ISSN 1835-9728

Environmental Economics Research Hub Research Reports

The Integration of Wind Generation within the South Australian Region of the Australia National Electricity Market

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Research Report No. 38

November 10 2009

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Environmental Economics Research Hub Research Reports are published by The Crawford School of Economics and Government, Australian National University, Canberra 0200 Australia.

These Reports present work in progress being undertaken by project teams within the Environmental Economics Research Hub (EERH). The EERH is funded by the Department of Environment and Water Heritage and the Arts under the Commonwealth Environment Research Facility.

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Abstract

This working paper aims to improve our understanding of wind integration issues for the Australian National Electricity Market (NEM) in the South Australian context by assessing the interaction of wind generation, electricity demand and regional spot prices over the most recent year of market data. The analysis is intended to provide insights into the potential implications of a greater expansion of installed wind generation in South Australia and across the other regions of the NEM under the recently legislated expanded Renewable Energy Target. With the current installed wind generation in South Australia, our results suggest that while electricity demand currently has the greatest influence on spot prices, fluctuating South Australian wind generation levels have a significant secondary influence.

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About CEEM and this report:
The UNSW Centre for Energy and Environmental Markets (CEEM) undertakes interdisciplinary research in the design and analysis of energy and environmental markets and their associated policy frameworks. Research areas include the design of electricity markets, market-based environmental regulation, sustainable energy technologies including wind energy and photovoltaics, and the broader policy context in which all these markets and emerging sustainable energy technologies operate. You can learn more of CEEM's work by visiting its website: www.ceem.unsw.edu.au.

This document is a working paper that explores the potential market impacts of current wind generation in the South Australian region of the National Electricity Market (NEM). All analysis is based on publicly available data from the National Electricity Market Management Company (NEMMCO) website including electricity demand, spot prices and wind generation in the South Australian region. Note that NEMMCO has now been incorporated into a new Australian Energy Market Operator (AEMO).

The research has received funding support from the Environmental Economics Research Hub (EERH) under the Commonwealth Environmental Research Facilities (CERF) program administered by DEWHA. It also draws upon research outcomes from a three year Federal Government funded CEEM project on wind integration under the Australian Wind Energy Forecasting Capability Initiative.

The authors would also like to acknowledge the contribution of Dr Paul Twomey and Mr Tim Larsen to this work. This is an area of ongoing research within CEEM and we welcome your comments and suggestions. The corresponding author for this report is:

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1. Introduction

Growing concerns about energy security and climate change have heightened interest in harnessing non-storable renewable energy resources as a response to these critical issues. In response to the Mandatory Renewable Energy Target (MRET) established by the Australian Government in 2001, South Australia has been the location of a large proportion of wind farm installations since the scheme commenced.

The Federal Government's recently enacted expanded Renewable Energy Target (eRET) will mandate an approximately four fold increase in new renewable generation by 2020 compared to that achieved by MRET to date. It is expected that wind may play a significant role in achieving this target and there are important questions regarding the potential impact that such generation may have on the operation of the National Electricity Market (NEM).

The experience in South Australia to date with wind may provide some insights into these issues given that wind generation now represents over 10% of electricity production in that State, by far the highest penetration of wind in any region of the NEM. This development has largely been driven by the ready availability of project sites with excellent wind regimes. This working paper aims to improve our understanding of wind integration issues for the NEM in the South Australian context by assessing the interaction of wind generation, electrical demand and regional spot prices over the most recent year of market data. It is hoped that this analysis will provide insights into the potential implications of greatly expanded wind generation in the NEM across regions including South Australia of course, but also Victoria, Tasmania and NSW.

2. Data

The data for this project was obtained from the AEMO website[1]. The common data time resolution used is 30-minutes and details for each individual set of data are summarised in Table 1. The period from 1st July 2008 to 30th June 2009 (the 2008-9 financial year) is used and during this time there is little change in the electricity supply portfolio in South Australia (SA) (Electricity Supply Industry Planning Council 2009). Many studies reported in this paper use the total wind power generation for SA, which consists of the sum of the generation from each of the 9 wind farms referred to in Table 1 below (6 non-scheduled and 3 scheduled) and listed with more details in Table 2. The total rating of these 9 wind farms is 742.75 MW.

Two of the wind farms were not fully operational for the first 4 months of the period studied and over this period the total rating of the wind farms increases from around 627 MW to around 727 MW (one of the wind farms, Mt. Millar still appears to be operating at around 54 MW instead of its nominated installed capacity of 70 MW, refer to Table 2). These variations are not thought to be significant for this study and are generally ignored. For comparison purposes, the period from 1st July 2000 to 30th June 2001 (the 2000-1 financial year) was chosen as a reference year in which there was little or no wind generation in the NEM. Note of course that there have been other very significant changes in the NEM over that time.

[1] AEMO website: www.aemo.com.au

Table 1: Summary of data used (all 30-minute averages)

Data name	Period(s)	Description and comments	Location
SA Demand	2008-9 2000-1	From "Aggregated Price and Demand data in the Operational Market Data". Native demand for SA to be met by scheduled and non-scheduled generation is calculated by adding this demand figure to non-scheduled wind power generation.	http://www.aemo.com.au/data/aggPD_2006to2010.html (and requires 'non-scheduled wind power generation' – see below)
SA Price	2008-9 2000-1	NEM spot prices in South Australia from same data set as above.	Same as above
Non-scheduled wind power generation	2008-9	The measured (metered) generation output from the 6 currently non-scheduled wind farms in SA. These are obtained with 5-min resolution but averaged in 30-min intervals. Total rating: 447.75 MW	http://www.aemo.com.au/data/csv.htm. See archived non-scheduled generation data.
Scheduled wind power generation	2008-9	The dispatched scheduled generation from the 3 currently scheduled wind farms in SA. Total rating: 330 MW	http://www.aemo.com.au/data/csv.htm. See archived daily aggregated dispatch data.
Scheduled SA generation	2008-9	The dispatched non-wind energy generators in SA.	As above.

Table 2: Some details on the 9 currently operational wind farms in South Australia

Wind farm name	Generator type	Terrain type	Location (ref to Adelaide)	Rating and details (MW capacity)
Hallett Hill	Scheduled	Inland ridge	North	94.5
Snowtown	Scheduled	Inland ridge	North	99 (ramps from 38 to 99 over Jul-Nov 2008)
Lake Bonney 2	Scheduled	Coastal	South-east	160
Canunda	Non-scheduled	Coastal	South-east	46
Cathedral Rocks	Non-scheduled	Coast/Cliff	West	66
Lake Bonney 1	Non-scheduled	Coastal	South-east	80.5
Mount Millar	Non-scheduled	Near coast	West	70 (mostly curtailed at 16 MW for Jul-Nov 2008, then approx. 54 MW to Jun 2009)
Starfish Hill	Non-scheduled	Near coast	South	35
Wattle Point	Non-scheduled	Near coast	South close	90.75

Details of the non-wind scheduled generation in SA are listed in Table 2a. By contrast with other major regions of the NEM, SA has considerably more gas generation than coal-fired generation. Wind generation capacity in SA now exceeds coal plant capacity, and is approaching some 20% of total installed capacity.

Table 2a: Some details on the non-wind generators in South Australia (> 20 MW capacity)

Generator name	Fuel source	Location (ref to Adelaide)	Rating and details (MW)
Hallett Power Station	Gas	North	180
Angaston Power Station 1	Diesel	North (but close)	30
Angaston Power Station 2	Diesel	North (but close)	20
Dry Creek 1	Gas	In Adelaide	52
Dry Creek 2	Gas	In Adelaide	52
Dry Creek 3	Gas	In Adelaide	52
Ladbroke Grove Power Station 1	Gas	South-east	40
Ladbroke Grove Power Station 1	Gas	South-east	40
Mintaro Turbine Station	Gas	North	90
Northern Power Station 1	Coal	North	265
Northern Power Station 2	Coal	North	265
Osborne Power Station	Gas	In Adelaide	180
Playford B Power Station	Coal	North	240
Port Lincoln Gas Turbine	Gas	West	50
Pelican Point Power Station	Gas	In Adelaide	478
Quarantine Power Station 1	Gas	In Adelaide	24
Quarantine Power Station 2	Gas	In Adelaide	24
Quarantine Power Station 3	Gas	In Adelaide	24
Quarantine Power Station 4	Gas	In Adelaide	24
Quarantine Power Station 5	Gas	In Adelaide	128 (although this appears to be available only from 1/1/2009)
Snuggery Power Station	Gas	South-east	63
Torrens Island Power Station A1	Gas	In Adelaide	120
Torrens Island Power Station A2	Gas	In Adelaide	120
Torrens Island Power Station A3	Gas	In Adelaide	120
Torrens Island Power Station A4	Gas	In Adelaide	120
Torrens Island Power Station B1	Gas	In Adelaide	200
Torrens Island Power Station B2	Gas	In Adelaide	200
Torrens Island Power Station B3	Gas	In Adelaide	200
Torrens Island Power Station B4	Gas	In Adelaide	200

3. Preliminary Results

3.1. Overview of the data set

To obtain a high level appreciation of the data set and the events that occurred, Figure 1 shows the time-series for electricity demand, spot prices and total SA wind power for the full 12-month period. Since the prices are dominated by about 5 events with extreme peaks exceeding $5000 per MWh, the time-series plot is shown again in Figure 2 with the price axis truncated at $150 and -$450 per MWh. Figure 2 shows that there are also around 11 events with significantly negative prices.

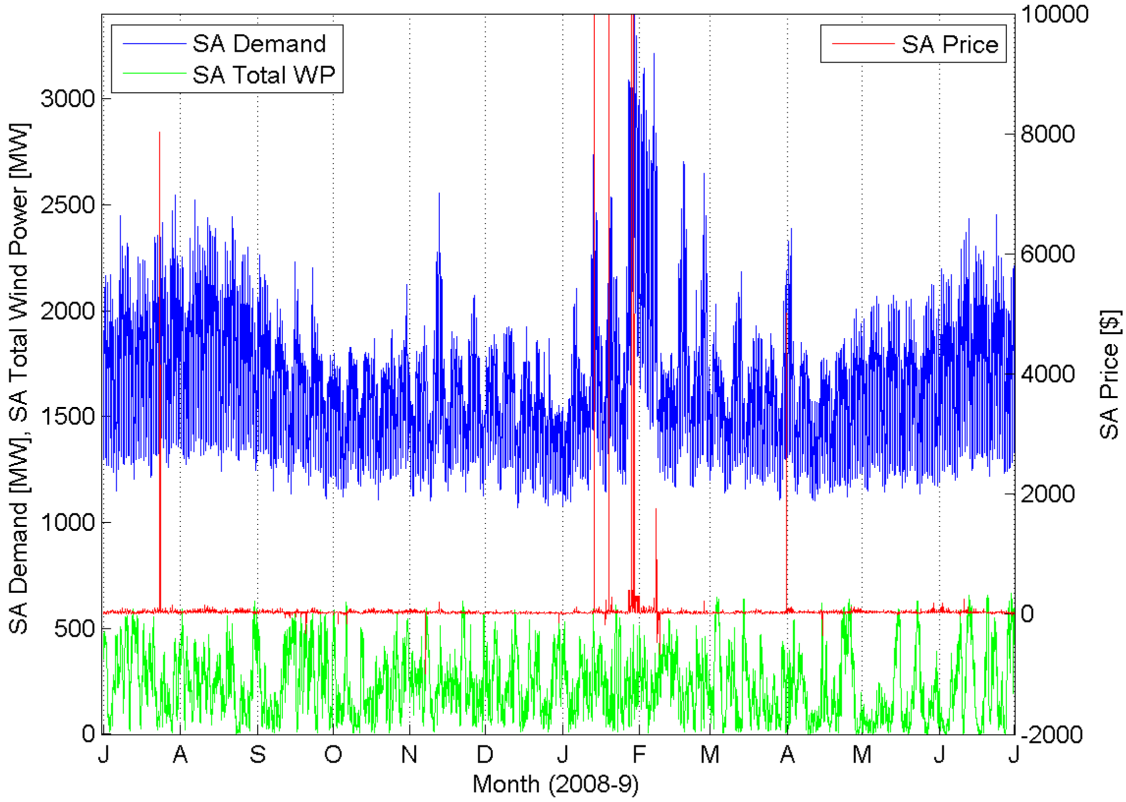

Figure 1: Time-series plots of the data for the full 12-month period

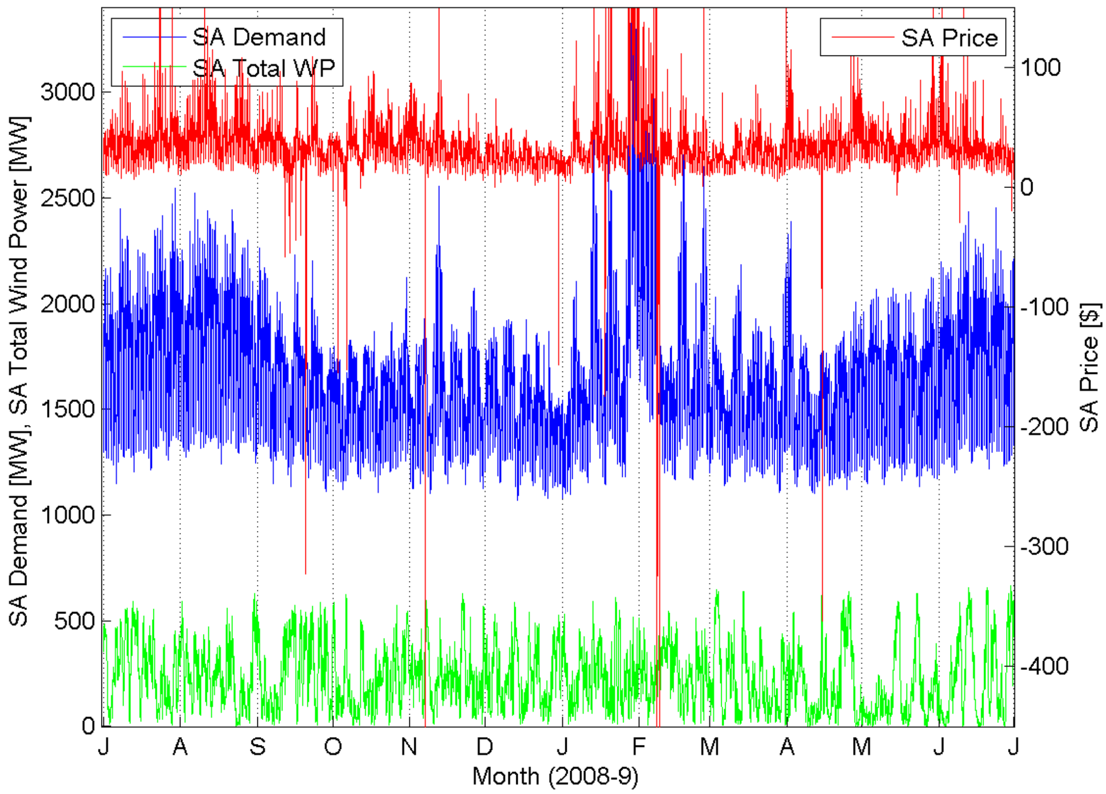

Figure 2: Time-series plots of the data for the full 12-month period with a truncated scale on the price axis

For comparison, Figure 3 shows the time-series plots for the 2000-1 financial year for the full price scale and a truncated price scale. The plots show that in 2000-1 there are many more events with prices above $200 per MWh than in 2008-9 but there are no events with prices above $5000 per MWh. This is because the NEM price cap was set at $5000 per MWh in 2001 and reset to $10000 per MWh in April 2002.

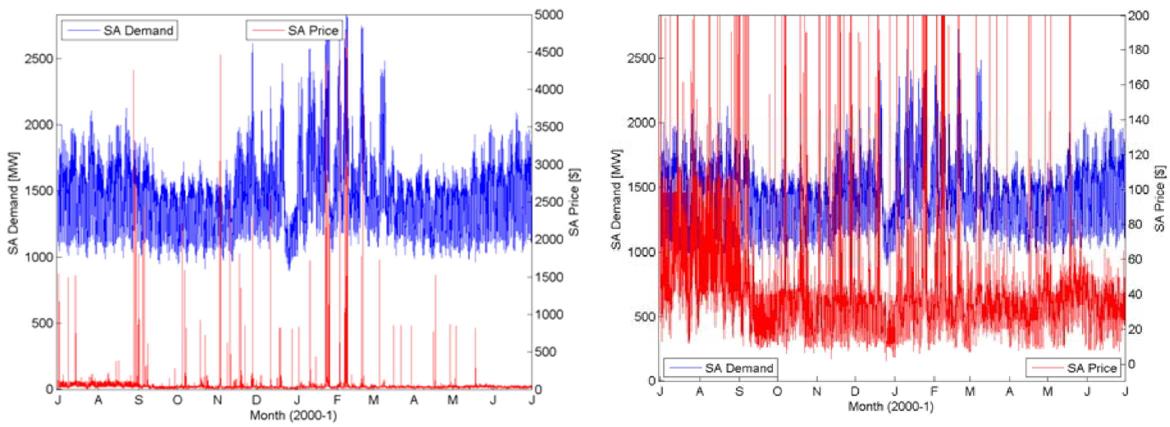

Figure 3: Time-series plots of the data for the full 12-month 2000-1 period without (left) and with (right) a truncated scale on the price axis

Figure 4 shows the price/revenue comparison stack plot. These plots show that prices above $1000 per MWh contributed to 42% of the revenue in 2008-9, but ony 30% in 2000-1. Further statistics to support Figure 4 are shown in Table 3.

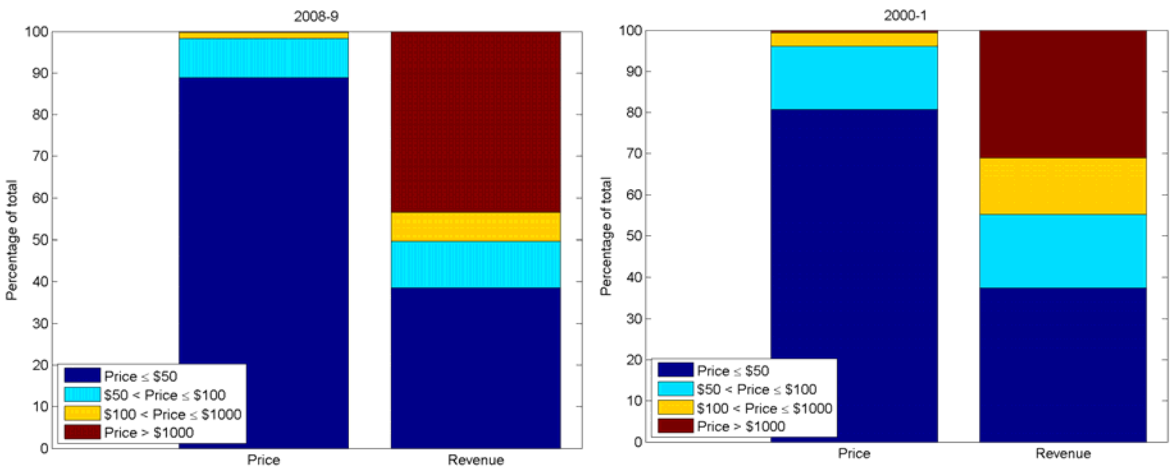

Figure 4: Price/revenue stack comparisons for 2000-1 and 2008-9

Table 3: Statistics to support Figure 4

Period	**Stack for Price (P)**	**Data fraction (%)**	**Mean Price** $/MWh	**Mean Demand (as fraction of annual mean demand)**
2000-1	P > $1000	0.3	6384	2922 MW (1.8)
	$100 < P < $1000	1.4	192	2672 MW (1.6)
	$50 < P < $100	9.5	64	2002 MW (1.2)
	P < $100	88.8	29	1599 MW (0.97)
2008-9	P > $1000	0.5	2548	2180 MW (1.5)
	$100 < P < $1000	3.4	208	1878 MW (1.2)
	$50 < P < $100	15.4	68	1686 MW (1.1)
	P < $100	80.7	31	1425 MW (0.96)

3.2. Duration curves

The time-series data sets shown in chronological order Figure 1, Figure 2 and Figure 3 can be reorganised into duration curves by re-ordering the chronological data sets in sequence from the largest to smallest values of a chosen variable, such as demand. Figure 5 shows load/price pairs sequenced to produce demand duration curves for the for the 2000-1 and 2008-9 financial years. A moving average with a window size of 999 data points is included in the plots. These indicate that in 2008-9, most of the high prices are concentrated during periods of high demand. In 2000-1 the result is similar but not as pronounced.

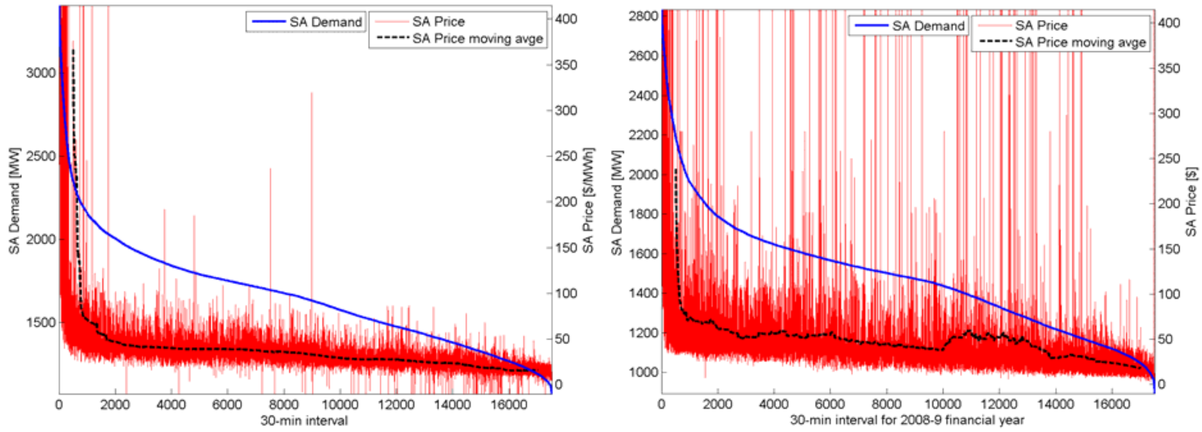

Figure 5: SA Demand duration curve for 2008-9 (left) and 2000-1 (right) with the corresponding price and moving average price (999 data points per window)

Figure 6 shows a price duration curve with corresponding SA total wind power for 2008-9. As might be expected, plotting the moving average wind power reveals an inverse relationship between price and wind power. The average wind power for the highest 10% of prices is around 200 MW and this increases with decreasing price to around 300 MW for the lowest 10% of prices.

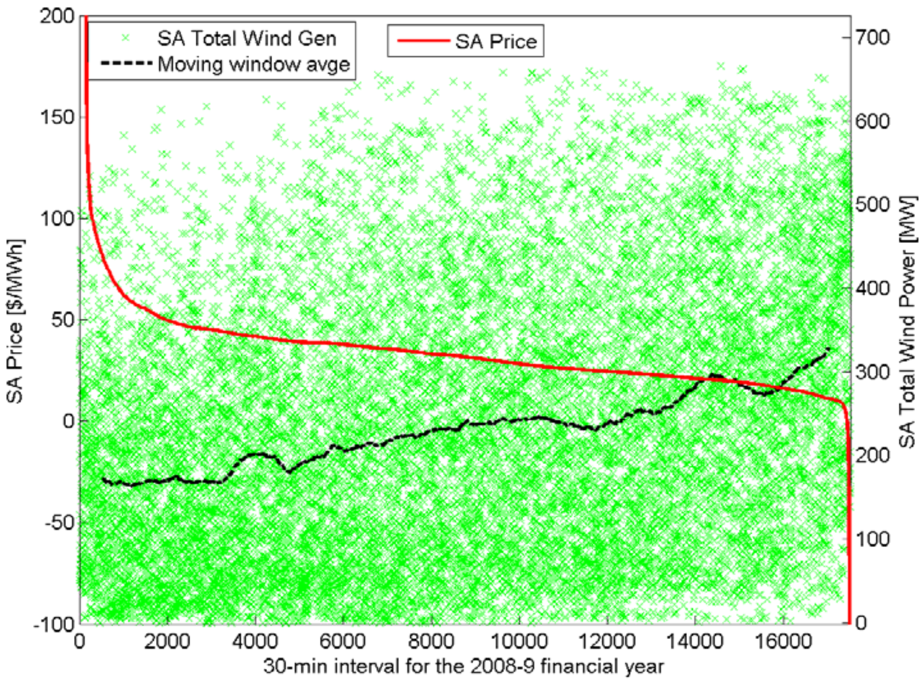

Figure 6: Price duration curve for 2008-9 with corresponding SA total wind power and moving average wind power (999 data points per window).
Note that the price axis is truncated for clarity

The six figures listed in Table 4 look at duration curves constructed from six different variables with the corresponding prices and the moving average of the prices. The goal with these plots is to discern something about how much the different variables relate with the spot price in the 2008-9 data set. Note that 'Δ' refers to the change in the quantity and is the defined as value at the current time-interval minus the value at the previous time-interval.

Finally, Figure 12 and Figure 13 show the moving averages only so they can be compared for the first 3 variables and the second 3 variables, respectively.

Table 4: The variables that the duration curves are based on for Figures 7-12

Figure number	Variable used to construct duration curve
Figure 5	SA Demand
Figure 7	SA Total Wind Power
Figure 8	SA Demand – SA Total Wind Power
Figure 9	ΔSA Demand
Figure 10	ΔSA Total Wind Power
Figure 11	ΔDemand – ΔSA Total Wind Power

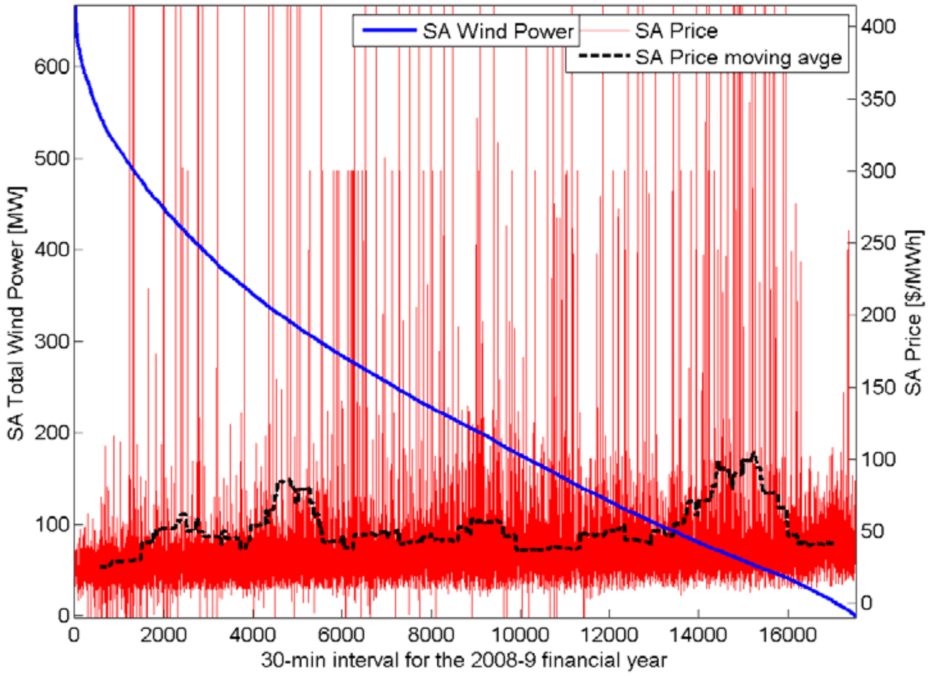

Figure 7: SA Total Wind Power duration curve for 2008-9 with the corresponding price and moving average price (999 data points per window)

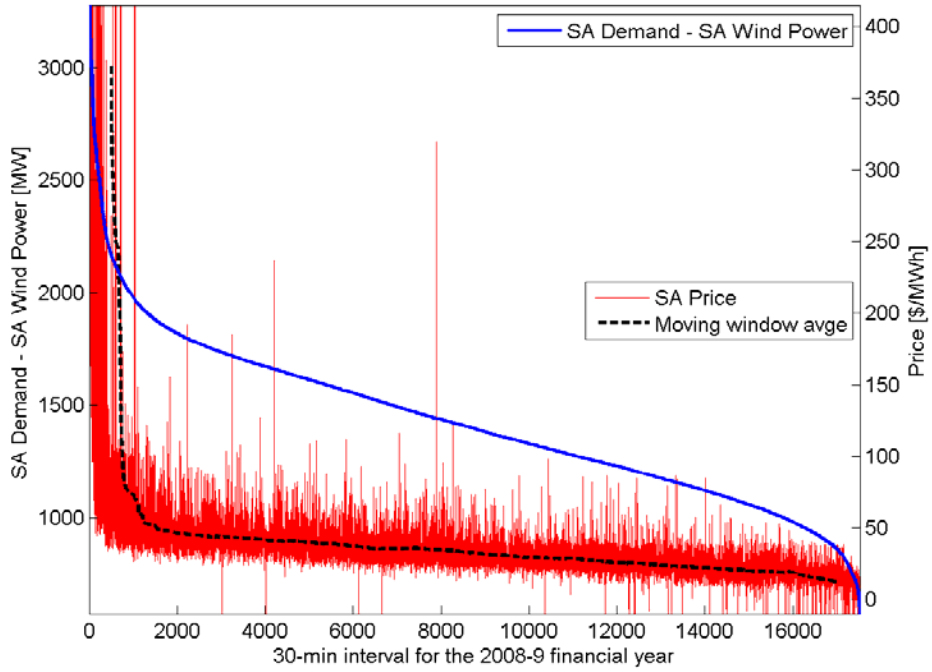

Figure 8: SA Demand minus SA total wind power duration curve for 2008-9 with the corresponding price and moving average price (999 data points per window)

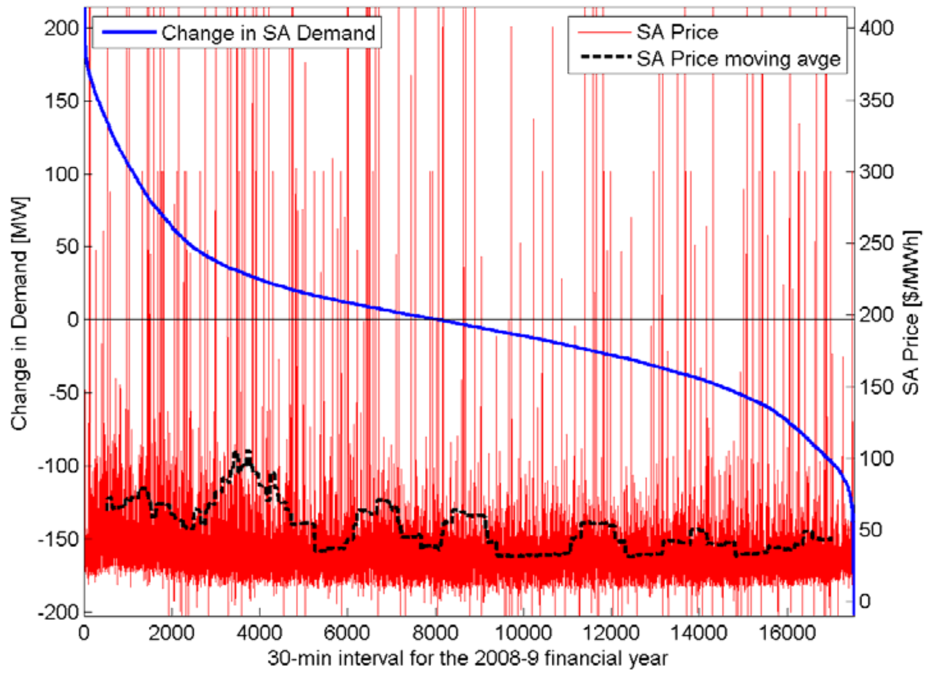

Figure 9: SA change in demand duration curve for 2008-9 with the corresponding price and moving average price (999 data points per window)

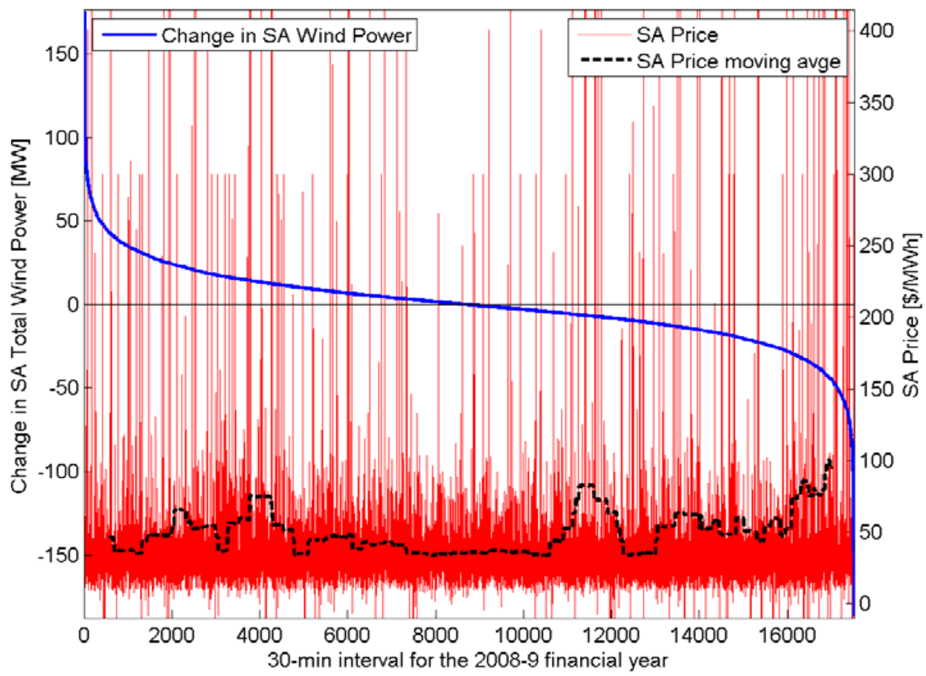

Figure 10: Change in SA total wind power duration curve for 2008-9 with the corresponding price and moving average price (999 data points per window)

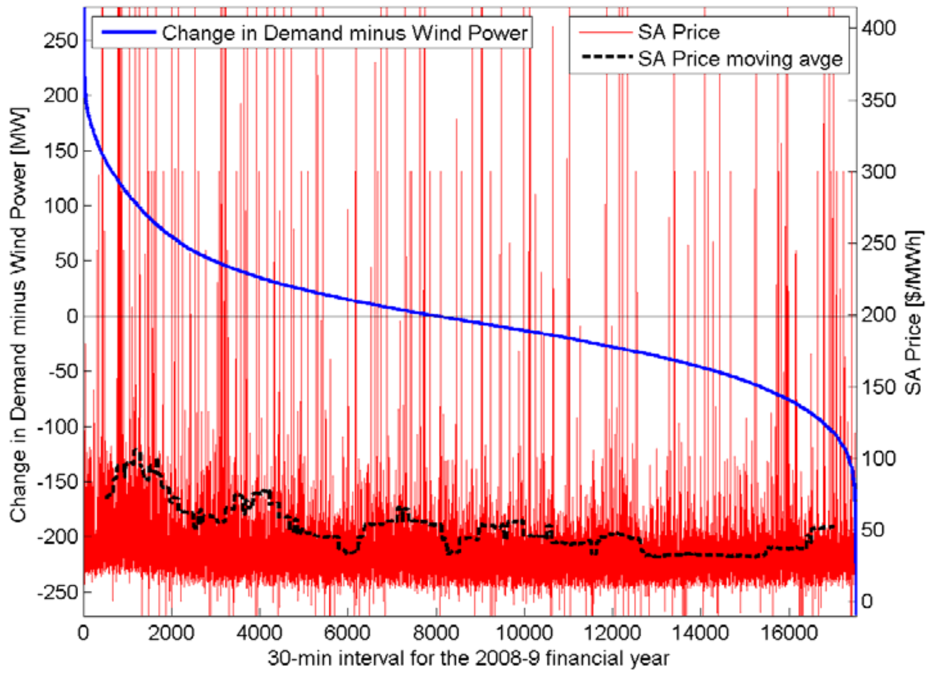

Figure 11: Change in SA Demand minus change in SA total wind power duration curve for 2008-9 with the corresponding price and moving average price (999 data points per window)

Figure 12 shows the 3 moving averages based on sorting on the 3 variables. Note that the moving average relating to SA Total Wind Power has been reversed since the opposite trend in price is expected with respect to Demand or Demand minus Wind Power. The plot shows the expected result that SA Demand has by far the largest influence on SA price[2], particularly the very high prices, which almost all occur during periods of high demand (refer to Figure 5). Subtracting wind power from the demand does not make much difference to the moving average curve, with the highest 999 values giving an average price of around $370 per MWh for both cases. SA Total Wind Power does appear to have a secondary influence on price, since there is a small upward trend in average prices for decreasing values of SA Total Wind Power. Figure 7 shows that no negative price events occur for the lowest third of wind power values (to the right of around 11700 data points). There is also a high concentration of negative price events for the top 10% of wind power values. This indicates a possible connection between negative prices and high levels of wind power where wind power generators may be competing with inflexible thermal plant to remain online at times of low demand. There is a curious result however, where for the lowest 1200 values of SA Total Wind Power, there is no price above $250 per MWh (refer to Figure 7). The moving average increases to above $100 per MWh for around the 14500th to 15500th SA Total Wind Power values but then decreases back to around $50 per MWh for the lowest 999 SA Total Wind Power Values. This is discussed further in regards to Figure 16.

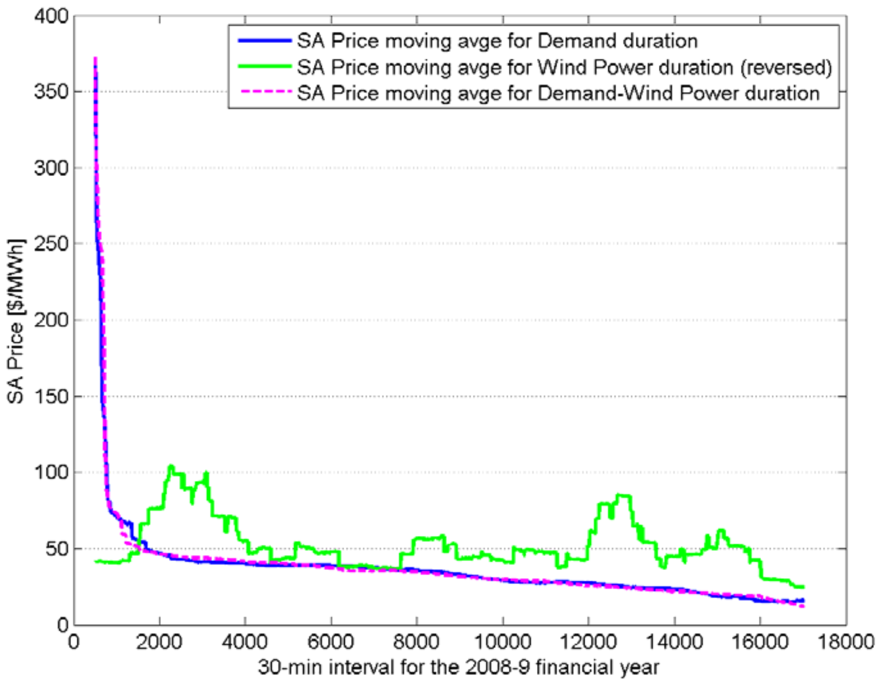

Figure 12: The 3 moving averages for SA price after sorting the data set on SA Demand, SA Total Wind Power and the difference between these two variables. Note that the SA Total Wind Power sorting is ascending where the other two are sorted descending

Figure 13 shows the 3 moving averages based on sorting on the change in the 3 variables over the 30-minute intervals, with the moving average for the change in SA Total Wind Power again reversed for the same reasons as above. The plot shows that all three moving averages have some considerable variation, yet there is a trend for higher average prices over the first 4000 values. All three curves have moving average prices above $100 per MWh at some point but with the variation around that, it is difficult to make any conclusion as

[2] It is noted here that the spot price is ultimately determined by generator bidding behaviour within the context of a security constrained economic dispatch, but this study attempts to draw some general conclusions that may be considered independent of generators bidding behaviour.

to which of the three variables has the most influence on price. However, the plot suggests that each of these variables have a similar effect on price, whereas for the actual values (refer to Figure 12), the demand dominates the effect of wind power.

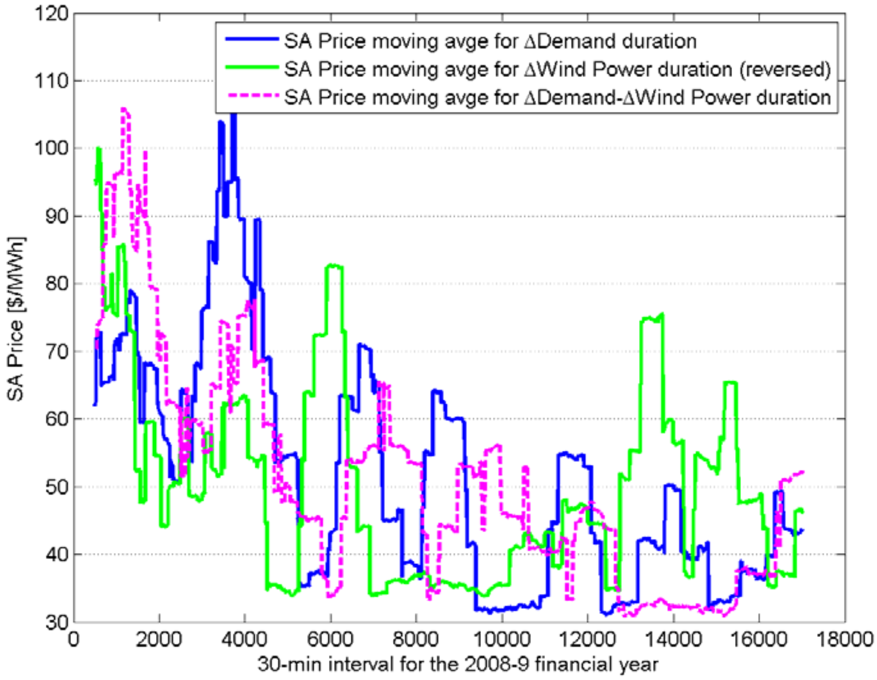

Figure 13: As in Figure 12, except for sorting on the change in the variables over a 30-minute interval, rather than on actual values

Figure 14 shows the 2008-9 demand duration curve with corresponding total wind power. It also shows the moving average total wind power with 999 data points per window. The moving average total wind power varies between 200 MW and 250 MW without a clear trend except a slight tendency for wind power generation to be low during times of very high demand. Furthermore, of the highest 500 demand values, 427 occur in hot summer weather. This may be expected as calm summer days are likely to be hot as a consequence of being associated with high pressure systems.

Figure 15 shows demand duration curves with associated wind power for each of the four seasons in 2008-9. The plots show that the lowest wind power occurs in autumn, which is also the season with the lowest levels of peak demand. The average wind power for the highest 999 demand values is 242 MW in winter, 212 MW in spring and summer and 166 MW in autumn. In winter, there are only a few low wind power readings associated with high demand values. In this sense, winter is the season with the best match between wind power and peak demand.

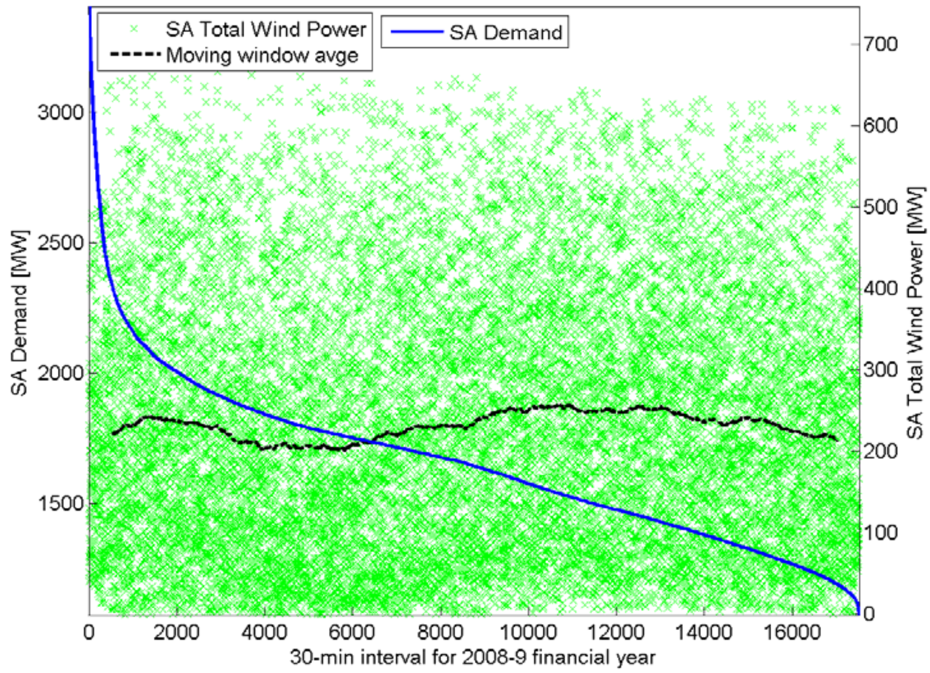

Figure 14: The demand duration curve for 2008-9 with the corresponding total wind power and moving average total wind power (999 data points per window)

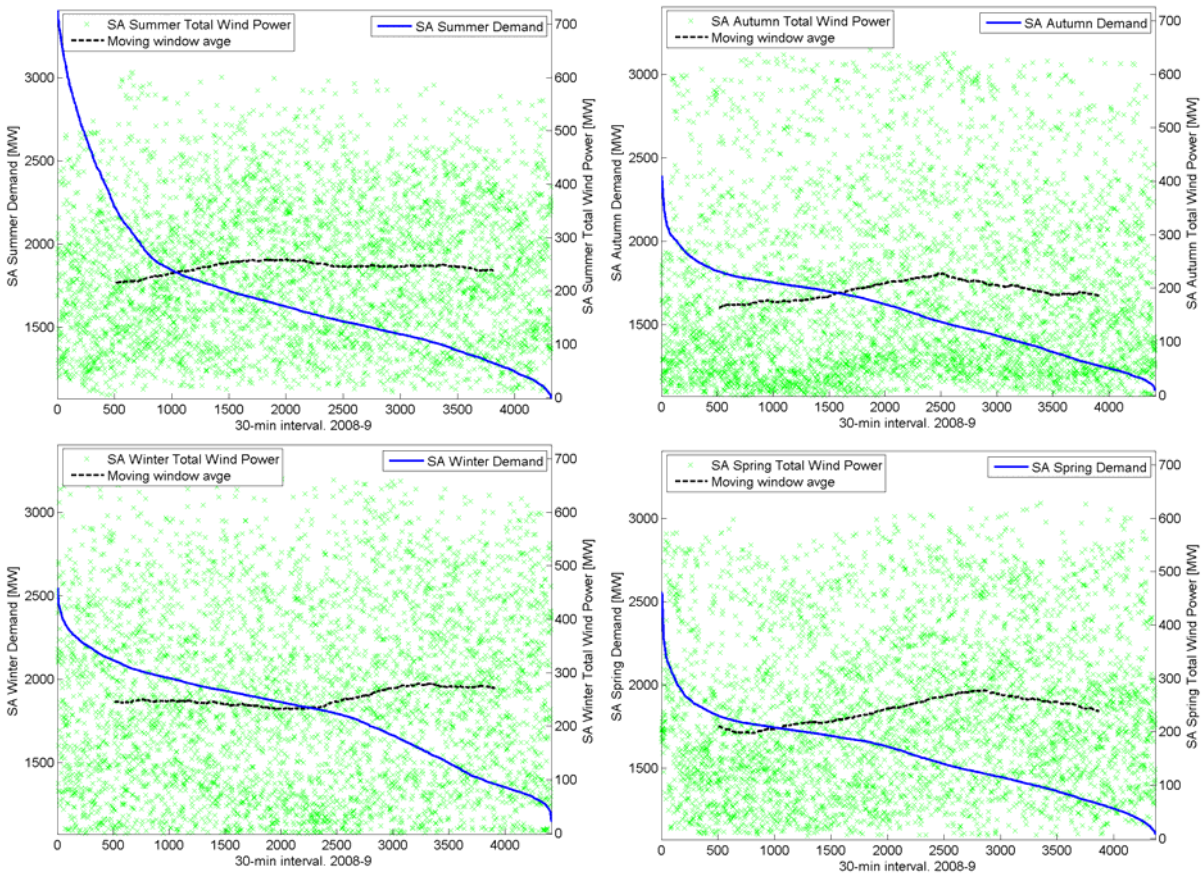

Figure 15: Demand duration curves for each season in 2008-9 with the corresponding total wind power and moving average total wind power (999 data points per window)

We can assess the contribution of wind power generation during peak demand periods by examining the wind power duration curve over a filtered data set of the 10% highest demand values. Along with the result for the full 2008-9 financial year, Figure 16 shows the result for two smaller data sets containing the top 10% of demand values in Summer and Winter. Of the data set for the top 10% of demand values over the full financial year, 40% of the intervals are in summer and 48% are in winter. Figure 16 shows that the total wind power is around 3.8% of installed capacity for 95% of the intervals over the full financial year, and is around 28% of installed capacity in 50% of the intervals. The equivalent percentages for the similar figure in the ESIPC Planning Report for 2009 (Electricity Supply Industry Planning Council 2009) are 3% and 20%. Their result appears to be taken over several years however, rather than the most recent financial year. There are disadvantages with either approach to assessing a generalised result – the ESIPC result contains many earlier years with a smaller number of wind farms operating in South Australia and Figure 16 contains data for only one year.

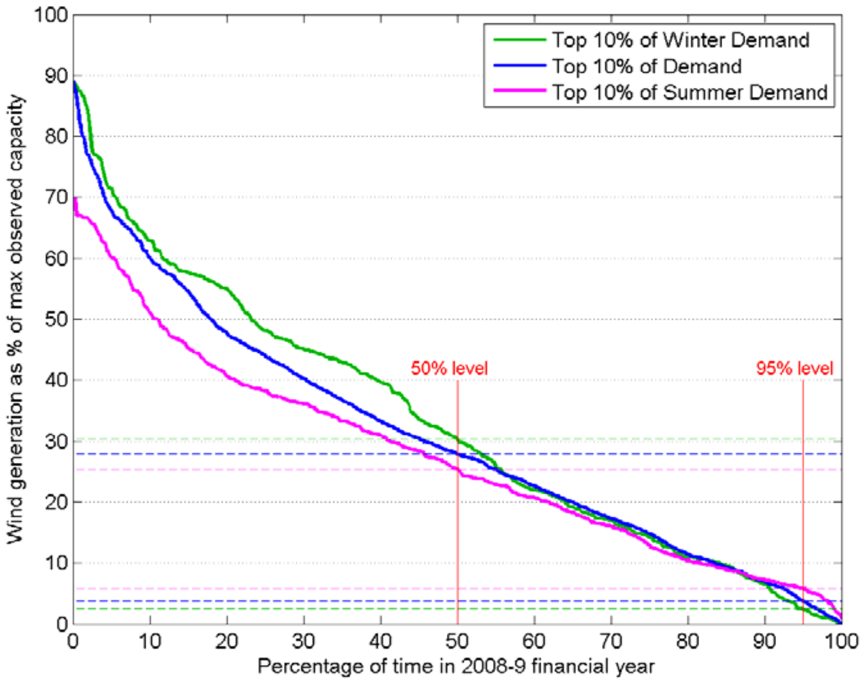

Figure 16: Histogram of normalised total SA wind output for high demand periods

3.3. Volume-weighted prices

Table 5 shows the volume-weighted prices for renewable generators and combustion generators. Data for 2005-8 have been taken directly from the Electricity Supply Industry Planning Council Annual Report (2009). The difference in volume-weighted prices between renewable and other generators may grow as wind energy penetration increases because of the current tendency of wind farm owners to offer their generation in the spot market at a low (and possibly negative) price – a reflection of their low operating costs and separate Renewable Energy Certificate income under MRET. Table 5 shows that the gap between the annual volume-weighted prices varies but with an upward trend. Variability in the price gap is to be expected for a range of reasons, such as weather-related uncertainty.

Table 5: Volume-weighted prices for all wind farms and all other generators in SA ($/MWh) and the difference between them as absolute values and as % of the volume-weighted price for total SA demand (VWP_d)

Period	All wind farms	All other generators	Absolute price difference	% Difference rel. to VWP_d
Financial year 2005-6	32.6	43.9	11.3	26.1%
Financial year 2006-7	49.7	58.7	9.0	15.5%
Financial year 2007-8	63.3	102	38.7	39.4%
Financial year 2008-9	46.7	70.5	23.8	35.4%

Table 6 shows some statistics using volume-weighted prices for different conditions, where ∆Dem refers to the change in demand between the previous 30-min interval and the current interval, and ∆WP refers to change in SA total wind power calculated in the same manner. For each condition, the volume-weighted price is shown using the data directly, and for a set of truncated price data where all prices less than $0 were set to $0 and all prices higher than $415 were set to $415. The prices were truncated to prevent extremely high or low prices dominating the calculated volume-weighted prices. The price cap of $415 was chosen based on the ACIL Tasman (2009) estimation of incremental operating costs of power plants in SA with the highest being around $412 per MWh for two of the distillate gas plants and one diesel plant.

The table shows that for splitting the data in two halves based on high and low SA Demand gives volume weighted prices of $99 and $24, respectively. Splitting in two halves based on low and high SA Total Wind Power gives volume weighted prices of $71 and $63, respectively, which are values much closer to each other. This result is consistent with the previous results where it appears that for this data set SA Demand has a dominant effect on SA price but SA Total Wind Power may have a secondary effect.

Table 6: Average prices and volume weighted prices (Price, P, is per MWh)

Condition	Volume Weighted Price		Proportion of data
	Price	Prices truncated to the range 0-415 $/MWh	2008-9
All data	$67	$40	100%
$0 < P < $100	$35	$35	97.9%
Dem > 1642 MW	$99	$51	50%
Dem < 1642 MW	$24	$25	50%
WP < 208 MW	$71	$40	50%
WP > 208 MW	$63	$36	50%
∆Dem > 0	$84	$44	46%
∆Dem < 0	$53	$36	54%
∆WP < 0	$76	$40	50%
∆WP > 0	$59	$40	50%

3.4. Seasonal trends

Figure 17 shows the seasonal patterns in the daily profile of demand, while total wind power and volume-weighted prices are shown in Figures 18 and 19 respectively. Negative prices are not truncated but positive prices are capped at $415 per MWh so that extremely high prices do not dominate the averages.

The average daily demand profiles are similar in autumn and spring. The winter average daily demand profile rises steeply in morning (6-9 am) and evening (6-9 pm). Summer has the largest variability in daily profile, which is presumably driven by temperature, whereas the largest average half-hour demand is at 7pm in winter.

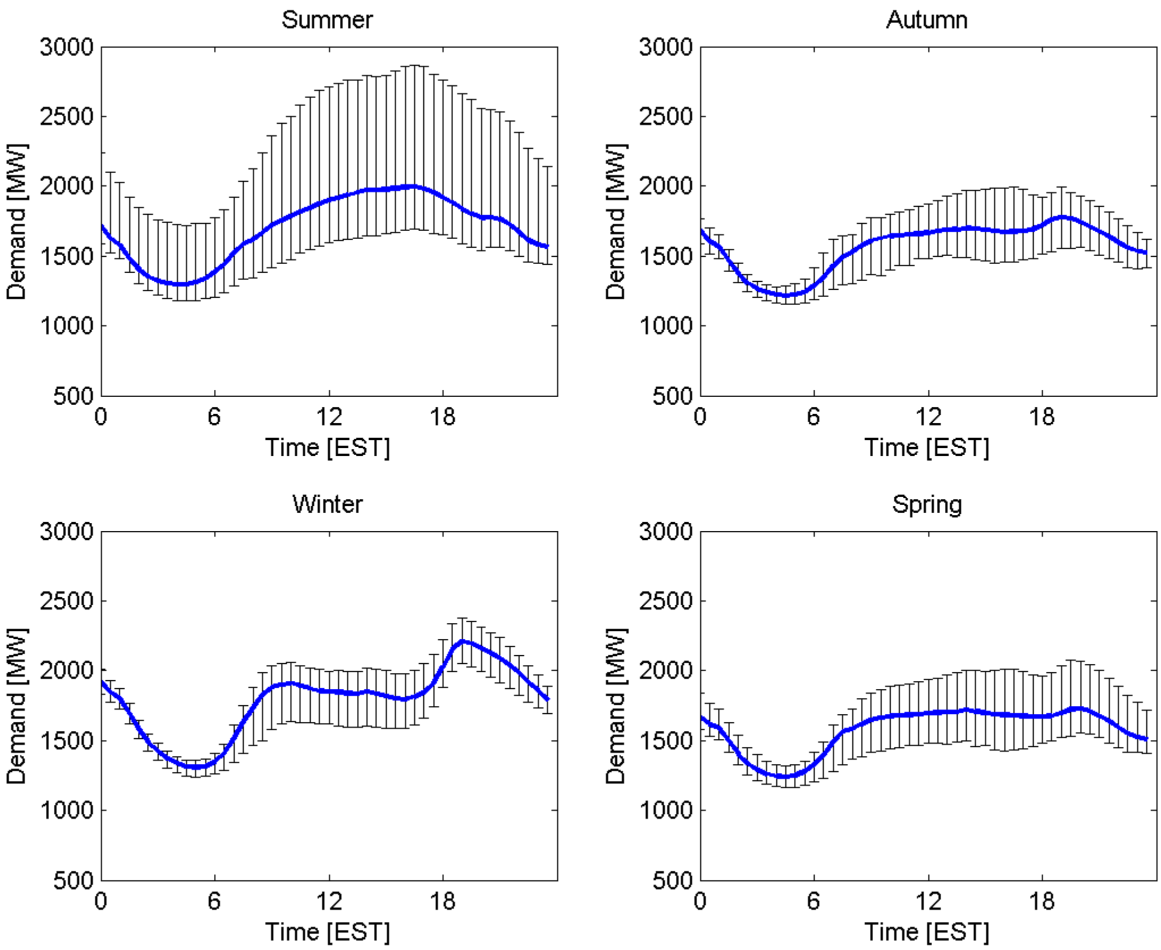

Figure 17: The average SA daily demand profile for each season in 2008-9 with error bars at 2 standard deviations above and below the average

The average seasonal wind power profiles in are relatively flat in all seasons except summer, which has a minimum at 12 pm and a steady increase from 12 pm to 6pm, presumably due to sea breezes. Autumn has the lowest average wind power with the entire average daily profile less than 200 MW. The volume-weighted average daily price profiles in Figure 19 look similar to those for demand, except during summer afternoons and around 6-7 pm in winter where relatively high demand occurs frequently. This indicates that prices can increase significantly for small increases in demand at high demand levels.

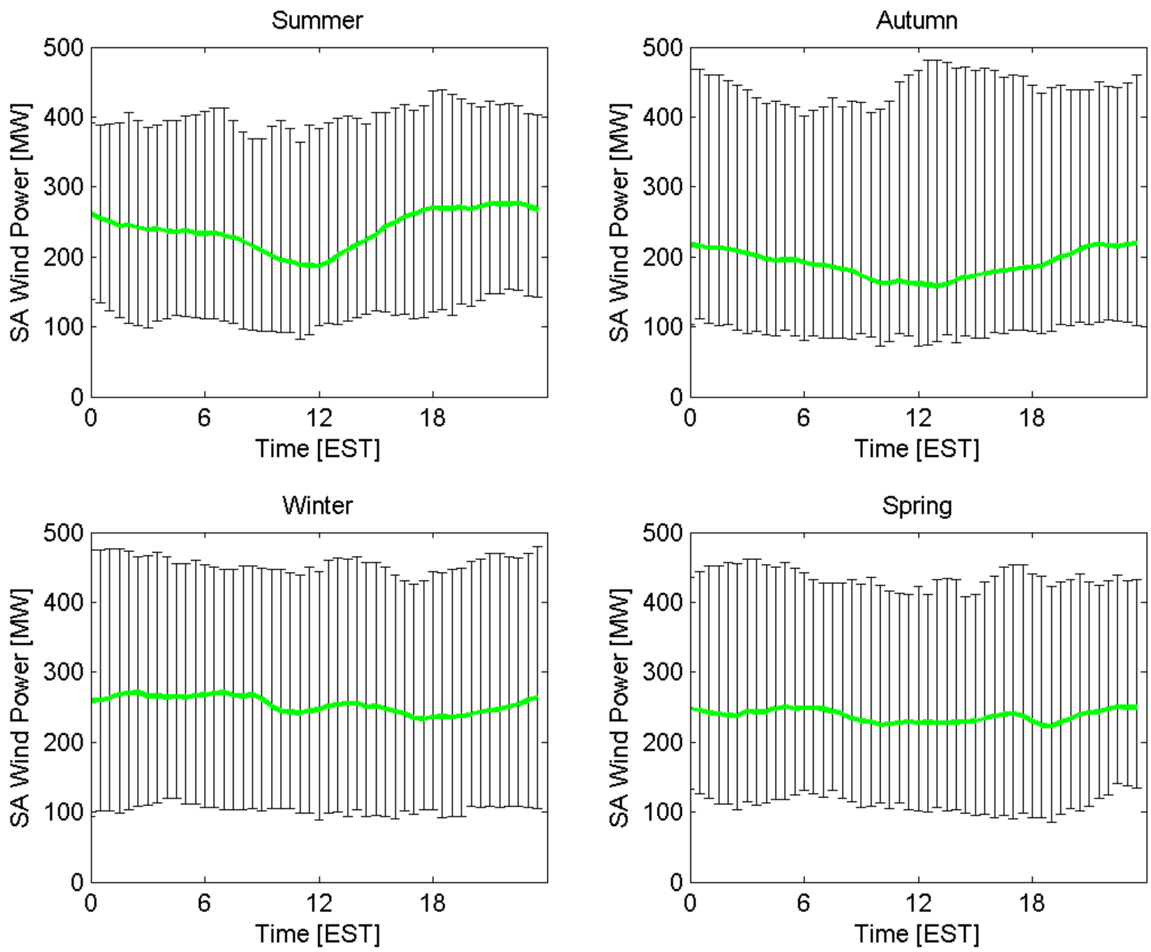

Figure 18: The average SA daily total wind power generation profile for each season in 2008-9 with the error bars indicating 2 standard deviations of the data points lying above and below the average

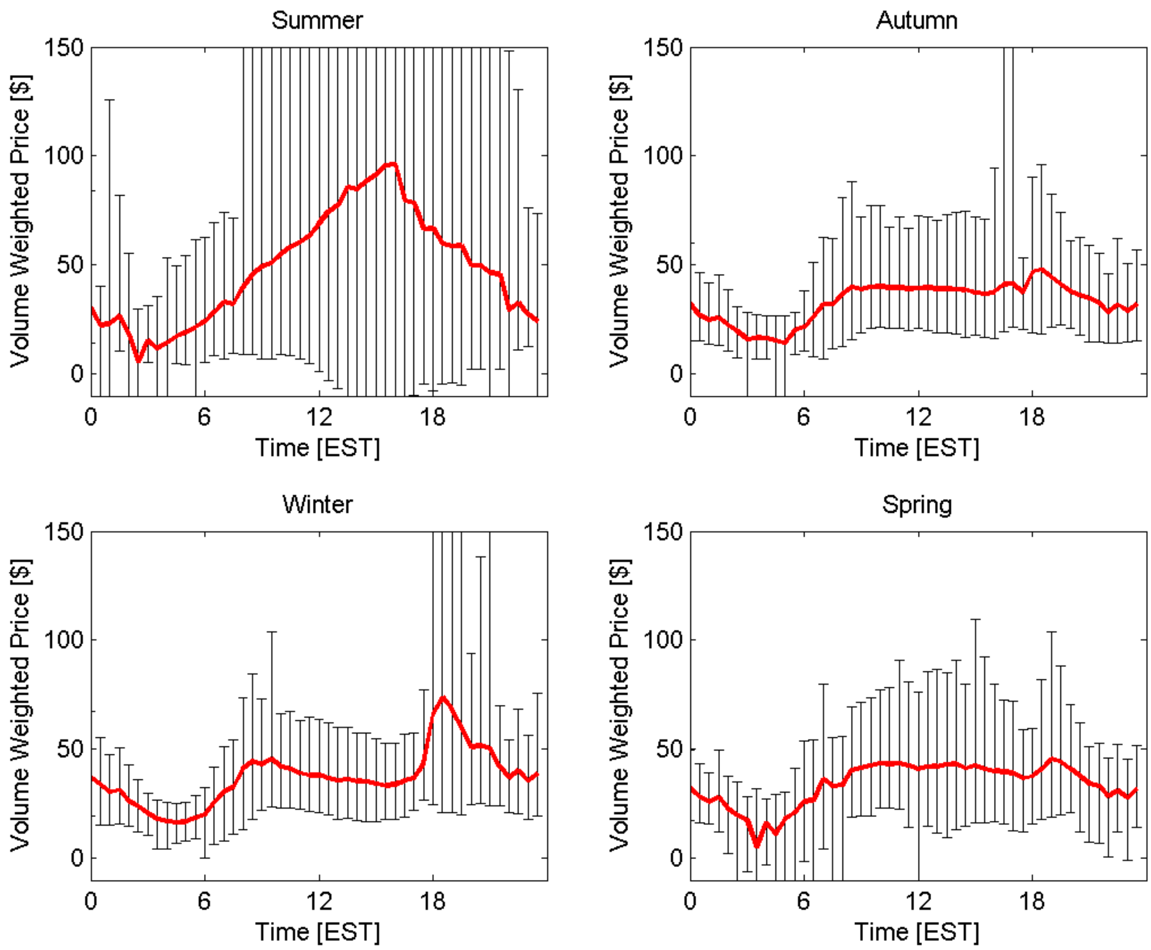

Figure 19: The volume weighted average SA daily price profile for each season in 2008-9 with the error bars indicating 2 standard deviations of the data points lying above and below the average, after capping the prices at $415

Figure 20 shows the average seasonal daily profiles for demand and wind power as seen previously on the same plot with some truncation for high demand levels for clarity. This shows that the average daily variation in wind power is small compared to that in demand. However the error bars in the plots show that the variability with respect to the average is larger for the wind power generation than for the demand at certain times. This is particularly apparent during the night for Autumn, Winter and Spring. However the plots do not how much the wind power generation may vary from one half-hour interval to the next, compared with demand.

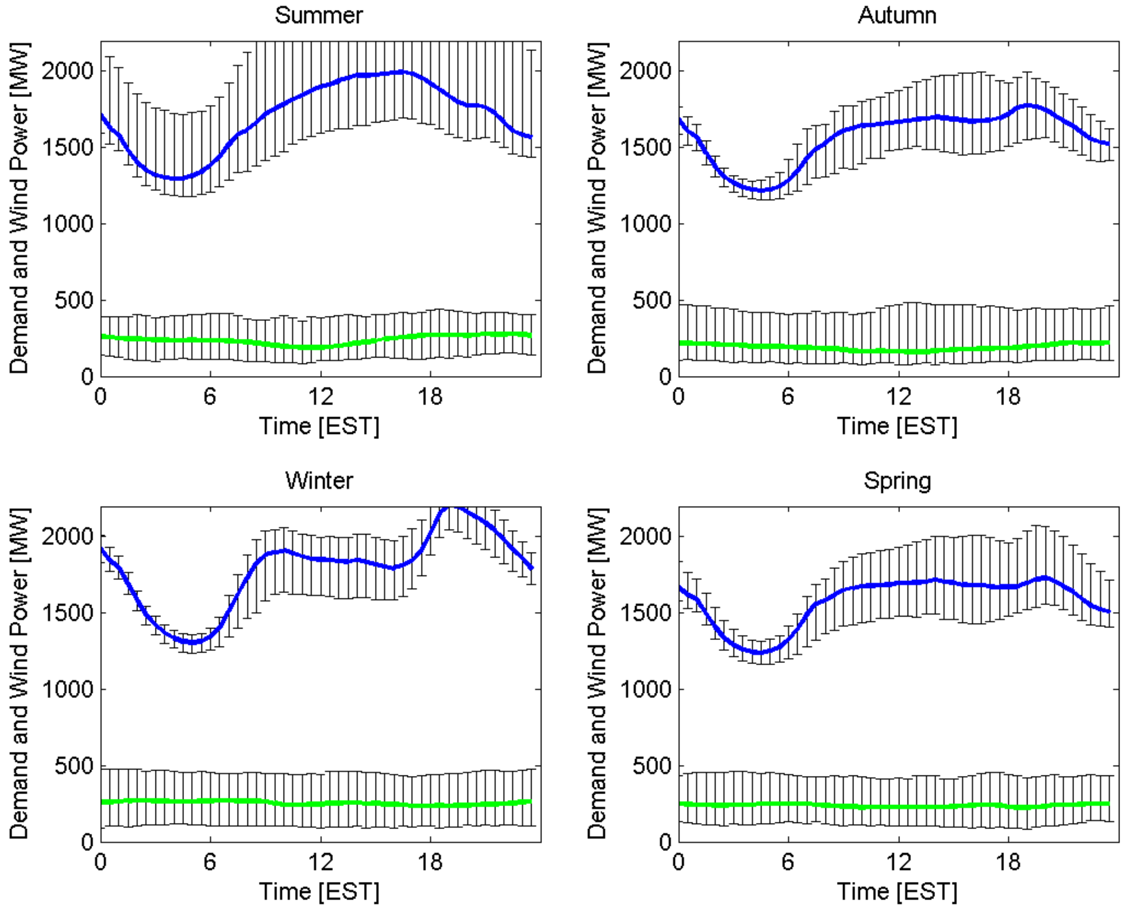

Figure 20: The average SA daily demand profile and total wind power daily profile, combining Figure 17 and Figure 18

Figure 21 and Figure 22 explore price differences during periods when wind power is either high or low. The mean wind power is calculated for each day, and then days are sorted on these values. The days with the top 25% of daily average wind power are defined to be high wind power days and the days with the bottom 25% of daily average wind power are defined to be low wind power days. The results are shown for each season in Figure 21 for actual prices and in Figure 22 for prices truncated to the range \$0 to \$415 per MWh. While the results for actual prices are dominated by extremely high prices, the results for capped prices show a clear trend for prices to be higher on low wind power days at all hours of the day. This trend is quite pronounced in autumn and spring at all hours of the day, whereas in winter and summer the major differences occur at the times of the highest average prices. For low wind power days, the average daily price profile reaches around \$100 per MWh at 4 pm in summer and 6:30 pm in winter. For high wind power days the equivalent times in summer have average prices of \$25 per MWh and peaks at only \$70 per MWh in winter.

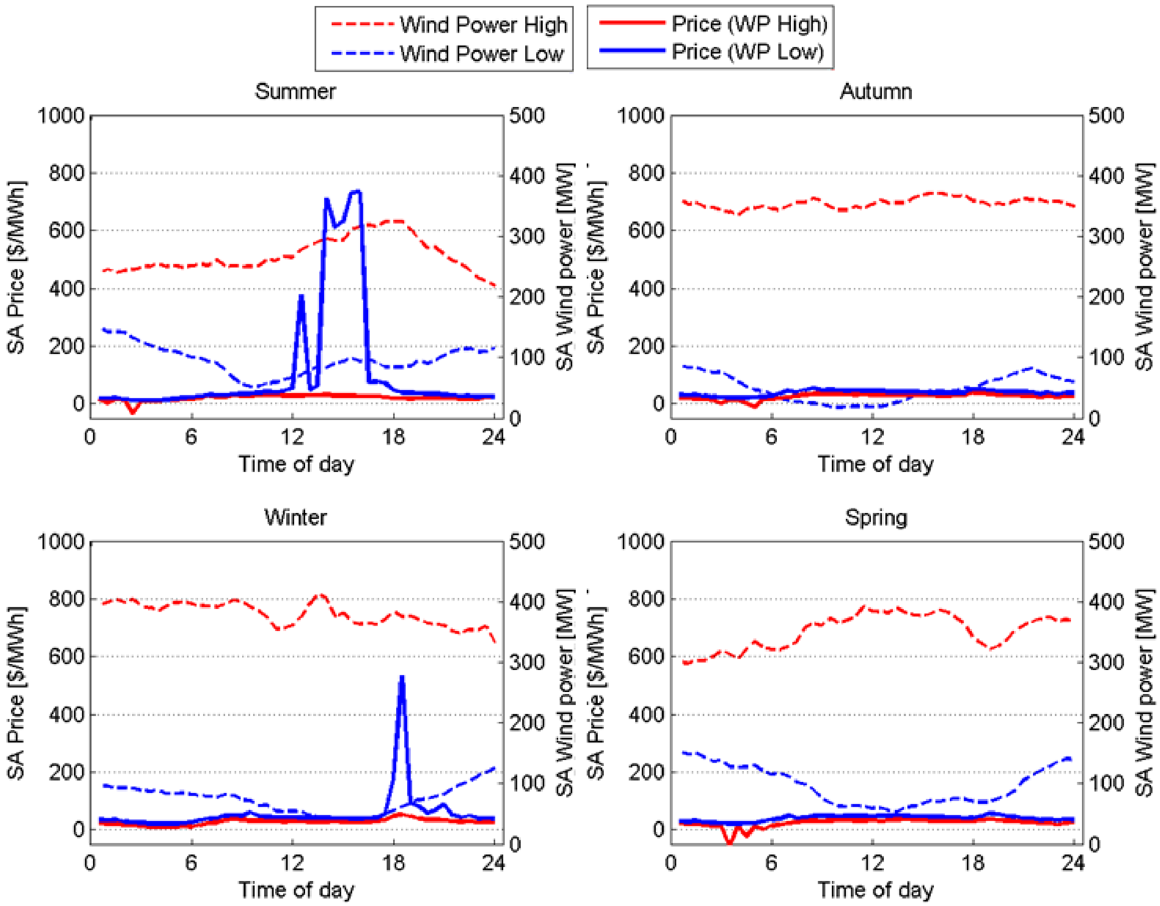

Figure 21: Daily profiles of wind power and price on working weekdays, after splitting the data set into high and low average levels of wind power

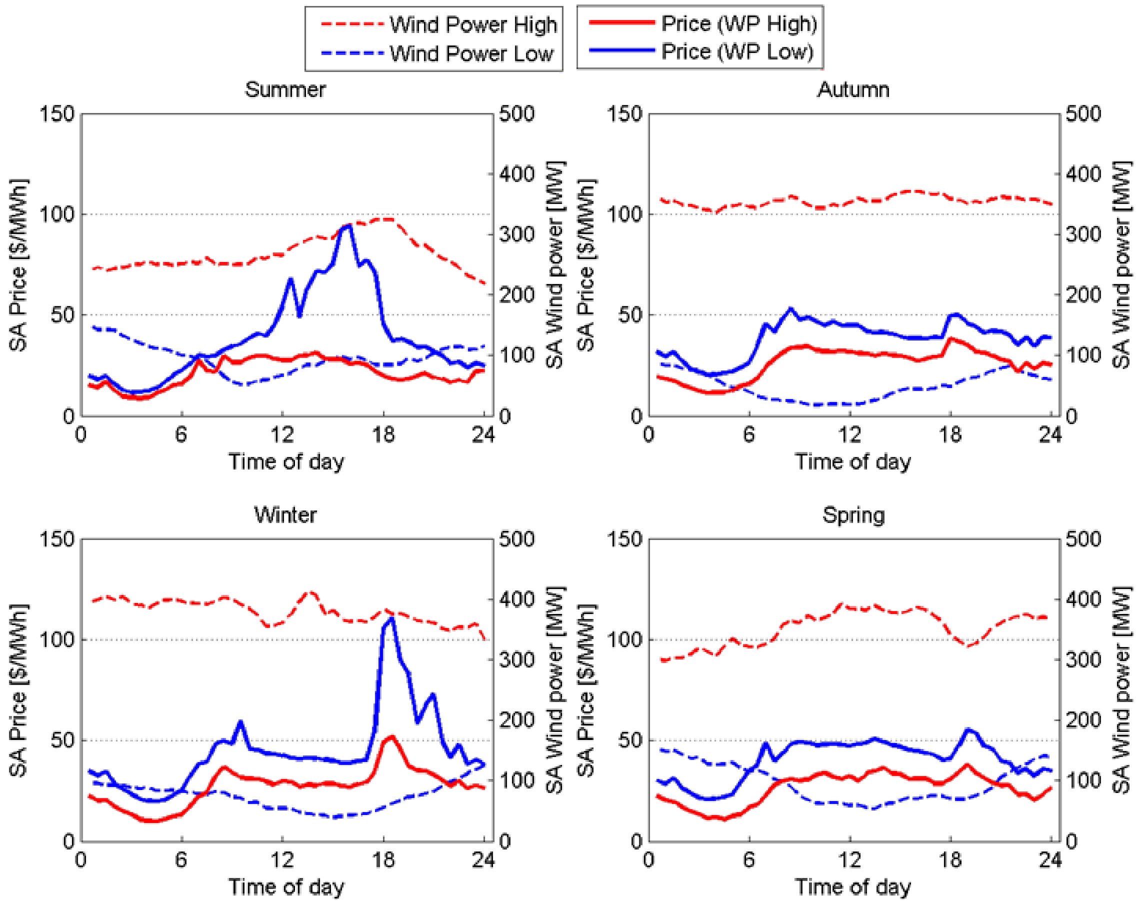

Figure 22: Daily profiles of wind power and price (after truncating between $0 and $415) on working weekdays, after splitting the data set into high and low average levels of wind power

The average daily profiles for wind power from individual wind farms are shown in the following 2 figures, organised by season and grouped according to the region where they are installed in South Australia. Figure 23 shows results for the two northern, inland wind farms Hallett Hill and Snowtown, as well as three of the wind farm around the peninsulas; Cathedral Rocks, Mount Millar and Wattle Point. For comparison purposes, the daily profiles of SA Demand, Volume Weighted Price and Total SA Wind Power Generation are also shown. Figure 24 shows results for the remaining four wind farms; the three coastal south-eastern wind farms, Lake Bonney 1, Lake Bonney 2 and Canunda, and the wind farm just south-west of Adelaide, Starfish Hill. A couple of points of interest are as follows:

Most wind farms show a strong sea breeze effect in summer afternoons, except Cathedral Rocks. Since Cathedral Rocks is installed on a coastal cliff, the reasons for this are not clear.

Most wind farms show relatively higher generation at night, except the three south-eastern wind farms. This may be because the south-eastern wind farms are the only ones not installed on a ridge or cliff. Overnight boundary layer effects such as inversion layers have been known to cause higher wind speeds at night at wind turbine hub height levels, particularly if they are located inland and on ridge tops.

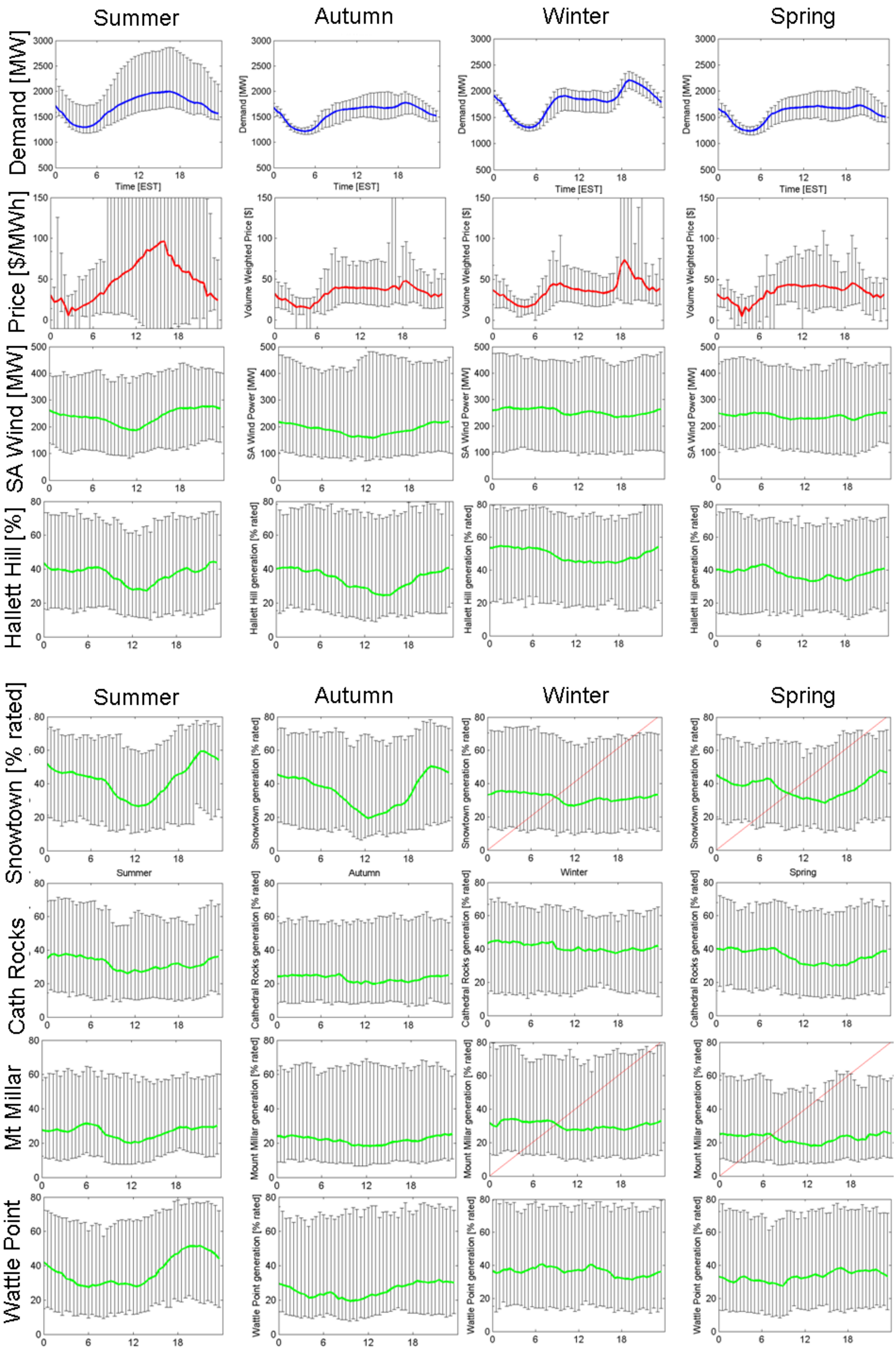

Figure 23: Average daily profiles where the columns represent the seasons and the rows represent different quantities. The first three rows show the SA total demand, volume weighted price and total SA wind power generation (in MW) and the remaining rows show individual wind farms (as % of rated power). Where wind farms are not fully operational, the results are not directly comparable and are hence crossed out

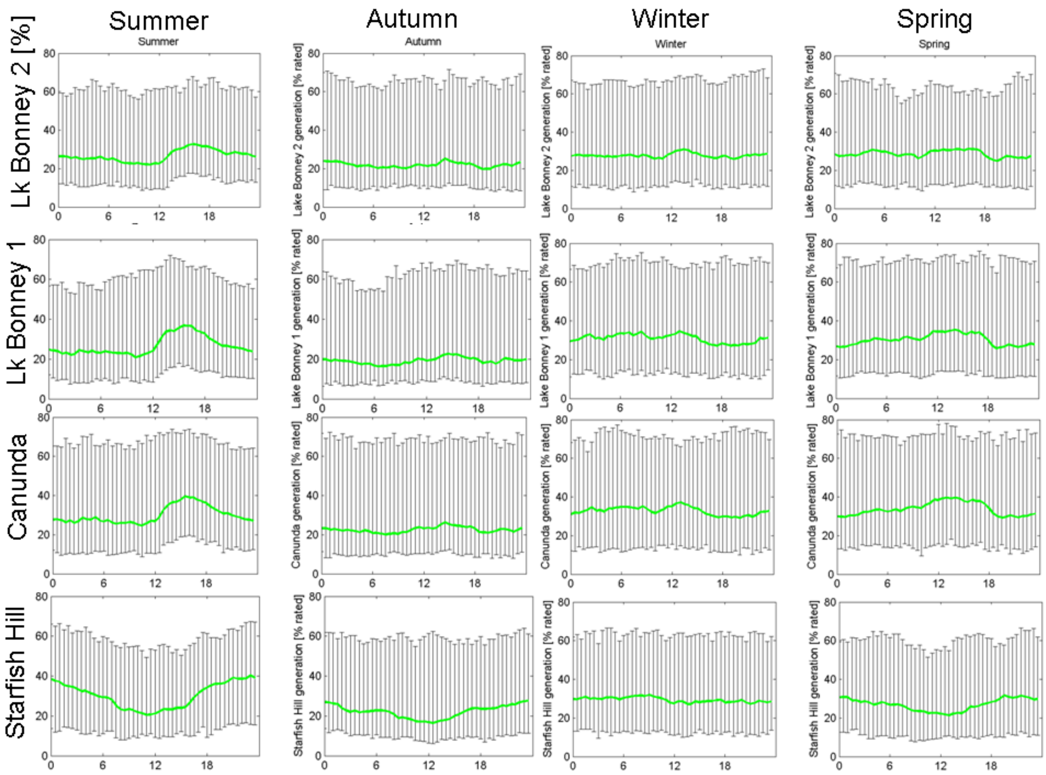

Figure 24: As in Figure 23, except for the average daily profiles of wind power generation for the four remaining individual wind farms

3.5. Extreme price events study

It is a complicated task to attempt to fully understand extreme price events, since they are a result of a complex bidding structure from various generators as well as other factors including such factors as binding network constraints or ramp rate limits nominated by generator (National Electricity Market Management Company Limited 2008). In South Australia a single corporation, AGL, owns 39% of the generation assets. When demand rises above around 2400 MW, AGL usually become an essential contributor to supply and have potentially significant opportunities to set the market price. During these periods the spot price is sometimes near the market price cap of $10,000[3] (Australian Energy Regulator 2008). The following section analyses some general trends in extreme price events in South Australia using the 12-month data set in order to help better understand the underlying drivers.

Over the 12-month period studied, 52 events are detected where the price exceeded $100 per MWh (high price events) and 32 events where the price fell below $0 (negative price events). A high price event where the price dropped back below $100 per MWh for one 30-minute interval and then increased again over $100 in the next interval is considered as one event (and visa versa with negative price events). These events have an average duration of 2 hours (4 time-steps). Table 7 summarises the occurrence of the extreme price events by season, showing a strong variation with season.

Table 7: The number of extreme price events by season in the 2008-9 data set

[3] From 1 July 2010, the NEM price cap is to increase to $12,500 (http://www.aemc.gov.au/).

Season	No. of high price events	No. of neg price events
Summer	23	8
Autumn	8	4
Winter	19	3
Spring	2	17
Total	52	32

A distinct pattern is detected in the cold weather from 21 July to 25 August 2008 and from 1 June to 30 June 2009. Of the 19 high price events in this period, 14 are at 18:00 as the demand increases sharply (refer to the daily demand pattern for winter in Figure 17). In 9 of these 14 cases, the wind power generation is less than 100 MW at the time step where the price exceeds $100 for the first time. Thus, the regular sharp increase in demand at around 18:00 in these months causes prices to rise over $100 on one in four days, particularly if wind generation is low. An example of one of the 12 cases where demand increases, wind power decreases and the price exceeds $100 is shown in Figure 25.

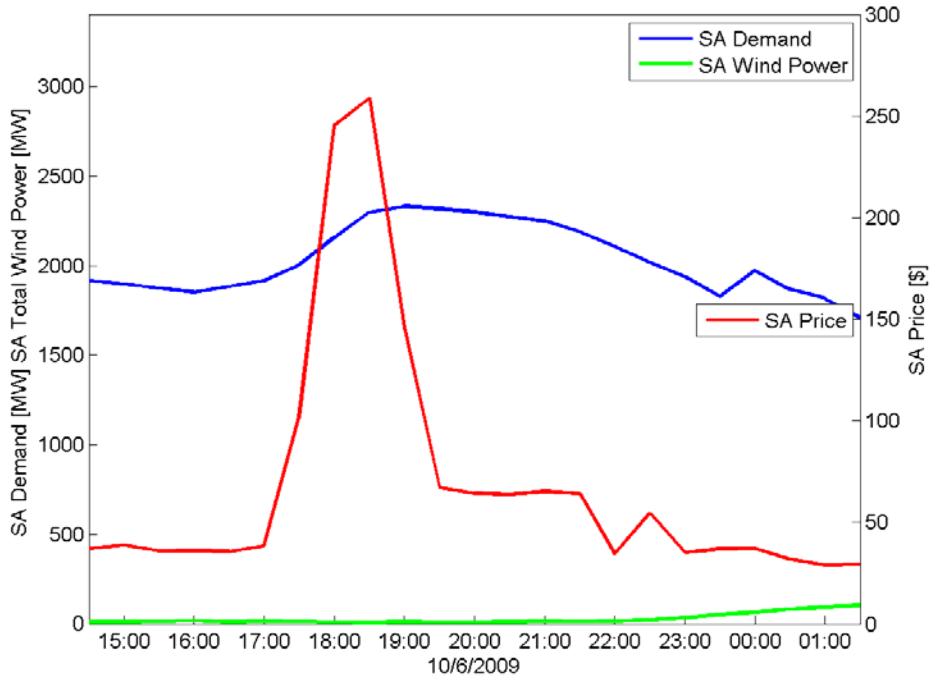

Figure 25: Example of a high price event occurring on 26 April 2009, showing the demand, price and total SA wind power generation over 24 hours

All of the 23 high price events in summer occur during January and February. Most of these high price events occur in the afternoon and some last for many hours. All of these appear to be due to very high demand during heat waves. In 17 of the events, wind power decreases in the half-hour interval preceding the start of the event and exhibits little change in the preceding half-hour in 3 of the remaining 4 cases.

Figure 26 shows a histogram of the 32 negative price events listed in Table 7. The minimum half-hour price lay between $0 and -$50 per MWh in 12 events and may indicate that a wind power offer was setting the price for at least part of the time during those events[4]. However,

[4] Since RECs are typically worth in the order of $20-40/MWh, it is feasible that a wind power offer could be negative by around this amount with the aim to still make a profit, taking into account their operating costs.

this has not been confirmed. As shown in Table 7, there were no negative price events in winter and only one in the aforementioned extended period of 26 April to 31 August. During the 16 negative price events in spring, wind power generation is judged as being high in 12 cases and medium in the other 4 cases.

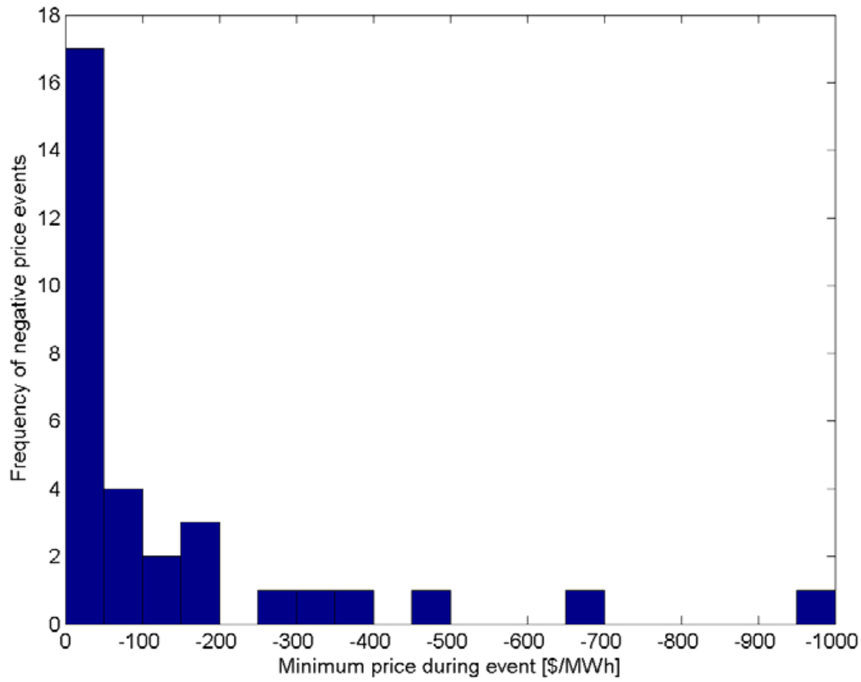

Figure 26: Frequency histogram of negative price events showing the minimum half-hour price during each event

4. Future work

The following points describe potential areas for future work on studying the effects of wind power generation on the NEM in South Australia.

- Incorporating forecast information into the study. Since generators are likely to use forecasts of demand and wind power generation to design their bidding strategy, an examination of the differences between demand forecasts and actual demand, as well as between wind power forecasts and actual wind power may show some interesting results. Predispatch data including forecasts of demand (updated half-hourly) with a 30-minute resolution is available at http://www.aemo.com.au/data/csv.htm. Wind power forecast data is more difficult to obtain, as market participants are required to pay NEMMCO for wind power forecasts from the AWEFS system. Obtaining AWEFS forecasts, and knowing what wind power forecast information market participants are using is likely to be significant challenge.
- Developing some further understanding on the causes of negative price events.
- Some further work on individual wind farms would be interesting. In particular it would be interesting to see individual wind farm earnings on a seasonal basis, or by time of day. This would show which wind farms are better located to support the SA market at particular times, depending on their wind regime.

A more in depth study, looking at the dispatch of the individual generators in the South-Australian region as well the interconnector flows to see how the market is settling the variations in wind power.

Studying the bidding behaviour of individual generators to gain more insight into very high price events, or negative price events.

5. Conclusions

For the 2008-9 data set, demand remains as the dominating factor affecting price in South Australia and wind power has a significant secondary influence. There is a clear inverse relationship between wind power generation and price, and the change in wind power from one time interval to the next may also play a role in price changes. For the 2008-9 data set, when wind power is low, the price tends to be higher and is sometimes very high. If the wind power is high, the converse is true. In some seasons there are distinct patterns of extreme price events in the 2008-9 data set and it is likely that good wind power forecasts would assist in forecasting such extreme price events if they continue to occur in the future. It is however difficult to make conclusions about the effect of SA Total Wind Power on SA Price in the future, because it is completely dependent on generator bidding strategies, which are subject to change.

6. References

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