Annual Wholesale Electricity Market Report to the Minister for Energy

For the period to June 2016

December 2016

Economic Regulation Authority
WESTERN AUSTRALIA

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Overview

The ERA considers that an effective wholesale energy market requires:

- customer choice with sufficient buyers and sellers competing to drive efficiencies and product differentiation, and reduce costs for consumers; and
- a market design which results in least cost dispatch and provides efficient energy resource investment signals.

However, the development of competition has been limited in the Wholesale Electricity Market (**WEM**), with one dominant gentailer[1], which also has a legislated monopoly to supply households and small businesses. Consequently, it has been necessary to use market rules and regulations to protect consumers from misuse of market power.

Weaknesses in the market design have led to inefficiencies and higher costs for consumers. These weaknesses include excess capacity paid for by market customers, inefficient generation investment signals and inefficient energy dispatch.

The State Government's Electricity Market Review (**EMR**) will address many of the weaknesses in the market design. The ERA considers these reforms should lead to a more efficient Wholesale Energy Market and lower costs for consumers. These reforms should be implemented as soon as possible to realise consumer benefits.[2]

The Government has also committed to introducing full retail contestability by July 2019 so that all customers can choose their retailer. This will introduce greater competition in electricity supply by increasing opportunities for new and existing retailers to enter the market or expand their business.

However, the planned reforms do not address the lack of competition in the generation and wholesale contract market that arises from Synergy controlling around three quarters of total generation. This lack of competition also hinders the development of a competitive retail sector, as retailers may need access to fixed price energy contracts to manage the risk of short- term volatility in the spot prices for wholesale electricity.

Consistent with the recommendations made in the EMR options paper, the ERA recommends restructuring or divesting Synergy's generation assets. This is necessary to achieve and sustain the level of competition that would drive efficiencies and lower costs in the wholesale contract market.

Without effective wholesale competition, retailers and consumers will continue to rely on regulation to ensure Synergy does not exercise its market power to their disadvantage.

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1 A gentailer is a market participant that both generates electricity and retails directly to consumers.

2 For example, the Public Utilities Office stated "Quantifiable efficiency benefits and avoided costs associated with the reform package … are estimated to be between $190 million and $375 million in present value terms": Final Report: Design Recommendations for Wholesale Energy and Ancillary Service Market Reforms, Department of Finance, Public Utilities Office, July 2016

While a small electricity market will always need market power controls, effective market-power mitigation measures in the market rules are critical with Synergy having such a dominant position.

The regulatory scheme established following the merger of Verve Energy and Synergy in 2014 is a necessary component of these market power controls. However, improvements to the scheme are required to ensure other retailers can access energy contracts on fair and reasonable terms.

Looking beyond the planned EMR reforms, policy makers need to anticipate emerging issues and refine market design. Energy markets, to be well functioning, require continual oversight to ensure timely debate that leads to policy change and market refinements on an ongoing, rather than sporadic, basis.

Industry Structure

Competition in the contestable sector of the retail electricity market has been vigorous since the WEM started. However, the lack of competition in the generation and wholesale markets continues to hinder further development in the retail market. This is because retailers seek to minimise their spot price volatility risk by entering into fixed price contracts (such as entering into forward contracts) with generators. Lack of effective competition amongst generators compromises retailers' ability to purchase efficiently priced risk management products.

The introduction of full retail contestability will increase the size of the market open to competition. However, retailers will need access to competitively priced wholesale energy contracts to be able to compete in the expanded market.

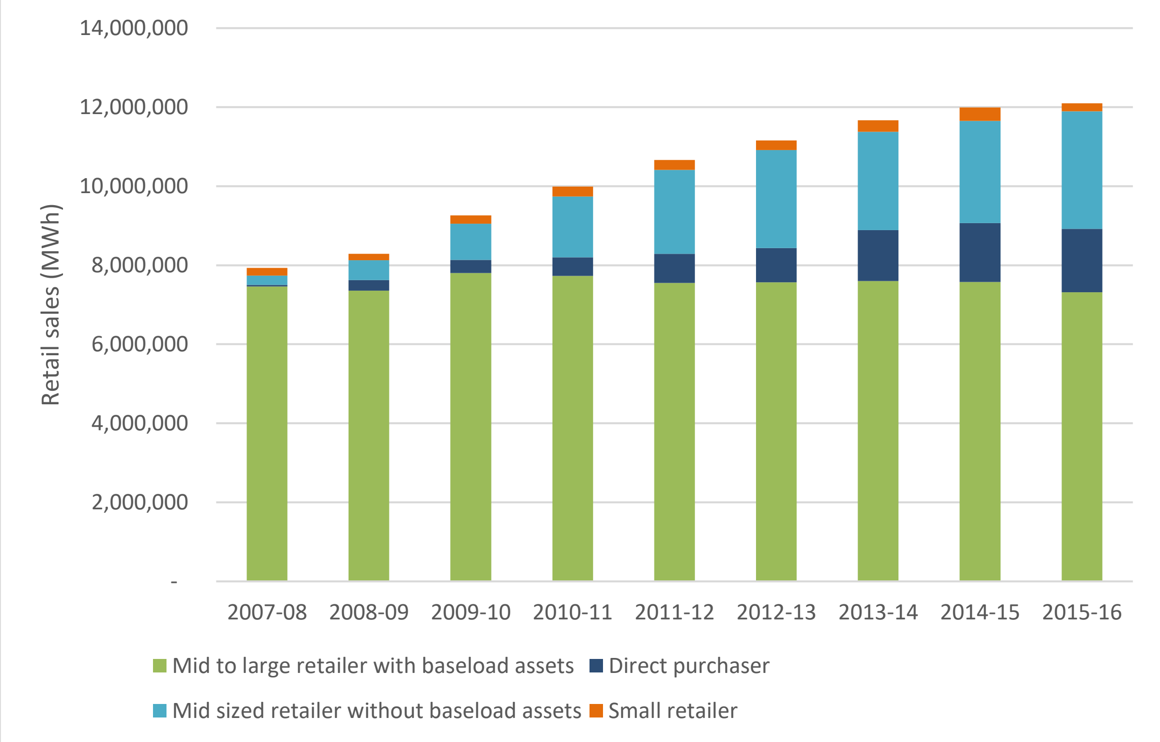
Figure 1 below provides a breakdown of the contestable retail market[3] since the market commenced in 2007. Sales volumes are aggregated[4] under four categories:

- mid to large "gentailers" that own baseload generation, including Synergy, Alinta, Perth Energy and Bluewaters Power;
- mid-sized retailers without baseload generation, including Premier Power, ERM Power and Southern Cross Energy;
- direct purchasers who purchase energy directly from the wholesale market for their own use, including large users such as mining companies and the Water Corporation; and
- small retailers, defined as those with less than three percent market share.

[3] In the retail sector, only Synergy can supply customers consuming less than 50 MWh hours per year. Approximately one-third of total energy supplied is to non-contestable customers.

[4] Individual retailer volumes are confidential.

Figure 1 Contestable Retail Market



Source: Australian Energy Market Operator, ERA Analysis

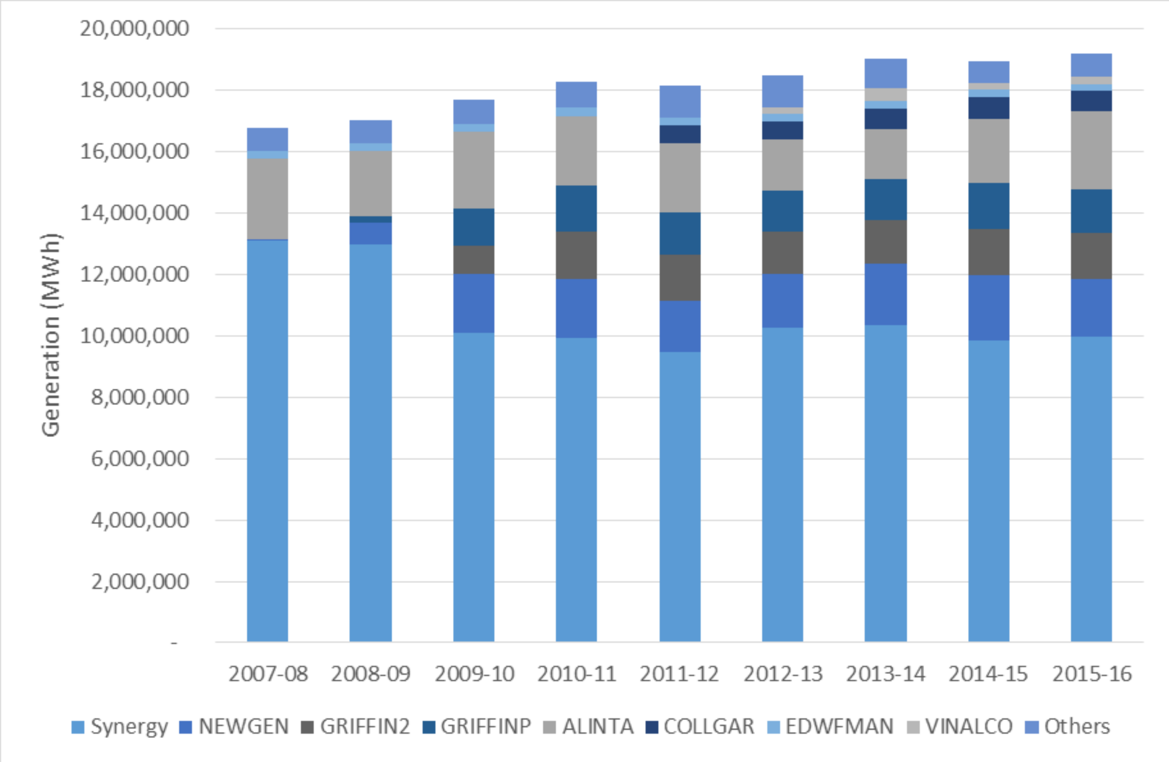
The volumes sold by mid to large retailers with baseload assets have been relatively stable. However, competition within this segment has been vigorous and Synergy has lost market share to mid-sized retailers.

The most significant growth in retail volumes has occurred in the direct purchaser and mid-size retailer categories, resulting from new retailers entering the market.

Figure 2 below shows generation by market participant since the market commenced. Synergy's share of generation reduced significantly in 2009/10, reflecting the entry of

Bluewaters and NewGen Kwinana power stations. However, since then there has been little change in any generators' share of output.

Figure 2 Generation by market participant



Source: Australian Energy Market Operator, ERA Analysis

Synergy is the major buyer of the output of several large power stations including Bluewaters, NewGen Kwinana, Emu Downs Wind Farm (EDWF) and Collgar Wind Farm. This means that Synergy's effective share of generation is higher than its own-source generation suggests.

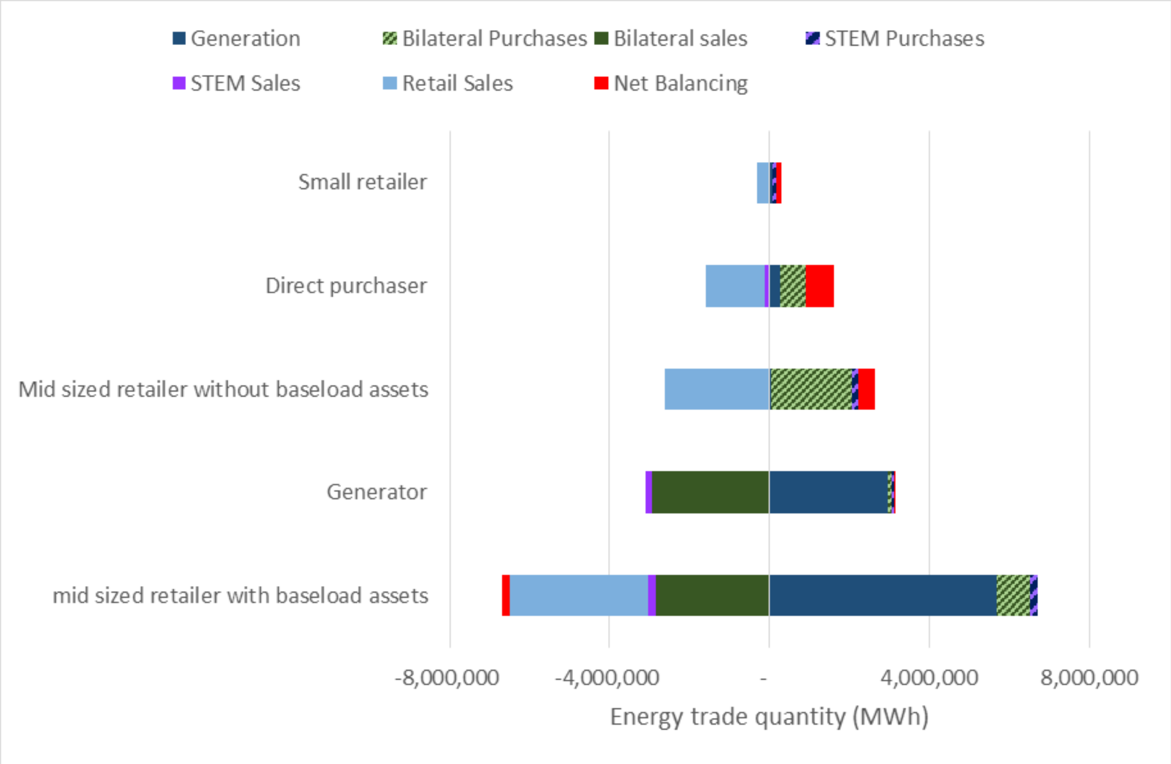
Although there has been robust competition in the contestable retail market, Synergy has maintained a dominant position in generation and the wholesale markets.

Retailers and direct purchasers can source their energy by self-generation (if they own generation assets), bilateral contracts with generators or through the wholesale energy markets. The energy markets include the short-term energy market, where energy is purchased a day ahead of when it is required, and the balancing market, where energy is purchased when it is required.

Figure 3 below summarises how participants have purchased and sold energy. The right hand side of the chart shows the quantities self-generated and purchased through bilateral contracts, the short term energy market or the balancing market. The left hand side of the chart shows the quantities consumed by the participants' retail customers or sold through bilateral contracts, the short term energy market or the balancing market.

To maintain confidentiality of participant data, Synergy has not been included. The ERA's analysis shows Synergy's actual generation combined with its bilateral contracts to purchase energy from other generators is greater than its combined retail and bilateral wholesale energy contracts, so it has been a net seller in the balancing market since it merged on 1 January 2014.

Figure 3 Electricity supply and disposal by market mechanism (2015 calendar year)



Source: Australian Energy Market Operator, ERA Analysis

In competitive wholesale electricity markets, electricity retailers typically manage their price risks by entering into forward energy contracts to lock in future energy prices. Otherwise, they are exposed to short-term price variations in energy markets.

However, as shown in Figure 3:

- small retailers purchased all of their energy from the short term energy market and balancing market;
- direct purchasers sourced around half of their energy requirements from the balancing market; and
- mid-sized retailers without baseload generators purchased around 18 per cent of their energy from the balancing market.

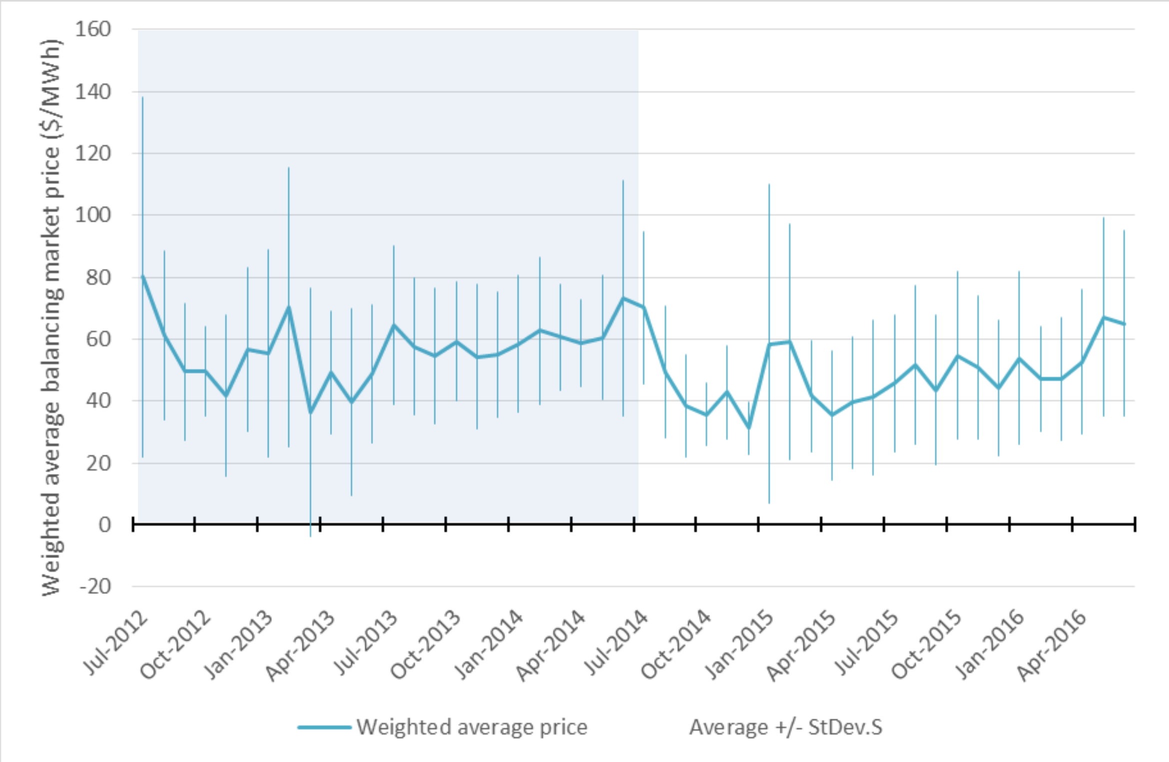
In contrast, retailers who own baseload generation assets have sourced most of their energy through self-generation and/or bilateral contracts.

On the sales side, small retailers, direct purchasers and mid-sized retailers without baseload assets, used all the energy they purchased to supply their retail customers. In contrast, mid-sized retailers with baseload assets sold around half of their energy to other retailers through bilateral energy contracts.

Currently, there is excess baseload generation capacity in the WEM. This has resulted in relatively low and stable prices in the short-term energy market and balancing market.

Figure 4 below shows weighted average balancing market prices since July 2012.[5] The carbon pricing mechanism, introduced on 1 July 2012 and repealed on 17 July 2014, added around $17/MWh to balancing prices during this period.

Figure 4 Wholesale Energy Prices



Source: Australian Energy Market Operator, ERA Analysis

If the carbon price is excluded, the chart shows balancing prices have been relatively stable, generally averaging between $40/MWh to $50/MWh. This has enabled participants, particularly small or mid-sized retailers who do not own generation assets, to source energy in the short term energy market and balancing market without needing energy contracts to protect against short term price variations.

Reforms to the Reserve Capacity Mechanism flowing from the State Government's Electricity Market Review are likely to reduce excess capacity. Additionally, the Minister for Energy has committed to reducing Synergy's generation capacity by 380 MW.

Reductions in capacity could lead to higher and more volatile prices. It is likely that retailers will have a greater need for energy contracts to manage their risk if prices in the short-term energy market and balancing market become more volatile as excess capacity falls.

Synergy controls around three-quarters of total energy supplied, through its own generation or long-term bilateral contracts with independent power producers. Synergy's large share of wholesale energy means it is the main supplier for any independent retailer wishing to expand its business, through either bilateral contracts or uncontracted generation purchased through the short-term energy market.

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5 Changes were made to improve the competitiveness of the balancing market in July 2012 to enable independent power producers to participate.

The ERA considers that the primary problem preventing development of a robust wholesale electricity bilateral and/or hedging derivative market is the large share of generation controlled by Synergy.

The first phase of the EMR identified similar issues. The options paper, published by the EMR Steering Committee in December 2014, noted that the current industry structure and market mechanisms "*were not delivering the outcomes expected in 2006 when reforms were implemented to introduce competition into the market and provide industry participants with additional incentives for investment*".

The major reforms recommended in the options paper were to:

- reduce the market dominance of Synergy to create a more competitive generation sector;
- introduce full retail contestability; and
- reform the wholesale electricity market mechanisms (particularly the reserve capacity mechanism) by adopting the national wholesale electricity market and network regulation arrangements.

The EMR Steering Group Options Paper noted, "*Synergy's market dominance constitutes a barrier to entry for new generation*." The paper considered four or five major market participants in the generation sector would be necessary to achieve and sustain the level of competition that would drive efficiencies and lower costs. In order to achieve this, the steering group considered it would be necessary to restructure or divest a proportion of Synergy's generation assets.

The ERA agrees restructuring or divesting Synergy's generation assets is necessary to increase competition. Consumers will not fully benefit from the EMR reforms unless the lack of competition in wholesale energy supply is resolved.

Additionally, the success of the introduction of full retail contestability is highly dependent on how many new retailers enter the market and the range of products they are able to offer. Effective competition in the wholesale market is required to ensure new retailers can access competitively priced energy hedges to enter the Western Australian market.

Market Power Mitigation

It is likely that some form of market power mitigation measures will be necessary even if there is structural reform to the generation sector. The small size of the SWIS and network configuration can result in even small generators having market power under certain conditions.[6]

[6] For example, they may be the only generator able to provide energy for a particular location and time period.

However, in the absence of effective competition, effective market power mitigation is critical to achieving close to efficient investment and production in the WEM.

As noted in a Brattle Group paper prepared for the EMR[7]:

> With one dominant gentailer in the WEM, the market is not structurally competitive. Market power mitigation is clearly needed to achieve least-cost outcomes similar to a competitive market.

The current market design incorporates a number of mitigation measures to address market power. These include monitoring market offers to ensure participants do not price above short run marginal cost[8] where that behaviour relates to market power, and setting price caps for the energy markets and capacity mechanism.

The ERA supports the retention of these mitigation measures, as is proposed by the EMR.

The EMR has flagged some refinements to the current mitigation measures[9], which it intends to implement in 2017. The Electricity Review Board is currently reviewing an alleged breach of the short run marginal cost bidding provisions by Vinalco Energy. The ERA is a party to this case, so it is not able to comment on it further. However, it considers that the Board's decision will provide useful precedents for market participants and the ERA on interpreting the market-power mitigation measures in the market rules.

Proposed reforms to the Reserve Capacity Mechanism will increase the scope for participants to exercise market power on both the supply and demand sides of the capacity auction, and so the EMR has proposed additional market-power mitigation measures in the capacity market.[10] The ERA supports this proposal.

The ERA also supports the EMR's decision to retain the short-term energy market, on the basis that it provides low cost hedges for participants. Retaining the current requirement for generators to offer all uncontracted capacity and limiting price offers to short run marginal cost ensures generators are not able to exercise market power by withholding energy.

Additional market power mitigation measures were introduced in January 2014 when the Western Australian Government established a regulatory scheme following the merger of Verve Energy and Synergy. The scheme includes measures to address the lack of competition in wholesale energy supplies.

Standard Products are the key mechanism to ensure third parties can access forward energy contracts on fair and reasonable terms. The regulatory scheme specifies the

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7 Newell S.A., Brown T., Graf W., Reitzes J. D., Trewn H., Van Horn K., (2016) Market Power Mitigation Mechanisms for the Wholesale Electricity Market in Western Australia, Brattle Group, Cambridge, pii
https://www.finance.wa.gov.au/cms/uploadedFiles/Public_Utilities_Office/Electricity_Market_Review/Market-Power-Mitigation-Mechanisms-for-the-Wholesale-Electricity-Market-and-Brattle-Group-Report.pdf

8 The Brattle Group paper describes the goal of market power mitigation as being to *recreate the maximally efficient outcome of a competitive market. In the WEM, where a capacity mechanism complements the energy market, the competitive ideal is for energy offers to reflect suppliers' short-run marginal costs (SRMC).*Error! Bookmark not defined.

9 The proposed refinements include defining prohibited pricing behaviour and development of guidelines for short run marginal costs.

10 https://www.finance.wa.gov.au/cms/uploadedFiles/Public_Utilities_Office/Electricity_Market_Review/Position-Paper-on-Reforms-to-the-Reserve-Capacity-Mechanism.pdf, pp34-37

difference between the sell and buy prices to encourage Synergy not to set its “sell price” too high, because if it does it may also have to buy energy at higher prices.

The Synergy Merger Implementation Group considered that Standard Products would act as a price discovery mechanism for the market on which to base customised contract negotiations.[11]

However, market participants have expressed a view that “prices are set too high to offer a reasonable ‘hedge’ for an electricity portfolio” and that the buy-sell spread does not reflect a reasonable forward price curve.[12]

Consequently, there have been relatively few transactions in standard products, with the ERA finding that only 14 transactions had occurring between 1 July 2014 and 31 March 2016.[13] This has probably contributed to certain classes of retailers choosing to remain largely unhedged.

In its most recent review of the effectiveness of the scheme, the ERA found the current buy/sell spread of 20 per cent is too wide. The ERA recommended the spread should be reduced to ensure the standard energy contracts provide a competitive benchmark price for energy contracts, helping retailers to hedge future price risks.

Reducing the spread and adopting the ERA’s other recommended changes to the scheme, notably increasing the transparency of segment reporting, would support the success of the EMR reforms.[14]

The ERA’s recommendations to improve the scheme should be considered as part of the overall package of EMR reforms, given the role the scheme has in mitigating Synergy’s market power.

The proposed introduction of full retail contestability will also reduce Synergy’s market power. Efficient retail tariffs will be achieved as retailers compete to gain or retain customers. However, residential and small business tariffs have not increased in line with

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[11] Economic Regulation Authority, Annual Report to the Minister on the Effectiveness of the Electricity Generation and Retail Corporations Regulatory Scheme, June 2016, p52.

[12] Jurat M., (2015) Submission for the ERA Annual Review of the Effectiveness of the WEM in Meeting Market Objectives, Amanda Energy Solutions, Perth, p2

https://www.erawa.com.au/cproot/14017/2/Amanda%20Energy%20-%20Public%20Submission%202015.pdf

This view on pricing was also articulated in the following submissions:

Alinta Energy (2015) Submission on the 2015 Annual Report to the Minister on the Effectiveness of the Electricity Generation and Retail Corporations Regulatory Scheme – Discussion Paper, Alinta Energy, Perth , p3

https://www.erawa.com.au/cproot/14016/2/Alinta%20Energy%20-%20Public%20Submission%202015.pdf

Rogers S., (2015) Submission on the 2015 Annual Report to the Minister on the Effectiveness of the Electricity Generation and Retail Corporations Regulatory Scheme, ERM Power, Perth, pp3-4

https://www.erawa.com.au/cproot/14019/2/ERM%20Power%20-%20Public%20Submission%202015.pdf

Gould S., (2014) Effectiveness of the EGRC Regulatory Scheme; Submission in response to ERA public consultation, Community Electricity, Perth, pp5-8

https://www.erawa.com.au/cproot/13123/2/20141224%20Public%20Submission%20-%20EGRC%20Regulatory%20Scheme%20-%20Community%20Electricity.pdf

[13] Economic Regulation Authority, Annual Report to the Minister on the Effectiveness of the Electricity Generation and Retail Corporations Regulatory Scheme, June 2016, p54.

[14] Note the Brattle Group report refers to the low transaction volume probably being due to the bid/ask spread or other provisions not being finely tuned.

costs and are currently subsidised by the State Government. The removal of government subsidies and development of efficient tariff structures will require careful planning and a period of transition.

During this transitional period, oversight is likely to be necessary in the form of independent retail price regulation to faciltiate the development of effective retail competition and ensure only efficient costs are passed through to consumers. This regulation can be removed once effective competition develops, with the regulator undertaking a price monitoring role from that point.

This is consistent with the experience in other jurisdictions where, for example, independent retail price regulation existed in New South Wales from 2002 to 2014, in South Australia from 2003 to 2014 and Victoria from 2002 to 2009.

Market Design

Previous reviews of the effectiveness of the wholesale electricity market undertaken by the ERA found the most significant areas requiring attention are:

- conflicts in the market governance arrangements;
- excess generation capacity;
- inefficiencies in the energy markets and ancillary services; and
- unconstrained network access.

The EMR reforms should address many of the issues raised in previous ERA reports. In particular:

- Reforming the reserve capacity mechanism will provide better investment signals for adding or retiring capacity and encouraging availability. This should reduce excess capacity in the market.
- Transferring market operation and system management functions to AEMO has resolved the governance issues resulting from:
  - the market operator also being responsible for rule changes and compliance; and
  - the network owner also being responsible for power system management.
- Establishing the independent rule change panel will provide confidence that objective assessment of proposed rule changes will occur.
- Introducing full retail contestability will introduce competition and increase opportunities for new and existing retailers to enter the market or expand their business.

- Plans to enable generators to access the network on a "constrained"[15] basis will reduce the need for investment to expand the network, compared with the current "unconstrained" network connection approach.[16]

The ERA considers that the planned redesign of the energy markets[17] will:

- remove the current inefficiencies in those markets;
- ensure a level playing field for all market participants and greater transparency in the energy markets, and
- remove many of the current barriers preventing independent power producers from providing ancillary services.

The ERA considers all of the reforms listed above should lead to a more efficient market design and lower costs for consumers. Implementing these reforms as soon as possible is important for the future efficiency of the market.

[15] Under a constrained network access model, generators compete through the wholesale energy market for access to the network to deliver energy to consumers. An unconstrained network access model requires the network to be built and operated to ensure that generators that connect under standard access contracts have full access to the network under normal operating conditions.

[16] The legislation to transfer network regulation to the national regime, and therefore adopt "constrained network access" cannot be progressed until after the State Election.

[17] These include requiring Synergy to offer each of its generators on an individual basis rather than as a portfolio, and integrating the ancillary service markets with the energy markets.

1 Background

1.1 Reporting requirements

The ERA reports to the Minister for Energy, at least annually on the effectiveness of the Wholesale Electricity Market (**WEM**) in meeting the wholesale market objectives. The ERA published its last report in September 2015, and covered market data to June 2014. This report includes market data to 30 June 2016.

The market objectives are:

- promoting the economically efficient, safe and reliable production and supply of electricity and electricity related services;
- encouraging competition among generators and retailers, including facilitating efficient entry of new competitors;
- avoiding discrimination against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or reduce overall greenhouse gas emissions;
- minimising the long-term cost of electricity supplied to customers; and
- encouraging measures to manage the amount of electricity used and when it is used.

The ERA's report must include:

- an assessment of the effectiveness of the market, including the effectiveness of the IMO, AEMO and System Management in carrying out their functions, with discussion of each of:
  - the reserve capacity market;
  - the market for bilateral contracts for capacity and energy;
  - the short term energy market (STEM);
  - the balancing market;
  - the dispatch process;
  - planning processes;
  - the administration of the market, including the rule change process; and
  - ancillary services.
- an assessment of specific events, behaviour or matters that affected the effectiveness of the market; and
- any recommended measures to increase the effectiveness of the market in meeting its objectives.

1.2 Previous reports

In its previous reports, the ERA highlighted issues affecting the ability of the WEM to meet the wholesale market objectives. Particular areas of concern included:

- industry structure, including a lack of competition;
- market governance;
- excess generation capacity;
- the absence of full retail competition;
- inefficiencies in the energy markets and ancillary services; and
- unconstrained network access.

The Electricity Market Review (**EMR**), launched by the Minister in March 2014, is currently developing detailed designs and implementation arrangements for reforms. The reforms selected by Government, together with the current status of each reform, are summarised in the table below.

Table 1 Key EMR Reforms and Status

Workstream	Reform	Status
Network regulation		
	Transferring regulation of the Western Power network to the national framework and regulator. This includes adopting constrained network access.	The legislation cannot be progressed until after the State Election in March 2017.
Market competition		
	Introduce full retail contestability	Government committed to introducing by 1 July 2019.
	Adoption of the national metering framework to facilitate developments in advanced metering and competition in metering services	The legislation cannot be progressed until after the State Election in March 2017.
Institutional arrangements		
	Introducing an independent rule change approval body Transferring system management functions to AEMO	Market operation functions transferred from the IMO to AEMO on 30 November 2015. System management functions transferred from Western Power to AEMO on 1 July 2016. Compliance monitoring and enforcement functions transferred from the IMO to the ERA on 1 July 2016. Regulations and market rules for establishing an independent rule change panel came into effect on 23 November 2016.
Wholesale Electricity Market Improvements		
	Reforming the reserve capacity mechanism	The EMR published a final report about reforms to the

		reserve capacity mechanism in April 2016.
	Reforming the energy market operations and processes	The EMR published a final report on the design of the energy and ancillary service markets in July 2016. The PUO is leading development of the detailed plans for the new market design and AEMO has started to build the new market systems.

The ERA has considered the developments outlined above when undertaking its review.

1.3 Process

On 20 November 2015, the ERA released an issues paper seeking public submissions on matters influencing the effectiveness of the WEM. In addition, the ERA held a stakeholder forum on 19 January 2016. Copies of public submissions received and slides from the stakeholder forum are available on the ERA website.

After consultation with the Minister for Energy, the ERA must publish its report.

1.4 Report structure

Section 2 provides a summary of the ERA's review, including matters of particular significance.

More detailed analysis and data specifically required by the market rules is included in Chapter 3 of this report.

2 Key findings

In undertaking its review of how effectively the WEM is meeting its objectives, the ERA has considered each of the WEM's five objectives:

- promoting the economically efficient, safe and reliable production and supply of electricity and electricity related services;
- encouraging competition among generators and retailers, including facilitating efficient entry of new competitors;
- avoiding discrimination 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;
- minimising the long-term cost of electricity supplied to customers; and
- encouraging the taking of measures to manage the amount of electricity used and when it is used.

The objectives do not include an overarching requirement or ranking of priorities. When making its assessment, the ERA has assumed:

- promoting the economically efficient, safe and reliable production and supply of electricity and electricity related services is consistent with minimising the long-term cost of electricity supplied to customers;
- encouraging competition and facilitating efficient entry of new competitors will promote economically efficient production and minimise the long-term cost to customers; and
- avoiding discrimination against particular options and technologies and encouraging the adoption of measures to manage electricity usage in the context of achieving all of the above objectives.

The ERA has reviewed market data to 30 June 2016 and considered actual and planned changes to the market up to November 2016.

A summary of the ERA's assessment and findings is set out below under the following headings:

- barriers to competition;
- market governance;
- reserve capacity mechanism;
- energy markets; and
- ancillary services.

2.1 Barriers to competition

Encouraging competition among generators and retailers, including facilitating efficient entry of new competitors, is a specific market objective. Competition is important because it drives efficiencies and reduces costs for consumers. Effective competition plays a key role in achieving the other market objectives.

The WEM includes a number of markets:

- bilateral contracts – participants can contract directly with each other to buy and sell energy;
- short term energy market – energy can be bought or sold a day ahead of when it is required,
- balancing market- all energy is dispatched through this market and participants buy or sell energy[18] "on the day";
- ancillary services – participants compete to provide services in the load following ancillary services market and System Management may seek offers for other ancillary services, such as spinning reserve, on a contractual basis; and
- retail markets - customers consuming more than 50 MWh per year can choose their retailer. Synergy is the only retailer that can supply customers using less than 50 MWh per year.

Competition in each market is necessary for overall competition to be effective. For example, a competitive retail market requires retailers to be able to access competitive wholesale energy supplies, so they can compete with other retailers. In turn, a competitive wholesale supply market will only develop if there are retailers competing to purchase energy from wholesale suppliers.

The contestable retail market has become increasingly competitive since the introduction of the WEM in 2006. Many new retailers have successfully entered the market, particularly since the introduction of the new balancing market in 2012. In addition, a number of large users now purchase electricity directly from the WEM. Competition between the larger retailers for market share in the contestable market has increased with customer churn[19] increasing, particularly over the last few years.

However, there are significant barriers to the development of competition in other parts of the market, which are also relevant to competition in the contestable retail market.

Stakeholder submissions expressed concerns about the lack of competition in the market.

Perth Energy's submission states it sees the "current high level of market concentration in the WEM, caused by the Verve-Synergy merger, as the show stopper towards the SWIS achieving a truly efficient and competitive market that will benefit consumers." The submission goes on to say:

[18] Bilateral contracts and short-term energy market transactions are taken into account first so participants only pay, or are paid for, quantities of energy that have not been bought or sold bilaterally or through the short term energy market.

[19] Rate of customers changing retailer.

> The Verve-Synergy merger has fundamentally undermined the competitive structure of the market in several ways:
>
> - it lifted the moratorium placed on Verve as the dominant generator not to be able to retail directly, and on Synergy as the dominant retailer not to be able to generate power directly, this moratorium being a critical measure to mitigate the utilities' market power
>
>   …..
>
> - it prevents the Balancing Market from being able to be made more efficient as a whole by having stringent SRMC rule being applied to all generators and especially (and correctly) Synergy.
>
> ….

Tesla's submission expresses disappointment that the EMR has not addressed

> the fundamental problems of high industry concentration (which increased appreciably following the merger of Synergy and Verve Energy)…

Tesla notes the Minister

> specifically ruled out the separation of Synergy into 2 to 3 competing gentailers, despite this being a key recommendation of the EMR.

Tesla considers:

> The way forward for an efficient market is less regulation, less prescription and less government ownership in the electricity market. The problems in the WEM will not be solved by changing administrative capacity pricing mechanisms or introducing capacity auctions, but by opening up the market to increased competition.
>
> The optimal solutions involves the following:
>
> - The Government permitting Synergy to retire baseload plant as this will help increase capacity and energy prices and increase cost recovery for both Synergy and other market participants.
> - Introducing Full Retail Contestability to provide further incentives for the right mix of plant in the WEM.
> - Government divesting both retail and generation assets in the medium term (3 to 5 years) to create a "truly" competitive market, and eliminating perceived conflicts of interest that currently exist, with the State Government currently formulating energy policy and owning competitive energy utilities.

The ERA considers the most significant barriers to competition are:

- Households and small businesses, which make up around one third of the total retail market, can only purchase their energy from Synergy;
- Synergy controls around three quarters of wholesale energy supplies;
- different rules apply to Synergy in the energy markets; and
- gaining physical access to the network is difficult for new entrants.

Each of these is considered below.

Non- contestable retail market

Customers using less than 50 MWh can only purchase their energy from Synergy. The Minister announced on 24 August 2016 that the State Government was committed to introducing full retail contestability from 1 July 2019. Opening the entire retail market to third parties will allow greater opportunity for retailers to compete with Synergy and each other.

Perth Energy's submission suggested the ERA should provide information, including customer details, to assist potential new entrants. The ERA does not consider this falls within its remit. However, making customers aware and educating them regarding their options will be necessary to maximise the benefits from full retail contestability. Policy makers will need to address this in the implementation plans for full retail contestability.

Residential and small business tariffs are currently below the actual cost of supply, so do not provide effective price signals. The introduction of full retail contestability and removal of government subsidies should result in more cost reflective retail tariffs for residential and small business customers.

The implementation plans for full retail contestability will need to ensure retail tariffs only reflect efficient costs. Ultimately this will be achieved through competition in the retail market as retailers compete to gain or retain customers. However, this will take time.

When making similar reforms, other jurisdictions adopted independent regulation of retail tariffs until there was effective competition in the retail market. For example, independent retial price regulation existed in New South Wales from 2002 to 2014, in South Australia from 2003 to 2014 and Victoria from 2002 to 2009.

Synergy control of wholesale energy supplies

A sustainably competitive market requires buyers and sellers to be able to quickly and easily trade energy contracts at cost reflective prices. Participants also need confidence there is a level playing field for all retailers (i.e. no cross subsidies, especially with non-contestable subsidised tariffs). Currently these conditions do not exist.

The oversupply of generation has been keeping prices in the STEM and balancing markets low and stable. Low and stable prices reduce the need for retailers and large users to minimise their risk exposure to short-term price volatility by entering into bilateral contracts. Consequently, the lack of liquidity in energy contracts has not been as significant a barrier to the development of contestable retail competition as it may have otherwise been, as there has been less need for such contracts.

As excess capacity reduces, particularly from the planned reforms to the reserve capacity mechanism, retailers and large users will have a greater need for energy contracts to hedge themselves against short term price variations in STEM and balancing market prices. Synergy controls around three quarters of electricity supplied, through its own generation or via bilateral contracts with other generators. This is a barrier to development of competition in the wholesale energy market.

The ERA considers, similar to the recommendations in the EMR options paper, that structural reform would be the best way to deal with the lack of competition in wholesale energy supplies. In the interim, market power mitigation measures are necessary to ensure only efficient costs are passed through to consumers.

The current market design incorporates a number of mitigation measures to address market power. These include monitoring market offers to ensure participants do not price above short run marginal cost where that behaviour relates to market power, and setting price caps for the energy markets and capacity mechanism. Further measures were introduced in January 2014 when the Western Australian Government established a regulatory scheme to mitigate Synergy's market power following the merger of Verve Energy and Synergy.

The ERA is responsible for assessing the effectiveness of the regulatory scheme. In its most recent review, the ERA focussed on whether market participants have access to forward energy contracts on fair and reasonable terms. Typically, electricity retailers manage their price risks by entering into forward energy contracts to lock in future energy prices. Otherwise, they are exposed to short-term price variations in energy markets.

The regulatory scheme requires Synergy to offer standard energy contracts (Standard Products) to buy and sell energy in the future, with the spread between the price to buy and sell energy specified in the scheme.

Perth Energy does not consider Synergy's Standard Products are effective:

> The Standard Product scheme was created so that all retailers could access energy at the same prices being offered to Synergy's Retail Business Unit (RBU) and so that the market has a price discovery channel which can be used as the basis of trades with Synergy and other parties. However, the buy/sell spread mandated in the scheme is wide because it reflects the excess capacity that Synergy holds- the utility is very long on energy and does not place value on buying back from the market.
>
> Under a properly functioning and competitive market where the energy and capacity markets move into balance, and Synergy's market power being mitigated, the Standard Product prices should be much closer to actual traded prices thus becoming a genuine risk management mechanism. Currently, the relative gap between Standard Prices and BM prices also reflect Synergy's market power so the premium required of fixed (i.e. hedged) energy prices is far higher than otherwise should be in a fully competitive market. In our view, the Standard Product scheme does not work in its current form due to the structural and policy defects blanketing the market.

The regulatory scheme specifies the difference between the sell and buy prices to encourage Synergy not to set its "sell price" too high, because if it does it may also have to buy energy at higher prices. The ERA considers the current spread of 20 per cent is too wide to ensure that Synergy's standard contract prices reflect a competitive benchmark price.

The ERA has recommended reducing the spread as this will increase the incentives for Synergy not to overprice its sell price. This will also benefit wholesale energy contracts more generally as the standard products provide a benchmark for negotiation of customised contracts.

Synergy is also required to segregate its generation, wholesale and retail businesses and produce financial reports for each segment. The ERA has recommended the regulations should be amended to require more detailed specification of the segment reporting requirements so they are prepared on a consistent basis and provide sufficient information on the allocation of costs between business units, including demonstrating there are no cross subsidies.[20]

The following amendments should be included:

- the segment reports should include only electricity activities at a company level (i.e. they should exclude the gas retail business and any subsidiaries or joint ventures);
- contestable and non-contestable retail segments should be reported separately;
- the general principles of cost allocation should be specified (e.g. costs directly attributable to a business unit should be allocated accordingly and costs not directly attributable should be allocated using a method that is publicly available to be scrutinised); and
- the transfer pricing arrangements between the generation business unit, wholesale business unit and retail business unit should be transparent.

Different rules for Synergy

The current market design applies a number of different rules for Synergy. These include:

- it can offer its generators as a portfolio rather than submitting offers for each generator as all other participants are required to do;
- it is the default provider of most ancillary services; and
- its generators are dispatched by System Management to manage system security.

These different rules result in both advantages and disadvantages for Synergy and the market. However, the different rules for Synergy and the nature of the relationship between Synergy and the system manager can create perceptions of conflict of interest and inequitable treatment. Responsibility for system management has now transferred from Western Power to AEMO. Removing the different rules (which the EMR reforms aim to do) will ensure Synergy is treated consistently with other market participants.

The ERA agrees with the EMR's view that removing this special treatment of Synergy should result in the market design appearing more conventional to investors who operate in other electricity markets, and reduce concerns that Synergy has an advantage. However, without structural changes, mitigation measures will still be necessary to deal with its potential to exert market power.

Access to the network

Network planning for congestion management is a key issue for all electricity networks.

The WEM design assumes all generators have unconstrained access to the network, which enables a simpler design for operation of the power system and market. However, it does

[20] In developing these requirements, the ERA acknowledges there will need to be an appropriate balance between transparency and the cost of preparing the information. The ERA also recognises information sensitive to Synergy's commercial operations will need to be adequately protected. This could be managed by including specification of a confidential and public version of the information.

not necessarily promote efficient investment in the network and can be a barrier to new entrants due to the investment required to maintain unconstrained access for all generators.

In contrast, the National Electricity Market (**NEM**) has a constrained network access regime. The constraint equations that form the NEM's security-constrained economic dispatch model capture transmission constraints. For any given potential transmission constraint, each generator's ability to alleviate (or worsen) congestion is represented mathematically, enabling appropriate dispatch to maintain system security and meet load within the pricing framework. Generators make their own judgement regarding the likelihood of dispatch when deciding whether to build and connect a new generation unit.

In the past, Western Power typically only offered new connections on an unconstrained basis. This has been a barrier to new entrants due to the significant investment required in the shared network to provide unconstrained network access.

More recently, Western Power has offered new connections on a constrained basis, which has enabled new generators to connect without requiring significant investment in the shared network. However, Western Power considers it will be operationally difficult to add more constrained connections to the network without implementing a centralised dispatch tool to manage the constrained connections.[21]

Tesla's submission expressed concerns that uncertainties around the future network access model had led to Western Power modifying its connection processes. Tesla considered Western Power's revised approach was not consistent with the current network regulatory framework. Tesla also considers the policy uncertainties for introducing a constrained network access model were leading to delays in network connections for current applicants.

The EMR reforms are centred on adopting the national framework and national regulator for network regulation. Adopting the national framework for network regulation would result in all generators (new and existing) having constrained connections.

The ERA considers, regardless of whether the transfer to the national network framework occurs, Western Power should continue to offer constrained connections to customers. Adopting a security constrained dispatch model, as is proposed in the EMR reforms for the energy market, will enable Western Power to continue to offer new connections on a constrained basis, which will remove many of the current barriers to new entrants.

In any case, under the current arrangements, System Management often needs to make manual interventions to the dispatch order to deal with network constraints. Adopting a security constrained dispatch engine will result in network constraints being included when determining which generators to dispatch, thus removing the need for manual intervention and ensuring economic dispatch.

The current network regulatory framework enables Western Power to offer constrained connections. An amendment to Western Power's Technical Rules to facilitate constrained network connections was approved by the ERA in November 2016. Western Power should also review its applications and queuing policy to provide clarity to market participants regarding constrained connections. It may also be necessary to amend the market rules to manage dispatch of a mixture of constrained and unconstrained generator connections.

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[21] In a submission to the ERA's determination of AEMO's allowable revenue for 2016/17-2018/19, Western Power stated it manages constrained generator connections using high-speed post contingent runbacks that operate to constrain certain generators before others in reverse order of the connection date ("first come first served" basis). It notes there is limited opportunity to connect new generation on high-speed runback systems due to complexity and risk to system security.

It is also important to encourage efficient investment in the network. Investment signals in the WEM are more complex than the NEM due to the reserve capacity mechanism, which also provides investment signals for new generators. The EMR is currently reviewing the effect of a constrained network access framework on the reserve capacity mechanism.

2.2 Market Governance

An effective governance framework is necessary to ensure the WEM achieves its objectives and is not compromised by conflicts or vested interests. Effective and cost efficient oversight arrangements will also ensure long-term costs to customers are minimised.

In previous reports, the ERA has expressed concerns about governance arrangements in the WEM. These include conflicts arising from the market operator also having responsibility for rule making, conflicts due to the network operator undertaking system management, and conflicts for policy making due to government ownership of the major market participants.

The small size of the market made it difficult to cost effectively adopt structural features adopted by larger markets such as separating the rule making function from market operation and having a stand-alone system manager. Transferring functions to the much larger national market operator, AEMO, has provided an opportunity to improve governance for market operation and system management. In particular, it has dealt with the previous conflicts from the market operator also being responsible for rule changes and compliance and the network operator undertaking system management.

Setting up an independent rule change panel, will provide further assurance of objective evaluation of rule changes.

Oversight and periodic reviews form part of governance arrangements. They need to be adequate, cost effective and timely. The ERA considers further improvements could be made to policy development and periodic review processes, and the role of the Electricity Review Board in enforcement of compliance. Each of these is considered below.

Policy development and periodic review processes

Electricity markets are complex and require continual refinement for the long-term interests of consumers. Prior to the commencement of the EMR, the ERA had concerns about the lack of progress in policy development for energy. This has now been addressed with the progress of the EMR.

However, once the EMR process is finalised it will be important to continue to develop policy on an incremental basis to address issues in a timely manner, rather than having to go through another major and lengthy review. Policy development needs to anticipate emerging issues as well as refine market design as necessary.

In conjunction with this, the periodic review processes included in the market rules should be reviewed to ensure they provide timely identification and resolution of issues. Greater use could be made of annual reviews to identify issues and establish the requirements for more in depth reviews when needed, rather than prescribing periodic reviews of specific areas in the rules.

Given the breadth of reform required and the policy changes needed, clearly it has been necessary for government to take the lead on the EMR. However, the ERA notes the concerns raised in stakeholder submissions that oversight of market reform, in particular the EMR Steering Committee, is too heavily weighted towards government and government owned market participants.

Government ownership of major market participants continues to cause concern that energy policy reflects conflicting objectives. Agencies responsible for energy policy should be separate from agencies responsible for overseeing government owned electricity corporations.

Electricity Review Board

The ability to enforce compliance in a timely and cost effective manner is an important component of a well-functioning market.

The current arrangements require the referral of the majority of non-compliance to the Electricity Review Board for enforcement.[22] Once the ERA has determined a participant has been non-compliant, the Electricity Review Board is then required to make its own assessment.

The ERA agrees participants should be able to seek a review of decisions when necessary to ensure fairness and due process. However, requiring two bodies (i.e. the ERA and the ERB) to undertake separate reviews of nearly all non-compliance is not cost effective or timely.

[22] A small number of items (Category A) do not need to be referred to the Electricity Review Board, however market participants can appeal any penalties levied against them.

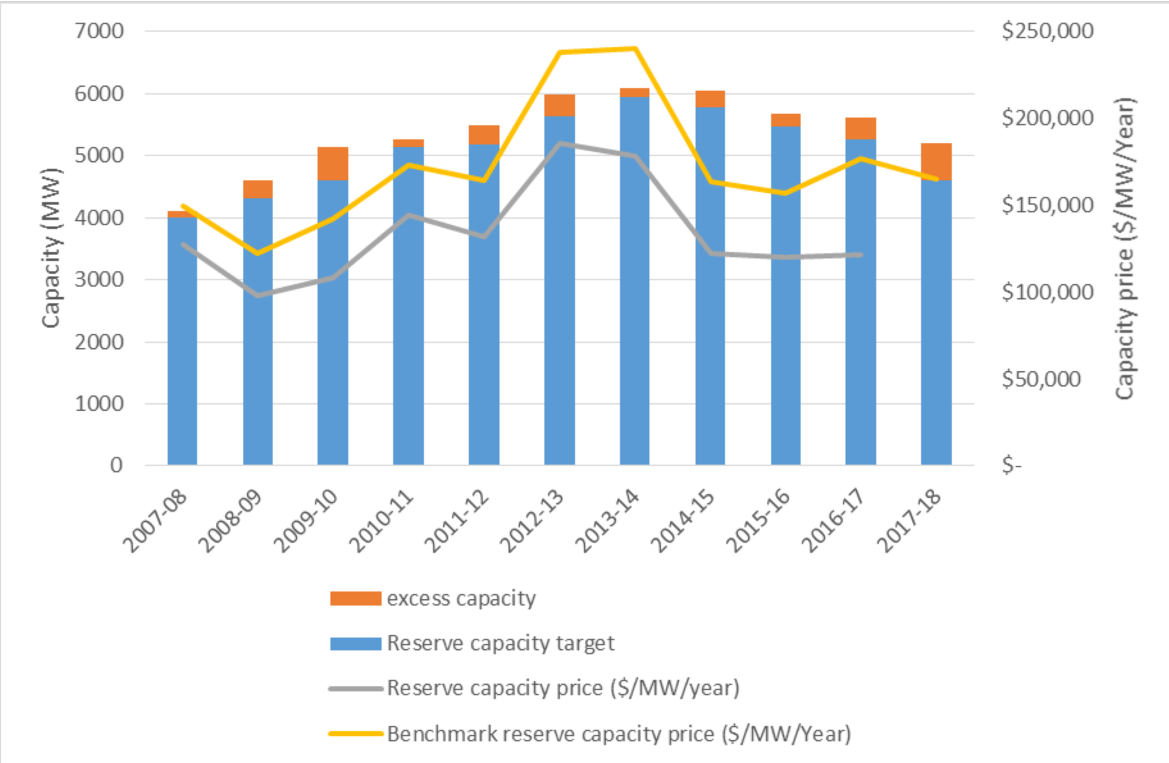
2.3 Reserve Capacity Mechanism

The initial market design was based on a view that, as the WEM is an isolated system, it could not rely on any interconnections with other systems and therefore needed to have sufficient capacity within itself to satisfy demand and deal with emergencies in supply. Consequently, a reserve capacity mechanism (**RCM**) was included to provide incentives for continued investment in existing and new capacity to meet system security and adequacy requirements.

AEMO (previously the IMO) determines how much capacity is required[23] and is responsible for procuring sufficient capacity. The price paid for capacity, the reserve capacity price, is based on a pricing formula set out in the market rules. Capacity costs are recovered from market customers (predominantly retailers).

The reserve capacity mechanism has secured more than sufficient capacity since the market commenced, as illustrated in the chart below.

Figure 5 Reserve capacity target, excess capacity credits, Benchmark reserve capacity price and reserve capacity price by capacity year



Stakeholder submissions to the ERA's public consultation also referred to the EMR's position paper proposing changes to the reserve capacity mechanism, published in December 2015.

Matters raised in submissions included the following:

[23] Based on a one-in-ten year peak demand event plus a margin for system support and reserve.

- A view that the current excess capacity has arisen due to factors other than the reserve capacity mechanism, whereas the EMR reforms primarily addressed the formula for the reserve capacity price.
- Concerns the planned reforms to the reserve capacity mechanism don't recognise the link between the balancing market and reserve capacity mechanism, particularly in relation to the price caps.
- Concerns no consideration had been given to the implications for the reserve capacity mechanism of adopting constrained network access.
- A view that the current reserve capacity price already provided incentives for Synergy to retire plant and so there is no need for the introduction of steep demand curves or auctions.
- Concerns that the proposed reforms will discourage merchant plant from entering the market in the future due to the potential price volatility that could result from auctions with steep demand curves for capacity, combined with the large number of market power mitigation measures needed due to the current industry structure not being conducive to competitive outcomes.

These stakeholder comments are considered further below.

As highlighted in its previous reports, the ERA considers the current surplus of capacity is not consistent with the market objective of minimising the long-term cost of electricity supplied to customers.

A number of factors have led to the current oversupply of capacity and consequent higher costs for consumers. The ERA considers these include:

- Basing the price paid for capacity on the maximum reserve capacity price was a flawed approach. The maximum reserve capacity price was intended to be a price cap applied to mitigate market power in the event that a capacity auction was held. It should not have been used for sending investment signals to investors for building new capacity, or pricing capacity payments for existing generators, as is currently the case. A market-based discovery tool such as an auction is a superior way to value and procure reserve capacity.
- The current capacity mechanism does not provide strong incentives for old and expensive plant to retire at an appropriate time. This has led to an inefficient mix of generation in the market, affecting the ability of more efficient and newer plants to enter the market.

The ERA agrees with stakeholder views that other factors have contributed to excess capacity including:

- Although demand forecasts are inevitably imperfect, the current arrangement, under which AEMO is responsible for ensuring sufficient capacity is available and also preparing the demand forecast, could unintentionally encourage it to over-forecast the energy and capacity needed. This is because AEMO bears considerable institutional risk if it under-forecasts demand, but does not bear any monetary risk if it over-forecast demand as the cost is met by market customers.
- Commonwealth and state government policies have led to increased investment in residential solar installations (which have reduced demand) and

large-scale renewable energy projects (which have increased generation capacity).

- Uncommercial decisions made by Synergy to retain underutilised ageing plant.

Prior to the commencement of the EMR, a number of rule changes were developed to address issues in relation to the reserve capacity mechanism. These included:

- Incentives to Improve Availability of Scheduled Generators (RC_2013_09)
- Harmonisation of Supply-Side and Demand-Side Capacity Resources (RC_2013_10)
- Changes to the Reserve Capacity Price and the Dynamic Reserve Capacity Refund Regime (RC_2013_20)

These rule changes were not implemented as planned, due to the EMR, but have been incorporated (with modifications) in the EMR reforms.

The EMR released its final report on reforms to the reserve capacity mechanism in April 2016. Key items included were:

- Adoption of a three-year ahead auction as the basis for procurement and pricing of capacity, with the first auction process to occur at the earlier of a pre-set level of excess capacity (five to six per cent) or a fixed date of 2021.[24]
- Changes to the capacity price formula for a transition period prior to the auction, that involves maintaining the existing administered price mechanism but with a steeper pricing curve and a different pricing arrangement for demand side management capacity.
- Implementation of measures to harmonise demand side management availability requirements with requirements for conventional generators.
- Stronger commercial incentives for all forms of capacity to be made available for dispatch.
- Rules relating to the capacity auction are to be developed following a more detailed evaluation of the auction design.
- When announcing the publication of the final report, the Minister also announced he had directed Synergy to retire 380 MW of plant.[25]

Initial changes to the reserve capacity mechanism reforms commenced on 1 June 2016. These included, amending the formula that determines the price paid for capacity from 1 October 2017, and removing demand side resources from the reserve capacity mechanism.

Demand side resources will be included in the reserve capacity mechanism when the auction regime commences. In the interim, demand side resources will be priced separately to reflect the value provided to system reliability, based on an estimate of the expected hours of dispatch and costs incurred.

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[24] For the delivery of capacity in the 2023/24 capacity year.

[25] http://www.parliament.wa.gov.au/Hansard/hansard.nsf/0/ef292507bcd0ef3848257fc7002449cf/$FILE/A39+S1+20160524+p199b-209a.pdf

The ERA considers the EMR's proposed reforms to the reserve capacity mechanism will provide better investment signals for adding or retiring capacity and encouraging availability. The following should also be considered:

- Introducing measures to mitigate the risk of AEMO being encouraged to over-forecast demand, such as providing market participants with a formal opportunity to review and challenge the assumptions.
- As noted in stakeholder submissions, adopting a constrained network access model may have implications for the reserve capacity mechanism. The EMR is currently assessing this. Any adjustments to incorporate a constrained network access model need to align with network investment incentive mechanisms.

The quantity of capacity certified for the 2017/18 year compared with 2016/17 has reduced by 425 MW, mainly due to reductions in demand side management quantities offered. Total certified capacity for 2017/18 is 5,194 MW compared with a capacity requirement of 4,552 MW (i.e. surplus capacity of 642 MW or 14 per cent).

The Western Australian Government announcement that Synergy will reduce its generation capacity by 380 MW by 1 October 2018, will affect the supply-demand balance for the 2018/19 year. Capacity credits for 2018/19 will be assigned by 5 September 2017.

The maximum reserve capacity price (now renamed the benchmark reserve capacity price) is used to calculate the reserve capacity price. Benchmark reserve capacity prices for 2017/18 and 2018/19 have already been approved, as required under the market rules. The 2019/20 benchmark reserve capacity price is currently being prepared by AEMO for submission to the ERA for approval.

The ERA became responsible for the benchmark reserve capacity price market procedure on 1 July 2016.[26] The ERA intends to initiate a review of the procedure in 2017.

As noted in stakeholder submissions, there is a link between the balancing market price caps and the reserve capacity mechanism. The ERA intends to undertake a review of the methodology for price caps in conjunction with its review of the benchmark reserve capacity price market procedure.

A successful market outcome from any reduction in the current surplus capacity will be dependent on the nature of the plant retired. This will need to be kept under review, with adjustments made to the reserve capacity mechanism if necessary, to encourage a mix of generation plant that delivers the lowest overall cost to the market whilst ensuring system reliability and security.

Stakeholder submissions noted that, despite the current reserve capacity price already providing incentives for Synergy to retire plant, it had chosen not to. Stakeholders were also concerned with the large number of market power mitigation measures needed due to the current industry structure not being conducive to competitive outcomes. Combined with the potential price volatility that could result from auctions with steep demand curves for capacity, stakeholders were concerned this will discourage merchant plant from entering the market in the future.

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[26] This was previously the responsibility of the IMO.

The ERA agrees that Synergy appears to have made non-commercial decisions to retain underutilised aging plant. As discussed elsewhere in this report, Synergy controls around three quarters of the total wholesale energy supplied. Potentially this lack of competition in generation has contributed to these decisions.

The EMR reforms to the Reserve Capacity Mechanism will increase the potential for participants to exercise market power on both the supply and demand sides of the capacity auction. The EMR has proposed additional market-power mitigation measures in the capacity market.[27]

The ERA considers restructuring or divesting Synergy's generation assets is necessary to increase competition to achieve efficient investment and production in the WEM. . However, in the absence of effective competition, market power mitigation measures, including for capacity auctions, are needed to protect consumers.

27 https://www.finance.wa.gov.au/cms/uploadedFiles/Public_Utilities_Office/Electricity_Market_Review/Position-Paper-on-Reforms-to-the-Reserve-Capacity-Mechanism.pdf, pp34-37

2.4 Energy markets

As set out in previous ERA reports, changes are necessary to improve the efficiency of the energy markets. Introduction of the competitive balancing market in 2012 was a significant improvement but further enhancement and developments are required to improve efficiency.

The EMR's final report on design recommendations for the energy and ancillary service market reforms incorporates improvements identified in previous ERA reports. Utilising AEMO expertise and existing systems provides a solid platform to improve the efficiency of the energy and ancillary service markets even further.

Key elements of the reforms include:

- adopting a security constrained dispatch design with explicit recognition of network constraints;
- requiring Synergy to offer each of its generators on an individual basis rather than the current portfolio basis;
- introducing ancillary service markets integrated with the energy market; and
- allocating ancillary service costs on a user or causer pays basis.

Implementing these reforms (currently planned for July 2018) is essential to remove inefficiencies in the market and allocate costs to those who cause them.

These reforms will lead to more efficient wholesale energy price signals and improve the effectiveness of the energy and ancillary service markets in meeting the WEM objectives of promoting economically efficient production and supply of electricity and minimising the long-term cost to consumers.

Since the ERA's last report, deficiencies in the planned outage scheduling and approval processes have continued to be of concern. In addition, there appears to have been a recent uplift in prices. Both of these matters are discussed further below.

Planned Outage Scheduling and Approval Processes

Previous reports to the Minister noted perverse market incentives may have led to generators being unavailable for extended periods. This was of particular concern when planned outages coincided with times of tight supply, leading to price spikes. This would arise if the facilities on planned outage included baseload generators and mid-merit gas units, which would typically have resulted in lower clearing prices if they had been available to be dispatched.

During the period under review, planned outages appear to have continued to lead to higher prices during some periods.

For example, during October and November 2015 a substantial quantity of baseload and mid-merit generation capacity was offline for planned maintenance. This coincided with a large number of price spikes and higher than usual balancing market clearing prices. Large baseload generators on outage, including Collie and Bluewaters, also affected prices in April 2016.

The ERA has previously identified three possible causes of the high rates of planned outages. These were:

- the design of the reserve capacity mechanism which resulted in some units being assigned capacity credits and receiving full payment for these credits, even though they were on planned outage for extended periods;
- a limited ability of the IMO to prevent poorly performing generators operating in the market; and
- rules limiting the ability of the IMO to monitor and enforce performance standards.

Prior to the EMR, a rule change proposal was developed (RC_2013_09), which would have addressed many of these concerns. The rule change proposal included:

- permitting the IMO to reduce the quantity of certified reserve capacity to scheduled generators displaying excessive outage rates over a 36 month period;
- specifying a range of factors to be considered by the IMO in making its decision, adding certainty, structure and transparency;
- progressively tightening the combined planned and forced outage rate thresholds from 30 per cent to 20 per cent over five years, commencing in 2016, with provision for review in 2018;
- imposing an upper limit on the number of trading intervals in any 36 month period for which a generator can claim a reduction of its reserve capacity obligation quantities due to planned outages;
- granting discretionary power to the IMO to require both performance and performance improvement reports from market participants concerning facilities with excessive planned outage rates, regardless of the availability of total system capacity.

Although the rule change did not proceed as planned due to commencement of the EMR, it is included in the reserve capacity mechanism reforms. The reserve capacity mechanism reforms also include additional measures which the EMR considers will bring stronger commercial incentives for all forms of capacity to be made available for dispatch. These include:

- adjusting capacity refund requirements to better reflect prevailing supply conditions; and
- allowing capacity refunds to be recycled to those market generators that are available during the refund periods.

The reforms to the reserve capacity mechanism should reduce the level of outages. Until these changes have an effect, the potential for planned outages to result in higher prices remains an issue. The ERA will keep this area under review to ensure outage approvals are undertaken as effectively as possible within the decision criteria of the market rules. It will also seek to identify any further changes needed to ensure outage-scheduling results in the lowest effect on energy prices, while maintaining system security.

Uplift in energy prices

Energy prices have been relatively stable over the last few years, which has enabled some retailers and large users to rely on the energy markets, rather than enter into contracts, for their energy needs. However, since April 2016 there appears to have been an increase in both the variability and level of prices. This coincides with the discontinuation of the South West Cogen plant and significant base load outages. Additional offer price increases have occurred since July.

Further reductions in excess capacity are likely to increase this variability in energy prices. The short run marginal cost bidding requirements and the regulatory scheme applying to Synergy, are essential to ensuring only efficient costs are passed on to consumers.

2.5 Ancillary Services

Ancillary Services are required to maintain power system security and reliability through the control of key technical characteristics, such as frequency and voltage, which ensures that electricity supplies are of an acceptable quality.

Each year System Management must determine the ancillary service requirements and make a plan describing how it will ensure those requirements are met. Synergy must make its capacity to provide ancillary services from its facilities available to System Management. In broad terms, if Synergy can't supply the required ancillary service, or there is a less expensive alternative, System Management can enter into a contract with another party.

The current market design, coupled with Synergy owning key generators, has resulted in Synergy providing nearly all ancillary services. Consequently, the rules include various processes for setting administered prices or contract oversight. Processes are time consuming and costly, and do not necessarily reflect actual costs.

The introduction of competition in load following ancillary service provision, and the increased transparency resulting from it, has provided significant benefits in focussing attention and increased understanding of LFAS and ancillary service costs generally. However, the LFAS market has not delivered benefits in terms of competition or reduced costs.

A number of reforms to the LFAS market had been identified prior to the EMR. The EMR design option paper captures all of the options identified previously and effectively leverages the current AEMO systems to deliver significant improvements to ancillary services.

However, it will be important to ensure the NEM ancillary service categories are adapted appropriately for the WEM conditions. In particular, System Management will no longer be able to manage the dispatch of Synergy's portfolio of generators to maintain system security.

The ERA also recommends further consideration is given by the EMR to the most efficient way to procure network support requirements and the use of constrained-on payments.

As set out in the ERA's last report, during the 2013/14 year there were significant network outages, due to the sudden loss of two key transformers, primarily affecting the Southern region. Consequently, it was necessary for the Muja AB plants owned by Vinalco Energy[28] to be dispatched out of merit for considerable periods of time, resulting in significant constrained-on payments being passed through to market participants.

In addition to concerns over the level of costs passed on to market participants, there were concerns about the processes for managing network outages. Under the current rules, Western Power is responsible for procuring network control support services[29] and System Management is responsible for procuring dispatch support service contracts[30]. Western Power funds network support services. Dispatch support services and constrained-on payments are funded by market participants. System Management managed network

[28] Vinalco Energy is 100 per cent owned by Synergy.

[29] Defined as a service provided by generation or demand side management that can be a substitute for transmission or network upgrades.

[30] Defined as any ancillary service not covered by the other ancillary service categories.

outages in 2013/14 by constraining-on generators and compensating them via constrained- on payments.

Issues include:

- the criteria for which type of contract may/or should be employed are not well-defined;
- the distinction between contract types is not clear;
- the incentives for System Management or Western Power to enter into contracts appear insufficient;
- the effort required to undertake contracting process limits the effectiveness of these contracts to long term constraints;
- the costs of dispatch support service contracts are allocated to Market Participants – who are unable to provide an effective response – rather than to Western Power, the party that is best able to assess the risks involved and manage the cause of the issue; and
- the constraint payment mechanism was designed to address short-term interruptions to normal dispatch, so may not adequately compensate a market participant due to the method used to calculate constrained on volumes (i.e. there is a shortfall in the volumes between what is actually dispatched and what is assessed as the constrained-on quantity).

In its last report, the ERA concluded the criteria System Management is required to use when dealing with forced network outages may not always result in the lowest cost. Although System Management had access to the merit order as expressed in the balancing merit order, it did not have visibility of prices. Visibility of prices would ensure the lowest cost option is chosen when deciding which market participants to constrain on, or whether to enter into an ancillary service contract.

Some stakeholders considered either System Management or Western Power should have entered into an ancillary service contract to deal with the network outage. However, if operating the Vinalco Energy units was the only option available to System Management and Vinalco was offering its generation at short run marginal cost in the balancing market, it is unclear how a contracted service could have resulted in a lower cost.

Regardless of the mechanism used, the ERA considers that, as System Management has responsibility for ensuring power system security, it is best placed to ensure that the most cost effective options are used, providing it has access to information on prices.

However, under the current rules, the costs of constrained-on generation and dispatch support services are smeared across all market customers. Allocating constrained on/off compensation and ancillary service costs on a user (or causer) pays basis would provide better incentives for efficient market outcomes. In particular, ensuring Western Power faces the costs arising due to transmission constraints (including those currently paid for by market customers) would provide better signals for network planning and investment.

Moving to a security constrained dispatch model will provide much greater visibility of network constraints and ensure least cost dispatch of energy. Allocating ancillary services on a causer pays basis, as is intended under the EMR reforms, will provide further transparency and opportunities for cost reduction.

However, as System Management is responsible for power system security, the ERA recommends consideration be given to System Management deciding how to deal with forced outages on the network. Providing it has access to all the relevant cost information, System Management is best placed to ensure the right balance between system security and cost. Allocating these costs on a causer pays basis (i.e. Western Power should pay for power system security costs arising due to network outages), will ensure appropriate investment signals for the network.

3 Market Data and Analysis

3.1 Reporting Requirements

The market rules set out specific reporting requirements for the ERA.

AEMO is responsible for collection and primary analysis of data to monitor the effectiveness of the market. It is required to compile data specifically identified in the market rules, the Market Surveillance Data Catalogue (**MSDC**) and to provide that data to the ERA. The market rules also set out certain analysis AEMO must undertake and provide to the ERA. These requirements are set out in Appendix 2.

The ERA is responsible for monitoring the effectiveness of the market in meeting the wholesale market objectives, and must investigate any market behaviour that has resulted in the market not functioning effectively. The ERA, with the assistance of AEMO, must monitor:

- ancillary services contracts, including the criteria and processes used to procure services;
- inappropriate and anomalous market behaviour (such as bidding in the Short Term Energy Market (**STEM**) and balancing markets, 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.

The ERA 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; and
- the IMO, System Management and AEMO in carrying out its functions under the regulations, the market rules and market procedures.

The report should include:

- a summary of the information and data compiled by AEMO and the ERA under clause 2.16.1, including the MSDC;
- an assessment of the effectiveness of the market, including the effectiveness of the IMO and System Management in carrying out their functions, with discussion of each of:
  - the reserve capacity market;
  - the market for bilateral contracts for capacity and energy;
  - the STEM;
  - balancing;
  - the dispatch process;
  - planning processes; and
  - the administration of the market, including the market rule change process;

- an assessment of any specific events, behaviour or matters that impacted 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.

The remainder of this chapter sets out relevant information about the above requirements in the following order:

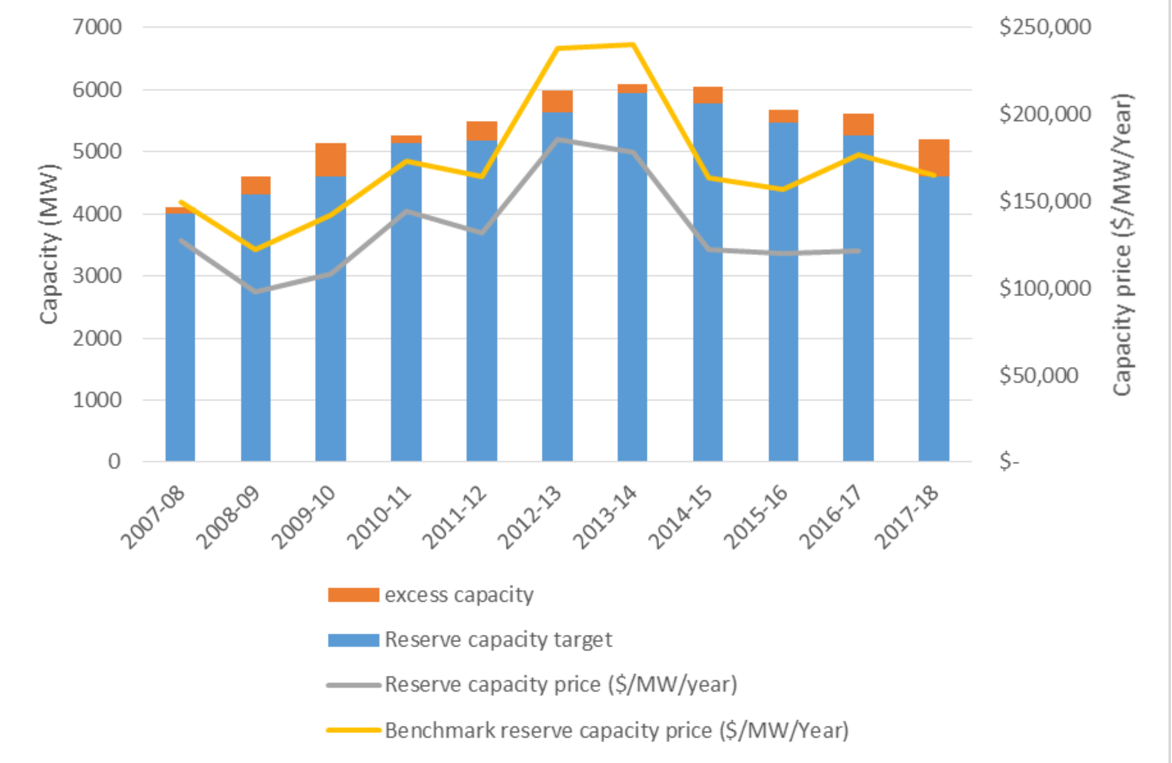
- reserve capacity mechanism
- energy markets
- ancillary services
- planning processes
- dispatch process
- market rule change and procedure change process
- compliance monitoring and enforcement measures
- effectiveness of AEMO/IMO and System Management
- inappropriate and anomalous behaviour

3.2 Reserve Capacity Mechanism

The primary objective of the reserve capacity mechanism is to ensure there is sufficient capacity to meet system reliability and adequacy requirements.

The reserve capacity mechanism has secured capacity in excess of forecast requirements since market start.

Figure 6 **Reserve capacity target, excess capacity credits, Benchmark reserve capacity price and reserve capacity price by capacity year**

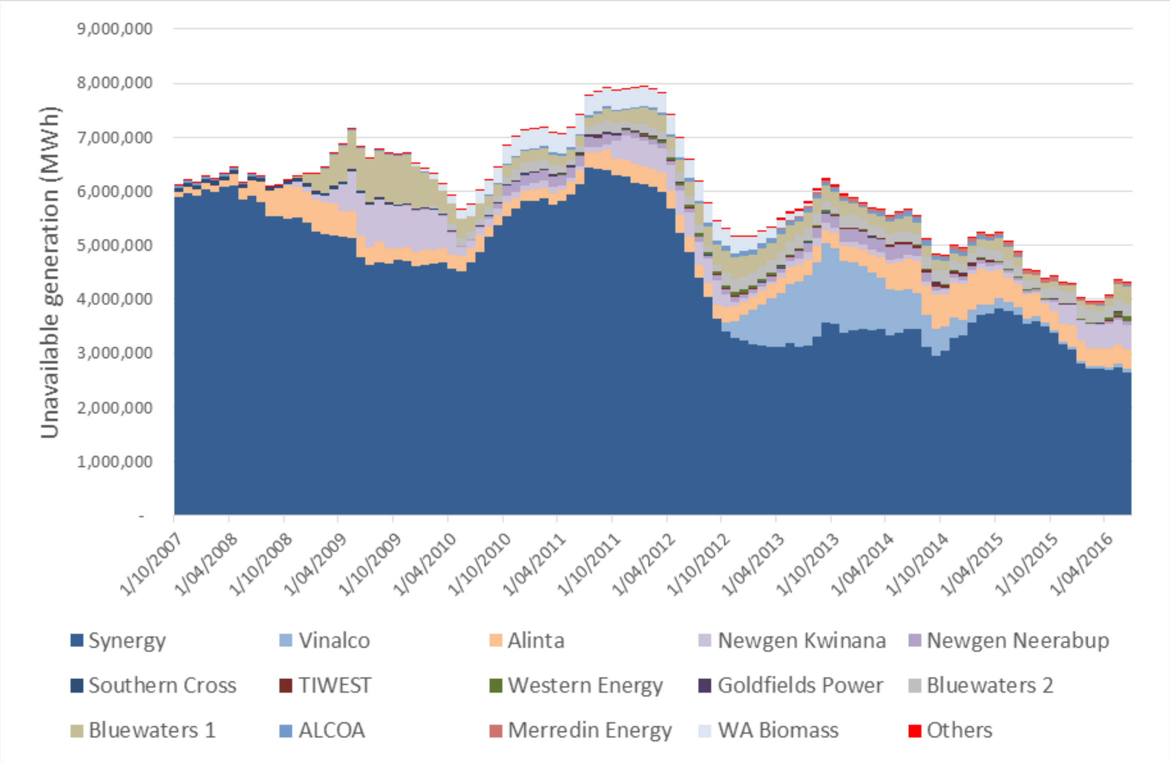


Performance of capacity

The ERA has assessed the performance of market participants with their reserve capacity obligations by comparing the quantity of a facility's forced outages and planned outages to the total assigned capacity credits for that facility.

As shown below, unavailable generation due to forced and planned outages is generally trending downwards in the WEM. The reduced outage levels in the WEM potentially contribute to the plant oversupply at the lower levels of the merit order.

Figure 7 Twelve month moving, total actual outages



Source: Australian Energy Market Operator, ERA Analysis

Table 2 below sets out, for each facility, the ratio of capacity subject to outages relative to the weighted total effective capacity, by capacity credits, for the financial years 2012-13 through 2015-16. Note that facilities Kwinana_G5 and Kwinana_G6 were retired on 8 July 2014 and 3 April 2015, respectively; and high forced outage rates for Vinalco units in part reflect delays in commencing active operation.

Table 2 Equivalent unavailability factors by outage type and average unavailable generation capacity (by financial year ending) [31]

Participant	Facility name	Installed capacity (mw)	Forced outages				Planned outages				Equivalent unavailability factor				Average unavailable capacity (MW)			
			2013	2014	2015	2016	2013	2014	2015	2016	2013	2014	2015	2016	2013	2014	2015	2016
ALCOA	ALCOA_WGP	25	3.7%	25.1%	1.4%	2.5%	29.5%	9.2%	3.4%	0.7%	33.2%	34.5%	4.7%	3.4%	8.29	8.62	1.18	0.86
ALINTA	ALINTA_PNJ_U1	143	0.0%	0.4%	0.1%	0.0%	5.4%	13.7%	9.0%	6.7%	5.4%	14.2%	9.1%	6.7%	7.77	20.29	13.07	9.62
	ALINTA_PNJ_U2	143	0.3%	0.3%	0.3%	0.1%	12.6%	12.9%	6.0%	9.4%	12.8%	13.2%	6.3%	9.5%	18.34	18.81	9.03	13.61
	ALINTA_WGP_GT	190	0.3%	0.2%	0.3%	0.5%	2.3%	6.4%	6.7%	4.2%	2.6%	6.5%	7.0%	4.9%	4.85	12.43	13.36	9.27
	ALINTA_WGP_U2	190	1.1%	0.5%	0.5%	0.3%	1.9%	6.7%	6.7%	3.4%	3.0%	7.2%	7.1%	3.9%	5.64	13.73	13.54	7.34
	ALINTA_WWF	89.1	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.3%	0.2%	-	0.00	0.24	0.14
COLLGAR	INVESTEC_COLLGAR_WF1	206	0.1%	0.0%	0.2%	0.0%	0.3%	0.1%	0.1%	0.0%	0.5%	0.1%	0.3%	0.0%	0.96	0.26	0.54	0.00
EDWFMAN	EDWFMAN_WF1	80	0.3%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.3%	0.1%	0.0%	0.0%	0.26	0.08	-	0.02
GLDFLDPW	PRK_AG	68	0.0%	0.1%	0.1%	1.4%	0.3%	0.1%	0.3%	0.7%	0.3%	0.3%	0.6%	2.3%	0.21	0.20	0.38	1.60
GRIFFIN2	BW2_BLUEWATERS_G1	217	0.5%	0.3%	1.5%	1.5%	11.4%	9.5%	8.0%	10.9%	11.9%	9.8%	9.5%	12.4%	25.75	21.33	20.60	26.81
GRIFFINP	BW1_BLUEWATERS_G2	217	4.9%	2.1%	0.2%	0.2%	9.0%	12.9%	9.2%	16.1%	13.9%	14.9%	9.5%	16.4%	30.07	32.40	20.51	35.48
GRNOUGH	GREENOUGH_RIVER_PV1	10	0.0%	0.2%	0.0%	0.0%	0.0%	0.2%	0.1%	0.2%	0.0%	0.4%	0.1%	0.2%	-	0.04	0.01	0.02
MERREDIN	NAMKKN_MERR_SG1	82	0.5%	1.4%	0.0%	0.8%	3.1%	3.2%	9.2%	6.8%	3.9%	4.6%	9.4%	8.1%	3.16	3.81	7.69	6.66
MUMBIDA	MWF_MUMBIDA_WF1	55	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.4%	0.1%	0.0%	0.0%	0.5%	0.1%	-	-	0.27	0.07
NEWGEN	NEWGEN_KWINANA_CCG1	335	0.4%	0.6%	0.1%	0.9%	3.3%	2.0%	2.6%	14.3%	3.6%	2.6%	2.7%	15.2%	12.17	8.75	8.97	50.81
	NEWGEN_NEERABUP_GT1	342	0.0%	0.0%	0.0%	0.0%	4.9%	4.9%	1.2%	2.0%	5.0%	5.9%	1.2%	2.0%	17.07	20.12	4.23	6.76

[31] Outages are reported as foregone generation. Unavailability factors have been determined using ANSI standard IEEE (2006) IEEE Standard Definitions for Use in Reporting Electric Generating unit Reliability, Availability and Productivity, IEEE Std 762-2006, IEEE Power Engineering Society, New York

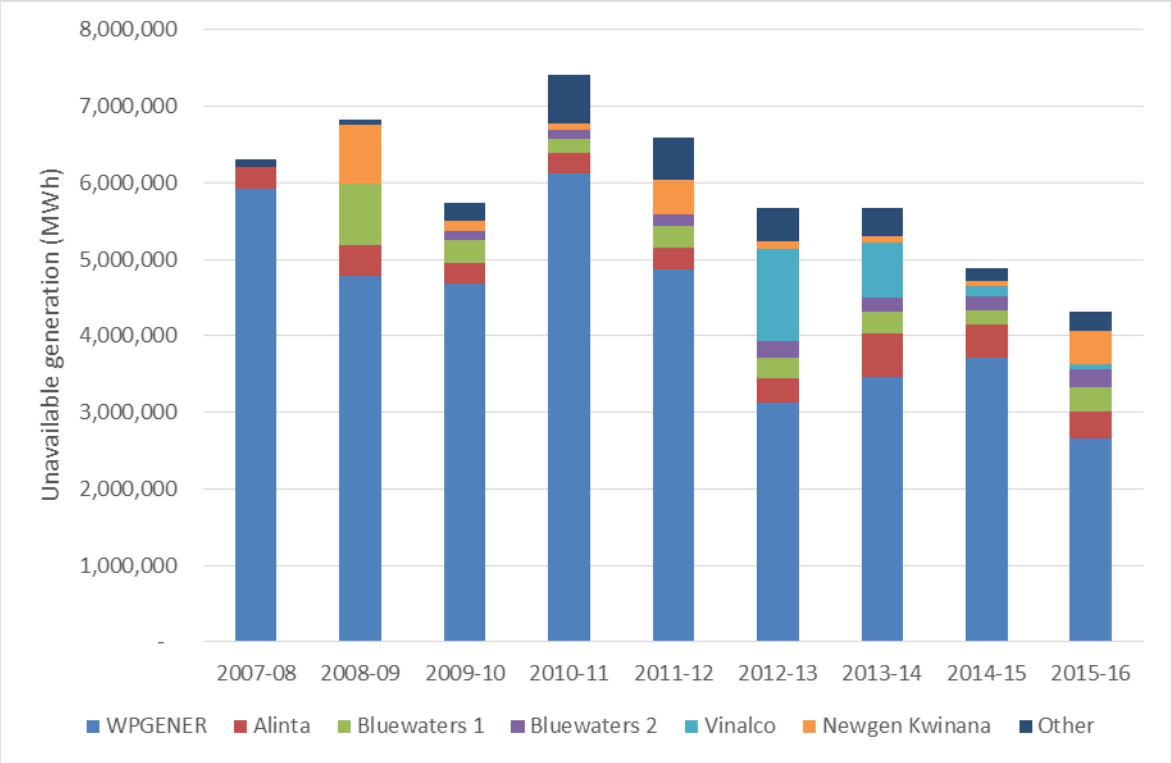
Participant	Facility name	Installed capacity (mw)	Forced outages				Planned outages				Equivalent unavailability factor				Average unavailable capacity (MW)			
			2013	2014	2015	2016	2013	2014	2015	2016	2013	2014	2015	2016	2013	2014	2015	2016
STHRNCRS	STHRNCRS_EG	23	3.1%	0.1%	0.0%	0.0%	2.7%	0.3%	0.0%	0.0%	5.8%	0.4%	0.0%	0.0%	1.34	0.09	-	-
TIWEST	TIWEST_COG1	42.1	0.9%	5.6%	1.9%	0.9%	2.0%	7.5%	1.2%	1.3%	2.9%	13.1%	3.1%	2.2%	1.20	5.52	1.31	0.91
TSLA_GER	TESLA_GERALDTON_G1	9.9	0.0%	0.0%	0.0%	0.0%	25.3%	3.5%	1.8%	0.6%	25.5%	3.5%	4.3%	1.5%	2.52	0.35	0.42	0.15
TSLA_KEM	TESLA_KEMERTON_G1	9.9	0.0%	0.0%	0.0%	0.0%	9.0%	1.3%	0.7%	0.8%	10.0%	1.3%	0.7%	1.0%	0.99	0.13	0.07	0.10
TSLA_MGT	TESLA_PICTON_G1	9.9	0.0%	0.0%	0.0%	0.0%	2.2%	2.0%	0.7%	0.4%	2.3%	2.0%	0.7%	1.5%	0.23	0.20	0.07	0.15
TSLA_NOR	TESLA_NORTHAM_G1	9.9	0.0%	0.0%	0.0%	0.0%	4.7%	0.8%	1.1%	4.8%	4.7%	1.7%	1.4%	4.9%	0.46	0.16	0.14	0.48
VINALCO	MUJA_G1	55	74.3%	67.7%	5.5%	0.1%	0.0%	0.0%	5.1%	1.5%	74.3%	67.7%	10.6%	1.7%	40.84	37.25	5.82	0.92
	MUJA_G2	55	74.2%	58.5%	2.3%	1.5%	0.0%	0.1%	2.8%	0.0%	74.2%	58.6%	9.6%	1.5%	40.84	32.21	5.28	0.84
	MUJA_G3	55	50.1%	4.7%	1.6%	0.1%	4.1%	9.6%	3.8%	1.7%	54.2%	14.3%	5.3%	1.9%	29.82	7.87	2.94	1.02
	MUJA_G4	55	38.1%	4.8%	0.6%	0.0%	7.3%	4.7%	2.4%	9.4%	45.4%	9.5%	3.0%	9.4%	24.95	5.24	1.63	5.18
WENERGY	PERTHENERGY_KWINANA_GT1	116	0.3%	0.0%	0.0%	0.4%	2.4%	1.5%	1.1%	8.6%	2.7%	1.5%	1.1%	8.9%	3.15	1.69	1.28	10.38
WPGENER	ALBANY_WF1	21.6	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.01	0.00	-	0.03
	COCKBURN_CCG1	236.6	0.3%	0.5%	0.4%	0.3%	2.6%	8.0%	6.2%	12.6%	4.0%	8.5%	6.6%	13.0%	9.37	20.22	15.68	30.80
	COLLIE_G1	318	0.6%	2.2%	0.7%	1.1%	3.4%	15.6%	5.4%	6.5%	4.0%	17.8%	6.1%	8.0%	12.76	56.54	19.46	25.35
	GERALDTON_GT1	15.9	0.0%	1.1%	57.4%	16.1%	15.3%	3.1%	1.2%	0.0%	15.3%	5.6%	58.6%	16.1%	2.43	0.88	9.31	2.57
	GRASMERE_WF1	13.8	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.2%	0.02	0.00	-	0.02
	KEMERTON_GT11	154	0.1%	0.0%	0.0%	0.0%	12.8%	1.2%	5.2%	3.4%	12.9%	1.4%	5.2%	3.5%	19.81	2.14	8.04	5.32
	KEMERTON_GT12	154	0.5%	0.0%	0.2%	0.1%	1.3%	15.9%	0.7%	3.3%	1.8%	15.9%	1.0%	3.4%	2.76	24.55	1.47	5.17
	KWINANA_G5	177.5	4.7%	5.2%	1.6%	0.0%	7.8%	8.3%	0.0%	0.0%	12.5%	14.5%	1.6%	0.0%	22.18	25.65	2.92	-

Participant	Facility name	Installed capacity (mw)	Forced outages				Planned outages				Equivalent unavailability factor				Average unavailable capacity (MW)			
			2013	2014	2015	2016	2013	2014	2015	2016	2013	2014	2015	2016	2013	2014	2015	2016
	KWINANA_G6	184	3.0%	2.5%	2.1%	0.0%	13.3%	19.1%	9.6%	0.0%	16.3%	21.6%	11.8%	0.0%	30.05	39.71	21.62	-
	KWINANA_GT1	20.8	0.1%	1.2%	4.1%	0.0%	15.9%	3.9%	6.6%	7.6%	16.0%	5.2%	10.7%	7.6%	3.33	1.07	2.23	1.57
	KWINANA_GT2	100.1	2.4%	0.9%	0.6%	2.0%	6.7%	23.6%	17.1%	18.2%	9.1%	24.5%	17.7%	20.3%	9.13	24.54	17.74	20.31
	KWINANA_GT3	100.1	3.4%	0.6%	4.5%	2.8%	5.4%	18.9%	13.3%	12.5%	8.7%	19.6%	17.8%	15.3%	8.74	19.59	17.82	15.36
	MUJA_G5	195.7	1.2%	1.6%	1.8%	7.9%	13.9%	22.5%	5.4%	14.3%	15.1%	24.2%	7.2%	23.1%	29.49	47.40	14.01	45.12
	MUJA_G6	190.75	0.5%	0.9%	20.7%	2.5%	46.8%	4.9%	2.3%	21.6%	47.4%	5.7%	23.0%	24.2%	90.33	10.90	43.94	46.22
	MUJA_G7	211	2.7%	0.3%	22.7%	0.8%	2.9%	9.1%	20.9%	14.0%	5.6%	9.4%	43.5%	14.8%	11.76	19.79	91.87	31.24
	MUJA_G8	211	2.5%	2.4%	6.0%	1.0%	6.9%	2.4%	30.5%	10.9%	9.4%	4.7%	36.5%	11.9%	19.91	9.95	77.00	25.10
	MUNGARRA_GT1	37.2	0.0%	0.7%	0.0%	1.7%	8.8%	8.8%	14.0%	0.4%	8.8%	9.5%	14.0%	2.2%	3.27	3.55	5.20	0.80
	MUNGARRA_GT2	37.2	0.1%	0.2%	0.4%	0.5%	0.4%	8.8%	1.0%	0.3%	0.5%	9.1%	1.4%	0.8%	0.19	3.37	0.52	0.30
	MUNGARRA_GT3	38.2	0.3%	1.5%	1.3%	0.2%	17.1%	0.6%	9.7%	5.8%	17.4%	2.1%	11.0%	5.9%	6.64	0.80	4.21	2.27
	PINJAR_GT1	37.2	0.0%	0.0%	0.6%	0.2%	1.2%	4.3%	0.1%	6.1%	1.2%	4.3%	0.7%	6.4%	0.45	1.59	0.27	2.38
	PINJAR_GT10	116	0.3%	0.7%	0.7%	0.7%	8.7%	36.7%	0.4%	6.7%	9.0%	37.3%	1.1%	7.4%	10.43	43.32	1.27	8.59
	PINJAR_GT11	123	0.0%	0.3%	6.1%	0.5%	6.0%	10.9%	8.3%	9.9%	6.1%	11.2%	14.4%	10.8%	7.46	13.76	17.70	13.23
	PINJAR_GT2	37.2	0.0%	0.4%	0.5%	0.1%	5.6%	5.2%	0.1%	5.8%	5.6%	5.6%	0.7%	6.0%	2.09	2.08	0.24	2.23
	PINJAR_GT3	38.2	0.0%	0.0%	0.2%	1.3%	12.8%	0.3%	9.9%	3.0%	13.0%	0.3%	10.2%	5.0%	4.96	0.13	3.88	1.90
	PINJAR_GT4	38.2	0.0%	0.4%	0.2%	0.1%	6.8%	0.3%	21.5%	2.6%	7.0%	0.7%	21.6%	3.4%	2.66	0.25	8.26	1.30
	PINJAR_GT5	38.2	0.0%	0.0%	0.0%	0.0%	6.0%	0.2%	0.2%	8.7%	6.0%	0.5%	0.2%	9.0%	2.30	0.20	0.07	3.45
	PINJAR_GT7	38.2	0.2%	0.0%	0.0%	0.2%	0.9%	9.7%	0.2%	0.2%	1.3%	9.7%	0.3%	0.7%	0.51	3.72	0.10	0.27

Participant	Facility name	Installed capacity (mw)	Forced outages				Planned outages				Equivalent unavailability factor				Average unavailable capacity (MW)			
			2013	2014	2015	2016	2013	2014	2015	2016	2013	2014	2015	2016	2013	2014	2015	2016
	PINJAR_GT9	116	0.2%	0.0%	2.5%	2.6%	19.1%	1.1%	21.4%	1.6%	19.4%	1.1%	23.9%	4.2%	22.51	1.27	27.78	4.85
	PPP_KCP_EG1	85.7	0.9%	0.1%	1.6%	0.0%	8.8%	5.6%	5.4%	3.6%	9.7%	5.8%	7.0%	3.6%	8.30	4.93	6.02	3.11
	SWCJV_WORSLEY_COGEN_COG1	116.4	0.4%	0.1%	0.6%	0.0%	3.0%	6.7%	2.0%	1.8%	3.3%	6.8%	2.6%	1.8%	3.90	7.97	3.05	2.15
	WEST_KALGOORLIE_GT2	38.2	0.0%	2.0%	1.5%	0.2%	9.3%	9.4%	2.5%	0.0%	9.3%	11.4%	4.1%	2.6%	3.57	4.36	1.56	0.99
	WEST_KALGOORLIE_GT3	24.6	0.2%	1.2%	0.8%	22.8%		2.2%	2.7%	0.3%	23.2%	3.4%	4.2%	2.5%	5.70	0.85	1.03	0.61

The proportion of outages by market participant is set out in Figure 8 below.

Figure 8 Outage by market participant by financial year



Source: Australian Energy Market Operator, ERA Analysis

In the 2015-16 financial year, forced outage rates were much lower. Geraldton GT1 had the largest forced outage rate of 16 per cent. Muja G5 was the second highest forced outage rate at 7.85 per cent. Muja (units G5, G6, G7 and G8), Newgen Kwinana, Kwinana GT2 and GT3, Cockburn CCGT and Bluewaters (units 1 and 2) all recorded planned outage rates above 10 per cent.

Outages at Muja units 5 through 8, Bluewaters units 1 and 2, Newgen Kwinana, Cockburn CCGT and Collie were the most material.[32] Collectively these plants' annual average unavailable capacity was 317MW. All of these plant are relatively low cost baseload or mid merit generators.

In the 2014-15 financial year, Synergy's facilities recorded the highest forced outage rates, with Geraldton_GT1 at 57 per cent, and Muja G7 and G6 at 20.6 per cent and 22.67 per cent, respectively. Vinalco's Muja facilities G1 and G2 showed marked declines from the highest forced outage rates in the previous 2013-14 financial year, falling from 67.7 per cent and 58.6 per cent to 5.5 and 2.3 per cent, respectively. Alcoa's Wagerup facility also reduced forced outages from 25 per cent to 1.4 per cent in 2014-15.

Synergy's facilities also accounted for the highest planned outage rates in 2014-15. Muja G8 and G7 recorded rates of 36 per cent and 43 per cent (respectively), while Pinjar units GT9 and GT4 were at 23.1 and 22.2 per cent, respectively. Alcoa Wagerup's planned outage rate continued its decline from levels previously persistently above 30 per cent to 4.7 per cent in the 2014-15 financial year, and 3.4 per cent in 2015-16. Synergy's Kwinana

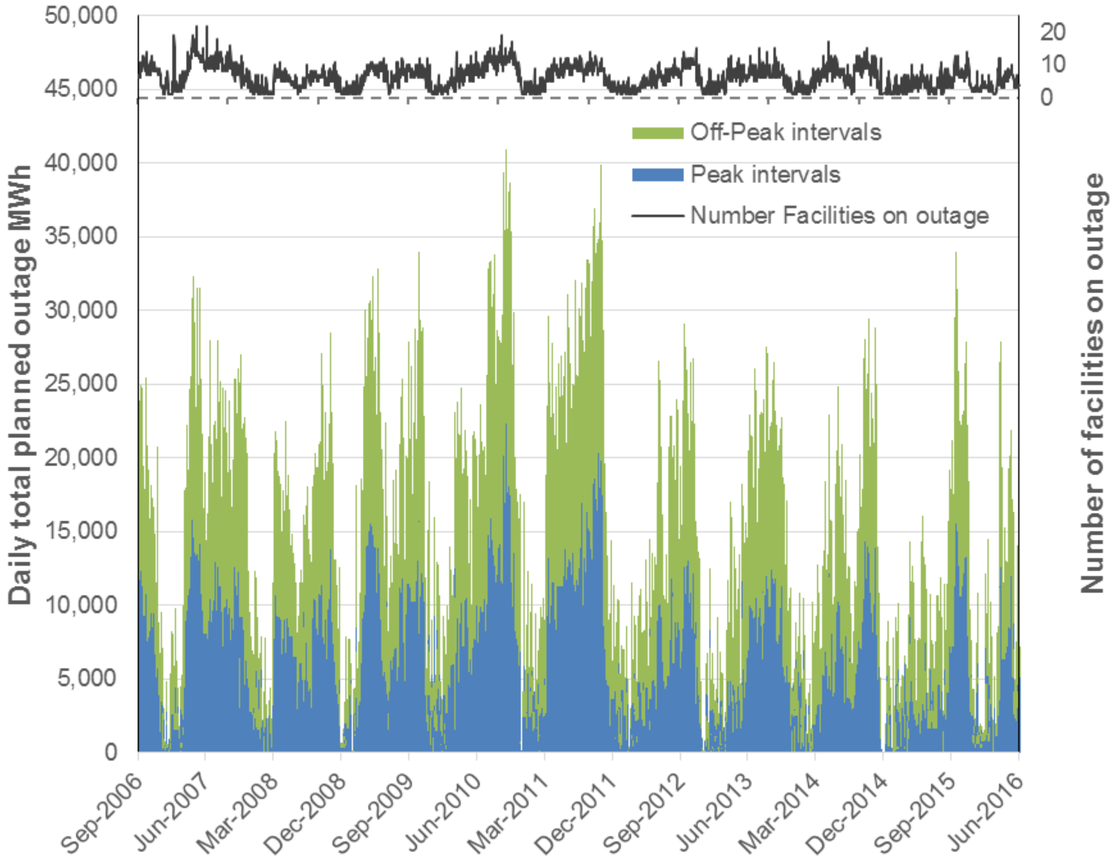
[32] An equivalent annual average outage exceeding 20MW.

gas units GT2 and GT3 planned outage rates reduced slightly from 25.7 and 20.6 per cent in 2013-14, to 18.1 per cent and 14.1 per cent in 2014-15.

Of the Independent Power Producer (**IPP**) facilities, all recorded both forced and planned outage rates below 10 per cent in financial year 2014-15 with the exception of Muja unit 1. Alinta's Pinjarra U1 and U2 reduced their planned outage rates from 14.8 per cent and 13.9 per cent in the 2013-14 financial year, to 9.7 and 6.5 per cent in 2014-15. Similarly, Griffin Power's Bluewater units G1 and G2 reduced planned outages from 9.5 and 12.9 per cent to 8.1 and 9.2 per cent, respectively.

Figure 9 below illustrates planned outages for all facilities as the daily total MWh, distinguishing outages in peak versus off-peak trading intervals. The top panel shows the total number of individual facilities recording outages on that day. Planned outages exhibit a clear seasonal pattern, with distinct increases in activity during the winter months and fewer outages during the peak demand months.

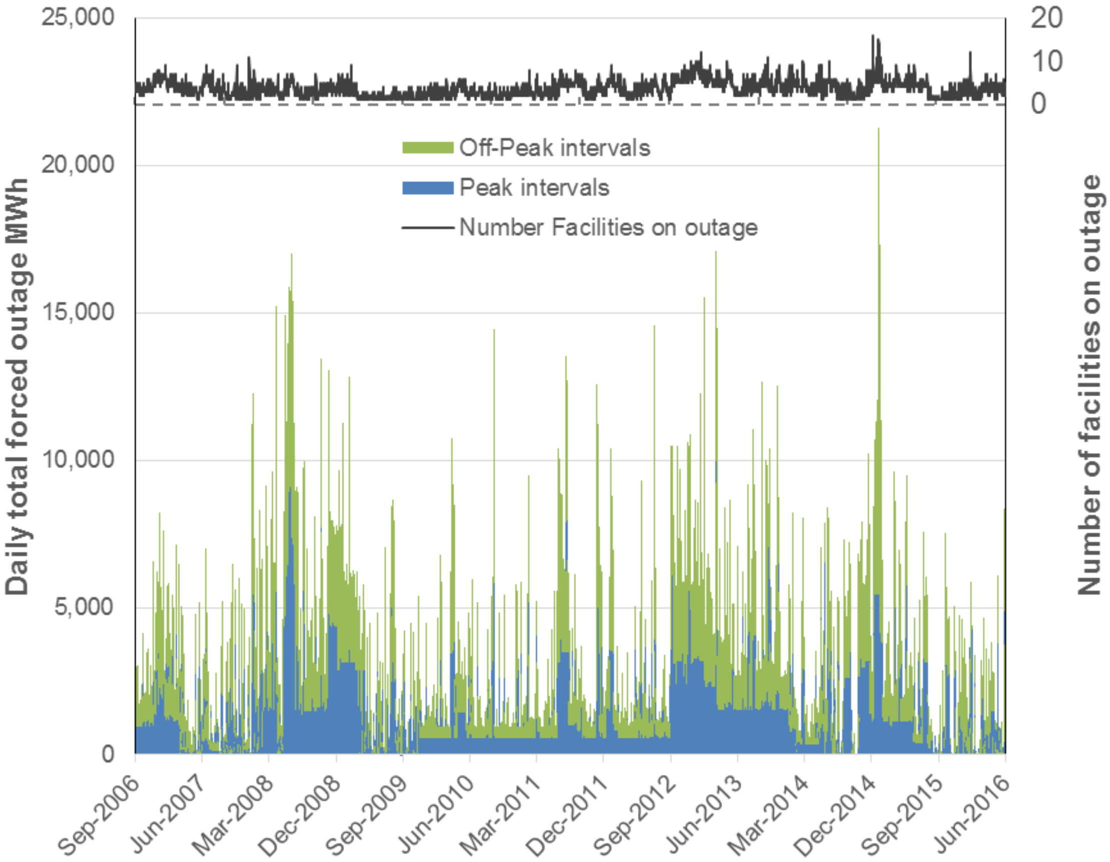
Figure 9 Daily total quantity of energy subject to planned outage by peak versus off-peak trading intervals



Source: Australian Energy Market Operator, ERA Analysis

Figure 10 below illustrates forced outages in the same manner as Figure 9 above. Note the smaller scale for number of facilities recording forced outages.

Figure 10 Daily total quantity of energy subject to forced outage by peak versus off-peak trading intervals



Source: Australian Energy Market Operator, ERA Analysis

Given the random nature of forced outages, there is no clear seasonal pattern, as occurs with planned outages.

Fuel Declarations

A market participant submitting a STEM submission must include a fuel declaration.[33] The fuel declaration is necessary for a market participant to offer a generation tranche above the maximum STEM price. Only participants registered as a liquid fuel plant or demand side management provider can offer prices above the maximum STEM price. During the period under review, STEM and balancing prices have not exceeded the maximum STEM price.

Availability Declarations

A market participant submitting a STEM submission must include an availability declaration on net available energy.[34] Figure 11 below shows monthly total availability declarations since market start by plant.

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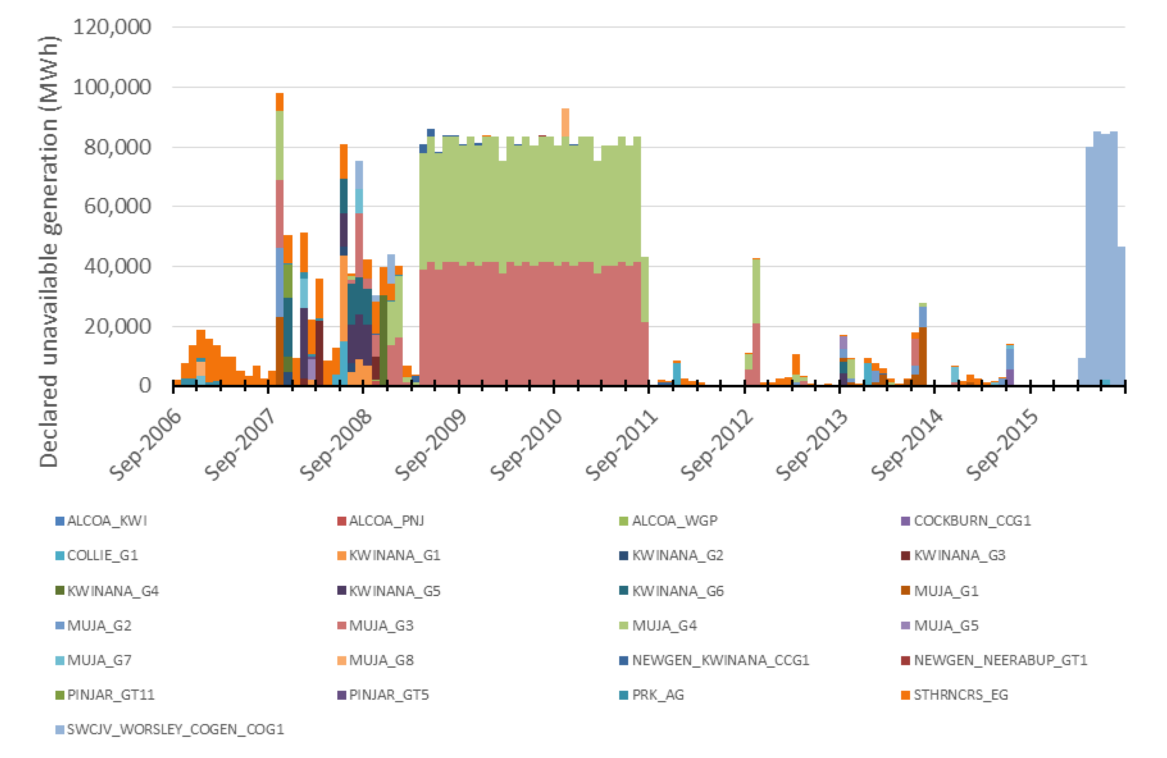
[33] See clause 6.6.1 of the Market Rules.

[34] See clause 6.6.1 of the Market Rules. The Availability Declaration is to set out, for each Trading Interval and for each of the Market Participant's facilities, as the difference between the energy available from the

Figure 11 Monthly total availability declarations (MWh unavailable)



Source: Australian Energy Market Operator, ERA Analysis

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 the remaining capacity available is less than the quantity supplied, this indicates that a facility has been available to supply the market more than was indicated in the STEM submission for that facility. The purpose of this statistic is to detect whether a market participant falsely declares that low cost capacity is unavailable. By leaving out low cost capacity the market participant will be able to put in a submission with a higher cost schedule. This could result in a higher STEM clearing price. The market participant could then generate with the low cost capacity, which is truly available, and make an excessive profit.

Figure 11 shows that since July 2014 the only material declaration related to unavailability was from South West Cogeneration Joint Venture which was withdrawn from service.

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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.

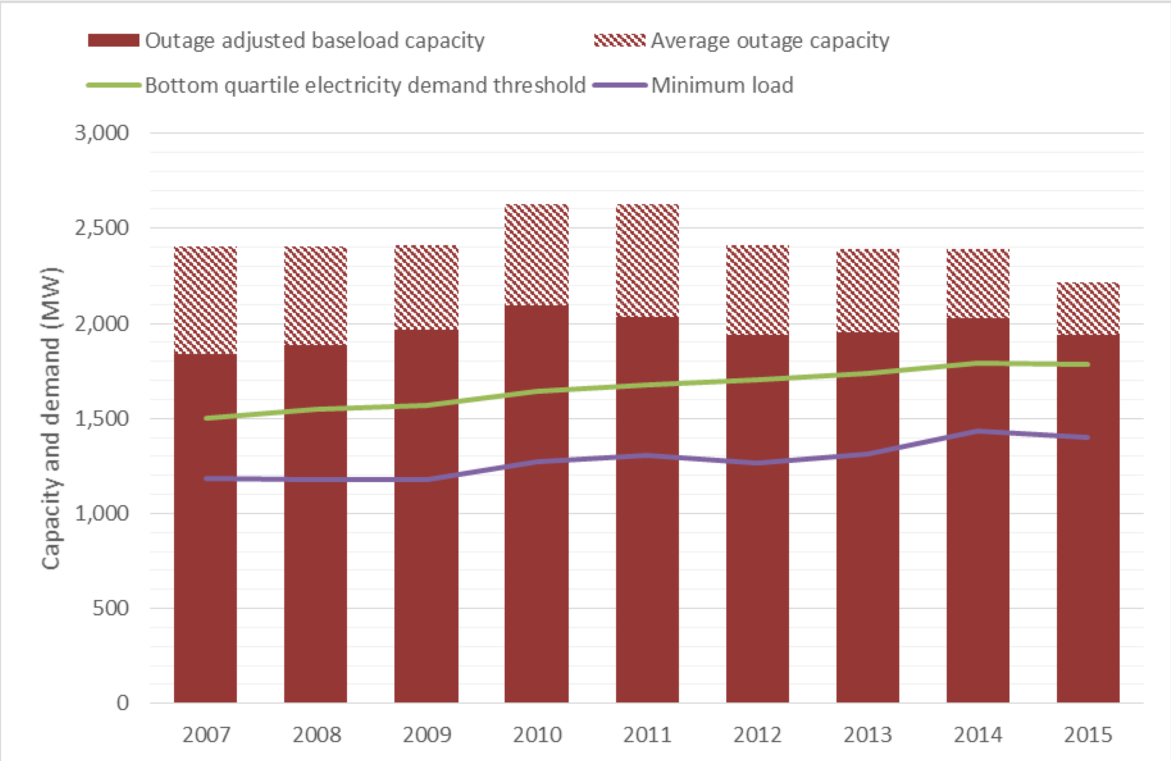
Excess capacity

The number of capacity credits assigned has exceeded the reserve capacity requirement since market start. The market has an excess of baseload and peaking generation.

Baseload units are typically large, with a low Short Run Marginal Cost (**SRMC**).[35] In contrast, peaking units are much smaller and have higher operating costs. Baselaod generators also typically have large start-up costs. Excess baseload generation not only reduces the operational use of mid merit generation but it will also act to supress prices during periods of low demand as generators compete to stay connected. This leads to more energy available at lower and more stable prices in the STEM and balancing markets.

After accounting for the average *ex post* planned and forced outage rates, there is substantially more baseload, cogeneration and non-scheduled generation capacity than is needed to meet baseload duty. In absolute terms, baseload generation capacity exceeded the bottom quartile of demand by around 65 percent in 2007 and 30 percent in 2015. After accounting for outages, this was around 27 percent in 2007 and 15 percent in 2015.

Figure 12 Baseload generation capacity and demand[36]



Source: Australian Energy Market Operator, ERA Analysis

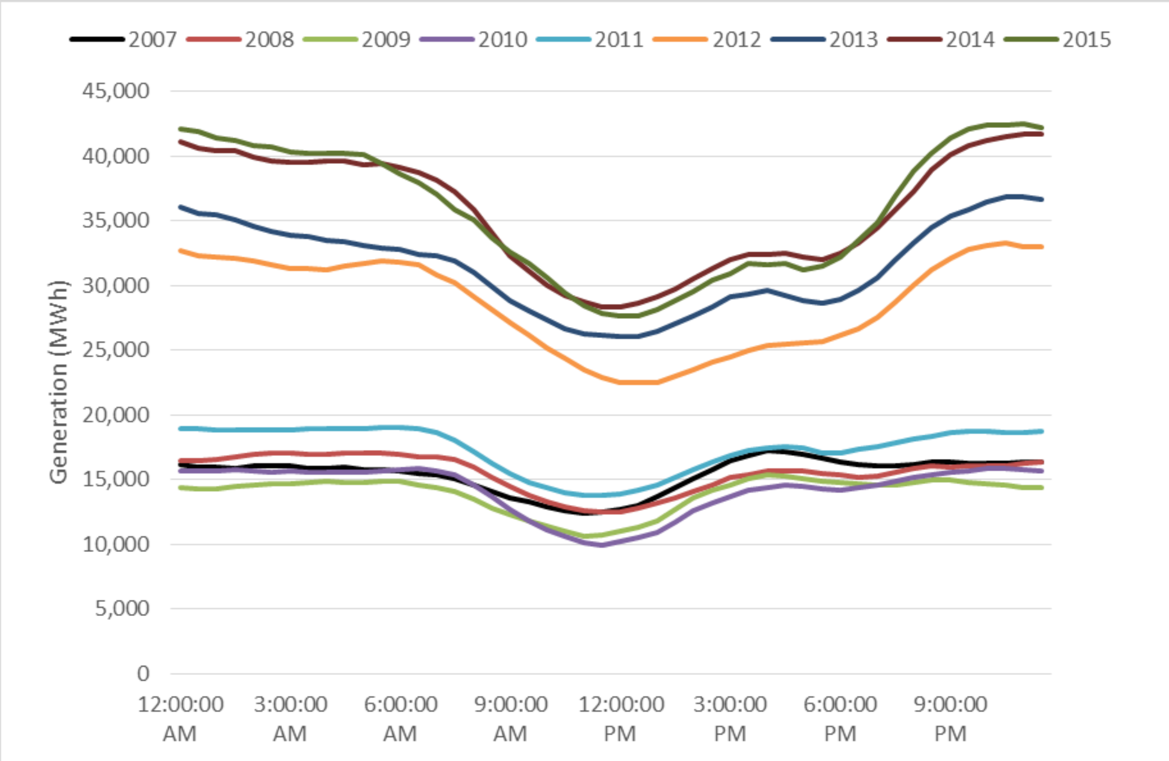
[35] Baseload units are those expected to serve demand that is nearly always on, and relatively flat. Energy Information Administration, Glossary, US Department of Energy, Viewed on 2 June 2016, http://www.eia.gov/tools/glossary/index.cfm?id=B

[36] In this chart 'baseload generation' capacity includes the installed capacity for large thermal plant installed to service baseload generation requirements, industrial cogeneration plant and the capacity credits from non-scheduled generation from wind and landfill gas. Outages only refers to planned and forced outages from plant aggregated in the columns.

Although baseload capacity surplus has reduced in recent years with plant retirement at Kwinana C, this has been partially offset by decreases in outages and additional non-scheduled generation.

Figure 13 plots the renewable generation profile sent out by calendar year and time of day.

Figure 13 Renewable sent-out generation by year and time of day

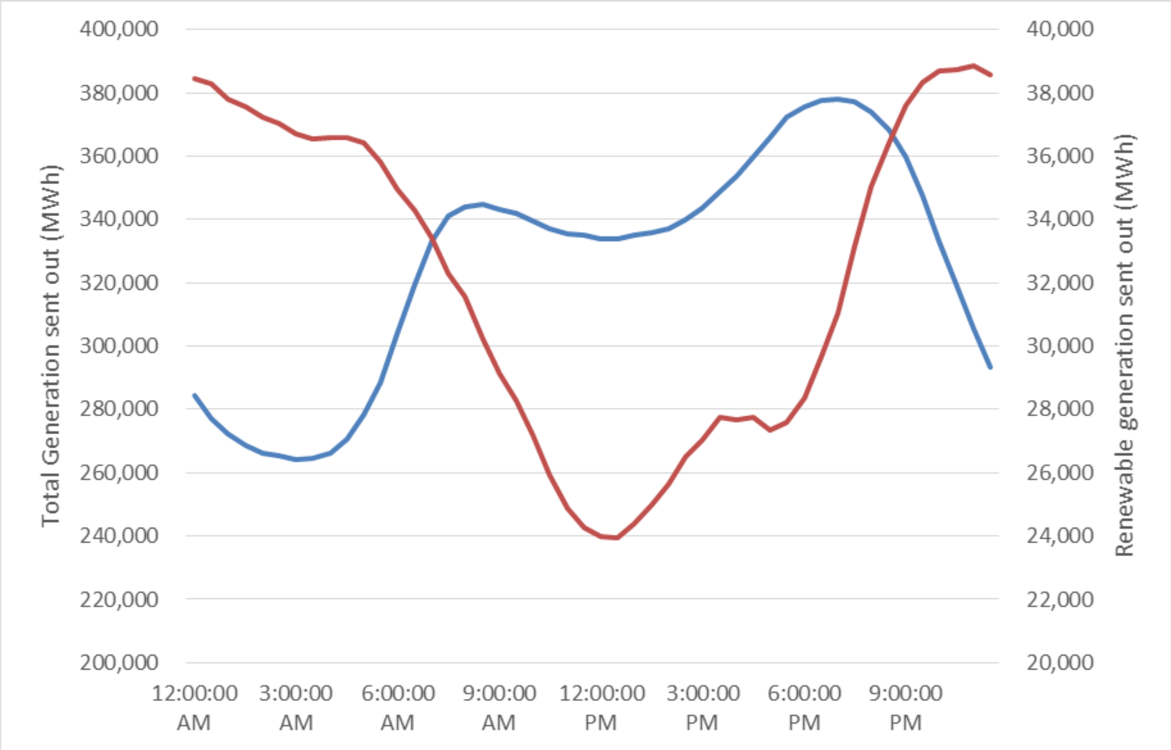


Source: Australian Energy Market Operator, ERA Analysis

Renewable generation output has greater availability during periods of low load (overnight), and so competes with baseload generation. Figure 14 shows the moderately strong inverse correlation between renewable and scheduled generation output.[37]

[37] That is, as renewable generation output increased, scheduled generation output decreased, and vice versa. The correlation coefficient r =-0.65

Figure 14 Total WEM generation and renewable generation sent out by time of day (2014-15 capacity year)[38]



Source: Australian Energy Market Operator, ERA Analysis

Baseload and mid-merit capacity factors have declined over the duration of the market. Figure 15 shows a 12-month moving weighted average capacity factor for baseload and mid-merit generators.[39] Excess baseload generation in the market reduces the operational use of mid merit generation, indicated by the capacity factor for the combined mid merit generation.[40] For example, the capacity factor for the Cockburn combined cycle power station reduced from around 75 percent in 2007 to under 25 percent in 2015.[41]

Figure 15 accounts only for plant currently operating as baseload, and thus it excludes the Kwinana Power Station and Muja AB. These generators were designed to do baseload duty, being large, inflexible thermal generators. However, the low capacity factors indicate that these generators are no longer operating as baseload generators.

[38] Please note the differences in scale between the two vertical axes. Although the units are the same, the difference in output between the overall sent out generation and the renewable contribution requires presentation on two different scales to highlight the inverse relationship.

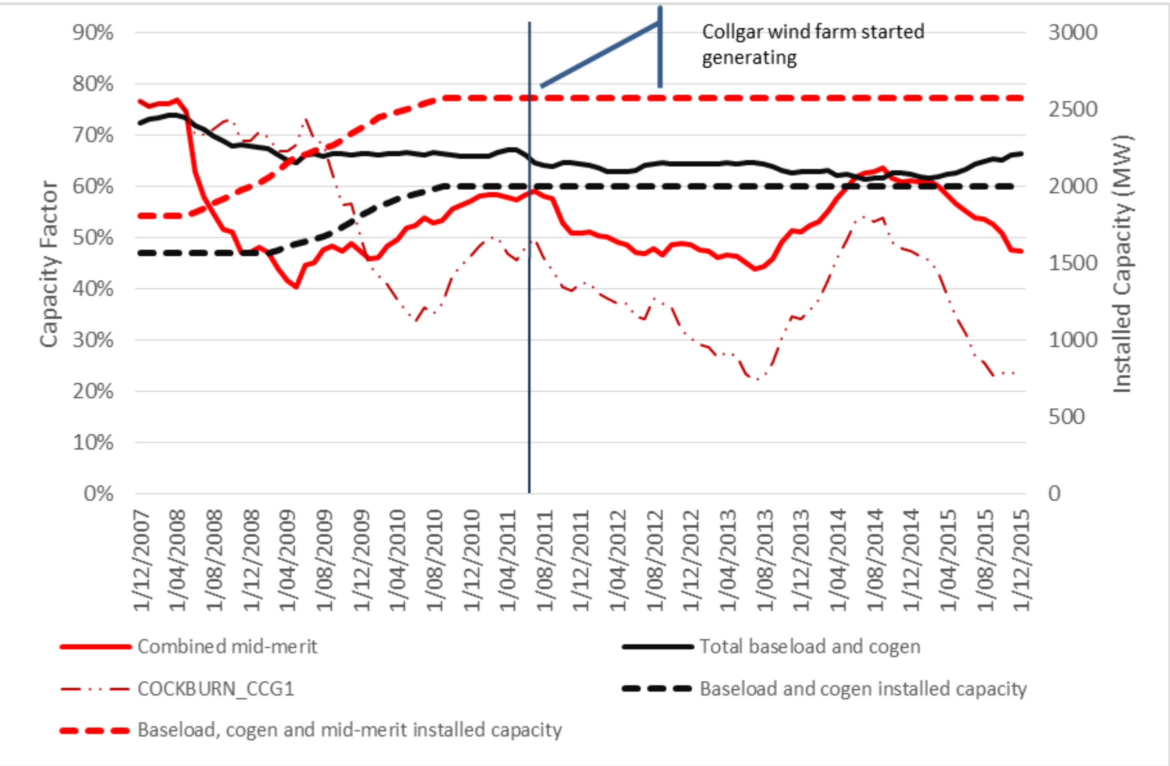
[39] Combined baseload comprises Collie, Muja CD, Bluewaters Units 1&2, Alinta Pinjarra Units 1 & 2, South West Cogen Joint Venture and TiWest cogeneration. Combined mid-merit units comprise Cockburn CCGT and the Newgen Kwinana CCGT power stations.

[40] The capacity factor of a power plant is the ratio of its actual output over a specified period, to its potential output if it were possible for it to operate at full capacity continuously over that same period.

IEEE (2006) IEEE Standard Definitions for Use in Reporting Electric Generating unit Reliability, Availability and Productivity, IEEE Std 762-2006, IEEE Power Engineering Society, New York, p30

[41] Cockburn Combined Cycle gas turbine is included in the “Combined mid merit” trace and also presented separately in the dashed burgundy line in the chart.

Figure 15 Twelve-month moving weighted average baseload and mid-merit capacity factors



Source: Australian Energy Market Operator, ERA Analysis

Reduced outage levels and a wind resource with low operational costs and skewed towards overnight production have contributed to plant oversupply at the lower levels of the merit order in the WEM, especially during periods of low demand. This baseload oversupply has reduced the requirement for mid-merit plant, keeping prices in the STEM and balancing markets low and less volatile than might otherwise be the case.

The consequences of unhedged market participation are lower when the likelihood of high volatility and prices is low. However, the extent of excess low cost generation is diminishing.

3.3 Energy Markets

Market Participants

Market participants in the WEM can be grouped into four main categories:

- Gentailers, which are integrated generators and retailers that generate electricity as well as sell directly to retail customers. These include Synergy, Alinta, Perth Energy, and Bluewaters Power;[42]

- Retailers, which purchase wholesale electricity and sell to retail customers. These include Premier Power,[43] ERM Power, Southern Cross Energy (who retail to mining companies in the Goldfields) and a number of small 'boutique' or 'niche' retailers (Amanda Energy, AER Retail, A-Star, Bluestar, and Community Electricity);

- Generators, which produce electricity and sell to the wholesale market. These include Newgen Kwinana, the Collgar and Emu Downs windfarms, and Vinalco; and

- Large users, which directly purchase wholesale electricity for their own use including Karara, and the Water Corporation (i.e., 'direct purchasers'). Some direct purchasers also generate electricity including Tiwest, Newmont Mining and Alcoa.

The AEMO website includes a complete list of market participants Figure 16 presents market participants' generation output over the period 2007 to 2016.

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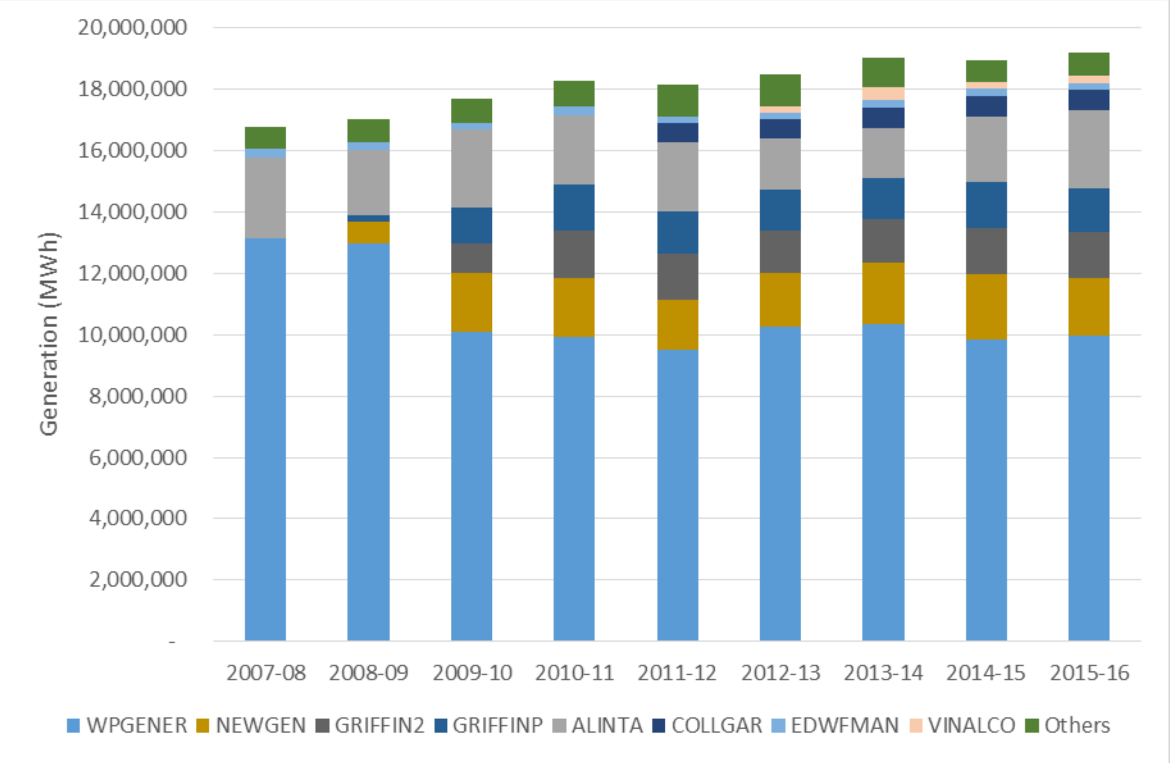
[42] Bluewaters Power was previously known as Griffin Power, but changed its name to Bluewaters Power in April 2013, following a change in ownership after the previous owners went into liquidation.

[43] A transfer of licence from Premier Power to Wesfarmers Kleenheat Gas Pty Ltd occurred on 1 July 2015, with amendment of the licence to authorise supply to small use customers.

Figure 16 Year on year sent out generation by market participant



Source: Australian Energy Market Operator, ERA Analysis

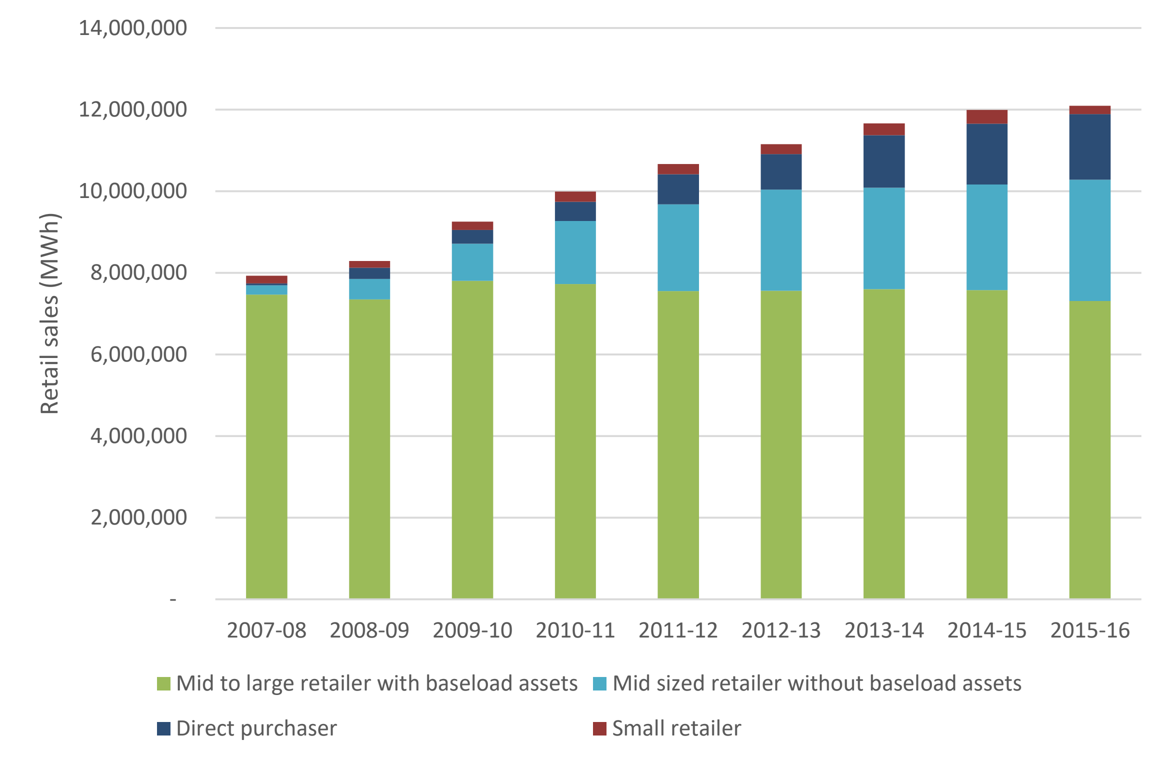
Synergy is the largest generator in the market, albeit reduced from around 80 per cent in 2007 to around 50 per cent in 2015/16. This change in market share was a function of plant retirement following the contracted capacity displacement tenders. Collectively, gentailers account for around 80 per cent of all generation. Stand-alone generators produce the remainder, of which NewGen Kwinana generates the greatest quantity.

After accounting for bilateral contracts with third parties, Synergy's generation share is substantial with little change since 2009.

Figure 17 provides contestable retail market share by participant type since the 2007-08 financial year. The ERA has defined retailers with less than three per cent market share as "small retailers".[44]

[44] Small retailers include AER Retail, Amanda Energy, A-Star, Blairfox, Bluestar, Community Electricity and Southern Cross Energy.

Figure 17 Contestable retail sales and direct consumption by participant (financial year)



Source: Australian Energy Market Operator, ERA Analysis.

The contestable segment of the retail market consists of customers consuming greater than 50MWh per year. Currently, only Synergy can supply customers below this threshold. However, the Government has signalled its intent to introduce full retail contestability, which would allow other retailers to compete with Synergy for these customers.[45]

The non-contestable market segment has decreased consistently since the market started due to increased photovoltaic (**PV**) installation, price response and energy efficiency. Contestable market growth has offset the fall in the non-contestable market segment.

A substantial proportion of contestable retail market growth in recent years is attributable to consumption by large entities that purchase electricity directly from the wholesale market for their own use i.e. direct purchasers. There has been little change in the total volume attributable to small retailers since 2012. The remaining contestable volumes have also been flat since 2009/10 albeit with significant churn between retailers.

Synergy's contestable sales have declined steadily since the market commenced. This is due to a combination of declining volumes in its customer base (most likely due to energy efficiency, price response and increasing PV installation) and customers churning away from it.

Customer 'churn' refers to customer transfers between competing retailers. Customer churn can provide an indication of the level of competition present in the market. Increased

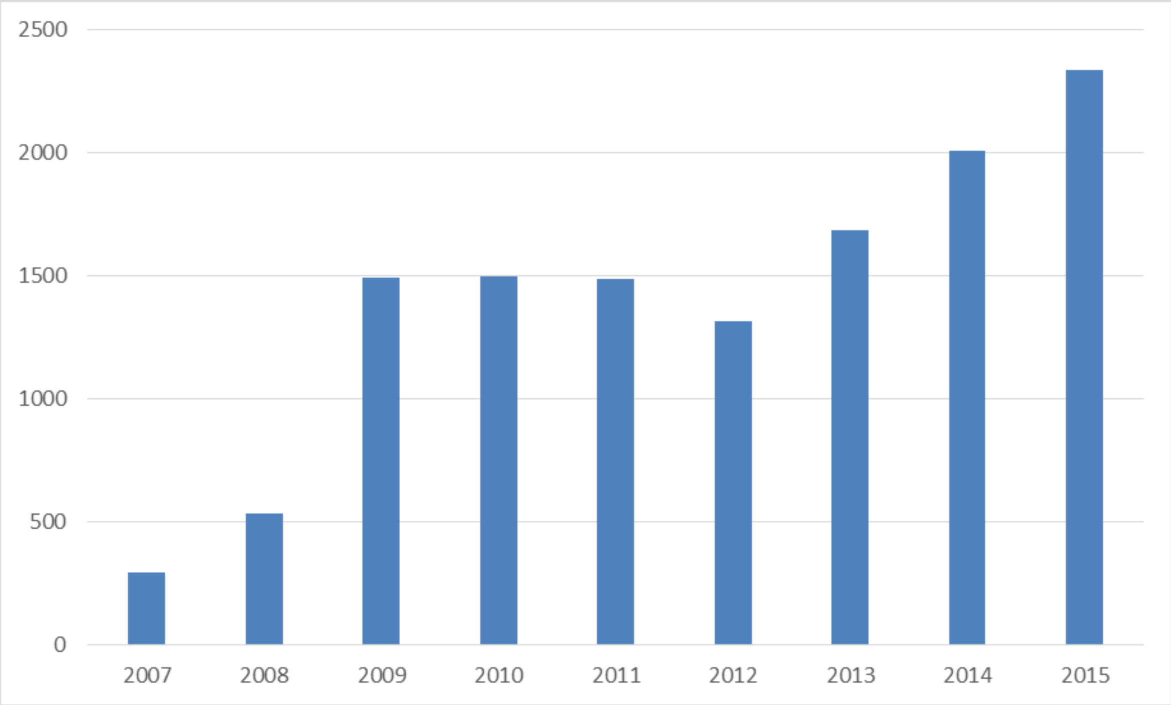
[45] https://www.mediastatements.wa.gov.au/Pages/Barnett/2015/03/Government-energised-for-electricity-reform.aspx

competition in the market may occur where the customer has greater choice in products or retailers are competing to provide the same product on terms that are more favourable.

Customer churn data captures contestable National Meter Identifier (**NMI**) transfers between retailers from September 2007 to November 2015. [46] Data includes the customers' incumbent retailer and network tariff, and the customers' incoming retailer and network tariff.

Due to the data set's composition, analysis likely overstates the amount of customer churn in the market.47 Analysis and comparisons drawn in this section therefore assume that the likelihood of a customer moving premises is relatively constant over time and across retailers. Figure 18 shows the number of NMI transferred in each year since 2007.[48]

Figure 18 Annual NMI churn 2007 to 2015



Source: Western Power data provided on request.

Examining the composition of customer churn can provide insights into competition between retailers. Most customer churn involves large retailers, reflecting their greater presence in the market.

Customer movements from Synergy account for more than half of all NMI transfers. Alinta and Perth Energy acquired the majority of NMIs leaving Synergy. There is also some exchange between Alinta and Perth Energy. These customer movements explain Synergy's market share reducing, and Alinta and Perth Energy's shares increasing.

[46] A National Meter Identifier is a number identifying each connection point in the network.

[47] The data represents NMI churn, not customer churn (one customer may have several premises, each with its own NMI) and each NMI is linked to the premises not the customer (a customer may move locations, but maintain retailer and be counted as having churned). Additionally, the data is collected based on the assumption that all NMIs with an interval meter are contestable customers. This means the data set is likely to include some non-contestable customers, and exclude some contestable customers as some non-contestable customers may have interval meters installed at a premises.

Large numbers of customer movements between Synergy, Alinta and Perth Energy have occurred since market start. With the exception of short periods in late 2008 and early 2009, and late 2012 and early 2013, Synergy has lost more customers than it acquired from its two largest competitors. Churn has increased in recent years, indicating increased competition in the contestable retail market.

A significant difference between Synergy and other retailers is that customers can only churn away from Synergy if they have an interval meter. For customers who do not have an existing interval meter, the metering costs can erode the benefit of changing supplier.

It is also more difficult for other retailers to identify customers who move from the non-contestable to contestable volume threshold. Neither Synergy nor Western Power is required to identify when non-contestable customers become contestable. Although Western Power can identify which connection points are contestable, Synergy is the only party that knows which retail tariff these customers are charged.

Full retail contestability will resolve this problem. However, in the interim, the Government might consider placing an explicit obligation for Synergy to identify and move customers from non-contestable products when they exceed the non-contestable threshold.

The market provides three mechanisms for retailers to source energy:

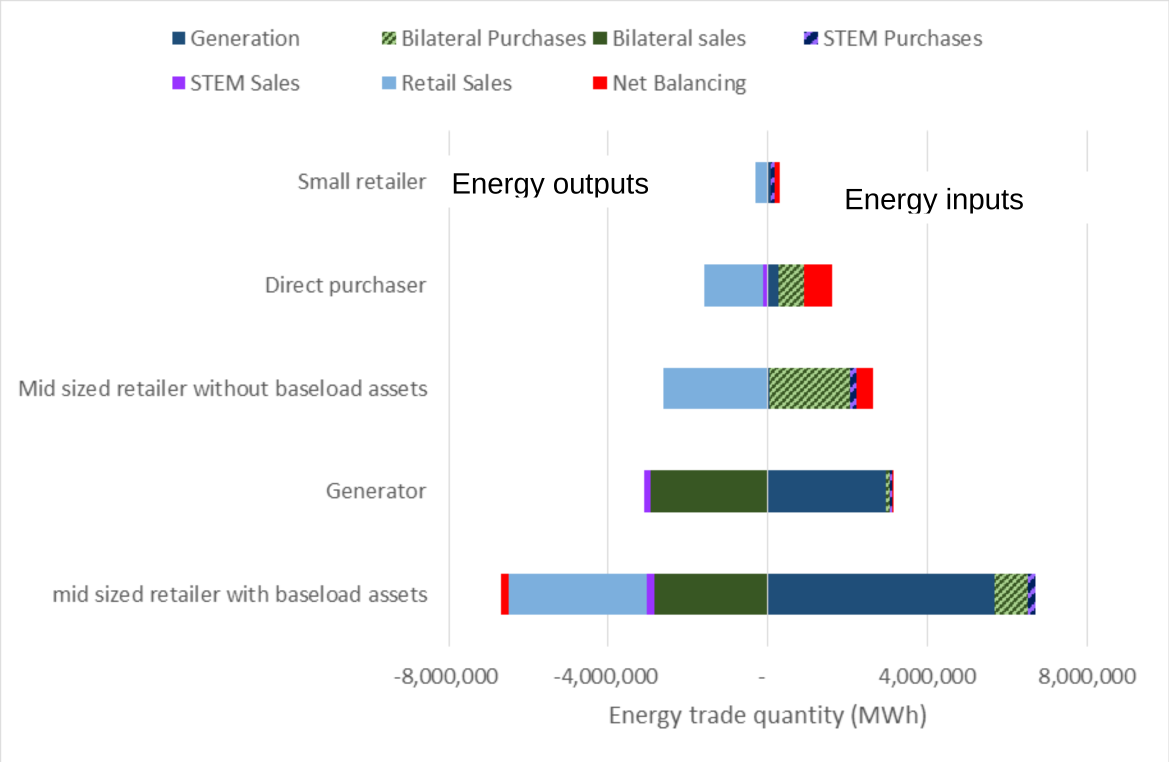
- bilateral contracts;
- the day ahead STEM; and
- the balancing market.

Figure 19 below shows the mechanisms used by market participants aggregated based on their generation assets, retail licenses and size.[49] Positive values on the x-axis are energy inputs in the form of bilateral supplies from third parties, STEM and net balancing market purchases. Negative values are sales in the form of end use consumption, retail sales, bilateral supplies to third parties, STEM sales and net balancing market sales.

The ‘net balancing’ position is the aggregate net balancing market position after accounting for generation, bilateral and STEM position and retail sales. When net balancing is on the disposal side, the market participant is long on energy inputs and disposes of it in the balancing market, and when net balancing is on the supply side of the graph, the market participant is short on the energy needed to meet its requirements and sources it from the balancing market.

[49] Market participants were aggregated into broad classes of no less than three unrelated entities.

Figure 19 Electricity supply and disposal by market mechanism (2015 calendar year)



Source: Australian Energy Market Operator, ERA Analysis

Small retailers are unhedged, relying entirely on short-term energy trading mechanisms.[50] Mid-sized retailers without baseload asset supplies were mostly bilaterally contracted with some STEM and balancing market exposure.[51] Mid-sized retailers with generation assets made substantial bilateral sales, with modest STEM and balancing market exposure.[52]

The charts may overstate direct purchasers' collective balancing market exposure, as some bilateral supply contracts with intermittent generators may settle outside the electricity market.

To protect confidential market participant data, Synergy has not been included in the chart. Synergy's actual generation combined with its contracts to purchase energy from other generators is greater than its combined retail and wholesale energy sales. Consequently, it was a net seller in the balancing market in 2015.

As shown above, market participants with no generation assets have utilised the STEM and balancing markets to source their energy. The majority of the generator bilateral contracts are with Synergy or other gentailers and mid-sized retailers. The energy available for sale in the STEM and balancing markets has predominantly come from Synergy and other gentailers.

Although retailers (and direct purchasers) would typically seek to hedge their exposure to short term price variations by entering into energy contracts, this has not been the case for

[50] Small retailers includes ADERRTL, Amanda Energy, AStar Energy, Bluestar Energy, Blair Fox, Community Electricity, Goldfields Power, Southern Cross Power and Tesla.

[51] ERM, Perth Energy and Premier Power

[52] Alinta Energy, Vinalco, Bluewaters Energy.

a number of market participants in the WEM. This appears to be due to an oversupply of baseload and peaking generation dominating supply, which has resulted in STEM and balancing market prices being lower and less volatile than might otherwise have been the case.

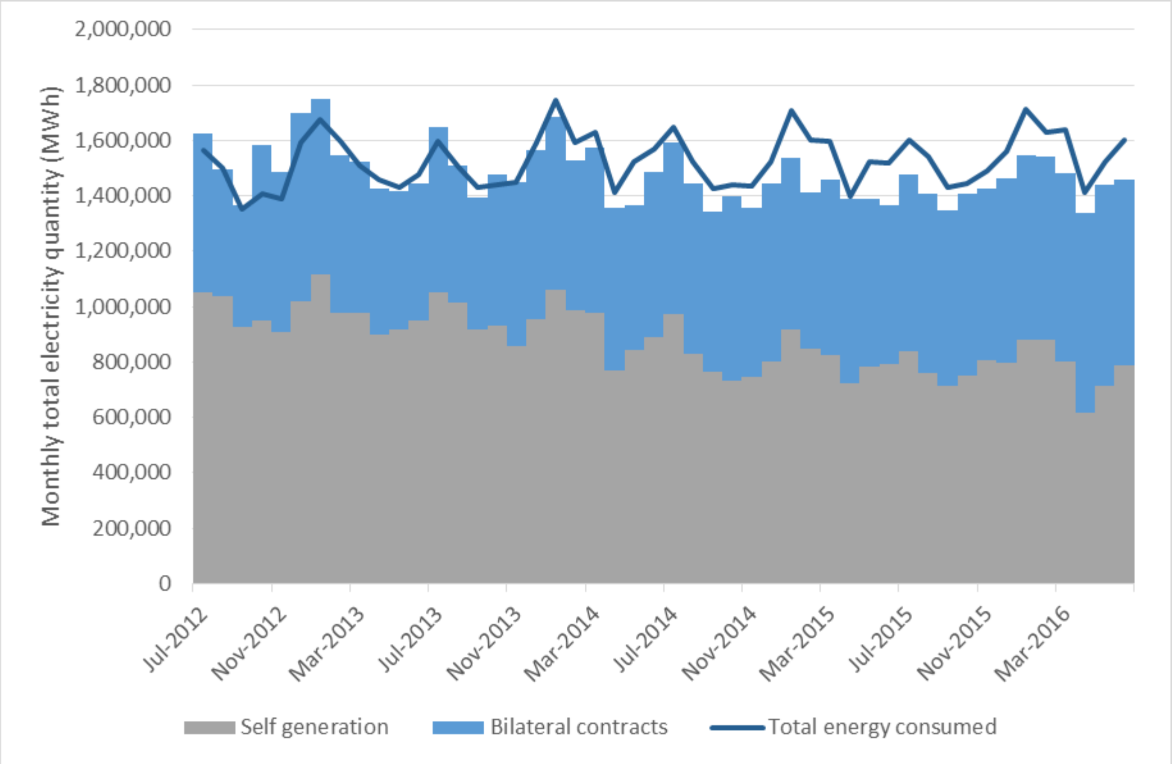
Each of the energy markets are considered below.

Bilateral Contracts

Market participants are free to enter into bilateral contracts to buy and sell energy if they wish. Generators are required to provide details in advance to AEMO of any contractual quantities sold and the contracted party to purchase the energy for each trading interval. Only the quantities are provided. Other terms in the contracts, such as price and length of contract, are confidential to the contracting parties.

Figure 20 shows most energy is traded bilaterally. A large part of this is energy generated and consumed by gentailers (i.e. self-generation). Around 37 per cent of third party trades in the 2015-16 financial year were either to or from Synergy.

Figure 20 Bilateral quantities traded and total consumption[53]



Source: Australian Energy Market Operator, ERA Analysis

Short Term Energy Market

The STEM is a day-ahead market where market participants can trade energy around their bilateral positions and expected load or generation. It allows participants to lock in a price one day ahead rather than be exposed to the real-time balancing price.

[53] Please note that bilaterally traded quantities can exceed consumption. Traded quantities can be onsold through other bilateral contracts or into the STEM or Balancing markets.

Market participants (both generators and retailers) can submit offers to sell energy to the STEM, or bids to buy energy from the STEM. Generators may choose to buy energy from the market if the STEM price is lower than its marginal cost of generation. Alternatively, generators may choose to sell energy in excess of any bilateral contracts. Similarly, retailers may use the STEM to trade out imbalances between bilateral contract positions and expected demand.

Short Term Energy Market traded quantities

Table 3 shows the average of STEM traded quantities among market participants (MWh per trading interval) over the last seven years.

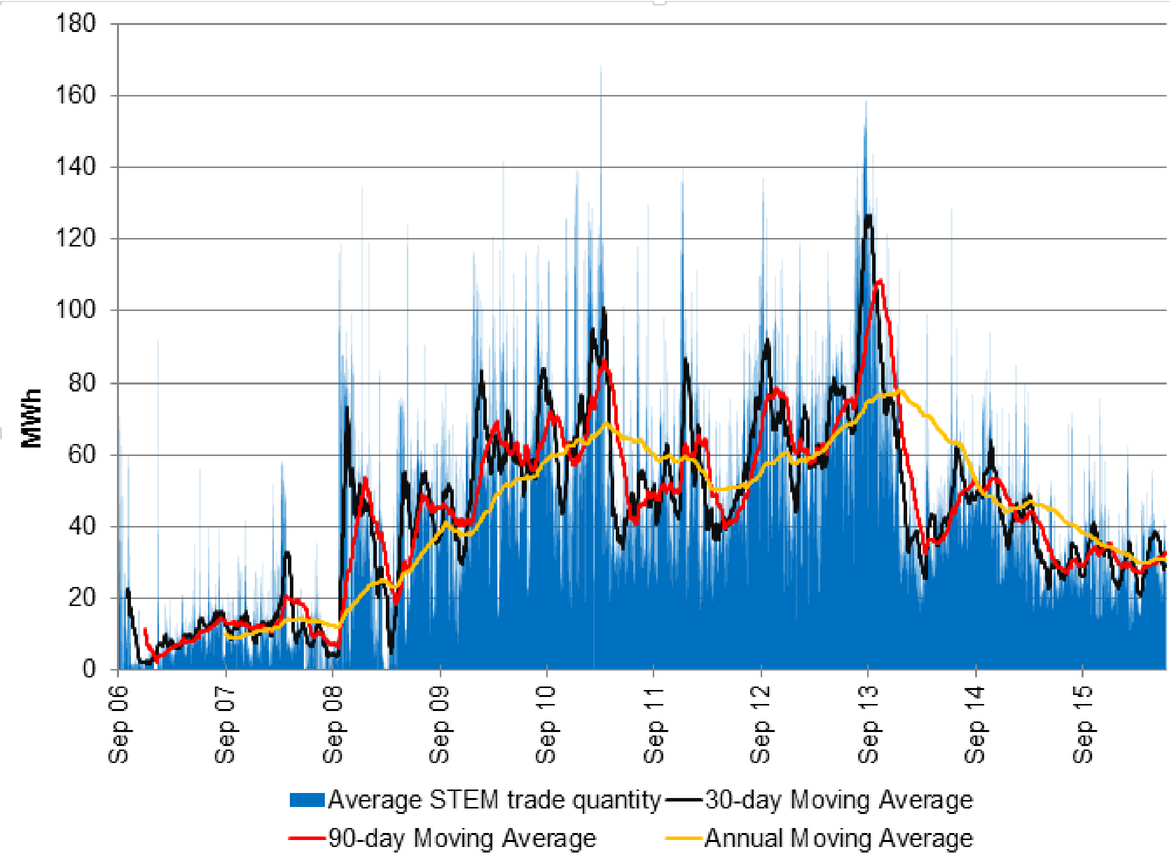
Table 3 Average STEM traded quantities per interval (MWh per trading interval)

	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16
STEM traded quantities	53.37	64.62	50.76	67.82	63.49	43.31	31.00

Note: 'Average quantities' are for the overall period, i.e., 21 September 2006 to 30 June 2016.

Figure 21 illustrates daily average quantities traded in the STEM from market commencement until 30 June 2016.

Figure 21 Average quantities traded in the STEM (21 September 2006 to 30 June 2016)

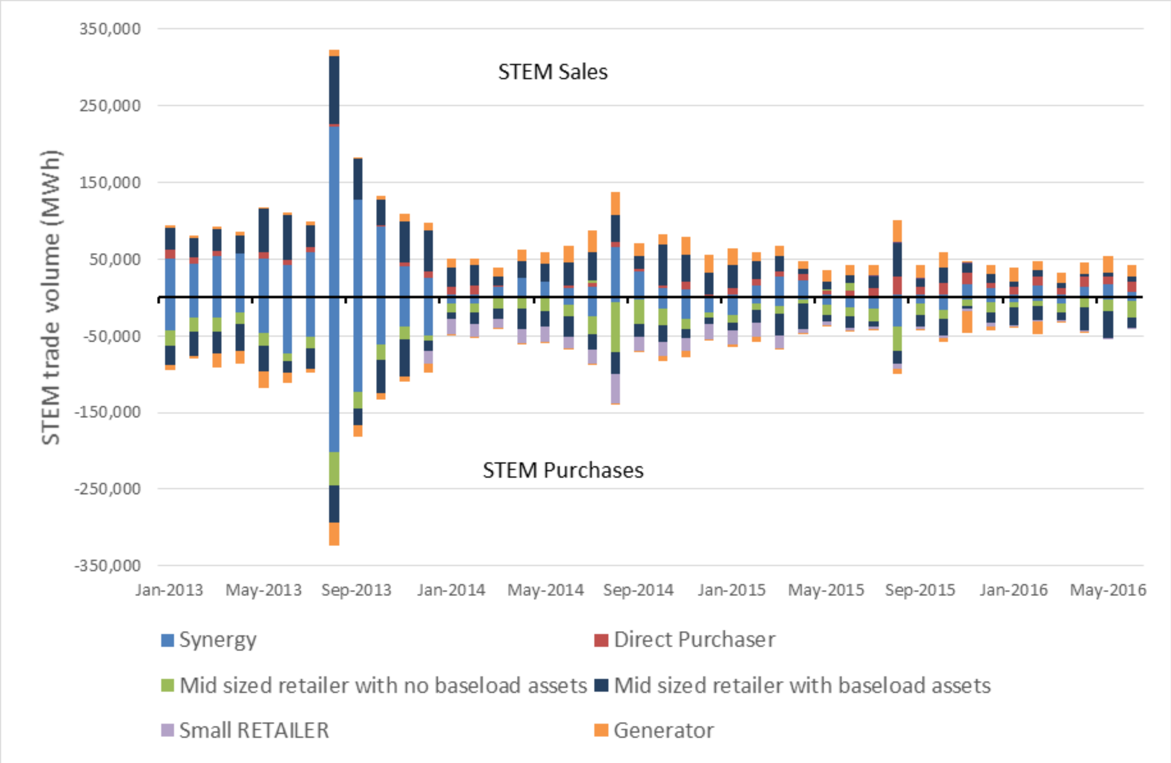


Source: Australian Energy Market Operator, ERA Analysis

Figure 22 shows the monthly volume bought and sold in the STEM by participant type from January 2013 to 30 June 2016.

STEM trades make up around three per cent of total energy generated. Volumes were substantially higher prior to the merger of Verve Energy and Synergy, reflecting excess volumes Synergy contracted from Verve Energy which it offered into the STEM. The chart below provides a summary of monthly volumes by market participant since January 2013.

Figure 22 Monthly total STEM trades (MWh)



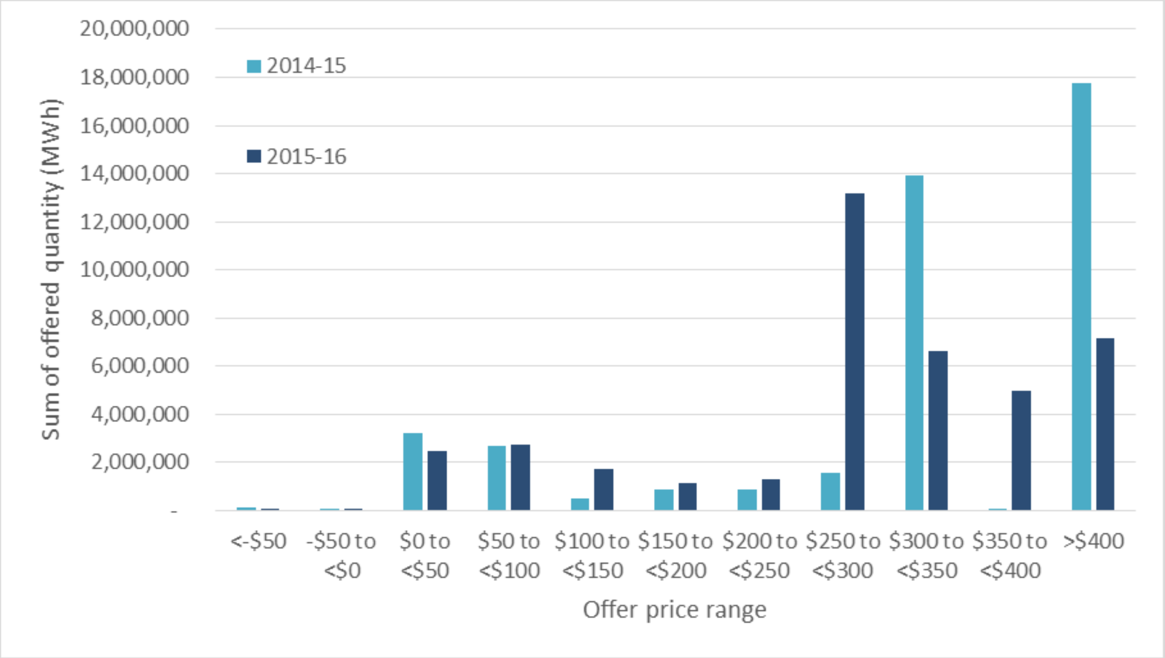
Source: Australian Energy Market Operator, ERA Analysis

Short Term Energy Market Prices

AEMO determines STEM offers and STEM bids by converting a market participant's portfolio supply curve and portfolio demand curve into a single STEM price curve, and then converting this into STEM offers and STEM bids, relative to the market participant's net bilateral position.

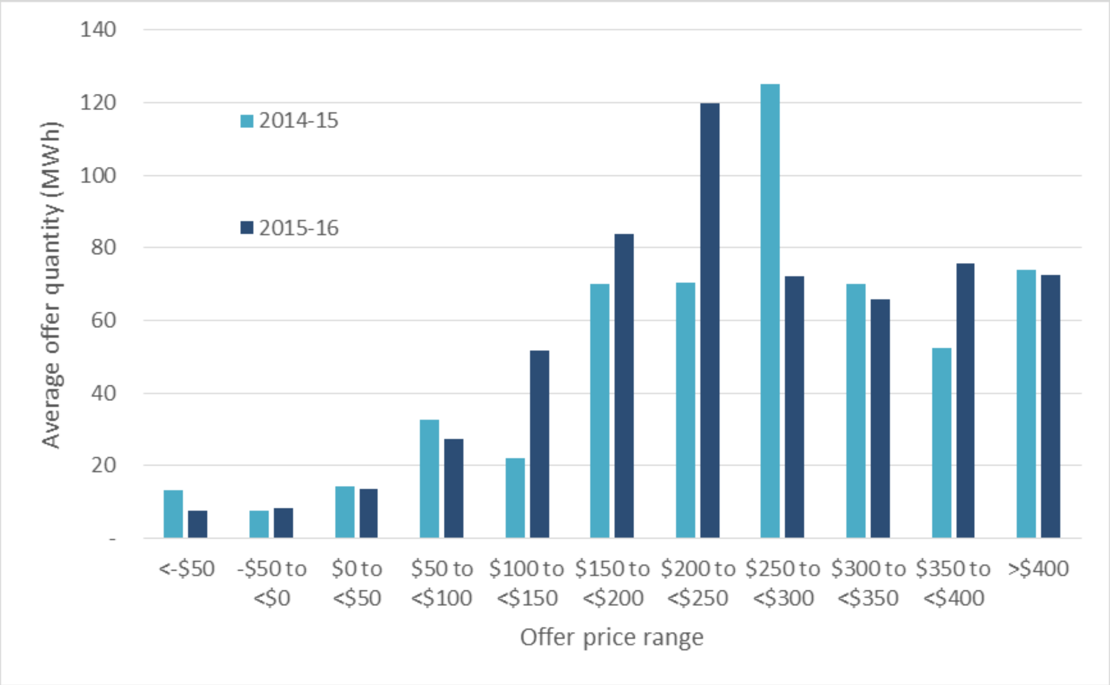
Figure 23 and Figure 24 illustrate the distribution of STEM offers within market participants during 2014/15 and 2015/16. Changes at the upper price bands most likely reflects offers at the caps.

Figure 23 Total energy offered into STEM within pricing band



Source: Australian Energy Market Operator, ERA Analysis

Figure 24 Average STEM offer size within pricing band



Source: Australian Energy Market Operator, ERA Analysis

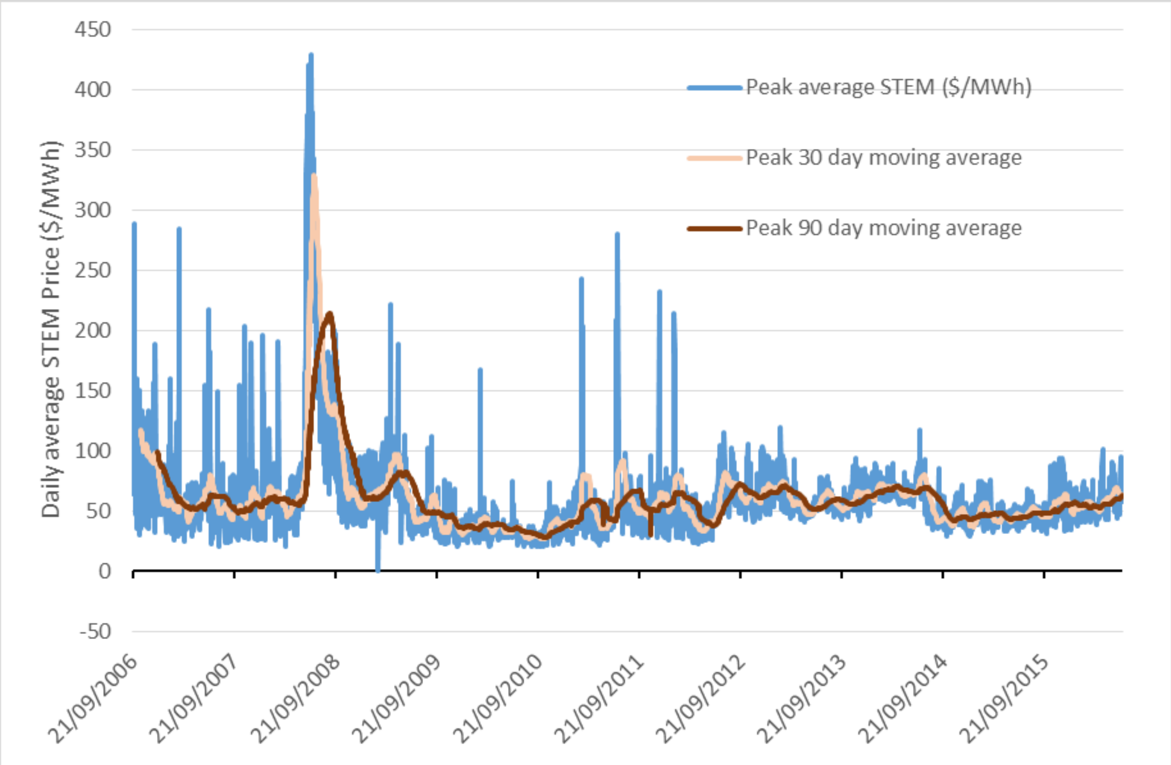
Annual mean STEM clearing prices are set out in Table 4 below.

Table 4 Average STEM clearing prices ($/MWh)

	Sep 06 – Jun 07	Jul 07 – Jun 08	Jul 08 – Jun 09	Jul 09 – Jun 10	Jul 10 – Jun 11	Jul 11 - Jun 12	Jul 12 - Jun 13	Jul 13 - Jun 14	Jul 14 - Jun 15	Jul 15 – Jun 16
Off-Peak	32.72	36.38	48.90	19.40	23.19	28.38	42.80	45.15	30.84	34.65
Peak	70.42	75.78	91.54	39.74	41.85	54.97	63.44	64.32	46.89	55.12

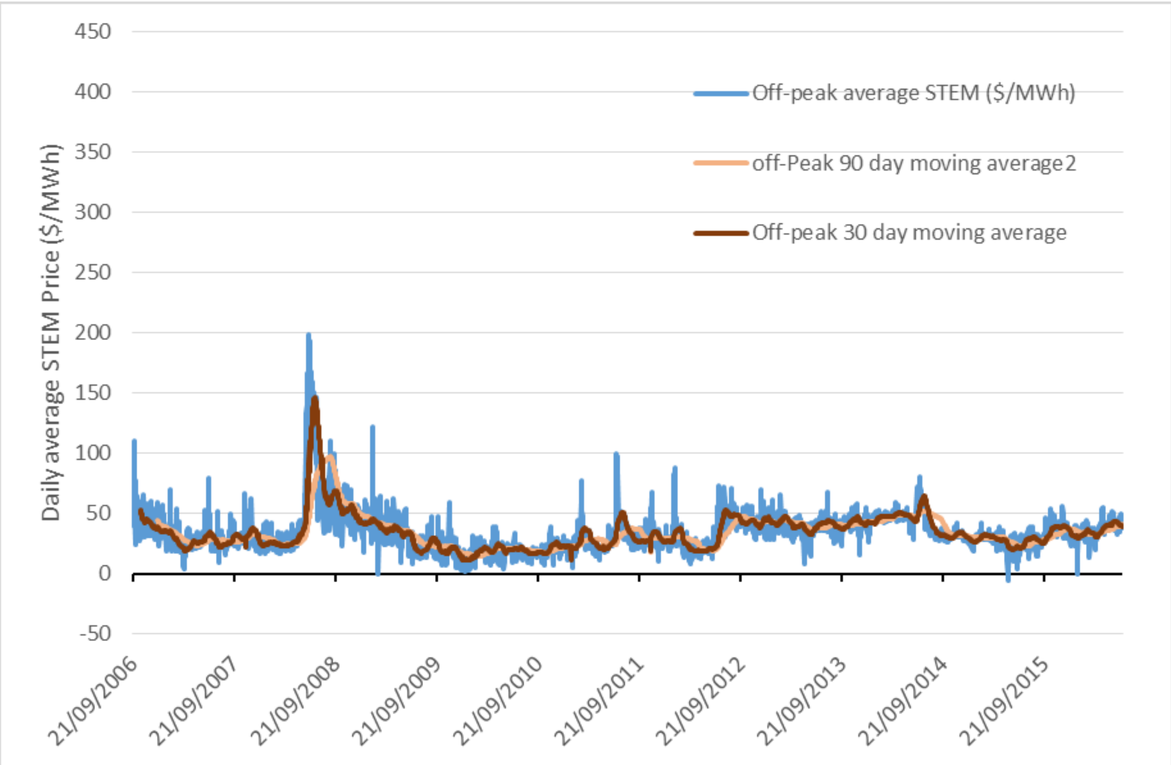
Figure 25 and Figure 26 below illustrate, respectively, daily average peak and off-peak STEM clearing prices since market start.

Figure 25 Daily average peak STEM prices



Source: Australian Energy Market Operator, ERA Analysis

Figure 26 Daily average off-peak STEM prices



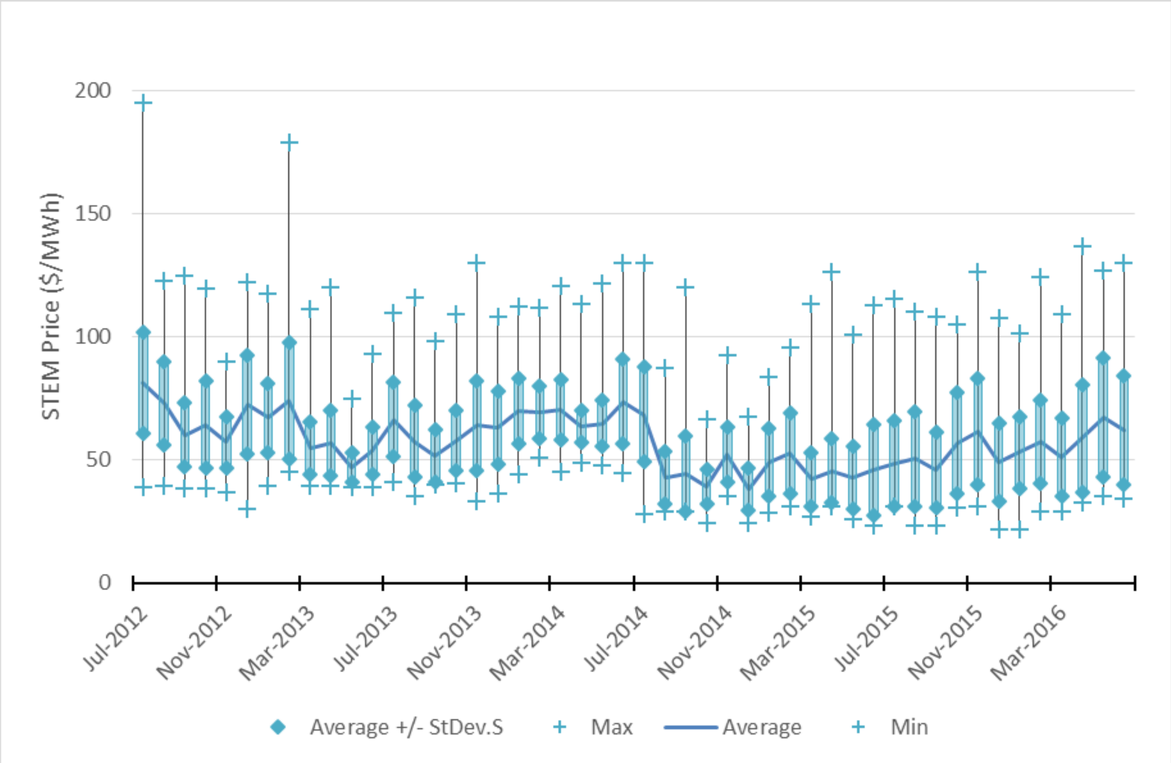
Source: Australian Energy Market Operator, ERA Analysis

The effect of the carbon pricing mechanism, introduced in July 2012 and repealed in July 2014, needs to be considered when comparing prices across periods.

Volatility of Short Term Energy Market Clearing Prices

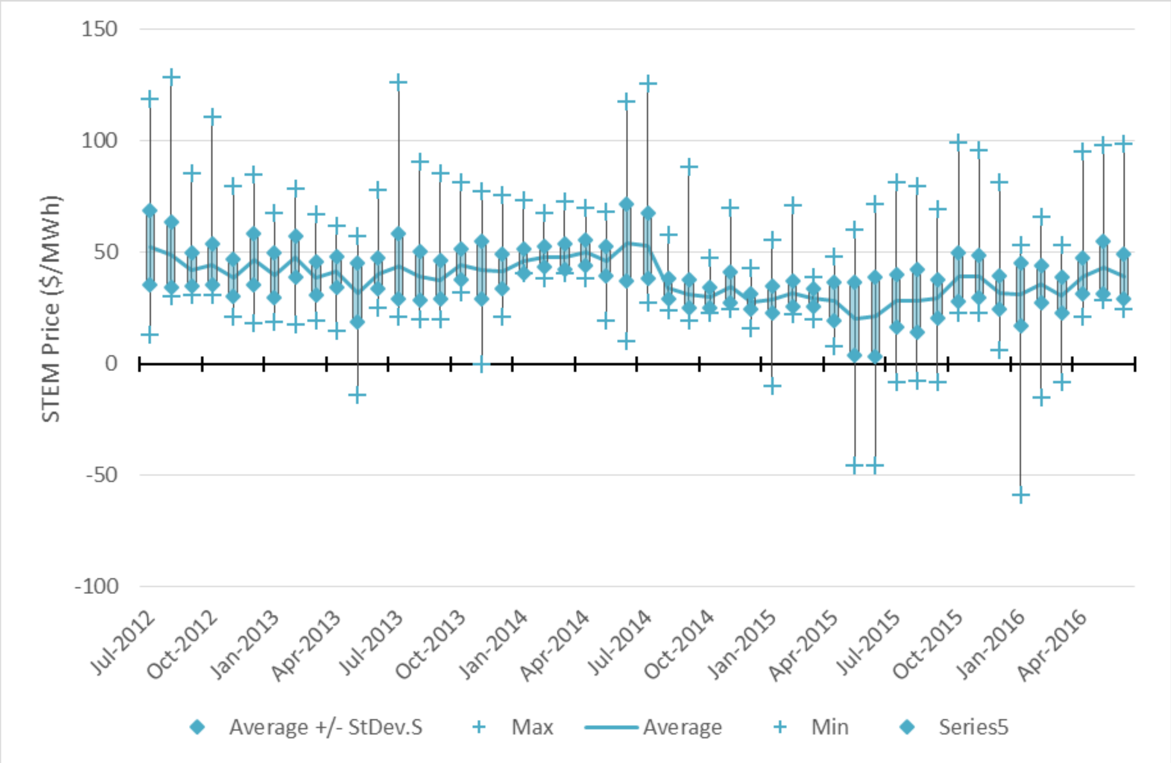
Figure 27 and Figure 28 show the mean and standard deviation (as well as maxima and minima), by month, of STEM clearing prices for peak and off-peak trading intervals, from the start of the Balancing Market to 30 June 2016.

Figure 27 Summary statistics for STEM clearing prices in peak trading intervals (per calendar month)



Source: Australian Energy Market Operator, ERA Analysis

Figure 28 Summary statistics for STEM clearing prices in off-peak trading intervals (per calendar month)

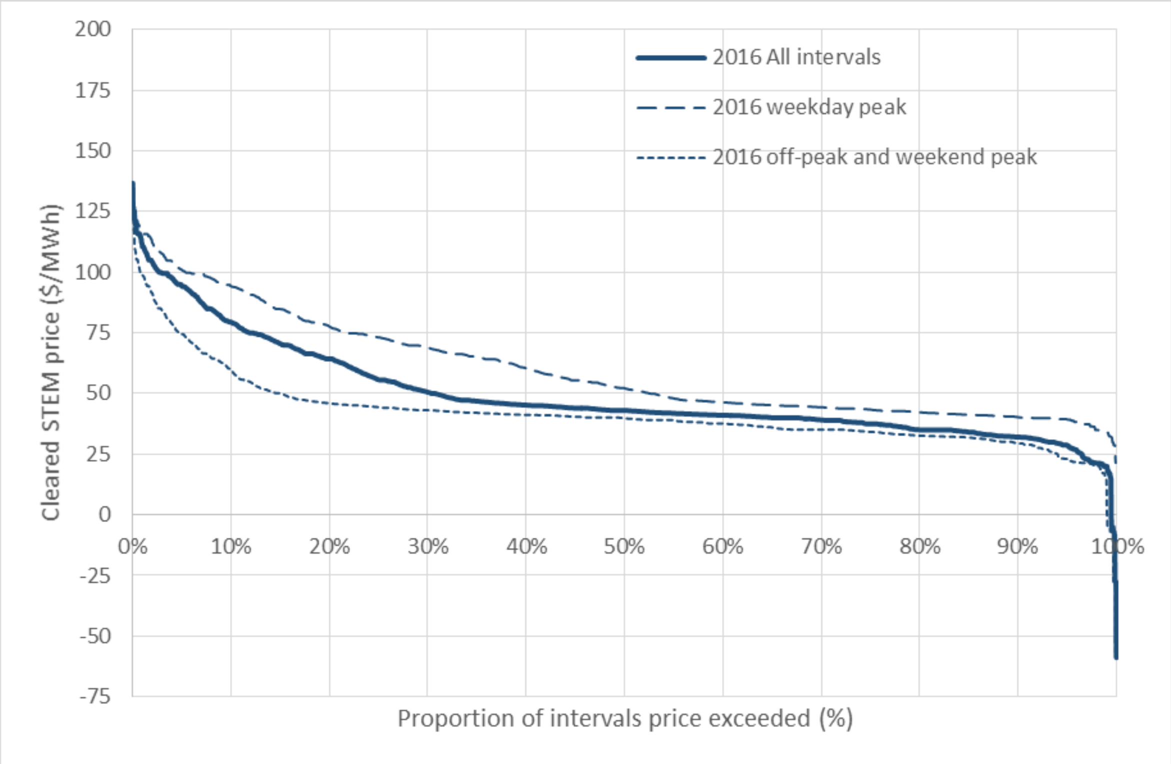


Source: Australian Energy Market Operator, ERA Analysis

High prices in the Short Term Energy Market

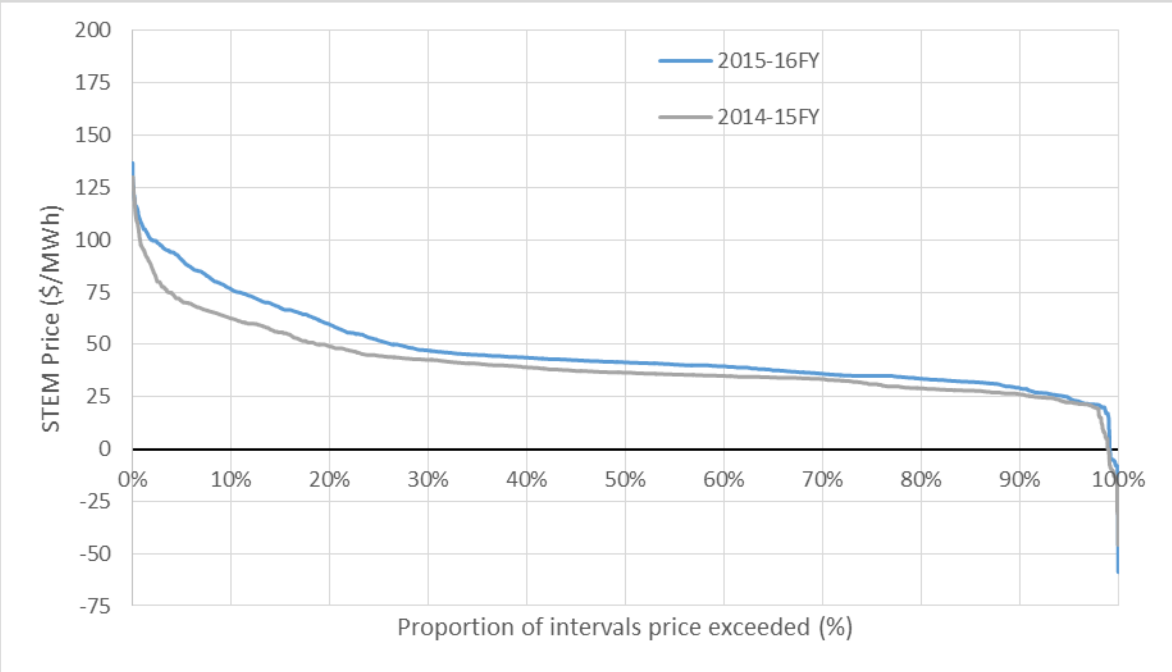
The price duration curves in the figures below show the average level of prices has increased during 2015/16 with a higher incidence of prices above $50 per MWh.

Figure 29 2015-16 financial year price duration curve including weekday peak and off-peak and weekend peak intervals



Source: Australian Energy Market Operator, ERA Analysis

Figure 30 Price duration curve 2014-15 financial year and 2015-16 financial year



Source: Australian Energy Market Operator, ERA Analysis

From 1 July 2012 to 30 June 2016, the STEM price has never reached the maximum STEM price or the alternative maximum STEM price.

Balancing Market

Since July 2012, all energy has been dispatched through the balancing market. Participants pay or receive the difference between their net contract position (i.e. quantities traded bilaterally or in the STEM) and their actual generation or load. The balancing market requires submission of balancing offers for all generators, apart from those on an approved planned outage or forced outage. Balancing offers include quantity and price pairs specifying the capacity at which a market participant is willing to be dispatched.

Market participants must offer prices within the energy price caps and must not exceed 'its reasonable expectation of the short run marginal cost' when they have market power.[54] Market participants other than Synergy are able to revise their offers up to two hours prior to the trading interval commencing to reflect changes in market conditions. Synergy has further restrictions and different gate closure times.

As has been the case since the WEM commenced, Synergy is able to offer its facilities on a portfolio basis and is treated as a single balancing facility. Synergy is able to offer its portfolio in 35 tranches and IPPs can offer 10 tranches for each scheduled generating facility. The market rules only allow intermittent generating units to offer as a single tranche with offers include price and estimated output. Synergy is also able to offer a facility on a stand-alone basis consistent with IPPs but to date has not.

The balancing offer submissions are used to develop the balancing merit order, which is used to determine which facilities are dispatched by System Management.

Any deviation market participants are required to make from their net contract position is treated as a balancing market transaction.[55] Market participants are paid the final balancing price on their metered balancing quantities, i.e. the difference between their net contract position and actual generation or load. This differs from the NEM where settlement is based on total generation and load, i.e. the balancing market is gross pool dispatch but net settlement.

The balancing market design assumes that all generators have unconstrained access to the network and requires System Management to dispatch generators based on the balancing merit order. The balancing merit order used to develop the dispatch order is based on the information included up to half an hour prior to commencement of the trading interval. However, sometimes System Management needs to change the dispatch order. This could be due to system related reasons (e.g. a transmission line or generator outage) or non-system related reasons (e.g. if the system load forecast is too low, System Management may fail to dispatch a generator that is later found to have been in merit).

Generators dispatched or curtailed out of merit by System Management receive compensation. Constrained on compensation is received by the generator if more energy is dispatched from that generator than indicated by its balancing submission offer price

[54] Market Rules 6.6.3 and 6.6.5
https://www.erawa.com.au/cproot/14629/2/Wholesale%20Electricity%20Market%20Rules%20(WEM%20Rules)%20-%20Rule%20Change%20Panel.pdf

[55] 'Net contract position' is a Participant's bilateral contract position net any energy traded on the STEM.

compared to the balancing price. For example, where System Management dispatch a generator to maintain system security in the event of a forced outage or a network outage.

Constrained off compensation is received by the generator if it was not or could not be dispatched by System Management despite having a balancing submission offer price lower than the balancing price. This could be due either to system related reasons (e.g. a transmission line outage) or non-system related reasons (e.g. if the system load forecast is too low, System Management may fail to dispatch a generator that is later found to have been in merit).

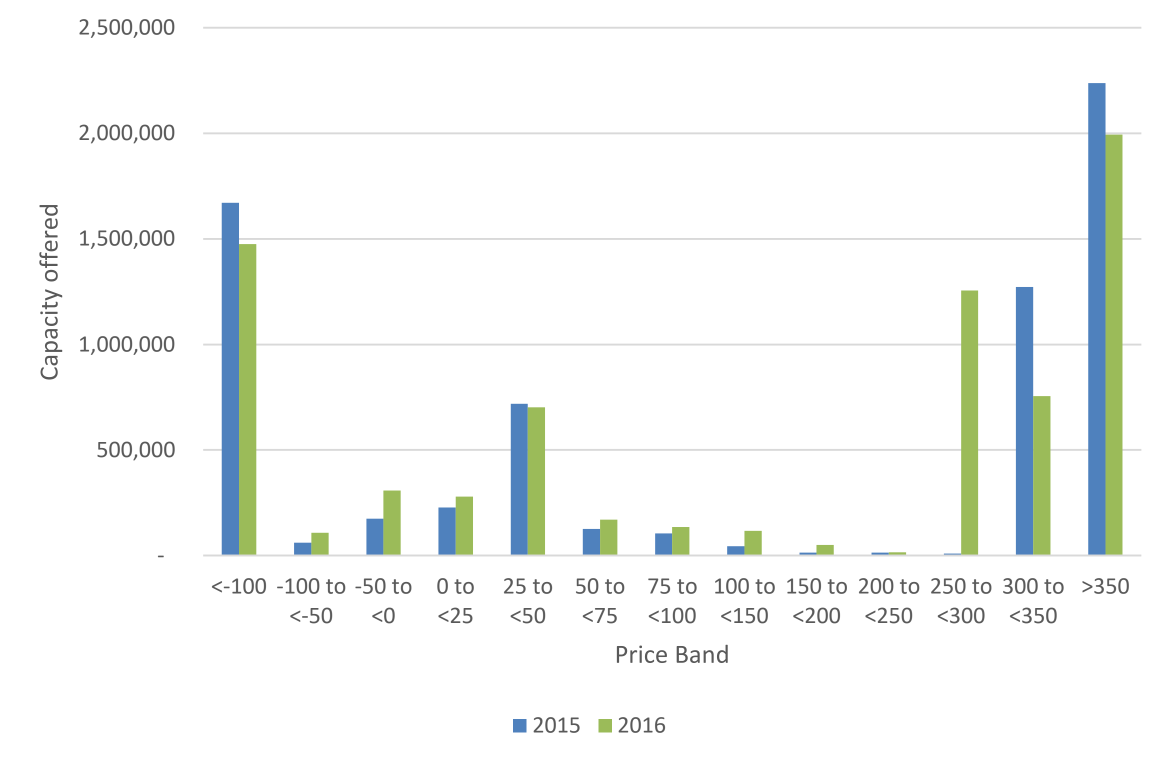
All market customers fund constrained on and off payments in proportion to their share of total energy consumption.

The new balancing market addressed many of the problems associated with the previous arrangement where Verve Energy was the sole provider of balancing services. The new market results in much greater transparency and provides greater opportunities for IPPs to participate. The shorter gate closure, compared with the STEM, enables generators to respond better to changing circumstances.

The ‘Market Rules Evolution Plan: 2013-2016’ identified a number of further potential improvements including:

- improving the timing and content of dispatch advisories issued by System Management so they provide sufficient notice and information of conditions to enable generators to respond appropriately;
- reducing gate closure times;
- improving the accuracy of forecast loads and prices; and
- requiring Synergy to offer each generation facility on a stand-alone basis, rather than the current portfolio arrangement.

Figure 31 Quantity of energy offered (MWh) in balancing by price bands and distribution of settlements within price bands

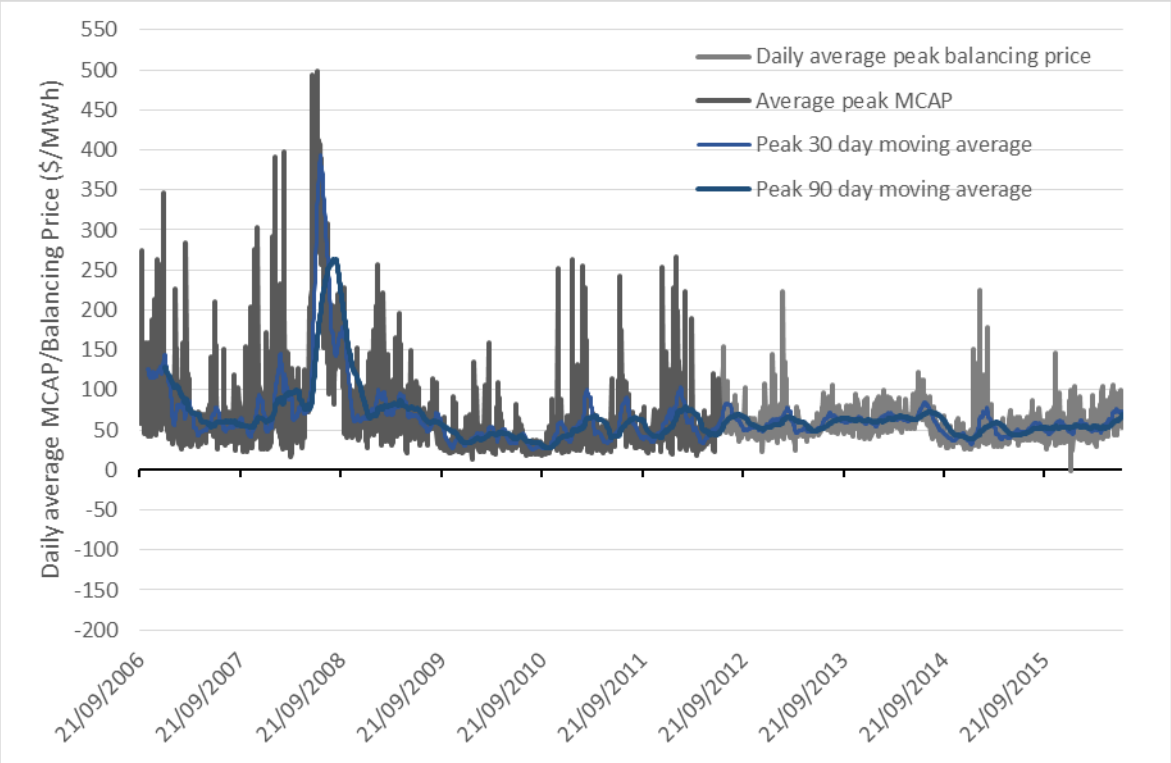


Source: Australian Energy Market Operator, ERA Analysis

Balancing Prices

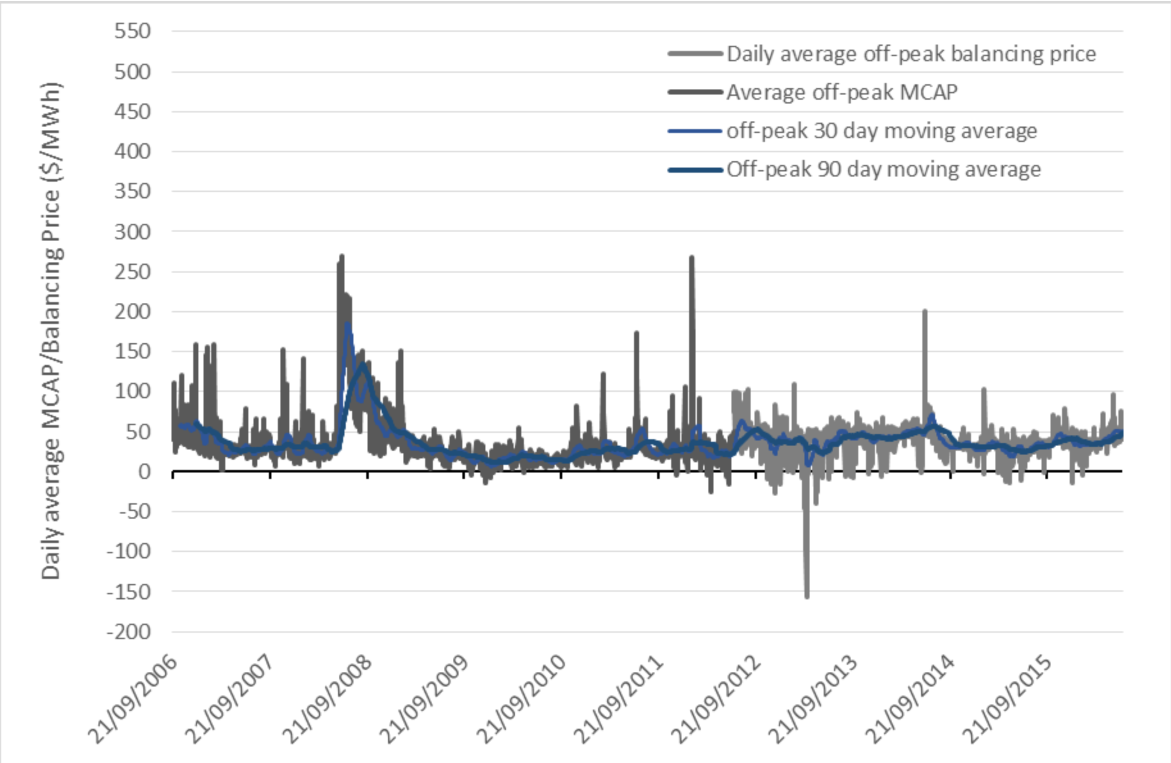
Figure 32 and Figure 33 illustrate, respectively, average daily peak and off-peak balancing prices for each trading day from market commencement up to 30 June 2016, as well as 30-day, 90-day and annual moving average prices.

Figure 32 Average daily peak MCAP and Balancing Market price



Source: Australian Energy Market Operator, ERA Analysis

Figure 33 Average daily off-peak MCAP and Balancing Market price



Source: Australian Energy Market Operator, ERA Analysis

Table 5 sets out the mean and standard deviations of the peak and off-peak final balancing price over the last four years.

Table 5 Mean and standard deviations of balancing prices ($/MWh)

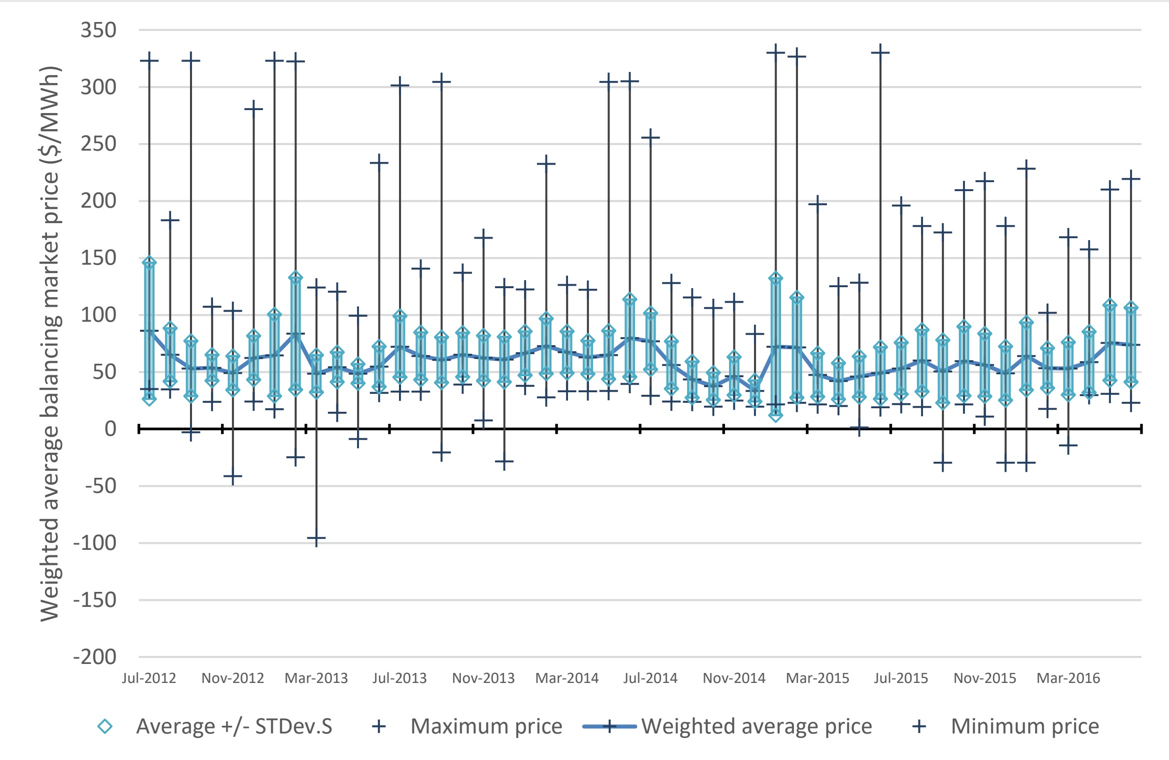
Financial Year Ending	Average peak balancing merit order_PRICE	StdDev peak balancing merit order _PRICE	Average off-peak balancing merit order _PRICE	StdDev off-peak balancing merit order _PRICE
2012-13	$58.21	$30.66	$38.19	$36.07
2013-14	$64.82	$22.54	$47.01	$20.60
2014-15	$49.88	$29.68	$32.55	$19.01
2015-16	$56.51	$28.29	$38.84	$17.36

Figure 34 and Figure 35 below illustrate average monthly weekday peak and off-peak period balancing prices (respectively) for each trading day, from market commencement to 30 June 2014.

The effect of the carbon pricing mechanism, introduced in July 2012 and removed in July 2014, needs to be considered when comparing prices across the period.

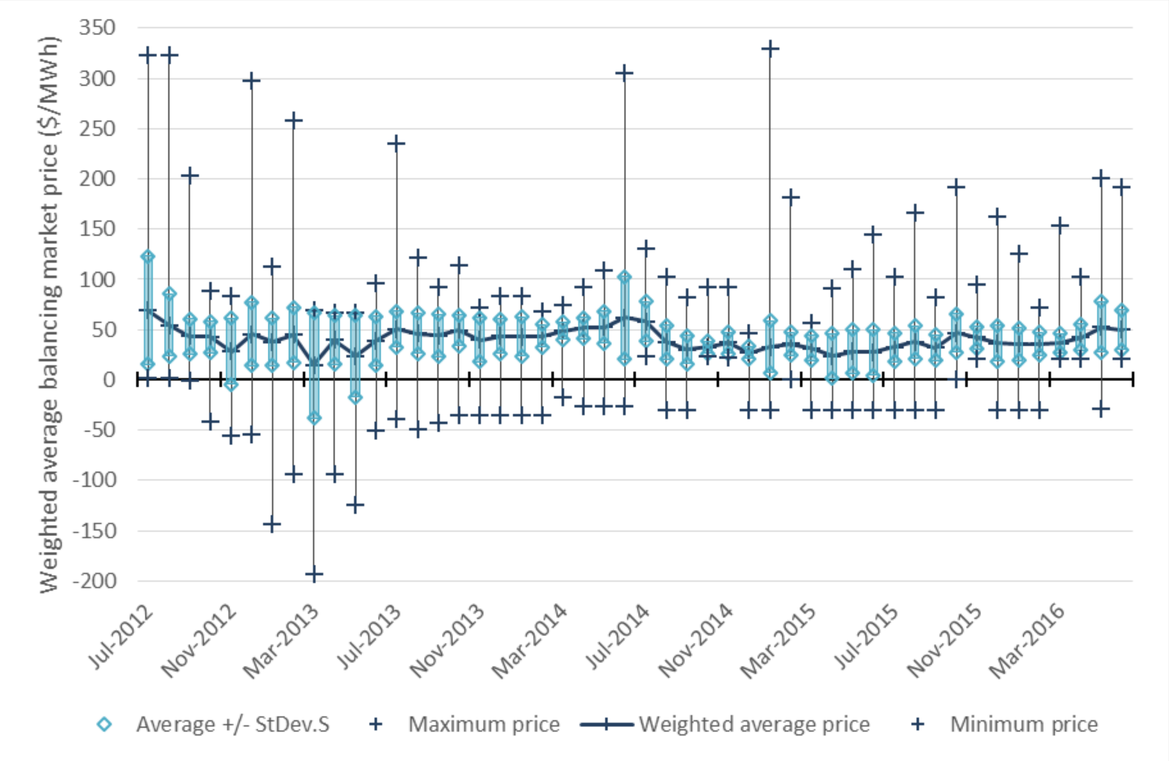
Volatility in balancing prices can be understood by comparing means and standard deviations. Figure 34 and Figure 35 show the means, standard deviations, maximum and minimum values from 1 July 2012 to 30 June 2016 of final balancing prices.

Figure 34 Summary statistics for final balancing price during peak trading intervals



Source: Australian Energy Market Operator, ERA Analysis

Figure 35 Summary statistics for final balancing price during off-peak trading intervals



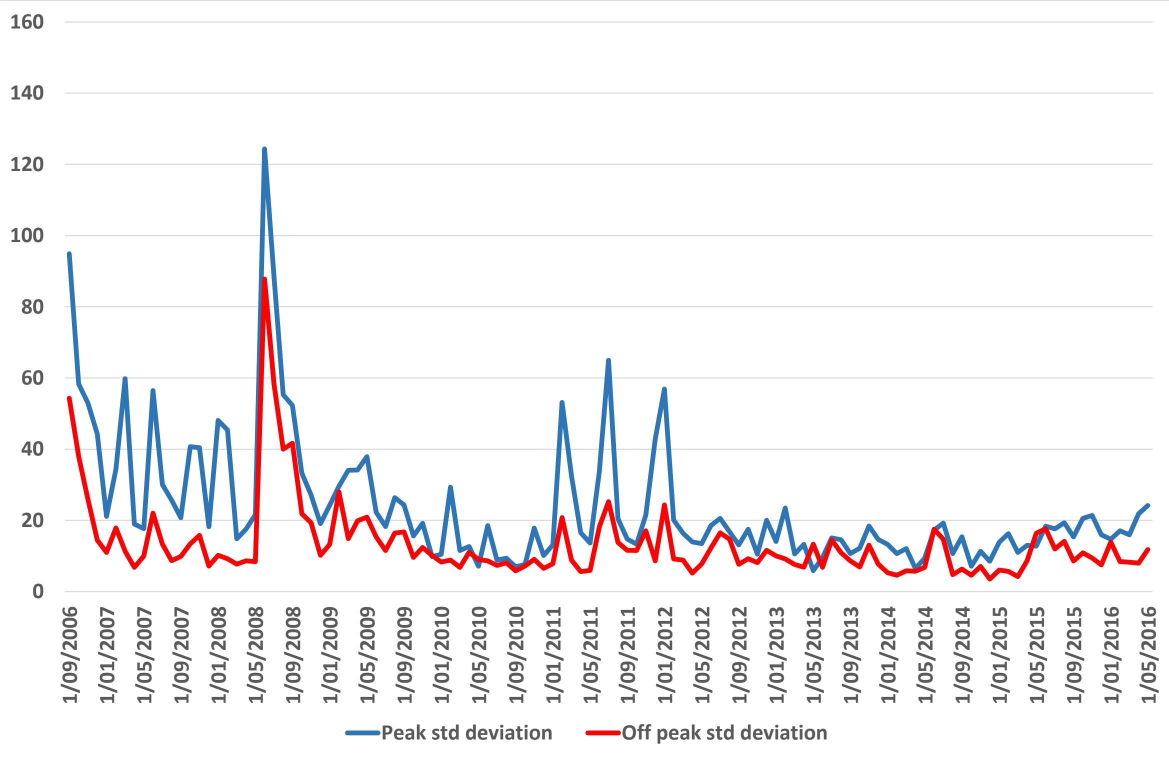
Source: Australian Energy Market Operator, ERA Analysis

Figure 36 and Figure 37 provide the standard deviation in prices for the STEM and marginal cost administered price,[56] and balancing markets, respectively. Standard deviation is a measure of how closely or widely a set of values are dispersed around the set's mean.[57] The higher the standard deviation, the more dispersed the data and, in this context, the more volatile the price.

[56] The 'marginal cost administered price' was in place from market start to 30 June 2012 when Verve was the default provider for balancing services and was paid the marginal cost administered price for providing any balancing energy deviations. The balancing market and its clearing price replaced the marginal cost administered price in July 2012. Data in Figure 32 and Figure 33 show the marginal cost administered price up to 30 June 2012 and balancing market data thereafter.

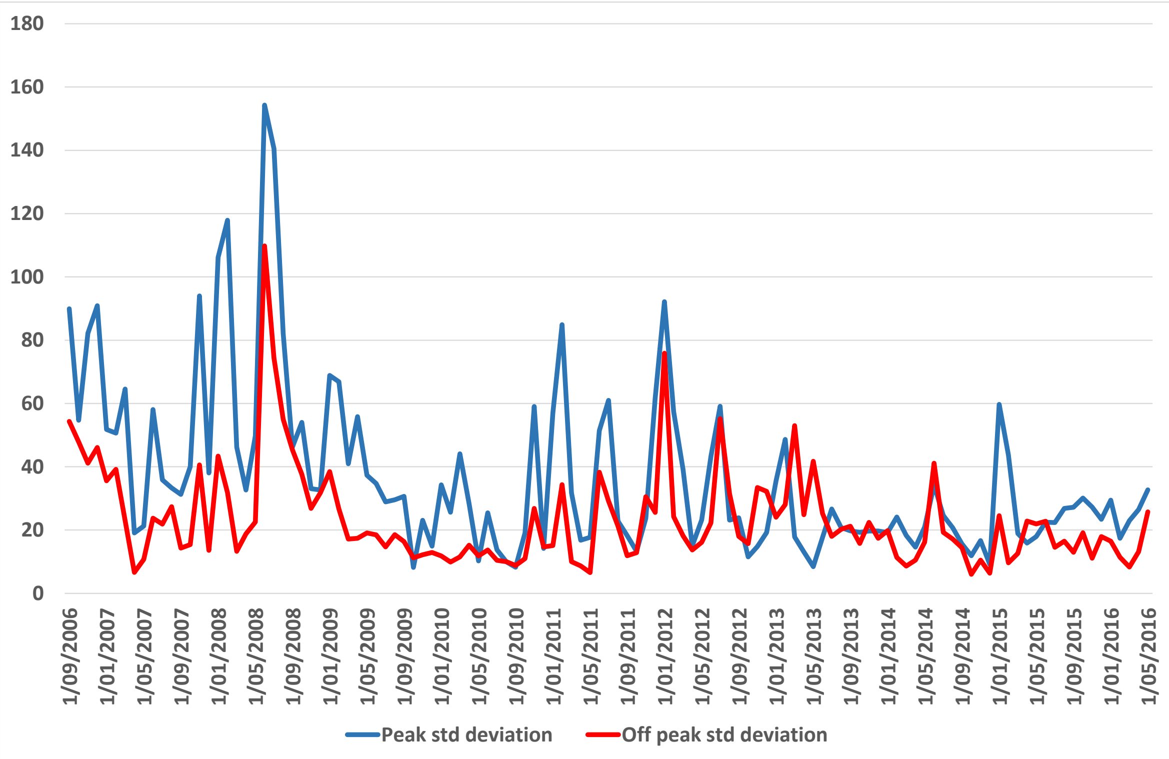
[57] D. Gujarati and D. Porter, *Basic Econometrics*, New York, McGraw-Hill Education, 2009, p. 810.

Figure 36 Monthly STEM peak and off-peak price standard deviation



Source: Australian Energy Market Operator, ERA Analysis

Figure 37 Monthly marginal cost administered price/balancing market peak and off-peak price standard deviation



Source: Australian Energy Market Operator, ERA Analysis

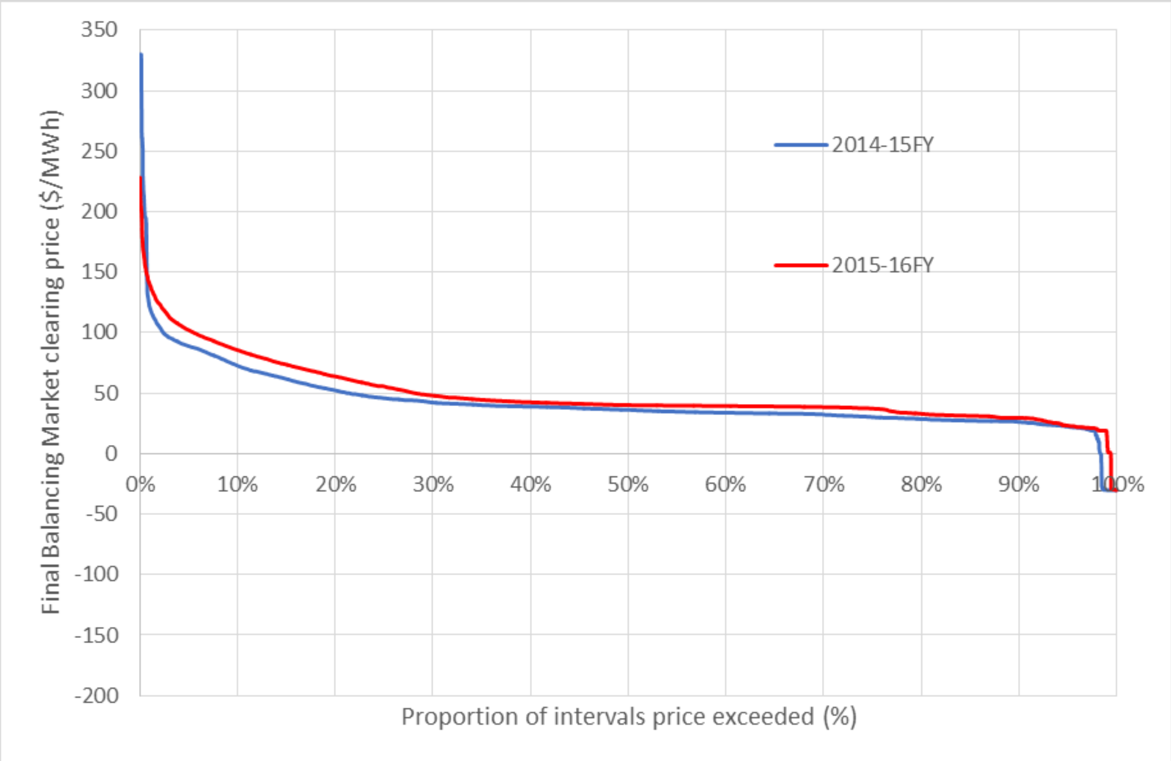
Volatility in prices in the STEM and balancing markets has decreased over time. STEM prices have been relatively stable since 2012, while balancing market prices remained volatile in 2012 and early 2013, before also becoming less volatile over time. Balancing market volatility in late 2012 and early 2013 may have been a result of the transition from Verve providing balancing services alone, to the new competitive balancing market, with the marginal cost administered price replaced on 1 July 2012.

The EMR process capacity reforms seek to resolve capacity oversupply. If these reforms are successful, price volatility is expected to increase.

High Balancing prices

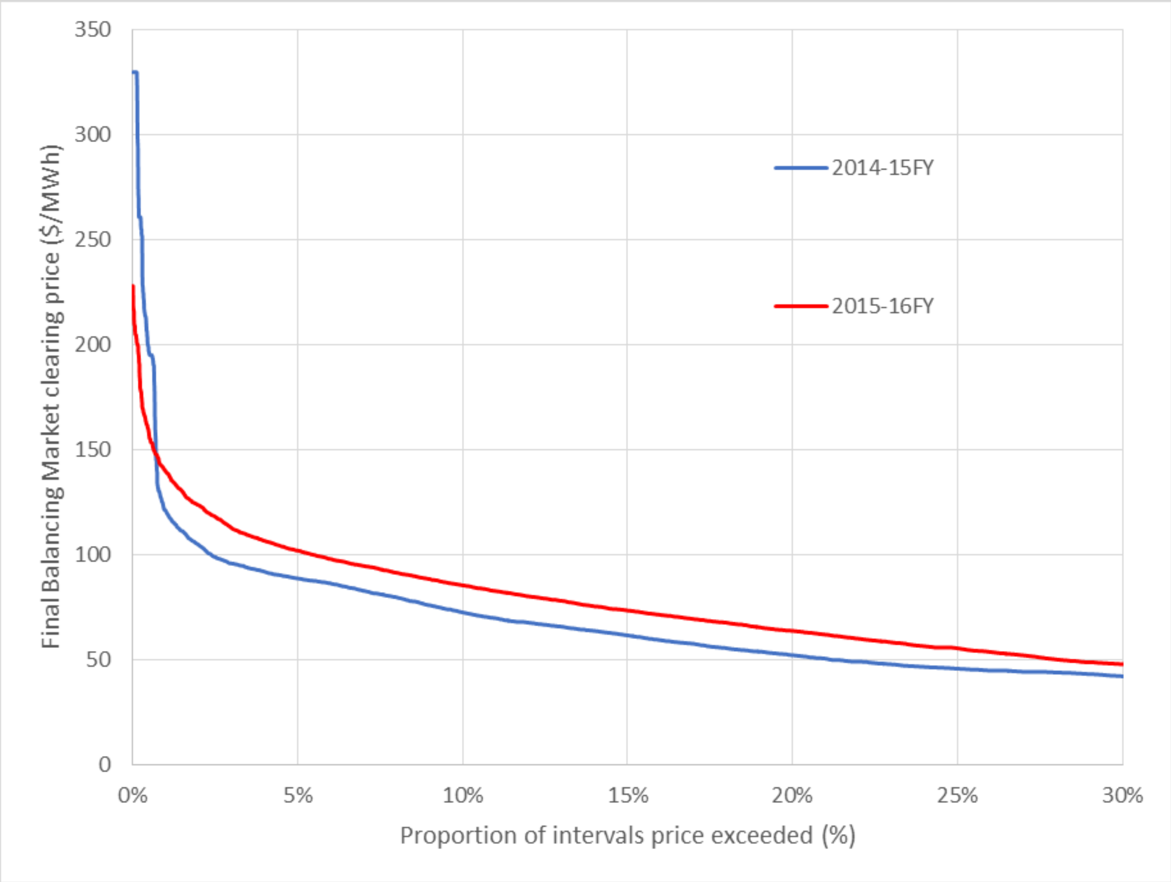
Figure 38 shows price duration curves for the balancing market by financial year. The upper 20% of the 2015-16 offer curve is higher than that of 2014-15 financial year, but for the highest two per cent moderated by a lower price cap. Figure 39 shows the upper portion of the curve.

Figure 38 Balancing market price duration curve by financial year



Source: Australian Energy Market Operator, ERA Analysis

Figure 39 Upper 30% of price duration curve by financial year.

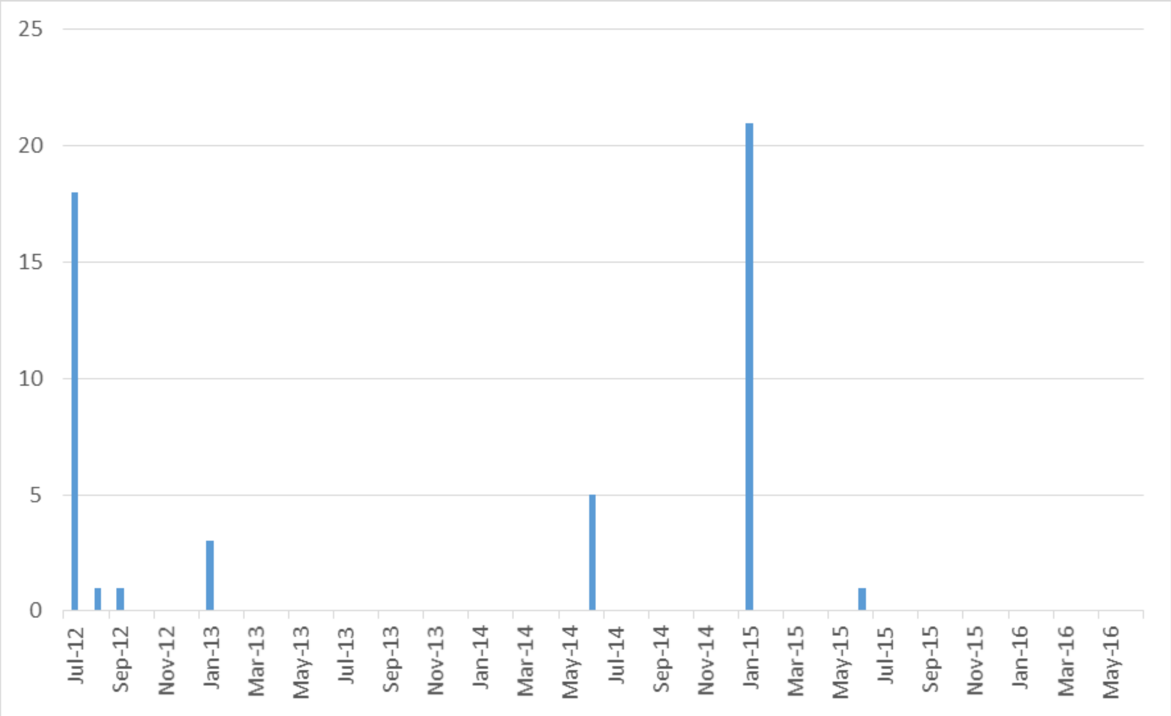


Source: Australian Energy Market Operator, ERA Analysis

From 1 July 2012 to 30 June 2016, the final balancing price did not reach the alternative maximum STEM price, but did reach the maximum STEM price in 50 trading intervals. Figure 38 shows the number of trading intervals per month where the final balancing price reaches the maximum STEM price from 1 July 2012 to 30 June 2016.[58]

[58] The Maximum STEM price is the Balancing and STEM market price cap for non liquid fuels. The Alternative Maximum STEM price is the price cap for plant expected to run on liquid fuels in the STEM and Balancing markets. These price caps are defined by Market rules 6.20.2 and 6.20.3.

Figure 40 Number of trading intervals per month where the final balancing price reaches the maximum STEM price



Source: Australian Energy Market Operator, ERA Analysis

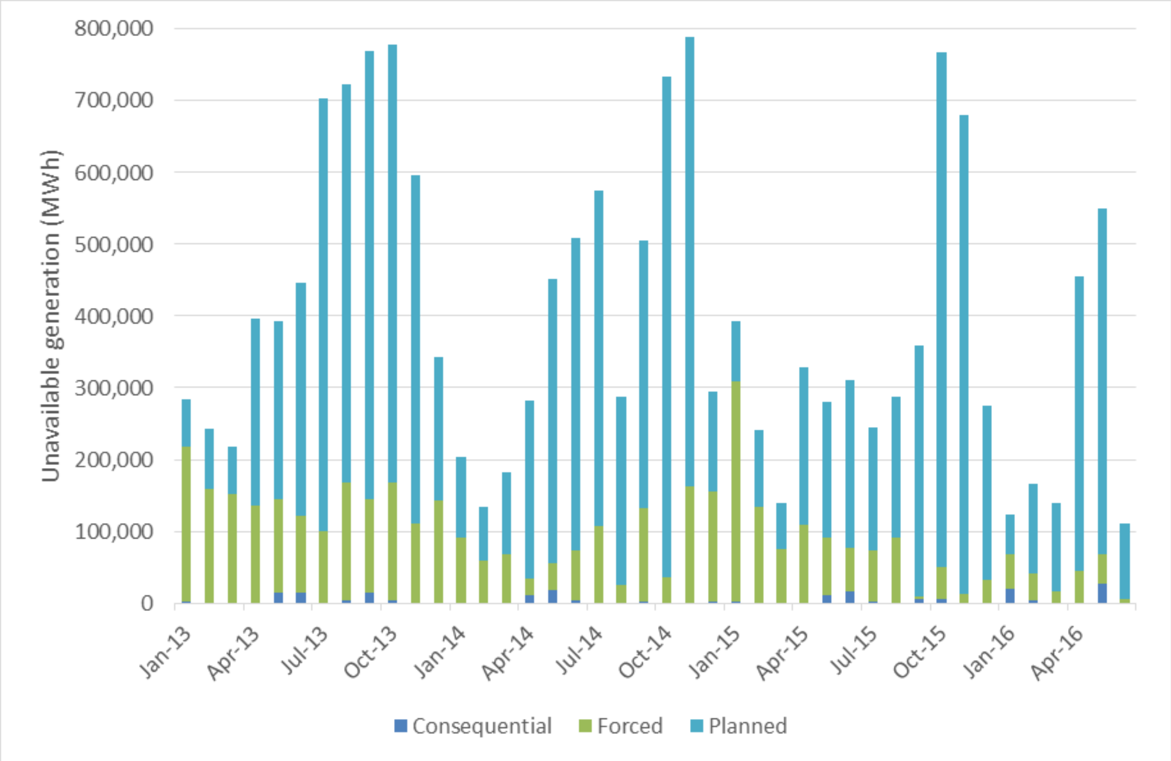
Effect of Planned Outages on Prices

Outages will influence the shape of the offer curve. As generators become unavailable, the offer curve above that point will shift to the left. How outages influence the shape of the offer curve will depend on the position in the balancing merit order plant normally occupies, at what time of day, and what time of year.

Drawing definitive conclusions about the influence of outages on price is difficult. In particular, portfolio bidding complicates the task of understanding how the offer curve relates to individual generators.

Figure 41 shows monthly unavailable generation by outage type. The planned outage pattern reflects generators preparing their plant for the summer peak period. Ideally, major maintenance should occur outside months where temperature sensitive loads increase demand (such as in winter or summer peaks).

Figure 41 Monthly unavailable generation by outage classification



Source: Australian Energy Market Operator, ERA Analysis

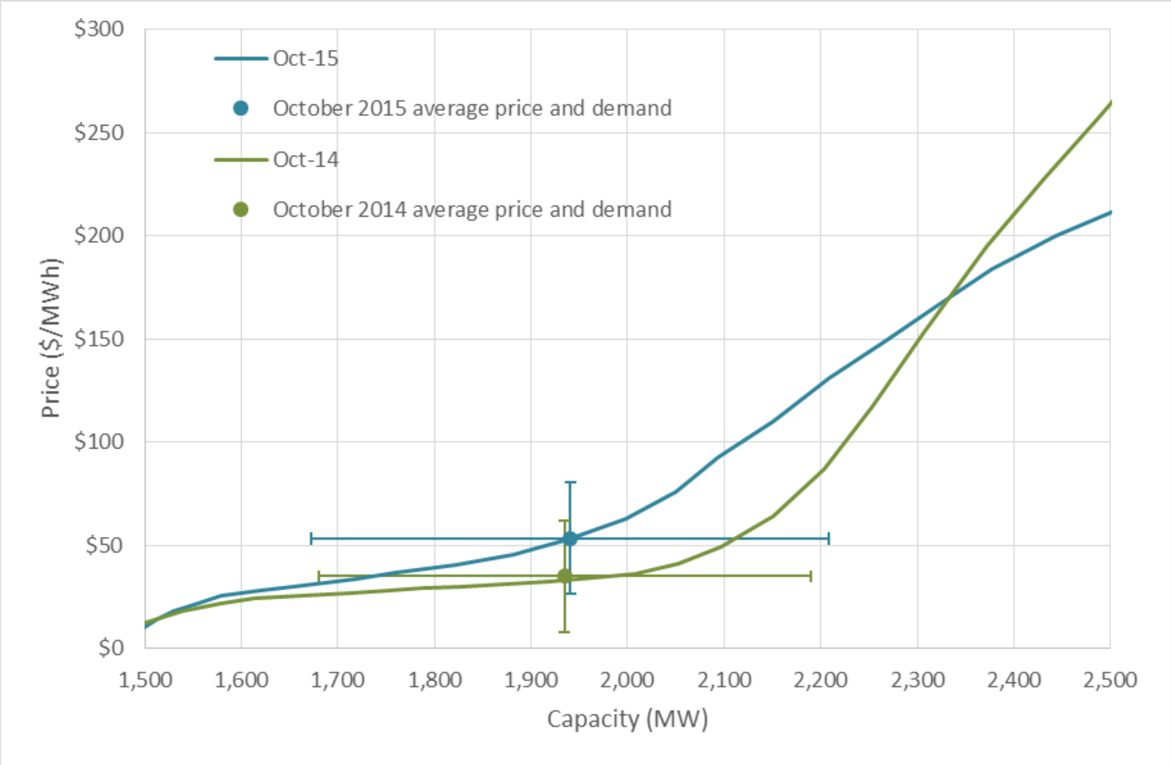
The October maintenance period in 2014 and 2015 provides a case in point. Throughout most of 2015, there was a strong positive correlation between price and demand averaging 0.64. However, October and November 2015 had an uncharacteristically low correlation of around 0.38 in October and 0.48 in November.

This relationship between price and demand also reduced at a similar time of year in October 2014. However, prices in 2015 were towards those in the summer peak period, in 2014 they were lower than annual average prices after adjusting for the influence of the carbon price.[59] Although outage levels were similar between October and November 2015 and the same period in 2014, the plant mix was different. The two mid-merit plant, Cockburn 1 and Newgen Kwinana were on extended outage in 2015. This may have been sufficient to alter the offer curve such that although the distribution of demand was very similar, pricing outcomes were different.

[59] This is after adjustment for the influence of the carbon pricing mechanism on electricity prices. The carbon pricing mechanism influence on prices was estimated using the average carbon intensity of the South West Interconnected System for the 2013/14 financial year published in the National Carbon Accounts multiplied by the carbon price for the same period. This will tend to overestimate the effect of carbon on electricity price as the marginal generator, usually gas, will be less intensive than the average carbon intensity that includes coal fired generation that is less influential in price setting. Cogeneration and renewable generators will shift the average carbon intensity down.

The offer curves have not been adjusted for the influence of the carbon pricing mechanism.

Figure 42 October 2014 and 2015 final balancing merit order offer curves, price and demand[60]

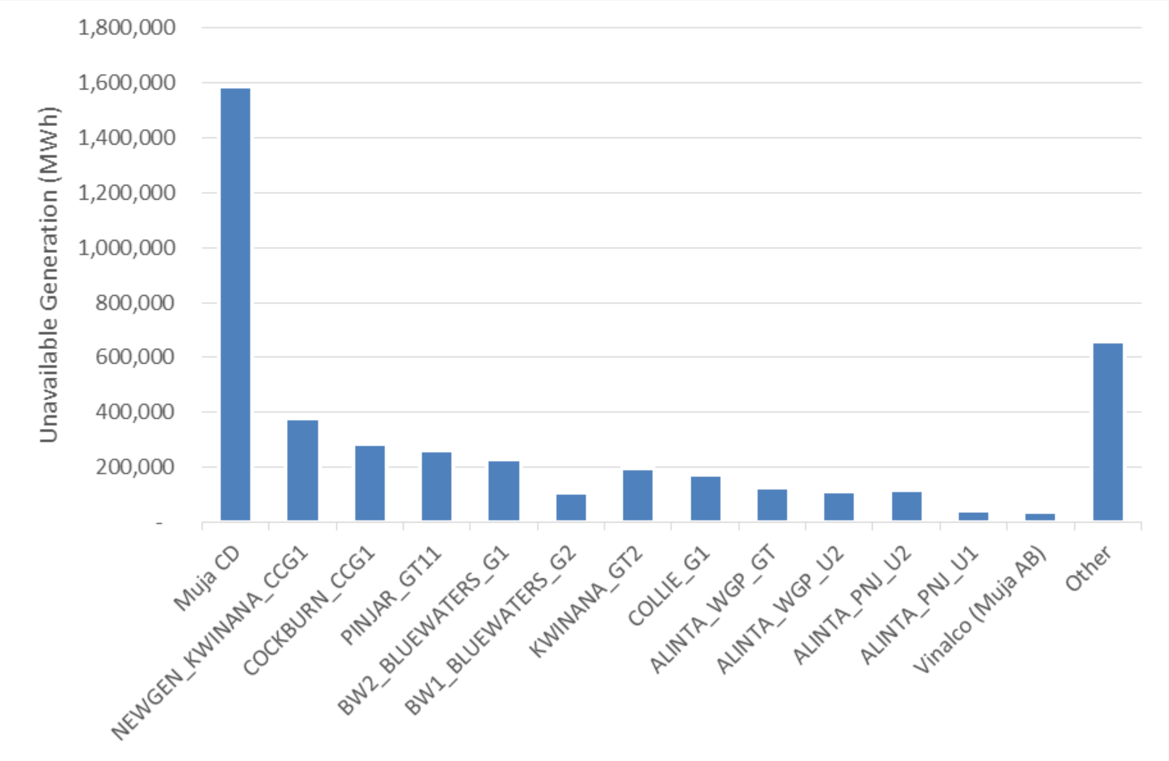


Source: Australian Energy Market Operator, ERA Analysis

During 2015, just over half of unavailable generation accrued to three plant, Muja CD (units 5 through 8), Newgen Kwinana and Cockburn 1. Muja CD was the single largest plant on outage in 2015, with an average outage over the year equivalent to 176 MW from a total installed capacity of 808 MW or just over one fifth of plant capacity. Figure 43 below shows outages by market participant during the 2015 calendar year.

[60] Error bars show one standard deviation in demand (horizontal) and price (vertical) for the average demand and price

Figure 43 Unavailable generation by plant (2015)



Source: Australian Energy Market Operator, ERA Analysis

The planned maintenance program in 2014 did not prevent substantial outages during the 2015 peak period. The highest level of forced outages occurred in January 2015. Muja CD (Muja Units five through eight) featured strongly in Synergy's planned and forced outages.

Although outages and prices are generally weakly correlated, some plant will be more important than others. For example, the outage of a baseload generator will be more likely to influence price than a peaking plant that rarely runs, even though the baseload generator may only rarely directly set the price. There may also be some thresholds above which prices become more sensitive.

The current rules for approving outages prevent the system manager from considering costs associated with outages.[61] Reforms merging the system manager and market operator may improve understanding of outage implications before the event. However, AEMO can only approve outages using criteria contained in the market rules.

Increases in Balancing Prices

Balancing market prices have been increasing since April 2016. This is more apparent in peak than off-peak intervals, and after adjusting for the influence of the carbon price on the balancing price.[62]

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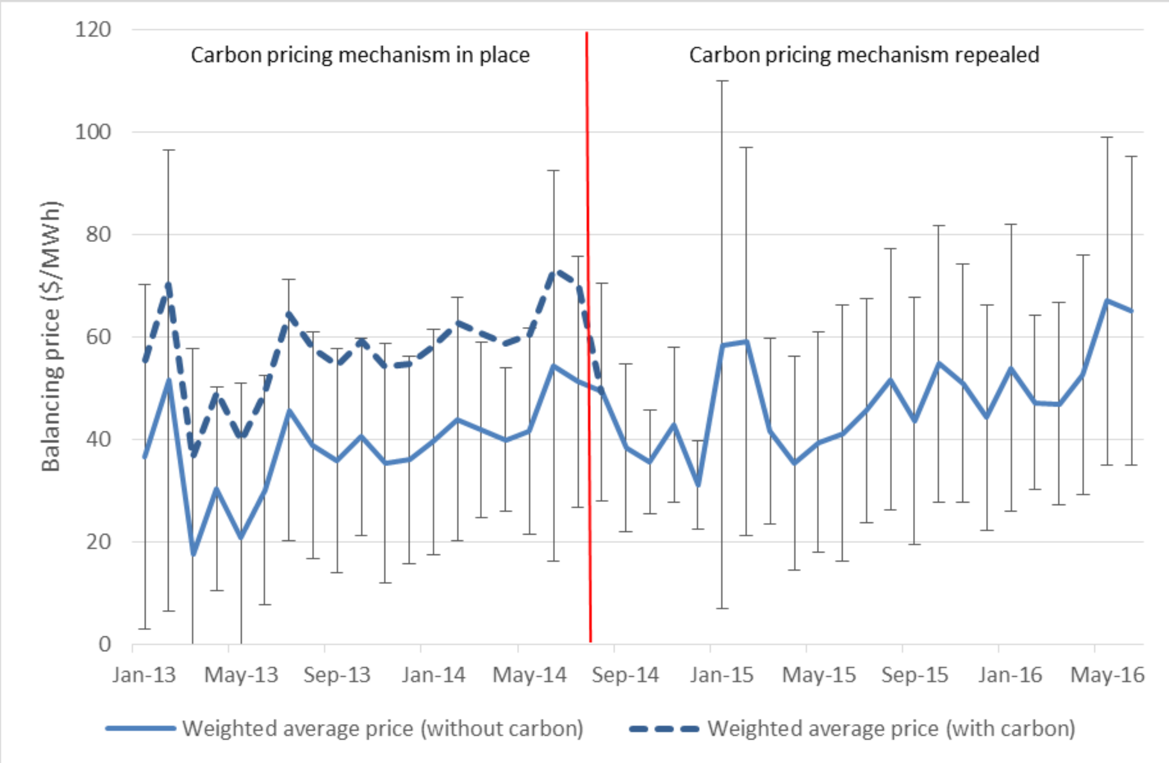
[61] Market rules 3.18.11 and 3.18.11A. http://www.finance.wa.gov.au/cms/uploadedFiles/Public_Utilities_Office/Electricity_Market_Review/WEM-Rules-with-Schedule-commencing-1-June-2016.pdf

[62] Carbon price adjustments are the product of the carbon price in place at the time multiplied by the average South West Interconnected System carbon intensity used for the National Greenhouse and Energy

Figure 44 shows monthly weighted average prices from January 2013 to end of June 2016. The weighted average price in the balancing market from January 2013 (up to the repeal of the carbon price) was around $57/MWh and just under $48/MWh after the carbon price was repealed. Since March 2016, the prices have exceeded those in the summer peak period of January and February into the range of prices witnessed when the carbon pricing mechanism was in place.

Figure 44 Balancing market weighted average prices – all intervals



Source: Australian Energy Market Operator, ERA Analysis

Figure 45, Figure 46, Figure 47 and Figure 48 show the average daily load profile over the month and the average balancing market prices for March, April, May and June, respectively, between 2015 and 2016. Although there are some differences in overall demand between March and June 2015 and 2016, the difference is relatively modest and in April and May, the difference was negligible.

Reporting System. This may overestimate the influence of carbon pricing as the electricity price is set by the marginal generator. The influence of the carbon pricing mechanism on balancing price is consequentially that of the marginal generator. However, it will provide a general indication of the carbon effects on pricing outcomes. These accounting factors are available from:

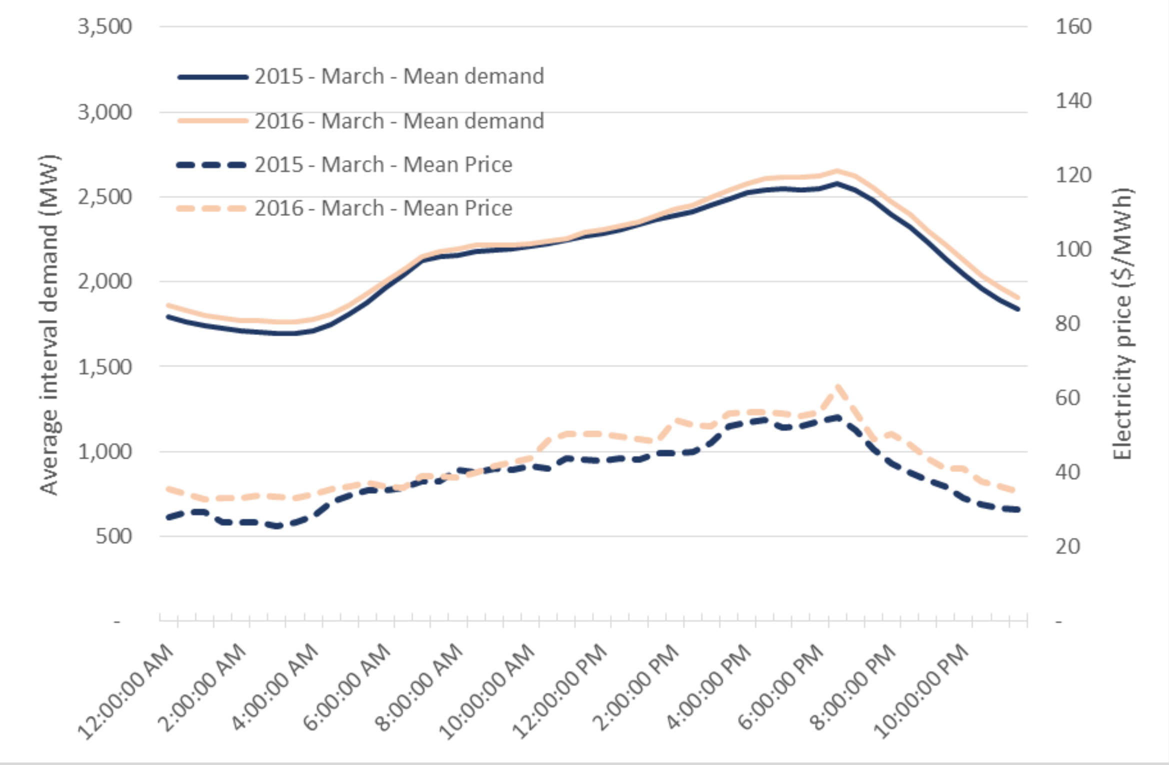
Department of Climate Change and Energy Efficiency (2012) National Greenhouse and Energy Reporting System – Technical Guidelines for the estimation of greenhouse gas emissions by facilities in Australia, July 2012, Environment Department, Canberra, p425, http://www.environment.gov.au/system/files/resources/5e11ecad-6d23-4e4b-bf9d-d4630a4e523b/files/nger-technical-guidelines-2012.pdf

and

Department of Climate Change and Energy Efficiency (2013) National Greenhouse and Energy Reporting System – Technical Guidelines for the estimation of greenhouse gas emissions by facilities in Australia, July 2012, Environment Department, Canberra, p581, http://www.environment.gov.au/system/files/resources/a1f1d8e6-6994-47ef-a6fa-f315084b33f2/files/nger-measurement-technical-guidelines-july-2013.pdf

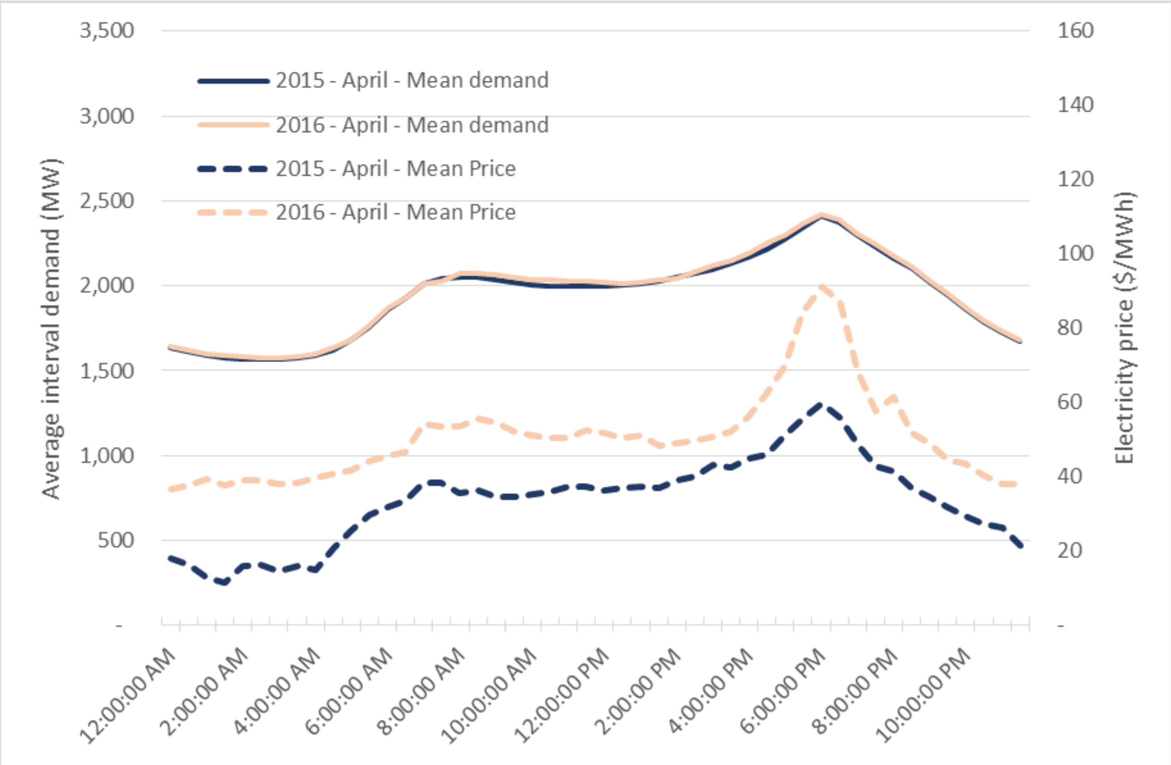
As the daily load profile shifted to the winter profile (typified by a morning and afternoon/evening peak), price increases became noticeable and were greatest during the morning and evening peaks.

Figure 45 Electricity demand and balancing market price March 2015 and March 2016



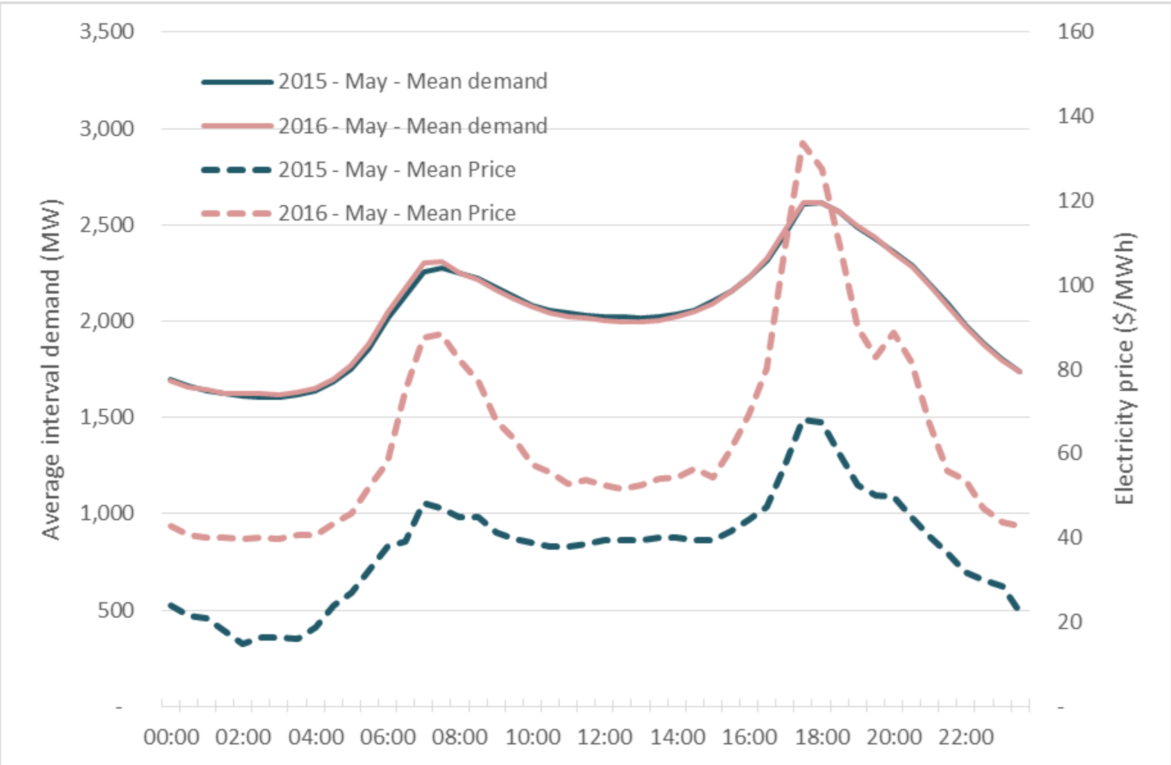
Source: Australian Energy Market Operator, ERA Analysis

Figure 46 Electricity demand and balancing market price April 2015 and April 2016



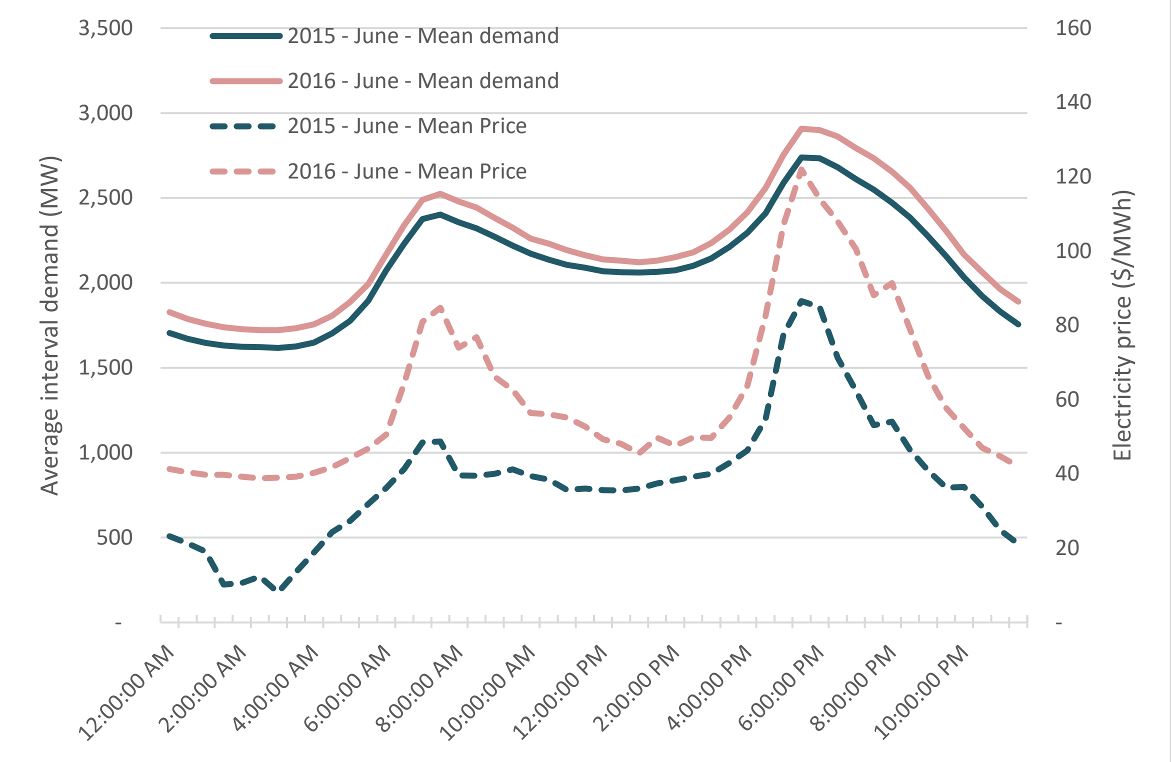
Source: Australian Energy Market Operator, ERA Analysis

Figure 47 Electricity demand and balancing market price May 2015 and May 2016



Source: Australian Energy Market Operator, ERA Analysis

Figure 48 Electricity demand and balancing market price June 2015 and June 2016



Source: Australian Energy Market Operator, ERA Analysis

3.4 Ancillary Services

Ancillary Services are required to maintain power system security and reliability through the control of key technical characteristics, such as frequency and voltage, which ensures that electricity supplies are of an acceptable quality.[63] The market rules define five types of ancillary services applicable in the SWIS:

- spinning reserve[64]
- load rejection reserve[65]
- Load Following Ancillary Service (**LFAS**)[66]
- system restart[67]
- dispatch support services[68].

The ancillary service standards and the basis for setting ancillary service requirements are reviewed on a five yearly basis. The last review, which was undertaken by the IMO, was published in November 2014. Responsibility for conducting the reviews transferred to the ERA on 1 July 2016.

Each year System Management must determine ancillary service requirements and make a plan describing how to meet those requirements.[69] The ERA must audit System Management's ancillary service requirements.[70] System Management publishes a report each year with details of the costs and quantities of ancillary services provided in the previous year and the requirements and plan for the coming year.

Synergy must make its capacity to provide ancillary services from its facilities available to System Management. In broad terms, if Synergy can't supply the required ancillary service, or there is a less expensive alternative, System Management can enter into a contract with another party.

Before entering into any contracts, System Management must seek to minimise the cost of meeting its obligations and consider using a competitive tender process. In the case of contracts for dispatch support services, System Management must obtain the approval of the ERA. The ERA must only review whether the proposed contract would achieve the lowest practicably sustainable cost of delivering the services.

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

[64] Spinning reserve is capacity connected and synchronised or curtailable load that is held in reserve to cover plant failure. It is defined in the market rule 3.9.2 and 3.9.3.

[65] Load rejection reserve is capacity held in reserve to cover scheduled generators rapidly reducing output or for dispatchable loads to rapidly increase consumption. It is defined in the market rule 3.9.6 and 3.9.7

[66] Load following ancillary services covers moment to moment changes in demand or generator output (such as from intermittent generators) to maintain electricity supply quality within system tolerance ranges. It is defined in market rule 3.9.1.

[67] System restart service is generation necessary to support system wide blackout recovery. It is defined in market rule 3.9.8.

[68] Dispatch support service covers generation or demand side arrangements (such as interruptible load) necessary to maintain power quality standards not covered by other ancillary service types. It is defined in market rule 3.9.9.

[69] In accordance with the SWIS operating standards and the ancillary service standards

[70] Previously this was a function of the IMO but transferred to the ERA on 1 July 2016.

The table below sets out the costs of each ancillary service from 1 April 2015 to 31 March 2016 together with how they were procured.

Table 6 Ancillary Services from 1 April 2015 to 31 March 2016

Name of Service	Cost $ million	Procurement Details
Spinning Reserve	$14.6	Synergy provided the majority of spinning reserve and is paid based on a pricing formula using parameters approved by the ERA. System Management also has contracts with Simcoa, and Bluewaters.
Load Rejection Reserve	$-	All provided by Synergy and paid based on a pricing formula using parameters approved by the ERA
Load Following Ancillary Services	$39.8[71]	Competitive market. One IPP who can provide up to 30 MW of the total 72 MW required. Synergy provides the balance and is paid the market price.
System Restart	$0.5	Contracts with Synergy and third parties. Total cost is approved by the ERA on a three yearly basis.
Dispatch Support Services	$2.1	One long standing contract put in place at market commencement with Synergy.
Total	$57.0	

Spinning Reserve

Synergy has been the default provider of the spinning reserve ancillary service[72] since market commencement. Synergy receives a payment from the market, which is calculated as the balancing price multiplied by a margin value that is determined by the ERA under the market rules.[73] System Management may enter into contracts with other participants, providing the cost is less than Synergy. Spinning reserve ancillary service costs are recovered from market generators.

Load Following

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

A competitive LFAS market was introduced on 1 July 2012. Prior to that date, Synergy was the sole provider of LFAS. The key elements of the new market included market derived prices rather than administratively derived prices, and participation being open to all IPPs.

71 Excludes capacity payment which forms part of the RCM

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

73 The margin values are determined for each financial year. For the 2013/14 financial year, these values were set at 15 per cent for Margin-Off Peak and 14 per cent for Margin Peak (without carbon price) which covers Synergy's costs for the provision of spinning reserve ancillary service.

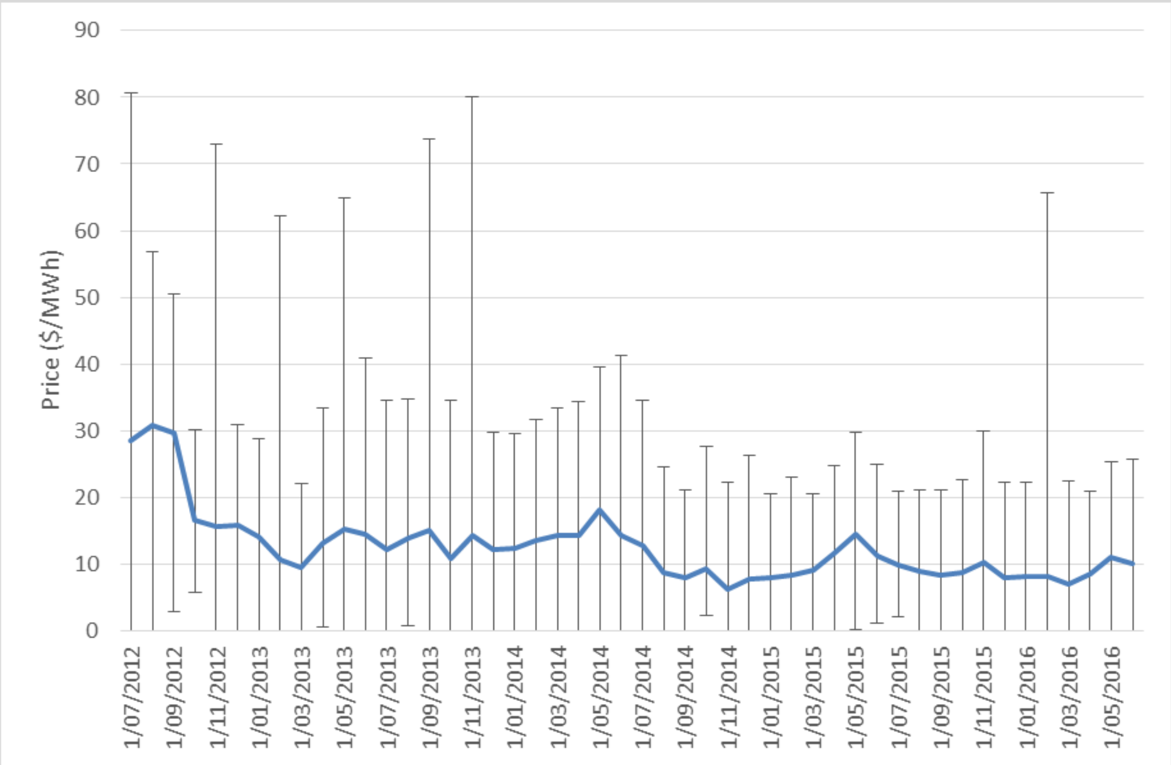
NewGen is the only IPP providing LFAS services in addition to Synergy. Synergy and NewGen receive a payment from the market for the provision of LFAS. Market customers and intermittent generators share the payment of LFAS costs.

The LFAS requirement is set by System Management and must meet the standard according to section 3.10.1 of the market rules. This states that the level must be the greater of 30 MW or the level sufficient to maintain system frequency between 49.80 Hz and 50.20 Hz for at least 99.9% of each month. The requirement is currently set at 72 MW.

The total cost of providing LFAS is passed on to market customers and non-scheduled generators, based on each market customer's monthly aggregate demand, as a proportion of that month's total system load. Figure 49 and Figure 50 below show the average daily LFAS prices since the competitive market commenced.

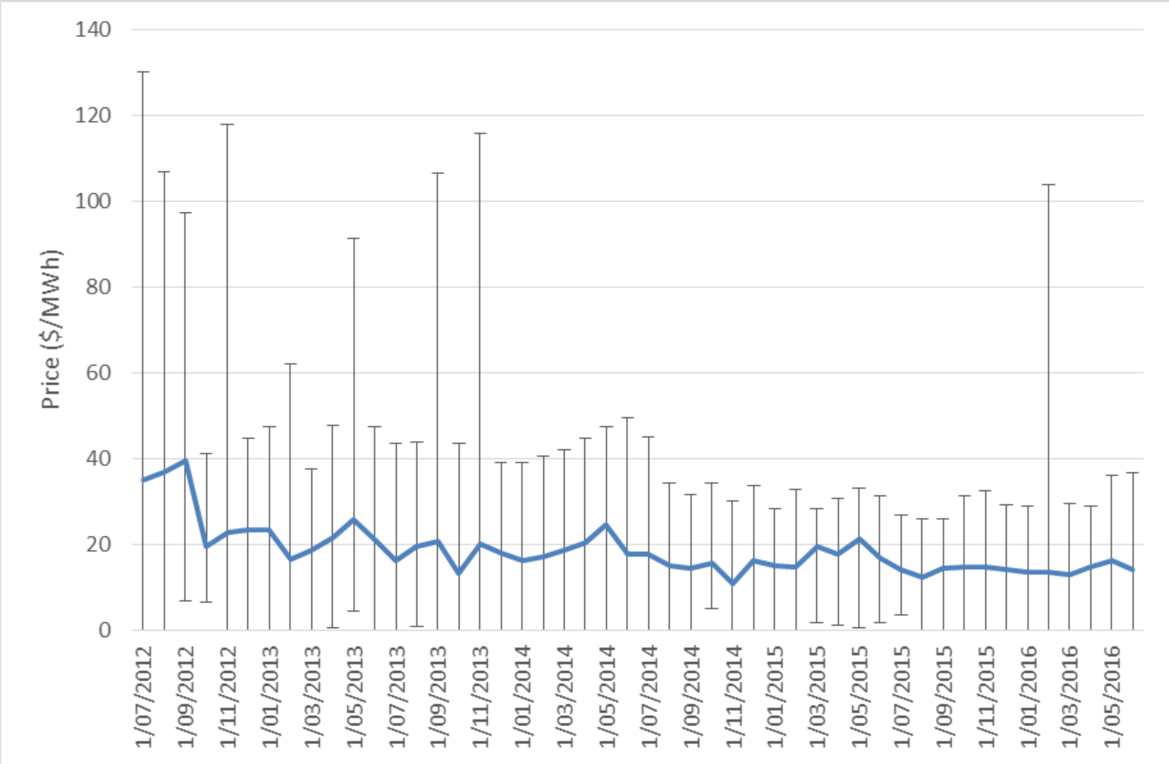
Error bars indicate maximum and minimum price

Figure 49 Monthly average LFAS up prices



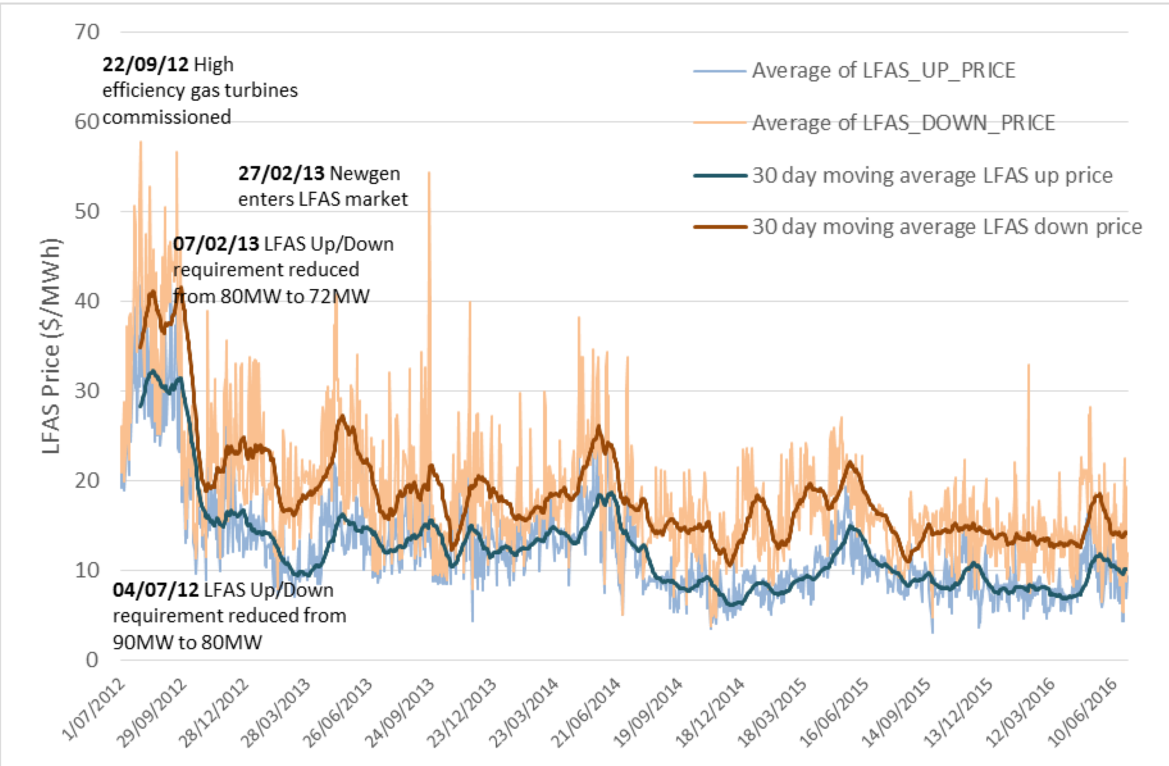
Source: Australian Energy Market Operator, ERA Analysis

Figure 50 Monthly average LFAS down prices



Source: Australian Energy Market Operator, ERA Analysis

Figure 51 LFAS prices since introduction of LFAS market



Source: Australian Energy Market Operator, ERA Analysis

LFAS costs have been a concern since the new market commenced. As can be seen in the chart above, initial prices were relatively high. Prices reduced following the introduction of Synergy's high efficiency gas turbines in September 2012. Further price reductions followed a decrease in the LFAS quantity requirement in July 2012 and February 2013, and NewGen's entry to the market in February 2013.

The IMO's five yearly review of ancillary services[74], noted the following:

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

The IMO, in conjunction with System Management and industry, identified a number of options with the potential to reduce LFAS costs. However, as these options required significant longer terms changes, further developments were deferred until the outcome of the EMR was known. The options to reduce costs included:

- a co-optimised energy and ancillary services market;
- reduced gate closure and dispatch cycle times;
- improved forecasting accuracy and the reduction/removal of system generated LFAS sources such as auxiliary load forecast error;
- facility based bidding and dispatch for all market participants (which would allow for more accurate measurement of LFAS usage and the contributing LFAS causes);
- 'causer pays' allocation of LFAS costs.
- reducing the LFAS requirement in some trading intervals;
- reviewing the performance standard being used by System Management for frequency stability, particularly given that it is higher than the standard required under the Technical Rules; and
- opening up other ancillary services to competition.

System Restart

System Management requires at least three generating stations to provide system restart ancillary services[75]. These generators should be situated at different locations to reduce the risk of system restart failure. As a result, System Management would prefer to have

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[74] Final report published 6 November 2014 https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Security-and-reliability/-/media/25E7F9BB35FF43958825392BD63F1D65.ashx

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

restart capability in the three electrical sub networks including the North Metropolitan, South Metropolitan and South Country.

Currently, System Management has three system restart services. These services are being provided by Synergy's gas turbines at Kwinana and Pinjar, as well as Perth Energy's Kwinana GT1 facility.

No system restart services were used in 2014/15 or 2015/16.

Payments for these system restart contracts are collected via the R value of the Cost_LR parameter as defined in the market rules.[76] Under clause 3.13.3C of the market rules, the Authority is responsible for determining the Cost_LR parameter. The Authority published its determination on the Cost_LR parameter for the 2016/17, 2017/18 and 2018/19 financial years in March 2016.

Load Rejection Reserve

The load rejection reserve service is determined by the extent of load lost during a network fault.[77] The requirement is set to maintain system frequency below 51.0 Hz, returned to less than 50.5 Hz within two minutes, and then returning to the 49.8 Hz to 50.2 Hz range within fifteen minutes. The current quantity is 120 MW and is based on the size of the load reductions that have occurred during past network fault events.

The L value of the Cost_LR parameter provides for compensation of the cost associated with the provision of this service.[76] As required under the market rules, the ERA made a determination on this value for the 2016/17, 2017/18 and 2018/19 financial years in March 2016.[78]

Dispatch Support

System Management use dispatch support services to maintain power system security and power system reliability in the WEM. System Management procures dispatch support services with the costs recouped from all market customers.

Synergy is the only market participant contracted to provide dispatch support services from its facilities at Mungarra, West Kalgoorlie and Geraldton.

ERA must approve any changes to the prices under the existing deed between Synergy and System Management. System Management submitted Synergy's proposed adjustments to the dispatch support services charges on 14 June 2016 for the ERA's approval.

The ERA assessed and considered that the proposed revisions in Synergy's start-up costs and short-run marginal cost did not satisfy the criterion of achieving the lowest practicably

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[76] The Cost_LR parameter covers the payment to a Market Generator for the costs of providing the Load Rejection Reserve and System Restart Ancillary Services, and specific Dispatch Support Ancillary Services. The "L" component refers to the load rejection component and the "R" component refers to the system restart service.

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

[78] Required by clause 3.13.3B of the Market Rules.

sustainable cost of delivering the service. The ERA rejected Synergy's proposed revision to the charges for providing dispatch support services on 31 August 2016.

Under the electricity market reforms, this contract will be terminated on 1 July 2018.

3.5 Planning processes

The planning processes consist of the following:

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

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

Long Term PASA

AEMO undertakes the long term PASA in order to determine the reserve capacity target for each year in the ten-year period of the long-term PASA study horizon. AEMO presents the results in the 'Statement of Opportunities' report, which is published on AEMO's website each year.[79]

Medium Term PASA

System Management must carry out a medium term PASA study by the 15th day of each month and provide it to AEMO for publication on the market website. Under clause 3.16 of the market rules, this study must consider each week of a three-year planning horizon, starting from the month following the month in which the medium term PASA study is performed.

The medium term PASA study assists System Management in:

- setting ancillary service requirements over the year;
- outage planning for registered facilities; and
- assessing facility availability in providing capacity credits, and the availability of other capacity.

Short Term PASA

Under clause 3.17 of the market rules, the short-term PASA study must consider each six-hour period of a three-week planning horizon (the short-term PASA planning horizon). System Management must carry out a short-term PASA study every Thursday and provides the results to AEMO for publication on the market website.

The short term PASA assists System Management in assessing:

- the availability of capacity holding capacity credits in each six-hour period during the short term PASA planning horizon;
- the setting of ancillary service requirements in each six-hour period during the short-term PASA planning horizon; and

79 A report prepared in accordance with clause 4.5.13 presenting the results of the Long Term PASA study.

- final approvals of planned outages.

The balancing market provides market participants with more dynamic, close to real time, information that complements the weekly short term PASA.

System Management also publishes dispatch advisories to all market participants to advise them of significant changes to market conditions to enable them to adjust their bids accordingly.

3.6 Dispatch process

In the balancing market, market participants provide balancing submissions for each trading interval, specifying prices at which their facilities may be dispatched and by how much. AEMO uses these prices to construct the balancing merit order, used by System Management for real time dispatch.

System Management uses the most recent balancing merit order to determine and issue dispatch instructions to generators, to meet the expected demand trend during the trading interval. System Management may only depart from the balancing merit order if it is necessary to maintain system security and reliability, and it may issue dispatch Instructions to demand side programmes or dispatchable loads if necessary.

System Management publishes a quarterly status report setting out the number and type of dispatch instructions issued, together with details of any non-compliance by market participants.[80]

The new market design (particularly requiring Synergy to submit offers for each generating unit) and adoption of AEMO's dispatch engine will remove the current inefficiencies and lack of transparency. Manual intervention should no longer be required.

[80] See reports published on IMO website http://www.imowa.com.au/home/electricity/market-information/system-management-reports

3.7 Market Rule Change Process and the Procedure Change Process

Information on market rule changes that have commenced, been rejected or are under development is available on the IMO's website.

There have not been any rule changes in this reporting period. With the commencement of the EMR in March 2014, a number of rule changes, which had been finalised but required approval by the Minister, as they included protected provisions, were rejected:

- RC_2013_09 Incentives to Improve Availability of Scheduled Generators;
- RC_2013_10 Harmonisation of Supply-Side and Demand-Side Capacity Resources;
- RC_2014_02 Removal of facility aggregation; and
- RC_2013_20 Changes to the Reserve Capacity Price and the Dynamic Reserve Capacity Refund Regime

The following rule changes under development were put on hold:

- RC_2014_09 Managing Market Information;
- RC_2013_15 Outage Planning Phase 2 – Outage Process Refinements;
- RC_2014_06 Removal of Resource Plans and Dispatchable Loads;
- RC_2014_03 Administrative Improvements to the Outage Process;
- RC_2014_05 Reduced Frequency of the Review of the Energy Price Limits and the Maximum Reserve Capacity Price;
- RC_2015_01 Removal of Market Operation Market Procedures;
- RC_2015_03 Formalisation of the Process for Maintenance Applications;
- RC_2013_21 Limit to Early Entry Capacity Payments;
- RC_2014_10 Provision of Network Information to System Management; and
- RC_2014_07 Omnibus Rule Change.

Transferring responsibility for rule change approvals from the market operator to an independent rule change panel will remove the previous governance conflicts.

3.8 Compliance Monitoring and Enforcement Measures

Compliance monitoring and enforcement transferred to the ERA on 1 July 2016. The ERA, IMO and AEMO have worked closely during the transition of this function. The ERA will be publishing a report in 2017 setting out the compliance monitoring and enforcement measures it has undertaken.

Further discussion on compliance monitoring and enforcement is included in the following sections on the IMO and System Management.

3.9 Effectiveness of IMO and System Management

Previous reports to the minister identified a number of institutional arrangement governance issues. Significant restructuring has already occurred, and has been ongoing since the ERA's last review, as part of the EMR. Market operation functions transferred from the IMO to the AEMO on 30 November 2015, and system management functions transferred from Western Power to AEMO on 1 July 2016, with the transfer of staff and assets occurring on 31 October 2016.

The revised institutional arrangements will remove the previous conflicts, where the market operator was also responsible for rule changes and compliance, and the network owner was also responsible for power system management. Transitioning functions between entities has created additional work but it would not appear at this stage that there has been any deterioration in outcomes as a result.

The reviews set out below of the effectiveness of the IMO and System Management in carrying out their functions stem from the results of audits covering the period 1 August 2014 to 31 July 2015. During this period, the IMO was still responsible for market operations, and System Management was operating as a segregated business unit within Western Power. The first audits of AEMO's performance were not available at the time of preparing this report.

The Effectiveness of the IMO in carrying out its functions

Under clause 2.1.2 of the market rules, the functions of the IMO have been to:

- administer the market rules;
- operate the reserve capacity mechanism, the STEM, the LFAS market, and the balancing market;
- settle such transactions as it is required to under the market rules;
- carry out a long-term PASA study and to publish the Statement of Opportunities report;
- do anything that the IMO determines to be conducive or incidental to the performance of the IMO's functions;
- process applications for participation, and for the registration, deregistration and transfer of facilities;
- release information required to be released by the market rules;
- publish information required to be published by the market rules;
- develop amendments to the market rules and replacements for them;
- develop market procedures, and amendments and replacements for them, where required by the market rules;
- make available copies of the market rules and market procedures, as are in force at the relevant time;
- monitor other rule participants' compliance with the market rules, to investigate potential breaches of the market rules, and if thought appropriate, initiate enforcement action under the regulations and the market rules;

- support the Authority in its market surveillance role, including providing any market related information required by the Authority;
- support the Authority in its role of monitoring market effectiveness, including providing any market related information required by the Authority; and
- carry out any other functions conferred, and perform any obligations imposed, on it under the market rules.

Clause 2.14.3 of the market rules requires that the IMO must ensure that the market auditor carries out the audits of such matters as the IMO considers appropriate, which must include the:

- compliance of the IMO's internal procedures and business processes with the market rules;
- IMO's compliance with the market rules and market procedures; and
- IMO's market software systems and processes for software management.

The IMO utilised PA Consulting to undertake these audits. PA Consulting's audits of the compliance of the IMO's internal procedures and business processes with the market rules and the IMO's compliance with the market rules and market procedures took the form of incremental audits. PA Consulting primarily focussed its audits in areas that had changed since last year's annual audits or that, in light of previous audit findings, posed non-compliance risks.

Where PA Consulting identified non-compliant procedures or actions, it classified them as being either material or non-material breaches. PA Consulting classified breaches as 'material' if they did not comply with the market rules and might affect decisions made by market participants, the outcome of the market, or the financial position of one or more rule participants. PA Consulting classified breaches as 'non-material' if they did not comply with the wording of the market rules but did comply with their intention; or they did not comply with the market rules but were unlikely to affect decisions made by market participants, the outcome of the market, or the financial position of one or more rule participants.

PA Consulting's main finding of concern related to the process of providing updated standing data to System Management. Whilst transfer of standing data to System Management mostly occurs automatically, the IMO uses documentary attachments to share some important information with System Management by email. This inconsistent communication process has meant that there is not a shared understanding between the IMO and System Management of which of the documents is current for each facility.

PA Consulting observed a material breach of clauses 4.26.1A, 4.29.3(d)(vi), and 9.3.3; two material breaches of 4.28.9; and multiple material breaches of 9.19.3(b). Clause 4.26.1A requires the IMO to calculate the 'facility reserve capacity deficit refund' using a particular formula that employs different refund rates for peak and off-peak periods. In the initial settlement run for January 2015 (executed in March 2015), the IMO applied incorrect refund rates for some periods on 1 January and 26 January, which were public holidays. The IMO settlements system incorrectly treated these days as business days, due to an oversight in the input data provided to the system. It was corrected for the first adjustment in July 2015, however, the error made a material difference to the amounts paid and received by market participants in the initial settlement run. The IMO introduced an alert to its systems ensure that updated public holiday data enters the settlement system before the initial settlement run.

Under clause 4.29.3(d)(vi), the IMO must provide certain data to the settlements system in time for settlement of the relevant trading month, including the total capacity cost refund to be paid by each market participant to the IMO. In September 2013, the IMO assigned capacity credits to a new demand side programme and set 1 June 2014 as the effective date from which the reserve capacity obligations would apply. However, registration of the facility occurred on 8 June 2014, with the facility failing to satisfy its reserve capacity obligations between 1 June 2014 and 8 June 2014. The IMO only charged the participant capacity cost refunds for two of the four business days in that week in the initial settlement run, making a material difference to the amount paid to the participant. The IMO recovered the amounts relating to the other two business days in the first adjustment. Additionally, the IMO implemented an alert flagging when a facility has been assigned capacity credits before being registered, and was considering changes to handle such situations automatically in the initial settlement run.

Clause 9.3.3 requires the IMO to determine the metered schedule for various facilities in accordance with clause 9.3.4. Clause 9.3.4 states that where interval meter data is available, the metered schedule is to be determined from meter data submissions received by the IMO. As part of upgrades to the IMO's settlement system, the IMO cut over the metering system from the primary data centre to the standby data centre in late November 2014. A misconfiguration meant that while the IMO received the meter data from the meter data agent for the entire month, five days' worth of data was not stored, and the initial settlement run did not include meter data for these five days. Whilst the IMO corrected the situation in the first adjustment, it initially gave rise to a material difference in payments to and from market participants. PA consulting noted that the IMO carries out daily checks of meter data upload success, and was in the process of implementing additional analysis and verification of settlement outputs, both of which will mitigate the risk that such events are not detected and resolved.

Clause 4.28.9 obliges the IMO to accept a load as non-temperature dependent only if the load meets the requirements of Appendix 5A of the market rules. For the November 2014 IRCR determination, a problem with the process of importing data into the IMO's non-temperature dependent load calculation tool meant that the tool was operated on incomplete data. This resulted in the IMO incorrectly assessing two loads as non-temperature dependent, when they did not satisfy the requirements of Appendix 5A. This incorrect status meant that the two participants made a smaller contribution to capacity payments than they otherwise should have, and other participants paid more than they would have. The IMO simplified the data import process to reduce the data volume transferred and make identification of such an event more likely in future.

Clause 9.19.3(b) requires the IMO to calculate interest on adjusted settlement statements in accordance with clause 9.1.3, which requires this interest to accrue daily at the bank bill rate. Until January 2015, the IMO had been calculating the interest using the bank bill rate that had been applied at the time of initial settlement, such that, where the bank bill rate changed between initial settlement and settlement adjustment, the IMO applied an incorrect interest rate. PA Consulting considered that although the error would have affected the amount of interest paid by market participants, the overall impact was relatively small. This is because of the small time-periods when interest is applicable, the fact that it occurred only for settlement adjustments and not initial amounts, and the relatively small change in interest rate.[81] The IMO updated its settlement procedures to include an explicit check for correctness of interest rates.

PA Consulting found that there were a higher number of material breaches in the present audit compared to the last audit period. However, almost all of the issues identified were isolated incidents due to human error. PA Consulting noted that the IMO demonstrated a

[81] The maximum error on a single settlement statement in the audit period was approximately $34.

proactive approach to self-reporting non-compliance (even for material non-compliance) and active management of remedial actions to address non-compliance incidents.

PA Consulting observed a continued improvement in the quality of controls employed to manage non-compliance risk. In particular, PA Consulting considered that the IMO continued to extend the scope of an alert system notifying IMO staff of impending deadlines and market events/incidents, and its use of issue and project tracking software was an effective means of managing compliance with a number of material rules obligations relating to administration, registration, market operations, settlement and prudential monitoring. Additionally, PA Consulting considered that the scope and quality of the IMO's internal procedures to cover its obligations was excellent, and noted that the IMO continued to expand and refine its use of electronic procedures to document work instructions, and was in the process of implementing formal governance for key pages.

PA Consulting noted two areas of risk for the market, which increase the risk of IMO non-compliance and affect market outcomes, including meter data quality and constrained on/off payments. PA Consulting noted that several of the observed non-compliances this year related to the use of incorrect meter data in the settlement or non-temperature dependent load processes. PA Consulting observed that the correct meter data to be used by the IMO often had missing values and that updated data was often provided to the IMO several times, making detecting and correcting errors in the IMO's processes more difficult and increasing the likelihood of incorrect market outcomes. However, the IMO adopts a proactive approach to ensuring accurate meter data and activity to identify improvements to the current process is ongoing.

The rules currently provide for constrained on/off payments to be made at initial settlement (even for facilities that have not complied with dispatch instructions), which is then followed by a manual review-and-recover process for these amounts in subsequent settlement adjustments. PA Consulting noted that while the risk that the IMO does this incorrectly is low, it could not investigate and recover all incorrect payments. It considered that System Management and IMO's systems could manage this automatically prior to initial settlement to contribute to more efficient market outcomes, and noted that the IMO is in the process of preparing a rule change proposal to improve this process.

PA Consulting considered that the IMO's suite of internal procedures were of a high quality, and noted that the IMO had addressed all but a handful of the minor non-compliances and omissions identified in the last audit. It noted a small number of instances in which the IMO's market procedures and internal procedures were non-compliant with the market rules, however, they were non-material. It was therefore, PA Consulting's opinion that the IMO's market procedures and internal procedures complied with the market rules in all material respects.

In its audit report on the IMO's processes for software management, PA Consulting considered that the IMO had continued to improve its IT processes and practices, with the main changes during this audit year being refinements rather than changes to procedures, as high levels of automation were already in place for the Wholesale Electricity Market Systems development process. It considered that, while the IMO has less ability to control settlement-system development practices (as a third party vendor develops them) than it does for the Wholesale Electricity Market Systems, the management of the settlement software had continued to improve over the course of the year. There were however opportunities for further improvement, in particular, in the automation of deployments.

PA Consulting did not observe anything that caused them to believe that the IMOs processes for software management had not been compliant in all material respects with the market rule and market procedures. In its opinion, the IMO's core market software-systems correctly implement the calculations embodied in the market rules and market procedures in all material respects.

After considering PA Consulting's report, the Authority is generally satisfied with the performance of the IMO in carrying out its functions prescribed in the market rules effectively.

The Effectiveness of System Management in carrying out its functions

Clause 2.2.1 of the market rules specifies that System Management has the function of operating the SWIS in a secure and reliable manner. Additionally, clause 2.2.2 prescribes other functions of System Management in relation to the WEM, which are to:

- procure adequate ancillary services where Synergy cannot meet the ancillary service requirements;
- assist the IMO in the processing of applications for participation and for the registration, de-registration and transfer of facilities;
- develop market procedures, and amendments and replacements for them, where required by the market rules;
- release information required to be released by the market rules;
- monitor rule participants' compliance with market rules relating to dispatch and power system security and reliability; and
- carry out any other functions or responsibilities conferred, and perform any obligations imposed, on it under the market rules.

The IMO was required to audit System Management's market rules and procedure compliance or require it to demonstrate compliance by providing records. [82] The rules required the IMO to do this at least annually or more frequently if it reasonably considered System Management was non-compliant with the market rules or procedures.

The IMO again utilised PA Consulting to undertake this function, which took the form of an incremental audit examining those aspects of the market rules, market procedures and System Management's internal processes that had changed or should have changed since the last annual audit. According to PA Consulting, whilst staff did not note all issues, self-reporting practices appeared robust. PA Consulting observed multiple material breaches by System Management of compliance with the market rules and market procedures.

PA Consulting observed a material breach of clause 3.22.3, which requires that System Management send monthly ancillary services payment data to the IMO for settlement. In July 2014, System Management sent incorrect ancillary services payment data to the IMO due to an issue in the spreadsheet that extracts the relevant information from SCADA data. System Management sent corrected data to the IMO in September 2014. The initial settlement run employed the incorrect payment data, with the affected participant compensated in the first adjustment, and the discrepancy in payment amounting to $37,169.33.

[82] Market rule 2.14.6

System Management is required to dispatch facilities in accordance with the BMO subject to the priority specified in clause 7.6.1C. Additionally, clause 7.6.1D stipulates that System Management may only depart from the priority in clause 7.6.1C to avoid a high or emergency operating state or to return to a normal state. PA Consulting noted that System Management did not follow the BMO when dispatching facilities on seven occasions, when none of the conditions in clause 7.6.1C(b)-(d) or 7.6.1D applied, resulting in six material breaches:

- on 24 June 2014 System Management did not dispatch a generator that was in merit leading to higher constraint payments to the market by approximately $12,000. It was unclear why this breach occurred due to a lack of audit trails in the control room;
- on 25 July 2014, System Management had IT issues where the real time dispatch engine BMO could not read the BMO. System Management verbally overwrote a dispatch instruction to a generator that did not reflect the BMO and consequently, the generator received a constraint payment of $30,832.58 that it would not have otherwise received;
- on 14 September 2014, System Management constrained on a generator of out of merit. The generator received a constraint payment of $1,563.72 it would not otherwise have received;
- on 21 April 2015, System Management dispatched a generator out of merit when it mistakenly placed a unit constraint on it intended for another generator. The affected generator ignored the new dispatch instruction and there was not a material impact on the market. In this instance, System Management also failed to issue a rectification dispatch instruction to the generator who should have been constrained;
- on 20 May 2015, System Management dispatched a generator out of merit when it mistakenly placed a unit constraint on it intended for another generator, resulting in a constraint payment of $1,069.17 that it would not otherwise have received; and
- on 23 June 2015, System Management instructed a generator to ignore a dispatch instruction as it thought that the real time dispatch engine was issuing incorrect dispatch instructions when it was not[83].

Clause 7.11.3 requires that System Management must issue dispatch advisories as soon as practicable after it becomes aware of a situation requiring the release of a dispatch advisory. PA Consulting observed 29 material breaches of this clause, which it considered was partly due to a reliance on a single system controller, leading to two issues. Firstly, when the system controller is addressing a serious power-system security issue, they may not alert the market operations team responsible for issuing dispatch advisories, or the market operations team may lack the information needed to issue the dispatch advisory until after the system controller has resolved the security issue. PA Consulting argued that timely dissemination of information to participants was most important during security incidents, highlighting the importance of having more than one controller.

Secondly, System Management does not issue dispatch advisories over night as the market operations team only works during business hours and issues retrospective advisories the following morning. PA Consulting considered that allowing market operations staff remote access to the dispatch advisory system would improve the timeliness of dispatch advisories.

Clause 7.11.5(d) requires that System Management issue dispatch advisories when significant outages of generation transmission or customer equipment are occurring or are expected to occur. PA Consulting noted three material breaches of this clause, in which

[83] At the time of the audit, the settlement adjustment for this period was not undertaken and it was unclear as to what the materiality of this breach was.

System Management did not issue dispatch advisories for generator outages greater than 100MW, including on:

- 12 November 2014 at approximately 7:00 a large generator failed to start;
- 21 April 2015 at approximately 14:30 a large generator tripped; and
- 2 August 2014 at approximately 5:30 a large generator went on forced outage due to operational issues.

Clause 7.11.5(g) requires that System Management issue a dispatch advisory if it expects to issue a dispatch advisory out of merit. System Management dispatched facilities out of merit and failed to issue dispatch advisories leading to material breaches on 14 September 2015 (as outlined above) and on 8 June 2015, when a facility was unable to return to service due to a forced network outage and was constrained off.

Under clause 7.11.6, System Management must provide particular information in dispatch advisories, including the time that the dispatch advisory will probably apply, the applicable operating state, and the probable out of merit quantities. PA Consulting noted that System Management did not provide all information required under clause 7.11.6, resulting in five material breaches of clause 7.11.6(dA)[84] and one material breach of 7.11.6A.[85] PA Consulting considered that the exclusion of this information can have material impacts on market participants as, without knowing the affected location or quantity of out of merit dispatch, they do not have sufficient information to adjust their offers to reflect system issues. PA Consulting reiterated its recommendation from last year that System Management publish a forecast dispatch plan to market participants to provide the requisite level of transparency around forecasted out of merit dispatch.

Clauses 7.13.1(e) and (eC) require that System Management provide the IMO with ex-post upwards and downwards LFAS enablement quantities by noon each business day. PA Consulting noted that, in a number of intervals over 24-26 January 2015, the files containing LFAS up and down enablement quantities included discrepancies that were attributable to errors in the spreadsheet used by System Management to send LFAS enablement quantities to the IMO. PA Consulting considered that the breaches were material, as providing incorrect enablement quantities directly affects settlement quantities and amounts paid to participants providing LFAS.

Clause 7A.3.15 requires that System Management provide the IMO with its forecast of the relevant dispatch quantity and update the forecasts and provide the update to the IMO each time it has new information on which to determine these quantities. System Management control room staff have a range of information available to assess the probable load, including the output of two forecasting tools.[86] System Management's Metrix load forecasting tool produces one of these forecasts, and it is this forecast that System Management provides to the IMO for use in its balancing forecast and real-time dispatch engine. However, PA Consulting notes that the Metrix load forecast does not always represent System Management's 'best estimate' of future relevant demand quantity, which it actually arrives at through a combination of load forecast tool outputs and similar past day profiles.

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[84] Clause 7.11.6 (dA) specifically requires that, where System Management is to release a dispatch advisory under clause 7.11.5(g), it provides details of the estimated out of merit quantities, reasons for the deviation from the BMO and all relevant information about the deviation.

[85] Clause 7.11.6A specifies that System management must include the name of the facility that has caused or materially contributed to the issuance of a dispatch advisory. On one occasion, System Management did not name the facility.

[86] It also has the abilities to plot similar past days against the current load, and to take a combination of the various inputs to arrive at the load forecast it thinks is the most likely to eventuate.

From 1 August 2014 to 31 July 2015, System Management control room staff used the Metrix forecast 96.87 percent of the time, and an alternate forecast the rest of the time.[87] PA Consulting considered that, as the purpose of the IMO's balancing forecast is to provide market generators with information to make an assessment regarding whether to make or update a balancing submission, it follows that a more accurate forecast could influence participants to make different decisions in the market. PA Consulting therefore considered that the breach was material.

Clause 7B.3.6 requires that System Management use facilities for LFAS in accordance with the selection information provided by the IMO. PA Consulting's analysis of a sample of LFAS merit orders and corresponding LFAS activation instructions uncovered multiple intervals across 63 days in which the amount of LFAS enabled for facilities did not match the amount cleared by the LFAS merit order. In cases where multiple participants provided LFAS, this constituted a breach of clause 7B.3.6, resulting in participants providing different amounts of LFAS than they otherwise would have and affecting market settlement payments.[88] PA Consulting therefore considered that these breaches were also material.

PA Consulting provided additional comments on areas of compliance risk noted in last year's audit that were still areas of concern. It considered that low staffing levels were of particular concern in the control room where there is only one controller on shift (with two shifts per day), a practice that is not consistent with comparable international system operators. It noted that in high-risk situations or emergencies, which are likely to arise during summer peak intervals, it could be challenging for a single controller to handle both security and dispatch, creating scope for dispatch non-compliance and/or non-compliance with power system security obligations.

PA Consulting further considered the timeliness of dispatch advisories is partly due to a single controller being on shift, and possibly too occupied with security and dispatch issues to notify market operations staff of the need to issue an advisory notice. Moreover, in the event that a controller is incapable of carrying out their duties (i.e., through sickness or other unforeseen circumstances), the control desk may remain unattended until a replacement controller arrives. PA Consulting recommended that System Management increase the level of staffing in the control room to two immediately, with one responsible for security and the other for scheduling and dispatch.

PA Consulting noted areas for improvement in general governance and management of processes used to implement material obligations. It considered that the sparse level of process documentation continued to be an area of compliance risk. It noted that the governance and ownership issues with respect to control room instructions noted in last year's audit remained unresolved, and that material obligations implemented by the planning team (e.g., outage planning, commissioning, dispatch planning and forecasting) were undocumented. However, PA Consulting understood that System Management had made some progress toward developing emergency and document management frameworks, and had engaged a contractor to write up the emergency management procedures and control room instructions.

[87] The use of an alternate forecast 3.13 percent of the time, was higher than in the previous audit period (i.e. 1.5 percent in 2013/14) but lower than in 2012/13 (i.e. 7 percent).

[88] As explained by PA Consulting, if multiple participants were providing LFAS, and the total LFAS cleared was 72 MW (30 MW for facility 1 and 42 MW for facility 2), but System management activated facility 1 for 30 MW, and facility 2 for 38 MW, facility 2 would have been cleared for 58 percent but only enabled for 55 percent.

Further, in relation to areas for improvement in general governance and management of processes, PA Consulting considered that:

- opportunities exist to improve the level of audit trail for some business processes, such as System Management's assessment and approval of commissioning test plans, and its network outage planning processes;
- the current level of audit trail makes it particularly difficult to determine System Management's basis for out-of-merit dispatch and declaration of high-risk or emergency operating states, both of which are of material importance to the market; and
- simple controls can be introduced to avoid recurring instances of non-compliance noted in previous audits, such as check list for daily activities and strengthening of controls in spreadsheet tools through automation of content or the introduction of validation controls for detecting errors.

Last year PA Consulting noted that interactions between System Management and other parts of Western Power had changed due to restructuring, with the organisation still working through the process of how parties will interact across the ring fence, and in some areas, the appropriate oversight and authority exercised by System Management. This year, it noted three areas of boundary related compliance risk where Network Operations staff implemented System Management's obligations. These included Network Operations Staff undertaking:

- risk assessment for network outages (prescribed under clauses 3.18.10 and 3.19.3), albeit in consultation with System Management;
- security assessments used by the control to place security constraints in the real time dispatch engine, in consultation with the controller; and
- the network aspects of system monitoring required to monitor the system state, as defined in clauses 3.3.1, 3.4.1 and 3.5.1 (relating to overloading of transmission lines, voltage or circuit issues).

PA Consulting noted that in previous audits it had recommended that System Management define a robust service level agreement for system support, including target response and resolution times, embedding the critical real-time nature of the systems in support processes. Whilst System Management had undertaken a comparative review of Western Power's service level agreements against its own requirements, to identify gaps, System Management had not progressed formally establishing the service level agreements.

The Authority notes PA Consulting's observation that on-going reform had created uncertainty that limited System Management's scope to make large changes to its systems and processes.

System management functions have now transferred to AEMO. The Authority expects AEMO will resolve the issues identified by PA Consulting.

3.10 Inappropriate and anomalous market behaviour

The ERA undertook two investigations into pricing by Vinalco Energy. The ERA published its findings on 30 October 2015 and requested the IMO, as required under clause 2.16.9G, to apply to the Electricity Review Board for an order for contravention of clause 7A.2.17 in relation to prices in a number of trading intervals.[89]

On 15 August 2016, the IMO lodged an application with the Electricity Review Board. The Electricity Review Board held a directions hearing on 31 October 2016 with the next hearing scheduled for April 2017.

[89] The Authority published its findings on the ERA website on 30 October https://www.erawa.com.au/cproot/13938/2/Notice%20-%20First%20Vinalco%20Investigation.pdf and https://www.erawa.com.au/cproot/13939/2/Notice%20-%20Second%20Vinalco%20Investigation.pdf

Appendix 1 Data catalogue summary

Table 7 MSDC data and analysis requirements under the Market Rules

Market Rule clause	Market Rule reporting requirement
2.16.2(a)	The number of Market Generators and Market Customers in the market
2.16.2(b)	The number of participants in each Reserve Capacity Auction
2.16.2(c)	Clearing prices in each Reserve Capacity Auction and STEM Auctions
2.16.2(d)	LFAS Submissions
2.16.2(dA)	All Reserve Capacity Auction offers
2.16.2(f)	All STEM Offers and STEM Bids, including both quantity and price terms
2.16.2(gA)	All Fuel Declarations
2.16.2(gB)	All Availability Declarations
2.16.2(gC)	All Ancillary Service Declarations
2.16.2(h)	Any substantial variations in STEM Offer and STEM Bid prices or quantities relative to recent past behaviour
2.16.2(hB)	The information in clause 7A.2.18(c) (i.e., any information as to whether a Facility was not able to comply with a Dispatch Instruction from System Management and the reasons for that non-compliance)
2.16.2(j)	The frequency and nature of Dispatch Instructions and Operating Instructions to Market Participants
2.16.2(k)	The number and frequency of outages of Scheduled Generators and Non-Scheduled Generators, and Market Participants' compliance with the outage scheduling process
2.16.2(l)	The performance of Market Participants with Reserve Capacity Obligations in meeting their obligations
2.16.2(m)	Details of Ancillary Service Contracts that System Management enters into
2.16.2(n)	All LFAS Prices
2.16.2(o)	The number of Rule Change Proposals received, and details of Rule Change Proposals that the IMO has decided not to progress under clause 2.5.6
2.16.2(p)	Such other items of information as the IMO considers relevant to the functions of the IMO and the Economic Regulation Authority under this clause 2.16.
2.16.4(a)	Where applicable, calculation of the means and standard deviations of values in the Market Surveillance Data Catalogue
2.16.4(b)	Monthly, quarterly and annual moving averages of prices for the STEM Auctions, the Balancing Market and the LFAS Market
2.16.4(c)	Statistical analysis of the volatility of prices in the STEM Auctions, the Balancing Market and the LFAS Market
2.16.4(cA)	Any consistent or significant variations between the Fuel Declarations, Availability Declarations, and Ancillary Service Declarations for, and the actual operation of, a Market Participant facility in real-time
2.16.4(d)	The proportion of time the prices in the STEM Auctions and through Balancing are at each Energy Price Limit
2.16.4(e)	Correlation between capacity offered into the STEM Auctions and the incidence of high prices

Market Rule clause	Market Rule reporting requirement
2.16.4(f)	Correlation between capacity offered into and made available in the Balancing Market and the incidence of high prices
2.16.4(fA)	Correlation between capacity offered into and made available in the LFAS Market and the incidence of high prices
2.16.4(g)	Exploration of the key determinants for high prices in the STEM, in Balancing, in the Balancing Market and in the LFAS Market, including determining correlations or other statistical analysis between explanatory factors that AEMO considers relevant and price movements
2.16.4(h)	Such other analysis as the IMO considers appropriate or is requested of AEMO by the Economic Regulation Authority

Appendix 2 Glossary of acronyms

AEMO	Australian Energy Market Operator
ERA	Economic regulation Authority
EMR	Electricity Market Review
ERB	Electricity Review Board
IMO	Independent Market Operator
IPP	Independent Power Producer
LFAS	Load Following Ancillary Service
MSDC	Market Surveillance Data Catalogue
NEM	National Electricity Market
NMI	National Meter Identifier
PASA	Projected Assessment of System Adequacy
PUO	Public Utilities Office
PV	Photovoltaic
RCM	Reserve Capacity Mechanism
SCADA	Supervisory Control and Data Acquisition
SRMC	Short Run Marginal Cost
STEM	Short Term Energy Market
WEM	Wholesale Electricity Market