INDEPENDENT
MARKET
OPERATOR

SWIS Electricity Demand Outlook

June 2014

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Executive summary

The SWIS Electricity Demand Outlook report presents peak demand and sent out energy forecasts for the Western Australian South West interconnected system (SWIS) between 2014-15 and 2023-24. The report also contains information about the development of the SWIS, from customer demand trends to the ongoing development of the Wholesale Electricity Market Rules (Market Rules).

Deferral of the 2014 Electricity Statement of Opportunities

In accordance with the Market Rules, the IMO usually publishes its annual Electricity Statement of Opportunities (ESOO) in June each year. The ESOO provides information on existing capacity and future electricity demand for current and potential participants in the Wholesale Electricity Market (WEM). The ESOO is a key process within the Reserve Capacity Mechanism – the mechanism through which the WEM secures sufficient capacity to meet peak demand – setting the capacity requirement for the relevant year of the Reserve Capacity Cycle.

On 29 April 2014, the IMO received a direction from the Minister for Energy to defer certain aspects of the 2014 Reserve Capacity Cycle. In light of this, the IMO has delayed publication of the 2014 ESOO and the setting of the Reserve Capacity Target for the 2016-17 Capacity Year until 17 June 2015.

This SWIS Electricity Demand Outlook report has been prepared by the IMO to provide updated electricity and peak demand forecasts for the period 2014-15 to 2023-24, for the information of current and potential participants in the WEM and other interested stakeholders.

Key findings

The key findings from this report are as follows:

- peak demand for 2013-14 was 3,702 MW, which occurred in the 5:30 pm to 6:00 pm trading interval on 20 January 2014;
- peak demand is forecast, under the 10 per cent probability of exceedance (PoE)[1], expected case forecast, to increase at an average annual rate of 2.1 per cent between 2014-15 and 2023-24;
- sent out energy is forecast, in the expected case, to grow at an average annual rate of 1.8 per cent between 2014-15 and 2023-24; and
- no new capacity will be required in the SWIS until 2023-24 on the 10 per cent PoE, expected case forecast (plus an indicative Reserve Margin).

In addition to the scenarios normally produced for the ESOO, the IMO has prepared a ‘high customer response’ scenario in this report. This is based on the 10 per cent PoE, expected case forecasts, and has been developed to explore the effect on peak demand of continued growth in customer demand response, through the Individual Reserve Capacity Requirement (IRCR) and installation of solar photovoltaic (PV) systems. Under this scenario, peak demand is forecast to grow at an average annual rate of 0.8 per cent between 2014-15 and 2023-24.

Recent trends in the SWIS summer peak demand

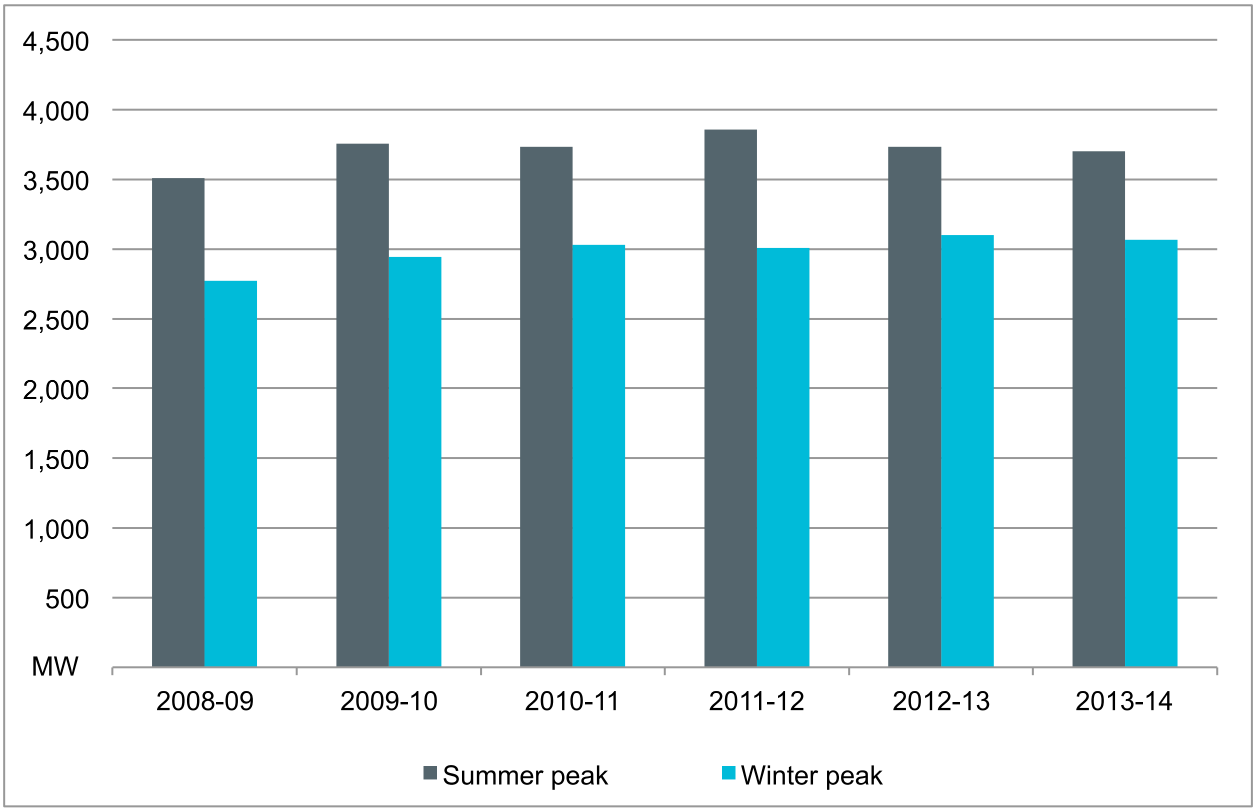
The SWIS is a summer peaking system, owing to high summer temperatures in the south west corner of Western Australia. Peak demand for 2013-14 was 3,702 MW, which occurred in the 5:30 pm to 6:00 pm trading interval on 20 January 2014, 0.9 per cent lower than 2012-13. Historically, peak demand in the SWIS has typically occurred in February, when commercial customers, schools and universities have returned from the summer break.

[1] The probability of exceedance relates to different weather scenarios. For example, the 10 per cent PoE is a forecast that is expected to be exceeded one in every ten years as a result of extreme weather events.

Demand on 20 January 2014 was lower during the day (8:00 am to 4:00 pm) compared to peak days in other years. The peak trading interval was also later (5:30 pm trading interval) than observed in previous years (4:00 pm or 4:30 pm trading intervals), largely because of the effect of solar PV generation offsetting demand during the afternoon.

Figure A shows the raw (that is, not weather adjusted) actual summer and winter peak demand between 2008-09 and 2013-14. Summer peak demand has grown at an average annual rate of 1.1 per cent over this period, while winter demand grew at an average annual rate of 2.0 per cent. The summer peak demand of 3,702 MW in 2013-14 is the lowest summer peak demand recorded since 2008-09. Varying weather conditions and other factors are expected to have affected recorded peaks, and these effects are explored further in this report.

Figure A: Historic summer and winter peak demand (raw), 2008-09 to 2013-14



Source: IMO

Western Australian growth context

According to the economic outlook taken into account in the forecasts, steady economic growth is likely over the outlook period. While it is unlikely that Western Australia's gross state product will continue to grow at rates as high as in the past five years (5.2 per cent on average), economic growth is forecast to average 3.5 per cent between 2013-14 and 2018-19. These figures are supported by the Western Australian Treasury in the 2014-15 State Budget[2].

Population in the SWIS is expected to grow at a similar rate to long-term historic growth, averaging 2.4 per cent a year between 2012-13 and 2018-19. This will support growth in electricity customer numbers in the SWIS.

[2] Source: Western Australian Department of Treasury, *2014-15 Budget: Economic and Fiscal Outlook,* available at: http://www.ourstatebudget.wa.gov.au/.

Customer behaviour and electricity demand

As electricity prices rise, customers are increasingly taking measures to reduce electricity consumption through technology and behaviour changes. Around 20,000 customers installed solar PV systems between 2012-13 and 2013-14, resulting in a total installed capacity of 336 MW in January 2014.

In addition to the growth in installed solar PV capacity, customer response to the IRCR mechanism remains strong. The effect of this on peak demand in 2013-14 was comparable to 2012-13, despite the system peak occurring at an unusual time. The number of customers who appear to have responded to the mechanism decreased by 15 in 2013-14, but the average reduction per customer was the same as in 2012-13 (1.1 MW). In 2012-13 and 2013-14, 91 unique customer loads have been identified as reducing demand in this way; if all of these customers respond in the same year at an average reduction of 1.1 MW each, the total reduction in system peak demand would be over 100 MW.

Average electricity use per household has fallen by 6.6 per cent between 2007-08 and 2012-13. This decline is largely a result of higher installation rates of energy efficient appliances, changes in behaviour to minimise electricity use (such as switching off lights in unoccupied rooms), or installing solar PV systems, partly in response to price increases since 2009. Rising electricity prices, coupled with decreasing costs of technology used to reduce electricity consumption, are expected to continue to dampen growth in electricity demand over the period to 2023-24.

Summary of the forecast

Table A shows the peak demand forecasts for the 10, 50 and 90 per cent PoE levels under the expected case economic growth assumptions. Peak demand is forecast to grow at an average annual rate of 2.1 per cent between 2014-15 and 2023-24 at the 10 per cent PoE. At the 50 and 90 per cent PoE levels, peak demand is forecast to grow at an average rate of 2.1 per cent and 2.0 per cent, respectively.

Table A: Peak demand forecasts for different weather scenarios, expected case

Scenario	2014-15 (MW)	2015-16 (MW)	2016-17 (MW)	2017-18 (MW)	2018-19 (MW)	5 year average annual growth	10 year average annual growth
10% PoE	4,352	4,469	4,588	4,699	4,817	2.6%	2.1%
50% PoE	4,046	4,151	4,260	4,362	4,470	2.5%	2.1%
90% PoE	3,827	3,925	4,027	4,122	4,225	2.5%	2.0%

Source: National Institute of Economic and Industry Research (NIEIR)

Table B shows the peak demand forecasts under the expected, high, and low economic growth scenarios at the 10 per cent PoE. As indicated above, peak demand is forecast to grow at an average annual rate of 2.1 per cent between 2014-15 and 2023-24 in the expected case. In the high and low cases, peak demand is forecast to grow at an average rate of 3.1 per cent and 1.8 per cent, respectively.

Table B: Peak demand forecasts for different economic growth scenarios, 10 per cent PoE

Scenario	2014-15 (MW)	2015-16 (MW)	2016-17 (MW)	2017-18 (MW)	2018-19 (MW)	5 year average annual growth	10 year average annual growth
High	4,390	4,521	4,666	4,804	4,946	3.0%	3.1%
Expected	4,352	4,469	4,588	4,699	4,817	2.6%	2.1%
Low	4,309	4,406	4,506	4,596	4,693	2.2%	1.8%

Source: NIEIR

Changes between forecasts

A new set of forecasts is generated annually to capture the latest historic data and any changes to growth assumptions. In some years, this has resulted in substantial changes between forecasts. The 2014 forecast presented in this report is lower than that presented in the 2013 ESOO, although the reduction in forecasts is smaller than in previous years. In particular, the 2014 10 per cent PoE peak demand forecast for 2014-15 is 209 MW lower than the forecast published in the 2013 ESOO.

The 2014 forecast includes updated assumptions that result in a reduction from previous forecasts, in particular:

- revisions to block load forecasts, reducing the 2014-15 forecast by 66 MW; and
- updated assumptions about growth in the temperature sensitive load, reducing the 2014-15 forecast by 154 MW.

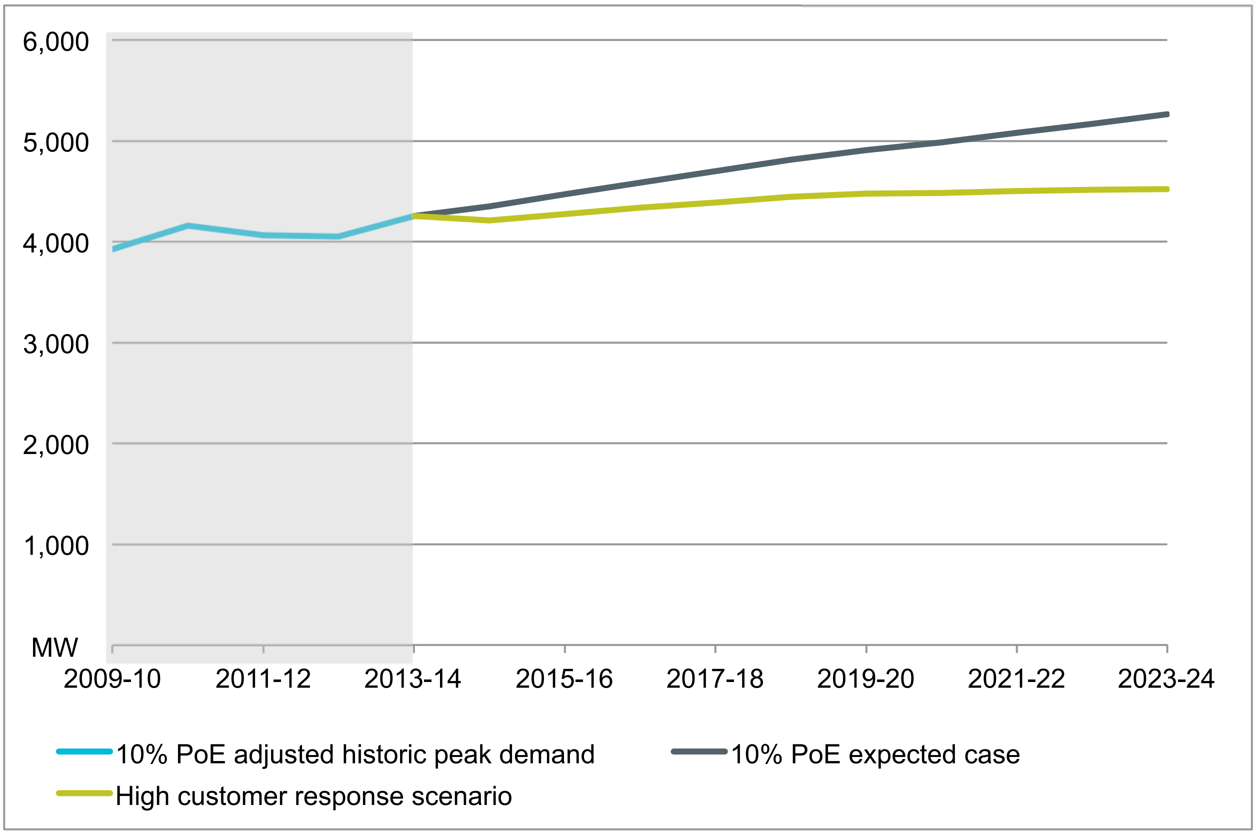
High customer response scenario

In light of the recent slowing of demand growth in the SWIS, the IMO has developed a high customer response scenario to indicate the possible range of peak demand growth over the forecast period. The additional scenario, which is based on the 10 per cent PoE and expected economic growth scenario, has been developed to explore the effect on peak demand of continued growth in customer demand response to the IRCR mechanism, and installation of solar PV systems.

This scenario accounts for higher than historically observed reductions in peak demand by customers attempting to avoid costs allocated through the IRCR mechanism. This scenario also assumes increased installation rates of solar PV systems and assumes 30 per cent of all customers have installed a solar PV system by 2023-24.

Figure B shows the 10 per cent PoE, high customer response scenario described in this section compared with the expected case forecast. In the high customer response scenario, average annual growth is comparable to short-term historic annual growth at 0.8 per cent between 2014-15 and 2023-24, compared to 2.1 per cent in the expected case forecast. By 2023-24, the high solar PV system uptake and IRCR response scenario results in 741 MW less demand in the SWIS than under the expected case assumptions.

Figure B: Peak demand, 10 per cent PoE, expected case and high customer response scenario, 2009-10 to 2023-24

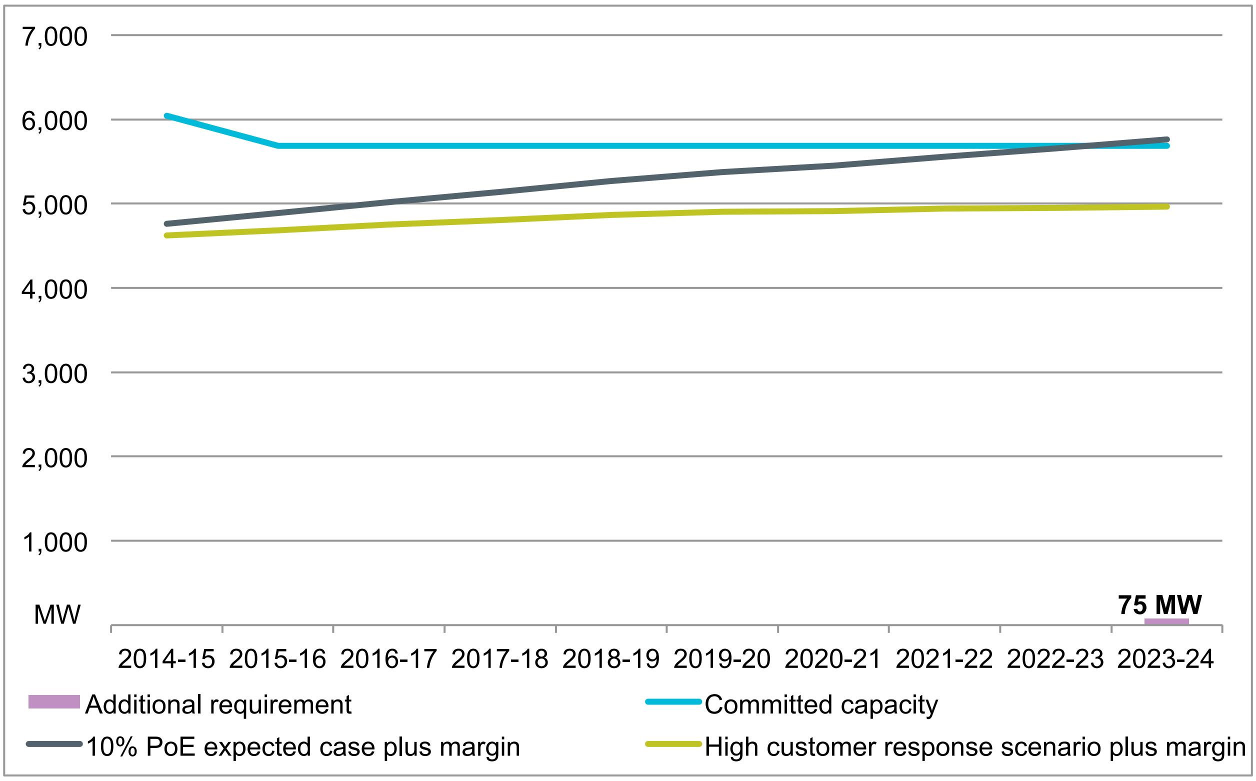


Source: IMO/NIEIR

Supply-demand balance

Figure C shows the supply-demand balance between 2014-15 and 2023-24, based on the 10 per cent PoE, expected case forecast and an estimated Reserve Margin[3], and the high customer response scenario plus an estimated margin. It is estimated that there will be around 1,280 MW of excess capacity in the SWIS in 2014-15. Excess capacity is expected to steadily decrease as peak demand increases, and reduces in 2015-16 with the planned retirement of the Kwinana Stage C facility.

Figure C: Supply-demand balance, 2014-15 to 2023-24



Source: IMO/NIEIR

Existing and committed capacity is expected to be sufficient to satisfy the 10 per cent PoE, expected case forecast until 2023-24, when an estimated 75 MW of new capacity is expected to be required. However, if the circumstances assumed in the high customer response scenario eventuate, no new capacity will be required during the outlook period.

[3] Includes an allowance for load following ancillary services, intermittent loads, and a 7.6 per cent margin to cover outages.

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1. Introduction

On 29 April 2014, the Independent Market Operator (IMO) received a direction from the Minister for Energy to defer certain aspects of the 2014 Reserve Capacity Cycle. In light of this, the IMO has decided to delay publication of the 2014 Electricity Statement of Opportunities (ESOO) and the setting of the Reserve Capacity Target for the 2016-17 Capacity Year until 17 June 2015.

More information on the Ministerial direction and the deferral of aspects of the 2014 Reserve Capacity Cycle is available from the IMO website[4].

This report presents the outlook for electricity peak demand and sent out energy for the South West interconnected system (SWIS) in Western Australia. It is intended to provide analysis and commentary about current and future trends in the SWIS for Market Participants, prospective investors, and other interested parties.

The structure of the report is as follows:

- chapter 2 provides an overview of electricity demand in the SWIS, including the system peak demand, load duration curves, load factor, and the daily demand profile;
- chapter 3 discusses some of the factors affecting customer demand, including economic growth, population, electricity prices, the Individual Reserve Capacity Requirement (IRCR), and solar photovoltaic (PV) systems;
- chapter 4 shows how the Wholesale Electricity Market (WEM) has evolved, and continues to evolve, since Market Start in 2005, including market diversification, structural changes, infrastructure developments, and other factors that may affect the future development of the market;
- chapter 5 presents the peak demand and energy forecasts between 2014-15 and 2023-24, and includes an explanation of the methodology, and a discussion of the factors affecting the forecasts, a separate forecast for uptake of solar PV systems, and presents a 'high customer response' scenario;
- chapter 6 reconciles actual data for 2013-14 with the forecast presented in the 2013 ESOO, and compares the forecasts in this report with forecasts in previous editions of the ESOO; and
- chapter 7 explains the Reserve Capacity Mechanism (RCM) in general, sets out the revised timeline for the 2014 Reserve Capacity Cycle, and discusses future opportunities for investing in capacity in the SWIS.

[4] Available at: http://imowa.com.au/reserve-capacity/reserve-capacity-timetable/reserve-capacity-timetable-overview.

2. Characteristics of the SWIS

This chapter gives an overview of the characteristics of the SWIS of Western Australia. The SWIS supplies electricity to around 1.1 million customers in a geographical area of 261,000 square kilometres, bordered by Kalbarri in the north, Kalgoorlie in the east, and Albany in the south. Being geographically isolated from the National Electricity Market (NEM), which supplies electricity in most of Australian states and territories, the SWIS must have enough generation and network capacity to supply all its electricity requirements.

Section 2.1 reviews the characteristics of the system peak, with particular emphasis on annual demand profiles and peak day demand profiles. Section 2.2 presents the load duration curve for the SWIS, and provides comparisons to the NEM. The daily demand profile is discussed in section 2.3.

2.1. System peak

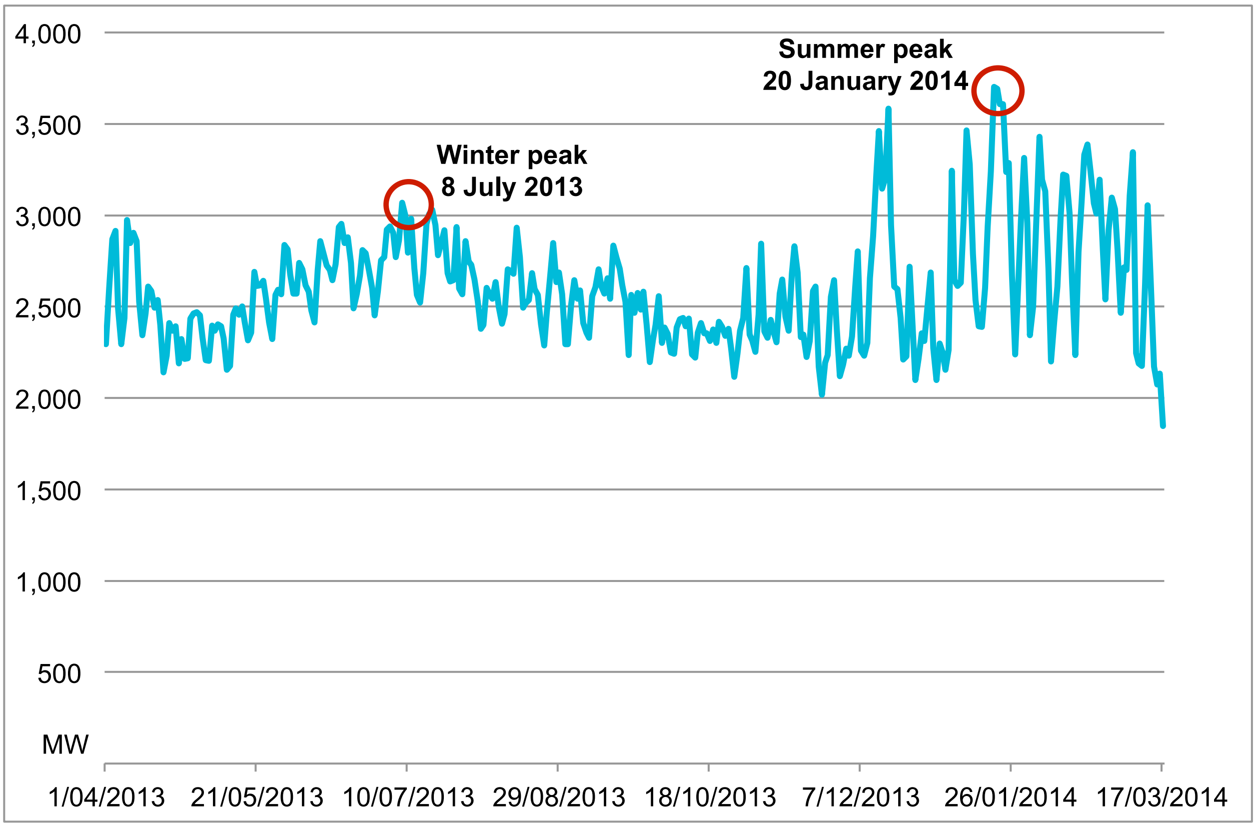
The SWIS is a summer peaking system, owing to high summer temperatures in the south west corner of Western Australia. In 2013-14, the summer peak was 3,702 MW, while the winter peak was 3,069 MW (year to date to March 2014).

Electricity demand varies substantially throughout the day, with overnight demand being much lower than daytime demand. Similarly, daily peak demand varies considerably throughout the year, ranging from less than 2,000 MW to over 3,700 MW on a weekday, depending on the temperature range. Daily peak demand is generally higher on business days than on weekends and public holidays, and is also generally higher during the school term than during school holidays. Typically, the peak demand is recorded when there is a sequence of four or more hot days (where the maximum temperature exceeds 35 degrees) coupled with high overnight temperatures.

2.1.1. Summer and winter demand

Figure 1 shows the daily raw (that is, not weather adjusted) peak demand between April 2013 and March 2014. The summer peak occurred in the trading interval between 5:30 pm and 6:00 pm on 20 January 2014, while the winter peak was observed in the 6:00 pm to 6:30 pm trading interval on 8 July 2013. The winter peak was about 630 MW lower than the summer peak during this period. While the summer peak is largely driven by air-conditioning load, the winter peak is largely driven by space heating load associated with cool temperatures. Increased use of lighting, as well as cooking equipment (which would normally also increase at this time), at 6:00 pm in winter compared to summer also contributes to the winter peak.

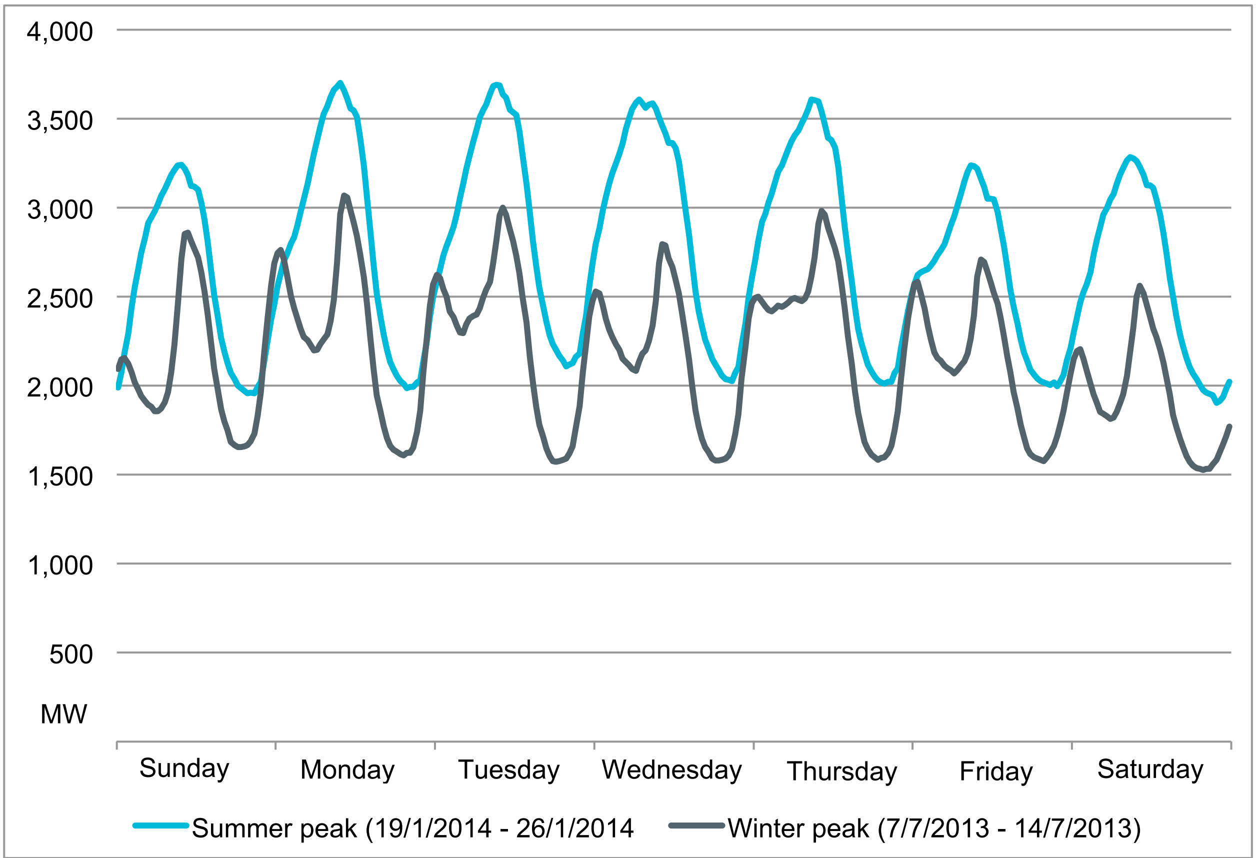
Figure 1: Daily peak demand (raw), April 2013 to March 2014



Source: IMO

Figure 2 shows the demand profile over the week of system peak for summer and winter. Winter days tend to show two peaks – one in the morning and another later in the evening. In contrast, demand tends to build during the day in summer and peaks in the late afternoon. Demand is higher during the week than on weekends, as commercial, industrial, and educational facilities are not generally operating over the weekend.

Figure 2: Demand profile over week of summer and winter peaks (raw), 2013-14



Source: IMO

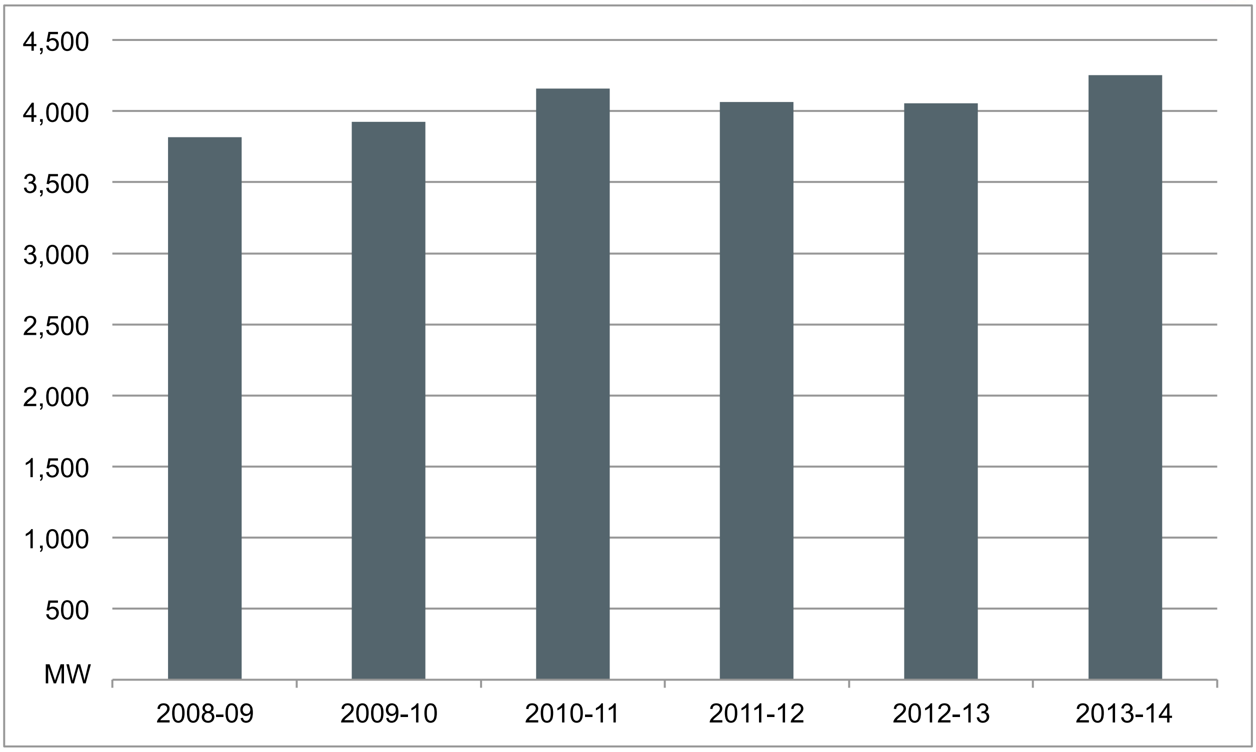
2.1.2. Summer peak demand

Average temperatures for the summer of 2013-14 were warmer than average, while weather on the day of peak demand for 2013-14 was relatively mild compared to previous years, particularly in the morning. The temperature built relatively slowly during the day, from 25.3 degrees at 8:00 am to 31.5 degrees at 10:30 am, and peaked at 2:30 pm. The maximum temperature on 20 January 2014 was 38.4 degrees, compared with maximum temperatures of up to 41.4 degrees on peak demand days in the previous five years.

The estimated weather adjusted peak demand was 5.2 per cent lower than the forecast peak. The 2013-14 peak occurred at a temperature around five degrees lower than would be expected on a 10 per cent probability of exceedance (PoE) day. The system peak was therefore lower than would have been observed if temperatures were closer to the 10 per cent PoE level. Another large proportion of the variance resulted from the peak demand occurring in January rather than February, when schools, universities and some commercial loads may not be operating. Slower than expected economic activity accounted for the remainder of the variance (see section 2.4 and chapter 6 below for more discussion on the summer peak demand).

Figure 3 shows the 10 per cent PoE adjusted historic summer peak demand between 2008-09 and 2013-13. During this period, summer peak demand grew from 3,818 MW in 2008-09 to 4,252 MW in 2013-14 at an average annual growth of 2.2 per cent. These figures have been adjusted to show the level of demand which would have been observed had a 10 per cent PoE weather event occurred on the day of system peak.

Figure 3: 10 per cent PoE adjusted historic summer peak demand, 2008-09 to 2013-14

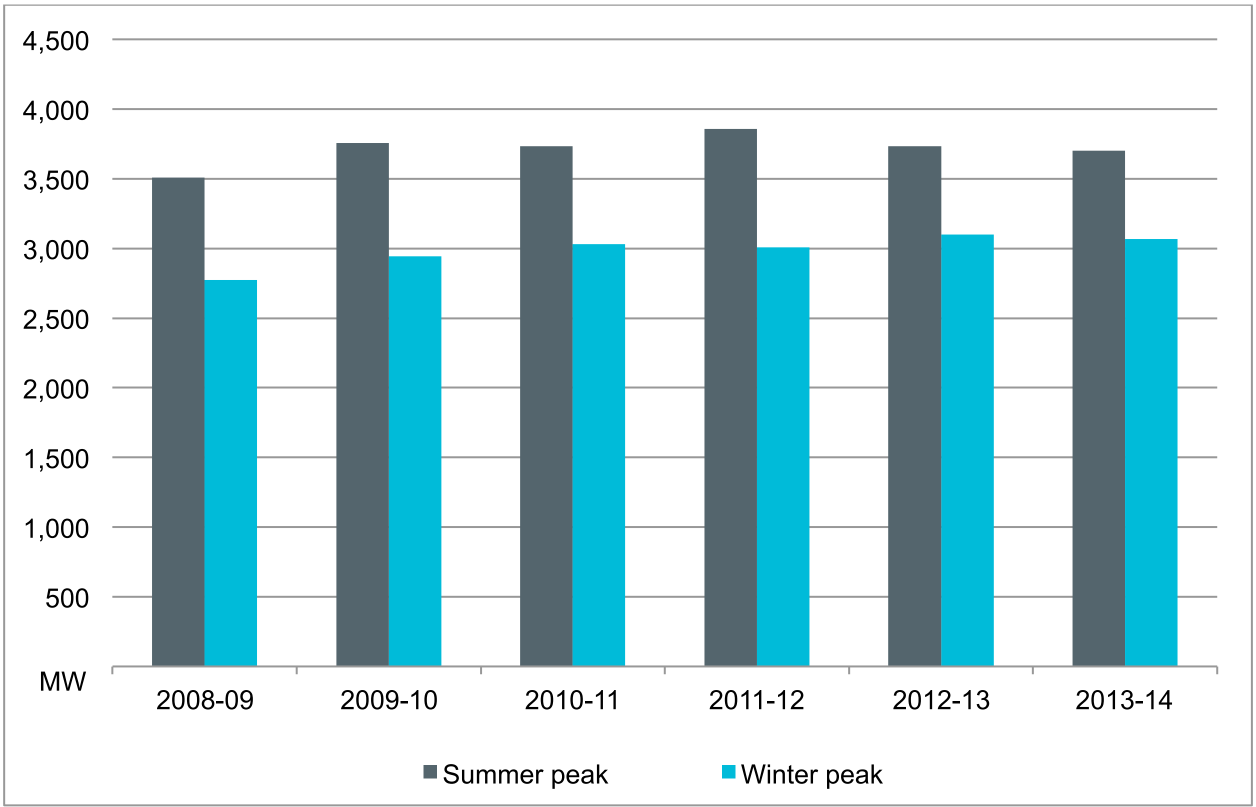


Source: NIEIR

2.1.3. *Winter peak demand growth*

Figure 4 shows the raw summer and winter peak demand between 2008-09 and 2013-14. Winter peak demand has consistently been below summer peak demand over this period, by between 560 MW and 760 MW. In 2012-13, the difference between the summer and winter peak was 788 MW; summer peak demand fell by 3.2 per cent, while winter peak demand grew by 3.0 per cent compared to 2011-12. The winter peak grew at an average annual rate of 2.0 per cent between 2008-09 and 2013-14, compared to summer peak growth of 1.1 per cent a year on average over the same period.

Figure 4: Summer and winter peak demand (raw), 2008-09 to 2013-14



Source: IMO

Increased penetration of reverse cycle air-conditioning units, which can be used to cool in summer and warm in winter, is believed to be largely responsible for higher growth rates in the winter peak compared with the summer peak. The penetration of reverse cycle air-conditioning systems among households with some form of cooling has increased from 41.6 per cent in 2005 to 54.4 per cent in 2011[5]. The Australian Bureau of Statistics (ABS) estimates that 14.2 per cent of Perth households do not have any form of heating.

According to the ABS, in 2011, 37.2 per cent of Perth households used electricity for space heating during winter, with the remainder using natural gas or wood[6]. Between 2005 and 2011, the proportion of electricity used for space heating in Western Australian households increased from 24.5 per cent to 35.9 per cent.

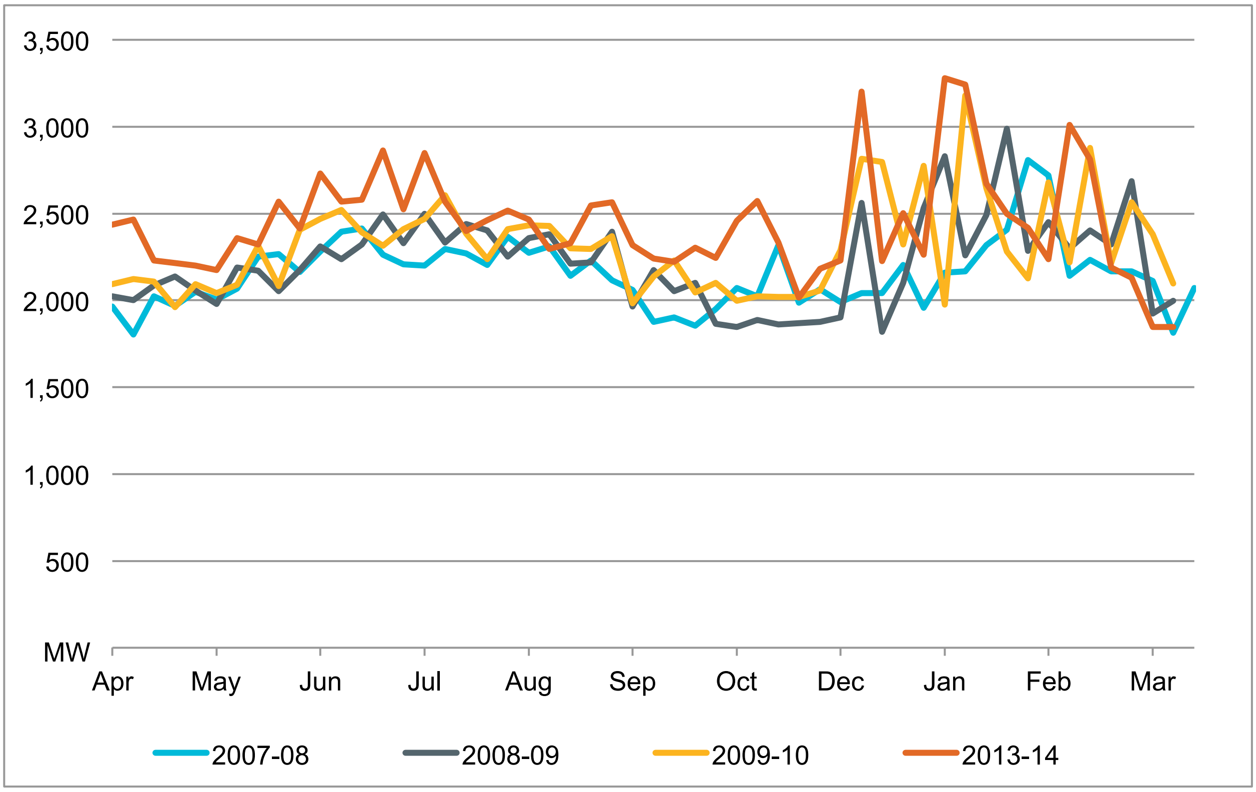
[5] Source: ABS, *Environmental Issues: Energy Use and Conservation, Mar 2011*, catalogue number 4602.0.55.001, available at: http://abs.gov.au/AUSSTATS/abs@.nsf/ProductsbyCatalogue/A38DDA7F40718E43CA25750E00112A97?OpenDocument.
[6] Source: ibid

2.1.4. The effect of Sunday trading on demand

Restrictions on retail trading hours have been gradually relaxed in Western Australia since 2010. In 2010, three special trading precincts in Joondalup, Armadale, and Midland were created (in addition to that already operating in Perth city and surrounding suburbs), which allowed retailers in these areas to open until 9 pm on weeknights, and for six hours on Sunday. Later the same year, general retail in the Perth metro area was permitted to open until 9 pm on weeknights, but not on Sundays (outside of the special trading precincts). On 26 August 2012, Sunday trading, as well as evening trade (until 9 pm) on weeknights, was allowed across the SWIS, and the special trading precincts were abolished.

Figure 5 shows peak demand on all Sundays in the years between 2007-08 and 2009-10 compared with peak demand on Sundays during 2013-14. On average, peak demand on Sundays in 2013-14 was 290 MW higher than Sundays during 2007-08. However, it is difficult to determine how much of this was caused by the introduction of Sunday trading, and how much was associated with other factors, such as weather or general demand growth.

Figure 5: Peak demand on Sundays, before and after the introduction of Sunday trading



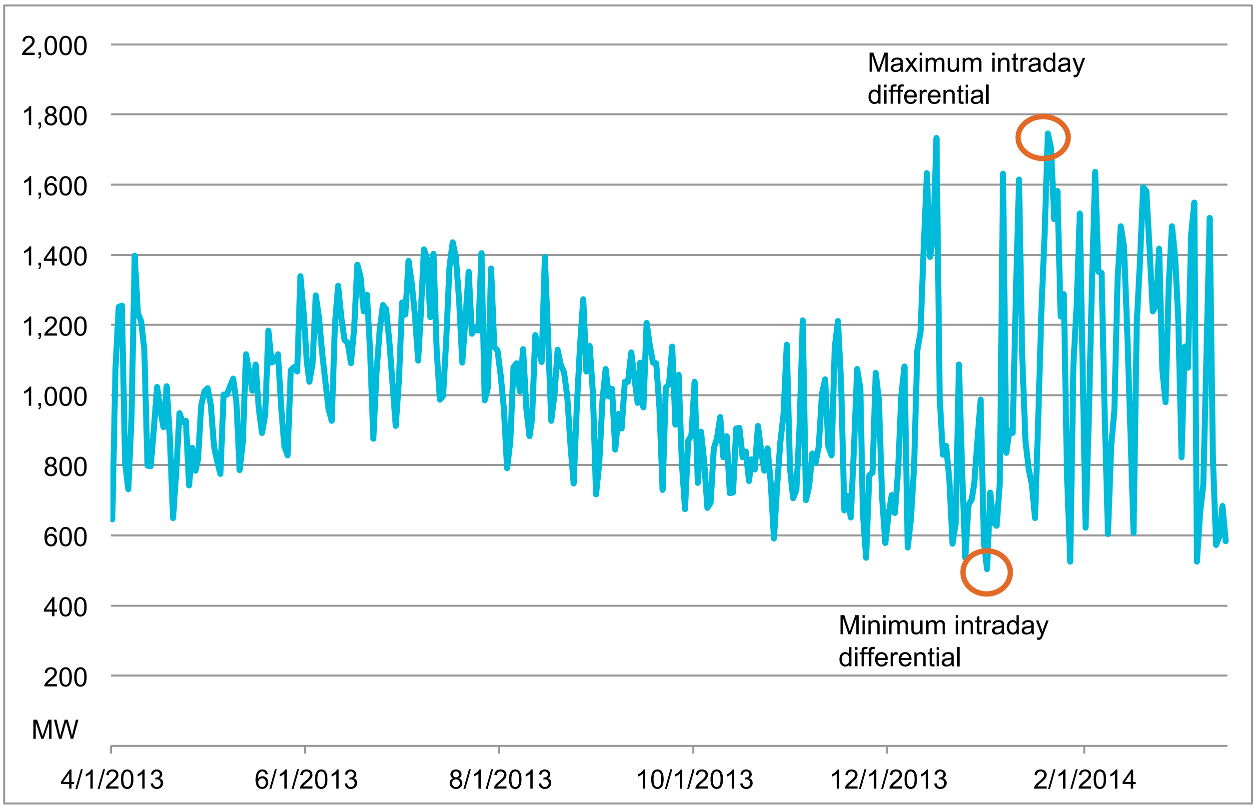
Source: IMO

2.1.5. Daily demand differentials

Figure 6 shows the daily demand differential, defined as the difference between daily maximum and minimum demand, from April 2013 to March 2014. The maximum demand differential was 1,745 MW on the annual peak demand day of 20 January 2014, when demand was between 1,957 MW and 3,702 MW. The lowest daily demand differential during this period was 504 MW on 1 January 2014, when demand was between 1,596 MW and 2,100 MW.

In summer, overall, the average demand differential was 1,045 MW, indicating that demand changes significantly during the day. However, demand during winter days tends to be more volatile, with demand differentials of around 1,133 MW on average. The differences between the summer and winter seasons is likely to be associated with weather patterns; overnight electricity use over summer, when temperatures are warmer, is generally higher than in winter.

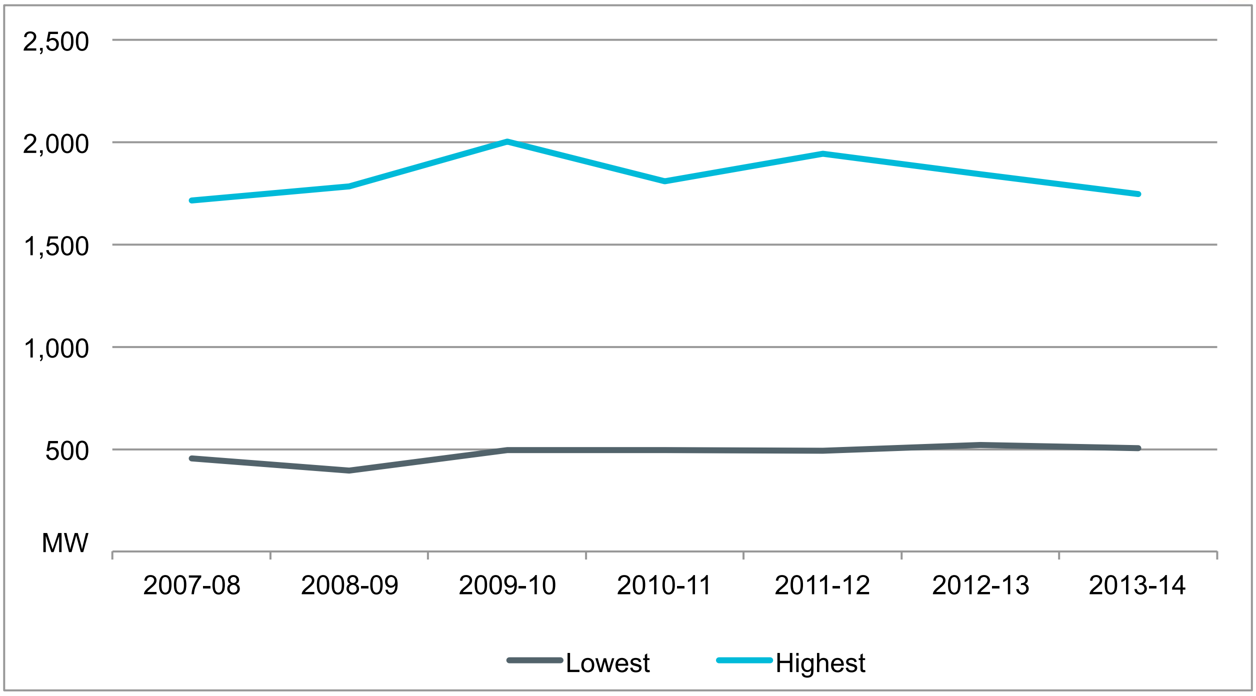
Figure 6: Daily demand differential, April 2013 to March 2014



Source: IMO

Figure 7 shows the annual maximum and minimum intraday demand differential between 2007-08 and 2013-14. The demand differential peaked in 2009-10, reaching 2,002 MW difference between the highest and lowest load on one day. The lowest demand differential was recorded in 2008-09 at 394 MW difference between the highest and lowest load in one day.

Figure 7: Intraday demand differential, 2007-08 to 2013-14



Source: IMO

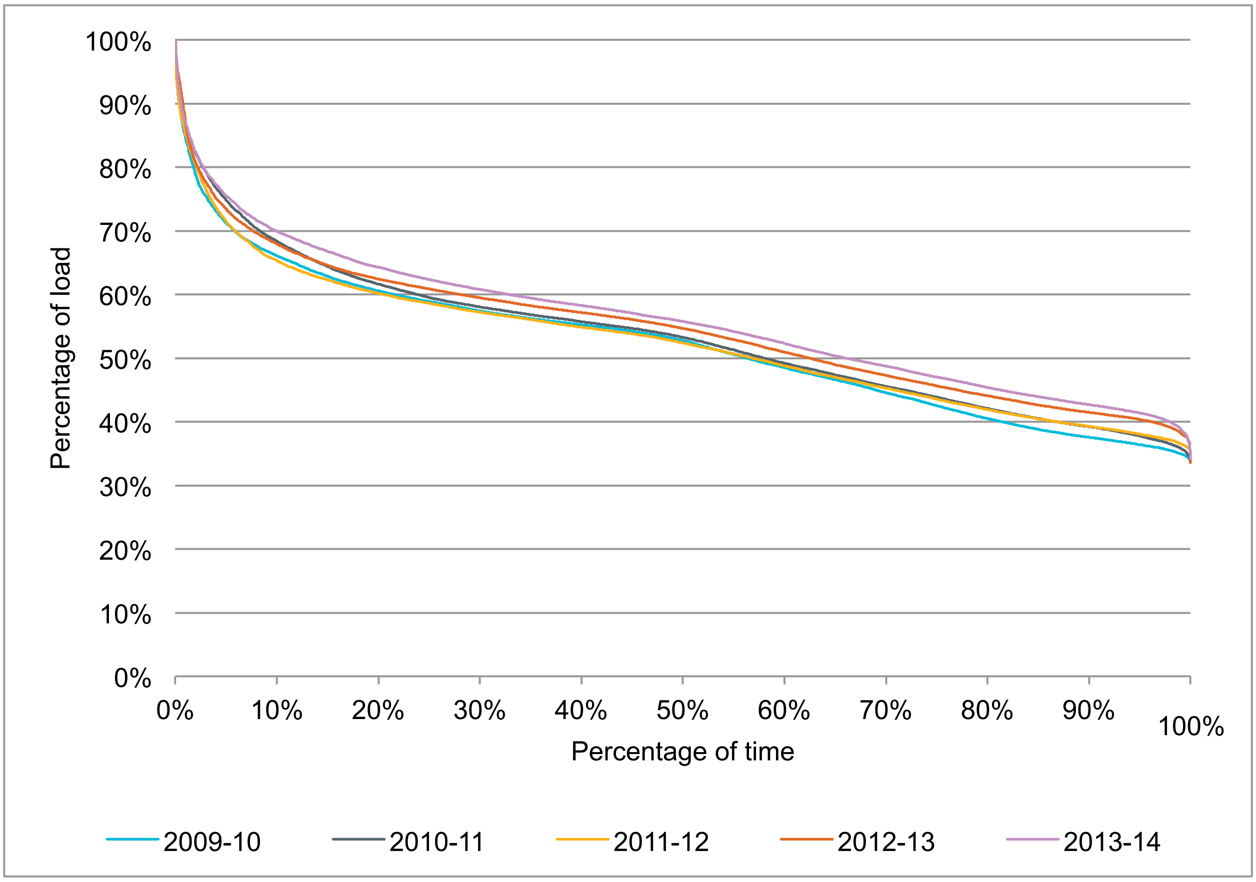
2.2. Load duration curves and load factor

2.2.1. Load duration curve

The load duration curve shows the variation in demand over time by graphing demand, in descending order, for each 30 minute trading interval. This shows the number of trading intervals for which a given level of demand is exceeded, and indicates the extremity of a system's peak. This can be used to determine the optimal mix of generation types, as different types of generation are best suited to different types of load. For example, peaking generators are best used for short periods during the year when demand is at its highest. This is because, while peaking generators are typically less expensive than base load generators to construct, the costs associated with running peaking generators tend to be higher.

Figure 8 shows the load duration curve for the WEM between 2009-10 and 2013-14 (where the year is defined as April to March). The load duration curve for the WEM in 2013-14 is similar to those from previous years. The SWIS is characterised by sharp summer peaks, which usually only occur for a few hours each year. Between 2009-10 and 2013-14, demand exceeded 90 per cent of the peak demand for between 0.5 and 0.7 per cent of the year (between 1.8 and 2.5 days). Over the same period, demand exceeded 80 per cent of the peak demand for between 2.0 and 3.0 per cent of the year (between 7 and 10 days).

Figure 8: Load duration curve, 2009-10 to 2013-14



Source: IMO

2.2.2. *National Electricity Market and Wholesale Electricity Market comparison*

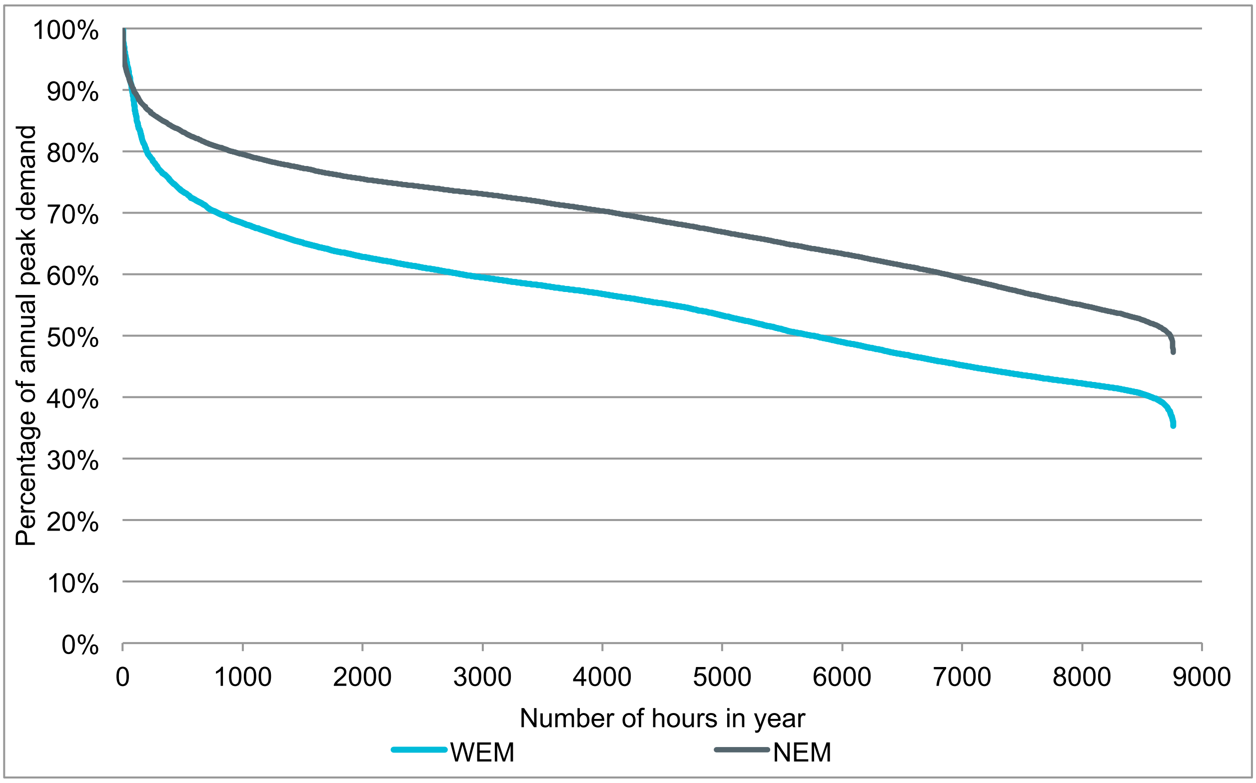
Figure 9 shows the load duration curve for the WEM and NEM for the 2013 calendar year. While both the NEM and WEM are characterised by a sharp summer peak, the curve for the NEM shows better capacity utilisation than for the WEM, where the minimum load in the NEM was 47 per cent of the peak demand, compared with a minimum load in the WEM of 35 per cent of the peak demand. The greater the variance between minimum and peak demand, the greater the requirement for mid-merit and peaking generation.

In 2013, demand in the WEM exceeded 80 per cent of the peak demand for 8 days, or 2.3 per cent of the year. Over the same period, demand in the WEM exceeded 75 per cent of peak demand for 17 days, or 4.6 per cent of the year.

For the NEM in 2013, demand exceeded 80 per cent of the peak demand for 38 days, or 10.4 per cent of the year and exceeded 75 per cent of the peak demand for 91 days, or 24.8 per cent of the year.

For the WEM, its demand volatility arises due to the high penetration of air-conditioning, variability of temperature (especially hot summer conditions) and the concentration of demand in a small geographical area; a hot day in Perth will affect the vast majority of customers in the SWIS. By contrast, the geographical spread of the NEM means that demand will usually peak in different regions at different times; an extremely hot day in Melbourne is unlikely to coincide with a similarly hot day in Sydney and Brisbane.

Figure 9: Load duration curve, WEM and NEM, 2013

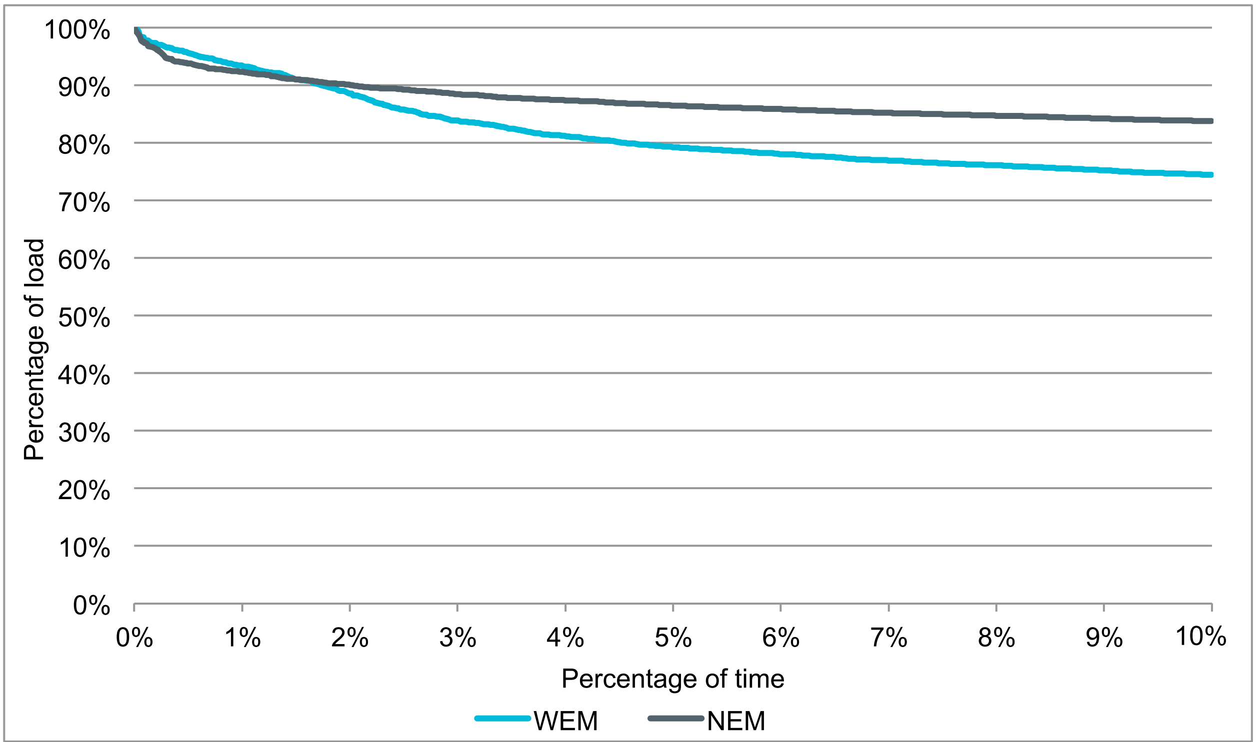


Source: IMO/Australian Energy Market Operator (AEMO)

Peaking generators are the most expensive type of generation to run, and place significant costs on the electricity market. These costs are then passed on to consumers in the form of higher prices. In addition to peaking generator costs, transmission and distribution networks must also have sufficient capacity to cater to peak demand. Reducing peak demand for a few days each year would decrease the amount of peaking generation and network capacity required, and, hence, costs.

Figure 10 shows the critical peak (the demand that is present for only 10 per cent, or about 36 days, of the year) for the NEM and WEM for the 2013 calendar year. For the WEM, 26 per cent of peak demand occurred for 10 per cent of the year, while in the NEM, 16 per cent of peak demand was required. Most of the generation used to supply this demand would be peaking plant.

Figure 10: Critical peak demand, WEM and NEM, 2013



Source: IMO/AEMO

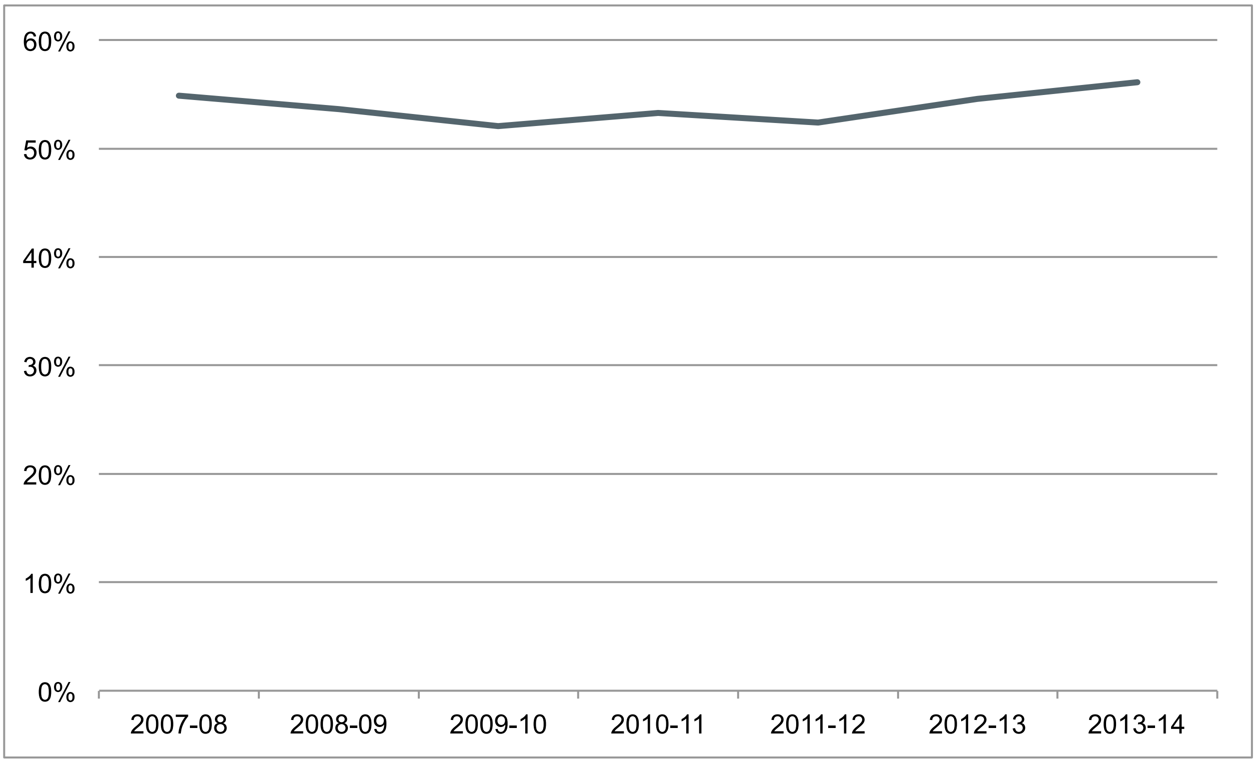
The above analysis and load duration curves suggest that the WEM experiences sharper peaks than the NEM.

2.2.3. *Load factor*

The load factor measures the consistency of electricity use over time, calculated as peak demand divided by average demand. A high load factor means the utilisation rate of generation and network assets is higher, and the system is subjected to fewer extreme peaks.

Figure 11 shows the annual load factor for the WEM for each year (1 April to 31 March) between 2007-08 and 2013-14. The load factor was 55 per cent in 2007-08 and fell to 52 per cent in 2011-12, before increasing again to 56 per cent in 2013-14. These trends were largely a result of average demand increasing at a slower rate than peak demand in 2008-09, 2009-10, and 2011-12. More recently, average demand has continued to increase at between 1 and 2 per cent in 2012-13 and 2013-14, while raw, non-weather adjusted peak demand declined by 1 per cent in 2013-14, which has led to the recent observed increase in load factor. However, this may be partly associated with a milder peak day than usual in 2013-14, coupled with peak demand occurring in January rather than February. Total energy use increased by 11 per cent between 2007-08 and 2013-14, while peak demand increased by 9 per cent over the same period (where a year is defined as 1 April to 31 March).

Figure 11: Load factor for year 1 April to 31 March, 2007-08 to 2013-14

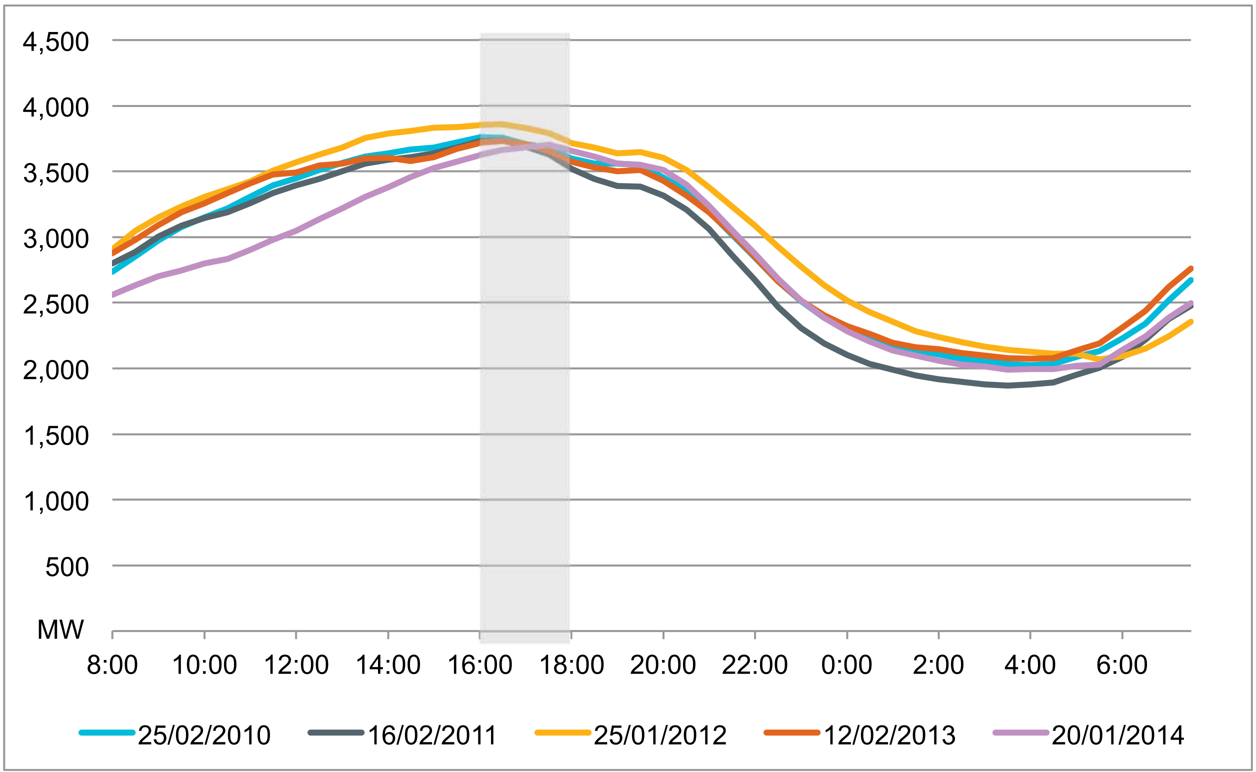


Source: IMO

2.3. Daily demand profile

Figure 12 shows the load profiles on peak demand days for the period 2009-10 to 2013-14. Demand on 20 January 2014 was lower during the day (8:00 am to 4:00 pm) compared to peak days in other years. The peak trading interval was also later (5:30 pm trading interval) than observed in previous years (4:00 pm or 4:30 pm trading intervals).

Figure 12: Daily load profiles for peak days, 2009-10 to 2013-14



Source: IMO

Weather on the day of peak demand for 2013-14 was relatively mild compared to previous years, particularly in the morning. The temperature built relatively slowly during the day, from 25.3 degrees at 8:00 am to 31.5 degrees at 10:30 am, and peaked at 2:30 pm. The maximum temperature on 20 January 2014 was 38.4 degrees, compared with maximum temperatures of up to 41.4 degrees on peak demand days in the previous five years.

The difference in load profiles between 2013-14 and previous years is partly associated with strong growth in installed solar PV system capacity, which reduces demand on the network, particularly during its peak generation times (around 10:00 am to 2:00 pm). This growth in solar PV system capacity has led to solar PV systems affecting demand during daylight hours more than in previous years. Generation from solar PV systems has also contributed to shifting the peak to the 5:30 pm to 6:00 pm trading interval. Without the solar PV systems, it is estimated that the 2013-14 peak demand would have been 3,755 MW in the 4:30 pm to 5:00 pm trading interval, 53 MW higher than that observed. Solar PV systems are discussed in more detail in sections 3.5 and 5.5.

Large customers managing exposure to IRCR costs have also contributed to lower peak demand in 2013-14, although less than the previous year. The IRCR mechanism allocates the costs of Capacity Credits to Market Customers by calculating their contribution to peak demand during 12 trading intervals;

three trading intervals on each of the four highest demand days of the previous hot season. Market Customers have an incentive to reduce these costs by reducing demand during these 12 trading intervals. Often, these Market Customers choose to reduce demand across the whole afternoon of a day they consider is likely to be a peak day (for example, a day where high temperatures have been forecast). The IRCR response is estimated to have reduced peak demand by around 50 MW in 2013-14. See section 3.4 for more detail on IRCR.

3. Customer demand in the SWIS

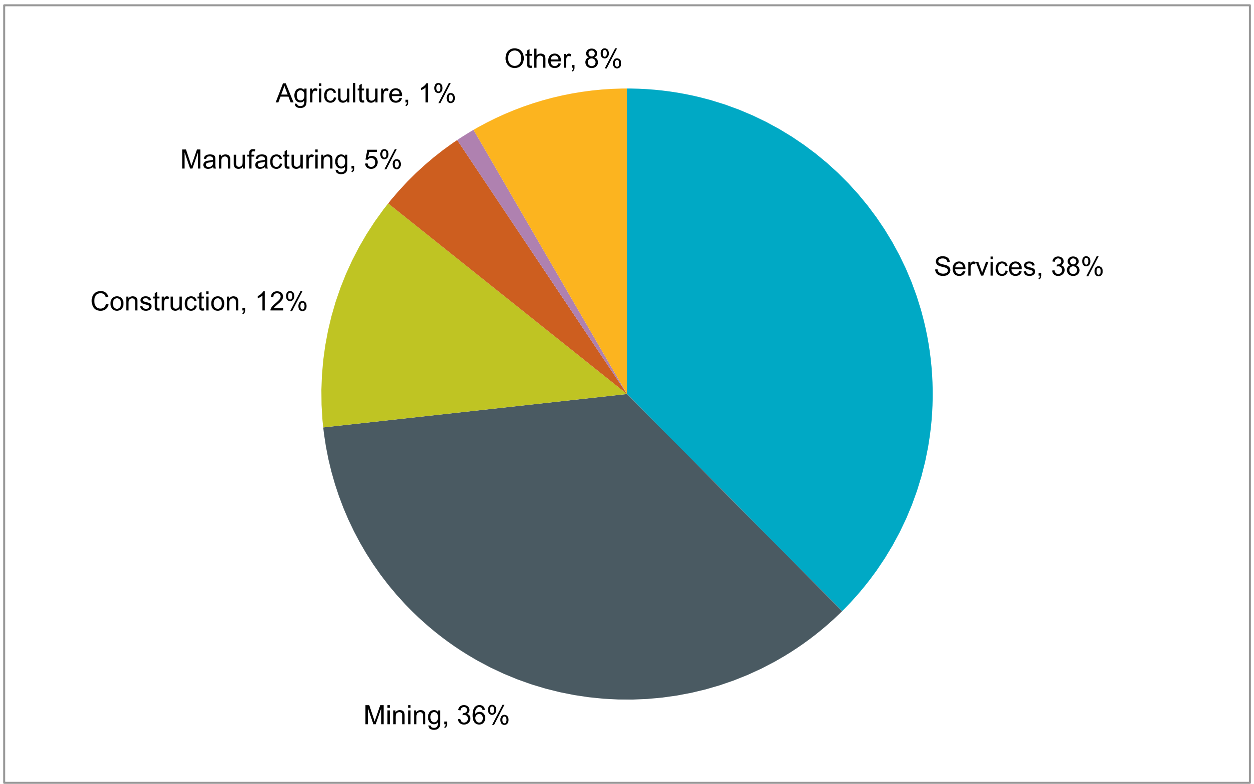
This chapter discusses some of the factors affecting customer demand for electricity, including economic growth, population, electricity prices, IRCR, and solar PV system generation (sections 3.1 to 3.5, respectively).

3.1. Economic growth

Electricity is an input into many production processes, especially manufacturing and mining. It is also integral to the service industries such as retail trade, health, and education. Thus, increasing economic activity is usually associated with an increase in electricity consumption.

Figure 13 shows the composition of the Western Australian economy based on industry gross value added in 2012-13. The mining and services industries contribute the most to gross value added, while construction, manufacturing and agriculture make up smaller proportions. The ‘other’ category includes the utilities sector, as well as gross value added from dwelling ownership. The services sector includes accommodation, education, retail and wholesale trade, transport, telecommunications, finance and insurance services, and real estate services, as well as other categories.

Figure 13: Share of industry gross value added, by sector, 2012-13



Source: ABS[7]

The mining and services sectors are also the fastest growing parts of the Western Australian economy. As shown in Table 1, the mining industry grew by 11 per cent in 2012-13, while the services sector grew

[7] Source: ABS, *Australian National Accounts: State Accounts, 2012-13*, catalogue number 5220.0, available at: http://abs.gov.au/AUSSTATS/abs@.nsf/ProductsbyCatalogue/E6765105B38FFFC6CA2568A9001393ED?OpenDocument.

at 4 per cent. In the services sector, the largest increases in gross value added in 2012-13 were observed in the rental, hiring, and real estate (10 per cent), administration and support (9 per cent), health care and social assistance (7 per cent), retail trade (6 per cent), and professional, scientific, and technical (6 per cent) services subsectors. The agricultural industry contracted by 44 per cent in 2012-13 as a result of a drought in the main agricultural regions of the state. Output from the agriculture sector is largely determined by rainfall – the latest seasonal outlook from the Bureau of Meteorology suggests that a wetter season is more likely for Western Australia in 2013-14, which should support agricultural output increasing.

Table 1 shows growth rates in some of the key economic indicators for the Western Australian economy between 2008-09 and 2012-13. State final demand, a measure of all domestic consumption, grew at an average annual rate of 6.7 per cent over the past five years, mainly associated with strong growth in business investment in the mining sector. Gross state product (GSP), which measures all of the state's output (including net exports), grew at an average annual rate of 5.2 per cent between 2008-09 and 2012-13.

Growth in total industry gross value added was in line with GSP at an average of 5.4 per cent a year, with some industries growing at a faster rate. The mining and electricity, gas, water and waste services industries showed the strongest growth at an average annual rate of 9.3 per cent and 5.4 per cent, respectively, between 2008-09 and 2012-13. Output in the agriculture industry declined over the same period, however as noted above agricultural output is dependent on water availability, and can fluctuate between years according to rainfall.

Table 1: Growth in key economic indicators, 2008-09 to 2012-13

	2008-09 (%)	2009-10 (%)	2010-11 (%)	2011-12 (%)	2012-13 (%)
State final demand	4.0	2.7	5.3	14.2	5.2
Net exports	0.6	14.0	3.2	-1.3	14.7
GSP	4.3	4.2	4.1	7.3	5.1
Industry gross value added	4.7	4.5	4.0	8.4	4.7
- Agriculture	27.2	-6.4	-38.2	35.6	-43.7
- Mining	4.5	10.1	7.0	9.0	11.1
- Manufacturing	1.9	-0.7	5.9	8.2	1.5
- Electricity, gas, water and waste services	2.4	5.0	10.2	9.0	-2.2
- Construction	5.3	0.9	0.9	17.6	-0.6
- Services	3.7	3.4	4.4	4.9	4.1

Source: ABS

3.2. Population

Western Australia's population increased at an average annual rate of 2.9 per cent between 2002-03 and 2012-13. Growth has been evenly distributed between the SWIS and the rest of Western Australia, with the SWIS maintaining a 94 per cent share of the total Western Australian population[8]. This strong growth in population has resulted in increasing demand for housing, which in turn has increased electricity consumption through increased housing occupancy rates.

Completion of new dwellings has been fairly stable over the past ten years at between 15,000 and 20,000 new dwellings per year[9]. New dwelling completion peaked at 21,000 in 2006-07. Compared to the

[8] Source: ABS, *Regional Population Growth, Australia, 2012-13*, catalogue number 3218.0, available at: http://abs.gov.au/AUSSTATS/abs@.nsf/ProductsbyCatalogue/797F86DBD192B8F8CA2568A9001393CD?OpenDocument.

[9] Source: ABS, *Building Activity, Australia, Dec 2013*, catalogue number 8752.0, available at: http://abs.gov.au/AUSSTATS/abs@.nsf/ProductsbyCatalogue/4FB5ACFC0074529ECA2576B00017C434?OpenDocument.

previous decade (1992-93 to 2002-03), dwelling completions increased by 18.4 per cent over the 10 years to 2012-13.

Table 2 shows key data for SWIS residential customers (defined as customers paying the A1 residential tariff or the SM1 SmartPower residential time of use tariff) between 2007-08 and 2012-13. Customer numbers, a proxy for growth in the occupied housing stock, have increased at an annual average rate of 1.9 per cent over this period. However, electricity sales grew at only 0.2 per cent a year on average, and fell by 7.4 per cent between 2010-11 and 2011-12, despite increases in the occupied housing stock. Average electricity use per household has fallen by 8.7 per cent, from 6,134 kWh in 2007-08 to 5,598 kWh in 2012-13. The recent decline in residential electricity sales and average use per household is largely a result of price increases since 2009 (see section 3.3). Increasing prices have driven consumers to reduce electricity consumption by installing more energy efficient appliances, installing a solar PV system, or changing behaviour (for example, switching off lights in unoccupied rooms) to reduce electricity bills.

Table 2: Key statistics for residential customers, 2007-08 to 2012-13

	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13	Average annual growth
Number of customers	812,177	832,192	845,511	873,701	893,750	899,356	2.1%
Residential electricity sales (GWh)	4,982	5,102	5,349	5,403	5,005	5,035	0.2%
Average annual household consumption (kWh)	6,134	6,131	6,326	6,184	5,600	5,598	-1.8%

Source: Synergy

Regulations are now in place to mandate a minimum energy efficiency requirement for new dwellings, as well as new commercial buildings. Therefore, newer housing stock will be, on average, more energy efficient than older stock. This is expected to limit growth in energy consumption over the long term, rather than cause immediate falls in energy consumption.

3.3. Electricity prices

Retail electricity prices for small use, non-contestable customers, including households and businesses who use 50 MWh of electricity a year or less, are regulated by the Western Australian Government. These customers do not have a choice of retailer and must be supplied by Synergy. Contestable customers, who use more than 50 MWh of electricity a year, are able to choose a retailer and negotiate their prices, although customers consuming between 50 MWh and 160 MWh a year are able to choose to be supplied at the standard capped rates offered by Synergy rather than negotiating a deal with a retailer of their choice.

Regulated tariffs have risen by around 86 per cent for residential customers and up to 70 per cent for commercial customers since 2009 (based on usage charges expressed in cents per kWh). Before this, prices had not increased since the early 1990s, resulting in falling real prices for more than 10 years. Prices are projected to continue to increase as the Government seeks to charge electricity users fully cost-reflective tariffs[10].

Although electricity has traditionally been considered to be relatively price inelastic (a one per cent increase in prices results in a fall in consumption of less than one per cent), some of the recent reduction in energy consumption has been attributed to the price rises observed since 2009. Many of the effects of

[10] Source: Western Australian Department of Treasury, *2014-15 Budget: Economic and Fiscal Outlook,* available at: http://ourstatebudget.wa.gov.au/.

price increases are long-term, as households replace older appliances with newer, more efficient models, or substitute to other sources of energy (for example, replacing an electric stovetop with a gas one).

Price rises are also expected to lead to more consumers installing solar PV systems to offset some or all of their consumption. Between January 2011 and January 2014, total installed PV capacity grew from 63 MW to 336 MW (see section 3.5 below for more detail), encouraged by rising prices as well as various government incentives. Assuming no change in the structure of electricity tariffs, rising prices and falling costs for solar PV systems are expected to continue to drive households' investment in solar PV systems.

As electricity prices increase, more households are expected to purchase more efficient appliances when older, less efficient models are due for replacement. The ABS' Energy Use and Conservation survey found that, of the Australian households that bought new appliances, around half cited the star rating of the appliance as a factor in their purchase decision in 2011, compared to around 40 per cent in 2005[11]. This increasing concern about energy efficiency is likely to have been caused in part by rising electricity prices, particularly since 2009, which has encouraged households to seek ways to reduce electricity consumption.

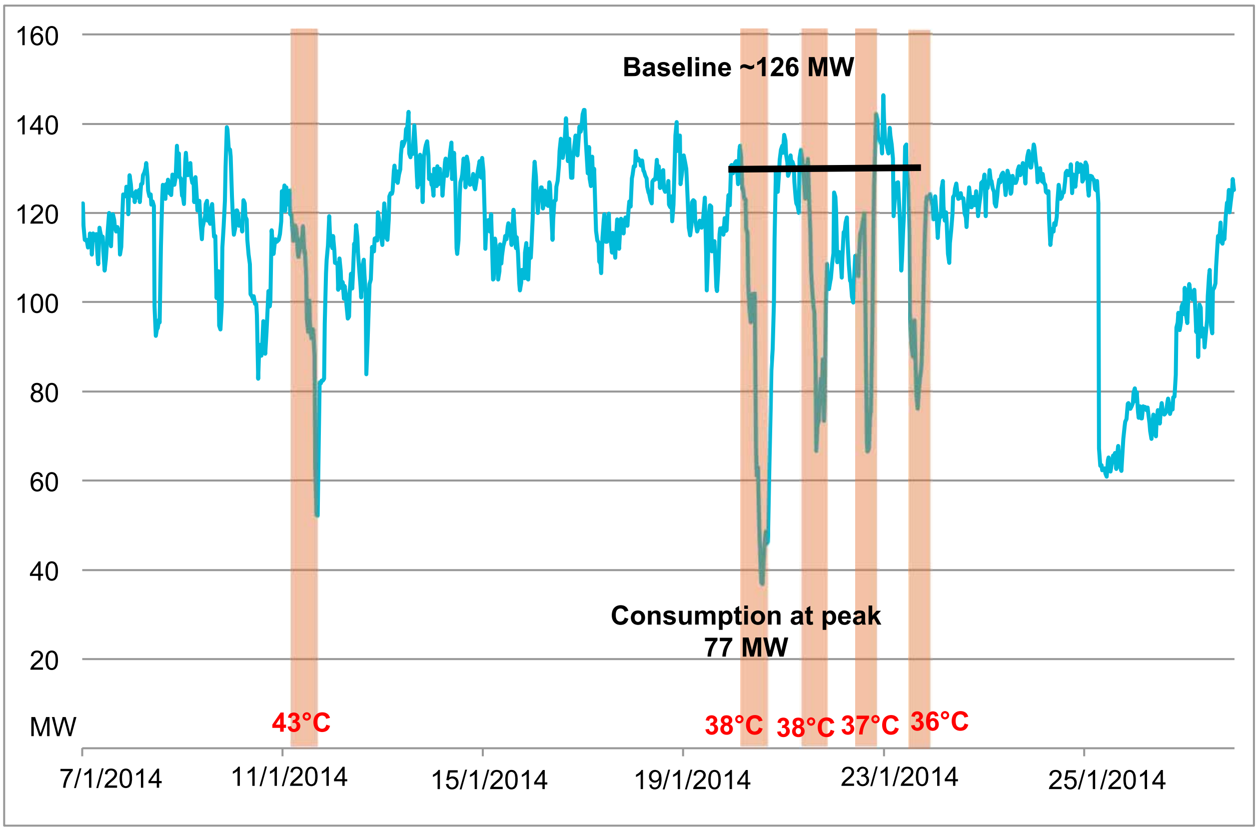
3.4. Individual Reserve Capacity Requirement

The IRCR is a quantity of capacity (in MW) which is based on a Market Customer's contribution to the total system load at peak times. This allows the cost of the Capacity Credits that are acquired through the RCM to be allocated to Market Customers. Customers exposed to the IRCR mechanism have an incentive to reduce consumption at times of system peak to minimise their contribution to funding capacity in the SWIS.

[11] Source: ABS, *Environmental Issues: Energy Use and Conservation, Mar 2011*, catalogue number 4602.0.55.001, available at: http://abs.gov.au/AUSSTATS/abs@.nsf/ProductsbyCatalogue/A38DDA7F40718E43CA25750E00112A97?OpenDocument.

Figure 14 shows the IRCR response of the 44 most responsive loads during January 2014. These 44 customers were filtered from a database of around 900 customers identified as likely to reduce consumption in this manner. The red shaded areas on the graph show the afternoons of the five hottest days (based on mean daily temperature) in January 2014, and the maximum temperature on each of these days. The total average reduction in peak demand for these customers over the five days was 66 MW.

Figure 14: IRCR response for 44 customers, 7-29 January 2014



Source: IMO

It is estimated that during the peak trading interval for 2013-14 (5:30 pm on 20 January 2014), the system peak demand was about 50 MW lower because of action taken by large customers to reduce their IRCR exposure. This is less than in 2012-13, when 59 customers were estimated to have reduced demand by around 65 MW. Given that the summer peak demand occurred on a relatively mild day in January (annual peak demand usually occurs on a warmer day in February), it is possible that fewer customers responded on this day, since they were likely expecting a February peak, or may not have been operating at full capacity after the summer break.

Twelve customers reduced demand at the time of system peak in both 2012-13 and in 2013-14. This means that, over the two years, 91 unique customer loads have reduced consumption because of the IRCR mechanism. On average, customers in both 2012-13 and 2013-14 reduced demand by 1.1 MW each. If each of these customers responded at this average rate, the maximum reduction from this behaviour could be over 100 MW. As more customers become aware of this mechanism, and customers already engaging in this behaviour increase their response, this figure is likely to grow.

3.5. Small-scale solar photovoltaic systems

The term small-scale solar PV system refers to grid-connected rooftop PV systems. These systems allow customers to generate some or all of their electricity needs and export any excess to the network, for which they may receive a payment. While solar PV systems do not directly reduce customer demand, they do reduce the quantity of electricity that needs to be supplied through the electricity network while the solar PV systems are generating during daylight hours.

Table 3 shows some key statistics for solar PV systems installed by Synergy's residential customers between 2009-10 and 2013-14. The number of systems has grown from around 17,000 in 2009-10 to over 136,000 in January 2014. The proportion of Synergy's residential customers with solar systems installed has also increased, from 2.1 per cent in 2009-10 to 15 per cent in January 2014. Over the same period, the average system size has increased by 50 per cent from 1.5 kW to 2.3 kW.

Table 3: Key statistics for solar PV systems, Synergy's residential customers, 2009-10 to 2013-14

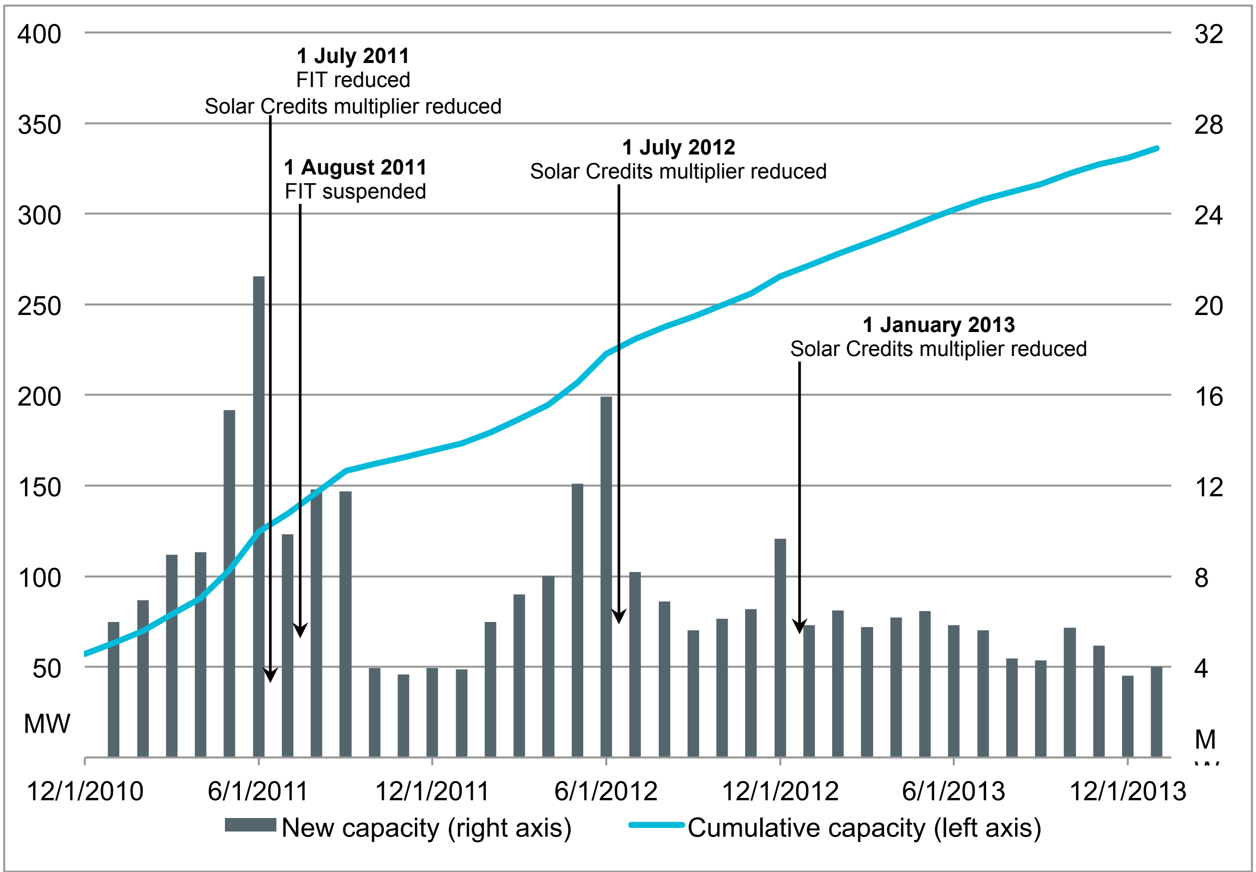
	2009-10	2010-11	2011-12	2012-13	2013-14[12]	Average annual growth
Number of systems	17,571	58,113	89,834	122,298	136,329	66.9%
Proportion of customers with PV installed (%)	2.1	6.7	10.1	13.6	15.0	63.5%
Average system size (kW)	1.5	1.9	2.1	2.2	2.3	11.3%

Source: Synergy

[12] Year to date January 2014

Figure 15 shows monthly and cumulative installed solar PV system capacity in the SWIS over the past three years. Installed PV capacity has increased substantially over this period, from 63 MW in January 2011 to 336 MW in January 2014 (an average annual increase of 75 per cent). The strong growth in installed solar PV system capacity has been encouraged by government incentives, such as the State Government net Feed-in-Tariff (FIT) scheme and Commonwealth Government Solar Credits, rising electricity prices, as well as increasing environmental awareness.

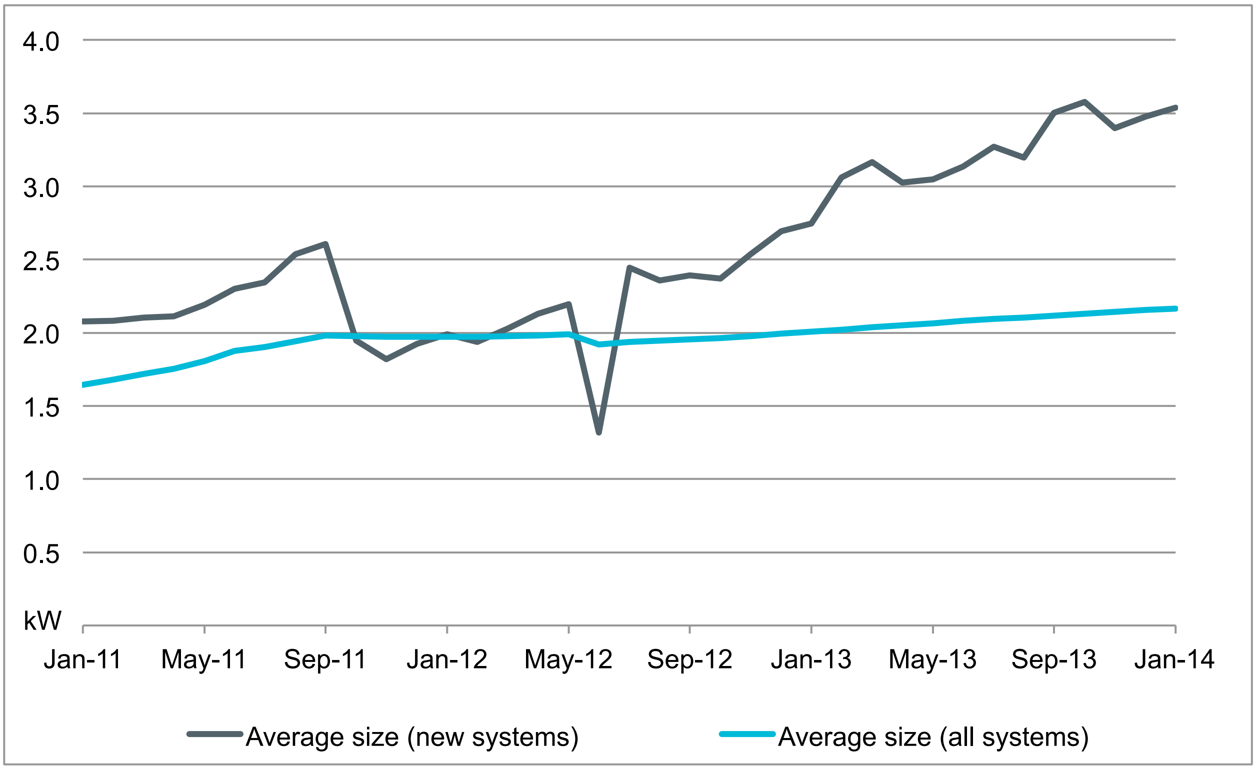
Figure 15: Monthly and cumulative installed solar PV system capacity, December 2010 to January 2014



Source: Clean Energy Regulator

Figure 16 shows the average size of solar PV systems installed in each month compared with the average system size of all systems in the SWIS. The average system size of new installations has increased, from 2.1 kW in January 2011 to 3.5 kW in January 2014. This increase in system size is likely to be mainly associated with falling prices for solar PV systems, but may also reflect more commercial and industrial customers installing systems, which would typically be larger than a residential system. The drop in installation size in June 2012 was associated with the reduction in the Solar Credits multiplier, which led to a large number of small systems being installed.

Figure 16: Average size of monthly solar PV system installations, January 2011 to January 2014



Source: Clean Energy Regulator

4. Evolution of the Wholesale Electricity Market

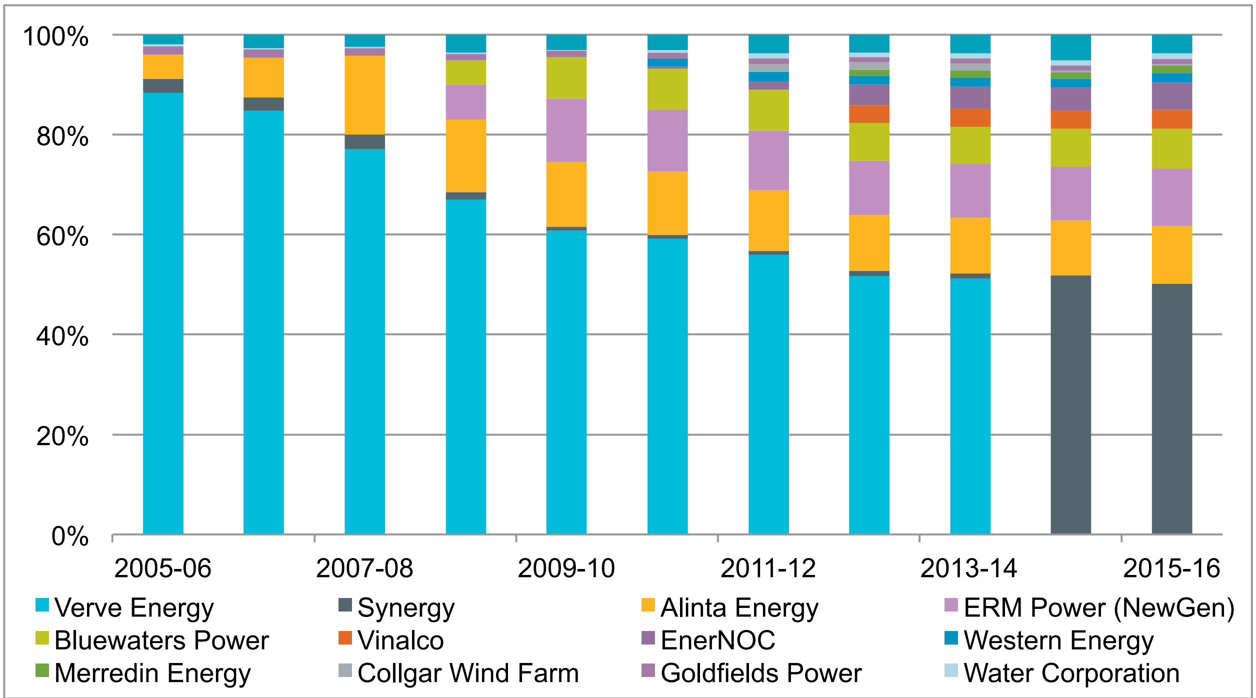
This chapter discusses changes in the WEM since market start. Section 4.1 reviews trends in the market, including Capacity Credits by Market Participant, generation by fuel type, and the capacity mix. Section 4.2 presents information about renewable energy generation in the SWIS. The age and availability of generation capacity is presented in section 4.3. Section 4.4 discusses the Western Australian Government Electricity Market Review. Section 4.5 discusses structural change in the WEM, including changes to the Wholesale Electricity Market Rules (Market Rules). Section 4.6 discusses future infrastructure development in the SWIS. Section 4.7 examines other factors that may influence the Western Australian electricity market, including the Renewable Energy Target (RET) review, the Commonwealth Government Energy White Paper, and the possible removal of the carbon price mechanism.

4.1. Market diversification

4.1.1. Capacity Credits by Market Participant

Figure 17 shows the Capacity Credits assigned to Market Participants as a proportion of the total number assigned between 2005-06 and 2015-16. Capacity Credits held by Synergy (post-merger) and Verve Energy (pre-merger[13]) fell from 88 per cent of total Capacity Credits in 2005-06 to 50 per cent in 2015-16. In 2015-16, other Market Participants will make up 50 per cent of total Capacity Credits; the two largest, Alinta Energy and ERM Power, accounting for around 11 per cent of Capacity Credits each. The number of Market Participants holding Capacity Credits has increased from 10 in 2005-06 to 30 in 2015-16, reflecting the increasing diversity of capacity providers available to wholesale customers.

Figure 17: Proportion of Capacity Credits by Market Participant, 2005-06 to 2015-16



Source: IMO

[13] The Western Australian Government merged Verve Energy and Synergy on 1 January 2014, with the new entity trading as Synergy.

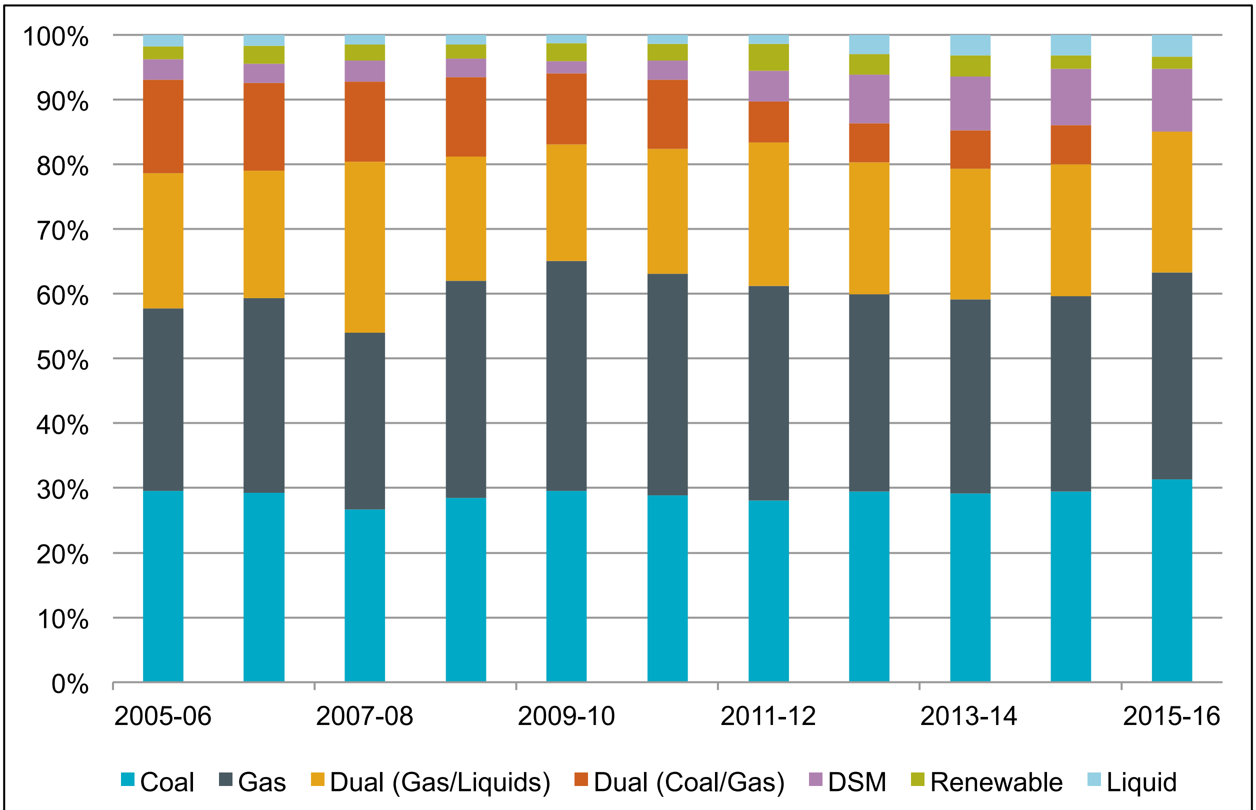
4.1.2. *Capacity Credits by fuel type*

Figure 18 shows generation capacity in the SWIS by fuel type between 2005-06 and 2015-16. The share of fossil fuel (that is, coal and gas) generation capacity has fallen since 2005-06, from 93 per cent to 85 per cent in 2015-16. The proportion of Capacity Credits assigned to renewable generators has remained stable over this period, averaging three per cent.

The total proportion of dual-fuelled capacity in the SWIS has fallen from around 35 per cent in 2005-06 to around 22 per cent in 2015-16. This largely reflects the staged decommissioning of the coal/gas fired Kwinana Power Station, with Kwinana Stage C expected to be decommissioned at the end of the 2014-15 Capacity Year. However, gas/liquid fuelled capacity has increased strongly, from 736 MW in 2005-06 to 1,239 MW in 2015-16, reflecting the commissioning of several large generators, and has maintained a 21 per cent share of Capacity Credits.

The proportion of Capacity Credits assigned to Demand Side Management (DSM) tripled between 2010-11 and 2015-16, from around three per cent to 10 per cent.

Figure 18: Percentage of Capacity Credits by fuel type, 2005-06 to 2015-16

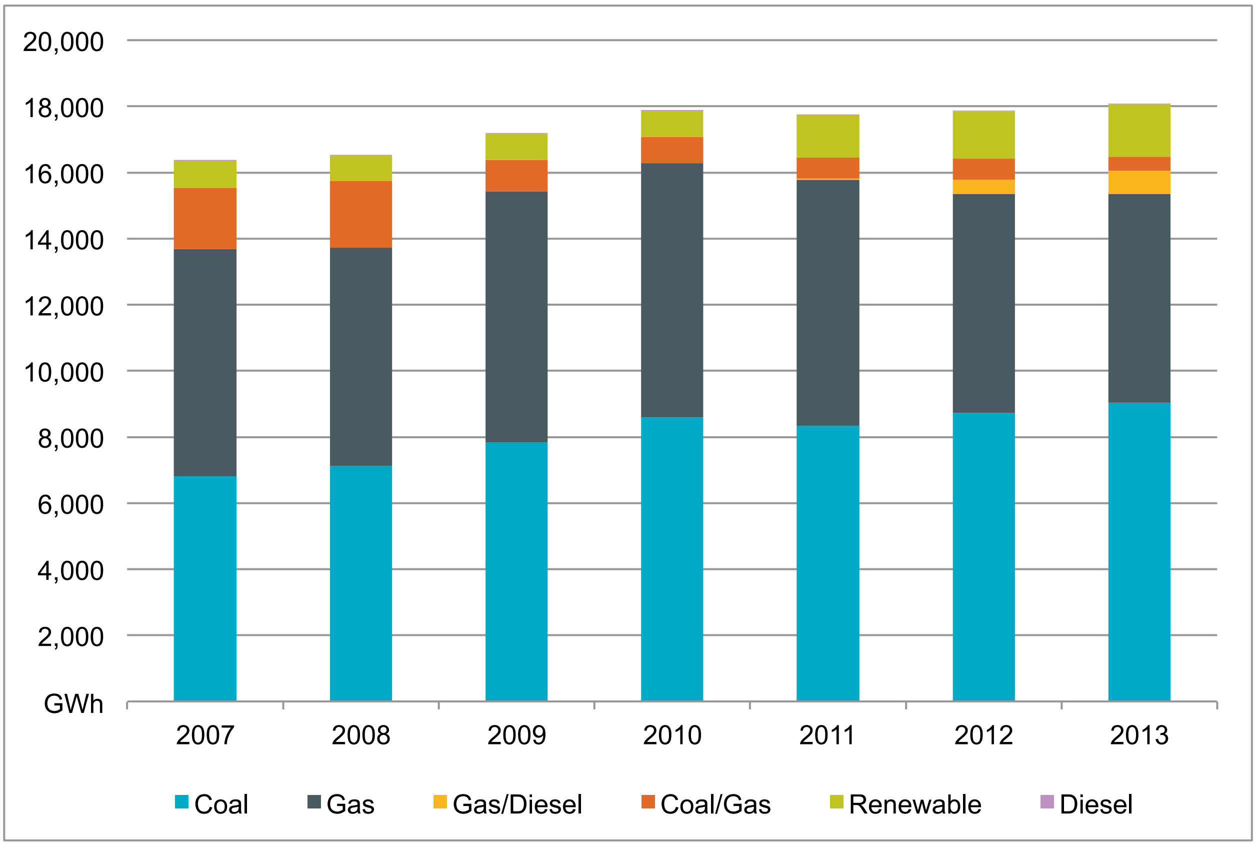


Source: IMO

Fuel diversity in the market is integral to maintaining security of supply, as well as supporting competition between technologies and generators. It mitigates events such as a restriction in the supply of one fuel that may otherwise result in a failure of the electricity system or supply disruptions. For example, fuel diversity in generation facilities was essential in minimising the impact of two gas supply disruptions in 2008 and 2011.

Figure 19 shows total sent out energy by fuel type for the calendar years between 2007 and 2013. Total generation by coal generators increased by 33 per cent over this period, while energy from gas generators declined by eight per cent. Energy generated from renewable sources almost doubled from 2007, and accounted for nine per cent of total sent out energy in 2013. Generation from dual-fuel and diesel facilities has declined from around 11 per cent in 2007 to six per cent in 2013, reflecting the staged retirement of the Kwinana Power Station.

Figure 19: Energy generation by fuel type, 2007 to 2013



Source: IMO

4.1.3. Load characteristics and generation mix

The optimal mix of capacity types will be driven to an extent by the variation in demand throughout the year. As discussed in section 2.2 above, the load duration curve for the SWIS shows a system characterised by sharp summer peaks and a large variance between minimum and peak demand. Based on this load duration curve, a mix of base load, mid-merit, and peaking facilities is desirable in the SWIS.

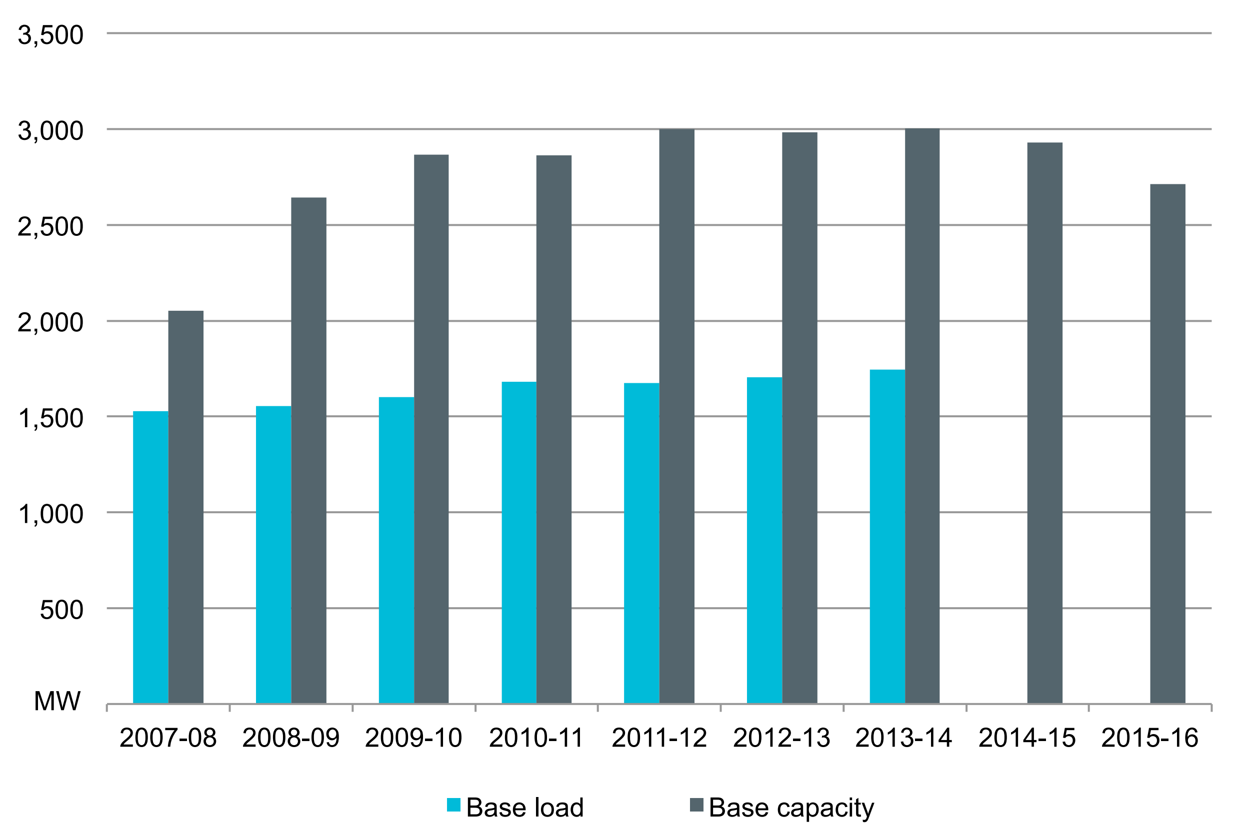
Figure 20, Figure 21, and Figure 22 show the load and capacity divided into three different categories – base, mid-merit, and peaking, which are defined as follows:

- base load/capacity – the capacity that is required for 75 per cent of the year;
- mid-merit load/capacity – the additional demand that is exceeded for at least 25 per cent of the year; and
- peaking load/capacity – the additional demand that is exceeded for less than 25 per cent of the year.

Capacity Credits have been allocated to these categories based on facility type and historical operating practices.

Figure 20 shows the base capacity compared to the base load between 2007-08 and 2015-16. Substantial investment in base load generation capacity was made between 2007-08 and 2011-12, increasing from 2,051 MW in 2007-08 to 3,000 MW in 2011-12. This led to a surplus of base load capacity and has required running some facilities at a lower level, or shutting down facilities, during periods of lower demand (for example, overnight). Kwinana Stage C is due to be retired in October 2015, which will result in base load capacity declining by 362 MW in 2015-16.

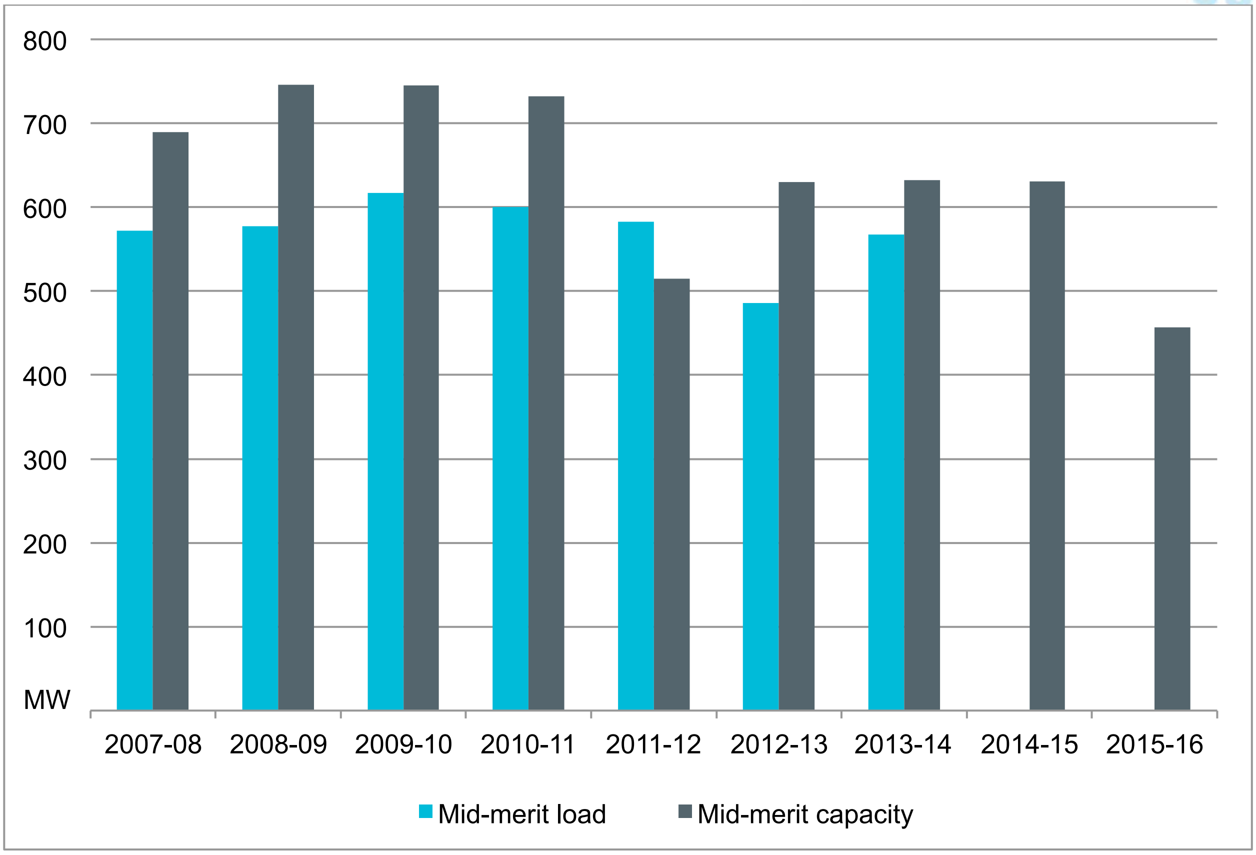
Figure 20: Base capacity compared to base load, 2007-08 to 2015-16



Source: IMO

Figure 21 shows the mid-merit load compared to mid-merit capacity between 2007-08 and 2015-16. Mid-merit capacity was above mid-merit load in all years except for 2011-12. Mid-merit capacity fell in 2011-12 following the decommissioning of Kwinana G1 and G2 (216 MW of Capacity Credits), and increased in 2012-13 with the start-up of the refurbished Muja G3 and G4 (110 MW of Capacity Credits).

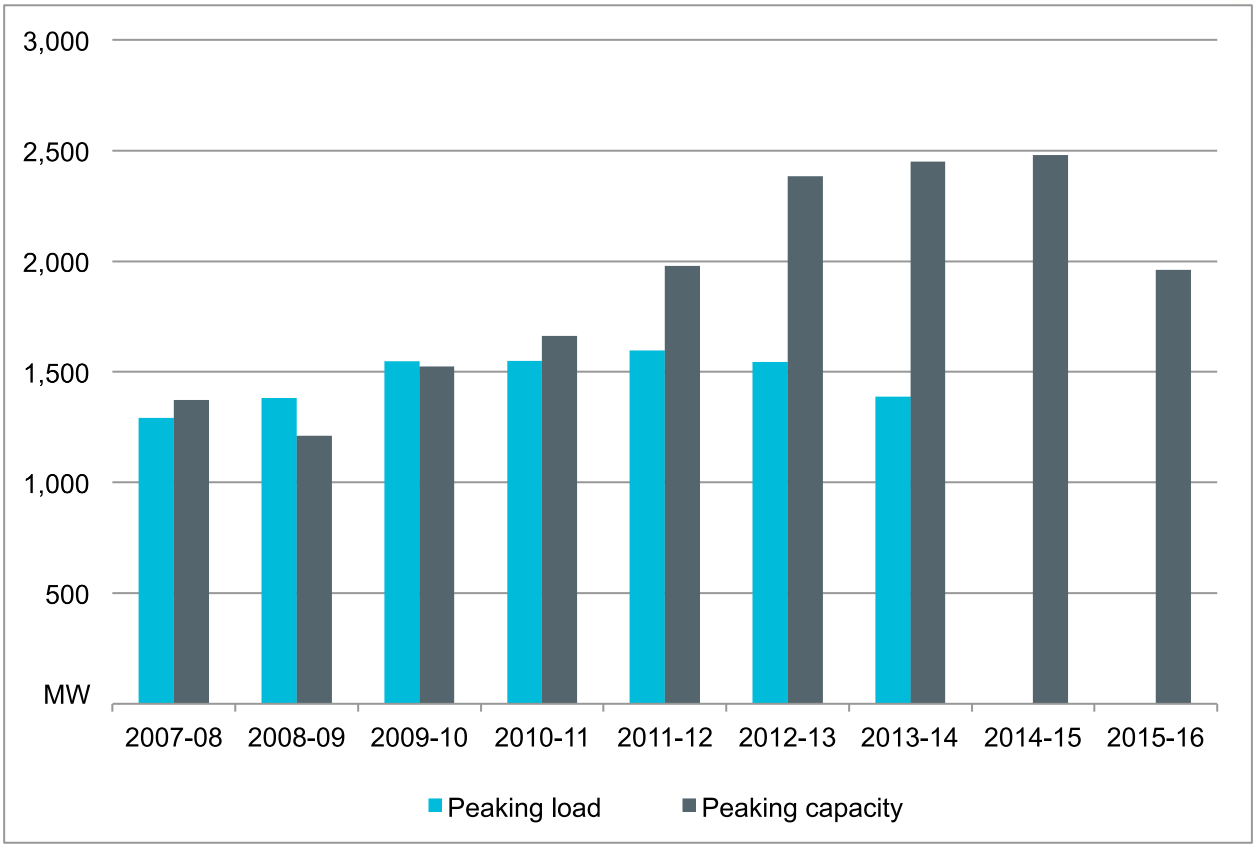
Figure 21: Mid-merit capacity compared to mid-merit load, 2007-08 to 2015-16



Source: IMO

Figure 22 shows peaking capacity compared to the peaking load between 2007-08 and 2015-16. Peaking capacity grew substantially between 2008-09 and 2013-14, from 1,210 MW to 2,450 MW. This was driven by an increase in diesel generation capacity and DSM. The quantity of peaking capacity available at market start was lower than the peaking load, but exceeded the peaking load by 2010-11.

Figure 22: Peaking capacity compared to peaking load, 2007-08 to 2015-16



Source: IMO

4.2. Renewable energy

Table 4 shows the renewable energy facilities that have been assigned Capacity Credits for the 2015-16 Capacity Year. There are currently 19 renewable energy facilities operating in the WEM, including 11 wind farms, seven landfill gas facilities, and one solar PV farm. The total number of Capacity Credits assigned to these facilities for 2015-16 is 108.9 MW. The largest of these facilities (by Capacity Credits) is Alinta Energy's Walkaway wind farm, while the smallest is Synergy's Bremer Bay wind farm.

This section refers only to renewable energy facilities that are registered as intermittent generators in the WEM; figures do not include solar PV systems (see sections 3.5 and 5.5 for discussions of solar PV systems).

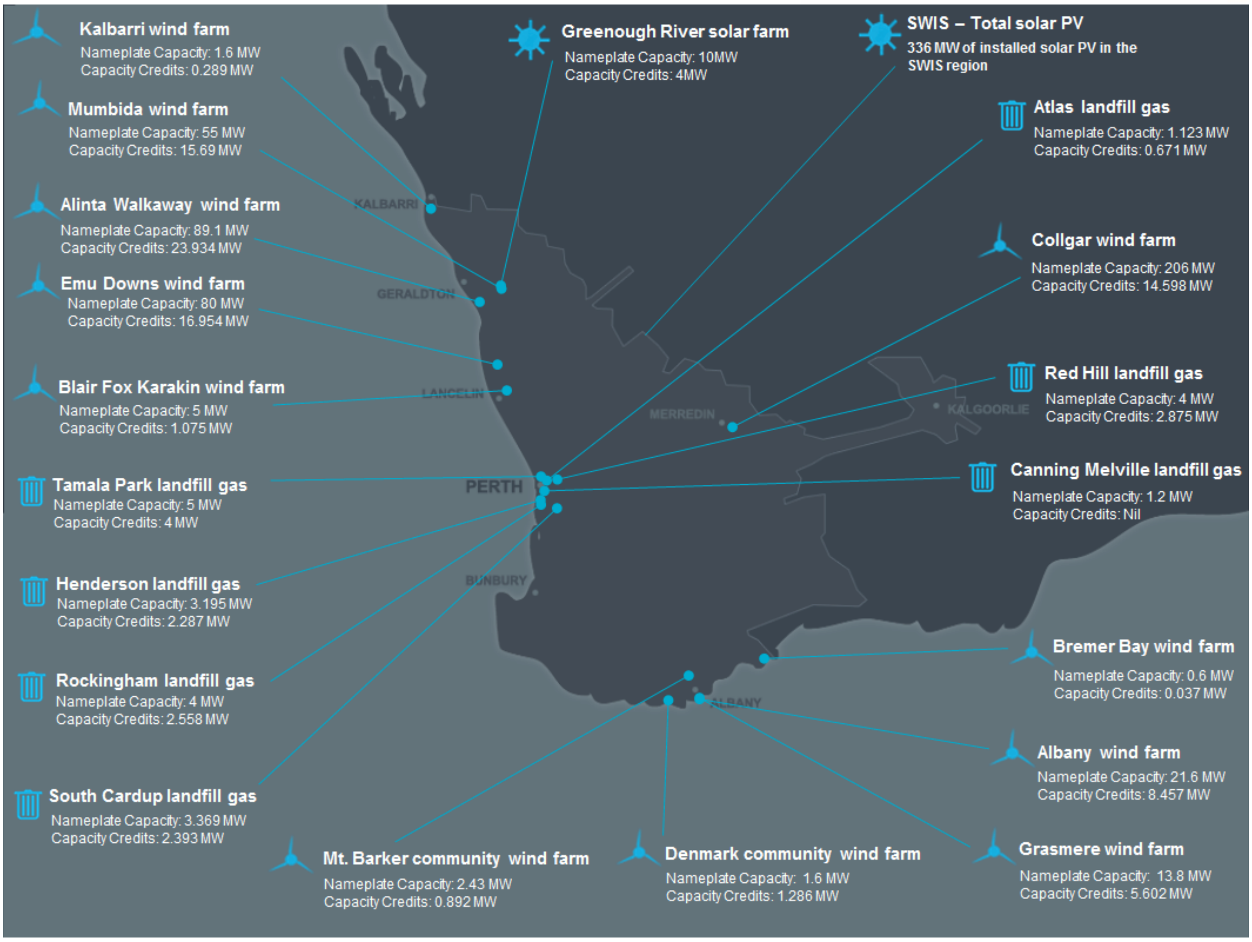
Table 4: Renewable energy facilities assigned Capacity Credits for the 2015-16 Capacity Year

Facility name	Renewable source	Capacity Credits (MW)
Albany	Wind	8.457
Alinta Walkaway	Wind	23.934
Atlas	Landfill gas	0.671
Blair Fox Karakin	Wind	1.075
Bremer Bay	Wind	0.037
Collgar	Wind	14.598
Denmark Community wind farm	Wind	1.286
Emu Downs	Wind	16.954
Grasmere	Wind	5.602
Greenough River	Solar	4.000
Henderson Renewable	Landfill gas	2.287
Kalamunda	Landfill gas	1.300
Kalbarri	Wind	0.289
Mount Barker	Wind	0.892
Mumbida	Wind	15.690
Red Hill	Landfill gas	2.875
Rockingham	Landfill gas	2.558
South Cardup	Landfill gas	2.393
Tamala Park	Landfill gas	4.000

Source: IMO

Figure 23 shows the location, nameplate capacity, and assigned Capacity Credits for 2015-16 for the renewable energy facilities in the SWIS. The map also shows the amount of installed solar PV system capacity. Data for installed solar PV system capacity has been obtained from the Clean Energy Regulator.

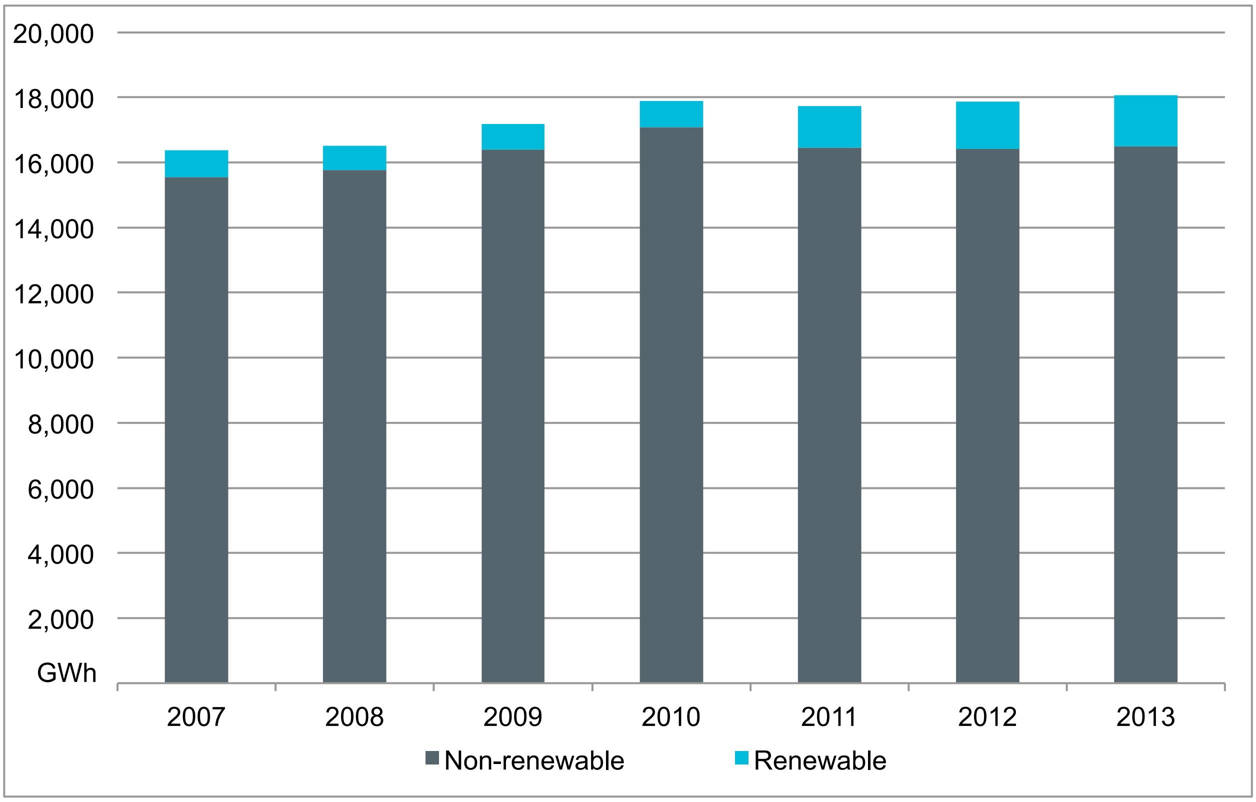
Figure 23: Renewable energy map for the SWIS



Source: IMO/Clean Energy Regulator

Figure 24 shows renewable energy as a proportion of total wholesale electricity generation between 2007 and 2013. Renewable energy generation grew at an average annual rate of 9.7 per cent over this period, compared with growth in non-renewable generation of 0.8 per cent a year on average. The share of renewable generation as a proportion of total generation nearly doubled, from five per cent in 2007 to nine per cent in 2013. The figures used for this graph do not include generation from solar PV systems (see sections 3.5 and 5.5 for more information on solar PV systems).

Figure 24: Renewable and non-renewable electricity generation, 2007 to 2013



Source: IMO

One wind farm project with expected Capacity Credits of 16 MW was identified through the 2014 Expressions of Interest (EOI) process. If completed, this could bring total Capacity Credits for renewable energy generators to 125 MW in 2016-17. Additional renewable energy projects are partly dependent on renewable energy policies at both state and federal level, including the RET (see section 4.7). However, while there is excess capacity in the SWIS, it is anticipated that no new large scale renewable energy projects will be commissioned in the short to medium-term.

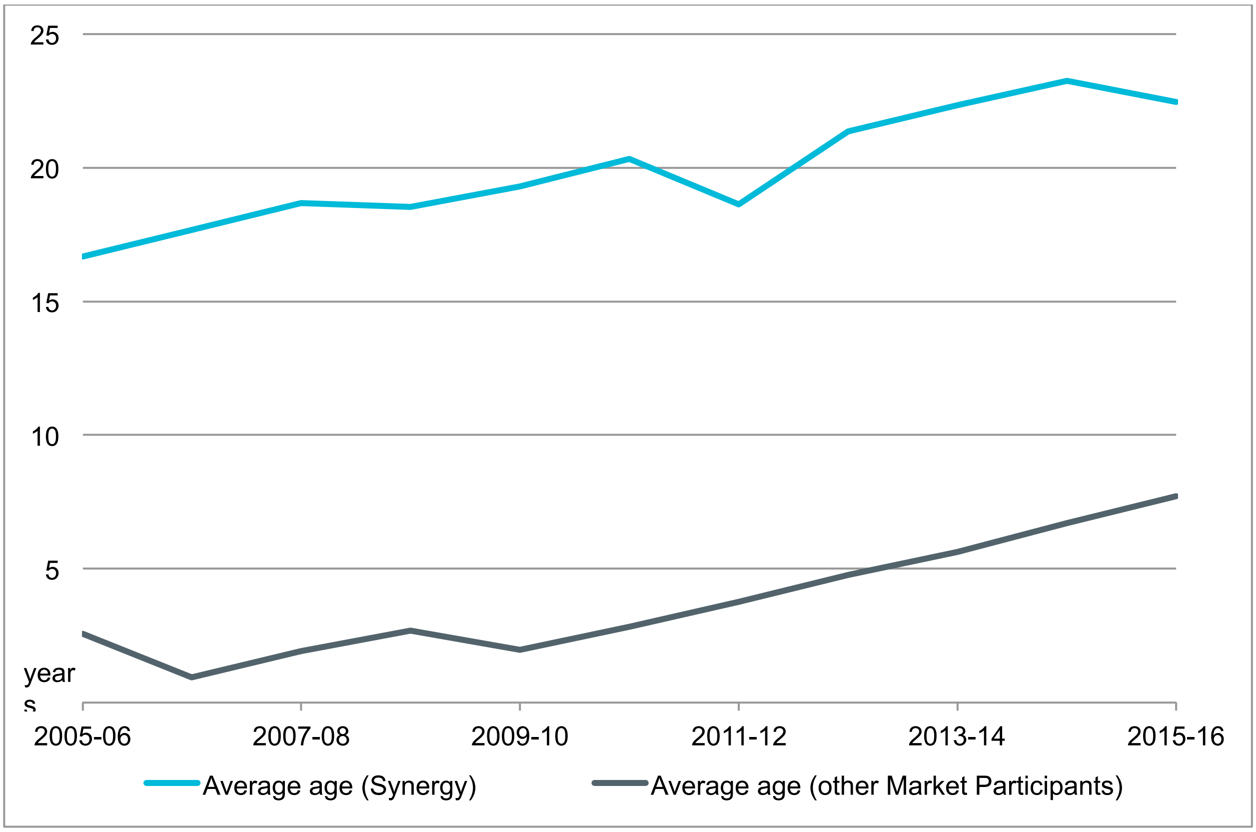
4.3. Age and availability of generation capacity

Figure 25 shows the average age, weighted by Capacity Credits, for (post-merger) Synergy compared with other Market Participants between 2005-06 and 2015-16. The average age of Synergy's generating fleet has increased from 16.7 years in 2005-06 to an expected 22.5 years in 2015-16 (based on assigned Capacity Credits). Over this same period, the average age of generators owned by other Market Participants has increased from 2.6 years to an expected 7.7 years. About one third of Synergy's total assigned Capacity Credits are associated with generation capacity built before 1990, while over 95 per cent of capacity owned by other Market Participants was built after 2003.

The fall in average age for Synergy facilities between 2010-11 and 2011-12 largely reflects the decommissioning of Kwinana G1 and G2 (216 MW Capacity Credits) as part of the planned staged retirement of this facility. In addition, two new units were commissioned at Kwinana during 2011 (190 MW Capacity Credits). The average age increased again in 2012-13 and 2013-14 with the commissioning of the refurbished Muja AB facility, which was originally built during the 1960s. Assuming that Synergy does not commission any new capacity, or retire aging capacity (other than the proposed retirement of the Kwinana Stage C), the average age of its generation fleet will reach 30 years by 2023-24.

The average age for facilities owned by Market Participants other than Synergy was below five years until 2012-13, reflecting the commissioning of several new large facilities, including NewGen Kwinana (320 MW Capacity Credits) and Neerabup (331 MW Capacity Credits) in 2008, Bluewaters Power's Bluewaters G2 (204 MW Capacity Credits) in 2008, and Bluewaters G1 (204 MW Capacity Credits) in 2009.

Figure 25: Average age of generation capacity, Synergy and other Market Participants, 2005-06 to 2015-16

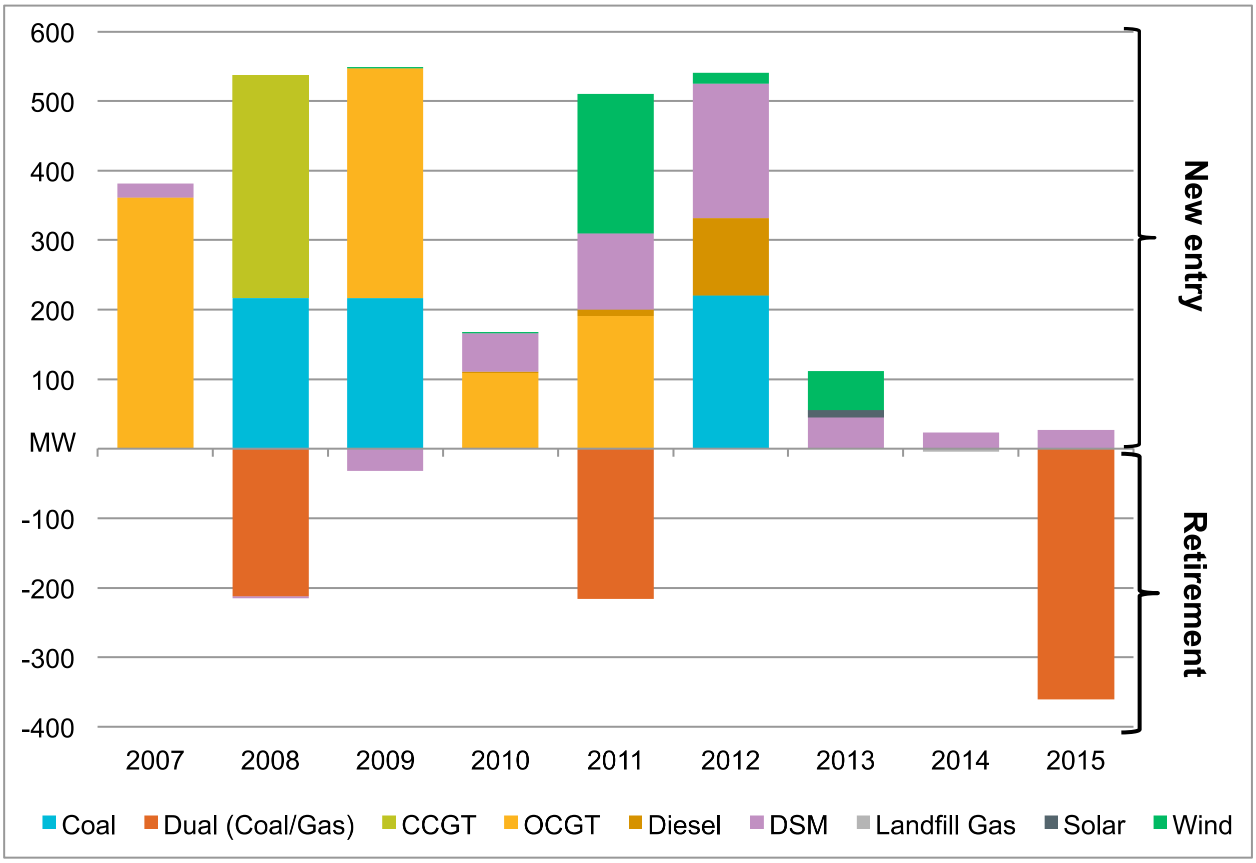


Source: IMO

The average age of generation capacity will continue to fluctuate from year to year depending on the addition of new capacity, upgrades to existing facilities and retirement of older facilities. However, the average age of generation capacity is expected to continue to rise over the medium term, considering that excess supply of capacity will limit new investment, and there are no known retirements of generating plant currently planned (with the exception of the Kwinana Power Station Stage C).

Figure 26 shows the entry and exit of generation capacity in the SWIS by fuel type between 2007 and 2015, in terms of Capacity Credits assigned (with the exception of intermittent generators, which have been included at nameplate capacity). Over this period, the net increase in generation capacity was 2,228 MW, with 3,057 MW of capacity commissioned and 829 MW shut down. Most of the capacity retired was dual-fuelled coal/gas facilities (789 MW), reflecting the staged retirement of the Kwinana facility. Around one third (974 MW) of the new capacity commissioned was gas fuelled from open cycle gas turbine and combined cycle gas turbine facilities. DSM contributed 439 MW of capacity, while renewable energy facilities (including landfill gas, solar, and wind facilities) contributed 361 MW of capacity. New diesel generation accounted for 123 MW of total new capacity, most of which (112 MW) was commissioned during 2012.

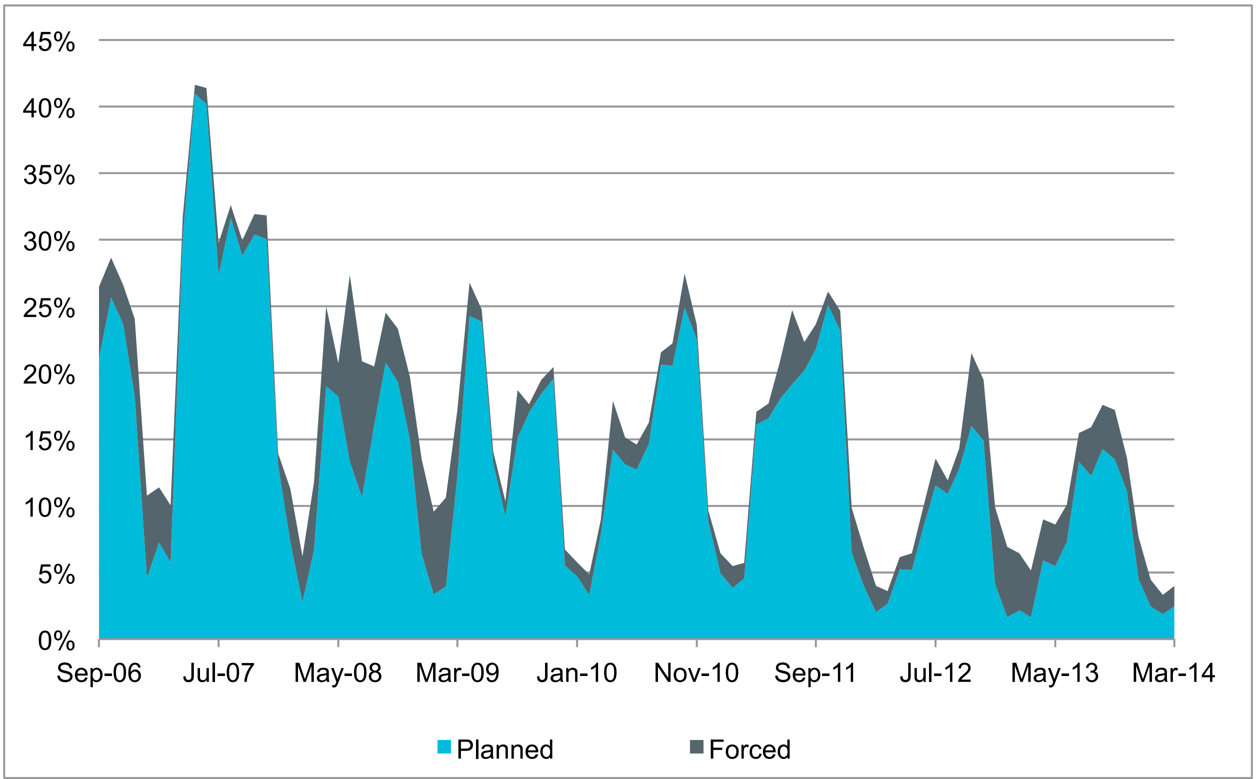
Figure 26: Entry and exit of generation capacity in the SWIS by fuel type, 2007 to 2015



Source: IMO

Figure 27 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 declined over the last year with monthly outage rates reaching only a maximum of approximately 18 per cent, compared with around 22 per cent in other years. Outage levels have also fallen during the peak summer period from up to 10 per cent in 2012-13 to up to 8 per cent for 2013-14.

Figure 27: Monthly average outage percentage, September 2006 to March 2014



Source: IMO

4.4. Western Australian Government Electricity Market Review

In March 2014, the Minister for Energy launched the state government's two phase Electricity Market Review. This review seeks to examine all existing structures of the WEM, including the regulatory framework and legal arrangements to examine options to:

- reduce the costs of production and supply of electricity and electricity related services, without compromising the safety and reliability of electricity supply;
- reduce the state government's exposure to energy market risks, by encouraging the private sector to fund future electricity infrastructure needs without subsidies from government; and
- develop a framework to attract an appropriate level of private sector investment to facilitate long-term stability in the WEM.

Phase One of the review aims to identify and assess the strengths and weaknesses of the current industry structure, market institutions and regulatory arrangements to develop options for electricity market reforms. The scope of Phase One is divided into six work streams as follows:

- the WEM;
- the retail electricity market;
- institutional arrangements;
- industry structure;
- fuel; and
- the network access and regulatory model.

The review will explore a range of issues within these work streams, including:

- whether an energy only market design would better suit the WEM;
- the cost of reliability and whether it is appropriate;
- the appropriate role of DSM;
- barriers to entry into the generation and retail markets;
- whether a constrained or unconstrained network access model is optimal for the SWIS;
- whether the current retail/network tariff design is appropriate in the future;
- how the institutional arrangements in the SWIS compare to other jurisdictions;
- whether metering services should be contestable; and
- the merits of different retail contestability thresholds.

A discussion paper is scheduled for release in late June 2014 with a call for public submissions, which are scheduled to close in late July 2014. The review is then due to deliver a Ministerial Reform Options Paper to the Minister for Energy by the end of October 2014.

Phase Two of the review will develop the detailed reforms and implementation arrangements for the options identified.

More information on the Electricity Market Review is available from the Public Utilities Office's website[14].

4.5. Structural change

4.5.1. Rule Changes and the Market Rules Evolution Plan

The IMO continually monitors and improves the operation of the WEM in accordance with the Wholesale Market Objectives outlined in the *Electricity Industry Act 2004* (WA), and administers proposed changes to the Market Rules.

[14] Available at: http://www.finance.wa.gov.au/cms/TwoColumns_Content.aspx?Pageid=17638&id=17731.

Any person, including the IMO, may propose changes to the Market Rules. In 2013 and 2014, the IMO sought to progress a number of key Rule Change Proposals including in relation to:

- incentives to improve availability of Scheduled Generators;
- harmonisation of supply-side and demand-side capacity resources;
- changes to the Reserve Capacity Price and the dynamic Reserve Capacity refund regime; and
- limiting early entry capacity payments.

More information on each of these Rule Change Proposals is available on the IMO website[15].

In addition, a Market Rules Evolution Plan (MREP) has been developed by the IMO in consultation with stakeholders, to determine the most important Market Rules evolution tasks to be addressed during 2013-2016. These priorities are intended to guide the IMO in the next phase of market development.

The highest priority was given to a range of potential improvements to the energy market, including:

- no longer requiring the submission of Resource Plans;
- changes to the Short Term Energy Market (STEM), including changes to timeframes, optional participation or removal of the STEM; and
- changes to the timeframes and requirements for bilateral submissions.

Other issues of importance include:

- reduction of the gate closure period for the Balancing Market; and
- introduction of a competitive market for Spinning Reserve Service.

Due to the broad scope of the Government's Electricity Market Review, the IMO has deferred work on substantive changes to the Market Rules, including the rule changes listed above and the highest priority items under the MREP. Once the outcomes of the review are known, the IMO will consider whether it is appropriate to continue to progress any of these rule changes.

4.5.2. Economic Regulation Authority Report – Five Yearly Review of the Methodology for Setting the Maximum Reserve Capacity Price and the 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 (MRCP) and the Energy Price Limits (EPL) at least once every five years, with the most recent review due by no later than 1 October 2013. The ERA completed the review during 2013, releasing a consultation paper in June 2013, followed by the receipt of public submissions. The ERA focused on the role that the various price limits played in mitigating against the abuse of market power.

On 15 January 2014, the ERA published its report on its five yearly review of the methodology for setting the MRCP and the EPL for the WEM. More information on the ERA's review, including the final report, is available on the ERA's website[16].

[15] Available at: http://www.imowa.com.au/rules/rule-changes/wem-rule-changes.
[16] Available at: http://www.erawa.com.au/energy-markets/electricity-markets/review-of-methodology-for-setting-the-maximum-reserve-capacity-price-and-energy-price-limits.

4.6. Infrastructure developments in the SWIS

Western Power's most significant new transmission project underway is the Mid-West Energy Project (MWEP) (Southern Section). This is a 330 kV double circuit transmission line from Neerabup to Three Springs, and is expected to facilitate the connection of new generation and customer loads.

Western Power has provided the IMO with the following information in relation to this project (as at 1 April 2014):

- 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 supply to the Karara Mining load. A 330/132 kV terminal station has also been established at Three Springs;
- final approval from the state government was secured in 2012;
- the project is under construction and progressing according to schedule;
- the 330 kV line is scheduled to be energised in mid-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 summer 2014; and
- 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.

Western Power's most recent project schedule indicates that the MWEP (Southern Section) will be completed by 2016-17.

4.7. Other factors affecting the Western Australian energy market

4.7.1. Renewable Energy Target review

The Commonwealth Government's RET aims for at least 20 per cent of Australia's energy demand to be supplied from renewable sources by 2020. This is a national target and does not apply to each of the states individually.

The RET involves the creation of certificates by eligible renewable energy facilities, based on the amount of electricity generated or displaced. A legal obligation is placed on liable entities (usually electricity retailers) to purchase and surrender a certain number of these renewable energy certificates each year.

In February 2014, the Commonwealth Government announced a review of the RET. This review will examine the economic, environmental, and social impacts of the scheme, in particular the impact on electricity prices, energy markets, the renewable energy sector, the manufacturing sector and households. It will also examine whether the objectives of the *Renewable Energy (Electricity) Act 2000* (Cwth) and related Commonwealth legislation are being met by the scheme. The review will also consider the interaction of the scheme with other Commonwealth and state government policies and regulations.

More information on the RET review is available from the Commonwealth Government Department of Prime Minister and Cabinet's website[17].

[17] Available at: http://retreview.dpmc.gov.au/.

4.7.2. Energy efficiency policy

Appliance and equipment energy efficiency

The Equipment Energy Efficiency Program (E3) coordinates energy efficiency activities in Australia through the mandatory Minimum Energy Performance Standard (MEPS) and Energy Rating Labels. E3 was established in 1992 and operates under the *Greenhouse and Energy Minimum Standards Act 2012* (Cwth).

MEPS are currently in place for a range of equipment in Australia, including commercial and industrial equipment as well as residential appliances. These standard specify the minimum level of energy performance that must be met for a product to be sold in Australia. The range of products currently under MEPS includes:

- air-conditioners (commercial and residential);
- distribution transformers;
- electric motors;
- electric and gas water heaters;
- set top boxes;
- televisions;
- lighting (including halogen, fluorescent, compact fluorescent lamp, and incandescent);
- refrigerators and freezers (commercial and residential);
- computers and monitors; and
- external power supplies.

However, some products that use large quantities of energy are not currently included, such as large servers and data centres, as well as swimming pool pumps. Other products, such as tablets, smartphones and games consoles, are also not currently covered by MEPS. Clothes washers and dishwashers are not currently included, but are covered by water efficiency standards, which have flow-on effects to energy use by reducing the amount of water needing to be heated (either by the appliance or in the household's hot water system).

The Energy Rating Label system was introduced to help consumers purchase more energy efficient appliances, by giving a star rating to many large appliances commonly purchased by households. These appliances include air-conditioners, clothes washers and dryers, computer monitors, televisions, dishwashers, refrigerators and freezers.

The E3 program forecasts that MEPS and Energy Rating Labels will save 2,021 PJ of energy between 2014 and 2030, with about 92 per cent of this (1,859 PJ or 516.4 TWh) being electricity[18]. The net benefit of this saving over this period is estimated at $57 billion.

Building energy efficiency

New residential dwellings, or major renovations to existing buildings, must meet minimum energy efficiency standards as mandated in the National Construction Code. These include the performance of the dwelling, including its materials, external glazing and shading, seals in the building, and the effects of air movement, as well as the performance of the services such as the hot water system, insulation, heating and cooling systems, lighting, and swimming pool pumps and heating. The main way of complying with these minimum standards is by assessing the house design using energy rating software, which must be accredited through the Nationwide House Energy Rating Scheme (NatHERS). The

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[18] Source: E3 program, *Impacts of the E3 program: Projected energy, cost and emissions savings*, March 2014, available at: http://www.energyrating.gov.au/blog/2014/03/21/e3-impact-projections-report-released/.

minimum star rating a house design must achieve was increased from three stars in 2003 to six stars in 2010[19].

NatHERS has estimated that a one star house would use around 133 kWh per square meter in a year, while a 3 star house would use 63 kWh per square meter. A six star house would only use 26 kWh per square meter each year. These figures account only for the thermal performance of the house, and not for the household makeup (that is, how many people live in the house and their ages), or the number and type of appliances in use.

4.7.3. Emissions reduction policy

The Commonwealth Government's carbon pricing scheme was introduced on 1 July 2012, and requires emitters of specified greenhouse gases to purchase and surrender emissions permits to cover the quantity of pollutants emitted (measured in terms of carbon dioxide equivalent). Eligible permits currently include carbon units, an Australian carbon credit unit issued as part of the Carbon Farming Initiative, or an international emissions unit. Carbon units are currently issued at a fixed price of $24.15 a tonne for 2013-14, and will increase to $25.40 a tonne in 2014-15. There is no limit on the quantity of these permits that may be issued.

Following the election in September 2013, the new Commonwealth Government introduced legislation to repeal the carbon pricing scheme, to take effect from 1 July 2014 if passed through both houses of Parliament. The scheme is to be replaced by the Emissions Reduction Fund, which will pay households and businesses to reduce emissions. The Government aims to reduce emissions (measured in terms of carbon dioxide equivalent) by five per cent of 2000 levels by 2020 through this fund. A Green Paper for the Emissions Reduction Fund was released in December 2013, with the White Paper released in April 2014. Draft legislation was released for public comment in May 2014.

The proposed Emissions Reduction Fund of up to $2.55 billion will be used to enter into contracts with individual households and business to reduce emissions. Projects eligible for funding may include:

- upgrades to commercial buildings;
- improving energy efficiency;
- reducing emissions from electricity generators;
- capturing landfill or coal seam gas;
- reforestation;
- improvements to agricultural soil; and
- upgrading vehicles and improving transport logistics.

Successful projects will receive emissions credits which can then be sold to the Government.

The Clean Energy Regulator will be responsible for running auctions to purchase emissions reductions. These auctions are to be run quarterly, beginning in late 2014, and will issue contracts to projects with the lowest bids (where a bid is a price at which each project can reduce emissions, expressed in dollars per tonne of carbon dioxide equivalent). Contracts are proposed to range in length, with a maximum of five years. A safeguard mechanism is also proposed to ensure that emissions do not rise elsewhere in the economy, which will be monitored using the existing National Greenhouse and Energy Reporting database.

More information about the Emissions Reduction Fund is available on the Commonwealth Government Department of the Environment's website[20].

[19] Zero stars indicates poor energy performance, while a 10 star rating reflects nearly no energy required to heat or cool the home.
[20] Available at: http://www.environment.gov.au/climate-change/emissions-reduction-fund.

4.7.4. Australian Renewable Energy Agency and Clean Energy Finance Corporation

The 2014-15 Commonwealth Government Budget announced that the Australian Renewable Energy Agency (ARENA) would be abolished. Its functions will be subsumed into the Department of Industry, with reduced funding. This will require the repeal of the *Australian Renewable Energy Agency Act 2011* (Cwth) by parliament. ARENA was created in 2012 to fund research and development of renewable energy projects, with the goal of improving the competitiveness and increasing the penetration of renewable energy technology in Australia.

The Commonwealth Government has also introduced legislation to abolish the Clean Energy Finance Corporation, an investment fund for clean energy projects and energy efficiency.

4.7.5. Commonwealth Government Energy White Paper

In December 2013, the Commonwealth Government announced it will publish an Energy White Paper in 2014. This document will develop a federal level resources and energy policy, designed to secure Australia's long-term domestic energy needs, maintain international competitiveness, and increase energy exports.

The terms of reference for the Energy White Paper state that the Government will consider policy and regulatory reforms needed to secure reliable energy that is competitively and transparently priced, including a consideration of the efficiency and effectiveness of regulatory bodies. The Government will also consider its role in the energy sector, opportunities to drive more efficient use of energy, the efficiency of energy markets, alternative transport fuels, and required skill development needs. Issues likely to affect future energy supplies, such as emerging technologies, new energy sources, and growth in exports of energy products, will also be examined.

The Energy White Paper is due for publication in September 2014. More information is available on the Commonwealth Government Department of Industry's website[21].

4.7.6. Microeconomic Reform Inquiry

In August 2013, the ERA began an inquiry into possible microeconomic reform in Western Australia, to recommend measures the state government can take to improve productivity and competition, as well as reducing regulation in the economy. A draft report was released in April 2014, with a final report due in June 2014.

In its draft report, the ERA made 19 recommendations across all sectors of the economy. In general, the energy sector was considered to be out of the scope of the inquiry, with the exception of electricity tariffs. The ERA recommended that electricity tariffs be increased to full cost-reflectivity[22] as soon as possible, and that other tariff structures, such as critical peak pricing or time of use pricing, be investigated. The sale of public assets that satisfy certain criteria for private ownership was also recommended.

While the ERA has not recommended specific public assets for sale, it has recommended a general review of public ownership of businesses and assets. The ERA has developed a set of criteria to be used to assess the potential for each business or asset to be sold. Western Power and Synergy were identified as warranting a cost-benefit analysis for divestment.

In the 2014-15 Western Australian State Budget, the Government intends to investigate selling assets as a way to manage debt and fund infrastructure. While no decisions have yet been made, the Government is currently assessing options for the sale of surplus public land, as well as port facilities and some Water

[21] Available at: http://ewp.industry.gov.au/.

[22] The ERA defines cost reflective charges as just sufficient to cover efficient input costs while providing a reasonable return to the retailer.

Corporation assets. After the completion of the Electricity Market Review, the Government will consider the sale of individual electricity generation assets, for example, the Muja Power Station.

4.7.7. 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)[23].

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 load carrying 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.

The NCMT, which contains information that is consistent with Western Power's 2013 Annual Planning Report (APR)[24], indicates that several Western Power zone substations are nearing capacity for times when Western Power's forecast peak demand is reached. Western Power advises that this is because of 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 2013 APR, Western Power is planning a range of transmission augmentations to alleviate generation and load constraints, of which the MWEP (Southern Section) is the most significant.

As the availability of transmission capacity varies across the transmission network, the ability for proposed new connections to receive transmission services will be dependent on the available capacity at a given point on the network. This needs to be accounted for when 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 loads 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.

More information on the revised AQP may be found on Western Power's website[25].

4.7.8. Opportunities for the provision of Network Control Services

The Electricity Networks 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 Access Code and Market Rules contemplate the use of Network Control Services (NCS) as a non-network option 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 load 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 load.

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[23] Available at: http://www.westernpower.com.au/ldd/ncmtoverview.html.
[24] Available at: http://www.westernpower.com.au/documents/reportspublications/western-power-annual-planning-report-2013.pdf?utm_source=Website&utm_medium=PDF&utm_campaign=Annual%20Planning%20Report.
[25] Available at: http://www.westernpower.com.au/business/aqp_revised.html.

Western Power has indicated that it expects potential NCS tender opportunities to be available at various locations. Western Power's APR[26] contains information on parts of the network that are forecast to need extra supply capacity in the next few years to meet load growth. Stakeholders seeking further information should contact Western Power.

4.7.9. Opportunities for provision of System Restart Ancillary Services

System Management has advised the IMO that it is aiming to procure three System Restart Services from 1 July 2016, following the expiry of the three existing contracts 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. In the unlikely event of a total system black out, these generators can be used to re-energise the 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 330 kV 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, around Bunbury, and Kemerton).

Interested parties may contact System Management[27] for further information.

[26] Available at: http://www.westernpower.com.au/aboutus/publications/Annual_planning_report_.html
[27] Email: market.operations@westernpower.com.au; Telephone: +61 8 9427 5943

5. Peak demand and energy forecasts, 2014-15 to 2023-24

This chapter presents the peak demand and energy forecasts for the period 2014-15 to 2023-24.

The first section summarises the methodology used in preparing these forecasts. Section 5.2 reviews the main drivers of the forecasts, including economic growth, population and dwelling stock, and electricity prices. Sections 5.3 and 5.4 present the peak demand and energy forecasts. Solar PV system forecasts are presented in section 5.5 and section 5.6 discusses the high customer demand response scenario.

5.1. Methodology

The IMO has engaged the NIEIR to prepare 12 different forecasts of economic activity, electricity consumption (sent out energy and energy sales), and peak demand for publication in the SWIS Electricity Demand Outlook.

The different cases (low, expected, and high) refer to the three economic activity scenarios that feed into the energy and demand forecasts. The PoE numbers (90 per cent, 50 per cent and 10 per cent) relate to different weather scenarios. For example, the 10 per cent PoE is a forecast that is expected to be exceeded one in every ten years as a result of extreme weather events.

NIEIR produces nine peak demand and three energy forecasts as follows:

- peak demand at 10, 50 and 90 per cent PoE levels with low, expected, and high case growth assumptions; and
- energy with low, expected, and high case growth assumptions.

The forecast methodology relies on historical demand data at the SWIS level. As the IMO does not receive regional consumption or peak demand data, no transmission constraints have been specifically considered when preparing these forecasts.

There are three main components of the forecasting model – energy sales, sent out energy, and peak demand. Each has a different methodology, which are discussed in more detail below.

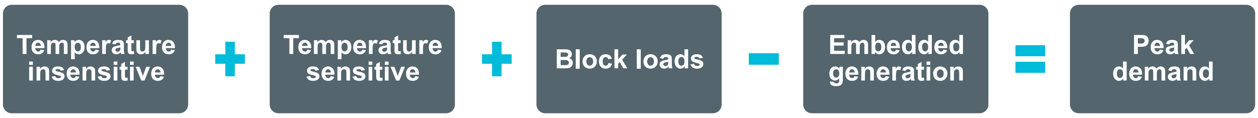
5.1.1. Sales and sent out energy forecasts

Energy sales (defined as sent out energy less transmission and distribution line losses) are forecast using an econometric model that links sales by industry to economic growth by industry, electricity prices, and weather conditions. Sales by tariff class are first linked with the appropriate Australian and New Zealand Standard Industrial Classification (ANZSIC) code to develop sales by industry. Residential electricity sales are forecast based on average sales per connection point, and are driven by real income growth, weather, and real electricity prices. Sent out energy forecasts are derived from these sales forecasts, where sales are defined as sent out energy less transmission and distribution losses.

5.1.2. Peak demand forecasts

Figure 28 shows the methodology for calculating peak demand as the sum of temperature insensitive load, temperature sensitive load and block loads, less embedded generation. Temperature insensitive load includes the proportion of residential and commercial consumption that is not dependent on temperature and includes electricity use for office buildings, industrial use, cooking, lighting, entertainment equipment and standby use. Temperature sensitive load is space heating and cooling use, which is highly dependent on temperature. Block loads comprise the largest customers in the SWIS.

Figure 28: Components of peak demand forecasts



5.2. Key factors affecting the peak demand and energy forecasts

This section discusses some of the factors that have been considered when preparing the peak demand and energy forecasts. The economic outlook for Western Australia, as well as population growth and electricity prices, will be discussed in the following sections.

5.2.1. Economic outlook

The economic outlook is an important driver of the electricity forecasts in the SWIS, particularly the energy sales forecasts for industry. Historically, electricity consumption growth has been correlated with economic growth. Peak demand is less sensitive to economic growth, being largely driven by temperature. This section summarises the economic growth outlook for the Western Australian economy.

Table 5 shows the expected case forecasts for major economic indicators for Western Australia between 2013-14 and 2018-19. Western Australia's GSP is forecast to grow at an average annual rate of 3.5 per cent between 2013-14 and 2018-19, supported by increasing commodity exports and private consumption expenditure. Over the same period, business investment is projected to slow compared with recent high levels, reflecting the completion of several major iron ore and natural gas projects.

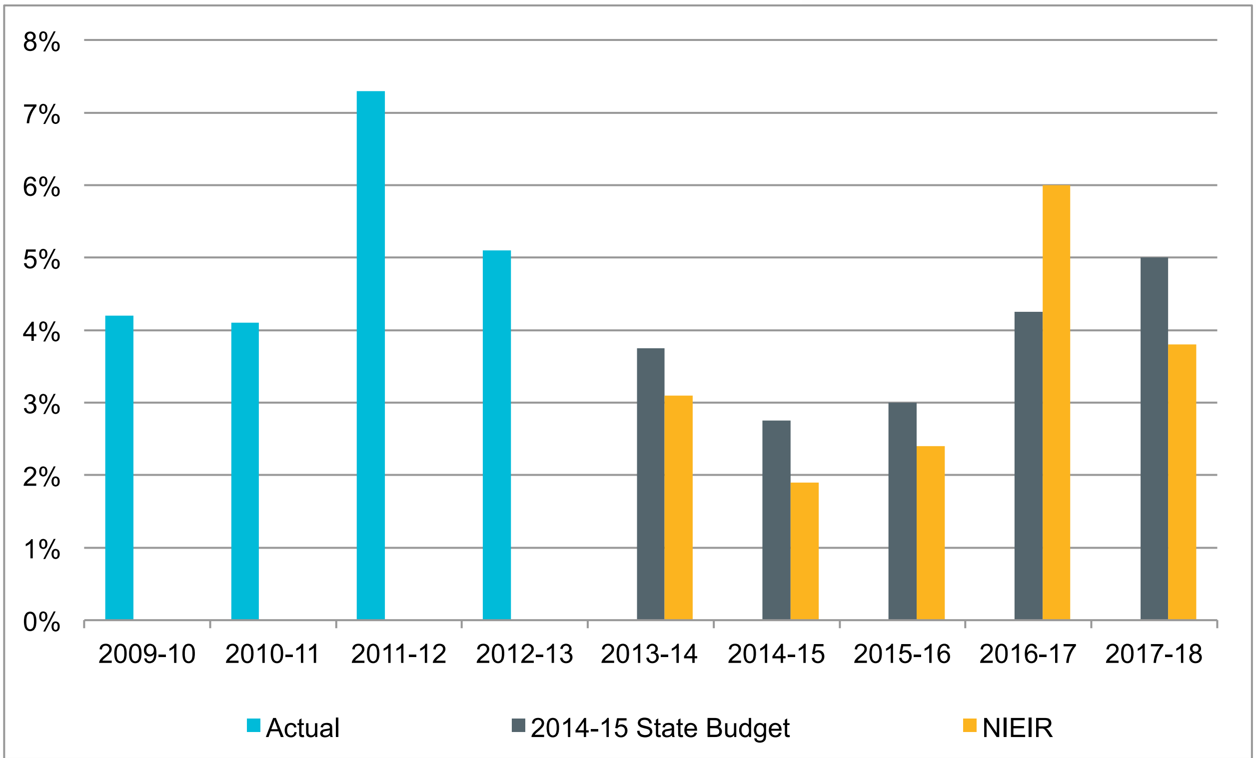
Table 5: Forecasts for growth of key economic indicators, expected case, Western Australia, 2013-14 to 2018-19

	2013-14 (%)	2014-15 (%)	2015-16 (%)	2016-17 (%)	2017-18 (%)	2018-19 (%)
Private consumption	1.8	2.2	1.2	3.3	5.8	5.2
Private dwelling investment	9.7	7.9	2.1	-4.6	-5.0	-0.1
Business investment	-11.7	-7.0	0.4	0.6	5.6	3.6
Government consumption	1.6	2.2	1.6	1.9	2.6	2.8
Government investment	5.3	7.4	3.2	3.2	3.2	3.2
State final demand	-2.5	-0.2	1.2	1.8	4.6	4.0
GSP	3.1	1.9	2.4	6.0	3.8	3.8
Population	2.6	2.6	2.5	2.2	2.2	2.2
Employment	0.6	1.7	1.2	1.2	1.8	2.2

Source: NIEIR

Figure 29 shows a comparison of GSP forecasts from NIEIR and the Western Australian Treasury (as published in the 2014-15 State Budget[28]) between 2013-14 and 2017-18, as well as actual growth in GSP between 2009-10 and 2012-13. In general, NIEIR's forecasts are lower than the Western Australian Treasury's by about one per cent, with the exception of 2016-17, when NIEIR's forecast is about two per cent higher than the Western Australian Treasury's.

Figure 29: Comparison of GSP forecasts, NIEIR and Western Australian Treasury, 2009-10 to 2017-18



Source: ABS[29]/ Western Australian Treasury[30]/NIEIR

5.2.2. Population and dwelling stock

Population growth is an indirect driver of electricity consumption. High population growth is generally correlated with growth in electricity consumption, especially when coupled with strong growth in new home construction.

The population of the SWIS is estimated to have increased by 3.3 per cent in 2012-13, from 2.3 million in 2011-12 to 2.4 million in 2012-13[31]. This was mainly driven by growth of 3.4 per cent in Perth's population from just under 1.9 million to nearly two million.

NIEIR has forecast growth in population at an average annual rate of 2.4 per cent between 2012-13 and 2018-19. This is expected to drive growth in the dwelling stock, which will in turn support increasing electricity consumption.

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[28] Source: Western Australian Department of Treasury, *2014-15 Budget: Economic and Fiscal Outlook,* available at: http://www.ourstatebudget.wa.gov.au/.

[29] Source: ABS, *Australian National Accounts: State Accounts, 2012-13*, available at: http://abs.gov.au/AUSSTATS/abs@.nsf/ProductsbyCatalogue/E6765105B38FFFC6CA2568A9001393ED?OpenDocument.

[30] Source: Western Australian Department of Treasury, *2014-15 Budget: Economic and Fiscal Outlook*, available at: http://www.ourstatebudget.wa.gov.au/.

[31] Source: ABS, *Regional Population Growth, Australia, 2012-13*, catalogue number 3218.0, available at: http://abs.gov.au/AUSSTATS/abs@.nsf/ProductsbyCatalogue/797F86DBD192B8F8CA2568A9001393CD?OpenDocument.

5.2.3. Electricity prices

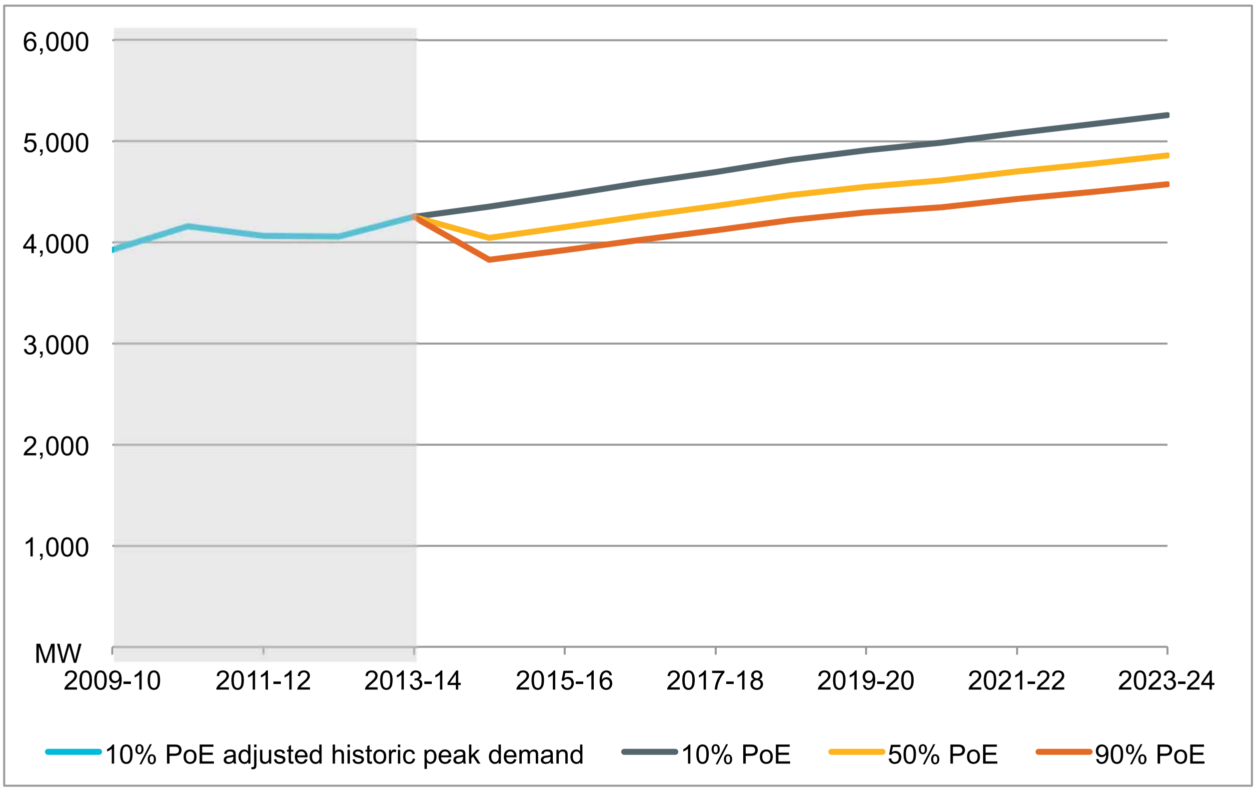
NIEIR has forecast average electricity price rises of around 2.7 per cent a year between 2014-15 and 2023-24, with higher growth early in the forecast period. The long-run residential price elasticity is assumed to be -0.25; that is, for every one per cent increase in the price of electricity, residential energy demand decreases by 0.25 per cent.

The IMO expects residential electricity to rise by seven per cent a year between 2015-16 and 2017-18, following a price increase of 4.5 per cent for the 2014-15 financial year, based on the 2014-15 Western Australian State Budget[32]. Similar increases have been included in the budget for charitable organisations and small business (L1) tariffs. Synergy's contestable tariffs are also forecast in the budget to increase by up to 30 per cent. However, the state government has limited control over contestable tariffs in the SWIS, as these customers are able to change retailer for cheaper prices.

5.3. Peak demand forecasts

Figure 30 shows the 10, 50, and 90 per cent PoE peak demand forecasts for the period 2014-15 to 2023-24, compared to the 10 per cent PoE adjusted historic peak demand. For the 10 per cent PoE, peak demand is forecast to grow at an average annual rate of 2.1 per cent over the outlook period. At the 50 and 90 per cent PoE levels, peak demand is forecast to grow at an average rate of 2.1 per cent and 2 per cent, respectively. These growth rates reflect differing weather conditions associated with the 10, 50 and 90 per cent PoE temperatures.

Figure 30: Peak demand, expected case, 2009-10 to 2023-24



Source: NIEIR

[32] Source: Western Australian Department of Treasury, *2014-15 Budget: Economic and Fiscal Outlook,* available at: http://www.ourstatebudget.wa.gov.au/.

Table 6 shows the peak demand forecasts for the three weather scenarios under expected case economic growth assumptions.

Table 6: Peak demand forecasts for different weather scenarios, expected case

Scenario	2014-15 (MW)	2015-16 (MW)	2016-17 (MW)	2017-18 (MW)	2018-19 (MW)	5 year average annual growth	10 year average annual growth
10% PoE	4,352	4,469	4,588	4,699	4,817	2.6%	2.1%
50% PoE	4,046	4,151	4,260	4,362	4,470	2.5%	2.1%
90% PoE	3,827	3,925	4,027	4,122	4,225	2.5%	2.0%

Source: NIEIR

Table 7 shows the peak demand forecasts for the three different economic growth scenarios at the 10 per cent PoE.

Table 7: Peak demand forecasts for different growth scenarios, 10 per cent PoE

Scenario	2014-15 (MW)	2015-16 (MW)	2016-17 (MW)	2017-18 (MW)	2018-19 (MW)	5 year average annual growth	10 year average annual growth
High	4,390	4,521	4,666	4,804	4,946	3.0%	3.1%
Expected	4,352	4,469	4,588	4,699	4,817	2.6%	2.1%
Low	4,309	4,406	4,506	4,596	4,693	2.2%	1.8%

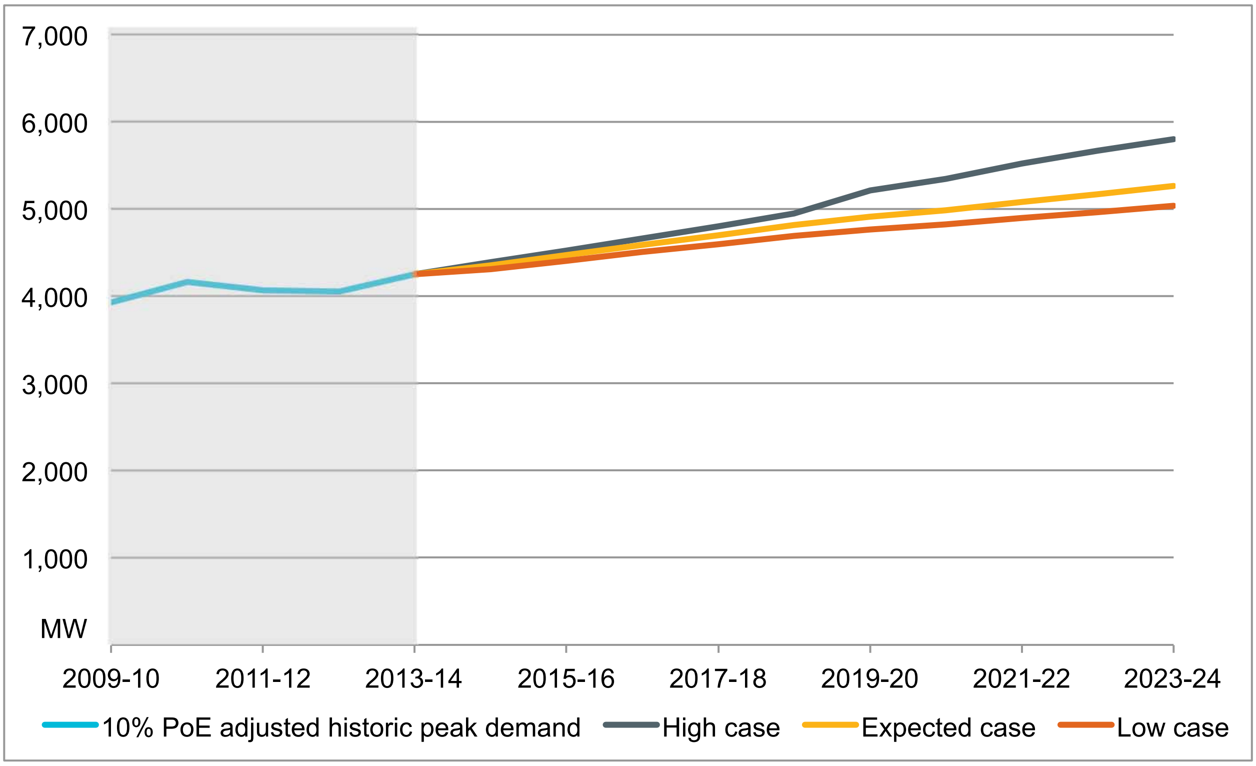
Source: NIEIR

Figure 31 shows the 10 per cent PoE forecasts for the three different economic growth scenarios, compared to the 10 per cent PoE adjusted historic peak demand. For the expected case, peak demand is forecast to grow at an average annual rate of 2.1 per cent over the outlook period. In the high and low cases, peak demand is forecast to grow at an average rate of 3.1 per cent and 1.8 per cent a year, respectively. These growth rates reflect different economic growth forecasts, with all other assumptions remaining constant.

The economic growth and population growth assumptions for the different economic growth scenarios over the outlook period are as follows:

- high case – GSP is forecast to grow at an average annual rate of 4.5 per cent, while population growth is forecast to grow at 2.4 per cent a year, on average;
- expected case – GSP is forecast to grow at an average annual rate of 3 per cent, while population growth is forecast to grow at 2.1 per cent a year, on average; and
- low case – GSP is forecast to grow at an average annual rate of 1.9 per cent, while population growth is forecast to grow at 1.8 per cent a year, on average.

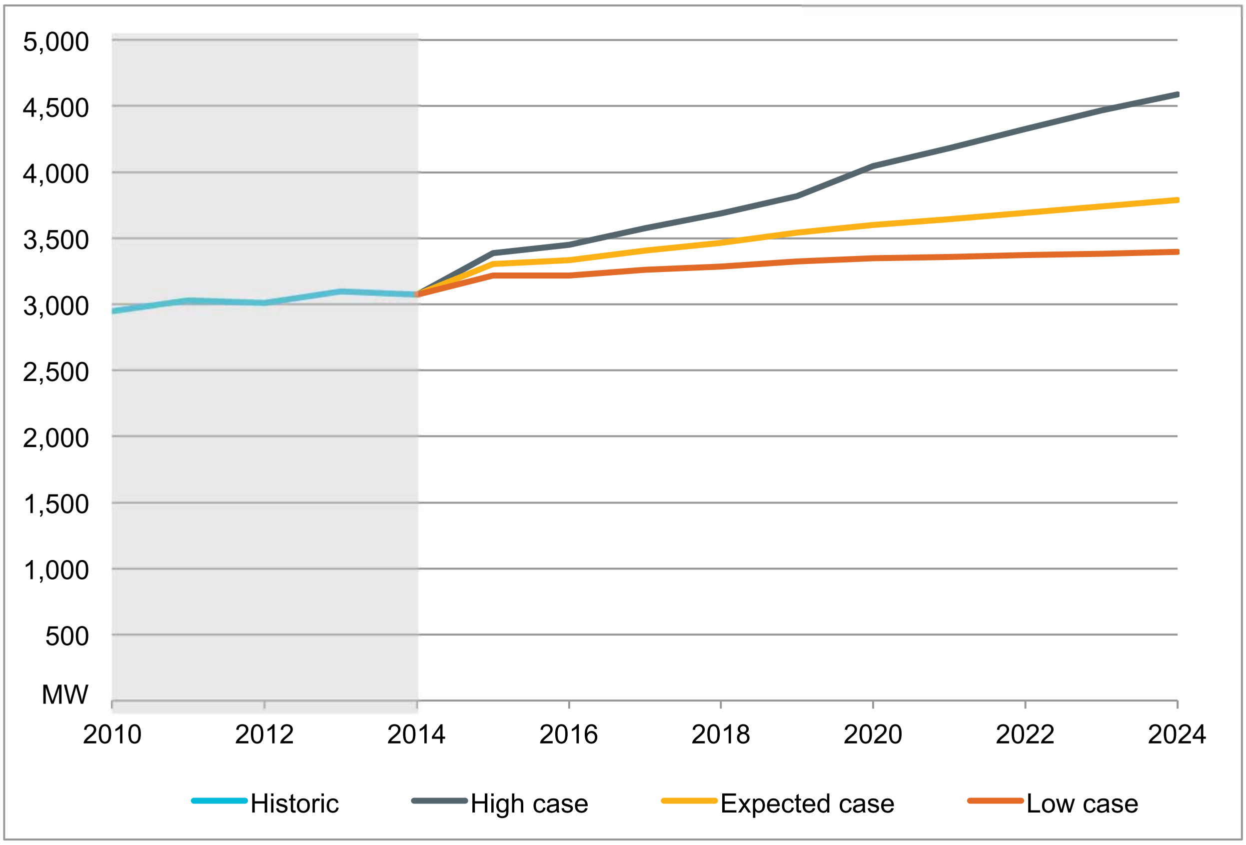
Figure 31: Peak demand, 10 per cent PoE, under different economic growth scenarios, 2009-10 to 2023-24



Source: NIEIR

Figure 32 shows the 10, 50, and 90 per cent PoE winter peak demand forecasts for the period 2015 to 2024, compared to the raw, non-weather adjusted historic annual demand peaks. For the all three PoE scenarios, winter peak demand is forecast to grow at an average annual rate of 1.5 per cent over the outlook period. These growth rates reflect differing weather conditions rather than changes in other assumptions between these scenarios.

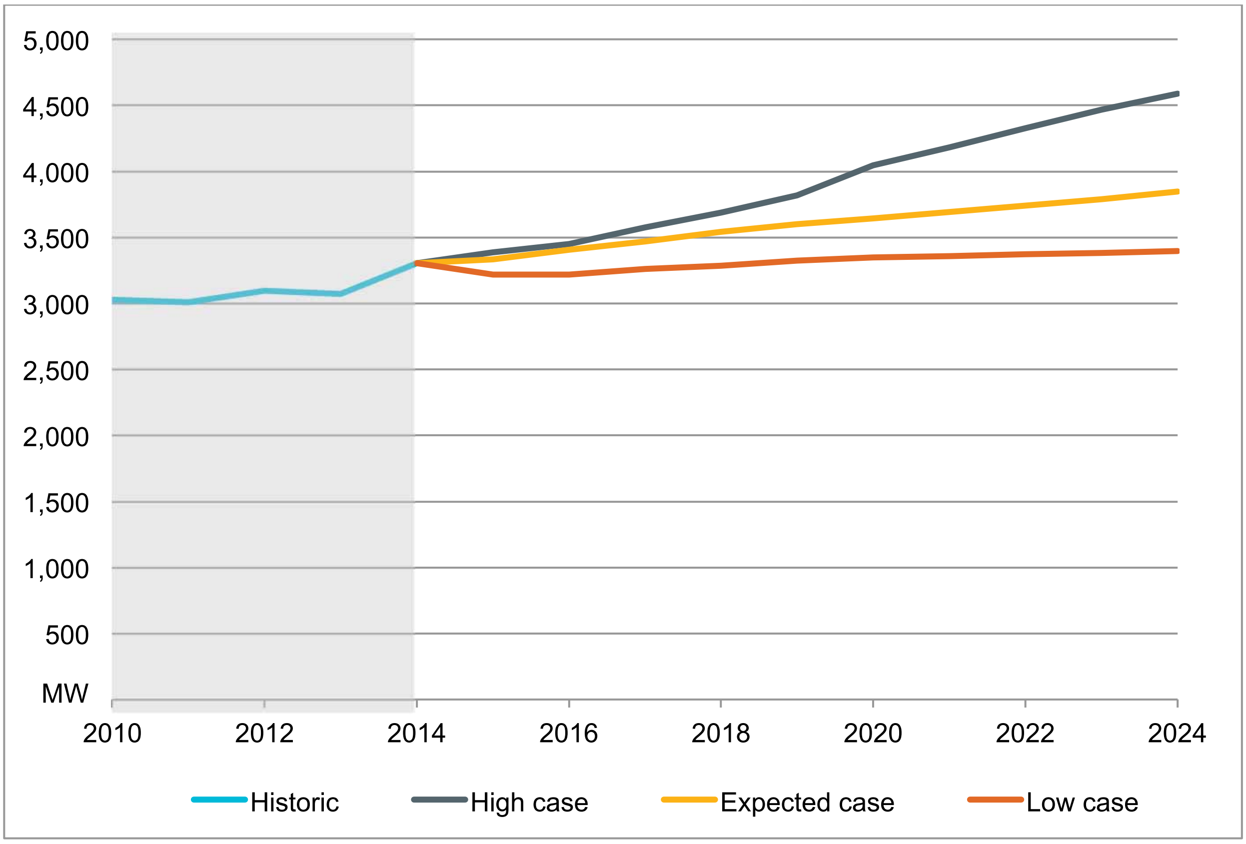
Figure 32: Winter peak demand, expected case forecasts, 2010 to 2024



Source: IMO/NIEIR

Figure 33 shows the low, expected and high case winter peak demand forecasts for the period 2015 to 2024 at the 10 per cent PoE level, compared to the raw, non-weather adjusted historic peak demand. In the expected case, winter peak demand is forecast to grow at an average annual rate of 1.6 per cent over the outlook period. For the high and low case, winter peak demand is forecast to grow at an average rate of 3.4 per cent and 0.6 per cent, respectively. These differences between growth rates reflect different economic and other assumptions rather than weather assumptions.

Figure 33: Winter peak demand 10 per cent PoE forecasts under different economic growth scenarios, 2010 to 2024



Source: *IMO/NIEIR*

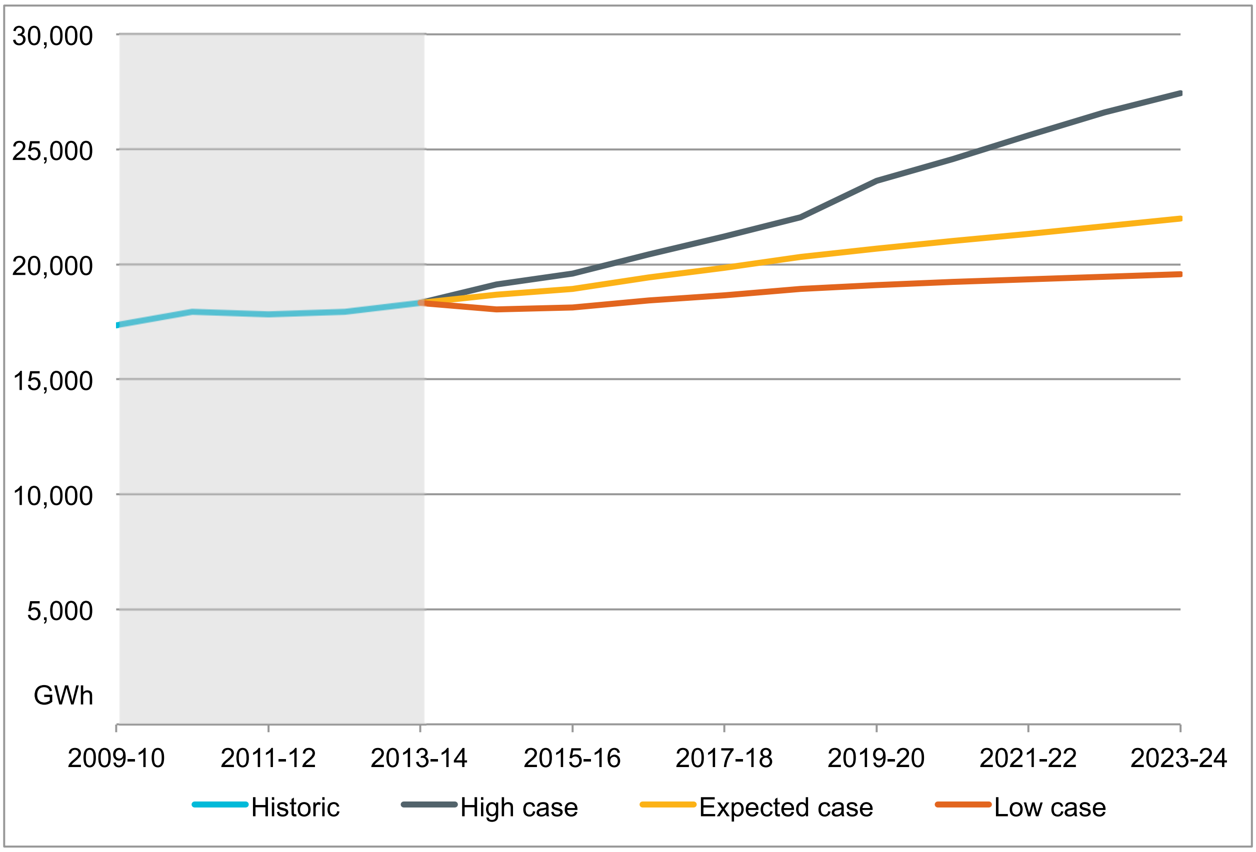
5.4. Energy forecasts

Figure 34 shows the energy forecasts under the three different economic growth scenarios compared to raw, non-weather adjusted historic sent out energy. For the expected case, energy is forecast to grow at an average annual rate of 1.8 per cent over the outlook period. In the high and low cases, energy is forecast to grow at an average rate of 4.1 per cent and 0.9 per cent a year, respectively. These growth rates reflect different economic growth forecasts, as well as changes in block load assumptions.

The same assumptions for economic growth and population are used for both peak demand and energy (see section 5.3 above for detail on these assumptions). In addition to these assumptions, the energy forecast also assumes over the outlook period:

- residential electricity sales growth averaging 2.9 per cent a year in the high case, 1.9 per cent a year in the expected case and 1.3 per cent a year in the low case;
- commercial sales growth of 5.3 per cent a year in the high case, 2.3 per cent a year in the expected case and 0.8 per cent a year in the low case; and
- industrial sales growth of 3.7 per cent a year in the high case, 1.5 per cent in the expected case and 0.4 per cent a year in the low case.

Figure 34: Energy forecasts under different economic growth scenarios, 2009-10 to 2023-24



Source: IMO/NIEIR

Table 8 shows the energy forecasts under the three different economic growth scenarios.

Table 8: Sent out energy forecasts

Scenario	2014-15 (GWh)	2015-16 (GWh)	2016-17 (GWh)	2017-18 (GWh)	2018-19 (GWh)	5 year average annual growth	10 year average annual growth
High	19,115	19,595	20,440	21,207	22,048	3.6%	4.1%
Expected	18,680	18,927	19,429	19,843	20,309	2.1%	1.8%
Low	18,035	18,120	18,435	18,656	18,923	1.2%	0.9%

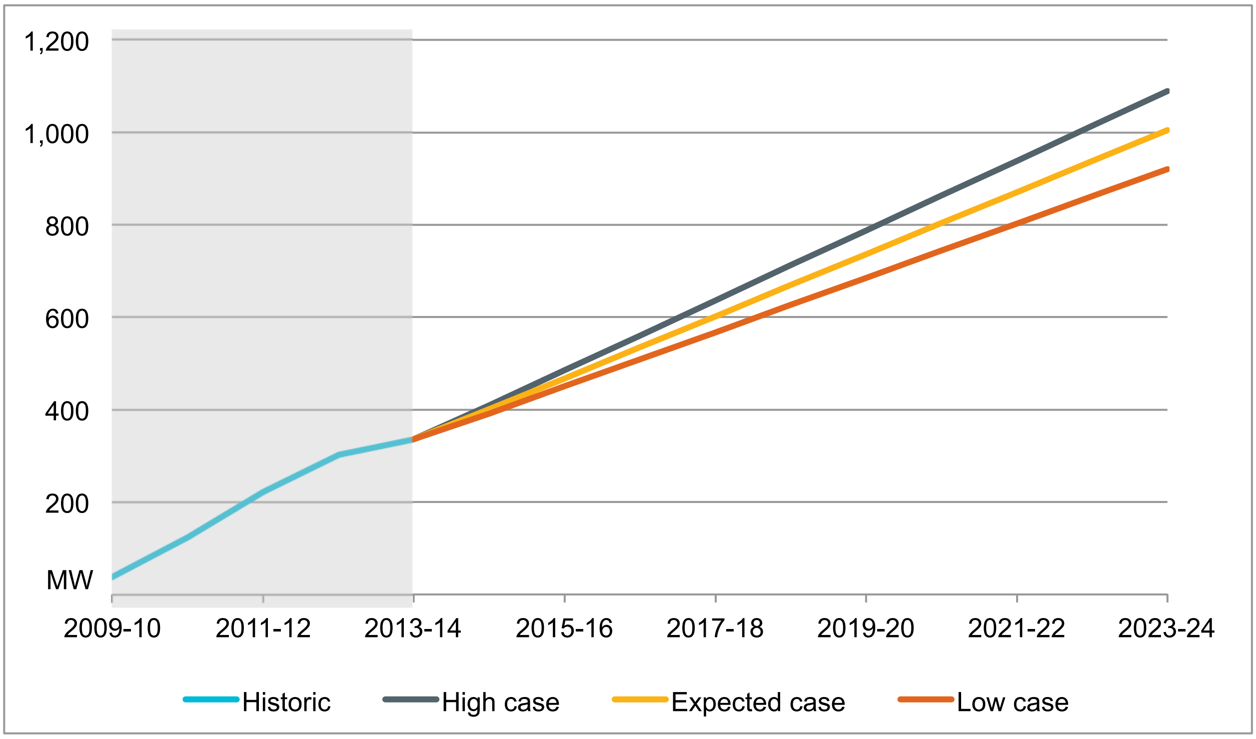
Source: NIEIR

5.5. Solar photovoltaic systems

As discussed in section 3.5 above, solar PV systems reduce the quantity of electricity needed to be supplied by the network. The peak demand and energy forecasts account for this effect by adjusting energy and peak demand according to the amount of solar PV system capacity expected to be installed. The effect of solar PV on peak demand is discounted, since peak production for solar PV panels (typically around noon) does not coincide with the system peak (typically around 4:30 pm).

Figure 35 shows the installed solar PV system capacity forecast for three different installation rate scenarios. The expected case assumes installations at a rate of 1,600 systems per month, while the low and high cases assume 1,400 and 1,800 systems per month, respectively. The system size is assumed to be 3.5 kW per system. Therefore, the expected case assumes an installation rate of 5.6 MW a month, while the low case assumes 4.9 MW and the high case assumes 6.3 MW a month. In the expected case, installed solar PV system capacity is forecast to grow from 336 MW in 2013-14 to 1,005 MW in 2023-24.

Figure 35: Installed solar PV system capacity, 2009-10 to 2023-24

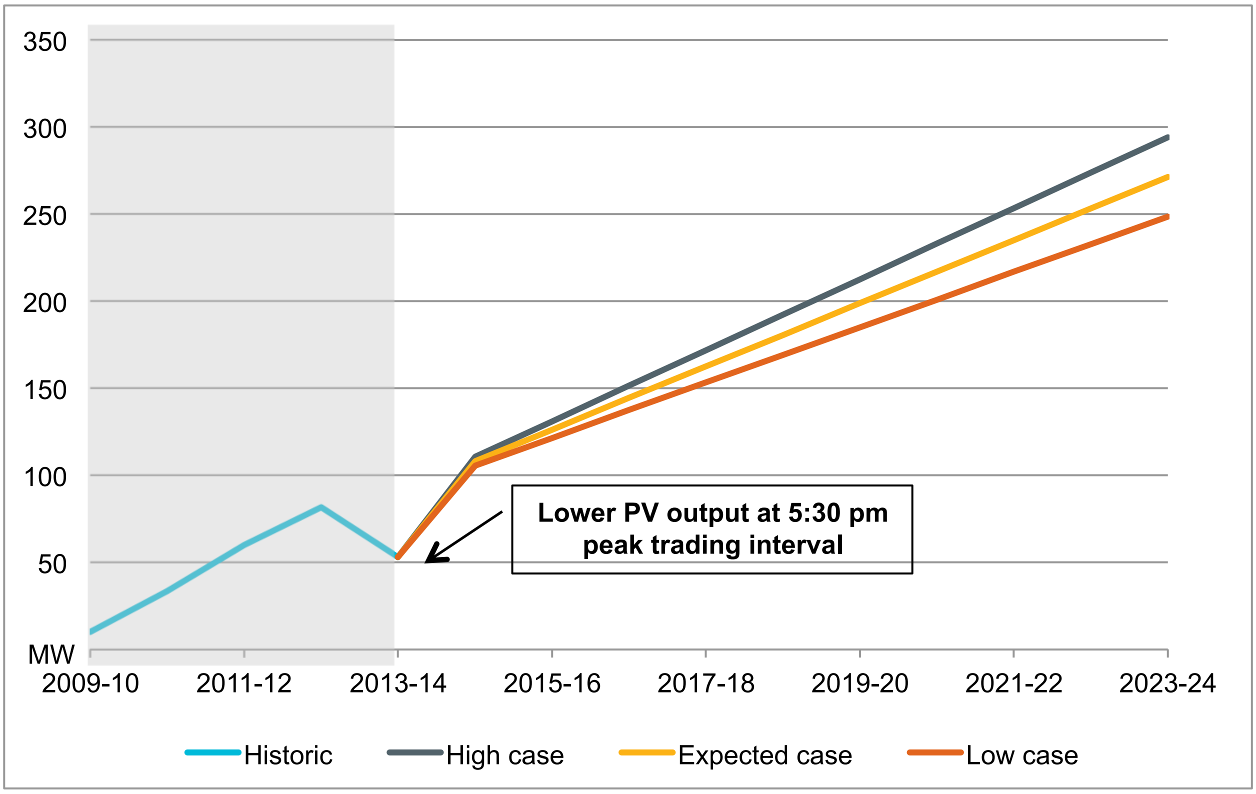


Source: IMO/NIEIR

The 2014 forecast for total installed solar PV system capacity is slightly lower than the forecasts in the 2013 ESOO. This is associated with a lower assumed figure for installed capacity in 2013-14 in the 2014 forecast compared with the 2013 forecast. Installation rates (in MW) are consistent between the two forecasts, where a decline in the installation rate, in terms of number of systems per month, was offset by an increase in the average system size of solar PV system installations. These updated assumptions reflect recent trends in installation rates and average sizes.

Figure 36 shows the forecast reduction in system peak demand from solar PV systems, based on an assumed output of 27 per cent of nameplate capacity at the time of system peak. Solar PV systems are forecast to reduce the peak demand by 271 MW in the expected case by 2023-24, growing from an estimated 53 MW reduction in 2013-14. This 53 MW reduction for 2013-14 is based on the peak occurring in the 5:30 pm trading interval, while the forecast years assume a peak trading interval of 4:30 pm.

Figure 36: Peak demand reduction from solar PV systems, 2009-10 to 2023-24



Source: IMO/NIEIR

5.6. High customer response scenario analysis

An additional scenario has been developed to explore the effect on peak demand of continued growth in customer demand response, through installation of solar PV systems and IRCR. While there is the potential for a number of other developments, such as battery storage and electric vehicles, to influence customer demand over time, this scenario has focused on IRCR and solar PV systems because of the predictability of their effect on long-term demand growth.

This scenario accounts for potentially higher installation rates of solar PV systems and models the effect this may have on peak demand. The scenario assumes that the installed capacity of solar PV systems in the SWIS reaches half of its maximum possible saturation by 2023-24.

This scenario assumes higher than historically observed reductions in peak demand by customers attempting to avoid costs allocated through the IRCR mechanism. The scenario assumes that half of the commercial loads in the SWIS are of the type than can potentially be curtailed, but that of these customers who have the opportunity, only a portion (20 per cent) are initially likely to participate. In addition, the scenario assumes that the initial effect is constrained by the difficulty of accurately picking the peak trading interval. Both the participation rates and accuracy of curtailment are expected to increase over the course of the forecast period.

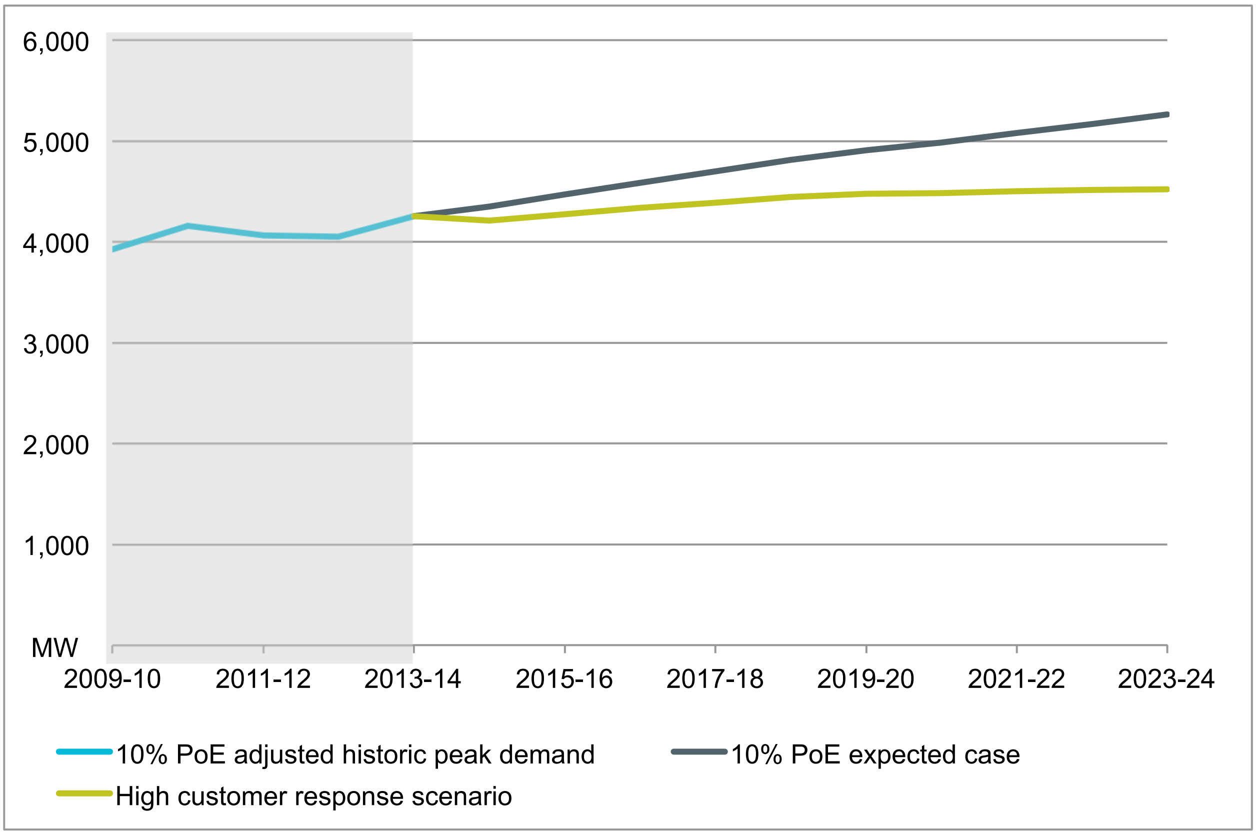
For the sake of this modelling, the level of installation of solar PV systems at which saturation would occur in the SWIS is defined as:

- installed systems on 75 per cent of all suitable residential dwellings (defined as all detached dwellings and semi-detached dwellings, as well as 30 per cent of other dwelling types) and 90 per cent of all commercial properties; and
- the average system size of installed solar PV systems reaching 3.5 kW for residential dwellings and 26.5 kW for commercial properties.

This level of uptake implies installation by approximately 30 per cent of all customers in the SWIS over the forecast period. These installation rates result in growth in solar PV system installed capacity at slower rates than have historically been observed. Installed capacity in the SWIS has grown by almost five per cent a month since 2010, and despite being a high response scenario it is assumed that growth will reduce to less than two per cent a month over the remainder of the outlook period.

Figure 37 shows the 10 per cent PoE high customer response scenario compared with the expected case forecast discussed in section 5.3 above, as well as 10 per cent PoE adjusted historic peak demand. In the high customer response scenario, average annual peak demand growth is comparable to short-term historic annual growth at 0.8 per cent between 2014-15 and 2023-24, compared to growth of 2.1 per cent a year, on average, in the expected case forecast. By 2023-24, the high customer response scenario results in 741 MW less demand in the SWIS than under the expected case assumptions.

Figure 37: Peak demand, 10 per cent PoE, expected case and high customer response scenario, 2009-10 to 2023-24



Source: IMO/NIEIR

The IMO considers that, in light of ongoing technological advances and expected further increases in electricity prices, the drivers of customer demand response are not likely to abate in coming years. The difference between the expected case and high customer response scenario indicates a range of possible outcomes over the forecast period.

6. Forecast reconciliation

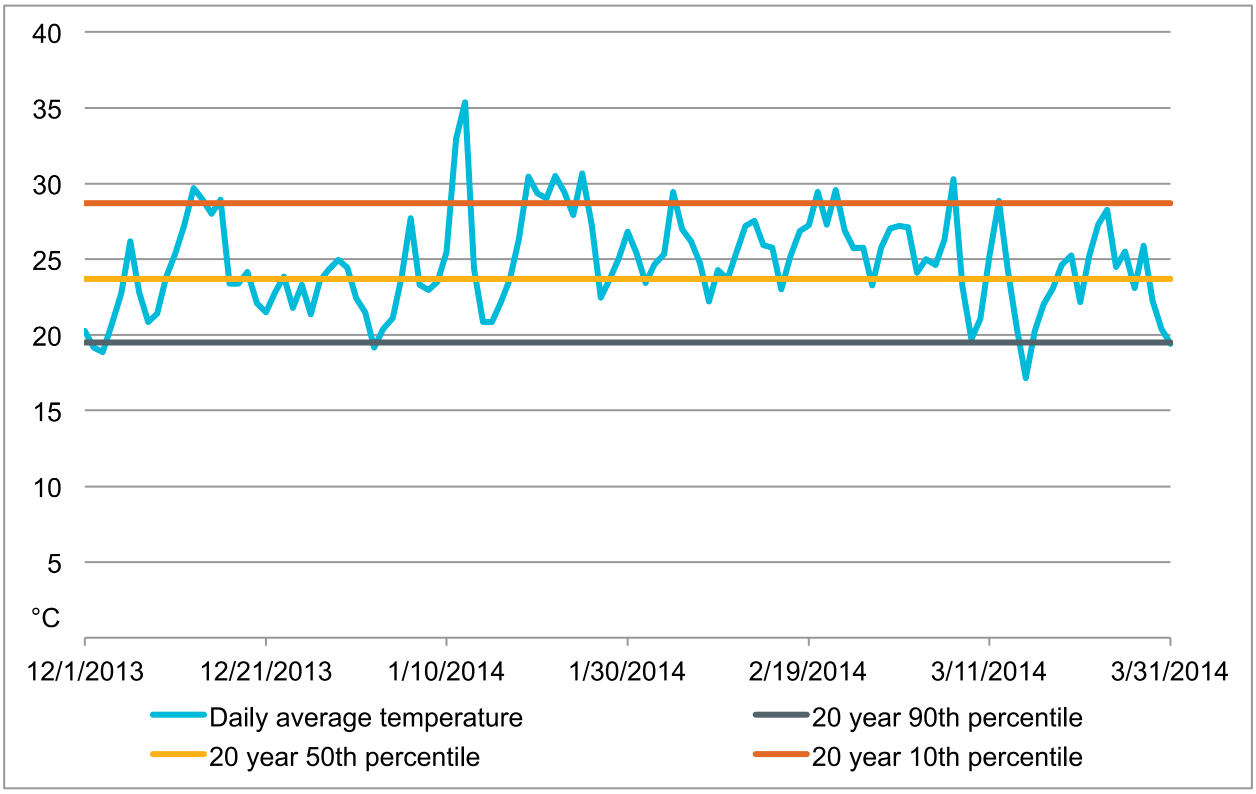
This chapter discusses forecast performance against actual observations, as well as how the IMO's peak demand and energy forecasts have changed over time. Section 6.1 presents the reconciliation of the 2013-14 actual data with the forecasts from the 2013 ESOO. Differences between previous forecasts and the forecast presented in chapter 5 of this year's forecast report are discussed in section 6.2.

6.1. Base year reconciliation

A key part of forecast reconciliation is understanding the effect of weather on the observed system peak. As forecasts generally assume a neutral weather situation, it is necessary to remove the effect of warmer or cooler temperatures. This allows the variance to be separated into a weather effect and other effects to enable analysis of underlying trends in electricity use and a critical review of forecasts and is why weather adjusted historical figures have been used in various places throughout this report.

Figure 38 shows the average daily temperatures over summer, compared with the historical 90th, 50th (median), and 10th percentiles, calculated over 20 years of daily summer temperature data. The summer of 2013-14 was warmer than average. The daily average temperature in 2013-14 exceeded the long-term average 10th percentile on 16 days, or 13 per cent of the time, and fell below the 90th percentile on only five days.

Figure 38: Daily average temperatures, December 2013 to March 2014

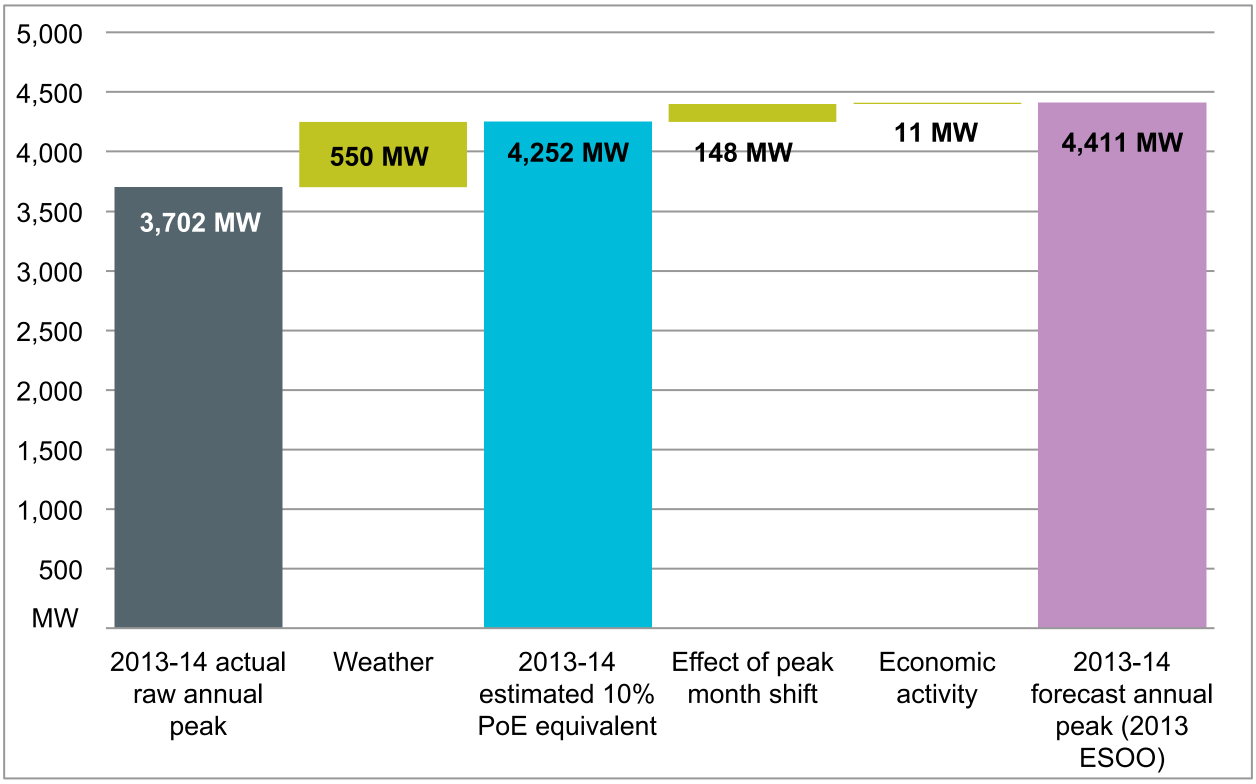


Source: Bureau of Meteorology

Figure 39 shows the variance between the 2013-14 actual peak demand and the 2013-14 forecast peak demand. The estimated weather adjusted peak demand was 5.2 per cent lower than the forecast peak.

The 2013-14 peak occurred at a temperature around five degrees lower than would be expected on a 10 per cent PoE day. The system peak was therefore lower than would have been observed if temperatures were closer to the 10 per cent PoE level. Another large proportion of the variance resulted from the peak demand occurring in January rather than February, when schools, universities and some commercial loads may not be operating. Slower than expected economic activity accounted for the remainder of the variance.

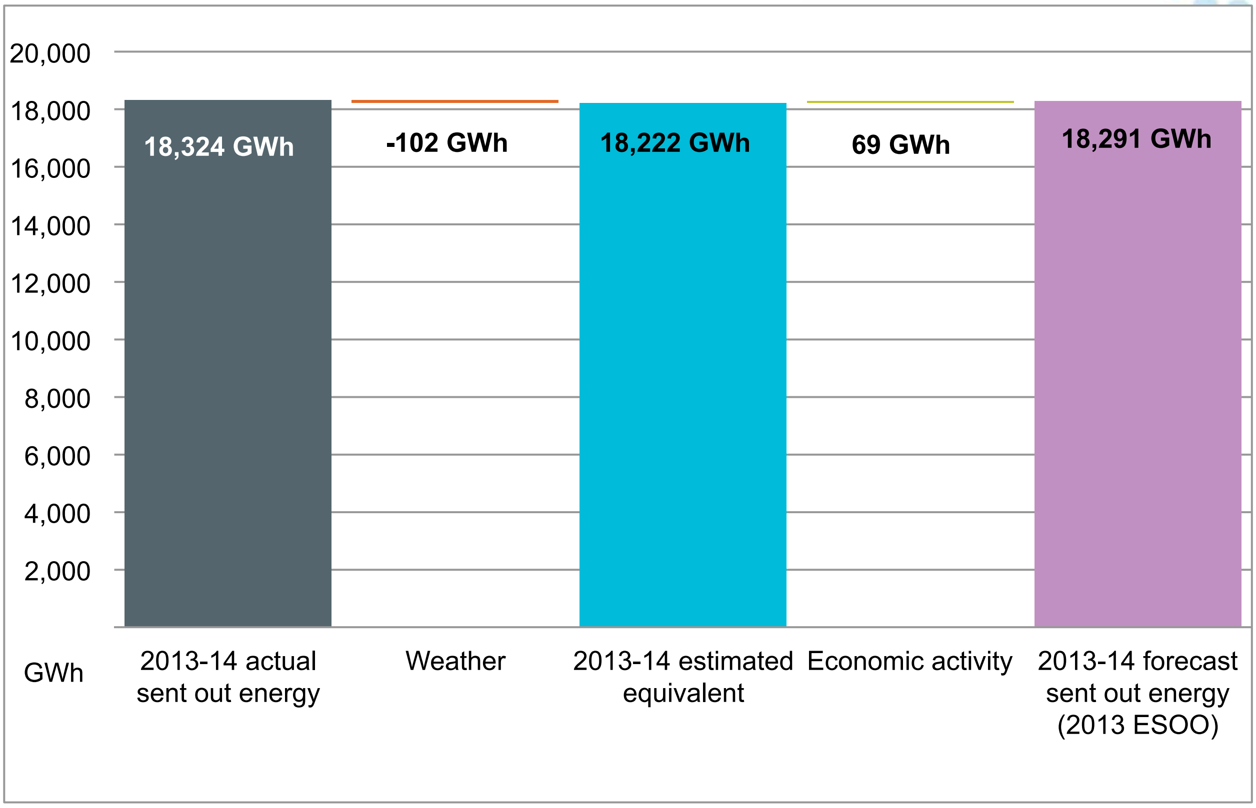
Figure 39: Peak demand variance analysis, 2013-14



Source: IMO/NIEIR

Figure 40 shows the variance between actual sent out energy in 2013-14 and forecast sent out energy from the 2013 ESOO. Actual sent out energy was within 1 per cent (slightly lower) of the forecast. A small adjustment was made to raw energy data to account for a warmer than average summer.

Figure 40: Sent out energy variance analysis, 2013-14



Source: IMO/NIEIR

6.2. Changes between previous forecasts

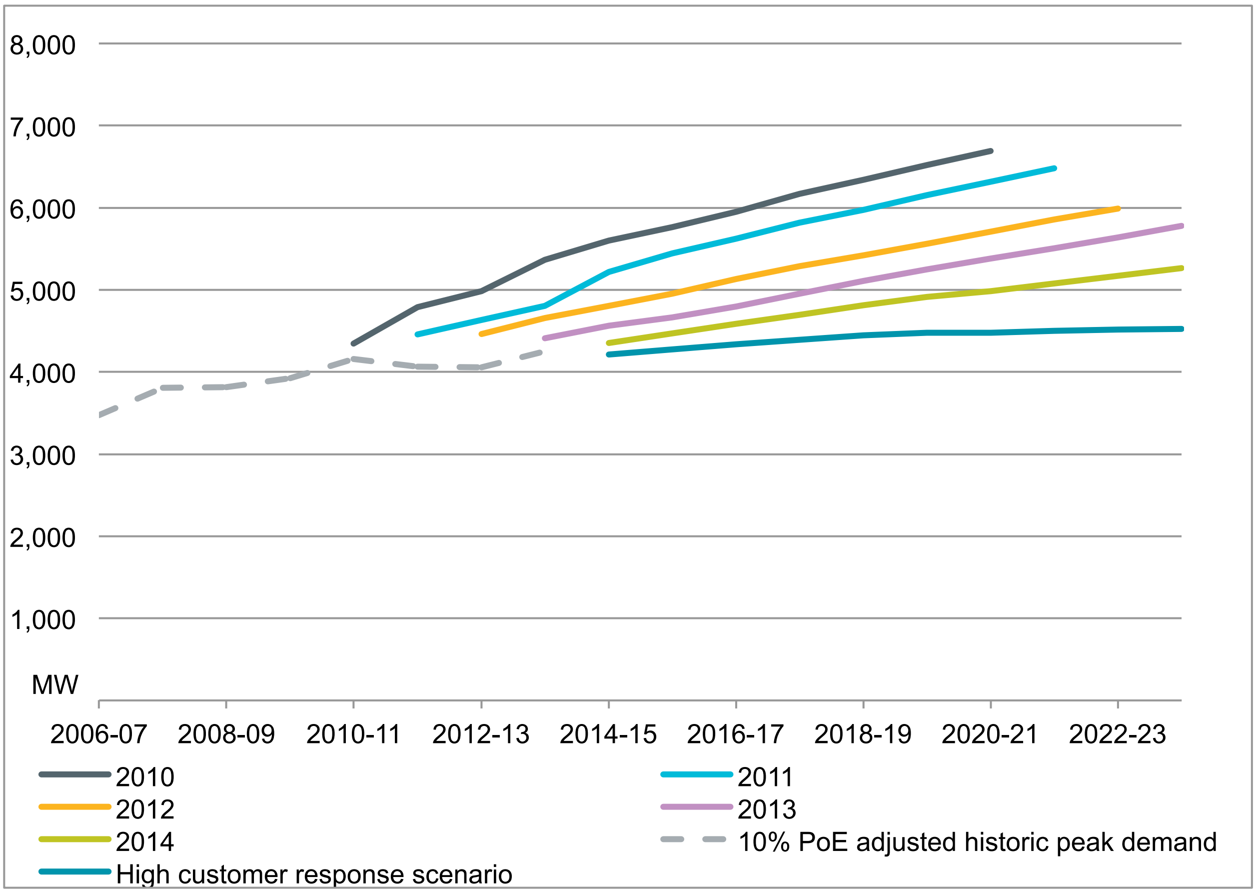
Figure 41 shows the peak demand forecasts from the 2010 through to 2013 ESOO reports, and the forecasts from this report, compared with historic peak demand data. Each forecast has been reduced compared with the previous years' forecast, with the 2014 peak demand forecast being the lowest of the five compared.

Changes between forecasts have been driven by a combination of updates to the assumptions, including:

- block load assumptions;
- the methodology for forecasting temperature sensitive load;
- the incorporation of solar PV system effects in the forecasts starting in the 2012 ESOO; and
- the consideration of IRCR responses in the forecasts starting in the 2013 ESOO.

All of these changes have resulted in progressively lower forecasts, with 2014 being the lowest set of forecasts to date. The revision of block load assumptions, combined with the introduction of solar PV system forecasting in 2012, resulted in a large difference between the 2011 and 2012 forecasts, with smaller differences more recently (other than in the high customer response scenario).

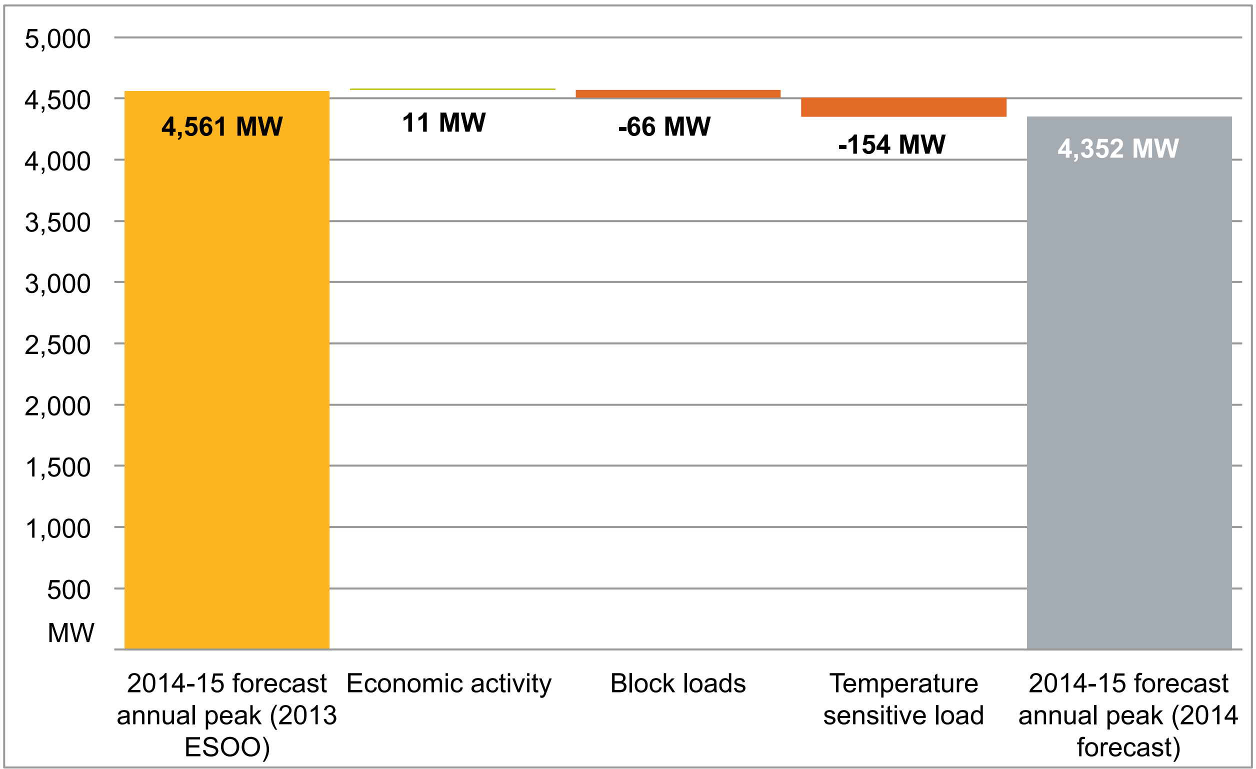
Figure 41: Change between peak demand 10 per cent PoE, expected case forecasts, 2010 to 2014 forecasts



Source: IMO/NIEIR

Figure 42 shows the change in the peak demand forecast for 2014-15 between the 2013 ESOO and the 2014 forecast. The 2014 forecast for 2014-15 is 4.6 per cent (209 MW) lower than the 2013 forecast for 2014-15. Most of this difference (154 MW) is associated with a reduction in the forecast for temperature sensitive load, with the remainder from block loads. However, an increase in economic growth assumptions has partly offset these reductions.

Figure 42: Change between peak demand 10 per cent PoE forecasts for 2014-15, 2013 ESOO and 2014 forecasts



Source: IMO/NIEIR

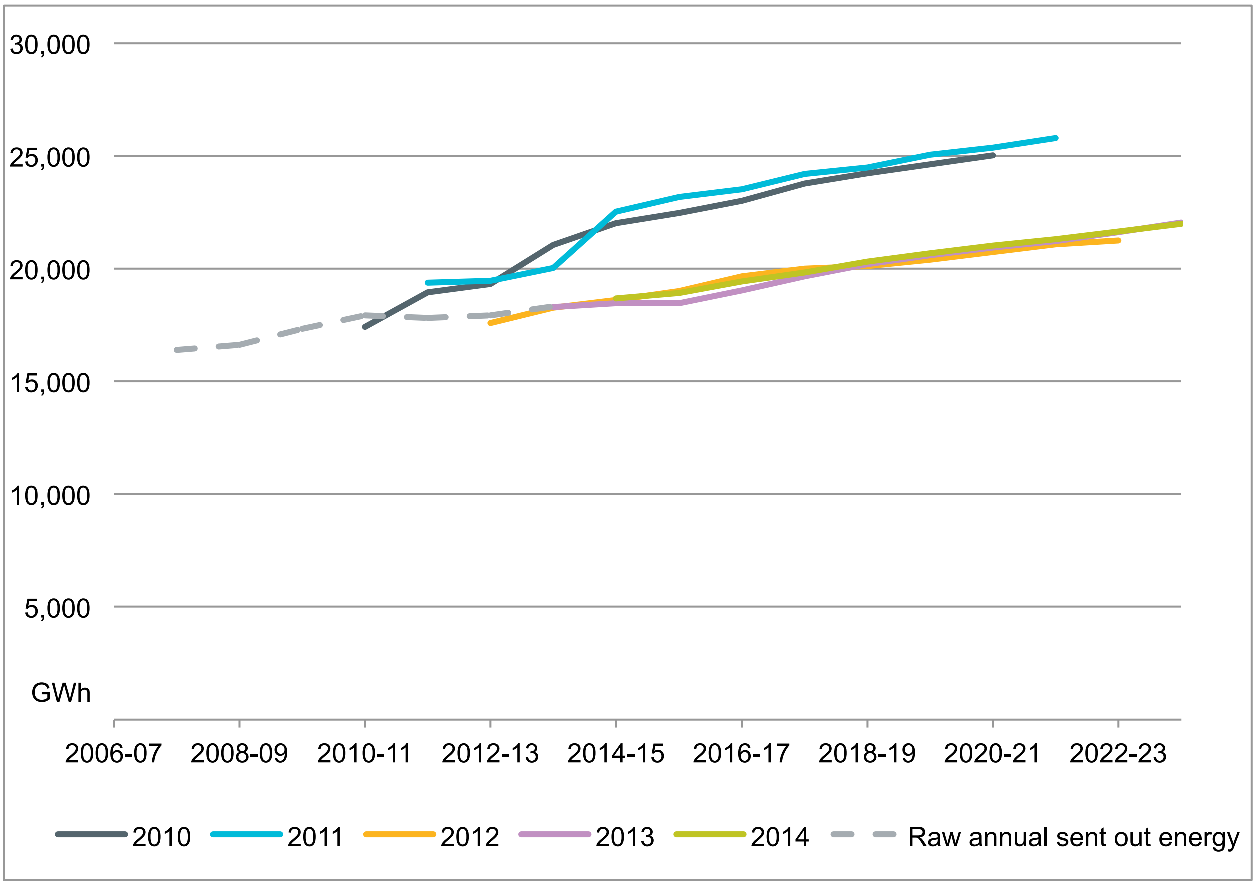
Figure 43 shows the sent out energy forecasts from the 2010 through to 2013 ESOOs and the 2014 forecast, compared with historic raw annual sent out energy. The 2010 and 2011 forecasts were markedly higher than the 2012 through to 2014 forecasts. The recent flattening of growth in sent out energy has resulted in lower forecasts for 2012, 2013 and 2014 compared with 2010 and 2011.

A revision of the assumptions for the sent out energy forecasts in 2012 resulted in a large change between the 2011 and 2012 forecasts. These revisions included:

- the introduction of solar PV system effects into the forecast in 2012;
- a reduction in the forecast for block loads; and
- updated price assumptions, including the effect of carbon pricing.

The forecasts between 2012 and 2014 have been broadly consistent, with variances explained by differences in economic growth assumptions and small changes in actual data.

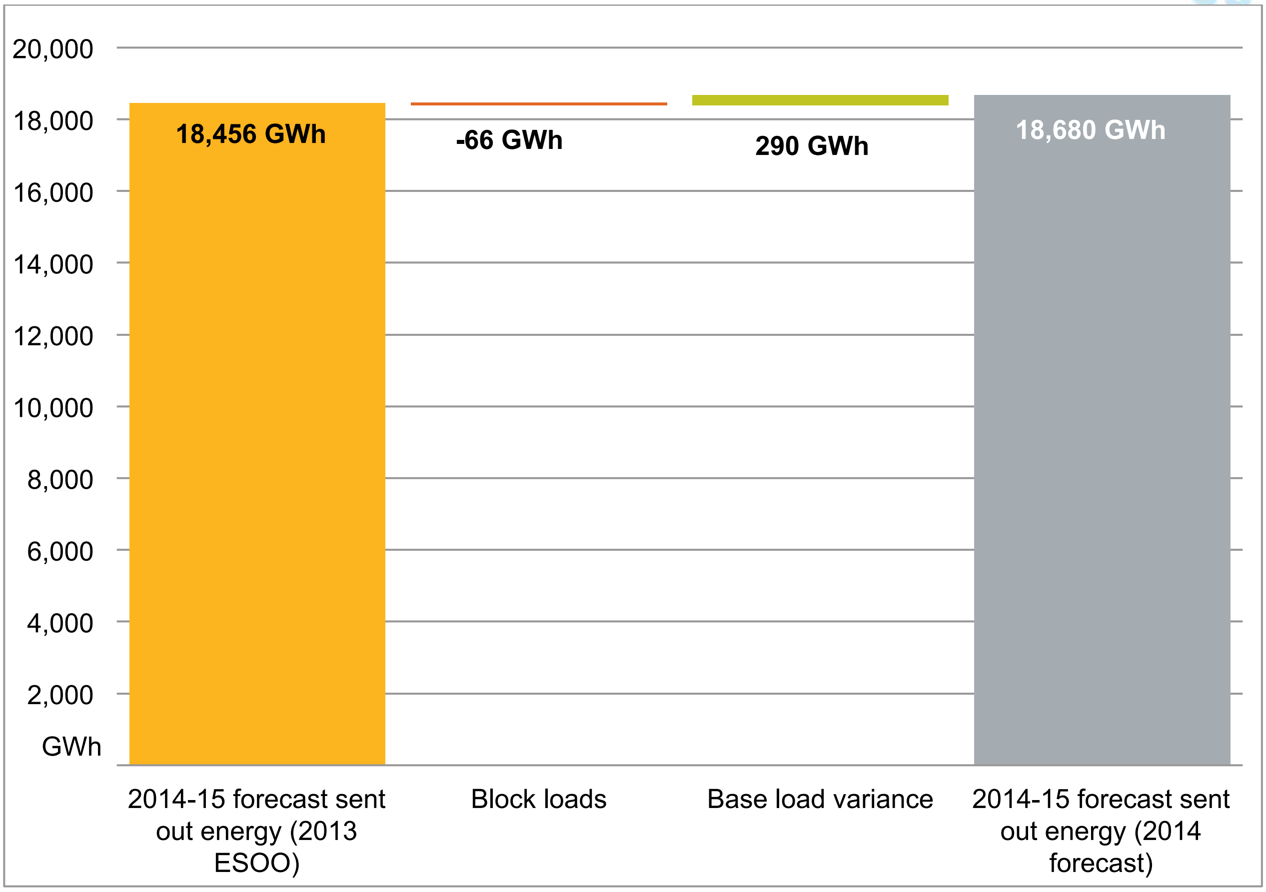
Figure 43: Change between sent out energy expected case forecasts, 2010 to 2014 forecasts



Source: IMO/NIEIR

Figure 44 shows the change in the sent out energy forecast for 2014-15 between the 2013 ESOO and 2014 forecast. The variance between the two forecasts is less than 1 per cent. Small adjustments have been made to the 2014 forecast to account for updated block load assumptions, and a change in base load consumption.

Figure 44: Change between sent out energy expected case forecasts for 2014-15, 2013 ESOO and 2014 forecasts



Source: IMO/NIEIR

7. The Reserve Capacity Mechanism

This chapter discusses the general RCM process, including the steps that must be followed to achieve Certification of Reserve Capacity. This chapter also presents the expected supply-demand balance in the SWIS, based on the 10 per cent PoE, expected case forecast, and shows the capacity outlook for 2016-17.

On 29 April 2014, the IMO received a direction from the Minister for Energy to defer certain aspects of the 2014 Reserve Capacity Cycle, and the IMO has extended timelines for this process in light of this direction. The IMO has also cancelled the Reserve Capacity Auction for 2014, and delayed publication of the 2014 ESOO until 17 June 2015.

7.1. The Reserve Capacity process

The Reserve Capacity process follows a set of steps each year, as set out below:

- the IMO determines the Maximum Reserve Capacity Price and calculates a preliminary Reserve Capacity Requirement;
- EOIs for Certified Reserve Capacity are sought from Market Participants, which are summarised and published on the IMO website;
- the ESOO is published, and the Reserve Capacity Target set;
- applications for certification of Reserve Capacity are submitted by Market Participants;
- the IMO assigns Certified Reserve Capacity to facilities, and Market Participants indicate their intention to bilaterally trade capacity or offer the Certified Reserve Capacity into the Reserve Capacity Auction;
- the IMO advises whether sufficient capacity has been procured through bilateral trades, and announces whether there will be a Reserve Capacity Auction. If the Reserve Capacity Requirement has been met, the Reserve Capacity Auction will be cancelled. If sufficient capacity has not been obtained, the IMO will advise that it will run a Reserve Capacity Auction to secure the remaining quantity; and
- if a Reserve Capacity Auction is required, Market Participants must lodge offers before the IMO runs the auction.

In light of the Ministerial Direction, the IMO has extended the following timelines for the 2014 Reserve Capacity Cycle:

- applications for certification of Reserve Capacity will open on 1 May 2015, and will close at 5:00 pm on 1 July 2015;
- the 2014 ESOO and Reserve Capacity Information Pack for the 2014 Reserve Capacity Cycle will be published on 17 June 2015;
- the IMO must notify each applicant of the Certified Reserve Capacity to be assigned for 2016-17 Capacity Year by 5:00 pm on 19 August 2015;

- Market Participants with facilities that are granted Certified Reserve Capacity must indicate their intention to bilaterally trade or offer the Certified Reserve Capacity into the Reserve Capacity Auction by 5:00 pm on 2 September 2015; and

- the IMO will advise Market Participants who have indicated an intention to bilaterally trade Capacity Credits about how much Certified Reserve Capacity each facility will be allocated by 5:00 pm on 3 September 2015.

On 4 June 2014, the IMO cancelled the Reserve Capacity Auction for 2014. An updated Reserve Capacity Cycle timetable is available from the IMO's website[33].

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

Disruptions to gas supply in 2008 and 2011 have focussed 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 documents.

Further information on the certification of Reserve Capacity process is available on the IMO's website[34].

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[33] Available at: http://imowa.com.au/docs/default-source/Reserve-Capacity/deferred-2014-reserve-capacity-mechanism-timetable.pdf?sfvrsn=0.
[34] Available at: http://imowa.com.au/reserve-capacity.

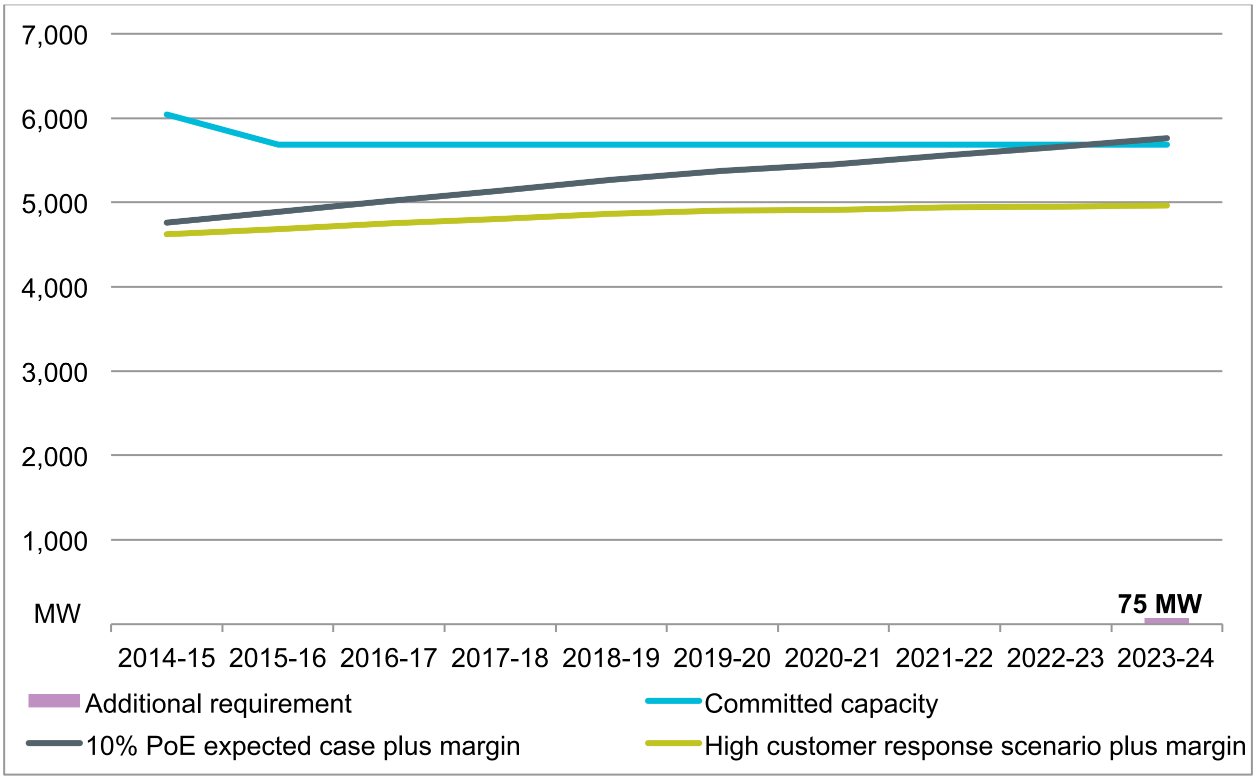
7.2. Opportunities for investment

7.2.1. Supply-demand balance

Figure 45 shows the supply-demand balance between 2014-15 and 2023-24, based on the 10 per cent PoE expected case forecast discussed in chapter 5 above, with an estimated Reserve Margin added, and the high customer response scenario plus an estimated margin.

Committed capacity (defined as Capacity Credits assigned to generators and DSM) is expected to fall from 6,040 MW in 2014-15 to 5,683 MW in 2015-16, and continues at this level until 2023-24. This fall is associated with the decommissioning of Kwinana Power Station Stage C (362 MW) and reductions in Capacity Credits assigned to intermittent generators. These committed capacity figures assume no new capacity is assigned Capacity Credits between 2016-17 and 2023-24, and that there are no additional retirements of existing capacity. These figures also assume that there is no reduction in Capacity Credits resulting from the Rule Change Proposal: Harmonisation of Supply-Side and Demand-Side Capacity Resources (RC_2013_10), which was rejected by the Minister for Energy in May 2014.

Figure 45: Supply-demand balance, 2014-15 to 2023-24



Source: IMO/NIEIR

Existing and committed capacity is expected to be sufficient to satisfy the 10 per cent PoE, expected case plus margin until 2023-24, when around 75 MW of new capacity would be required. It is estimated that there will be around 1,280 MW of excess capacity in the SWIS in 2014-15. Excess capacity is expected to steadily decrease as peak demand increases. However, if the circumstances assumed in the high customer response scenario eventuate, no new capacity will be required during the outlook period.

This analysis suggests that, based on the latest forecasts, it is likely that no new capacity will be required in the SWIS in the next ten years. However, 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.

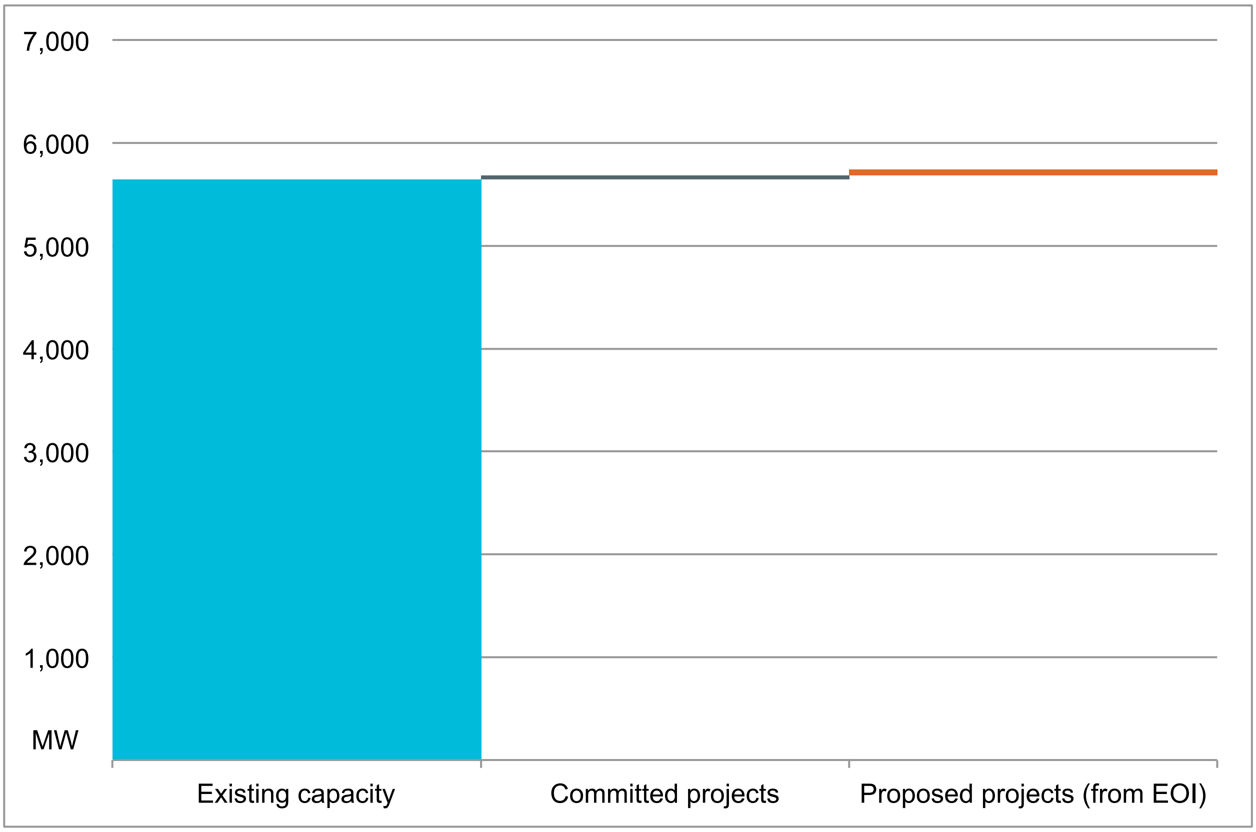
7.2.2. *Expressions of Interest*

The most recent EOI process identified proposals for 56.05 MW of new Reserve Capacity for the 2016-17 Capacity Year. It should be noted, however, that the proponents of these developments have not necessarily indicated any level of commitment to proceed, and the IMO has not assessed the probability of each of the potential projects.

While the EOI process provides an indication of potential future capacity, the submission of an EOI does not necessarily translate into certified capacity. In 2013, EOIs were received for 59 MW of new capacity but none of this capacity was assigned Capacity Credits for the 2015-16 Capacity Year.

Figure 46 shows the capacity outlook for the 2016-17 Capacity Year, including existing capacity, committed projects, and proposed projects from the 2014 EOI. The total existing capacity is more than sufficient to meet the forecast 10 per cent PoE, expected case peak demand of 4,588 MW in 2016-17 and 4,699 MW in 2017-18. Consequently, there is limited opportunity for new investment in the near term.

Figure 46: Capacity outlook for 2016-17



Source: IMO

Table 9 shows the amount of capacity offered each year during the EOI process, compared with the amount of capacity previously offered that was actually certified, as well as all other capacity certified in that year. The low quantity of capacity offered this year continues the downward trend in new capacity being offered through the EOI process. This reflects a more general trend of declining new capacity receiving Capacity Credits. While the EOI process provides an indication of future capacity, the submission of an EOI by a project developer does not necessarily result in the development of that capacity. Some of the capacity may potentially be developed for subsequent Reserve Capacity Cycles.

Table 9: Capacity offered through EOI compared to capacity certified, 2007 to 2013

Capacity (MW)	2007	2008	2009	2010	2011	2012	2013	2014
Capacity offered	1,192	1,036	1,279	644	337	214	59	56
Capacity offered and certified	370	24	454	391	33	0	0.4	N/A
Total other capacity certified	205	113	123	135	7	25	15	N/A

Source: IMO

Appendix 1 Abbreviations

- ABS – Australian Bureau of Statistics
- AEMO – Australian Energy Market Operator
- APR – Annual Planning Report
- ARENA – Australian Renewable Energy Agency
- CEFC – Clean Energy Finance Corporation
- CER – Clean Energy Regulator
- DSM – Demand Side Management
- EOI – Expressions of Interest
- ERA – Economic Regulation Authority
- ESOO – Electricity Statement of Opportunities
- FIT – Feed-in Tariff
- GSP – gross state product (for Western Australia)
- GWh – gigawatt hour
- IMO – Independent Market Operator
- IRCR – Individual Reserve Capacity Requirement
- kWh – kilowatt hour
- MREP – Market Rules Evolution Plan
- MW – megawatt
- MWEP – Mid West Energy Project
- MWh – megawatt hour
- NEM – National Electricity Market
- NIEIR – National Institute of Economic and Industry Research
- PJ – petajoule
- PoE – probability of exceedance
- PV – photovoltaic
- RCM – Reserve Capacity Mechanism
- RCMWG – Reserve Capacity Mechanism Working Group
- RET – Renewable Energy Target
- STEM – Short Term Energy Market
- SWIS – South West interconnected system
- TWh – terawatt hour
- WEM – Wholesale Electricity Market

Appendix 2 Forecasts of economic growth

Table I: Growth in Australian gross domestic product

Year	Actual (%)	Expected (%)	High (%)	Low (%)
2006-07	3.8			
2007-08	3.7			
2008-09	1.7			
2009-10	2.0			
2010-11	2.2			
2011-12	3.6			
2012-13	2.7			
2013-14		2.3	3.4	1.8
2014-15		2.4	3.0	2.0
2015-16		2.1	3.4	1.5
2016-17		2.2	3.6	1.4
2017-18		2.4	3.1	1.9
2018-19		2.7	4.3	2.3
2019-20		2.3	3.7	1.4
2020-21		1.7	2.8	0.5
2021-22		2.2	3.4	1.4
2022-23		2.6	3.9	1.4
2023-24		2.7	3.1	0.8
Average growth		**2.4**	**3.5**	**1.5**

Source: NIEIR

Table II: Growth in Western Australian gross state product

Year	Actual (%)	Expected (%)	High (%)	Low (%)
2006-07	6.2			
2007-08	4.0			
2008-09	4.3			
2009-10	4.2			
2010-11	4.1			
2011-12	7.3			
2012-13	5.1			
2013-14		3.1	4.2	2.2
2014-15		1.9	3.3	0.8
2015-16		2.4	3.7	1.4
2016-17		6.0	7.6	4.8
2017-18		3.8	5.3	2.6
2018-19		3.8	5.2	2.8
2019-20		2.2	3.8	0.9
2020-21		1.9	3.4	0.7
2021-22		2.5	3.9	1.4
2022-23		2.7	4.4	1.4
2023-24		2.6	4.3	1.4
Average growth		**3.0**	**4.5**	**1.9**

Source: NIEIR

Appendix 3 Solar PV system forecasts

Table III: Peak demand contribution of solar PV systems

Year	Expected (MW)	High (MW)	Low (MW)
2014-15	110	112	107
2015-16	128	133	123
2016-17	146	153	139
2017-18	164	174	155
2018-19	182	194	171
2019-20	200	214	186
2020-21	219	235	202
2021-22	237	255	218
2022-23	255	276	234
2023-24	273	296	250

Source: IMO

Table IV: Annual energy contribution of solar PV systems (financial year basis)

Year	Expected (GWh)	High (GWh)	Low (GWh)
2014-15	601	614	587
2015-16	702	728	675
2016-17	803	841	764
2017-18	903	955	852
2018-19	1,004	1,068	940
2019-20	1,105	1,181	1,028
2020-21	1,206	1,295	1,116
2021-22	1,306	1,408	1,205
2022-23	1,407	1,522	1,293
2023-24	1,508	1,635	1,381

Source: IMO

Table V: Annual energy contribution of solar PV systems (Capacity Year basis)

Year	Expected (GWh)	High (GWh)	Low (GWh)
2014-15	626	642	609
2015-16	727	756	697
2016-17	827	869	785
2017-18	928	983	874
2018-19	1,029	1,096	962
2019-20	1,130	1,210	1,050
2020-21	1,231	1,323	1,138
2021-22	1,331	1,436	1,226
2022-23	1,432	1,550	1,314
2023-24	1,533	1,663	1,403

Source: IMO

Appendix 4 Block load forecasts

Table VI: Peak demand contribution of new large loads

Year	Expected (MW)	High (MW)	Low (MW)
2014-15	103	120	75
2015-16	108	120	80
2016-17	108	120	80
2017-18	108	120	80
2018-19	108	120	80
2019-20	108	205	80
2020-21	108	235	80
2021-22	108	255	80
2022-23	108	270	80
2023-24	108	270	80

Source: IMO

Table VII: Annual energy contribution of new large loads (financial year basis)

Year	Expected (GWh)	High (GWh)	Low (GWh)
2014-15	606	706	492
2015-16	697	768	530
2016-17	697	768	530
2017-18	697	768	530
2018-19	697	768	530
2019-20	697	1,324	530
2020-21	697	1,625	530
2021-22	697	1,791	530
2022-23	697	1,916	530
2023-24	697	1,916	530

Source: IMO

Appendix 5 Forecasts of summer peak demand

Table VIII: Summer maximum demand forecasts with expected case economic growth

Year	Actual (MW)[35]	10 per cent PoE (MW)	50 per cent PoE (MW)	90 per cent PoE (MW)
2006-07	3,474			
2007-08	3,806			
2008-09	3,818			
2009-10	3,926			
2010-11	4,160			
2011-12	4,064			
2012-13	4,054			
2013-14	4,252			
2014-15		4,352	4,046	3,827
2015-16		4,469	4,151	3,925
2016-17		4,588	4,260	4,027
2017-18		4,699	4,362	4,122
2018-19		4,817	4,470	4,225
2019-20		4,911	4,554	4,301
2020-21		4,985	4,614	4,350
2021-22		5,081	4,702	4,432
2022-23		5,170	4,780	4,503
2023-24		5,263	4,863	4,579
Average growth (%)		**2.1**	**2.1**	**2.0**

Source: NIEIR

Table IX: Summer maximum demand forecasts with high case economic growth

Year	10 per cent PoE (MW)	50 per cent PoE (MW)	90 per cent PoE (MW)
2014-15	4,390	4,082	3,862
2015-16	4,521	4,202	3,974
2016-17	4,666	4,336	4,101
2017-18	4,804	4,463	4,222
2018-19	4,946	4,597	4,350
2019-20	5,213	4,852	4,596
2020-21	5,348	4,973	4,708
2021-22	5,524	5,140	4,869
2022-23	5,672	5,278	4,999
2023-24	5,799	5,395	5,109
Average growth (%)	**3.1**	**3.1**	**3.2**

Source: NIEIR

[35] 10 per cent PoE adjusted history

Table X: Summer maximum demand forecasts with low case economic growth

Year	10 per cent PoE (MW)	50 per cent PoE (MW)	90 per cent PoE (MW)
2014-15	4,309	4,004	3,787
2015-16	4,406	4,092	3,868
2016-17	4,506	4,182	3,952
2017-18	4,596	4,264	4,027
2018-19	4,693	4,353	4,112
2019-20	4,767	4,417	4,169
2020-21	4,822	4,459	4,201
2021-22	4,898	4,528	4,265
2022-23	4,966	4,586	4,316
2023-24	5,038	4,649	4,373
Average growth (%)	**1.8**	**1.7**	**1.6**

Source: NIEIR

Table XI: Summer maximum demand forecasts under high customer response scenario

Year	10 per cent PoE (MW)
2014-15	4,211
2015-16	4,274
2016-17	4,337
2017-18	4,391
2018-19	4,446
2019-20	4,476
2020-21	4,482
2021-22	4,504
2022-23	4,514
2023-24	4,522
Average growth (%)	**0.8**

Source: IMO/NIEIR

Appendix 6 Forecasts of winter maximum demand

Table XII: Winter maximum demand forecasts with expected economic growth

Year	Actual (MW)	10 per cent PoE (MW)	50 per cent PoE (MW)	90 per cent PoE (MW)
2008	2,705			
2009	2,774			
2010	2,944			
2011	3,029			
2012	3,008			
2013	3,098			
2014	3,071			
2015		3,304	3,233	3,172
2016		3,333	3,261	3,199
2017		3,408	3,334	3,271
2018		3,467	3,392	3,328
2019		3,540	3,463	3,397
2020		3,599	3,521	3,453
2021		3,646	3,567	3,498
2022		3,691	3,611	3,540
2023		3,741	3,659	3,587
2024		3,788	3,704	3,632
Average growth (%)		**1.5**	**1.5**	**1.5**

Source: IMO/NIEIR

Table XIII: Winter peak demand forecasts with high case economic growth

Year	Actual (MW)	10 per cent PoE (MW)	50 per cent PoE (MW)	90 per cent PoE (MW)
2008	2,705			
2009	2,774			
2010	2,944			
2011	3,029			
2012	3,008			
2013	3,098			
2014	3,071			
2015		3,385	3,309	3,253
2016		3,449	3,371	3,313
2017		3,577	3,497	3,437
2018		3,689	3,606	3,544
2019		3,818	3,733	3,668
2020		4,048	3,960	3,893
2021		4,184	4,094	4,025
2022		4,329	4,236	4,165
2023		4,469	4,374	4,300
2024		4,588	4,491	4,415
Average growth (%)		**3.4**	**3.5**	**3.5**

Source: IMO/NIEIR

Table XIV: Winter peak demand forecasts with low case economic growth

Year	Actual (MW)	10 per cent PoE (MW)	50 per cent PoE (MW)	90 per cent PoE (MW)
2008	2,705			
2009	2,774			
2010	2,944			
2011	3,029			
2012	3,008			
2013	3,098			
2014	3,071			
2015		3,219	3,149	3,094
2016		3,219	3,149	3,094
2017		3,261	3,189	3,133
2018		3,287	3,214	3,157
2019		3,324	3,250	3,192
2020		3,347	3,272	3,213
2021		3,360	3,285	3,225
2022		3,372	3,296	3,235
2023		3,384	3,307	3,246
2024		3,396	3,318	3,256
Average growth (%)		**0.6**	**0.6**	**0.6**

Source: IMO/NIEIR

Appendix 7 Forecasts of sent out energy

Table XV: Forecasts of sent out energy (financial year basis)

Year	Actual (GWh)	Expected (GWh)	High (GWh)	Low (GWh)
2007-08	16,387			
2008-09	16,628			
2009-10	17,342			
2010-11	17,930			
2011-12	17,813			
2012-13	17,935			
2013-14	18,324			
2014-15		18,680	19,115	18,035
2015-16		18,927	19,595	18,120
2016-17		19,429	20,440	18,435
2017-18		19,843	21,207	18,656
2018-19		20,309	22,048	18,923
2019-20		20,693	23,634	19,102
2020-21		21,011	24,574	19,225
2021-22		21,317	25,605	19,337
2022-23		21,657	26,595	19,457
2023-24		21,984	27,430	19,572
Average growth (%)		**1.8**	**4.1**	**0.9**

Source: IMO/NIEIR

Table XVI: Forecasts of sent out energy (Capacity Year basis)

Year	Actual (GWh)	Expected (GWh)	High (GWh)	Low (GWh)
2007-08	16,519			
2008-09	16,690			
2009-10	17,500			
2010-11	17,861			
2011-12	17,914			
2012-13	18,028			
2013-14	18,423			
2014-15		18,771	19,321	17,964
2015-16		18,989	19,718	18,141
2016-17		19,557	20,660	18,515
2017-18		19,948	21,407	18,712
2018-19		20,428	22,266	18,990
2019-20		20,791	24,059	19,148
2020-21		21,092	24,819	19,256
2021-22		21,395	25,874	19,366
2022-23		21,743	26,852	19,488
2023-24		22,067	27,645	19,601
Average growth (%)		**1.8**	**4.1**	**1.0**

Source: IMO/NIEIR

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