SOUTH AUSTRALIAN HISTORICAL MARKET INFORMATION REPORT

SOUTH AUSTRALIAN ADVISORY FUNCTIONS

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AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

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Version control

Version	Release date	Changes
1	31/8/2016	

EXECUTIVE SUMMARY

The 2016 *South Australian Historical Market Information Report* (SAHMIR) provides historical information on South Australian electricity market prices, generation, demand, and interconnector supply between South Australia and Victoria, focusing on the past five financial years (2011–12 to 2015–16, and winter 2016 where applicable).

There have been a number of electricity supply changes in the South Australian region in the past year, notably the end of coal-powered generation in May 2016 and the increase to the Heywood Interconnector capability from December 2015.

The change in electricity supply from 2014–15 to 2015–16 is detailed in Table 1.

Table 1 South Australian electricity supply by fuel type (gigawatt hours, GWh), comparing 2014–15 to 2015–16

Local generation by fuel type	2014–15	Percentage share	2015–16	Percentage share	Change	% Change
Gas	4,599	37.3%	4,538	36.6%	-61	-1.3%
Wind	4,223	34.2%	4,322	34.8%	99	2.3%
Coal	2,645	21.4%	2,601	21.0%	-44	-1.7%
Diesel	2	0.02%	8	0.06%	6	300%
Rooftop PV	872	7.1%	938	7.6%	66	7.6%
Total	**12,341**	**100%**	**12,407**	**100%**	**66**	**0.5%**
Combined interconnector flows						
Interconnector net imports	1,528		1,941		413	27.0%
Total imports	1,904		2,227		323	17.0%
Total exports	376		286		-90	-23.9%

Supply mix changes over the last financial year

- In May 2015–16, South Australia's last coal-powered power station, Northern, closed. Analysis since the withdrawal of coal from the region, from 10 May to 31 July 2016, gives an indication of the resulting change in generation mix – gas 48.5%, wind 42.9%, rooftop photovoltaics (PV) 7.8%[1], and diesel and small non-scheduled generators 0.8%.
- Total local electricity generation from scheduled, semi-scheduled, selected[2] non-scheduled South Australian market generators, and estimated rooftop PV increased by 0.5%.

[1] Rooftop photovoltaic (PV) generation estimates for this period are taken from the Australian Solar Energy Forecasting System ASEFS2 half-hourly estimates, converted to GWh.

[2] Selected non-scheduled generators include all wind farms greater than or equal to 30 MW, and Angaston power station.

Interconnector performance and upgrade

- Combined interconnector net imports to South Australia have generally trended upward since 2007–08. Net imports increased 27% in the past year, from 1,528 gigawatt hours (GWh) in 2014–15 to 1,941 GWh in 2015–16.
- Heywood Interconnector import maximum flows are higher since commissioning of the third Heywood transformer increasing nominal flow capability by 140 MW between December 2015 and August 2016.
- Following the closure of Northern Power Station there has been no discernible trend of increasing interconnector imports, due to a confluence of factors including network outages.

Renewable generation in South Australia

- Over the last five years, South Australia has had the highest penetration of renewables of all National Electricity Market (NEM) regions. Total renewable generation including wind and rooftop photovoltaic (PV) for 2015–16 was 5,260 GWh, 3% higher than in 2014–15.
- Both wind and rooftop PV capacity has increased in the last five years:
  - Rooftop PV rapidly increased from 294 megawatts (MW) in 2011–12 to 679 MW in 2015–16, and more than 29% of dwellings in South Australia now have rooftop PV systems installed.[3]
  - Registered wind capacity increased from 1,203 MW in 2011–12 to 1,576 MW in 2015–16.
- Hornsdale Stage 1 Wind Farm (102.4 MW) was registered in June 2016 and is presently under construction.[4]

South Australian electricity spot price trends

- Spot prices for South Australia have been volatile throughout 2015–16. There were more occurrences of both negative prices and prices above $100/MWh (megawatt hour) than in the previous four years.
- Pricing events[5] during 2015–16 in South Australia can be attributed to a combination of factors. These included planned and unplanned generator and transmission outages, higher gas prices, changes in generation offers, high or sudden regional demand including changes in hot water load, and variable weather conditions resulting in low wind and solar generation at times.

Demand trends

- For the previous four years (2011–12 to 2014–15) the South Australian average daily operational consumption was declining. This trend was reversed in 2015–16 as South Australia's average daily operational consumption increased. The region experienced mean temperatures in the top 10 on record, additional water pumping due to drier conditions, increased air-conditioner load, and Port Pirie metals recovery and refining plant's redevelopment also contributed to the increased load for the year.
- The 3,005 MW maximum demand for 2015–16 was consistent with a one in two year event.

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[3] Analysis taken from: Australian PV Institute (APVI) Solar Map, funded by the Australian Renewable Energy Agency, accessed from pv-map.apvi.org.au. Viewed 24 June 2016.

[4] Waterloo Stage 2 and Hornsdale Stage 2 wind farms are committed, but not yet registered.

[5] Pricing events refer to occurrences when the wholesale electricity spot price is above the threshold of $2,000/MWh, or below -$100/MWh, or the sum of all eight Frequency Control Ancillary Services (FCAS) half-hourly averaged prices exceeds $150/MWh.

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FIGURES

1. INTRODUCTION

The 2016 *South Australian Historical Market Information Report* (SAHMIR) provides historical information on South Australian electricity market prices, generation, demand, and interconnector supply between South Australia and Victoria, focusing generally on the last five financial years, 2011–12 to 2015–16.

From 2016, the SAHMIR includes additional content previously published in the now defunct *South Australian Electricity Market Economic Trends Report* (SAEMETR) and *South Australian Wind Study Report* (SAWSR), as described in Table 2 below. Table 2 also illustrates that the remaining content from the SAEMETR and SAWSR will go into two new reports from 2016, namely the *South Australian Renewable Energy Report* (SARER) and the *South Australian Generation Forecasts*.[6]

Table 2 Changes to South Australian reports from 2016

Report	2015 content	2016 content	2016 publication month
***South Australian Historical Market Information Report* (SAHMIR)**	Generation, interconnectors.	Generation, interconnectors, spot price, demand, basic wind performance, historical electrical energy requirements.	August
***South Australian Electricity Market Economic Trends Report* (SAEMETR)**	Spot price, demand, historical and forecast electrical energy requirements.	(Not published in 2016.)	n/a
***South Australian Wind Study Report* (SAWSR)**	Basic and advanced wind performance.	(Not published in 2016.)	n/a
***South Australian Renewable Energy Report* (SARER)**	(Not published in 2015.)	Advanced wind performance, rooftop photovoltaic (PV) performance.	October
South Australian Generation Forecasts	(Not published in 2015.)	Forecast electrical energy requirements.	November

The data that supports the tables and figures in this report is published on AEMO's website.[7] Any discrepancy between data presented in the commentary of this report and the derived data is attributable to rounding in the tables and figures.

1.1 Information sources and assumptions

The SAHMIR reports on electricity generated by South Australian power plants that operate in the NEM. These are typically greater than or equal to 30 megawatts (MW) registered capacity and are described in Appendix B.

Some sections of this report also include aggregated generation output from smaller embedded (non-scheduled) power plants, so-called "small non-scheduled generation" (SNSG). This data is gathered from the Market Settlements and Transfer Solutions (MSATS) system, and is aggregated to ensure anonymity of individual generators' output. Details of generators included in this category are in Appendix C.

Historical estimates of rooftop PV installed capacity and generation output are taken from the 2016 *National Electricity Forecasting Report* (NEFR)[8], to illustrate its impact on reducing operational NEM consumption.[9]

6 South Australian reports for 2015 and 2016 are available on AEMO's website at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions.

7 Data files to accompany the 2016 SAHMIR. Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions.

8 AEMO. *2016 National Electricity Forecasting Report*. Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report.

9 Annual operational consumption is the electrical energy supplied by scheduled, semi-scheduled, and significant non-scheduled generating units. Annual operational consumption does not include the electrical energy supplied by small non-scheduled generating units.

Analysis displaying generator outputs, operational demand, and interconnector flows, whether as duration curves, peak output, or daily averages, uses 5-minute generation or power flow data, measured in MW, to give a representation of peaks and changes over time. For generator output or interconnector flow analysed over a financial year or season, 5-minute power generation or flow data is aggregated and converted to an equivalent energy amount (measured in GWh).

The 2016 SAHMIR reports on as-generated electrical output which includes the electricity supplied to generator auxiliary loads.[10] Table 3 summarises the data sources used in the reporting presented in the 2016 SAHMIR, and any changes from reporting in 2015.

Table 3 SAHMIR data sources summary and comparison to previous reports

Data reported	Data source(s) in 2016 reports	Change from 2015 reports
Reporting on: • **Generation output (including for capacity factor and volume-weighting of average prices)** • **Interconnector flows** • **Demand**	5-minute averages of as-generated SCADA metering. When not available, 5-minute SCADA snapshots or the last known good SCADA value were used instead.	Previous reports generally used 5-minute cleared generation dispatch targets for scheduled and semi-scheduled generators, or SCADA snapshots for non-scheduled generators. (There is no change to the as-generated nature of the data).
Capacity	Registered capacity from AEMO Registrations database.[11] Nameplate capacity from AEMO Generation Information database.[12]	N/A
Pricing	Average of 6 x 5-minute dispatch prices over 30-minute trading interval.	N/A
Greenhouse gas emissions	5-minute averages of as-generated SCADA metering for generators and interconnectors. Emissions factors for AEMO Planning studies.[13]	Emissions factors are updated for 2016.
Small non-scheduled generation	Aggregated MSATS 30-minute metering for selected generators.	Included generators list has changed from 2015 list – Lonsdale no longer included.* Please refer to Appendix B for further details.
Rooftop PV capacity and generation estimates	As provided in 2016 NEFR. Refer to Appendix D for more information.	2016 NEFR has changes to capacity and generation estimates from the 2015 NEFR, due to improved modelling.
Annual consumption, including auxiliary loads and network losses	As provided in 2016 NEFR.	Network losses have been estimated separately for transmission and distribution networks, as explained in 2016 NEFR forecasting methodology information paper.[14]

* Lonsdale is now registered as a scheduled generator.

The key change in the 2016 SAHMIR discussed in Table 3 is the move to reporting generator output, interconnector flow, and demand using 5-minute average SCADA metering, as opposed to cleared generation dispatch targets and supervisory control and data acquisition (SCADA) snapshot values.

While the new data inputs are more representative of actual electrical performance of the systems being analysed, and are now consistent across all generation and interconnector sources, the resultant analysis reported in 2016 is in some cases noticeably different to the analysis presented in 2015 and earlier. Trends and insights generally have not changed, but some historical numbers reported will be different. Where AEMO believes the difference is in some way significant, commentary is provided.

[10] Auxiliary loads refers to the energy from equipment used by a generating system for ongoing operation.

[11] AEMO. Current registration and exemptions list. Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Participant-information/Current-participants/Current-registration-and-exemption-lists. Viewed 1 August 2016.

[12] AEMO Generation Information database. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information. SA-2016, August 11.

[13] AEMO 2016 *Emissions Factor Assumptions Update* (ACIL Allen). Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan/NTNDP-database.

[14] AEMO. 2016 *NEFR Forecasting Methodology Information Paper*. Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report.

Lastly, as a minimum, the SAHMIR now presents at least five years or seasons of history in its analysis. In cases where only three years were presented in previous reports, the trends shown this year, and hence the insights provided, may be different.

Assumptions made throughout the report

A number of assumptions have been made throughout the report.

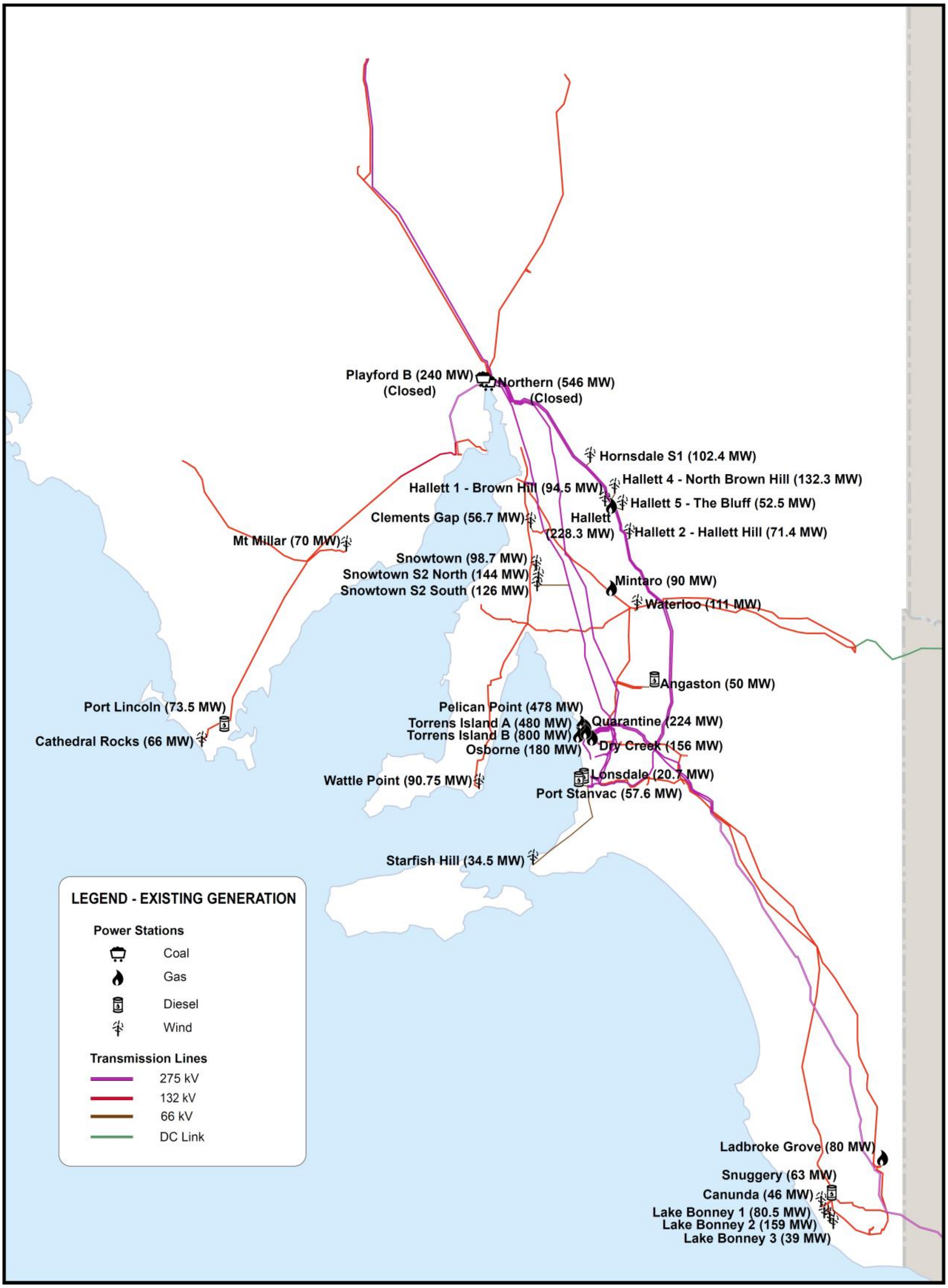
- Pricing analysis for five and 10 year trends have been presented in real June 2016 dollars, using the Adelaide Consumer Price Index (CPI)[15] as the basis for adjustment. Where analysis has been undertaken within only the most recent two financial years, nominal dollar values are presented.
- Time has been expressed in Australian Eastern Standard Time (AEST) with no daylight savings applied. This is referred to as NEM time (or market time).
- Summer has been defined as the period from 1 November to 31 March, and winter from 1 June to 31 August.

[15] Australian Bureau of Statistics (ABS). *6401.0 Consumer Price Index (CPI) – Series ID A2325821J (Adelaide CPI)*. Available at: http://www.abs.gov.au/AUSSTATS/abs@.nsf/DetailsPage/6401.0Jun%202016?OpenDocument. Viewed 28 July 2016.

1.2 Generation map

Figure 1 shows the location and nameplate capacity of South Australian scheduled, semi-scheduled, and significant non-scheduled generators, as at 1 July 2016.

Figure 1 Location and capacity of South Australian generators



2. DEMAND ANALYSIS

This chapter looks at South Australian demand through demand duration curves and average daily profiles. For further analysis on annual consumption, please see the 2016 *South Australian Electricity Report* (SAER).[16]

For this analysis, demand is the South Australian operational demand. The specific generating units have been defined in Appendix B.

2.1 Demand duration curves

Demand duration curves represent the percentage of time that electricity demand (in MW) is at or above a given level over a defined period.

Figure 2 to Figure 4 show demand duration curves for South Australia. Separate curves are shown for summer and winter. Factors contributing to changes in demand over time include:

- Increasing rooftop PV generation.
- Increasing energy efficiency savings.
- Population changes.
- Changes in residential and business consumption.
- Seasonal weather conditions.

2.1.1 Summer demand duration curves

Both Figure 2 and Figure 3 show the demand duration curves for South Australia for summer 2011–12 to 2015–16. Figure 3 identifies the top 10% of summer demand periods.

Comparison of these curves shows that:

- Demand throughout summer 2015–16 has increased from a five year low in 2014-15. This has been attributed to warmer temperatures as Adelaide experienced its fourth-hottest summer on record[17], causing cooling loads to increase. Drought conditions due to El Niño[18], which required additional water pumping throughout the region, and Port Pirie metals recovery and refining plant's continued redevelopment[19] have also contributed to the increase in demand.
- Historically from 2011–12 to 2015–16, South Australian maximum demand has fluctuated between 2,811 MW and 3,286 MW. In summer 2015–16, maximum demand was 3,005 MW; this was approximately a one in two year event. The 2015–16 maximum demand was 194 MW higher than 2014–15, and 281 MW lower than the maximum of 3,286 MW in 2013–14 (a one in 10 year scenario).

There has been a historical trend of declining operational consumption[20] over the last five years in South Australia. From 2011–12 to 2015–16, operational consumption reduced by 433 GWh (from 13,367 GWh to 12,934 GWh), an average annual decrease of 0.8%. This was driven by a fall in residential consumption, resulting from electricity price growth and penetration of rooftop PV generation, as well as industrial consumption.

[16] AEMO. *2016 South Australian Electricity Report*. Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions.

[17] Bureau of Meteorology (BOM). *Adelaide in summer 2015-16: temperatures above average; rainfall near average.* Available at: http://www.bom.gov.au/climate/current/season/sa/archive/201602.adelaide.shtml. Viewed on 26 July 2016.

[18] Bureau of Meteorology (BOM). *Tracking Australia's climate and El Nino 2015.* Available at: http://www.bom.gov.au/climate/updates/articles/a013.shtml. Viewed on 12 August 2016.

[19] Nyrstar. *Port Pirie The Redevelopment.* Available at: http://www.portpirietransformation.com/index.php/the-port-pirie-operation. Viewed on 22 July 2016.

[20] Operational consumption reported here is as sent-out and is based on values reported in the 2016 NEFR and 2016 SAER.

Figure 2 Summer demand duration curves

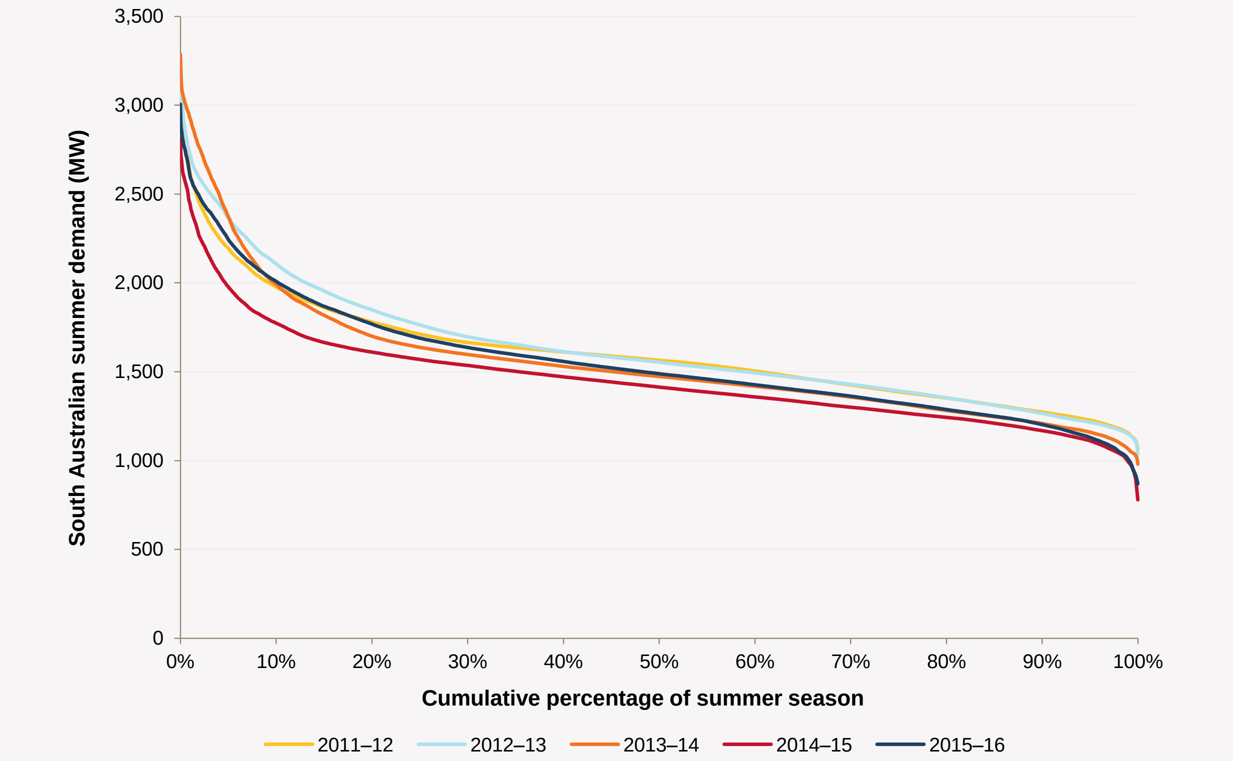
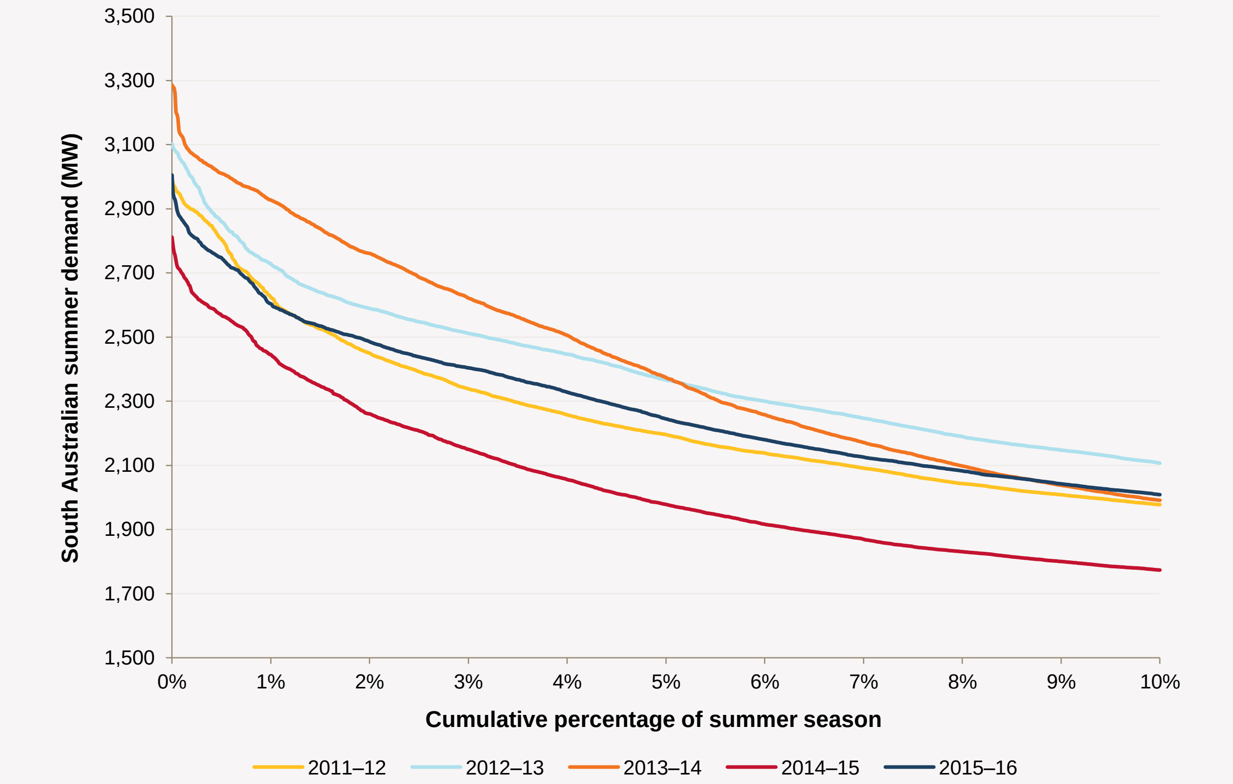


Figure 3 Summer demand duration curves (top 10% of demands)



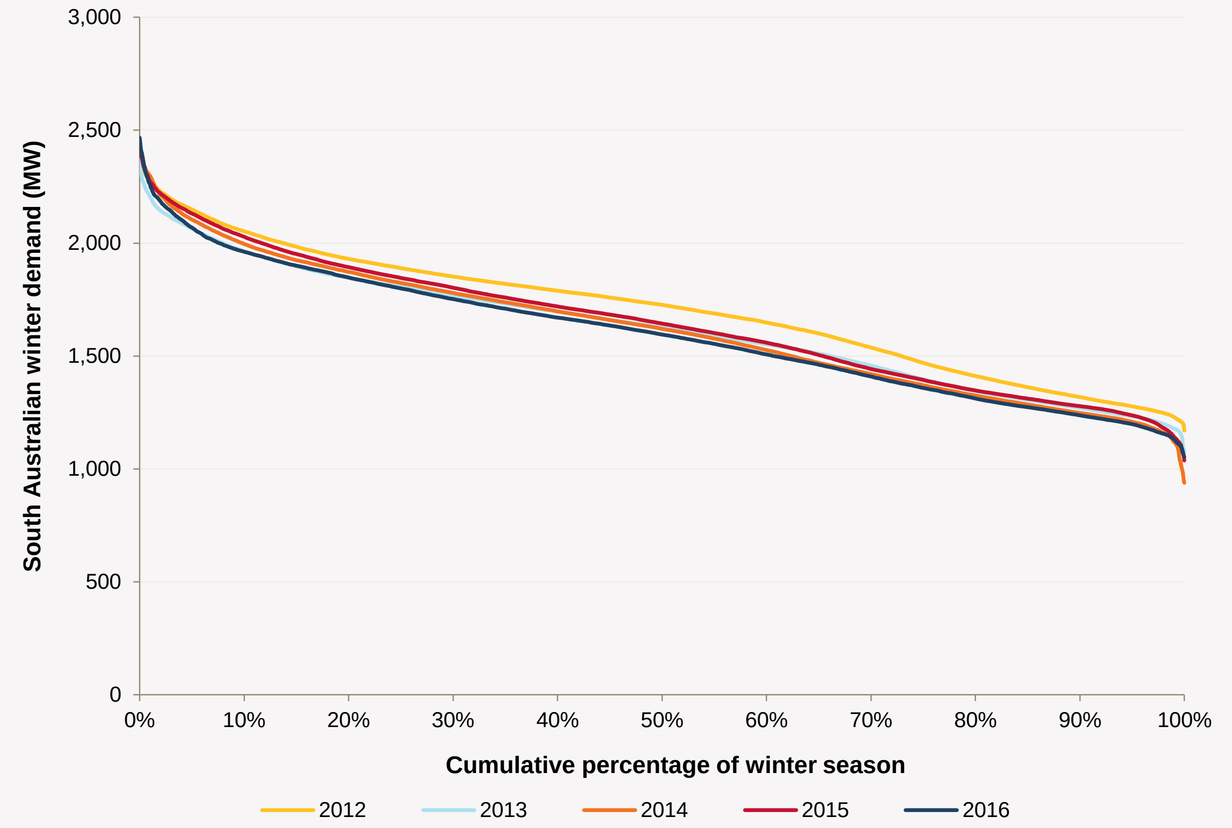
2.1.2 Winter demand duration curves

Figure 4 shows the demand duration for winter 2012 to 2016. For winter 2016, only the months of June and July have been included in the analysis.

For South Australia, winter demand duration curves tend to be flatter than the summer demand curves. A flatter duration curve indicates that demand is generally more constant and exhibits fewer periods of extreme peaks and troughs.

Comparison of these curves shows that, for most of the season, the winter 2016 demand in South Australia was lower than for the previous four winters, although the differences between years are relatively small. A major contributor to this is the decreased heating load, due to the consistently warmer than average nights during June and July[21], with Adelaide reaching its warmest July day in 14 years (noting that a cold front beginning 12 July 2016[22] caused unusually high demands on some days). Figure 47 in Appendix A provides more information on the trend in temperature across the part winter, which suggests that the coolest temperatures for winter were higher than previous years.

Figure 4 Winter demand duration curves



2.2 Average daily demand profiles

Average daily demand profiles represent the demand (in MW) for each 5-minute dispatch interval of a day, averaged over the relevant days of the selected period.

Changes to the average daily demand profile over time can provide insights into the impact of increasing small-scale renewable generation and demand-side management.

Only South Australian workdays are included in the analysis. Weekends and gazetted public holidays are excluded.

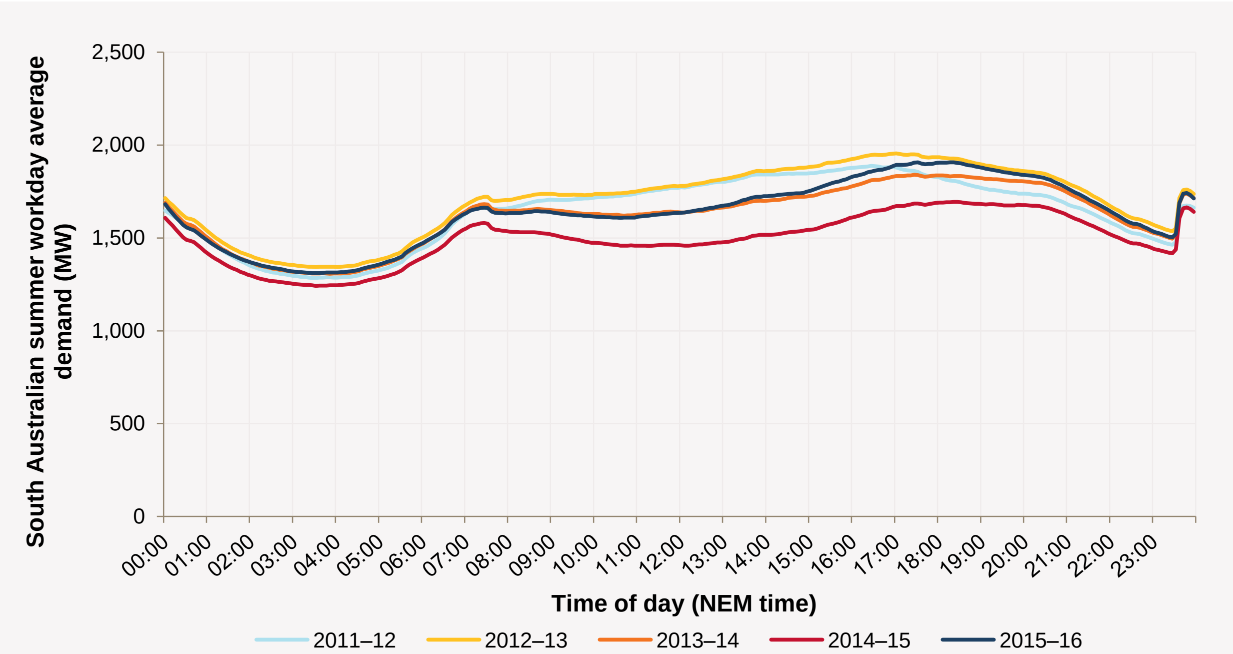
[21] Bureau of Meteorology (BOM). *South Australia in June 2016: above average rainfall and warm nights.* Available at: http://www.bom.gov.au/climate/current/month/sa/archive/201606.summary.shtml. Viewed: 3 August 2016.
[22] Bureau of Meteorology (BOM). *South Australia in July 2016: Above average rainfall for southeast agricultural areas, average temperatures.* Available at: http://www.bom.gov.au/climate/current/month/sa/summary.shtml. Viewed 24 August 2016.

2.2.1 Summer workday average daily demand profiles

Figure 5 shows the South Australian average workday demand profile for summer 2011–12 to 2015–16. Comparison of these profiles shows that:

- Historically, average demand has been decreasing each summer, particularly between daylight hours (about 8:00 am to 8:00 pm).
- AEMO attributes this reduction to increasing rooftop PV generation mainly due to growth in installations, and energy efficiency gains.
- In 2015–16 this trend reversed, with the average daily profile higher than in 2014–15. This may be attributed to:
  - The slowing in growth of rooftop PV capacity, as well as natural variations in solar radiation across different years.[23]
  - Adelaide experiencing one of its hottest summers due to El Niño.[24]
  - The Port Pirie metals recovery and refining plant's continued redevelopment to diversify its functions to a poly-metallic processing and recovery facility.
- Average demand consistently rises at 11:30 pm due to the controlled switching of electric hot water systems at the start of the off-peak period. The Australian Energy Regulator (AER) has noted that "off-peak hot water load caused changes in demand of 15–20% at exactly 2330 each day".[25] South Australia Power Networks[26] (SAPN) has initiated a project to re-program up to 90 MW[27] of hot water demand, to reduce the impacts of the switching on system security in the event of South Australia operating as an islanded network.

Figure 5 Summer workday average demand profiles



[23] More information on rooftop PV capacity and generation is available in Section 2.6 of the 2016 SAER. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions.

[24] Bureau of Meteorology (BOM). *Tracking Australia's climate and El Nino 2015.* Available at: http://www.bom.gov.au/climate/updates/articles/a013.shtml. Viewed on 12 August 2016.

[25] South Australian Council for Social Services (SACOSS). *High SA Electricity Prices: A Market Power Play?* Page 10. Available at: https://www.sacoss.org.au/sites/default/files/public/131212_CMU%20SACOSS%20Final%20Report_High%20SA%20Electricity%20Prices_0.pdf. Viewed on 3 August 2016.

[26] SA Power Networks Flexible load strategy October 2014. https://www.aer.gov.au/system/files/SAPN%20-%2020.34%20PUBLIC%20-%20SAPN%20Flexible%20Load%20Strategy.pdf. Viewed on 3 August 2016

[27] More information is available in Section 5.5 of the 2016 SAER. Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions.

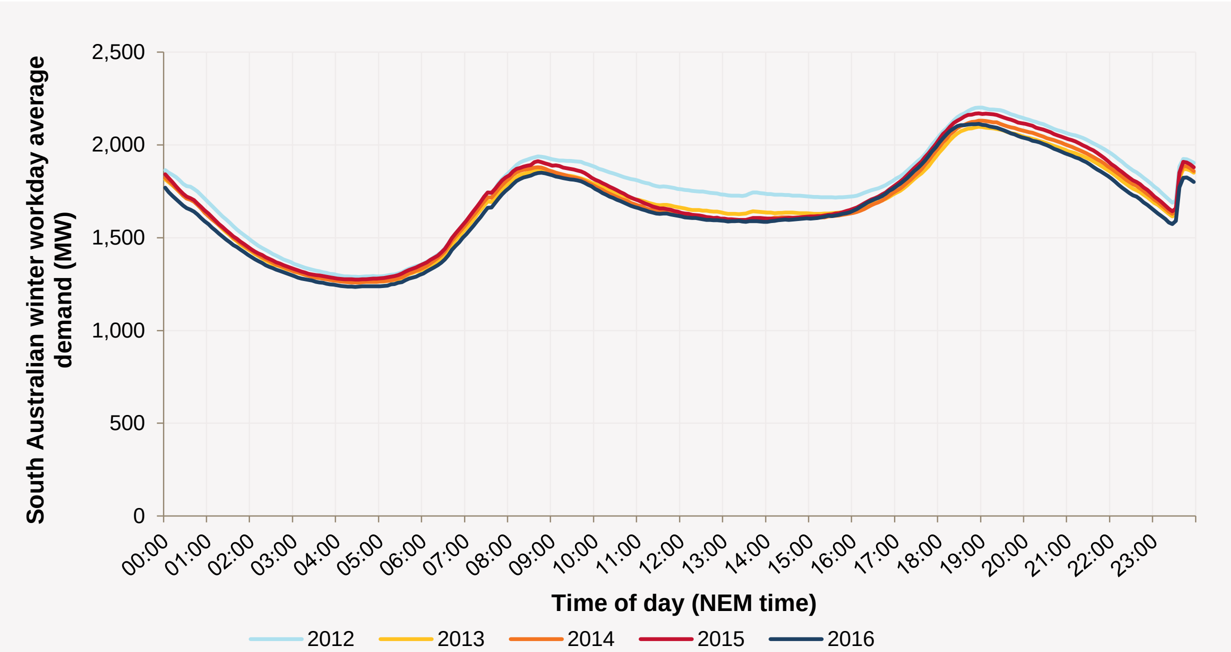
2.2.2 Winter workday average daily demand profiles

Figure 6 shows the South Australian average winter workday demand profile for winter 2012 to 2016.

Comparison of these profiles shows:

- Average demand has been generally steady each winter, with most variation between years shown in the evenings. The lower evening demand observed in winter 2016 reflects the higher than average winter evening temperatures discussed in Section 2.1.2.
- The higher demand in winter 2012 is attributed to lower levels of rooftop PV installed. Rooftop PV generation increased by 67% in the 2012–13 financial year.
- Average morning and evening peaks are higher in winter than summer, most likely due to the heating loads in winter and reduced summer demand from rooftop PV generation.
- Average demand consistently rises at 11:30 pm due to the controlled switching of electric hot water systems, as discussed in Section 2.2.1 for the average summer workday daily profile.

Figure 6 Winter workday average demand profiles



3. HISTORICAL SUPPLY

3.1 Supply changes

During 2015–16 the South Australian supply mix fundamentally changed, with the retirement of the Northern Power Station in May 2016 marking the end of coal generation in the region.

This withdrawal of coal-powered generation has resulted in an increased reliance on gas generation and Victorian imports over the Heywood and Murraylink interconnectors.

Previous financial year

Table 4 summarises, for the period from 2011–12 to 2015–16:

- The energy generated by fuel type from scheduled, semi-scheduled, and selected non-scheduled South Australian generators.
- The net interconnector imports into South Australia from Victoria (via the Heywood and Murraylink interconnectors).
- The estimated rooftop PV generation[28] in South Australia.

Refer to Appendix F for a breakdown of the generation into fuel type and individual generators.

The following key changes occurred from 2014–15 to 2015–16:

- Total wind generation increased 99 GWh to 4,322 GWh, the highest in five financial years.
- Total gas generation decreased 61 GWh to 4,538 GWh, the lowest in five financial years.
- Total coal generation decreased by 44 GWh to 2,601 GWh.
- Total diesel generation increased by 6 GWh to 8 GWh.
- Combined interconnector net imports from Victoria increased 413 GWh to 1,941 GWh, the highest increase in four financial years.
- Rooftop PV estimated generation increased 66 GWh to 938 GWh, the lowest increase in four financial years.

South Australian operational consumption increased from 2014–15 to 2015–16 by 466 GWh to 12,934 GWh.[29]

Table 4 South Australian generation and net interconnector imports (GWh)

Fuel type	2011–12	2012–13	2013–14	2014–15	2015–16
Gas	6,391	6,795	5,566	4,599	4,538
Wind	3,563	3,475	4,088	4,223	4,322
Coal	2,999	2,231	2,096	2,645	2,601
Diesel	2	5	2	2	8
Interconnector net imports	1,094	1,377	1,637	1,528	1,941
Rooftop PV	294	492	678	872	938
Small non-scheduled generation	62	58	60	59	52
Total	**14,405**	**14,433**	**14,127**	**13,928**	**14,400**

[28] Rooftop PV generation is sourced from the 2015 *National Electricity Forecasting Report* (NEFR). Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report.

[29] AEMO. *2016 South Australian Electricity Report*. Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions.

Long-term trend

Table 4 and Figure 7 also illustrate the following trends from 2011–12 to 2015–16:

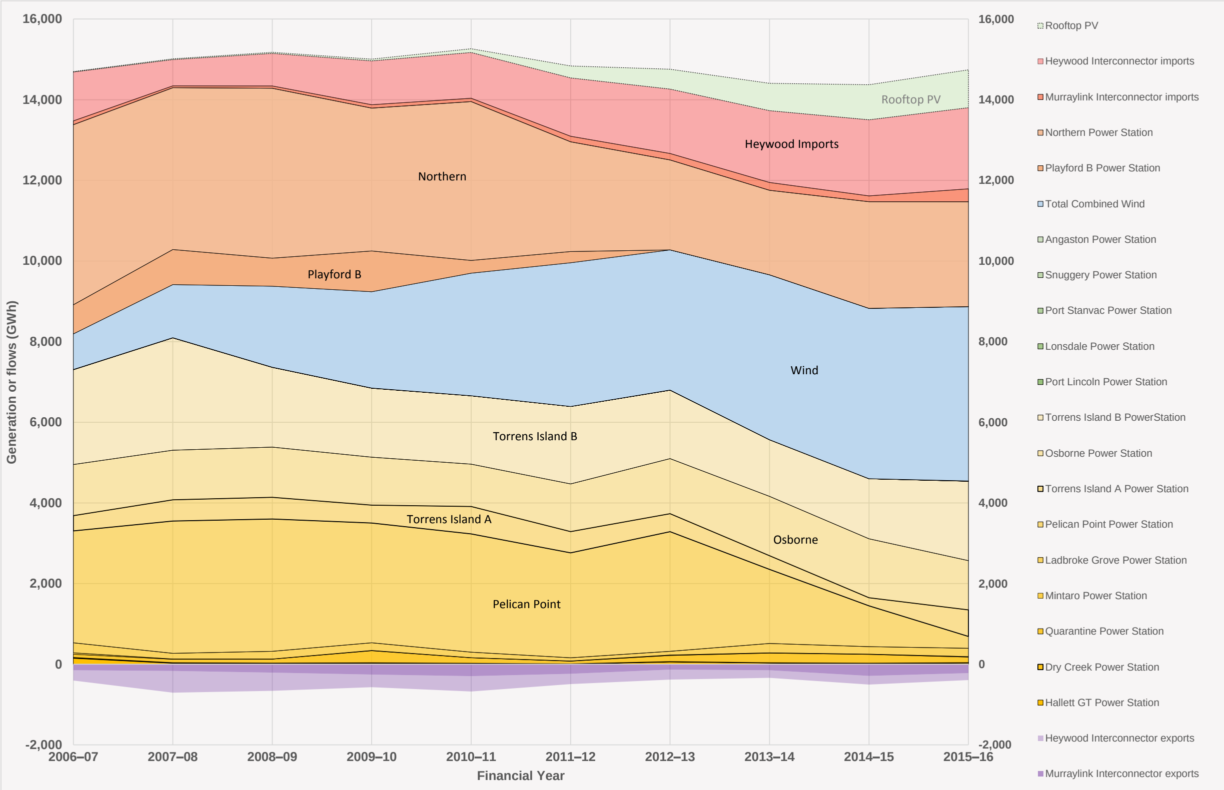
- Northern Power Station reduced to summer-only operation in March 2013. It then resumed year-round operation after the end of carbon pricing in July 2014, but closed on 9 May 2016 (at 10:20 am).
- Gas generation from Pelican Point Power Station steadily decreased from 2,967 GWh in 2012–13 to 293 GWh in 2015–16, with 50% of its capacity mothballed in April 2015 and a reduction to zero capacity during winter 2016.
- In 2015–16, decreases from Pelican Point and Osborne were largely offset by increased gas generation from Torrens Island A and B Power stations to their highest level in five years (659 GWh and 1,969 GWh respectively). Notably, the decision to mothball Torrens Island A power station was reversed in June 2016.[30]
- There has been a continued increase in wind generation from 2011–12 to 2015–16 (with 2012–13 as an exception), from 3,563 GWh to 4,322 GWh. There was reduced generation during 2012–13 due to no additional registered wind capacity and lower wind speeds.
- Rooftop PV generation increased by 644 GWh to 938 GWh between 2011–12 and 2015–16, with installed rooftop PV capacity growing by 385 MW in the same period to 679 MW. This appears to have slowed in 2015–16, when the increase from the previous financial year was 69 GWh (see Figure 10 for more details of the growth of rooftop PV capacity).
- There has been a steady year-on-year increase in net interconnector imports from Victoria, except in 2014–15 when Northern Power Station returned to full operation.

Section 5.1 provides further details on interconnector changes.

Figure 7 displays the changes to generation mix labelled by individual generators over the last five years. A tabulated version of this can be found in Appendix F.

[30] AGL, "AGL to defer mothballing of South Australian generation units", 6 June 2016. Available at: https://www.agl.com.au/about-agl/media-centre/article-list/2016/june/agl-to-defer-mothballing-of-south-australian-generating-units.

Figure 7 Historical generation in South Australia 2006–07 to 2015–16



3.2 Generation mix

Figure 8 shows the mix of energy generated in South Australia by fuel type from 2011–12 to 2015–16. This includes generation from:

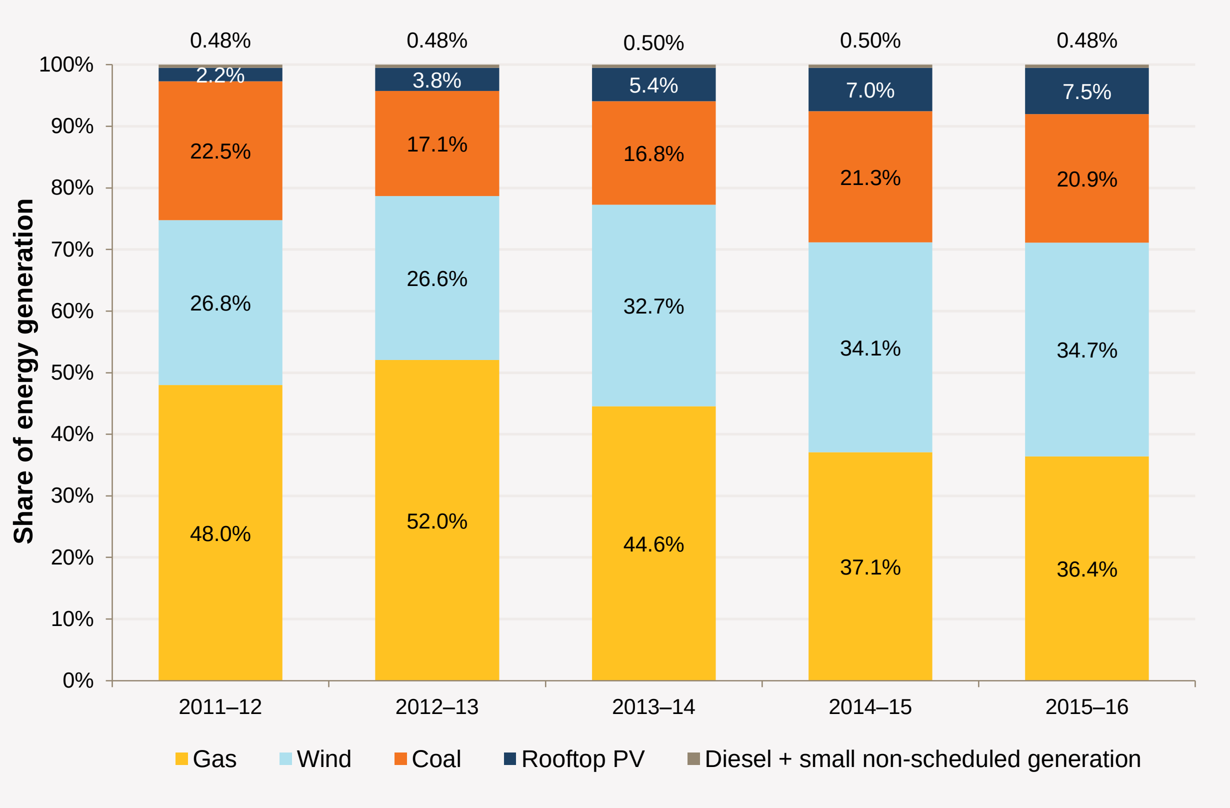
- All scheduled generators.
- All semi-scheduled and market non-scheduled wind farms.
- Selected smaller market and non-market non-scheduled generators (SNSG).
- Rooftop PV (as estimated in the 2016 NEFR).[31]

It does not include how much generation was exported or imported via the South Australia to Victoria interconnectors.[32]

[31] The rooftop PV historical generation calculation methodology is detailed in Appendix G.

[32] This differs to the analysis provided in the 2015 SAHMIR, which did include net interconnector imports. AEMO now considers that the inclusion of net interconnector imports and exports does not provide an accurate fuel mix, as local generation that is exported cannot be feasibly separated by fuel type. This exclusion, as well as revisions to rooftop PV due to better modelling, accounts for the material differences in historical values reported.

Figure 8 South Australian energy generation by fuel type



Comparing 2014–15 and 2015–16, there is little difference in the generation mix by fuel type. In 2015–16, South Australia's electricity generation by fuel type, as a percentage of total generation within the state, was:

- 36.4% from gas, down from 37.1% in 2014–15.
- 34.7% from wind, a slight increase from 34.1% in 2014–15.
- 20.9% from coal, down from 21.3% in 2014–15.
- 7.5% from rooftop PV, up from 7.0% in 2014–15.
- 0.48% from diesel and small non-scheduled generators, down from 0.50% in 2014–15.

Total local South Australian generation increased 66 GWh (0.5%) between 2014–15 and 2015–16.

3.2.1 Average daily supply profile

The average daily supply profile for South Australia, seen in Figure 9, represents the supply (in MW) for each 30-minute trading[33] interval of a day, averaged over the 2015–16 financial year. The figure displays the average mix of generation dispatched on an average day, split between wind, thermal (coal, gas and diesel), and combined interconnector flows. Rooftop PV is displayed above the demand curve, and shows the underlying energy that is consumed at the household level.

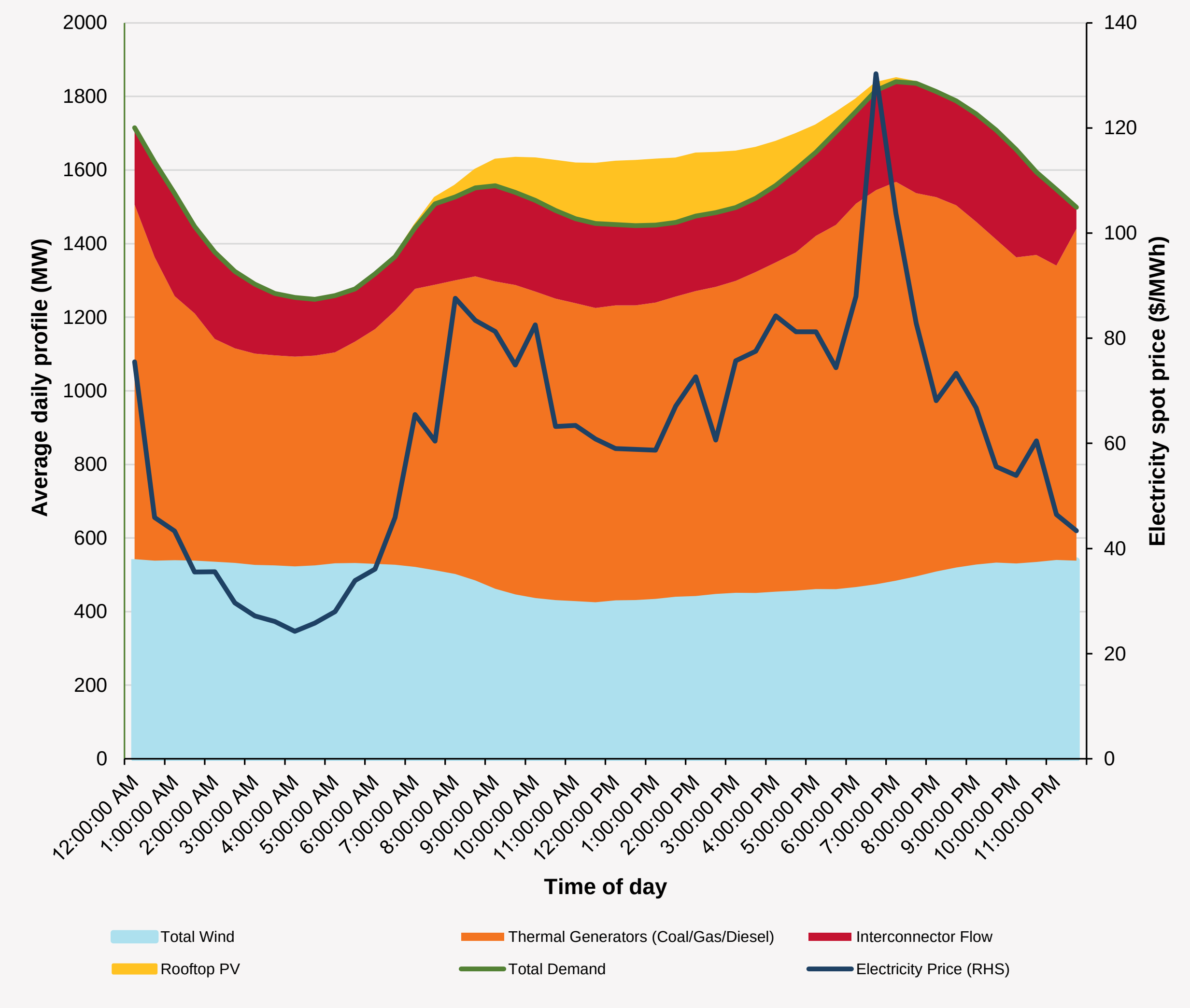
Figure 9 shows that:

- Average wind output is slightly higher during the evening and early morning periods, complementing average rooftop PV generation, which produces most of its output between 8.00 am and 6.00 pm.

[33] 5-minute dispatch intervals for scheduled generation, wind generation, and interconnector flows, have been averaged to a 30-minute dispatch interval to better correlate with 30-minute rooftop PV.

- Scheduled generation includes coal, gas, and diesel powered generation for 2015–16, and contributed the most to the daily profile. On average, at least 570 MW of thermal generation is dispatched in every period (trading interval).
- The average price correlates closely with average demand, particularly in the early morning hours. Price peaks at 6.00 pm, in line with increases in demand from residential loads.
- Interconnectors are consistently relied on throughout the day to make up the shortfall that local generation does not meet. This chart is based on averaged interconnector data across the year. Times of excess supply will reduce import from Victoria or result in net export.

Figure 9 Average daily supply profile



3.3 Generation capacity

Figure 10 shows the registered generation capacity[34] by fuel type in South Australia from 2001–02 to 2015–16, at the end of each calendar month.

It highlights the evolving generation mix in the region over that time:

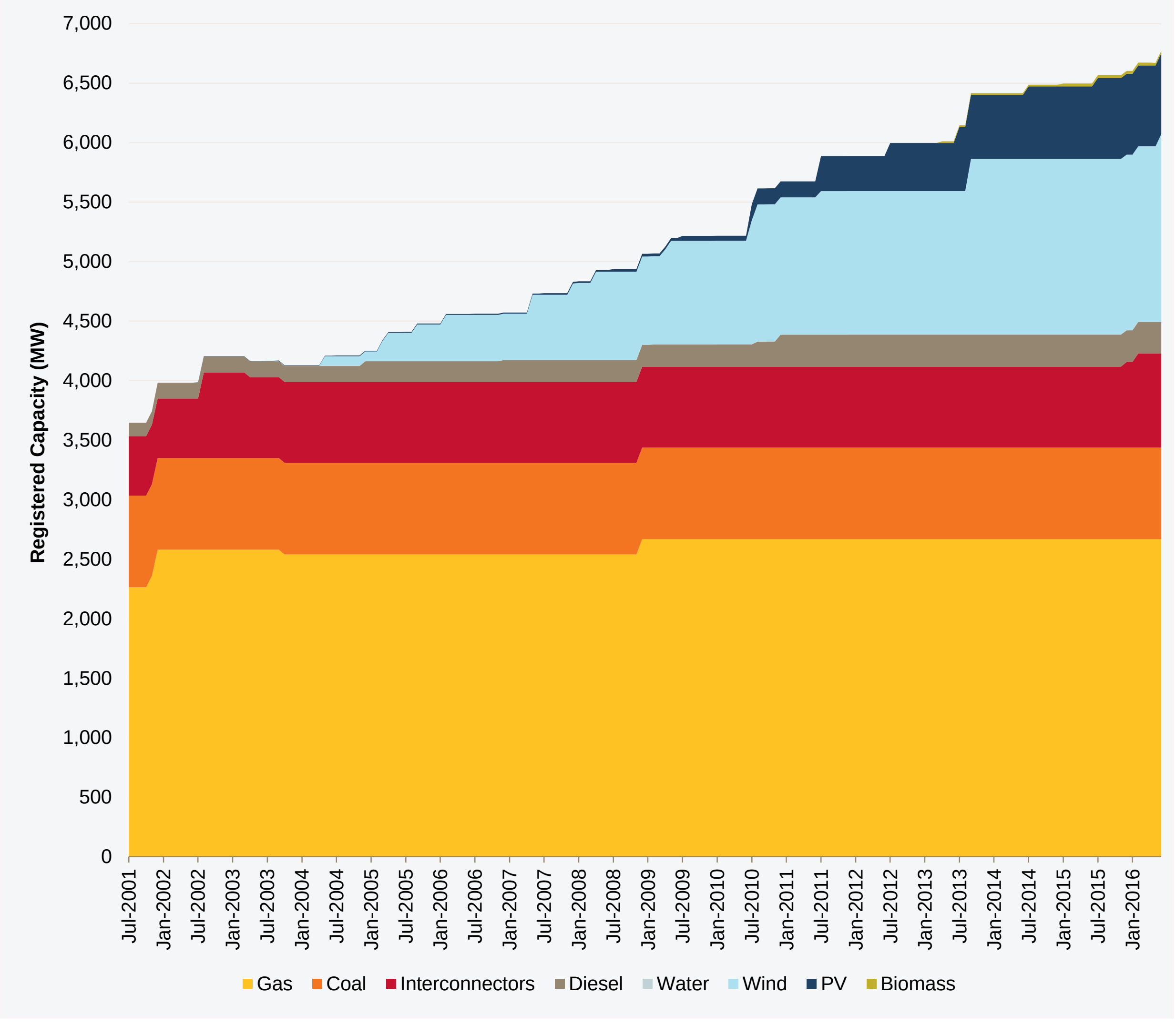
- With the closure of Northern Power Station, coal capacity has reduced to zero by the end of 2015–16 (although both Playford (240 MW) and Northern (530 MW) are still registered, so the capacity reduction is not shown in the figure).

[34] Registered capacity values for generators, including pro rata timing of changes during a financial year, have been determined from AEMO registration data.

- Net interconnector import capacity increased moderately with the addition of Murraylink from 2002–03.
- Heywood Interconnector's transfer capacity is currently being upgraded from 460 MW to 650 MW.
- There was no wind generation until 2003–04 when 80.5 MW was installed, growing to 1,576 MW in 2015–16, an average annual growth of 28%.
- Hornsdale Stage 1 Wind Farm was registered in June 2016, and is currently under construction.[35]
- Rooftop PV capacity was negligible until 2008–09. Since then, there has been average annual growth of 74% (14 MW to 679 MW in 2015–16), although growth has slowed over the last year (11% annual increase).
- Overall registered capacity increased from 3,983 MW in 2001–02 to 6,772 MW in 2015–16. With the closure of Northern and Playford Power Stations, the available capacity has since decreased to 6,002 MW at the end of 2015–16.

Wind and rooftop PV actual generation capabilities are highly dependent on weather conditions at any given time.

Figure 10 Registered capacity by fuel type, 2001–02 to 2015–16



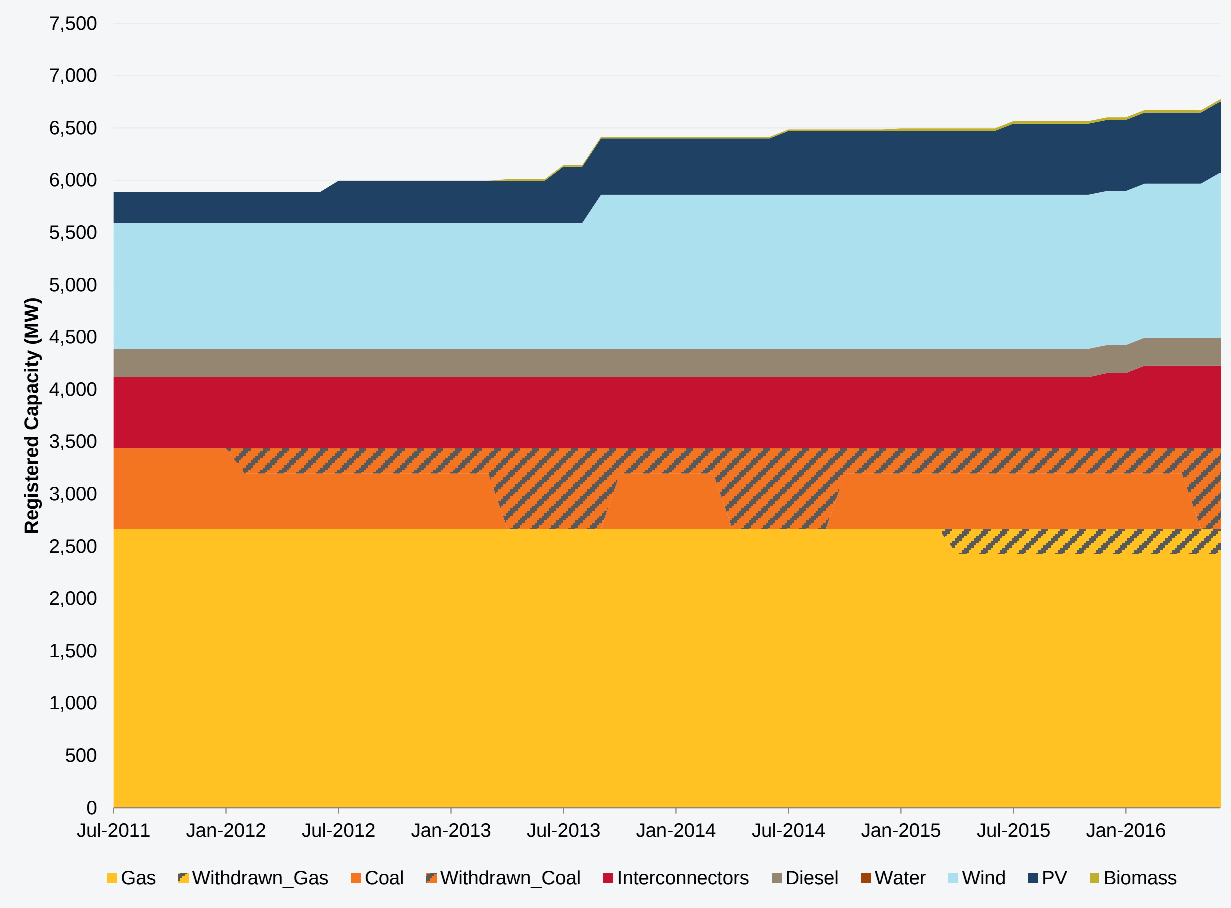
Note: Figure shows registered capacity at the end of each calendar month. Northern and Playford Power Stations have withdrawn but have not deregistered.
Note: Biomass includes landfill methane and waste water treatment plant.

[35] This does not include committed generation. Waterloo Stage 2 and Hornsdale Stage 2 wind farms have been committed but are not registered.

Figure 11 shows the same data as Figure 10, but:

- Narrowed down to look more closely at the last five financial years only.
- Also plotting the major withdrawals of capacity.
  - Withdrawn gas-powered generation includes Pelican Point Power Station's half capacity status since April 2015.
  - Withdrawn coal is due to the reduced summer-only operation of Northern Power Station in 2013 and 2014, the mothballing of Playford B Power Station since 2012, and the permanent closure of both power stations by May 2016.

Figure 11 Registered capacity by fuel type, 2011–12 to 2015–16, showing significant withdrawals



3.4 Capacity factors

Capacity factor is a ratio (expressed as a percentage) of the actual output of generating systems over a period of time, compared to the maximum possible output during that time.

Figure 12 and Figure 13 show the financial year capacity factors for South Australian generators based on each power station's historical registered capacity, split between scheduled and non-scheduled or semi-scheduled wind farms respectively.

In this analysis, AEMO has calculated capacity factors for each generator based on the proportion of the financial year or season they were listed as registered. Where a generator was seasonally or permanently withdrawn, these periods were excluded from the capacity factor analysis[36], although times when generators were impacted by network and other constraints were not considered. This gives a representative annual capacity for each generating system, and should facilitate direct comparison with future annual capacity factors. Consideration was given to newly-constructed or discontinued

[36] This change in methodology for the 2016 analysis means that historical capacity factors for Northern, Playford B, and Pelican Point are materially different to those capacity factors published in the 2015 SAHMIR.

generators, and if a generator was not operating for 90% of the analysis period it was not considered for analysis, as data would be skewed.

Figure 14 to Figure 17 further display the capacity factors for scheduled generators and non-scheduled or semi-scheduled wind farms, by season.

Previous financial year

Changes of note between the 2014–15 and 2015–16 financial years are:

- Northern Power Station's capacity factor reversed the recent increase in 2014–15 from 76.2% back down to 65.2% in 2015–16, due to its impending and ultimate closure.
- Pelican Point Power Station's capacity factor continued to decline, reducing from 24.3% in 2014–15 to 14.0% in 2015–16. This reduction was in due to the mothballing of 50% of the station's capacity from April 2015[37] and an outage during winter 2016 of the remaining capacity.
- Osborne Power Station's capacity factor decreased from 92.7% to 77.2%.
- Torrens Island A and B have an increased capacity factor as the power stations covered the load in the absence of some of Pelican Point's capacity.

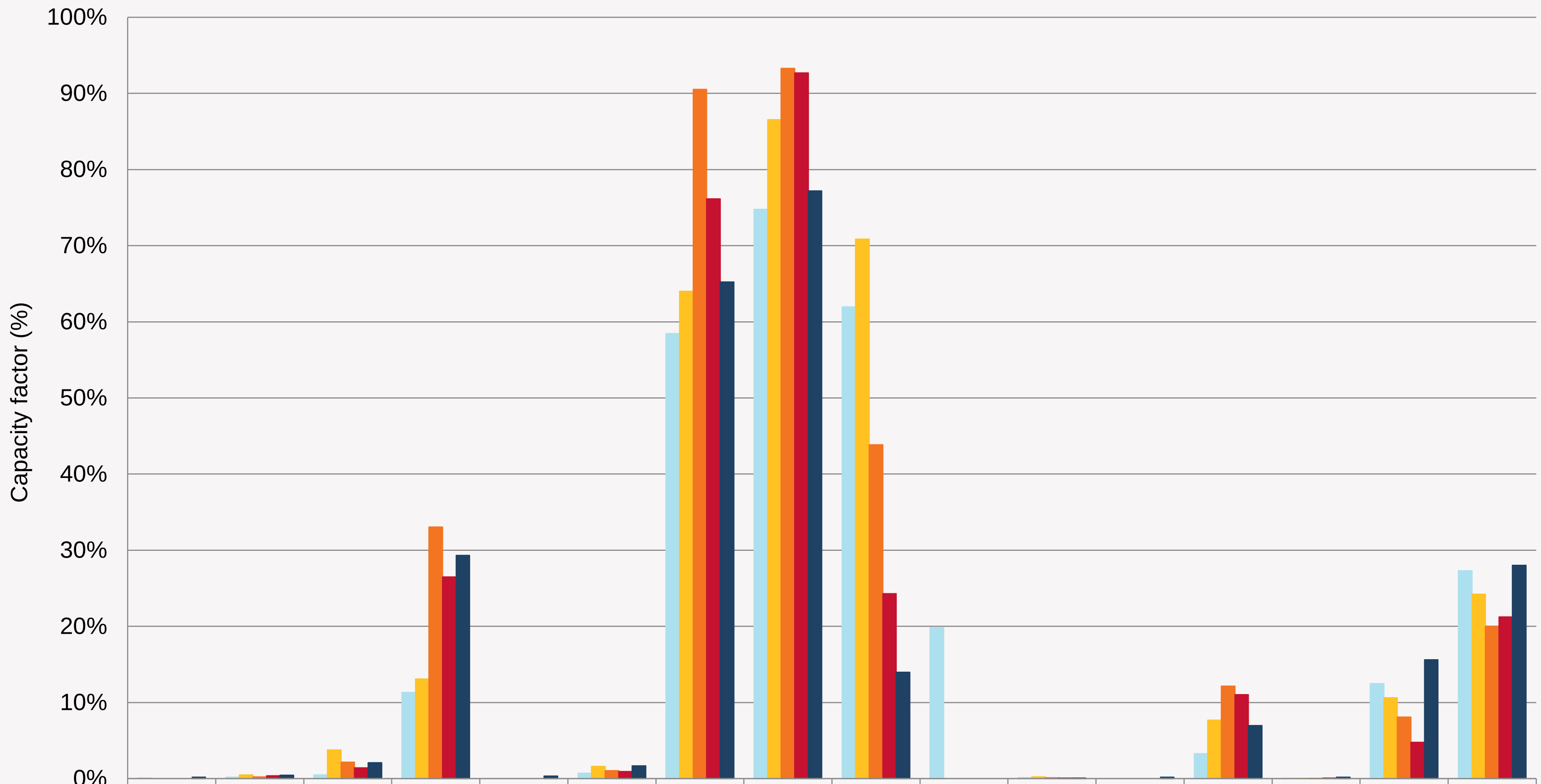
Long-term trend

Figure 14 to Figure 17 show the capacity factors over the past five years for both summer (defined as 1 November to 31 March) and winter (defined as 1 June to 31 August). They highlight the different seasonal operating patterns for specific generators, and illustrate that wind farms and gas-powered generators on average have higher capacity factors in the winter.

Note that in Figure 15, Osborne Power Station's capacity factor was calculated as greater than 100% for winter 2014. This is due to calculations being made on registered capacity (180 MW), which in this case is substantially lower than both the maximum capacity (204 MW) and the actual generation output levels achieved during this time period.

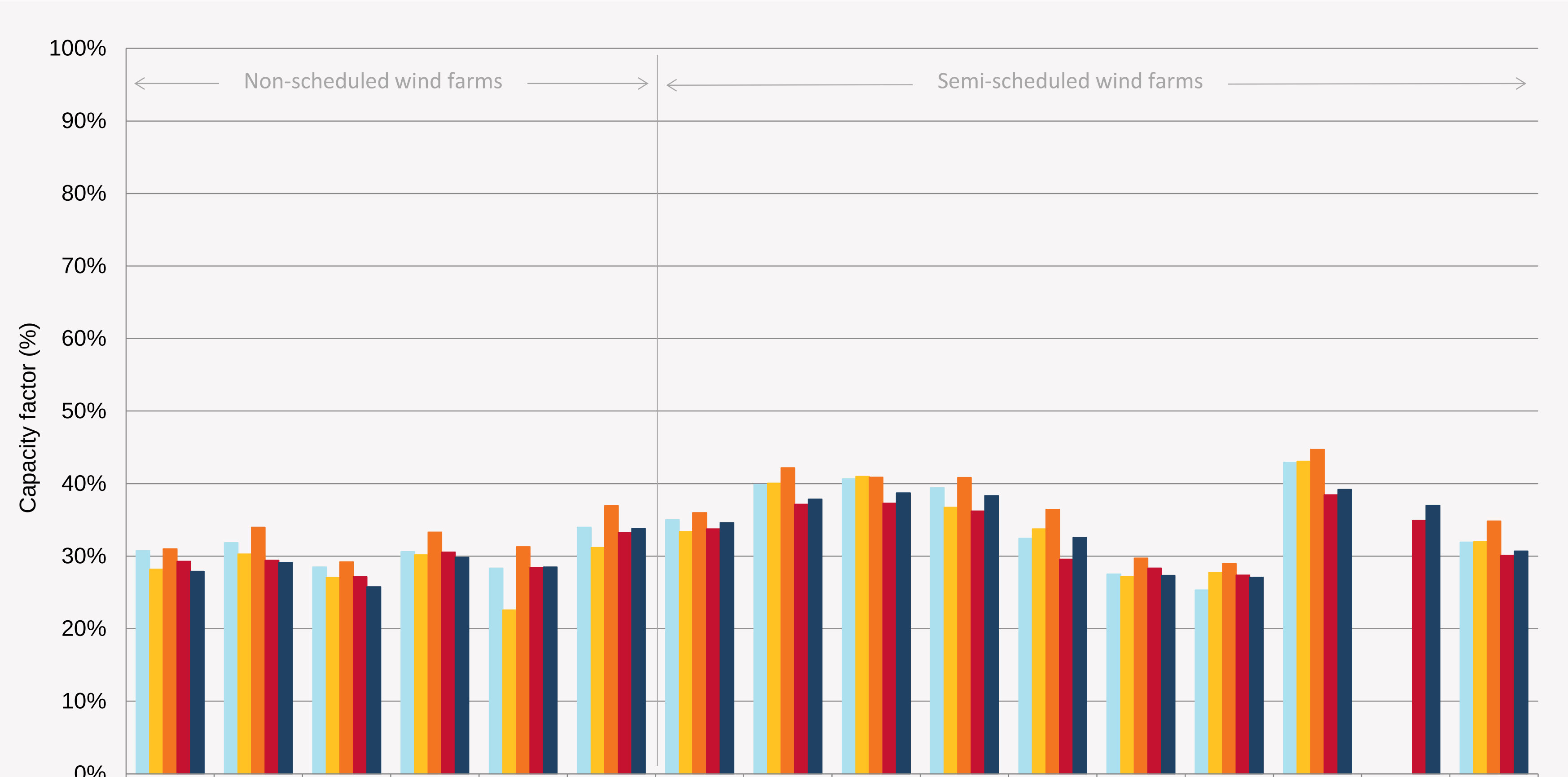
[37] AEMO Generation Information Pages. Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

Figure 12 Financial year capacity factors for scheduled generators



	Angaston	Dry Creek	Hallett GT	Ladbroke Grove	Lonsdale	Mintaro	Northern	Osborne	Pelican Point	Playford B	Port Lincoln GT	Port Stanvac	Quarantine	Snuggery	Torrens Island A	Torrens Island B
2011–12	0.1%	0.2%	0.5%	11.3%		0.7%	58.4%	74.8%	62.0%	19.8%	0.1%		3.3%	0.1%	12.5%	27.3%
2012–13		0.5%	3.8%	13.1%		1.6%	64.0%	86.6%	70.8%		0.2%		7.7%	0.1%	10.6%	24.2%
2013–14		0.2%	2.1%	33.0%		1.0%	90.6%	93.3%	43.9%		0.1%		12.2%	0.0%	8.1%	20.0%
2014–15		0.4%	1.4%	26.5%		0.9%	76.2%	92.7%	24.3%		0.1%		11.0%	0.1%	4.8%	21.2%
2015–16	0.2%	0.5%	2.1%	29.3%	0.4%	1.7%	65.2%	77.2%	14.0%		0.1%	0.2%	7.0%	0.2%	15.6%	28.0%

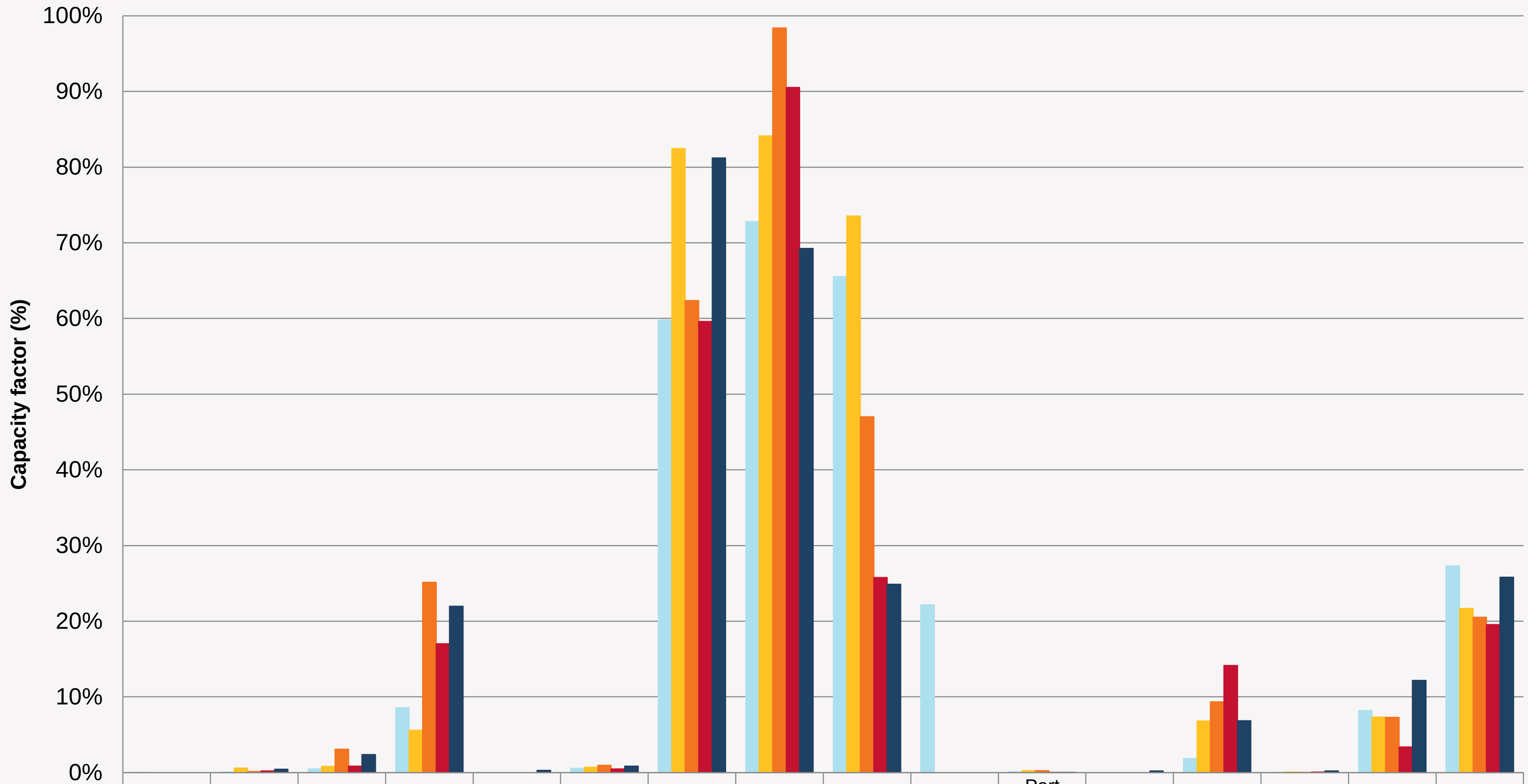
Figure 13 Financial year capacity factors for non-scheduled and semi-scheduled wind farms



	Canunda	Cathedral Rocks	Lake Bonney	Mount Millar	Starfish Hill	Wattle Point	Clements Gap	Hallett 1 (Brown Hill)	Hallett 2 (Hallett Hill)	Hallett 4 (North Brown Hill)	Hallett 5 (The Bluff)	Lake Bonney Stage 2	Lake Bonney Stage 3	Snowtown	Snowtown Stage 2	Waterloo
2011–12	30.8%	31.9%	28.5%	30.6%	28.3%	34.0%	35.0%	39.9%	40.7%	39.4%	32.5%	27.5%	25.3%	42.9%		31.9%
2012–13	28.2%	30.3%	27.0%	30.2%	22.6%	31.2%	33.4%	40.1%	41.0%	36.7%	33.8%	27.2%	27.8%	43.1%		32.0%
2013–14	31.0%	34.0%	29.2%	33.3%	31.3%	37.0%	36.0%	42.2%	40.9%	40.8%	36.4%	29.7%	29.0%	44.7%		34.8%
2014–15	29.3%	29.4%	27.2%	30.5%	28.4%	33.3%	33.8%	37.2%	37.3%	36.2%	29.6%	28.4%	27.4%	38.4%	34.9%	30.1%
2015–16	27.9%	29.1%	25.8%	29.8%	28.5%	33.8%	34.6%	37.8%	38.7%	38.3%	32.6%	27.4%	27.1%	39.2%	37.0%	30.7%

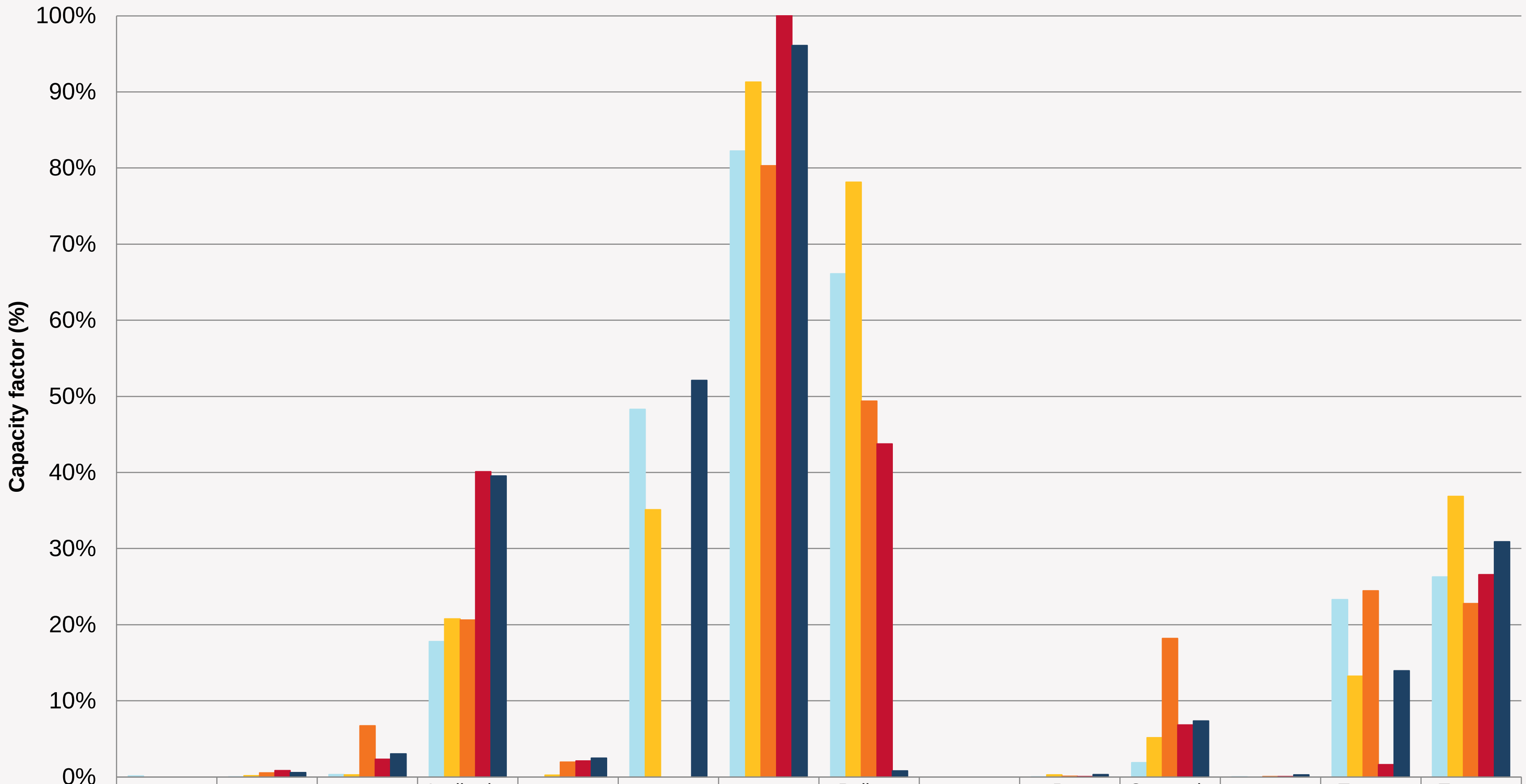
Note: Snowtown Stage 2 capacity factor is calculated for Snowtown Stage 2 North and Snowtown Stage 2 South wind farms combined.

Figure 14 Summer capacity factors for scheduled generators



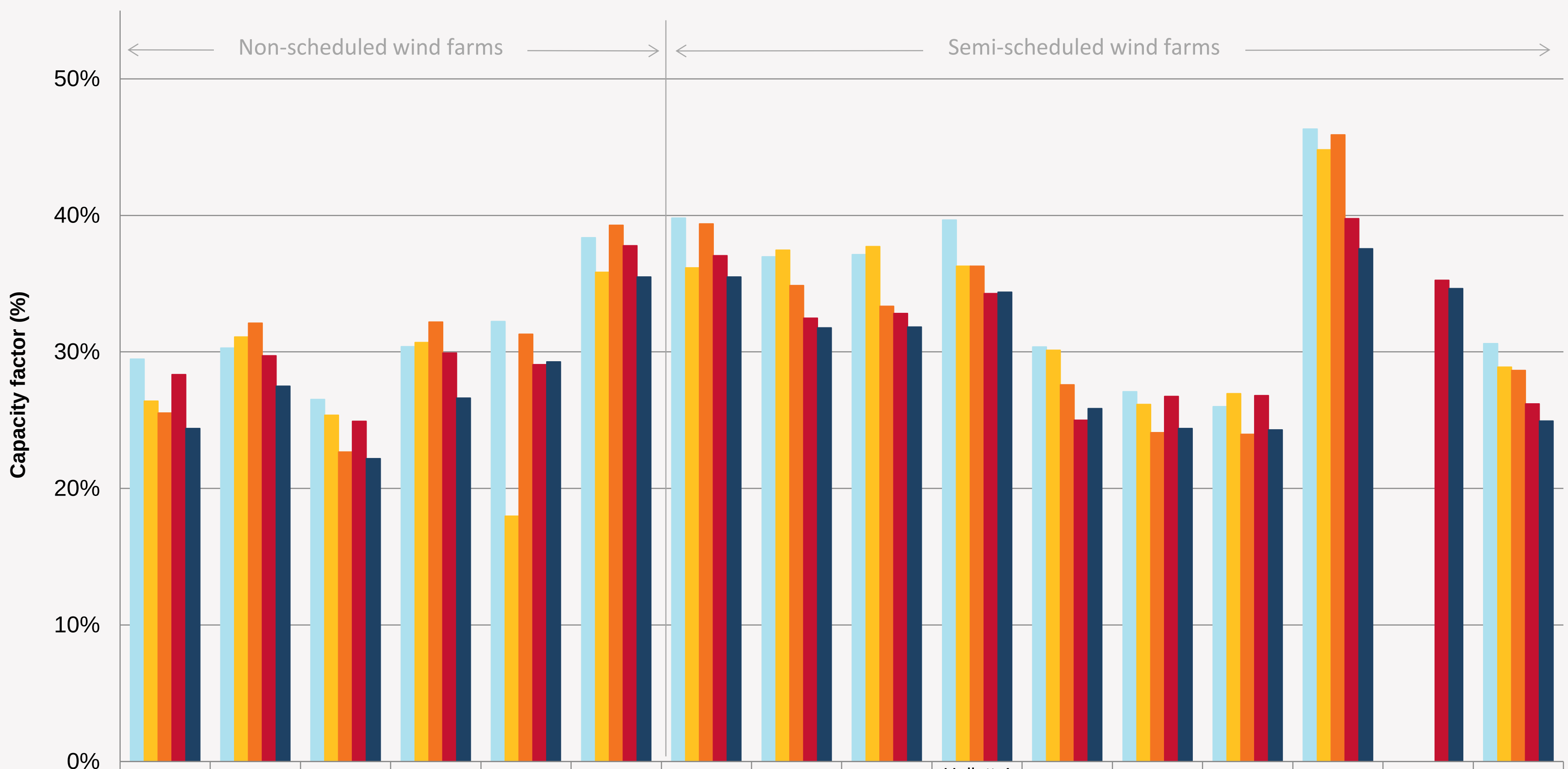
	Angaston	Dry Creek	Hallett GT	Ladbroke Grove	Lonsdale	Mintaro	Northern	Osborne	Pelican Point	Playford B	Port Lincoln GT	Port Stanvac	Quarantine	Snuggery	Torrens Island A	Torrens Island B
2011–12	0.0%	0.1%	0.5%	8.6%		0.5%	59.8%	72.8%	65.5%	22.2%	0.1%		1.8%	0.0%	8.2%	27.3%
2012–13		0.6%	0.8%	5.6%		0.7%	82.5%	84.1%	73.5%		0.2%		6.8%	0.1%	7.4%	21.7%
2013–14		0.1%	3.1%	25.1%		0.9%	62.3%	98.4%	47.0%		0.3%		9.4%	0.0%	7.3%	20.5%
2014–15		0.2%	0.9%	17.0%		0.5%	59.6%	90.5%	25.8%		0.0%		14.1%	0.1%	3.4%	19.5%
2015–16		0.4%	2.4%	22.0%	0.3%	0.9%	81.2%	69.2%	24.9%		0.0%	0.2%	6.8%	0.2%	12.2%	25.8%

Figure 15 Winter capacity factors for scheduled generators



	Angaston	Dry Creek	Hallett GT	Ladbroke Grove	Mintaro	Northern	Osborne	Pelican Point	Playford B	Port Lincoln GT	Quarantine	Snuggery	Torrens Island A	Torrens Island B
2011	0.2%	0.0%	0.3%	17.8%	0.0%	48.3%	82.2%	66.1%	0.0%	0.0%	1.9%	0.0%	23.3%	26.3%
2012		0.2%	0.3%	20.8%	0.2%	35.1%	91.3%	78.2%		0.3%	5.2%	0.0%	13.3%	36.9%
2013		0.6%	6.7%	20.6%	2.0%		80.3%	49.4%		0.1%	18.2%	0.0%	24.5%	22.8%
2014		0.8%	2.3%	40.1%	2.1%		101.0%	43.8%		0.1%	6.8%	0.0%	1.6%	26.6%
2015		0.6%	3.0%	39.5%	2.5%	52.1%	96.1%	0.8%		0.3%	7.4%	0.3%	14.0%	30.9%

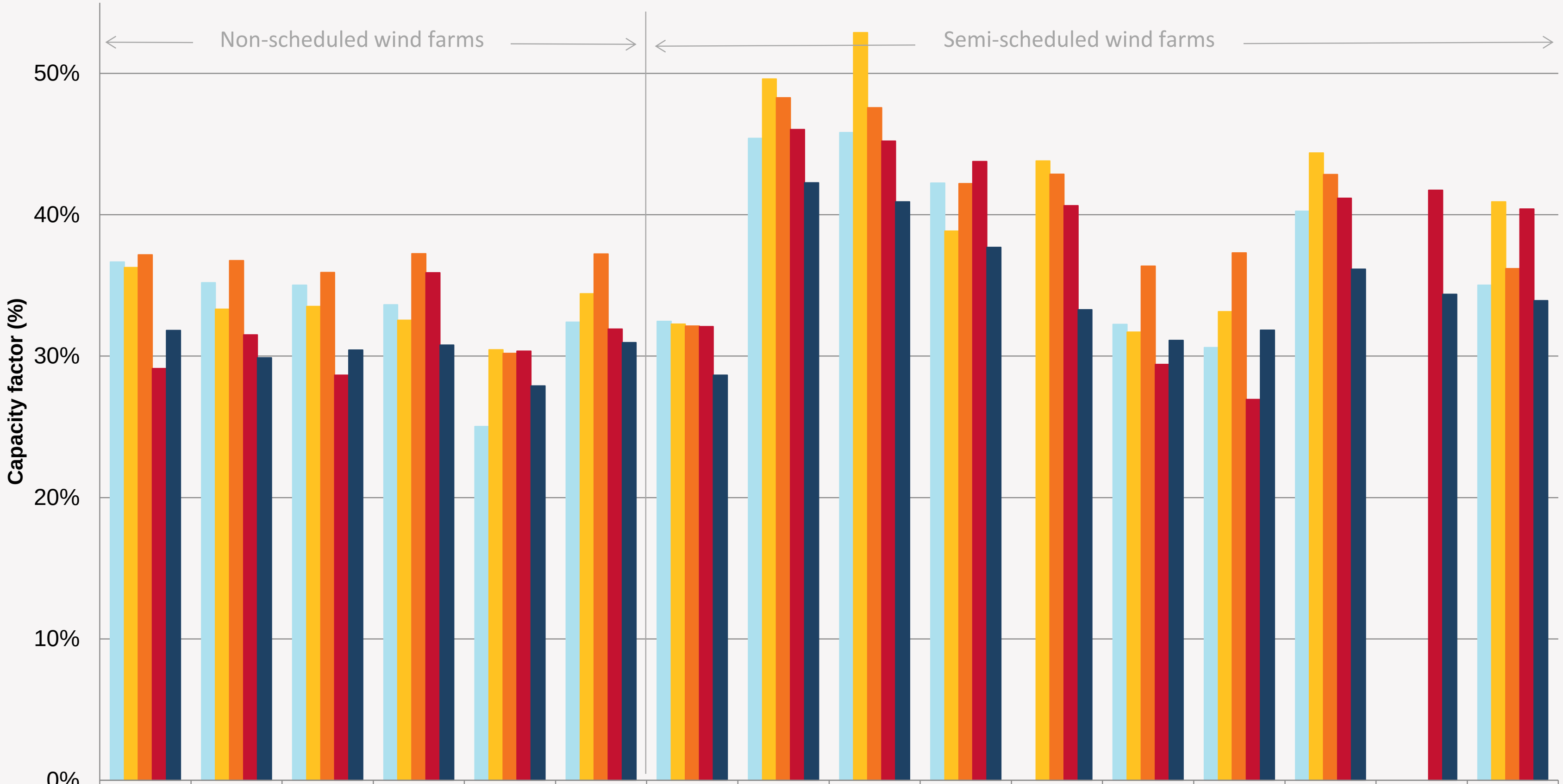
Figure 16 Summer capacity factors for non-scheduled and semi-scheduled wind farms



	Canunda	Cathedral Rocks	Lake Bonney	Mount Millar	Starfish Hill	Wattle Point	Clements Gap	Hallett 1 (Brown Hill)	Hallett 2 (Hallett Hill)	Hallett 4 (North Brown Hill)	Hallett 5 (The Bluff)	Lake Bonney Stage 2	Lake Bonney Stage 3	Snowtown	Snowtown Stage 2	Waterloo
2011–12	29.5%	30.3%	26.5%	30.4%	32.2%	38.4%	39.8%	37.0%	37.1%	39.7%	30.4%	27.1%	26.0%	46.3%		30.6%
2012–13	26.4%	31.1%	25.4%	30.7%	18.0%	35.8%	36.2%	37.5%	37.7%	36.3%	30.1%	26.2%	26.9%	44.8%		28.9%
2013–14	25.5%	32.1%	22.7%	32.2%	31.3%	39.3%	39.4%	34.9%	33.4%	36.3%	27.6%	24.1%	24.0%	45.9%		28.7%
2014–15	28.3%	29.7%	24.9%	29.9%	29.1%	37.8%	37.1%	32.5%	32.8%	34.3%	25.0%	26.7%	26.8%	39.8%	35.3%	26.2%
2015–16	24.4%	27.5%	22.2%	26.6%	29.3%	35.5%	35.5%	31.8%	31.8%	34.4%	25.9%	24.4%	24.3%	37.6%	34.7%	24.9%

Note: Snowtown Stage 2 capacity factor is calculated for Snowtown Stage 2 North and Snowtown Stage 2 South wind farms combined.

Figure 17 Winter capacity factors for non-scheduled and semi-scheduled wind farms



	Canunda	Cathedral Rocks	Lake Bonney	Mount Millar	Starfish Hill	Wattle Point	Clements Gap	Hallett 1 (Brown Hill)	Hallett 2 (Hallett Hill)	Hallett 4 (North Brown Hill)	Hallett 5 (The Bluff)	Lake Bonney Stage 2	Lake Bonney Stage 3	Snowtown	Snowtown Stage 2	Waterloo
2011	36.7%	35.2%	35.0%	33.6%	25.0%	32.4%	32.5%	45.4%	45.8%	42.3%		32.3%	30.6%	40.3%		35.0%
2012	36.3%	33.3%	33.5%	32.6%	30.5%	34.4%	32.3%	49.6%	52.9%	38.8%	43.8%	31.7%	33.2%	44.4%		40.9%
2013	37.2%	36.8%	35.9%	37.2%	30.2%	37.2%	32.1%	48.3%	47.6%	42.2%	42.9%	36.4%	37.3%	42.9%		36.2%
2014	29.1%	31.5%	28.7%	35.9%	30.4%	31.9%	32.1%	46.0%	45.2%	43.8%	40.6%	29.4%	26.9%	41.2%	41.7%	40.4%
2015	31.8%	29.9%	30.4%	30.8%	27.9%	31.0%	28.6%	42.3%	40.9%	37.7%	33.3%	31.1%	31.8%	36.2%	34.4%	33.9%

Note: Snowtown Stage 2 capacity factor is calculated for Snowtown Stage 2 North and Snowtown Stage 2 South wind farms combined.

3.5 Greenhouse gas emissions

Figure 18 illustrates the level of greenhouse gas emissions in metric tonnes of carbon dioxide equivalent ($MtCO_2$-e) produced from South Australian electricity generation, and the emissions associated with electricity imported into South Australia from the remainder of the NEM. It shows that total emissions declined from 2011–12 to 2013–14, but increased by 0.55 $MtCO_2$-e (annual average increase of 4%) from 2013–14 to 2015–16.

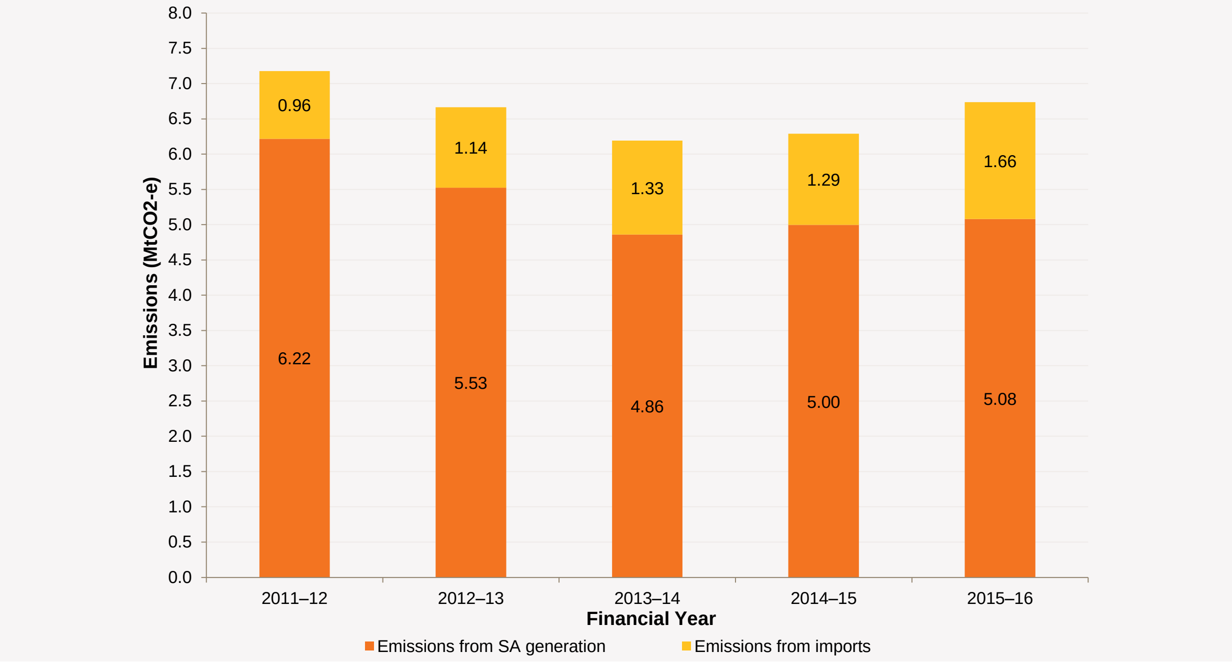
Emissions calculations are made up of:

- **Thermal efficiencies and emission factors** for each generation unit, as published in August 2016[38], which are used to calculate state based emissions.
- **State-based emissions**, determined using actual annual generation for South Australian power stations, and then added to interconnector emissions.
- **Interconnector emissions**, calculated using:
  - Net annual interconnector imports into South Australia.
  - Average emissions intensity of all NEM-based emissions (based on actual annual generation from all NEM power stations excluding those in South Australia).
  - An assumption that the emissions intensity of generation exported to South Australia is the same as the NEM-wide average excluding South Australia.

During 2015–16, despite a small decline in generation from gas and coal, local emissions increased slightly (1.6%) from 2014–15 values. This is attributed to a small increase in diesel generation and net increase in gas generation[39] emissions. Also, there has been an increase in net imports and their associated emissions. Refer to Section 3.1 for details of generation and Section 5.1 interconnector changes in the last financial year.

Factors affecting the historical decline in emissions from 2011–12 to 2013–14 include increased wind generation, reduced coal and gas generation, and declining electricity consumption from the grid, due in part to increasing rooftop PV.

Figure 18 Greenhouse gas emissions for South Australia per financial year



[38] All assumptions and inputs used for AEMO's planning studies, including thermal efficiencies and emission factors, are available at: http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan/NTNDP-database.

[39] Gas-powered generation emissions have increased in 2015–16 due to increased generation from less efficient generators, compared to 2014–15.

4. WIND GENERATION PERFORMANCE

4.1 Registered capacity and maximum wind generation

South Australia has the highest wind generation capacity and penetration of any NEM region in Australia. Table 5 shows the total capacity for all South Australian semi-scheduled and non-scheduled wind farms registered with AEMO, together with the maximum 5-minute generation output, over the past five financial years from 2011–12 to 2015–16.

Changes in registered wind farm capacity do not always match changes in maximum 5-minute generation. Maximum generation can change each year because geographic diversity means not all windfarms contribute their maximum generation in the same 5-minute period. Hornsdale Wind Farm Stage 1 was registered in June 2016, and began generating in this month although it is still under construction.[40] Waterloo Stage 2 and Hornsdale Stage 2 wind farms have been committed but not yet registered.

Table 5 Registered wind generation capacity and maximum 5-minute wind generation

Financial Year	Registered capacity (MW)*	Reason for increase in capacity	Maximum 5-minute generation (MW)*
2011–12	1,203	NA	1,096
2012–13	1,203	NA	1,067
2013–14	1,473	Snowtown Stage 2 (270MW)	1,325
2014–15	1,473	NA	1,365
2015–16	1,576	Hornsdale Stage 1 (102.4MW)	1,384

* Data is captured from when each wind farm was entered into AEMO systems, and includes the commissioning period.

4.2 Total wind generation

4.2.1 Annual energy from wind generation

Table 6 summarises annual wind generation and its annual change from 2011–12 to 2015–16.

Key observations are:

- Annual wind generation in South Australia has increased in line with installed capacity increases since 2010–11. In 2012–13, when there was no new registered wind capacity and lower wind speeds, a 2% reduction in annual output was observed.
- In 2013–14, Snowtown Stage 2 Wind Farm was brought online, and first reached 90% of its registered capacity in June 2014. Growth in wind generation in 2014–15 was largely driven by Snowtown Stage 2 Wind Farm's availability for the full financial year.
- Increased wind speeds contributed to the 2% growth in annual wind generation in 2015–16.
- Annual capacity factors for individual wind farms can vary by up to 5% year on year, though in aggregate the variation is no more than 2%.

[40] As reported in Appendix F, Hornsdale Stage 1 Wind Farm output less than 1 GWh of energy in 2015–16 (in June 2016), and did not contribute to the maximum 5-minute generation in 2015–16, which occurred in May 2016.

Table 6 Total South Australian wind generation

Financial year	Annual South Australian wind generation (GWh)	Annual change in wind generation	Annual capacity factor*
2011–12	3,563		34%
2012–13	3,475	-2%	33%
2013–14	4,088	18%	32%
2014–15	4,223	3%	33%
2015–16	4,322	2%	33%**

* Capacity factor is based on the annual generation in this table compared to theoretical maximum possible assuming the annual capacity reported in Table 5.
** Capacity factor calculation does not include Hornsdale Stage 1 wind farm, currently under construction.

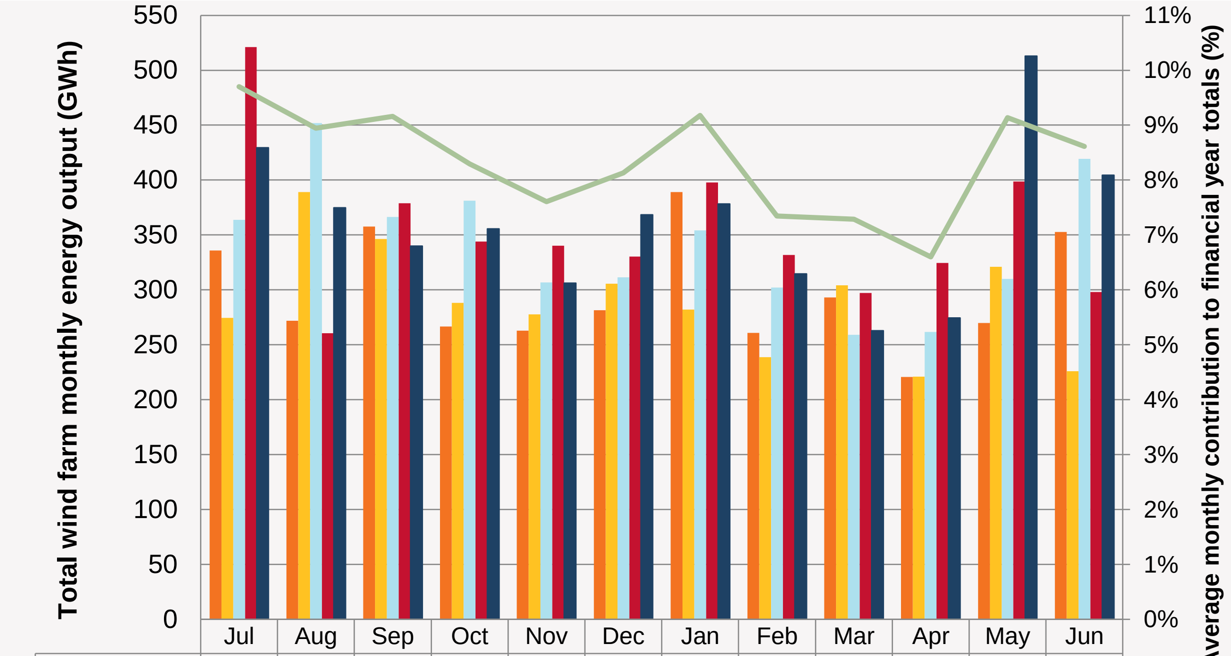
4.2.2 Monthly wind generation variability

Figure 19 shows the monthly South Australian wind generation in GWh over the last five financial years from 2011–12 to 2015–16. Also shown is the average monthly contribution to financial year totals.

Monthly totals show noticeable variation and some underlying seasonal deviations with average contribution peaking through winter (namely July), and some reduction from February to April.

In the last two years, wind output has been highest during May and July. January consistently has moderately high wind speeds, which accounts for its peak compared to the months either side.

Figure 19 South Australian total monthly wind energy output and average monthly contribution



	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
2011–12	336	272	358	267	263	282	389	261	293	221	270	353
2012–13	275	389	346	288	278	306	282	239	304	221	321	226
2013–14	364	452	366	381	307	311	354	302	259	262	310	419
2014–15	521	261	379	344	340	330	398	332	297	325	399	298
2015–16	429	375	340	356	306	368	378	315	263	274	513	404
Avg %	9.7%	8.9%	9.2%	8.3%	7.6%	8.1%	9.2%	7.3%	7.3%	6.6%	9.1%	8.6%

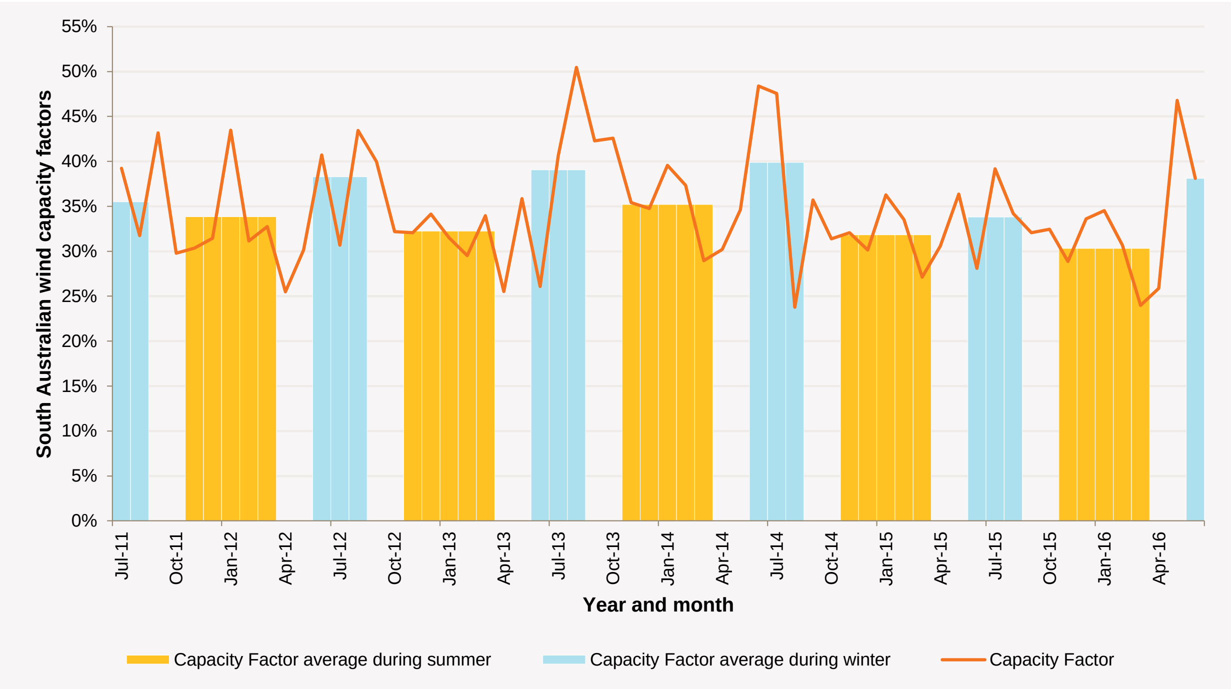
Seasonal capacity factors

Figure 20 shows the capacity factors for South Australian wind generation, based on the total registered capacity for each month, over the last five financial years from 2011–12 to 2015–16.[41]

Key observations are:

- Average winter capacity factors are usually 4% higher than average summer ones.
- Capacity factors are usually highest in the winter months than the summer and shoulder months.
- There is variation across the years for any given month or season, which is attributable to seasonal changes in wind speeds across the region's wind farm sites.

Figure 20 South Australian wind generation capacity factors



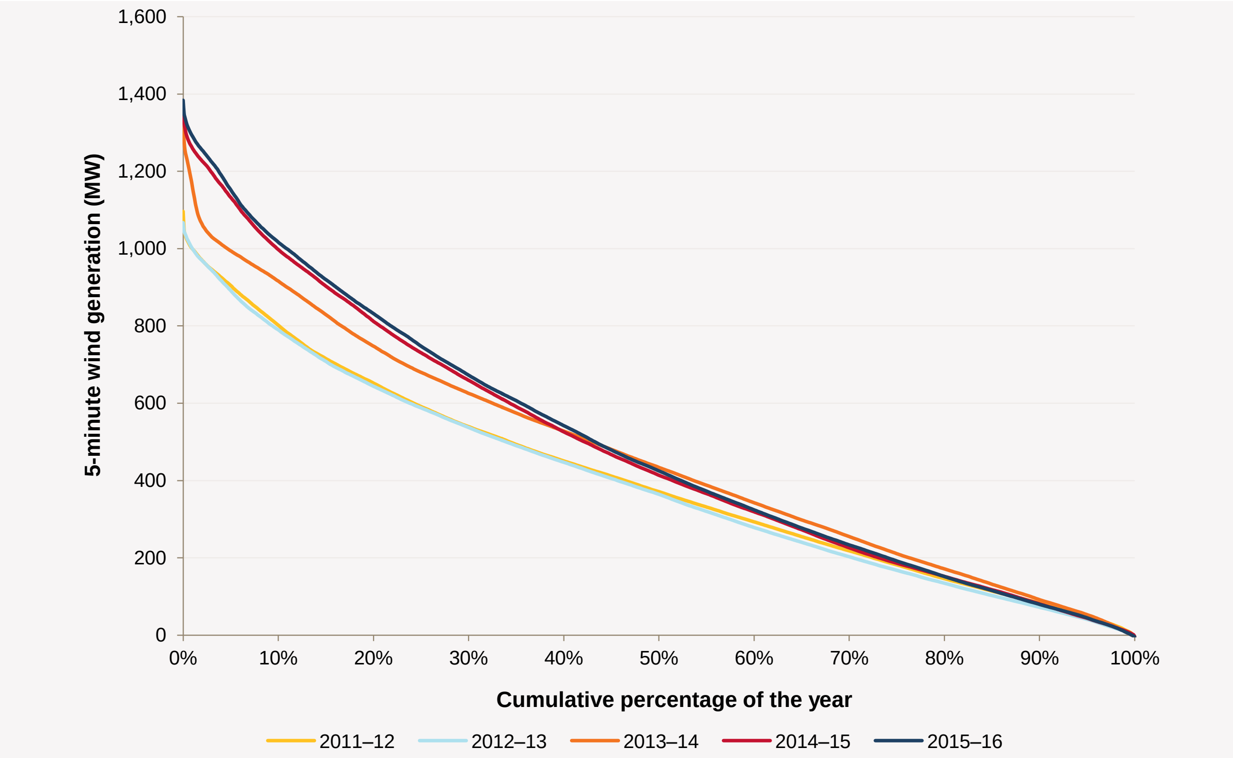
[41] Values prior to July 2015 differ to those reported in the 2015 *South Australian Wind Study Report* due to improved methodology.

4.2.3 Wind generation duration curves

Figure 21 shows the wind generation duration curves for 2011–12 to 2015–16, indicating the percentage of time wind generation was at or above a given level for each financial year. Calculations are based on 5-minute average generation, aligned to dispatch intervals.

These duration curves clearly show the increase in total wind output from 2013–14 after Snowtown Stage 2 Wind Farm was brought online. Little change was seen in the last two financial years.

Figure 21 Annual South Australian wind generation duration curves

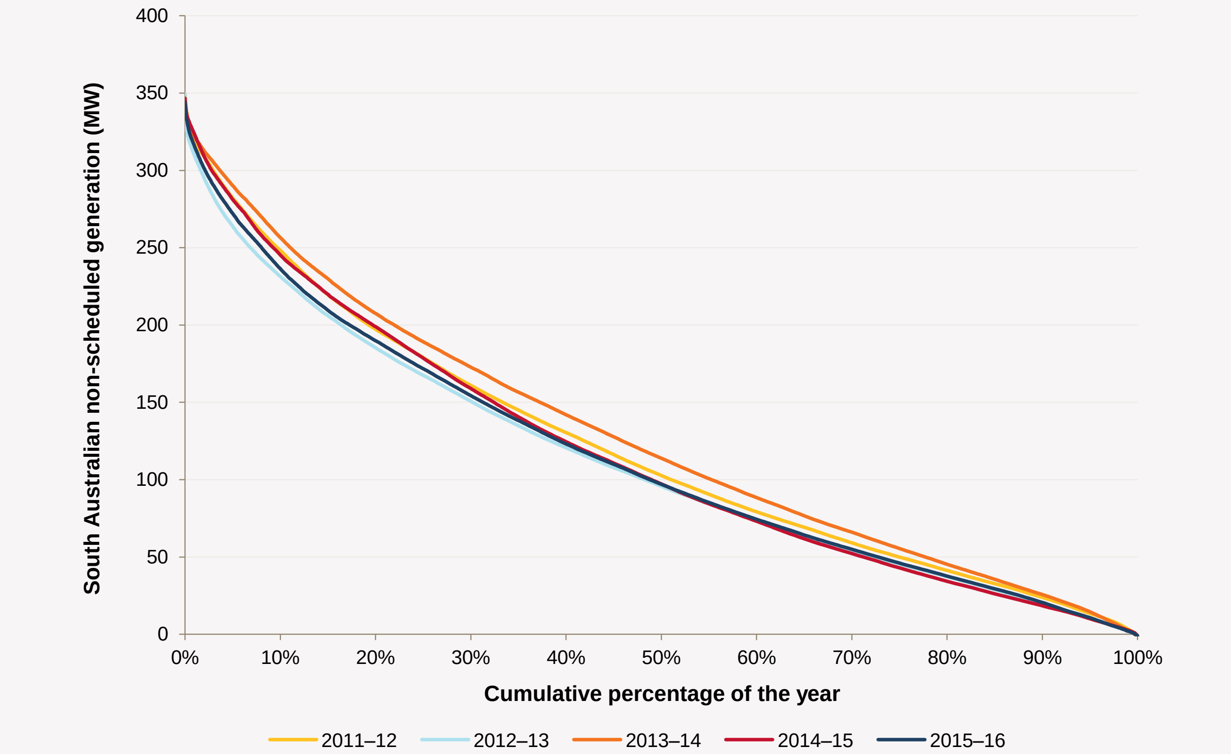


4.2.4 Non-scheduled wind generation duration curves

Figure 22 shows the aggregate annual generation duration curves from the six South Australian significant non-scheduled wind generating systems (outlined in Appendix B), for financial years 2011–12 to 2015–16.

In 2015–16, aggregate non-scheduled wind generation decreased by 1.6% (16 GWh) compared with 2014–15.[42]

Figure 22 Annual generation duration curves for non-scheduled wind generating systems



[42] There was little difference in total wind generation and an increase in semi-scheduled wind generation, reflecting wind speeds across the region.

5. INTERCONNECTOR PERFORMANCE

This chapter analyses power flows between South Australia and Victoria across the Heywood and Murraylink interconnectors. Import is defined as the energy flow from Victoria to South Australia, and export as energy flow from South Australia to Victoria.

5.1 Annual interconnector flows

Figure 23 shows total interconnector imports and exports for South Australia from 2006–07 to 2015–16. Energy imported into South Australia from Victoria during the year is plotted in the orange column bars above the 0 GWh line (x-axis), and energy exported from South Australia to Victoria is shown below the line.

Over the last decade, South Australia has predominantly been a net importer from Victoria. From 2007–08, there has been a steady increase in annual imports from Victoria to South Australia. Import in 2015–16 was 2,227 GWh, mainly via the Heywood Interconnector. This was the highest import in ten years, and a 961 GWh or 6% increase since 2006–07.

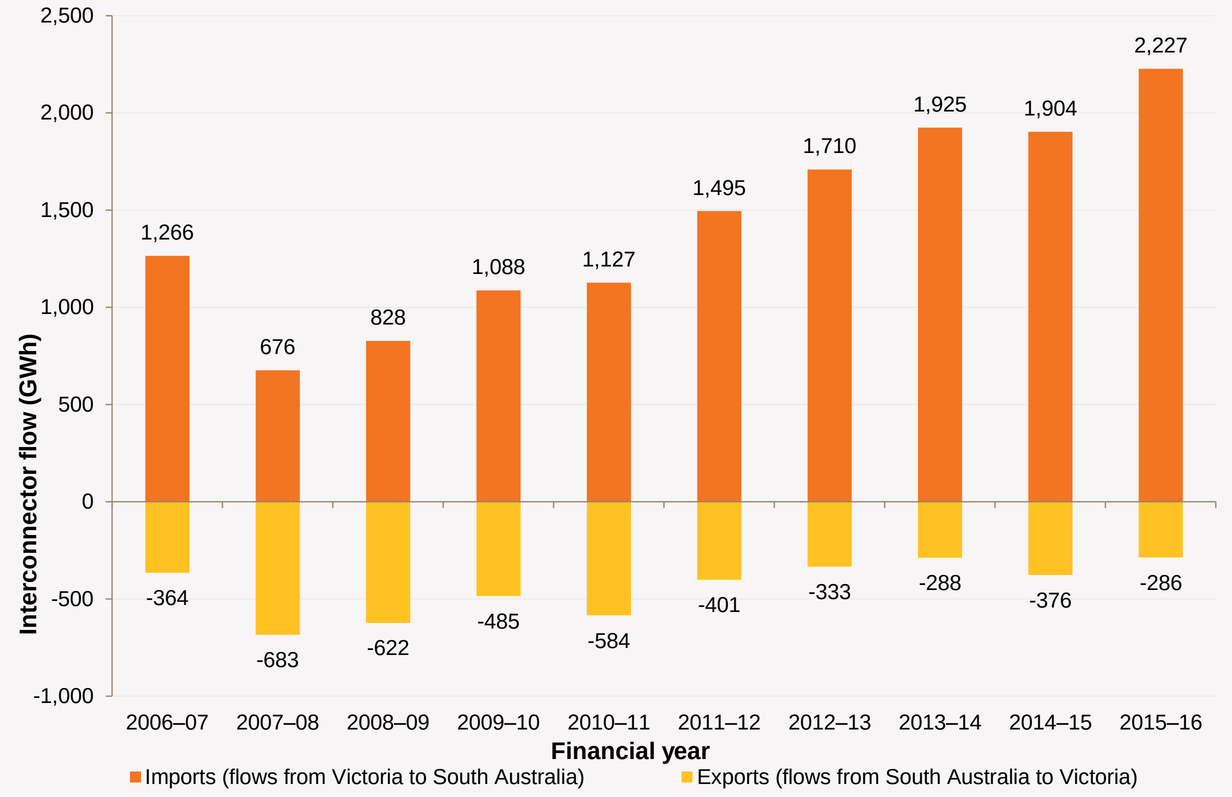
A variety of factors led to greater imports, including:

- Reduction in local installed baseload capacity due to generating plant withdrawals.
- Increase in interconnector capacity.

The factors that drive exports include:

- Drier or drought conditions affecting interstate hydro generation supplies.
- Availability of interstate supply.
- An increase in the number of wind farm generators in South Australia and increased wind generation, predominantly at times of low overnight demand when coal generation is at minimum stable generation.

Figure 23 Total interconnector imports and exports*



* In some cases import and export totals from 2006–07 to 2014–15 are significantly different to values presented in the 2015 SAHMIR. The key reason for material changes is because AEMO has in 2016 calculated net interconnector flow at each 5-minute interval considered, and then aggregated the total imports and exports. In previous SAHMIRs, AEMO had aggregated total Heywood and Murraylink imports and exports separately, then aggregated to total imports and exports, without consideration of time-alignment of flows across the two interconnectors. The new approach in 2016 gives a measure of the actual net regional boundary flow to and from South Australia across every 5-minute interval, which is consistent with the daily average flow and flow duration curve analysis.

Table 7 to Table 9 show the annual energy imported and exported from 2006–07 to 2015–16, and the annual total power flows for the Heywood and Murraylink interconnectors. Heywood Interconnector's average import during 2015–16 and Murraylink's average import and export during 2015–16 were the highest in ten years. This is due to increases in Heywood interconnector capacity as well as a reduction in local generation.

In 2015–16:

- Combined interconnector total imports increased by 323 GWh (from 1,904 GWh to 2,227 GWh) or 17% compared to 2014–15.
- Combined interconnector total exports decreased by 90 GWh (from 376 GWh to 286 GWh) or 24%.
- Combined net interconnector imports increased by 413 GWh (from 1,528 GWh to 1,941 GWh) or 27%.

This indicates a greater reliance on interconnectors to meet operational demand.

Table 7 Historical Heywood Interconnector power flow

Financial year	Total imports (GWh)	Total exports (GWh)	Import average (MW)	Export average (MW)	Maximum Exports (MW)*	Maximum Imports (MW)*
2006–07	1,212	255	190	106	497	377
2007–08	653	539	140	131	457	383
2008–09	808	451	159	122	431	329
2009–10	1087	313	181	114	453	364
2010–11	1,136	381	194	132	493	476
2011–12	1,448	255	216	122	469	469
2012–13	1,598	248	243	113	491	466
2013–14	1,781	188	254	108	516	437
2014–15	1,887	215	265	130	486	469
2015–16	2,013	172	275	118	583	498

* Maximum imports and exports have been derived from 30-minute average flows.

Table 8 Historical Murraylink Interconnector power flow

Financial year	Total imports (GWh)	Total exports (GWh)	Import average (MW)	Export average (MW)	Maximum Exports (MW)*	Maximum Imports (MW)*
2006–07	94	149	24	31	223	171
2007–08	46	166	15	29	217	160
2008–09	57	208	21	34	221	162
2009–10	84	256	33	42	223	173
2010–11	83	295	43	43	223	171
2011–12	138	237	47	41	223	169
2012–13	160	133	38	29	223	174
2013–14	194	149	48	32	223	174
2014–15	144	289	45	52	222	181
2015–16	320	220	67	55	223	182

* Maximum imports and exports have been derived from 30-minute average flows.

Table 9 Historical combined interconnector power flow*

Financial year	Total imports (GWh)	Total exports (GWh)	Net imports (GWh)	Maximum Exports (MW)**	Maximum Imports (MW)**
2006–07	1,266	364	902	680	459
2007–08	676	683	-7	661	493
2008–09	828	622	206	589	474
2009–10	1,088	485	603	640	466
2010–11	1,127	584	543	673	614
2011–12	1,495	401	1,094	657	590
2012–13	1,710	333	1,377	689	581
2013–14	1,925	288	1,637	680	549
2014–15	1,904	376	1,528	676	592
2015–16	2,227	286	1,941	801	607

* Refer to the footnote for Figure 40 for explanation of material differences in total imports and total exports between the 2015 and 2016 SAHMIRs. The material differences in net imports, however, are attributable only to the change to using 5-minute average SCADA metering in 2016 (versus dispatch targets analysed in 2015).
** Maximum imports and exports have been derived from 30-minute average flows.

5.2 Daily average interconnector flow patterns

Figure 24 to Figure 27 show interconnector flow patterns, averaged at the time of day. Values above the vertical axis mean the interconnector is importing into South Australia, while negative values mean it is exporting.

Figure 24 shows the annual flow patterns for combined interconnector imports (from Victoria to South Australia), with times expressed in NEM time. On average, combined interconnector imports exhibit a peak from around 6:00 pm to 10:00 pm, and a trough from around 2:00 am to 7:00 am. These correlate with the peaks and troughs in South Australian daily operational consumption.

The sudden dip then subsequent spike in imports occurring around 11:30 pm to midnight is caused by automated "off-peak" electric hot water systems switching on in Victoria, followed by South Australia.

Figure 24 Combined interconnector daily 5-min average flow

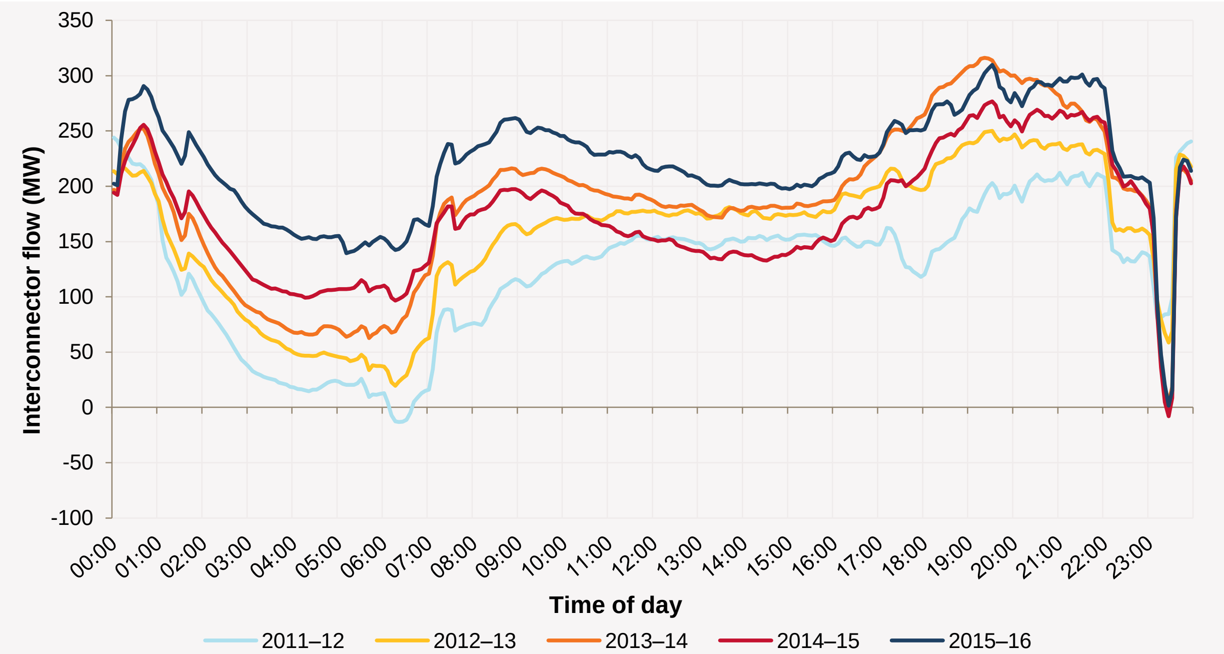


Figure 25 provides a breakdown of the interconnector flow patterns for 2015–16. It shows that, on average, Heywood tends to import electricity, whereas Murraylink tends to import or export depending on the time of day although both follow a similar profile over the day.

Figure 25 2015–16 Heywood, Murraylink and combined interconnector daily 5-min average flow

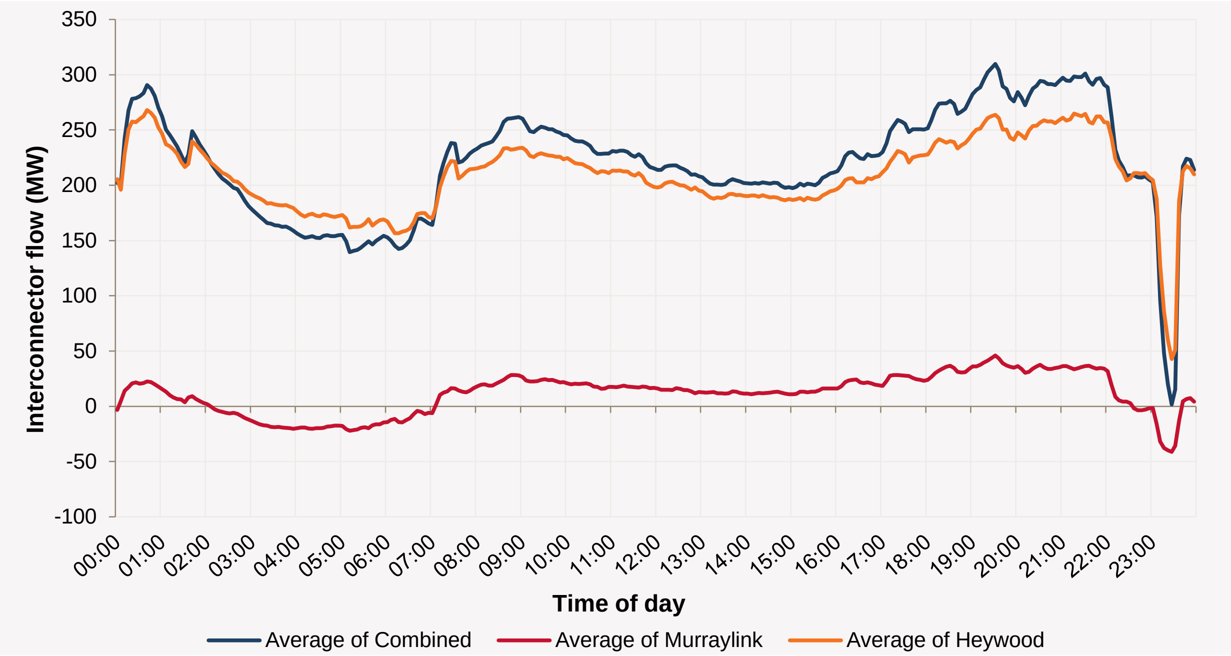


Figure 26 and Figure 27 show interconnector flow averages for each 5-minute dispatch interval of each day over the past five years for workdays in summer and winter. Note that the winter 2016 curve only includes data for June and July 2016. Daily average imports are generally higher during winter, generally due to a reduction in PV generation.

In 2015–16, average daily winter imports were lower than the previous two years due to planned outages on the Heywood Interconnector, and despite the retirement of Northern Power Station.

Figure 26 Combined interconnector summer daily 5-min average min average flow (workdays only)

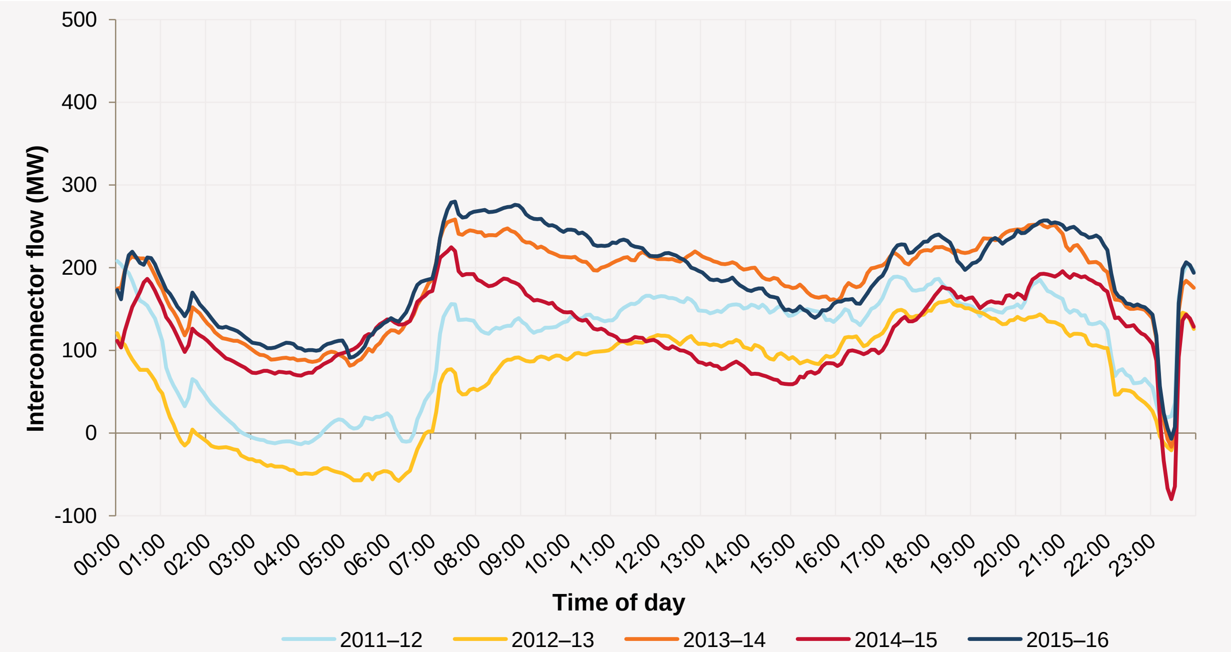
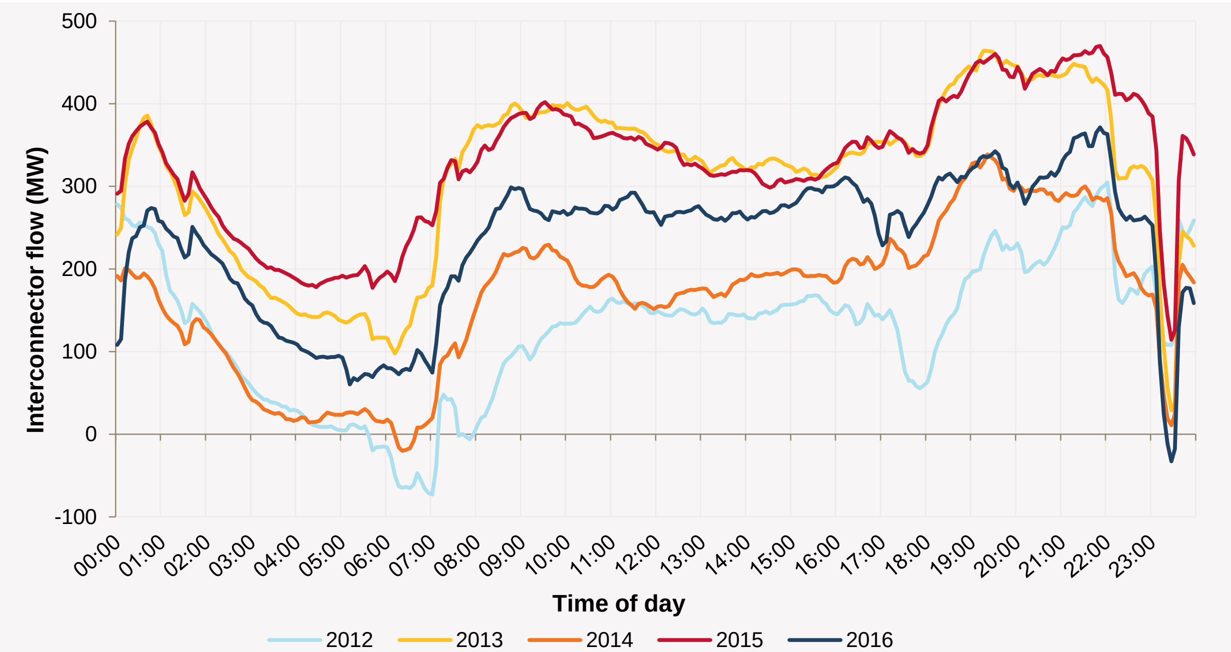


Figure 27 Combined interconnector winter daily 5-min average flow (workdays only)



5.3 Flow duration curves

Flow duration curves are a graphical representation of the percentage of time that electricity transferred via interconnectors (in MW) is at or above a given level over a defined period. Lines above the x-axis indicate imports from Victoria into South Australia. The area between the curves and the x-axis represents the amount of energy being transferred between these regions. Flow duration curves indicate interconnector utilisation.

Heywood and Murraylink currently have a nominal import capacity of 600 MW [43] and 220 MW respectively, and a combined nominal import capacity of 790 MW. Under normal system operating conditions, combined export capability is 650 MW, due to electricity network stability constraints.[44] Under certain conditions, the interconnectors can exceed the maximum nominal import capacity for brief periods; this typically depends on the short-term equipment ratings.

Figure 28 and Figure 29 show flow duration curves for the Heywood and Murraylink interconnectors over the past five financial years. The somewhat stepped flow duration curves for Murraylink reflect its banded transfer constraints. The figures also illustrate the utilisation of the Heywood and Murraylink interconnector import capacity.

Table 10 quantifies the percentage of time, in each of the past five financial years, where each interconnector was being utilised at or above 100% of its nominal import capacity. Network constraints are one factor that can force interconnectors to be utilised below nominal import capacity. For further information regarding how constraints affect the actual capability of these interconnectors, please refer to AEMO's *NEM Constraint Report*.[45]

Table 10 Percentage of financial year having full utilisation of nominal import capacity

Interconnector	2011–12	2012–13	2013–14	2014–15	2015–16
Heywood	0.2%	3.7%	2.6%	3.0%	2.2%
Murraylink	0.3%	0.6%	0.2%	0.1%	1.7%

43 With the completion of the Heywood upgrade, its nominal import capacity will be 650 MW.
44 ElectraNet. *South Australian Transmission Annual Planning Report,* May 2015. Available at: https://www.electranet.com.au/wp-content/uploads/report/2016/06/20160630-Report-SouthAustralianTransmissionAnnualPlanningReport.pdf. Viewed: 29 July 2015.
45 AEMO. *NEM Constraint Report*, 2014.Sections 5.5 and 5.6. Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Congestion-information/Statistical-Reporting-Streams.

Figure 28 Heywood Interconnector flow duration curves

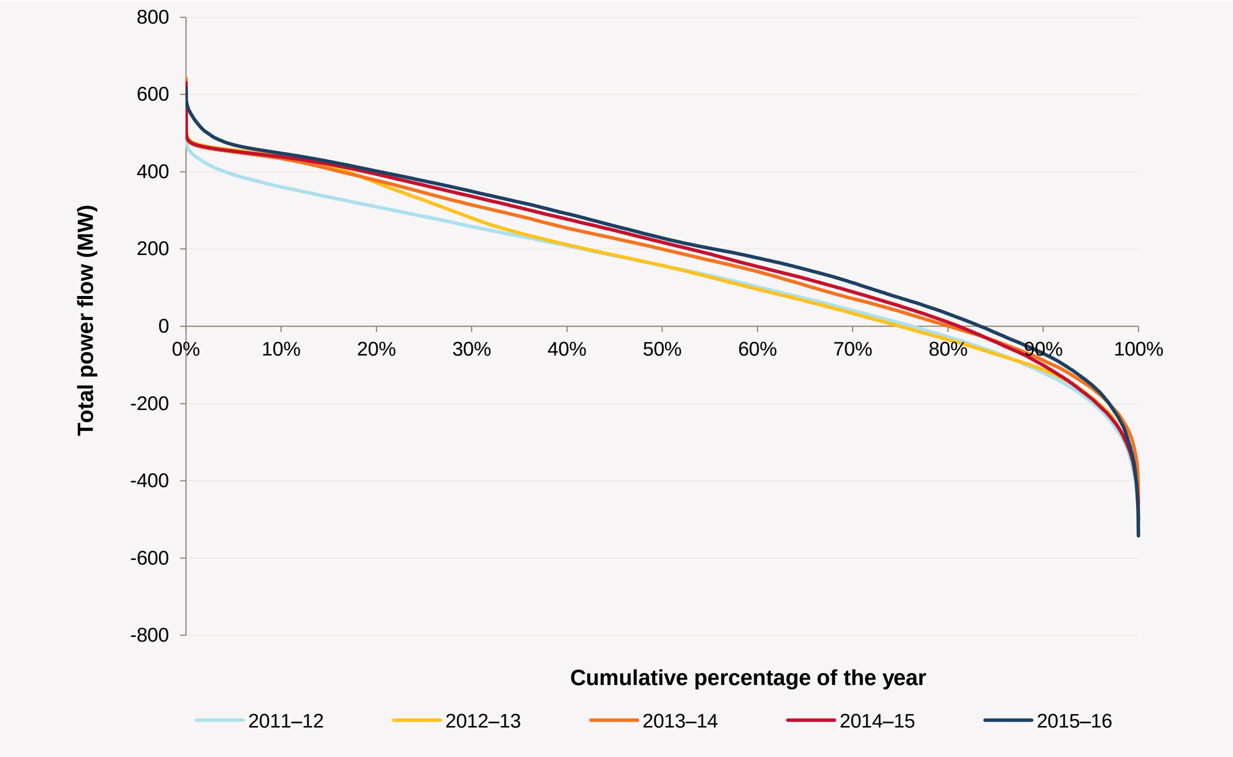


Figure 29 Murraylink Interconnector flow duration curves

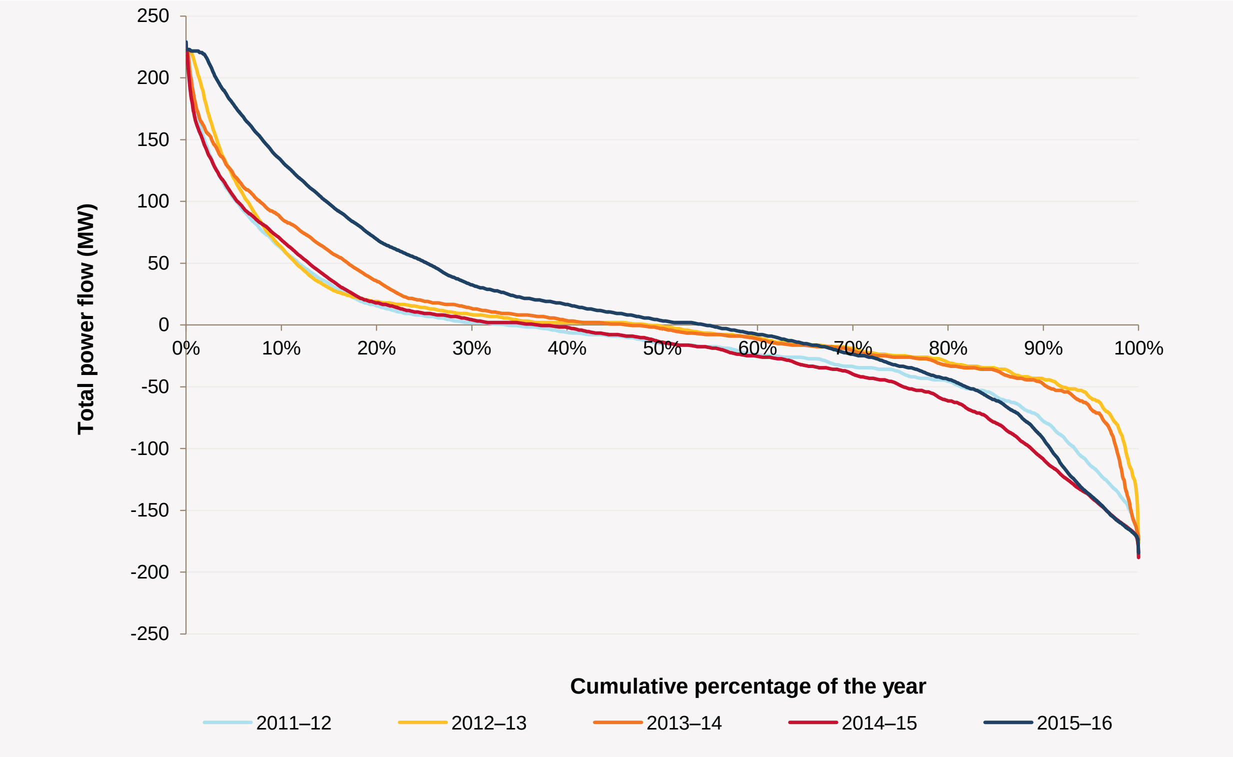


Figure 30 shows the combined Heywood and Murraylink electricity flows, and further demonstrates that South Australia increased its net import from Victoria compared to previous years, while net exports have decreased from 2014–15 to 2015–16.

Figure 31 shows interconnector utilisation as a percentage of total transfer capacity. This indicates that imports over the Heywood Interconnector are closer to its total capacity compared to Murraylink, which conversely shows better utilisation of its export capacity.

The different characteristics observed between Murraylink import and export trends are a product of the NEM's optimised operation, which includes the following pertinent factors:

- Network constraints, which can lower the observed utilisation.
- Location of generation, particularly South Australian wind farms.
- Transmission network electrical and geographical characteristics.
- Location of major load centres.
- Generator operating patterns.

Figure 30 Combined interconnector flow duration curves

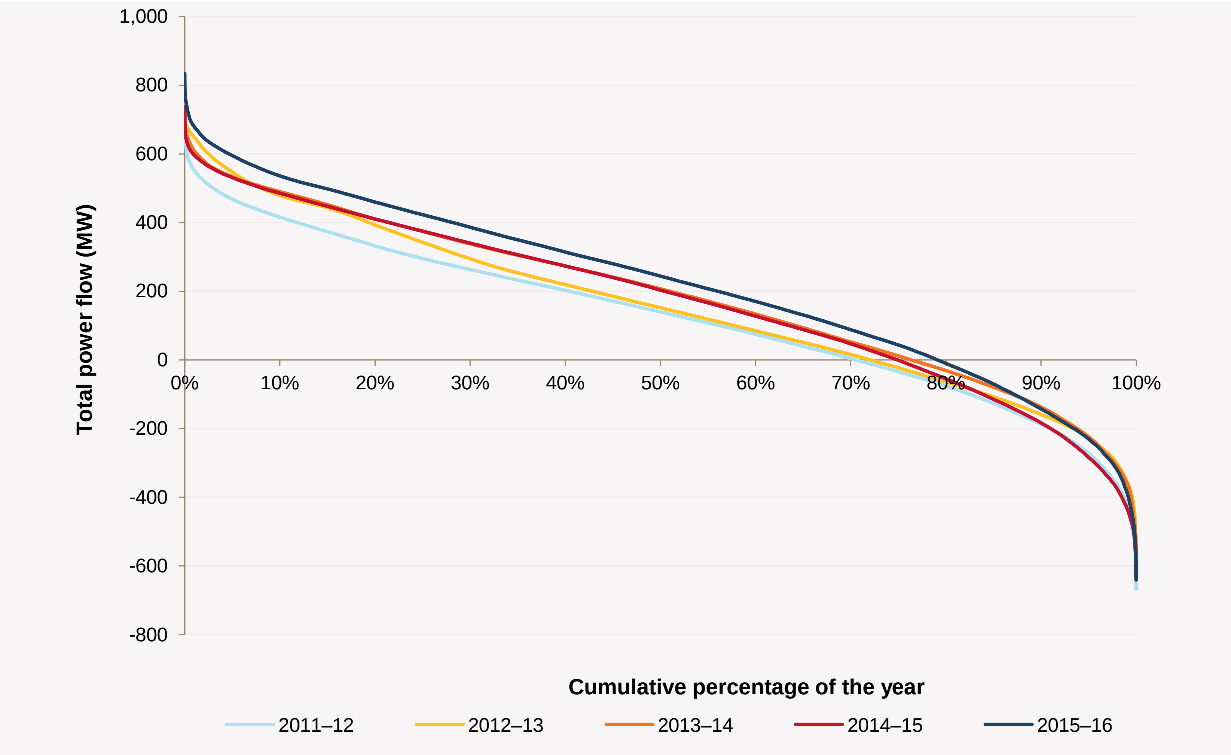
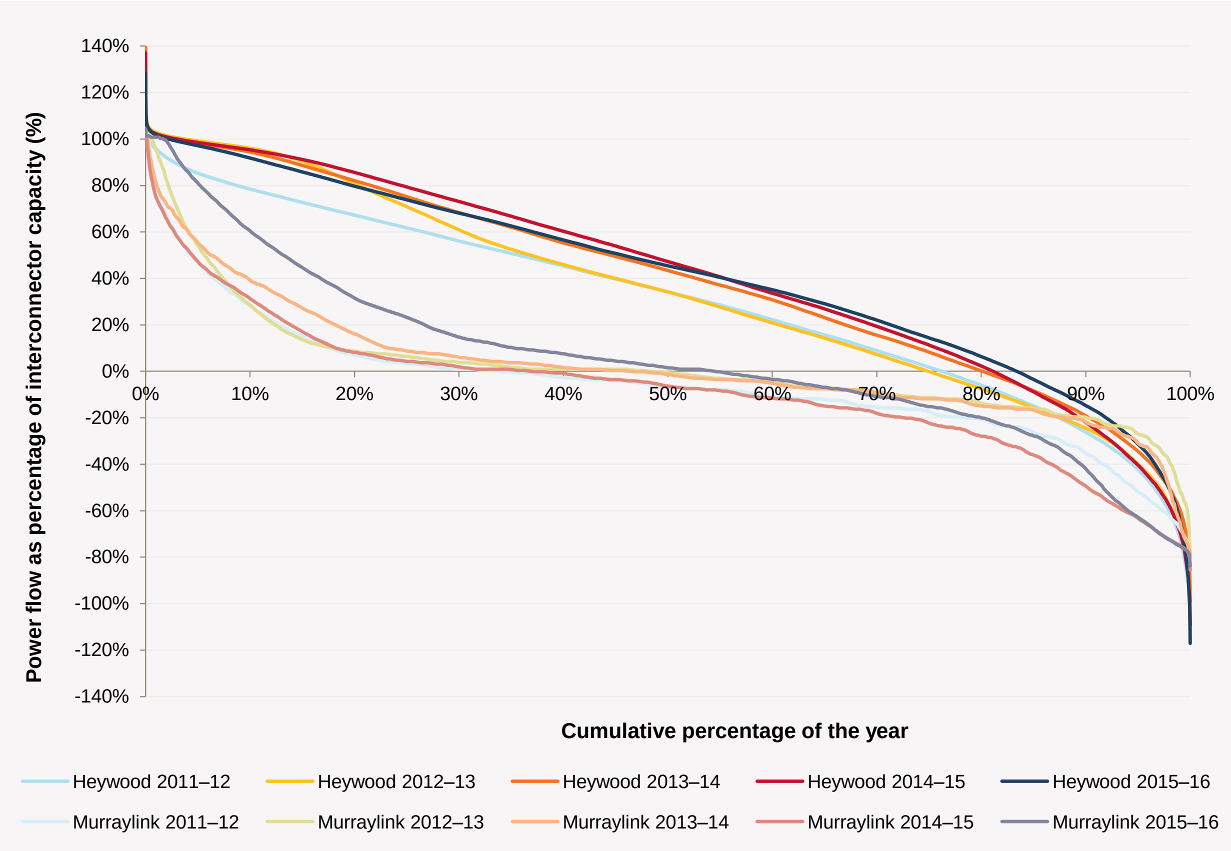


Figure 31 Interconnector flow as a percentage of interconnector nominal capacity



Heywood Interconnector upgrade

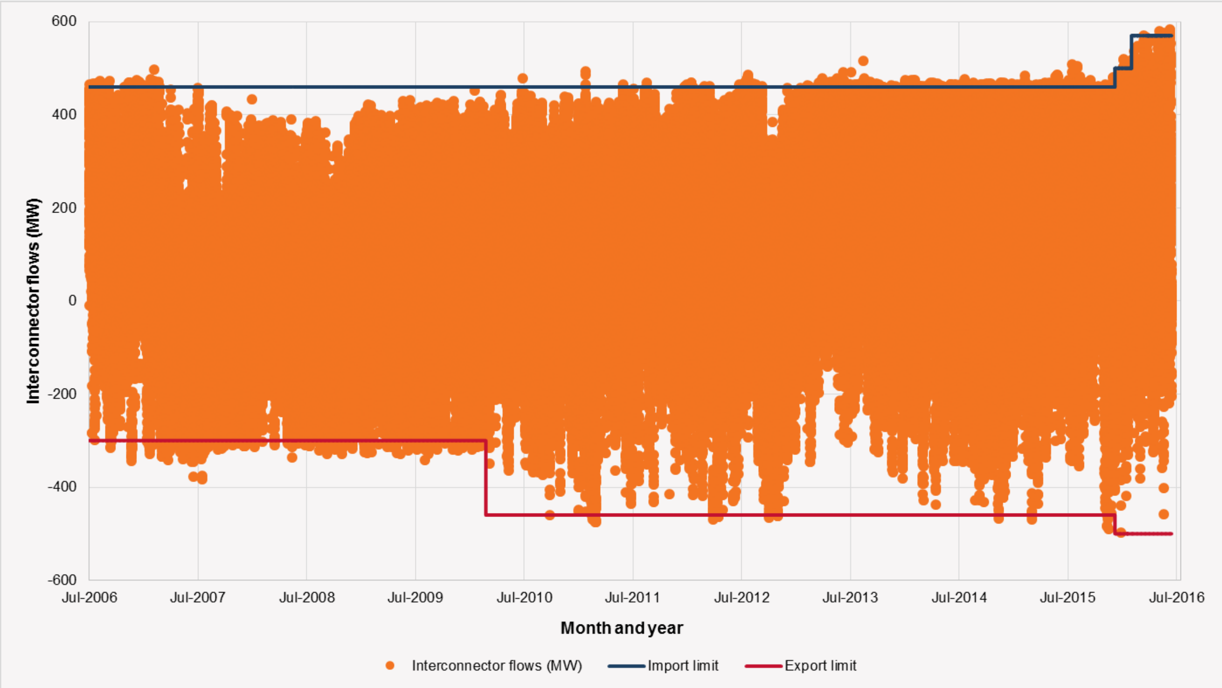
Heywood Interconnector import maximum flows have been higher since commissioning of the third Heywood transformer. The interconnector's nominal flow import capability was upgraded by 40 MW in December 2015, 70 MW in February 2016, and 30 MW in August 2016 to 600 MW. During the same time in December, the nominal export capability was upgraded by 40 MW to 500 MW.

Figure 32 illustrates that the interconnector import maximum flows have increased since commissioning of the upgrade,[46] although export flows have not yet changed.

An upgrade to the export capability occurred in 2010 from 300 MW to 460 MW, as evident in Figure 32.

Continued upgrades are being undertaken on the import and export capability of the Heywood Interconnector, to increase to a total capacity of 650 MW. Certain market conditions are required for testing before the nominal limits can be increased.

Figure 32 Heywood Interconnector flows



[46] Note that flows are derived from 30-minute averages.

6. ELECTRICITY SPOT PRICE ANALYSIS

6.1 Introduction

There are a number of supply and consumption factors that influence electricity spot price and its volatility over time.

Supply factors include:

- The available capacity of generating systems.
- The availability of wind generation and wind conditions.
- The availability of solar generation and degree of cloud cover.
- The costs of generation (for example, changes in fuel costs).
- Non-market generation, which includes rooftop PV and some embedded generation.
- Interconnector flows and network constraints and outages.

Consumption factors include:

- Temperature-dependent loads (heating and cooling).
- Consumer behaviour (for example, residential and commercial consumer response to higher prices reflected in increased energy efficiency savings).
- Large industrial loads (for example, manufacturing and mining consumption).
- Off-peak electricity hot water load switching.

Policy changes (for example, carbon pricing, the COP21 commitment, and the Renewable Energy Target) and individual company electricity and gas contracting positions can affect both supply and consumption.

6.2 Spot price trends

6.2.1 Time-weighted average price

In 2015–16, the average time-weighted average price (TWAP) was $61.81/MWh, the highest since 2009–10, excluding the two carbon-priced years (as seen in Table 11).

This has been attributed, in part, to:

- Increase in operational consumption during 2015–16, due to additional water pumping in response to drier conditions, and increased air-conditioner load (both residential and commercial).
- Exposure of gas-powered generation to Adelaide spot gas prices, which have increased in the past year (from a monthly average ex-ante price of $4/GJ in June 2015 to nearly $8/GJ in June 2016), as discussed in Section 6.2.5.
- The withdrawal of Pelican Point Power station to half capacity from April 2015 and unavailability for winter 2016.
- The closure of Northern Power Station changing the region’s fuel mix and increasing the region’s dependence on higher cost gas-powered generation, for part of the year.

6.2.2 Volume-weighted average price

Volume-weighted average price (VWAP) takes into account the amount and price of electricity for a given interval, while time-weighted average price does not take into account the different volumes of energy sold within the interval.

Table 11 compares the VWAP for South Australian renewable generation[47], thermal generation, and total market generation, on a financial year basis and each summer from 2006–07 to 2015–16. This is also displayed graphically in Appendix D. It shows that South Australian thermal generation has a higher VWAP than renewable generation. The TWAP for each financial year is also shown for comparison. VWAP values are based on 30-minute average generation volumes and the corresponding spot price (in real June 2016 dollars). A comparison of VWAPs using nominal values is available in Appendix E.

Summer VWAPs were typically higher than financial year VWAPs, due to the greater proportion of high demand days throughout summer. This difference was reasonably pronounced until 2010–11, after which summer and financial year VWAPs have converged as summer peaks have reduced, mainly from increased rooftop PV and energy efficiency trends seen in air-conditioning. A noticeable upward shift in VWAPs occurred in 2012–13 and 2013–14, due to carbon pricing.

Table 11 South Australian spot price trends, in real June 2016 $/MWh, 2006–07 to 2015–16

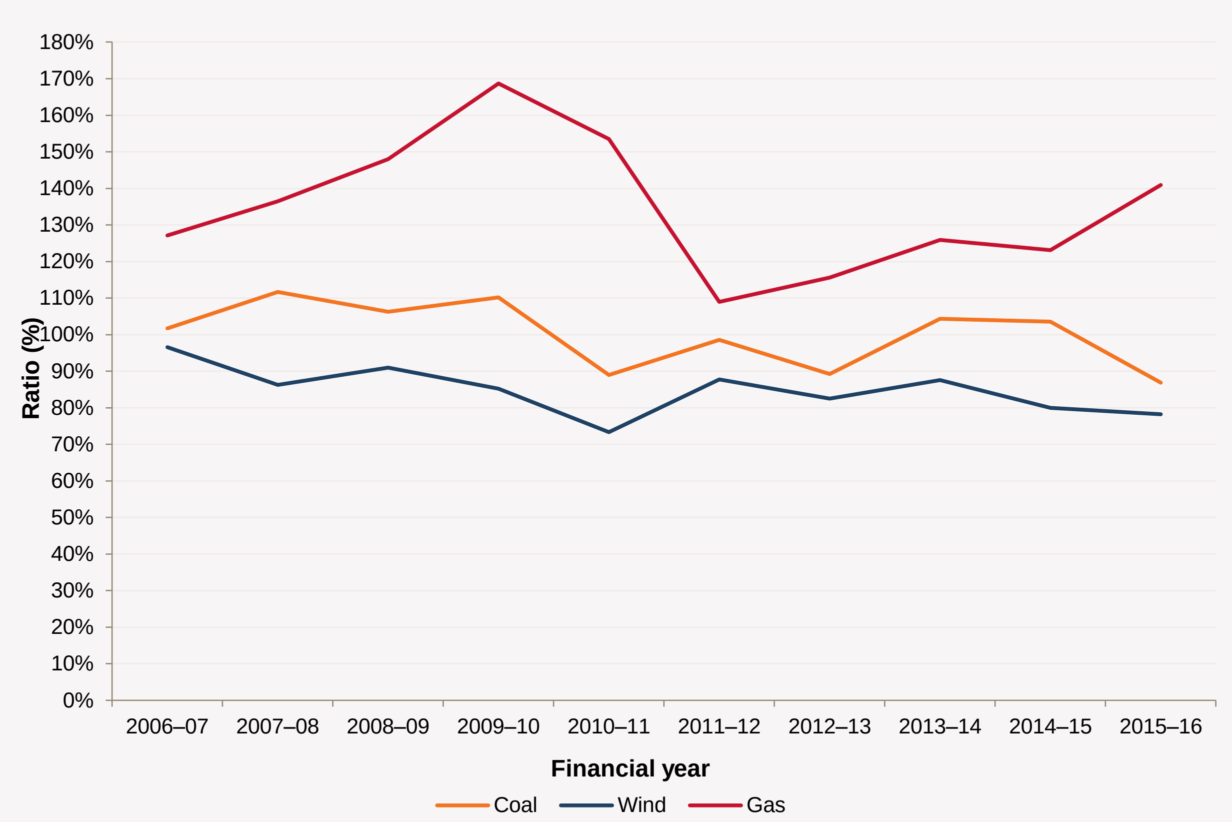
	SA wind generation		SA thermal generation		Total SA market generation		SA spot price
	Financial year	Summer*	Financial year	Summer*	Financial year	Summer*	Financial year
	Volume-weighted average	Volume-weighted average	Volume-weighted average	Volume-weighted average	Volume-weighted average	Volume-weighted average	Time-weighted average
	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)
2006–07	61.75	58.94	74.59	76.09	73.74	74.90	63.92
2007–08	75.97	107.65	114.04	184.60	110.54	177.72	88.09
2008–09	54.00	78.06	78.92	129.78	75.41	122.19	59.35
2009–10	53.67	92.78	93.40	168.33	86.52	156.31	62.98
2010–11	26.32	27.70	46.34	65.64	41.98	57.30	35.86
2011–12	28.54	26.18	34.41	30.49	32.80	29.31	32.54
2012–13	60.59	56.44	80.18	70.02	74.73	66.64	73.45
2013–14	55.56	56.64	76.11	89.33	68.96	79.47	63.42
2014–15	31.76	28.54	46.13	41.04	40.84	36.63	39.73
2015–16	48.34	44.63	75.21	65.38	65.08	58.59	61.81

* Summer is defined as November to March inclusive for NEM reporting on the Australian mainland states.

Figure 33 shows the ratio of wind, coal, and gas powered generation VWAP to TWAP by financial year. TWAP represents the average price a generator would have received if it generated at full capacity for the full financial year. It highlights that, during times of high wind generation, spot prices are typically lower than average. In 2015–16, on average, the VWAP received by a wind generation was 85% of the total TWAP. The average VWAP for gas was 135% of the TWAP and for coal about 100% of TWAP. The higher gas VWAP reflects the operating mode of these generators, typically during higher demand periods, or when supply availability is reduced. For more information on these trends for wind generators, refer to the SARER, due to be published in October 2016.[48]

[47] Renewable generation here comprises the semi-scheduled and non-scheduled wind farms listed in Appendix C.
[48] AEMO. *South Australian Renewable Energy Report*. Previous wind study reports are available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions. The 2016 report will be available at the same page in October 2016.

Figure 33 Ratio of VWAP by fuel to Total TWAP



6.2.3 Spot price duration curves

Spot price duration curves show how frequently a particular 30-minute spot price occurs or is exceeded over a given period. Spot prices have been CPI-adjusted, with June 2016 used as the reference price.

Figure 34 and Figure 35 show the spot price duration curves for financial years 2011–12 to 2015–16. Analysis has been undertaken to estimate the electricity price had the carbon price not been imposed during 2011–12 and 2012–13, is represented by the dashed lines.

Figure 34 highlights that for the highest 13% of price periods, spot prices for 2015–16 were higher than the previous four years. Section 6.2.4 discusses reasons for 2015–16 price changes in more detail.

Figure 35 shows that in the past four financial years, the top 1% of spot prices have been above $100/MWh.

Figure 34 South Australian spot price duration curves

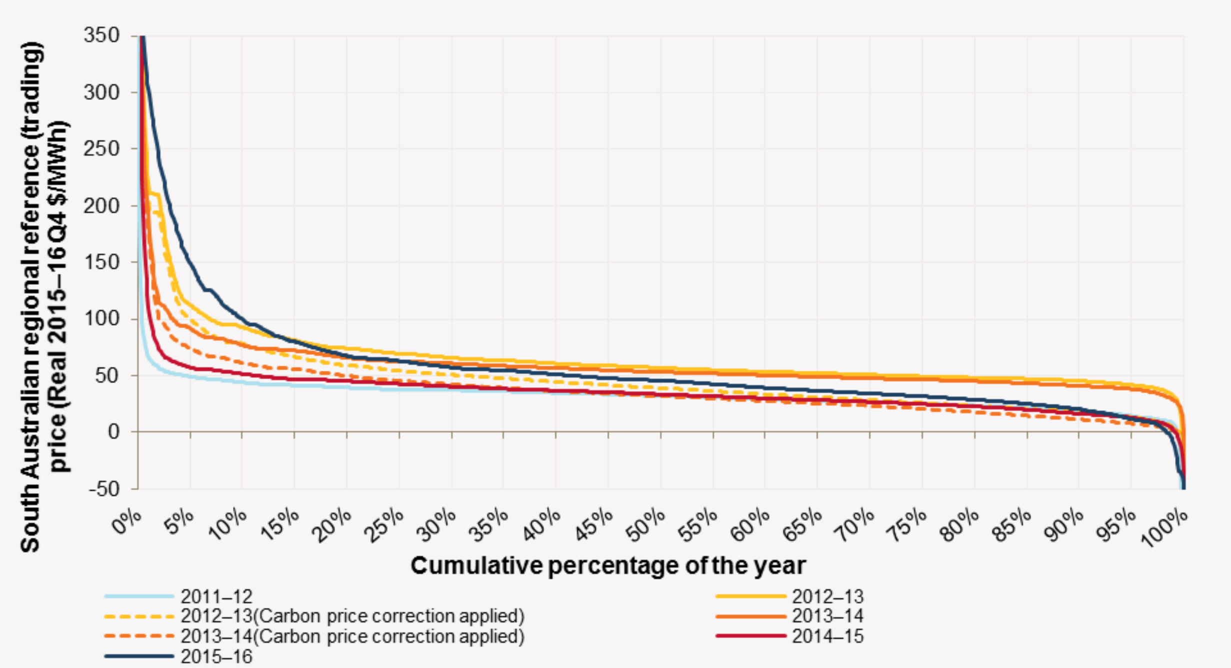
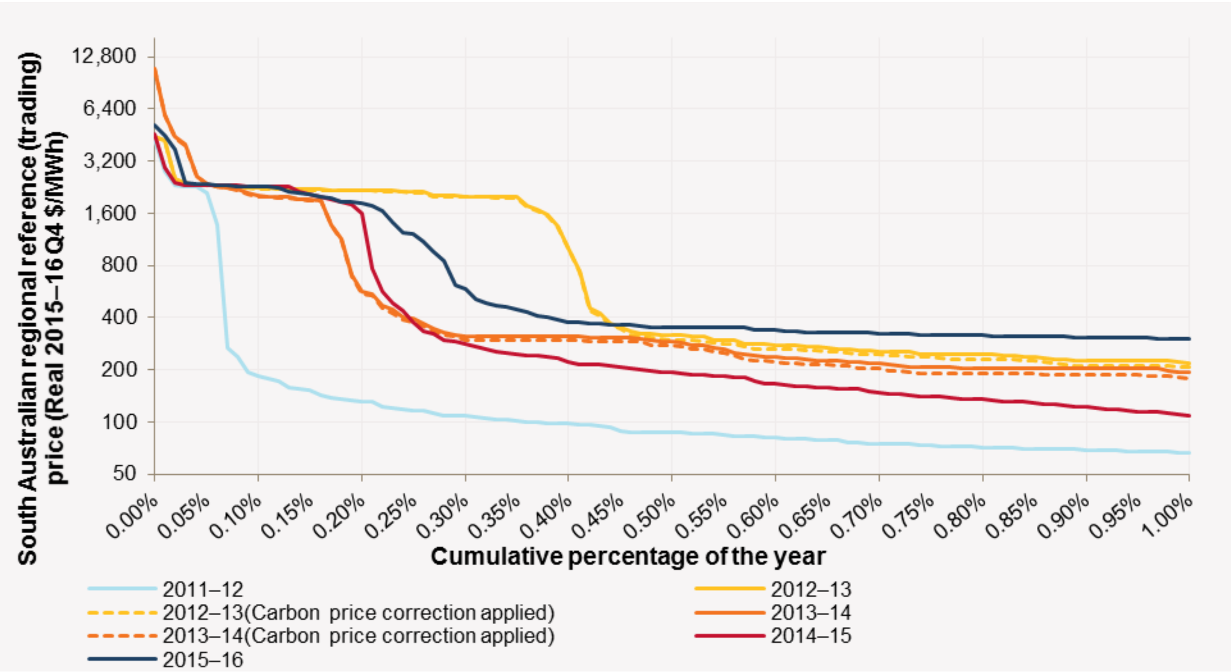


Figure 35 South Australian spot price duration curves (top 1% of prices)



NOTE: Logarithmic scale applied to vertical axis.

6.2.4 Price volatility

In 2015–16, there were more occurrences of both negative prices and prices above $100/MWh than observed in the previous four years, as well as a greater dispersion throughout multiple price bands:

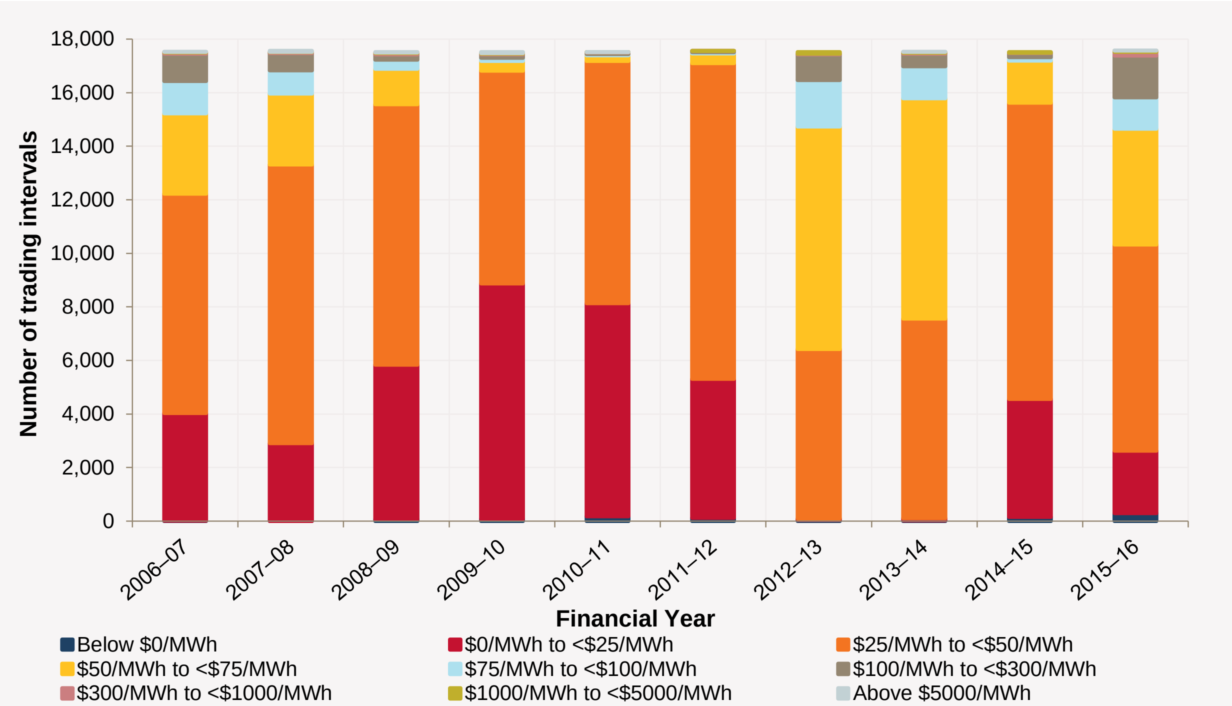
- Negative prices were observed 1.6% of the time, typically when wind energy penetration was above average, most commonly overnight, coinciding with times of low demand and dispatch close to minimum stable levels for thermal plants. See Section 6.3 for further details.
- Prices exceeding $100/MWh were observed 10% of the time. These higher spot prices were driven by a variety of factors including planned and unplanned generator outages, transmission outages impacting the Heywood Interconnector, higher gas spot prices, and, sometimes, low levels of wind generation.
- For 90% of the year, prices were dispersed from $0–300/MWh, whereas historically, 90% of prices were less than $100/MWh.

South Australia has experienced varying levels of electricity spot price volatility throughout its participation in the NEM, which can be shown by the frequency of spot price occurrence in different pricing bands, as summarised in Table 12 and Figure 36.

Table 12 Frequency of occurrence of spot prices for South Australia

Price Band	2006–07	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15	2015–16
Below $0/MWh	0.1%	0.0%	0.4%	0.5%	1.0%	0.7%	0.2%	0.1%	0.9%	1.6%
$0/MWh to <$25/MWh	23.0%	16.5%	32.9%	50.2%	45.4%	29.5%	0.3%	0.5%	25.1%	13.3%
$25/MWh to <$50/MWh	46.7%	59.2%	55.6%	45.4%	51.6%	67.1%	36.1%	42.6%	63.1%	43.8%
$50/MWh to <$75/MWh	17.1%	15.0%	7.5%	2.0%	1.2%	2.0%	47.4%	46.9%	9.0%	24.6%
$75/MWh to <$100/MWh	6.9%	5.0%	2.0%	0.7%	0.3%	0.3%	9.9%	6.8%	0.7%	6.7%
$100/MWh to <$300/MWh	5.8%	3.6%	1.1%	0.7%	0.3%	0.2%	5.5%	2.7%	0.9%	8.9%
$300/MWh to <$1000/MWh	0.3%	0.2%	0.3%	0.1%	0.0%	0.0%	0.1%	0.2%	0.1%	0.8%
$1000/MWh to <$5000/MWh	0.1%	0.1%	0.1%	0.2%	0.0%	0.1%	0.4%	0.2%	0.2%	0.3%
Above $5000/MWh	0.0%	0.3%	0.2%	0.3%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%

Figure 36 Frequency of occurrence of spot prices for South Australia



6.2.5 Impact of changes in generation mix

South Australian energy and price trends

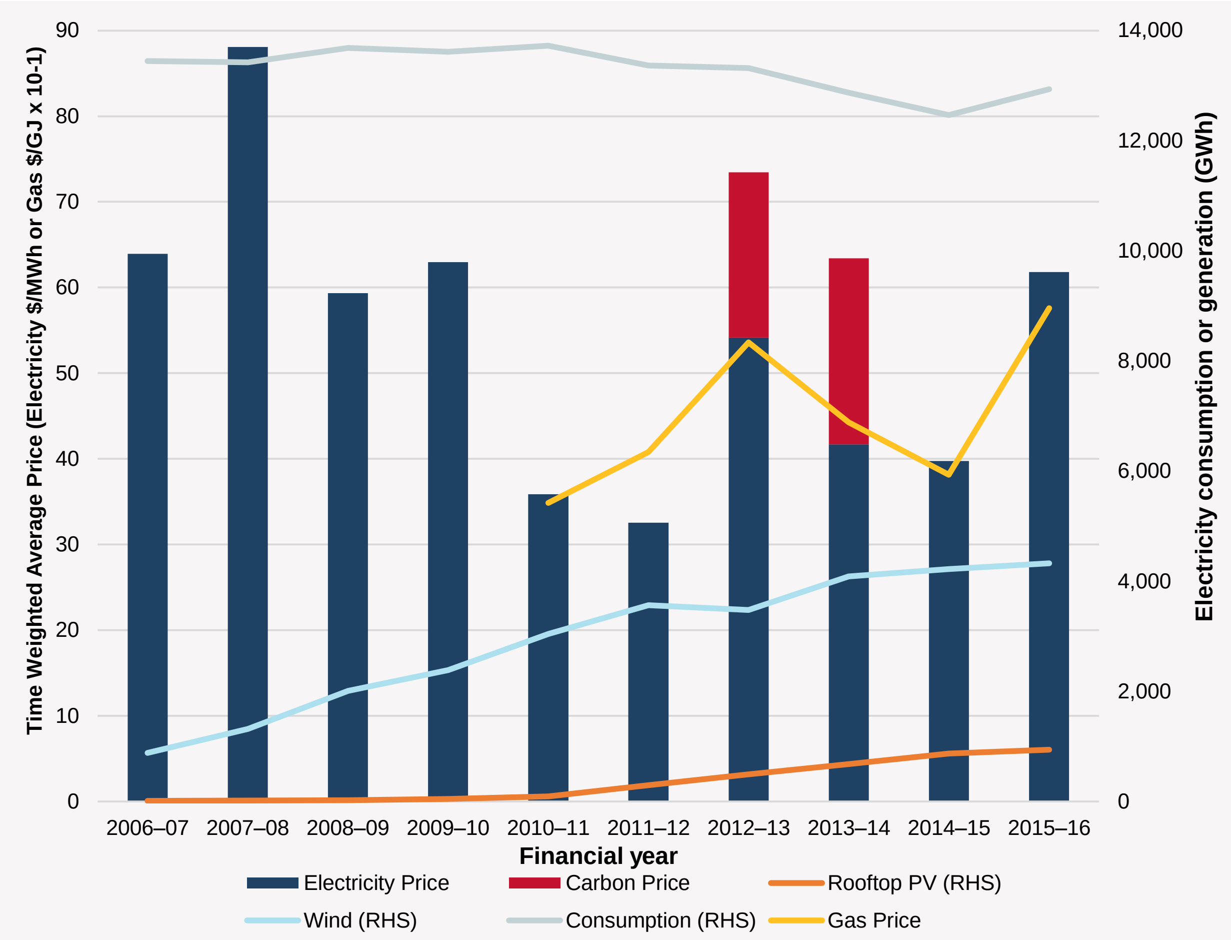
Historical average electricity and gas price trends are shown in Figure 37. The analysis includes:

- Average annual electricity prices, with an adjustment made to consider the estimated price with the carbon price removed during 2012–13 and 2013–14.
- Average annual gas prices. Ex-ante prices have been used for the Short Term Trading Market (STTM) Adelaide hub which began operation on 1 September 2010.
- Rooftop PV generation estimates, using the methodology detailed in Appendix G.
- Wind generation, determined from SCADA data.

Figure 37 shows that both electricity and gas prices have fluctuated each year, following a similar trend to each other. This suggests the average annual spot market prices are strongly influenced by gas prices due to South Australia's high reliance on gas-powered generation.

The growth of renewables has also been highlighted in the figure, showing that both rooftop PV and wind have increased more than three-fold since 2006–07. This trend does not correlate with annual TWAP variations.

Figure 37 South Australian energy and price trends

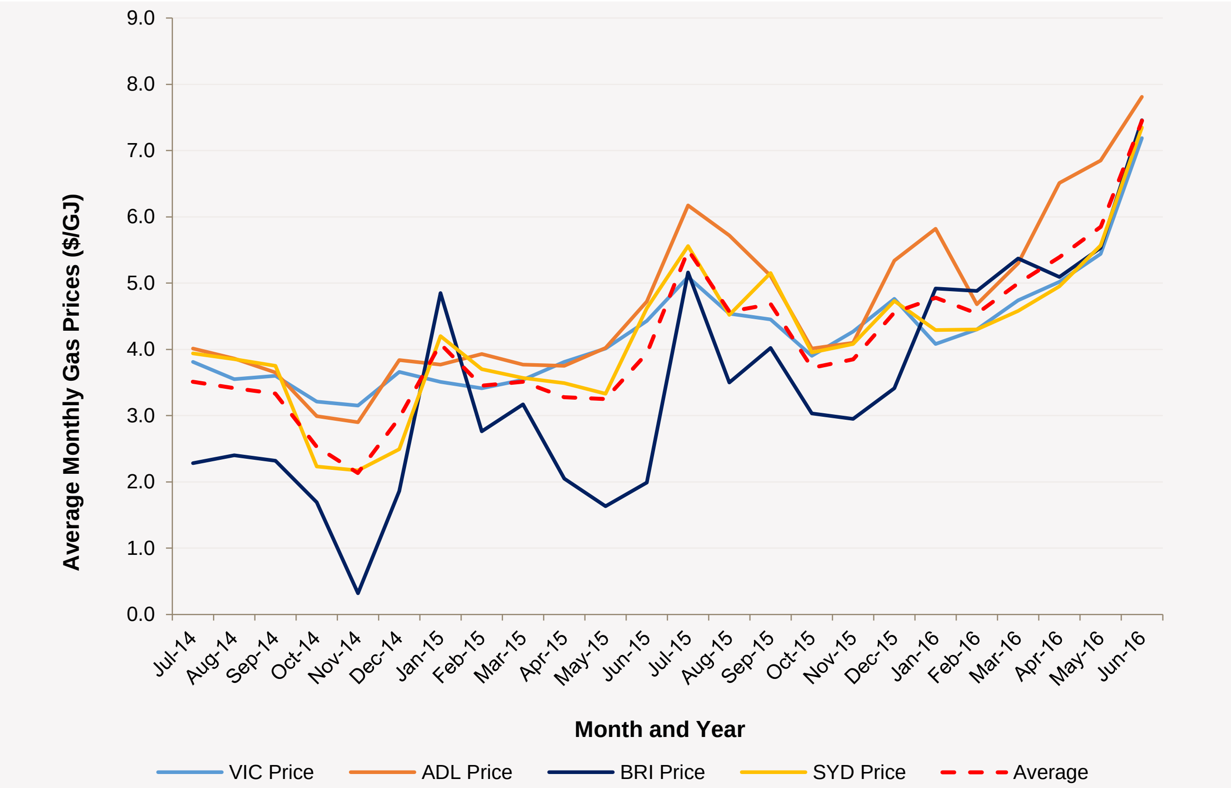


Gas spot price impact on electricity spot prices

Across the NEM, gas-powered generation has been setting the electricity spot price more frequently in 2015–16 than in 2014–15. This is due to declining black coal generation from plant aging and withdrawals, and higher gas prices.

Gas spot prices have approximately doubled in the past two years across all jurisdictions (for Adelaide, the price grew from $4.01/GJ in July 2014 to $7.81/GJ in June 2016). This increases generation costs for gas-powered generation in cases where gas supplies are not fully contracted, and ultimately influences electricity prices as discussed above. Figure 38 shows average monthly ex-ante gas prices across AEMO gas jurisdictions from July 2014 onwards. The start-up of Queensland's liquefied natural gas (LNG) facilities has linked domestic wholesale gas prices to international markets, resulting in increased gas prices for domestic gas supplies across the NEM.

Figure 38 Monthly average of wholesale gas market prices from July 2014 to June 2016



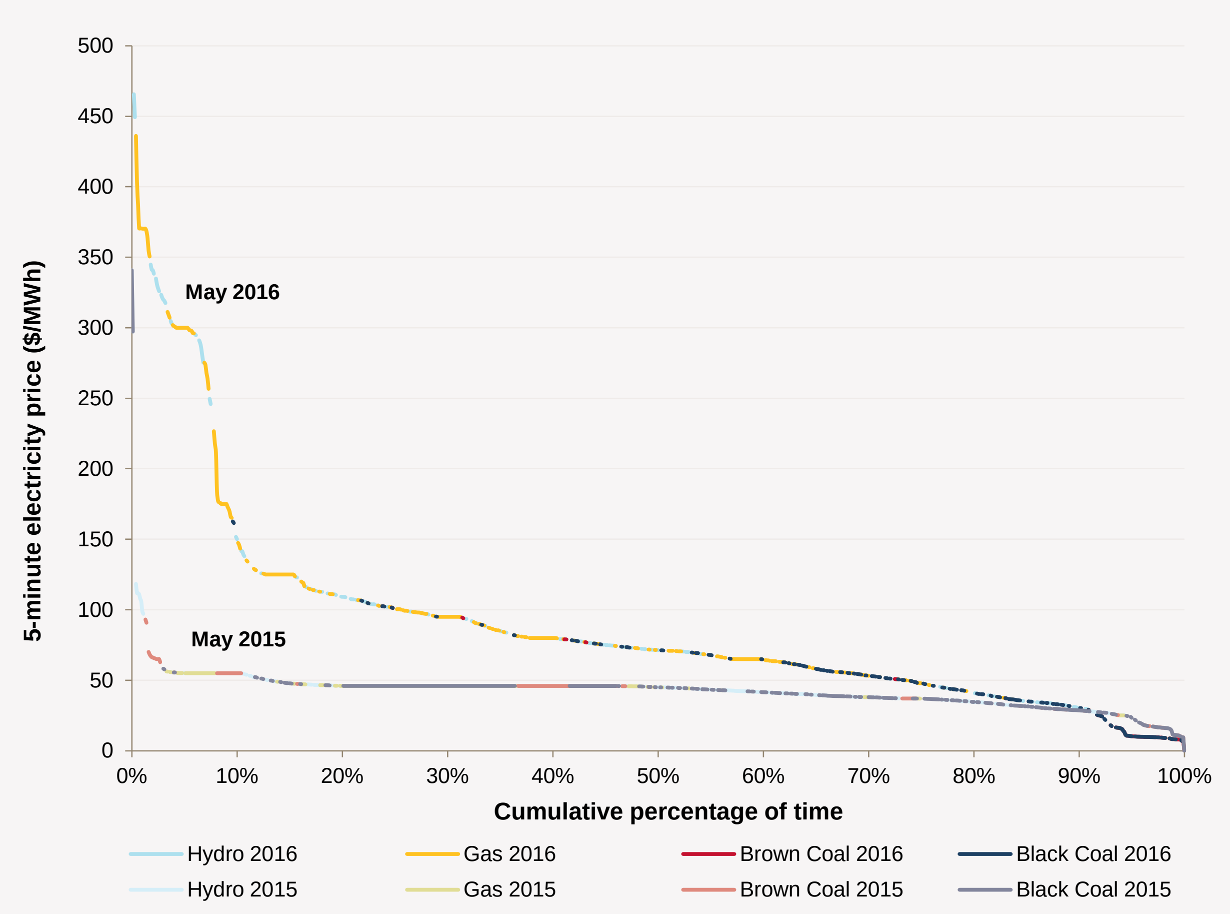
Note: STTM (Adelaide, Brisbane and Sydney) prices are ex-ante. DWGM (Victoria) prices are for the 6.00am daily interval.

The increasing influence of gas-powered generation setting the electricity spot price in South Australia can be seen in Figure 39. This figure shows the fuel responsible for setting the price, and compares the same month over two separate years. In May 2014–15, when prices in South Australia were predominately set by coal and hydro generators, via imports[49], the average price set by gas was $46.46/MWh. In May 2015–16, this increased to an average of $137.79/MWh.

Similar trends are observed across all NEM regions, but most notably NSW.

[49] It is possible that the price setter generator/s may be located in a different region of the NEM, when the interconnector is not at its limit.

Figure 39 South Australia price duration curve by price-setting fuel



Note: This data includes only peak periods between 7am to 10pm, where both the electricity and RRN band price is greater than or equal to zero.

Spot prices and wind generation

Market prices are not typically set by wind generators, except during periods of low demand, since:

- Wind generators have no fuel cost, and have additional revenue from participation in the Large-scale Renewable Energy Target (LRET) scheme. The creation of Large Scale Generation Certificates (LGCs) allows wind generation to bid near the negative LGC price.
- Average wind generation is slightly higher overnight when demand is low, corresponding to periods when baseload thermal generation typically bid low to remain scheduled on.[50]
- Wind generators depend on wind availability. Wind farms are limited to bidding at times when wind is available, and cannot increase generation in response to high market prices.

However, the volume of wind generation does have some influence on spot prices. Figure 40 shows spot prices for the South Australian region and the corresponding average wind generation levels for each 30-minute dispatch interval for 2015–16. Spot prices are plotted on a logarithmic axis to better represent the variance; it is split between the positive (upper graph) and negative (lower graph) prices.

The VWAP (in nominal dollars) for South Australia wind generation over the 12-month period is also displayed (as a horizontal line) for reference against the positive prices.

The graph shows that very high prices (above $1000/MWh) tend to occur when wind generation is low, while low prices (below $1/MWh) tend to occur when wind generation is high.

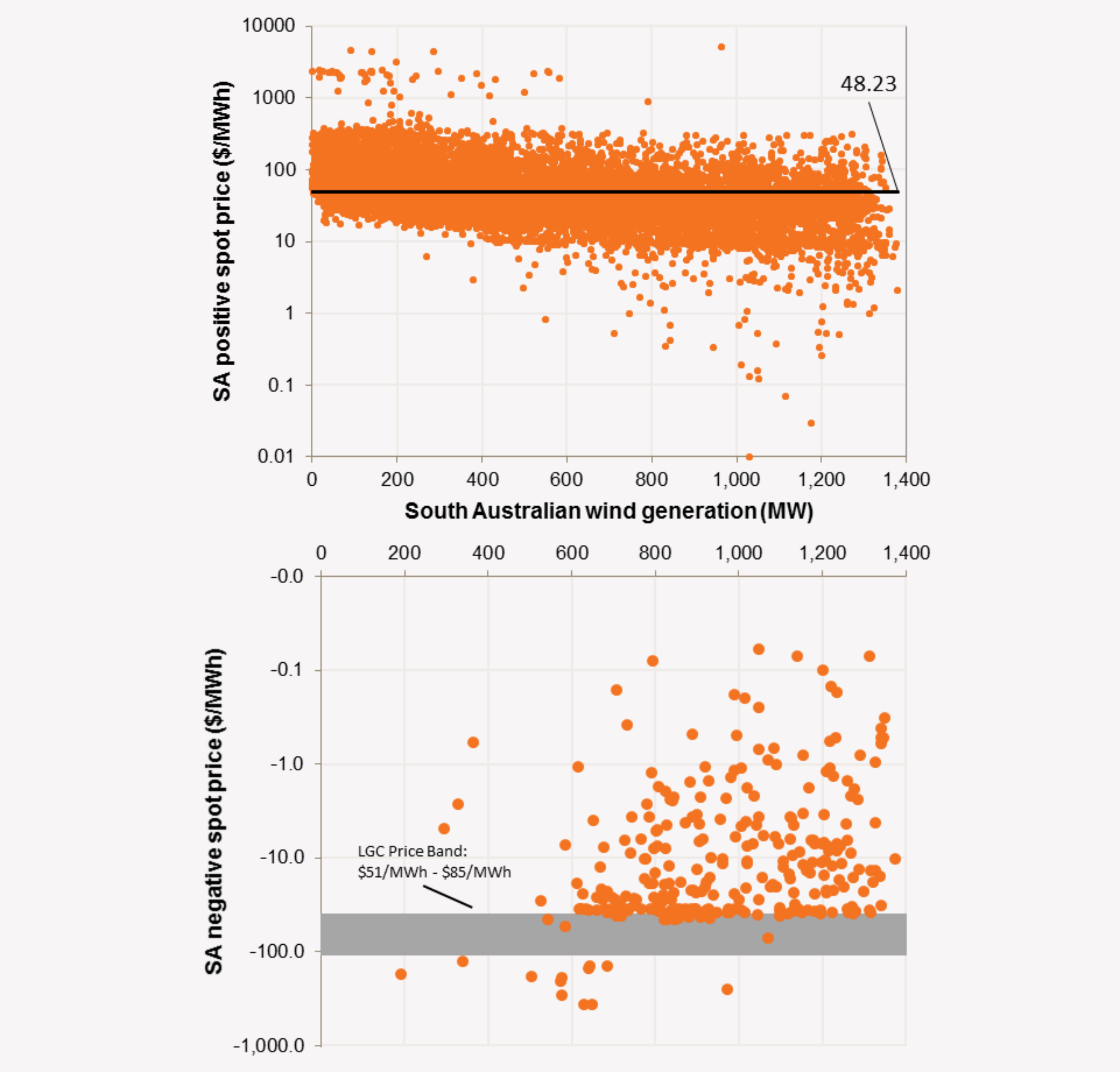
[50] For further detail on typical wind generation, please see the AEMO 2015 *South Australia Wind Study Report*. Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions.

The 2015–16 negative LGC price band, $51/MWh to $85/MWh[51], has been highlighted in grey. This suggests that wind generators continue operating during negative price events, if available, provided the electricity spot price does not fall below the negative of the LGC price.

Wind generation at prices below the LGC price band occurred over four separate days in 2015–16. The low prices occurred during network outages.

Further historical information on spot prices and wind generation in South Australia will be published in AEMO's *South Australian Renewable Energy Report*, to be published in October 2016.[52]

Figure 40 South Australian 30-minute spot prices and average wind generation for 2015–16



Note: Logarithmic axis

[51] LGC price band from Green Markets Solar Market Update May 2016. Available at: http://greenmarkets.com.au/images/uploads/Resources/Presentations/2016/Brazzale_Solar_2016_Policy_Solar_Market_Update.pdf. Viewed on 26 July 2016.

[52] To be available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions.

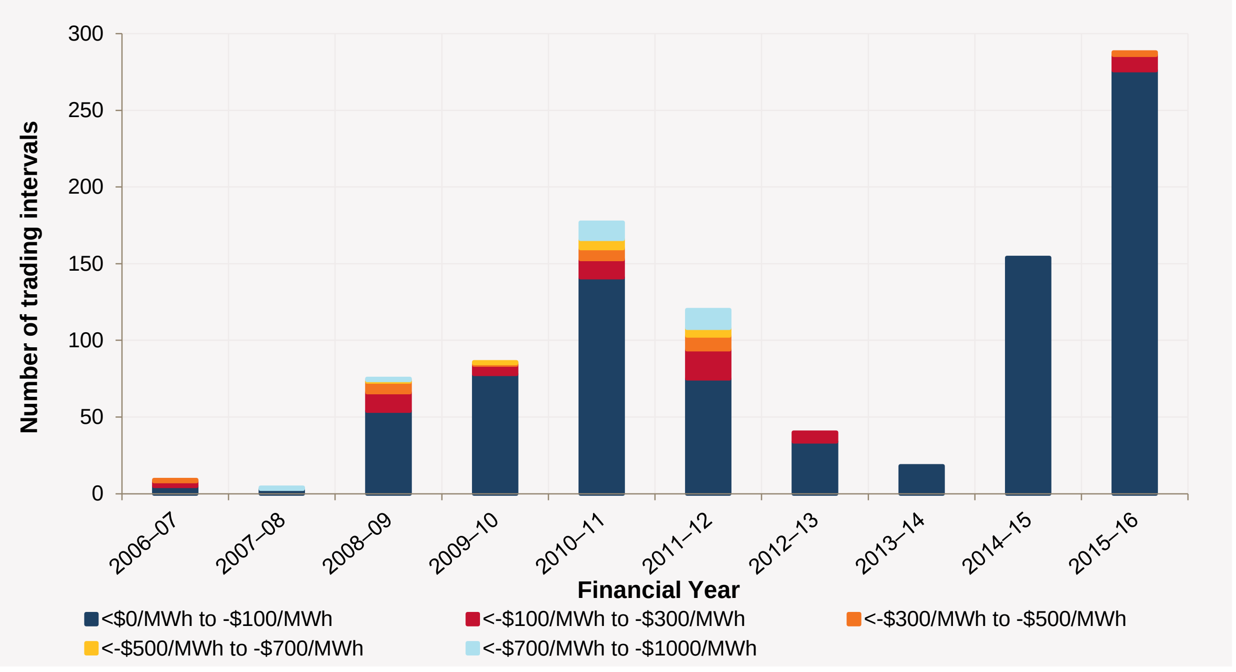
6.3 Negative pricing analysis

6.3.1 Frequency of negative pricing events

Figure 41 shows the count of negative South Australian market prices from 2006–07 to 2015–16, with the colours indicating the frequency of different price band occurrences.

There were 288 negative priced 30-minute trading intervals during 2015–16, higher than the previous four years. In general, negative prices may occur due to generating unit commitment decisions to maintain generation at minimum levels, rather than shutting down, during lower operational demand and high wind generation conditions. Due to additional revenue that wind farms can gain from LGCs, it is not unusual for wind to continue operating during negative pricing events, provided the LGC revenue exceeds the price they pay to continue generating. A return to negative prices lower than -$100/MWh, not seen since 2012–13, occurred during 2015–16.

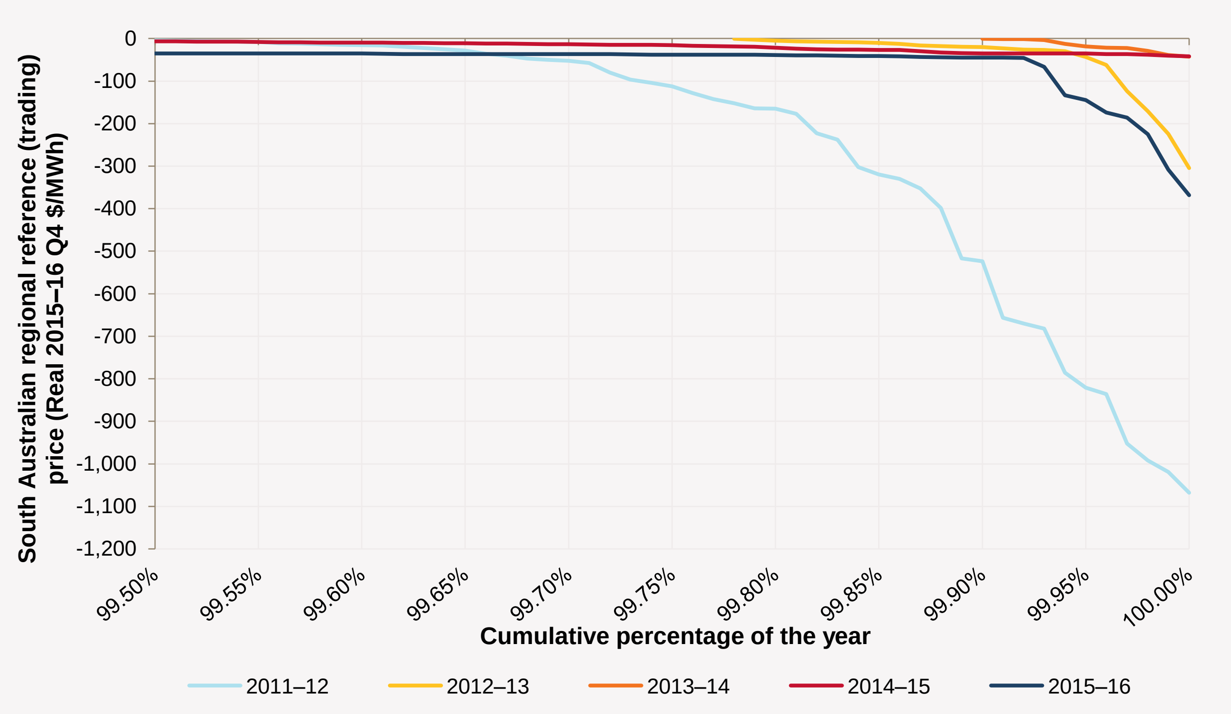
Figure 41 Count of negative price trading intervals per year



6.3.2 Negative price duration curves

Figure 42 shows the price duration curves for negative price events, indicating the increased frequency and greater magnitude of negative price events in 2015–16, compared to the previous three financial years. Despite less installed wind capacity and more thermal generation, 2011–12 also saw a high occurrence of negative prices. This was due to a high supply capacity to demand ratio. The negative prices throughout 2011–12 show the delayed response in the market to adapt to the declining demand in South Australia, following changes in consumer behaviour and electricity consumption.

Figure 42 South Australian spot price duration curves, negative values only

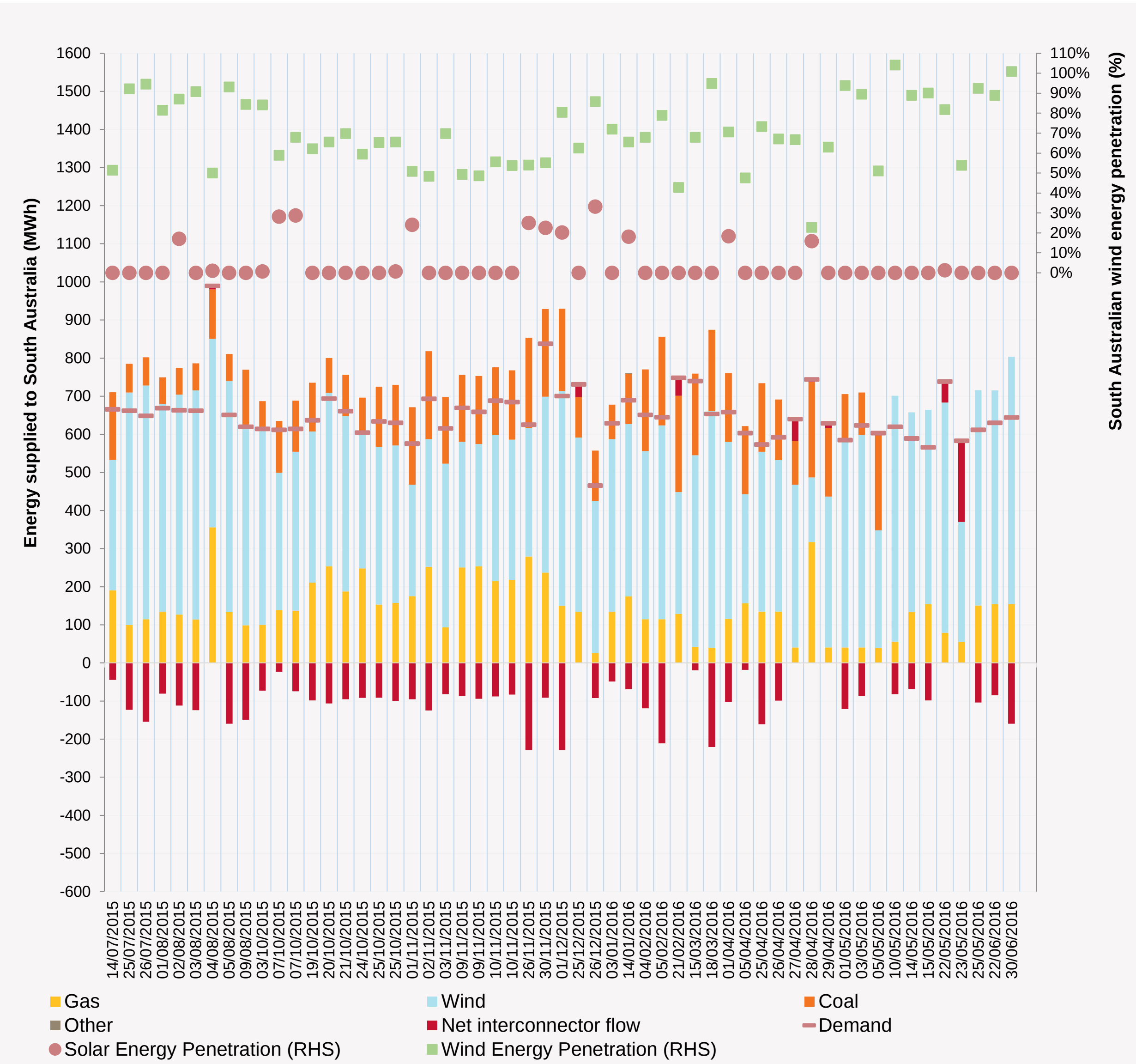


6.3.3 Generation mix during negative spot price intervals

Figure 43 provides details on the mix and magnitude of South Australian generation and net interconnector import during 30-minute periods that had negative prices. As all 288 negatively priced trading intervals occurred across 55 days, only the most extreme negative price is shown for each day.

In 2015–16, most negative prices occurred during times when wind energy penetration was above the typical average (33% as calculated in the 2015 *South Australian Wind Study Report*[53]), and often when South Australia was net exporting electricity to Victoria and operational demand was below 700 MW. Rooftop PV additionally reduced demand during a number of the negative price scenarios.

Figure 43 Supply summary at selected times of negative South Australian spot price during 2015–16



Note: Wind energy penetration (%) refers to the fraction of wind generation to operational demand, while solar energy penetration (%) refers to the fraction of solar energy generation to underlying demand.

[53] AEMO 2015 *South Australia Wind Study Report*. Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions. For an updated value, please refer to the 2016 *South Australian Renewable Energy Report*, to be published in October 2016.

6.4 Pricing events

AEMO monitors and reports on significant pricing events in the NEM.[54] "Significant pricing events" are trading intervals where either:

- The wholesale electricity spot price is above the threshold of $2,000/MWh.
- The wholesale electricity spot price is below -$100/MWh.
- The sum of all eight[55] Frequency Control Ancillary Services (FCAS) half-hourly averaged prices exceeds $150/MWh.[56]

AEMO also publishes brief reports for trading intervals with wholesale electricity spot prices between $500/MWh and $2,000/MWh.

This section summarises the pricing events that occurred in South Australia during 2015–16, and examines two recent significant pricing events, outlining the multiple contributing factors.

6.4.1 Summary of pricing events in 2015–16

Table 13 summarises the number of pricing events and affected hours in South Australia during 2015–16. There were 54 pricing events reported, including events where both the energy spot price and the sum of FCAS price reporting thresholds were exceeded.[57] In some cases, the reporting threshold was exceeded for several consecutive days, while other events only exceeded the threshold for a single trading interval.

Table 13 Summary of AEMO's published pricing events for South Australia in 2015–16

	Reporting Criteria		
	Spot price > $500/MWh	Spot price < -$100/MWh	Sum of FCAS price > $150/MWh
Number of reported events*	38	7	15
Event affected hours	305.5	8.5	528.5

* Some of these spot price and FCAS price events occurred at the same time and are counted as a single reported event in the total of 54 noted above.

Pricing events can be attributed to a number of factors. The major factors that have influenced South Australian price events are listed below:

- **Network outages:** Planned and unplanned network outages reduce the transfer capability across transmission lines, including the interconnectors. Network outages related to interconnectors can reduce the amount of FCAS support available from adjoining states, as well as constraining energy transfer capability.
- **Generator outages**: Planned and unplanned generator outages reduce the amount of available generation capacity, thereby steepening the supply curve.
- **Low wind generation**: Wind generators generally submit offers at the bottom of the price merit order. Low wind generation can contribute to high prices, as higher priced generation is dispatched to meet demand.
- **Changes in generation offers**: Scheduled and semi-scheduled generators may adjust their commercial offers for diverse reasons, including changing market conditions or on the basis of the physical or technical capabilities of their plant (technical parameters).
- **High regional demand:** Higher bid-priced generation needs to be dispatched during periods of high demand.

[54] Significant price event reports are published on the AEMO website: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Market-notices-and-events/Pricing-event-reports.

[55] The eight Frequency Control Ancillary Services include: raise regulation, lower regulation, fast raise, slow raise, delay raise, fast lower, slow lower and delay lower prices for a half hour period. For introductory information on Frequency Control Ancillary Services, see AEMO's *Guide to Ancillary Services in the National Electricity Market*. Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Ancillary-services.

[56] In Tasmania, the FCAS threshold is $3,000/MWh.

[57] A single price event report can include a combination of spot price and FCAS events as well as a combination of high and low spot price events.

- **Changes in hot water load**: In South Australia, an off-peak electricity tariff is available to certain classes of devices, including electric hot water systems and slab heating. These devices are designed to take advantage of the lowest price and demand period of the day, traditionally between 11.30 pm and 7.30 am. Approximately 300,000[58] hot water systems are set to switch on at 11.30 pm, when the off-peak tariff starts.

6.4.2 Recent pricing events

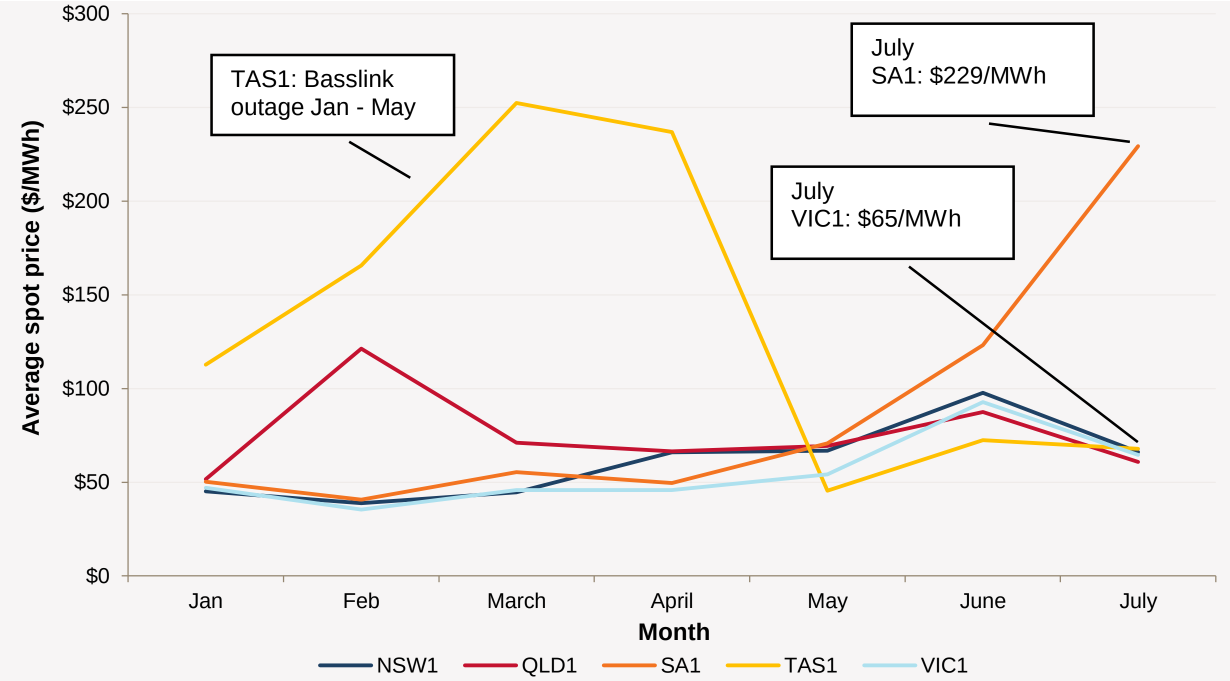
To highlight the various factors that can contribute to a pricing event, a case study of high spot prices that occurred in South Australia during winter 2016 is detailed below.

July 2016 – high spot prices during planned outages

Figure 44 shows that the monthly time-weighted average South Australian wholesale electricity price in July was higher than in any other NEM region.

A confluence of factors contributed to the high electricity spot prices in this month including: high wind variability and low solar production, planned transmission outage impacting interconnector flows between Victoria and South Australia, availability of thermal generating units, and cold weather which increased demand for both electricity and gas, driving higher than average gas and diesel prices.

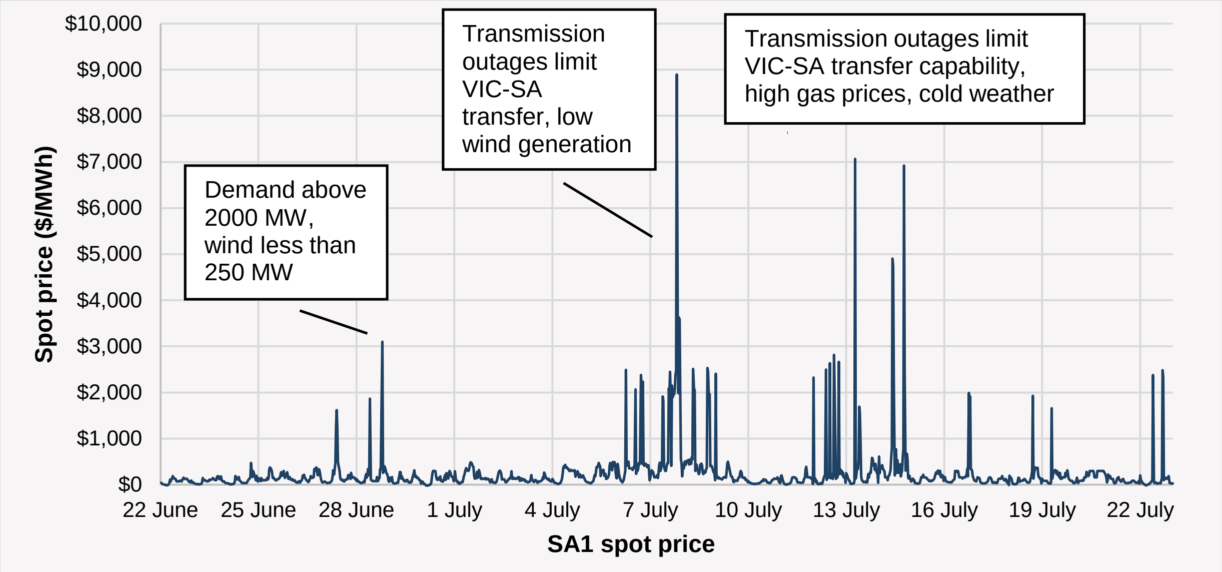
Figure 44 Monthly electricity spot prices by NEM region in 2016 (nominal $/MWh)



[58] SAPN flexible load Strategy October 2014 Section 3.4. Available at: https://www.aer.gov.au/system/files/SAPN%20-%2020.34%20PUBLIC%20-%20SAPN%20Flexible%20Load%20Strategy.pdf. Viewed 3 August 2016.

Planned outages of the Tailem Bend – South East No. 1 and 2 275 kV line were required in turn between 4–14 July and 16–24 July 2016. During this period, wholesale electricity spot prices in South Australia were volatile and higher than average, ranging between $501.46/MWh and $8,897.80/MWh for 77 trading intervals between 6 July and 22 July 2016, as shown in Figure 45.

Figure 45 South Australian price events from 22 June to 22 July 2016



The high spot prices can be attributed to a combination of factors including:

- Planned network outages of each of the Tailem Bend – South East lines limited energy transfer on the Heywood Interconnector from Victoria to South Australia. This is due to a transient stability limit, which co-optimises the flow on the Heywood Interconnector with generation in the south-east area of South Australia. As a result, energy transfer was forced from South Australia to Victoria across the Heywood Interconnector. Since the price in South Australia was high, Murraylink imported into South Australia at the maximum allowable limit.
- Generation supply in South Australia was tight at various times, as several local units were bid unavailable, including up to 1,270 MW of generation capacity unavailable from Torrens Island A and B Power Station and Pelican Point combined-cycle gas turbine (CCGT) Power Plant. The lower availability of generation contributed to AEMO declaring lack of reserve (level 1)[59] conditions in South Australia on six occasions.
- The bulk of South Australian generation capacity was offered at either low-priced bands or high-priced bands, with very little offered in between. This resulted in a steep supply curve in South Australia during some of the high-priced dispatch intervals.
- While wind generation varied between high and low levels, high wind speeds caused some turbines to cut out resulting in sudden drops in wind generation, most noticeably on 12 and 22 July.
- As a result of colder weather, South Australia's actual maximum demand in July was 150 MW higher than the June maximum regional demand, as forecast in AEMO's pre-dispatch systems.
- Gas prices were also higher than average, reflecting tightening of supply due to a combination of cold weather and increases in usage for gas-powered power generation.

[59] Lack of reserve (level 1) is declared when AEMO considers there are insufficient capacity reserves available in an operational forecasting timeframe to replace the contingency capacity reserve if the most significant credible contingency event occurs in that period. This is generally be the instantaneous loss of the largest generating unit on the power system, but could be the loss of an interconnector under some conditions.

7. ELECTRICAL ENERGY REQUIREMENTS

This chapter reports the historical underlying energy breakdown for South Australia from 2006–07 to 2015–16, showing different sources of energy production on the one side and different consumption of that energy on the other side. Underlying energy here refers to what is needed in total by electricity grid-connected consumers, and is supplied not only from operational generators and the interconnectors (as discussed in Appendix B), but also small non-scheduled generators and rooftop PV (with both of these contributions being estimates).

With reference to Table 14 below:

- The “South Australian generation” and “NEM balancing” sections present actual generation and interconnector flows for South Australia, as calculated in Chapters 3 and 5 respectively.
- Data in the “South Australian consumption” section is sourced from the 2016 NEFR except for the 2015–16 data.[60] Rooftop PV estimates have been included this year, and appear on both sides of the table.
- Most data is aggregated from, or further derived from analysis of, high resolution average SCADA data. The exception is “Small non-scheduled generation” data which is revenue metered data sourced from the MSATS system.[61]
- The “Balancing residual” column seeks to compare total South Australian generation plus imports with total South Australian consumption plus exports. Ideally the value would always equal zero, but data quality in some metering, accumulated rounding, and necessary estimations used in calculations of some quantities mean this is not always the case.

Some anomalies noted include:

- Comparatively larger NEM balancing residuals in 2006–07 and 2007–08. This is due to lower quality SCADA readings from non-scheduled wind farms captured at that time.

[60] Due to the NEFR’s publication in June 2016, it reports actual data from July 2015 to March 2016 and estimates the remaining three months (April 2016 to June 2016) for the most recent financial year, 2015-16. This report incorporates the full financial year’s actual generation values instead. In the case of rooftop PV estimates it utilises nine months of CER input data instead of six months used for the NEFR.

[61] Refer to Appendix G of the 2015 NEFR’s *Forecasting Methodology Information Paper*. Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report.

Table 14 Annual electrical energy requirement breakdown (GWh)

	SA generation					NEM balancing			SA consumption							
	Wind (SS , NS)	SNSG	Rooftop PV	Scheduled (S)	Total generation	Imports Vic-SA	Balancing residual	Exports SA-Vic	Total Electricity Requirement	Auxiliary energy use	Total electricity requirement excl. auxiliary	Transmission network losses	Distribution network losses	Residential + Business Consumption	SNSG	Rooftop PV
Historical output																
2006–07	882	79	12	12,498	13,471	1,266	64	-364	14,309	773	13,536	309	739	12,409	79	12
2007–08	1,316	74	17	12,981	14,388	676	26	-683	14,355	840	13,515	309	738	12,394	74	17
2008–09	2,008	69	25	12,275	14,378	828	1	-622	14,583	807	13,776	315	752	12,640	69	25
2009–10	2,388	68	44	11,403	13,903	1,088	-2	-485	14,507	780	13,728	313	748	12,598	68	44
2010–11	3,039	65	91	10,914	14,109	1,127	2	-584	14,650	769	13,881	311	755	12,750	65	91
2011–12	3,563	62	294	9,392	13,311	1,495	1	-401	14,404	681	13,723	310	734	12,617	62	294
2012–13	3,475	58	492	9,031	13,056	1,710	-3	-333	14,436	567	13,869	312	732	12,767	58	492
2013–14	4,088	60	678	7,665	12,491	1,925	-2	-288	14,130	520	13,610	335	705	12,510	60	678
2014–15	4,223	59	872	7,247	12,401	1,904	2	-376	13,927	528	13,399	357	681	12,301	59	872
2015–16	4,322	52	938	7,147	12,459	2,227	33	-286	14,367	443	13,924	378	706	12,787	52	938

The following should be noted when interpreting this table:

- Wind generation includes generation that occurred during commissioning of the site (such as Snowtown Stage 2 during 2013–14, and Hornsdale Stage 1 during 2015–16).
- SS stands for Semi-scheduled, NS for Non-scheduled, S for Scheduled, and SNSG for Small non-scheduled.
- Small non-scheduled generation on both sides of the table is materially different to the 2015 results (published in the 2015 SAEMETR) due to a revision of SNSG plant used, plus an improved data source used for input.
- S, SS and NS generation data in some cases differs from the 2015 results, due to the different input data used, as discussed in Section 1.1.
- Rooftop PV generation on both sides of the table has changed from data reported in 2015 SAAF reports, due to a revision in rooftop PV capacity estimates and a new generation estimation model, as discussed in the 2016 SAER.
- Scheduled includes Angaston power station, including periods when it was registered as non-scheduled.

APPENDIX A. TEMPERATURE DURATION CURVES

Temperature duration curves show the percentage of time that the temperature was above a certain a threshold. Half-hourly temperature duration curves for Adelaide are shown in Figure 46 and Figure 47, for summer and winter, respectively. Higher overall temperatures are seen in both seasons for a greater percentage of the season, compared to the previous four financial years, although the highest temperatures seen in 2015–16 do not exceed the maximums seen in 2012–13 to 2014–15.

Figure 46 Adelaide city temperature duration curve (summer generation period)

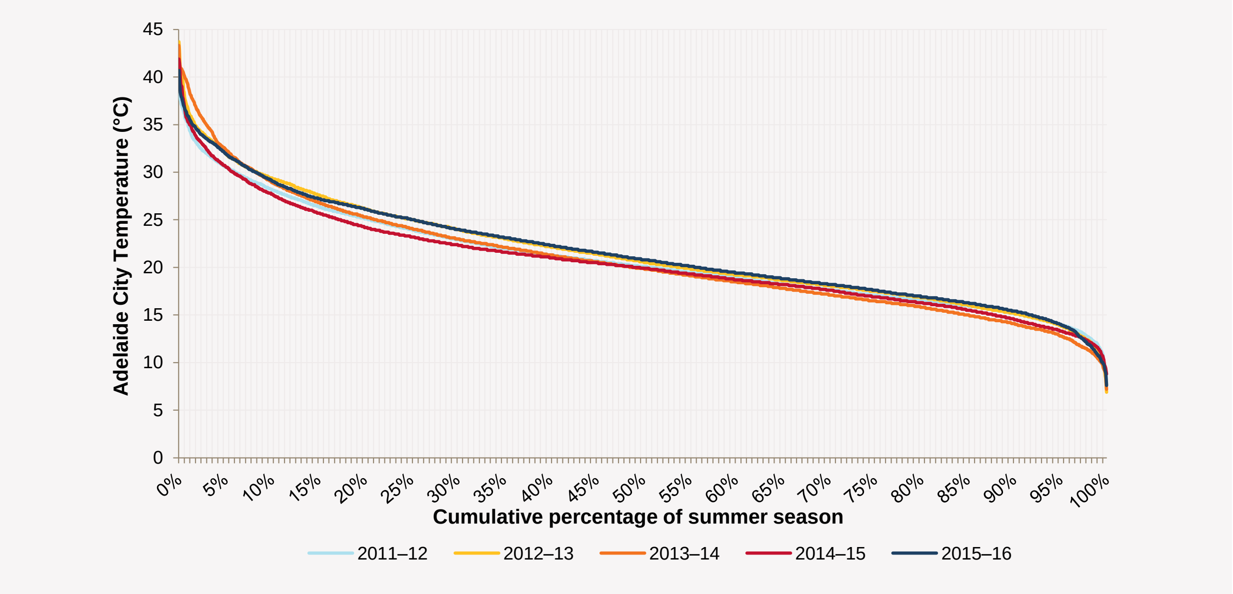
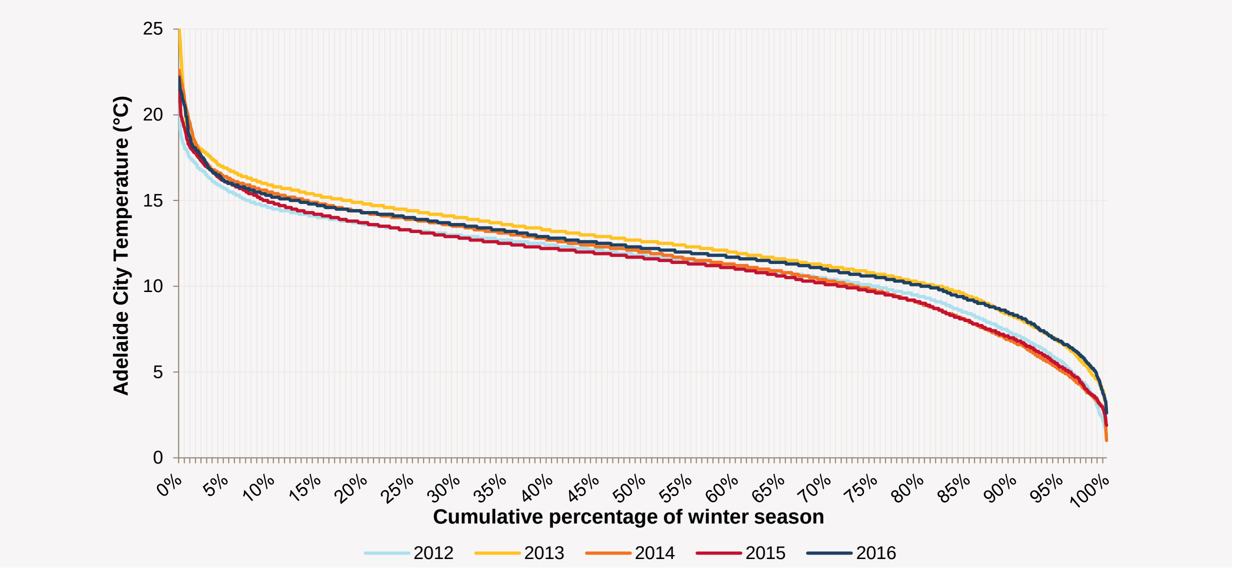


Figure 47 Adelaide city temperature duration curve (winter generation period)



Heating degree days (HDD) and cooling degree days (CDD) relate to the number of degrees a region's average temperature is below (in the case of HDD) or above (CDD) the regional temperature threshold, and the amount of time the region experiences temperatures below (HDD) or above (CDD) these thresholds. It is seen as a measure for heating and cooling requirements in a season based on comfort levels. Please refer to 2016 NEFR Methodology[62] for further details on this calculation.

The duration curve for CDD values during summer in Adelaide is shown in Figure 48. It illustrates that 2015–16 had the highest CDD values throughout the season, but not the most extreme, compared to the previous four financial years. For 35% of the season, based on the NEFR 2016 CDD definition, cooling was not deemed to be required.

Figure 49 shows the HDD duration curves for the winter season in Adelaide. The 2015–16 winter required less heating over the season compared to the previous two calendar years, according to the 2016 NEFR HDD threshold.

Figure 48 Adelaide Cooling Degree Day duration curve (summer generation period)

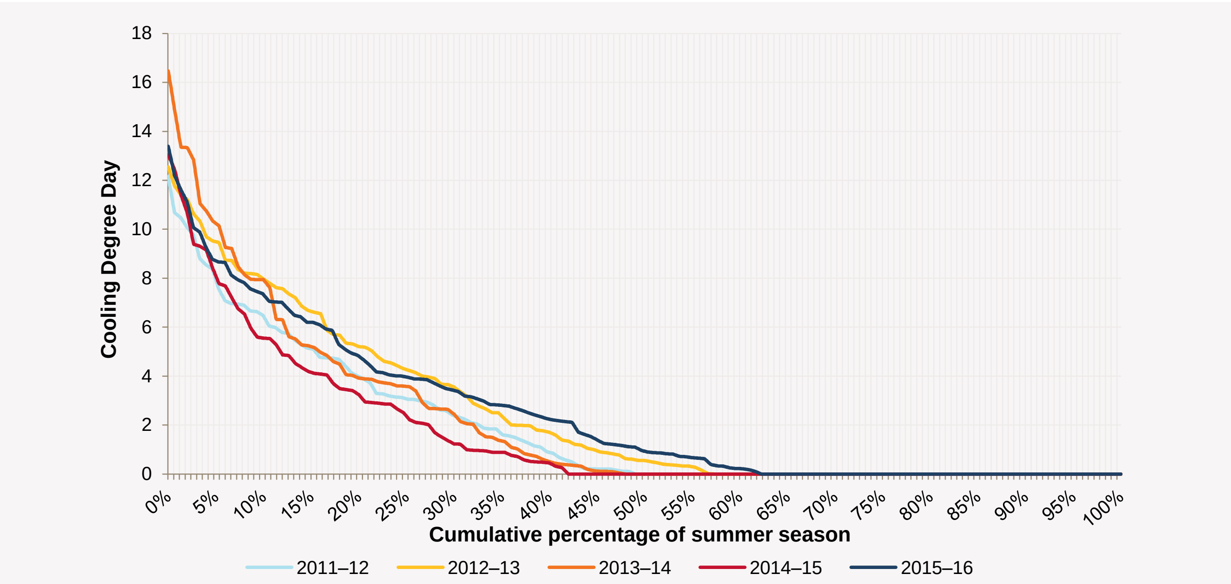
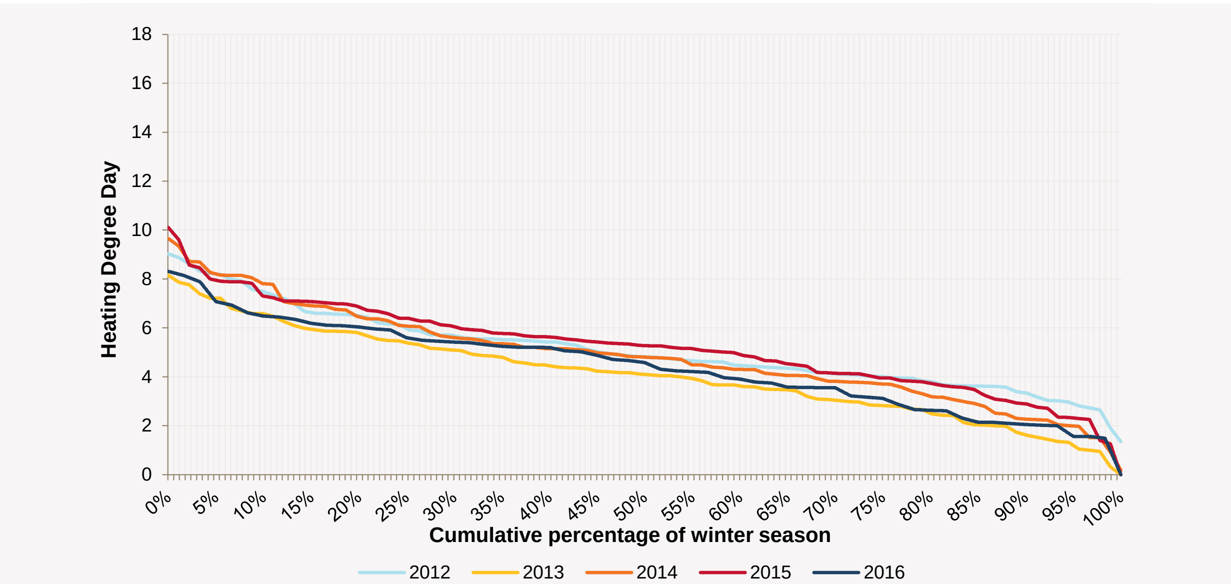


Figure 49 Adelaide Heating Degree Day duration curve (winter generation period)



[62] AEMO. *2016 National Electricity Forecasting Methodology Information Paper*. Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report.

APPENDIX B. GENERATORS INCLUDED IN REPORTING

Table 15 presents the name, dispatchable unit identifier (DUID), fuel type, and nameplate and registered capacity of the scheduled, semi-scheduled, and significant non-scheduled generators used in this report's analysis. They make up the generators used in operational[63] generation, consumption, and demand analysis in this report.

Due to changes in their scheduling type in 2015–16, Angaston, Lonsdale, and Port Stanvac power stations are included in operational demand and generation analysis only from 12 January 2016. Angaston power station is also included in reporting on individual generator outputs and capacity factors before this date.

A generating system's registered capacity is the nominal MW capacity registered with AEMO.[64] The registered capacity is often the same as a generating system's nameplate capacity. Nameplate capacity represents the maximum continuous output or consumption in MW, as specified by the manufacturer, or as subsequently modified. Nameplate capacity can change for a number of reasons, such as upgrade projects, age or a review of performance.

Small non-scheduled generators and embedded generators are discussed in Appendix C.

Table 15 South Australian generating systems and capacities including in reporting

Generating system	Current DUID(s)*	Fuel type	Nameplate capacity (MW)	Registered capacity (MW)
Scheduled generating systems				
Angaston**	ANGAST1	Diesel	50	50
Dry Creek	DRYCGT1, DRYCGT2, DRYCGT3	Gas	156	156
Hallett GT	AGLHAL	Gas	228.3	205.6
Ladbroke Grove	LADBROK1, LADBROK2	Gas	80	80
Lonsdale***	LONSDALE	Diesel	20.7	20
Mintaro	MINTARO	Gas	90	90
Northern	NPS1, NPS2	Coal	546	530
Osborne	OSB-AG	Gas	180	180
Pelican Point	PPCCGT	Gas	478	478
Playford B	PLAYB-AG	Coal	240	240
Port Lincoln GT	POR01, POR03	Diesel	73.5	73.5
Port Stanvac***	PTSTAN1	Diesel	57.6	57.6
Quarantine	QPS1, QPS2, QPS3, QPS4, QPS5	Gas	224	224
Snuggery	SNUG1	Diesel	63	63

[63] Operational reporting includes the electrical energy supplied by scheduled, semi-scheduled, and significant non-scheduled generating units. Operational reporting does not include the electrical energy supplied by small non-scheduled generating units or rooftop PV. On a regional basis, as in this South Australian report, it also includes net interconnector imports for the State.

[64] AEMO. Generation Information (2016 August 11, SA). Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information. Viewed: 11 August 2016.

Generating system	Current DUID(s)*	Fuel type	Nameplate capacity (MW)	Registered capacity (MW)
Torrens Island A	TORRA1, TORRA2, TORRA3, TORRA4	Gas	480	480
Torrens Island B	TORRB1, TORRB2, TORRB3, TORRB4	Gas	800	800
Semi-scheduled generating systems				
Clements Gap Wind Farm	CLEMGPWF	Wind	56.7	57
Hallett 1 (Brown Hill) Wind Farm	HALLWF1	Wind	94.5	94.5
Hallett 2 (Hallett Hill) Wind Farm	HALLWF2	Wind	71.4	71.4
Hallett 4 (North Brown Hill) Wind Farm	NBHWF1	Wind	132.3	132.3
Hallett 5 (The Bluff) Wind Farm	BLUFF1	Wind	52.5	52.5
Hornsdale Stage 1 Wind Farm	HDWF1	Wind	102.4	102.4
Lake Bonney Stage 2 Wind Farm	LKBONNY2	Wind	159	159
Lake Bonney Stage 3 Wind Farm	LKBONNY3	Wind	39	39
Snowtown Wind Farm	SNOWTWN1	Wind	98.7	99
Snowtown Stage 2 Wind Farm	SNOWNTH1, SNOWSTH1	Wind	270	270
Waterloo Wind Farm	WATERLWF	Wind	111	111
Significant non-scheduled generating systems				
Canunda Wind Farm	CNUNDAWF	Wind	46	46
Cathedral Rocks Wind Farm	CATHROCK	Wind	66	66
Lake Bonney Wind Farm	LKBONNY1	Wind	80.5	80.5
Mount Millar Wind Farm	MTMILLAR	Wind	70	70
Starfish Hill Wind Farm	STARHLWF	Wind	34.5	34.5
Wattle Point Wind Farm	WPWF	Wind	90.8	90.75

* Some generators have used different DUIDs historically.
** Angaston was scheduled from 2004 to 2012, was then non-scheduled but still reportable, and became a scheduled generator again on 27 May 2016.
*** Lonsdale and Port Stanvac became scheduled generators on 12 January 2016.

APPENDIX C. SMALL NON-SCHEDULED AND EMBEDDED GENERATORS

C.1 Small non-scheduled generators

Table 16 presents the SNSG included in this year's reporting, as in the 2016 NEFR.

Table 16 South Australian small non-scheduled generating systems for 2016

Generating system	Generation type	Fuel type	Capacity (MW)
Amcor Glass, Gawler Plant*	Compression Reciprocating Engine	Diesel	4
Blue Lake Milling Power Plant	Compression Reciprocating Engine	Diesel	1
Highbury Landfill Gas Power Station**	Spark Ignition Reciprocating Engine	Biogas	2
Pedler Creek Landfill Gas Power Station	Spark Ignition Reciprocating Engine	Biogas	3
SA Water Seacliff Park Mini Hydro	Hydro - Gravity	Water	1.155
Tatiara Bordertown Plant	Compression Reciprocating Engine	Diesel	0.5
Tea Tree Gully Landfill Gas Power Station**	Spark Ignition Reciprocating Engine	Biogas	1
Terminal Storage Mini Hydro Power Station	Hydro - Gravity	Water	2.5
Wingfield 1 Landfill Gas Power Station	Spark Ignition Reciprocating Engine	Biogas	4.12
Wingfield 2 Landfill Gas Power Station	Spark Ignition Reciprocating Engine	Biogas	4.12

* Amcor Glass, Gawler Plant became de-registered from the NEM effective 1 January 2016.
** Highbury Landfill Gas Power Station and Tea Tree Gully Landfill Gas Power Station became de-registered from the NEM effective 19 June 2016.

C.2 Embedded generators

In 2016 AEMO engaged ORC International to survey selected local government, educational, medical, industrial, and business entities, to provide the South Australian Government with a sample of generators across the state which are either off-grid or embedded within the electricity distribution networks. In total 132 entities were surveyed. This was not an exhaustive or random survey, nor does it necessarily represent a complete picture of particular sectors or geographical regions. Information is based on information volunteered by survey participants.

Table 17 summarises the generation capacity by fuel type, with full details available in a separate data file on AEMO's website.[65]

Table 17 Summary of other South Australian generating systems

Primary Fuel Source	Aggregate generating capacity (kW)
Diesel / fuel oil	7,104
Gas	480
Solar	6,704
Wind	4
Total	14,292

65 AEMO. *2016 SAHMIR Data File – Embedded Generators Survey worksheet*. Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions.

APPENDIX D. VOLUME WEIGHTED AVERAGE PRICE COMPARISON

Figure 50 and Figure 51 illustrate the values shown in Table 11 in Section 6.2.2, of VWAP trends for renewable, thermal and total market generation.

Renewable generation comprises the semi-scheduled and non-scheduled wind farm, while thermal generation refers to all scheduled, semi-scheduled and non-scheduled generators as detailed in Appendix B. VWAPs have been adjusted to real June 2016 values.

Figure 50 Comparison of financial year volume-weighted average prices

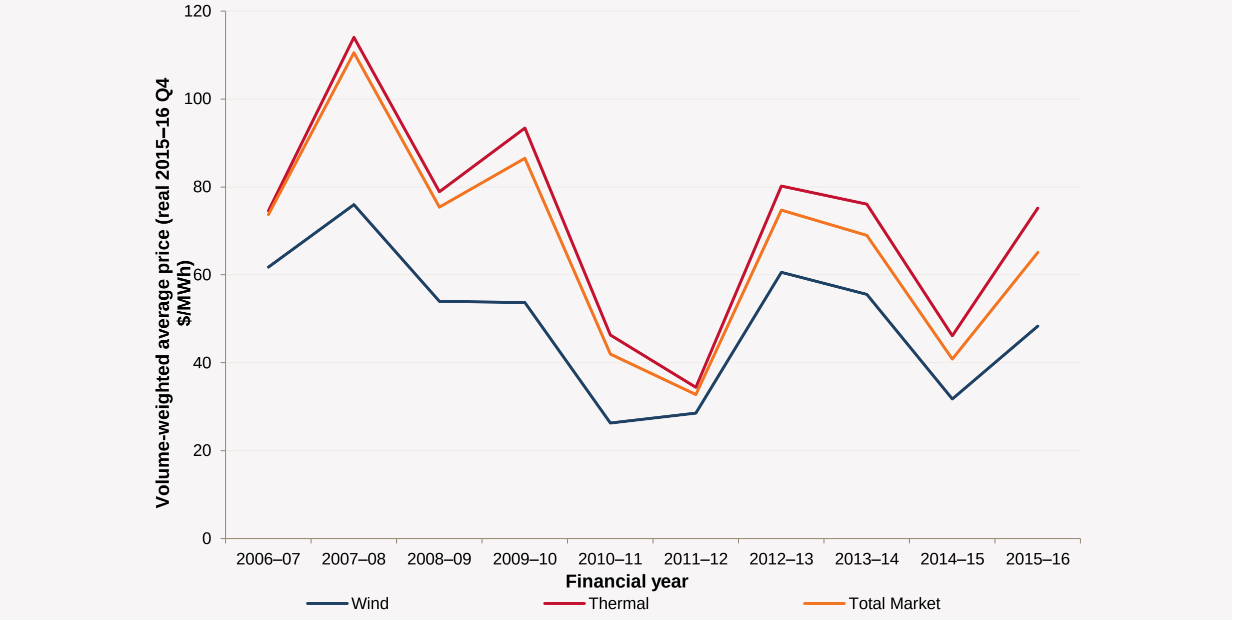
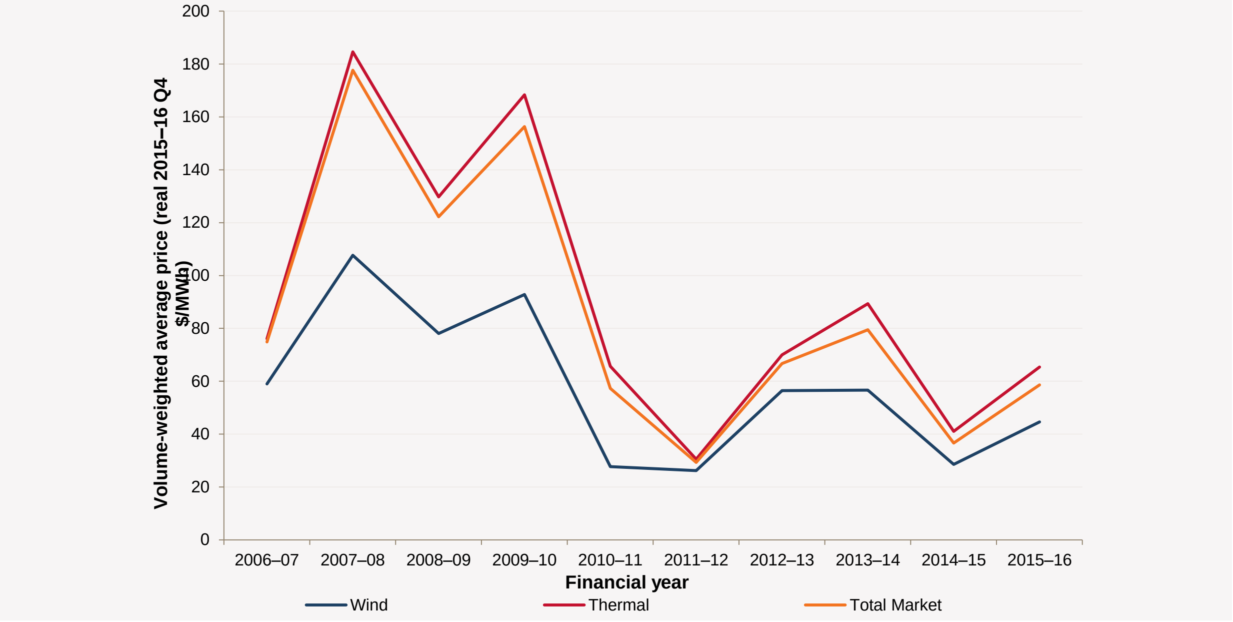


Figure 51 Comparison of summer volume-weighted average prices



APPENDIX E. NOMINAL VOLUME-WEIGHTED AVERAGE PRICE

The VWAPs using nominal electricity spot prices are shown in Table 18. A similar analysis is shown in Table 11 except where prices have been CPI-corrected, using June 2016 as the reference quarter.

Table 18 Nominal volume-weighted average price

	SA renewable generation		SA thermal generation		Total SA market generation		SA spot price
	Financial year	Summer*	Financial year	Summer*	Financial year	Summer*	Financial year
	Volume-weighted average	Volume-weighted average	Volume-weighted average	Volume-weighted average	Volume-weighted average	Volume-weighted average	Time-weighted average
	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)
2006–07	49.85	47.35	60.21	61.12	59.53	60.17	51.61
2007–08	63.40	90.05	95.20	154.44	92.28	148.68	73.50
2008–09	46.38	66.95	67.77	111.31	64.76	104.80	50.98
2009–10	47.11	81.46	82.02	147.77	75.98	137.22	55.31
2010–11	23.92	25.17	42.11	59.76	38.15	52.16	32.58
2011–12	26.56	24.34	32.02	28.35	30.52	27.24	30.28
2012–13	57.51	53.61	76.12	66.51	70.95	63.29	69.75
2013–14	54.04	55.23	74.11	87.12	67.13	77.50	61.71
2014–15	31.40	28.21	45.61	40.57	40.38	36.20	39.29
2015–16	48.23	44.48	75.03	65.16	64.93	58.39	61.67

As seen in Table 18, the average wholesale electricity price for South Australia for 2015–16 was $62/MWh (in nominal time-weighted average dollars), approximately 59% higher than for 2014–15 ($39/MWh). This compares to 2015–16 average prices of:

- $52/MWh in New South Wales (49% higher than for 2014–15).
- $60/MWh in Queensland (13% higher).
- $103/MWh in Tasmania (178% higher).
- $46/MWh in Victoria (53% higher).

APPENDIX F. HISTORICAL ENERGY GENERATION FOR SOUTH AUSTRALIAN POWER STATIONS

Table 19 Historical energy generation for South Australian power stations (GWh)

Generator name	Schedule type	Fuel type	2011–12	2012–13	2013–14	2014–15	2015–16
Angaston Power Station	Scheduled	Diesel	0.30	-	-	-	0.91
Dry Creek Power Station	Scheduled	Gas	2.64	6.79	2.96	4.95	6.34
Hallett GT Power Station	Scheduled	Gas	7.92	59	34	22	33
Ladbroke Grove Power Station	Scheduled	Gas	80	92	232	186	206
Lonsdale Power Station	Scheduled	Diesel	-	-	-	-	0.62
Mintaro Power Station	Scheduled	Gas	5.59	13	8.21	7.33	13
Northern Power Station	Scheduled	Coal	2,721	2,231	2,096	2,645	2,601
Osborne Power Station	Scheduled	Gas	1,182	1,365	1,471	1,461	1,221
Pelican Point Power Station	Scheduled	Gas	2,602	2,967	1,837	1,012	293
Playford B Power Station	Scheduled	Coal	278	0.00	0.00	0.00	0.00
Port Lincoln Power Station	Scheduled	Diesel	0.70	1.39	0.81	0.39	0.50
Port Stanvac Power Station	Scheduled	Diesel	-	-	-	-	0.95
Quarantine Power Station	Scheduled	Gas	65	150	239	216	137
Snuggery Power Station	Scheduled	Diesel	0.30	0.31	0.09	0.43	1.00
Torrens Island A Power Station	Scheduled	Gas	527	447	340	201	659
Torrens Island B PowerStation	Scheduled	Gas	1,920	1,697	1,403	1,488	1,969
Clements Gap Wind Farm	Semi-scheduled	Wind	175	167	180	169	173
Hallett 1 (Brown Hill) Wind Farm	Semi-scheduled	Wind	331	332	349	308	314
Hallett 2 (Hallett Hill) Wind Farm	Semi-scheduled	Wind	255	256	256	233	243
Hallett 4 (North Brown Hill) Wind Farm	Semi-scheduled	Wind	458	426	473	420	446
Hallett 5 (The Bluff) Wind Farm	Semi-scheduled	Wind	131	155	168	136	150
Hornsdale Stage 1 Wind Farm	Semi-scheduled	Wind	-	-	-	-	0.48
Lake Bonney Stage 2 Wind Farm	Semi-scheduled	Wind	384	379	414	395	382
Lake Bonney Stage 3 Wind Farm	Semi-scheduled	Wind	87	95	99	94	93
Snowtown Stage 2 Wind Farm	Semi-scheduled	Wind	-	-	302	826	877
Snowtown Wind Farm	Semi-scheduled	Wind	373	374	388	333	341
Waterloo Wind Farm	Semi-scheduled	Wind	311	311	339	293	299
Angaston Power Station	Non-scheduled	Diesel	0.29	3.35	1.59	1.26	4.11
Canunda Wind Farm	Non-scheduled	Wind	124	114	125	118	113
Cathedral Rocks Wind Farm	Non-scheduled	Wind	185	175	196	170	169
Lake Bonney Wind Farm	Non-scheduled	Wind	202	191	206	192	182
Mount Millar Wind Farm	Non-scheduled	Wind	188	185	204	187	183
Starfish Hill Wind Farm	Non-scheduled	Wind	86	68	95	86	86
Wattle Point Wind Farm	Non-scheduled	Wind	271	248	294	265	269
Total			**12,955**	**12,506**	**11,753**	**11,470**	**11,469**

* Dashes (-) in the table indicate that the generator was not registered with AEMO in that financial year, or was not registered as a particular schedule type.

APPENDIX G. ROOFTOP PV METHODOLOGY

Capacity estimation

Historical installed capacity for rooftop PV is extracted from a data set provided by the Clean Energy Regulator (CER). The dataset contains anonymous data of existing installations with more detail than is regularly reported on the CER public website, allowing AEMO to keep track of daily variations.

Generation estimation

The energy generated by a rooftop PV system is estimated using a model developed by the University of Melbourne.[66] For each half-hour, the generation model takes into account solar radiation and cloud coverage. It models inefficiencies related to shading effects and takes into account the geographic distribution of the rooftop PV installations at that time.

The historical values of rooftop PV generation are obtained by multiplying the existing capacity (calculated from CER data) by the modelled generation of a 1 kW rooftop PV installation. AEMO then applies corrections for assumed loss in performance of ageing solar panels, by estimating that a panel loses 0.4% of its efficiency for every year since its installation. An illustrative example of the effect of this assumption is that the total rooftop PV generation estimate for South Australia in January 2016 is reduced by 1% once ageing of panels is taken into account.[67]

[66] "Rooftop PV Model Technical Report", V.D. Ruelle, M. Jeppesen and M. Brear (July 2016), Available at http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/-/media/CEDBBF70073149ABAD19F3021A17E733.ashx

[67] This corresponds to an assumed average panel age across the region of 2.5 years.

MEASURES AND ABBREVIATIONS

Units of measure

Abbreviation	Unit of measure
CDD	Cooling Degree Day
GWh	Gigawatt-hour
HDD	Heating Degree Day
MW	Megawatts
MWh	Megawatt-hour
MtCO2-e	Megatonnes of carbon dioxide equivalent

Abbreviations

Abbreviation	Expanded name
AEMO	Australian Energy Market Operator
ESOO	Electricity Statement of Opportunities
MSATS	Market Settlements and Transfer Solutions
NEFR	National Electricity Forecasting Report
NEM	National Electricity Market
PV	Photovoltaic
VWAP	Volume-weighted average price

GLOSSARY

Term	Definition
capacity factor	The output of generating units or systems, averaged over time, expressed as a percentage of rated or maximum output.
contingency FCAS	Contingency FCAS is enabled to correct the generation/demand balance following a major contingency event, such as the loss of a generating unit or major industrial load, or a large transmission element.
cooling degree day (CDD)	A sum of the products of: • The time that a region experiences ambient temperatures above its threshold temperature; and • The number of degrees that the ambient temperature is above the threshold temperature.
COP21	Paris 21st Conference of Parties, 2015, where countries including Australia committed to emissions reduction targets. Australia set a target to reduce carbon emissions by 26% to 28% below 2005 levels by 2030. The Council of Australian Governments (COAG) Energy Council has stated that a 28% reduction from 2005 levels by 2030 is an appropriate constraint for AEMO to use in its ongoing forecasting and planning processes. AEMO analysis suggests that meeting the COP21 commitment is likely to require both generation withdrawals and investment in low-emission generation capacity.
frequency control ancillary services (FCAS)	FCAS is used to maintain the frequency on the electrical system, at any point in time, close to fifty cycles per second as required by the NEM frequency operating standards. Regulation FCAS is enabled to continually correct the generation/demand balance in response to minor deviations in load or generation. There are two types of regulation FCAS: • Raise (used to correct a minor drop in frequency). • Lower (used to correct a minor rise in frequency). Contingency FCAS is enabled to correct the generation/demand balance following a major contingency event, such as the loss of a generating unit or major industrial load, or a large transmission element. There are six types of contingency FCAS: • Fast raise (6 seconds) to arrest a major drop in frequency following a contingency event. • Fast lower (6 seconds) to arrest a major rise in frequency following a contingency event. • Slow raise (60 seconds) to stabilise frequency following a major drop in frequency. • Slow lower (60 seconds) to stabilise frequency following a major rise in frequency. • Delayed raise (5 minutes) to recover frequency to the normal operating band following a major drop in frequency. • Delayed lower (5 minutes) to recover frequency to the normal operating band following a major rise in frequency.
generating capacity	Amount of capacity (in megawatts (MW)) available for generation.
generating unit	Power stations may be broken down into separate components known as generating units, and may be considered separately in terms (for example) of dispatch, withdrawal, and maintenance.
heating degree day (HDD)	A sum of the products of: • The time that a region experiences ambient temperatures below its threshold temperature; and • The number of degrees that the ambient temperature is below the threshold temperature.
Heywood Interconnector	The Heywood Interconnector is a connection between the Victorian and South Australian power systems. It consists of two 275 kV AC electricity transmission lines, between Heywood Terminal Station in Victoria and South East Switching Station in South Australia. Following the completion of upgrade works currently underway, it will have a rated capacity of 650 MW power transfer in either direction.
installed capacity	The generating capacity (in megawatts (MW)) of the following (for example): • A single generating unit. • A number of generating units of a particular type or in a particular area. • All of the generating units in a region. Rooftop PV installed capacity is the total amount of cumulative rooftop PV capacity installed at any given time.
interconnector power transfer capability	The power transfer capability (in megawatts (MW)) of a transmission network connecting two regions to transfer electricity between those regions.
large-scale generation certificates (LGCs)	Under the LRET target, generators are awarded large-scale generation certificates (LGCs) by the Clean Energy Regulator for every MWh of renewable energy they produce, and sell these LGCs in a market to RET-liable entities, who must meet a yearly target for certificates to cover their electricity purchases.
large-scale renewable energy target (LRET)	The large-scale renewable energy target is set as 41,000 GWh of utility-scale renewable generation in Australia by 2020, compared with 1997 levels.

Term	Definition
load factor	This is a measure of MD relative to annual consumption; the lower the load factor, the greater the difference between average hourly energy and MD.
Low Reserve Condition (LRC)	When AEMO considers that a region's reserve margin (calculated under 10% Probability of Exceedance (POE) scheduled and semi-scheduled maximum demand (MD) conditions) for the period being assessed is below the reliability standard.
mothballed	A generation unit that has been withdrawn from operation but may return to service at some point in the future.
native consumption	This includes all residential, commercial, and large industrial consumption, and transmission losses (as supplied by scheduled, semi-scheduled, significant non-scheduled, and small non-scheduled generating units). Native consumption equals operational consumption plus generation from small non-scheduled generating units.
nominal dollars	The actual price in dollars at the time a cost was incurred. See *real dollars*.
non-scheduled generation	Generation by a generating unit that is not scheduled by AEMO as part of the central dispatch process, and which has been classified as a non-scheduled generating unit in accordance with Chapter 2 of the NER.
operational consumption	This includes all residential, commercial, and large industrial consumption, and transmission losses (as supplied by scheduled, semi-scheduled and significant non-scheduled generating units). Significant non-scheduled generation is: wind generators greater than 30 MW, generators treated as scheduled generators in dispatch, generators that are required to model network constraints, and generators previously classified as scheduled.
probability of exceedance (POE) maximum demand	The probability, as a percentage, that a maximum demand (MD) level will be met or exceeded (for example, due to weather conditions) in a particular period of time. For example, for a 10% POE MD for any given season, there is a 10% probability that the corresponding 10% POE projected MD level will be met or exceeded. This means that 10% POE projected MD levels for a given season are expected to be met or exceeded, on average, 1 year in 10.
real dollars	An adjusted price in dollars, as referenced from a particular period in time. In this report, Consumer Price Index is the basis for adjustment. See *nominal dollars*.
reliability standard	The power system reliability benchmark set by the Reliability Panel. The reliability standard for generation and inter-regional transmission elements in the national electricity market is a maximum expected unserved energy (USE) in a region of 0.002% of the total energy demanded in that region for a given financial year.
scheduled generation	Generation by any generating unit that is classified as a scheduled generating unit in accordance with Chapter 2 of the NER.
semi-scheduled generation	Generation by any generating unit that is classified as a semi-scheduled generating unit in accordance with Chapter 2 of the NER.
sent-out	A measure of demand or energy (in megawatts (MW) or megawatt hours (MWh), respectively) at the connection point between the generating system and the network. This measure includes consumer load and transmission and distribution losses.
small non-scheduled generation	This represents non-scheduled generating units that typically have a capacity less than 30 MW.
summer	Unless otherwise specified, refers to the period 1 November – 31 March.
supervisory control and data acquisition (SCADA)	Supervisory Control and Data Acquisition is a system that gathers real-time data from remote terminal units and other communication sources in the field and enables operators to control field devices from their consoles. SCADA data: • may be transmitted to or from electrical substations, power stations, and control centres, and • is normally collected for a variety of power system quantities at rates of once every two to four seconds (depending on the quantities measured). The equipment can also be used to send or receive control signals for power system equipment and generating units. The data and control signals are used to manage the operation of the power system from control centres.
transmission losses	Electrical energy losses incurred in transporting electrical energy through a transmission network.
winter	Unless otherwise specified, refers to the period 1 June – 31 August.
workday	Every official working day of the year, it excludes gazetted public holidays of the region and weekends.