INFORMATION

ACIL Tasman modelling report

Projections of wholesale energy component for AEMC report

The AEMC engaged ACIL Tasman to project the wholesale electricity component for its report on possible future retail electricity price movements: 1 July 2011 to 30 June 2014, which was published on 9 December 2011. The results of that modelling were used in calculating the wholesale electricity component in the cost build up for projected residential electricity prices.

How the ACIL Tasman modelling report should be interpreted

The ACIL Tasman modelling report represented one input to the AEMC report. Its intention was to provide an indication of the likely impact of the Clean Energy Future legislation on residential electricity prices. The intention of the AEMC report was to provide an indication of likely future trends in residential electricity price movements in Australia, and the drivers behind those trends.

In this regard, the ACIL Tasman report was not intended to provide an actual projection of the future carbon impact. That impact on residential electricity prices will be determined by jurisdictional regulators in their regulated pricing determinations.

Engagement of ACIL Tasman to undertake modelling

The AEMC engaged ACIL Tasman to use two separate modelling methodologies to examine the wholesale electricity component associated with serving residential energy users in the six jurisdictions that participate in the National Electricity Market, and in the Western Australian wholesale electricity market. The analysis covered the period from 1 July 2011 to 30 June 2014.

The modelling methodologies utilised were market simulation modelling and long-run marginal cost.

In addition, to reflect the Commonwealth Government's Clean Energy Future legislation, a carbon scenario (using the key parameters of the Clean Energy Future policy) and a no carbon scenario were modelled for both methodologies.

How the results were used in the AEMC report

ACIL Tasman's modelling results were used to calculate the wholesale electricity component for each state and territory. Where residential electricity prices are regulated, the methodology outlined in the jurisdictional regulators pricing determinations was used. That is, to the modelling data an allowance was added for the following items:

- NEM fees;
- Losses;
- Ancillary fees; and
- Other jurisdictional specific components, such as hedging uplift.

In Victoria where residential electricity prices are not regulated, the market simulation modelling data was used with estimates of the additional components to determine the wholesale electricity component.

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Wholesale energy cost forecast for serving residential users

Three year projection for all states and the ACT

Prepared for the Australian Energy Market Commission

5 October 2011

ACIL Tasman

Economics Policy Strategy

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Executive summary

At the request of the Ministerial Council on Energy (now the Standing Committee on Energy and Resources), the Australian Energy Market Commission (the Commission) is undertaking a review of energy cost trends for households in Australia. As part of this review, the Commission commissioned ACIL Tasman to undertake modelling of the wholesale energy costs associated with serving residential energy users in the six jurisdictions that participate in the National Electricity Market (NEM), and in the Western Australian Wholesale Electricity Market (WEM) that supplies the south-west of that state.

ACIL Tasman's modelling:

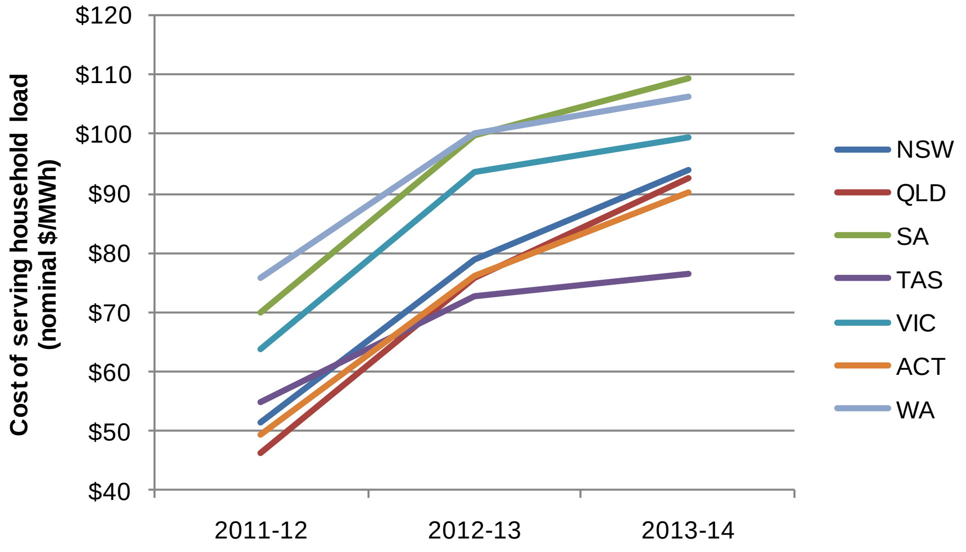
- covered the period from 1 July 2011 to 30 June 2014
- utilised two separate modelling approaches: market simulation modelling using the *PowerMark* simulation model and long-run marginal cost (LRMC) modelling using the *PowerMark LT* least-cost optimising model
- analysed two separate scenarios: a Carbon scenario involving the introduction of carbon pricing from 1 July 2012 as announced by the Commonwealth Government on 10 July 2011, and a No Carbon scenario.

This modelling examines wholesale energy costs associated with serving residential load only, and includes costs associated with contracting to manage the risk of serving this load ('hedging costs') under the market simulation approach. However, these results do not include costs associated with losses incurred when transporting electricity from the point at which wholesale market prices are determined to the point of final consumption, or costs associated with 'green schemes' such as the Large-scale Renewable Energy Target. ACIL Tasman also did not model other components of residential energy costs such as network costs, retail operating costs and retail margins.

Market simulation modelling results

As would be expected, the introduction of carbon pricing results in an uplift in the wholesale energy costs associated with serving residential customers in all jurisdictions. This increase is shown for each jurisdiction in Figure ES 1.

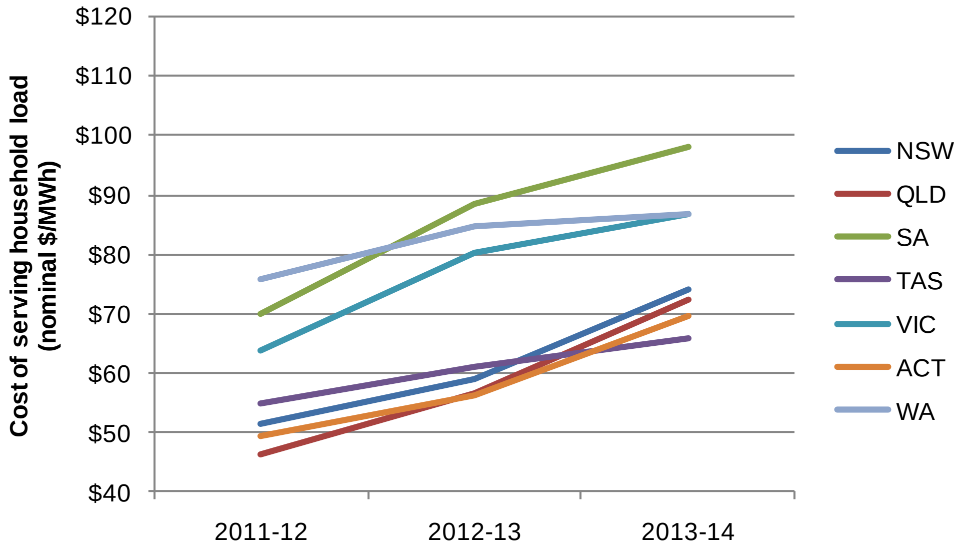
Figure ES 1 **Market wholesale energy cost of serving residential load – Carbon scenario**



Source: PowerMark modelling

However, even in the absence of carbon pricing, the No Carbon scenario sees a general uplift in wholesale energy costs to serve residential load. This is due primarily to tightening supply-demand balance over time (particularly at peak times) and increasing gas prices.

Figure ES 2 **Market wholesale energy cost of serving residential load – No Carbon scenario**

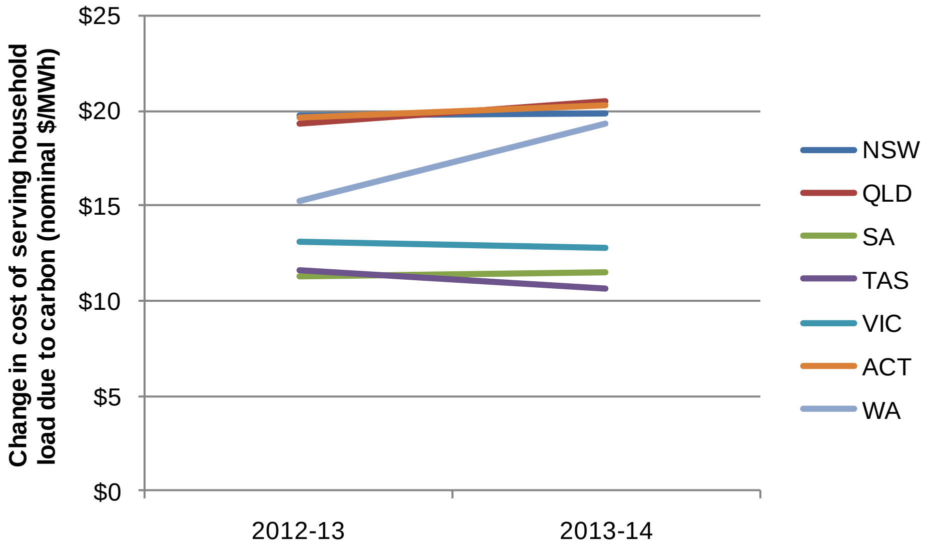


Source: PowerMark modelling

The change in wholesale energy costs between scenarios can be attributed to carbon pricing, and is presented in Figure ES 3. New South Wales, Queensland

and the ACT experience the greatest increase in costs due to carbon pricing, with Victoria, South Australia and Tasmania the lowest. Western Australian cost increases sit broadly in-between the outcomes for the various NEM jurisdictions.

Figure ES 3 **Increase in wholesale energy costs due to carbon pricing**



Note: Prices in 2011-12 are identical due to absence of carbon pricing in that year
Source: PowerMark modelling

Long-run marginal cost modelling

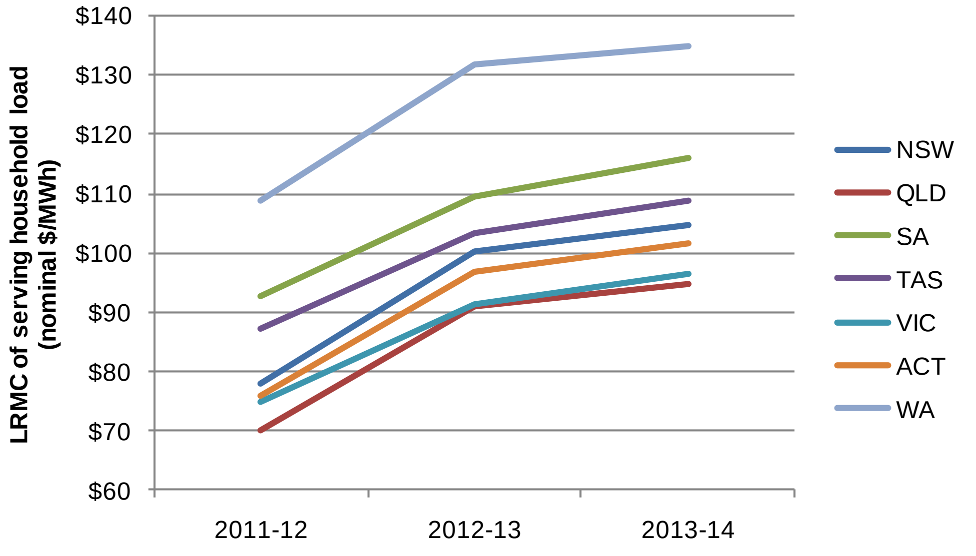
LRMC modelling outcomes are more 'stable' than market simulation modelling results because of the stylised nature of the exercise: a new generation system is 'built' for each model year, and is optimised to serve residential load alone at least-cost. The average cost of this generation system represents the long-run marginal cost of serving an additional increment of load with the same usage characteristics of the residential load profile modelled. All new entrants face generic capital cost and fuel assumptions, resulting in a stylised optimised system.

By contrast, market modelling outcomes are affected by a range of market variables that do not affect the LRMC modelling. These include the existing level and mix of generation plant, the operation of interconnectors, a range of pre-existing fuel contracts and strategic bidding by generators to maximise profits. The greater complexity of market modelling makes it more sensitive to subtle changes in circumstances, and allows prices to go below or above the stylised LRMC modelling outcomes for periods of time.

With these points noted, LRMC modelling can provide a useful guide and reference point with which to compare market simulation modelling outcomes.

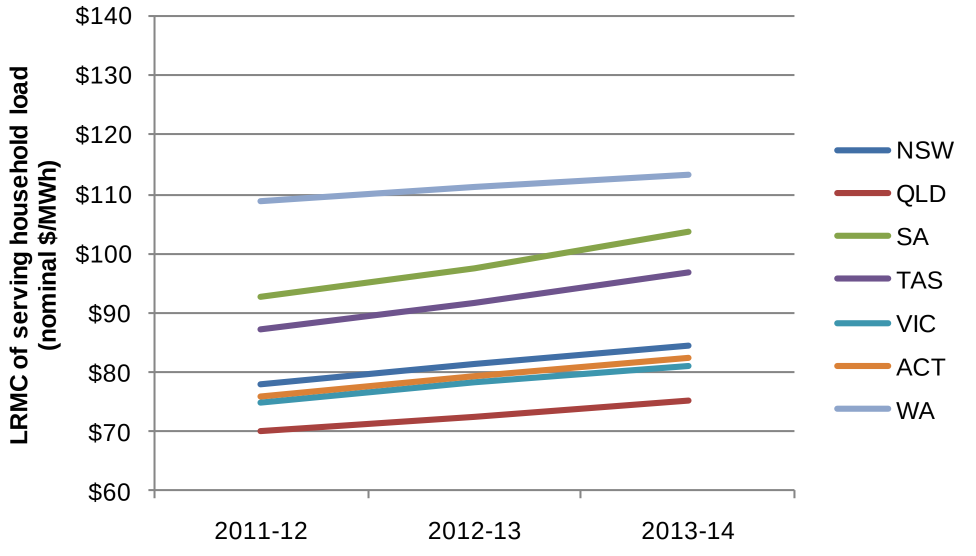
LRMC modelling outcomes from this analysis are presented below, with Figure ES 4 showing Carbon scenario LRMC outcomes, Figure ES 5 showing No Carbon scenario LRMC outcomes and Figure ES 6 illustrating the difference between the two.

Figure ES 4 **LRMC of serving residential load – Carbon scenario**



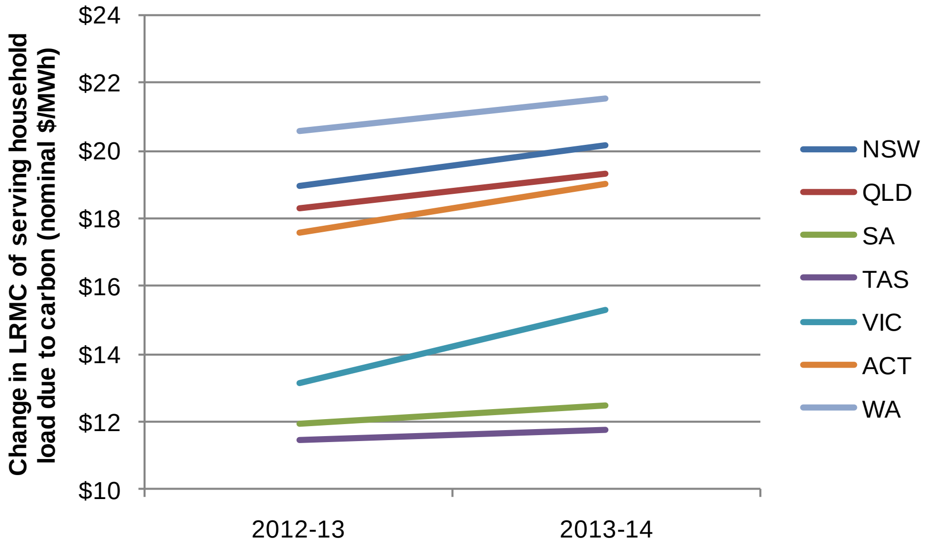
Source: PowerMark LT modelling

Figure ES 5 **LRMC of serving residential load – No Carbon scenario**



Source: PowerMark LT modelling

Figure ES 6 **Increase in LRMC of serving residential load due to carbon pricing**



Note: Prices in 2011-12 are identical due to absence of carbon pricing in that year

Source: PowerMark LT modelling

Comparison of market and LRMC modelling outcomes

As noted above, a range of factors cause market simulation modelling and LRMC modelling outcomes to differ.

A key factor at play in the market simulation modelling is the transition from price levels that are below 'new entrant' levels, that is, the level required to bring forward a new entrant base load generator, towards this level. This transition occurs primarily due to increasing demand and a tightening of the supply-demand balance, and a resultant need for prices to increase to motivate new entry to serve this growing demand.

This factor dominates the uplift in prices in the No Carbon market simulation modelling. By contrast, the more gradual uplift in No Carbon LRMC outcomes primarily reflects increases in gas prices over the projection period (as, by definition, the LRMC modelling captures a full return on capital costs in each modelled year, and so is always by definition at a new entrant level).

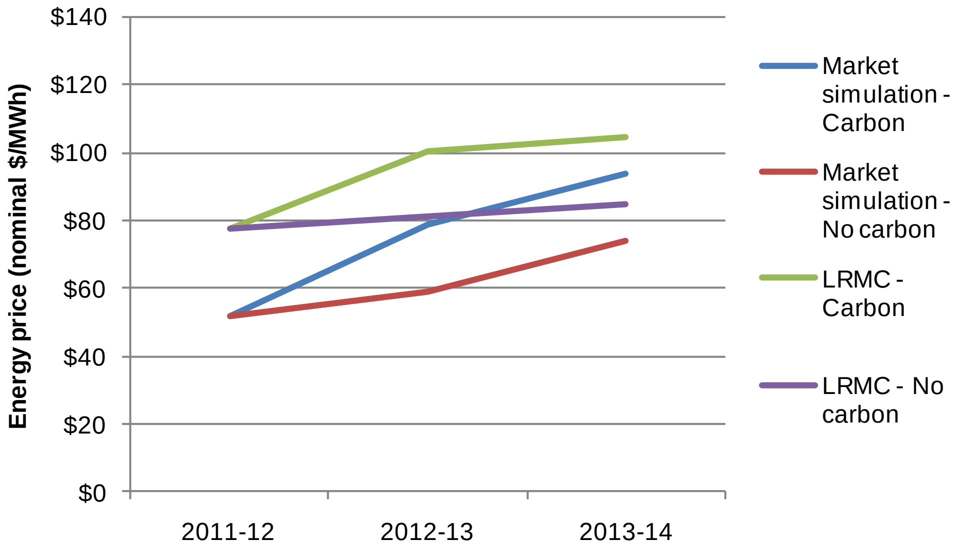
Similarly, the increase in the LRMC of serving residential loads due to carbon pricing is greater in 2013-14 than 2012-13, due to higher gas and carbon prices. By contrast, the market simulation modelling is ambiguous in this respect: in some jurisdictions, the uplift in prices due to carbon pricing increases and in others it is flat or declining. This reflects the variations in other variables, including the tightening of the supply-demand balance, and timing of new entry.

Market simulation and LRMC outcomes for each jurisdiction are presented below.

The key trends to observe are broadly:

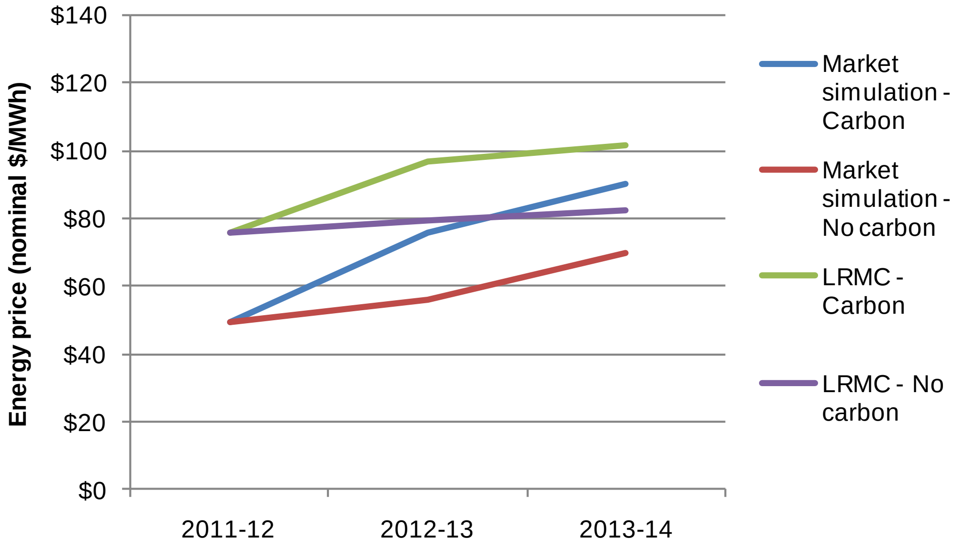
- the clear gap between LRMC (higher) and market simulation modelling (lower) costs in New South Wales, the Australian Capital Territory, Tasmania and Western Australia: this reflects the 'overhang' of base load generating capacity in these regions
- the closing gap between LRMC (higher) and market simulation modelling (lower) costs in Queensland as the latter approaches new entrant levels, reflecting the strong rate of growth in energy demand in that region
- the more mixed relationship between LRMC and market simulation modelling in Victoria and South Australia: this primarily reflects large differences in the existing (market simulation) generation mix and the optimised (LRMC) generation mix, and the importance of summer peak price events, wind generation and interconnection between regions on prices in these regions in the market simulation modelling.

Figure ES 7 **Comparison of LRMC and market simulation outcomes – New South Wales**



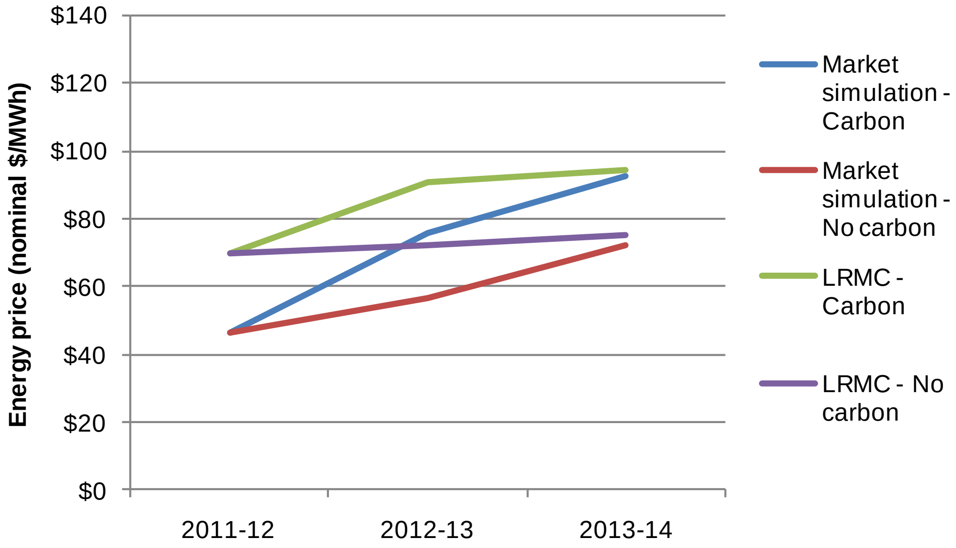
Source: PowerMark modelling; *PowerMark LT* modelling; additional ACIL Tasman analysis of hedging costs

Figure ES 8 **Comparison of LRMC and market simulation outcomes – Australian Capital Territory**



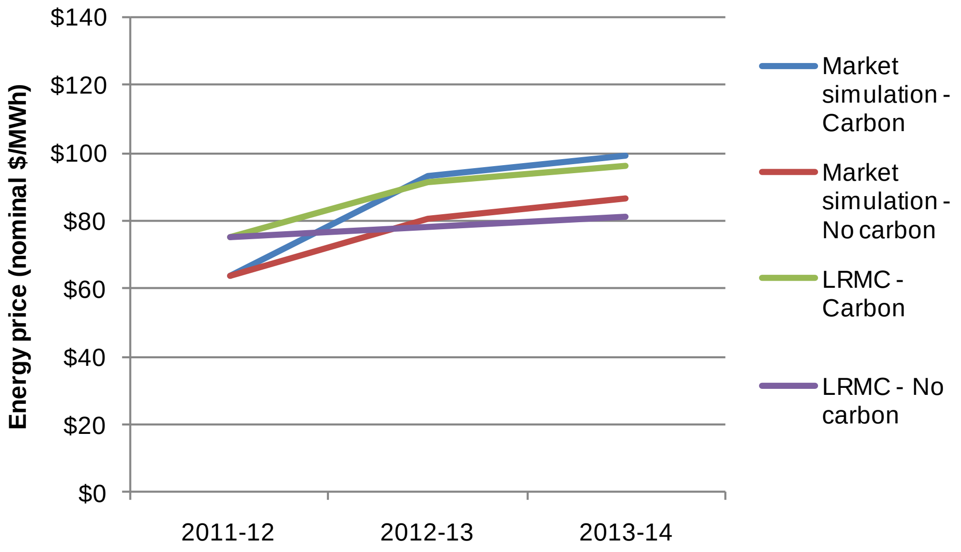
Source: PowerMark modelling; *PowerMark LT* modelling; additional ACIL Tasman analysis of hedging costs

Figure ES 9 **Comparison of LRMC and market simulation outcomes – Queensland**



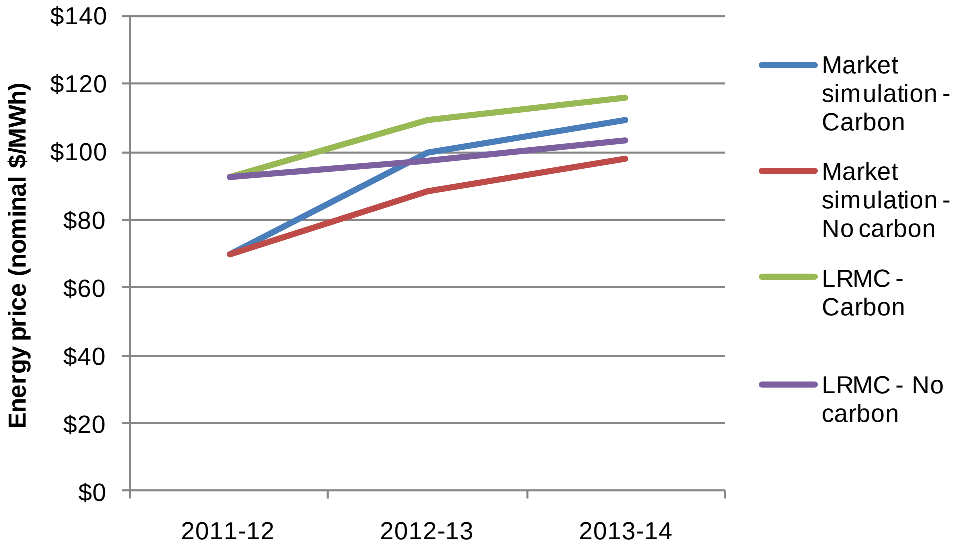
Source: PowerMark modelling; *PowerMark LT* modelling; additional ACIL Tasman analysis of hedging costs

Figure ES 10 **Comparison of LRMC and market simulation outcomes – Victoria**



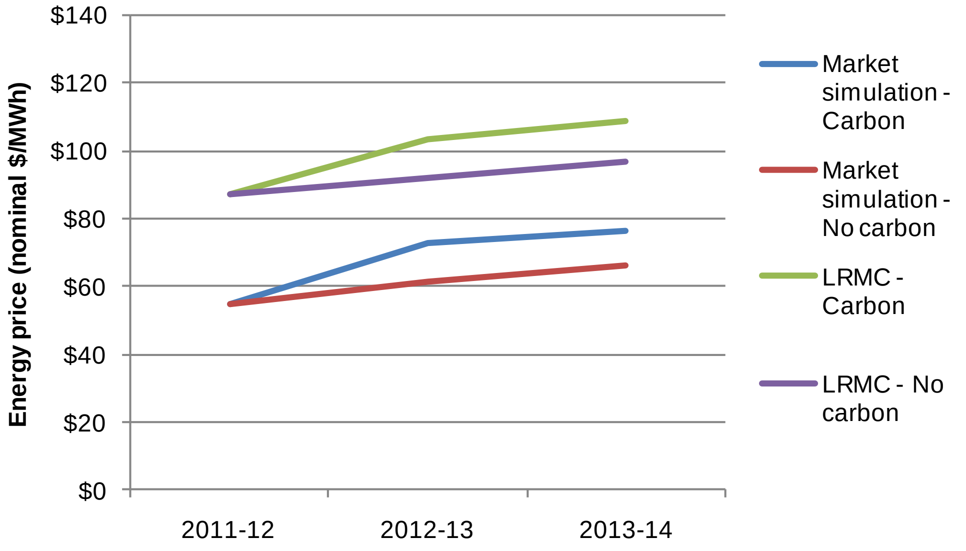
Source: PowerMark modelling; *PowerMark LT* modelling; additional ACIL Tasman analysis of hedging costs

Figure ES 11 **Comparison of LRMC and market simulation outcomes – South Australia**



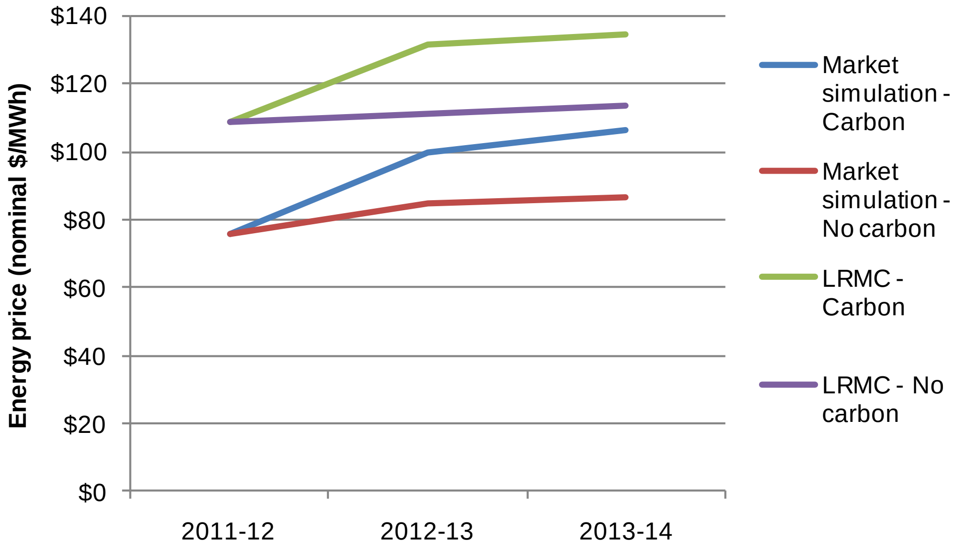
Source: PowerMark modelling; *PowerMark LT* modelling; additional ACIL Tasman analysis of hedging costs

Figure ES 12 **Comparison of LRMC and market simulation outcomes – Tasmania**



Source: PowerMark modelling; *PowerMark LT* modelling; additional ACIL Tasman analysis of hedging costs

Figure ES 13 **Comparison of LRMC and market simulation outcomes – Western Australia**



Source: PowerMark modelling; *PowerMark LT* modelling; additional ACIL Tasman analysis of hedging costs

1 Introduction

At the request of the Ministerial Council on Energy (now the Standing Committee on Energy and Resources), the Australian Energy Market Commission (the Commission) is undertaking a review of energy cost trends for households in Australia. This review builds on similar work undertaken during 2010 and released publicly by the Commission in its 30 November 2010 paper *Future Possible Retail Electricity Price Movements: 1 July 2010 to 30 June 2013*.

As part of this review, the Commission commissioned ACIL Tasman to undertake modelling of the wholesale energy costs associated with serving residential energy users in the six jurisdictions that participate in the National Electricity Market (NEM), and in the Western Australian Wholesale Electricity Market (WEM) that supplies the south-west of that state. The analysis covers the period from 1 July 2011 to 30 June 2014.

The Commission requested that ACIL Tasman use two separate modelling methodologies to examine wholesale energy costs:

- Market simulation modelling, which represents the potential future behaviour of the energy system given present circumstances and informed assumptions about a range of variables that will affect its future operation
- Long-run marginal cost modelling, which examines the full capital and operating cost of satisfying projected energy demand from a hypothetical generation system that is 'built' in the model to serve this demand in an optimal manner.

To undertake these two components, ACIL Tasman drew on its two key electricity market models: *PowerMark*, a detailed simulation model capable of representing the NEM, WEM and other electricity markets; and *PowerMark LT*, a least-cost optimising model capable of designing and analysing an optimised generation system given input assumptions on demand and generation costs.

On 10 July 2011, the Commonwealth Government announced details of its proposed Clean Energy Future policy, which includes a carbon pricing mechanism that would impose direct costs on electricity generators that burn fossil fuels. The carbon pricing mechanism is proposed to start on 1 July 2012.

Accordingly, this policy has the potential to significantly affect energy costs in the NEM and the WEM over the period of analysis. However, the policy has not been legislated and remains subject to political debate. Reflecting this, ACIL Tasman has modelled two scenarios in this analysis: a Carbon scenario that incorporates the key parameters of the Clean Energy Future policy as announced; and a No Carbon scenario that assumes that no carbon pricing policy is implemented during the period of analysis (or in a way that affects outcomes during the period of analysis).

ACIL Tasman was not requested to model components of residential energy costs other than the wholesale energy costs associated with serving these customers. In other words, the analysis excludes network costs, retail operating costs, retail margins and other cost components.

Importantly, as discussed in section 2.1 below, it also excludes costs associated with electrical losses in the transmission and distribution system that occur when electricity is transported from the point of the network at which wholesale prices are settled to the point of consumption, and costs associated with supporting renewable generation or equivalent 'green schemes'.

Section 2 outlines the methodology adopted in the market simulation modelling and long-run modelling approaches in more detail.

Section 3.1 examines results from the market simulation modelling, while section 3.2 examines results from the long-run marginal cost modelling.

Finally, section 3.2 compares the results from both modelling approaches to provide further insights from the analysis.

2 Methodology

2.1 Scope of analysis

2.1.1 Geographic scope

ACIL Tasman's analysis for the Commission is limited to the six jurisdictions that participate in the NEM – New South Wales, Queensland, Victoria, South Australia, Tasmania and the Australian Capital Territory – and south-western Western Australia. Broadly, south-western Western Australia can be considered as the region that is physically interconnected through the 'South-West Interconnected System', and which operates under the rules of the WEM.

2.1.2 Treatment of transmission and distribution losses

To allow for the effect of electrical losses in the transmission and distribution system, a full analysis of the wholesale energy cost associated with serving residential load should take into account the fact that energy will be lost between the point of generation and consumption. This lost energy has value, and therefore the cost of these losses should be attributed to energy consumers.

Generally speaking, the methodology adopted for this analysis does not capture the effect of losses, which will be adjusted for separately by the Commission in its analysis of the overall cost of serving residential load.

ACIL Tasman has examined wholesale energy prices and costs at the 'regional reference node' (RRN) of each market examined, which is the point at which prices are settled but not the point at which electricity is actually consumed.

This methodology captures some losses, in that the average loss incurred by generators in transporting energy from each point of generation to the RRN are factored into generator bids and prices at the RRN. However, the correct adjustment for losses to determine the true (delivered) wholesale energy cost of serving residential users would also capture losses between the RRN and the various points of consumption. ACIL Tasman understands that the Commission will undertake this adjustment through its broader analysis of the total cost of serving residential energy users.

2.1.3 Treatment of 'green scheme' costs

ACIL Tasman also notes that this analysis does not take into account the costs associated with supporting renewable generation through government schemes such as the Commonwealth Government's Large-scale Renewable Energy

Target (LRET). Whilst the costs of these schemes are correctly considered a cost of serving various energy users, and are associated with the wholesale generation of electricity, typically they are estimated separately and not included within the definition of 'wholesale energy costs'. This is true of this analysis.

However, ACIL Tasman notes that the cost of the LRET scheme is typically inversely related to the wholesale cost of energy across Australia. This is because higher energy costs make renewable generators supported by the LRET more financially viable, which reduces the level of subsidy that this policy needs to deliver to meet its objectives.

For this reason, readers should use in caution in inferring patterns about the total change in energy costs for residential users from this analysis. Such an assessment can only be considered, whether in relative or absolute terms, in conjunction with all other cost components associated with serving these customers. Whilst the cost of the LRET in particular will tend to offset the increase in wholesale energy costs as a result of carbon pricing, other cost components may move in ambiguous ways.

Nevertheless, the general point holds that the overall cost impact should not be directly inferred from modelling that addresses only a single component of total delivered energy costs, even when changes in this component are likely to be the largest impact arising from the introduction of a carbon price.

2.2 Market simulation modelling approach

The market simulation modelling approach has three important elements:

1. Modelling market prices
2. Analysing the time-of-use and seasonal patterns of residential demand to assess the level of correlation between wholesale energy prices and residential load over the projection period
3. Designing a stylised hedge portfolio to reflect the cost associated with managing price and volume risks associated with serving residential load.

These elements are brought together to assess the total cost of serving residential load.

2.2.1 Modelling market prices

ACIL Tasman's market simulation modelling of energy purchase costs for residential loads utilised the *PowerMark* model for both the NEM and the WEM.

In this exercise, *PowerMark* modelling simulated hourly price outcomes in each region of the NEM, and half-hourly price outcomes in the WEM's 'short-term energy market' (STEM). This level of resolution is important to allow analysis of how market prices vary according to the time-of-day and time of year (which in turn reflect underlying, often weather driven, demand dynamics).

To capture the specific effect of a carbon price, ACIL Tasman modelled two scenarios:

- A 'with carbon' scenario, incorporating a fixed carbon price of $23/tonne of carbon dioxide equivalence (CO_2-e) in 2012/13 and increasing at 5% in nominal terms for three years (as announced in the Commonwealth Government's *Clean Energy Future* policy package)
- A 'no carbon' scenario where no carbon price is introduced.

It is important to note that the NEM and WEM operate in quite a different manner, and so the relationship between *PowerMark* modelling results and likely future energy costs is subtly different.

The NEM operates as a 'gross pool' market, which means that all energy that is sold in a given half-hour period is settled through a pool at a single clearing price (before losses and other factors are taken into account). By contrast, most energy traded in the WEM is dispatched and settled in accordance with pre-agreed bilateral contracts struck between buyers and sellers. The STEM operates as a 'balancing' market such that adjustments from these pre-determined positions are bid into the market and settled at the STEM market price.

The corollary of this difference in market structure in that actual financial settlements in the NEM are transparent to external observers, whereas transparent market outcomes in the STEM are not necessarily representative of the price at which the majority of (bilaterally-traded) energy is settled. As is outlined in section 2.2.3, participants in the NEM enter into financial contracts that manage the financial risks associated with their pool purchases and sales, and these arrangements affect the true cost of energy purchased. However, as these financial contracts themselves are generally settled by reference to spot market outcomes, NEM spot market outcomes are a clearer representation of the traded price of energy to consumers than STEM prices.

Notwithstanding this difference, given the opaqueness of contractual positions, ACIL Tasman adopts the approach of modelling the WEM on the basis that all energy is bid into and settled within the STEM in accordance with WEM rules. Whilst this is not an accurate representation of how the WEM works in practice, it is direct representation of both the opportunity cost of contracted energy (which could be on-sold into the STEM, irrespective of its contractual supply commitment) and the potential revenue available at the margin to a new generator.

For these two reasons, the STEM price modelled in this way (when combined with capacity credit costs that are incurred in the WEM – see section 3.1.4) provide a robust representation of the underlying cost of energy in that market.

Put another way, the modelled price outcome is a robust representation of the level at which bilateral contracts would be struck under WEM market arrangements under long-term competitive circumstances.

2.2.2 Matching residential and total system load

Jurisdictions with net system load profiles

ACIL Tasman has analysed the historic relationship between total NEM load and the load of residential users (or small users more generally where pure residential demand was not readily available) to infer how this relationship will impact on the cost of serving residential users over the projection period.

Market outcomes in the NEM are strongly driven by market outcomes at times of peak demand, which are in turn driven by extreme weather events (particularly heatwaves).

This particularly affects price outcomes for retailers serving residential users: air-conditioning and space heating loads make up a large proportion of peak demand for households, meaning that residential load is strongly correlated with weather-induced price spikes.

This illustrates the importance of understanding how the variability of market prices in the *PowerMark* model translates to an increase in the average cost per unit of electricity consumed by households.

In the NEM jurisdictions of New South Wales, Queensland, Victoria, South Australia and the ACT, the most readily available data on household energy usage was that captured in 'net system load profiles' (NSLPs) used by the Australian Energy Market Operator (AEMO) to perform financial settlements on energy purchased on behalf of small customers that do not have time-of-use meters. The NSLP data provides time-of-use data disaggregated on a half-hourly basis.

Whilst the NSLP data includes usage of some small business loads, the increasing move towards time-of-use metering for commercial loads means that recent NSLP data provides a reasonably undiluted representation of household load. ACIL Tasman's analysis indicates that, while the portion of residential load in total NSLP load varies by jurisdiction, it is generally greater than 70%, and approaches 90% in Victoria. This penetration, when combined with the fact that usage of some small businesses may be reasonably well correlated with household use (particularly at times of peak air-conditioning usage), means that we use NSLP data as a proxy for residential loads in these jurisdictions, and refer to NSLP load and residential load interchangeable for simplicity.

Accordingly, in these jurisdictions, ACIL Tasman used NSLP data to:

- Match historic residential load with historic total system load
- Sort historic total system load into descending order, i.e. a load duration curve
- Express this load profile as a percentage of maximum total system load (A)
- Express the corresponding residential loads for each period as a percentage of maximum residential load
- 'Smooth' this residential load profile using a simple rolling average (B)
- Calculate the ratio of A and B
- Apply this ratio to the synthetic load profiles[1] used in *PowerMark* to determine the likely residential demand in each hour of the projection period as a percentage of maximum residential load, i.e. a synthetic residential load profile
- Weight price outcomes for each hour by the synthetic residential load in the relevant period to determine a load-weighted residential energy price.

This methodology provides a stylised reflection of likely residential load over the projection period: the use of a rolling average to minimise the impact of random variability and the inferred constant relationship between total system load and residential load could introduce systemic errors in the forecast.

This representation of the relationship between residential load and total system load is presented graphically in a supplementary document to assist understanding.

However, to test the potential for this methodology to distort results, ACIL Tasman compared the prediction of this methodology when applied to historic NSLPs and market prices with historic load-weighted prices for each NSLP over the calendar years 2008, 2009 and 2010. This analysis demonstrated that

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[1] ACIL Tasman's core simulation of the NEM and the WEM is based on a 'synthetic' load reflecting a notional 'typical' weather year given underlying (non-weather related) demand trends. At a high level, this synthetic load can be considered to reflect a '1 in 2' demand level, that is, a level of demand that is likely to be reached or exceeded every other year. This level is also known as a 50% POE level, meaning that it has a 50% 'probability of exceedence'. As other weather outcomes are possible, further modelling has been undertaken to assess the risks associated with supplying household load under different market circumstances.

the methodology delivered results consistently within 3% of actual NSLP load-weighted prices, with the exception of NSW in 2009.

The outcomes of this methodology testing are demonstrated below in Table 1, with two methods being presented: the 'annual' approach, where a synthetic NSLP is derived for each calendar year separately; and the 'three year average' approach, where the synthetic NSLP for each of the three years analysed is averaged, and this average profile is then applied to each year's price outcomes. The projection adopted the three year average approach to minimise the impact of abnormalities that could arise in any individual year.

Table 1 **Comparison of historic and predicted LWP for households**

Jurisdiction	Year	Residential LWP – actual	Prediction method	Residential LWP - predicted	Error
		$/MWh		$/MWh	%
New South Wales	2008	$44.00	Annual	$44.59	1.4%
			Three year average	$44.43	1.0%
	2009	$56.11	Annual	$57.47	2.4%
			Three year average	$58.62	4.5%
	2010	$36.31	Annual	$36.64	0.9%
			Three year average	$36.51	0.5%
Victoria	2008	$45.85	Annual	$45.17	-1.5%
			Three year average	$45.27	-1.3%
	2009	$49.07	Annual	48.67	-0.8%
			Three year average	47.99	-2.2%
	2010	$43.79	Annual	$42.9	-2.0%
			Three year average	$43.13	-1.5%
Queensland	2008	$53.02	Annual	$51.96	-2.0%
			Three year average	$51.83	-2.3%
	2009	$39.22	Annual	$38.98	-0.6%
			Three year average	$39.08	-0.4%
	2010	$29.92	Annual	$29.71	-0.7%
			Three year average	$29.54	-1.3%
South Australia	2008	$109.81	Annual	$107.70	-1.9%
			Three year average	$109.87	0.1%
	2009	$110.53	Annual	$108.76	-1.6%
			Three year average	$107.24	-3.0%
	2010	$65.91	Annual	$64.60	-2.0%
			Three year average	$64.08	-2.7%

Data source: AEMO; ACIL Tasman manipulation

Results for the Australian Capital Territory using this methodology did not demonstrate as robust a correlation. However, when ACT loads were separated out into summer and winter loads, the explanatory power of this methodology was substantially stronger: in effect, ACT retail load has a clearer correlation with NSW NEM load in winter than summer, and distinguishing between these periods in developing the ACT's synthetic net system load profile provides a far stronger explanation of historic prices (as shown in Table 2). Accordingly, this seasonal methodology was adopted for the projection of ACT wholesale prices for households.

Table 2 **Comparison of historic and predicted LWP in ACT**

Year	Period	Residential LWP – actual	Residential LWP – predicted (annual prediction method)	Error	Residential LWP – predicted (three year average prediction method)	Error
		$/MWh	$/MWh	%	$/MWh	%
2008	Calendar year	$43.36	$45.26	4.4%	$44.56	2.8%
	Summer	$42.73	$43.64	2.1%	$44.41	3.9%
	Winter	$43.76	$43.65	-0.3%	$43.75	-0.0%
2009	Calendar year	$50.16	$53.34	6.3%	$57.12	13.9%
	Summer	$74.32	$77.70	4.6%	$75.87	2.1%
	Winter	$33.24	$33.19	-0.2%	$33.31	0.2%
2010	Calendar year	$34.37	$35.67	3.8%	$35.86	4.3%
	Summer	$39.20	$39.31	0.3%	$39.47	0.7%
	Winter	$31.22	$31.03	-0.6%	$31.15	-0.2%

Data source: AEMO; ACIL Tasman manipulation

Tasmania

Given the absence of an NSLP for Tasmania, and with the assistance of the Commission and the Tasmanian Government, ACIL Tasman sought and received data from Aurora Energy on historic residential loads for the years 2008-09, 2009-10 and 2010-11 to allow analysis of the correlation of residential and NEM loads in this jurisdiction.[2]

However, for Tasmania a different methodology for predicting future small-user load-weighted electricity costs was adopted due to the poor predictive power of the synthetic net system load profile derived in the manner as for the jurisdictions discussed above.

[2] The data for 2008-09 was not primarily used for this analysis due to the different composition of retail load presented in that year, in that it included a larger share of non-residential electricity consumers.

Instead, for Tasmania, retail load data was analysed on a '12 by 24' basis, that is, creating a daily load profile for each month of the year. This profile can be weighted by the number of days in each month to produce a load-weighted 12 by 24 profile accurately reflecting all demand over the year.

Historic NEM prices for the Tasmanian region were then averaged on a comparable 12 by 24 basis, and the predicted load-weighted price for retail customers in Tasmania compared with the actual load-weighted price.

As for the synthetic net system load profile methodology used for the states discussed above, the 12 by 24 approach successfully predicted historical price outcomes sufficiently that it could be confidently adopted for converting modelled future NEM prices from *PowerMark* into load-weighted retail electricity costs. The predictive power of this approach is illustrated in Table 3.

Table 3 **Comparison of historic and predicted LWP in Tasmania**

Period	Residential LWP – actual	Residential LWP – 12 by 24 prediction method	Error
2009-10	$31.38	$30.78	-1.9%
2010-11	$34.20	$33.53	-2.0%

Data source: Aurora Energy; AEMO; ACIL Tasman manipulation.

As this methodology produced a slight underestimate of the actual residential load-weighted price, ACIL Tasman uplifted the forecast load-weighted residential price by 2% for each year of the projection period.

Western Australia

For Western Australia, ACIL Tasman's task for this analysis was simplified relative to the NEM states discussed above due to the provision of a residential ('A1') load forecast for the full projection period. Again, the provision of this data was sought by ACIL Tasman, facilitated by the WA Government and the Commission, and provided by Synergy.

Given the provision of a residential load forecast, ACIL Tasman only undertook minimal manipulation of this data to allow the development of a load-weighted Short-term Energy Market (STEM) cost associated with the residential load profile in WA. This manipulation involved aligning the day of the week assumptions used in *PowerMark* with the days of the week underpinning Synergy's forecast. In simple terms, *PowerMark* utilises a standard 365 day year based on the days of the week and public holiday cycle of the financial year 1999-2000. Therefore, weekends and respective weekdays in Synergy's forecast, which are based on the actual days of the week over the projection period, were aligned with the relevant day of the equivalent week in 1999-2000. Relevant adjustments were also made for the leap year in 2012.

The results derived in this manner are discussed in section 3.1.4.

Summary

This analysis indicates that the load-weighted (unhedged) energy cost for serving household loads from the wholesale market can be reasonably robustly projected for alignment with model outcomes for future years through a range of methods, depending on the data available.

However, the load-weighted residential energy cost modelled using the methodologies described above represents the cost that retailers would pay if they had perfect foresight and if normalised weather conditions were certain to occur in every year. Clearly, in practice these conditions do not hold.

Accordingly, as discussed below in section 2.2.3, additional costs need to be applied to reflect the risk for retailers that market conditions will vary from these 'normal' conditions (specifically, in the direction of higher prices), and capture the premium that retailers will be willing to pay to insure against this outcome.

2.2.3 Hedging costs – NEM

Electricity retailers act as intermediaries between small energy consumers such as households and the NEM wholesale market. However, as electricity retailers generally supply consumers on pre-agreed, fixed price terms, but purchase electricity from a volatile wholesale spot market in which prices can vary between -$1,000/MWh and $12,500/MWh, these entities routinely enter into a range of commercial agreements to manage the financial risks they face in supplying their customers. These 'hedging' costs are widely recognised as an integral element of the true cost of supplying any electricity load, and particularly residential users whose load is decentralised (and thereby difficult to control), unpredictable and highly variable.

To analyse potential hedging costs associated with supplying residential load in the NEM states[3], ACIL Tasman developed a stylised hedge portfolio that would reduce the exposure of a hypothetical retailer that was supplying the entire residential load to adverse market price outcomes (i.e. higher prices). This is necessary because the normalised price outcomes delivered by *PowerMark* modelling does not capture this risk premium that such a retailer would be willing to pay to avoid such outcomes.

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[3] The market structure of the WEM, which includes capacity credits, 'short-run marginal cost bidding' in its energy market, low market price cap and floor and a heavy reliance on bilateral contracts, necessitates a very different approach to capturing hedging costs.

ACIL Tasman emphasises that 'hedging' in the NEM and other wholesale electricity markets takes many forms. In some cases, it involves financial contracts. Increasingly, retailers in the NEM use 'physical hedges' to manage their exposures: this involves purchasing or otherwise controlling physical generation assets and using these assets to ensure that a retailer has offsetting generation revenue whenever it is exposed to high market prices as a purchaser.

Further, the approach adopted in this analysis abstracts from reality in that, in practice, electricity retailers do not hedge their residential customers' load separately from commercial and industrial customers. In practice, it is highly likely that synergies can be achieved by hedging diverse loads with different demand patterns, and using hedging mechanisms flexibly to cover the range of exposures and circumstances a retailer may face. Nevertheless, for the purpose of this analysis, and given the fairly unique characteristics of residential loads, it is satisfactory to consider the costs associated with supplying a 'stand-alone' residential load.

Noting these simplifications, the stylised hedge portfolio developed by ACIL Tasman for this analysis:

- Assumed that the hypothetical retailer would use a combination of common hedge instruments to hedge the load under analysis, namely peak swaps, base swaps and caps
- Applied a premium to peak and base swaps to reflect the risk management premium that retailers would be willing to pay to manage the risk of higher average prices through swaps
- Modelled price outcomes under an extreme price year (reflecting 10% POE outcomes under current 2011 planning report peak demand forecast) to estimate the risk premium that retailers would be willing to pay to enter into cap contracts to manage their exposure to prices events above $300/MWh
- Modelled total cash flows (in the form of 'difference payments') that would arise between the hypothetical retailer and the suppliers of its hedge position under the contract position modelled
- Tested various combinations of swap and cap positions to ensure that the final contract position modelled was cost-efficient.

Swap prices were calculated as the time-weighted average price in the relevant NEM region, adjusted by a premium to reflect the skewness of the distribution of possible market price outcomes in the direction of higher prices. In effect, retailers are more concerned about avoiding the possibility of high market prices than generators are about avoiding the possibility of low market prices, and so retailers are willing to a net premium to generators to gain certainty over market price outcomes, even though generators also benefit from increased certainty.

A standard swap premium of 5% was applied to both peak and base swaps in all regions.

To estimate cap contract premiums, ACIL Tasman used modelling of an extreme weather year (reflecting a 10% POE outcome) to assess the materiality of higher prices for retailers, and therefore the premium they would be willing to pay to avoid such an outcome. The materiality of extreme price outcomes will vary from region to region and year to year, depending on, amongst other things, the supply-demand balance in that year and the extent to which extreme (10% POE) demand peaks exceed the demand peak that would be expected in an average (50% POE) year.

2.2.4 Capacity credit costs – WEM

As noted above, the Western Australian Wholesale Electricity Market (WEM) operates in quite a different manner to the NEM. Reflecting the concentration of market power with Verve Energy in the WEM, the WEM has several significant design features that affect this analysis:

- The STEM is treated as a 'net' or 'balancing' market, where the majority of energy is dispatched and settled in accordance with bilateral contracts and only the 'net' or residual volumes of electricity are settled through the market
- Participants in the STEM are required to use 'short-run marginal cost' (SRMC) bidding unless this would not constitute an abuse of market power, which greatly limits the return available to generators from the STEM
- the STEM has a price cap that is far lower than that in effect in the NEM (currently $522/MWh in the STEM compared to $12,500/MWh in the NEM)
- The WEM includes a capacity credit mechanism where generators are paid for making capacity available to the market (irrespective of dispatch).

Given the SRMC bidding requirement in the STEM, the capacity credit mechanism is the primary way in which generators can get a return on capital, and thereby recover their long-run marginal costs of generating.

The SRMC bidding approach and the lower price cap prevents the STEM from witnessing the sort of price volatility witnessed in the WEM. In effect, the combination of SRMC bidding and the capacity credit mechanism displaces the important cost component of 'hedging' costs associated with serving energy loads in the NEM.

To model the cost of capacity credits that should be attributed to serving residential load within the WEM, ACIL Tasman:

- Modelled the Reserve Capacity Price for each capacity year[4] that overlaps with the analysis period
- Took the (normalised) 50% POE forecast maximum WEM demand for each capacity year that overlaps with the analysis period
- Took the forecast maximum residential demand provided by Synergy for the January to March quarter of the relevant capacity year, this being the time of year where WEM maximum demand is most likely to occur
- Divided the forecast maximum January to March residential demand by the forecast maximum WEM demand to determine the share of capacity credits that should be attributed to serving residential load
- Took the Reserve Capacity Requirement determined by the Independent Market Operator of Western Australia (IMOWA) for each capacity year and calculated the residential share of this requirement
- Multiplied the notional residential capacity requirement by the Reserve Capacity Price (on a quarterly basis) to determine a quarterly cost of capacity credits associated with residential load
- Divided by the total cost of capacity credits for each financial year by the forecast residential load in that financial year to determine the capacity credit cost per megawatt of residential load.

2.3 LRMC modelling approach

To complement the market simulation modelling component of this analysis, the Commission also commissioned ACIL Tasman to undertake LRMC modelling. LRMC modelling offers an alternative, stylised, representation of an energy system that can provide additional insights to those gleaned from literally modelling current and future market circumstances. However, due to the stylised nature of LRMC modelling, it is important to note the specific methodological approach adopted in this analysis and the corresponding limitations of the modelling.

ACIL Tasman used *PowerMark LT* to undertake this modelling component. *PowerMark LT* is a least-cost optimising model that can readily optimise and construct a new generation system given a suite of available technologies and an assumed load profile to estimate the stylised LRMC of serving such a load with the technology suite available.

[4] Capacity years in the WEM span from 1 October to 30 September.

2.3.1 LRMC methodology

Various jurisdictional regulators use LRMC modelling as an input to the regulation of retail prices and different jurisdictional regulators adopt different methodological approaches.

A comparison of LRMC modelling approaches adopted in various jurisdictions is set out in Table 4 below.

Table 4 **Jurisdictional approaches to LRMC modelling**

Jurisdiction	LRMC used in regulated process?	LRMC approach	Other comments
New South Wales	Yes – regulated price higher of market and LRMC prices	Greenfields	Renewable generation not included
Victoria	No – retail price unregulated	N/A	-
Queensland	Yes – regulated price average of market and LRMC prices for 2010-11 (approach for 2011-12 not finalised)	Greenfields	Covers entire market load and includes effects of interconnection between NEM regions.
South Australia	Yes – regulated price is based on LRMC	Greenfields	Retail load only. ESCOSA considered merits of 'hybrid' approaches
Western Australia	No – tariffs not cost-reflective	N/A	-
Tasmania	Yes – regulated price is the LRMC	Greenfields	Hydro-electric system ignored – effectively CCGT and OCGT new entrants
Northern Territory	No – tariffs not cost-reflective	N/A	-
Australian Capital Territory	No – market prices adjusted for NSLP. LRMC considered by ActewAGL in submission.	N/A	-

Data source: IPART; Frontier Economics for IPART; QCA; ACIL Tasman for QCA; ESCOSA; OTTER.

For comparability across jurisdictions, ACIL Tasman adopted an approach that effectively replicates the New South Wales, South Australian and Tasmanian approach to modelling LRMC, but differs from the Queensland approach used in 2010-11, which modelled the entire Queensland load and incorporated the effect of interconnectors).

Under this approach, ACIL Tasman:

- Adopted the 'greenfields' LRMC modelling approach, that is, where a hypothetical new generation system is built in each year to satisfy the residential load on a stand-alone basis
- Adopted a discrete model outcome for each financial year analysed (that is, the generation system is built anew for each year, and does not 'carry over' for the three years of analysis)
- Satisfied the residential load entirely from within the local region, such that interconnectors are essentially removed from the analysis.

The logic for adopting this approach to modelling LRMC is broadly as follows:

- Optimising the system year-by-year is the most coherent approach to ensure a full return of and return on capital in the entire period analysed. Optimising the system over, say, a three year period would result in excess returns to capital in some years and under-returns in others in response to new entry and policy changes such as carbon pricing, which would produce an inconsistent series of LRMC outcomes.
- Examining the residential load on a stand-alone basis is also an effective method of ensuring that the capital costs associated with serving this load are fully captured. For example, modelling the entire system could result in arbitrary allocations capital costs between customer classes.
- Once the approach of modelling residential load on a stand-alone basis is made, incorporating existing interconnectors (which are sized to serve the entire NEM load) would distort modelling results greatly. The approach of serving load entirely from within the local region effectively assumes that marginal increments in load will need to be served locally rather than accessed from other regions through additional interconnector capacity.
- In relation to Tasmania and other regions with 'legacy' hydro generation, this approach should be seen as forward-looking, which is essential to a proper LRMC analysis. Existing capital costs are sunk and should not be taken into account when considering the long-run (i.e. capital inclusive) cost of incremental additions to supply. If economically viable new hydro generation options were available in Tasmania or elsewhere, these should be taken into account in the LRMC modelling, but we assume that all economically attractive large-scale hydro projects have been undertaken in Australia (taking into account factors such as restrictions on developments in national parks and transmission connection requirements).

This approach is stylised in that the generation system is optimised and rebuilt for each year meaning that, for example, the optimal plant mix changes substantially between 2011-12 and 2012-13 on the introduction of a carbon price: in effect, the transitional costs of incrementally altering the capital stock are assumed away and the system smoothly responds to deliver a new, optimised capital stock for 2012-13.

Accordingly, the results from this modelling are a useful reference point for understanding the market simulation modelling results, but care should be taken in drawing conclusions about likely or realistic short-term market price outcomes on the basis of this modelling.

As for the market simulation modelling component, ACIL Tasman considered both Carbon and No Carbon scenarios in the LRMC modelling.

However, as each model year is separate to the other, the LRMC approach involved effectively five model runs for each jurisdiction: 2011-12, 2012-13 with carbon, 2012-13 without carbon, 2013-14 with carbon and 2013-14 without carbon. As each model year is entirely separate from every other, there is by definition no difference between the 2011-12 with and without carbon scenarios, and so only a single 2011-12 model run was performed.

One further assumption should be noted: the LRMC modelling for this analysis adopted the 'relaxed integer' approach to plant sizing. This means that plant of any increment in size can be constructed, e.g. the system can build a 1 MW open-cycle gas turbine if that is what is required to meet the final increment of demand.

Whilst this assumption is, clearly, unrealistic in practice, it should be considered acceptable within the broader (stylised) approach of LRMC modelling. This is because the fundamental approach of modelling the residential load in complete isolation from commercial and industrial loads is itself unrealistic, and could over-estimate the cost of serving the residential load due to ruling out the possibility of synergies with those other loads.

In this context, the relaxed integer approach can be considered to offset in part the synergy that could arise when a certain increment of capacity (reflecting real-world component sizing) is installed and notionally 'shared' between residential and other loads. As the stand-alone basis removes any such synergies by considering the residential load in isolation, the relaxed integer approach reduces the risk of this artificial isolation causing arbitrary over-estimates of the cost of serving the load.

Under the LRMC modelling methodology adopted in this analysis, the load-weighted price of the total energy system built to serve residential load on a stand-alone basis is equivalent to the long-run marginal cost of an additional increment of load with the same load factor. This is because the cost of the system is not related to the absolute size of the load (due to the relaxed integer assumption and perfectly elastic supply curve for all inputs), and so the cost of one more (or one less) unit of demand at the same load factor would have the same load-weighted cost. Accordingly, the load-weighted pool costs for each region are representative of the LRMC of serving the residential load modelled.

2.3.2 Construction of stand-alone residential load

To deliver the LRMC modelling component using the stand-alone methodology, ACIL Tasman constructed residential loads for each jurisdiction. For the jurisdictions of New South Wales, Victoria, Queensland, South Australia and the ACT, these load profiles were based on historic small customer loads derived from 'net system load profiles' published by AEMO, which were used as a proxy for residential load (as discussed in section 2.2.2).

For Tasmania, historic data provided by Aurora energy for 2009-10 and 2010-11 was combined to imply a typical residential load shape.

For New South Wales, Queensland and South Australia, these net system load profiles were amended to reflect the separate 'controlled load' component of residential energy usage, which were estimated based on AEMO data published in conjunction with the NSLPs.

Unlike for the market simulation modelling component, there was no need to translate the residential load profiles implied by the historical data against broader NEM regional or system demand, as the LRMC modelling simply modelled the residential load on a stand-alone basis. Consequently, the load profile for all NEM jurisdictions was estimated on the following basis:

- Historic total energy use by households in each jurisdiction was estimated using the relevant historical data
- The maximum demand in each jurisdiction in any half-hour period over the same three years was estimated for both 'summer' (broadly, December to March) and 'winter' (broadly, June to August)
- The total energy use was grown in line with growth forecast in 2011 jurisdictional annual planning reports (with the ACT being assumed to grown in line with NSW, and QLD residential demand being grown at lower rates given the predominance of industrial load growth in the Queensland APR)
- Winter and summer maximum demand was assumed to grow in line with AEMO's forecast 50% probability of exceedence demand level for each jurisdiction in the 2010 Electricity Statement of Opportunities
- The higher of winter and summer maximum demand for each jurisdiction was taken to model the system peak in each period
- The historic load patterns were subtly adjusted so that the increments and durations of demand in each region satisfied both the peak demand growth and total energy growth assumptions derived as above.

As noted above, the NEM region loads were modelled in the absence of any interconnectors.

For Western Australia, the load profile, peak and total energy growth for residential demand were directly inferred from the Synergy data provided and modelled.

For this exercise, *PowerMark LT* was modelled with 50 demand points per year (by contrast with the 8760 used in *PowerMark*). Importantly, the different demand points are differently weighted so that the overall load shape modelled is very close to one achievable with many more demand points. For example, the most extreme peak is given a weighting of '1', representing that it would only occur for one hour in the modelled year, whereas a more moderate demand level might receive a weighting of over 1000, reflecting that demand around that level would be likely to occur for over 1000 hours in a year.

PowerMark LT does not capture outages in the same way as *PowerMark*. In effect, outages are smoothed across all periods such that each piece of plant only operates at its average availability factor in every period of every year. This means that, in effect, *PowerMark LT* builds a reserve margin into the total capacity delivered, but this margin would not necessarily satisfy the planning requirements adopted in practice in the NEM or other markets.

To further ensure that the true cost of serving the entire residential load was adopted, ACIL Tasman relaxed the assumption about the market price cap ($12,500/MWh in the NEM) to ensure that the NEM unserved energy standard of 99.998% was met. In practice, this mean that there was no unserved energy in the LRMC modelling, i.e. 100% of demand was met. The very high market prices incurred in the top demand increment reflects that, in the unrandomised approach to outages adopted in the LRMC modelling, the 'last' increment of capacity needed would need to recover its entire annualised capital cost (and running costs) in that hour. In practice, uncertainty around the potential for random price spikes throughout the year (including in response to outages and weather events) would allow that increment of capacity to recover its capital in different ways (e.g. cap contracts) and thus this modelling result does not imply that the current NEM price cap is insufficient.

2.3.3 Capital cost assumptions

LRMC modelling must, by definition, capture a full return on capital of the generation system used to supply the load in question: this is necessary in order to truly capture the long-run marginal cost, being the marginal cost of the system over a timeframe where all costs, including capital costs, are variable.

Therefore, capital costs are particularly critical to outcomes of LRMC modelling. The capital costs used for this analysis are presented in absolute terms in Table 5, and in annualised terms in Table 6.

Table 5 **Total capital costs by technology ($ real 2011-12)**

Technology	Market/region	$/kW
Supercritical coal	NSW, ACT, QLD	$2,276
	VIC	$2,503
	WEM	$2,733
Combined cycle gas turbine	NEM	$1,322
	WEM	$1,585
Open-cycle gas turbine	NEM	$952
	WEM	$1,148
Wind	NEM	$2,410
	WEM	$3,006

Note: Victorian capital costs for supercritical coal vary to the NSW and QLD regions due to the use of brown coal. Supercritical coal is not available in SA or TAS.

Data source: ACIL Tasman assumptions

Table 6 **Annualised capital and fixed operating and maintenance costs by technology ($ real 2011-12)**

Technology	Market/region	$/kW
Supercritical coal	NSW, ACT, QLD	$303
	VIC	$336
	WEM	$348
Combined cycle gas turbine	NEM	$174
	WEM	$194
Open-cycle gas turbine	NEM	$112
	WEM	$126
Wind	NEM	$281
	WEM	$343

Note: Victorian capital costs for supercritical coal vary to the NSW and QLD regions due to the use of brown coal. Supercritical coal is not available in SA or TAS.

Data source: ACIL Tasman assumptions

2.3.4 Fuel cost assumptions

Fuel cost assumptions are also critical to LRMC modelling outcomes.

For this analysis, a single fuel cost has been adopted for all generators of a certain type in each region and each year. This contrasts with market simulation modelling where individual incumbent and new entrant generators each have different fuel costs.

Coal prices used in this analysis are presented in Table 7.

Table 7 **Coal prices ($ real 2011-12)**

	2011-12	2012-13	2013-14
	$/GJ	$/GJ	$/GJ
New South Wales	$1.69	$1.79	$1.83
Queensland	$1.26	$1.25	$1.25
South Australia	$0.61	$0.61	$0.61
Tasmania	N/A	N/A	N/A
Victoria	N/A	N/A	N/A
Australian Capital Territory	$1.69	$1.79	$1.83
Western Australia	$3.86	$3.86	$3.86

Note: Fuel costs do not reflect fugitive emissions associated with production, which are calculated at the point of combustion for simplicity
Data source: ACIL Tasman assumptions

Gas prices vary between combined cycle and open-cycle gas turbines due to differences in the typical load profile of these generators. Open-cycle gas turbines (OCGTs) generally operate in a peaking mode and so have different pipeline access requirements, and which typically result in an increase in the per unit transport cost associated with delivering gas to these generators. By contrast, combined-cycle gas turbines (CCGTs) typically achieve a higher capacity factor and therefore lower per unit transport costs. Consequently, the 'delivered' gas cost for CCGTs is assumed to be lower than for OCGTs in the same region.

Naturally, gas prices vary between regions and over time due to different supply and demand factors.

CCGT delivered gas prices are presented in Table 8, whilst OCGT delivered gas prices are presented in Table 9.

Table 8 **Gas prices – combined cycle gas turbine ($ real 2011-12)**

	2011-12	2012-13	2013-14
	$/GJ	$/GJ	$/GJ
New South Wales	$5.89	$6.22	$6.55
Queensland	$5.39	$5.97	$6.59
South Australia	$4.37	$4.60	$4.86
Tasmania	$5.68	$6.00	$6.33
Victoria	$5.24	$5.50	$5.79
Australian Capital Territory	$5.89	$6.22	$6.55
Western Australia	$11.18	$11.28	$10.50

Note: Fuel costs do not reflect fugitive emissions associated with production, which are calculated at the point of combustion for simplicity
Data source: ACIL Tasman assumptions

Table 9 **Gas prices – open-cycle gas turbine ($ real 2011-12)**

	2011-12	2012-13	2013-14
	$/GJ	$/GJ	$/GJ
New South Wales	$7.36	$7.78	$8.18
Queensland	$6.74	$7.45	$8.24
South Australia	$5.46	$5.76	$6.08
Tasmania	$7.09	$7.50	$7.92
Victoria	$6.55	$6.89	$7.24
Australian Capital Territory	$7.36	$7.78	$8.18
Western Australia	$13.48	$13.45	$13.41

Note: Fuel costs do not reflect fugitive emissions associated with production, which are calculated at the point of combustion for simplicity
Data source: ACIL Tasman assumptions

3 Results

3.1 Market simulation modelling

3.1.1 Pool costs – NEM

ACIL Tasman's *PowerMark* modelling of the NEM in the carbon scenario indicates a strong uplift in wholesale energy prices from 2012-13 as a result of the introduction of a carbon price. However, the extent to which electricity prices increase in response to carbon pricing varies between NEM regions and over time. Further, the modelling results demonstrate an underlying increase in average pool prices over the projection period in the absence of carbon pricing.

The key drivers of the overall pattern of results are:

- Ongoing growth in demand, particularly peak demand, in most NEM regions, leading to a tightening supply-demand balance and general uplift in prices
- Increasing gas prices as existing supply contracts end and are replaced by higher-prices contracts, and as forward gas-pricing becomes affected by potential alternative use in liquefied natural gas (LNG) facilities
- The general uplift in generation costs in response to the imposition of a carbon price, moderated by competition from relatively lower-emissions generation sources such as gas, wind and hydro (including between NEM regions)
- Slight differences in demand between the Carbon and No Carbon scenarios, reflecting the demand response to increased electricity prices in the Carbon scenario.

More detailed model outcomes in relation to new entry, generation shares and interconnector flows are presented in Appendix A.

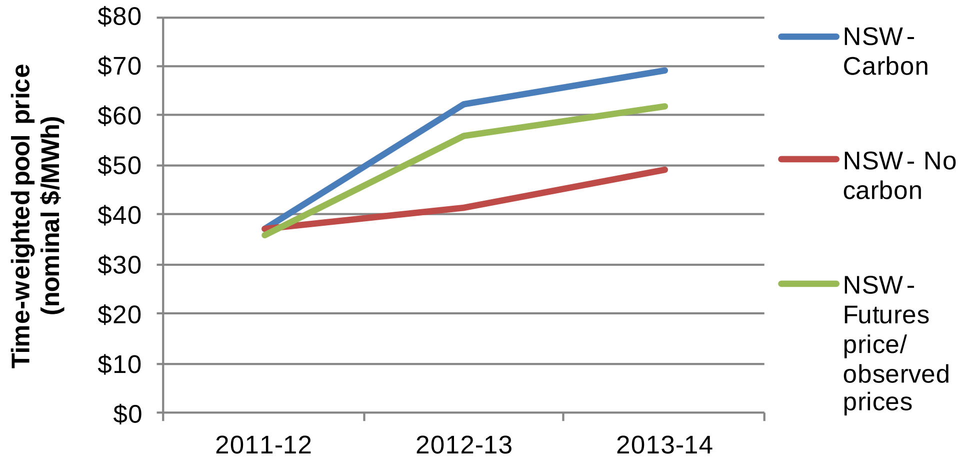
Key underlying assumptions used in the *PowerMark* modelling, including demand assumptions, fuel price assumptions and other key inputs are presented in Appendix B.

Annual time-weighted average pool prices for each NEM region are presented below in Figure 1 to Figure 5.

In addition, for comparability with present market pricing outcomes, prices of base futures traded on the ASX are presented below for the NSW, VIC, QLD and SA NEM regions. 2011-12 ASX futures pricing outcomes are based on Q4 2011, Q1 2012 and Q2 2012 base futures ('swaps'), plus three months of actual market prices as quoted by AEMO. 2012-13 and 2013-14 ASX futures pricing outcomes are based on financial year base strip futures for the relevant periods and regions. ACIL Tasman notes that futures for 2012-13 and 2013-14 will likely reflect a probability weighting on the passage of legislation implementing a carbon price, and so would be likely to trade between the 'perfect foresight' modelled outcomes represented by the Carbon and No Carbon scenarios. ACIL Tasman also notes that base futures should trade at a premium to 'expected' normalised pool price outcomes of the type modelled by *PowerMark*, for the reasons discussed above in section 2.2.3.

With the exception of prices in the VIC region, ASX base futures prices throughout the projection period trade within the bounds of our Carbon and No Carbon scenarios, indicating that these results are broadly consistent with current views of market participants.

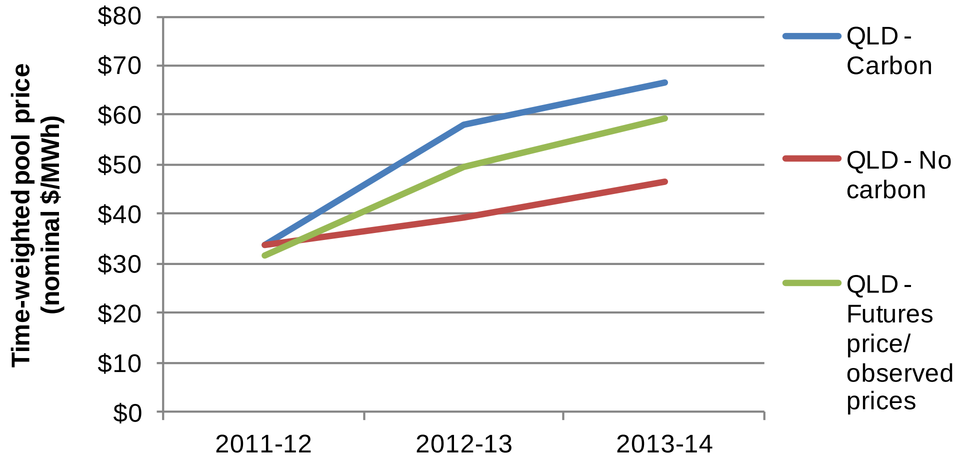
Figure 1 **NSW time-weighted average pool prices and comparison with ASX futures prices and observed prices**



Note: 2011-12 prices are a combination of observed and futures prices. 2012-13 and 2013-14 are based on financial year strip futures.

Source: PowerMark modelling; d-cyphatrade.com.au (accessed 5 October 2011); AEMO

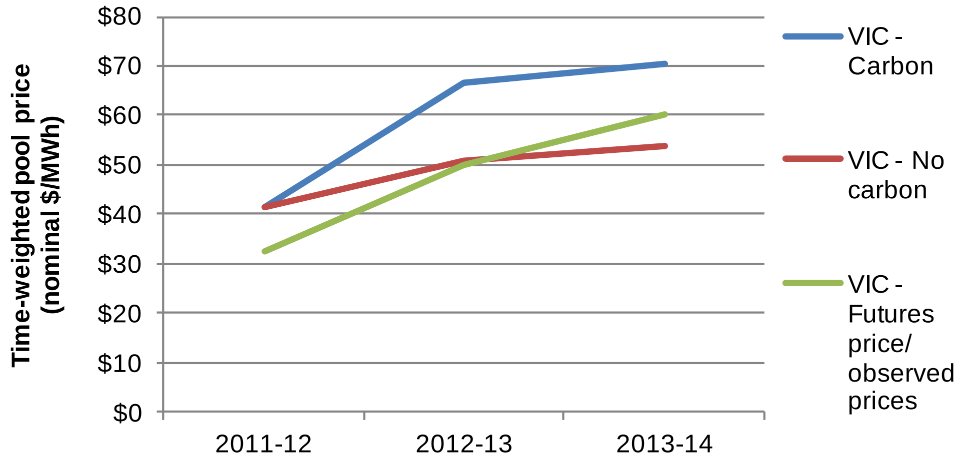
Figure 2 **QLD time-weighted average pool prices and comparison with ASX futures**



Note: 2011-12 prices are a combination of observed and futures prices. 2012-13 and 2013-14 are based on financial year strip futures.

Source: PowerMark modelling; d-cyphatrade.com.au (accessed 5 October 2011); AEMO

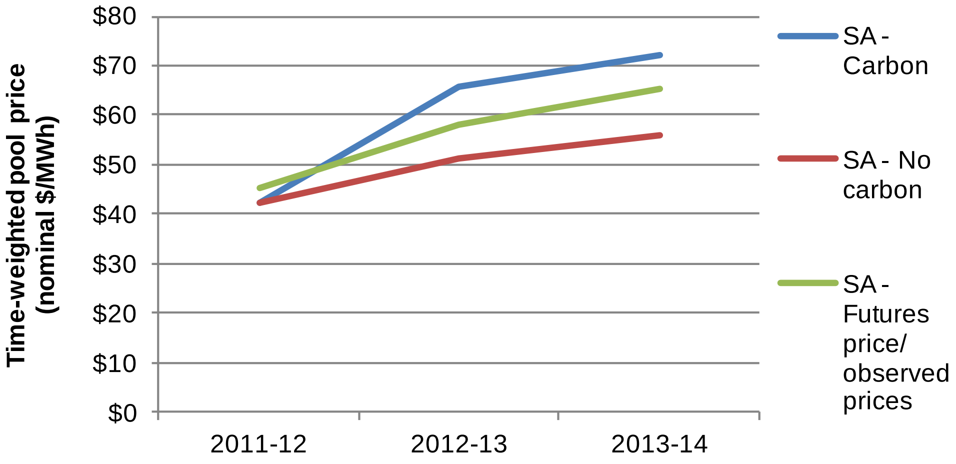
Figure 3 **VIC time-weighted average pool prices and comparison with ASX futures**



Note: 2011-12 prices are a combination of observed and futures prices. 2012-13 and 2013-14 are based on financial year strip futures.

Source: PowerMark modelling; d-cyphatrade.com.au (accessed 5 October 2011); AEMO

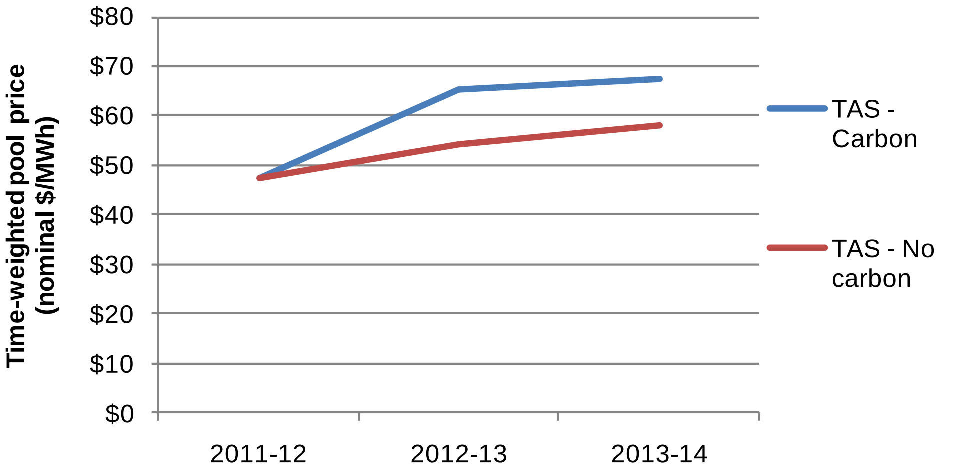
Figure 4 **SA time-weighted average pool prices and comparison with ASX futures**



Note: 2011-12 prices are a combination of observed and futures prices. 2012-13 and 2013-14 are based on financial year strip futures.

Source: PowerMark modelling; d-cyphatrade.com.au (accessed 5 October 2011); AEMO

Figure 5 **TAS time-weighted average pool prices**



Source: PowerMark modelling.

These prices are also presented in Table 10 below, with the effect of carbon pricing highlighted in Table 11.

Table 10 **NEM pool prices**

NEM region	2011-12		2012-13		2013-14	
	Carbon	No Carbon	Carbon	No Carbon	Carbon	No Carbon
	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh
NSW	$36.96	$36.96	$62.36	$41.52	$69.34	$49.24
QLD	$33.85	$33.85	$58.17	$39.10	$66.73	$46.72
SA	$42.49	$42.49	$65.87	$51.28	$72.24	$55.77
TAS	$47.39	$47.39	$65.23	$54.13	$67.64	$58.24
VIC	$41.59	$41.60	$66.52	$50.96	$70.31	$53.79

Note: Nominal $/MWh

Data source: *PowerMark* modelling

Table 11 **NEM pool prices – effect of carbon pricing**

NEM region	2012-13				2013-14			
	Carbon	No Carbon	Difference due to carbon	Implied pass through	Carbon	No Carbon	Difference due to carbon	Implied pass through
	$/MWh	$/MWh	$/MWh	tCO_2-e/MWh	$/MWh	$/MWh	$/MWh	tCO_2-e/MWh
NSW	$62.36	$41.52	$20.84	0.91	$69.34	$49.24	$20.10	0.83
QLD	$58.17	$39.10	$19.07	0.83	$66.73	$46.72	$20.01	0.83
SA	$65.87	$51.28	$14.59	0.63	$72.24	$55.77	$16.47	0.68
TAS	$65.23	$54.13	$11.10	0.48	$67.64	$58.24	$9.40	0.39
VIC	$66.52	$50.96	$15.56	0.68	$70.31	$53.79	$16.53	0.68

Note: Nominal $/MWh. 'Implied pass through' illustrates the pass through of carbon costs to the electricity price, and is calculated as the change in pool price due to carbon divided by the carbon price.

Data source: *PowerMark* modelling

However, as noted above, time-weighted average pool prices do not provide a complete picture of trends in the wholesale energy costs associated with supplying most loads, and particularly residential loads. In general, the usage of most energy consumers is on average positively correlated with market prices, and so the 'load-weighted average' purchase cost of supplying this load is greater than the average pool price. This is true of both NEM load in aggregate, and is particularly true of residential loads. Accordingly, it is necessary to estimate the load-weighted average purchase cost of energy for a given load in order to estimate the true cost of supplying this load.

Table 12 and Table 13 sets out ACIL Tasman's estimates of the load-weighted average cost of supplying residential energy users (in the Carbon and No Carbon scenarios respectively) based on the synthetic net system load profile derived as described in section 2.2.2. It also sets out the load-weighted average price for NEM demand in total, and the NEM time-weighted average price, so as to illustrate the 'uplift' between NEM time-weighted and load-weighted prices and the load-weighted cost of serving residential load.

Table 12 **Comparison of residential and general NEM prices – Carbon scenario**

Jurisdiction	Variable	2011-12	2012-13	2013-14
New South Wales	Residential LWP	$46.00	$72.93	$83.56
	NEM region LWP	$41.84	$67.96	$76.81
	Uplift from region LWP to residential LWP	10.0%	7.3%	8.8%
	NEM region TWP	$36.96	$62.36	$69.34
	Uplift from region TWP to residential LWP	24.5%	17.0%	20.5%
Queensland	Residential LWP	$41.01	$66.83	$79.41
	NEM region LWP	$38.72	$64.07	$75.34
	Uplift from region LWP to residential LWP	5.9%	4.3%	5.4%
	NEM region TWP	$33.85	$58.17	$66.73
	Uplift from region TWP to residential LWP	21.2%	14.9%	19.0%
South Australia	Residential LWP	$60.27	$84.65	$96.30
	NEM region LWP	$53.44	$77.44	$87.05
	Uplift from region LWP to residential LWP	12.8%	9.3%	10.6%
	NEM region TWP	$42.49	$65.87	$72.24
	Uplift from region TWP to residential LWP	41.8%	28.5%	33.3%
Tasmania	Residential LWP	$50.28	$68.63	$71.55
	NEM region LWP	$48.69	$72.20	$68.87
	Uplift from region LWP to residential LWP	3.3%	-5.0%	3.9%
	NEM region TWP	$47.39	$65.23	$67.64
	Uplift from region TWP to residential LWP	6.1%	5.2%	5.8%
Victoria	Residential LWP	$55.44	$83.06	$88.73
	NEM region LWP	$50.69	$77.28	$82.25
	Uplift from region LWP to residential LWP	9.4%	7.5%	7.9%
	NEM region TWP	$41.59	$66.52	$70.31
	Uplift from region TWP to residential LWP	33.3%	24.9%	26.2%
Australian Capital Territory	Residential LWP	$44.17	$70.38	$80.33
	NEM region LWP*	$41.84	$67.96	$76.81
	Uplift from region LWP to residential LWP	5.6%	3.6%	4.6%
	NEM region TWP*	$36.96	$62.36	$69.34
	Uplift from region TWP to residential LWP	19.5%	12.9%	15.8%

Note: ACT adopts NSW NEM region prices.

Data source: *PowerMark* modelling

Table 13 **Comparison of residential and general NEM prices – No Carbon scenario**

NEM region	Variable	2011-12	2012-13	2013-14
New South Wales	Residential LWP	$46.00	$52.27	$65.23
	NEM region LWP	$41.84	$47.31	$57.71
	Uplift from region LWP to residential LWP	10.0%	10.5%	13.0%
	NEM region TWP	$36.96	$41.52	$49.24
	Uplift from region TWP to residential LWP	24.5%	25.9%	32.5%
Queensland	Residential LWP	$41.01	$48.78	$59.83
	NEM region LWP	$38.73	$45.68	$55.64
	Uplift from region LWP to residential LWP	5.9%	6.8%	7.5%
	NEM region TWP	$33.85	$39.10	$46.72
	Uplift from region TWP to residential LWP	21.2%	24.7%	28.1%
South Australia	Residential LWP	$60.27	$75.85	$83.63
	NEM region LWP	$53.44	$66.30	$72.83
	Uplift from region LWP to residential LWP	12.8%	14.4%	14.8%
	NEM region TWP	$42.49	$51.28	$55.77
	Uplift from region TWP to residential LWP	41.8%	47.9%	50.0%
Tasmania	Residential LWP	$50.28	$57.33	$60.99
	NEM region LWP	$48.69	$56.15	$60.96
	Uplift from region LWP to residential LWP	3.3%	2.1%	0.0%
	NEM region TWP	$47.39	$54.13	$58.24
	Uplift from region TWP to residential LWP	6.1%	5.9%	4.7%
Victoria	Residential LWP	$55.44	$71.69	$76.02
	NEM region LWP	$50.70	$64.45	$68.39
	Uplift from region LWP to residential LWP	9.4%	11.2%	11.2%
	NEM region TWP	$41.60	$50.96	$53.79
	Uplift from region TWP to residential LWP	33.3%	40.7%	41.3%
Australian Capital Territory	Residential LWP	$44.16	$50.05	$61.47
	NEM region LWP*	$41.84	$47.31	$57.71
	Uplift from region LWP to residential LWP	5.6%	5.8%	6.5%
	NEM region TWP*	$36.96	$41.52	$49.24
	Uplift from region TWP to residential LWP	19.5%	20.5%	24.8%

Note: ACT adopts NSW NEM region prices.

Data source: *PowerMark* modelling

ACIL Tasman's modelled residential load-weighted energy costs are summarised in Table 14.

Table 14 **Residential load-weighted average energy costs**

Jurisdiction	2011-12		2012-13		2013-14	
	Carbon	No Carbon	Carbon	No Carbon	Carbon	No Carbon
	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh
New South Wales	$46.00	$46.00	$72.93	$52.27	$83.56	$65.23
Queensland	$41.01	$41.01	$66.83	$48.78	$79.41	$59.83
South Australia	$60.27	$60.27	$84.65	$75.85	$96.30	$83.63
Tasmania	$50.28	$50.28	$68.63	$57.33	$71.55	$60.99
Victoria	$55.44	$55.44	$83.06	$71.69	$88.73	$76.02
Australian Capital Territory	$46.00	$46.00	$72.93	$52.27	$83.56	$65.23

Note: Nominal $/MWh
Data source: *PowerMark* modelling

3.1.2 Hedge costs – NEM

As noted above in section 2.2.3, the load-weighted average cost of serving residential load captures the (positive) correlation between residential demand and pool prices, and therefore the broad extent of 'uplift' in cost of serving this load under a given set of market outcomes, but does not capture the risks associated with the potential for market outcomes to vary (particularly in the direction of higher prices) and the costs associated with managing these risks.

In this analysis, and in practice, these costs generally manifest as expenditure by retailers on hedge contracts that reduce their exposure to higher prices. As was noted above, retailers have a greater incentive to avoid the negative outcome of higher prices than the incentive of generators to avoid the negative outcome of lower prices, and so hedge contracts generally imply a premium paid by energy consumers to energy generators.

Swap contracts

As discussed in section 2.2.3, ACIL Tasman assumed a standard swap premium of 5%. Peak swap prices were calculated as the time-weighted average price for peak periods only (using the NEM definition of peak periods, being 0700-2300 on business days), increased by the premium. Base swaps were calculated as the time-weighted average price for all periods, increased by the premium.

Quarterly peak and base swap prices are set out in Table 15 and Table 16 respectively.

Table 15 **Peak swap prices**

Period	NSW		QLD		SA		TAS		VIC	
	Carbon	No Carbon	Carbon	No Carbon	Carbon	No Carbon	Carbon	No Carbon	Carbon	No Carbon
	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh
Q3 2011	$54.1	$54.1	$45.8	$45.8	$51.7	$51.7	$61.8	$61.8	$54.0	$54.0
Q4 2011	$74.8	$74.8	$76.6	$76.6	$102.8	$102.8	$51.1	$51.1	$107.2	$107.2
Q1 2012	$61.1	$61.1	$58.1	$58.1	$69.3	$69.3	$76.5	$76.5	$69.9	$69.9
Q2 2012	$43.0	$43.0	$32.9	$32.9	$56.2	$56.2	$57.5	$57.5	$48.7	$48.7
Q3 2012	$76.7	$63.0	$66.9	$47.8	$80.7	$65.9	$81.0	$69.0	$81.6	$66.9
Q4 2012	$77.9	$74.6	$88.3	$86.2	$120.4	$130.7	$76.9	$88.4	$128.8	$139.8
Q1 2013	$129.7	$88.6	$117.1	$89.0	$106.6	$99.8	$122.1	$113.6	$120.5	$108.7
Q2 2013	$59.9	$37.2	$51.5	$30.7	$75.0	$53.2	$67.9	$50.4	$64.9	$42.1
Q3 2013	$98.3	$67.6	$82.6	$60.4	$91.5	$74.5	$85.8	$71.6	$86.8	$70.0
Q4 2013	$107.5	$90.9	$134.9	$128.1	$140.9	$115.5	$82.1	$105.4	$128.0	$118.3
Q1 2014	$132.4	$128.9	$122.1	$95.8	$134.8	$138.8	$142.8	$153.3	$141.3	$148.0
Q2 2014	$60.6	$39.8	$54.4	$34.4	$70.8	$49.8	$68.3	$49.3	$66.6	$45.6

Note: Nominal $/MWh

Data source: *PowerMark* modelling

Table 16 **Base swap prices**

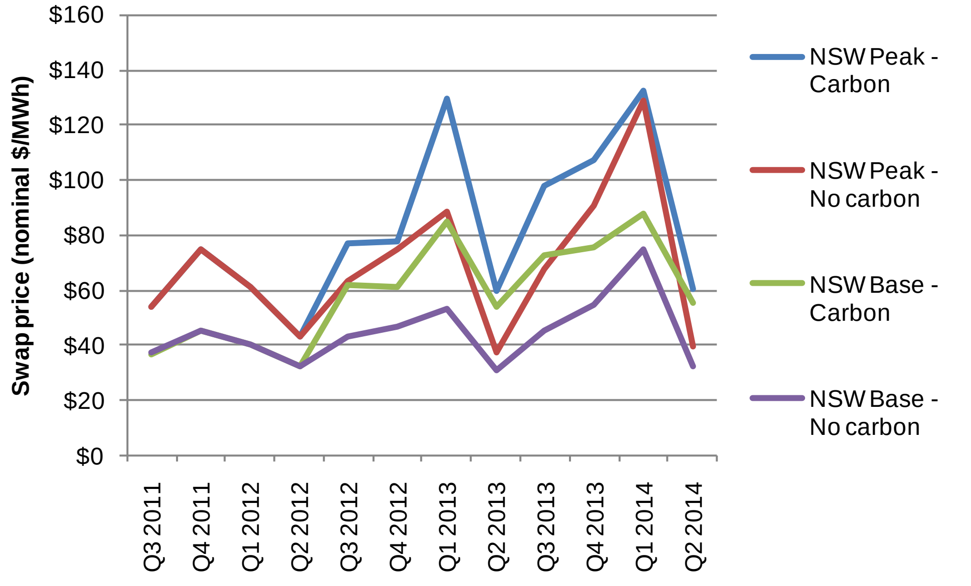
Period	NSW		QLD		SA		TAS		VIC	
	Carbon	No Carbon	Carbon	No Carbon	Carbon	No Carbon	Carbon	No Carbon	Carbon	No Carbon
	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh
Q3 2011	$37.0	$37.0	$32.0	$32.1	$38.2	$38.2	$49.2	$49.2	$36.8	$36.8
Q4 2011	$45.1	$45.1	$45.5	$45.5	$57.4	$57.4	$45.8	$45.8	$59.1	$59.1
Q1 2012	$40.6	$40.6	$38.0	$38.0	$43.9	$43.9	$56.8	$56.8	$43.7	$43.7
Q2 2012	$32.6	$32.6	$26.5	$26.5	$38.8	$38.9	$47.4	$47.4	$35.0	$35.0
Q3 2012	$62.0	$43.1	$55.2	$34.5	$65.2	$46.8	$64.0	$51.1	$63.7	$45.1
Q4 2012	$61.3	$47.1	$64.1	$51.0	$78.4	$71.5	$63.9	$61.2	$82.1	$75.2
Q1 2013	$85.0	$53.5	$77.7	$52.7	$73.4	$58.7	$85.3	$71.8	$78.3	$60.8
Q2 2013	$53.9	$30.7	$47.5	$26.2	$59.7	$38.3	$61.0	$43.4	$55.2	$32.9
Q3 2013	$72.9	$45.6	$63.0	$40.6	$71.4	$51.9	$66.8	$50.5	$66.9	$46.9
Q4 2013	$75.6	$54.3	$85.6	$69.7	$88.6	$65.2	$66.7	$66.9	$83.1	$66.0
Q1 2014	$87.6	$74.9	$81.5	$57.4	$85.7	$80.4	$92.2	$88.1	$88.8	$78.8
Q2 2014	$55.2	$32.2	$50.2	$28.5	$57.8	$37.0	$58.8	$39.5	$56.6	$34.4

Note: Nominal $/MWh

Data source: *PowerMark* modelling

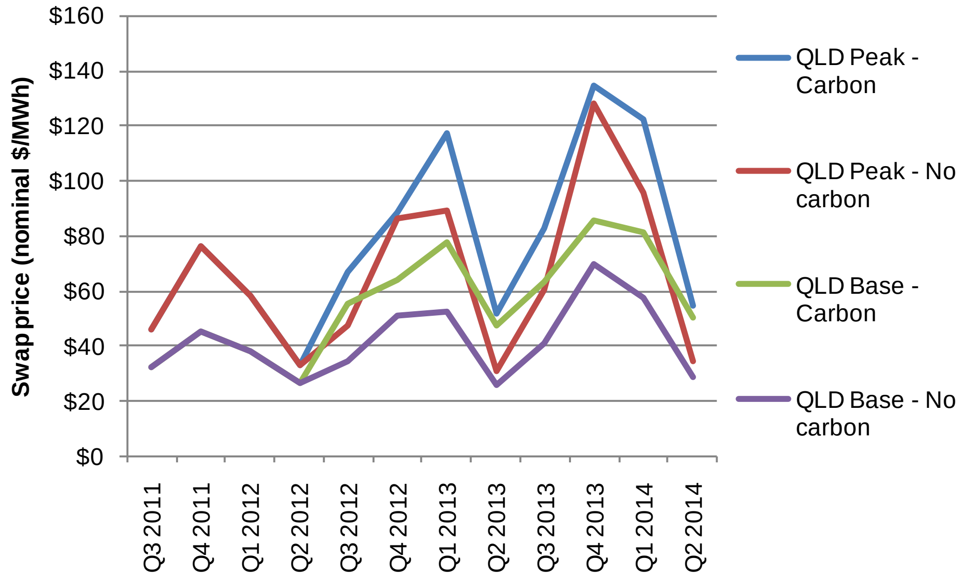
The differences in swap prices in each region between the Carbon and No Carbon scenarios, between peak and base products, seasonally and over time are illustrated in Figure 6 to Figure 10 below.

Figure 6 **NSW swap prices**



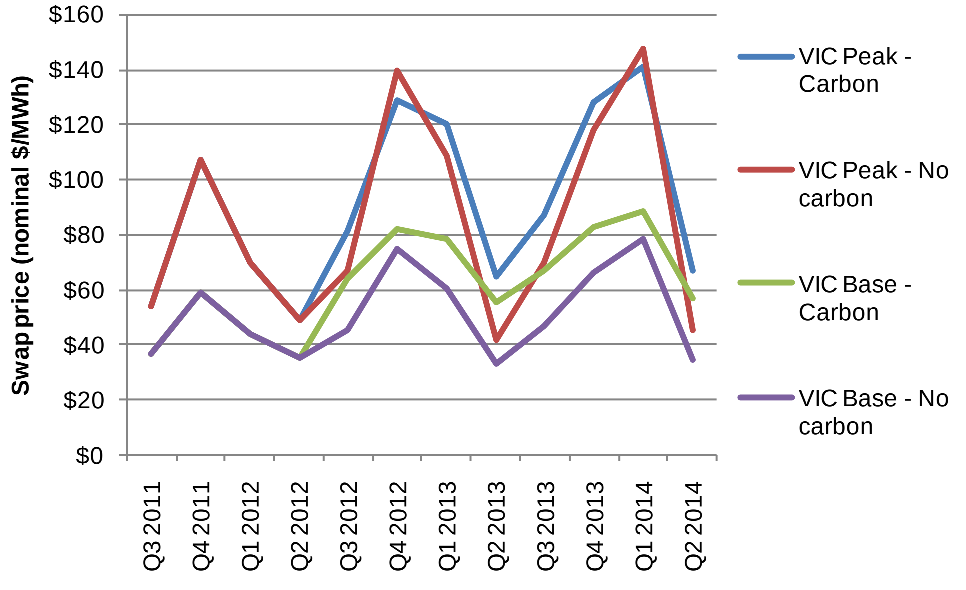
Source: PowerMark modelling

Figure 7 **QLD swap prices**



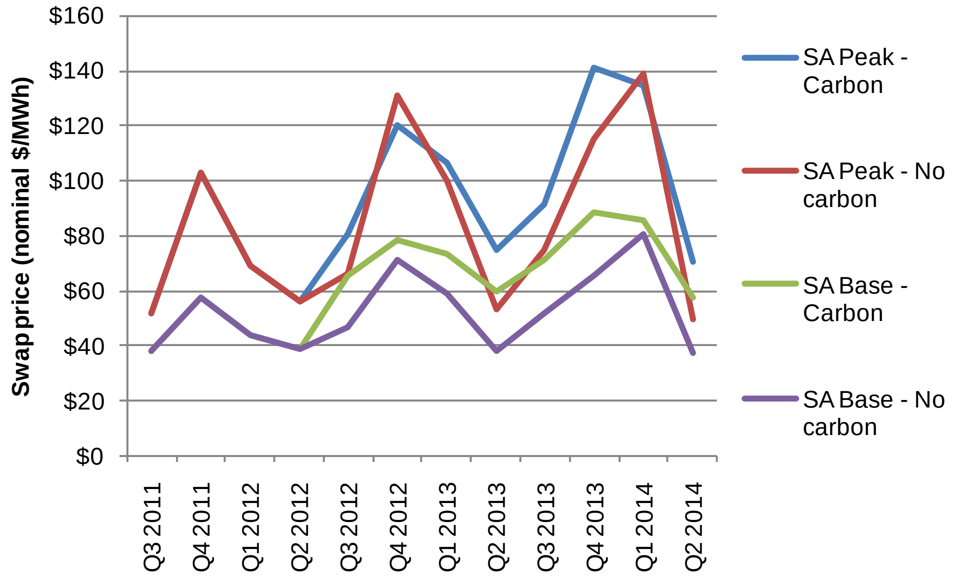
Source: PowerMark modelling

Figure 8 **VIC swap prices**



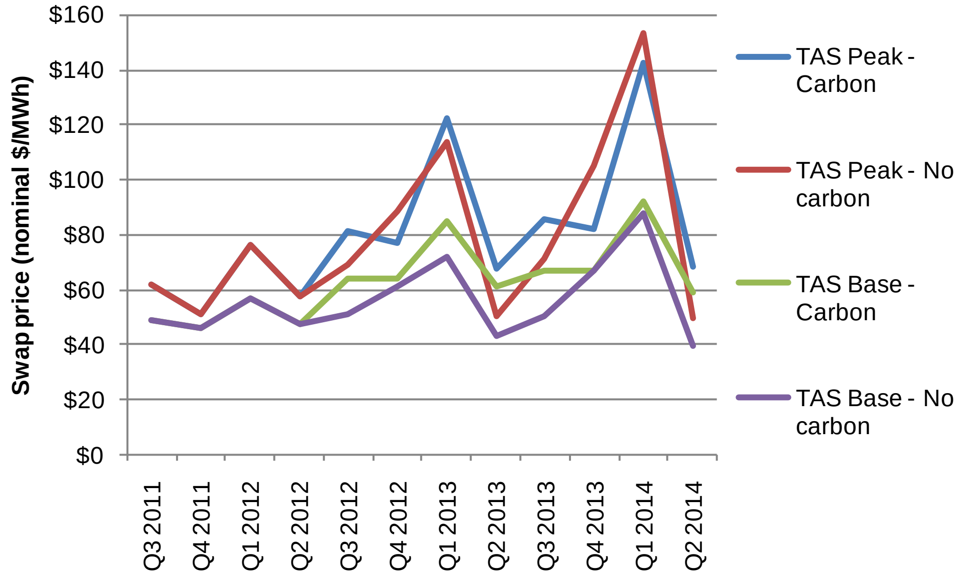
Source: PowerMark modelling

Figure 9 **SA swap prices**



Source: PowerMark modelling

Figure 10 **TAS swap prices**



Source: PowerMark modelling

Cap contracts

As noted above, to estimate cap contract premiums, ACIL Tasman used modelling of an extreme weather year (reflecting a 10% POE outcome) to assess the materiality of higher prices for retailers, and therefore the premium they would be willing to pay to avoid such an outcome.

In general, retailers would expect to pay a premium for a cap contract that exceeds the level of difference payments that the seller of the contract (notionally, a peaking generator) would make to the holder under the stylised 50% POE weather year modelled as the central scenario in this analysis. More particularly, the level of this premium would likely reflect the materiality and frequency of extreme (i.e. above $300/MWh) price events under an adverse weather year.

Accordingly, ACIL Tasman modelled the NEM under a 10% POE scenario to assess the sensitivity of prices above $300/MWh (and therefore difference payments payable under a cap contract) to such an outcome. Using this modelling, the premium for a cap contract in each quarter of the projection period was calculated as being equal the difference payments payable under the contract under the 50% POE model scenario, plus a probability adjusted premium. This probability adjusted premium was equal to the increase in difference payments between the 50% and 10% POE scenarios, weighted at 20%. This is equivalent to weighting the difference payments under the 50% POE scenario and 10% POE scenario at 80% and 20% respectively.

Cap contract premiums were determined separately for the Carbon and No Carbon scenarios. A minimum cap contract premium of $1/MWh was assumed for periods where the POE 10% modelling scenario did not result in any price events over $300/MWh: this is appropriate as unplanned outages of generation plant or other market events can still produce such price events even in the absence of adverse weather conditions.

The cap contract premiums for each contract and each NEM region were estimated as set out in Table 17 and Table 18 below.

Table 17 **Cap contract premiums – Carbon scenario ($/MWh)**

Quarter	NSW	QLD	SA	TAS	VIC
Q3 2011	$6.37	$5.24	$3.34	$4.95	$5.07
Q4 2011	$14.81	$14.17	$28.23	$1.00	$32.06
Q1 2012	$11.88	$13.93	$18.13	$16.17	$16.67
Q2 2012	$2.38	$1.00	$5.85	$2.81	$3.03
Q3 2012	$5.18	$3.99	$3.97	$5.19	$5.21
Q4 2012	$7.73	$15.84	$32.48	$6.17	$37.14
Q1 2013	$27.03	$30.13	$25.89	$20.91	$24.66
Q2 2013	$1.00	$1.00	$4.22	$1.00	$1.00
Q3 2013	$13.34	$9.56	$7.22	$7.17	$7.19
Q4 2013	$15.64	$33.46	$35.37	$5.84	$27.23
Q1 2014	$35.40	$37.05	$31.66	$28.56	$34.73
Q2 2014	$1.00	$1.00	$1.54	$1.00	$1.00

Data source: ACIL Tasman analysis.

Table 18 **Cap contract premiums – No Carbon scenario ($/MWh)**

Quarter	NSW	QLD	SA	TAS	VIC
Q3 2011	$6.37	$5.24	$3.34	$4.95	$5.07
Q4 2011	$14.81	$14.17	$28.23	$1.00	$32.06
Q1 2012	$11.88	$13.93	$18.13	$16.17	$16.67
Q2 2012	$2.38	$1.00	$5.85	$2.81	$3.03
Q3 2012	$8.14	$4.64	$6.18	$7.37	$7.49
Q4 2012	$12.65	$18.02	$40.94	$16.40	$45.23
Q1 2013	$21.89	$26.09	$30.60	$23.44	$27.44
Q2 2013	$1.00	$1.00	$3.96	$1.00	$1.00
Q3 2013	$9.80	$8.74	$8.39	$8.98	$9.07
Q4 2013	$16.03	$38.31	$34.06	$22.56	$33.07
Q1 2014	$42.91	$34.87	$46.51	$37.86	$44.30
Q2 2014	$1.00	$1.00	$1.56	$1.00	$1.00

Data source: ACIL Tasman analysis.

Using these hedge product prices, ACIL Tasman examined the cost of various hedge portfolios (i.e. combination of peak and base swaps and cap contracts) given modelled market price outcomes. The cost of different hedge portfolios varies due to the level of difference payments that are made between the parties under different combinations of contracts.

ACIL Tasman tested three broad portfolios of the notional retailer supplying the residential load represented by our synthetic net system load profile. Each portfolio held total contract cover up to 105% of the volume of the 1 in 10 year (10% POE) maximum demand in each quarter, with the summer maximum demand being used for calendar year quarters 1 and 4, and the winter maximum demand being used for calendar year quarters 2 and 3.

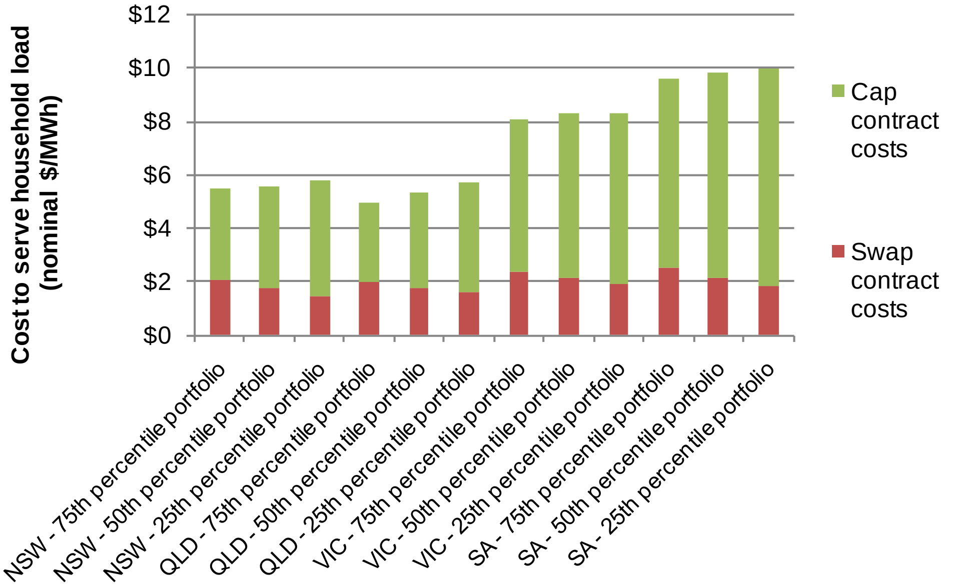
What varied between the portfolios was the combination of peak swaps, base swaps and caps used to cover this total maximum demand level. ACIL Tasman tested portfolios that adopted the following positions:

- The 25th percentile of off-peak demand for each quarter was hedged using base swaps, the additional load up to the 25th percentile of peak demand in each quarter was hedged using peak swaps, and the remainder of the contract load was hedged using caps (the 25th percentile portfolio)
- The 50th percentile of off-peak demand for each quarter was hedged using base swaps, the additional load up to the 50th percentile of peak demand in each quarter was hedged using peak swaps, and the remainder of the contract load was hedged using caps (the 50th percentile portfolio)
- The 75th percentile of off-peak demand for each quarter was hedged using base swaps, the additional load up to the 75th percentile of peak demand in each quarter was hedged using peak swaps, and the remainder of the contract load was hedged using caps (the 75th percentile portfolio).

This testing indicated that total hedging costs vary slightly depending on the NEM region, year and scenario analysed, but that the overall level is not highly sensitive to the portfolio used (generally varying by less than $1/MWh). Accordingly, for clarity and comparability, ACIL Tasman adopted the 50th percentile portfolio for all jurisdictions and all years.

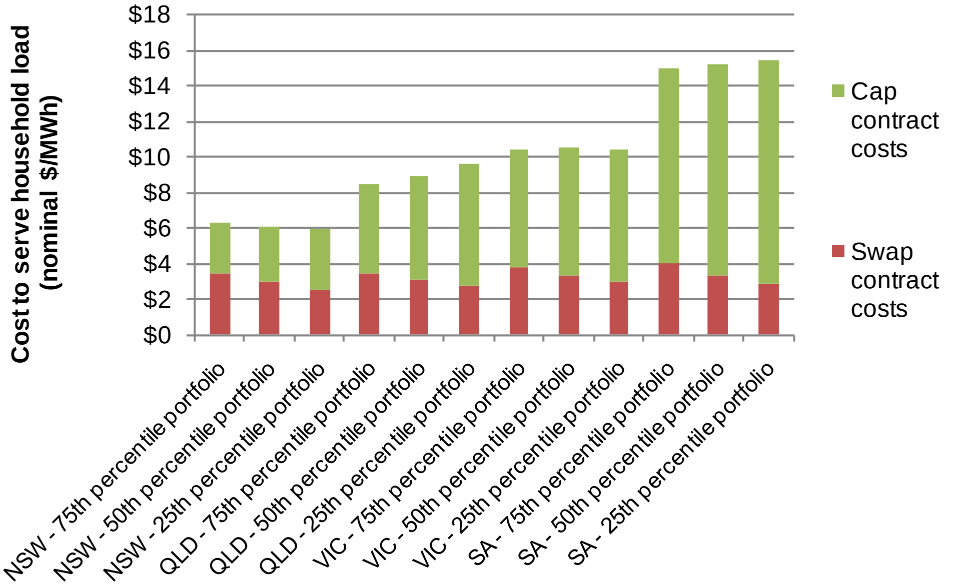
The relative stability of these costs across the three hedging approaches analysed is illustrated for a selection of years and scenarios below.

Figure 11 **Comparison of hedging portfolios – 2011-12**



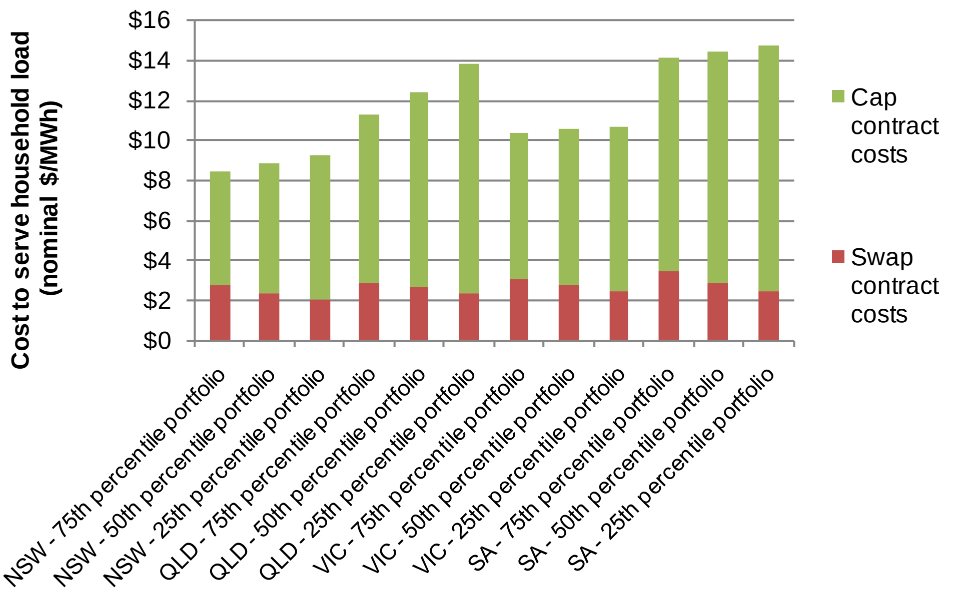
Source: ACIL Tasman analysis

Figure 12 **Comparison of hedging portfolios – 2012-13, Carbon scenario**



Source: ACIL Tasman analysis

Figure 13 **Comparison of hedging portfolios – 2013-14, No Carbon scenario**



Source: ACIL Tasman analysis

With the preferred hedge portfolio selected for the analysis, hedging costs for each jurisdiction can be analysed and illustrated. In the discussion below, total hedging costs are presented in the form of a 'waterfall' chart comprising three elements.

Firstly, in this analysis the notional retailer will make positive net swap difference payments to the seller of peak and base swaps throughout the projection period. In practice net swap difference payments from the retailer to sellers of swap contracts could be positive or negative depending on contract strike prices and market outcomes, with negative payments being likely to arise due to variations between expected and actual market outcomes. However, as we have set swap prices at a level that is equal to modelled market outcomes plus a premium in this analysis, net swap difference payments from the retailer to sellers are positive by definition.

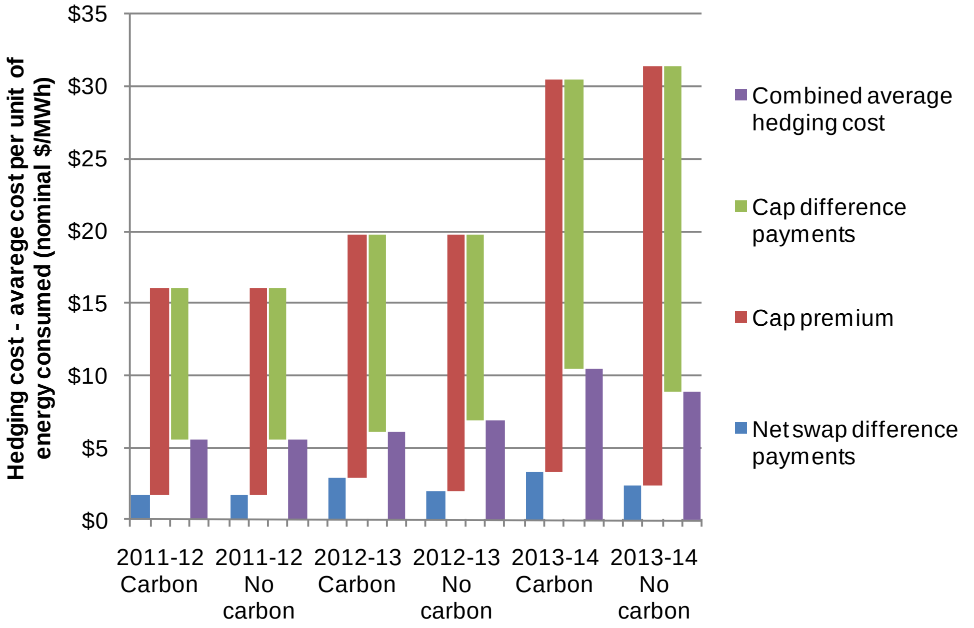
Secondly, the notional retailer will pay premiums to enter into cap contracts. Under the standardised cap contract used in this analysis, the purchaser of a cap contract is not liable to make any payments to the seller of the contract other than the premium to enter into the contract. This contrasts with swaps, where payments go in both directions and the net payment must be considered.

Thirdly, we have separately considered the difference payments that sellers of cap contracts will make to the notional retailer under the core (50% POE) model scenarios (both with and without carbon).

The sum of these hedging cost components provides the total hedging cost for each scenario below. The total hedging cost for each region are presented below.

In New South Wales, total hedging costs vary between around $5/MWh and $11/MWh. Hedging costs are higher in 2013-14 due to a slight tightening of the supply-demand balance.

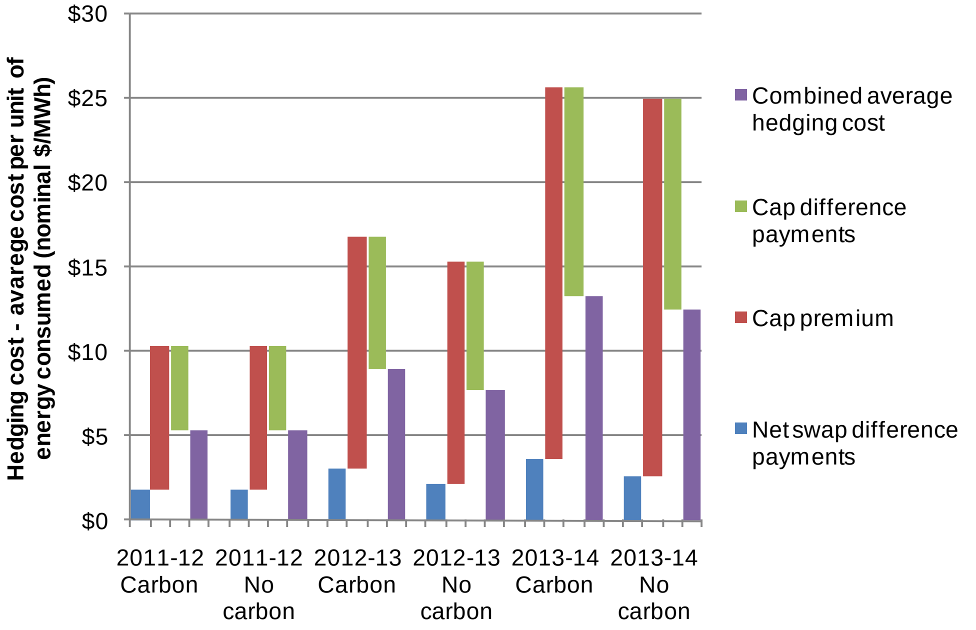
Figure 14 **New South Wales – combined average hedging costs**



Source: ACIL Tasman analysis

In Queensland, hedging costs increase strongly over time, from around $5/MWh in 2011-12 to around $13/MWh in 2013-14, reflecting ongoing demand growth causing tightening in wholesale markets (even though demand growth in Queensland is more attributable to industrial than residential loads).

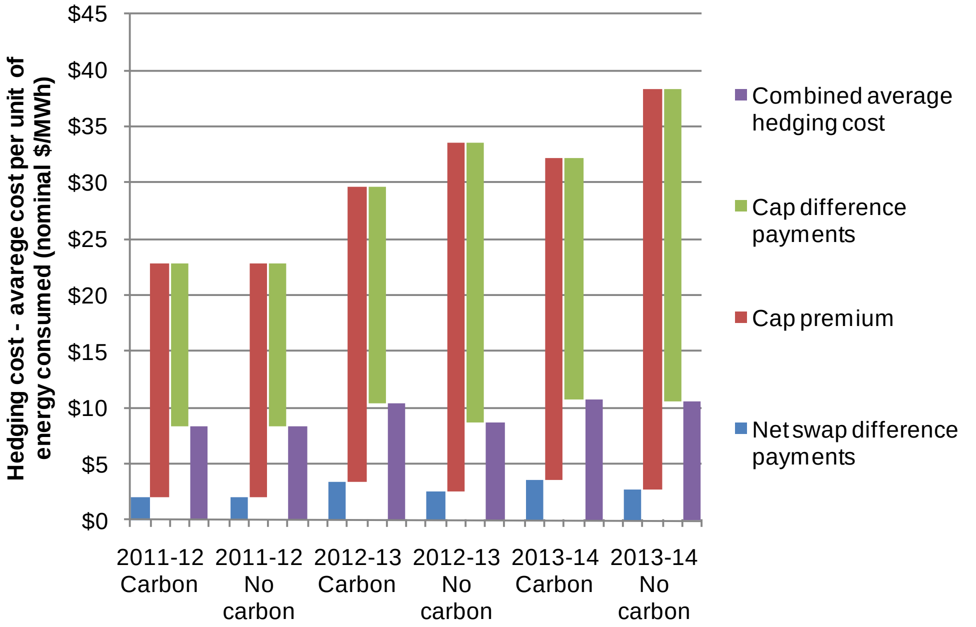
Figure 15 **Queensland – combined average hedging costs**



Source: ACIL Tasman analysis

In Victoria, total hedging costs start at a higher level than in New South Wales, but increase less such that they reach a similar level by 2013-14. Total hedging costs increase (irrespective of carbon) towards 2013-14 due to the tightening supply-demand balance, from around $8/MWh to almost $11/MWh over the projection period. The extent of this increase is more moderate than seen in Queensland.

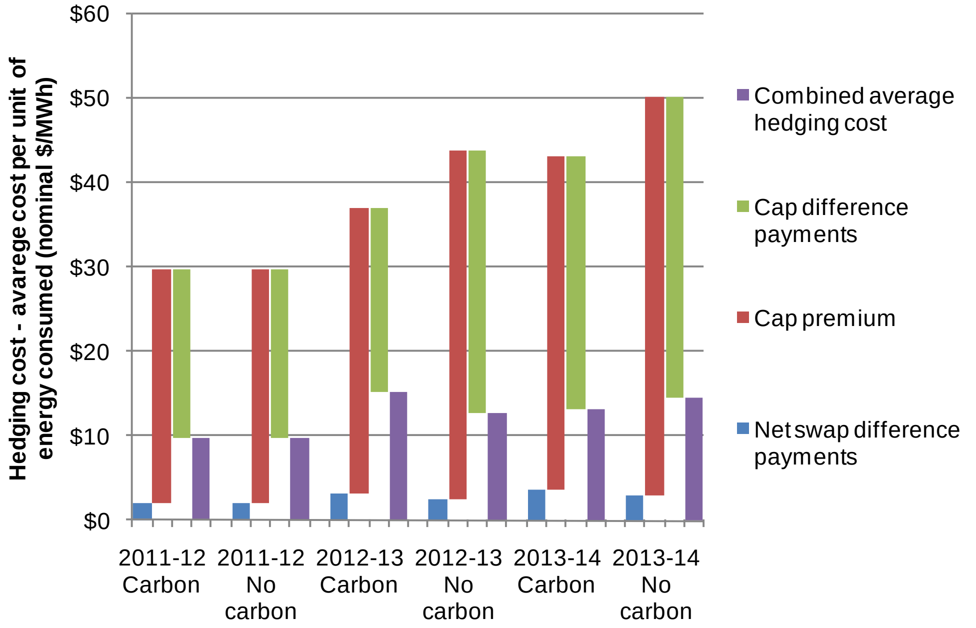
Figure 16 **Victoria – combined average hedging costs**



Source: ACIL Tasman analysis

In South Australia, total hedging costs are consistently higher than in the other jurisdictions, reaching around $13-15/MWh in 2012-13 and 2013-14, irrespective of carbon pricing policies. This reflects the peaky demand profile in that state, due to a combination of high air-conditioner penetration and the role of wind generation in forcing thermal generation to operate at lower capacity factors (driving up average cost and increasing price volatility).

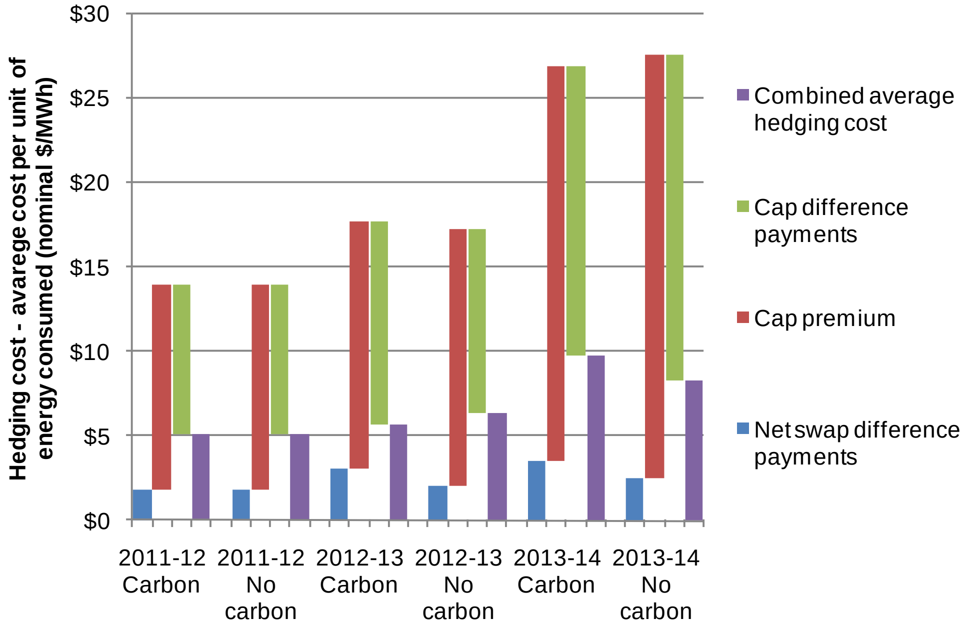
Figure 17 **South Australia – combined average hedging costs**



Source: ACIL Tasman analysis

Hedging costs in the Australian Capital Territory are similar to, but slightly lower than, those in NSW for every modelled year, varying in the range of $5-10/MWh and increasing over time. This reflects in part the lower summer peak demands in the ACT (as a share of total demand) than in NSW, meaning that the volume of expensive Q1 (January to March) caps required to hedge ACT is lower per unit of energy, bringing down average hedging costs.

Figure 18 **Australian Capital Territory – combined average hedging costs**

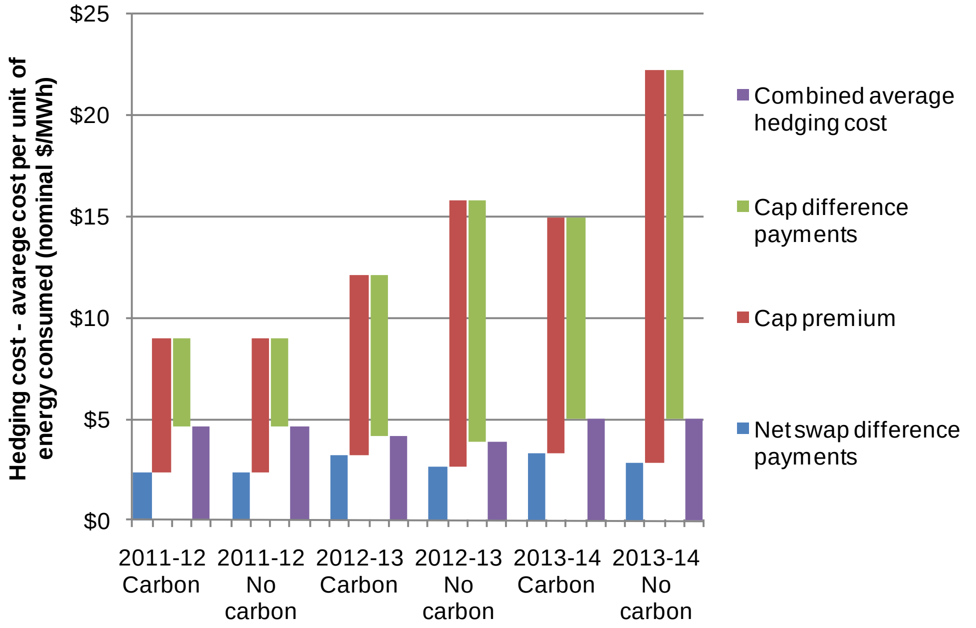


Source: ACIL Tasman analysis

Tasmanian hedging costs are generally lower, varying in the range from just under $4/MWh to just over $5/MWh. This reflects in part the low correlation between residential energy use in Tasmania and summer price peaks in the NEM generally: while summer price peaks in the NEM are driven by hot weather conditions, Tasmania's cool climate and low penetration of air-conditioning (cooling) loads means that the cost of hedging Tasmanian retail loads against these price spikes is modest.

Tasmanian hedging costs do not vary greatly in response to the introduction of a carbon price.

Figure 19 **Tasmania – combined average hedging costs**



Source: ACIL Tasman analysis

3.1.3 Total energy costs – NEM

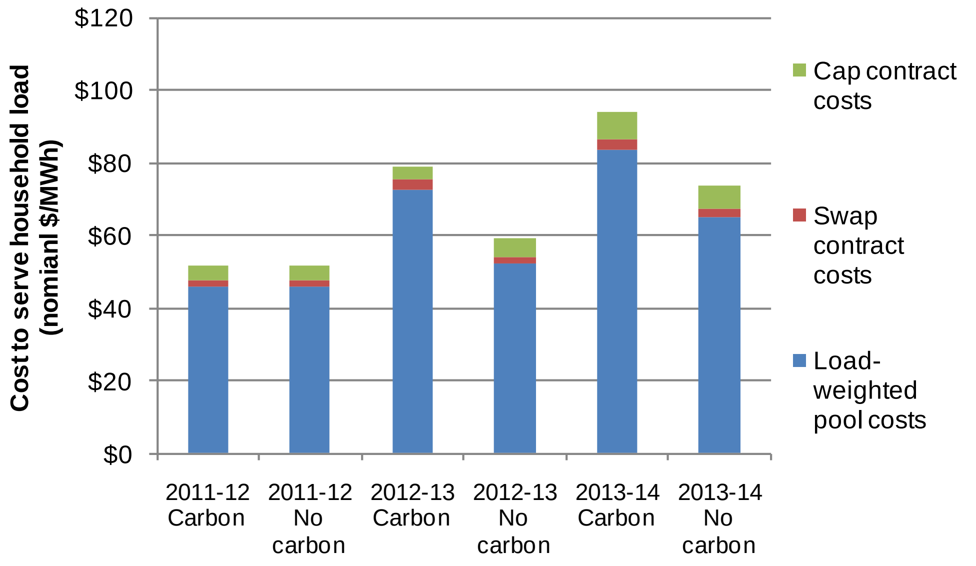
The load-weighted energy costs set out in Table 14 and the hedging costs discussed above can be combined to provide a projection of costs to serve the residential energy loads in each region, in each year and under the Carbon and No Carbon scenarios. These are presented for each region below.

In New South Wales, our modelling suggests an increase in wholesale energy costs to supply residential consumers from around $52/MWh in 2011-12 to $74/MWh by 2013-14 in the absence of a carbon price.

The introduction of a carbon price sees an earlier and higher increase in residential energy costs, which increase by around 53% to almost $79/MWh in 2012-13, and then a further 9% in 2013-14 to $94/MWh.

This pattern of price patterns implies that the rate of carbon cost pass-through reduces only slightly in 2013-14, from around 0.86 tonnes of CO_2-e/MWh in 2012-13 to 0.82 tonnes of CO_2-e/MWh in 2013-14.

Figure 20 **Residential wholesale energy purchase costs – New South Wales**



Source: ACIL Tasman analysis

Table 19 **Impact of a carbon price on residential wholesale energy purchase costs – New South Wales**

	Unit	2011-12	2012-13	2013-14
No Carbon	$/MWh	$51.61	$59.16	$74.12
Year on year increase	%	N/A	15%	25%
Carbon	$/MWh	$51.61	$78.98	$94.04
Year on year increase	%	N/A	53%	19%
Increase due to carbon	$/MWh	N/A	$19.82	$19.92
Percentage increase	%	N/A	33%	27%
Pass-through of carbon cost	tCO_2-e /MWh	N/A	0.86	0.82

Data source: ACIL Tasman analysis

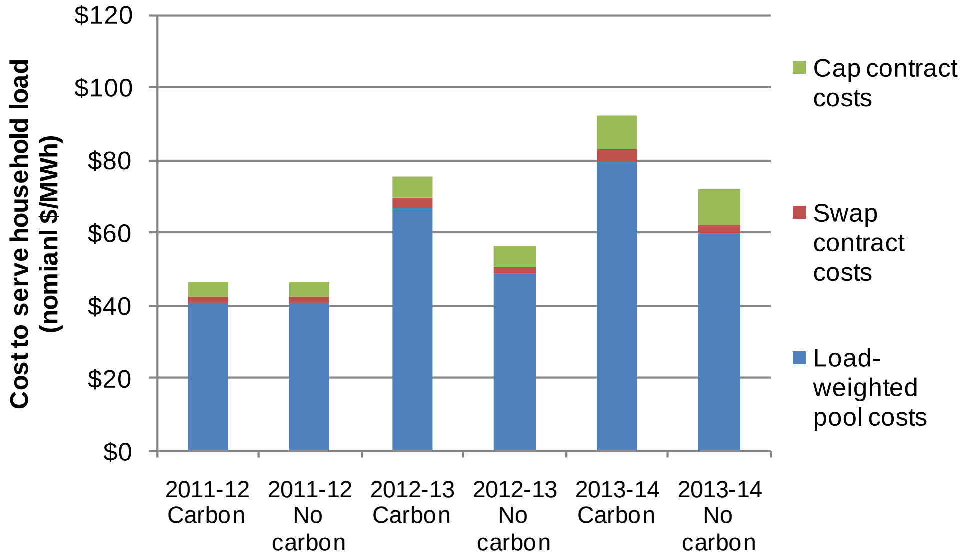
Wholesale energy costs to supply Queensland residential consumers also increase significantly in the absence of a carbon price, driven primarily by strong region-wide demand growth and increasing gas prices due to increased demand and gradual withdrawal of LNG 'ramp gas' from the domestic market. From around $46/MWh in 2011-12, residential energy costs increase to around $72/MWh by 2013-14 in the absence of a carbon price.

The introduction of a carbon price produces a further increase of around $20/MWh in both 2012-13 and 2013-14. These increases represent a 34% and a 28% increase from the No Carbon to the Carbon scenario in 2012-13 and 2013-14 respectively.

The introduction of a carbon price results in a 64% year-on-year increase in wholesale energy costs in 2012-13, compared to a year-on-year increase of 22%

in the absence of a carbon price. The rate of carbon cost pass-through is relatively constant across 2012-13 and 2013-14, at around 0.85 tonnes of CO_2-e/MWh.

Figure 21 **Residential wholesale energy purchase costs – Queensland**



Source: ACIL Tasman analysis

Table 20 **Impact of a carbon price on residential wholesale energy purchase costs – Queensland**

	Unit	2011-12	2012-13	2013-14
No Carbon	$/MWh	$46.34	$56.52	$72.28
Year on year increase	%	N/A	22%	28%
Carbon	$/MWh	$46.34	$75.80	$92.74
Year on year increase	%	N/A	64%	22%
Increase due to carbon	$/MWh	N/A	$19.29	$20.46
Percentage increase	%	N/A	34%	28%
Pass-through of carbon cost	tCO_2-e /MWh	N/A	0.84	0.85

Data source: ACIL Tasman analysis

As in New South Wales and Queensland, wholesale energy costs to supply Victorian residential consumers are projected to increase even in the absence of a carbon price.

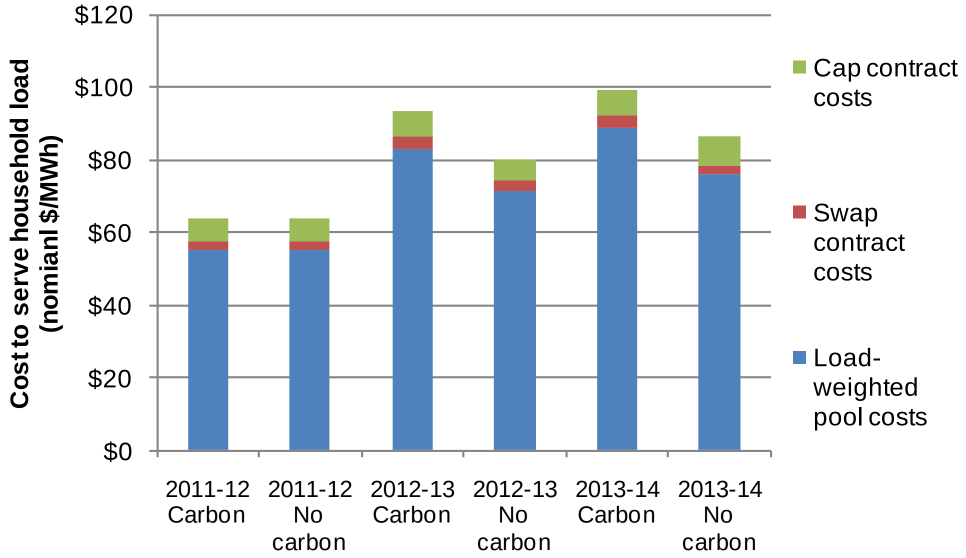
In 2012-13, wholesale energy costs are projected to increase 26% in the absence of a carbon price (from $64/MWh to $80/MWh), or 47% with a carbon price (to $94/MWh). However, in 2013-14, the rate of increase in wholesale energy costs is more modest in both scenarios, with an increase of

8% in the No Carbon scenario and 6% in the Carbon scenario, resulting in a strong narrowing in the differences between the scenarios.

The increase in wholesale energy costs for residential consumers in Victoria attributable to a carbon price is around $13/MWh or 15-16% in both 2012-13 and 2013-14, representing a rate of carbon cost pass-through of 0.53-0.57 tonnes of CO_2-e. This rate of carbon cost pass-through is far lower than the average emissions intensity of Victorian generation, reflecting price competition from lower-emissions generation sources in the regions with which the VIC NEM region is connected, namely NSW, TAS and SA. In particular the Victorian pass-through outcome is affected by competition from lower emissions gas and wind (South Australia) and hydro (Tasmania) generation, resulting in a clear divergence from NSW pass-through outcomes.

It is also relevant to note that the Victorian level of carbon cost pass-through in residential wholesale energy costs is significantly lower than that evident from examining time-weighted prices in the VIC NEM region. Whilst the level of pass-through for residential loads is around 0.53-0.57 tonnes of CO_2-e, the pass-through in time-weighted VIC NEM region prices is around 0.68 tonnes of CO_2-e (as illustrated in Table 11). This reflects the fact that carbon pricing has a greater impact on wholesale energy prices at off-peak (e.g. overnight) times, whilst residential energy use is weighted to the daytime and evening. Accordingly, the impact of carbon pricing on residential load-weighted energy purchase costs is more moderate.

Figure 22 **Residential wholesale energy purchase costs – Victoria**



Source: ACIL Tasman analysis

Table 21 **Impact of a carbon price on residential wholesale energy purchase costs – Victoria**

	Unit	2011-12	2012-13	2013-14
No Carbon	$/MWh	$63.74	$80.42	$86.64
Year on year increase	%	N/A	26%	8%
Carbon	$/MWh	$63.73	$93.53	$99.47
Year on year increase	%	N/A	47%	6%
Increase due to carbon	$/MWh	N/A	$13.11	$12.84
Percentage increase	%	N/A	16%	15%
Pass-through of carbon cost	tCO_2-e /MWh	N/A	0.57	0.53

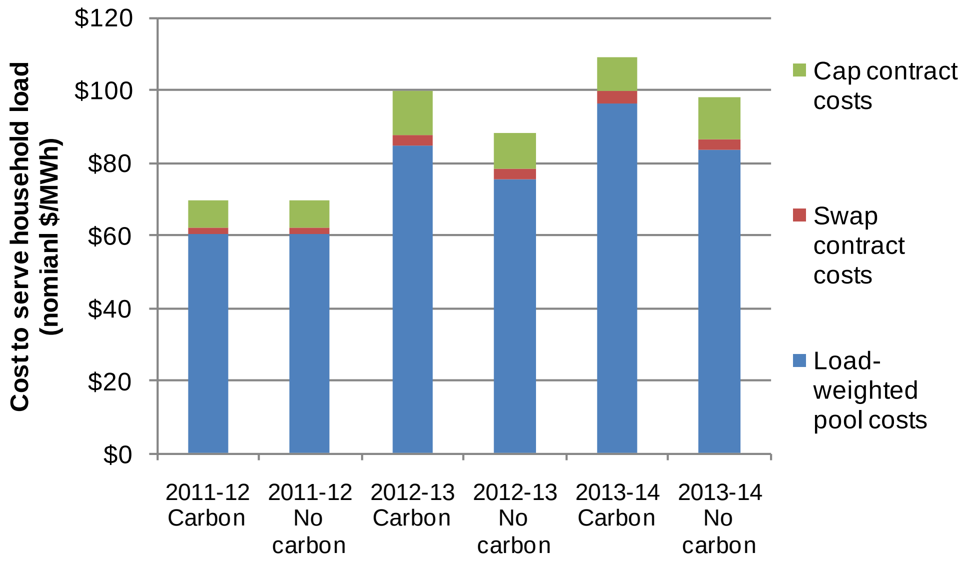
Data source: ACIL Tasman analysis

Of all the NEM jurisdictions, South Australia has the highest wholesale energy costs associated with supplying residential consumers, reflecting the extremely low load factor of both residential and total load in that state, the high risk of price spikes during summer heatwaves, and the impact of wind on the operation of thermal generation. In effect, the intermittent nature of wind generation makes the load to be supplied by scheduled thermal generation peakier, reducing the capacity factor of these plants (whether incumbent or potential new entrants), pushing up their average cost.

The overall outcome is that wholesale energy costs are projected to increase from around $70/MWh in 2011-12 to $89/MWh in 2012-13 in the absence of a carbon price (a 26% increase). If a carbon price is introduced, prices in 2012-13 are a further 13% higher, at almost $100/MWh (representing a 42% year-on-year increase). As in Victoria, prices in both scenarios increase more modestly in 2013-14: by around 10-11% year on year.

The increase in wholesale energy costs for South Australian residential customers due to a carbon price implies a carbon cost pass through rate of 0.49 tonnes of CO_2-e/MWh in 2012-13 and 0.47 tonnes of CO_2-e/MWh in 2013-14.

Figure 23 **Residential wholesale energy purchase costs – South Australia**



Source: ACIL Tasman analysis

Table 22 **Impact of a carbon price on residential wholesale energy purchase costs – South Australia**

	Unit	2011-12	2012-13	2013-14
No Carbon	$/MWh	$70.10	$88.60	$98.07
Year on year increase	%	N/A	26%	11%
Carbon	$/MWh	$70.10	$99.88	$109.54
Year on year increase	%	N/A	42%	10%
Increase due to carbon	$/MWh	N/A	$11.29	$11.46
Percentage increase	%	N/A	13%	12%
Pass-through of carbon cost	tCO_2-e /MWh	N/A	0.49	0.47

Data source: ACIL Tasman analysis

Unsurprisingly given that the ACT is located entirely within the NSW NEM region, wholesale energy prices to supply ACT households demonstrate a similar pattern to those in NSW.

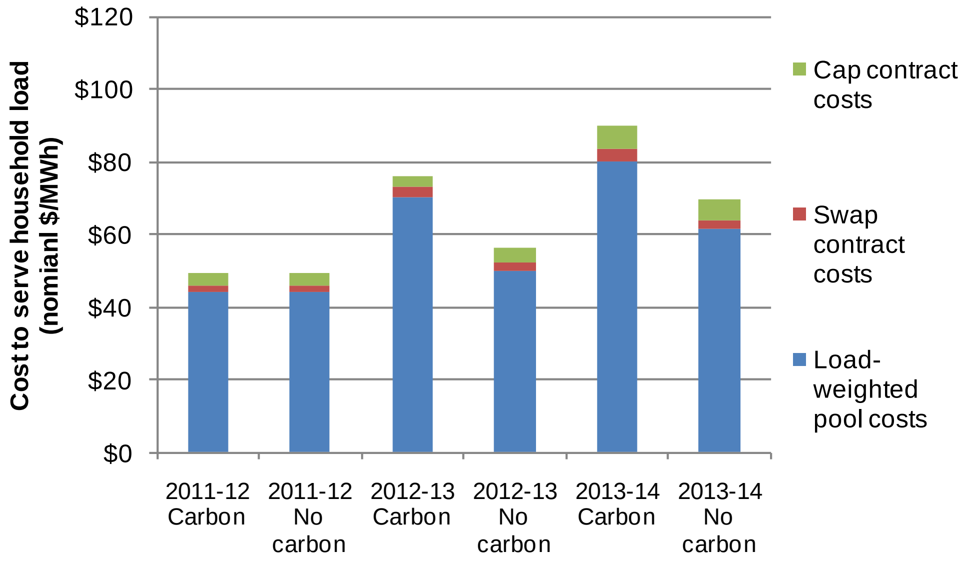
This analysis suggests an increase in wholesale energy costs to supply residential consumers from around $49/MWh in 2011-12 to $70/MWh by 2013-14 in the absence of a carbon price (a 14% year-on-year increase in 2012-13 and a 24% year-on-year increase in 2013-14).

The introduction of a carbon price further increases this to around $76/MWh in 2012-13, representing a 54% year-on-year increase or a total increase of around 35% when compared to the No Carbon scenario in that year.

However, as in other jurisdictions, the rate of increase in electricity prices moderates in 2013-14 in the Carbon scenario, with a year-on-year increase of 18% taking prices to $90/MWh.

As in New South Wales, the rate of carbon cost pass reduces slightly between 2012-13 and 2013-14, from around 0.86 tonnes of CO_2-e/MWh 0.84 tonnes of CO_2-e/MWh.

Figure 24 **Residential wholesale energy purchase costs – Australian Capital Territory**



Source: ACIL Tasman analysis

Table 23 **Impact of a carbon price on residential wholesale energy purchase costs – Australian Capital Territory**

	Unit	2011-12	2012-13	2013-14
No Carbon	$/MWh	$49.30	$56.36	$69.77
Year on year increase	%	N/A	14%	24%
Carbon	$/MWh	$49.30	$76.06	$90.10
Year on year increase	%	N/A	54%	18%
Increase due to carbon	$/MWh	N/A	$19.70	$20.33
Percentage increase	%	N/A	35%	29%
Pass-through of carbon cost	tCO_2-e /MWh	N/A	0.86	0.84

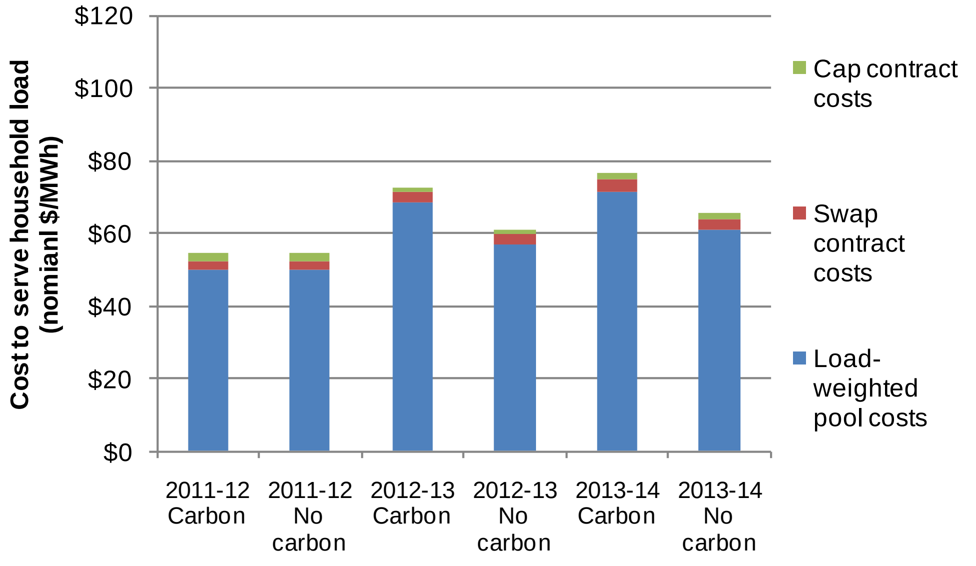
Data source: ACIL Tasman analysis

Consistent with results in other jurisdictions, Tasmanian energy costs for residential users increase steadily over 2012-13 and 2013-14 under the No Carbon scenario, but increase earlier and further in the Carbon scenario. With the introduction of a carbon price, Tasmanian energy costs increase 33% in 2012-13 for residential users, but then by only a further 5% in 2013-14.

By contrast, under the No Carbon scenario energy costs increase only around 12% in 2012-13 and 8% in 2013-14, resulting in an increase from around $55/MWh in 2011-12 to $66/MWh by 2013-14.

The increase in wholesale energy costs when comparing the Carbon and No Carbon scenarios is around 19% in 2012-13, declining to 16% in 2013-14.

Figure 25 **Residential wholesale energy purchase costs – Tasmania**



Source: ACIL Tasman analysis

Table 24 **Impact of a carbon price on residential wholesale energy purchase costs – Tasmania**

	Unit	2011-12	2012-13	2013-14
No Carbon	$/MWh	$54.88	$61.22	$65.98
Year on year increase	%	N/A	12%	8%
Carbon	$/MWh	$54.88	$72.82	$76.58
Year on year increase	%	N/A	33%	5%
Increase due to carbon	$/MWh	N/A	$11.60	$10.61
Percentage increase	%	N/A	19%	16%
Pass-through of carbon cost	tCO_2-e /MWh	N/A	0.50	0.44

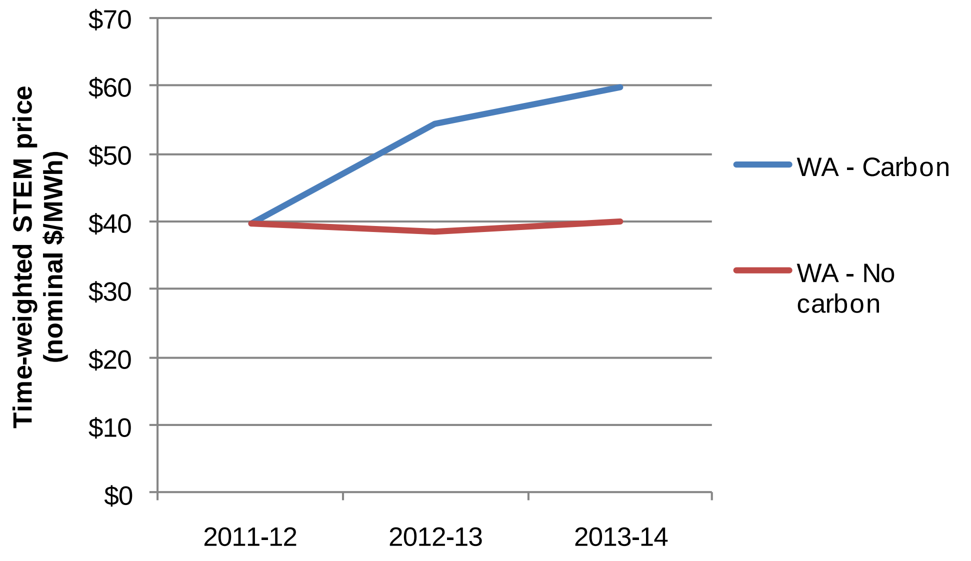
Data source: ACIL Tasman analysis

3.1.4 Wholesale energy costs – WEM

As discussed above in section 2.1, the WEM operates quite differently to the NEM. Accordingly, wholesale energy costs in the WEM comprise an energy component (which in our *PowerMark* modelling is based on a representation of the Short-term Energy Market, or STEM) and a capacity component (which we model based on the IMOWA's process for determining the price of capacity credits).

Figure 26 below presents the change in the time-weighted average STEM price in the Carbon and No Carbon scenarios. STEM (energy) costs are relatively stable in the No Carbon scenario, but increase strongly from 2012-13 onwards due to the introduction of a carbon price.

Figure 26 **Annual time-weighted average STEM prices**

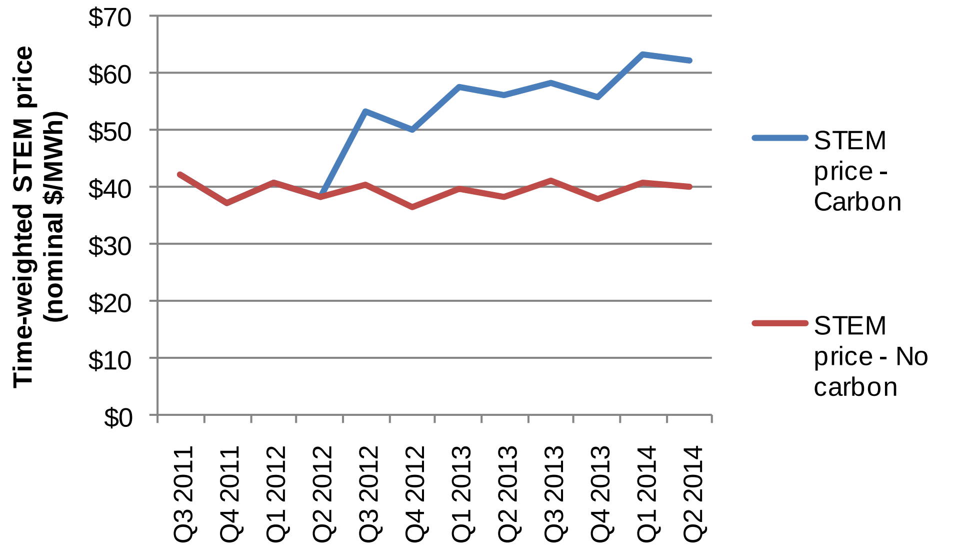


Note: 50% POE scenario only

Source: ACIL Tasman analysis

The stability of STEM prices (reflecting the SRMC bidding rules and broader market structure in the WEM) is illustrated in Figure 27: this price pattern can be contrasted with the stronger seasonal price variations in the NEM illustrated by Figures 6 to 10.

Figure 27 **Quarterly time-weighted average STEM prices**



Note: 50% POE scenario only

Source: PowerMark modelling

Capacity credit prices are slightly lower in the Carbon scenario when compared to the No Carbon scenario, reflecting a slight decrease in maximum demand as a result of carbon pricing. For the capacity credit years 2010-11, 2011-12 and 2012-13, the capacity credit prices modelled are identical in both scenarios and equal to the Reserve Capacity Credit price set by the IMOWA.

Table 25 **Capacity credit prices**

	2010-11 capacity credit year	2011-12 capacity credit year	2012-13 capacity credit year	2013-14 capacity credit year
Carbon scenario	$144,235	$131,805	$186,001	$183,535
No Carbon scenario	$144,235	$131,805	$186,001	$184,219

Note: Capacity credit years span from 1 October to 30 September

Data source: IMOWA; *PowerMark* modelling

Capacity credit costs are broadly stable across the Carbon and No Carbon scenarios (with only a slight divergence in the 2013-14 capacity year), but increase over time due to increasing costs of peaking generation in WA.

To derive the wholesale energy costs associated with serving residential load, ACIL Tasman made three adjustments to the average STEM prices and capacity credit prices presented above:

1. A share of the total cost of capacity credits in the WEM were attributed to residential load as described in section 2.2.4
2. STEM prices (by half-hour) were reconciled against forecast residential demand to produce a load-weighted energy cost associated with this load
3. A second set of STEM prices were modelled to reflect the potential for higher STEM prices under more extreme weather conditions (which is discussed further below).

As in the NEM, STEM prices will respond to high demand events that most commonly occur in response to more extreme weather conditions such as heatwaves. Accordingly, ACIL Tasman modelled a more extreme weather year (reflecting weather driven demand peaks consistent with a 1 in 10 year heatwave, or a 10% POE scenario) to assess the response of market outcomes to this situation.

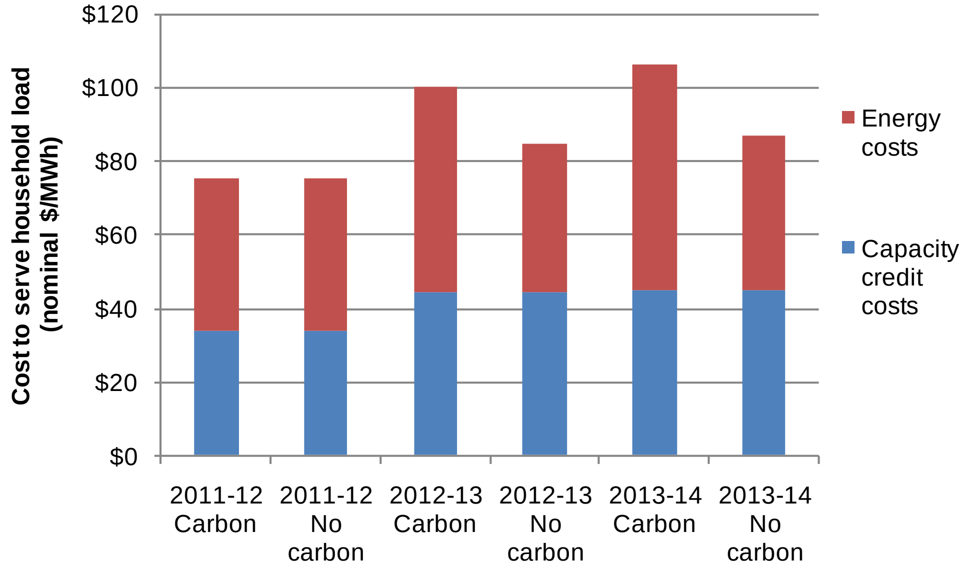
Load-weighted energy costs associated with serving residential load were then weighted across the 10% POE scenario and the core (50% POE) scenario. The weighting adopted was 20% to 80% respectively.

Capacity credit costs increase materially over the period of analysis, irrespective of carbon pricing assumptions. On a per unit basis, capacity credit costs that have been attributed to serving residential load in this analysis increase from around $34/MWh in 2011-12 to almost $45/MWh in 2012-13 and 2013-14, reflecting growing peak demand for both the general WEM load and residential load (and therefore the greater volume of capacity credits that must be purchased per unit of energy consumed) and the increasing cost of each capacity credit (reflecting increases in the cost of hypothetical new peaking generators and the reducing gap between available capacity and the capacity credit requirement).

Unsurprisingly, load-weighted energy (STEM) costs associated with serving residential load increases significantly between the Carbon and No Carbon scenario: this is the primary source of the $15/MWh increase in total energy costs in 2012-13 between the scenarios (an 18% increase) and the $19/MWh increase in 2013-14 (a 22% increase). Put another way, whilst total wholesale energy costs increase by 12% year-on-year in 2012-13 in the absence of carbon pricing, this increase to 32% if a carbon price is introduced.

The overall trend in the cost of serving residential load is illustrated in Figure 28, and presented in a tabular form in Table 26.

Figure 28 **Residential wholesale energy purchase costs – Western Australia**



Source: ACIL Tasman analysis

Table 26 **Impact of a carbon price on residential wholesale energy purchase costs – Western Australia**

	Unit	2011-12	2012-13	2013-14
No Carbon	$/MWh	$75.73	$84.83	$86.88
Year on year increase	%	N/A	12%	2%
Carbon	$/MWh	$75.73	$100.09	$106.25
Year on year increase	%	N/A	32%	6%
Increase due to carbon	$/MWh	N/A	$15.26	$19.37
Percentage increase	%	N/A	18%	22%
Pass-through of carbon cost	tCO_2-e /MWh	N/A	0.66	0.80

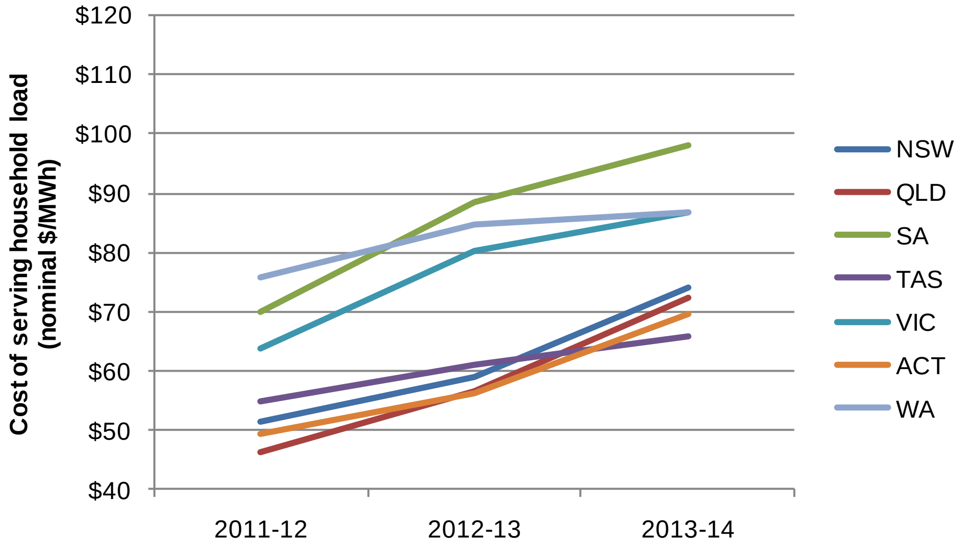
Data source: ACIL Tasman analysis

3.1.5 Comparison across regions

To allow clearer comparison of results across regions, the following data on the market-based wholesale energy costs associated with serving residential load in each region is presented below (in both graphical and tabular form):

- Wholesale energy costs for the No Carbon scenario
- Wholesale energy costs for the Carbon scenario
- Absolute increase between Carbon and No Carbon scenarios
- Pass-through rates.

Figure 29 **Market wholesale energy cost of serving residential load – No Carbon scenario**



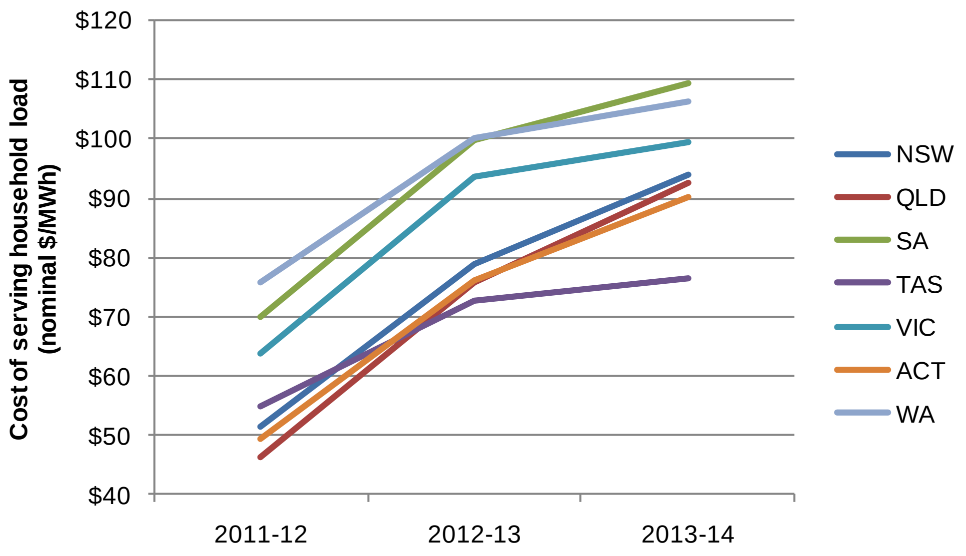
Source: PowerMark modelling

Table 27 **Market wholesale energy cost of serving residential load – No Carbon scenario**

Jurisdiction	2011-12	2012-13		2013-14	
	Wholesale energy cost	Wholesale energy cost	Year on year increase	Wholesale energy cost	Year on year increase
	$/MWh	$/MWh	%	$/MWh	%
New South Wales	$51.61	$59.16	15%	$74.12	25%
Queensland	$46.34	$56.52	22%	$72.28	28%
South Australia	$70.10	$88.60	26%	$98.07	11%
Tasmania	$54.88	$61.22	12%	$65.98	8%
Victoria	$63.74	$80.42	26%	$86.64	8%
Australian Capital Territory	$49.30	$56.36	14%	$69.77	24%
Western Australia	$75.73	$84.83	12%	$86.88	2%

Data source: *PowerMark* modelling

Figure 30 **Market wholesale energy cost of serving residential load – Carbon scenario**



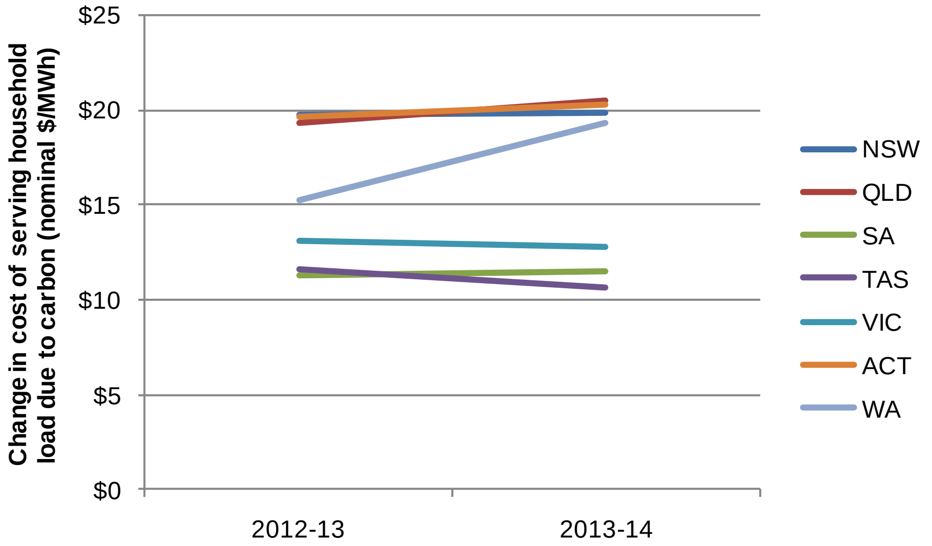
Source: PowerMark modelling

Table 28 **Market wholesale energy cost of serving residential load – Carbon scenario**

Jurisdiction	2011-12 Wholesale energy cost	2012-13 Wholesale energy cost	2012-13 Year on year increase	2013-14 Wholesale energy cost	2013-14 Year on year increase
	$/MWh	$/MWh	%	$/MWh	%
New South Wales	$51.61	$78.98	53%	$94.04	19%
Queensland	$46.34	$75.80	64%	$92.74	22%
South Australia	$70.10	$99.88	42%	$109.54	10%
Tasmania	$54.88	$72.82	33%	$76.58	5%
Victoria	$63.73	$93.53	47%	$99.47	6%
Australian Capital Territory	$49.30	$76.06	54%	$90.10	18%
Western Australia	$75.73	$100.09	32%	$106.25	6%

Data source: *PowerMark* modelling

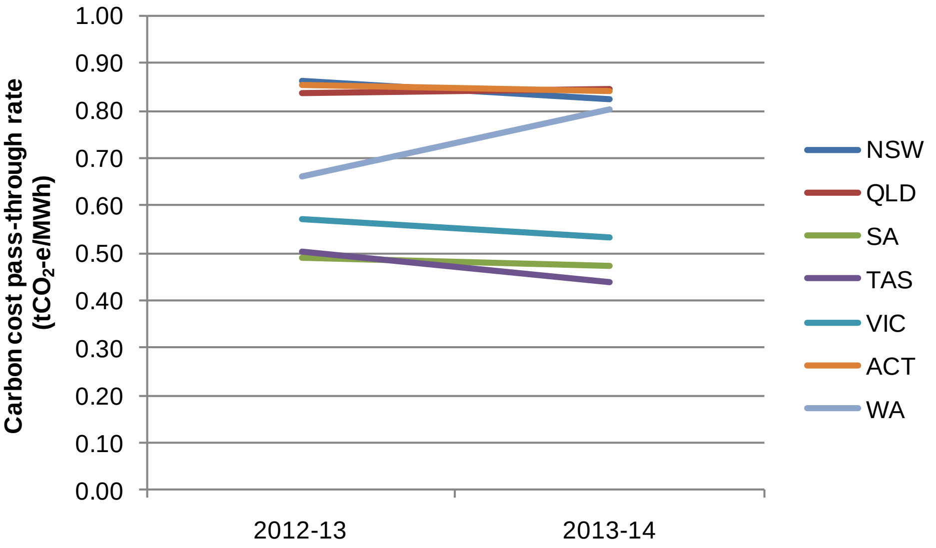
Figure 31 **Increase in market wholesale energy cost of serving residential load due to carbon pricing**



Note: Prices in 2011-12 are identical due to absence of carbon pricing in that year

Source: PowerMark modelling

Figure 32 **Implied carbon cost pass-through from market simulation modelling**



Source: PowerMark modelling

Table 29 **Increase in market wholesale energy cost due to carbon pricing and implied carbon cost pass-through**

Jurisdiction	2011-12	2012-13		2013-14	
	Increase in wholesale energy cost due to carbon	Increase in wholesale energy cost due to carbon	Carbon cost pass-through	Increase in wholesale energy cost due to carbon	Carbon cost pass-through
	$/MWh	$/MWh	tCO_2-e /MWh	$/MWh	tCO_2-e /MWh
New South Wales	N/A	$19.82	0.86	$19.92	0.82
Queensland	N/A	$19.29	0.84	$20.46	0.85
South Australia	N/A	$11.29	0.49	$11.46	0.47
Tasmania	N/A	$11.60	0.50	$10.61	0.44
Victoria	N/A	$13.11	0.57	$12.84	0.53
Australian Capital Territory	N/A	$19.70	0.86	$20.33	0.84
Western Australia	N/A	$15.26	0.66	$19.37	0.80

Data source: *PowerMark* modelling

3.2 LRMC modelling results

3.2.1 New South Wales

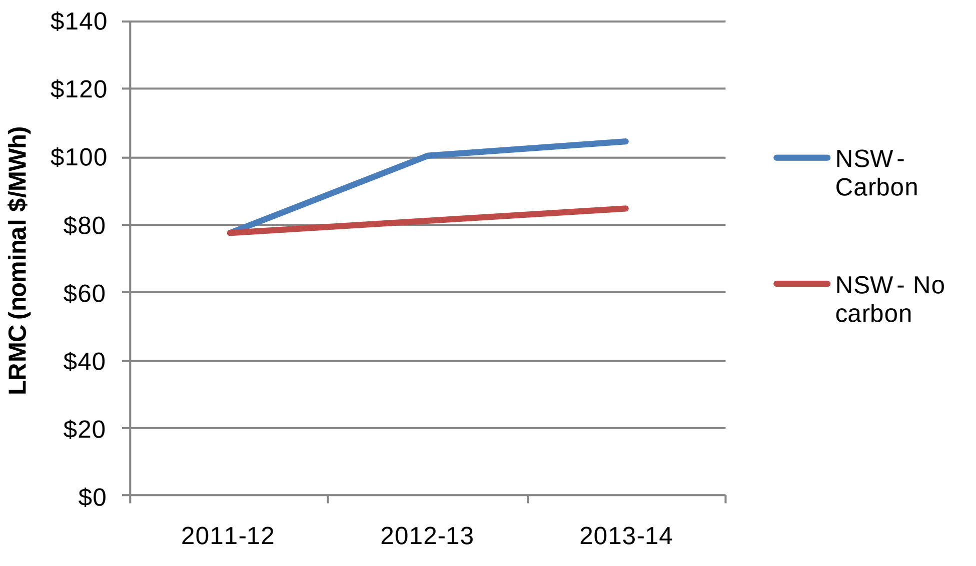
For New South Wales, the system LRMC increases slightly in the absence of carbon due largely to increasing gas and coal costs.

However, the introduction of a carbon price sees prices rise due to the increase in generation costs of all fossil-fuelled generation types and the increased resource (capital and fuel) costs associated with the shift away from supercritical coal and towards CCGT generation in the optimised generation mix. LRMC costs are around 23-24% higher in the Carbon scenario than in the No Carbon scenario, representing a pass-through rate of around 0.82 to 0.83 tonnes of CO_2-e/megawatt-hour.

Wind generation retains a share of around 20% of the optimised generation mix by dispatch in all scenarios and years. This result reflects its cost-competiveness as a source of energy (rather than capacity) with fossil-fuelled sources, given the external subsidy available to this technology through the LRET scheme (the cost of which is not included in the LRMC calculated under this methodology).

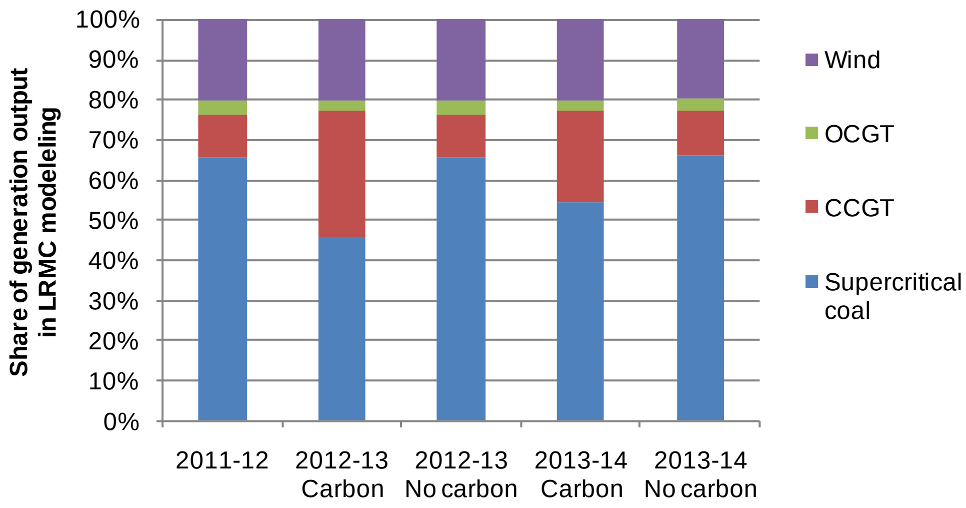
These results are presented in Figure 33 and Figure 34 below and numerically in Table 30.

Figure 33 **Long-run marginal cost of residential load – New South Wales**



Source: PowerMark LT modelling

Figure 34 **Optimised generation mix by dispatch – New South Wales**



Source: PowerMark LT modelling

Table 30 **Impact of a carbon price on LRMC of serving residential load – New South Wales**

	Unit	2011-12	2012-13	2013-14
No Carbon	$/MWh	$77.88	$81.28	$84.60
Year on year increase	%	N/A	4%	4%
Carbon	$/MWh	$77.88	$100.23	$104.74
Year on year increase	%	N/A	29%	5%
Increase due to carbon	$/MWh	N/A	$18.95	$20.14
Percentage increase	%	N/A	23%	24%
Pass-through of carbon cost	tCO_2-e /MWh	N/A	0.82	0.83

Data source: *PowerMark LT* modelling

3.2.2 Queensland

Trends in system LRMC for Queensland demonstrate a similar pattern to NSW (albeit at a lower absolute level than in New South Wales). The LRMC of serving residential load increases slightly in the absence of carbon due largely to increasing gas and coal costs.

Again, the introduction of a carbon price sees prices rise due to the increase in generation costs of all fossil-fuelled generation types and the increased resource (capital and fuel) costs associated with the shift away from supercritical coal and towards CCGT or wind generation in the optimised generation mix.

However, the introduction of a carbon price sees prices rise due to the increase in generation costs of all fossil-fuelled generation types and the increased resource (capital and fuel) costs associated with the shift away from supercritical coal and towards CCGT or wind generation in the optimised generation mix.

The optimised Queensland generation mix demonstrates a different pattern of response to the introduction of a carbon price in 2012-13 as to 2013-14:

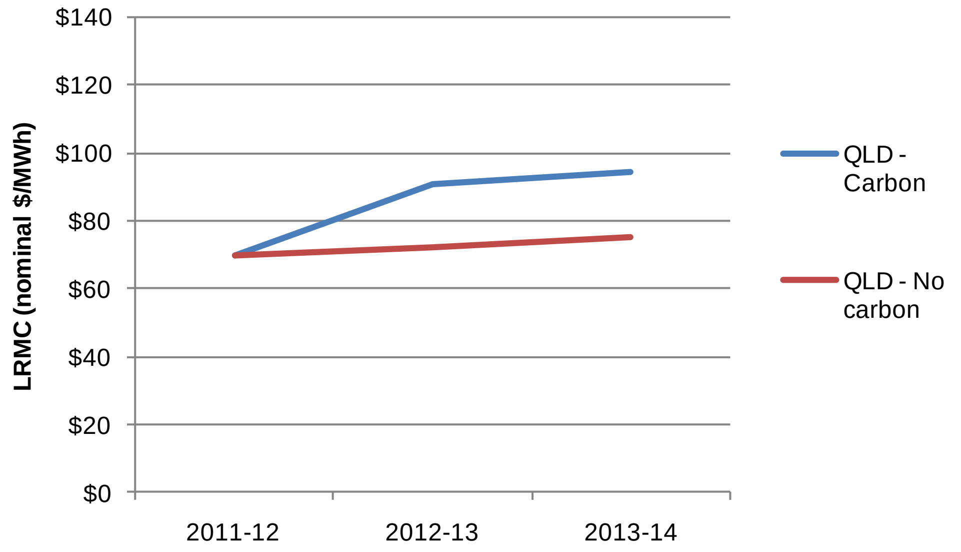
- In 2012-13 the optimised generation mix is substantially different, with around 20% of dispatch coming from each of wind and CCGT generation in the Carbon scenario, compared to around 10% for CCGT and no wind generation in the No Carbon scenario
- By contrast, the Carbon and No Carbon generation mixes in 2013-14 are identical.

Despite this, the overall price effects of carbon are similar for both years. These results are compatible because the modelling approach of building a system anew in each year accentuates the effect of a marginal change in the relative cost of different plant (e.g. due to rising carbon or fuel prices). This result illustrates that the LRMC of a system constructed with a quite different generation mix would result in a broadly similar price outcome, e.g. if the 2013-14 No Carbon generation mix were similar to the 2012-13 No Carbon generation mix, the 2013-14 No Carbon LRMC would not change significantly.

LRMC costs are around 25-26% higher in the Carbon scenario than in the No Carbon scenario. This is a smaller absolute change than in New South Wales, but a greater relative change due to the lower level of energy costs in Queensland (reflecting lower fuel costs). This change represents a pass-through rate of around 0.80 tonnes of CO_2-e/megawatt-hour.

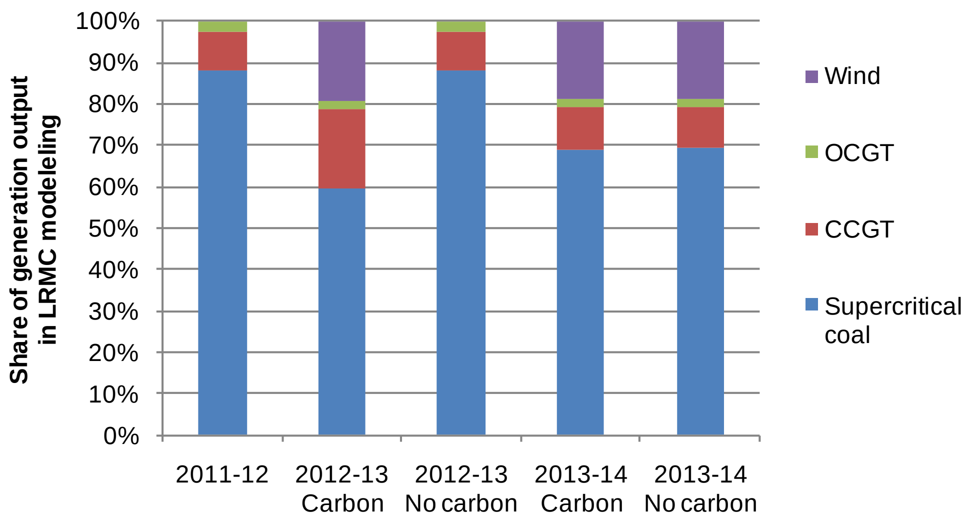
These results are presented in Figure 35 and Figure 36 below and numerically in Table 31.

Figure 35 **Long-run marginal cost of residential load – Queensland**



Source: PowerMark LT modelling

Figure 36 **Optimised generation mix by dispatch – Queensland**



Source: PowerMark LT modelling

Table 31 **Impact of a carbon price on LRMC of serving residential load – Queensland**

	Unit	2011-12	2012-13	2013-14
No Carbon	$/MWh	$69.95	$72.56	$75.31
Year on year increase	%	N/A	4%	4%
Carbon	$/MWh	$69.95	$90.84	$94.62
Year on year increase	%	N/A	30%	4%
Increase due to carbon	$/MWh	N/A	$18.29	$19.31
Percentage increase	%	N/A	25%	26%
Pass-through of carbon cost	tCO_2-e /MWh	N/A	0.80	0.80

Data source: *PowerMark LT* modelling

3.2.3 Victoria

An in New South Wales and Queensland, the LRMC of serving residential load in Victoria increases slightly in the absence of carbon, due largely to increasing gas costs.

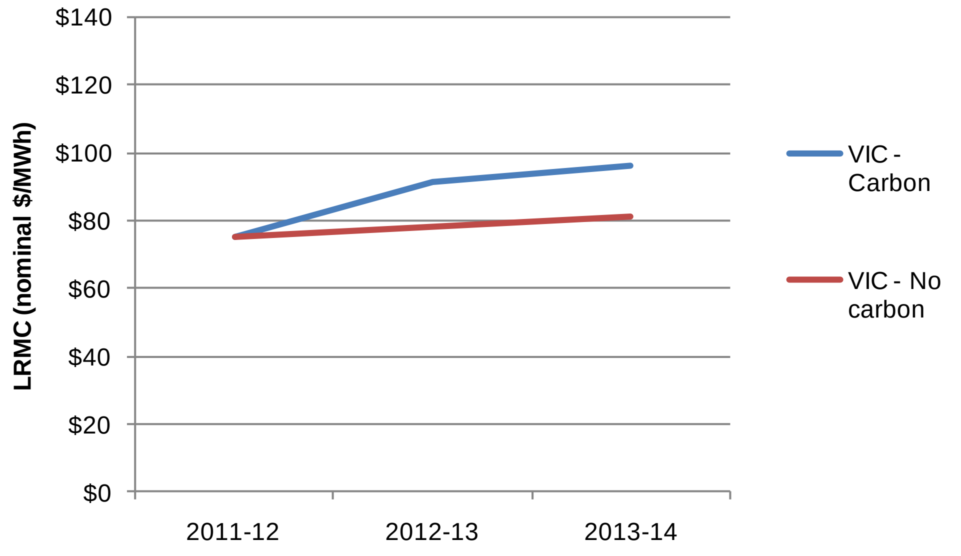
However, the impact of carbon pricing in Victoria is significantly lower than New South Wales and Queensland, amounting to an absolute increase of around $13/MWh in 2012-13 and $15/MWh in 2013-14 compared to figures approaching $20/MWh in New South Wales and Queensland.

This result reflects the higher capital cost of supercritical brown coal generation in Victoria than supercritical black coal generation in New South Wales and Queensland, and lower gas prices in Victoria than New South Wales. This means that the optimised system's adjustment away from supercritical brown coal and towards CCGT and wind generation results in a lower marginal cost impact, and hence a lower rate of carbon cost pass-through.

The No Carbon generation mix in Victoria differs markedly between 2012-13 and 2013-14, with a significant increase in the penetration of wind in 2013-14. This result reflects the higher gas prices in 2013-14 and higher effective subsidies to renewable generation, which underpins the viability of wind and reduces both coal and CCGT generation output.

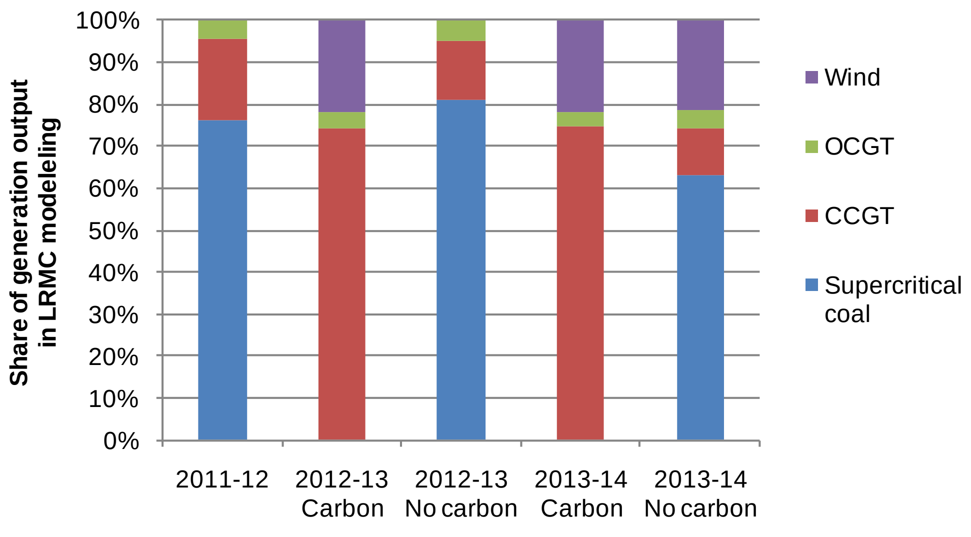
These results are presented in Figure 37 and Figure 38 below and numerically in Table 32.

Figure 37 **Long-run marginal cost of residential load – Victoria**



Source: PowerMark LT modelling

Figure 38 **Optimised generation mix by dispatch – Victoria**



Source: PowerMark LT modelling

Table 32 **Impact of a carbon price on LRMC of serving residential load – Victoria**

	Unit	2011-12	2012-13	2013-14
No Carbon	$/MWh	$75.03	$78.16	$81.17
Year on year increase	%	N/A	4%	4%
Carbon	$/MWh	$75.03	$91.27	$96.46
Year on year increase	%	N/A	22%	6%
Increase due to carbon	$/MWh	N/A	$13.12	$15.29
Percentage increase	%	N/A	17%	19%
Pass-through of carbon cost	tCO_2-e /MWh	N/A	0.57	0.63

Data source: *PowerMark LT* modelling

3.2.4 South Australia

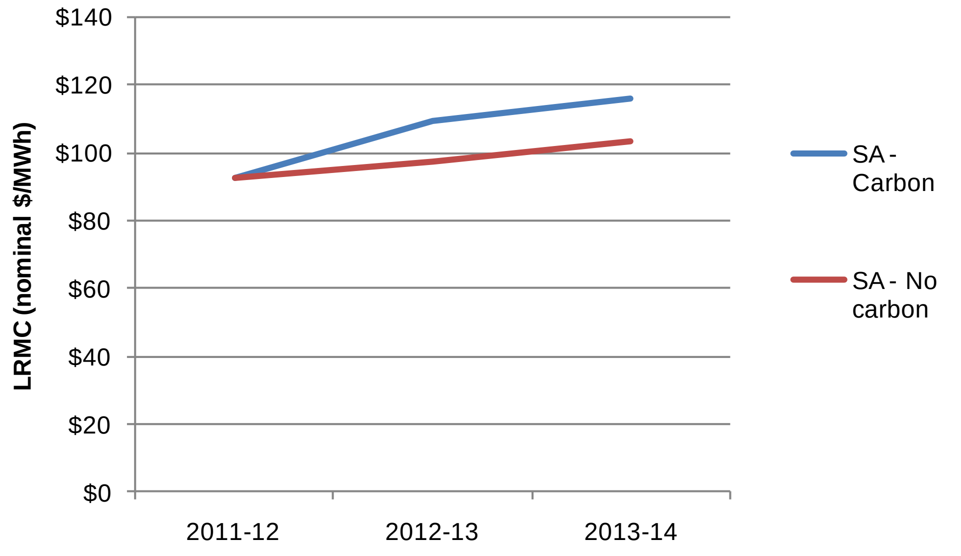
The optimised generation mix in South Australia is almost unchanged across all years analysed and in response to the introduction of carbon pricing. This reflects the absence of competition in the optimised generation mix between coal and gas generation: due to the absence of commercial coal reserves in South Australia, no coal-fired new entrant is available in the LRMC modelling for this state.

Accordingly it is clear that, as for other regions, increasing gas prices drives the overall increase in the LRMC of serving residential load in SA.

In contrast to New South Wales, Queensland and Victoria, the increase in the LRMC of serving residential load in SA between the Carbon and No Carbon scenarios is not materially affected by substitution between different generation types. Instead, the rate of pass through of around 0.52 tonnes of CO_2-e/MWh primarily reflects the average emissions intensity of the generation mix (including upstream fugitive emissions associated with production of gas), being a combination of CCGT, OCGT and wind.

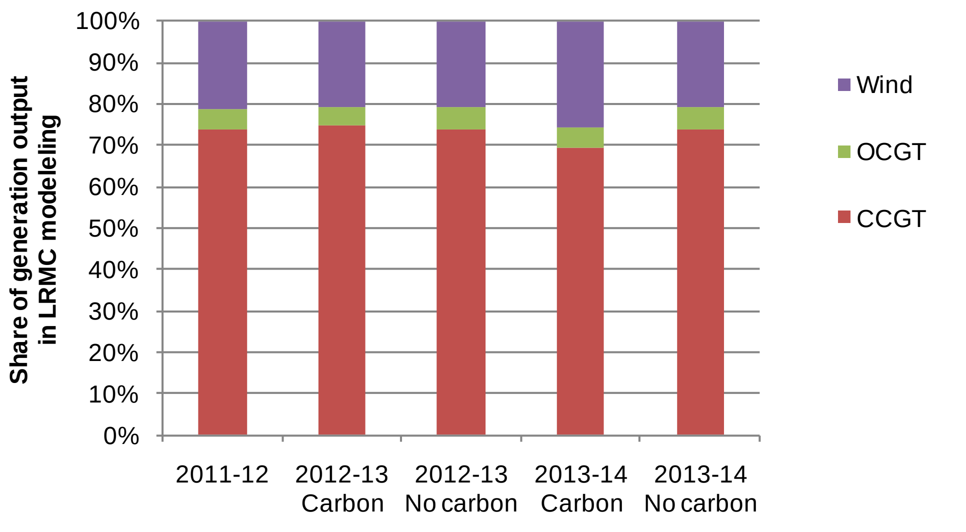
These results are presented in Figure 39 and Figure 40 below, and numerically in Table 33.

Figure 39 **Long-run marginal cost of residential load – South Australia**



Source: PowerMark LT modelling

Figure 40 **Optimised generation mix by dispatch – South Australia**



Source: PowerMark LT modelling

Table 33 **Impact of a carbon price on LRMC of serving residential load – South Australia**

	Unit	2011-12	2012-13	2013-14
No Carbon	$/MWh	$92.56	$97.66	$103.57
Year on year increase	%	N/A	6%	6%
Carbon	$/MWh	$92.56	$109.59	$116.09
Year on year increase	%	N/A	18%	6%
Increase due to carbon	$/MWh	N/A	$11.93	$12.52
Percentage increase	%	N/A	12%	12%
Pass-through of carbon cost	tCO_2-e /MWh	N/A	0.52	0.52

Data source: *PowerMark LT* modelling

3.2.5 Tasmania

As in the SA region, trends over time in Tasmania are driven primarily by changing gas prices. Due to the absence of commercial coal resources in Tasmania, there is no new entrant coal-fired generator available in the LRMC modelling, and the generation mix consists exclusively of OCGT, CCGT and wind generation.

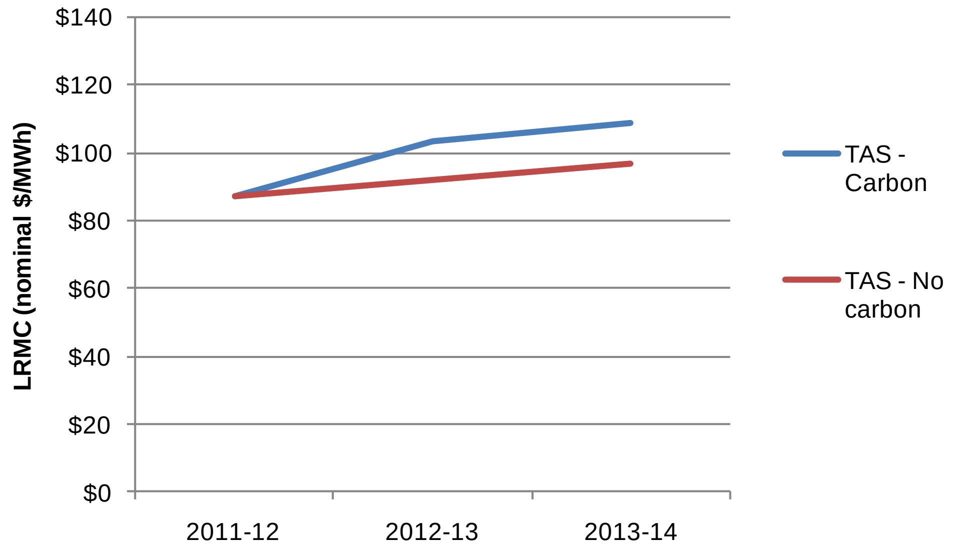
The optimised generation mix in Tasmania varies more than in South Australia, with a substitution away from OCGT and towards CCGT in 2012-13 with the introduction of a carbon price. By contrast, the Carbon and No Carbon scenarios demonstrate almost identical generation mixes in 2013-14.

In light of this, the observation that the rate of pass-through in 2012-13 is similar to that in 2013-14 indicates that the resource cost of the different generation mixes is marginal. This result emerges in Tasmania but not in South Australia due to the slightly lower gas prices in Tasmania, meaning that the resource cost of using an OCGT with lower capital costs and lower generation efficiencies is lower than the resource cost of CCGT generation (which has higher capital costs but higher generation efficiency) over a greater range of capacity factors than in South Australia.

The introduction of a carbon price results in a 12% increase in the LRMC of serving residential load in Tasmania in both years, representing an absolute increase of around $11-12/MWh, or a rate of pass through of around 0.5 tonnes of CO_2-e/MWh.

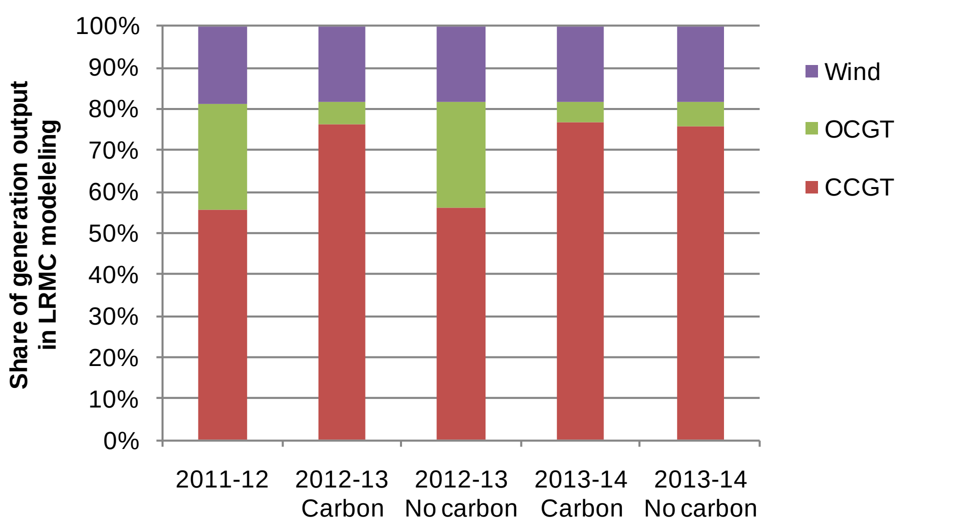
These results are presented in Figure 41 and Figure 42 below, and numerically in Table 34.

Figure 41 **Long-run marginal cost of residential load – Tasmania**



Source: PowerMark LT modelling

Figure 42 **Optimised generation mix by dispatch – Tasmania**



Source: PowerMark LT modelling

Table 34 **Impact of a carbon price on LRMC of serving residential load – Tasmania**

	Unit	2011-12	2012-13	2013-14
No Carbon	$/MWh	$87.16	$91.84	$96.97
Year on year increase	%	N/A	5%	6%
Carbon	$/MWh	$87.16	$103.32	$108.74
Year on year increase	%	N/A	19%	5%
Increase due to carbon	$/MWh	N/A	$11.47	$11.77
Percentage increase	%	N/A	12%	12%
Pass-through of carbon cost	tCO_2-e /MWh	N/A	0.50	0.49

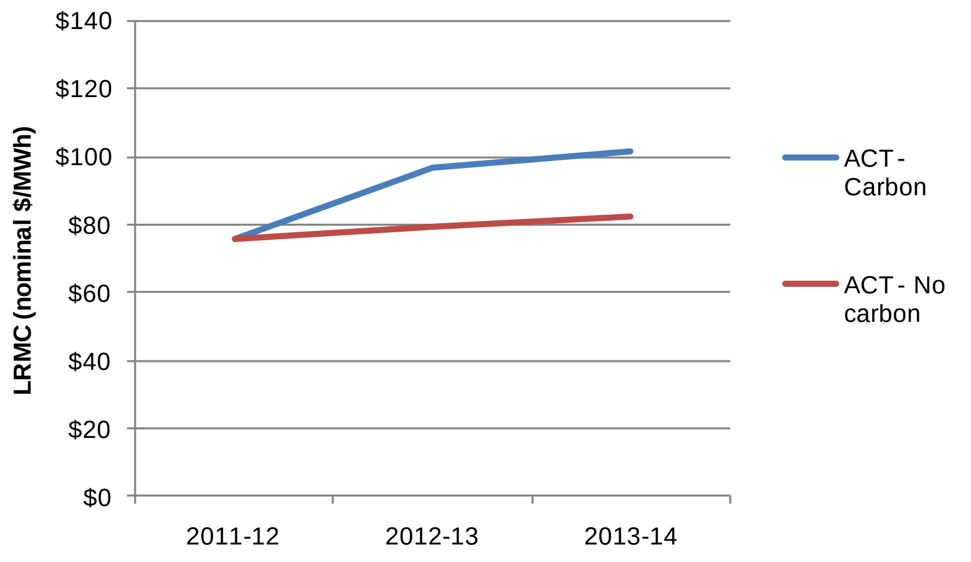
Data source: *PowerMark LT* modelling

3.2.6 Australian Capital Territory

Unsurprisingly, LRMC and generation mix outcomes in the ACT are broadly similar to those in New South Wales, with an uplift in the LRMC of serving residential load due to the introduction of a carbon price of around 22-23%.

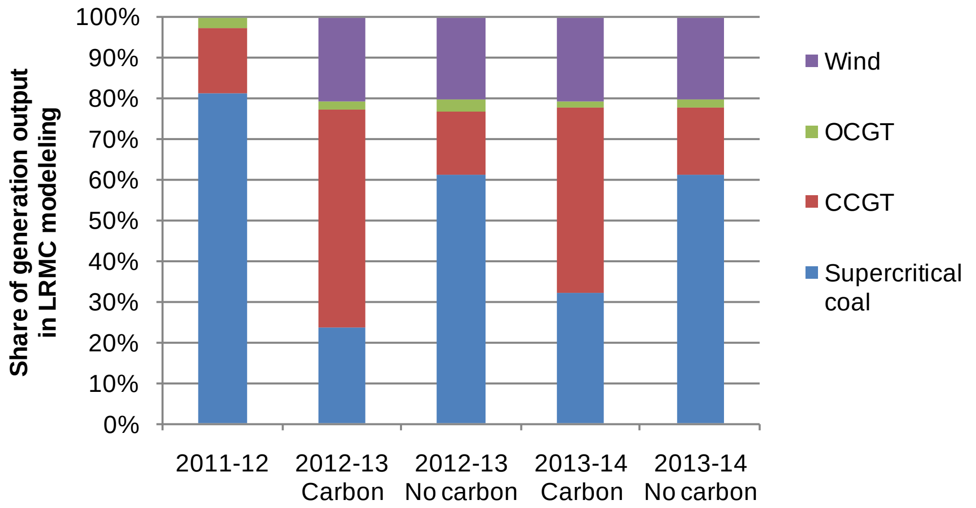
These results are presented in Figure 43 and Figure 44 below, and numerically in Table 35.

Figure 43 **Long-run marginal cost of residential load – Australian Capital Territory**



Source: PowerMark LT modelling

Figure 44 **Optimised generation mix by dispatch – Australian Capital Territory**



Source: PowerMark LT modelling

Table 35 **Impact of a carbon price on LRMC of serving residential load – Australian Capital Territory**

	Unit	2011-12	2012-13	2013-14
No Carbon	$/MWh	$75.94	$79.28	$82.56
Year on year increase	%	N/A	4%	4%
Carbon	$/MWh	$75.94	$96.87	$101.61
Year on year increase	%	N/A	28%	5%
Increase due to carbon	$/MWh	N/A	$17.59	$19.04
Percentage increase	%	N/A	22%	23%
Pass-through of carbon cost	tCO_2-e /MWh	N/A	0.76	0.79

Data source: *PowerMark LT* modelling

3.2.7 Western Australia

The LRMC of serving residential load in Western Australia is higher than in all NEM states, due in large part to high gas prices in that state and higher assumed capital costs (reflecting smaller unit sizes and higher labour and general materials costs in Western Australia).

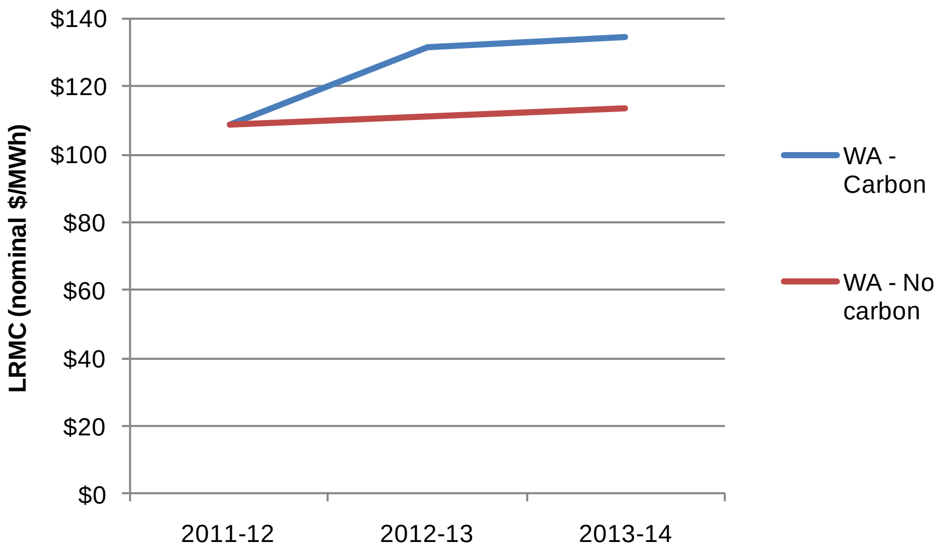
The LRMC of serving residential load in Western Australia increases to above $110/MWh in the absence of carbon pricing, and approaches $135/MWh by 2013-14 in the Carbon scenario.

The optimised generation mix in Western Australia remains largely constant over time and between the Carbon and No Carbon scenarios. This indicates that CCGT generation is unable to compete with coal-fired generation under prevailing coal, gas and carbon prices. However, as the LRMC modelling approach sees the system rebuilt each year to reflect market circumstances in that year, this result does not indicate that an investor building a new generation asset in Western Australia would not look beyond 2013-14 and trade-off present gas prices with the prospect of higher carbon prices and conclude that a CCGT is an optimal investment in the WA market at the present time.

The introduction of a carbon price results in around a 18-19% increase in the LRMC of serving residential load in Western Australia, representing an absolute increase of over $20/MWh, or a pass through rate approaching 0.9 tonnes of CO_2-e/MWh.

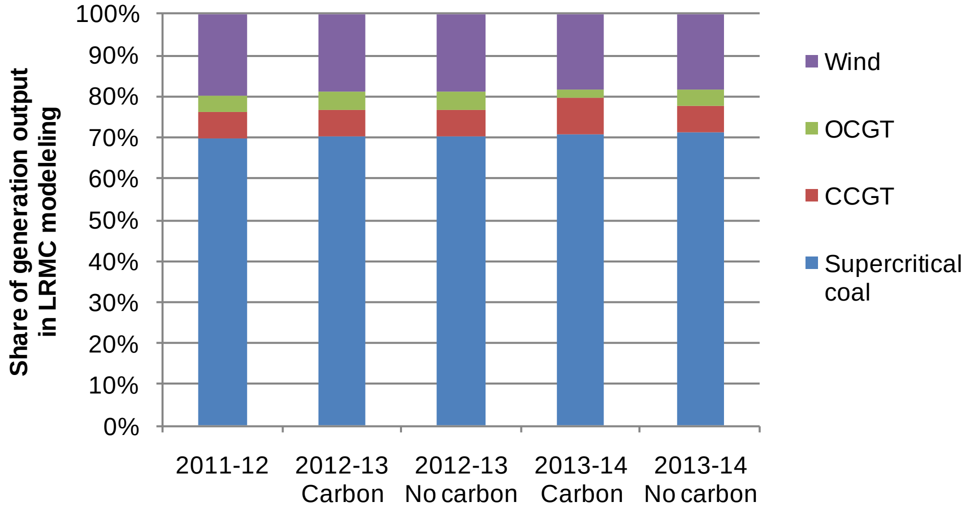
These results are presented in Figure 45 and Figure 46 below, and numerically in Table 36.

Figure 45 **Long-run marginal cost of residential load – Western Australia**



Source: PowerMark LT modelling

Figure 46 **Optimised generation mix by dispatch – Western Australia**



Source: PowerMark LT modelling

Table 36 **Impact of a carbon price on LRMC of serving residential load – Western Australia**

	Unit	2011-12	2012-13	2013-14
No Carbon	$/MWh	$108.78	$111.36	$113.43
Year on year increase	%	N/A	2%	2%
Carbon	$/MWh	$108.78	$131.93	$134.97
Year on year increase	%	N/A	21%	2%
Increase due to carbon	$/MWh	N/A	$20.57	$21.54
Percentage increase	%	N/A	18%	19%
Pass-through of carbon cost	tCO_2-e /MWh	N/A	0.89	0.89

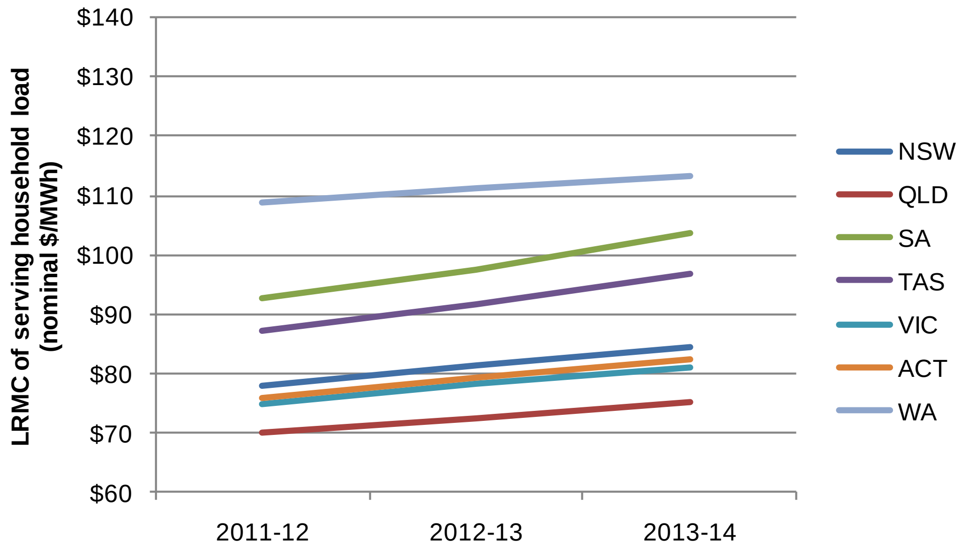
Data source: *PowerMark LT* modelling

3.2.8 Comparison across regions

To allow clearer comparison of results across regions, the following data on the LRMC of serving residential load in each region is presented below (in both graphical and tabular form):

- LRMC for the No Carbon scenario
- LRMC for the Carbon scenario
- Absolute increase between Carbon and No Carbon scenarios
- Pass-through rates.

Figure 47 **LRMC of serving residential load – No Carbon scenario**



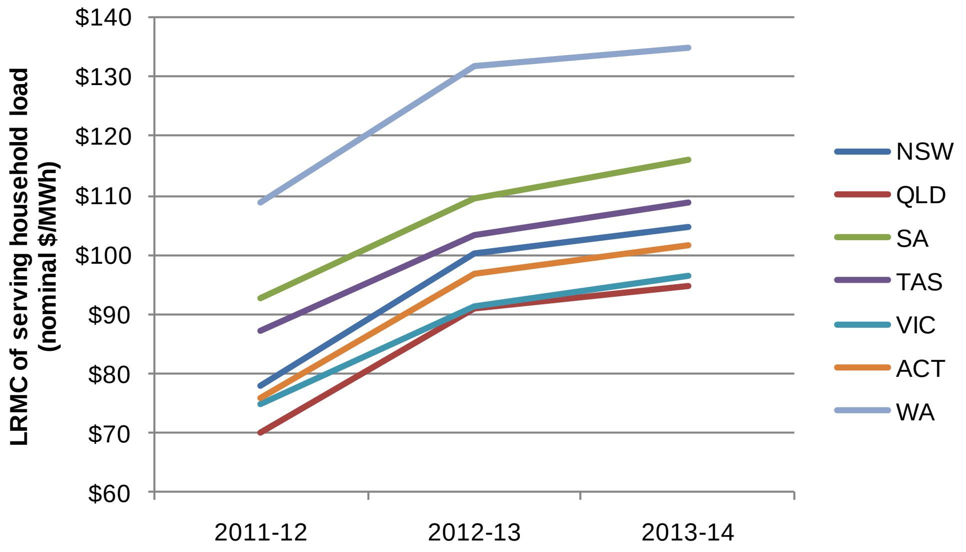
Source: PowerMark LT modelling

Table 37 **LRMC of serving residential load – No Carbon scenario**

Jurisdiction	2011-12 LRMC	2012-13 LRMC	2012-13 Year on year increase	2013-14 LRMC	2013-14 Year on year increase
	$/MWh	$/MWh	%	$/MWh	%
New South Wales	$77.88	$81.28	4%	$84.60	4%
Queensland	$69.95	$72.56	4%	$75.31	4%
South Australia	$92.56	$97.66	6%	$103.57	6%
Tasmania	$87.16	$91.84	5%	$96.97	6%
Victoria	$75.03	$78.16	4%	$81.17	4%
Australian Capital Territory	$75.94	$79.28	4%	$82.56	4%
Western Australia	$108.78	$111.36	2%	$113.43	2%

Data source: *PowerMark LT* modelling

Figure 48 **LRMC of serving residential load – Carbon scenario**



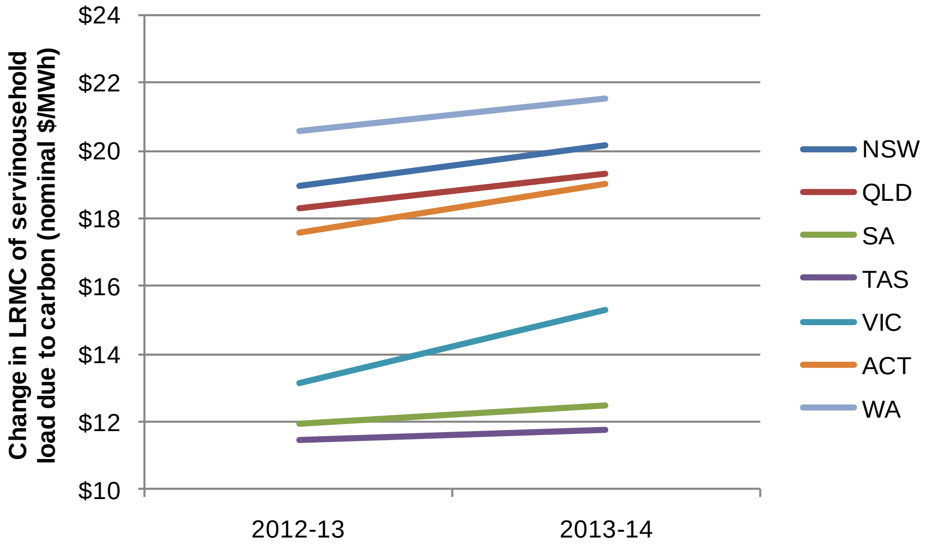
Source: PowerMark LT modelling

Table 38 **LRMC of serving residential load – Carbon scenario**

Jurisdiction	2011-12 LRMC	2012-13 LRMC	2012-13 Year on year increase	2013-14 LRMC	2013-14 Year on year increase
	$/MWh	$/MWh	%	$/MWh	%
New South Wales	$77.88	$100.23	29%	$104.74	5%
Queensland	$69.95	$90.84	30%	$94.62	4%
South Australia	$92.56	$109.59	18%	$116.09	6%
Tasmania	$87.16	$103.32	19%	$108.74	5%
Victoria	$75.03	$91.27	22%	$96.46	6%
Australian Capital Territory	$75.94	$96.87	28%	$101.61	5%
Western Australia	$108.78	$131.93	21%	$134.97	2%

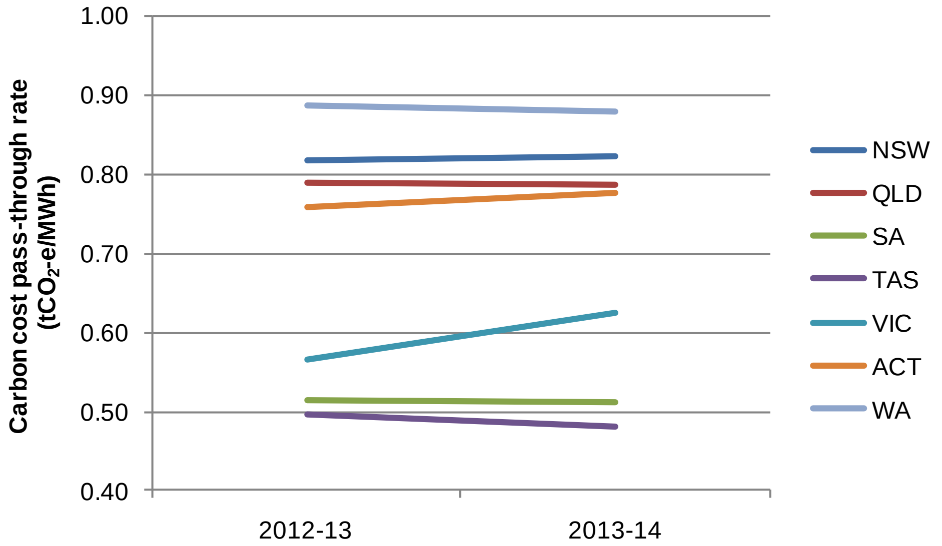
Data source: *PowerMark LT* modelling

Figure 49 **Increase in LRMC of serving residential load due to carbon pricing**



Source: PowerMark LT modelling

Figure 50 **Implied carbon cost pass-through from LRMC modelling**



Source: PowerMark LT modelling

Table 39 **Increase in LRMC of serving residential load due to carbon pricing and implied carbon cost pass-through**

Jurisdiction	2011-12	2012-13		2013-14	
	Increase in LRMC due to carbon	Increase in LRMC due to carbon	Carbon cost pass-through	Increase in LRMC due to carbon	Carbon cost pass-through
	$/MWh	$/MWh	tCO_2-e /MWh	$/MWh	tCO_2-e /MWh
New South Wales	N/A	$18.95	0.82	$20.14	0.83
Queensland	N/A	$18.29	0.80	$19.31	0.80
South Australia	N/A	$11.93	0.52	$12.52	0.52
Tasmania	N/A	$11.47	0.50	$11.77	0.49
Victoria	N/A	$13.12	0.57	$15.29	0.63
Australian Capital Territory	N/A	$17.59	0.76	$19.04	0.79
Western Australia	N/A	$20.57	0.89	$21.54	0.89

Data source: *PowerMark LT* modelling

3.3 Comparison of market simulation and LRMC modelling results

The very different modelling methodologies used in the market simulation and LRMC modelling analyses can offer some high-level insights into what is driving outcomes.

In particular, the fact that the generation system built in the LRMC modelling approach is perfectly sized to serve residential load and analysed in a way that ensures that its capital and operating costs are fully recovered means that this approach can abstract away from short-term supply-demand balance issues (e.g. an over-supply of generation capacity) to look at the 'underlying' cost of serving residential load. In other words, the LRMC modelling approach abstracts away from the present mix of plant in the market, including whether that mix of plant is appropriately sized or combined to serve existing (total system) load, and focuses on the load factor of residential load, and the capital and fuel costs that would be incurred in serving that load.

The difference between serving residential and total system load also creates several sources of potential difference between market simulation and LRMC modelling.

The key sources of potential difference are summarised in Table 40.

Table 40 **Key sources of variation between market and LRMC modelling**

Variable	Market simulation approach	LRMC approach	Direction of difference between LRMC and market simulation modelling
Supply-demand balance	Examines total system demand and existing, committed and potential new plant	System optimally sized to serve residential load	Market simulation modelling may deliver lower prices than LRMC modelling where there is an 'overhang' of capacity. Real world constraints leading to delayed new entry could result in the reverse, but this is not generally observed in practice.
Load factor	Examines the cost of serving the total system load, and then examines residential load as a sub-set of total system load	Examines the cost of serving residential load on a stand-alone basis	Where total system load has a higher load factor than residential load, the cost of serving residential load in the market simulation modelling may be lower than the LRMC approach
Mix of base load, intermediate and peaking capacity	Examines mix of existing, committed and potential new plant, including suitability for different load duties	Builds optimal mix of base load, intermediate and peaking capacity	Where there is an excess of base load capacity, market simulation modelling costs may be lower than LRMC. Conversely, an excess of peaking capacity in market simulation modelling would, over time, be unlikely to deter new base load or new entrant generators

Variable	Market simulation approach	LRMC approach	Direction of difference between LRMC and market simulation modelling
Effect of inter-connectors	Uses existing inter-connectors to share capacity and moderate price outcomes between NEM regions	Excludes inter-connectors	Where peak demands are non-coincident, or where generation costs (e.g. fuel costs) diverge between regions, the use of inter-connectors may contribute to lower costs in market simulation modelling than in LRMC modelling. Interconnectors can allow market prices to rise toward new entrant levels (due to export of low cost electricity to higher price regions), but should not contribute to prices exceeding new entrant levels.
Treatment of wind generation	Wind generation responds to long-run incentive of LRET scheme and forward looking market prices	Wind is selected by the model at a level that will allow a return on capital in the model year (taking into account an external LRET subsidy and prices in that year).	Wind entry can suppress market prices in market simulation modelling, particularly in the short term, as wind farms look forward to future increases in electricity and/or LGC prices. This dynamic is not present in LRMC modelling.
Effect of 'legacy' hydro plant	Deploys existing hydro capacity to maximum value in the market	Does not utilise hydro new entrants on the assumption that all economic large-scale hydro generation sources have been utilised	Access to low marginal cost, flexible hydro plant will tend to result in lower market simulation costs than costs modelled under an LRMC approach. Hydro generation is also does not face a direct cost impost from a carbon price.
Fuel contracts for incumbent generators	Bids existing plant based on existing gas or coal contracts, where known	All thermal generators access a market-reflective new entrant fuel price	Low-cost legacy gas or coal contracts can change bidding behaviour and suppress prices in market simulation modelling compared to LRMC modelling
Strategic bidding	Generators employ strategic bidding to maximise profits	Generators are dispatched on the basis of SRMC bidding	Strategic bidding could result in market simulation modelling prices exceeding LRMC modelling outcomes. However, in the long-term, this effect should be mitigated by new entry
Response to carbon pricing	The existing mix of plant emissions-intensities is largely fixed in the short-term, with gradual change due to retirement and new entry	Builds optimal mix of generation each year taking into account emissions costs, responding instantly and efficiently to the introduction of a carbon price	Market simulation modelling costs may exceed LRMC outcomes due to a sub-optimal plant mix under a carbon price.

This analysis indicates that, methodologically, market simulation modelling is more likely to result in prices lower than LRMC modelling due to the greater range of factors that can lead to this outcome than those working in the other direction.

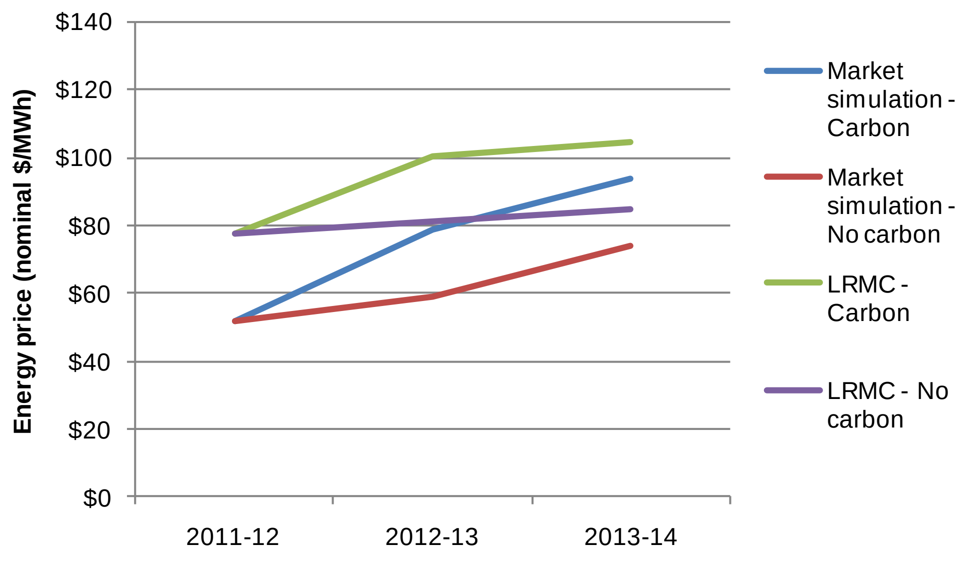
In effect, only two effects work in the direction of causing market simulation modelling costs to exceed LRMC: the potential for the existing mix of plant to be sub-optimal in the face of a carbon price; and strategic bidding.

By contrast a range of factors present in the can potentially lead to lower costs in market simulation modelling than LRMC modelling:

- an excess of capacity in general, or of base load capacity in particular,
- synergies between serving residential and other loads (i.e. commercial and industrial)
- the role of interconnectors
- the short-term potential for wind new entrants to suppress prices
- access to low-cost, flexible 'legacy' hydro plant
- low-cost incumbent fuel contracts.

With this analysis in mind, outcomes in New South Wales illustrate that the overhang of capacity, particularly base load capacity, in that state tends to suppress market prices when compared to the LRMC of serving retail load. This effect predominates over the fact that the existing plant mix is likely to be sub-optimal following the introduction of a carbon price.

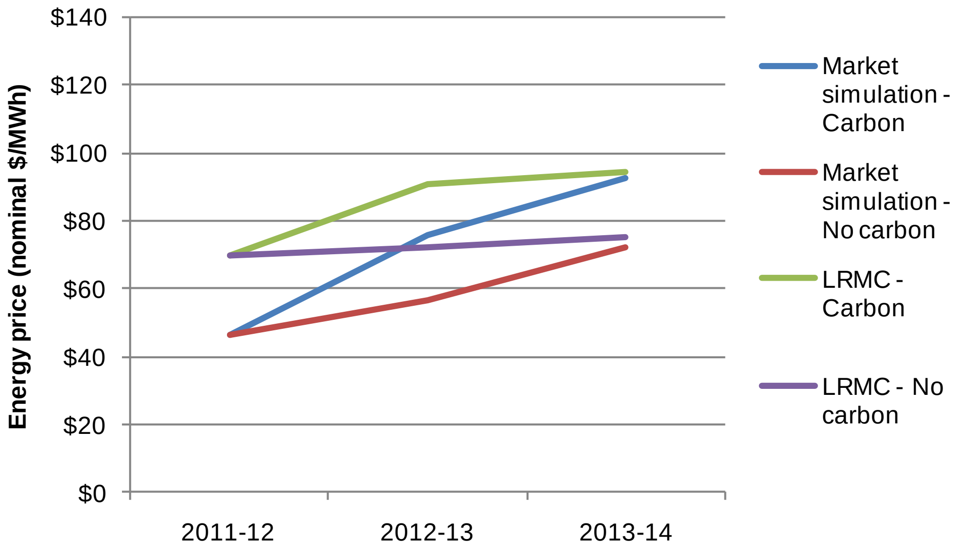
Figure 51 **Comparison of LRMC and market simulation outcomes – New South Wales**



Source: PowerMark modelling; *PowerMark LT* modelling; additional ACIL Tasman analysis of hedging costs

A comparison of market and LRMC modelling outcomes also illustrates that Queensland is experiencing some overhang of capacity, suppressing market prices when compared to the LRMC of serving retail load. However, stronger demand growth in Queensland than in New South Wales sees almost complete convergence between market simulation modelling and LRMC modelling outcomes by 2013-14 in Queensland. Nevertheless, market prices remain below the modelled LRMC despite the fact that the existing plant mix is likely to be sub-optimal following the introduction of a carbon price.

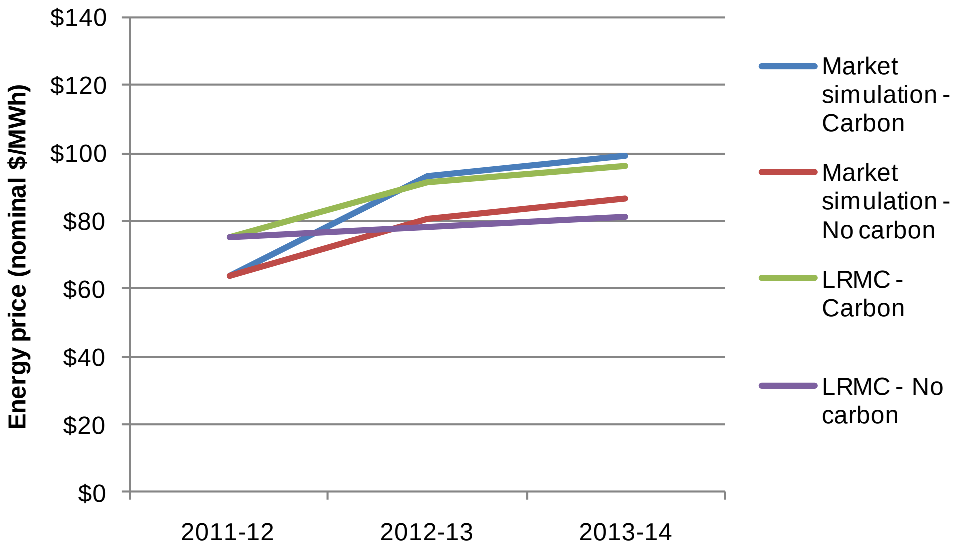
Figure 52 **Comparison of LRMC and market simulation outcomes – Queensland**



Source: PowerMark modelling; *PowerMark LT* modelling; additional ACIL Tasman analysis of hedging costs

By contrast with New South Wales and Queensland, Victorian market price outcomes exceed LRMC modelled outcomes in 2012-13 and 2013-14 in both the Carbon and No carbon scenarios. This result is fairly marginal, and indicates that it is not so much the introduction of a carbon price that makes the Victorian generation mix 'sub-optimal', but likely the operation of strategic bidding that allows VIC region market prices to exceed the LRMC modelled outcome.

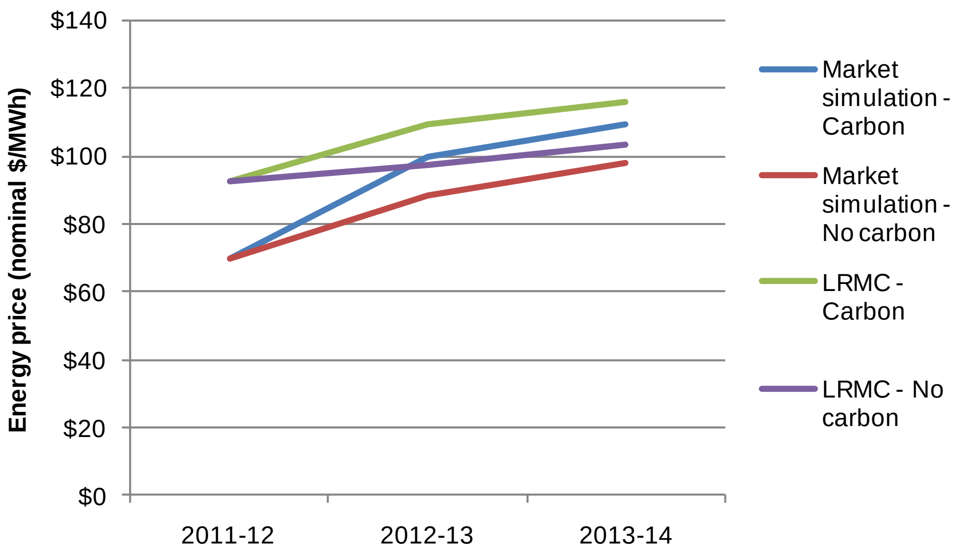
Figure 53 **Comparison of LRMC and market simulation outcomes – Victoria**



Source: PowerMark modelling; *PowerMark LT* modelling; additional ACIL Tasman analysis of hedging costs

South Australian market price outcomes remain below LRMC modelled outcomes in both scenarios and across all years. One possible driver of this result is the operation of the LRET policy bringing in potentially a greater than optimal level of wind generation to the SA NEM region, which would tend to suppress wholesale market prices below the LRMC of an optimised new build system.

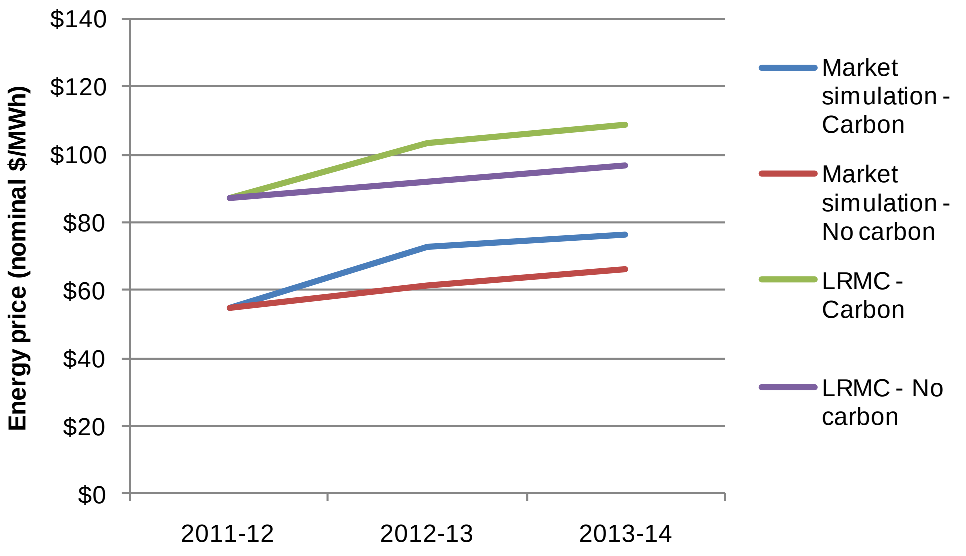
Figure 54 **Comparison of LRMC and market simulation outcomes – South Australia**



Source: PowerMark modelling; *PowerMark LT* modelling; additional ACIL Tasman analysis of hedging costs

In this modelling, market prices in Tasmania remain substantially below LRMC levels over the period of analysis. This reflects the excess of capacity in that state, and the fact that LRMC modelling cannot take advantage of the legacy hydro generation plant in that state. This latter effect is particularly critical under the Carbon scenario given that hydro generation does not incur a carbon cost. However, the BassLink interconnector obviates some of this effect under the market simulation modelling approach by allowing electricity to be transported to and from the VIC NEM region, and therefore a degree of price interaction between those regions, an effect that is not present in the LRMC modelling.

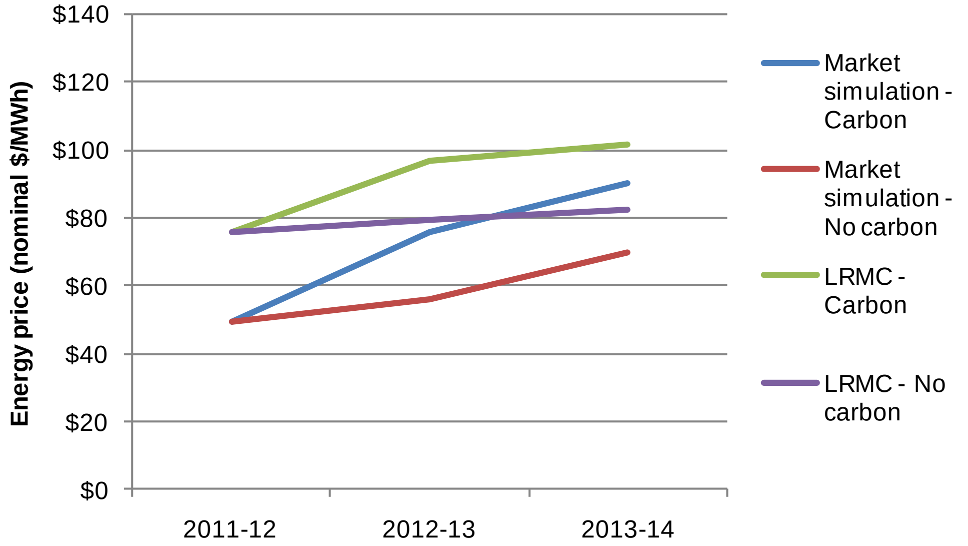
Figure 55 **Comparison of LRMC and market simulation outcomes – Tasmania**



Source: PowerMark modelling; *PowerMark LT* modelling; additional ACIL Tasman analysis of hedging costs

Market simulation modelling outcomes in the ACT reflect the broader market circumstances in the NSW NEM region of which it is part, namely that the overhang of capacity, particularly base load capacity, in New South Wales tends to suppress market prices when compared to the LRMC of serving retail load.

Figure 56 **Comparison of LRMC and market simulation outcomes – Australian Capital Territory**



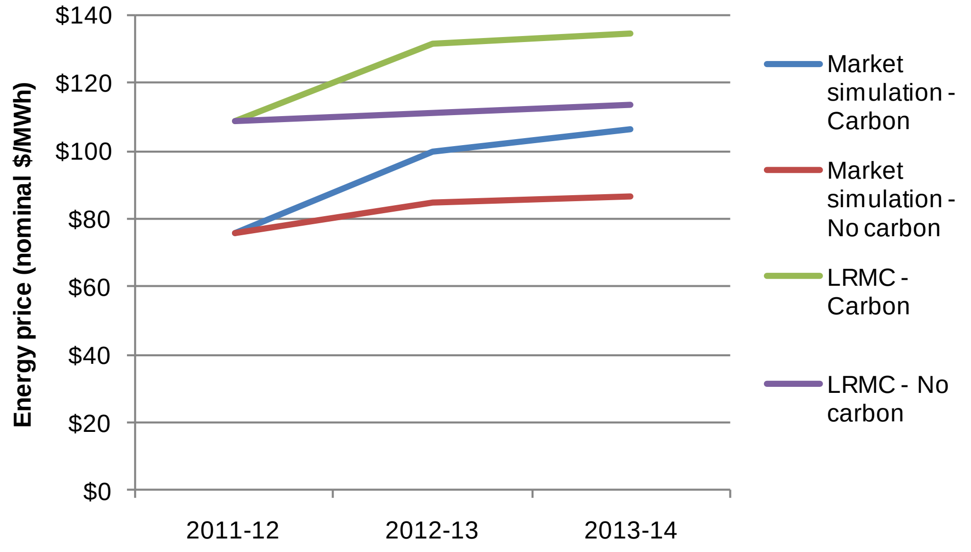
Source: PowerMark modelling; *PowerMark LT* modelling; additional ACIL Tasman analysis of hedging costs

A comparison of market simulation modelling and LRMC modelling outcomes in Western Australia indicate an excess of capacity and, potentially, the role of legacy low-cost gas contracts in suppressing market prices below LRMC levels.

The excess of capacity is likely to take two forms: there appears to be a (slight) excess of total capacity in the WEM, as reflected by the number of capacity credits issued in the WEM for the 2012-13 capacity year (5,995.6123 MW) exceeding the capacity credit requirement for that year (5,501 MW).

Further, the historic development of significant co-generation facilities (e.g. alumina refineries) and substantial coal-fired generation capacity may indicate a slight over-weight of effective base load capacity compared to the optimal mix reflected in LRMC modelling.

Figure 57 **Comparison of LRMC and market simulation outcomes – Western Australia**



Source: PowerMark modelling; *PowerMark LT* modelling; additional ACIL Tasman analysis to attribute capacity credit costs to residential load.

A *PowerMark* detailed results

Given the short-term nature of this modelling exercise, only limited differences in new entry patterns are possible over the projection period. Differences in new entry patterns NEM-wide are as follows:

- Due to slightly lower rates of demand growth, 124 MW of open-cycle gas turbine generation (OCGT) does not occur in the VIC NEM region in 2012-13 in the Carbon scenario that occurs in the No Carbon scenario
- However, this OCGT development does occur in 2013-14, such that new entry levels for OCGTs are identical in that year
- In 2013-14, the Carbon scenario sees 68 MW of wind located across SA and VIC that was located in QLD in the No Carbon scenario.

Overall, new entry and retirement patterns in the NEM consist primarily of new OCGT and wind generation, with a small reduction in coal-fired generation capacity as Swanbank B exits the market.

Table 41 **New entry by technology and scenario**

Technology	Scenario	2011-12	2012-13	2013-14	Total
OCGT	Carbon	0	0	648	648
	No carbon	0	124	524	648
	Difference	0	-124	+124	0
Steam turbine (coal)	Carbon	0	-100	-150	-250
	No carbon	0	-100	-150	-250
	Difference	0	0	0	0
Wind	Carbon	0	391	737	1.127
	No carbon	0	391	737	1,127
	Difference	0	0	0	0

Note: Excludes committed generators
Data source: *PowerMark* modelling

Table 42 and Table 43 outline total generation capacity across all the NEM regions by generation type under the no carbon and the carbon scenario, respectively.

Table 42 **Generation capacity by generation type (MW) - No Carbon scenario**

		2011-12	2012-13	2013-14
Cogeneration	NSW1	176	176	176
Gas turbine	NSW1	1,378	1,378	1,378
Gas turbine combined cycle	NSW1	410	410	410
Hydro	NSW1	3,165	3,165	3,165
Pump	NSW1	0	0	0
Steam turbine	NSW1	12,090	12,090	11,941
Wind	NSW1	144	187	187
Cogeneration	QLD1	0	0	0
Gas turbine	QLD1	2,000	2,000	2,274
Gas turbine combined cycle	QLD1	1,395	1,395	1,395
Hydro	QLD1	641	641	641
Pump	QLD1	60	60	60
Steam turbine	QLD1	8,329	8,229	8,229
Wind	QLD1	0	0	137
Cogeneration	SA1	180	180	180
Gas turbine	SA1	859	859	983
Gas turbine combined cycle	SA1	485	485	485
Hydro	SA1	0	0	0
Pump	SA1	0	0	0
Steam turbine	SA1	2,041	2,041	2,041
Wind	SA1	798	815	879
Cogeneration	TAS1	0	0	0
Gas turbine	TAS1	163	163	163
Gas turbine combined cycle	TAS1	200	200	200
Hydro	TAS1	2,157	2,157	2,157
Pump	TAS1	0	0	0
Steam turbine	TAS1	0	0	0
Wind	TAS1	0	0	179
Cogeneration	VIC1	0	0	0
Gas turbine	VIC1	1,963	2,087	2,213
Gas turbine combined cycle	VIC1	0	0	0
Hydro	VIC1	2,169	2,169	2,169
Pump	VIC1	0	0	0
Wind	VIC1	35	366	723
Cogeneration	NEM	356	356	356
Gas turbine	NEM	6,363	6,487	7,011
Gas turbine combined cycle	NEM	2,490	2,490	2,490
Hydro	NEM	8,132	8,132	8,132
Pump	NEM	60	60	60
Steam turbine	NEM	29,666	29,566	29,416
Wind	NEM	977	1,368	2,105

Data source: ACIL Tasman

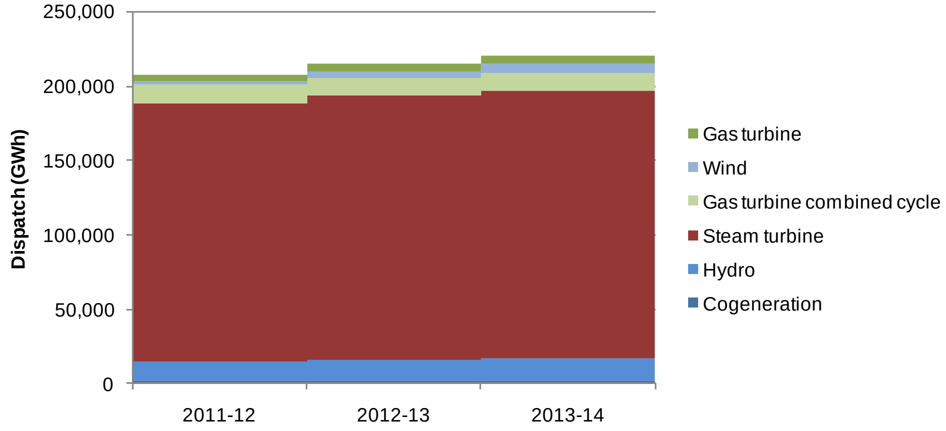
Table 43 **Generation capacity by generation type (MW) - Carbon scenario**

		2011-12	2012-13	2013-14
Cogeneration	NSW1	176	176	176
Gas turbine	NSW1	1,378	1,378	1,378
Gas turbine combined cycle	NSW1	410	410	410
Hydro	NSW1	3,165	3,165	3,165
Pump	NSW1	0	0	0
Steam turbine	NSW1	12,090	12,090	11,941
Wind	NSW1	144	187	187
Cogeneration	QLD1	0	0	0
Gas turbine	QLD1	2,000	2,000	2,274
Gas turbine combined cycle	QLD1	1,395	1,395	1,395
Hydro	QLD1	641	641	641
Pump	QLD1	60	60	60
Steam turbine	QLD1	8,329	8,229	8,229
Wind	QLD1	0	0	69
Cogeneration	SA1	180	180	180
Gas turbine	SA1	859	859	983
Gas turbine combined cycle	SA1	485	485	485
Hydro	SA1	0	0	0
Pump	SA1	0	0	0
Steam turbine	SA1	2,041	2,041	2,041
Wind	SA1	798	815	939
Cogeneration	TAS1	0	0	0
Gas turbine	TAS1	163	163	163
Gas turbine combined cycle	TAS1	200	200	200
Hydro	TAS1	2,157	2,157	2,157
Pump	TAS1	0	0	0
Steam turbine	TAS1	0	0	0
Wind	TAS1	0	0	179
Cogeneration	VIC1	0	0	0
Gas turbine	VIC1	1,963	1,963	2,213
Gas turbine combined cycle	VIC1	0	0	0
Hydro	VIC1	2,169	2,169	2,169
Pump	VIC1	0	0	0
Wind	VIC1	35	366	731
Cogeneration	NEM	356	356	356
Gas turbine	NEM	6,363	6,363	7,011
Gas turbine combined cycle	NEM	2,490	2,490	2,490
Hydro	NEM	8,132	8,132	8,132
Pump	NEM	60	60	60
Steam turbine	NEM	29,666	29,566	29,416
Wind	NEM	977	1,368	2,104

Data source: ACIL Tasman

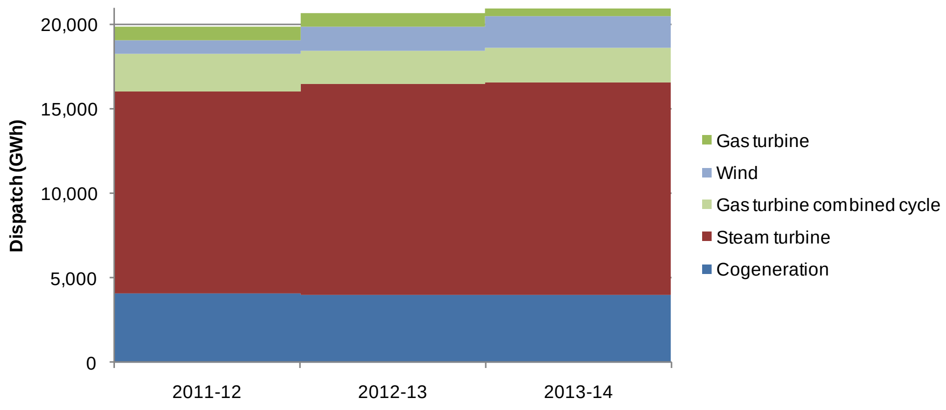
ACIL Tasman's *PowerMark* modelling of the NEM and WEM in the No Carbon scenario shows that the majority of the generation in both regions is based on coal (steam turbines). This can be seen in Figure 58 and Figure 59.

Figure 58 **Dispatch by generation type (GWh) – No Carbon scenario NEM**



Data source: PowerMark

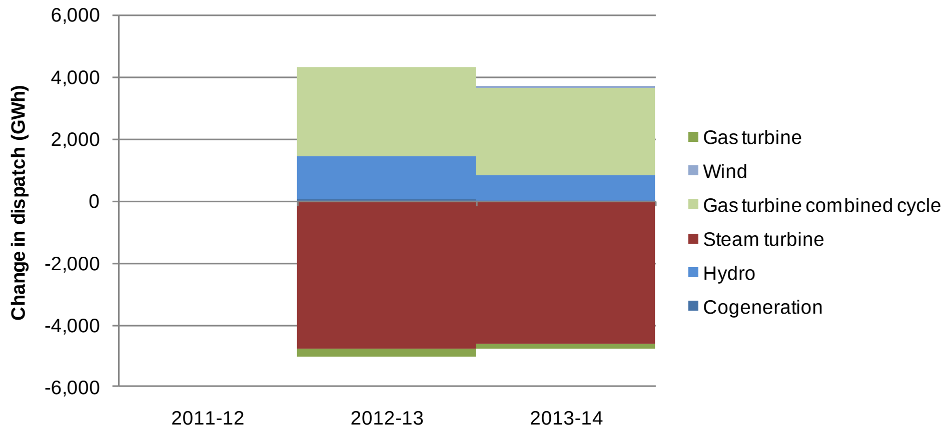
Figure 59 **Dispatch by generation type (GWh) – No Carbon scenario WEM**



Data source: PowerMark

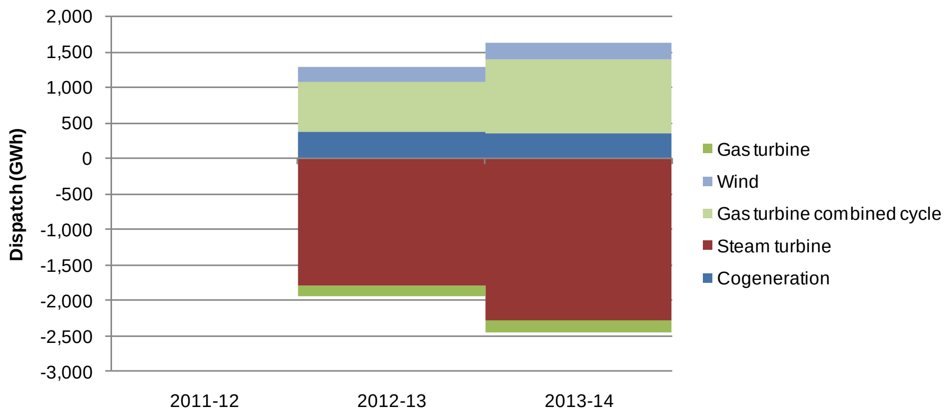
Figure 60 and Figure 61 shows the change in dispatch, comparing the No Carbon to the Carbon scenario. It can be seen that as a result of introducing the carbon tax the coal-based dispatch reduces in both the NEM and WEM. The reduction in coal based generation is only 2.6% in the NEM. In contrast, in the WEM the reduction is much higher – around 20% - due to high coal costs. In both regions the main generation type replacement is CCGT as the technology becomes more competitive due to its lower emissions intensity. In the WEM some of the reduction in coal generation gets also offset by an increase in wind generation, with around 50 MW of extra wind generation installed in the Carbon scenario. In NEM the wind capacity installed remains roughly the same across the two scenarios.

Figure 60 **Change in dispatch by generation type – between No Carbon and Carbon scenario – NEM**



Data source: PowerMark

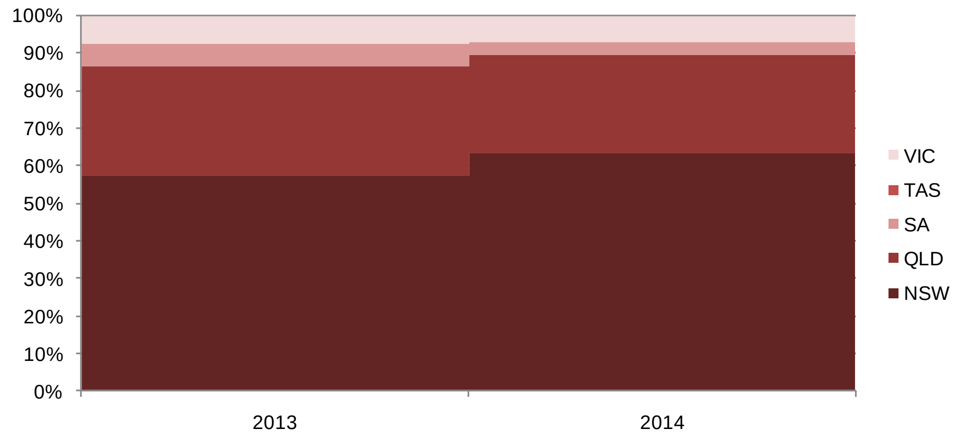
Figure 61 **Change in dispatch by generation type – between No Carbon and Carbon scenarios – WEM**



Data source: PowerMark

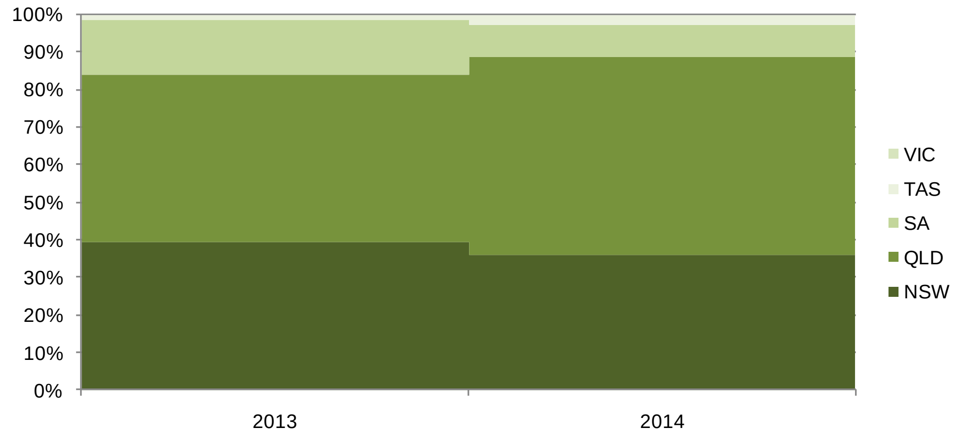
In the NEM, NSW and Queensland coal based generators are most affected by the introduction of carbon pricing, as they make up the majority of the coal based generation reduction (see Figure 62). As outlined above, the coal based generation reduction is offset by increases in gas based generation, with NSW and Queensland accounting for the majority of this increase (see Figure 63). A feature of the modelling is the low response to the carbon price in Victoria. This highlights the cost competitiveness of brown coal against any other generation technology despite its relatively high emission intensity. A side effect of this competitive advantage of brown coal is the increase in exports of relatively higher carbon intensive energy from Victoria to NSW (see Table 44).

Figure 62 **Change in steam turbine dispatch by state – between No Carbon and Carbon scenarios**



Data source: PowerMark

Figure 63 **Change in CCGT dispatch by state – between No Carbon and Carbon scenarios**



Data source: PowerMark

Table 44 **Interconnector flows (GWh)**

Year ending June	Exports Basslink	Exports Heywood	Exports Murraylink	Exports QNI	Exports Terranora	Exports Vic to NSW	Imports Basslink	Imports Heywood	Imports Murraylink	Imports QNI	Imports Terranora	Imports Vic to NSW
No Carbon												
2012	215	1,660	265	104	21	2,540	1,088	371	241	5,378	724	1,594
2013	386	1,689	265	102	26	2,620	452	386	238	5,843	756	1,710
2014	484	1,834	327	189	44	2,952	170	361	227	5,132	670	1,801
Carbon												
2012	215	1,660	265	104	21	2,540	1,088	371	241	5,378	724	1,594
2013	540	1,554	176	64	18	3,198	66	327	250	5,607	710	927
2014	668	1,639	229	110	29	3,496	29	380	255	5,200	658	991
Difference (Carbon - No Carbon)												
2012	0	0	0	0	0	0	0	0	0	0	0	0
2013	154	-135	-89	-39	-8	578	-387	-59	12	-236	-46	-783
2014	184	-195	-98	-78	-15	544	-140	19	28	68	-12	-810

Data source: PowerMark

B PowerMark modelling assumptions

This section sets out the detailed input assumptions used in the two *PowerMark* modelling scenarios, and covers the following areas:

- The carbon reduction target and associated carbon price path used as inputs to the modelling
- Energy and peak demand projections used as inputs to the modelling
- Existing supply including all key operational parameters used in the modelling
- Supply side offer strategies and the treatment of electricity contracts
- Non-renewable new entrant assumptions for the suite of candidate technologies assumed in the modelling
- Interconnector capacity including any likely increase in that capacity over the projection period
- The manner in which the Large-scale Renewable Energy Target (LRET) is modelled in the Carbon and No Carbon scenarios.

B.1 Carbon pricing

On 10 July 2011 the Australian Government released a policy document, *Securing a Clean Energy Future*, which foreshadowed the introduction of a carbon tax commencing on 1 July 2012 at a nominal rate of $23.00 per tonne of CO_2-e emissions to apply to the top 500 emitters in Australia including the coal mining industry. The tax rate is to increase by 2.5 per cent per year in real terms and remain in place until 30 June 2015. From 1 July 2015, the carbon tax is to be replaced by an emissions permit trading scheme.

The policy document was accompanied by a Treasury report, *Strong Growth, Low Pollution*. This report provided some information on an estimated carbon price trajectory out to 2050 and estimated effects of the emissions abatement package. The Treasury report included forecasts of inflation and an index of forecast future export coal prices. Subsequently, more detailed information was released regarding the estimated carbon price trajectory.

Under the medium global action scenario, Treasury has estimated that the international market price in 2015/16 will average around $A29/t CO_2-e in nominal terms and increase at around 5.0 percent per annum in real terms to 2050. The trajectory for the carbon tax and subsequent estimated carbon permit prices in the medium global action scenario are shown below.

It is important to note that the medium global action scenario includes co-ordinated global action to stabilise greenhouse gas concentration levels at 550 parts per million of CO_2-e, and assumes permit trading between countries from 2016.

Table 45 **Carbon price (AUD/tCO_2-e) assumed in the Carbon scenario**

Year ending June	Nominal $/tonne	Real 2011 $/tonne
2013	$23.00	$22.17
2014	$24.15	$22.72
2015	$25.48	$23.29
2016	$29.00	$25.95
2017	$31.18	$27.21
2018	$33.51	$28.54
2019	$36.03	$29.93
2020	$38.73	$31.39
2021	$41.64	$32.93
2022	$44.76	$34.53
2023	$48.12	$36.22
2024	$51.73	$37.99
2025	$55.61	$39.84
2026	$59.78	$41.78
2027	$64.27	$43.82
2028	$69.09	$45.96
2029	$74.27	$48.20
2030	$79.84	$50.56
2031	$85.83	$53.02
2032	$92.27	$55.61
2033	$99.19	$58.32

Data source: Federal Government reports *Securing a Clean Energy Future* and *Strong Growth, Low Pollution*

A price on carbon is expected to affect thermal plant in two major ways:

- The carbon prices will reduce the competitiveness of less efficient/higher carbon emitting thermal plant which will lead to a reduction in dispatch of the plant as other more efficient/lower carbon emitting plant enter the market
- The net revenues of the less efficient/higher carbon emitting thermal plant will fall because of reduced margins (higher SRMC due to cost of carbon) and lower levels of dispatch.

B.2 NEM assumptions

B.2.1 Demand projections and load profiles

We have used as a starting point for the demand projection, the official projection of regional summer and winter peak demands and annual energy published on 30 June 2011 by the jurisdictional Transmission Network Service Providers (TransGrid in NSW, PowerLink in Queensland, Transend in Tasmania) and AEMO for South Australia and Victoria, in the 2011 Annual Planning Reviews (APRs). The projections in the APRs are usually adopted by

AEMO in the forthcoming Electricity Statement of Opportunities (ESOO) - which will be published in September 2011.

The load forecast is based on the medium growth outlook and peak summer and winter peak demands are the 50% POE level. All load forecast data is on an "as generated" basis.

The Queensland load forecast in the PowerLink APR includes an allowance for the coal seam gas (CSG) pumping and compression and associated loads load in Queensland commencing in 2012/13 and increasing to around 800MW by 2015/16.

The energy and load projections used as a basis in the two scenarios are the "medium" energy and "50% probability of exceedence" peak demands. The energy forecast is related to a set of underlying GDP growth assumptions – put simply, the energy forecast used in the scenarios assumes the most likely economic growth conditions in each region of the NEM. The peak load forecast takes into account typical ambient temperature conditions and is developed by each of the regional transmission authorities. These assumptions are implicit within the APR forecasts and are not explicitly available to ACIL Tasman.

Table 46 and Table 47 show the energy and peak loads for all the jurisdictions for the carbon and no-carbons scenario, respectively.

Table 46 **Projected energy (GWh, sent out) and peak load (MW, gross) requirements Carbon scenario – adjusted APRs**

Peak summer MW gross	NSW	Qld	SA	Tas	Vic
2011/12	14,449	9,776	3,180	1,465	10,224
2012/13	14,673	10,371	3,221	1,506	10,551
2013/14	14,952	10,966	3,296	1,529	10,796

Peak winter MW gross	NSW	Qld	SA	Tas	Vic
2011	13,789	8,663	2,516	1,758	8,298
2012	14,000	8,928	2,538	1,786	8,497
2013	14,213	9,377	2,563	1,806	8,643

Energy GWh sent out	NSW	Qld	SA	Tas	Vic	NEM
2011/12	74,249	51,350	13,140	10,138	46,130	195,008
2012/13	75,838	54,334	13,303	10,378	47,257	201,111
2013/14	76,508	57,585	13,593	10,450	48,045	206,181

Note: Includes impact of LRET and a price on carbon as assumed in the carbon scenario.
Data source: 2011 APRs and ACIL Tasman analysis.

Table 47 **Projected energy (GWh, sent out) and peak load (MW, gross) requirements No Carbon – adjusted APRs**

Peak summer MW gross	NSW	Qld	SA	Tas	Vic
2011/12	14,449	9,776	3,180	1,465	10,224
2012/13	14,688	10,377	3,224	1,506	10,566
2013/14	14,984	10,980	3,302	1,529	10,820

Peak winter MW gross	NSW	Qld	SA	Tas	Vic
2011	13,789	8,663	2,516	1,758	8,298
2012	14,015	8,933	2,540	1,786	8,509
2013	14,244	9,389	2,568	1,807	8,662

Energy GWh sent out	NSW	Qld	SA	Tas	Vic	NEM
2011/12	74,249	51,350	13,140	10,138	46,130	195,008
2012/13	75,995	54,401	13,327	10,382	47,389	201,495
2013/14	76,836	57,732	13,644	10,458	48,256	206,926

Note: Includes impact of LRET and adjustment for the removal of the carbon price.
Data source: 2011 APRs and ACIL Tasman analysis.

ACIL Tasman's *PowerMark* model simulates the NEM on an hourly basis (that is, it uses hourly settlement periods) – therefore, a set of hourly loads for each region is required for each year of the projection.

PowerMark is capable of simulating the market on a half-hourly basis and therefore the process described below creates a set of standard half hourly loads. However, for the scenarios, the first half hour of each hour is modelled. Our experience is that modelling on a half hourly basis is not warranted for a 10+-year scenario type projection – the slight increase in data richness is not worth the cost of the doubling of model run time. Typically, *PowerMark* is run on a half-hourly basis for more detailed, short-term analysis (such as assessing the impact on revenue of a unit outage for insurance purposes).

It is possible to use the set of actual hourly loads for any of the past recent years and then grow this set of loads to a set of winter/summer peak demand and annual energy parameters. However, it is well recognised that load is affected by weather and therefore the risk of using this approach is the assumption that the weather of the past few years is typical and will continue into the future.

Instead of making this assumption, the approach used in creating a set of hourly loads attempts to remove atypical weather effects to produce a load profile that could be expected given a typical weather pattern.

The simulated hourly load profile for each region is based on actual half-hour generated load observations for the four years 2005/06 to 2008/09 and temperature and humidity data for 1970/71 to 2008/09.

A summary of the process used to create a standard set of hourly loads is described in the Box 1.

Box 1 **Process for constructing a standard set of hourly loads**

Step 1 - The actual hourly loads from 2005/2006 to 2008/09 are grown to 2008/09 levels by modelling a general level of growth across the four years on a quarterly basis. This has the outcome of accounting for economic growth over the four years but does not remove the impact of weather on the loads. In a sense, four sets of loads are produced for 2008/09 accounting for each of the annual weather patterns of the past four years.

Step 2 – At the completion of Step 1, there exists 39 years worth of weather data and 4 years worth of load data, which overlap in terms of time. The purpose of Step 2 is to create 39 sets of load data – one for each of the 39 'weather years'. The hourly load profile for each day for each weather year is selected from the four load data years with the closest matching temperature conditions (as well as accounting for day type and season). This is achieved by finding the closest least squares match between the temperature profile for that day and the temperature profile for a day in one of the four load data years.

Step 3 – At the completion of Step 2, there exists 39 sets of annual hourly load data. Each set differs and this difference is directly related to the weather conditions associated with each set. The purpose of Step 3 is to create a single representative combination of the 39 sets of loads – referred to as the 'standard year of loads'. If there existed only one region then an approach to ensure that the standard year of loads represented the 39 sets of loads would be to choose the median set of hourly loads for each day of the year. However, because there a multiple regions and we wish to preserve the correlation between regional loads another approach is required. This is achieved by randomly choosing one of the 39 load sets for each day of the standard year.

Step 4 – At the completion of Step 3, there exists, for each region, a single set of hourly load data – representing the standard year of loads. Given that a random number generator is used to construct this set of loads there is no guarantee that the resulting set of loads is indeed representative of the 39 sets. Therefore, the purpose of Step 4 is to ensure that the standard year of loads is representative. This is done using a number of summary statistics and graphs.

Step 3 and 4 are repeated until a reasonably representative set of loads is selected.

The standard year of simulated hourly loads is then scaled for each year of the projection based on the projected winter and summer peak demands and annual energy. Technically, a non-linear transformation method is used to ensure all hourly data conform to both the annual energy and the winter and summer peak loads.

The outcome of this process is a set of loads that could be expected given typical weather conditions. In other words, the short-term stochastic influences of weather on load have been removed. This is an important step in the scenario development process - as variation in load profile due to weather does have a significant impact on the projection results.

This matching approach removes the often contentious obstacle of attempting to derive mathematical formulas to quantify the relationship between load and temperature.

B.2.2 Generator assumptions

When taken together with the electricity demand forecast, the assumptions regarding plant additions and retirements will determine the supply-demand balance and are critical to the modelling results.

Existing and committed plant

Table 48 below outlines the committed or advanced withdrawals and additions of plant assumed in the two scenarios.

In NSW:

- Nearly 1,500MW of peaking plant was commissioned in 2009 in the form of Uranquinty and Colongra. It is recognised that Uranquinty has limited gas supplies, at least in the early years of the projection. Attention is given to Uranquinty's running regime to ensure that it is consistent with this gas supply.
- Previously announced expansion plans to Mt Piper appears to have fallen by the wayside and this expansion is assumed not to occur. However, an expansion is assumed to occur at the Eraring coal fired station during 2010/2011, adding 60MW per unit.
- Munmorah is assumed to close in 2014/2015 in accordance with the ESOO projections on the basis of a price for carbon renders the plant uneconomic.
- The Redbank Power Purchase Agreement (PPA) is assumed not to influence the plant operating economics and any decision to close it with the introduction of a price on carbon is made purely on economic grounds.

In Queensland:

- Gladstone is assumed to have the equivalent of one of its six units off-line – Gladstone has been operating on a five unit basis since 2005 to improve the viability of the station by reducing capacity available to the NEM in attempt to increase price outcomes.
- Swanbank B is assumed to close by 2012 as announced by CS Energy in March 2010. Our previous modelling suggested closure of Swanbank B on economic grounds from about 2012/2013 in any case as a result of a price on carbon.
- Darling Downs was commissioned in 2010.
- The Rio Tinto cogeneration facility at Yarwun is assumed to be commissioned by January 2011.

In Victoria:

- Mortlake is assumed to commence in January 2011 with two OCGT units for a total of 550 MW.
- The recent drought conditions mean that Dartmouth had zero output through 2009 and is assumed to recover over three years to full output by end of 2012. Similarly Eildon will have a 20% reduced output in 2010 recovering gradually to full output in 2012.

We have assumed in the two scenarios that generation from Snowy hydro plant recovers gradually from about 3,800GWh in 2009 to normal output of around 4,600 GWh in 2012.

In South Australia:

- In South Australia, with the assumed exhaustion of the Leigh Creek coal resource in December 2017, we assume that Playford closes, if not earlier due to economics associated with the introduction of a price on carbon. We understand that Alinta will access a deeper seam of coal from 2018 onwards which is not suitable for Playford. Northern will continue to operate on this new seam, which has 25% higher mining costs and a lower heat content which is reflected in the delivered coal price to Northern from 2018 onwards.

In Tasmania water storage levels at Hydro Tasmania fell to about 18 percent capacity early in 2009. The low water storage levels resulted in Hydro Tasmania importing power through Basslink to meet existing demand. However heavy winter rains in 2009 returned storage levels to around 40% and similarly in 2010 winter rains have resulted in a current storage level at around 36%. We assume that generation volumes from Hydro Tasmania return to normal levels from 2012 onwards.

The key changes to committed new investment largely relate to wind farms which have recently reached financial close, as shown in the table below for NSW, SA and Victoria.

Table 48 **Near-term additions to and withdrawals from generation capacity, by region – all scenarios**

Portfolio	Generator	Type	Nameplate capacity (MW)	Date-on	Date-off
			Victoria		
Origin Energy	Mortlake	OCGT	550	Jan 2011	
AGL	Macarthur	Wind	420	2012-2013	
			New South Wales		
Delta	Munmorah	Black Coal	-600		Jul 2014
Eraring	Eraring	Black coal	+60MW per unit	2010	
Infigen	Woodlawn	Wind	42	2011	
Eraring	Crookwell 2	Wind	92	2011	
Origin	Gunning	Wind	46.5	Late 2010	
			South Australia		
Infigen	Lake Bonney Stage 3	Wind	39	2010	
Pacific Hydro	Clements Gap	Wind	57	2010	
AGL Energy	Brown Hill - Hallet Stage 4	Wind	132	Late 2010	
AGL Energy	Oaklands Hill	Wind	63	2011	
Roaring 40s	Waterloo	Wind	111	2011	
			Queensland		
CS Energy	Swanbank B	Black coal	-440		April 2012
Rio Tinto	Yarwun	CCGT/Cogen	168	January 2011	

Data source: AEMO 2010 SOO and ACIL Tasman

Fuel prices

Fuel costs are more complex as they escalate at different rates and the escalation, in some cases, is not smooth – reflecting step changes in the demand/supply balance of gas as well as changes (expiry and renewal) in coal contracts.

Gas costs for existing stations is dependent on a number of factors including:

- Contractual arrangements including pricing, indexation, tenure and take or pay provisions
- Gas field and power station ownership arrangements
- Availability of fuel through spot purchases or valuation on an opportunity cost basis
- Projected prices for new long-term contracts.

As virtually all existing gas plant rely upon long-term gas sales agreements, prices are estimated as the average contract price on a delivered basis. However, as details of contractual arrangements are almost never publicly available, contract prices, volumes and tenures are required to be estimated.

As these existing contracts expire, gas costs for the station transition to reflect the projected 'market' price for gas at that location (i.e. the same price which applies to new entrant plant – discussed in the following section). This will occur at different times for each station, depending upon their contractual positions.

There are two key factors that are likely to affect gas demand on the East Coast of Australia over the next 20 years:

- Increased reliance on gas for power generation with the introduction of a price on carbon.
- Expansion of Liquefied Natural Gas (LNG) production, including proposed development of an East Coast LNG industry based on coal seam gas (CSG).

A key question therefore is the extent to which establishment of an LNG export industry based on Coal Seam Gas (CSG) in Central Queensland might reduce availability of supply for the local market and affect domestic gas prices.

While it has been suggested in some quarters that establishment of LNG exports will "expose the local market to international prices" and thereby see domestic prices move up to full import parity, we consider that to be an unlikely outcome. There is some logic to the notion that large scale LNG will commit to exports significant quantities of low-cost CSG that might otherwise have been made available to the domestic market. However this is, in our view, a simplistic assessment. Large scale development of export LNG projects in Central Queensland would imply a high level of success in demonstrating the scalability of CSG resources and production. It will only come about if technological development allows large areas of gas-bearing coal measures to be brought into commercial production. In such circumstances, there is no obvious reason why producers would not incrementally expand production to service domestic consumers that are profitable to supply. In a sense, the larger the LNG development, the greater the "vote of confidence" in the reliability, competitiveness and scalability of CSG production.

Nevertheless it must be expected that production of the Eastern Australian CSG resource will follow a normal depletion pathway that will see (on average) large, easily accessible and lower cost resources produced first and smaller, less accessible and higher cost resources produced later. In other words, we must expect that production will move generally along a "supply cost curve" that will see costs of production (and therefore the minimum prices required to justify investment in new productive capacity) increasing over time.

Ramp-up gas associated with LNG production is a significant matter for the gas market over the next decade. Under our assumptions, we conclude that the ramp-up gas can be dealt with through a number of mitigating measures. We assume that a number of the gas fired plant absorb the majority of the ramp-up gas in Queensland. For example, a February 2010 press release from Alinta includes information on the tolling deal for Braemar with QGC. In particular the arrangement allows up to 60 TJ/day which is around another 55% of capacity. As Braemar runs between a 25 and 30% capacity factor currently, we would expect this to increase to between 75 and 90% capacity factor for the period 2011 and 2013, which we have included in the model.

Gas prices for base/intermediate load plant are determined either:

- on a cost plus basis for gas fired power stations sited on dedicated resources (e.g. Darling Downs and Condamine)
- from estimated contract prices where information is available
- from estimated market based nodal prices (GasMark Global projection) incorporating transportation costs when contracts expire or for new entrants sited remotely from gas fields

Where existing power stations contracts expire over time, a blended average of existing contract and estimated market prices is used.

Peaking plant gas prices are set in the same way as the base/intermediate load except that a 50% premium is added to reflect the optional value and intermittent nature of the gas supply. While many peaking plants store distillate as an emergency reserve, we assume that in the normal course of business that this reserve is not used.

Different gas price assumptions are adopted for each of the three scenarios modelled, reflecting expected different patterns of demand (particularly for power generation) under different carbon pricing regimes.

We continue to assume that upon expiry of existing contracts replacement black coal is linked to market-based rates. We assume that power stations are able to negotiate contracts at either a Run of Mine ROM cost plus rate (allowing a return on capital employed in the mine) or 80% of the ROM netback price whichever is the higher. For power stations that are not mine mouth, we include the efficient cost of transportation - either rail or road.

By contrast, the marginal price of coal for the Victorian power stations is generally taken as the cash costs for mining the coal. In the cases where the coal mine is owned by the power station (Yallourn, Hazelwood and Loy Yang A) the short run marginal costs mainly consist of the additional electricity and royalty costs involved in mining the marginal tonne of coal. For Anglesea the marginal cost of coal is taken to be the cost of extraction using trucks and shovels. The marginal price of coal for the two stations that purchase coal from nearby mines (Loy Yang B and Energy Brix) is taken to be the estimated cost per unit of production.

Station assumed fuel costs are set out in Table 49 below. The plant identified commencing with "ZNE_" denotes new entrant plant in the modelling.

Table 49 **Assumed nominal fuel costs ($/GJ) by station by year**

Region	Generator	Fuel	2011-12	2012-13	2013-14
NSW1	Bayswater	Black coal	$1.53	$1.58	$1.56
NSW1	Eraring	Black coal	$1.94	$2.24	$2.38
NSW1	Liddell	Black coal	$1.53	$1.58	$1.56
NSW1	Mt Piper	Black coal	$2.08	$2.17	$2.25
NSW1	Munmorah	Black coal	$2.05	$2.19	$2.52
NSW1	Redbank	Black coal	$1.06	$1.08	$1.11
NSW1	Vales Point B	Black coal	$2.05	$2.19	$2.52
NSW1	Wallerawang C	Black coal	$2.08	$2.17	$2.25
QLD1	Callide B	Black coal	$1.40	$1.43	$1.46
QLD1	Callide C	Black coal	$1.40	$1.43	$1.46
QLD1	Collinsville	Black coal	$2.23	$2.28	$2.33
QLD1	Gladstone	Black coal	$1.66	$1.69	$1.73
QLD1	Kogan Creek	Black coal	$0.79	$0.81	$0.83
QLD1	Millmerran	Black coal	$0.90	$0.92	$0.94
QLD1	Stanwell	Black coal	$1.48	$1.51	$1.55
QLD1	Swanbank B	Black coal	$4.11	$4.02	$3.82
QLD1	Tarong	Black coal	$1.07	$1.09	$1.11
QLD1	Tarong North	Black coal	$1.07	$1.09	$1.11
SA1	Northern	Black coal	$1.56	$1.60	$1.64
SA1	Playford B	Black coal	$1.56	$1.60	$1.64
VIC1	Anglesea	Brown coal	$0.41	$0.42	$0.43
VIC1	Energy Brix	Brown coal	$0.61	$0.63	$0.64
VIC1	Hazelwood	Brown coal	$0.09	$0.09	$0.09
VIC1	Loy Yang A	Brown coal	$0.09	$0.09	$0.09
VIC1	Loy Yang B	Brown coal	$0.38	$0.39	$0.40
VIC1	Yallourn	Brown coal	$0.10	$0.10	$0.10
NSW1	Hunter Valley GT	Liquid Fuel	$31.87	$32.67	$33.49
QLD1	Mackay GT	Liquid Fuel	$31.87	$32.67	$33.49
QLD1	Mt Stuart	Liquid Fuel	$31.87	$32.67	$33.49
SA1	Port Lincoln	Liquid Fuel	$31.87	$32.67	$33.49
SA1	Snuggery	Liquid Fuel	$31.87	$32.67	$33.49
VIC1	Angaston	Liquid Fuel	$31.87	$32.67	$33.49
NSW1	Colongra	Natural gas	$7.00	$7.32	$7.69
NSW1	Smithfield	Natural gas	$4.23	$4.31	$4.39
NSW1	Tallawarra	Natural gas	$3.84	$3.91	$3.99
NSW1	Uranquinty	Natural gas	$6.03	$6.28	$6.56
NSW1	ZNE NSW NE1 CCGT1	Natural gas	$5.60	$5.86	$6.15
NSW1	ZNE NSW NE1 Peaker1	Natural gas	$7.00	$7.32	$7.69
QLD1	Barcaldine	Natural gas	$6.73	$6.84	$6.96
QLD1	Braemar 1	Natural gas	$2.71	$2.76	$2.82
QLD1	Braemar 2	Natural gas	$2.95	$3.01	$3.76

Region	Generator	Fuel	2011-12	2012-13	2013-14
QLD1	Condamine	Natural gas	$1.57	$2.00	$2.46
QLD1	Darling Downs	Natural gas	$3.78	$4.07	$4.39
QLD1	Oakey	Natural gas	$4.28	$4.36	$4.44
QLD1	Roma	Natural gas	$5.07	$5.53	$6.08
QLD1	Swanbank E	Natural gas	$3.53	$3.66	$3.80
QLD1	Townsville	Natural gas	$4.09	$4.16	$4.24
QLD1	Yarwun	Natural gas	$3.64	$3.70	$3.76
QLD1	ZNE Qld NE1 CCGT1	Natural gas	$5.07	$5.53	$6.08
QLD1	ZNE Qld NE1 Peaker1	Natural gas	$6.33	$6.92	$7.59
SA1	Dry Creek	Natural gas	$4.76	$4.85	$6.15
SA1	Hallett	Natural gas	$6.85	$7.24	$7.68
SA1	Ladbroke Grove	Natural gas	$5.39	$5.65	$5.94
SA1	Mintaro	Natural gas	$6.85	$7.24	$7.68
SA1	Osborne	Natural gas	$4.17	$4.25	$4.33
SA1	Pelican Point	Natural gas	$4.02	$4.09	$5.03
SA1	Quarantine	Natural gas	$5.75	$6.03	$6.35
SA1	Torrens Island A	Natural gas	$4.11	$4.19	$4.26
SA1	Torrens Island B	Natural gas	$4.11	$4.19	$4.26
SA1	ZNE SA NE1 CCGT1	Natural gas	$5.39	$5.65	$5.94
SA1	ZNE SA NE1 Peaker1	Natural gas	$6.74	$7.06	$7.43
TAS1	Bell Bay	Natural gas	$6.24	$6.50	$6.80
TAS1	Bell Bay Three	Natural gas	$6.24	$6.50	$6.80
TAS1	Tamar Valley	Natural gas	$4.99	$5.20	$5.44
TAS1	Tamar Valley GT	Natural gas	$6.24	$6.50	$6.80
TAS1	ZNE TASNE1CCGT1	Natural gas	$4.99	$5.20	$5.44
VIC1	Bairnsdale	Natural gas	$4.44	$4.55	$5.79
VIC1	Jeeralang A	Natural gas	$4.02	$5.13	$6.37
VIC1	Jeeralang B	Natural gas	$4.02	$5.13	$6.37
VIC1	Laverton North	Natural gas	$4.26	$5.37	$6.61
VIC1	Mortlake	Natural gas	$5.31	$5.61	$5.95
VIC1	Newport	Natural gas	$4.23	$5.34	$6.58
VIC1	Somerton	Natural gas	$4.26	$5.38	$6.62
VIC1	Valley Power	Natural gas	$4.02	$5.13	$6.36
VIC1	ZNE Vic NE1 CCGT1	Natural gas	$4.15	$4.34	$4.56
VIC1	ZNE Vic NE1 Peaker1	Natural gas	$5.19	$5.43	$5.70

Note: These values are applied to the HHV heat rates to give a fuel cost in $/MWh within *PowerMark*.
Data source: *ACIL Tasman*

Short run marginal costs

Table 50 summarises the nominal SRMC for each station assumed in the Carbon case.

Table 50 **Station nominal SRMC ($/MWh) for existing or committed plant and generic new entrants**

	No Carbon Scenario	Carbon Scenario

		2011-12	2012-13	2013-14	2011-12	2012-13	2013-14
NSW1	Bayswater	$16.5	$17.1	$16.8	$16.5	$40.0	$41.2
NSW1	Bendeela Pumps	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
NSW1	Blowering	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
NSW1	Colongra	$88.0	$91.8	$96.2	$88.0	$109.8	$115.2
NSW1	Crookwell 2 WF	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
NSW1	Eraring	$20.9	$24.0	$25.4	$20.9	$47.1	$49.9
NSW1	Gunning WF	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
NSW1	Guthega	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
NSW1	Hume NSW	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
NSW1	Hunter Valley GT	$419.4	$429.9	$440.6	$419.4	$452.2	$464.2
NSW1	Liddell	$17.4	$18.1	$17.8	$17.4	$43.1	$44.3
NSW1	Mt Piper	$21.5	$22.5	$23.3	$21.5	$44.1	$46.2
NSW1	Munmorah	$26.1	$27.8	$31.3	$26.1	$54.6	$59.7
NSW1	Redbank	$14.2	$14.5	$14.8	$14.2	$42.6	$44.5
NSW1	Shoalhaven Bendeela	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
NSW1	Smithfield	$39.5	$40.3	$41.1	$39.5	$53.6	$55.1
NSW1	Tallawarra	$26.7	$27.2	$27.8	$26.7	$40.2	$41.4
NSW1	Tumut 1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
NSW1	Tumut 3	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
NSW1	Tumut 3 Pumps	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
NSW1	Uranquinty	$77.0	$80.0	$83.5	$77.0	$98.0	$102.4
NSW1	Vales Point B	$22.0	$23.5	$26.8	$22.0	$46.7	$51.4
NSW1	Wallerawang C	$23.9	$25.0	$25.9	$23.9	$49.2	$51.5
NSW1	Woodlawn WF	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
NSW1	ZNE NSW NE1 CCGT1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
NSW1	ZNE NSW NE1 Peaker1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
QLD1	Barcaldine	$57.4	$58.9	$61.4	$57.4	$75.8	$77.6
QLD1	Barron Gorge	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
QLD1	Braemar 1	$35.1	$36.3	$38.5	$35.1	$57.0	$58.8
QLD1	Braemar 2	$36.8	$38.1	$48.7	$36.8	$60.0	$70.1
QLD1	Callide B	$15.1	$15.4	$15.8	$15.1	$37.8	$39.5
QLD1	Callide C	$15.7	$16.1	$16.4	$15.7	$38.2	$39.9
QLD1	Collinsville	$30.2	$30.9	$31.6	$30.2	$58.4	$60.7
QLD1	Condamine	$7.4	$11.1	$15.9	$7.4	$25.4	$29.3
QLD1	Darling Downs	$25.5	$28.2	$32.0	$25.5	$42.6	$45.7
QLD1	Gladstone	$18.1	$18.5	$18.9	$18.1	$40.8	$42.5
QLD1	Kareeya	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
QLD1	Kogan Creek	$8.8	$9.1	$9.3	$8.8	$30.4	$31.9
QLD1	Mackay GT	$418.8	$429.3	$440.0	$418.8	$451.6	$463.6
QLD1	Millmerran	$11.6	$11.9	$12.2	$11.6	$33.1	$34.6
QLD1	Mt Stuart	$391.5	$401.3	$411.3	$391.5	$422.1	$433.4
QLD1	Oakey	$51.5	$53.0	$55.5	$51.5	$72.5	$74.4
QLD1	Roma	$65.0	$71.2	$79.3	$65.0	$92.0	$99.7
QLD1	Stanwell	$17.8	$18.2	$18.7	$17.8	$39.4	$41.1
QLD1	Swanbank B	$49.6	$0.0	$0.0	$49.6	$0.0	$0.0
QLD1	Swanbank E	$22.5	$23.9	$26.5	$22.5	$39.2	$40.9
QLD1	Tarong	$18.1	$18.5	$18.9	$18.1	$40.2	$41.9
QLD1	Tarong North	$10.9	$11.1	$11.4	$10.9	$31.5	$32.9
QLD1	Townsville	$27.3	$28.3	$30.4	$27.3	$43.9	$45.1
QLD1	Wivenhoe	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
QLD1	Wivenhoe Pump	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
QLD1	Yarwun	$31.7	$32.7	$34.7	$31.7	$53.1	$54.5
QLD1	ZNE Qld NE1 CCGT1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
QLD1	ZNE Qld NE4 Peaker1	$0.0	$0.0	$90.8	$0.0	$0.0	$108.8
SA1	Bluff WF	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
SA1	Clements Gap WF	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0

		No Carbon Scenario			Carbon Scenario		
		2011-12	2012-13	2013-14	2011-12	2012-13	2013-14
SA1	Dry Creek	$75.6	$77.0	$95.2	$75.6	$99.4	$118.9
SA1	Hallett	$112.4	$118.4	$125.2	$112.4	$142.7	$150.9
SA1	Hallett 2 WF	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
SA1	Hallett WF	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
SA1	Ladbroke Grove	$68.3	$71.4	$75.1	$68.3	$90.9	$95.6
SA1	Lake Bonney 2 WF	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
SA1	Lake Bonney 3 WF	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
SA1	Mintaro	$97.7	$102.9	$108.8	$97.7	$123.7	$130.8
SA1	North Brown Hill WF	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
SA1	Northern	$17.3	$17.7	$18.2	$17.3	$39.7	$41.4
SA1	Osborne	$40.9	$41.6	$42.4	$40.9	$55.5	$57.1
SA1	Pelican Point	$31.2	$31.8	$38.8	$31.2	$43.9	$51.6
SA1	Playford B	$28.6	$29.4	$30.1	$28.6	$64.4	$67.1
SA1	Port Lincoln	$450.9	$462.2	$473.7	$450.9	$485.6	$498.6
SA1	Quarantine	$73.6	$77.0	$80.9	$73.6	$95.9	$100.8
SA1	Snowtown WF	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
SA1	Snuggery	$450.9	$462.2	$473.7	$450.9	$485.6	$498.6
SA1	Torrens Island A	$51.6	$52.6	$53.5	$51.6	$72.0	$74.1
SA1	Torrens Island B	$48.5	$49.4	$50.3	$48.5	$67.6	$69.6
SA1	Waterloo WF	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
SA1	ZNE SA NE1 CCGT1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
SA1	ZNE SA NE2 Peaker1	$0.0	$0.0	$91.0	$0.0	$0.0	$110.5
TAS1	Bastyan	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
TAS1	Bell Bay	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
TAS1	Bell Bay Three	$84.3	$87.8	$91.8	$84.3	$105.2	$110.1
TAS1	Cethana	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
TAS1	Devils Gate	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
TAS1	Fisher	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
TAS1	Gordon	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
TAS1	John Butters	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
TAS1	Lake Echo	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
TAS1	Lemonthyme_Wilmot	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
TAS1	Liapootah_Wayatinah	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
TAS1	Mackintosh	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
TAS1	Meadowbank	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
TAS1	Poatina	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
TAS1	Reece	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
TAS1	Tamar Valley	$36.3	$37.9	$39.8	$36.3	$50.0	$52.4
TAS1	Tamar Valley GT	$89.8	$93.4	$97.6	$89.8	$110.4	$115.6
TAS1	Tarraleah	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
TAS1	Trevallyn	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
TAS1	Tribute	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
TAS1	Tungatinah	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
TAS1	ZNE TASNE1CCGT1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
VIC1	Angaston	$450.9	$462.2	$473.7	$450.9	$485.6	$498.6
VIC1	Anglesea	$6.6	$6.7	$6.9	$6.6	$34.7	$36.5
VIC1	Bairnsdale	$49.3	$50.5	$63.6	$49.3	$64.5	$78.4
VIC1	Dartmouth	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
VIC1	Eildon	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
VIC1	Energy Brix	$11.4	$11.6	$11.9	$11.4	$46.1	$48.4
VIC1	Hazelwood	$2.6	$2.7	$2.7	$2.6	$38.0	$40.1
VIC1	Hume VIC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
VIC1	Jeeralang A	$72.3	$89.9	$109.6	$72.3	$110.6	$131.6
VIC1	Jeeralang B	$72.3	$89.9	$109.6	$72.3	$110.6	$131.6
VIC1	Laverton North	$57.2	$70.5	$85.5	$57.2	$87.3	$103.1

		No Carbon Scenario			Carbon Scenario		
		2011-12	2012-13	2013-14	2011-12	2012-13	2013-14
VIC1	Loy Yang A	$2.3	$2.4	$2.4	$2.3	$30.5	$32.2
VIC1	Loy Yang B	$6.3	$6.4	$6.6	$6.3	$35.2	$37.0
VIC1	Macurthur WF	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
VIC1	McKay	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
VIC1	Mortlake	$66.8	$70.3	$74.4	$66.8	$86.5	$91.4
VIC1	Murray	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
VIC1	Newport	$47.9	$60.0	$73.5	$47.9	$74.3	$88.6
VIC1	Oaklands Hill WF	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
VIC1	Somerton	$73.6	$90.4	$109.3	$73.6	$110.3	$130.3
VIC1	Valley Power	$69.8	$86.6	$105.5	$69.8	$106.5	$126.5
VIC1	West Kiewa	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
VIC1	Yallourn	$2.7	$2.8	$2.8	$2.7	$35.7	$37.6
VIC1	ZNE Vic NE1 CCGT1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
VIC1	ZNE Vic NE2 Peaker1	$0.0	$67.4	$69.3	$0.0	$0.0	$85.9

Note: The SRMCs reported are as at 1 January for the given year. An SRMC of zero indicates the station is not available. The SRMCs for CCGTs in Queensland are reduced by an assumed GEC price prior to a price on carbon; the SRMCs for CCGTs in other regions are reduced by an assumed NGAC price prior to a price on carbon.

Data source: *ACIL Tasman generator database*

Offer strategies

Generation portfolios enter into electricity derivative contracts to hedge pool revenues in order to reduce earnings risk and avoid insolvency. In entering into these contracts generators are indifferent to pool price movements across the volume of these contracts except where the pool price fall below the SRMC. Hence a short term optimal strategy is to offer all generation that is contracted at SRMC. However if all generators contract heavily and then offer all generation that is contracted at a price of SRMC, the pool price will tend to spiral downwards and future contracts will tend to reflect lower pool price expectations. Hence long term optimal strategies require some generation to be bid above SRMC to maintain underlying pool prices and by implication contract prices.

PowerMark provides a range of options with regard to the offer strategy used by each portfolio. Offer strategies include:

- Maximising dispatch, so that each portfolio attempts to maximise its output in each period – typically for price takers
- Maximising net uncontracted revenue – for price makers.

Net pool revenue is dispatch weighted pool revenue in each period less fuel costs. Only uncontracted revenue is maximised as the portfolio is assumed to be indifferent in the short term to the price it receives from the pool for that volume of its dispatch, which is contracted. It will only attempt to maximise its revenue for that proportion of its output, which is not under contract.

In order to avoid the downward price spiral noted above, the contract volume setting in *PowerMark* is not designed to fit exactly with actual contract volumes. Rather it is a setting that allows accurate simulation of the way in which portfolio generators bid in the market – i.e. large portions of volume at SRMC to guarantee a minimum volume with smaller portions of volume at multiples of SRMC to reflect the total cost of supply.

In the scenarios, for the most part, we have assumed the second optimising strategy (as we do in nearly all runs of *PowerMark*) that each portfolio will offer energy in order to attempt to maximise the returns from uncontracted revenue, reflecting an objective of maximising the returns from contracted and uncontracted revenues over the long term.

Hydro plant have very low SRMCs so if *PowerMark* were to 'start' their bid curves at their true SRMC, in a manner similar to a thermal plant, then they would over the course of a year generate well beyond their energy constraints. Instead the model uses the notion of an opportunity cost for the water which attempts to maximise the net revenue of the plant but not break the energy constraint.

PowerMark allows the hydro plant to offer their capacity strategically – that is, they attempt to optimise their net pool revenue but at the same time satisfying their energy (water availability and storage) constraints. As a consequence, the offer curves may vary by season, day of week and time-of-day to reflect the energy constraints and profit maximising behaviour. Rather than using their true SRMC as a starting point, the hydro plant are assigned an opportunity cost which will change year on year depending on the demand/supply balance in the market.

We assume an annual energy constraint equal to the long term annual generation of the plant (which is equal to the long term average inflows).

By contrast, *PowerMark* models the existing wind plant which are classified as semi-scheduled or scheduled by AEMO.

Wind, solar and geothermal plant are assumed to offer their available capacity at a zero price to maximise the chance of dispatch.

Plant availability

PowerMark includes a planned maintenance schedule and a set of random unplanned or forced outages for each generator.

ACIL Tasman assumes an availability of 90% for coal plant, and 92% for CCGT plant. ACIL Tasman assumes a 1.5% forced outage rate for peaking plant. Although peaking plant undergo planned maintenance, we assume that this maintenance is scheduled during the off-peak months when the plant are rarely used. Given these plants typically have annual capacity factors of less than 5%, it appears reasonable to assume that their planned maintenance can be scheduled during periods when there is a very low probability of high priced outcomes in the NEM.

Therefore, ACIL Tasman proposes to use an availability of 98.5% for OCGT plant. Hydro plants are assumed to have an overall availability of 95% per year. Geothermal plants are assumed to have an overall availability of 90% per year.

It is worth noting that the forced outages for some of the older coal plant seem relatively low when compared with newer plant – this is because we have allowed for a larger tranche of planned maintenance for the older plant.

Table 51 summarises the assumed annual forced outage rate by station for the two scenarios.

Table 51 **Annual forced outage rate, by station**

Region	Generator	Fuel	UPO
NSW1	Bayswater	Black coal	3.0%
NSW1	Colongra	Natural gas	1.5%
NSW1	Eraring Power Station 330kv	Black coal	3.0%
NSW1	Eraring Power Station 500kv	Black coal	3.0%
NSW1	Hunter Valley Gas Turbine	Fuel oil	2.5%
NSW1	Liddell	Black coal	3.0%
NSW1	Mt Piper Power Station	Black coal	3.0%
NSW1	Munmorah Power Station	Black coal	7.0%
NSW1	Redbank Power Station	Black coal	4.0%
NSW1	Smithfield Energy Facility	Natural gas	2.5%
NSW1	Tallawarra	Natural gas	3.0%
NSW1	Unranquinty	Natural gas	1.5%
NSW1	Vales Point B Power Station	Black coal	3.0%
NSW1	Wallerawang C Power Station	Black coal	3.0%
QLD1	Barcaldine Power Station	Natural gas	2.5%
QLD1	Braemar	Natural gas	1.5%
QLD1	Braemar_Two	Natural gas	1.5%
QLD1	Callide B Power Station	Black coal	4.0%
QLD1	Callide Power Plant	Black coal	6.0%
QLD1	Collinsville Power Station	Black coal	4.0%
QLD1	Condamine Power Station	Natural gas	1.5%
QLD1	Darling Downs ATR	Natural gas	3.0%
QLD1	Gladstone	Black coal	4.0%
QLD1	Kogan Creek	Black coal	4.0%
QLD1	Mackay Gas Turbine	Fuel oil	1.5%
QLD1	Millmerran Power Plant	Black coal	5.0%
QLD1	Mt Stuart Gas Turbine	Liquid Fuel	2.5%
QLD1	Oakey Power Station	Natural gas	2.0%
QLD1	Roma Gas Turbine Station	Natural gas	3.0%
QLD1	Stanwell Power Station	Black coal	2.5%
QLD1	Swanbank B Power Station	Black coal	7.0%
QLD1	Swanbank E Gas Turbine	Coal seam methane	3.0%
QLD1	Tarong North Power Station	Black coal	3.0%
QLD1	Tarong Power Station	Black coal	3.0%
QLD1	Townsville Power Station	Coal seam methane	3.0%
QLD1	Yarwun Cogen	Natural gas	3.0%
SA1	Angaston	Distillate	1.5%
SA1	Dry Creek Gas Turbine Station	Natural gas	3.0%
SA1	Hallett Power Station	Natural gas	1.5%
SA1	Ladbroke Grove Power Station	Natural gas	3.0%
SA1	Mintaro Gas Turbine Station	Natural gas	1.5%
SA1	Northern Power Station	Black coal	5.0%
SA1	Osborne Power Station	Natural gas	3.0%
SA1	Pelican Point Power Station	Natural gas	3.0%
SA1	Playford B Power Station	Black coal	10.0%
SA1	Port Lincoln Gas Turbine	Distillate	1.5%
SA1	Quarantine Power Station	Natural gas	2.5%
SA1	Snuggery Power Station	Distillate	2.0%
SA1	Torrens Island Power Station A	Natural gas	4.5%
SA1	Torrens Island Power Station B	Natural gas	4.5%
TAS1	Bell Bay	Natural gas	3.0%
TAS1	Bell Bay Three	Natural gas	3.0%
TAS1	Tamar Valley Power Station CCGT1	Natural gas	3.0%
VIC1	Anglesea Power Station	Brown coal	3.0%
VIC1	Bairnsdale Power Station	Natural gas	2.5%
VIC1	Energy Brix Complex	Brown coal	2.5%
VIC1	Hazelwood Power Station	Brown coal	3.5%
VIC1	Jeeralang A Power Station	Natural gas	2.5%
VIC1	Jeeralang B Power Station	Natural gas	2.5%
VIC1	Laverton North Power Station	Natural gas	1.5%
VIC1	Loy Yang A Power Station	Brown coal	3.0%
VIC1	Loy Yang B Power Station	Brown coal	4.0%
VIC1	Mortlake OCGT	Natural gas	1.5%
VIC1	Newport Power Station	Natural gas	2.0%
VIC1	Somerton Power Station	Natural gas	1.5%
VIC1	Valley Power Peaking Facility	Natural gas	1.5%
VIC1	Yallourn W Power Station	Brown coal	4.0%

Data source: ACIL Tasman assumptions

Water-cooled black coal plant are generally assumed to have planned maintenance schedules that equate to about one month every two years.

Air-cooled black coal plant tend to have a schedule that equates to one month every year

The newer brown coal plant tend to have a schedule that equates to one month every four years and the older brown coal plant a schedule that equates to one month every year.

New entrant CCGTs and coal plant are assumed to be off-line one month every four years for planned maintenance.

B.2.3 New entrant generators

Table 52 summarises ACIL Tasman's assumptions for capital costs for 2010 to 2030 in nominal terms.

Table 52 **Projected capital costs by technology (AUD/kW, nominal)**

	2011-12	2012-13	2013-14
CCGT	$1,323	$1,343	$1,356
OCGT	$952	$966	$975
Black coal SC	$2,276	$2,293	$2,323
Brown coal SC	$2,504	$2,522	$2,555
Black coal USC	$2,436	$2,453	$2,485
Brown coal USC	$2,679	$2,698	$2,733

Note: Brown coal assumes a third party coal supply and hence the above values exclude mining costs.

Data source: ACIL Tasman analysis

The discount factor (or WACC) used in the modelling, 6.81% post-tax real, is derived using the components shown in the table below.

Table 53 **WACC parameters**

	Parameter	Value
D+E	Liabilities	100%
D	Debt	60%
E	Equity	40%
rf	Risk free RoR	6.00%
MRP = (rm-rf)	Market risk premium	6.00%
rm	Market RoR	12.00%
T	Corporate tax rate	30%
Te	Effective tax rate	22.50%
Tc	Imputation adjusted tax	15.00%
	Debt basis point premium	200
rd	Cost of debt	8.00%
G	Gamma	0.5
ba	Asset Beta	0.8
bd	Debt Beta	0.16
be	Equity Beta	1.75
re	Required return on equity	16.50%
F	Inflation	2.50%
	Post tax real WACC (Officer)	6.81%

Data source: ACIL Tasman and various sources

For the purpose of calculating the long run marginal cost of a new plant a project life of 30 years has been assumed. The build time assumed for each type of technology is shown in the table below.

Table 54 **Construction profile (% of project capital cost)**

Technology	Year -4	Year -3	Year -2	Year -1
CCGT	0%	0%	40%	60%
OCGT	0%	0%	0%	100%
SC - black coal	10%	20%	35%	35%
SC - brown coal	10%	20%	35%	35%
USC - black coal	10%	20%	35%	35%
USC - brown coal	10%	20%	35%	35%

Data source: ACIL Tasman analysis of various sources

Fixed O&M costs include maintenance, operating, and overhead costs that are not dependent on the hour-by-hour level of generation from the station.

These estimates are presented as a cost per MW of installed capacity (not sent-out capacity).

Table 55 **Estimated fixed O&M cost in 2010 and escalation rate**

Technology	AUD$/MW/year (real 2010 $)	Escalation rate (% of CPI)
CCGT	$31,775	100%
OCGT	$13,325	100%
SC - black coal	$49,200	100%
SC - brown coal	$56,375	100%

USC - black coal	$49,200	100%
USC - brown coal	$56,375	100%

Data source: ACIL Tasman analysis

ACIL Tasman's assumptions of variable O&M costs are provided in the table below. Note that these estimates are presented as a cost per MWh sent-out.

Table 56 **Variable O&M cost (sent-out) in 2010 and escalation rate**

Technology	AUD$/MW/year (real 2010 $)	Escalation rate (% of CPI)
CCGT	$1.08	100%
OCGT	$7.69	100%
SC - black coal	$1.23	100%
SC - brown coal	$1.23	100%
USC - black coal	$1.23	100%
USC - brown coal	$1.23	100%

Data source: ACIL Tasman analysis

ACIL Tasman has utilised its *RECMark* model to examine the outlook for renewable generation developments in response to the Large-scale Renewable Energy Target (LRET).

This has been undertaken using the black energy prices from the *PowerMark* modelling in order to provide an internally consistent outlook for both renewable and fossil fuel generation.

Details of *RECMark* modeling assumptions, including renewable new entrant costs, are provided in Appendix C below.

B.2.4 Interconnectors

Interconnectors can either be a source of lower priced electricity coming into a region, or a means to export surplus capacity. A summary of the interconnectors and interconnector expansion assumed in the scenarios is shown in Table 57.

Interregional interconnection capacity assumed in the scenarios takes into account limitations of the transmission system. For this reason, the assumed interconnector capacities may well be less than the capacity of the physical interconnectors. For example, the total of the physical interconnector capacity between NSW and Queensland is about 1,000MW – but the location of the interconnectors and the constraints of the NSW grid limits the flow of generation from the Hunter Valley region in NSW to Queensland such that the effective capacity of the NSW to Queensland interconnection is about 500MW, reducing even further during peak and shoulder periods.

Murraylink and Directlink have been granted regulated status and we include this assumption in the projections.

Basslink is set in *PowerMark* as an entrepreneurial interconnector linking Tasmania to Victoria. Basslink is operated by Hydro Tasmania, who is paying a form of toll charge. It is therefore bid in a way that attempts to maximise the net revenue of the Hydro Tasmania assets but at the same time accounting for the energy constrained capacity in Tasmania.

Table 57 **Assumed total interconnection capacity (MW)**

From	To	Capacity (MW)
NSW	Vic	1300
Vic	NSW	1500
Vic	SA	400
SA	Vic	300
Vic – ML	SA - ML	220
SA - ML	VIC – ML	120 (Off-Peak); 30 (Peak - Summer); 70 (Peak - Winter)
Vic	Tas	478
Tas	Vic	594
NSW	Qld	550 (Off-peak); 400 (Peak/Shoulder) April to November, 250 (Peak/Shoulder) December to March
Qld	NSW	1078
NSW - DL	Qld - DL	135 (Peak – Summer); 175 (Off-peak - Summer); 145 (Peak – Winter); 180 (Off-peak - Winter)
Qld - DL	NSW - DL	55 (Peak – Summer); 135 (Off-peak - Summer); 180 (Winter)

Data source: NEMMCO/AEMO with ACIL Tasman amendments

B.3 WEM assumptions

ACIL has utilised its simulation model of the WEM – *PowerMark WA* – to analyse the power price outlook under the alternative scenarios. The modelling simulates the operation of a gross energy spot market, with projected prices representing wholesale energy costs. This approach mimics the outcomes of an efficiently operating STEM and can be interpreted as the projected energy price on the spot market.

The modelling is undertaken at a half-hourly resolution for the period 2011 through to 2030.

B.3.1 Load forecast

Forecasts of annual energy (GWh sent-out) and peak demand (MW sent-out) are important inputs to the modelling. Annual energy is the amount of electricity supplied over the course of a year while peak demand is the highest average electricity load for the year over a half hour period for each year. For the SWIS this is forecast to occur on a hot day in February and driven by air-conditioning.

The modelling has utilised the official forecast of peak demands and annual energy as published in the IMO's 2011 Statement of Opportunities (SOO). The modelling uses annual energy and 50% POE for peak summer demand based on the expected economic growth.

IMO's forecast assumes emissions prices in line with the Commonwealth Government's *Clean Energy Future* policy, commencing in July 2012. The IMO forecasts have been adjusted upwards slightly for the No Carbon scenario to account for the lower electricity prices under this scenario. The 2011 SOO projects energy and demand values to 2020-21.

Table 58 shows the projected annual energy, summer peak demand and average demand for the No Carbon scenario. Table 59 summarises the projections for the Carbon scenario.

Table 58 **Forecast energy and demand for the No Carbon scenario (sent-out basis)**

	Summer peak demand (MW)	Annual minimum demand (MW)	Annual average demand (MW)	Annual energy (GWh)
2011/12	4,181	1,484	2,212	19,377
2012/13	4,410	1,539	2,294	20,099
2013/14	4,576	1,596	2,379	20,839

Note: All values provided on a sent-out basis.

Data source: ACIL Tasman, 2011Statement of Opportunities

Table 59 **Forecast energy and demand for the Carbon scenario (sent-out basis)**

	Summer peak demand (MW)	Annual minimum demand (MW)	Annual average demand (MW)	Annual energy (GWh)
2011/12	4,181	1,484	2,212	19,377
2012/13	4,340	1,491	2,222	19,468
2013/14	4,487	1,535	2,288	20,040

Note: All values provided on a sent-out basis.

Data source: ACIL Tasman, 2011 Statement of Opportunities

As the *PowerMark* model simulates the SWIS for each half-hour period, it requires a half-hourly load trace covering the projection period. The most recent full year of actual data (calendar year 2009) has been chosen as the load profile for this purpose.

This base year of half hourly loads is scaled for each year of the projection based on the forecast annual peak, average and minimum loads as detailed above. Technically, a non-linear transformation method is used to ensure all hourly data conform to both the annual energy and the summer peak loads.

B.3.2 Generator assumptions

Future capacity to supply electricity during the projection period is dependent on:

- capacity and type of existing generation
- capacity, type and timing of plant retirements
- capacity, type and timing of new plant (new entrants)
- frequency and length of maintenance programmes as well as assumed forced outage rates.

When taken together with the electricity load forecast, the assumptions regarding plant additions and retirements will determine the supply-demand balance.

ACIL Tasman has taken into account information obtained from the market as well as published by the IMO in its SOO when constructing the assumptions regarding the timing of new plant and withdrawal of existing plant.

Table 60 **Generation capacity by generation type (MW) - No Carbon scenario**

		2011-12	2012-13	2013-14
Cogeneration	WEM	592	592	592
Gas turbine	WEM	2,043	2,110	2,212
Gas turbine combined cycle	WEM	547	548	548
Hydro	WEM	0	0	0
Pump	WEM	0	0	0
Steam turbine	WEM	1,889	2,058	2,113
Wind	WEM	247	418	564

Data source: ACIL Tasman *PowerMark* WA database

Table 61 **Generation capacity by generation type (MW) - Carbon scenario**

		2011-12	2012-13	2013-14
Cogeneration	WEM	592	592	592
Gas turbine	WEM	2,043	2,110	2,212
Gas turbine combined cycle	WEM	547	548	548
Hydro	WEM	0	0	0
Pump	WEM	0	0	0
Steam turbine	WEM	1,889	2,058	2,113
Wind	WEM	247	469	619

Data source: ACIL Tasman *PowerMark* WA database

Availability of plant is dependent on a number of factors including age of the plant, maintenance practices, weather and operating conditions. Plant outages in the modelling include major planned maintenance and unplanned outages (forced outages). The planned maintenance programs and forced outage rates have been set in the modelling based on experience and performance of similar plant in the NEM. Planned outages have been timed to ensure all plants are available at peak times.

Table 62 **Average annual outage rates for existing and committed stations**

Station_Name	Availability (% of time)	Planned outage (% of time)	Forced outage (% of time)
Albany	100.0%	0.0%	0.0%
Alcoa Kwinana Cogen	91.0%	5.2%	3.8%
Alcoa Pinjarra Cogen	91.0%	5.2%	3.8%
Alcoa Wagerup Cogen	91.0%	5.2%	3.8%
Bluewaters	92.1%	4.9%	3.0%
BP Cogen	90.9%	4.1%	5.0%
Canning/Melville LFG	95.0%	0.0%	5.0%
Cockburn	85.7%	10.1%	4.2%
Collgar Wind Farm	100.0%	0.0%	0.0%
Collie	88.3%	8.5%	3.2%
Emu downs	100.0%	0.0%	0.0%
Geraldton	85.1%	9.0%	5.9%
Kalgoorlie	90.0%	4.1%	5.9%
Kalgoorlie Nickel	90.1%	4.7%	5.2%
Kemerton	86.1%	7.9%	6.0%
Kwinana A	79.8%	14.8%	5.4%
Kwinana B	79.8%	14.8%	5.4%
Kwinana C	84.9%	9.9%	5.2%
Kwinana GT	84.9%	9.9%	5.2%
Kwinana HEGT	90.7%	4.1%	5.2%
Manjimup Biomass	91.9%	5.5%	2.6%
Muja A&B	91.7%	4.1%	4.2%
Muja C	85.9%	9.9%	4.2%
Muja D	85.2%	9.9%	4.9%
Mungarra	84.9%	9.9%	5.2%
Neerabup Peaker	93.9%	2.2%	3.9%
Newgen Power	96.7%	3.3%	0.0%
Parkeston SCE	89.9%	4.9%	5.2%
Pinjar A B	84.9%	9.9%	5.2%
Pinjar C	84.9%	9.9%	5.2%
Pinjar D	84.9%	9.9%	5.2%
Pinjarra Alinta Cogen	92.0%	4.1%	3.9%
Tiwest Cogen	90.0%	4.1%	5.9%
Wagerup Alinta Peaker	92.0%	4.1%	3.9%
Walkaway	100.0%	0.0%	0.0%
Western Energy Peaker	90.7%	4.1%	5.2%
Worsley	91.1%	4.1%	4.8%
Worsley SWCJV	90.9%	4.1%	5.0%
Worsley_Griffin	90.9%	4.1%	5.0%

Note: Wind farms are not modelled to have outages in the same way as fossil fuel plant are modelled, but rather adhere to a stochastic output profile, governed by an annual capacity factor.

Data source: ACIL Tasman *PowerMark* WA database

Sent-out capacity for units are de-rated for summer in accordance with the following profiles. The derating of plant in *WAPowerMark* reflects the impact on plant capability of varying ambient temperature conditions.

Table 63 **De-rating applied (% of maximum sent-out capacity)**

Profile	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CCGT	12%	12%	11%	9%	7%	0%	0%	0%	7%	7%	9%	11%
COAL	5%	5%	4%	0%	0%	0%	0%	0%	0%	0%	3%	4%
COGEN	5%	5%	4%	0%	0%	0%	0%	0%	0%	0%	3%	4%
OCGT	18%	18%	16%	13%	11%	0%	0%	0%	10%	11%	13%	16%

Data source: ACIL Tasman

Fuel Costs

Table 64 details the assumed fuel prices used within the projection. These prices are specified in nominal $/GJ delivered to the power station.

The fuel costs do not explicitly account for the Minerals Resource Rent Tax (MRRT) or the extension of the PRRT to all petroleum producers. However the impact of changes is not expected to affect fuel prices into local generation to any noticeable degree. The main reasons for this are:

- current fuel supplies are under long term contracts although a number of these contracts have regular price resets.
- prices are not generally linked to production costs but arrived at in a competitive process
- current royalties on coal are around $2.50 per tonne or 5.5% of value which, given the relatively marginal nature of these mines is likely to be more than the MRRT.
- price of coal has generally been set in a competitive environment to compete with gas not based on production costs. However long term contractual arrangement have not allowed coal prices to keep pace with the very rapid increase in gas prices in recent years.
- for off-shore gas (the major source of gas) there is no change as the present PRRT is retained in most cases and in any case domestic gas prices tend to be linked to the LNG net back value of gas rather than the cost of production

Table 64 shows that the coal prices remain noticeably lower than gas prices. The gas prices are expected to remain at relatively high levels being driven by the LNG net-back value and the ever increasing production costs for off-shore facilities. The strong outlook for gas prices is of clear advantage to coal fired generators which are expected to maintain a SRMC advantage over the projection period.

Table 64 **Fuel price series (Nominal $/GJ delivered to station)**

	2011-12	2012-13	2013-14
Alcoa gas price	$6.72	$6.89	$7.07
Alinta - existing contracts	$5.39	$7.74	$10.16
Aviva coal	$1.90	$1.95	$2.01
Coal and gas into Kwinana	$5.97	$6.13	$6.28
Distillate prices	$25.23	$25.48	$25.73
Goldfields existing	$7.69	$10.18	$12.74
Griffin coal	$1.68	$1.72	$1.75
New Gas Goldfields	$14.62	$14.93	$15.24
New Gas Perth	$12.33	$12.59	$12.86
NewGen gas price	$5.16	$5.29	$5.42
Verve - existing contract	$9.66	$9.91	$10.16
Vinalco energy coal price	$2.98	$3.08	$3.20
Wesfarmers coal - new	$2.28	$2.34	$2.41
Wesfarmers/Griffin coal - Exist	$2.28	$2.34	$2.41
Wood waste	$1.11	$1.13	$1.15

Data source: ACIL Tasman

Short run marginal costs

The SRMC of a station is its fuel cost plus variable operation and maintenance (O&M) costs plus emissions costs. These costs, by definition, vary with station output. Thermal efficiencies and variable O&M figures are detailed in Table 61. The thermal efficiency values tabulated are measured as sent-out high heat values (HHV).

Variable O&M costs relate to station consumables (such as water, ash disposal, chemicals etc) and any maintenance related to run-time. It does not include any allowances for periodic maintenance as these are captured within a separate annual fixed O&M figure. For all plant, it is assumed that the O&M costs escalate at the same rate (90%) of CPI. This assumption is based on assumed on-going automation of plant thereby reducing labour requirements.

Aside from the stations' marginal costs the only other factor which affects the relative competitiveness between stations is the Marginal Loss Factor (MLF). The MLFs are used as part of the market clearing mechanism to adjust the offer prices of the generators to take into account average transmission losses to a common reference point on the network, known as the reference node. In the WEM this node is notionally set at Muja. The MLFs for all other nodes on the network have MLFs which are set relative to Muja. Table 65 details the nominal SRMC for selected generation units assumed in the Carbon and No Carbon scenarios. These SRMC figures are inclusive of fuel, variable O&M and emissions costs.

Table 65 **SRMC by unit: CPRS-5 (Nominal $/MWh)**

	Carbon Scenario			No-Carbon Scenario		
	2011-12	2012-13	2013-14	2011-12	2012-13	2013-14
Albany	$1.1	$1.1	$1.1	$1.1	$1.1	$1.1
Alcoa Kwinana Cogen	$60.8	$77.3	$82.7	$60.8	$61.8	$62.9
Alcoa Pinjarra Cogen	$60.8	$77.3	$82.7	$60.8	$61.8	$62.9
Alcoa Wagerup Cogen	$60.8	$77.3	$82.7	$60.8	$61.8	$62.9
Pinjarra Alinta Cogen	$26.9	$41.2	$45.7	$26.9	$27.6	$28.3
Wagerup Alinta Peaker	$301.0	$322.1	$333.7	$301.0	$308.5	$316.3
Walkaway	$1.1	$1.1	$1.1	$1.1	$1.1	$1.1
Bluewaters	$18.8	$40.1	$46.4	$18.8	$19.1	$19.5
Cockburn	$39.1	$49.4	$52.9	$39.1	$39.8	$40.5
Collgar Wind Farm		$1.1	$1.1		$1.1	$1.1
Collie	$24.1	$45.8	$52.4	$24.1	$24.8	$25.4
Emu downs		$1.1	$1.1		$1.1	$1.1
Geraldton	$352.3	$377.0		$352.3	$361.1	
Kemerton	$58.0	$72.7	$77.6	$58.0	$59.1	$60.2
Kwinana C	$44.7	$59.7	$64.6	$44.7	$45.6	$46.6
Kwinana HEGT		$54.7	$58.8		$43.2	$43.9
Muja C	$25.4	$48.4	$55.4	$25.4	$26.1	$26.8
Muja D	$24.8	$47.1	$53.9	$24.8	$25.4	$26.1
Muja A&B			$70.7			$34.1
Mungarra	$66.4	$83.5	$89.3	$66.4	$67.6	$68.8
Newgen Power	$35.4	$45.6	$49.0	$35.4	$36.0	$36.6
Neerabup Peaker	$55.5	$70.9	$76.0	$55.5	$56.4	$57.4
Western Energy Peaker		$150.2	$158.8		$135.7	$140.3
Pinjar A B	$66.4	$83.5	$89.3	$66.4	$67.6	$68.8
Pinjar C	$66.4	$83.5	$89.3	$66.4	$67.6	$68.8
Pinjar D	$66.4	$83.5	$89.3	$66.4	$67.6	$68.8
BP Cogen	$16.2	$30.6	$35.0	$16.2	$16.6	$17.0
Parkeston SCE	$105.3	$122.0	$128.6	$105.3	$107.9	$110.6
Kalgoorlie Nickel	$105.3	$122.0	$128.6	$105.3	$107.9	$110.6
Worsley SWCJV	$26.9	$41.6	$46.3	$26.9	$27.6	$28.3
Tiwest Cogen	$26.9	$42.1	$46.8	$26.9	$27.6	$28.3
Worsley	$28.9	$56.8	$65.2	$28.9	$29.7	$30.5
Kalgoorlie	$310.7	$332.5	$344.5	$310.7	$318.5	$326.5
WIND_Badgingarra			$1.1			$1.1
WIND_Milyeannup			$1.1			
Worsley_Griffin	$16.2	$38.2	$44.7	$16.2	$16.6	$17.0

Note: SRMC is as at January each year. Where a station is not operational (either through retirement or has not yet been constructed) a blank cell is shown. SRMC is presented in dollars of the day and is inclusive of fuel, variable O&M and emissions costs.

Generator offer curves

Generator offer curves are simpler to those in the NEM with a plant offering at no more than short run marginal cost (SRMC) with no competitive bid bands. STEM prices are capped at $336/MWh for gas and coal fired fuel plant and $522/MWh for liquid fuel. The WEM design requires generators to offer all capacity into the STEM at SRMC. This results in a much more predictable spot market relative to the NEM, where there are essentially no regulatory controls imposed upon generator bidding.

The modelled unit offer curve is therefore comprised of two segments:

- Minimum generation level: typically associated with coal plant or cogeneration units, reflecting the lowest level of stable generation before unit decommitment. For coal plant this is normally in the range 40-50% of sent-out capacity, while cogeneration units can typically turn down to around 60% and continue to provide host steam. This quantity is offered at a price level which approximates the STEM floor price (currently –$336/MWh)
- SRMC band: The volume in this band is the residual capacity of the unit and is offered to the market at the unit's SRMC.

B.3.3 New entrant generators

Future capacity to supply electricity over the 20 year projection period is dependent on:

- capacity and type of existing generation
- capacity, type and timing of plant retirements
- capacity, type and timing of new plant (new entrants)
- capacity requirements under the market rules (IMO's reserve capacity)
- frequency and length of maintenance programmes as well as assumed forced outage rates.

In developing the scenarios, ACIL Tasman assumes that the LRMC of new entrants provides a long-term ceiling on wholesale electricity prices (STEM + capacity). The logic of this approach derives from the view that if prices exceed the LRMC of new entrants for any period of time, new investors will be attracted into the market until prices are driven back below the long-term ceiling. These new investors may include electricity retailers induced to build plant of their own if existing generators were to demand contract prices above new entry costs.

The LRMC of new entrants is not used directly within *PowerMark* modelling. However, it is used by ACIL Tasman analysts as a guide as to the timing of base load new entrants in the simulations (as capacity additions assumptions).

In the projection, new base load plant is introduced when the prices (STEM plus capacity) available to new entrants equals or exceeds the LRMC of the lowest cost base load new entrant. When prices are inadequate then the regulated capacity requirement is assumed to be met by new OCGTs.

New entrant technologies examined in this study are:

- Gas-fired open cycle gas turbine (OCGT)
- Gas-fired combined cycle gas turbine (CCGT)
- Gas-fired cogeneration (Cogen)
- Sub-critical coal

Assumptions relating to renewable new entrants are not examined with *PowerMark*. Instead, renewable new entry is taken from outputs of ACIL Tasman's *RECMark* model and used as input into *WA PowerMark* as discussed in Appendix C.

To estimate the new entry life cycle cost, ACIL Tasman uses a discounted cash flow financial model that requires a number of key assumptions which are outlined below. Table 66 details the key cost and performance inputs used for new entrant technologies.

Table 66 **New entrant assumptions for the WEM**

	CCGT	OCGT	Black Coal	Gas Cogen	USC
Capital cost ($/KW)	1,516	1,098	2,614	1,673	3,346
Installed capacity (MW)	240	150	200	160	450
Auxiliary requirements	2.40%	2.00%	7.50%	2.40%	7.50%
Anticipated capacity factor	65%	2%	85%	90%	85%
Thermal efficiency (sent out HHV)	50%	34%	36%	34%	44%
Economic life (years)	30	30	30	30	30
Fixed O&M ($/MW/year)	18,827	11,032	50,430	47,909	52,531
Fixed O&M escalation rate (% of CPI)	100%	100%	100%	100%	100%
Variable O&M ($/MWh)	6.11	9.46	1.51	0	1.51
Variable O&M escalation rate (% of CPI)	100%	100%	100%	100%	100%
Emissions factor (tonnes CO2/GJ fuel)	0.0513	0.0513	0.0931	0.0257	0.0931
Emissions factor (tonnes CO2/MWh sent out)	0.3694	0.5432	0.931	0.2716	0.4929

Note: USC=Ultra-super critical coal; IGCC=integrated gasification combined cycle

Data source: ACIL Tasman

B.3.4 Transmission assumptions

Western Power is currently investigating a number of transmission augmentations and developments to account for forecast load growth over the next 10 years. The developments under consideration are outlined within Western Power's 2009 Annual Planning Review. As Western Power is a regulated monopoly, network expansions are required to pass a Regulatory

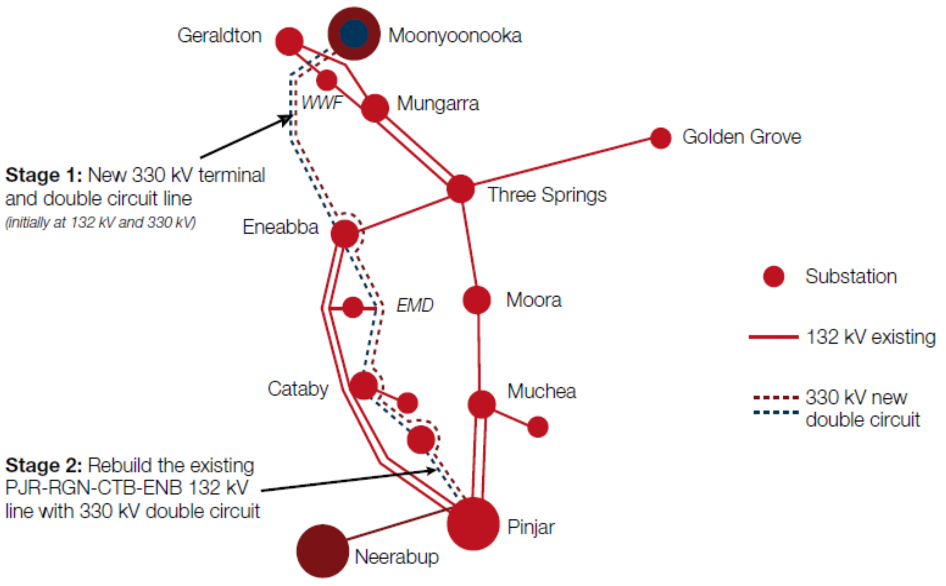
Test before the Economic Regulatory Authority (ERA) will allow these new assets to be rolled into Western Power's asset base.

The most significant upgrade currently under consideration is the Pinjar to Geraldton 300 kV transmission line as shown in Figure 64. This line is required to support a number of new mining loads proposed in the northern part of the SWIS. In addition, the new line will also allow a number of proposed wind farm projects in the north to access sufficient network capacity to facilitate their development.

The modelling, by including some 680MW of new wind farms, effectively assumes that this line will be built. By allowing more wind generation to enter the WEM, STEM prices will be marginally lower with the transmission link than without so the modelling approach could be considered conservative.

Within its modelling ACIL Tasman implicitly assumes this line proceeds and allows the proposed wind farm developments in the North to proceed.

Figure 64 **Pinjar to Geraldton 330 kV transmission line**



Data source: Western Power 2009 Annual Planning Report, p39

Other areas of Western Power's network will become increasingly loaded and will require augmentation over time. Western Power is planning several new bulk receiving terminals and transmission lines which are anticipated to be required to meet load growth over the next 10 years. However, due to the uncertain nature of generation developments and the fact that Western Power has no control over where these projects are located, transmission planning tends to be somewhat reactive.

ACIL Tasman is not aware of any transmission limitation (existing or impending) which would have a negative impact upon STEM prices and therefore do not incorporate any transmission constraints within the SWIS modelling undertaken for this project.

C RECMark modelling assumptions

C.1 *RECMark* modeling assumptions

ACIL Tasman has utilised its *RECMark* model to examine the outlook for renewable generation developments in response to the Large-scale Renewable Energy Target (LRET) policy.

This has been undertaken using the black energy prices projected from ACIL Tasman *PowerMark* modelling for both the NEM and SWIS systems. The following sections provide an overview of the model, the key inputs used in developing the projection and the results.

RECMark utilises a large scale linear programming solver with an objective function to meet the RET in a rational least cost manner. It operates on an inter-temporal least cost basis, under the assumptions of perfect certainty and perfect competition.

The model operates on an annual basis for the period 2010 to 2060. This time horizon extends well beyond the end of the RET scheme (2030) in order to account for the economics of renewable plant beyond the end of the subsidy. The model projects, amongst other things, installation patterns for renewable generators in response to the LRET, and the price of Large-scale Generation Certificates (LGCs) under the scheme. LGCs were previously known as Renewable Energy Certificates, or RECs.

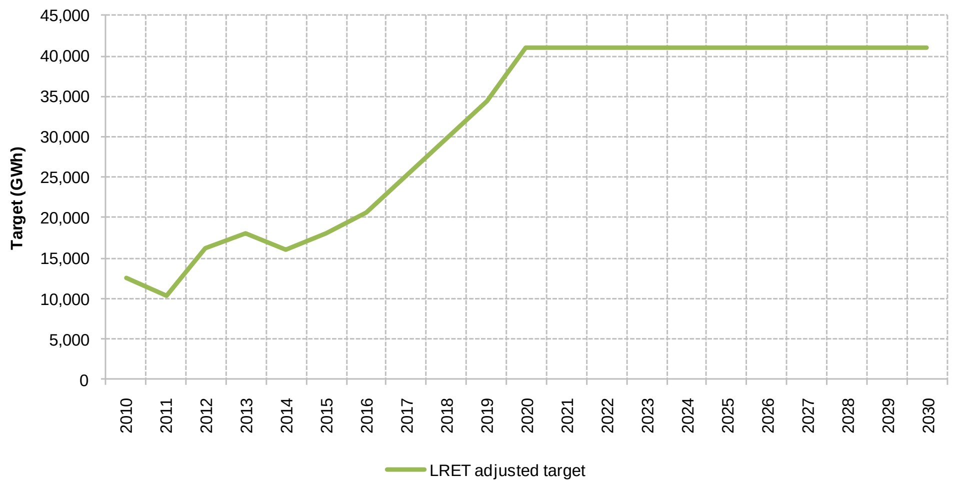
In essence, the model develops new renewable projects on a least cost basis across Australia and projects the marginal REC price required to ensure projects are commercially viable.

C.1.1 Modelling supply and demand of LGCs

LGCs created from existing renewable generators is projected outside of *RECMark* and feed to the model as an input. The projection is based upon historical REC creation, with assumptions made for new projects committed or under construction. Baselines for existing renewable generators are incorporated. Above baseline output (particularly relevant for hydro) is sourced from *PowerMark* modelling.

The demand for RECs/LGCs stem for liable party's obligation to surrender certificates to the ORER, or alternatively, pay a shortfall penalty (see section C.1.2). With the scheme into SRES/LRET, the revised aggregate target under the revised LRET is shown in Figure 65. The split in the scheme has resulted in the target reducing by around 4,000 GWh in all years from 2011 to 2030.

Figure 65 **Large-scale renewable energy target**

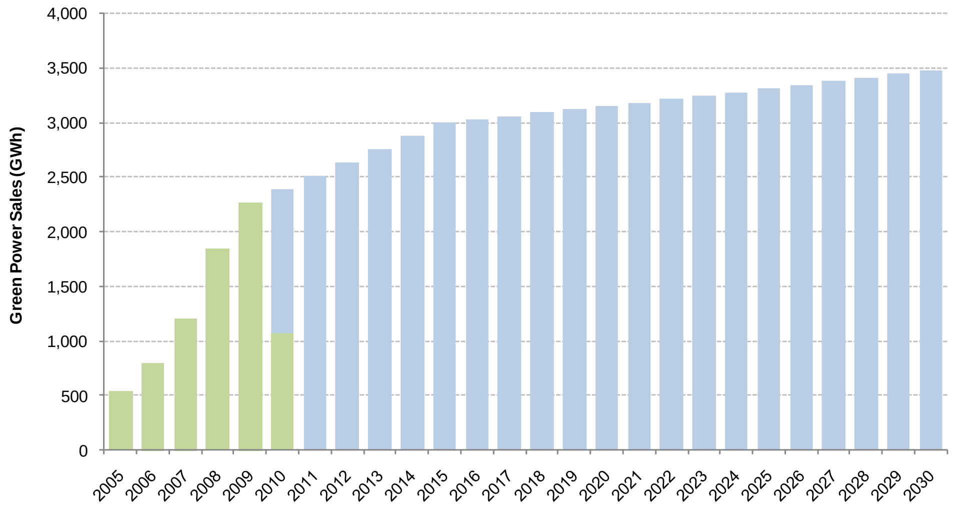


Note: Excludes existing CMM generation
Data source: Department of Climate Change, Enhanced Renewable Energy Target Factsheet, February 2010

In addition to the mandated target retailers also demand renewable energy to acquit their GreenPower sales. LGCs created relating to energy sold as GreenPower must be voluntarily surrendered and therefore effectively adds to the demand for renewable energy.

Figure 66 provides an assumed level of Green Power sales for the period 2010 to 2030.

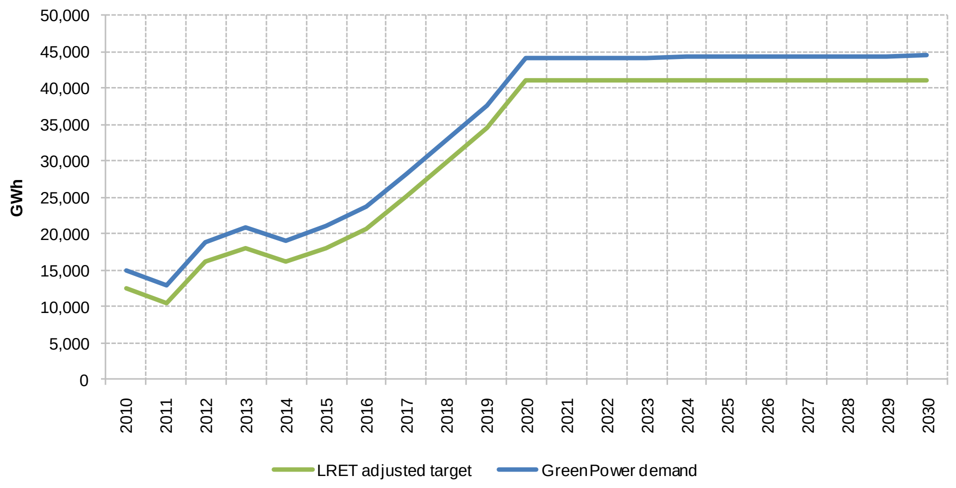
Figure 66 **Projected Green Power sales to 2030**



Note: Actuals to Quarter 2, 2010.
Data source: ACIL Tasman, Green Power audit reports

Figure 67 shows the total LGC demand which is comprised of the mandated target as well as projected GreenPower sales.

Figure 67 **Total LRET demand**



Data source: ACIL Tasman

LGCs are primarily created by large renewable power stations (accredited generators). As the LRET scheme seeks to encourage the development of additional renewable energy, renewable power stations that were in existence prior to the commencement of the original Mandatory Renewable Energy Target (MRET) scheme in 2001 are baselined. The scheme regulator – the Office of the Renewable Energy Regulator (ORER) – determines the baseline, which was generally based on the average amount of electricity generated over the 1994 to 1996 period. Eligible parties can only create RECs for electricity generated above their baseline.In total around 16,600 GWh of existing renewable generation is baselined.

Unlimited banking of permits is allowed. That is, certificates created can be withheld for surrender in later years. There are no restrictions on the amount of certificates which may be banked for future surrender.

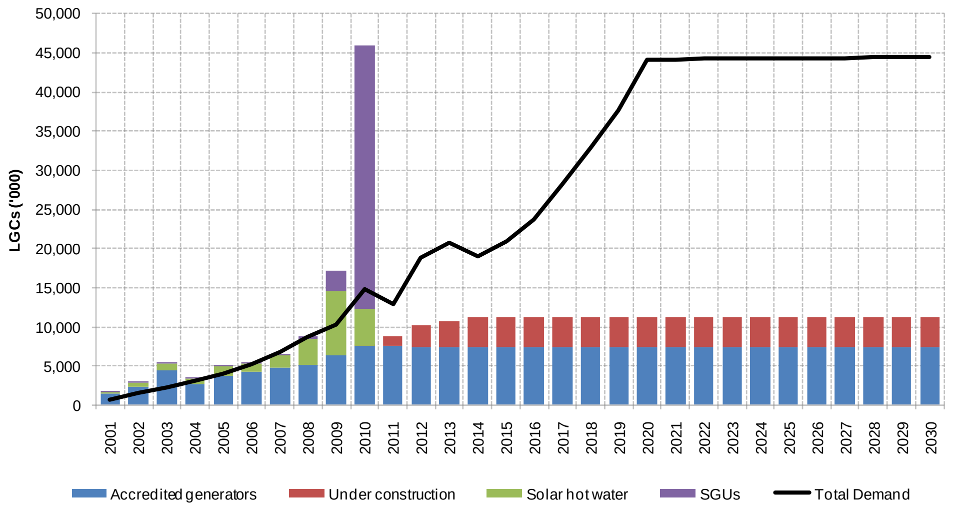
Free borrowing under the scheme is effectively limited to 10% of each liable entities liability as outlined within Section 36(2). This provision is provided because it is often difficult for a retailer to accurately predict what its exact REC liability will be. The 10% provides liable parties some leeway in estimating liabilities.

With the potential to pay penalties and have them refunded in future years (as described in the previous section), there is no effective limit on borrowing (for a rolling 3 year period) under the scheme.

Therefore a liable party may refrain from purchasing high cost certificates to meet a liability in a particular year if it believes it can source significantly cheaper permits within the refund period. A rational liable entity will pay the penalty for any shortfall, and have this refunded once the lower cost certificates became available. The only cost of this strategy appears to be a cost of capital holding cost and potential reputational damage to the firm as any shortfalls are made public.

Figure 68 shows the REC demand against actual and projected contributions from existing generators, small generating units (SGUs) and solar hot water (SHW). The commencement of separate Small-scale Renewable Energy Scheme (SRES) in 2011 removes SGU/SHW from the supply mix. The gap between the assumed output from existing generators and the target from 2011 onwards represents the supply gap *RECMark* attempts to fill on a least cost basis.

Figure 68 **RET and assumed contribution from existing generators and SGU/SHW**



Note: Based on adjusted LRET target plus GreenPower demand. Excludes CMM volumes.
Data source: ACIL Tasman, ORER for historical data

C.1.2 Shortfall penalty

Liable parties under the scheme are required to acquire and surrender RECs or pay a charge of \$65/certificate for any shortfall in LGCs (previously \$40/ certificate under MRET). As penalties paid are not deductible business expenses (they are treated as fines), the effective maximum cost of the penalty is \$92.86/certificate based on a marginal tax rate of 30% (i.e. \$65/(1-30%)).[5]

Importantly, the shortfall penalty is specified as $65/certificate in nominal terms and is not indexed for inflation. Therefore, the effective tax-adjusted penalty faced by firms is $92.86/certificate and declines in real terms.

Based on an inflation assumption of 2.5%, the tax adjusted penalty falls to $56.67/certificate in real terms by 2030 as shown below.

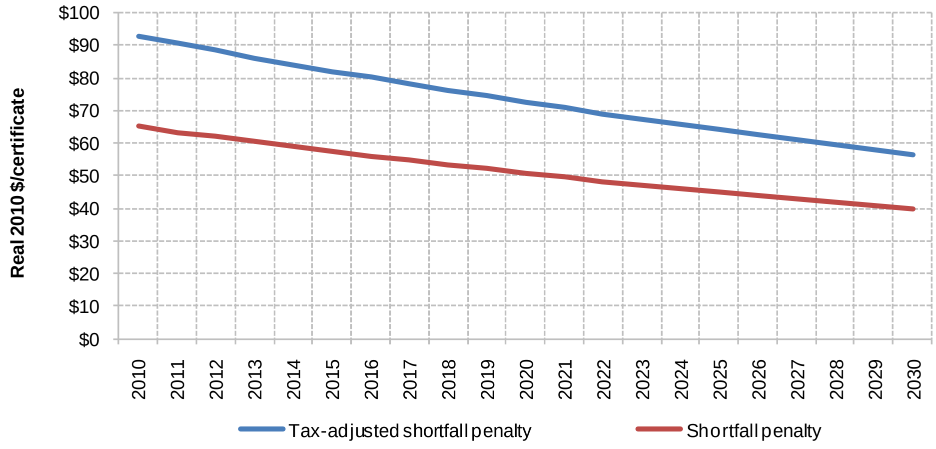
Table 67 **Shortfall penalty in nominal and real terms**

Calendar year	Shortfall penalty (Nominal)	Tax-adjusted shortfall penalty (Nominal)	Shortfall penalty (Real 2010 $)	Tax-adjusted shortfall penalty (Real 2010 $)
2010	$65	$92.86	$65.00	$92.86
2011	$65	$92.86	$63.41	$90.59
2012	$65	$92.86	$61.87	$88.38
2013	$65	$92.86	$60.36	$86.23
2014	$65	$92.86	$58.89	$84.12
2015	$65	$92.86	$57.45	$82.07
2016	$65	$92.86	$56.05	$80.07
2017	$65	$92.86	$54.68	$78.12
2018	$65	$92.86	$53.35	$76.21
2019	$65	$92.86	$52.05	$74.35
2020	$65	$92.86	$50.78	$72.54
2021	$65	$92.86	$49.54	$70.77
2022	$65	$92.86	$48.33	$69.04
2023	$65	$92.86	$47.15	$67.36
2024	$65	$92.86	$46.00	$65.72
2025	$65	$92.86	$44.88	$64.11
2026	$65	$92.86	$43.79	$62.55
2027	$65	$92.86	$42.72	$61.03
2028	$65	$92.86	$41.68	$59.54
2029	$65	$92.86	$40.66	$58.08
2030	$65	$92.86	$39.67	$56.67

Note: Assumed inflation of 2.5%

Data source: ACIL Tasman analysis

Figure 69 **Effective tax-adjusted shortfall penalty in real terms**



Data source: ACIL Tasman

Any shortfall penalties paid by liable parties can be refunded in subsequent years if the required certificates are surrendered. The allowable refund period is three years from the time the entity lodges its renewable energy shortfall statement. Shortfall charges are refunded in full (at the nominal penalty price of $65/LGC) provided the required certificates are surrendered within a 3 year refund period.

C.1.3 Accredited generator new entrant database

ACIL Tasman maintains a comprehensive database of proposed renewable developments and assumed costs. The database comprises of around 230 specific and generic renewable projects across Australia. Projects include:

- Wind (approximately 130 sites comprising of 14,300 MW)
- Small-scale hydro
- Bagasse/biomass
- Geothermal
- Solar: PV, parabolic trough, linear Fresnel, parabolic dish).

Generic renewable costs assumed are presented in Table 68. For remote projects additional costs are assumed for transmission connection to the network.

Table 69 provides the indicative costs for each technology on a short-run and long-run basis.

Table 68 Renewable new entrant assumptions

Technology	Headline Capex ($/kW installed)	Capex incl IDC ($/kW installed)	Implied IDC ($/kW installed)	FOM ($/MW /year)	Economic Life (years)	Annualised equivalent cost ($/kW installed)	Fuel cost ($/GJ)	Capacity factor (%)	Aux (%)	Thermal efficiency (%)
Wind	2,700	3,037	337	30,000	25	359	0.00	35%[1]	0.0%	100%
Solar thermal (Parabolic trough)	5,500	6,334	834	40,000	30	700	0.00	25%	3.0%	100%
Solar thermal (Linear Fresnel)	5,250	6,046	796	40,000	30	670	0.00	22%	3.0%	100%
Solar thermal (Parabolic dish)	8,200	9,443	1,243	40,000	30	1,024	0.00	27%	3.0%	100%
Solar PV	4,000	4,391	391	30,000	30	488	0.00	22%	0.0%	100%
Geothermal HFR	7,000	8,648	1,648	50,000	30	951	0.00	85%	20.0%	100%
Biomass - Landfill gas	3,000	3,374	374	50,000	30	402	0.50	80%	2.0%	40%
Biomass - Bagasse	2,700	3,037	337	50,000	30	366	1.50	40%	2.5%	35%
Biomass - Wood waste	2,800	3,149	349	50,000	30	378	1.50	80%	2.5%	35%
Biomass - Municipal waste	5,000	5,624	624	50,000	30	636	5.00	80%	2.5%	30%
Hydro	2,500	2,980	480	20,000	30	330	0.00	40%	0.0%	100%

Note: 1. Wind capacity factor varies across sites

Data source: ACIL Tasman

Table 69 Indicative SRMC and LRMC for renewable technologies

Technology	SRMC ($/MWh sent-out)	Indicative LRMC ($/MWh sent-out)
Wind[1]	0.0	117
Solar thermal (Parabolic trough)	1.0	321
Solar thermal (Linear Fresnel)	1.0	349
Solar thermal (Parabolic dish)	1.0	434
Solar PV	0.0	253
Geothermal HFR	2.0	130
Biomass - Landfill gas	7.5	65
Biomass - Bagasse	20.4	125
Biomass - Wood waste	20.4	74
Biomass - Municipal waste	65.0	156
Hydro	0.0	94

Note: 1. Based on assumed capacity factor of 35%.

Data source: ACIL Tasman

Table 70 **Treatment and constraints on technology deployment**

Technology	Offered to the model as	Constraints
Wind	Actual proposed projects plus generic projects	Aggregate wind capacity installed into any one region limited to 95% of average demand
Solar thermal (Parabolic trough)	Single generic project in each region	No constraints
Solar thermal (Linear Fresnel)	Single generic project in each region	No constraints
Solar thermal (Parabolic dish)	Single generic project in each region	No constraints
Solar PV	Single generic project in each region	No constraints
Geothermal HFR	Single generic project in each region	Constraints on annual build of 250 MW per year; overall limit on development of 1,000 MW by 2020; 5,000 MW by 2030
Biomass - Landfill gas	Actual proposed projects	No constraints but development limited to 50 MW per year
Biomass - Bagasse	Actual proposed projects	
Hydro	Actual proposed projects	No constraints

Data source: ACIL Tasman

C.1.4 Committed new entrants

There are a number of projects which have been committed or are under construction. ACIL Tasman has estimated LGCs created from these new generators and included their output within the model as shown in Table 71.

Table 71 **Committed renewable new entrants**

Project	Type	Region	Capacity (MW)	Assumed LGC creation ('000 LGCs)			
				2011	2012	2013	2014
Crookwell II	Wind	NSW	92	192	274	274	274
Hallett Stage 4 (North Brown Hill)	Wind	SA	132.3	288	480	480	480
Waterloo	Wind	SA	111	288	360	360	360
Oaklands Hill	Wind	VIC	63	65	195	195	195
Macarthur	Wind	VIC	420	50	350	700	1,288
Woodlawn	Wind	NSW	42	63	125	125	125
Grasmere (Albany expansion)	Wind	WA	14	0	33	44	44
Collgar	Wind	WA	206	0	602	722	722

Note: Output assumed to be constant from 2014 through to 2030 from these projects.
Data source: ACIL Tasman

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