

# Electricity market power in South Australia

A report for the Energy Users Association of  
Australia



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## **EXECUTIVE SUMMARY**

Many electricity users consider that electricity prices would be lower if the National Electricity Market (NEM) was more competitive. However there is little detailed analysis of the competitiveness of the NEM. Is there a competition problem, and if so how bad is it, and what has it meant for consumers and producers? Can changes to the design and regulation of the NEM be justified to deal with it?

The Energy Users Association of Australia has commissioned this research paper to analyse these issues with a focus specifically on South Australia.

The analysis in this document has concluded that concerns over the competitiveness of the wholesale electricity market in South Australia over the period from 2008 to 2011 seem to be well founded.

Over this period, higher average spot prices in South Australia, compared to other parts of the NEM, are attributable to a few half-hourly settlement periods typically in the last few weeks of January or first two weeks in February during which prices reached extremely high levels.

The analysis in this paper suggests that spot market prices in these periods reflect the exercise of market power rather than scarce supply. The South Australian electricity system appears to have ample capacity even at the times of peak demand.

### **Evidence of the exercise of market power in South Australia**

The level of “spare” capacity in a market at the times of extremely high prices can be used to draw conclusions on whether those high prices reflect the exercise of market power, or whether they reflect the reasonable outcome in a market where there is scarcity of supply.

If the market is competitive, generators would seek to maximise production when prices are higher than their production costs. If the evidence is that they consistently have spare capacity when prices are extremely high, then this can be taken as evidence that they have withheld capacity from the market (or, equivalently, only made it available to the market at much higher prices).

The analysis of the very high priced settlement periods in South Australia suggest that there has not been a scarcity of supply at these times. When extreme prices occurred, typically (but not always) at times of very high demand, there were still substantial amounts of generating capacity that could have been made available to the market, but was not. For example, in 2008 for the half hourly settlement periods when the South Australian spot prices were at the Market Price Cap of \$10,000 per MWh, there was on

average 667 MW of generating capacity at the Torrens Island Power Station that was not producing electricity. Similar outcomes occurred in 2009 and 2010.

In 2011 however the situation changed. This time the Torrens Island Power Station generating units were producing at or near their full capacity, while the brown coal generators (Playford and Northern) had substantial amounts of capacity unavailable (on average 423 MW) when the market price was at or near the Market Price Cap.

For 2012 to-date, the highest price in half-hourly settlement periods in the spot market has been just \$147/MWh – a fraction of the peak price in the previous 5 years – suggesting generators have not exercised market power in 2012.

### **Impact of the exercise of market power on consumers**

The effect of extreme high spot prices in South Australia, on average annual spot prices in South Australia, has been particularly significant. In some years, the extreme prices that occurred for less than 0.4% of the year, more than doubled the average annual spot price from what it otherwise would have been.

The extreme spot prices in South Australia have also resulted in a significant divergence between average prices in South Australia and those in other NEM regions. Specifically, while spot prices in South Australia have typically been comparable to the spot prices in the other regions of the NEM for 99.6% of the half-hourly settlement periods in a year, the extreme prices in South Australia in a few settlement periods have raised the average annual spot prices (in South Australia) by more than 50% when compared to the rest of the NEM, for the period from 2007 to 2011.

The extent to which spot price outcomes have affected electricity consumers depends to a large extent on outcomes in contract markets (for non-household consumers) and prices for residential consumers on standing contracts with AGL (as determined by the Electricity Supply Commission of South Australia).

The data suggests that contract market outcomes have tended to follow spot market outcomes, so that outcomes in spot markets have been passed through to end users in due course.

### **Impact on non-residential electricity consumers**

With regard to contract market outcomes, other than in the first quarter of each year, the quarterly Base futures contract prices in South Australia have been predictable and comparable to prices in other regions of the NEM over the period from 2007 to 2011. The price of this contract has seemed to roughly match the outcomes in the spot market over the same time periods.

However, quarterly Base futures prices in the first quarter of each year have been substantially higher in South Australia than in other regions of the NEM in the period from 2008 to 2010. This reflects the significantly higher average spot prices in South Australia in the first quarter of each year compared to the rest of the NEM.

The outcomes in 2008, suggest that the contract market failed to fully recognise the impact of the exercise of market power in that year, on average spot prices. Since then, and up to 2012, however, the quarterly Base futures prices have matched average spot prices reasonably accurately. In 2012, the quarterly Base futures price for the first quarter have been substantially higher than the spot price reflecting the inability of the contract market to anticipate the absence of market power in the spot market in the first quarter of 2012. Broadly, however, the conclusion on contract market outcomes is that for several years, the futures contract market has reasonably accurately anticipated spot market outcomes

### **Impact on residential electricity consumers**

With regard to residential electricity consumers, the picture is fairly clear: the Essential Services Commission of South Australia calculates the prices that AGL is able to charge small consumers on standing contracts in South Australia. Retailers compete, possibly offering discounts to these tariffs, in order to attract customers. The AEMC's report<sup>1</sup> on retail electricity prices shows that in the calculation of residential electricity prices in South Australia (based on AGL's standing contract), wholesale electricity prices are higher (typically about 20%-30%) in South Australia than in other NEM regions.

### **Impact of the exercise of market power on producers**

The extreme prices in a few settlement periods has made the least difference to wind farms, causing their spot market revenues to rise by around 25% from what they otherwise would have been. For brown coal generators, Combined Cycle Gas Generators (CCGT) and Torrens Island Power Station B ("Torrens B"), the high priced settlement periods roughly doubled the average annual spot market revenues. For the Open Cycle Gas Turbines (OCGT), and Distillate plant, the high priced events accounted for almost all their spot market income.

For those generators that were actually exposed to spot prices (i.e. had not entered into financial contracts to hedge spot prices) the high prices will have significantly improved their profitability. For example, for Torrens B the high priced events delivered revenues

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<sup>1</sup> AEMC, November 2011. "Possible future Retail Electricity Price Movements: 1 July 2011 to 30 June 2014.

of \$332m over the four years. Per MW of capacity, this translates into about \$0.7m per MW of capacity.

The high priced events from 2008 to 2011 delivered \$374m of spot market revenue for the 729 MW of OCGT plant in South Australia. Assuming, hypothetically, that this plant was unhedged (i.e. fully exposed to spot prices), this translates into revenue of \$0.5m per MW, a little bit less than the OCGT plant would have cost to build. To put this another way, less than two years of these extreme spot prices would have allowed the owners of this OCGT plant to recoup most of their capital outlay. This is for generating plant that has an expected operating life of many decades.

Most of the South Australian generating capacity will have been hedged against the spot price either by entering into contracts, or by virtue of vertical integration with retailers.<sup>2</sup> In practice therefore only some of the generation capacity (possibly most of the output from the Torrens Island Power Station) would have received the full benefit of the extreme spot prices in the period to the end of 2010.

However, as discussed, higher spot prices have flowed into higher contract prices (and regulated tariffs), and in this way generators (and retailers) have, over time, benefitted from the higher spot prices that occurred in the period from 2008 to 2011.

### **Implications and next steps**

Average electricity demand appears to be declining gradually in South Australia as in other parts of the NEM. Peak demand is growing slowly, at best. If this continues, the gap between supply and demand will continue to widen. This will make the exercise of market power more difficult. If the spot market continues to exhibit the competitiveness it has shown in 2012, lower wholesale prices can be expected in future compared to the outcomes in the period from 2008 to 2011, notwithstanding the introduction of greenhouse gas emission charges.

However, the outcomes over the period from 2008 to 2011 are remarkable and merit detailed study to fully understand their cause and effect. For example, the extreme spot prices evident in South Australia from 2008 to 2011 have not been experienced in other electricity markets in the world. Has the very high Market Price Cap in the NEM provided excessive incentive to generators to exercise market power?

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<sup>2</sup> If a generator is part of a vertically-integrated business, the higher spot prices received by the “generator” side of the business would have been off-set by the higher spot prices to be paid by the “retail” side of the business.

We would like to stress that the analysis presented in this paper in respect of the flow-through of spot market outcomes should be considered to be preliminary. The way that outcomes in the spot market affects producers and consumers is not certain because producers, retailers and consumers enter into various forms of contract, often independently of the spot market. The observations in this paper on the way that spot market outcomes flow through to retail customers would be better informed through access to confidential information in the possession of generators and retailers and some large energy users, on electricity contracts.

Several possibilities might be considered to address market power concerns. The least intrusive approach would be to strengthen transparency and market monitoring, perhaps through greater disclosure of contract positions or the actual margins that retailers are achieving.

More radical approaches might be structural constraints (limits on generator-retailer vertical integration, mandatory contracting of a percentage of production, mandatory sale of generation rights such as occurred in Alberta in the 1990s) or changes to the market design (such as lower Market Price Caps, tighter Cumulative Price Thresholds, or the introduction of capacity payments). Any changes should be carefully analysed to assess the best response and minimise the likelihood of unexpected outcomes.

Finally, while this paper has focussed on South Australia, high spot prices in a few settlement periods have also had a significant impact on average prices in other regions of the NEM. Over the period from 2007 to 2011, prices in the 72 highest priced settlement periods in each year caused the average annual prices in Victoria, NSW, Queensland and Tasmania to rise by 30%, 37%, 32% and 17% respectively. The analysis in this paper should be extended to those regions to assess the extent to which similar observations on outcomes in those regions might be made, as have been made in this paper for South Australia.



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# 1 Introduction

Many electricity users consider that electricity prices would be lower if the National Electricity Market (NEM) was more competitive. However there is little detailed analysis of the competitiveness of the NEM. Is there a competition problem, and if so how bad is it, and what has it meant for consumers and producers? Can changes to the design and regulation of the NEM be justified to deal with it?

The Energy Users Association of Australia has commissioned this research paper to analyse these issues. The analysis in this document has concluded that concerns over the competitiveness of the wholesale electricity market in South Australia over the period from 2008 to 2011 seem to be well founded.

The objective of this analysis is to provide information that electricity users, market participants, policy analysts and regulators might find useful to inform their perspectives, and in their consideration of possible solutions.

The next section presents summary NEM-wide information on demand, investment, spot and futures prices. This provides general context and draws attention to the situation in South Australia in particular. The third section presents evidence of the exercise of market power in South Australia from 2008 to 2011 and analyses what this has meant for electricity consumers and producers. The last section summarises the main points and presents a preliminary discussion of some of the issues and questions arising from this analysis.

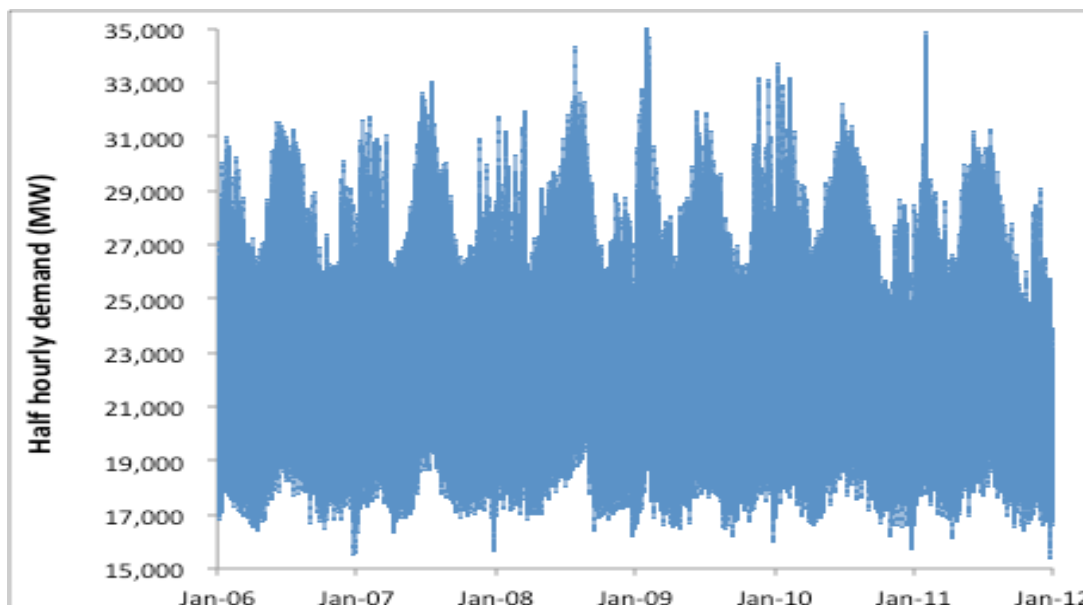
## 2 NEM overview: demand, investment, spot and futures prices

This section establishes the context to the exercise of market power in the NEM by presenting summary NEM-wide data on half-hourly demand, investment in NEM-dispatched generation, half-hourly spot prices and futures (contract) prices.

### 2.1 Demand

Figure 1 shows the half-hourly simultaneous demand in the NEM over the six years from 2006 to 2011. The chart shows that demand has not grown over this period.

**Figure 1. Half-hourly simultaneous NEM-wide demand from 2006 to 2011**



*SOURCE: Data from NEM-Review™, CME analysis*

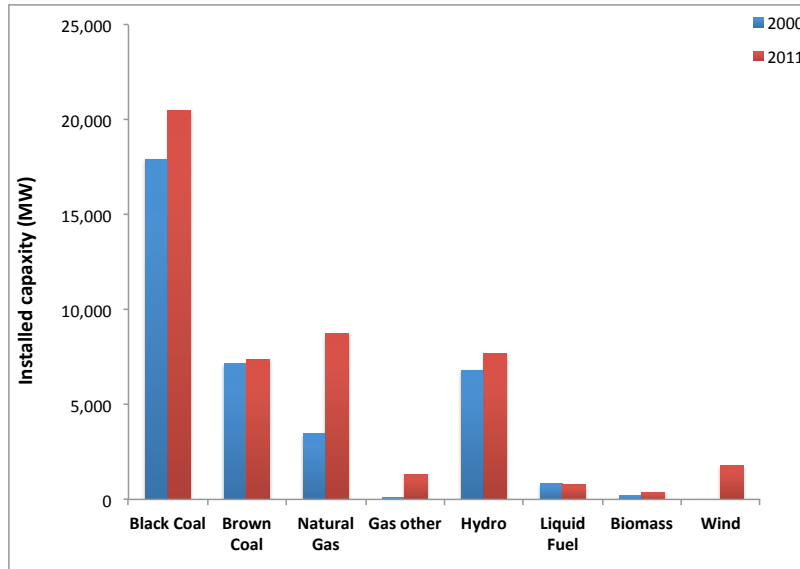
The highest half-hourly NEM-wide peak demand was reached in 2009. The peak demand over the last six year period – 35,437 MW – is about 2/3rds of the average annual demand of 23,342 MW over this period.

The highest demands in the NEM, typically occur in the last two weeks of January and first two weeks in February. This corresponds to high summer temperatures, the return to school and recommencement in industry and commerce after the summer holidays. Only 21 of the highest 200 half hourly demands in the last six years occurred outside of this period. However, despite the extreme summer peaks, average winter demand is higher than average summer demand.

## 2.2 Investment

Figure 2 shows the installed capacity in the NEM, by technology type, in 2000 and 2011. The greatest growth has been in gas generation from both conventional gas sources and coal seam methane (labelled “Gas other” in the figure).

**Figure 2. Installed generating capacity in the NEM in 2000 and 2011**



Source: AEMO Electricity Statement of Opportunities 2011. Figure 2-3 p. 2-6

The bulk of the gas generation investment has been in Open Cycle Gas Turbines (OCGT) which is plant that can be brought into operation quickly and provides a way to reduce risks associated with extremely high prices for short periods.

There have been small additions in brown coal, hydro, and biomass generation capacity. The additional capacity in wind generation is approximately equivalent to the additional capacity in black coal generation (which is mainly the Kogan Creek power station that was planned and under construction before the NEM was established).

The aggregate installed capacity in the NEM has risen a little over 12,000 MW over this period. The Bureau of Resource and Energy Economics<sup>3</sup> reported a further 1,829 MW of “advanced projects” in October 2011 – some of which have since been commissioned. Whereas there has been a healthy increase in supply, the aggregate NEM-wide peak demand only grew from approximately 28,502 MW in 2001 to 34,939 MW in 2011 (after adjusting for the entry of Tasmania into the NEM in 2006). The average demand has grown from about 21,120 MW per hour in 2001 to 22,978 MW per hour in 2011.

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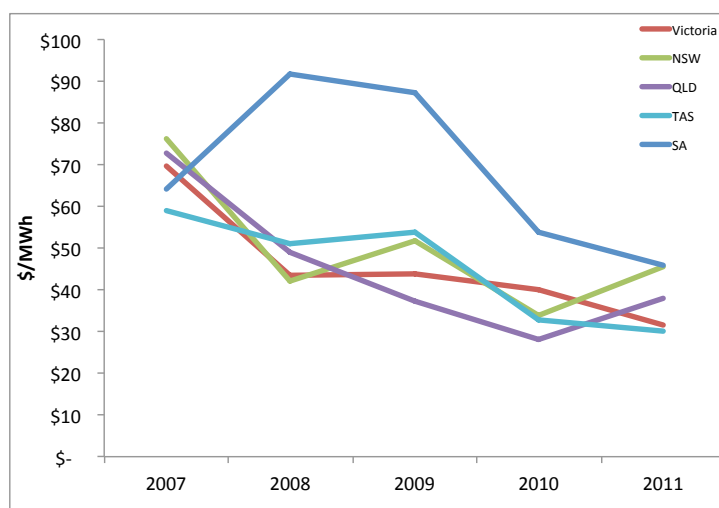
<sup>3</sup> Bureau of Resources and Energy Economics, October 2011. “Major electricity generation projects”.

Clearly supply has grown more strongly than demand, and hence the surplus of supply over demand (both average and peak) has grown over this period. This is likely to be the cause, in part, of declining average prices particularly outside the peak demand periods where the exercise of market power is not possible (or at least very much more difficult).

## 2.3 Spot prices

Figure 3 shows the demand-weighted annual average prices in the NEM from 2007 to 2011. Although there can be significant regional variation in half-hourly prices over the course of a year, annual average demand-weighted prices have been reasonably similar in most regions (other than South Australia), despite varying mixes of fossil fuel and renewable energy sources in the different regions.

**Figure 3. Demand-weighted average annual prices in the NEM**

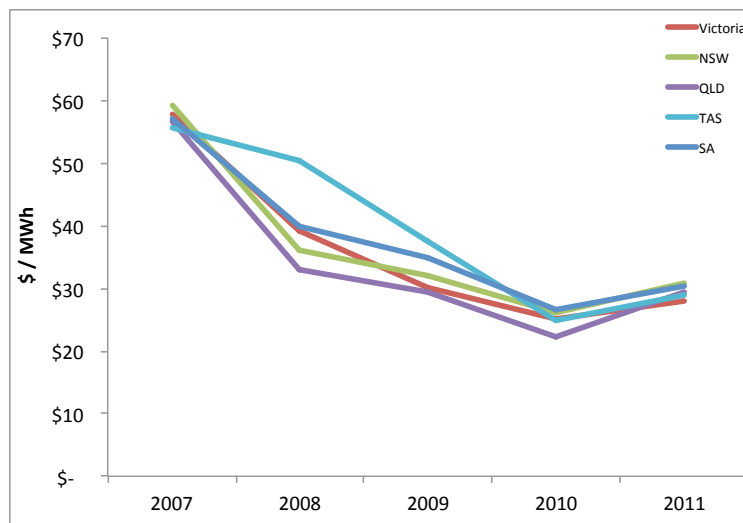


SOURCE: Data from NEM-Review<sup>TM</sup>, CME analysis

The large difference between prices in South Australia and the other NEM regions shown in Figure 3 over the period from 2008 to 2010 is explained by exceptionally high prices in a few settlement periods – typically above several thousand dollars per MWh. This is the focus of examination in the next section.

Figure 4 has excluded the prices in the 72 highest price settlement periods (which in total is 0.4% of the year) in each NEM region for each year to show the annual average prices in each NEM region for the remaining 99.6% of the year. This shows that all NEM regions (other than Tasmania in 2008) had similar annual average prices.

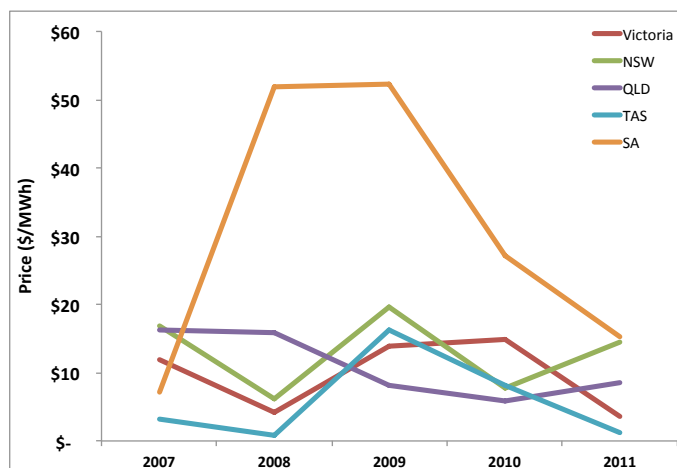
**Figure 4. Demand-weighted average prices excluding the highest priced 72 settlement periods in each year**



SOURCE: Data from NEM-Review™, CME analysis

Figure 5 examines the effect that prices in the highest 72 settlement periods in each year have had on overall average prices in each NEM region. It shows the exceptional outcomes in South Australia from 2008 to 2010. Although the effect of the extreme prices in South Australia stand out, the outcomes in the other NEM regions are nonetheless significant: prices in the highest priced 72 settlement periods resulted in average annual prices that were around \$15 / MWh to \$20 / MWh higher than they otherwise would be in some years.

**Figure 5. Change in annual average prices attributable to prices in the highest 72 settlement periods in each year**



SOURCE: Data from NEM-Review™, CME analysis

Over the period from 2007 to 2011, the 72 highest priced settlement periods in each year caused the average annual NEM prices in Victoria, NSW, Queensland and Tasmania to rise by 30%, 37%, 32% and 17% respectively. In other words, if not for the prices in the highest 72 settlement periods (0.4% of the year), average prices in NSW, VIC and QLD

over the period from 2007 to 2011 would be around a third lower than they have been. In TAS they would be about a fifth lower and in South Australia they would be about half as high.

To be clear, these are statements of fact. It should not be taken from this that we imply that prices *should* necessarily be lower. If prices are higher to reflect scarce supply, then such prices are a legitimate market outcome. The next section examines the situation in South Australia to determine whether this is the case.

## **2.4 Futures prices**

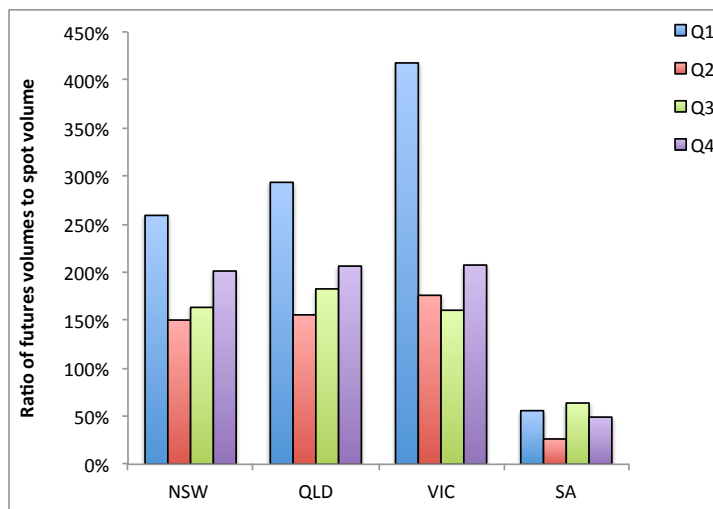
The NEM is a mandatory, centrally settled spot market – all generators above 30 MW are required to sell their production to the NEM. Market participants (generators, retailers, and some very large customers that buy directly from the spot market rather than through retailers) are able to hedge themselves against the extremely high prices in the NEM by entering into financial contracts that are referenced to the spot price (half-hourly settlement price) in the NEM.

Most such financial contracts are traded through the Sydney Futures Exchange. The remaining third is either negotiated bi-laterally between market participants or through intermediaries. Contracts can take various forms. Commonly traded futures contracts are quarterly / annual “Base” contracts. These specify a fixed price per MW for every hour for the quarter / year.

Volumes and price data for quarterly Base futures contracts traded through the Sydney Futures Exchange is publicly available. We have analysed these data to make general observations on contract market outcomes. Figure 6 shows the annual volume of Base futures contracts sold for each quarter of 2011 for each region of the NEM, as a percentage of the physical electricity transacted through the NEM for that region for that quarter. The data shows that the volume of “Base” quarterly futures contracts is comparable in NSW, QLD and VIC for all but the first quarter. For the first quarter of 2011, the VIC futures volumes are considerably higher than in other NEM regions. The percentage ratio of contracts traded in South Australia (to physical demand in South Australia) is around a quarter of the volume in other NEM regions.



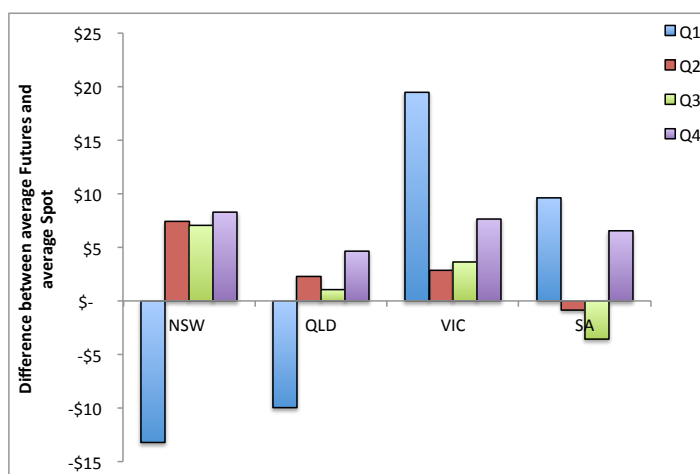
**Figure 6. Percentage ratio of the volume of “Base” quarterly futures contracts to NEM quarterly demand for each quarter of 2011**



SOURCE: Data from NEM-Review™, CME analysis

Figure 7 compares the prices in Base quarterly futures contracts with the average spot price for each quarter of 2011. The Base futures price is the weighted average price (weighted by volume of contracts sold).

**Figure 7. Difference between the average price of “Base” futures contracts compared to the average spot price for each quarter in 2011**



SOURCE: Data from NEM-Review™, CME analysis

The data in Figure 7 shows that there is a reasonably significant difference, particularly in the first quarter of the year, between the average spot price and the average base contract price: in NSW and QLD, the contract price was substantially below the average spot price, while in VIC it was substantially higher. These significant differences reflect the difficulty in predicting average Q1 futures prices in view of the impact of extreme spot prices which occur, as we noted earlier, predominantly in the last two weeks of January and first two weeks of February.

The data in Figure 7 also shows that the difference between Base quarterly futures and quarterly spot prices in the remaining three quarters of the year is relatively small in all NEM regions. This reflects the greater competitiveness and hence predictability of spot prices in the remaining three quarters of each year.

### 3 The exercise of market power in South Australia

The previous chapter drew attention to the impact on average annual prices in South Australia particularly in the period from 2008 to 2010, of extreme prices that occurred in a few settlement periods in these years. This section focuses in more detail on the situation in South Australia to establish whether it would be reasonable to conclude that these outcomes reflect the exercise of market power or whether the spot prices properly reflects scarcity in the South Australian electricity market.

The electricity market in South Australia is the second smallest of the five regional electricity markets in the NEM. The South Australian power system has significant inter-annual demand variation. Minimum annual demand is around 1,000 MW, the highest ever peak demand was around 3,400 MW and average annual demand is around 1,500 MW - about half peak demand. The South Australia power system is connected to the Victorian power system through two separate interconnectors that together have sufficient interconnector capacity to meet around a third of the average demand in South Australia (or a sixth of the peak demand).

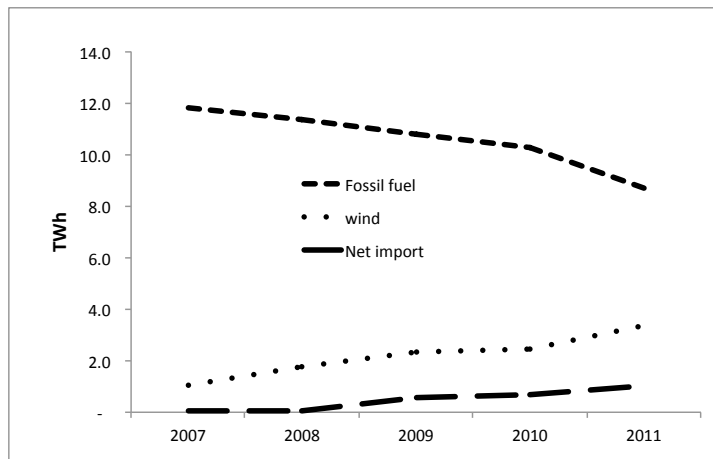
Electricity production in South Australia is dominated by conventional fossil fuel plant. There is 780 MW of brown coal generation from units that were commissioned between 1967 and 1985. This is currently (before the inclusion of the greenhouse gas emission prices) the lowest variable cost production. There is also 1,280 MW of gas steam-cycle (thermal) generation capacity that was commissioned between 1967 and 1977, 663 MW of Combined Cycle Gas Turbine (CCGT) capacity in two plants commissioned in 2000 and 2002, and around 729 MW of Open Cycle Gas Turbine (OCGT) plant, the last of which was commissioned in 2002, although there have been some minor additions since then.

A particular feature of the South Australian electricity market (although not highly relevant to this paper) is the very high penetration of wind generation in the energy mix. In 2011 wind generation accounted for 2.9% of the electricity transacted in the NEM, but in South Australia 26.7% of the electricity transacted in the National Electricity Market (NEM) and produced in South Australia, came from wind farms<sup>4</sup>. Wind farms have steadily taken market share from conventional fossil fuel generators, as shown in Figure 8.

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<sup>4</sup> Mountain, B. 2012. "Market power and generation from renewables: the case of wind in the South Australian electricity market", Centre for Strategic Economics Studies, Victoria University, forthcoming.

**Figure 8. Market share of electricity produced by fossil fuel generation, wind farms and net imports**



**Source:** Mountain, B. 2012. “Market power and generation from renewables: the case of wind in the South Australian electricity market”, Centre for Strategic Economics Studies, Victoria University, forthcoming.

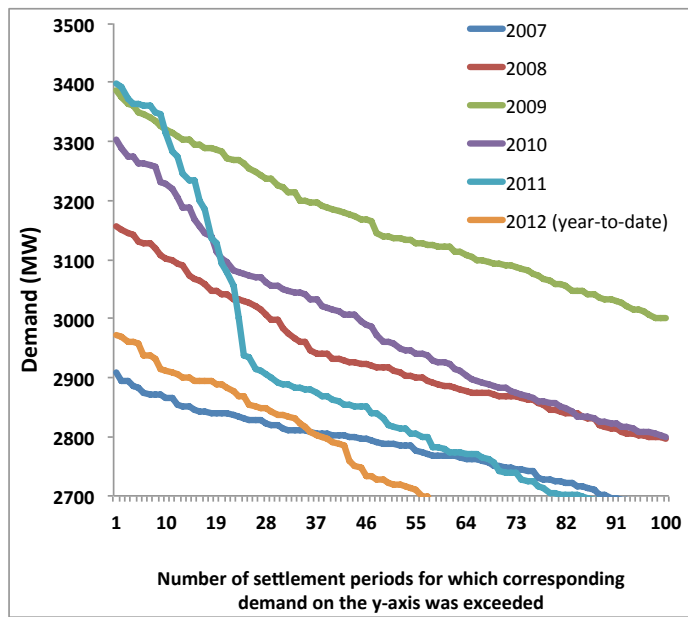
The South Australian electricity retail market is dominated by one retailer (AGL energy) that serves around 60% of small customers, with the remaining 40% of small customers split roughly equally between another two retailers.

There are also a number of small retailers who have an inconsequential customer base. Each of the three main retailers (AGL Energy, Truenergy and Origin Energy) is understood to also own and/or control enough generation to meet their South Australian demand. Alinta Energy – which owns the brown coal generators – is the only major South Australian generator that does not have any significant retail market share in South Australia.

### 3.1 Demand and prices

The examination of market power in South Australia begins by focussing on the demand in the highest settlement periods in each year. Figure 9 is the “load duration curve” for the highest 100 settlement periods in South Australia in each year from 2007 to 2011. This shows the number of settlement periods (on the x-axis) for which the corresponding level of demand (on the y-axis) has been equalled or exceeded. The figure shows that the peak demand in 2011 was almost exactly the same in 2011 as 2009, although in 2011 it rapidly declined. The unusual result in 2011 is explained by the outcomes on one day – Monday the 31<sup>st</sup> of January between 10am and 9.30pm – when extreme heat combined with the return to school and work to create extraordinarily high demand.

**Figure 9. Load duration curve in South Australia for 100 highest half hourly demand per year from 2007 to 2012 (year-to-date)**



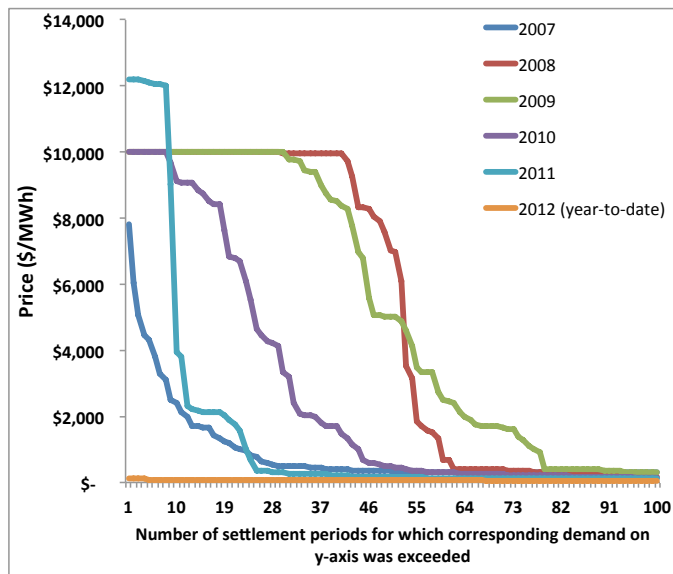
SOURCE: Data from NEM-Review<sup>TM</sup>, CME analysis

With the exception of this one extraordinary day, the general pattern in the figure shows that the consistently highest demand occurred in 2009, then 2010, 2008, 2011, 2012 year-to-date and then 2007. The maximum demand in 2012 year-to-date, is 2971 MW, about the same as 2007.

It is generally the case (but not always as will be clear a little later) that extreme prices occur during the very high demand periods. It is at these times that the gap between demand and supply is sufficiently small that the withdrawal of generation capacity (or, equivalently re-bidding the capacity into the spot market at much higher prices) by one or more producers is able to drastically increase spot prices in South Australia.

Figure 10 uses half-hourly prices rather than half-hourly demand in the duration curve. It shows that in 2008 and 2009, prices reached \$10,000 per MWh for extended periods (around 45 and 31 settlement periods respectively). In 2011, the peak prices rose higher in response to the raised price cap (\$12,500 / MWh) but then dropped away quickly to much lower levels. In 2012 to-date, the highest half-hourly pot price has been just \$147/MWh – a fraction of the highest price in any of the previous 5 years.

**Figure 10. Price duration curve in South Australia for highest 100 price half-hours from 2007 to 2012 year-to-date**

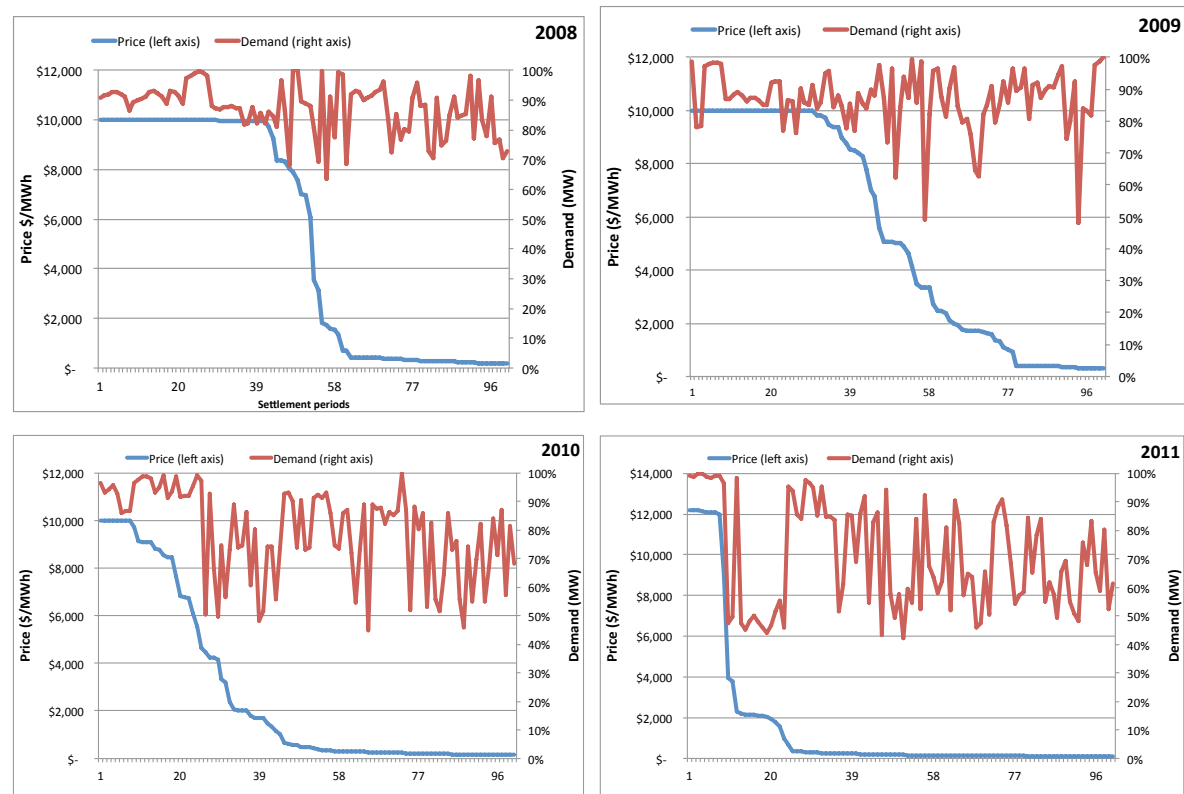


*SOURCE: Data from NEM-Review<sup>TM</sup>, CME analysis*

The four charts in Figure 11 bring together the price and demand data from 2008 to 2011 to show, in each figure, a plot of the price duration curve and the actual demand (as a percentage of the annual peak demand) that occurred at the same time as those prices. These charts show, somewhat surprisingly, that the extreme prices (at or close to the market price cap) have occurred when demand is typically above 85% of the maximum demand. However there have been several instances where this occurred when demand was some way (10% or around 300 MW) below the peak demand. Only in 2011 have the very highest prices (above \$12,000 / MWh) coincided clearly with the highest half-hourly demands.

Furthermore, the data shows that there have been several settlement periods in each year where extremely high prices (although not at the market price limit) have occurred even when demand is not much above annual average levels over the year.

**Figure 11. Price duration curve plotted against demand for top 100 settlement periods in 2008, 2009, 2010 and 2011**



SOURCE: Data from NEM-Review<sup>TM</sup>, CME analysis

### 3.2 Evidence of the exercise of market power

There have been a number of studies of the exercise of market power in South Australia. These studies have typically been a forensic analysis of the exercise of market power over a few trading intervals.<sup>5</sup>

In the analysis in this section, we develop a generalised, systematic analysis that would allow conclusions to be drawn on the likely extent of the exercise of market power since 2008, and the consequences of this for producers and consumers.

Figure 12 presents an analysis of the “residual demand”, spot prices and generation production during the extreme price periods (when prices were above \$300 / MWh) in 2008 and 2009. The measure of “residual demand” used is the South Australian demand (in the NEM) less production from South Australian wind farms and (net) imports over the interconnectors to Victoria. This measure of demand shows how much production

<sup>5</sup> See for example “THE THEORY AND PRACTICE OF THE EXERCISE OF MARKET POWER IN THE AUSTRALIAN NEM”, Darryl Biggar, June 2011.

would be needed from NEM-dispatched generation located in South Australia to meet the residual demand in each settlement period.

By then comparing how much of the South Australian generating capacity was dispatched during each settlement period, it is possible to calculate how much “spare” capacity there is in that settlement period (i.e. capacity that could have been sold in the market but was not).

The definition of “spare capacity” for each generator in each settlement period is the difference between that generator’s actual generation in that settlement period and 95% of its maximum annual generation. We have used 95% of its maximum capacity rather than 100%, to allow for some reduction in generation capacity that may reasonably be expected from time to time to reflect capacity reductions attributable to ambient conditions (such as very high temperatures – which often co-incide with very high demands).

The level of “spare” capacity is evidence of whether the high prices reflect the exercise of market power, or whether they reflect a reasonable response of generators to genuine scarcity (i.e. bidding up their prices when the market is tight).

If the market was competitive, generators would want to maximise production at those times that market prices are higher than their production costs. If the evidence is that they have spare capacity when prices are extremely high, then this must be because, by withholding capacity from the market (or, equivalently only making it available to the market at much higher prices) they are able to increase the price they are paid.

For example, if a generator withheld half its capacity and in so doing was able to raise the price it was paid, from its production costs of say \$50/ MWh to say \$10,000/ MWh, it would still earn 100 times as much revenue than if it made all of its capacity available to the market at its production costs.

We recognise that there may well be technical limitations (such as the failure of some component of a power station) that renders that generating unit unavailable for a period of time. To the extent that this always occurred at the times of the extreme prices then this would mean that that capacity could not reasonably be counted as “spare” capacity in our analysis.

It is impossible to be certain that this has not occurred. But if the market was competitive and generators accordingly sought to maximise production when prices exceed marginal production costs, it is unlikely that a significant amount of generation capacity would consistently be unavailable (for technical reasons) when spot prices far exceeded production costs. Therefore we have no reason to believe that our estimate of spare capacity is unreliable.



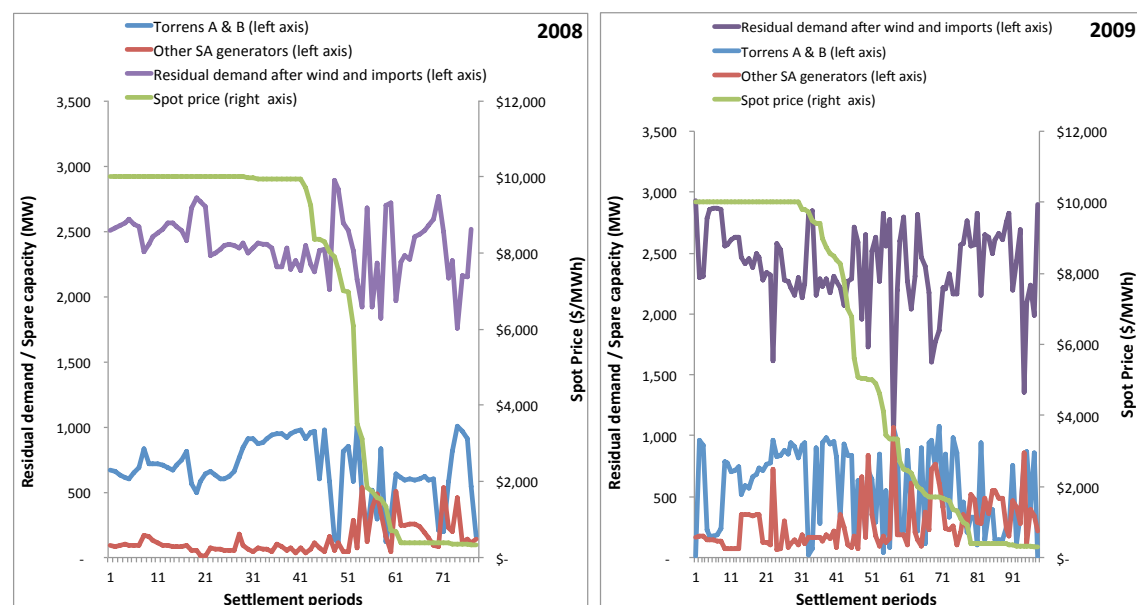
In this analysis we have distinguished Torrens Island Power Station A and B from all other South Australian generators, which we have put into one group. The information in the two charts in Figure 12 show that Torrens A and B have withheld substantial amounts of capacity (on average 667 MW in 2008 and 655 MW in 2009) when half hourly spot prices were at the market price cap.

The charts in Figure 12 show that all other generators had little to no spare capacity when the price reached the market price cap and the residual demand was high. The other competing generators were effectively producing as much as they could when prices were very high.

During the extreme price periods, the residual demand could not have been met unless Torrens Island Power Station was producing. This gave Torrens Island Power Station the ability to raise spot prices. It capitalised on this opportunity by effectively withholding capacity from the market either by not making it available at all, or by only making it available at the market price cap. In so doing, it was able to raise prices to the level of the Market Price Cap.

The amount of capacity that Torrens Island had to withhold from the market in order to force prices up to the market price cap – on average 667 MW in 2008 and 655 MW in 2009, and a maximum of 982 MW in 2008 and 962 MW in 2009 - is particularly remarkable. Evidently, the extreme prices in these years did not reflect a scarcity of generation capacity.

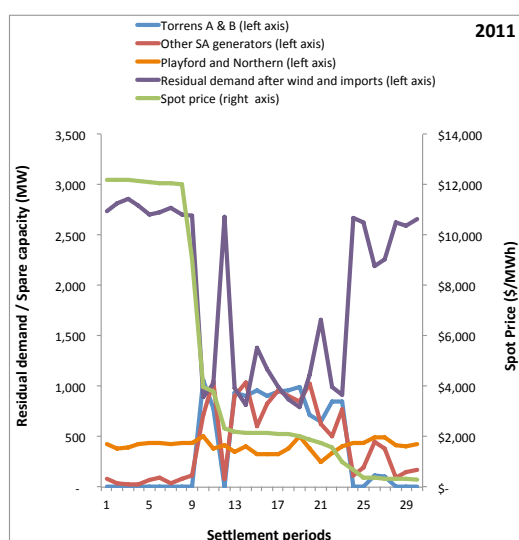
**Figure 12. Analysis of residual demand and spare generation capacity when prices were above \$300 / MWh in 2008 and 2009**



*SOURCE: Data from NEM-Review<sup>TM</sup>, CME analysis*

The outcomes for 2008 and 2009 were replicated, although to a lesser extent, in 2010. In 2011 however the situation changed. This time Torrens A and B were producing at or near their maximum capacity, while the brown coal generators (Playford and Northern), withheld substantial amounts of capacity (on average 423 MW and a maximum of 440 MW) when the market price was near the market price cap. This is shown in Figure 13.

**Figure 13. Analysis of residual demand and spare generation capacity when prices were above \$300/ MWh in 2011**



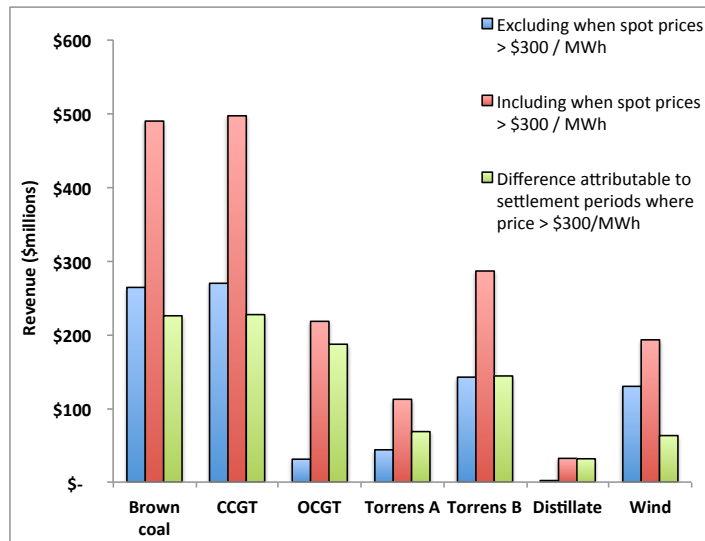
SOURCE: Data from NEM-Review<sup>TM</sup>, CME analysis

We understand that the difference between the Torrens Island and Playford/Northern bidding patterns over the period from 2008 to 2011, reflected the levels of their hedge contracts. Torrens Island was, we understand, substantially uncontracted from 2008 to 2010, but substantially contracted from 2011, while the reverse is apparently the case for the Playford/Northern units.

### 3.3 Impact on producers

The previous subsection examined evidence of the exercise of market power. This subsection examines how this has affected outcomes for electricity producers in South Australia. Figure 14 shows the average annual NEM revenues for the four years from 2008 to 2011 for different generators, distinguished by their primary energy source. The chart shows the average annual revenues excluding the impact of spot prices above \$300/ MWh (in blue) and then including all prices above \$300/ MWh (in red). The difference (in green) shows the increase in revenues attributable to the few settlement periods in each year (typically less than 80 settlement periods or 40 hours per year) when spot prices rose above \$300/ MWh.

**Figure 14. Average annual NEM revenues from 2008 to 2011**



SOURCE: Data from NEM-Review<sup>TM</sup>, CME analysis

The chart shows that for wind farms, the high priced event made the least difference, causing revenues to rise by around 25%. For brown coal generators, Combined Cycle Gas Generators (CCGT) and Torrens B, the high priced settlement periods roughly doubled the average annual revenues. For the Open Cycle Gas Turbines (OCGT), and Distillate plant, the high priced events accounted for almost all their income.

For those generators that were actually exposed to spot prices (i.e. had not entered into financial contracts to hedge spot prices) the high prices will have significantly improved their profitability. For example, for Torrens B the high priced events produced revenues of \$332m over the four years. Per MW of capacity, this translates into about \$0.7m per MW of capacity.

The high priced events from 2008 to 2011 delivered \$374m of spot market revenue for the 729 MW of OCGT plant in South Australia. Assuming, hypothetically, that this plant was unhedged (i.e. exposed to spot prices), this translates into revenue of \$0.5m per MW – a little bit less than the plant would have cost to build. To put this another way, less than two years of these extreme prices would have allowed their owners to recoup most of their capital outlay for plant with an expected operating life of many decades.

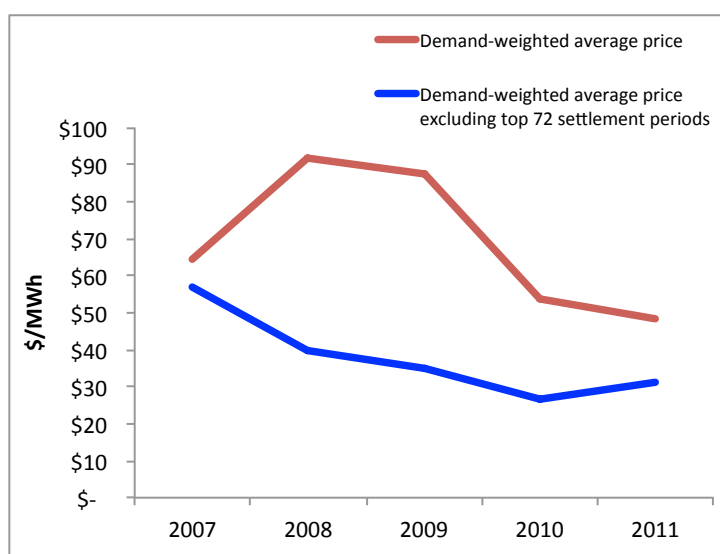
We recognise that most of the South Australian generating capacity will have been hedged against the spot price either by entering into fixed price contracts, or by virtue of vertical integration: If the generator was part of a vertically-integrated generator-retailer, the higher spot prices received by the “generator” side of the business would have been off-set by the higher spot prices to be paid by the “retail” side of the business. In practice therefore only some of the generation capacity (possibly most of the Torrens Island power station) would have received the full benefit of the extreme spot prices. However, as discussed in the next sub-section in detail, higher spot prices flowed into higher

contract prices, and in this way generators (and retailers) will, over time, have benefitted from the higher spot prices

### 3.4 Impact on consumers

Figure 4 showed that, excluding the highest priced 72 settlement periods, average spot prices in South Australia (for 99.4% of the year) are generally a little higher than other NEM regions. Differences in the generation mix in South Australia compared to other parts of the NEM do not explain the higher prices in South Australia. The reason for significantly higher average annual wholesale electricity prices in South Australia is the impact of prices in the few extreme settlement periods as shown in Figure 15.

**Figure 15. Annual demand-weighted average prices in South Australia excluding and including the effect of prices in the top 72 settlement periods in each year**



SOURCE: Data from NEM-Review<sup>TM</sup>, CME analysis

The way that these high prices flow through to electricity consumers is complex, and to some degree uncertain:

- For residential consumers the picture is reasonably clear: the Essential Services Commission of South Australia calculates the standing tariffs that AGL is allowed to charge to its customers in South Australia. Retailers then compete, possibly offering discounts to this standing tariff, in order to attract customers. The AEMC's report<sup>6</sup> on retail electricity prices shows that in the calculation of residential electricity prices in South Australia, wholesale electricity prices are far higher (typically about 20%-30% higher) than in other NEM regions.

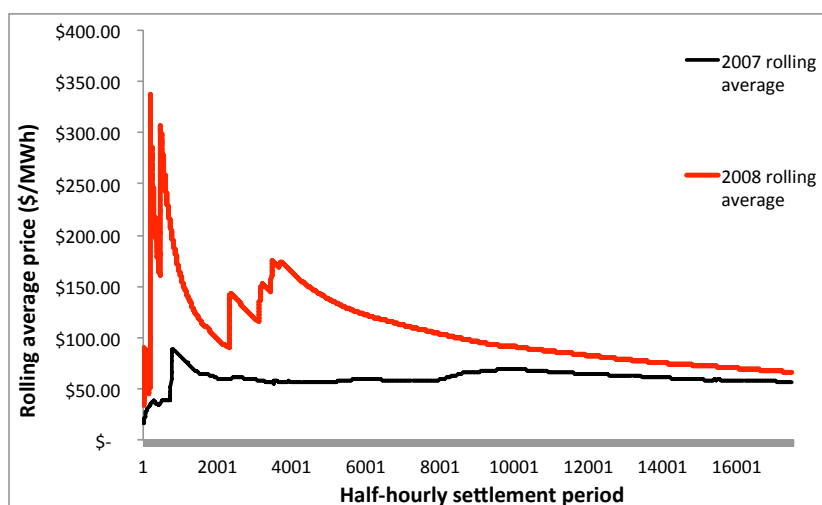
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<sup>6</sup> AEMC, November 2011. "Possible future Retail Electricity Price Movements: 1 July 2011 to 30 June 2014.

- For larger electricity consumers who negotiate supply agreements with retailers, or even in some cases buy directly from the NEM, the way that extreme price periods affect them over time is less clear. The greater uncertainty (for larger energy users) is because contracts insulate customers from the extreme spot prices that occur when those contracts are in place. However, the effect of the extreme spot prices in one year is then typically reflected in higher contract prices in subsequent years. This is shown in Figure 17.

Figure 16 shows the rolling average of the spot prices in 2007 and 2008.

**Figure 16. Rolling average annual price of electricity transacted through the NEM in South Australia**



SOURCE: Data from NEM-Review<sup>TM</sup>, CME analysis

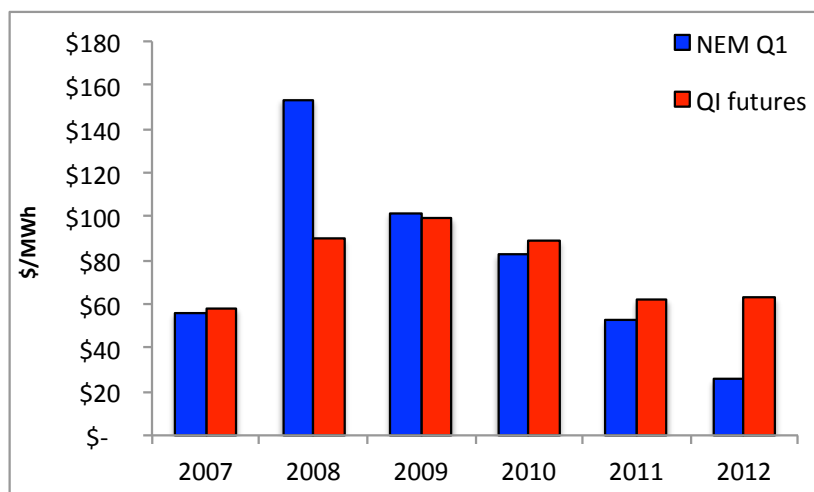
In 2007, the rolling average spot prices showed a spike up to about \$90/MWh and then declined to end the year at around \$75/MWh. During 2006, generators and retailers agreed contracts to hedge their exposure to spot prices in 2007. Figure 17 shows that for the first quarter (Q1) of 2007, the base futures price for that quarter was around \$60/MWh. Evidently during 2007 when retailers and generators agreed contract prices for 2008, they expected spot prices in Q1 of 2008 to be much higher than in Q1 of 2007, since the weighted average contract price had now risen to around \$90/MWh. However, even these heightened expectations proved to be an under-estimate of the actual outcome – which as shown in Figure 17 is an average spot price in the first quarter of 2008 of around \$155/MWh.

Figure 17 and Figure 18 show how the extreme spot prices were effectively passed through to energy users in the form of higher contract prices (consistently above \$90/MWh for the period from 2008 to 2010).

The difference between the Q1 average spot and base futures prices is shown in Figure 18. The large gap between spot and base futures prices is seen in 2008, but from then to 2011 the gap was consistently much smaller, and in 2010 and to a greater extent 2011,

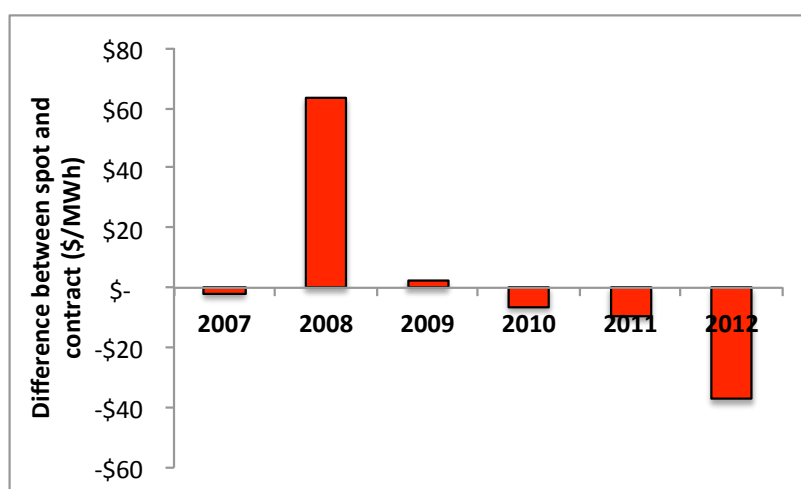
contract prices were above average spot prices. In Q1 2012, spot prices collapsed relative to expectations in the prices paid for Q1 2012 base futures: the Q1 base futures price was more than twice the average spot price. Evidently consumers (and retailers) would have been far better off buying directly from the spot market in 2012, in same way that they would have been far better-off buying from the contract market in 2008.

**Figure 17. Average spot prices and average Q1 futures prices**



SOURCE: Data from NEM-Review™ and D-Cypha CME analysis

**Figure 18. Difference between average spot price and average futures price for the first quarter of each year**

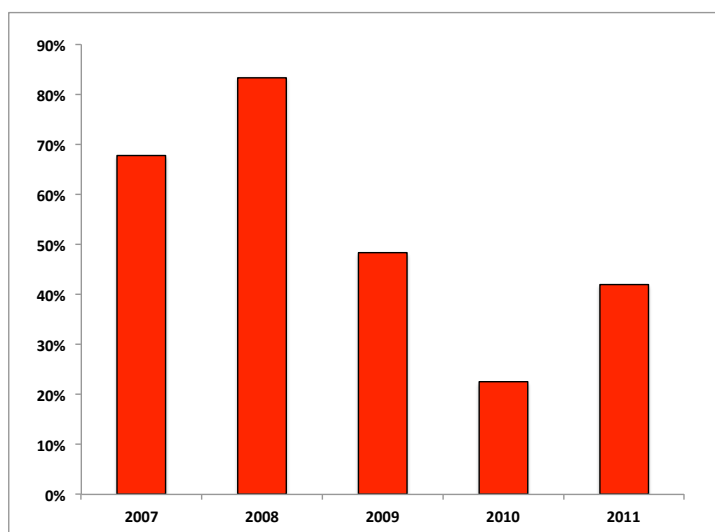


SOURCE: Data from NEM-Review™ and D-Cypha CME Analysis

Extreme prices in South Australia seem to have also affected the liquidity of the contract market. This is shown in Figure 19, which charts the volume of Q1 future contracts as a percentage of the physical NEM electricity demand. In Figure 6, we noted that the volume of futures contracts in South Australia was substantially below that in VIC, NSW or QLD. Figure 19 shows that in South Australia futures contract volumes (for quarterly contracts) declined to just 20% of physical NEM demand in 2010.

Market participants are able to contract other than through futures contracts, for example through bi-laterally negotiated contracts. This is likely to be the predominant method for hedging spot prices, amongst the incumbent generators and retailers in South Australia. However openly traded and transparently priced futures contracts such as through the Sydney Futures Exchange are valuable to end users and also to generators and retailers in hedging against volatile spot prices. The low liquidity of the market for futures contracts in South Australia will reduce the ability, particularly of new entrant retailers and generators, to hedge their exposure to volatile spot prices. This will be a deterrent to new entrants and hence is likely to undermine the competitiveness of the wholesale market in South Australia.

**Figure 19. Volume of Q1 base quarterly futures contracts as a percentage of NEM sales in each quarter**



*SOURCE: Data from D-Cypha CME analysis*

### **3.5 Possible future price outcomes**

The analysis to this point reflects the outcomes in the electricity market in South Australia up to the end of 2011. The outcomes for 2012 year-to-date, are very different to what has been observed for the last five years.

The average Q1 futures price in the NEM for South Australia for 2012 has been just \$25.54 per MWh, less than half the comparable price in 2011, and far below any of the previous years' average Q1 prices.

The highest spot price in 2012 to-date has been just \$145 per MWh, and the demand-weighted average spot price in the highest 72 settlement periods for 2012 has been just \$67 / per MWh. It has been between 18 and 108 times higher than that for the previous five years.

Evidently this outcome was not expected in the contract market: the Q1 base futures contracts for 2012 sold for an average price of \$63 / MWh (on total volume of 716 contracts), compared to the average NEM price for Q1 of \$25.54 per MWh. The outcomes for 2012 to-date are clearly not consistent with the exercise of market power.

Looking ahead, there are a number of supply-side changes that may affect prices in future, including:

- From 1 July 2012, an emission price of \$23 / tonnes of CO<sub>2</sub>e will affect all the main NEM-connected fossil fuel generators;
- Alinta Energy is understood to be planning to close the Playford brown coal plant for at least part of the year;
- The possible expansion of interconnector capacity to Victoria is being considered;
- There is around 2,400 MW of additional prospective wind farm capacity in South Australia at various stages of planning, although none is currently under construction or imminently planned;
- Possible expansion of the Torrens Island Power Station.

The impact of emission prices will be relatively predictable – causing rises of \$15 - \$20 per MWh on average) when the market is competitive. The exercise of market power from 2008 to 2011, as evidenced in this report, has had a far higher impact on electricity prices than this.

It is difficult to imagine that other supply-side factors will have a significant impact on prices. Mountain (2012) suggests that wind farms, despite their high market penetration in South Australia are unlikely to have had a major impact on electricity prices, in view of the dominant impact of market power.<sup>7</sup>

The possible closure of Playford during low demand periods is also unlikely to have a major impact in view of the substantial supply surplus through-out the year.

Possible interconnector augmentation is at early stages of consideration and the effect of this on prices, if any, would need to be considered once proposals are brought forward.

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<sup>7</sup> Mountain, B. 2012. "Market power and generation from renewables: the case of wind in the South Australian electricity market", Centre for Strategic Economics Studies, Victoria University, forthcoming.



Prima facie, in the absence of very significant interconnector augmentation, it is difficult to imagine that this would have much impact on South Australian electricity prices.

The possible expansion of Torrens Island seems irrelevant – the analysis in the previous section suggested that there is already a substantial capacity surplus in South Australia. Expanding this surplus even more is unlikely to make a difference unless there is some sort of compulsion to make that additional capacity available to the market.

An important factor in predicting future outcomes is to understand the hedge contract positions of the major generators (particularly Torrens Island, Playford and Northern), and then to anticipate their commercial and strategic behaviour, not least in view of the high level of attention that this area is now receiving from regulators and consumer advocates.

## 4 Implications and next steps

The analysis in this document has concluded that concerns over the competitiveness of the wholesale electricity market in South Australia over the period from 2008 to 2011 seem to be well founded.

Over this period, higher average spot prices in South Australia, compared to other parts of the NEM, are attributable to a few extreme price settlement periods typically in the last few weeks of January or first two weeks in February. The analysis suggests that spot market prices in these periods reflect the exercise of market power rather than scarce supply. The South Australian electricity system appears to be well supplied even at the times of its highest demand.

High spot prices have fed into high contract prices, and the allowances for wholesale electricity costs in regulated residential tariffs are 20-30% higher in South Australia than in other NEM regions.

However in 2012, spot prices in South Australia have fallen considerably from the levels in the past five years. This suggests that concerns about market power in the period from 2008 to 2011, have not continued in 2012. Spot market outcomes in 2012 have yet to feed into contract markets and the prices paid by most South Australian electricity users.

Average electricity demand appears to be declining in South Australia as in other parts of the NEM. Peak demand is growing slowly, at best. If this continues, the gap between supply and demand is likely to continue to widen. This will make the exercise of market power more difficult. If the spot market continues to exhibit the competitiveness it has shown in 2012, lower wholesale prices can be expected in future compared to the outcomes in the period from 2008 to 2011, notwithstanding the introduction of greenhouse gas emission charges.

Do the outcomes in 2012 to-date obviate the need for a deeper investigation of market power in the previous years? We suggest not. The outcomes over the period from 2008 to 2011 were remarkable and merit detailed study to fully understand their cause and effect. For example, the extreme spot prices evident in South Australia from 2008 to 2011 have not been experienced in other electricity markets in the world. Has the very high Market Price Cap in the NEM provided excessive incentive to generators to exercise market power?

The analysis in this paper has postulated that extreme spot prices have flowed through to consumers in time, through higher contract practices. Confidential information on contracts would provide a deeper understanding of price transmission between spot and contract markets.

Several approaches might be considered to deal with market power concerns. The least intrusive approach would be to strengthen transparency and market monitoring, perhaps through greater disclosure of contract positions or the actual margins that retailers are achieving. More radical approaches might be structural constraints (limits on generator-retailer vertical integration, mandatory contracting of a percentage of production, mandatory sale of generation rights such as occurred in Alberta in the 1990s) or changes to the market design (such as lower market price caps, tighter cumulative price thresholds, or the introduction of capacity payments). Alternative approaches require careful thought.

Finally, while this paper has focussed on South Australia, high spot prices in a few settlement periods have also had a significant impact on average prices in other regions of the NEM. The analysis in this paper should be extended to those regions to assess the extent to which similar observations on outcomes in those regions might be made, as have been made in this paper for South Australia.