Discussion Paper:

2014 Wholesale Electricity Market Report to the Minister for Energy

November 2014

Economic Regulation Authority
WESTERN AUSTRALIA

This document is available from the Economic Regulation Authority's website at www.erawa.com.au. For further information, contact:

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Invitation to make submissions

The purpose of this discussion paper is to assist interested parties in making submissions on any operational, strategic, policy or otherwise high-level issues, including those raised in this discussion paper, that are considered to be impacting on the effectiveness of Western Australia's Wholesale Electricity Market (**WEM**) in meeting the Wholesale Market Objectives (**Market Objectives**).

Submissions should be marked to the attention of the Assistant Director Electricity.

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Submissions must be received by **4:00 pm (WST) on Monday, 12 January 2015**.

CONFIDENTIALITY

In general, all submissions from interested parties will be treated as being in the public domain and placed on the Authority's website. Where an interested party wishes to make a submission in confidence, it should clearly indicate the parts of the submission for which confidentiality is claimed, and specify in reasonable detail the basis for the claim. Any claim of confidentiality will be dealt with in the same way as is provided for in section 55 of the *Economic Regulation Authority Act 2003*.

The publication of a submission on the Authority's website shall not be taken as indicating that the Authority has knowledge either actual or constructive of the contents of a particular submission and, in particular, whether the submission in whole or part contains information of a confidential nature and no duty of confidence will arise for the Authority.

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1 Introduction

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

Section 128 of the *Electricity Industry Act 2004* requires the Authority to provide a report to the Minister every three years, based on a review of the extent to which the market objectives set out in the Act have been, or are being, achieved. The last triennial report was published on 10 August 2011. The next triennial report must be provided to the Minister within three years and six months of the previous report being tabled in Parliament, i.e. no later than February 2015.[1]

The Authority intends to prepare a single report covering both obligations, consistent with the approach taken in previous years.

The purpose of this issues paper is to assist interested parties in making submissions on any operational, strategic, policy or otherwise high-level issues, including those raised in this paper, that are considered to be impacting on the effectiveness of Western Australia's Wholesale Electricity Market (**WEM**) in meeting the Wholesale Market Objectives (**Market Objectives**).

Submissions from interested parties on issues impacting the effectiveness of the WEM will assist the Authority in preparing its 2014 Minister's Report. The Report will be provided to the Minister following consideration of the submissions received in response to this discussion paper, and analysis of the available market data. The Minister is required to lay the report before each House of Parliament as soon as practicable after receiving the report. The Authority will publish the report once this has been done.

1.1 Wholesale Market Objectives

Under the Market Rules, the Authority is responsible for monitoring the effectiveness of the market in meeting the Market Objectives and providing to the Minister a report each year that includes the Authority's assessment of the effectiveness of the market. The requirements for the report required under Section 128 of the *Electricity Industry Act 2004* are essentially the same as the Authority must assess the extent to which the Market Objectives have been, or are being, achieved.

The Market Objectives[2] are:

- to promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the South West Interconnected System (**SWIS**)[3];
- to encourage competition among generators and retailers in the SWIS, including by facilitating efficient entry of new competitors;

1 Section 128(3) of Electricity Industry Act 2004

2 Refer to clause 1.2.1 of the Market Rules http://www.imowa.com.au/market-rules

3 The SWIS is defined in the *Electricity Industry Act 2004* and refers to the interconnected transmission and distribution systems located in the South West of the State, extending between Kalbarri, Albany and Kalgoorlie. See the State Law Publisher website, *Electricity Industry Act 2004*.

- to avoid discrimination in that market against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or that reduce overall greenhouse gas emissions;
- to minimise the long-term cost of electricity supplied to customers from the SWIS; and
- to encourage the taking of measures to manage the amount of electricity used and when it is used.

1.2 Reporting requirements

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 the following:
  - the Reserve Capacity Market;
  - the market for bilateral contracts for capacity and energy;
  - the Short Term Energy Market (**STEM**);
  - Balancing;
  - the dispatch process;
  - the planning processes;
  - the administration of the market, including the Market Rule change process;
  - Ancillary Services;
  - 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 Market Objectives to be considered by the Minister.

The requirements under section 128 of the *Electricity Industry Act 2004* only state that, if the Authority considers that some or all of the Market Objectives have not been or are not being achieved, the report should set out recommendations as to how those objectives can be achieved, which is similar to the final point listed above.

1.3 Summary of the 2013 Minister's Report

The Authority provided its 2013 Minister's Report to the Minister in December 2013, and published a public version of that report on its website on 19 March 2014. The summary table below, which was included in the 2013 Report, sets out the matters raised in previous reports and the status of those items at the time the 2013 Report was prepared.

Issue	Report year issue commented on	Status as at 2013 Report
Reserve Capacity Mechanism – excess capacity, efficiency of generation mix, no market derived price	2008, 2009, 2012	Improvements have been made within the constraints of the current market design but there has not been a review of whether the overall market design is achieving the best outcome.
Network planning – possible modification of the unconstrained approach, access process	2008, 2009, 2010, 2012	Preliminary work undertaken but has not been progressed.
Review of market governance and transparency – including in bilateral contracting, System Management processes, multiple roles of IMO relating to rule change and administration	2008, 2011	No progress
Day ahead STEM – reduction in timeframe to move closer to real time trading	2008,2012	Introduction of new competitive balancing market in July 2012 has addressed much of this concern.
For the longer term- consideration of an energy only market	2008	Could be considered as part of WEM review
Regulated Electricity tariffs and lack of retail competition	2008, 2009, 2010, 2012	No progress
Concerns over cost efficiency of dispatch order	2009	Introduction of new Balancing Market in July 2012 addresses much of this concern.
Treatment of intermittent generation – relating to displacement of base load generation, methodology of calculating capacity credits	2010	Improvements have been made within the constraints of the current market design but there has not been a review of whether the overall market design is achieving the best outcome.
Treatment of DSM – review as to whether should be similar to generators	2010, 2011, 2012	In progress. Rule change RC_2013_10 undertaken by the IMO to harmonise requirements for capacity suppliers.
Capacity credit payments and unavailability of plant – incentives for plant to be available	2011, 2012	In progress. Rule change RC_2013_09 undertaken by the IMO.
Lack of competition for the provision of ancillary services	2012	This is one of the higher ranking issues raised by the Market Advisory Committee to examine over the next few years.

The 2013 report included a preliminary assessment of the merger of Verve and Synergy which was that it would increase already significant market power concerns that would need to be addressed to minimise barriers to effective competition and to ensure efficient dispatch of generation. The Authority noted the Government's intentions to address this through ring fencing and non-discriminatory pricing requirements, including regular audits of those requirements, but considered that these arrangements would not address the existing conflict of interest which arises due to the Government both participating in the market and setting the rules. The Authority noted that, whilst the ring fencing arrangements may serve to ensure the market power issues in relation to Verve and Synergy does not increase, they would not appear to lessen existing market power issues.

The Authority recognised that the Merger Implementation Group was conscious of the potential impact of the merger on the WEM and was seeking to address this in various ways. However, until further detail of these measures was known, as well as some experience with their operation, it was not possible for the Authority to comment.

The 2013 Report also highlighted three significant outstanding issues identified in previous reports which it considered needed to be addressed as soon as possible. These are summarised below.

Review of the market design in relation to ensuring capacity is available

In particular the Authority noted:

- The cost to the market of the substantial and continued excess capacity that is currently secured under the RCM, notwithstanding the level of excess capacity reduced in 2013;
- The types of capacity attracted to the market and the implications that this mix of capacity has on the cost of electricity to consumers; and
- Perverse market incentives that allow for some Verve Energy units to be unavailable, yet still receive full payments for Capacity Credits.

Whilst recognising that the IMO was continuing to progress development of Rule Changes[4] which might alleviate many of the above issues, the Authority considered that an overall review led by the Public Utilities Office (**PUO**), as described in the 2012 Minister's Report, was essential to ensure the issues raised by the Authority were addressed.

Governance arrangements for the WEM

The Authority recognised that the current governance arrangements in the WEM reflect the desire to minimise the implementation and operational costs. The small size of the market makes it more difficult to cost effectively adopt structural features adopted by larger markets such as separating the rule making function from market operation and having a standalone system manager.

However, continuing concerns regarding the governance arrangements for the WEM have been raised by stakeholders, including the system manager and network operator, both directly to the Authority and in submissions to proposed rule changes by the IMO. The Authority considered that a review was still urgently required to establish the limitations of

[4] The changes being progressed by the IMO included:

- changes to the RCP proposed by the RCMWG (not yet in formal rule change process)
- Harmonisation of demand-side and supply –side capacity resources proposed by RCMWG (RC_2013_10 released for consultation in August 2013)
- Incentives to improve availability of scheduled generators (RC_2013_09 released for consultation in June 2013)

the existing arrangements and to identify what improvements could be made. It may be that the current arrangements are fit for purpose. However, undertaking such a review would strengthen confidence in the market, particularly following the merger of the two largest market participants. The Authority noted that, whilst the PUO was the most appropriate body to undertake the review, it was not entirely independent as it also represents the Government as owner of the largest market participants and the network operator.

Review of market design in relation to access to the network

The WEM design is based on an 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. An unconstrained network approach facilitates simpler operation of the power system and market because of the absence of dynamic physical constraints.

In its 2010 Report to the Minister, the Authority had noted that unconstrained network access 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 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; and
- 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.

In its 2010 Report, 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. The Authority noted that the review would need a very clear set of objectives, be well resourced with full and open consultation and undertake proper consideration of all the relevant interactions within the WEM design.

In its 2013 Report, the Authority highlighted this issue as becoming of more concern given the increasing prevalence of interruptible supplies being offered or considered by Western Power in the last few years. Whilst recognising such supplies are likely to deliver more efficient network connection costs, the Authority noted the interaction with the operation of the WEM also needed to be considered, particularly in relation to the assessment of capacity credits and constrained on/off payments. The Authority's view was that a piecemeal and uncoordinated adoption of constrained network access was unlikely to result in an optimal overall solution.

New Balancing and LFAS Markets

The 2013 Report also included an initial assessment of the new Balancing Market and Load Following Ancillary Services (**LFAS**) Market which were introduced on 1 July 2012 enabling all generators to offer balancing and load following services. This replaced the previous arrangement where Verve Energy was the sole provider of balancing and ancillary services.

Notwithstanding issues in relation to dispatch, feedback from stakeholders on the new components of the WEM had been positive although further time was needed for a detailed assessment of how effective the new market arrangements are. The Authority noted it would continue to work with the IMO and System Management to evaluate the market further to ensure it is resulting in the most efficient dispatch of generation. In addition to improvements required in dispatch processes and market information, specific issues that the Authority considered needed attention included:

- Significant volumes were still being offered at the minimum and maximum price cap levels, although there had been an increase in the volumes of generation offered in the price bands between $0/MW and $100/MW. Whilst recognising there were a number of reasons for generators to bid in this manner to ensure they are either dispatched or not, the Authority planned to investigate this further to ensure bidding behaviour is incentivised appropriately and resulting in the most efficient outcomes for the market.
- The requirement for a Market Participant not to bid in excess of its reasonable expectation of SRMC when such behaviour relates to market power, is key to ensuring the lowest cost generation is dispatched. The Authority planned to continue to develop its assessment of SRMC and the monitoring tools it uses with the IMO to ensure the SRMC requirement is being complied with.
- Market Participants receive constrained on or constrained off payments, if they are dispatched (or not) out of merit. Total compensation for 2012/13 amounted to around $11 million. Some of these payments related to network constraints and network outages. The Authority planned to review further whether the current arrangements are working effectively to ensure the most efficient dispatch and minimum cost to the market.
- Since the market commenced, Verve Energy has been able to bid on a portfolio basis. This was a pragmatic approach when it was the sole provider of balancing energy. However, this approach reduces the transparency of Verve Energy's bids in the balancing market and may be impacting on the ability of the new Balancing Market to deliver the most efficient outcomes for the market.

In relation to the LFAS market, the Authority noted that the introduction of competition and the increased transparency resulting from it had provided significant benefits in focussing attention and increased understanding of the factors driving LFAS and ancillary service costs generally.

The Authority recognised that considerable effort had been made by the IMO and System Management to better understand the LFAS requirement and that this work was ongoing. The Authority noted that there were many difficult issues to resolve and it was not possible or sensible to adopt hurried solutions. However, the Authority noted that experience in the NEM, where the quantity of LFAS is lower relative to total demand, highlighted potential opportunities to reduce LFAS costs in the WEM, which should be explored.

The Authority considered that the work planned by the IMO and System Management should be developed further before committing to significant changes or extending competition to other ancillary services.

1.4 Approach and focus for the 2014 Minister's Report

As noted in its submission to the Government's Electricity Market Review (**EMR**), the Authority welcomes the EMR commissioned by the Minister of Energy, particularly as it covers issues of concern to the Authority that have been raised for a number of years in its annual Wholesale Electricity Market reports.

The ERA considers that the original Western Australian market design was a good first step given the circumstances (e.g. the uncertainty of attracting investment and the willingness to accept a very conservative security buffer). Unfortunately, until recently, insufficient priority has been given to making the necessary changes in policy settings to refine the market.

As noted above, examples of matters which were identified by the Authority a number of years ago as requiring action include the Reserve Capacity Mechanism (**RCM**), the market governance framework and the high costs associated with unconstrained network access. The Authority identified that these issues were too broad to be captured fully by the normal Market Rule change process. However, in the absence of an appropriately resourced policy body with sufficient remit, these matters have not been properly addressed.

As set out in its submission to the EMR Panel, the Authority considers the focus of reform should be on restructuring Synergy and dealing with the known issues with the existing market design before considering fundamental changes to the market design (e.g. a capacity versus energy only wholesale market). It is possible that a more competitive industry structure, along with some necessary adjustments to the current market design, would be sufficient to achieve the objectives of the EMR, thus saving significant costs associated with undertaking fundamental redesign of the market.

In any case, a fundamental redesign of the market should only be considered once the industry structure issues have been dealt with, as all market designs are problematic without a competitive industry structure. The Authority notes that this view appears to also be held by most stakeholders who provided submissions to the EMR.

In summary, the ERA considers the most pressing problems to be:

- industry structure including government ownership and lack of competition;
- market governance (including State Government's conflict);
- the RCM; and
- constrained network access.

Recognising that the EMR is now putting significant resources into a number of long standing issues identified by the Authority, including those listed above, the Authority does not consider it efficient for this review to duplicate the work being undertaken by the EMR project team.

In particular, the issues relating to industry structure, market governance and the RCM are well known and have been covered in depth in previous reports by the Authority. The Authority notes that a number of submissions provided to the EMR address these matters in detail and suggest various alternatives for dealing with them. In relation to these issues, the Authority does not propose to make significant further comment until the EMR has progressed its review.

However, because constrained network access is an evolving matter the Authority intends to cover it to some extent in this review. In particular, the Authority intends to consider issues arising as a result of some generators currently having constrained network access and that prospective network connections are currently being considered by Western Power on a constrained basis.

In addition, the Authority intends to focus this review on assessing:

- how effectively the new balancing and LFAS markets have developed since they were first implemented in July 2012; and

- how effectively the market has managed significant events which have arisen over the last year and whether any lessons can be learnt, particularly in relation to the impacts of:
  - the merger of Synergy and Verve Energy.
  - sustained network outages arising as a result of transformer failures at Muja.

Further detail on each of these issues is set out in section 2.

Beyond these specific issues, the Authority welcomes comments from stakeholders on any other strategic, policy or high-level issues that impact on the effectiveness of the WEM in meeting the Wholesale Market Objectives.

A Stakeholder Workshop was held on 25 September 2014 to seek views on what issues should be considered in this review. The Authority intends to continue to work with the electricity industry and the broader community. In addition to seeking formal submissions, the Authority would be happy to meet with stakeholders to discuss any matters related to this review. The Authority will take into account the views expressed by stakeholders in the preparation of its report to the Minister.

The structure of this discussion paper is as follows:

- Section 2 outlines the key matters the Authority intends to focus on in the 2014 Minister's Report.
- Section 3 provides a summary of key activities and outcomes of the WEM since its inception including a summary of the Market Surveillance Data Catalogue (**MSDC**).

2 Key Wholesale Electricity Market Matters

As discussed in section 1.4, for the 2014 Minister's Report, the Authority intends to particularly focus on:

- issues arising as a result of some generators currently having constrained network access and future network connections currently being considered on a constrained basis.
- how effectively the new balancing and LFAS markets have developed since they were first implemented in July 2012; and
- how effectively the market has managed significant events which have arisen over the last year and whether any lessons can be learnt, particularly in relation to the impacts of:
  - the merger of Synergy and Verve Energy:
  - sustained network outages arising as a result of transformer failures at Muja.

2.1 Constrained network

As noted above, the WEM design is based on an 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. An unconstrained network approach facilitates simpler operation of the power system and market because of the absence of dynamic physical constraints.

In its 2010 Report, 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. The Authority noted that the review would need a very clear set of objectives, be well resourced with full and open consultation and undertake proper consideration of all the relevant interactions within the WEM design.

The EMR is including consideration of whether the market should move to a constrained model. The Authority supports this review and notes that a number of submissions to the EMR Panel provide useful discussion and suggestions in relation to this matter.

In the interim, the issue remains of concern given the increasing prevalence of interruptible supplies being offered or currently being considered by Western Power. Whilst such supplies are likely to deliver more efficient network connection costs, the interaction with the operation of the WEM also needs to be considered, particularly in relation to the assessment of capacity credits and constrained on/off payments. Until a policy decision in relation to the overall approach is agreed there is a significant risk that a piecemeal and uncoordinated adoption of constrained network access may lead to issues.

The Authority notes the concerns raised by the IMO in its submission to the EMR in relation to the growing impact of network constrained connections. These include:

- Runback schemes and the generation constraint arrangements being proposed by Western Power through the CAG process have the potential to override price-based economic dispatch outcomes and increase costs for consumers. For example, if two generators are located behind a single constraint, such arrangements may result in the higher cost generator being given preference over the lower cost generator on the basis of specific conditions contained within confidential network connection contracts or its relative contribution to the constraint.

- Current systems and processes will make it virtually impossible for System Management to manage the growing number of constraints, and the competing constraints, around the network. The IMO understands that the existing runback schemes have been implemented with bespoke systems that operate on an individual basis, without regard for other constraints on the SWIS. The management and prioritisation of a growing number of these systems would be extremely complex and in many cases impossible to manage with existing systems or additional bespoke constrained dispatch tools, as proposed by Western Power.

The Authority notes that since 2012 it has received several applications from Western Power for exemptions from its Technical Rules to enable it to offer constrained connections to certain customers (both loads and generators)[5]. It is also aware that connections being considered for new customers typically involve a constrained connection. When approving Technical Rule exemptions, the Authority must follow the requirements of the *Electricity Networks Access Code 2004* (**Code**). Although these requirements include having regard to the effect the proposed exemption will have on users of the network, there is no specific requirement in the Code to consider the impact on the WEM. The Authority is not aware of any adverse impact on the WEM in relation to the exemptions granted to date but notes this may become an issue in future.

In this review the Authority intends to focus on identifying and analysing issues which are arising now, or emerging, as a result of constrained network connections. Although such issues should be resolved when an overall solution is adopted, depending on how long this takes, it may be necessary to make changes in the interim. Matters the Authority intends to consider include:

- Impact on the market from Western Power offering non-firm services;
- Approval requirements for offering non-firm services;
- Rules around generator bidding with constrained connections; and
- Interaction with constrained on/off payments in market.

2.2 Balancing Market

The new competitive balancing market was introduced on 1 July 2012 enabling all generators to offer balancing services. Prior to that, all balancing services were provided by Verve Energy (now Synergy). The objectives of the Balancing Market are to:

- enable all balancing facilities to participate in the Balancing Market;
- dispatch the lowest cost combination of facilities made available for Balancing;

[5] See http://www.erawa.com.au/electricity/electricity-access/western-power-network/technical-rules/exemptions-from-technical-rules for details of exemptions approved by the Authority.

- establish a balancing price which is consistent with dispatch;
- seek to ensure timely and accurate balancing pricing and quantity information, including forecasts, and system security information, is provided to all Market Participants; and
- seek to ensure timely and accurate information relevant to the operation and administration of the Balancing Market is provided to affected Rule Participants.

Balancing offers are required to be submitted for all generators, apart from those on an approved planned outage or forced outage. Balancing offers include the quantity and price at which a Market Participant is willing to be dispatched. Prices offered must be within the Price Cap (i.e. between the maximum and minimum STEM price) and must not be in excess of the Market Participant's reasonable expectation of its short run marginal cost when such behaviour relates to market power. Market Participants other than Synergy are able to revise their offers up to two hours prior to the Trading Interval commencing to reflect changes in market conditions. Synergy has further restrictions and different gate closure times.

Under the new balancing market, Synergy has continued to be able to offer its facilities on a portfolio basis and is treated as a single Balancing Facility. Synergy is able to offer its portfolio in 35 tranches and IPPs can offer ten tranches for each scheduled generating facility. Intermittent generating units can only be offered as a single tranche and offers include price and estimated output. Synergy is also able to offer a facility on a stand - alone basis consistent with IPP's but, to date, has not.

The IMO uses the balancing offer submissions to develop the Balancing Merit Order (**BMO**) which is used to determine which facilities are dispatched by System Management.

Any deviation Market Participants are required to make from their Net Contract Position (**NCP**) is treated as a Balancing Market transaction. Market Participants are paid the Final Balancing Price on their Metered Balancing Quantities (**MBQ**), i.e. the difference between actual generation or load and their NCP. This differs from the NEM where settlement is based on total generation and load.

In the period prior to 1 July 2012, Market Participants would be penalised for any upwards or downward deviation in real-time from their previous day's declared NCP. Upwards Deviation Administered Price (**UDAP**) and Downwards Deviation Administered Price (**DDAP**) were used to settle deviations outside a tolerance[6] for non-Verve Energy Scheduled Generators (excluding those subject to a test) that deviated from their Resource Plans without instruction from System Management.[7] These administered penalties were incurred by IPPs if circumstances changed between the previous day's declared NCP and the real-time dispatch (like changes in forecast load, facility outages etc).

With the commencement of the new Balancing Market, the administered penalties UDAP and DDAP on IPPs were removed. System Management is required to dispatch all participants based on the BMO. Any generator that is dispatched out-of-merit by System Management receives compensation. A generator receives Constrained On

6 As provided for under clause 6.17.9 of the Market Rules.

7 UDAP was set at a discount to MCAP to discourage upwards deviations without instruction from System Management and DDAP was set at a premium to MCAP to discourage downward deviations without instruction from System Management.

compensation if more energy is dispatched from that generator than its Balancing Submission indicated when compared to the Balancing Price (for example, a situation like Forced Outage when another generator covers for lost generation). A generator receives Constrained Off compensation if it was within the BMO but was not, or could not be dispatched by System Management for system related reasons (e.g. a transmission line outage).

The magnitude of the compensation payment is affected by the generator's bid price. In some instances, price bids of -$1,000 can lead to a significant compensation payment if a generator is not dispatched.

The 2013 Report included an initial assessment of the new Balancing Market. The Authority found that generally stakeholders were happy with the new arrangements though some noted further time was needed to make a proper assessment.

In addition to improvements required in dispatch processes and market information, specific issues that the Authority considered needed attention included:

- Significant volumes are still being offered at the minimum and maximum price cap levels, although there has been an increase in the volumes of generation offered in the price bands between $0/MW and $100/MW. Whilst there are a number of valid reasons for generators to bid in this manner to ensure they are either dispatched or not, the Authority intends to investigate this further to ensure bidding behaviour is incentivised appropriately and resulting in the most efficient outcomes for the market.
- The requirement for a Market Participant not to bid in excess of its reasonable expectation of SRMC when such behaviour relates to market power, is key to ensuring the lowest cost generation is dispatched. The Authority will continue to develop its assessment of SRMC and the monitoring tools it uses with the IMO to ensure the SRMC requirement is being complied with.
- Market Participants receive constrained on or constrained off payments, if they are dispatched (or not) out of merit. Total compensation for 2012/13 amounted to around $11 million. Some of these payments related to network constraints and network outages. The Authority intends to review further whether the current arrangements are working effectively to ensure the most efficient dispatch and minimum cost to the market.
- Since the market commenced, Synergy has been able to bid on a portfolio basis. This was a pragmatic approach when it was the sole provider of balancing energy. However, this approach reduces the transparency of Synergy's bids in the balancing market and may be impacting on the ability of the new Balancing Market to deliver the most efficient outcomes for the market.

The Authority noted that the IMO had a number of potential rule changes under consideration which would further refine the operation of the energy market. These included:

- removal of the requirement to submit Resource Plans;
- potential changes to the STEM, including changes to timeframes and making participation optional;
- changes to gate closure times; and
- changes to the timeframes and requirements for Bilateral Submissions.

The Authority recognises that the IMO has not been able to progress any of the planned refinements of the Balancing Market whilst the EMR is underway.

In this review the Authority intends to focus on identifying any barriers that may be unnecessarily limiting effective participation of generators in the market. In addition to revisiting the issues noted in the 2013 Report, the Authority also intends to consider the following:

- Price spikes, and whether generators are responding effectively to these.
- Negative prices, and whether these are occurring for valid reasons.
- Plant availability, and whether these have had any impact on prices.
- Fuel constraints, and whether these have had any impact on prices.
- Post-merger Synergy bidding behaviour.
- Incentives affecting bidding behaviour related to constrained on/off payments.
- Impact of any bilateral contracts on generator performance and bidding behaviour.
- Future of the STEM market in light of development of the Balancing Market.

2.3 LFAS Market

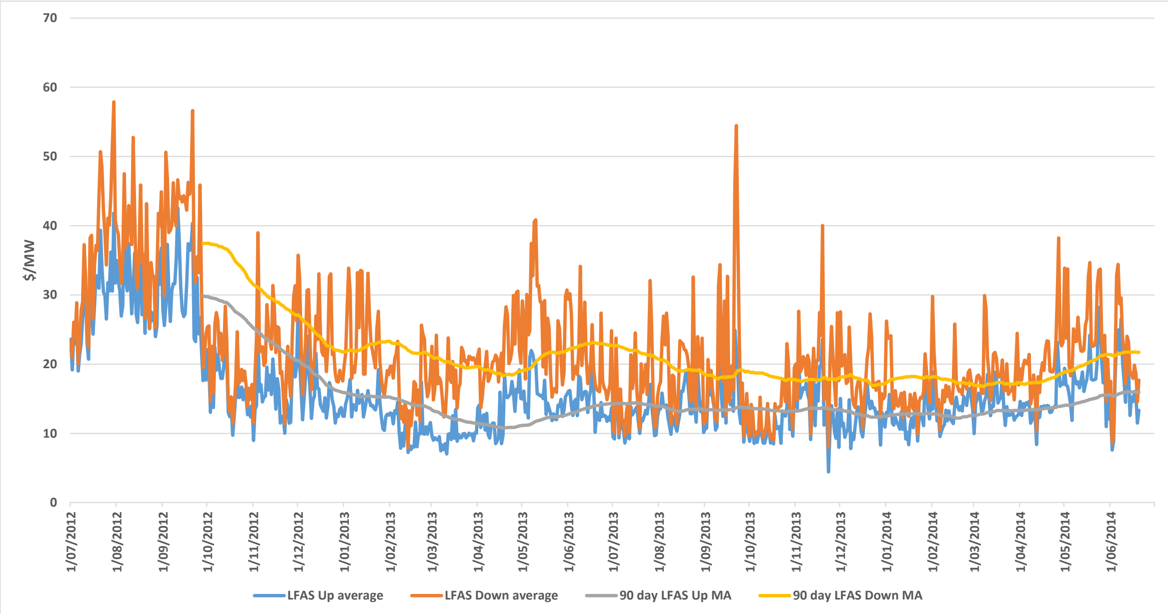
LFAS are the primary mechanism in real-time to ensure that supply and demand are balanced. Load following accounts for the difference between scheduled energy and actual load. Load following resources must have the ramping capability to pick up the load ramp between scheduling steps as well as maintain the system frequency. Load following can only be provided by units operating under Automatic Generation Control (**AGC**). LFAS Up refers to the service of adjusting output upwards to meet demand and LFAS Down refers to the service of adjusting output downwards, when demand is low.

LFAS has been provided since the inception of the WEM, with Synergy being contracted to be the sole provider of this service until 30 June 2012. Up to this date, payment for the provision of LFAS was based on a proportion of the MCAP, which was in turn based on prices in the previous Balancing Market. A new competitive LFAS market was established on 1 July 2012, with the key elements of this new market being market derived prices rather than administratively derived prices, and participation being open to all IPPs in addition to Synergy.

The LFAS requirement is set by System Management and must meet the standard according to section 3.10.1 of the Market Rules. This states that the level must be the greater of 30 MW or the capacity sufficient to cover 99.9% of short term fluctuations in load and output. The current requirement for both LFAS Up and LFAS Down is 72 MW. The requirement does not change from Trading Interval to Trading Interval.

The total cost of providing LFAS is passed on to Market Customers and Non Scheduled Generators, based on each Market Customer's monthly aggregate demand, as a proportion of that month's total system load. **Error! Reference source not found.** below shows the average daily LFAS prices since the competitive market commenced.

Figure 1 Daily average LFAS Up and LFAS Down prices July 2012 to June 2014



The previous period saw a number of "events" impact on the LFAS Up and Down markets. The LFAS requirement for both LFAS Up and LFAS Down was reduced twice in the period, firstly from 90 MW to 80 MW and then from 80 MW down to 72 MW. In addition Synergy's High Efficiency Gas Turbines (HEGTs) become available to provide LFAS and NewGen became the first IPP to enter the LFAS market in February 2013. All of these events helped to reduce the initial high prices.

Feedback from stakeholders for the 2013 WEM review primarily focused on concerns with the costs of providing the LFAS. Stakeholders considered the contributing factors to this included:

- the amount procured is highly conservative;
- A lack of transparency as to whether the most efficient facilities were providing the service (due to Synergy providing services on a portfolio basis); and
- A lack of competition for the first eight months of market operation and only limited competition subsequent to that (with only one participant joining Synergy in providing this service).

Suggestions for further reforms to the LFAS market included:

- shorter gate closure times;
- introduction of a causer pays model;
- better intermittent generation forecasting;
- reducing LFAS requirement in some trading intervals;
- relaxing technical rules around frequency stability; and
- more frequent dispatch intervals.

Stakeholders were also supportive of opening up other Ancillary Services to competition.

The Authority noted in the 2013 Report that the introduction of competition and the increased transparency resulting from it had provided significant benefits in focussing attention and increased understanding of the factors driving LFAS and ancillary service costs generally.

The Authority recognised that considerable effort had been made by the IMO and System Management to better understand the LFAS requirement and that this work was ongoing. The Authority noted that there were many difficult issues to resolve and it was not possible or sensible to adopt hurried solutions. However, the Authority noted that experience in the NEM, where the quantity of LFAS is lower relative to total demand, highlighted potential opportunities to reduce LFAS costs in the WEM, which should be explored.

The Authority considered that the work planned by the IMO and System Management should be developed further before committing to significant changes or extending competition to other ancillary services.

In the current period the LFAS requirement has remained unchanged at 72 MW, no additional facilities have provided LFAS and no new participants have entered the market.

Referring back to **Error! Reference source not found.** above, it can be seen that prices have been relatively flat since July 2013 with the average LFAS Up and LFAS Down prices for the Current Period being lower than the Previous Period, particularly in peak trading intervals. However, there appears to have been a slight up-turn in the last two months of the current period.

The IMO has undertaken its required five yearly review of ancillary services with the final report published on 6 November.

A study prepared for the IMO by its consultant noted the following:

> *The cost of frequency control in the WEM is higher than those in any other market studied. This is particularly due to the WEM's LFAS costs. ROAM found that regulation requirements vary significantly depending on the nature of a system and that the particular nature of the market services, structure and also the type of generation assets available heavily dictate the necessary regulation requirements. The WEM's relatively small size, lack of inter-connectedness, load concentration and absence of significant hydro generation in particular are all factors contributing to high regulation (LFAS) requirements and therefore high LFAS costs. ROAM has made a number of recommendations for actions that would help to minimize LFAS requirements based on international experience and review.*

The Authority recognises that, other than conducting the five-year review, it has not been possible for the IMO to progress further improvements to the LFAS market whilst the EMR is being undertaken.

For the purposes of this review, the Authority intends to focus on how the market has operated during the period to ensure:

- current issues are properly identified; and
- any other potential sources of LFAS are identified.

2.4 Sustained network and generator outages

During the Current Period there have been a number of significant outages, primarily affecting the Southern region. These include:

- Failure of a second transformer at Muja on 22 February 2014.
- Worsley COGen planned outage from 9 June 2014 to 30 June 2014.
- Picton to Merredin 132 kV transmission planned outage.

As a consequence it has been necessary for the Muja AB plants to be run out of merit for considerable periods of time resulting in significant “Constrained On” payments being passed through to Market Participants.

Several comments made by the IMO in its submission to the EMR are relevant to this:

- *The WEM’s current constraint payment mechanism has been designed on the basis that constraints occur occasionally and for short periods of time. As network constraints bind more frequently, the volume and frequency of constraint payments will increase and may have a material impact on the cash flow of Market Participants. Consequently, Market Participants will require a greater level of transparency and predictability of these cash flows to inform efficient investment decision making and risk management.*
- *However, there is currently very little transparency over network ratings, outages, constraints and flows. This means that stakeholders are unable to assess the likelihood or impact of constraints on their operations and financial position. This has been highlighted in recent workshops the IMO has held with Market Participants in relation to the ongoing impacts of the Muja bus-tie transformer failures.*

The Authority is currently undertaking an investigation referred to it by the IMO in relation to prices offered by Vinalco Energy during March and June 2014. These investigations are separate from the Authority’s annual WEM review but are likely to provide useful insight regarding whether the current rules are adequate for dealing with such events.

In this review of the WEM the Authority intends to give consideration to the following:

- Whether the current market rules are adequate to deal with sustained outages such as the failure of two transformers at Muja.
- Whether the criteria System Management is required to use under the Market Rules when dealing with forced outages results in the lowest cost option.
- Whether the criteria System Management is required to use for approving planned network and generator outages results in the lowest cost option.
- Whether there are sufficient incentives for Western Power to manage network outages in a way that results in the lowest overall cost to electricity consumers.
- Whether the rules in relation to how “constrained on” generators must bid are appropriate – including provisions for investigations.
- Whether it is appropriate that costs of constrained on generation are always allocated to all Market Customers.
- Whether “constrained on” generators are adequately compensated in all cases.

2.5 Synergy post-merger

The Authority’s 2013 report included a preliminary assessment of the merger of Verve and Synergy which was that it would increase already significant market power concerns that would need to be addressed to minimise barriers to effective competition and to ensure efficient dispatch of generation.

The Authority recognised that the Merger Implementation Group was conscious of the potential impact of the merger on the WEM and was seeking to address this through ring fencing and non-discriminatory pricing requirements, including regular audits of those requirements. However, until further detail of these measures was known, as well as some experience with their operation, it was not possible for the Authority to comment.

The Authority is currently undertaking its first annual review of the effectiveness of the Electricity Generation and Retail Corporation (**EGRC**) Regulatory Scheme[8] which sets out the requirements Synergy must meet following the merger. The Authority published a Discussion Paper calling for public submissions on 10 November 2014.

The review of the EGRC Regulatory Scheme will consider how effective the Scheme has been in achieving the objectives of the Scheme. These objectives include:

- Ensuring the merged entity does not unduly preference its own retail and generation arms over third party retailers and generators;

[8] The EGRC Regulatory Scheme (which comprises the Electricity Corporations (Electricity Generation and Retail Corporation) Regulations 2013, the Segregation and Transfer Pricing Guidelines 2013 and the Electricity (Standard Products) Wholesale Arrangements 2014) was put in place to impose requirements on the new merged entity. These requirements include ring-fencing, business segregation, transfer pricing and non-discriminatory wholesale electricity trading.

- Providing the private sector with access to electricity on non-discriminatory terms; and
- Mitigating the concerns of private-sector market participants.

In relation to its review of the WEM, the Authority will need to consider how effective the EGRC Regulatory Scheme has been in mitigating Synergy's market power.

The Authority also intends to review:

- whether the existing market power mitigation measures, including provisions for investigations, are sufficient in light of Synergy's increased size and dominance; and
- any impact on trading volumes and prices in the STEM and Balancing Market as a result of the merger.

3 Outcomes in the Wholesale Electricity Market

The WEM in Western Australia is a market with separate capacity and energy components. The RCM seeks to ensure that supply capacity is sufficient to achieve the required level of reliability and is adequately renumerated to attract investment when needed. In contrast, the energy market provides a platform in which electricity generators and retailers interact to supply and purchase electricity. In the WEM, therefore, a generator will receive two payment streams, the capacity payment for making its capacity available to the market, and the energy payment for the amount of electricity that it has produced and made available to the market.

This section provides a brief overview of outcomes in the capacity and energy markets from market commencement in September 2006 to the end of June 2014. It should be noted that as a result of the Ministerial decision relating to the extension of the 2014 Reserve Capacity Cycle to September 2015, reporting on the RCM will include up to the previous, i.e. 2013, Reserve Capacity Cycle.

A summary of the key information from the MSDC[9] for the period from 1 July 2013 to 30 June 2014 (**Reporting Period**) is also included in this section.

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;[10] 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 RCM.

[9] 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 MSDC, analysing the compiled data, and providing both the data and analysis to the Authority. 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.

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

3.1 Reserve Capacity Mechanism

The IMO was issued with a Direction by the Minister for Energy on 29 April 2014 to defer certain aspects of the 2014 Reserve Capacity Cycle for twelve months. This relates to the Reserve Capacity required between 1 October 2016 and 1 October 2017. Consequently, many of the charts and tables below in relation to the RCM are unchanged from the 2013 Report.

As a result of this, the IMO exercised its discretion under clause 4.1.32 of the Market Rules to extend the time for publication of the 2014 Electricity Statement of Opportunities Report under clause 4.1.8 of the Market Rules. The new timeframe for publication of the 2014 Electricity Statement of Opportunities Report is 17 June 2015.

3.1.1 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.[11]

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.

3.1.2 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.

3.1.3 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.

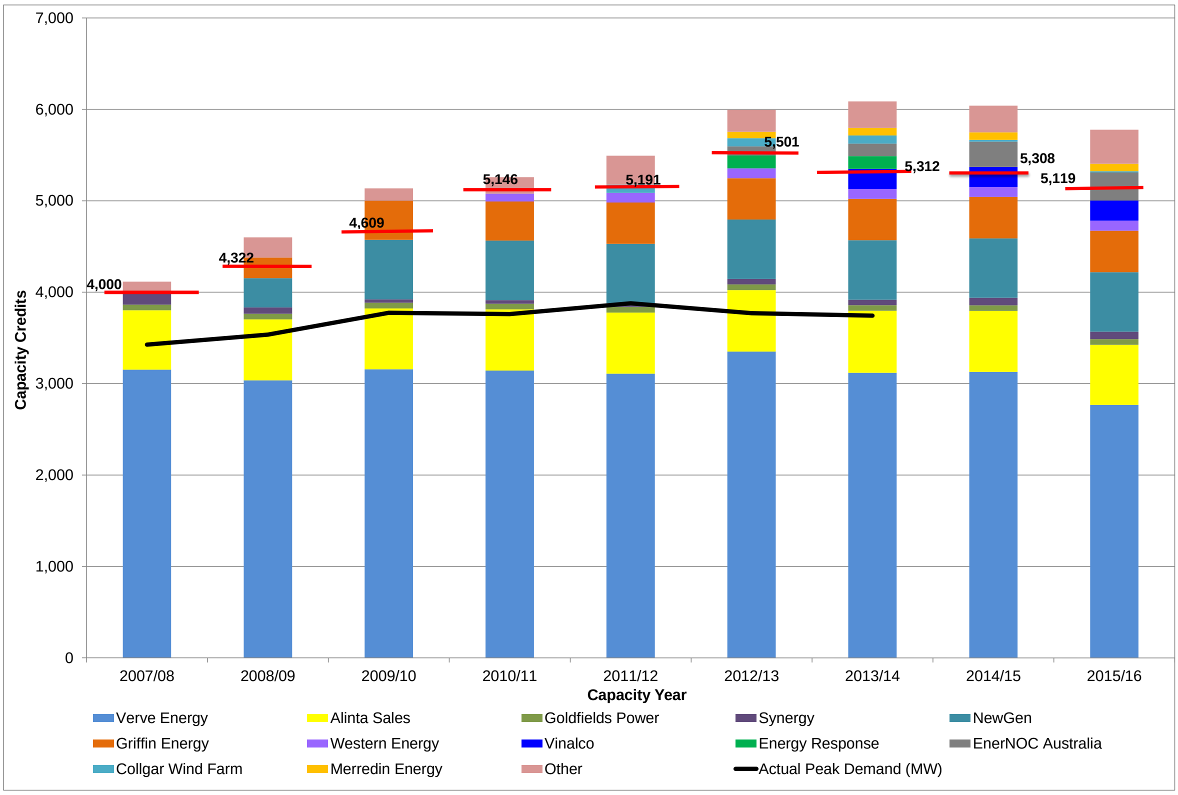
3.1.4 Capacity Credits assigned

Although not required under the Market Rules, this section provides data on Capacity Credits assigned to Market Participants.

[11] 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.

Figure 2 below shows the Capacity Credits assigned to Market Participants for the 2007/08 to the 2015/16 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). As noted above, the Reserve Capacity Cycle has been deferred for a year so Capacity Credits for the 2016/17 Capacity Year have not yet been assigned.

Figure 2 Capacity Credits assigned to Market Participants for the 2007/08 to 2015/16 Capacity Years



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

3.1.5 Maximum Reserve Capacity Price and Reserve Capacity Price

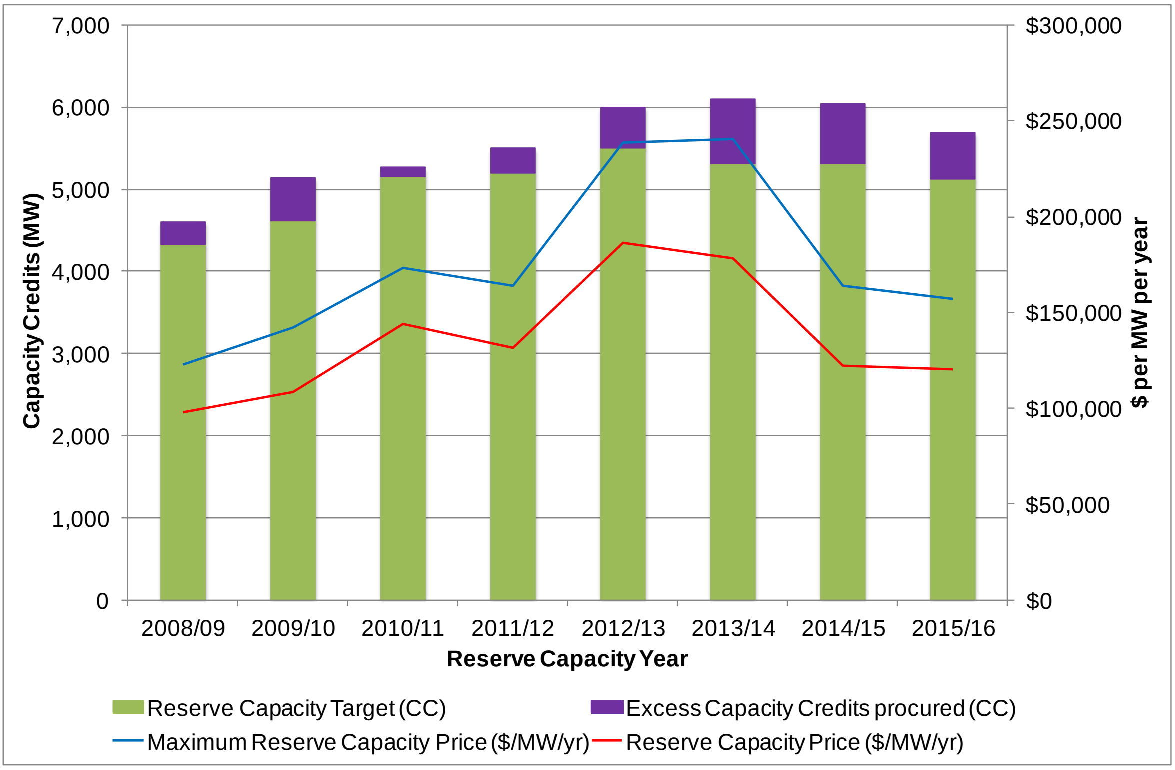
Although not required under the Market Rules, this section provides data on the Maximum Reserve Capacity Price (**MRCP**) and the Reserve Capacity Price (**RCP**).

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. 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 3 below 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 2015/16. As noted above, the Reserve Capacity Cycle has been deferred for a year so Capacity Credits for the 2016/17 Capacity Year have not yet been assigned.

Figure 3 The Reserve Capacity Target, excess Capacity Credits, Maximum Reserve Capacity Price and Reserve Capacity Price from the 2008/09 Capacity Year to the 2015/16 Capacity Year



3.1.6 *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 1 below 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 2010/11 through 2013/14 Capacity Years.

In the previous reporting period the most notable Forced Outage rates were displayed by the four Vinalco Muja facilities. These were all substantially high with Muja G1 (99.5 per cent), Muja G2 (99.5 per cent), Muja G3 50.2 per cent) and Muja G4 (38.2 per cent). All four facilities had much lower Forced Outage rates in the current reporting period, with Muja G1

(46.4 per cent), Muja G2 (35.3 per cent), Muja G3 (4.8 per cent) and Muja G4 (5.2 per cent). Only one other facility had a Forced Outage rate higher than 10 per cent and that was Alcoa's Wagerup facility which had a forced outage rate of 25.6 per cent, up from 3.2 per cent in the previous period.

Out of Synergy's 16 facilities with generating capacity greater than 100 MW, seven had lower Planned Outage rates than the previous reporting period. The most notable improvement was seen in the Muja G5 facility (decreasing from 33.2 per cent in 2012/13 to 2.3 per cent in 2013/14) and the Muja G6 facility (decreasing from 23.5 per cent in 2012/13 to 3.7 per cent in 2013/14). On the other hand the most notable increases in Planned Outage rates were from the Kemerton GT12 facility (increasing from 1.3 per cent in 2012/13 to 16 per cent in 2013/14) and Muja G7 facility (increasing from 4.3 per cent in 2012/13 to 24.4 per cent in 2013/14). For Synergy's remaining generation, five out of the 17 facilities displayed a deterioration in their Planned Outage rates.

Alinta's four facilities with generating capacity greater than 100 MW all had a higher planned outage rate in the current period compared to the previous period, with their Pinjarra U1 (16.1 per cent) and Pinjarra U2 (12.9 per cent) both having planned outage rates higher than 10 per cent. Out of the remaining six IPP facilities with generating capacity greater than 100 MW, only Griffin Power's BW2 Bluewaters G1 facility had a higher planned outage rate than the previous period with a planned outage rate of 10.9 per cent. No other IPP facility had a planned outage rate greater than 10 per cent.

Table 1 Ratio of quantities subject to outages to maximum generating capacity for the 2010/11 to the 2013/14 Capacity Years

Participant	Resource Name	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	Max Gen (MW) 2012/13 Cap Year	Forced 2012/13 Cap Year	Planned 2012/13 Cap Year	Max Gen (MW) 2013/14 Cap Year	Forced 2013/14 Cap Year	Planned 2013/14 Cap Year
Alcoa	ALCOA_WGP	25.0	5.1%	10.3%	25.0	4.1%	29.5%	25.0	3.2%	21.6%	25.0	25.6%	9.9%
Alinta	ALINTA_PNJ_U1	145.0	0.2%	14.0%	145.0	0.1%	4.3%	145.0	0.0%	6.1%	143.0	0.5%	16.1%
Alinta	ALINTA_PNJ_U2	145.0	0.1%	7.0%	145.0	0.2%	11.6%	145.0	0.3%	1.7%	143.0	0.3%	12.9%
Alinta	ALINTA_WGP_AGG	380.0	0.0%	0.8%									
Alinta	ALINTA_WGP_GT	190.0	1.3%	1.8%	190.0	0.0%	2.1%	190.0	0.4%	2.5%	190.0	0.0%	7.6%
Alinta	ALINTA_WGP_U2	190.0	0.0%	2.9%	190.0	0.4%	1.7%	190.0	1.2%	3.3%	190.0	0.8%	7.0%
Alinta	ALINTA_WWF				89.1	0.0%		89.1	0.0%		89.1	0.0%	0.0%
Blair Fox Pty Ltd	BLAIRFOX_KARAFIN_WF1							5.0			5.0		
Blair Fox Pty Ltd	BLAIRFOX_WESTHILLS_WF3							5.0			5.0		
Denmark Community	DCWL_DENMARK_WF1							1.4			1.4		
EDWF Manager	EDWFMAN_WF1	80.0	0.0%	0.0%	80.0		0.0%	80.0	0.3%	0.0%	80.0	0.0%	0.1%
Goldfields Power	PRK_AG	68.0	1.4%	6.1%	68.0		0.5%	68.0		0.3%	68.0	0.1%	0.2%
Greenough River	GREENOUGH_RIVER_PV1							10.0			10.0	0.2%	0.2%
Griffin Power	BW1_BLUEWATERS_G2	217.0	1.2%	10.1%	217.0	5.8%	14.2%	217.0	2.3%	12.5%	217.0	1.9%	8.0%
Griffin Power 2	BW2_BLUEWATERS_G1	217.0	2.4%	8.7%	217.0	1.6%	4.5%	217.0	0.2%	8.7%	217.0	1.1%	10.9%
COLLGAR	INVESTEC_COLLGAR_WF1				200.0	0.1%		206.0	0.0%	0.3%	206.0	0.0%	0.1%
Landfill Gas & Power	CANNING_MELVILLE	3.0	0.0%	0.0%	1.2			1.0			1.0		
Landfill Gas & Power	RED_HILL	3.3	0.0%	0.0%	4.0			3.8			3.8		
Landfill Gas & Power	KALAMUNDA_SG							1.3			1.3		
Landfill Gas & Power	TAMALA_PARK	4.5	0.0%	0.0%	5.0			4.8			4.8		
Merredin Energy	NAMKKN_MERR_SG1							82.0	1.4%	4.5%	82.0	0.5%	2.5%
Mt Barker Power	SKYFRM_MTBARKER_WF1							2.4			2.4		
Mount Heron	MHPS							1.4			1.4		
Mumbida Wind Farm	MWF_MUMBIDA_WF1							55.0			55.0		
NewGen Neerabup	NEWGEN_NEERABUP_GT1	342.0	0.0%	6.0%	342.0	0.1%	2.7%	342.0	0.0%	6.1%	342.0	0.0%	1.5%
NewGen Kwinana	NEWGEN_KWINANA_CCG1	324.0	0.9%	2.3%	324.0	0.2%	15.5%	324.0	0.3%	4.5%	324.0	0.7%	2.3%
Perth Energy	ATLAS							1.1			1.1		
Perth Energy	ROCKINGHAM							4.0			4.0		
Perth Energy	SOUTH_CARDUP							3.4			3.4		
Western Energy	PENERGY_KWINANA_GT1	116.0	0.1%	0.2%	116.0	1.9%	3.2%	116.0	0.3%	2.4%	116.0	0.0%	1.6%

Participant	Resource Name	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	Max Gen (MW) 2012/13 Cap Year	Forced 2012/13 Cap Year	Planned 2012/13 Cap Year	Max Gen (MW) 2013/14 Cap Year	Forced 2013/14 Cap Year	Planned 2013/14 Cap Year
Southern Cross	STHRNCRS_EG	23.0	0.0%	0.0%	23.0	0.7%	1.4%	23.0	3.0%	2.8%	23.0		
TESLA	TESLA_GERALDTON_G1				9.9		0.5%	9.9		27.4%	9.9		0.9%
TESLA	TESLA_KEMERTON_G1							9.9		9.1%	9.9		1.2%
TESLA	TESLA_NORTHAM_G1							9.9		4.7%	9.9		1.2%
TESLA	TESLA_PICTON_G1				9.9	0.3%	3.6%	9.9		1.6%	9.9		1.9%
Tiwest	TIWEST_COG1	37.7	1.2%	3.1%	36.0	0.1%	3.7%	39.7	1.2%	2.1%	39.7	7.0%	7.9%
Verve Energy	ALBANY_WF1	21.6	0.0%	0.2%	21.6		0.0%	21.6		0.0%	21.6		
Verve Energy	COCKBURN_CCG1	236.6	0.0%	17.5%	236.6	1.0%	4.8%	236.6	0.2%	2.8%	236.6	0.5%	9.4%
Verve Energy	COLLIE_G1	318.0	0.6%	14.7%	318.0	3.6%	11.7%	318.0	0.2%	9.0%	318.0	2.2%	7.1%
Verve Energy	GERALDTON_GT1	20.8	0.4%	0.3%	20.8	0.0%	4.2%	20.8	0.9%	11.4%	20.8		2.3%
Verve Energy	GRASMERE_WF1				13.8		0.0%	13.8		0.1%	13.8		
Verve Energy	KALBARRI_WF1							1.6			1.6		
Verve Energy	KEMERTON_GT11	154.0	0.0%	4.2%	154.0	0.1%	3.2%	154.0	0.0%	13.1%	154.0		0.9%
Verve Energy	KEMERTON_GT12	154.0	0.0%	15.7%	154.0		0.1%	154.0	0.5%	1.3%	154.0	0.2%	16.0%
Verve Energy	KWINANA_G1	111.5	5.2%	9.7%									
Verve Energy	KWINANA_G2	111.5	4.9%	16.9%									
Verve Energy	KWINANA_G5	177.0	0.0%	53.6%	177.0	0.4%	23.0%	180.0	8.4%	3.0%	180.0	2.7%	7.5%
Verve Energy	KWINANA_G6	177.0	2.5%	49.6%	177.0	1.4%	25.9%	184.0	2.3%	24.0%	184.0	2.1%	5.4%
Verve Energy	KWINANA_GT1	20.8	0.0%	21.9%	20.8		2.0%	20.8	0.1%	19.5%	20.8	1.2%	6.0%
Verve Energy	KWINANA_GT2				100.1	0.1%		100.1	2.5%	12.0%	100.1	1.1%	19.8%
Verve Energy	KWINANA_GT3				100.1	0.1%		100.1	3.8%	12.6%	100.1	4.4%	12.0%
Verve Energy	MUJA_G5	185.0	15.8%	18.7%	185.0	0.5%	13.9%	195.7	1.2%	33.2%	195.7	2.5%	2.3%
Verve Energy	MUJA_G6	185.0	0.4%	20.5%	185.0	4.1%	40.3%	190.8	1.0%	23.5%	190.8	5.4%	3.7%
Verve Energy	MUJA_G7	211.0	0.0%	42.9%	211.0	0.1%	5.5%	211.0	2.7%	4.3%	211.0	0.3%	24.4%
Verve Energy	MUJA_G8	211.0	1.9%	18.5%	211.0	0.4%	15.2%	211.0	4.5%	6.6%	211.0	0.5%	9.5%
Verve Energy	MUNGARRA_GT1	37.2	0.0%	5.4%	37.2	1.9%	0.4%	37.2		8.9%	37.2	0.7%	22.4%
Verve Energy	MUNGARRA_GT2	37.2	0.1%	0.7%	37.2	0.2%	6.4%	37.2	0.1%	1.6%	37.2	0.6%	7.6%
Verve Energy	MUNGARRA_GT3	38.2	1.5%	10.9%	38.2	0.0%	0.5%	38.2	1.1%	17.1%	38.2	1.4%	0.7%
Verve Energy	PINJAR_GT1	37.2	0.0%	7.4%	37.2	0.0%	0.1%	37.2	0.0%	5.3%	37.2		0.2%
Verve Energy	PINJAR_GT10	116.0	0.4%	10.4%	116.0	0.5%	27.9%	116.0	0.3%	21.7%	116.0	0.7%	21.8%
Verve Energy	PINJAR_GT11	123.0	0.1%	49.3%	123.0	0.1%	19.9%	123.0	0.2%	10.7%	123.0	0.2%	5.2%

Participant	Resource Name	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	Max Gen (MW) 2012/13 Cap Year	Forced 2012/13 Cap Year	Planned 2012/13 Cap Year	Max Gen (MW) 2013/14 Cap Year	Forced 2013/14 Cap Year	Planned 2013/14 Cap Year
Verve Energy	PINJAR_GT2	37.2	0.2%	5.2%	37.2		1.4%	37.2		9.6%	37.2	0.5%	0.2%
Verve Energy	PINJAR_GT3	38.2	0.3%	0.1%	38.2		12.7%	38.2		0.2%	38.2	0.0%	7.3%
Verve Energy	PINJAR_GT4	38.2	0.0%	1.7%	38.2		6.7%	38.2	0.2%	0.2%	38.2	0.2%	7.2%
Verve Energy	PINJAR_GT5	38.2	0.4%	7.8%	38.2	1.0%	1.0%	38.2		6.0%	38.2	0.0%	0.2%
Verve Energy	PINJAR_GT7	38.2	0.1%	0.2%	38.2	0.4%	5.9%	38.2	0.0%	0.3%	38.2	0.0%	9.8%
Verve Energy	PINJAR_GT9	116.0	0.0%	27.3%	116.0	0.1%	16.7%	116.0	0.2%	5.9%	116.0		6.3%
Verve Energy	PPP_KCP_EG1	85.7	0.0%	4.7%	85.7	0.0%	0.5%	85.7	0.9%	8.8%	85.7	0.1%	5.6%
Verve Energy	WORSLEY_COGEN_COG1	116.4	1.8%	17.1%	116.4		3.5%	116.4	0.5%	2.7%	116.4	0.1%	6.7%
Verve Energy	WEST_KALGOORLIE_GT2	38.2	0.1%	4.3%	38.2	1.0%	0.1%	38.2	0.2%	18.5%	38.2	2.2%	0.2%
Verve Energy	WEST_KALGOORLIE_GT3	24.6	0.0%	3.5%	24.6		19.7%	24.6	1.2%	5.5%	24.6	0.2%	0.2%
Vinalco Energy	MUJA_G1							55.0	99.5%		55.0	46.4%	3.8%
Vinalco Energy	MUJA_G2							55.0	99.5%		55.0	35.3%	0.3%
Vinalco Energy	MUJA_G3							55.0	50.2%	6.1%	55.0	4.8%	8.9%
Vinalco Energy	MUJA_G4							55.0	38.2%	11.4%	55.0	5.2%	1.8%
Waste Gas	HENDERSON_RENEWABLE_IG1	3.2	0.0%	0.0%	3.0	0.2%		3.0	0.2%		3.0		

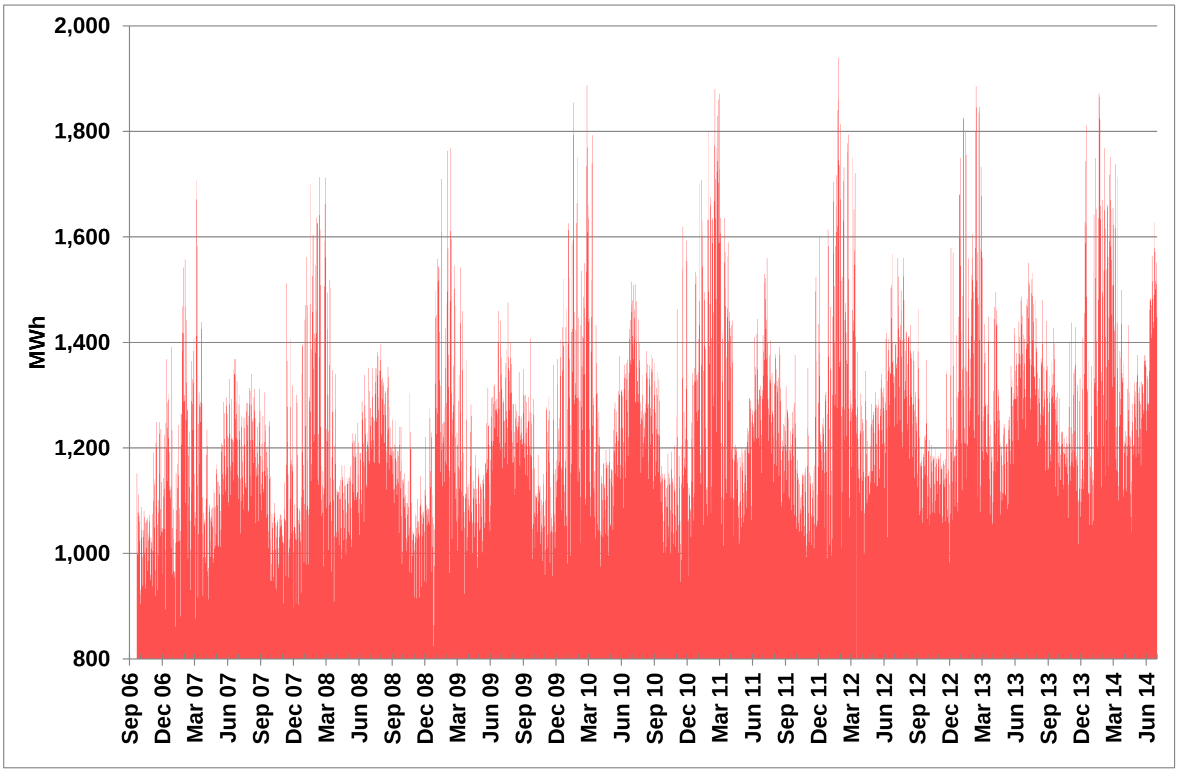
*Capacity Year starts 1 October and ends 30 September the following year. Maximum Generating Capacity of each facility was sourced from IMO's website. Planned and Forced Outages include full and partial ex-post outages for each facility for the Reporting Period. Blanks in the above table for some facilities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

3.2 Energy markets

Figure 4 illustrates the maximum SWIS demand each day (measured in megawatt hour (MWh) per Trading Interval[12]) from market commencement (21 September 2006) to 30 June 2014.

The maximum daily demand in 2014 was the lowest maximum in five years. The highest daily maximum demand recorded for the current reporting period was 1,872.1 MWh (or 3,744.2 MW), which was observed during the 5:30 pm Trading Interval on 20 January 2014. The current reporting period's maximum demand is 0.7% lower than the maximum demand for the previous reporting period i.e., 1,885.4 MWh (or 3,770.8 MW). This follows on from a 2.8% drop in maximum demand in the period prior to that.

Figure 4 Daily maximum demand (21 September 2006 to 30 June 2014)



3.2.1 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;

[12] A Trading Interval is a period of 30 minutes commencing on the hour or half-hour during a day. Settlement calculations in the WEM are based on Trading Interval data.

- statistical analysis of the volatility of prices in STEM Auctions;
- the proportion of time that clearing prices in STEM Auctions are at each Energy 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.

3.2.1.1 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.

Error! Reference source not found. sets out the mean and standard deviations of peak and off-peak clearing prices from:

- 1 August 2010 to 31 July 2011;
- 1 August 2011 to 30 June 2012;
- 1 July 2012 to 30 June 2013 (i.e. the previous Reporting Period); and
- 1 July 2013 to 30 June 2014 (i.e. the current Reporting Period).

Average prices increased from July 2012 as a result of the imposition of the carbon tax. A slight increase in average peak and off-peak prices occurred in the 2013-14 period compared to the 2012-13 period. Volatility in off-peak and peak STEM clearing prices have continually reduced over the four periods presented in the table.

Table 2 Mean and standard deviations of STEM Clearing Prices ($/MWh)

Trading Intervals	1 Aug 10 - 31 Jul 11		1 Aug 11 - 30 Jun 12		1 Jul 12 - 30 Jun 13		1 Jul 13 - 30 Jun 14	
	Mean	Std Dev	Mean	Std Dev	Mean	Std Dev	Mean	Std Dev
Off-Peak	26.49	15.28	29.04	13.79	41.05	11.90	**41.92**	**10.76**
Peak	47.92	34.24	50.86	28.84	60.78	18.24	**61.51**	**14.58**

Figure 5 and **Error! Reference source not found.** below 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 2014, as well as 30-day, 90-day and annual moving average prices.

Figure 5 Daily Average STEM Clearing Prices (Peak Trading Intervals)

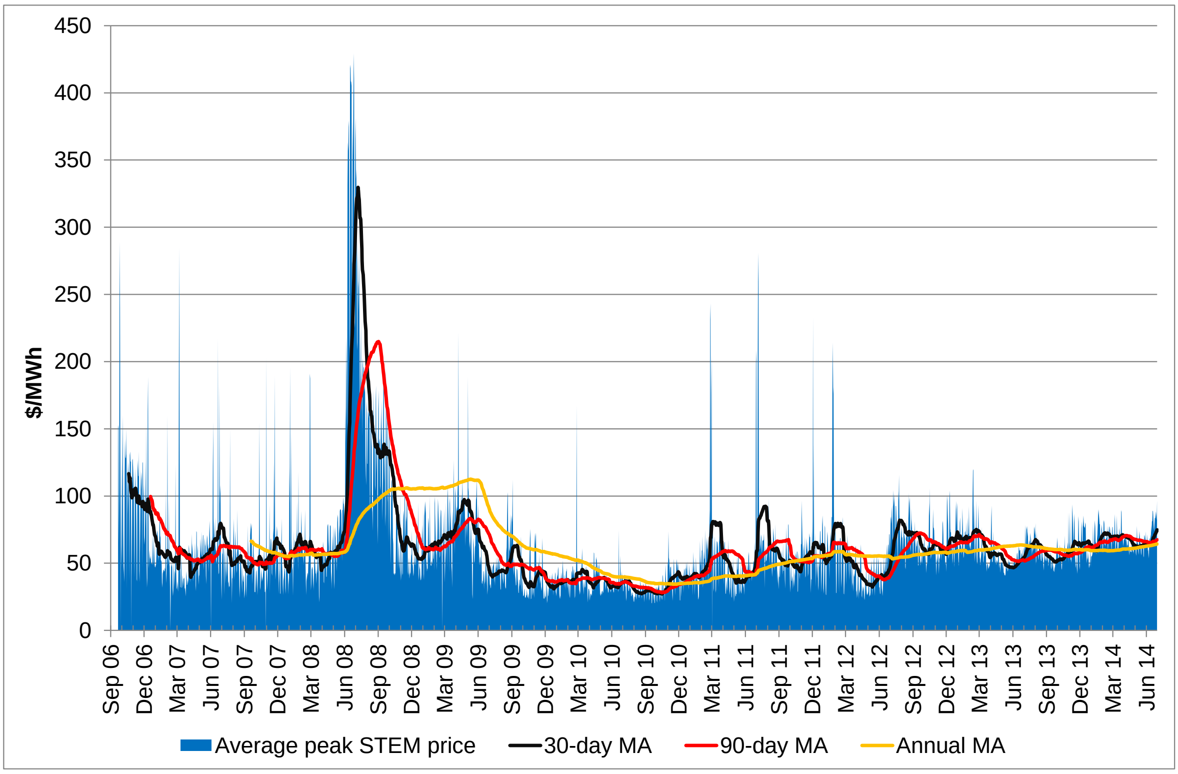
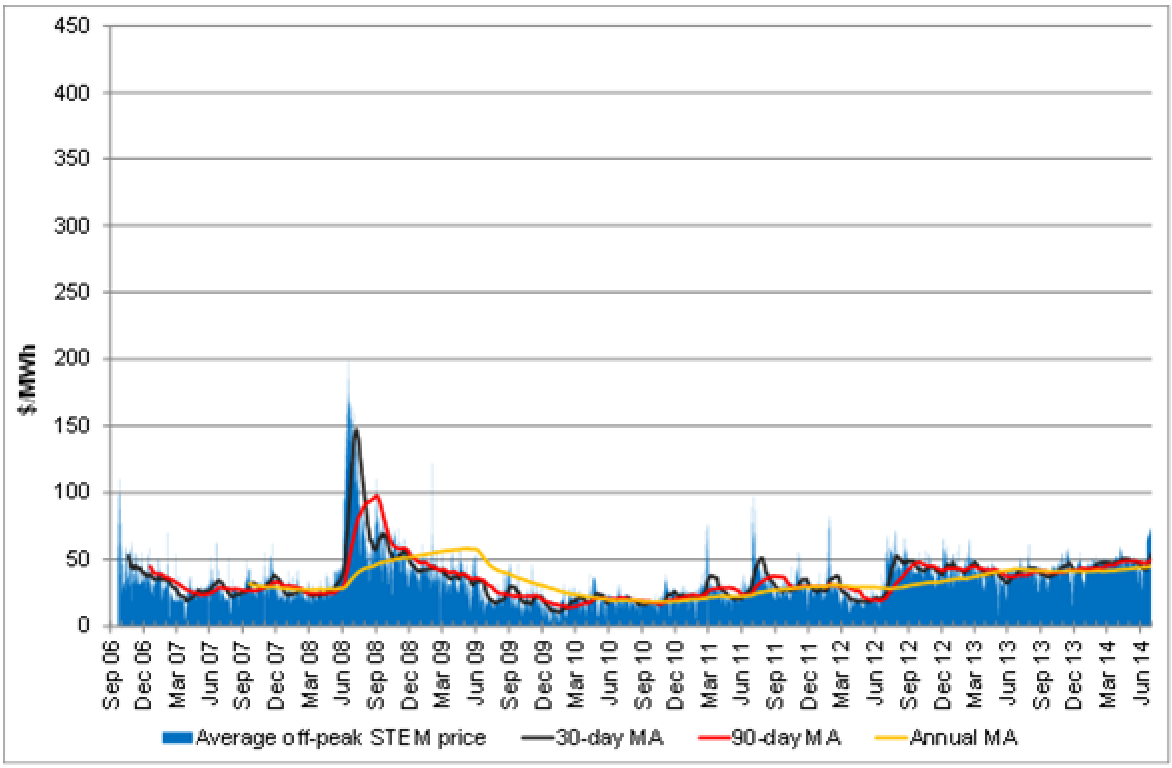


Figure 6 Daily Average STEM Clearing Prices (Off Peak Trading Intervals)



During the current reporting period prices have increased from the previous reporting period. The average Peak Trading Interval STEM Clearing Price was $64.36/MWh in 2013/14 compared with $63.44/MWh in 2012/13 and $51.68/MWh in 2011/12.

The average Off-Peak Trading Interval STEM Clearing Price also increased, with an average of $45.01/MWh compared with $42.80/MWh in 2012/13 and $26.17/MWh in 2011/12.

3.2.1.2 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 7 Figure 7 and Figure 8 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 2014.

From the two figures below it can be seen that in the July 2013 to June 2014 periods the STEM clearing prices have transacted in a narrower band than in previous periods.

Figure 7 Summary statistics for STEM Clearing Prices in Peak Trading Intervals (per calendar month)

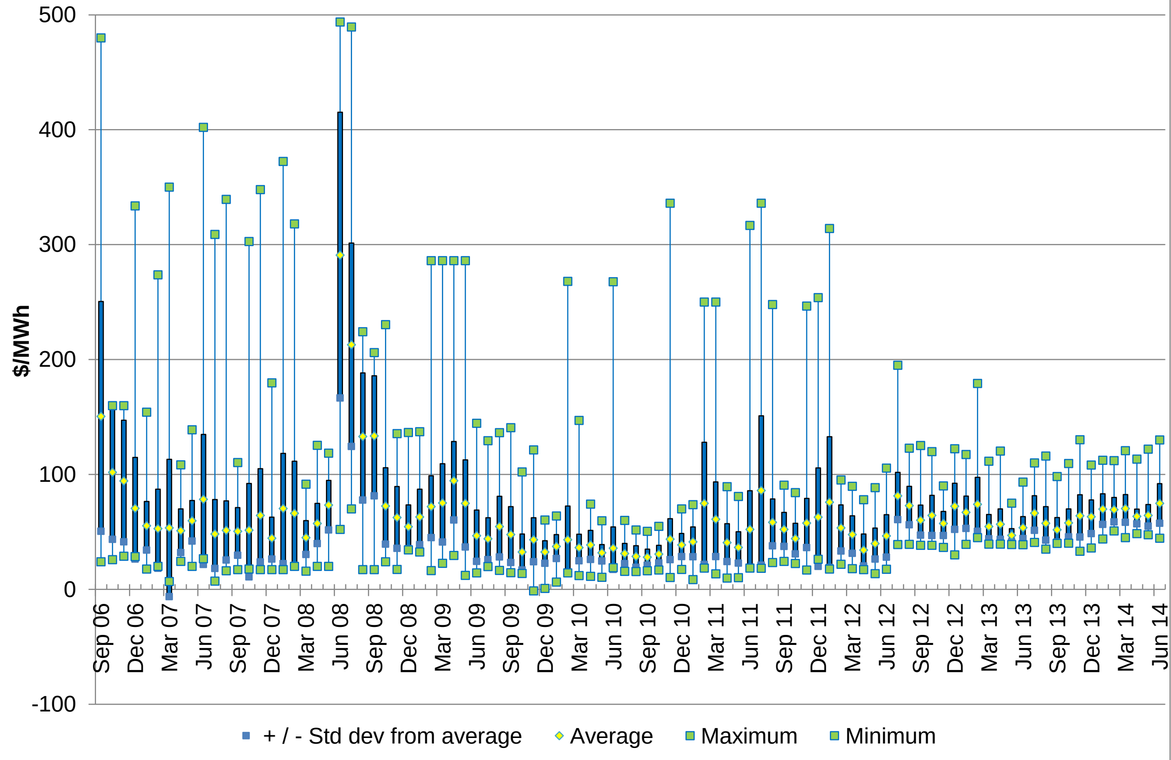
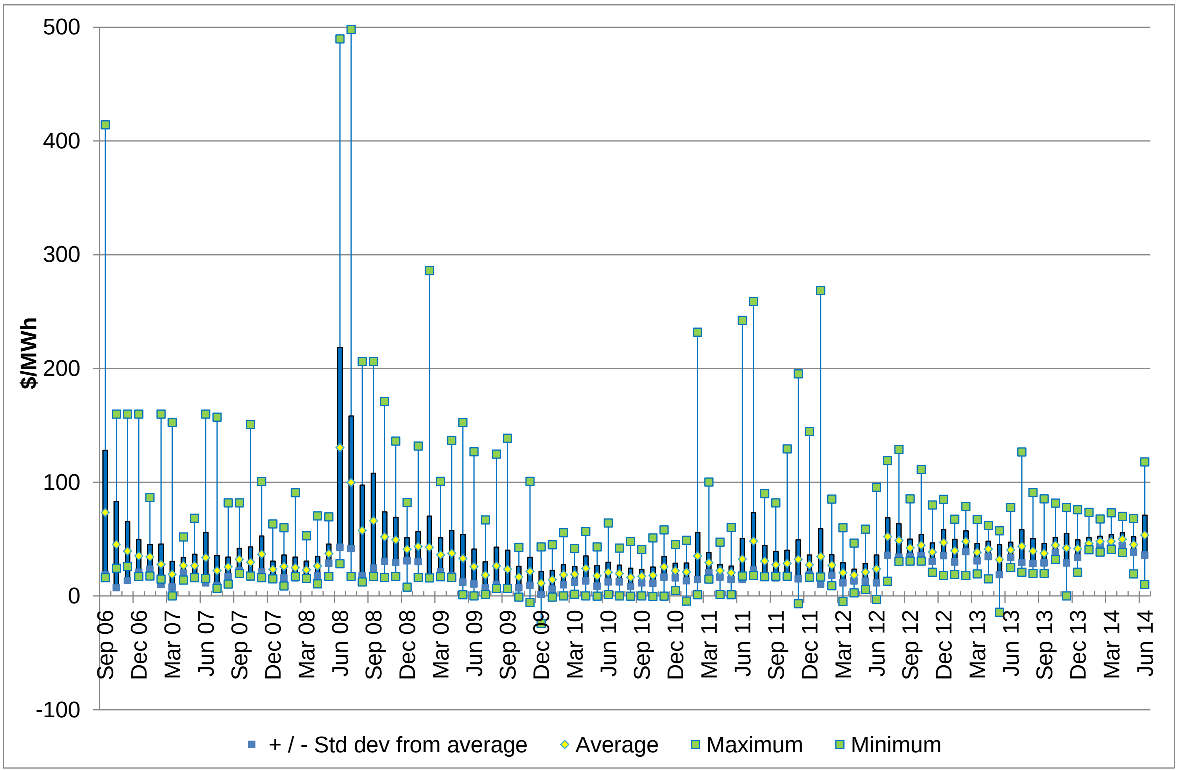


Figure 8 Summary statistics for STEM Clearing Prices in Off-Peak Trading Intervals (per calendar month)



3.2.1.3 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.[13] 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 SRMC 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 current Reporting Period, the Maximum STEM Price was $305/MWh, compared with $323/MWh in the previous Reporting Period.
- 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 $500/MWh (for July and August 2013) and $571/MWh (for April 2014).[14]

Figure 9 and Figure 10 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.

[13] 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.

[14] 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).

Figure 9 Proportion of Trading Intervals STEM Clearing Prices at Maximum STEM Price (per calendar month)

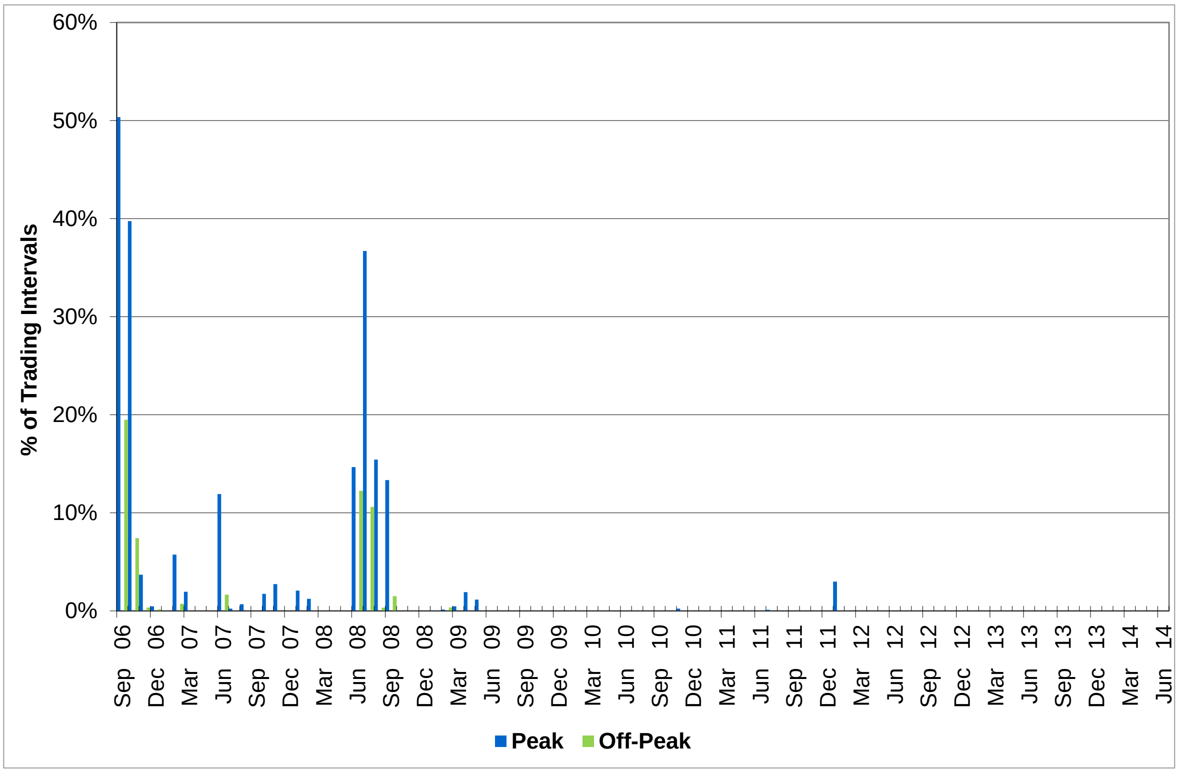
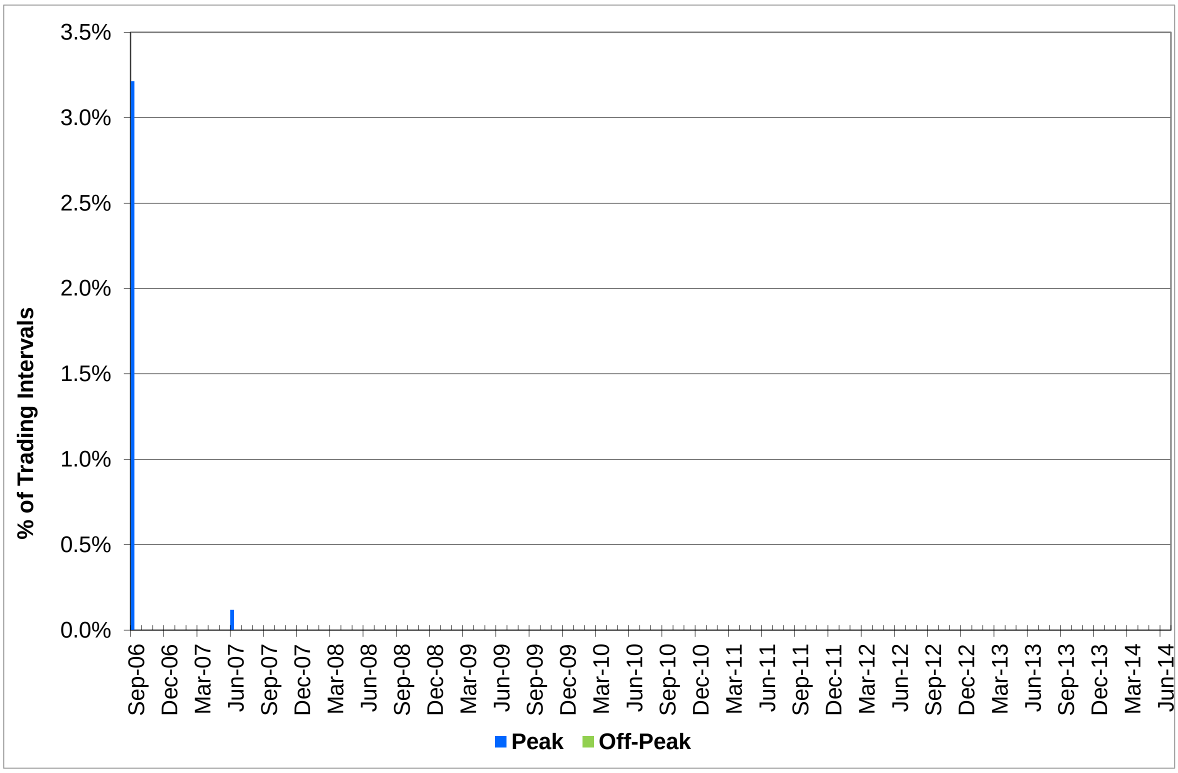


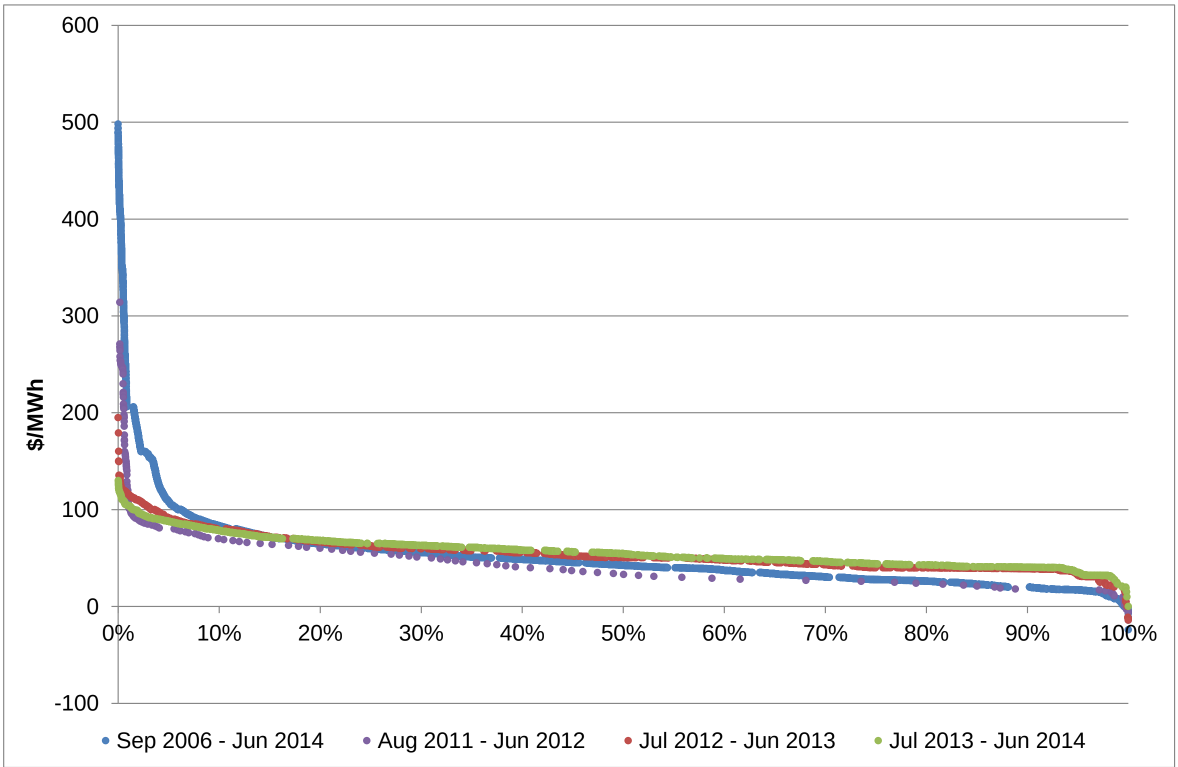
Figure 10 Proportion of Trading Intervals STEM Clearing Prices at Alternative Maximum STEM Price (per calendar month)



Another way of examining the incidence of high prices is to plot a price duration curve. Figure 11 sets out the price duration curves for STEM Clearing Prices, covering all Trading Intervals from 21 September 2006 (market commencement) to 30 June 2014, and comparing the curve for the current Reporting Period with the curves from the previous two Reporting Periods (August 2011 to June 2012 and July 2012 to June 2013) and the current Reporting Period.

Figure 11 shows that STEM Clearing Prices were between $0.00/MWh and $100.00/MWh for approximately 98.45 per cent of Trading Intervals during the current Reporting Period. The prices ranged between $40.00/MWh and $70.00/MWh for 76 per cent of Trading Intervals, with the $40.00/MWh to $50.00/MWh range comprising 35.79 per cent of Trading Intervals. In contrast, prices ranged between $40.00/MWh and $70.00/MWh for 58.40 per cent of Trading Intervals in the previous Reporting Period, with the $40.00/MWh to $50.00/MWh range only comprising 19.55 per cent of Trading Intervals. There were no negative prices during the current Reporting Period. The lowest STEM Clearing Price reached was $0/MWh which occurred during 24 Trading Intervals.

Figure 11 Comparison of price duration curves for STEM Clearing Prices



3.2.1.4 Short Term Energy Market Offers and Bids

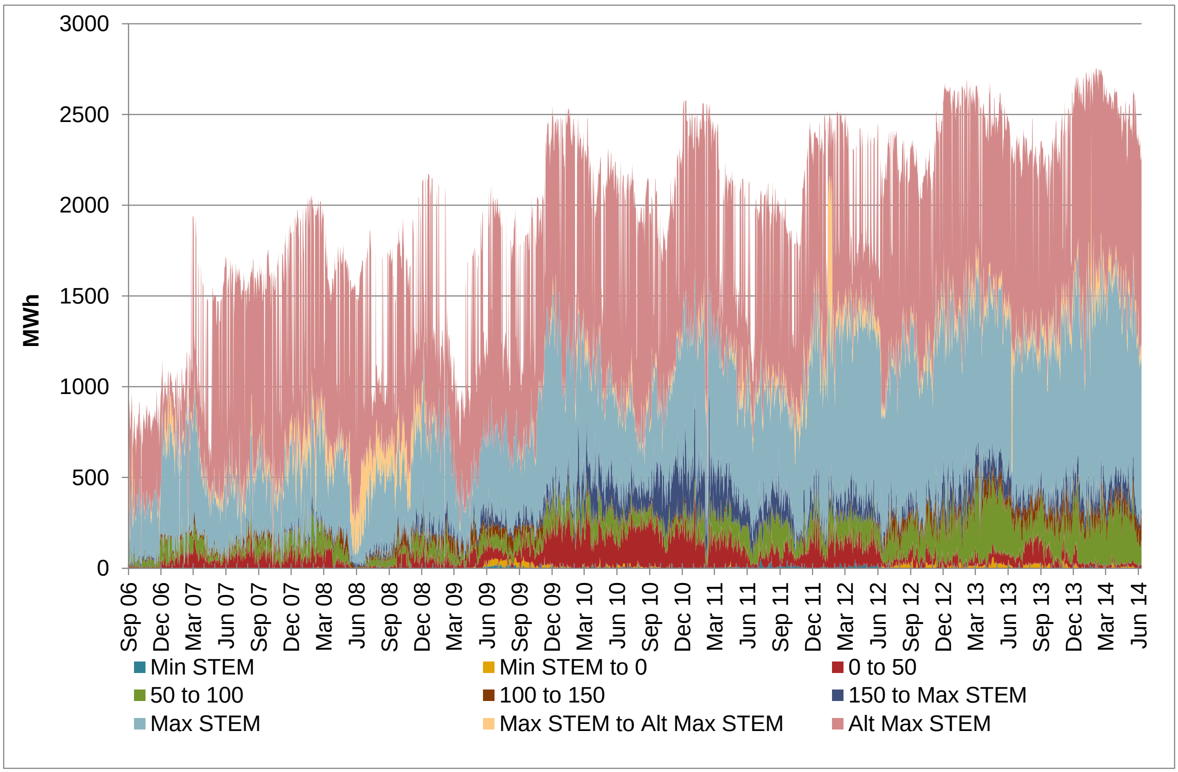
Clause 2.16.2(f) of the Market Rules requires that the MSDC identify all STEM Offers and STEM Bids, including both quantity and price terms.

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 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 12 illustrates the daily average quantity of STEM Offers per Trading Interval for all Market Participants from market commencement until 30 June 2014.

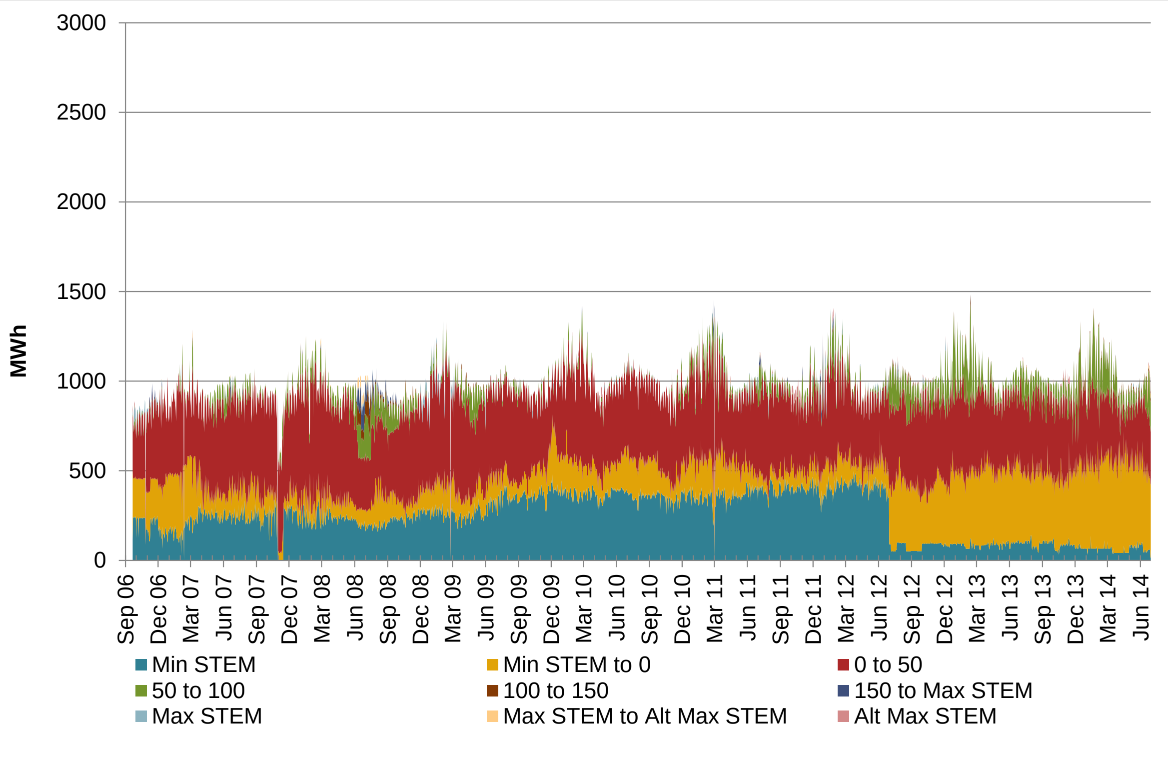
Figure 12 Daily average quantity of STEM Offers (MWh per Trading Interval)



Short Term Energy Market Bids

STEM Bids reflect a decrease in generation or an increase in consumption. Figure 13 illustrates the daily average quantity of STEM Bids per Trading Interval for all Market Participants, from market commencement until 30 June 2014.

Figure 13 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 12 and Figure 13.

3.2.1.5 Short Term Energy Market traded quantities

Although not required under the Market Rules, this section provides information on STEM traded quantities.

Table 3 shows the annual average of STEM traded quantities among Market Participants (cumulative MWh per Trading Interval) for six periods since August 2008, as well as an overall average from market commencement to 30 June 2014.

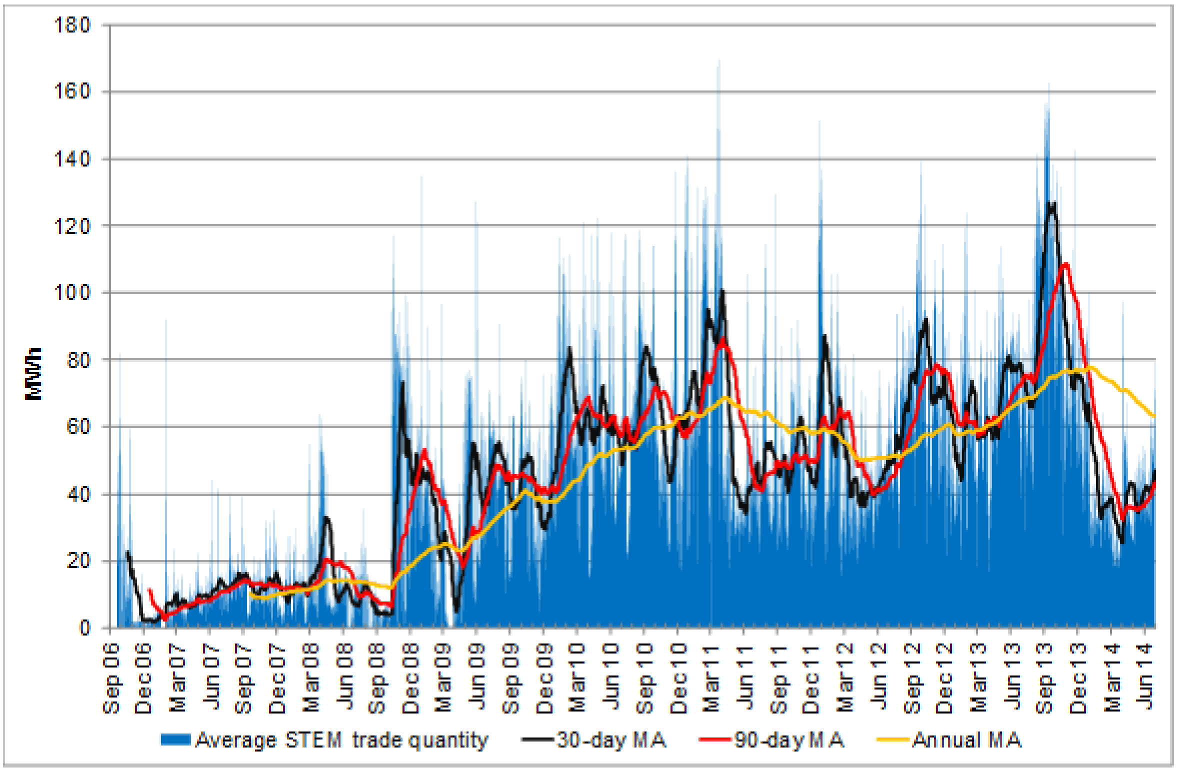
Table 3 Average STEM traded quantities (MWh per Trading Interval)

	1 Aug 08 - 31 Jul 09	1 Aug 09 - 31 Jul 10	1 Aug 10 - 31 Jul 11	1 Aug 11 - 30 Jun 12	1 Jul 12 - 30 Jun 13	1 Jul 13 - 30 Jun 14	Average
STEM traded quantities	32.31	53.60	64.39	50.56	67.82	**63.49**	45.14

Note: 'Average quantities' are for the overall period, i.e., 21 September 2006 to 30 June 2014.

Error! Reference source not found. illustrates daily average quantities traded in the STEM from market commencement until 30 June 2014.

Figure 14 Daily average quantities traded in the STEM (21 September 2006 to 30 June 2014)



In the current reporting period the STEM traded volume has declined from the previous reporting period. The amount of STEM trade was much larger in the first half of the current reporting period (i.e. July 2013 to December 2013) than the second half of the current reporting period (i.e. January 2014 to June 2014).

The greater activity in the STEM in the last six months of 2013 was largely due to the continuation of Synergy selling large quantities of energy in the STEM to Verve Energy. In the last six months of 2013 there was a total of 781,499 MWh of energy traded in the STEM and out of this Synergy sold 428,347 MWh of energy whilst Verve Energy bought 412,697 MWh of energy. IPPs sold 322,694 MWh of energy and bought 356,071 MWh in the last six months of 2013. Synergy bought the remaining 12,731 MWh of energy whilst Verve Energy sold the remaining 30,458 MWh of energy during this period of time.

In the first six months of 2014, there was a total of 330,680 MWh of energy traded in the STEM. Of this, the merged entity sold 82,821 MWh of energy and bought 26,559.3 MWh of energy. The majority of trade was conducted by IPPs, where 247,859 MWh of energy was sold and 304,121 MWh of energy was purchased.

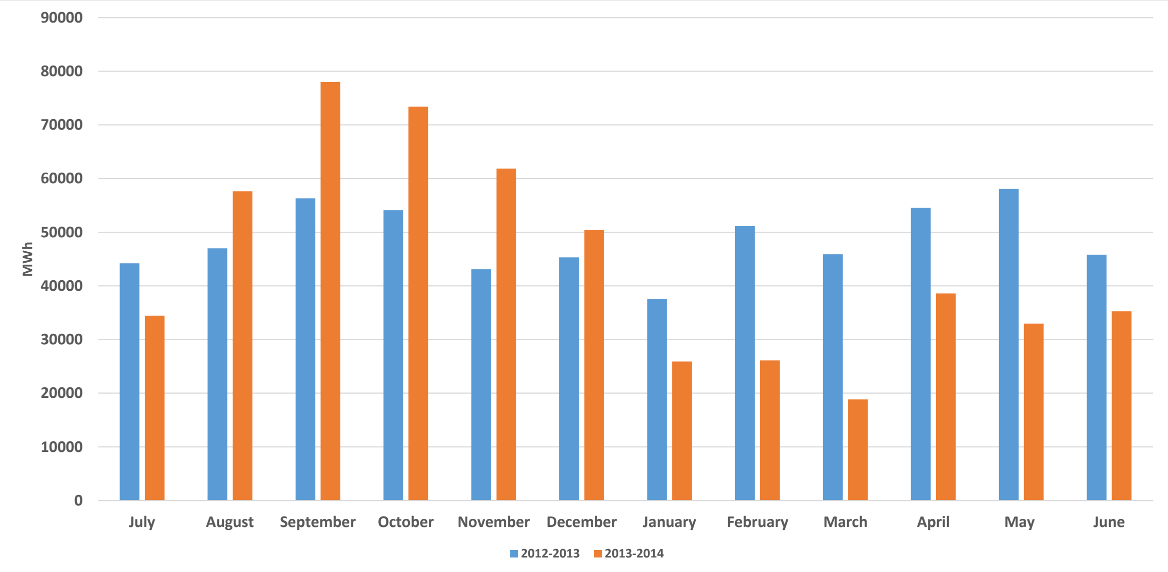
The reduction in quantity traded in the first six months of 2014 is likely to be an effect of the merger between Verve Energy and Synergy whereby the quantity of energy on offer in the Peak periods was lower as a result of the ceasing of the conditions under the Vesting Contract.

The average quantity traded during Peak Intervals during the current reporting period was 52 MWh, compared to 57 MWh traded in the previous reporting period. On average the maximum amount of trade per trading interval in peak periods fell by 10% between 2012/13 to 2013/14. The average quantity traded during Off-Peak Intervals during the current reporting period was 80 MWh, compared to 83 MWh traded in the previous reporting period.

There were larger quantities traded in Peak trading intervals in the July to December 2013 period than the January to June 2014 period. Between July 2013 and December 2013, the average quantity traded during Peak Intervals was 69.05 MWh per trading interval whilst from 1 January 2014 there was a large drop off in trade, with the average quantity traded during Peak intervals decreasing to 34.73 MWh per trading interval. For Off-Peak trading intervals the average quantity traded was more consistent between the July to December period (with an average quantity traded of 77.58 MWh per trading interval) and the January 2014 to June 2014 period (with an average quantity of 81.52 MWh per trading interval).

Figure 15 below compares the quantity traded in peak periods between July 2012 and June 2013 with the period between July 2013 and June 2014.

Figure 15 Quantity traded in peak periods 2012-13 and 2013-14



For each month in the January to June period, the amount of energy traded in peak intervals was higher in the 2012/13 months than those in 2013/14. Aside from July, between the July and December period the amount of energy traded in peak intervals was higher in the 2013/14 months than those in 2012/13.

The 2012/13 period saw 86 trading intervals with over 150 MWh of energy traded in peak trading intervals, whilst in 2013/14 there were 241. All of these 241 instances occurred in the pre-merger period. In the last six months of 2013 there were 1,120 peak trading intervals where STEM trade was over 100 MWh, however this only occurred 78 times in the first six months of 2014.

Figure 16 and Figure 17 show the daily average volume bought and sold in the STEM, respectively, for all Market Participants, from market commencement to 30 June 2014.

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

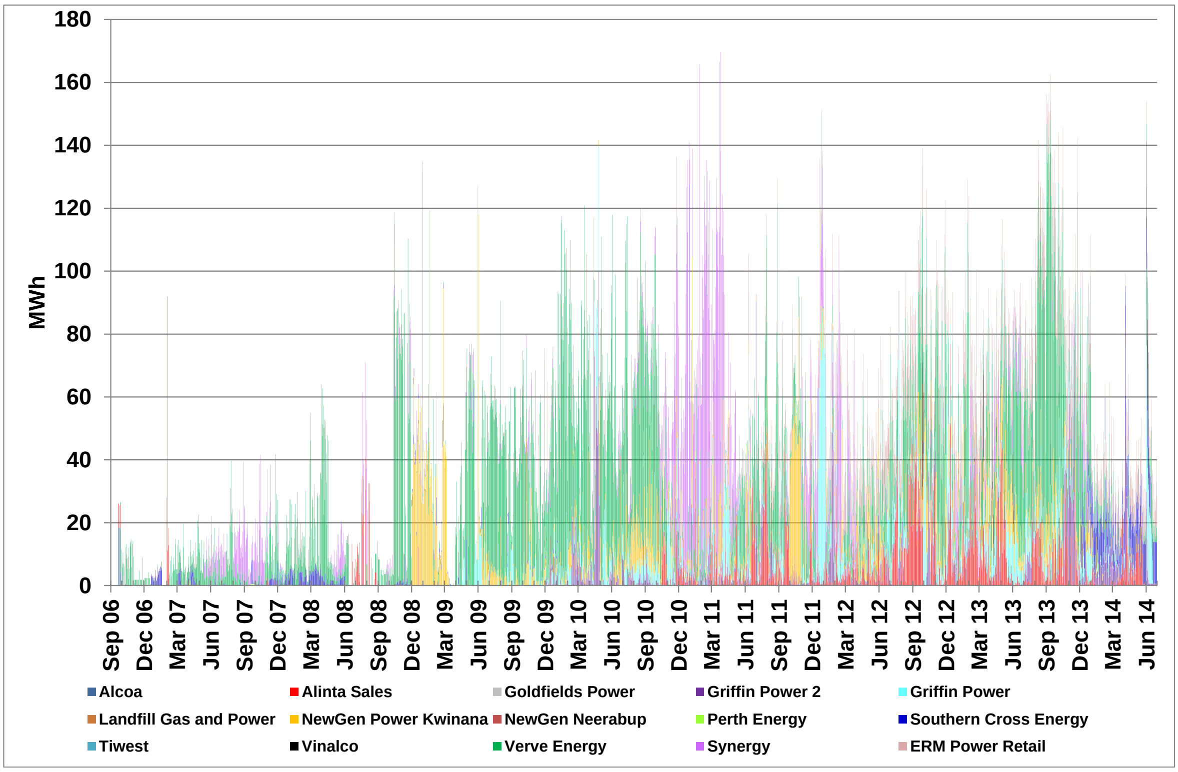
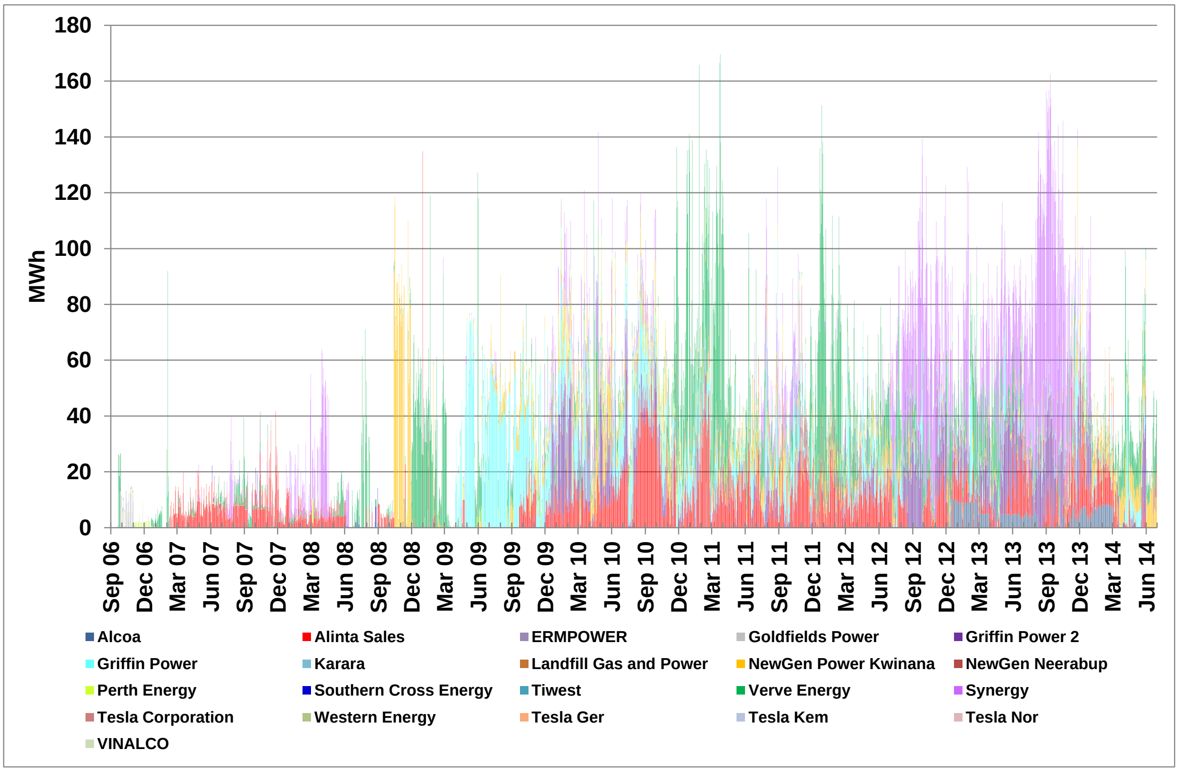


Figure 17 Daily average quantities sold in the STEM (MWh)



3.2.2 Balancing

Clause 2.16.2(g) of the Market Rules (from 1 July 2012) requires that the MSDC includes the Balancing Submissions, associated Balancing Price-Quantity Pairs and Ramp Rate Limits.[15] 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 Competitive Balancing market since 1 July 2012. Clause 2.16.2(hC) of the Market Rules (from 1 July 2012) requires that the MSDC includes any substantial variations in Balancing Prices, Non-Balancing Facility Dispatch Instruction Payments or Balancing Quantities relative to recent past behaviour. This section is provided mainly to fulfil the Authority's obligations for the current Reporting Period from 1 July 2013 to 30 June 2014 under the new Competitive Balancing Mechanism. The Authority has also included the historic data related to the old Balancing Market i.e., pre-1 July 2012.

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.

3.2.2.1 Balancing prices

Balancing enables Market Participants to adjust their Net Contract Position (**NCP**) so that supply equals demand in real-time. System Management, as a Dispatch Operator, will match supply and demand in the system. Since market commencement in 2006 to 30 June 2012, Verve Energy was the sole provider of Balancing. Under this arrangement, System Management would dispatch Verve Energy's facilities for balancing purposes in real-time and Verve Energy would get paid the MCAP for providing any balancing energy deviations[16].

From 1 July 2012, IPP Market Participants have been able to compete to provide balancing services. Final Balancing Prices are based on the Balancing Merit Order (**BMO**) produced by the IMO. The BMO includes all balancing facilities' (i.e. all scheduled and non-scheduled generating facilities apart from those on an approved Planned Outage) price-quantity offers at which that facility is willing to be dispatched. The Final Balancing Prices are published within 48 hours after completion of a Trading Day.

Table 4 sets out the mean and standard deviations of the peak and off-peak MCAP or Final Balancing Price for the following three periods:

- mean and standard deviations of the peak and off-peak MCAP from 1 August 2011 to 30 June 2012.

[15] In the period pre 1 July 2012, Clause 2.16.2(d) of the Market Rules required that the MSDC includes the Balancing Data prices and other Standing Data prices used in Balancing.

[16] IPPs were required to commit and dispatch their facilities to meet their respective day ahead Resource Plans, i.e. 'reflective of NCP'. They were penalised through the application of UDAP and DDAP for deviations from their Resource Plans except when the facilities were dispatched by System Management for system security reasons.

- mean and standard deviations of the peak and off-peak Final Balancing Price 1 July 2012 to 30 June 2013.
- mean and standard deviations of the peak and off-peak Final Balancing Price 1 July 2013 to 30 June 2014.

The patterns of Balancing prices broadly reflect the pattern of STEM Clearing Prices, with higher and more volatile prices during peak periods.

Table 4 Mean and standard deviations of Balancing Prices ($/MWh)

		1Aug11-30Jun12		1Jul12-30Jun13		1Jul13-30-Jun14	
	Trading Interval	Mean	Std Dev	Mean	Std Dev	Mean	Std Dev
MCAP/Final Balancing Price	Off-Peak	22.79	31.18	34.24	36.07	**44.93**	**20.60**
	Peak	47.99	47.43	59.44	58.21	**65.68**	**22.54**

Figure 18 and Figure 19 illustrate average daily peak and off-peak period Balancing Prices for each Trading Day, from market commencement to 30 June 2014.

Figure 18 Daily average Balancing prices (Peak Trading Intervals, 21 September 2006 to 30 June 2014)

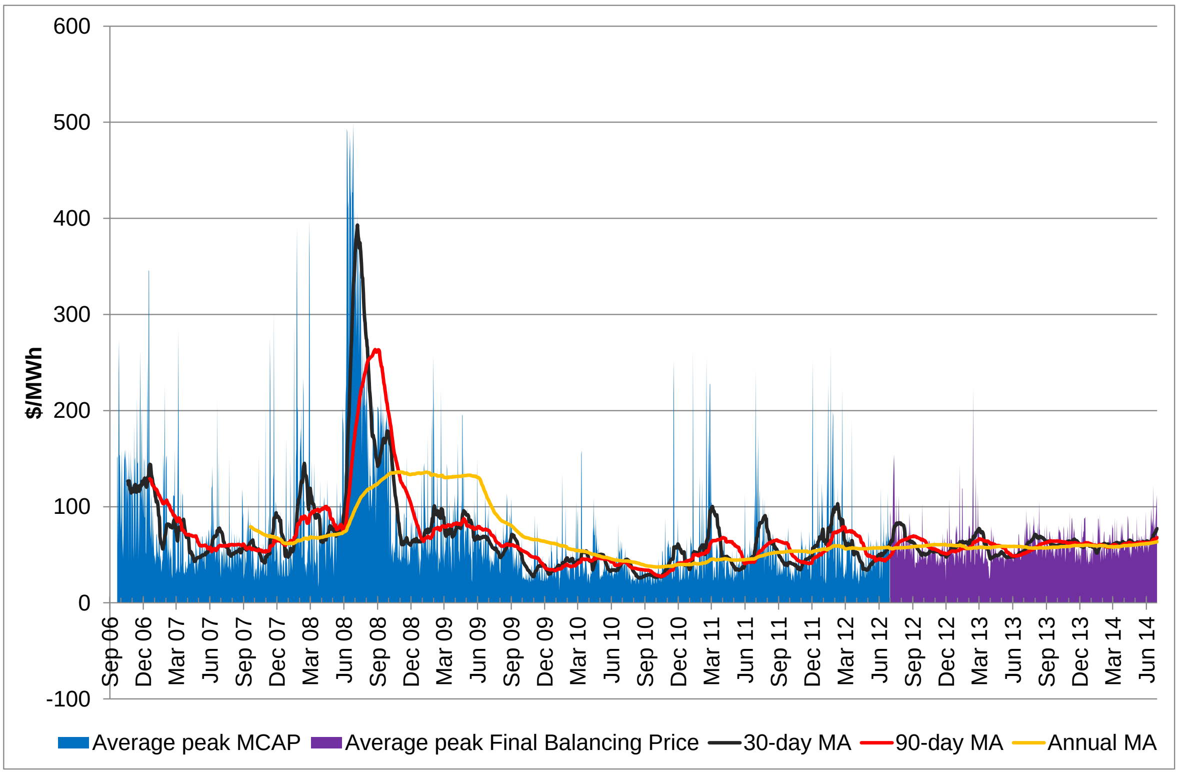


Figure 19: Daily average Balancing prices (Off-Peak Trading Intervals, 21 September 2006 to 30 June 2014)

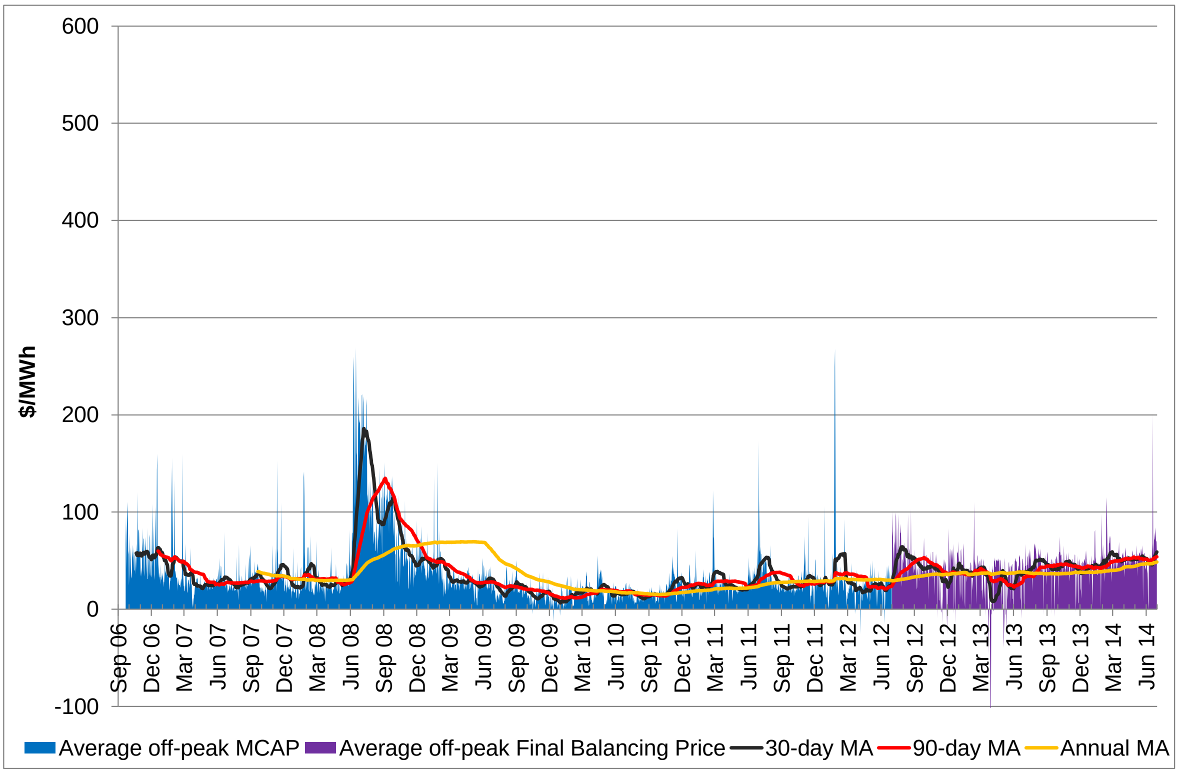


Figure 20 and Figure 21 illustrate average daily peak and off-peak period Balancing Prices for each Trading Day, from market commencement to 30 June 2014.

Figure 20 Peak Trading Intervals Final Balancing Prices (1 July 2011 to 30 June 2014)

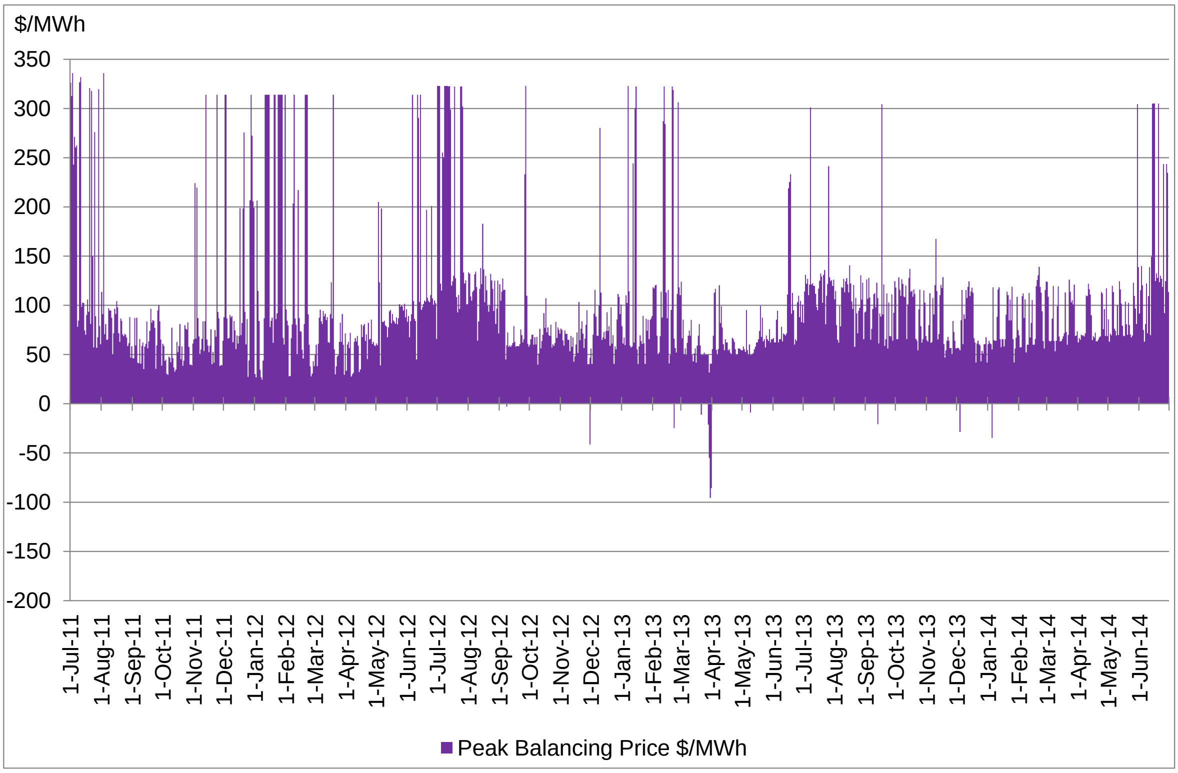
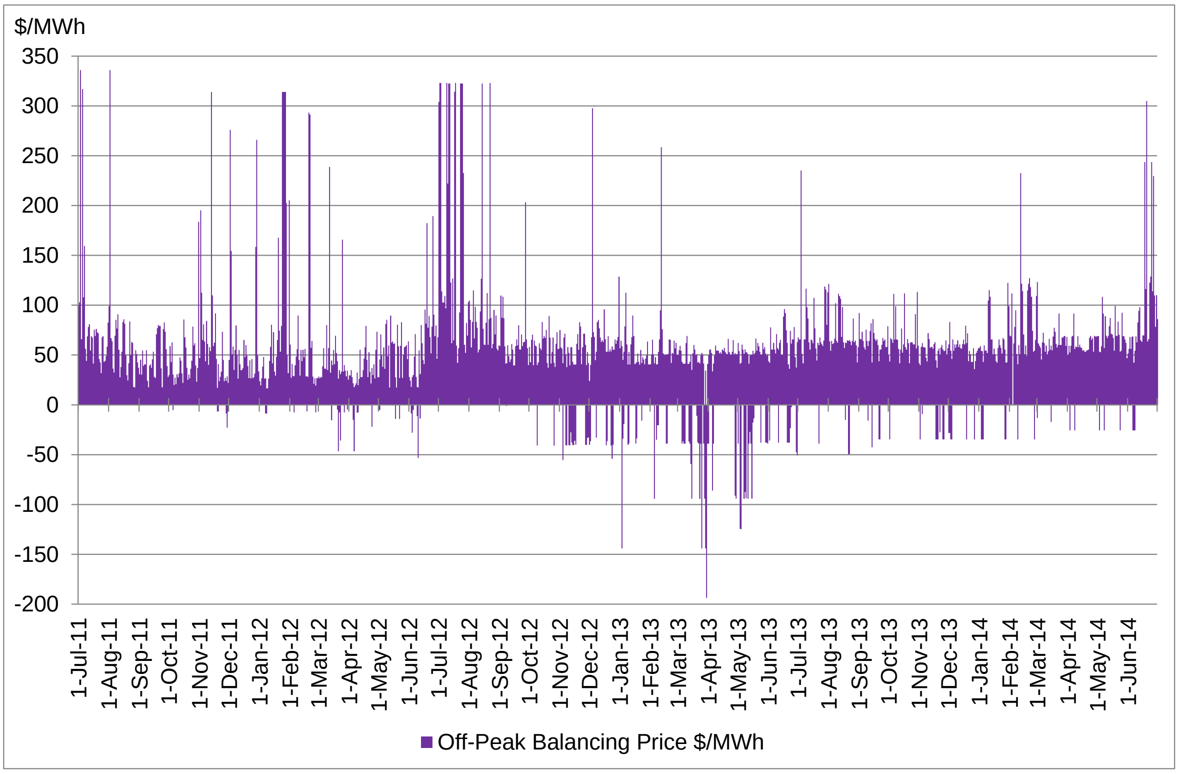


Figure 21 Off-Peak Trading Intervals Final Balancing Prices (1 July 2011 to 30 June 2014)



3.2.2.2 Volatility of Balancing prices

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) from market commencement to 30 June 2014 of MCAP/ Final Balancing prices are illustrated in Figure 22 and Figure 23.

Figure 22 Summary statistics for MCAP/ Final Balancing Price during Peak Trading Intervals (per calendar month)

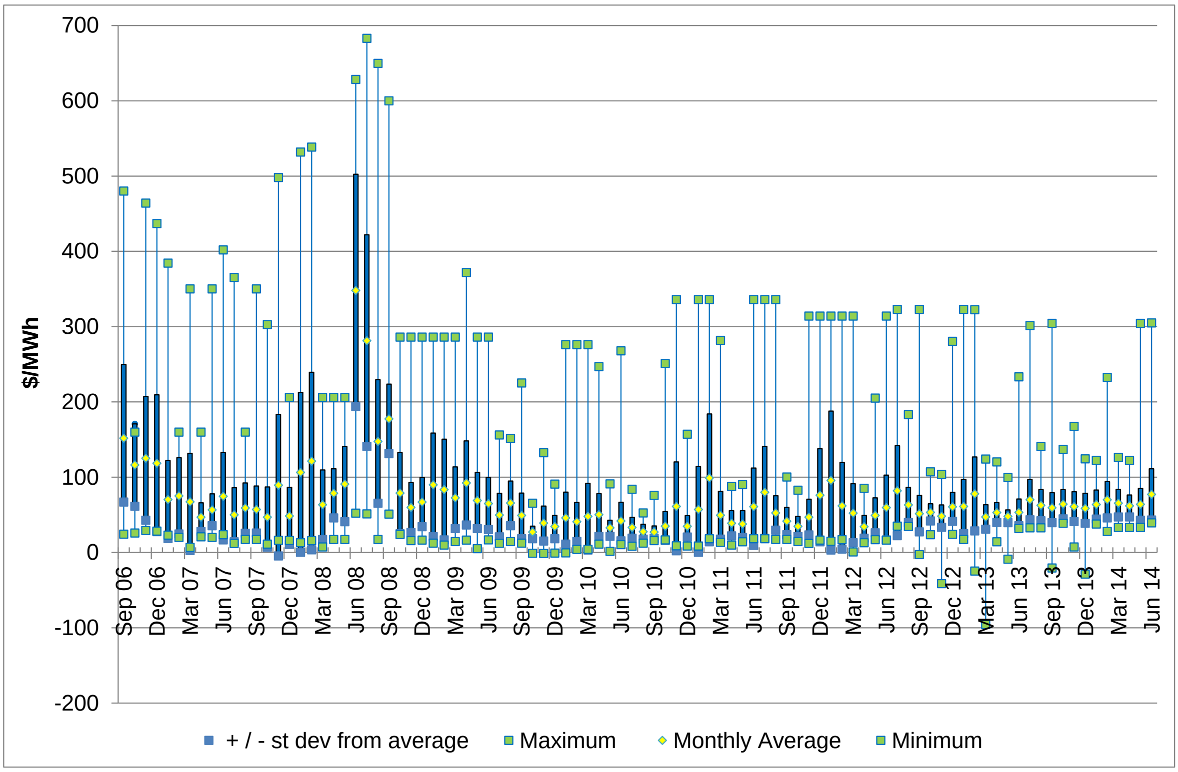
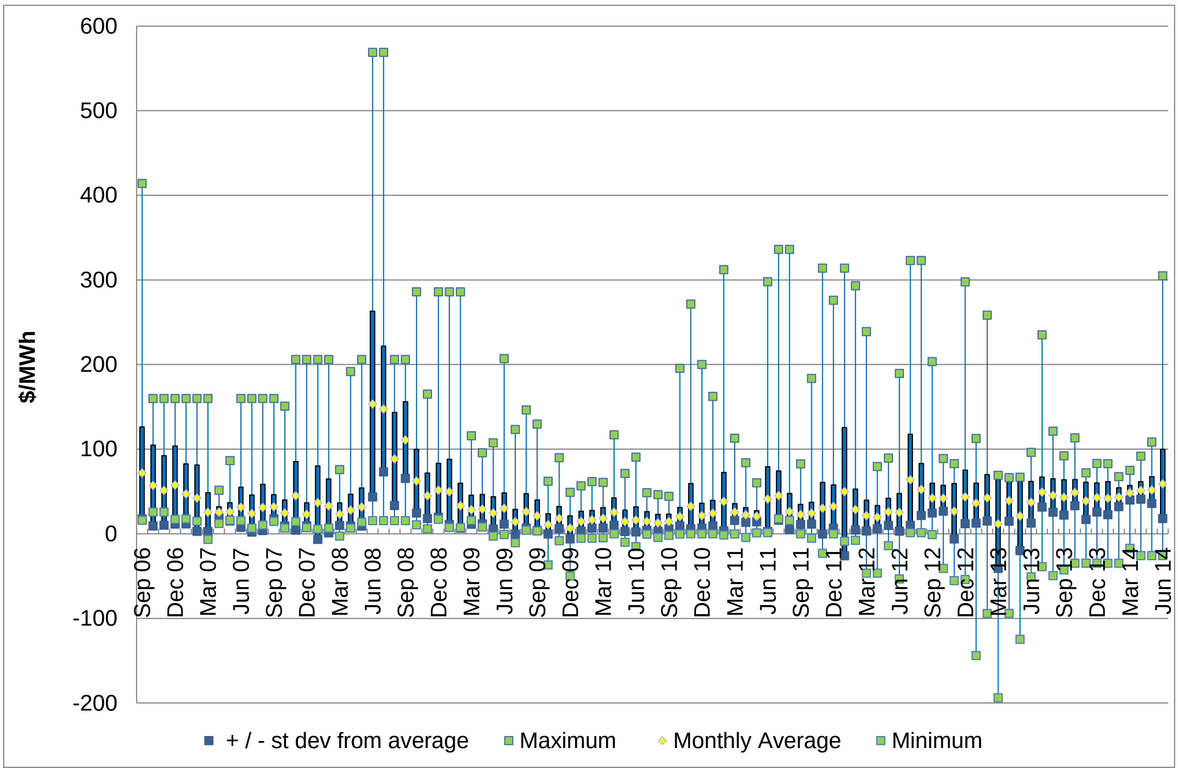


Figure 23 Summary statistics for MCAP/ Final Balancing Price during Off-Peak Trading Intervals (per calendar month)



3.2.2.3 *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 24 illustrates the proportion of Peak Trading Intervals and Off-Peak Trading Intervals during which MCAP/ Final Balancing prices were at the Maximum STEM Price.

Figure 24 Proportion of Trading Intervals MCAP/Final Balancing prices at Maximum STEM Price (per calendar month)

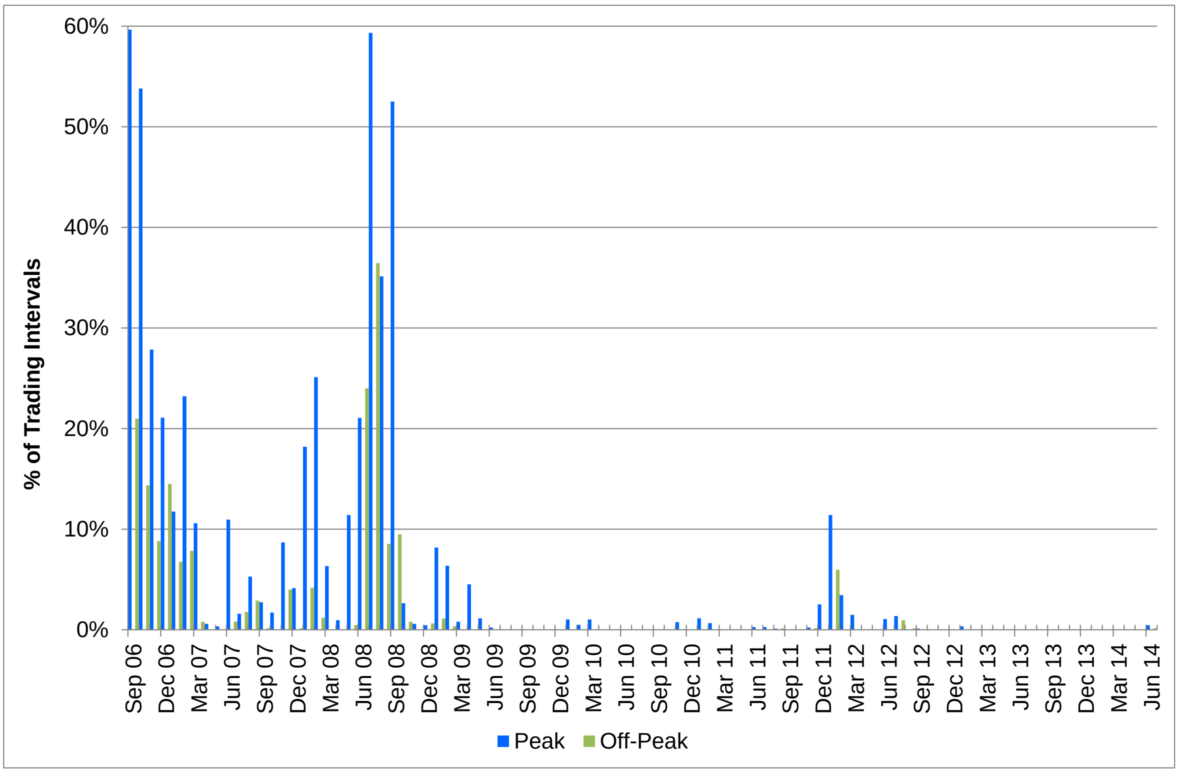


Figure **25** illustrates the proportion of peak and off-peak periods during which MCAP/Final Balancing prices were at the Alternative Maximum STEM Price.

Figure 25 **Proportion of Trading Intervals MCAP/Final Balancing prices at Alternative Maximum STEM Price (per calendar month)**

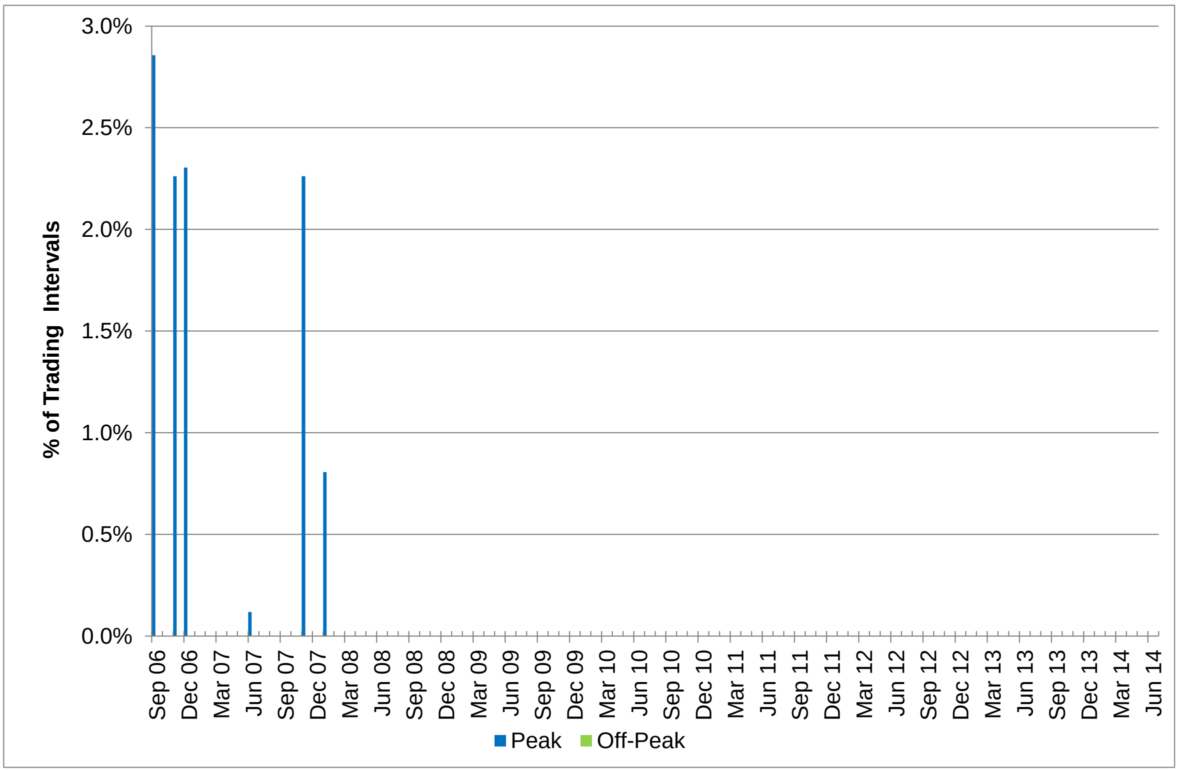
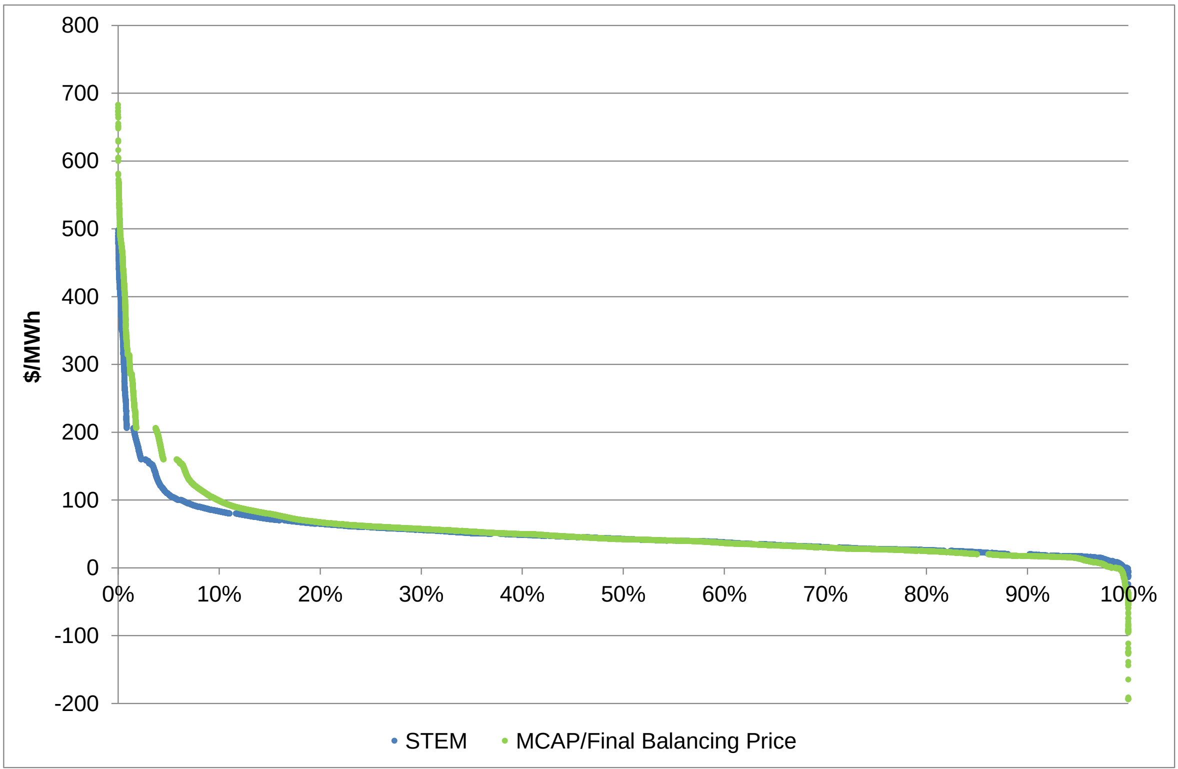


Figure 26 shows the Price duration curves for STEM clearing prices and Balancing prices from market commencement to 30 June 2014.

Figure 26 Price duration curves for STEM Clearing Prices and Balancing Prices (21 September 2006 to 30 June 2014)



3.3 Retail sector

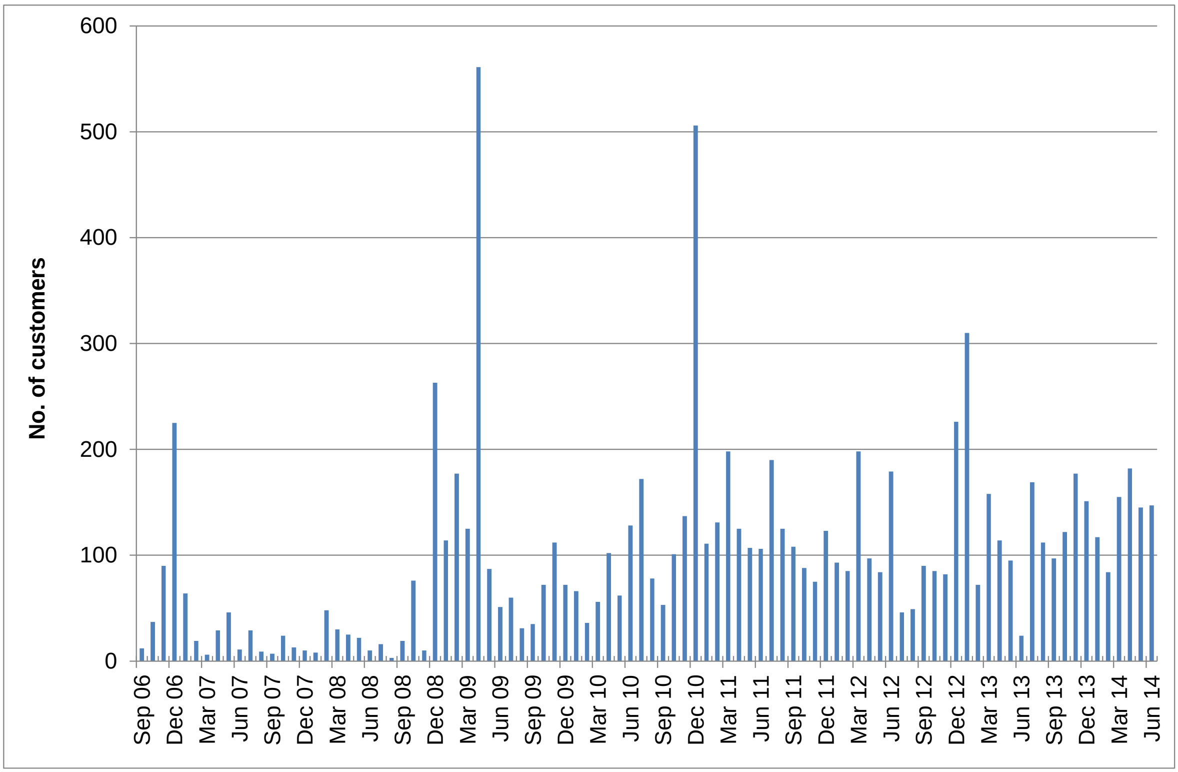
3.3.1 Number of customers changing retailer

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 lack of specific plans to extend competition in the retail electricity market has been a concern raised by the Authority since the market commenced. The Authority notes that this matter is being considered as part of the EMR.

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 2014.

Figure 27 illustrates levels of customer transfer[17] in the contestable section of the electricity market in the SWIS since market commencement.

Figure 27 Number of customers changing retailer (customers per month)



[17] Customer churn is measured by the number of National Meter Identifiers (NMIs) transferred between retailers.

3.4 Surveillance items

3.4.1 Fuel Declarations

A Market Participant submitting a STEM Submission must include a Fuel Declaration.[18] Clause 2.16.2(gA)i 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 5 below details Fuel Declarations for the last three Capacity Years.

[18] See clause 6.6.1 of the Market Rules.

Table 5 Fuel Declarations (last three Capacity Years)

Participant	Resource Name	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	Liquid declaration 2012/13 Cap Year	Non-liquid declaration 2012/13 Cap Year	Liquid declaration 2013/14 Cap Year	Non-liquid declaration 2013/14 Cap Year
Alcoa	ALCOA_KWI								
Alcoa	ALCOA_PNJ								
Alcoa	ALCOA_WGP	36.7%							
Alinta	ALINTA_WGP_AGG	1.6%	20.8%						
Alinta	ALINTA_WGP_GT	8.3%	69.0%	20.3%	79.7%		100.0%		100.0%
Alinta	ALINTA_WGP_U2	6.9%	70.3%	20.0%	80.0%		100.0%		100.0%
Goldfields Power	PRK_AG	97.9%	1.8%	100.0%		98.3%	1.7%	99.7%	
NewGen Neerabup	NEWGEN_NEERABUP_GT1				30.9%		100.0%		100.0%
Perth Energy	PERTHENERGY_KWINANA_GT1	99.7%		100.0%		100.0%		100.0%	
Southern Cross	STHRNCRS_EG								
Verve Energy	KEMERTON_GT11	1.1%	98.6%		100.0%		100.0%		99.7%
Verve Energy	KEMERTON_GT12	1.1%	98.6%		100.0%		100.0%		99.7%
Verve Energy	KWINANA_G3								
Verve Energy	KWINANA_G4								
Verve Energy	KWINANA_G5	1.1%	98.6%	0.3%	99.7%		94.1%		90.4%
Verve Energy	KWINANA_G6		99.5%		71.2%		75.5%		91.8%
Verve Energy	KWINANA_GT1	99.7%		100.0%		100.0%		99.7%	
Verve Energy	KWINANA_GT2				30.1%		100.0%		99.7%
Verve Energy	KWINANA_GT3				38.8%		100.0%		99.7%
Verve Energy	PINJAR_GT1	0.3%	99.5%	0.3%	99.7%		100.0%		99.7%
Verve Energy	PINJAR_GT2	99.2%	0.6%	99.7%	0.3%	100.0%		99.7%	
Verve Energy	PINJAR_GT3	0.6%	99.2%	0.3%	99.7%		100.0%		99.7%
Verve Energy	PINJAR_GT4	99.2%	0.6%	99.5%	0.5%	100.0%		99.7%	
Verve Energy	PINJAR_GT5	0.6%	99.2%	0.3%	99.7%		100.0%		99.7%
Verve Energy	PINJAR_GT7	99.2%	0.6%	99.5%	0.5%	100.0%		99.7%	

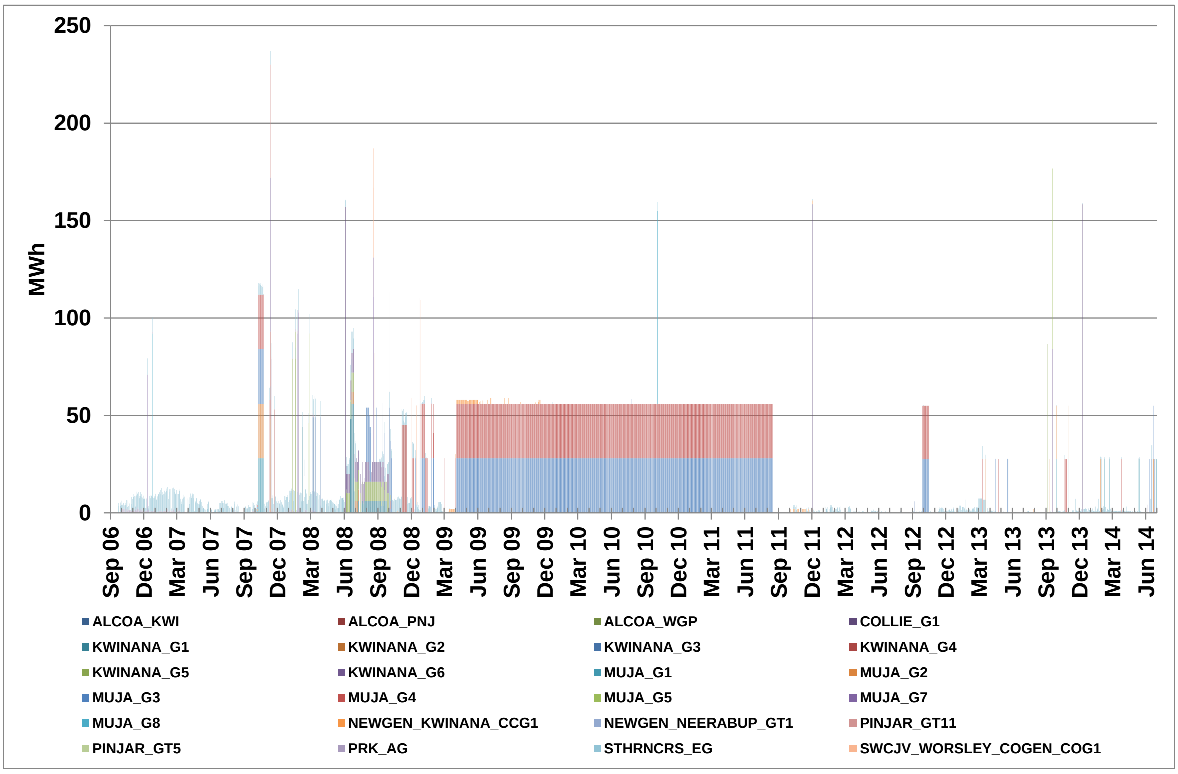
3.4.2 Availability Declarations

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.[19]

Figure 28 below details the daily average Availability Declarations since market inception.

Figure 28 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

[19] 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.

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.

Table 6 sets out the proportion of Trading Intervals for which a Facility was actually available to a greater extent than set out in a STEM Submission during the 2011/12 through 2013/14 Capacity Years.

Table 6 Proportion of Trading Intervals for which actual output exceeds Availability Declarations (last three Capacity Years)

Participant	Resource Name	Cold season 2011/12 Cap Year	Hot season 2011/12 Cap Year	Intermediate season 2011/12 Cap Year	Cold season 2012/13 Cap Year	Hot season 2012/13 Cap Year	Intermediate season 2012/13 Cap Year	Cold season 2013/14 Cap Year	Hot season 2013/14 Cap Year	Intermediate season 2013/14 Cap Year
Alcoa	ALCOA_WGP	2.31%		9.29%	5.98%	2.41%	0.33%	1.81%		1.88%
Alinta Sales	ALINTA_PNJ_U1	1.50%			0.03%		0.01%	3.26%		
Alinta Sales	ALINTA_PNJ_U2	1.50%					0.90%	1.53%		4.54%
Alinta Sales	ALINTA_WGP_U2				0.10%			0.01%		
Alinta Sales	ALINTA_WGP_GT							0.38%		
Blair Fox Pty Ltd	BLAIRFOX_WESTHILLS_WF3							0.02%		
Collgar Wind Farm	INVESTEC_COLLGAR_WF1	0.06%		16.97%	0.20%	0.21%	0.01%			
Goldfields Power	PRK_AG	0.02%		0.14%		0.03%	0.02%	0.01%		0.07%
Greenough River	GREENOUGH_RIVER_PV1	0.38%								
Griffin Power 2	BW2_BLUEWATERS_G1	1.53%				0.03%	0.02%	0.02%	0.03%	0.61%
Griffin Power	BW1_BLUEWATERS_G2	0.02%	1.50%			0.10%	0.01%	0.08%	0.22%	0.48%
Landfill Gas and Power	KALAMUNDA_SG	0.02%	0.09%		0.07%			0.02%		0.07%
Landfill Gas and Power	RED_HILL							0.07%		37.43%
Landfill Gas and Power	TAMALA_PARK	7.99%	32.17%							
Merredin	NAMKKN_MERR_SG1	0.06%				0.03%	0.07%	0.03%		0.10%
Mount Barker	SKYFARM_MTBARKER_WF1	0.03%						0.02%		
NewGen Power Kwinana	NEWGEN_KWINANA_CCG1	0.18%		6.22%			0.11%	0.27%	0.05%	0.07%
NewGen Neerabup	NEWGEN_NEERABUP_GT1		0.31%	0.10%			0.02%	0.41%	0.03%	
Perth Energy	ATLAS									
Perth Energy	ROCKINGHAM						15.91%			
Perth Energy	SOUTH_CARDUP	1.58%		0.34%	0.03%					
Southern Cross Energy	STHRNCRS_EG					0.03%				
Tesla	TESLA_GERALDTON_G1	0.01%			3.24%	2.82%	0.38%	0.02%	0.02%	
Tesla	TESLA_KEMERTON_G1							0.12%	0.03%	
Tesla	TESLA_NORTHAM_G1							0.01%	0.05%	
Tesla	TESLA_PICTON_G1	0.01%	0.02%	0.10%			0.01%	0.16%	0.05%	
Tiwest	TIWEST_COG1	0.03%	0.14%	0.00%	0.03%	0.96%	0.06%	0.17%		0.10%

Participant	Resource Name	Cold season 2011/12 Cap Year	Hot season 2011/12 Cap Year	Intermediate season 2011/12 Cap Year	Cold season 2012/13 Cap Year	Hot season 2012/13 Cap Year	Intermediate season 2012/13 Cap Year	Cold season 2013/14 Cap Year	Hot season 2013/14 Cap Year	Intermediate season 2013/14 Cap Year
Verve Energy	ALBANY_WF1	0.01%	0.26%							
Verve Energy	COCKBURN_CCG1	10.29%	1.28%	8.23%	2.32%		5.59%	12.67%	2.74%	24.15%
Verve Energy	COLLIE_G1	0.79%	1.83%	0.79%	0.41%	2.98%	0.74%	1.02%	0.55%	3.72%
Verve Energy	GERALDTON_GT1	0.06%		0.24%		0.03%				0.03%
Verve Energy	KEMERTON_GT11	1.50%	0.72%	0.55%	0.20%	0.55%	0.98%	0.35%	0.40%	0.38%
Verve Energy	KEMERTON_GT12	0.57%	3.31%	0.79%	0.07%	0.33%	0.11%	0.92%	0.24%	0.24%
Verve Energy	KWINANA_G1									
Verve Energy	KWINANA_G2									
Verve Energy	KWINANA_G4									
Verve Energy	KWINANA_G5	1.71%	0.67%	1.02%	0.07%	0.31%	0.73%	0.03%		
Verve Energy	KWINANA_G6	0.55%	0.97%	0.14%	0.07%		0.22%	0.02%	0.03%	
Verve Energy	KWINANA_GT1		0.05%		0.07%		0.07%			
Verve Energy	KWINANA_GT2	1.63%			0.79%	1.12%	0.86%	0.40%	0.26%	0.24%
Verve Energy	KWINANA_GT3	1.98%			0.79%	4.67%	2.54%	1.55%	0.09%	0.44%
Verve Energy	MUJA_G5	13.35%	16.12%	13.59%	4.68%	3.00%	2.34%	0.03%		2.49%
Verve Energy	MUJA_G6		3.53%	7.41%	0.03%	12.24%	9.64%	0.20%		1.64%
Verve Energy	MUJA_G7	3.01%	3.33%	6.39%	0.14%	0.29%	1.05%	1.38%	0.98%	0.41%
Verve Energy	MUJA_G8	0.68%	3.69%	4.34%	2.05%	0.33%	0.58%	1.48%	0.84%	0.03%
Verve Energy	MUNGARRA_GT1	0.01%			0.61%		0.17%	0.52%	0.03%	
Verve Energy	MUNGARRA_GT2	0.44%		0.10%	0.44%		0.72%	0.40%	0.14%	
Verve Energy	MUNGARRA_GT3	0.03%				0.02%	0.09%	0.07%	0.29%	
Verve Energy	PINJAR_GT1	0.01%					0.22%	0.02%		
Verve Energy	PINJAR_GT10	0.66%	0.24%	0.65%	0.17%	0.12%	0.09%	0.71%	0.05%	0.03%
Verve Energy	PINJAR_GT11	0.58%	1.37%			0.02%	0.02%	0.06%	0.09%	0.07%
Verve Energy	PINJAR_GT2	0.03%						0.01%		
Verve Energy	PINJAR_GT3	0.03%	0.26%			0.02%	0.01%	0.02%	0.02%	
Verve Energy	PINJAR_GT4	0.60%	0.03%			0.07%	0.02%	0.02%	0.02%	
Verve Energy	PINJAR_GT5	0.02%	0.02%			0.19%	0.09%	0.02%		

Participant	Resource Name	Cold season 2011/12 Cap Year	Hot season 2011/12 Cap Year	Intermediate season 2011/12 Cap Year	Cold season 2012/13 Cap Year	Hot season 2012/13 Cap Year	Intermediate season 2012/13 Cap Year	Cold season 2013/14 Cap Year	Hot season 2013/14 Cap Year	Intermediate season 2013/14 Cap Year
Verve Energy	PINJAR_GT7	0.01%	0.05%			0.03%	0.01%	0.03%		
Verve Energy	PINJAR_GT9	1.05%	0.22%	0.10%	0.65%		0.18%	0.10%		0.61%
Verve Energy	PPP_KCP_EG1	7.22%	6.20%	9.12%	9.97%	0.59%	21.99%	30.78%	1.20%	12.40%
Verve Energy	SWCJV_WORSLEY_COGEN_COG1	91.80%	59.17%	87.19%	88.70%	59.21%	94.57%	80.02%	41.56%	65.47%
Verve Energy	WEST_KALGOORLIE_GT2		0.02%			0.03%	0.06%	0.03%		
Verve Energy	WEST_KALGOORLIE_GT3		0.03%		0.24%					
Vinalco	MUJA_G1							0.06%	0.24%	0.1%
Vinalco	MUJA_G2							0.83%	0.15%	
Vinalco	MUJA_G3					7.28%	3.71%	0.01%	1.27%	
Vinalco	MUJA_G4	0.07%				23.64%	7.18%	0.01%	0.03%	0.03%

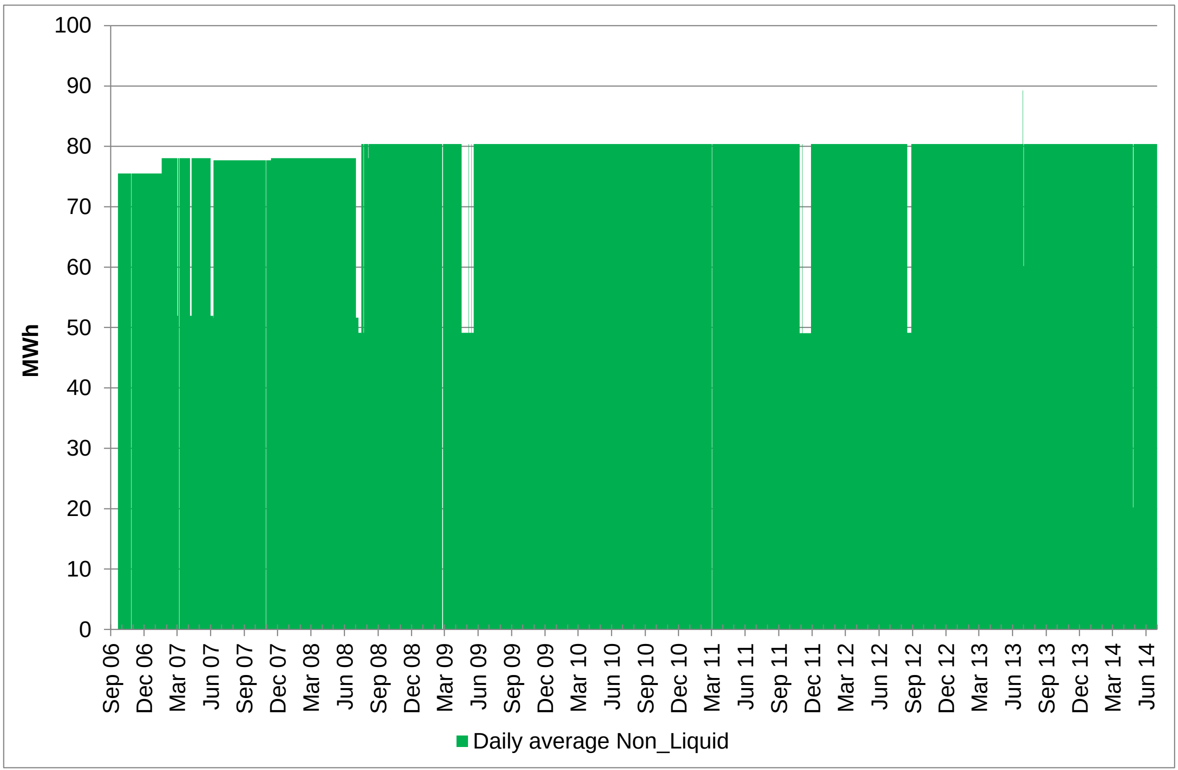
*Blanks in the above table denote no values to be reported in respective category.

3.4.3 Ancillary Service Declarations

A Market Participant that is a provider of Ancillary Services must include an Ancillary Services Declaration in its STEM Submission.[20] 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.

Up until March 2013, Verve Energy was the only Market Participant providing Ancillary Services and therefore the only Market Participant required to make an Ancillary Services declaration. Subsequent to the introduction of NewGen into the LFAS market, Rule Change RC_2013_06 was introduced, relating to the exclusion of LFAS Quantities from Daily Ancillary Service Files. This Rule Change resulted in a removal of the obligation on System Management to include LFAS in the Ancillary Service estimate each Scheduling Day. Figure 29 below displays the Daily average Ancillary Services declarations since market commencement.

Figure 29 Daily average Ancillary Services declarations (MWh per Trading Interval)



3.4.4 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.

[20] 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.

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

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

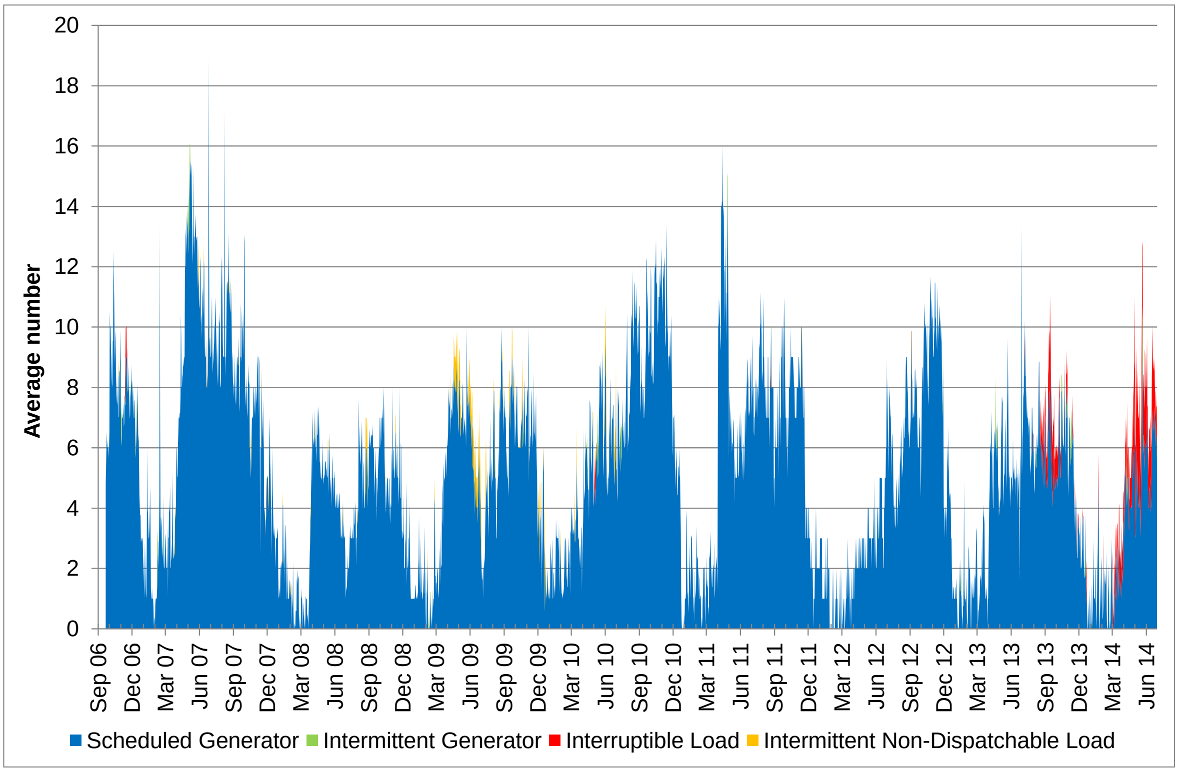


Figure 31 illustrates the accompanying MWh quantity of Planned Outages.

Figure 31 Quantity of energy subject to Planned Outage (cumulative daily average MWh per facility)

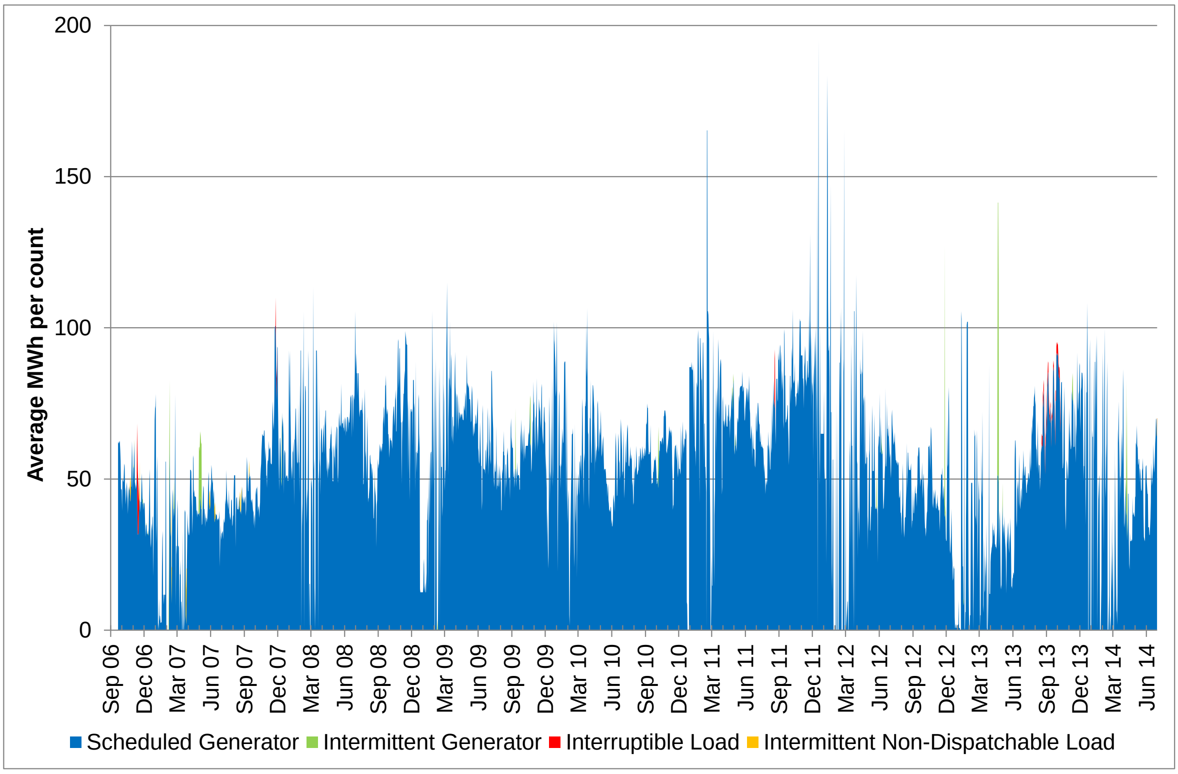


Figure 32 illustrates the daily average number of units subject to Forced Outages per Trading Interval.

Figure 32 Number of Facilities on Forced Outages (cumulative daily average)

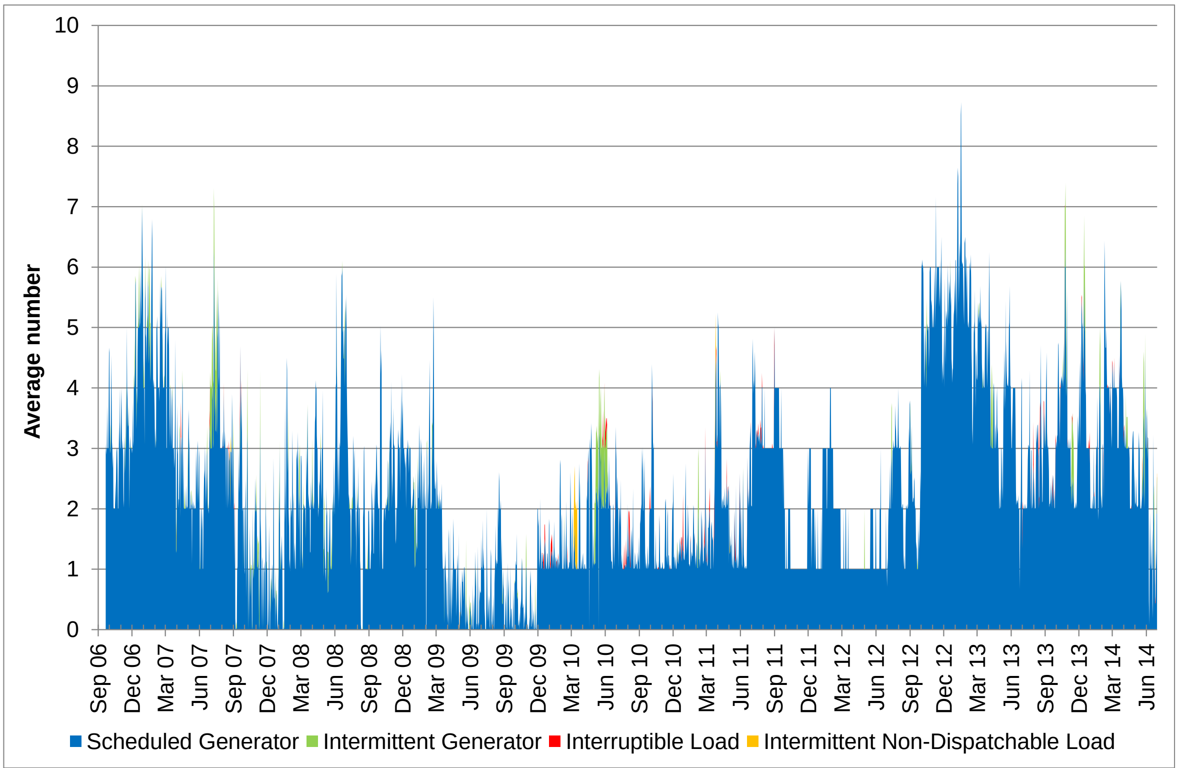


Figure 33 illustrates the accompanying MWh quantity of Forced Outages.

Figure 33 Quantity of energy subject to Forced Outage (cumulative daily average MWh per Trading Interval)

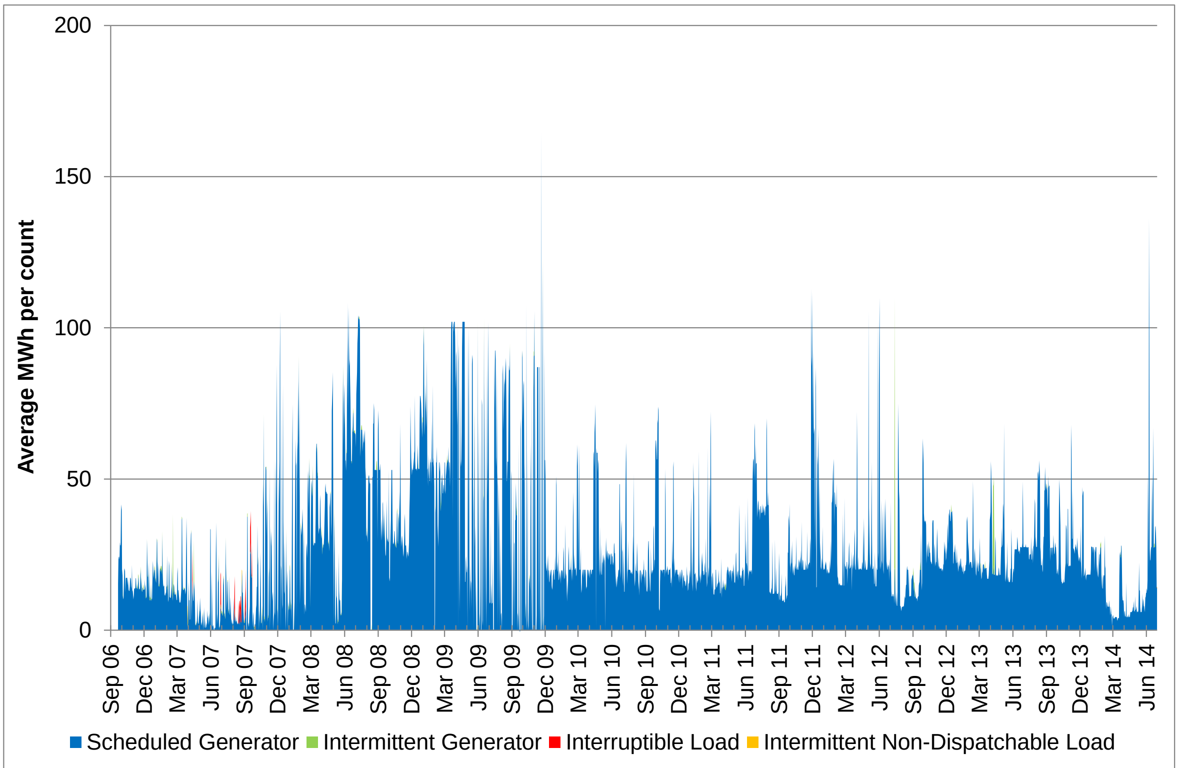
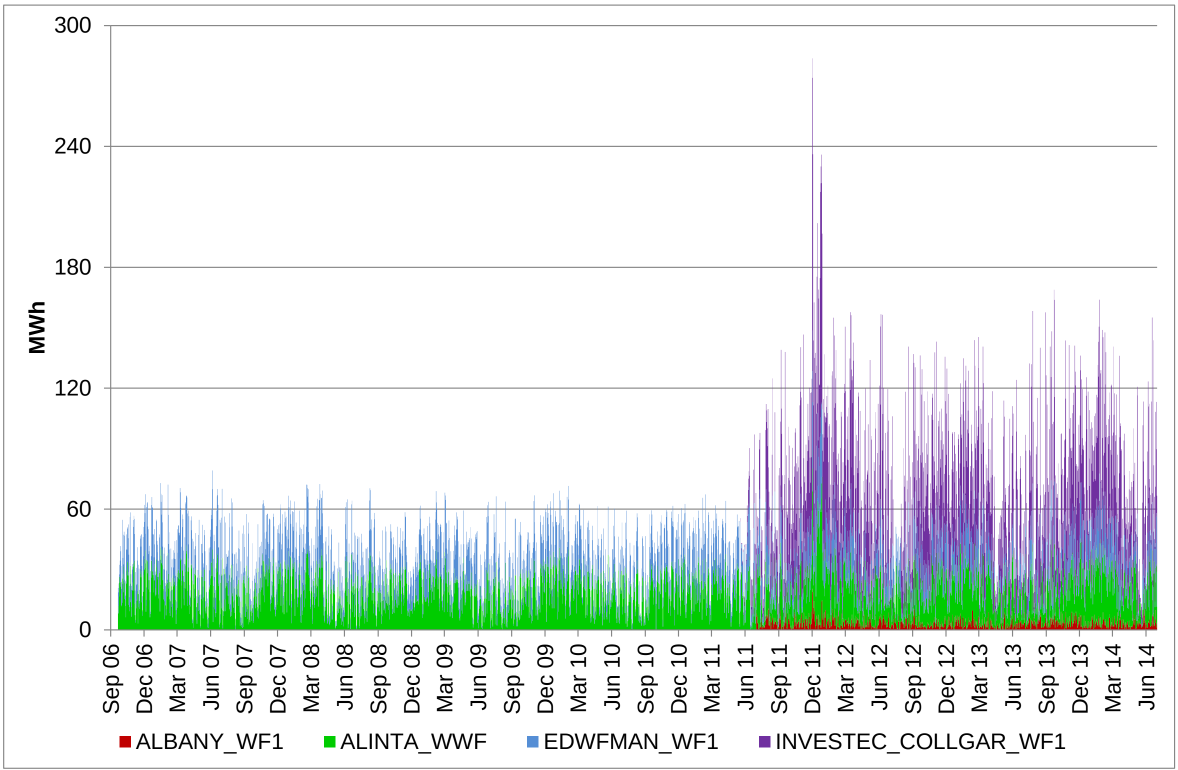


Figure 34 WindFarm Generation (cumulative daily average MWh per Trading Interval)



3.5 Other information

3.5.1 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 1 October 2014 the following participants were registered with the IMO:

- 37 entities registered as Market Generators only. There were no new participants in this category during the current reporting period;
- 19 entities registered as Market Customers only. There were four new participants in this category in this reporting period, which are A Star Electricity, Amanda Energy Pty Ltd, Blue Star Energy Ltd and Community Electricity; and
- 12 entities registered as both Market Generators and Market Customers.

This is a total of 68 registered entities.

In addition to these Market Generators and Market Customers, there was one entity registered as a Network Operator which was Western Power.

3.5.2 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.[21]

Information on Market Rule changes that have commenced, been rejected or are under development is available on the IMO's website. Table 77 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 2014.

Table 7 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[22]	-	-	-
1 August 2007 and 31 July 2008	36	36[23]	-	-	-
1 August 2008 and 31 July 2009	37	24[24]	-	3	10
1 August 2009 and 31 July 2010	19	15[25]	2	1	1
1 August 2010 and 31 July 2011	29	25[26]	2	-	2
1 August 2011 and 30 June 2012	13	10[27]	-	1	2
1 July 2012 and 30 June 2013	23	19[28]	-	2	2
1 July 2013 and 30 June 2014	12	7[29]	-	1	4

[21] 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.

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

[23] All of which have commenced.

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

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

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

[27] As at the time the 2012 Report to the Minister was released.

[28] As at the time the 2013 Report to the Minister was released.

[29] As at the time the 2014 Report to the Minister Discussion Paper was released.