Special Report

Market outcomes in South Australia during
April and May 2013

July 2013

AUSTRALIAN
ENERGY
REGULATOR

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Table of contents

Introduction and overview

This Special Report focuses on market events in the South Australia region of the National Electricity Market (**NEM**) during April and May 2013. High spot prices, un-forecast fluctuations in price, and low reserve events (situations where there is an increased likelihood of a shortfall in generation leading to blackouts) occurred frequently during this period. As such market outcomes are unusual for this time of year, the AER has published this report to examine the events in more detail.

High prices are predominantly associated with tight supply/demand conditions or strategic behaviour by generators. While a number of factors can contribute to tight supply/demand conditions, these conditions are normally observed in South Australia during the summer when electricity demand peaks. The shoulder periods either side of summer and winter are typically the low point for spot prices. Generators and network businesses take advantage of this quiet time of the year to undertake maintenance of plant and network equipment, as there is usually surplus generation and network capability to facilitate this. Spot prices in South Australia during April and May 2013 departed from this trend, with autumn seeing the highest sustained prices in the region since the summer of 2011.

These price outcomes have been accompanied by unusually tight reserve conditions, with South Australia narrowly avoiding interrupting customer load in early June. The supply conditions were the tightest in South Australia since blackouts during the summer of 2009. However, the conditions were not due to a lack of installed capacity in South Australia.

We found that a combination of factors contributed to the tight supply conditions and high price outcomes, including:

- a significant amount of generation capacity choosing not to participate in the market due to challenging conditions in South Australia for certain generators
- inconsistent output levels from wind generators during peak demand periods
- interconnector limits and how these are managed by the Australian Energy Market Operator (**AEMO**) (an issue the AER has sought to improve by requesting AEMO change the design of certain constraints)
- off-peak hot water load creating significant step changes in demand (an issue the AER is seeking to improve through discussions with SA Power Networks), and
- changes in generators' pricing strategies.

We found that with very tight supply conditions in a small region of the NEM, such as South Australia, price outcomes and reserve forecasts can fluctuate significantly in response to relatively small changes in demand, generator availability, interconnector capability or generator bidding strategies.

We consider that these types of market outcomes may become more frequent as conventional merchant generators react to challenging wholesale market conditions associated with flattening demand, input costs and increasing levels of installed renewable energy capacity. The AER does, however, consider the market will continue to deliver a reliable supply of electricity to meet demand.

Spot Prices

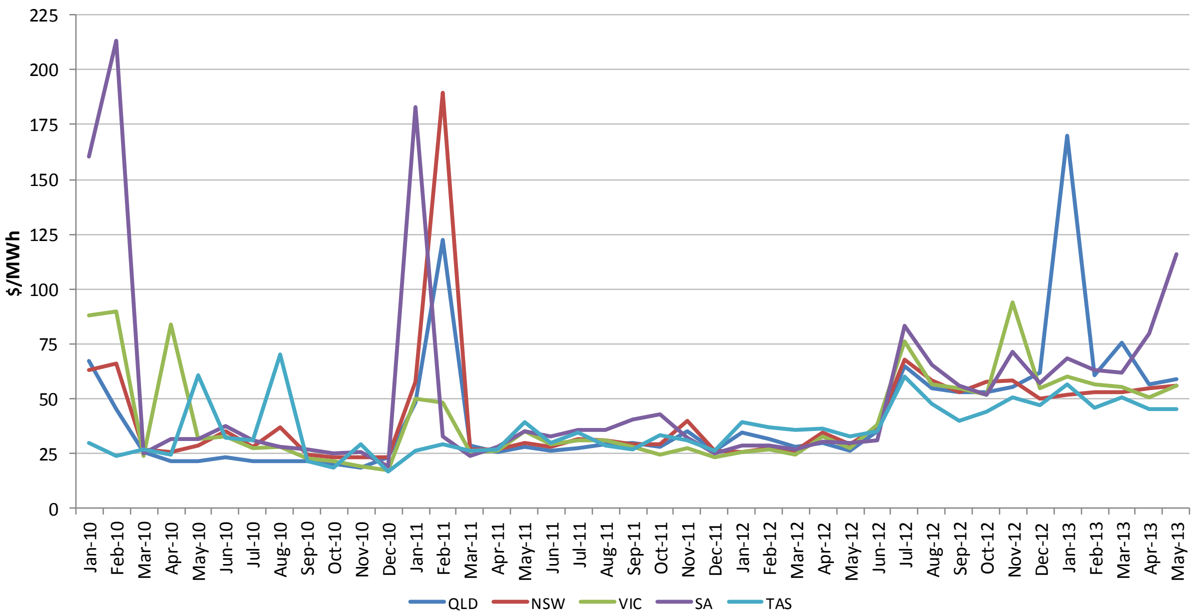
Spot price outcomes in South Australia during April and May 2013 bore a marked difference to those observed in other regions of the NEM for the same period. Table 1 shows the volume weighted average (**VWA**) monthly spot prices for each region of the NEM during April and May 2013.[1]

Table 1: VWA monthly spot prices during 2013

Month	Queensland	NSW	Victoria	South Australia	Tasmania
April 2013	56	55	51	80	45
May 2013	59	56	56	116	45

Figure 1 below tracks VWA monthly prices in all regions since 2010. The VWA monthly spot prices in 2013 for April and May were the highest for those months in South Australia since the market start. Further, May 2013 had the highest South Australia VWA monthly price ($116/MWh) of any month since January 2011 ($183/MWh).

Figure 1: VWA monthly spot prices from January 2010 to May 2013



The high VWA monthly prices in South Australia for April and May were mostly driven by a high number of outlier high prices. Table 2 sets out the count of spot prices in South Australia that were equal to or greater than $200/MWh and $1000/MWh. April and May 2013 had 212 prices equal to or greater than $200/MWh, of which 19 were greater than $1500/MWh. There were no prices above $200/MWh during the equivalent period in 2012.

[1] The average price is weighted against demand for electricity.

Table 2: Count of spot prices in South Australia

Month(s)	Spot price ≥ $200/MWh	Spot price ≥ $1500/MWh
April 2012	0	0
May 2012	0	0
April 2013	23	6
May 2013	189	13

Note: Spot prices were rounded up to the nearest dollar

Notwithstanding the high prices observed, a number of the price outcomes in April and May were actually significantly lower than that forecast by the market system. This is discussed in more detail in the *Forecast extreme prices* section of the report.

Lack of Reserves

In order to ensure the reliability of the power system and manage contingent events, there have to be sufficient reserves of available generation above that required to meet demand and manage contingent events. During April/May 2013, AEMO issued market notices forecasting lack of reserve level 1 (**LOR1**) conditions for a total of 34 days and lack of reserve level 2 (**LOR2**) conditions for seven days. LOR1 means insufficient reserves to meet demand in the event of the loss of the two largest generating units. LOR2 means insufficient reserves to manage the loss of the largest generating unit.

The majority of these forecast lack of reserves did not eventuate, either due to a reduction in AEMO's demand forecast or market participants increasing offered generator availability. More detail on the low reserve conditions (both actual and forecast) is provided is the *Low reserve events* section of this report.

Supply conditions

South Australia has a mix of baseload, peaking, intermediate and renewable generation (plus smaller non-scheduled generators). Installed capacity is set out in Table 3 below.

Table 3: Installed capacity in South Australia by type

Generation type	Maximum winter availability	Major power stations
Base-load	736	Northern Power Station, Osborne
Intermediate	1 838	Torrens Island, Pelican Point, Ladbroke Grove
Peaking plant	821	Quarantine, Hallett, Dry Creek, Mintaro, Port Lincoln, Snuggery
Renewable (wind)	1 205	Lake Bonney 1,2 & 3, Hallett 1 & 2, Snowtown, Waterloo, Cathedral Rocks, North Brown Hill, Clements Gap, The Bluff, Wattle Point, Canunda, Mt Millar, Starfish Hill
Non-wind non-scheduled	152	Includes Pt Stanvac, Angaston, Lonsdale and others

Baseload plant has relatively low operating costs but long duration and high start-up costs, making it economical to run for long periods and continuously. Peaking generators have higher operating costs and lower start-up costs, and are used to supplement baseload when prices are high (typically, in periods of peak demand). While peaking generators are expensive to run, they can start-up quickly to operate at short notice. Intermediate generators are slow start and operate more frequently and for longer periods than peaking plants, but not continuously (cycling on and off with demand variation). Intermittent generation such as wind can only operate when the weather conditions are favourable.

South Australia has around 3 400 MW of installed conventional capacity, with additional 1 357 MW of intermittent and non-scheduled generation. This compares to the highest ever peak summer demand of 3 397 MW (in 2011) and winter demand of 2 534 MW (in 2008). Once interconnector capabilities are factored in, South Australia generally has excess capacity to meet peak demand.

Available generation

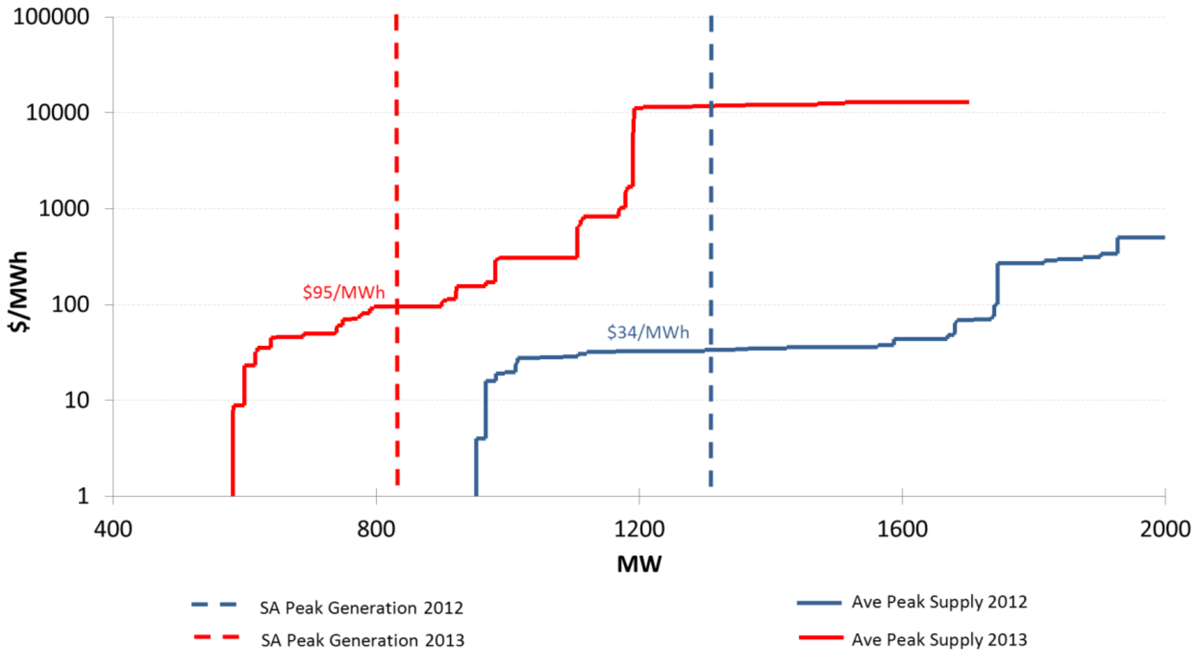
The recent increase in price volatility in South Australia correlated with a marked change in the supply curve.

Figure 2 compares the South Australian supply curve for April/May 2013 against that for April/May 2012. Each supply curve excludes wind generation (due to its intermittent availability) and is the average supply offered during the "peak period" (7 am to 10 pm Eastern Standard Time (**EST**) weekdays).[2] Also included is the average output level of South Australian generation (on the same basis and over the same timeframe).[3]

[2] Note that market time is eastern standard time (**EST**).

[3] Regional generation output is a function of regional demand less imports. Imports have the effect of moving the demand curve to the left if offer prices in South Australia are higher than in adjoining regions of the NEM. Exports shift the demand curve to the right.

Figure 2: Average supply curves and output level (excluding wind) in South Australia during peak periods in April/May 2013 and 2012 (log scale)



The shift of the supply curve to left in Figure 2 illustrates the significant reduction in baseload and intermediate plant capacity in April and May 2013 compared to the same period in 2012. The majority of this reduction was Alinta taking both Northern Power Station units offline (546 MW) and GDF Suez taking half of Pelican Point power station offline (a further 240 MW). These units came progressively offline from the end of March (traditionally the end of the peak summer demand period) to mid-April. AGL also amended the availability and pricing of Torrens Island capacity from 2012 (discussed below). The key drivers behind this withdrawal of capacity are likely the longer-term pattern of low pool prices, the impact of wind generation and increases in input costs (including the carbon price and gas price increases). Further analysis of these factors is set out below in the section titled *Drivers for the withdrawal of generation capacity.*

The impact of this reduction in available capacity on prices is illustrated by the change in the intersection point between the average output level and the supply curve. Notwithstanding higher average import levels in April/May 2013 compared to April/May 2012 and lower average daily peak demand in April/May 2013 (1492 MW) compared to April/May 2012 (1619 MW), the price at which the average output level intersects is significantly higher in 2013.

Torrens Island Power Station

AGL's Torrens Island is the largest power station in South Australia, consisting of eight separate units (four 200 MW B units and four 120 MW A units). This, combined with the intermediate nature of the Torrens Island plant, makes the station the most flexible power station in South Australia.

Figure 3: Average supply curves and output level for Torrens Island during peak periods in April/May 2012 and 2013

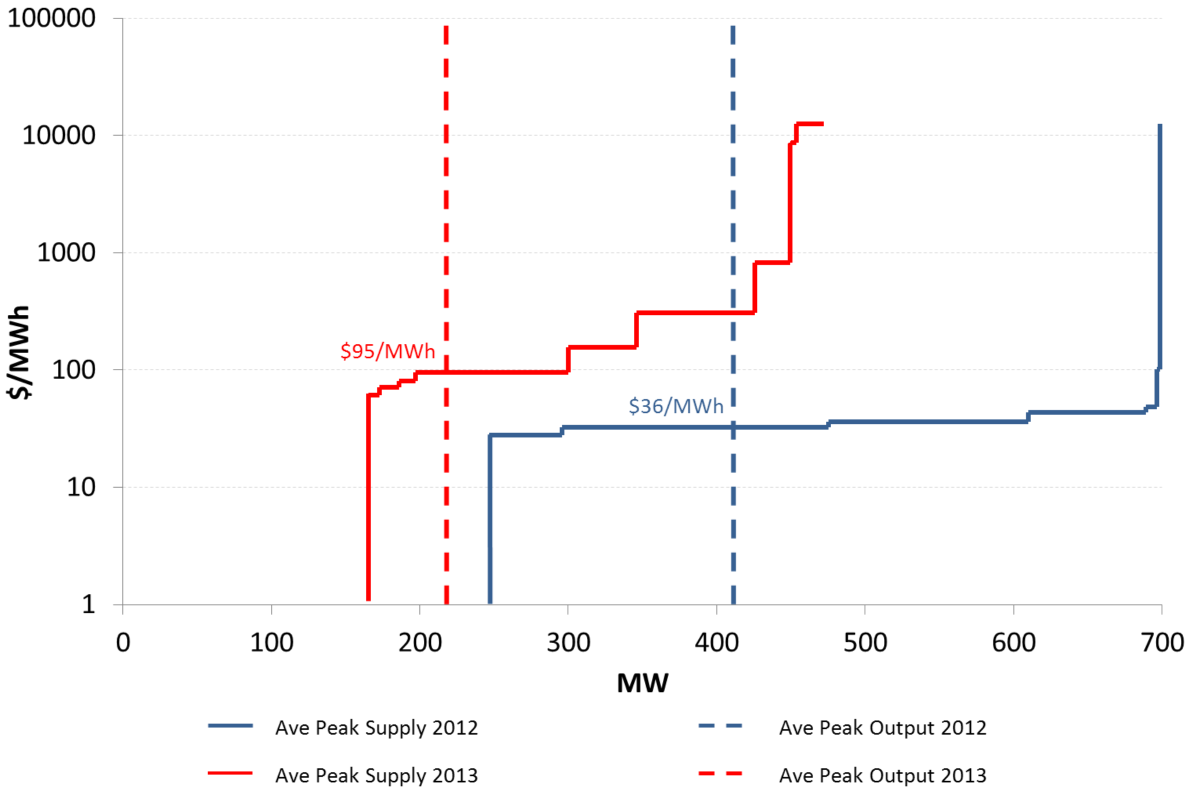


Figure 3 compares the Torrens Island average supply curve during the peak periods of April/May 2013 with the same period in 2012. AGL significantly changed its offer profile for Torrens Island in 2013, reducing the amount of available capacity by around 225 MW and offering a greater proportion of that capacity at higher price bands. In April and May 2012, up to 700 MW of Torrens Island capacity was offered in at prices less than $50/MWh compared to only 165 MW in 2013. In line with this change in offer strategy, Torrens Island's average dispatch level (represented by the dashed vertical lines) in April and May was nearly 200 MW lower in 2013. The intersection point of Torrens Island average dispatch levels with the relevant supply curves is closely aligned with the intersection points for the South Australia region in Figure 2 above, which reflects the fact that Torrens Island constitutes close to 40 per cent of installed conventional capacity in the region.

The change of Torrens Island's supply curve (in addition to the withdrawal of other lower priced capacity) has had a significant impact on the prevailing spot price in South Australia. Torrens Island was strongly positioned during April and May to have a material influence on spot price outcomes. During April and May there was an average peak demand of 1492 MW. With only 524 MW of other baseload and intermediate generation online, Torrens Island was the key online generator available to meet demand when the interconnectors were importing at limit and/or there was low wind output.

South Australia saw 247 hours of spot prices between $100/MWh and $300/MWh in April/May 2013. Figure 4 shows that, during those periods where a single South Australian generator predominantly set the dispatch price for South Australia,[4] Torrens Island set the price 76 per cent of the time when the dispatch price was between $100/MWh and $200/MWh and 89 per cent when the dispatch price

[4] When the dispatch price in South Australia was greater than $100/MWh, South Australian generators predominantly set the price 85 per cent of the time.

was between $200/MWh and $300/MWh.[5] Peaking plant are generally not responsive to dispatch prices less than $300/MWh.[6]

Figure 4: Count of which South Australian generators set price in South Australia during April and May 2013

Note: count excludes generators from other regions or where multiple participants jointly set price.

Wind generator output

South Australia has the highest concentration of installed wind generator capacity in the NEM. Across the NEM wind generation accounts for 4 per cent of installed capacity, whereas in South Australia the figure is 24 per cent. The level of wind generation is wholly dependent on weather conditions with wind generators unable to vary output in response to spot prices in the same way as conventional generation.[7]

Table 4: April/May average wind output (MW)

Period	April-May 2013	April-May 2012	April-May 2011
All time	370	335	313
Peak time	326	346	289
Installed capacity	1205	1204	1152

As set out in Table 4, average wind output (semi-scheduled and non-scheduled) during April-May 2013 was slightly higher than the same period in the previous two years. Wind output during peak

5 The spot price for a trading interval is the average of the six dispatch trading intervals within that half hour. The dispatch price in a region can be set by generators outside the region; multiple generators can contribute to setting the price. For the purposes of this analysis, where a number of units of the same power station jointly set the price, this was treated as the station setting the price**.**

6 Most peaking plant sell cap contracts providing cover for spot prices in excess of $300/MWh. Although spot prices greater than $100/MWh are in excess of many peaking plants' short run marginal cost, peaking plant may opt not to run due to wear and tear associated with starting and stopping the plant. Where supply/demand conditions are finely balanced, a peaking plant coming online can also cause a high price to not eventuate.

7 Wind farms can choose to shut down in response to very low prices.

periods was, however, slightly lower in 2013 than 2012. As set out in the *High price events* section below, wind output tended to be lower during the high price events.

Interconnectors

In the NEM, the term 'interconnector' refers to the elements of transmission network between one regional reference node (close to each capital city) and that of the adjoining region. Interconnectors can consist of many meshed transmission elements rather than a simple path.

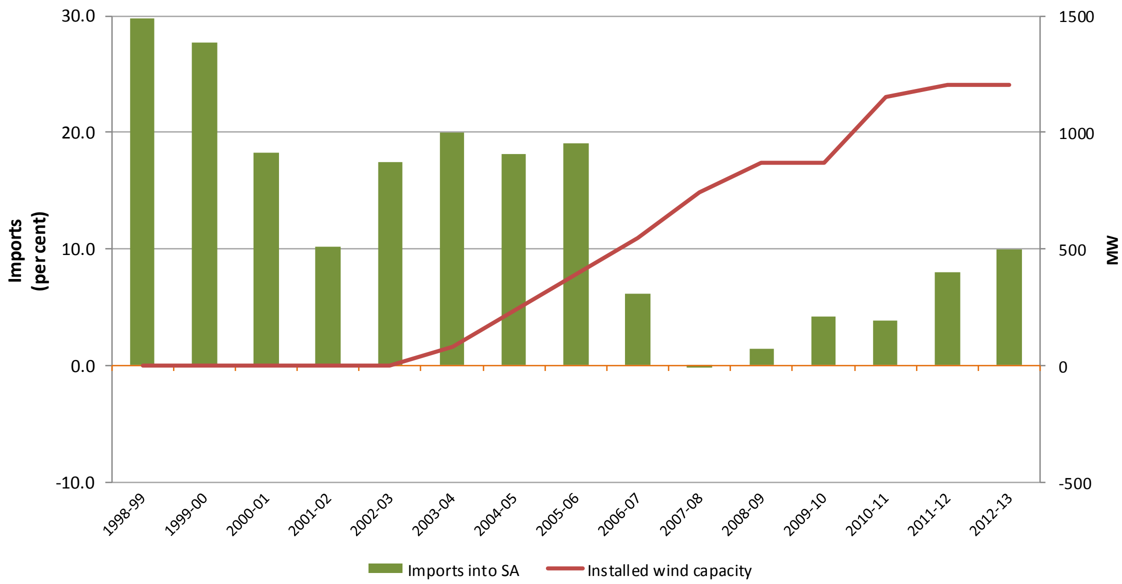
South Australia is connected to rest of the NEM by two interconnectors: the Murraylink interconnector, a direct current (**DC**) link with a maximum import limit into South Australia of 220 MW, and the Heywood interconnector (which has a maximum import limit of 460 MW).[8] The Heywood interconnector is relatively simple, consisting of the double circuit 500 kV line from Sydenham (Melbourne) to the border and then a double circuit 275 kV line to Adelaide. In the case of the Murraylink interconnector, the interconnector itself is a DC cable running between Monash and Red Cliffs, but there are a myriad lines from Adelaide to Monash and Melbourne to Red Cliffs.

The amount of energy imported into a region is a function of two key factors: the offer price of local generation compared to that in other regions and the limitations of the interconnectors.

Import levels

As illustrated by Figure 5 below, South Australia had been heavily dependent on imports at the beginning of the NEM. The level of imports had, however, steadily declined until South Australia became a net exporter in 2007-08. Subsequently, South Australian import levels have increased to the highest levels since 2005-06, notwithstanding the increased installation of wind farms in the state.

Figure 5: Interregional trade as a percentage of South Australian energy demand compared with installed wind capacity



Sources: AEMO; AER.

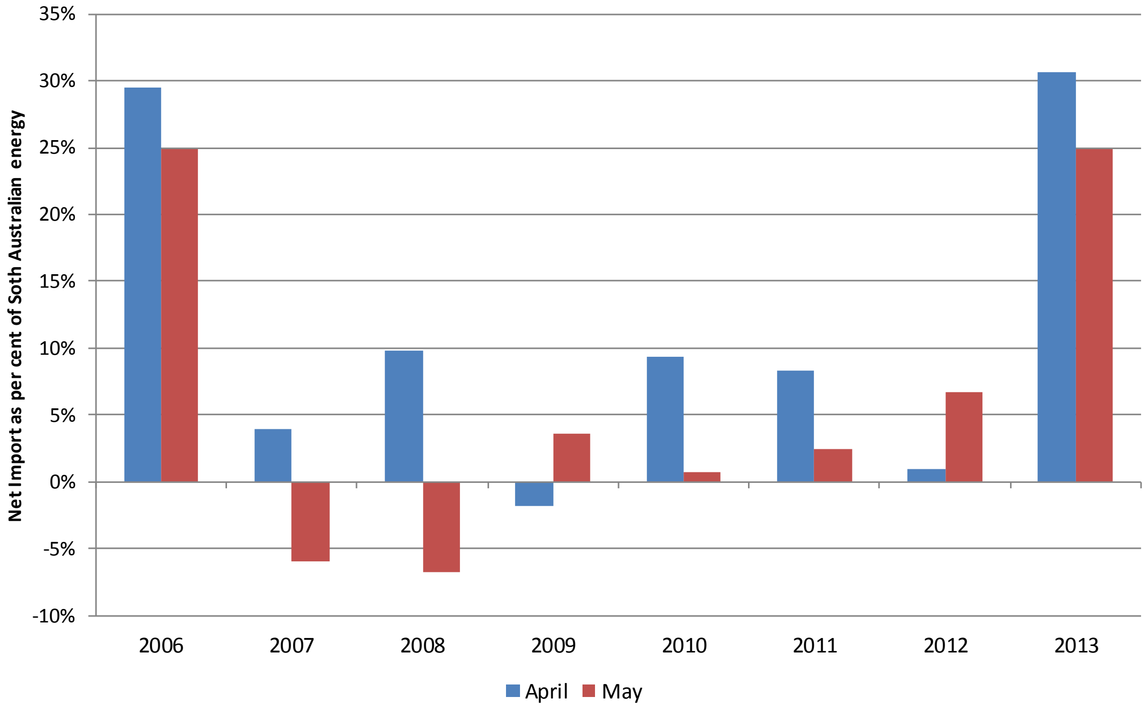
Note: a negative number indicates the region was exporting energy and regional demand was fully met by local generation

8 The Heywood and Murraylink interconnectors have an assigned directional flow from Victoria to South Australia. For the purposes of this report, references to importing / exporting or to import / export limits on the interconnectors is based on the perspective of energy movement into or out of the South Australia region rather than the direction of the relevant interconnector.

On average Heywood imported 341 MW into South Australia over the April-May period. This is the highest level of average imports since 2006 for the equivalent two month period, with the next highest level of average imports of 105 MW in 2011. Similarly, Murraylink on average imported 40 MW over the April-May period, again the highest level since 2006. This is despite the outage of Murraylink from 15 May as a result of a cable fault. Murraylink returned to service on 7 June.

Figure 6 illustrates the proportion of South Australian energy consumption which was imported during April and May 2013, compared against levels from the previous seven years. Over a quarter of South Australian energy demand over the two months was met by imports, significantly higher than the same timeframe over the preceding six years.

Figure 6: Net imports as a percentage of South Australian energy for April and May



The amount of energy imported into South Australia, and the large price differential between South Australia and Victoria, has led to record settlement residues for flows across both interconnectors from Victoria to South Australia.[9] More than $36 million of residues has accrued for the April-June quarter; the proceeds of the auctions to acquire the rights to these residues were $1.9 million (the highest paid since 2007).

Low reserve events

AEMO regularly performs assessments of sufficiency of reserves by comparing generator availability and interconnector capability against different levels of forecast demand, referred to as Projected Assessment of System Adequacy (**PASA**). PASA is done over three timeframes:

[9] Inter-regional settlement residues occur when the prices between regions separate. Generators are paid at their regional spot price while retailers pay the spot price in their region. The difference between the price paid in the importing region (by retailers) and the price received in the exporting region (by generators), multiplied by the amount of flow across the interconnector, is called a settlement residue. The rights to these residues are auctioned ahead of time by AEMO in settlement residue auctions (SRAs).

- Pre-dispatch PASA (**PD PASA**) which assesses reserves on a half hour resolution until the end of the next trading day

- Short Term PASA (**STPASA**) which is assessed on a half hour resolution on the six day time horizon after PD PASA and

- Medium Term PASA (**MTPASA**) which is assessed for the peak demand each day for the next two years.

Generators bid in two main types of availability—capacity which is offered as available to be dispatched by the NEM dispatch engine (**NEMDE**) in real time and capacity that is currently offline but can come online within certain timeframes. PASA availability is the availability of a generator given 24 hours notice. Wind output forecasts are included in AEMO's calculations of reserves.

Insufficient reserves in the event of a contingency are referred to as a 'lack of reserves' (**LOR**). For South Australia there are three main categories of LOR:

- LOR1: insufficient supply to meet demand in the event of the loss of the two largest generating units

- LOR2: insufficient reserves to manage the loss of the largest generating unit; and

- LOR3: insufficient generation to meet demand, which requires customer load to be interrupted.

A lack of generation reserves is signalled to the market by AEMO through the issuing of market notices advising of forecast lack of reserves. April and May 2013 saw an unusually high number of reserve notices for South Australia.[10]

As noted in the *Introduction and overview*, AEMO issued market notices forecasting LOR1 conditions for a total of 34 days and LOR2 conditions for seven days. The majority of these forecast lack of reserves did not eventuate, either due to a reduction in AEMO's demand forecast or market participants increasing offered generator availability. Actual LOR1 conditions eventuated for two days in April.[11]

This tight supply situation peaked in early June. On the evening of Friday 31 May, a switchboard fault at the Torrens Island power station caused three 200 MW Torrens Island B units to trip within half an hour of each other. Coincidently, Origin's 190 MW Osborne unit tripped at the same time. A total of 790 MW of capacity had become unavailable. Fortuitously, Alinta had brought back one 273 MW Northern Power Station unit (offline since 19 April) early that morning. Alinta had made the decision earlier in the week to bring forward Northern Power Station unit 1's return to service with the aim to be operational by the following Monday (3 June); the unit was able to come online sooner than anticipated.[12]

10 During April and May 2013, South Australia needed between 440 and 546 MW of reserves to satisfy LOR1 levels and between 240 to 273 MW for LOR2. These figures are based on the largest generating units online in South Australia at the relevant time. The largest units are (in order) the Northern Power Station units, Pelican Point and Torrens Island B units.

11 LOR2 conditions notified by AEMO associated with planned outages of one circuit of the Heywood interconnector are excluded. These LOR2s reflect insufficient frequency control ancillary services offers in the event of the separation of South Australia from the rest of the NEM during import conditions. In this event customer load may be interrupted to restore the power system frequency to the standard; there are sufficient capacity reserves to otherwise meet demand in the event of the loss of generating units or the interconnector (although these reserves may be in the form of offline generators).

12 Alinta had originally planned to operate Northern Power Station unit 1 for a six week period from mid-June to late July to coincide with the peak winter demand period. Alinta changed the PASA availability of Northern Power Station unit 1 to reflect the change on Monday 27 May.

With 790 MW of generation capacity unavailable and the Murraylink interconnector still out of service, reserve conditions were on a knife edge as wind output progressively dropped off over the weekend. On Sunday afternoon, AEMO issued market notices advising that, under current supply conditions, there would be LOR3 conditions (mandatory customer interruptions) for two and half hours on Tuesday evening (4 June) commencing from the 6.30 pm trading interval and there were insufficient reserves in the event of the largest unit tripping (LOR2 conditions) for the majority of Tuesday.

Late Monday morning, AEMO advised the market that, although the magnitude and length of customer interruption for Tuesday evening had reduced since last advised, AEMO had no options for intervention through directing offline generation to come online. AEMO called for the market to respond. An hour later, AEMO cancelled the forecast load shedding due to the market response.

AEMO had also issued market notices throughout Monday forecasting LOR2 conditions for Monday morning and evening. Actual LOR1 conditions were declared from 7.10 am and were forecast to continue for the rest of the day. At around midday, AGL advised that one of its 120 MW Torrens Island A units was unavailable due to a steam tube leak. An hour later, AEMO issued a market notice advising of mandatory customer interruptions for the 6.30 pm and 7 pm trading intervals Monday evening. Within 20 minutes, the LOR3 condition was cancelled after non-scheduled generation responded.[13] Reserve conditions continued to improve through the day, with forecast LOR2 conditions cancelled after Osborne returned to service on Monday afternoon.

Spot prices reflected the tight conditions, with thirteen spot prices in excess of $1889/MWh on Monday and a VWA price of $640/MWh for the day. Tuesday evening had five prices in excess of $1889/MWh.

The loss of four units almost simultaneously is a very rare event. Fortunately this occurred after Alinta had returned a unit to service, after the peak demand on Friday evening had passed and leading into the weekend (the lowest daily demand period of the week).

Drivers for the withdrawal of generation capacity

As was noted earlier, a large quantity of South Australian capacity has chosen not to participate (in part or in full) in the NEM. This section of the report seeks to explore the factors contributing to that withdrawal.

Spot price outcomes across the NEM over the last few years have created a challenging environment, particularly for merchant baseload generators. The amount of wind generation in South Australia creates additional challenges as it contributes to significant price volatility, some of which is difficult to predict. These factors, combined with recent flattening demand and increasing input costs, have influenced the recent withdrawal of low-priced capacity from South Australia during April and May 2013.

Low pool prices

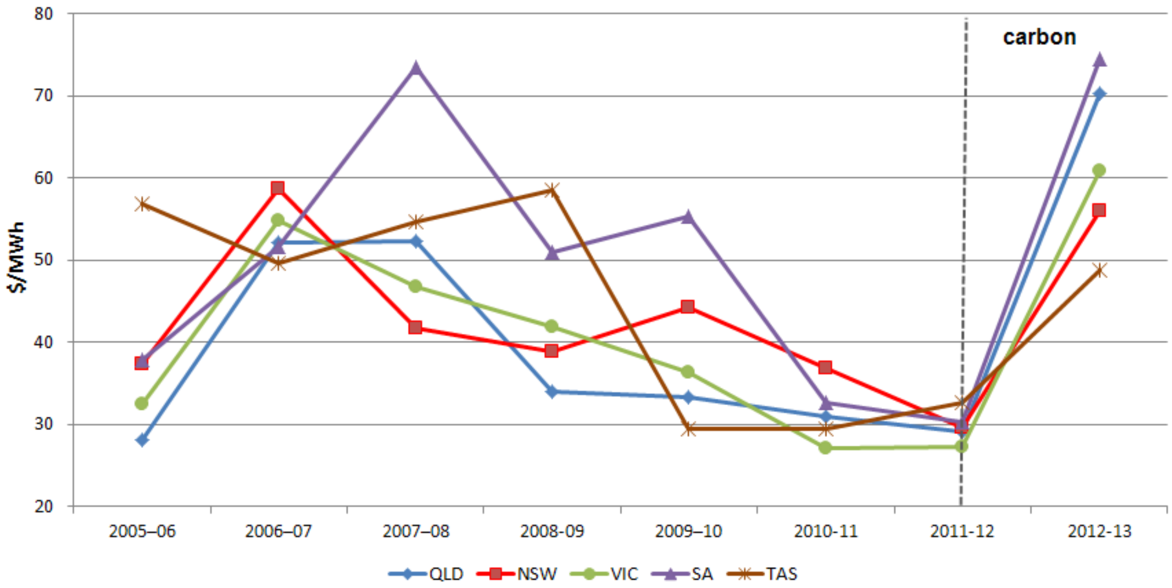
Prevailing spot prices strongly influence a generator's profitability in the long run.[14] Flat average yearly pool prices across the NEM have been trending downwards over the last five years from the

[13] Non-scheduled generators do not participate in dispatch and therefore do not offer availability. They in effect reduce demand, which is how the non-scheduled generators relieved the supply shortfall.

[14] Most generators are not fully exposed to the spot price. Most base-load and intermediate generators will aim to hedge a significant proportion of their capacity to lock in firm prices for electricity produced in the future. This reduces generators' exposure to pool prices and reduces the risk of generating at a loss. However, while there is usually a premium associated for the certainty of a hedge contract, the price of the hedge contract is strongly influenced by historical pool prices.

high observed during the drought in 2007. With the introduction of the carbon price, pool prices for the 2012-13 financial year have increased but this generally reflects the pass-through of the increase in input costs for conventional fossil-fuelled generation.

Figure 7: Average financial year pool prices by region since 2005/06



Market conditions in South Australia have influenced generators' decisions about making capacity available to the pool. Alinta made a commercial decision in early 2012 to take Playford offline and not to operate Northern Power Station for the third quarter of 2012 and during April to September from 2013 onwards. Alinta's decision was due to the fact that prevailing market conditions made operating in those months uneconomic; Alinta indicated that the introduction of a carbon price did not influence its decision.[15]

The impact of wind generation on pool prices

In South Australia, wind accounted for 28 per cent of output in 2012-13 (figure 8).[16] On particular days during 2012-13, wind has accounted for up to 69 per cent of total generation in the state (and up to 75 per cent of generation for a trading interval).

15 See: http://alintaenergy.com.au/Everything-Alinta-Energy/News/Alinta-Energy-clarifies-market-reports

16 AEMO, *2012 South Australian electricity report*, 2012, p. 16.

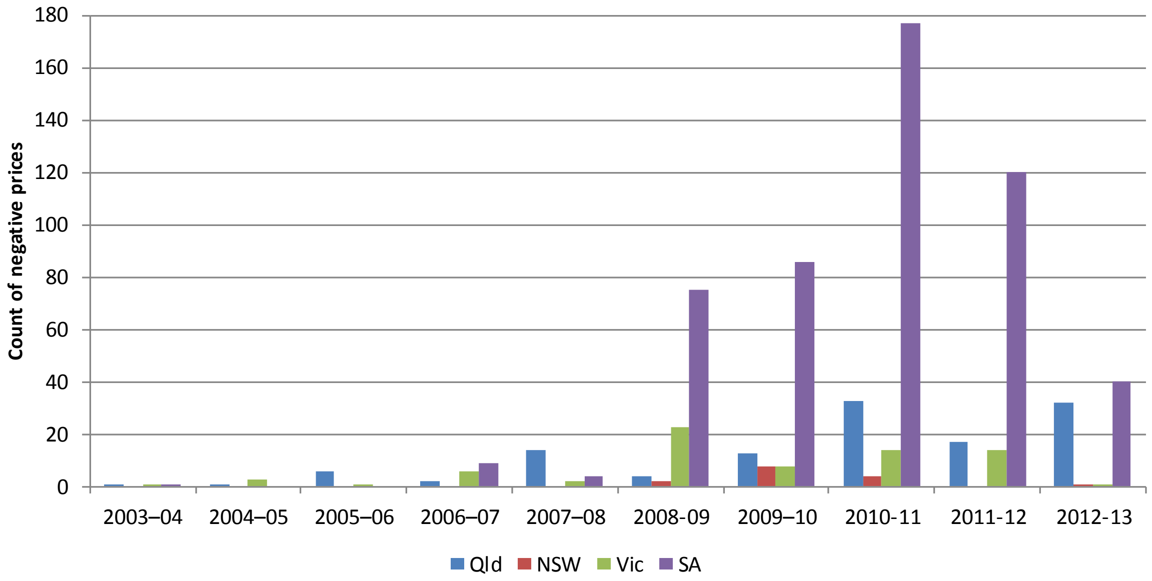
Figure 8: Average wind generation output as a percentage of total regional output

Wind generation is generally lower at times of peak demand. For reserve assessments in South Australia it is assumed wind will contribute 8.6 per cent of its installed capacity during summer peak conditions and 7.9 per cent during winter. There is evidence that wind generation is having a moderating impact on electricity prices in South Australia; spot prices are typically higher at times of low wind.[17] Figure 13, later in this report, illustrates the moderating impact of wind output on spot prices in more detail.

Figure 9 below highlights how increased construction of wind generation since 2008-09 is correlated with an increased incidence of spot prices below zero. Wind generators bid low and often at slightly negative prices to ensure dispatch, because they receive the value of renewable energy certificates in addition to spot market returns. However, Figure 9 should be interpreted with caution, because some of the instances of the price being very low (i.e. well below zero) are associated with strategic generator bidding or rebidding by AGL.

[17] AEMO, *South Australian wind study report*, 2012, p.2-1.

Figure 9: Number of spot prices below zero for mainland regions



Changes in generator input costs

At the same time that pool prices in South Australia have been trending downwards and there is an increased prevalence of negative spot prices, a number of fossil fuelled generators in South Australia have experienced increases in their operating costs.

Carbon price

On 1 July 2012, the Australian Government introduced a carbon price as part of its Clean Energy Future Plan. The central mechanism places a fixed price on carbon for three years, starting at $23 per tonne of carbon dioxide equivalent (**CO_2e**) emitted. Electricity generators are required to purchase and surrender carbon permits to offset their emissions, which increases their operating costs. This cost increase has flowed through to generator offers and electricity spot prices as reflected by the increase in spot prices observed in all regions for 2012-2013 in Figure 1 above.

The impact of the carbon price on a generator's short run marginal cost will depend on the carbon intensity of its plant (expressed in tonnes of CO_2e per megawatt hour). Coal and liquid-fuelled plant are the most carbon intensive, with gas-fuelled plant usually the least carbon intensive of fossil fuelled generators. The carbon intensity will also depend on the characteristics of each plant, newer combined cycle gas-fired stations tend to be less carbon intensive than older plant. For example, the brown coal fuelled Northern Power Station was estimated by ACIL Tasman in 2009 to have a carbon intensity of 0.90 tonnes of CO_2e per megawatt hour generated (or around $21/MWh at the 2012/13 carbon price of $23/tonne). Pelican Point, a combined cycle gas turbine commissioned in 2000, has an estimated carbon intensity of 0.51 CO_2e tonnes/MWh generated compared to 0.87/MWh for Torrens Island A units (which uses older technology from the 1960s).[18]

[18] ACIL Tasman, *Fuel resource, new entry and generation costs in the NEM*, 2009, pp 25 and 31.

Gas fuel price

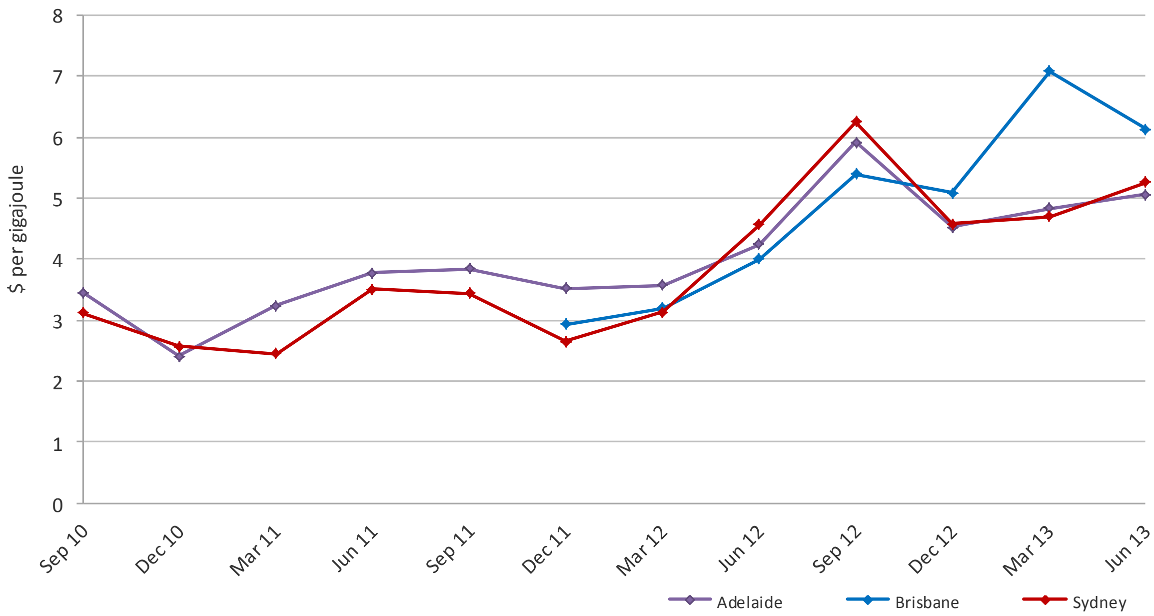
South Australia has the highest proportion of gas-fuelled generation capacity in the NEM, with nearly 75 per cent of South Australian conventional capacity gas-fuelled. The east coast liquefied natural gas (**LNG**) projects are starting to impact gas generators' input costs.[19]

Australian eastern seaboard wholesale gas supply prices have historically been low by international standards (around A$3.50–$4/GJ).[20] The recent development of LNG export capacity in Queensland is exposing the eastern seaboard to international energy prices. EnergyQuest estimates long run LNG netback prices at the (LNG) plant inlet at Gladstone to be $9.41/GJ.[21] While LNG exports from Queensland are not expected to begin until 2014, the project developers are securing gas reserves to underpin supply contracts.

Because the majority of trading in Australian gas markets is through confidential long-term bilateral contracts, it is difficult to precisely quantify the effect LNG exports are having on domestic gas prices. However, even if gas-fuelled generators have fuel prices locked in under long term gas contracts, generators face an opportunity cost where there is the option to sell the gas in the STTM or to other participants. Where the return offered by the prevailing spot price for electricity is less than the current price (or opportunity cost) for gas, there is an incentive for generators to reduce the amount of electricity produced and sell their excess gas on the spot market.

Figure 10 demonstrates ex-ante gas price movements in the Adelaide, Sydney and Brisbane hubs of the STTM over the last two years. It can be seen that the ex-ante price of gas traded in the Adelaide hub has trended upwards over the last two years in line with the other hubs.

Figure 10: Average daily ex ante gas prices by quarter for the Adelaide, Brisbane and Sydney STTM hubs



Note: these prices are the delivered cost of gas

19 There are currently six LNG trains under construction or development in Queensland. An LNG train is an LNG plant's liquefaction and purification facility.

20 EnergyQuest, *Energy Quarterly*, August 2011, p 94

21 EnergyQuest, *Energy Quarterly*, May 2013 p 97. This is understood to be the price of gas delivered to Gladstone. It can be calculated by removing the costs of liquefaction at Gladstone as well as the further costs to ship and deliver gas to Asian customers from the final price paid.

High spot price outcomes

As set out in the *Introduction and overview*, there have been an unusually number of high spot prices between $1600/MWh and $2220/MWh during April and May 2013. This section explores the triggers for the high prices in detail.

South Australia saw eighteen 30 minute spot prices during the period in excess of $1500/MWh.[22] Each of these high spot prices was caused by a single five minute dispatch price in excess of $11 000/MWh.

Accuracy of forecasts

Where a high price is forecast it will often not eventuate, as generators have a chance to respond. Very few of the April/May high prices were forecast. Analysing why forecasts were different to the actual prices typically explains what contributed to the high prices.

Table 5 below sets out the factors which the AER identified as contributing to spot prices being different to the prices forecast four hours and half an hour ahead. The factors include:

- Reduction in availability of generation (including wind generation)
- Rebidding by generators
- An increase in five-minute demand
- Network and interconnector changes (usually changes in import capability)

The majority of prices in excess of $1500/MWh were higher (**H**) than forecast, with three spot prices lower than forecast (**L**).

[22] In addition there was a single high price of $1602/MWh on Tuesday 28 May which was associated with conditions in Victoria.

Table 5: Contributing factors to high prices in South Australia during April and May 2013

Day	Trading interval	Compared to forecast		Generation		Demand	Network (Interconnector)
		4 hours ahead	**Half hour ahead**	**Availability Reduction**	**Rebid**		
15 April	7.30 am	H	H				✓
23 April	Midnight	H	H			✓	
24 April	8.30 pm	H	H			✓	✓
25 April	Midnight	H	H			✓	
29 April	8.30 am	H	H	✓	✓		
	9 am	H	H	✓		✓	✓
8 May	11.30 am	H	H	✓	✓		✓
17 May	8 am	H	H	✓	✓		
	8.30 am	H	H	✓		✓	✓
	9.30 am	H	H	✓		✓	✓
	6.30 pm	L	L			✓	✓
	8.30 pm	L	L				✓
	10.30 pm	H	L	✓	✓		
	Midnight	H	H	✓		✓	
24 May	Midnight	H	H			✓	
31 May	12.30 pm	H	H	✓		✓	✓
	8.30 pm	H	H	✓			✓
	9.30 pm	H	H	✓			✓

5/30 issue

As set out above, each of the high spot prices listed in Table 5 was associated with a single five minute dispatch price close to the cap. The wholesale electricity market is settled on a half hourly basis (trading interval). A participant's average output over each trading interval, multiplied by the respective spot price for that half hour is used in settlement.

Despite the half hourly trading period, NEMDE dispatches generators and determines an ex-ante price every 5 minutes (a dispatch price). The average of the six 5-minute dispatch prices is used to determine the spot price for the trading interval.[23]

Where there is a material change in conditions close to dispatch that causes an un-forecast five minute price spike, this significantly impacts participants' ability to respond. Usually participants are able to assess the impact of changing conditions through the forecast systems and have sufficient to time to respond, including by bidding to ensure a plant is on or off or moving offered capacity into lower or higher price bands. Last minute changes in demand, availability or network conditions reduces the likelihood that a price spike will be forecast and reduces the ability of participants to respond.

[23] The 6.30 pm spot price, for example, is the average of six 5-minute dispatch prices for the 6.05 pm, 6.10 pm, 6.15 pm, 6.20 pm, 6.25 pm and 6.30 pm dispatch intervals.

Where an un-forecast price spike occurs early in a trading interval, generators will do whatever they can after the price spike to lower the average price or increase their output for the remainder of the trading interval to minimise their exposure.

Un-forecast spikes in the five-minute dispatch price in the last one or two dispatch intervals in a trading interval are difficult to respond and cause the most damage to market participants (particularly peaking plant). Peaking plant generally have higher operating costs compared to base and intermediate plant and are therefore offline for the majority of time, generating only in response to high prices. A peaking plant can take up to 10-15 minutes to start and must operate at or above specified minimum level for a period of time before shutting down. Therefore it may not be economic for the plant to turn on for a few dispatch intervals, where there is a risk of generating at a loss in subsequent trading intervals. The units best able to respond to un-forecast short-term high prices are units that are already on (typically baseload/intermediate plant).

The next sections of this report explore some of the factors behind the high dispatch prices and explain why most were not forecast.

Demand changes

Every five minutes NEMDE dispatches generation to meet demand in the next five minutes according to merit order (but subject to network limitations). This requires, amongst other things, NEMDE to calculate what the level of demand will be at the end of the five minute dispatch interval. NEMDE uses actual demand (based on a combination of values such as metered output from generators and interconnectors) which is adjusted by predictions of where demand will move (usually based on recent historic demand).

In the normal course of events, generators can be ramped up and down in merit order to manage relatively small variations of demand and price is relatively stable. In conditions where a region is importing at or close to the interconnector limit, a change in demand can only be managed by ramping generators in that region. In South Australia around one quarter of conventional generation is fast start peaking plant that can start up in less than 30 minutes (but which cannot start in five minutes). When there are relatively few generators online, small changes in demand cannot be met by ramping generation in merit order, which can cause high priced offers to be dispatched setting very high five minute dispatch prices. During April and May, when wind output was low, the interconnectors were often running at the maximum import level and there were very few generators running.

As set out in Table 5, demand changes were assessed as contributing to ten of the high price events. Of these, five involved demand increases of less than 80 MW over five minutes (or only around 5 per cent of demand) which were sufficient to cause a high price. The most significant demand increases were associated with storage hot water systems switching on at 11.30 pm EST, (explained further below).

Hot water systems

The lowest spot prices of the day usually occur during the late evening and early morning. Demand for electricity is significantly lower and usually met by low priced generation.

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 between 11.30 pm and 7.30 am EST, ensuring that they are not operating during peak demand periods (typically in the morning and early evening). An off-peak meter is fitted to eligible devices, which automatically switches the devices on at specified times. In older meters, this is performed by a mechanical timer switch. A significant amount of hot water systems are set to switch on at 11.30 pm EST, which marks the commencement of the off-peak tariff. Actual switch-on times tend to be staggered as one of the features of older mechanical timers is that the timer 'drifts' and becomes less accurate.

April and May 2013

During April-May, there were four un-forecast spot prices in excess of $2000/MWh for the midnight trading interval (which covers the period from 11.30 pm to midnight EST). Each of these spot prices was associated with a five-minute dispatch price in excess of $11 000/MWh for the 11.35 pm (or a subsequent) dispatch interval.

Table 6: Demand increases in South Australia associated with hot water load

Day	Dispatch interval	Five minute price ($/MWh)	Scheduled Demand (MW)		Interconnector (Heywood)		Interconnector (Murraylink)	
			Scheduled	**Increase**	**Target**	**Limit**	**Target**	**Limit**
23 April	11.30 pm	91	1398	-	460	460	173	173
	11.35 pm	12195	1590	192	460	460	199	167
25 April	11.30 pm	61	1316	-	291	291	81	153
	11.35 pm	12 898	1528	212	358	355	169	169
17 May	11.30 pm	64	1638	-	241	460	0	0
	11.35 pm	12 191	1858	220	460	460	0	0
24 May	11.30 pm	61	1578	-	167	460	0	0
	11.35 pm	70	1738	160	419	460	0	0
	11.40 pm	200	1789	51	460	460	0	0
	11.45 pm	12 880	1826	37	449	449	0	0

Table 6 sets out the increase in scheduled demand associated with the 11.35 pm dispatch interval, along with the targets and import limits for the interconnectors. On each of the occasions, there was a sharp increase in scheduled demand (around 200 MW) in the 11.35 pm dispatch interval. Given that the Heywood and Murraylink interconnectors were at, or close to, limit, high priced online generation in South Australia was required to be dispatched to meet the jump in scheduled demand.

Factors affecting off-peak electric hot water load

From July 2008, the South Australian Government introduced an energy efficiency scheme which, except under certain circumstances, requires new or replacement hot water systems installed to be high energy efficient gas, solar or electric heat pump systems. The purpose of the scheme is to improve the energy efficiency of residential water heaters thereby assisting to reducing greenhouse emissions. By replacing eligible conventional electric hot water systems with other systems, the amount of load from the remaining systems will reduce over time.[24]

Another energy efficiency policy introduced by the South Australian Government at the same time is a scheme requiring feed-in-tariffs for electricity generated by solar panels installed by eligible

[24] Electric heat pumps work by using the ambient temperate of the surrounding air to heat the water, requiring less energy than conventional electric hot water systems. The AER understands that the majority of electric heat pumps in South Australia are not on off-peak tariffs.

customers. This policy, in conjunction with the Australian Government's Renewable Energy Target scheme, saw a significant amount of solar panels installed in South Australia (approximately 388 MW of installed capacity).[25] When solar panels are installed, SA Power Networks replaces the existing meter with a new import-export meter which, in addition to measuring peak and off-peak consumption, also measures the output of the solar panels. One of the characteristics of these meters is that there is no mechanical timer for off-peak load, they use electronic timers instead. As a result, the timers remain more accurate than with older mechanical timers. SA Power Networks has advised that these electronic meters are programmed to randomise when off-peak load is switched on after 11.30 pm EST. This randomisation is, however, scheduled to occur over a fifteen minute timeframe (i.e. between 11.30 – 11.45 pm EST).

SA Power Networks has also advised that, in addition to replacing meters as a result of the installation of solar PVs, it has been progressively replacing older meters with new electronic meters. Since 2005 SA Power Networks has installed over 79 000 electronic meters which control off-peak load. Just over 36 000 of these meters were installed in 2011 and 2012.

Table 7: Demand increase in South Australia associated with hot water load in April-May 2013 vs 2009

Year	Scheduled Demand (MW)			Metered Demand (MW)		
	Average demand (11.35 pm)	**Average demand increase (11.30 pm - 11.35 pm)**	**Proportion of demand (%)**	**Average demand (11.35 pm)**	**Average demand increase (11.30 pm - 11.35 pm)**	**Proportion of demand (%)**
2009	1630	138	8%	1618	126	8%
2013	1577	202	13%	1557	175	11%

Table 7 compares the average increase in demand in April-May 2013 associated with hot water systems coming on at 11.35 pm with the same months in 2009. Notwithstanding the South Australian Government's policy to move away from conventional hot water systems, the size of the increase in scheduled and metered demand during the 11.35 pm dispatch interval has increased since 2009. Overall average demand, however, is slightly lower in 2013 than 2009, with hot water load making up a greater proportion of demand. This means the demand increase is higher in 2013 both in MW and proportional terms.

SA Power Networks has advised that the average demand change from the 11.30 pm trading interval to the midnight trading interval has increased in magnitude by over 130 MW (a threefold increase) since 2003. Over 55 MW of this increase has occurred since 2010, when there was a large rate of replacement of meters as a result of feed-in tariffs for solar power.

With South Australia importing at greater levels in 2013 than four years ago, the step change in demand is more likely to be met only by online generation in South Australia without assistance from generators in neighbouring regions. Where generators are either ramp rate limited, or at or close to maximum output, high priced capacity is required to be dispatched. This creates a perverse outcome,

[25] The Renewable Energy Scheme creates a financial incentive for owners to install eligible small-scale installations including solar panel systems. It does so by legislating demand for Small-scale Technology Certificates (STCs) (called Renewable Energy Certificates prior to January 2011). STCs are created for these installations according to the amount of electricity they produce or displace.

where off-peak load designed to take advantage of low priced demand periods cause high prices to eventuate.

AEMO determines the five-minute scheduled demand increase (from the current demand) based on demand changes in previous periods.[26] Following discussions with the AER, AEMO has reduced the maximum allowable scheduled demand step change from 220 to 190 MW. AEMO is continuing to explore issues around hot water load.

The AER is also discussing options with SA Power Networks to address the significant increase in the five minute demand increase at 11.35 pm.

Changes in interconnector limits

As set out in the *Supply conditions* section, South Australia has been importing a large proportion of the regional energy requirements during April and May. The amount of energy that can be imported into a region at any given time is dependent on the import limit(s) of the relevant interconnector(s) at the time. Limits can vary depending on network conditions and generator dispatch offers.

During the April-May period, South Australia was importing at limit over the Heywood interconnector for 54 per cent of the time; this rose to 69 per cent during peak periods (7 am to 10 pm EST). This compares to 24 per cent at all times, and 21 per cent during peak periods for the same period in 2012. Imports across Murraylink during peak period were at limit 44 per cent of the time in April-May 2013 (including the period when Murraylink was unavailable); for the same period in 2012 Murraylink was at limit 15 per cent.[27]

As noted above, when a region is importing at limit across one or more interconnectors, the region is reliant on local online generation to meet any increase in demand. In addition, any sudden reduction in interconnector import limits must be met by local online generation.

Interconnector limits

NEMDE manages the maximum amount of flow over an interconnector through the use of limits (the maximum amount of energy that can flow over every network element that forms part of the interconnector taking into account network conditions and system security). The maximum import limit on an interconnector is usually determined by the amount of energy that can flow over each element of the interconnector without overloading other key elements under certain contingency events (such as the loss of a key element such as a line or transformer, or loss of the largest generating unit in a region). As the transmission network is meshed, import limits can also be reduced in order to manage other parts of the transmission network remote from the region boundary.[28] AEMO's forecast systems include forecasts of network limits and targets (flow level) for interconnectors. These forecasts depend on models of dispersed customer load and network capabilities. Accordingly the limit of an interconnector can change from that forecast due to a discrepancy in the model or a change in network conditions.

[26] This automatic system uses a neural network that learns from previous periods how much the demand is likely to move in the next five minutes.

[27] For April/May 2013, Murraylink was importing at limit 39 per cent of the time. During April/May 2012, this figure was 21 per cent.

[28] When managing a particular network element in a region, NEMDE can manage flows over that element by changing the output of relevant generators or by changing the direction or magnitude of flows into or out of the region. Where flows over the interconnector can be changed by NEMDE to manage flows over another part of the transmission network, this is shown as a reduction in import or export limit.

South Australian interconnectors during April-May 2013

Several of the short duration price spikes observed were associated with a change in interconnector import limit. The AER considers that these changes were greater than necessary due to the design of the relevant constraint equation. While some of these import limit changes may not have caused high prices in the normal course of events, they were sufficient to do so during April and May given the tight supply/demand situation in South Australia.

Heywood interconnector

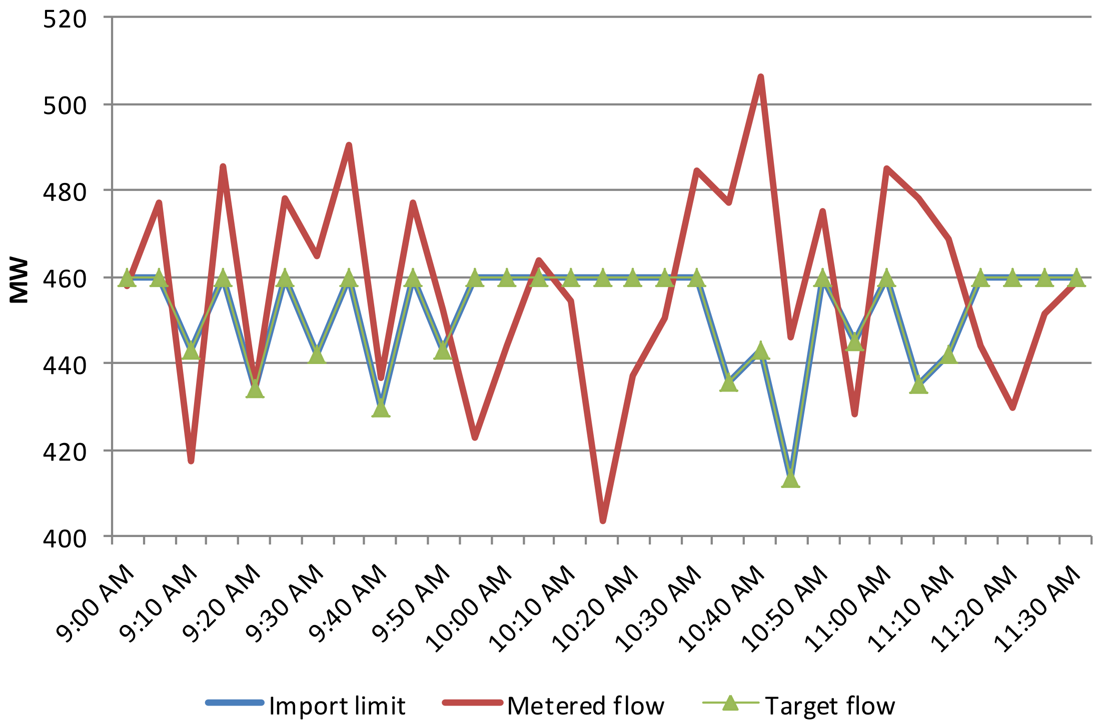
V>S_NIL_HYTX_HYTX is the constraint equation managing the post-contingent load on a Heywood 275/500 kV transformer in the event of the loss of the other Heywood 275/500 kV transformer. The constraint is designed to ensure that the flow through a single transformer remains at or below 460 MW. Although the transformer can manage flow above 460 MW without tripping, if the flow remains above 460 MW for an extended period of time, the transformer's thermal capabilities are reduced (and accordingly the rating is reduced for a number of hours to ensure the transformer is not compromised).

When NEMDE economically dispatches generation every five minute dispatch interval to simultaneously meet demand in every region (while satisfying network conditions), it determines the subsequent flow over an interconnector (i.e. sets a target). The target is usually equal to, or lower than, the limit. However, the actual metered flow (measured at the instant NEMDE calculates dispatch targets) can be higher than target (and the limit).[29] This typically occurs when there is a shortfall of output from generation in the region to meet demand (either through generators not following their dispatch target or demand being higher than anticipated), and higher levels of energy flow across the interconnector to meet that shortfall.

When metered flows into South Australia exceed the maximum import limit (460 MW) by more than 10 MW for a dispatch interval, the V>S_NIL_HYTX_HYTX constraint works by reducing the import limit for the next dispatch interval. The reduction in import limit is equal to the amount flow was above 460 MW (such that if flow was 470 MW, the limit is reduced by 10 MW), up to a capped amount. During April and May 2013, the maximum amount the import limit could be reduced by was 50 MW. Where flows were metered significantly above the target, this limit reduction swings the flow across the interconnector by in excess of 100 MW for the dispatch interval. As soon as metered flows reduce below 460 MW, the import limit increases to 460 MW. The swing this causes in interconnector flows and limits is illustrated in Figure 11 below.

[29] The metered flow can also be lower than the target.

Figure 11: Import limit, target and metered flows across Heywood interconnector on 6 May 2013



Note: Metered flow has been offset by five minutes

The reduction in limit from this constraint is not forecast as NEMDE assumes perfect alignment (that is, NEMDE assumes that demand is as anticipated, generators follow dispatch instructions precisely and the flow across an interconnector will be at target). In the circumstances where South Australia was importing at limit across Heywood for a significant proportion of time, and the South Australian supply curve was steep, any sudden reduction in limit across Heywood had the ability to trigger high prices. Step reductions in the Heywood interconnector limit due to the V>S_NIL_HYTX_HYTX constraint contributed to a five minute price spike in nine out of the eighteen occasions where the dispatch price reached excess of $11 000/MWh.

Following discussions with the AER, on 13 June AEMO reduced the amount by which the import limit can be reduced (by the V>S_NIL_HYTX_HYTX constraint) from 50 MW to 25 MW.[30] This reduces the magnitude of the swings in the interconnector. However, the constraint still continues to reduce limits as soon as metered flow exceeds 470 MW such that swings in the interconnector remain. The AER considers AEMO should examine whether this arrangement for managing misalignment of single dispatch interval target and metered flows for interconnectors is appropriate.

Murraylink

The $2149/MWh spot price in South Australia for 7.30 am on 15 April was associated with a sudden reduction in import limit across the Murraylink interconnector of close to 120 MW in one five minute dispatch interval. The reduction in import limit was not forecast.

This reduction in limit was due to a planned outage of one of the three 220 kV lines (the Buronga to Balranald to Darlington Pt line) which feed into the Eastern end of the Murraylink interconnector. The outage of this line leads to an increase in flows over the two other 220 kV lines connected to the

[30] AEMO is also reviewing similar constraints which effect other interconnectors, including QNI.

interconnector (the Horsham to Waubra line, and the Bendigo to Kerang line) in proportion to the flow across the Murraylink interconnector. This means that the flows on those two lines can approach their limits, which is determined with reference to the contingent loss of the other line. On the day, Murraylink was importing into South Australia at limit. After the outage commenced, an outage constraint managing the overloading of the Horsham to Waubra 220 kV line on the trip of Bendigo to Kerang 220 kV line (V>SML_BUDP_2) bound. In this situation, the only way to reduce flows across the lines that feed into the Eastern end of the Murraylink interconnector is to reduce the import flow across Murraylink. When the constraint bound it caused a sudden reduction in the import limit across Murraylink from 220 MW to 101 MW.

Despite this network outage being planned, the reduction in limit was not forecast in the pre-dispatch system. When a planned outage is undertaken, AEMO invokes particular outage constraints to manage the flows over those transmission elements which are in close proximity to the relevant elements being taken out of service. Although NEMDE uses various inputs to forecast likely flows over the network, it does not factor in changes in energy flows as a result of a planned outage when forecasting whether outage constraints will bind. Accordingly the relevant constraint was not forecast to bind and no reduction in import limit was forecast by NEMDE. The AER has asked AEMO to assess whether there is a way of better modelling outages to ensure that pre-dispatch can accurately forecast the impact of network outages on interconnectors.

When a planned outage is scheduled that is forecast to affect interconnector limits, AEMO invokes ramping constraints. Ramping constraints are designed to avoid a sudden step change in interconnector limits as a result of a planned outage coming into effect, ramping the limits slowly down over a period of time to reduce the magnitude in the change in limit. This reduces the likelihood of high price spikes. As pre-dispatch did not forecast that, under outage conditions, the interconnector limit would need to be reduced to manage the Buronga to Balranald outage, the ramping constraints did not act to reduce the limit. AEMO has made changes to the pre-dispatch version of the relevant constraint to improve its performance.

Generation availability and rebidding

When supply and demand conditions are tight, generators have greater ability to influence price outcomes by engaging in strategic behaviour (such as withdrawing low priced capacity during forecast peak demand periods). The incentive to engage in this behaviour will depend on the extent to which a generator’s capacity is unhedged (such that the generator will reap the benefits of a high pool price).[31]

Rebidding of capacity and/or offer price

During April and May, the AER did not observe a pattern of generators systematically rebidding availability or offer prices to drive the unforecast five-minute dispatch peak price outcomes. Generally, changes in the availability of conventional plant were due to fuel or plant issues. On four occasions, rebidding within the trading interval contributed to a five-minute dispatch price spike. These involved re-pricing relatively small amounts of offered capacity into high price bands: the largest amount of capacity shifted was 95 MW and the smallest amount 30 MW.

However, as noted earlier, April and May did see a general shift in the supply curves of many generators (through withdrawal of capacity or re-pricing of capacity compared to previous years, particularly by Torrens Island), which was a significant factor in prices often lying in the $100/MWh to $300/MWh range. This shift in the supply curve also created the conditions which made the market

[31] Generators may also engage in this type of behaviour as part of a long-term strategy to influence the forward price curve.

more susceptible to five minute dispatch prices spiking close to the market cap in response to minor step changes in supply or demand.

Wind generator output

The availably of wind generation is also a factor in whether high prices occur in South Australia. The availability of wind generation is highly dependent on weather conditions, although strategic pricing behaviour can also be a factor (i.e. a generator may withdraw low priced wind capacity to push up the price).

Actual wind generator output

During the eighteen trading intervals in April and May with a spot price greater than $1500/MWh, the average wind output was 132 MW. Given the installed capacity of 1200 MW, this translates to a capacity factor of just over 10 per cent.

The link between low wind output and high prices is illustrated by Figures 12 and 13. Figure 12 charts actual trading interval output against spot price. Each of the high prices is associated with low levels of wind output, with half of the high prices associated with wind generator output less than 50 MW. Figure 13 shows average spot prices at different wind output levels.

Figure 12: Correlation between spot prices in South Australia and wind generator output during April/May 2013 (log scale)

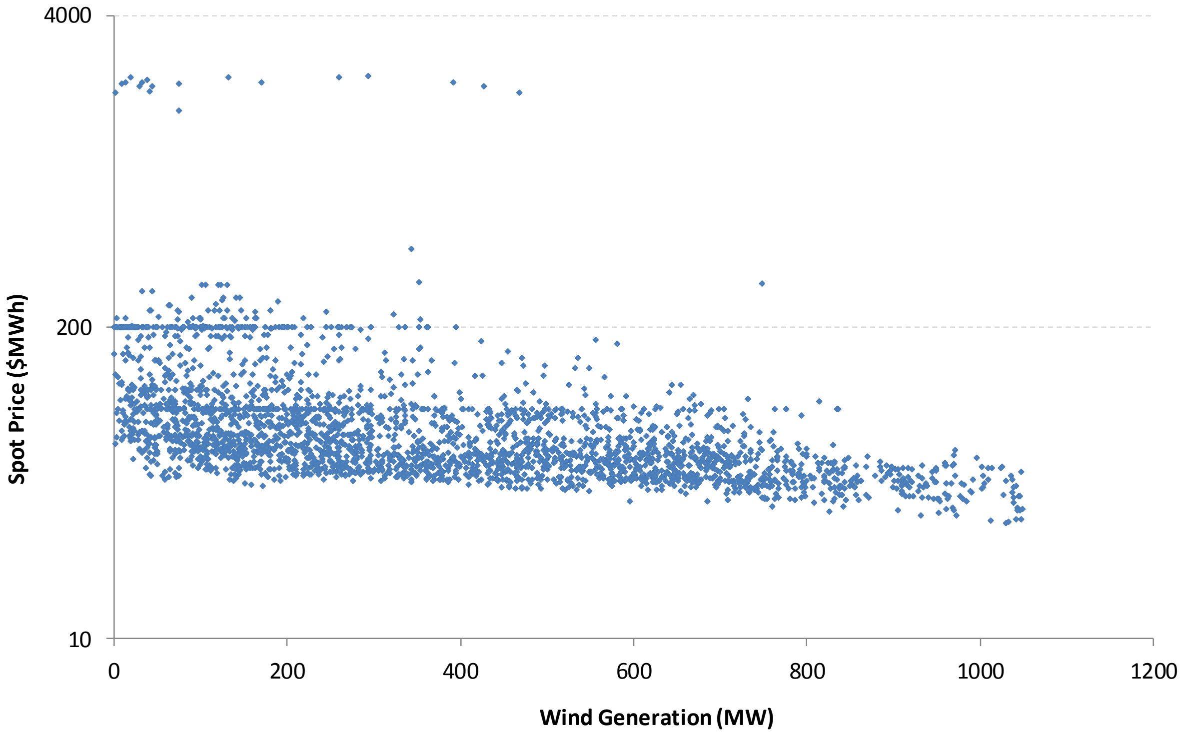
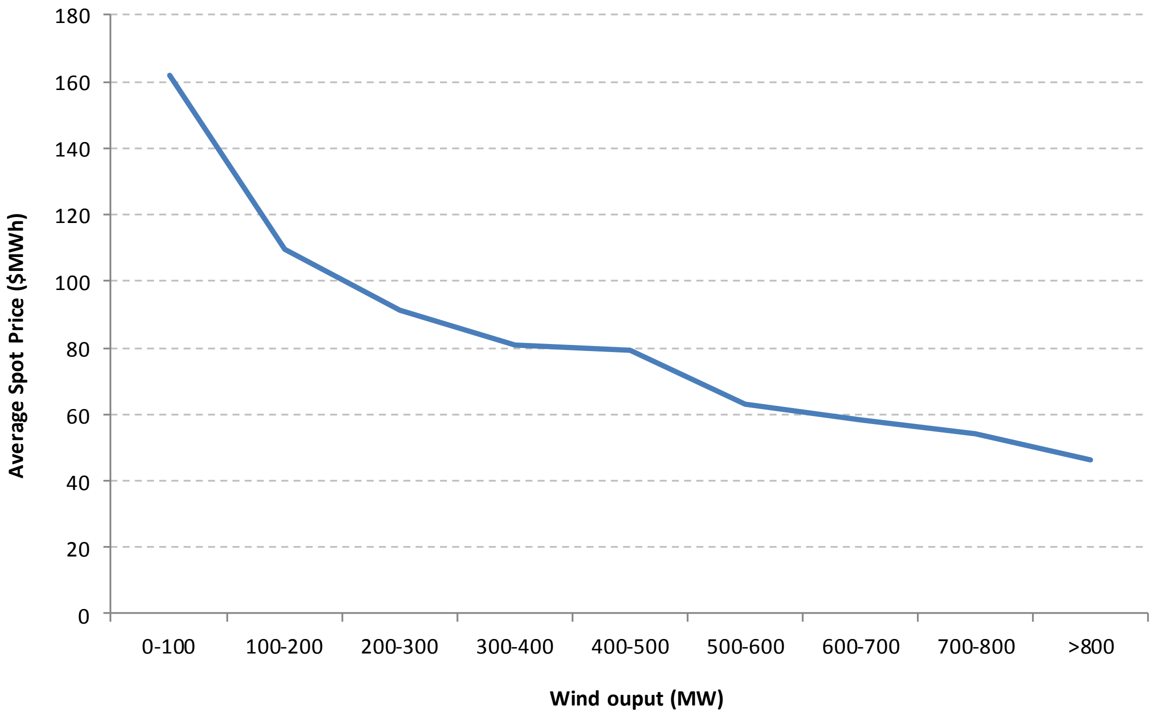


Figure 13: Average spot prices in South Australia per wind generator output level during April/May 2013



Forecast wind generator output

Given the intermittent nature of wind, AEMO uses a forecasting system, the Australian Wind Energy Forecasting System (**AWEFS**), to predict wind generator output over different time horizons (to match AEMO's pre-dispatch and PASA processes).[32] Wind generators advise of their turbine availability and AWEFS uses that availability combined with forecast wind speeds to predict the level of wind generator output.

Depending on the type of wind generator, AEMO uses the forecasts as inputs in its assessments of demand and dispatch targets for scheduled generation.[33] The accuracy of wind forecasts will determine whether more or less generation needs to be dispatched than originally forecast. During the periods where the spot price was above $1500/MWh, semi-scheduled wind generation was lower than that forecast four hours ahead for 80 per cent of occasions, requiring an increase in dispatch of scheduled generation. The forecast error ranged from 4 MW to 206 MW lower than forecast.

[32] AWEFS publishes forecast output on a five minute resolution for five-minute pre-dispatch and thirty minute resolution for pre-dispatch, ST PASA and MT PASA.

[33] The output of non-scheduled wind farms is treated as a reduction in scheduled demand, while output from semi-scheduled wind farms is measured as supplied generation.

Forecast extreme prices

In addition to a large number of un-forecast high spot prices, South Australia also saw a number of forecast spot prices in excess of $10 000/MWh which did not eventuate. Forty nine spot prices across thirteen days were forecast in pre-dispatch systems twelve and/or four hours ahead, usually aligning with the peak demand during the evening. These high prices did not eventuate, with the majority disappearing from pre-dispatch forecasts more than an hour ahead of dispatch.

Forecasting prices

As noted earlier, AEMO publishes information in pre-dispatch systems that forecasts demand levels, price outcomes and dispatch targets for generators. AEMO publishes two pre-dispatch forecasts (one on a half hourly resolution every half hour for the remainder of the current trading day[34] and a five minute pre-dispatch forecast on a five minute resolution for the next hour ahead). This information allows generators and market customers to respond to forecast prices and dispatch targets. Scheduled generators can amend the amount of capacity made available to the market (including whether to start-up or shut down plant) or re-price their offered capacity. Non-scheduled generators can also decide whether to start-up or shut down plant.

Prices being lower than forecast can be due to a number of factors including: demand being lower than forecast, an increase in non-scheduled generation, generators rebidding to increase their available capacity or repricing offered capacity to ensure dispatch; or network limitations easing. Of the 49 spot prices that were lower than forecast in pre-dispatch, thirty six saw demand lower than forecast either twelve and four hours ahead.

Two trends of note the AER identified as contributing to the significant variation between forecast and actual spot prices were that:

- the supply curve during the relevant periods was so steep that relatively minor demand forecast errors resulted in spot prices being much lower than forecast; and
- output from non-scheduled generators materially reduced scheduled demand, moderating spot price outcomes.

To illustrate these trends, a detailed case study of forecast prices for 16 May 2013 is set out below.

16 May 2013

On Thursday 16 May, price in South Australia was forecast to exceed $12 000/MWh for the 6.30 pm to 9.30 pm trading intervals, but these high prices did not eventuate. The high prices were forecast from Wednesday 15 May and remained unchanged in the pre-dispatch forecast system until 6.30 pm on Thursday.[35]

Generator availability or pricing did not materially change in the pre-dispatch timeframe, and actual wind output was close to forecast. Similarly, import limits across Heywood were accurately forecast to be at nominal 460 MW transfer capability. The main reason for the lower than forecast prices on the day was demand forecast inaccuracy in the pre-dispatch system. For the 6.30 pm and 7 pm trading intervals, this inaccuracy persisted right up to dispatch, with the last pre-dispatch run before the trading interval forecasting spot prices in excess of $12 000/MWh. However, although the pre-

[34] From 1 pm, pre-dispatch has forecast values for the following trading day.

[35] This differed from most of the other very high forecast prices during April and May, which left the pre-dispatch forecast a number of hours before the time of dispatch.

dispatch system forecast high spot prices to eventuate for the next trading interval, the five-minute pre-dispatch system forecast demand and dispatch prices at much lower levels. When the forecast systems deliver such different outcomes, this creates challenges for retailers and generators in managing their position.

Pre-dispatch vs five-minute pre-dispatch

The different time horizons of pre-dispatch versus five-minute pre-dispatch can deliver different price forecasts. Pre-dispatch assumes an average demand over the thirty minute trading interval and uses that average against the generator offer stack (and assumed network conditions) to determine a forecast spot price. Five-minute pre-dispatch is more aligned with the dispatch process, providing a more granular forecast, assessing demand on a five-minute basis for the next hour and deriving forecast dispatch prices.

A key reason for the disparity is the different inputs used to forecast demand. In the five minute pre-dispatch system, the first five minutes of the forecast is based on the EMS neural network demand forecaster with the remaining 11 dispatch intervals based on the average demand change for the relevant dispatch interval over the previous two weeks. In comparison, the 30 minute pre-dispatch uses the 50 per cent probability of exceedence demand in a region for a particular trading interval.[36]

Table 8 demonstrates the discrepancy between the thirty minute and five minute pre-dispatch systems. The table compares the demand and price forecasts delivered by the pre-dispatch and five-minute pre-dispatch systems at 6 pm for the next hour ahead.

Table 8: Actual and forecast demand and prices (30 minute and 5 minute pre-dispatch) for 16 May in South Australia (6 pm pre-dispatch run)

	Time (pm)	30 minute pre-dispatch forecast at 6 pm		5 minute pre-dispatch forecast at 6 pm		Actual outcomes	
		Demand (MW)	**Price ($/MWh)**	**Demand (MW)**	**Price ($/MWh)**	**Demand (MW)**	**Price ($/MWh)**
	6:05	-	-	1729*	91*	1729	91
	6:10	-	-	1749	91	1749	91
	6:15	-	-	1774	201	1793	300
	6:20	-	-	1789	201	1798	91
	6:25	-	-	1792	201	1796	91
	6:30	-	-	1793	201	1781	91
Trading interval	**6:30**	**1830**	**12 190**	**1771^**	**164^**	**1774**	**126**
	6:35	-	-	1787	201	1794	91
	6:40	-	-	1773	201	1810	63
	6:45	-	-	1772	201	1809	64
	6:50	-	-	1779	300	1805	300
	6:55	-	-	1767	201	1802	300
	7:00	-	-	1757	201	1812	300
Trading interval	**7 pm**	**1886**	**12 191**	**1773^**	**218^**	**1805**	**186**

* The five minute pre-dispatch run at 6 pm uses the actual dispatch values for the 6.05 pm dispatch interval. Subsequent runs of five minute pre-dispatch not included.
^ Calculated based on the average of the six dispatch intervals.

[36] These forecasts are based upon half hourly historical metering records of as-generated demand, which are assumed to include electricity consumption by normally on dispatchable loads and which also include interconnector flow.

Table 8 demonstrates that the five minute pre-dispatch forecasts were closer to actual outcomes for the 6.30 and 7 pm trading intervals than the pre-dispatch forecast. However, Table 8 also illustrates that forecast 30 minute demand for the 6.30 pm trading interval was only 59 MW (or 3 per cent) higher than the actual demand. The 6.30 pm and 7 pm pre-dispatch runs for the next hour ahead are shown in Attachment A.

The fact that a 59 MW demand error can cause a divergence of $12 000/MWh between pre-dispatch forecast and actual spot prices demonstrates how steep the supply curve was on the day, with no capacity priced between $300 and $11 000/MWh for the 6.30 pm trading interval. In those circumstances, minor differences between demand as forecast in the pre-dispatch and five minute pre-dispatch systems and actual scheduled demand creates challenges for generators in deciding how to operate plant. On this occasion, several peaking plant were generating in anticipation of a potential extreme spot price. Those extreme spot prices did not eventuate. The actual spot price may, for some plant, have been below their fuel cost.

Role of non-scheduled generation

The most significant demand forecast error observed close to dispatch was for the 7.30 pm trading interval. There was a 156 MW over forecast (or 9 per cent forecast error) at the 6.30 pm pre-dispatch run and 100 MW over forecast (6 per cent error) at the 7 pm pre-dispatch run. The corresponding five minute pre-dispatch runs also over-forecast for the same time period (see Tables A1 and A2 in Attachment A). These demand errors were largely due to non-scheduled generation.

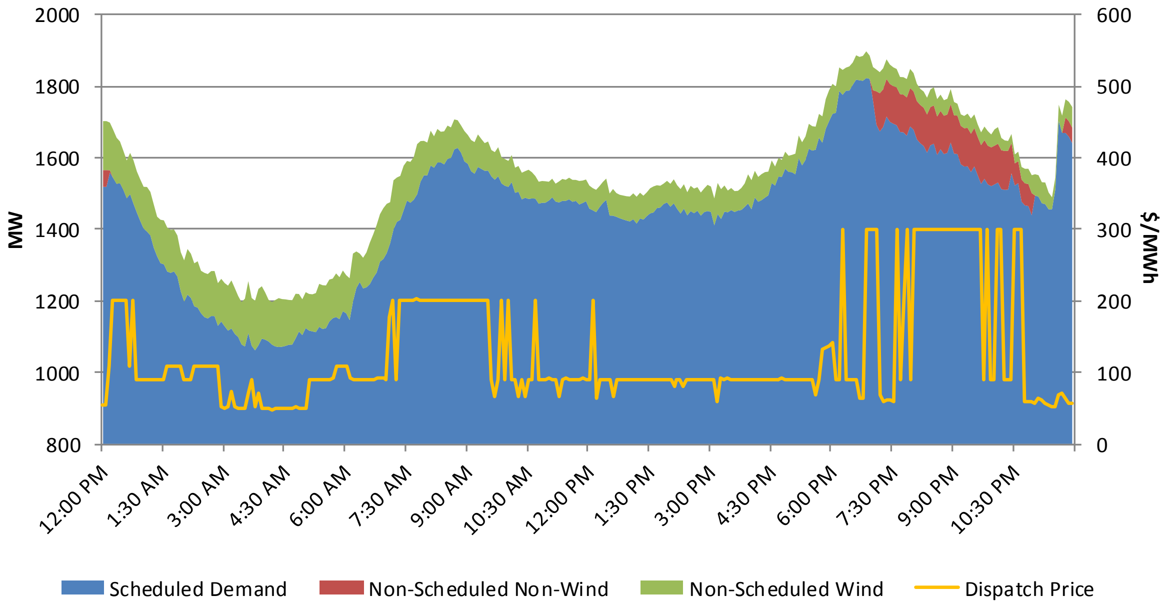
All generators in excess of 30 MW have to be registered with AEMO as scheduled generators for central dispatch by AEMO. Scheduled generators are obligated to advise AEMO of their available capacity and to offer that capacity in at different price bands for economic dispatch by NEMDE. Generators which are smaller than 30 MW can opt to register as non-scheduled generation, which means that their output is not controlled by NEMDE. Market non-scheduled generators still receive the spot price for their output.

Non-scheduled generation is treated as a reduction in demand. As non-scheduled generators do not bid in their available capacity for dispatch, NEMDE is not able to forecast their likely output level. The exception is for non-scheduled wind farms, which are required to bid turbine availability to AWEFS, which delivers a likely output level. AEMO uses actual metered values to determine the likely output levels for non-wind non-scheduled generation for dispatch and five minute pre-dispatch forecasts (on an assumed persistence basis). Pre-dispatch demand forecast systems use historic data (which may or may not have non-scheduled non-wind generation).

Accordingly, non-scheduled non-wind generation can cause material demand forecasting errors where:

- the historical demand data used by AEMO as an input for pre-dispatch demand forecasts did not include online non-scheduled non-wind generation;
- non-scheduled non-wind generation starts or significantly increases output.

Figure 14: Demand and output via generation type in South Australia on 16 May 2013



Source: AEMO

Figure 14 above demonstrates the significant impact that non-scheduled non-wind generation can have on scheduled demand. The chart shows the level of generation output by non-scheduled generation (wind and non-wind), the level of scheduled demand (demand met by dispatched scheduled and semi-scheduled generation and imports) against the five minute dispatch price. The rapid increase in non-scheduled non-wind generation from around 7 pm (which is the beginning of the 7.30 pm trading interval) explains why the pre-dispatch and five minute pre-dispatch forecasts were materially away from scheduled demand for that trading interval. The red section represents the output of the non-scheduled non-wind generation units owned by Infratil, which are the largest in South Australia. Together, the Infratil Angaston, Pt Stanvac and Lonsdale units have a registered capacity of 128 MW. Infratil has a retail arm, Lumo, which has a retail presence in South Australia.

During the April-May period, there were a significant number of occasions where non-scheduled generation increased in response to high dispatch prices, which had the effect of lowering the price in subsequent intervals. Over the two months, there were 14 days when spot prices exceeded $500/MWh. On 10 of these 14 days, there was an apparent non-scheduled non-wind generation response, which had the effect of lowering price through reducing the need to dispatch high priced scheduled generation.

The main reason that generators less than 30 MW in size are exempted from being scheduled by AEMO is that their output is assumed to have relatively little impact on price outcomes or system security in the normal course of events. However, where supply/demand conditions are tight, non-scheduled non-wind generation in South Australia can significantly impact on market outcomes. Indeed, non-scheduled non-wind generation played a key role in ensuring sufficient generation reserves on 3 and 4 June.

Conclusion

Market outcomes in South Australia during April and May 2013 diverged significantly from those in previous years and from market expectations. Spot prices in South Australia during April and May were the highest since the summer of 2011, notwithstanding the lower levels of demand. Despite the large amount of installed capacity in the region, supply conditions in South Australia during April and May were very tight with import levels the highest for six years. Tight supply conditions were evidenced by multiple days of lack of reserve conditions in South Australia, with the lowest levels of reserves for four years. Nevertheless the market was at all times able to deliver adequate generation to meet demand.

The supply conditions were largely due to three major generation owners, Alinta, GDF Suez and AGL, making a commercial decision to reduce the amount of available capacity to the market (or reducing the amount of low-priced capacity). Historically the majority of this capacity had been offered to the market at low prices. When conventional generation withdraws from the market, South Australia cannot rely on the significant amounts of installed wind capacity to deliver high output when weather conditions are not optimal. These factors meant that South Australia was heavily reliant on imports to deliver low priced energy into the region.

In these circumstances, issues which are relatively minor in the overall scheme of the market can contribute to high spot price outcomes. During April and May, South Australia saw a number of high prices associated with step changes in demand associated with hot water load and minor design flaws in the tools used to manage network limitations impacting interconnector limits. The AER has worked closely with AEMO to improve market systems to lessen the impact of these issues.

Similarly, relatively small forecasting errors caused by the design of the forecast system or non-wind non-scheduled generation can deliver false market signals (both high prices which do not eventuate as well as un-forecast high prices) where there is such a finely tuned balance. These factors increase the risk profile for generators and retailers operating in the region.

Based on the period reviewed, it did not appear that merchant generators were seeking to capitalise on the tight supply conditions to spike the pool price to high levels through strategic behaviour. Instead, the general withdrawal of capacity by generators over the period created tight supply conditions that made the market susceptible to spikes caused by a range of different factors.

The AER will consider whether further refinements to the market design or operation might be appropriate to alleviate any inefficiencies identified, particularly around the inaccuracy of forecasts. The AER will also continue to work with AEMO and SA Power Networks to seek to mitigate some of the specific issues identified.

Appendix A: Forecast and actual price outcomes for 16 May 2013

Tables A1 and A2 compare the demand and price forecasts delivered by the pre-dispatch and five-minute pre-dispatch systems with actual outcomes. Table A1 shows the forecasts as at the 6.30 pm run for the next hour out.

Table A1: Actual and forecast demand and prices (30 minute and 5 minute pre-dispatch) for 16 May in South Australia (6.30 pm pre-dispatch run)

	Time (pm)	30 minute pre-dispatch forecast at 6.30 pm		5 minute pre-dispatch forecast at 6.30 pm		Actual outcomes	
		Demand (MW)	**Price ($/MWh)**	**Demand (MW)**	**Price ($/MWh)**	**Demand (MW)**	**Price ($/MWh)**
	6:35	-	-	1794*	91*	1794	91
	6:40	-	-	1780	91	1810	63
	6:45	-	-	1778	91	1809	64
	6:50	-	-	1785	91	1805	300
	6:55	-	-	1773	91	1802	300
	7:00	-	-	1763	91	1812	300
Trading interval	**7 pm**	**1844**	**12 190**	**1779^**	**91^**	**1805**	**186**
	7:05	-	-	1748	91	1747	300
	7:10	-	-	1747	91	1670	68
	7:15	-	-	1745	91	1633	60
	7:.20	-	-	1743	91	1669	61
	7:25	-	-	1733	91	1686	61
	7:30	-	-	1721	91	1682	60
Trading interval	**7:30**	**1837**	**12 190**	**1740^**	**91^**	**1681**	**102**

* The five minute pre-dispatch run at 6:30 pm uses the actual dispatch values for the 6.35 pm dispatch interval. Subsequent runs of five minute pre-dispatch not included.
^ Calculated based on summing and averaging the six dispatch intervals.

Table A2 shows the forecast price and demand at the 7 pm run for the next hour out.

Table A2: Actual and forecast demand and prices (30 minute and 5 minute pre-dispatch) for 16 May in South Australia (7 pm pre-dispatch run)

	Time (pm)	30 minute pre-dispatch forecast at 7 pm		5 minute pre-dispatch forecast at 7 pm		Actual outcomes	
		Demand (MW)	**Price ($/MWh)**	**Demand (MW)**	**Price ($/MWh)**	**Demand (MW)**	**Price ($/MWh)**
	19.05	-	-	1747*	300*	1747	300
	19.10	-	-	1745	300	1670	68
	19.15	-	-	1744	300	1633	60
	19.20	-	-	1741	300	1669	61
	19.25	-	-	1732	300	1686	61
	19.30	-	-	1720	300	1682	60
Trading interval	**19:30**	**1797**	**300**	**1738^**	**300^**	**1681**	**102**
	19.35	-	-	1703	300	1681	300
	19.40	-	-	1701	300	1670	91
	19.45	-	-	1696	300	1636	201
	19.50	-	-	1684	300	1636	300
	19.55	-	-	1675	300	1630	91
	20.00	-	-	1671	300	1654	300
Trading interval	**20:00**	**1771**	**300**	**1688^**	**300^**	**1651**	**214**

* The five minute pre-dispatch run at 7 pm uses the actual dispatch values for the 7.05 pm dispatch interval. Subsequent runs of five minute pre-dispatch not included.
^ Calculated based on summing and averaging the six dispatch intervals.