Public Version

2010 Annual Wholesale Electricity Market Report for the Minister for Energy

14 June 2011

Economic Regulation Authority

WESTERN AUSTRALIA

Economic Regulation Authority
Perth, Western Australia
Phone: (08) 9213 1900

Contents

List of Tables

List of Figures

Executive summary

The electricity market in the South West of Western Australia is at a cross-road.

The market that has been established thus far has been adequate for its purpose and relatively successful. Over the past five years, a number of new entrants have become established in the market, providing new generation capacity of over 1,000 MW out of an overall capacity of 6,000 MW, with an estimated investment value of $2.6 billion. As a result, Verve Energy's market share (in terms of certified capacity) has reduced from 77 per cent in 2007 to 60 percent in 2010.

The Authority is observing increased trade volumes in the Short Term Energy Market and greater bilateral contracting activities between market participants other than Verve Energy and Synergy.

However, there are issues that are limiting the progression to a competitive electricity market.

The market is still dominated by Verve Energy and Synergy. Synergy's market share (in terms of energy sold) has remained steady in recent years, at around 80 per cent.

The Authority has concerns about the Replacement Vesting Contract between Synergy and Verve Energy. This contract lacks the pro-competitive features included in the original Vesting Contract, in particular the Displacement Mechanism and the associated information provision by Synergy to the market, i.e. the Displacement Statement of Opportunities. A significant proportion of new generation investment over recent years has been effectively underwritten by Synergy under the Displacement Mechanism.[1] However, there is no such mechanism for private sector generation to tender for Synergy's load under the Replacement Vesting Contract. This will affect further private investment in electricity generation in the South West interconnected system (**SWIS**).

The State Government's deregulation and reforms in the electricity sector were successful in creating an attractive environment to private sector investment in the SWIS. New generating capacity has been introduced by Alinta, ERM Power and Griffin Energy mainly as a result of Western Power/Synergy procurement programs.

The displacement of Synergy's pre-market contracted capacity with Verve Energy under the original Vesting Contract Displacement Mechanism has been conducted in a competitive manner, with neutral treatment to all bidders, including Verve Energy. Verve Energy has been successful in the tenders for the supply of capacity as part of the 2008 supply procurement program and subsequent procurement programs.

The Authority notes that the Wholesale Electricity Market established in the SWIS includes a Reserve Capacity Mechanism that provides a payment for certified capacity to both Verve Energy and private sector generators alike.

---

[1] The Displacement Mechanism Ministerial Direction had three main functions: (1) to reduce the level of contracting between Verve Energy and Synergy over time and thereby providing opportunities for new entrants in both retail and generation; (2) to mitigate the market power of Verve Energy and Synergy; and (3) to provide a low risk profile for vested volumes for Synergy. The Displacement Mechanism Ministerial Direction required that the tender processes that Synergy undertook to fulfil its obligations under the Displacement Mechanism in the Vesting Contact (2006) were open and fair; and the market was provided with appropriate information to participate in the tender processes. See the Office of Energy's website for further information on the Displacement Mechanism Ministerial Direction, Vesting Contract 2006 web page.

The Authority also notes that the current notional surplus supply capacity observed in the WEM includes a significant proportion of 'non-generation' capacity, namely Demand Side Management programs, the majority of which may only be called upon for one to two days a year.[2]

There are currently structural barriers to effective retail competition. The absence of a clear framework for increasing retail competition, which includes cost-reflective retail tariffs and the introduction of full retail contestability, limits the prospect of entry and expansion of new retailers.

The Authority acknowledges the complexity associated with setting cost reflective tariffs. The Authority considers that the Tariff Equalisation Fund (**TEF**)[3] for the supply of electricity to regional areas of the state outside the SWIS should be funded by a Community Service Obligation (**CSO**) payment to make this cost more transparent and shared by all taxpayers in Western Australia. This arrangement would have the added benefit of removing the cross subsidisation of regional WA electricity customers by customers in the SWIS. The Authority notes the TEF is currently being collected from SWIS customers through the distribution network charges. The need to include the TEF in setting electricity tariffs adds further complexity to the process of setting tariffs.

The Authority notes that a provision of a CSO payment of $152 million has been made to Synergy in the 2010/11 State Budget.[4] The gazetted TEF amount for the 2010/11 financial year is $175.7 million,[5] to which Synergy will be the majority contributor via the network charges it pays to Western Power. The Authority estimates that the TEF will add approximately $80 to household electricity charges in the 2011/12 financial year. If Synergy's CSO payment is made directly into the TEF and the TEF is excluded from network charges that flow through to electricity retail tariffs, the current electricity retail tariffs would be approximately cost reflective.

The market is impeded by a lack of clarity about the State Government's policy intentions and timeframe for increasing competition, particularly in the electricity retail sector. The State Government needs to signal to the market its commitment to promoting competition in the market. Otherwise, market confidence could be undermined, which will put timely private sector investment at risk.

There are also significant cost pressures as a result of incentives for renewable energy:

- the extended Renewable Energy Target implemented by the Federal Government is resulting in increased costs to consumers. The Independent Pricing and Regulatory

[2]The Market Rules include the concept of Availability Classes. This approach recognises the value of DSM, but ensures that the time limitations of DSM are properly considered when assessing system reliability. There are three Availability Classes applicable to DSM: 24-48 hours every year, 48-72 hours every year and 72-96 hours every year.

[3] The TEF was set up in support of the State Government's uniform electricity tariff policy so that customers in regional WA pay the same prices for electricity as of SWIS customers. The TEF is funded through the Tariff Equalisation Contribution (TEC) which is collected as part of Western Power's distribution network charges. Western Power's wholesale distribution customers, the largest of which is Synergy, pay their network charges out of the retail revenue collected from households and small to medium business customers in the SWIS. In 2009, the Government gave notice that over the next two years, the TEC will be increased by $59 million to $181.2 million in 2011/12. Source: Government Gazette No.153, 25 August 2009, p. 3325; and Government Gazette No.208, 17 November 2009, p. 4639.

[4] At present, Synergy receives an explicit operational subsidy – a CSO payment – to fund the shortfall in revenue whilst uniform retail tariffs are below the cost of electricity supply in the SWIS. This CSO payment was forecast to be $152 million in 2010/11 Budget Paper No. 3, Appendix 8, p 237.

[5] Government Gazette Western Australia, No. 208, 17 November 2009.

Tribunal of New South Wales has estimated that changes to the Renewable Energy Target scheme will increase regulated electricity prices in NSW by six percentage points from 1 July 2011;

- the feed-in tariff scheme introduced by the State Government is driving high uptake of inefficient small-scale renewable generation (particularly roof-top solar systems) that are not otherwise commercially viable;
- Synergy's procurement of renewable energy is not constrained by competitive pressures or regulatory oversight; and
- incentives for wind generation are overly generous and new wind generators do not face the costs they are likely to impose on others.

These schemes are likely to result in inefficient investment and a distortion in prices, which represents a cost to consumers.

Cost pressures are also emerging as a result of the approach that Western Power is required to apply when connecting new generators to the grid. The current approach allows connected generators to have full access to the network, in the absence of dynamic physical constraints. This has facilitated a simpler operating regime for the power system and the market as a whole. While this approach was reasonable when the network had surplus capacity, it is no longer efficient. It is likely that an alternative approach that allows Western Power to accommodate new generation in a constrained manner, without making significant augmentation to the network, will lead to more efficient investment in the future.

Whilst the market has evolved in an incremental manner since its inception, it is currently undergoing accelerated development led by the Independent Market Operator. The Authority supports the work-streams that are currently underway, including:

- the design framework for introducing competitors to Verve Energy in the provision of Balancing and Ancillary Services, as long as it can be demonstrated that the benefits will exceed the costs. This project will require significant changes to the existing market design and operations. The associated costs, which will be funded by participants in the market, could be substantial, and will eventually be passed through to consumers.
- the proposed capacity valuation method for assigning Capacity Credits to wind generation that better reflects its contribution at times of peak demand; and
- the review of the Reserve Capacity Mechanism of the market, including consideration of whether the mechanism is efficient in delivering the optimal mix of generation and Demand Side Management capacity.

The Authority supports the Independent Market Operator, on the advice of the Market Advisory Committee, taking the lead on specific projects that will improve the efficiency of the market. This process would be improved by refining the Market Objectives so that it is clear that economic efficiency is the priority. At present, the Market Objectives include a mix of potentially inconsistent objectives.

However, the challenges facing the market (i.e. the lack of policy direction, the cost pressures arising from renewable energy incentives, the move to a constrained network) are too substantive to be left to the Independent Market Operator alone. The Office of Energy should be funded to take the lead on this work, which should be conducted in a transparent and consultative manner. Importantly, this work needs to be conducted, to the extent possible, at arm's-length from the State Government, given the conflict of interest the State Government has as owner of the two dominant players in the market, Verve Energy and Synergy.

Summary of Recommendations and Findings

Recommendation 1

Section 2.1

The Authority is of the view that the establishment of a strategy for the future development of the Wholesale Electricity Market ('WEM Future Strategy') requires urgent attention.

The primary objective of the WEM Future Strategy should be to provide oversight and coordination to guide continued market evolution, so as to promote the Market Objectives. This market evolution process should be transparent and consultative.

The development of the WEM Future Strategy should be coordinated by the Office of Energy, so that the consideration of any changes is consistent with the Market Objectives.

Recommendation 2

Section 2.1

The Authority considers that the development of an overriding economic efficiency objective would provide a better framework for prioritising the Market Objectives.

Recommendation 3

Section 2.1

The Authority recommends a Rule Change proposal to clause 2.4.2 of the Market Rules that seeks to amend the criteria, from 'would be consistent with the Market Objectives', to 'would better address the Market Objectives'.

Recommendation 4

Section 2.2

The Authority recommends that the Tariff Equalisation Fund be funded through a Community Service Obligation payment.

Recommendation 5

Section 2.2

Enhanced retail competition is required for the future efficient operation of the Wholesale Electricity Market. The Authority recommends that a clear framework for increasing retail competition be established, which may include setting cost-reflective retail tariffs and the introduction of full retail contestability.

Recommendation 6

Section 2.3

The Authority recommends the Independent Market Operator include further high level detail of the potential changes for Intermittent Generators in its future Statement of Opportunities. Additional information could include details of the methodology to be applied in determining the allocation of Capacity Credits, and the impact this may have in terms of the potential for variability of the Capacity Credit allocation to the various intermittent generation technologies (e.g. wind and solar) from year to year.

Recommendation 7

Section 2.3

The Authority recommends that further investigations should be undertaken to more clearly assess the effectiveness of Demand Side Management in meeting the Market Objectives.

Finding 1

Section 2.4

Renewable energy incentive schemes will be a major driver of higher electricity prices in Western Australia and impose significant additional costs on consumers. The Authority is concerned that unless there is pressure on retailers to procure 'green' electricity at the lowest cost, then inefficient costs will be passed onto consumers.

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

Recommendation 8

Section 2.5

The Authority recommends that a full and detailed review be undertaken of the costs, benefits and possible implementation issues relating to a move towards a constrained network access framework. This review would need to:

- **consider all the relevant interactions with the Wholesale Electricity Market's design; and**
- **be well resourced with support in key areas and strong program management to ensure timeframes are met.**

Recommendation 9

Section 2.5

The Authority recommends that a mechanism be developed to provide timely information to the market about access to available network capacity, to allow generators to make efficient locational decisions. This information needs to be made public in a useful and affordable form. The Authority also recommends that a formal reporting requirement should be brought into effect through the *Electricity Networks Access Code 2004*, the Access Arrangement or a Licence condition.

Recommendation 10

Section 2.6

The Authority recommends a review of the overall level of competition in the market be carried out once the key changes to the Wholesale Electricity Market's design (including the introduction of competitive Balancing) have been implemented. The Authority considers this review is necessary in order to assess whether, across the whole market, the appropriate level of market power mitigation is still in place. The Authority is strongly of the view that this review should be transparent and consultative, and be coordinated by the Office of Energy.

Finding 2

Section 2.6

The Authority is concerned about information provision in the Wholesale Electricity Market, including a lack of volume and price information associated with the Replacement Vesting Contract. The Authority considers that an evaluation is necessary to assess whether the contract efficiently meets Synergy's pricing, load and volume requirements.

Recommendation 11

Section 4.5

Recommendation: The Authority recommends that the Independent Market Operator apply greater scrutiny of price changes submitted by Market Participants in Standing Data to ensure such changes represent the Market Participant's reasonable costs, as required by the Market Rules.

INTRODUCTION

1 Background

1.1 Reporting requirements for the Report to the Minister

The *Wholesale Electricity Market Rules* (**Market Rules**)[6] require the Economic Regulation Authority (**Authority**) to provide to the Western Australian Minister for Energy (**Minister**) a report (**Report to the Minister**) on the effectiveness of the Wholesale Electricity Market (**WEM**) in meeting the Wholesale Market Objectives (**Market Objectives**), at least annually.[7] The *Electricity Industry Act 2004* (**Act**) requires the Authority to provide to the Minister a report 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 Market Objectives are:

- to promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the South West interconnected system;[8]
- to encourage competition among generators and retailers in the SWIS, including by facilitating efficient entry of new competitors;
- to avoid discrimination in that market against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or that reduce overall greenhouse gas emissions;
- to minimise the long-term cost of electricity supplied to customers from the SWIS; and
- to encourage the taking of measures to manage the amount of electricity used and when it is used.

Given the substantial overlap between these two requirements, this report fulfils the requirements under both the Act and the Market Rules.

A comprehensive guide to the Authority's reporting requirements and where these requirements are addressed in this report is set out in Appendix 1.

1.2 Process

The Authority released a Discussion Paper[9] on 25 June 2010 to assist interested parties in making submissions. A notice was posted on the Authority's website advising the release of the Discussion Paper and inviting submissions to be lodged with the Authority

---

[6] See State Law Publisher website, Electricity Industry (Wholesale Electricity Market) Regulations 2004: Wholesale Electricity Market Amending Rules (September 2006).

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

[8] 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.

[9] See ERA website, Discussion Paper - Annual Wholesale Electricity Market Report to the Minister for Energy, June 2010.

by 23 July 2010. A list of stakeholders who made submissions is provided in Appendix 2. The submissions received are available on the Authority's website.[10]

On 6 December 2010, a notice was published on the Authority's website regarding the combination of the Authority's dual obligation to report to the Minister on the effectiveness of the WEM under both the Market Rules and the Act. This commenced the public consultation period required under the Act and the consultation period ended on 11 January 2011. Submissions from Synergy and Alinta were received in response to this notice.

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

The Authority has also taken into account of the analysis and findings of key reviews that relate to the WEM. The Authority notes the recent developments following the Government's consideration of the Oates Report; namely the recommendations made by the Verve Review Implementation Coordination Committee, and the Strategic Energy Initiative Direction Paper prepared by the Office of Energy.

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

1.3 Confidentiality

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

This version of the Minister's Report is the public version. Information that is classed as confidential under Chapter 10 of the Market Rules has been identified by the Authority and has been aggregated or removed. Where information that is required to be included in the Minister's Report has been removed from this public version due to it being classed as confidential, the removal of that confidential information is noted. The Minister has been provided with the confidential version of this report.

1.4 Structure of this report

This report is structured as follows:

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

[10] See ERA website, Annual Wholesale Electricity Market Report to the Minister for Energy web page.

PART A

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

Clause 2.16.12(c) of the Market Rules requires that the Report to the Minister contains the Authority's assessment of any specific events, behaviour or matters that have impacted on the effectiveness of the WEM. This section sets out the Authority's assessment.

The WEM commenced operation in September 2006. The WEM was introduced as part of a suite of electricity industry reforms implemented by the WA Government following a review of the industry.[11] The WEM design was intended to be a 'low risk' and 'low cost' option based upon considerations of maintaining security of supply, providing operational simplicity and flexibility to implement incremental changes.

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

While the WEM's design has continued to evolve, the Authority considers the WEM is at a crossroads due to the constraints/pressures that are impacting on the effectiveness of the WEM in meeting the Market Objectives. These issues need to be addressed through policy decisions and key pathway decisions.

This section focuses on the emerging issues which, in the Authority's view, require urgent attention of both policy makers and stakeholders to ensure the continued effective operation of the WEM:

- Section 2.1 considers the evolution of the WEM and the clarity of the current Market Objectives;
- Section 2.2 considers the cost reflectivity of electricity retail tariffs and the development of greater retail contestability in the context of market effectiveness;
- Section 2.3 discusses incentives in the Reserve Capacity Mechanism (**RCM**), in particular regarding intermittent generation and Demand Side Management (**DSM**) technologies;
- Section 2.4 analyses renewable energy incentive schemes in the context of achieving the objectives of climate change policies and the impact these are having on market effectiveness;
- Section 2.5 discusses network investment issues and improved access to the transmission network; and
- Section 2.6 discusses the implications of the new Replacement Vesting Contract between Verve Energy and Synergy.

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

2.1 Market evolution

2.1.1 Coordinating market evolution

While the WEM has evolved incrementally since its inception, it is currently undergoing accelerated development[12] to address major issues[13] raised by the Oates review[14] and various stakeholders. The Market Evolution Program (**MEP**) led by the IMO has aimed at introducing a competitive market for Balancing[15] and some Ancillary Services,[16] which requires significant change to the existing market design. The Authority is supportive of market review processes that promote competition and deliver a net benefit to the market and consumers.

The Authority has identified a number of significant challenges that are facing the market:

- cost reflectivity of electricity retail tariffs and the impact on retail competition and further retail contestability;
- the rapid increase in intermittent generation and DSM programs under the RCM and their impact on the market and system operations;
- climate change policies and the associated uncertainties on investment decisions and cost pressure to consumers;
- the debate on constrained versus unconstrained network approach and their implications for the market and system operations; and
- the implications of the Replacement Vesting Contract between Verve Energy and Synergy.

The scale and scope of these challenges dictate that urgent attention is required of both policy makers and stakeholders. The Authority considers that these challenges will require timely policy decisions and timely implementation of changes to the electricity market design. The Authority also considers that these challenges need to be addressed concurrently through a coordinated approach to maximise the benefits.

The Authority reiterates its previous recommendation that a process needs to be established to determine a strategy for the future development of the WEM ('**WEM Future Strategy**'). The primary objective of the WEM Future Strategy should be to provide oversight and coordination for guiding continued market evolution. The development of the WEM Future Strategy should be coordinated by the Office of Energy to ensure any recommendations are consistent with the Market Objectives.

Where matters are of sufficient importance to warrant government decisions, these decisions should be based on recommendations developed through a market evolution process that is transparent and consultative. This is particularly the case where the

---

[12] A brief précis of the current and recent WEM reviews is contained in Appendix 4.

[13] In particular, relating to day ahead planning and real time dispatch as reflected in the operation of the Short Term Energy Market, the Balancing mechanism and the provision of Ancillary Services.

[14] The Oates Report (Verve Energy Review, August 2009) considered the causes of Verve Energy's financial position and performance (including the structure of the market), and presented options for improving Verve Energy's financial outlook.

[15] Balancing services involve real-time balancing of actual demand and the electricity sent out by available generation.

[16] Ancillary Services are required to maintain power system security and reliability through the control of key technical characteristics, such as frequency and voltage.

government owns significant infrastructure in the electricity market. The Authority is concerned that, in the absence of a WEM Future Strategy and a coordinated approach led by the Office of Energy, market confidence in the WEM could be undermined, which will put timely private sector investment at risk.

The Authority notes that measures to address the specific challenges may have significant implications for the WEM's design and development. The Authority is concerned that the lack of a coordinated strategy to date may result in decisions taken on WEM design changes being progressed in isolation of the broader challenges, leading to inefficient market outcomes.

Recommendation 1

Section 2.1

The Authority is of the view that the establishment of a strategy for the future development of the Wholesale Electricity Market ('WEM Future Strategy') requires urgent attention.

The primary objective of the WEM Future Strategy should be to provide oversight and coordination to guide continued market evolution, so as to promote the Market Objectives. This market evolution process should be transparent and consultative.

The development of the WEM Future Strategy should be coordinated by the Office of Energy, so that the consideration of any changes is consistent with the Market Objectives.

2.1.2 Wholesale Market Objectives

The Authority considers that clarity of the Market Objectives is crucial to ensuring that the ongoing evolution of the market is appropriate. The Market Objectives include: the promotion of the economically efficient, safe and reliable production and supply of electricity in the SWIS; encouraging competition among generators and retailers; avoiding discrimination against particular energy options; minimising the long term cost of electricity; and the taking of measures to manage the amount of electricity used and when it is used. From an economic efficiency perspective, electricity prices should encourage efficient investment in and use of the infrastructure; namely the generation assets, transmission and distribution systems.

In its submission to the Authority, Alinta considered that while, on balance, the Market Objectives remained appropriate, there was emerging evidence that the WEM may no longer be effective in meeting the Market Objectives. Synergy noted there are inherent contradictions in the current Market Objectives, while Landfill Gas and Power considered that Market Objective (c),[17] regarding non-discrimination between different energy types, requires recasting to clarify its intent of the avoidance of discrimination against particular energy options and technologies.

[17] Market Objective (c) is to avoid discrimination in the market against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or that reduce overall greenhouse gas emissions.

As noted in the 2009 Report to the Minister, the Authority believes that clarity would be improved by providing greater guidance around the application of the market objectives in practice. It is the Authority's view that the development of an overriding economic efficiency objective would provide a better framework for prioritising the Market Objectives. Having an overarching objective would also align with the overriding objective in the *Electricity Networks Access Code 2004* (**Access Code**), which states:

> The objective of this [Access] Code is to promote the economically efficient investment in, and operation and use of, networks and services of networks in Western Australia in order to promote competition in markets upstream and downstream of the networks.[18]

Economic efficiency, as an objective, would assist in:

- ensuring optimal investment in technology (dynamic efficiency);
- minimising the costs of electricity supply (technical efficiency); and
- allocating resources to where they are most highly valued (allocative efficiency).

Economic efficiency achieved through competition would ensure that all costs (rather than just direct financial costs) and benefits are taken into account. These include the external costs of electricity production, e.g. the cost of greenhouse gas emissions. In addition, an overriding economic efficiency objective, achieved through the workings of a competitive market, is likely to maximise the long term interests of consumers.

Under the overriding objective of economic efficiency, the current Market Objectives could become guiding principles.

The Authority notes that the current Market Objectives are defined in the Act. The provision of an overriding objective will require changes to the Act.

Recommendation 2

Section 2.1

The Authority considers that the development of an overriding economic efficiency objective would provide a better framework for prioritising the Market Objectives.

In its submission, Alinta noted that there was an anomaly in the criteria used to assess whether the Market Objectives are being met when amending the Market Rules. Alinta noted that the criteria applied by the IMO for assessing whether a Rule Change proposal should be accepted into the formal Rule Change process (being that the Rule Change would *better* address the Market Objectives) differed from the criteria applied by the IMO when it makes final determination of whether the proposal should be adopted (being that the Rule Change would be *consistent* with the Market Objectives).

The Authority believes that the criteria should be applied consistently when assessing Rule Changes from a proponent (which can be any person including the IMO) and when the IMO makes its final determination following the Rule Change process. Accordingly, the Authority recommends a Rule Change proposal to clause 2.4.2 of the Market Rules

[18] See Section 2.1 of the Access Code.

that seeks to amend the criteria, from 'would be consistent with the Market Objectives', to 'would better address the Market Objectives'.

Recommendation 3

Section 2.1

The Authority recommends a Rule Change proposal to clause 2.4.2 of the Market Rules that seeks to amend the criteria, from 'would be consistent with the Market Objectives', to 'would better address the Market Objectives'.

2.2 Electricity retail tariffs and retail competition

Cost-reflective retail tariffs are essential for ensuring the market continues to operate efficiently. Setting electricity tariffs that are not cost-reflective limits the ability of customers to make efficient consumption and expenditure decisions. The Authority notes the wide support of cost-reflective tariffs expressed in the submissions to the Authority. In particular, Western Power noted that non-cost reflective tariffs hinder the meeting of the Market Objectives.

The Office of Energy considers that the "current residential electricity charges in Western Australia are significantly less than the cost of providing the service".[19] The Office of Energy is currently undertaking a review of electricity retail tariffs[20] and investigating the means of achieving equitable cost-reflective retail tariffs, including the application of Inclining Block Tariff pricing (i.e. the price of electricity increases with increasing consumption).[21]

The Authority acknowledges the complexity associated with setting cost reflective tariffs. There are many variables to be considered, such as the impact of a carbon tax (or Carbon Pollution Reduction Scheme); various state and federal renewable energy schemes; changes in generation and network costs. The Authority supports initiatives that investigate and deliver cost reflective electricity retail tariffs. The Authority also supports regular reviews of tariffs to ensure that they remain cost reflective.

The Authority considers that the Tariff Equalisation Fund (**TEF**)[22] should be funded by a Community Service Obligation (**CSO**) payment to make this cost more transparent and

---

[19] Office of Energy, Tariff and Concession Framework Review web page. Note that residential electricity tariffs in Western Australia did not increase over the period 1997/98 to 2008/09, while business tariffs for businesses did not increase between 1991/92 and 2007/08. The Government approved price increase of electricity to households of 10 per cent in April 2009, followed by 15 per cent in July 2009. In March 2010, the Government approved a further two increases of 7.5 per cent and 10 per cent to take effect in April and July 2010.

[20] The Minister is required by the *Electricity Corporation Act 2005* to review Section 55 which relates to the level of retail contestability in the market.

[21] Under an Inclining Block Tariff structure, the price of electricity is lower for lower levels of consumption, up to a certain threshold. Consumption exceeding this threshold is then charged at a higher price. Effectively, the more electricity people use, the more they will pay per unit.

[22] The difference between Horizon Power's (retailer of electricity to regional customers) costs and the economic costs of providing electricity to customers in the SWIS is funded through the TEF. The TEF is funded through the Tariff Equalisation Contribution (TEC) included as part of Western Power's network

shared by all taxpayers in Western Australia. This arrangement would have the added benefits of removing the cross subsidisation of regional WA electricity customers by customers in the SWIS. The Authority notes the TEF is currently being collected from SWIS customers through the distribution network charges. The need to include TEF in setting electricity tariffs adds further complexity to the process.

A recent review by the Authority found that, if the efficient levels of Horizon Power's operating and capital expenditure were used to calculate the TEF payment, then the payment required by Horizon Power would be significantly lower than the gazetted level.[23] If the Government continues to choose to fund the TEF via network charges in the SWIS, then the Authority considers that lower TEF payments (reflecting efficient Horizon Power expenditure) should be passed through to reduce distribution network tariffs for the benefit of all Western Power's customers.

The Authority notes that a provision of a CSO payment of $152 million has been made to Synergy in the 2010/11 State Budget.[24] The gazetted TEF amount for the 2010/11 financial year is $175.7 million,[25] to which Synergy will be the majority contributor via the network charges it pays to Western Power. The Authority estimates that the TEF will add approximately $80 to household electricity charges in the 2011/12 financial year. If Synergy's CSO payment is made directly into the TEF and the TEF is excluded from network charges that flow through to electricity retail tariffs, the current electricity retail tariffs would be approximately cost reflective.

Recommendation 4

Section 2.2

The Authority recommends that the Tariff Equalisation Fund be funded through a Community Service Obligation payment.

Under the WEM design competition was intended to be supported by the introduction of a number of factors, including the establishment of short term energy trading, in which retailers and generators could trade electricity in addition to their bilateral contracts; and an introduction of a competitively based capacity market, to ensure that sufficient generation capacity entered the market to provide a reasonable buffer between supply and demand. These factors, along with market power mitigation measures provided in the Market Rules,[26] the *Electricity Corporations Act 2005*, and Ministerial Directions have assisted in new entrants becoming established in the WEM.

charges to its distribution customers. Western Power's wholesale distribution customers, the largest of which is Synergy, pay their network charges out of the retail revenue collected from households and small to medium business customers in the SWIS. In 2009, the Government gave notice that over the next two years, the TEC will be increased by $59 million to $181.2 million in 2011/12. Source: Government Gazette No.153, 25 August 2009, p. 3325; and Government Gazette No.208, 17 November 2009, p. 4639.

[23] ERA 2011, Final Report: Inquiry into the Funding Arrangements of Horizon Power, March 2011.

[24] At present, Synergy receives an explicit operational subsidy – a CSO payment – to fund the shortfall in revenue whilst uniform retail tariffs are below the cost of electricity supply in the SWIS. This CSO payment was forecast to be $152 million in 2010/11 Budget Paper No. 3, Appendix 8, p 237.

[25] Government Gazette Western Australia, No. 208, 17 November 2009.

[26] Under the Market Rules, prices offered by a Market Generator should reflect its reasonable expectation of the short run marginal cost of generating the relevant electricity.

As a result, Synergy's share (of electricity sold) in the contestable market (>50MWh per annum) decreased from 90 per cent in 2006 to 66 per cent in 2009.[27] The other most active retailers in the contestable market are Griffin Energy, Perth Energy and Alinta. Increased retail competition has also been reflected in a higher number of customers switching between retailers.

It is the Authority's view that ongoing cost reflectivity of electricity retail tariffs is essential for the efficient operation of the market. Competition between retailers exerts pressure on both the incumbents and new entrants to adopt cost reflective prices and deliver innovative services to meet customer needs. The absence of a clear framework for increasing retail competition (which would include setting cost reflective retail tariffs, reducing the contestability threshold, and the introduction of full retail contestability (**FRC**)), limits the entry and expansion of new retailers.

The Authority notes that the Office of Energy is currently undertaking a review of the introduction of further retail competition in the Western Australian electricity market.[28]

Recommendation 5

Section 2.2

Enhanced retail competition is required for the future efficient operation of the Wholesale Electricity Market. The Authority recommends that a clear framework for increasing retail competition be established, which may include setting cost-reflective retail tariffs and the introduction of full retail contestability.

2.3 Incentives in the Reserve Capacity Mechanism

The Reserve Capacity Mechanism (RCM) underpins the operation of the capacity market, an important feature of the WEM structure. The RCM provides a guarantee of payment to investors providing certified capacity in terms of Capacity Credits. The RCM was designed to promote investment in sufficient capacity to meet demand in the SWIS. This mechanism operates on a two-year-ahead cycle and has been operating since 2005.

During 2010, the IMO decided to examine aspects of the RCM, including consideration of whether the RCM's pricing mechanisms are efficient and whether the RCM is delivering the optimal mix of generation and DSM capacity.[29] Early in 2011, the IMO engaged an economic consultant to assist in reviewing the RCM. The consultant's report is due to be presented to the IMO by mid-year 2011.

The Authority notes that there are a number of related reviews that are currently underway, or have been recently completed.[30] These reviews have focused on providing

[27] Office of Energy, Verve Energy Review, August 2009.

[28] The Minister is required by the *Electricity Corporation Act 2005* to review Section 55 which relates to the level of retail contestability in the market.

[29] IMO MAC Meeting, MAC Meeting No. 34 Papers, 15 December 2010, 'Strategic Review of Reserve Capacity Mechanism for IMO Board' Presentation, p. 15.

[30] These include: the Renewable Energy Generation Working Group; the Maximum Reserve Capacity Working Group; a Rule Change proposal on the treatment of Curtailable Loads and Demand Side

appropriate incentives to intermittent generation and DSM technologies. The Authority has examined these in the context of incentives provided by the RCM.

Intermittent generation

Capacity Credits assigned under the RCM to wind generation in the SWIS have increased from 78 MW in the 2009/10 Capacity Year to 167 MW in the 2012/13 Capacity year. This represents an increase in wind generation's share of total capacity, from 1.5 per cent to 2.8 per cent of credited capacity.

Under the current Market Rules, there are concessions for intermittent generation that include:

- an exemption from funding Spinning Reserve Ancillary Service costs;
- a requirement to fund a share of the Load Following Ancillary Service costs, however, the share funded is disproportionately small;[31]
- an option to participate in the STEM and submit Resource Plans if owned by an independent power producer (**IPP**);
- no exposure to the upwards deviation administrative price (**UDAP**) and the downwards deviation administrative price (**DDAP**);[32] and
- Reserve Capacity Credits are allocated based on its output at all times (i.e. all Trading Intervals) and not just at times of peak demand (e.g. hot summer afternoons).[33]

Stakeholders have previously informed the Authority of their view that wind generation was disproportionately benefiting from the RCM. One identified issue was the potential over-allocation of Capacity Credits to intermittent generation, which seldom operates at full capacity during times of peak demand. The current calculation method in the Market Rules uses average power output over the last three years, which delivers an approximate 40 per cent of nameplate capacity.

A number of submissions received by the Authority supported introducing a Capacity Credits allocation method that better reflects the available capacity from intermittent generation at times of peak load.[34] The submissions indicated overall support for the principle that costs should be borne by those who cause them, and allocated in a

Programmes (RC_2010_29); and proposed adjustments to the Reserve Capacity Refunds mechanism (a work stream of the Market Evolution Program).

[31] ROAM Consulting estimated that the proportion of Load Following Service costs (total around $6 million) funded by Intermittent Generators during 2008/09 was four per cent, with the remainder funded by other Loads. See IMO website, MAC Meeting No. 33 Papers, 10 November 2010, p. 126.

[32] MCAP is used to settle deviations from Net Contract Position by Verve Energy, by non-scheduled generators, by non-dispatchable, interruptible and curtailable loads, and by non-Verve Energy scheduled generators subject to commissioning tests or tests of their reserve capacity requirements. UDAP and DDAP are used to settle deviations by non-Verve Energy scheduled generators (excluding those subject to a test) that deviate from their schedules without instruction from System Management. In general terms, the value of the MCAP for a trading interval is either equal to the STEM price for that trading interval or is based on STEM bids and STEM offers for that trading interval. The value of the UDAP is zero during off-peak periods and is equal to the MCAP multiplied by 0.5 during peak periods. The value of the DDAP is the MCAP multiplied by 1.1 during off-peak periods and the MCAP multiplied by 1.3 during peak periods.

[33] The rationale for discriminating between all times and times of peak demand for the purpose of Reserve Capacity Crediting of Intermittent Generation is that, the average of a small number of periods of peak demand allows for a more accurate reflection of the Intermittent Generation fleet's actual energy contribution (from accredited Intermittent Generation capacities), at times the system requires the most energy from across the entire generation fleet.

[34] Mid-West Energy, Landfill Gas and Power, Western Power and Synergy (second submission).

transparent manner. The Authority notes that there should be transparency and clarity around how the charges are being developed and how they are to be attributed to classes of generation, so that a nexus is established between costs and charges.

The Authority's view is that all impacts on the market need to be taken into account when assessing the net benefits of intermittent generation. This is particularly relevant to the reliable provision of services. The Authority notes that a method for assessing the reliability contribution of wind generation during peak periods has been developed for the NEM.[35] South Australia has the highest wind installed capacity in Australia (868 MW in 2010).[36] The Planning Council (South Australia) found that, based on the recorded wind performance during the top ten per cent of demand periods, 95 per cent of the time wind generation in South Australia is producing at least three per cent of its installed capacity and for 50 per cent of the time it is producing at least 20 per cent of its installed capacity. VENCorp determined that eight per cent of the installed capacity of a wind farm in Victoria will be available during peak summer periods.[37]

The IMO's Renewable Energy Generation Working Group (**REGWG**) has assessed the treatment of intermittent generation in the RCM and the reliability contribution of intermittent generation.[38] While failing to reach a consensus on the method of assigning Capacity Credits to intermittent generation, the REGWG supported that the IMO would nominate a valuation methodology that better served the Market Objectives.[39] The IMO has recommended the implementation of a methodology,[40] through the Market Rule Change process,[41] that would deliver a Capacity Credit valuation (as a percentage of nameplate capacity) of 16-20 per cent for wind generation and 40-50 per cent for solar. The Authority notes that the contribution of wind generation in the SWIS during the peak summer period for 2008-10 was around 19 per cent.[42]

The proposed IMO capacity valuation is based on a method that assesses the contribution of intermittent generation at times of peak demand.[43] Utilising peak demand contributions is the typical method used in electricity markets to assess the reliability of capacity. In the proposed Rule Change, the IMO notes the importance of 'ensuring that the investment signals provided by the RCM strike a balance between providing appropriate

---

[35] Note that the NEM does not have a capacity market and the assumed 5 per cent of capacity for wind farms is used for reliability planning purposes.

[36] Electricity Supply Industry Planning Council (SA) 2009, Annual Planning Report, June 2009.

[37] Electricity Supply Industry Planning Council (SA) 2009, Annual Planning Report, June 2009.

[38] The REGWG work program included reviewing the methodology for calculating the capacity value of Intermittent Generation, an assessment of the frequency keeping requirements and the allocation of that cost to Intermittent Generators and recommendations on updated technical rules. Regarding capacity value, a draft report by MMA to REGWG advised that the current level 40 per cent of rated capacity was in line with the proposed approach. No resolution was reached on the MMA advice and Tenet Consulting was engaged to conduct further analysis. Three hybrid proposals on determining Reserve Capacity Credits were then presented to the REGWG.

[39] IMO 2011, REGWG - Summary of Processes and Outcomes, February 2011, p. 11.

[40] Note that the IMO had proposed a methodology on the basis that that the MMA approach 'was based on modelling using a limited data set which did not reflect a one in ten year event'; Allan Dawson (IMO), Chair IMO MAC, MAC Meeting No. 34 - Minutes, 15 December 2010, p. 12.

[41] IMO MAC Meeting, MAC Meeting No. 33 Papers, 10 November 2010, Calculation of the Capacity Value of intermittent Generation, PRC_2010_25, p.104.

[42] For 95 per cent of the summer peak period, 35 MW of output or 19 per cent of wind farm capacity was available. Figures were calculated for the summer period, Feb 1 to March 14; 15:30 to 17:30, 2008-10. IMO MAC Meeting, MAC Meeting No. 35 Papers, 9 February 2011, p. 21.

[43] The method identifies critical peak demand intervals by utilising 12 Trading Intervals which experienced the highest Load for Scheduled Generation (LSG). LSG is calculated using the load that remains after removing the level of intermittent generation in the market.

remuneration for intermittent generation and ensuring system security and reliability can be maintained'.[44] The Authority notes that System Management has raised concerns with the IMO 'around the security associated with allocation of Capacity Credits to Intermittent Generators at the current levels'.[45] Given the RCM is required to deliver sufficient generation and DSM capacity to meet the stringent reliability standards set for the SWIS at periods of peak demand, the Authority considers that the IMO proposal has merit, as it better reflects the value of intermittent generation at times of peak demand.

The Authority considers that any capacity valuation needs to be regularly reviewed to reflect factors such as technological improvements and changes in demand patterns (e.g. shifting of system peak load).

The IMO makes reference to potential changes for Intermittent Generators in past instalments of its annual Statement of Opportunities (**SOO**).[46] The Authority considers, to the extent possible, that further detail of the potential changes for Intermittent Generators should be included in future SOO's. These details could include the potential for variability of the Capacity Credit allocation from year to year, depending on the particular intermittent generation technology and the applicable method for determining Reserve Capacity Credits. For example, if the level of Capacity Credits is changed to be in the range of 16-20 per cent for wind generation, future data analysis and refinements to the method may see further variations to the designated capacity valuation. The Authority considers that potential investors should be made explicitly aware that the percentage of Capacity Credit allocation to intermittent generation can change in the future – a risk factor to be considered by investors.

Recommendation 6

Section 2.3

The Authority recommends the Independent Market Operator include further high level detail of the potential changes for Intermittent Generators in its future Statement of Opportunities. Additional information could include details of the methodology to be applied in determining the allocation of Capacity Credits, and the impact this may have in terms of the potential for variability of the Capacity Credit allocation to the various intermittent generation technologies (e.g. wind and solar) from year to year.

Demand Side Management

The current 'supply capacity surplus' observed in the WEM includes a growing component of DSM. DSM is expected to account for eight per cent or 454 MW of the certified capacity by October 2012, worth $84 million per annum.[47] A DSM provider often signs up

[44] IMO MAC Meeting, MAC Meeting No. 33 Papers, 10 November 2010, Calculation of the Capacity Value of intermittent Generation, PRC_2010_25, p. 124.

[45] Allan Dawson (IMO), Chair IMO MAC, MAC Meeting No. 34 - Minutes, 15 December 2010, p. 13.

[46] For example, see the IMO website, 2010 Statement of Opportunities, p. 60.

[47] Calculated from the 454 MW of capacity multiplied by the $186,000 per MW capacity payment.

with a number of curtailable loads[48] and presents an aggregate portfolio for capacity certification under the RCM, two years in advance.

In its submission, Alinta considered that the RCM fails to recognise that DSM may be an inferior capacity 'service' when compared with that provided by scheduled generators. Also, Alinta considered that the continuing increase in the amount of certified capacity provided by DSM programs, in an environment where there is already surplus supply capacity, suggests that the RCM may not be effectively meeting the Market Objectives.

The Authority notes that DSM is typically a less 'firm' or reliable resource[49] than thermal generation and thus may need to demonstrate its reliability on an ongoing basis. If reliability can be satisfactorily demonstrated, then DSM providers should be entitled to the equivalent capacity payments (per MW) as generators. Whilst DSM can be an efficient solution, the lack of past experience in dispatching many of the new DSM sites means that it is not yet possible to assess their effectiveness.[50]

With the rapid growth in DSM and the increasing probability of DSM being called on in peak demand periods, the role of DSM and the associated costs and benefits have become a key issue for the efficient operation of the WEM. The Authority considers that, in having regard for the long-term interests of consumers, there is justification in undertaking further investigations to more clearly assess the effectiveness of DSM in meeting the Market Objectives.

Recommendation 7

Section 2.3

The Authority recommends that further investigations should be undertaken to more clearly assess the effectiveness of Demand Side Management in meeting the Market Objectives.

2.4 Impact of climate change policies

Many countries, including Australia, now have climate change policies to increase the utilisation of renewable energy resources. The WEM operates within this broader framework, which can present challenges for achieving market efficiencies. Balancing the

[48] Refer Clause 2.30.3 of the Market Rules. To improve dispatch efficiencies, a Rule Change (RC_2010_29) has been proposed to allow DSM providers to aggregate their loads as a single Demand Side Programme (DSP), with the main benefit from a system's security perspective is that System Management can dispatch the aggregated DSP, rather than having to dispatch numerous smaller loads. This Rule Change proposal also allows loads to interact with the energy market through one Market Participant (their electricity retailer) and with the RCM through a different Market Participant (their DSM provider).

[49] The Market Rules include the concept of Availability Classes. This approach recognises the value of DSM, but ensures that the time limitations of DSM are properly considered when assessing system reliability. There are three Availability Classes applicable to DSM: 24-48 hours every year, 48-72 hours every year and 72-96 hours every year. The majority of certified DSM capacity under the RCM is in the Availability Class of 24-48 hours every year. In contrast, certified capacity of scheduled generators is required to be available for every hour of the year, except for planned outages. Penalties apply to scheduled generators on forced outages.

[50] In other markets (albeit with different commercial arrangements), it has sometimes been found that actual demand reduction differs from the expected or contracted amount.

goals of renewable energy incentive schemes with the impact on economic efficiency is a key issue in many electricity markets, including the WEM.

For the purposes of preparing this Report to the Minister, the Authority has reviewed the current renewable energy incentive schemes in order to gauge the impact they may be having on the effectiveness of the WEM in meeting the Market Objectives. Details of this review are discussed in the following sections:

- Section 2.4.1 summarises the key climate change polices in place in Australia;
- Section 2.4.2 discusses the incentives for small scale renewable generation;
- Section 2.4.3 provides an analysis of renewable energy incentive schemes; and
- Section 2.4.4 discusses the impact of these climate change polices on the WEM.

The Authority is concerned that the current renewable energy incentive schemes are a key driver of higher electricity prices, impose significant additional costs on consumers and lead to inefficient investment and inefficient utilisation of resources. The Authority considers that these incentive schemes promote investment in renewable generation (particularly for wind generation and small-scale photo voltaic (**PV**) systems) that would not be justified if all costs (including network constraints or the impact on system reliability) were taken into account.

2.4.1 Key climate change policies

There are two key Federal Government climate change policy instruments, a Renewable Energy Target (**RET**) and a proposed Carbon Pollution Reduction Scheme (**CPRS**).

To meet the Government's commitment to achieving a 20 per cent share of renewables in Australia's electricity supply by 2020, the RET was established in 2001 to mandate the additional purchase of electricity from renewable energy sources.[51] The RET legislation set the framework for both the supply and demand of Renewable Energy Certificates (**REC**) via a REC market. In the past decade, the spot market price of RECs has been in the range of $15-$60.[52] The Authority notes that the number of registered RECs exceeded the 2010 target of 34,500 GWh by 8,076 GWh.[53]

Since 1 January 2011, the enhanced RET has been split into two parts, the Large-scale Renewable Energy Target (**LRET**) and the Small-scale Renewable Energy Scheme (**SRES**).[54] The Office of Renewable Energy Regulator (**ORER**) has also set up a clearing house to facilitate the exchange of small-scale technology certificates between buyers and sellers at the fixed price of $40 (excl. GST).

The original intention of the Federal Government was to introduce a CPRS in 2011/12. At the heart of the CPRS was an Emissions Trading Scheme (**ETS**), which was to have a $10 fixed permit price on carbon emissions and other greenhouse gases for the first year of the scheme. In April 2010, the Government announced that the planned introduction of a CPRS would be re-assessed in late 2012, after the conclusion of the current Kyoto

---

[51] The RET legislation placed a legal liability on wholesale purchasers of electricity to proportionally contribute to an additional 45,000 GWh of renewable energy per year by 2020.

[52] Office of the Renewable Energy Regulator 2011, LRET/SRES - the basics, January 2011.

[53] Office of the Renewable Energy Regulator 2011, 'Whats New' January 2011: LRET Target Adjustments.

[54] There is no cap on the number of SRES certificates that will be created.

commitment period.[55] In February 2011, the Government released a paper which outlines a carbon pricing mechanism and proposed that a carbon price scheme commences on 1 July 2012.[56]

2.4.2 Incentives for small scale renewable generation

There are two key renewable energy incentive schemes used in Australia for small scale renewable generation (**SSRG**). The first scheme is the Federal Government funded Solar Credits,[57] which are provided to owners who install new PV systems.[58] At a state level, premium rates are paid for the electricity generated by SSRG under feed-in tariff (**FIT**) schemes. New South Wales and the Australian Capital Territory have gross FIT schemes, while the schemes operating in other Australia jurisdictions are based on net tariffs.[59]

A FIT scheme commenced in WA on 1 August 2010, with a net tariff of 40c/kWh. This tariff is estimated to be equivalent to a gross tariff of 26c/kWh.[60] The WA scheme applies to PV, wind, and micro-hydro technologies at residential premises, with recipients receiving FIT payments for ten years. FIT payments are in addition to the payment from the Renewable Energy Buyback (**REB**) scheme offered through Synergy and Horizon Power.[61] The FIT scheme in WA will be reviewed every three years or when the uptake reaches 10 MW of new generation.[62] The State Government is currently considering the introduction of a FIT scheme for the commercial segment.[63]

Both the upfront Solar Credits and the ongoing payments from a FIT scheme deliver private benefits to the owners of PV systems. The Office of Energy estimated the average financial benefit to the owner of installing a 1.5kW system at around $750 per annum (included REBs, FIT and avoided costs).[64] Regarding the rates of return from the FIT

---

[55] On 27 April 2010, the Prime Minister announced that the start of the CPRS will be delayed until after the end of the current commitment period of the Kyoto Protocol (2012) and until there is further clarification on the actions of other major economies.

[56] Prime Minister 2011, 'Climate change framework announced', Media release 24 February 2011.

[57] Solar Credits is a mechanism which increases the number of STCs to be created for eligible installations of small generation units (e.g. small-scale solar panel, wind or hydro systems) through the use of a multiplier. The multiplier applies to the first 1.5 kilowatts (kW) of on-grid capacity or to the first 20kW of capacity for off-grid systems. STC's can be traded via the market or at a fixed price of $40 through the ORER's STC Clearing House. With Solar Credits, a new 1.5 kW system installed in Perth would be eligible for 155 STC's, with a value of approximately $6200.

[58] From 1 July 2011, owners will receive four STCs (instead of the current five) for every megawatt hour of solar power (equivalent to reducing the subsidy from $6,200 to $5,000 for a 1.5 kW system). See the Hon. G Combet, 'Solar Credits amendments', Media release, 1 December 2010.

[59] With net tariff schemes, a tariff is paid on all excess electricity exported to the grid, while gross tariff schemes pay for each kilowatt of generated electricity.

[60] AECOM Australia Pty Ltd 2010, Solar Bonus Scheme - Forecast NSW PV Capacity and Tariff Payments, Report prepared for Industry and Investment, October 2010.

[61] To be eligible for FIT payments, an applicant must also be eligible for and participate in the REB scheme. The current REB price from Synergy is 7c/kWh, while Horizon Power offer 18.94c/kWh – the differential reflects the higher cost of generation in remote areas.

[62] See the Office of Energy website, Feed-in tariff webpage.

[63] The Office of Energy commissioned a consultant (MMA) to investigate the impact of introducing a FIT scheme to the commercial segment. The Office of Energy provided the Government with the consultant's final report, along with the agency's accompanying advice, in September 2010. The Government is currently considering its position.

[64] Office Energy 2011, Feed-In Tariff Scheme: Myths & Misconceptions, February 2011.

scheme in the ACT, the Independent Competition and Regulatory Commission (**ICRC**) estimated that an occupier with a 1.5 kW system would earn a return of 16.9 per cent.[65]

In public submissions, Western Power and Synergy noted their support for the introduction of a FIT scheme in WA, while Verve Energy noted that FIT schemes contribute to achieving the RET. The Energy Supply Association of Australia (**esaa**) and Mid-West Energy noted their opposition to the introduction of the FIT, primarily because the FIT scheme is unlikely to meet the electricity or emission abatement objectives at least cost (given a FIT provides incentives for relatively inefficient SSRG such as PV systems).

Several submissions called for the monitoring of the impacts on the distribution network before extending the FIT scheme beyond the current tranche. As solar penetration increases, there are associated issues with short-term network stability (e.g. high PV output on peak days could result in voltage fluctuations) and longer-term network reinforcement (can involve significant costs).[66]

The Authority agrees that monitoring of the distribution network needs to take place and that the party best placed to be responsible for undertaking this monitoring is Western Power, particularly with its Perth Solar City project.[67]

2.4.3 Analysis of renewable energy incentive schemes

The current Federal Government has committed more than $15 billion towards climate change initiatives.[68] In a 2010 review of five Federal Government climate change programs, the Australian National Audit Office (**ANAO**) noted that:[69]

> Identifying and assessing risks is particularly important for programs involving inherently high risk innovative technologies and high levels of project expenditure. Of the five programs examined, only one program, Solar Cities, undertook a risk assessment in the early stages of the program's design and continued to monitor and revise the risk assessment as the program was implemented.

The Federal Government programs, together with the introduction of state-based FIT schemes and a decline in PV system costs have led to a sharp rise in the uptake of PV systems from late 2008. Total Australian small-scale PV capacity (as at September 2009) was around 60 MW.[70] As a result of the rapid uptake and associated costs, the Solar Homes and Communities Plan (**SHCP**) was closed in 2009. The original funding for the

---

[65] ICRC 2010, Final Report Electricity Feed-in Renewable Energy Premium: Determination of Premium Rate – Report 4 of 2010 March 2010. Return estimated under the 45.7c/kWh (gross) premium rate.

[66] These costs may be in the order of billions of dollars. 'Barnett wants to increase solar power tariff', Australian Financial Review, 7 December 2010.

[67] See the Perth Solar City website, http://www.perthsolarcity.com.au/

[68] Department of Climate Change 2009, Climate Change Budget Overview 2009–2010, p. 3.

[69] ANAO 2010, Administration of Climate Change Programs, April 2010. The five programs are the Greenhouse Gas Abatement Program, Low Emissions Technology Demonstration Fund, Renewable Remote Power Generation Program, Solar Cities, Solar Homes and Communities Plan.

[70] South Australia has the highest installed capacity of small-scale PV systems, with capacity of 13.9MW in September 2009 (South Australia Feed-In Tariff Review 2009 – Final Report). Total installed PV capacity (including large-scale) in Australia at the end of 2009 was 184MW, an increase of nearly 80 per cent compared to the previous year. The majority of new capacity (around 70 per cent) was installed under the Solar Homes and Communities Plan (SHCP), which ended in June 2009 (IEA PVPS program 2010, op. cit.). PV installations are now eligible for Renewable Energy Certificates, which include the Solar Credits REC multiplier.

program (for the five years from 2007–08) was $150 million, compared to the estimated total cost of $1.05 billion.[71]

Analysis undertaken for a NSW Government review of the Solar Bonus Scheme[72] (commenced 1 January 2010) forecast that the initial 25 MW of installed PV capacity would increase to nearly 1,000 MW by the end of the scheme (2016) – taking total tariff payments to around $4 billion.[73] Following the review, the NSW Government reduced the gross feed-in tariff from 60c/kWh to 20c/kWh for new installations and a cap of 300 MW was placed on the scheme.[74] In April 2011, the Government announced that the processing of new applications (received after 28 April 2011) would be suspended.[75]

These outcomes reflect international experiences (e.g. Spain, Germany and France) where rapid uptake rates (resulting in higher than anticipated costs for the schemes) have typically led to caps being placed on renewable schemes and reductions in the tariffs paid under FIT schemes.

The Authority notes that there is no consistency with the FIT schemes across jurisdictions in Australia, thereby creating different incentives. Consumer expectations that payment structures under FIT schemes will be lowered over time reinforces the early uptake of FIT schemes and the associated technology. As PV technology is rapidly evolving, this encourages the uptake of relatively less efficient technology in the early stages of these schemes.

While competitive electricity markets typically deliver efficient least-cost generation projects at optimal locations, renewable energy incentive schemes, which include the LRET and the SRES, and State-based feed-in tariff schemes, result in electricity being delivered as a result of these schemes at a relatively higher cost.

There are a range of challenges, including technical issues, in successfully integrating high levels of penetration of variable non-storable renewable energy (including wind and solar) in an electricity industry. As the penetration of variable non-storable renewable energy (including wind and solar) increases, the value of adding more of this renewable energy declines, both in economic value and in emission reduction effectiveness. Particular attention is required to the design of efficient short-term markets to correctly allocate costs and benefits to renewable energy generation and to implement complementary network regulation.[76]

---

[71] ANAO 2010, Administration of Climate Change Programs, April 2010.

[72] See the Industry and Investment (NSW Government)web site, 'Customers already participating in the Solar Bonus Scheme before 29 April 2011', Solar Bonus Scheme FAQ webpage.

[73] AECOM Australia Pty Ltd 2010, Solar Bonus Scheme - Forecast NSW PV Capacity and Tariff Payments, Report prepared for Industry and Investment, October 2010.

[74] NSW Government 2010, 'NSW Government Revamps Solar Bonus Scheme', Media Release, 27 October 2010.

[75] Applications to the NSW Solar Bonus Scheme were 'placed on hold', with no new applications to be considered from midnight 28 April 2011. The Government is holding a Solar Summit to investigate options to limit costs by restructuring the Scheme. Applications are on hold pending the results of the Solar Summit. Source: NSW Government 2011, 'Current scheme status (announced 29 April 2011)', NSW Solar Bonus Scheme - frequently asked questions.

[76] N Cutler, N Boerema, I MacGill and H Outhred 2010, 'Wind generation impacts on the South Australian region of the Australian National Electricity Market', submitted to *IAEE Energy Journal,* September 2010. Gerardi W. and P Nidras 2010(a), *Greenhouse Gas Abatement from Wind Farms in NSW,* MMA Report to NSW Department of Environment, Climate Change and Water. Gerardi W. and P. Nidras 2010(b), *Greenhouse Gas Abatement from Wind and Solar in the Victorian Region of the NEM,* MMA Report to

In Australia and abroad, analysis of renewable incentive schemes has found these schemes to be a costly way of reducing greenhouse gases. The following points set out the results of three studies showing the relative economic inefficiency of renewable energy incentive schemes when compared to more economically efficient methods of abating greenhouse gas emissions.

- A study of the renewable incentives in the German electricity market estimated that abatement costs for PV systems were as high as A$960/tonne/CO2-e, compared to an abatement cost of A$72 per tonne for wind power.[77] The study found that it would be economically more efficient to curb greenhouse gas emissions via the European Union ETS, rather than by subsidising renewable energy technologies.[78]
- Grid-connected small-scale PV systems are an expensive option for reducing greenhouse emissions. An Australian study[79] found that the SHCP[80] was relatively ineffective and costly, with the rebated PV systems estimated to reduce Australia's emissions level (as at 2008) by 0.015 per cent, at an average social abatement cost of between $257/tCO2-e and $301/tCO2-e. This study assumed that the average generation life of a PV system is 30 years. Given the actual life of a small scale PV system is often less than 30 years; the actual abatement cost is likely to be higher. A review by the ANAO calculated that the marginal cost of greenhouse gas abatement under the SHCP was $447/tCO2-e.[81] This compares to a market carbon price closer to $20–$30/tonne/CO2-e under an emissions trading scheme.[82]
- Although carbon abatement was not among the designated objectives of the NSW FIT scheme, the review noted that the carbon abatement costs had been estimated to be in the order of $640/tonne/CO2-e for a 1.5kW system.[83] The ICRC noted costs under the ACT FIT scheme to be in the range of $195 to $434/tonne/CO2-e, compared to abatement costs of $70/tonne/CO2-e under an existing 'green energy scheme' offered by ActewAGL.[84]

The Authority notes that studies such as these typically calculate the cost of greenhouse gas abatement by assessing the cost and full life-cycle emissions of the abatement technology versus a baseline that would have occurred had the abatement technology not been deployed. Such studies do not usually account for external costs, such as the cost of network augmentation. Therefore, the cost of abatement (including for the examples given in the points above) would be even higher for renewable energy incentive schemes if external costs were taken into account.

Sustainability Victoria; Outhred H. and S. Thorncaft 2010, op cit.; Ofgem 2010, 'Creating Britain's low carbon future – Today', Low Carbon Networks Fund Brochure.

[77] Manuel Frondel, Nolan Ritter, Christoph M. Schmidt, Colin Vance 2009. 'Economic Impacts from the Promotion of Renewable Energy Technologies: The German Experience', Ruhr Economic Papers No. 156, University of Ruhr.

[78] This study also noted that for PV, it appears to be more cost-effective to invest in research and development to achieve competitiveness (given the relatively low technological efficiency of current PV), rather than to promote their large-scale production.

[79] Macintosh A and D. Wilkinson 2010. The Australian Government's solar PV rebate program: An evaluation of its cost-effectiveness and fairness, The Australian Institute, Canberra.

[80] Note that the program ran from 2000-2009 and was originally called the Photovoltaic Rebate Program.

[81] ANAO 2010. Administration of Climate Change Programs, Audit Report No.26 2009–10, April 2010.

[82] ANAO 2010. Administration of Climate Change Programs, Audit Report No.26 2009–10, April 2010.

[83] National Generators Forum 2010, Submission to the Solar Bonus Scheme – Statutory Review.

[84] ICRC 2010, Final Report Electricity Feed-in Renewable Energy Premium: Determination of Premium Rate – Report 4 of 2010 March 2010.

The Authority notes that a CPRS framework ensures that investment and operating decisions in the electricity sector take account of the negative externality associated with such emissions. The Authority also notes that the WEM's design allows for the cost of a carbon permits to be added to the generator's short run marginal cost of electricity production. Generation plant would continue to be dispatched in merit order, with the environmental 'cost' included in the bid prices of Market Participant's trading in the STEM.

However, as noted in the 2008 Report to the Minister, the introduction of a CPRS does imply some additional risks for the WEM. Depending on the design of the scheme, there may be implications for the financial viability of generators in the WEM as well as for the availability and reliability of generation plant in the WEM. There may also be implications for the financial viability of small retailers due to higher short term energy market prices, (i.e. in the STEM and Balancing) and therefore greater prudential obligations. The Authority notes that retailers also face risks as a result of the ongoing regulation of tariffs and the ability to pass-through the costs of the LRET/SRES scheme or a carbon tax scheme.

Due to the relative uncertainty surrounding the proposed carbon tax and the market operation in WA, there is potential for the LRET to impact strongly on the WEM. The LRET favours certain generation plant technologies over others and, compared to a carbon tax, delivers a 'second-best' means of reducing greenhouse gas emissions. In addition, a LRET has the potential for unintended consequences, such as the 'crowding out' of more efficient generation (e.g. gas-fired plants) by wind or solar generation or the risk that the additional investment in non-renewable generation (and/or transmission augmentation), which is required to maintain system reliability, is not forthcoming in the SWIS.

There are interactions between policy objectives and renewable energy incentive schemes that have yet to be quantified. If policy maker's objective is to reach certain greenhouse gas abatement targets, these targets can be achieved in a more cost effective manner than introducing such incentive schemes, and this has been demonstrated to be particularly the case for small-scale PV systems. In the Authority's view, from a market effectiveness perspective, it would be more economically efficient to target climate change objectives with a broader approach, including the use of a carbon price.

2.4.4 Impact of climate change policies on retail tariffs

The extended RET scheme under the LRET/SRES framework imposes higher compliance costs on retailers. Under this framework, retailers are required to manage dual liabilities in having to acquire certificates from two distinct renewable sources, Small-scale Technology Certificates (**STCs**) and Large-scale Generation Certificates (**LGCs**). Electricity retailers are required to surrender LGCs annually to meet the Renewable Power Percentage, the rate of liability for LRET, and STCs quarterly to meet the Small-scale Technology Percentage, the rate of liability for the SRES.[85]

The Independent Pricing and Regulatory Tribunal of New South Wales has estimated that changes to the RET scheme will increase regulated electricity prices in NSW by

[85] The Small-scale Technology Percentage for 2011 was set at 14.8 per cent by ORER (as a proportion of total estimated electricity consumption for the 2011 year), which equates to 27 million STCs. The Renewable Power Percentage for 2011 was set at 5.62 per cent (equivalent to 10.6 million LGCs).

6 percentage points from 1 July 2011, about $84 to a standard annual bill of residential customers.[86]

Recent analysis by ROAM Consulting on the impact of LRET/SRES on electricity retail prices found that:

- the annual LRET cost is around $35 per household in 2011, which may double by 2020 (estimated cost of $48-$68 in 2020); and
- the annual SRES cost is around $43 per household in 2011, and this decreases ($5-$19 per annum by 2020) as the Solar Multiplier reduces.

Note that all costs were calculated in 2011 dollars.

ROAM Consulting also calculated the impact of the FIT scheme on average residential consumer electricity bills in Western Australia, in the event that scheme costs were to be a direct pass through to retail tariffs.[87] The cost, if the scheme remains uncapped, was estimated at $94 per annum. As a comparison, if the scheme were to be capped at 150 MW (forecast to be reached in 2014), the cost would be lower at $43 per annum.

Over the same period, 2011-2020, network costs were expected to add an average of $68 per annum to the consumer retail electricity bill in Western Australia.[88]

The 2009 Australian Energy Market Operator's (**AEMO**) modelling of the impact of the RET and proposed CPRS on the National Electricity Market (**NEM**) found that RET targets are likely to drive five years of rapid wind generation development, with wholesale electricity prices doubling to around $55/MWh in that time.[89] With a significant increase in wind generation in the SWIS, there could be displacement of lower cost base load generation by more expensive (but more flexible) generation such as open cycle gas turbines (**OCGT**), in order to meet the increasing load following requirements of the power system.[90]

Renewable energy incentive schemes will be a major driver of higher electricity prices in Western Australia and impose significant additional costs on consumers. The Authority is concerned that unless there is pressure on retailers to procure 'green' electricity at the lowest cost, then inefficient costs will be passed onto consumers. Cost recovery, in essence, is smeared across all SWIS customers, which raises cross-subsidisation and equity issues. Also, regarding small-scale PV systems, there is an up-front cost, even with rebates, that may exclude many low to medium income households from installing a system.[91]

---

[86] Independent Pricing and Regulatory Tribunal New South Wales, Changes in regulated electricity retail process from 1 July 2011, Electricity - Draft Report, April 2011.

[87] Currently, the FIT scheme is funded via Consolidated Revenue.

[88] ROAM Consulting 2011, Impact of renewable energy policies on retail electricity prices, Report to the Clean Energy Council, 28 February 2011.

[89] AEMO 2009, National Transmission Statement: National Grid 2030 for a Low Carbon Australia.

[90] Load Following is the service of frequently adjusting the output of one or more Scheduled Generators within a Trading Interval, so as to match total system generation to total system load in real time in order to correct any SWIS frequency variations. With a significant increase in wind generation in the SWIS, the Authority notes that, under the current Market Rules, the Load Following Ancillary Services requirement could result in the displacement of lower cost generation by OCGT.

[91] A recent study found that under the SHCP only 33 per cent of recipients resided in areas that were rated as low to medium-low on a socio-economic scale. Macintosh A. and D. Wilkinson 2010, The Australian Government's solar PV rebate program – An evaluation of its cost-effectiveness and fairness, The Australian Institute, Canberra.

Finding 1

Section 2.4

Renewable energy incentive schemes will be a major driver of higher electricity prices in Western Australia and impose significant additional costs on consumers. The Authority is concerned that unless there is pressure on retailers to procure 'green' electricity at the lowest cost, then inefficient costs will be passed onto consumers.

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

2.5 Transmission network issues

Secure and reliable electricity supply depends on adequate infrastructure to transport the electricity from its source to the end user.

While the transmission network access framework (inclusive of WEM mechanisms) has delivered adequate generation capacity in the recent past, the developing market context presents challenges to the existing framework. The 'unconstrained' network access approach (defined in Section 2.5.1) has been previously identified as a potential cause of inefficiency in the WEM by stakeholders, the AEMC and by the Authority. The issues can be broadly split into two areas:

- the current unconstrained network access approach is likely to lead to inefficient investment in network assets;[92] and
- there are areas where the current network access arrangements, processes and their application create barriers and delays to new generation entry and therefore create inefficiencies.

These issues are discussed in detail in this section, which is structured as follows:

- Section 2.5.1 discusses the issues surrounding the unconstrained network access approach; and
- Section 2.5.2 discusses the current access processes and their application, and access connection costs.

In summary, the Authority's review of the unconstrained network access approach in the SWIS has found that:

- the current network does not have the capacity to connect much more generation on an 'unconstrained' basis;
- meeting forecast load growth will require very large amounts of network investment – more than under a 'constrained' approach;

[92] Under the current WEM framework generators, discrete (larger) consumers or end consumers pay for network assets.

- new network assets built as a result of the unconstrained network access approach will not be highly utilised and may only provide a minimal increase in reliability (or at least one which is not justified by the costs);[93] and
- regardless of how costs are allocated, there will be a need for an increase in electricity prices – it is certain that increases will be higher under an unconstrained network access approach than under a constrained network access approach.

The Authority considers that the current unconstrained network access approach in the SWIS does not enhance the Market Objectives for the following reasons.

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

The State Government has acknowledged that WA faces network infrastructure challenges over the next 20 years, particularly in the electricity sector, and that significant new capital investment is required to extend or strengthen networks to serve new users, accommodate new suppliers, and to improve the reliability and security of the system.[94] As part of its Strategic Energy Initiative, the State Government's short term goal is to optimise major energy transmission infrastructure by developing a constrained network access model for the Western Power transmission network, and a pathway to implementation[95] The Authority supports this initiative and recommends that a full and detailed analysis be undertaken of the costs and benefits relating to a move towards a constrained network access model.[96] As the unconstrained network access approach is interlinked with other key parts of the WEM design, such a review would need to consider all the relevant interactions. The main linkages are with the Bilateral contracting arrangements, the RCM, and the market and system operations functions.[97]

The potential efficiency benefits would appear, on the level of analysis included in this report (see section 2.5.1), to make such a review worth undertaking. The Authority considers that such a review would not be a simple undertaking, would need a very clear set of objectives, be well resourced, with full and open consultation and proper consideration of all the consequences of recommended changes. With such a wide-ranging impact, the review would need support in key areas and strong program management to ensure timeframes are met.

---

[93] The investment will be even less efficient when it supports peak period access for intermittent generation which is not normally available at times of peak demand (e.g. wind farms).

[94] Office of Energy 2011, Strategic Energy Initiative Energy 2031: Directions Paper, p, 22.

[95] Office of Energy 2011, Strategic Energy Initiative Energy 2031: Directions Paper, p, 43.

[96] The Authority has included in Appendix 4 of this report a list of issues that, in the Authority's view, should be consider in the scope of the government's review to a move towards a constrained network access model.

[97] The linkages between the current network access arrangements and the WEM design are discussed in further detail in Section 2.5.1 and Appendix 4.

Recommendation 8

Section 2.5

The Authority recommends that a full and detailed review be undertaken of the costs, benefits and possible implementation issues relating to a move towards a constrained network access framework. This review would need to:

- **consider all the relevant interactions with the Wholesale Electricity Market's design; and**
- **be well resourced with support in key areas and strong program management to ensure timeframes are met.**

Regarding the current network access arrangements, processes and their application, the Authority has found there are a range of issues which represent a barrier to the entry of new generation capacity. Issues relate to:

- limited information on available capacity by location (or area) and projected development of the network; and
- processes which, although well established, are not executed in a transparent way. Of particular concern is the application of the NFIT, which is central to determining the cost of access to new entrants.

Recommendation 9

Section 2.5

The Authority recommends that a mechanism be developed to provide timely information to the market about access to available network capacity, to allow generators to make efficient locational decisions. This information needs to be made public in a useful and affordable form. The Authority also recommends that a formal reporting requirement should be brought into effect through the *Electricity Networks Access Code 2004*, the Access Arrangement or a Licence condition.

2.5.1 Unconstrained network access

The unconstrained network access approach of the electricity market design is directly linked to the Market Objective of supply security and reliability,[98] and the relative simplicity of the power system and market operations.

The concept of unconstrained access to the network is that it allows generators to have full access to the network during times of peak electricity demand, even after a single credible network fault. Various definitions of this concept exist, and the terms

[98] Market Objective 1 is to 'promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the SWIS'.

'unconstrained access' or 'firm access' are often used.[99] For consistency, the term 'unconstrained access' is used in this report.

An unconstrained network facilitates simpler operation of the power system and market because of the absence of dynamic physical constraints.[100] This is reflected in the relative simplicity of the WEM's current design and operation.[101] A summary of how the unconstrained network access framework interacts with the relevant WEM arrangements is shown in Table 9 in Appendix 5.

Under the RCM, the certification of Capacity Credits requires a generator to have an Electricity Transfer Access Contract (**ETAC**) for access to the transmission network. By way of Western Power's planning criteria, in most cases this must include an unconstrained access. A summary of the origins and application of the unconstrained network access approach in the SWIS is included in Appendix 5.

The following examples provide an estimation of the inefficiency of investment in the transmission network under an unconstrained network access approach, from the perspectives of:

- meeting the SWIS's continuing summer peak demand growth at a time where the transmission network is (generally accepted) as being fully utilised; and
- expanding the network to serve a peak demand profile where peak loads only exceed 80 per cent of the annual peak load for a relatively small number of hours (i.e. 140 hours per year).

Example: Cost of network investment in the next ten years under an unconstrained network access approach

> Significant network investment in network capacity will be required in the next ten years to allow the forecast 6,000 MW summer peak demand to be met.[102] Assuming the transmission capital cost used for the Maximum Reserve Capacity Price for the 2013/14 Reserve Capacity Year, an indicative network investment forecast to give access to the projected requirement of 2,000 MW of new generation is around $0.6bn.[103]

The level of possible inefficient investment in network capacity – that is, assets which are built to allow unconstrained network access at times of peak demand – may increase substantially in the future. As unconstrained network access needs to be available (or at least committed to) before a generator can participate in the RCM, there may be a delay

---

[99] A term used in the Australian Energy Market Commission's recent 'Review of Energy Market Frameworks in Light of Climate Change' report (AEMC report), which is perhaps more accurate, is 'normally unconstrained'.

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

[101] Unconstrained access to the transmission network allows for any generator to contract with any retailer through a Bilateral Contract, regardless of their respective entry and access points.

[102] Based on forecast SWIS maximum demand until 2020/21 (for the 50 per cent probability of exceedance case provided by NIEIR), which takes into account expected economic growth conditions and other new major loads identified by the IMO. IMO 2010, 2010 Statement of Opportunities, July 2010, p. 35.

[103] Using the calculated Transmission Connection cost of $48.8m and dividing it by 160 MW (size of the notional OCGT power station defined in the MRCP Market Procedure). See the ERA website, Decision on the Maximum Reserve Capacity Price proposed by the Independent Market Operator for the 2013/14 Reserve Capacity Year, January 2001.

in the connection of new generation to a much greater extent than seen in the past. This risk was articulated by stakeholders in written submissions and in informal consultation.[104]

There are two main reasons for the need for increased network investment and the resulting potential delay in connection of new generation. Firstly, the locations and size of the existing generators and loads use the majority of the currently available secure network capacity. New generation connection will therefore drive a need for further network investment to allow it to meet the requirements for unconstrained network access during periods of peak demand. Secondly, summer peak demand continues to grow, with the IMO forecasting more than 2,000 MW increase (around 50 per cent) in peak demand over the next ten years (i.e. until 2021).[105] In comparison, summer peak demand in the NEM is expected to increase by around 30 per cent to 2020.[106]

Only a very small proportion of annual energy is being 'secured' by the provision of unconstrained network access capacity.[107] Much of the new capacity will then only be required to cover the risk of a fault during the few hours of peak demand each year, and this capacity would not actually be used unless a fault occurs. Given the potentially low value of load at risk, this outcome does not appear to be an efficient trade-off. That is, the benefits in terms of the incremental reliability would not cover the cost of capacity assets, regardless of which entity pays for them.

This inefficiency, which is characterised by low utilisation of expensive assets, is recognised in many other developed electricity markets where:

- exposing customers to the risk of some level of unserved energy is considered efficient, with the market designed to inherently take into account this risk;[108]
- some level of congestion is considered efficient – where the costs of managing the constraint are less than the cost of building assets to remove the constraint (assuming no other quantifiable benefits exist); and
- managing the peak load growth and underlying load shape is becoming an important policy objective.[109]

Further, the inefficiency will be even more pronounced if unconstrained network access is provided to intermittent generation (such as wind farms) to its full rated capacity, as it must under the current arrangements, before the RCM can be accessed. In the case of wind generation, this is inefficient because they are unlikely to generate to full capacity at

[104] To understand the rationale behind some of the written submissions in response to the Authority's Discussion Paper, the Authority and a consultant engaged to assist in the review of network issues, met with a broad range of stakeholders. Meetings were held with Synergy, Western Power, System Management, the Independent Market Operator, Griffin Energy, ERM, Perth Energy, Verve Energy, ERM Power and Midwest Energy.

[105] IMO 2010, 2010 Statement of Opportunities, July 2010, p. 35.

[106] AEMO 2010, Electricity Statement of Opportunities, August 2010.

[107] The load profile information for the SWIS for the year ended July 2010,[107] indicates that the load only exceeded 80 per cent of the annual peak (of 3,137 MW) for around 140 hours – about 1.6 per cent of the time. In providing secure transmission capacity, 'extra' assets exist to cover the risk of a fault within this small window of time.

[108] For example, the NSW distribution network planning criteria specify a threshold for the size of loads at the end of radial feeders which need to be secured for a single fault (varying by areas, between 5 and 15 MVA). This inherently (and somewhat crudely) takes account of the value of securing that load.

[109] This management of peak load has been trialled by Western Power in the recent past, and on a much wider scale, would be one of the key benefits of investment in the 'smart grid'.

times of peak demand.[110] Currently, there is no mechanism in the WEM to re-allocate any unused network capacity in the short term.

In addition to the inefficiency of investment in the transmission network under an unconstrained network access approach, the Authority is also of the view this approach results in a barrier to new generation entry.

The IMO's 2010 SOO suggests new generation will be required by around 2013/14 to meet the forecast Reserve Capacity Target. The next generators connecting to the system will likely drive the need for investment in 'deep' network assets to ensure there is unconstrained access to network capacity. Under the current process, a significant proportion of these costs are likely to be passed through to the new generator. This is a clear 'first-mover' disincentive for investors in generation at any given location since the ability to recover a proportion of the 'deep' augmentation costs from the next adjacent generator is not clearly defined and complex.

2.5.2 Current access processes and their application

There are aspects of the current network access arrangements, including the processes and how they are applied, which create barriers and delays to new generation entry and are inefficient. The Authority considers that there is a strong case for addressing these issues promptly, given a move to a constrained network access approach is a longer term development. As the current network has little or no spare entry capacity, these processes will become increasing important due to the need for more generation capacity generally and the need for increasing renewable generation connections to meet the RET.

As part of the Authority's review, the Authority has assessed the issues at five distinct stages in the access process:

- Access to information
- Application queuing
- Application assessment
- Allocation of 'deep connection' costs
- Delivery of access infrastructure.

These stages are discussed in further detail below.

Access to information

The Authority has found that there is a lack of accessible information to allow generators to make efficient locational choices. This is relatively unusual in deregulated electricity markets. Currently, prospective generators have no network information to inform an efficient trade-off between network costs and fuel or renewable resources. Generators only have access to a cost estimate after a (potentially) long wait in the queue and then paying Western Power to process an application for a specific access point. The effectiveness of a potentially strong locational signal for generation investment is significantly negated by the requirement (and associated cost) for network investment becoming known only late in the process.

[110] On average, higher wind power occurs at night-time in summer, rather than matching the peak periods which occur in daytime. Western Power Generation Business Unit, Submission To The Western Australian Office Of Energy Electricity Reform Implementation Unit On The Draft Econnect Report, 'Maximising The Penetration Of Intermittent Generation In The SWIS'.

Even then, the cost estimate for the delivery of transmission assets by Western Power is not firm and generators carry any risk of additional costs during construction. This is covered in more detail in the 'Delivery of access infrastructure' section below.

The Authority notes that while an indicative 'access map' does exist to guide small generation connections around the Perth metropolitan area, an equivalent information source for the whole SWIS is not currently available.

Section 14 of the *Electricity Networks Access Code 2004* addresses the spare capacity information that service providers need to make available.

> 14.3 A service provider must on an annual basis determine as a reasonable and prudent person the spare capacity, if any, in that part of the covered network which is a transmission system and must either:
>
> (a) specify the spare capacity in a register which is available for inspection by users and applicants on reasonable terms; or
>
> (b) make available on payment of a reasonable fee a report on the spare capacity.

While this requires the production of information on spare capacity, there is a choice between providing information widely in a register (a) or providing information to specific requests for a fee (b). The first option would be more useful to market participants.

Until such information about spare capacity is made available, generators will not be able to optimise their location decisions, or at least will not have the ability to do so until they have progressed some way through Western Power's access processes. This inevitably requires proponents to have spent time and money pursuing an uncertain outcome, making project financing more difficult and expensive.

The Authority recommends that a mechanism is required to provide timely information to the market about access to available network capacity, to allow generators to make efficient locational decisions (see Recommendation 9). This information needs to be made public in a useful and affordable form. The Authority also recommends that a formal reporting requirement should be brought into effect through the Access Code, Access Arrangement or a Licence condition.

Application queuing

The Applications and Queuing Policy (**AQP**) sets out the process for applicants seeking a connection to Western Power's network. The AQP was approved in early 2010 as part of Western Power's Access Arrangement. The key features of the current policy are set out in Appendix 5 of this report.

The current process creates delays in the processing of the access applications of generators which may otherwise be ready to connect at the expense of processing applications that have higher queue positions. In the worst case scenario (and accounting for all other barriers to entry) this could potentially lead to generation capacity shortages.

With the need for new generator capacity and an increase in renewable generator connections, access queuing processes have been found to be an issue elsewhere in Australia and overseas.[111] In the NEM, ongoing changes to transmission access processes and the *National Electricity Rules* are expected to address similar issues. Rule

[111] UK and California for example.

changes for the creation of 'connection hubs' are under consultation to address the 'first mover disincentive' and changes to confidentiality provisions are also being considered.

On 23 December 2010, the Authority received a proposal from Western Power to vary the AQP during the current Access Arrangement period. Western Power's variation proposal contained numerous proposed revisions to the AQP.[112] After carrying out public consultation on Western Power's proposal and consideration of the concerns raised in the public submissions, the Authority determined not to approve the proposal. The Authority considered that the concerns raised by interested parties should be addressed by Western Power and taken into account when it submits its proposed revised access arrangement later this year.[113]

Application assessment

Processing access applications is reported by stakeholders to be slow. Western Power's own information to participants indicates that it can take around a year from when an application is lodged to an access offer being made, assuming there are no delays caused by the queue.[114] This includes up to three months for Western Power to receive approval from its Executive, Board, and the Authority as well as from Government.

Even once these different approvals are granted and a proponent is ready to commit to an ETAC immediately, Western Power estimates that it can take years for transmission connection assets, including system augmentations, to be commissioned.[115] Further, under the current AQP, applications are only considered one at a time, so generators normally have to wait to get to the front of the queue before their access application is assessed.[116]

Some proponents consulted consider the costs of network studies performed by Western Power to be expensive and, when results were different from 'expected', generators were expected to bear the costs of further studies. There is little option for generators to have the studies performed by other parties. Further, proponents consider that the technical requirements which need to be fulfilled (in terms of their generators having an acceptable impact on the system and other users) were not always clear.[117]

It is likely that these issues reflect a genuine desire within Western Power to ensure the power system is secure and safe. Similar issues have been observed elsewhere in Australia and overseas. However, they have rightly been identified as creating barriers to entry at a time when new generation investment is required, to meet load growth, replace old plant and meet low carbon policy objectives. Responses have included changes and clarification to technical standards, pressure on transmission network owners to focus on

---

[112] See ERA website, Electricity Access - Access Arrangement Variations (Second Access Arrangement Period) web page.

[113] See ERA website, Final Decision on Proposed Variations to Western Power's Access Arrangement for 2009/10 to 2011/12: Applications and Queuing Policy Submitted by Western Power, 1 April 2011.

[114] Western Power 2008, 'An introduction to Power Systems and the Connection Process', p38, May 2008.

[115] May take up to five years, according to Western Power's document, 'An introduction to Power Systems and the Connection Process'. It would not be considered unusual for this to occur in some cases, especially where new line routes are required.

[116] In some cases they can be considered earlier but all generators with a higher position in the queue are assumed to get access. The studies undertaken at this early stage can therefore be relatively meaningless.

[117] Examples discussed during consultation included that there can be different applications of technical standards applied by different personnel and that there was no transparency over where decisions were being made in Western Power and on what basis.

the market access elements of their roles and customer needs, and improvements in connection processes.

Allocation of 'deep connection' costs

Western Power's Capital Contributions Policy, which forms part of the Access Arrangement, provides a framework for the allocation of deep connection costs to generators. In summary, this Policy states that generators will pay for any transmission works 'which do not meet the New Facilities Investment Test' (**NFIT**). In effect this means that any part of the investment which does not provide benefit to all transmission users is paid for by the new generator. In practical terms the Capital Contributions Policy allows for the recovery of the minimum cost required to allow the generator access, and that Western Power may decide to undertake additional work or build the assets to a higher capacity.[118]

The consultation raised some stakeholder concerns with the processes for cost allocation. There is an incentive for Western Power to allocate as much costs to a generator as possible for two reasons. Firstly, there is the risk that the Authority will not agree with the NFIT application with the result that Western Power cannot add those assets to the asset base. Secondly, there may be implicit pressure on Western Power to allocate more costs to the generator to minimise the requirement for funding investments.[119] Stakeholders also questioned whether the market-wide benefits of connecting new, lower cost generation were fully considered during NFIT applications. This review has not analysed this issue in detail although comments mirror experiences in other jurisdictions, where the analysis of 'market benefit' network investments has proved complex.[120] In any event stakeholders do not consider the current cost allocation process to be transparent.

Delivery of asset infrastructure

Western Power currently passes through all cost and timing risk to generators, although it manages the contracts for the delivery of the work. This creates a lack of certainty for generators and is a particular problem for those seeking external finance. Consultation discussions indicated that this was the only approach considered by Western Power and one written response suggested a review of the Western Power's WACC to take account of the reduced risk to Western Power.

On this level of review, it does seem to be an inappropriate allocation of risk which may be driven by pressure (internal or Treasury) on Western Power, together with a perception of regulatory risk. Regardless, the generator is not best placed to manage such risks. This is reflected to an extent elsewhere in Australia, where transmission companies may offer a capped fee for connection costs and/or 'funded augmentations'.[121] In the Authority's view, this allocation of risk further discourages generation entry into the SWIS.

---

[118] Also, a full NFIT may not be applied at the time but an 'NFIT-like' process may be used to expedite the process. However, this leaves a residual risk with Western Power if the Authority later disagrees with the efficiency of an investment.

[119] There would be a return on the investment over the life of the asset but it still needs to be funded by Western Power, through borrowing from WA Treasury.

[120] In particular, the experience in the NEM has shown that it is difficult for analysis to show that an investment provides a level of market benefit and debate has been focused on modelling approaches and assumptions. In New Zealand, the modelling approach and key assumptions were well defined but the rules around 'passing' the Grid Investment Test were not.

[121] These are network investments that generators pay for to reduce their risk of being constrained off the network.

2.6 Changes to the Vesting Arrangements

The original Vesting Arrangements (**OVA**) were a transitional mechanism intended to support the development of a competitive electricity market in Western Australia.[122] The OVA provided for the initial wholesale electricity supply from Verve Energy to Synergy. The OVA comprised of a Vesting Contract (2006) (**VC**)[123] and a Ministerial Direction issued under the *Electricity Corporations Act 2005* (**Corporations Act**) (the 'Displacement Mechanism Ministerial Direction').[124]

The VC commenced upon the disaggregation of Western Power Corporation on 1 April 2006. Under the Displacement Mechanism, Synergy's load volumes were progressively exposed to competitive sourcing, with Verve Energy and IPP's being able to tender for these volumes.[125] This mechanism was designed to gradually reduce the level of wholesale electricity supply from Verve Energy to Synergy.

The VC was typical of transitional arrangements used to facilitate a transition from one state to another – in this case, the transition from the former Western Power Corporation as a single monopoly utility in WA into four separate companies, namely Verve Energy, Synergy, Western Power, and Horizon Power, operating in the context of a competitive electricity market. In addition to the VC, there were a number of other measures put in place to facilitate the introduction of competition and to mitigate the market power of Verve Energy and Synergy. These measures included: Verve Energy's ownership of generation capacity (non-renewable) was capped at 3,000 MW; Verve Energy was unable to sell to any party for its own consumption until 2013 (extendable to 2016) (the 'Restriction'); and Synergy was unable to generate until 2013 (extendable to 2016) (the 'Prohibition').

These measures have been effective in assisting in the entry of new generators, including Griffin Energy, ERM Power and Perth Energy. Over the past five years, more than 1,000 MW of new capacity has entered the WEM, with the value of private investment in electricity generation estimated at $2.6 billion.[126] A large proportion of this new capacity

---

[122] Vesting arrangements typically have a number of objectives related to the specific transition that is intended to be facilitated. Some common objectives include supporting the financial viability of the new entities in a similar manner to a commercial agreement. Some features, however, are invariably required to achieve policy objectives. The policy objectives vary from instance to instance, as they depend on the starting point, process and timetable over which reforms are being driven.

[123] The Minister for Energy made an order under section 82(1) of the *Electricity Corporations Act 2005* prescribing the terms and conditions of the initial contractual arrangements between Verve Energy and Synergy under the Vesting Contract (2006). See the Office of Energy's website for further information on the Vesting Contract (2006), Vesting Contract 2006 web page.

[124] The Displacement Mechanism's three main functions were to: move from a high level of contracting between Verve Energy and Synergy from market commencement declining over time and thereby providing an opportunity for new entry in both retail and generation; to mitigate the market power of Verve Energy and Synergy; and provide a low risk profile for vested volumes for Synergy. The Displacement Mechanism Ministerial Direction was to ensure that: the tender processes that Synergy undertook to fulfil its obligations under the Displacement Mechanism in the Vesting Contact (2006) were open and fair; and the market was provided with appropriate information to participate in the tender processes. See the Office of Energy's website for further information on the Displacement Mechanism Ministerial Direction, Vesting Contract 2006 web page.

[125] Private investment in Neerabup and Griffin 2 was underwritten by winning tenders (2006 and 2007 tenders) with Synergy for displaced loads. Note that NewGen's Kwinana plant was underwritten by Western Power's 'Power Procurement' process (2002-2005), which was designed to procure privately funded generation.

[126] Includes private investment by Griffin Energy (Bluewaters 1 and 2), ERM Power (NewGen Kwinana and Neerabup), Perth Energy (Kwinana Swift), UBS International Infrastructure Fund and the Retail Employees Superannuation Trust (Collgar wind farm), Tesla Corporation (diesel units) and Merredin Energy (Merredin Power Station).

has been underwritten through Synergy's Supply Procurement program required under the Displacement Mechanism in the VC.[127] As a result of this new private sector investment in generation, Verve Energy's market share of generation capacity (excluding Demand Side Management capacity) will have decreased from 80 per cent in 2007 to 60 per cent in 2012.[128]

Part 4 of the Corporations Act makes provision for the operation of the two corporations (State Generation (Verve Energy) and State Retail (Synergy)) and the imposition of requirements relating to their roles in the WEM as prescribed by the Minister for Energy (Minister). Section 81 of the Corporations Act prescribes the objective of Part 4:

> 81. Object of this Part
>
> The object of this Part is to confer on the Minister power to determine arrangements between the corporations in order to —
>
> 1) encourage the development of competition in the generation, wholesaling and retailing of electricity; and
>
> 2) establish the terms and conditions of the initial arrangements that are to have effect between them.

The VC was intended to meet the objectives of both parts of the Corporations Act. The official Objectives set out for the VC were to:[129]

- mitigate the market power of State Generation (Verve Energy);
- support market development by providing appropriate incentives to both entities; and
- ensure the financial viability of both State Generation and State Retail (Synergy) in the transition to a competitive electricity market.

The timetable for the VC's Displacement Mechanism[130] determined when the VC was due to expire, which was within three years of the introduction of FRC in the SWIS. At the time the VC was put in place FRC was to be introduced once the WEM was 'efficient' and at that time there should be no further need for the Vesting Contract.

The VC was terminated in October 2010 and replaced with the Replacement Vesting Contract (**RVC**). The Government considered that the VC needed to be replaced as it had directly resulted in the:

- procurement of excess generation capacity from IPP's, which lead to either the underutilisation or inefficient utilisation of State-owned generation; and

[127] Private investment in NewGen's 330MW open-cycle, gas-fired peaking plant at Neerabup and Griffin Energy's 200MW Bluewaters coal-fired power station was underwritten by winning tenders (2006 and 2007 tenders) with Synergy for displaced loads. Note that NewGen's Kwinana plant was underwritten by Western Power's 'Power Procurement' process (2002-2005), which was designed to procure privately funded generation.

[128] Calculated from the IMO assigned Capacity Credits for the 2007/08 and the 2012/13 Capacity Years. For jointly owned assets, credits are assigned to reflect operational control rather than the ownership structure and Verve is assigned 220MW of credits in the 2012/13 Capacity Year for the 'mothballed' Muja 'A' and Muja 'B' plants.

[129] See the Office of Energy's web site, Vesting Contract.

[130] Set out in Schedule 10 of the Vesting Contract.

- significant financial losses incurred by Verve Energy between the 2006/07 and 2008/09 financial years.[131]

The RVC is designed to achieve fewer objectives than the VC and is simpler to operate.

Arrangements within the RVC are relevant to the Authority's WEM monitoring function, including the impact on the market's effectiveness in meeting the Market Objectives. In order to determine the extent to which the RVC supports the development of a competitive electricity market in WA, the Authority has carried out the following assessments:

- the extent to which the objectives set out in section 81(a) of the Corporations Act were met by the VC, compared to how the RVC meets these objectives (see Section 2.6.1); and
- in qualitative terms, the cost implications of the RVC for the market and the parties to the contract (i.e. Verve Energy and Synergy) compared to the VC (see Section 2.6.2).

2.6.1 The objective of the Vesting Contract and summary of competitive impacts

As noted earlier, Section 81(a) of the Corporations Act included the objective of encouraging "the development of competition in the generation, wholesaling and retailing of electricity". The focus on the development of competition implies that competition may not be the starting point, but should be the direction of progress. In that light, it is possible to consider how a vesting contract's design promotes productive, allocative and dynamic efficiency in the wholesale and retail electricity markets.[132]

Table 1 shows a comparison of the original VC (2006) and the RVC (2010) in terms of the original VC's official objectives.

---

[131] See for example, Extract from Hansard [COUNCIL - Tuesday, 21 September 2010], p6884d-6885a, Hon Kate Doust; Hon Peter Collier, p. 1. Regarding Verve Energy's losses each year, according to the Verve Energy Review (August 2009), $212 million of pre-tax loss (of a total $454 million pre-tax loss) over these three financial years were a result of mechanisms or terms in the Vesting Contract (specifically due to the Netback Mechanism and anomalies in the terms in the Vesting Contract). See Office of Energy website, Verve Energy Review, p 29.

[132] Since the purpose of a vesting contract is inherently to facilitate a transition, the primary expectation is that the overall market will develop or mature in ways that, over time, make it possible to reduce or remove the vesting contract. At the same time, the existence of a high level of vesting contract cover can, itself, stifle the development of the normal commercial contract market – by limiting growth of market liquidity and possibly increasing risk. Thus, an effective vesting contract arrangement must carefully balance providing sufficient transitional support while not being overly rigid.

Table 1 Comparison of the original Vesting Contract (2006) and Replacement Vesting Contract (2010) in terms of the original Vesting Contract's official objectives

Feature	Original Vesting Contract	Replacement Vesting Contract
Mitigate market power of State Generation (Verve Energy) Support market development: Appropriate incentives for Retail (Synergy)	*This information is confidential and is not presented in the public version of the report.*	
Support market development: Liquidity	Balancing Hedge provided a template for a financial hedge that may encourage more hedging around the STEM and improve STEM liquidity and price discovery.	No features in this area.
Support market development: Lowering barriers to new entry	Displacement Mechanism required Synergy to tender for increasing proportions of its capacity requirement – giving new entrants a clear route to market where they could compete for market share on an equal footing with Verve Energy.	No features in this area.
Support market development: Information	The Displacement Mechanism included requirements to publish information about demand, vesting prices, volumes and Synergy's Displacement requirements. This gave new entrants more information about the market demands and price discovery in the market to enable them to make decisions about entry.	There are no information disclosure requirements in the RVC. The price and volume terms are confidential thus reducing price discovery in the market compared with the previous situation.

The Authority considers that the RVC is substantially a commercial arrangement between Synergy and Verve Energy, save for the price at which the capacity and energy is sold. The comparison of the original VC and the RVC shows that the new contract no longer includes several of the features of the VC, particularly those that were specifically designed to promote market development.

A key limitation of the WEM is the lack of price discovery in the market. The capacity price is not a market price; the STEM and balancing mechanism are illiquid and resultant prices are not reflective of actual contracting. This makes it more difficult for new entrants to assess whether or not they should enter the market and thus can be a source of information asymmetry between larger existing players and new entrants and a possible barrier to competition.

The Displacement Mechanism included requirements to publish information about demand, vesting prices, volumes and Synergy's Displacement requirements. While vesting arrangements are not a typical method for enhanced price discovery, the original arrangements did provide a valuable source of information about market opportunities. The implementation of the RVC has diminished the level of price discovery in the market.

The Authority has considered:

- whether the change from the VC to the RVC has made it more difficult to achieve the objectives of the Act, particularly with respect to the development of competition in the retail, wholesale and generation markets; and
- whether a sufficient level of competition had already been achieved at the time the VC was replaced with the RVC.

To address these questions, it is necessary to consider the structure of the Market Participants, the overall market design, policy instruments and contracts in order to identify the drivers of (or barrier to) competition in the market. While a complete evaluation is outside the scope of the assessment carried out for this report, the following list summarises the key areas where competition is reduced in the RVC compared to the VC.

- Barriers to entry – the RVC has no mechanism for volumes to be displaced by Market Participants other than Verve Energy. This represents a barrier to new entry and the loss of an opportunity for Synergy to ensure the pricing in the contract is competitive.
- Information provision – the RVC prices and volumes are confidential and there is no equivalent of the VC's Displacement Statement of Opportunities which gave potential new entrants information about prices and volumes in the market.
- Market power mitigation – the RVC contains no market power mitigation features.

One of the official objectives of the original VC was to mitigate the market power of State Generation (Verve Energy). However, many of the market power mitigation features of the VC have been removed from the RVC.

The Authority considers that a potentially useful piece of analysis would be to review the new market arrangements (in aggregate, once the changes to the Balancing mechanism and other areas of the WEM's design have been implemented) to assess whether, across the whole market, the appropriate level of market power mitigation is still in place.

Recommendation 10

Section 2.6

The Authority recommends a review of the overall level of competition in the market be carried out once the key changes to the Wholesale Electricity Market's design (including the introduction of competitive Balancing) have been implemented. The Authority considers this review is necessary in order to assess whether, across the whole market, the appropriate level of market power mitigation is still in place. The Authority is strongly of the view that this review should be transparent and consultative, and be coordinated by the Office of Energy.

The Authority considers that, compared to the VC, there are a number of areas where market competition is reduced under the RVC. In particular, the absence of a Displacement Mechanism in the RVC has removed a significant pro-competition feature that was present in the VC. The Displacement Mechanism played a key role in providing information to the market, creating a route for new entrant generators to enter the market, and allowed Verve Energy to 'mark to market'[133] any electricity it sold to Synergy to replace vested volumes. Under the RVC, there is no mechanism for non-Verve generators to tender for Synergy loads.

RVC prices and volumes are confidential and there is no equivalent of the VC's Displacement Statement of Opportunities, which provided potential new entrants with information about prices and volumes in the market. Verve Energy is likely to supply a greater quantity of contracted electricity to Synergy over the period 2013-2020 than would have occurred if displacement had continued under the VC.[134] Also, there is no price discovery value to this contract as the contract prices and volumes are confidential and there is no obligation to publish any ongoing documents about the contract.

The Authority recommends that a review should be undertaken into the provision of information in the WEM, including the provision of volume and price information in the RVC. The Authority has concerns about how the pricing in the RVC was derived. The Authority considers that such a review should also evaluate whether the contract efficiently meets Synergy's pricing, load and volume requirements. The analysis of these issues is highly relevant in the context of the electricity tariff review that the Office of Energy in currently undertaking.

2.6.2 Cost implications

The Authority has considered how the costs of Verve Energy's operations have been priced, if at all, into the RVC. Information relating to this review is confidential and is not

---

[133] 'Mark-to-market' or 'fair value' accounting refers to accounting for the value of an asset or liability based on the current market price of the asset or liability (or for similar assets and liabilities), or based on another objectively assessed 'fair value'. In this context, the term relates to the ability to compare the contract price to the current electricity contract market price, or 'fair value' of the contract price.

[134] Note that the actual outcome would have been dependent on the success of IPP's in tendering for displaced loads under the VC and that supply volumes are confidential under the RVC.

presented in the public version of the report. However, based on this review (and as noted earlier), the Authority has concerns about how the pricing in the RVC was derived.

Finding 2

Section 2.6

The Authority is concerned about information provision in the Wholesale Electricity Market, including a lack of volume and price information associated with the Replacement Vesting Contract. The Authority considers that an evaluation is necessary to assess whether the contract efficiently meets Synergy's pricing, load and volume requirements.

PART B

3 Monitoring of the Wholesale Electricity Market

Clause 2.16.11 of the Market Rules requires that the Report to the Minister provides an assessment on the effectiveness of the market in dealing with matters identified in clause 2.16.9.

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

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

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

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

3.1 Ancillary Services Contracts and Balancing Support Contracts

3.1.1 Ancillary Services Contracts

In the WEM, Ancillary Services are required to maintain power system security and reliability through the control of key technical characteristics, such as frequency and voltage, which facilitates the orderly trading in electricity and ensures that electricity supplies are of acceptable quality. There are five defined types of Ancillary Services applicable in the SWIS, which are Spinning Reserve, Load Following, System Restart, Load Rejection Reserve and Dispatch Support.[135]

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

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

At present, there are only limited opportunities for IPP's to source revenue streams from providing Ancillary Services. In respect of System Restart Ancillary Service, System Management has recently contracted for two System Restart services following competitive tender processes, with both contracts commencing in the 2011/12 financial year for a period of five years.[136] However, System Management's first call for Expressions of Interest in the competitive procurement of Load Following Ancillary Service in February 2010 resulted in no expressions being received, so Verve Energy will continue to be the sole provider of this service at this time.

Providing Load Following Ancillary Service is complex in terms of the provider having to potentially incur significant capital costs to retrofit control mechanisms to provide the service, which would then need to be recovered through energy payments. The difficulty with acquiring Load Following Ancillary Service from IPP's would appear to be related to the current design limitation, where the availability payment is linked to the Marginal Cost Administrative Price (**MCAP**), which can be negative. Another disincentive for prospective providers is that MCAP is difficult to forecast, due to it being set on the basis of a formula that has variability in the inputs.

As a part of its contribution to the IMO MAC's REGWG Work Package 3,[137] ROAM Consulting recommended that a market should be introduced for Ancillary Services, with separate pricing for Load Following and Spinning Reserve Ancillary Services. Even after taking this recommendation into consideration, the current design could still inappropriately price both services for the following reasons:

- IPP supply is required by the Market Rules to be lower in price in comparison with the supply from Verve Energy; and
- supply from Verve Energy is priced at average cost, not the cost of the marginal unit dispatched, and is thus not priced at the efficient cost of supply.

ROAM Consulting also recommended that the Ancillary Service payment equations in the Market Rules should be adjusted to allow for the appropriate distribution of Load Following Ancillary Service Costs between Loads and Intermittent Generators (i.e. the parties primarily giving rise to the need for these services). The IMO has noted its intention to implement the recommendations,[138] which resulted in the draft Rule Change (set out in the Pre Rule Change Discussion Paper PRC_2010_27), considered by the MAC for the first time in November 2010 and again in February 2011. If progressed, these changes would likely result in a significant increase in Load Following Ancillary Service costs for intermittent generation.

System Management has continued to investigate options which could make provision of this service a more viable option to providers other than Verve Energy. In October 2010, System Management provided a presentation to the RDIWG on how this could be achieved using an offers and bids process in a day-ahead market.[139] This process would be a departure from the current 'lower than Verve Energy' average-cost criteria in the Market Rules.

[136] ERA 2011, Determination of Ancillary Service Cost _ LR parameter, April 2011.

[137] A précis of the REGWG work streams and outcomes is included in Appendix 4.

[138] IMO 2011, REGWG - Summary of Processes and Outcomes, February 2011.

[139] System Management provided a presentation to the RDIWG on the Load Following Ancillary Service Day Ahead Market on 23 November 2010. See IMO 2010, RDIWG Meeting No. 6 Papers, 23 November 2010, pp. 28 - 44.

In the 2008 and 2009 Reports to the Minister, the Authority strongly supported further moves towards competitive procurement of Ancillary Services – especially for high cost services such as Load Following and Spinning Reserve Ancillary Services. The Authority supports the initiative by the IMO's MEP (through the work of the RDIWG) in progressing the introduction of a competitive market for Load Following Ancillary Services, in tandem with the introduction of a competitive Balancing market. The target is to have these measures operational by April 2011. This matter is discussed in further detail in Section 4.5.

The Authority recognises the Rule Change proposed in PRC_2010_27 seeks to allocate costs more appropriately to technology types on a causer pays basis, but does not deal with the equally important issues of differentiating between intermittent generation technology types and providing the means to Intermittent Generators to minimise their need for Load Following Ancillary Services at a facility level. The Authority understands that the IMO will be progressing work in this area in the near future and the Authority supports this initiative.

3.1.2 Balancing Support Contracts

Balancing Support Contracts allow IPP facilities to assist Verve Energy in balancing the energy market.[140] The Market Rules allow System Management to initiate the development of these contracts or for Verve Energy to enter into them of its own accord.

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

As noted in Section 4.5, the RDIWG is tasked with developing a solution to provide increased economic opportunities for generators other than Verve Energy to participate in Balancing. The RDIWG assessed several options, including the introduction of enhanced arrangements for Balancing Support Contracts. Ultimately, the RDIWG agreed that enhanced Balancing Support Contracts arrangements (such as increased transparency around dispatch and Balancing costs) were unlikely to meet the objective of increased economic opportunities for IPP participation in Balancing. A major identified barrier was that an IPP's participation in Balancing would be limited to times (or events) that Verve Energy opted to contract for Balancing assistance.

The Authority notes that one advantage of introducing a competitive market for Balancing is that IPPs will have greater certainty as to when they will be providing Balancing support as it would form a part of dispatch, rather than being called upon intermittently under a contract.

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

3.2 Inappropriate and anomalous market behaviour

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

The Authority considers that Market Participants behaviour has been largely acceptable. There are, however, some incidences of Balancing Data prices (pay-as-bid prices) submitted by IPP's – particularly from Non-Scheduled Generators – that do not appear to be cost reflective. This matter is discussed in further detail in Section 4.5 and Section 5.2.2.1.

In addition to the market power mitigation measures embedded in the Market Rules,[141] other measures introduced at market commencement include:

- a 3,000 MW generation capacity cap on Verve Energy;
- Verve Energy could not retail electricity until 2013 (extendable to 2016) and Synergy cannot generate until 2013 (extendable to 2016); and
- the Displacement Mechanism in the original Vesting Contract (2006).

The Authority considers that the market power mitigation measures have been effective in introducing new entry generation into the WEM, which has resulted in a steady reduction of Verve Energy's market share.

The Authority has previously highlighted that any changes to the WEM, including incremental modifications, will raise issues of market power. For example, design changes being considered by the RDIWG include introducing rolling gate closures ('rebidding') into a new competitive market for Balancing and Load Following Ancillary Services. Allowing rebidding reduces inefficiencies associated with Balancing services, but has implications for the potential use of market power by dominant participants. This matter is discussed in further detail in Section 4.5.

As noted in Section 2.6, the Authority recommends a review of the overall level of competition in the market be undertaken after the implementation of the new Balancing and Ancillary Services market and other key changes to the WEM's design (e.g. Reserve Capacity refunds). This review would also need to take into account the recent changes to the Vesting Contract between Verve Energy and Synergy, and the government's decision on whether or not to extend the trading moratoriums on Verve Energy and Synergy in the retail and generation sector, respectively. The Authority considers this review is necessary in order to assess whether, across the whole market, the appropriate level of market power mitigation is still in place.

Some Market Participants have questioned the clarity of the Market Rules regarding the reference to market power and in the definition and application of short run marginal cost (**SRMC**). In its submission, Synergy considers that the inclusion of a definition of SRMC within the Market Rules would be a useful point of reference for all Market Participants.

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

The Authority notes that SRMC is not a defined term in the legislation or the Market Rules. The costs associated with SRMC are not easily defined on a prescriptive basis, which would be a requirement if a definition was to be included in the Market Rules. To clarify the meaning of SRMC in the context of the market and to assist participants in its practical application, the Authority has held seminars and published three papers on its website.[142] The Authority notes that Market Participants have shown a growing understanding of the practical application of SRMC in their activities.[143] These include an understanding of the variable costs that are included in SRMC and an awareness of the proportion of fixed costs that can also be included. The Authority will continue to engage with Market Participants to assist with their practical application of SRMC.

3.3 Wholesale Electricity Market design problems or inefficiencies

The design of the WEM was influenced by the characteristics of the Western Australian energy market and the legacy of the industry's structure prior to Energy Market Commencement. Stakeholders, including the ESAA, have expressed concern that the complexity of the WEM – including the rules that govern the Reserve Capacity Mechanism, the net pool and associated mechanisms, as well as contractual arrangements between the state-owned corporations – could be a barrier to new entry.

The Authority notes that a number of market design problems and inefficiencies have been identified in the IMO's MREP (mid 2008) and the Verve Energy Review (September 2009). These issues have been further defined in the work of the Market Rules Design Team,[144] and most recently by the IMO MAC's RDIWG, which commenced in mid-2010.

These market evolution processes have canvassed both refinements and fundamental changes to the WEM. The Authority supports these processes but notes that it will be important to achieve the right balance in this process between addressing short-term objectives and minimising barriers to new entrants in order to promote competition at both the generation and retail levels. The Authority will comment on the status of these work streams in future reports to the Minister.

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

- Ancillary Services Contracts and Balancing Support Contracts (Section 4.1);
- the Reserve Capacity market (Section 4.2);
- the STEM (Section 4.4); and
- the Balancing (Section 4.5).

---

[142] See ERA web site, Short Run Marginal Cost web page.

[143] This is evidenced, for example, by the stakeholder submissions in response to the Authority's Determination of the Ancillary Service Cost LR, Margin Peak and Margin Off-Peak parameters - Issues Paper. See the ERA's website, Determination of the IMO and System Management Allowable Revenue and Ancillary Service Parameters web page.

[144] IMO 2010, RDIWG Meeting No. 1 Papers, 27 September 2010.

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

A feature of the WEM is the continuing dominance of Verve Energy and Synergy, by virtue of their incumbent market positions. The Authority notes that Verve Energy's market share of credited generation capacity will be 60 per cent in 2012.[145] Synergy's share of the retail market has remained steady in recent years, at around 80 per cent. There are currently structural barriers to effective retail competition, in particular at the residential and small commercial levels of the market. At the same time the upstream market in fuel supply (and transport) is still very much a long term bilateral contract arrangement. Together, these market characteristics limit flexible competitive operations in the WEM.

The Authority notes that the Minister is reviewing the restriction on Verve Energy from the direct sale of electricity to consumers ('Restriction') and the prohibition on Synergy from generating electricity ('Prohibition').[146] If the Minister decides to lift the Restriction and Prohibition, both Verve Energy and Synergy will be allowed to have integrated generation-retail businesses from 2013.

The Authority notes that vertical integration between generation and retailing can deliver commercial advantages to the 'gentailer' business. However, vertical integration may not necessarily deliver broader consumer benefits if cost savings are not passed through to consumers. For example, small use customers could be allocated a greater share of costs via higher retail margins, with larger customers allocated a lesser share (known as cross-subsidisation).

In December 2010, the Minister requested that the Authority provide its views about the effect that the Restriction and Prohibition have had, and are likely to have, on the encouragement of competition in the electricity market. The Authority's provided its views in a report to the Minister in April 2011. In preparing this advice, the Authority undertook a public consultation process and published an issues paper.[147]

In correspondence to the Market Advisory Committee in January 2011, the Office of Energy advised it was conducting the review of the Restriction and Prohibition on behalf of the Minister. The Office noted that it would commence the review upon receipt of the Authority's advice, and it was planning to submit its recommendations to the Minister by mid-2011.[148]

---

[145] Derived from the IMO Capacity Credit allocation for the 2012/13 Reserve Capacity Year – excluding credited DSM capacity.

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

[147] See ERA website, Prohibition and Restriction on Synergy and Verve Energy under the *Electricity Corporations Act 2005* web page.

[148] IMO MAC Meeting, MAC Meeting No. 35 Papers, 9 February 2011, p. 93.

4 Effectiveness of the Wholesale Electricity Market

Clause 2.16.11 of the Market Rules requires that the Report to the Minister provides an assessment on the effectiveness of the market in dealing with matters identified in clause 2.16.10 of the Market Rules.

Clause 2.16.10 sets out that the Authority must review the effectiveness of:

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

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

i) the Reserve Capacity market;

ii) the market for Bilateral Contracts for capacity and energy;

iii) the STEM;

iv) Balancing;

v) the dispatch process;

vi) planning processes; and

vii) the administration of the market, including the Market Rule change process.

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

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

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

4.1.1 The Market Rule change and Procedure change processes

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

The Authority observes that the Market Rule and Procedure change processes are working as intended. The Authority considers it appropriate that incremental changes to the WEM should continue to be managed through these processes.

As the market has matured, Market Participants have grown in their knowledge of the practical application of the Market Rules and Market Procedures. Informed debate occurs on market design development and on Market Rule, Procedure and system changes. While this debate may have slowed the change process in some instances, the Authority considers that such scrutiny is an indicator of a healthy evolution in the market.[149]

Over the past year considerable effort has been directed towards considering the next stage in the development of the market, particularly on the part of the IMO and many Rule Participants. Rule Change Proposals have been deferred when the issues raised are being addressed by broader market review processes. [150] The Authority considers this to be a reasonable and prudent approach to the Rule Change process.

The Authority notes that stakeholders have, as in previous year's submissions, commented on the IMO's dual roles of Rule making and operation (including enforcement), and have made the case for a clearer delineation or separation of those roles. The Authority continues to be of the view that, given the relatively small size of the WEM and at this stage of market development, it is more practicable for the IMO to have the dual roles. As the market matures in the longer term, there could be justification (i.e. net benefits) for the separation of the rule making function from the IMO.

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

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

The IMO monitors other Rule Participants' compliance with the Market Rules, investigates potential breaches of the Market Rules and takes enforcement action where appropriate. Enforcement action can include applying to the Energy Review Board (**ERB**) for fines or

---

[149] For example, the Rule change proposals 2009_08 'Updates to Commissioning Provisions' and 2009_22 'The use of tolerance levels by System Management' both required the IMO to extend the timelines for the IMO to prepare its decisions due to the need for the IMO to carry out analyses on matters raised in public consultation on the proposed Amending Rules.

[150] An IMO draft decision on a Market Participant's Rule change proposal 2010_09 'Removal of DDAP Uplift when less than facility minimum generation' was deferred until the RDIWG had arrived at an in principle decision regarding changes to the application of UDAP and DDAP. Ultimately, the work of the RDIWG should result in Rule change proposals in relation to this matter.

other orders. Pursuant to clause 2.13.26 of the Market Rules, the IMO's produces biannual reports on enforcement action taken to the ERB. During the period 1 August 2009 to 20 March 2011 no new proceedings were brought before the ERB by the IMO.[151]

The IMO's compliance with the Market Rules is audited once a year by the Market Auditor.[152] Pursuant to the Market Rules, the IMO require that System Management either demonstrate compliance with the Market Rules and Market Procedures or undergo an audit by the Market Auditor. A summary of the Market Auditor's 2010 annual reports on compliance by the IMO, and by System Management, are available in Section 4.1.3 of this report.

The Authority understands that System Management has automated systems capable of identifying breaches of the Market Rules. System Management particularly focuses on its monitoring obligations regarding correct declaration of Forced Outages,[153] IPP's compliance with Resource Plans and Dispatch Instructions, and Verve Energy's compliance with dispatch orders and Ancillary Services requirements.

The Authority observes that System Management has also been diligent in making changes to the Market Rules and Market Procedures to address perceived short comings in compliance monitoring where required. However, it is sometimes challenging to capture the physical realities in the Market Rules and Market Procedures, so some abstractions will be imposed on the market. For example, one observed inequity in the Market Rules is the requirement for each Scheduled Generator to prove its capacity as if it was operating on a day where the temperature was equivalent to 41^{o}C.

The Authority considers that some breaches of the Market Rules are more difficult to monitor, including non-cost reflective pricing and overstating demand quantities.

In order to address the effective monitoring of these particular matters the Authority considers that greater effort is required to clarify the surveillance responsibilities between the IMO - being the Rule Participant responsible for frontline monitoring and surveillance - and the Authority - to review matters of concern independently and impartially from the frontline. Any changes that are required to clarify the IMO's and the Authority's respective surveillance roles could necessarily require clarification through the Market Rules.

Ultimately, the Authority considers that the focus of any changes to the compliance monitoring and enforcement measures in the Market Rules and Regulations need to take into consideration and be tailored for the particular circumstances of the WEM.

[151] Since market commencement, the IMO has brought two proceedings before the ERB. Both of these proceedings have concluded and orders were made by the ERB. See the IMO website for further information, Six-Monthly Compliance Reports web page.

[152] The audit covers: the compliance of the IMO's internal procedures and business processes with the Market Rules; the IMO's compliance with the Market Rules and Market Procedures; and the IMO's market software systems and processes for software management.

[153] A Forced Outage is defined as any outage of a Facility or item of listed equipment that has not received System Management's approval. System Management manages a list of equipment subject to outages - see the IMO website, System Management Reports web page.

4.1.3 *The effectiveness of the Independent Market Operator and System Management*

Among other matters, Clause 2.16.10 of the Market Rules requires the Authority to review the effectiveness of both the IMO and System Management in carrying out their respective functions under the Regulations, the Market Rules and Market Procedures.

In its 2009 Report to the Minister, the Authority considered that stakeholder comments, as well as the positive conclusions of the 2009 audit reports of the IMO and System Management,[154] indicate that the IMO and System Management have been generally operating effectively. Based on submissions for this report, the Authority notes that most Market Participants continue to view the performance of the IMO and System Management in a favourable light.

While noting the matters raised in the most recent annual independent audit reports into the IMO's and System Management's compliance with the Market Rules, the Authority considers that both the IMO and System Management continue to effectively carry out their respective functions in the market under the Regulations, the Market Rules and Market Procedures.

4.1.3.1 The Independent Market Operator

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

> The IMO must ensure that the Market Auditor carries out the audits of such matters as the IMO considers appropriate, which must include:
>
> a) the compliance of the IMO's internal procedures and business processes with the Market Rules;
>
> b) the IMO's compliance with the Market Rules and Market Procedures; and
>
> c) the IMO's market software systems and processes for software management.

In its audit report of the compliance of the IMO's internal procedures and processes with the Market Rules, and the IMO's compliance with the Market Rules and Market Procedures, PA Consulting found that the IMO has generally complied with its obligations under the Market Rules.[155]

In its audit report of the compliance of the IMO's market software systems and processes for software management, PA Consulting concluded that the IMO's systems and process comply with the Market Rules.

4.1.3.2 System Management

Clause 2.14.6 of the Market Rule sets out the requirements for the audit of System Management:

---

[154] The Market Rules require the IMO to appoint a market auditor to carry out an audit, at least annually, of the IMO's compliance with the Market Rules and Market Procedures and System Management's compliance with the Market Rules and Market Procedures. The IMO has appointed PA Consulting to be the market auditor each year since 2007.

[155] PA Consulting found 45 non-material breaches, and no material breaches. PA Consulting noted that in its opinion the increased number of non-material breaches should not be construed as a deterioration in performance of the IMO or a source of concern for the operation of the market generally. Rather, PA Consulting considered, it should be seen as a manifestation of the on-going improvement in the integrity of the operation and development of the market as the IMO strives for higher standards of performance.

In accordance with the Monitoring Protocol, the IMO must at least annually, and may more frequently where it reasonably considers that System Management may not be complying with the Market Rules and Market Procedures:

a) require System Management to demonstrate compliance with the Market Rules and Market Procedures by providing such records as are required to be kept under these Market Rules or any Market Procedure; or

b) subject System Management to an audit by the Market Auditor to verify compliance with the Market Rules and Market Procedures.

In its audit report of System Management's compliance, PA Consulting found that System Management has generally complied with its obligations under the Market Rules. PA Consulting found one instance in which System Management has not complied, however, this one area of non-compliance was subject to a Rule Change due to take effect in December 2010.[156]

The Authority notes that PA Consulting did qualify its findings with three caveats.

- Some potential areas of non-compliance relating to System Management's activities during the audited year were still to be investigated, and at the time of writing its report, there was insufficient basis for determining the outcome of these investigations.
- PA Consulting noted that it typically takes some time for Rule Changes to be cascaded down through the Power System Operating Procedures and ultimately reflected in its Internal Procedures.
- System Management had not recorded any new entries in its compliance log since the time of the last audit; and, in the normal course of events, it would be expected to find at least some instances of non-compliance during any 12 month period. PA Consulting put forward its view that it would be prudent for System Management, in addition to its current practices, to monitor and document operational practices for potential breaches in order to provide an increased level of precision and rigour.

The Authority will monitor these issues and report on relevant outcomes in its next report to the Minister.

In its public submission, Synergy suggested that System Management should adopt publicly reviewable performance standards, such as Key Performance Indicators, as adopted by the IMO.[157] The Authority's view is that this suggestion is best left for System Management to consider. At the level more appropriate for this report, the Authority considers it more meaningful to gauge System Management effectiveness in a more qualitative way.

The Authority considers that System Management has made significant contributions to the operation of the market. Besides imparting the necessary engineering perspective regarding the day-to-day operation of the system to ensure supply reliability and security, System Management has also been diligent in its contributions to market development reviews and processes, particularly regarding the application of due caution on renewable energy penetration in the SWIS from a system operations perspective.

[156] PA Consulting found one instance in which System Management has not complied, however, this one area of non-compliance was subject to a Rule change due to take effect on 1 December 2010. The Rule Change referred to was 'RC_2009_22 - The use of tolerance levels by System Management'. See the IMO website, RC_2009_22 web page.

[157] Synergy also suggested that the Authority should introduce measurable performance standards.

4.2 The Reserve Capacity market

Clause 2.16.12(b)(i) of the Market Rules requires that the Report to the Minister contains the Authority's assessment of the effectiveness of the market, including the effectiveness of the Reserve Capacity market.

The Authority continues to be of the view that the RCM has been successful in securing sufficient capacity to meet forecast requirements,[158] with the number of Capacity Credits[159] assigned to participants exceeding the Reserve Capacity Requirement in each Capacity Year (see Figure 1 and Figure 2 in Section 5).

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

- between the 2007/08 and 2012/13 Capacity Years, the SWIS will have seen the introduction of nearly 1,900 MW of new generation and DSM capacity;
- a significant increase in the Capacity Credits assigned to new entrants, where the share of capacity provided by IPPs has grown from 11 per cent in 2005/06 to 44 per cent in 2012/13;
- a significant decrease in the average generation fleet Forced Outage rate (from 3.3 per cent in 2007/08 to 1 per cent in 2009/10), and for the same period, an increase in the average fleet Planned Outage rate (from 8.5 per cent in 2007/08 to 12.5 per cent in 2009/10), which indicates that Market Generators are making better use of the market's scheduled maintenance mechanism; and
- there have been no reported instances of lost load due to capacity shortages since market commencement.

As discussed in the Authority's previous reports to the Minister, generating plant investment decisions are based on a host of factors including projected price and quantity values resulting from the RCM, such as: the Maximum Reserve Capacity Price (**MRCP**) and the Reserve Capacity Price (**RCP**) (discussed in more detail below); energy and fuel prices; carbon tax; other business variables; and factors outside of the WEM. These factors are designed to work together to incentivise the right mix, timing and location of new generation capacity, and therefore should not be considered in isolation.

Since market commencement, a large proportion of new generation capacity entering the WEM, particularly base load and mid-merit generation, has been supported necessarily by bilateral contracts, such as those with Synergy,[160] and the contract between Griffin Energy and the Boddington gold mine. However, as would be expected given the RCM's design and the method for determining the RCP, it is considered to be the dominant element for

[158] The RCM operates on a two-year-ahead cycle and is designed to secure sufficient capacity to meet forecast demand.

[159] The RCM is built around the concept of a Capacity Credit. This is a notional unit of Reserve Capacity provided by a generator or DSM provider. Each year, the IMO prepares an assessment of the amount of capacity that is required to meet the forecast demand. If, in a particular year, the IMO determines that 100 MW of capacity is required, it will seek to ensure that this is provided by offering to purchase 100 Capacity Credits from generators and DSM providers. Capacity Credits have significant value. Capacity Credits can either be traded bilaterally or through the market. In return for receiving this payment, generators are required to offer their capacity into the market at all times (unless undergoing scheduled maintenance on a Planned Outage).

[160] As a result of Synergy's Supply Procurement program required under the Displacement Mechanism in the original Vesting Contract (2006).

investment decision making for peaking plant generation projects, i.e. OCGTs.[161] Given there is sufficient investment well ahead of the two years, the RCP (in attracting new entry) can also play a significant role in moderating energy prices in the STEM and facilitating the STEM process to achieve optimum dispatch, i.e. on a marginal cost basis.[162]

While the RCM has been successful in meeting the Reserve Capacity Requirement each year, Rule Participants have argued their concerns on various aspects of the RCM's effectiveness. These concerns have been raised in many market forums and been subject to review in recent market evolution processes.[163]

In summary, concerns on the RCM include the following.[164]

- The quantity and type of capacity procured, including whether the RCM is delivering:
  - economically efficient outcomes based on the current Capacity Credit allocation process and prioritisation methodology; and
  - the optimal mix of generation and DSM capacity.
- The price of capacity, including:
  - the appropriateness of an administratively set capacity price (i.e. the MRCP), and whether the price of capacity should be set by an alternative method, e.g. auction based; and
  - the responsiveness of the capacity price to the supply-demand position.
- The funding of Reserve Capacity, including whether the Individual Reserve Capacity Requirement[165] mechanism provides a fair and equitable allocation of capacity costs to Market Customers and adequate transparency.
- Other elements of the RCM, including whether the current:
  - Reserve Capacity refund mechanism results in Market Generators being conservative in their pricing of energy in the short term markets (STEM and Balancing – through Standing Balancing Data submissions) due to the static nature of the mechanism, i.e. not responding to the level of Reserve Capacity in the system at the time of the refund being applicable; and
  - timing of the RCM, with capacity procured two years in advance, delivers the most economically efficient outcomes.

---

[161] In this instance, having a RCP that is based on the capital cost of an OCGT will provide an assurance to investors (two years ahead) to invest in an OCGT operating on distillate fuel, in the event of a projected shortfall of capacity.

[162] This factor relates to the Reserve Capacity Credits (**RCC**) having partly paid the marginal generator's premium that may otherwise have been included in its STEM Offer prices. The presence of RCCs should therefore temper STEM Offer prices to be closer to the generations cost of producing that energy. This is in contrast to the NEM's value of lost load (VOLL), which is a much higher value than the administered energy price caps in the WEM.

[163] Including in the IMO's MREP and the Verve Energy Review.

[164] Some of these concerns were raised in the submissions received by the Authority in conducting its review of the market's effectiveness, which has resulted in this Report to the Minister.

[165] The Individual Reserve Capacity Requirement is the MW quantity determined by the IMO in respect of a Market Customer.

In its 2009 Report to the Minister, the Authority considered that certain issues identified with the RCM since market commencement are best addressed incrementally through the market's Rule Change process administered by the IMO.

During 2010, the IMO recognised that the concerns raised with the RCM required an in-depth review.[166] Early in 2011, the IMO engaged the services of an economic consultant to assist it in reviewing the RCM. The Authority understands the RCM issues identified by the IMO and the MAC (through the MREP) are included in the consultant's scope. The consultant's recommendations report is due to be presented to the IMO Board by around mid-year in 2011. The Authority will comment on the outcome of this review and the implementation of its recommendations in due course.

In its public submission, LGP noted its concerns about the substantial increase in the MRCP for the 2012/13 Capacity Year and its consequences for the RCP in that year. LGP noted the increases in the RCP increased the costs of un-contracted retailers and bilaterally contracted generators via the Reserve Capacity refund mechanism. LGP noted in particular the significant increase in the shared network costs from $10.1 million (in the 2011/12 Capacity Year) to $46.8 million (in the 2012/13 Capacity Year) - an increase of 360 per cent, which in turn contributes $31,000 per MW per year to the price of capacity.

The Authority notes that network cost of the MRCP for the 2013/14 Capacity Year moderated in comparison to the 2012/13 Capacity Year, with the shared network cost component decreasing from $46.8 million (in the 2012/13 Capacity Year) to $36 million (in the 2013/14 Capacity Year). The Authority also notes that, as part of the IMO's five yearly review of the MRCP Market Procedure,[167] the IMO has appointed a consultant to review the method for determining the MRCP's shared network costs. The MRCPWG endorsed the consultant's preferred methodology to forecast network costs, including shared costs, based on analysing historical connection costs.[168] Network costs in the MRCP could have decreased in the order of 50 per cent in the 2013/14 Capacity Year if this methodology was applied, due to a reduction in the forecast for shared network costs. The Authority notes, if this methodology is adopted, such a decrease may not be realised in future MRCP determinations, as increases (or decreases) in forecast network costs for the MRCP will be reflective of connecting generators actual costs.

The Authority also notes that volatility will be a feature of a small electricity market such as the WEM. The Authority is due to review the methodology for determining the MRCP by no later than October 2013.[169] While the Authority has the option of undertaking this review earlier, the Authority considers that this review should not be brought forward until the IMO's RCM review[170] has been completed (and has demonstrated that the current arrangements can be improved) and there is a defined outcome for the future network access model, i.e. a decision on whether to move to constrained transmission network operation.

---

[166] IMO MAC Meeting, MAC Meeting No. 34 Papers, 15 December 2010, 'Strategic Review of Reserve Capacity Mechanism for IMO Board' Presentation, p. 15.

[167] Being undertaken by the MAC's MRCPWG.

[168] Sinclair Knight Merz's methodology uses real costs from historical projects and costs from the access offers for future projects. The IMO has incorporated this methodology into a revised procedure for determining the MRCP. See IMO website, MRCPWG Meeting No. 9 Papers, 5 May 2011, p. 41.

[169] Pursuant to Market Rule 2.26.3.

[170] The RCM review by the economic consultant engaged by the IMO is due to be completed by mid-2011.

4.3 The market for Bilateral Contracts for capacity and energy

Clause 2.16.12 (b) (ii) of the Market Rules requires that the Report to the Minister contains the Authority's assessment of the effectiveness of the market, including the effectiveness of the market for bilateral contracts for capacity and energy.

As noted in the 2009 Report to the Minister, while the Authority has an interest in ensuring that the bilateral market helps promote the Wholesale Market Objectives, particularly in terms of facilitating new entry in the generation sector and the retail sector, the precise counterparties and terms of Bilateral Contracts are confidential and are not a topic for the report to the Minister.

The Authority supports the bilateral contracting arrangements for capacity and energy in the market's design, which allow Market Participants to negotiate flexible contracts that are appropriate to the counter parties. Market data shows that commercial bilateral agreements have progressively replaced the 'non-contestable' supply of capacity (Capacity Credits) and energy from Verve Energy to Synergy, with the Displacement Mechanism in the original Vesting Contract (2006) being a major influence on this outcome.

However, in its 2009 Report to the Minister, the Authority noted there are a number of issues that can affect the growth of competition in the bilateral market, including that the concentrated monopoly market structure in the WEM (Verve Energy and Synergy) reinforces the barriers to new entry resulting from non-cost reflective tariffs and the absence of FRC. The Authority's view was that any significant change to the Vesting Contract should not reduce opportunities for new private sector participation in the WEM. Since that report, the original Vesting Arrangements have been replaced. The implications of the changes to the Vesting Arrangement for new participant's entry into the WEM are discussed in Section 2.6.

In the current reporting period (August 2009 and July 2010), Bilateral trade accounted for the majority of overall wholesale market traded quantities. The Authority notes that, while bilaterally traded quantities have remained steady over time, increasing STEM traded quantities continue to erode the proportion of overall wholesale market trades made up under Bilateral Contracts.

As discussed in Section 5.3.1, the majority of bilaterally traded quantities continue to be traded between Verve Energy and Synergy. This outcome is to be expected given Verve Energy and Synergy continue to be the largest generator and the largest retailer in the market, respectively.

The Authority also observes an increase in bilaterally traded quantities between Market Participants other than between Verve Energy and Synergy in the current reporting period. The Authority notes that this increase in bilaterally traded quantities between IPPs and independent retailers has coincided with an increase in the number and size of these entities in the market. The Authority expects that this increased competition in the bilateral market should lead to more efficient outcomes in that market.

4.4 The Short Term Energy Market

Clause 2.16.12 (b) (iii) of the Market Rules requires that the Report to the Minister contains the Authority's assessment of the effectiveness of the market, including the effectiveness of the STEM.

The STEM allows Market Participants to make adjustments around their bilateral positions. The STEM is operated a day ahead, with half hourly prices established by auction for the subsequent day. As a part of the STEM's design, STEM Clearing Prices capture the system marginal price irrespective of the quantities traded in the STEM. The effectiveness of the STEM in capturing the system marginal price is dependent on the cost reflectivity of the STEM offers and bids and how close the conditions assumed in STEM Submissions are to real-time conditions (discussed in further detail below).

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

A key limitation identified with the STEM's design is the timing of its single gate closure, which occurs one to two days ahead of dispatch. The concern with this design is that changes in Market Participant's circumstances (e.g. fuel and plant availability) and improved (temperature) forecasts cannot be factored in to adjust participant's contract positions and they are therefore exposed to the Balancing mechanism for any deviations between contract and actual positions.

This matter was reviewed by the RDIWG as a part of its deliberations. The RDIWG investigated moving the timeline from the morning to the afternoon of the Scheduling Day. The main perceived benefit in making this change was to capture a later, more accurate, temperature forecast from the Bureau of Meteorology, which would assist participants with their forecast accuracy. The results of analysis did not provide any material evidence that a significant improvement in forecast accuracy would be expected by moving the Scheduling Day timeline to the afternoon.[171] The RDIWG noted that there were insufficient benefits compared with costs to warrant a change to the Scheduling Day timeline. The RDIWG noted that further work on proposing changes to the Scheduling Day timelines was to be put on hold pending a review of the outcomes of its work on the provision of competitive Balancing.

While the current STEM design has its limitations, the Authority's view is that a transparent wholesale price – such as that provided by STEM Clearing Prices – is an important feature of an effective energy market, particularly in promoting new investment. Indeed, with the removal of the price discovery mechanism under the original Vesting Contract's Displacement Mechanism, the STEM is now the only information mechanism whereby new entrants can discover information about demand and pricing in the market that is based on a competitive outcome to enable them to make decisions about entry. The Authority considers that a transparent energy market is important if the market is to continue to achieve the Market Objectives.

The Authority notes that STEM Clearing Prices have generally reflected the balance of supply and demand. Regarding supply, there is currently an oversupply of thermal and cogeneration plant in the SWIS, particularly during periods of low overnight load, and this has resulted in negative STEM Clearing Prices being observed at times.

---

171 The move of the STEM's Scheduling Day timeline was also identified as being operationally problematic for a number of Market Participants and likely to involve significant implementation costs.

Section 5.2.1 reports on STEM outcomes since market commencement, including STEM Clearing Prices, traded quantities, and bids and offers. This section also includes a discussion on particular outcomes for the current reporting period, August 2009 to July 2010.

4.5 Balancing

Clause 2.16.12 (b) (iv) of the Market Rules requires that the Report to the Minister contains the Authority's assessment of the effectiveness of the market, including the effectiveness of the Balancing mechanism.

In the WEM, Balancing refers to the process for meeting Market Participant's actual (real-time) supply and consumption energy levels from contracted bilateral and STEM positions. Currently, Balancing support services are provided by Verve Energy as default balancer and there is only limited opportunity for IPP's to provide Balancing at certain times.[172]

The Balancing mechanism has been debated by stakeholders since market commencement until the present, including being identified as a priority issue to be addressed in the IMO's MREP (mid 2008) and the Verve Energy Review (September 2009). As a result of these two work streams, the IMO's MAC convened the RDIWG in mid-2010. As a part of its scope, the RDIWG was tasked with developing a solution to provide increased economic opportunities for participants other than Verve Energy to participate in Balancing.

The key issue identified with the Balancing mechanism is that it is less efficient than it could otherwise be due to Verve Energy being obliged to provide Balancing and IPPs (and other Market Participants) being largely excluded from providing the service. This results in the cost of Balancing to be likely higher than it needs to be because not all potential resources are available for Balancing much of the time.

After considering options including enhanced Balancing Support Contract arrangements, and incremental improvement of the current Balancing mechanism,[173] the RDIWG focussed on proposing revised arrangements for the short term operation of the WEM that did not require modifications to the current market design's hybrid framework.[174] The resultant design is intended to allow IPPs to compete for the provision of Balancing and Load Following Ancillary Services.[175] In April 2011, the RDIWG members agreed in the majority that the proposed design is consistent with the Market Objectives and

[172] IPP's participation in Balancing is restricted to times of: system security situations; or as alternatives to the dispatch of Verve Energy's distillate facilities when there has been a shortfall between the market's requirements and Verve Energy's supply capacity.

[173] Related issues were also identified with the Balancing mechanism, including how the Portfolio Supply Curve, set one to two days ahead of dispatch, became the basis for paying Verve Energy for providing Balancing energy and that this likely does not represent the cost of the Verve Energy's marginal unit dispatched by System Management to provide the Balancing service. As the work of the RDIWG progressed, it departed from seeking to incrementally improve the existing mechanism and opted for a new design, on the basis that this would best meet the objective of provide increased economic opportunities for participants other than Verve Energy to participate in Balancing.

[174] Which includes that IPPs develop Resource Plans for their own facilities; System Management develops dispatch plans for the Verve Energy portfolio; and Verve Energy is the default provider of Balancing services.

[175] The IMO MAC decided that the competitive provision of Ancillary Services and the competitive Balancing design proposal should be developed as a package. See IMO 2010, MAC Meeting No. 34 - Minutes, 15 December 2010.

recommended to the MAC the creation of a new competitive market for Balancing and Load Following Ancillary Services, to be developed through the Rule Change process.

In its 2009 Report to the Minister, the Authority recommended that the case for a move to competitive Balancing in the WEM should be considered. While the Authority considered that work on assessing the benefits of reform to Balancing arrangements could usefully occur within the framework of the IMO's MREP, the Authority also considered it important that this work be informed by policy input from the Office of Energy.

While the Authority supports the work of the IMO's RDIWG in introducing competitive markets for Balancing and Ancillary Services, the Authority notes the following two matters regarding the proposed revised arrangements for the short term operation of the WEM.

Firstly, the proposed design is necessarily complex (and sophisticated) to accommodate competitive provision of Balancing and Ancillary Services in the current hybrid framework, and there are a number of outstanding issues that need to be worked through in relation to the proposal – including the fuller proposal of the competitive market for Load Following Ancillary Services.

Secondly, the IMO has noted that the current mechanisms for mitigating potential market power will continue for the operation of the proposed design, insofar as Market Generators will be required to price electricity at its reasonable expectation of the short run marginal cost of generating the relevant electricity when such behaviour relates to market power. The IMO has also noted that, should the proposal proceed to the Rule Change process, the IMO Board has requested an independent assessment of the implications for market power mitigation.

The Authority notes that a key design element of the proposal is rolling gate closure times (or 'rebidding'), which has a target outcome of two hours for participants bidding by facility. The rationale for the shortened time frame between gate closure and dispatch is to allow participants to take into account actual circumstance closer to real-time so they may price their energy more accurately, such as in response to load changes and other factors. The Authority acknowledges this benefit, however, rebidding rules have raised concerns in other jurisdictions, including in the NEM. Concerns over rebidding in the NEM are partly because it may help certain generators to exercise market power. For example, some peaking units in the NEM have been observed as using rebidding to adapt to changes in market conditions, instead of using the daily offer/bid opportunities. These concerns may be amplified in a small electricity market like that in the SWIS, with relatively few participants and (at times) a low level of competitive tension. The Authority considers that without the appropriate and tailored market power mitigation measures to suit the WEM, dominant participants may be unfettered in raising prices beyond their cost of supply. Also, as Verve Energy's role of default provider of Balancing services remains unchanged under the proposed design, it has the potential to be advantaged in periods of high STEM prices.[176] The Authority will monitor developments in this area.

The proposed design will likely result in a significant departure in the way the short term electricity markets (STEM and Balancing) operate in the WEM, which gives rise to the question whether the current market mitigation measures will still be appropriate and sufficient under the new design. As noted in Section 2.6, the Authority recommends a

[176] The STEM price generally sets the balancing price. Depending on its net buy-sell position, Verve Energy, as the default provider of Balancing services, has the potential to be advantaged in periods of high STEM prices.

review of the overall level of competition in the market be carried out once the new Balancing and Ancillary Services market and changes to other areas of the WEM's design (e.g. Reserve Capacity refunds) have been implemented.

As noted earlier, Balancing enables Market Participant's to meet their actual (real-time) supply and consumption energy levels from contracted bilateral and STEM positions. Generally, System Management will match supply and demand in the system using Verve Energy's facilities. However there are circumstances in which System Management can issue Dispatch Instructions to other Market Participants.

Where Market Participants are issued Dispatch Instructions to increase or decrease supply in real-time, these deviations are settled on a 'pay-as-bid' price basis. Market Participants other than Verve Energy must specify pay-as-bid prices for increasing and decreasing the output of their facilities (and for decommitting facilities including switching off Intermittent Generators).[177]

The Authority observes that the pay-as-bid prices submitted by Non-Scheduled Generators for decreased supply may not be reflective of the costs incurred. The Authority will continue to monitor this matter and may carry out investigations if it considers that this behaviour has resulted in the market not functioning effectively.[178]

Under the Market Rules, the IMO is required to review changes of Standing Data submitted by Market Participants, including pay-as-bid Balancing prices. Part of this requirement is to ensure submitted data represents the reasonable costs of the Market Participant in the circumstances related to the price or payment.

The Authority has raised its concern with the IMO regarding the IMO's policing of Standing Data related to prices and payments that are submitted by Market Participants to the IMO. Under clause 2.34.7 of the Market Rules, the IMO may reject a change in Standing Data related to prices and payments if it is not satisfied with evidence provided that the submitted data represents the reasonable costs of the Market Participant in the circumstances related to that price or payment. The Authority understands that the IMO's IT systems do not currently require Market Participants to provide evidence in support of a submitted Standing Data price change, therefore the IMO does not evaluate whether submitted prices should be accepted or rejected based on whether those submitted prices represent the reasonable costs of the Market Participant. In response to the Authority's concern, the IMO has advised that the new Market Participant Interface (MPI) will require Market Participant's to submit such evidence in support of pay-as-bid price changes, and the IMO is developing a set of criteria for assessing whether the submitted prices represent the reasonable costs of the Market Participant in the circumstances related to that price. The Authority will provide an update on this matter in its next report to the Minister.

[177] One set of prices apply for the whole Trading Day. IPP Market Participants can submit energy related Balancing Data to the IMO daily or can specify it via Standing Data that applies for every day. Pay-as-bid decrease prices for non-scheduled generators and decommitment price data is only recorded in facility Standing Data (as opposed to trading Standing Data) and cannot be submitted daily with energy market submissions. The IMO use Balancing Data to produce a number of Dispatch Merit Orders, describing the order in which non-Verve Energy facilities should have their output increased, decreased, or decommitted by System Management. Facilities with multiple fuel options appear multiple times in the Dispatch Merit Order, once for each fuel.

[178] Pursuant to the requirement of Market Rule 2.16.9(b).

Recommendation 11

Section 4.5

Recommendation: The Authority recommends that the Independent Market Operator apply greater scrutiny of price changes submitted by Market Participants in Standing Data to ensure such changes represent the Market Participant's reasonable costs, as required by the Market Rules.

Section 5.2.2 reports on Balancing outcomes since market commencement, including Balancing prices (Standing Data and MCAP, UDAP and DDAP), capacity available through Balancing and number and frequency of Dispatch Instructions. This section also includes a discussion on particular outcomes for the current reporting period, August 2009 to July 2010.

4.6 The dispatch process

Clause 2.16.12 (b) (iii) of the Market Rules requires that the Report to the Minister contains the Authority's assessment of the effectiveness of the market, including the effectiveness of the dispatch process.

The dispatch process under the Market Rules allows System Management to adjust schedules in real-time to ensure that power system security and reliability is maintained while, to the extent possible, facilitating trade in accordance with bilateral and STEM positions. The dispatch process is based on the market design of having a large incumbent generator (Verve Energy) in the role as the default balancing generator. System Management schedules Verve Energy's resources in accordance with a dispatch plan agreed by Verve Energy, and can only change IPP schedules (Resource Plans) under special circumstances.[179]

In its public submission, System Management highlighted that the Dispatch Merit Orders may not be operating effectively. System Management noted that it raised this issue previously in its submission to the Authority in 2009;[180] and also noted that the issue has not yet been addressed.

System Management considers that the system operations in off-peak times would seem to indicate that the current Market Rules surrounding the Dispatch Merit Orders do not support the Market Objective to *promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the SWIS*. System Management notes that the dispatch order requires Verve Energy to be dispatched prior to all other facilities and this is therefore not based on price and so may be inefficient, especially for generation reduction overnight.

The Authority agrees that there is an inherit lack of efficiency in the current dispatch process due to it not being based on economic dispatch. The Authority notes that

[179] System Management may issue Dispatch Instructions to other Market Generators and to Curtailable Loads or Dispatchable Loads if it cannot otherwise maintain security and reliability, or if it would have to use Verve Energy's liquid fuelled plant when non-liquid fuel capacity was still available.

[180] System Management 2009, Submission in response to the Authority's 2009 Discussion Paper.

significant changes to the dispatch process are being considered as part of the RDIWG's proposed revised arrangements for the short term operation of the WEM, which includes allowing IPPs to provide for competitive provision of Balancing and Ancillary Services. This is discussed in detail in Section 4.5.

The Authority understands that proposed changes to the short term operation of the WEM will include added complexity to the dispatch process managed by System Management, including:

- the need to schedule Verve Energy's facilities around IPP's Balancing schedules (i.e. in addition to around IPP's Resource Plan schedules);
- providing information on operational limitations to develop a 'Real Time Balancing Merit Order'; and
- non-scheduled generators (e.g. wind generation) may submit a decommitment price and thus be incorporated in the Balancing Merit Order, therefore System Management may be required to dispatch (decommit) these units.

These proposed changes to the dispatch process will require significant modifications to systems and management practices around scheduling and real-time dispatch of facilities. The Authority considers it will be challenging for System Management to adapt its systems and processes to accommodate these change to the dispatch process for two reasons:

- the Authority understands that System Management operates what is essentially a manual/semi-automated dispatch process that would unlikely to be able to be adapted to the complexity of the proposed changes; and
- the April 2012 target date for the full roll out of the changes is a tight time frame to implement and bed down such fundamental system and process changes.

Now that it appears likely that the proposed design will be implemented, the Authority understands that System Management has commenced the scoping and resourcing for this project.

4.7 Planning processes

Clause 2.16.12 (b) (vi) of the Market Rules requires that the Report to the Minister contains the Authority's assessment of the effectiveness of the market, including the effectiveness of the planning processes.

The Projected Assessment of System Adequacy (**PASA**) is a forecasting study, undertaken by the IMO in the case of the Long Term PASA, and undertaken by System Management in the case of a Short Term PASA and a Medium Term PASA.[181]

The annual Long Term PASA study determines the Reserve Capacity Target[182] for each Reserve Capacity Cycle[183] in the Study Horizon.[184] The study results are presented in the IMO's Statement of Opportunities report.[185]

[181] The Short Term PASA is conducted in accordance with clause 3.17 of the Market Rules, while the Medium Term PASA is conducted in accordance with clause 3.16 of the Market Rules.

[182] In respect of a Capacity Year, the IMO's estimate of the total amount of generation or Demand Side Management capacity required in the SWIS to satisfy the Planning Criteria for that Capacity Year

The Short Term PASA assists System Management in assessing: the availability of capacity holding Capacity Credits; the setting of Ancillary Service Requirements in each six-hour period during the Short Term PASA Planning Horizon; and final approvals of Planned Outages. The Short Term PASA studies are based on a three week planning horizon. Medium Term PASA studies are developed for the same purposes as the Short Term PASA, but are instead based on a longer three year planning horizon.

The Authority notes that information contained in the Short Term and Medium Term PASA reports can be an indicator of market prices in the immediate term, a function which would be enhanced if more details were provided in the PASA reports (e.g. aggregating Planned Outages capacities by Scheduled Generator type, i.e. base load, mid-merit and peaking). However, providing this level of detail would have to be balanced against disclosing price sensitive information. Due to the small number of generators in the market and the makeup of the generator fleet, individual Market Generators could be identified. Participants could potentially use this information in negotiating short-term bilateral contracts.

Pursuant to the Market Rules, at least once in every five year period, the IMO, with the assistance of System Management, must conduct a review of the outage planning process against the Market Objectives. This review must include a technical study of the effectiveness of the criteria System Management must apply when evaluating Outage Plans and include a public consultation process with Rule Participants. The Authority understands the IMO has appointed a consultant to undertake this review, and the consultant's final report is due in August 2011. The consultant is required to recommend any necessary updates to the Market Rules or *Power System Operating Procedure:* Facility Outages following the outcomes of the review and public consultation process.

The Authority observes that this is the first review of the effectiveness of the outage planning process in meeting the Market Objectives, and therefore there is currently an absence of information for stakeholders and investors to gauge the effectiveness and efficiency of this mechanism.

The Authority considers this review will be useful for the RDIWG's consideration of whether to adopt a dynamic method for calculating Reserve Capacity Refunds that is based on the actual level of available capacity on the system. Currently, different set (or static) Reserve Capacity Refunds apply at different times of day and at different times of year. The concern is that this mechanism provides only a smoothed and general (i.e. and therefore not specific) incentive to have capacity available, which can result in (at different times) the capacity refund arrangements under and over pricing the value of capacity leading to inefficient decisions by participants about the timing of maintenance and presentation of capacity. However, under a dynamic refunds mechanism that is derived based on available capacity, Market Generators could be potentially exposed to a high level of refunds at any time in the event of a forced outage, e.g. even in off-peak periods during spring or autumn, if available capacity is tight. Such a dynamic mechanism is therefore intrinsically linked to the outage approval process, which plays a major role in setting the level of available capacity on the system. The Authority considers that gaining

---

determined in accordance with clause 4.5.10(b), where Planning Criteria has the meaning given in clause 4.5.9.

[183] The cycle of events described in clause 4.1.

[184] The ten-year period commencing on 1 October of Year 2 of a Reserve Capacity Cycle.

[185] A report prepared in accordance with clause 4.5.13 presenting the results of the Long Term PASA study, including a statement of required investment if Power System Security and Power System Reliability are to be maintained.

an insight into the effectiveness of the current outage approval process will assist in the RDIWG's understanding of whether it can underpin such a significant proposed change to the Reserve Capacity Refund mechanism.

5 Summary of the Market Surveillance Data Catalogue

Clause 2.16.12(a) of the Market Rules requires that the Report to the Minister contains a summary of the information and data compiled by the IMO under Clause 2.16.1 of the Market Rules. Clause 2.16.1 deems the IMO responsible for collecting and compiling the data identified in the Market Surveillance Data Catalogue (**MSDC**), analysing the compiled data, and providing both the data and analysis to the Authority.[186]

The required summary of the MSDC data and analysis items for the reporting period from 1 August 2009 to 31 July 2010 (**the Reporting Period**) is set out in this section and Appendix 3 of the report.[187]

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

- drawn on MSDC data and analysis from periods earlier than the Reporting Period to show trends that have taken place since Energy Market Commencement (**EMC**) on 21 September 2006;
- drawn on other market data that is not a part of the MSDC data and analysis items;[188] and
- reported on annual periods from 1 October (8 AM) until the following 1 October (8 AM) when reporting on aspects of the Reserve Capacity market, as this is the period of time covered by a Reserve Capacity Year.

5.1 Reserve Capacity market

5.1.1 Number of participants in each Reserve Capacity Auction

Clause 2.16.2(b) of the Market Rules requires that the MSDC identifies the number of participants in each Reserve Capacity Auction.[189]

A Reserve Capacity Auction is run by the IMO only if the number of Capacity Credits assigned to facilities that have indicated their intention to trade their capacity bilaterally is insufficient to meet the system requirement and there are remaining certified capacities. As yet, there has been no requirement for the IMO to run a Reserve Capacity Auction.

---

[186] 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.

[187] This Reporting Period is consistent with previous Reports to the Minister prepared by the Authority, i.e. previous reports to the Minister have reported on the MSDC data and analysis items from 1 August to the following 31 July.

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

[189] The process for determining the Reserve Capacity Price for a Reserve Capacity Cycle and the quantity of Reserve Capacity scheduled for the IMO for each Market Participant under Clause 4.19.

5.1.2 Reserve Capacity Auction offers

Clause 2.16.2(dA) of the Market Rules requires that the MSDC identify all Reserve Capacity Auction offers. As no Reserve Capacity Auction has been required to date, no auction offers can be reported.

5.1.3 Prices in each Reserve Capacity Auction

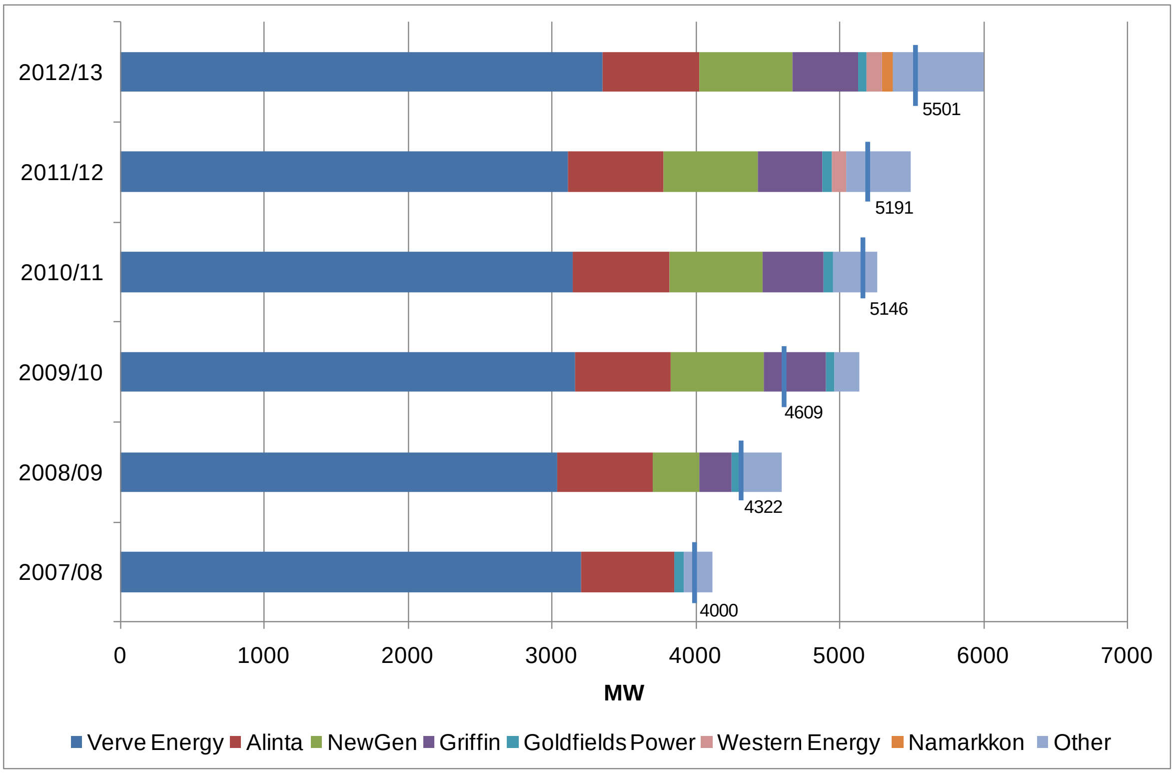
Clause 2.16.2(c) of the Market Rules requires that the MSDC identify clearing prices in each Reserve Capacity Auction. To date, there has been no requirement for the IMO to run a Reserve Capacity Auction.

5.1.4 Capacity Credits assigned

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

Figure 1 illustrates the Capacity Credits assigned to Market Participants for the 2007/08 to the 2012/13 Capacity Years.

Figure 1 Capacity Credits assigned to Market Participants



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

Between 2007/08 and 2012/13, the SWIS will have seen the introduction of approximately 1,900 MW of new generation and DSM capacity. The number of capacity providers and the proportion of capacity provided by IPPs have each grown considerably since EMC, driven in part by the RCM, the Displacement Mechanism in the original Vesting Contract (2006) and the 3,000 MW generation capacity cap applying to Verve Energy.

The increasing competitiveness of the generation sector is also reflected in other outcomes in the market. The 2009/10 Capacity Year saw the entry of both the NewGen Neerabup and Griffin Power 2 power stations. This resulted in a significant increase in volumes traded in the STEM, with both NewGen Neerabup and Griffin Power 2 actively trading in the STEM. The 2009/10 Capacity Year also saw an increase in bilateral quantities traded between participants other than directly between Verve Energy and Synergy. On the whole, this indicates that as the generation sector becomes more competitive, there should be an increase in the competitiveness and liquidity of bilateral markets and the STEM.

Notably, a key long term trend of the RCM is that, with the exception of 2010/11 Capacity Year, procured capacity has exceeded the Reserve Capacity Requirement each year by greater than five per cent. Market Participants have argued that procuring excess capacity is inefficient. This matter is discussed in more detail in Section 4.2.

5.1.5 Maximum Reserve Capacity Price and Reserve Capacity Price

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

The RCM's pricing mechanism is the administratively set MRCP, which is the price cap determined by the IMO for the Reserve Capacity Auction.[190] To date, there has been no requirement to procure capacity through a Reserve Capacity Auction. Without an auction, an administered RCP is paid per MW per year for Capacity Credits held by generators and DSM aggregators.[191]

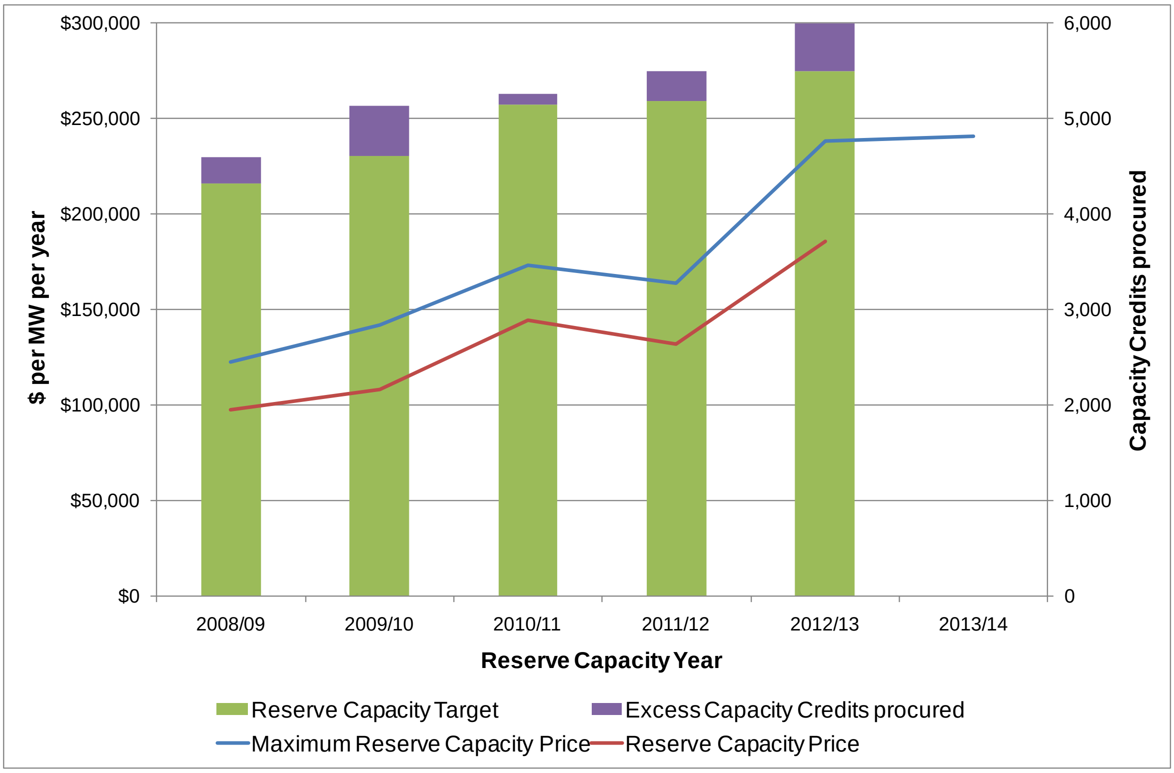
Figure 2 shows the MRCP, the RCP, the Reserve Capacity Target and the excess Capacity Credits procured (i.e. in excess of the Reserve Capacity Requirement) for each Capacity Year from 2008/09 to 2012/13.[192]

[190] If the Reserve Capacity Requirement is not met through bilaterally traded capacity, the IMO can run the Reserve Capacity Auction to procure Capacity Credits for on-sale to Market Customers. The Reserve Capacity Auction is only held if there is insufficient capacity to meet forecast demand following the Bilateral Declaration process. Market Participants can offer capacity in the Reserve Capacity Auction at prices between zero ($0/MW) and the MRCP. If the Reserve Capacity Auction is held in any one year, the clearing price for the Reserve Capacity Auction becomes the Reserve Capacity Price for all Capacity Credits traded through the IMO, except for facilities covered by a Special Price Arrangement granted in a previous year. If a Reserve Capacity Auction is held and a proponent is assigned Capacity Credits through the auction, it may take an option of a ten-year Special Price Arrangement. See the IMO website for further information, Special Price Arrangements webpage.

[191] If a Reserve Capacity Auction is not held because enough capacity has been secured through bilateral trade nominations, the Market Rules set the price of all Capacity Credits at 85 per cent of the MRCP, as well as using a scale to adjust the value of Capacity Credits to take into account any oversupply of Capacity Credits in excess of the Reserve Capacity Target for that Capacity Year.

[192] Figure 2 also shows the MRCP for the 2013/14 Capacity Year.

Figure 2 The Maximum Reserve Capacity Price, the Reserve Capacity Price, the Reserve Capacity Requirement and the excess Capacity Credits procured for the 2008/09 to 2013/14 Capacity Years



Notably, a key long term trend of the RCM's administered pricing mechanism is that, with the exceptions of the 2011/12 and 2013/14 Capacity Years, the MRCP has increased significantly each year. Market Participants have questioned the appropriateness of an administratively set capacity price (i.e. the MRCP), and have called for consideration of the price of capacity being set by an alternative method (e.g. auction based). This matter is discussed in more detail in Section 4.2.

5.1.6 Performance in meeting Reserve Capacity obligations

Clause 2.16.2(l) of the Market Rules requires that the MSDC identify the performance of Market Participants with Reserve Capacity obligations in meeting these obligations.

The performance of Market Participants with Reserve Capacity obligations is assessed by comparing the quantity of a Facility's Forced Outages and Planned Outages to the maximum generating capacity of the Facility, as registered by the IMO.

This information is confidential and is not presented in this public version of the report; however, aggregated information can be reported. In particular, the Authority notes that the forced outage rate for generation plant has been low. Planned outage rates are more variable, reflecting the different stages of generation plant in their maintenance cycles.

5.2 Energy markets

5.2.1 Short Term Energy Market

Clause 2.16.2(c) of the Market Rules requires that the MSDC identify clearing prices in each STEM Auction.

As well as the requirement under clause 2.16.2(c) of the Market Rules that the MSDC identify clearing prices in STEM Auctions, there are also requirements under clause 2.16.4 to calculate:

- means and standard deviations of clearing prices in STEM Auctions;
- monthly, quarterly and annual moving averages of clearing prices in STEM Auctions;
- statistical analysis of the volatility of prices in STEM Auctions;
- the proportion of time that clearing prices in STEM Auctions are at each price limit;
- the correlation between capacity offered into the STEM Auctions and the incidence of high prices; and
- exploration of key determinants for high prices in the STEM.

This section summarises the results of the requirements under both clause 2.16.2 and clause 2.16.4.

5.2.1.1 Short Term Energy Market Clearing Prices

STEM Clearing Prices are summarised separately for Peak Trading Intervals (occurring between 8am and 10pm) and Off-Peak Trading Intervals (occurring between 10pm and 8am). There are significant differences between peak and off-peak clearing prices, both in terms of the average level of prices and the volatility of prices.

Table 2 sets out the mean and standard deviations of peak and off-peak clearing prices from:

- 21 September 2006 (EMC) to 31 July 2010;
- 1 August 2008 to 31 July 2009 (i.e. the previous reporting period); and
- 1 August 2009 to 31 July 2010 (i.e. the current Reporting Period).

It can be seen that, for both peak and off-peak periods, clearing prices for the Reporting Period were approximately half that compared to the corresponding prices in the previous reporting period. Clearing prices were also significantly lower than the long term average, i.e. represented by the period from EMC to 31 July 2010.

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

Trading Intervals	21 Sep 06 – 31 Jul 10		1 Aug 08 – 31 Jul 09		1 Aug 09 – 31 Jul 10	
	Mean	Std Dev	Mean	Std Dev	Mean	Std Dev
Off-Peak	34.10	31.34	41.84	26.75	**19.51**	**11.63**
Peak	68.32	60.88	76.95	44.46	**38.65**	**18.80**

Figure 3 and Figure 4 illustrate, respectively, average daily off-peak and peak STEM Clearing Prices for each Trading Day from 21 September 2006 (EMC) up to 31 July 2010, as well as 30-day, 90-day and annual moving average prices.

Figure 3 **Average Off-Peak Trading Interval STEM Clearing Prices (per Trading Day)**

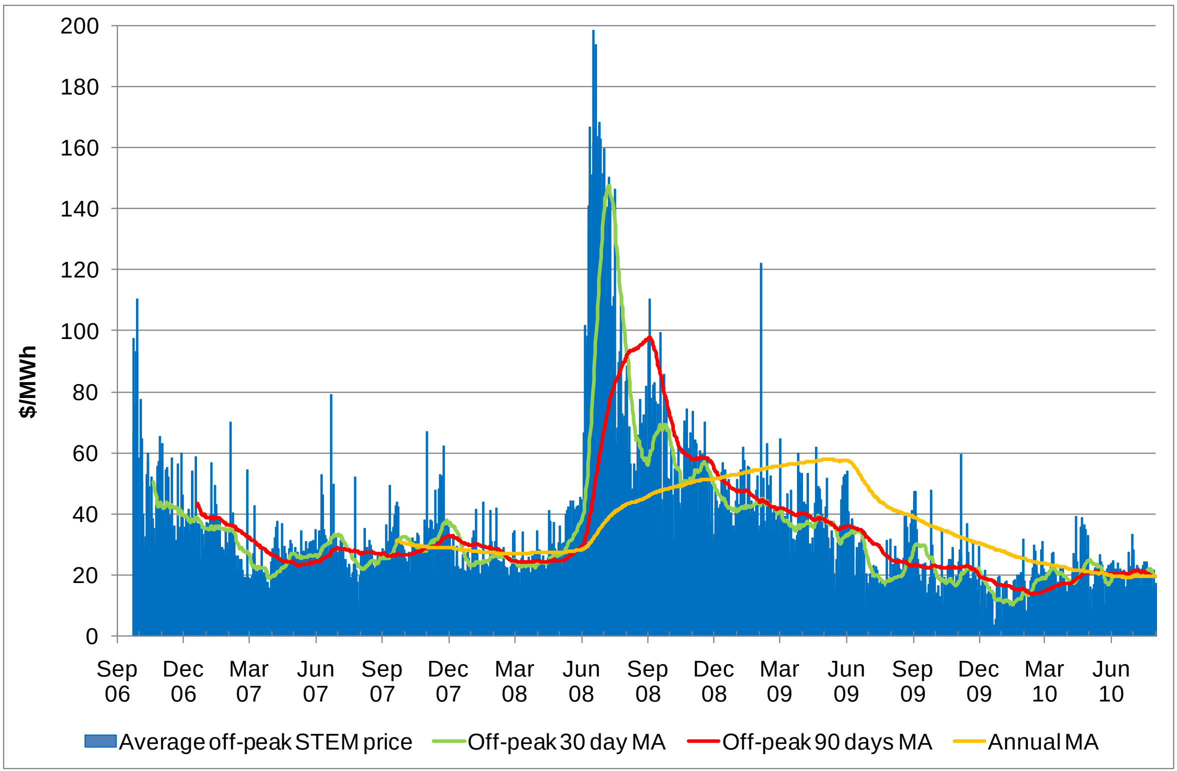
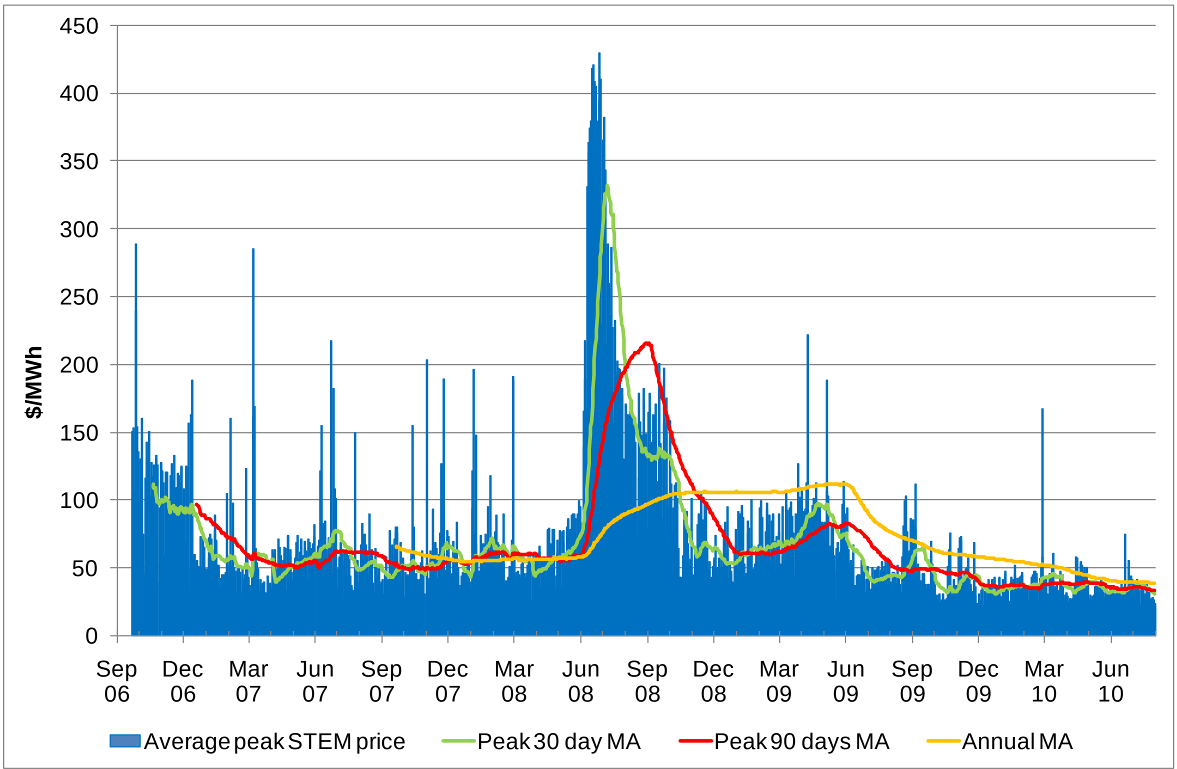


Figure 4 **Average Peak Trading Interval STEM Clearing Prices (per Trading Day)**



Both peak and off-peak STEM Clearing Prices remained stable during the Reporting Period, and on average, are lower than the prices observed in the previous reporting period. Also, average prices in the Reporting Period are lower than those observed prior to the Varanus Island incident. The key factor that is likely to have influenced downward pressure on clearing prices in the Reporting Period was the oversupply of capacity in the 2008/09 and 2009/10 Capacity Years (of six per cent and 10 per cent respectively), which resulted in increased competition in the generation sector.[193]

The lowest STEM Clearing Prices observed in off-peak periods during the Reporting Period occurred during December 2009 and January 2010, and were likely due to periods of low overnight load coinciding with lower cost capacity being available to the WEM. The maximum average STEM Clearing Prices for the Reporting Period during peak periods occurred in February 2010 and June 2010, which were likely due to a high rate of Planned Outage of generation plant coinciding with periods of high demand. As noted in Section 4.7, the IMO is in the process of undertaking a five-yearly review of the effectiveness of the planned outages process, and this review is scheduled to be completed by August 2011. The Authority will comment on the outcomes of this review in its next report to the Minister.

5.2.1.2 Volatility of Short Term Energy Market Clearing Prices

The Market Rules require the Authority to publish statistical analysis of the volatility of prices in STEM Auctions. Figure 5 and Figure 6 show the mean and standard deviation (as well as maxima and minima) by month of STEM Clearing Prices for off-peak and peak Trading Intervals from EMC up to 31 July 2010. Figure 5 and Figure 6 indicate that the volatility of both off-peak and peak STEM Clearing Prices has diminished since May 2009.

During the Reporting Period, the highest volatility in STEM Clearing Prices was observed in September 2009 and November 2009.

[193] In relation to the Reserve Capacity Requirement in those Reserve Capacity Cycles.

Figure 5 Summary statistics for STEM Clearing Prices in Off-Peak Trading Intervals (per calendar month)

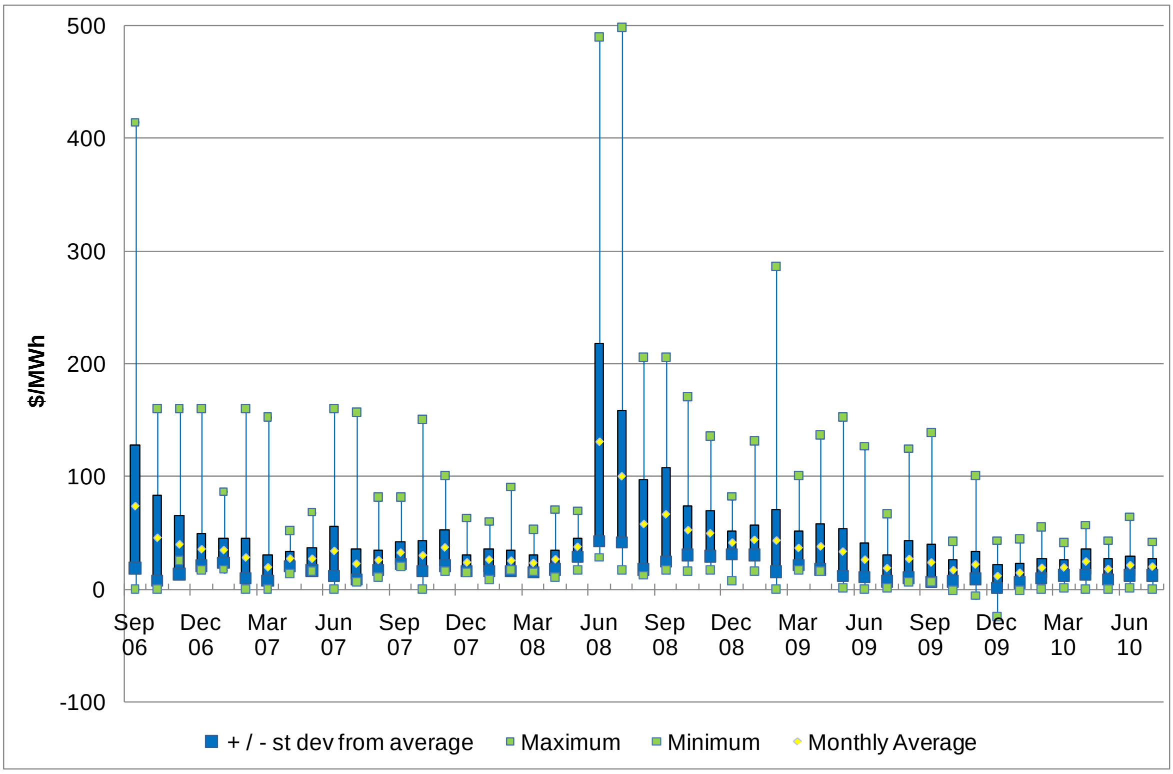
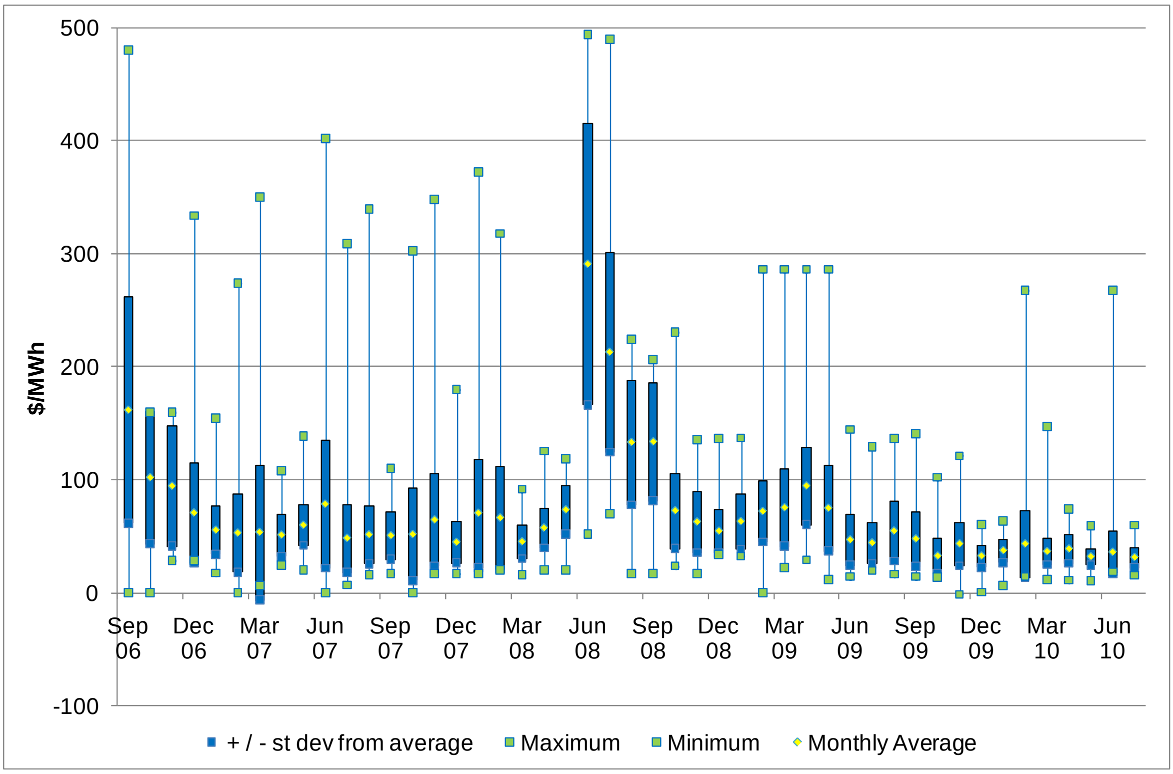


Figure 6 **Summary statistics for STEM Clearing Prices in Peak Trading Intervals (per calendar month)**



5.2.1.3 High prices in the Short Term Energy Market

Clause 2.16.4 of the Market Rules requires an examination of both the incidence and the causes of high prices in the STEM. One way of examining the incidence of high prices is to assess the proportion of time that STEM Clearing Prices are at the Energy Price Limits. There are two Energy Price Limits set out in the Market Rules that act as a cap on high prices.

- Generation Capacity not running on Liquid Fuel must not be priced above the Maximum STEM Price. The Maximum STEM Price is based on the cost of an open cycle gas turbine. The Market Rules specify that the Maximum STEM Price is adjusted annually subject to review by the IMO. For the period from 1 October 2009 to 1 October 2010 the Maximum STEM Price was $276/MWh.
- Generation Capacity running on Liquid Fuel must not be priced above the Alternative Maximum STEM Price. The alternative Maximum STEM Price is based on the cost of a liquid fuel facility. The Market Rules specify that the Alternative Maximum STEM Price is adjusted monthly to reflect changes in oil prices and the consumer price index, and is subject to review by the IMO. Since EMC, the Alternative Maximum STEM Price has been as low as $380/MWh and as high as $779/MWh.

Figure 7 and Figure 8 illustrate the proportion of peak and off-peak Trading Intervals during which STEM Clearing Prices were at the Maximum STEM Price and Alternative Maximum STEM Price.

Figure 7 shows that, since 2007, the highest incidence of both off-peak and peak STEM Clearing Prices reaching the Maximum STEM Price occurred between June 2008 and September 2008, which coincided with period of the Varanus Island incident. STEM Clearing Prices also reached the Maximum STEM Price during peak Trading Intervals between March and May 2009 due to a significant number of plant outages, coinciding with a period of high demand. Since then, including during the current Reporting Period, STEM Clearing Prices have not reached the Maximum STEM Price.

Figure 7 Proportion of Trading Intervals STEM Clearing Prices at Maximum STEM Price (per calendar month)

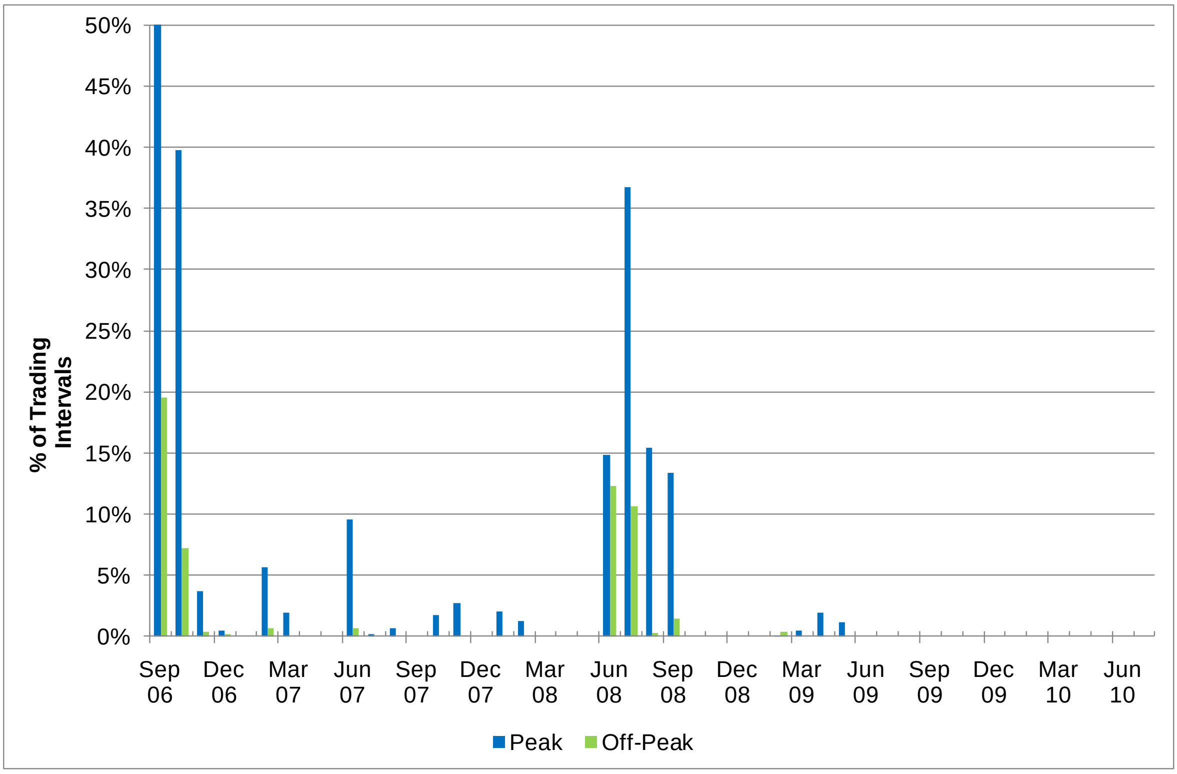
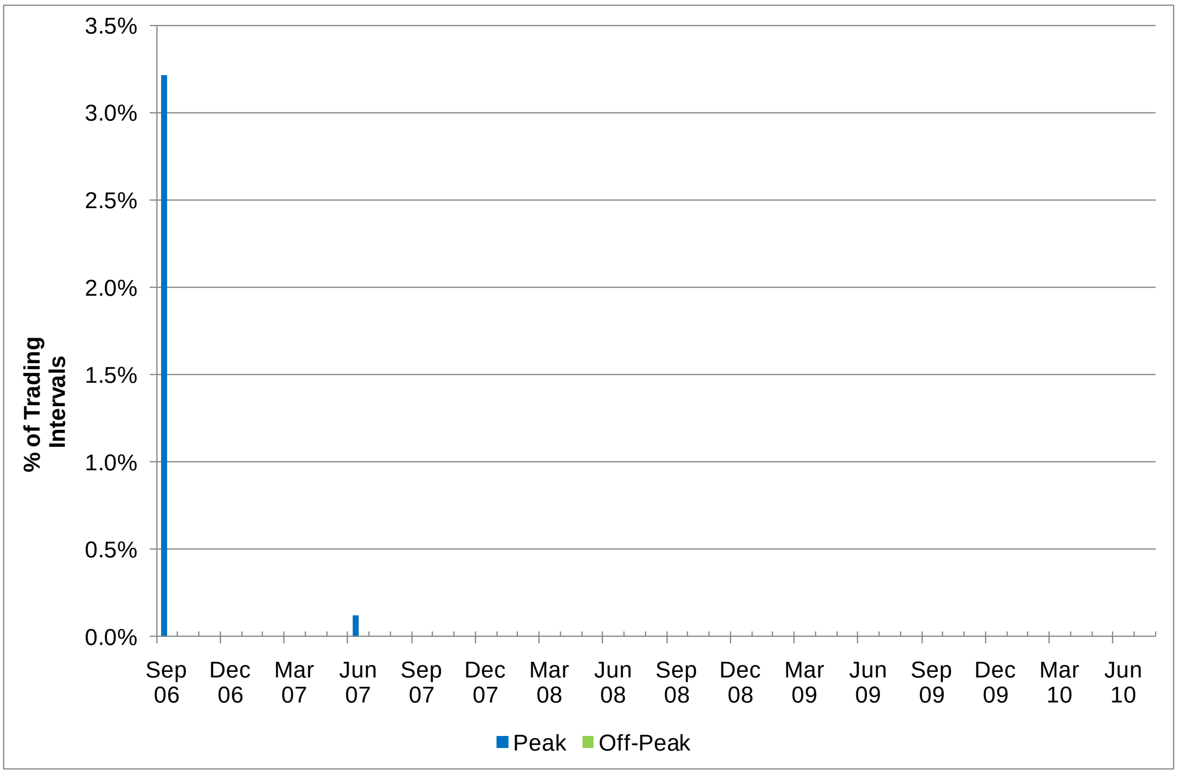


Figure 8 shows that STEM Clearing Prices have only reached the Alternative Maximum STEM Price during peak Trading Intervals in September 2006 and June 2007.

Figure 8 Proportion of Trading Intervals STEM Clearing Prices at Alternative Maximum STEM Price (per calendar month)

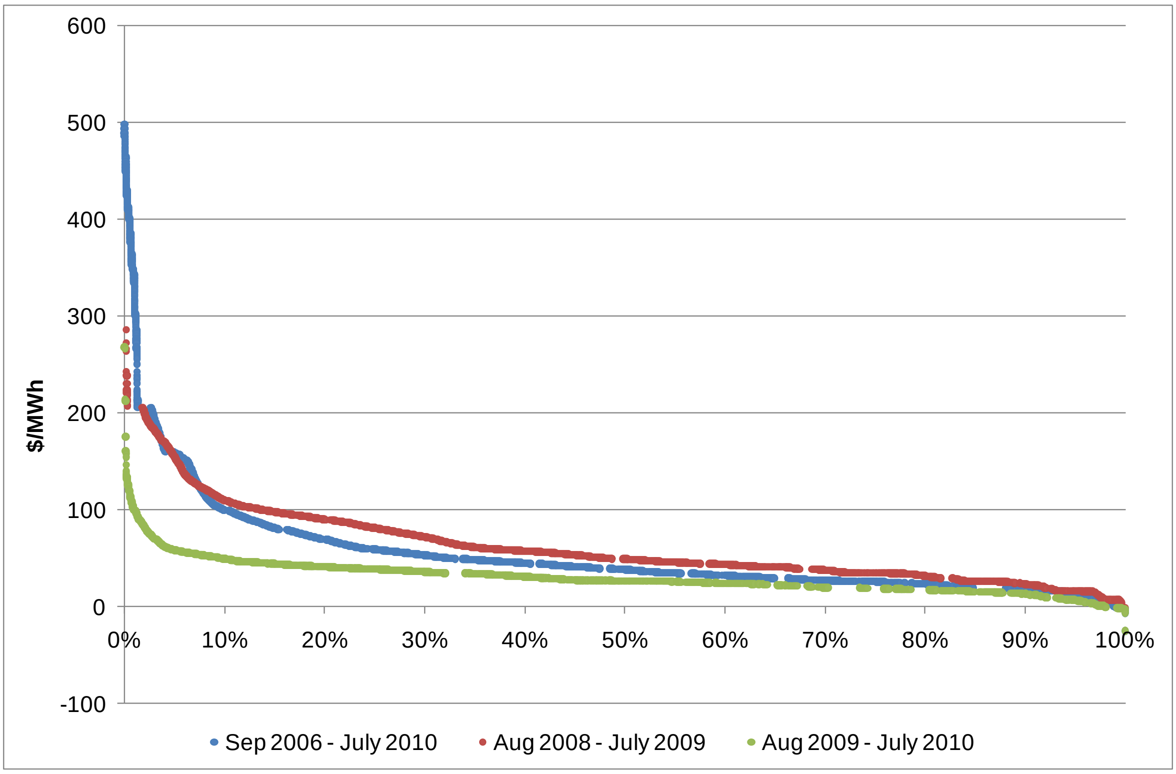


Another way of examining the incidence of high prices is to plot a price duration curve. Figure 9 sets out the price duration curves for STEM Clearing Prices, covering all Trading Intervals since 21 September 2006 (EMC) to 31 July 2010, compared to the previous reporting period (August 2008 to July 2009) and the current Reporting Period.[194]

Figure 9 shows that STEM Clearing Prices fell between -$5.00/MWh and $100.00/MWh for approximately 98 per cent of Trading Intervals during the current Reporting Period, with a fairly even distribution of prices within this range. In the previous reporting period, prices fell between $0/MWh and $100.00/MWh for approximately 86 per cent of Trading Intervals.

[194] Price duration curves for off-peak and peak period STEM Prices during the current Reporting Period are set out in Figure 64 and Figure 65 (respectively).

Figure 9 Comparison of price duration curves for STEM Clearing Prices (past two annual reporting periods and 21 September 2006 and 31 July 2010)



Clause 2.16.4(e) of the Market Rules requires the IMO to calculate the correlation between capacity offered into STEM Auctions and the incidence of high prices. In previous Reports to the Minister the Authority highlighted that a simple correlation between capacity and prices will fail to capture other factors that can influence STEM Clearing Prices, such as bidding behaviour and demand conditions, and that more detailed analysis was required to understand the key determinants of high prices in the STEM[195] (this is discussed in further detail below). For these reasons, correlations between STEM Clearing Prices and quantities offered are not included in this report.

Clause 2.16.4(g) of the Market Rules requires the IMO to explore the key determinants for high prices in the STEM and Balancing. The Authority reported in its previous report to the Minister that it was working together with the IMO to develop an appropriate econometric model[196] for undertaking the analysis required under clause 2.16.4 (e) and clause 2.16.4 (g) of the Market Rules.[197]

A working model for STEM Clearing Prices was completed by December 2009. Based on this model, a list of determinants and the correlations each has with high STEM Clearing Prices was derived at the end of 2009. The key determinants of high STEM Clearing Prices predicted by this model were:

- bilaterally and STEM traded supply and demand quantities;

[195] See for example ERA 2007, Annual Wholesale Electricity Market Report for the Minister for Energy, 21 December 2007, pp.18-20.

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

[197] ERA 2010, 2009 Annual Wholesale Electricity Market Report for the Minister for Energy, 18 February 2010, p. 49.

- the extended gas supply disruption caused by the Varanus Island incident in 2008;
- Forced Outages, in particular extended Forced Outages including Griffin Energy's Bluewaters 1 outage during the 2008/09 Reserve Capacity Year and Verve Energy's Collie G1 outage during the 2007/08 Reserve Capacity Year; and
- Planned Outages.

Since the model's last run in late 2009, the Authority and the IMO have not had an opportunity to rerun the model to verify whether each of the determinants and their correlations to high STEM Clearing Prices remain unchanged. However, the IMO staff who had been involved in the development of the model are of the opinion that each of the determinants previously identified are still likely to be a significant determinants, and the order of magnitude of the correlations is likely to be consistent with the previous analysis.

Outstanding items to be progressed on the analysis required under clause 2.16.4(e) and clause 2.16.4(g) involve the following.

- Development of an operational report based on the statistical working model for STEM Clearing Prices that can be provided by the IMO to the Authority as a part of the monthly instalments of MSDC data and analysis. The IMO has advised that this is a complex task that cannot be progressed until required resources engaged with the MEP project work become available.
- Explore options to develop a statistical model for MCAP. This was previously scheduled to be completed in early 2010, but the IMO-Authority working group agreed that there was insufficient MCAP data required for modelling purposes and as a result this work was deferred for one year until 2011. Given the current market evolution processes, this work will also need to be cognisant of the changes made to the Balancing mechanism, which may include that MCAP will not be retained as a part of the revised Balancing mechanism's design. These proposed changes to the Balancing mechanism are discussed in further detail in Section 4.5.

5.2.1.4 Short Term Energy Market Offers and Bids

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

The Market Rules require that the IMO determine STEM Offers and STEM Bids for each Market Participant, and for each Trading Interval that a STEM Submission is received. The IMO determines STEM Offers and STEM Bids by converting a Market Participant's Portfolio Supply Curve and Portfolio Demand Curve into a single STEM price curve, and then convert this into STEM Offers and STEM Bids relative to the Market Participant's net bilateral position.

Short Term Energy Market Offers

STEM Offers reflect an increase in generation or a decrease in consumption. Figure 10 illustrates the daily average quantity of STEM Offers per Trading Interval for all Market Participants from EMC until 31 July 2010.

The majority of energy has consistently been offered at prices equal to the Maximum STEM Price and the Alternative Maximum STEM Price.[198] Smaller volumes tend to be offered at prices below the Maximum STEM Price, and the extent of offers below the Maximum STEM Price varies significantly over time. It is notable that, since June 2009 onwards, Market Participants have offered increasing quantities in the STEM in the price range of the Minimum STEM Price to $0/MWh.

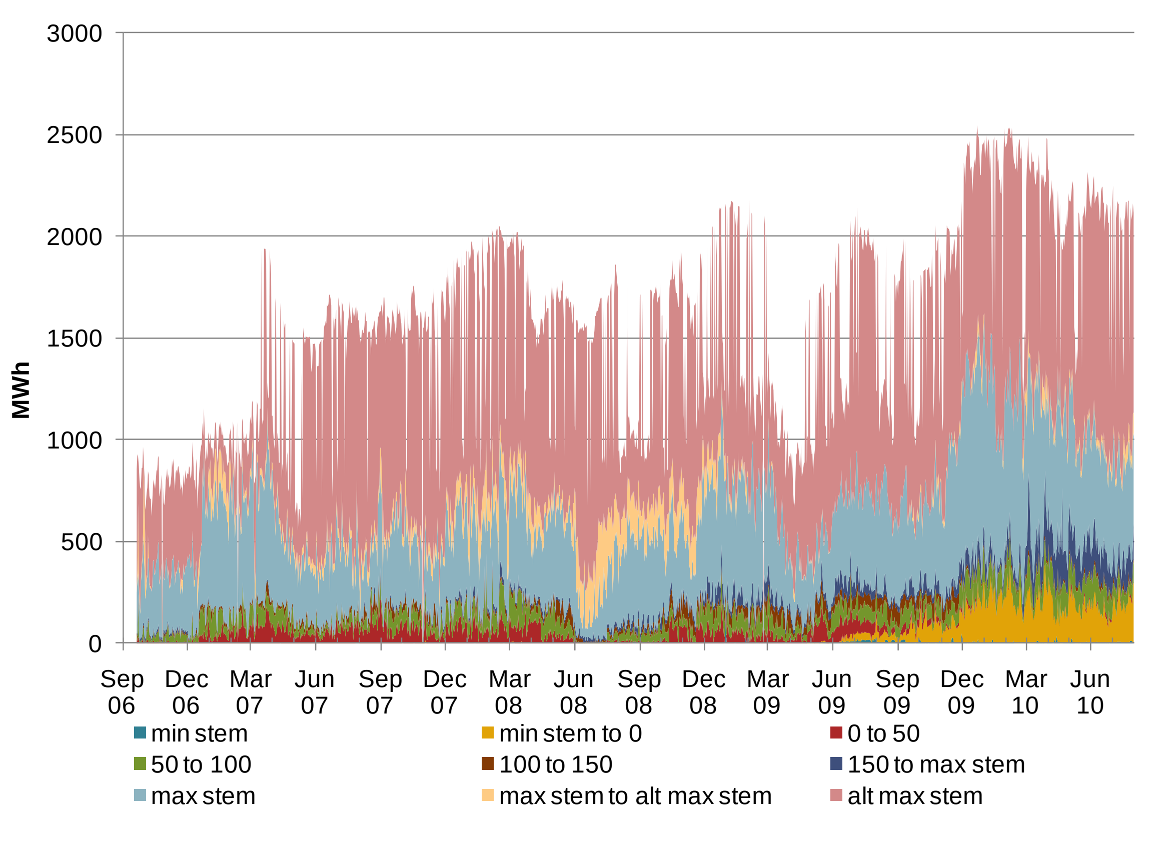
STEM Offers for each Market Participant are separately set out in Figure 25 to Figure 35 in Appendix 3. These figures show clear differences in the volumes and prices at which Market Participants have offered quantities into the STEM.

As seen in Figure 35 in Appendix 3, Verve Energy consistently offers significant volumes into the STEM, with the majority of Verve Energy's offers priced at the Maximum STEM Price. Since November 2008, Verve Energy has tended to offer larger volumes at prices below the Maximum STEM Price, with these offers accounting for a significant proportion of Verve Energy's total offers. As seen in Figure 26 and Figure 34, Alinta and Synergy also continue to offer significant volumes into the STEM, primarily priced at the Alternative Maximum STEM Price. More recently, as seen in Figure 32 and Figure 33, Perth Energy and Southern Cross Energy have also offered significant volumes into the STEM, primarily priced at the Alternative Maximum STEM Price.

Since the 2009 Report to the Minister, the most significant change in STEM Offers has resulted from the entry of Griffin Power 2 and NewGen Neerabup. As seen in Figure 29 and Figure 31 in Appendix 3, since the beginning of the 2009/10 Capacity Year, both Griffin Power 2 and NewGen Neerabup have at times offered significant volumes into the STEM, in a range of price bands. NewGen Neerabup's offers have been almost exclusively priced at the Maximum STEM Price, while Griffin Power 2 has made offers at a range of prices.

[198] In constructing the STEM Offers and STEM Bids, a Market Customer's demand that is covered in a Bilateral Contract is defined as a STEM Offer. Since the value of electricity for end users is high, as evidenced in high value of lost load (VOLL) in the National Electricity Market, Market Customers normally price reductions in their demand to reflect the high value for that electricity. In the WEM, this high priced demand becomes STEM Offers at the Alternative Maximum STEM Price. Thus, large quantities offered at the Alternative Maximum STEM Price are to be expected in the STEM.

Figure 10 Daily average quantity of STEM Offers (cumulative MWh per Trading Interval)



Short Term Energy Market Bids

STEM Bids reflect a decrease in generation or an increase in consumption. Figure 11 illustrates the daily average quantity of STEM Bids per Trading Interval for all Market Participants from EMC until 31 July 2010.

By design, the high level of Market Customer's bilateral commitment (in terms of its demand) will result in the volume of STEM Bids being lower than the volume of STEM Offers. This is evident in a comparison of Figure 11 and Figure 10.

As can be seen in Figure 11, significant quantities of energy have consistently been bid in the STEM between the Minimum STEM Price and $50/MWh. In the STEM's design this outcome would be expected – given it covers quantities already contracted and represents must-run[199] and lower cost capacities (such as coal fired generators) which can be expensive to shutdown and restart. Quantities have been bid at higher prices only infrequently, including the period following the Varanus Island incident, when STEM Bids reflected an increase in the cost of supplying energy during this time.

STEM Bids for each Market Participant are set out separately in Figure 36 through Figure 46 in Appendix 3. These figures show clear differences in the prices and volumes at which Market Participants have bid quantities in the STEM.

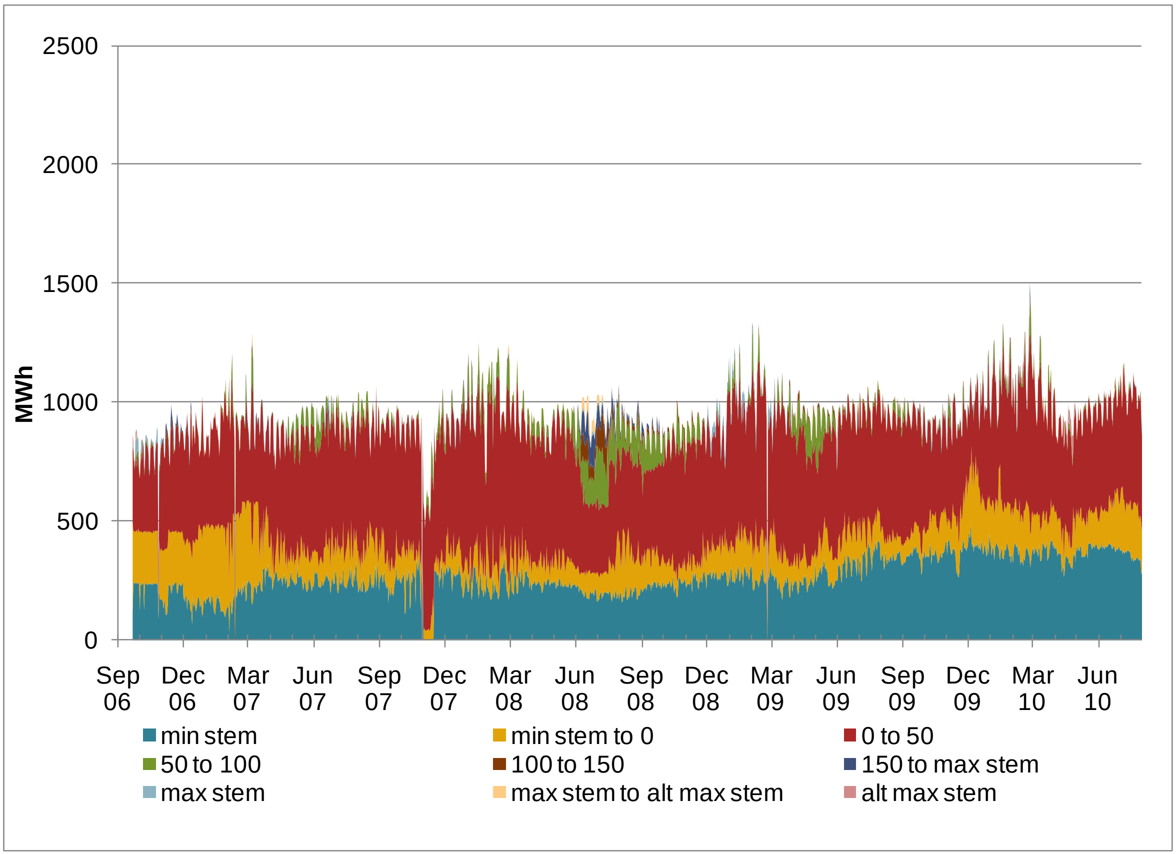
As with STEM Offers, Verve Energy accounts for the largest volumes of STEM Bids. Figure 46 in Appendix 3 illustrates that Verve Energy has consistently bid significant

---

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

volumes in the STEM, principally at low or negative prices. Alinta has also consistently bid significant volumes in the STEM, almost entirely at the Minimum STEM Price, thereby ensuring that its commitment to Alcoa is met. As seen in Figure 40 in Appendix 3, the biggest change in STEM Bids since the beginning of the 2009/10 Capacity Year has resulted from the entry of Griffin Power 2, that has at times bid significant volumes into the STEM in a range of price bands.

Figure 11 Daily average quantity of STEM Bids (cumulative MWh per Trading Interval)



5.2.1.5 Short Term Energy Market traded quantities

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

Error! Reference source not found. shows the annual average of STEM traded quantity among Market Participants (cumulative MWh per Trading Interval) for four yearly periods since EMC, as well as an overall average from EMC to 31 July 2010.

Table 3 Annual average of Short Term Energy Market traded quantities among Market Participants (cumulative MWh per Trading Interval)

	21 Sep 06 - 31 Jul 07	1 Aug 07 - 31 Jul 08	1 Aug 08 - 31 Jul 09	1 Aug 09 - 31 Jul 10	Average quantity
STEM traded quantities	9.61	13.75	32.31	53.60	27.85

Note: 'Average quantities' are for the overall period, i.e. 21 September 2006 to 31 July 2010.

Figure 12 and Figure 13 show the daily average volume bought and sold in the STEM for all Market Participants from EMC to 31 July 2010.

The historical volume traded in the STEM remained relatively low until the commencement of the 2008/09 Capacity Year in October 2008. Since then traded volumes have increased substantially, which is largely attributed to the entry of NewGen and Griffin Power in that Capacity Year.

Increased STEM trade volume carried on into the 2009/10 Capacity Year and was driven primarily by a number of IPP's seeking to sell energy in the STEM, which included Alinta, Griffin and NewGen. With the exception of the period December 2008 to March 2009, when NewGen was sourcing significant volumes of energy from the STEM, the most significant buyer in the STEM from EMC to the end of the current Reporting Period has been Verve Energy.

Figure 12 Daily average quantities bought in the STEM (MWh)

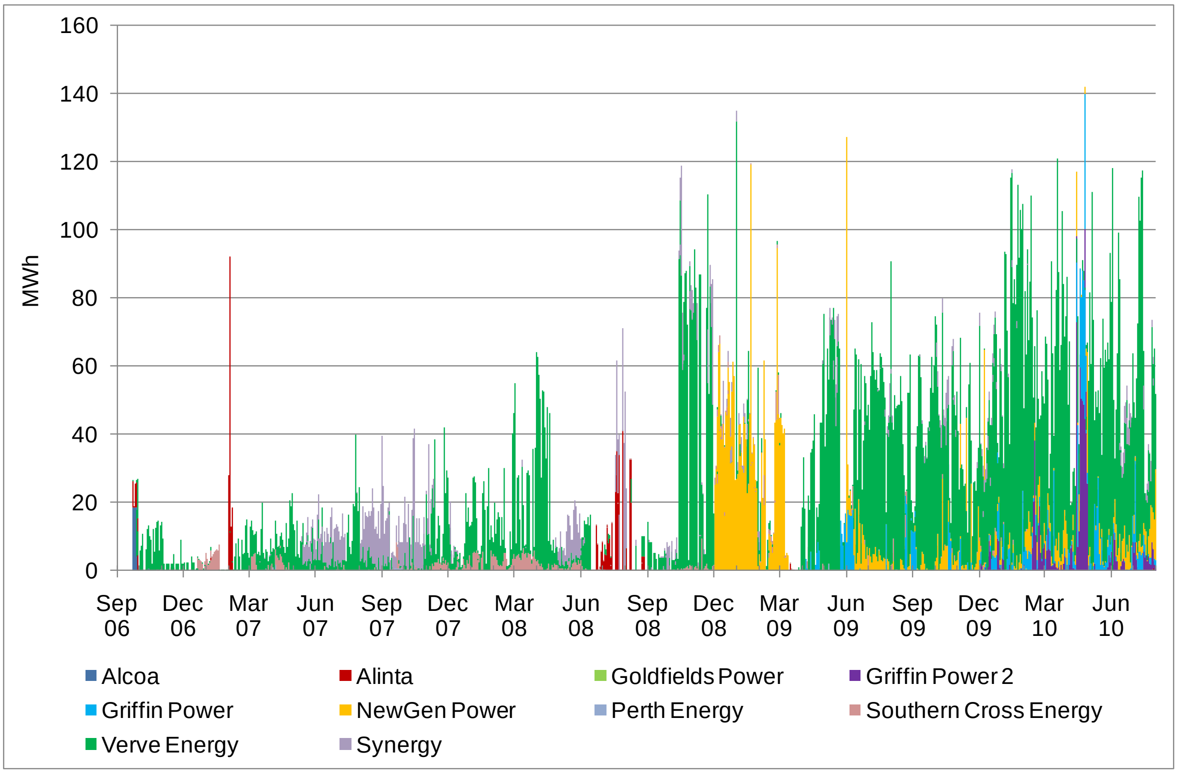


Figure 13 Daily average quantities sold in the STEM (MWh)

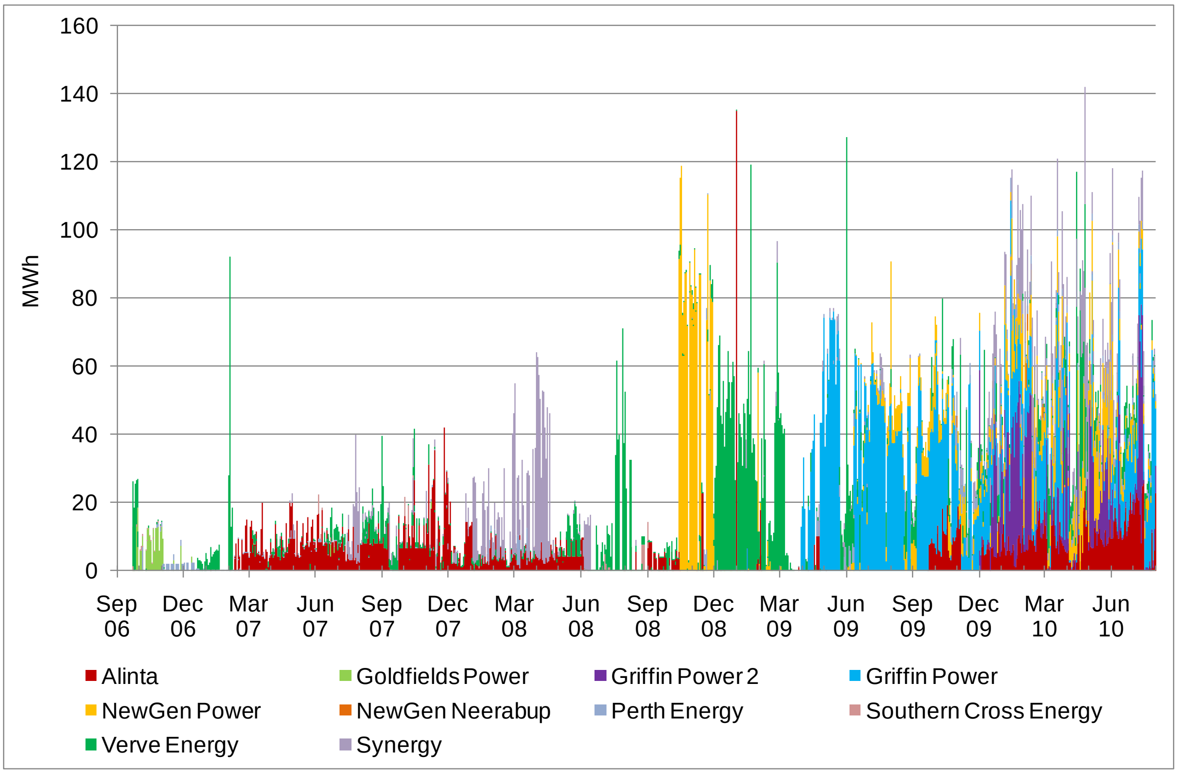


Figure 47 in Appendix 3 shows average daily STEM Clearing Quantities for each Trading Day from 21 September 2006 (EMC) to the end of the current Reporting Period (31 July 2010), as well as 30-day, 90-day and annual moving average quantities.

5.2.2 Balancing

Clause 2.16.2(d) of the Market Rules requires that the MSDC includes the Balancing Data prices and other Standing Data prices used in balancing.

There is also a requirement under clause 2.16.4 to calculate:

- means and standard deviations of Balancing Data prices;
- monthly, quarterly and annual moving averages of Balancing Data prices;
- statistical analysis of the volatility of Balancing Data prices;
- the proportion of time that Balancing Data prices are at each price limit;
- the correlation between capacity available for Balancing and the incidence of high prices; and
- exploration of key determinants for high Balancing prices.

This section summarises the results of the requirements under both clause 2.16.2 and clause 2.16.4.

5.2.2.1 Balancing prices

Balancing enables Market Participants to adjust their Net Contract Position so that supply equals demand in real-time. Generally, System Management will match supply and demand in the system using Verve Energy's facilities. However, there are circumstances in which System Management can issue Dispatch Instructions to other Market Participants.

Standing Data prices used in Balancing

Where Market Participants other than Verve Energy are issued Dispatch Instructions by System Management, these deviations are settled on a pay-as-bid basis. The Standing Data prices used in Balancing consist of prices bid to increase or decrease supply by Market Participants other than Verve Energy.

The Standing Data prices used in Balancing are summarised in Figure 48 through to Figure 52 in Appendix 3, for the period from EMC to 31 July 2010. These figures present average daily prices bid to increase and decrease consumption, by the type of facility: non-liquid generation, liquid generation, intermittent generation and Curtailable Loads.[200]

Broadly, IPPs want to be paid close to the applicable Maximum STEM Prices when instructed to increase generation from their Scheduled Generators irrespective of the time of the day. When instructed to reduce the level of generation, IPPs also want to be paid if a Non-Liquid generator is backed off, but are willing to pay a low price (relative to distillate generation cost) for generation backed off from a Liquid Scheduled Generator.

In previous discussions with the Authority, the IMO has explained why some Market Participants have high increase and decrease supply prices.[201]

The Authority has raised its concern with the IMO regarding the IMO's policing of Standing Data related to prices and payments that are submitted by Market Participants to the IMO. This matter is discussed in further detail in Section 4.5.

MCAP, UDAP and DDAP

In addition to Standing Data balancing prices, there are three other balancing prices determined by the IMO, being the:

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

MCAP is used to settle deviations from Net Contract Position[202] by Verve Energy, by Non-Scheduled Generators, by Non-Dispatchable, Interruptible and Curtailable Loads, and by non-Verve Energy Scheduled Generators.[203] In other words, rather than paying or receiving pay-as-bid prices for deviations, these facilities pay or receive MCAP for these deviations.

UDAP and DDAP are used to settle deviations outside a tolerance[204] for non-Verve Energy Scheduled Generators (excluding those subject to a test) that deviate from their schedules without instruction from System Management. UDAP is set at a discount to MCAP to discourage upward deviations without instruction from System Management and

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

[201] ERA 2010, 2009 Annual Wholesale Electricity Market Report for the Minister for Energy, 18 February 2010, pp. 24-25.

[202] A Market Participant's Net Contract Position is its amount of contracted energy corresponding to its bilateral trades plus its STEM trades. In real-time, the actual energy provided may deviate from this Net Contract Position. The Balancing mechanism provides the means for trading these deviations.

[203] Subject to Commissioning Tests or tests of their Reserve Capacity Requirements as well as within tolerance deviations in the output of these generators.

[204] As provided for under Market Rule Clause 6.17.9.

DDAP is set at a premium to MCAP to discourage downward deviations without instruction from System Management. The formula under the Market Rules for calculating UDAP and DDAP is set out in Table 7 in Appendix 3.

As with the analysis of STEM Clearing Prices, Balancing prices are summarised separately for peak and off-peak periods.

Table 4 sets out the mean and standard deviations of the peak and off-peak MCAP, UDAP and DDAP from:

- 21 September 2006 (i.e. EMC) to 31 July 2010;
- 1 August 2008 to 31 July 2009 (i.e. the previous reporting period); and
- 1 August 2009 to 31 July 2010 (i.e. the current Reporting Period).

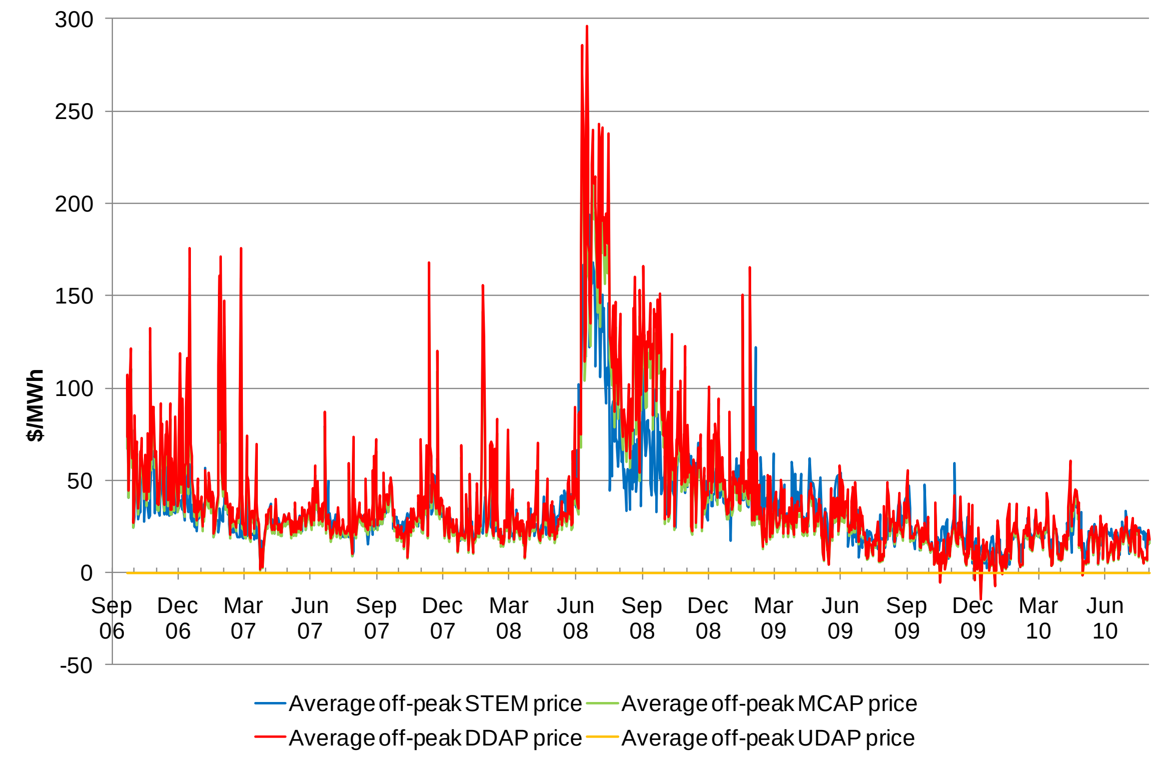
The patterns of Balancing prices broadly reflect the pattern of STEM Clearing Prices, with higher and more volatile prices during peak periods. This result is as expected, since the MCAP for a given Trading Interval (and, by extension, the UDAP and the DDAP for that Trading Interval) is based on STEM Bids and STEM Offers for that Trading Interval.

Table 4 Mean and standard deviations of the MCAP, UDAP and DDAP ($/MWh)

	Trading Interval	21 Sep 06 – 31 Jul 10		1 Aug 08 – 31 Jul 09		1 Aug 09 – 31 Jul 10	
		Mean	Std Dev	Mean	Std Dev	Mean	Std Dev
MCAP	Off-Peak	38.63	45.01	47.30	41.58	**16.88**	**14.24**
	Peak	82.02	83.67	87.66	62.41	**42.38**	**27.91**
UDAP	Off-Peak	0.00	0.00	0.00	0.00	**0.00**	**0.00**
	Peak	41.01	41.84	43.83	31.21	**21.19**	**13.95**
DDAP	Off-Peak	42.50	49.51	52.03	45.73	**18.57**	**15.67**
	Peak	105.68	104.42	113.83	80.91	**55.09**	**36.29**

Figure 14 illustrates average daily off-peak Balancing and STEM Clearing Prices for each Trading Day from EMC to 31 July 2010. Because the DDAP is set equal to the MCAP multiplied by 1.1 during off-peak periods, a clear link between the two can be observed in Figure 14. UDAP is set at zero during Off-Peak Trading Intervals, and therefore is not visible in Figure 14.

Figure 14 Average daily Off-Peak Balancing prices

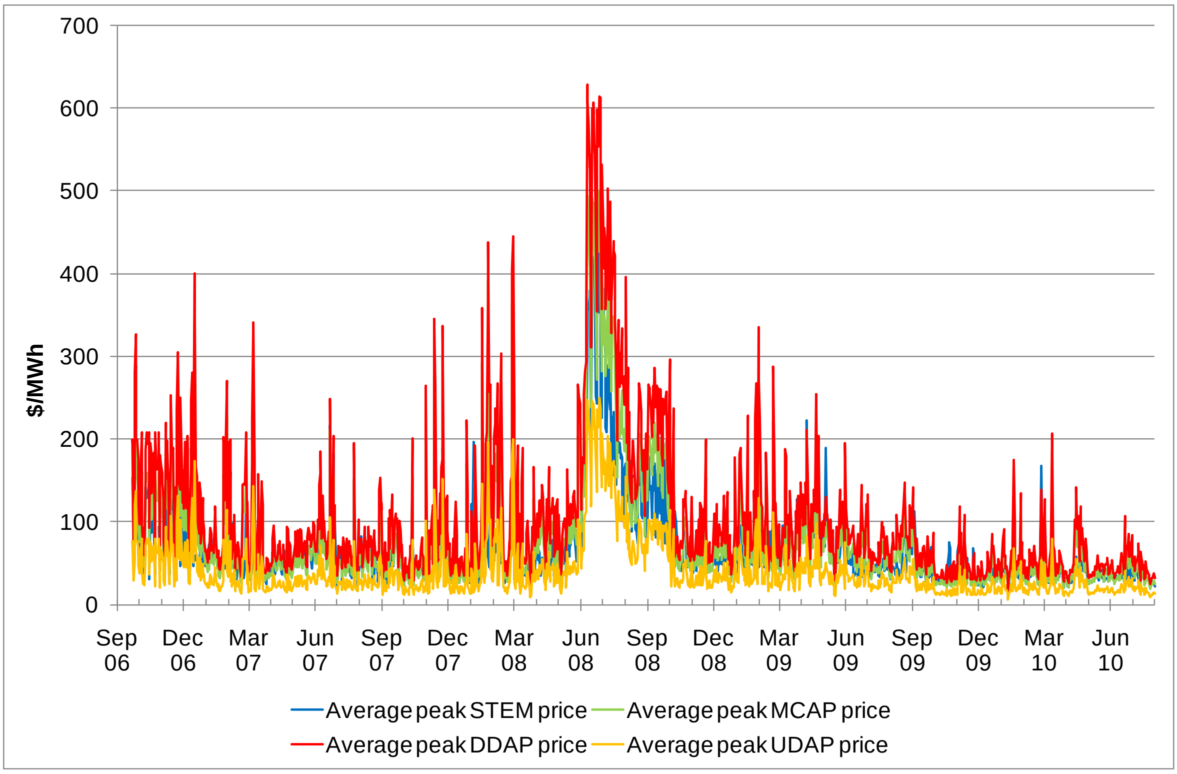


The negative Balancing prices observed during off-peak periods in October 2009 and again in December 2009 were due to the activities of new commissioning generators. These generators priced their energy at negative prices to ensure they stayed on during periods of low overnight load, so as not to interrupt their commissioning process.

A strong correlation between off-peak balancing prices and STEM Clearing Prices can be seen more clearly in Figure 53 and Figure 54 in Appendix 3, which compare the 30-day and 90-day moving averages of off-peak STEM and balancing prices, respectively.

Figure 15 illustrates average daily peak Balancing prices for each Trading Day from EMC to 31 July 2010. Because the UDAP and the DDAP are set with reference to the MCAP, there is a clear correlation between the three prices.

Figure 15 Average daily Peak Balancing prices



As with off-peak periods, the pattern of Balancing prices (i.e. MCAPs, DDAPs and UDAPs) during peak periods is similar to the pattern of peak STEM Clearing Prices. This similarity is shown in Figure 55 and Figure 56 in Appendix 3, which compare 30-day and 90-day moving averages of peak STEM and Balancing prices, respectively.

Similar to off-peak prices, higher STEM Clearing Prices and Balancing prices during Peak Trading Intervals in mid-2008 resulted from the Varanus Island incident, to then decline to their lowest market level by July 2009 since EMC. Notably, from the start of 2008, peak MCAPs were consistently higher than STEM Clearing Prices. However, since March/April 2009, Trading Interval STEM Clearing Prices and MCAPs have broadly converged.

Figure 57 and Figure 58 in Appendix 3 show annual moving average STEM and Balancing prices for off-peak and peak periods, respectively. These figures show that annual average prices increased significantly at the time of the Varanus Island incident, but have since fallen to be at the lowest levels since EMC.

5.2.2.2 Volatility of Balancing prices

As indicated by the price trends in Figure 14 and Figure 15, the level and volatility of both STEM Clearing Prices and Balancing prices are currently at their lowest level since EMC.

Volatility in Balancing prices is more accurately analysed by determining means and standard deviations. The means and standard deviations (as well as the maxima and minima) of Balancing prices are illustrated in Figure 59 through to Figure 63 in Appendix 3. In general, Peak Trading Interval Balancing prices are more volatile than Off-Peak Trading Interval prices for MCAP and DDAP, as was the case for STEM Clearing Prices. As with Off-Peak Trading Interval STEM Clearing Prices, the volatility of Off-Peak Trading Interval MCAPs and DDAPs has diminished since the Varanus Island incident. Peak MCAPs and DDAPs, as with peak STEM Clearing Prices, have also become much less volatile since July 2008.

5.2.2.3 High Balancing prices

The Market Rules require an examination of both the incidence and causes of high balancing prices.

As with STEM Clearing Prices, the incidence of high Balancing prices is examined by considering the proportion of time that Balancing prices are at the Energy Price Limits and by considering the price duration curve for Balancing prices.

Figure 16 illustrates the proportion of Peak Trading Intervals and Off-Peak Trading Intervals during which MCAPs were at the Maximum STEM Price. This shows that MCAPs were regularly at the Maximum STEM Price during Peak Trading Intervals in the first few months of the market, over the summer of 2007/08 and from June to September 2008 during the Varanus Island interruption. MCAPs were also often at the Maximum STEM Price during Off-Peak Trading Intervals during the Varanus Island interruption. During this Reporting Period MCAPs reached the Maximum STEM Price for less than one per cent of total Peak Trading Intervals.

Comparing Figure 7 with Figure 16, it is clear that MCAPs were at the Maximum STEM Price more frequently than have STEM Clearing Prices in the earlier years of the market; however, during the Reporting Period, the occurrence of MCAPs (and STEM Clearing Prices) at the Maximum STEM Price have become very infrequent.

Figure 16 Proportion of Trading Intervals MCAPs at Maximum STEM Price (per calendar month)

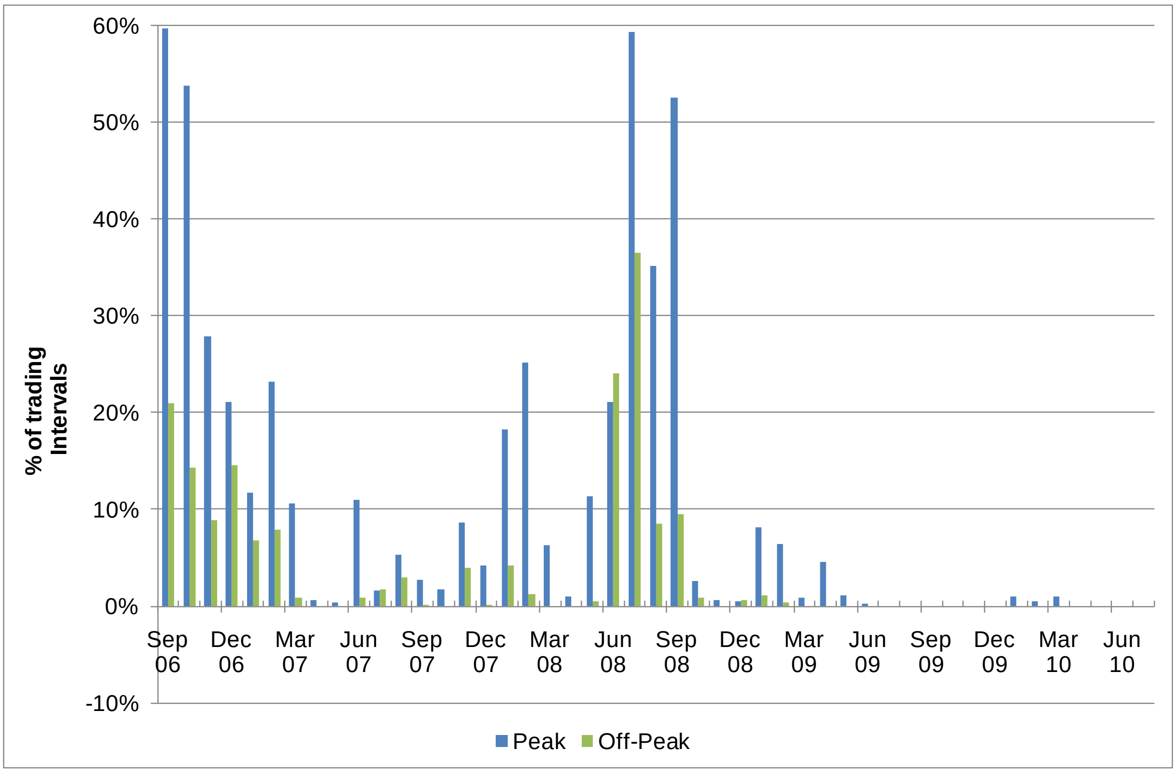


Figure 17 illustrates the proportion of peak and off-peak periods, during which MCAPs were at the Alternative Maximum STEM Price. This shows that the last time when MCAPs reached the Alternative Maximum STEM Price was in January 2008.

Figure 17 Proportion of Trading Intervals MCAPs at Alternative Maximum STEM Price (per calendar month)

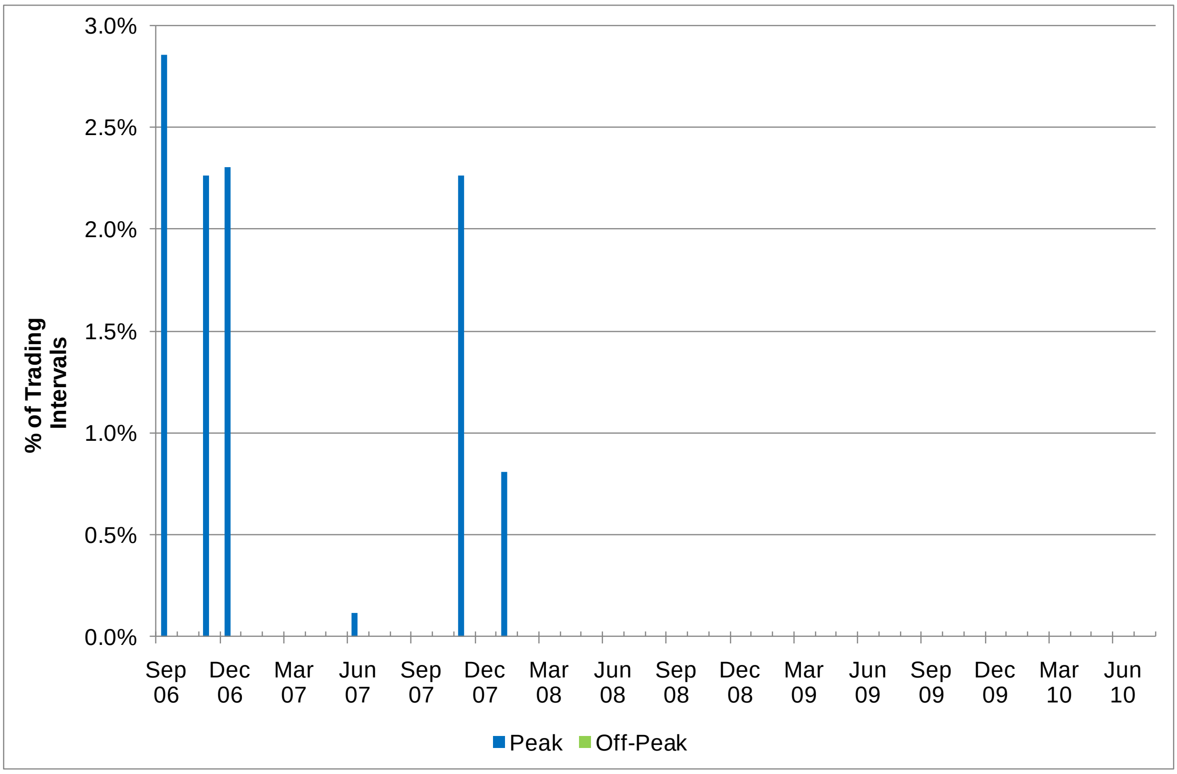


Figure 18 sets out the MCAP duration curve, covering all Trading Intervals from 21 September 2006 (EMC) to 31 July 2010. For comparison, Figure 18 also includes the UDAP, DDAP and STEM price duration curves for the same period.[205] As expected, the MCAP is bounded by the UDAP and the DDAP.

As can be seen in Figure 18, the MCAP duration curve follows the price duration curve for STEM Clearing Prices relatively closely, although high MCAPs occur more frequently than high STEM Clearing Prices. A notable divergence between the MCAP and STEM Clearing Prices is at around the $100/MWh – STEM Clearing Prices are less likely to be above $100/MWh than are MCAPs. This reflects the prior observation that MCAPs tend to be at the Maximum STEM Price more frequently than STEM Clearing Prices.

[205] Price duration curves for off-peak and peak period MCAPs are set out in Figure 64 and Figure 65 (respectively).

Figure 18 Price duration curves for STEM Clearing Prices, MCAPs, UDAPs and DDAPs (21 September 2006 to 31 July 2010)

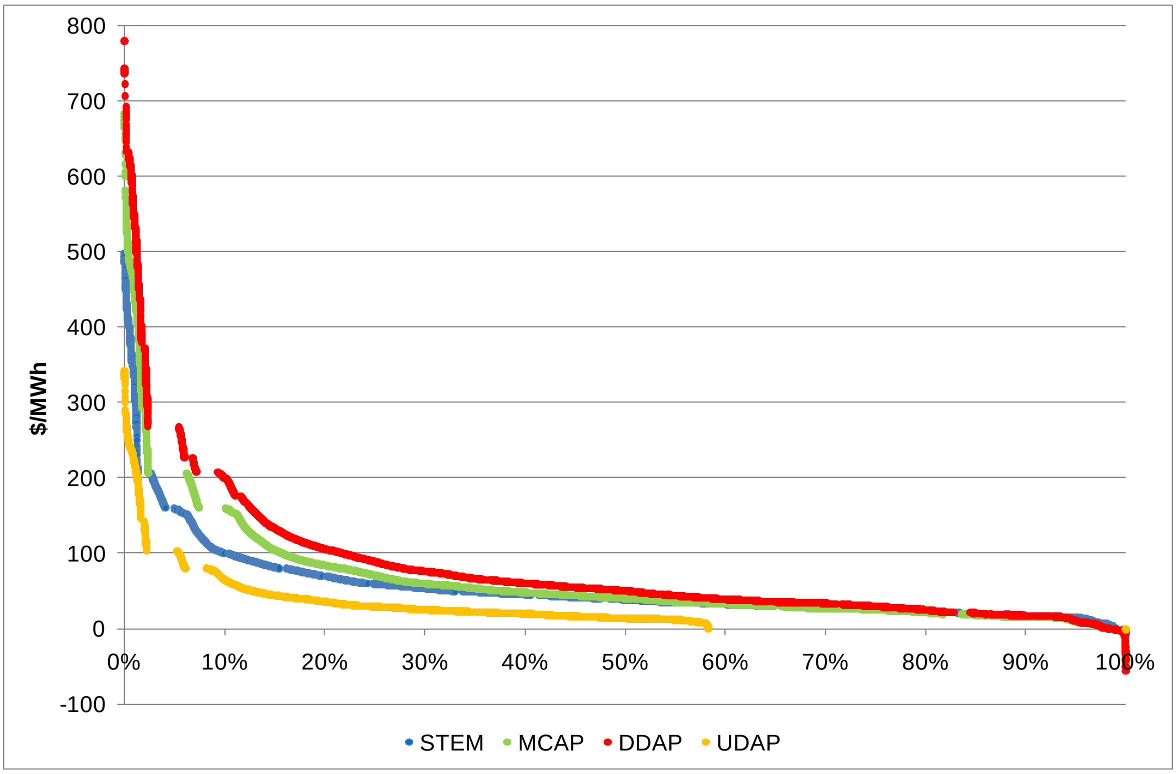
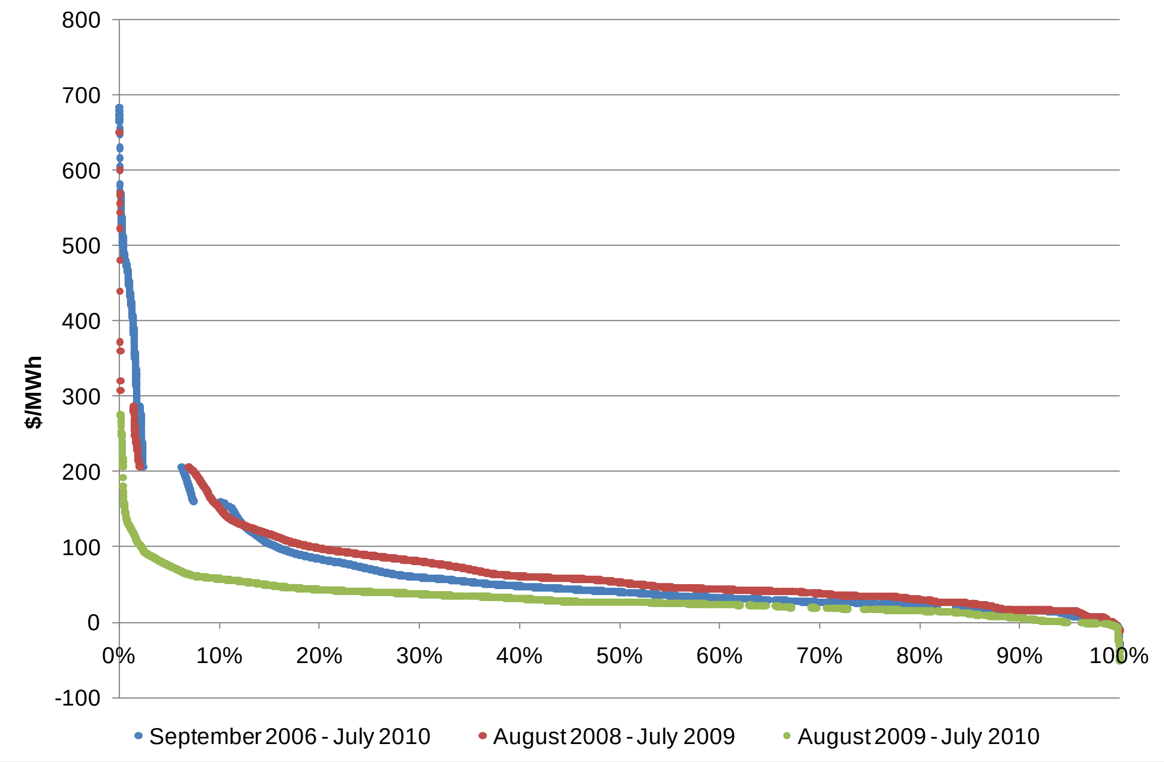


Figure 19 illustrates a comparison MCAP price duration curves for the periods 21 September 2006 (EMC) to 31 July 2010, 1 August 2008 to 31 July 2009 and 1 August 2009 to 31 July 2010.

Figure 19 Comparison of price duration curves for MCAPs (past two annual reporting periods and 21 September 2006 to 31 July 2010)



It can be seen that the MCAPs were higher during the previous reporting year (1 August 2008 to 31 July 2009) due to the impact from the Varanus Island incident and a greater number of plant outages. The MCAP for the current Reporting Period remained at comparatively low levels, under $100/MWh for 97 per cent of the total Trading Intervals. This was primarily due to fewer plant outages during peak periods and the availability of cheaper energy from two new large IPP generation units introduced to the market towards the end of 2009. The four-year average has MCAPs exceeding $100/MWh for 15 per cent of total Trading Intervals, and a maximum MCAP of $682/MWh was reached in July 2008.

Figure 66 and Figure 67 in Appendix 3 illustrate price duration curves for STEM Clearing Prices and MCAPs during peak Trading Intervals, for the reporting periods 1 August 2008 to 31 July 2009 and 1 August 2009 to 31 July 2010. A comparison of these figures shows the gap between STEM Clearing rices and MCAPs during Peak Trading Intervals has closed significantly, particularly in the $100/MWh to $200/MWh price range.

Clause 2.16.4(f) of the Market Rules requires the calculation of the correlation between capacity available in Balancing and the incidence of high prices. When considering the correlation between STEM Clearing Prices and quantities offered into the STEM, the correlation between capacity available in Balancing and the incidence of high Balancing prices will fail to usefully capture key determinants of Balancing prices. Therefore, correlations are not included in this report; however, the Authority is continues to work with the IMO on developing appropriate forms of analysis to explain the incidence of high Balancing prices. This is discussed in detail in Section 5.2.1.3.

In addition to analysing the key determinants of high prices in the STEM, clause 2.16.4(g) requires the IMO to explore the key determinants for high Balancing prices. As noted above, this is being considered on an ongoing basis by the joint IMO-Authority working group process, and is discussed in Section 5.2.1.3.

5.2.2.4 Capacity available through Balancing (through Dispatch Instructions)

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

At this stage, the IMO calculates the capacity available through Balancing from Market Participants other than Verve Energy. This is because, in effect, all of Verve Energy's capacity is available to provide Balancing. The IMO derives the capacity available through Balancing from a facility as:

- the Facility capacity limit;
- less the Loss Factor adjusted generation for the Facility (as set out in the Resource Plan); and
- less quantities for the Facility set out in an Availability Declaration.

This information is confidential and is not presented in this public version of the report.

5.2.2.5 Number and frequency of Dispatch Instructions

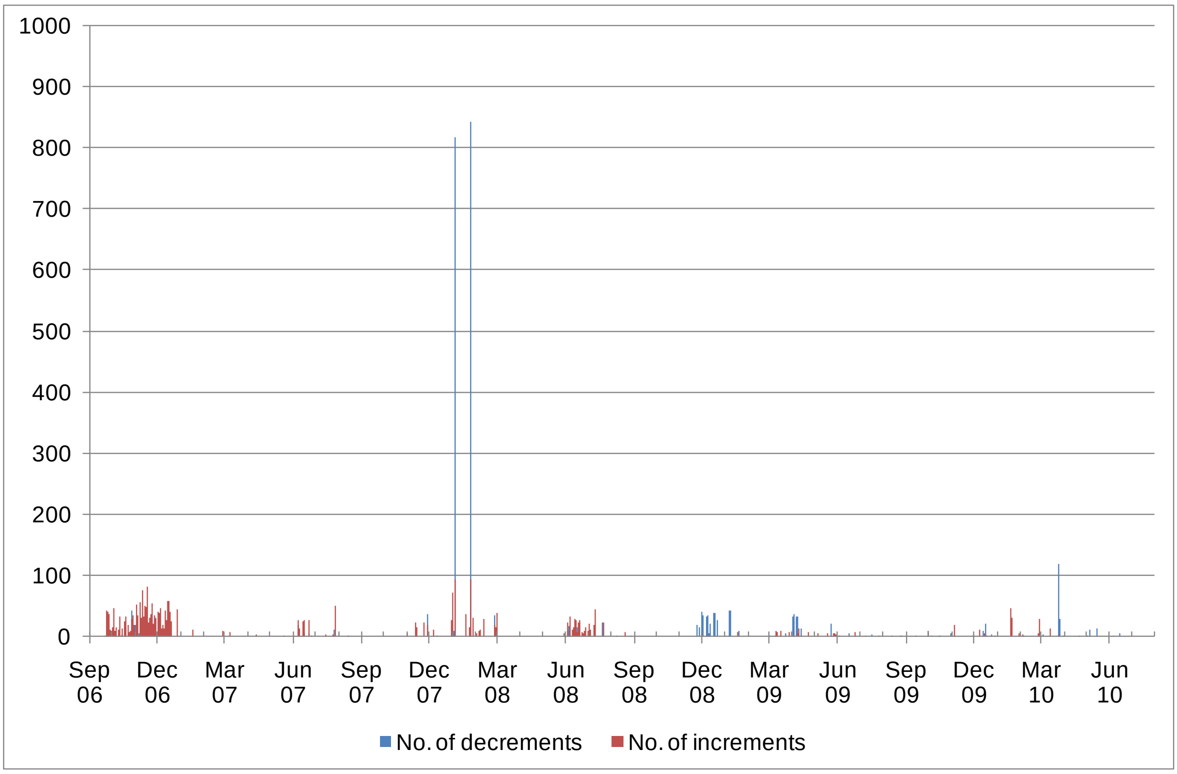
Clause 2.16.2(j) of the Market Rules requires that the MSDC identify the frequency and nature of Dispatch Instructions to Market Participants other than Verve Energy.

Dispatch Instructions are issued by System Management to Market Participants other than Verve Energy, directing the participant to vary the output or consumption of one of its facilities from the level indicated in its Resource Plan, or to vary the output or consumption of one of its facilities holding Capacity Credits.

Figure 20 illustrates the number of Trading Intervals per Trading Day for which there were increment Dispatch Instructions and decrement Dispatch Instructions, from 21 September 2006 (EMC) to 31 July 2010.[206] As noted in the 2008 Report to the Minister, it is clear that there are two outliers on 3 January 2008 and 24 January 2008, where the total number of Dispatch Instructions increased to above 900 in a Trading Day. The first of these was the result of gas constraints due to a failure of domestic gas production by North West Shelf and the latter was due to a number of large outages on the system.

[206] Note that this counts a Dispatch Instruction for multiple Trading Intervals as multiple Dispatch Instructions.

Figure 20 Daily average number of Dispatch Instructions (21 September 2006 to 31 July 2010)

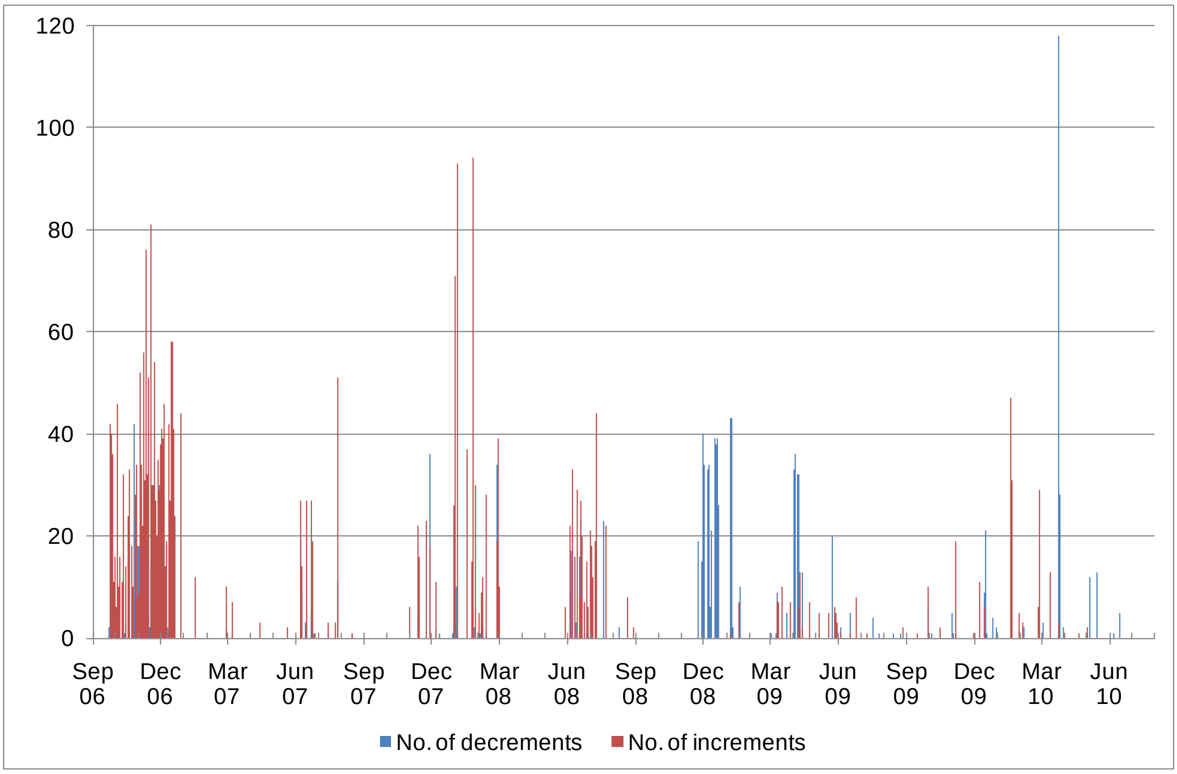


Leaving aside the two outliers discussed above, it is clear from Figure 21 that Dispatch Instructions were most frequently issued during the first few months following EMC, and during higher demand periods in summer and winter. Dispatch Instructions also occur during gas constraints, which lead to an increased likelihood that Verve Energy's facilities would run on Liquid Fuel. This, in turn, means that System Management relies on other Market Participant's facilities to provide Balancing.

Figure 21 shows that, in the current Reporting Period, the maximum numbers of Dispatch Instruction (118 decrements and three increments) was issued on 23 March 2010. This coincided with a high risk Dispatch Advisory from System Management notifying a severe weather warning and storm front may compromise power system security.[207]

[207] See IMO website, Dispatch Advisory 22 March 2010, http://www.imowa.com.au/n130,43,index=44.html

Figure 21 Daily average number of Dispatch Instructions - outliers removed (21 September 2006 to 31 July 2010)



5.3 Bilateral market

5.3.1 Bilateral quantities

Clause 2.16.2(e) of the Market Rules requires that the MSDC identify all bilateral quantities scheduled with the IMO.

Bilateral quantities scheduled with the IMO are classified as confidential information. In principle, information on bilateral quantities could be aggregated and included in this public version of the report. However, the majority of bilateral quantities are traded between Verve Energy and Synergy (albeit with a decreasing trend over the past two years), so that aggregation would not necessarily mask the data. As a result, information on the bilateral quantities scheduled with the IMO has not been presented in this public version of the report.

Nevertheless it can be noted that total bilateral quantities scheduled with the IMO have remained relatively consistent over time. Certainly, total bilateral quantities show a seasonal trend, with greater quantities and some spikes in quantities occurring during summer, but, on the whole, quantities have remained relatively steady.

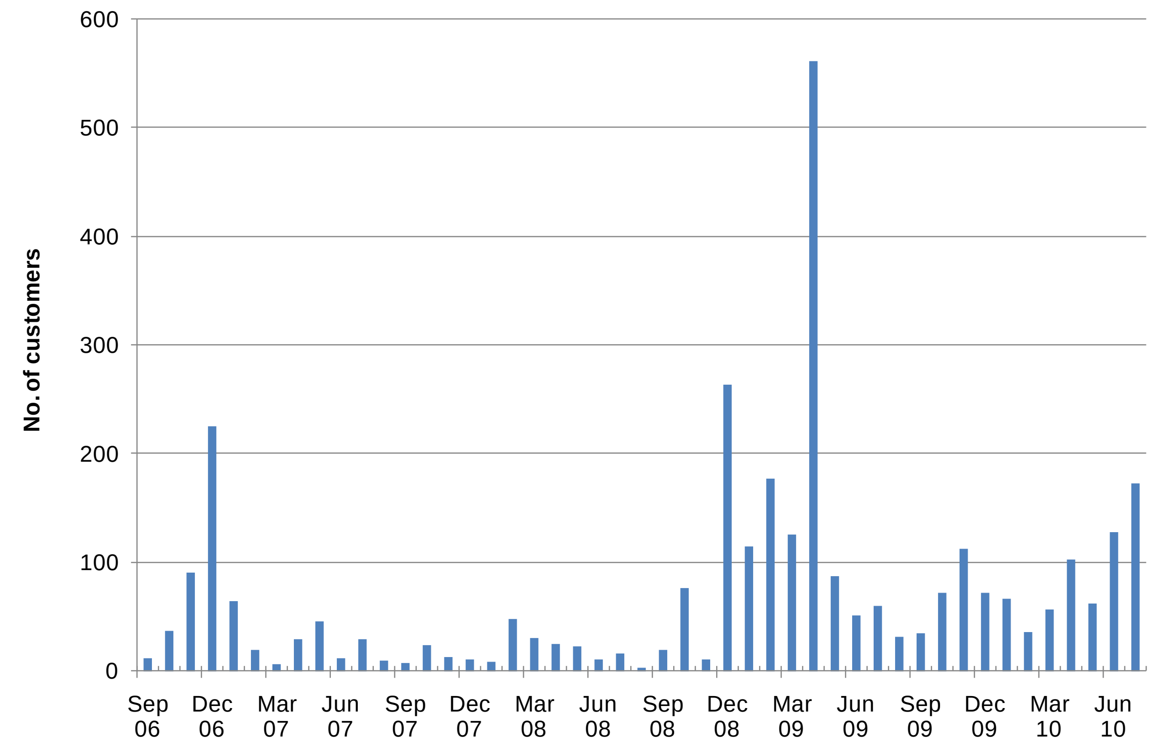
5.4 Retail sector

5.4.1 Customer churn

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 (EMC) to 31 July 2010.

Figure 22 sets out the rate of customer churn since EMC. The rate at which customers have churned increased significantly in late 2008 and during 2009, reaching a peak in April 2009. Since then customer churn rates have returned to lower levels, although retailer switching is still occurring more frequently than during the bulk of 2007 and 2008. While the lack of FRC in Western Australia imposes a limit on the extent to which retail competition can develop, there are nevertheless clear signs of the evolution of a competitive retail sector.

Figure 22 Customer churn (21 September 2006 to 31 July 2010)



5.5 Surveillance items

5.5.1 Fuel Declarations

A Market Participant submitting a STEM Submission must include a Fuel Declaration.[208] Clause 2.16.2(gA) of the Market Rules requires that the MSDC identify all Fuel Declarations. There is also a requirement under Clause 2.16.4(cA) to calculate any consistent or significant variations between Fuel Declarations and the actual real-time operation of a Market Participant.

Table 5 summarises the Fuel Declarations for each dual fuel Facility, showing the percentage of all Trading Intervals for which each dual fuel Facility was assumed to be operating on Non-Liquid and Liquid Fuels, for the 2007/08 through 2009/10 Reserve Capacity Years. Dual fuel facilities tend to declare either liquid or non-liquid for the majority of the Trading Intervals for which they make a declaration, suggesting that dual fuel facilities have a primary fuel supply, with occasional use of a secondary fuel supply.[209]

---

[208] See Clause 6.6.1.

[209] Fuel Declarations for these facilities are influenced by the expected availability of gas, although Market Participants are not always aware of gas supply constraints at the time that they are required to make their

One exception in the 2009/10 Reserve Capacity Year is a change to the Fuel Declarations for Alinta's Wagerup facilities, which has seen these units declared to be run on Non-Liquid Fuel for approximately 36 per cent of the time.

STEM Submissions. This can result in variations between Fuel Declarations and the actual operation of a facility. The IMO monitors variations between Fuel Declarations and actual operation.

Table 5 Fuel Declarations (last three Capacity Years)

Participant	Resource Name	Liquid declaration 2007/08 Cap Year	Non-liquid declaration 2007/08 Cap Year	Liquid declaration 2008/09 Cap Year	Non-liquid declaration 2008/09 Cap Year	Liquid declaration 2009/10 Cap Year	Non-liquid declaration 2009/10 Cap Year
Alcoa	ALCOA_KWI			7.9%			
Alcoa	ALCOA_PNJ			7.9%			
Alcoa	ALCOA_WGP			98.9%		91.8%	
Alinta	ALINTA_WGP_GT	96.7%	0.3%	99.7%		55.8%	35.9%
Alinta	ALINTA_WGP_U2			98.4%	1.1%	55.8%	36.0%
Goldfields Power	PRK_AG	99.6%	0.1%	99.7%		91.8%	
Southern Cross	STHRNCRS_EG	23.8%		6.6%			
Verve Energy	KEMERTON_GT11	3.6%	96.2%		99.7%	0.3%	91.5%
Verve Energy	KEMERTON_GT12	80.3%	19.4%	69.9%	29.9%	0.8%	91.0%
Verve Energy	KWINANA_G3	33.1%	66.7%	0.8%			
Verve Energy	KWINANA_G4	20.5%	78.7%		25.2%		
Verve Energy	KWINANA_G5	7.9%	91.8%	0.3%	99.5%		91.8%
Verve Energy	KWINANA_G6	1.4%	96.7%	14.8%	84.9%		91.8%
Verve Energy	KWINANA_GT1	99.7%		99.7%		91.8%	
Verve Energy	PINJAR_GT1	6.6%	93.2%		99.7%		91.8%
Verve Energy	PINJAR_GT2	82.5%	17.2%	99.5%	0.3%	91.8%	
Verve Energy	PINJAR_GT3	6.3%	93.4%		99.7%		91.8%
Verve Energy	PINJAR_GT4	86.6%	13.1%	99.7%		91.8%	
Verve Energy	PINJAR_GT5	15.3%	84.4%		99.7%		91.8%
Verve Energy	PINJAR_GT7	92.1%	7.7%	99.7%		91.8%	

5.5.2 Availability Declarations

Clause 2.16.2(gB) of the Market Rules requires that the MSDC identify all Availability Declarations. There is also a requirement under Clause 2.16.4(cA) to calculate any consistent or significant variations between Availability Declarations and the actual real-time operation of a Market Participant's facility.

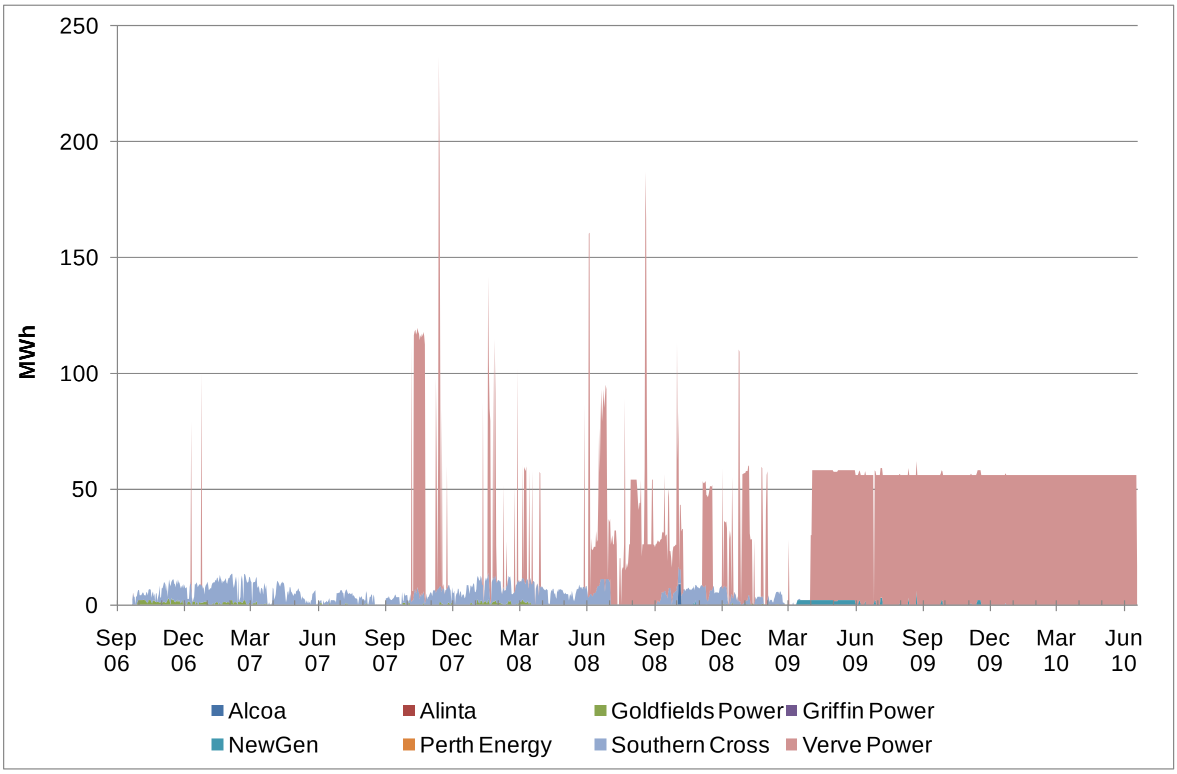
A Market Participant submitting a STEM Submission must include an Availability Declaration on net available energy.[210]

Figure 23 illustrates daily average Availability Declarations by Market Participant. Since the beginning of the 2007/08 Capacity Year, Availability Declarations have increased, principally from Verve Energy (which accounts for the majority of generating capacity in the market).

The Authority notes Verve Energy's unavailability declaration of approximately 56 MWh since April 2009, which is for the Muja G3 and Muja G4 units. The Authority understands that these units are registered but not capacity credited. This creates a situation where Verve Energy needs to account for the capacity (so it is not considered as a short fall in capacity for market settlement purposes) but does not need to include the capacity in its Portfolio Supply Curve (via its STEM Submission). In order to achieve this, Verve Energy declares these units as unavailable through the Availability Declarations mechanism. However, the reasons for Verve Energy's declarations regarding these two units do not appear to meet the requirements of making an Availability Declaration under the Market Rules (which takes account of any Ancillary Service Obligations or facility outages). The IMO has advised the Authority that it will liaise with Verve Energy on this matter. The Authority will provide an update on this matter in the next report to the Minister.

[210] See Clause 6.6.1. The Availability Declaration is to set out, for each Trading Interval and for each of the Market Participant's facilities, the difference between the energy available from the facility based on its Standing Data (adjusted to account for any energy committed to providing Ancillary Services and any energy unavailable due to outages reported by the IMO) and the energy assumed to be available from the facility in forming the Portfolio Supply Curve for the Trading Interval. Only quantities greater than zero need to be reported in the Availability Declaration.

Figure 23 Daily average Availability Declarations (MWh unavailable per Trading Interval) (fig 26 last year)



Significant variations between Availability Declarations and the actual real-time operation of a Market Participant are assessed by comparing:

- the remaining capacity available after taking into account quantities declared in an Availability Declaration, with
- the total (Loss Factor-adjusted) quantity supplied, as measured by System Management's Supervisory Control and Data Acquisition (**SCADA**) system.

If, on the basis of this comparison, the remaining capacity available is less than the quantity supplied, this indicates that a Facility has been available to supply the market to a greater extent than was indicated in the STEM Submission for that Facility. The significance of this statistic is to detect if a Market Participant is declaring falsely that a low cost capacity is unavailable. By leaving out low cost capacity the Market Participant will be able to put in a submission with a higher cost schedule. This could result in a higher STEM Clearing Price. The Market Participant could then generate with the low cost capacity which is truly available and make an excessive profit.

Significant variations between Availability Declarations and the actual real-time operation has been determined for each facility in the market, but the information is commercially sensitive and so is not presented in this public version of the report.

5.5.3 Ancillary Service Declarations

A Market Participant that is a provider of Ancillary Services must include an Ancillary Services Declaration in its STEM Submission.[211] 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) to calculate any consistent or significant variations between Ancillary Service Declarations and the actual real-time operation of a Market Participant.

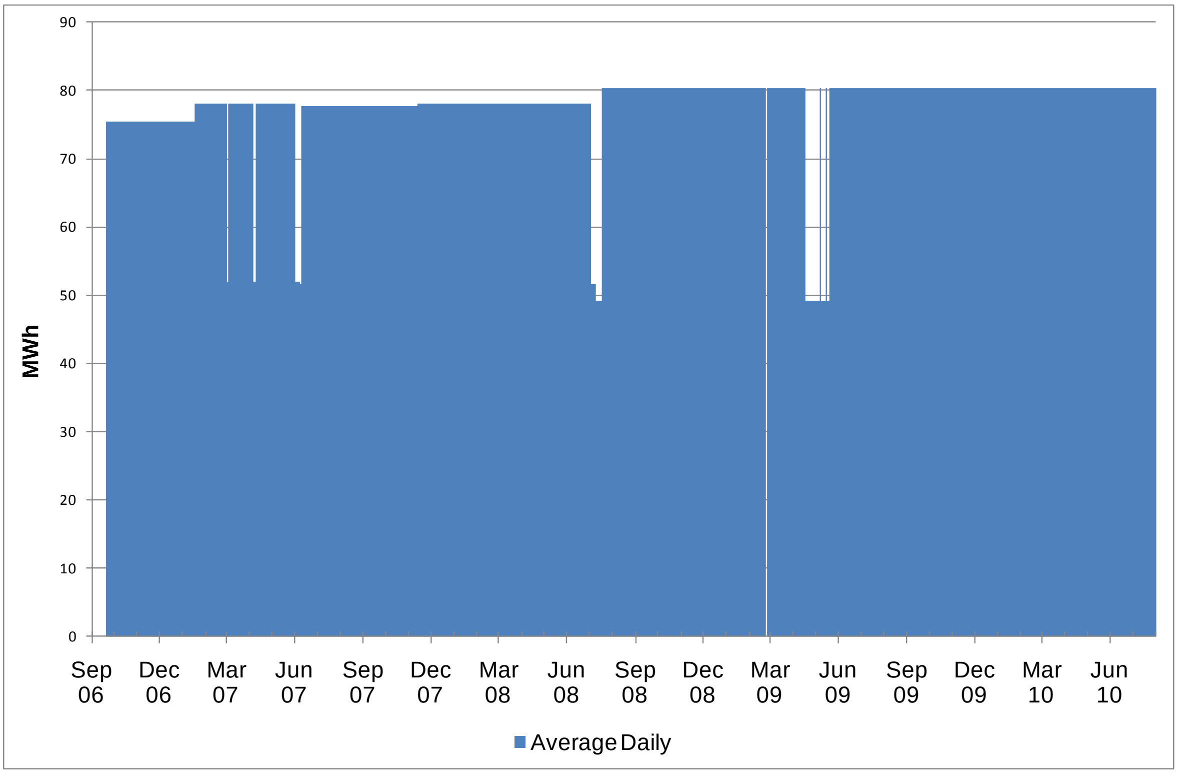
Figure 24 shows that the only Market Participant to submit an Ancillary Service Declaration has been Verve Energy, with the quantities of Ancillary Services fairly consistent at between 70-80 MWh per Trading Interval.[212]

As Verve Energy is the only Market Participant to submit an Ancillary Service Declaration, to date there has been no analysis of significant variations between declarations and the actual outcomes. In the event that other Market Participants begin to provide Ancillary Services, the Authority will commence reporting on variations between declarations and the actual real-time operation of facilities in future reports to the Minister.

[211] See Clause 6.6.1. The Ancillary Services declaration is to set out the MWh of energy, from both liquid and non-liquid facilities that the Market Participant has not included in the Portfolio Supply Curve because it expects to have to maintain surplus capacity with which to provide Ancillary Services.

[212] The decreases in Ancillary Service Declarations from May to July 2008, and from April to May 2009 were due to Collie Power Station being on outage during those times.

Figure 24 Daily average Ancillary Services declarations (MWh per Trading Interval)



5.5.4 Variations in Short Term Energy Market Offers and Bids

Clause 2.16.2(h) of the Market Rules requires that the MSDC identify any substantial variations in STEM Offers and STEM Bid prices or quantities relative to recent past behaviour.

The prices and quantities of STEM Offers and STEM Bids by each Market Participant are illustrated in Figure 25 through Figure 46 in Appendix 3. As has been observed in previous Reports to the Minister, there are significant variations in the prices and/or quantities of offers and bids of all Market Participants. In many cases, these variations occur both in the short-term (day-to-day) and longer term (since EMC).

Significant variations in STEM Offers and STEM Bids present difficulties in the development of a robust system for identifying substantial variations relative to recent past behaviour. Development of a robust system requires conceptual issues to be addressed: including what constitutes a 'substantial variation' in prices or quantities and the definition of 'recent past behaviour'. The resolution of these two will impact on the variations that are required to be identified by the MSDC.

In attempting to track how a Market Participant STEM offers and bids change over time the IMO has defined a variable summarising the participant offers for a Trading Interval into a single number and similarly for bids. The Authority has been provided with a record of this variable for each of the Market Participants since EMC. Given the challenges in the conceptual issues identified, the Authority will continue to examine how this variable could be used, as well as explore other methods of analysis, to satisfy the requirement under clause 2.16.2(h).

5.5.5 Evidence of Market Customers overstating consumption

Clause 2.16.2(hA) of the Market Rules requires that the MSDC identify any evidence that a Market Customer has significantly over-stated its consumption, as indicated by its Net Contract Position, with a regularity that cannot be explained by a reasonable allowance for forecast uncertainty or the impact of loss factors.

In order to identify whether a Market Customer has significantly overstated its consumption, it is necessary to determine both the Market Customer's planned load and actual load:

- Planned load is determined in a different way for stand-alone Market Customers and Market Customers that are also Market Generators,
  - For stand-alone Market Customers, planned load is measured as its Net Contract Position.
  - For Market Customers that are also Market Generators, planned load is measured as demand as set out in the Market Customer's Resource Plan. The reason that Net Contract Position does not provide a useful measure of planned load for Market Customers that are also Market Generators is that these participants are able to meet their own demand using their own generation facilities, so that this demand will not be reflected in their Net Contract Position.
- Actual load is determined on the basis of settlement quantities for a Market Customer. This provides a measure of real-time load, taking into account any Dispatch Instructions.

The extent to which a Market Customer over-states its consumption is determined by calculating actual load less planned load. If actual load less planned load is positive, this indicates that the Market Customer has under-stated its consumption. If actual load less planned load is negative, this indicates that the Market Customer has over-stated its consumption. To understand the extent of any over-statement or under-statement, it is also useful to determine any over-stated or under-stated amount as a proportion of planned demand.

This information is confidential and is not presented in this public version of the report.

5.5.6 Number and frequency of outages

Clause 2.16.2(k) of the Market Rules requires that the MSDC identify the number and frequency of outages of Scheduled Generators and Non-Scheduled Generators, and Market Participants' compliance with the outage scheduling process.

Information on outages is confidential and is not presented in this public version of the report; however, aggregated information can be reported. The Authority notes that planned outages tend not to occur during January, February and March, in line with the low level of reserve margins prevailing at these peak demand times. In respect of forced outages the Authority notes that, as would be expected, there is no clear seasonal pattern for forced outages.

5.5.7 Key determinants of high prices in the STEM and Balancing

Clause 2.16.4(g) requires the IMO to explore the key determinants for high prices in the STEM and balancing. The Authority reported last year that it would work together with the IMO to develop the most appropriate approach for undertaking this analysis. The Authority is continuing to work with the IMO to develop appropriate forms of analysis to explain the incidence of high Balancing prices. This matter is discussed in detail in Section 5.2.1.3.

5.6 Other information

5.6.1 Number of Market Generators and Market Customers

Clause 2.16.2(a) of the Market Rules requires that the MSDC identify the number of Market Generators and Market Customers in the WEM.

As at 14 October 2010 the following participants were registered with the IMO:

- 21 entities registered as Market Generators only (Advanced Energy Resources and McNabb Plantation Alliance Pty Ltd are new participants in this category compared to when last reported on 6 October 2009);
- 12 entities registered as Market Customers only (ERM Power Retail Pty Ltd, Amanda Australia Pty Ltd and EnerNOC Australia Pty Ltd are new participants in this category compared to when last reported on 6 October 2009); and
- 9 entities registered as both Market Generators and Market Customers (Metro Power Company Pty Ltd is the new registered participant in this category compared to when last reported on 6 October 2009).

This is a total of 42 registered entities and represents an increase from 15 entities at EMC, 30 entities as at 2 September 2008 and 36 as at 6 October 2009. Table 8 in Appendix 3 provides a list of these participants, at EMC, 2 September 2008, 6 October 2009 and 14 October 2010.

In addition to these Market Generators and Market Customers, there are other classes of Market Participants. As of 14 October 2010, there were two entities registered as Network Operators: Western Power and Alinta Sales Pty Ltd.

5.6.2 Ancillary Service Contracts and Balancing Support Contracts

Clause 2.16.2(m) of the Market Rules requires that the MSDC identify details of Ancillary Service Contracts and Balancing Support Contracts that System Management enters into.

System Management currently has Ancillary Service Contracts in place with two providers to supply Spinning Reserve in the order of 50MW. One of these Spinning Reserve contracts pre-dates EMC and was inherited by System Management upon the disaggregation of the old Western Power; the other is a short extension of an existing contract.

In addition, System Management currently has a deed of undertaking with Verve Energy for the provision of dispatch support services in the Eastern Goldfields and North Country

(Mungarra and Geraldton) regions. This deed is due to expire when the 330kV transmission line to Geraldton is commissioned.

System Management also has an Ancillary Service Contract with Verve Energy for the supply of System Restart from three geographically dispersed Verve Energy sites in the South West Interconnected System (**SWIS**). This contract is due to expire on 30 June 2011.

System Management has not entered into any Balancing Support Contracts between 21 September 2006 (EMC) and 31 July 2010. Since EMC, Verve Energy has been principally responsible for providing Balancing for the market.

5.6.3 Rule Change proposals

Clause 2.16.2(o) of the Market Rules requires that the MSDC identify the number of Rule change proposals received, and details of Rule change proposals that the IMO has decided not to progress under Clause 2.5.6.

The formal Rule change process under the Market Rules commenced on 15 December 2006.

Prior to this, the Office of Energy was responsible for administering the Rule change process on behalf of the Minister for Energy. Between EMC 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.[213]

Information on Market Rule changes that have commenced, been rejected or are under development is available on the IMO's website. Based on this information, since the commencement of the formal Rule change process, the IMO has processed Rule change proposals as follows:

- between 15 December 2006 and 31 July 2007, the IMO received nine Rule change proposals, all of which had been commenced by the end of 2007;
- between 1 August 2007 and 31 July 2008, the IMO received 36 Rule change proposals, all of which have now commenced;
- between 1 August 2008 and 31 July 2009, the IMO received 37 Rule change proposals, 24 of which have now commenced, three of which have been rejected and 10 of which remain under development; and
- between 1 August 2009 and 31 July 2010, the IMO received 19 Rule change proposals, 15 of which have now commenced, one of which had been rejected, one of which remains under development and two of which have not progressed.

[213] 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.

APPENDICES

Appendix 1 Electricity Industry Act and Market Rules reporting requirements and report's section structure

Reporting Requirements under the Electricity Industry Act 2004

The *Electricity Industry Act 2004* (**Act**) requires the Authority to provide to the Minister a report based on a review of the extent to which the market objectives set out in the Act have been or are being achieved.

(1) the expiration of 3 years from the commencement of this Part and thereafter as soon as practicable after the expiration of 3 years from a report being laid before each House of Parliament under subsection (5)(a).

(2) The purpose of the review is to assess the extent to which the objectives set out in section 122(2) have been or are being achieved.

(3) Not later than 3 years and 6 months after the commencement of this Part, or after the last preceding report was laid before each House of Parliament under subsection (5)(a), as the case may be, the Authority is to give the Minister a written report based on the review.

(4) If the Authority considers that some or all of the objectives set out in section 122(2) have not been and are not being achieved, the report is to set out recommendations as to how those objectives can be achieved.

(5) As soon as practicable after receiving the report, the Minister is to —

   (a) cause the report to be laid before each House of Parliament; and

   (b) prepare a response to the report and cause the response to be laid before each House of Parliament.

(6) As soon as practicable after the report is laid before each House of Parliament, the Authority is to post a copy of the report on an internet website maintained by the Authority.

Reporting Requirements under the Market Rules

The Market Rules require the Authority to provide to the Minister for Energy a report on the effectiveness of the market in meeting the Wholesale Market Objectives, and set out specific reporting requirements for the Authority.

Clause 2.16.11 of the Market Rules sets out a requirement for the Report to the Minister to report on the effectiveness of the market in dealing with the matters identified in clauses 2.16.9 and 2.16.10.[214]

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

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

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

Clause 2.16.10 of the Market Rules sets out that the Authority must review the effectiveness of:

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

Clause 2.16.12 of the Market Rules sets out further requirements for the Report to the Minister, as follows:

- a summary of the information and data compiled by the IMO and the Economic Regulation Authority under clause 2.16.1;
- the Economic Regulation Authority's assessment of the effectiveness of the market, including the effectiveness of the IMO and System Management in carrying out their functions, with discussion of each of:
  - i) the Reserve Capacity market;
  - ii) the market for Bilateral Contracts for capacity and energy;
  - iii) the Short Term Energy Market;
  - iv) Balancing;
  - v) the dispatch process;
  - vi) planning processes; and
  - vii) the administration of the market, including the Market Rule change process;
- an assessment of any specific events, behaviour or matters that impacted on the effectiveness of the market; and
- any recommended measures to increase the effectiveness of the market in meeting the Wholesale Market Objectives to be considered by the Minister.

Reporting requirements mapped to the sections of this report

Table 6 Mapping of the reporting requirements under the Market Rules to the Report Sections

Market Rule clause	Market Rule reporting requirement	See report section
2.16.9 (a)	Monitoring of Ancillary Services Contracts and Balancing Support Contracts	3.1
2.16.9 (b)	Monitoring of inappropriate and anomalous market behaviour	3.2
2.16.9 (c)	Monitoring of market design problems or inefficiencies	3.3
2.16.9 (d)	Monitoring of problems with the structure of the market	3.3
2.16.10 (a)	Effectiveness of the Market Rule change process and Procedure change process	4.1.1
2.16.10 (b)	Effectiveness of the compliance monitoring and enforcement measures in the Market Rules and Regulations	4.1.2
2.16.10 (c)	Effectiveness of the IMO in carrying out its functions under the Regulations, the Market Rules and Market Procedures	4.1.3
2.16.10 (d)	Effectiveness of System Management in carrying out its functions under the Regulations, the Market Rules and Market Procedures	4.1.3
2.16.12 (a)	Summary and analysis of the Market Surveillance Data Catalogue	5
2.16.12 (b)	Effectiveness of the market	4
2.16.12 (b) i.	Effectiveness of the Reserve Capacity market	4.2
2.16.12 (b) ii.	Effectiveness of the market for Bilateral Contracts for capacity and energy	4.3
2.16.12 (b) iii.	Effectiveness of the Short Term Energy Market	4.4
2.16.12 (b) iv.	Effectiveness of Balancing	4.5
2.16.12 (b) v.	Effectiveness of the dispatch process	4.6
2.16.12 (b) vi.	Effectiveness of planning processes	4.7
2.16.12 (b) vii.	Effectiveness of the administration of the market, including the Market Rule change process	4.1 and 4.1.1
2.16.12 (c)	Assessment of any specific events, behaviour or matters that impacted on the effectiveness of the market	2
2.16.12 (d)	Any recommended measures to increase the effectiveness of the market in meeting the Wholesale Market Objectives to be considered by the Minister	See Summary of Recommendations

Appendix 2 Submissions received

In response to the Authority's (initial) invitation for public submissions (June 2010)

Energy Supply Association of Australia

Griffin Energy

Landfill Gas and Power Pty Ltd

Mid West Energy Pty Ltd

Sustainable Energy Now

Synergy

System Management

Verve Energy

Western Power

In response to the Authority's (further) invitation for public submissions (December 2010)

Alinta Sales Pty Ltd

Synergy

Appendix 3 Market Surveillance Data Catalogue – additional information

Short Term Energy Market

Short Term Energy Market Offers and Bids

Short Term Energy Market Offers

Figure 25 Alcoa's daily average STEM Offers (cumulative MWh per Trading Interval)

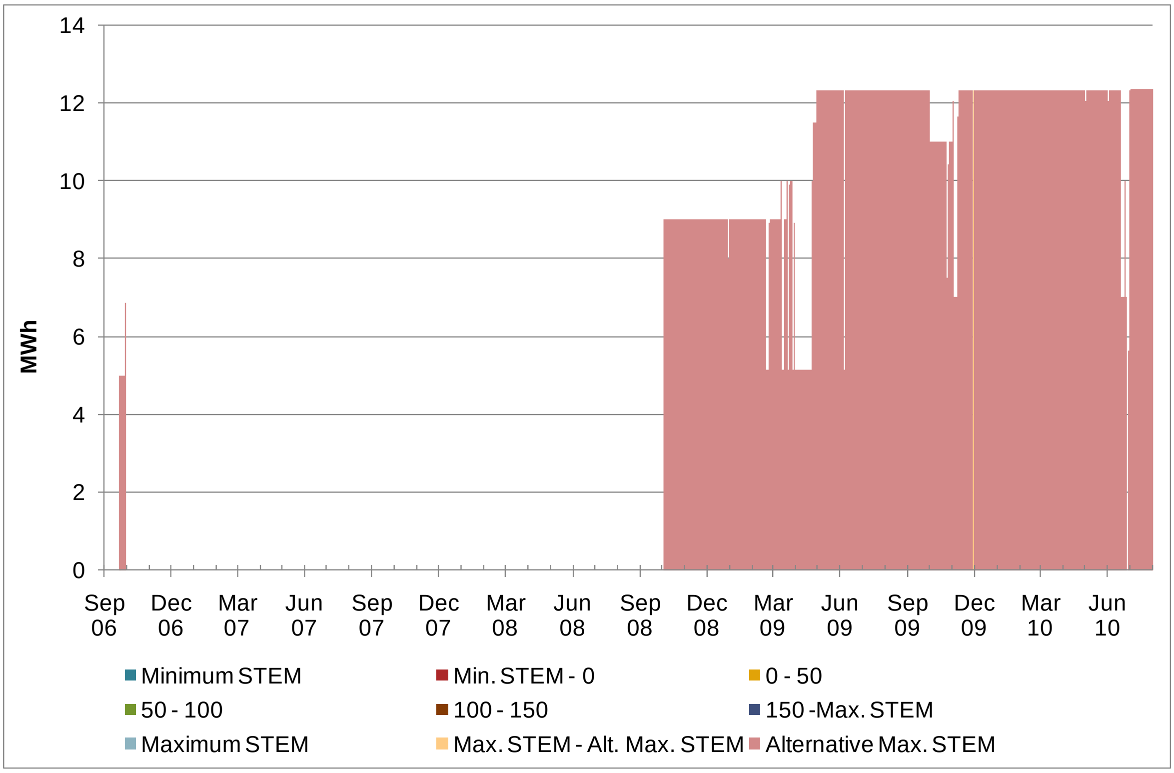


Figure 26 Alinta's daily average STEM Offers (cumulative MWh per Trading Interval)

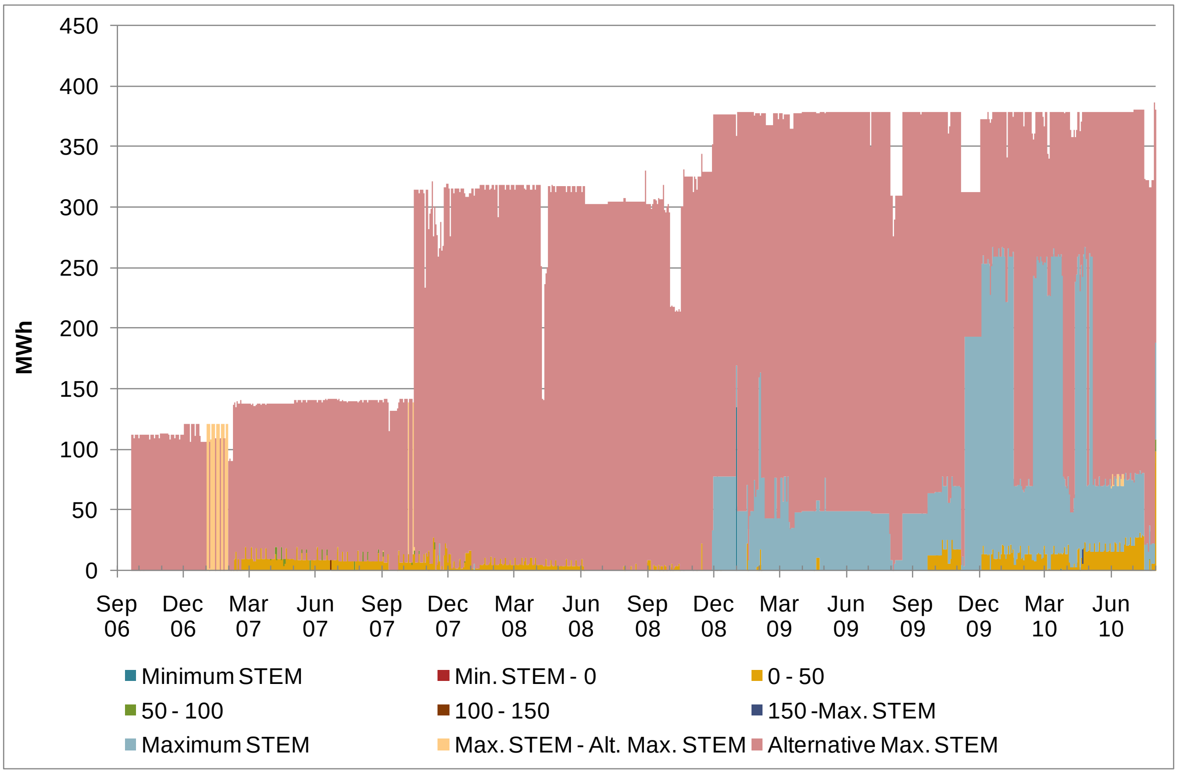


Figure 27 Goldfields Power's daily average STEM Offers (cumulative MWh per Trading Interval)

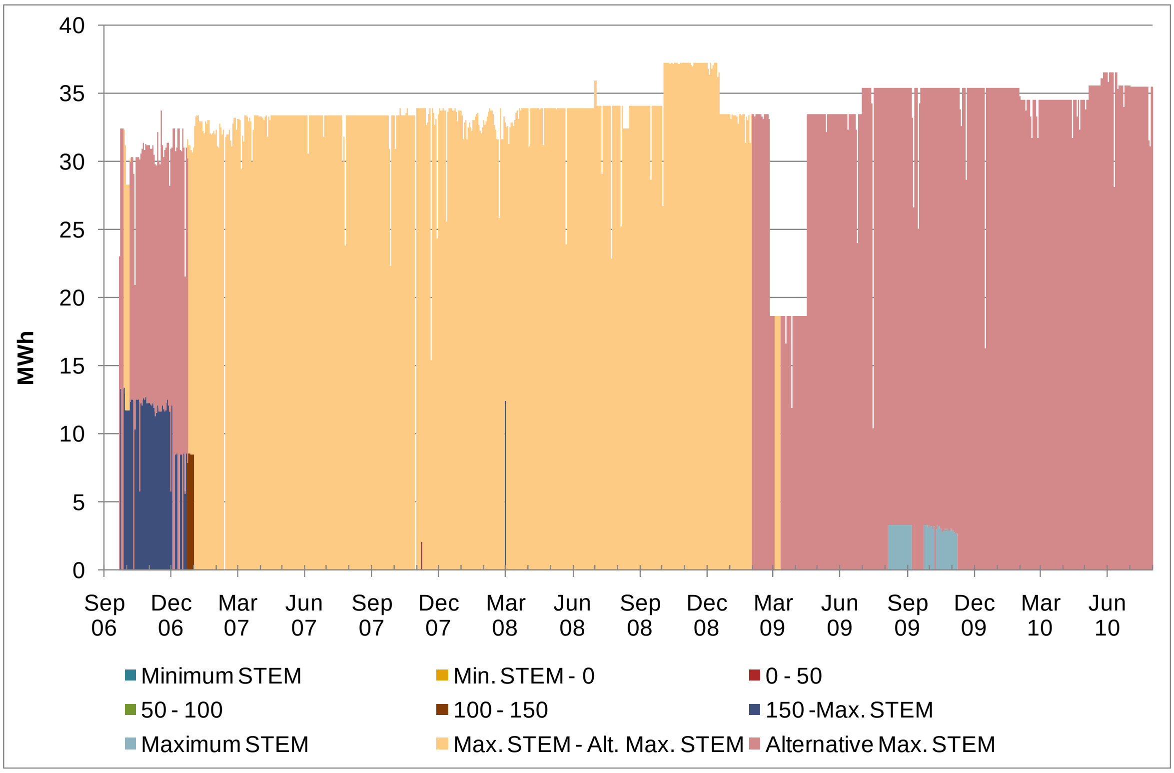


Figure 28 Griffin Power's daily average STEM Offers (cumulative MWh per Trading Interval)

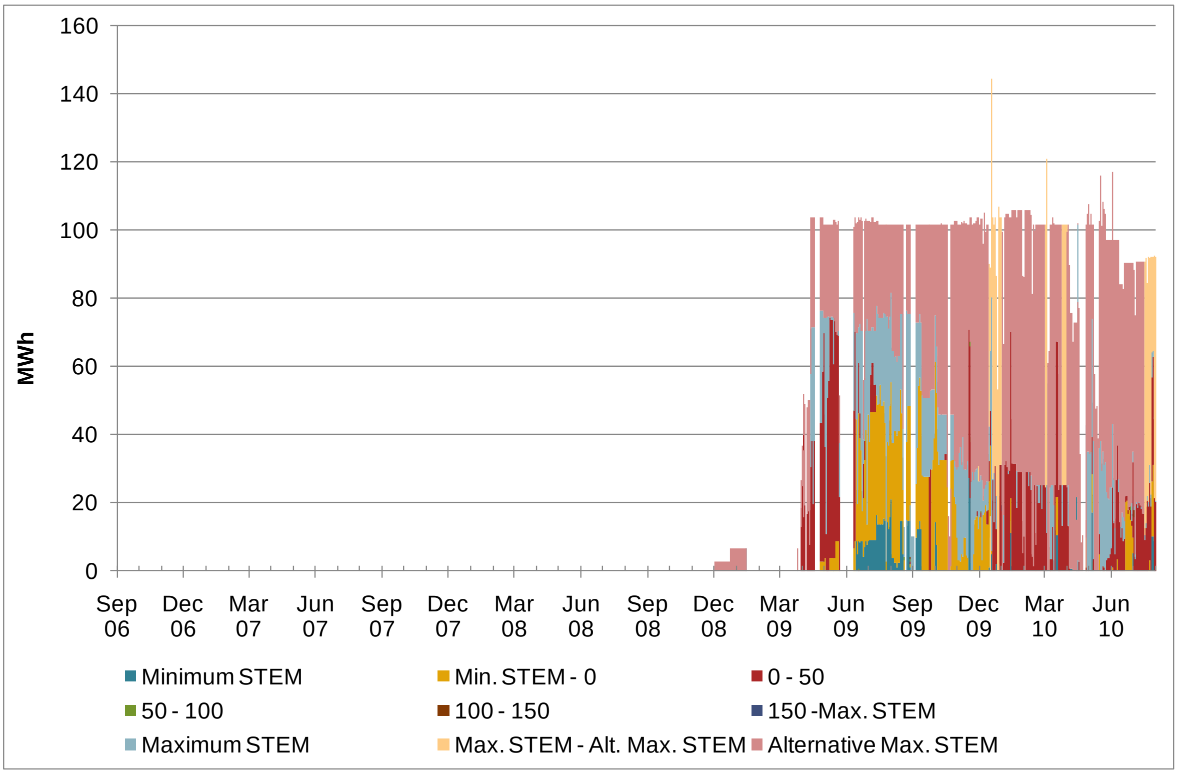


Figure 29 Griffin Power 2's daily average STEM Offers (cumulative MWh per Trading Interval)

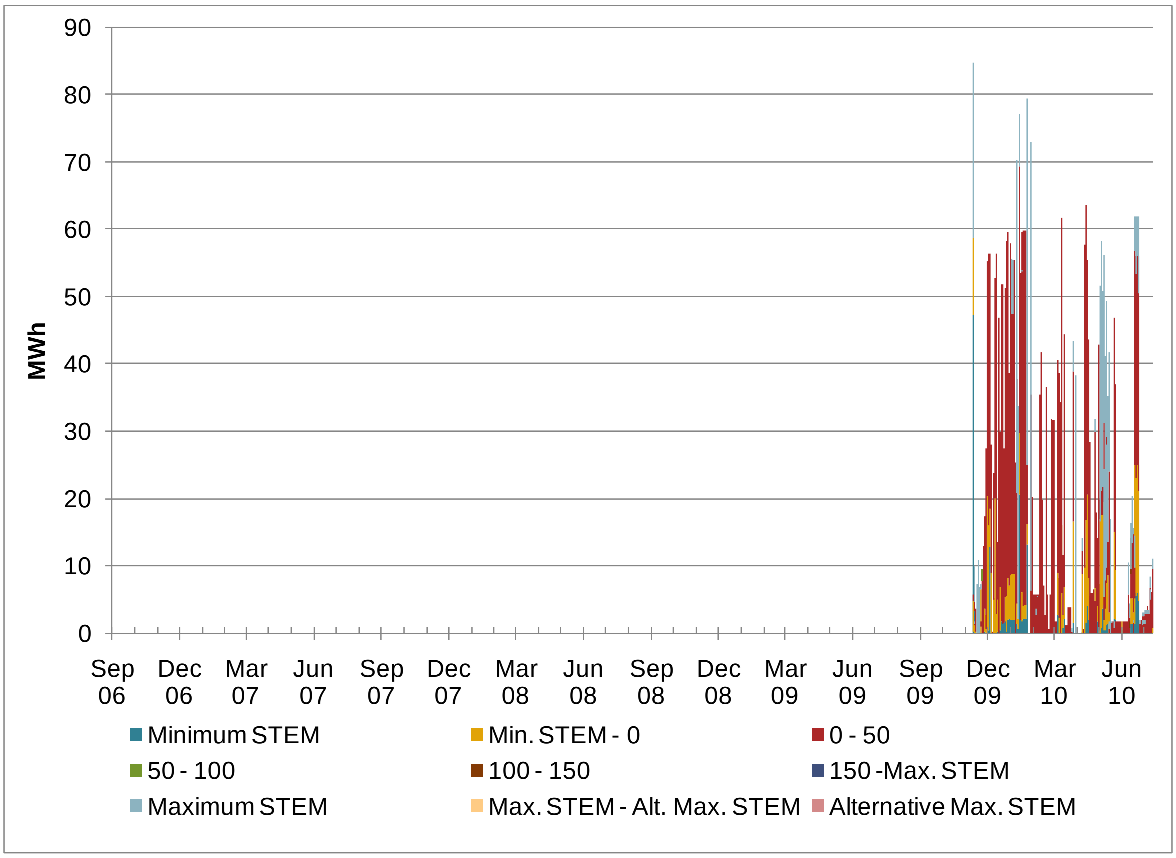


Figure 30 NewGen Power Kwinana's daily average STEM Offers (cumulative MWh per Trading Interval)

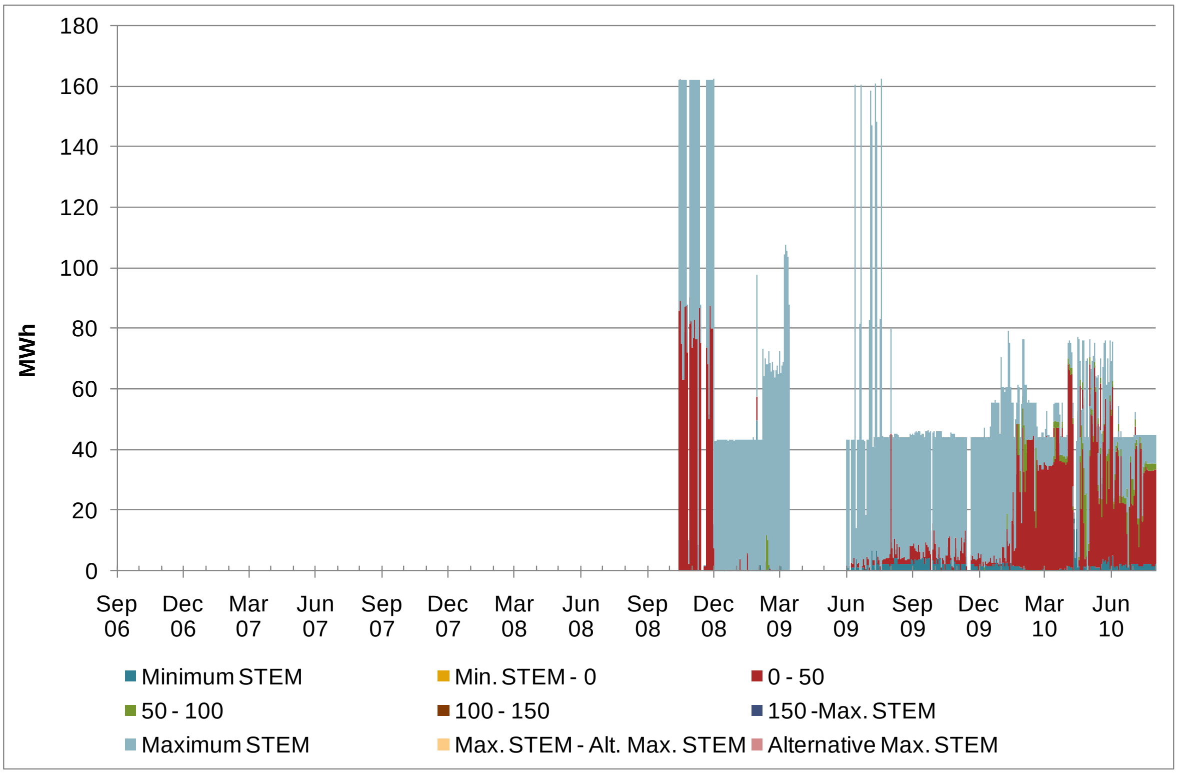


Figure 31 NewGen Neerabup's daily average STEM Offers (cumulative MWh per Trading Interval)

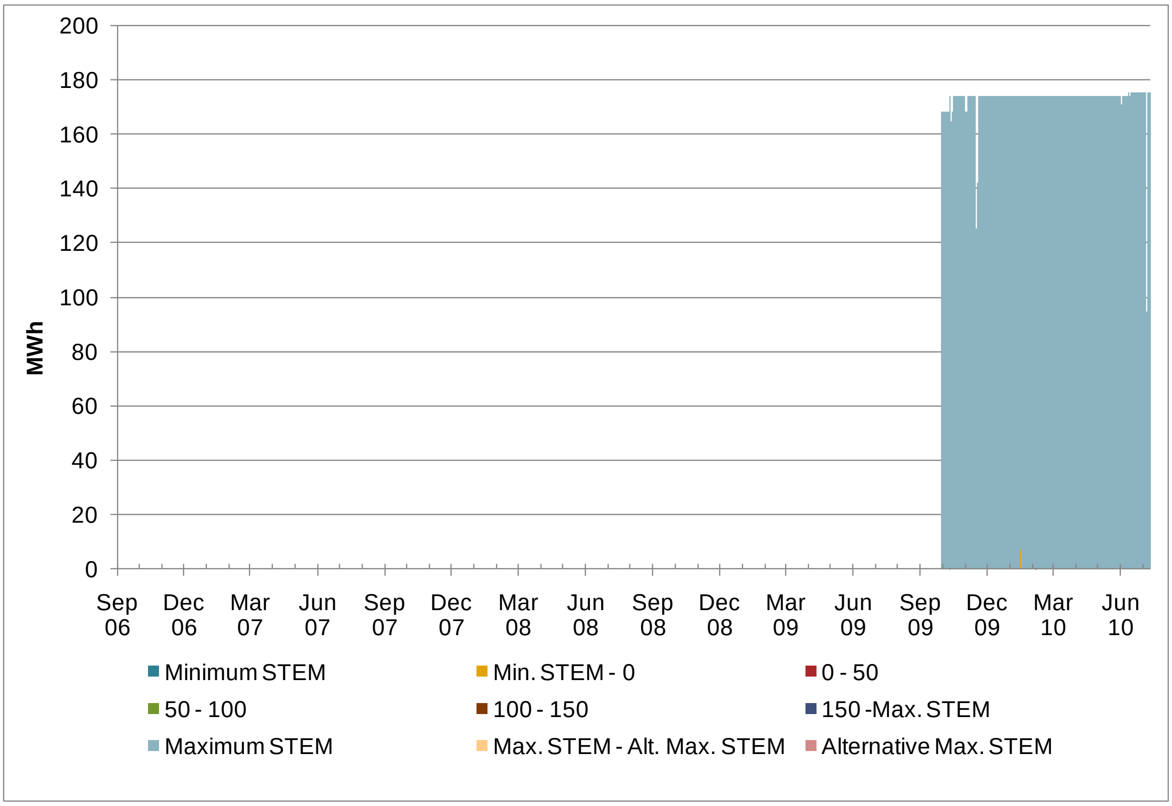


Figure 32 **Perth Energy's daily average STEM Offers (cumulative MWh per Trading Interval)**

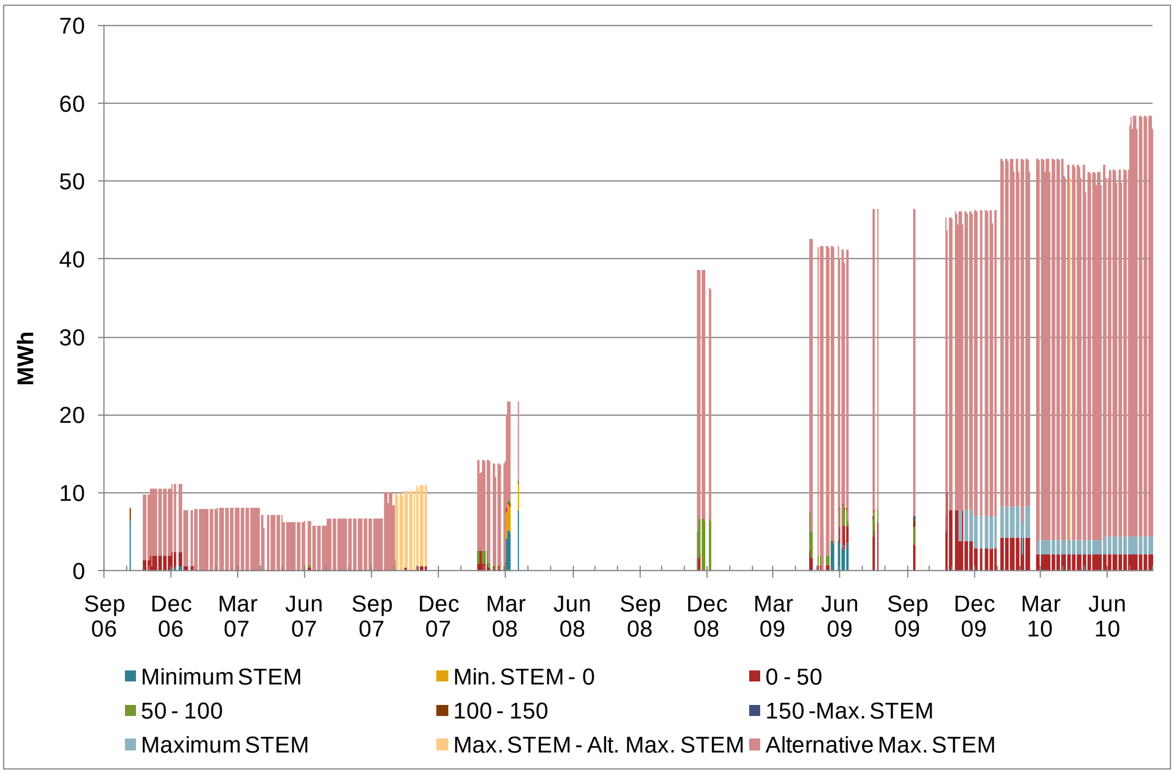


Figure 33 **Southern Cross Energy's daily average STEM Offers (cumulative MWh per Trading Interval)**

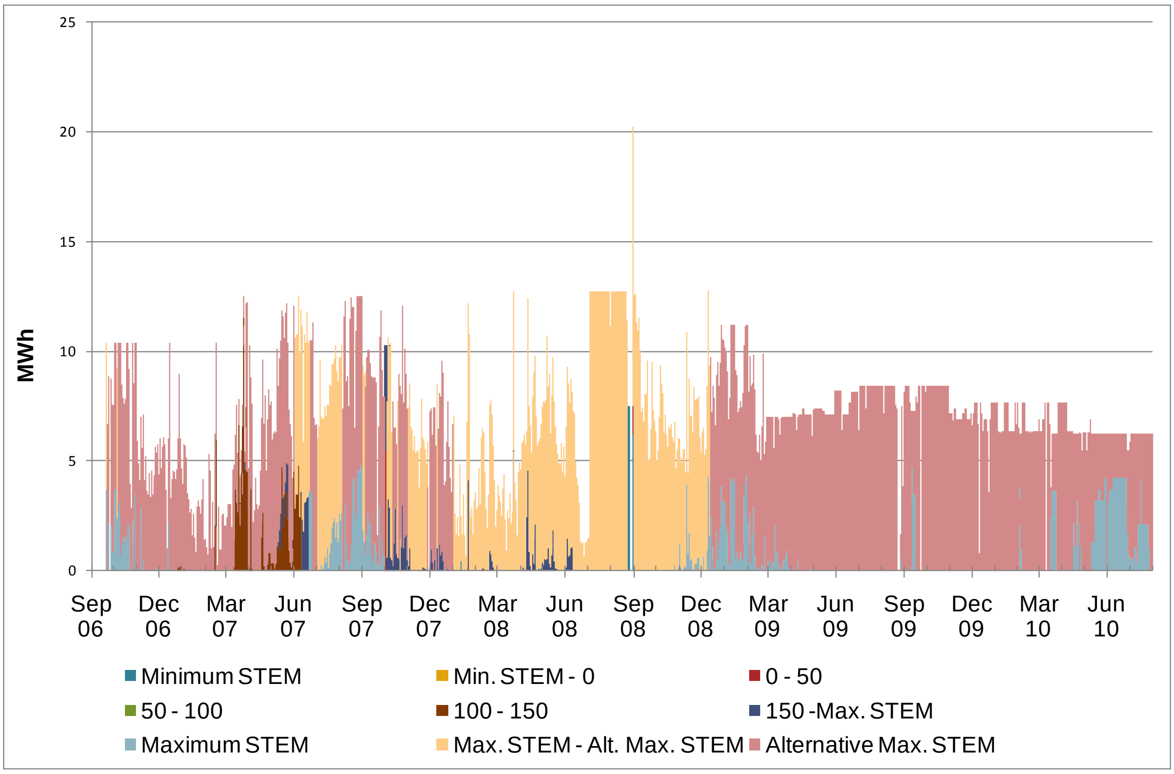


Figure 34 Synergy's daily average STEM Offers (cumulative MWh per Trading Interval)

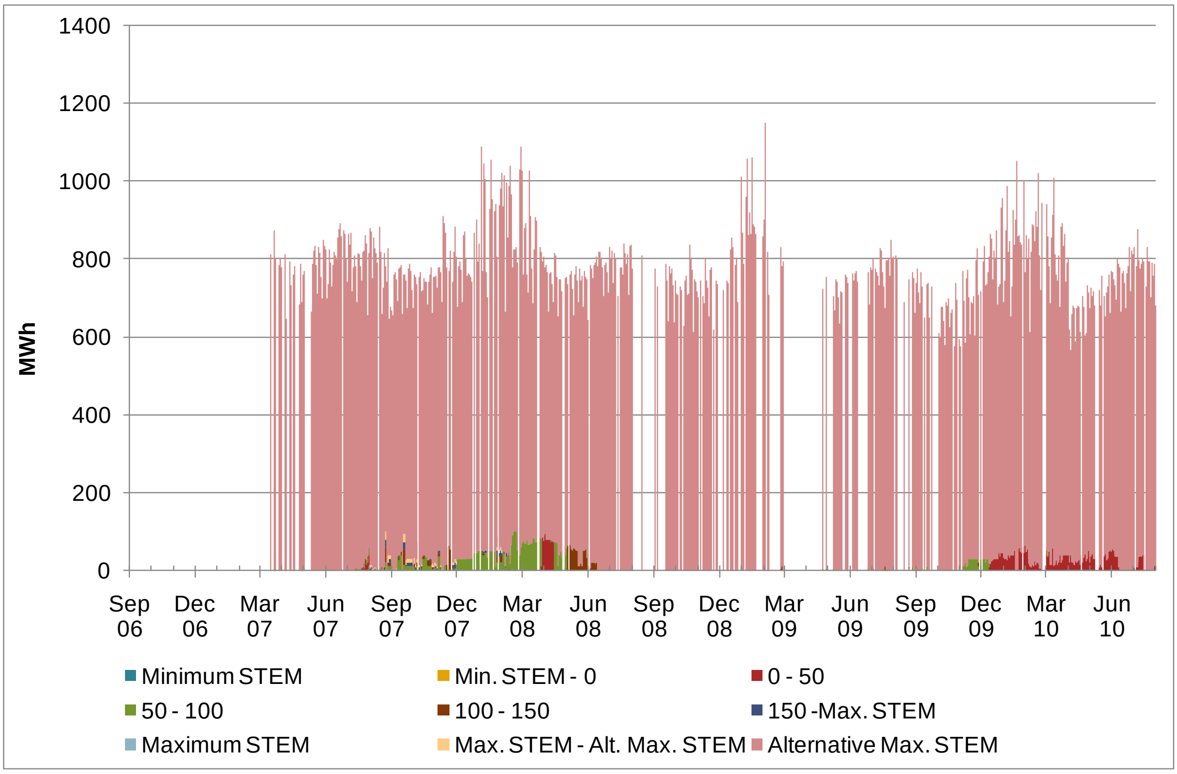
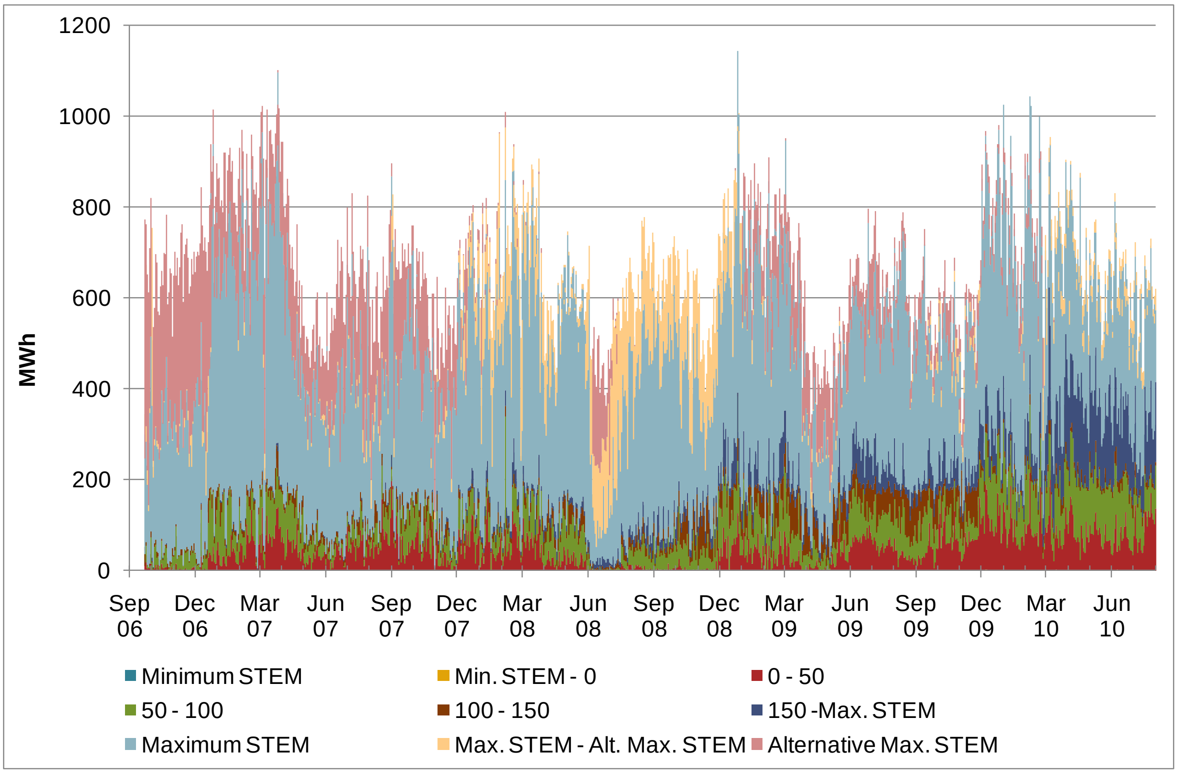


Figure 35 Verve Energy's daily average STEM Offers (cumulative MWh per Trading Interval)



Short Term Energy Market Bids

Figure 36 Alcoa's daily average STEM Bids (cumulative MWh per Trading Interval)

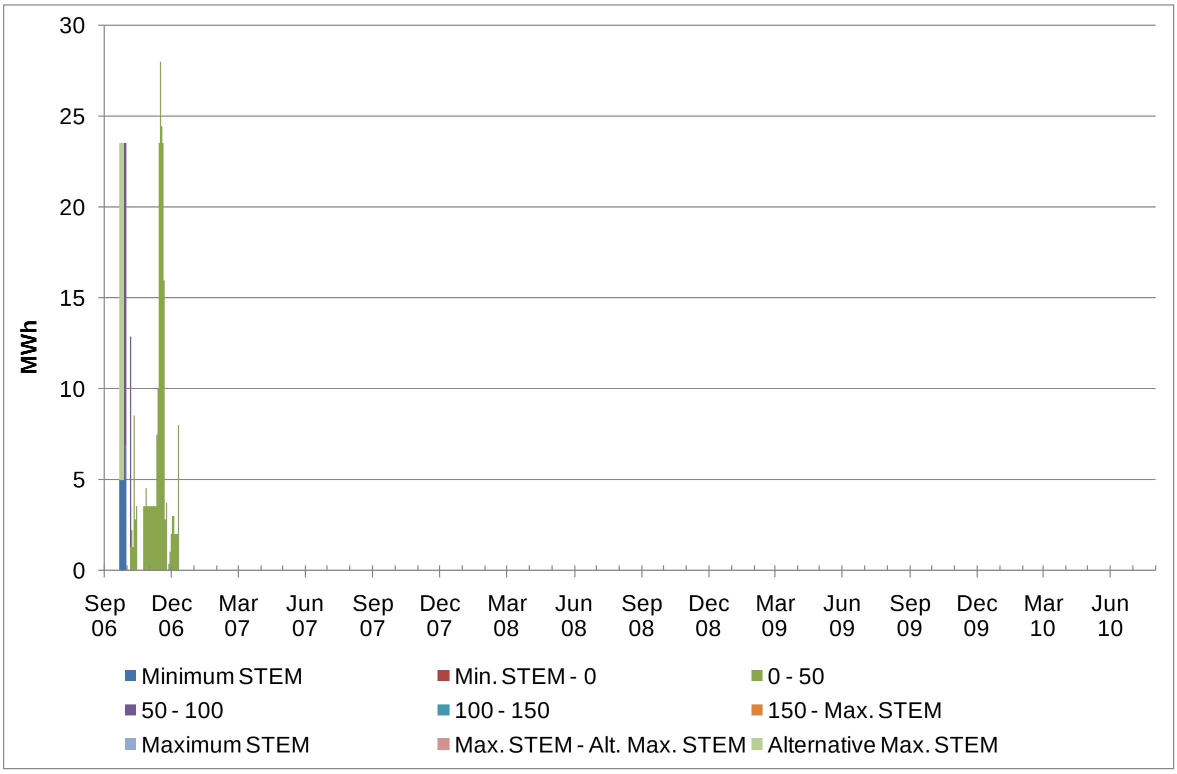


Figure 37 Alinta's daily average STEM Bids (cumulative MWh per Trading Interval)

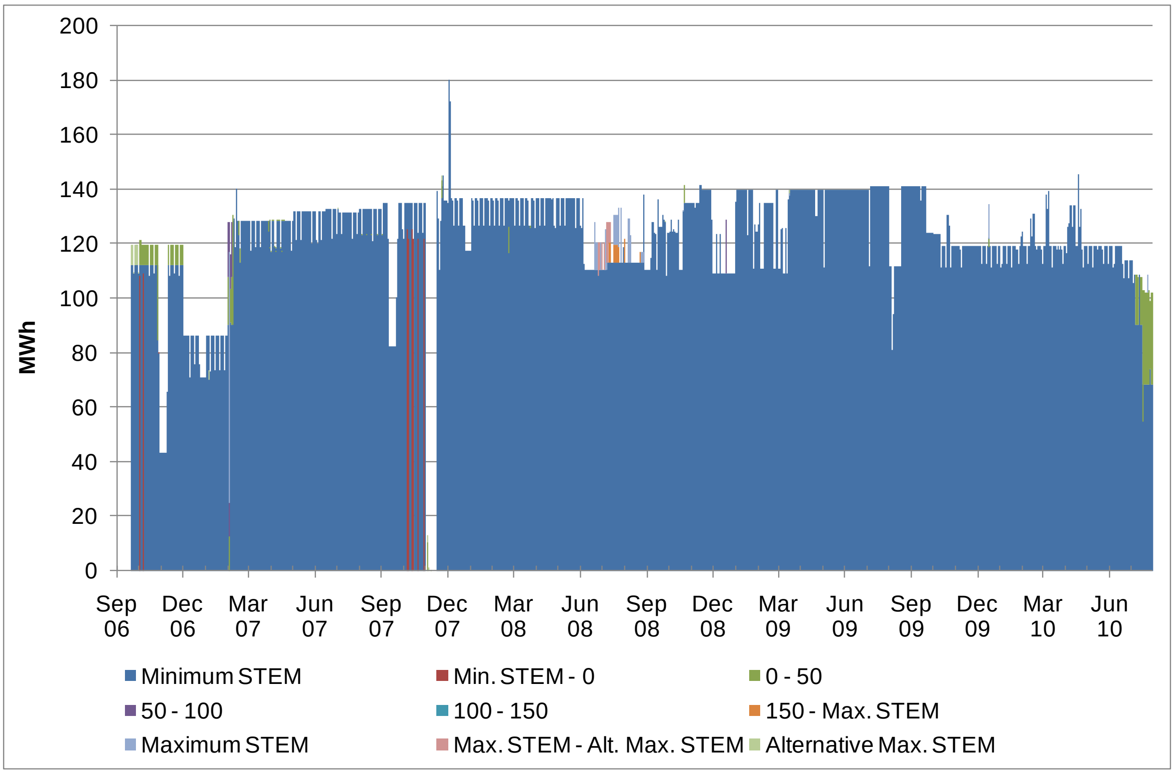


Figure 38 Goldfields Power's daily average STEM Bids (cumulative MWh per Trading Interval)

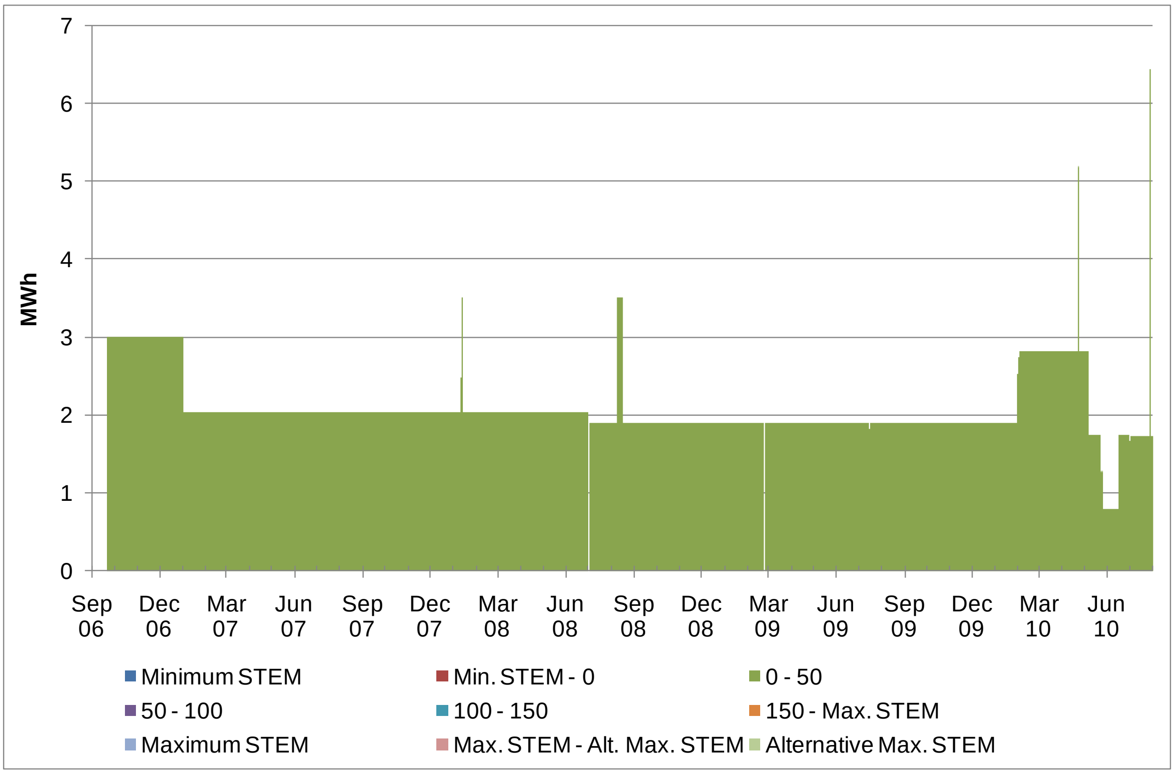


Figure 39 Griffin Energy's daily average STEM Bids (cumulative MWh per Trading Interval)

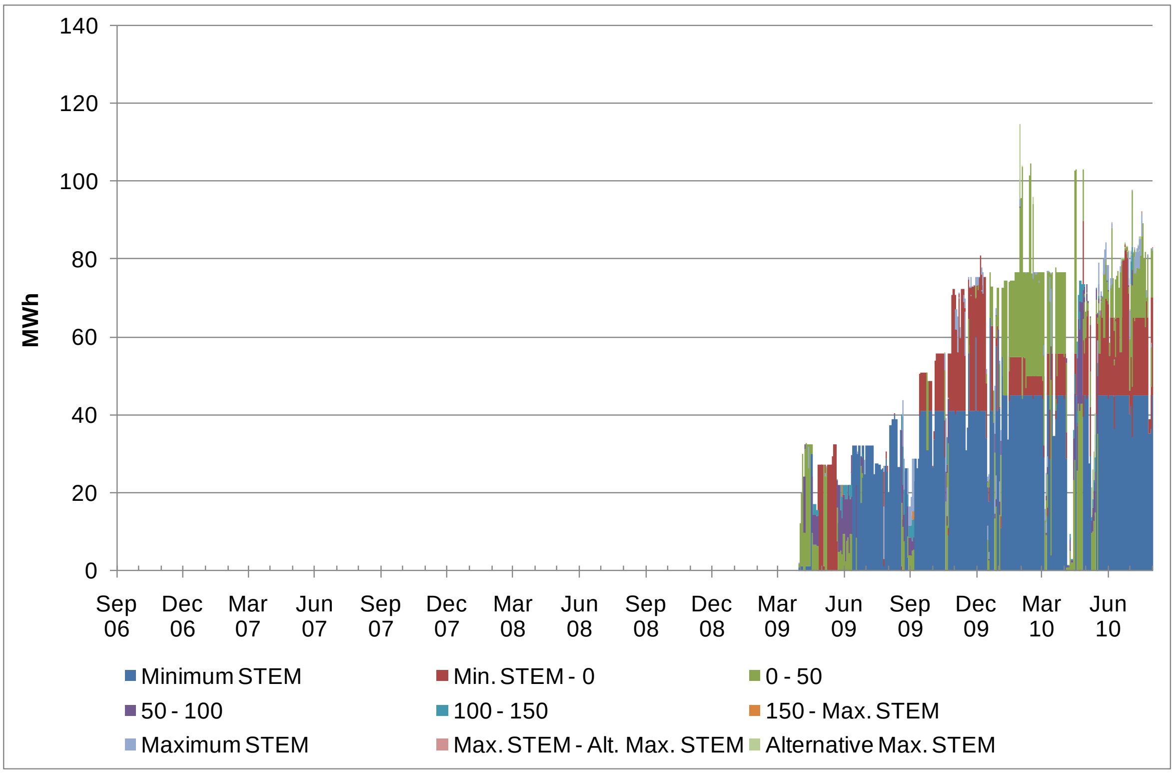


Figure 40 Griffin Energy 2's daily average STEM Bids (cumulative MWh per Trading Interval)

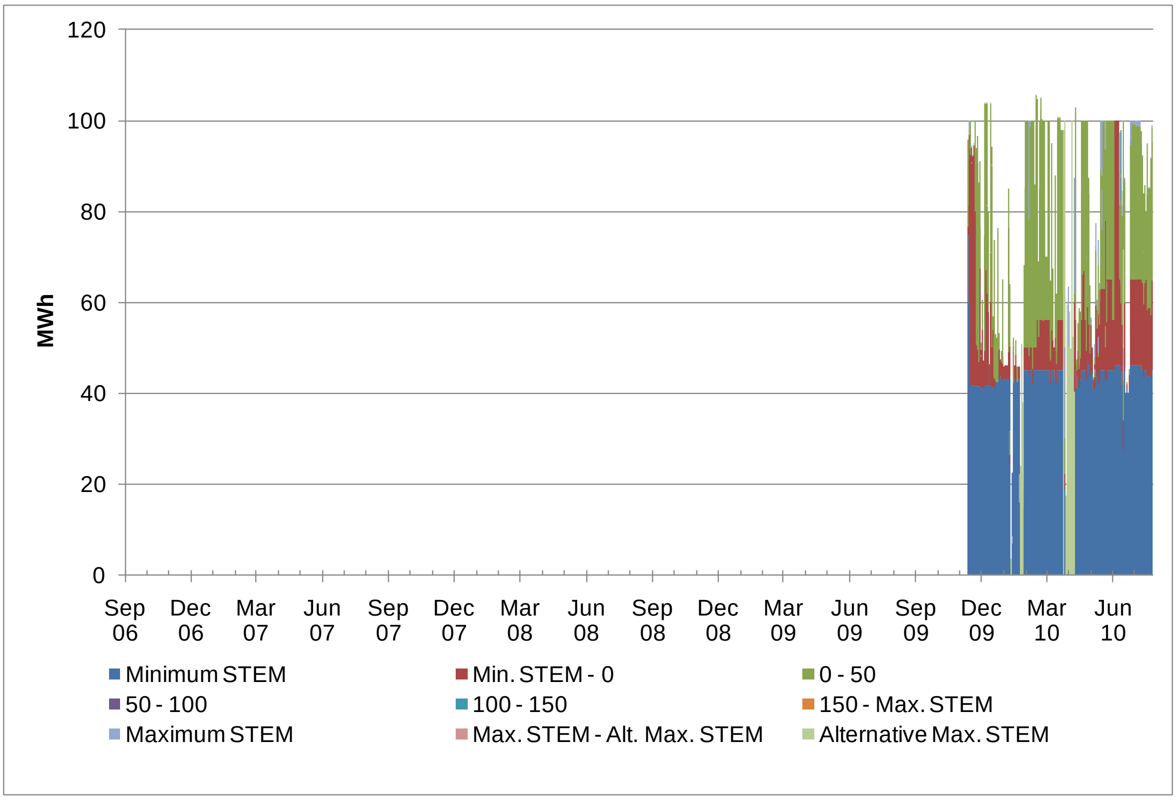


Figure 41 NewGen Power Kwinana's daily average STEM Bids (cumulative MWh per Trading Interval)

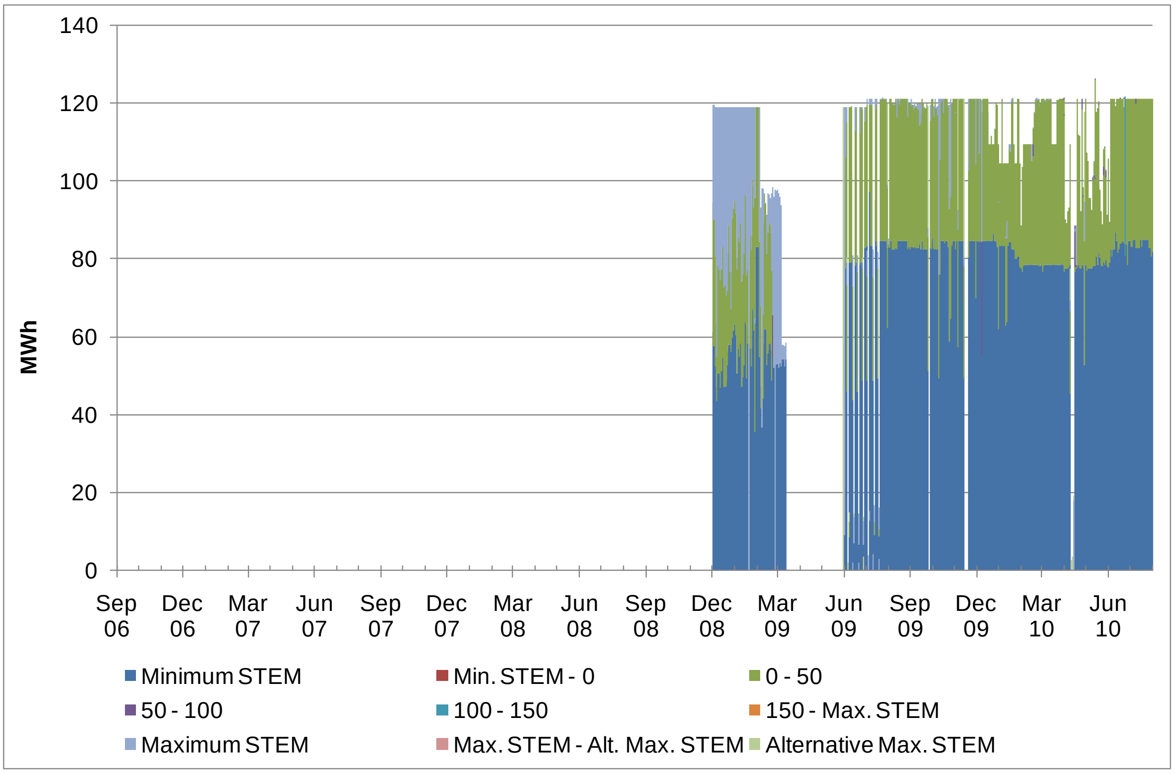


Figure 42 **NewGen Neerabup's daily average STEM Bids (cumulative MWh per Trading Interval)**

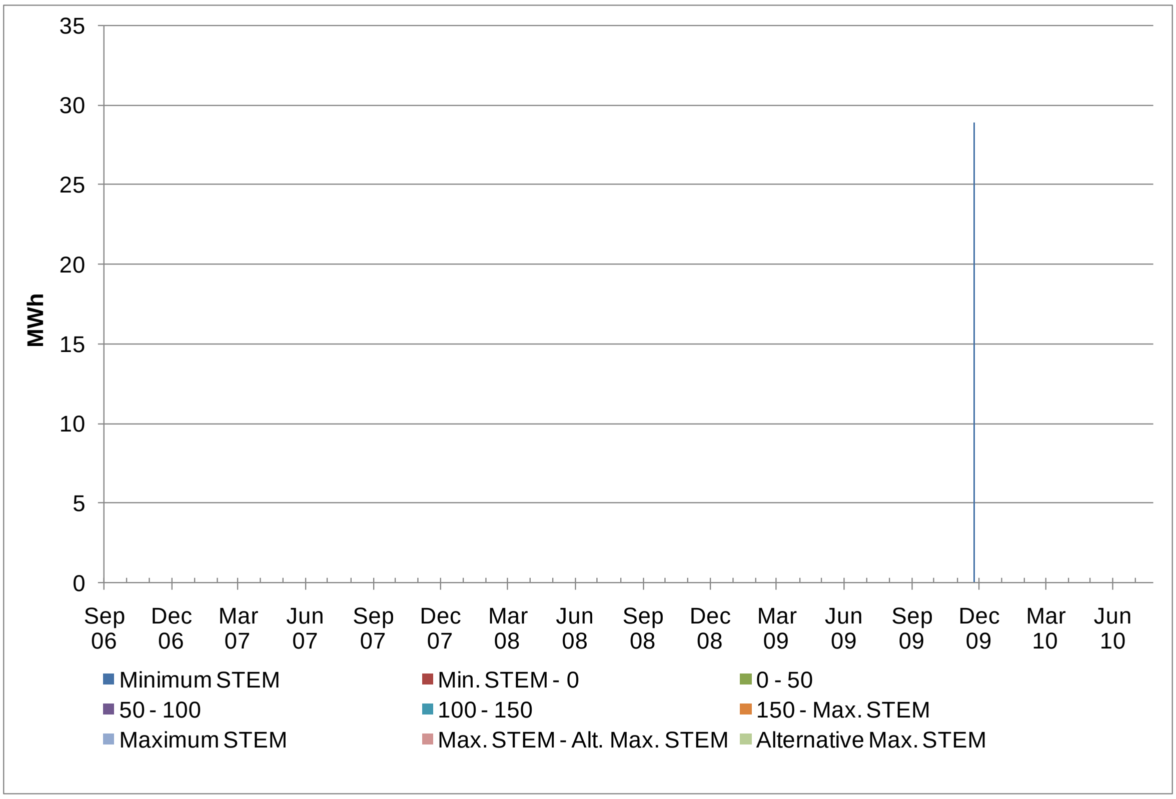


Figure 43 **Perth Energy's daily average STEM Bids (cumulative MWh per Trading Interval)**

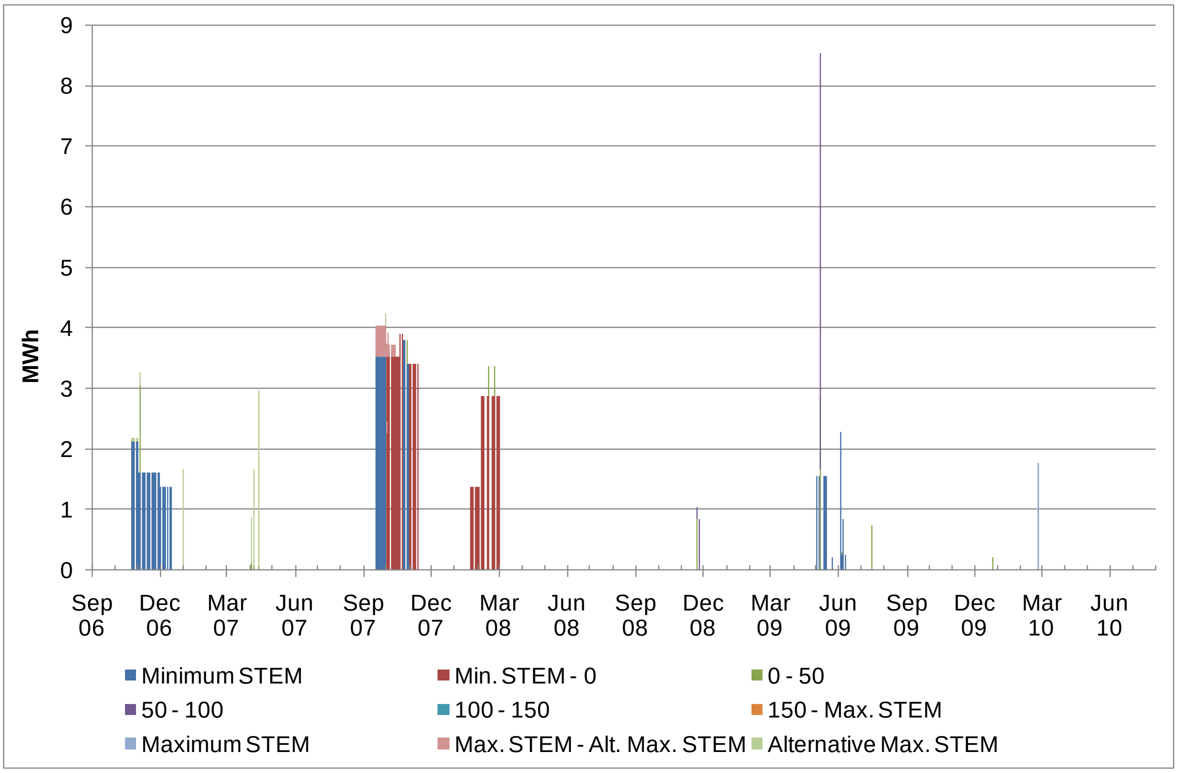


Figure 44 Southern Cross Energy's daily average STEM Bids (cumulative MWh per Trading Interval)

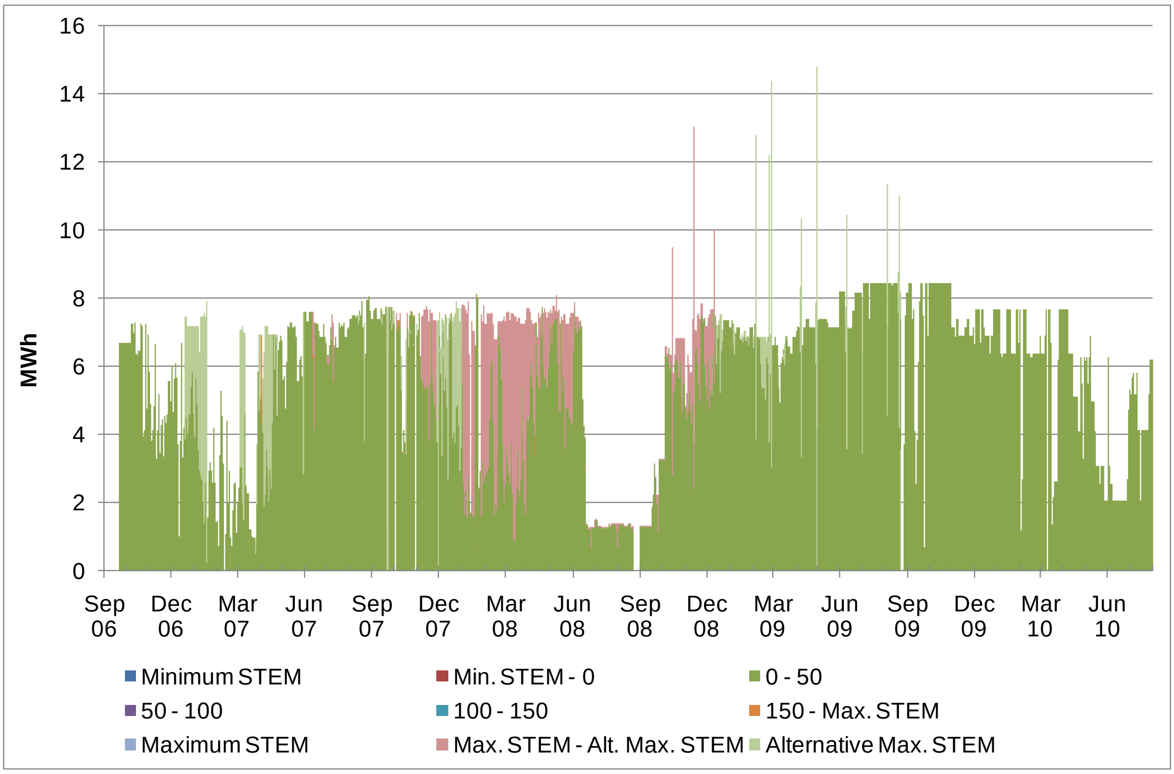


Figure 45 Synergy's daily average STEM Bids (cumulative MWh per Trading Interval)

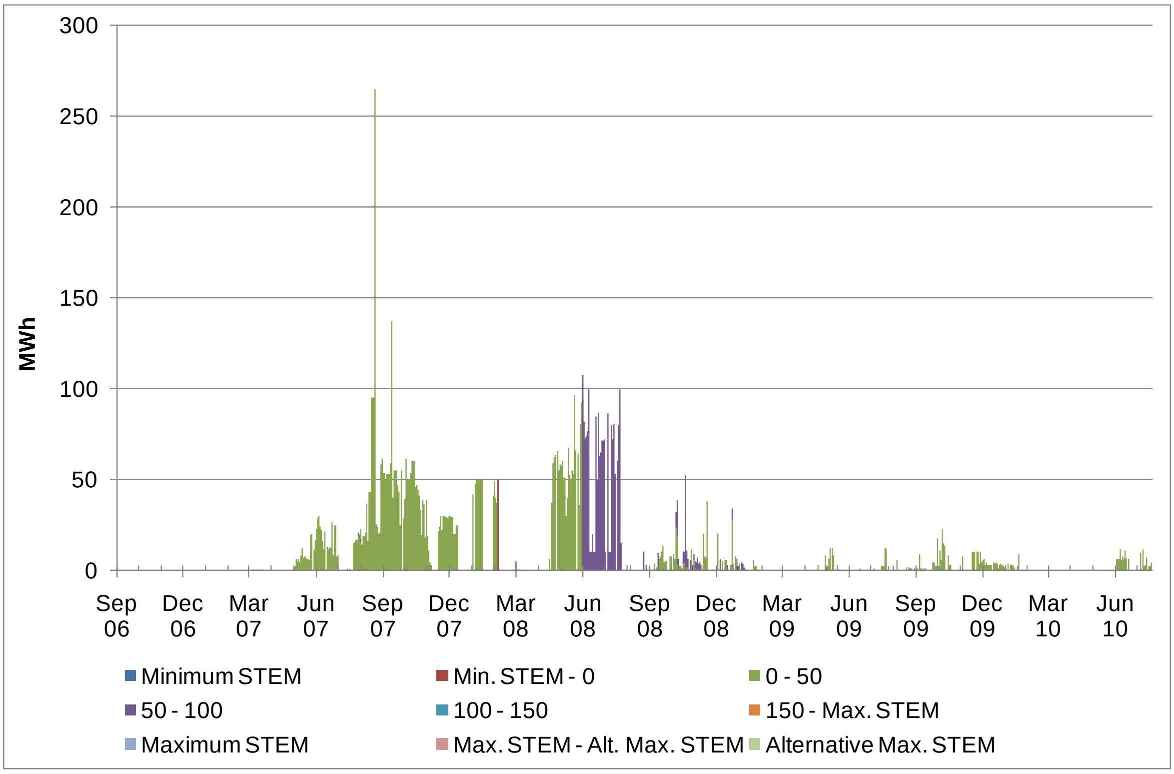
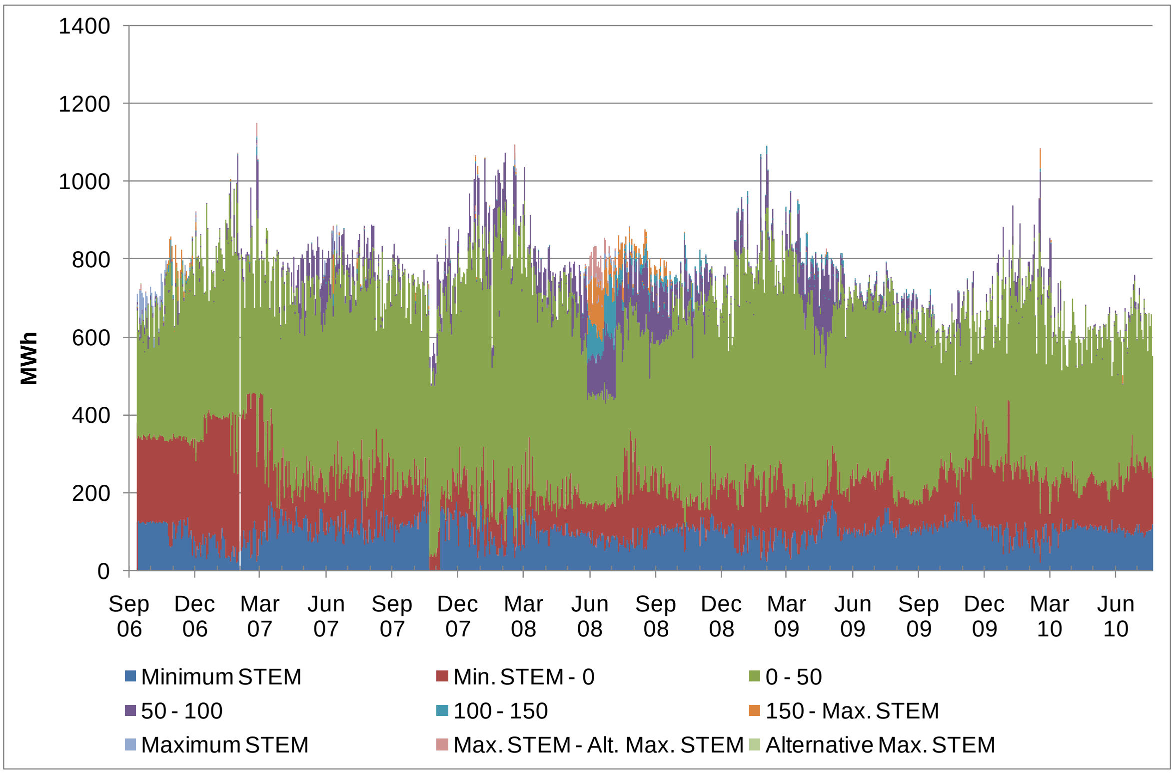
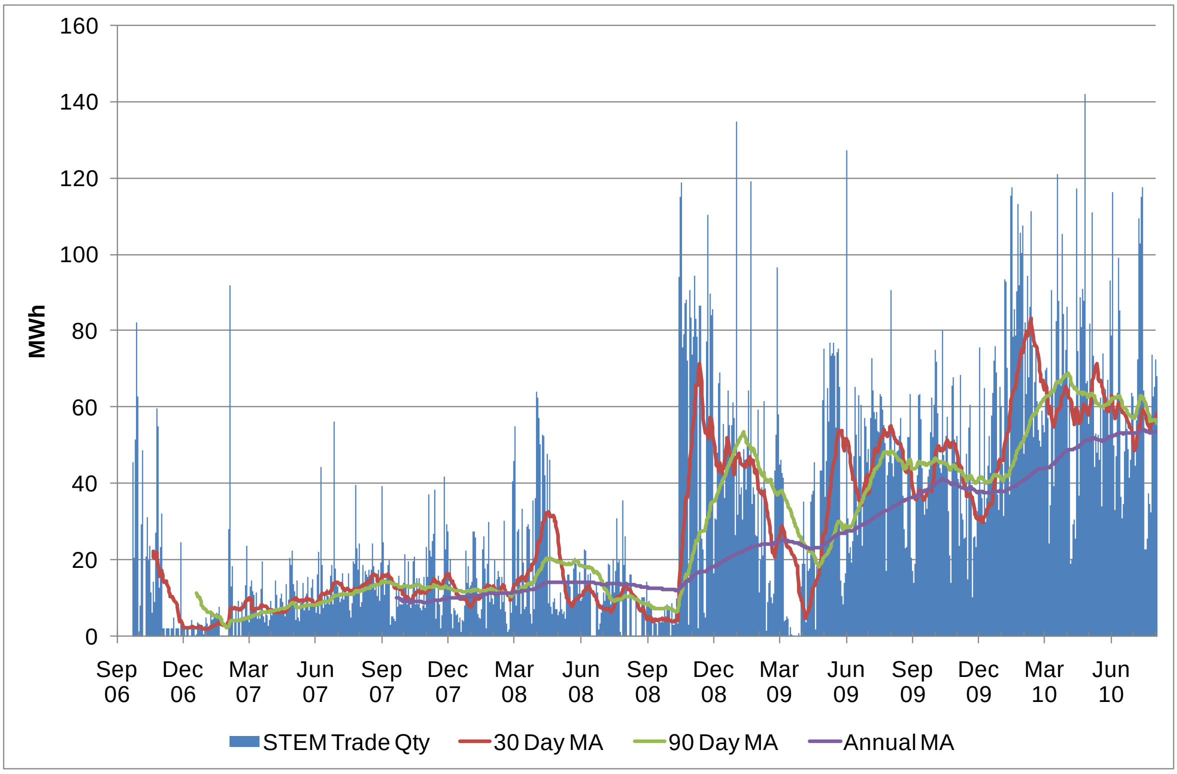


Figure 46 Verve Energy's daily average STEM Bids (cumulative MWh per Trading Interval)



Short Term Energy Market traded volumes

Figure 47 Average STEM Clearing Quantities (per Trading Day)



Balancing

Balancing prices

Standing Data prices used in Balancing

Figure 48 illustrates average Standing Data Balancing prices for Non-Liquid Fuel facilities.[215]

Broadly, IPPs want to be paid close to the applicable Maximum STEM Prices when instructed to increase generation from their Non-Liquid Fuelled facilities irrespective of the time of the day (on average, approximately $209/MWh for the Reporting Period). When instructed to 'back off' their Non-Liquid fuelled generation, IPPs are willing to pay a low price for the energy they did not have to produce irrespective of the time of the day (on average, approximately $147/MWh for the Reporting Period).

Figure 48 Average Standing Data Balancing prices for Non-Liquid Fuel facilities

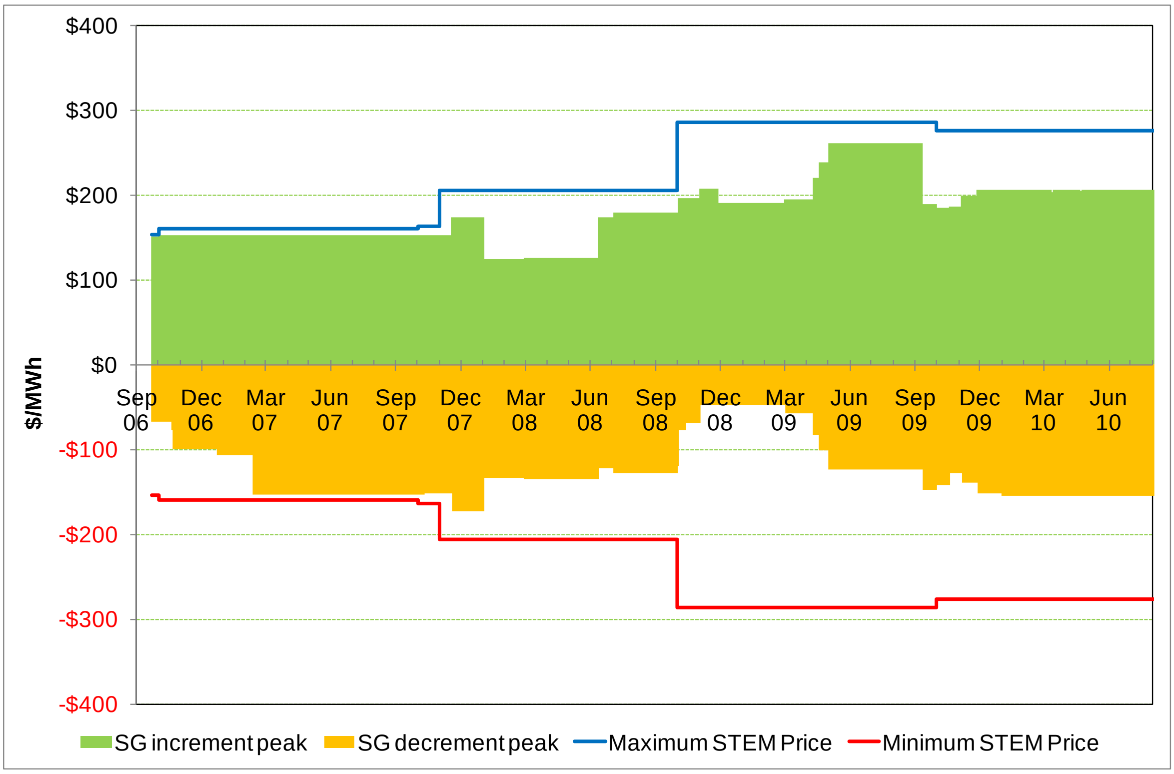


Figure 49 illustrates average Standing Data Balancing prices for Liquid Fuel facilities.[216]

Broadly, IPPs want to be paid close to the applicable Alternative Maximum STEM Prices when instructed to increase generation from their Liquid Fuelled facilities irrespective of the time of the day (on average, approximately $416/MWh for the Reporting Period).

[215] Average daily Standing Data Balancing prices for Non-Liquid Fuel facilities during peak and off-peak Trading Intervals are equal, or less than $0.50/MWh different for both increment and decrement. Since the magnitude of any difference is so small, only peak period have been presented.

[216] Average daily Standing Data Balancing prices for Liquid Fuel facilities during peak and off-peak periods are equal, or less than $0.50/MWh different for both increment and decrement. Since the magnitude of any difference is so small, only peak period have been presented.

When instructed to 'back off' their Liquid fuelled generation, IPPs are willing to pay a low price for the energy they did not have to produce irrespective of the time of the day.

Figure 49 Average Standing Data Balancing prices for Liquid Fuel facilities

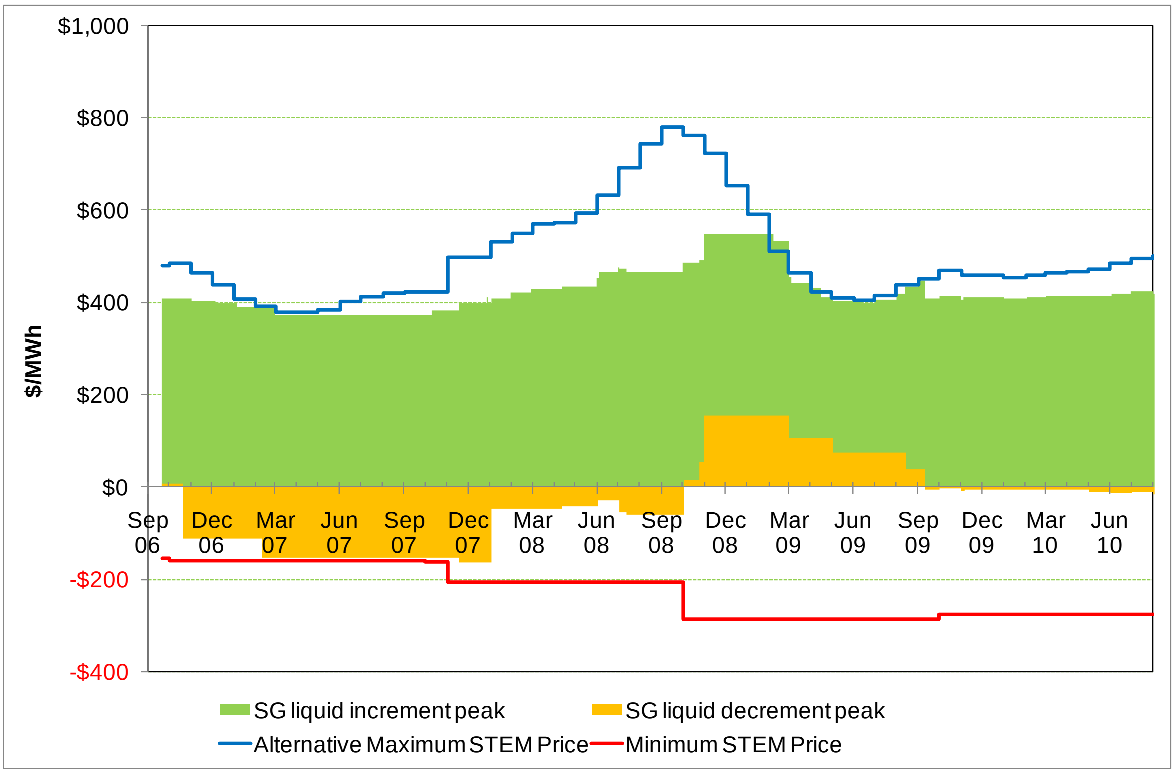


Figure 50 illustrates average Standing Data Balancing prices for Intermittent Generators during off-peak periods.

Figure 50 Average Standing Data Balancing prices for Intermittent Generators (Off-Peak)

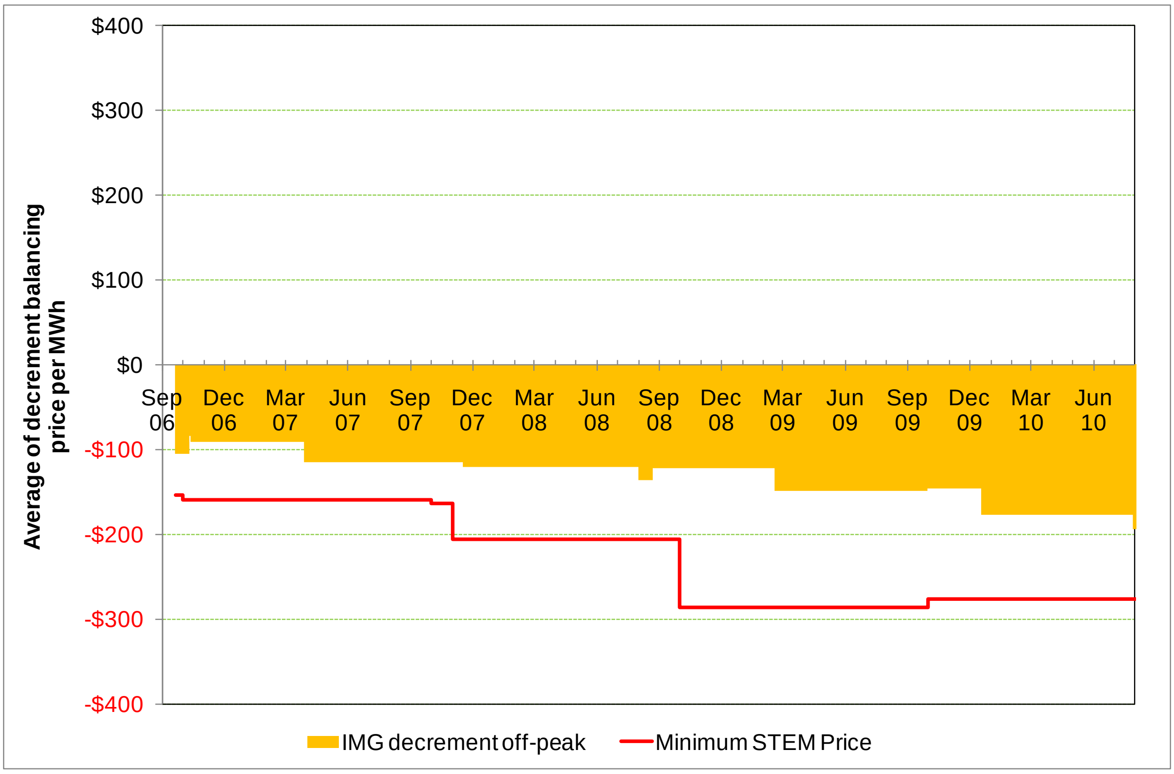


Figure 51 illustrates average Standing Data Balancing prices for Intermittent Generators during peak periods.

Broadly, during the Reporting Period IPPs wanted to be paid on average $159/MWh during off-peak Trading Intervals and $166/MWh during Peak Trading Intervals when instructed to 'back off' their intermittent generation. This represents an average increase of $32/MWh and $31/MWh for off-peak and peak period (respectively) when compared to the previous reporting period.

Figure 51 Average Standing Data Balancing prices for Intermittent Generators (Peak)

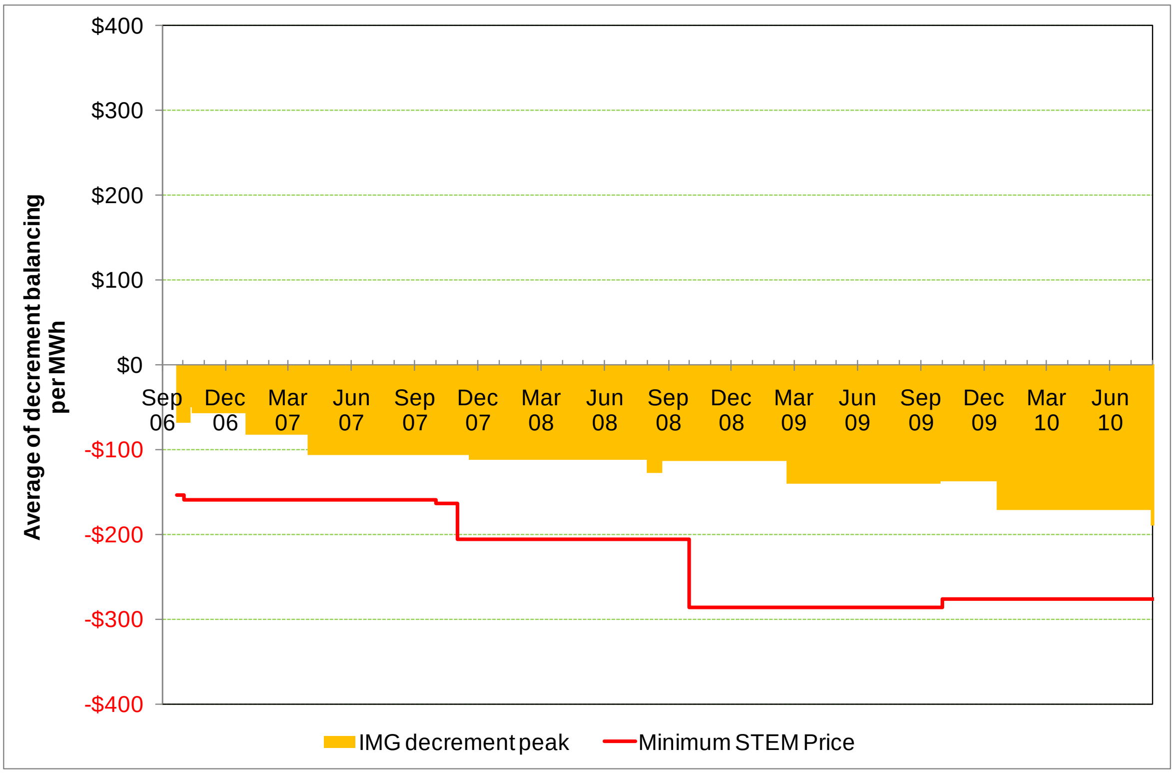


Figure 52 illustrates average Standing Data Balancing prices for Curtailable Loads.[217] [218]

Broadly, Market Customers controlling Curtailable Loads want to be paid close to the applicable Alternative Maximum STEM Prices when instructed to curtail the applicable load (on average, approximately $442/MWh for the Reporting Period).

[217] Average daily Standing Data Balancing prices for Curtailable Loads during peak and off-peak periods are equal, or less than $0.50/MWh different for both increment and decrement. Since the magnitude of any difference is so small, only peak period have been presented.

[218] In this figure, for consistency with the other figures relating to Standing Data Balancing prices, a reduction in Curtailable Loads is represented as an 'increment' of energy.

Figure 52 Average Standing Data Balancing prices for Curtailable Loads

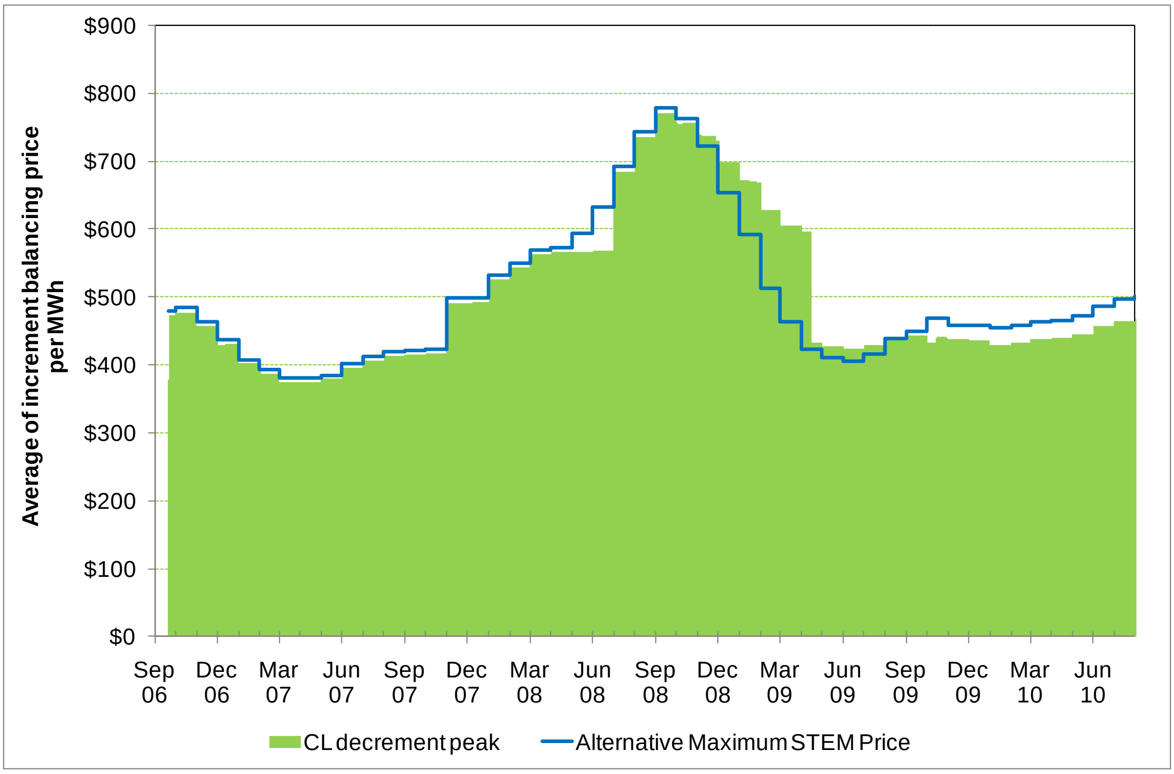


Table 7 sets out the formulas prescribed in the Market Rules for calculating UDAP and DDAP.

Table 7 Method for calculating the UDAP and DDAP

Trading Interval	UDAP ($/MWh)	DDAP ($/MWh)
Off-Peak	0.00	1.1 * MCAP
Peak	0.5 * MCAP	1.3 * MCAP
Participant receives	Yes	
Participant pays		Yes

Figure 53 and Figure 54 compare 30-day and 90-day moving averages of off-peak STEM and Balancing prices, respectively.

Figure 53 30-day moving average Off-Peak STEM and Balancing prices

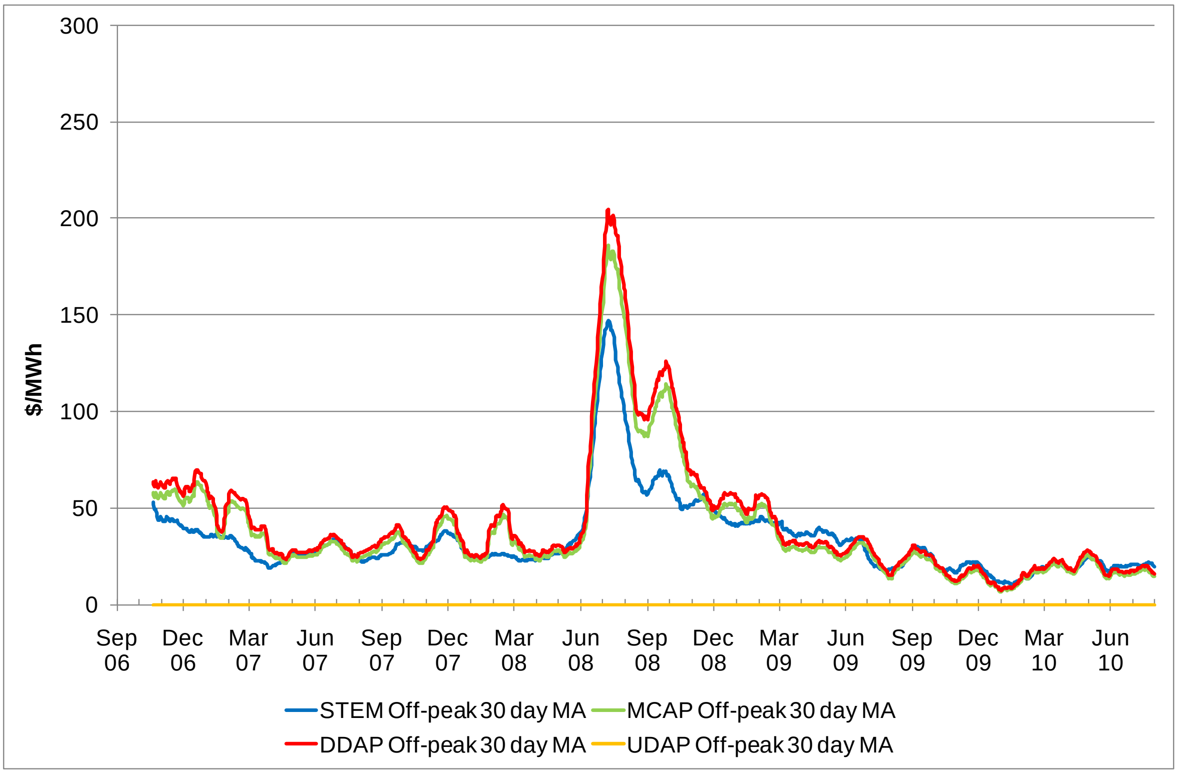
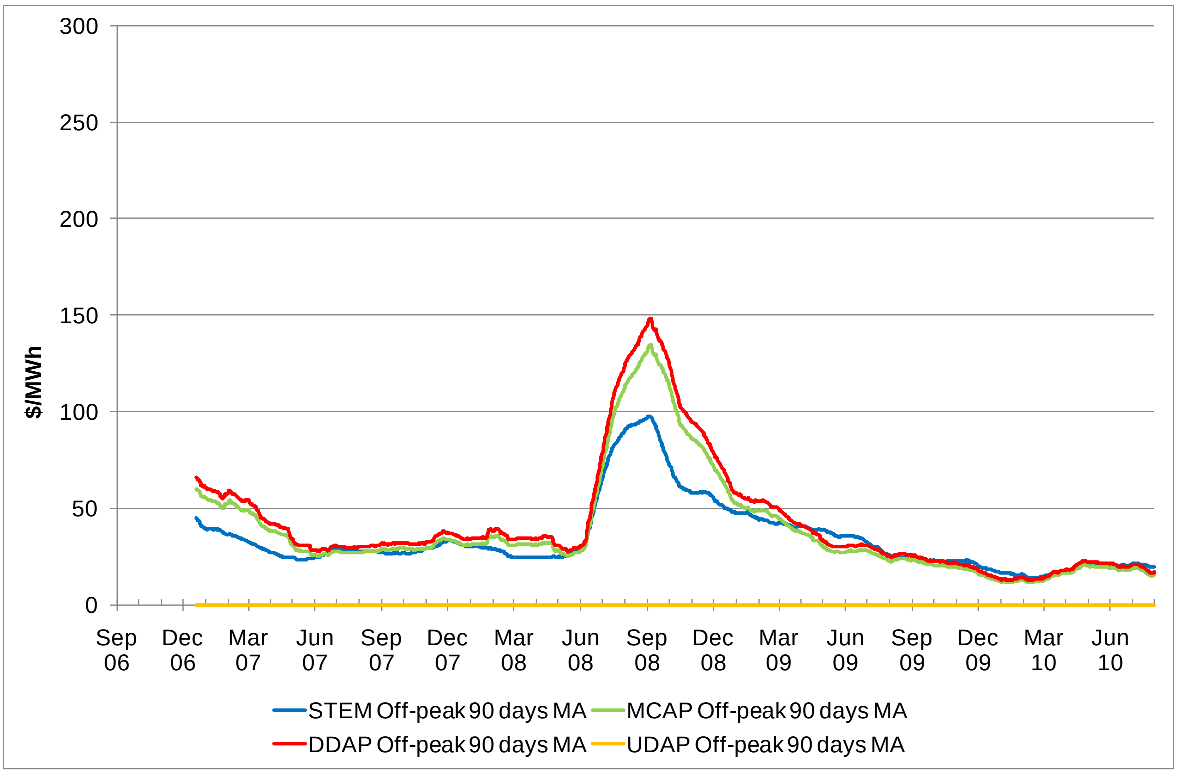


Figure 54 90-day moving average Off-Peak STEM and Balancing prices

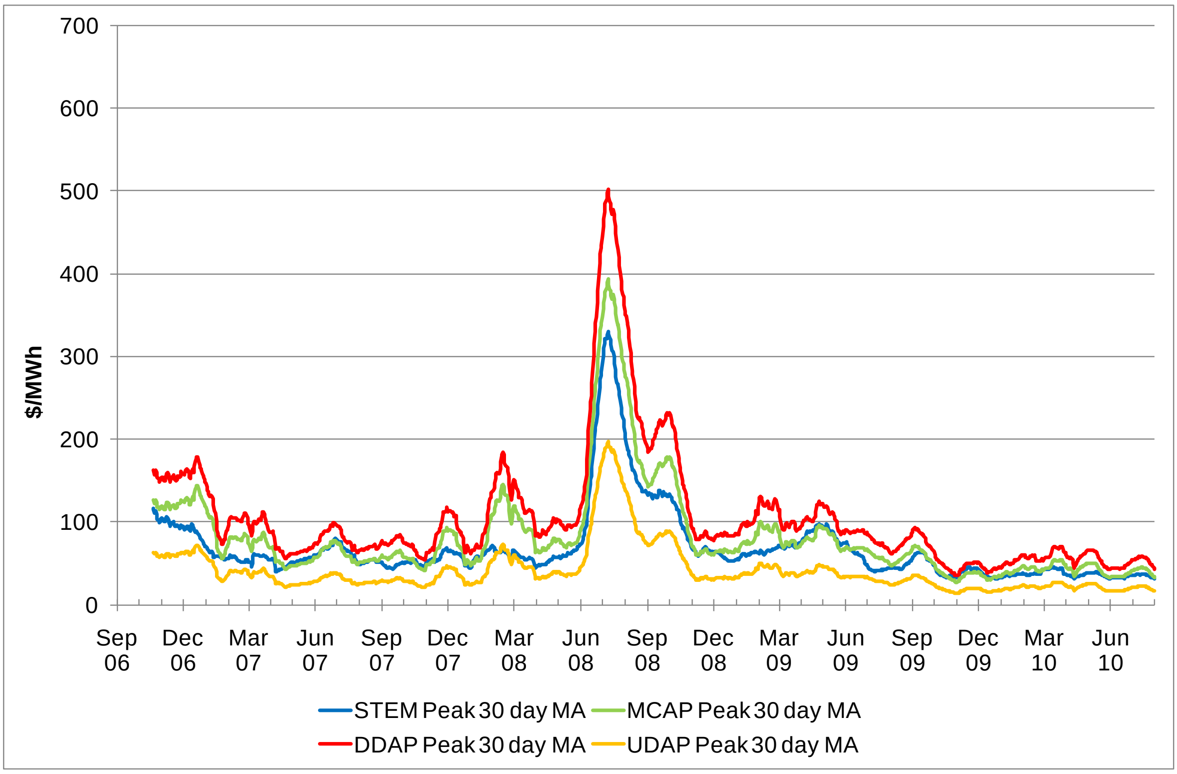


During off-peak periods, both STEM prices and balancing prices increased in mid-2008 due to the Varanus Island incident. Notably, from the start of the gas supply interruption until November 2008, off-peak MCAPs were consistently higher than STEM prices. Since

March 2009, the situation has reversed with a downward trend in MCAPs. After declining and maintaining their low levels between March 2009 and July 2009, the prices declined further between November 2009 and February 2010, reaching their lowest levels in the current period. After February 2010, the prices have remained steady in the range of \$15/MWh to \$30/MWh.

Figure 55 and Figure 56 compare 30-day and 90-day moving averages of off-peak STEM and Balancing prices, respectively.

Figure 55 30-day moving average Peak STEM and Balancing prices



It is observed that Balancing prices are higher than STEM prices during the peak period compared to the off-peak period.

Figure 56 90-day moving average Peak STEM and Balancing prices

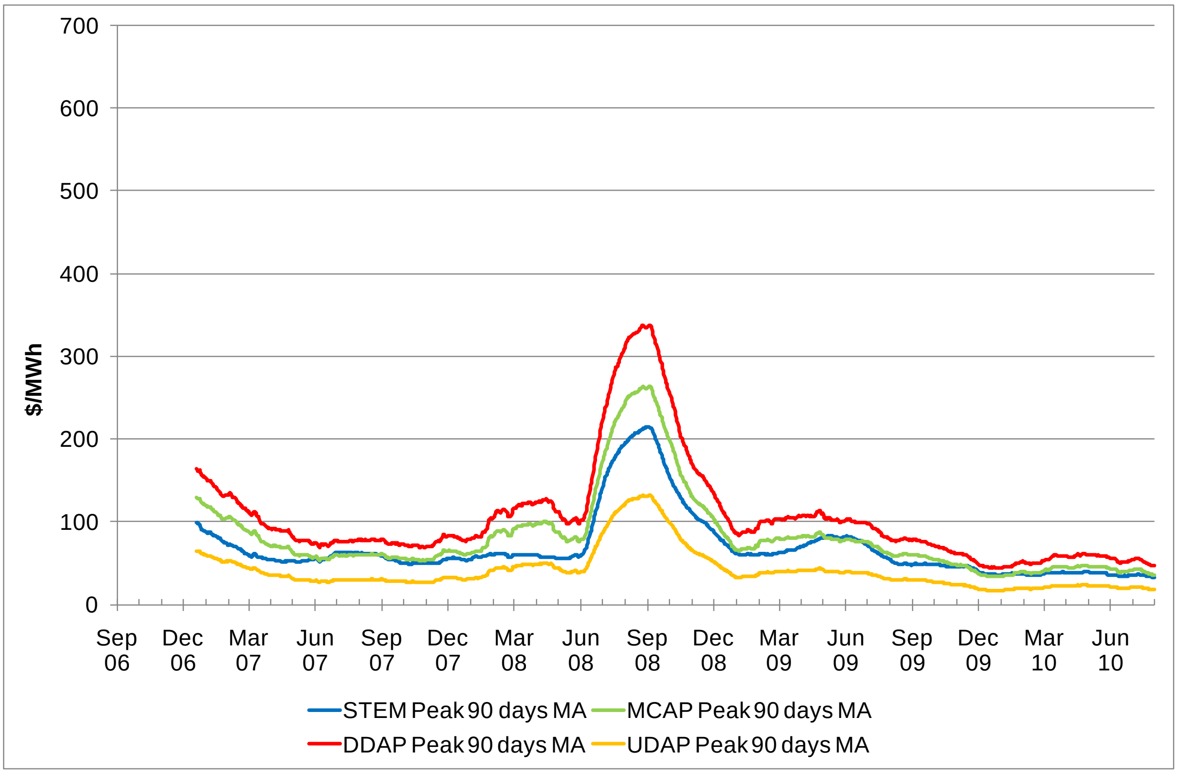


Figure 57 and Figure 58 show annual moving average STEM and Balancing prices for off-peak and peak periods, respectively.

Figure 57 Annual moving average Off-Peak STEM and Balancing prices

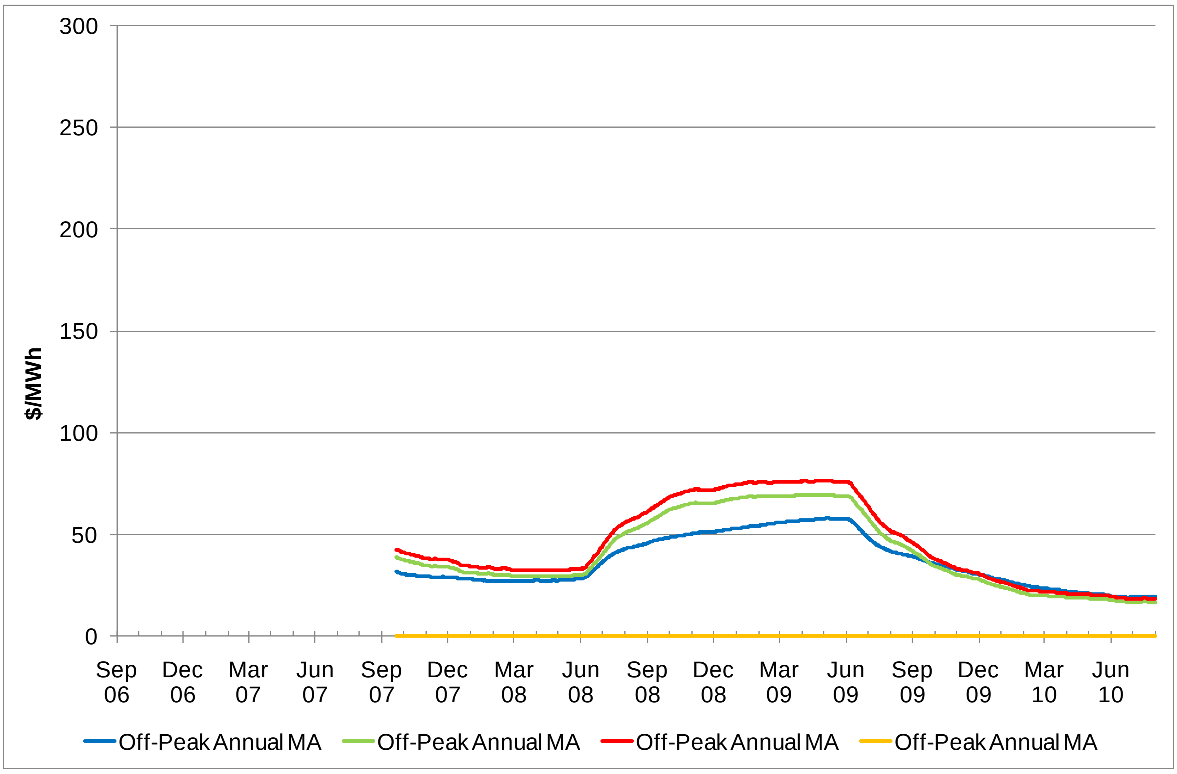
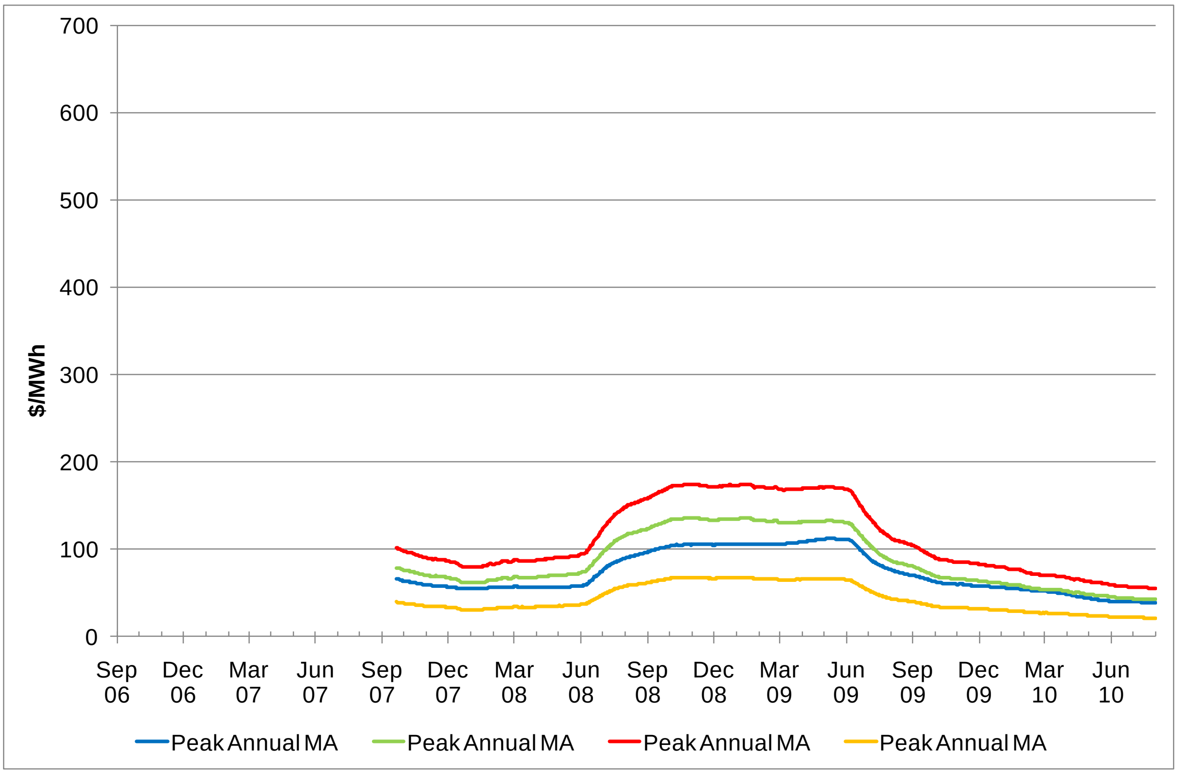


Figure 58 Annual moving average Peak STEM and Balancing prices



Volatility of Balancing prices

Figure 59 to Figure 63 illustrate the means and standard deviations (as well as the maxima and minima) of Balancing prices.

Figure 59 Summary statistics for MCAPs during Off-Peak Trading Intervals (per calendar month)

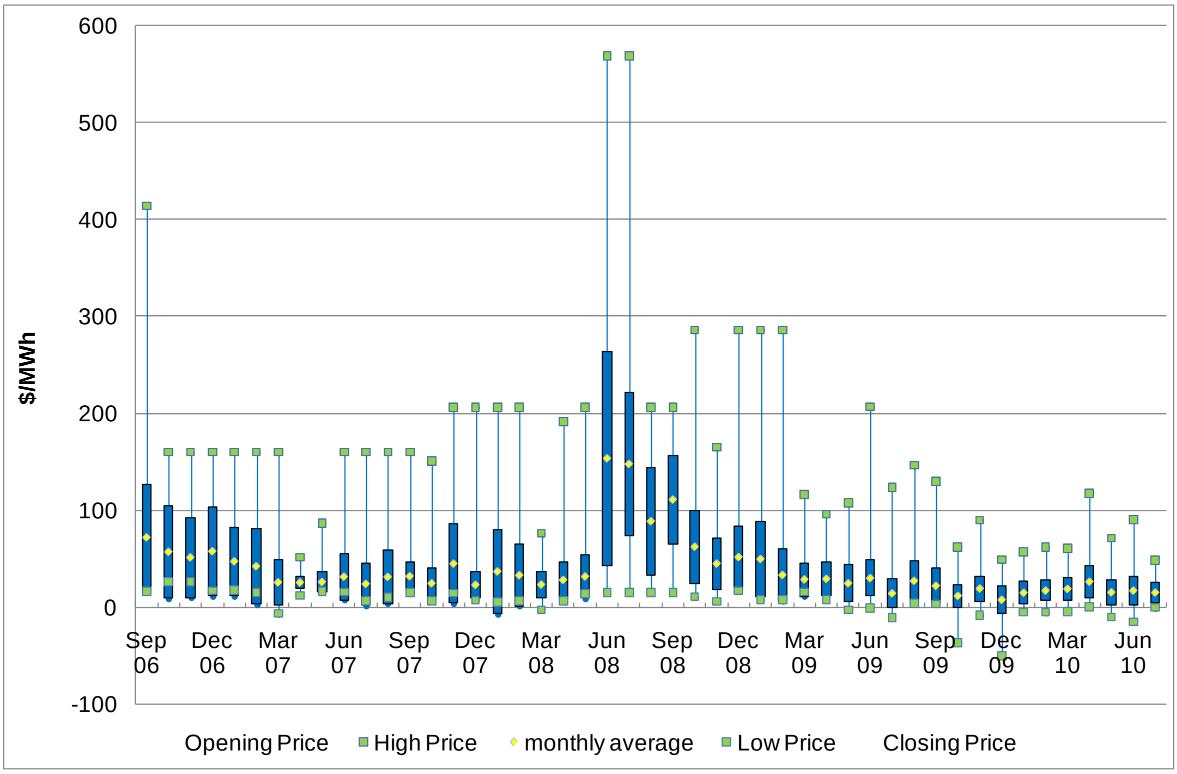


Figure 60 Summary statistics for MCAPs during Peak Trading Intervals (per calendar month)

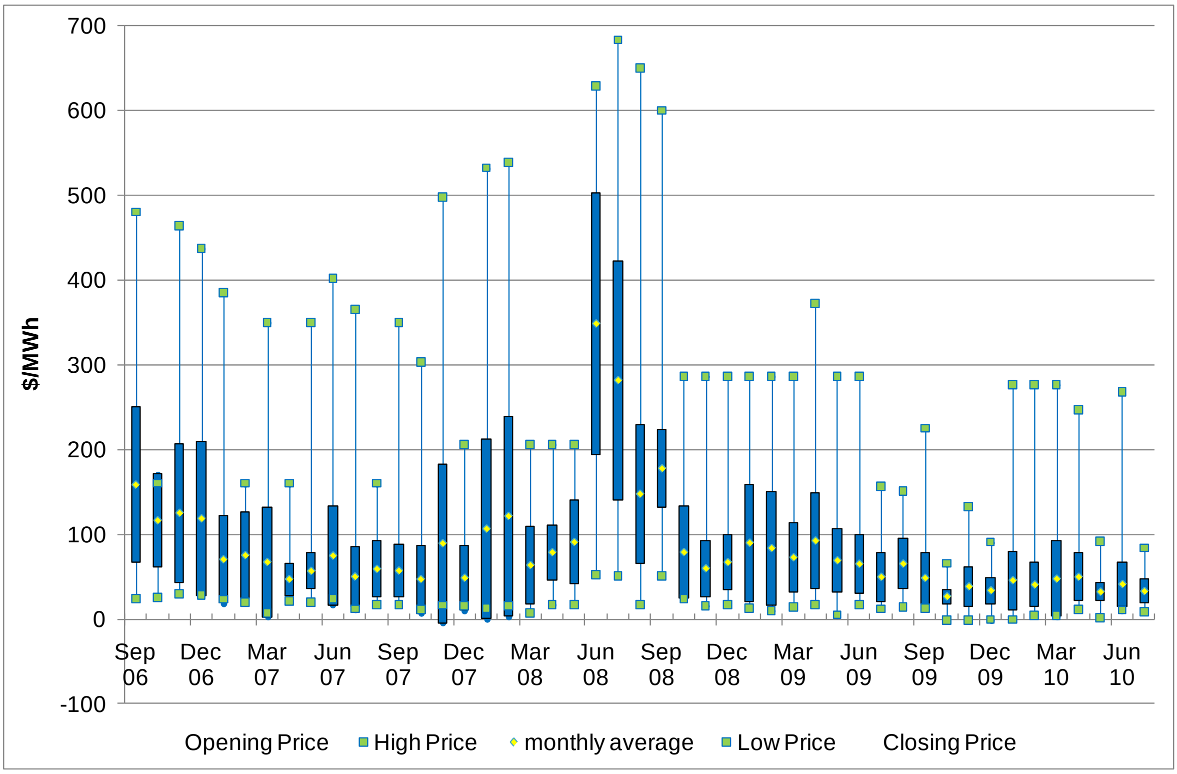


Figure 61 Summary statistics for DDAPs during Off-Peak Trading Intervals (per calendar month)

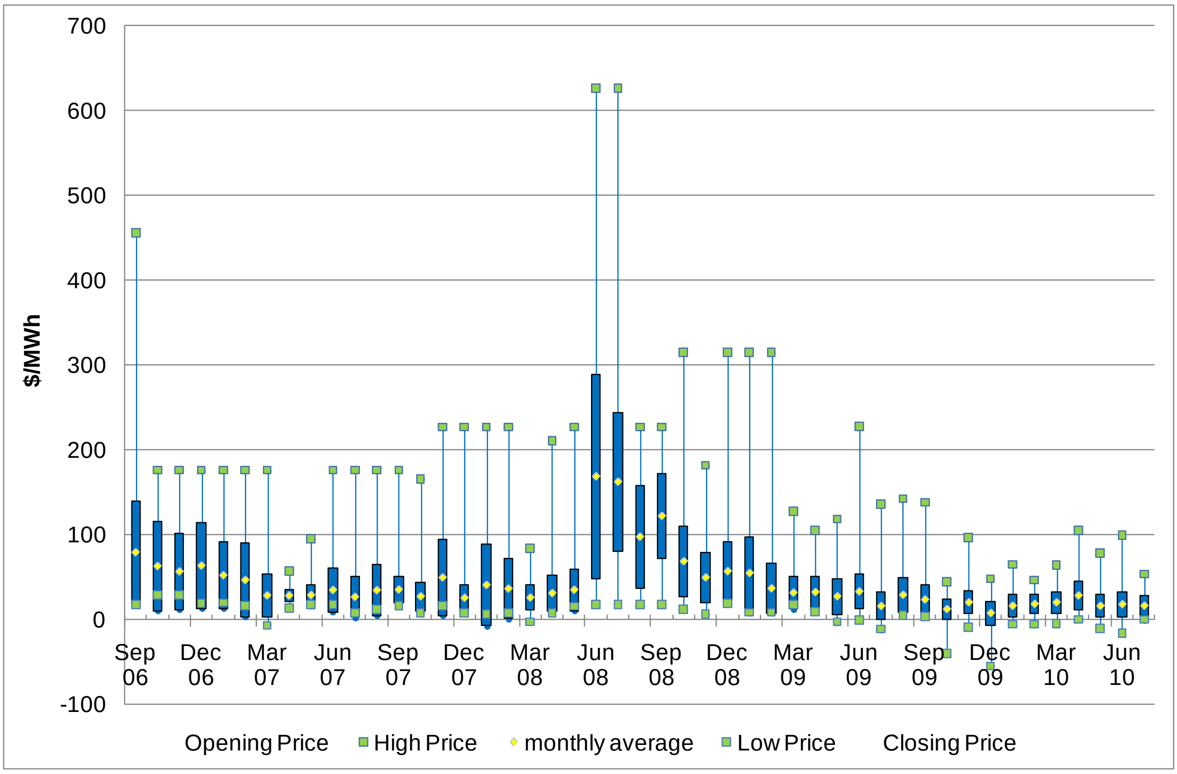


Figure 62 Summary statistics for DDAPs during Peak Trading Intervals (per calendar month)

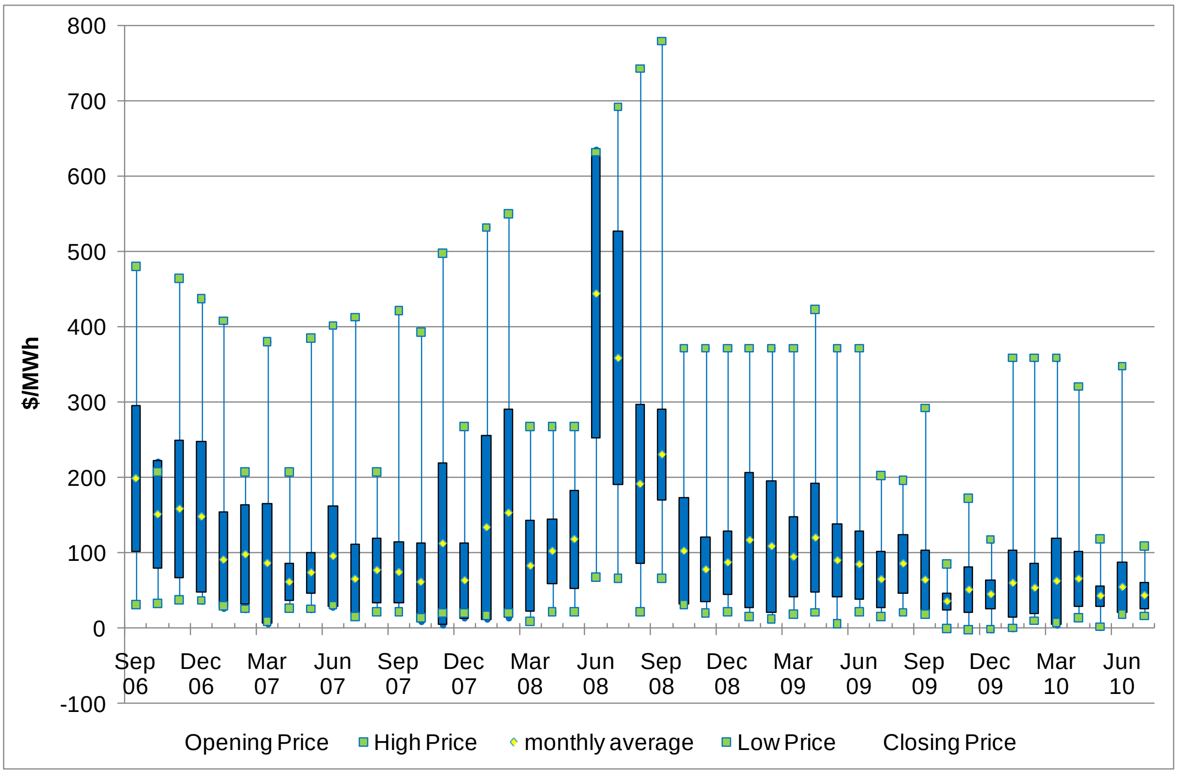
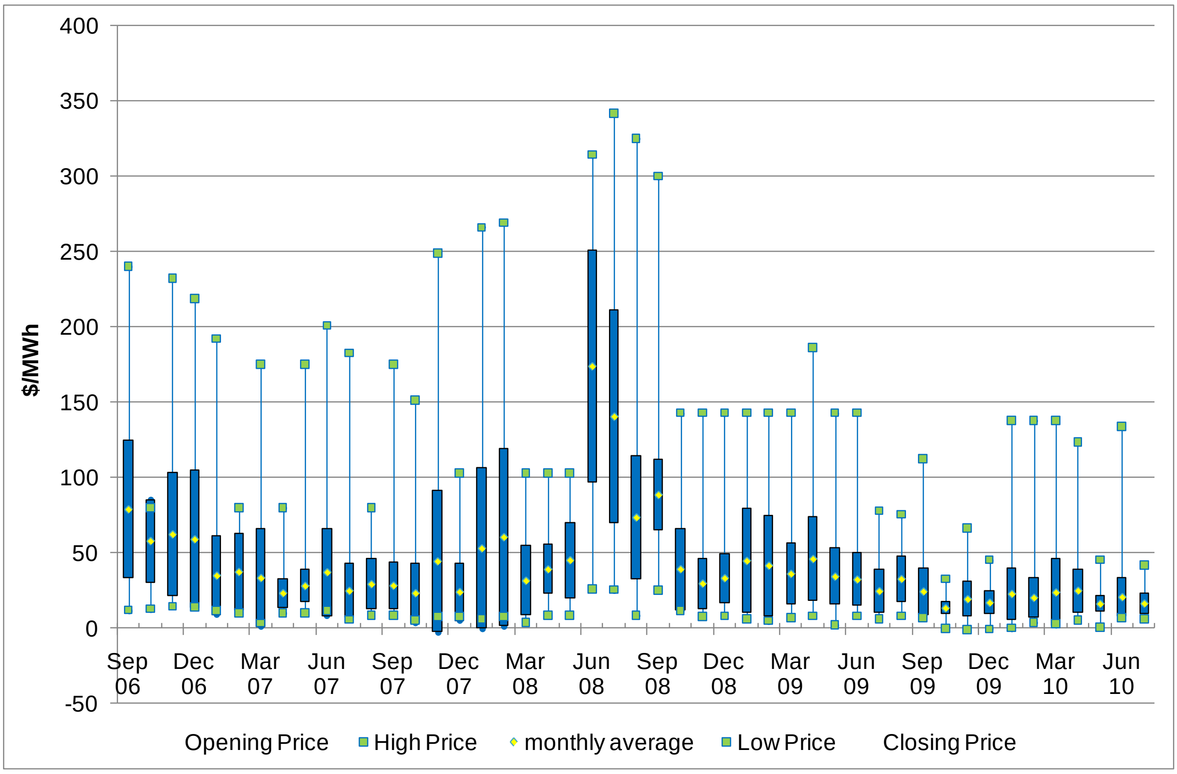


Figure 63 Summary statistics for UDAPs during Peak Trading Intervals (per calendar month)



High Balancing prices

Figure 64 and Figure 65 illustrate the price duration curves for MCAPs during off-peak and peak periods for 21 September 2006 to 31 July 2010.

Figure 64 Price duration curves for STEM Clearing Prices, MCAPs, UDAPs and DDAPs during Off-Peak periods (21 September 2006 to 31 July 2010)

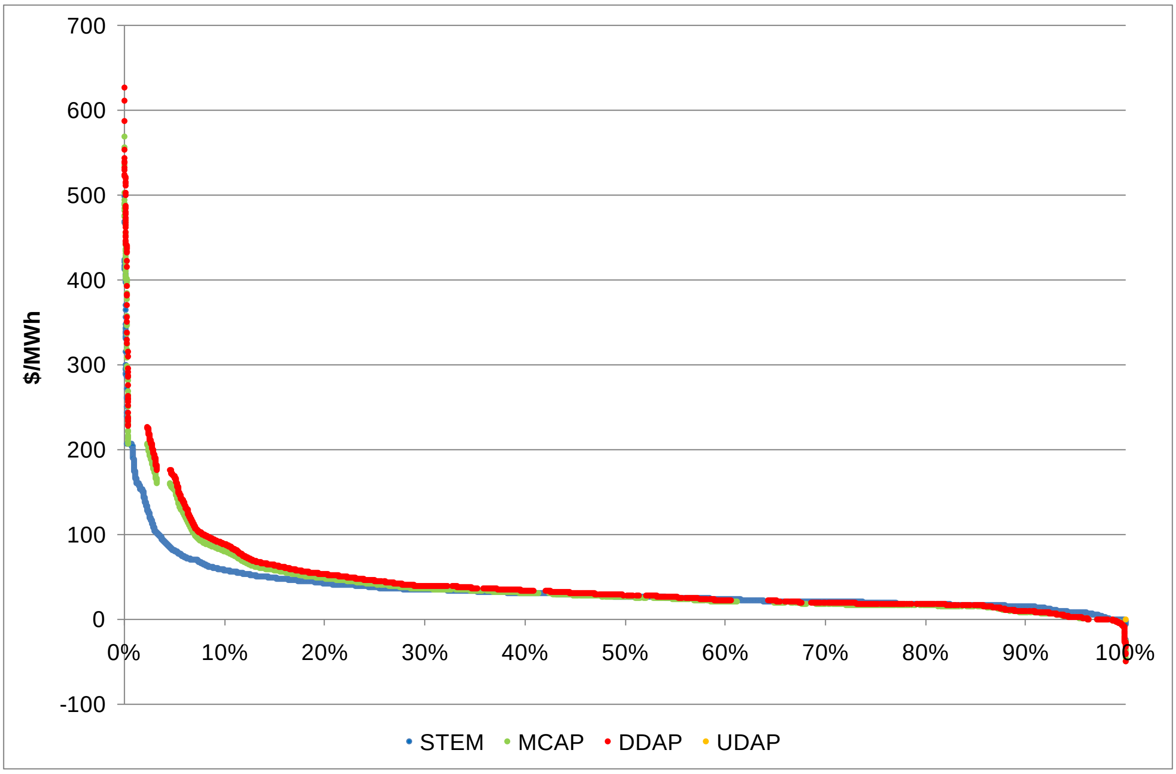


Figure 64 shows that during off-peak periods, the majority of DDAPs occur in a broad range below $100/MWh (between $100/MWh and negative $55/MWh) for approximately 92 per cent of the total Off-peak Trading Intervals, with a fairly even distribution of prices within this range. For about 46 per cent of the total Trading Intervals, DDAPs were closely aligned with MCAP and STEM Clearing Prices, and for 12 per cent of the total Trading Intervals DDAP and MCAP were lower than STEM Clearing Prices.

Figure 65 Price duration curves for STEM Clearing Prices, MCAPs, UDAPs and DDAPs during Peak periods (21 September 2006 to 31 July 2010)

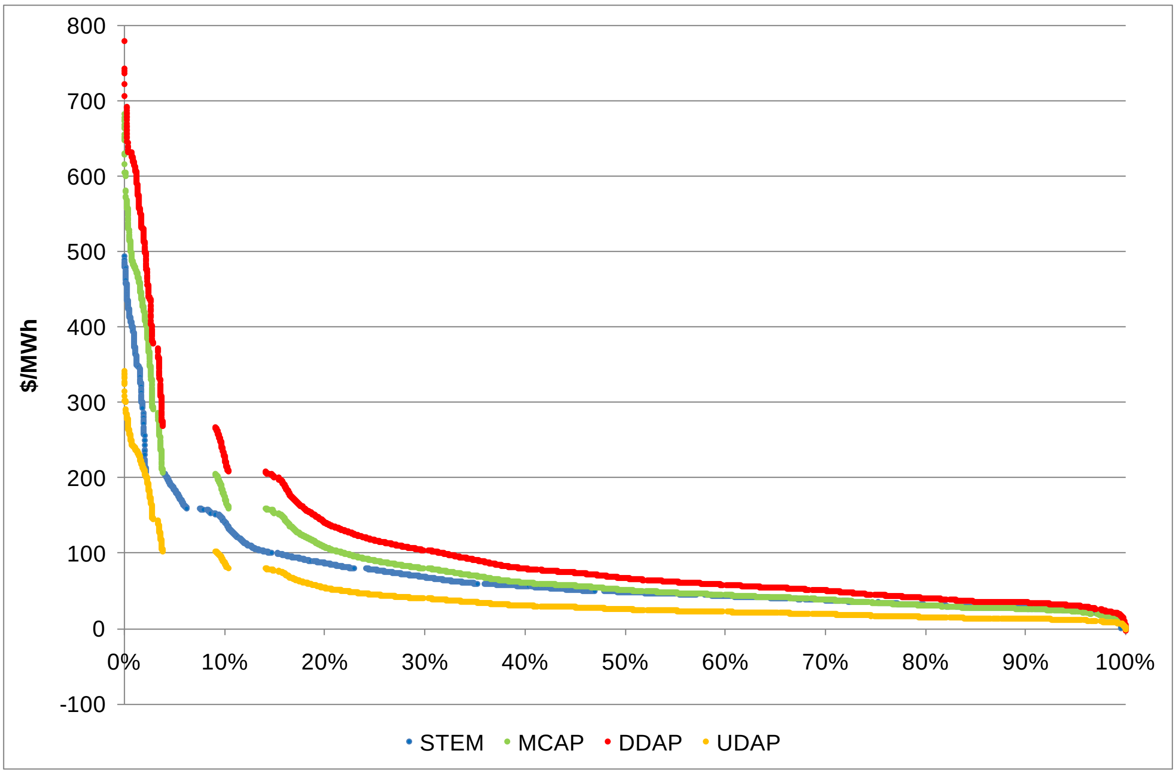


Figure 65 shows that DDAPs are significantly higher than the STEM prices in peak period across all the Trading Intervals from EMC.

Figure 66 and Figure 67 illustrate price duration curves for MCAPs during Peak periods, for the periods 1 August 2008 to 31 July 2009 and 1 August 2009 to 31 July 2010, respectively.

Figure 66 Price duration curves for STEM Clearing Prices and MCAPs during Peak periods (01 August 2008 to 31 July 2009)

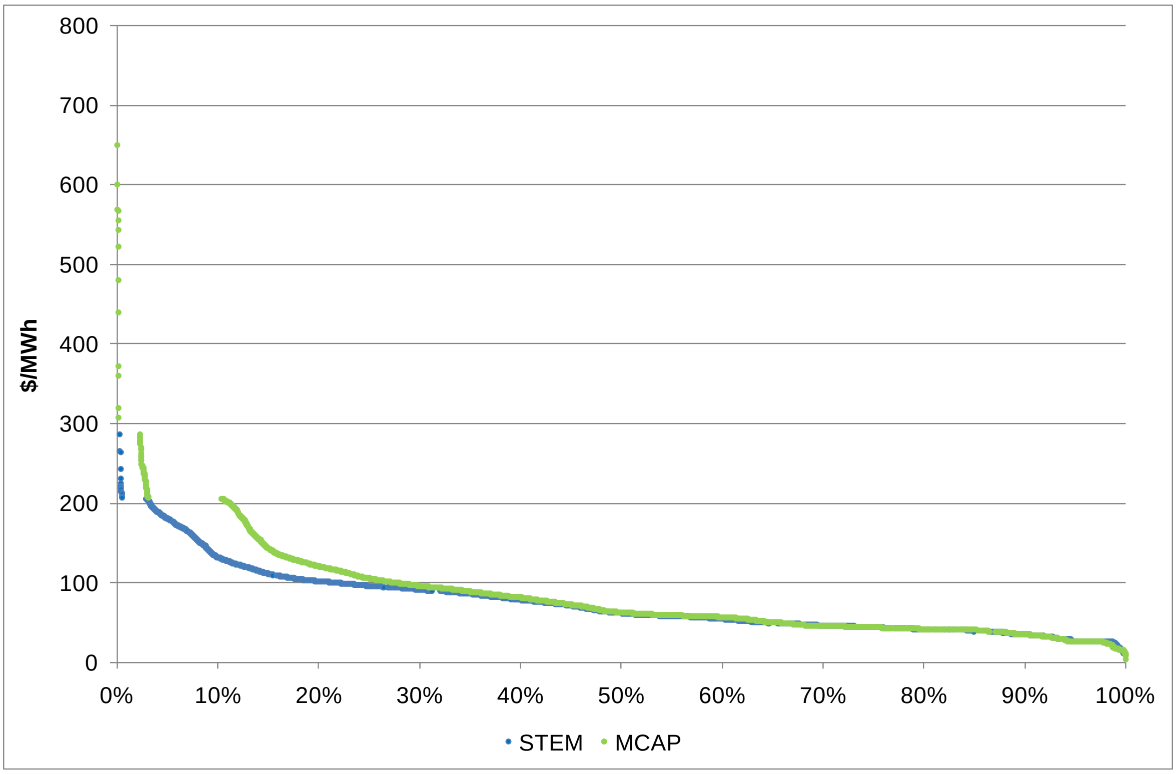
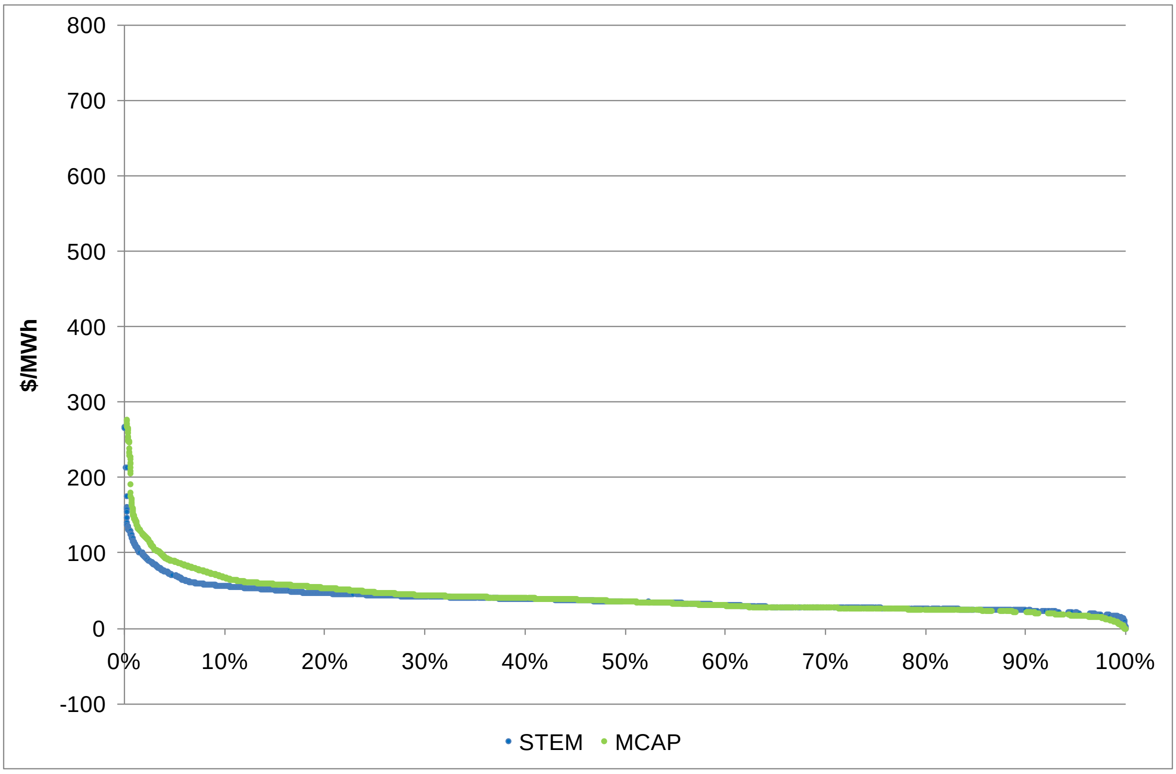


Figure 67 Price duration curves for STEM Clearing Prices and MCAPs during Peak periods (01 August 2009 to 31 July 2010)



Number of Market Generators and Market Customers

Table 8 Registered Market Participants

	21 September 2006 (Energy Market Commencement)	2 September 2008	6 October 2009	14 October 2010
Market Generators and Market Customers	Alcoa of Australia Limited	Alcoa of Australia Limited	Alcoa of Australia Limited	Alcoa of Australia Limited
	Alinta Sales Pty Ltd	Alinta Sales Pty Ltd	Alinta Sales Pty Ltd	Alinta Sales Pty Ltd
	Landfill Gas and Power Pty Ltd	Griffin Power Pty Ltd	Griffin Power Pty Ltd	Griffin Power Pty Ltd
	Perth Energy Pty Ltd	Griffin Power 2 Pty Ltd	Griffin Power 2 Pty Ltd	Griffin Power 2 Pty Ltd
	Southern Cross Energy	Landfill Gas and Power Pty Ltd	Landfill Gas and Power Pty Ltd	Landfill Gas and Power Pty Ltd
	Verve Energy	Perth Energy Pty Ltd	Perth Energy Pty Ltd	Metro Power Company Pty Ltd
		Southern Cross Energy	Southern Cross Energy	Perth Energy Pty Ltd
		Verve Energy	Verve Energy	Southern Cross Energy
				Verve Energy
Market Generators (only)	EDWF Manager Pty Ltd	Biogen	Biogen	Advanced Energy Resources
	Goldfields Power Pty Ltd	Coolimba Power Pty Ltd	Collgar Wind Farm	Biogen
	Mount Herron Engineering Pty Ltd	EDWF Manager Pty Ltd	Coolimba Power Pty Ltd	Collgar Wind Farm
	Waste Gas Resources Pty Ltd	Eneabba Gas Limited	EDWF Manager Pty Ltd	Coolimba Power Pty Ltd
		Eneabba Energy Pty Ltd	Eneabba Gas Limited	EDWF Manager Pty Ltd
		Goldfields Power Pty Ltd	Eneabba Energy Pty Ltd	Eneabba Gas Limited
		Mount Herron Engineering Pty Ltd	Goldfields Power Pty Ltd	Eneabba Energy Pty Ltd
		Namarkkon Pty Ltd	Mount Herron Engineering Pty Ltd	Goldfields Power Pty Ltd
		NewGen Power Kwinana Pty Ltd	Namarkkon Pty Ltd	McNabb Plantation Alliance Pty Ltd
		NewGen Neerabup Pty Ltd	NewGen Power Kwinana Pty Ltd	Mount Herron Engineering Pty Ltd
		SkyFarming Pty Ltd	NewGen Neerabup Pty Ltd	Namarkkon Pty Ltd
		Wambo Power Ventures Pty Ltd	NewGen Neerabup Partnership	NewGen Power Kwinana Pty Ltd
		Waste Gas Resources Pty Ltd	SkyFarming Pty Ltd	NewGen Neerabup Pty Ltd
		Western Australia Biomass Pty Ltd	Tesla Corporation Pty Ltd	NewGen Neerabup Partnership

	21 September 2006 (Energy Market Commencement)	2 September 2008	6 October 2009	14 October 2010
			Vinalco Energy Pty Ltd	SkyFarming Pty Ltd
			Wambo Power Ventures Pty Ltd	Tesla Corporation Pty Ltd
			Waste Gas Resources Pty Ltd	Vinalco Energy Pty Ltd
			Western Australia Biomass Pty Ltd	Wambo Power Ventures Pty Ltd
			Western Energy Pty Ltd	Waste Gas Resources Pty Ltd
				Western Australia Biomass Pty Ltd
				Western Energy Pty Ltd
Market Customers (only)	Barrick (Kanowna) Limited	Barrick (Kanowna) Limited	Barrick (Kanowna) Limited	Amanda Australia Pty Ltd
	Newmont Power Pty Ltd	Clear Energy Pty Ltd	Clear Energy Pty Ltd	Barrick (Kanowna) Limited
	Premier Power Sales Pty Ltd	Energy Response Pty Ltd	DMT Energy	Clear Energy Pty Ltd
	Synergy	Karara Energy Pty Ltd	Energy Response Pty Ltd	DMT Energy
	Water Corporation	Newmont Power Pty Ltd	Karara Energy Pty Ltd	EnerNOC Australia Pty Ltd
		Premier Power Sales Pty Ltd	Newmont Power Pty Ltd	Energy Response Pty Ltd
		Synergy	Premier Power Sales Pty Ltd	ERM Power Retail Pty Ltd
		Water Corporation	Synergy	Karara Energy Pty Ltd
			Water Corporation	Newmont Power Pty Ltd
				Premier Power Sales Pty Ltd
				Synergy
				Water Corporation

Appendix 4 Summary of market evolution processes

Market Rules design review

The IMO's Market Rules Evolution Plan (**MREP**)[219] and the Verve Energy Review (**Verve Review**)[220] both identified the need for an evaluation of the Market Rules with respect to a number of aspects of the WEM's design. Issues with the WEM's design identified during the course of development of both the MREP and the Verve Review had considerable overlap (see list below).

- MREP:
  - Improvements to the Balancing mechanism
  - Review of the Reserve Capacity Mechanism
  - Improvements to STEM, including: closer to real time or multiple gate closures; transparency of STEM offers and preliminary calculation of MCAP
  - Closer alignment of gas and electricity nominations
  - Introducing markets in Ancillary Services
- Verve Review:
  - Broader participation in the Balancing mechanism
  - Review of the capacity deficiency penalties
  - Pricing provisions relating to the STEM and the Balancing mechanism
  - The provision of Ancillary services

A 'Market Rules Design Team'[221] was established to undertake an evaluation of these issues (titled the Market Rules Design Review (**MRDR**)).[222] As a part of its deliberations, consideration was given to which 'pathway' should be pursued for the more effective operation of the WEM, including enhancements to the current hybrid design or changing to a more mature market design (net or gross dispatch arrangements).

The IMO's Market Evolution Program (MEP)

Following on from the MRDR, the Market Evolution Program (**MEP**) seeks to resolve the WEM design issues identified by the MRDR and the processes that preceded it, within the framework that the current hybrid design of the WEM would be retained.

---

[219] The MREP incorporates a list of WEM issues raised by stakeholders since the commencement of the WEM and outlines a number of IMO initiated market development reviews to address each of these issues over a rolling three-year period. The MREP's priorities and timelines, which are established in consultation with the IMO's Market Advisory Committee, may change during the rolling three-year period in the circumstances where new high-priority issues are identified and resources have to be diverted to address these issues. The IMO reviews and updates the MREP six-monthly and presents this to the MAC for its re-prioritisation of issues. An updated MREP is to be published on the IMO website following each review.

[220] Office of Energy 2009, Verve Energy Review, August 2009.

[221] The 'Market Rules Design Team' was made up of representatives from the IMO, System Management and Oakley Greenwood (for the Oates Review Committee).

[222] See IMO website, Market Rules Design Review web page.

An industry working group – the Rules Development Implementation Working Group (**RDIWG**) – led by the IMO, was established in August 2010 to develop options to address eleven market design issues/problems as set out in its Terms of Reference, which broadly fall into the following three categories:

- increase participation in Balancing by providers other than Verve Energy;
- improve the operation of the components of the short term energy market, including the operation of the STEM, the Balancing mechanism and dispatch processes; and
- investigate ways of introducing incremental improvement to the Reserve Capacity refunds mechanism.

In April 2011, the IMO provided the RDIWG with a recommendation paper on the Balancing and Load Following Ancillary Services proposal. The paper outlined the key principles and concepts of the proposed Balancing and Load Following Ancillary Services markets, and suggested a number of recommendations to the Market Advisory Committee for the RDIWG to endorse. The paper received majority support from RDIWG members.

RDIWG's meeting papers, and other papers relevant to this working group (including consultant's reports), are available from the IMO's website.[223]

The IMO Market Advisory Committee's (MAC) Maximum Reserve Capacity Price Working Group (MRCPWG)

Each year the IMO is required to conduct a review of the Maximum Reserve Capacity Price (**MRCP**). The Market Procedure for the determination of MRCP details the methodology and process for determining the MRCP. The IMO is required to review this Market Procedure at least once in every five year period (Clause 4.16.9 of the Market Rules).

To assist in undertaking this five year review, the Market Advisory Committee (**MAC**) nominated the MRCPWG be established to consider, assess and develop any necessary change to the Market Procedure.

As at the time of publication of this report to the Minister, the IMO was planning to submit the revised draft Market Procedure developed by the MRCPWG into the Procedure Change Process.

MRCPWG's meeting papers, and other papers relevant to this working group (including consultant's reports) are available from the IMO's website.[224]

The IMO MAC's Renewable Energy Generation Working Group (REGWG)

The REGWG was nominated by the MAC at its meeting on 12 March 2008 and held its final meeting on 2 September 2010. The group's scope was to consider and assess system and market issues arising from the increase in the national Mandatory Renewable Energy Target (**MRET**) to 45,000 GWh by 2020. In particular, the Working Group focuses on issues related to:

- intermittent renewable energy generation;

[223] See IMO website, Rules Development Implementation Working Group web page.

[224] See IMO website, Maximum Reserve Capacity Price Working Group web page.

- Capacity Credits allocated to intermittent generators through the Reserve Capacity Mechanism; and
- the impact on demand for ancillary services and system security at times of low load.

The IMO prepared a summary report on the process and outcomes of the REGWG that was presented to MAC at the 10 November 2010 meeting and this report was finalised after the receipt of this report by MAC members. This report, REGWG meeting papers, and other papers relevant to this working group (including consultant's reports) are available from the IMO's website.[225]

The REGWG was tasked with investigating the range of issues presented by renewable energy generators and to develop and propose solutions to the various issues. A work program which was broadly comprised of four work packages was established to address these issues.

Work Package 1: Scenarios for Modelling Renewable Generation in the SWIS

The IMO appointed a consultant to undertake Work Package 1 and the consultant was required to:

- identify existing policies or regulations that may promote or impede intermittent generators or dispatchable renewable energy generators locating in the SWIS as a precursor to scenario development;
- determine the likely scenarios for the future generation mix in the SWIS as a result of State and Federal Government policies and regulations; and
- identify the key drivers and constraints that determine these scenarios and how changes in those drivers would change the scenario outcomes.

Work Package 2: Reserve Capacity and Reliability Impacts

The IMO appointed a consultant to undertake Work Package 2 and the consultant was required to:

- review whether capacity based on average output is a reasonable approximation to the capacity value of intermittent generation sources; and
- If not, identify and review other available measures that:
    - reflect the impact on system reliability;
    - are robust with acceptable volatility of measure; and
    - are easy to understand and apply without detailed system modelling.

Work Package 3: Frequency Control Services

The IMO appointed a consultant to undertake Work Package 3 and the consultant was required to:

- determine whether the existing spinning reserve, load following, curtailment and demand response criteria in the SWIS are adequate for the forecast levels of intermittent generation, and the projected scenarios for the overall generation mix;

[225] See IMO website, Renewable Energy Generation Working Group web page.

- determine whether intermittent generators can be used to provide the frequency control
- services required including load following for overnight load troughs; and
- determine the cost and the method of allocating of these costs associated with the provision of frequency control services for the forecast penetration levels of intermittent generation.

Work Package 4: Technical Rules

The IMO appointed a consultant to undertake Work Package 4 and the consultant was required to:

- evaluate the appropriateness of the existing Technical Rules and Power System Operating Procedures as applied to intermittent generators; and
- recommend changes resulting from increased penetration of intermittent generators in the South West Interconnected System (SWIS).

Appendix 5 Supplementary information on transmission network issues

Interaction between the WEM arrangements and the unconstrained network access framework

The matters detailed in Table 9 were taken into account in the design of the WEM, with key design drivers including little change from arrangements which existed at the time, a clear objective for a secure and reliable electricity supply, and operational simplicity. Even small amounts of constraints would need to be catered for properly within the market frameworks and incremental change from unconstrained to constrained access therefore requires these 'counter-factual' situations to be properly addressed.

Table 9 Interaction between WEM arrangements and the unconstrained network access framework

WEM attribute	Interaction
Bilateral Contracting	The unconstrained network access framework greatly simplifies contracting as network constraints between generation and off-take points do not need to be considered and there is no risk of 'non-delivery'. *Counter-factual* – if there was a constrained network access framework, because of real-time physical limits, contracting parties would need to manage the risk of non-delivery, for example through locational hedging.
Reserve Capacity Mechanism	The RCM is premised on allocating Capacity Credits to generation which has guaranteed access to load at times of peak demand through its Electricity Transfer Access Contract . The required level of generation capacity (forecast load plus a contingency margin) is set under the assumption that the unconstrained access model provides this access. *Counter-factual* – if there was a constrained network access regime, the analysis of the 'required' amount of Capacity Credits to meet security of supply needs would be more complex. The analysis would need to take account of the risk and impact of network constraints and how much more capacity, at diverse locations, would be required to cover this.
Market and power system operations	Although it is a trade-off with the cost of network assets, because of the absence of dynamic physical constraints, the power system and market are easier to operate with less resources, systems and simpler mechanisms. *Counter-factual* – A more constrained network, where physical constraints must be managed and generator's access 'rationed', requires substantially more complex market mechanisms and operational systems, with associated higher resource requirements.

Origins and application of unconstrained network access in the SWIS

The unconstrained access approach to the network is brought into effect through Western Power's role in making access offers for transmission services and its interpretation and application of the Technical Rules.[226]

While it seems widely accepted that this current approach is a deliberate market design attribute, the basis for this in the Technical Rules is not clear. This ambiguity was noted in the AEMC report and the more detailed Energy Market Consulting Associates (**EMCA**) report that informed it. Broadly, the issue is with the lack of clarity in the specification of which parts of the network need to be designed to withstand a fault. Western Power's apparent interpretation – that all generation needs to be considered secure at times of peak demand after a fault – is not immediately obvious. More detail can be found in the EMCA report.[227]

Furthermore, there are some cases where Western Power has allowed generators to connect to the network on a 'constrained' basis.[228] While these arrangements do not appear to be clearly defined in the framework, the constraints in question are active at night, i.e. not at times of peak demand, and as such there is little risk to security of supply (and interaction with the RCM).[229] Nevertheless, the existence of these exceptions does introduce confusion over what is possible under the Technical Rules and access framework. Other generators may consider that they should also be offered access to the network on the basis of such a scheme. It is not clear how such decisions to offer 'constrained' network access are made and whether they represent equitable treatment of new entrants.

Summary of submissions to the Discussion Paper and informal consultation

There were nine submissions to the Discussion Paper. It is clear from submissions that the framework for access to the network presents difficulties to a comprehensive sample of stakeholders including new generators, retailers and Western Power. Submissions almost universally agree that the current network access framework has a negative impact upon the effectiveness of the WEM. There was general consensus that the current 'unconstrained access' philosophy drives inefficient investment in network assets.

Western Power noted that network control services, which potentially increase the efficient use of network assets, are disadvantaged by the current framework. There was consensus that a 'constrained' framework should be considered, following a clear consideration of the costs, benefits and wider implications. Stakeholders also considered that there was a need for a more strategic network planning approach, which would give

---

[226] The Technical Rules consist of the standards, procedures and planning criteria governing the construction and operation of an electricity network, and deal with all the matters listed in Appendix 6 of the *Electricity Networks Access Code 2004* (**Access Code**).

[227] The areas of uncertainty are described in Section 4.2.1, 'Review of WA Energy Market Framework in Light of Climate Change Policies – Advice on Network Issues Identified in AEMC's First Interim Report', Energy Market Consulting Associates, 22 June 2009.

[228] 'Emu Downs' and 'Walk Away' wind farms are subject to a network protection scheme which will automatically reduce generation output if particular faults occur. EMCA Report, p38.

[229] Western Power has assessed that the relevant network constraints occur at night, when power flows reverse on particular assets due to lower overnight loads. A 'runback' scheme is used which automatically reduces the output of the particular generators in response to network faults which would otherwise lead to breach of a technical capability. As the situation can only occur at night there is no threat to security of supply during peak loads.

more information to the market on network issues, including information on the indicative costs of access in various locations.

The current allocation of network access costs was considered to present a significant barrier to new generation entrants. Western Power noted that the *Electricity Network Access Code 2004* (**Access Code**) itself creates barriers to efficiency and transparency in the allocation of costs. However, Synergy considered that the framework is equitable in that it drives efficient location of new generation capacity and noted that access for new wind generators must not be cross-subsidised by other users. Synergy also discussed ways in which the existing framework could be developed to allow deep connection costs to be shared over time. However, even incumbent generator Verve Energy (which could in some circumstances be considered a potential beneficiary of high barriers to entry) noted some issues with the equity of the current 'deep connection' cost allocation approach.

There was some consensus that Western Power's processes (e.g. for queuing) and its application of those processes do not promote timely access. Some stakeholders also considered that Western Power's decisions were often taken with too much emphasis on minimising its commercial risk.

To understand the rationale behind some written submissions, the Authority and a consultant[230] (engaged to assist in the review of network issues), met with a broad range of stakeholders.

Discussions were structured around an assumed separation of the strategic longer term issues from the process issues apparent in the application of the current framework. The issues from the written submissions were discussed in a further level of detail.

As well as the informative discussions regarding submission details, the most significant additional findings were as follows.

- Participants consider that there is a 'policy gap' and a lack of clear direction for the WEM and many consider that the SEI review process will not provide this in detail. It was also clear that there was broad support for a review of the access framework and a possible move towards constrained access. There was a clear preference among participants that any review of this kind be undertaken somewhat independently,[231] within a wider but detailed policy framework. However, many participants questioned whether an access review would be effective in increasing competition and attracting new entrants, if the other aspects of the market, which are considered competition barriers, were not also addressed.[232] There was also an expressed need for the consideration of renewable energy and carbon policy to guide any access review.
- Participants expressed dissatisfaction with the access processes and Western Power's performance in applying them. There was a commonly held view that there is little transparency and some inconsistency in how policies and technical

[230] PricewaterhouseCoopers were engaged to take part in the consultation and review the network issues in conjunction with the Authority.

[231] While many suggested that the Authority should be central to this, it was noted that this is not the intention of the Authority's role.

[232] For example, there was concern about the signal presented to the market by continuing government ownership, the structure of the new Verve – Synergy contract and recent decisions to re-open Verve Energy coal plant.

requirements are applied.[233] However, the Authority notes that Western Power considers that it is constrained by the current framework, particularly in respect of its lack of clarity and in the government investment review processes. Other respondents concurred with this view and also described a marked improvement in Western Power's recent performance.

Recommendation on the unconstrained network access framework

The Authority recommends 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 approach.

Regarding this recommendation, the Authority considers that it is important that policy-makers consider the wider goals for the WEM, including the following matters.

- The benefits of the implementation of a fully competitive electricity market, with more private Market Participants in retail and generation. Given possible government funding priorities, and a need to attract private investment, do the current arrangements encourage this?
- How does ongoing government ownership and other energy policies impact on new entrants?
- How will electricity price rises be treated going forward? For example, how will they be passed on to consumers?

In the Authority's view, the scope of the review should include:

- Costs, including:
  - o a small increase in the risk (and value) of unserved energy under fault conditions; and
  - o implementation costs, such as for market redesign, training, IT systems, process changes and contract changes.
- Benefits, including:
  - o timely investment in new generation, perhaps off-setting the small impact on reliability noted above;
  - o creation of a more competitive market, resulting in lower costs and lower prices;
  - o the likelihood of more private, rather than government funded investment; and
  - o lower costs due to lower investment needs, passed on to customers through lower prices (or less increases than would otherwise be the case).
- Resourcing and governance of any implementation of change, including:
  - o whether Market Participants and other stakeholders would be in a position to commit an appropriate level of resources to the review and implementing changes (given existing operational commitments and other ongoing review processes); and
  - o the governance requirements for the review and implementation, such as policy direction to set the scope and objectives, an independent entity to lead and full consultation and participation arrangements.
- Implementation risks, including:

---

[233] For example, one participant noted that a technical test on its generator site, while initially passed by one Western Power representative, then had to be repeated as another Western Power engineer interpreted the result differently. This caused a delay.

- o unintended consequences of a poor or 'compromise' design;
- o the risk of delayed investment, further uncertainty, commercial impacts on Market Participants; and
- o creating a perception of 'sovereign risk'.

Appendix 6 Glossary of acronyms

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
ANAO	Australian National Audit Office
AQP	Application and Queuing Policy
CPRS	Carbon Pollution Reduction Scheme
DDAP	Downward Deviation Administrative Price
DSM	Demand Side Management
ERB	Electricity Review Board
ETAC	Electricity Transfer Access Contract
ETS	Emissions Trading Scheme
FIT	Feed in tariff
FRC	Full retail contestability
ICRC	Independent Competition and Regulatory Commission
IMO	Independent Market Operator
IPP	Independent Power Producer
LGCs	Large-scale Generation Certificates
LRET	Large-scale Renewable Energy Target
MAC	Market Advisory Committee
MCAP	Marginal Cost Administrative Price
MEP	Market Evolution Program
MRCP	Maximum Reserve Capacity Price
MRET	Mandatory Renewable Energy Target
MSDC	Market Surveillance Data Catalogue
MW	Megawatt
MWh	Megawatt hour
NEM	National Energy Market
NFIT	New Facilities Investment Test
OCGT	Open cycle gas turbine
ORER	Office of the Renewable Energy Regulator
OVA	Original Vesting Arrangements
PV	Photo voltaic
RCM	Reserve Capacity Mechanism
RDIWG	Rules Development Implementation Working Group
REB	Renewable Energy Buyback
REGWG	Renewable Energy Generation Working Group
RET	Renewable Energy Target

RCP	Reserve Capacity Price
RVC	Replacement Vesting Contract
SHCP	Solar Homes and Communities Plan
SOO	Statement of Opportunities
SRC	Supplementary Reserve Capacity
SRES	Small-scale Renewable Energy Scheme
SRMC	Short run marginal cost
SSRG	Small-scale renewable generation
STEM	Short Term Energy Market
STCs	Small-scale Technology Certificates
SWIS	South West interconnected system
UDAP	Upward Deviation Administrative Price
VC	Vesting Contract
WEM	Wholesale Electricity Market