Estimating the Impact of Renewable Energy Generation on Retail Prices

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SINCLAIR KNIGHT MERZ

SKM

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Sinclair Knight Merz
ABN 37 001 024 095
Floor 11, 452 Flinders Street
Melbourne VIC 3000
PO Box 312, Flinders Lane
Melbourne VIC 8009 Australia

Tel: +61 3 8668 3000
Fax: +61 3 8668 3001
Web: www.globalskm.com

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Executive summary

The impact on retail prices associated with the policies that support renewable energy generation – either under the Large-scale Renewable Energy Target (LRET) or the Small-scale Renewable Energy Scheme (SRES) – is a controversial issue.

SKM MMA undertook a study of the impacts of the large scale renewable energy targets on wholesale prices, with this impact ultimately flowing through to retail tariffs.

The net impact for customers associated with the LRET is calculated as the changes to wholesale prices caused by the injection of new supply into the market, minus the cost of running the scheme and paying for the certificates that are created under the scheme. Net impact on retail prices from the LRET are shown in Table 1.

Table 1: Retail price impacts, $/MWh, real dollars mid-2012.

	With Carbon			Without carbon		
Period	2011-2015	2016-2020	2021-2025	2011-2015	2016-2020	2021-2025
South Australia	-3.20	-9.74	-4.40	-2.77	-9.16	-7.31
Victoria	-1.34	-7.67	-5.99	-0.05	-7.76	-7.49
NSW	-0.31	1.98	6.30	1.09	2.27	2.68
Queensland	0.00	2.84	5.41	1.48	3.62	3.08
Weighted Average	-0.83	-1.87	1.32	0.46	-1.54	-3.07

Note: negative numbers indicate savings to consumers.

These results show that customers in Australia are on average likely to have a price reduction over the period to 2020 as a result of the LRET, albeit that there may be a modest increase in prices from sometime after 2020.

By way of example, a typical Victorian household using 7,000 kWh per annum is saving approximately $35 per annum under the LRET over the period 2011-2025 (in real mid-2012 dollars) compared to a scenario in which the LRET did not exist.

The price reduction is due to the wholesale price effect of the LRET, which - at approximately $12/MWh over the period 2011-2025 (in real mid-2012 dollars) - more than outweighs the impact of increased liabilities for certificates as the target grows.

In addition, to the extent that competition amongst retailers is limited, and to the extent that the LRET creates greater contestability through the creation of economically sustainable new entrant retailers, there will be further downward pressure on the retail margins. Under such conditions, the RET scheme may, by providing an opportunity for the creation of integrated new entrants, increase retail contestability and, hence, retail prices. SKM has not sought to quantify this effect in this report, but recognises that this may be a further benefit of the RET.

1. Introduction

Deployment of wind and solar energy generation has occurred over the past few years induced by the incentives provided by the Renewable Energy Target Scheme (and its predecessor the Mandatory Renewable Energy Target Scheme). Penetration of these technologies is still a small proportion of total generation but should grow to around 12% of total generation by 2020. Penetration in some regions is very high, particularly South Australia where penetration is already over 20% of total capacity.

Debate has raged over the impact that the incentives provided to support renewable energy generation (either under the Large-scale Renewable Energy Target (LRET) or the Small-scale Renewable Energy Scheme (SRES)) has on retail prices. The gap between the cost of the renewable energy generation and the revenue received from electricity sales is made up by the creation and sale of certificates, which have to be redeemed by liable parties to demonstrate compliance with scheme targets. The cost of these certificates is smeared across all retail electricity sales, putting upward pressure on retail tariffs.

However, large scale deployment of renewable technologies may depress wholesale prices as the variable cost of some renewable generation technologies is low. This so called merit-order effect may lead to high cost plant being displaced in the merit order and this puts downward pressure on wholesale prices which will flow through to retail prices under competitive market conditions. However, there is considerable debate over the magnitude and duration of this impact. Furthermore there are countervailing impacts which would lead to upward pressure on prices.

Similarly, there is a view that the renewable energy targets could increase the level of competition in retail markets, by leading to the creation of viable integrated retailers that are economically sustainable and independent from the major retailers. Increased competition would ultimately lead to lower retail margins.

SKM MMA undertook a study of the impacts of the LRET on wholesale and retail margins, both of which will ultimately flow through to retail tariffs. An empirical analysis was undertaken to determine the presence, magnitude and duration of any price impact. The analysis focuses on the impact of the level of variable generation technologies such as solar and wind as these were identified to likely have the most impact due to their low variable costs and their high penetration in the market.

A number of approaches were adopted to empirically determine any impact. The approaches were developed based on the insights gleaned from a review of the literature on the possible impacts. Whilst not definitive, the results of the analysis point to the likely magnitude and highlight some key factors that are likely to determine direction and duration of the impact on electricity prices. The empirical analysis was national in scope, but had a focus on the South Australian market as this state has experienced a penetration level of both technologies sufficient to elicit a detectable response.

This report contains the findings of this study. Whilst the findings may provide insights on the distributional impacts, the study does not represent a full economic benefit cost study of this scheme. For example, whilst the finding may suggest some price reduction to consumers, this implied benefit represents a transfer and could come at the expense of reduced revenues for generators[1].

Note all monetary values in this report are in mid-2012 dollar terms unless otherwise stated.

[1] For an example of the welfare impacts, see T. Nelson, P. Simshauser and J. Nelson (2012), "Queensland Solar Feed-In Tariffs and the Merit-Order Effect: Economic Benefit, or Regressive Taxation and Wealth Transfers?", *Economic Analysis & Policy*, Vol. 42 No. 3, December 2012

2. Literature Review

2.1 Overview

The LRET impact on retail prices could work through two components. First, by potentially reducing the wholesale price. Second, by enhancing retail competition and thereby reducing retail margins. Most of the literature has concentrated on the wholesale price impact, with a focus on empirical verification of its impact.

The effects of large-scale renewable generation on wholesale and retail prices will be likely to be minimal to date in most states due to the low level of penetration of renewable generation (see Table 2). Although there are high penetrations of hydro-electric generation, penetration of wind and solar generation is low in most States except South Australia, where penetration is around 27% of peak demand and around 97% of minimum demand.

Table 2: Penetration of renewable technologies, 2012-13, MW

	Thermal capacity	Renewable capacity	Total capacity	Proportion renewable	Proportion renewable to minimum demand	Proportion renewable to maximum demand
NSW	13801	2587	16388	16%	51%	19%
QLD	11841	654	12495	5%	16%	8%
SA	3417	816	4233	19%	94%	27%
TAS	386	2170	2556	85%	329%	136%
VIC	9132	2606	11738	22%	72%	27%

Source: ESOO (2012), SKM analysis. Capacity is installed capacity.

Retail tariffs to customers are made up of several components. These components and the contribution of renewable generation supported by the RET scheme are outlined below:

- Wholesale prices, which are prices set in the established wholesale market of the NEM and WEM and also include prices for supporting ancillary services. Financial or bilateral contracts may override prices set by the spot market, with such contracts including a margin to cover the risks protected by the contract. Renewable generation under the RET scheme may lower or increase wholesale costs depending on the interaction of the renewable generation in the spot markets and the need for additional ancillary services to cope with variable generation patterns.
- Market administration and operation fees, which cover the cost of administering and operating the wholesale markets, and monitoring compliance with the market rules. Renewable generation has no direct impact, although a high level of embedded renewable generation (say from roof-top PV) may mean that these (essentially fixed) costs are spread over fewer customers.
- Transmission costs, covering the costs of high voltage networks that transmit electricity from the generators to the major load centres (including some large final end-use customers). Renewable generation is likely to have no direct impact although to the extent that renewable generation is more remote then there may be an impact through the need for additional infrastructure.
- Distribution costs, covering the costs of distributing electricity from transmission off-take points to final end use customers such as households and commercial centres. Renewable generation is unlikely to have a direct impact, but the extent of embedded generation will indirectly impact on tariffs under the existing revenue cap arrangements.
- Retail costs including retail margins, which cover for the costs of retailing services such as billing and metering.
- LGC certificate costs, which include the cost of covering the subsidy required to support renewable generation under the LRET. This covers the cost of purchasing certificates so is directly linked to the price of certificates.

2.2 Wholesale price impact

Wholesale prices can be considered to be made up of several components. First, there is the spot market price which covers the cost of purchasing energy (and capacity) on the wholesale markets. This is determined through auctions at central exchanges. Prices on these exchanges are usually determined by factors that affect the balance between supply and demand plus the costs of operation of power stations. Second, there are premiums paid on hedges or bilateral contracts to mitigate the risk of dealing solely on spot exchanges. These premiums are determined by the perceived volatility in prices and the participants' attitudes towards risk. Finally there are the costs for ancillary services that support reliable operation of a grid system, usually paid on a causer or user pays basis (determined through spot markets or through tender). High levels of wind and solar PV penetration can impact on these cost elements.

The principle impact on wholesale prices occurs through the merit order effect. The merit order effect occurs because of the low variable costs of two principal sources of renewable generation, namely wind and solar generation[2].

The effect is illustrated in Figure 1, which is a conceptual representation of the price setting process for a typical trading interval. In any trading interval, the central dispatcher will rank generation bids in order of rising bids, leading to a rising curve of capacity offered and their associated bids. The bid curve represents a supply curve, typically showing rising levels of generation offered with price. The bid from the marginal generator required to meet the demand for that interval at lowest cost (represented by the curve D_t) sets the price for that trading interval (point P_o). Introduction of renewables with low variable cost effectively shifts the supply curve to the right (because typically renewable generation has low or zero variable cost so will tend to be put in the low cost part of the curve). The same demand can now be met by generation with lower variable cost, and thus there is a lower clearing price (i.e. P_r).

Several studies have attempted to test the prevalence of the merit order effect and its magnitude. Ketterer (2012) illustrates that there is a negative relationship between price and the level of wind generation in the German market – high levels of wind generation tended to lead to lower wholesale prices[3]. Time-series methods were used to determine a significant relationship between the level of wind generation and decreasing wholesale prices. This occurred also when forecasts of the following day's wind generation were used as the independent variable. Green and Vasilakos (2011), applying an optimisation model to hypothetical market structures, found an impact of wind generation on prices, but determined this impact was relatively small especially once thermal capacity adjusted bids in response to higher levels of renewable generation[4]. Woo et.al. (2010) found that wind generation tended to reduce the spot price in the Texas electricity markets, with every 10% increase in wind capacity leading to price decreases of around 2% to 9%[5]. Traber and Kemfort (2011) found that for the German electricity markets power prices were reduced by more than 5% as a result of the level of wind generation[6]. And a study of the Irish electricity market found that wholesale electricity prices would have been 12% higher if no wind generation had been installed[7].

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[2] Biomass generation incurs a fuel cost, which can be a high variable cost. Hydro-electric generation, to the extent that water inflows can be stored even for short periods, has a potentially high opportunity costs because operators can elect to use the water for generation in high price periods

[3] Janina C. Ketterer (2012), *The Impact of Wind Power Generation on the Electricity Price in Germany*, Leibniz Institute for Economic Research.

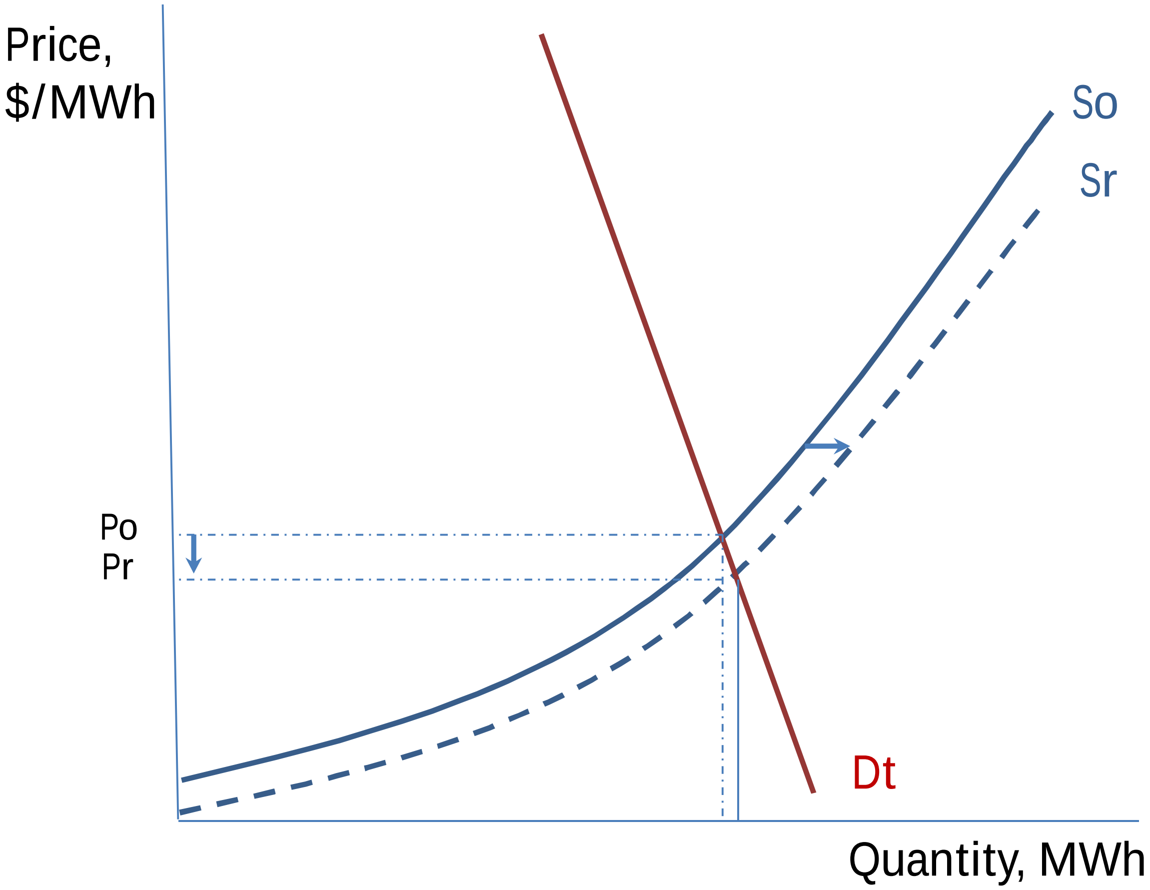
[4] Richard Green and Nicholas Vasilakos (2011), "The long-term impact of wind power on electricity prices and generating capacity", *Department of Economics Discussion Paper 11-09*, University of Birmingham.

[5] C. K. Woo, I. Horowitz, J. Moore and A. Pacheco (2010), "The impact of wind generation on the electricity spot market price level and variance", *Energy Policy*, 39 (7).

[6] Thure Traber and Claudia Kemfort (2011), "Gone with the wind? Electricity market prices and the incentives to invest in thermal power plants under increasing wind energy supply", *Energy Economics*, 33, pages 249-256.

[7] A. Mahoney and E, Denny (2011), "The Merit Order Effect of Wind Generation in the Irish Electricity Market", paper presented at the 30th IAEE/USAEE North American Conference, Washington DC, Oct 2011

Figure 1: Illustration of the merit order effect



The American Wind Energy Association (AWEA) reviewed and summarised the findings of several studies to show that[8]:

- Consultants for the New York State Energy Research and Development Authority, using regression analysis, found that the addition of renewable generation to the New York grid have lowered wholesale electricity prices by US$1.60/MWh to US$2.50/MWh. This was additional or separate from the impacts caused by lower natural gas prices and by a lower demand.

- The PJM System Operator found that adding 15,000 MWh of wind to the system reduced wholesale prices by between US$5.00/MWh to US$5.50/MWh.

- A study conducted for the Midwest Independent System Operator, showed that prices in the Midwest in 2020 could be US$3.68/MWh lower if 20 GW of wind capacity could be installed (and 12 GW of coal capacity retired).

All except the first study relied on simulation analysis to study the impact of future wind capacity. Only the study relating to New York prices was based on a statistical analysis of historical data.

Although most studies have related to the impact of wind generation on market prices, some recent studies in Europe have concentrated on the impact of increased penetration of solar PV generation.

[8] AWEA (2012), *Wind Lowers Energy Prices*,

A number of factors were found to impact on the magnitude of the effect. The magnitude of any price impacts depends on when generation occurs. This depends on the structure of the supply curve. In the Australian context, electricity generation in most NEM regions exhibit low variable cost base load generation (traditionally mainly coal-fired generation) for a large amount of capacity and then sharply rising costs as capacity exceeds some threshold, typically when gas-fired generation capacity is required. If the bulk of wind generation occurs in off-peak periods then there will be generally a low impact as only relatively low-cost base load generation is displaced. If the bulk of wind generation occurs in peak periods, then there could be a high impact as relatively high cost plants are displaced in the merit order. This effect is illustrated in Figure 2.

In the case of South Australia, this effect has been observed[9]. Wind generation is typically biased towards low price periods so the merit order effect may be small. In addition, there is a seasonal impact with little wind generation in the high priced peak periods in summer.

Other factors that can determine the impact on prices include:

- Nature and structure of ownership of the wind farms. If the wind farms are owned by the incumbent generators then the degree to which they can game the market (by controlling wind farm output or output of their thermal plant) or organise the dispatch of each plant can reduce the price impact[10]

- The imposition of carbon prices, if they continue to increase over time, will ameliorate the difference between peak and off-peak price impacts as the carbon prices will tend to narrow the difference between peak and off-peak prices. However, in the short to medium term, carbon prices can amplify the impact of the wholesale price reduction since carbon prices will increase the margin between the thermal plant being displaced and zero marginal cost of wind generation.

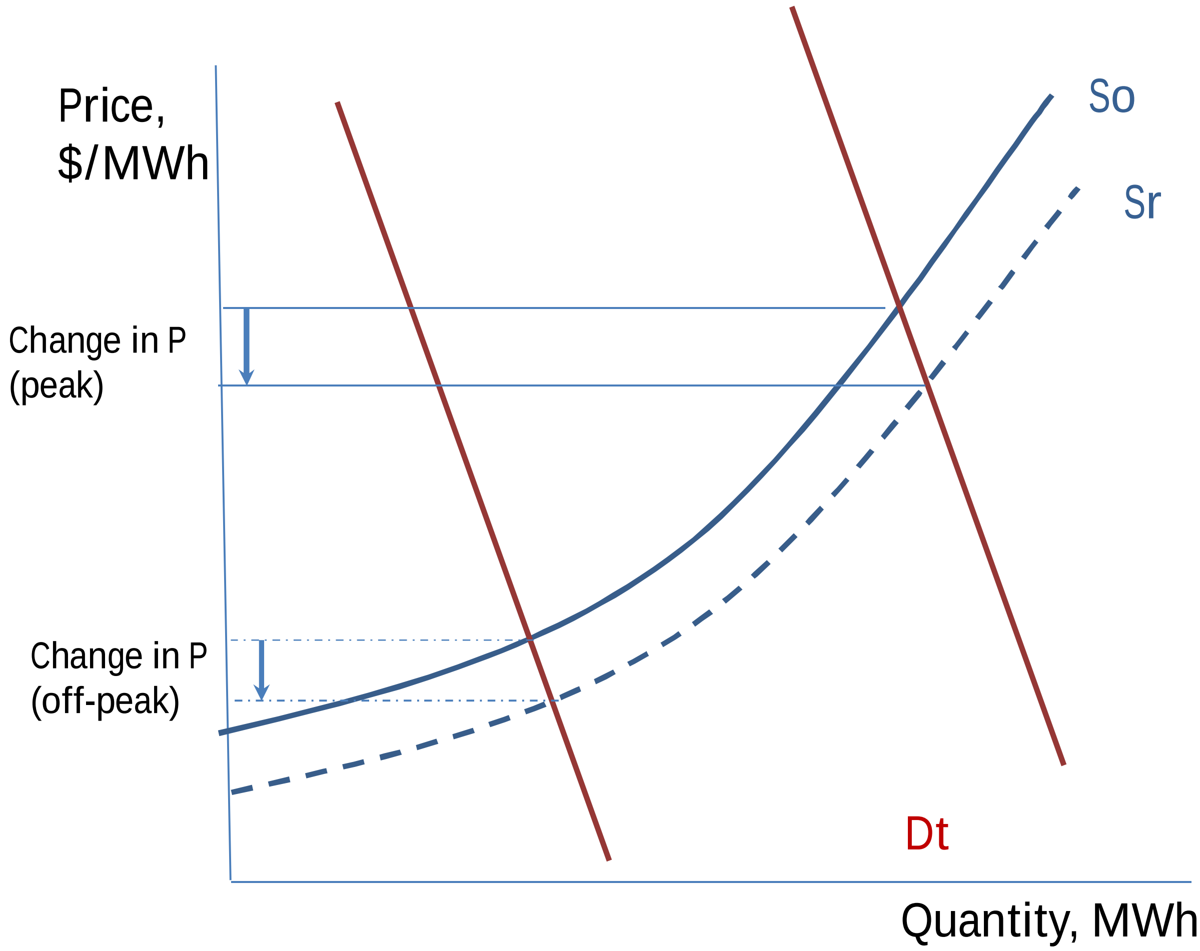
- Structure of the markets, with differences in the magnitude between a capacity/energy style market (as occurs in Western Australia) and in energy only markets (as in the NEM).

- Operational parameters, with the magnitude affected by the degree of transmission constraints and the level of must run thermal generators that must be committed for dispatch.

[9] I. MacGill (2012), "Possible merit order impacts of wind in the Australian NEM", paper presented at the *CEC Workshop on the Merit Order Effect*, February 2012, Melbourne

[10] R. Green and N. Vasilakos (2011), op. cit.; N. Misir (2012), *Wind Generators and Market Power: Does it Matter Who Owns Them*.

Figure 2: Price impact in peak and off-peak periods



Although wind generation may decrease energy prices, a consistent finding in the literature is that higher levels of wind capacity also can lead to increased levels of price variability[11]. Sudden variations in wind generation may require the dispatch of high variable cost plant with quick start or rapid ramp rate capabilities, which typically (but not always) have high variable operating costs. Dispatch of these plants to replace sudden downturns in wind generation can lead to higher spot prices as the need to use the fast ramp plant intensifies.

In the Australian case, South Australia is the region with the highest penetration of wind generation. Simple correlation analysis (see Table 3) indicates no impact or very little correlation between wind generation levels and price volatility.

Two factors can amplify the impact of this variable generation. First, fast start gas turbines generally use gas at low load factors. Such gas can be expensive and can approach distillate prices for the gas turbines that are rarely used. The presence of a spot market for gas can ameliorate this impact. Second, even though the price effect may be felt for the overall market, the impact is more pronounced for some market customers than others, especially customers where demand matches periods with potentially low levels of wind generation.

[11] C. K. Woo, I. Horowitz, J. Moore and A. Pacheco (2010), op. cit; L. Hirth (2012), *The Market Value of Variable Renewables*, available at http://ssrn.com/abstract=2110237

Table 3: Correlation coefficients between levels of wind generation and price changes

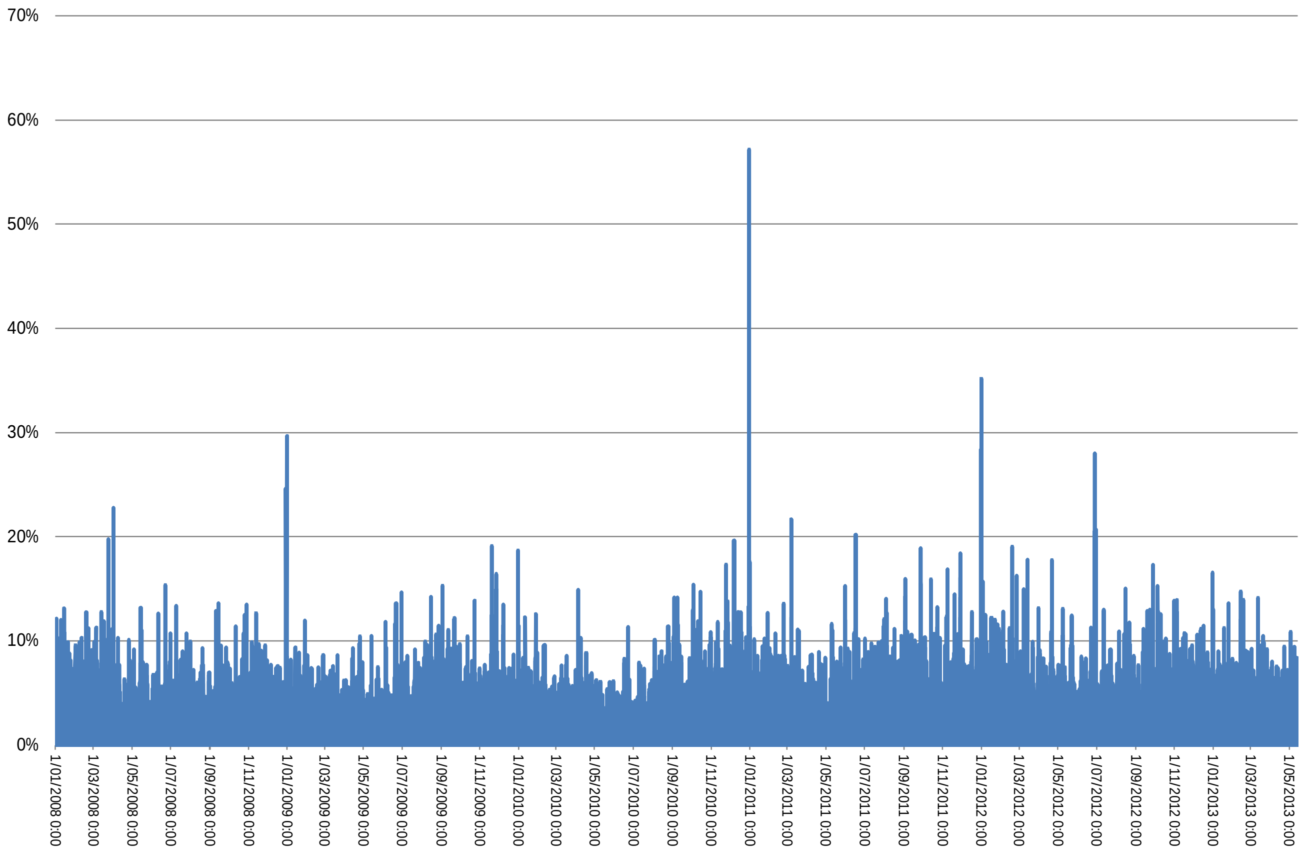
Variable	From 2008	From 2009	From 2010	From 2011	From 2012	In 2012/13
Price	-0.02	-0.02	-0.01	0.00	0.00	0.01
Price variation	-0.36	-0.26	-0.16	0.00	0.04	-0.05

Note: SKM analysis using data from AEMO. The correlations are between the change in wind generation from half-hour to half-hour and the change in price. That is, for a 1% change in wind generation from one half-hour to another, the correlation coefficient indicates the percentage change in price.

On the other hand the degree of variability may be overplayed in the Australian context. There has been a reasonable geographic spread of wind farms. Further, day ahead forecasting for wind generation can also lead to commitment plans that minimise the cost of the swings in generation. Moreover, for some of the States, low cost hydro-electric generation backed by storage is available to minimise the swing in prices.

This can be seen when examining data for South Australia. As shown in Figure 3, the level of volatility in wind generation has remained relatively low, averaging around 2% of wind capacity and generally less than 10% of total wind capacity.

Figure 3: Change in half hourly wind generation



Note: SKM analysis using AEMO data. The data points represent the change in wind generation from half-hour to half-hour as a proportion of total wind capacity.

Wind generation can cause variability in prices to increase. The issue is what level of wind capacity does the variability increase beyond what normally occurs with say swings in demand and to the point where high priced plant are called upon.

Another key finding of the literature is that the merit order effect may dissipate over the long term. New thermal plant will be required in the market and for this to happen market prices will have to return to levels that reflect the long run marginal cost of these plants. A rebalancing of fossil generation portfolio could occur to bring prices back to the long run marginal cost and encourage future capacity needs[12]. This long term impact will clearly be more relevant towards the time new thermal plant are required. With the target increasing to 2020 at a time of subdued demand growth, the impact of this rebalancing is not likely to occur until sometime after 2020.

The change in the load profile faced by thermal generation could also lead to a different investment mix in new plant towards low capital costs but high operating cost plant[13]. This will increase volume weighted prices in the wholesale market over time.

There is a natural barrier to the price reduction effect. A consistent finding in the literature shows increasing levels of penetration of wind in the market reduces the price that wind farms receive from the market (and therefore increases the level of certificate price or subsidy required). Recent evidence for this comes from South Australia, where wind farms used to earn 110% of the time weighted price but more recently this has dropped to around 90% and projections indicate this price could reduce further if more wind farms are developed (and if the interconnect to Victoria is not upgraded) to the low 80's.

Wind power can affect the ability for incumbents to game the market and induce higher wholesale prices. Incumbents with market power can bid up above marginal costs for part of their capacity in some markets. The ability to do this depends on tacit collusion and the ability to signal bidding intentions. Higher bids can become highly profitable to the extent that supply constraints hold in a trading interval. Sudden upswings and downswings in wind generation may make such a strategy more risky and lessen the scope for high margins on bids. The empirical evidence for this is somewhat muted with one study suggesting that wind farms are not likely to reduce market power and that "wind farms are not likely to have reduced spot prices in South Australia to the extent that seems apparent in electricity markets in other countries where wind farms are as prevalent but market power is less significant[14]".

[12] V. Di Cosmo and L. M. Valeri (2012), "The incentive to invest in thermal plants in the presence of wind generation", available at http://www.esri.ie/pubs/WP446.pdf

[13] C. K. Woo (2010), op. cit.

[14] B. Mountain (2012), "Market Power and Generation from Renewables: The Case of Wind in the South Australian Electricity Market", *Australian Economic Report: No. 2*, Centre for Strategic Economic Studies, Victoria University, Melbourne

3. Method and Assumptions

3.1 Overview

Wholesale power markets are complex in nature, influenced by a number of factors, including weather, electricity demand, natural gas prices, transmission constraints, and location. Therefore, determining the direct impact of a single variable, in this case renewable energy, on the financial economics of power generators can be difficult[15].

The literature identified the following factors as having an impact on wholesale prices in an energy-only market:

- The nature of the dispatch curve (the price bid curve) with price impacts less the flatter the dispatch curve.
- The degree of surplus capacity, with a tight supply-demand balance prior to wind generation leading to greater price impacts than a market with excessive surplus capacity.
- The structure and nature of the market.
- The period during which wind generation occurs, with bigger price impacts if wind generation mostly occurs in peak periods.
- The degree of market power. On the one hand, wind generation can help ameliorate market power thus reducing prices. On the other hand, wind generation may have little impact.
- The cost and availability of fast start plant to cover down turns in the market.
- Volatility in wind generation.

In this section, we outline modelling approaches that seek to measure the impact of wind farms on prices taking into account all the important factors identified in the literature. The wholesale price impact is determined in two ways: simulating wholesale markets (the NEM) to determine the impact on wholesale market prices (dispatch prices) without wind in the NEM; and statistical analysis of historical prices to determine the impact that wind generation alone has had on prices (separating out the impact of other factors). Retail price impacts are determined through the use of a market share model that determines the market share and retail margin as a function of the number of retailers in the market. Anecdotal evidence from a number of state markets is used to back up findings of this model.

3.2 Simulation modelling

SKM uses its proprietary simulation model of the NEM to estimate the price impact. Details of the modelling approach and assumptions used are shown in Appendix A.

The model simulates hourly market outcomes in the regional markets in the NEM. Market simulations are carried out for the period from 2008 to 2030. Wholesale price impacts of the RET are determined as follows:

- Simulate hourly price outcomes for each region of the NEM with wind generation under the RET. The amount and location of wind generation is determined by SKM's REMMA model of the renewable energy market, which determines the amount of wind generation in the NEM in competition with other locations (say Western Australia) and other technologies. We use AEMO's medium demand projections as the base demand projection. The model determines hourly clearing prices for a typical week for each season and determines the amount and type of new fossil fuel investment required to meet reliability criteria and be profitable. The prices are determined by the short-run marginal costs (principally based on fuel costs) and the bidding strategies of generators. The hourly prices are a function of the hourly pattern of wind and solar generation in each State – typically two to three representative shapes are used.

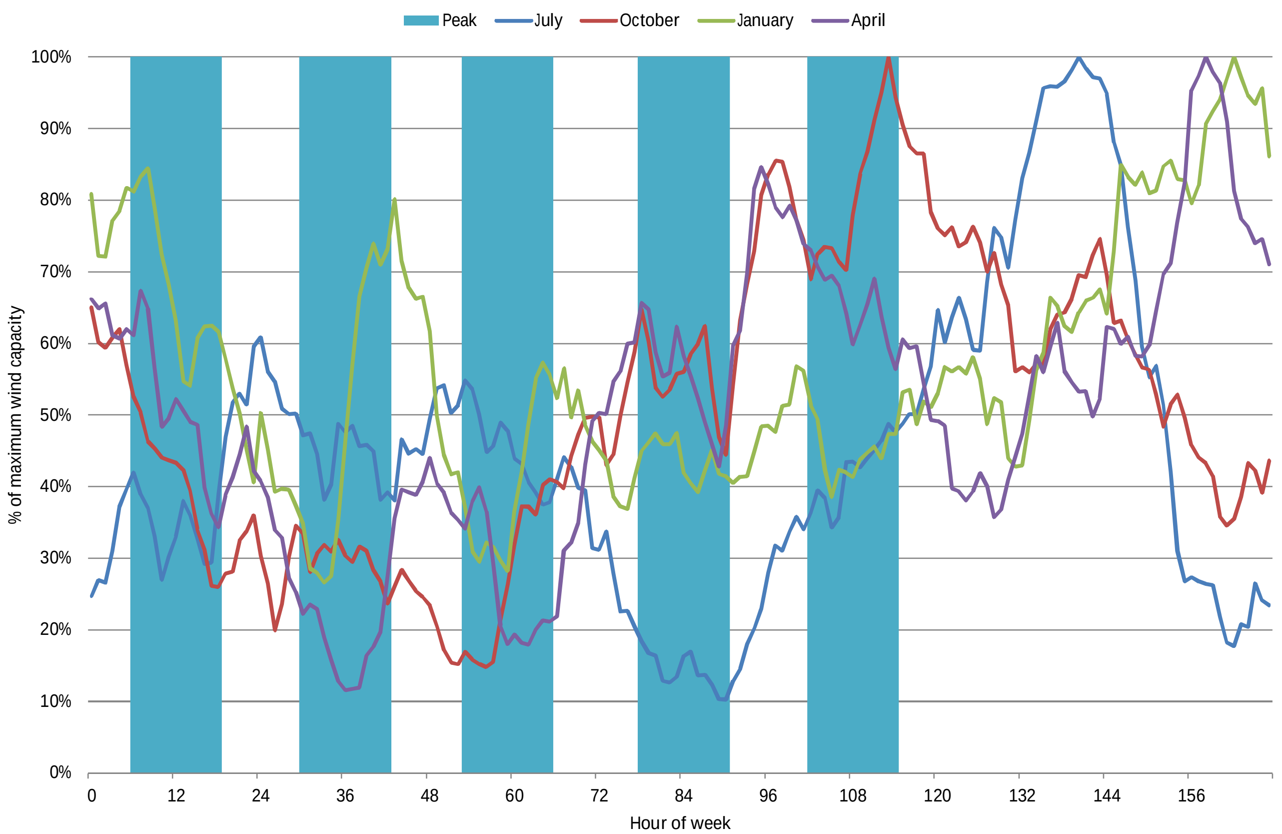
[15] P. Brown (2012), *U.S. Renewable Electricity: How Does Wind Generation Impact Competitive Power Markets*?, CRS Report for Congress, United States

- Simulate hourly prices with the contribution of renewable energy generation from the RET. All assumptions are the same as in the prior simulation but with the level of renewable generation encouraged by the LRET removed and replaced with thermal generation if new capacity is required to maintain supply reliability. There is still some level of renewable generation either to meet Greenpower demand or because they are profitable with the higher electricity prices engendered by carbon pricing.

The difference in prices between the two simulations is an estimate of the price impact of the RET. Prices are calculated on an average all year basis and average prices for the peak and off peak periods. Volume weighted prices for typical residential, commercial and industrial customers are also derived.

The magnitude of any impact depends on the profile of generation. Typically, generation from variable sources concentrated in peak periods will have more of an impact than generation concentrated in off-peak periods. In the NEM, however, the wind is generally concentrated in the off peak periods, as illustrated for South Australia in Figure 4. The difference is not large – around 60% in the off-peak period and 40% in the peak period.

Figure 4: Typical weekly generation profiles for wind in South Australia



Source: SKM analysis based on historical dispatch data. Note: numbers on chart represent the proportion of available wind capacity typically generating (as a proportion of maximum wind capacity) in each hour of the week.

3.3 Regression modelling

A statistical analysis was undertaken to determine the impact of the level of wind and solar PV generation on prices. The analysis was carried out from 2008 to 2013 investigating prices in the South Australian market because this State has experienced significant penetration of both wind and solar PV.

The approach is based on regression analysis in which half hourly spot price is the independent variable. The specification, in log-linear form, of the regression equation is as follows:

$$Ln(P_t) = Ln(CM_t) + Ln(GP_t) + Ln(WG_t) + Ln(T_t) + Ln(Et)$$

Where: P_t = Spot price (in $/MWh) (in real end 2012 dollar terms);

CM_t = The margin of capacity over demand expressed in MW;

GP_t = The gas price as determined through the Victorian spot gas price being representative of gas prices earned by gas peaking and high shoulder plant, and representative of fuel cost movements;

WG_t = The average level of wind generation in MW;

T_t= time trend to represent long term capital and other general cost trends;

E_t = error term.

The time interval, *t*, is half-hourly. Regression analysis, using Ordinary Least Squares estimation, is undertaken on actual half hourly data and 12 month moving averages to each half hour period to smooth out any seasonal impacts. The parameter estimates obtained through this specification represent the elasticity of the impact of the factors. For example, the parameter associated with wind generation (WG_t) is an estimate of the per cent impact on price of a one per cent change in the level of wind generation. Structural tests were undertaken to test if the parameter values are stable over time.

Data for the analysis is sourced mainly from AEMO. Data was collected on half hourly bases and comprised:

- Half hourly trading prices at the SA regional reference node from the NEM database;
- Half hourly demand from the NEM database;
- Generation capacity availability using capacity data from AEMO ESOO and MTPASA sources;
- Gas prices being start of day Victorian hub gas prices, being the best proxy available for the opportunity cost of gas in each half-hour for that day;
- Wind generation levels for SA based on dispatch data available from NEM databases for scheduled and semi-scheduled generation.

The analysis was conducted on data from 1 January 2008.

4. Wholesale Price Modelling

4.1 Simulation model results

4.1.1 With carbon prices

Figure 5 shows the indicative pool price difference between the No RET case and the With RET case. A positive number indicates a higher pool price for the No RET case. The price differences are all clearly positive until 2028, with the exception of New South Wales from 2020-21 and Queensland in 2021, and range from about $3/MWh - $8/MWh at present up to $10/MWh - $25/MWh, with the greatest price difference occurring in the southern states where there is a greater penetration of renewable energy. The price differences tend to peak from 2018 to 2020 (although Queensland peaks in 2025), and they all eventually track back to the zero line from 2028 for Queensland until 2033 for South Australia and Tasmania. This time period coincides with the cessation of the scheme, but is also when prices for the With RET case reach the new entry line, and new thermal base load plant is needed in the NEM for that case. Base load new entry for the No RET case is earlier, commencing in 2026 for Victoria and 2028 for Queensland. Another difference between the cases is the With RET case has one unit of Yallourn and Gladstone power stations mothballed until 2023, whereas in the No RET case, both units are brought back in 2016. Furthermore, Northern power station is retired in the With RET case by 2021, whereas in the No RET case the power station continues to operate profitably indefinitely.

Figure 5 Price differences between No RET case and With RET case

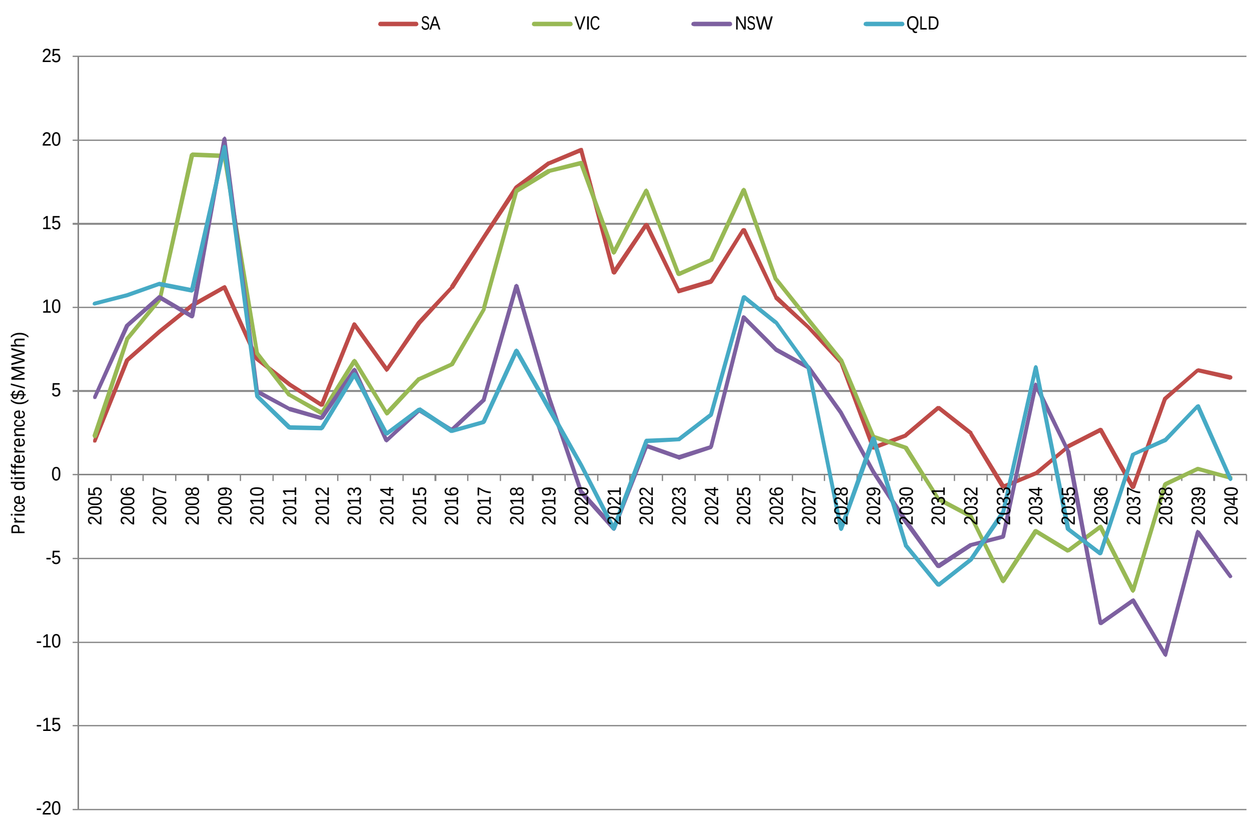


Figure 6 and Figure 7 show South Australian and Victorian pool prices respectively under both scenarios. In 2013 there is a larger price separation between the scenarios for South Australia, which reflects the larger penetration of wind farms in that region. The price difference expands for both regions as more wind is taken up in both regions under the With RET scenario until 2021. This is the point when the LRET ceases to escalate and hence the pressure to take up large-scale renewables eases. The Victorian price difference is comparable with the South Australian difference from 2018, at which point Victoria is projected to have 30% more wind capacity than South Australia.

Figure 6 Comparison of South Australian pool prices for both scenarios

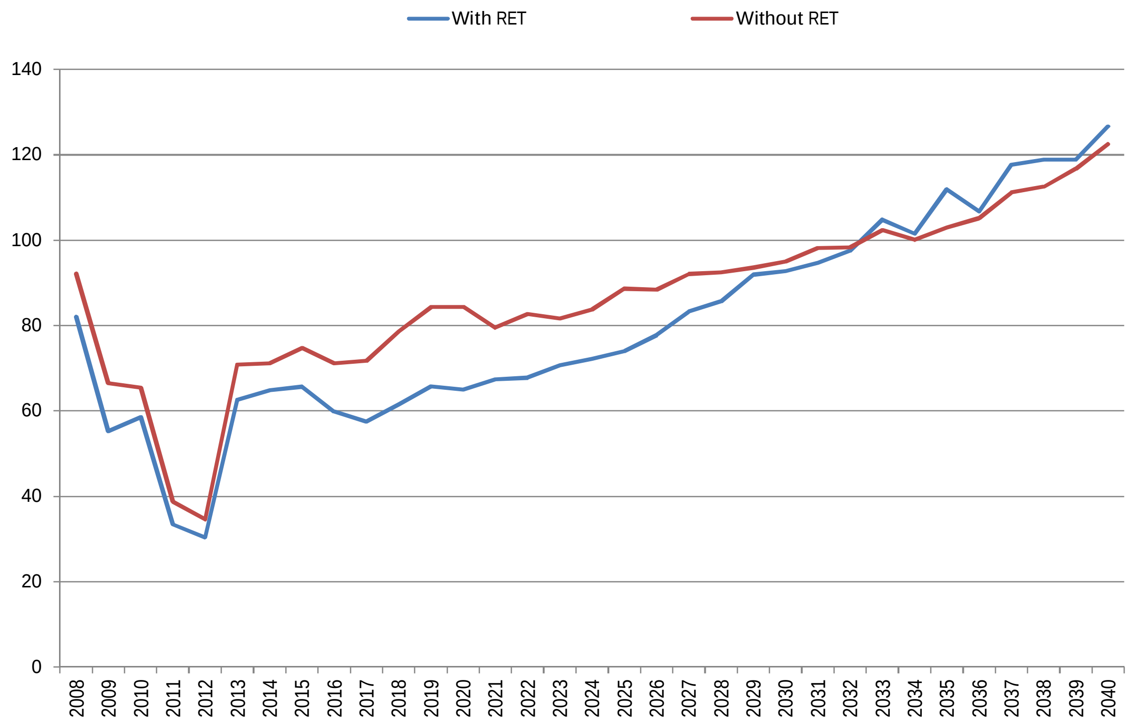
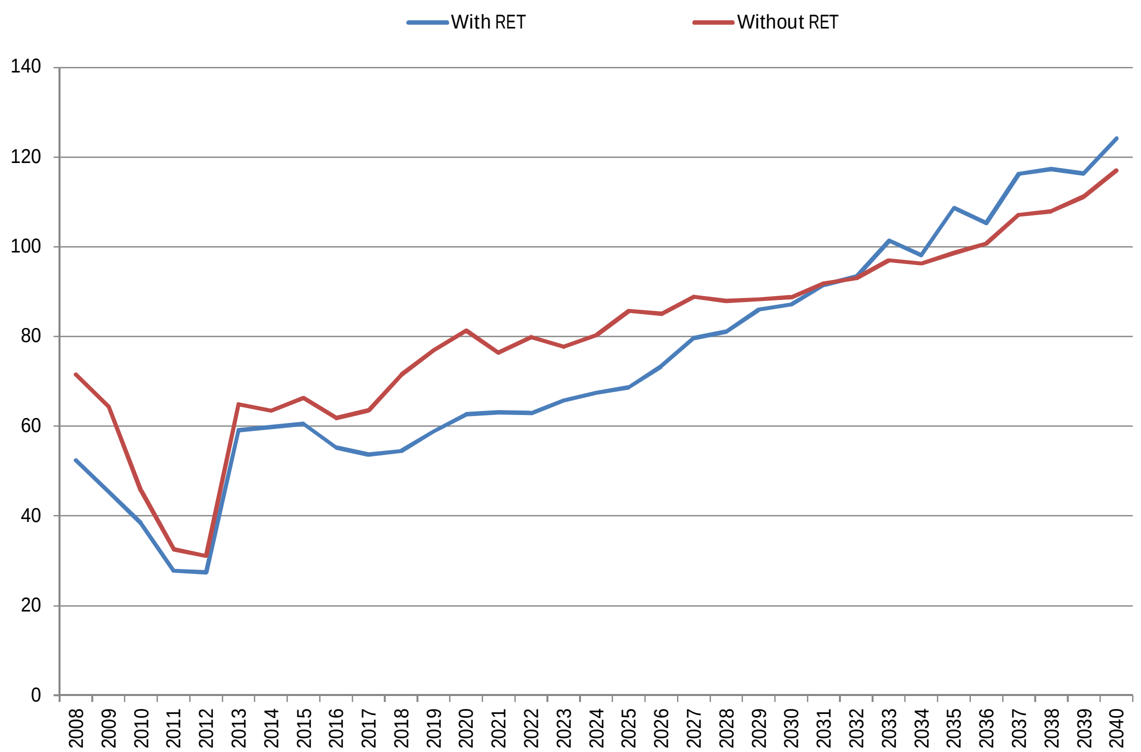


Figure 7 Comparison of Victorian pool prices for both scenarios



The difference in prices are summarised in Table 4. The analysis indicates substantial reductions in the wholesale market price due to the RET. The magnitude of the reductions reflects the fact that demand is subdued in the period to 2020, and additional capacity from renewable energy exacerbates the capacity overhang. It is possible that additional retirements of existing plant with extra renewable generation (to optimise portfolio profits) as well as modification of bidding strategies may reduce the price impacts due to the LRET.

Table 4: Reduction in wholesale price due to the RET, $/MWh

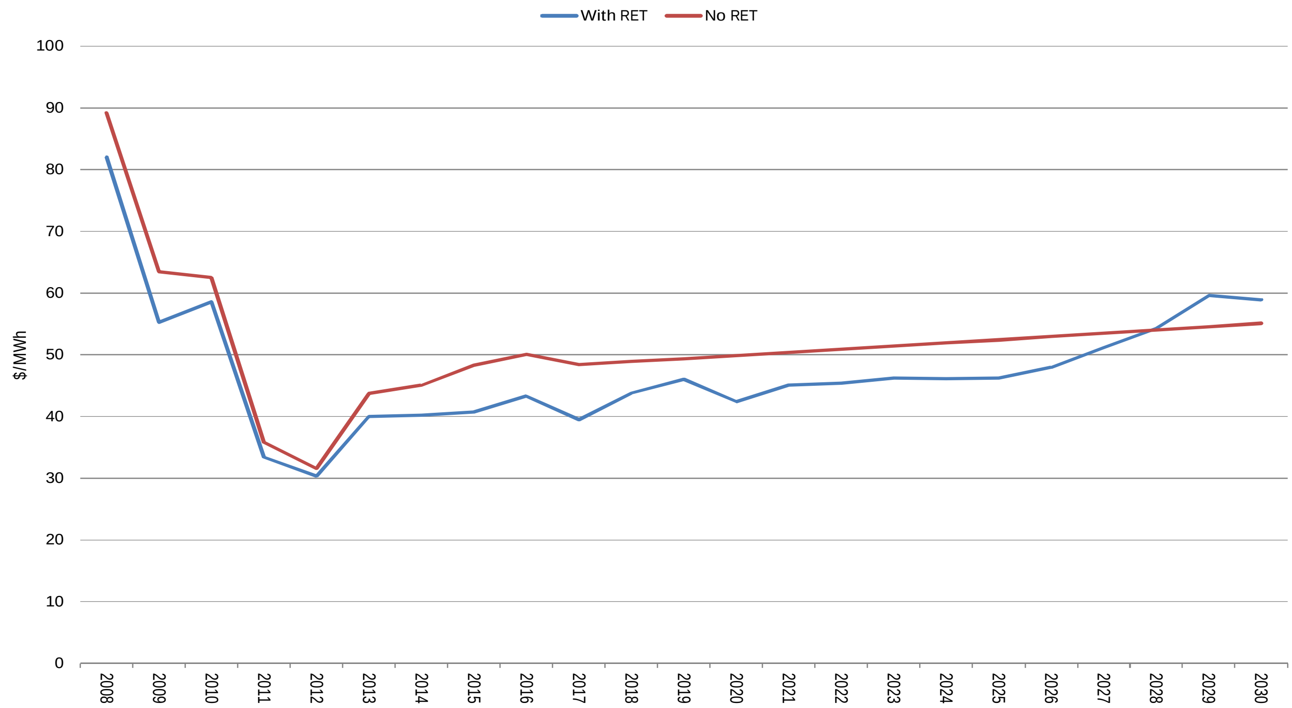
	With carbon			Without carbon		
	2011-2015	2016-2020	2021-2025	2011-2015	2016-2020	2021-2025
South Australia	3.59	16.12	12.83	4.53	17.54	18.95
Victoria	6.79	14.05	14.42	6.94	16.14	25.13
NSW	3.59	4.40	2.13	2.69	6.11	8.96
Queensland	3.90	3.54	3.02	3.08	4.76	8.55

Source: SKM analysis

4.1.2 Without carbon prices

The reduction in wholesale prices remains, even if the carbon pricing is replaced by other non-pricing measures. As Figure 8 shows, the gap in prices is narrower and is of shorter duration. The reason for this is that carbon pricing increases the short run marginal (or variable operating) cost of thermal plants. Thus the variable cost of thermal generation is higher. When zero cost generation enters the market, it displaces this higher cost plant.

Figure 8: Comparison of South Australian wholesale prices without a carbon price



4.1.3 Volume weighted prices

One of the consistent findings in the literature is that volume weighted prices may change over time as the mix of plant alters towards more low capital but high operating cost plant. Figure 9 and Figure 10 show the capacity mix that has occurred with and without the LRET scheme. The analysis indicates a switch to more open cycle plant in the long term in the scenarios with the LRET scheme in place, although the difference is not large. Without the LRET there is more mid-merit type plant (such as combined cycle gas turbines) expected to enter. The switch is not as great as expected since a lower demand growth rate has deferred the need for new plant. The LRET scheme prolongs this deferral.

Figure 9: Proportion of fossil fuel plant mix by type of plant – with RET

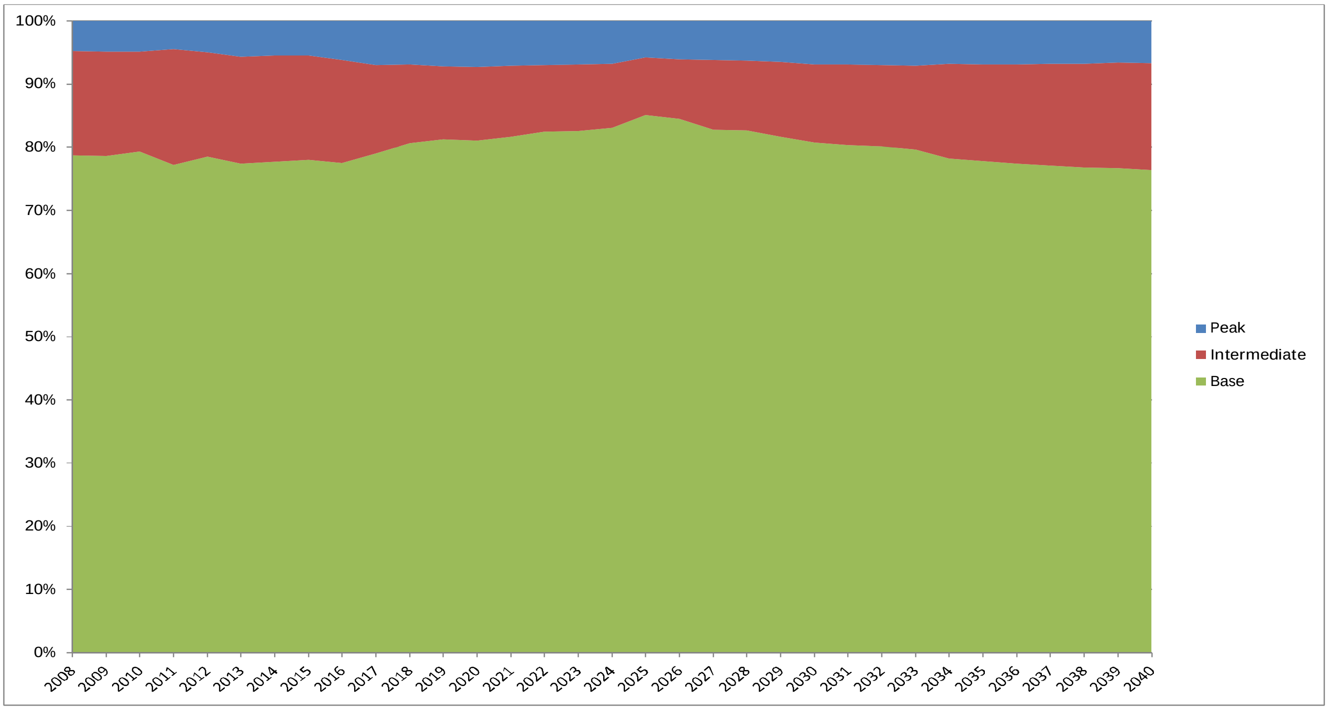
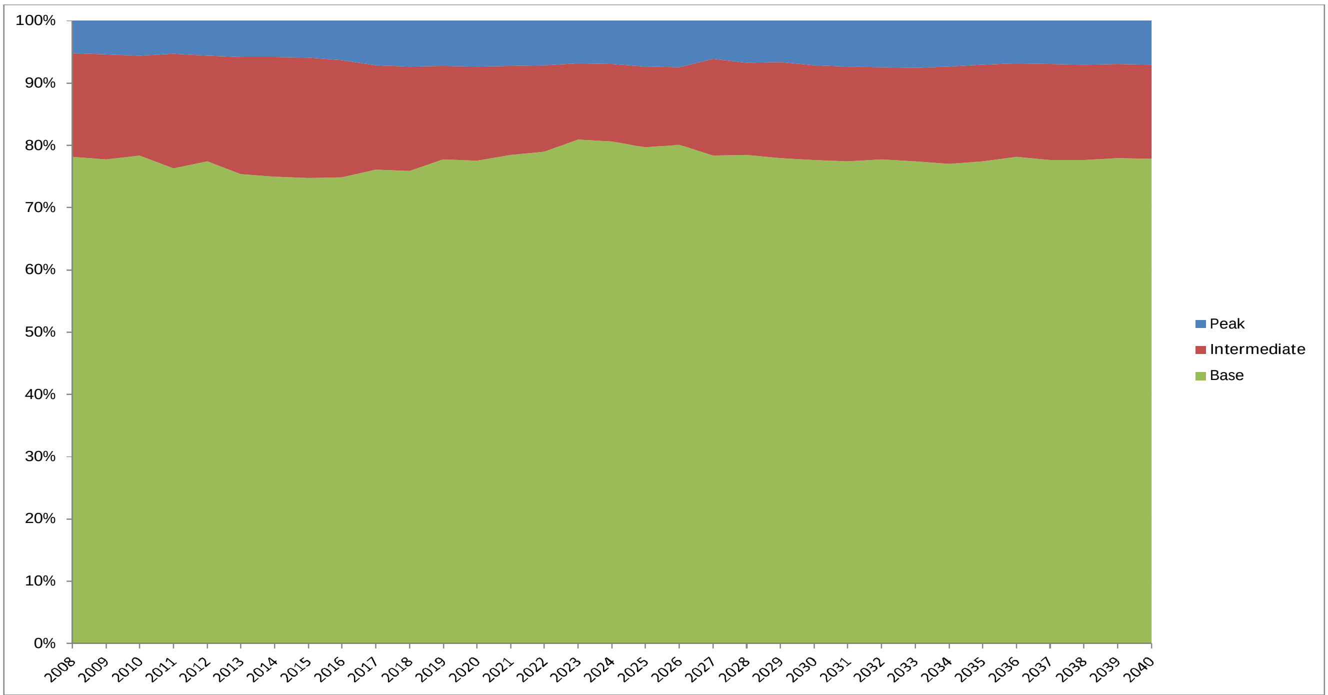


Figure 10: Proportion of fossil fuel plant mix by type of plant – no RET



The following charts show the volume weighted price with hourly prices weighted by typical load patterns for typical residential and commercial customers. All customers seem to benefit from the reductions in the wholesale price. Commercial and residential loads are typically concentrated in peak periods whilst the bulk of large scale renewable generation is concentrated more in off-peak periods. But there are still substantial reductions in the peak period due to the impact of roof-top solar generation and the fact that price reduction impact from a quantum of renewable generation tends to be greater in the peak period than in off-peak periods.

Figure 11: Price reductions in wholesale market due to LRET – commercial customers

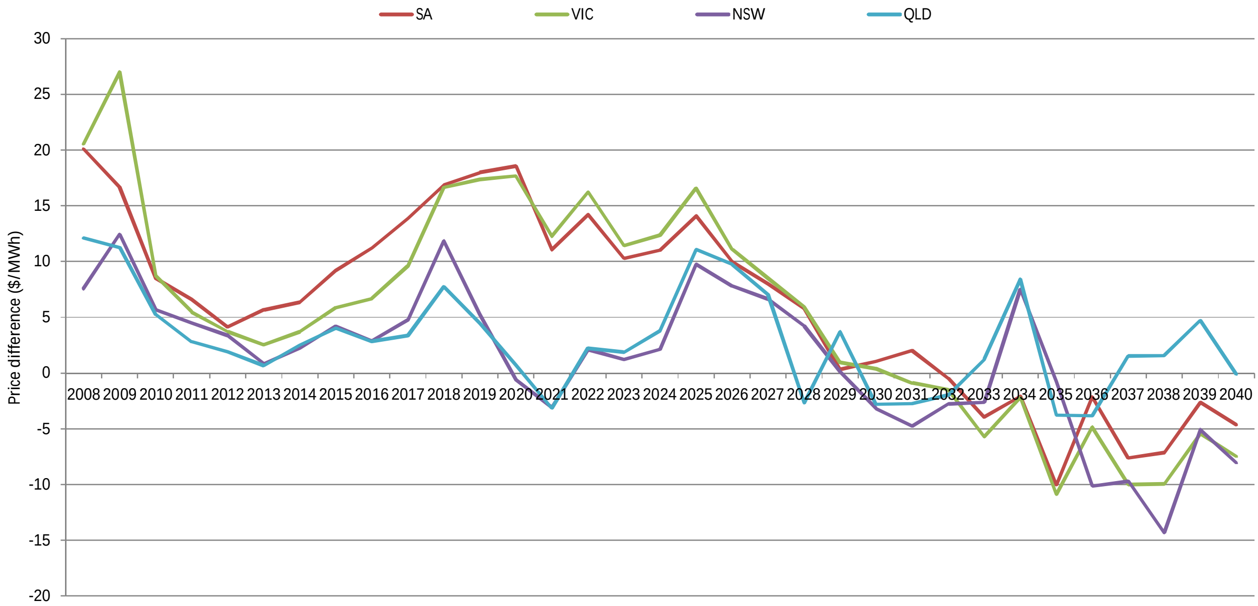
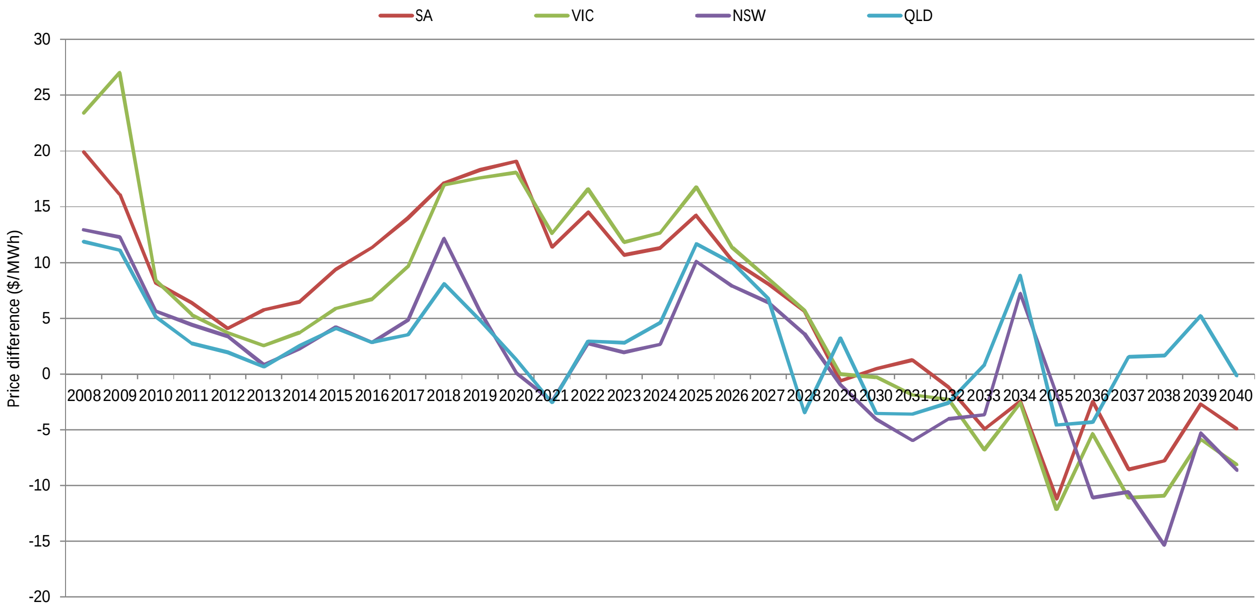


Figure 12: Price reductions in wholesale market due to LRET – residential customers



The results are also sensitive to the gas prices assumed. If gas prices are lower than assumed, then the price reduction due to the RET will be reduced and vice-versa[16].

4.2 Regression model results

As outlined in Section 3.3, a statistical analysis was conducted on wholesale prices in South Australia to see if the level of renewable energy generation in that State has had an impact on wholesale prices. The results of the analysis, regressing half-hourly prices with a range of explanatory factors are shown in the following Table. The adjusted R^2 is 0.32 which indicates modest explanatory power. All parameters listed had a significant impact on prices and had the correct signs. Because a log-linear form was adopted for estimation, the coefficients represent estimates of the point elasticities.

Table 5: Factors affecting price movements in the South Australian wholesale price

Parameter	Coefficients	Significance level
Intercept	3.32	1% level
Capacity Margin	-0.27	1% level
Gas Price	0.09	5% level
Renewable Generation	-0.02	5% level
Carbon Price	0.66	1% level

Source: SKM analysis

The results indicate that the capacity margin, daily gas price and renewable generation level all had an impact on the wholesale price, with the impact of a change in renewable generation levels similar to the impact of a change in gas price.

For the impact of renewable generation, the analysis indicates that for every 1% increase in renewable generation (from half hour to half hour), the wholesale price fell by about 0.02%.

The analysis was repeated using weekly data instead of half-hourly data. Similar results were obtained although the impact of renewable generation on price was larger – for every 1% change in weekly renewable energy generation levels, prices fell by around 0.3%.

Table 6: Factors affecting price movements in the South Australian wholesale price, using weekly data

Parameter	Coefficients	Significance level
Intercept	4.94	1% level
Capacity Margin	-0.49	5% level
Gas Price	0.29	1% level
Renewable Generation	-0.30	1% level
Carbon Price	0.50	1 % level

Source: SKM analysis

It should be noted that the results of this analysis are indicative of the price impact.

[16] Gas price assumptions used in the simulation modelling are shown in Section A.1.6. The base assumptions indicate real gas prices (for base-load gas usage) increasing to $6/GJ and continuing to rise in the long term to reach around $8/GJ by 2030 in real terms.

5. Retail Prices

The net impact for customers associated with the LRET is calculated as the sum of the changes to wholesale prices and the liabilities to cover the cost of running the scheme and paying for the certificates. Net impact on retail prices from the LRET are shown in the following Table.

Table 7: Retail price impacts, $/MWh

	With Carbon			Without carbon		
	2011-2015	2016-2020	2021-2025	2011-2015	2016-2020	2021-2025
South Australia	-3.20	-9.74	-4.40	-2.77	-9.16	-7.31
Victoria	-1.34	-7.67	-5.99	-0.05	-7.76	-7.49
NSW	-0.31	1.98	6.30	1.09	2.27	2.68
Queensland	0.00	2.84	5.41	1.48	3.62	3.08
Weighted Average	-0.83	-1.87	1.32	0.46	-1.54	-3.07

Note: negative numbers indicate savings to consumers

Customers are likely to have a price reduction over the period to 2020 as a result of the RET. However prices are projected to be higher from sometime after 2020. The price reduction is due to the wholesale price effect of the LRET, which more than outweighs the impact of increased liabilities as the target grows.

Customers in some States experience smaller benefits and even increased retail tariffs. This result is dependent on the location of new renewable energy under the LRET. If more large-scale renewables are located in NSW and Queensland and less in Victoria, then they will also experience lower prices.

On a weighted average basis across the NEM regions, customers are likely to experience a reduction in retail tariffs as a result of the LRET in the period to 2020.

Appendix A. Simulation Model Assumptions

A.1 Model Assumptions

A.1.1 Scenario assumptions

The two scenarios to be modelled are the Reference scenario, which does not have the RET scheme included in it, and the "With RET" scenario, which includes the RET in its present form with a 41,000 GWh 2020 target for the LRET component of the scheme.

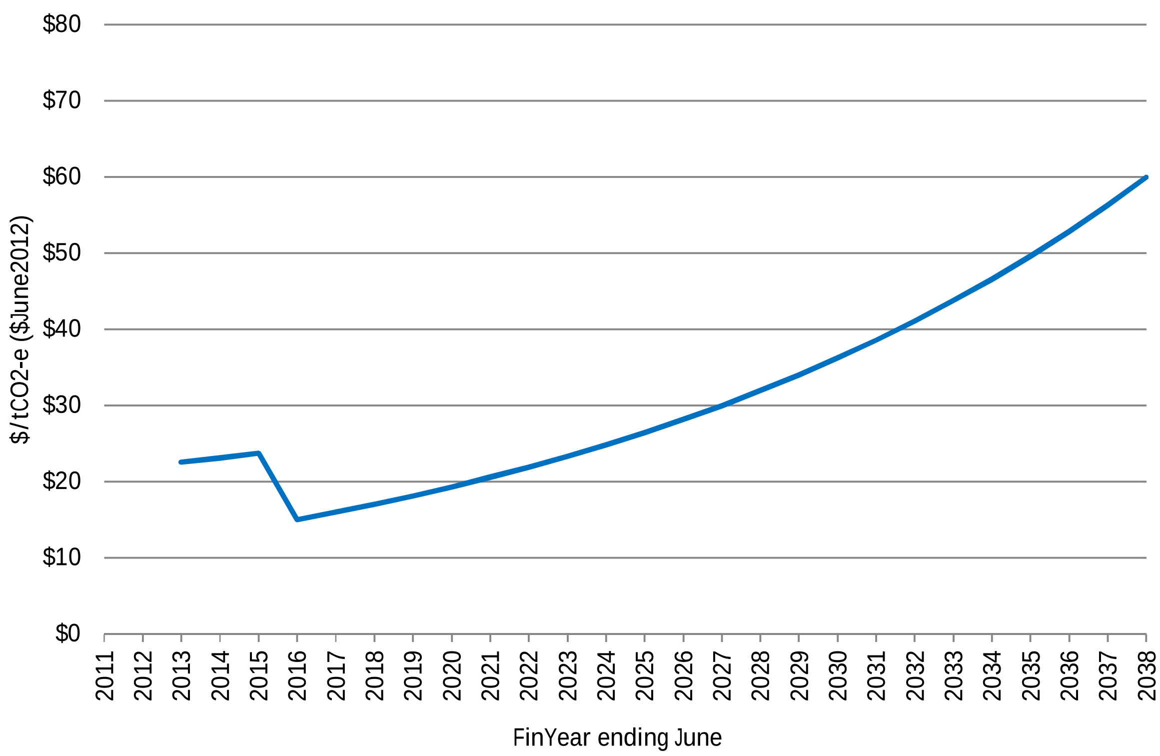
For the (no RET) Reference scenario, demand was adjusted for the level of solar PV generation that has entered the market as a result of the RET. It has been assumed that 50% of the level of PV generation installed since 2010 would not have occurred in the absence of the RET. The inclusion of the additional demand from this source had a negligible impact on the simulation of wholesale price effects.

All other assumptions for both scenarios are the same, including the assumed carbon price and the underlying (i.e. non-PV related) demand.

A.1.2 Carbon price

Figure A- 1 shows the assumed carbon price used for both scenarios. The step-down in FY2016 represents the end of the fixed price period and the CPM's linkage to the European market, whose carbon price at present is well below the Australian price. It has been assumed that the carbon price will step down to $15/tonne in 2016 and will escalate at 6.5% per annum in real terms thereafter.

Figure A- 1 Assumed carbon price



A.1.3 Operation expenditure

SKM MMA has used its standard OPEX costs for new and existing market entrants. The marginal costs of thermal generators consist of the variable costs of fuel supply including fuel transport plus the variable component of operations and maintenance costs. The indicative variable costs for various types of existing thermal plants are shown in Table A- 1. We also include the net present value of changes in future capital expenditure that would be driven by fuel consumption for open cut mines that are owned by the generator. This applies to brown coal in Victoria and for Leigh Creek coal in South Australia.

Table A- 1 Indicative average variable costs for existing thermal plant – excluding carbon cost ($June 2012)

Technology	Variable Cost $/MWh	Technology	Variable Cost $/MWh
Brown Coal – Victoria	$3 - $10	Brown Coal – SA	$24 - $31
Gas – Victoria	$46 - $64	Black Coal – NSW	$20 - $23
Gas – SA	$37 - $111	Black Coal - Qld	$9 - $31
Oil – SA	$250 - $315	Gas - Queensland	$25 - $56
Gas Peak – SA	$100 - $164	Oil – Queensland	$241 - $287

A.1.4 Plant performance and production costs

Thermal power plants are modelled with planned and forced outages with overall availability consistent with indications of current performance. Coal plants have available capacity factors between 86% and 95% and gas fired plants have available capacity factors between 87% and 95%.

A.1.5 New entry costs

New entrant generation annualised capital costs are illustrated in Figure A- 2 for various technologies. The profile of annualised costs tracks the trend in capital costs over time but ensures that capital can be recovered at the weighted average cost of capital (WACC). The WACC was taken as 10.6% real pre-tax and the costs are defined accordingly.

A long run marginal view of cost is built up for each potential new entrant using capital costs, operating costs, fuel costs and abatement costs. Where a region is likely to obtain a significant portion of its supply from the inter-regional network rather than within its own region, external new entrants with a transmission supply cost are also considered, for example Tasmania and South Australia. Capital costs are adjusted for interest during construction expenses and then annualised before being added to the other costs. This total cost is then adjusted for sent out capacity and losses, as opposed to being set at generator terminals. The new entry cost in any given year is then determined by the lowest cost new entrant for that year, which is presented in Figure A- 3.

Figure A- 2 Trend in new entry capital recovery costs ($/kW/year, $Jun 2012)

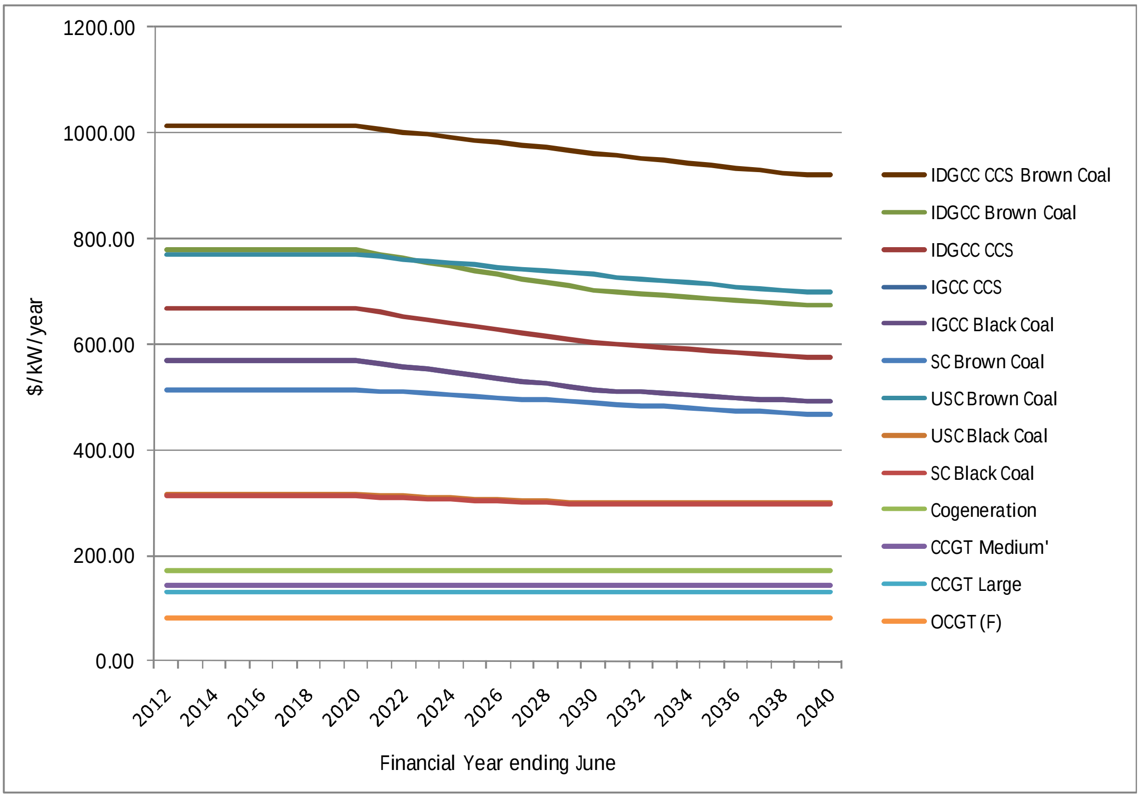
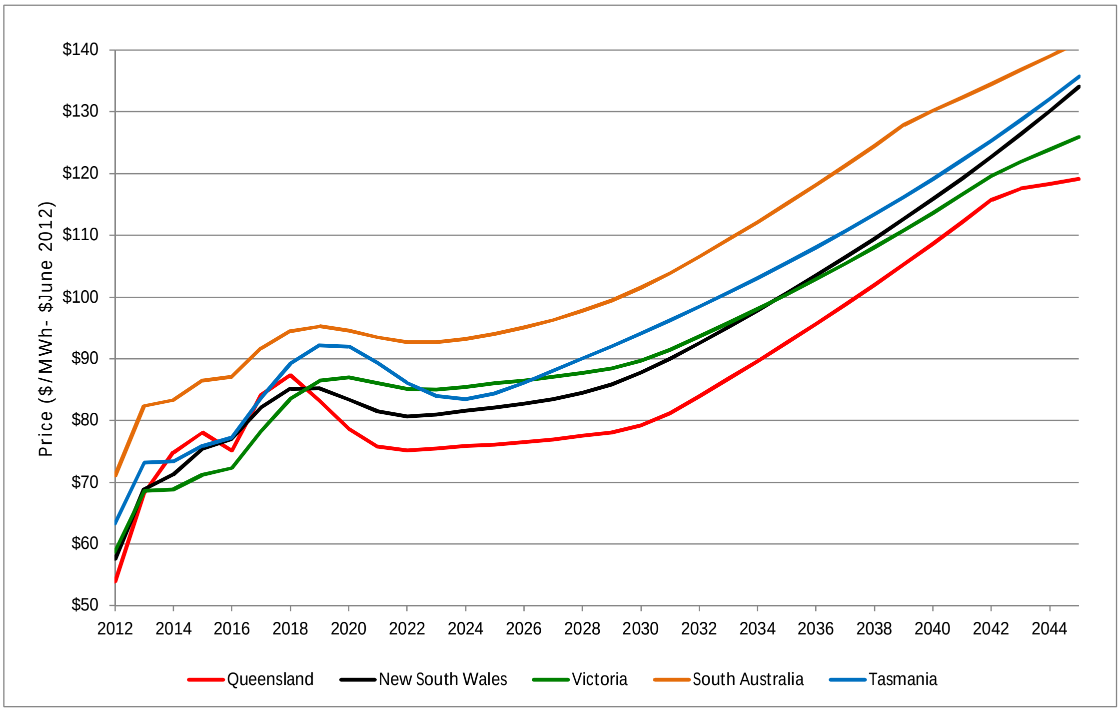


Figure A- 3 New entry prices with carbon pricing from July 2012 (June 2012 $/MWh)



A.1.6 Gas prices

SKM MMA prepares gas price forecasts based on projected demand-supply balance in Eastern Australia using MMA's proprietary model, MMAGas (Market Model Australia – Gas), which intends to replicate the essential features of Australian wholesale gas markets:

- A limited number of gas producers
- Dominance of long term contracting and limited short term trading
- A developing network of regulated and competitive transmission pipelines
- Domestic market growth driven by gas-fired generation and large industrial projects.

MMAGas has been developed to provide realistic assessments of long term outcomes in the Australian gas market, including gas pricing and quantities produced and transported to each regional market. The "gas market" in MMAGas is the market for medium to long-term gas contracts between producers and buyers such as retailers or generators. Competition between producers is represented as a Nash-Cournot game in which each producer seeks to maximise its profit subject to constraints imposed by its competitors. The role of buyers is replicated by modelling the activities of an arbitrage agent. Transmission costs are treated as cost inputs.

The applicable wholesale average city gate gas prices that have been used are shown in Figure A- 4. These are the gas prices that apply to incumbent generators. The prices have been extrapolated beyond the modelling year of 2032 towards an estimated ultimate price by 2050. Higher new contract prices are applied to new entrants as shown in Figure A- 5.

Figure A- 4 Wholesale average city gate gas prices for electricity market modelling ($June 2012)

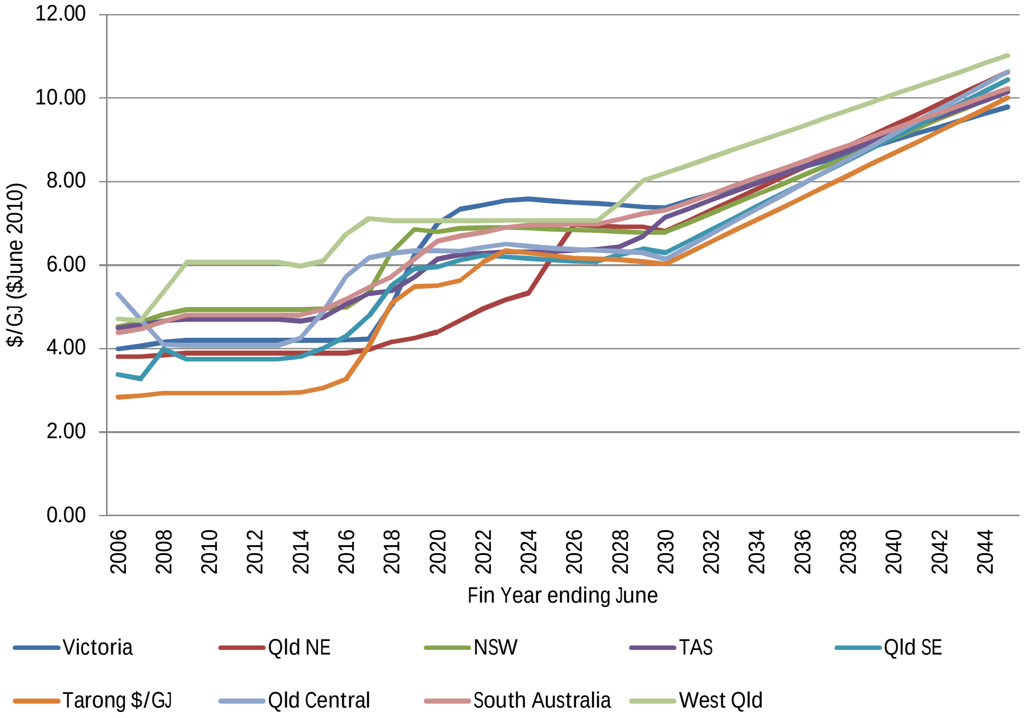
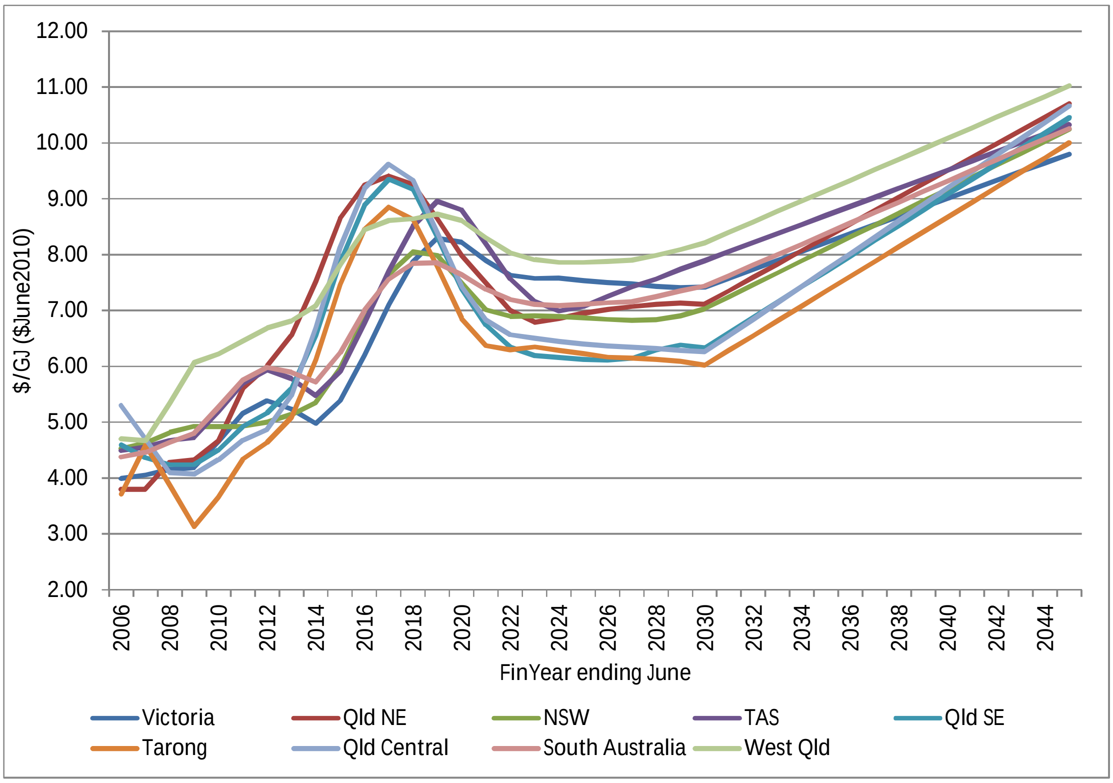


Figure A- 5 Wholesale new entry city gate gas prices for electricity market modelling ($June 2012)



A.1.7 Renewable Energy Target and other abatement schemes

Large-scale Renewable Energy Target

The Commonwealth Government's policy is to achieve 20% additional renewable energy by 2020. The previous 45,000 GWh target was split into two parts effective 1 January 2011. The Large-scale Renewable Energy Target (LRET) will deliver the 2020 target but with an annual target that is now 41,000 GWh. The Small-scale Renewable Energy Scheme (SRES) will provide an incentive for small scale renewable projects such as solar PV and solar water heaters.

The targets under LRET are shown in Table A- 2 where it is noted that the 41,000 GWh target, which is less than the original expanded RET target of 45,000 GWh, continues until 2030. This assumption will only be used for the "With RET" scenario.

The demand reduction effect of the SRES scheme has assumed to be taken into account in the new 2012 forecasts by the jurisdictional planning bodies, which feed into the AEMO demand forecast. As such, no additional demand reduction was made to the load forecasts. For the Reference scenario, small-scale PV generation capacity that would not have been built without the RET will be added back onto the demand projections, which implicitly account for this. The impact of this inclusion of additional demand on the analysis of wholesale price impacts was negligible.

Table A- 2 Required GWh from renewable energy sources to meet LRET

Calendar year	Target (GWh)
2011	10,400
2012	16,338
2013	18,238
2014	16,100
2015	18,000
2016	20,581
2017	25,181
2018	29,781
2019	34,381
2020-2030	41,000
2031	0

Queensland Cleaner Energy Strategy (CES)

In May 2000, the Queensland Government announced the Queensland Energy Policy – A Cleaner Energy Strategy. A key initiative of the energy policy is the Queensland 13% Gas Scheme. This scheme requires electricity retailers and other liable parties to source at least 13% of their electricity from gas-fired generation from 1 January 2005.

The 13% Gas Scheme is a certificate based scheme consisting of:

- Accredited parties – generators of eligible gas-fired electricity who can create Gas Electricity Certificates (GECs), which have value and can be traded separately to the electricity to which they relate,
- Liable parties (largely electricity retailers and others that sell electricity to end users) - parties who are required to surrender GECs to the Regulator to acquit a liability, which in general terms, is 13% of the electricity sold by the liable party in Queensland.

Liabilities may be incurred by parties which are connected to, or sell to end users that are connected to, a major grid. A major grid is defined as a grid with an installed capacity which exceeds 100 MW. The success of the scheme led to an increase in the target for gas-fired generation to 15% in 2010.

On 8 March 2013 the Queensland government announced that the gas scheme is to be abolished on 31 December 2013. This was the result of a review of the scheme triggered by the introduction of the CPM in July 2012. The review found that the Queensland Gas Scheme probably duplicates the impact of the CPM, and this is borne out by the price of GECs which have traded between $0.2/MWh and $0.3/MWh since the introduction of the CPM.

A.1.8 Generator mothballing

On 11 October 2012 Stanwell Corporation announced that it would withdraw two units of its Tarong power station from October and December 2012 for at least two years, or until there was an improvement in wholesale market prices. On 17 October 2012 Energy Australia announced that it would only be operating three of its four generating units at its Yallourn power station in the Latrobe Valley, and on 8 January 2013, Energy Australia took one of the two NSW Wallerawang units offline for the remainder of the calendar year, citing falling electricity demand in an over-supplied market. Furthermore, Northern Power Station in South Australia is modelled as operating only from October to March over the spring and summer period as per Alinta Energy's July 2012 announcement, which at this stage is set to continue for two years.

A.1.9 Demand forecasts

Demand forecasts for regions in the NEM were formulated based on the projections in the 2012 National Electricity Forecasting Report (NEFR), released by AEMO. The energy and peak demand forecast was applied to the 2010/11 actual half-hourly demand profiles and is shown in Figure A- 6 for each region after being adjusted for the carbon price that has been adopted for that scenario. The adjustment for the scenarios takes into account of the differences in assumptions related to carbon prices in formulating the AEMO demand forecast. The resulting change in Figure A- 7 shows in percentage terms, the adjustment to the regional loads taking into account the difference between the carbon price assumed for the Base scenario and that used in forming the original AEMO medium growth scenario.

Figure A- 6 Base demand growth forecast sent out

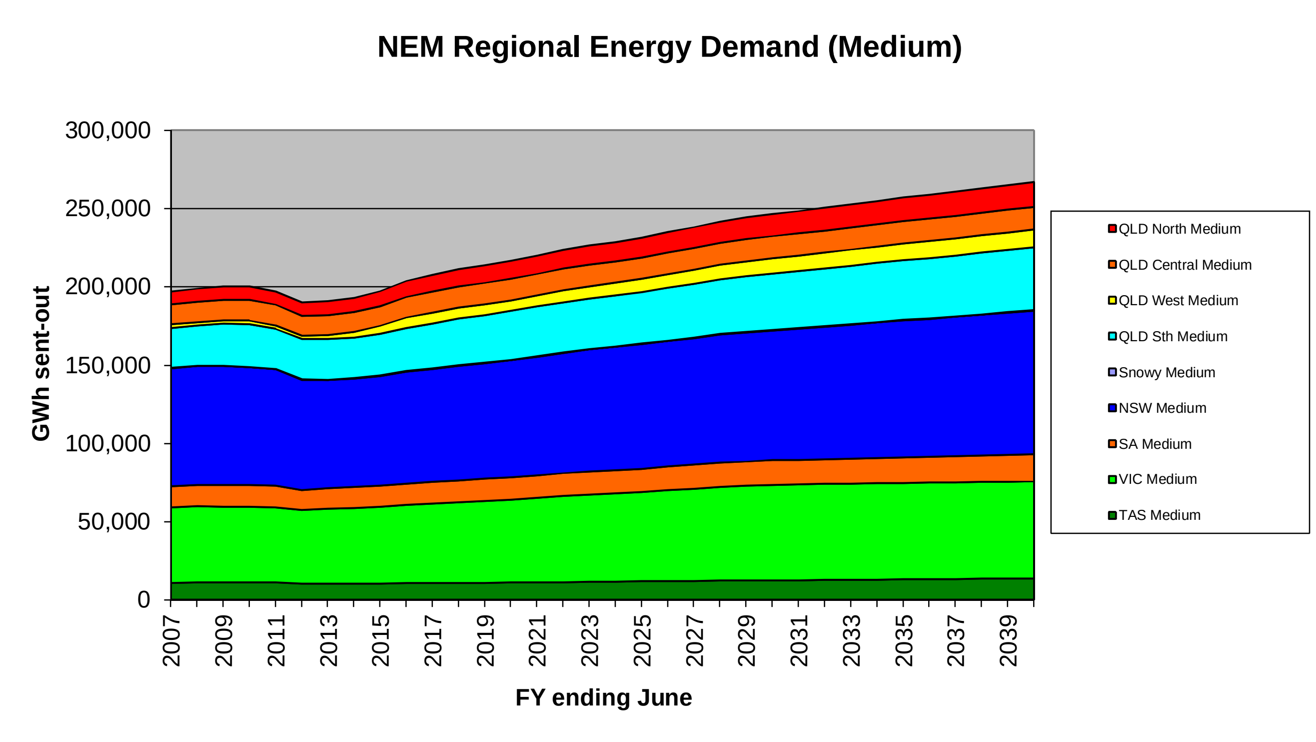
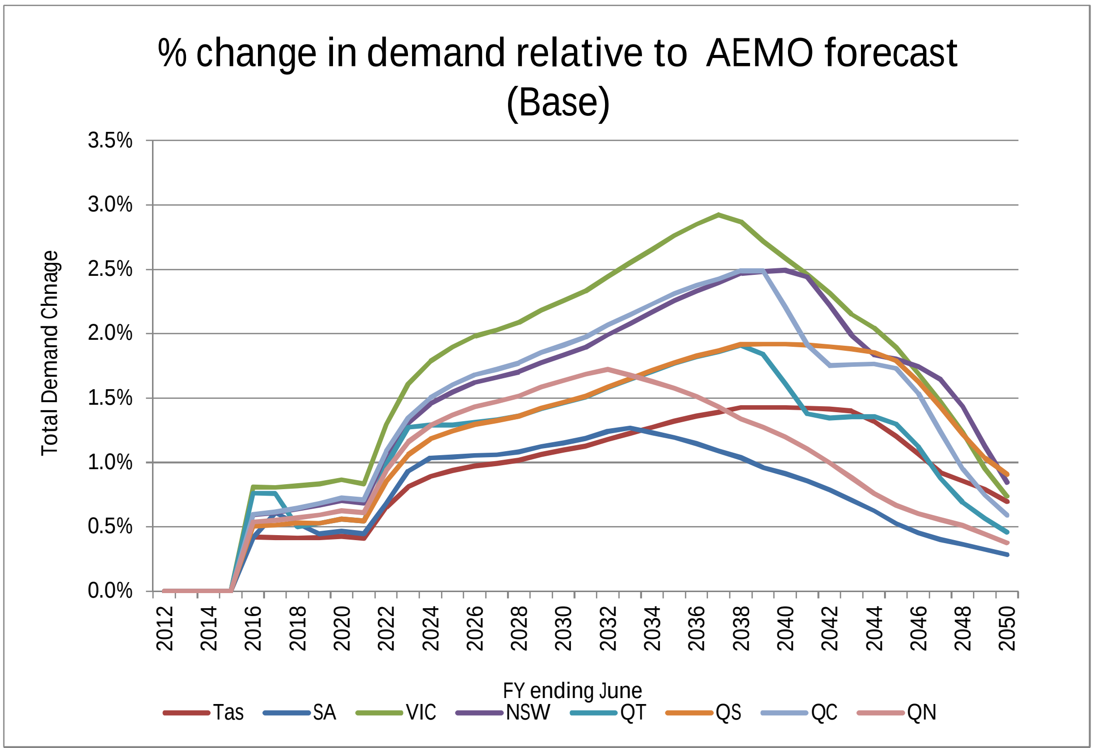


Figure A- 7 Demand Adjustments to correct for the announced core policy carbon price with medium economic growth from the planning statements for the Base scenario



We have used the 2010/11 load shape as it reflects demand response to normal weather conditions and captures the observed demand coincidence between the States. The demand and energy forecasts were originally developed by AEMO. SKM MMA adjusts the AEMO forecasts presented in the ESOO to add back in the "buy-back" component of the renewable embedded generation. SKM MMA's Strategist model is then used in conjunction with a renewable energy model to explicitly project the renewable energy. Some embedded generation, such as small scale cogeneration is not included in the Strategist model, and the native load forecasts are adjusted accordingly.

The use of the 50% POE peak demand is intended to represent typical peak demand conditions and thereby provide an approximate basis for median price levels and generation dispatch.

The load is modelled hourly and therefore the peak is applied as an hourly load in Strategist rather than half-hourly as it occurs in the market. Because the Strategist model applies this load for one hour in a modelled typical week it is effectively applied for 4.3 hours per year and therefore it represents a slightly higher peak demand exposure than the pure half-hour 50% POE. This compensates to some degree for not explicitly representing the variation up to 10% POE.

The introduction of the CPM adds yet another complexity to the demand forecasting as it is anticipated that there will be some demand response to the predicted increase in electricity prices. The published forecasts already include assumptions on how demand may change in response to these higher electricity prices. The 2009 ESOO reported the long-run own price elasticity of electricity demand (PED) by region used to derive this anticipated demand response; these values are summarised in Table A- 3. This PED represents the percentage change in demand expected for a 1% increase in electricity price. The price demand elasticities for New South Wales and Victoria are generally higher due to more energy intensive industrial loads.

Table A- 3 Assumed regional price elasticity of demand

State	Price elasticity (%)
NSW	-0.37
VIC	-0.38
QLD	-0.29
SA	-0.25
TAS	-0.23

Source: Table 3.51 NEMMCO SOO 2008 with SA updated in 2009 ESOO

The magnitude of the expected electricity price increase depends on a number of assumptions, but the key driver is the carbon price that is assumed.

With respect to peak demand, we assumed the demand response would be significantly lower and therefore the corresponding change in peak demand was assumed to be only 25% that of the energy reduction or increase. This method allows for the observation that air-conditioning load which dominates the summer peak is not very price sensitive (i.e. inelastic).

A.2 Modelling methodology

Energy market modelling was conducted using SKM MMA's energy market database and modelling tools in conjunction with use of probabilistic market modelling software 'Strategist', licensed from ABB/Ventyx of Atlanta. More information on Strategist is presented in section A.3.

For any given scenario Strategist represents the major thermal, hydro and pumped storage resources as well as the interconnections between the regions in the NEM. Economic optimisation tools (both internal and external to Strategist) are employed to adjust inter-related elements of the model and iteratively derive a solution that is more economically efficient. These elements may include thermal plant bids, uptake of renewable or thermal generation and appropriate retirement of existing generation. Average hourly pool prices are determined within Strategist based on thermal plant bids derived from marginal costs or entered directly, while LGC prices are estimated outside of Strategist in SKM MMA's Renewable Energy Market Management Model (REMMA) and are based on the net long run average cost of marginal renewable generation options.

A.2.1 Spot price modelling

Development of the future pool price path is driven by the supply and demand balance, with long-term prices being effectively capped near the cost of new entry on the premise that prices above this level provide economic signals for new generation to enter the market. Consequently, price drivers include carbon prices, fuel costs, unit efficiencies and capital costs of new plant. Year to year prices will deviate from the new entry cost level based on the timing of new entry. In periods when new entry is not required, the market prices reflect the cost of generation to meet regional loads, and the bidding behaviour of the market participants as affected by market power. The market price forecasts developed have taken into account regional and temporal demand forecasts, generating plant performance, timing of new generation including renewable projects, existing interconnection limits and potential for interconnection development.

The timing of new generation is determined by developing a generation expansion plan. SKM MMA has used the PROVIEW module of Strategist to assist with this task and has developed a plan that minimises total costs of the generation system plus interconnection augmentation. This is similar to the outcome afforded by a competitive market. However, due to the computational burden and the structural limitations of the Strategist package, it is not feasible to find in one analysis an optimal expansion plan that is completely consistent with external scheme outcomes (e.g. level of renewable generation afforded by the LRET scheme) and with review of individual generators' contract positions and opportunities to game spot market prices. SKM MMA therefore conduct a number of iterations of PROVIEW to develop a workable expansion plan based upon an initial estimate of renewable generation. The expansion plan is then refined to achieve a sustainable price path, applying market power where it is apparent, until a consistent set of renewable and thermal new entry plant mix is obtained. The final expansion plan must meet reserve constraints in each region, and satisfy maximum emergency energy requirements and maximum loss of load hour requirements. Generators must behave rationally, with uneconomic capacity withdrawn from the market and bidding strategies limited by the cost of new entry. This is a conservative assumption as there have been periods when prices have exceeded new entry costs when averaged over 12 months. Infrequently-used peaking resources are bid near the Market Price Cap or removed from the simulation to represent strategic bidding of these resources when demand is moderate or low.

A.2.2 Large-scale Generation Certificate prices

LGC prices are developed in the REMMA model assuming that the dominant mechanism for trading is long term contracts. SKM MMA has also developed a database of prospective renewable energy projects and their estimated future costs allowing for expected long-term improvements in cost and efficiency.

The model identifies the lowest cost resource that would meet the incremental target requirement in each year, assesses the revenue that would be expected to be earned by the project and calculates the long-run revenue that would be needed to be earned from the LRET market over the permissible time frame to match the long run cost of the project. Constraints that affect eligibility for projects to sell into the various markets are included.

A.3 Strategist software platform

The wholesale market price forecasts are developed utilising SKM MMA's NEM model having regard to the renewable and abatement markets for the Gas Electricity Certificates (GEC) in Queensland and the Renewable Energy Certificates (REC). Strategist represents the major thermal, hydro and pumped storage resources as well as the interconnections between the NEM regions. In addition, SKM MMA partitions Queensland into three zones to better model the impact of transmission constraints and the trends in marginal losses and generation patterns change in Queensland. These constraints and marginal losses are projected into the future based on past trends.

The simplifications in bidding structures and the way Strategist represents inter-regional trading, results in slight under-estimation of the expected prices because:

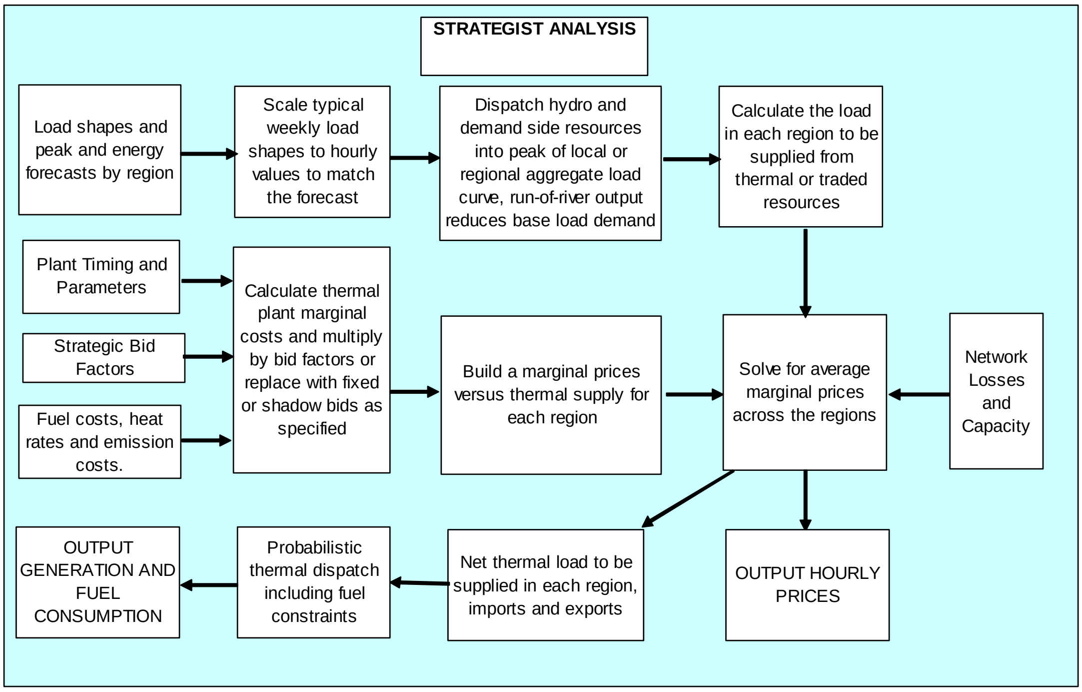
- All the dynamics of bid gaming over the possible range of peak load variation and supply conditions are not fully represented.
- Extreme peak demands and the associated gaming opportunities are not fully weighted. These uncertainties are highly skewed and provide the potential for very high price outcomes with quite low probability under unusual demand and network conditions.
- Marginal prices between regions are averaged for the purposes of estimating inter-regional trading resulting in a tendency to under-estimate the dispatch of some intermediate and base load plants in exporting regions such as Gladstone Power Station (GPS) in Central Queensland and Hazelwood in Victoria.

However, overall corrections can be made where these measures are important and in any case the error in modelling is comparable to the uncertainty arising from other variable market factors such as contract position and medium term bidding strategies of portfolios such as Energy Australia and AGL. Overall the forecasts produced using Strategist under the key assumptions presented in this report represent a conservative view, applicable for long-term investment in generation capacity. Specific supply/demand scenarios can be provided to quantify unusual market conditions.

A.3.1 Strategist methodology

Average hourly pool prices are determined within Strategist based on thermal plant bids derived from marginal costs or entered directly. The internal Strategist methodology is represented in Figure A- 8 and the SKM MMA modelling procedures for determining the timing of new generation and transmission resources, and bid gaming factors are presented in Figure A- 9.

Figure A- 8 Strategist Analysis Flowchart



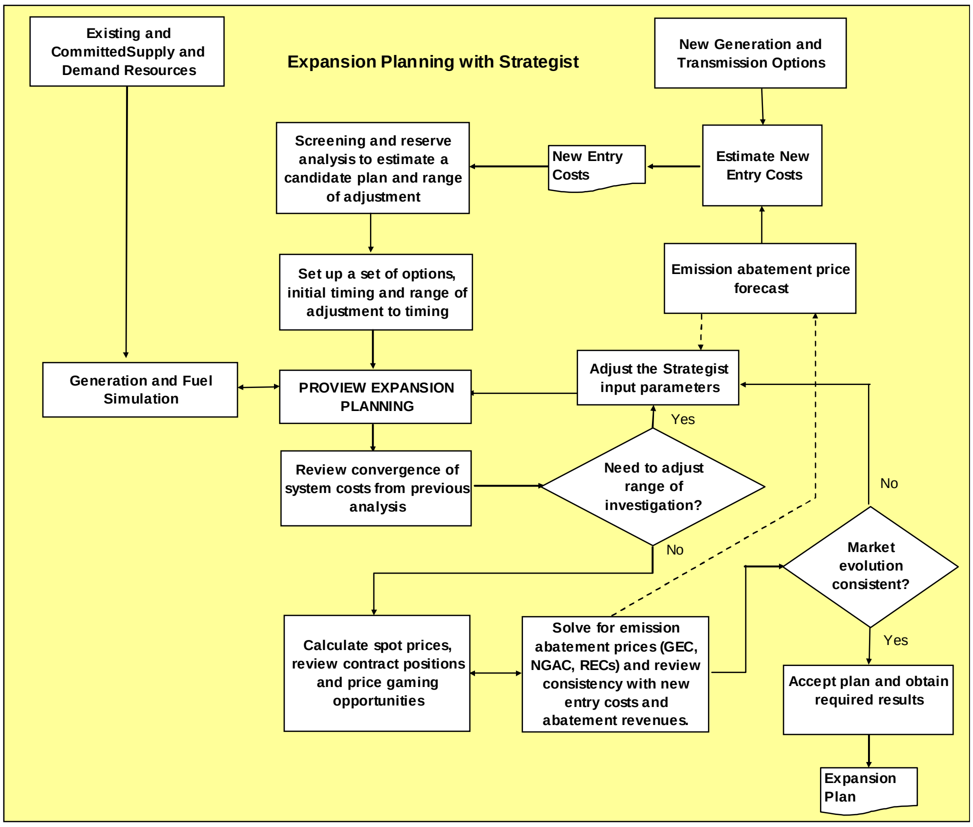
The PROVIEW module of Strategist has been used to develop the expansion plan with a view to minimising the total costs of the generation system plus interconnection augmentation. This is similar to the outcome afforded by a competitive market. However due to computational burden and structural limitations of the Strategist package, it is not feasible to complete in one analysis:

- The establishment of an optimal expansion plan (multiplicity of options and development sequences means that run time is the main limitation)
- The continued economic viability of high emissions coal-fired plant under a carbon pricing mechanism
- A review of the contract positions and the opportunity for gaming the spot market prices (in the case of the NEM).

Therefore, a number of iterations of PROVIEW are conducted to develop a workable expansion plan and then the expansion plan is refined to achieve a sustainable price path applying market power where it is apparent, and to obtain a consistent set of coal plant retirements and new entry plant mix.

Strategist generates average hourly marginal prices for each hour of a typical week for each month of the year at each of the regional reference nodes, having regard to thermal plant failure states and their probabilities. The prices are solved across the regions of the NEM having regard to inter-regional loss functions and capacity constraints. Failure of transmission links is not represented although capacity reductions are included based on historical chronological patterns. Constraints can be varied hourly if required and such a method is used to represent variations in the capacity of the Heywood interconnection, between Victoria and South Australia,

Figure A- 9 SKM MMA Strategist Modelling Procedures



which have been observed in the past when it was heavily loaded. Such variations occur during thunderstorms, to enhance system security, and during transmission line outages.

Bids in the NEM are generally formulated as multiples of marginal cost and are varied above unity ratio to represent the impact of contract positions and the price support provided by dominant market participants. Some capacity of cogeneration plants is bid below short run marginal cost to represent the value of the steam supply which is not included in the power plant model. The modelling of Smithfield allows for the typical peak and off-peak dispatch levels having regard to the cogeneration requirements.