and increase when a shortage of capacity occurs.

The excess capacity represents a significant and unnecessary cost. The Authority notes that the Market Rules includes a price adjustment mechanism to reduce the capacity price in proportion to the amount of excess capacity. The intention of this adjustment mechanism is to lower the RCP to the point where consumers do not have to pay for any excess capacity (i.e. the total cost of capacity would be the same irrespective of whether there is any excess capacity). However, this mechanism is not completely effective, such that the direct costs of excess capacity to consumers in the 2011/12 year is estimated at approximately $26 million. Moreover, the investment in excess capacity could have been better spent elsewhere in the economy; hence there are indirect costs to the economy as well as direct costs to consumers. Whilst the extent of this total cost to the economy has not been quantified, it is clear that it is not an economically efficient outcome and, as such, does not meet the Wholesale Market Objectives.

Given the significance of the issue, the Authority recommends that the PUO undertake a comprehensive, holistic review of the current market design of the RCM in its entirety, with a view to considering the long term evolution of the market and the realisation of efficient economic outcomes.

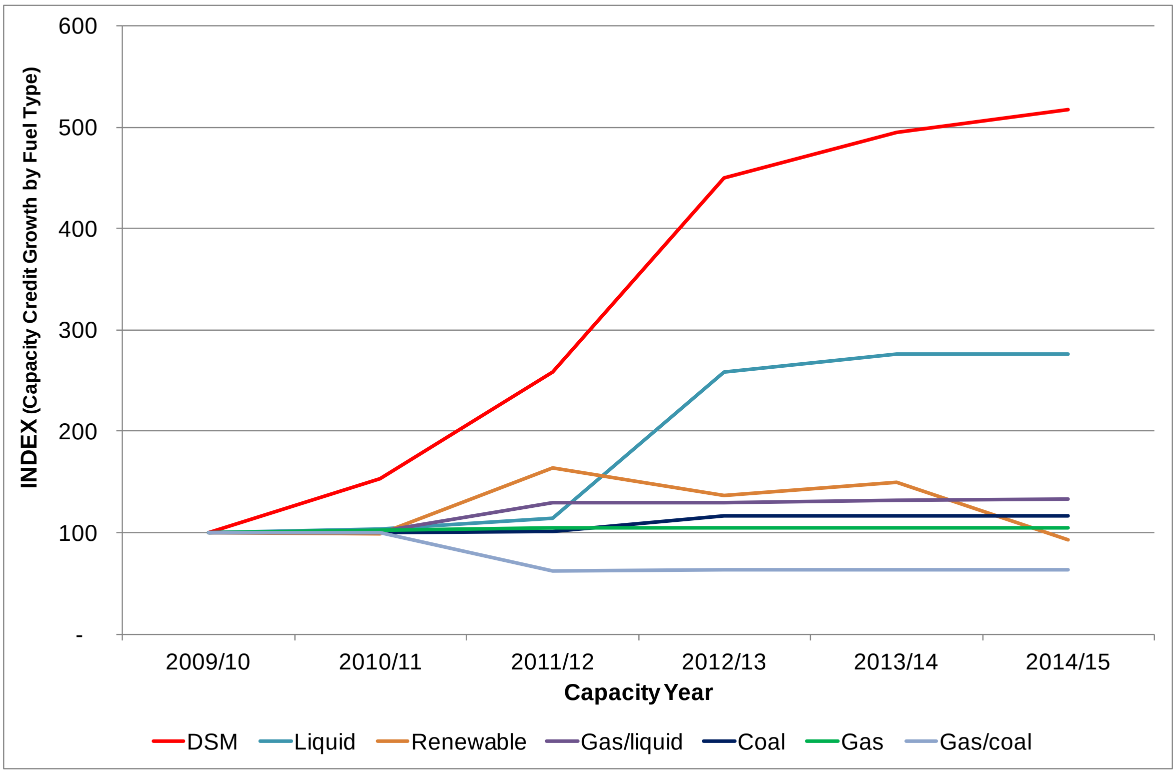
Capacity Mix

The Authority considers that the current Market Rules are unlikely to result in an optimal mix of capacity types and that they create the potential for inefficient outcomes in the market.

The figure below displays the new generation capacity entering the market by fuel type and the new entry of DSM capacity. This is shown as an index (with a base year as 2009/10) to demonstrate the relative growth in each type of capacity in relation to growth in the other capacity types. The figure shows that growth in liquid fuel generation and DSM capacity, in particular, has outstripped growth in all other capacity types.

[6] Refer to the IMO website for details http://www.imowa.com.au/RCMWG.

Figure A3 Entry of capacity by fuel type, year on year, 2009/10 to 2014/15 Capacity Years



The table below provides this information in terms of Capacity Credits by fuel[7] type from 2009/10 Capacity Year to 2014/15 Capacity Year.

Table A1 Allocated Capacity Credits by fuel type, 2009/10 to 2014/15 Capacity Years

Fuel Type	2009/10 MW	2010/11 MW	2011/12 MW	2012/13 MW	2013/14 MW	2014/15 MW
Coal	1,518	1,518	1,542	1,766	1,771	1,777
DSM	99	154	260	455	500	524
Gas	2,118	2,179	2,217	2,227	2,226	2,219
Gas-liquid	631	636	821	821	833	840
Liquid	69	71	79	179	190	190
Renewable	138	137	224	187	205	129
Gas-coal	564	564	351	362	362	362

[7] Facilities fuel type classification sourced from IMO's website - *2012 Margin Peak and Margin Off-Peak Review*, http://www.imowa.com.au/f6364,2926859/SH43336_Assumptions_-_v3_1_PUBLIC_for_publication.pdf, 11 September 2012, pp. 21-23

Liquid fuel generators that require relatively lower capital costs to install play an important role in maintaining the optimal portfolio mix of plant types. For example, they provide the flexibility needed if a generator is required to be called on at short notice to maintain system security. Although they have a relatively lower capital cost, they have a significantly higher cost of producing energy through burning liquids. Their entry into the market has the potential to impact the financial viability of other potential new entrants fuelled by gas or coal, who may have a higher capital cost but lower energy costs, and lower overall costs of electricity supply.

Likewise, DSM adds value to the portfolio mix, such as by providing a fuel free source of capacity in the market. DSM has the potential to truncate demand during system peaks as well as to reduce the investment required in generation and network capacity to meet this peak demand. The role of DSM is especially beneficial in times of fuel shortages as it is fuel independent.

Currently, DSM capacity does not have to meet the same operational requirements as generators. There are limitations on the number of times each year that DSM can be called on, the number of hours that it can be used when it is called, and there is a minimum of a four hour ramp-up period for DSM to come on line. The treatment of DSM contrasts with the treatment of generators, which are required to provide unlimited availability and have a half hour ramp-up period.

Nevertheless, under the current Market Rules capacity provided by DSM receives the same remuneration as generators, i.e. the value of 1 MW curtailed by DSM is considered to be equal to the value of 1 MW provided by generators.

The Authority recognises that a mix of capacity types is desirable as they all contribute to a well functioning market and no single source is able to provide an efficient source of supply. However, if the recent trends continue, there is a risk that the market will move further away from an efficient outcome, and the overall cost of capacity and energy will be higher than it needs to be.

A review of other forward capacity markets shows that they are experiencing similar concerns around the treatment of DSM. These concerns relate to risks to reliability due to limited availability requirements, the treatment of DSM as equivalent to generators (resulting in the same returns regardless of differences in costs of service provision) and distorted capacity prices. Accordingly, in other capacity markets, consideration is currently being given to the remuneration of DSM products on the basis of reliability attributes such as their availability, flexibility of dispatch options, and the cost of DSM.

The Authority is aware of the work stream undertaken by the RCMWG and the proposal to harmonise the operational requirements of DSM with generators presented to the RCMWG by the consultant engaged by the IMO. The Authority understands that the IMO intends to proceed with this proposal to the formal Rule Change process. However, given the wide implications of this matter, the Authority considers further investigation is warranted to ensure an efficient outcome for the market.

The Authority recommends that as part of the comprehensive review suggested earlier, the PUO evaluates whether the market design provides the incentives necessary to ensure the achievement of an economically efficient mix of capacity and energy resources.

Unavailability of generating plants

The Authority considers there are perverse market incentives that lead to the high level of unavailability of some Verve Energy generating plants that have been assigned Capacity Credits and yet are provided full payments for these Capacity Credits by the market.

In a capacity market, generators are paid for capacity on the expectation that this capacity will be made available. While it is expected that generation facilities will not be available during plant maintenance, the observed high level of planned outages of some Verve Energy generating plant is a concern. For example, in the 2010/11 Capacity Year, a number of Verve Energy's plants had planned outage rates of about 50 per cent. Verve Energy's planned outage rates improved in the following year, but still remained high, with some units (for example, Verve Energy's Muja G6 facility, which has a certified capacity of 186.5 MW[8]) having a planned outage rate as high as 40 per cent.

The Authority notes that the observed unavailability rates in the WEM are significantly higher than the rates for similar plant in other electricity markets and is concerned that generating facilities that are unavailable for half the year are able to receive full capacity payments.[9]

The Authority has also noted a high level of planned outages during periods of tight supply in 2011. As a result, the Authority engaged a consultant to study the relationship between generators' planned outages and high prices in the STEM. This specifically related to price spike periods where the STEM price exceeded $100/MWh during times when levels of planned outages were high.

The following charts illustrate STEM prices ($/MWh), operational load (MW) and the volume of planned outages (MW), over the periods 1 December 2010 to 29 July 2011, and 1 December 2011 to 28 July 2012, respectively. The charts show that price spikes occur through the winter period, when demand is generally lower than what occurs in the summer period, and comparatively lower prices are expected. Of note is the coincidence of large volumes of planned outage and high STEM prices, particularly between 27 June 2011 and 9 July 2011. Similarly, high STEM prices are observed to coincide with large volumes of planned outages in early July 2012.

[8] Based on the Certified Reserve Capacity figure for the Capacity Year running from 1 October 2014 to 1 October 2015).

[9] Refer to the IMO's presentation to the March 2013 MAC meeting: Generator Availability, Incentives to Improve Performance, http://www.imowa.com.au/f7189,3763063/Availability_Incentives_-_MAC_Presentation_final_for_publication.pdf

Figure A4 STEM Price, Operational Load and Planned Outage (1/12/2010 to 31/7/2011)

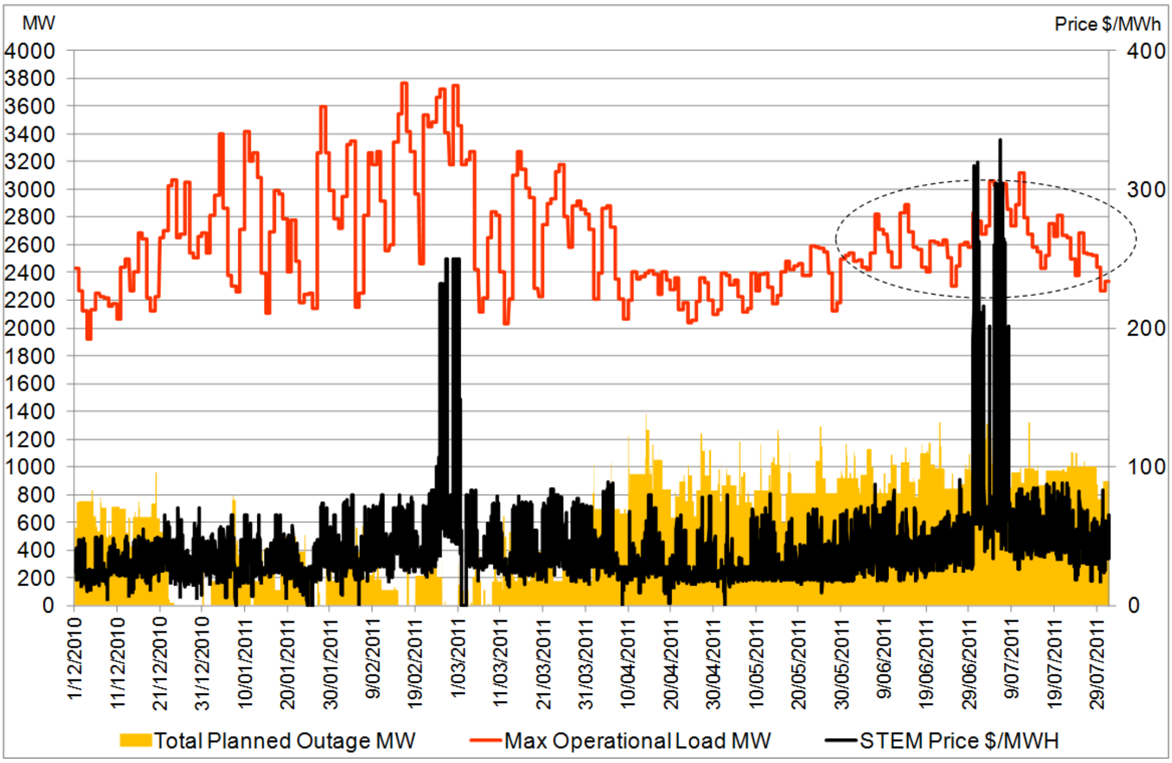
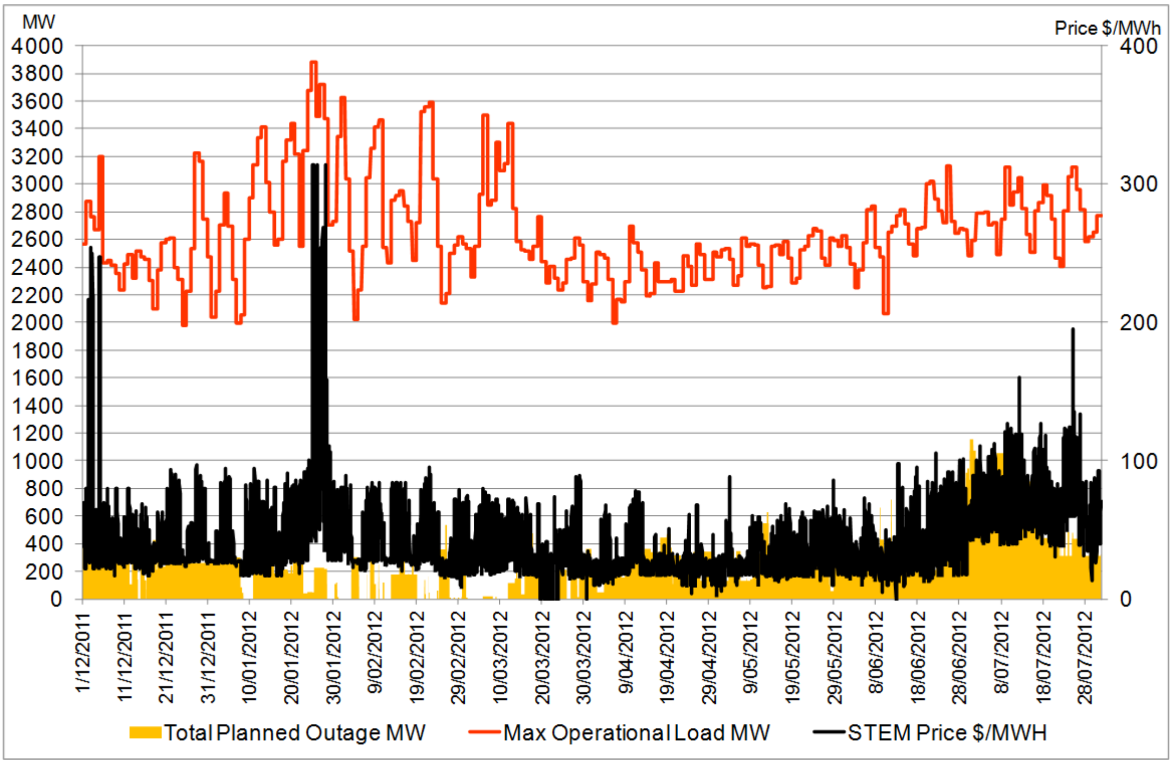


Figure A5 STEM Price, Operational Load and Planned Outage (1/12/2011 to 31/07/2012)



The facilities on planned outage included a number of base-load generators, i.e. major, low cost coal units, as well as a number of mid-merit gas units, which would typically result in lower clearing prices when dispatched. The Authority considers that the primary driver for the observed price spikes was likely to be the unavailability of a high amount of base-load capacity. Simulations of market operations showed that the price spikes observed in 2011 would have been significantly reduced if two of the large base-load units were returned to service, whilst the return of three large base-load units would have completely eradicated the spikes.[10]

The Authority considers that incentives to maximise plant availability need to be reviewed. The Authority notes that the IMO has commenced a review of current generator availability and the incentives to improve performance. The Authority supports this undertaking.[11]

Despite the apparent weakness in the Market Rules that is currently under the review of the IMO, the Authority recognises that the issue of plant unavailability appears to be a matter associated with Verve Energy specifically. The Authority considers the inefficient outcomes may also be attributable to certain aspects of the arrangements in the contract between Verve Energy and Synergy, assigned by the State Government in 2010. Hence, the Authority recommends that the PUO, as a representative of the owner of the two entities, undertakes a review of the contractual arrangements between Verve Energy and Synergy, to ensure the contract does not provide perverse incentives, which result in inefficient market outcomes.

Conclusion

The Authority has three main concerns in relation to the capacity mechanism within the WEM.

The first concern relates to the substantial excess capacity that has accumulated in the market over recent years. This problem is largely due to the pricing mechanism and the requirement for the IMO to purchase, without limit, all certified capacity that has been nominated for bilateral trade.

The second concern relates to the significant amount of liquid generation and DSM capacity that has entered the market in recent years. Whilst acknowledging the valuable role that these types of capacity play in the successful working of the market (particularly in regard to plant diversity, which enhances system security), the Authority is concerned that the current Market Rules are resulting in an overall cost of capacity and energy that is higher than it needs to be, largely due to the incentives that the current mechanism provides.

The final concern relates to the high plant outage rates observed for certain generation units in the WEM. The Authority believes that the current Market Rules do not provide sufficient incentives for plant availability to be maximised.

The Authority recommends that the three highlighted concerns be investigated to ensure that the Reserve Capacity Mechanism functions more efficiently. The Authority recommends that the PUO, as the policy advisor, takes the lead in addressing these policy related, strategic issues. The Authority recognises that the IMO has the expertise and responsibility to address a number of specific operational matters relating to the

[10] The Authority has not undertaken further analysis on the price spikes noted in the 2012 period.

[11] The IMO has commenced a review of the relevant clauses in the Market Rules and provided a concept paper to the March 2013 MAC meeting.

Authority's concerns, and is doing so in its existing work programs. However, the Authority considers market reform issues that have wide implications and are more strategic in nature should be addressed by the PUO, with the assistance of the IMO.

A key driver for much of these inefficiencies is likely to be the administered price setting mechanism for capacity in the market. The Authority will be investigating this further as part of its review of the MRCP methodology, which is due for completion by September 2013.

The remainder of this Executive Summary provides an overview of the outcomes in the market.

Overview of outcomes in the WEM

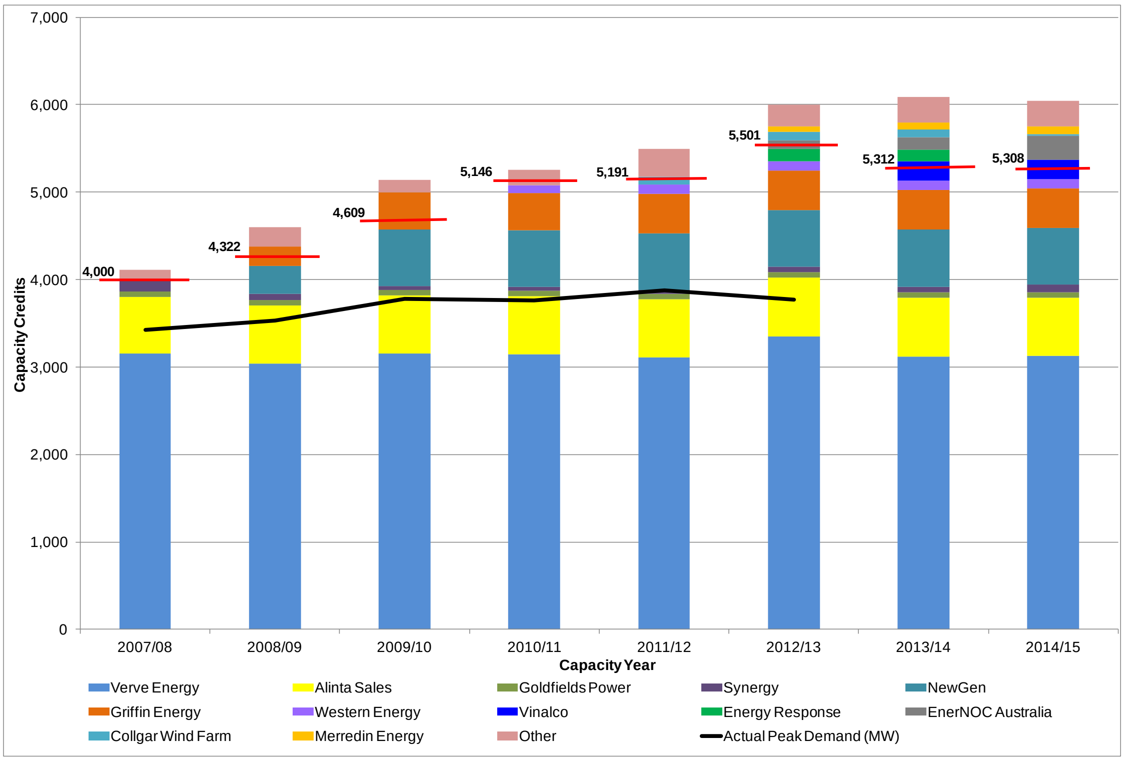
This section provides a brief overview of outcomes in the RCM and energy market of the WEM, from market commencement in September 2006 to the end of June 2012.

The Reserve Capacity Mechanism

The figure below provides a summary of the Capacity Credits assigned to participants in each Capacity Year, as well as the RCR for that year (shown as the red horizontal line for each Capacity Year) and the actual demand measured based on the maximum Operational Load Estimate (shown as the black line). It is clear from the figure that in each Capacity Year the number of Capacity Credits assigned to participants (in aggregate) has exceeded the RCR.

The figure also shows that the Capacity Credits assigned to new entrants continues to increase. For the 2014/15 Capacity Year, Verve Energy is expected to provide approximately 52 per cent of the total SWIS certified capacity, compared to approximately 90 per cent when the WEM commenced. There is also an increase in participation. The Authority notes that the number of participants has more than doubled since market commencement.

Figure A6 Capacity Credits assigned to Market Participants for the 2007/08 to 2014/15 Capacity Years



Note: In the figure above, the red horizontal lines with the corresponding value represent the Reserve Capacity Requirement (RCR) in each Capacity Year. The black line represents the actual peak demand measured in Operational System Load Estimate.

The table below summaries the actual demand, the RCR, total allocated Capacity Credits and the amount of excess Capacity Credits above the RCR. As can be seen from the table, the excess Capacity Credits assigned to participants has ranged from 2.2 per cent (in the 2010/11 Capacity Year) to 14.6 per cent (in the 2013/14 Capacity Year), with an average of 8.3 per cent over the eight Capacity Years from 2007/08 to 2014/15.

Table A2 Excess Capacity Credits assigned to Market Participants for the 2007/08 to 2014/15 Capacity Years.

Period	Actual Peak Demand* MW	Reserve Capacity Requirement MW	Allocated Capacity Credits MW	Excess Capacity Credits MW	Excess Capacity Credits %
01/10/07 to 01/10/08	3,426	4,000	4,115	115	2.9%
01/10/08 to 01/10/09	3,536	4,322	4,600	278	6.4%
01/10/09 to 01/10/10	3,775	4,609	5,136	527	11.4%
01/10/10 to 01/10/11	3,761	5,146	5,259	113	2.2%
01/10/11 to 01/10/12	3,879	5,191	5,493	302	5.8%
01/10/12 to 01/10/13	3,771	5,501	5,996	495	9.0%
01/10/13 to 01/10/14	-	5,312	6,087	775	14.6%
01/10/14 to 01/10/15	-	5,308	6,040	732	13.8%
Average				**417**	**8.3%**

*Measured based on the maximum Operational System Load Estimate.

The table below sets out the Reserve Capacity Price (**RCP**) values for the period from market commencement in 2006 to the 2014/15 Capacity Year. Under the Market Rules, the RCP is calculated in accordance with a prescribed formula using the MRCP[12] when no Reserve Capacity Auction is held. As no Reserve Capacity Auction has been held since market commencement, the value of the RCP for each Capacity Year has been calculated as 85 per cent of the MRCP, adjusted by the ratio of the RCR to the total number of Capacity Credits assigned by the IMO for the relevant Capacity Year.[13]

The table below also sets out the implied value of Capacity Credits for each Capacity Year, which is calculated as the RCP times the total Capacity Credits assigned in each Capacity Year. The implied value of Capacity Credits for the 2014/15 Capacity Year is markedly lower than the value for the 2013/14 Capacity Year. This is a result of the reduced RCP affected by the lower MRCP value set for the 2014/15 Capacity Year (in accordance with the revised MRCP Market Procedure that took effect in October 2011).

Table A3 Reserve Capacity Price, 2006/07 to 2014/15 Capacity Years ($/MW/year).

Period	Reserve Capacity Price (per MW per year)	Maximum Reserve Capacity Price (per MW per year)	Implied value* of Capacity Credits ($ million per year)
21/09/06 to 01/10/06	$127,500	$150,000	
01/10/06 to 01/10/07	$127,500	$150,000	477
01/10/07 to 01/10/08	$127,500	$150,000	525
01/10/08 to 01/10/09	$97,835	$122,500	450
01/10/09 to 01/10/10	$108,459	$142,200	557
01/10/10 to 01/10/11	$144,235	$173,400	758
01/10/11 to 01/10/12	$131,805	$164,100	724
01/10/12 to 01/10/13	$186,001	$238,500	1,115
01/10/13 to 01/10/14	$178,477	$240,600	1,086
01/10/14 to 01/10/15	$122,427	$163,900	739

Bilateral trade

The energy market in the WEM is dominated by bilateral trades, which account for approximately 90 per cent of the total energy traded between Market Participants. The annual average of quantities traded bilaterally among Market Participants for the current Reporting Period (between 1 August 2011 and 30 June 2012) was 1,015 MWh per Trading Interval.[14] Whilst the bilateral trade between the two Government-owned utilities Verve Energy and Synergy remains significant in the market, there has been an increase in the quantities traded bilaterally between Independent Power Producers (**IPPs**) and independent retailers during the current Reporting Period:

- energy traded between Verve Energy and independent retailers has averaged 107 MWh per Trading Interval, i.e. an increase of 12 per cent in comparison to an average of 95 MWh per Trading Interval between August 2010 and July 2011;

[12] This value is determined in accordance with the MRCP Market Procedure, with reference to a 160 MW Open Cycle Gas Turbine peaking facility and a capacity factor of 2 per cent.

[13] No such adjustment applied at the start of the market, i.e. for the period from 21 September 2006 to 1 October 2008.

[14] A Trading Internal represents a period of 30 minutes commencing on the hour or half-hour during a day.

- energy traded between IPPs and Synergy has averaged 210 MWh per Trading Interval, i.e. a decrease of five per cent in comparison to an average of 221 MWh per Trading Interval between August 2010 and July 2011; and
- energy traded between IPPs and independent retailers has averaged 233 MWh per Trading Interval, i.e. an increase of 26 per cent in comparison to an average of 186 MWh per Trading Interval between August 2010 and July 2011.

The remaining amount traded during the current Reporting Period was between Verve Energy and Synergy (averaged at 465 MWh per Trading Interval), which represents a decrease of about six per cent from the previous reporting period (between August 2010 and July 2011).

The Authority considers that this increased activity in bilateral trades between IPPs and independent retailers is an indication of more competition in the market, which should lead to more efficient market outcomes.

The Short Term Energy Market (STEM)

The STEM is a day-ahead market where a Market Participant can trade energy around its bilateral position. Whilst the STEM has certain limitations the Authority considers that it has fulfilled 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 market commencement up to 30 June 2012. These figures also show 30-day, 90-day, and annual moving average prices.

Following a period of high prices immediately after market commencement, prices in the STEM were relatively stable in 2007 and in 2008 prior to the Varanus Island incident (which occurred in June 2008).[15] The incident resulted in significant gas supply curtailment due to which prices in the STEM increased considerably, reaching 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. The prices have trended down subsequently, with the average STEM prices reported in the 2009/10 Reporting Period[16] at around $38.65/MWh during Peak Trading Intervals and $19.51/MWh during Off-Peak Trading Intervals.[17] Since then, there has been an upward trend in the STEM prices. For the 2010/11 Reporting Period, the average Peak and average Off-Peak STEM prices increased to $46.63/MWh and $25.68/MWh, respectively. For the current Reporting Period (from 1 August 2011 to 30 June 2012), the average STEM prices were at $52.10/MWh for Peak Trading Intervals and $26.55/MWh for Off-Peak Trading Intervals.

[15] 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 partially resumed in late August 2008. By mid-October, gas production was running at two-thirds of normal capacity, with 85 per cent of full output restored by December 2008.

[16] A Reporting Period for the Report to the Minister is from 1 August to 31 July of the following year, except for the current Reporting Period. The current Reporting Period covers the period from 1 August 2011 to 30 June 2012 in consideration of the significant changes occurred in the market resulting from the implementation of the competitive Balancing and Load Following Ancillary Service market, from 1 July 2012.

[17] A Peak Trading Interval is a Trading Interval occurring between 8am and 10 pm and an Off-Peak Trading Interval is a Trading Interval occurring between 10 pm and 8am.

Figure A7 Daily Average STEM Clearing Price (Peak Trading Intervals, 21 September 2006 to 30 June 2012)

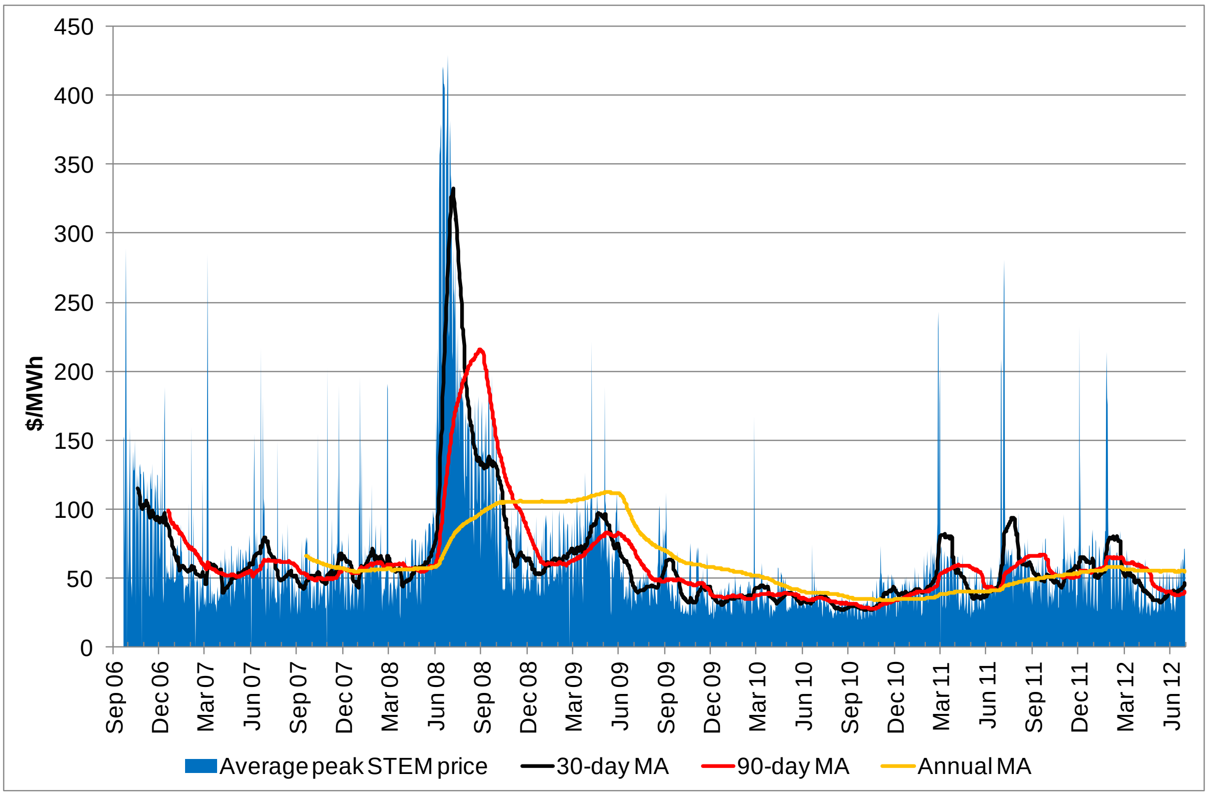
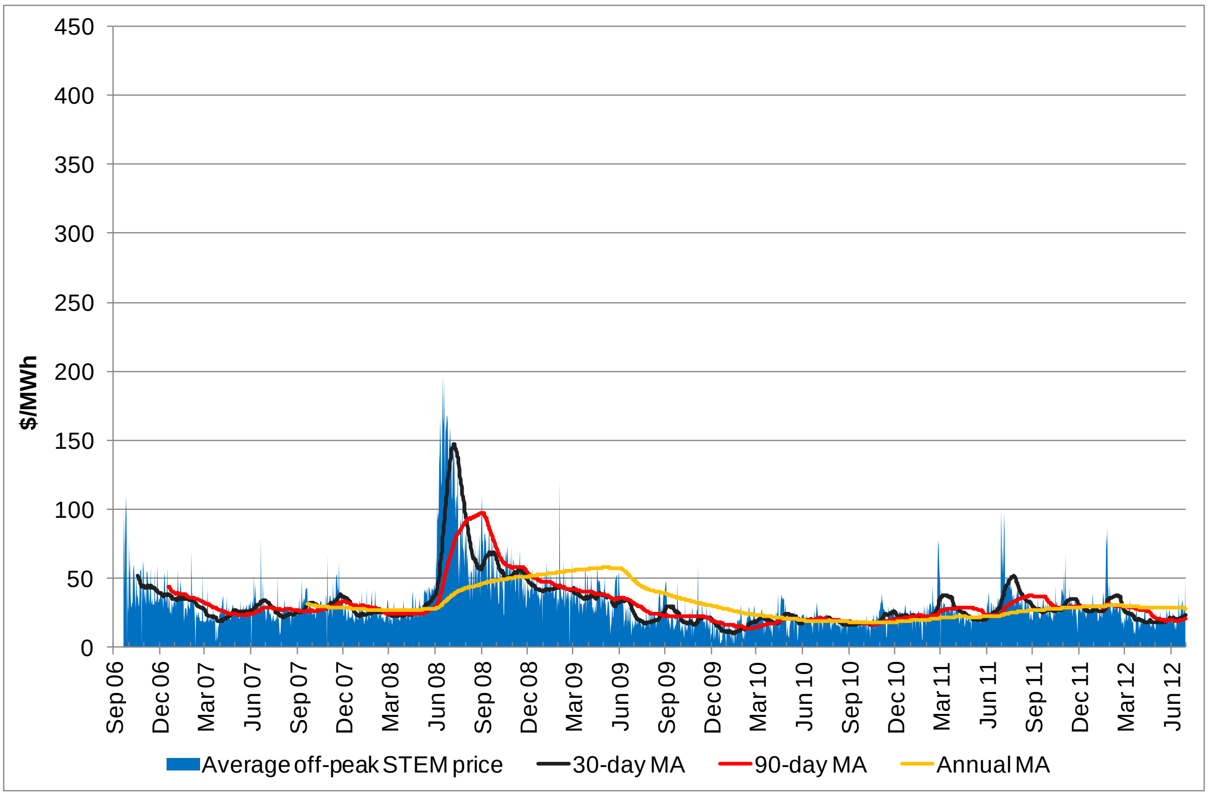


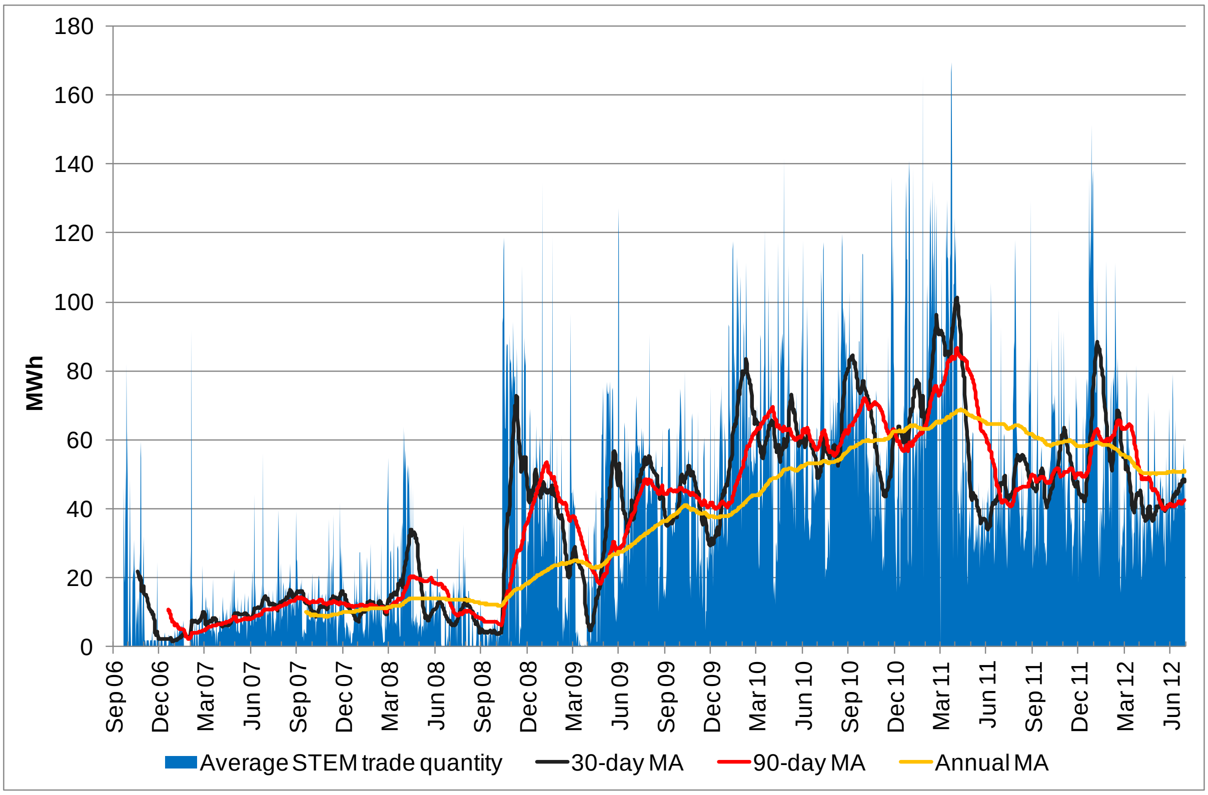
Figure A8 Daily average STEM Clearing Price (Off-Peak Trading Intervals, 21 September 2006 to 30 June 2012)



The Authority has also noted the increased volume traded through the STEM. The figure below illustrates daily average quantities traded in the STEM from market commencement until 30 June 2012. The historical volume traded in the STEM remained relatively low until the commencement of the 2008/09 Capacity Year (in October 2008). In the Authority's view, the steep change at the commencement of the 2008/09 Capacity Year was largely attributable to the entry of NewGen's Kwinana facility and Griffin Power's first unit at Bluewaters in that year. Increased STEM trade volume carried on into the 2009/10 and 2010/11 Capacity Years and eased down in recent times.

Figure A9 Daily average quantities traded in the STEM

(21 September 2006 to 30 June 2012)



The Balancing Mechanism

The Balancing prices have followed similar patterns to the STEM prices. The figures below illustrate the daily average peak and off-peak Balancing prices from market commencement to 30 June 2012, respectively. The Balancing price shown in these figures is the MCAP.[18]

Following a period of high prices immediately after market commencement, both peak and off-peak Balancing prices were relatively stable until June 2008, when the Varanus Island incident occurred. The event resulted in significant curtailment of gas supplies for electricity generation in the SWIS. Balancing prices increased significantly in June 2008 and remained at elevated levels for a number of months.

The Authority noted some high Balancing prices from late June 2011 to early July 2011. This was associated with a large volume of Planned Outages that were approved by

[18] The method for determining the Balancing price has changed from 1 July 2012 due to the implementation of the new competitive Balancing market.

System Management at that time, coupled with some unexpected Forced Outages of plant. Some high Balancing prices were also observed between December 2011 and February 2012 as a result of high summer demand (ranging between 3,000 MW to 3,880 MW) associated with high temperatures, and a number of the price spikes were triggered by Forced Outages of plant.

Figure A10 Daily average Balancing prices
(Peak Trading Intervals, 21 September 2006 to 30 June 2012)

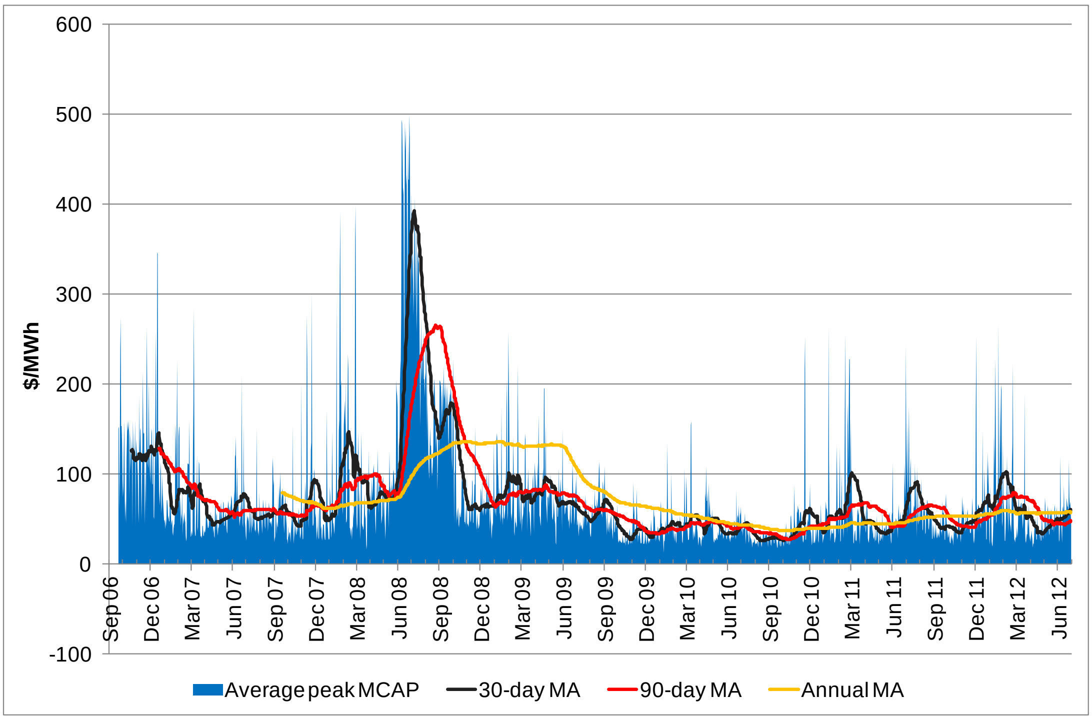
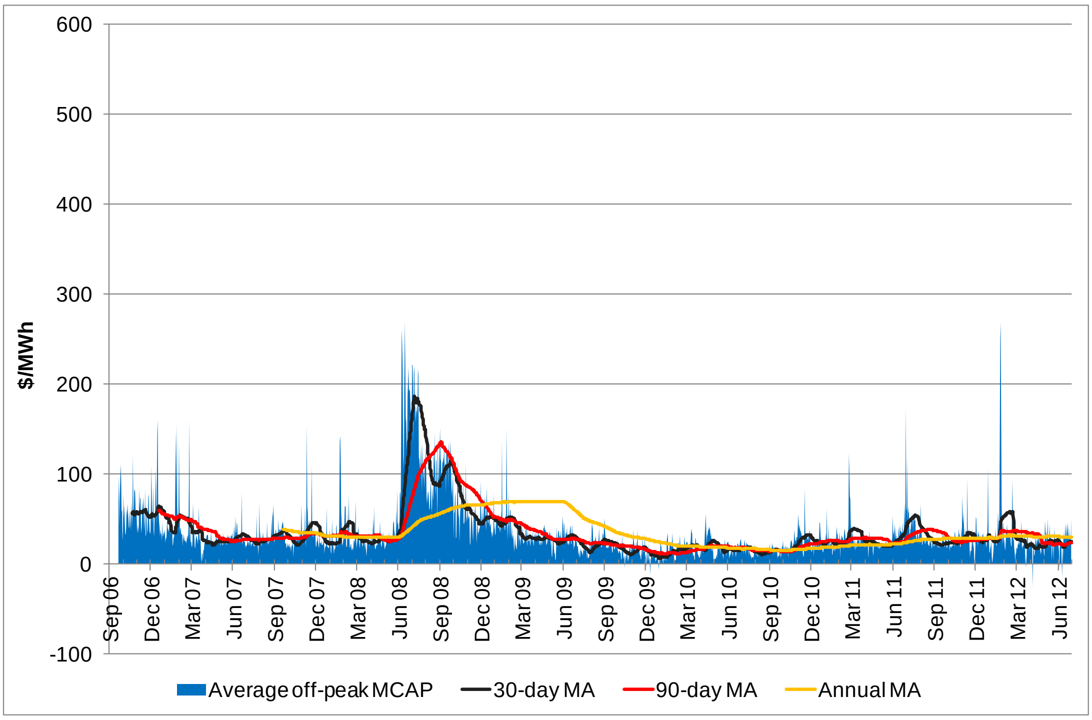


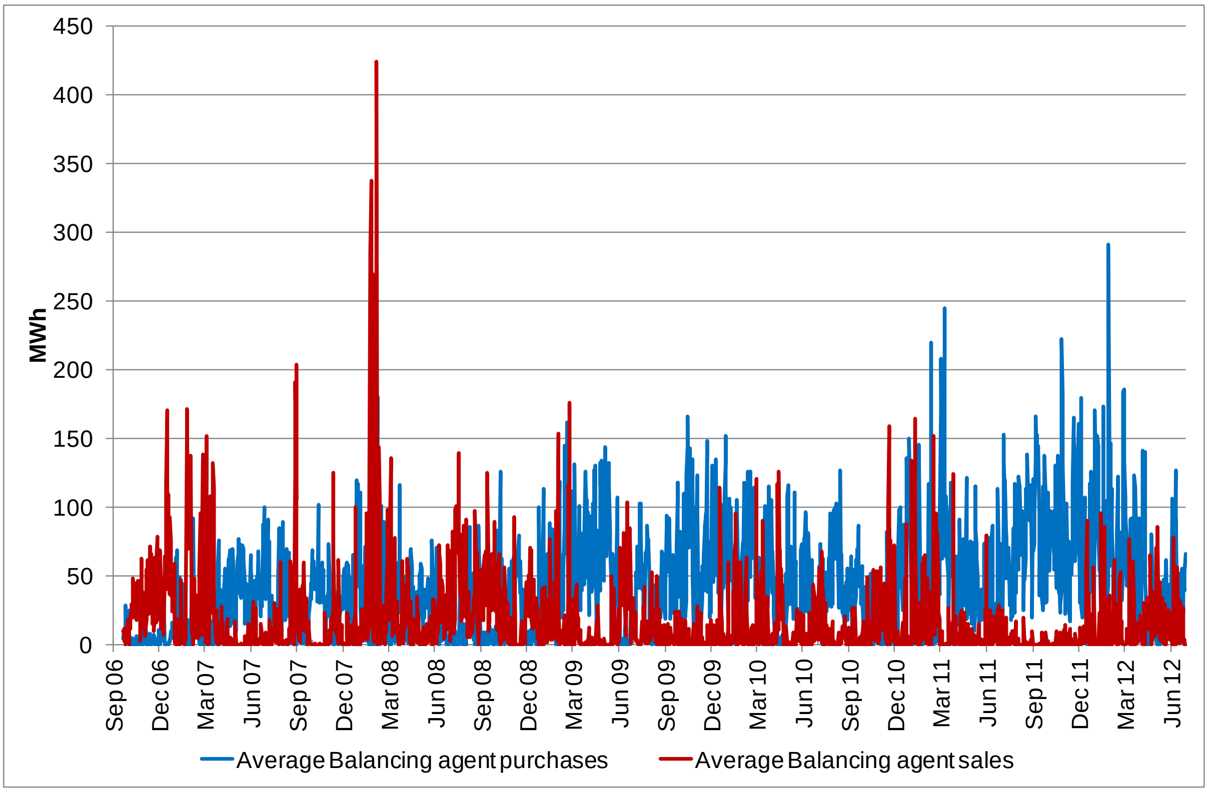
Figure A11 Daily average Balancing prices
(Off-Peak Trading Intervals, 21 September 2006 to 30 June 2012)



The figure below shows the daily average quantity per Trading Interval purchased and sold in Balancing by Verve Energy as the sole balancing agent (from market commencement until 30 June 2012).[19] As a balancing agent, Verve Energy makes purchases when others are spilling energy into the market relative to their pre-committed positions (shown in blue), and provide any energy shortfalls as sales when others fall short of their pre-committed positions for energy (shown in red). Verve Energy has predominantly been a net purchaser in Balancing since 2009, shown by the relatively higher values of the blue line compared to the red line in the figure. This may be attributable to two main factors: energy produced by Intermittent Generators and forecast errors by Market Customers.

Figure A12 Daily average quantities traded in Balancing[20]

(21 September 2006 to 30 June 2012)



Whilst Scheduled Generators[21] in the market were required to follow their Resource Plans, committed one day ahead, the Market Rules allowed Intermittent Generators[22] to spill energy into Balancing, without any pre-commitment. This energy would contribute to purchases by Verve Energy as the default balancer. There has been an increase in

[19] The daily average quantity per Trading Interval bought is calculated as the total quantity purchased by Verve Energy each day divided by 48 Trading Intervals. Similarly, the daily average quantity per Trading Interval sold is calculated as the total quantity sold by Verve Energy each day divided by 48 Trading Intervals.

[20] Data sourced from the IMO website: 'Balancing Quantity (MWh)' for the period 21 September 2006 – 30 March 2011 from the *Balancing Information - 6 Month Summary* webpage http://imowa.com.au/n4841.html; and 'Balancing Trade Estimate' for the period 31 March 2011 – 30 June 2012 is sourced from the *Weekly Market Report* webpage http://imowa.com.au/market-data-weekly-market-report

[21] Scheduled Generators refer to generators that can increase or decrease the quantity of electricity they generate in response to instructions from their operators.

[22] Intermittent Generators refer to generators that cannot be scheduled because their output level is dependent on factors beyond the control of their operators, e.g. wind, solar, etc.

capacity and output from wind generators in recent years, in particular with the commissioning of the Collgar Wind Farm since June 2011.

Forecast errors by Market Customers[23] may also contribute to Verve Energy's purchase quantity in Balancing. When a Market Customer requires less energy than it has committed through bilateral nomination and trading in the STEM, the difference will constitute a Balancing purchase by Verve Energy. The Market Rules provides a regulatory prohibition on Market Customers to over-state demand. [24] The Authority engaged a consultant to look further into the matter in light of the large balancing purchase quantities made by Verve Energy. The consultant found no evidence of anomalous behaviour or abuse of market power by any participants. The consultant suggested that there is a commercial risk asymmetry in the market, attributable to the cost of supply along the supply curve being upward sloping (and potentially very steep). As a result, the costs to a Market Customer associated with being somewhat short of its actual requirement (i.e. making a purchase from Verve Energy, which would contribute to sales by Verve Energy in Balancing (shown in red) can exceed the costs associated with being equivalently long (i.e. making a sale to Verve Energy, which would contribute to purchases by Verve Energy in Balancing). Hence, there is a commercial incentive to commit somewhat more than the expected requirement under certain market conditions (for example, the steepness and expectations around the supply curve and the level of demand, as well as specific contract-related costs in order to manage the risk asymmetry associated with being caught short over being long.

Competition in the contestable electricity market

The electricity industry in Western Australia is not fully deregulated. Currently, only customers with annual electricity consumption of more than 50 MWh can choose their electricity suppliers in the SWIS. Synergy is the sole supplier of electricity to customers that use less than 50 MWh of electricity per annum in the SWIS. The dominance of Synergy and the slow progress of competition in the retail electricity market has been a concern raised by the Authority previously.[25]

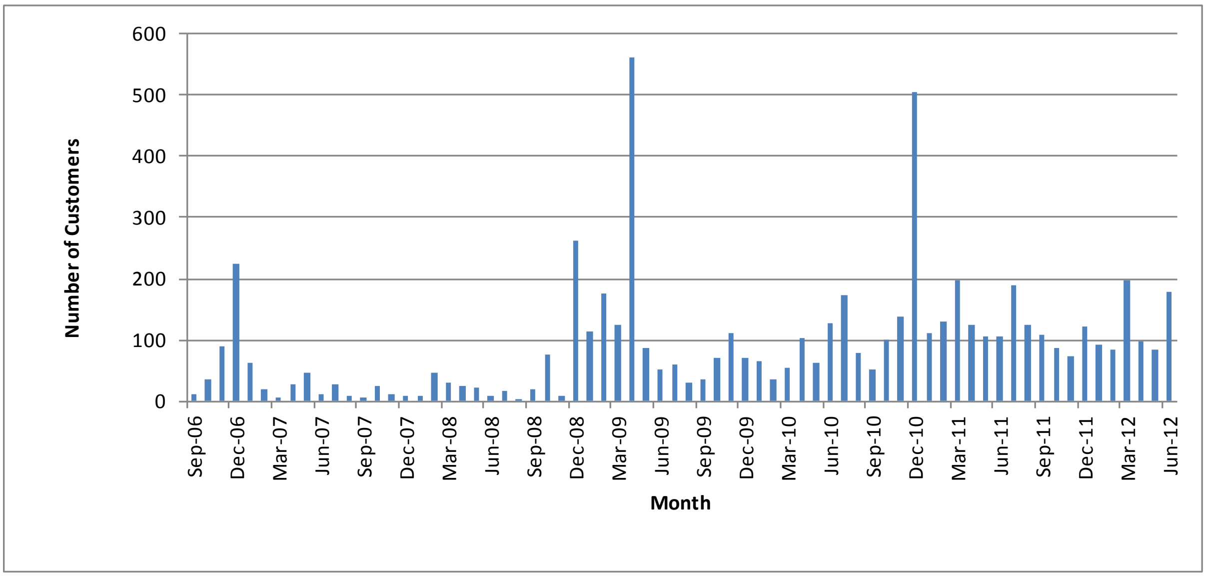
The figure below shows the level of customer transfer between retailers in the contestable section of the electricity market in the SWIS. Customer transfer numbers each month appear to have stabilised since December 2010. The number of customers changing retailers over the 2011/12 financial year averaged at around 120 customers each month. Compared to the total number of contestable electricity customers in the SWIS (approximately 21,000), the average monthly customer churn rate was approximately 0.6 per cent, with the maximum rate of 0.9 per cent in March 2012 and the minimum rate of 0.4 per cent in November 2011.

[23] Market Customers are retailers and DSM providers registered to participate in the WEM. Market Generators are generators registered to participate in the WEM.

[24] Refer to clause 6.7.4 of the Market Rules.

[25] ERA, *2008 Wholesale Electricity Market Report to the Minister for Energy*, http://www.erawa.com.au.

Figure A13 Number of customers changing retailer per month (September 2006 to June 2012)



Summary of Recommendations and Findings

Finding 1

Section 2.2.1.5

The substantial volume of excess capacity that exists in the market is an inefficient outcome which results in higher costs that are borne directly by consumers and, more broadly, by the economy as a whole.

Recommendation 1

Given the significance of the issue of excess capacity, the Authority recommends that the Public Utilities Office undertake a comprehensive, holistic review of the current design of the Reserve Capacity Mechanism, with a view to steering the long term evolution of the market towards economically efficient outcomes.

Finding 2

Section 2.2.2.3

The current market arrangements have resulted in a significant increase in the amount of peaking capacity entering the market in recent years, further contributing to the issue of excess capacity. Whilst the Authority acknowledges the valuable contribution that these resources provide to the overall portfolio of capacity mix, it is concerned that the incentives provided in the current Market Rules are resulting in an overall cost of capacity and energy that is higher than it needs to be.

Recommendation 2

The Authority recommends that as part of the comprehensive review suggested under Recommendation 1, the Public Utilities Office evaluates the market design in its entirety to ensure it achieves an economically efficient mix of capacity and energy resources in the market.

Finding 3

Section 2.2.3.3

A number of Verve Energy generation units recorded high rates of planned outage over consecutive years. These generators received full capacity payments under the current market arrangements, whilst being unavailable for extended periods on planned outage, causing higher prices in the energy market than would otherwise be the case, resulting in inefficient outcomes.

Recommendation 3

The Authority recommends incentives to maximise plant availability to be reviewed. The Authority notes that the IMO has commenced a review of current generator availability and the incentives to improve performance. The Authority supports this undertaking.

Recommendation 4

The issue of plant unavailability appears to be a matter associated with Verve Energy specifically. Hence, the Authority recommends that the Public Utilities Office, acting on behalf of the owner of Verve Energy, undertake a review of the contractual arrangements between Verve Energy and Synergy, to ensure that the designated contract assigned to the two entities by the State Government does not provide perverse incentives for inefficient market outcomes.

Introduction

1 Background

1.1 Reporting requirements for the Report to the Minister

The *Wholesale Electricity Market Rules* (**Market Rules**)[26] 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**),[27] at least annually.[28]

This report fulfils the Authority's requirements under the Market Rules for the period from 1 August 2011 to 30 June 2012.

According to clause 2.16.12 of the Market Rules, the Authority's report to the Minister must contain (but is not limited to) the following:

- a summary of the information and data compiled by the Independent Market Operator (**IMO**) and the Authority under clause 2.16.1;
- 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 Short Term Energy Market (**STEM**);
  - Balancing;
  - the dispatch process;
  - planning processes;
  - the administration of the market, including the Market Rule change process; and
  - Ancillary Services.
- an assessment of any specific events, behaviour or matters that impacted on the effectiveness of the market; and

[26] 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

[27] The Market Objectives are: (a) to promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the South West interconnected system; (b) to encourage competition among generators and retailers in the SWIS, including by facilitating efficient entry of new competitors; (c) to avoid discrimination in that market against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or that reduce overall greenhouse gas emissions; (d) to minimise the long-term cost of electricity supplied to customers from the SWIS; and (e) to encourage the taking of measures to manage the amount of electricity used and when it is used.

[28] 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.

- any recommended measures to increase the effectiveness of the market in meeting the Market Objectives to be considered by the Minister.

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

1.2 Process

As part of the preparation process of the 2012 Report to the Minister, the Authority released a Discussion Paper[29] seeking public submissions on issues impacting the effectiveness of the WEM on 19 November 2012.

The Authority also posted a notice on the Authority's website advising of the release of the Discussion Paper and invited interested parties to make submissions to the Authority by 18 December 2012. A list of stakeholders who made submissions in response to the Authority's Discussion Paper is provided in Appendix 2. The Authority sought permission to publish submissions from the respective stakeholders. Where permission for publication of a submission was provided, the submission is made available on the Authority's website.[30]

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 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 that 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 specific events, behaviour or matters that impacted on the effectiveness of the market and the Authority's

[29] See ERA website, Discussion Paper – 2012 Wholesale Electricity Market Report to the Minister for Energy – 16 November 2012, http://www.erawa.com.au/cproot/10962/2/20121119%20-%20D99560%20-%20Discussion%20Paper%202012%20Wholesale%20Electricity%20Market%20Report%20to%20the%20Minister%20for%20Energy.pdf

[30] See ERA website, Annual Wholesale Electricity Market Report to the Minister for Energy web page, http://www.erawa.com.au/markets/electricity-markets/annual-wholesale-electricity-market-report-to-the-minister-for-energy/

recommended measures to increase the effectiveness of the market in meeting the Market Objectives;

- 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 and the Authority.

Part A

2 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 influenced or detracted from the effectiveness of the Wholesale Electricity Market (**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 was established to facilitate competition and encourage efficient investment in the generation and retail sectors, thus ultimately working to minimise the cost of electricity supplied to consumers. Whilst the Authority recognises that the market has evolved since its inception, the Authority has put forward its view in previous reports to the Minister, that the market is at a cross-roads and has highlighted a number of issues that are limiting the progression to a competitive electricity market. In particular, the Authority raised its concerns that the market is still dominated by Verve Energy and Synergy, which in the absence of a clear policy framework for increasing retail competition, severely limits the prospect of entry and expansion of new retailers.

The Authority has also raised its concerns about the significant cost pressures resulting from incentive schemes for renewable energy, which have had the effect of inefficient investment and a distortion in prices, leading to higher cost to consumers. Regarding the operation of the WEM, the Authority has identified a number of issues that require attention, including the substantial excess capacity procured in the market, the increasing costs to the market of Demand Side Management (**DSM**) programs, the high rates of planned outages allowed for certain generation facilities and the potential for conflict of interest under the current market governance arrangement.

The WEM is comprised of two key components; an energy market and a capacity mechanism. The energy market deals with the trading of energy between Market Participants and includes Bilateral Contracts, the Short Term Energy Market (**STEM**) and a regime for energy balancing. The WEM was designed under the assumption that retailers would cover the majority of their electricity requirements through Bilateral Contracts with generators. The STEM enables Market Participants to adjust their contract positions by buying or selling energy on the day before the energy will be delivered. The Balancing regime manages real time deviations from these pre-committed positions.

The purpose of the capacity mechanism is to provide incentives for continued investment in existing and new capacity to meet system security and adequacy requirements. The South West Interconnected System (**SWIS**), covered by the WEM, is an isolated system. In other words, it cannot rely on any interconnections with other systems and must therefore have sufficient capacity within itself to satisfy demand and deal with emergency situations in supply.[31]

The energy market in the WEM has recently undergone significant changes with the commencement of the competitive Balancing market which became operational on 1 July 2012. The intent behind the establishment of the competitive Balancing market was to provide opportunities for Independent Power Producers (**IPPs**) to participate in the

[31] Interconnected systems have the added security due to diversity of demand; that is, the benefit gained from different parts of the interconnected system peaking at different times, allowing for sharing of the resources between the interconnected systems.

provision of energy for the purposes of balancing the market. Prior to the change, under the provisions of the Market Rules and the pre-existing market structure, Verve Energy played the exclusive role of providing the balancing energy to the market.

Another newly established market is that for the provision of the Load Following Ancillary Service (**LFAS**), which also came into effect on 1 July 2012. Again, the establishment of this market now enables IPPs to compete with Verve Energy to provide this service.[32]

Given that the above changes were implemented only recently, there is relatively little data to form a sound view of the effectiveness of these new markets. The focus of this chapter is thus on the effectiveness of the Reserve Capacity Mechanism (**RCM**) in securing capacity efficiently. The section below contains an overview of the role and workings of the RCM.

2.1 The Reserve Capacity Mechanism

The RCM underpins the operation of the capacity component of the WEM.

Electricity generating plants produce 'energy' over a period of time, measured in Megawatt hours (**MWh**). The maximum amount of energy a plant can produce is referred to as 'capacity' and is measured in Megawatts (**MW**).

The role of the RCM is primarily to ensure that sufficient 'capacity' is secured in order to maintain reliability and meet peak summer demand. The **IMO** is responsible for forecasting the total generation capacity required to provide this level of reliability to customers, i.e. the annual Reserve Capacity Requirement (**RCR)**, through projected assessments of system adequacy. The Planning Criterion[33] that is used by the IMO when making these assessments requires there to be sufficient available capacity in each Capacity Year[34] to:

(a) meet the expected peak demand supplied through the SWIS plus a reserve margin equal to the greater of:

  a. 8.2% of forecast peak demand, including transmission losses and allowing for Intermittent loads;[35] and

  b. the maximum capacity of the largest generating unit, measured at 41ºC.

  whilst maintaining normal frequency control; and

(b) limit expected shortfalls to 0.002% of annual energy consumption (including transmission losses).

The IMO publishes an annual Statement of Opportunities (**SOO**) Report considering capacity requirements and projected capacity shortfalls for the next ten years. This report is released around June/July each year and sets the RCR for the Capacity Year starting in October, two years later. The peak demand forecast used to calculate the RCR is

[32] Verve Energy was the sole provider of this service since market commencement.

[33] Refer to clause 4.5.9 of the Market Rule.

[34] A Capacity Year is a period of 12 months commencing at the start of the Trading Day, which commences on 1 October and ending on the Trading Day ending on 1 October of the following calendar year.

[35] There is a proposal for the percentage to be reduced to 7.6% currently being evaluated by the IMO.

conservative in that it is only likely to be under-forecast if a one-in-ten-year set of circumstances occurs, causing demand to be unusually high (i.e. a 'superpeak').

The RCM provides an incentive for existing and new generation, and DSM providers, to invest in capacity by providing a possible income stream through the trade of a notional construct representing 1 MW of Reserve Capacity that has been certified by the IMO, known as a Capacity Credit.

Each year, the capacity providers must firstly apply to the IMO for Certified Reserve Capacity in order to receive an allocation of Capacity Credits. Upon entering an agreement with the IMO, a capacity provider will be allocated an amount of Capacity Credits equal to the certified capacity it has committed to provide. Under the Market Rules, the IMO requires electricity retailers to purchase these Capacity Credits from capacity providers, with the amount being based on each retailer's contribution to peak demand, referred to as their Individual Reserve Capacity Requirement (**IRCR**). Hence, capacity providers earn revenue by contracting to sell these Capacity Credits to retailers bilaterally or through transactions with the IMO.

Capacity providers holding Certified Reserve Capacity will declare to the IMO the amount of Certified Reserve Capacity they intend to trade bilaterally, the amount of Certified Reserve Capacity they intend to offer to the Reserve Capacity Auction, or whether they want to terminate any Certified Reserve Capacity (e.g. with the cancellation of a new generation project).

The IMO monitors the amount of certified capacity that is declared to be traded bilaterally between Market Participants and the amount of capacity that Market Participants have indicated they would offer into the Reserve Capacity Auction. In the event that insufficient capacity to meet the RCR is identified during this process (and if there has been certified capacity offered into an auction), the IMO will procure the shortfall by holding a Reserve Capacity Auction.

To date, however, the RCR has always been met through certified capacity being offered for bilateral trading, resulting in the IMO cancelling the Reserve Capacity Auction. Hence, there has been no Reserve Capacity Auction held since the commencement of the RCM.

Declarations of the amount of capacity to be traded bilaterally between Market Participants are not binding. Under the Market Rules, the IMO must allocate Capacity Credits to all Certified Reserve Capacity that has been declared for bilateral trade (unless the capacity holder decides to withdraw prior to the IMO's allocation decision is made). There is no quantity limit to the amount of Capacity Credits that the IMO can allocate, even when the total certified capacity is well above the RCR. Capacity providers can sell Capacity Credits that were previously identified for use in bilateral trading directly to the IMO.

To fund payments for Capacity Credits, Market Customers are assigned obligations for their Individual Reserve Capacity Requirement (**IRCR**). In order to meet the IRCR obligations, Market Customers can either procure Capacity Credits bilaterally from providers holding Capacity Credits, or they can make payments to the IMO for the purchase of the Capacity Credits by the IMO from capacity providers.

The Market Rules stipulate that when no Reserve Capacity Auction is held, the Reserve Capacity Price (**RCP**) will be set using the formula specified in the Market Rules. According to the formula, the administered RCP is set at 85 per cent of the Maximum Reserve Capacity Price (**MRCP**), which reflects the capital cost of a 160 MW Open Cycle

Gas Turbine (**OCGT**) power station.[36] An adjustment factor is also employed to take into account the impact of any excess capacity procured above the RCR.

2.2 The effectiveness of the Reserve Capacity Mechanism

As a result of its work in monitoring the WEM, and through communication with stakeholders, the Authority is aware of a number of issues related to the outcomes from the RCM in achieving the capacity requirements. Broadly, these issues fall within three categories. These are:

- The cost to the market of the capacity, and in particular the substantial and continued excess capacity, that is secured under the RCM;

- The type of capacity attracted to the market and the implications that this mix of capacity has on the cost of electricity to consumers. The treatment of Demand Side Management (**DSM**) within the RCM has been highlighted under this category.

- The relationship between the RCM and plant outages, including the matter of whether the operation of the RCM provides Market Participants with appropriate incentives to make their generation plant available; and

These three issues are considered in more detail in the sections below.

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, in recent years there has been a marked increase in the level of excess capacity in the market, as measured by the excess of Capacity Credits issued by the IMO, above the RCR. In the 2007/08 Capacity Year, the excess of Capacity Credits above the RCR was 115 MW (equivalent to 2.9 per cent of the RCR at the time). By the 2014/15 Capacity Year, this excess has increased to 732 MW (or 13.8 per cent of the RCR) as shown below in Table 1.

[36] Refer to MRCP market procedure for further details.

Table 1 Excess Capacity Credits assigned to Market Participants for the 2007/08 to 2014/15 Capacity Years

Period	Actual Peak Demand (MW)	Reserve Capacity Requirement (MW)	Capacity Credits allocated (MW)	Excess Capacity Credits (MW)	Excess Capacity Credits (%)
01/10/07 to 01/10/08	3,426	4,000	4,115	115	2.9%
01/10/08 to 01/10/09	3,536	4,322	4,600	278	6.4%
01/10/09 to 01/10/10	3,775	4,609	5,136	527	11.4%
01/10/10 to 01/10/11	3,761	5,146	5,259	113	2.2%
01/10/11 to 01/10/12	3,879	5,191	5,493	302	5.8%
01/10/12 to 01/10/13	3,771	5,501	5,996	495	9.0%
01/10/13 to 01/10/14	-	5,312	6,087	775	14.6%
01/10/14 to 01/10/15	-	5,308	6,040	732	13.8%
Average				**417**	**8.3%**

The Authority considers that the volume of excess capacity that currently exists in the market is indicative of an inefficient market outcome. The costs of these inefficiencies are borne directly by consumers of electricity and more broadly through the whole economy.

2.2.1.1 Possible reasons for excess capacity

The Authority considers that there are two aspects of the RCM that are likely to have contributed to the excess capacity accumulated in the WEM.

Firstly, the Market Rules do not set a limit on the amount of Capacity Credits that can be issued each year by the IMO, only a stipulation that sufficient capacity be obtained so as to satisfy the Reserve Capacity Requirement (**RCR**).[37]

Secondly, the ongoing excess is an indication that the administratively set capacity price is too high. To date, the Reserve Capacity Auction provided in the Market Rules has never been utilised as there has always been excess capacity in the market. Thus, rather than being competitively determined, the price for capacity has always been set administratively in accordance with the prescribed formula in the Market Rules.

This leads to a significant and unnecessary cost, which is likely to be directly borne by consumers through higher electricity prices. In a market where excess capacity exists, the efficient value of any further capacity entering the market should be close to zero. However, the administrative price values this further capacity significantly higher, thus continuing to attract investment in the market, which is inefficient.

In its report on the review of the RCM, the Lantau Group stated that:[38]

[37] The majority of stakeholders providing feedback in response to the Authority's Discussion Paper did not support the idea of setting a limit for the quantity of Capacity Credits procured by the IMO in excess of the RCR. SEA, in particular, felt that the introduction of a cap in the market would be a retrograde step, acting as a disincentive to move to a more open market. However, Synergy considered that a price mechanism alone was not sufficient enough to deter excess capacity from entering the market and thus supported the idea of limiting the quantity of Capacity Credits, suggesting that new plant entering the market should be paid for by retailers or absorbed by merchant generators if they decided to bring in excess capacity.

[38] *Review of the RCM: Issues and Recommendations*, The Lantau Group, September 2011.

"Once the WEM is in an excess reserve capacity situation, the value of adding additional supply or demand side capacity to the system falls towards zero. This incremental ('marginal') value is essentially the spot market value of capacity, taking into account demand conditions and how much reserve capacity exists at that point in time."

The Authority has also noted the weakening in demand growth in the WEM since the Global Financial Crisis (**GFC**), which has hampered business investment through the restricted availability of capital and the increased cost of financing. However, there appears to be a long lag time for this change in market and economic conditions to be reflected in the demand forecast that underpins the setting of the RCR under the RCM. This has resulted in the widening of the gap between the forecast and actual peak demand (i.e. the gap between the yellow and black lines in Figure A2). The downward adjustment for demand only came through in 2011 when the RCR for the 2013/14 Capacity Year was set, resulting in a reduction of 190 MW (or 3 per cent) compared to the RCR value for the 2012/13 Capacity Year. Despite the reduced RCR, the total Capacity Credits allocated by the IMO for the 2013/14 Capacity Year was 90 MW higher than the amount allocated for the 2012/13 Capacity Year, contributing further to the excess capacity situation. As shown in Table 1, the percentage of excess capacity has increased from 9 per cent (495 MW) in the 2012/13 Capacity Year to 14.6 per cent (775 MW) in the 2013/14 Capacity Year.

Stakeholders who responded to the Authority's Discussion Paper for the preparation of this report also identified a number of differing sources of excess capacity, including:

- Capacity committed before market start, including Western Power's power procurement pre market start; Decisions by the State Government, e.g. the Displacement Mechanism required under the former Vesting Contract between Synergy and Verve Energy, the refurbishment and recommissioning of Muja A & B;
- Entry of renewable generation as a result of renewable energy schemes;
- Increase in DSM participation, partially attributable to technology advances; and
- The existence of a large amount of old and unreliable capacity in the market.

2.2.1.2 Costs to electricity consumers

The existence of excess capacity results in additional costs to the market because under the Market Rules, the IMO recovers from Market Customers the cost of excess Capacity Credits issued (defined as those Capacity Credits issued above the RCR).

The Authority notes that there is a mechanism that partly offsets the costs of the excess capacity to the market in instances where no capacity auction is held. Specifically, the value of the administratively set RCP is reduced in proportion to the amount of excess capacity in the market.[39]

The intent of the price adjustment mechanism in the Market Rules, as mentioned above, is to achieve market outcomes whereby the total cost of capacity to meet the RCR, valued at 85 per cent of the MRCP, is unaffected by excess capacity. If the mechanism was completely effective then there would be no direct costs borne by electricity consumers resulting from the presence of excess capacity in the market.

[39] The reduction is achieved by the application of the Excess Capacity Adjustment factor. The Excess Capacity Adjustment factor is equal to the Reserve Capacity Requirement for a Capacity Year divided by the total number of Capacity Credits assigned by the IMO for that Capacity Year. See clause 4.29.1 of the Market Rules.

In practice such an outcome may only be partly achieved. The RCP only applies to payments for Capacity Credits that are settled with the IMO. Reductions in the RCP brought on by the existence of excess capacity may not necessarily translate to reductions in the capacity prices that are bilaterally negotiated between buyers and sellers of capacity in long term contracts. In situations where a Market Customer has secured some portion of its expected requirement for Capacity Credits through long term bilateral contracts, the bilaterally agreed price of those Capacity Credits may not be reduced in line with any reductions in the RCP.

As explained in the Authority's Discussion Paper, the cost impact of excess capacity comes in two directions: a reduction in the cost of Capacity Credits paid through the IMO in meeting the RCR; and an additional cost for the excess amount of Capacity Credits over the RCR. The following table demonstrates the estimated cost impact of the excess capacity over the 2007/08 to 2014/15 Capacity Years via the two elements of payments collected from Market Customers in the IMO settlement process.

The first element is the Shared Reserve Capacity Cost (**SRCC),** which covers the payment for the amount of excess capacity (i.e. Capacity Credits assigned above the RCR) at the prevailing capacity price. The estimated impact of excess capacity on the SRCC is demonstrated in column (2) of Table 2 below. For example, the amount of excess Capacity Credits issued for the 2011/12 Capacity Year is 302 MW. At the prevailing capacity price of $131,805 per MW per year (refer to Table A3 presented earlier), the cost of these excess Capacity Credits amounts to approximately $40 million.[40]

The second element is the Targeted Reserve Capacity Cost (**TRCC**), which covers the payment for the amount of Capacity Credits that are required to meet the RCR (which is exclusive of any excess capacity). This payment is also calculated at the prevailing capacity price. As the prevailing capacity price is adjusted downward when excess capacity exists, it reduces the required payment. This compared to the case of no excess capacity, whereby the price would be higher, resulting in a higher payment. This estimated impact of excess capacity on TRCC is demonstrated in column (3) of Table 2. For the 2011/12 Capacity Year, the amount of Capacity Credits settled under TRCC each month is about 1,800 MW on average (or 35 per cent of the RCR).[41] At the prevailing capacity price of $131,805 per MW per year, the payment is around $237 million. The capacity price would be $139,485 per MW per year (i.e. 85 per cent of the MRCP value of $164,100 per MW per year for the 2011/12 Capacity Year) if no excess Capacity Credits were procured. At this price, the payment for the amount of Capacity Credits settled under the TRCC would be $251 million. The estimated reduction in payments under TRCC due to the existence of excess capacity is $14 million (i.e. $237 million minus $251 million) for the 2011/12 Capacity Year.

The net cost impact to retailers (i.e. Market Customers) is the combined impact on both the SRCC and the TRCC. This is shown in column (4) of Table 2. For the 2011/12 Capacity Year, this net cost is estimated at $26 million (i.e. $40 million minus $14 million).

[40] The total number of Capacity Credits accounted for in the IMO's settlement process each month during a Capacity Year may vary from the total number of Capacity Credits allocated by the IMO prior to start of the Capacity Year for various reasons, e.g. a reduction in the number of Capacity Credits allocated to a specific facility due to its failure to pass the capacity test. These variations will affect the amount of excess capacity charged through the SRCC for the relevant months. The Authority is unable to reconcile the actual quantities in the IMO's settlement data. Hence the estimated cost impact of excess Capacity Credits on the SRCC assumed these Capacity Credits would be paid out for all 12 months during the relevant Capacity Year.

[41] This is calculated based on data obtained from the IMO.

Table 2 Estimated cost impact of excess capacity (nominal, $million)

Period	Excess Capacity Credits (MW) (1)	Estimated impact on SRCC* ($m) (2)	Estimated impact on TRCC** ($m) (3)	Net cost impact ($m) (4)
01/10/07 to 01/10/08	115	15	-	15
01/10/08 to 01/10/09	278	27	-5	23
01/10/09 to 01/10/10	527	57	-11	46
01/10/10 to 01/10/11	113	16	-7	9
01/10/11 to 01/10/12	302	40	-14	26
01/10/12 to 01/10/13	495	92	-46	46
01/10/13 to 01/10/14	775	138	-69	69
01/10/14 to 01/10/15	732	90	-45	45

*This refers to the explicit cost component charged to retailers through the Shared Reserve Capacity Cost (SRCC) which is calculated as the amount of excess capacity multiplied by the prevailing capacity price.

**This refers to the implicit impact of excess capacity. As the prevailing capacity price is reduced by the Excess Capacity Adjustment factor, a retailer will pay a lower price than it would otherwise pay for any shortfalls in meeting its allocated capacity obligation under the Reserve Capacity Requirement, i.e. the Targeted Reserve Capacity Cost (TRCC). The exact amount of shortfall may vary from one retailer to another depending on its respective bilateral contract position. Hence, the net cost impact of excess capacity to individual retailers varies depending on its contribution to the system peak and its bilateral contract position. This column is presented mainly for illustrative purposes. The estimated cost impact on TRCC from 2012/13 onwards is calculated based on the assumption that 50 per cent[42] of the RCR is settled with the IMO, whilst the estimates between 2007/08 and 2011/12 Capacity Years are calculated based on data obtained from the IMO. As variations in the total number of Capacity Credits accounted for in the IMO's monthly settlement process may occur, these estimated values have not reconciled with the IMO's settlement data.

2.2.1.3 Costs to the economy

In addition to the direct costs outlined above, the existence of excess capacity in the market is indicative of an inefficient utilisation of resources in the State's economy. In economic terms, an outcome whereby there is capacity in generation that is surplus to the requirements of the market is not an allocatively efficient outcome. Allocative efficiency can only be satisfied when the goods and services being produced match the needs and preferences of consumers, as measured by the value that they place on the goods and services. The loss to the economy brought about by the excess resources that are allocated to the production of electricity is referred to by economists as a "deadweight loss".

The Authority is not clear on how the costs arising from the allocatively inefficient outcome affect different parts of the economy.[43] It is clear, however, that there is a cost to the economy as a whole and that this cost is, in the first instance, most likely to result in electricity prices being higher than necessary.

[42] This is the highest percentage of uncontracted RCR reported for the 2011/12 Capacity Year. The higher the percentage, the larger the flow-on effect of the reduction in pricing due to excess capacity. Hence, the use of a higher percentage provides a conservative estimate for the net cost impact.

[43] The only way that such an outcome could be estimated would be through detailed economic modelling.

2.2.1.4 Observations from other forward capacity markets

Electricity market designs that provide arrangements for a forward capacity market are likely to be driven by a stronger emphasis on system security and adequacy. Accordingly, administrators often err on the side of having too much capacity rather than having too little capacity. Additionally, it is likely that over-procurement may occur due to the lumpiness of investment in electricity generation and forecast variations.[44] Thus, the over-procurement of capacity may well be an anticipated characteristic of capacity markets.

A review of Pennsylvania, New Jersey Maryland System's (**PJM**'s) Reliability Pricing Model (which is often used to exemplify a successful forward capacity market) shows that with the exception of the 2010/11 auction, each capacity auction has produced a greater amount of cleared capacity than what is needed to meet reserve requirements since its inception in June 2007.[45] For instance, the reserve margins in the 2012/13 and 2013/14 auctions were 20 and 21 per cent, respectively.[46]

2.2.1.5 Conclusions on excess capacity

The Authority believes the substantial volume of excess capacity that exists in the market is an inefficient outcome, which results in higher costs that are borne directly by consumers and, more broadly, by the economy as a whole.

The Authority considers that there are two aspects of the RCM that are likely to have contributed to the excess capacity accumulated in the WEM. Firstly, the ongoing excess is an indication that the administratively set capacity price is too high. Secondly, the current Market Rules do not set a limit on the amount of Capacity Credits that can be issued each year by the IMO, only a stipulation that sufficient capacity be obtained so as to satisfy the capacity required.

The Authority is aware of the work program that has been undertaken by the RCMWG.[47] Feedback from stakeholders responding to the Authority's Discussion Paper indicates that Market Participants are generally in support of modifications to the administrative formula for setting the RCP to make it more responsive to market conditions, and the use of a market based mechanism for the procurement of reserve capacity in the future. However, it is generally acknowledged that such an undertaking would be complex and would require significant inquiry and review.

Given the significance of the issue of excess capacity, the Authority recommends that the Public Utilities Office (**PUO**) undertake a comprehensive, holistic review of the current market design of the RCM, with a view to steering the long term evolution of the market towards economically efficient outcomes.

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[44] Ausubel, L.M. & Cramton P. (2010) *Using Forward Markets to Improve Electricity Market Design*. 8 January 2010, University of Maryland. http://www.cramton.umd.edu/papers2005-2009/ausubel-cramton-forward-markets-in-electricity.pdf

[45] EMRI & APPA (2010) *A Review of PJM's Reliability Pricing Model*
http://www.publicpower.org/files/PDFs/APPAReviewofRPM10012010.pdf

[46] See Appendix 5 for further information.

[47] The Lantau Group has been engaged by the IMO to assist with this review of the RCP.

Finding 1

Section 2.2.1.5

The substantial volume of excess capacity that exists in the market is an inefficient outcome which results in higher costs that are borne directly by consumers and, more broadly, by the economy as a whole.

Recommendation 1

Given the significance of the issue of excess capacity, the Authority recommends that the Public Utilities Office undertake a comprehensive, holistic review of the current design of the Reserve Capacity Mechanism, with a view to steering the long term evolution of the market towards economically efficient outcomes.

2.2.2 Investment incentives and efficient capacity mix

The Market Objectives include the economically efficient production and supply of electricity and the minimisation of the long-term cost of electricity to customers. This will require the use of the most efficient mix of capacity types to meet demand. Consequently, it will also require appropriate incentives in the market to attract investment in the right types of capacity that deliver the most efficient outcomes.

The Authority notes the substantial increase in new peaking capacity that has been attracted to the market in recent Reserve Capacity Cycles and, in particular, for the 2010/11 Capacity Year to the 2013/14 Capacity Year, as shown in Table 3 below.

Table 3 Capacity Credits assigned to peaking capacity

Reserve Capacity Cycle	Capacity Year	Total CCs MW	YOY Change MW	Peaking MW*	YOY Change MW	Proportion of Peaking to total CCs
2005	2007/08	4,115	-	1,373	-	33%
2006	2008/09	4,600	+484	1,210	-163	26%
2007	2009/10	5,136	+537	1,523	+313	30%
2008	2010/11	5,259	+122	1,662	+139	32%
2009	2011/12	5,493	+235	1,978	+316	36%
2010	2012/13	5,996	+502	2,384	+406	40%
2011	2013/14	6,087	+91	2,450	+66	40%

*Source: IMO in its submission to the Authority's Discussion Paper.

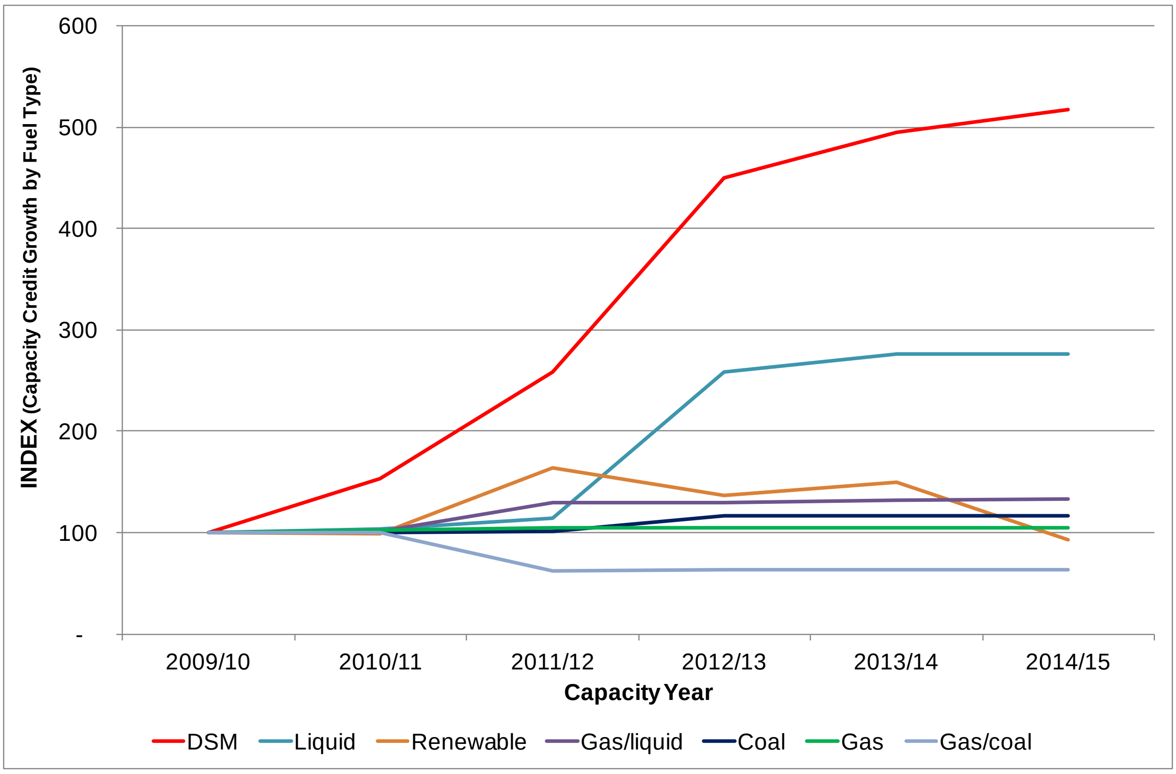
The total number of Capacity Credits assigned by the IMO to Market Participants for the 2013/14 Capacity Year has increased by 950 MW from the 2009/10 Capacity Year. Over the same period, the number of Capacity Credits allocated to peaking capacity has increased by 927 MW.

The Authority notes that the increase in peaking capacity has occurred concurrently with the excess in base-load generation and the accumulation of excess capacity above the RCR in the market. The Authority considers that the incentives provided in the current Market Rules are unlikely to result in an optimal mix of capacity types, leading to the potential for inefficient outcomes in the market.

2.2.2.1 Growth in different capacity types in the market

Figure 1 below presents an indexation of the growth in the different capacity types (in MW per Capacity Year), with generators distinguished on the basis of fuel type and using 2009/10 as a baseline.

Figure 1 Relative entry by capacity types (by fuel type), year on year, 2009/10 to 2014/15 Capacity Years



As can be seen in the above figure, growth in liquid only generation and DSM capacity, in particular, has outstripped growth in all other generation capacity fuel types.

Table 4 below provides the underlying quantities of Capacity Credits by each fuel type from 2009/10 Capacity Year to 2014/15 Capacity Year.

Table 4 Allocated Capacity Credits by fuel type, 2009/10 to 2014/15 Capacity Years

Fuel Type	2009/10 MW	2010/11 MW	2011/12 MW	2012/13 MW	2013/14 MW	2014/15 MW
Coal	1,518	1,518	1,542	1,766	1,771	1,777
DSM	99	154	260	455	500	524
Gas	2,118	2,179	2,217	2,227	2,226	2,219
Gas-liquid	631	636	821	821	833	840
Liquid	69	71	79	179	190	190
Renewable	138	137	224	187	205	129
Gas-coal	564	564	351	362	362	362

Table 5 below provides an overview of the Capacity Credits (and their value) allocated to DSM providers since market commencement. Since 2005, the number of megawatts allocated by the IMO to providers of DSM has increased from 131 MW (about 3 per cent of total Capacity Credits allocated) to 524 MW (about 9 per cent of the total Capacity Credits allocated).

Table 5 Capacity Credits allocated to Demand Side Management providers

Reserve Capacity Cycle	Period	Capacity Credits allocated to DSM (MW)	YOY change (MW)	YOY change (%)	Proportion of total Capacity Credits provided by DSM (%)	Implied value of Capacity Credits provided by DSM ($ million per year)*
	21/09/06 to 01/10/06	111			3.1%	
	01/10/06 to 01/10/07	111			3.0%	14
2005	01/10/07 to 01/10/08	131	20	18%	3.2%	17
2006	01/10/08 to 01/10/09	128	-3	-2%	2.8%	13
2007	01/10/09 to 01/10/10	99	-29	-23%	1.9%	11
2008	01/10/10 to 01/10/11	154	55	56%	2.9%	22
2009	01/10/11 to 01/10/12	260	106	69%	4.7%	34
2010	01/10/12 to 01/10/13	454	194	75%	7.6%	85
2011	01/10/13 to 01/10/14	500	46	10%	8.2%	89
2012	01/10/14 to 01/10/15	524	24	5%	8.7%	64

* This implied value is calculated as Capacity Credits allocated to DSM multiplied by the prevailing Reserve Capacity Price for the relevant Capacity Year.

Under the Market Rules, capacity secured through DSM is treated the same and receives the same payment as capacity secured through generation. This is consistent with the assumption that the value of 1 MW provided by generation is equal to the value of 1 MW curtailed by DSM. A number of stakeholders have raised concerns as to whether such an assumption is valid, given that the capacity secured through DSM is not perfectly substitutable with capacity secured through generation. This is because there are a number of limitations on DSM that do not apply in the case of generation, and vice versa. These include certain limitations on the number of times each year that DSM can be called on and the number of hours that can be used when DSM is called. In addition, there is a minimum of a four hour ramp up period for DSM to come on line, thus limiting the ability of DSM to curtail at short notice. DSM capacity receives the same remuneration as generation capacity, without having to meet the same operational requirements.

The Authority is aware of the work stream undertaken by the RCMWG and the proposal to harmonise the operational requirements of DSM with generators that the IMO intends to proceed to the formal Rule Change process.[48] However, given the wide implications of this matter, the Authority considers further investigation is warranted to ensure an efficient outcome for the market.

[48] Refer to IMO website http://www.imowa.com.au/RCMWG.

Co-optimisation of capacity and energy cost

The optimal capacity mix is one that provides the least cost solution for energy and capacity combined. Whilst the capacity price encourages least cost capacity to enter the market, it does not necessarily consider the lowest total cost of electricity supply, i.e. capacity and energy combined. Generators with high capacity costs are unlikely to enter the WEM without obtaining a satisfactory return for their investment based on expected revenue streams from both capacity and energy. The peaking capacity attracted to this market may have a lower capital cost but may have overall higher costs of electricity supply to consumers as the dispatch cost may be more expensive.

The Authority intends to examine these issues further in the next Report to the Minister, which is expected to be completed in 2013/14. In doing so, it will take into account the limitations of achieving an optimal outcome, such as the small scale of the WEM and the lumpiness of additions in generation capacity.

2.2.2.2 Observations from other markets

Demand Response in the PJM and ISO-New England Forward Capacity Markets

The Forward Capacity Market designs of both PJM and ISO-NE have provided for the successful integration of demand resources, leading to increased competition, with the ISO-NE market's reliability needs being met at noticeably lower prices than the cost of new generation, and PJM's market further benefitting through reductions in price volatility (refer to Appendix 4).

Both markets have, however, experienced challenges around the treatment of demand resources as equivalent to generation resources, including concerns around differences in availability requirements, costs of service provision and distorted capacity prices. Consequently, in both markets there is a call for remunerating demand response products in accordance with reliability attributes, such as the availability and flexibility of dispatch options and the costs of demand response provision.

Capacity Mix

With increasing levels of DSM entering the market and the potential for increasing levels of intermittent renewable resources into the future, an important consideration will be the ability to achieve an efficient mix of the resource capabilities for meeting system reliability (refer to Appendix 5). The task of ensuring resource adequacy has traditionally involved a planning process that focuses more on the quantity of capacity that is required at a particular time, and how that capacity will be acquired, rather than considering the mix of the resource capabilities.

In North American markets, the need to ensure an efficient mix of generation plant has led to the consideration of the use of apportioned markets that differentiate the value of capacity payment streams based on a set of critical operational capabilities or reliability attributes. In apportioned markets, capacity sources having greater reliability attributes are afforded a competitive advantage over those capacity sources with lesser reliability attributes. The approach also avoids the trap of segregating resources on the basis of criteria that are not related to reliability (e.g. distinctions based on new vs. existing resources, or strategic reserves vs. other forms of firm capacity) that would inevitably distort energy market outcomes.

For example, prior to the implementation of PJM's current capacity market design, a market apportioned on the basis of four categories of resources, including dispatchable (i.e. rampable), flexible cycling (rapid and frequent stop start), supplemental reserves, and everything else, was proposed. The market was to be cleared in stages based on the required quantities of each type of resource. The proposal was, however, dropped in the final market design due to stakeholder concerns around complexity and market liquidity. Nevertheless, PJM recently adopted a three-tranche structure instead of the previous single-clearing price auction for the demand response portion of its capacity market.

Additionally, ISO-NE has proposed to apportion their forward capacity auction into several tranches based on specified resource capabilities (e.g. a ten minute product,[49] a 30-minute product and flexible resources). The proposal in part has been precipitated by the impending retirement of a number of older firm supply resources.[50]

Thus, both the PJM and the ISO-NE Forward Capacity Markets are moving toward an apportioned market approach. Whether such an option would be suitable for the RCM in the WEM is questionable, especially given the dominant market structure by the two State Government owned utilities (i.e. Synergy and Verve Energy), and the potential for issues of market power. Nevertheless, the undertaking of a thorough review of the operation and outcomes of the implementation of apportioned markets within the context of the PJM and ISO-NE markets may be instructive in this regard.

2.2.2.3 Conclusions

The Authority acknowledges the valuable role that liquid generation and DSM capacity play in the successful working of the market, particularly in regard to plant diversity which enhances system security. However the Authority is concerned that the current market arrangements have been providing an incentive for investment in peaking capacity. If this trend continues into the future, regardless of market conditions such as excess capacity and when other forms of capacity are needed (i.e. capacity that produces energy on a regular basis), there is a risk that the market will move further away from an efficient outcome, and result in the overall cost of capacity and energy being higher than it needs to be.

A review of other forward capacity markets shows that they are experiencing similar concerns around the treatment of demand resources. These concerns relate to risks to reliability due to limited availability requirements, the treatment of demand resources as equivalent to generation (resulting in the same returns regardless of differences in costs of service provision) and distorted capacity prices. Accordingly, consideration is currently being given to the remuneration of demand response products on the basis of reliability attributes such as their availability, flexibility of dispatch options, and the costs of demand response provision.

The Authority considers that an efficient market would be able to provide incentives to attract the right mix of investment when it is needed.

The Authority recommends that as part of the comprehensive review suggested earlier, the Public Utilities Office evaluates the current market design in its entirety to ensure it achieves an economically efficient mix of capacity and energy resources in the market.

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[49] This refers to the ability to produce energy within ten minutes.

[50] Other reasons for the proposal included uncertain resource performance, an increased reliance on natural gas-fired capacity, integration of a greater level of variable resources, and the need to better align wholesale market procurements with transmission planning processes. Refer to ISO New England (2012). *Using the Forward Capacity Market to Meet Strategic Challenges*, May 2012. Strategic Planning Initiative. http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/fcm_whitepaper_final_may_11_2012.pdf

Finding 2

Section 2.2.2.3

The current market arrangements have resulted in a significant increase in the amount of peaking capacity entering the market in recent years, further contributing to the issue of excess capacity. Whilst the Authority acknowledges the valuable contribution that these resources provide to the overall portfolio of capacity mix, it is concerned that the incentives provided in the current Market Rules are resulting in an overall cost of capacity and energy that is higher than it needs to be.

Recommendation 2

The Authority recommends that as part of the comprehensive review suggested under Recommendation 1, the Public Utilities Office evaluates the market design in its entirety to ensure it achieves an economically efficient mix of capacity and energy resources in the market.

2.2.3 Rates of plant outage

Observed planned outage rates at some Verve Energy generation facilities are high and have been for some time.

In its 2011 Report to the Minister, the Authority noted the high planned outage rates observed for some Verve Energy's facilities during 2010/11:

- 53.6 per cent at the Kwinana G5 plant, with a capacity of 174 MW;
- 49.6 per cent at the Kwinana G6 plant, also with a capacity of 174 MW;
- 49.3 per cent at the Pinjar GT11 plant, with a capacity of 105 MW; and
- 42.7 per cent at the Muja G7 plant, with a capacity of 211 MW.

Whilst an improvement in planned outage rates has been observed in 2011/12, the Authority still considers the observed planned outage rates for some Verve Energy's facilities to be high. These are:

- 40.3 per cent at the Muja G6 plant;
- 27.9 per cent at the Pinjar GT10 plant;
- 25.9 per cent at the Kwinana G6 plant;
- 23.0 per cent at the Kwinana G5 plant; and
- 19.9 per cent at the Pinjar GT11 plant.

As a means of comparison, the Australian Energy Market Operator's National Transmission Network Development Plan contains indicative estimates of rates of planned outage for generation facilities. The Authority acknowledges that there may be some differences in the definitions of planned outage between different organisations. Still, the acceptable rates of planned outage published by the AEMO range from as low as 1.5 per cent up to a maximum of 6.5 per cent and vary within this range, depending on the type of plant.[51]

2.2.3.1 Possible reasons for high rates of plant outage

The Authority has identified three possible causes of the high rates of planned outage that have been observed in the WEM during recent years. These are:

- the design of the reserve capacity refund payments that are paid by generators when generation facilities are unavailable;
- a limited ability of the IMO to prevent poor performing generators operating in the market; and
- a limited ability of the IMO to monitor and enforce performance standards.

These points are discussed below.

Reserve Capacity Refund Payments

An effective market structure would create the appropriate incentives to encourage generators to keep outage rates to a minimum and for aged, inefficient plant to retire if they are characterised by poor performance.

In the WEM, incentives for generators to have plant available are influenced by three main factors:

- potential energy market revenues;
- capacity payments for being available or unavailable under planned outage; and
- the imposition of requirements for generators that are not available when on forced outage to pay refund payments through the operation of the RCM.

The Authority is concerned that the reserve capacity refund payment process may be partly responsible for the problem. Refund payments for forced outages can result in significant costs to generators. As the risk for a forced outage occurring is generally greater for aged, unreliable plants, there is likely a preference to keep such plant under planned outage for as long as possible, in order to reduce the possibility that a forced outage may occur, and hence to minimise the potential refund payments. This can only be a viable option if such plant is not required for energy production by its owner. Whilst the plant may not be needed by its owner for energy production, the unavailability of such plant could have adverse implications for the overall market, leading to higher prices in the energy market than would otherwise occur.

The following charts illustrate STEM prices ($/MWh), operational load (MW) and the volume of planned outages (MW), over the periods 1 December 2010 to 29 July 2011, and 1 December 2011 to 28 July 2012, respectively. The charts show that price spikes occur through the winter period, when demand is generally lower than in the summer period, and comparatively lower prices are expected. Of note is the coincidence of large volumes of planned outage and high STEM prices, particularly between 27 June and

[51] Specifically, recommended rates are between 3.0 and 6.0 per cent for coal-fired generation plants; 3.5 and 4.0 per cent for Combined Cycle Gas Turbine plants (CCGT); and 1.5 and 6.5 per cent for Open Cycle Gas Turbine (OCGT) plants.

9 July 2011. Similarly, in 2012 high STEM prices are observed to coincide with large volumes of planned outages in early July 2012.

The facilities on planned outage included a number of base-load generators, i.e. major, low cost coal units, as well as a number of mid-merit gas units, which would typically result in lower clearing prices when dispatched. The Authority considers that the primary driver for the observed price spikes was likely to be the unavailability of a high amount of base-load capacity. Simulations of market operations showed that the price spikes observed in 2011 would have been significantly reduced if two of the large base-load units were returned to service, whilst the return of three large base-load units would have completely eradicated the spikes.[52]

[52] The Authority has to date not hired a consultant to investigate the spikes noted in the 2012 period, however it should be noted that a similar outcome was observed.

Figure 2 STEM Price, Operational Load and Planned Outage (1/12/2010 to 31/7/2011)

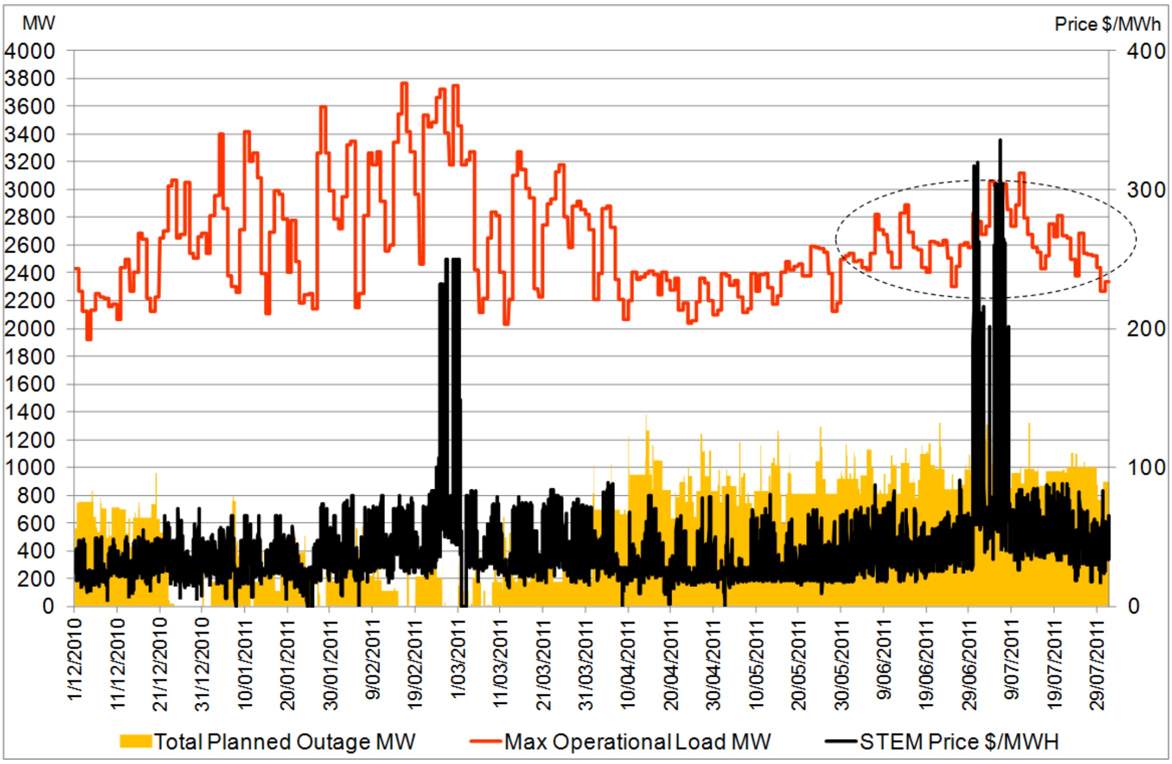
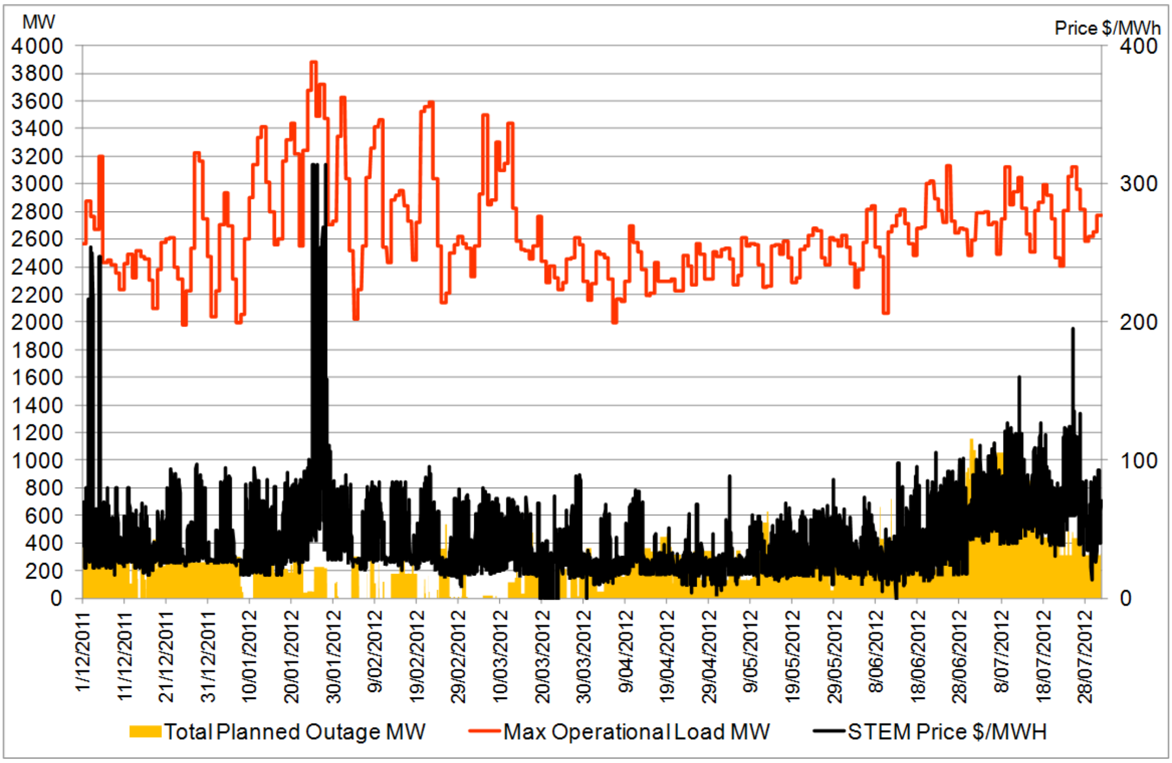


Figure 3 STEM Price, Operational Load and Planned Outage (1/12/2011 to 31/7/2012)



Under the current Market Rules, refund payments paid by generators[53] are unrelated to the scarcity of capacity at the time of an outage. This means that there are no market-

[53] Refund payments are made by market generators to the IMO in instances where they do not provide their reserve capacity obligation quantity for a specific Trading Interval.

based price signals provided to generators as an incentive for them to have capacity available when it is needed most. Indeed, the ability to receive full capacity payments, whilst unavailable for extended periods, provides an incentive for inefficient generators (i.e. those who may be unavailable for extended periods) to remain in the system.

The Authority is aware of the proposal presented to the RCMWG for the introduction of a dynamic refund regime by the Lantau Group.[54] The Authority understands further work will be required for it to go through the Rule Change process.

The ability to restrict poor performing generators receiving certified capacity

The Market Rules (specifically clause 4.11.1(h)) give the IMO discretion to choose not to grant certified capacity status to a facility that:

- has a poor record of availability[55] provided that the facility has operated for at least 36 months; or
- if the facility has not operated for 36 months or is yet to commence operation but for which the IMO has cause to believe the facility is likely to have a poor record of availability over a period of 36 months.[56]

While these clauses exist, they are only guideline clauses rather than instructive clauses. Ultimately, the IMO has discretion on whether or not it grants Capacity Credits to generators. To date, the IMO has not exercised its ability to enforce these availability requirements. The high rates of planned outage observed in the market is perhaps, demonstrative of a need for there to be more defined standards on plant availability and its effect on the granting of Capacity Credits.

Limited ability to monitor and enforce performance standards

Clause 4.27 of the Market Rules enables the IMO to monitor rates of planned outages and to query generators if (i) rates of planned outage are sufficiently high and (ii) if these rates are encountered in instances where system availability is below a defined threshold.[57] To date, these two events have not occurred simultaneously and hence, there have been no instances where the IMO, operating in accordance with the Market Rules, has been able to require generators to provide explanatory documentation for high rates of planned outage.

[54] Refer to the IMO website http://www.imowa.com.au/RCMWG

[55] As defined as either (i) a forced outage rate of greater than 15 per cent over a period of 36 months or (ii) a combined planned and forced outage rate of greater than 30 per cent over a period of 36 months.

[56] As defined as either (i) an expected forced outage rate of greater than 15 per cent over a period of 36 months or (ii) an expected combined planned and forced outage rate of greater than 30 per cent over a period of 36 months.

[57] Specifically, the IMO must require Market Participants with a facility that has been unavailable due to planned outage 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 that explains the planned outages and sets out the expected maximum number of planned outages for the relevant facility in the next 24 months. However, these provisions are only triggered in circumstances in which SWIS-wide available capacity drops below 80 per cent during a hot season or 70 per cent during an intermediate or cold season for at least 40 days in any 12 month period. To date, there have been instances where the facility availability threshold has been reached but there have been no instances where the 40 day system capacity threshold has been reached. Thus, the requirement for market participants with high rates of planned outage to provide an explanatory report has never been triggered.

In its 2011 Report to the Minister, the Authority noted that it considered that the threshold for the IMO's monitoring of individual plant availability under clause 4.27 of the Market Rules could be set too high. The Authority maintains this conclusion.

Stakeholder feedback in response to the Authority's Discussion Paper for the current report was generally in support of improvements to the above two clauses. System Management in particular, suggested that the relevant clauses should be amended to require the IMO to document the methodology they must consider when determining whether it is necessary to apply this clause to withhold assigning Certified Reserve Capacity to a facility. In developing the procedure, System Management indicated that factors such as the reason for the outage, the ability to recall facilities from planned outage quickly, and the time of year planned outages are taken, particularly with respect to available spare capacity, should be considered. System Management considered that this amendment would reduce the quantity of Capacity Credits offered to facilities that have a record of frequent or long duration planned and forced outages and may not be sufficiently available to cover reserve margins.

In its submission to the Authority's Discussion Paper, the IMO expressed its support to review clauses 4.11.1(h) and 4.27 in the Market Rules highlighted by the Authority and noted the IMO's intention to commence this work in 2013.[58]

2.2.3.2 Observations from other markets

A recent review of PJM by Wittenstein and Hausman (2011) that examined flaws in capacity market design indicated that the PJM market may also be incentivising the retention of aged and inefficient plant (refer to Appendix 5).[59] Since the Reliability Pricing Model was approved, nearly 278 MW of installed capacity came out of retirement, 1,917 MW of retirements were postponed or cancelled and 2,030 MW of deactivation requests were withdrawn (a total of 4,225 MW of installed capacity). In the six years prior to the Reliability Pricing Model, retirements averaged 1,000 MW a year but following commencement retirements averaged 384 MW per year, through 2010.[60]

Originally, the expectation of capacity markets was that capacity resources would bid at or near their net cost of new entry (i.e. the cost that a new resource would need to recover its fixed costs, plus a reasonable return on equity, whilst taking into account revenues from the energy and ancillary services markets). Net cost of new entry is administratively determined by PJM based on an estimate of costs and expected energy revenues for a 'proxy' new resource, such that stable prices near or above this value should 'theoretically' attract new investment.

In contrast to this, in the majority of auctions held in the PJM Market, Reliability Pricing Model prices have been below PJM's estimate of net cost of new entry in non-constrained regions. However, the non constrained regions have experienced new resource additions, whilst the prices in constrained (capacity-short) regions have been much higher and new supply resources have not been added.[61]

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[58] Note that the IMO has commenced a review of the relevant clauses in the Market Rules and provided a concept paper to the March 2013 MAC meeting.

[59] Wittenstein M. & Hausman E. (2011). *Incenting the Old, Preventing the New: Flaws in Capacity Market Design, and Recommendations for Improvement.* Synapse Energy Economics, Inc., Cambridge.

http://www.publicpower.org/files/PDFs/2011APPACapacityMarketsReport.pdf

[60] Also see: http://nj.gov/bpu/pdf/announcements/2011/capacityissues.pdf

[61] Interestingly, a similar scenario exists in the New York market where clearing prices are well below the estimated CONE for each region, which appears to be incentivising natural gas plants in its western region where there is an existing capacity surplus and these plants might otherwise not be profitable.

According to the authors, the vast majority of the financial benefits of the mandatory single clearing-price capacity market (i.e. 95 per cent of all Reliability Pricing Model revenues) actually accrued to incumbent generators, a third of which went to existing coal generators. Together, the lack of new generation investment and the retention of aged plant was explained in terms of PJM's forward capacity market providing only limited guarantees, i.e. capacity payments for only one year, and not offering developers a stable enough revenue stream over the longer term (i.e. the one year price guarantee is not sufficient enough to drive large investments in generating resources that have operating lives of decades).[62]

Additionally, the authors considered that it is against the self interest of incumbent and new generation developers (who rely on or profit from the high capacity prices) to add capacity to constrained, high priced areas. That is, incumbent generators are aware that by putting in new developments, they run the risk of reducing their revenue.

2.2.3.3 Conclusions on high rates of plant outage

The Authority is concerned by the high rates of planned outage that have been observed for some Verve Energy plant over consecutive years. These generators received full capacity payments under the current market arrangements, whilst being unavailable for extended periods on planned outage, causing higher prices in the energy market than would otherwise be the case. The Authority considers that this is an inefficient market outcome.

The Authority considers there are a number of possible causes of the high planned outage rates. These include: the current design of the reserve capacity refund payments, and the limited abilities of the IMO to prevent poor performing generators operating in the market and to enforce performance standards.

Comments from stakeholders in response to the Authority's Discussion Paper are generally in support of the view that more can be done to address the high rates of planned outage that have been observed in the market.

The Authority recommends that the incentives to maximise plant availability should be reviewed. The Authority notes that the IMO has commenced a review and consideration of current generator availability and incentives to improve performance. The Authority supports this undertaking.[63]

Despite the apparent weakness in the Market Rules that is currently under the review of the IMO, the Authority recognises that the issue of plant unavailability appears to be a matter associated with Verve Energy in particular. The Authority considers that the inefficient outcomes may also be likely attributable to certain aspects of the arrangements in the contract between Verve Energy and Synergy, assigned by the State Government in 2010. Hence, the Authority recommends that the PUO undertakes a review of the contractual arrangements between Verve Energy and Synergy to ensure that the contract does not provide perverse incentives for inefficient market outcomes.

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[62] In the Columbian market Reliability contracts have a lead time of between 3 and 7 years. The contract duration for existing plant is 1 year, whilst plant not yet built can optionally increase the contract duration and thus lock in payments for longer periods of up to 20 years. For plants that require additional investment, an intermediate solution is used.

[63] The IMO has commenced a review of the relevant clauses in the Market Rules and provided a concept paper to the March 2013 MAC meeting.

Finding 3

Section 2.2.3.3

A number of Verve Energy generation units recorded high rates of planned outage over consecutive years. These generators received full capacity payments under the current market arrangements, whilst being unavailable for extended periods on planned outage, causing higher prices in the energy market than would otherwise be the case, resulting in inefficient outcomes.

Recommendation 3

The Authority recommends incentives to maximise plant availability to be reviewed. The Authority notes that the IMO has commenced a review of current generator availability and the incentives to improve performance. The Authority supports this undertaking.

Recommendation 4

The issue of plant unavailability appears to be a matter associated with Verve Energy specifically. Hence, the Authority recommends that the Public Utilities Office, acting on behalf of the owner of Verve Energy, undertake a review of the contractual arrangements between Verve Energy and Synergy, to ensure that the designated contract assigned to the two entities by the State Government does not provide perverse incentives for inefficient market outcomes.

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, including but not limited to bidding in the STEM and Balancing, as well as declarations for availability, ancillary service and fuel type;
- market design problems or inefficiencies; and
- problems with the structure of the market.

This section sets out 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 discusses issues surrounding the structure of the market.

3.1 Ancillary Services Contracts and Balancing Support Contracts

3.1.1 Ancillary Services Contracts

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.[64] 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.[65] System Management is required to estimate the technical requirements for Ancillary Services, based upon standards set out in the Market Rules. Pursuant to its obligations under clause 3.11.11 of the Market Rules, System Management must prepare a report each year, which comprises three parts:

[64] The Technical Rules for the South West Interconnected Network is the basis for the setting of operating parameters in WEM.

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

- quantities of each of the Ancillary Services provided in the preceding year, including Ancillary Services provided under Ancillary Service Contracts, and the adequacy of these quantities;
- total cost of each of the categories of Ancillary Services provided, including Ancillary Services provided under Ancillary Service Contracts, in the preceding year; and
- Ancillary Service requirements for the coming year and the Ancillary Services plan to meet those requirements.

System Management is required to source Ancillary Services on a least cost basis, either from Verve Energy (the default provider) or from Independent Power Producers (**IPPs**). The IMO recovers the costs of the Ancillary Services from Market Participants through the market settlement process.

Spinning Reserve

Verve Energy has been the sole default provider of the Spinning Reserve Ancillary Service[66] since market commencement. Verve Energy receives a payment from the market, which is calculated as the Balancing price multiplied by a margin value that is determined by the Authority under the Market Rules.[67] The Spinning Reserve Ancillary Service cost is recovered from Market Generators. Verve Energy, besides being the provider, is also responsible for a large portion of the Spinning Reserve Ancillary Service cost.

The requirement for the Spinning Reserve Ancillary Service is determined by System Management in accordance with clause 3.10.2 of the Market Rules. In its 2011 Ancillary Service Report,[68] System Management has estimated that the maximum Spinning Reserve level that may be required for the 2011/12 year is 240 MW, and the minimum level required is between 150 MW to 180 MW. This service can be provided by such facilities as synchronised generation and interruptible loads.[69]

Load Following

Verve Energy has been the sole default provider of the Load Following Ancillary Service (**LFAS**)[70] from market commencement until 1 July 2012 when the market for LFAS was implemented to allow IPPs to compete with Verve Energy for the provision of this service.[71]

Clause 3.10.1 of the Market Rules specifies the criterion for determining the level of LFAS. For the 2011/12 year, System Management's forecast for the Load Following requirement

[66] Spinning Reserve is reserve that is synchronised to the system that can respond almost immediately and provide frequency or voltage support for a short duration.

[67] The margin values are determined for each financial year. For the 2011/12 financial year, these values are set at 43 per cent for Margin-Off Peak and 25 per cent for Margin Peak which covers Verve Energy's costs for the provision of spinning reserve ancillary service and load following ancillary service.

[68] See http://www.imowa.com.au/ancillary-services-annual-reports.

[69] For 2011/12, 52 MW of Spinning Reserve will be provided by interruptible load supplied by two market participants. This will reduce to 42 MW in October 2011 as the contract to supply 10MW from one supplier will expire. The remaining Spinning Reserve will be supplied by synchronising additional Verve Energy generators.

[70] Generators providing LFAS are run in a manner that allows for the generators' output to be rapidly changed to balance real-time fluctuations between load and generation.

[71] Prior to the implementation of the LFAS market, System Management had worked towards competitively procuring LFAS from IPPs but had not been successful in securing any service contract with an IPP. System Management issued its first call for Expression of Interest (**EOI**) to competitively procure LFAS from the market in February 2010, which resulted in no EOI being received.

was +/- 60 MW in July 2011, increasing to +/- 90 MW from November 2011 onwards, with the commissioning of the Collgar Wind Farm.[72]

As the default provider of LFAS, Verve Energy receives a payment from the market which is calculated as the Balancing price multiplied by a margin value that is proposed by the IMO and determined by the Authority, under the Market Rules. Payments for LFAS costs are shared between Market Customers and Intermittent Generators.

System Restart

Verve Energy was assigned a five-year arrangement at a fixed payment for the provision of the System Restart Ancillary Service[73] at the commencement of the WEM, which expired on 30 June 2011. In 2010, System Management undertook competitive procurement processes to provide System Restart Ancillary Services in three of the five SWIS sub-networks. System Management has a Deed of Arrangement with Verve Energy[74] for the provision of System Restart for two sub-networks.[75] For the remaining required sub-network, System Management directly negotiated a fee with Verve Energy for a two-year service contract[76] for the sub-network in Kwinana, as no offers were received.[77]

Payments for these contracts are collected via the R value of the Cost_LR parameter[78] 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 determination on the Cost_LR parameter for the 2011/12 and 2012/13 financial years in April 2011.[79]

Load Rejection Reserve

Verve Energy currently provides Load Rejection Reserve Ancillary Service[80] as part of its ancillary obligations under clause 3.11.7A of the Market Rules. System Management assessed that this requirement will be provided by the ability to turn down or turn off Verve Energy's facilities and expected that there is sufficient capacity to manage this even at times of minimum Verve Energy generation. However, System Management noted that this will get harder to manage as overnight load supplied by Verve Energy is reduced. In its 2011 Ancillary Service Report, System Management set the Load Rejection Reserve

[72] Frequency variations are expected to increase with the operation of the Collgar wind farm.

[73] System Restart Ancillary Services are provided by generators capable of starting up without the need to use power from the power system and are also able to energise the power system to enable other generators to be started up.

[74] From 1 July 2011 to 30 June 2016.

[75] Sub-network in Pinjar and Donaldson Road.

[76] From 1 July 2011 to 30 June 2013.

[77] 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

[78] 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 Services.

[79] The R values determined by the Authority are $40,933 per month for the 2011/12 financial year and $41,583 per month for the 2012/13 financial year. See http://www.erawa.com.au/cproot/9514/2/20110420%20Decision-%20Determination%20of%20the%20Ancillary%20Service%20Cost_LR%20parameter.pdf.

[80] In providing Load Rejection Ancillary Services, generators shut down quickly in the event of lost load, such as when a transmission line trips, in order to keep the power system stable.

requirement at 120 MW for the 2011/12 year, which was unchanged from the previous year.[81]

The L value of the Cost_LR parameter provides for the compensation of the cost associated with the provision of this service. System Management has not sought a cost allocation for the L value because it does not have information demonstrating that the provision of this service is at a particular annual unremunerated cost to any Market Participant. Hence the value has been set at nil since market commencement.

Dispatch Support

The current Deed of Undertaking between System Management and Verve Energy for the provision of Dispatch Support Ancillary Services in the Eastern Goldfields and the North Country regions was approved by the Authority in April 2008.[82] Verve Energy's facilities at Mungarra, West Kalgoorlie and Geraldton are contracted to supply these Dispatch Support Ancillary Services. For the 2011/12 year, System Management determined that the services will continue to be supplied from Verve Energy's facilities at Mungarra, West Kalgoorlie and Geraldton and does not anticipate entering into further arrangements for dispatch support.

3.1.2 Balancing Support Contracts

A Balancing Support Contract (**BSC**) allows an IPP facility to assist Verve Energy in providing the required balancing requirements to the energy market. 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. The Authority notes BSC provisions have been removed from the Market Rules with the implementation of the competitive Balancing market on 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 and the exploitation of shortcomings in the Market Rules or Market Procedures.

A substantial change took place in the Balancing market in July 2012, whereby the market was opened up to competition and Verve Energy was no longer the default provider of Balancing services. Prior to this change, the Authority had noted the presence of high Balancing quantities purchased by Verve Energy and was concerned that there may be inappropriate market behaviour involved. The Authority engaged the services of the Lantau Group to investigate this observation further.

[81] Refer to the IMO website:
http://www.imowa.com.au/f2841,1297737/Ancillary_Service_Report_2011_FINAL.pdf

[82] 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.

The result of the review was that there was no evidence to suggest that any Market Participant:

- had exhibited inappropriate or anomalous market behaviour;
- exploited its market power; or
- exploited shortcomings in the Market Rules or Market Procedures.

The explanation for the high Balancing quantities was a result of sales made by:

- wind generators;
- Synergy; and
- new capacity developments (for example, the Bluewater coal units).

The output of Intermittent Generators, such as wind generators, is accounted for under the Balancing regime. This has the effect of reducing Verve Energy's production from its planned production, thus requiring it to purchase this difference. Synergy's selling activity was not considered to be inappropriate market behaviour, but was rather considered to be prudent risk management.

Furthermore, the market design allows a new facility to spill into Balancing during the commissioning stage. The operator of the new facility may also have difficulty predicting the output levels accurately at the early stage of the operation of the new facility. If these predictions are conservative, it will result in an increase of supply in Balancing. Both of these circumstances would require Verve Energy to increase its purchases in Balancing.

The Authority, with the assistance of the IMO, is continuing its observation of the behaviour of participants under the new Balancing market design.

The Authority also noted a high level of planned outages during periods of tight supply. As a result, the Authority engaged a consultant (Market Reform) to study the relationship between generators' planned outages and high prices in the STEM. This specifically related to price spikes observed between June 2011 and August 2011 where some high STEM prices coincided with high levels of planned outages (refer to Figure 2 in Section 2). The facilities on planned outage included a number of major low-cost coal units as well as a significant number of mid-merit order gas units.

Whilst the price spikes in the STEM were associated with high level of unavailability of some relatively low-cost base-load and mid-merit plant, the review concluded that there was no evidence to suggest that those planned outages were undertaken in an attempt to take advantage of any resulting higher prices by any participant. There was also no evidence to suggest that a participant could benefit by taking out a unit (on planned outage) to profit from high prices or to avoid paying Reserve Capacity Refunds.

The behaviour of participants in the STEM is being actively monitored by the Authority, in conjunction with the IMO, to ensure generators offer their electricity at prices that are reflective of their expected short run marginal cost (**SRMC**) for generating the electricity.[83] This continued monitoring has not revealed any inappropriate or anomalous market behaviour.

[83] Refer to clause 2.16.9 of the Market Rules for details.

3.3 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. The Authority notes that the WEM has evolved significantly since its inception, in particular, with the implementation of the competitive Balancing and LFAS market from 1 July 2012.

In the past, stakeholders have expressed concerns that the complexity of the WEM, including the Market Rules that govern the RCM, net pool energy market, as well as contractual arrangements between the State-owned corporations, can be barriers to new entry to the market.

The Authority has identified a number of issues surrounding the operation of the RCM that the Authority considers have implications for the effectiveness of the market in meeting the Market Objectives. These issues have been discussed in detail in Section 2 of this report.

In relation to the operation of the energy markets in the WEM, the Authority considers the one-off Bilateral and STEM Submissions on the Scheduling Day (i.e. the day before the day when electricity is actually consumed) may be too restrictive, leading to some inefficient market outcomes. The STEM Bids and Offers are constructed around Market Participants' Net Bilateral Positions. Outcomes of the STEM clearance result in Resource Plans setting the dispatch of the IPPs' facilities for the following Trading Day up to 44 hours in advance. Over this period, the demand forecast underpinning the Bilateral and STEM Submissions would have changed. The plant and fuel availability could have also deviated from that underpinning the STEM Submissions. The IPPs were, however, locked in to their Resource Plans and Verve Energy, as the default provider for the Balancing service, would have to deal with changes in demand forecast and supply from IPPs. This deficiency has been addressed to some degree by the implementation of the new competitive Balancing market, whereby revised submissions by generators can be made two hours before the Trading Interval commences. This enables generators to move away from the dispatch plans that were set in advance, previously on the Scheduling Day, and to manage any changes in load, plant availability and fuel supply in a more efficient way. The Authority's assessment on issues surrounding the STEM is further discussed in Section 4.4.

The Authority notes that Verve Energy remains the sole default provider for the provision of the Spinning Reserve Ancillary Service. The Authority considers a competitive market should be implemented for the provision of the Spinning Reserve Ancillary Service. This has been an issue raised by the Authority previously. The Authority is aware that the IMO has included the implementation of a market for the Spinning Reserve Ancillary Service in its Market Rules Evolution Plan.[84]

3.4 Issues surrounding the structure of the market

The WEM operates in the broader context of:

- the networks and its operations within the Technical Rules;
- a market structure with continued dominance by Verve Energy and Synergy; and

[84] See http://www.imowa.com.au/market_rules_evolution_plan

- regulated electricity tariffs; and
- limited retail competition.

These elements will affect the operation of the WEM and market outcomes. Advances in generation technology including distributed generation, intelligent network applications and energy storage will also influence the operation of the WEM.

3.4.1 Network access

The WEM design is based on the unconstrained network access concept, which allows generators to have full access to the network during times of peak electricity demand, even after a single credible network fault.[85] An unconstrained network approach facilitates simpler operation of the power system and market because of the absence of dynamic physical constraints.[86]

In its 2010 Report to the Minister, the Authority noted that the current unconstrained network access approach in the SWIS does not enhance the Market Objectives for the following reasons:

- Unconstrained network access does not fully promote economically efficient supply of electricity because it is likely to cause investment in assets that are likely to have a low utilisation. Whilst there is a contribution to reliability, the incremental increase in reliability is unclear and it may be difficult to justify if considered against the increased costs;
- The requirement for unconstrained network access creates a barrier to competition, as new entrant generators must pay a proportion of the costs of the next network augmentation. As the network is considered to be close to its capacity, this cost can be high even for small increments of generation; and
- It is not clear that the requirement for unconstrained network access minimises the long term cost of supply, in the sense that the requirement may provide more reliability than customers are willing to pay for through increased electricity prices.

The Authority recommended that a full and detailed review be undertaken of the costs, benefits and possible implementation issues relating to a move towards a constrained network access framework. This review would need a very clear set of objectives, be well resourced, with full and open consultation, and proper consideration of all the relevant interactions within the WEM design. The Authority notes that such review is yet to be undertaken by the newly established Public Utilities Office (PUO).

Network access in the SWIS is governed by *the Electricity Networks Access Code 2004* (**Access Code**). The Authority notes that the Access Code has not been reviewed since it came into force in 2005. The Authority is aware that the PUO previously initiated its review of the operation of the Access Code but decided not to proceed with the review until after the Authority's assessment of Western Power's proposed changes to its access arrangement in accordance to the requirements of the Access Code was concluded. The Authority released its final decision on 29 November 2012. The PUO indicated that it

[85] There are various definitions of the concept of unconstrained network access and the terms 'unconstrained access' or 'firm access' are often used.

[86] 'Physical constraints' are limitations on the operation of a network asset, a group of assets or a whole area of the network due to performance requirements across a range of factors including power quality, security of supply, safety and power system stability.

would publish an issues paper on the Access Code review after this date.[87] This issues paper is yet to be released at the time this report is finalised. The Authority considers that the Access Code review could be considered together with the move to constrained network operation.

3.4.2 Dominance of Verve Energy and Synergy

The continuing dominance of Verve Energy and Synergy has been an issue raised by the Authority in its previous Reports to the Minister. The Authority notes that Verve Energy's market share of credited generation capacity will be around 52 per cent of the total credited capacity in 2014.[88] The reported market share for Synergy in the retail market is around 65 per cent as at 30 June 2012.[89] The Authority considers that this concentrated market structure creates barriers to effective competition, particularly in the retail sector.

As part of the market power mitigation measures put in place at the start of the WEM, Verve Energy is restricted from the direct sale of electricity to consumers and Synergy is prohibited from generating electricity for a designated period.[90] These legislated requirements are provided on the basis that a vesting contract between Verve Energy and Synergy are put in place, ensuring that the majority of Synergy's supply requirements are met by Verve Energy, which in turn receives revenue from Synergy, with some degree of certainty.

On 3 December 2010, Western Australia's Minister for Energy requested that the Authority provide its views to the Minister as to the effect that the operation of sections 38(1) and 47(1) of the *Electricity Corporations Act 2005* (**Corporations Act**) have had, and are likely to have, on the encouragement of competition in the generation, retail and the wholesale electricity market. To assist its review of the provisions in the Corporations Act, the Authority undertook a public consultation process and published an Issues Paper on its website.[91] The Authority received ten submissions in response to its Issues Paper and these submissions are available on the Authority's website.

The Authority delivered its report in April 2011[92] and in forming its views, the Authority considered the comments raised in the submissions provided to the Authority. The Authority also considered whether the provisions should lapse at 1 April 2013 or be extended to 1 April 2016.

In March 2013, the Minister made the decision to extend the designated period for the prohibition of Synergy from generating and restriction on Verve Energy from retailing to ten years, i.e. extended the prohibition and restriction to 1 April 2016.[93]

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[87] See PUO website: http://www.finance.wa.gov.au/cms/content.aspx?id=14552

[88] Derived from the IMO Capacity Credit allocation for the 2014/15 Reserve Capacity Year.

[89] See Synergy web site, Annual Report 2011/12, p. 2, http://www.synergy.net.au/docs/Annual_Report_2011-12.pdf

[90] Refer to sections 3891) and 47 91) of the *Electricity Corporations Act 2005*. The designated period is until 1 April 2013 which can be extended to 1 April 2016.

[91] See http://www.erawa.com.au/cproot/9282/2/20110125%20Prohibition%20and%20Restriction%20on%20Synergy%20and%20Verve%20Energy%20under%20the%20ECA%202005%20-%20IP.pdf

[92] See http://www.erawa.com.au/cproot/11251/2/20130328%20D62747.2%20-%20Prohibition%20and%20Restriction%20on%20Synergy%20and%20Verve%20Energy%20under%20the%20Electricity%20Corporations%20Act%202005%20-%20Final%20Report.pdf

[93] The Minster's decision was gazetted in the Western Australian Government Gazette on 28 March 2013.

3.4.3 Regulated electricity tariffs and retail competition

In its 2010 Report to the Minister, the Authority noted that cost-reflective tariffs are essential for ensuring that the market continues to operate efficiently. Setting electricity tariffs that are not cost-reflective limits the ability of customers to make efficient consumption and expenditure decisions. The Authority considered that enhanced retail competition is required for the future efficient operation of the WEM. The Authority recommended that a clear framework for increasing retail competition be established, which may include setting cost-reflective retail tariffs and the introduction of full retail contestability.

The Authority is aware that electricity retail tariffs are still not at cost-reflective levels even after the large increases in recent years. Through its inquiry into the efficiency of Synergy's costs and electricity tariffs,[94] the Authority understands that the regulated tariffs, averaged across all customer groups, would need to increase by approximately 21 per cent in 2012/13 to reach cost-reflective levels.

The Authority notes that the lack of a clear policy framework for the introduction of full retail contestability (**FRC**) will contribute to barriers to entry for attracting new investments in this market. The Authority understands that some early investments in this market were made on the expectation that full retail contestability will occur in the not too distant future. In the absence of a clear timetable for FRC, existing retailers other than Synergy will be unable to achieve critical scale and the entry and expansion of new retailers will be delayed. Both of these outcomes will have adverse implications for the prospect of new entrant generation. As with retail tariffs that are below cost-reflective levels, the absence of FRC will have adverse implications for the competitiveness, liquidity and efficiency of the WEM.

In its previous Reports to the Minister, the Authority suggested that there is a need for a road map to be developed and that the development of that agenda for the future should be led by the PUO (as the key policy body) but it should consult widely with all stakeholders including the IMO and the Authority. The Authority noted two very important issues that need to be kept in mind when looking at future changes to the market. First, and perhaps most important, the terms of reference for the road map must specify the fundamental requirement for full cost reflectivity to be included. One of the drivers behind reform of energy markets in WA was to remove cross subsidies and this should remain a key driver going forward. Second, given the size of the WA market, any proposals for change should be subjected to a thorough cost/benefit analysis. The benefits of any proposed change will need to outweigh the costs.

The Authority is aware that the *Strategic Energy Initiative* document published by the former Office of Energy (now known as the PUO) in March 2011[95] has included a short term action item to implement a plan to extend customer choice of electricity supplier to customers using less than the current contestability threshold of 50 MWh per annum, including strategies to achieve FRC in the electricity market. The Authority notes further progress is yet to be seen in this regard.

[94] See ERA, Synergy's Costs and Electricity Tariffs Final Report. http://www.erawa.com.au/cproot/10639/2/20120704%20Synergys%20Costs%20and%20Electricity%20Tariffs%20-%20Final%20Report.PDF

[95] See http://www.parliament.wa.gov.au/publications/tabledpapers.nsf/displaypaper/3813100cb1e5bc616f7914cc48257855000f71a1/$file/3100-15.03.11.pdf

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. Whilst the Authority's reporting requirements under clause 2.16.9 are provided in Chapter 3, 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; and
- 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, including a discussion on the Market Rule and Procedure change processes, the 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 mechanism;
- 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) of the Market Rules.

Rule Change Process

Under clause 2.5 of the Market Rules, any person, including the IMO, may formulate a Rule Change Proposal by completing a Rule Change Proposal form. The IMO may subject a Rule Change Proposal to the Fast Track Rule Change Process or the Standard Rule Change Process.[96] The Fast Track Rule Change Process takes about one month, while the Standard Rule Change Process takes six months or longer.

As noted in Section 5.6.3 the IMO received 13 Rule Change Proposals during the current Reporting Period (i.e. between 1 August 2011 and 30 June 2012). At the time of the release of this report, 10 Rule Change Proposals had commenced, 2 remained under development and 1 proposal was rejected.

The Authority notes that there are three main Rule Change Proposals that were progressed during the current Reporting Period that have had material implications for the market. The Authority's discussion of these Rule Change Proposals is provided below.

1. *Calculation of the Capacity Value of Intermittent Generation (RC_2010_25 and RC_2010_37)*

Concerns were raised by stakeholders about the Capacity Credit valuation methodology for Intermittent Generators. Specifically, doubts were expressed as to whether the three-year average methodology for determining Capacity Credits for these facilities accurately reflects the capacity they can reliably deliver; and it was widely acknowledged that the valuation methodology was unsuitable for solar generation and undervalues this capacity. Given these concerns, the appropriateness of the Capacity Credit valuation methodology was reviewed by the Renewable Energy Generation Working Group (**REGWG**). The REGWG supported the proposal that the IMO would nominate the valuation methodology that it felt best served the Wholesale Market Objectives.

Rule Change Proposals RC_2010_25 and RC_2010_37 were initiated by the IMO and Griffin Energy, respectively, to amend the methodology for valuing the capacity of Intermittent Generation in the WEM. The two Rule Changes proposed alternative methodologies.[97]

The IMO extended the timelines for the Rule Change Proposals eight times following the original Rule Change Proposals, published in late November 2010. On 20 December 2011, the IMO Board published its Final Rule Change Report, with the decision to accept the proposed amendments presented in a modified version of the IMO's original proposal,

[96] Refer to clause 2.6 of the Market Rules for the Fast Track Rule Change Process and clause 2.7 for the Standard Rule Change Process.

[97] For details on the Rule Change Proposals, see IMO website, http://www.imowa.com.au/RC_2010_25

i.e. Modified Methodology 1, and to reject Griffin Energy's proposed amendments in Methodology 2.[98]

The IMO also decided to implement a three-year glide path for the implementation of Modified Methodology 1, to apply for the 2012 – 2014 Reserve Capacity Cycles, and required a three-year review of the methodology to be undertaken by the IMO prior to 1 January 2015. The Modified Methodology 1 Rule Change commenced on 1 January 2012.

During the public consultation periods, the IMO received a large number of submissions, some of which were not taken into account by the IMO, including:

- that the glide path period should be extended, as the proposed glide path period of three years may not be long enough to mitigate sovereign risk issues;
- the IMO should not progress with the Rule Change Proposal, given the significant modifications to it in comparison to the original proposal, and instead, the IMO should start over with a new Rule Change Proposal that reflects the modified proposal; and
- Collgar Wind Farm's data should be included in the modelling so that stakeholders can gauge what the impact is of omitting this information on the Capacity Credit allocation under Modified Methodology 1.

Notably, as a result of this Rule Change, certified capacity value for the Collgar Wind Farm was reduced from 90 MW to about 20 MW. The reduction in capacity revenue is in excess of $8 million for the 2014/15 Capacity Year alone, an outcome that was not foreseen through the Rule Change process, which predicted a total impact of less than $5 million.

2. *Reassessment of Allowable Revenue during a Review Period (RC_2011_02)*

Rule Change Proposal RC_2011_02 was initiated by the Authority to lower the threshold that provides for the reassessment of Allowable Revenue for the IMO and System Management. Specifically, the Authority proposed that the threshold for a reassessment should be reduced from 15 per cent to 10 per cent in clauses 2.22.8 and 2.23.8 of the Market Rules.

The Authority submitted its proposal to the IMO on 10 March 2011, which was processed by the IMO under the Standard Rule Change Process. This Rule Change Proposal went through two rounds of consultation with Market Participants. Submissions received during the consultations indicated full support for the proposal from Market Participants.

On 5 April 2012, the IMO published its Final Rule Change Report on the Authority's Rule Change Proposal. Contrary to the expectation of the Authority and the views expressed in submissions from Market Participants, the IMO decided to retain the 15 per cent threshold

[98] Modified Methodology 1 was accepted on the following basis:

- Modified Methodology 1 is more accurate at reflecting the actual performance of Intermittent Generators during peak periods and thereby better achieves the Market Objectives than Methodology 2.
- Given the lack of available data on the performance of Intermittent Generators during peak periods and the complexity of the matter at hand, a more conservative approach is warranted.
- The adoption of a lesser number of Trading Intervals on which the performance of an Intermittent Generator is assessed appears to be better aligned with the intent of the Planning Criterion, in conditions where there is sufficient energy-producing plant available on the SWIS.

for the reassessment of allowable revenue, and only endorsed the lowering of the threshold for the reassessment of capital expenditure to 10 per cent.

The Authority considers that the IMO's decision is not aligned with the Authority's intention to enhance the achievement of the Market Objectives. It is the Authority's view that the retention of the 15 per cent threshold will reduce the level of scrutiny of operational costs incurred by the IMO and System Management. The Authority is also concerned that the IMO, in its role of determining whether to approve amendments to the Market Rules, can make changes without providing stakeholders the opportunity to comment on the revised amendment. Such a process is not consistent with the intent of the transparency reasonably expected of rule change processes.

The Authority considers that the IMO should have elected to carry out further consultation on this material revision to the Rule Change Proposal in the interest of procedural fairness, given the support from industry, which created a legitimate expectation that the threshold should be reduced.

3. Competitive Balancing and Load Following Market (RC_2011_10)

Rule Change Proposal (RC_2011_10): Competitive Balancing and Load Following Market led to the implementation of the new Balancing and LFAS markets on 1 July 2012. This significant change in the Balancing market design and the introduction of the LFAS market called for significant resources from the IMO, System Management and other participants in the market. The smaller participants appeared to eventually disengage due to a lack of resources. Some larger Market Participants were, however, able to sustain the effort to carry on beyond the final Rule Change Report into the implementation stage. System Management, being a significant part in the operation of the new markets, expended the effort to implement the interim design in July and carried on to bring its other systems into place for the full implementation in December last year.

Some Market Participants suggested that the pace of change was too fast and that there was a lack of thoroughness. This view was supported by several Fast Track Rule Changes introduced post the July 2012 start date, the unexpected Constrained Payments, and the rule breaches by the IMO and System Management to avoid unexpected outcomes.

Due to the optimal timelines projected in the Rule Change Proposal, the new competitive Balancing market was implemented under transitional arrangements and only became fully operational on 5 December 2012. Additionally, Verve Energy remained the sole provider of the LFAS service up until February 2013, with the costs of this service increasing significantly beyond most Market Participant's expectations.

The Authority considers that the IMO must ensure that a desire to introduce a Rule Change in a timely fashion should not come at the expense of thoroughness in ensuring that the Rule Change can be implemented in an efficient way.

In light of the concerns highlighted above, the Authority suggests the IMO conduct a post-Rule Change review on the effectiveness of the processes it employed in deriving and implementing these Rule Changes, especially on those processes relating to Rule Changes with relatively significant implications to the market.

Procedure Change Process

Pursuant to clause 2.10 of the Market Rules, the IMO or System Management may initiate the Procedure Change Process by developing a Procedure Change proposal and Rule Participants may notify the IMO.

During the current Reporting Period, the IMO submitted nine Procedure Change Proposals into the formal Procedure Change Process, eight of which have commenced and one of which is still under development.[99] System Management submitted four Procedure Change Proposals during the Reporting Period, all of which have commenced.

The Authority has noted one particular Procedure Change, i.e. PC_2011_06,[100] proposing amendments to the MRCP Market Procedure. This was to implement the recommended changes from the IMO's five-yearly review of the MRCP Market Procedure required under the Market Rules. This Procedure Change was approved and the amended procedure took effect in October 2011. As a result, the MRCP value determined in early 2012 for the 2014/15 Capacity Year was reduced by approximately 32 per cent compared to the value for the 2013/14 Capacity Year. Whilst this outcome may be justified, it came as a surprise to most Market Participants, including members in the working group that recommended the changes. Consequently the Authority is concerned that the impact of this sizeable change was not fully examined and communicated to Market Participants.

Overall, the Authority considers the Rule Change and Procedure Change processes are effective. However, the Authority notes that market governance has been an area of concern raised by Market Participants and by the Authority previously. In its 2011 Report to the Minister, the Authority discussed in detail the matter of the dual roles conferred on the IMO under the existing WEM governance arrangements. These arrangements require the IMO to determine whether to approve amendments to the Market Rules and also to administer and comply with the Market Rules. The Authority recommended that the existing governance arrangements in the WEM be reviewed to determine whether the existing arrangements remain appropriate for the ongoing development of the market. This recommendation is still current and relevant and needs to be addressed, particularly in light of the concerns discussed above.

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.

Compliance monitoring and enforcement requirements are defined under clauses 2.12 to 2.16 of the Market Rules with specific obligations on the IMO, System Management and the Authority.

Compliance monitoring and enforcement measures undertaken by the IMO

Clause 2.13.2 of the Market Rules provides that the IMO must monitor other Rule Participants' behaviour for compliance with the Market Rules and Market Procedures, in accordance with the Monitoring Protocol. The IMO is required to investigate potential

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[99] All submitted Procedure Changes by the IMO or System Management are listed on the IMO's website. See IMO website, http://www.imowa.com.au/procedure-changes

[100] Refer to IMO website for details, http://www.imowa.com.au/PC_2011_06

breaches of the Market Rules and take enforcement action where appropriate, which can include applying to the Electricity Review Board (**ERB**) for fines or other orders. Under clause 2.15.3, the purpose of the Monitoring Protocol is to:

- outline the IMO's processes for assessing compliance by Rule Participants with the Market Rules and Market Procedures;
- outline a process for System Management to demonstrate compliance with the Market Rules, Market Procedures and audit processes, where the IMO requires such demonstration or an audit;
- outline a process for Rule Participants to report alleged breaches of the Market Rules and Market Procedures;
- outline processes for investigating alleged breaches;
- specify guidelines for the IMO when issuing warnings about alleged breaches to Rule Participants; and
- specify the procedure for bringing proceedings in respect of specified Market Rule breaches before the ERB.

The IMO has been producing biannual reports on enforcement action taken to the ERB pursuant to clause 2.13.26 of the Market Rules. During the period 21 September 2011 to 20 September 2012 no new proceedings were brought before the ERB by the IMO.[101]

The Authority notes that the IMO has strengthened its compliance team as part of the implementation of the new Balancing and LFAS markets. The team has been actively monitoring the major Market Generators' bidding behaviour since commencement of the new Balancing and LFAS markets. The Authority considers it too early to determine whether the IMO has been effective in monitoring compliance in the new Balancing and LFAS markets but it applauds the IMO's efforts in encouraging new entrants into the LFAS market.

The IMO's compliance with the Market Rules is audited once a year by the Market Auditor.[102] 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 an audit by the Market Auditor. A summary of the Market Auditor's 2012 annual reports on compliance by the IMO, and by System Management, are set out in Section 4.1.3 of this report.

Compliance monitoring and enforcement measures undertaken by System Management

Clause 2.13.6 of the Market Rules provides that System Management must monitor Rule Participants' behaviour for compliance with the provisions of the Market Rules referred to

[101] IMO website, six-monthly compliance reports September 2011 to March 2012, and March 2012 to September 2012, http://www.imowa.com.au/six-monthly-compliance-reports

[102] 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.

in clause 2.13.9 of the Market Rules and the Power System Operation Procedures developed by System Management. System Management must report any alleged breaches of the provisions of the Market Rules referred to in clause 2.13.9 of the Market Rules or the Power System Operation Procedures to the IMO, in accordance with the Monitoring and Reporting Protocol.[103]

Specifically, clause 2.13.9 of the Market Rules requires System Management to monitor Rule Participants for breaches of clause 7.7.6(b) of the Market Rules which states that a Market Participant must confirm receipt of the Dispatch Instruction when issued and as soon as practicable confirm its ability to comply with the Dispatch Instruction.[104]

Clause 2.13.9 also requires System Management to monitor IPPs' compliance with Resource Plans and Dispatch Instructions[105]. An IPP must comply with its Resource Plan except where it relates to Intermittent Generators; the most recently issued Dispatch Instruction applicable to the Registered Facility for the Trading Interval; and a direction given under clauses 7.6 or 7.10.7(a) of the Market Rules.[106] A Market Participant must inform System Management as soon as practicable where it cannot meet its Resource Plan, Dispatch Instruction, or direction given under clauses 7.6 or 7.10.7(a).[107]

In addition, clause 2.13.9 requires System Management to monitor Market Participants' compliance with requests made under clause 7.10.5[108] for explanation for deviating from its Resource Plans and Dispatch Instructions in a manner that threatens Power System Security or Power System Reliability; would require System management to issue instructions to the Registered Facilities covered by any Balancing Support Contract or Ancillary Service Contract; or would require System Management to issue Dispatch Instructions to Other Registered Facilities; and is outside the Tolerance Range determined in accordance with the Market Rules.[109]

As part of System Management's reporting obligations, clause 7.12.1 of the Market Rules[110] requires System Management to provide a report once every three months on

[103] IMO website, Power System Operation Procedure: Monitoring and Reporting Protocol, http://www.imowa.com.au/f3707,1384171/PPCL0019_Final_Amended_Procedure_Clean_.pdf

[104] After the commencement of the Balancing market, the Market Rules stipulate that a Market Participant must confirm receipt of the Dispatch Instruction or Operating Instruction and advise if it cannot comply or cannot fully comply with the Dispatch Instruction or Operating Instruction.

[105] Clause 7.10.1, 7.10.3, 7.10.6 and 7.10.6A of the Market Rules.

[106] After the commencement of the Balancing market, the Market Rules stipulate that a Market Participant must comply with the most recently issued Dispatch Instruction, Operating Instruction or Dispatch Order applicable to its Registered Facility for the Trading Interval.

[107] After the commencement of the Balancing market, clause 7.10.2 of the Market Rules provides that where a Market Participant becomes aware that it cannot comply or fully comply with a Dispatch Instruction or an Operating Instruction, it must inform System Management as soon as practicable.

[108] Clause 7.10.6 of the Market Rules.

[109] After the commencement of the Balancing market, clause 7.10.6 of the Market Rules requires that a Market Participant must comply with a request made under clause 7.10.5 by System Management for an explanation for deviating from its Resource Plan or Dispatch Instructions in a manner that is not within the Tolerance Range determined under the Market Rules.

[110] After the commencement of the new Balancing market, in addition to the items required to be reported under clause 7.12.1 of the Market Rules before the commencement of the Balancing market, the report must also include details of the incidence and extent of issuance of Operating Instructions; the incidence and extent of non-compliance with Operating Instructions; the incidence and reasons for the issuance of Dispatch Instructions to Balancing Facilities Out of Merit, including for the purposes of clause 7.12.1, issuing Dispatch Orders to the Verve Energy Balancing Portfolio in accordance with clause 7.6.2 of the Market Rules; and the incidence and reasons for the selection and use of LFAS Facilities under clause 7B.3.8 of the Market Rules. The report no longer requires inclusion of details on the incidence of any Equipment Test approved in accordance with clause 3.21AA of the Market Rules.

the performance of the market with respect to the dispatch process to the IMO.[111] This report must include details of:

- the incidence and extent of issuance of Dispatch Instructions;
- the incidence and extent of non-compliance with Dispatch Instructions;
- the incidence and extent of transmission constraints; and
- the incidence and extent of shortfalls in Ancillary Services, involuntary curtailment of load, High Risk Operating States and Emergency Operating States, together with:
  - a summary of the circumstances that caused each such incident; and
  - a summary of the actions that System Management took in response to the incident in each case.
- the incidence of any Equipment Test approved in accordance with clause 3.21AA of the Market Rules, including the date the Equipment Test occurred and the Facility details.

System Management has sufficiently fulfilled its monitoring and reporting requirements under the Market Rules. In particular, System Management has produced four status reports for the period from 22 June 2011 to 30 June 2012, on the performance of the market with respect to the dispatch process pursuant to clause 7.12.1 of the Market Rules.

As discussed above, each year since market commencement, System Management has elected to undergo an audit by the Market Auditor, pursuant to the Market Rules. A summary of the Market Auditor's 2012 annual reports on compliance by System Management is discussed in more detail in Section 4.1.3 of this report.

Compliance monitoring undertaken by the Authority

Pursuant to clause 2.16.9 of the Market Rules, the Authority, with the assistance of the IMO, must monitor whether prices offered by a Market Generator in its Portfolio Supply Curve reflect the Market Generator's reasonable expectation of the Short Run Marginal Cost (**SRMC**) of generating the relevant electricity. If a Market Generator with market power submits a Portfolio Supply Curve that does not reflect its reasonable expectation of SRMC for any given Trading Interval, and the Authority determines that to be the case, the Authority must request that the IMO refer the matter to the ERB for a civil penalty to be imposed on the relevant Market Participant.

The Authority and the IMO have utilised an SRMC modelling tool to assist in the monitoring of prices offered by a Market Generator in its Portfolio Supply Curve to assess whether these prices reflect the Market Generator's reasonable expectation of the SRMC of generating the relevant electricity. The Authority has issued information requests to Market Generators that it believes have market power, for the necessary data and information as inputs into the SRMC model. The IMO manages the operation of the SRMC model, which involves reviewing the modelled results in order to determine whether the prices submitted with Market Generators' Portfolio Supply Curves reflect the reasonable expectation of the SRMC of generating the relevant electricity. The Authority and the IMO regularly review these results in monitoring the compliance of Market Generators in the prices offered in their Portfolio Supply Curves. To date, the Authority has not determined that any Market Generator has breached this Market Rule.

[111] See the IMO website, http://www.imowa.com.au/system_management_reports

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.

For the preparation of this report, the Authority published a Discussion paper and sought feedback from stakeholders on the effectiveness of the IMO and System Management in carrying out their respective functions. The Authority has noted the views expressed by stakeholders in their submissions in response to the Authority's Discussion Paper. The Authority has also noted the matters raised in the recent audit reports into the IMO's and System Management's compliance with the Market Rules.[112] Overall, the Authority considers that both the IMO and System Management continue to effectively carry out their respective functions required under the Regulations, Market Rules and Market Procedures. However, there are a number of areas that the Authority considers continuous improvements can be made.

4.1.3.1 The Independent Market Operator

Clause 2.1.2 of the Market Rules (as of 30 June 2012) provides that the functions of the IMO are:

- to administer the Market Rules;
- to operate the Reserve Capacity Mechanism, the STEM, the LFAS Market, and the Balancing Market;
- to settle such transactions as it is required to under the Market Rules;
- to carry out a Long Term PASA study and to publish the Statement of Opportunities Report;
- to process applications for participation, and for the registration, deregistration and transfer of facilities;
- to release information required to be released by the Market Rules;
- to publish information required to be published by the Market Rules;
- to develop amendments to the Market Rules and replacements for them;
- to develop Market Procedures, and amendments and replacements for them, where required by the Market Rules;
- to make available copies of the Market Rules and Market Procedures, as are in force at the relevant time;
- to monitor other Rule Participants' compliance with the Market Rules, to investigate potential breaches of the Market Rules, and if thought appropriate, initiate enforcement action under the Regulations and the Market Rules;
- to support the Authority in its market surveillance role, including providing any market related information required by the Authority;
- to support the Authority in its role of monitoring market effectiveness, including providing any market related information required by the Authority; and

[112] The IMO has appointed PA Consulting to be the Market Auditor each year since 2007. PA Consulting's audit reports are available on the IMO's website: http://www.imowa.com.au/market_compliance_audit

- to carry out any other functions conferred, and perform any obligations imposed, on it under the Market Rules.

In submissions to the Authority's Discussion Paper, stakeholders commented on the performance of the IMO in particular contexts.

Regarding the introduction of the LFAS market, Synergy and Perth Energy, responding to the significant cost increase, suggested that the LFAS market could have been delayed until an IPP was able to participate. Perth Energy considered the inconsistency in key operational decision making between System Management and the IMO contributed greatly to the cost increase and noted particularly the technical issues resulting from the lack of progress in developing System Management's systems to facilitate IPPs participation in the LFAS market.

In relation to market governance, Perth Energy notes it would support more transparency of the IMO and the IMO Board's decision making process with respect to changes to the Market Rules. Perth Energy suggests that a WEM Rule Committee should be set up by the Minister to oversee and gate-keep any proposed Rule changes submitted by the IMO.

Sustainable Energy Association (**SEA**) considers that the IMO is doing a good job in its role as the market operator and suggests that the public consultation processes before a decision is made is as valuable to extending view points beyond those just in the working groups.

Community Electricity shares SEA's view in relation to the IMO's performance, stating that the design and implementation of the Balancing Market was its headline achievement. Community Electricity also considers that the IMO has made good progress in "reforming" the RCM, with particular emphasis on making the RCP more responsive to market conditions, harmonising DSM with Scheduled Generation, and changing the Capacity Refund Mechanism to incentivise good performance and penalise poor performance, according to system conditions.

Clause 2.14.3 of the Market Rules sets out the requirements for the audit of the IMO, 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.

The IMO commissioned the 2012 market audit for the period from 13 August 2011 to 10 August 2012. This audit was undertaken by PA Consulting which was completed in October 2012. In its report on 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 concluded that the IMO has generally complied with its obligations under the Market Rules.[113] PA Consulting noted 20 incidents of non-compliance of which seven were classified as material.[114]

[113] http://www.imowa.com.au/f189,1613045/Audit_1.pdf.

[114] PA Consulting considered an item to be material if it could affect decisions made by Market Participants, affect the outcome of the market or affect the financial position of one or more Rule Participants.

The majority of the material incidents of non-compliance that arose during the period related to the treatment of a small number of participants in the calculation of some refunds and prices. Three of the material incidents related to the compliance of IMO's procedures with Chapter 4 of the Market Rules (specifically clause 4.26 "Financial Implications of Failure to Satisfy Reserve Capacity Obligations"). Whilst PA Consulting stated that additional changes needed to be made in order for the IMO to be compliant under Chapter 4 of the Market Rules, it did note that actions have been taken to remedy these breaches. Three of the remaining material incidents were deemed by PA Consulting to be a one-off occurrence. This included a compliance issue relating to the calculation of the Marginal Cost Administered Price (**MCAP**) which was found to be excluding some participants due to an erroneously imposed limit of 50 participants in the system. As a result, Balancing and commissioning prices were found to be higher than would otherwise be the case for 94 Trading Intervals between April and October 2011. Whilst the last remaining material incident was a residual item that was still being investigated at the time of preparation of the audit report, it has been subsequently resolved with the introduction of a new Market Rule.

PA Consulting was satisfied that all non-compliances were responded to by the IMO in a way that made their repetition unlikely. PA Consulting also commented that there was a marked improvement in the quality of the IMO's internal procedures.

In its report on 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 processes for software management comply with the Market Rules.[115]

Whilst the Authority is generally satisfied with the IMO's performance in carrying out its functions prescribed in the Market Rules, the Authority considers that the IMO should take on board the feedback from the stakeholders and take effective actions to address the areas of non-compliances identified in the market audit reports, in particularly the prevention of potential incidents in the future.

4.1.3.2 System Management

Clause 2.2.1 of the Market Rules provides that System Management has the function of operating the SWIS in a secure and reliable manner. The other functions of System Management in relation to the WEM are:

- to procure adequate Ancillary Services, where Verve Energy cannot meet the Ancillary Service Requirements;
- to assist the IMO in the processing of applications for participation and for the registration, de-registration and transfer of facilities;
- to develop Market Procedures, and amendments and replacements for them, where required by the Market Rules;
- to release information required to be released by the Market Rules;
- to monitor Rule Participants' compliance with Market Rules relating to dispatch and Power System Security and Power System Reliability; and
- to carry out any other functions or responsibilities conferred, and perform any obligations imposed, on it under the Market Rules.

[115] See http://www.imowa.com.au/f189,1613058/Audit_2.pdf

Clause 2.14.6 of the Market Rules 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.*

As noted previously, the IMO commissioned PA Consulting to undertake the 2012 market audit covering the period from 13 August 2011 to 10 August 2012. In its assessment of System Management's compliance with the Market Rules and Market Procedures, PA Consulting found that, with some exceptions, System Management has complied with its obligations under the Market Rules. In its audit report for System Management,[116] PA Consulting noted 28 breaches of the Market Rules, of which ten were considered material. Two of the material breaches were carried over from the previous year and System Management was still progressing to resolve them. However, PA Consulting was satisfied that the material breaches were either responded to in a way that made their repetition unlikely or would be addressed through the scheduled introduction of new systems in the year.

Although the number of beaches identified for the audit period appeared high, PA Consulting considered was not surprising and attributed them to:

- the introduction of the new competitive Balancing and LFAS markets; and
- better monitoring of its own compliance operation, resulting in more cases being logged.

The Authority has noted one of the material incidents of non-compliance identified in the 2012 audit report for System Management that is in relation to incorrect SCADA data were provided by System Management to the IMO for the calculation of the Marginal Cost Administered Price (**MCAP**) for Balancing settlements for the period from 29 December 2011 to 14 February 2012. The incorrect data provision was initially identified by the Authority in its monitoring role of market outcomes. The incorrect data directly affected the calculation of the MCAP, with variations of more than $200/MWh for some Trading Intervals. The Market Rules do not allow ex-post corrections of market prices after they are published. This issue therefore had material impact on the market.

Another material incidence of non-compliance identified in the 2012 audit report for System Management was in relation to the exclusion of Intermittent Generation, newly commissioned generators and Curtailable Load in the calculation of the reserve margin in its preparation of the Medium Term Projected Assessment of System Adequacy (**MT PASA**). This was an issue identified in the previous audit report which has a material impact on outage planning and the amount of outages allowed. Whilst System Management made some progress to address the issue since the previous audit (i.e. by the inclusion of an estimate of the likely available Intermittent Generation), the issue had not been fully addressed by System Management at the time of the audit.

[116] See http://www.imowa.com.au/f189,1613071/Audit_3.pdf

In its response to the Authority Discussion Paper for the preparation of this report, Perth Energy's submission suggests that System Management has to ensure that it is focused on helping the market to function properly and not hinder market developments that the Market Participants deem as good, efficient and yielding good commercial outcomes. EnerNOC and Community Electricity are satisfied with System Management's performance.

The Authority is generally satisfied with System Management's performance in carrying out its functions prescribed in the Market Rules. However, the Authority is concerned about the number of breaches identified in the 2012 audit report on System Management's compliance with the Market Rules and Market Procedures which could result in a loss of confidence in the market and inefficient market outcomes. The Authority will continue to monitor System Management's performance in implementing its new systems for the new Balancing and LFAS markets.

4.2 The Reserve Capacity Mechanism

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 Mechanism (**RCM**).

The RCM has been in operation since 2005. The primary objective of the RCM is to ensure that there is sufficient generation and DSM capacity to meet system reliability and adequacy requirements.

The Authority notes that there has been sufficient capacity secured under the RCM to meet forecast capacity requirements, with the number of Capacity Credits[117] assigned to participants exceeding the Reserve Capacity Requirement (**RCR**) in each of the Capacity Years since its inception. There are other positive market outcomes that have flowed, at least in part, from the RCM:

- a significant increase in the Capacity Credits assigned to new entrants, where the share of capacity provided by IPPs has grown from approximately 12 per cent in 2005/06 to approximately 48 per cent in 2014/15; and
- there have been no reported instances of curtailment of electricity supply due to capacity shortages since market commencement.[118]

However, the Authority has noted the rapid increase in the amount of Capacity Credits allocated to peaking capacity (mostly DSM and diesel generation capacity) over recent Reserve Capacity Cycles[119] and the associated costs for procuring these Capacity Credits. The Authority has also noted the existence of substantial excess capacity in the

[117] The RCM is built around the concept of a Capacity Credit, which is a notional unit of one mega watt (MW) of Certified Reserve Capacity provided by a generator or DSM provider. Capacity Credits have value and can be traded either bilaterally between Market Participants or with the IMO. In return for receiving Capacity Credits, generators are required to offer their capacity into the market at all times (unless undergoing scheduled maintenance on a Planned Outage).

[118] 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.

[119] Clause 4.1 of the Market Rules defines the Reserve Capacity Cycle and the events comprising a single Reserve Capacity Cycle. A Reserve Capacity Cycle covers a period of four years. Year 1 of a Reserve Capacity Cycle is the calendar year in which the Reserve Capacity Auction is scheduled to be held and Capacity Credits are allocated to capacity providers for the Capacity Year two years in advance. The Reserve Capacity Cycle is repeated for each Capacity Year.

market, i.e. capacity procured by the IMO in excess of the RCR. The Authority is concerned that if such a trend continues, the efficiency of the market could be adversely affected. The market could move away from the optimal capacity mix that minimises the long-term cost of electricity supplied to consumers. These matters are discussed in more detail in Section 2 of this report.

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.

Bilateral Contracts are confidential to the contracting parties. The market is informed through informal and individually formed market intelligence. The formal information will be received by the IMO at the time for settlement by way of STEM submissions for energy and Capacity Credit Allocation submissions for Reserve Capacity. In both cases only the quantities are provided to the IMO. Other terms in the contracts such as price, length of the contracts and other conditions will be known only to the contracting parties. In contrast, a market could be organised to allow greater transparency albeit around more standardised contract terms.

Bilateral Contracts in capacity and energy, separately or combined, play an important role in supporting new investments. This tends to happen for the larger investments requiring outside financing, giving the financiers greater cash flow certainties. The challenge is the lack of depth in the Bilateral Contract market in the WEM, given the concentrated market structure. This is particularly the case when the credit worthiness of the counter party is important to the financiers.

This lack of depth in the Bilateral Contract market may have contributed to the composition of new capacity coming into the market in recent Reserve Capacity Cycles. Smaller capacity additions are relatively easier to bring about than larger capacity additions which require larger borrowings and the support of a bilateral contract for risk mitigation purposes.

As noted in its previous Reports to the Minister, the Authority has an interest in ensuring that the Bilateral Contract market is working effectively, particularly in terms of facilitating new entry in the generation sector and the retail sector. The Authority will continue monitoring this 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.

The STEM is a day-ahead market where a Market Participant can trade energy around its bilateral position. 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 Authority has also noted the active trading activities in the STEM and the upward trend in the quantity traded since market commencement. Section 5.2.1 provides more detailed discussion on the STEM outcomes since market commencement, including STEM Clearing Prices, trade quantities, and Bids and Offers.

However, the STEM has certain limitations. Firstly, the time for gate-closure of STEM Submissions is up to 44 hours in advance and no re-bidding into the STEM is allowed. This arrangement can be too restrictive considering the dynamic nature of changes in electricity supply and demand conditions. Secondly, the STEM Clearing Prices may not reflect the system marginal price in that the STEM does not capture the total forecast system supply as certain generation capacity is not accounted for in the STEM. This is because Intermittent Generator participation in the STEM is optional. Their absence effectively under-states supply and thus could result in higher clearing prices. While forecasting wind generation will be a challenge, particularly with the up to 44 hours STEM cycle, the impact may become more significant as more wind generation capacity is being added to the system.

Despite its limitations, the Authority considers the STEM continues to provide a useful platform for bilaterally contracted parties to adjust their positions closer to real time. The Authority notes that the STEM is currently the only mechanism available for Market Customers to adjust their bilateral positions through a market, rather than through bilateral contract negotiations and re-negotiations. The new Balancing market that commenced on 1 July 2012 only allows Market Generators to adjust their pre-committed positions.

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.

Energy Balancing refers to the process for meeting supply and consumption deviations from contracted bilateral and STEM positions in each Trading Interval. At the commencement of the WEM, Verve Energy was assigned the role as the default provider of the Balancing service. Under this arrangement, there was only limited opportunity for IPPs to provide Balancing. The IPPs would only be called upon by System Management to provide Balancing energy when Verve Energy's capacity to provide the service was stressed. At such times, the IPPs would be issued Dispatch Instructions by System Management to increase or decrease generation output from their pre-committed positions and these deviations were settled on a 'pay-as-bid' price basis.[120]

The operation of the Balancing mechanism required that Verve Energy, as the default balancer, maintained a large enough generation portfolio to be efficient, without involving the IPP facilities. While this mechanism provided a simplified market design, it also introduced various constraints to the market in achieving more efficient operational outcomes. IPPs were locked into their Resource Plans one day in advance. There were no opportunities for making changes even when plant conditions assumed at the time of making STEM Submissions were no longer true. This had significant commercial implications for the IPPs.

[120] 'pay-as-bid' prices are specified in the Standing Data submitted by IPPs to the IMO.

Despite the constraints in the Balancing mechanism, the Authority considers that the mechanism has fulfilled its role in facilitating the appropriate function of the WEM in the early stages of market development. A detailed discussion on Balancing outcomes since market commencement until 30 June 2012, including trade quantities and prices, is provided in Section 5.2.2.

The competitive Balancing market introduced in July 2012 addresses these limitations. Under the new regime, most generation facilities connected on the system are required to register as Balancing Facilities and are obliged to make Balancing Submissions, whereby changes can be made two hours prior to the Trading Interval commencing. The new market is also expected to provide greater transparency, which may encourage Market Generators to be more vigilant in assessing their circumstances. The Authority will provide an analysis on the effectiveness of the new Balancing market in its next Report to the Minister, due in 2013/14, when more operational data becomes available.

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.

Chapter 7 of the Market Rules defines the dispatch process in the WEM. For the Reporting Period to 30 June 2012, the WEM operates under a 'hybrid' design in terms of dispatch. Under this design, IPPs commit and dispatch their facilities to meet their respective Resource Plans, i.e. 'net dispatch,' whilst Verve Energy generation portfolio is dispatched to meet residual requirements in the market under the 'gross dispatch' regime. IPPs will be penalised through the application of UDAP and DDAP for deviations from their Resource Plans except when the facilities are dispatched by System Management for system security reasons. System Management manages overall system security, scheduling and dispatching Verve Energy's facilities and resorting to IPPs' facilities by issuing Dispatch Instructions, only when Verve Energy's balancing capability is stretched.

The Authority considers the dispatch process operated by System Management has been effective in meeting the system security objective. However, the 'hybrid' dispatch approach in the original market design may not necessarily deliver the minimum cost dispatch and hence, may impact on the efficiency of the market.

The Authority has noted the incidences of non-compliance associated with System Management's obligations under Chapter 7 of the Market Rules identified in the 2012 audit report prepared by PA Consulting. Some of the incidences have resulted in material impact on the market. The Authority considers these issues must be addressed by System Management to ensure the efficient operation of the market and to provide continued confidence to Market Participants.

The Authority notes that the new competitive Balancing market that commenced from 1 July 2012 has brought along a fundamental change to the dispatch regime in the WEM. Given the short time period this market has been in place, the Authority is not in a position to assess its effectiveness and intends to provide its assessment in the next Report to the Minister.[121]

[121] The Authority notes that the application of UDAP and DDAP was redundant as part of the implementation of the new Balancing market from 1 July 2012.

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 planning processes envisaged in the Market Rules are carried out in three levels of planning:

- long term planning, which is conducted annually;
- medium term planning, which is undertaken each month; and
- short term planning, which is carried out each week.

Each of the above planning processes involves a forecasting study, also known as the Projected Assessment of System Adequacy (**PASA**).

Under the Market Rules, the Long Term PASA is undertaken by the IMO in order to determine the Reserve Capacity Target for each year in the ten-year period of the Long Term PASA Study Horizon. The results are presented in the IMO's Statement of Opportunities report, which is published on the IMO's website each year.[122]

System Management is required to undertake the Short Term PASA and the Medium Term PASA.[123]

Under clause 3.17 of the Market Rules, the Short Term PASA study must consider each six-hour period of a three week planning horizon (**the Short Term PASA Planning Horizon**). System Management must carry out a Short Term PASA study every Thursday and provides the results to the IMO for publication on the Market website.

The Short Term PASA assists System Management in assessing:

- the availability of capacity holding Capacity Credits in each six-hour period during the Short Term PASA Planning Horizon;
- the setting of Ancillary Service Requirements in each six-hour period during the Short Term PASA Planning Horizon; and
- final approvals of Planned Outages.

System Management must carry out a Medium Term PASA study by the 15th day of each month and provide it to the IMO for publication on the Market website. Under clause 3.16 of the Market Rules, this study must consider each week of a three year planning horizon.

The Medium Term PASA study provides assistance to System Management with respect to:

- setting ancillary Service Requirements over the year;

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[122] 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.

[123] 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.

- outage planning for Registered Facilities; and
- assessing the availability of Facilities providing Capacity Credits.

Overall, the Authority considers that the Short, Medium and Long Term PASA studies are operating as intended.

Long Term PASA

In relation to the Long Term PASA, the Authority is aware of concerns raised by Market Participants with respect to the accuracy of the demand forecasts that underpin the setting of the Reserve Capacity Target. Since the commencement of the WEM, forecasts have been prepared for the IMO by the National Institute of Economic and Industry Research (**NIEIR**).

The IMO appointed ACIL Tasman to undertake a review of the SWIS demand forecasting processes, which analysed the performance of the demand forecasts published by the IMO and made recommendations in relation to the forecasting process. In its final report,[124] ACIL Tasman has identified a number of areas where additional analysis and amendments to the current methodology could lead to a more robust and improved methodology. These are:

- NIEIR's models tend to under-predict Western Australian Gross State Product (**GSP**) and population growth. Improvements to the methodology should be identified to remove this downward bias.
- NIEIR should adopt the use of simulation based weather normalisation methods as the basis for the maximum demand forecasts as soon as it is suitable to do so.
- NIEIR and the IMO should consider producing electricity consumption forecasts conditional on different weather scenarios in a way that is similar to the approach taken for system maximum demand.
- NIEIR and the IMO should conduct further analysis of the energy output of solar PV systems in the SWIS, in light of the differences between NIEIR's forecasts and alternative sources.
- NIEIR and the IMO should undertake a detailed ex-post evaluation of forecast performance with a focus on:
    - o Errors in the forecast model inputs such as GSP and population growth.
    - o Structural issues within the models, which may lead to less accurate forecasts.
    - o Identifying factors that the models may be failing to capture, such as new behavioural or technological trends and policy changes.
- The ex-post forecast evaluation should be conducted annually and that it be required under the Market Rules.
- NIEIR should recalibrate its models every year using the latest available information.

[124] See the IMO website, http://www.imowa.com.au/f184,3029362/Forecast_review_of_the_SWIS-_Final_report.pdf

- A process of data quality assurance should be implemented to ensure that any data used in the forecasting process is free from errors, reliable, complete and timely.

- The Market Procedures should be altered to require the timely acquisition of data requested from other organisations to facilitate the generation of the forecasts.

- NIEIR should take additional steps to improve the transparency of its processes, both of its models calculations between the input assumptions and the generated outputs and any judgements made during the forecasting processes and the underlying rationale behind them.

- The IMO should adopt a more critical stance in evaluating new block loads by:

  - Applying probability weights to its block load forecasts.

  - Heavily discounting or excluding altogether those loads that are expected to come online after three years or more.

  - Giving careful consideration to the degree of uncertainty associated with new mining loads and that these be reflected in the probability weights.

  - Making some adjustments for the level of coincidence at the time of the system peak and an appropriate coincidence factor be applied to the forecasts block loads.

- The IMO should put its contract to provide energy consumption and maximum demand forecasts out to competitive tender on a regular basis, at least every three years.

Following ACIL Tasman and various submitting parties' recommended amendments to the Market Rules and Market Procedure, the IMO is currently preparing a Rule Change Proposal to amend the Market Rules and Market Procedure as follows:

- The Market Rules be amended to require that the SOO contains the results of the ex-post evaluation of forecasts;

- The Market Rules be amended to reconcile its forecasts with those produced by Western Power; and

- The Market Procedure be amended to commence at the same time as any Amending Rules. These amendments will include requirements on Rule Participants for the timely provision of data to facilitate the generation of the forecasts.

Medium Term PASA

The Authority notes the audit report prepared by PA Consulting (who were engaged by the IMO to conduct the 2012 Annual Compliance Audit) has identified a non compliance issue by System Management, whereby capacity from Intermittent Generation, newly commissioned generators and DSM was excluded in determining available capacity to meet projected load in the preparation of the Medium Term PASA.[125] System

[125] See http://www.imowa.com.au/market_compliance_audit

Management has responded to the PA Consulting audit report[126] Such that Intermittent Generation capacity is now included, and by July 2013 System Management is expecting to also include newly commissioned generator capacity and DSM capacity.

Short Term PASA

The Authority considers the Short Term PASA provides useful information for Market Participants to refine their operational plans based on the information presented in the Short Term PASA. The Authority notes that the implementation of the new competitive Balancing market provides Market Participants with more dynamic, close to real time, information that compliments the weekly Short Term PASA.

Outage Planning

Pursuant to clause 3.18.18 of the Market Rules, at least once in every five years, the IMO, with the assistance of System Management, must conduct a review of the outage planning process against the Market Objectives. The IMO engaged PA Consulting to undertake this review. The final report prepared by PA Consulting was published on the IMO's website on 10 October 2011.[127] In its report, PA Consulting concluded that the outage planning process is generally functioning well and that wholesale changes are not required. However, PA Consulting considered some fine-tuning would be required to address issues identified in four main areas. These included:

1. the reserve margin criteria for evaluating outage plans and approving outages in the short-term;
2. the interaction between generation and transmission outage planning;
3. outage approval timelines and constraints; and
4. information disclosure, given that the Market Rules and the PSOP are silent on System Management's obligations with respect to information disclosure.

In relation to information disclosure, PA Consulting recommended that the IMO, in conjunction with System Management, develop changes to the Market Rules and Market Procedures to establish System Management's obligations for disclosure of information on Planned Outages. Following this recommendation, the IMO developed a Rule Change Proposal (RC_2012_11): Transparency of Outage Information and submitted it into the Standard Rule Change Process, on 30 July 2012. In its Rule Change Proposal, the IMO noted that System Management had already disclosed certain information about Planned Outages, even in the absence of any requirement in the Market Rules or the PSOP in some circumstances.

However, the IMO recognised that, at times, a lack of transparency may have resulted in sub-optimal outcomes for Market Participants and energy consumers. The IMO intended to introduce new standards for the disclosure of information relating to outages, aimed at improving transparency in the market. The IMO considered advancements to the level of information disclosure will result in improved economic efficiency in electricity generation (Wholesale Market Objective (a)) and improved efficiency in price outcomes for consumers (Wholesale Market Objective (d)). To date, this Rule Change Proposal has been through two rounds of consultation. The initial date for the IMO to publish its Final Rule Change Report was 22 March 2013. On 21 March 2013, the IMO issued an

[126] Refer to page 23 in PA Consulting Group report for the IMO on Compliance of System Management with the Market Rules and Market Procedure (16 October 2012)

[127] See http://www.imowa.com.au/5yearoutageplanningreview

extension notice and extended the publication date to 16 April 2013. The IMO's Final Rule Change report is now available on its website.[128]

[128] See http://www.imowa.com.au/f6099,3899555/RC_2012_11_Final_Rule_Change_Report_FINAL.pdf

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 specifies the IMO's responsibility for collecting and compiling the data identified in the Market Surveillance Data Catalogue (**MSDC**), analysing the compiled data, and providing both the data and analysis to the Authority.[129]

The required summary of the MSDC data and analysis for the period from 1 August 2011 to 30 June 2012 (**Reporting Period**) is set out in this section and Appendix 3 of this report.[130]

To support the discussion of the MSDC data and analysis for the Reporting Period, where relevant, the Authority has:

- drawn on MSDC data and analysis from previous periods to show trends that have taken place since market commencement on 21 September 2006;
- drawn on other market data that is not included as part of the MSDC data and analysis;[131] and
- reported on a Capacity Year basis which covers a period of 12 months, commencing on 1 October (8 AM) and ending on 1 October (8 AM) of the following calendar year, when reporting on aspects of the Reserve Capacity Mechanism.

5.1 Reserve Capacity Mechanism

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.[132]

Under clause 4.15.1 of the Market Rules, the IMO may cancel the Reserve Capacity Auction if no Certified Reserve Capacity is made available for auction and the IMO considers that the Reserve Capacity Requirement (**RCR**) will be met without an auction. As there has been sufficient capacity to meet the RCR in each Reserve Capacity Cycle so far, the IMO has not called the Reserve Capacity Auction.

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[129] 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.

[130] This Reporting Period is different from the 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. This Reporting Period covers the MSDC data and analysis items from 1 August to the following 30 June, excludes July 2012, due to the commencement of the Competitive New Balancing Market from 1 July 2012.

[131] In such cases, this is pointed out in the relevant discussion in support of the summary of such other market data.

[132] 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 held to date, no auction offers can be reported.

5.1.3 Prices in each Reserve Capacity Auction

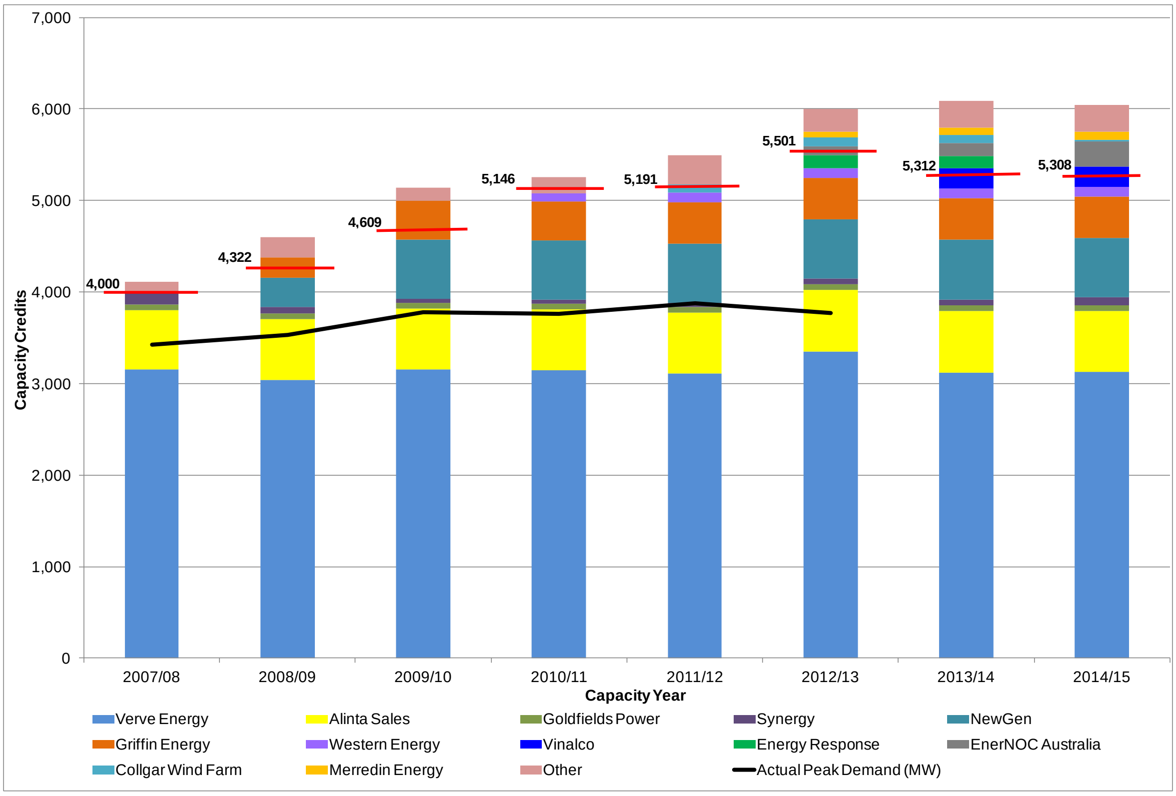
Clause 2.16.2(c) of the Market Rules requires that the MSDC identify clearing prices in each Reserve Capacity Auction. To date, there has been no requirement for the IMO to run a Reserve Capacity Auction. Hence, no price outcomes can be reported.

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 4 shows the Capacity Credits assigned to Market Participants for the 2007/08 to the 2014/15 Capacity Years, as well as the RCR for that year (shown as the red horizontal line for each Capacity Year) and the actual demand measured based on maximum Operational System Load Estimate (shown as the black line). Over this period the RCR has grown at an average of 4.2 per cent per Capacity Year.

Figure 4 Capacity Credits assigned to Market Participants for the 2007/08 to 2014/15 Capacity Years



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

It is clear from Figure 4 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 2.2 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 of 8.3 per cent over the eight Capacity Years from 2007/08 to 2014/15.

For the 2014/15 Capacity Year, 6,040 MW Capacity Credits have been assigned to participants for a RCR of 5,308 MW. This indicates excess capacity of 732 MW (approximately 14 per cent). The Authority has noted the amount of Capacity Credits allocated to Collgar Wind Farm in the 2014/15 Capacity Year of 20 MW represents a significant reduction to the amount it was allocated in the 2013/14 Capacity Year of 90 MW.[133] This reduction is due to the implementation of the revised methodology for calculating reserve capacity values for intermittent generation as a result of Rule Change RC_2010_25.[134]

Table 15 in Appendix 3 provides a list of Market Generators and Market Customers registered at 2 September 2008, 6 October 2009, 14 October 2010, 3 October 2011 and 10 December 2012. There has been an increased participation in the market from independent power producers (**IPPs**). The number of IPPs registered in the market has increased from nine in 2006 to 44 in 2014/15. By the 2014/15 Capacity Year, Verve Energy is expected to provide approximately 52 per cent of the total certified capacity in the SWIS, compared to 90 per cent when the WEM commenced.

5.1.5 Maximum Reserve Capacity Price and Reserve Capacity Price

Although not required under the Market Rules, this section provides data on the Maximum Reserve Capacity Price (**MRCP**) and the Reserve Capacity Price (**RCP**).

The MRCP is the price cap that is set administratively for capacity offers into the Reserve Capacity Auction. Under the Market Rules, the IMO is required to develop a Market Procedure documenting the methodology and processes for determining the MRCP and publish the MRCP for each Reserve Capacity Cycle after it has received approval from the Authority on its proposed MRCP value.

The RCP is the price for settlement of payments to capacity procured by the IMO. If the Reserve Capacity Auction was run for the Reserve Capacity Cycle, the RCP would be set by the clearing price of the auction. Without an auction, the RCP is set administratively, in accordance with the formula specified under clause 4.29.1 of the Market Rules.[135] Since there has been no Reserve Capacity Auction held by the IMO to date, the RCP has been a calculated value, based on the RCP formula for each Reserve Capacity Cycle.

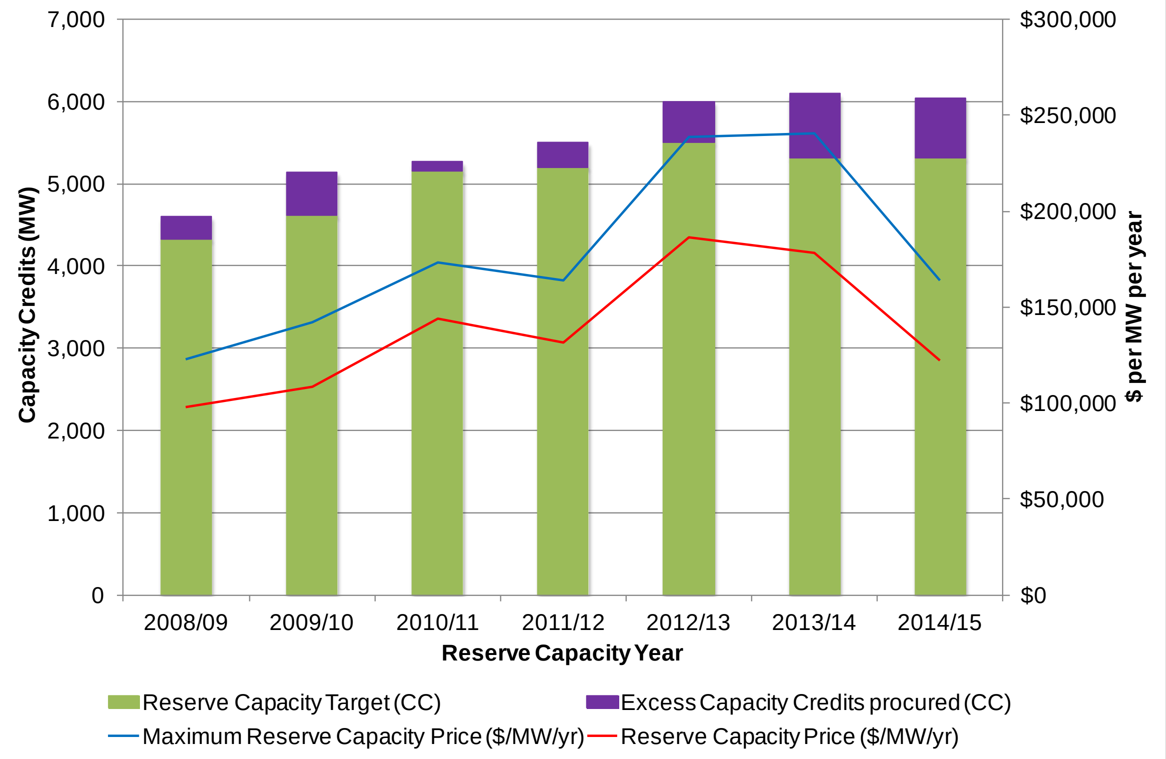
Figure 5 shows the MRCP, RCP, Reserve Capacity Target and excess Capacity Credits (i.e., in excess of the Reserve Capacity Requirement) procured for each Capacity Year from 2008/09 to 2014/15.

[133] See IMO website, Capacity Credits by Facility - market start to 2014/15, http://www.imowa.com.au/f180,2624820/Summary_of_Capacity_Credits_assigned_by_Facility_for_the_2012_Reserve_Capacity_Cycle.pdf

[134] http://www.imowa.com.au/RC_2010_25

[135] 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.

Figure 5 The Reserve Capacity Target, excess Capacity Credits, Maximum Reserve Capacity Price and Reserve Capacity Price from the 2008/09 Capacity Year to the 2014/15 Capacity Year



As can be seen from Figure 5, the MRCP has fluctuated noticeably over the period from the 2008/09 Capacity Year to the 2014/15 Capacity 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.[136] 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, resulting in a similar MRCP value for the 2013/14 Capacity Year.

The MRCP value for the 2014/15 Capacity Year reduced by approximately one third in comparison to the 2013/14 Capacity Year, i.e. from $240,600 per MW per year for the 2013/14 Capacity Year to $163,900 per MW per year for the 2014/15 Reserve Capacity year. This reduction is mainly attributable to changes in the calculation methodology as a result of the revised MRCP Market Procedure, which came into effect in October 2011.[137]

The RCP followed similar patterns to the MRCP over the same period. This is because the RCP has been determined with reference to the MRCP, based on the formula defined in the Market Rules (i.e. because no capacity auction has ever been held since market commencement). The issues surrounding the RCP are discussed in detail in Chapter 2 of this report.

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[136] 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

[137] 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

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 6 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, for four periods, i.e. the 2008/09 through 2011/12 Capacity Years.

Generally, the Forced Outage rate for generation plant has been low. For most plant it has been well below two per cent. Some plants had notable Forced Outage rates during the Reporting Period, e.g. Alcoa Wagerup (4.1 per cent), Griffin Bluewaters 1 (5.8 per cent), and Verve Energy's Collie G1 (3.6 per cent) and Muja G6 (4.1 per cent). The overall fleet Forced Outage rate dropped to 0.8 per cent in comparison to 1.0 per cent in the previous Reporting Period.

Planned Outage rates are variable, reflecting the different stages of generation plant in their maintenance cycles. In the 2010/11 Reporting Period, the Authority highlighted a number of Verve Energy's facilities having extremely high Planned Outage rates (i.e. between 40 per cent and 55 per cent). The Planned Outage rates for those facilities were comparatively lower during the current Reporting Period, but were still notably high (refer to Table 6 below). Verve Energy's Kwinana G5 reduced to 23.0 per cent (53.6 per cent in 2010/11); Kwinana G6 to 25.9 per cent (49.6 per cent in 2010/11); Pinjar GT 11 to 19.9 per cent (49.3 per cent in 2010/11) and Muja G7 to 5.5 per cent (42.9 per cent in 2010/11). The Authority has also noted a significant increase in the Planned Outage rates of Muja G6 (40.3 per cent) and Pinjar GT10 (27.9 per cent) during the current Reporting Period.

Amongst IPPs, relatively high Planned Outage rates were observed for NewGen Kwinana (15.5 per cent), Griffin Bluewaters 1 (14.2 per cent) and Alcoa's Wagerup facility (29.5 per cent) during the current Reporting Period.

Table 6 Ratio of quantities subject to outages to maximum generating capacity for the 2008/09 to the 2011/12 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	Max Gen (MW) 2011/12 Cap Year	Forced 2011/12 Cap Year	Planned 2011/12 Cap Year
Alcoa	ALCOA_WGP	25.0	2.1%	5.9%	25.0	2.4%	4.6%	25.0	5.1%	10.3%	25.0	4.1%	29.5%
Alinta	ALINTA_PNJ_U1	145.0	1.1%	4.5%	145.0	0.1%	3.6%	145.0	0.2%	14.0%	145.0	0.1%	4.3%
Alinta	ALINTA_PNJ_U2	145.0	0.2%	5.6%	145.0	0.0%	6.3%	145.0	0.1%	7.0%	145.0	0.2%	11.6%
Alinta	ALINTA_WGP_AGG							380.0	0.0%	0.8%			
Alinta	ALINTA_WGP_GT	190.0	5.6%	2.1%	190.0	1.1%	0.6%	190.0	1.3%	1.8%	190.0	0.0%	2.1%
Alinta	ALINTA_WGP_U2	190.0	0.0%	1.4%	190.0	1.0%	1.2%	190.0	0.0%	2.9%	190.0	0.4%	1.7%
Alinta	ALINTA_WWF										89.1	0.0%	
EDWF Manager	EDWFMAN_WF1	80.0	0.0%	0.0%	80.0	0.0%	0.1%	80.0	0.0%	0.0%	80.0		0.0%
Goldfields Power	PRK_AG	68.0	0.7%	1.6%	68.0	0.0%	1.5%	68.0	1.4%	6.1%	68.0		0.5%
Griffin Power	BW1_BLUEWATERS_G2	208.0	39.3%	8.6%	217.0	1.7%	9.2%	217.0	1.2%	10.1%	217.0	5.8%	14.2%
Griffin Power 2	BW2_BLUEWATERS_G1				217.0	4.2%	2.4%	217.0	2.4%	8.7%	217.0	1.6%	4.5%
COLLGAR	INVESTEC_COLLGAR_WF1										200.0	0.1%	
Landfill Gas & Power	CANNING_MELVILLE	3.0	0.0%	0.0%	3.0	0.0%	0.0%	3.0	0.0%	0.0%	1.2		
Landfill Gas & Power	RED_HILL	3.3	0.6%	0.0%	3.3	0.0%	0.0%	3.3	0.0%	0.0%	4.0		
Landfill Gas & Power	TAMALA_PARK	4.5	0.8%	0.0%	4.5	0.1%	0.0%	4.5	0.0%	0.0%	5.0		
NewGen Neerabup	NEWGEN_NEERABUP_GT1				342.0	0.1%	3.3%	342.0	0.0%	6.0%	342.0	0.1%	2.7%
NewGen Kwinana	NEWGEN_KWINANA_CCG1	324.0	1.2%	26.9%	324.0	0.7%	3.2%	324.0	0.9%	2.3%	324.0	0.2%	15.5%
Perth Energy	PENERGY_KWINANA_GT1							116.0	0.1%	0.2%	116.0	1.9%	3.2%
Southern Cross	STHRNCRS_EG	23.0	10.4%	2.6%	23.0	0.7%	1.4%	23.0	0.0%	0.0%	23.0	0.7%	1.4%
TESLA	TESLA_GERALDTON_G1										9.9		0.5%
TESLA	TESLA_PICTON_G1										9.9	0.3%	3.6%
Tiwest	TIWEST_COG1	37.7	0.0%	3.0%	37.7	0.0%	4.6%	37.7	1.2%	3.1%	36.0	0.1%	3.7%
Verve Energy	ALBANY_WF1	21.6	0.0%	0.1%	21.6	0.0%	0.0%	21.6	0.0%	0.2%	21.6		0.0%
Verve Energy	COCKBURN_CCG1	236.6	0.2%	10.7%	236.6	0.0%	5.3%	236.6	0.0%	17.5%	236.6	1.0%	4.8%
Verve Energy	COLLIE_G1	315.0	0.8%	12.8%	318.0	0.3%	9.1%	318.0	0.6%	14.7%	318.0	3.6%	11.7%
Verve Energy	GERALDTON_GT1	20.8	0.0%	0.3%	20.8	0.2%	2.2%	20.8	0.4%	0.3%	20.8	0.0%	4.2%
Verve Energy	GRASMERE_WF1										13.8		0.0%
Verve Energy	KEMERTON_GT11	154.0	0.0%	10.8%	154.0	0.0%	3.4%	154.0	0.0%	4.2%	154.0	0.1%	3.2%
Verve Energy	KEMERTON_GT12	154.0	0.2%	8.8%	154.0	0.0%	3.4%	154.0	0.0%	15.7%	154.0		0.1%
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%			

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	Max Gen (MW) 2011/12 Cap Year	Forced 2011/12 Cap Year	Planned 2011/12 Cap Year
Verve Energy	KWINANA_G5	177.0	0.0%	12.1%	177.0	1.0%	31.8%	177.0	0.0%	53.6%	177.0	0.4%	23.0%
Verve Energy	KWINANA_G6	177.0	0.2%	12.1%	177.0	0.0%	53.5%	177.0	2.5%	49.6%	177.0	1.4%	25.9%
Verve Energy	KWINANA_GT1	20.8	16.2%	35.6%	20.8	2.2%	22.8%	20.8	0.0%	21.9%	20.8		2.0%
Verve Energy	KWINANA_GT2										100.1	0.1%	
Verve Energy	KWINANA_GT3										100.1	0.1%	
Verve Energy	MUJA_G5	185.0	2.5%	22.2%	185.0	0.7%	48.4%	185.0	15.8%	18.7%	185.0	0.5%	13.9%
Verve Energy	MUJA_G6	185.0	1.7%	25.5%	185.0	1.1%	28.0%	185.0	0.4%	20.5%	185.0	4.1%	40.3%
Verve Energy	MUJA_G7	211.0	0.4%	4.9%	211.0	1.6%	8.6%	211.0	0.0%	42.9%	211.0	0.1%	5.5%
Verve Energy	MUJA_G8	211.0	0.1%	28.4%	211.0	1.0%	4.8%	211.0	1.9%	18.5%	211.0	0.4%	15.2%
Verve Energy	MUNGARRA_GT1	37.2	0.8%	1.1%	37.2	0.3%	2.7%	37.2	0.0%	5.4%	37.2	1.9%	0.4%
Verve Energy	MUNGARRA_GT2	37.2	0.3%	1.1%	37.2	0.6%	5.4%	37.2	0.1%	0.7%	37.2	0.2%	6.4%
Verve Energy	MUNGARRA_GT3	38.2	0.9%	3.6%	38.2	1.5%	0.6%	38.2	1.5%	10.9%	38.2	0.0%	0.5%
Verve Energy	PINJAR_GT1	37.2	0.2%	4.2%	37.2	0.4%	1.1%	37.2	0.0%	7.4%	37.2	0.0%	0.1%
Verve Energy	PINJAR_GT10	116.0	0.4%	35.1%	116.0	0.2%	11.8%	116.0	0.4%	10.4%	116.0	0.5%	27.9%
Verve Energy	PINJAR_GT11	123.0	0.2%	16.4%	123.0	0.0%	65.1%	123.0	0.1%	49.3%	123.0	0.1%	19.9%
Verve Energy	PINJAR_GT2	37.2	2.1%	5.5%	37.2	0.0%	1.1%	37.2	0.2%	5.2%	37.2		1.4%
Verve Energy	PINJAR_GT3	38.2	0.0%	4.0%	38.2	0.0%	10.3%	38.2	0.3%	0.1%	38.2		12.7%
Verve Energy	PINJAR_GT4	38.2	0.2%	4.1%	38.2	0.0%	20.4%	38.2	0.0%	1.7%	38.2		6.7%
Verve Energy	PINJAR_GT5	38.2	0.0%	8.4%	38.2	0.2%	8.4%	38.2	0.4%	7.8%	38.2	1.0%	1.0%
Verve Energy	PINJAR_GT7	38.2	0.1%	0.3%	38.2	0.0%	29.9%	38.2	0.1%	0.2%	38.2	0.4%	5.9%
Verve Energy	PINJAR_GT9	116.0	0.0%	16.4%	116.0	0.1%	9.4%	116.0	0.0%	27.3%	116.0	0.1%	16.7%
Verve Energy	PPP_KCP_EG1	79.2	0.8%	4.6%	79.2	7.7%	1.9%	85.7	0.0%	4.7%	85.7	0.0%	0.5%
Verve Energy	WORSLEY_COGEN_COG1	119.0	22.8%	5.1%	119.0	1.0%	2.3%	116.4	1.8%	17.1%	116.4		3.5%
Verve Energy	WEST_KALGOORLIE_GT2	38.2	0.4%	2.0%	38.2	0.0%	0.0%	38.2	0.1%	4.3%	38.2	1.0%	0.1%
Verve Energy	WEST_KALGOORLIE_GT3	24.6	0.0%	1.8%	24.6	0.0%	0.0%	24.6	0.0%	3.5%	24.6		19.7%
Waste Gas	HENDERSON_RENEWABLE_IG1	2.1	0.2%	0.0%	3.2	0.3%	0.0%	3.2	0.0%	0.0%	3.0	0.2%	
	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%**	**5685.6**	**0.8%**	**8.1%**

*Capacity Year starts 1 October and ends 30 September the following year. Maximum Generating Capacity of each facility was sourced from IMO's website. Planned and Forced Outages include full and partial ex-post outages for each facility for the Reporting Period. Blanks in the above table for some facilities denote no Outages to be reported.

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. 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 7 sets out the mean and standard deviations of peak and off-peak clearing prices from:

- 21 September 2006 (market commencement) to 30 June 2012;
- 1 August 2009 to 31 July 2010;
- 1 August 2010 to 31 July 2011 (i.e. the previous Reporting Period); and
- 1 August 2011 to 30 June 2012 (i.e. the current Reporting Period).

It can be seen that, for peak periods, the mean STEM Clearing price during the current Reporting Period increased notably compared to the corresponding price in the previous Reporting Period. The mean STEM Clearing Price for the off-peak period remained at a similar level as recorded in the previous Reporting Period. Nevertheless, clearing prices in this Reporting Period remained lower than the long term average, i.e. from market commencement to 30 June 2012.

Table 7 Mean and standard deviations of STEM Clearing Prices ($/MWh)

Trading Intervals	21 Sep 06 - 30 Jun 12		1 Aug 09 - 31 Jul 10		1 Aug 10 - 31 Jul 11		1 Aug 11 - 30 Jun 12	
	Mean	Std Dev	Mean	Std Dev	Mean	Std Dev	Mean	Std Dev
Off-Peak	31.45	27.23	19.51	11.63	25.68	15.28	**26.55**	**13.79**
Peak	62.00	53.81	38.65	18.80	46.63	34.24	**52.10**	**28.84**

Figure 6 and Figure 7 illustrate, respectively, average daily peak and off-peak STEM Clearing Prices for each Trading Day from 21 September 2006 (market commencement) up to 30 June 2012, as well as 30-day, 90-day and annual moving average prices.

Figure 6 Daily Average STEM Clearing Prices (Peak Trading Intervals)

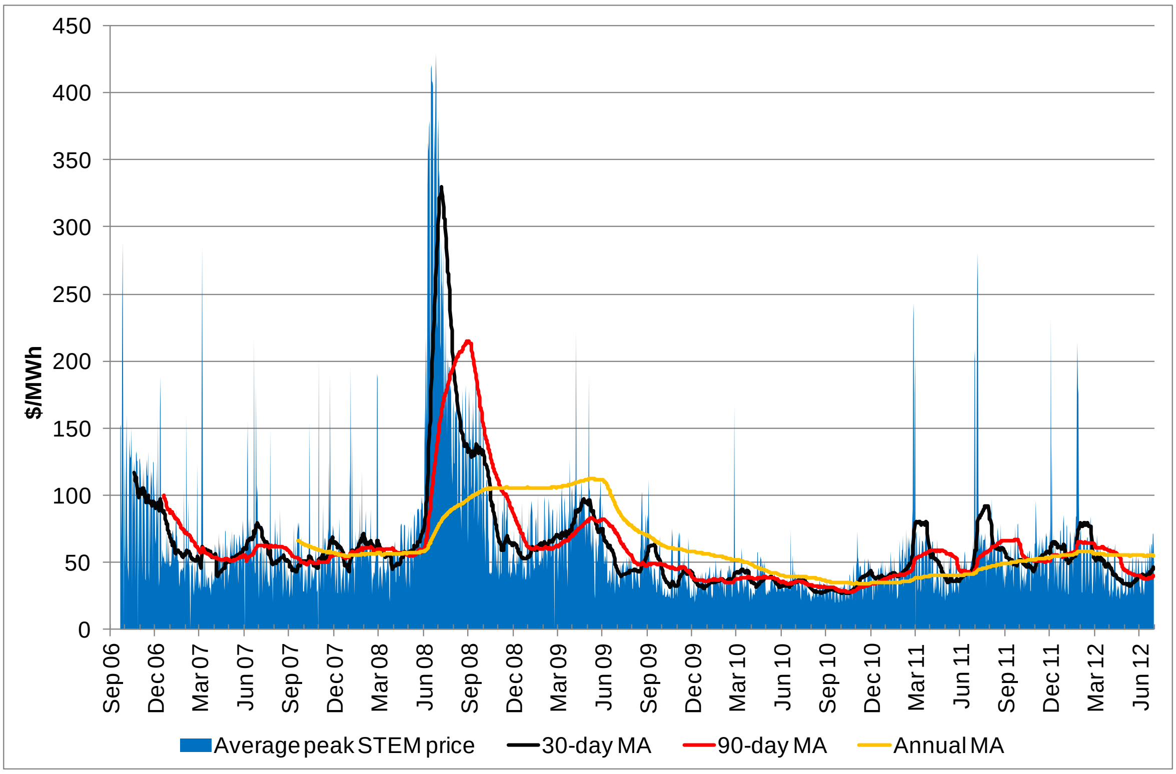
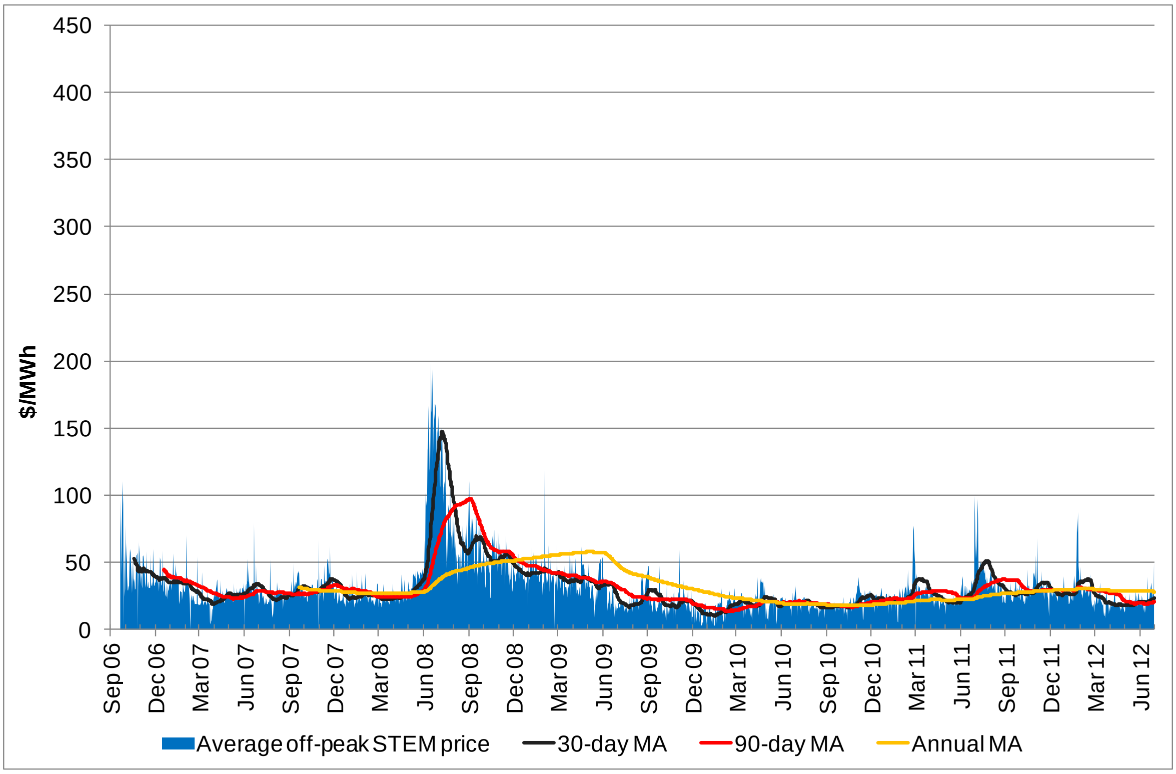


Figure 7 Daily Average STEM Clearing Prices (Off-Peak Trading Intervals)



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 (which occurred in June 2008).[138] 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. The average peak and off-peak prices have been at lower levels each Reporting Period since that event in June 2008. It is observed that the average clearing price for peak periods during the current Reporting Period was notably higher than the corresponding price in the previous two Reporting Periods. The average clearing price for the off-peak period remained at the same level as the corresponding price in the previous Reporting Period. The average clearing price for the off-peak period, as shown in Figure 7, was high during the last week of January 2012 due to peak summer period.

During the current Reporting Period, significantly higher prices (for both peak and off-peak periods) were observed during the first week of December 2011 and late January 2012. The higher prices in early December 2011 were attributed to the absence of lower priced STEM Offer quantities due to a high level of Planned Outages. The high prices in late January 2012 were attributed to the high load forecast and the absence of lower priced STEM Offer quantities (due to high load forecast).

The lowest STEM Clearing Prices observed during the current Reporting Period occurred in late November 2011 and late March 2012. These were primarily due to periods of low overnight load forecast coinciding with a relatively large volume of lower priced quantities 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 the STEM Auctions. Figure 8 and Figure 9 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 30 June 2012.

Figure 8 and Figure 9 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 November 2011, December 2011 and January 2012. Volatility in off-peak periods was also observed in March 2012 and June 2012.

[138] 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.

Figure 8 **Summary statistics for STEM Clearing Prices in Peak Trading Intervals (per calendar month)**

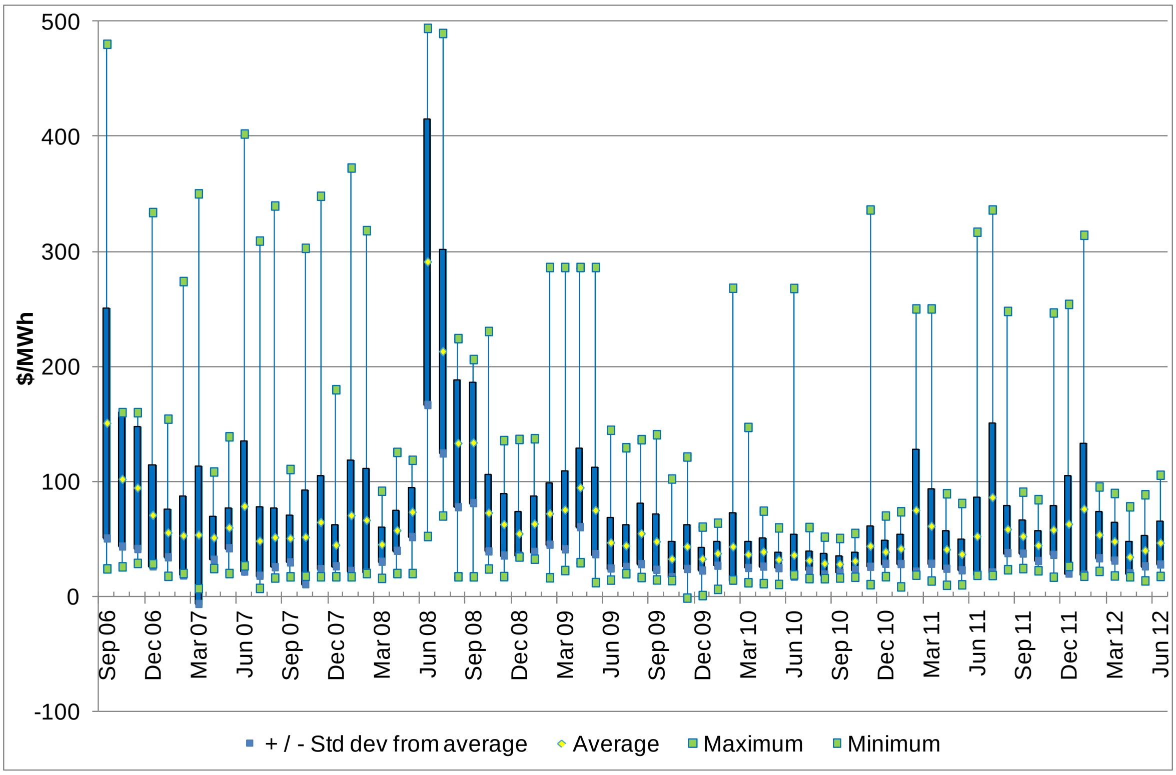
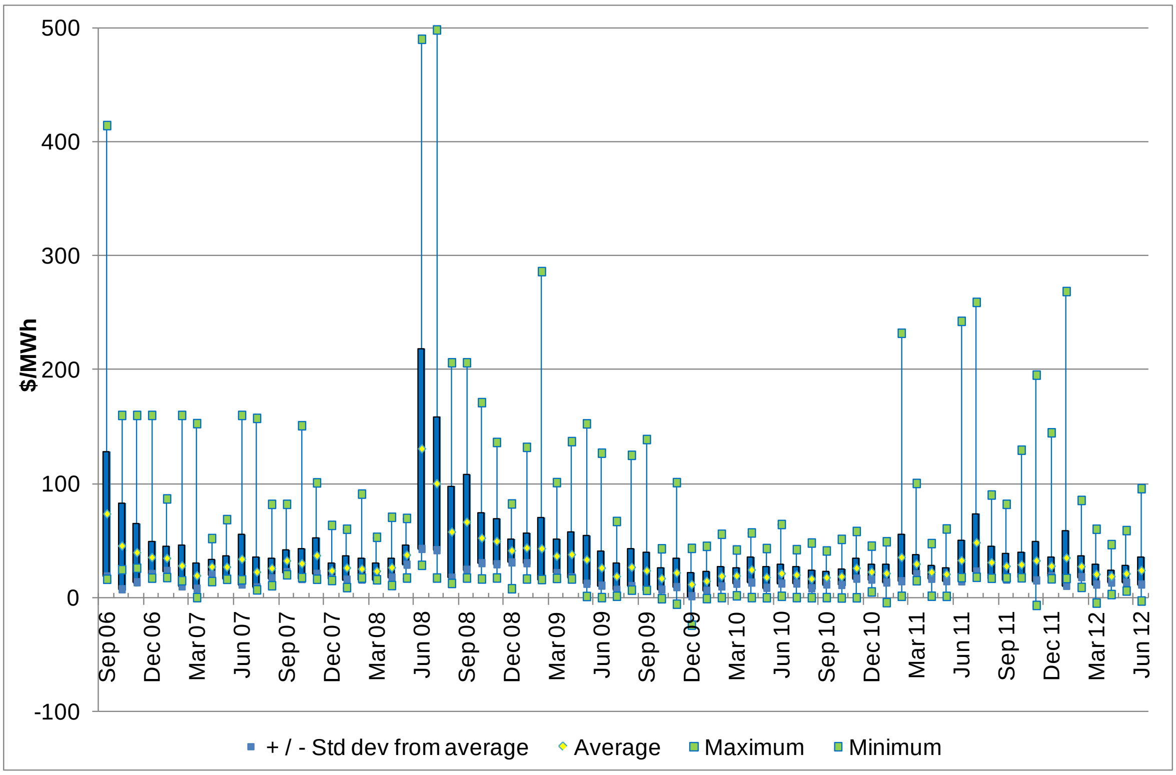


Figure 9 **Summary statistics for STEM Clearing Prices in Off-Peak Trading Intervals (per calendar month)**



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.[139] There are two Energy Price Limits set out in the Market Rules that act as a cap on high prices.

- The Maximum STEM Price sets the price cap for generators using fuel types other than liquid fuel. This price is determined based on the IMO's estimate of the short run marginal cost of the highest cost generating unit in the SWIS fuelled by natural gas. The Market Rules specify that the IMO must review the Maximum STEM Price annually. For the period from 1 August 2011 to 31 October 2011 of the current Reporting Period, the Maximum STEM Price was $336/MWh,[140] whilst from 1 November 2011 to 1 July 2012 the Maximum STEM Price was $314/MWh.[141]

- The Alternative Maximum STEM Price sets the price cap for generators running on liquid fuel. This price is determined based on the IMO's estimate of the short run marginal cost of the highest cost generating unit in the SWIS fuel by distillate. The Market Rules specify that the IMO must review the Alternative Maximum STEM Price annually and the price is adjusted monthly to reflect changes in oil prices and the Consumer Price Index (**CPI**). During the current Reporting Period, the Alternative Maximum STEM ranged between $522/MWh (for September 2011) and $571/MWh (for June 2012).[142]

Figure 10 and Figure 11 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 10 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 2009 and May 2009 and during three Peak Trading Intervals, twice on 3 November 2010 and once on 6 July 2011. In the current Reporting Period STEM Clearing Prices reached the Maximum STEM Price during 26 Peak Trading Intervals in January 2012,[143] eight intervals on 25 January 2012, 11 on 26 January 2012 and seven on 28 January 2012.

[139] The Energy Price Limits comprise of the Maximum STEM Price, the Alternative Maximum STEM Price and the Minimum STEM Price. Refer to clause 6.20 of the Market Rules for more details.

[140] The Maximum STEM Price of $336/MWh applicable for the period from 1 October 2010 to 1 November 2011 has been the highest since the market commenced, with the lowest being $153.73/MWh in September 2006.

[141] The final Maximum STEM Price value was delayed and came to effect on 1 November 2011.

[142] Since market commencement, the Alternative Maximum STEM Price has been as low as $380/MWh (during March 2007 and April 2007) and as high as $779/MWh (during September 2008).

[143] The STEM Clearing Price reached the Maximum STEM Price during the 1.30 pm to 4.00 pm, 9.00 pm and 9.30 pm Trading Intervals on 25 January 2012; during the 12:30 pm to 5:30 pm Trading Intervals on 26 January 2012; and during the 1:30 pm to 4:30 pm on 28 January 2012. These high prices were due to a combination of factors; i.e. high expected demand associated with high temperature forecast, and planned outages. .

Figure 10 Proportion of Trading Intervals STEM Clearing Prices at Maximum STEM Price (per calendar month)

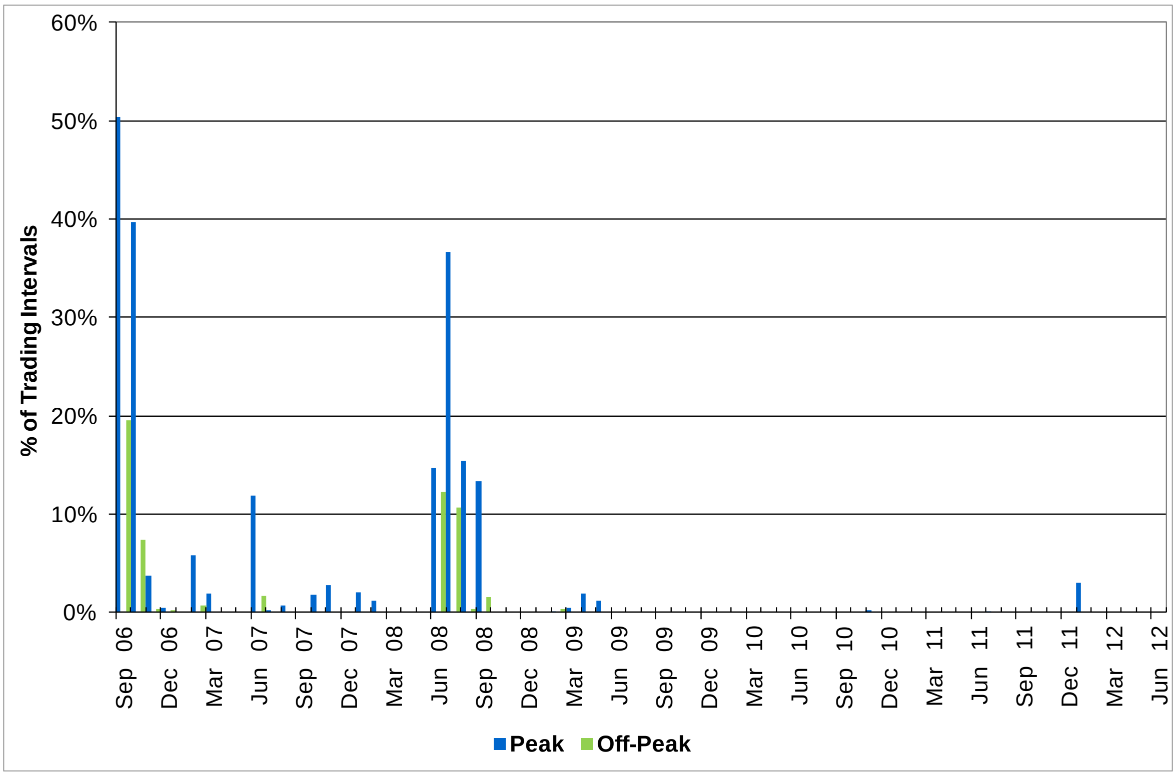
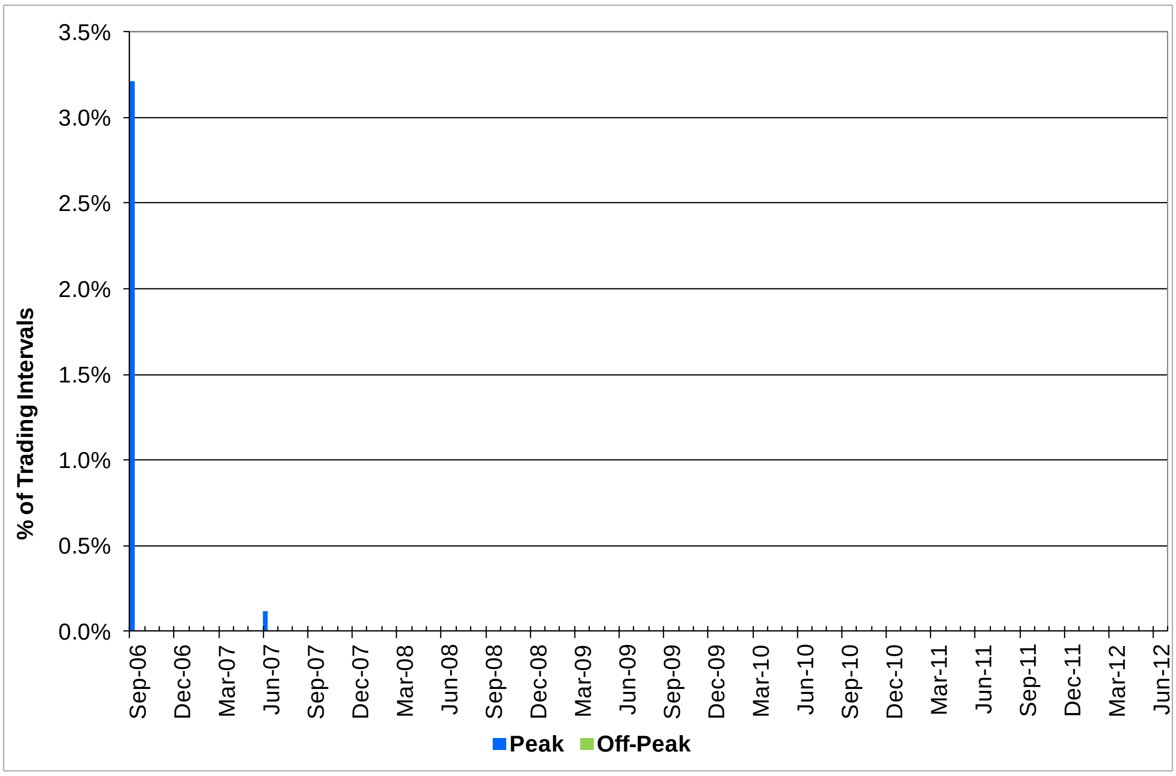


Figure 11 shows that STEM Clearing Prices only reached the Alternative Maximum STEM Price during Peak Trading Intervals in September 2006 and June 2007. Since then, STEM Clearing Prices have not reached the Alternative Maximum STEM Price.

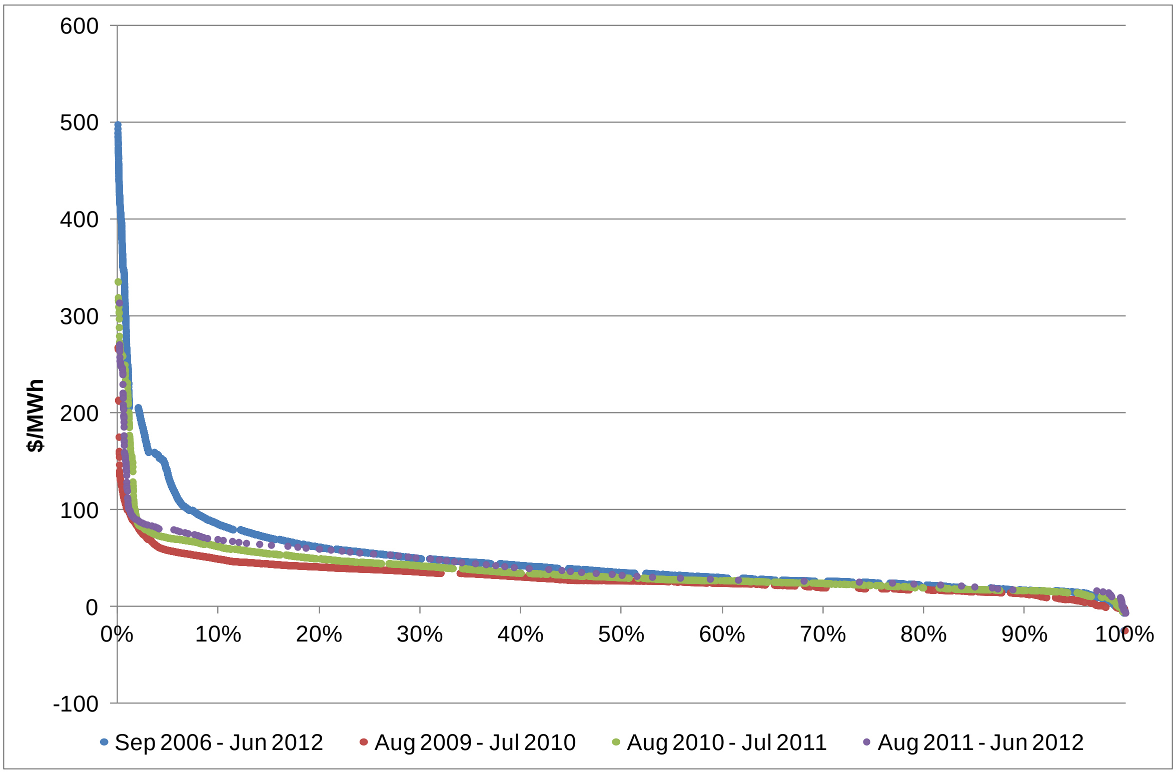
Figure 11 Proportion of Trading Intervals STEM Clearing Prices at Alternative Maximum STEM Price (per calendar month)



Another way of examining the incidence of high prices is to plot a price duration curve. Figure 12 sets out the price duration curves for STEM Clearing Prices, covering all Trading Intervals from 21 September 2006 (market commencement) to 30 June 2012, and comparing it to curves from the previous two Reporting Periods (August 2009 to July 2010, and August 2010 to July 2011) and the current Reporting Period.

Figure 12 shows that STEM Clearing Prices fell between -$6.00/MWh and $100.00/MWh for approximately 98.7 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 97.0 per cent of Trading Intervals.

Figure 12 Comparison of price duration curves for STEM Clearing Prices



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[144]. 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[145] for undertaking the analysis required under clause 2.16.4(e) and clause 2.16.4(g) of the Market Rules (see discussion under Figure 22).

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.

The Market Rules require that the IMO determines 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

[144] 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

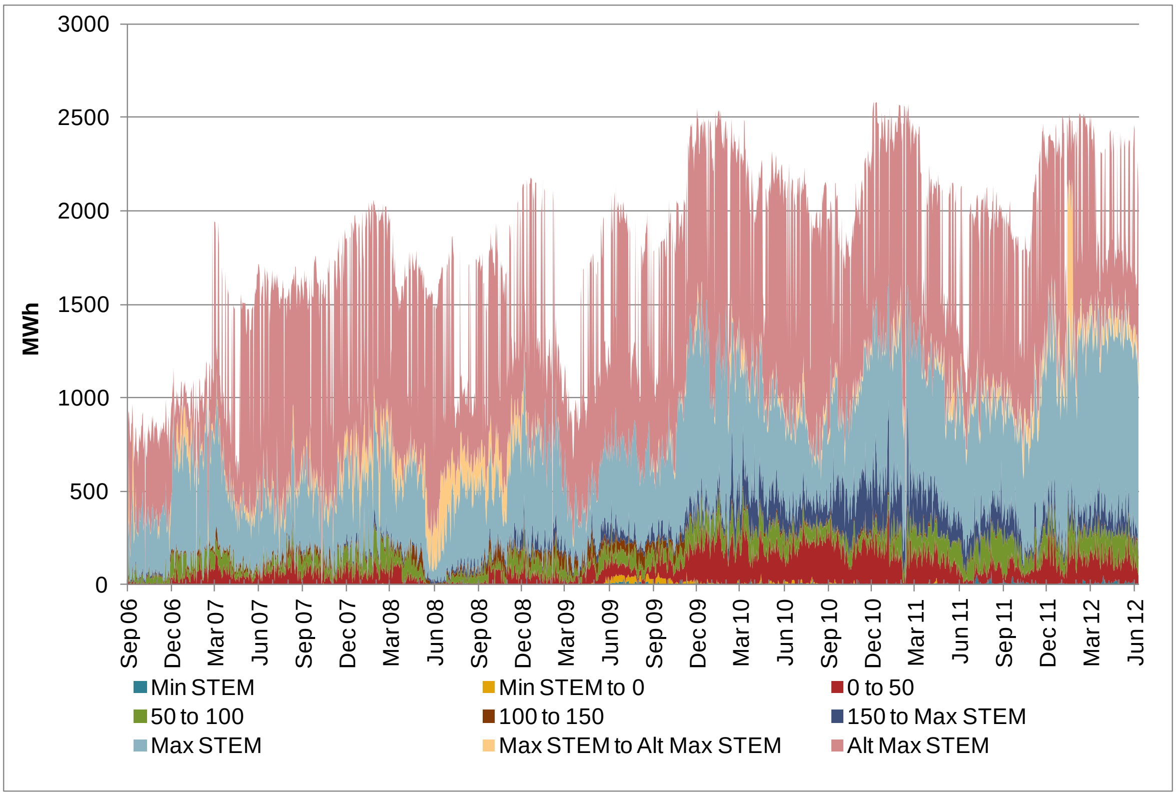
[145] This model estimates the numerical relationships between WEM variables such as temperature, load forecasts, energy prices, plant availability and fuel curtailments.

then converting 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 13 illustrates the daily average quantity of STEM Offers per Trading Interval for all Market Participants from market commencement until 30 June 2012.

Figure 13 Daily average quantity of STEM Offers (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.[146] 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.

It is notable that, between March 2010 and October 2011, Market Participants offered increasing quantities into the STEM in the price range of $150/MWh to the Maximum STEM Price. In the Reporting Period there is also a notable drop in STEM Offer quantities in the price range of $0/MWh to $50/MWh, as compared to the corresponding quantities offered in the previous Reporting Period.

STEM Offers for each Market Participant are set out separately in Figure 33 to Figure 49 in Appendix 3. These figures show clear differences in the volumes and prices at which

[146] 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.

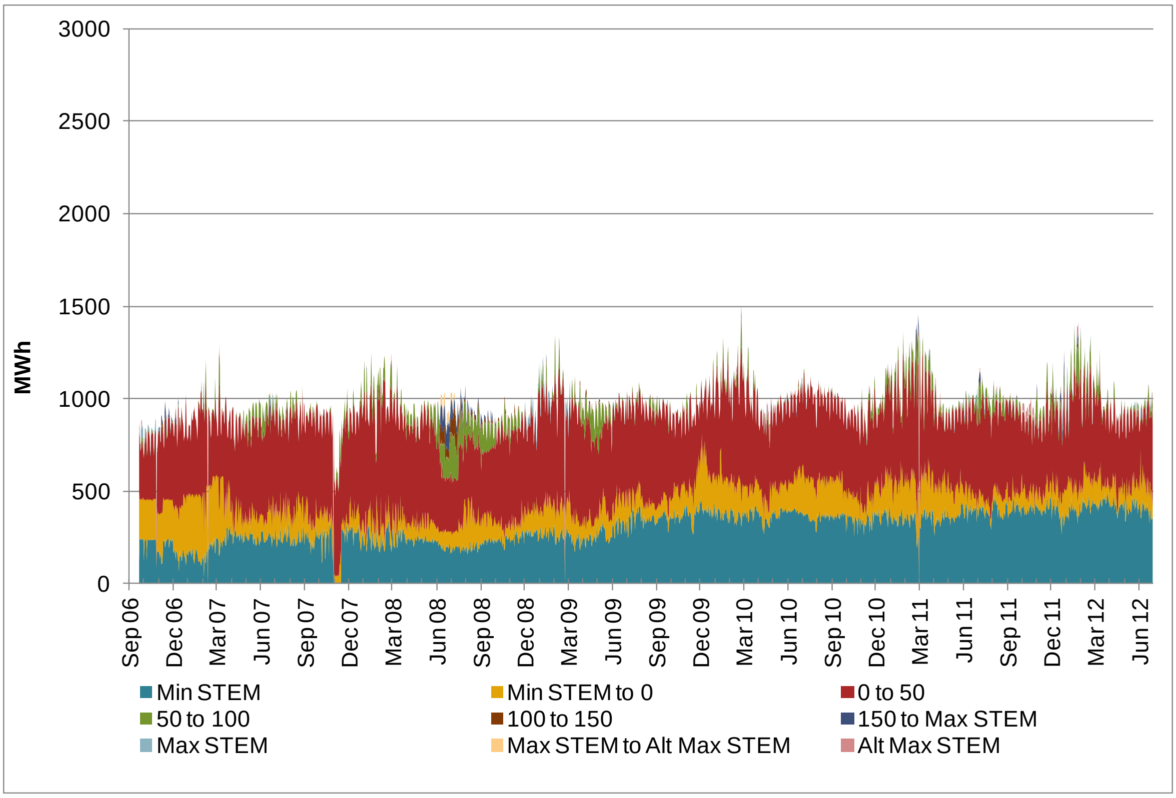
Market Participants have offered quantities into the STEM since market commencement. A discussion of notable changes in Market Participants' STEM Offers during the current Reporting Period is also included in Appendix 3.

It is notable that Verve Energy continues to account for the largest volumes of STEM Offers, with an average of 32 per cent of the total offer volumes during the current Reporting Period (compared to 31 per cent in the previous Reporting Period).

Short Term Energy Market Bids

STEM Bids reflect a decrease in generation or an increase in consumption. Figure 14 illustrates the daily average quantity of STEM Bids per Trading Interval for all Market Participants, from market commencement until 30 June 2012.

Figure 14 Daily average quantity of STEM Bids (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 13 and Figure 14.

As can be seen in Figure 14, significant quantities of energy have consistently been bid into the STEM between the Minimum STEM Price and $50/MWh. In the STEM's design this outcome would be expected, given that it covers quantities already contracted and represents must-run[147] 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.

[147] Generator co-located with, and providing steam to, an industrial plant.

STEM Bids for each Market Participant are set out separately in Figure 50 through Figure 64 in Appendix 3. These figures show clear differences in the prices and volumes at which Market Participants have put their Bids in the STEM.

Similar to the STEM Offers, Verve Energy accounted for the largest volumes of STEM Bids (approximately 57 per cent) for the current Reporting Period.

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 8 shows the annual average of STEM traded quantities among Market Participants (cumulative MWh per Trading Interval) for five yearly periods since market commencement, as well as an overall average from market commencement to 30 June 2012.

Table 8 Average STEM traded quantities (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	1 Aug 11 - 30 Jun 12	Average
STEM traded quantities	9.61	13.75	32.31	53.60	64.39	**50.56**	37.98

Note: 'Average quantities' are for the overall period, i.e., 21 September 2006 to 30 June 2012.

Figure 15 and Figure 16 show the daily average volume bought and sold in the STEM, respectively, for all Market Participants, from market commencement to 30 June 2012.

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 during the last two Reporting Periods 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 15, the major buyers in the STEM in the current Reporting Period were Verve Energy, closely followed by Synergy, ERM Power Retail and NewGen.

Figure 16 shows that during the current Reporting Period Verve Energy was the largest STEM seller, followed by Alinta Sales. Synergy also sold notable volumes in STEM during the period July 2011 to October 2011.

Figure 15 Daily average quantities bought in the STEM (MWh)

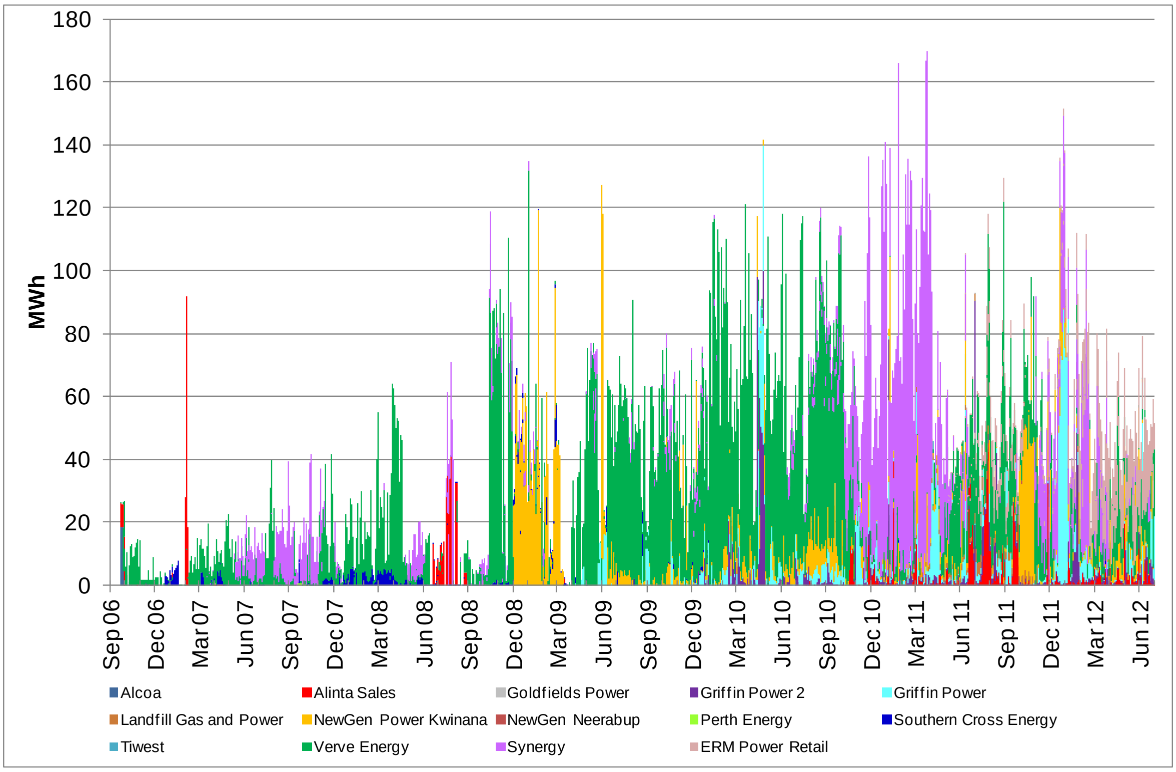


Figure 16 Daily average quantities sold in the STEM (MWh)

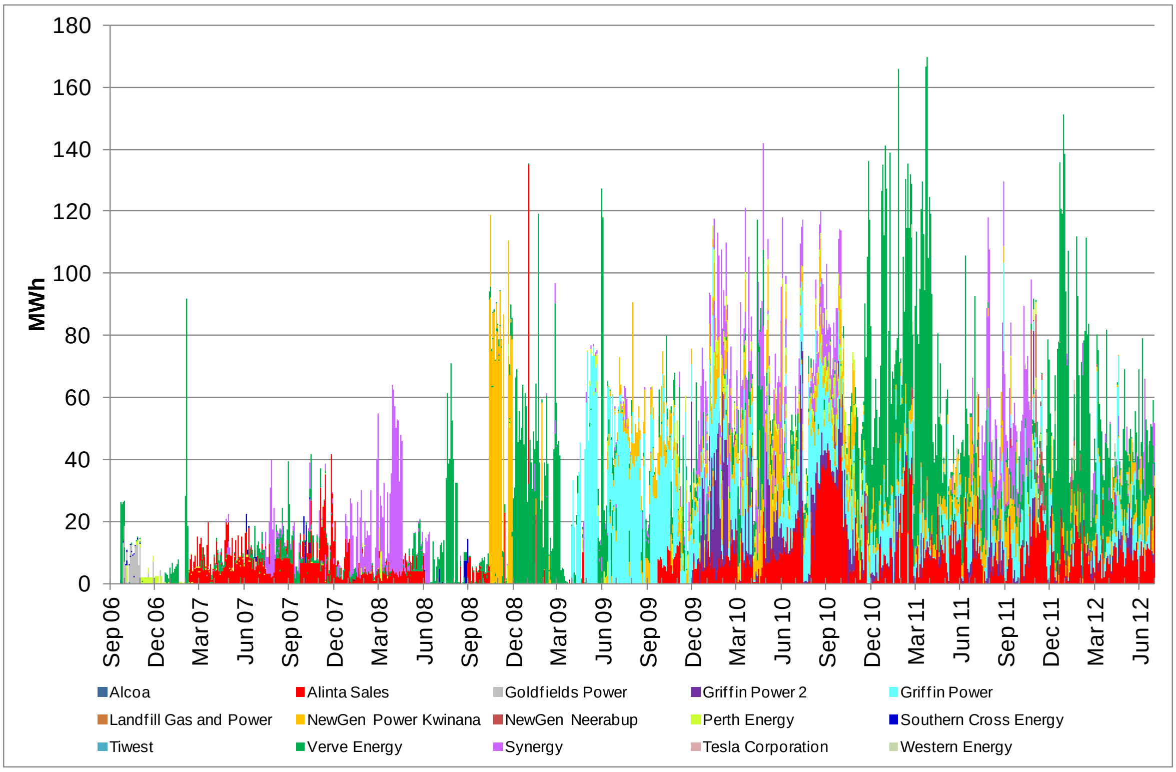


Figure 65 in Appendix 3 shows average daily STEM Clearing Quantities for each Trading Day from 21 September 2006 (market commencement) to the end of the current Reporting Period (30 June 2012), as well as 30-day, 90-day and annual moving average quantities. The average STEM Clearing Quantity for each Trading Day was significantly higher and exceeded 100 MWh during the period 22 December 2011 to 31 December 2011, as compared to the remaining Trading Days in December 2011. This was attributable to purchases in the STEM by some participants in order to cover their energy requirements due to Planned Outages or high expected demand.

5.2.2 Balancing

Clause 2.16.2(d) of the Market Rules (as of 30 June 2012) requires that the MSDC includes the Balancing Data prices and other Standing Data prices used in Balancing.[148] The Authority notes that there have been significant changes to the Balancing regime in the WEM as a result of the implementation of the new Balancing market in July 2012. This section is provided mainly to fulfil the Authority's obligations for the current Reporting Period to 30 June 2012 under the previous Balancing Mechanism.

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 (**NCP**) 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 for increasing or decreasing supply by Market Participants other than Verve Energy.

The Standing Data prices used in Balancing are summarised in Figure 66 through to Figure 70 in Appendix 3, for the period from market commencement to 30 June 2012. These figures present average daily prices for increasing and decreasing supply for

[148] This clause was modified as part of the implementation of Rule Change RC_2011_10: Competitive Balancing and Load Following Market on 1 July 2012.

generators by the type of facility: non-liquid generation, liquid generation, Intermittent Generation, or for the reduction of consumption for DSM (i.e. Curtailable Loads).[149]

Broadly, IPPs want to be paid close to the applicable price caps when instructed to increase generation irrespective of the time of the day. When instructed to reduce the level of generation, IPPs will only be paid up to the Maximum STEM Price regardless of the type of fuel they are on.

MCAP, UDAP and DDAP

In addition to prices specified by individual Market Participants in the Standing Balancing Data, there are three types of prices applicable in Balancing settlement. These are:

- Marginal Cost Administered Price (**MCAP**);
- Upwards Deviation Administered Price (**UDAP**); and
- Downwards Deviation Administered Price (**DDAP**).

MCAP is used to settle deviations from Net Contract Position[150] by Verve Energy, by Non-Scheduled Generators, by Non-Dispatchable, Interruptible and Curtailable Loads, and by non-Verve Energy Scheduled Generators[151] (i.e. Authorised Deviation Quantity).

UDAP and DDAP are used to settle deviations outside a tolerance[152] for non-Verve Energy Scheduled Generators (excluding those subject to a test) that deviate from their Resource Plans 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 14 in Appendix 3.

Table 9 sets out the mean and standard deviations of the peak and off-peak MCAP, UDAP and DDAP for the following three periods:

- 21 September 2006 (i.e., market commencement) to 30 June 2012;
- 1 August 2010 to 31 July 2011 (i.e., the previous Reporting Period); and
- 1 August 2011 to 30 June 2012 (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.

[149] Curtailable Load is measured a metered point through which electricity is consumed, where consumption can be curtailed at short notice.

[150] 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 market provides the means for trading these deviations.

[151] Subject to Commissioning Tests or tests of their RCRs, as well as within tolerance deviations in the output of these generators.

[152] As provided for under clause 6.17.9 of the Market Rules.

Table 9 Mean and standard deviations of the MCAP, UDAP and DDAP ($/MWh)

		21Sep06-30Jun12		1Aug10-31Jul11		1-Aug11-30-Jun12	
	Trading Interval	Mean	Std Dev	Mean	Std Dev	Mean	Std Dev
MCAP	Off-Peak	34.83	40.34	26.48	22.82	27.91	**31.18**
	Peak	72.27	74.98	50.40	47.69	55.08	**47.43**
UDAP	Off-Peak	0.00	0.00	0.00	0.00	0.00	**0.00**
	Peak	36.14	37.49	25.20	23.85	27.54	**23.72**
DDAP	Off-Peak	38.91	44.37	29.13	25.10	30.70	**34.30**
	Peak	93.32	94.12	65.46	61.67	71.60	**61.66**

Figure 17 and Figure 18 illustrate average daily peak and off-peak period Balancing prices for each Trading Day, from market commencement to 30 June 2012. Because the UDAP and the DDAP are set with reference to the MCAP, there is a clear relationship between the three prices. The upwards and downward penalties could be really high or low depending on the resulting MCAP.

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 17, average peak period MCAP prices were notably higher on a number of Trading Days during the summer period from December 2011 to February 2012.[153]

As can be seen in Figure 18, average off-peak period MCAP prices were high in late January 2012. Negative average MCAP prices in off-peak periods were observed in early April 2012 and early June 2012[154].

[153]MCAP reached $314.00/MWh (the Maximum STEM Price) in December 2011, January 2012 and February 2012. The majority of these high MCAP events occurred during periods of high summer demand (ranged between 3,000 MW to 3,880 MW) as a result of high temperature and a number of these high MCAP events were triggered by unit's Forced Outages.

[154]The negative MCAP value during April 2012 and June 2012 was attributed to overnight low demand and very high Intermittent Generation. The lowest MCAP during the current Reporting Period reached negative $53.39/MWh at 2:00 am on 10 June 2012, which was the lowest MCAP observed since market commencement.

Figure 17 Daily Average Balancing prices (Peak Trading Intervals, $/MWh)

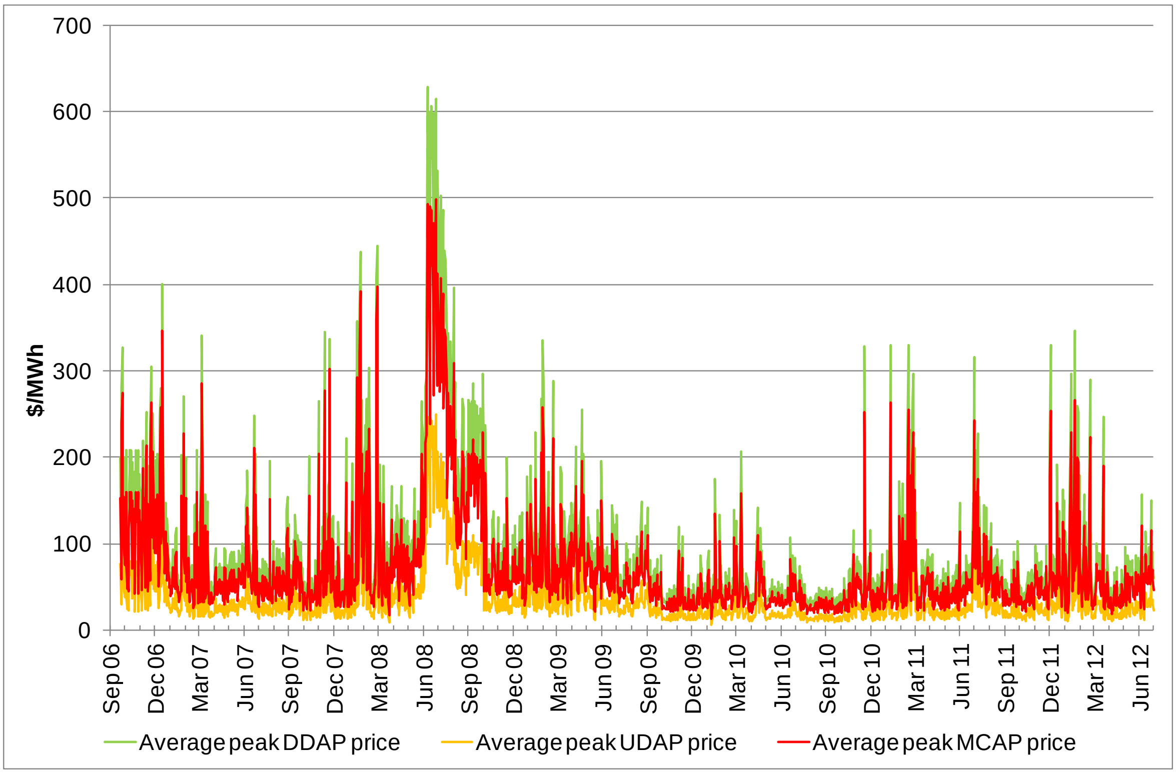
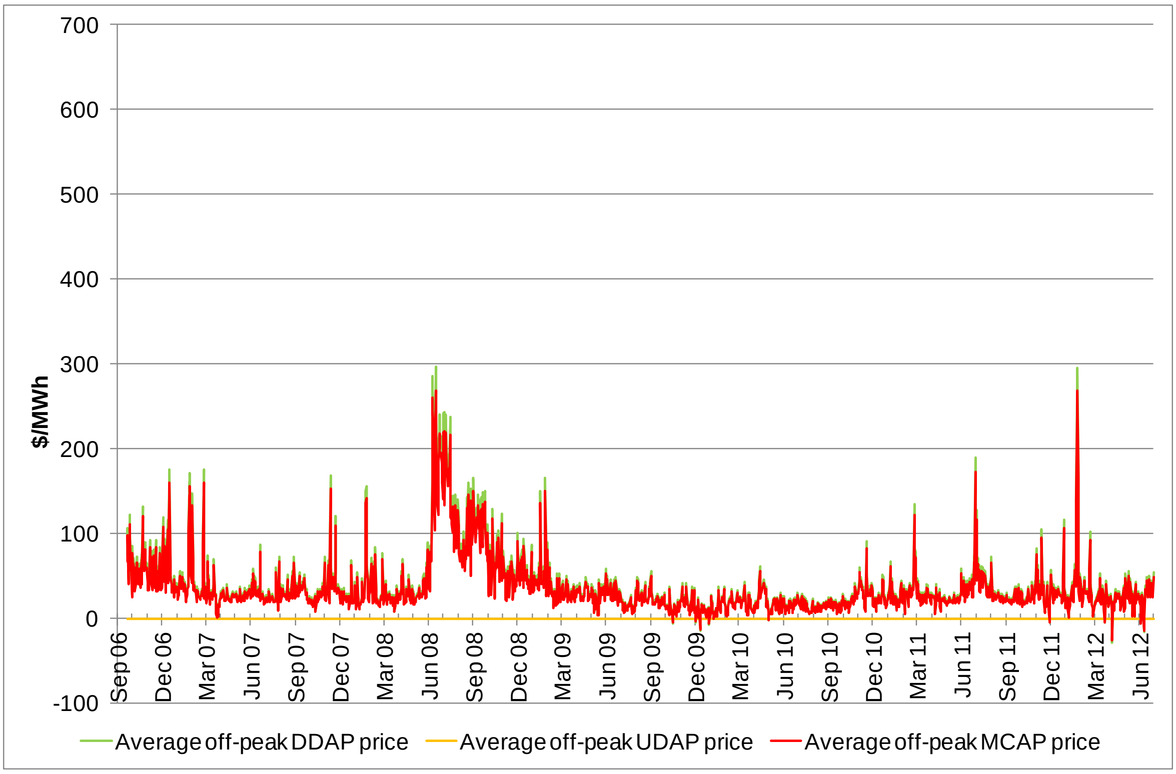


Figure 18 Daily Average Balancing prices (Off-Peak Trading Intervals, $/MWh)



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 71 and Figure 72 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 relationship between off-peak Balancing prices and STEM Clearing Prices can be seen more clearly in Figure 73 and Figure 74 in Appendix 3, which compare the 30-day and 90-day moving averages of off-peak STEM and Balancing prices, respectively.

Figure 75 and Figure 76 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 movement presented in Figure 17 and Figure 18, with the exception of a number of days in the summer period between December 2011 and February 2012, and a few days in April 2012 and June 2012, the level and volatility of Balancing prices was stable and at relatively low levels 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 77 through to Figure 81 in Appendix 3. In general, Peak Trading Interval Balancing prices are more volatile than Off-Peak Trading Interval prices for MCAP and DDAP. The volatility of Off-Peak Trading Interval MCAPs and DDAPs (indicated by Figure 78 and Figure 80) were comparatively high for the current Reporting Period in comparison to the previous one.

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 19 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 2008 to September 2008 during the Varanus Island interruption. In the previous two Reporting Periods MCAPs reached the Maximum STEM Price for less than one per cent of total Peak Trading Intervals. During the current Reporting Period, MCAP reached the Maximum STEM Price for an increased number of Peak Trading Intervals between December 2011 and March 2012, when compared to the previous Reporting Periods. The majority of these events occurred during periods of high summer demand (ranging between 3,000 MW to 3,880 MW) as a result of very high temperatures and some events triggered by Forced Outages of plant. About 11 per cent of the total Peak Trading Intervals in January 2012 had MCAP at the Maximum STEM Price. In the same month MCAP reached the Maximum STEM Price for six per cent of the total Off-Peak Trading Intervals.

Comparing Figure 10 and Figure 19, it is clear that MCAPs were at the Maximum STEM Price more frequently than STEM Clearing Prices each Reporting Period since market commencement. The percentage occurrence of MCAPs at the Maximum STEM Price during Peak Trading Intervals exceeded 10 per cent in January 2012, the first time since the Varanus Island incident in 2008. The Off-Peak Trading Intervals percentage occurrence remains under 10 per cent post the Varanus Island incident.

Figure 19 Proportion of Trading Intervals MCAPs at Maximum STEM Price (per calendar month)

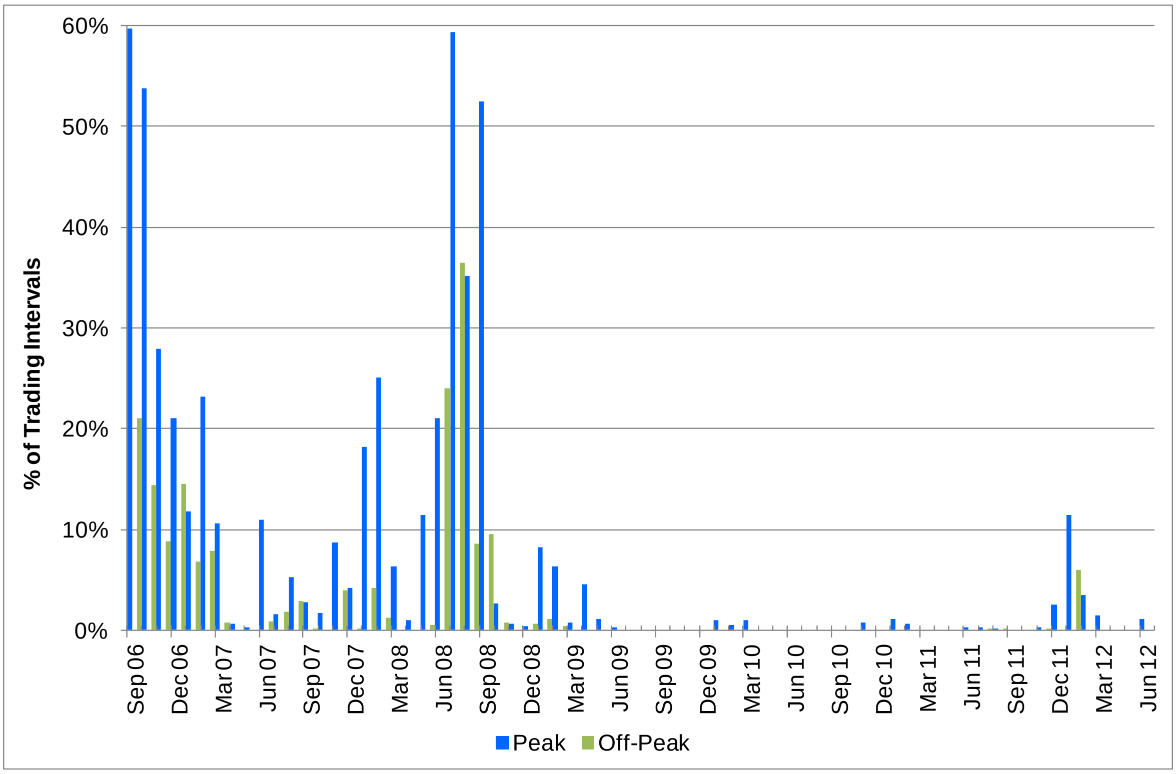


Figure 20 illustrates the proportion of peak and off-peak periods during which MCAPs were at the Alternative Maximum STEM Price. As was the case in the previous Reporting Period, there were no instances of MCAPs reaching the Alternative Maximum STEM Price in the current Reporting Period. The last time the MCAPs reached the Alternative Maximum STEM Price was in January 2008.

Figure 20 Proportion of Trading Intervals MCAPs at Alternative Maximum STEM Price (per calendar month)

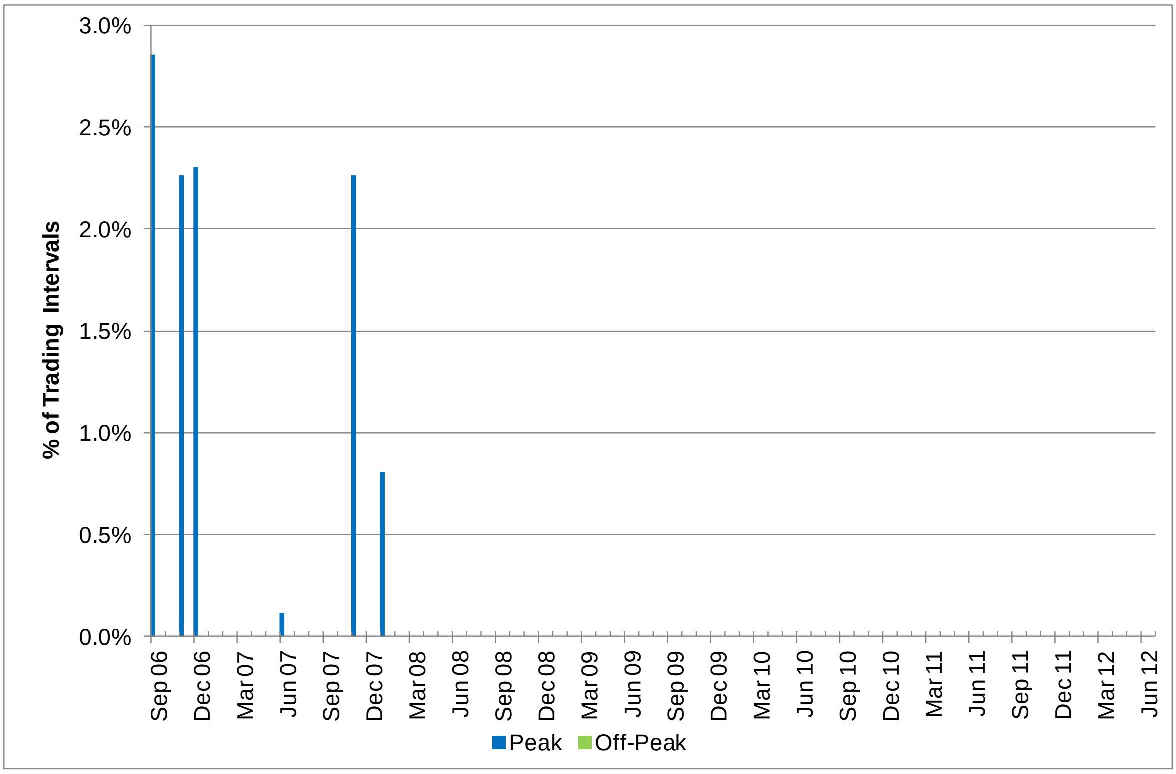


Figure 21 sets out the MCAP duration curve, covering all Trading Intervals from 21 September 2006 (market commencement) to 30 June 2012. For comparison purpose, Figure 21 also includes the UDAP, DDAP and the STEM price duration curves for the same period.[155] As expected, the MCAP is bounded by the UDAP and the DDAP.

As can be seen in Figure 21, 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. About 50 per cent of the time the STEM Clearing Prices and MCAPs appear to overlap each other, whilst the STEM Clearing Prices fall under the MCAPs for the remaining period. 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. The STEM Clearing Price was under \$100/MWh for 93 per cent of the time, whilst MCAP was under \$100/MWh for only 88 per cent of the time.

[155] Price duration curves for peak and off-peak period MCAPs are set out in Figure 82 and Figure 83 in Appendix 3, respectively.

Figure 21 Price duration curves for STEM Clearing Prices, MCAPs, UDAPs and DDAPs (21 September 2006 to 30 June 2012)

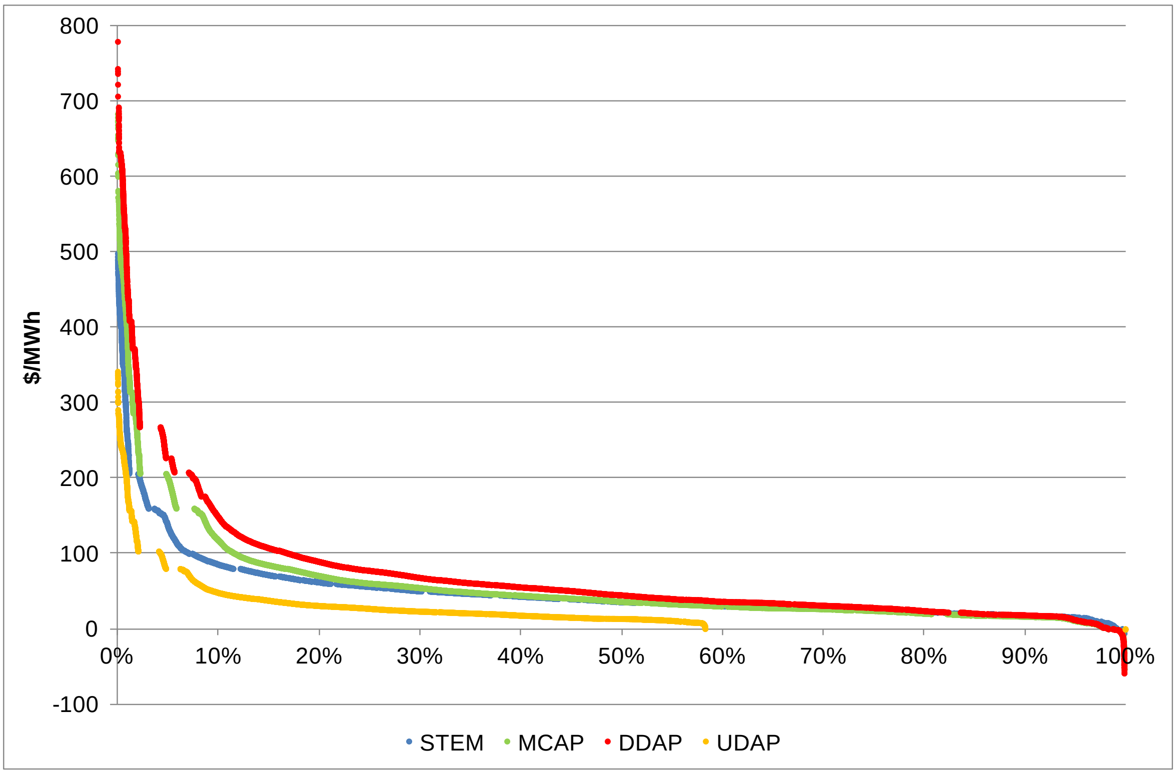


Figure 22 illustrates a comparison of MCAP price duration curves for the periods 21 September 2006 (market commencement) to 30 June 2012, 1 August 2009 to 31 July 2010, 1 August 2010 to 31 July 2011, and 1 August 2011 to 30 June 2012.

Figure 22 Comparison of price duration curves for MCAPs

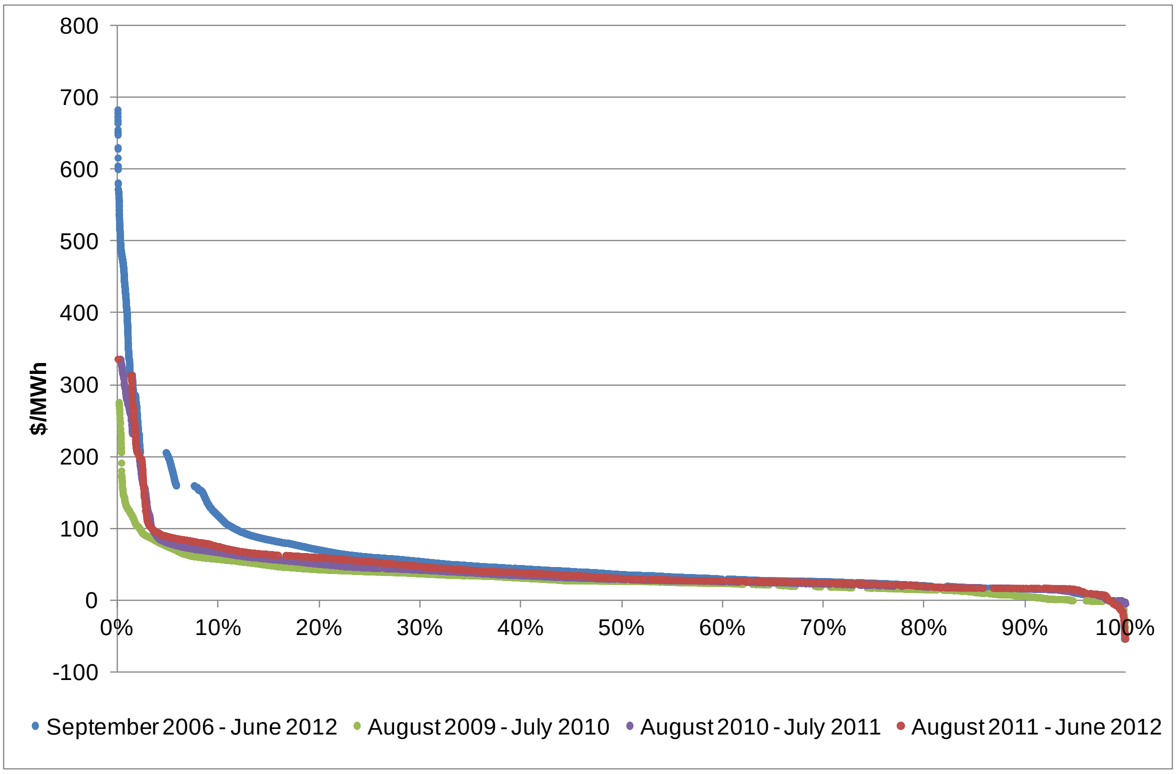


Figure 22 shows that of the four periods examined, MCAPs were lowest during the 2009/10 Reporting Period (1 August 2009 to 31 July 2010). MCAPs for the current Reporting Period exceeded $100/MWh for 3.4 per cent of the total Trading Intervals, very similar to the previous Reporting Period. However, the MCAPs for the current and the previous Reporting Periods were comparatively higher than the MCAPs for 2009/10 Reporting Period (as can be seen in Figure 22, the green line is smoother than the red and the purple lines). The price duration curve for the period September 2006 to June 2012 (denoted in blue) remains notably higher than the individual Reporting Periods as it covers the volatile period around the Varanus Island incident and it also includes the early days of market commencement. Of the total Trading Intervals since market commencement MCAPs exceeded $100/MWh for 11.6 per cent of the time and the maximum MCAP reached $682/MWh during July 2008 (i.e., shortly after the Varanus Island gas supply disruption).

Figure 84, Figure 85 and Figure 86 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, 1 August 2010 to 31 July 2011, and 1 August 2011 to 30 June 2012. A comparison of these figures shows the gap between STEM Clearing Prices and MCAPs during Peak Trading Intervals was relatively lower for the 2009/10 Reporting Period as the MCAP and the STEM Clearing Price exceeded $100/MWh for 3.6 per cent and 1.8 per cent of the total Trading Intervals, respectively. For the 2010/11 Reporting Period and the current Reporting Period the STEM Clearing Prices exceeded $100/MWh for 2.6 per cent and 1.9 per cent of the total Trading Intervals, respectively, whilst the MCAPs exceeded $100/MWh for 5.1 per cent and 4.8 per cent of the total Trading Intervals, respectively. A notable gap between STEM Clearing Prices and MCAPs during Peak Trading Intervals is evident for the 2010/11 Reporting Period and the current Reporting Period.

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. 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 notes the IMO has a process for analysing the key drivers associated with high price incidents observed in Balancing. The results from this analysis are provided to the Authority and discussed at the regular surveillance meeting held between the two organisations. The IMO is currently in the process of formally documenting this process and exploring options for the development of appropriate models for undertaking the analyses required under clause 2.16.4(g) and 2.16.4(f) of the Market Rules.

5.2.2.4 Capacity available through Balancing (through Dispatch Instructions)

Clause 2.16.2(i) of the Market Rules (as at 30 June 2012) requires that the MSDC identify the capacity available through Balancing from Scheduled Generators and Non-Scheduled Generators and Dispatchable Loads.

The IMO calculated the capacity available through Balancing from Market Participants other than Verve Energy. This was because, in effect, all of Verve Energy's capacity was available to provide Balancing. The IMO derived 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 (as at 30 June 2012) 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 23 shows the total number of increment Dispatch Instructions and decrement Dispatch Instructions issued per Calender Day[156], from 21 September 2006 (market commencement) to 30 June 2012.[157]

[156] Due to the data complexity, the daily count of the Dispatch Instructions has been reported as per Calender Day.

During the current Reporting Period, the maximum numbers of Dispatch Instructions recorded per Day were:

- 91 increment and 5 decrement on 25 January 2012;
- 54 increment on 26 January 2012 and on 27 January 2012 each; and
- 48 decrement on 22 June 2012 and on 23 June 2012 each.

The issuance of the Dispatch Instructions during late February 2011 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 to Demand Side Management (**DSM**) providers to dispatch Curtailable Load. Since that event the total number of Dispatch Instructions issued daily has remained under 100, including the current Reporting Period. Ninety One increment dispatch instructions, the maximum for the current Reporting Period, were issued on 25 January 2012. The temperature reached 41.1ºC on this Trading Day and the dispatch instructions issued were triggered by significantly high system demand and generator fuel supply restrictions.

Figure 23 Daily count of Dispatch Instructions (21 September 2006 to 30 June 2012)

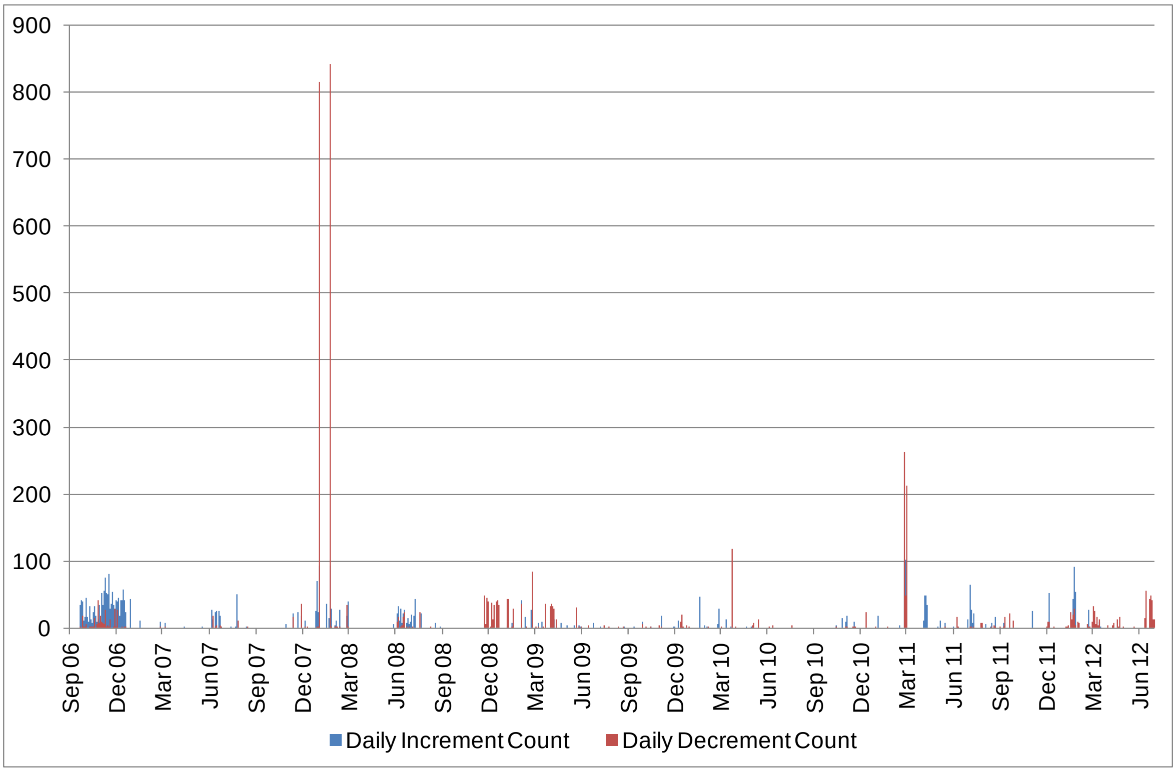
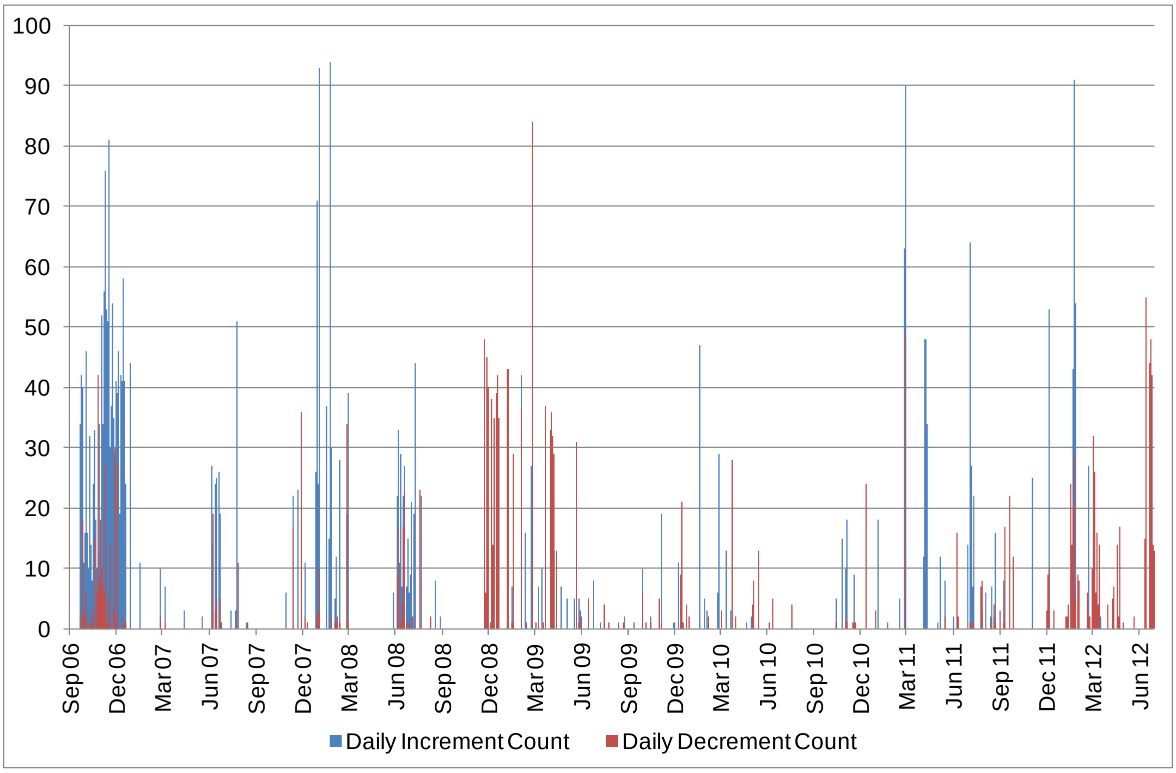


Figure 24 shows the total number of increment Dispatch Instructions and decrement Dispatch Instructions issued per Calender Day, from 21 September 2006 (market commencement) to 30 June 2012, with the outliers removed (i.e., increment or decrement Dispatch Instructions recorded per Day above 100 in total). The highest number of daily

[157] Note that this counts a System Management Dispatch Instruction that spans multiple Trading Intervals as multiple Dispatch Instructions.

decrement dispatch instructions recorded for the current Reporting Period was 48, issued on 22 June 2012 and on 23 June 2012. These decrement dispatch instructions were issued to a Non-Scheduled Generator (Alinta's Walkaway Wind Farm), triggered by Power System and Transmission constraints in the North Country Region.

Figure 24 Daily count of Dispatch Instructions - outliers removed (21 September 2006 to 30 June 2012)



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.

Details of Bilateral quantities scheduled with the IMO by individual participants 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 average Bilateral quantities per Trading Interval scheduled with the IMO in the current Reporting Period increased by approximately two per cent in comparison to the previous Reporting Period, and approximately 26 per cent higher than the 2007/08 Reporting Period. Also, total average Bilateral quantities show a seasonal trend, with greater quantities occurring during summer period. 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

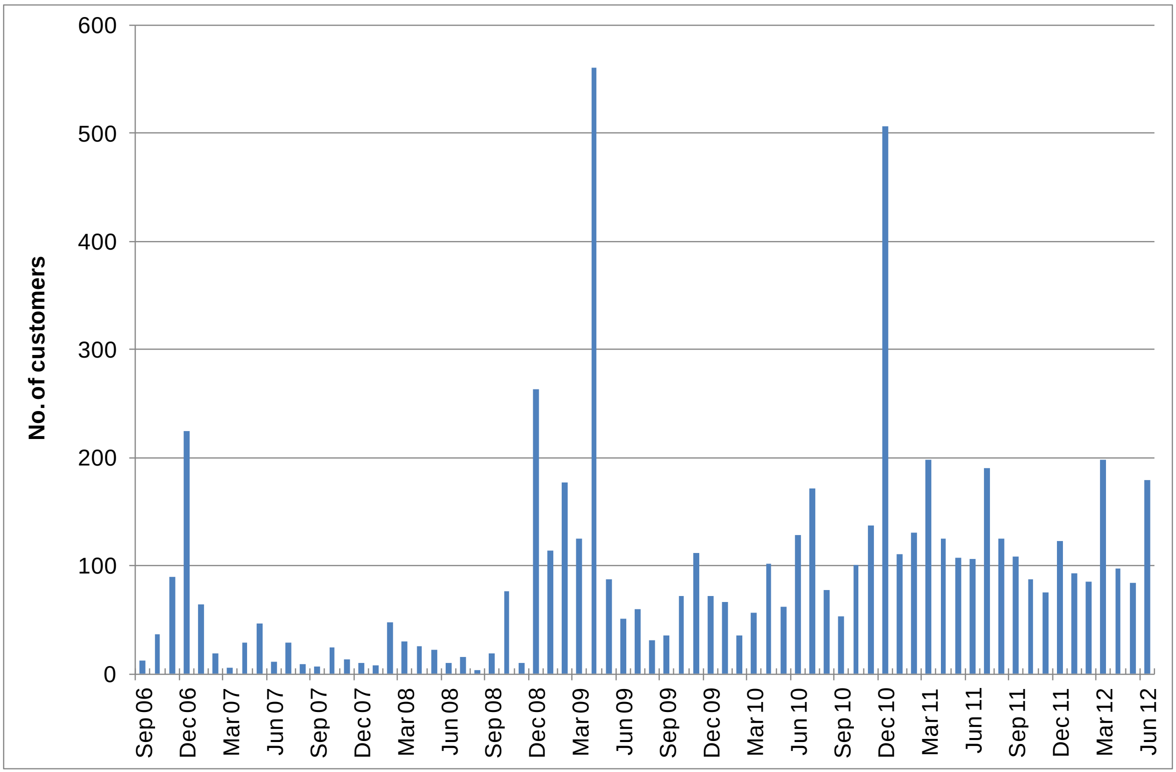
Although not required under the Market Rules, this section provides data on the rate at which customers have switched, or 'churned,' between retailers from 21 September 2006 (market commencement) to 30 June 2012.

Figure 25 illustrates levels of customer transfer[158] 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).

For the current Reporting Period, the monthly average customer transfer number was 120, compared to a monthly average of 156 in the previous Reporting Period. The maximum number of customer transfers reached 198 in March 2012.

Figure 25 Number of customers changing retailer (customers per month)



[158] 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.[159] 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 10 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 2011/12 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.[160]

In the 2011/12 Reserve Capacity Year, the Fuel Declarations for Alinta's Wagerup facilities to be run on Liquid Fuel increased to approximately 20 per cent, compared to approximately 7 to 8 per cent during the previous capacity year. Verve Energy's Kwinana_G6 facility declared to run on Non-Liquid Fuel for 71 per cent of the total time during the 2011/12 Reserve Capacity Year, as compared to 100 per cent of the time during the previous Reserve Capacity Year. NewGen Neerabup and Verve Energy's Kwinana_GT2 and Kwinana_GT3 were observed making Non-Liquid Fuel Declarations for the first time during the 2011/12 Reserve Capacity Year.

[159] See clause 6.6.1 of the Market Rules.

[160] 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 10 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	Liquid declaration 2011/12 Cap Year	Non-liquid declaration 2011/12 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%	20.3%	79.7%
Alinta	ALINTA_WGP_U2	98.4%	1.1%	62.6%	37.4%	6.9%	70.3%	20.0%	80.0%
Goldfields Power	PRK_AG	99.7%		100.0%		97.9%	1.8%	100.0%	
NewGen Neerabup	NEWGEN_NEERABUP_GT1								30.9%
Perth Energy	PERTHENERGY_KWINANA_GT1			6.3%		99.7%		100.0%	
Southern Cross	STHRNCRS_EG	6.6%							
Verve Energy	KEMERTON_GT11		99.7%	0.3%	99.7%	1.1%	98.6%		100.0%
Verve Energy	KEMERTON_GT12	69.9%	29.9%	0.8%	99.2%	1.1%	98.6%		100.0%
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%	0.3%	99.7%
Verve Energy	KWINANA_G6	14.8%	84.9%		100.0%		99.5%		71.2%
Verve Energy	KWINANA_GT1	99.7%		100.0%		99.7%		100.0%	
Verve Energy	KWINANA_GT2								30.1%
Verve Energy	KWINANA_GT3								38.8%
Verve Energy	PINJAR_GT1		99.7%		100.0%	0.3%	99.5%	0.3%	99.7%
Verve Energy	PINJAR_GT2	99.5%	0.3%	100.0%		99.2%	0.6%	99.7%	0.3%
Verve Energy	PINJAR_GT3		99.7%		100.0%	0.6%	99.2%	0.3%	99.7%
Verve Energy	PINJAR_GT4	99.7%		100.0%		99.2%	0.6%	99.5%	0.5%
Verve Energy	PINJAR_GT5		99.7%		100.0%	0.6%	99.2%	0.3%	99.7%
Verve Energy	PINJAR_GT7	99.7%		100.0%		99.2%	0.6%	99.5%	0.5%

*Blanks in the above table denote no values to be reported in respective category.

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.

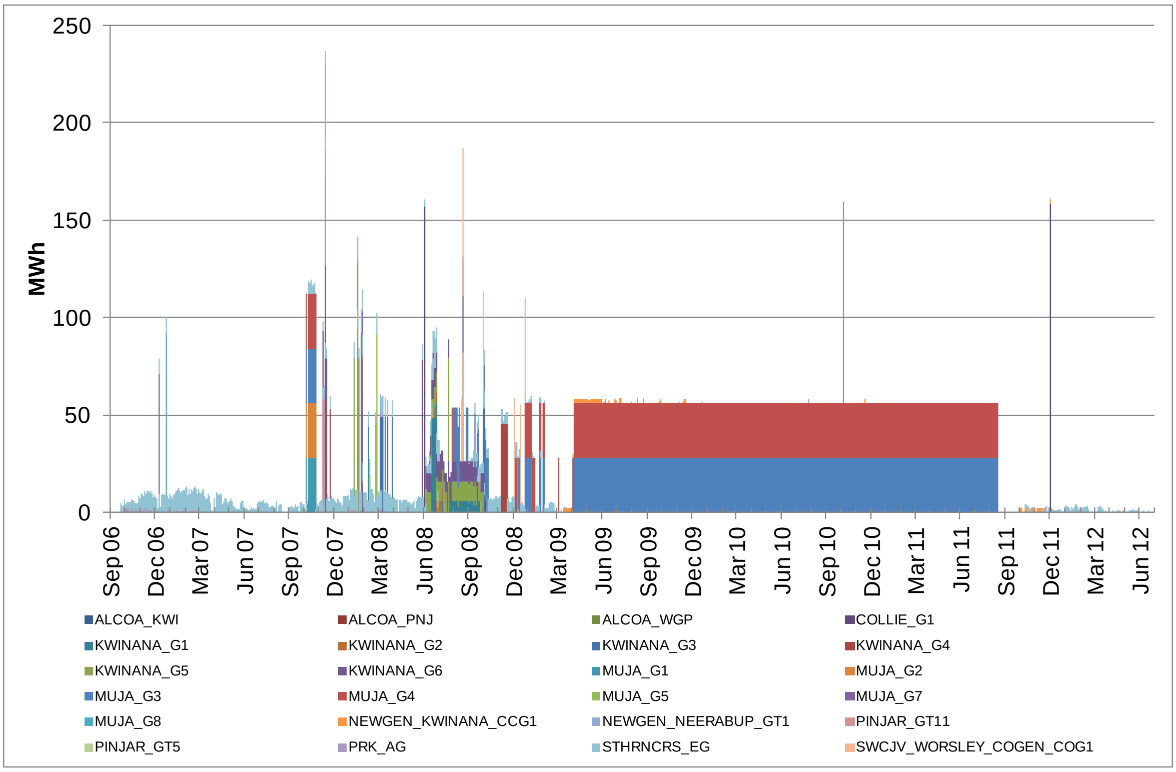
A Market Participant submitting a STEM Submission must include an Availability Declaration on net available energy.[161]

Figure 26 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 continued in the current Reporting Period, until 17 August 2011. These units were declared unavailable through the Availability Declarations to avoid System Management dispatching them as per the Dispatch Merit Order (**DMO**). There were no unavailability declarations made after 17 August 2011, as the units were deregistered under Verve Energy's name. The facilities were again registered under the name Vinalco *(Verve Energy and Inalco Joint Venture)* on 1 July 2012. These facilities received Capacity Credits allocation for the 2012/13 Capacity Year and their Reserve Capacity Obligations did not begin until 1 October 2012. The Authority is aware of the delays in the completion of the refurbishment works at the facilities which resulted in these facilities being on Forced Outages since 1 October 2012 until February/March 2013.

[161] 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, as 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 26 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 purpose of this statistic is to detect whether a Market Participant falsely declares that 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 have 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.

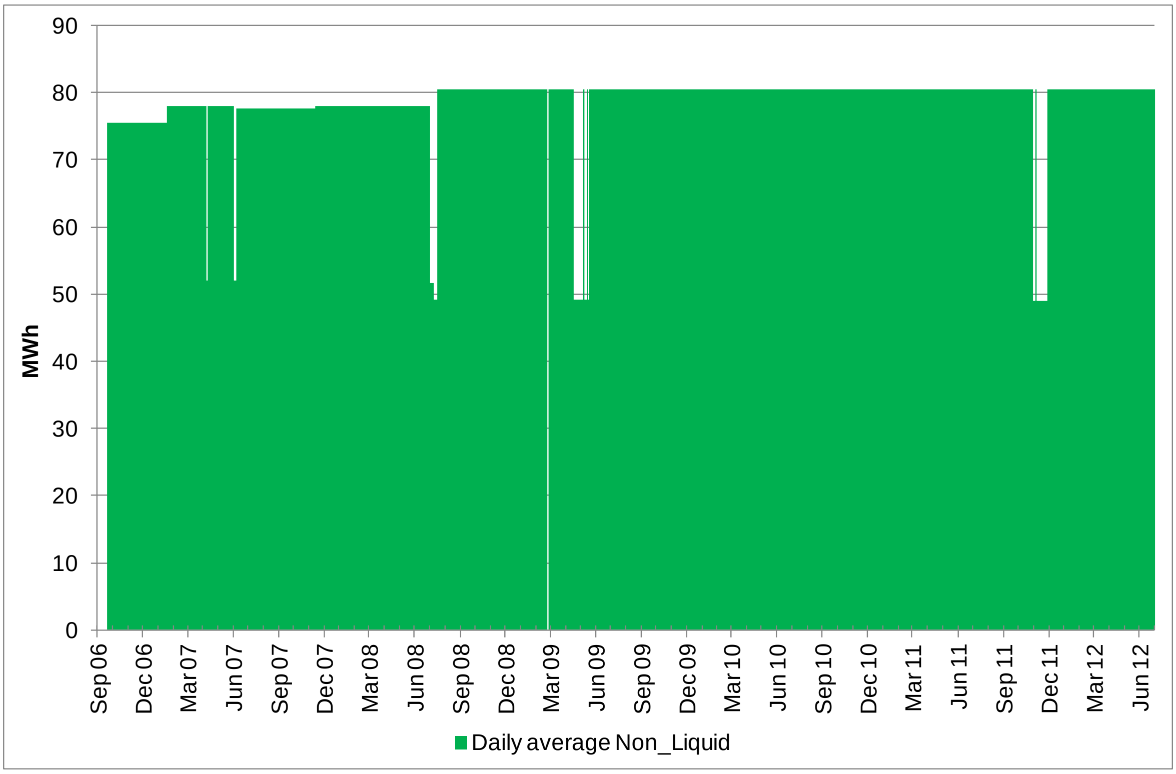
5.5.3 Ancillary Service Declarations

A Market Participant that is a provider of Ancillary Services must include an Ancillary Services Declaration in its STEM Submission.[162] 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 27 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.[163]

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 to the Minister on variations between declarations and the actual real-time operation of facilities in future Reports to the Minister.

Figure 27 Daily average Ancillary Services declarations (MWh per Trading Interval)



[162] See Clause 6.6.1. The Ancillary Services declaration is to set as 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.

[163] The decreases in Ancillary Service Declarations from May to July 2008, from April to May 2009, and from late October 2011 to late November 2011, 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 33 through Figure 64 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 issues will impact on the variations that are required to be identified by the MSDC.

In attempting to track how a Market Participant’s STEM offers and bids change over time, the IMO has defined a variable summarising the participant offers and bids for a Trading Interval into a single number. 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 over-stating 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 over-stated its consumption, it is necessary to determine the Market Customer’s planned load and actual load in accordance with the following.

- Planned load is determined in a different way for a stand-alone Market Customer and a Market Customer that is also a Market Generator.
- For a stand-alone Market Customer, planned load is measured as its Net Contract Position.
- For a Market Customer that is also a Market Generator, planned load is measured as demand set out in the Bilateral Nominations. The reason that the Net Contract Position does not provide an appropriate measure of planned load for a Market Customer that is also a Market Generator is that the Net Contract Position may also include results from STEM trading.
- 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.

Variations between planned load and actual load for individual Market Customers are classified as confidential. Hence, this information 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 28 illustrates the daily average number of units subject to Planned Outages per Trading Interval.

Figure 28 Number of Facilities on Planned Outages (cumulative daily average)

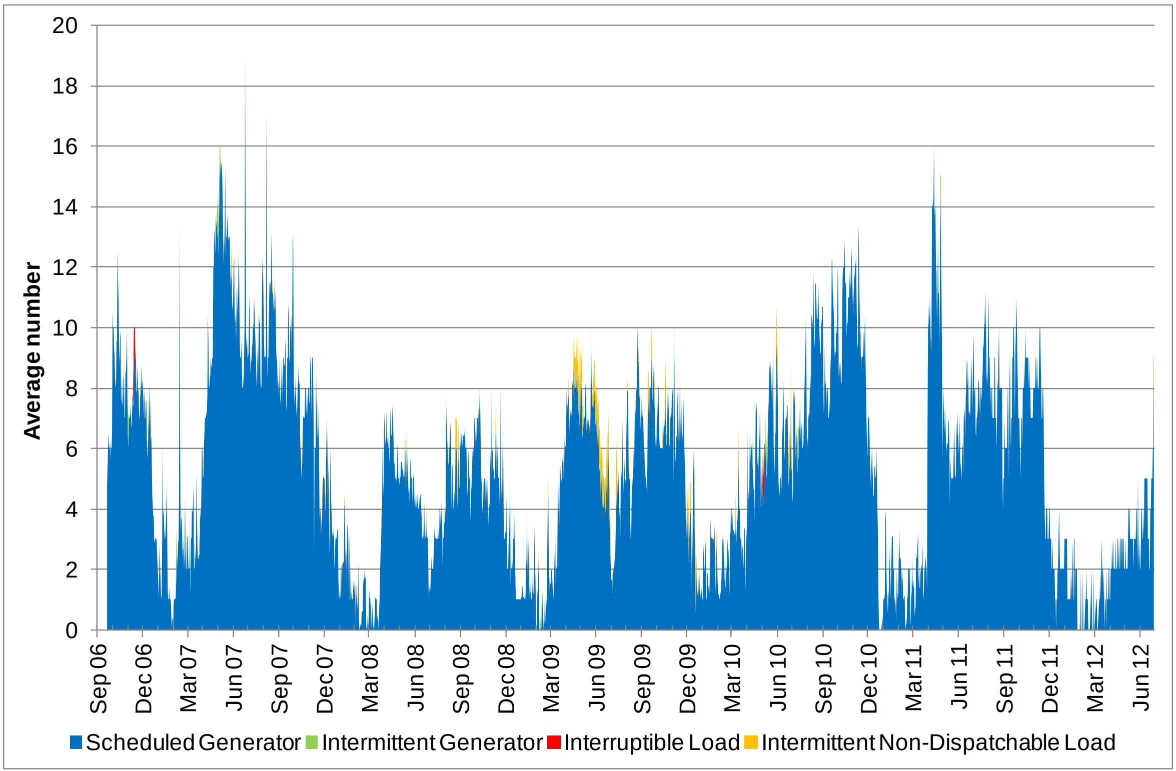


Figure 29 illustrates the accompanying MWh quantity of Planned Outages. As in previous years, it is clear from Figure 28 and Figure 29 that Planned Outages tend not to occur during December, January, February and March, in line with the low level of reserve margins prevailing at these peak summer demand times. The number of Planned Outages was notably high during the low demand period August 2011 to November 2011, similar to the high level of Planned Outages between the August and November months in the previous two Reporting Periods. A number of Verve Energy's facilities, Alinta's Pinjarra and Wagerup facilities, Griffin Power and Griffin Power 2 facilities were on Planned Outage for many Trading Days during this period. NewGen's Kwinana facility was on a Planned Outage for the full October 2011 and the majority of the November 2011 month. A large number of these Planned Outages comprised of coal-run facilities and mid-merit gas facilities not available to the market for many Trading Days. The Authority is also concerned about the impact of a large number of Planned Outages on the economic efficiency of the market. The Authority has raised its concerns over prolonged Planned Outages granted by System Management, particularly to Verve Energy's facilities. Refer to Chapter 2 for a discussion of this topic.

However the overall plant availability was high between late December 2011 and March 2012 to meet the peak summer demand. The Authority also observed fewer Planned Outages during May 2012 and June 2012, as compared to the similar periods in the previous years.

Table 5 presented in Section 5.1.6 previously provides the information on each Facility's capacity subject to outages relative to the Facility's maximum generating capacity.

Figure 29 Quantity of energy subject to Planned Outage (cumulative daily average MWh per facility)

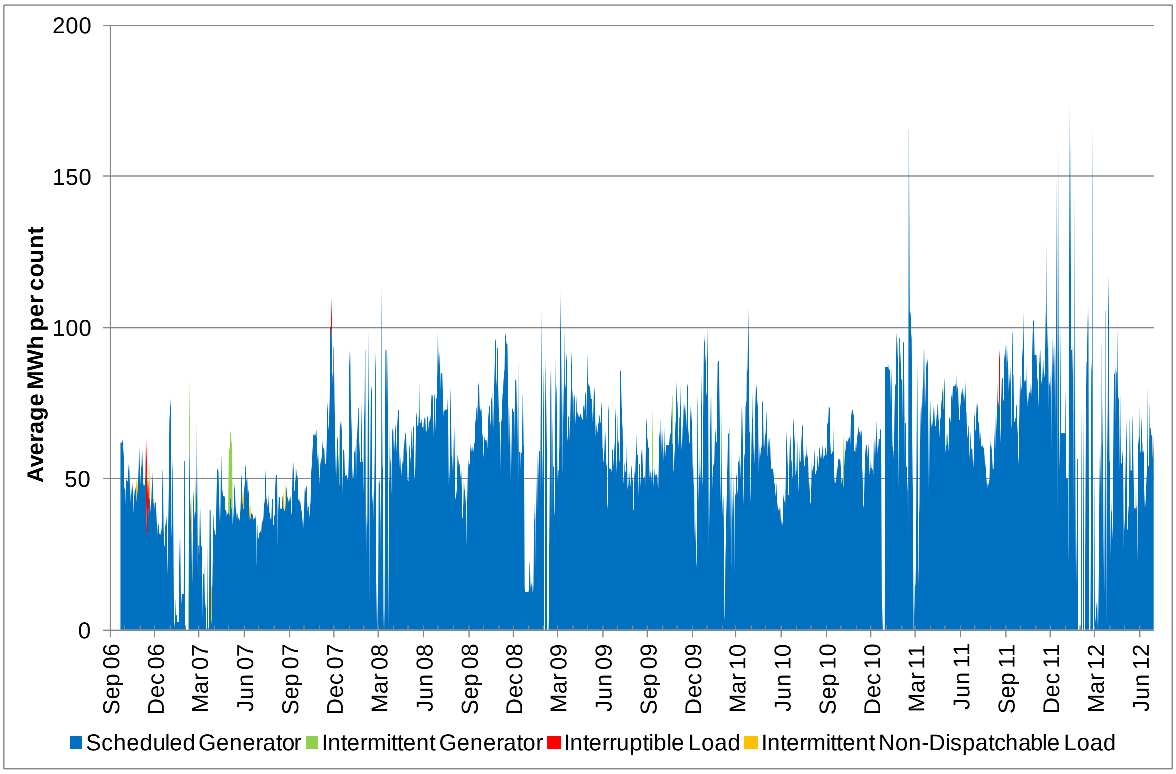


Figure 30 illustrates the daily average number of units subject to Forced Outages per Trading Interval.

Figure 30 Number of Facilities on Forced Outages (cumulative daily average)

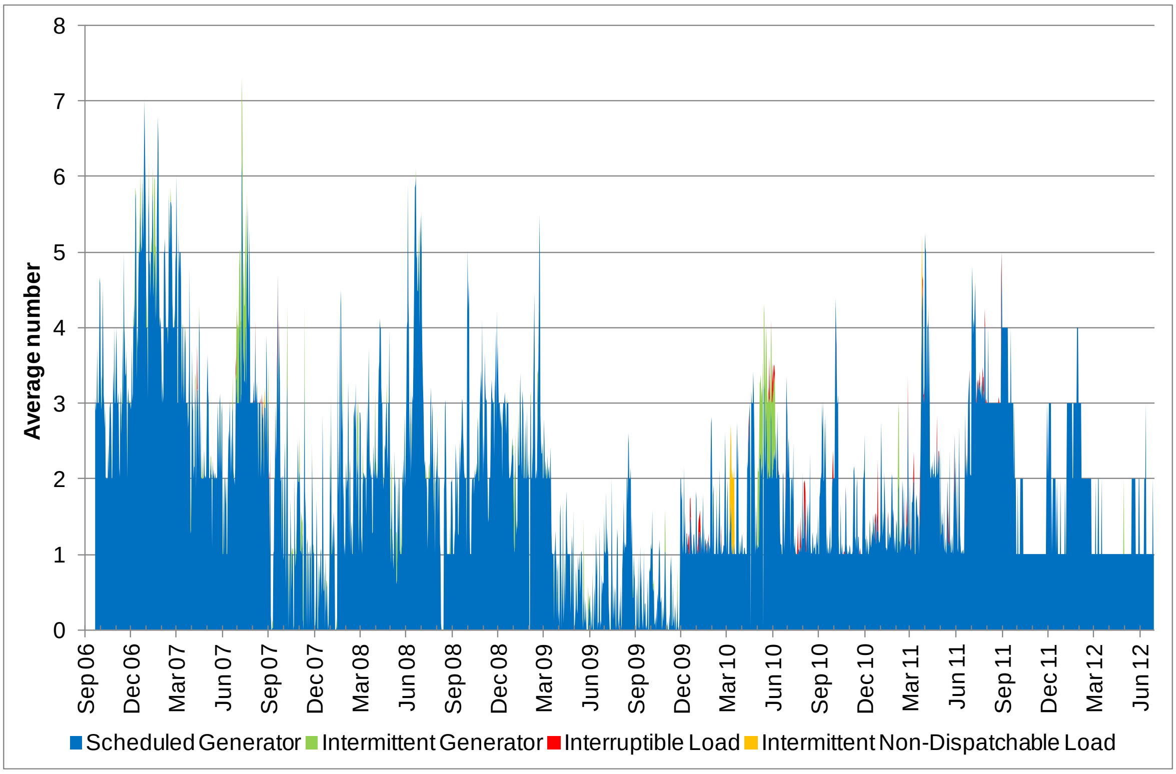


Figure 31 illustrates the accompanying MWh quantity of Forced Outages. As would be expected, there is no clear seasonal pattern for Forced Outages.

The overall number of Forced Outages for the current Reporting Period continued to be low, similar to the previous Reporting Period. For the majority of the current Reporting Period, the average number of Forced Outages remained under two per day. The number of facilities on Forced Outages ranged between 3 to 5 during August 2011 and September 2011, but the associated quantities on Forced Outage only averaged approximately 20 MWh. The average number of Forced Outages and the average associated quantities on Forced Outage (approximately 84 MWh) was high during late November 2011 to early December 2011. Verve Energy's large base load units like Collie_G1 (159 MWh) and Cockburn_CCG1 (116 MWh) were on Forced Outage during this period. Also IPPs like Alinta's Wagerup_U2 (88 MWh) facility had a Forced Outage for 2 Trading Days during this period. Collie_G1 (159 MWh) also had a Forced Outage during late May 2012 to early June 2012, which can be seen in Figure 31 with the spike in the associated average quantities on Forced Outage. The Authority also observed frequent shorter duration Forced Outages from both of the Griffin Power's Bluewaters facilities throughout the Reporting Period, with the associated Forced Outage quantities ranging between 10 MWh and 108 MWh.

No major Forced Outages were observed during the current Reporting Period for Intermittent Generators, Interruptible Loads and Intermittent Non-Dispatchable Loads.

The average Forced Outage quantities remained under 50 MWh for the majority of the current Reporting Period.

Figure 31 Quantity of energy subject to Forced Outage (cumulative daily average MWh per Trading Interval)

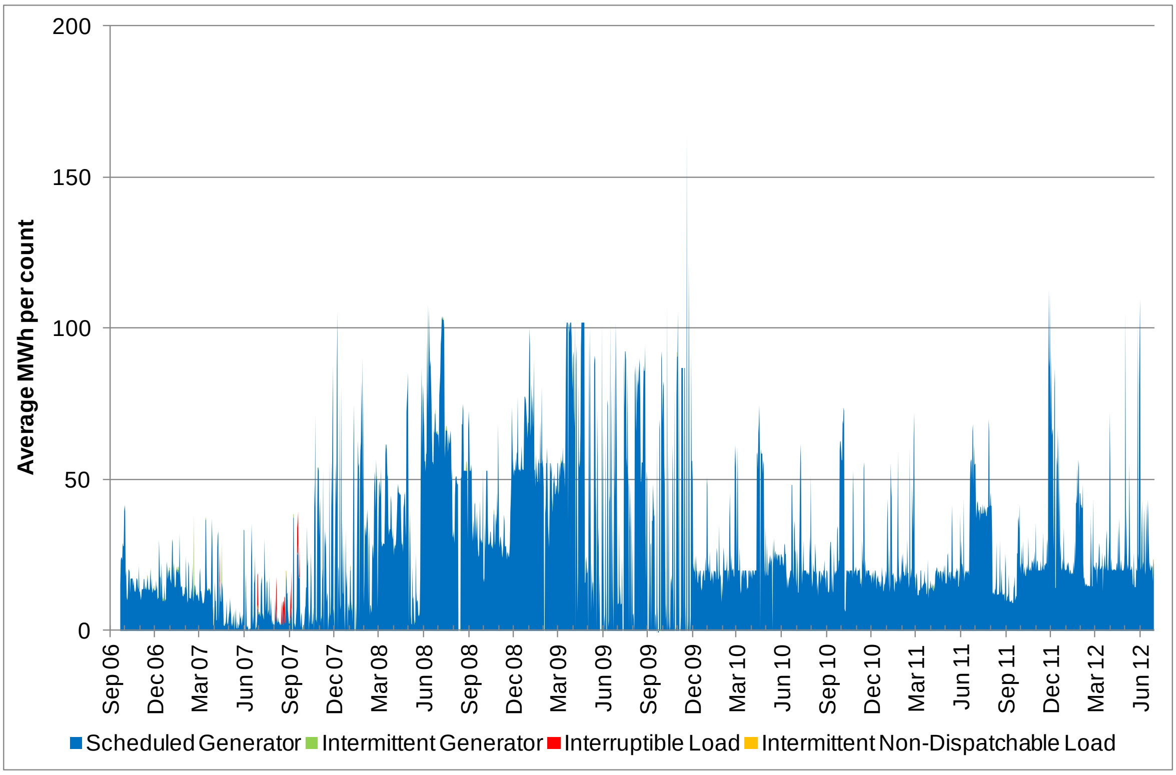
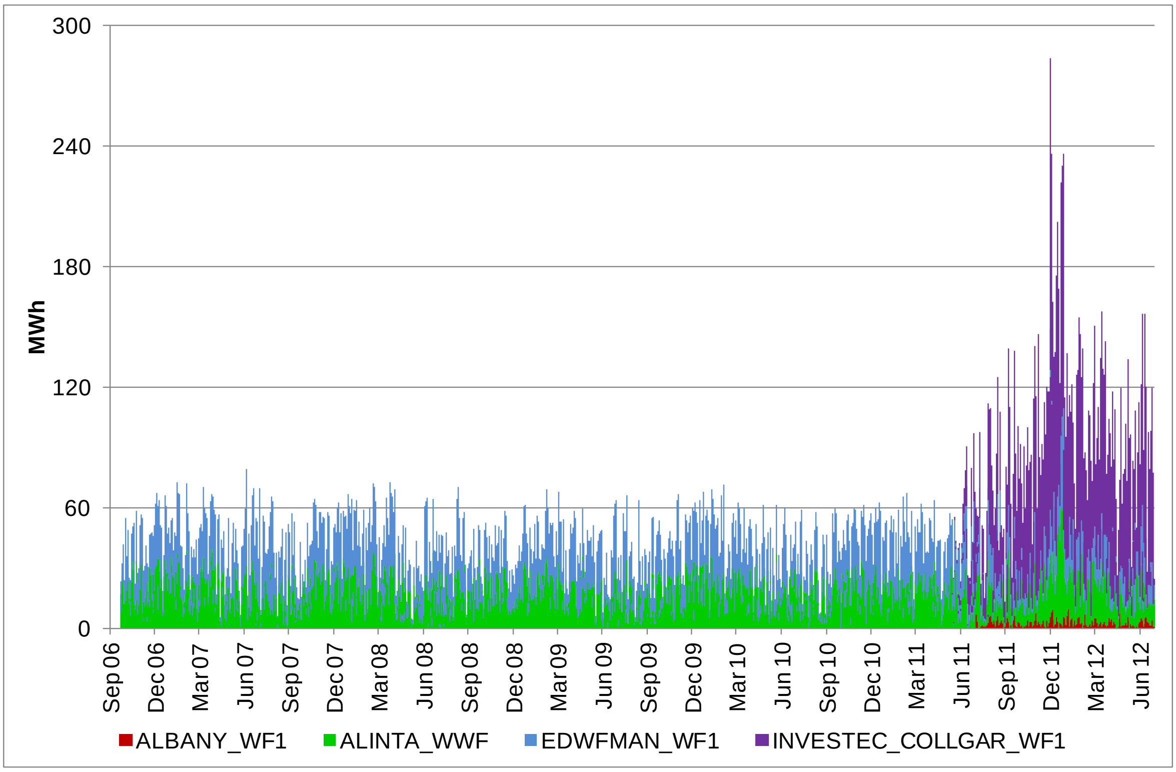


Figure 32 shows the cumulative daily average MWh quantities generated by major Wind Farms since market commencement, in September 2006. The cumulative daily average remained around 60 MWh between September 2006 and June 2011, with Alinta's Walkaway Wind Farm and Emu Downs Wind Farm being the dominant Intermittent Generators. Since early June 2011 the cumulative daily average nearly doubled with the Collgar Wind Farm becoming operational. During the current Reporting Period the cumulative daily average Intermittent Generation was markedly high and exceeded 250 MWh in the first week of December 2011.

Figure 32 WindFarm Generation (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 of high prices in the STEM and Balancing market. The Authority notes that the IMO has established a process for analysing the key drivers associated with the high price incidents observed in the STEM and Balancing market. The results from this analysis are provided to the Authority and discussed at the regular surveillance meeting held between the two organisations. The IMO is currently in the process of formally documenting this process and exploring options for the development of appropriate models for undertaking the analysis required under and clause 2.16.4 (g) of the Market Rules.

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 10 December 2012 the following participants were registered with the IMO:

- 34 entities registered as Market Generators only. There are 5 new participants in this category compared to when last reported on 3 October 2011. These new participants are Denmark Community Wind Farm, Genthrust Pty Ltd, Greenough River, Moonies Hill Energy and UON Pty Ltd;
- 15 entities registered as Market Customers only. There are 3 new participants in this category compared to when last reported on 3 October 2011. These new

participants are Focus Operations, HBJ Minerals Pty Ltd and La Mancha Resources; and

- 11 entities registered as both Market Generators and Market Customers (Blair Fox Pty Ltd is the only new registered participant in this category compared to when last reported on 3 October 2011).

This is a total of 60 registered entities and represents an increase of 9 entities as at 3 October 2011, 30 entities registered as at 2 September 2008, 36 as at 6 October 2009 and 42 as at 14 October 2010. Table 15 in Appendix 3 provides a list of these participants at 2 September 2008, 6 October 2009, 14 Octoberf 2010, 3 October 2011 and 10 December 2012.

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 Balancing Support Contracts (**BSCs**) that System Management enters into.

During 2011/12, 52 MW of Spinning Reserve Ancillary Service was provided by Interruptible Load, supplied by two Market Participants other than Verve Energy. This reduced to 42 MW in October 2011 after the contract to supply 10 MW from one supplier expired. For 2012/13, 42 MW of Spinning Reserve will be provided by an Interruptible Load supplied by one Market Participant. The remaining Spinning Reserve Ancillary Service will be supplied by synchronising additional Verve Energy generators. It is expected Verve Energy has sufficient capacity to meet this requirement even with the largest unit for providing Spinning Reserve 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. Historically, the Mungarra units have been dispatched most of the time for this service, with few dispatch events from the West Kalgoorlie units. The Geraldton unit has not been used for this service so far, but System Management has anticipated the use of it in the future, due to load increases in the Geraldton area. The forecast requirements for Dispatch Support Ancillary Services for 2012/13 will continue to be supplied from Verve Energy facilities as System Management does not anticipate entering into further arrangements for dispatch support.

System Management also has contractual arrangements with Verve Energy and Perth Energy for System Restart Service, procured through a competitive tendering process. No System Restart Services were used in 2011/12 and the arrangements are expected to be sufficient to cover the requirements for 2012/13.[164] Payments for these services are determined by the Authority, based on the proposal submitted by System Management. For the 2011/12 and 2012/13 financial years, the Authority determined the value for

[164] Refer to the IMO website http://www.imowa.com.au/f2841,2379223/Ancillary_Service_Report-2012_FINAL.pdf

System Restart Ancillary Service as $40,933 per month and $41,583 per month, respectively.[165]

System Management has not entered into any BSCs between 21 September 2006 (market commencement) and 30 June 2012. From market commencement until 30 June 2012, 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 former Office of Energy (now the PUO) 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.[166]

Information on Market Rule changes that have commenced, been rejected or are under development is available on the IMO's website. Table 11 provides a summary of the IMO's progression of Rule Change Proposals, since the commencement of the formal Rule Change process in December 2006 to June 2012.

Table 11 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[167]	-	-	-
1 August 2007 and 31 July 2008	36	36[168]	-	-	-
1 August 2008 and 31 July 2009	37	24[169]	-	3	10
1 August 2009 and 31 July 2010	19	15[170]	2	1	1
1 August 2010 and 31 July 2011	29	25[171]	2	-	2
1 August 2011 and 30 June 2012	13	10[172]	-	1	2

[165] Refer to ERA website http://www.erawa.com.au/cproot/9514/2/20110420%20Decision-%20Determination%20of%20the%20Ancillary%20Service%20Cost_LR%20parameter.pdf

[166] 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.

[167] As at the end of the 2007 calendar year.

[168] All of which have commenced.

[169] As at the time the 2009 Report to the Minister was released.

[170] As at the time the 2010 Report to the Minister was released.

[171] As at the time the 2011 Report to the Minister was released.

[172] As at the time the 2012 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.[173]

Clause 2.16.9 of the Market Rules specifies 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 requires 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 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 Short Term Energy Market;
  - Balancing;

[173] 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.

  - o the dispatch process;
  - o planning processes; and
  - o 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 12 Mapping of the reporting requirements under the Market Rules (as of 30 June 2012) 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	3
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	4.5
2.16.12 (b) v.	Effectiveness of the dispatch process	4.6
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 and the Executive Summary
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 13 Mapping of the MSDC data and analysis requirements under the Market Rules (as of 30 June 2012) 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	5.3.1
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
2.16.4(c)	Statistical analysis of the volatility of prices in the STEM	5.2.1 and 5.2.2

Market Rule clause	Market Rule reporting requirement	See report section
	Auctions and Balancing	
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

To assist the Authority's preparation of the 2012 Report to the Minister, the Authority published a Discussion Paper on 19 November 2012, inviting interested parties to make submissions on issues impacting the effectiveness of the WEM. The submission period closed on 18 December 2012.

The Authority received 30 submissions in response to the Discussion Paper as listed in the table below. These consisted of 18 original submissions, and 12 copies (or a slightly modified version) of the same submission that was jointly or individually signed by Demand Side Management (**DSM**) providers.

The Authority sought permission for publication of the submissions from the respective stakeholders. Where permissions for publication of a submission was provided, the submission is available on the Authority's website.

The Authority wishes to acknowledge the time and effort that goes into the preparation of these submissions. The Authority continues to value stakeholder feedback on issues impacting on the effectiveness of the WEM. Whilst the Authority has taken into the feedback received from stakeholders in the preparation of this report, the Authority notes some issues raised by stakeholders are considered to be out of scope for this report and will be addressed at a later stage where appropriate.

List of stakeholders who provided submissions

	Stakeholder	Description	Permission to publish
1	BGC Australia Pty Ltd	DSM Provider	No
2	Big Country	DSM Provider	Yes
3	Chamber of Commerce and Industry (CCI)	Not-for-profit, member driven organisation providing information, professional services and support for business	Yes
4	Community Electricity	Provider of Electricity Retail Services and Market Consultancy, Member of MAC and Technical Rules Committee	Yes
5	Corpwest Investments Pty	DSM Provider	Yes
6	Dobbie Dico (Foundry)	DSM Provider	Yes
7	Queens Supa IGA (Retail Grocery)	DSM Provider	Yes
8	City of Melville (Local Government)	DSM Provider	Yes
9	Doral (Mineral Sands)	DSM Provider	Yes
10	George Weston Foods (Food Processing)	DSM Provider	Yes
11	AusOils Pty Ltd (Food Processing)	DSM Provider	Yes
12	W McPhail & Sons (Agriculture)	DSM Provider	Yes
13	Macco Feeds (Agriculture)	DSM Provider	Yes
14	Inghams (Agriculture)	DSM Provider	Yes
15	DomGas Alliance	State's peak energy user group. Represents gas users, infrastructure investors and prospective domestic gas producers. Members account for around 80% of the state's gas consumption and transmission capacity, which includes the supply of gas and electricity to 800,000 households and 200,000 small businesses.	Yes

	Stakeholder	Description	Permission to publish
16	Energetics Pty Ltd	Management consultancy focussed on energy and carbon with offices across Australia.	No
17	Energy Supply Association of Australia (ESAA)	Peak industry body for the stationary energy sector in Australia. Represents policy positions of the Chief Executives of 36 electricity and downstream natural gas businesses.	Yes
18	EnerNOC	Independent Aggregator of DSM	Yes
19	Independent Market Operator (IMO)	Administers and operates the WEM	Yes
20	Perth Energy	Retailer (with generator interests)	Yes
21	Presbyterian Ladies College	DSM Provider	Yes
22	Redmond Pty Ltd	DSM Provider	Yes
23	Southern Metropolitan Regional Council	DSM Provider	Yes
24	Sustainable Energy Association of Australia (SEA)	Peak business body for Sustainable Energy Industry and for enterprises supporting sustainable energy	Yes
25	Synergy	Retailer	Yes
26	System Management	Responsible for dispatching the Power System - ensures that the power system is operated in a safe, secure and reliable manner.	Yes
27	The Loose Leaf Lettuce Company	DSM Provider	Yes
28	The West Australian	DSM Provider	Yes
29	WA Bluemetal	DSM Provider	Yes
30	Western Power	Build, maintain and operate the electricity network	Yes

Appendix 3 Market Surveillance Data Catalogue – additional information

Short Term Energy Market Offers and Bids

Short Term Energy Market Offers

Figure 33 to Figure 49 show STEM Offers for each Market Participant from market commencement to 30 June 2012. In the current Reporting Period, two Market Participants have commenced making offers in the STEM, namely ERM Power and Tesla.

Figure 33 shows Alcoa's offers were exclusively priced at the Maximum STEM Price throughout the current Reporting Period, which is a change in pricing behaviour (offered at Alternative Maximum STEM Price during the last two Reporting Periods).

Figure 33 Alcoa's daily average STEM Offers (cumulative MWh per Trading Interval)

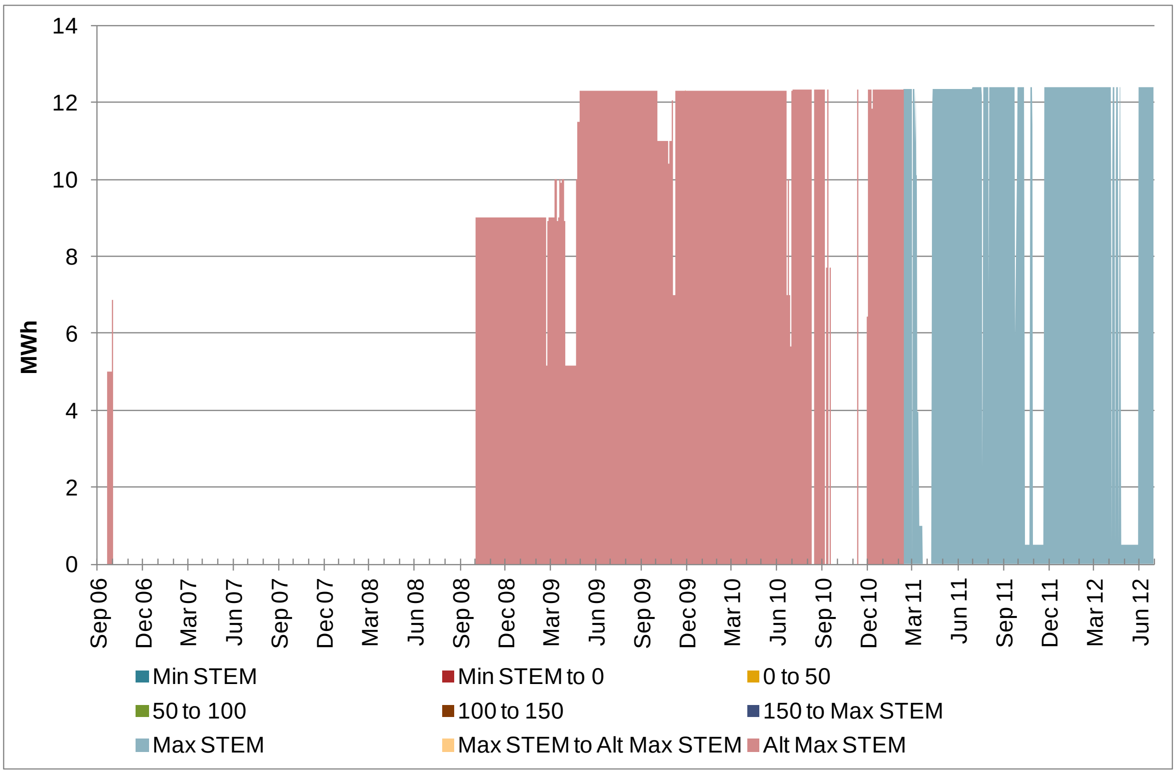


Figure 34 shows that Alinta continued to offer large volumes into the STEM, priced at the Alternative Maximum STEM Price, and also offered large volumes priced at the Maximum STEM Price. It also offered some volumes in mid-price range of $50/MWh to $100/MWh.

Figure 34 Alinta's daily average STEM Offers (cumulative MWh per Trading Interval)

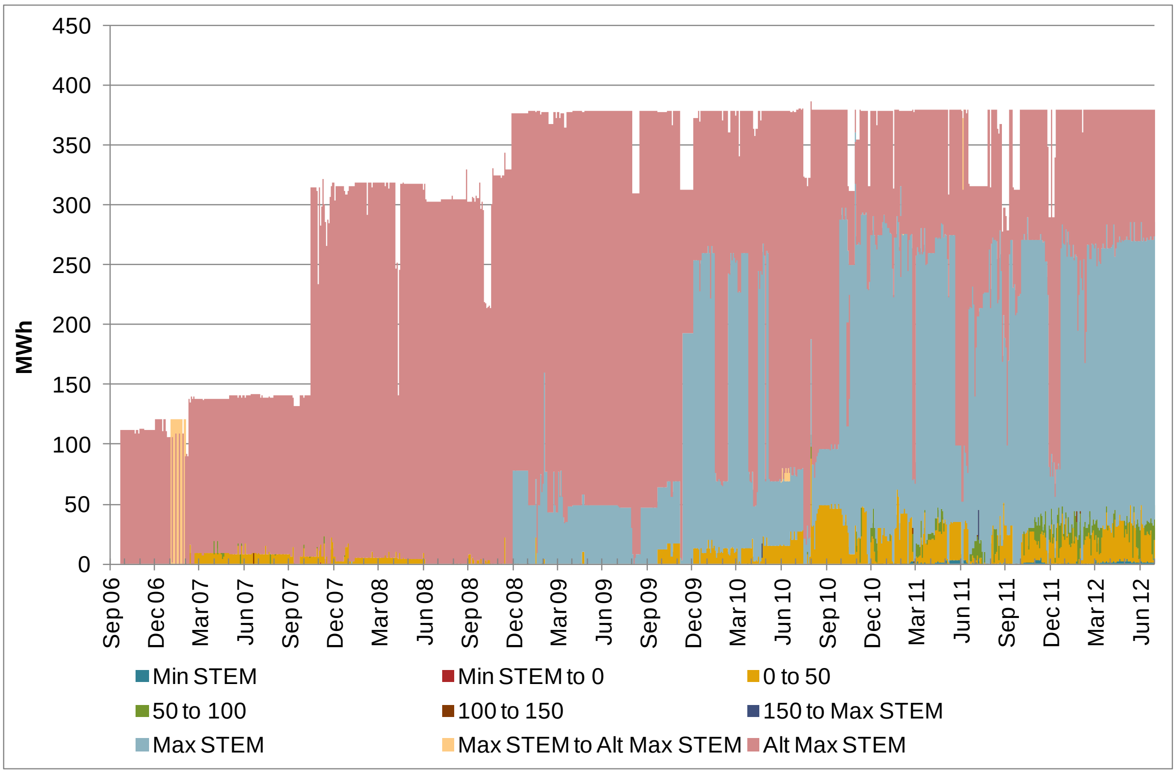


Figure 35 shows ERM Power offered the majority of its volumes, in the range 0 MWh to 8 MWh, for the first time in STEM at price greater than Maximum STEM Price.

Figure 35 ERM Power's daily average STEM Offers (cumulative MWh per Trading Interval)

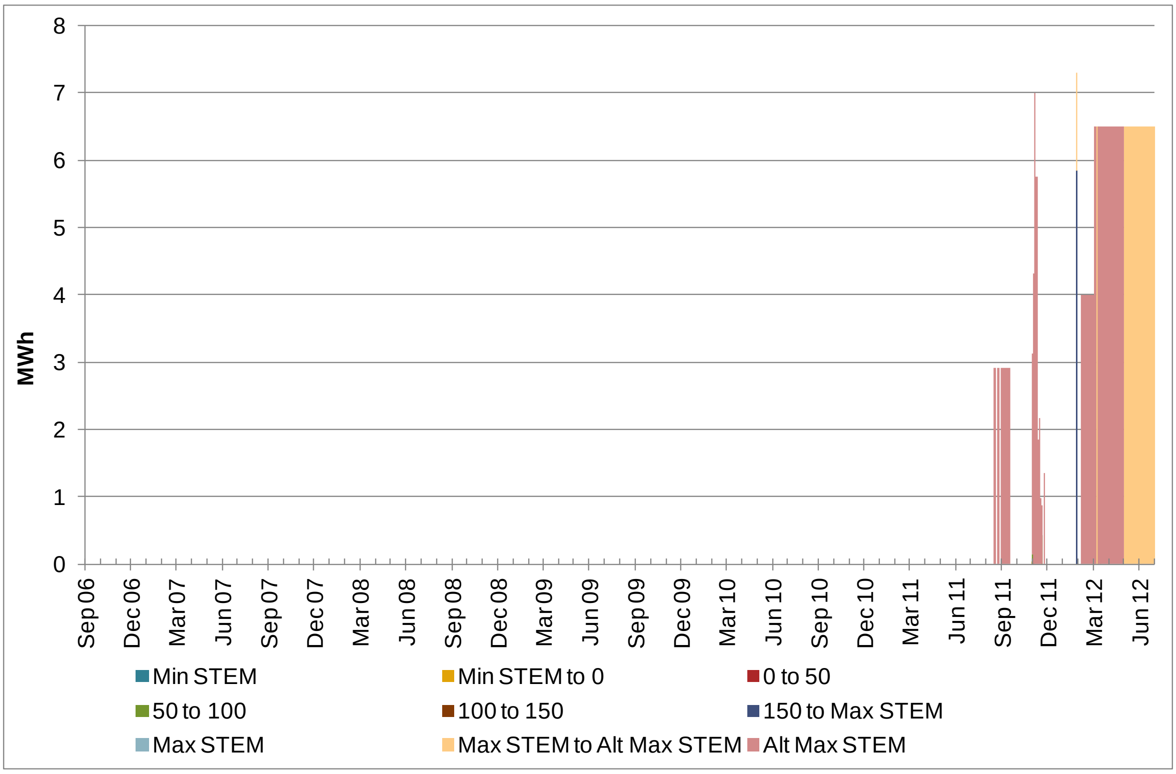


Figure 36 shows Goldfields Power continued to offer volumes priced almost exclusively at the Alternative Maximum STEM Price during the current Reporting Period.

Figure 36 Goldfields Power's daily average STEM Offers (cumulative MWh per Trading Interval)

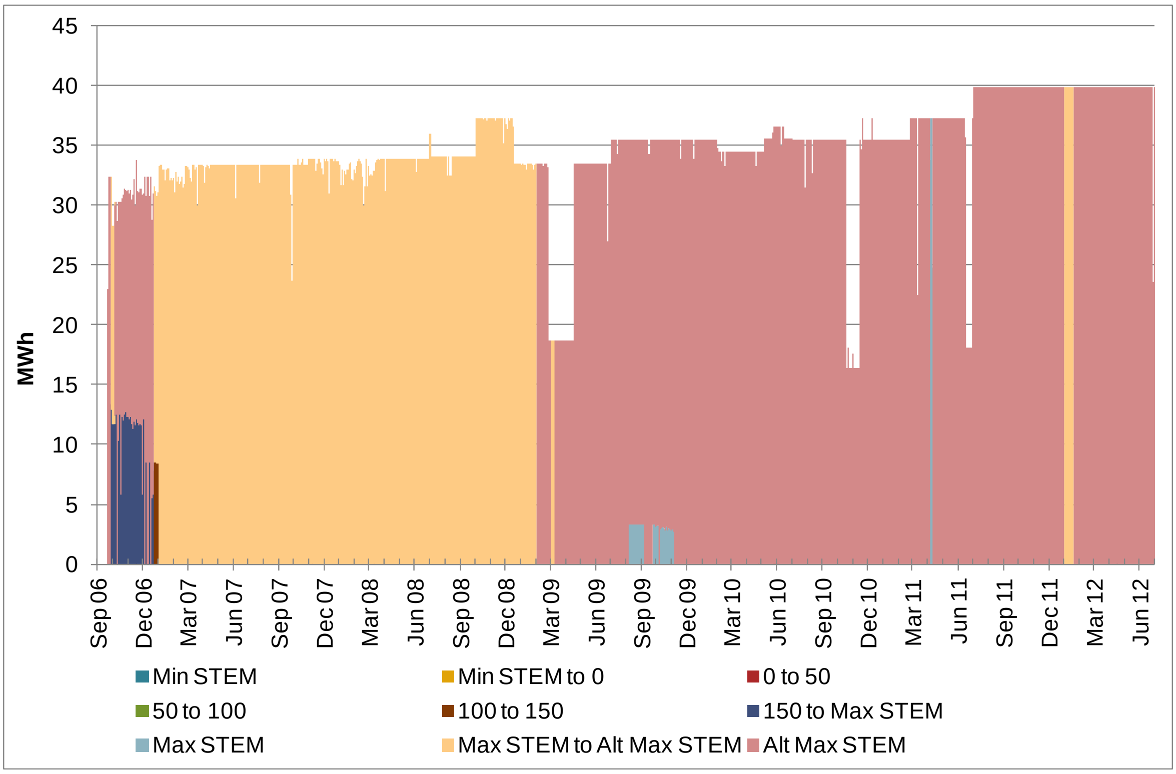


Figure 37 shows that during the current Reporting Period, Griffin Power offered the majority of its volumes in the STEM at Alternative Maximum STEM Price, whilst Figure 38 shows that Griffin Power 2 offered STEM volumes in a range of prices.

Figure 37 Griffin Power's daily average STEM Offers (cumulative MWh per Trading Interval)

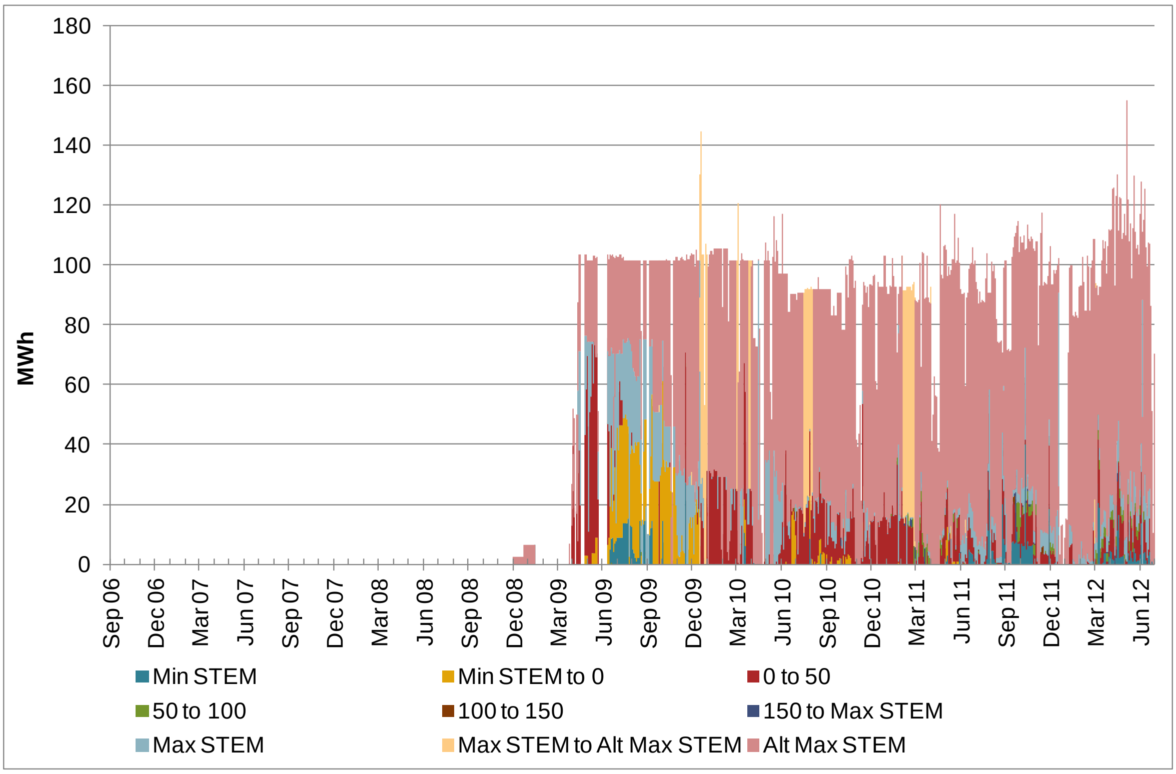


Figure 38 Griffin Power 2's daily average STEM Offers (cumulative MWh per Trading Interval)

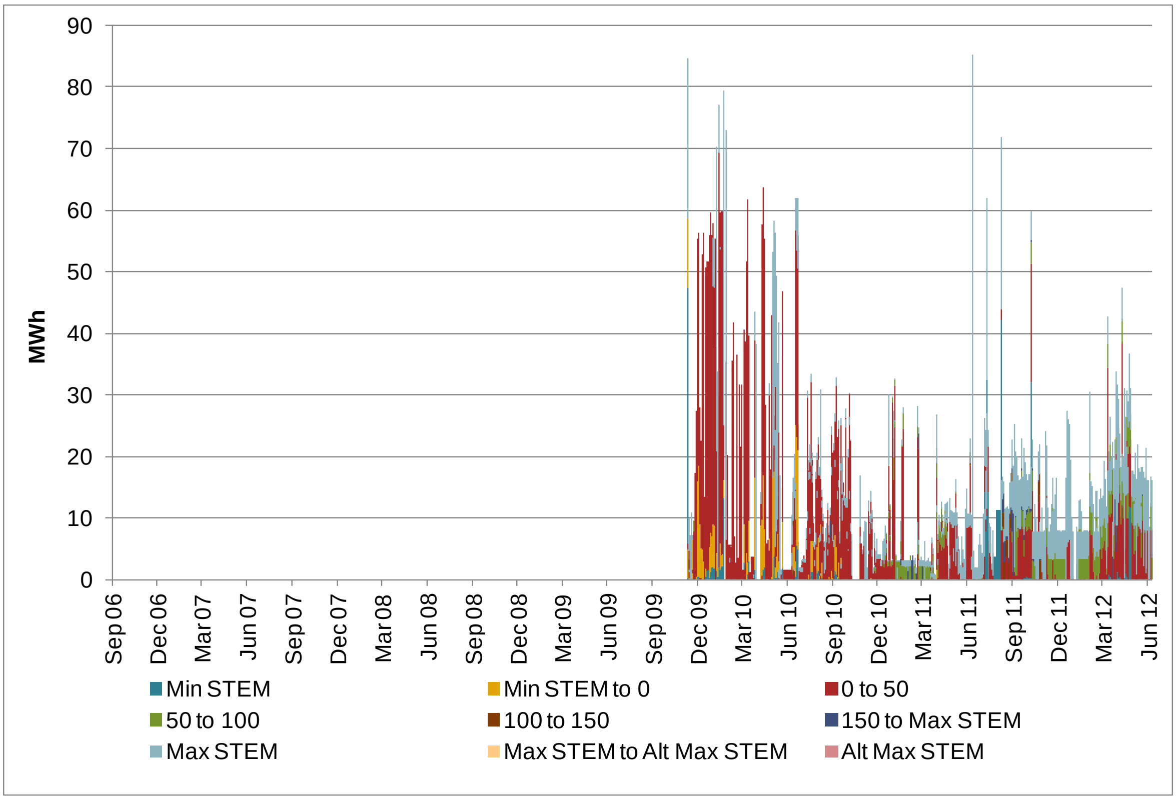


Figure 39 shows Karara Energy (registered as a Market Customer since 2007) offered into the STEM for the first time a daily average of 30 MWh at the Alternative Maximum STEM Price during last week of June 2012.

Figure 39 Karara's daily average STEM Offers (cumulative MWh per Trading Interval)

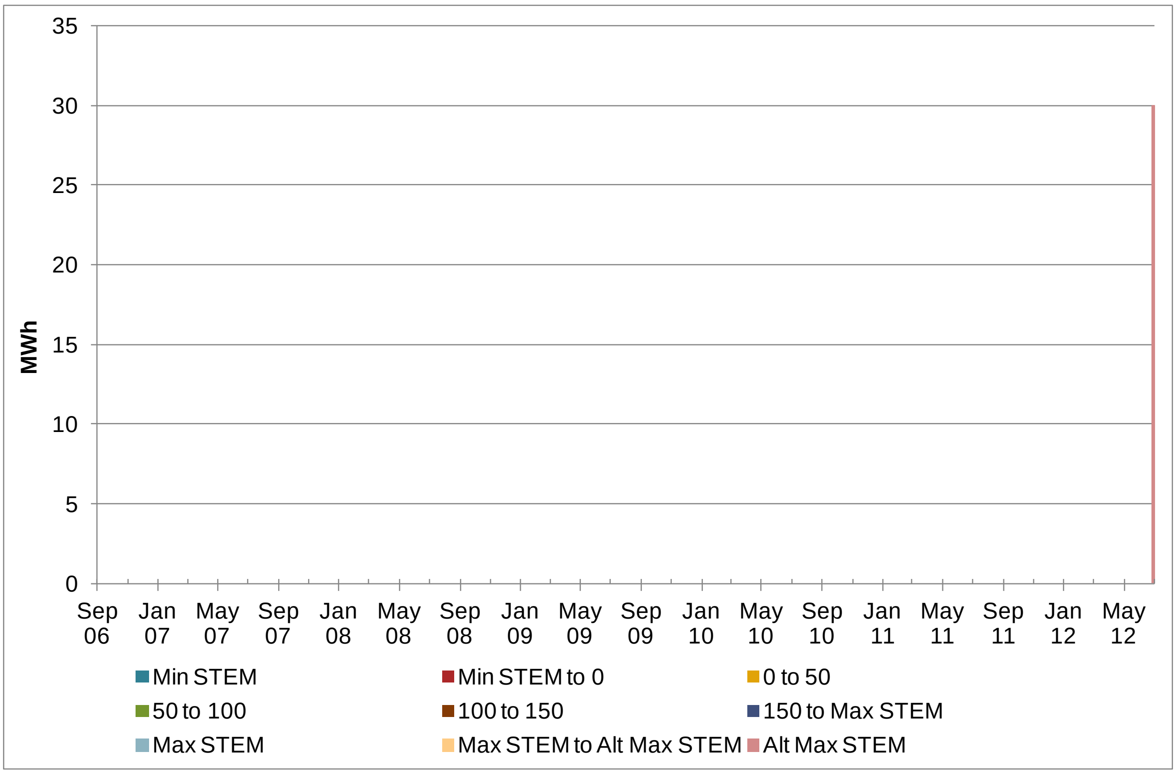


Figure 40 shows Landfill Gas and Power has offered volumes consistently at prices between the Maximum STEM Price and Alternative Maximum STEM Price throughout the current Reporting Period.

Figure 40 Landfill Gas and Power's daily average STEM Offers (cumulative MWh per Trading Interval)

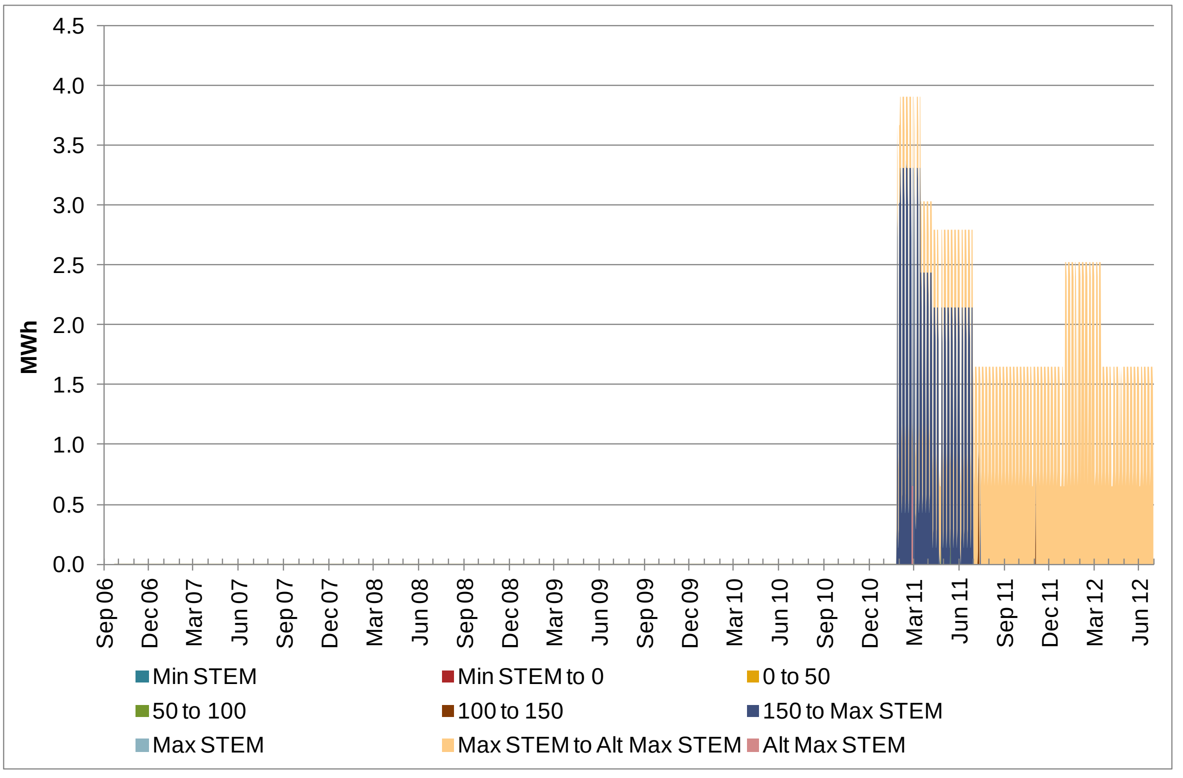


Figure 41 shows that NewGen Kwinana offered the majority of its STEM volumes at the Maximum STEM Price, notable volumes can also be seen in the $0/MWh to $50/MWh and $50/MWh to $100/MWh ranges. The period of no STEM Offers during October 2011 and November 2011 was a result of the facility being on long duration Planned Outage.

Figure 41 NewGen Power Kwinana's daily average STEM Offers (cumulative MWh per Trading Interval)

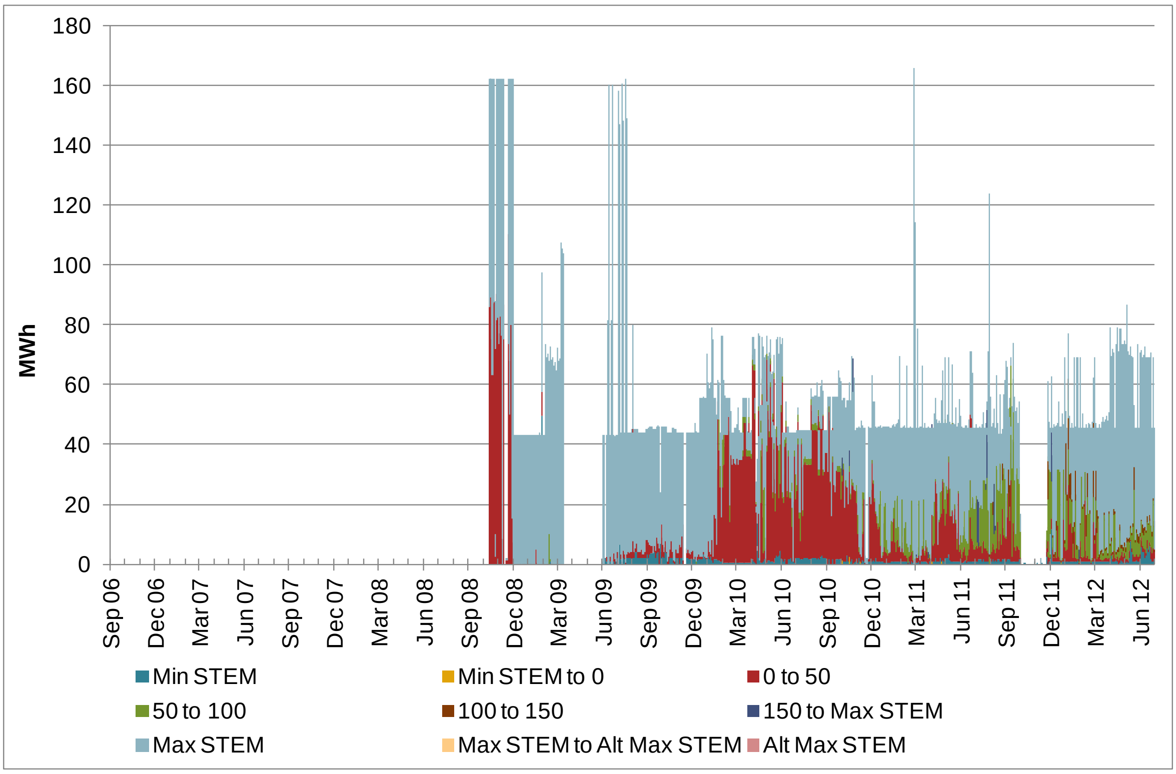


Figure 42 shows that NewGen Neerabup's STEM Offers continue to be almost exclusively priced at the Maximum STEM Price during the current Reporting Period.

Figure 42 NewGen Neerabup's daily average STEM Offers (cumulative MWh per Trading Interval)

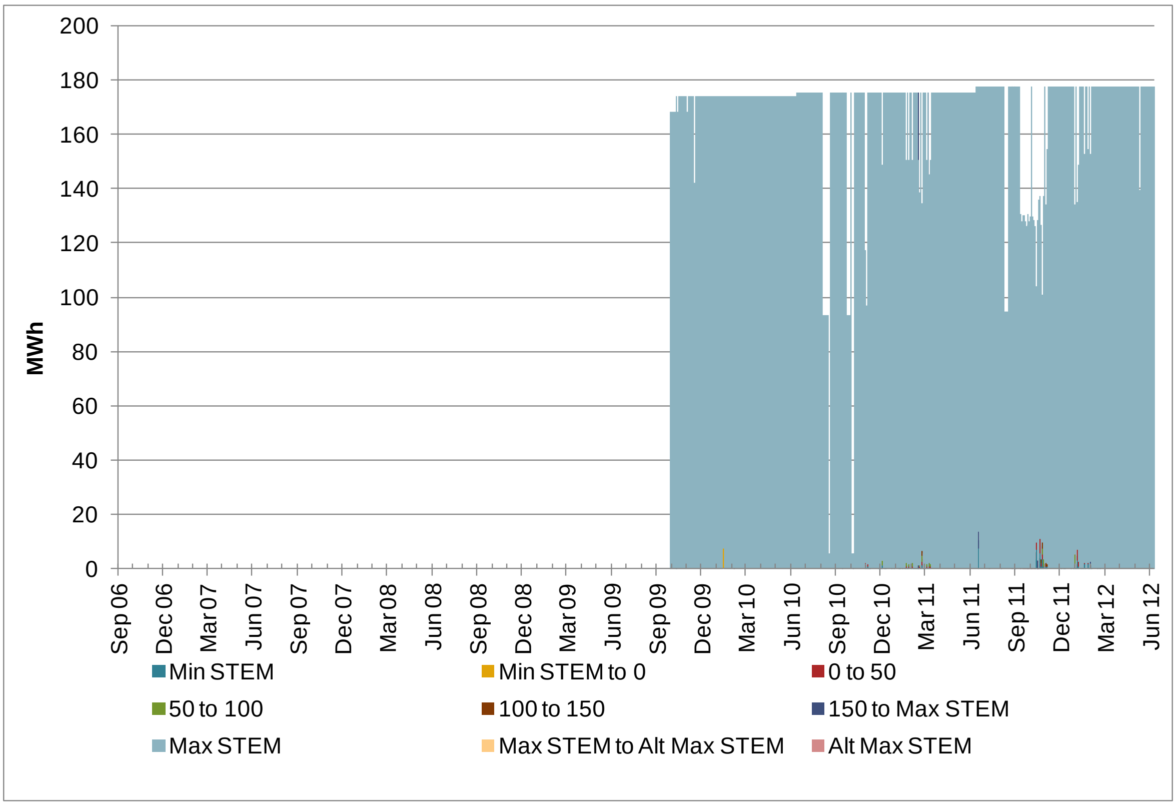


Figure 43 and Figure 44, respectively, shows that Perth Energy and Southern Cross Energy have priced most of their STEM Offers at the Alternative Maximum STEM Price during the current Reporting Period.

Figure 43 Perth Energy's daily average STEM Offers (cumulative MWh per Trading Interval)

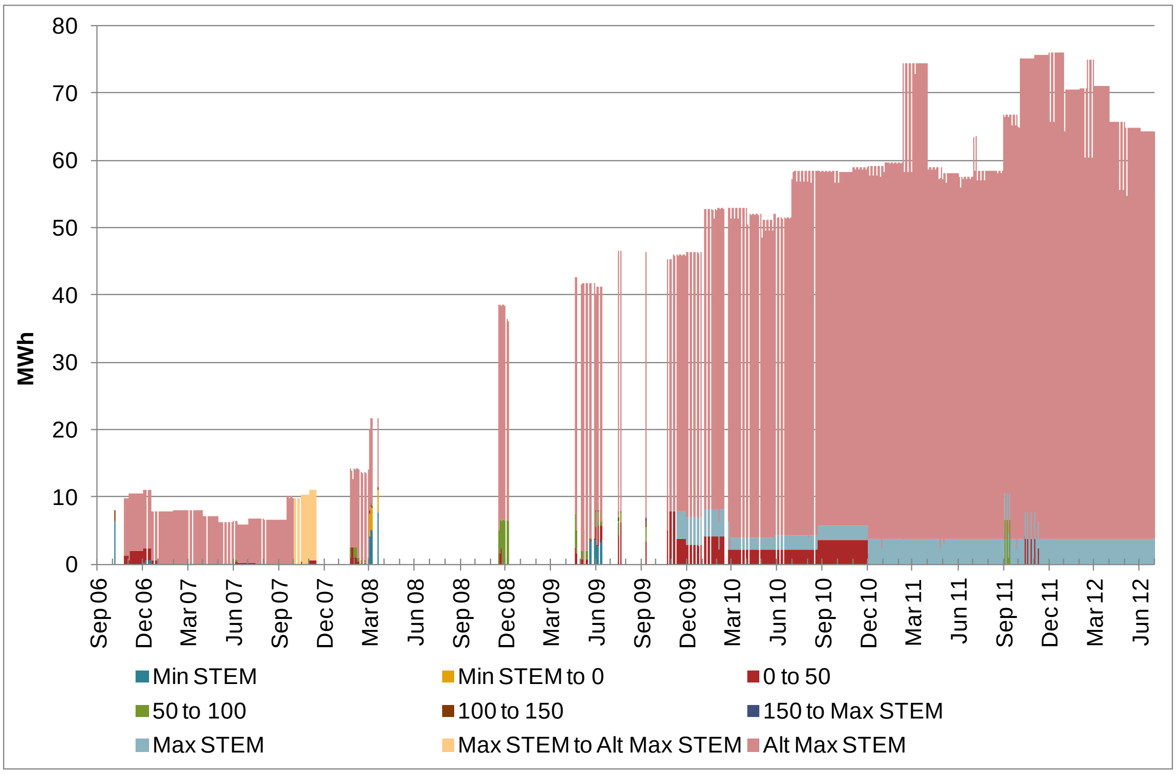


Figure 44 Southern Cross Energy's daily average STEM Offers (cumulative MWh per Trading Interval)

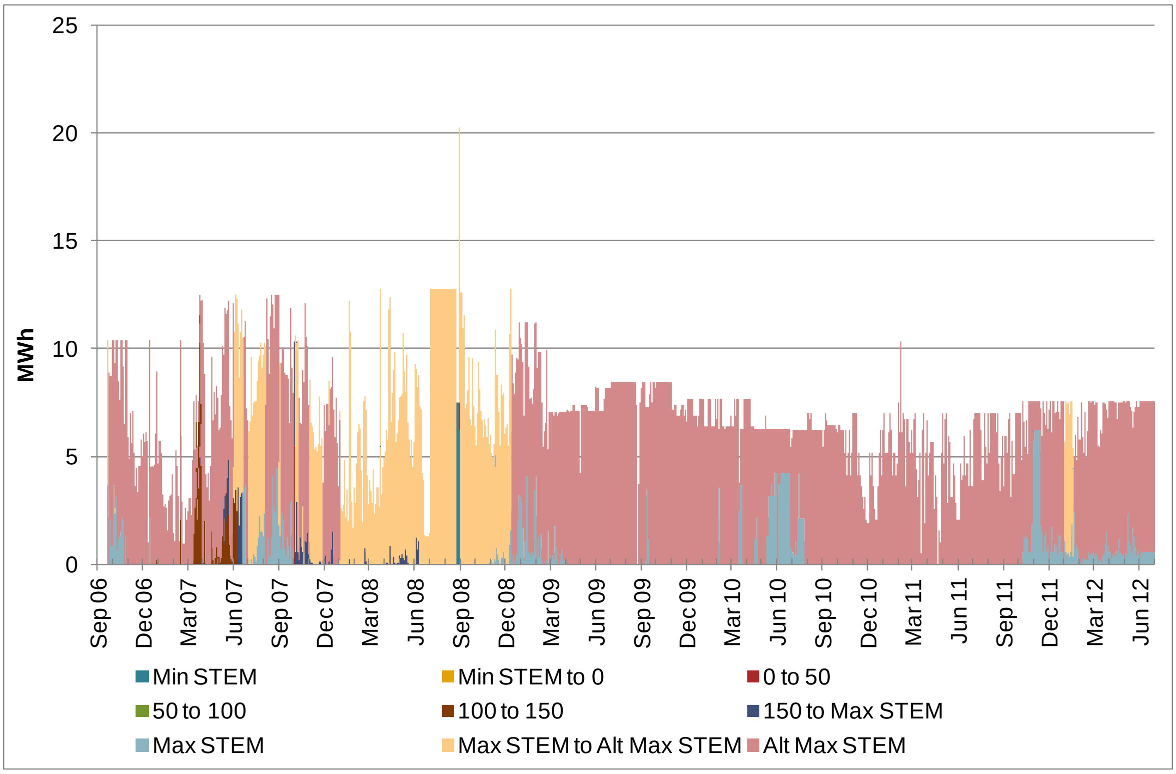


Figure 45 shows that Tiwest continues to offer energy at the Alternative Maximum STEM Price throughout the current Reporting Period, except for a small period in March 2012 and during May 2012 and June 2012.

Figure 45 Tiwest's daily average STEM Offers (cumulative MWh per Trading Interval)

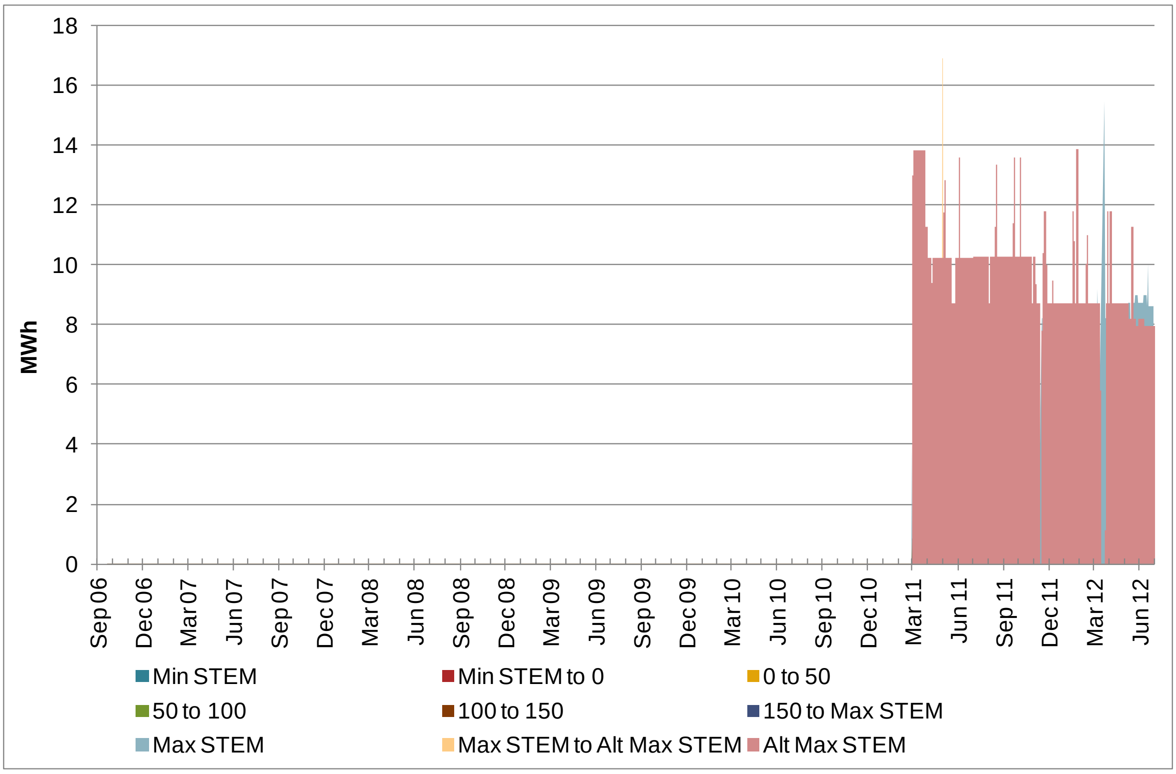


Figure 46 shows Tesla, a new entry to the market in the 2011/12 Capacity Year, offered smaller volumes in the STEM notably at the Alternative Maximum STEM Price, and at prices between the Maximum STEM Price to the Alternative Maximum STEM Price.

Figure 46 Tesla's daily average STEM Offers (cumulative MWh per Trading Interval)

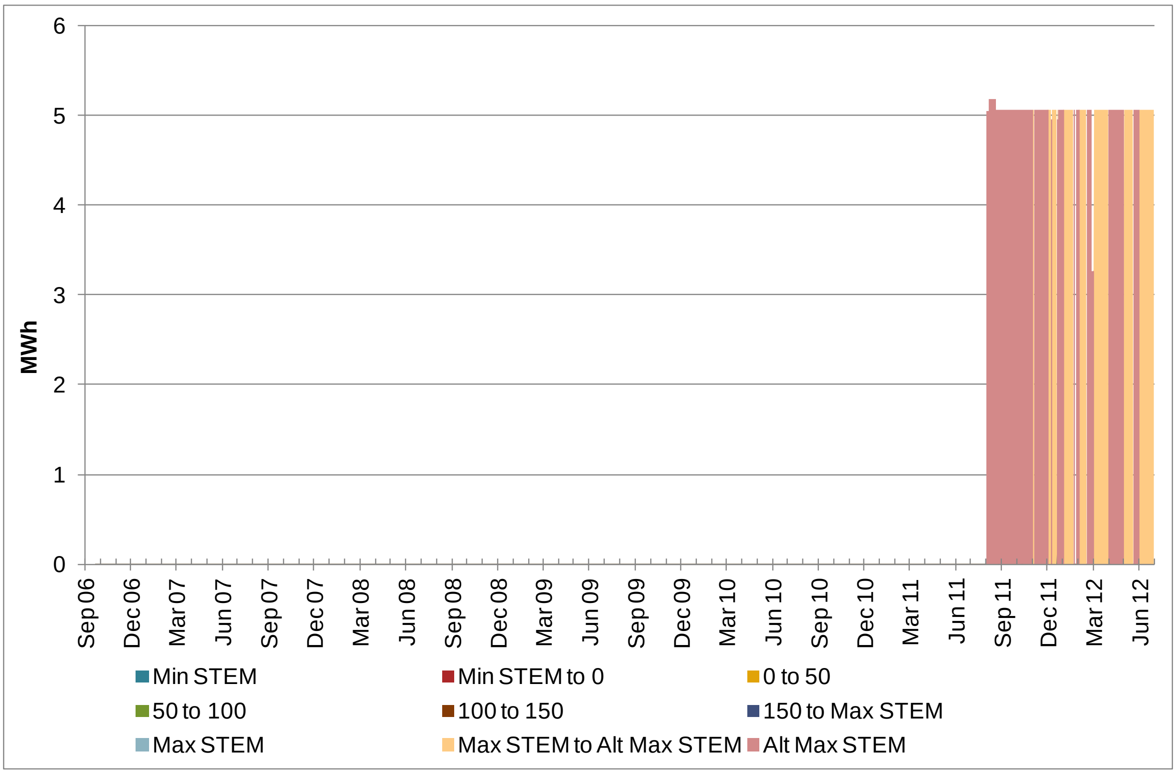


Figure 47 shows that, during the start of the current Reporting Period, Western Energy made offers at prices between $150/MWh and the Maximum STEM Price. This changed for the majority of the current Reporting Period as the offer prices increased and ranged between the Maximum STEM Price and the Alternative Maximum STEM Price.

Figure 47 Western Energy's daily average STEM Offers (cumulative MWh per Trading Interval)

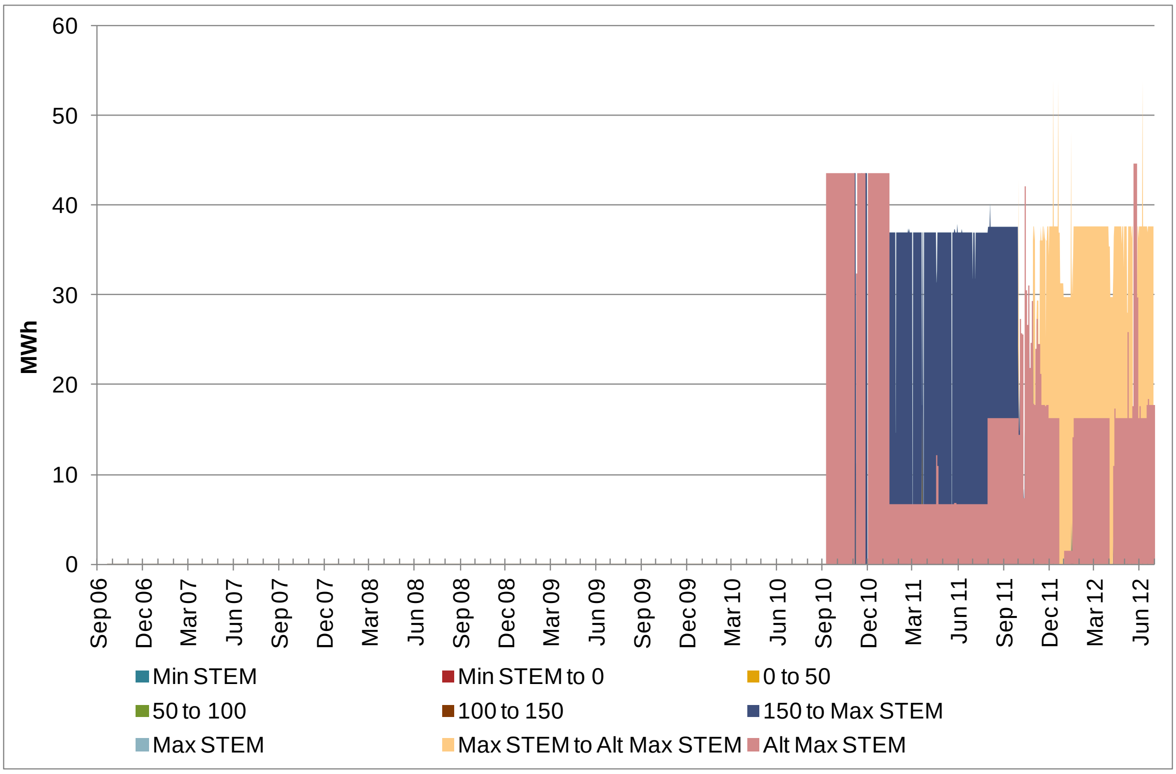


Figure 48 shows that Synergy has continued to offer significant volumes into the STEM in the current Reporting Period, primarily priced at the Alternative Maximum STEM Price to cover its demand positions. Synergy offered notable STEM volumes in the price range 0/MWh to 50/MWh, during the July 2011 to October 2011 period (denoted by red in Figure 48). During the first half of February 2012, Synergy also offered STEM volumes between the Maximum STEM Price and the Alternative Maximum STEM Price.

Figure 48 Synergy's daily average STEM Offers (cumulative MWh per Trading Interval)

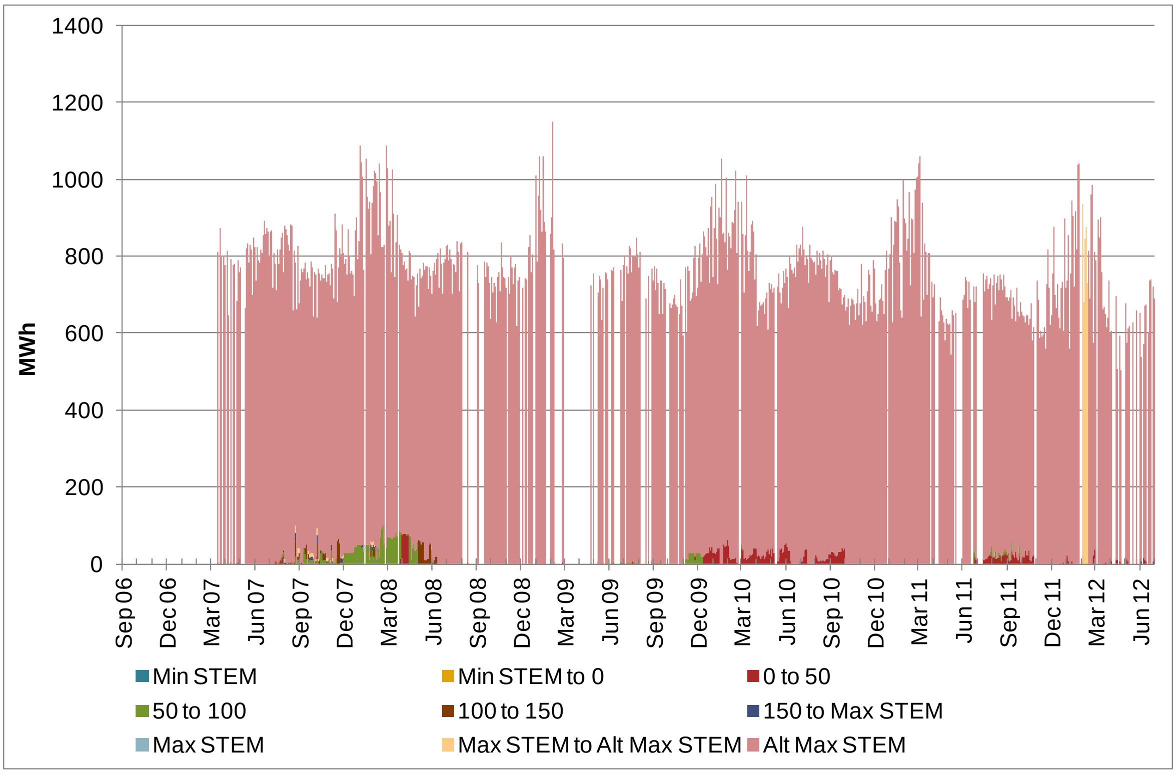
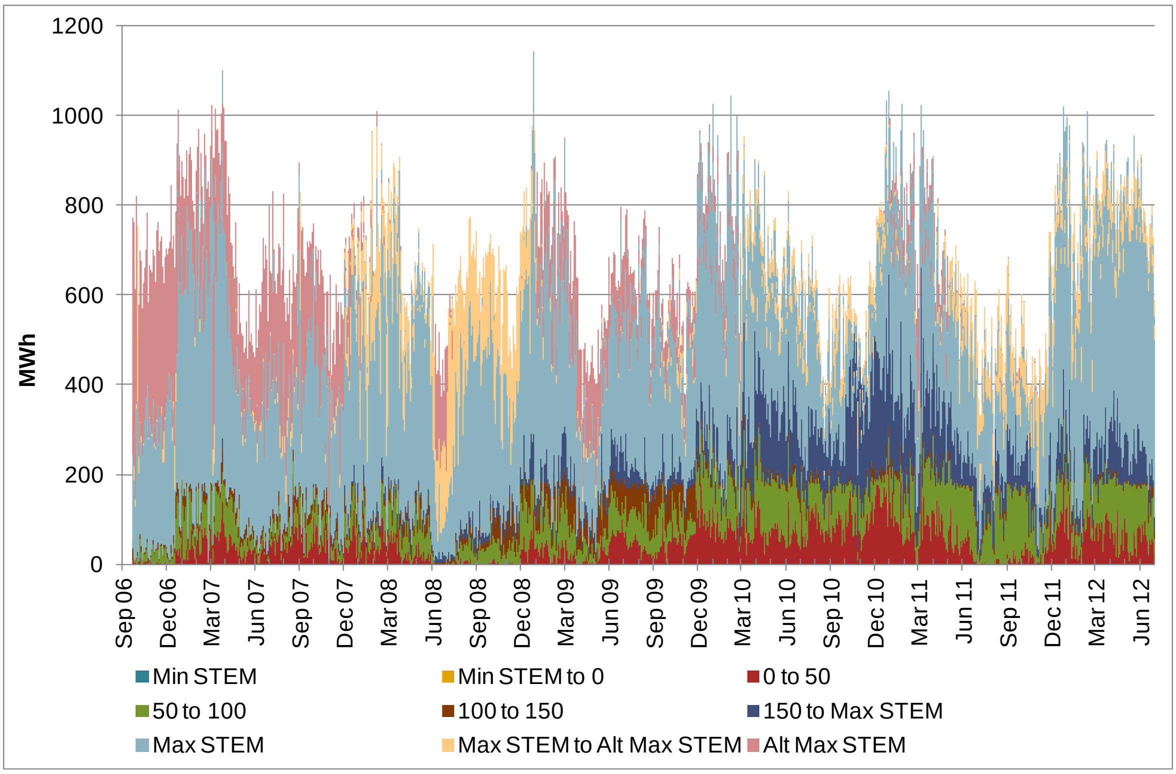


Figure 49 shows that Verve Energy has consistently offered significant volumes into the STEM since market commencement, with the majority of Verve Energy's offers priced at the Maximum STEM Price. STEM Offer quantities from Verve Energy remained at a very low level during July 2011 to November 2011, as this period coincided with a very high level of Planned Outages. A number of Verve Energy's coal and gas facilities were on extended Planned Outages, which resulted in the disappearance of the quantities offered in price range of $0/MWh and $50/MWh and fewer quantities were offered in the price range of $150/MWh to the Maximum STEM Price. Each year a drop in total STEM quantities offered by Verve Energy can be observed at the end of the peak summer period (end of March), as a number of facilities undertake planned maintenance after meeting high summer demand. However, the Offer quantities remained at a fairly consistent level between April 2012 and June 2012 in the current Reporting Period. During the period December 2011 to June 2012, i.e. the last seven Trading Months of the current Reporting Period, a general increase in the quantities priced at the Maximum STEM Price was observed.

Figure 49 Verve Energy's daily average STEM Offers (cumulative MWh per Trading Interval)



Short Term Energy Market Bids

Alcoa has not presented any STEM Bids since mid December 2006.

Figure 50 to Figure 64 show the STEM Bids for each Market Participant from market commencement to 30 June 2012.

Figure 50 shows that Alcoa has not presented any STEM Bids since mid December 2006.

Figure 50 Alcoa's daily average STEM Bids (cumulative MWh per Trading Interval)

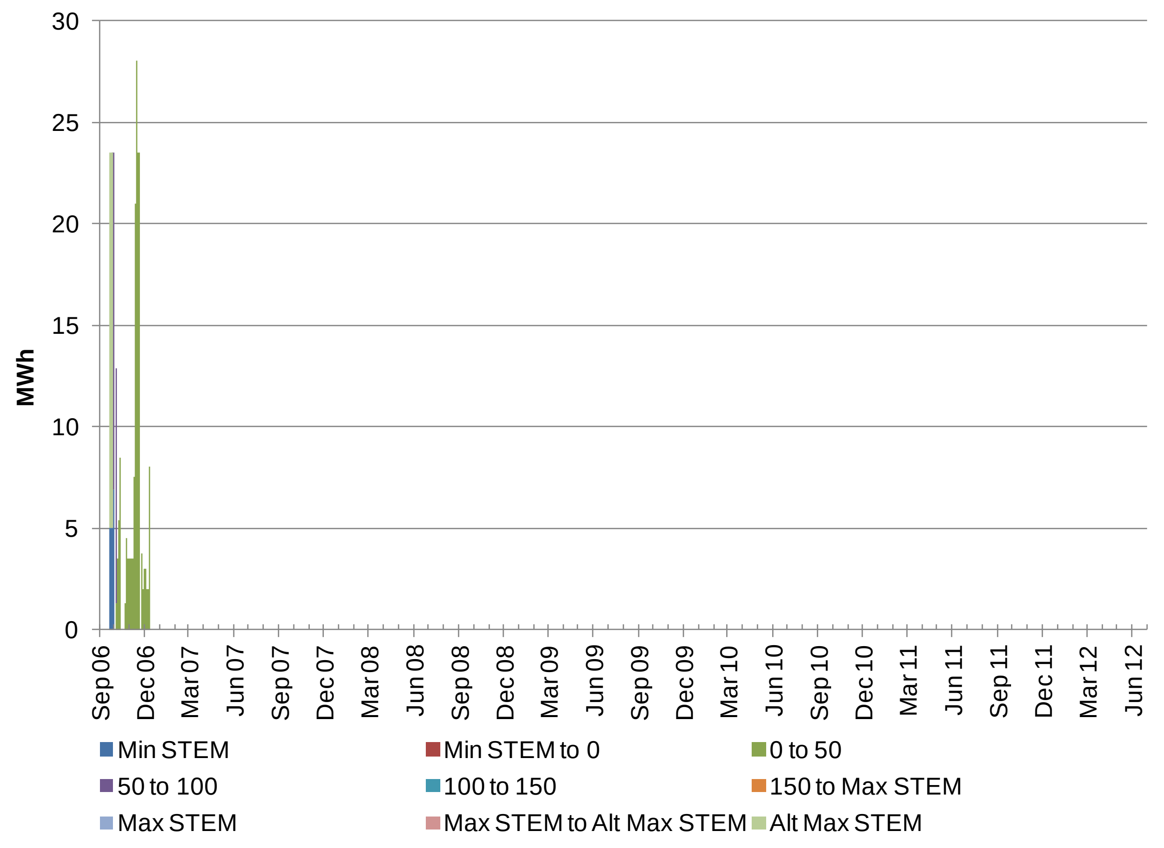


Figure 51 shows that Alinta consistently bid large volumes into the STEM, at the Minimum STEM Price between market commencement and July 2010. Alinta bid in the price range between $0/MWh and $50/MWh throughout the current Reporting Period.

Figure 52 shows STEM Bids for ERM Power since the end of the previous Reporting Period. ERM Power bid for small volumes (0 MWh to 10 MWh) in the price ranges of Minimum STEM Price to $0/MWh, $0/MWh to $50/MWh and $50/MWh to $100/MWh. Its requirement more than doubled, 20 MWh to 25 MWh, during the peak summer months of January 2012 and February 2012. During the summer period ERM Power, as a retailer, could be seen bidding at prices exceeding $100/MWh to procure volumes.

Figure 51 Alinta's daily average STEM Bids (cumulative MWh per Trading Interval)

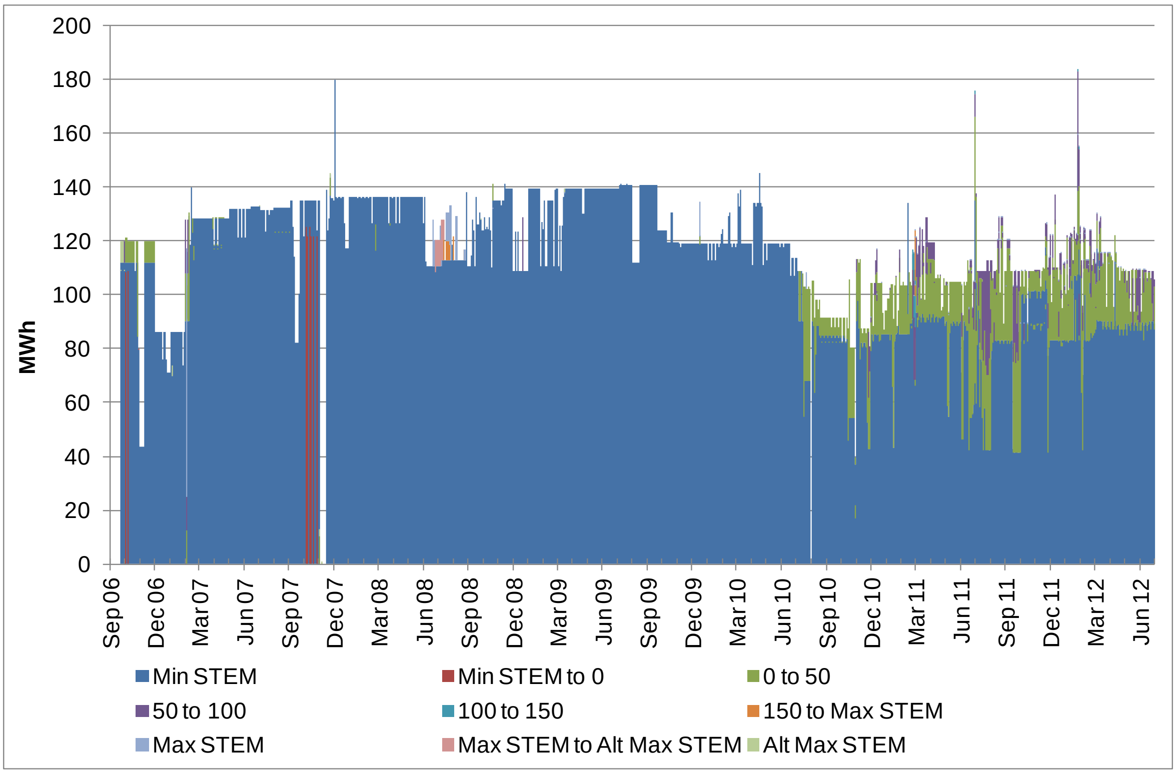


Figure 52 ERM Power's daily average STEM Bids (cumulative MWh per Trading Interval)

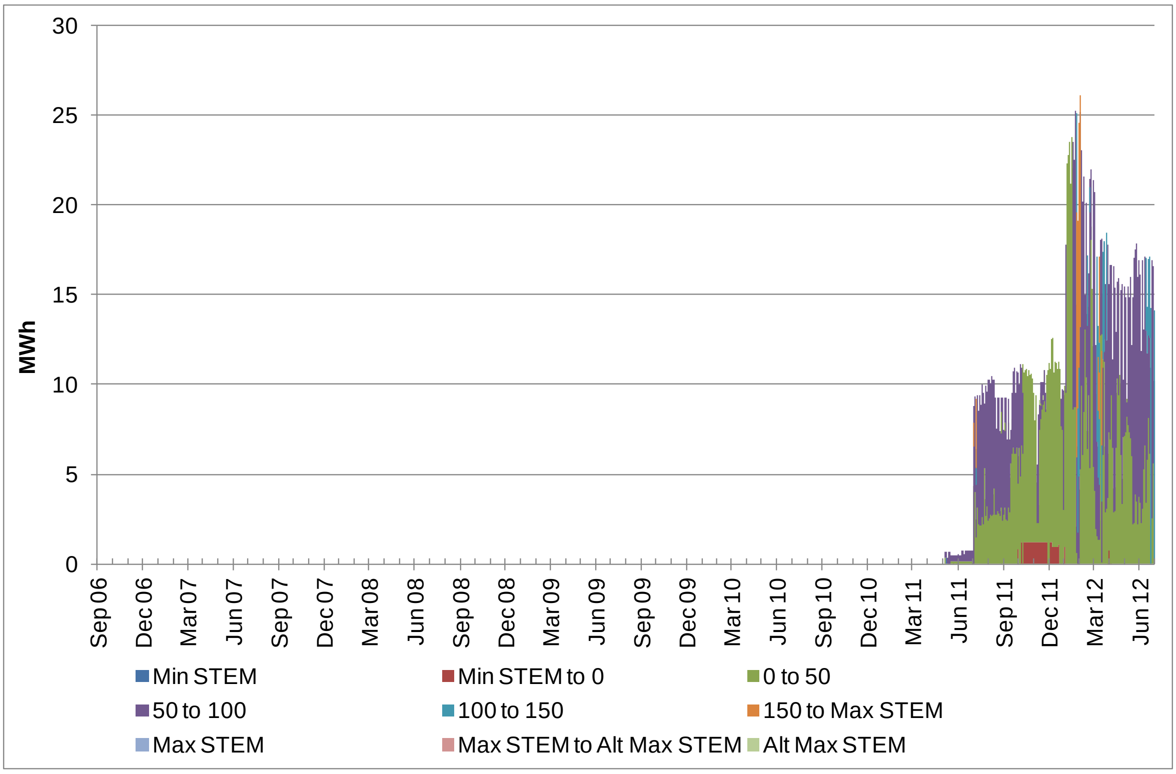


Figure 53 Goldfields Power's daily average STEM Bids (cumulative MWh per Trading Interval)

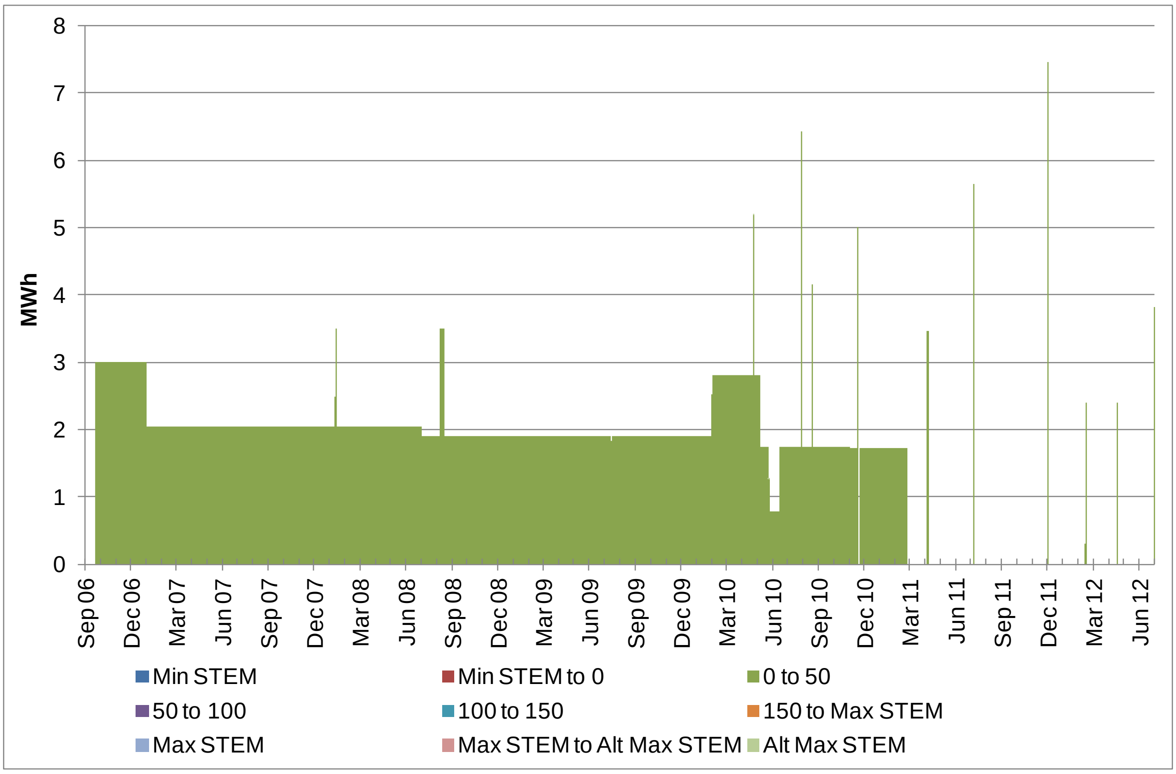


Figure 54 Griffin Power's daily average STEM Bids (cumulative MWh per Trading Interval)

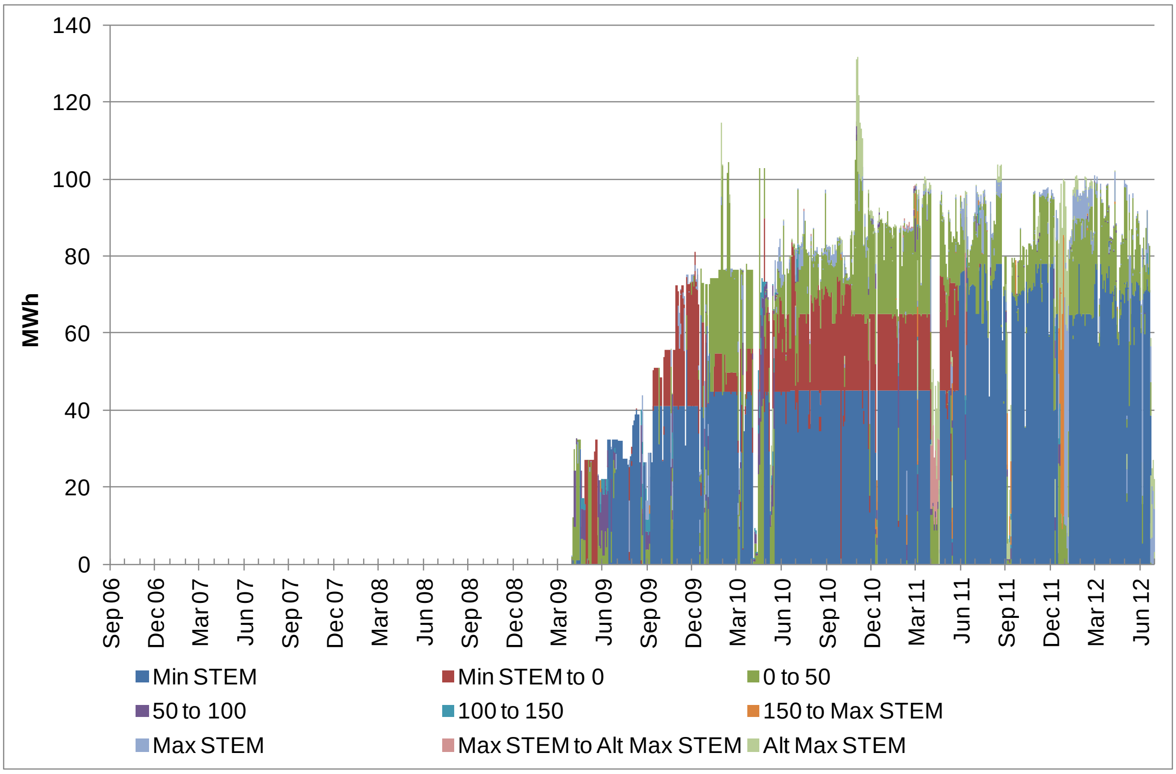


Figure 55 Griffin Power 2's daily average STEM Bids (cumulative MWh per Trading Interval)

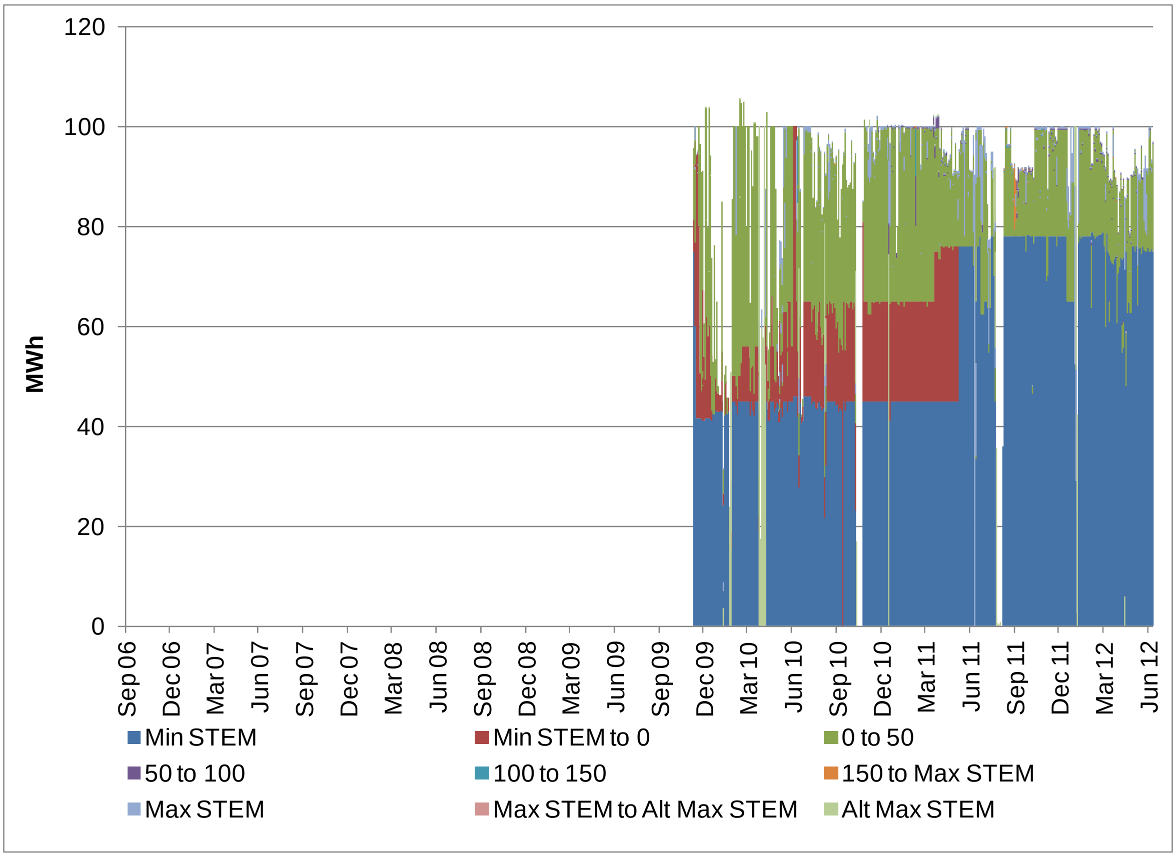


Figure 56 Landfill Gas and Power's daily average STEM Bids (cumulative MWh per Trading Interval)

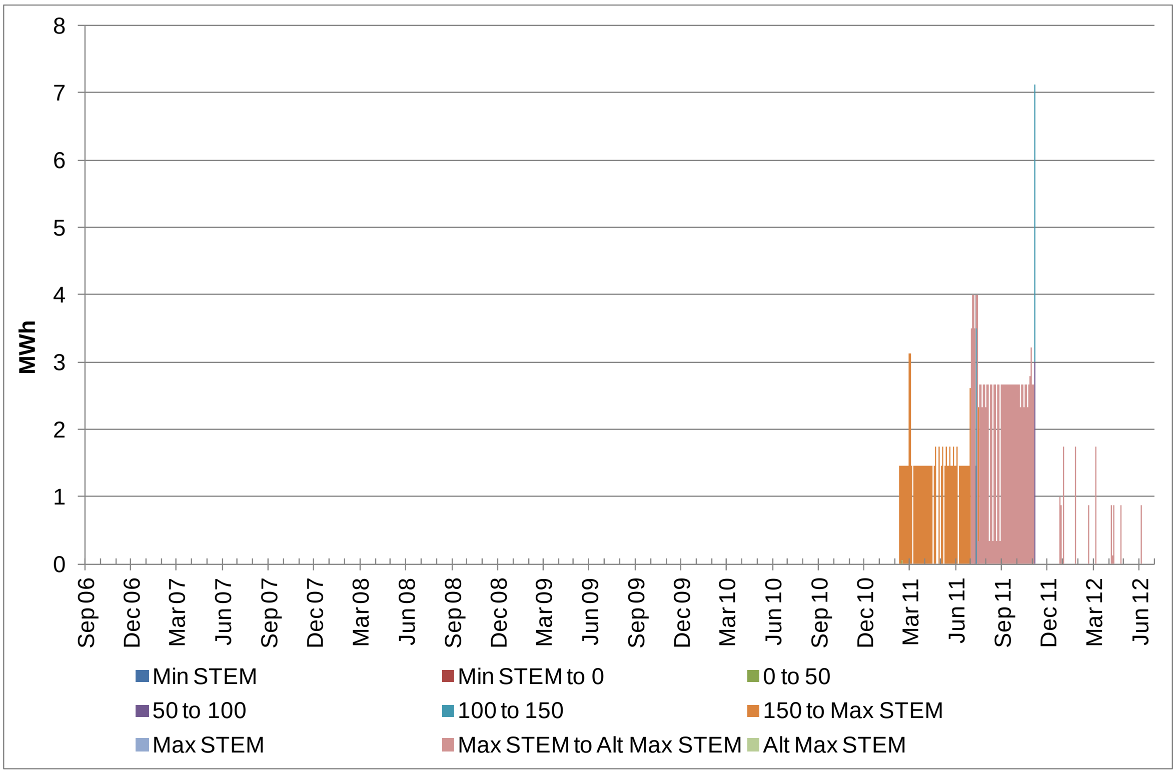
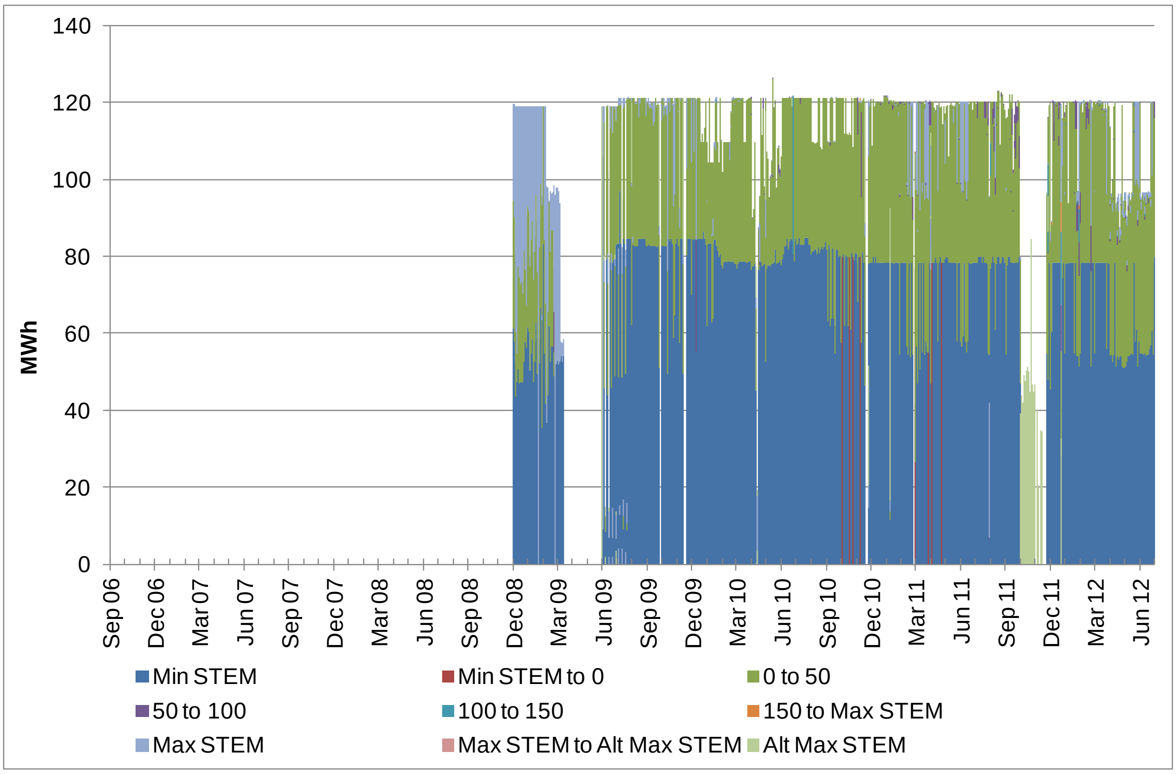


Figure 57 NewGen Power Kwinana's daily average STEM Bids (cumulative MWh per Trading Interval)



As can be seen from Figure 54, Figure 55 and Figure 57 Griffin Power, Griffin Power 2 and NewGen Kwinana bid their respective STEM quantities at either the Minimum STEM Price or in the range of $0/MWh to $50/MWh throughout the current Reporting Period.

Figure 58 NewGen Neerabup's daily average STEM Bids (cumulative MWh per Trading Interval)

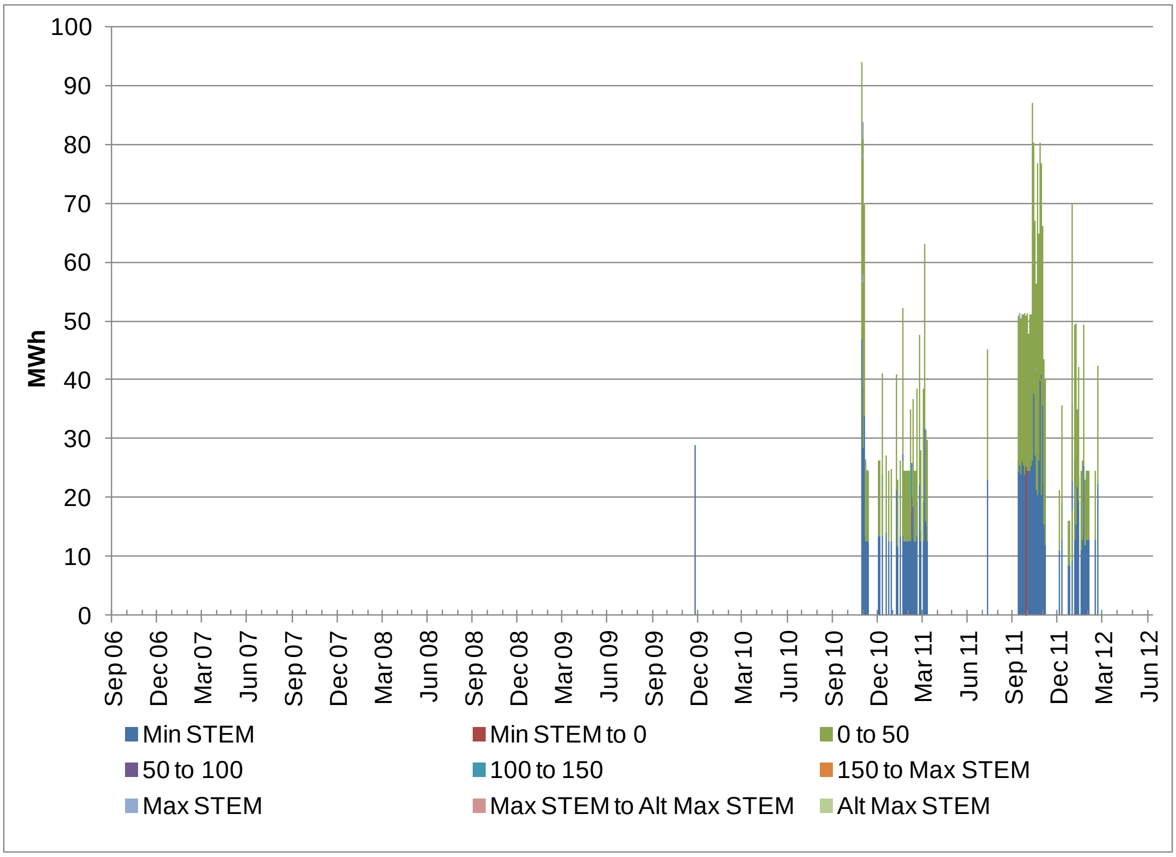


Figure 59 Perth Energy's daily average STEM Bids (cumulative MWh per Trading Interval)

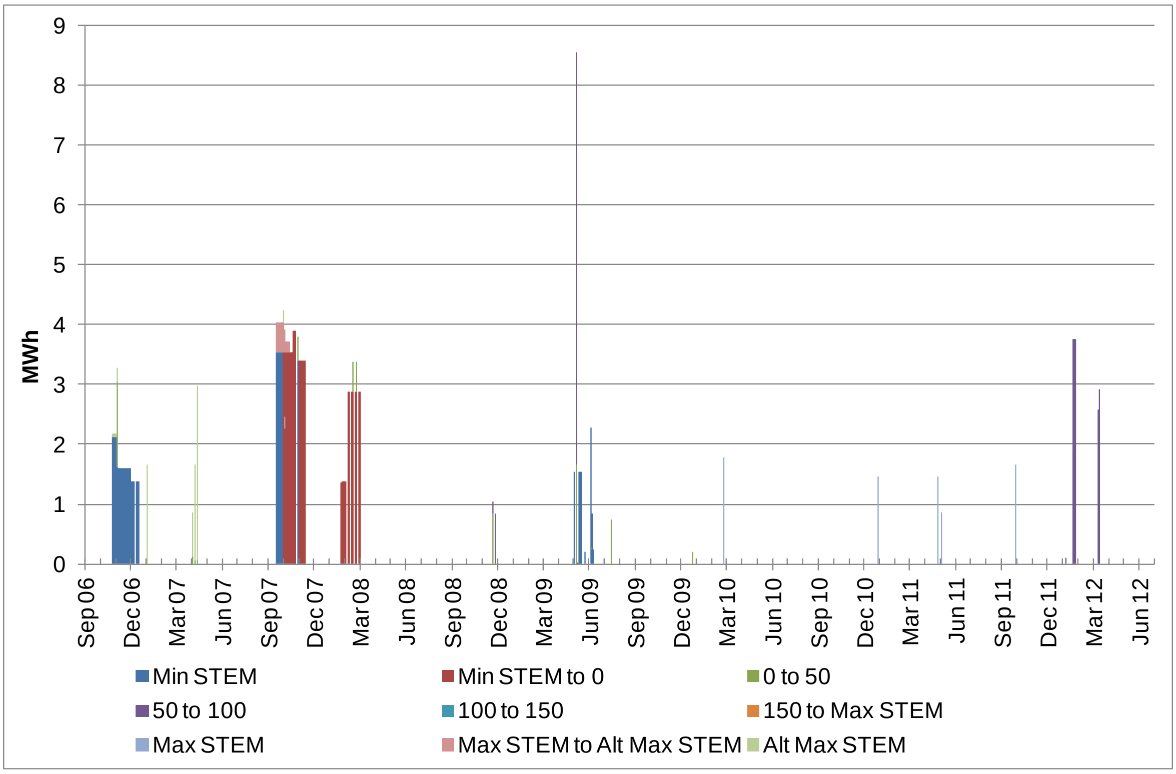


Figure 60 **Southern Cross Energy's daily average STEM Bids (cumulative MWh per Trading Interval)**

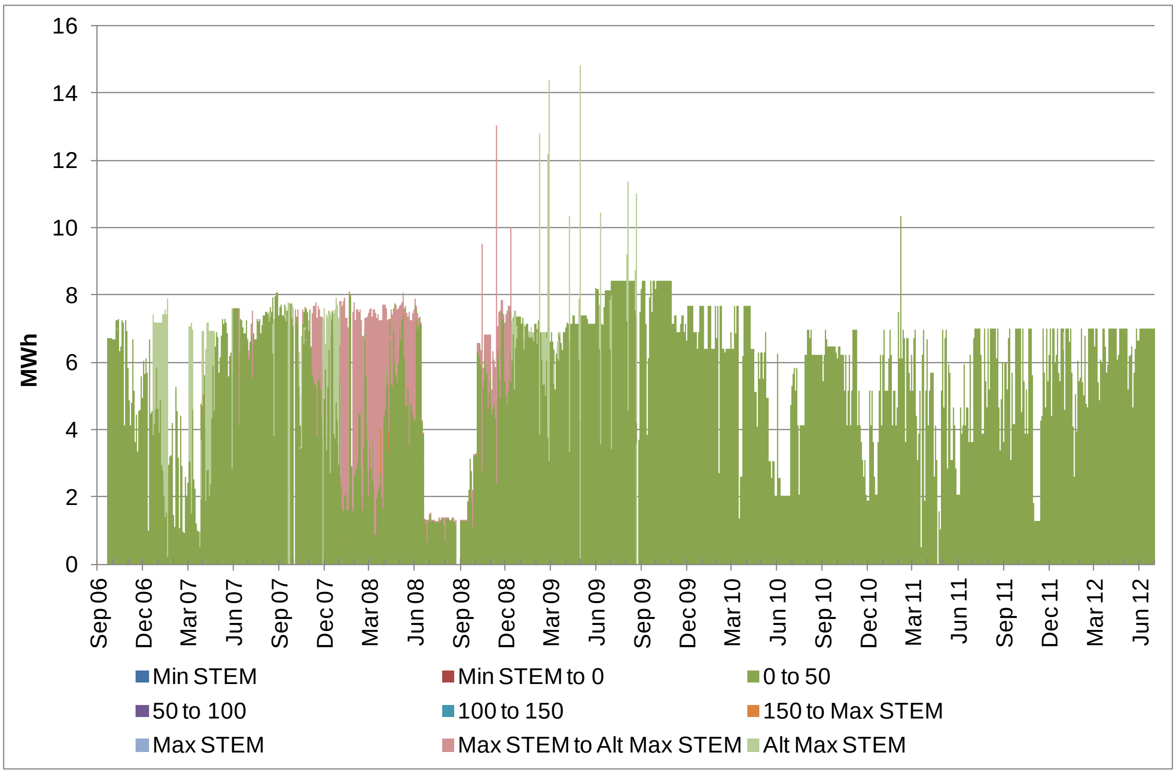


Figure 61 **Tiwest's daily average STEM Bids (cumulative MWh per Trading Interval)**

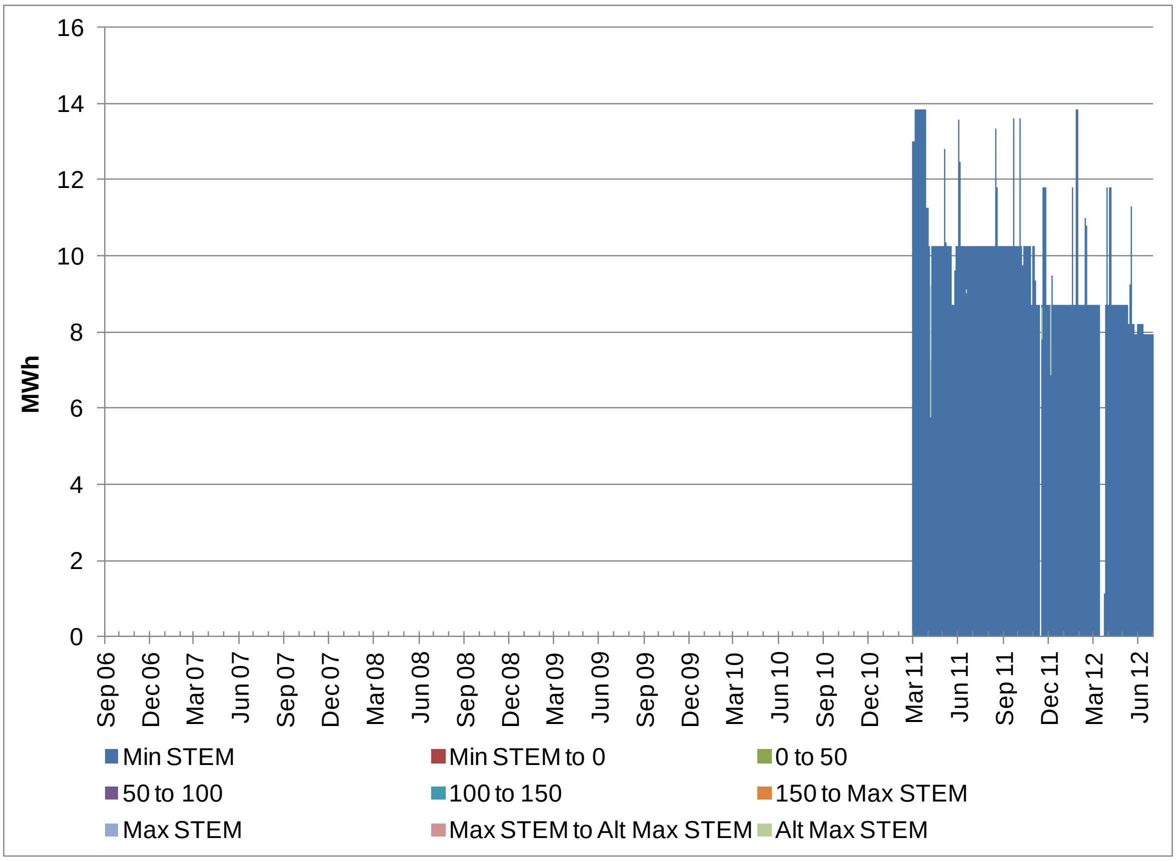


Figure 62 Western Energy's daily average STEM Bids (cumulative MWh per Trading Interval)

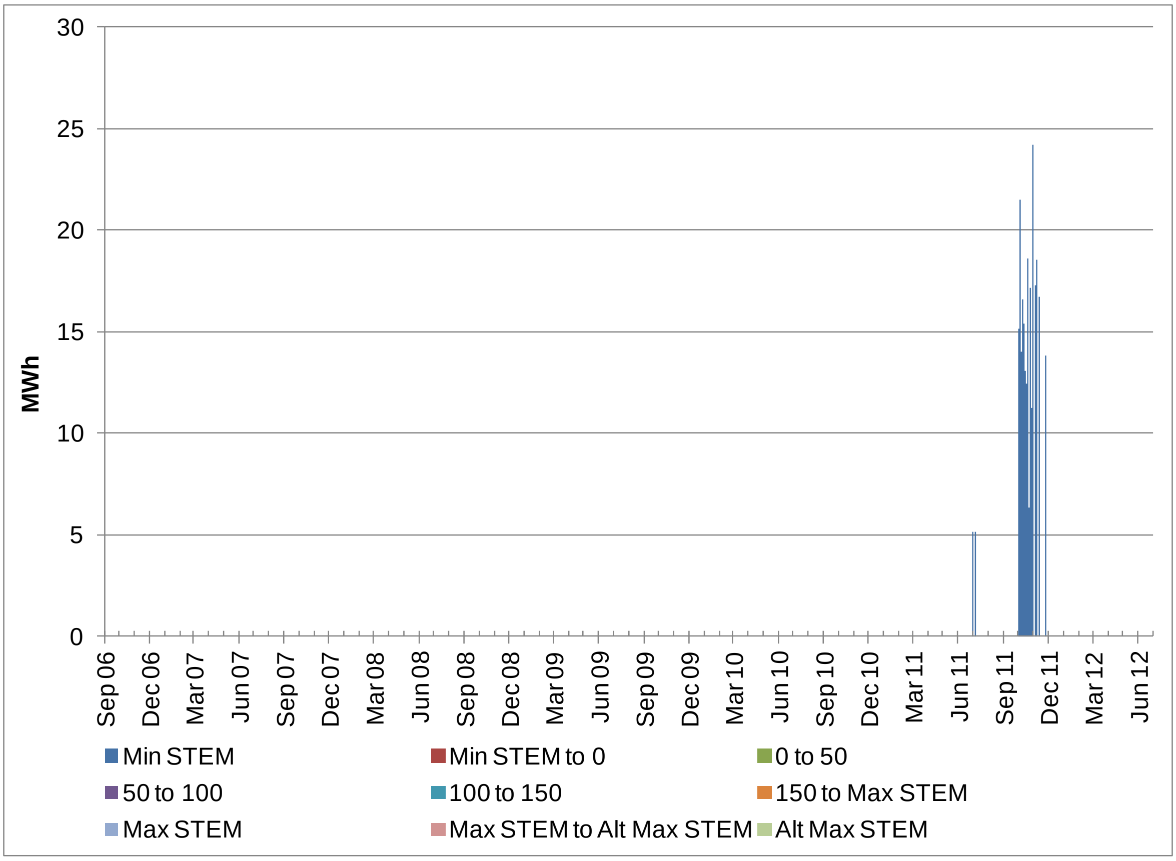


Figure 63 Synergy's daily average STEM Bids (cumulative MWh per Trading Interval)

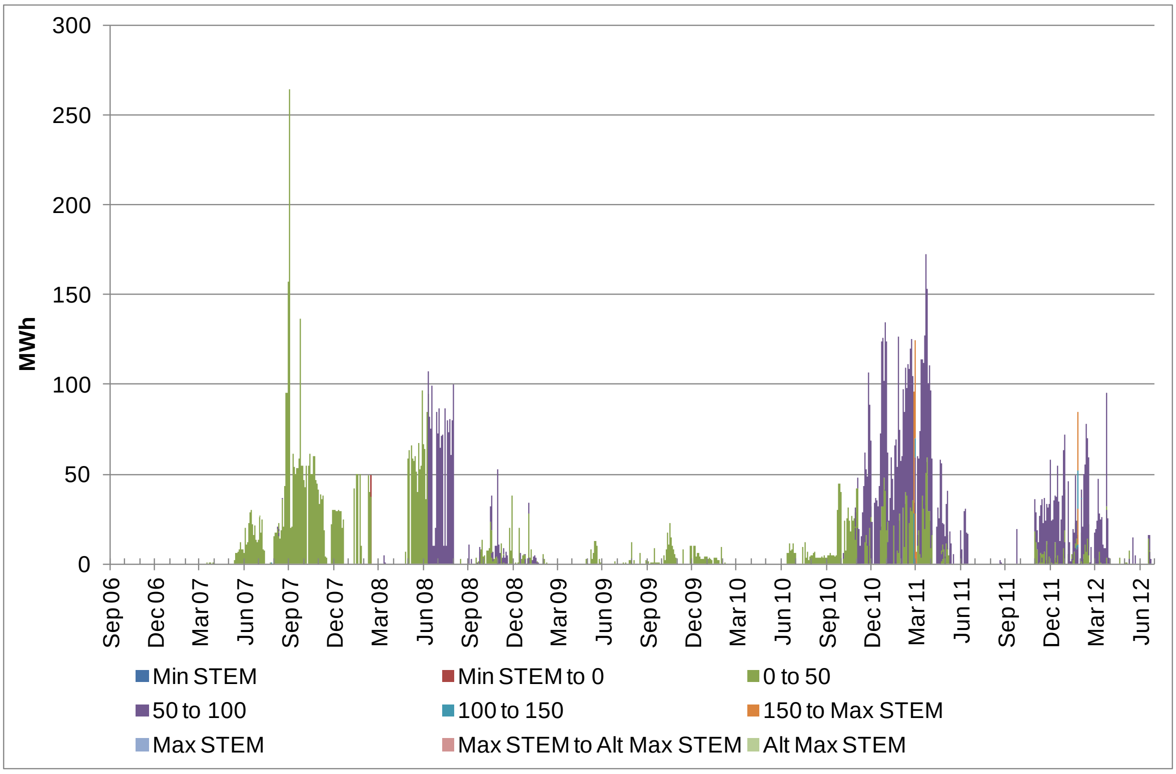
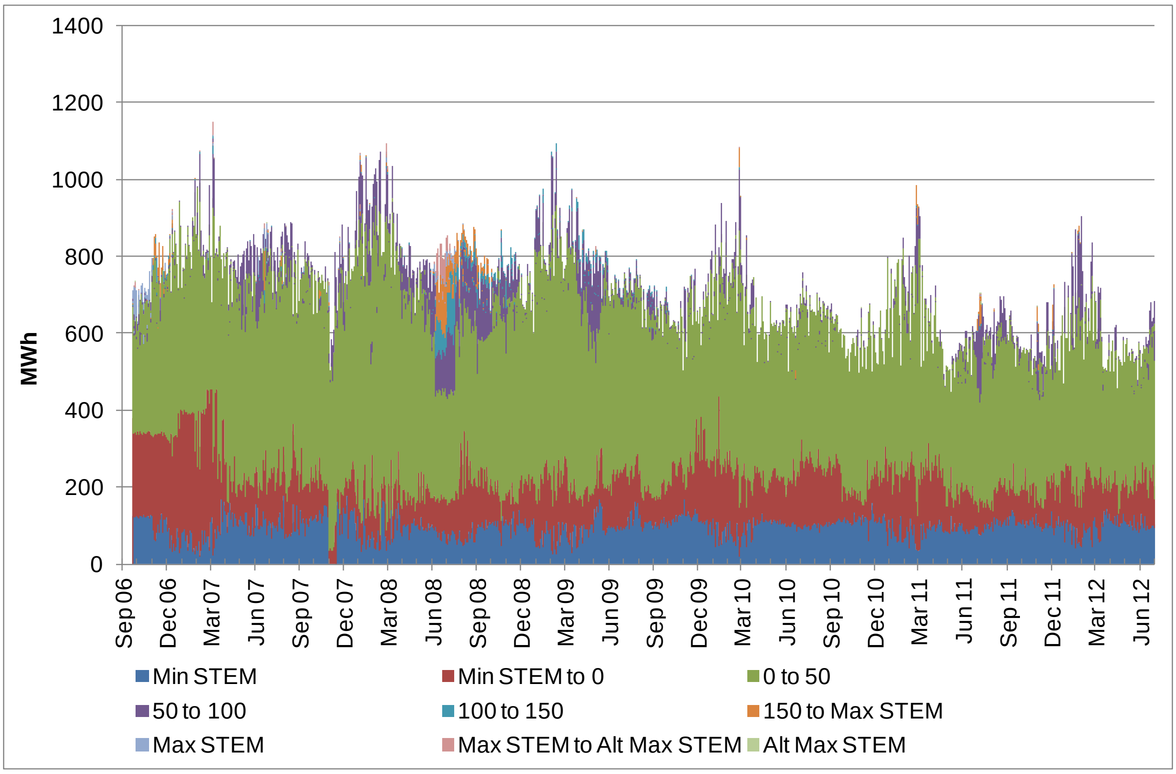


Figure 63 shows that Synergy bid notable STEM volumes during November 2011 to March 2012 (warmer months) at price range between \$50/MWh and \$100/MWh.

However, there is a marked reduction in the volumes bid by Synergy during this period, as compared to the volumes bid in the similar months in the previous Reporting Period.

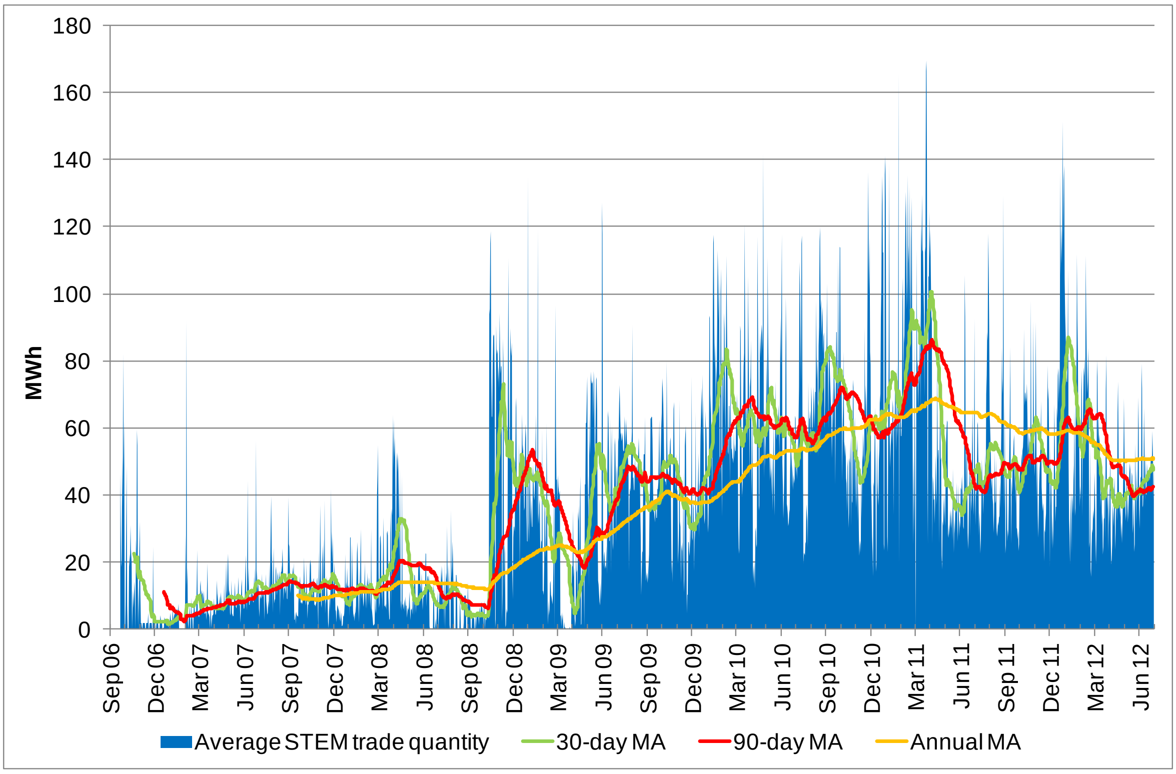
Figure 64 shows Verve Energy's volumes of Bids have been reasonably consistent since market commencement. These Bids were priced primarily at relatively low price (in the $0 to $50/MWh range shown in green) or at negative prices (i.e. at the Minimum STEM price shown in blue and between $0 to the Minimum STEM range shown in red).

Figure 64 Verve Energy's daily average STEM Bids (cumulative MWh per Trading Interval)



Short Term Energy Market traded volumes

Figure 65 Average STEM Clearing Quantities (per Trading Day)



Balancing

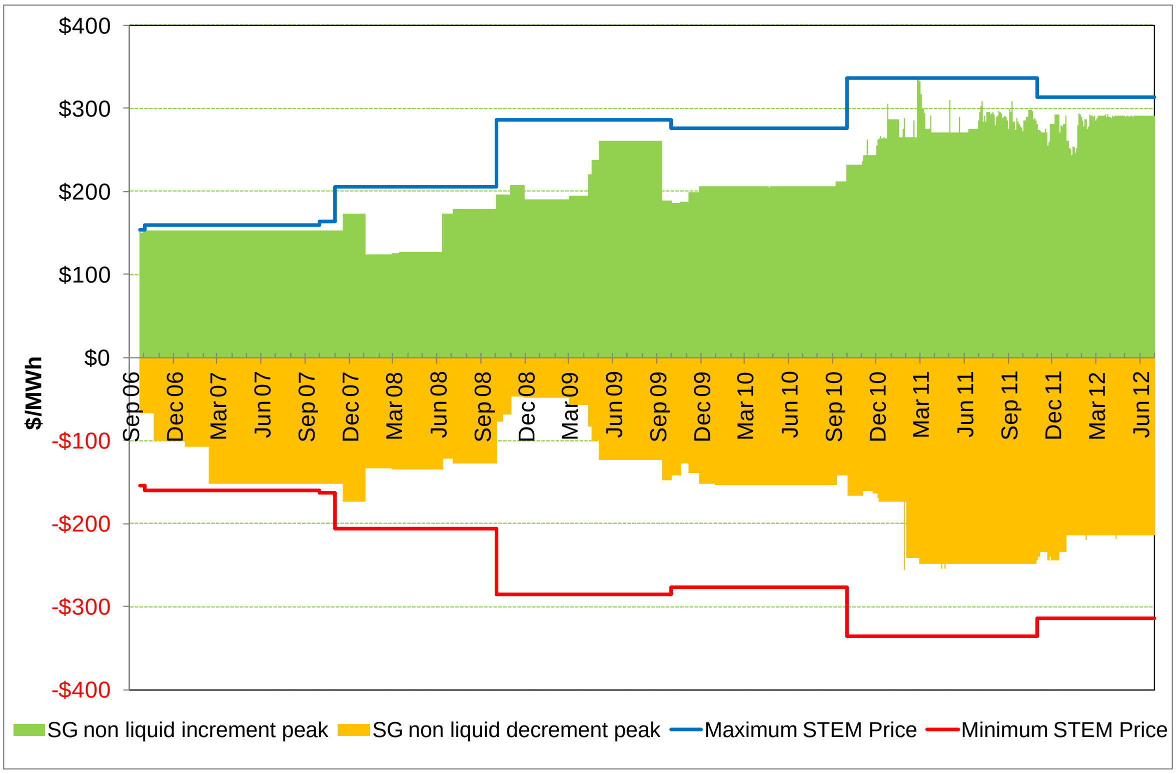
Balancing prices

Standing Balancing Data

Figure 66 illustrates the average prices in the Standing Balancing Data for IPPs Non-Liquid Fuel Scheduled Generators.[174]

[174] 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 66 Average prices in Standing Balancing Data for Non-Liquid Fuel facilities

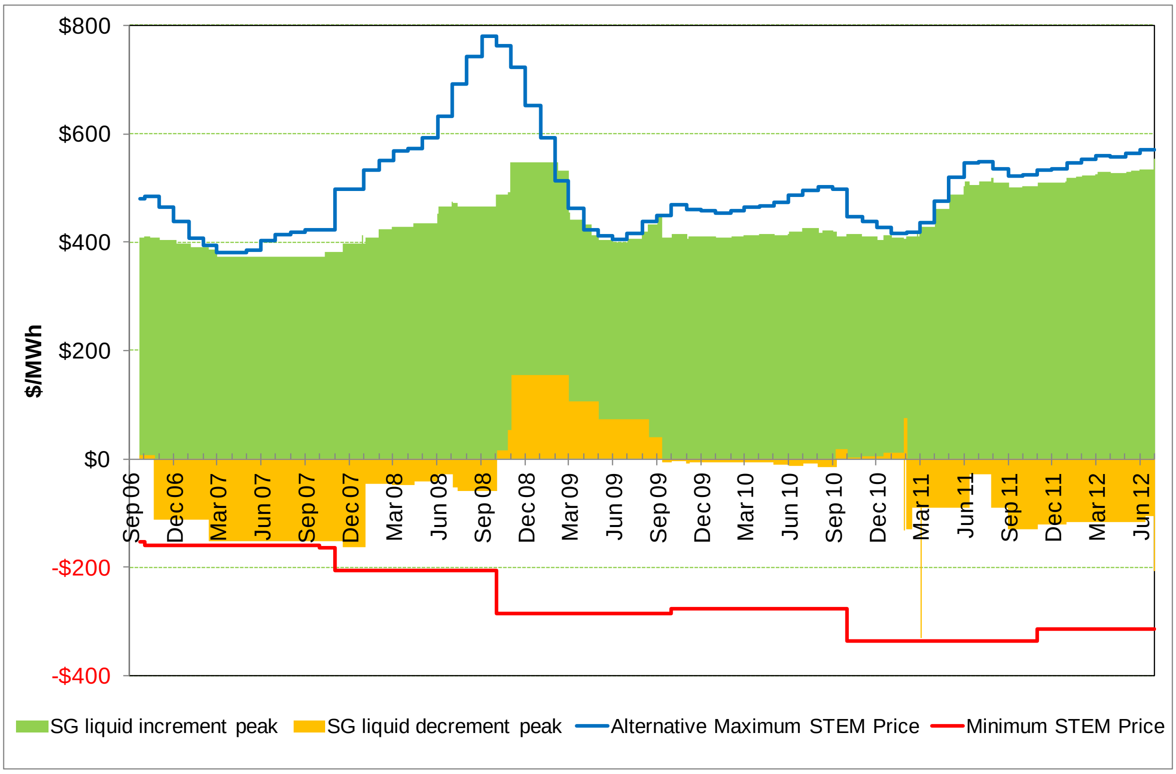


Broadly, IPPs want to be paid close to the applicable Maximum STEM Prices when they are instructed to increase generation from their Non-Liquid Fuelled facilities irrespective of the time of the day (on average, approximately $283/MWh for the Reporting Period). The average Non-Liquid increment price increased by nine per cent compared to the previous Reporting Period ($259/MWh). When they are instructed to reduce output from their Non-Liquid Fuelled generation, IPPs also want to be paid. The average Non-Liquid decrement price for the Reporting Period was $228/MWh, which increased by 12 per cent compared to the previous Reporting Period ($204/MWh).

Figure 67 illustrates average prices in the Standing Balancing Data for IPPs Liquid Fuel Scheduled Generators.[175]

[175] 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 67 Average prices in Standing Balancing Data for Liquid Fuel facilities



Broadly, IPPs want to be paid close to the applicable Alternative Maximum STEM Prices when they are instructed to increase generation from their Liquid Fuelled facilities irrespective of the time of the day (on average, approximately $441/MWh for the Reporting Period). The average Liquid increment price has decreased by four per cent compared to the previous Reporting Period ($461/MWh). When they are instructed to reduce output from their Liquid fuelled generators, IPPs generally are willing to receive a lower price for the energy they did not have to produce, irrespective of the time of the day.

Figure 68 illustrates average prices in the Standing Balancing Data for IPPs Intermittent Generators during peak periods.

Figure 68 Average prices in Standing Balancing Data for Intermittent Generators (Peak)

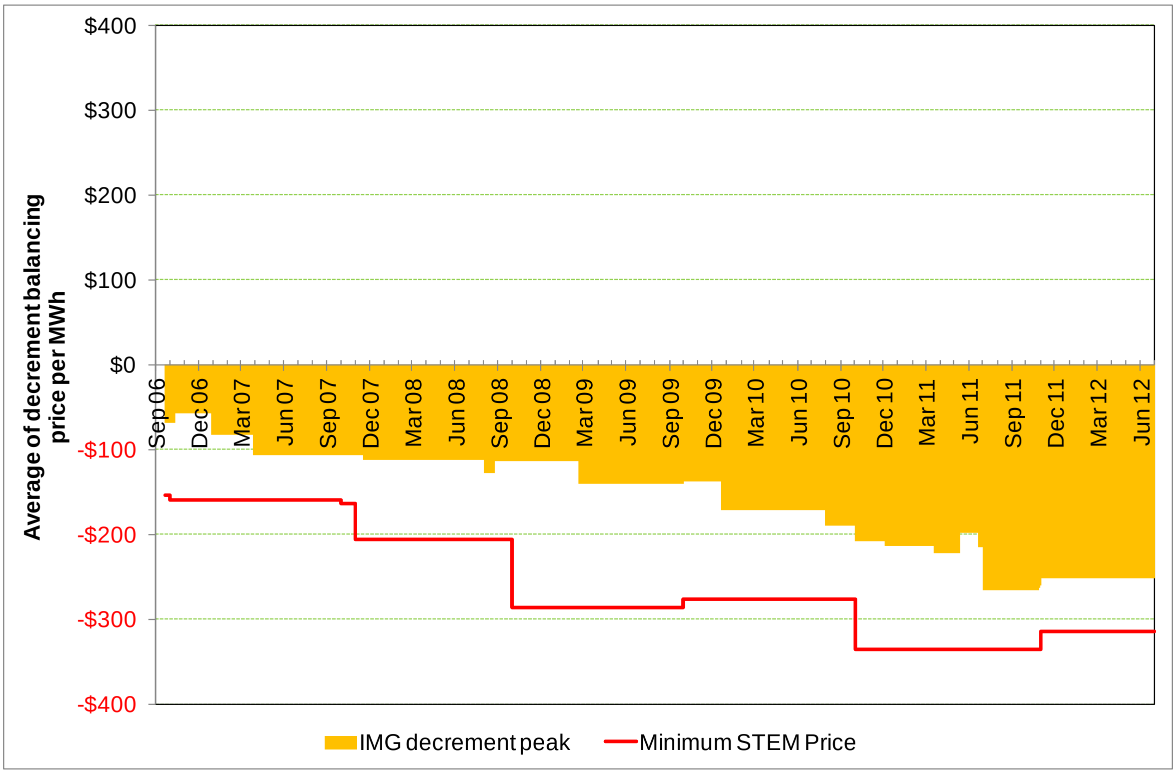
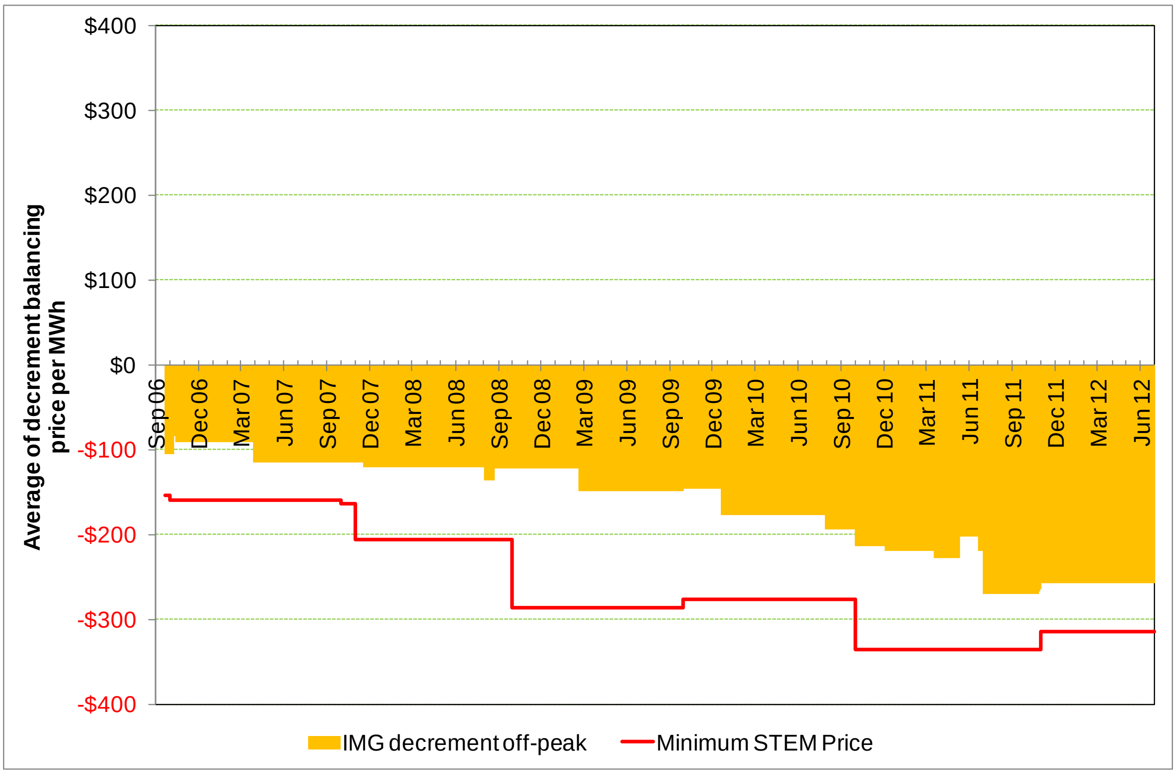


Figure 69 illustrates average prices in the Standing Balancing Data Balancing for IPPs Intermittent Generators during off-peak periods.

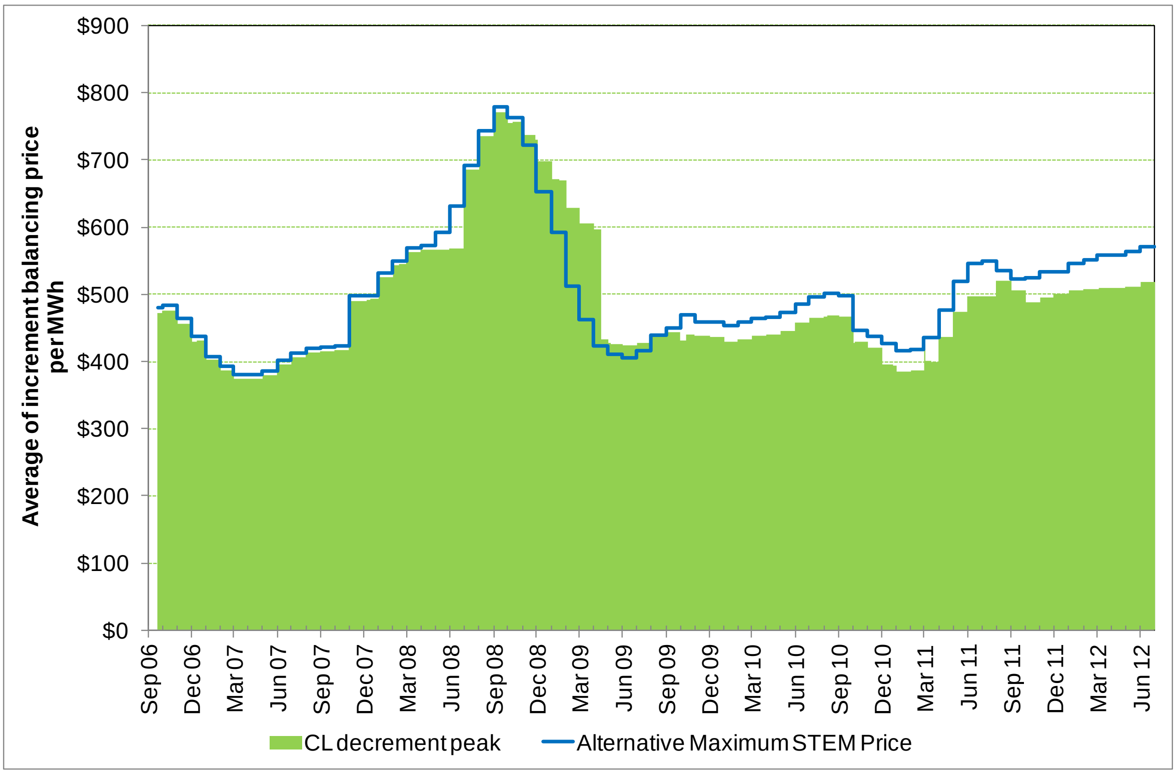
Figure 69 Average prices in Standing Balancing Data for Intermittent Generators (Off-Peak)



Broadly, during the Reporting Period IPPs wanted to be paid on average $256/MWh during Peak Trading Intervals and $260/MWh during Off-Peak Trading Intervals when they are instructed to reduce output from their intermittent generators. This represents an average increase of $44/MWh and $43/MWh for peak and off-peak periods (respectively) when compared to the previous Reporting Period. At times Intermittent Generators would be reluctant to reduce their output, except for transmission network constraints, as they may incur revenue loss from Renewable Energy Certificates (RECs).

Figure 70 illustrates average Standing Data Balancing prices for Curtailable Loads (CL).[176] [177]

Figure 70 Average Standing Data Balancing prices for Curtailable Loads (Peak)



A Curtailable Load is a Demand Side Management (DSM) option that could be curtailed by System Management, and be compensated at pay-as-bid prices for the quantity curtailed. 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 $506/MWh for the Reporting Period). This represents a significant increase in the average decrement price for the Reporting Period when compared to the previous Reporting Period ($436/MWh).

MCAP, UDAP and DDAP

Table 14 sets out the formulas prescribed in the Market Rules for calculating UDAP and DDAP.

[176] 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.

[177] 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.

Table 14 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 71 and Figure 72 compare 30-day and 90-day moving averages of peak STEM and Balancing prices, respectively.

Figure 71 30-day moving average Peak STEM and Balancing prices

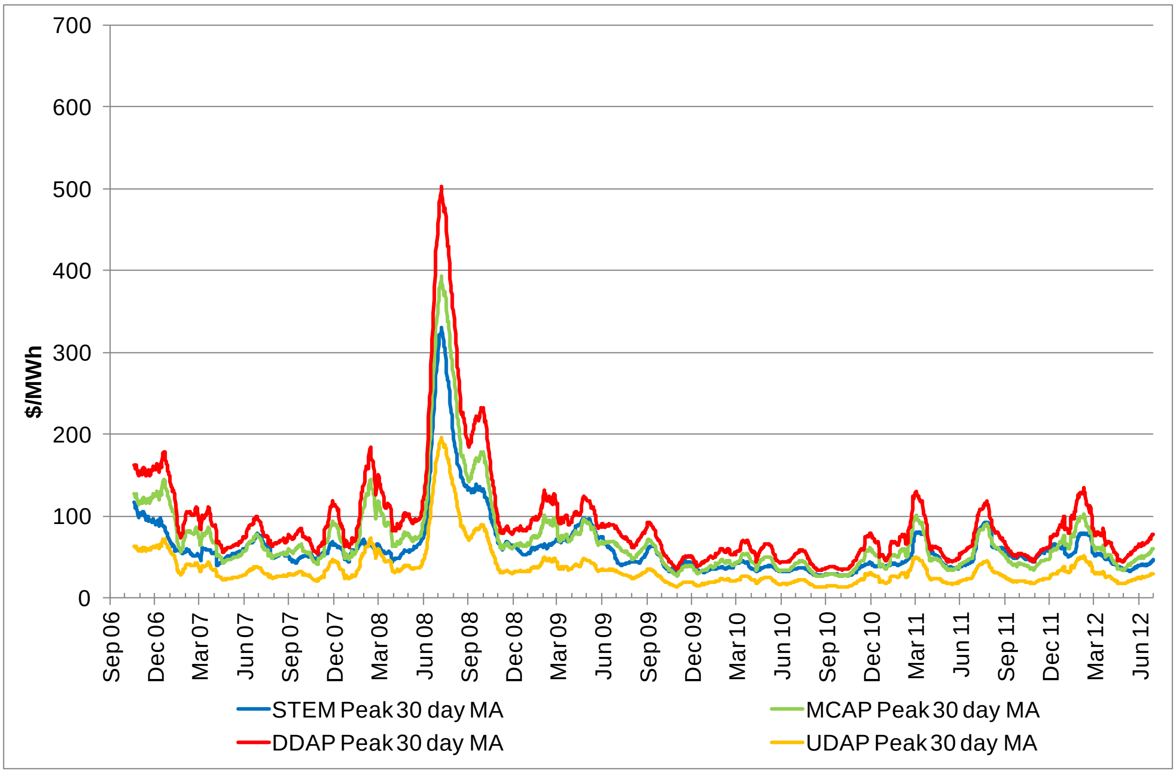


Figure 72 90-day moving average Peak STEM and Balancing prices

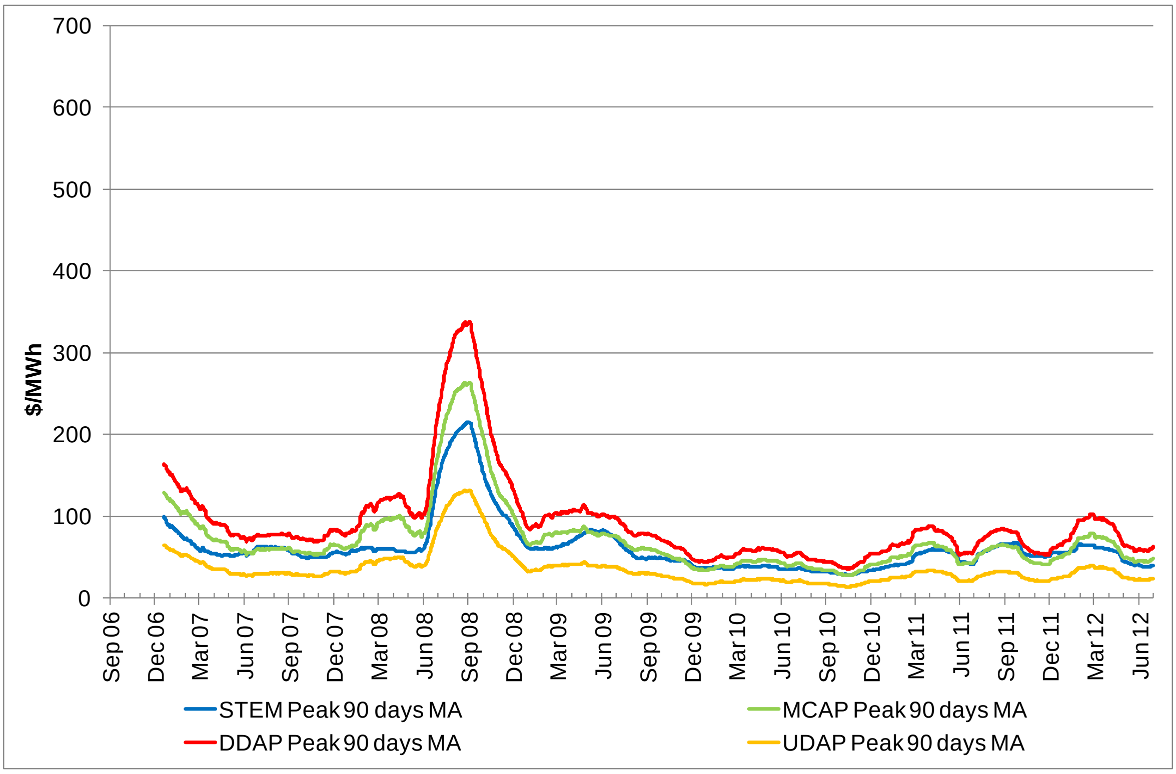


Figure 73 and Figure 74 compare 30-day and 90-day moving averages of off-peak STEM and Balancing prices, respectively.

Figure 73 30-day moving average Off-Peak STEM and Balancing prices

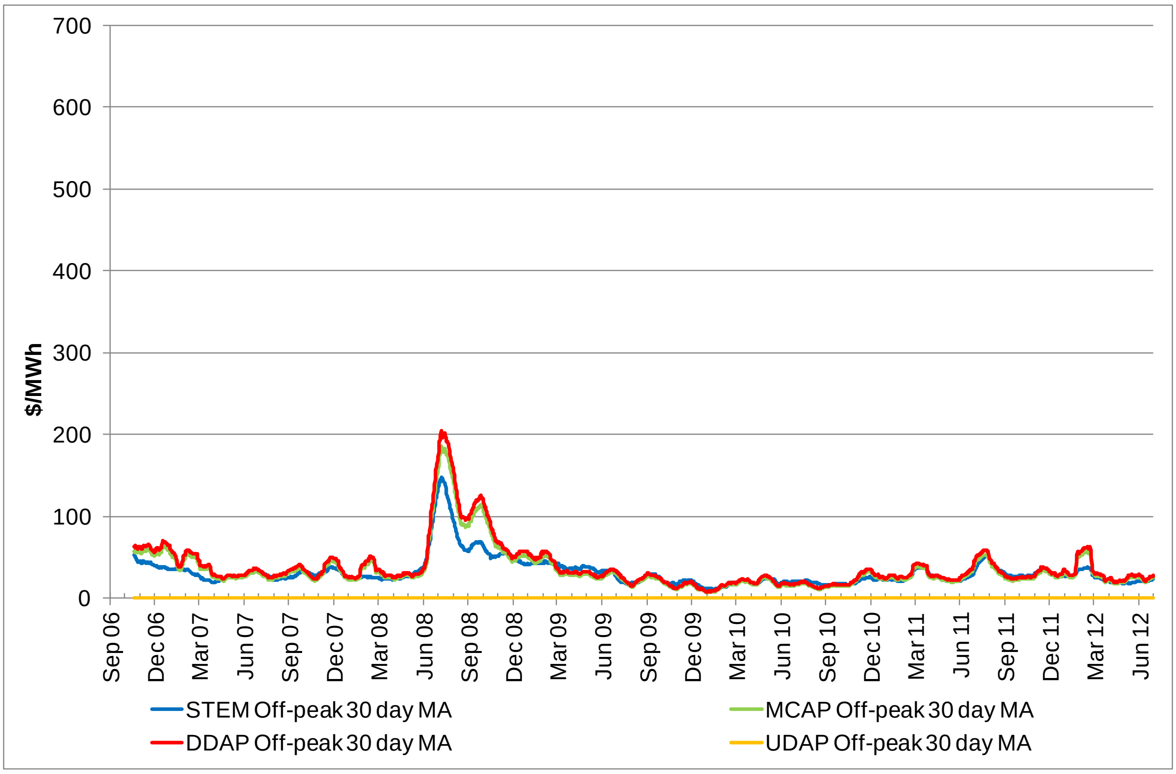


Figure 74 90-day moving average Off-Peak STEM and Balancing prices

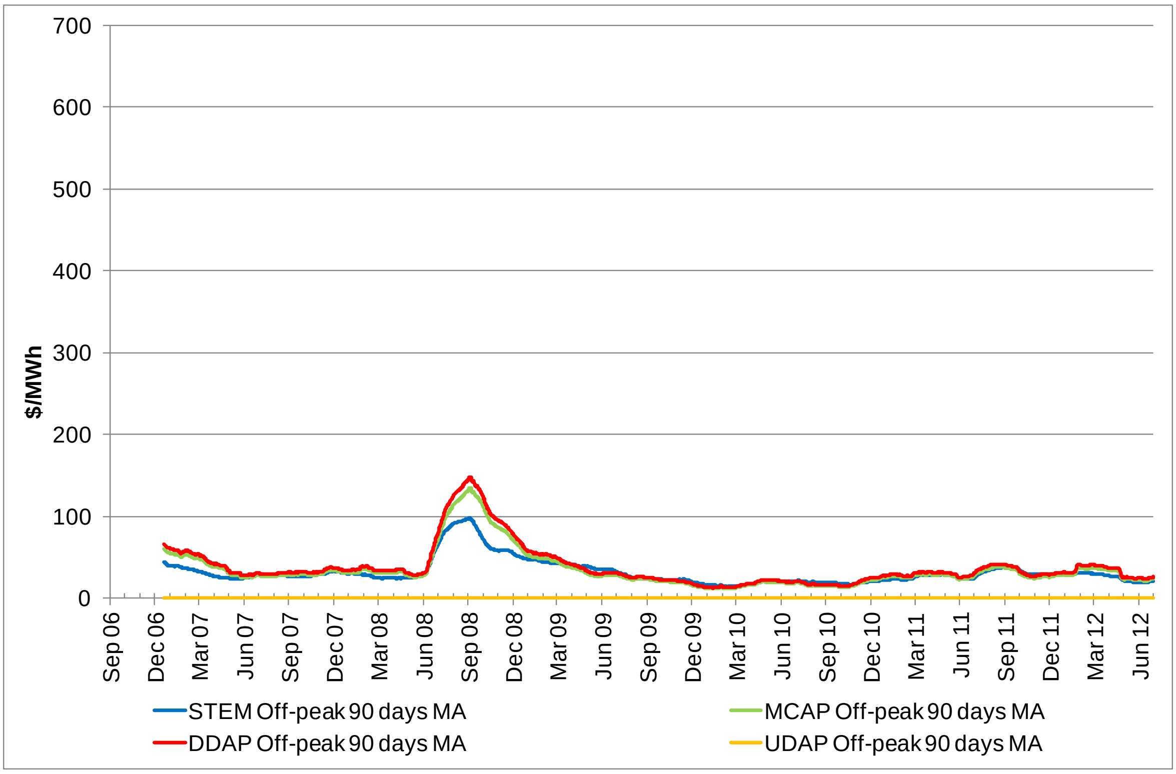


Figure 75 and Figure 76 show annual moving average STEM and Balancing prices for peak and off-peak periods, respectively.

Figure 75 Annual moving average Peak STEM and Balancing prices

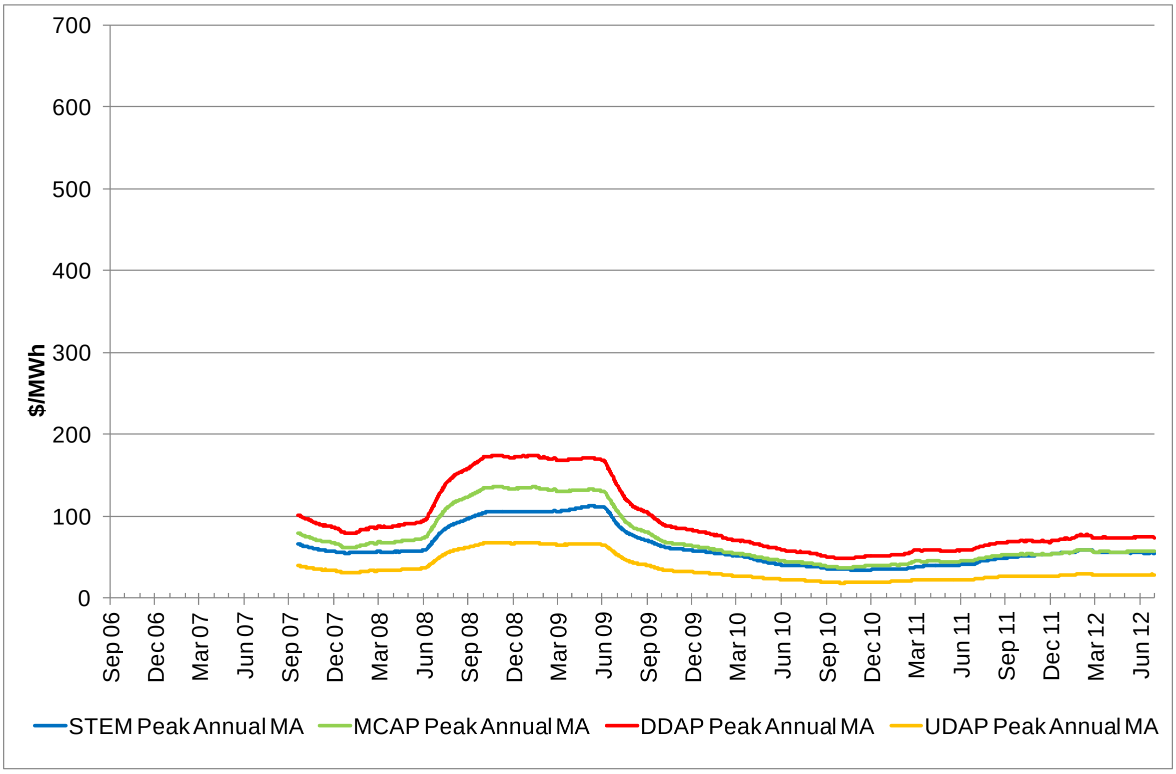
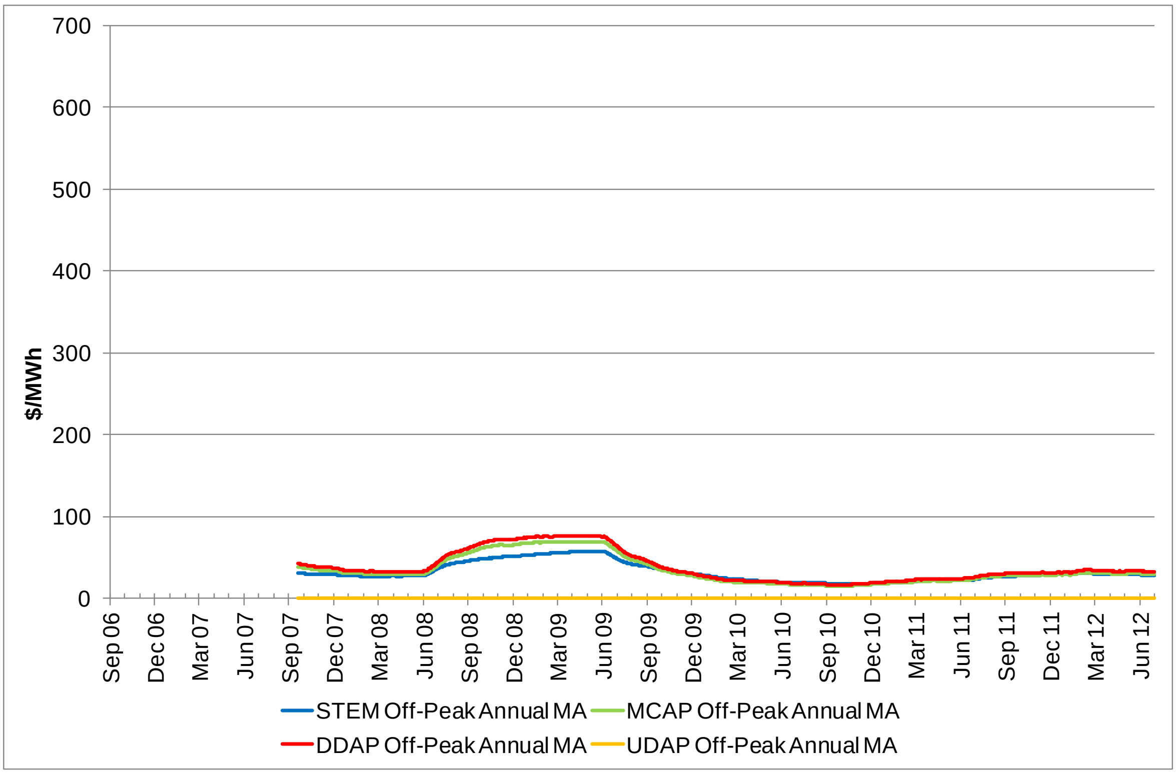


Figure 76 Annual moving average Off-Peak STEM and Balancing prices



Volatility of Balancing prices

Figure 77 to Figure 81 illustrate the means and standard deviations (as well as the maxima and minima) of Balancing prices. Since October 2010, there has been a widening of the difference between minimum and maximum prices. Maximum prices have tended to be realised at relatively higher levels since October 2010 when compared to the period following the Varanus Island incident in June 2008. Minimum prices have been fairly similar across these periods.

Figure 77 Summary statistics for MCAPs during Peak Trading Intervals (per calendar month)

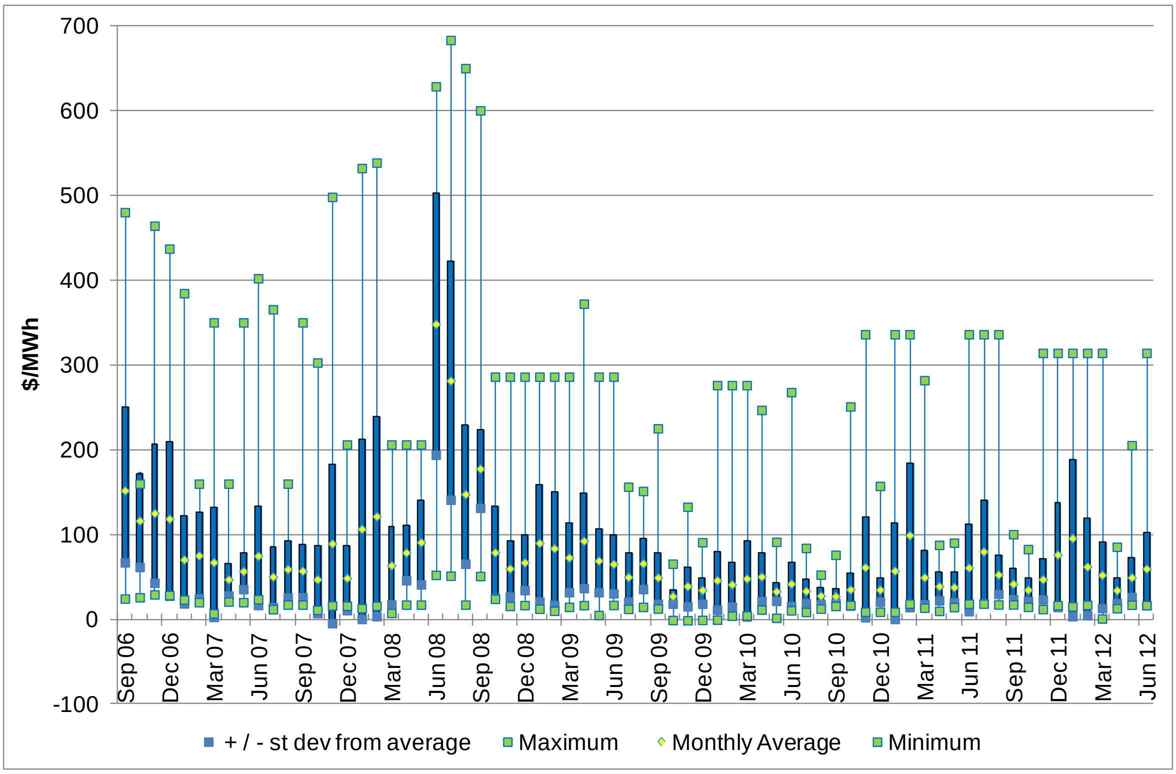


Figure 78 Summary statistics for MCAPs during Off-Peak Trading Intervals (per calendar month)

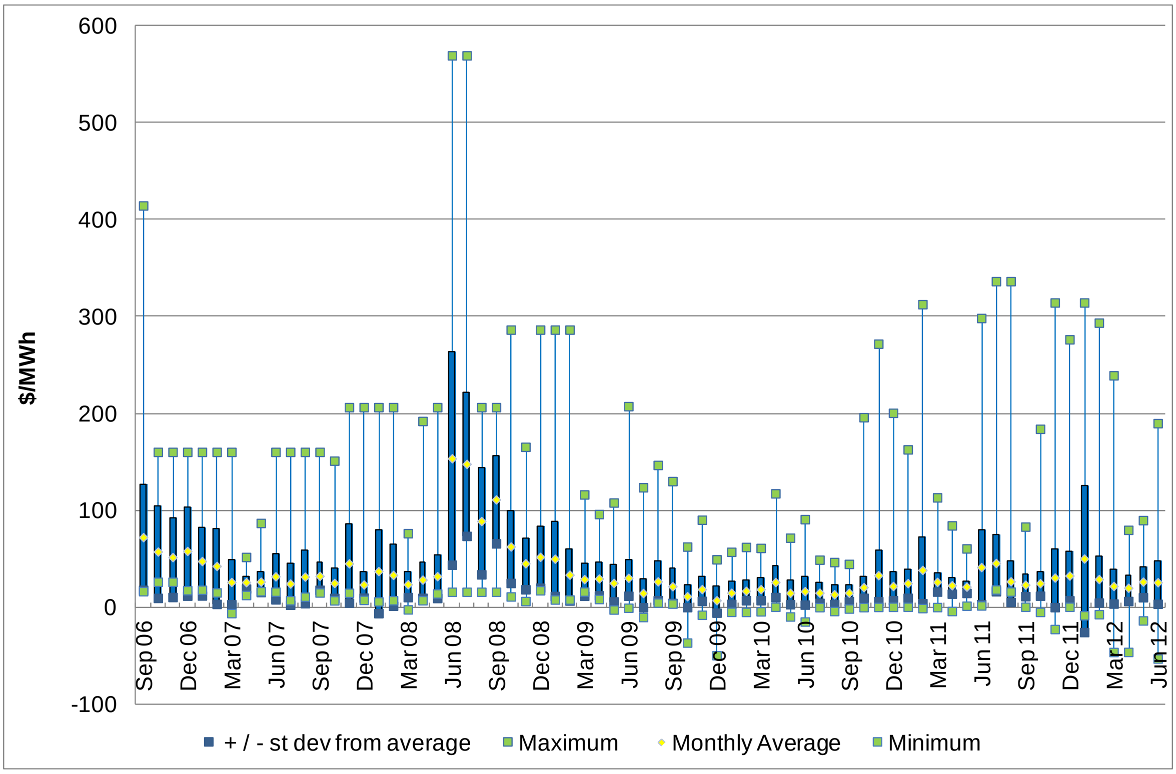


Figure 79 **Summary statistics for DDAPs during Peak Trading Intervals (per calendar month)**

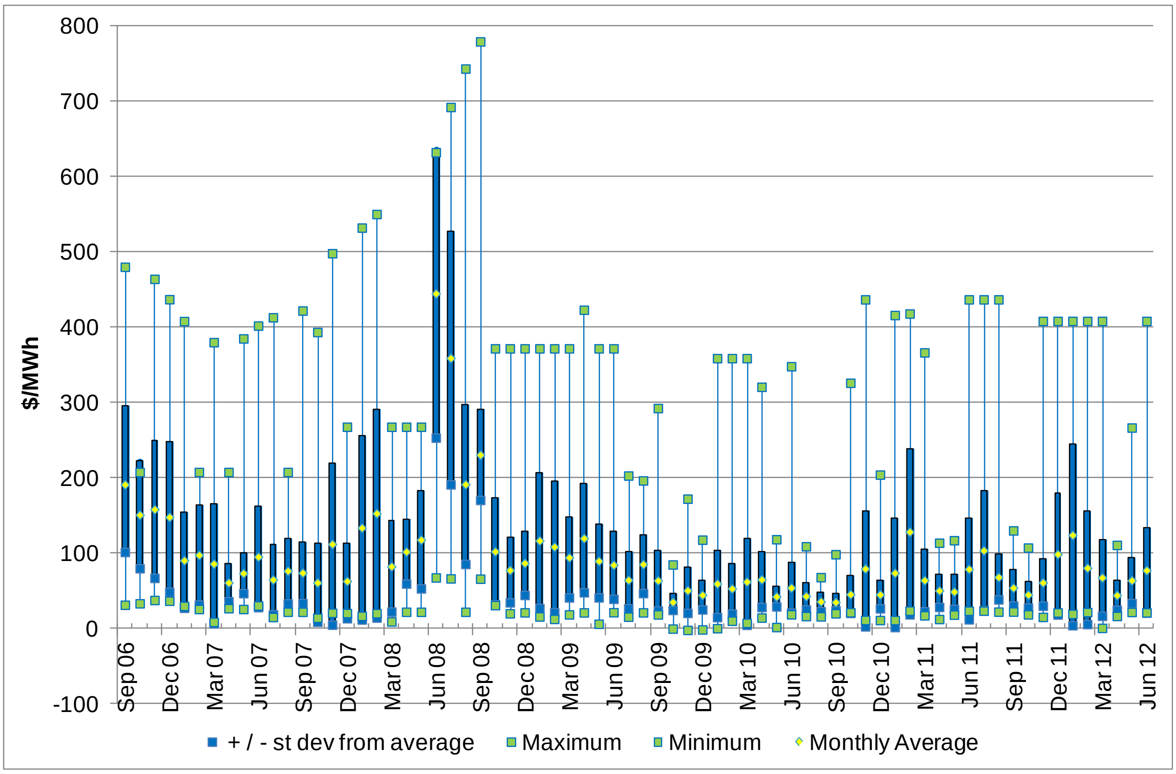


Figure 80 **Summary statistics for DDAPs during Off-Peak Trading Intervals (per calendar month)**

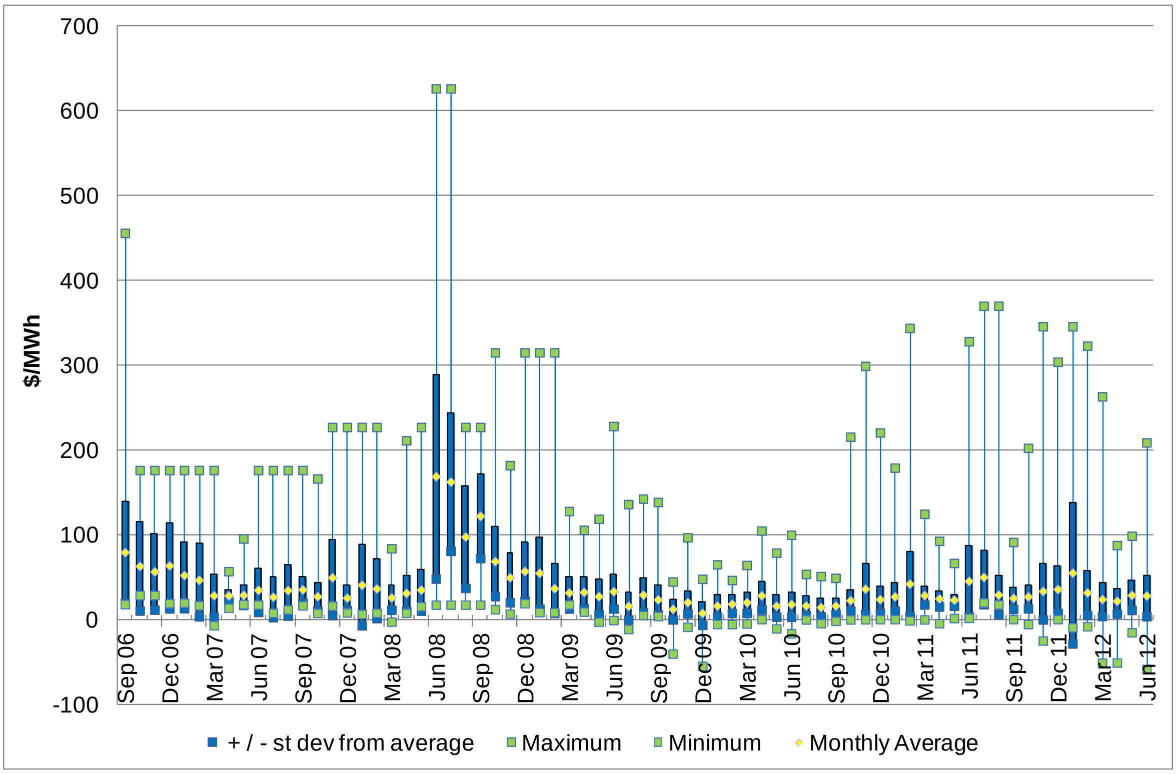
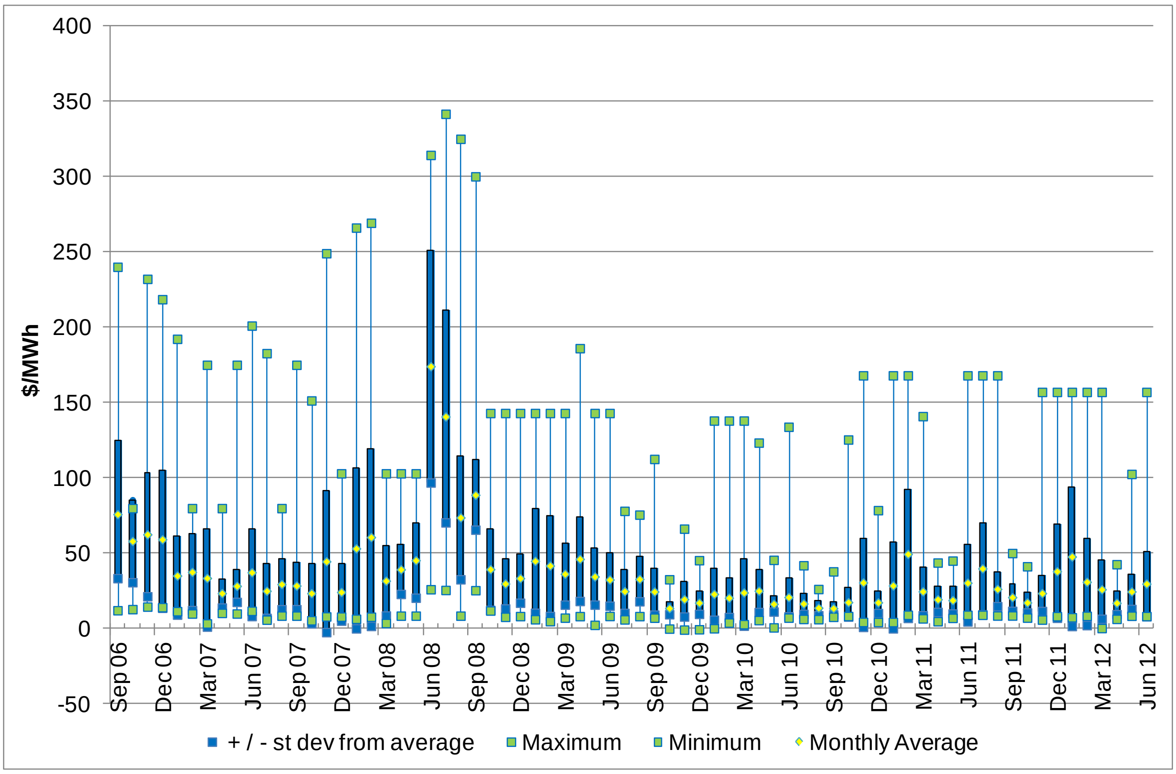


Figure 81 Summary statistics for UDAPs during Peak Trading Intervals (per calendar month)



High Balancing prices

Figure 82 and Figure 83 illustrate the price duration curves for MCAPs during peak and off-peak periods for 21 September 2006 to 30 June 2012.

Figure 82 shows that DDAPs were notably higher than the STEM prices in peak periods across all the Trading Intervals from market commencement. DDAP and UDAP price duration curves can be seen in a related shape to the MCAP price duration curve, as DDAP is derived from the MCAP.

Figure 82 Price duration curves for STEM Clearing Prices, MCAPs, UDAPs and DDAPs during Peak periods (21 September 2006 to 30 June 2012)

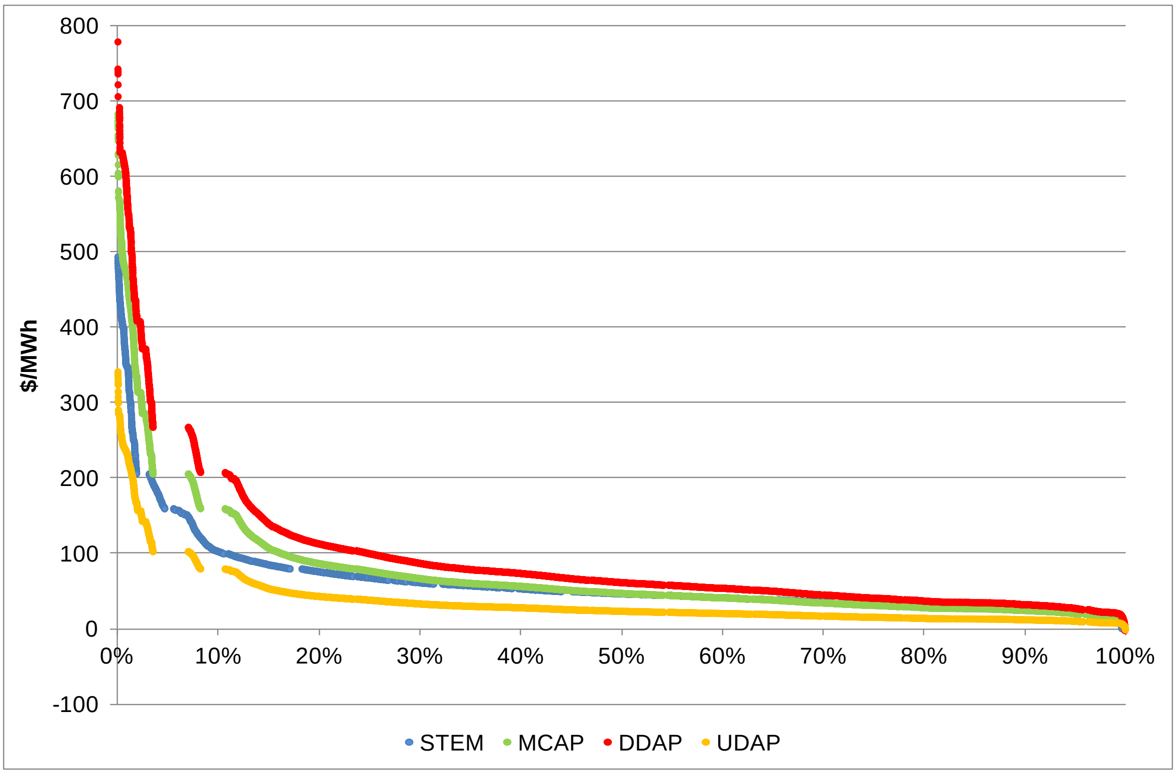


Figure 83 shows that during off-peak periods, the majority of DDAPs occur in a broad range below $100/MWh (between negative $55/MWh and $100/MWh) for approximately 94.30 per cent of the total Off-peak Trading Intervals, with a fairly even distribution of prices within this range (no notable change from previous Reporting Period's price duration curve). It can also be seen that STEM prices have comparatively remained under $100/MWh for longer durations (about 98 per cent) during off-peak periods than the peak periods (about 89 per cent).

Figure 83 Price duration curves for STEM Clearing Prices, MCAPs, UDAPs and DDAPs during Off-Peak periods (21 September 2006 to 30 June 2012)

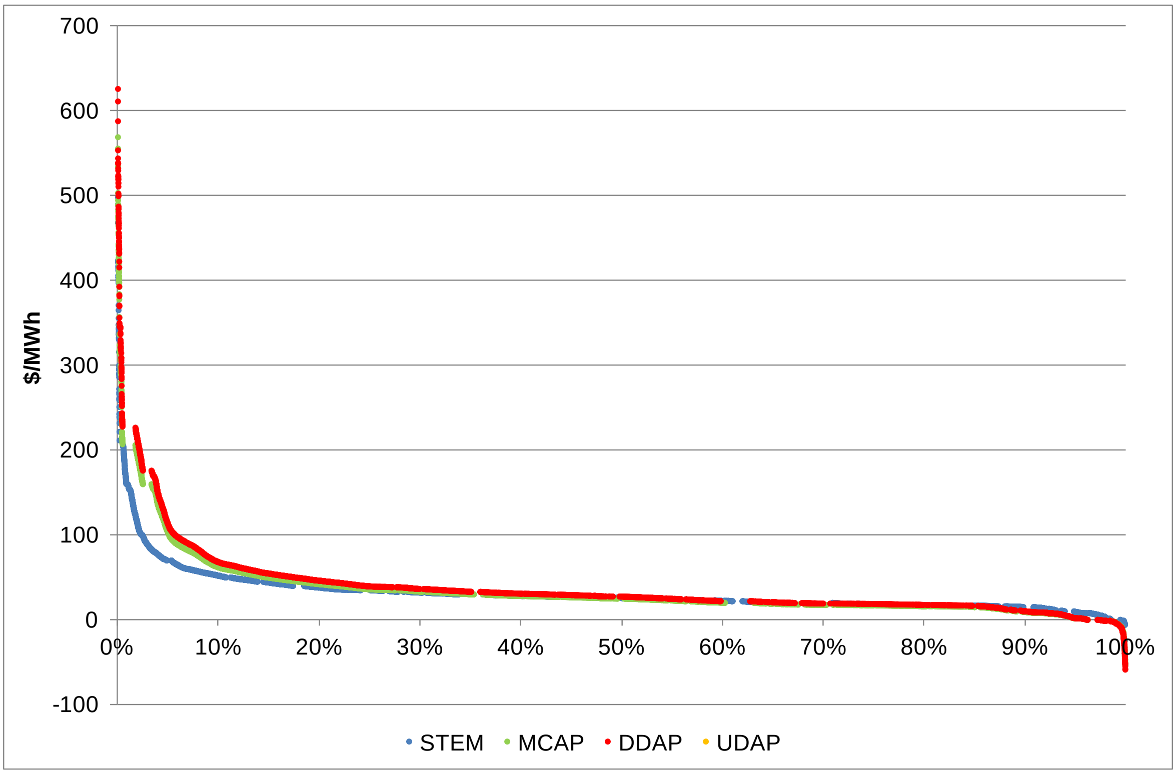


Figure 84, Figure 85 and Figure 86 illustrate price duration curves for STEM prices and MCAPs during Peak periods, for the periods 1 August 2009 to 31 July 2010, 1 August 2010 to 31 July 2011, and 1 August 2011 to 30 June 2012 respectively. STEM and MCAP price duration curves for the 2009/10 Reporting Period were comparatively smoother than the respective prices duration curves for the 2010/11 Reporting Period and the 2011/12 Reporting Period.

Figure 84 Price duration curves for STEM Clearing Prices and MCAPs during Peak periods (01 August 2009 to 31 July 2010)

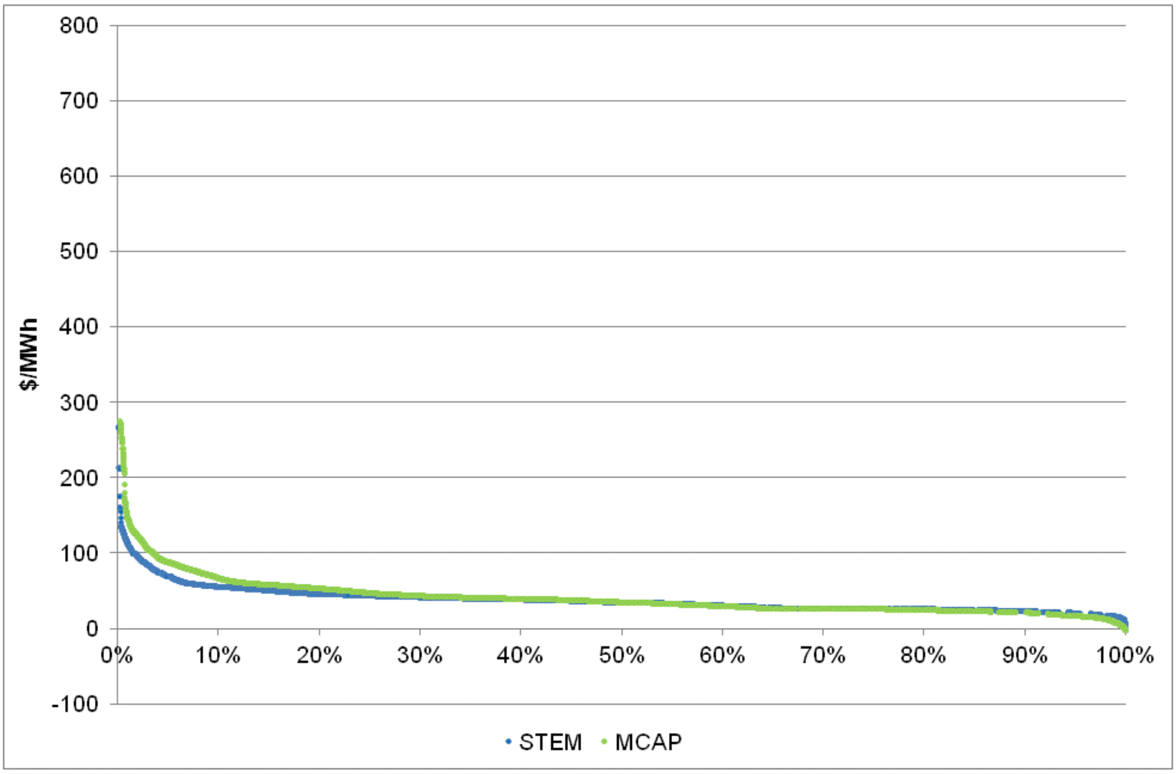


Figure 85 Price duration curves for STEM Clearing Prices and MCAPs during Peak periods (01 August 2010 to 31 July 2011)

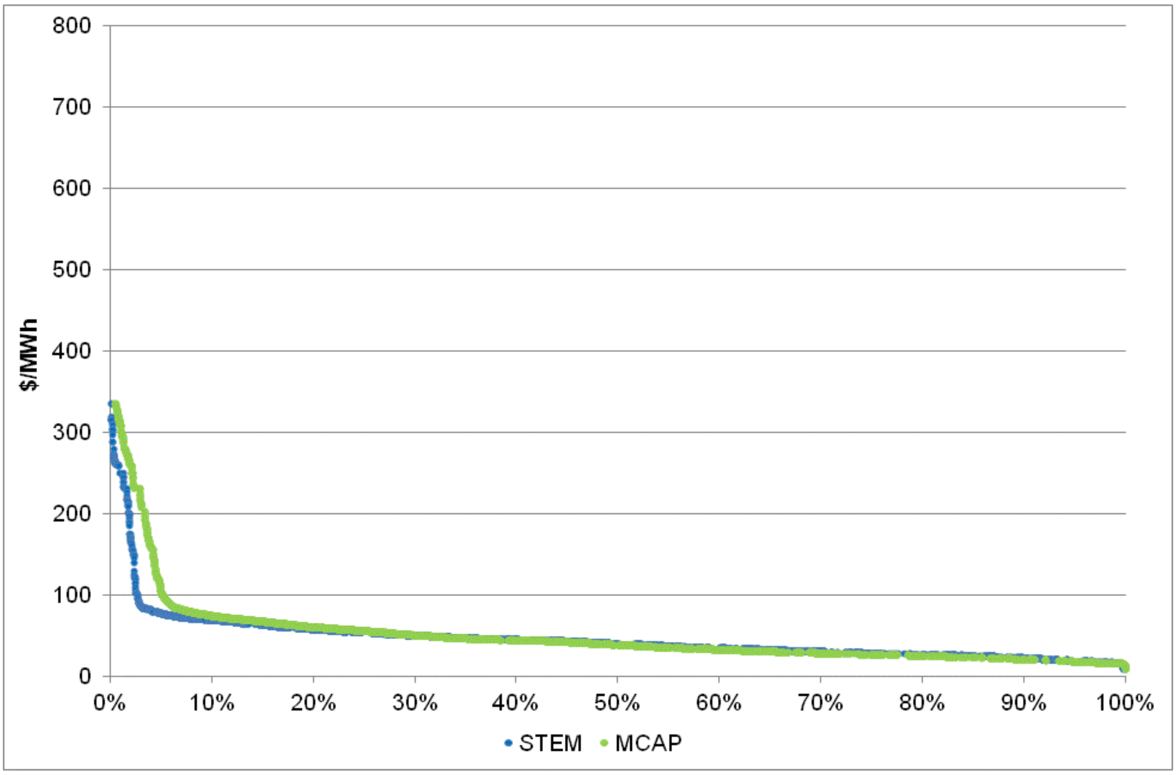
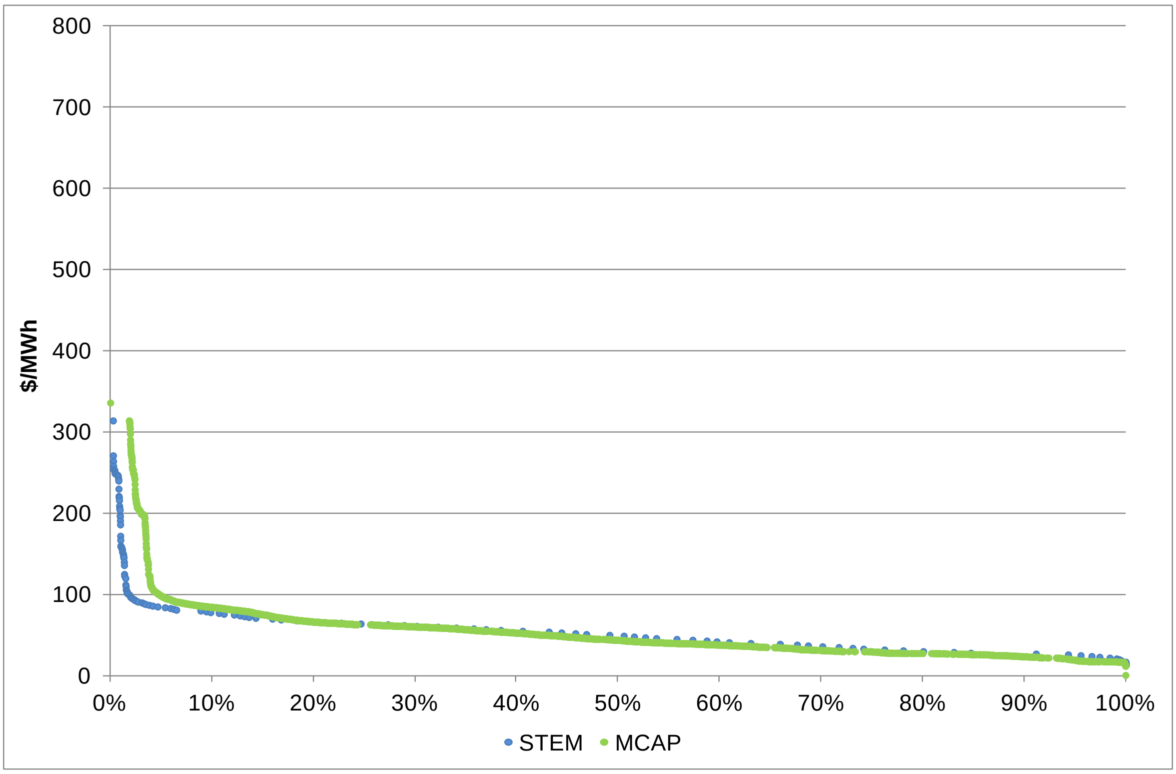


Figure 86 Price duration curves for STEM Clearing Prices and MCAPs during Peak periods (01 August 2011 to 30 June 2012)



Evidence of Market Customers over-stating consumption

Positive ‘planned load less actual load’ values denote an over-statement of consumption, whereas negative values denote an under-statement of consumption. The variations between planned load and actual load by individual Market Customers have been examined by the Authority. As this information is classified as confidential, it is not presented in this public version.

Registered Market Generators and Market Customers

Table 15 Registered Market Generators and Market Customers

	2 September 2008	6 October 2009	14 October 2010	3 October 2011	10 December 2012
Market Generators and Market Customers	Alcoa of Australia Limited	Alcoa of Australia Limited	Alcoa of Australia Limited	Alcoa of Australia Limited	Alcoa of Australia Limited
	Alinta Sales Pty Ltd	Alinta Sales Pty Ltd	Alinta Sales Pty Ltd	Alinta Sales Pty Ltd	Alinta Sales Pty Ltd
	Griffin Power Pty Ltd	Griffin Power Pty Ltd	Griffin Power Pty Ltd	Griffin Power 2 Pty Ltd	Blair Fox Pty Ltd
	Griffin Power 2 Pty Ltd	Griffin Power 2 Pty Ltd	Griffin Power 2 Pty Ltd	Griffin Power Pty Ltd	Griffin Power 2 Pty Ltd
	Landfill Gas and Power Pty Ltd	Landfill Gas and Power Pty Ltd	Landfill Gas and Power Pty Ltd	Landfill Gas and Power Pty Ltd	Griffin Power Pty Ltd
	Perth Energy Pty Ltd	Perth Energy Pty Ltd	Metro Power Company Pty Ltd	Metro Power Company Pty Ltd	Landfill Gas and Power Pty Ltd
	Southern Cross Energy	Southern Cross Energy	Perth Energy Pty Ltd	Perth Energy Pty Ltd	Metro Power Company Pty Ltd
	Verve Energy	Verve Energy	Southern Cross Energy	Southern Cross Energy	Perth Energy Pty Ltd
			Verve Energy	Tiwest	Southern Cross Energy
				Verve Energy	Tiwest
					Verve Energy
Market Generators (only)	Biogen	Biogen	Advanced Energy Resources	Advanced Energy Resources	Advanced Energy Resources
	Coolimba Power Pty Ltd	Collgar Wind Farm	Biogen	Biogen	Biogen
	EDWF Manager Pty Ltd	Coolimba Power Pty Ltd	Collgar Wind Farm	Blair Fox Pty Ltd	Collgar Wind Farm
	Eneabba Gas Limited	EDWF Manager Pty Ltd	Coolimba Power Pty Ltd	Collgar Wind Farm	Coolimba Power Pty Ltd
	Eneabba Energy Pty Ltd	Eneabba Gas Limited	EDWF Manager Pty Ltd	Coolimba Power Pty Ltd	Denmark Community Windfarm Ltd
	Goldfields Power Pty Ltd	Eneabba Energy Pty Ltd	Eneabba Gas Limited	EDWF Manager Pty Ltd	EDWF Manager Pty Ltd
	Mount Herron Engineering Pty Ltd	Goldfields Power Pty Ltd	Eneabba Energy Pty Ltd	Eneabba Energy Pty Ltd	Eneabba Gas Limited
	Namarkkon Pty Ltd	Mount Herron Engineering Pty Ltd	Goldfields Power Pty Ltd	Eneabba Gas Limited	Eneabba Energy Pty Ltd
	NewGen Power Kwinana Pty Ltd	Namarkkon Pty Ltd	McNabb Plantation Alliance Pty Ltd	Goldfields Power Pty Ltd	Genthrust Pty Ltd
	NewGen Neerabup Pty Ltd	NewGen Power Kwinana Pty Ltd	Mount Herron Engineering Pty Ltd	McNabb Plantation Alliance	Goldfields Power Pty Ltd

	2 September 2008	6 October 2009	14 October 2010	3 October 2011	10 December 2012
				Pty Ltd	
	SkyFarming Pty Ltd	NewGen Neerabup Pty Ltd	Namarkkon Pty Ltd	Merredin Energy	Greenough River
	Wambo Power Ventures Pty Ltd	NewGen Neerabup Partnership	NewGen Power Kwinana Pty Ltd	Mount Herron Engineering Pty Ltd	Merredin Energy
	Waste Gas Resources Pty Ltd	SkyFarming Pty Ltd	NewGen Neerabup Pty Ltd	Mt.Barker Power Company Pty Ltd	Moonies Hill Energy
	Western Australia Biomass Pty Ltd	Tesla Corporation Pty Ltd	NewGen Neerabup Partnership	Mumbida Wind Farm Pty Ltd	Mount Herron Engineering Pty Ltd
		Vinalco Energy Pty Ltd	SkyFarming Pty Ltd	Namarkkon Pty Ltd	Mt.Barker Power Company Pty Ltd
		Wambo Power Ventures Pty Ltd	Tesla Corporation Pty Ltd	NewGen Neerabup Partnership	McNabb Plantation Alliance Pty Ltd
		Waste Gas Resources Pty Ltd	Vinalco Energy Pty Ltd	NewGen Neerabup Pty Ltd	Mumbida Wind Farm Pty Ltd
		Western Australia Biomass Pty Ltd	Wambo Power Ventures Pty Ltd	NewGen Power Kwinana Pty Ltd	NewGen Power Kwinana Pty Ltd
		Western Energy Pty Ltd	Waste Gas Resources Pty Ltd	SkyFarming Pty Ltd	NewGen Neerabup Partnership
			Western Australia Biomass Pty Ltd	Tesla Corporation Management Pty Ltd	NewGen Neerabup Pty Ltd
			Western Energy Pty Ltd	Tesla Corporation Pty Ltd	SkyFarming Pty Ltd
				Tesla Geraldton Pty Ltd	Tesla Corporation Pty Ltd
				Tesla Holdings	Tesla Geraldton Pty Ltd
				Tesla Kemerton Pty Ltd	Tesla Holdings
				Tesla Northam Pty Ltd	Tesla Kemerton Pty Ltd
				Vinalco Energy Pty Ltd	Tesla Corporation Management Pty Ltd
				Walkaway Wind Power Pty Ltd	Tesla Northam Pty Ltd
				Wambo Power Ventures Pty Ltd	UON Pty Ltd
				Waste Gas Resources Pty Ltd	Vinalco Energy Pty Ltd
				Western Australia Biomass Pty Ltd	Western Australia Biomass Pty Ltd
				Western Energy Pty Ltd	Walkaway Wind Power Pty Ltd
					Wambo Power Ventures Pty Ltd

	2 September 2008	6 October 2009	14 October 2010	3 October 2011	10 December 2012
					Western Energy Pty Ltd
					Waste Gas Resources Pty Ltd
Market Customers (only)	Barrick (Kanowna) Limited	Barrick (Kanowna) Limited	Amanda Australia Pty Ltd	Amanda Australia Pty Ltd	Amanda Australia Pty Ltd
	Clear Energy Pty Ltd	Clear Energy Pty Ltd	Barrick (Kanowna) Limited	Barrick (Kanowna) Limited	Clear Energy Pty Ltd
	Energy Response Pty Ltd	DMT Energy	Clear Energy Pty Ltd	Clear Energy Pty Ltd	DMT energy
	Karara Energy Pty Ltd	Energy Response Pty Ltd	DMT Energy	DMT Energy	EnerNOC Australia Pty Ltd
	Newmont Power Pty Ltd	Karara Energy Pty Ltd	Energy Response Pty Ltd	Energy Response Pty Ltd	Energy Response Pty Ltd
	Premier Power Sales Pty Ltd	Newmont Power Pty Ltd	EnerNOC Australia Pty Ltd	EnerNOC Australia Pty Ltd	ERM Power Retail Pty Ltd
	Synergy	Premier Power Sales Pty Ltd	ERM Power Retail Pty Ltd	ERM Power Retail Pty Ltd	Focus Operations
	Water Corporation	Synergy	Karara Energy Pty Ltd	Karara Energy Pty Ltd	HBJ Minerals Pty Ltd
		Water Corporation	Newmont Power Pty Ltd	Newmont Power Pty Ltd	Barrick (Kanowna) Limited
			Premier Power Sales Pty Ltd	Premier Power Sales Pty Ltd	Karara Energy Pty Ltd
			Synergy	Synergy	La Mancha Resources
			Water Corporation	Water Corporation	Newmont Power Pty Ltd
					Premier Power Sales Pty Ltd
					Water Corporation
					Synergy

Appendix 4 Review of arrangements for Demand Side Management in other jurisdictions

Demand Side Involvement in Electricity Markets

Electricity markets differ to other commodity markets in that customers are physically interconnected, electricity cannot be meaningfully stored and because access to electricity is central to economic and social well being. Accordingly, the balance between supply and demand is critical and must be assured at all times, over sustained periods. Demand side resources encompass demand response, energy efficiency, and distributed generation. Demand side resources can moderate price spikes and enhance reliability in a manner comparable to supply-side generation, through short term customer demand responsiveness during peak demand periods or when supply is constrained due to emergency situations, or through permanent and continuous reductions in peak demand (i.e., energy efficiency or shift in consumption patterns).

As described by Gottstein and Schwartz (2010, pp.12)[178], the opportunities afforded by the inclusion of demand side resources are:

- Lowered cost of power delivery, reducing congestion, and improving the reliability of the delivery system.
- Enhancing regional power system reliability, using a range of demand side resources to meet planning and operational reserves.
- Economically balancing supply and demand in wholesale power markets through demand-side bidding and market transactions for energy supply released through demand reduction.
- Cost effectively reducing long term demand and lowering throughput through energy efficiency resources, both on the power grid as a whole and within the resource portfolio of power suppliers.

Additionally, in the Midwest Independent System Operator (**MISO**) market, demand response is seen to improve reliability in the short term, contribute to resource adequacy in the long term, reduce price volatility and other market costs, and mitigate supplier market power[179].

Other benefits of demand side resources may also include bill savings and reduced exposure to forced outages for customers, a reduction in peaking plant requirements and innovation in retail markets[180].

Accordingly, market administrators place emphasis on developing both the demand side and supply side of electricity markets[181].

[178] Gottstein, M. and Schwartz, L. (2010). *The Role of Forward Capacity Markets in Increasing Demand-Side and Other Low-Carbon Resources: Experience and Prospects*. May 2010, The Regulatory Assistance Project.

[179] http://www.potomaceconomics.com/uploads/midwest_reports/2011_SOM_Report.pdf

[180] Refer to “Instituto de Ingenieria Energetica. CIGRE WG C6.09. Item 4 Demand-Side Response Initiatives” for benefits and costs of DR http://www.etsii.upct.es/antonio/html_der/papers/CIGRE%20WG%20C6_WP4_web.pdf .

[181] A review of the early versions of the National Electricity Market (NEM) Electricity Statement of Opportunities (ESOO) reports, for example, shows the equivalent focus afforded to the provision of both demand and supply side considerations in market planning and forecasting following commencement of the market.

Nevertheless, there are costs associated with the provision of demand side resources. For example, there may be participation costs, such as the costs associated with technology investments, establishing response plans, lost business, rescheduling costs and maintenance costs. There may also be system costs associated with metering (communication) system upgrades, utility equipment or software costs, customer education, program administration, marketing, payments to participants, program evaluation and metering tariffs.

The use of demand side resources can be considered efficient when the savings in supply side costs are greater than the benefits that would be obtained by consuming the electricity.

Demand Response in Organised Markets with Forward Capacity Auctions

There are two organised markets in the US that conduct Forward Capacity Auctions (**FCA**s) and allow for a range of demand side resources to compete on a level playing field with supply side resources in meeting the resource adequacy requirements of a region. These include the Pennsylvania, New Jersey Maryland (**PJM**) System and Independent System Operator New England (**ISO-NE**)[182]. The following paragraphs provide a brief overview of the main rationale, arrangements for, and criticisms of the use of demand side resources in these markets.

Demand Response in PJM's Reliability Pricing Model

In PJM, a demand side resource is a resource that has a demonstrated capability to provide reduced demand or otherwise control load, and that offers and clears that capability into a PJM capacity auction or through a Fixed Resource Requirement (**FRR**) capacity plan[183].

In PJM's Reliability Pricing Model (**RPM**) capacity market, in order to secure capacity for a future delivery year, PJM conducts forward auctions[184], allowing existing and proposed generation, demand response, and energy efficiency resources to be offered into an auction, in competition to meet the regions installed capacity needs.

Prior to the RPM, Load Serving Entities (**LSE**s) reduced the amount of installed generating capacity that they had to commit for peak loads by demonstrating to PJM that they had contractually committed customers who would interrupt their load during peak demand periods. In the last delivery year before the implementation of the RPM, the amount of participating load response was around 1.5 per cent of peak load.

With the introduction of the RPM, demand side resources qualified for inclusion on the basis that they:

- Could be interrupted during the hours 12:00pm to 8:00pm on non-holiday weekdays during the months of June through September;
- Could be called upon for interruptions up to 10 times during that period each year; and
- Could remain interrupted for up to six hours when called upon.

[182] New York ISO (NYISO) and Midwest ISO (MISO) also run capacity markets in the US, however, only PJM and ISO-NE run forward auctions (i.e., several years in advance) and permit energy efficiency and DR to compete with generation to meet future reliability requirements. Brazil's also runs a forward capacity market, however, it does not allow DSM to participate.

[183] http://www.ferc.gov/EventCalendar/Files/20110429165650-ER11-2288-001.pdf

[184] PJM conducts a Base Residual Auction (BRA) 3-years ahead of each delivery year (in which it procures the majority of capacity that will be required in that year), and then subsequent to this, conducts three scheduled incremental auctions.

However, PJM was concerned that as more megawatts of resources were committed that were only available during narrowly defined peak periods, fewer megawatts of more broadly available resources were being committed. According to PJM, the commitment of fewer resources that were more broadly available increased the risk that PJM may have to call on a resource at a time, or in a manner, in which the resource was not required to respond, thus creating reliability concerns[185].

Consequently, PJM proposed to retain the existing demand response product, but rename it to Limited Demand Response (Limited DR), and to establish two additional demand response products. The first, Annual Demand Response (Annual DR), is required to be available on any day of the year, for an unlimited number of interruptions during the year. However, there are limits on the hours of the day when it must be available i.e., 10:00 am to 10:00 pm May through October, 6:00 am to 9:00 pm November through April, and a ten hour cap on the duration of the required interruption.

The second, Extended Summer Demand Response (Extended Summer DR), involves an expanded summer commitment period (compared to Limited DR), being required to be available on any day from May through October from 10:00 am to 10:00 pm, with a ten hour cap on the duration of the interruption (refer to the table below).

DR Product	Availability Days	Availability Hours	Number of Interruptions	Cap on Duration of Interruption
Limited DR	Non-holiday weekdays during the months of June through September	12:00pm to 8:00pm	10	6 hours
Annual DR	Any day of the Year	10:00 am to 10:00 pm May through October, 6:00 am to 9:00 pm November through April	Unlimited	10 hours
Extended Summer DR	Any day from May through October	10:00 am to 10:00 pm	Unlimited	10 hours

The limits to the Annual DR product were set to encompass the times in which load management resources have historically been needed in PJM, since the 2000/2001 delivery year, i.e. ranging between 12:00pm and 8:00pm. The ten-hour duration limit also addressed concerns around the original demand response product's duration limit of only 6 hours.

Under PJM's proposal, minimum requirements were to be set for the amount of Annual Resources (including generation, Annual DR and energy efficiency) and the combination of Annual and Extended Summer DR resources that reflect their superior availability[186]. As

[185] http://www.troutmansandersenergyreport.com/wp-content/uploads/2011/02/PJM-Capacity-Markets-File.pdf
http://www.pjm.com/~/media/documents/ferc/2011-filings/20111201-er12-513-000.ashx

[186] The minimum requirements i.e., Minimum Annual Resource Requirement and Minimum Extended Summer Resource Requirement are determined for both the PJM region as a whole and for the three Locational Deliverability Areas (LDAs). The Minimum Annual Resource Requirement is calculated by subtracting the short term resource procurement target (i.e. a 2.5 percent hold-back of PJM's procurement of capacity resources from the BRA for a delivery year to the incremental auctions for that delivery year) and the Extended Summer DR target from the PJM region reliability requirement. The Minimum Extended Summer Resource Requirement is calculated by subtracting the short term resource procurement target and Limited DR target from the PJM region reliability requirement. The Limited DR target is defined by the lower of a) the level of Limited DR commitment at which there is 90 percent probability of requiring ten or fewer DR

long as the auction produced more than the minimum requirements, all resources accepted in the auction would be paid the same price (including demand response), as no resource types would be needed in preference to others. However, if either of the minimum requirements were not met (whether Annual or Extended Summer DR or both), PJM would procure sufficiently more resources and pay higher prices so as to satisfy the minimum requirements, and procure and pay less for the other resources. The demand response products would thus be priced in accordance with their availability[187].

The Federal Energy Regulatory Commission (**FERC**) accepted PJM's proposal, recognising the ability of some demand resources to provide expanded response capabilities (i.e. to participate for longer periods), whilst establishing just and reasonable pricing for these resources. Additionally, FERC indicated that together, the three demand response products would add flexibility to PJM's ability to procure adequate capacity in the RPM auctions, and would significantly enhance PJM's emergency dispatch options.

Notably, PJM did not suggest that the existing, i.e., Limited DR, product should be eliminated or that it was in anyway unjust or unreasonable, just that it must not place an overreliance on the product, given the limits on when it is required to respond. The Limited DR product was instead viewed as providing additional options, with appropriate pricing for customers that could satisfy the requirements, in much the same way as the Extended DR product. Furthermore, as noted in PJM's 'Markets Implementation Committee' proposal, the Limited DR product was maintained for those customers who had become accustomed to that particular product and those customers who were contractually obligated to it[188].

Demand response providers can choose which of the demand response options suits them and, even where certain demand response products are available only for a limited period they can combine with other resources under an aggregator, to provide an annual resource bid that is eligible for higher prices. However, market sellers are required to specify which resource type they are using as the basis for an offer (or bid) in the RPM auctions, and providers that qualify under more than one demand response type are able to submit linked alternative offers for their resource as Limited DR, Extended Summer DR or Annual DR.

According to PJM, the RPM Capacity Auction in 2011 (i.e. the first to include the two new demand response products) led to a 50 per cent increase over the previous year in the amount of demand response that cleared (refer to Figure 1 below, adapted from Table 4-7 of the 2012 Quarterly State of the Market Report for PJM: January through September[189]). In their 2011 assessment of the performance of the RPM, Brattle noted that as a result of offers from a wide variety of new resources, particularly demand response, the Base Residual Auction (**BRA**) supply curves have become smoother and less steep over time. Thus, the inclusion of demand resources in the BRA contributed to the mitigation of the steep offer curves that were observed in the first few auctions, increasing competition between resources in the more recent auctions and providing reductions in price volatility going forward.

interruptions; and b) the level of Limited DR commitment that would effectively reduce the peak load, given the obligation to curtail for up to 6 hours per interruption.

[187] Note that Extended Summer DR can receive higher prices than Limited DR because it provides capacity over a longer period, and Annual DR will receive higher prices still, as it is available for an entire year. If the system does not need the less-limited product, the auction will clear the DR capability at the lower price, and consumers will pay no more than is needed to satisfy reliability.

[188] http://www.pjm.com/~/media/committees-groups/committees/mic/20100818/20100818-item-06-dr-saturation.ashx

[189] http://www.monitoringanalytics.net/reports/PJM_State_of_the_Market/2012/2012q3-som-pjm.pdf

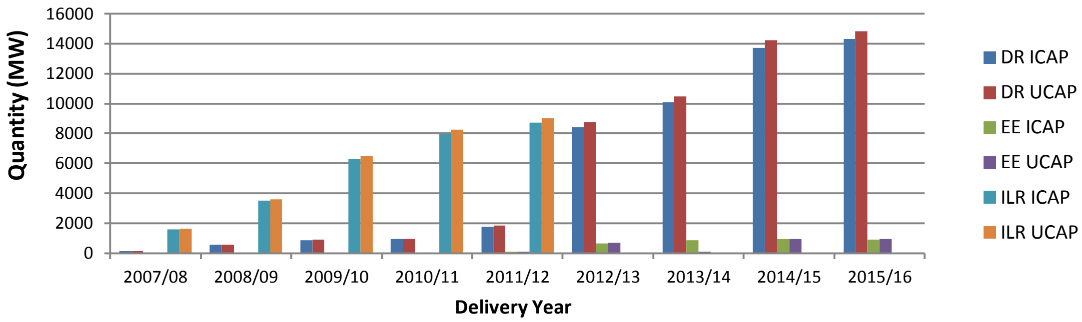


Figure 1. RPM Demand Response (DR), Energy Efficiency (EE), and Interruptible Load for Reliability (ILR) Cleared Installed Capacity (ICAP) and Unforced Capacity (UCAP): 2007/08 through 2015/16

In contrast to this, however, the Market Monitor has recommended that the Limited DR and Extended Summer DR products be eliminated from the capacity market, as they are 'inferior' products that pose a risk to system reliability, threaten competitive outcomes and distort capacity prices. Furthermore, it has been noted that Limited DR is less expensive to provide than Annual DR and generation but it receives the same capacity price as these resources.

Demand Response in the ISO-NE Market

ISO-NE defines demand side resources as installed measures that result in verifiable reductions in end use consumption of electricity in the New England power system. These measures may include products, equipment, systems, services, practices and strategies.

Prior to the start of the Forward Capacity Commitment Period on 1 June 2010 the ISO operated four active real time demand response programs including[190]:

- a real time 30-minute demand response program – these resources could be deployed with 30 minute notice for a minimum duration of 2 hours and received the higher of the Locational Marginal Price (**LMP**) or $500 per MWh;
- a real time 2-hour demand response program - these resources could be deployed with 2-hour notice for a minimum duration of 2 hours and received the higher of the LMP or $350 per MWh;
- a real time Profiled Response program – these resources were able to be interrupted within a specified time period for a minimum duration of 2 hours and received the higher of the LMP or $100 per MWh; and
- a real time Price Response Program – these resources had the option of reducing load when they received notice on the previous day but they were not required to do so. If they reduced their load, they received the higher of the LMP or $100 per MWh for the eligibility period.

The first three demand response programs were reliability based and activated emergency response resources during a capacity deficiency. The fourth program was a price based response that was activated when the wholesale price was expected to be greater than or equal to $100 per MWh.

Demand side resources were integrated into the Forward Capacity Market (**FCM**) in 2010 and like supply-side resources they can compete in Forward Capacity Auctions (**FCA**), take on capacity obligations and receive capacity payments.[191] The two broad categories of

[190] http://www.iso-ne.com/markets/mktmonmit/rpts/ind_mkt_advsr/emm_mrkt_rprt.pdf

[191] FCA's are held every year 3 years in advance of the delivery year. Each auction is held in two stages i.e., a descending clock auction followed by an auction clearing process. There are multiple rounds in the descending clock auction. During one of the rounds the capacity willing to remain in the auction will equal or

Demand side resources in the FCM are Active Demand Resources (**Active DRs**), which are dispatchable and reduce load in response to ISO dispatch instructions, and Passive Demand Resources (**Passive DRs**), which are not dispatchable and provide load reductions during predetermined periods.

Active DRs (such as load management, emergency generation, and dispatchable distributed generation) are designed to reduce peak loads and to reduce load based on real time system conditions or ISO-NE instructions. Active DRs consist of Real-Time Demand Response (**RTDR**) resources, which include load management and distributed generation, and Real Time Emergency Generation (**RTEG**) resources, i.e. distributed generation whose operation is limited to emergency conditions due to state air quality permits. Their operation is limited to 600 MW and they must be available from 7:00 am to 7:00 pm, Monday through Friday on non-holidays. Active DRs must curtail electrical usage within 30 minutes of receiving a dispatch instruction and until receiving a release/recall dispatch instruction.

Passive DRs consist of On-peak Demand Resources (**On-peak DRs**), i.e. measures that are not weather sensitive and reduce demand across a fixed set of on-peak hours (e.g. motors), or Seasonal Peak Demand Resources (**Seasonal Peak DRs**), i.e. weather sensitive measures that reduce load during high demand conditions, e.g. air-conditioners. Seasonal Peak DRs must reduce load when system load is equal to 90 per cent of the most recent peak load forecast for the relevant summer or winter season.

DR Product	Availability Days	Availability Hours
On Peak DR	Summer On-peak hours non-holiday weekdays from June to August	1.00 pm to 5 pm
	Winter On-Peak Hours non-holiday weekdays in December and January.	5.00 pm to 7 pm
Seasonal Peak DR	Non-holiday weekdays when the real-time system hourly load is equal to or greater than 90 per cent of the most recent 50/50 system load peak forecast for the applicable Summer or Winter season.	

Most Passive DRs are offered by Participants such as investor owned utilities, with state sponsored energy efficiency programs.

The ISO also administered two demand response programs in 2011 to provide financial incentives for customers to reduce load in response to day-ahead and real-time energy prices. These included the Real Time Price Response (**RTPR**) Program and the Day-Ahead Load-Response Program (**DALRP**). The RTPR provided financial incentives to Market Participants to reduce load voluntarily when the ISO forecast LMP was greater than or equal to $100/MWh. Participants were paid the greater of $100/MWh or the real time LMP.

The DALRP was an optional program that allowed Market Participants with assets registered as RTDR or RTPR to offer load reductions in response to day-ahead LMPs. Market Participants were paid for their cleared offers the day-ahead LMP and were obligated to

fall below the Installed capacity Requirement (ICR). Resources that are still in the auction at this point will move on to the auction clearing stage, during which auction clearing software is run to determine the minimum capacity payment and calculate final capacity zone clearing prices. Reconfiguration auctions take place prior to and during the commitment period (i.e., annually, monthly or seasonally) to allow participants to trade capacity obligations and adjust their positions annually or within the commitment period.

reduce load by the day-ahead amount cleared. The Participant was then charged or credited for any deviations in curtailment in real time, with the amount cleared a day ahead, at the real time LMP.

Both of these programs were scheduled to expire on May 31, 2012 and to be replaced by a new transitional program, designed to comply with FERC Order 745[192] and anticipated to remain in effect until June 1, 2017, when new market rules will become effective that are designed to fully integrate dispatchable demand resources into the day-ahead and real-time energy markets. FERC Order 745 rules that, when a demand resource participating in the wholesale energy market has the capability to balance supply and demand as an alternative to generation and dispatch of that demand resource is cost effective, as determined by a net benefits test, the demand resource must be compensated for the service that it provides at the LMP for energy.

In 2011, the total capacity supply obligation for all demand resources in the FCM increased by 14 per cent i.e., a gain of 244 MW from 2010. The Active DRs capacity supply obligations actually decreased by 9 per cent, whilst the Passive DRs increased by 67 per cent over the 2010 value. Notably, this increase occurred at a time when the price for capacity ($/kW-month) decreased.

	Active Demand Resources			Passive Demand Resources		
	Real Time Demand Response (RTDR).	Real Time Emergency Generation (RTEG)	Total Active Demand Resources	On-Peak Demand Resource	Seasonal Peak Demand Resource	Total Passive Demand Resources
Year ending 2010	669	522	1,191	406	118	1,716
Year ending 2011	649	436	1,085	617	259	1,960

The Independent Market Monitor (IMM) has identified two main concerns with the demand response programs in the ISO-NE market, including:

- Instances where RTDR asset owners participating in the DALRP have submitted inaccurate, over-stated, meter data to the ISO; and
- Compensation paid to market participants resulting from load reductions that were not the result of the asset taking actions in response to the ISO's dispatch instructions or LMPs (e.g. when a meter malfunction results in zero load being reported for the period).

In view of this, the IMM has made recommendations to improve demand response data accuracy and to improve the reporting of demand response availability.

Similarly, in their recent Market Assessment, Potomac Economics noted that when demand resources were deployed their performance varied widely, with only a small portion of resources curtailing an amount of load within 10 per cent of the instructed amount, i.e. the performance threshold for assessing uninstructed deviation penalties to generators. This raised questions around whether the demand resources selling capacity to the market provided the same level of reliability benefits as generators, leading Potomac Economics to

192 http://www.ferc.gov/EventCalendar/Files/20110315105757-RM10-17-000.pdf

suggest a reassessment of the performance criteria and settlements with demand resources that do not perform as instructed to bring them into line with generators.

Additionally, Potomac Economics noted that the activation of demand resources in real time during shortage conditions can inefficiently depress real-time prices below the marginal cost of foregone consumption for demand response, which is likely to be much higher than the marginal cost for most generators. For example, on the two occasions when emergency demand resources were activated in 2011, the reserve clearing price for 30-minute reserves was $100 per MWh. This low price under-stated the shortage event and effectively increased its severity, where it could have been reduced through higher prices signalling the need for the use of import capacity and increased purchases. Consequently, the ISO is addressing this issue by raising the 30-minute reserve price to $500 per MWh.

The ISO-NE *2011 Annual Markets Report* notes that the clearing prices in the annual reconfiguration auctions have steadily declined and are significantly lower than the price in the related FCA. Far more capacity has been cleared than is needed to meet the Installed Capacity Requirement (**ICR**)[193] and over half of this (i.e. 55.9 per cent in the 2006/07 to 2014/15 period) has been attributed to demand resources that are able to enter the market quickly and at prices much lower than the estimated Cost of New Entry (**CONE**) for generators.

There is currently a move toward the establishment of differentiated capacity products in the ISO-NE FCM.[194] The rationale behind this move is that not all capacity resources provide the same operating attributes, reliability benefits and/or services, and thus it is argued that they should be compensated accordingly.[195] In relation to this, the *Draft FCM Framework Document* suggests that, among other things, ISO-NE should:

- identify and specifically procure attributes needed to achieve reliability requirements and system operations;
- treat demand, supply and imported resources on an equivalent basis (i.e. they should be fuel and technology neutral) to the degree that they meet the same reliability and capacity requirements;
- acquire resource attributes in tranches within the total ICR; and
- not allow demand resources to set the FCM prices.

Summary

There has been a substantial growth in DSM capacity observed in the WEM. Whilst this growth is expected to slow in the coming years, the rapid rate of technological change impacting demand management could have a material impact on load forecasts and electricity consumption patterns in the coming decades. This, together with the issues raised in relation to DSM within the context of the recent review of the RCM, necessitate the examination of the evolution of the integration of demand resources into other jurisdictions.

[193] The surplus capacity cleared after FCA number 1 was 1,773 MW. This rose to 5,373 MW after the fourth capacity auction and dropped to 3,718 MW after the fifth capacity auction.

[194] See, for example, the Draft FCM Framework Document http://www.iso-ne.com/key_projects/fcm_redesign/other/fcm_framework_document_jan_4_12.doc and http://www.iso-ne.com/key_projects/fcm_redesign/other/fcm_redesign_long_term_framework_document.pdf and http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/2011/2011_amr_final_051512.pdf

[195] http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/prtcpnts/mins/2012/npc_2012_0815.pdf

Toward this end, a review of the forward capacity market designs of both PJM and ISO-NE shows that both have provided for the successful facilitation of participation of demand side resources into their respective markets. This has led to increased competition, with the ISO-NE market's reliability needs being met at noticeably lower prices than the cost of new generation, and PJM's market further benefitting through reductions in price volatility.

However, both markets have experienced concerns around the treatment of demand side resources as equivalent to generation resources, citing among other things, major concerns around differences in availability requirements, costs of service provision and distorted capacity prices. Accordingly, there have been calls in both markets for remunerating demand response products in accordance with reliability attributes such as the availability, flexibility of dispatch options, and costs of demand response.

Appendix 5 Review of capacity markets

The primary purpose of a capacity market is to ensure security and reliability of supply, which it does by ensuring that sufficient capacity is available to achieve a required level of reliability, that is centrally determined, based on maximum demand and energy forecasts made some years ahead.

Capacity markets are also designed to incentivise sufficient investment in generation and non-generation capacity, including existing generators, new builds and other forms of capacity such as Demand Side Management (**DSM**), by providing some degree of certainty of revenue streams and returns on the investment. In this way, it solves the 'missing money' problem associated with energy only markets[196] whereby returns on investment for peaking capacity rely mainly on occasional price spikes.[197]

Capacity markets also encourage liquidity by facilitating capacity transactions among market participants, and Market Participants and consumers alike, can benefit from the provision of a capacity market through supply security and increased price stability.

Different Capacity Market Designs

The main characteristics of differing capacity markets, the advantages and disadvantages of these designs are summarised in the following table.[198]

[196] In an energy only market the only revenue to a generator is through the sale of electricity in the energy market. The capacity to produce energy is not valued separately and the reserve margin for ensuring resource adequacy is not determined explicitly.

[197] Botterud A. & Doorman G. (2008). *Generation investment and capacity adequacy in electricity markets.* International Association for Energy Economics. Botterud and Doorman noted that historical electricity prices in the US (with some exceptions, e.g., New York City Zone) tended to be below the total cost of new power generation. They suggested that low reserve margins combined with insufficient revenues from the energy market to recover new generation investments may explain why several US markets (PJM, ISO-NE, and NY-ISO) have capacity markets.

[198] Brattle Group (Pfeifenberger J., Spees K. & Schumaker A., 2009). *A Comparison of PJM's RPM with Alternative Energy and Capacity Market Designs.* September 2009. The Brattle Group for PJM Interconnection L.L.C. http://www.brattle.com/_documents/uploadlibrary/upload807.pdf

Eurelectric (2011). RES Integration and Market Design: Are Capacity Remuneration Mechanisms Needed to Ensure Generation Adequacy? http://www.eurelectric.org/media/26300/res_integration_lr-2011-030-0464-01-e.pdf

Chaigneau M. (2012). Forward Capacity Markets: Maintaining Grid Reliability in Europe. Master Thesis Project. http://kth.diva-portal.org/smash/get/diva2:515402/FULLTEXT01

Types of Capacity Markets

Type	Description	Advantages	Disadvantages
Energy Market with Capacity Payment (e.g., Chile, Colombia, South Korea, Spain, Peru, Argentina before 2000, and the UK before the New Electricity Trading Arrangements, i.e. NETA[199]).	Pays a fixed, administratively determined amount for available capacity to all generators. The payment provides additional revenue to generators to allow the full recovery of fixed costs. Allows the operator to impose price caps and other mitigation measures to avoid severe price spikes. There are no reserve requirements, which allows for the differentiation of capacity payments among new and existing resources. Payments can be awarded also when the plant does not run, but certain availability criteria have to be met.	Simple and flexible tool for policymakers to retain and attract necessary generation capacity. Can differentiate incentives for new investment and retention of existing resources. The payment automatically reduces to zero when the required reserve margin is reached. If capacity payments are broadly available to all market participants, energy market price caps can be lower, allowing market operators to reduce price shocks and issues of market power. Payments can solve the missing money problem in energy markets with low price caps. Stable capacity payments and improved reliability reduce price risk and the risk premium required for new investments.	The use of administrative payments adds regulatory risk where the payments can be changed in an ad hoc or non-transparent manner, increasing regulatory risk. Capacity payments that are too low will fail to attract investments, while payments that are too high will inefficiently burden customers. Resource adequacy levels remain uncertain. Capacity payments, often recovered from customers through uplift charges based on their energy consumption rather than based on peak loads, such that economically efficient market signals for reducing peak load through demand response are lost. Risk of significant market distortions if payments are differentiated for new and existing capacity.

[199] Carreon Rodriguez V.G. & Rosellon J. (2009). *Incentives for Supply Adequacy in Electricity markets: An Application to the Mexican Power Sector*. Economia Mexicana, Vol. XVIII, number 2., pp. 249-282.

Type	Description	Advantages	Disadvantages
Energy Market with Strategic Reserve or Tender for Targeted Resource (e.g. Nord Pool)	Capacity Payments are only given to resources needed to make up for any shortfall in the market. The level of payment can be set through a competitive tendering process. In principle, the strategic reserves only operate in extreme peak conditions.	Easy to implement. Retains only necessary peak load reserve plants at limited system costs. No disturbance of the spot wholesale price formation mechanism, i.e. energy prices remain the main driver to attract new investments at the location where needed. Potentially less expensive than other models (since only a limited part of the capacity is remunerated).	Existing models mainly targeted at existing peaking plant that would otherwise close i.e., there is no direct incentive or support for new investment. Not ideal to remunerate stand by service for intermittent renewable energy plants as tender for targeted resources may be called too often. Lower demand response in the spot market, especially if demand is allowed to participate in the tender for targeted resources. If supply/demand is in balance but there is a high price, some available tender for targeted resources may not be used because the price boundary to activate them is not reached.
Capacity Obligation	An obligation on suppliers to contract with generators for a certain level of capacity (determined by Transmission System Operator/regulator and related to their average off-take or off-take profile) or pay a buy-out price/fine if not enough capacity is contracted. The price for capacity is determined in a decentralised way through the contracts. This model could also include a market of exchangeable obligations.	Decentralised mechanism reduces degree of regulatory intervention. Straightforward tool for regulators - simple obligation placed on suppliers equal to the desired reserve margin. Cost of capacity adequacy assigned to suppliers whose customers are causing more peak load demand (give suppliers more incentives to flatten their off-take profiles).	Lack of forward requirements limits long-term price signals for investments. Potential barriers for new entrants who have to purchase tickets before knowing their customer portfolio, especially if many customers switch. If markets of exchangeable obligations are not liquid and transparent enough (new entrant) suppliers may face high risks. In a market with many suppliers, verifying their voluntary compliance is a complex process.
Energy Market with Reserve Requirements (e.g. South West Power Pool (SPP), former Eastern US power pools	Imposes administratively determined reserve requirements that must be maintained by Load Serving Entities (**LSEs**) through either resource ownership or bilateral contracting. The reserve	Clearly defines and enforces existing reliability standards that LSEs can satisfy through self supply or bilateral contracts. Directly assigns the costs of capacity to LSEs whose customers are causing	Required Reserve Margins may not appropriately balance the value of increased reliability against the cost of providing the reserves. 'Voluntary' compliance is not reliable in restructured

Type	Description	Advantages	Disadvantages
(NYPP, PJM and NEPOOL), some Canadian Markets).	requirement on LSEs is monitored and enforced through regulation, and creates a bilateral capacity market in which both demand side and supply side resources, as well as both existing and new capacity resources, are equally valuable.	reserve requirements based on peak load. Reserve requirement imposed on LSEs creates bilateral capacity market that addresses the missing money problem. Focus on Reserve Margins i.e., the difference between available resources and peak load, also allows for integration of demand response resources.	markets with many (and often small) LSEs. Enforcement of and penalties for non-compliance can be difficult due to the range of bilateral contract terms and the potentially large number of LSEs. Lack of a forward requirement means there may be too little time to make alternative arrangements once a system wide reserve deficiency is discovered. Potential lack of transparent mechanisms for backstop capacity procurement by system operator in case of deficiencies. Lack of liquid, transparent capacity markets imposes additional costs and uncertainties, particularly on LSEs with migrating customer demand. Small LSEs often face higher transaction costs and may find it more difficult to meet the requirements bilaterally or self supply. Bilateral market structure makes it more difficult to monitor and mitigate market power, which can be costly in restructured markets with mostly unregulated generation and retail competition.
Energy Market with Reserve Requirements and Centralised Capacity Markets (e.g., NY-ISO, MISO).	A centralised capacity market provides a transparent backstop procurement mechanism for the system operator. It offers LSEs a third option to satisfy or adjust their mandated reserve requirements, in addition to avenues such as asset ownership and bilateral contracting. That is, a new LSE entering the market may have a customer base that is too uncertain to justify a long term bilateral contract for capacity but they can	Centralised capacity markets provide transparent pricing and a standardised capacity product and help to facilitate efficient bilateral transactions, including long term contracts; Small LSEs fulfil their resource requirements, with better information and at lower transaction costs. It supports retail competition by facilitating capacity transactions of small LSEs and allowing adjustments to reflect load migration across LSEs. Market prices are	Small changes in fixed resource requirements can result in large changes in market prices. The lack of a forward resource requirement can leave little time to respond to identified capacity deficiencies and can lead to price volatility and market power concerns, as it may be impossible to supply new capacity on short notice. The increased complexity of market design increases the risk of initial design flaws. Changing capacity market

Type	Description	Advantages	Disadvantages
	acquire sufficient capacity resources via the centralised market.	determined through market forces, rather than administrative judgement. Provides market monitors with the information necessary to monitor and mitigate market power. Creates an in-market mechanism for the operator to acquire necessary resources on behalf of any deficient LSEs, thereby reducing the need for out of market contracts. Allow the inclusion of a downward sloping demand curve to help stabilise capacity prices, reflect the value of incremental resources, and reduce incentives to exercise market power. Capacity markets with locational requirements improve the pricing and deliverability of capacity in transmission constrained systems.	rules impose regulatory risk. Clearly visible capacity prices draw attention to the high cost of ensuring reliability at current target Reserve Margins (a cost that may be even higher but less visible in market designs that rely solely on bilateral arrangements to satisfy reserve requirements) and can create a political backlash.
Energy Market with Forward Reserve Requirement (e.g., CAISO)	In markets with a forward resource requirement, LSEs must show that they have secured sufficient reserves one or several years in advance. The forward requirement, which can be imposed on a locational basis in transmission constrained areas, creates a bilateral capacity market that allows sufficient time for additional capacity resources to come on line.	The forward requirement increases the ability of suppliers to bring new units online and adjust construction plans to meet the forward needs of their contract partners. Inadequate reserves can be discovered with sufficient time to allow the system operator to contract for needed resources, increasing their ability to physically and economically remedy the deficiency. Forward procurement facilitates the entry of new resources, increasing competition and mitigating market power. The capacity value of bilateral contracts restores revenue sufficiency in mitigated energy markets. Forward procurement generally stabilises prices and reduces risk premiums on generation investment.	In the absence of a centralised capacity market, exclusive reliance on self provision or bilateral arrangements will tend to reduce liquidity and transparency of the capacity market. This can increase risks and transaction costs, particularly in retail access markets with many LSEs and migrating customer demand. Backstop procurement on behalf of deficient LSEs may not be transparent. Long forward commitment periods can increase risks for some resources, in particular demand response. Small LSEs often face higher transaction costs and may find it more difficult to meet the requirements bilaterally or to self supply. The bilateral market structure makes it more difficult to monitor and mitigate market power, which

Type	Description	Advantages	Disadvantages
			can be costly in restructured markets that are mostly unregulated.
Energy Market with Forward Reserve Requirement and Centralised Capacity Market (e.g. PJM, ISO-NE, Brazil).	This design combines the forward reserve requirement with a centralised capacity market. The capacity requirement is set centrally, usually a number of years in advance. The price is determined by auction and paid to all resources, new and existing, clearing the auction. The total auction value is charged to final customers through suppliers/distributors based on their off-take.	Forward reserve requirement advantages (such as stabilisation of investment and price volatility, and competition through new entry) combined with the advantages of centralised capacity markets (i.e. liquid and transparent price formation and backstop procurement mechanism for deficient LSEs, reduced transaction costs, and improved market monitoring and mitigation of market power). Supports retail competition by facilitating capacity transactions to address load migration and assist small LSEs. Allows for the incorporation of demand response into the design, increasing competition and reducing the system-wide cost of ensuring reliability. Allows for locational forward capacity requirements.	Added complexity of market design imposes high implementation costs on the Operator and market participants. Complex market design also carries risks of initial design flaws and inefficiencies i.e., changing capacity market rules can produce regulatory risk. Lengthy forward commitment periods can increase supplier risks and also increases risk that suppliers default on their forward obligations. Clearly visible capacity prices can draw attention to the high cost of ensuring reliability and can create a political backlash. Cost of locked in forward commitment could appear unnecessarily high after changes in market conditions reduces resource needs. Hailed as being successfully implemented in the US but volatility of capacity prices and therefore of price signals for investments have been observed in the US.
Reliability Market /Reliability Option (RO) (e.g. Colombia).	This model is also based on a forward auction but as a financial call option backed by a physical resource that is capable of producing firm energy (i.e. thermal units in Colombia). Generators must be available to the system operator for dispatch above a defined strike price,	Strike price ensures stable payments to generators, reducing the risk for both producers and consumers. Good incentives for generators to invest and to maximise their output/availability during shortages (i.e. dry periods in the hydro-dominated Colombian market).	There is only one main example of this type of market in use. Determination of the strike price level is the key to making the model successful. If it is set too high, it can be likened to an energy-only model, if set too low, there is the risk of interfering with other price drivers (e.g., increasing

Type	Description	Advantages	Disadvantages
	which is set above the marginal cost of thermal units[200].		fuel costs alone should not lead to reaching the strike price).

[200] http://www.cramton.umd.edu/papers2005-2009/ausubel-cramton-forward-markets-in-electricity.pdf
http://www.cramton.umd.edu/papers2005-2009/cramton-stoft-colombia-firm-energy-market.pdf

The Evolution of Capacity Markets in the US

The evolution of forward capacity markets in the US was recently described by Gottstein and Schwartz (2010) for the Regulatory Assistance Project.[201] According to these authors, prior to the development of these markets, power pools established reserve margin requirements for individual LSEs who were each responsible for acquiring the installed capacity necessary to meet their individual loads plus that margin, or face financial penalties. Each LSEs reserve requirements were significantly lower than they would be if they were a stand-alone entity, as the capacity requirement was set for the pool as a whole. Participants thus benefited from the greater diversity of supply resources that made up the combined system, and the pool facilitated bilateral trading of capacity, which was valuable in pools where system peaks were temporally differentiated.[202]

Following the restructuring of the market, LSEs were able to trade in capacity auctions that were run by the system operator, generally just a few days before the one-month delivery period. However, there were difficulties with these capacity markets:

- they provided insufficient incentives for plants to be available when required and this led to 'bipolar pricing', with prices that were effectively zero if there was a surplus of capacity and prices close to the price cap (if any) if there was a shortfall (the zero to infinity problem);
- the short time horizons for the auctions limited offers for new capacity; and
- issues of market power surfaced in areas with significant transmission constraints after utilities sold their power plants as part of the industry restructuring.

The Federal Energy Regulatory Commission (**FERC**) responded to this by introducing price caps to the energy market, which unfortunately had the added effect of limiting scarcity pricing signals. That is, the energy only power markets that pay clearing prices for energy on a day ahead or shorter basis were not paying high enough prices for investors to build sufficient peaking resources to maintain resource adequacy into the future. At the same time, merchant generators were subject to high fuel prices for new natural gas fired plants and older, less efficient generators filed requests for retirement.

In order to maintain system reliability and keep needed plants generating, FERC approved expensive Reliability Must Run (**RMR**) contracts.[203] They also mandated the development of a more systematic approach to paying for capacity (making capacity payments available to all generators, not just those due for retirement) and to develop more efficient capacity where it was most needed.

In the Independent System Operator New England (**ISO-NE**) market, the high price tag of such contracts led to legal action that, in 2006, resulted in a capacity market that allows energy efficiency and other demand side resources to compete with generation to meet reliability requirements several years in advance of when it is needed, much like the

[201] Gottstein, M. & Schwartz, L. (2010). *The Role of Forward Capacity Markets in Increasing Demand-Side and Other Low Carbon Resources: Experiences and Prospects*. May 2010, Regulatory Assistance Project.

[202] For example, in New England, the northern states peak in winter, whilst the southern states peak in summer.

[203] The Brattle Group (2009) describe RMR contracts as targeted backstop measures that assure reliability and prevent the retirement of power plants. These measures are often attractive initially because they avoid the severe price spikes that would otherwise be required to encourage investment and they limit the additional capacity like payments that need to be paid to only a few older plants being mothballed or retired. Ultimately, however, they can have the effect of market price suppression, increases in retirements of other existing plants, reduced entry of new plants, and delayed development of demand-response measures. Such distortions can be costly, self perpetuating and inefficient.

Pennsylvania, New Jersey Maryland (**PJM**) System. In 2007, the Midwest ISO (**MISO**) region also adopted a similar capacity market to that run by PJM.

Thus, forward capacity markets evolved in response to the need to maintain resource adequacy at reasonable costs to electricity consumers, through a combination of system planning and organised markets.

Comparing the RCM to North American Capacity Markets

The Wholesale Electricity Market (**WEM)** established for the South West Interconnected System (**SWIS**) in Western Australia includes a Reserve Capacity Mechanism (**RCM**).[204] The RCM shares many similarities with North American forward capacity markets. The main characteristics of these markets are provided below.[205]

[204] Refer to Chapter 2 of this report for a more detailed discussion of the RCM in the WEM.

[205] Pfeifenberger, J. (2012) Presentation: *Resource Adequacy and Capacity Markets: Overview, Trends, and Policy Questions*. Prepared for New England Electricity Restructuring Roundtable, Boston, MA September 21, 2012. http://www.raabassociates.org/Articles/Pfeifenberger%20Presentation_9_21.12.final.pdf

Patton D.B. (2011). *High Level Comparison of RTO Markets.* December 7, 2011 Potomac Economics, MISO Independent Market Monitor. https://www.midwestiso.org/Library/Repository/Meeting%20Material/Stakeholder/BOD/Markets%20Committee/2011/20111207/20111207%20Markets%20Committee%20of%20the%20BOD%20Item%2005%20Market%20Comparison.pdf

Refer to RCM WG Meeting 4 Papers (from Page 43 of 272) 'Appendix A: International Capacity Markets' for a broader overview of these markets. http://www.imowa.com.au/f5415,2873659/Meeting_4_Combined_Papers.pdf

	SWIS	MISO	PJM	NYISO	ISO-NE	CAISO
Procurement	Bilateral or trade through the IMO + Voluntary Auction + Supplementary Reserve Capacity Mechanism	Bilateral + Voluntary Auction	Bilateral + Mandatory Centralised Auction[206]	Bilateral + Mandatory Centralised Auction	Bilateral + Mandatory Centralised Auction	Bilateral Contracts Only
Timing of Auctions	September, Annually, (but only held if RCR is not met through bilateral trade declaration).	Monthly, month-ahead (centralised auction for capacity available in the current year).	Annual, Mandatory three-yr Auction, with three Voluntary or Readjustment Auctions prior to the delivery period.	Capability period, seasonal/monthly (centralised auction for capacity available in the current year).	Annual, Mandatory three-yr Auction, with three Voluntary or Readjustment Auctions prior to the delivery period and monthly voluntary auctions throughout.	No centralised capacity auction, so retailers independently procure capacity rights.
Time Scope	two-yr forward	Upcoming Year	Three-year forward with incremental readjustment options, as above.	Mostly spot; up to six month forward	three-year forward with incremental reconfiguration options.	Upcoming Year
Auction Format	Simple Auction	Simple Auction	Demand Curve	Demand Curve	Descending Clock	N/A
Requirement	Annual	Monthly	Annual	Seasonal (Summer, Winter).	Annual	N/A
Demand Curve	Sloped at negative one through Excess	Vertical/NA	Sloped	Sloped	Vertical	N/A

206 nb. producers can self supply and therefore avoid the market and any risk associated with it.

	SWIS	MISO	PJM	NYISO	ISO-NE	CAISO
	Capacity Adjustment if an auction is not held (i.e., all willing certified capacity is allocated Capacity Credits) or vertical if an auction is held.					
Locational markets	No	Yes, filing approved	Yes	Yes	Limited; plans for full configuration	Yes
Deliverability		Proposing Zonal	Full Zonal	Hybrid Zonal	Full Zonal	
Buyer Side Mitigation[207]		Under Development (offer floor)	Offer Floor	Offer Floor (NYC only)	Under Development	
Bid limit	Capped at the Maximum Reserve Capacity Price based on a reference peaking generator for capacity offers in auction.		$1,000/MWh			

[207] Buyer side mitigation takes the form of a Minimum Offer Floor price for all new generation entrants and was implemented by the FERC in an attempt to deter the subsidisation of new entry by large net buyers or local governments that could unduly depress capacity market prices. Refer to http://www.felj.org/docs/elj332/16-449-Miller[FINAL11.9].pdf

Comparing the RCM to Other Designs for Resource Adequacy

Pfeifenberger (2012) of the Brattle Group recently summarised the different market design options for resource adequacy in a presentation for the New England Electricity Restructuring Roundtable.[208] Within this summary, the WEM was identified along with markets like PJM and New York ISO (**NY-ISO**), as a market based capacity and energy market, with a mandatory near or forward term auction. However, such a description of the WEM may not be entirely accurate, given that capacity procurement under the RCM in the WEM has not relied on the use of the auction mechanism to date. Indeed, the WEM may better be defined as a hybrid market that can employ both administrative and market-based mechanisms, with the risk of uneconomic investment decisions imposed on suppliers and customers within the market, as set out in the table below.

[208] Refer to Brattle Group Report (Pfeifenberger, Spees & Schumaker, 2009) http://www.brattle.com/_documents/uploadlibrary/upload807.pdf

Mechanism	Administrative Mechanism		Hybrid (Administration with Provision for Auction)	Market-Based Mechanism		
Risk of uneconomic investment decisions	Customers Bear Risk		Risk is dependent on the capacity type: DSM, diesel genset and OCGT incur customer risk. Suppliers share pain through a reduced RCP if excess capacity exists. Higher capital cost generator risks lie partly with generators.	Suppliers Bear Risk		
Market Design	Regulated Utilities	Bilateral contracts or capacity payments	RCM including a provision for auction, plus Supplementary Reserve Capacity process.	LSE Resource Adequacy Requirement	Capacity Market	Energy-Only Markets
Examples	SPP, BC Hydro, SaskPower, Most of WECC, South East US	Ontario, Argentina, Chile, Colombia, Peru, Spain, South Korea.	WEM	California, MISO	PJM, NYISO, ISO-NE, Brazil, Italy, Russia.	Texas, Alberta, Australia's NEM, NoordPool, Great Britain (current)
Resource Adequacy Requirement?	Yes (Utility IRP)	Yes/No (yes through bilateral contracts; No if relying on capacity payments	Yes (To date has relied on bilateral trades and administrative pricing through IMO.	Yes (creates bilateral capacity market)	Yes (Mandatory near-term or forward capacity auction)	No (resource adequacy not assured)

How are Capital Costs Recovered?	Regulated retail rate recovery	Long-term bilateral contracts or capacity payment plus energy market	To date - bilateral contracting or administrative based contracting with IMO for capacity, plus energy market.	Bilateral capacity payments and energy market	Capacity and energy markets	Energy market only (except if Renewable Energy, which also receives revenue from RECs).

The Capacity Market in the PJM

The Reliability Pricing Model (**RPM**) used in PJM is often used to exemplify capacity markets, with major North American markets and the RCM in the WEM, considering the use of similar mechanisms (e.g. downward sloping demand curves and forward markets), given the significant benefits (e.g. a reduction in investment and reliability risks) that it affords. It is noteworthy however, that even with this success, there is some indication that it may be experiencing similar issues to those currently observed in the WEM. For instance, it is interesting to note that Monitoring Analytics 2012 Quarterly State of the Market Report for PJM: January through September highlighted PJM's ongoing concerns in relation to the integration of DSM into their market design.[209] In particular, it identified the inclusion of 'inferior' demand side products as one source of suppressed market prices that results in capacity market prices failing to reflect underlying supply and demand fundamentals.[210]

Additionally, in 2010, a review of PJM's RPM by the American Public Power Association (**APPA**) and Electric Market Reform Initiative (**EMRI**) raised concerns in relation to excess capacity[211]. According to this review, with the exception of 2010/11, each auction has produced a greater amount of cleared capacity than in the previous year. However, these increases are greater than what is needed to meet reserve requirements. As an example of this, the authors noted that, the capacity cleared in the 2012/13 auction represented a reserve margin of 20.9 per cent, resulting in a net excess of 5,754.4MW over the reliability requirement of 133,732.4 MW (Installed Reserve Margin, **IRM**, of 16.2 per cent).[212] Similarly, the capacity cleared in the 2013/14 auction represented a reserve margin of 20.2 per cent, resulting in a net excess of 6,518.3 MW over the reliability requirement of 149,988 MW (IRM of 15.3 per cent).[213]

Of note is the fact that these values are comparable to the total reserve capacity as a percentage of maximum demand in the RCM for the same time period (i.e. 20.23 per cent in 2012/13 and 26.49 per cent in 2013/14). This suggests that over-procurement of capacity may be an anticipated characteristic of capacity markets. Indeed, in relation to the Colombian Market, which also employs a forward procurement process to assure the availability of adequate resources and to allow coordinated entry (among other things), Ausubel and Cramton (2010) note that:

[209] Monitoring Analytics, LLC (2012). *2012 Q3 Quarterly State of the Market Report for PJM: January through September*. http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2012.shtml

[210] The 2014/15 Base Residual Auction (BRA), which opened 2 May 2011, was the first conducted under new rules that established two additional DR products to the standard, limited DR product. These include Annual DR, which is available throughout the year, and Extended Summer DR, which is available for an extended summer period.

[211] EMRI & APPA (2010) *A Review of PJM's Reliability Pricing Model*

http://www.publicpower.org/files/PDFs/APPAReviewofRPM10012010.pdf

[212] In the 'PJM Manual 20: PJM Resource Adequacy Analysis' the PJM Reserve Requirement is defined as the level of installed reserves needed to maintain the desired reliability index of ten years on average, per occurrence (a loss of load expectation of one occurrence in 10 years) after emergency procedures to invoke load management. The PJM IRM is the reserve as a percentage of annual peak load that results in a loss of load expectation adhering to this standard. http://www.pjm.com/~/media/documents/manuals/m20.ashx

[213] It is noteworthy that in the context of the PJM market, it is considered a 'reality' that additional capacity above a target installed reserve margin has value. It notes that reserves beyond the required level are valuable for reducing the risk of capacity shortfalls, it can lessen the risk that large suppliers are pivotal or can otherwise exercise market power, it can reduce the frequency and duration of scarcity energy prices in the system and provide energy savings to LSEs, and it reduces capacity price volatility and investment risk to capacity (in particular, generating) resources. Refer to 'PJM Manual 18: PJM Capacity Market' Revision 17, pp. 15. http://www.pjm.com/~/media/documents/manuals/m18.ashx

> "Some over-procurement will occur as a result of the lumpiness of investment and mistaken load forecasts, but it is not necessary to deliberately procure extra resources in recognition of uncertain entry, as would be necessary with a spot firm energy market (pp. 3)[214]."

Notably, in relation to the issue of excess capacity, is that PJM view additional capacity above a target IRM as having at least four sources of value, including that[215]:

- in the face of uncertain load growth, weather and capacity availability, the probability of available capacity being less than what is required to meet load and operating reserves never reaches zero, even for large reserve margins. Thus reserves beyond the target are valuable for reducing the risk of capacity shortfalls;
- the slope of the curve can lessen the risk of large suppliers being pivotal or otherwise able to exercise market power;
- excess resources can reduce the frequency and duration of scarcity energy prices in the system and provide energy savings to Load Serving Entities; and
- there is a reduction in capacity price volatility and the resulting investment risk to capacity resources, in particular to the generating resources. Lower investment costs would tend to reduce capacity prices.

However, it could be argued that the benefits associated with the excess capacity outlined above should already be addressed through PJM's Resource Adequacy analysis and encompassed within the IRM, such that any excess capacity above this margin is redundant and inefficient, rather than having value.[216] Indeed, it could be argued that if the benefits associated with having this excess capacity outweighs the associated costs, then it may be the case that the IRM is set incorrectly.

More recently, a review of PJM by Wittenstein and Hausman (2011) that examined flaws in capacity market design indicated that the PJM market may be incentivising the retention of aged and inefficient plant.[217] For example, it was noted that, since the RPM was approved, nearly 278 MW of installed capacity came out of retirement, 1,917 MW of retirements were postponed or cancelled and 2,030 MW of deactivation requests were withdrawn (a total of 4,225 MW of installed capacity). In the six years prior to the RPM, retirements averaged 1,000 MW a year but following commencement retirements averaged 384 MW per year, through 2010.[218]

As explained by Wittenstein and Hausman (2011), the expectation of capacity markets when they were originally established was that capacity resources would bid at or near their net Cost of New Entry (**CONE**) (i.e. the cost that a new resource would need to

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[214] Ausubel, L.M. & Cramton P. (2010). *Using Forward Markets to Improve Electricity Market Design*. 8 January 2010, University of Maryland. http://www.cramton.umd.edu/papers2005-2009/ausubel-cramton-forward-markets-in-electricity.pdf

[215] Refer to PJM Manual 18 (pp. 15). http://www.pjm.com/~/media/documents/manuals/m18.ashx

[216] Refer to PJM's 'Planning Resource Adequacy Analysis, Assessment and Documentation' Standard No. BAL-502-RFC-02 http://www.nerc.com/files/BAL-502-RFC-02.pdf

[217] Wittenstein M. & Hausman E. (2011). *Incenting the Old, Preventing the New: Flaws in Capacity Market Design, and Recommendations for Improvement.* Synapse Energy Economics, Inc., Cambridge.

Note however, that it was recently reported that between 1 November 2011 and 31 December 2012, PJM received some 104 retirement requests totalling 13,868 MW. This resulted from low natural gas prices and strict environmental rules, making coal the more expensive option.

http://www.publicpower.org/files/PDFs/2011APPACapacityMarketsReport.pdf

[218] Also see: http://nj.gov/bpu/pdf/announcements/2011/capacityissues.pdf

recover its fixed costs, plus a reasonable return on equity, whilst taking into account revenues from the energy and ancillary services markets). Net CONE is administratively determined by PJM based on an estimate of costs and expected energy revenues for a 'proxy' new resource, such that stable prices near or above this value should 'theoretically' attract new investment.

In contrast to this, in five out of the six auctions held in the PJM market, RPM prices have been below PJM's estimate of netCONE in non-constrained RTO regions, the very regions experiencing new resource additions. At the same time, prices in constrained (capacity-short) regions have been much higher, yet new supply resources have not been added.[219]

A main concern raised in the Wittenstein and Hausman (2011) review related to the flow of revenues, with the vast majority of the financial benefits of the mandatory single clearing-price capacity market (i.e. 95 per cent of all RPM revenues) having accrued to the incumbent generators, a third of which went to existing coal generators. Together, the lack of new generation investment and the retention of aged plant was explained in terms of PJM's forward capacity market providing only limited guarantees, i.e. capacity payments for only one year, and not offering developers a stable enough revenue stream over the longer term (i.e., the one year price guarantee is not sufficient enough to drive large investments in generating resources that have operating lives of decades).[220]

Additionally, according to Wittenstein and Hausman (2011), in regions with tight Reserve Margins, incumbent generators are aware that by putting in new developments, they run the risk of cutting the revenue stream out from under themselves by driving local capacity (and energy) prices down. That is, it is against the self interest of incumbent and new generation developers (who rely on or profit from the high capacity prices) to add capacity to constrained, high priced areas. As a consequence, the RPM has operated at what Wittenstein and Hausman (2011) referred to as an "extraordinarily" high cost to consumers (p. 16). They warned that consumers ultimately pay the price for ensuring resource adequacy, and that they should not be held hostage to market designs that put incumbent generator interests before their own.

However, not everyone agrees with the findings in relation to PJM presented above. Pfeifenberger (2012), in particular, asserts that capacity market prices have a public relations challenge. Transparency makes the total costs in capacity markets more visible and the notions that these markets are just regulated constructs, that they only provide a windfall to existing generators, and that they keep 'dirty' old plants around without attracting new resources, are just misperceptions.

Nevertheless, the similarities in issues observed between the RCM and PJM's RPM may well indicate that these issues are endemic to markets that have capacity mechanisms, a possibility that requires further investigation. Certainly, it is also worth considering whether a similar scenario might occur in the WEM, whereby the RCM may actually incentivise generators to defer investment in times of high prices and short supply, rather than encourage new investment, to ensure that they maintain high profits.

[219] Interestingly, a similar scenario exists in the New York market, where clearing prices are well below the estimated CONE for each region, and which appears to be incentivizing natural gas plants in its western region, where there is an existing capacity surplus and these plants might otherwise not be profitable.

[220] In the Columbian market, Reliability contracts have a lead time of between 3 and 7 years. The contract duration for existing plant is 1 year, whilst plant not yet built can optionally increase the contract duration and thus lock in payments for longer periods up to 20 years. For plants that require additional investments, an intermediate solution is used.

At the very least, care should be taken to ensure that the RPM design is not viewed as a panacea for all of the issues identified in the WEM and that any suggested modifications are suitable to its particular context, and the particular problems that the RCM is designed to address.

Future Capacity Markets: Obtaining an Efficient and Cost Effective Generation Mix

The future of capacity markets and electricity markets, in general, was considered in a recent article published by the Regulatory Assistance Project (RAP, 2012) in the US. Capacity markets are set to be impacted by the policy driven addition of variable renewable supply resources. This, in turn, will influence system quality, i.e. the mix of resource capabilities that is required to keep supply in balance with demand, and make resource flexibility an increasingly important characteristic of a generation mix. Described by RAP (2012), flexible resources are capable of responding to system needs by ramping up or down and turning on and off rapidly and frequently.[221] If flexible resources are unable to be obtained, consumers will pay for higher operating costs, unnecessary capital investment and lower reliability.

The challenge for capacity markets will thus be to ensure that the market supports investment in new and existing supply and demand side resources that are capable of efficiently and cost effectively meeting the projected need for flexible resource capabilities over the longer term. To date, system operators have traditionally been able to utilise legacy resource portfolios to meet their flexibility requirements and many may expect to continue to be able to do so into the future. However, there are a number of markets that have reached the point where they need to ensure not only that the quantity of firm resources[222] meets resource adequacy requirements but also that the portfolio is capable of efficiently addressing emerging system quality needs.[223]

According to RAP (2012), flexibility is currently undervalued in markets with capacity mechanisms that provide long term visibility to the more tangible, lower cost, firm capacity, indirectly devaluing other resource attributes. Moreover, Gottstein and Schwartz (2010) note that the task of ensuring resource adequacy has traditionally involved a planning process, with a focus on quantity and timing (what level of capacity is required and when?), and a procurement process (how will the capacity be acquired?), but not a focus on the mix of resources that is required to efficiently meet system reliability.

One potential approach to addressing the desire for additional flexibility resources may be to employ a capability market design option that involves apportioning a forward capacity mechanism into tranches, based on the target mix of resource capabilities derived from a net demand forecast.[224] Net demand forecasts take into account gross demand and expected energy production from variable resources in providing an estimate of the mix of resource capabilities that can most efficiently deliver the desired level of system quality.

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[221] RAP (2012). What Lies “Beyond Capacity Markets”? Delivering Least-cost Reliability under the New Resource Paradigm. A “Straw Man” Proposal for Discussion. 14 August 2012. The Regulatory Assistance Project, US. www.raponline.org/document/download/id/6041

[222] Firm, in this context, refers to the portion of the maximum capacity of a resource that can be confidently relied upon to deliver whenever required.

[223] In particular, RAP (2012) identifies the Denmark, Pacific Northwest, Ireland, Germany and California markets as requiring a focus on attaining the right mix of generation resources and note that there are many other markets that are not far behind.

[224] RAP (2012) note that additional flexibility is not desirable at any cost. It is only desirable if the cost of obtaining it is less than the alternative i.e., the full life cycle cost of curtailing renewable resources or the costs of procuring or committing back up generation capacity.

Using this approach, the total quantity of firm resources would be broken into successive tranches, based on specified resource attributes, and all resources (including demand response and end-use energy efficiency resources) would bid into the highest-value tranche for which they qualify. The most flexible tranche of firm resources would be cleared first, followed by the next most flexible tranche, and so on until the least most flexible firm resource tranche is cleared at whatever residual quantity of requirement remains.[225] The demand curve for each tranche would reflect the relative values of the specified resource, and the clearing price for each successive tranche would be lower than the last. As explained by RAP (2012), "the desired realignment among resources would be driven by the size of each tranche, with value set by the relationship between the size of the tranche and the supply and costs of appropriate resources"(pp. 13).

The idea for the use of an apportioned forward capacity market is in fact, not new, having been considered by PJM in its original (August 2005) filing for its current capacity market. Specifically, this filing proposed a forward capacity market apportioned on the basis of four categories of resources, including dispatchable (i.e., rampable), flexible cycling (rapid and frequent stop start) supplemental reserves and everything else. The capacity market was to be cleared in stages based on the required quantities of each type of resource. The proposal was however, dropped in the final market design due to stakeholder concerns around complexity and market liquidity. Nevertheless, PJM recently adopted a three-tranche structure instead of the previous single-clearing price auction for the demand response portion of its capacity market.

Additionally, more recently, ISO-NE (2012) has proposed to apportion their forward capacity auction into several tranches based on specified resource capabilities (i.e., a ten minute product i.e., able to produce energy within ten minutes, a 30-minute product and flexible resources), a proposal in part precipitated by the impending retirement of a number of older firm supply resources.[226]

The apportioned approach would thus allow market operators to differentiate the value of capacity payment streams available to resources based on a set of critical operational capabilities and, in particular would afford more valuable flexible resources a competitive advantage over less flexible resources in the capacity market.[227] The apportioned approach can be easily incorporated into markets where capacity mechanisms are already in place or under design. It would also avoid the trap of segregating resources on the basis of criteria that are not related to reliability (e.g., distinctions based on new vs. existing resources, or strategic reserves vs. other forms of firm capacity), that would inevitably distort energy market outcomes.

The apportioned capacity market approach may thus provide a credible and useful alternative in the pursuit of more efficient and cost effective generation mixes. However,

[225] Refer to RAP (2012), Appendix A (pp. 20-22) for illustrated examples of how Multiple Clearing Price Auctions work.

[226] Other reasons for the proposal included uncertain resource performance, an increased reliance on natural gas-fired capacity, integration of a greater level of variable resources, and the need to better align wholesale market procurements with transmission planning processes. Refer to ISO New England (2012). *Using the Forward Capacity Market to Meet Strategic Challenges*, May 2012. Strategic Planning Initiative. http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/fcm_whitepaper_final_may_11_2012.pdf

[227] http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/fcm_performance_white_paper.pdf

Pfeifenberger (2012) argues that the observed price signals in capacity markets are efficient and that discrimination wouldn't work. He warns that it is efficient for new generation, existing upgrades and demand response to compete on the same basis, as price discrimination would:

- undermine the market;
- deter merchant entry; and
- cause uneconomic retirements.

Notably, in the context of the RCM in the SWIS, careful consideration would be required into the question of just how possible issues of market power might be impacted or mitigated by the development of such a market.

Conclusion

The RCM in the SWIS shares many similarities with North American forward capacity markets, and appears to be experiencing similar difficulties to those experienced in these markets. In particular, a review of the PJM market reveals (among other things) ongoing concerns in relation to the integration of DSM products into the market, excess capacity issues, the retention of aged plant (cf. new investment), difficulties establishing suitable administrative pricing parameters, and investment in unconstrained regions, i.e. contrary to pricing signals. This suggests that such issues may actually characterise capacity markets, rather than being specific to the RCM.

Moving forward, with the integration of intermittent renewable resources (e.g. wind energy) and differing DSM products into electricity markets, the ability to be able to incentivise an appropriate generation mix that is capable of efficiently and cost effectively meeting system requirements will become increasingly important. This has led to the consideration of the use of apportioned markets that differentiate the value of capacity payment streams based on a set of critical operational capabilities or reliability attributes. Whether such an option would be suitable for the RCM is questionable, given the potential for issues of market power. However, the undertaking of a thorough review of the operation and outcomes of the implementation of apportioned markets within the context of the PJM and ISO-NE markets may be instructive in this regard.

Appendix 6 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