INDEPENDENT
MARKET
OPERATOR

Electricity Statement of Opportunities

June 2013

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Executive Summary

The Statement of Opportunities Report (SOO) is published annually by the Independent Market Operator (IMO). The SOO provides information on existing supply capacity and future electricity demand to current and potential participants in the Wholesale Electricity Market (WEM).

The SOO is a key process within the Reserve Capacity Mechanism (RCM) – the mechanism through which the WEM secures sufficient capacity to meet peak demand. The RCM has provided positive outcomes for the Western Australian economy, with more than 2,500 MW of new generation plant and Demand Side Management (DSM) being committed since 2005. This increased investment has resulted in an increased number of Market Participants and greater competition in the market.

The SOO focuses on opportunities for investment in generation and DSM capacity over the medium term. The 2013 SOO places emphasis on the 2015/16 Capacity Year, setting the capacity requirement for the year commencing 1 October 2015. Information is also provided on forecast maximum demand and electricity consumption within the South West interconnected system (SWIS) through to September 2024.

In addition, the SOO provides stakeholders with:

- a detailed profile of the WEM, including information on SWIS demand profiles and existing market participants;
- analysis of the performance of previous demand forecasts;
- commentary on the current status of the transmission network;
- a discussion on the availability of fuel for generation; and
- information on key areas of reform that are planned or underway in the WEM.

Key results for 2015/16

- The Reserve Capacity Requirement for 2015/16 is set at 5,119 MW. This is based on the one-in-ten year peak demand forecast with additional allowances for unplanned facility outages (7.6% of the peak demand forecast), provision of frequency control services and Intermittent Loads.
- Annual growth in one-in-ten year peak demand forecasts through to 2023/24 is 2.7% over the ten-year forecast horizon, materially lower than the projected average growth rate from the 2012 SOO of 3.0% over ten years.
- Forecast average annual growth in sent out energy is 1.9%, which is lower than the 2012 SOO forecast of 2.1%.
- The IMO anticipates that 6,029 MW of generation and DSM capacity, either existing or committed with Capacity Credits for 2014/15, will continue in service through to 2015/16.
- The existing in-service or committed facilities represent a surplus of 910 MW of capacity above the Reserve Capacity Requirement for 2015/16, prior to the introduction of any new capacity for that year.

Table A shows the Reserve Capacity Target for each year of the Long Term Projected Assessment of Supply Adequacy (LT PASA) Study Horizon, as determined from the peak demand requirement of the Planning Criterion.

The lower SWIS demand forecasts this year reflect the fall in underlying electricity demand over the last four years, consistent with observations in the eastern states of Australia. In addition, newly-observed customer behaviour at times of peak demand has led to specific reductions in the peak demand forecasts since last year.

Table A – Reserve Capacity Targets (all figures in MW rounded to nearest integer)

Year	Maximum Demand	Intermittent Loads	Reserve Margin	Load Following	Total
2013/14	4,411	14	336	72	4,833
2014/15	4,561	15	348	76	5,000
2015/16	4,668	15	356	80	5,119
2016/17	4,797	16	366	84	5,263
2017/18	4,955	17	378	88	5,438
2018/19	5,107	16	389	92	5,604
2019/20	5,247	16	400	96	5,759
2020/21	5,379	17	410	100	5,906
2021/22	5,506	17	420	104	6,047
2022/23	5,641	17	430	108	6,196
2023/24	5,779	17	440	112	6,348

Changes to demand forecasts since 2012

Electricity markets in many developed economies are currently experiencing an unprecedented shift in electricity demand patterns, driven by technological advancement and behavioural change. In addition, new information has been exposed during the last four years about the price elasticity of demand.

The demand forecasts this year represent a significant reduction from those presented in the 2012 SOO, following similarly-sized reductions in 2011 and 2012. Various factors have contributed to these reductions:

- The curtailment of consumption by some commercial and industrial customers at times of peak demand, described below, has led to the incorporation of this behaviour in the peak demand forecasts for the first time.
- The estimated contribution of small-scale solar photovoltaic (PV) generation to meeting peak demand has been increased. A softening of demand for new PV installations had been expected following the reduction of State and Commonwealth Government incentives for the installation of PV systems. However, underlying demand has remained stronger than previously expected with an average of 2,800 systems being installed per month in the second half of 2012 (the 2012 forecasts had projected an installation rate of 2,000 systems per month).
- The National Institute of Economics and Industry Research (NIEIR) projects lower commodity prices in the medium term, leading in turn to lower terms of trade and a weaker Australian dollar. These have resulted in lower economic growth projections for Western Australia since last year, with the average annual growth in Gross State Product (GSP) forecast to be 3.1% per year, compared with 3.8% last year.
- Recent observations of the temperature dependence of SWIS demand suggest that the temperature coefficient[1] for the SWIS has reduced since 2011, as described below. NIEIR has adjusted its model for temperature-sensitive load in response to these observations.

In addition to these changes to the forecasts, two further changes have reduced the calculated Reserve Capacity Requirement:

[1] Measured as the incremental demand (in MW) for each degree increase in temperature above 21°C.

- Rule Change RC_2012_21[2] reduced the reserve margin from 8.2% to 7.6% of the one-in-ten year peak demand forecast. This change was recommended during the five-yearly review of the Planning Criterion that was conducted in 2012.
- System Management has recently reduced the quantity of Load Following capacity required for maintaining system frequency from 80 MW to 72 MW. This change has not been driven by any reduction to the quantity of Intermittent Generation (which continues to grow) or lessening volatility in customer demand or Scheduled Generator output. Following consultation with System Management, the IMO has reduced the Load Following quantities by 20% from those in the 2012 SOO. The IMO is continuing a review of Load Following with System Management and may, subject to the outcome of this review, make further amendments to the Load Following quantities in future forecasts.

Table B provides causal analysis of the reduction from the 2014/15 Reserve Capacity Requirement to the 2015/16 Reserve Capacity Requirement.

Table B – Comparison of 2014/15 and 2015/16 Reserve Capacity Requirements

2014/15 Reserve Capacity Requirement	**5,308 MW**
Reduction in reserve margin from 8.2% to 7.6%	- 30 MW
Response to IRCR mechanism*	- 56 MW
Increased 2014/15 solar PV forecast*	- 28 MW
Reduced economic growth forecasts*	- 61 MW
Adjustment to temperature-sensitive load model*	- 97 MW
Other calibrations to forecasting model*	- 12 MW
Year-on-year load growth, 2014/15 to 2015/16*	+ 115 MW
Change to Load Following requirement	- 20 MW
2015/16 Reserve Capacity Requirement	**5,119 MW**

* Includes contribution of 7.6% reserve margin.

Customer response at times of peak demand

The Individual Reserve Capacity Requirement (IRCR) mechanism, which allocates the cost of Capacity Credits to Market Customers, provides an incentive for customers that are exposed to competitive tariffs to reduce their demand during system peak demand intervals. The new Balancing Market in the WEM has brought improvements in market transparency that assist these customers in predicting peak demand periods, through frequent forecasts of system demand, Balancing Merit Orders and energy prices.

Analysis by the IMO has identified the apparent management of energy usage during peak intervals by some large commercial and industrial customers. By reducing consumption during the hottest summer afternoons, these customers are able to reduce their exposure to IRCR payments.

Figure A shows the cumulative demand during February 2013 from the 59 most responsive loads identified by the IMO as having reduced their consumption in this way. The shaded areas on the graph represent the afternoons of the five hottest days (assessed by mean daily temperature[3]) in February 2013. The maximum temperature for each of these days is shown on the graph.

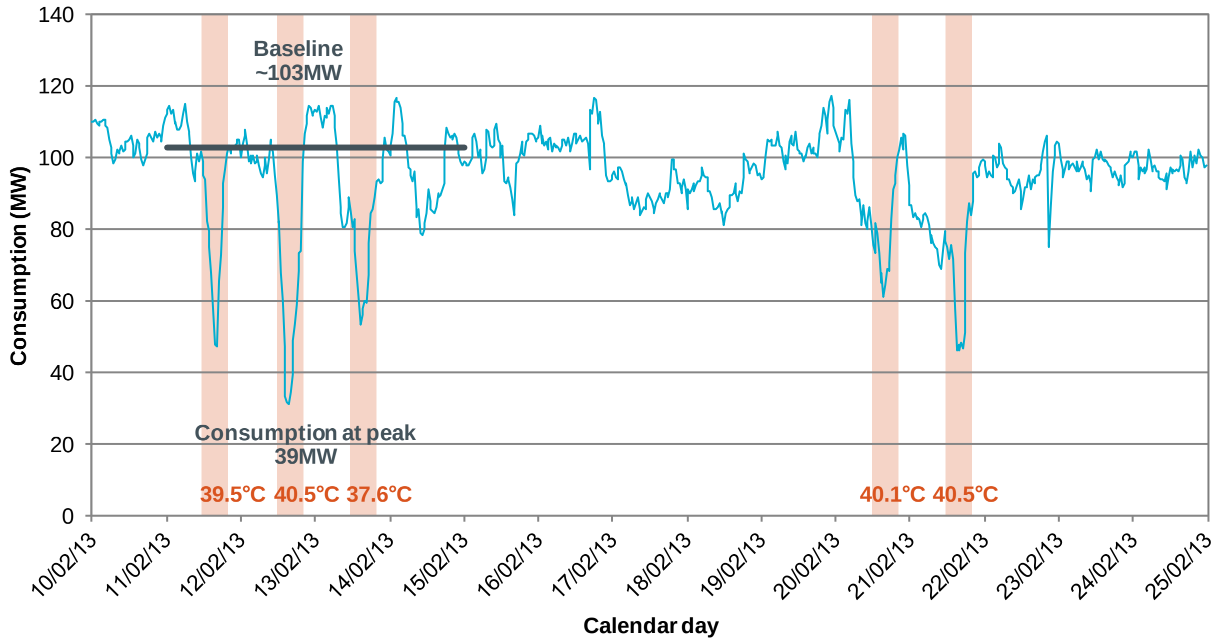
[2] See http://www.imowa.com.au/RC_2012_21 for more information.
[3] Mean daily temperature refers to the arithmetic mean of the daily maximum temperature and the daily minimum temperature.

As shown in Figure A, it is estimated that the maximum peak demand for 2012/13 was reduced by approximately 65 MW as a result of the IRCR response implemented by larger customers. This represents almost 2% of the SWIS summer peak demand.

This trend has grown exponentially relatively recently, from as little as 15 MW in 2010. This year's forecasts represent the first time that the IMO has specifically considered the impact of this price-driven incentive in the peak demand forecasts. The IMO anticipates that potential changes to the Market Rules, to prevent a load from selling more capacity (through Capacity Credits) than it buys (through IRCR)[4], may reduce the quantity of load that is curtailed in this way.

Given the substantial costs associated with meeting growth in peak demand, particularly network and generation investment, this behaviour, which is incentivised by the design of the RCM, has the potential to reduce the need for investment in generation and network capacity over the long term.

Figure A – Targeted reduction of consumption, 11-24 Feb 2013, 59 loads



Customer awareness campaigns in recent years, such as "Beat the Peak" and "Switch the Future", have informed customers more broadly on the long-term costs of meeting growth in peak demand. Behavioural change as a result of these campaigns, by customers that may not be directly exposed to the IRCR mechanism, is likely to have further moderated the peak demand in recent summers. This can be observed in the reduced temperature sensitivity of demand, which is discussed below.

Recent trends in electricity demand

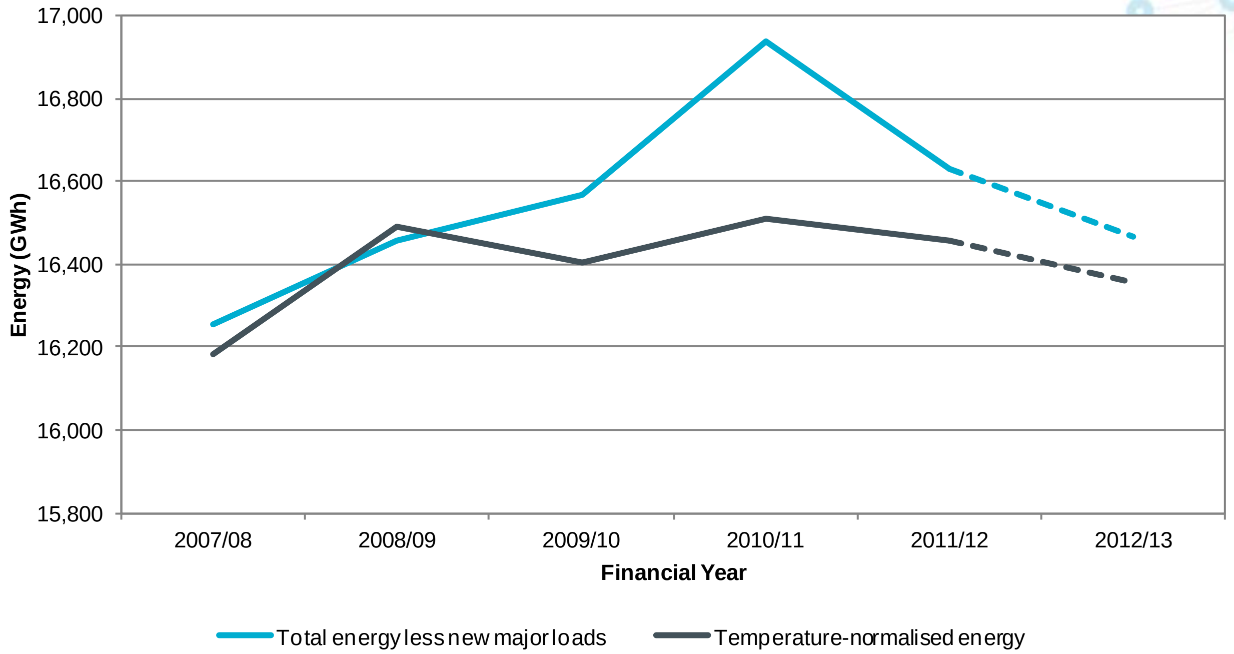
Up until 2008, electricity consumption grew consistently at rates broadly aligned with economic growth. For more than a decade, peak demand grew at an even faster rate.

However, recent electricity consumption data in the SWIS has demonstrated a material dislocation between economic growth in Western Australia and the growth in underlying electricity demand. Figure B shows the total sent out energy by financial year since 2007/08, after deducting consumption from new major loads that

[4] See Section 8.3 of this report for more information.

have commenced operation during that period[5]. Given the sensitivity of electricity demand to temperature, both in summer and winter, NIEIR has normalised for the effect of temperature, as shown in the dark grey line.

Figure B – Sent out energy, adjusted for new major loads and temperature



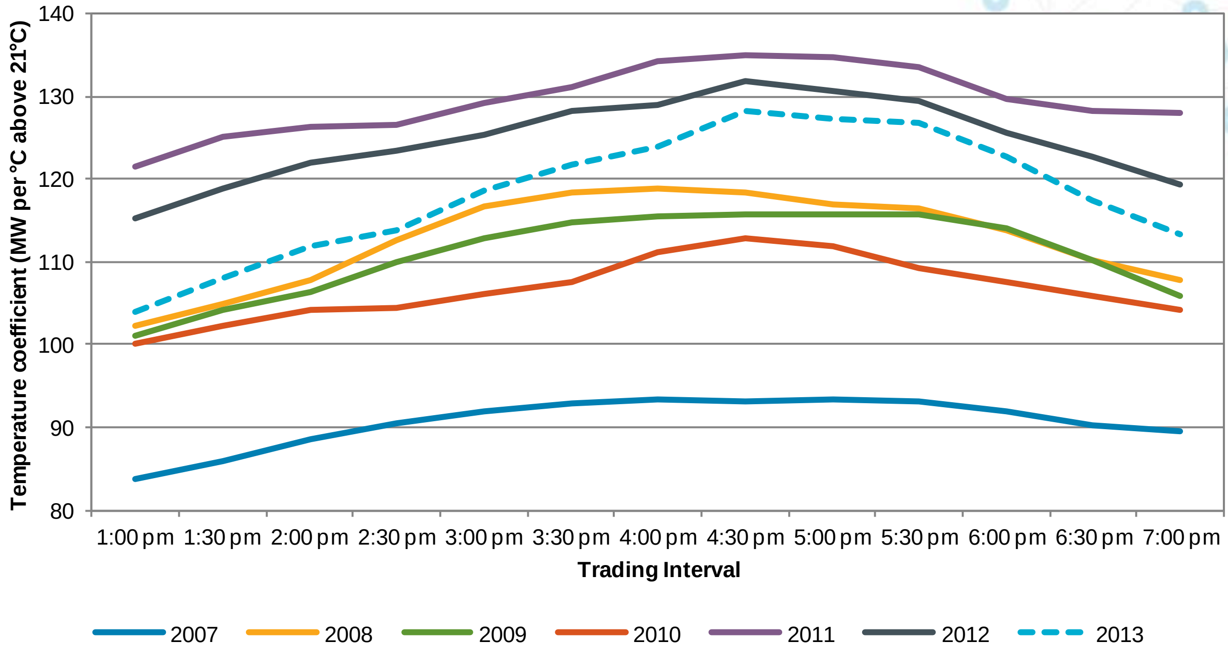
The temperature-normalised data shows that underlying energy sales have fallen since 2008/09. This is consistent with observed drops in consumption in the eastern states of Australia. A number of factors are likely to have contributed to this change:

- the increases in domestic regulated electricity tariffs, which will have increased by 78% for residential customers from March 2009 to July 2013 (with similar increases for regulated tariffs that apply to small commercial and industrial customers);
- the growth in small-scale solar PV systems, which are seen at the wholesale level as reduced consumption;
- the restricted availability and increased cost of finance since the onset of the global financial crisis (GFC) in late 2008 that has hampered investment for small-to-medium enterprises in Western Australia since that time; and
- the increasing impact of energy efficient appliances, energy efficiency programs and public awareness campaigns that are driving behavioural change amongst consumers.

While underlying energy demand has reduced, analysis of temperature-sensitive load suggests that the temperature coefficient for the SWIS reached a peak in 2011 but has fallen since. Figure C displays the results of NIEIR's analysis of the relationship between summer temperatures and demand for each summer since 2006/07. This analysis has not been corrected for the impact of small-scale solar PV generation as half-hourly generation data for these systems is not available.

[5] The projected 2012/13 figures are indicative only, including nine months of data from the current financial year plus the final three months of the 2011/12 financial year.

Figure C – Modelled temperature coefficient (incremental demand per degree above 21°C)



At higher temperatures, the increased PV penetration explains roughly half of the reduction in temperature coefficient in the late afternoon. This suggests that air-conditioning demand has also reduced during this time, either due to reduced utilisation or improved efficiency as older air-conditioners are replaced with more energy-efficient models.

Supply-demand balance

The WEM has seen the entry of a significant amount of base load generation from 2006 to 2009 driven by expectations for a number of large new mining loads, some of which remain unrealised. The technologically-driven growth of DSM from 2010 to 2013 and construction of several diesel-fuelled power stations has subsequently boosted peaking capacity in the SWIS.

Assessment of the supply-demand balance in the SWIS suggests that opportunities for investment in generation and DSM capacity in Western Australia are limited in the near term. However, opportunities exist in the longer term for between 300 MW and 700 MW of new capacity in the latter half of the coming decade to meet load growth.

Figure D and Figure E show the supply-demand balance over the period 2013/14 through to 2023/24. Two scenarios are presented:

- Figure D anticipates the decommissioning of Verve Energy's Kwinana Stage C facilities for the 2016/17 Capacity Year.
- Figure E assumes that Kwinana C remains in service for the entire forecast horizon.

The IMO notes that the timing of the retirement of Kwinana C is subject to a commercial decision by Verve Energy.

Figure D – Supply-demand balance, 2013/14 to 2023/24, Kwinana C decommissioned for 2016/17

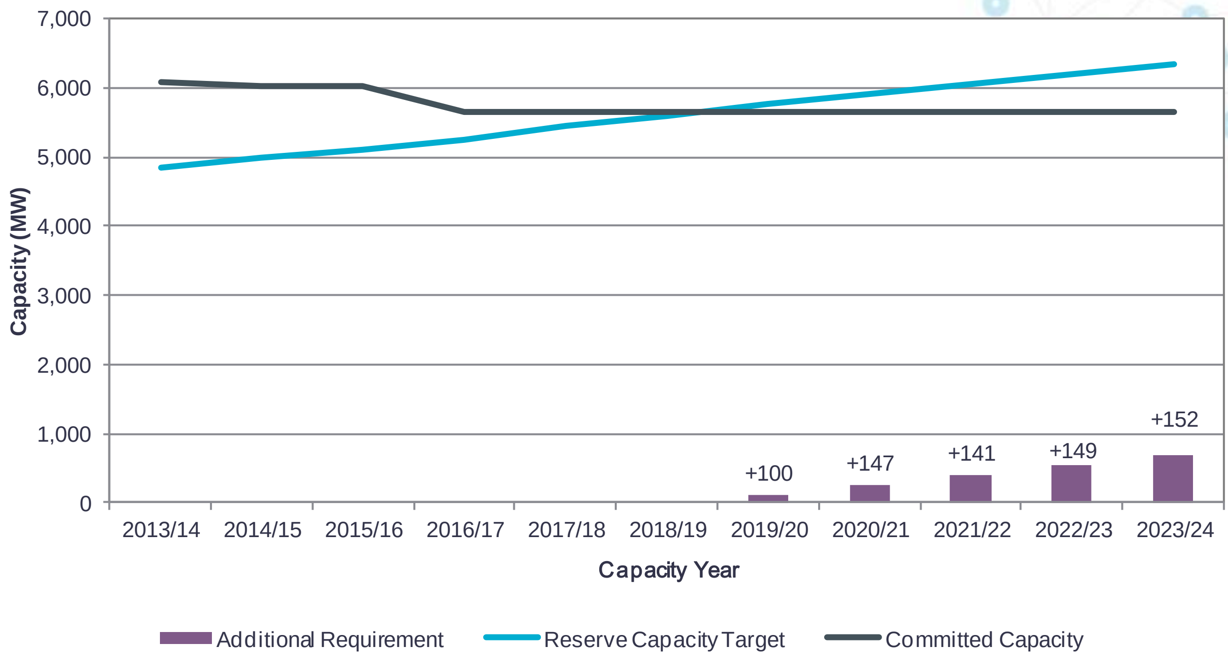
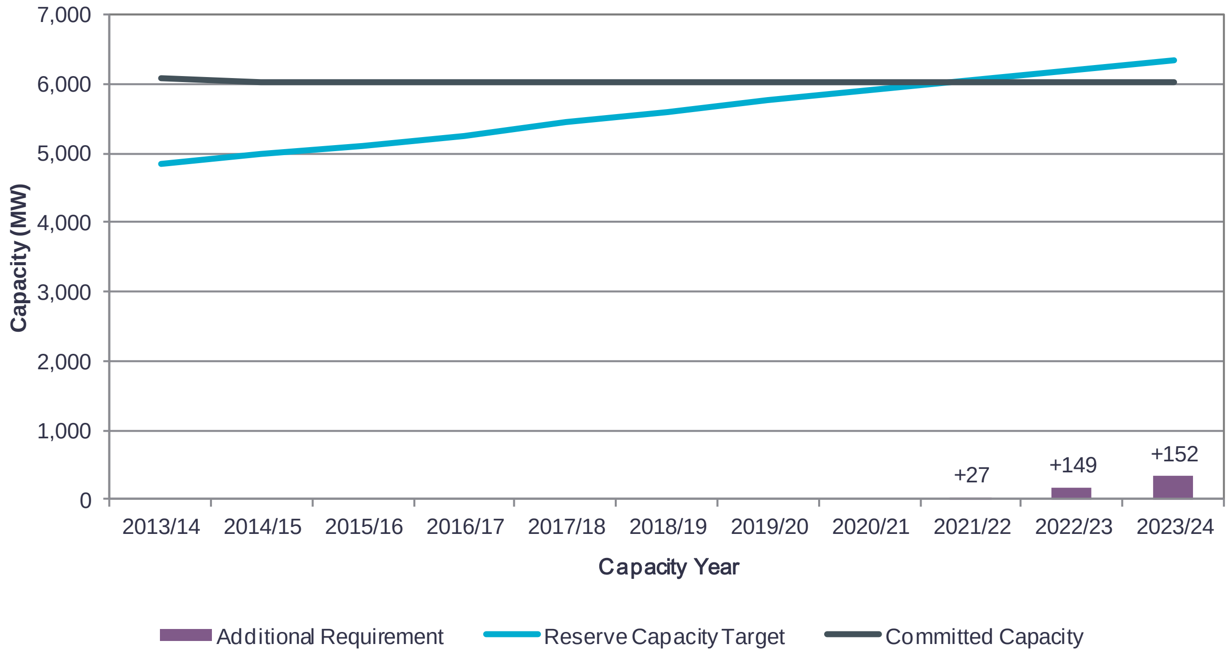


Figure E – Supply-demand balance, 2013/14 to 2023/24, Kwinana C remains in service



Key points to note from these graphs are:

- Sufficient Capacity Credits have been procured in previous years to meet the Reserve Capacity Target during 2013/14 and 2014/15.

- The level of committed capacity has been reduced for 2015/16 and 2016/17 by the IMO's estimate of the likely reduction in Capacity Credits for Intermittent Generators following the implementation of Rule Change RC_2010_25[6] (11 MW and 9 MW reductions respectively).
- If Kwinana Stage C is decommissioned, existing and committed capacity is expected to be sufficient to satisfy the Reserve Capacity Target through to 2018/19. If Kwinana Stage C remains in service, existing and committed capacity is expected to be sufficient to satisfy the Reserve Capacity Requirement through to 2020/21.
- By 2023/24 the total capacity requirement is forecast to be 6,348 MW. After allowing for the anticipated retirement of Kwinana Stage C, additional capacity of 689 MW is forecast to be required to service demand growth. If Kwinana Stage C remains in service, additional capacity of 328 MW is required through to 2023/24.

Circumstances may change over the period through to 2023/24. Project proponents, investors and developers should make independent assessments of the possible supply and demand conditions.

Expressions of Interest for new capacity

In direct response to the unprecedented reductions in load forecasts and the current capacity surplus, the Expressions of Interest (EOIs) submitted since 2009 have dramatically reduced from more than 1,200 MW for the 2011/12 Capacity Year to 59 MW in the recently completed EOI process for 2015/16.

Nine EOIs were received this year, covering a total potential Reserve Capacity of 59 MW. This quantity was dominated by renewable projects (57 MW) with only one potential DSM facility (2 MW) submitted into the process. No EOIs were received in respect of thermal generation.

Table C below shows the capacity offered into the EOI process for each year since 2007.

Table C – Quantity of capacity offered into Expression of Interest (EOI) process

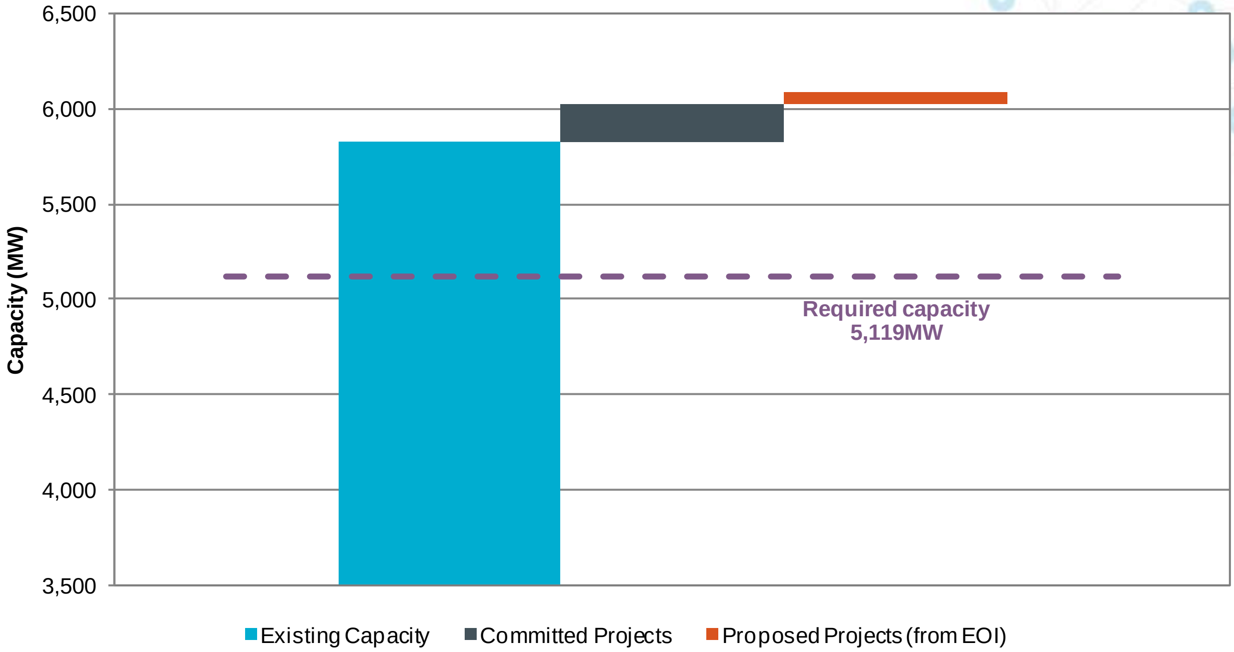
EOI year	2007	2008	2009	2010	2011	2012	2013
Capacity Year	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16
EOI capacity (MW)	1,192	1,036	1,279	644	337	214	59

While it provides an indication of potential future capacity, the submission of an EOI does not necessarily translate into certified capacity. In 2012, EOIs were received for 214 MW of new capacity but none of this capacity was assigned Capacity Credits for the 2014/15 Capacity Year.

Given the quantities of existing capacity, committed projects and potential new capacity, the IMO considers it likely that there will be more than sufficient capacity for the 2015/16 Capacity Year. This is illustrated in Figure F.

[6] See Rule Change entitled *Calculation of the Capacity Value of Intermittent Generation – Methodology 1 (IMO)*, available at http://www.imowa.com.au/RC_2010_25, for more information.

Figure F – Forecast Reserve Capacity status for 2015/16



Reform in the Wholesale Electricity Market

The WEM has undergone a significant transformation over the last three years, moving from a net market reliant on Verve Energy as the monopoly provider of Balancing to a competitive gross dispatch market.

The next phase of market development will be guided by the Market Rules Evolution Plan (MREP), which lists key issues identified and prioritised by industry stakeholders. The 2013-2016 MREP includes enhancements to the Balancing Market, publication of an Emissions Intensity Index and the introduction of a competitive market for Spinning Reserve services.

In addition to the MREP, a number of reforms and reviews are currently underway that may result in changes to the WEM. These include:

- the merger of Verve Energy and Synergy, announced by the State Government in April 2013;
- changes to the RCM, being developed following the work of the Reserve Capacity Mechanism Working Group; and
- the review by the Economic Regulation Authority of the methodologies for setting the Maximum Reserve Capacity Price and the Energy Price Limits, being conducted during 2013.

These reviews, and other potential changes to the market, are described in greater detail in Chapter 8.

Next steps

Parties offering a generation or a DSM facility as Reserve Capacity must register with the IMO as a Rule Participant and must register their facilities for the purposes of Reserve Capacity. Rule Participants must then apply for their facilities to be certified and apply to be assigned Capacity Credits.

Certification is required for all new and existing facilities. Applications for Certification of Reserve Capacity of generation and DSM capacity for the 2015/16 Capacity Year must be provided to the IMO by 5:00 pm WST on Monday, 1 July 2013.

Further information on the Reserve Capacity process is available on the IMO website at http://www.imowa.com.au. Parties planning to participate in these processes should familiarise themselves fully with the requirements of the relevant Market Rules and Market Procedures. Parties intending to participate in the WEM for the first time are strongly encouraged to contact the IMO at an early stage to discuss the market requirements for new entrants.

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Requirements of the Wholesale Electricity Market Rules

The following table is provided to assist readers wishing to find particular information in this report as required by the Market Rules. Market Rule 4.5.13 specifies the information that must be included in the Statement of Opportunities Report. The table below provides links to the appropriate section of the report for each of these items.

Market Rule	Report section where item is addressed
4.5.13. The Statement of Opportunities Report must include: (a) the input information assembled by the IMO in performing the Long Term PASA study including, for each Capacity Year of the Long Term PASA Study Horizon: i. the demand growth scenarios used;	Chapters 4 and 5 Appendices 3 to 8
ii. the generation capacities of each generation Registered Facility;	Appendix 12
iii. the generation capacities of each committed generation project;	Appendix 12
iv. the generation capacities of each probable generation project;	Section 6.6
v. the Demand Side Management capability and availability;	Appendix 12
vA. the amount of Reserve Capacity forecast to be required to serve the aggregate Intermittent Load;	Section 6.3
vi. the assumptions about transmission network capacity, losses and network and security constraints that impact on study results; and	Sections 5.2, 5.3 and 8.5.3
vii. a summary of the methodology used in determining the values and assumptions specified in (i) to (vi), including methodological changes relative to previous Statement of Opportunities Reports;	Chapters 4, 5 and 6
(b) the Reserve Capacity Target for each Capacity Year of the Long Term PASA Study Horizon;	Section 6.3
(c) the amount by which the installed generation capacity plus the Demand Side Management available exceeds or falls short of the Reserve Capacity Target for each Capacity Year and each demand growth scenario considered in the study;	Section 6.5 Appendix 9
(d) the extent to which localised supply restrictions will exist while satisfying the Reserve Capacity Target for each Capacity Year and each demand growth scenario considered in the study;	Sections 5.2, 5.3 and 8.5.3
(e) a statement of potential generation, demand side and transmission options that would alleviate capacity shortfalls relative to the Reserve Capacity Target and to capacity requirements in sub-regions of the SWIS; and	Section 6.6
(f) the Availability Curve for the 2nd and 3rd Capacity Years of the Long Term PASA Study Horizon.	Section 6.4 and Appendix 11

1. Introduction

Economic activity in Western Australia (WA) has continued to out-pace the rest of Australia, maintaining the recovery since the onset of the global economic downturn. However, following massive growth in recent years, the level of private investment in WA, particularly in the mining and resources sector, is expected to peak in the current financial year before steadily declining over the coming years.

Recent years have also seen the emergence of new government policy and consumption trends that have led to an unprecedented shift in electricity consumption patterns. Sharp increases in electricity prices and a range of Government incentives have combined to drive strong growth in distributed solar PV generation, energy efficient appliances and energy efficiency programs, as well as influencing consumption behaviour. These factors have contributed to the falls in electricity demand across Australia in recent years and have seen demand forecasts reduced for all jurisdictions.

Further, growing customer awareness of the design of the Wholesale Electricity Market (WEM) has influenced the behaviour of some customers on the hottest summer afternoons, times at which peak electricity demand events are expected to occur. This behaviour results from the design of the Reserve Capacity Mechanism (RCM) and has the potential to reduce the need for investment in generation and network capacity over the long term. This emerging demand behaviour has not previously been analysed in detail and has been considered in this year's demand forecasts for the first time.

The softening growth in electricity demand is delaying the absorption of the material capacity cushion that has developed within the South West interconnected system (SWIS) since 2009, despite the substantial reduction in new generation and Demand Side Management (DSM) investment. The 2011 and 2012 Reserve Capacity Cycles have seen the lowest entry of new capacity since the commencement of the WEM, culminating in a reduction in assigned Capacity Credits in 2012[7].

The recently completed Expression of Interest (EOI) process confirms the reducing interest in further capacity development, which is a direct response to the unprecedented reductions in load forecasts and the current capacity surplus. The IMO received EOIs for only 59 MW of potential new capacity, the lowest level of interest since the commencement of the WEM. The vast majority of these projects were for renewable generation, reflecting the ongoing Government policy measures such as the Renewable Energy Target (RET) that continue to stimulate interest in this sector.

The growth of DSM capacity has slowed significantly as it reaches a point of saturation. Following substantial growth from 154 MW in 2010/11 to 500 MW in 2013/14, only 25 MW of new DSM was certified for the 2014/15 Capacity Year. Only one EOI was received this year for new DSM, being for 2 MW.

This Statement of Opportunities Report (SOO) is published to primarily provide information on existing supply capacity and future electricity demand to parties considering participation in the RCM and to set the Reserve Capacity Requirement for the 2015/16 Capacity Year.

The SOO is a key element in the RCM, a series of processes through which the IMO identifies the requirement for future generation and DSM capacity and facilitates the introduction of this capacity onto the SWIS.

The 2013 SOO contains a detailed profile of the SWIS, including:

- historical demand data, a current load duration curve and typical load profiles (Section 2.1);
- an analysis of the current generation mix (Section 2.3);
- analysis of the current economic environment (Chapter 4);

[7] The reduction was driven by a change in the methodology for calculating the capacity valuation for Intermittent Generators. This led to a lower assignment of Capacity Credits for some of these facilities.

- energy consumption and peak demand forecasts for the Long Term PASA Study Horizon (Chapter 5); and
- updated expectations of the capacity available within the SWIS from that provided in the 2012 SOO, incorporating the 2013 Summary of Expressions of Interest that was published in May 2013 (Section 6.5).

The 2013 SOO also includes enhanced analysis of the performance of previous forecasts. Chapter 3 provides detailed comparisons of previous forecasts with actual observed demand over the last year, including the factors that have contributed to deviations. Following a request from Market Participants, Section 5.9 also includes a comparison with forecasts from Western Power's Annual Planning Report (APR) for the first time.

As the WEM uses sent out capacity quantities (the net amount of electricity exported onto the transmission grid), the information provided in the SOO is presented in terms of sent out capacity expressed in megawatts (MW), unless otherwise specified. Energy production is also presented in sent out terms and is measured in gigawatt-hours (GWh).

Throughout the SOO, temperatures and electricity demand in the SOO are compared to probability of exceedance (PoE) levels. The probability of exceedance is the likelihood that the temperature or electricity demand will exceed a certain level. For example:

- a 10% PoE peak demand forecast would be expected to be exceeded only once in every ten years (10% of the time);
- a 50% PoE peak demand forecast would be expected to be exceeded once in every two years (50% of the time); and
- a 90% PoE peak demand forecast would be expected to be exceeded nine times in every ten years (90% of the time).

To ensure that sufficient capacity is secured for extreme weather events, the IMO is required under the Market Rules to set the Reserve Capacity Requirement based on the 10% PoE forecast.

2. Electricity generation and consumption in the SWIS

2.1. Characteristics of demand

2.1.1. Historical SWIS demand

Since Energy Market Commencement (EMC) in 2006, peak demand within the SWIS has grown by 11% from 3,364 MW in 2007 to in excess of 3,700 MW in 2013. Similarly, sent out energy has grown by 9% from 16,387 GWh in the 2007/08 financial year to 17,882 GWh for the 2012/13 financial year[8]. The growth in the penetration of air-conditioning, particularly since 2000, has been the main reason that peak demand grew at a faster rate than average demand.

Up to 2011/12, summer peak demand consistently increased, continuing a decades-long trend. This trend accelerated during the first decade of this century, when the growth in penetration of air-conditioning caused peak demand to grow at four times the rate than had been the case in the early 1990's. Growth continued even during the initial years after 2008's Global Financial Crisis (GFC), as economic activity within the SWIS was largely unaffected.

However, as shown in Figure 1, this growth trend has slowed considerably, and potentially reversed, over the last few years. This graph shows histograms of the SWIS demand for the yearly periods from 1 April to 31 March, including the average and peak demand values for each year. Growth in average demand has been flat since 2010/11, while the 2013 summer demand peak was the lowest in four years. The 2012/13 peak demand of 3,735 MW is 3.1% lower than the 2011/12 summer peak of 3,854 MW.

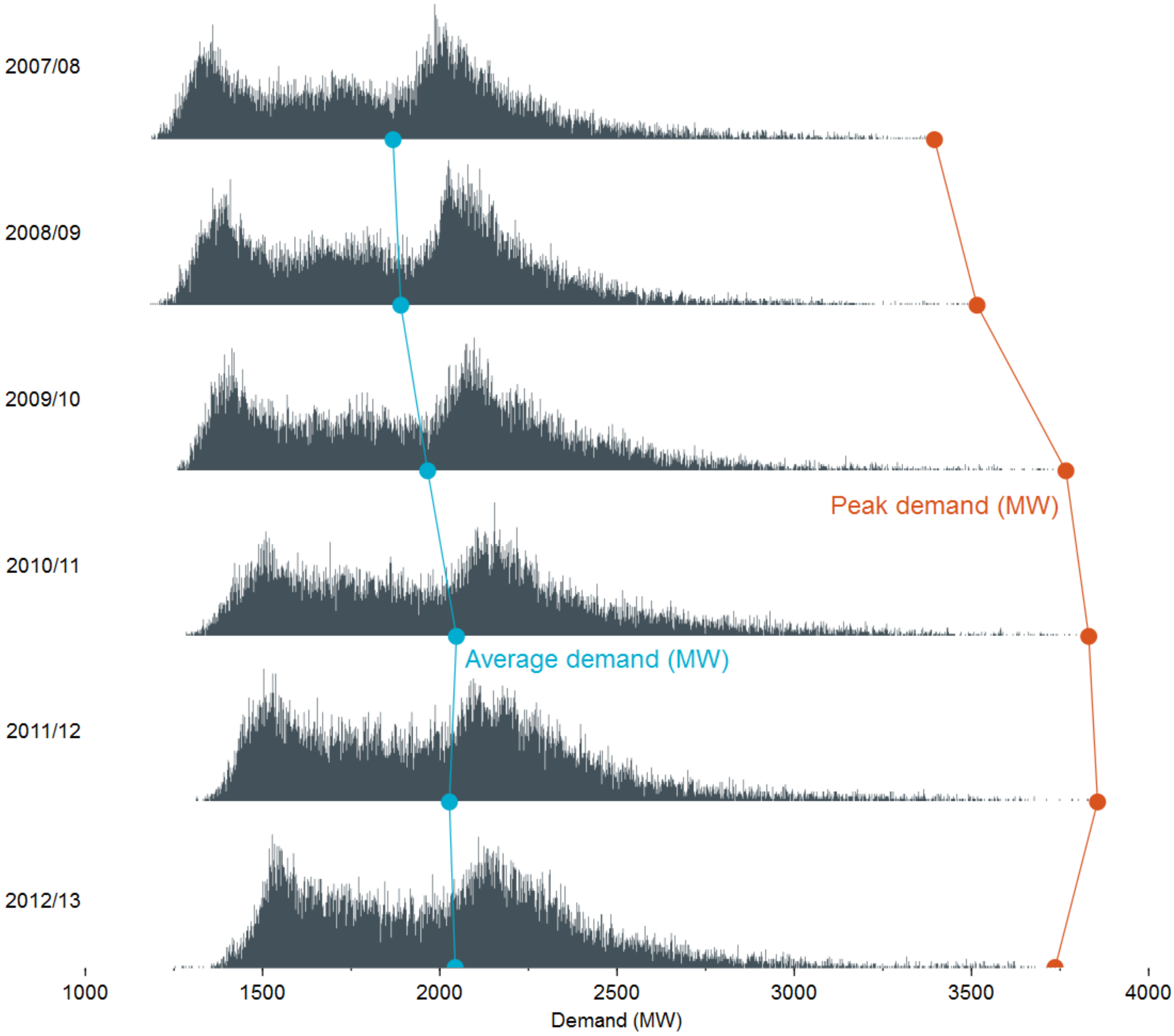
The phenomenon of reduced peak demand is not unique to the SWIS with the National Electricity Market (NEM) experiencing a reduction in maximum demand in recent years of 5.5% from 33,208 MW in 2007/08 to 31,381 MW in 2011/12[9]. Despite record-breaking temperatures in many locations in the eastern states of Australia in the 2013 summer, Queensland experienced its lowest summer demand peak in five years, Victoria experienced its lowest in six years and the peak in New South Wales was only its fifth highest on record[10].

Major factors in the reversal of the peak demand growth trend in the SWIS are:

- the emergence and continued growth of small-scale solar photovoltaic (PV) generation, which is seen at the wholesale level as reduced consumption;
- growth in domestic regulated electricity tariffs, which will have increased by 78% for residential customers from March 2009 to July 2013[11] (with similar increases for regulated tariffs that apply to small commercial and industrial customers);
- an increased focus by large industrial users of energy on reducing their capacity costs by managing their demand during peak demand intervals in order to minimise their Individual Reserve Capacity Requirement (IRCR). This effect has had a significant dampening effect on the 2013 summer demand peak and is analysed further in Chapter 3; and
- an apparent reduction in the temperature coefficient[12] for the SWIS since 2011, as described below.

[8] This estimate comprises nine months of actual data plus three months of estimated data.
[9] See Tables 2-1 and 2-2 in the *NEM-wide historical information report*, available at http://www.aemo.com.au/Electricity/Planning/Related-Information/Historical-Market-Information-Report. Both peaks occurred in winter.
[10] http://energy.unimelb.edu.au/files/site1/docs/42/Summer%20on%20the%20NEM.pdf
[11] Estimated from http://www.finance.wa.gov.au/cms/content.aspx?id=15096, https://www.synergy.net.au/docs/MR-Synergy-releases-expected-carbon-impact-on-resdential-prices.pdf and announcement by the Hon Troy Buswell, 9 May 2013, *Striking a balance of household costs* (available at http://www.mediastatements.wa.gov.au/Pages/Default.aspx).
[12] Measured as the incremental demand (in MW) for each degree increase in temperature above 21°C.

Figure 1 – SWIS demand profile, 2007/08 to 2012/13 (1 April to 31 March)

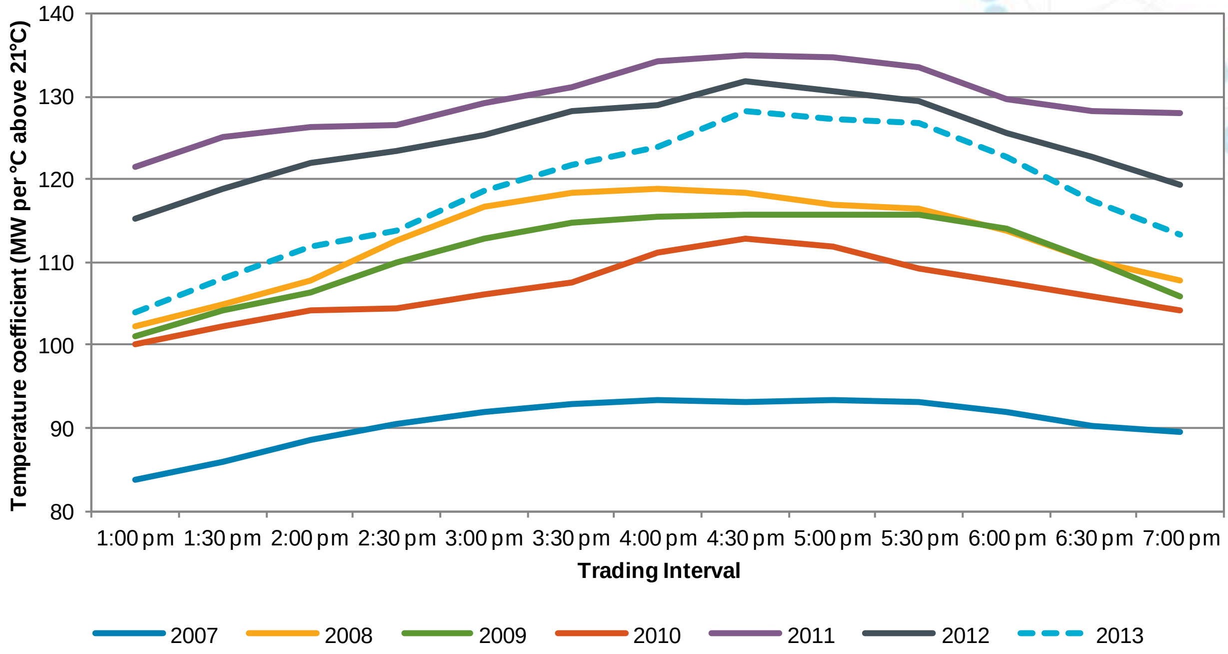


Analysis of temperature-sensitive load suggests that the temperature coefficient for the SWIS reached a peak in 2011 but has fallen since. Figure 2 displays the results of analysis by the National Institute of Economics and Industry Research (NIEIR) of the relationship between summer temperatures and demand for each summer since 2006/07. This analysis has not been corrected for the impact of small-scale solar PV generation as half-hourly generation data for these systems is not available.

At higher temperatures, the increased PV penetration explains roughly half of the reduction in the late afternoon. This suggests that air-conditioning demand has also reduced during this time, either due to reduced utilisation or improved efficiency as older air-conditioners are replaced with more energy-efficient models.

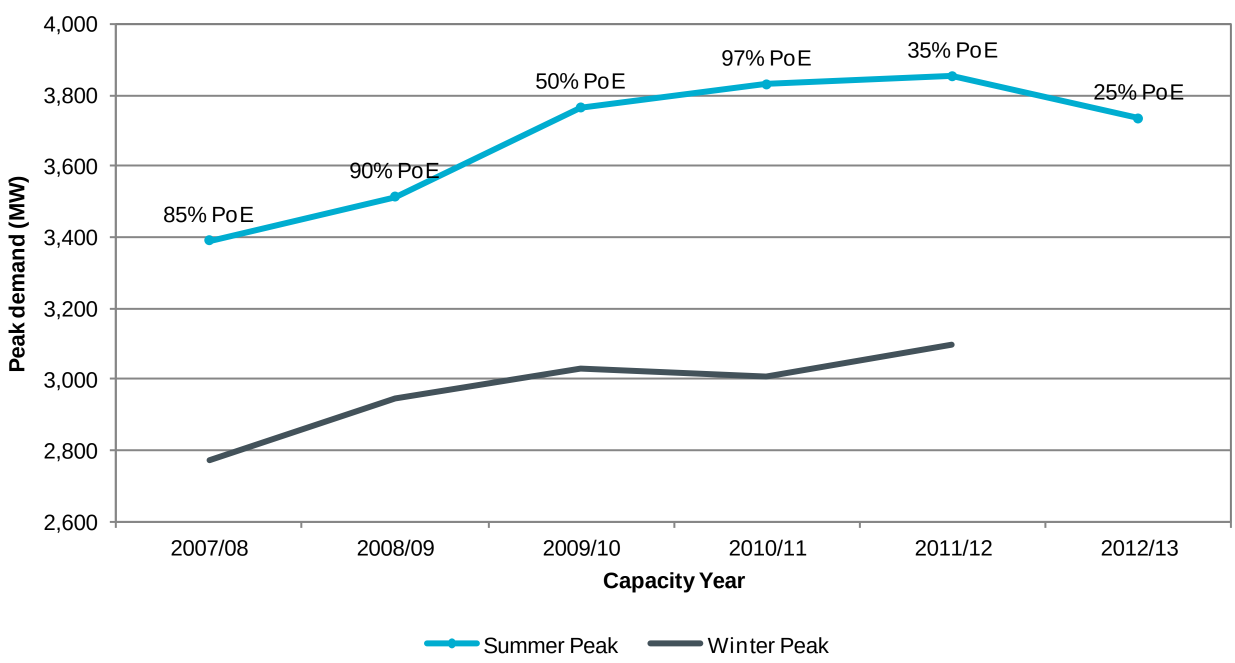
Customer awareness campaigns in recent years, such as “Beat the Peak” and “Switch the Future”, have informed customers more broadly on the long-term costs of meeting growth in peak demand. Behavioural change as a result of these campaigns is likely to have contributed to the moderation in peak demand in recent summers and is likely to be reflected in the reducing temperature coefficient.

Figure 2 – Modelled temperature coefficient (incremental demand per degree above 21°C)



The SWIS summer and winter peak demand levels are shown in Figure 3. The PoE level of the peak demand day, based solely on the mean daily temperature[13], is shown for each year. Despite the low summer peak in 2013, this graph shows that the summer peak demand level remains substantially higher than the winter peak at present.

Figure 3 – History of summer and winter peak demand



[13] Mean daily temperature refers to the arithmetic mean of the daily maximum temperature and the daily minimum temperature.

Up until 2008, annual electricity consumption grew consistently at rates broadly aligned with economic growth. However, recent electricity consumption data in the SWIS has demonstrated a material dislocation between economic growth in WA and the growth in underlying electricity demand.

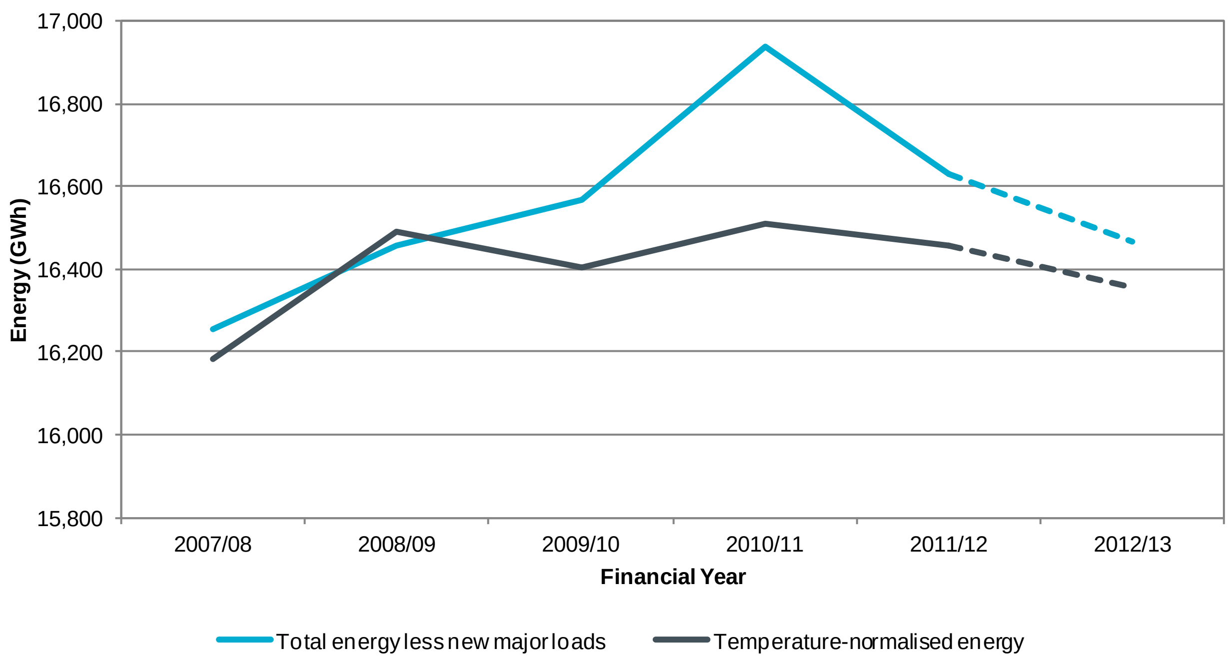
Figure 4 shows the total sent out energy by financial year since 2007/08, after deducting consumption from new major loads that have commenced operation during that period. In this case, the projected 2012/13 figures are indicative only, including nine months of data from the current financial year plus the final three months of the 2011/12 financial year.

The observed sent out quantities are sensitive to temperature, both in summer and winter. Consequently, NIEIR has normalised this data for the effect of temperature, enabling analysis of the underlying demand trend[14]. The temperature-normalised data is shown as the dark grey line in Figure 4.

This data shows that, after adjusting for new major loads and temperature, underlying energy sales have fallen since 2008/09. This trend has been masked by above-average temperatures during the last four summers. A number of factors are likely to have contributed to this change:

- the increases in regulated electricity tariffs;
- the growth in small-scale solar PV systems;
- the restricted availability and increased cost of finance since the onset of the GFC in late 2008 that has hampered investment for small-to-medium enterprises in WA since that time; and
- increasing impact of energy efficient appliances, energy efficiency programs and public awareness campaigns that are driving behavioural change amongst consumers.

Figure 4 – Sent out energy, adjusted for new major loads and temperature



2.1.2. SWIS load duration curve

In an electricity system, variation in demand can be examined in a load duration curve. This shows the demand in the system against the percentage of time for which it is reached or exceeded.

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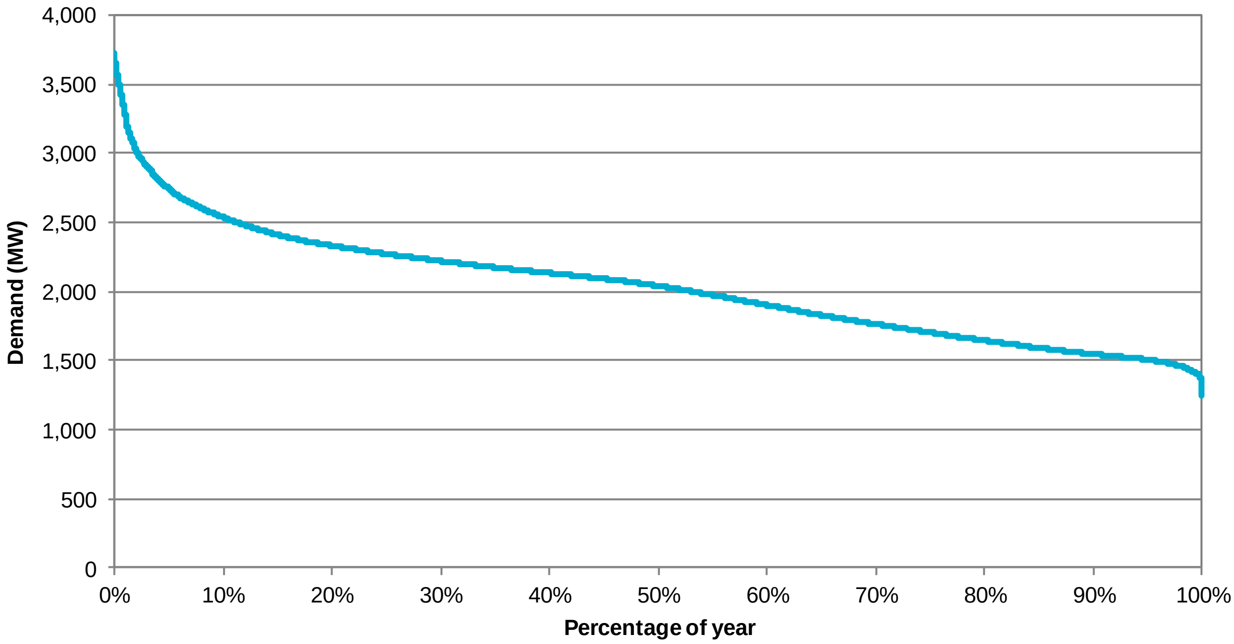
[14] The IMO notes that the results of the temperature normalisation shown in Figure 4 differ from the corresponding data presented in the 2012 SOO. This year, NIEIR has normalised to a warming temperature trend to reflect observed changes in temperatures over time.

The load duration curve provides an insight into the likely optimum mix of generation types. Base load and mid-merit generation facilities are best suited to meet demand that is present for much of the year. Conversely, demand that only occurs for a small part of the year is best supplied by peaking generators or DSM.

The load duration curve for the SWIS is characterised by sharp summer peaks, a feature that is evident in Figure 5, which shows the load duration curve for the period from April 2012 through to March 2013. During this period, the load exceeded 90% of the annual maximum (i.e. 3,362 MW) for 135 half-hour Trading Intervals, representing less than 0.75% of the year. Similarly, the load exceeded 80% of the annual maximum (i.e. 2,988 MW) for only 2.2% of the year. This indicates that a significant level of generation, DSM and network capacity is only utilised for a few hours or days each year.

Figure 5 – Load duration curve, April 2012 to March 2013



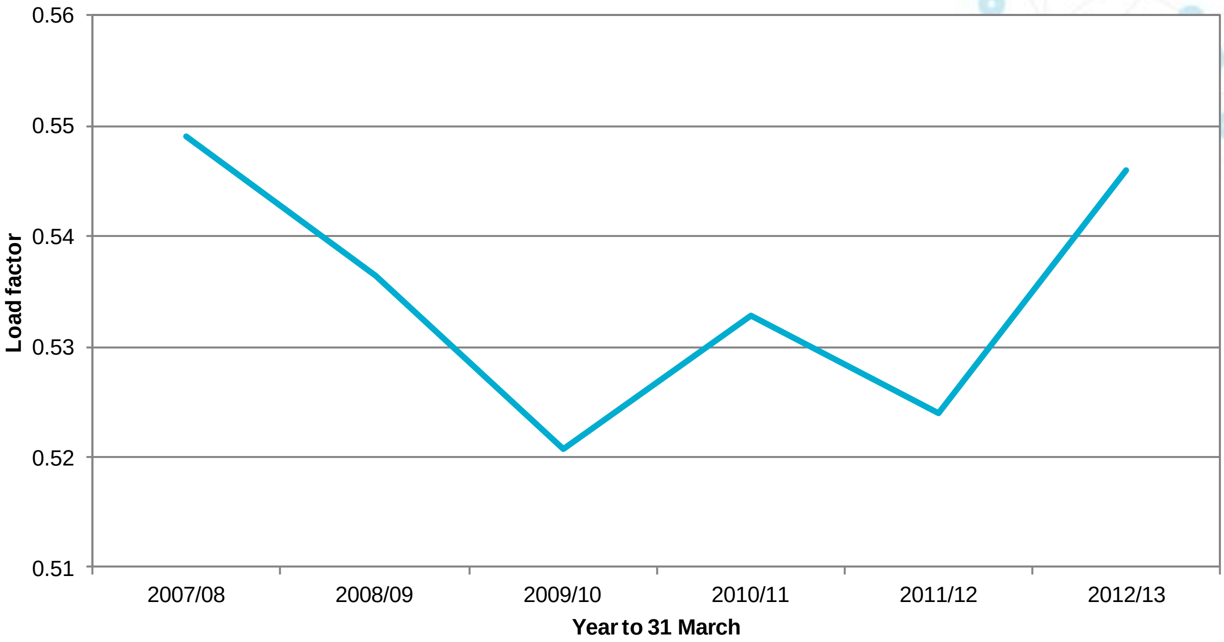
Other observations from this figure are that:

- The mean load over the year was 2,039 MW, which is 54% of the maximum demand compared with 52% last year.
- The minimum load was 1,253 MW at 12:00 am on 11 June 2012 compared with 1,313 MW last year. The June 2012 minimum load event occurred after storms that left more than 100,000 homes without power[15].

From 2007/08 up to 2009/10 the load factor for the SWIS trended downward, demonstrating that peak demand was growing at a faster rate than average demand. Since 2010/11 this trend has reversed with the load factor increasing from 52% to 54% for 2012/13. Whilst peak demand was only 3,735 MW, 3% lower than the previous year, average load increased by 1% to 2,039 MW. The increase in the load factor for 2012/13 reflects the low peak demand experienced during the recent summer, which is analysed further in Chapter 3.

[15] http://www.abc.net.au/local/stories/2012/06/11/3522450.htm?site=perth

Figure 6 – Load factor for year ending 31 March



2.1.3. Daily demand profile

Electricity demand varies substantially through each day with overnight loads being markedly lower than daytime demand. Summer maximum temperatures can range from the mid-twenties to the mid-forties, with consequent daily peak electricity demands ranging from below 2,000 MW to above 3,800 MW. The daily peak demand is generally higher on business days than on weekends and public holidays, and is also higher during school term than during school holidays. Typically, the highest maximum demands are recorded when there is a sequence of hot days with high overnight temperatures.

Figure 7 illustrates this, showing the level of demand in each Trading Interval on 12 February 2013, the day of highest demand in the 2012/13 Capacity Year. The peak demand for the day reached 3,735 MW, while demand in the early morning of the same day was as low as 2,036 MW. Appendix 10 includes further daily load curves covering the winter day with the highest maximum demand, as well as typical autumn and spring day profiles.

In the period between April 2012 and March 2013, the largest intra-day differential between maximum and minimum load was 1,843 MW, which occurred on 20 February 2013. The minimum load on this day was 1,797 MW and the maximum load was 3,641 MW. The lowest intra-day differential of 522 MW occurred on 17 February 2013, with a minimum load of 1,683 MW and maximum load of 2,205 MW. Figure 8 shows the maximum and minimum intra-day demand differentials for the previous six years. Maximum and minimum intra-day demand differentials typically occur during summer.

Figure 7 – Daily load curve, 2013 peak demand day (12 February 2013)

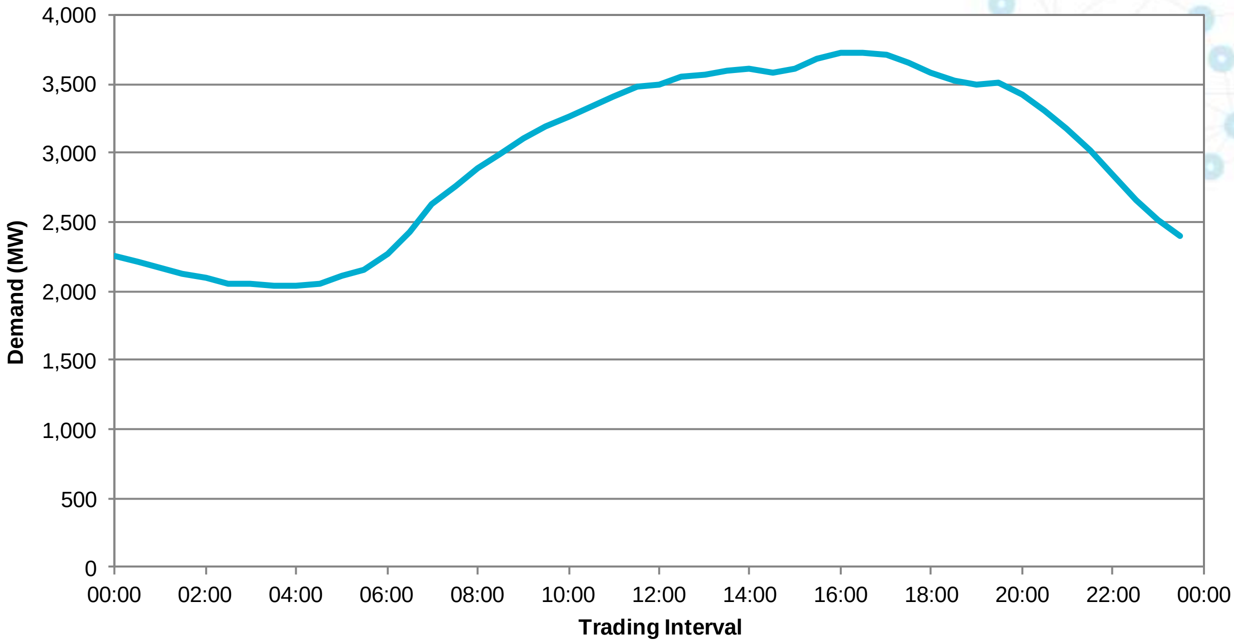
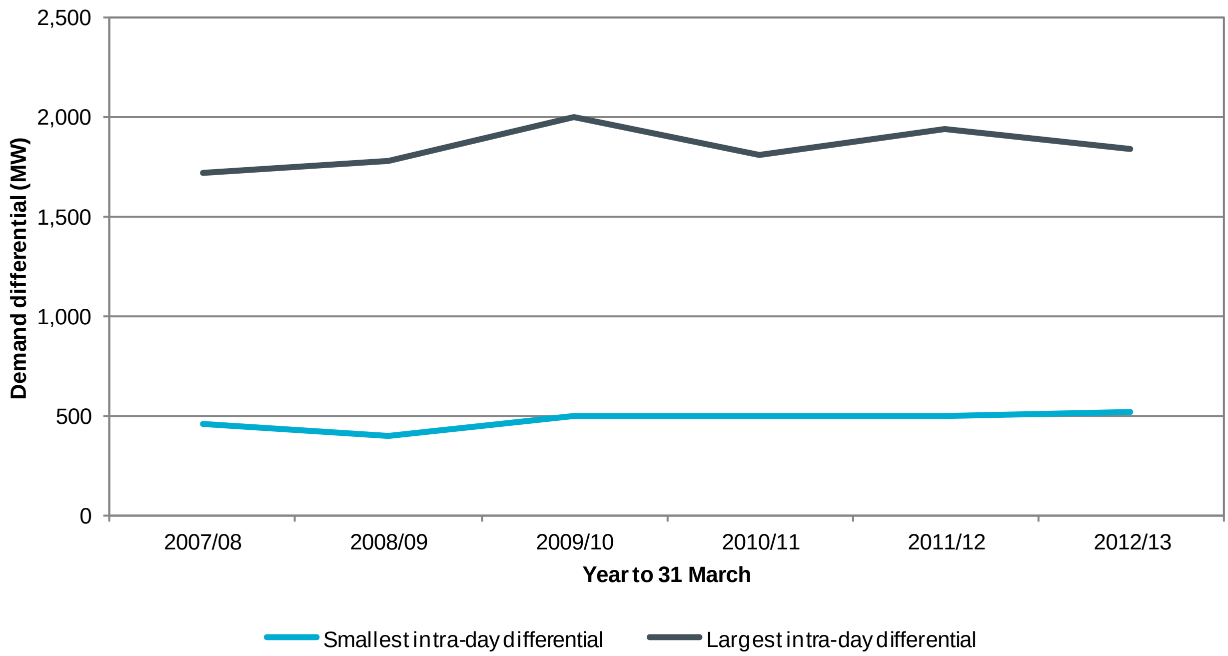


Figure 8 – Intra-day demand differential for year ending 31 March

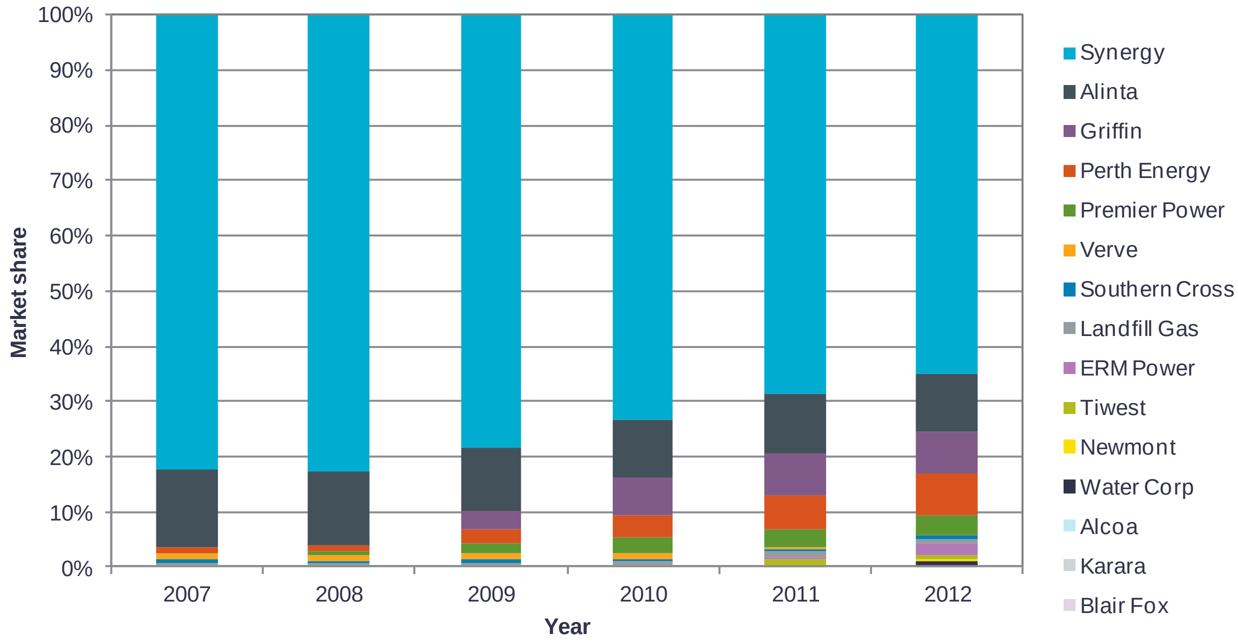


2.2. Market Customers

While Synergy remains the largest retailer within the SWIS, its market share has progressively reduced since 2008. This is demonstrated in Figure 9, which shows the market share of each Market Customer in each calendar year as measured by energy purchased. Synergy's market share has dropped from 82.5% at market start to 65% in the 2012 calendar year. Over the same period Alinta's market share has declined from 14% to 10%.

Increased total energy demand and increasing retail competition for contestable customers have contributed to the substantial decline in Synergy's and Alinta's market shares over this period. Griffin and Perth Energy have grown from market share levels below 1% to above 7% each, and Premier Power and ERM Power have also grown market share in recent years.

Figure 9 – Market share of Market Customers



2.3. Generation and DSM capacity

2.3.1. Capacity Credits by Market Participant

Various measures were implemented at the commencement of the WEM that have increased the diversity of Market Participants providing capacity to the SWIS and decreased the proportion of capacity provided by Verve Energy. These measures have included:

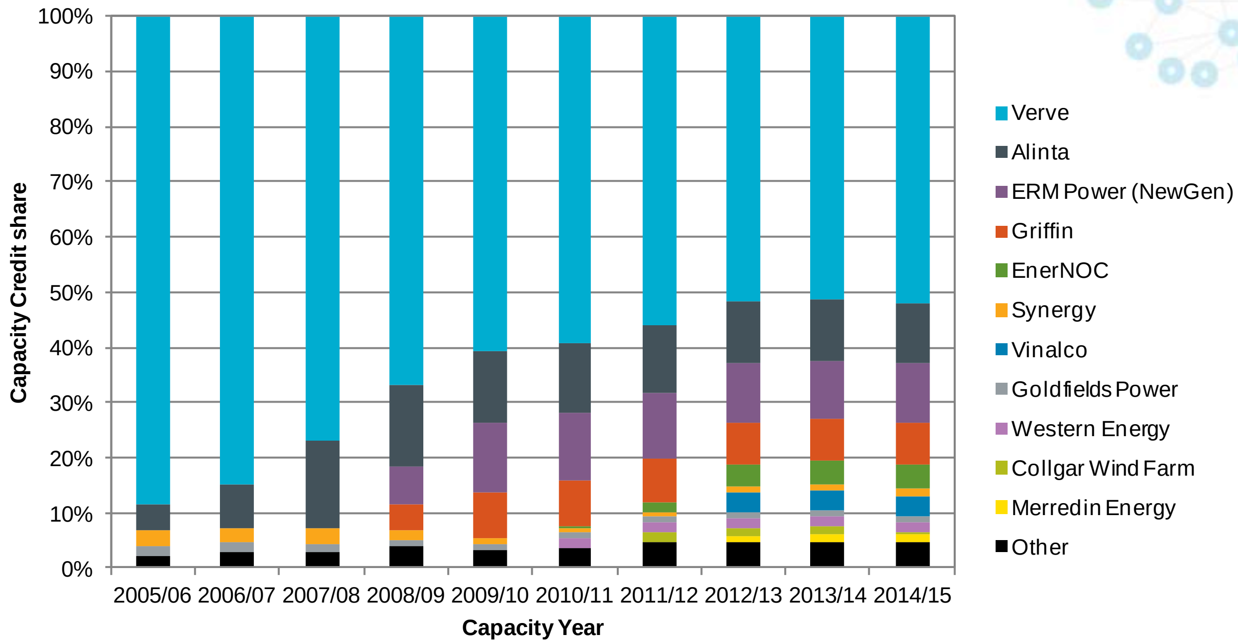
- the Displacement Mechanism within the original Vesting Contract between Synergy and Verve Energy, which required Synergy to procure specified volumes of capacity through a competitive tender process (no longer in effect);
- the Ministerial Direction on Verve Energy that capped Verve Energy's generation capacity at 3,000 MW[16]; and
- the RCM.

Figure 10 shows the Capacity Credits assigned to Market Participants as a percentage of the total number assigned in the SWIS for each year since the 2005/06 Capacity Year. The proportion of Capacity Credits held by Verve Energy has reduced from 89% at EMC and is projected to be 52% in 2014/15. The growth in

[16] The capacity cap refers to nameplate capacity within the SWIS and excludes renewable generation facilities. The Direction exempted certain pre-existing Power Purchase Agreements in place between Verve Energy and facilities owned by third parties. Verve Energy was granted an exemption to the capacity cap for the refurbishment of the Muja AB facilities by Vinalco (a joint venture between Verve and Inalco Energy), though these facilities have now been transferred to Vinalco and this exemption has expired. A copy of the Ministerial Direction is available at http://www.imowa.com.au/cap-credit-info.

the number of Market Participants providing capacity to the SWIS, from 10 in 2005/06 to 26 in 2014/15, reflects the increased diversity of supply of Capacity Credits since market start.

Figure 10 – Capacity Credits by Market Participant (minimum 1% market share)



2.3.2. Capacity Credits by fuel type

Diversity of fuel types is desirable in an electricity market as it lowers operational risk and supports competition between technologies.

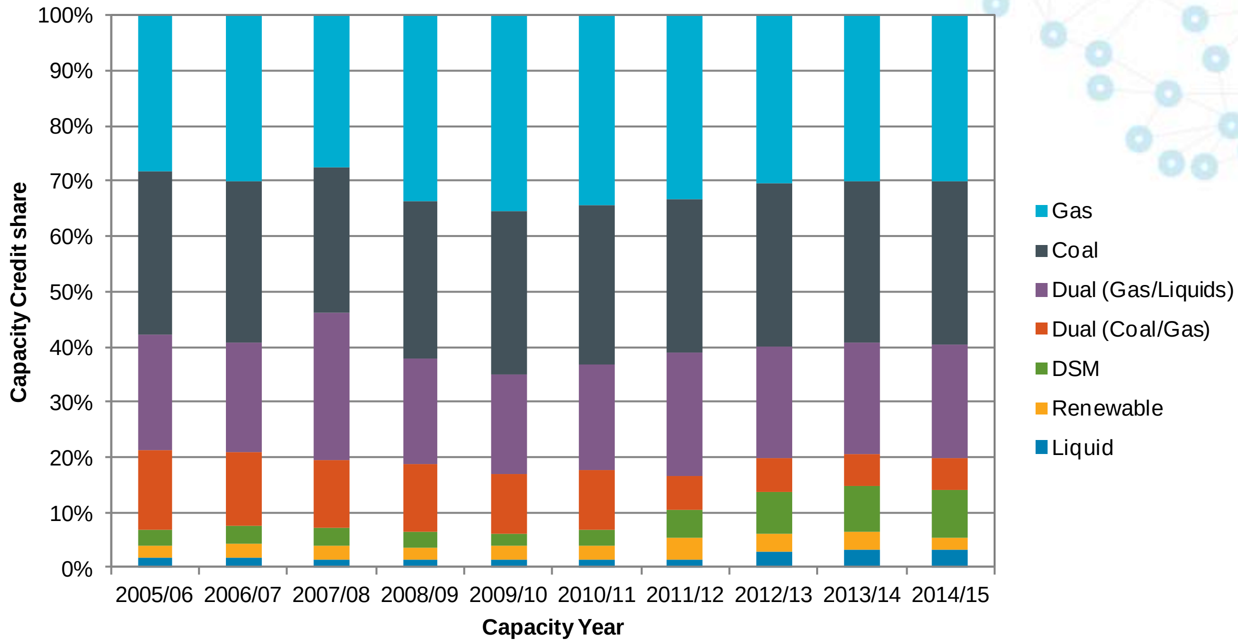
Highly utilised generators (base load and mid-merit) will usually use low-cost fuels such as coal or natural gas. However, low-cost fuels can incur large fixed costs for transport, storage and processing. Facilities with high capital and fixed costs become viable if utilisation is high. These facilities have a focus on income from the energy market.

Conversely, plants operating only rarely (peaking) may have lower total costs if other fuels are used – perhaps with higher unit costs, but lower fixed costs. For example, high-cost distillate fuel can be the best choice for plants which will run only for a small number of Trading Intervals at peak demand times. These facilities will typically be more reliant on Reserve Capacity payments.

Diversity of fuel types can mitigate against failures or restrictions in the supply of a particular fuel type. For instance, access to coal-fired, distillate-fired and dual-fuelled generation capacity was very important in minimising the impacts of the Varanus Island gas supply disruption in 2008. The impact of the February 2011 gas supply disruption from Varanus Island due to Tropical Cyclone Carlos was mitigated by fuel diversity and the contribution of DSM.

Figure 11 illustrates the composition of generation and DSM capacity based on fuel type for each year since the 2005/06 Capacity Year. Increases in capacity have been experienced across each of the fuel types within the SWIS excluding dual-fuelled coal/gas capacity, which has reduced with the retirement of the Kwinana Stage A and B plant.

Figure 11 – Percentage of Capacity Credits by fuel type



A number of observations may be made from this graph:

- More than 85% of capacity in the WEM continues to be coal or gas-fired.
- From 2010/11 to 2013/14, the percentage of Capacity Credits assigned to liquid-fuelled plant and DSM has increased significantly. However, this rate of growth slowed substantially for the 2014/15 Capacity Year and is not expected to grow in the near term.
- The level of DSM, in particular, appears to be at a point of saturation, as demonstrated by the slowing in the rate of growth in DSM since 2012/13. The level of DSM penetration in the SWIS now represents a similar level to that of other electricity markets with mature capacity markets, such as PJM, ISO New England and New York ISO. The only EOI for new DSM capacity this year was for 2 MW of prospective new capacity.
- The proportion of Capacity Credits assigned to renewable generators grew through to 2013/14, but dropped substantially from 2013/14 to 2014/15. This drop from 204 MW to 129 MW is due to the implementation of the Relevant Level Methodology[17], which calculates the capacity valuation for Intermittent Generators. This methodology is based on generation performance during peak-demand periods, rather than average annual generation as had previously been the case.
- The percentage of dual-fuel capacity has reduced from in excess of 35% to 26% since market start. While more than 650MW of dual-fuelled gas/liquid capacity has been added in this period, this has been partially offset by the retirement of more than 400MW of capacity from the Kwinana Power Station.

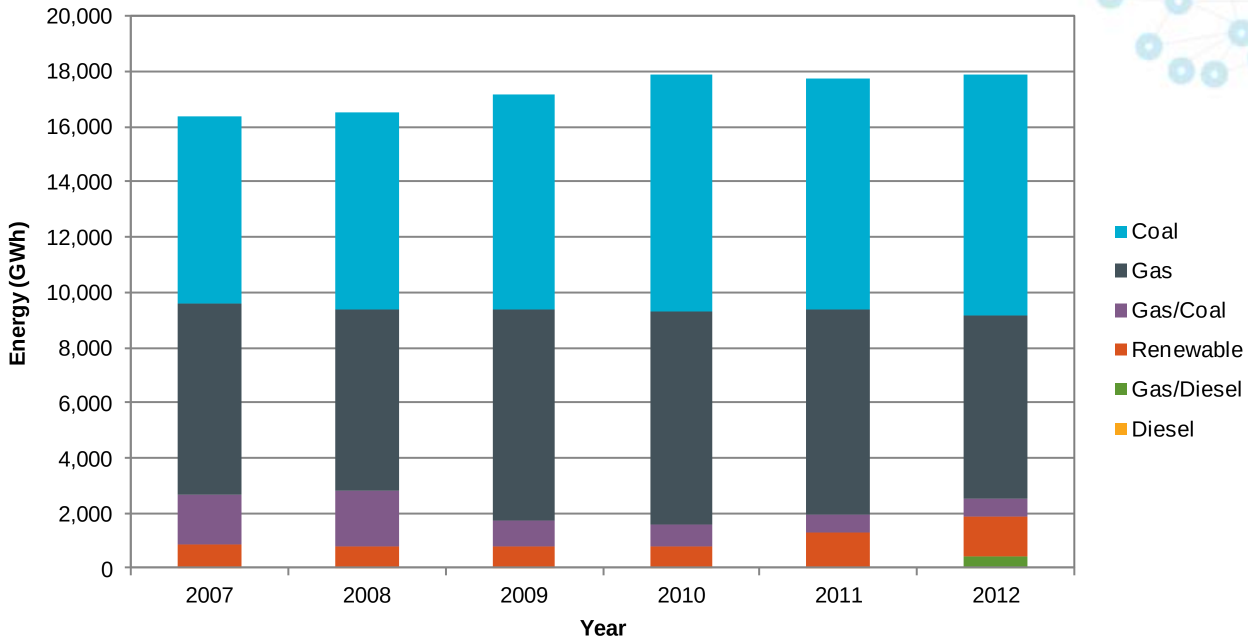
Following two significant gas supply disruptions in 2008, the Gas Supply and Emergency Management Committee recommended the development of incentives for investment in dual-fuelled generation plant. However, as noted in Section 8.8, the Public Utilities Office (PUO) indicated in 2012 that it does not intend to proceed with any changes in this area at this time.

Figure 12 illustrates the total sent out energy for each fuel type for each calendar year since market start. Total energy from coal has increased by 28% over this time, energy from gas has declined marginally, whilst energy from renewables has increased substantially by 75% to represent more than 8% of total sent out

[17] The Relevant Level Methodology was implemented by Rule Change RC_2010_25. See http://imowa.com.au/RC_2010_25 for more information.

energy at the wholesale level in 2012. Total generation from dual-fuel and diesel-powered facilities has declined since EMC from low starting levels.

Figure 12 – Energy generation by fuel type



2.3.3. Load characteristics and generation mix in the SWIS

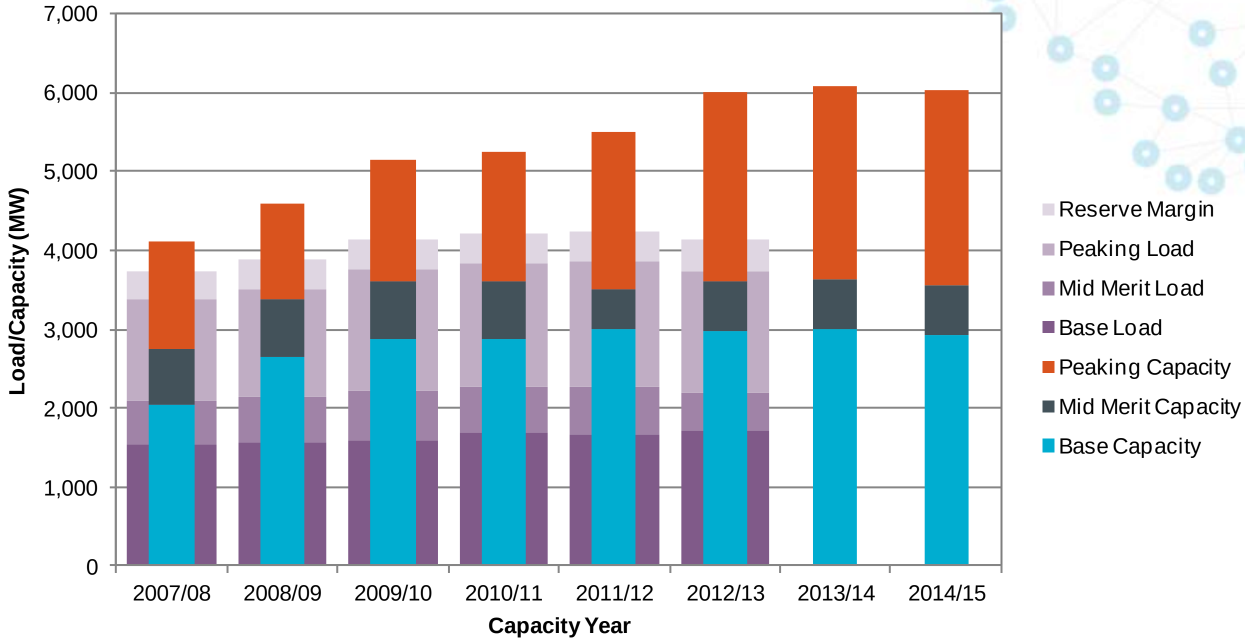
As discussed in Section 2.1.2, the optimum mix of capacity will be driven to some extent by variation of demand throughout the year, as displayed in the load duration curve. A healthy mix of base load, mid-merit and peaking facilities is desirable for the SWIS given the 'peaky' nature of the load profile.

Figure 13 analyses this by categorising both load and capacity into base, mid-merit and peaking classes. Base load has been defined as the level of demand that is exceeded for 75% of the year, mid-merit load as the additional demand that is exceeded for 25% of the year and peaking load is the additional demand that is only present for less than 25% of the time. The available capacity has been similarly classified based on plant type and historical operating practices.

As can be seen in Figure 13, substantial investment was made in new base load generation capacity for the SWIS in the early years of the WEM (2006 through 2009). This has led to a surplus of this capacity in the near term and has required some cycling of base load generation plant during periods of lower demand (e.g. overnight). The level of base load capacity has remained steady at around 3,000 MW since 2011/12, but would reduce by 361.5 MW if the Kwinana C facilities were to be decommissioned.

Peaking capacity then grew substantially from 2010/11 to 2013/14, driven by the introduction of substantial volumes of liquid-fuelled generation and DSM. As is demonstrated in Figure 13, the quantity of peaking capacity at market start was smaller than the peaking portion of SWIS demand, but has now grown to exceed the peaking load.

Figure 13 – SWIS load characteristics and capacity mix



2.3.4. Age and availability of generation plant

The age of generation plant can influence its efficiency, reliability, flexibility and production cost.

As can be seen in Figure 14, the average age of generating capacity on the SWIS fell dramatically from 2005/06 to 2011/12. This reflected the introduction of new generation capacity and the retirement of Verve Energy's Kwinana Stage A and B facilities.

This trend reversed in 2012/13 primarily due to the refurbishment of the Muja AB facilities (originally commissioned in stages in the second half of the 1960's) for the 2012/13 Capacity Year. Since 2012/13 there has been limited investment in new generation capacity, leading to an increase in the average age for generation to just under 17 years in 2014/15[18], higher than at market start.

There will continue to be fluctuations in average age from year to year depending on the addition of new capacity, upgrades to existing facilities and retirement of older plant. It is anticipated that in the short-term there will be limited growth in new capacity, which in the absence of substantial retirements would lead to a continuation of the recent trend of increasing average age of generation capacity. In the event that Verve Energy's Kwinana Stage C facilities are retired, the average weighted age of generating capacity in the SWIS would fall by approximately 1.5 years.

[18] The average weighted age increased by more than 1 year for 2014/15 primarily due to a reduction in Capacity Credits for some Intermittent Generators following the implementation of the Relevant Level Methodology.

Figure 14 – Average age of generation capacity

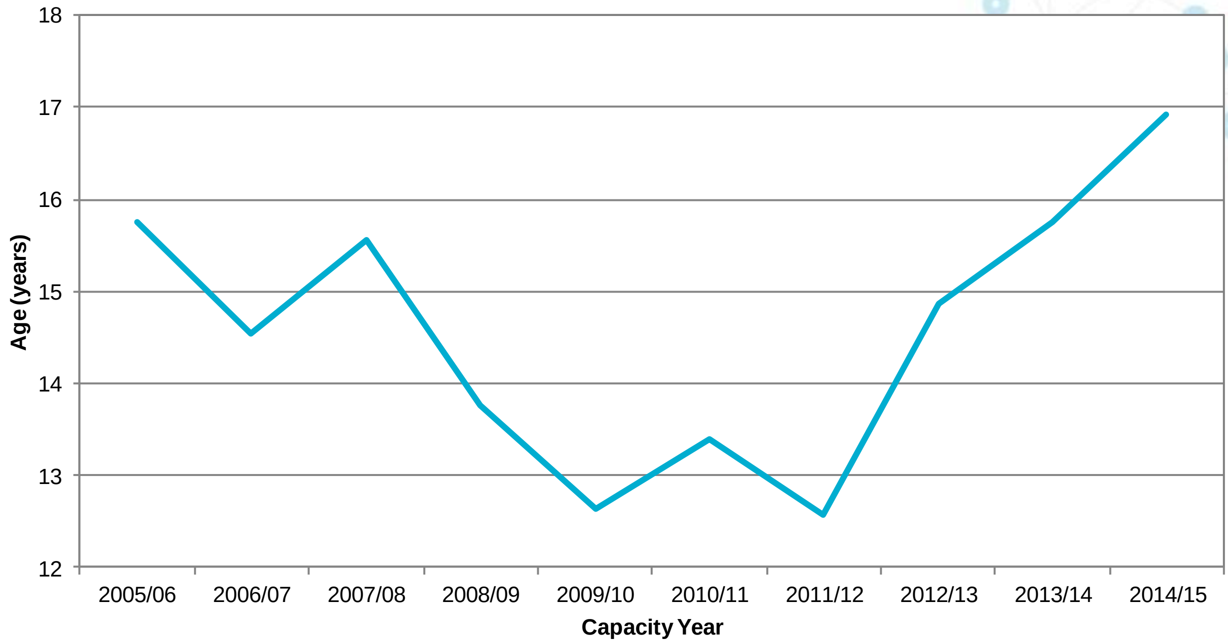
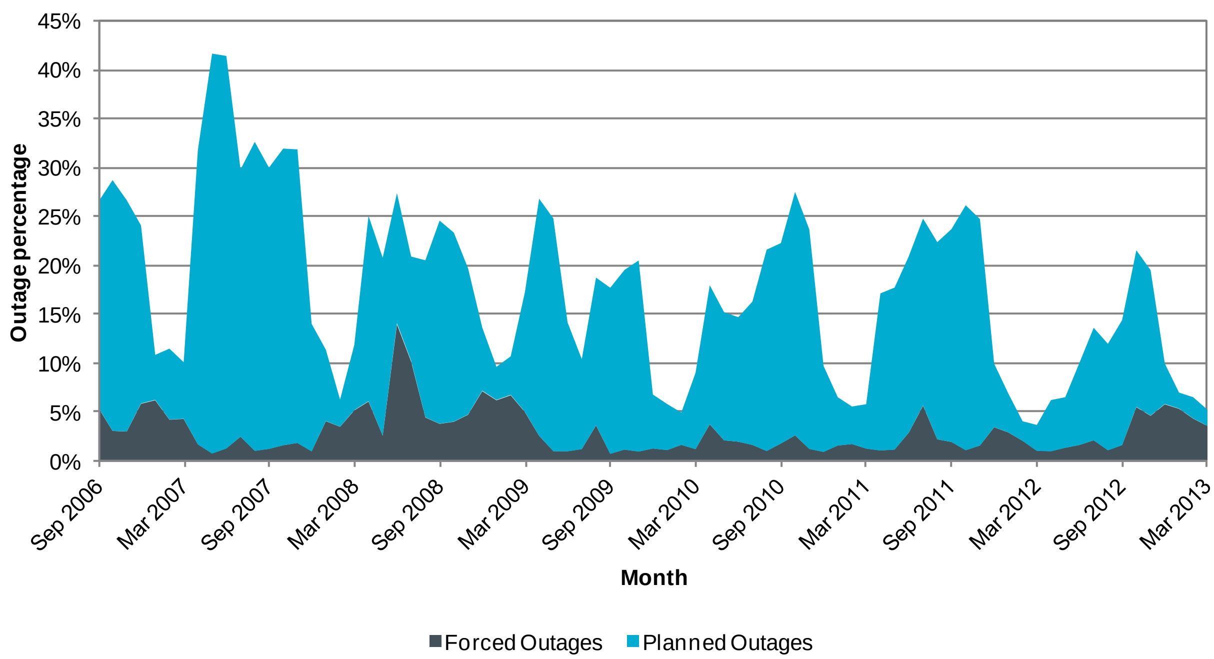


Figure 15 shows the planned and forced outage rates displayed as a percentage of the allocated Capacity Credits in the market. The total rate of facility outages has reduced substantially over the last year with monthly outage rates reaching a maximum of approximately 22%, compared to levels in previous years in excess of 25%. Levels during the peak summer period have remained fairly stable between 5-10%.

Figure 15 – Monthly average outage percentage



2.4. Small-scale solar PV generation

The penetration of small-scale PV generation in the SWIS has increased more than tenfold since the 2010 summer, from an estimated 21 MW (nameplate capacity) in February 2010[19] to more than 274 MW in February 2013 (at more than 130,000 sites). To date, this growth has occurred almost exclusively in the residential sector.

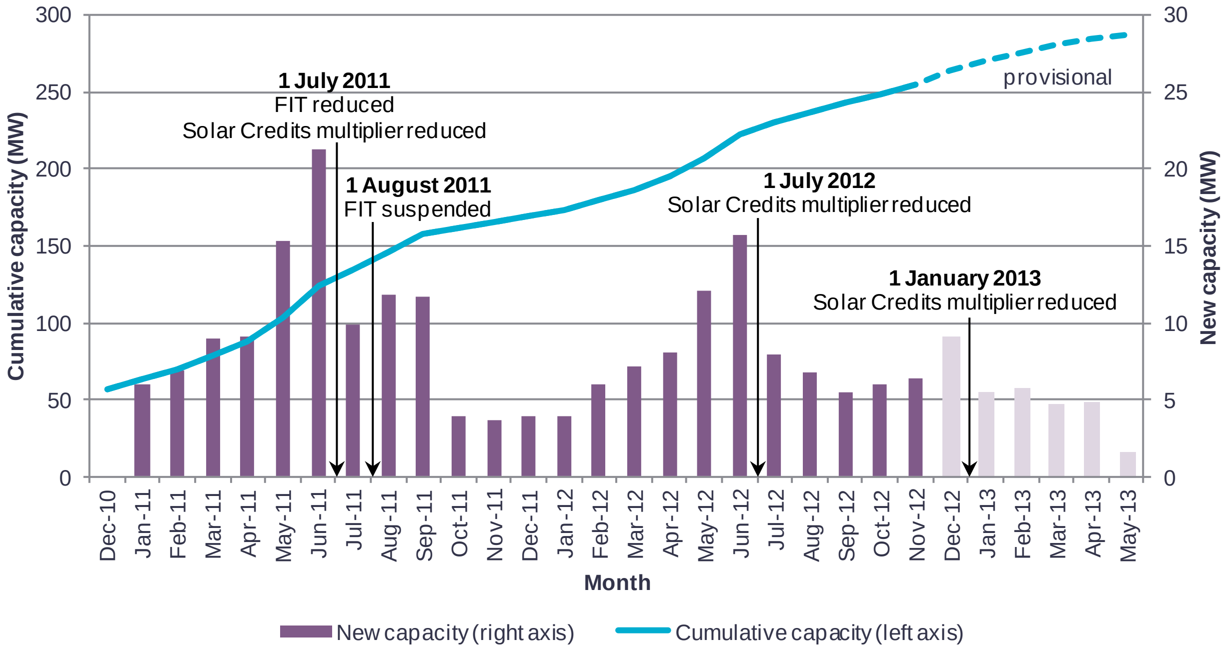
For the vast majority of small-scale PV systems, the gross generation is not separately metered, so energy production by these systems is observed as reduced consumption. Consequently, these systems have reduced, and will continue to reduce, the demand for generation and DSM capacity from registered facilities.

The sharp growth in PV installations has resulted from the combination of:

- rising residential electricity tariffs;
- Government subsidies including the RET and feed-in tariffs; and
- reducing PV system costs.

Figure 16 shows the growth in small-scale PV capacity in the SWIS in recent years. This graph has been prepared from data published by the Clean Energy Regulator (CER)[20], which publishes data on PV systems up to 100 kW that are registered for small-scale technology certificates (STCs).

Figure 16 – Installed small-scale solar PV capacity in SWIS



(Source: Clean Energy Regulator, RET postcode data June 2013)

The CER determines the capacity of each system from the capacity of the PV panels, not the inverter capacity, making the CER data suitable for estimating the annual energy production of the PV fleet, as well as the contribution to reducing peak demand. As registration for STCs may occur up to twelve months after installation, the capacity for the most recent months may be underestimated. However, analysis of sequential

[19] Estimated from Clean Energy Regulator data, available at http://ret.cleanenergyregulator.gov.au/ArticleDocuments/205/ORER-data-0911.xls.aspx. Accessed 27 May 2013.
[20] Available at http://ret.cleanenergyregulator.gov.au/REC-Registry/Data-reports

CER data releases by the IMO suggests that approximately 98% of registrations occur within six months of installation.

The CER publishes the number of PV systems and capacity for each postcode. Appendix 4 includes the list of postcodes that the IMO has determined to be covered by the SWIS.

The periods of accelerated growth in Figure 16 have occurred immediately prior to reductions in Government incentives for small-scale PV. These incentives have been in the form of the Feed-in Tariff (FIT) offered by the State Government and the STCs and Solar Credits multiplier that form part of the Commonwealth Government's RET.

- FIT: A FIT of 40c/kWh commenced on 1 July 2010 for residential customers who connected small-scale renewable generation. The Minister for Energy announced on 21 May 2011 that the FIT would reduce to 20c/kWh from 1 July 2011[21] and the FIT was suspended immediately on 1 August 2011[22]. The FIT is paid to eligible customers in addition to payments under the Renewable Energy Buyback Scheme (REBS), which is available to eligible residential customers in WA.
- STCs and Solar Credits multiplier: Renewable generators have been eligible for STCs since 2001 (known as Renewable Energy Certificates (RECs) prior to 2011). In 2009, the Commonwealth Government increased the STC eligibility for the first 1.5kW of grid-connected solar generation capacity through a Solar Credits multiplier of five. The Commonwealth Government progressively reduced the multiplier to three from 1 July 2011 (announced on 5 May 2011), to two from 1 July 2012 (also announced on 5 May 2011) and to one from 1 January 2013 (announced on 16 November 2012).

Figure 17 shows the number of new SWIS PV installations per month, extracted from the CER data. This graph clearly shows the sharp increases in installations just prior to the reduction of incentives in mid-2011 (FIT and Solar Credits multiplier reductions), mid-2012 (multiplier reduction) and late 2012 (multiplier reduction). Despite the withdrawal of these incentives, Figure 17 shows that the underlying demand has remained above 2000 systems per month, placing it in the high range of the forecasts provided in the 2012 SOO. This suggests that small-scale PV may have reached a rate of growth which may be self-sustaining.

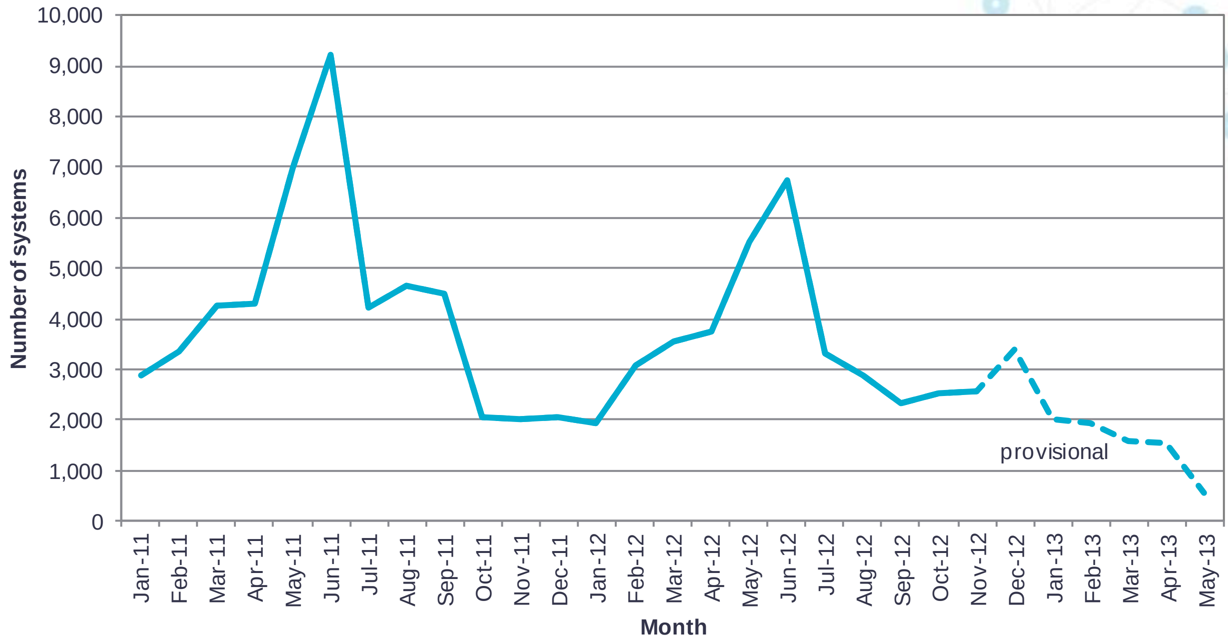
The average PV system size has progressively increased over the last two-and-a-half years, as shown in Figure 18. This suggests that customers may be installing larger systems as purchase costs continue to decline.

It appears from the CER data that the penetration of PV generation in the commercial and industrial sectors remains low but has begun to increase in recent months. The IMO has examined the CER data for the postcodes representing Malaga (postcodes 6090 and 6944) and Welshpool (postcode 6106) as these predominantly contain commercial and industrial customers. Total installations in these postcodes grew from 22 to 32 systems from October 2012 to February 2013, with an average system size for these postcodes of 13 kW.

Commercial and industrial customers are not currently eligible for REBS payments. Also, installations of systems greater than 30kW are subject to a network study by Western Power, which takes longer than the 30 days typically required for the technical review and approval of a 3kW-30kW system[23]. Changes that increase the incentives or reduce restrictions could lead to significant growth in PV in these sectors.

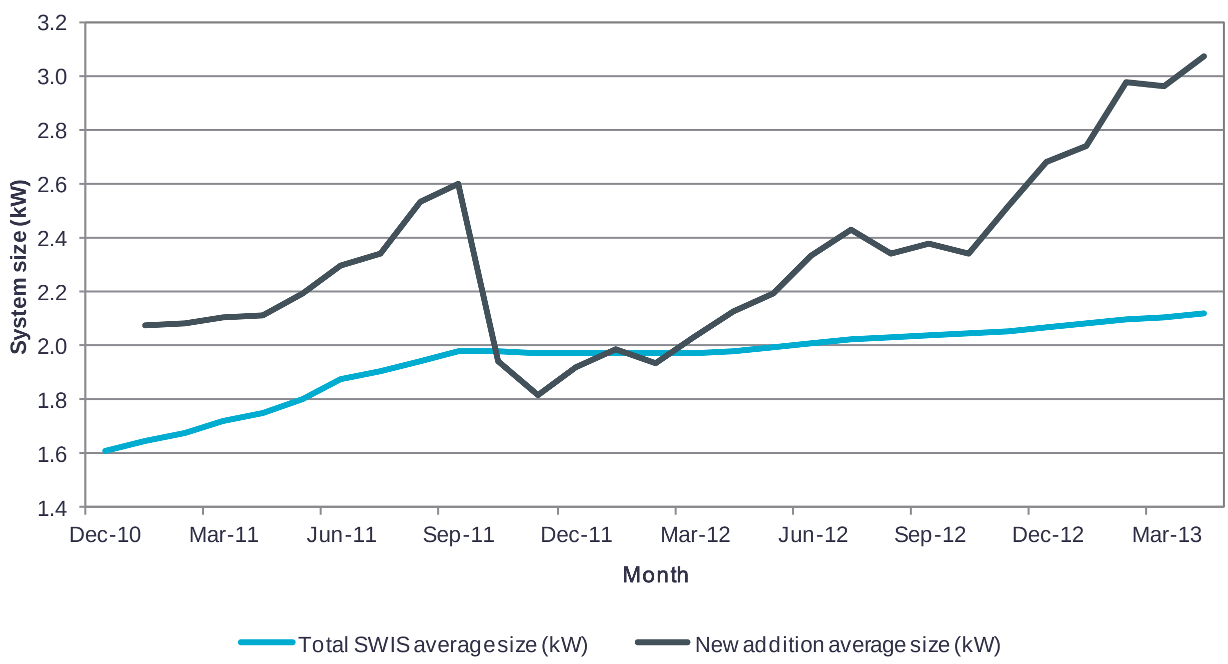
[21] Announcement by the Hon Peter Collier, 21 May 2011, *Changes to popular renewable energy scheme* (available at http://www.mediastatements.wa.gov.au/Pages/Default.aspx)
[22] Announcement by the Hon Peter Collier, 1 August 2011, *Residential feed-in tariff scheme suspended after reaching its quota* (available at http://www.mediastatements.wa.gov.au/Pages/Default.aspx)
[23] http://www.westernpower.com.au/residents/solarpvsystem/index.html. Please contact Western Power for further details.

Figure 17 – New installations per month (RET registered)



(Source: Clean Energy Regulator, RET postcode data June 2013)

Figure 18 – SWIS average PV system size



(Source: Clean Energy Regulator, RET postcode data June 2013)

2.5. Energy pricing in the Wholesale Electricity Market

The energy trading component of the WEM, the Short-Term Energy Market (STEM), has been in operation since EMC on 21 September 2006. In that time, the energy price has proven to be responsive to changes in the supply-demand balance in the SWIS.

A significant milestone in the development of the energy trading market in the SWIS was achieved with the commencement of the new Balancing and Load Following Ancillary Services (LFAS) Markets during 2012. These markets commenced operations on a transitional basis from 1 July 2012, with the transition arrangements ending from 5 December 2012. These changes have seen an increased level of competition and transparency in the WEM, with Market Balancing and LFAS requirements no longer exclusively provided by Verve Energy.

Historically, high STEM prices have typically been correlated with periods of high demand, usually related to periods of consistently high temperatures, or high system facility outages. The impact of any particular plant outage on STEM prices will depend on the particular characteristics of the plant in question and where the plant is located in the merit order. For example, an outage of a base load power plant would be expected to have a greater impact on market prices than an outage on a similarly sized peaking plant.

As the trading mechanisms in the WEM have matured and energy demand within the SWIS has increased, traded STEM quantities have increased substantially. During the same period, prices have remained reasonably stable with no discernible upward trend. The STEM and Balancing prices and quantities traded are shown in Figure 19 and Figure 20 respectively.

Figure 19 – Monthly average STEM and Balancing prices

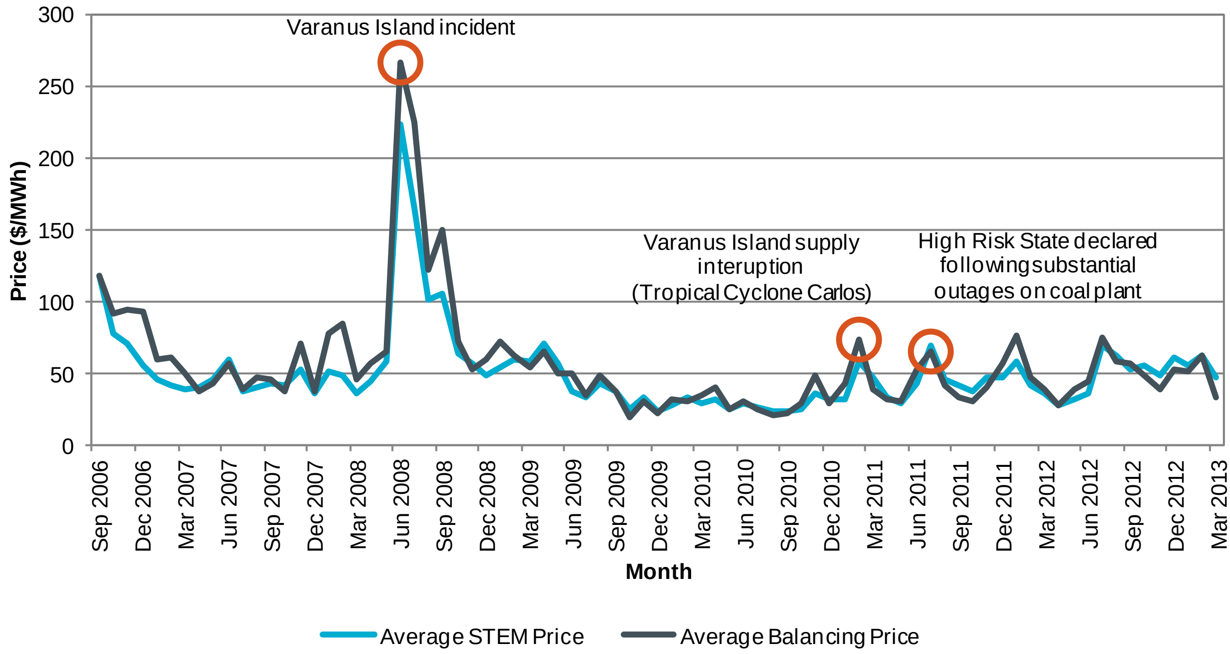
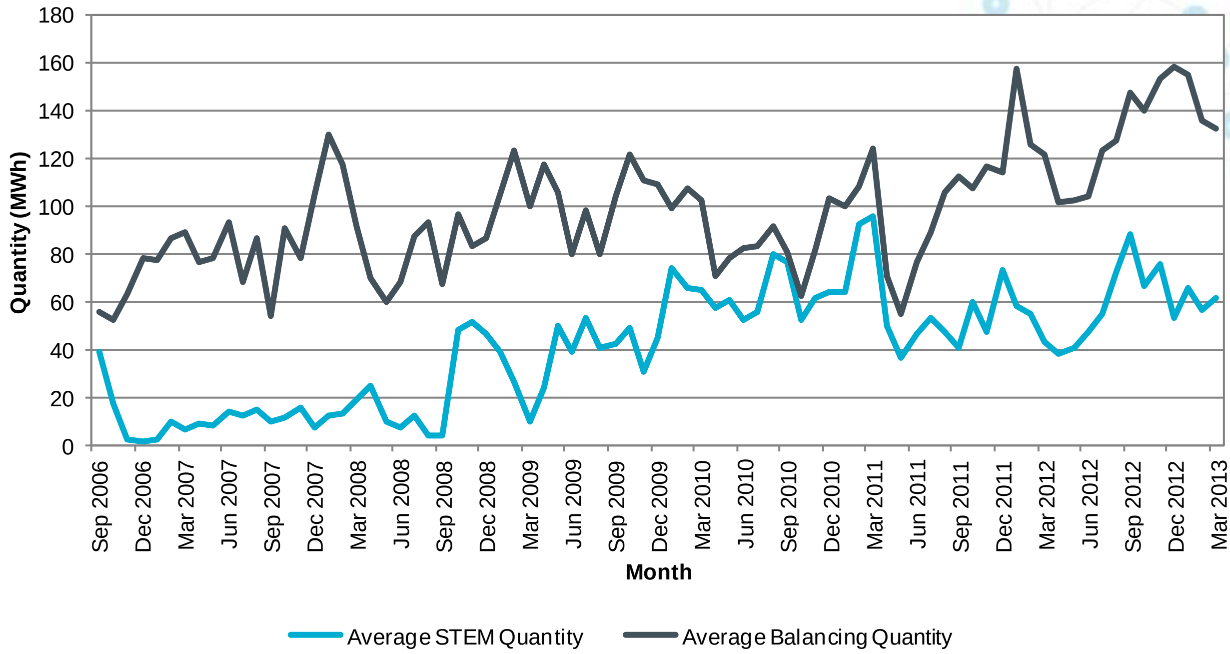


Figure 20 – Monthly average quantities settled at STEM and Balancing prices



There have been periods where monthly average STEM prices have spiked substantially as shown in Figure 19. The monthly price can be seen to be high initially at EMC, suggesting an adjustment period reflective of inexperience with the trading mechanisms. The average price then generally reduced through to the end of 2010 with increased supply and competition.

The dependency of the SWIS on gas-fired generation is highlighted by price spikes caused by disruptions to the supply of gas from Varanus Island. The larger of these disruptions, caused by a gas explosion on 3 June 2008, caused severe price spikes between June and August due to gas supply restrictions during that time. The price spike during February and March 2011 was caused by a shorter one-week interruption of supply from Varanus Island triggered by Tropical Cyclone Carlos.

The impact of outages of base load generation was observed in July 2011 when as much as 54% of the coal-fired capacity in the SWIS was unavailable. Approximately 200 MW of coal-fired generation was on forced outage for the whole month, while the quantity of coal-fired generation on planned outage approached 900 MW over three Trading Days during the first week of July. STEM prices exceeded $300/MWh on four days during the first week of July, reaching the Maximum STEM Price of $336/MWh on 6 July 2011.

Energy prices are also strongly correlated with hot weather. Balancing prices exceeded $240/MWh on ten Trading Days during January and February 2013, reaching the Maximum STEM Price of $323/MWh on 7 January 2013 and $322.50 on the peak demand day of 12 February 2013, as well as on 15 January 2013 and 20 February 2013. Similarly, STEM prices exceeded $260/MWh on four consecutive Trading Days starting with the peak demand day of 25 January 2012, reaching the Maximum STEM Price of $314/MWh on all but 27 January 2012.

Figure 20 shows a continued increase in the quantities traded at the STEM Price and at the Balancing Price, particularly in the Balancing Market, which is consistent with increasing competition and increasing energy demand since EMC. The entry of new independent power producers (IPP's) into the WEM, and the implementation of the new Balancing Market in 2012 have been key drivers towards increased competition.

3. Ex-post reconciliation of forecasts

This chapter contains detailed comparisons of the 2013 summer peak demand and 2012/13 energy consumption with the forecasts presented in the 2012 SOO. Some comparison with earlier SOOs is also performed.

The analysis in this chapter has been significantly extended from the previous SOOs. This was one of the recommendations from the five-yearly review of the IMO's demand forecasting processes[24], conducted in 2012 by the IMO and ACIL Tasman, which was supported by stakeholder submissions. The IMO will further increase this analysis in years to come, with a particular focus on quantifying the environmental and assumption changes that have occurred since the two-year ahead forecasts that are used to set the Reserve Capacity Requirement.

In its report for the forecasting processes review, ACIL Tasman noted that "*the current forecasting environment is characterised by a number of uncertainties and structural changes which are having a material effect on energy and maximum demand forecasts across all Australian jurisdictions.*" Demand forecasts for the SWIS, and for other Australian states, have been reduced materially over the last three years due to a range of factors, including:

- increasing penetration of solar PV systems;
- dampened investment by small-to-medium enterprises due to the restricted availability and increased cost of finance since the onset of the GFC;
- continuing uncertainty associated with the level of Chinese economic activity and the European and United States economies;
- the impact of significant (and unprecedented) increases in regulated electricity tariffs; and
- changing customer behaviour resulting from various energy efficiency measures.

3.1. 2012/13 summer weather

During the 2012/13 summer period, Perth experienced temperatures more than 1°C above the 20-year average, with February being the hottest month of the summer, as shown in Table 1 below.

Table 1 – Average hot season temperatures, 2012/13 and 20-year averages

		Month			
		Dec	Jan	Feb	Mar
Mean min temperature (°C)	2012/13	16.8	18.5	18.6	15.2
	20 yr average	16.3	18	18.2	16.6
Mean max temperature (°C)	2012/13	31.4	32.3	34.6	28.4
	20 yr average	28.9	31.1	31.4	29.6

As was noted in Chapter 2, the highest electricity demand events have historically been recorded when there is a sequence of hot days with high overnight temperatures.

The daily maximum temperature reached 40°C on six occasions in the 2012/13 summer, with four of these occasions on business days (one in December and three in February). In addition there were six occurrences of consecutive days above 37°C, with the following periods fitting the profile of a "typical" peak demand event:

[24] See http://www.imowa.com.au/rcreviews for more information.

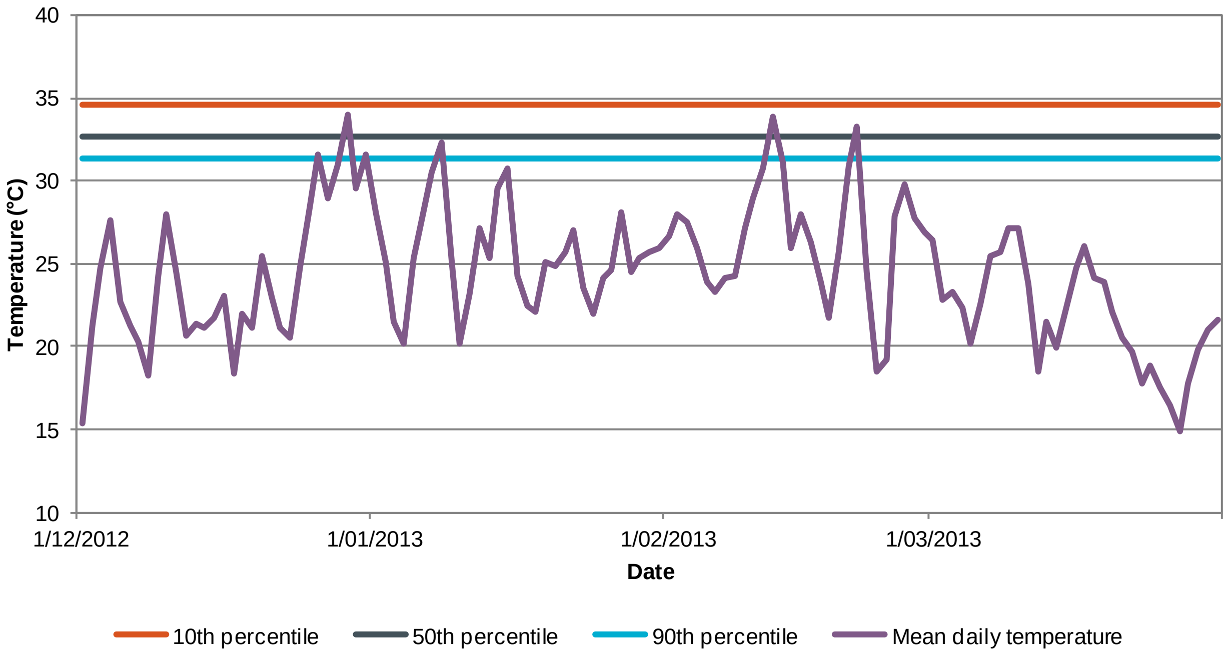
- five consecutive days on 9-13 February from Saturday to Wednesday;
- two consecutive days on 20-21 February (Wednesday and Thursday); and
- two consecutive days on 25-26 February (Monday and Tuesday).

For forecasting purposes, NIEIR has determined 10%, 50% and 90% PoE temperature conditions through analysis of historic weather data. Mean daily temperatures (the arithmetic mean of the daily maximum and daily minimum temperature) for the Perth metropolitan region are the metrics used. Mean daily temperatures of 34.6°C, 32.7°C and 31.4°C correspond to the 10%, 50% and 90% PoE temperature conditions respectively.

There were six days when the mean daily temperature exceeded the 90% PoE level, compared to four instances in the 2011/12 Hot Season. The mean daily temperature exceeded the 50% PoE level on three occasions during the Hot Season, with one occurrence in December and two in February. Both occurrences in February were on business days including the peak demand day on the 12th of February. The mean daily temperature did not reach the 10% PoE level during the 2012/13 Hot Season, nor has the 10% PoE level been exceeded since EMC.

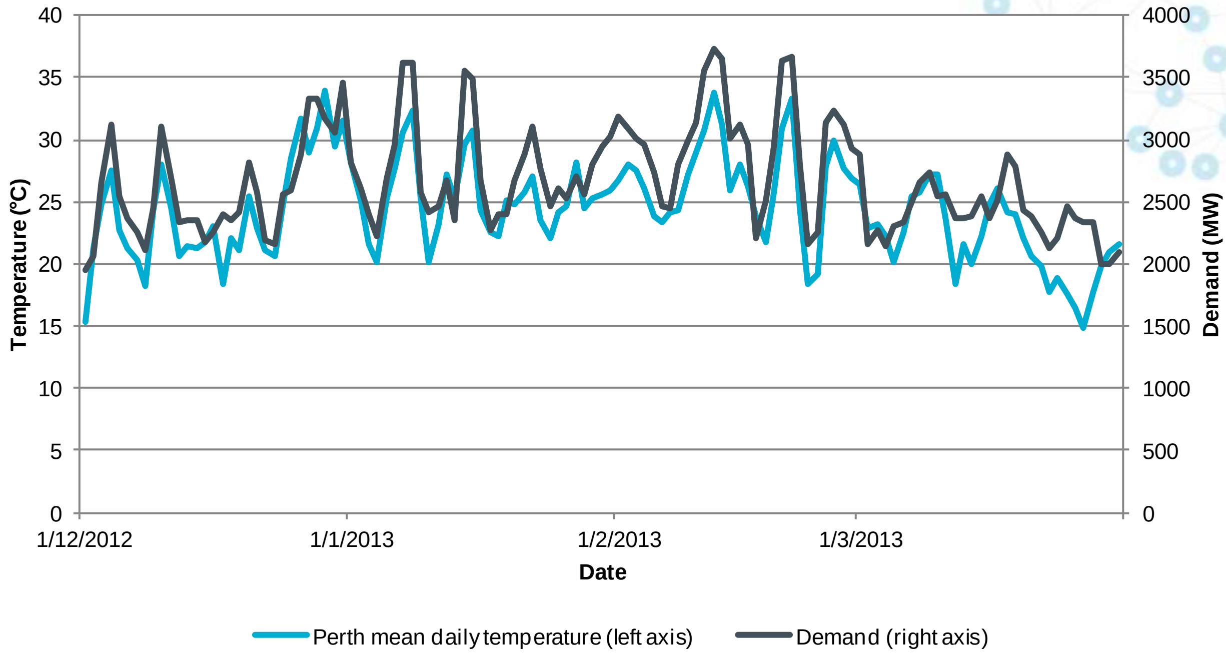
Figure 21 shows the daily average temperature for the period from December 2012 to March 2013. The strong relationship between temperature and electricity demand during the Hot Season is shown in Figure 22.

Figure 21 – Perth mean daily temperatures, December 2012 to March 2013



(Source: Bureau of Meteorology)

Figure 22 – Perth mean daily temperature and daily peak demand



3.2. 2012/13 summer peak demand

As noted above, NIEIR's forecasting of the maximum demand event is based on the arithmetic mean of the minimum overnight temperature and the maximum temperature for each day. This "mean daily temperature" has historically proven to be a strong predictor of electricity demand on the hottest days.

However, the mean daily temperature does not consider all of the weather variables that can affect electricity consumption. Given the cooling impact of the sea breeze in the South-West of WA, the time at which this sea breeze commences can impact peak demand. Also, higher humidity would be expected to increase electricity demand due to greater air-conditioning load.

The maximum sent out generation for 2012/13 was 3,735 MW, which occurred between 4:30pm and 5:00pm on 12 February 2013. This demand peak was significantly lower than had been forecast – not only the longer-term forecasts in previous SOOs, but also System Management's forecasts on the morning of 12 February.

The mean daily temperature on 12 February was 33.8°C, making it the second hottest day of the summer. On the basis of the mean daily temperature alone, this corresponds to a PoE level of approximately 25%. This was preceded by a mean daily temperature of 30.8°C on the previous day.

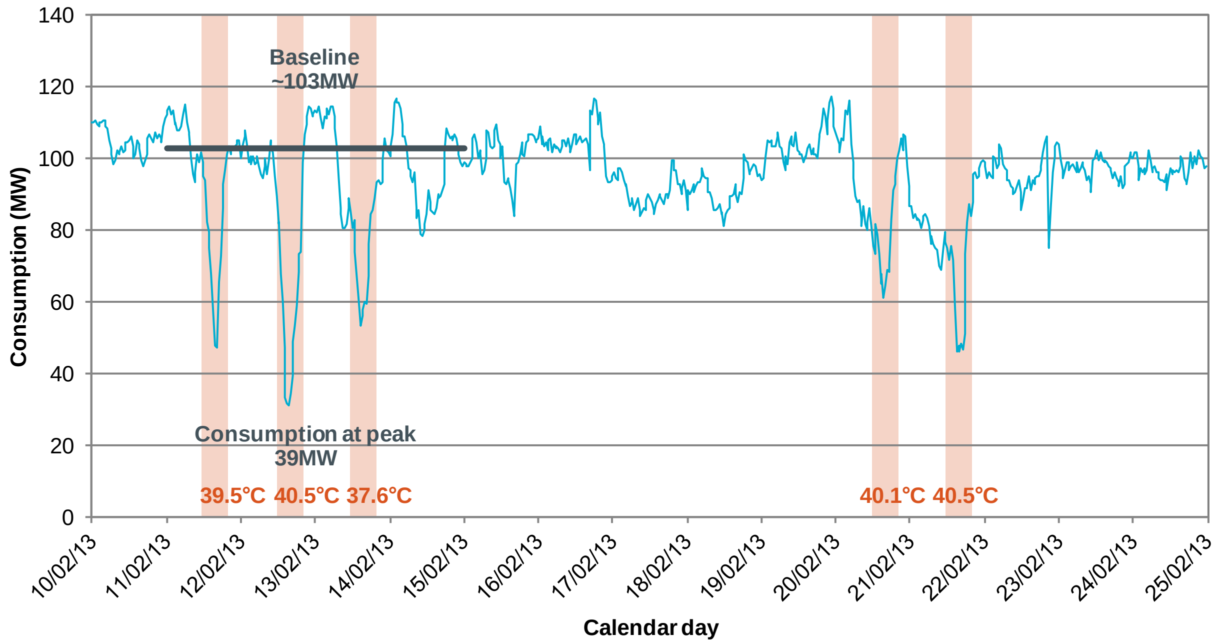
However, the early arrival of the sea breeze on that day had a significant cooling effect in Perth and surrounding areas. The average Perth temperature (Perth Metro weather station) during the 4:30pm to 5:00pm Trading Interval was 34.8°C, having fallen from a maximum of 40.5°C. By contrast, the average temperature during the 2012 peak demand period (4:30pm to 5:00pm on 25 January 2012) was 39.4°C, which was only marginally lower than the maximum temperature on that day of 41.1°C.

Another significant factor in the low demand peak is the apparent management of energy usage during peak intervals by some large commercial and industrial customers. By reducing consumption during the hottest summer afternoons, these customers are able to reduce their exposure to IRCR payments.

The IRCR mechanism, which allocates the cost of Capacity Credits to Market Customers, provides an incentive for customers that are exposed to competitive tariffs to reduce their demand during system peak demand intervals. The new Balancing Market in the WEM has brought improvements in market transparency that assist these customers in predicting peak demand periods, through frequent forecasts of system demand, Balancing Merit Orders and energy prices.

Figure 23 shows the cumulative demand during February 2013 from the 59 most responsive loads identified by the IMO as having reduced their consumption in this way. These were filtered from nearly 1,000 loads considered the most likely customers to engage in this behaviour, being the highest 500 loads by total consumption and all loads associated with a Demand Side Programme (DSP). The shaded areas on the graph represent the afternoons of the five hottest days (assessed by mean daily temperature) in February 2013.

Figure 23 – Targeted reduction of consumption, 11-24 Feb 2013, 59 loads



As shown in Figure 23, it is estimated that the demand during the peak Trading Interval for 2012/13 was reduced by approximately 65 MW as a result of the direct response implemented by larger customers. This represents almost 2% of the 2012/13 SWIS summer peak demand.

The IMO has subsequently analysed the consumption of the same customers during the 2010 and 2012 peak demand events[25]. This analysis confirms that the IRCR response has grown exponentially relatively recently from as little as 15 MW in 2010. Likely causes of the growth of this customer response are increasing customer awareness of the IRCR mechanism and increasing electricity prices. Similar graphs of the 2010 and 2012 peak demand periods are shown in Appendix 2.

Given the substantial costs associated with meeting growth in peak demand, particularly network and generation investment, this behaviour, which is incentivised by the design of the RCM, also has the potential to reduce the need for investment in generation and network capacity in the long term.

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[25] The 2011 peak demand event, on 25 February 2011, was not reviewed as DSM was dispatched by System Management.

However, the IMO anticipates that potential changes to the Market Rules, to prevent a load from selling more capacity (through Capacity Credits) than it buys (through IRCR)[26], may reduce the quantity of load that is curtailed in this way in future years.

Table 2 shows the difference between the actual peak demand in 2013 and the 50% PoE forecasts provided in the SOOs since 2007. The 50% PoE forecasts have been used in this comparison as are more consistent with the observed temperature conditions on the peak demand day. The peak demand of 3,735 MW is significantly below the 2012/13 peak demand forecasts published in each of the 2007 to 2012 SOOs.

Table 2 – Comparison of 2012/13 peak demand with forecasts

Maximum demand = 3735 MW		Variance (MW)	Accuracy (%)
2007 SOO	4,281	546	14.6%
2008 SOO	4,689	954	25.5%
2009 SOO	4,722	987	26.4%
2010 SOO	4,569	834	22.3%
2011 SOO	4,340	605	16.2%
2012 SOO	4,164	429	11.5%

Various factors have contributed to the 2012/13 peak demand being significantly lower than forecasts provided in previous SOOs:

- As noted above, the IRCR response is estimated to be 65 MW. This price-driven customer response at times of peak demand was not incorporated into previous demand forecasts.
- The forecasts provided for 2012/13 in the 2012 SOO included an allowance for three major block loads, two of which were not fully operational on 12 February 2013. These delays resulted in 60 MW from these loads, previously included in forecasts, not contributing to the peak demand event. In addition, observed consumption from another established major load was 14 MW lower than in the peak interval from 2012.
- The allowance for new block loads for 2012/13 was greater in the 2008 and 2009 SOOs, which had included an additional 165 MW associated with magnetite projects in the Mid-West. These projects have experienced significant delays or cancellations.
- The 2012 SOO estimated that there would be 2000 new solar PV installations per month and that the contribution of solar PV at the time of peak demand would have an impact of reducing peak demand by 60MW. In fact, in the second half of 2012, there were an average of 2800 new installations per month and the IMO estimates that the contribution of solar PV during the peak demand interval was a reduction in system load of 74 MW. Therefore the net impact of the additional solar PV capacity was an estimated reduction of 14 MW in peak load.
- NIEIR has analysed the impact of the cooler temperature during the peak demand interval on 12 February 2013 and estimates that this has reduced the peak demand by between 100 and 200 MW. This estimate may be conservative as it considers only the lower temperature and not any additional impact of the sea breeze (Perth weather station measured the breeze at 17 km/hr from the west at 3pm).

Table 3 shows how these factors have contributed to the difference between the 50% PoE forecast from the 2012 SOO and the observed 2013 summer peak demand.

[26] See Section 8.3 of this report for more information.

Table 3 – Comparison of 2012/13 peak demand with 2012 forecast

50% PoE forecast peak demand (2012 SOO)	**4,164 MW**
IRCR response	- 65 MW
Block load delays	- 60 MW
Change in large load operating level	- 14 MW
Change in solar contribution	- 14 MW
Economic growth	0 MW
Sub-total	4,011 MW
Weather impact/cool change	- (100 to 200) MW
Unaccounted	- (76 to 176) MW
2012/13 peak demand	**3,735 MW**

Economic growth is listed in Table 3 but is not considered to have contributed to the deviation as the Gross State Product (GSP) growth estimate for 2012/13 of 6.5% matches the expected growth forecast in the 2012 SOO.

The unaccounted quantity shown in Table 3 may reflect conservatism in the estimated impact of the early sea breeze, behavioural change by customers or other factors not considered in the forecasting model. For example, NIEIR's forecast model does not predict home vacancies that may occur due to fly-in/fly-out work rotations or international travel, both of which have increased markedly over the last decade.

3.3. 2012/13 sent out energy

Despite the lower peak demand, total sent out energy for the 2012/13 financial year is expected to increase marginally from 2011/12 and exceed the Expected growth forecast in the 2012 SOO.

The estimated energy consumption for the 2012/13 financial year is 17,882 GWh. The forecast of total sent out energy for 2012/13 under the Expected scenario published in the 2012 SOO was 17,585 GWh. The actual GSP for WA for 2012/13 matched the growth estimate of 6.5% from the 2012 SOO.

As with peak demand, a number of factors have contributed to the deviance from the 2012/13 energy forecast in the 2012 SOO:

- Weather conditions over the 2012/13 financial year, in both summer and winter, are estimated to have contributed an additional 110 GWh compared to average temperature conditions upon which the forecasts are based.
- Delays in the commencement of the two new block loads have been partially offset by above expected consumption by other block loads that have recently commenced operation. The net impact of these variations was a 179 GWh reduction in total energy.
- The 2012 SOO estimated that the contribution of solar PV's would be a reduction in annual energy use of 345 GWh. Based on a higher than expected number of installations during the last year, the IMO estimates that the contribution of solar PV to reducing sent out energy in the 2012/13 financial year is 387 GWh. Therefore the net impact of the additional solar PV capacity was a further reduction of 42 GWh in sent out energy.

Table 4 shows how these factors have contributed to the difference between the Expected sent out energy forecast from the 2012 SOO and the observed 2013 summer peak demand.

Table 4 – Comparison of 2012/13 sent out energy with 2012 forecast

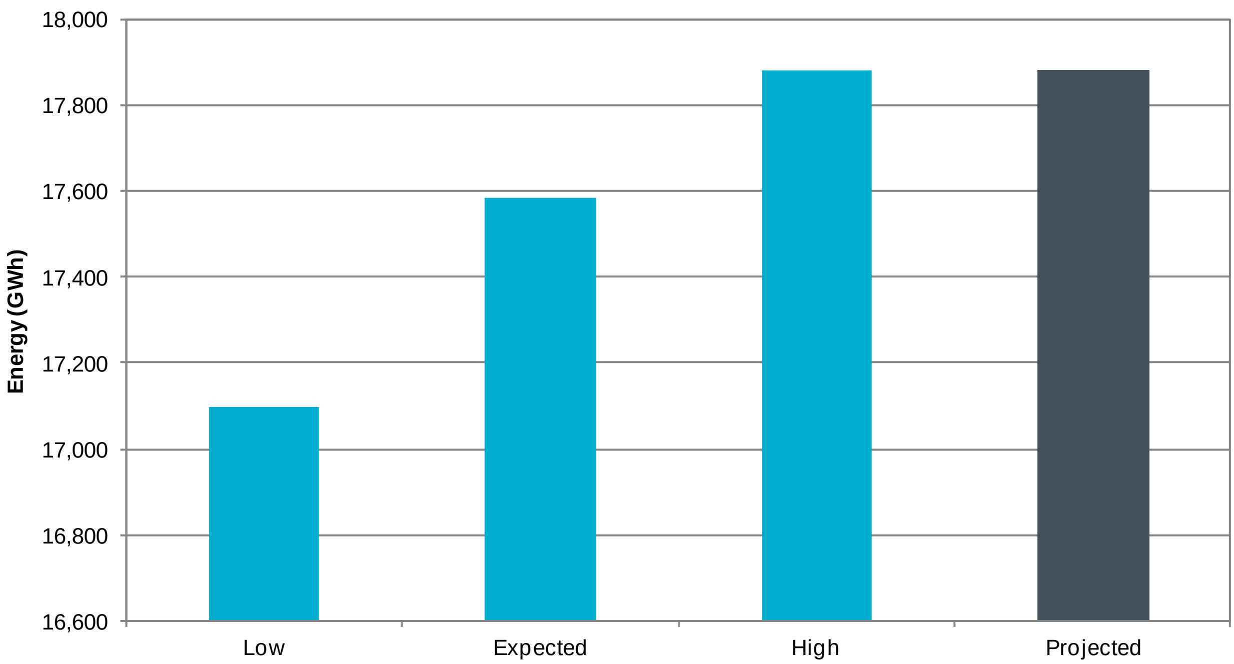
Expected sent out energy forecast for 2012/13 (2012 SOO)	**17,585 GWh**
Weather impact	+ 110 GWh
Block load delays	- 179 GWh
Est. solar contribution versus forecast	- 42 GWh
Economic growth	0 GWh
Unaccounted	+ 408 GWh
Estimated sent out energy 2012/13 FY	**17,882 GWh**

As with the peak demand analysis in Table 3, economic growth is listed in Table 4 but is not considered to have contributed to the deviation as the GSP growth estimate for 2012/13 of 6.5% matches the forecast in the 2012 SOO.

The unaccounted quantity shown above reflects higher than forecast sales volumes. The IMO notes that the 2012 SOO had predicted consumption in the 2012/13 financial years to fall by 0.5% from the estimated 2011/12 consumption of 17,673 GWh. Instead, 2012/13 consumption is estimated to grow by 0.4% from the actual 2011/12 consumption of 17,813 GWh.

Figure 24 compares energy forecasts from the 2012 SOO for the Expected, Low and High growth scenarios for the 2012/13 financial year with the projected energy consumption for the same period of 17,882 GWh. This estimate comprises nine months of actual data plus three months of estimated energy consumption to the end of June 2013.

Figure 24 – Comparison of projected and forecast sent out energy, 2012/13 financial year



4. Economic environment

4.1. Background

Economic forecasts are an essential input in projections of electricity and gas demand. The level of economic activity has both a general and specific impact on the maximum demand for, and consumption of, energy. Economic conditions affect the level of discretionary spending by consumers, including purchasing and using items such as air-conditioning systems and other energy-intensive consumables.

Resource extraction, processing and export are important to the Australian and WA economies and can be a key driver in energy demand growth. The Department of Mines and Petroleum has reported that resource projects worth an estimated $177 billion were under construction or committed as at 31 March 2013, dominated by liquefied natural gas (LNG) and iron ore developments. Capital expenditure in the mining industry represented 82% of all new capital expenditure in WA during 2012.[27]

However, given the high dependence of the WA economy on the resources industry, growth rates in WA will be more volatile than in other more diversified economies. WA has experienced strong growth in resource-related investment over the last decade, but this is expected to peak in 2012/13 before steadily declining over the next four years, as projects move from the construction phase to normal operation.

Beyond current commitments, further activity in the resources sector is highly dependent on economic activity in Asia, in an environment where the recovery has been slower than expected in the United States and Europe. At present, it is expected that growth in developed economies will remain fragile as many struggle with high debt and other structural issues. Despite continued strong growth in developing economies, world economic growth is expected to be constrained to the 3% to 4% range in the short term due to fiscal consolidation (the withdrawal of fiscal stimulus).

In the aftermath of the global economic slowdown some marginal resource development projects have experienced significant delays or cancellation. This reflects a continuing aversion to invest significant capital and debt in speculative projects, as well as the reduced availability and higher cost of finance since the GFC.

While the majority of the resources projects under development are located outside of the SWIS there are some projects that are located close enough to the SWIS to require consideration when preparing WEM demand forecasts. Of particular relevance at present are iron ore projects in the Mid-West region, either proposed or under construction, which have substantial power needs.

Major developments in regional areas outside of the SWIS can also have a significant impact on SWIS electricity demand:

- Much of the design, procurement and management support related to the resources industry is provided by personnel based within the Perth metropolitan area.
- Much of the fly-in/fly-out workforce resides in the SWIS.
- Substantial quantities of basic materials, equipment and services are sourced from within the SWIS.
- This economic activity has boosted population growth in WA, particularly through interstate and overseas migration during the last 5 years. It is estimated that the population of WA (not all of whom reside in the SWIS) has increased by over 15% during this period, to the current level of approximately 2.4 million people.

It is expected that the current levels of investment in the resources industry should remain a key driver for energy usage in the SWIS in the medium term.

[27] http://www.dmp.wa.gov.au/12410.aspx

This chapter includes discussion on changes in economic outlook which have occurred since the 2012 SOO. A comparison is also provided between NIEIR's forecasts and a number of other publicly available forecasts.

NIEIR's forecasts are prepared using available economic data up to the December 2012 release of the Australian National Accounts by the Australian Bureau of Statistics (ABS), which occurred on 6 March 2013.

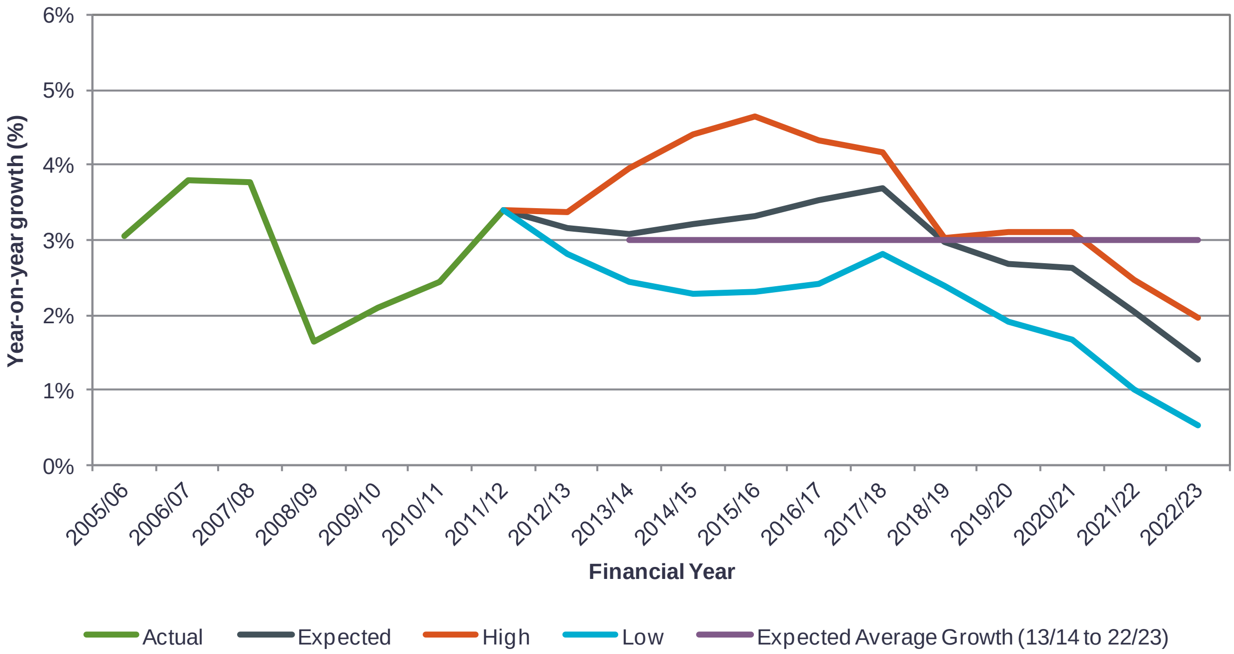
4.2. Economic outlook

Figure 25 shows the forecasts of growth in Australian Gross Domestic Product (GDP) and Table 5 shows forecasts of the key demand and supply drivers of GDP formation for the Expected growth scenario. The GDP growth forecasts are shown in tabular form in Appendix 3.

NIEIR forecasts that Australia's annual average economic growth over the period from 2013/14 to 2022/23 will be at an average rate of 3.0%, consistent with the ten-year average growth rate of 3.0% forecast in the 2012 SOO.

Recent growth in GDP since 2010/11 has been strongly supported by the acceleration of mining investment. NIEIR considers that the mining expansion explains the majority, or the near majority, of growth in GDP over this period when flow-on multiplier effects of this investment through the economy are considered. However, the benefits of the mining boom have been offset by the high import content of construction and equipment, and the "Dutch disease"[28]. NIEIR advises that GDP growth in 2011/12 would have been 5.4% (rather than 3.4%) if imports had been neutral.

Figure 25 – Forecast Australian economic growth



[28] The term "Dutch disease" is typically used to describe the apparent relationship between the increase in exploitation of natural resources, boosting a country's revenues and its exchange rate at the expense of competitiveness in the manufacturing sector and other export industries.

Table 5 – Australian growth projections for key economic metrics, Expected growth scenario (% growth)

Metric	Financial Year							
	2010/ 11	2011/ 12	2012/ 13	2013/ 14	2014/ 15	2015/ 16	2016/ 17	2017/ 18
Private consumption	3.6	3.3	2.4	3.1	3.0	3.0	3.5	3.5
Dwelling investment	2.3	-3.7	-0.1	4.0	-0.8	0.6	4.0	5.9
Business investment	8.6	22.0	5.9	-2.3	-3.0	-4.2	-1.0	5.7
Government consumption	3.1	3.4	1.4	2.3	3.4	3.7	3.3	3.1
Government investment	-2.5	-2.2	3.5	4.7	2.5	2.6	0.8	1.4
Domestic final demand	3.6	5.3	2.8	2.1	1.8	1.8	2.6	3.7
Overseas exports	-0.4	3.8	6.6	4.9	3.6	7.6	8.4	6.9
Overseas imports	6.9	9.3	2.0	0.2	-1.1	2.6	5.8	7.0
Gross Domestic Product	**2.4**	**3.4**	**3.2**	**3.1**	**3.2**	**3.3**	**3.5**	**3.7**
Population	1.2	1.4	1.5	1.5	1.6	1.6	1.5	1.5
Employment	2.9	0.6	1.0	1.4	1.1	1.3	1.7	2.1
Exchange rate (A$/US$)	1.0	1.0	1.0	0.9	0.8	0.8	0.8	0.8

The decline in mining investment over the coming years will contribute negatively to growth. However, NIEIR forecasts that a range of factors will contribute to maintaining GDP growth of over 3% through to 2017/18, such as:

- a decline in imports;
- steady stimulus from mining production (following the high level of investment);
- a return to more typical levels of public demand growth after a period of fiscal withdrawal;
- recovery in the world economy; and
- a weakening in the Australian dollar from 2014, boosting the competitiveness of the manufacturing sector and other export industries.

NIEIR forecasts that growth will moderate after 2018, due mostly to slower growth in the world economy. NIEIR predicts that the loss of capacity since the GFC, caused by lost investment and increased long-term unemployment, will lead to developed nations reaching capacity constraints.

Figure 26 shows the forecasts of growth in WA GSP and Table 6 shows forecasts of the key drivers of GSP formation for the Expected growth scenario. The GSP growth forecasts are shown in tabular form in Appendix 3.

Average growth in the WA economy over the next ten years is forecast to be 3.1% per year, compared with 3.8% in the 2012 SOO.

Figure 26 – Forecast Western Australian economic growth

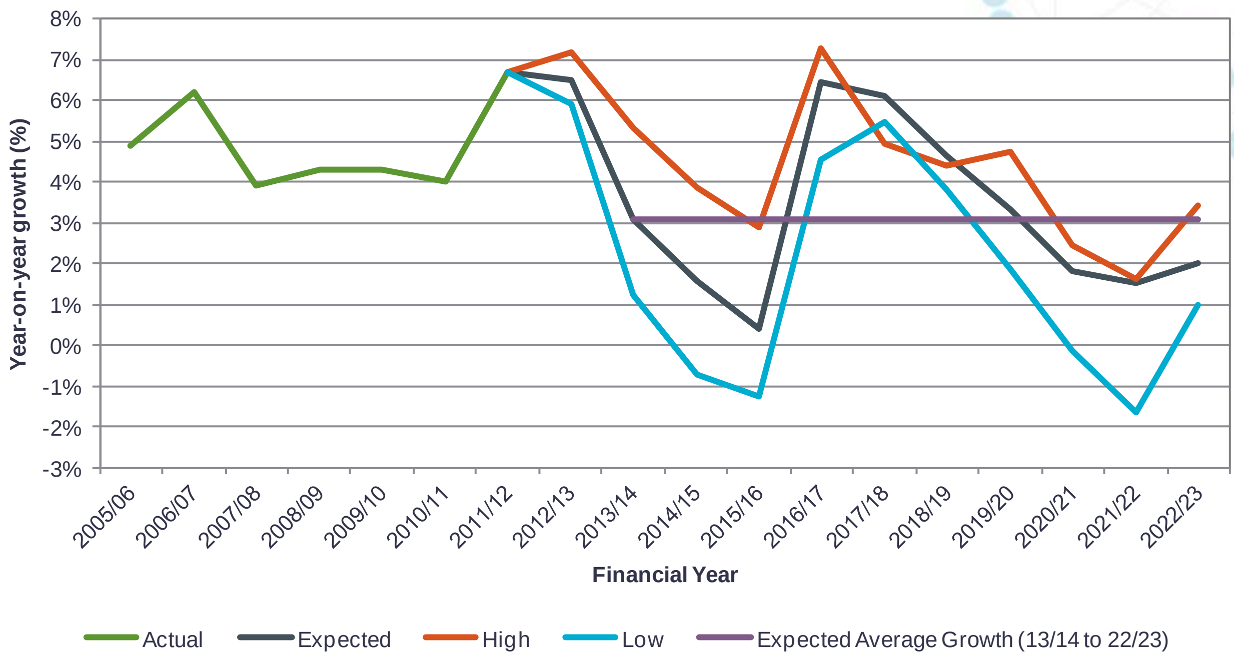


Table 6 – Western Australian growth projections for key economic metrics, Expected growth scenario (% growth)

	Financial Year							
Metric	**2010/ 11**	**2011/ 12**	**2012/ 13**	**2013/ 14**	**2014/ 15**	**2015/ 16**	**2016/ 17**	**2017/ 18**
Private consumption	5.3	5.9	4.7	4.0	3.7	0.7	0.7	5.5
Dwelling investment	5.5	-15.1	0.2	9.9	2.0	3.3	5.0	4.0
Business investment	9.7	37.7	16.7	-4.5	-8.3	-15.5	1.9	17.4
Government consumption	2.9	4.8	2.2	3.1	4.3	4.5	3.9	3.6
Government investment	1.3	7.7	18.8	9.1	0.4	3.2	3.2	3.2
State final demand	5.3	13.5	9.1	1.2	-0.7	-3.8	1.9	8.4
Gross State Product	**4.0**	**6.7**	**6.5**	**3.1**	**1.6**	**0.4**	**6.4**	**6.1**
Population	2.3	3.0	2.6	2.4	2.6	2.5	2.2	2.2
Employment	3.2	2.4	0.8	0.9	1.7	1.4	1.4	2.4

Growth in the WA economy is more heavily dependent on business investment than other Australian states. NIEIR reports that business investment now accounts for 34% of all expenditure in the state, compared with 20% in Queensland and 13% in New South Wales and Victoria.

NIEIR forecasts that growth in Western Australia will moderate considerably over the next three years, reflecting the contraction in mining investment as well as a slowing of household expenditure. However, the housing construction market is expected to recover during this period.

NIEIR has noted that the risks to its forecasts of GSP growth are weighted slightly to the downside. The average annual GSP growth in the Low scenario is forecast to be 1.7% per annum below the Expected growth, whereas the average growth in the High scenario is forecast to be 1.0% above the Expected growth profile.

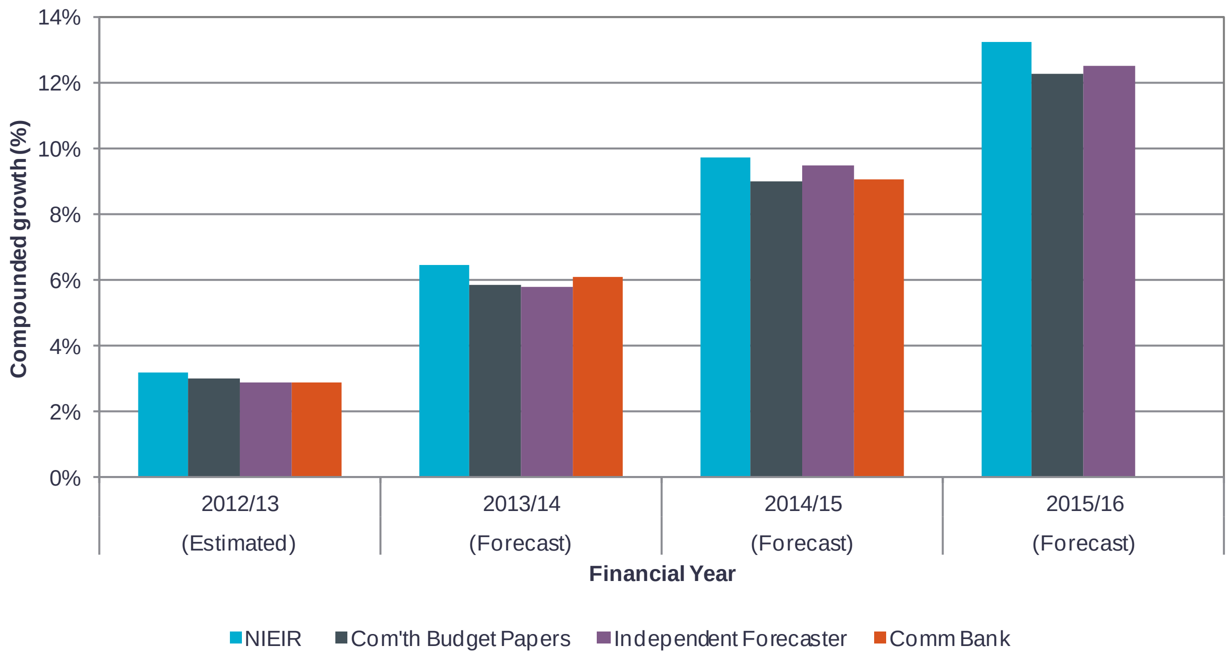
4.3. Comparisons with other forecasters

Figure 27 compares NIEIR's Australian economic growth forecasts with those of three other organisations:

- the Commonwealth Government Budget Papers (published in May 2013);
- a major independent forecaster[29] (published in April 2013); and
- the Commonwealth Bank Economic Forecast[30] (published May 2013).

This comparison of Australian growth rate forecasts is presented on a compounded basis to smooth out the variations that occur from year to year. The comparison shows general agreement between the forecasters, with NIEIR's forecasts being the highest displayed.

Figure 27 – Comparison of compound Australian economic growth forecasts



The 2013 State budget has yet to be published, but Figure 28 compares the NIEIR forecasts of WA GSP growth with those published by the WA Department of Treasury in the May 2012 budget papers for the period from 2012/13 through to 2015/16. This comparison is also presented on a compounded basis. While NIEIR estimates higher growth for 2012/13, Figure 28 demonstrates that NIEIR's forecasts are lower than the WA Treasury forecasts over the medium term. As is shown in the next section, this is a result of revisions to NIEIR's forecasts since 2012.

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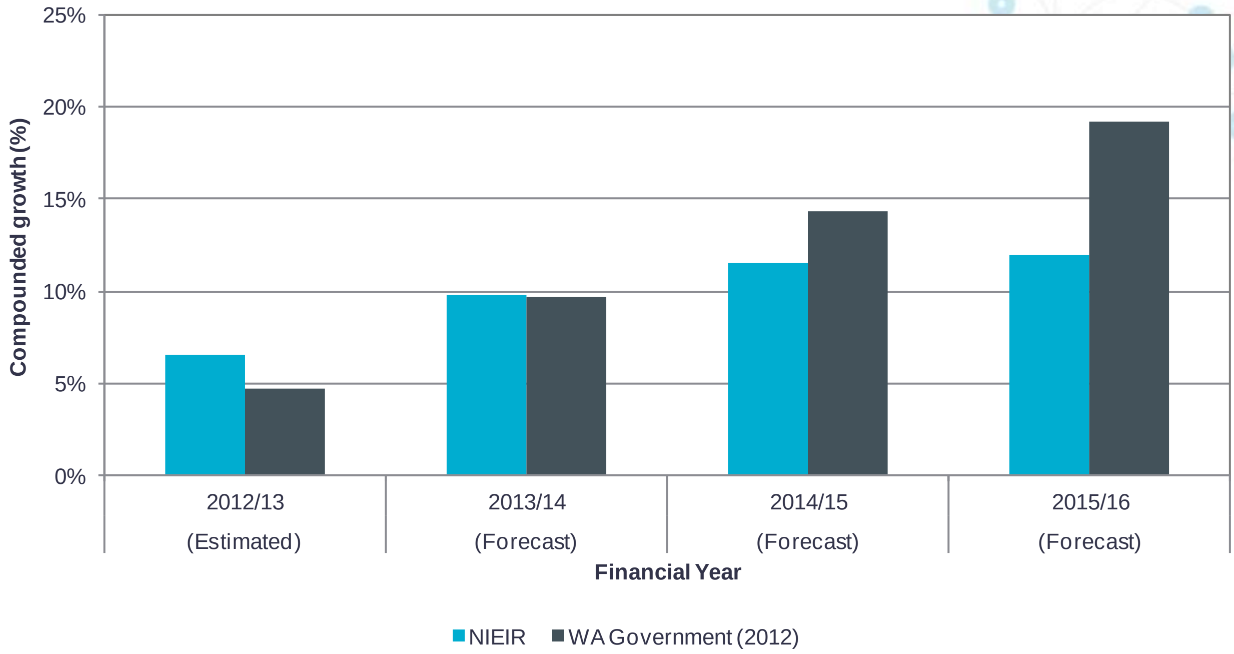
[29] The "Independent Forecaster" included in the graph has requested that it not be named.
[30] Note that the Commonwealth Bank forecast extends only to 2014/15, so it is excluded from the 2015/16 comparison.

Figure 28 – Compound Western Australian economic growth forecasts



4.4. Differences between the 2012 and 2013 economic forecasts

Figure 29 and Figure 30 compare NIEIR's 2012 and 2013 short-term forecasts for GDP and GSP respectively. The estimated growth rates for the 2012/13 financial year are consistent with the forecasts presented last year.

Compared to the forecasts in the 2012 SOO, NIEIR projects lower commodity prices in the medium term, leading in turn to lower terms of trade and a weaker Australian dollar.

These revisions have resulted in slightly higher GDP growth forecasts over the next few years. The lower exchange rate is expected to lessen the impact of the Dutch disease and produce higher growth rates in the non-mining states.

However, as shown in Figure 30, NIEIR's forecast for GSP growth is significantly lower than in the 2012 SOO. This results from the lower forecasts of commodity prices and terms of trade.

Figure 29 – Comparison of 2012 and 2013 Australian economic growth forecasts

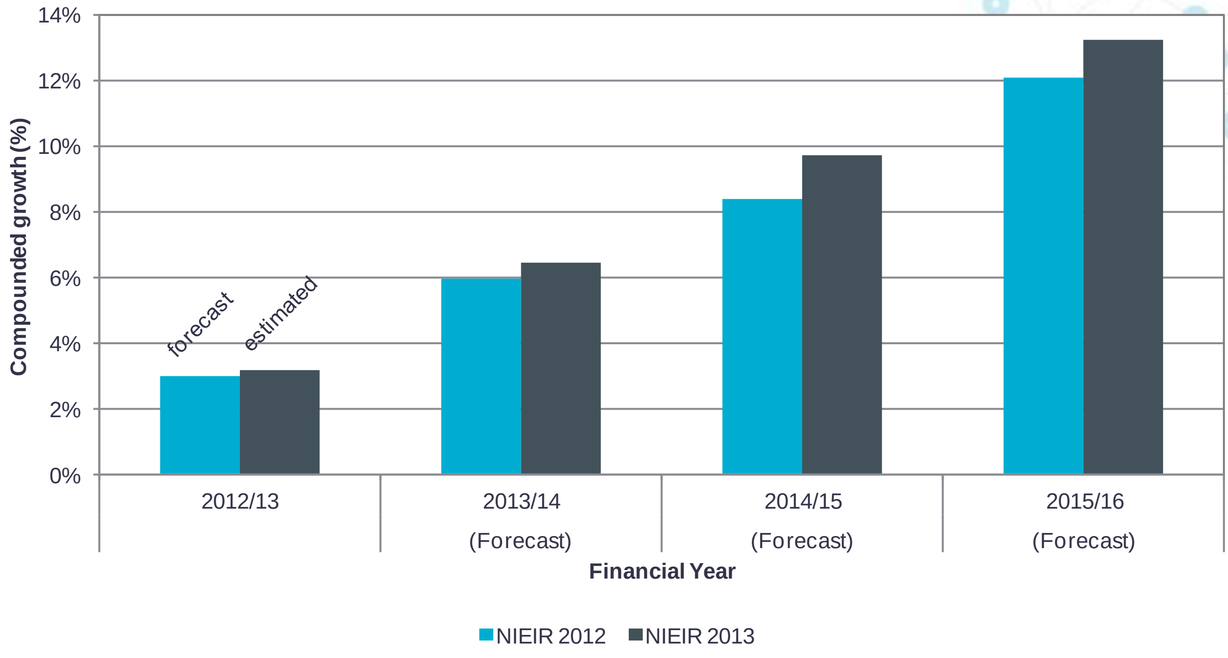
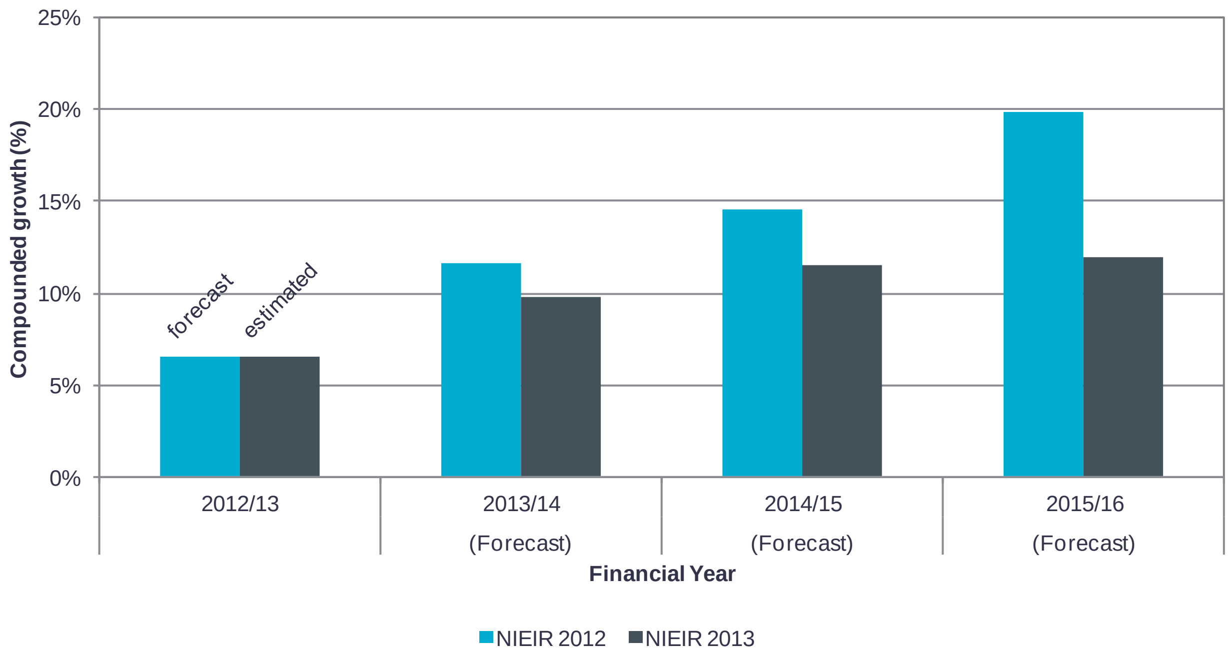


Figure 30 – Comparison of 2012 and 2013 Western Australian economic growth forecasts



5. Peak demand and energy forecasts, 2013/14 to 2023/24

5.1. Background

The IMO publishes two sets of forecasts each year within the SOO. These forecasts cover:

- the maximum demand, which is the measure of the highest level of power consumption in any half-hour Trading Interval during the year (measured in MW); and
- electricity consumption, which is the amount of energy sent out and consumed within the SWIS over the full year (measured in GWh).

As noted in Chapter 4, underlying economic-based drivers are key inputs to electricity consumption forecasts. Maximum demand is less dependent on economic growth but is highly correlated with ambient temperatures.

The IMO provides three groups of peak demand forecasts based on specific temperature conditions for the peak day in the summer:

- the 10th percentile temperature condition which is expected to be exceeded only once in every ten years (10% PoE);
- the 50th percentile temperature condition which is expected to be exceeded once in every two years (50% PoE); and
- the 90th percentile temperature condition which is expected to be exceeded nine times in every ten years (90% PoE).

As noted in Section 3.1, mean daily temperatures of 34.6°C, 32.7°C and 31.4°C correspond to the 10%, 50% and 90% PoE temperature conditions respectively.

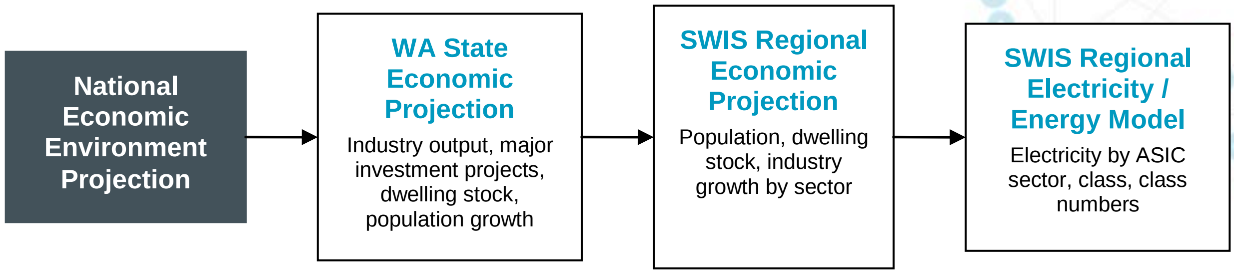
The maximum demand and electricity consumption forecasts used to determine the Reserve Capacity Target are based on Expected economic growth conditions. The forecast outcomes associated with High or Low economic growth conditions are provided as a guide to the variability in outcomes that could be expected.

5.2. NIEIR's forecasting methodology

NIEIR prepares forecasts of economic activity, electricity consumption and maximum demand for many of the electricity jurisdictions within Australia. For the SWIS, NIEIR has prepared forecasts for the past ten years, initially for Western Power Corporation and subsequently for the IMO's SOO. The energy forecasting process used by NIEIR is comprised of a number of different econometric forecasting modules.

Figure 31 shows the relationships between the major components of NIEIR's integrated energy modelling systems.

Figure 31 – NIEIR energy and electricity forecasting systems



The core tool used by NIEIR is its national econometric model of the Australian economy. This provides projections of national economic growth using inputs from various statistical sources including the ABS and the Australian Taxation Office.

The national economic projections are used as inputs into a state economic projection model which provides an estimate of GSP and other indicators. The State model is then further disaggregated into the statistical subdivisions that make up the region served by the SWIS.

The economic forecasts of the SWIS include projections of population growth, dwelling stock composition and industry growth by sector. This portion of the forecasting system then links the SWIS regional economic forecast with electricity use based on assumptions about appliance penetration and efficiency, weather conditions and separate forecasts of major industrial loads.

NIEIR's forecasting methodology relies on historical demand data at a SWIS level as the IMO does not receive regional demand data. Consequently, no transmission constraints have been specifically considered when preparing demand forecasts.

5.3. New major loads

In developing the demand forecasts in this SOO, the IMO and NIEIR have considered several new major loads identified by the IMO through consultation with the industry. Generally, the IMO considers 20 MW to be minimum threshold for new major block loads.

To assess the size and likelihood that various projects will go ahead, the IMO engages with developers of these major projects. However, there is always some uncertainty in this assessment relating to:

- decisions by the project developer to proceed with the actual development of the new load;
- the scale of the project, including the quantity of electricity that will be required; and
- the timing for the provision of support infrastructure; in particular, new transmission lines and associated facilities.

While the IMO considers the likely timing and size of these loads using the information available at the time of publication, this process can be extremely challenging. Since 2008, the prediction of new block loads has been dominated by four major mining projects, three of which are magnetite iron ore projects in the Mid-West and Great Southern regions. The Boddington gold mine and Karara magnetite project have now commenced operation. However, Grange Resources announced in late 2012 that it was putting its Southdown magnetite project on hold indefinitely[31] and expansion at Karara has been delayed[32]. A further magnetite project has yet to be formally committed.

[31] http://www.abc.net.au/news/2012-11-29/grange-puts-the-hold-on-magnetite-project/4399330
[32] http://www.abc.net.au/news/2012-09-19/iron-ore-prices-to-delay-karara-expansion/4269914

These projects have appeared to be well advanced at the time of their inclusion in previous forecasts. However, following delays to these projects in the aftermath of the GFC, they have now been impacted by increased capital costs and reduced certainty regarding commodity prices.

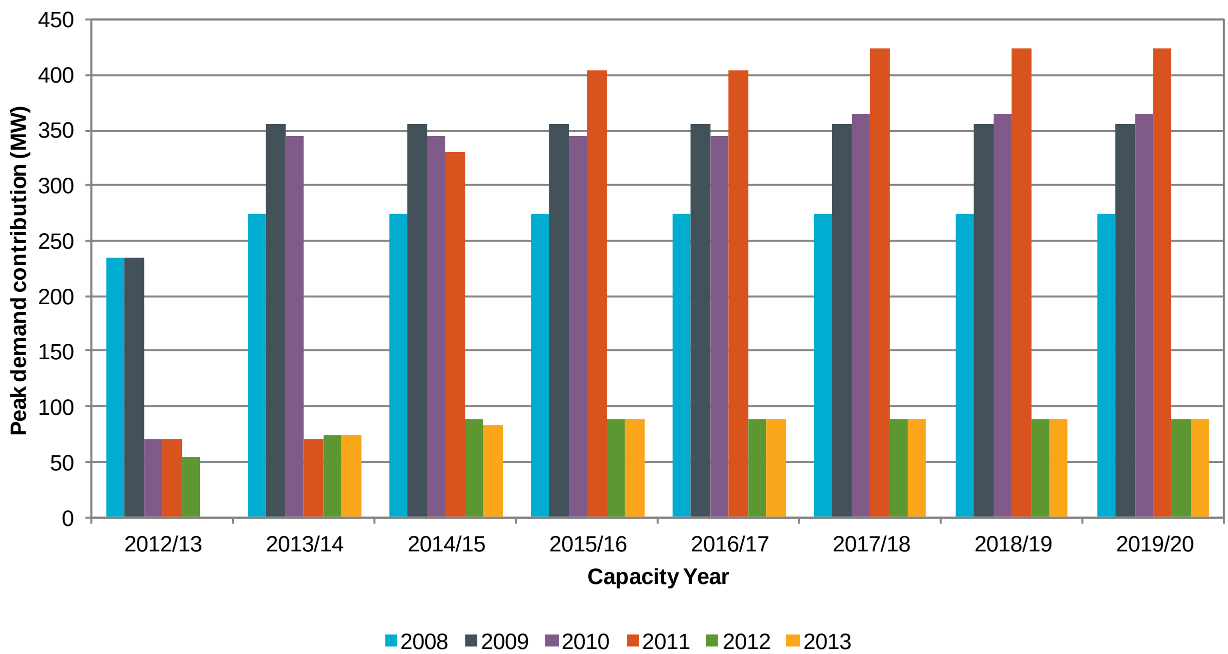
In response to these project delays and delays in the schedule of Western Power's Mid West Energy Project (MWEP) (Southern Section), the IMO delayed the expected commencement dates for the magnetite projects in its forecasts from 2009 to 2011.

The IMO made significant revisions to the block load forecasts in 2012 following reassessment of the status of the iron ore developments that had yet to be committed. Given the lack of demonstrable progress, the IMO shifted these projects into the High growth forecasts and delayed their introduction into the forecasts. The IMO also reduced the allowance for each of the new mining loads, consistent with observations of projects that had commenced operation where consumption had been lower than originally projected. As a result, the IMO has considered that the Southern Section of the MWEP will be in operation prior to these projects being completed.

The allowances for new block loads this year in the peak demand and energy forecasts are provided in Appendix 5 for all scenarios. The allowances in the Low and Expected growth scenarios are largely unchanged from last year. The allowance in the High forecast has been reduced by approximately 140 MW (peak demand) and more than 1,000 GWh (annual energy) as a result of the project delays that have been publicly announced in the last year.

The impact of these delays on the peak demand forecasts in the Expected growth scenario is shown in Figure 32. Loads that have commenced operation have been removed from previous forecasts to allow comparison across the years on a consistent basis.

Figure 32 – New block load allowances for future projects, Expected growth scenario



5.4. Solar PV projections

The demand forecasts in the 2012 SOO represented the first time that the impact of small-scale PV generation was considered by the IMO and NIEIR. Previous forecasts had not specifically considered this impact, largely due to the lack of available information from government agencies and state-owned utilities. It is also worth noting that the level of penetration in early 2011 was still relatively small, less than 80 MW nameplate capacity as at March 2011, and grew by 137% in the year to March 2012.

For the vast majority of small-scale PV systems, the gross electricity generation is not separately metered. Consequently, energy production by these systems is observed as reduced consumption and is expected to reduce the future requirement for generation and DSM capacity from registered facilities.

The IMO's forecasts are based on the following equations:

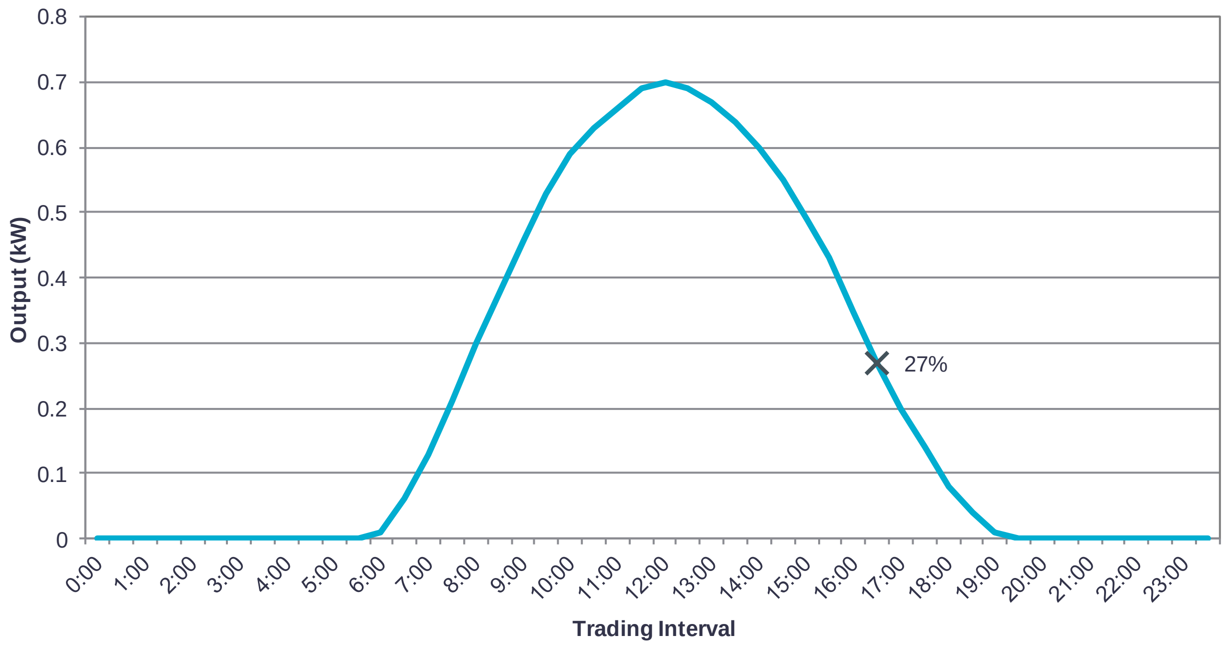
Reduction in peak demand (MW) = Installed nameplate capacity (MW) x contribution at time of peak demand (%)

Reduction in annual energy demand (GWh) = Installed nameplate capacity (MW) x average annual output of 1 MW of capacity (GWh/MW/year)

Solar PV data published by the CER has enabled the IMO to expand its solar PV projections this year to consider commercial and industrial installations. The CER data includes all PV systems smaller than 100 kW that are registered for STCs, and excludes only a handful of larger systems that are not registered in the WEM (such as the Perth Arena and Perth Zoo PV systems). This represents an improvement on the solar PV projections in the 2012 SOO, which only considered the residential sector.

The IMO has analysed a range of publicly available data sources[33] and consulted with stakeholders in revising its assumptions around small-scale PV generation. To estimate the contribution at time of peak demand, the IMO has estimated a "typical" peak day profile of a 1kW PV system, displayed below in Figure 33, by averaging the performance on the hottest summer days of a number of PV systems in the Perth metropolitan area that are oriented towards north. The maximum output of 70% reflects the reduction in system generation at hotter temperatures.

Figure 33 – "Typical" peak day profile of 1kW northward-facing PV system in Perth



[33] Including http://www.pvoutput.org and http://www.sunnyportal.com

To estimate the average annual output of one MW of capacity, the IMO analysed the annual output of a number of PV systems in the Perth metropolitan area and compared the results with a number of publicly available references, including the Clean Energy Council[34], CER[35] and Perth Solar City trial[36].

The key assumptions are listed below.

- The contribution at time of peak demand has been set at 27%, which has been increased from 24% in last year's forecasts following a review of publicly available PV production data as described above. It is assumed that the SWIS peak demand occurs in the Trading Interval from 4:30pm to 5:00pm, as has been the case for the last three summers. Analysis by the IMO suggests that the contribution of solar PV, considered in isolation, is unlikely to shift the time of the SWIS demand peak until the PV nameplate capacity approaches 1,000 MW.
- The average annual output of one MW of capacity has been set at 1.5 GWh/MW/year, which has been decreased from 1.68 GWh/MW/year in last year's forecasts. This change has resulted from a review of publicly available data and references as described above.
- Future installations have been projected at a rate of:
    - 2,250 systems per month in the Expected case;
    - 2,000 systems per month in the Low case; and
    - 2,500 systems per month in the High case.

  These rates are 250 systems per month higher than the 2012 forecasts, which only considered the residential sector. A softening of demand had been expected following the reduction of State and Commonwealth Government incentives for the installation of PV systems. While demand spikes were observed immediately prior to the reductions of the feed-in tariff and Solar Credits multiplier, underlying demand has remained stronger than previously expected with an average of 2,800 systems being installed per month in the second half of 2012.
- The 2012 forecasts assumed a reduction in the installation rate from 2015 as market penetration increases. The IMO considers it likely that increasing penetration will lead to a reduction in demand in the residential sector during the forecast horizon. However, it is expected that some growth will transfer to the commercial and industrial sectors. Consequently, the reduction in the installation rate has been removed this year on the expectation that installations in the commercial and industrial sectors would increase as residential installations decline.
- The average size of new systems has been set at 2.5 kW, consistent with the average of new installations to date in the second half of 2012.

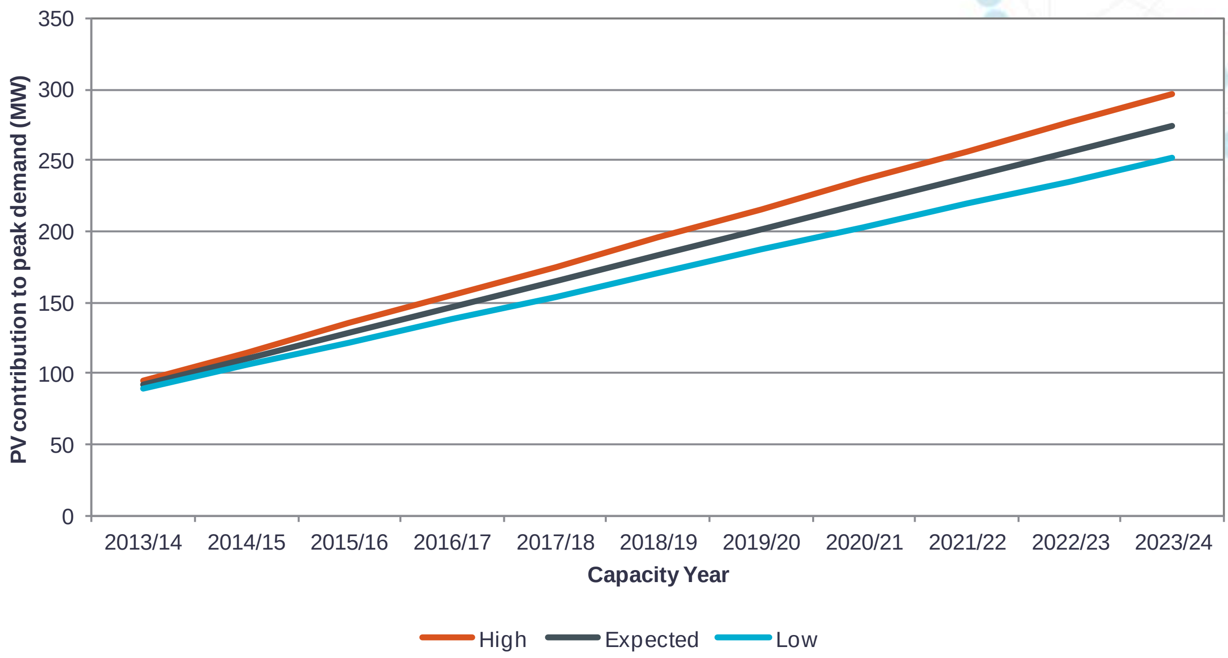
Figure 34 shows the forecast contribution from small-scale solar PV generation for the three growth scenarios. Appendix 4 contains the projected PV contributions to peak demand and annual energy for all scenarios.

[34] Value of 4.4 kWh/kW/day (1.61 GWh/MW/year), *Consumer guide to buying household solar panels (photovoltaic panels)*, Volume 21, 19 December 2012, available at http://www.cleanenergycouncil.org.au/resourcecentre/Consumer-Info/solarPV-guide.html

[35] Small Generation Unit STC Calculator, available at https://www.rec-registry.gov.au/sguCalculatorInit.shtml, suggests 1.38 GWh/MW/year.

[36] Advice from Western Power. Observations from the Perth Solar City trial, based on only one year of data, suggested 1.51 GWh/MW/year.

Figure 34 – Forecast contribution to peak demand of small-scale solar PV



The IMO notes that a number of factors could materially impact these projections, including:

- changes in Government policy, such as:
  - incentives for solar PV installation in the commercial and industrial sectors;
  - incentives for customers to orient their PV systems towards the west in order to increase the contribution at times of peak demand; or
  - revised tariff structures, such as the potential transition to a higher fixed charge and lower variable charge so that customers with PV systems pay a greater contribution to network and metering costs;
- technological change that lowers the cost or improves the performance of PV systems;
- the relative strength of the Australian dollar; and
- changes in customer behaviour that change the daily demand profile in the SWIS, such as the shifting of consumption from afternoons to evenings in summer by customers receiving the feed-in tariff.

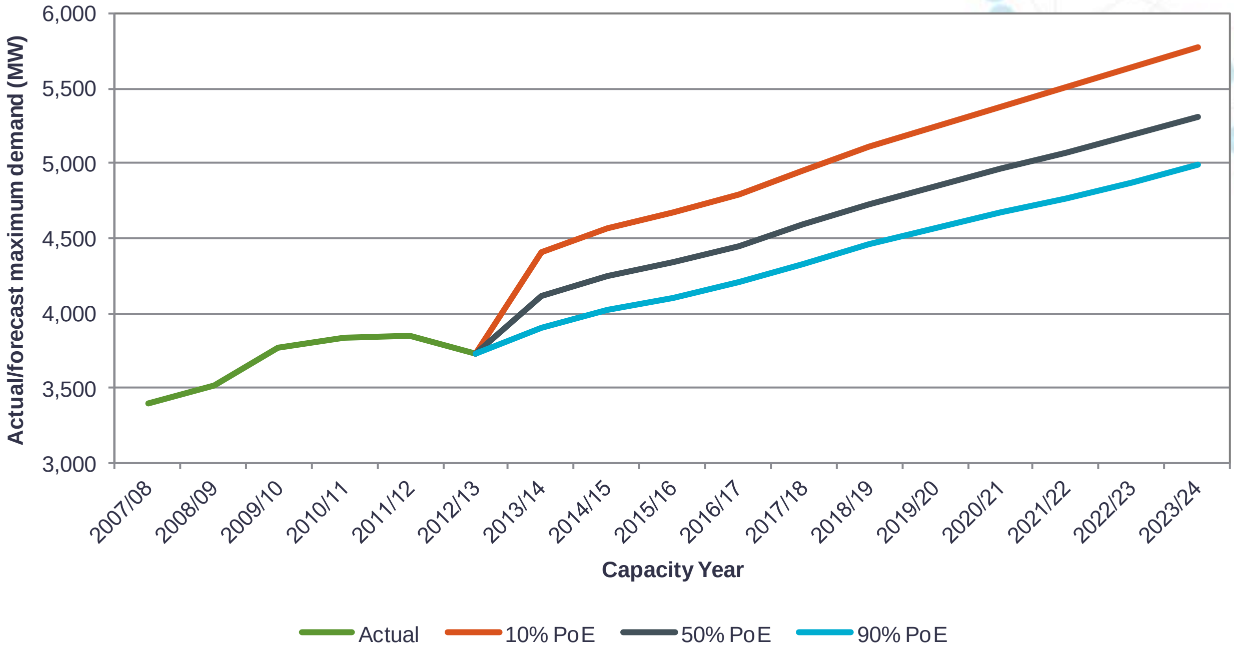
5.5. Maximum demand forecasts

NIEIR has forecast that the 10% PoE maximum demand will increase at an annual compound growth rate of 2.7% over the ten-year period from 2013/14 to 2023/24. In 2015/16, the main year of focus in this report, the maximum demand in a 10% PoE scenario is forecast to be 4,668 MW.

Figure 35 shows the SWIS maximum demand forecast developed by NIEIR for each year in the period to 2023/24 and for each of the 10%, 50% and 90% PoE cases. These forecasts are based on Expected economic growth conditions. The peak demand forecasts are tabulated in Appendix 6.

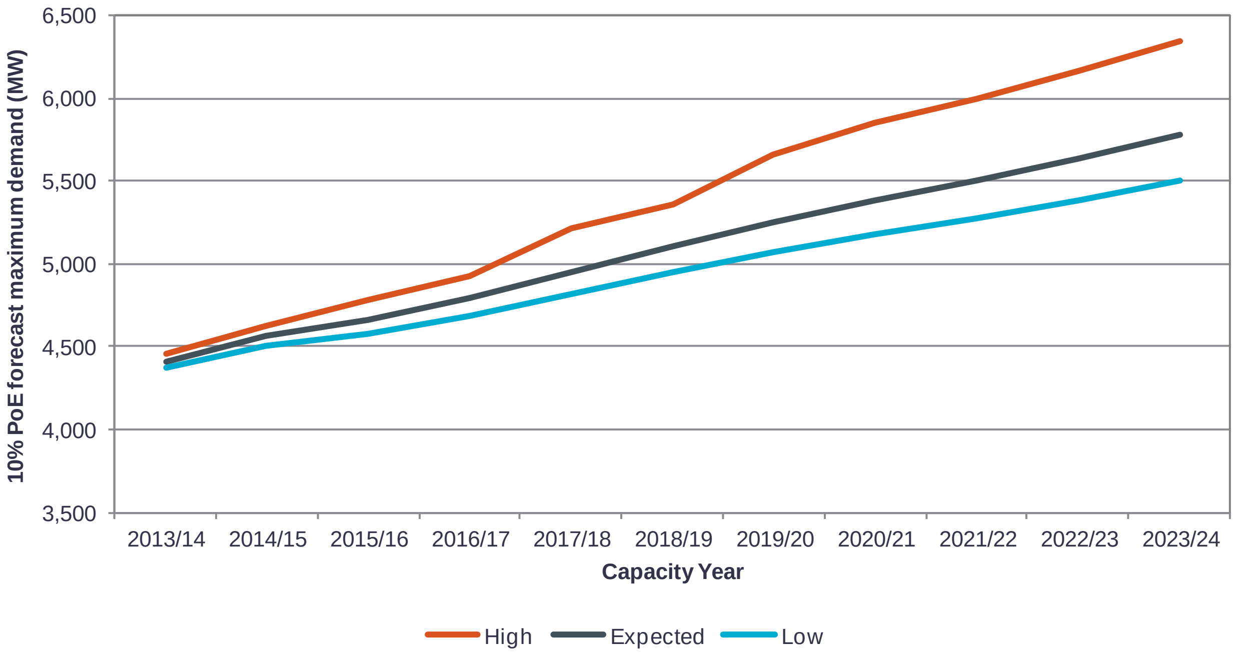
The sensitivity of maximum demand to temperature can be seen in the differences between the PoE values in Figure 35. For the 2015/16 Capacity Year, if average (50% PoE) temperature conditions are experienced, the maximum demand is forecast to be 7.1% lower (331 MW) than the 10% PoE forecast. Similarly, if the system maximum demand is experienced on a cooler than average day (e.g. 90% PoE), the maximum demand is forecast to be 12.2% lower (567 MW) than the 10% PoE scenario.

Figure 35 – Forecast maximum demand, Expected economic growth



The effect of state economic growth (as forecast by GSP) on the maximum demand forecasts is shown in Figure 36. The 10% PoE forecasts for the Expected, High and Low economic growth scenarios are shown.

Figure 36 – Impact of economic growth on maximum demand (10% PoE Forecast)



Sensitivity analysis of the economic assumptions on maximum demand shows that if conditions similar to the High economic case are experienced up to 2015/16, the maximum demand is forecast to be approximately 90 MW (1.9%) higher than for the Expected case. Should economic growth be aligned with the Low scenario, the 10% PoE maximum demand is forecast to be approximately 105 MW (2.2%) lower than the Expected case.

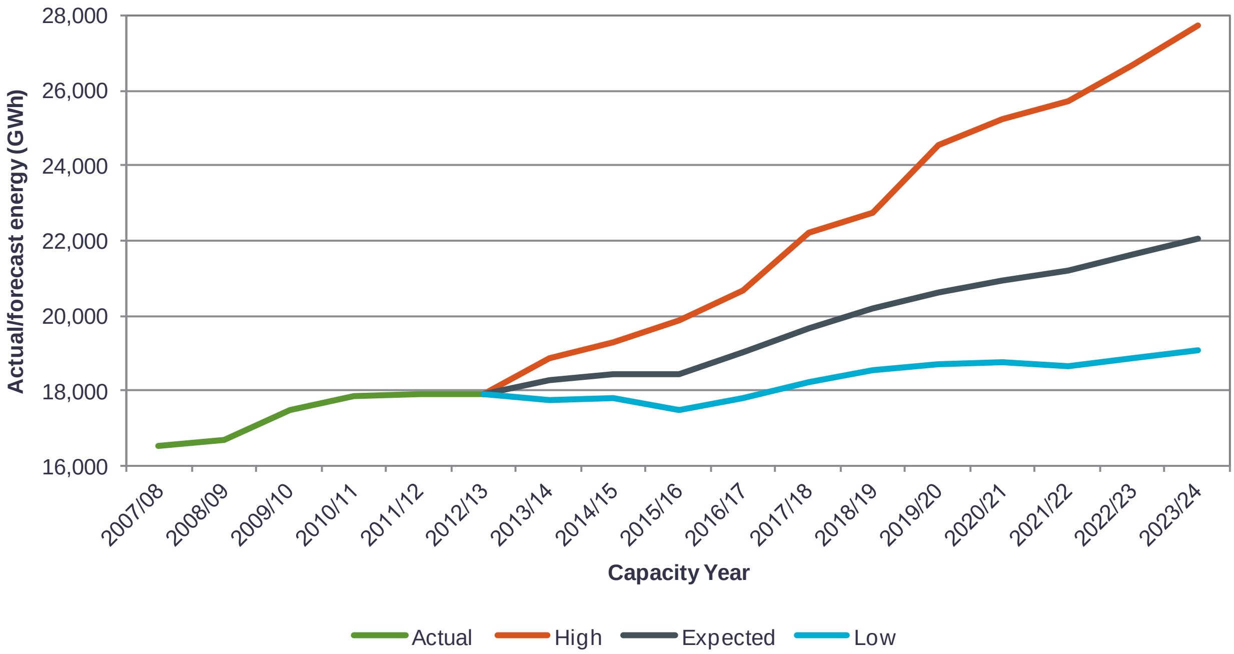
5.6. Energy forecasts

Figure 37 presents the energy consumption forecasts for the SWIS through to 2023/24. Over this period, energy consumption is forecast to grow on average by 1.9% per annum.

Under the High economic growth scenario, the growth in energy consumption is forecast to be 3.9%, while in the Low economic growth scenario energy consumption is forecast to increase at 0.7% per annum on average. Approximately 16% of the variation between the High and Low forecasts is caused by different assumptions for new major loads.

Using its temperature normalisation model, NIEIR has estimated the impact of above-average and below-average summer temperatures on annual energy consumption. If temperatures were 1°C warmer than normal for the months of December, January and February, NIEIR estimates that annual energy would increase by approximately 0.8% in each year (153GWh in 2013/14, growing to 185GWh in 2023/24). NIEIR estimates an equivalent reduction in annual energy if temperatures were 1°C cooler than normal in these months.

Figure 37 – Forecast sent out energy



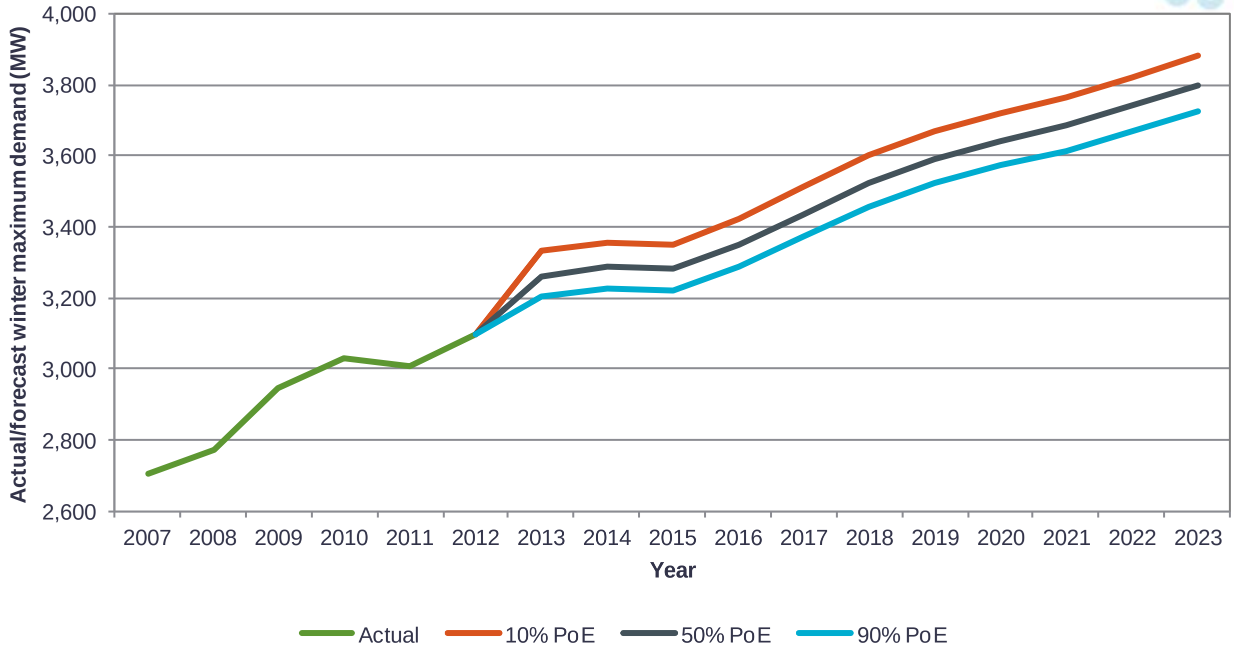
The expected energy requirements of the SWIS in 2015/16 are forecast to be 18,456 GWh. The energy forecasts are tabulated in Appendix 8.

5.7. Winter maximum demand forecasts

Winter peak demand is strongly influenced by the requirement for heating. However, electricity competes directly with gas and other energy sources in this sector so only supplies a portion of total peak demand. Electricity demand for winter heating is substantially lower than the demand for summer cooling, which generally does not have alternative fuel sources.

Because the total demand is lower, the contribution from base industrial and commercial loads during the winter is proportionately higher than in summer. This results in lower temperature variability in winter maximum demand. This lower variability is reflected in Figure 38, which shows the winter maximum demand forecasts for the Expected economic growth scenario. As can be seen, the 10% PoE and 90% PoE forecasts are each within 100 MW of the 50% PoE forecasts.

Figure 38 – Winter maximum demands



Residential and commercial lighting is a significant component of the maximum demand. These, coupled with demand for domestic heating and cooking, cause the winter peak to occur in the evening, typically around 6:00pm. However, the timing of cold weather can affect the contribution of lighting to the winter peak. If the coldest weather occurs in late June or early July, closer to the winter solstice, the contribution of lighting will be greater than in August, when daylight hours have increased.

A number of factors will influence the rate of growth in the winter peak demand including:

- the increased use of reverse-cycle air conditioning for domestic heating;
- the decreased use of domestic wood heaters and non-ducted gas heaters; and
- government programs to replace incandescent lights with more energy efficient units.

Currently, the 50% PoE winter peak demand is forecast to grow at an average rate of 1.5% to reach a level of 3,801 MW in 2023. This is 73% of the forecast 50% PoE summer maximum demand, reinforcing that the SWIS is a summer peaking system.

5.8. Differences between the 2012 and 2013 forecasts

The forecasts provided this year for 2015/16 are significantly lower than those presented in the 2012 SOO. A number of significant factors have contributed to the lower peak demand predictions, many of which have been discussed earlier in this report, including:

- consideration, for the first time, of the curtailment of demand during peak periods by some commercial and industrial customers;
- increased estimates of the contribution of small-scale PV generation;

- lower economic growth projections for WA; and
- adjustments by NIEIR to its model for temperature-sensitive load in response to observed reductions in temperature-sensitive load over the last two years.

Table 7 compares the 10% PoE maximum demand forecasts prepared in 2012 and 2013.

Table 7 – Comparison of 2012 and 2013 10% PoE peak demand forecasts

Capacity Year	2012 10% PoE Forecast (MW)	2013 10% PoE Forecast (MW)	Change in 10% PoE Demand from 2012 to 2013 Forecast (MW)
2013/14	4,659	4,410	-249
2014/15	4,804	4,561	-243
2015/16	4,950	4,668	-282
2016/17	5,135	4,797	-338
2017/18	5,290	4,955	-335
2018/19	5,419	5,109	-310
2019/20	5,563	5,258	-304
2020/21	5,711	5,400	-311
2021/22	5,859	5,533	-325
2022/23	5,990	5,672	-319

Table 8 compares the Expected annual energy forecasts (by Capacity Year) prepared in 2012 and 2013. The variations here are predominantly driven by the revisions to the economic growth scenarios. As shown in Figure 30, this year's GSP forecasts are significantly lower than last year's forecasts through to 2015/16, but higher than last year's forecasts in the later years of the forecast horizon. In addition, changes to the assumptions for the contribution of PV generation have contributed to an increase in the forecasts that grow to nearly 200 GWh by 2022/23.

Table 8 – Comparison of 2012 and 2013 Expected energy forecasts

Capacity Year	2012 Expected Energy Forecast (GWh)	2013 Expected Energy Forecast (GWh)	Change Expected Energy from 2012 to 2013 Forecast (GWh)
2013/14	18,433	18,290	-143
2014/15	18,711	18,456	-255
2015/16	19,122	18,459	-663
2016/17	19,814	19,025	-789
2017/18	20,083	19,650	-433
2018/19	20,141	20,205	64
2019/20	20,476	20,609	133
2020/21	20,827	20,946	119
2021/22	21,162	21,215	53
2022/23	21,277	21,624	347

5.9. Comparison with Western Power forecasts

Western Power determines its own peak demand and energy forecasts for its APR. Western Power employs a dedicated forecasting team with strong local knowledge and expertise and has access to a considerable quantity of demand data. Western Power's most recent public forecasts were published in the 2012 APR.

Figure 39 compares the IMO's 10% PoE and 50% PoE peak demand forecasts with similar forecasts from the 2012 APR. It is important to note that the IMO forecasts represent the maximum sent out generation and are hence inclusive of transmission and distribution losses. However, the peak demand forecasts published in Western Power's APR are aggregated from substation forecasts and exclude network losses that occur upstream of the substation. Western Power estimates that, on average, these losses amount to just over 3% of the sent out generation. To enable comparison, Figure 39 shows Western Power forecasts plus estimated network losses.

After accounting for this different treatment of network losses, the IMO's 50% PoE forecasts are below those of Western Power. This reflects the revised projections for economic growth and solar PV penetration. However, the IMO's 10% PoE forecasts overlay the Western Power forecasts in the early years of the forecast horizon and exceed the Western Power forecasts in the outer years. This reflects different methodologies for temperature normalisation (Western Power does not perform temperature normalisation at this time) and PoE adjustment between the two sets of forecasts.

Figure 39 – Comparison between IMO (2013) and Western Power (2012) peak demand forecasts, Expected case

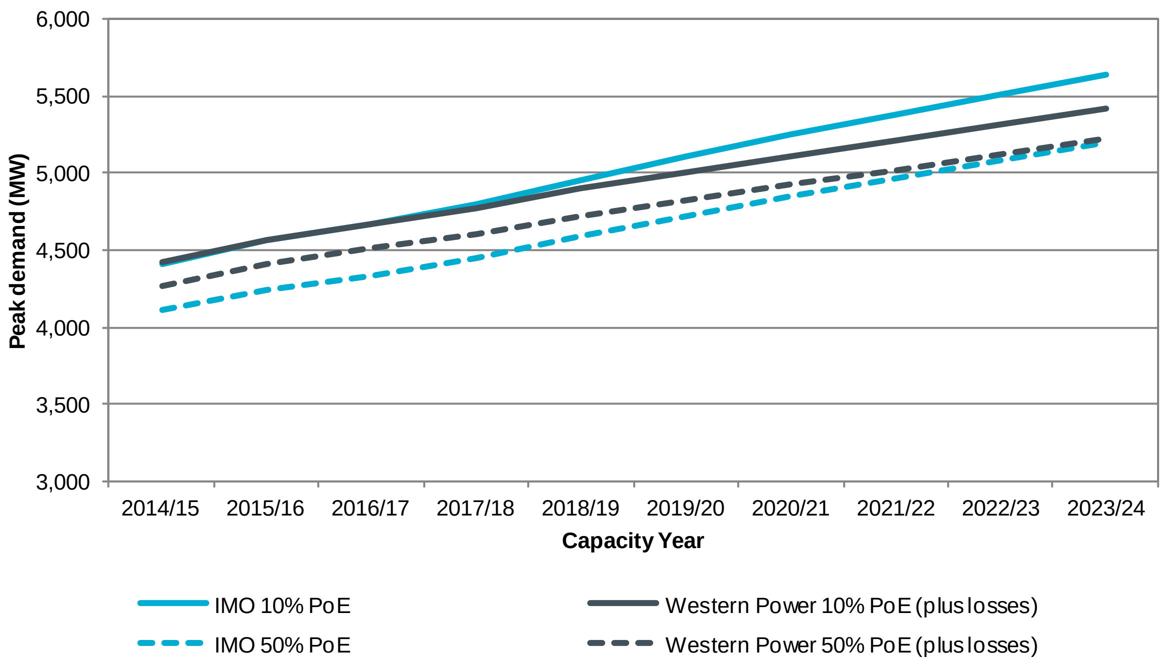


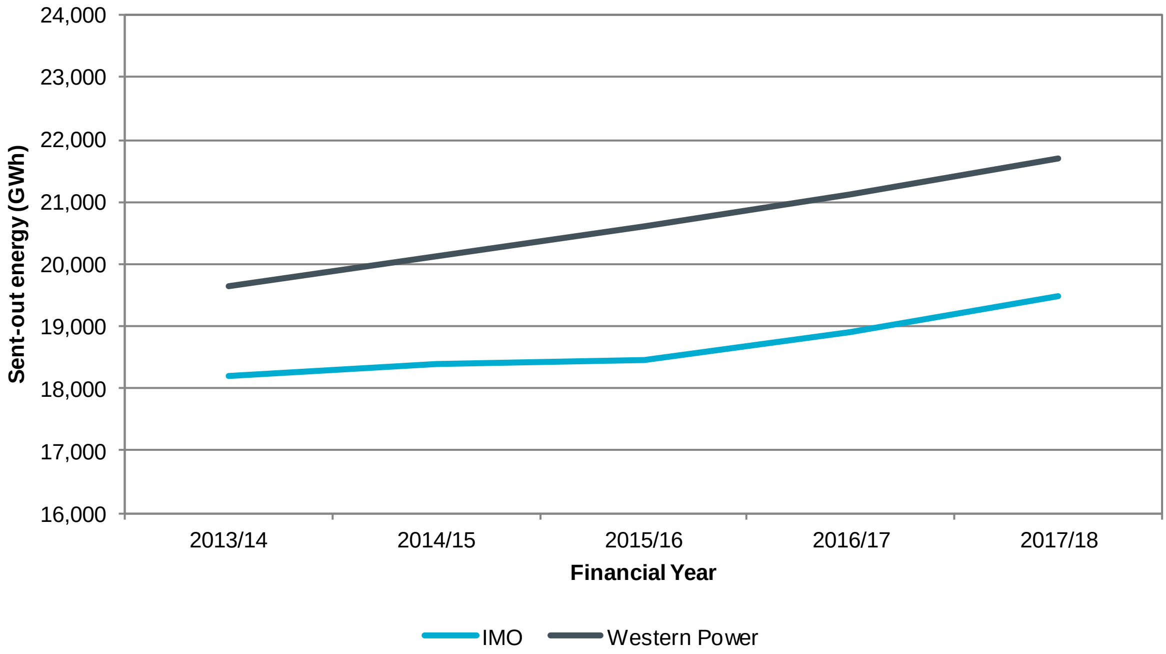
Figure 40 compares the IMO's and Western Power's forecasts of sent out energy for the next five financial years for the Expected (or Central[37]) case. In this case, the forecasts published in the APR are inclusive of network losses and are on a consistent basis with the IMO's forecasts. Western Power uses econometric models to derive forecasts for each network tariff, aggregates these and then corrects for network losses.

As shown in Figure 40, the IMO's forecast for sent out energy is substantially lower than Western Power's. The majority of the difference results from contrasting forecasting approaches and the benefit of updated

[37] As denoted by Western Power in the APR

consumption data – Western Power's forecast for the 2012/13 financial year was more than 900 GWh higher than the estimated energy consumption of 17,882 GWh. The IMO's revised projections for economic growth have also contributed to the difference, resulting in a reduction since the 2012 SOO of approximately 500 GWh in the IMO's forecast for 2014/15. However, Western Power's PV forecast appears to have assumed a slightly greater contribution from PV.

Figure 40 – Comparison between IMO (2013) and Western Power (2012) sent out energy forecasts, Expected case



5.10. Other influences on future electricity consumption

The current rapid rate of technological change in the electricity sector, particularly change that impacts electricity demand management, is having a material influence on WA's load forecasts and has the potential to transform electricity consumption patterns in the coming decades.

The potential influences described in this section have not been explicitly considered in this year's demand forecasts but may be considered in the future.

5.10.1. Initiatives associated with smart-grid

Trials conducted by Western Power have demonstrated the ability to materially impact consumer behaviour and drive energy efficiency through a range of initiatives, some of which are enabled by smart meter technology.

The Perth Solar City trial conducted by Western Power has provided some valuable insights on the impacts of improved information for customers (through methods such as in-home displays), direct load control of air-conditioners, time-of-use tariffs and behavioural change programs.

The Western Power trial measured the impacts of various measures related to the installation of various smart grid or smart meter technologies. These measures are shown in Table 9.

Table 9 – Reported impact on demand, Perth Solar City trial[38]

Measure	Reported impact
In-Home Displays (IHD)	1.5% reduction energy consumption (5% at peak)
Living Smart behaviour change program	7.5% reduction in energy consumption
Direct Load Control of air-conditioners	25% reduction at peak time
Time of use tariffs	9% reduction at peak (13% with IHD)
Home Eco-Consultations	12.3% reduction in energy consumption

Some analysts have suggested that voluntary trials such as this exhibit an upward bias, exaggerating the impacts of the measures being assessed[39]. The IMO also notes that the table above predominantly reflects the impact of each measure individually, and that the combined impact of two measures employed in combination is unlikely to reach the sum of the individual impacts. However, even a lower level of impact could materially transform electricity consumption in the SWIS.

5.10.2. Energy storage

Research into energy storage options, particularly battery technology, has grown significantly in recent years. It is likely that this research will lead to reductions in the cost of energy storage over the medium term[40]. Some have also postulated that a fleet of plug-in electric vehicles (PEVs) could provide energy storage for a large power grid[41].

A number of Australian utilities have deployed energy storage in remote areas to aid the stability of small, isolated networks. Other applications may include network support, ancillary services and participation in electricity markets.

A large penetration of energy storage has the potential to materially change the load profile of a large power grid such as the SWIS, particularly demand peaks. However, a recent study for the Clean Energy Council by Marchment Hill Consulting[42] has suggested that this application is only likely to grow materially once storage becomes more cost-competitive and is unlikely to be significant prior to 2020.

5.10.3. Electric vehicles

While still making up a small segment of the new vehicle market, global sales of PEVs have risen to 120,000 units in 2012[43]. Given the large number of PEV models that are under development or being released to market, this number is expected to grow over the next decade – a recent study by Pike Research suggests that global sales of PEVs will grow at a compound annual growth rate of 39% from 2012 to 2020.

With only 253 electric vehicles sold in Australia in 2012[44], it is too early to be able to predict the rate of sales growth in Australia and the potential impact on electricity demand. The eventual impact will likely depend on the regulatory structure, including price signals and metering requirements.

[38] Data sourced from Perth Solar City, Annual Report 2012, available at http://www.perthsolarcity.com.au/annual-report/
[39] For example, *Interval Meter Technology Trials and Pricing Experiments, Issues for Small Consumers*, C.Riedy, available at http://www.isf.uts.edu.au/publications/riedy2006intervalmeters.pdf, accessed 28 May 2013.
[40] *Energy Storage in Australia, Commercial Opportunities, Barriers and Policy Options*, 2 November 2012, available at http://www.cleanenergycouncil.org.au/resourcecentre/reports.html, accessed 28 May 2013.
[41] http://en.wikipedia.org/wiki/Vehicle-to-grid
[42] See Section 4.3.4, *Energy Storage in Australia, Commercial Opportunities, Barriers and Policy Options*, 2 November 2012, available at http://www.cleanenergycouncil.org.au/resourcecentre/reports.html, accessed 28 May 2013.
[43] http://www.navigantresearch.com/research/electric-vehicle-market-forecasts
[44] http://news.drive.com.au/drive/motor-news/the-rise-and-fall-of-better-place-20130218-2emmn.html

6. Reserve Capacity Requirements

6.1. Planning Criterion

The IMO is required to set a Reserve Capacity Target for each year at a level which ensures that the two elements of the Planning Criterion are met. The first element relates to meeting demand in the half-hour Trading Interval with the highest maximum demand. The second element ensures that adequate levels of energy can be supplied throughout the year.

The Market Rule[45] in respect of the maximum demand criterion requires the Reserve Capacity Target be set so there is sufficient generation and DSM capacity to:

> *"meet the forecast peak demand (including transmission losses and allowing for Intermittent Loads) supplied through the SWIS plus a reserve margin equal to the greater of:*
>
> *i. 7.6%[46] of the forecast peak demand (including transmission losses and allowing for Intermittent Loads); and*
>
> *ii. the maximum capacity, measured at 41℃, of the largest generating unit;*
>
> *while maintaining the Minimum Frequency Keeping Capacity for normal frequency control. The forecast peak demand should be calculated to a probability level that the forecast would not be expected to be exceeded in more than one year out of ten;"*

The second element of the criterion[47] requires that sufficient capacity be provided to:

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

The Planning Criterion applies to the provision of generation and DSM capability. It does not specifically include transmission reliability planning or cover for a major fuel disruption such as a sudden and prolonged outage of gas supply.

The most stringent element of the Planning Criterion is used to determine the Reserve Capacity Target. In each year of the Long Term PASA Study Horizon, 7.6% of the forecast maximum demand is greater than the capacity of the largest generating unit (measured at 41°C). The 7.6% factor therefore sets the level of reserve margin.

The capacity required to meet the first element (peak demand) is shown in Table 10, contained in Section 6.3.

System Management has recently reduced the quantity of Load Following capacity required for maintaining system frequency from 80 MW to 72 MW. These changes have not been driven by any reduction to the quantity of Intermittent Generation (which continues to grow) or lessening volatility in customer demand or Scheduled Generator output. Following consultation with System Management, the IMO has reduced the Load Following quantities by 20% from those in the 2012 SOO. The IMO is continuing a review of Load Following with System Management and may, subject to the outcome of this review, make further amendments to the Load Following quantities in future forecasts.

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[45] Clause 4.5.9(a) of the Wholesale Electricity Market Rules

[46] This reserve margin has reduced since 2012 as a result of Rule Change RC_2012_21, which commenced on 1 May 2013. See http://www.imowa.com.au/RC_2012_21 for more information.

[47] Clause 4.5.9(b) of the Wholesale Electricity Market Rules

6.2. Role of the second element of the Planning Criterion

Although the annual peak demand occurs in summer, the availability of capacity is very important for reliability throughout the year. This is because it is necessary for plant to be regularly taken out of service for maintenance to ensure its ongoing reliability. These plant outages are typically scheduled for lower load periods in autumn, spring and, to a lesser extent, in winter. The outage scheduling process is designed to ensure orderly planning of outages so that sufficient capacity is available at all times.

A key role of the second element of the Planning Criterion, relating to energy shortfalls, is to ensure that there is sufficient capacity to accommodate this required maintenance throughout the year. This year, the IMO has appointed PA Consulting to conduct reliability modelling of the SWIS to assess the energy-related element of the Planning Criterion and to develop the Availability Curve, which is provided in Section 6.4. This is the second year that PA Consulting has conducted this analysis.

Energy shortfall is tested by modelling the power system in detail across the year. This modelling takes account of the need for plant maintenance and the anticipated level of unplanned (or "forced") outages. The result is an estimate of the percentage of demand that would not be met due to insufficient supply capacity. The criterion is very stringent, requiring that this "energy shortfall" is less than 0.002% of the annual forecast demand.

For a particular peak demand and generation capacity, the level of energy shortfall across the year would be expected to increase with either:

- an increase in load factor (flatter demand); or
- deterioration in plant availability.

Load factor could increase with an increase in base load, such as the commencement of new industrial or mining loads, or with higher domestic winter loads, perhaps through a move to reverse-cycle air-conditioning rather than gas heating. As demonstrated in Chapter 2, load factor can also increase as a result of targeted customer behaviour that lessens the system peak demand. Plant availability may deteriorate as a result of increased forced outage rates or planned maintenance.

To date, load factors and plant availability have been such that the Reserve Capacity Target has been set by the first element of the Planning Criterion, relating to annual peak demand. For the 2015/16 Capacity Year, the peak demand-based capacity requirement exceeds the energy-based requirement by more than 700 MW. Based on this, it is expected that the peak demand forecast will continue to set the Reserve Capacity Target for the immediate future.

However, ongoing assessment of the level of unserved energy ensures that changes in plant performance or load shape are being monitored so that the appropriate Reserve Capacity Target is set and reliability of supply is maintained.

6.3. Forecast capacity requirements

Table 10 shows the Reserve Capacity Target for each year of the Long Term PASA Study Horizon, as determined from the peak demand requirement of the Planning Criterion.

Table 10 – Reserve Capacity Targets (all figures in MW rounded to nearest integer)

Year	Maximum Demand	Intermittent Loads	Reserve Margin	Load Following	Total
2013/14	4,411	14	336	72	4,833
2014/15	4,561	15	348	76	5,000
2015/16	4,668	15	356	80	5,119
2016/17	4,797	16	366	84	5,263
2017/18	4,955	17	378	88	5,438
2018/19	5,107	16	389	92	5,604
2019/20	5,247	16	400	96	5,759
2020/21	5,379	17	410	100	5,906
2021/22	5,506	17	420	104	6,047
2022/23	5,641	17	430	108	6,196
2023/24	5,779	17	440	112	6,348

The figure of 5,119 MW, as shown in Table 10, is therefore the Reserve Capacity Requirement for the 2013 Reserve Capacity Cycle.

This represents a material reduction from the 2014/15 Reserve Capacity Requirement, published in the 2012 SOO, of 5,308 MW. Various factors have contributed to this reduction, most of which have been described earlier in this report:

- The curtailment of consumption by some commercial and industrial customers at times of peak demand has led to the incorporation of this behaviour in the peak demand forecasts for the first time.
- The estimated contribution of small-scale solar PV generation to meeting peak demand has been increased.
- Economic growth projections for WA have been lowered since last year.
- NIEIR has adjusted its model for temperature-sensitive load in response to the apparent reduction in temperature coefficient for the SWIS since 2011.

In addition to these changes to the forecasts, two further changes have reduced the calculated Reserve Capacity Requirement:

- Rule Change RC_2012_21[48] reduced the reserve margin from 8.2% to 7.6% of the one-in-ten year peak demand forecast. This change was recommended during the five-yearly review of the Planning Criterion that was conducted in 2012.
- As noted above, the IMO has reduced the Load Following quantities by 20% from those in the 2012 SOO.

Table 11 provides causal analysis of the reduction from the 2014/15 Reserve Capacity Requirement to the 2015/16 Reserve Capacity Requirement.

[48] See http://www.imowa.com.au/RC_2012_21 for more information.

Table 11 – Comparison of 2014/15 and 2015/16 Reserve Capacity Requirements

2014/15 Reserve Capacity Requirement	**5,308 MW**
Reduction in reserve margin from 8.2% to 7.6%	- 30 MW
Response to IRCR mechanism*	- 56 MW
Increased 2014/15 solar PV forecast*	- 28 MW
Reduced economic growth forecasts*	- 61 MW
Adjustment to temperature-sensitive load model*	- 97 MW
Other calibrations to forecasting model*	- 12 MW
Year-on-year load growth, 2014/15 to 2015/16*	+ 115 MW
Change to Load Following requirement	- 20 MW
2015/16 Reserve Capacity Requirement	**5,119 MW**

* Includes contribution of 7.6% reserve margin.

6.4. Availability Curve

The Market Rules include the concept of Availability Classes, where capacity is assigned to a class that reflects the maximum number of hours per year that the capacity is available. This approach recognises the value of DSM but ensures that the lower availability of DSM is considered when assessing system reliability.

Four Availability Classes are defined under the Market Rules:

- Class 1 relates to generation capacity;
- Class 2 relates to capacity from DSM[49] that is available for at least 72 hours every year;
- Class 3 relates to capacity from DSM that is available for at least 48, but less than 72, hours every year; and
- Class 4 relates to capacity from DSM that is available for at least 24, but less than 48, hours every year.

Capacity from an Availability Class with higher availability can be used to meet the requirement for an Availability Class with lower availability.

Assuming that the Reserve Capacity Target is just met, the Availability Curve indicates the minimum amount of capacity required to be provided by generation capacity to ensure that the energy requirements of users are satisfied. The remainder of the Reserve Capacity Target can be met by further generation capacity or by DSM.

The Availability Curve information for 2014/15, 2015/16 and 2016/17 is shown in Table 12.

[49] May be provided by Demand Side Programmes, Interruptible Loads or Dispatchable Loads

Table 12 – Availability Curve data

	2014/15 (MW)	2015/16 (MW)	2016/17 (MW)
Market Rule 4.5.12(a):			
Capacity required for more than 24 Hours	4,358	4,453	4,574
Capacity required for more than 48 Hours	4,214	4,305	4,422
Capacity required for more than 72 Hours	4,111	4,198	4,313
Market Rule 4.5.12(b):			
Minimum Generation Required	4,275	4,394	4,578
Market Rule 4.5.12(c):			
Capacity associated with Availability Class 1	4,275	4,394	4,578
Capacity associated with Availability Class 2	0	0	0
Capacity associated with Availability Class 3	83	59	0
Capacity associated with Availability Class 4	642	666	685

Compared to last year, the proportion of capacity associated with Availability Class 1 has increased. This is caused by the higher load factor in this year's forecasts, resulting from the incorporation of the IRCR response into the forecasts, the revisions to the small-scale PV projections and recalibration of the temperature-sensitive load forecasting model.

Due to the complexity of the Availability Curve determination, the IMO has provided a more detailed explanation and graphs of the capacity requirements in Appendix 11.

The Market Rules do not limit the amount of Capacity Credits assigned to any Availability Class where there is intent to bilaterally trade. The quantities shown are not expected to be binding in the 2014/15 and 2015/16 Capacity Years.

Following the work of the Reserve Capacity Mechanism Working Group (RCMWG), described further in Section 8.3, the IMO is developing a Rule Change Proposal that would increase the minimum availability requirements for Demand Side Programmes. If approved, this proposal would require changes to the Availability Class definitions and the determination of the Availability Class quantities.

6.5. Supply-demand balance

Figure 41 and Figure 42 show the supply-demand balance over the period 2013/14 through to 2023/24. Two scenarios are presented:

- Figure 41 anticipates the decommissioning of Verve Energy's Kwinana Stage C facilities for the 2016/17 Capacity Year.
- Figure 42 assumes that Kwinana C remains in service for the entire forecast horizon.

The IMO notes that the timing of the retirement of Kwinana C is subject to a commercial decision by Verve Energy.

On these graphs:

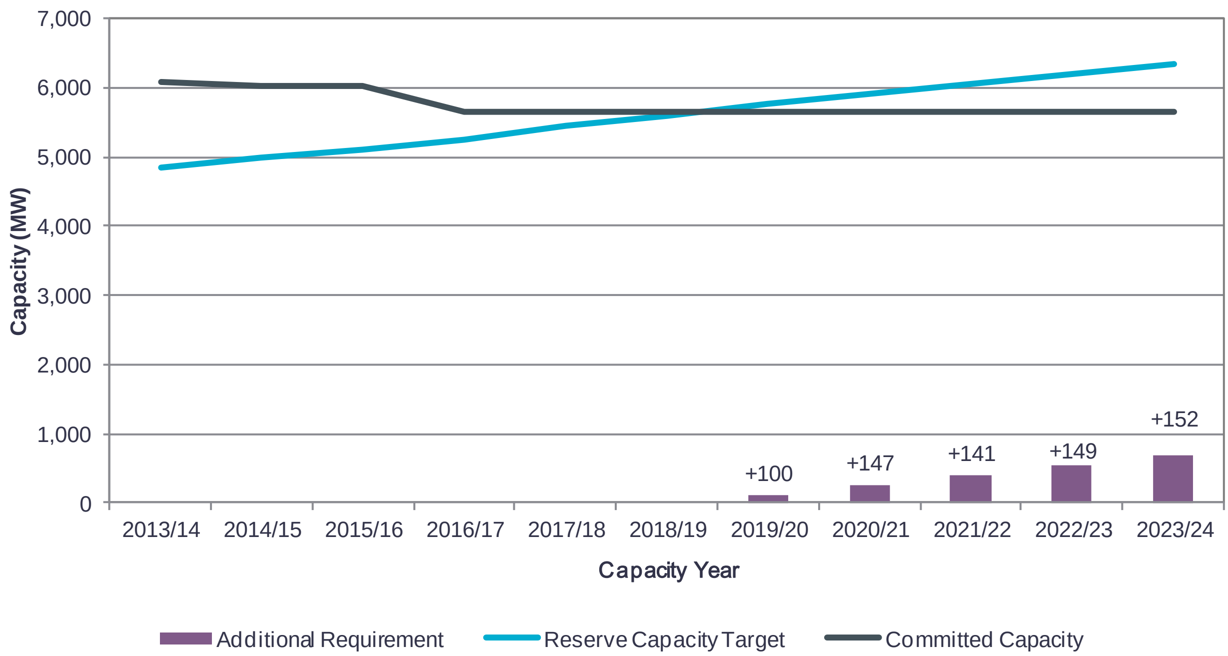
- The blue lines show the Reserve Capacity Target, increasing from 4,833 MW in 2013/14 to 6,348 MW by 2023/24.
- The dark grey lines show the level of generation and DSM capacity which is in place or committed.

- For the 2013/14 and 2014/15 Capacity Years, the level of capacity is set by the assigned Capacity Credits. The decrease in capacity from 2013/14 to 2014/15 represents reductions in the capacity allocation to some Intermittent Generators following the commencement of the Relevant Level Methodology[50], which has been implemented with a three-year transition path.
- The level of capacity has been reduced further for the remaining years of the transition (2015/16 and 2016/17) by the IMO's estimate of the likely reduction in Capacity Credits for these Intermittent Generators (11 MW for 2015/16 and 9 MW for 2016/17).
- In Figure 41, the IMO has anticipated the decommissioning of Verve Energy's Kwinana Stage C facilities (361.5 MW) for the 2016/17 Capacity Year.
- The purple bars show the cumulative requirement for additional capacity to meet the Reserve Capacity Target over the next ten years, while the labels indicate the incremental capacity requirement in each year.

Key points to note from these graphs are:

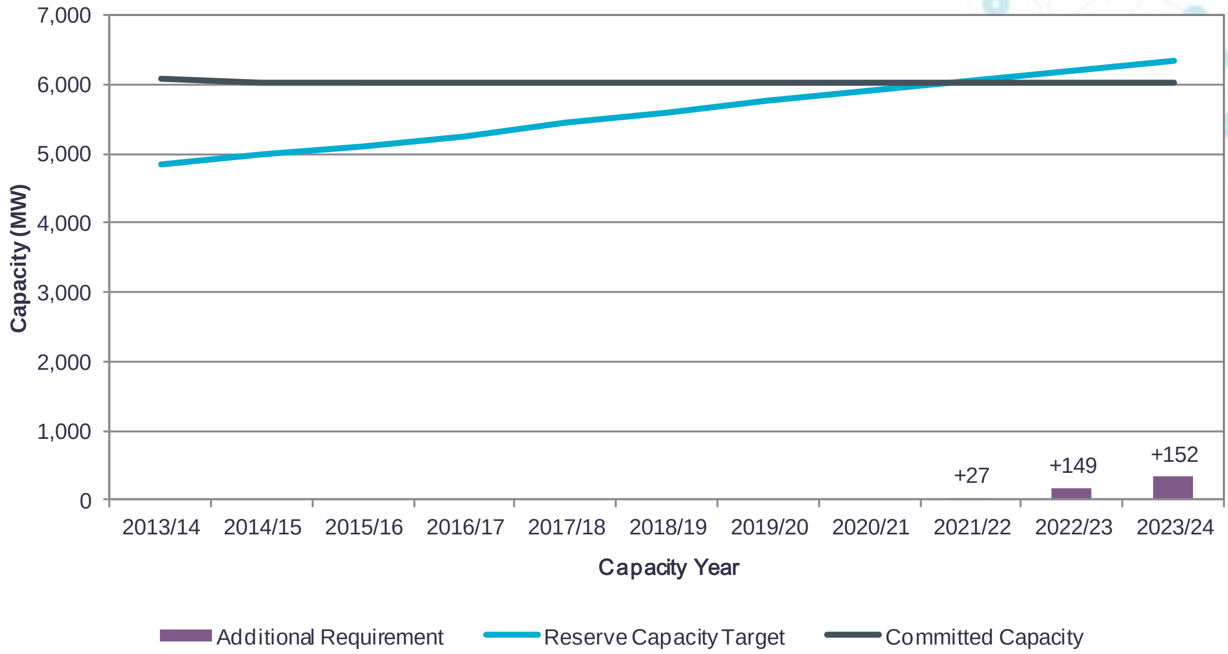
- If Kwinana Stage C is decommissioned, existing and committed capacity is expected to be sufficient to satisfy the Reserve Capacity Target through to 2018/19.
- If Kwinana Stage C remains in service, existing and committed capacity is expected to be sufficient to satisfy the Reserve Capacity Requirement through to 2020/21.
- In-service and committed facilities, prior to the introduction of any new capacity, will provide surplus capacity of 910 MW in 2015/16.
- A further 689 MW of Capacity Credits will be needed to meet the increase in the Reserve Capacity Target from 2014/15 to 2023/24 after accounting for the likely retirement of Kwinana Stage C. This quantity is only 328 MW if Kwinana C remains in service.
- This analysis suggests that opportunities for investment in generation and DSM capacity in WA are limited in the near term. However, opportunities exist in the longer term for between 300 MW and 700 MW of new capacity in the latter half of the coming decade to meet load growth.

Figure 41 – Supply-demand balance, 2013/14 to 2023/24, Kwinana C decommissioned



50 Implemented through Rule Change RC_2010_25. See http://www.imowa.com.au/RC_2010_25 for more information on the Relevant Level Methodology.

Figure 42 – Supply-demand balance, 2013/14 to 2023/24, Kwinana C remains in service



Circumstances may change over the period through to 2023/24. Project proponents, investors and developers should make independent assessments of the possible supply and demand conditions.

Graphs of the supply demand balance for High and Low economic forecasts are provided in Appendix 9.

6.6. Opportunity for investment

A total of 5,119 MW and 5,263 MW of generation and DSM capacity must be available to meet the Reserve Capacity Requirements in 2015/16 and 2016/17 respectively.

It is estimated that capacity already in place or under construction will provide an excess of 910 MW of capacity in 2015/16, prior to the introduction of any new capacity. In 2016/17, the excess is estimated to be 396 MW if Kwinana Stage C is decommissioned and 787 MW if Kwinana C remains in service. This is summarised in Table 13.

Table 13 – Opportunity for investment

	2015/16	2016/17	
		Kwinana C decommissioned	Kwinana C in service
Existing Capacity	5,823 MW	5,453 MW	5,814 MW
Committed Generation and DSM	206 MW	206 MW	206 MW
Reserve Capacity Requirement	5,119 MW	5,263 MW	5,263 MW
Surplus Capacity	910 MW	396 MW	787 MW

The most recent EOI process identified proposals for 59 MW of new Reserve Capacity for the 2015/16 Capacity Year. It should be noted, however, that the proponents of these developments have not necessarily indicated any level of commitment to proceed.

The IMO has not assessed the probability of each of the potential projects. As with any competitive market, the probability of a proposed project is partly determined by the success of competing projects. Accordingly, for the purposes of this report, the IMO has not determined that any of the potential projects are “probable”.

While the EOI process provides an indication of potential future capacity, the submission of an EOI does not necessarily translate into certified capacity. In 2012, EOIs were received for 213.7 MW of new capacity but none of this capacity was assigned Capacity Credits for the 2014/15 Capacity Year.

The opportunity for new investment is illustrated in Figure 43, Figure 44 and Figure 45. In these figures “Proposed Projects” relates to the 59 MW of potential projects identified in the EOI process.

As these graphs show, existing and committed capacity is more than sufficient to meet the capacity requirements of the SWIS beyond the middle of this decade. Consequently, there is limited opportunity for new investment in the near term.

Figure 43 – Opportunity for investment – 2015/16

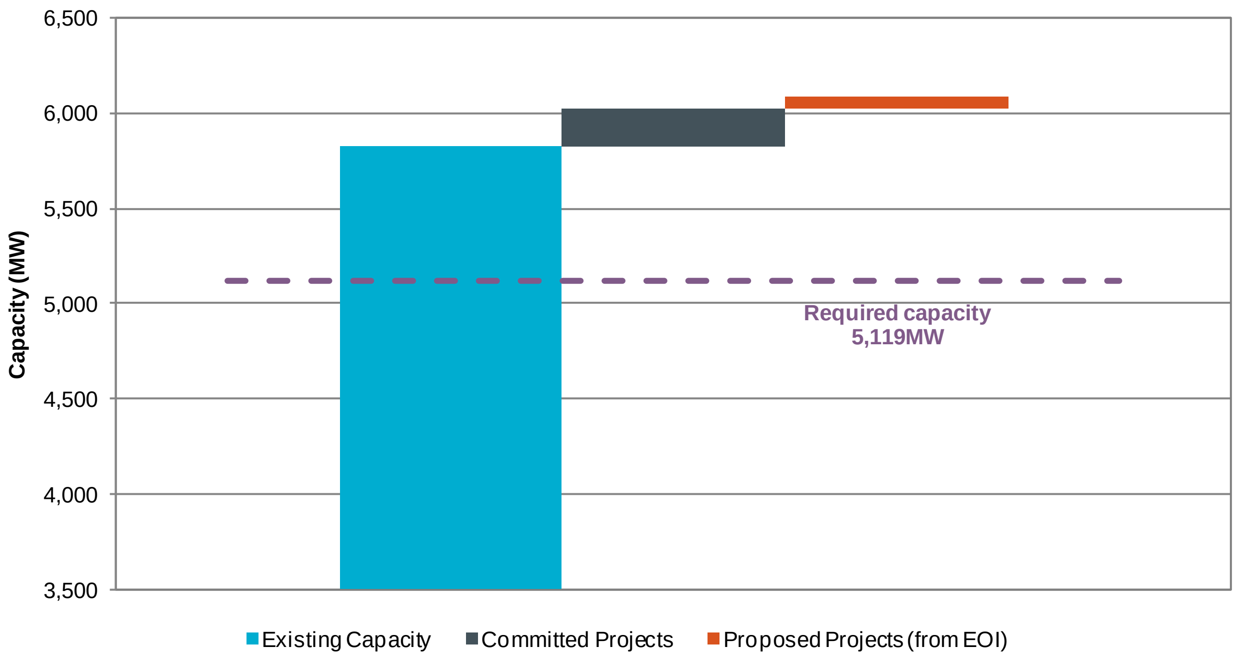


Figure 44 – Opportunity for investment – 2016/17, Kwinana C decommissioned

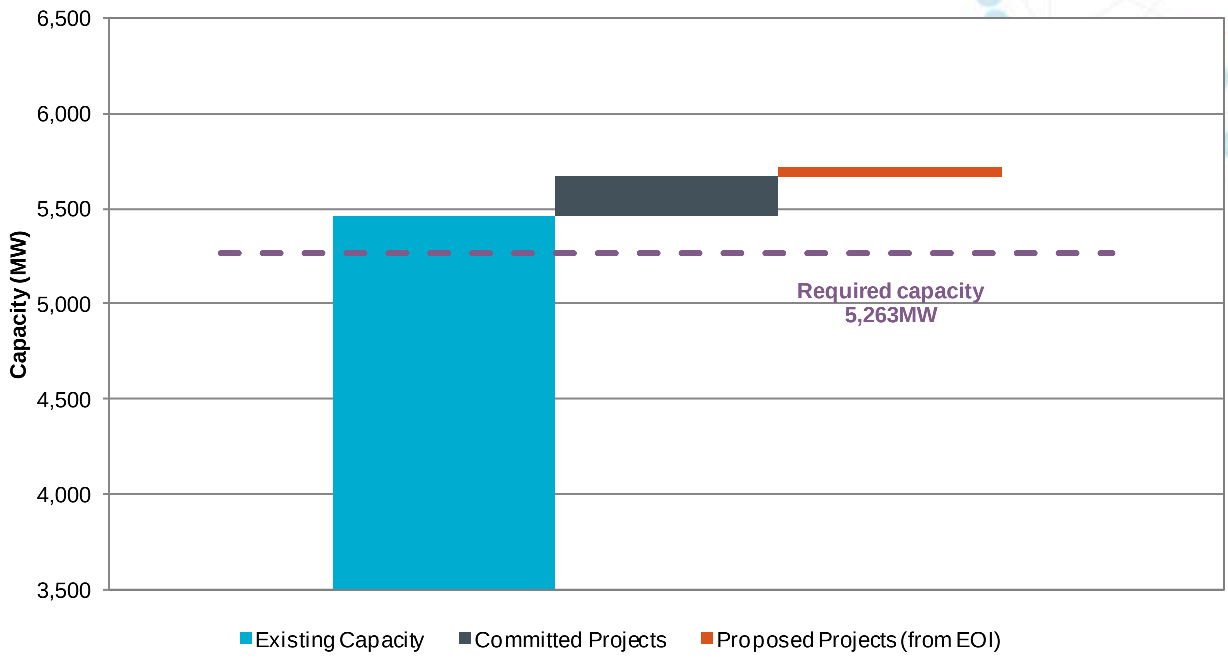
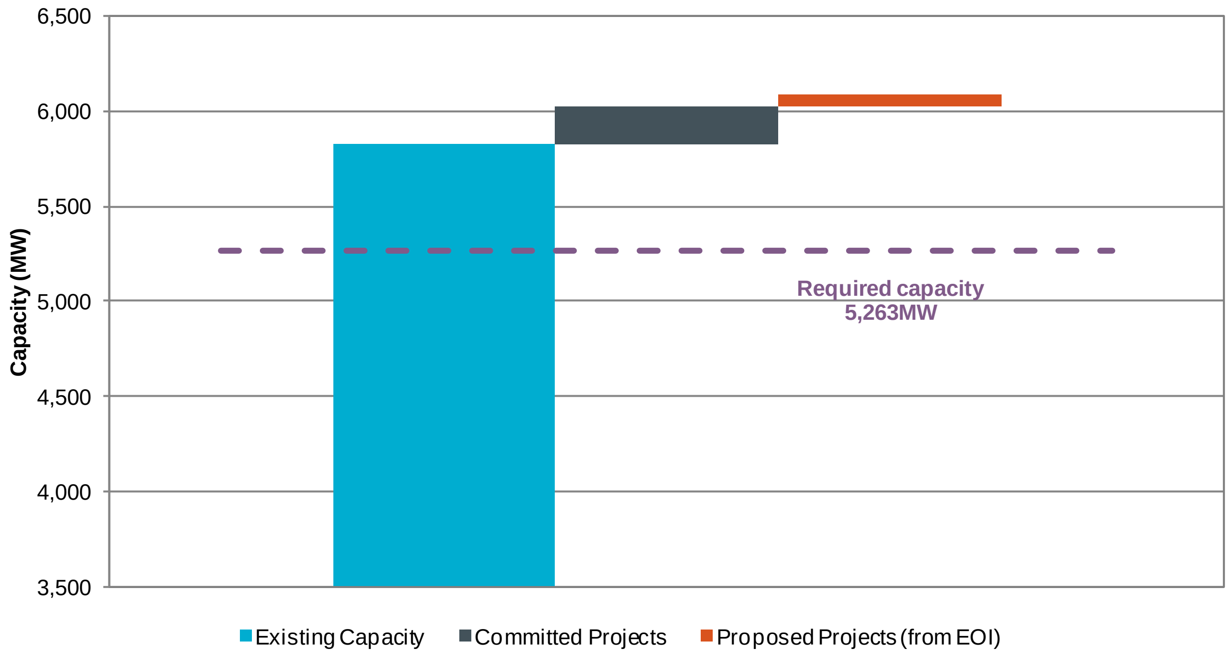


Figure 45 – Opportunity for investment – 2016/17, Kwinana C remains in service



7. Next steps in the Reserve Capacity process

The next stage in the Reserve Capacity process is for Market Participants to apply for Certified Reserve Capacity and then apply to be assigned Capacity Credits. Certification and Capacity Credits apply only to one year so new applications must be made each year for all existing or planned generation and DSM facilities.

The timetable for the 2013 certification process is as follows:

- Applications for certification of Reserve Capacity are now open and must be provided to the IMO by 5:00 pm WST on Monday 1 July 2013.
- By 5:00 pm on Monday 19 August 2013 the IMO must advise each applicant of the Certified Reserve Capacity to be assigned for the 2015/16 Capacity Year.
- Market Participants with facilities that are granted Certified Reserve Capacity must then indicate whether they intend to trade capacity bilaterally or offer the Certified Reserve Capacity into a Reserve Capacity Auction (if one is required). This process must be completed by 5:00 pm on Monday 2 September 2013.
- On Tuesday 3 September 2013, the IMO will advise Market Participants who have indicated their intention to trade their capacity bilaterally as to how many Capacity Credits will be assigned to their facilities.
- By 5:00 pm on Wednesday 4 September 2013, the IMO will advise whether sufficient capacity has been secured through bilateral trades. If the Reserve Capacity Requirement has been met, no Reserve Capacity Auction will be held. If sufficient capacity has not been secured through bilateral trades, the IMO will advise that it will run a Reserve Capacity Auction to secure the outstanding quantity.
- If a Reserve Capacity Auction is required, Market Participants must provide their offers between Thursday 5 September and Friday 13 September 2013. The IMO would run the Reserve Capacity Auction on Monday 16 September 2013.

Prospective developers should note that for a facility to receive Certified Reserve Capacity, it must fully meet the requirements of Market Rule 4.10.1 in respect to network access and environmental approvals. Both of these processes can be lengthy and potential developers are encouraged to contact Western Power and the Department of Environment and Conservation at the earliest opportunity.

Disruptions to gas supply in 2008 and 2011 have focused attention on ensuring that appropriate fuel supply arrangements are in place for all facilities. In seeking certification for generation facilities, Market Participants must provide full details of their fuel supply and transport contract arrangements with appropriate supporting documentation. The IMO acknowledges that fuel supply arrangements are often complex and may comprise a portfolio of supply and transport arrangements. Market Participants should develop a presentation that will address potential questions and assist the IMO in undertaking the certification assessment within the short timeframe provided.

Further information on the Certification of Reserve Capacity process[51], and the procedure for Declaration of Bilateral Trades and the Reserve Capacity Auction[52], are available on the IMO website.

[51] http://www.imowa.com.au/crc
[52] http://www.imowa.com.au/market-procedures

8. Key issues for potential developers

8.1. Proposed merger of Verve Energy and Synergy

On 10 April 2013, the State Government announced the merger of WA's state-owned electricity generator Verve Energy and retailer Synergy[53]. The Government announced that a single Board of Directors would be in place by 1 July 2013. This would be followed by legislative changes to integrate the two organisations into a single entity with two ring-fenced business units by 1 January 2014.

The proposed merger would entail a review of the Market Rules, including information disclosure requirements and market power mitigation measures.

8.2. Market Rules Evolution Plan

The Market Rules Evolution Plan (MREP)[54] reflects the most important Market Rules evolution issues to be addressed during the 2013-2016 Review Period, as determined by the Market Advisory Committee (MAC). These priorities, set by stakeholders, guide the IMO in the next phase of market development, and assist the IMO and System Management in developing their Allowable Revenue submissions for each three year Review Period.

To develop the plan, candidate issues were identified through review of the previous MREP and direct consultation with industry stakeholders. Issues for which work was already underway or planned for the 2012/13 financial year were excluded from consideration. The list of candidate issues was then prioritised by the MAC using a ballot process.

The highest priority was assigned to investigating a range of potential enhancements to the Balancing mechanism, including:

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

Other top ranking issues included:

- the publication by the IMO of an Emissions Intensity Index for the WEM;
- reduction of the gate closure period for the Balancing Market from two hours to thirty minutes; and
- the introduction of a competitive market for Spinning Reserve Service.

In addition to these changes, the IMO is currently progressing Market Rule changes to implement:

- the findings of the 2011 Outage Planning Review[55]. Rule changes to implement the first phase, to improve the transparency of outages, have been finalised and are scheduled to commence on 1 October 2013[56]. Consultation on rule changes to implement other recommendations from the review are likely to commence during 2013/14; and
- the outcomes of the RCMWG, which are outlined in Section 8.3 below.

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[53] See announcements at http://www.mediastatements.wa.gov.au/pages/StatementDetails.aspx?listName=StatementsBarnett&StatId=7284 and http://www.mediastatements.wa.gov.au/pages/StatementDetails.aspx?listName=StatementsBarnett&StatId=7285.

[54] Available at http://imowa.com.au/market_rules_evolution_plan

[55] Information on this review is available at http://imowa.com.au/5yearoutageplanningreview

[56] See http://imowa.com.au/RC_2012_11 for further information.

8.3. Reserve Capacity Mechanism review

The RCMWG was constituted by the MAC to consider, develop and assess changes to the Market Rules associated with the issues raised, and recommendations made, by The Lantau Group in its report *Review of RCM: Issues and Recommendations* which was presented and discussed at the MAC in 2011[57].

The RCMWG was convened over the period from February 2012 to February 2013 and focussed on the following four work areas:

1. Reserve Capacity Price;
2. Harmonisation of Demand Side and Supply Side Resources;
3. Reserve Capacity Refunds; and
4. IRCR.

Following the work of the RCMWG, the following Rule Change Proposals will be developed for consultation over 2013 and 2014.

- Individual Reserve Capacity Requirement: Modification of the IRCR methodology to select the four days of highest peak demand, not highest daily demand. Rule Change Proposal RC_2013_08[58] was submitted into the Rule Change Process on 21 May 2013, with the first submission period scheduled to close on 3 July 2013.
- Harmonisation of Demand Side and Supply Side Resources: Closer alignment of the availability requirements for demand side and supply side resources. Further details may be found in the Concept Paper provided to the June 2013 meeting of the MAC[59]. This proposal will include:
  - relaxation of the requirement for facilities to have firm fuel supply contracts if the capacity refund mechanism is assessed to provide sufficient commercial incentives for facilities to be available when required;
  - increases to the minimum availability requirements for Demand Side Programmes, including removing annual limits for dispatch hours per year and number of dispatch events per year, and requiring availability to be dispatched for up to six hours in a day between the hours of 10:00 am and 8:00 pm;
  - the requirement for a Demand Side Programme to provide a telemetry service that enables real-time information on availability and performance; and
  - implementation of the principle that a load may not sell more capacity (through Capacity Credits) than it buys (through the IRCR).
- Reserve Capacity Price and Dynamic Reserve Capacity Refunds: Changes to the Reserve Capacity Price formula and implementation of a dynamic Reserve Capacity refund regime. This Rule Change Proposal is expected to be released for consultation in the second half of 2013.

Further information on these proposals is available on the IMO's website.

8.4. Review of the methodologies for the Maximum Reserve Capacity Price and Energy Price Limits

Clause 2.26.3 of the Market Rules requires the Economic Regulation Authority (ERA) to review the methodology for setting the Maximum Reserve Capacity Price and the Energy Price Limits at least once in every five years, with the first review to take place not later than the fifth anniversary of the first Reserve Capacity Cycle.

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[57] The Lantau Group report and the full proceedings of the RCMWG are available at http://www.imowa.com.au/rcmwg
[58] Available at http://www.imowa.com.au/RC_2013_08
[59] Available at http://www.imowa.com.au/MAC_61

The ERA is conducting this review during 2013. The ERA is expected to publish an Issues Paper during June 2013 and will seek public submissions.

More information will be available on the ERA's review at http://www.erawa.com.au.

8.5. South West Interconnected Network

8.5.1. Western Power's new Applications and Queuing Policy

Transmission capacity varies across the transmission network. Because of this, the ability for proposed new connections to receive transmission services (e.g. the transport of electricity to and from a connection) will be dependent on the available capacity at a given point on the network. This needs to be taken into account when parties are considering where to locate new generation and load connections.

At locations where transmission system capacity is at or approaching its technical limits applicants seeking to connect new, or increase existing, generation or load are considered to be competing with others for connection. Western Power's Applications and Queuing Policy (AQP) sets out (amongst other things) how competing applications will be managed.

Western Power has recently implemented revisions to the AQP that have been targeted to:

- improve the visibility of transmission constraints;
- define a structure for the sharing of costs for shared network investments;
- enable the connection of several individual connection applications for a single set of shared works; and
- provide clearer information on the timeframes and costs for connection to the SWIS.

More information on the revised AQP may be found on the Western Power website[60].

8.5.2. Mid West Energy Project (Southern Section)

Western Power's most significant new transmission project underway is the MWEP (Southern Section) 330 kV double circuit transmission line from Neerabup to Eneabba. This project is expected to facilitate the connection of new generation and additional load.

Western Power has provided the IMO with the following information in relation to the MWEP (Southern Section) as at 01 April 2013:

- The project will provide a double circuit 330 kV line (initially operated as one 330 kV and one 132 kV circuit) from Neerabup to Eneabba where it will connect to a 330 kV line already constructed to provide an initial supply to the Karara mining load[61]. A 330/132 kV terminal station will also be established at Three Springs.
- Final approval from the State Government to execute the project has been secured.[62]
- The project is under construction and progressing according to schedule.
- The 330 kV line is scheduled to be energised in June 2014, with remaining works (including 132 kV connection to Three Springs 132/33 kV Substation via Three Springs 330/132 kV Terminal Station) to be completed by August 2014.
- Western Power is now able to consider connection applications from generators wishing to connect to the transmission network in the Mid-West region south of Three Springs, but notes that the connection of a generator may trigger the need to reconfigure the network to allow operation of both circuits of the new line at 330 kV.

[60] http://www.westernpower.com.au/business/aqp_revised.html
[61] ASX Announcement (ASX:GBG) 27 June 2012, http://gindpublic.powercreations.com.au/images/gind---aerohkieze.pdf
[62] Ministerial Statement, 18 May 2012, "State Budget 2012/13: Building the State – Government to power up Mid-West", at http://www.mediastatements.wa.gov.au

Given the information provided by Western Power, including the most recent project schedule, the IMO considers that the MWEP (Southern Section) will be completed in advance of the 2015/16 Capacity Year.

However, certification of Reserve Capacity for any new generator is dependent on specific information related to the connection of that facility to the SWIS, as described in Section 8.5.6 below.

8.5.3. Transmission network restrictions on the SWIS

To assist potential developers, Western Power, in collaboration with the Department of Planning and the Western Australian Planning Commission, has prepared a geospatial map viewer called the Network Capacity Mapping Tool (NCMT)[63].

The NCMT is an information service that is available to all external parties. It provides access to some of Western Power's electricity network planning information, including a 20-year outlook of the annual forecast remaining capacity available at Western Power zone substations. This enables the customer to view Western Power's current and proposed electrical network and understand how it may affect their development plans and investment options.

As is indicated in the NCMT, the transmission system is nearing capacity in several locations. Western Power advises that this is due to forecast increases in overall electricity demand, requests for connections for new generators and loads and to accommodate differing energy flows across the system. Consequently, as noted in its 2012 APR[64], Western Power is planning a range of transmission augmentations to alleviate constraints, of which the MWEP (Southern Section) is the most significant.

8.5.4. Considering the transition to a constrained access network regime

The regulatory framework for the SWIS is predicated on an unconstrained network. Analysis for the Planning Criteria is based also on the consistent assumption of an unconstrained network.

This model means that network access is offered for the full operating capacity of the generator with the power system operating within the planning criteria of the Technical Rules. If the access offer is accepted, the generator then has the right and ability to input energy into the system up to that capacity with the knowledge that the network will be able to accommodate it. This method provides simplicity and certainty for the generator. It is also simpler for the system manager who can operate without the need for a mechanism to curtail or constrain the output of certain generators once an element of the system reaches capacity.

It should be noted that some generators in the SWIS have not accepted the cost of upgrades to provide unconstrained network access, and new generators and customers are increasingly seeking to connect to the SWIS on a constrained basis. The level of constraint for a new connecting generator may vary from run back schemes to constrained dispatch. Run back schemes operate automatically when required to prevent equipment damage from overloading, and are already in place for some existing generators. Constrained dispatch will limit the output of generators prior to a network contingency. Constrained dispatch is required where the level of potential runback would cause issues with system frequency and impact on spinning reserve requirements or where a post contingent runback scheme is not able to prevent damage to plant.

In the Strategic Energy Initiative *Energy2031* Final Paper[65], the "*Strategies towards pro-active energy planning*" include the development of a constrained network access model for the SWIS, "*subject to the outcomes of a pre-feasibility study and future cost-benefit analysis*". Constrained access models are used in several other electricity markets including the NEM, New Zealand, Singapore and PJM.

Under a constrained model, generators calculate and assume the risk of gaining access to the network upon completion of their plant rather than access being guaranteed. A constrained access model may require

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[63] http://www.westernpower.com.au/ldd/ncmtoverview.html

[64] Available at http://www.westernpower.com.au/documents/reportspublications/apr/apr_2012_web.pdf

[65] Available at http://www.finance.wa.gov.au/cms/content.aspx?id=13638

more generation investment than an unconstrained model to ensure demand is met even if some generation is constrained. However, this arrangement has the potential to deliver more efficient levels of expenditure in network and generation combined.

A constrained access model requires a mechanism to resolve dispatch in constraints as well as the allocation of capacity to generators. The design and implementation of such a model is a significant undertaking, with some previous estimates indicating many years of development as well as dedicated staff required for ongoing maintenance.

The recently revised AQP has provisions that enable constrained access to be offered to applicants that are competing for limited network capacity. Through these provisions Western Power may offer runback schemes to multiple connection applications through an allocation process. Western Power has advised that it is currently analysing how this may operate in practice.

8.5.5. Opportunities for the provision of Network Control Services

The Network Access Code requires Western Power to demonstrate that it has efficiently minimised costs when implementing a solution to remove a network constraint. Prior to committing to a solution, Western Power must consider both network and non-network options.

Both the Network Access Code and Market Rules contemplate the use of Network Control Services (NCS) as non-network options for assessment in the investment decision making process. NCS may be provided by generation and/or DSM. In the case of a generation option, this may take the form of a power station connected to the network which is operated for a short duration during peak network loading periods to provide support to the network. In the case of DSM, specific customers may, by prior arrangement, agree to curtail load, run on-site standby generation or disconnect from the network for short periods to reduce their impact on the network during times of peak network loading.

Western Power has indicated that it expects potential NCS tender opportunities to be available at various locations. Stakeholders seeking further information should contact Western Power.

8.5.6. Consideration of network access by the IMO for Certified Reserve Capacity

Transmission access is a key determinant in assessing the eligibility of new capacity for Reserve Capacity Certification. Each Market Participant applying for Certified Reserve Capacity in respect of a generation facility is required under the Market Rules to provide evidence of an Arrangement for Access or evidence from Western Power indicating:

- that it has made a transmission access proposal; and
- that the facility will be entitled to firm access from the nominated service date.

To be certified in the 2013 Reserve Capacity Cycle, a new facility must be capable of fully meeting its Reserve Capacity obligations by 1 October 2015. Thus, proponents must provide evidence that firm access will be available prior to that date.

Where the Arrangement for Access, Access Offer or Preliminary Access Offer indicates that the generator is, or will be, connected to the SWIS on a constrained basis, the IMO will consider these arrangements when determining the quantity of Certified Reserve Capacity to assign to the generator. This could result in a lower allocation of Certified Reserve Capacity Credits than would be allocated in the case of unconstrained network access.

8.6. Opportunities for the provision of System Restart Ancillary Services for 2013/14

System Management has advised the IMO that it is aiming to procure three System Restart services commencing 1 July 2016, following the expiry of three existing contracts that are due to expire on 30 June 2016.

To be eligible, a generator will need to be capable of starting without the need to draw power from the transmission network. These generators are then used to re-energise the power system. A facility may be eligible for system restart if it has a smaller, offline generator which can start the main generator.

System Management has indicated that the following capabilities would be preferred in a potential provider for this service:

- manned 24 hours per day, seven days per week or capable of being remotely started and controlled by System Management;
- able to run at full speed with no load for up to 60 minutes for testing and starting purposes;
- able to start and be ready to export real and reactive power within 60 minutes; and
- connected to the 132 kV or 330kV transmission network.

System Management is especially interested in possible services to be located close to existing thermal power stations in the metropolitan area (Pinjar, Neerabup and Kwinana) and the South-West region (Collie / Bunbury / Kemerton).

Interested parties may contact System Management[66] for further information.

8.7. Availability of fuel for generation

Capacity in the SWIS is dominated by conventional generation facilities, which burn some form of non-renewable fossil fuel. As was shown in Figure 11, approximately 50% of Capacity Credits for the 2014/15 Capacity Year are allocated to gas fuelled plants or gas-liquids dual fuelled plant. Coal and dual fuelled coal/gas plant accounts for a further 35% of Capacity Credits. As shown in Figure 12, about 51% of sent out electricity in 2012 was produced from coal, 41% from gas and 8% from renewables[67]. Liquid fuel is used sparingly, predominantly for commissioning and compliance testing purposes.

In the SWIS, a mixture of coal plant and some gas-fired plant (particularly cogeneration plants and combined cycle gas turbines) is typically used as base load capacity, with renewable generation also operating throughout the day (excluding solar PV generation). Mid-merit operations are typically performed by gas-fired plant, though some cycling of coal-fired plant overnight has been required. Peak-load plants are dominated by gas, dual-fuelled gas-liquids and liquids plant.

This section provides an overview of the main fuel supplies used in SWIS conventional power generation, being coal and gas, with some commentary on liquids (distillate).

8.7.1. Coal

WA's coal supply for power generation is currently sourced entirely from two operators in the Collie Basin, around 200 km south east of Perth: Premier Coal (purchased by Yancoal Australia in 2011 and transferred to Yanzhou Coal Mining Company Ltd in 2012) and Griffin Coal (purchased by Lanco Infratech Limited in December 2010). The area also hosts the three major coal-fired power stations in the SWIS, the only other coal-fired plant being located at Kwinana. Additional coal reserves are located near Eneabba in the Mid-

[66] E: brendan.clarke@westernpower.com.au T: (08) 9427 5940 F: (08) 9427 4228

[67] Data aggregated from individual facility data. For gas-liquid dual-fuel generation facilities, gas has been assumed. For coal-gas dual-fuel generation facilities, energy has been allocated equally to coal and gas based on advice from Verve Energy. Embedded generation, including small-scale solar PV generation, is not included.

West. There are several other known but undeveloped coal deposits in WA, including the Irwin River, Vasse and Scaddan (near Esperance) deposits.

For the 2012 calendar year, WA's coal production was close to 7.5 million tonnes[68]. The vast majority of this is consumed within WA, with almost 80% of that consumption being for power generation[69]. All WA coal-fired power generation is located in the SWIS, mostly adjacent to or very close to the producing coal mines. In 2011/12, some 488,000 tonnes of coal was exported (down from 1.1 million tonnes in 2010/11)[70] with the remainder of WA's consumption occurring in manufacturing and mineral processing.

The two coal mine operators have indicated that substantial coal resources remain. Premier Coal has indicated resources of 535 million tonnes with an estimated reserve (proved and probable) of 138 million tonnes[71], while Lanco has estimated resources of 1.1 billion tonnes[72]. Some of these reserves will be committed under long-term contracts.

Proposed coal-related developments in the South-West of WA include:

- expansion of the Griffin Coal mine capacity from 4 mtpa to 18 mtpa[73], coupled with a 12 mtpa coal export facility at Bunbury[74];
- Perdaman's coal-to-urea project at Collie, slated to require three million tonnes of coal per year[75], though the project is currently under review[76]; and
- the South West Hub Project, a government-industry partnership being led by the Department of Mines and Petroleum, which is examining the potential for carbon capture and storage from surrounding industries (including the Collie region).

8.7.2. Natural gas

Natural gas first became available from the Perth Basin in the Mid-West in 1971, delivered to Perth through the Parmelia Pipeline. The commencement of production from the much larger capacity North West Shelf production area in 1984 saw significant growth in the penetration of gas in the WA energy mix. This gas, supplied from the Karratha Gas Plant (KGP), was delivered through the Dampier to Bunbury Natural Gas Pipeline (DBNGP).

Gas supply diversity further increased with the commissioning of the Varanus Island gas processing facilities, operated by an Apache Corporation subsidiary, in 1992 and enabled an increase in energy market penetration. In February 2013, the Devil Creek Gas Plant added to this diversity, which is expected to expand further in 2013 with the Macedon project[77]. The Gorgon and Wheatstone developments are anticipated to supplement the existing domestic gas production during the coming decade. These developments will ensure that WA's domestic gas supply will continue to be dominated by supply from the Pilbara.

Domestic gas consumption in WA has grown significantly from about 100 terajoules per day (TJ/d) in 1984, when gas from the north west of the state was introduced, to around 950 TJ/d in 2012.

The quantity of gas used in the SWIS for power generation increased last decade as a result of electricity demand growth and the commissioning of new gas-fired generation capacity. However, as shown in

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[68] http://www.dmp.wa.gov.au/1525.aspx
[69] *2012 Australian energy statistics data*, Bureau of Resources and Energy Economics (BREE), Table F5, http://www.bree.gov.au/publications/aes-2012.html
[70] Fremantle Ports *2012 Annual Report.*
[71] Page 7, *Wesfarmers Annual Report 2011,* http://www.wesfarmersinsurance.com.au/Documents/wes_ar11_asx_220911.pdf. Note that the reserves data in the *Yanzhou Coal Mining Company Limited, Annual Report 2012* (1.562 million tonnes) appears to be erroneous.
[72] Lanco Infratech Limited, *Annual Report 2011-12*
[73] Lanco Infratech Limited, *Annual Report 2011-12*
[74] Western Australia Mineral and Petroleum Statics Digest 2011-12, available at http://www.dmp.wa.gov.au/documents/Statistics_Digest_2011-12.pdf
[75] Western Australia Mineral and Petroleum Statics Digest 2011-12
[76] http://au.news.yahoo.com/thewest/business/a/-/national/16934170/perdaman-settles-legal-fightcwith-lanco/
[77] Western Australia Mineral and Petroleum Statics Digest 2011-12

Figure 12, gas-fired power generation has reduced since 2010 due to flat demand growth and displacement by newly-commissioned renewable generation.

Gas is transported into the SWIS via three routes:

- DBNGP, which receives gas from the KGP, Varanus Island and Devil Creek facilities, and will receive gas from other new offshore developments when they are commissioned, such as Macedon, Gorgon and Wheatstone;
- Parmelia Pipeline from the Perth Basin fields, which is also connected to the DBNGP at Mondarra; and
- Goldfields Gas Pipeline (GGP), which is connected to the Varanus Island facilities and with the DBNGP at the GGP inlet and delivers gas to the Goldfields region.

WA also has one underground gas storage facility at Mondarra, wholly owned and operated by APA Group, which is connected to both the Parmelia Gas Pipeline and the DBNGP. APA is due to complete an expansion of this facility during 2013, which is underwritten by a 20-year commercial arrangement with Verve Energy covering a significant portion of the increased storage capacity. The expansion of the facilities will increase the commercial storage capacity of the facility to 15 PJ, more than five times its earlier level. It is anticipated that the facility will be able to provide in excess of 120 TJ/d of gas supply for several weeks upon completion of the project. Verve Energy's contract arrangements will provide it "with up to 90 TJ/d, enabling an additional 800 megawatts of gas-fired generation to operate during peak demand periods for up to 60 days".[78]

Commencing in 2013, the Gas Statement of Opportunities (GSOO) and Gas Bulletin Board (GBB) will bring greater transparency to the WA domestic gas market. The IMO has responsibility for both initiatives.

- The IMO will be publishing the inaugural GSOO in July 2013. This annual planning document will provide a comprehensive medium to long-term outlook of gas supply and demand in WA, highlighting potential shortfalls or constraints.
- The GBB will commence operation in August 2013 and will consist of a website to publish information about short and near-term natural gas supply, transmission, storage and demand in WA. The GBB will also provide an emergency management page to assist in the management of supply disruptions.

Further information on these initiatives is included on the IMO website[79].

8.7.3. Liquid fuel

Diesel is the dominant liquid fuel used for power generation in the SWIS. Generators typically contract directly with the oil companies to supply their requirements. Diesel is typically used in the SWIS for short-term peaking generation.

Australian oil refineries tend to maintain only limited stocks of around 10-15 days of refinery consumption[80], so prolonged use of diesel for generation of significant quantities of energy may place strains on the supply chain unless mitigations are put into effect ahead of the requirement. It should be noted that the swift mobilisation of diesel supplies from Singapore following the 2008 Varanus Island incident enabled local inventories to be supplemented at short notice.

8.8. Potential changes for dual-fuelled facilities

As mentioned previously, dual-fuel plant played an important part in maintaining system reliability and security during the Varanus Island incidents in 2008 and 2011. However, the IMO recognises that the Market

[78] www.openbriefing.com.au/AsxDownload.aspx?pdfUrl=Report%2FComNews%2F20110526%2F01183952.pdf and statement by the Hon Peter Collier, 26 May 2011, *State Government announces key projects to boost energy security*.
[79] http://www.imowa.com.au/gisp-overview
[80] *Maintaining Supply Reliability in Australia*, Australian Institute of Petroleum, April 2008.

Rules currently provide no incentive for generators that are capable of running on more than one fuel type, yet require that additional Reserve Capacity tests are performed on such facilities.

Previous SOOs have highlighted the potential development of incentives for investment in dual fuel equipped electricity generation facilities. Such an initiative was proposed in the *Energy2031* Strategic Energy Initiative Directions paper.

However, the Strategic Energy Initiative *Energy2031* Final Paper did not include the development of incentives for dual-fuelled generation among the listed strategies. Further, the PUO advised the MAC in August 2012 that it considered that the market had changed since the initial recommendation was made and that the development of such an incentive mechanism was not a high priority at present. It committed to revisit the issue with the MAC in the future if the MAC's advice was required.

8.9. Incentives for renewable generation and carbon emission reduction

The Commonwealth Government has announced numerous mechanisms designed to increase the proportion of energy produced by renewable generation and reduce carbon emissions. Some of these initiatives are listed below. This list may not be exhaustive and the IMO recommends that proponents perform their own research into the various schemes and their eligibility for any associated funding.

It should be noted that not all of the measures listed below have bipartisan support. A change of government following the federal election in September 2013 may result in some of these measures being amended or terminated.

Many programmes previously offered by the State Government, such as the solar feed-in tariff and the Low Emissions Energy Development Fund, have now finished.

8.9.1. Renewable Energy Target

Originally introduced in 2001, the Commonwealth Government's RET scheme[81] seeks to encourage additional renewable energy generation to meet the Government's commitment for 20% of Australia's energy demand to be supplied by renewable sources by 2020. This is a national target, with no requirement for the installation of renewable generation to be equally shared across the states and territories.

The scheme involves the creation of certificates by eligible renewable energy sources based on the amount of electricity either generated or displaced and places a legal obligation on liable entities (usually electricity retailers) to purchase and surrender a certain amount of these certificates each year.

On 1 January 2011, the RET scheme separated into two parts: the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES). RECs were replaced with large-scale generation certificates (LGCs) that must be surrendered to meet the annual LRET, and STCs that serve to meet the SRES targets.

Renewable power stations register LGCs at a rate of one LGC per MWh of electricity generated. These may be sold bilaterally to liable entities (such as electricity retailers) or traded on the market. Any LGCs registered in a year that are surplus to the LRET for that year may be held by a liable entity and surrendered in a subsequent year to meet a liable entity's obligations.

There is currently a substantial surplus of RECs and LGCs in the market[82], driven by the large number of RECs created in 2009 and 2010 by small-scale PV generation and solar water heater units (prior to the separation into the LRET and SRES). The Australian Energy Market Operator (AEMO) has conducted

[81] Previously named the Mandatory Renewable Energy Target

[82] As at 25 May 2013, the Clean Energy Regulator reports that there are in excess of 16 million LGCs pending surrender. Data sourced from https://www.rec-registry.gov.au/getSearchPublicRecHoldings.shtml?recType=LGC.

analysis on the impact of this surplus[83], suggesting that the surplus LGCs, combined with expected generation from existing and committed renewable generators, will be sufficient to satisfy the LRET through to 2015.

However, as noted in Table 14 below, AEMO has projected a substantial shortfall in LGCs from 2016 onwards. The LRET grows at an average rate of 4.6 million LGCs per year from 2016 to 2020.

Table 14 – Large Scale Renewable Energy Target 2011-2020

Large-Scale Renewable Energy Target 2011-2020		
Year	LRET Target (GWh)	AEMO forecast LGC deficit (GWh)*
2011	10,400	-
2012	16,763	-
2013	19,088	-
2014	16,950	-
2015	18,850	-
2016	21,431	8,200
2017	26,031	15,400
2018	30,631	20,000
2019	35,231	24,600
2020	41,850	31,200

* Sourced from Table 2-6, *2012 Electricity Statement of Opportunities*, Australian Energy Market Operator.

Significant new investment is expected in renewable energy in Australia in the coming years to meet this shortfall. The Bureau of Resource and Energy Economics reports that, as at October 2012, there are 14 renewable energy projects (total nameplate capacity of 2029 MW) at an advanced stage of development with a further 91 proposed projects (total nameplate capacity of 16,837 MW) at a less advanced stage of development.[84]

The next review of the RET is due in 2016.

8.9.2. Carbon pricing

Under the Commonwealth Government's Carbon Pricing Mechanism, emitters of the greenhouse gases carbon dioxide, methane, nitrous oxide and perfluorocarbons have to surrender eligible emissions units to satisfy their liability for their emissions, measured in carbon dioxide equivalence (CO_2-e)[85]. An eligible emissions unit is:

- a carbon unit;
- an eligible Australian carbon credit unit issued as part of the Carbon Farming Initiative; or
- an eligible international emissions unit.[86]

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[83] See Chapter 2 of the 2012 Electricity Statement of Opportunities (ESOO), available at http://www.aemo.com.au/Electricity/Planning/Electricity-Statement-of-Opportunities. As AEMO notes, this analysis does not consider actual LGCs created in 2012.
[84] See Table 15, *Energy in Australia, May 2013*, available at http://www.bree.gov.au.
[85] http://www.cleanenergyregulator.gov.au/Carbon-Pricing-Mechanism/About-the-Mechanism/What-emission-types-are-in-and-out/Pages/default.aspx#Covered-emissions
[86] http://www.cleanenergyregulator.gov.au/Carbon-Pricing-Mechanism/About-the-Mechanism/Emissions-units/Pages/default.aspx

The Carbon Pricing Mechanism commenced operation on 1 July 2012. Carbon units are currently issued at a fixed price ($23 per tonne in 2012/13, indexed with inflation for two years) with no limit on quantity.

From 1 July 2015, each financial year will have a pollution cap and carbon units up to this quantity will be auctioned. For the first three years the auction will have a price cap, initially set at $20 above the expected international price for 2015/16 and then rising by 5% in real terms each year. Carbon units can be banked (carried over to future years) or borrowed (surrendered to satisfy the preceding year's liability, up to 5% of total liability).[87] Under the Energy Security Fund, nine highly emissions-intensive coal-fired generators are eligible for free carbon units from 1 September 2013 and then annually until 2016/17, but none of these is in the SWIS.[88] Emitters may also trade their carbon units on a secondary market.[89] Any shortfall will be paid for at a price set in the regulations or at double the benchmark average auction price for the relevant financial year.[90]

The total quantity of carbon units available for each year after free carbon units have been issued (to the coal-fired generators mentioned previously and under the Jobs and Competitiveness Program[91]) will be auctioned in eight equal parts: one in each of the three preceding years, four during the relevant financial year and one the following year.[92]

8.9.3. Australian Renewable Energy Agency (ARENA)

ARENA commenced operation in July 2012 with a mandate to support "innovations that improve the competitiveness of renewable energy technologies and increase the supply of renewable energy in Australia". It seeks to achieve these goals through the provision of financial assistance for the development of renewable energy technologies, from research through to commercialisation, and through knowledge sharing in relation to renewable energy technologies.[93]

8.9.4. Clean Energy Finance Corporation (CEFC)

The CEFC, due to commence operation on 1 July 2013, is a $10 billion investment fund dedicated to investment in clean energy projects. Its aim is to work in parallel with private sector co-financiers to overcome capital market barriers to investment in renewable energy, emissions reduction and energy efficiency projects. The CEFC is intended to be commercially-oriented, making a positive return on its investments that will be reinvested after payment of a dividend to ARENA (to be determined by the CEFC Board).[94]

[87] http://www.cleanenergyregulator.gov.au/Carbon-Pricing-Mechanism/About-the-Mechanism/Flexible-Price-from-2015/Pages/default.aspx

[88] http://www.cleanenergyregulator.gov.au/Carbon-Pricing-Mechanism/Industry-Assistance/coal-fired-generators/Pages/default.aspx

[89] http://www.cleanenergyregulator.gov.au/Carbon-Pricing-Mechanism/Fact-sheets-FAQs-and-guidelines/Fact-sheets/Pages/purchasing-eligible-emissions-units-in-the-secondary-market.aspx

[90] See http://www.cleanenergyfuture.gov.au/clean-energy-future/carbon-price/ and http://www.cleanenergyregulator.gov.au/Carbon-Pricing-Mechanism/Pages/default.aspx for more information.

[91] http://www.cleanenergyregulator.gov.au/Carbon-Pricing-Mechanism/Industry-Assistance/jobs-and-competitiveness-program/Pages/default.aspx

[92] http://www.cleanenergyfuture.gov.au/auctions-for-carbon-units/

[93] See http://www.arena.gov.au/ for more information.

[94] See http://www.cleanenergyfinancecorp.com.au/ for more information.

Appendix 1 Abbreviations

- ABS – Australian Bureau of Statistics
- APR – Annual Planning Report
- ARENA – Australian Renewable Energy Agency
- CEFC – Clean Energy Finance Corporation
- CER – Clean Energy Regulator
- DBNGP – Dampier to Bunbury Natural Gas Pipeline
- DSM – Demand Side Management
- DSP – Demand Side Programme
- EMC – Energy Market Commencement
- ERA – Economic Regulation Authority
- FIT – Feed-in Tariff
- GBB – Gas Bulletin Board
- GDP – Gross Domestic Product (for Australia)
- GFC – Global Financial Crisis
- GGP – Goldfields Gas Pipeline
- GSOO – Gas Statement of Opportunities
- GSP – Gross State Product (for Western Australia)
- GWh – Gigawatt-hour
- IMO – Independent Market Operator
- IPP – Independent Power Producer
- IRCR – Individual Reserve Capacity Requirement
- KGP – Karratha Gas Plant
- kV – Kilovolt
- LFAS – Load Following Ancillary Service
- LGC – Large-scale Generation Certificate
- LNG – Liquefied Natural Gas
- LRET – Large-scale Renewable Energy Target
- LT PASA – Long Term Projected Assessment of System Adequacy
- MAC – Market Advisory Committee
- MREP – Market Rules Evolution Plan
- Mt – Megatonne
- Mtpa – Million tonnes per annum
- MW – Megawatt
- MWEP – Mid West Energy Project
- MWh – Megawatt-hour
- NCMT – Network Connection Mapping Tool
- NCS – Network Control Services
- NEM – National Electricity Market
- NIEIR – National Institute of Economic and Industry Research
- PASA – Projected Assessment of Supply Adequacy
- PEV – Plug-in Electric Vehicle
- PJ – Petajoule
- PoE – Probability of Exceedance
- PUO – Public Utilities Office
- PV – Photovoltaic
- RCM – Reserve Capacity Mechanism
- RCMWG – Reserve Capacity Mechanism Working Group
- REBS – Renewable Energy Buyback Scheme
- REC – Renewable Energy Certificate

- RET – Renewable Energy Target
- SOO – Statement of Opportunities Report
- SRES – Small-scale Renewable Energy Scheme
- STC – Small-scale Technology Certificate
- STEM – Short Term Energy Market
- SWIS – South West interconnected system
- TJ – Terajoule
- WEM – Wholesale Electricity Market

Appendix 2 IRCR response

Figure I – Four hot days in 2012

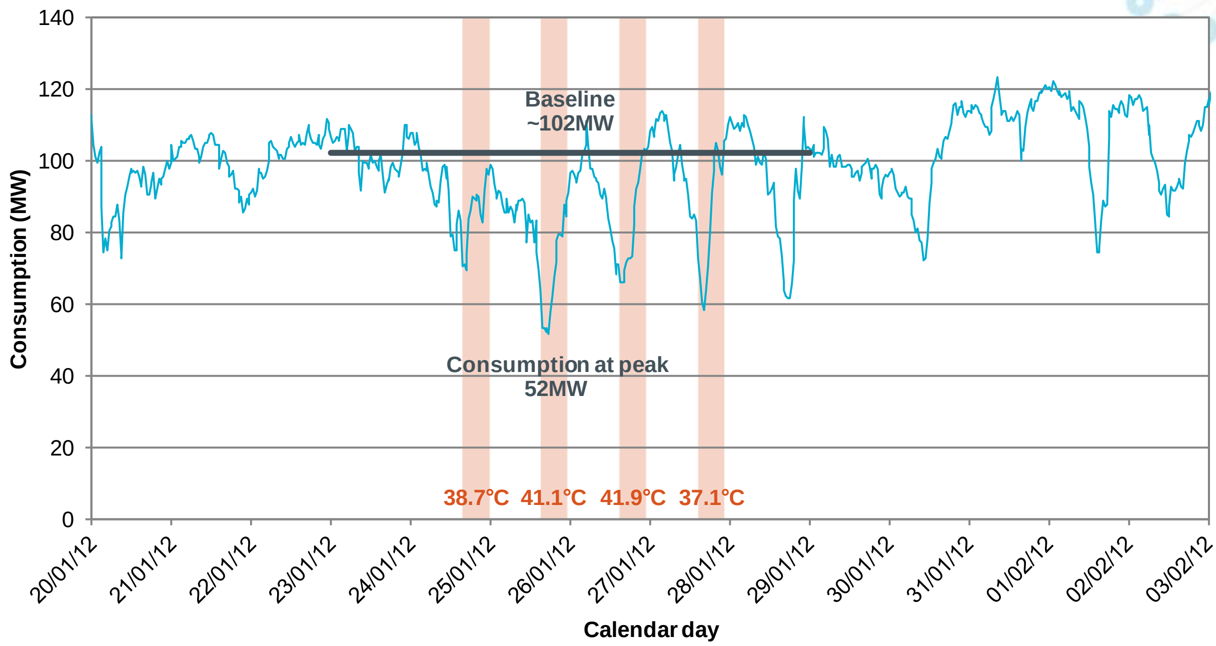
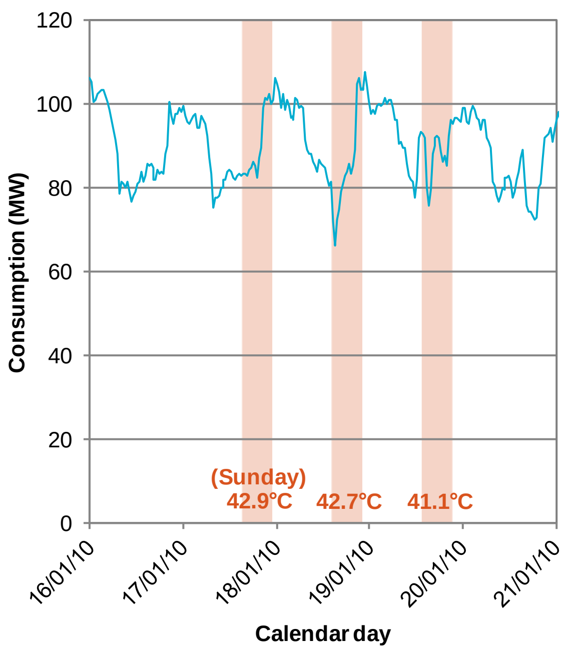
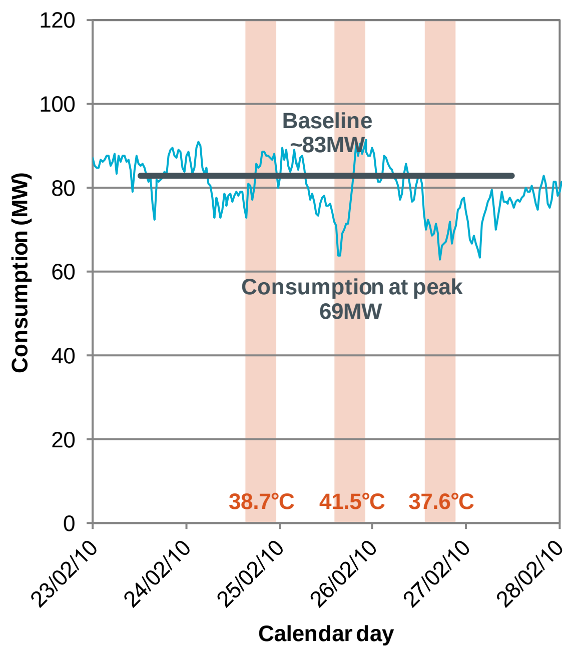


Figure II – Six hot days in 2010





Appendix 3 Forecasts of economic growth

Table I – Growth in Australian Gross Domestic Product (% Year on year growth)

Year	Actual	Expected	High	Low
2006/07	3.8			
2007/08	3.8			
2008/09	1.6			
2009/10	2.1			
2010/11	2.4			
2011/12	3.4			
2012/13		3.2	3.4	2.8
2013/14		3.1	4.0	2.5
2014/15		3.2	4.4	2.3
2015/16		3.3	4.6	2.3
2016/17		3.5	4.3	2.4
2017/18		3.7	4.2	2.8
2018/19		3.0	3.0	2.4
2019/20		2.7	3.1	1.9
2020/21		2.6	3.1	1.7
2021/22		2.0	2.5	1.0
2022/23		1.4	2.0	0.5
Average Growth %		**3.0**	**3.7**	**2.2**

Table II – Growth in Western Australian Gross State Product (% Year on year growth)

Year	Actual	Expected	High	Low
2006/07	6.2			
2007/08	3.9			
2008/09	4.3			
2009/10	4.3			
2010/11	4.0			
2011/12	6.7			
2012/13		6.5	7.2	5.9
2013/14		3.1	5.3	1.2
2014/15		1.6	3.9	-0.7
2015/16		0.4	2.9	-1.2
2016/17		6.4	7.3	4.6
2017/18		6.1	4.9	5.5
2018/19		4.7	4.4	3.8
2019/20		3.3	4.8	1.9
2020/21		1.8	2.5	-0.1
2021/22		1.5	1.6	-1.6
2022/23		2.0	3.4	1.0
Average Growth %		**3.1**	**4.1**	**1.4**

Appendix 4 Solar PV forecasts

Table III – Postcodes within the SWIS

6000	6028	6062	6107	6162	6221	6271	6326	6370	6421	6489	6535	6632	6946
6001	6029	6063	6108	6163	6223	6275	6327	6372	6423	6490	6536	6901	6951
6003	6030	6064	6109	6164	6224	6280	6328	6375	6425	6501	6556	6902	6952
6004	6031	6065	6110	6165	6225	6281	6330	6383	6426	6502	6558	6904	6953
6005	6032	6066	6111	6166	6226	6282	6331	6386	6428	6503	6560	6906	6954
6006	6033	6068	6112	6167	6227	6284	6332	6390	6429	6504	6562	6907	6955
6007	6034	6069	6121	6168	6228	6285	6333	6391	6430	6505	6564	6909	6956
6008	6035	6070	6122	6169	6229	6286	6335	6392	6432	6506	6566	6910	6957
6009	6036	6071	6123	6170	6230	6288	6336	6393	6433	6507	6567	6911	6959
6010	6037	6072	6124	6171	6231	6290	6337	6394	6436	6509	6568	6912	6963
6011	6038	6073	6125	6172	6232	6302	6338	6395	6442	6510	6569	6914	6964
6012	6041	6074	6126	6173	6233	6304	6341	6396	6460	6511	6572	6915	6966
6013	6042	6076	6147	6174	6236	6306	6343	6397	6461	6512	6574	6916	6968
6014	6043	6077	6148	6175	6237	6308	6346	6398	6465	6513	6575	6918	6979
6015	6044	6078	6149	6176	6239	6309	6350	6401	6466	6514	6603	6920	6981
6016	6050	6081	6150	6180	6240	6311	6352	6403	6467	6515	6606	6921	6982
6017	6051	6082	6151	6181	6243	6312	6353	6405	6468	6516	6608	6922	6984
6018	6052	6083	6152	6207	6244	6313	6355	6407	6472	6517	6609	6923	6985
6019	6053	6084	6153	6208	6251	6315	6356	6409	6473	6518	6612	6924	6988
6020	6054	6090	6154	6209	6252	6316	6359	6410	6475	6519	6613	6926	6989
6021	6055	6100	6155	6210	6253	6317	6361	6411	6476	6521	6616	6929	6990
6022	6056	6101	6156	6211	6254	6318	6363	6413	6477	6522	6620	6931	6991
6023	6057	6102	6157	6213	6255	6320	6365	6414	6479	6525	6623	6933	6992
6024	6058	6103	6158	6214	6256	6321	6357	6415	6480	6528	6627	6934	
6025	6059	6104	6159	6215	6258	6322	6367	6418	6485	6530	6628	6935	
6026	6060	6105	6160	6218	6260	6323	6368	6419	6487	6531	6630	6943	
6027	6061	6106	6161	6220	6262	6324	6369	6420	6488	6532	6631	6944	

Table IV – Peak demand contribution of small-scale solar PV (MW)

Year	Expected	High	Low
2013/14	92	94	90
2014/15	110	115	106
2015/16	128	135	122
2016/17	147	155	138
2017/18	165	175	154
2018/19	183	196	171
2019/20	201	216	187
2020/21	220	236	203
2021/22	238	256	219
2022/23	256	277	235
2023/24	274	297	252

Table V – Annual energy contribution of small-scale solar PV (GWh) – Financial Year

Year	Expected	High	Low
2013/14	503	515	491
2014/15	604	627	581
2015/16	705	740	670
2016/17	807	853	761
2017/18	908	965	851
2018/19	1009	1077	941
2019/20	1110	1190	1030
2020/21	1212	1303	1121
2021/22	1313	1415	1211
2022/23	1414	1527	1301
2023/24	1515	1640	1390

Table VI – Annual energy contribution of small-scale solar PV (GWh) – Capacity Year

Year	Expected	High	Low
2013/14	528	543	513
2014/15	629	655	603
2015/16	730	768	693
2016/17	832	880	783
2017/18	933	993	873
2018/19	1034	1105	963
2019/20	1135	1218	1053
2020/21	1237	1330	1143
2021/22	1338	1443	1233
2022/23	1439	1555	1323
2023/24	1540	1668	1413

Appendix 5 Block load forecasts

Table VII – Peak demand contribution of new large loads (MW)

Year	Expected	High	Low
2013/14	74	89	54
2014/15	84	89	74
2015/16	89	114	74
2016/17	89	114	74
2017/18	89	114	74
2018/19	89	174	74
2019/20	89	244	74
2020/21	89	264	74
2021/22	89	264	74
2022/23	89	264	74

Table VIII – Annual energy contribution of new large loads (GWh) – Financial Year

Year	Expected	High	Low
2013/14	410	494	299
2014/15	564	649	538
2015/16	649	836	538
2016/17	649	836	538
2017/18	649	836	538
2018/19	649	1,163	538
2019/20	649	1,722	538
2020/21	649	1,937	538
2021/22	649	1,937	538
2022/23	649	1,937	538

Appendix 6 Forecasts of summer maximum demand

Table IX – Summer maximum demand forecasts with Expected economic growth (MW)

Year	Actual	10% PoE	50% PoE	90% PoE
2007/08	3,392			
2008/09	3,515			
2009/10	3,766			
2010/11	3,831			
2011/12	3,854			
2012/13	3,735			
2013/14		4,411	4,113	3,901
2014/15		4,561	4,244	4,020
2015/16		4,668	4,336	4,101
2016/17		4,797	4,451	4,204
2017/18		4,955	4,592	4,333
2018/19		5,107	4,727	4,456
2019/20		5,247	4,850	4,568
2020/21		5,379	4,966	4,672
2021/22		5,506	5,077	4,771
2022/23		5,641	5,196	4,878
2023/24		5,779	5,317	4,987
Average Growth %		**2.7**	**2.6**	**2.5**

Table X – Summer maximum demand forecasts with High economic growth (MW)

Year	10% PoE	50% PoE	90% PoE
2013/14	4,456	4,157	3,944
2014/15	4,620	4,302	4,075
2015/16	4,778	4,444	4,206
2016/17	4,929	4,580	4,331
2017/18	5,215	4,848	4,587
2018/19	5,364	4,981	4,708
2019/20	5,666	5,265	4,980
2020/21	5,850	5,434	5,137
2021/22	5,997	5,564	5,255
2022/23	6,164	5,714	5,394
2023/24	6,341	5,875	5,542
Average Growth %	**3.6**	**3.5**	**3.5**

Table XI – Summer maximum demand forecasts with Low economic growth (MW)

Year	10% PoE	50% PoE	90% PoE
2013/14	4,368	4,072	3,862
2014/15	4,509	4,196	3,973
2015/16	4,583	4,255	4,023
2016/17	4,685	4,344	4,101
2017/18	4,823	4,466	4,212
2018/19	4,954	4,581	4,315
2019/20	5,070	4,682	4,405
2020/21	5,176	4,773	4,484
2021/22	5,272	4,852	4,553
2022/23	5,386	4,951	4,641
2023/24	5,503	5,053	4,731
Average Growth %	**2.3**	**2.2**	**2.1**

Appendix 7 Forecasts of winter maximum demand

Table XII – Winter maximum demand forecasts with Expected economic growth (MW)

Year	Actual	10% PoE	50% PoE	90% PoE
2007	2,705			
2008	2,774			
2009	2,944			
2010	3,029			
2011	3,008			
2012	3,098			
2013		3,332	3,263	3,204
2014		3,357	3,287	3,227
2015		3,353	3,282	3,222
2016		3,422	3,350	3,288
2017		3,511	3,437	3,373
2018		3,600	3,524	3,459
2019		3,668	3,590	3,523
2020		3,722	3,643	3,575
2021		3,765	3,685	3,615
2022		3,822	3,740	3,669
2023		3,884	3,801	3,728
Average Growth %		**1.5**	**1.5**	**1.5**

Appendix 8 Forecasts of energy sent out

Table XIII – Forecasts of energy sent out for the SWIS (GWh) – Capacity Year

Year	Actual	Expected	High	Low
2007/08	16,519			
2008/09	16,690			
2009/10	17,500			
2010/11	17,861			
2011/12	17,914			
2012/13	17,899			
2013/14		18,290	18,892	17,737
2014/15		18,456	19,311	17,801
2015/16		18,459	19,866	17,508
2016/17		19,025	20,693	17,795
2017/18		19,650	22,234	18,248
2018/19		20,205	22,755	18,573
2019/20		20,609	24,578	18,725
2020/21		20,946	25,243	18,771
2021/22		21,215	25,741	18,658
2022/23		21,624	26,685	18,886
2023/24		22,055	27,734	19,094
Average Growth %		**1.9**	**3.9**	**0.7**

Table XIV – Forecasts of energy sent out for the SWIS (GWh) – Financial Year

Year	Actual	Expected	High	Low
2007/08	16,387			
2008/09	16,628			
2009/10	17,342			
2010/11	17,930			
2011/12	17,813			
2012/13	17,881			
2013/14		18,207	18,683	17,766
2014/15		18,406	19,183	17,794
2015/16		18,448	19,726	17,565
2016/17		18,907	20,494	17,749
2017/18		19,498	21,868	18,146
2018/19		20,061	22,573	18,486
2019/20		20,498	24,155	18,677
2020/21		20,855	25,020	18,752
2021/22		21,142	25,594	18,677
2022/23		21,526	26,461	18,844
2023/24		21,948	27,472	19,043
Growth %		**1.9**	**3.9**	**0.7**

Appendix 9 Supply-demand balance for High and Low economic forecasts

Figure III – Supply-demand balance, High economic growth scenario, Kwinana C decommissioned for 2016/17

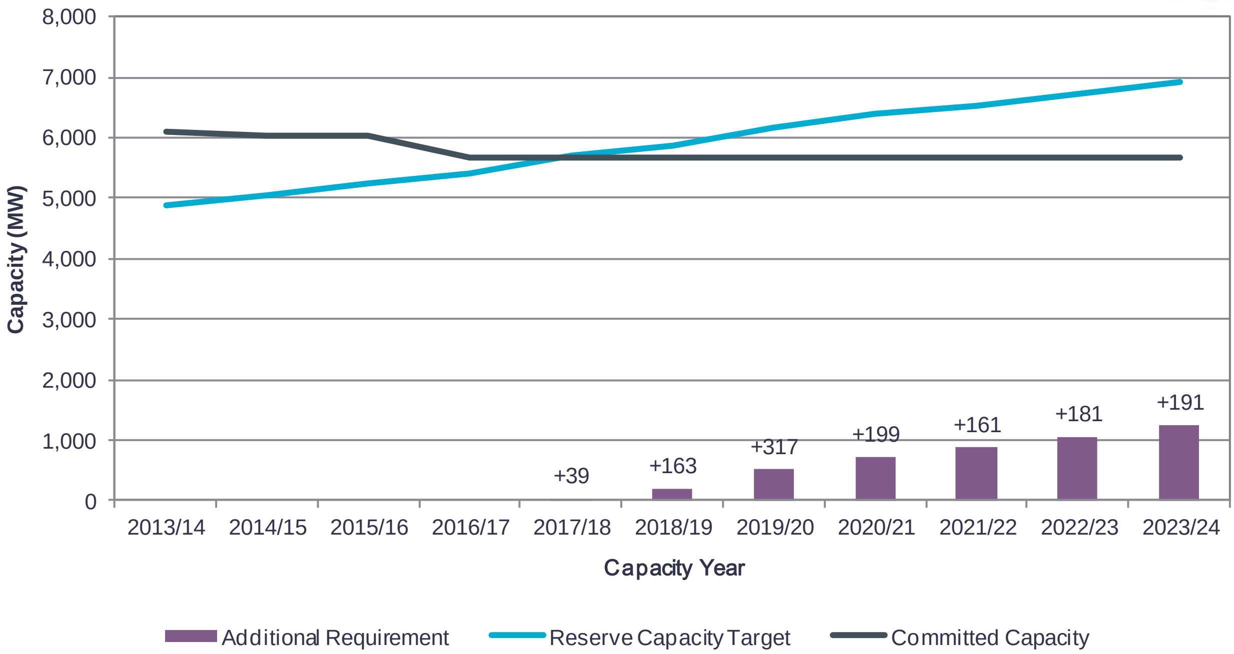


Figure IV – Supply-demand balance, High economic growth scenario, Kwinana C remains in service

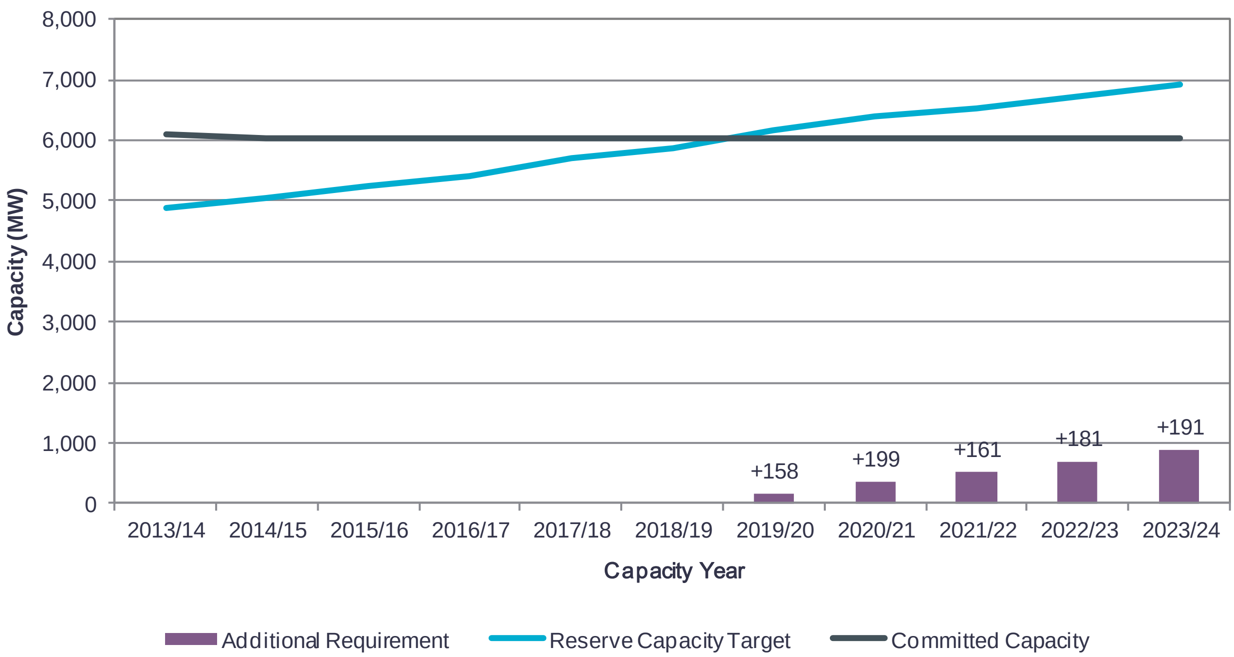


Figure V – Supply-demand balance, Low economic growth scenario, Kwinana C decommissioned for 2016/17

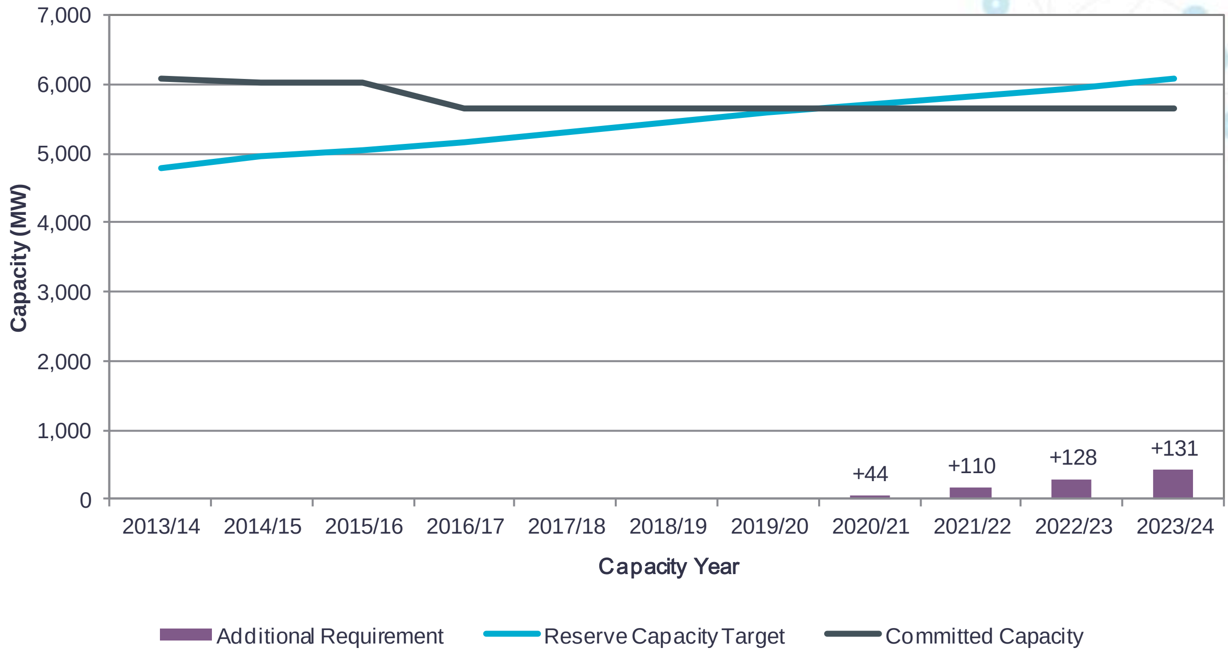
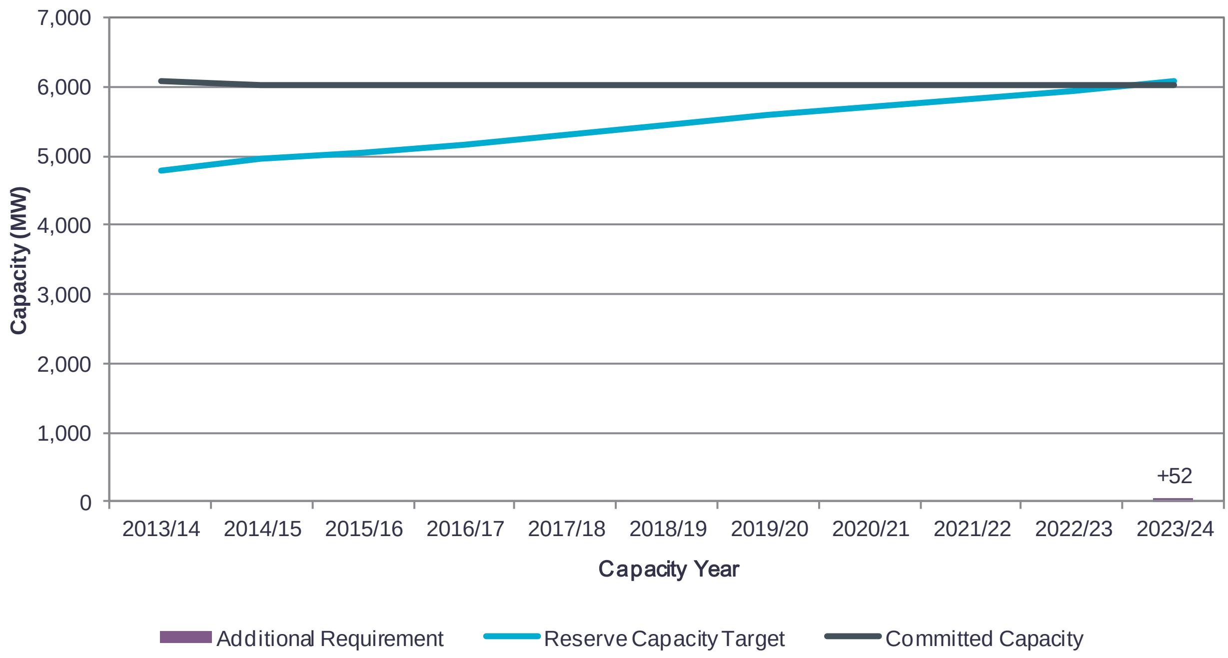


Figure VI – Supply-demand balance, Low economic growth scenario, Kwinana C remains in service



Appendix 10 Typical daily load curves

Figure VII – Summer peak day – 12 February 2013

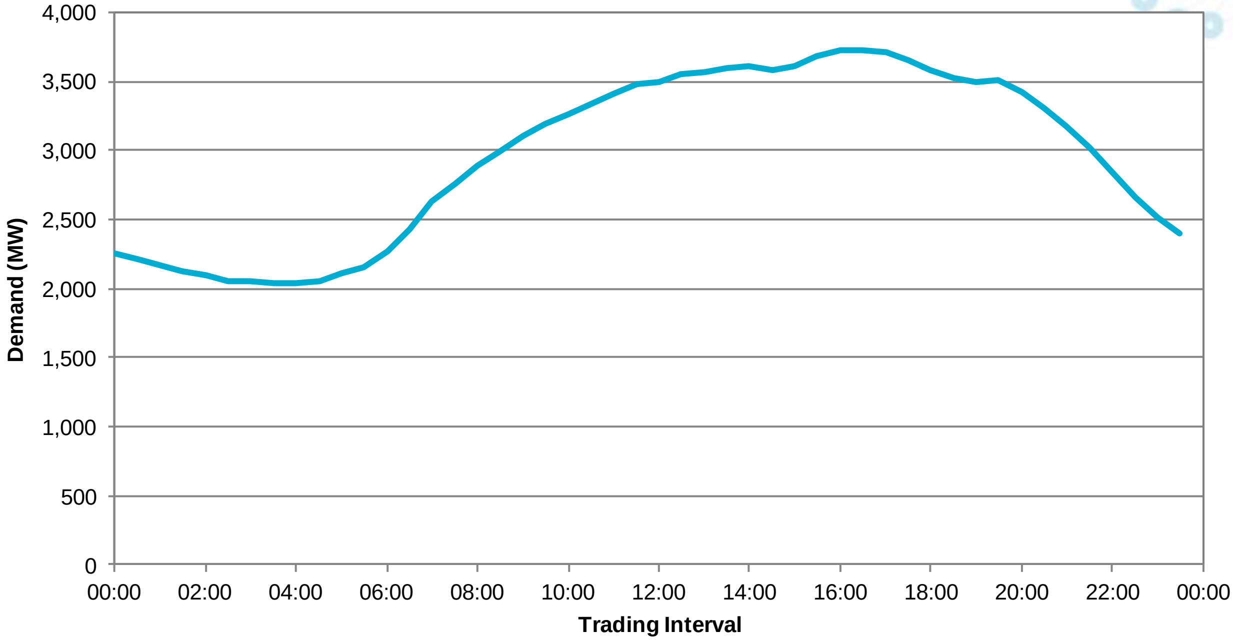


Figure VIII – Winter peak day – 25 July 2012

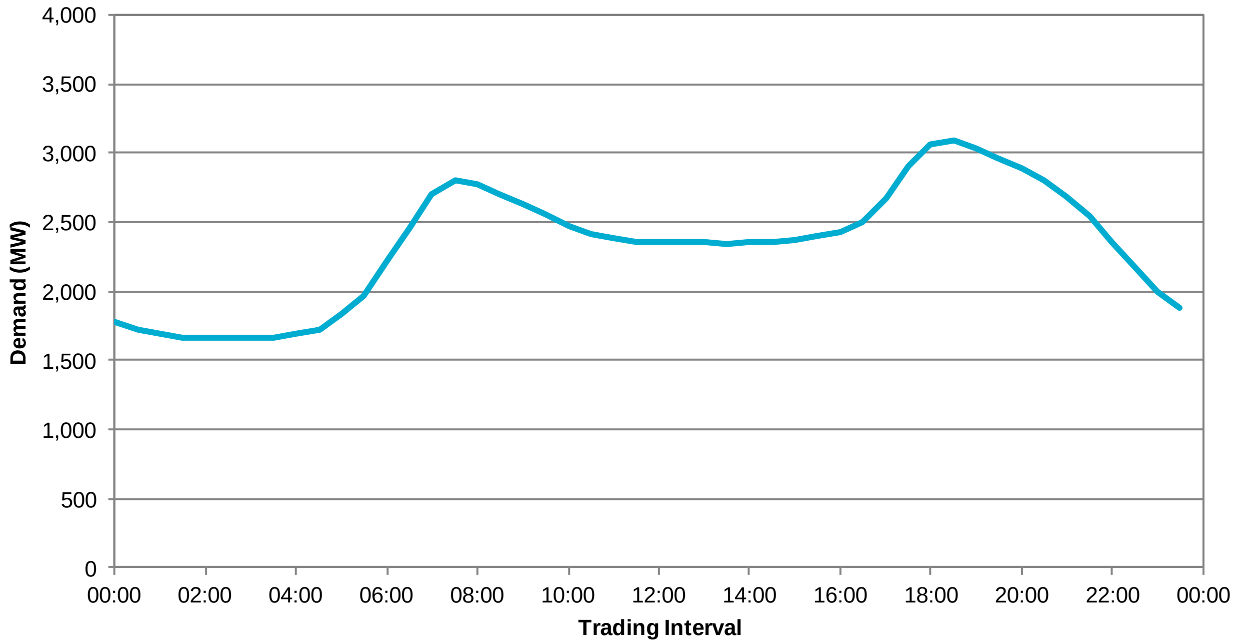


Figure IX – Average autumn profile

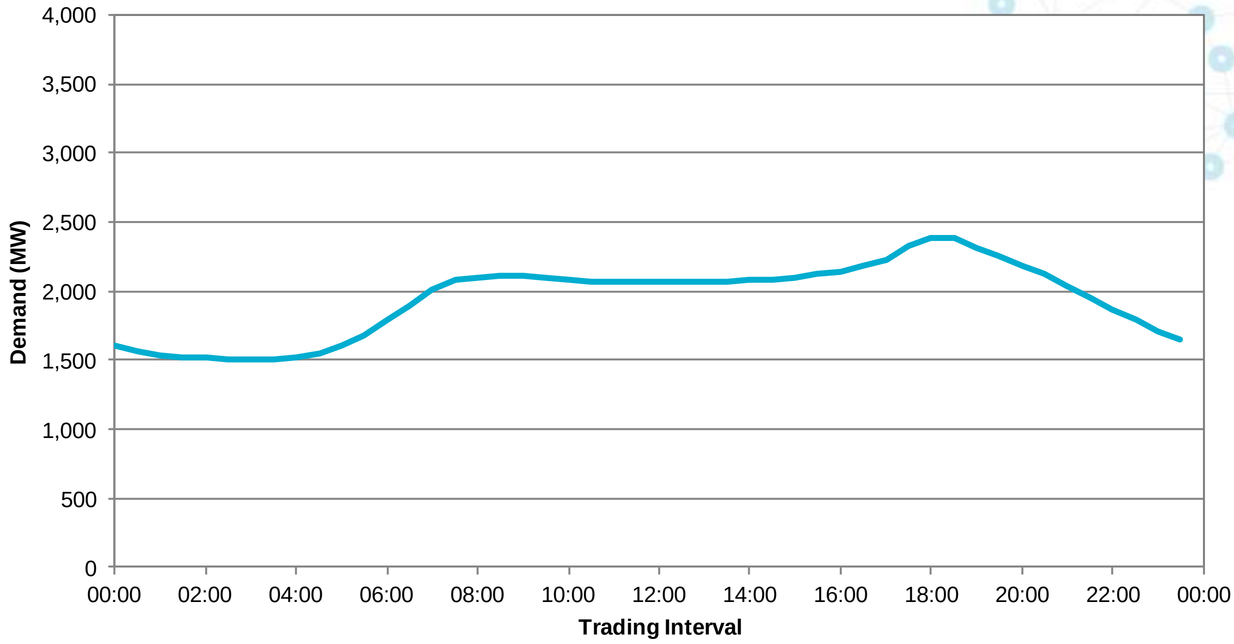
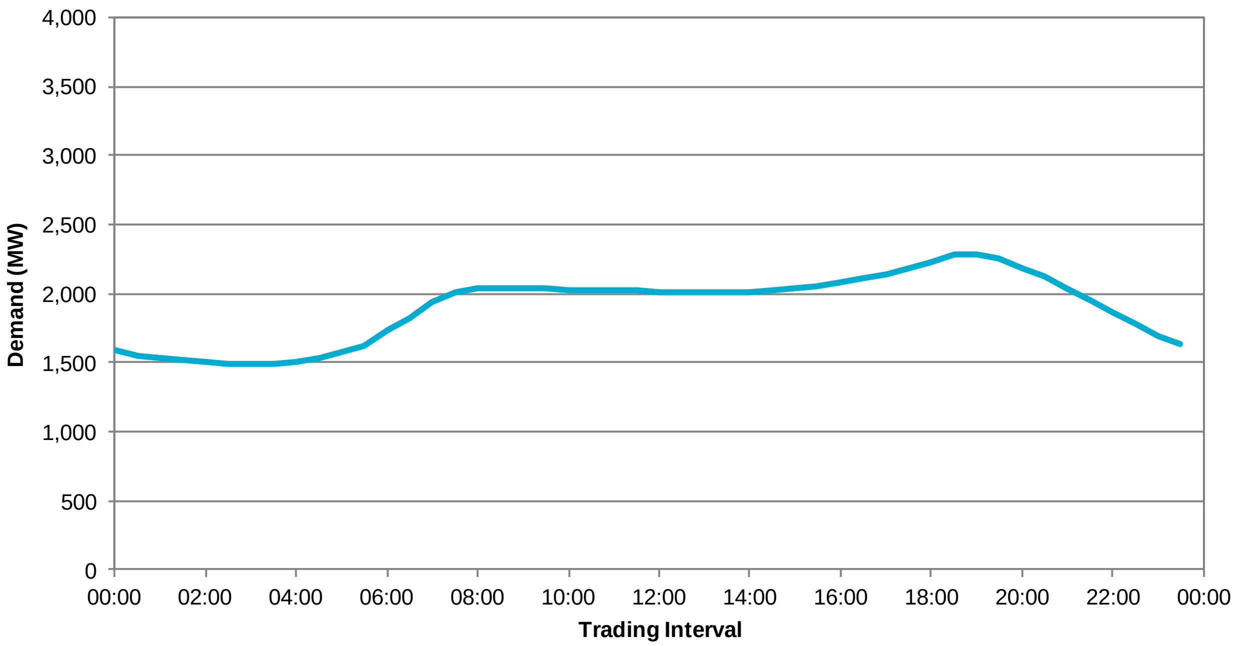


Figure X – Average spring profile



Appendix 11 Determination of Availability Curve

The Availability Curve ensures that there is sufficient capacity at all times to satisfy both elements of the Planning Criterion (10% PoE peak demand + Margin and 0.002% Unserved Energy), as well as ensuring that sufficient capacity is available to satisfy the criteria for evaluating Outage Plans.

Assuming that the Reserve Capacity Target is just met, the Availability Curve indicates the minimum amount of capacity required to be provided by generation capacity to ensure that the energy requirements of users are satisfied. The remainder of the Reserve Capacity Target can be met by further generation capacity or by DSM.

The determination of the Availability Curve follows the following steps, consistent with clause 4.5.12 of the Market Rules.

1. A load curve is developed from the average of the annual load curves from the last five years. The shape of this average load curve would be expected to approximate a 50% PoE demand profile, so it is then scaled up to match the 50% PoE peak demand and expected energy consumption forecasts for the relevant year. The peak demand interval is then set at the 10% PoE forecast.

   Experience from the most recent year with a 10% PoE peak demand event in the SWIS (2003/04) indicates that the 50% PoE load level was exceeded for less than 24 hours. Consequently, the Availability Curve from the 24th hour onwards would be the same irrespective of whether the 50% PoE peak demand forecast or 10% PoE peak demand forecast was used for the peak interval.

2. The reserve margin is added to the load curve (including the allowances for frequency keeping and Intermittent Loads) to form the Availability Curve. The capacity required for more than 24 hours per year, 48 hours per year and 72 hours per year is determined from this curve (clause 4.5.12(a)).

3. A generation availability curve is developed by assuming that the level of generation matches the Reserve Capacity Requirement for the relevant year, then allowing for typical levels of plant outages and for variation in the output of Intermittent Generators. For existing facilities, future outage plans (based on information provided by Market Participants under clause 4.5.4) are included in this consideration.

4. Generation capacity is then incrementally replaced by DSM capacity, while maintaining the total quantity of capacity at the Reserve Capacity Requirement until either the Planning Criterion or the criteria for evaluating Outage Plans is breached. If the Reserve Capacity Target has been set based on the peak demand criterion (10% PoE peak demand + Margin), then the minimum capacity required to be provided by generation ("Minimum Generation", clause 4.5.12(b)) will be the quantity of generation at which either:

   1. The total unserved energy equals 0.002% of annual energy consumption, thus breaching the Planning Criterion; or

   2. The spare generation capacity drops below 515 MW[95], thus breaching the criteria for evaluating Outage Plans.

The capacity associated with each Availability Class is then calculated from the capacity requirement curve and the Minimum Generation according to the method outlined in clause 4.5.12(c) of the Market Rules.

- Availability Class 4 is defined as the Reserve Capacity Requirement less the greater of the capacity required for more than 24 hours and the Minimum Generation;
- Availability Class 3 is defined as the Reserve Capacity Requirement less the greater of the capacity required for more than 48 hours and the Minimum Generation, less the capacity associated with Availability Class 4;

[95] The quantity required to provide Ancillary Services and satisfy the Ready Reserve Standard, consistent with the information published in the Medium Term Projected Assessment of Supply Adequacy (PASA) at http://www.imowa.com.au/mtpasa.html.

- Availability Class 2 is defined as the Reserve Capacity Requirement less the greater of the capacity required for more than 72 hours and the Minimum Generation, less the capacity associated with Availability Classes 3 and 4;
- Availability Class 1 is defined as the Reserve Capacity Requirement less the capacity associated with Availability Classes 2, 3 and 4.

The Availability Curves for the 2014/15, 2015/16 and 2016/17 Capacity Years are shown below.

Figure XI – Availability Curve 2014/15

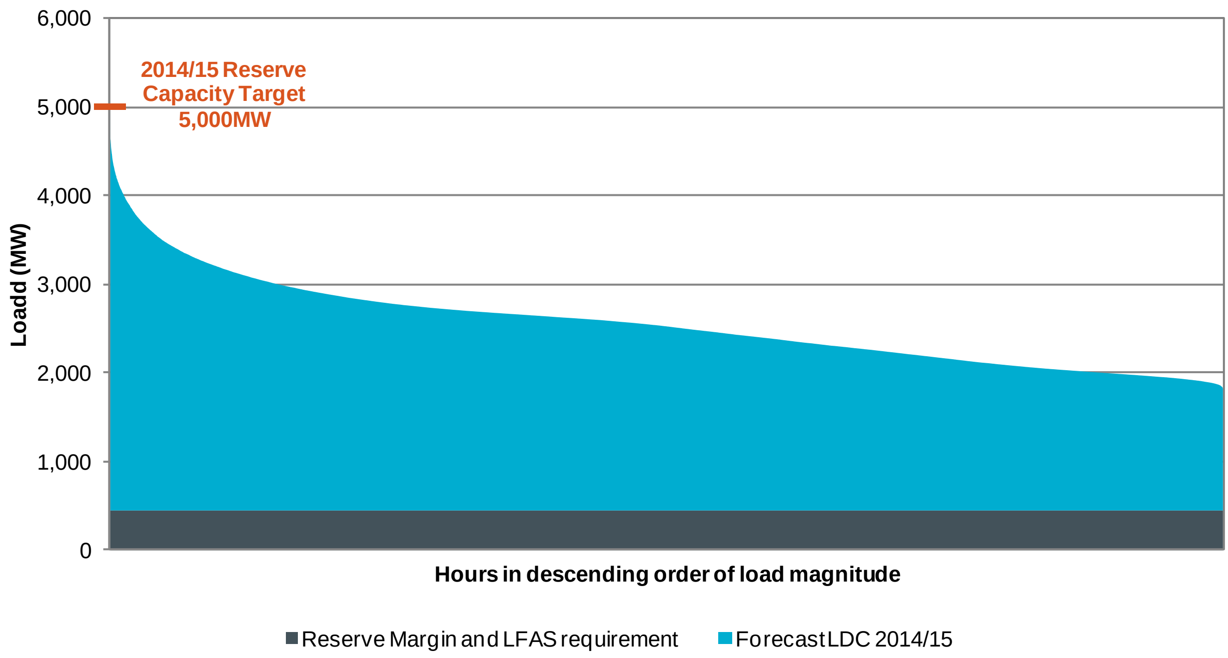


Figure XII – Availability Curve 2015/16

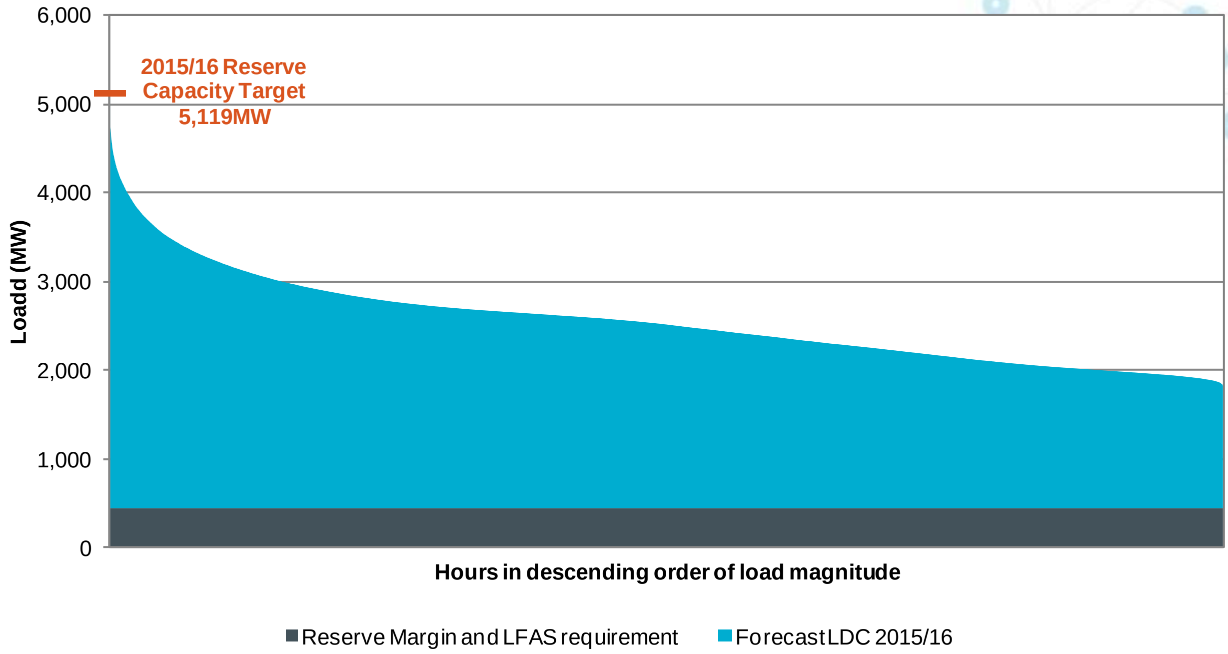
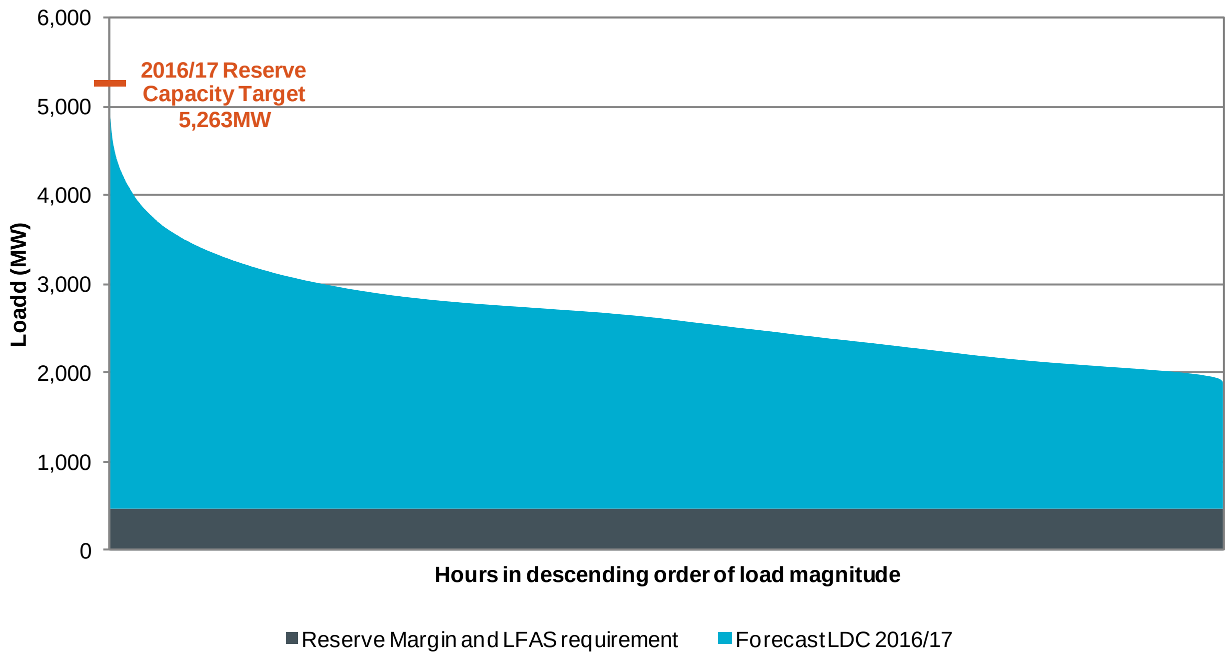


Figure XIII – Availability Curve 2016/17



Appendix 12 Facility Capacities

Table XV – Registered generation facilities – existing and committed

Participant Name	Facility Name	Capacity Credits (2014/15)
Alcoa of Australia	ALCOA_WGP	24
Alinta Sales	ALINTA_PNJ_U1	132.823
Alinta Sales	ALINTA_PNJ_U2	132.355
Alinta Sales	ALINTA_WGP_GT	179.063
Alinta Sales	ALINTA_WGP_U2	179.063
Alinta Sales	ALINTA_WWF	27.477
Blair Fox	BLAIRFOX_KARAKIN_WF1	1.366
Collgar Wind Farm	INVESTEC_COLLGAR_WF1	20.099
Denmark Community Windfarm	DCWL_DENMARK_WF1	1.276
EDWF Manager	EDWFMAN_WF1	22.353
Goldfields Power	PRK_AG	61.4
Greenough River Solar Farm	GREENOUGH_RIVER_PV1	5.856
Griffin Power	BW1_BLUEWATERS_G2	217
Griffin Power 2	BW2_BLUEWATERS_G1	215.9
Landfill Gas & Power	KALAMUNDA_SG	1.3
Landfill Gas & Power	RED_HILL	2.819
Landfill Gas & Power	TAMALA_PARK	3.877
Merredin Energy	NAMKKN_MERR_SG1	82
Mt. Barker Power Company	SKYFRM_MTBARKER_WF1	0.99
Mumbida Wind Farm	MWF_MUMBIDA_WF1	18.193
NewGen Neerabup Partnership	NEWGEN_NEERABUP_GT1	330.6
NewGen Power Kwinana	NEWGEN_KWINANA_CCG1	320
Perth Energy	ATLAS	0.69
Perth Energy	ROCKINGHAM	2.521
Perth Energy	SOUTH_CARDUP	2.496
Tesla Corporation	TESLA_GERALDTON_G1	9.9
Tesla Corporation	TESLA_KEMERTON_G1	9.9
Tesla Corporation	TESLA_NORTHAM_G1	9.9
Tesla Corporation	TESLA_PICTON_G1	9.9
Tiwest (Tronox)	TIWEST_COG1	32.618
Verve Energy	ALBANY_WF1	10.358
Verve Energy	COCKBURN_CCG1	231.8
Verve Energy	COLLIE_G1	317.2
Verve Energy	GERALDTON_GT1	15.4
Verve Energy	GRASMERE_WF1	6.148
Verve Energy	KALBARRI_WF1	0.279
Verve Energy	KEMERTON_GT11	145.5
Verve Energy	KEMERTON_GT12	145.5
Verve Energy	KWINANA_G5	177.5
Verve Energy	KWINANA_G6	184
Verve Energy	KWINANA_GT1	14.9
Verve Energy	KWINANA_GT2	95.2
Verve Energy	KWINANA_GT3	95.2
Verve Energy	MUJA_G5	195
Verve Energy	MUJA_G6	190
Verve Energy	MUJA_G7	211
Verve Energy	MUJA_G8	211
Verve Energy	MUNGARRA_GT1	33
Verve Energy	MUNGARRA_GT2	31.5
Verve Energy	MUNGARRA_GT3	31.4
Verve Energy	PINJAR_GT1	31.8
Verve Energy	PINJAR_GT10	108.7
Verve Energy	PINJAR_GT11	120
Verve Energy	PINJAR_GT2	30.4
Verve Energy	PINJAR_GT3	37

Participant Name	Facility Name	Capacity Credits (2014/15)
Verve Energy	PINJAR_GT4	37
Verve Energy	PINJAR_GT5	36.3
Verve Energy	PINJAR_GT7	36
Verve Energy	PINJAR_GT9	108.7
Verve Energy	PPP_KCP_EG1	80.4
Verve Energy	SWCJV_WORSLEY_COGEN_COG1	107
Verve Energy	WEST_KALGOORLIE_GT2	34.25
Verve Energy	WEST_KALGOORLIE_GT3	19
Vinalco Energy	MUJA_G1	55
Vinalco Energy	MUJA_G2	55
Vinalco Energy	MUJA_G3	55
Vinalco Energy	MUJA_G4	55
Waste Gas Resources	HENDERSON_RENEWABLE_IG1	2.291
Western Energy	PERTHENERGY_KWINANA_GT1	108

Table XVI – Registered DSM facilities – existing and committed

Participant Name	Facility Name	Capacity Credits (2014/15)	Availability (hr / year)
Alinta Sales	ALINTA_DSP_01	16.3	24
Amanda Australia	AMAUST_DSP_01	9.9	24
Amanda Australia	AMAUST_DSP_02	5	24
EnerNOC Australia	ENERNOC_DSP_01	92	24
EnerNOC Australia	ENERNOC_DSP_02	92	24
EnerNOC Australia	ENERNOC_DSP_03	92	24
EnerNOC Australia	KANOWNA_DSP_01	11	24
Griffin Power	GRIFFINP_DSP_01	20	48
Premier Power Sales	PREMPWR_DSP_01	10	24
Premier Power Sales	PREMPWR_DSP_02	23	24
Premier Power Sales	PREMPWR_DSP_03	3	24
Premier Power Sales	PREMPWR_DSP_04	3	24
Premier Power Sales	PREMPWR_DSP_05	2	24
Premier Power Sales	PREMPWR_DSP_07	3	24
Synergy	SYNERGY_DSP_01	10	32
Synergy	SYNERGY_DSP_02	5	32
Synergy	SYNERGY_DSP_03	5	32
Synergy	SYNERGY_DSP_04	42	48
Synergy	SYNERGY_DSP_05	20	32
Water Corporation	WATERCORP_DSP_01	20.5	24
Water Corporation	WATERCORP_DSP_02	17	24
Water Corporation	WATERCORP_DSP_03	22	24

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