Benchmarking NEM Wholesale Prices Against Estimates of Long Run Marginal Cost

A Report for the AEMC

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Executive Summary

The Australian Energy Market Commission (the Commission) is considering a rule change proposed by the Major Energy Users, which seeks to constrain the contended exercise of market power by generators in the National Electricity Market (NEM). This report responds to a request by the Commission to apply a hypothetical monopolist test to inform its consideration of market definition for the purpose of evaluating concerns about the potential existence and exercise of market power in the NEM.

Taking the relevant market definition resulting from the application of a hypothetical monopolist test, we have undertaken a quantitative comparison of estimates of long run marginal cost (LRMC) of generation with historic wholesale spot and indicative contract prices. The purpose of fund comparison is to assess whether there is any evidence of prices persistently exceeding competitive benchmark levels. This report presents the results of these analyses.

Applying a Hypothetical Monopolist Test to the NEM

The starting point for an analysis of competition questions is to define the relevant boundaries within which competition takes place. At the core of market definition is the concept of substitutability, whereby the market establishes the set of products, functions and the geographic area over which there is potential for:

- buyers to substitute from one source of supply to another (ie, 'demand-side' substitution); or
- sellers to switch from one production plan to another (ie, 'supply-side' substitution).

Market definition for the purposes of competition analysis is typically undertaken by reference to a hypothetical monopolist test. This involves identifying the smallest area of product, functional and geographic space within which a hypothetical monopolist could profitably impose a small but significant and non-transitory increase in price (a 'SSNIP').

The application of a SSNIP to the generation function within the NEM is particularly challenging given the complexities involved with the operation of generators as they interact with the physical characteristics and limitations of the network. Our approach has involved the use of a market model, starting with a NEM region and quantifying whether it would have been profitable for a hypothetical monopolist owning all scheduled generation in the region to have increased prices by 5 per cent above short run costs. This approach explicitly takes into account interconnector capacities and conditions in each of the adjacent regions.

The result of this analysis supports a conclusion that each NEM region is its own market for the purpose of the geographic dimension of market definition.

In each NEM region the results show that it would have been profitable for a hypothetical monopolist to have increased prices by 5 per cent above the competitive level, this highlights that there was insufficient wholesale generation and associated interconnector capacity in the other regions to negate the profitability of this strategy. In other words, connection to adjacent regions is not sufficient to constrain price rises from increasing the profitability of a hypothetical monopoly generator in each NEM region.

Analysing Whether There is Historic Evidence of the Existence of Market Power in the NEM

In order to assess whether there is any historical evidence of the existence of market power in the NEM, we compared observed market prices with estimates of the LRMC of generation. If observed prices *persistently* deviate from estimates of the LRMC, this would warrant a deeper analysis to determine whether that deviation was as a consequence of:

- unanticipated market conditions or uncertainties; or
- inaccuracies or uncertainties in the LRMC estimation methodology employed; or
- potential existence of market power.

Importantly, because we are interested in enduring market power, we have compared the estimates of LRMC against average observed prices over one year.

In our opinion, the comparative analysis of the LRMC of generation with market price outcomes supports a conclusion that there is no evidence of the existence of market power, irrespective of whether this analysis is undertaken for each NEM region separately or as a whole.

Our analysis has focused on each NEM region, except for Tasmania. The Tasmanian region was not considered because of the difficulty of obtaining appropriate LRMC benchmark estimates and the unique features of the Tasmanian electricity market. Indeed, the rule change proposal recognised that Tasmania is a special case and so might warrant either exclusion from consideration or a different approach. [1]

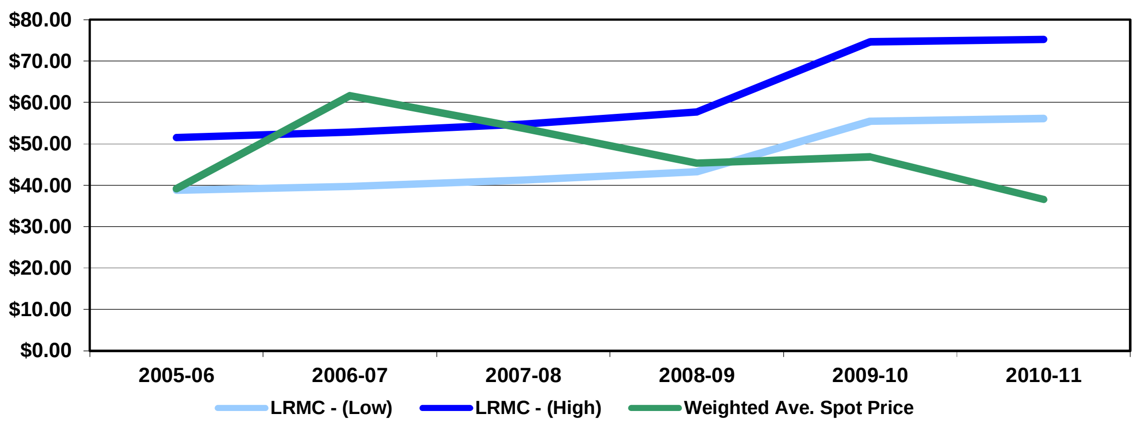
In addition to comparing estimates of LRMC with historic wholesale spot prices, we also undertook a comparison with wholesale prices accounting for contracting. The methodology adopted is an approximation of the likely cost of energy taking into account assumptions about broad retailer hedging strategies. There are a number of limitations with the approach that has been used, including the uncertainty about actual market contract prices and hedging strategies. As a consequence, the insights that can be drawn from this analysis are necessarily limited.

The National Electricity Market

Our estimates of the LRMC as compared to observed market prices for the NEM as a whole are set out in Figure E.1.

[1] See Page50 and 51, Major Energy Users Inc, (2010), 'Proposed Rule Change to Enhance Generator Competition Outcomes During High Demand Periods in the NEM' Headberry Partners Pty and Bob Lim &Co Pty Ltd, November.

Figure E.1
National Electricity Market Weighted Average Prices Compared with Long Run Marginal Cost



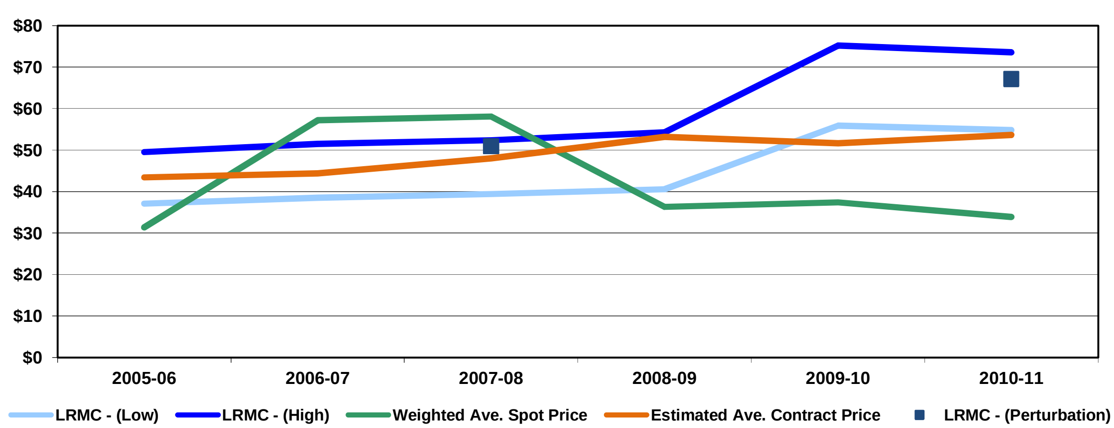
The deviation of observed prices in 2006-07 strongly reflects drought conditions across the NEM, which affected electricity production to varying degrees from hydro and thermal plants because of difficulties accessing cooling water.

Lower observed prices in 2009-10 and 2010-11 likely reflect a combination of milder climatic conditions and increased wind generation capacity across the NEM.

Queensland

Our estimates of the LRMC as compared to observed market prices for the Queensland region is set out in Figure E.2.

Figure E.2
Queensland Weighted Average Prices Compared with Long Run Marginal Cost



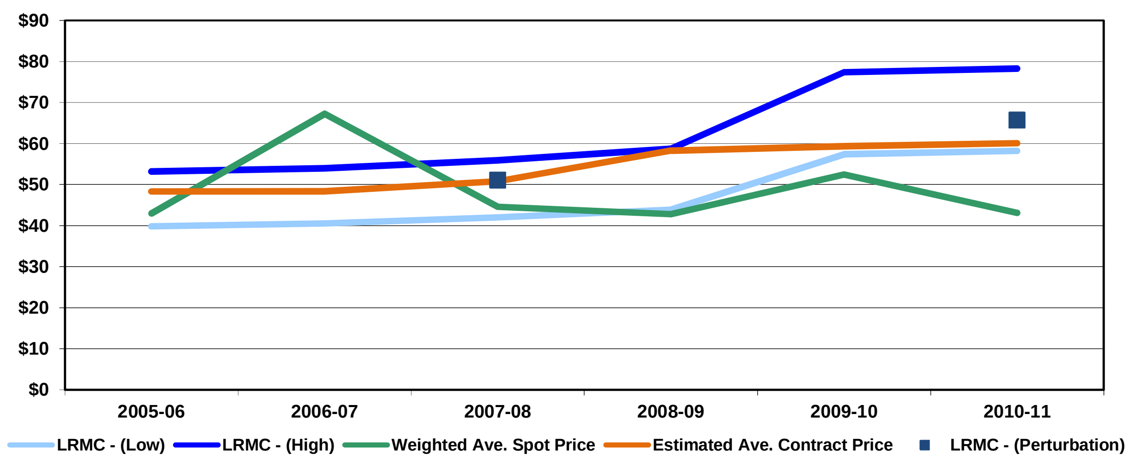
We observe two years (2006-07 and 2007-08) where prices exceed the LRMC band. Prices from around March 2007 occurred during an extended drought across eastern Australia that affected the output of generation in both Queensland and New South Wales. Specifically, the availability of cooling water reduced supply capacity in Queensland by approximately 10.4 per cent due to the unavailability of Tarong and Swanbank from around January 2007.

The low prices in 2009-10 and 2010-11 are likely to be the result of a number of factors, including the continuing expansion of generation capacity, combined with milder climatic conditions. An additional 8 per cent of capacity was installed since July 2009, which is faster than the growth in demand for the same period. In addition, the estimates of LRMC for these years are likely to have been influenced by the use of relatively high new entrant gas price assumptions, as compared with lower actual gas prices.

New South Wales

Our estimates of the LRMC as compared to observed market prices for the New South Wales region is set out in Figure E.3.

Figure E.3
New South Wales Weighted Average Prices Compared with Long Run Marginal Cost



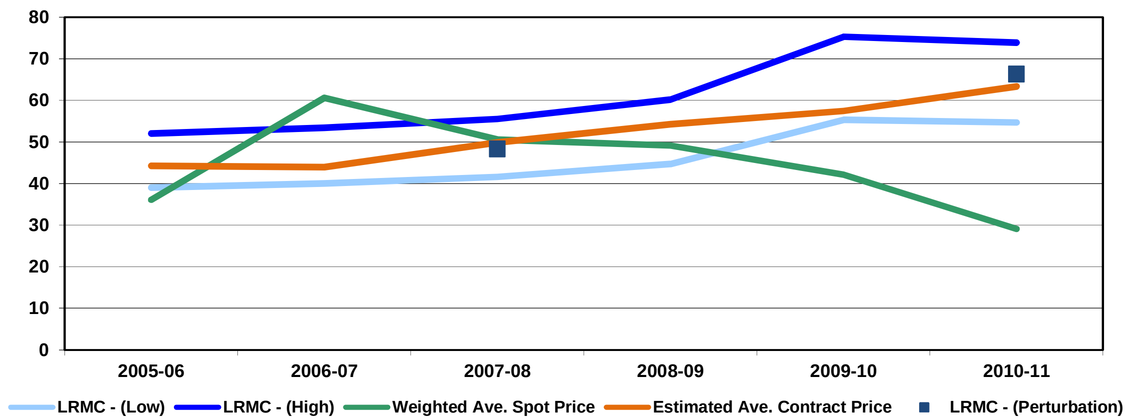
Prices in 2006-07 reflect continuing drought impacting on supply capacity and a significant price event in June 2007, which was the consequence of drought- induced electricity capacity limitations, combined with short term electricity production restrictions in the Hunter Valley due to flooding.

The low observed prices in 2009-10 and 2010-11 reflect milder climatic conditions over the period. The load duration curve for New South Wales in 2010-11 is lower than every year over the past five years. This would be expected to reduce average prices compared to expectations based on forecast load.

Victoria

Our estimates of the LRMC as compared to observed market prices for the Victorian region are set out in Figure E.4.

Figure E.4
Victoria Weighted Average Prices Compared with Long Run Marginal Cost



As with New South Wales and Queensland, a period of extended drought that affected generation production in the Snowy region, New South Wales and Queensland contributed to the observed prices in 2006-07 being higher than the LRMC band. In addition, bushfires in January 2007 resulted in a Victoria-Snowy interconnector outage, while further unanticipated generation outages in June 2007 also led to periods of high prices and contributed to an increase annual average price.

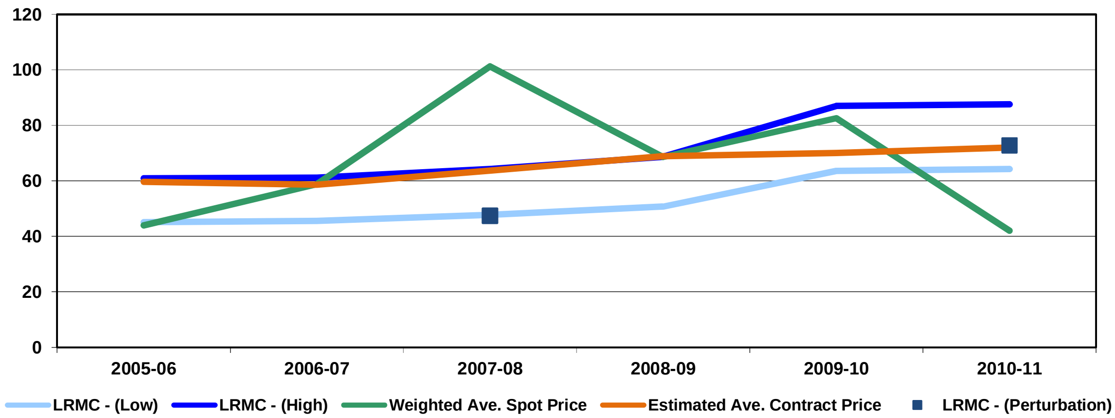
Prices in 2009-10 and 2010-11 are considerably below the lower estimate of the LRMC (31 and 47 per cent respectively). Lower prices in these years are to be expected because:

- 2010-11 saw substantially less time at high demands compared with all of the previous seven years, which would have had a significant dampening effect on outturn prices; and
- there has been almost 400 MW of new wind generation capacity brought online since October 2009, which would also have placed downward pressure on spot prices.

South Australia

Our estimates of the LRMC as compared to observed market prices for the South Australian region is set out in Figure E.5.

Figure E.5
South Australia Weighted Average Prices Compared with Long Run Marginal Cost



The results for South Australia differ from the other regions in that the average price in 2007-08 is considerably higher than the upper estimate of the LRMC. This high average annual price was contributed to significantly by a period of 12 days in March 2008 where prices exceeded $5000/MWh for 26 half hourly periods, which represented approximately half the number of such events for the year.

There appear to be two contributing factors that led to these high prices, namely:

- South Australia experienced an unprecedented 15 day heat wave over this period, which led to record levels of electricity demand; and
- the capability of the interconnector to Victoria at high price times was the lowest level observed at these times, thereby limiting electricity flows from Victoria.

High demand combined with unexpected and lower than typical flows from Victoria contributed considerably to the outturn prices. These unanticipated events are consistent with the observed deviation from the LRMC band. Importantly, the observed high price in 2007-08 did not persist once these conditions ameliorated in subsequent years.

The low observed price in 2010-11 is likely to be a consequence of lower than typical demand for most of the year and increasing development of wind generation placing downward pressure on prices.

1. Introduction

This report has been prepared by NERA Economic Consulting (NERA) for the Australian Energy Market Commission (the Commission) to present the result of:

- our application of the hypothetical monopolist test to the generation function within the National Electricity Market (NEM); and
- our analysis comparing estimates of the long run marginal cost (LRMC) for wholesale generation in the NEM with historic wholesale NEM spot and indicative contract prices.

The purpose of our analysis is to inform the Commission's consideration of a rule change proposal submitted by the Major Energy Users (MEU). The MEU rule change proposal seeks to address concerns that, on days of very high demand, large generators are able to cause the wholesale spot price for electricity to increase by more than it should by offering prices that far exceed their costs.

This report follows our earlier reports in these matters, in particular:

- in June 2011, we developed a paper describing the economic concepts of 'competition' and 'market power' to develop a framework for assessing the concerns identified in the MEU rule change proposal.[2] Our earlier paper also considered the appropriate market definition for the consideration of the Rule change; and
- in December 2011, we set out our intended approach to apply the concepts developed in our earlier paper to estimate long run marginal cost (LRMC), calculate average market prices, and apply the hypothetical monopolist or SSNIP test.[3]

The analysis reported in this paper was undertaken by a joint team involving NERA and Oakley Greenwood. The analysis included:

- estimating LRMC for each of the years 2005-06 to 2011-12 using the 'approximate modelling approach' set out in section 3.2.2 of our paper of 19 December 2011;
- estimating LRMC for 2010-11 and 2007-08 using the 'NEM market modelling' approach set out in section 3.2.1 of our paper of 19 December 2011;
- calculating volume weighted average annual wholesale spot prices for each of the years 2005-06 to 2010-11;
- estimating the cost of contracting for each of the years 2005-06 to 2011-12; and
- applying the hypothetical monopolist [4] test in accordance with the approach set out in chapter 5 of our paper of 19 December 2011.

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2 Green, H., Houston, G., and Kemp, A., (2011), 'Potential Generator Market Power in the NEM', *A Report for the AEMC,* NERA Economic Consulting, June.

3 Kemp, A., Chow, M., Houston, G., and Thorpe, G., (2011), 'Estimating Long Run Marginal Cost in the National Electricity Market', *A Paper for the AEMC,* NERA Economic Consulting, December.

4 SSNIP stands for small but significant non-transitory increase in price.

Our analysis focuses on each NEM region except for the Tasmanian region. Tasmania was excluded in part because of the difficulty of adequately modelling hydro generation, which would be required to estimate appropriate LRMC benchmark estimates. In addition, the original MEU proposal also recognised that Tasmania is a special case and should be excluded from the proposed new rule change.[5]

The remainder of the report is structured as follows:

- section 2 provides an overview of the SSNIP approach and the results of the application of the SSNIP test to the NEM;
- section 3 describes the two methodologies that we used to estimate the long run marginal cost for each NEM region; and
- section 4 sets out the results of our comparison of observed market spot price and contract price outcomes to our estimates of long run marginal cost for each NEM region.

The appendices provide further details on the assumptions used to estimate LRMC.

5 See Page50 and 51, Major Energy Users Inc, (2010), 'Proposed Rule Change to Enhance Generator Competition Outcomes During High Demand Periods in the NEM' Headberry Partners Pty and Bob Lim &Co Pty Ltd, November.

2. Applying a Hypothetical Monopolist Test to the NEM

This chapter describes the results of the application of a hypothetical monopolist test to the NEM. Before presenting the results, we briefly describe the approach used and, in particular, how it has been applied in practice. Further detail on the methodology can be found in our earlier papers.

2.1. Overview of the approach

Market definition is the process of establishing the relevant boundaries within which particular questions concerning competitive conduct can be evaluated and assessed. At its core is the concept of substitutability, whereby the market establishes the set of products and functions and the geographic area over which there is the potential for:

- buyers to substitute from one source of supply to another (ie, 'demand-side' substitution), or
- sellers to switch from one production plan to another (ie, 'supply-side' substitution).

The relevant market is the smallest area of product, functional and geographic space within which a hypothetical profit maximising monopolist could successfully impose a small but significant and non-transitory increase in price (a 'SSNIP'). The SSNIP involves:[6]

> '… considering the product, geographic and functional areas of supply by the firm whose conduct is in question. One then asks whether a hypothetical monopolist could profitably impose a SSNIP on those products, usually of between 5 and 10 per cent above the price level that would apply under conditions of workable competition, and assuming that the price of all other products remain constant.'

Where the SSNIP is not profitable, the geographic boundaries of the market can be widened and the exercise repeated until a product and geographic area has been identified where the hypothetical monopolist is capable of profitably increasing prices.

2.2. Applying the SSNIP

Applying a SSNIP to wholesale generation markets is particularly challenging given the complexities involved with the operation of the market as it interacts with the physical characteristics and limitations of the network. This is particularly relevant for the NEM, given that wholesale market spot prices are based on the outworking of generator bids and demand given network constraints, for every 5 minute dispatch period, which is then averaged to determine a 30 minute settlement price.

In our previous reports we have expressed our opinion that:[7]

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6 Page 34, Green, H., Houston, G., and Kemp, A., (2011), 'Potential Generator Market Power in the NEM', *A Report for the AEMC*, NERA Economic Consulting, June.

- the product dimension can be defined with reference to the type of plant used to supply electricity, which is itself a homogenous product; and
- the functional dimension can be confined to electricity generation (ie, it should not be expanded to incorporate electricity retailing).

The geographic dimension of the market involves considering an assessment of the locations over which it would be profitable for the hypothetical monopolist to increase prices by 5 or 10 per cent. As a starting point for the analysis, we have applied a SSNIP to a hypothetical monopolist operating all of the scheduled generation within a NEM region.

Applying the SSNIP to NEM, for the purpose of identifying the geographic dimension of the market therefore involves:

- identifying the smallest relevant product, geographic and functional areas of supply for consideration (in this case starting with a NEM region);
- calculating the optimal dispatch across the entire NEM for each half hour in the one or more years in which the SSNIP is to be applied, assuming that plant is offered to the market at its short run marginal costs (the base case or assumed competitive price level);
- recalculating the optimal dispatch across the entire NEM for each half hour in the one or more years in which the SSNIP is to be applied, assuming that plant in the relevant region is offered to the market at its short run marginal cost plus 5 per cent, and taking account of changes in interconnector flows as a consequence of changes in "costs" of the hypothetical monopolist;
- calculating the market price applying under each of the dispatch scenarios for each of the two short run marginal cost scenarios described above (ie, the base case short run marginal cost, the base case plus 5 per cent);[8]
- calculating the gross margin for the hypothetical monopolist under each of these market price/dispatch scenarios, based on energy sent out from the monopolist's plants; and
- comparing the gross margin under the plus 5 per cent scenario with that applying under the base case to determine whether the SSNIPs are profitable.

Importantly, this approach abstracts from the realities of the market in that the outturn prices reflect the short run marginal costs of supply, and so involve no allowance for the capital costs to be recovered, particularly those from peaking generators. Estimated prices may therefore differ from observed spot prices. However, the intrinsic conservatism of this approach also means that the estimated prices will not be affected by the cellophane fallacy.[9]

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7 Page 40 and 50, Green, H., Houston, G., and Kemp, A., (2011), 'Potential Generator Market Power in the NEM', *A Report for the AEMC,* NERA Economic Consulting, June.

8 The test was applied using 10 POE demand levels to ensure that the estimated gross margins appropriately included some dispatch of peaking capacity.

9 The cellophane fallacy arises where the boundary of a market may be inappropriately expanded as a consequence of the SSNIP being applied to prices that are already affected by one or more firms exercising a degree of market power..

To conduct the empirical analysis for the SSNIP we have used a market optimisation model – CEMOS – which is a model of wholesale electricity market that has been set up to represent the regions of the NEM. We have used CEMOS to determine the least cost dispatch of generation plants to satisfy energy demand requirements in 2010-11, which was the year selected for application of the SSNIP.[10]

Our key assumptions for the SSNIP include:

- the forecast load profile for 2010-11, for each NEM region;
- the actual installed capacity in 2010-11, for each NEM region;
- generation fuel prices reflecting the assumptions developed by the Australian Energy Market Operator for 2010-11, for each NEM region; and
- no change in investment in non-scheduled generation when the price is increased.

The SSNIP was applied in the CEMOS model by increasing the SRMC of each generator within the portfolio of the hypothetical monopolist operating in the region being considered.

The CEMOS model was used to generate both a base case, representative of a competitive market price where generation is bid at its short run marginal cost, and a 5 per cent price increase scenario for each NEM region in turn. The gross margins for generation for the 5 per cent scenarios were compared against the base case to determine whether the price increase strategy was profitable.

2.3. Conclusions on the geographic dimension of the market

Table 2.1 sets out the results of the SSNIP as applied to each NEM region.

Table 2.1: Results of the SSNIP for each NEM region

NEM Region	5 per cent increase
Queensland	Profitable
New South Wales	Profitable
Victoria	Profitable
South Australia	Profitable

The empirical results support a conclusion that each NEM region is its own market for the purposes of the geographic dimension of market definition. The empirical results highlight that there is insufficient wholesale generation and associated interconnector capacity in other regions to defeat the SSNIP in each region, and so connection to the adjacent regions is not

[10] 2010-11 was chosen simply because it represented the most recent information available on existing generation capacity and demand.

sufficient to constrain prices. However it is important to note the results of the SSNIP test do not provide any insight on the need for additional interconnector capacity.[11]

The detailed results indicate that the SSNIP in the South Australian region results in the largest increase in gross margin as compared to the application of the SSNIP in each of the other regions. Victoria has the smallest increase in the gross margin as a consequence of the imposed SSNIP.

It is important to emphasise that a result of 'profitable' from the SSNIP test only defines the market boundary for an assessment of market power. It does not provide any insight on whether there is evidence of market power, as indicated by prices above the competitive level.

[11] This is because the SSNIP test is only relevant for a consideration of market definition. It does not assess interconnector costs, and while additional interconnection investments might change the results of the test, additional interconnection may not be the most cost effective way address demand changes.

3. Methodology for Estimating Long Run Marginal Cost

We have adopted two methodologies to estimate LRMC for each NEM region, namely:

- a methodology that estimates LRMC with reference to the least cost combination of generation to satisfy demand in the year being investigated – the average incremental cost approach; and
- a market modelling approach that makes use of a market optimisation model to estimate LRMC using a perturbation approach – the perturbation approach.

We have used the average incremental cost approach to estimate a LRMC range for each NEM region for each year over the period 2005-06 to 2010-11. The market modelling approach has been used to estimate LRMC for each NEM region for both 2007-08 and 2010-11. While the perturbation approach implemented with a market model is expected to best represent the LRMC given its capability to account for the many factors that influence the profile of investment and dispatch, it was not practical to apply the methodology for every NEM region and historic year. The average incremental cost approach has allowed us to understand the potential range of the LRMC for each year over the five year historic time period.

The average incremental cost LRMC estimates are consistent with the perturbation approach estimates for all regions for both 2007-08 and 2010-11. This indicates that the range estimated by the average incremental cost approach is a reasonable approximation and the range would likely encompass the perturbation estimates in other years,

This chapter explains the methodologies that have been used to estimate LRMC in detail. In addition we explain our approach to calculating the average historic wholesale spot and contract prices. A more detailed explanation of these methodologies can be found in our earlier paper.[12] The modelling assumptions are set out in Appendices A and B.

3.1. The average incremental cost approach

The average incremental cost approach has been implemented by estimating the LRMC by determining the least cost combination of generation capacity to satisfy a load duration curve for a NEM region in a particular year, given information on new entrant technology costs. This approach assumes that existing capacity is already optimal, and that future demand is constant and with no change to the load profile.

This approach involves:

- calculating the least cost combination of new entrant generation capacity to satisfy electricity demand within a given year and region;

12 See in particular Kemp, A., Chow, M., Houston, G., and Thorpe, G., (2011), 'Estimating Long Run Marginal Cost in the National Electricity Market', *A Paper for the AEMC,* NERA Economic Consulting, December.

- applying an increment to the electricity demand and recalculating the least cost combination of new entrant generation capacity to satisfy the new load profile within the given year and region; and
- estimating the LRMC as the difference in the costs of new entrant generation divided by the increment in electricity demand.

Algebraically this can be expressed as:

$$\mathrm{LRMC}_{year} = \frac{Gen2_{year} - Gen1_{year}}{Increment}$$

Where:

- $Gen1_{year}$ is the total cost of generation to satisfy demand in the relevant year;
- $Gen2_{year}$ is the total cost of generation to satisfy demand in the relevant year following an increment in demand;
- *Increment* is the permanent increment in demand that is applied to the load profile; and
- *year*, is the year for which the LRMC is being estimated.

This approach is computationally simpler than the detailed market modelling approach, but has a number of deficiencies, namely:

- it assesses investment region-by-region and year-by-year and so misses the potential for inter-regional generation capacity support to optimise the timing of investments;[13]
- it presumes that generation investment is completely divisible so that demand can be optimally satisfied;
- it approximates an optimal, existing investment profile by assuming that new entrant generation has been constructed and is available to satisfy known demand within the period with certainty; and
- it does not take into account expected future growth in demand and the particular way in which changes in demand relative to existing capacity may influence LRMC.

For the purposes of applying this methodology we limited new entrant technologies to open cycle gas turbines (OCGT) and closed cycle gas turbines (CCGT). The new entrant assumptions are based on information developed for the Australian Energy Market Operator (AEMO), and are set out in Appendix A.[14]

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13 For example, it might be possible to delay investment in higher cost generation technology for a short period by relaying on increased inter-regional electricity flows.

14 ACIL Tasman, (2007), ‘Fuel Resource, New Entry and Generation Costs in the NEM Report 2 – Data and Documentation’, *Final report prepared for NEMMCO*, June, and ACIL Tasman, (2009), ‘ Fuel Resource, New Entry and Generation Costs in the NEM’, *Final Report Prepared for the Inter-Regional Planning Committee*, April.

We also calculated a range for the LRMC to reflect uncertainty in the cost and cost of capital assumptions. The upper cost reflects both a high cost of capital (ie, weighted average cost of capital) and high capital construction cost.[15]

Importantly, this methodology does not explicitly include the influence of the renewable energy target on the profile of investment, and so does not examine the impact of wind investments on the estimated LRMC nor does it allow for increased transfers from other regions. We anticipate that this results in the LRMC estimate being higher than would be the case if the spot market cost of wind (ie, new entrant costs less the contribution to revenue from the creation of renewable energy certificates) and inter-regional transfers were explicitly included in the methodology.

3.2. The perturbation approach

The perturbation approach has been implemented with a market model to estimate LRMC for both 2007-08 and 2010-11 for each NEM region. The perturbation approach estimates LRMC by considering how future capital and operating costs vary as a consequence of an increment or decrement of demand. It involves:

1. Forecasting average annual and maximum demand as reflected by the anticipated load duration curve over a future time horizon of, say, 20 years;
2. Developing a least cost program of generation capacity expansion that ensures that supply can satisfy demand, given the reliability standard or reserve margin;
3. Increasing or decreasing forecast average and/or peak demand by a small but permanent amount and recalculating the least cost generation costs needed to meet demand;[16] and
4. Calculating the long run marginal cost (LRMC) as the present value of the change in the least cost capital program plus the change in operating costs, divided by the present value of the revised demand forecast compared to the initial demand forecast.

Algebraically, the perturbation approach to estimating LRMC can be expressed as follows:

$$\text{LRMC} = \frac{\text{PV(revised optimal capex plus opex} - \text{optimal capex plus opex)}}{\text{PV(revised demand} - \text{initial demand)}}$$

We use a market optimisation model to develop the least cost program of generation capacity expansion to ensure that supply satisfies demand. The market optimisation model:

- assesses generation entry and exit given announced new plant and retirement schedules to ensure there is sufficient capacity to satisfy energy demand, given minimum reserve requirements and any other constraints; and

[15] The range for the cost of capital was relatively narrow: plus and minus 2 per cent relative to the assumed cost of capital.

[16] It is important to consider how increments or decrements in both peak and average demand influence the future capacity plan, since these could result in a different combination of generation plant investments to satisfy demand at least cost.

- determines the least cost dispatch of generation plants across the NEM to satisfy energy demand requirements.

Particular features of the market are captured in the modelling framework through the use of constraints to the optimisation problem. For example, we constrain the generation capacity formulation to ensure that a minimum level of renewable generation is available in the market in line with the requirements of the large-scale renewable energy target.

There are a number of particular features of the modelling that are relevant to estimating LRMC, namely:

- both 2007-08 and 2010-11 assumed that a price on carbon would be introduced at a level and timeframe based on the expectations at the time. We note that the LRMC is likely to be affected by expectations about future carbon prices, which influence investment choices and also the cost of incremental dispatch to meet the increment of demand. This means that any deviation from our assumed carbon price expectation assumptions would result in the modelled estimate being higher than observed;
- the model selects new generation capacity entry based on the most cost effective combination of capacity to satisfy demand and capacity reserve requirements over the full modelling time horizon. This means that the model has perfect foresight. In practice, other factors are likely to influence generation investment decisions such as policy uncertainty, discount rates, appetite for risk, and certainty of timing of planned retirements. Annual generation from wind plants is based on an annual capacity factor (as per the AEMO database) but dispatch during peak periods is limited to three per cent of total installed wind capacity to reflect its lower contribution to peak capacity. The impact of an increment of demand was assumed not to change the level of renewable investment on the basis that renewable investment in the period of interest is driven by external targets;
- there are no other limitations placed on generation dispatch, which means that some thermal plants that currently have take or pay fuel contracts, or which operate for minimum system loading requirements may in practice have lower dispatch than seen in the modelling. This removes the need for us to assume how long these factors may influence dispatch. While this is an approximation, as the focus of our analysis is to assess changes in capital and operating expenditure from a change in demand the base level of dispatch is not critical provided the technology mix is approximately correct;
- gas prices are assumed to be independent of changes in installed gas generation capacity, and so do not change as generation capacity changes;
- we have assumed an increment of 5 per cent of regional demand for the purposes of calculating the LRMC and considered the sensitivity of the LRMC results to the choice of increment; and
- for the purposes of this analysis the capacity expansion profile was based on an expansion plan that considered market bids and profitability. The effect of the capacity expansion increments on market prices were then assessed using a least cost based approach and assumed “SRMC bidding” combined with 10 per cent probability of exceedence (10

POE) demand forecasts. This approach was compared against a full probabilistic market based bidding strategy approach and was found to deliver similar estimates of the LRMC.

Appendix B sets out the detailed modelling data and assumptions used in the analysis.

3.3. Average historic wholesale spot price

Average volume weighted historic wholesale spot prices have been calculated for each year over the period between 2005-06 and 2010-11, for each region. The weighted averaging of spot prices involves summing over each trading period the volume of energy dispatched multiplied by the regional reference price, and then dividing by the sum of dispatch over the relevant period. Algebraically:

$$\overline{RRP}_{volume} = \frac{\sum_{i=1}^{n} l_i RRP_i}{\sum_{i=1}^{n} l_i}$$

Where:

- $\overline{RRP}_{volume}$ is the load weighted mean of the regional reference node price;
- l_i is the load dispatched in settlement period i;
- RRP_i is the regional reference node price in settlement period i; and
- n is the number of settlement periods that are being averaged.

3.4. Impact of contracting

In addition to wholesale spot prices, we have also compared estimates of LRMC with wholesale prices accounting for contracts. In the absence of detailed public information on actual outturn contract prices, we have used information on contract prices as traded through the Sydney Futures Exchange and reported by d-cyphaTrade.

Our approach to estimating average contract prices for a specific year has involved assumptions that:

- retailers use a combination of base and peak contracts to meet the actual peak demand in a quarter;
- retailers choose the combination of base and peak contracts to minimise total cost of providing electricity subject to the peak contract constraints (ie, peak contracts are available only during the defined peak period);
- where there is excessive demand for base contracts (ie, it is cheaper to use base contracts to cover peak periods), the number of base contracts are constrained by the amount of

base load capacity[17] and an allowance for planned maintenance (ie, only 80 per cent of base capacity will be contracted out to reflect the likely limits on contracting to cover plant failures. In practice contract limits are likely to be based on portfolios across multiple generators and so this is another source of approximation in the analysis);

- peak and base contracts to meet actual demand are purchased in each of the four years prior to the specified year;[18]
- the price for the base and peak contracts is based on the arithmetic average of the settlement prices of base and peak contracts;
- \$300/MWh cap contracts are purchased to cover upside cost risks to a retailer, and so cover the difference between the 10% POE and 50% POE forecasts for the peak period only; during off-peak, retailers purchase additional energy from the spot market when needed to meet demand above the contracted 50% POE (with the price capped to \$300/MWh); and
- the price for the \$300 cap contracts is based on the arithmetic average of the settlement prices of cap contracts.

Algebraically:

$$AveContract_{y(t)r(x)} = \sum_{n=1}^{4}\left[25\% \times \left(P\,\mathrm{Pr}(x) \times PC_{y(t-n)r(x)}\right) + \left(PBr(x) \times BC_{y(t-n)r(x)}\right)\right]$$
$$+ \sum_{n=1}^{4}\left[33\% \times \left(\left((PL_{r(x)}^{10\%POE} - PL_{r(x)}^{50\%POE}\right) / PL_{r(x)}^{50\%POE}\right) \times CC_{y(t-n)r(x)}\right)\right]$$

where:

- *AveContract* is the average contract price for year *t* for region *x*;
- *PP* is the proportion of peak load in 2005-06 for region *x*;
- *PC* is the arithmetic average of the settlement prices for peak contracts in year *t-n* for region *x*;
- *PB* is the proportion of base load forecast in 2005-06 for region *x*;
- *BC* is the arithmetic average of the settlement prices for base contracts in year *t-n* for region *x*;
- *IC* is the arithmetic average of the settlement prices for intermediate contracts in year *t-n* for region *x*;
- *PL* is the 10% and 50% POE peak load forecast in 2005-06 for region *x*; and

---

17 We have defined base load capacity as the total installed capacity of black and brown coal in each NEM region with the exception of South Australia where we have included combined cycle natural gas and an assumption that up to 800 MW of gas fired steam plant will also be available under base contracts.

18 The d-cyphaTrade data was limited in the earlier years and so the weighting factors across years were adjusted according to the availability of data (e.g, if three years of data were available, we used 11.3 per cent to cover each year). Notably, only three years of historical cap contract prices were available for each year.

- *CC* is the arithmetic average of the $300 cap price contract in year *t-n* for region *x*.

Our analysis has been based on NEM region demand profiles. We also assume sufficient volume is available at these prices to meet demand. We have developed the volume in contract portfolios and prices on a quarterly basis. Further, the period for which contract data has been available also covers a period of considerable policy uncertainty, which investors claim to have inhibited investment decisions and reduced liquidity of contracting.

Importantly, this methodology is simply a rough approximation of the possible cost of energy taking into account assumptions about hedging strategies. There are a number of deficiencies with this approach, including:

- the d-cyphaTrade data do not include information on bilateral contract prices and so might not reflect the actual contract prices for the periods considered;
- the number of base load contracts available has been approximated using a crude approach. However, in the event where base contracts are needed to satisfy demand in off-peak periods, we have assumed that retailers are able to obtain sufficient contracts to satisfy their requirements; and
- individual hedging strategies in practice will vary for individual retailers and generators, and so our approach of using an average market hedging strategy may not be equivalent to the sum of the hedging strategies of each individual entity.

As a consequence the inferences that can be drawn from the analysis of contract prices are limited and that the focus of comparison should be against spot prices. We discuss this further in section 4.7.

4. Comparing LRMC with Market Outcomes

This chapter sets out the results of our comparison of observed market spot prices and contract price outcomes.

4.1. Overview of the results

Comparing actual market prices with estimates of the LRMC provides information to assist with an analysis of market power in the wholesale generation market. If observed prices were to *persistently* deviate from estimates of the LRMC, then such an observation would warrant a deeper analysis to determine whether such deviations:

- are simply a response to unanticipated changes in underlying demand and supply conditions, and so are representative of a well-functioning market providing price signals to equate supply and demand in the short term, and create incentives for new investment in the medium to long term;
- reflect inaccuracies and uncertainties with the assumptions underpinning the estimates of LRMC; or
- whether the only explanation is potential existence of market power.

In particular, estimates of LRMC are based on assumptions about the future that involve ‘typical’ or ‘average’ market conditions, eg, for generator failure rates and customer demand. Such an approach does not account for unexpected events, such as floods, droughts, bushfires, multiple failures and network condition, and does not incorporate every possible combination of demand. While subsets of these factors can be analysed for particular purposes, it is impractical to determine the, generally very low, probabilities of all different combinations over the long term. As a result our results can vary from forecast and historic prices and, realistically, differences can only be reconciled on a case by case basis.

Importantly, observing deviations between actual prices and LRMC is not in and of itself sufficient to conclude that there is evidence of market power. Given the uncertainties involved, such a mechanical approach would be inappropriate. All of the circumstances affecting observed market prices should be taken into consideration.

Our analysis of LRMC compared with spot and contract market outcomes supports a conclusion that there is no evidence of market power. This conclusion holds irrespective of whether the NEM as a whole, or each NEM region, is treated is a market for the purposes of market definition.

The conclusion on market power arises because:

- across the NEM as a whole, there is only one year (2006-07) where the observed actual NEM-wide price exceeds the LRMC range and there are a number of reasonable explanations for the deviation relating to the prevailing demand and supply conditions arising at the time;
- within all the individual regions, prices are not persistently above the LRMC range;
- there are plausible reasons for each instance where price exceeds the LRMC range; and

- there are plausible reasons to explain the observation that price is below the LRMC range in 2009-10 and 2010-11.

Finally, across the NEM in its entirety wholesale prices have been trending down relative to LRMC. Such an outcome is unlikely to be viable for the wholesale generation industry, which will likely mean that spot prices can be expected to grow over the medium term, in addition to the carbon price impact, as prices more closely align with the LRMC of electricity production.

Importantly, LRMC is a forward looking and long term concept, and so it is appropriate to compare it against average observed prices over a reasonable time period. For this study we compared prices each year but, even then, outcomes are influenced by year-to-year variations, such as warmer or cooler seasons, and events that can last for extended periods of time. We have reconciled these variations on a case-by-case basis in the analysis. It follows that comparing estimates of LRMC against observed market prices over shorter periods does not provide any insights on whether there is evidence of market power.

4.2. The National Electricity Market

One view of the relevant market boundary that should be considered when examining prices is the NEM as a whole. This first section reviews NEM-wide prices and subsequent sections examine each region in turn.

Across the NEM as a whole outturn prices in 2006-07 were above the upper LRMC estimate on average. Prices fell within the range for 2005-06, 2007-08 and 2008-09. Prices were below the lower estimate of the LRMC for 2009-10 and 2010-11 – Figure 4.1 and Table 4.1.

Figure 4.1
National Electricity Market Weighted Average Prices Compared with Long Run Marginal Cost

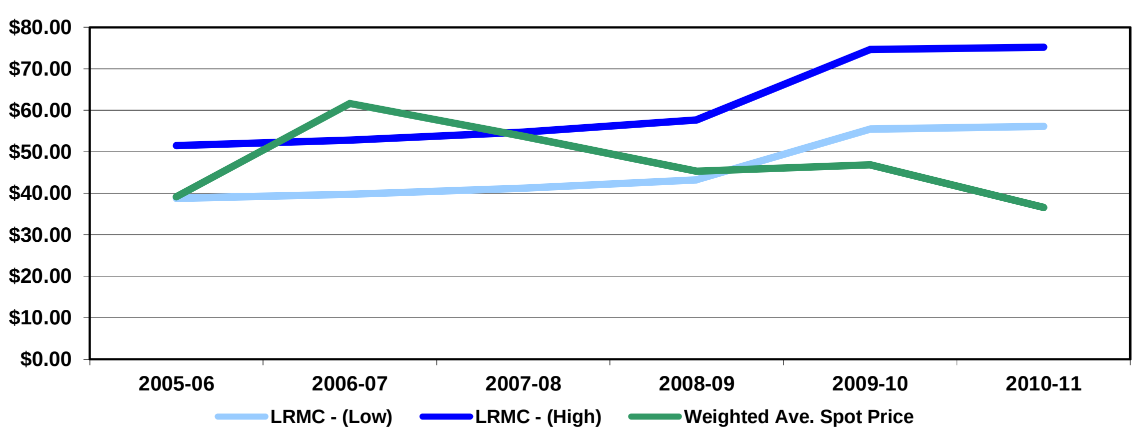


Table 4.1
Long Run Marginal Cost and Spot Prices for the National Electricity Market ($/MWh)

	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11
LRMC (average incremental cost)						
- upper bound	51.6	52.8	54.8	57.7	74.7	75.3
- lower bound	38.8	39.7	41.3	43.3	55.5	56.1
Volume weighted spot price	39.2	61.7	53.8	45.3	46.9	36.6

An analysis of the observed differences in the LRMC estimates and observed prices is set out for each NEM region in the following sections. In short:

- in 2005-06, prices reflected the underlying demand and supply conditions across each NEM region, as a typical year;
- high prices in 2006-07 were associated with drought affecting electricity production to varying degrees from hydro and thermal stations (impacting on availability of cooling water). The resulting reduced supply capacity combined with a number of weather events meant that prices would be expected to be considerably above long run average conditions;
- prices in 2007-08 were down on 2006-07 but remained high consistently with drought continuing to restrict supply, which resulted in high prices, for example in Queensland. Regardless, prices fell to within the estimated range of LRMC across the NEM as a whole;
- prices in 2008-09 were lower and within the LRMC range;
- prices for 2009-10 and 2010-11 are below the lower estimate of the LRMC (average incremental cost), which likely reflects:
  - less time spent at periods of high demand which is to be expected given the overall relatively milder weather;
  - increased wind generation capacity, resulting in suppressed wholesale market prices (albeit at the expense of retail costs); and
  - lower than expected gas prices, particularly in Queensland likely associated with the presence of ‘ramp gas’, leading to lower spot prices.

The following sections explain these results in greater detail.

4.3. Queensland

4.3.1. Overview of results

Actual electricity spot prices for the Queensland region exceeded the upper bound of the LRMC range in both 2006-07 and 2007-08, but were below the range for the remaining years, particularly for 2009-10 and 2010-11. Indicative contract prices are within the bound between 2005-06 and 2008-09 but are below the range for the remaining years –Figure 4.2, Table 4.2.

Figure 4.2
Queensland Weighted Average Prices Compared with Long Run Marginal Cost

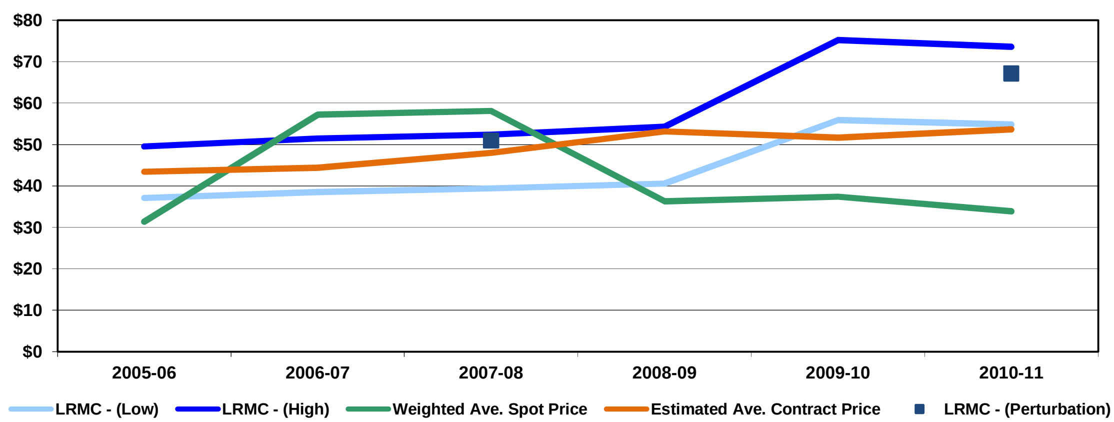


Table 4.2
Long Run Marginal Cost, Spot and Contract Prices for Queensland ($/MWh)

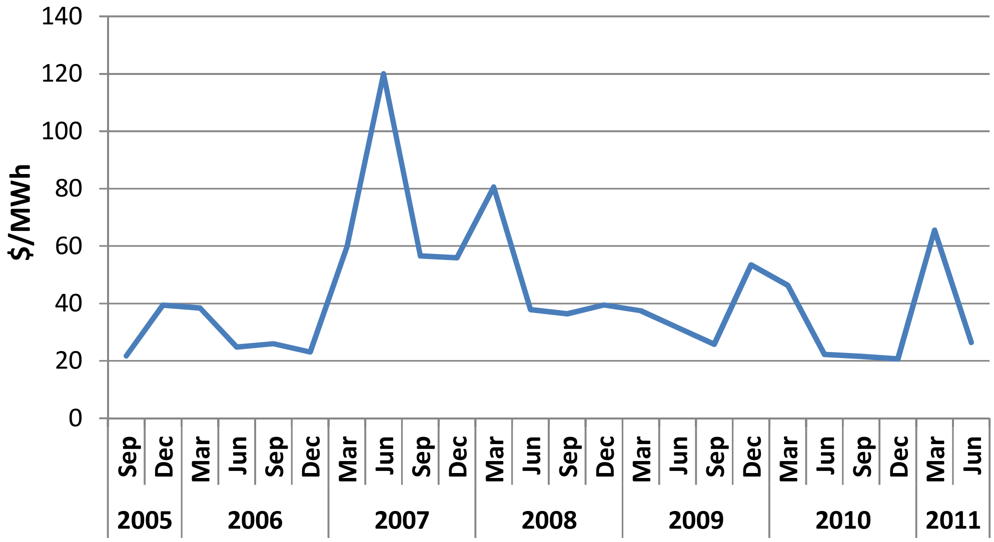
	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11
LRMC (perturbation)	-	-	50.9	-	-	67.1
LRMC (average incremental cost)						
- upper bound	49.5	51.5	52.4	54.3	75.2	73.6
- lower bound	37.1	38.5	39.4	40.6	55.9	54.8
Volume weighted spot price	31.4	57.2	58.1	36.3	37.4	33.9
Average region wide contract price	43.4	44.4	48.0	53.1	51.7	53.7

4.3.2. Historic price and demand information

To understand the differences between observed spot prices and LRMC for a year it is necessary to consider the price levels within the year. Figure 4.3 sets out the volume weighted average quarterly prices for the Queensland region from the September quarter 2006 to June 2011. The June quarter of 2007 represents the highest price, followed by the

March quarter of 2008. The ramp up of prices occurred from the March quarter in 2007 and extended until June 2008. The observed prices from the June quarter of 2010 to December 2010 represent the period with the lowest price.

Figure 4.3
Quarterly Volume Weighted Prices, Queensland ($/MWh)



The high prices in 2006-07 and 2007-08 were driven by more occurrences of very high prices and higher overall prices when compared with other years. The price duration curves (Figure 4.4) highlight that both 2006-07 and 2007-08 had consistently higher overall prices when compared to the other years. The number of periods where prices exceeded $5000/MWh in 2006-07 and 2007-8 were also higher when compared to other years - Figure 4.5.

For the years 2006-07 and 2007-08, the price duration curves (Figure 4.4) show that both years had consistently higher overall prices when compared to the other years including the incidence of prices in excess of $5,000/MWh.

Figure 4.4
Queensland Price Duration Curves, 2003-04 to 2010-11

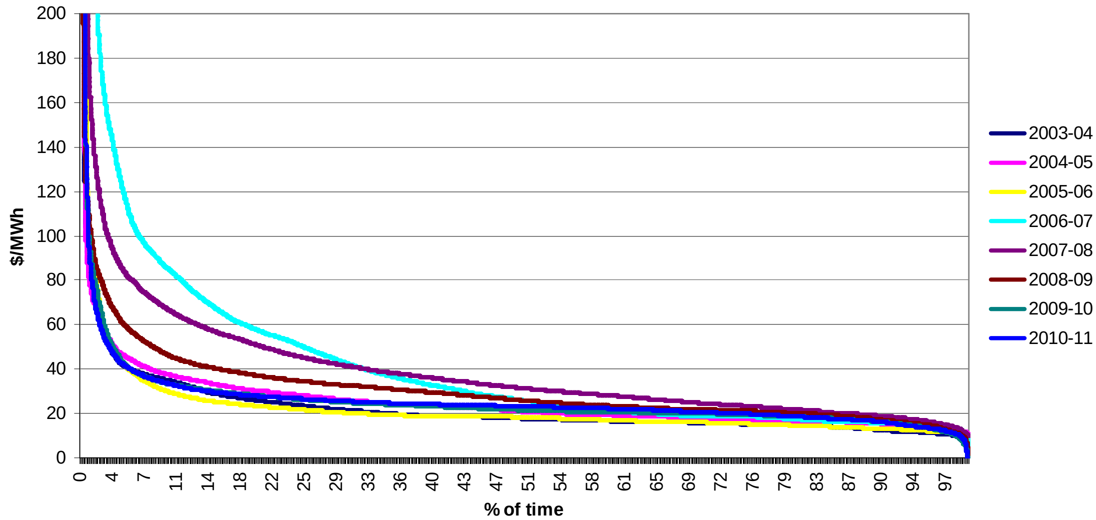
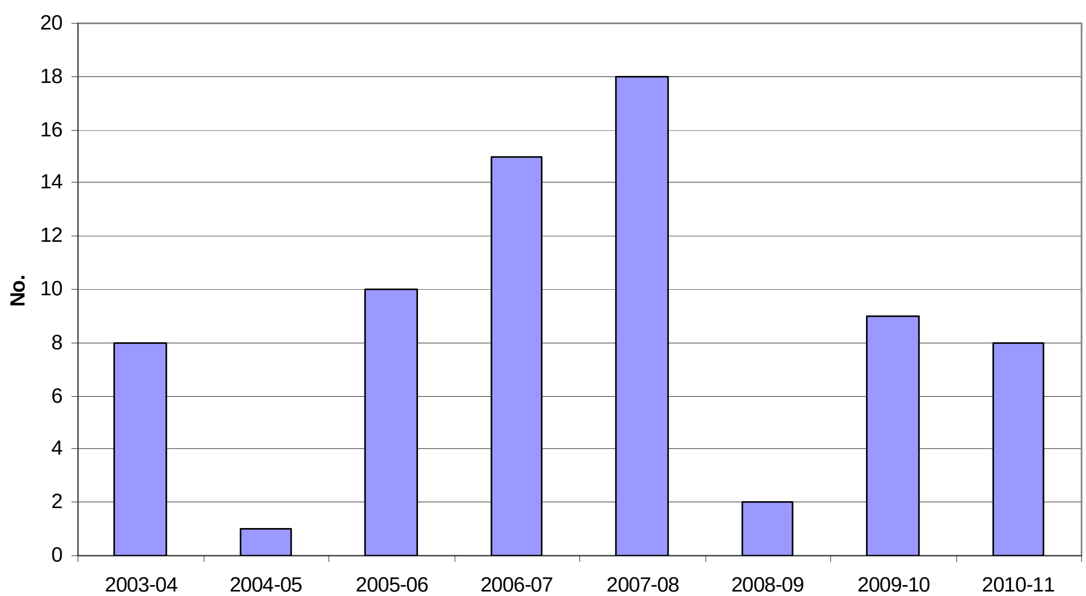


Figure 4.5
Frequency of Half Hourly Price exceeding $5000/MWh, Queensland, 2003-04 to 2010-11



Demand does not appear to play a significant role in the high prices observed in 2006-07 and 2007-08, or the low prices that appeared in 2009-10. Demand followed broadly similar patterns within each year except for 2010-11, where demand was lower than trend – Figure 4.6. Peak demand for 2006-07 and 2007-08 are both below the peak demand observed in 2009-10 and 2010-11, with 2007-08 peak demand below the overall trend - Figure 4.7.

Figure 4.6
Queensland Load Duration Curves, 2003-04 to 2010-11

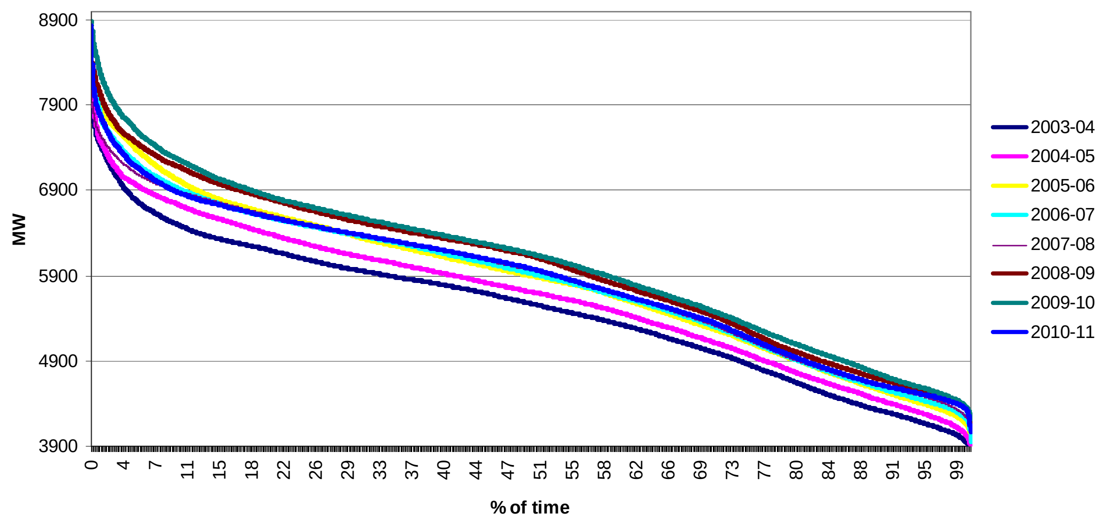
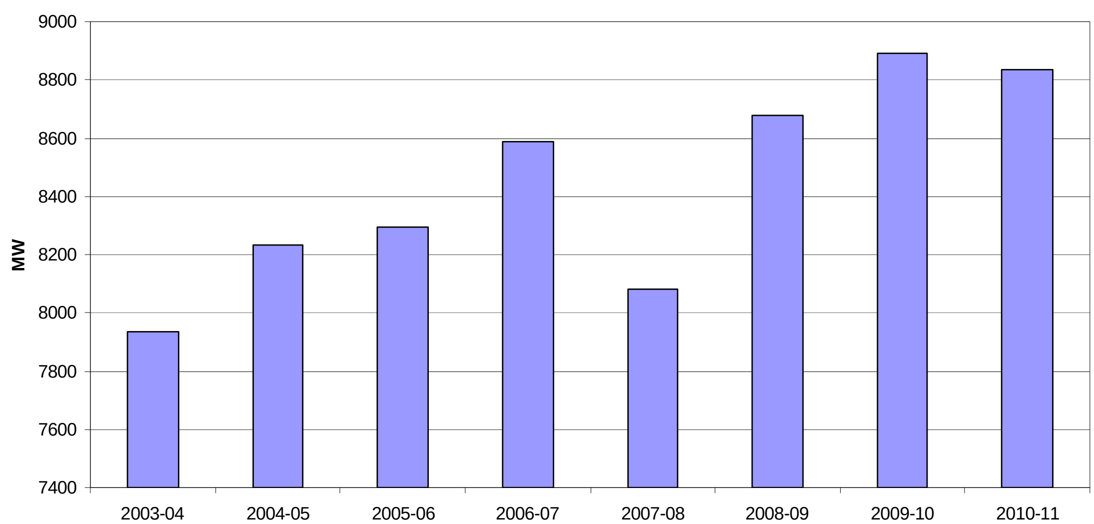


Figure 4.7
Queensland Peak Load (MW)



4.3.3. Discussion of results

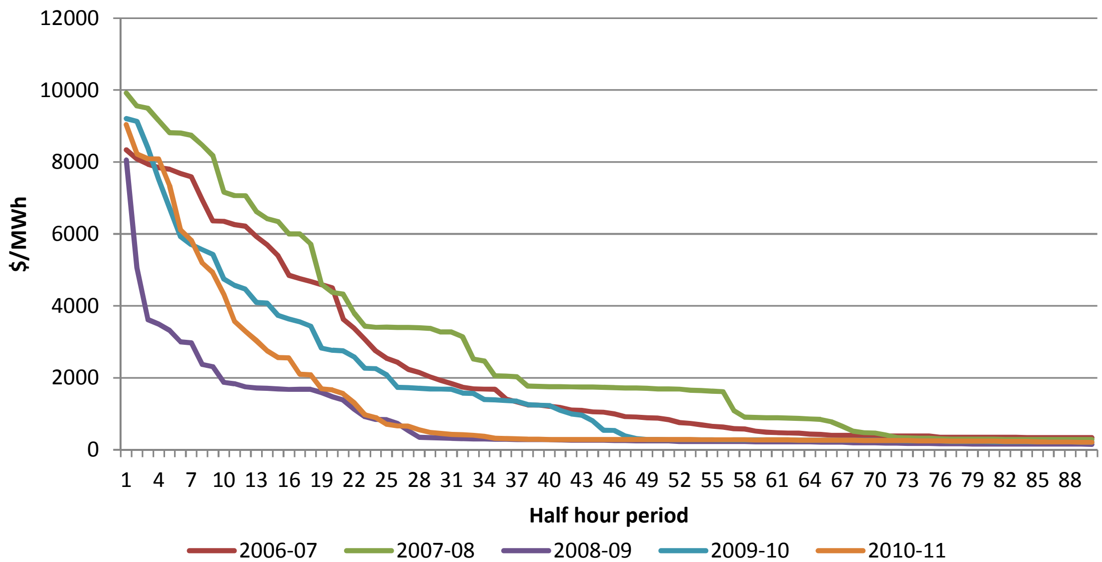
There are several circumstances that suggest prices should have been higher than the long run trend in 2006-07 and 2007-08.

The high prices from March 2007 cover a period of extended drought that affected the output of a number of large generators, mostly in Queensland and New South Wales, and the availability of hydro generation.

The reduced generation capacity would be expected to lead to increased prices above the LRMC estimates based on average conditions. In particular the drought impacted on the availability of cooling water to Tarong (reduction of 700 MW or 6.4 per cent of total installed capacity) and Swanbank (reduction of 480 MW or 4.4 per cent of total installed capacity) from around January 2007.

Looking in more detail at the price duration curves it is evident that the annual higher prices in 2006-07 and 2007-08 were driven by higher prices across much of the year at most levels of price. At the high end, 2006-07 and 2007-08 had a higher number of occurrences with prices above $5,000/MWh – Figure 4.5 and Figure 4.8. In addition, the overall price levels were higher in 2006-07 and 2007-08 with price curves lying above both earlier and later years – Figure 4.4. This is consistent with a temporary reduction in base load capacity.

Figure 4.8
Highest half hourly prices – Queensland



A number of events in 2006-07 and 2007-08 contributed significantly to the high levels of spot price and were caused by abnormal conditions. Between 12 June and 28 June 2007, a combination of Queensland recording its highest ever winter peak on 20 June, the reduced availability of Tarong and Swanbank, and constrained generation capacity as a consequence of wet coal, due to flooding in the Hunter Valley in New South Wales impacting prices across both New South Wales and Queensland contributed to prices exceeding $5000/MWh on 12 occasions across the year. The capacity reductions represented between 9 per cent and 22 per cent of installed capacity not being available during the period.

Prices were also high in the March 2008 quarter of 2007-08 as drought continued to affect generating capacity. Two relatively short lived events caused by lightning in February and March also contributed to the high prices observed.

Finally, observed prices in 2009-10 and 2010-11 are considerably lower than the lower bound of the LRMC range (33 and 38 per cent respectively), particularly away from peak. There are a number of possible explanations for this observed difference, namely:

- outturn gas fuel prices in Queensland might be considerably lower than the assumptions that have been used in our analysis, which has been based on fuel price assumptions developed for the AEMO[19]. Specifically, we have assumed that gas is priced at new entrant fuel costs of \$5.17/GJ in 2009-10 and \$5.13/GJ in 2010-11, which is a growth of 58 per cent compared to 2008-09. We anticipate that if gas prices had been kept at 2008-09 prices, then the lower LRMC estimate would have fallen to \$42.7/MWh. Lower gas prices likely reflect continued availability of relatively cheap 'ramp gas' associated with the development of LNG facilities in Queensland; and
- continuing expansion in generation capacity with an additional 1,031MW of CCGT and OCGT investment (approximately 8 per cent of total installed capacity) since July 2009. This is considerably faster than the growth in demand but is typical of the lumpy investment pattern in the industry.

Overall, periods of prices higher than LRMC benchmarks were associated with conditions that would be expected to give rise to fuel outcomes and were also not sustained in later years.

4.4. New South Wales

4.4.1. Overview of results

Actual electricity spot prices for the New South Wales region are observed to exceed the upper estimate of the LRMC range in 2006-07. For the remaining years, prices are either within the lower estimate of the range, or below the range for 2008-09, 2009-10 and 2010-11 – Figure 4.9, Table 4.3. Indicative contract prices are within the estimated LRMC from 2005-06 to 2010-11.

19 ACIL Tasman, (2009), *Fuel Resource, New Entry and Generation Costs in the NEM*, April.

Figure 4.9
New South Wales Weighted Average Prices Compared with Long Run Marginal Cost

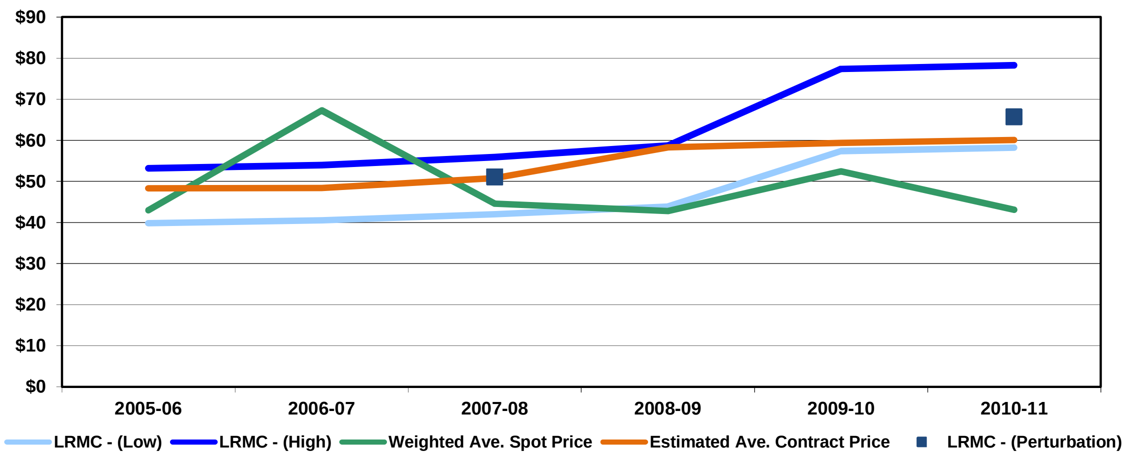


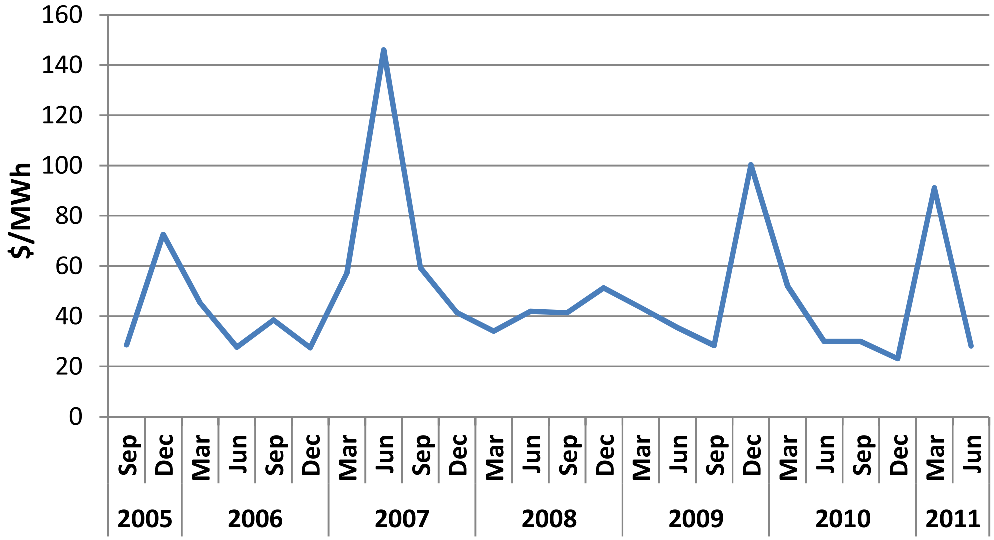
Table 4.3
Long Run Marginal Cost, Spot and Contract Prices for New South Wales ($/MWh)

	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11
LRMC (perturbation)	-	-	51.1	-	-	65.7
LRMC (average incremental cost)						
- upper bound	53.2	54.0	55.9	58.7	77.4	78.3
- lower bound	39.8	40.5	42.0	43.9	57.4	58.2
Volume weighted spot price	43.0	67.3	44.6	42.8	52.4	43.1
Average region wide contract price	48.3	48.4	50.8	58.3	59.4	60.1

4.4.2. Historic price and demand information

Figure 4.9 sets out the historical volume weighted average quarterly prices for the New South Wales region from the September quarter 2005 to June 2011. The June quarter of 2007 represents the highest price, followed by the December quarter of 2009.

Figure 4.10
Quarterly Volume Weighted Prices, New South Wales ($/MWh)



The price duration curves (Figure 4.11) highlight that 2006-07 was an unusually high priced year. The high prices in 2006-07 were driven by the outcomes in the June 2007 quarter, which had an average weighted price of over $140/MWh. In addition, 2005-06, 2006-07 and 2009-10 all had significant numbers of instances with price above $5000/MWh but only 2006-07 had an annual price above the LRMC benchmark – Figure 4.12. Indeed, 2009-10 had a result falling below the LRMC benchmark range.

Figure 4.11
New South Wales Price Duration Curves, 2003-04 to 2010-11

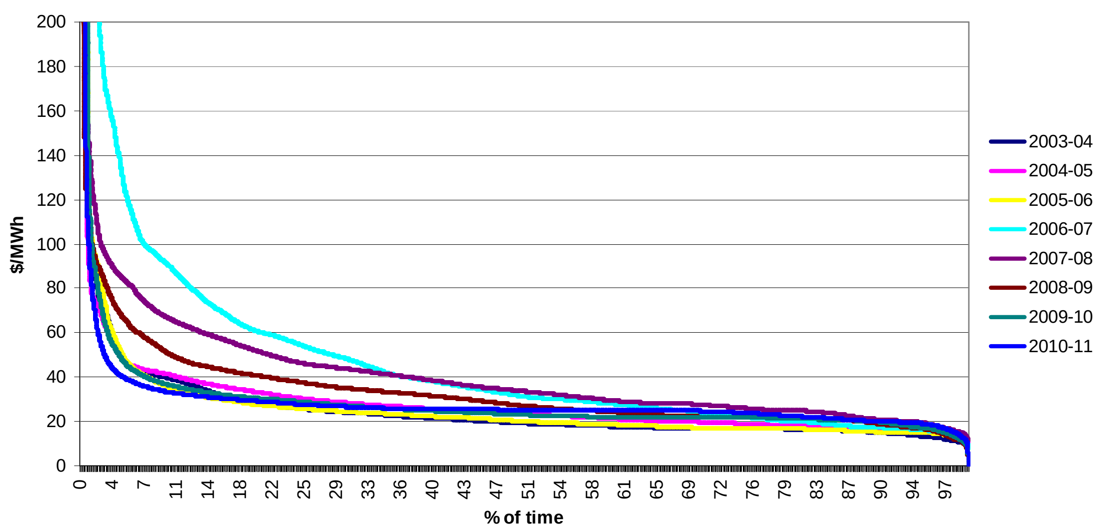
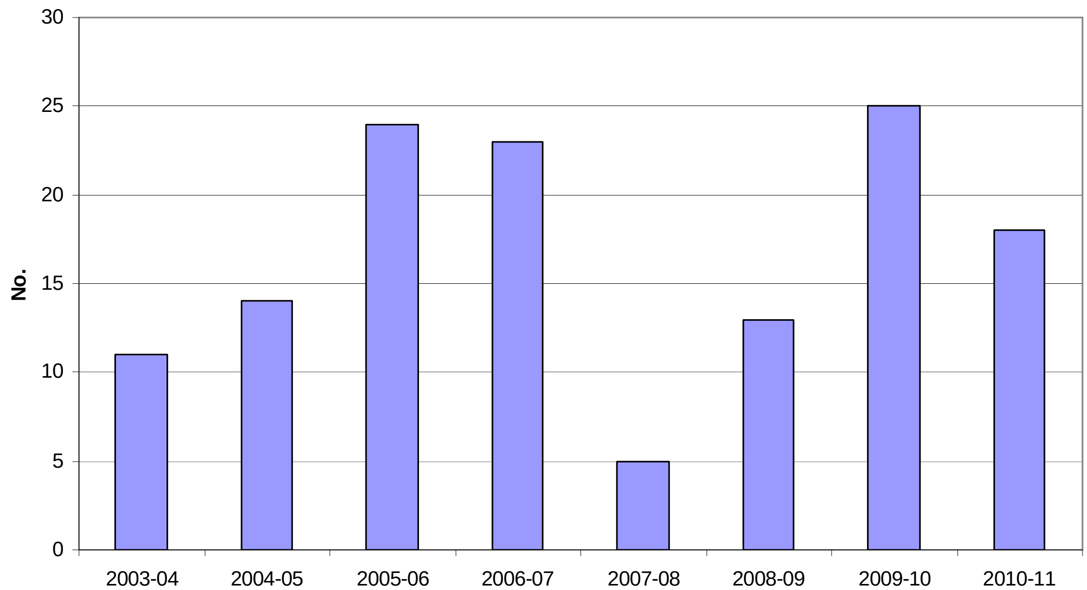


Figure 4.12
Frequency of Half Hourly Price exceeding $5000/MWh, New South Wales, 2003-04 to 2010-11



Demand alone does not explain the observed higher prices in 2006-07. The profile of demand in 2006-07 was broadly similar to other years – Figure 4.13. In addition, peak demand has grown steadily over the period to 2010-11 – Figure 4.14.

Figure 4.13
New South Wales Load Duration Curves, 2003-04 to 2010-11

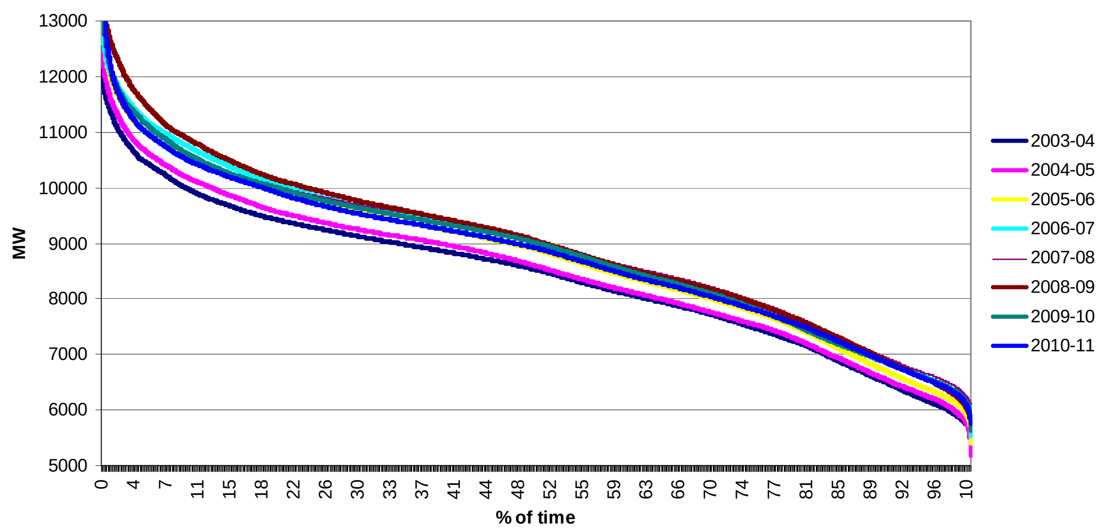
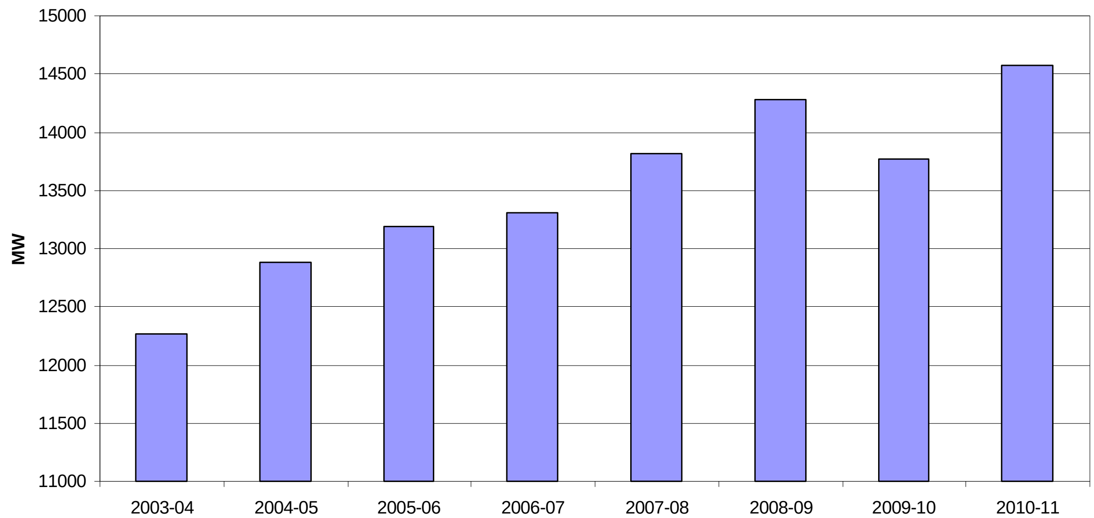


Figure 4.14
New South Wales Peak Load (MW)



4.4.3. Discussion of results

There are two circumstances that suggest prices in 2006-07 would be higher than the long run trend, namely:

- continuing drought over the period impacting on supply capacity; and
- a significant price event in June 2007, resulting from a combination of high winter demand combined with restricted supply capacity due to drought, and short term electricity production restrictions in the Hunter Valley due to localised flooding.

This caused the volume weighted spot price in June 2007 to be significantly higher when compared to other periods. Indeed, the monthly volume weighted average price in the month of June was $272/MWh and had 17 half hours where price exceeded $5,000/MWh.

These are similar conditions to those affecting prices in Queensland over the same period, although New South Wales prices fall prior to Queensland.

Observed prices in 2009-10 and 2010-11 are lower than the lower estimate of the LRMC range (9 and 26 per cent respectively). The load duration curve for New South Wales in 2010-11 is lower than every year over the past five years, suggesting that load was generally lower across most periods compared to earlier years - Figure 4.13. This would be expected to reduce average prices when compared to expectations based on forecast load.

Finally, for the remaining years actual prices are towards the lower estimate of the LRMC range. Observing the load and price duration curves for these periods highlights that the load within these years appears to be generally typical. As a consequence, there does not appear to have been any unexpected circumstances and so there is no reason to expect prices would have deviated from the LRMC range.

4.5. Victoria

4.5.1. Overview of results

Outturn electricity spot prices for the Victorian region exceeded the upper estimate of the LRMC range in 2006-07, but are within or below the estimates for the remaining years – Figure 4.15, Table 4.4. Contract prices are within the estimates between 2005-06 and 2010-11.

Figure 4.15
Victoria Weighted Average Prices Compared with Long Run Marginal Cost

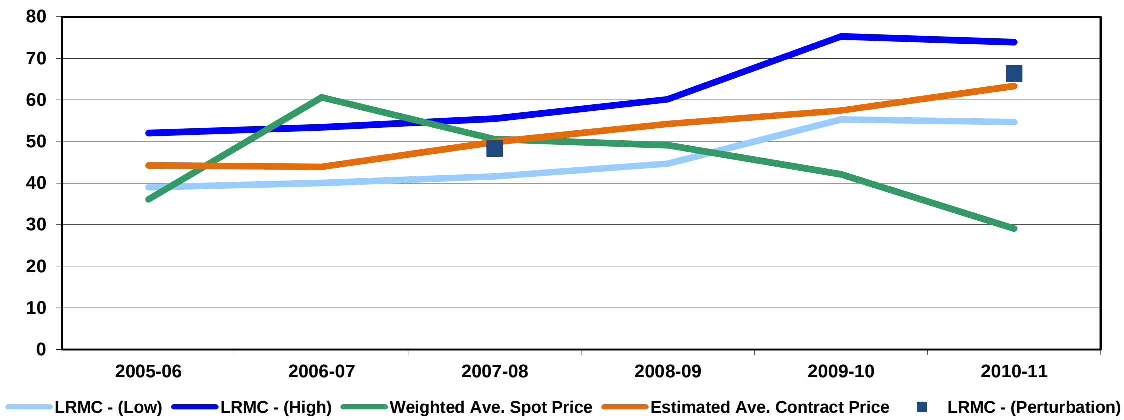


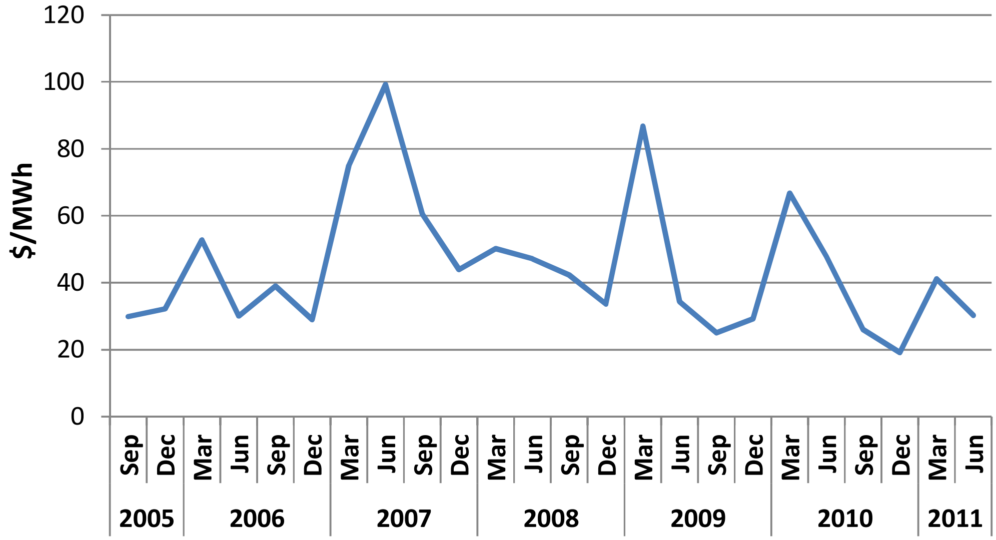
Table 4.4
Long Run Marginal Cost, Spot and Contract Prices for Victoria ($/MWh)

	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11
LRMC (perturbation)	-	-	48.3	-	-	66.3
LRMC (average incremental cost)						
- upper bound	52.0	53.4	55.5	60.2	75.3	73.9
- lower bound	39.0	40.0	41.6	44.7	55.3	54.7
Volume weighted spot price	36.1	60.6	50.6	49.1	42.1	29.1
Average region wide contract price	44.2	43.9	49.9	54.3	57.5	63.3

4.5.2. Historic price and demand information

Figure 4.16 sets out the historical volume weighted average quarterly prices for the Victorian region from the September quarter 2006 to June 2011. As with New South Wales and Queensland, quarterly prices in Victoria increased from March to December 2007. Prices then continue to remain high with a subsequent peak in March 2009.

Figure 4.16
Quarterly Volume Weighted Prices, Victoria ($/MWh)



The main driver of high prices in 2006-07 is the high prices observed in the March and June quarters of 2007 with a volume weighted spot price of around $75/MWh and $99/MWh respectively. The price duration curves (Figure 4.17) show that prices were generally higher when compared to the other years. However, the number of significant price events where prices were higher than $5000/MWh is not abnormally higher when compared to other years - Figure 4.18.

Figure 4.17
Victoria Price Duration Curves, 2003-04 to 2010-11

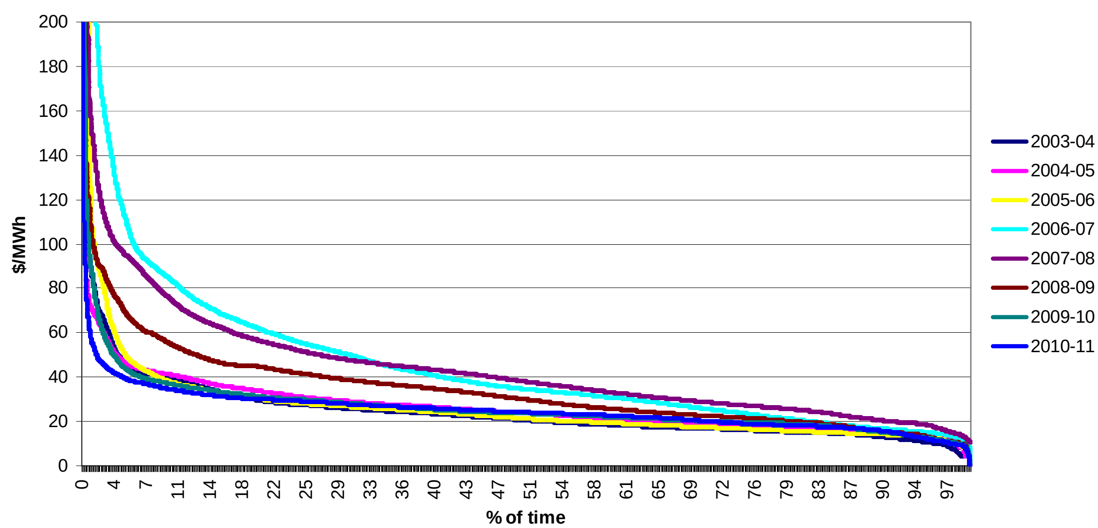
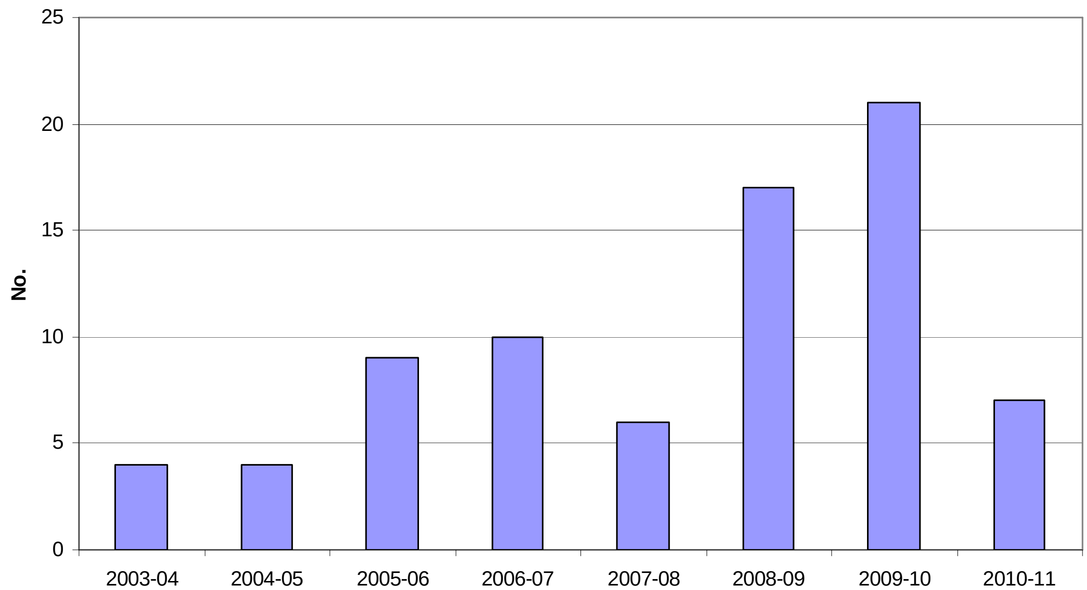


Figure 4.18
Frequency of Half Hourly Price exceeding $5000/MWh, Victoria, 2003-04 to 2010-11



Demand does not appear to have had a role in the higher spot prices in 2006-07. The profile of demand in 2006-07 was a broadly similar pattern to other years – Figure 4.13. From 2006-07 onwards, peak demand in each year has exceeded 2006-07 – Figure 4.14.

Figure 4.19
Victoria Load Duration Curves, 2003-04 to 2010-11

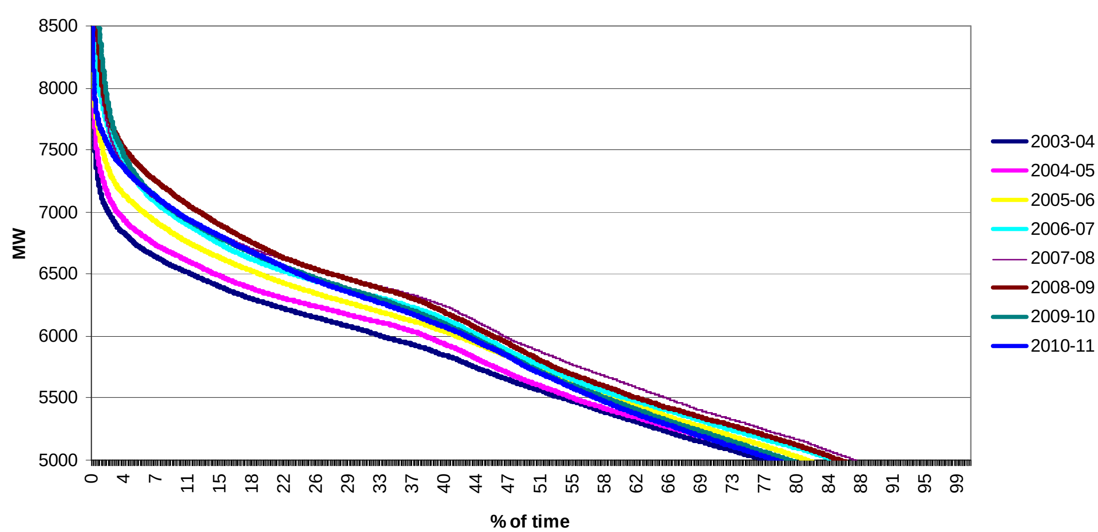
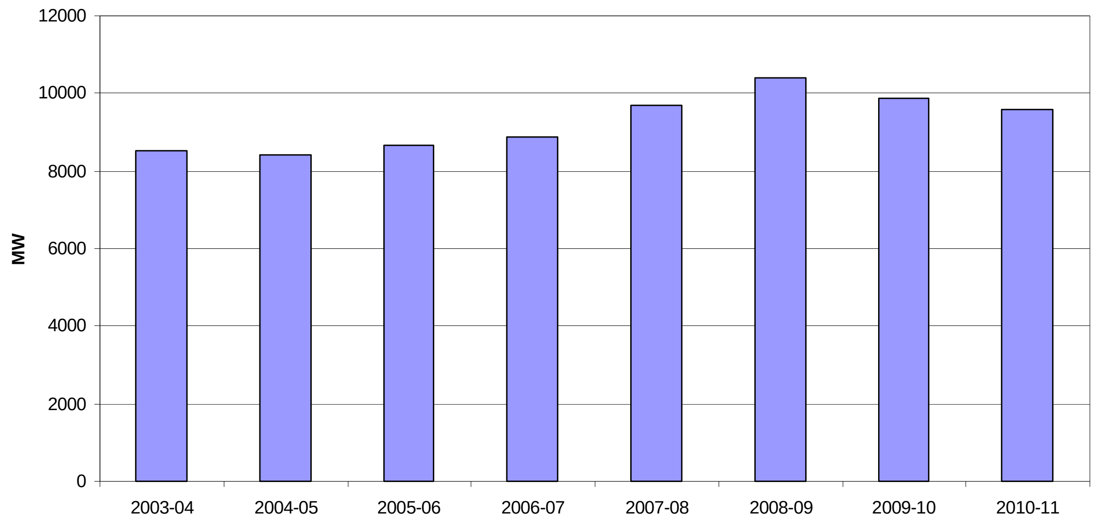


Figure 4.20
Victoria Peak Load (MW)



4.5.3. Discussion of results

The high spot prices during 2007 were associated with:

- a period of extended drought affecting generation production in the Snowy region, New South Wales, Queensland and Victorian hydro capability;
- a period in June 2007 where high demand, combined with reduced generation capacity in both Victoria and New South Wales as a consequence of the drought and unanticipated generation outages or constraints; and
- bushfires in January 2007 resulting in an outage of the Victoria-Snowy interconnector,[20] leading to price spikes and an interruption of around 2,600MW of customer load.

The higher price in the March quarter of 2008-09 off a relatively low base is associated with record demand in both Victoria and South Australia in late January. Temperatures in both Melbourne and Adelaide exceeded 43 degrees, leading to a record peak maximum demand in Victoria of 10,494MW – Figure 4.20. This demand was slightly short of the AEMO's 2008 forecast for 10 per cent probability of exceedance of 10,525MW. While the demands during summer were at the high end of forecasts the annual load duration curve (ie, the number of times different levels of demand were reached) was persistently near the peak relative to most other years (see Figure 4.21). This is reflected in the persistent spot price near peak (Figure 4.22) and number of periods where prices exceed $5,000/MWh (Figure 4.18) as would be expected. The extent of high prices was exacerbated by the failure of the Basslink interconnector, which shut down due to temperature conditions on one of the extreme days.

[20] The Snowy region was abolished from July 2008

Figure 4.21
Victoria Load Duration Curves – Top 0.5 Per Cent of Demand

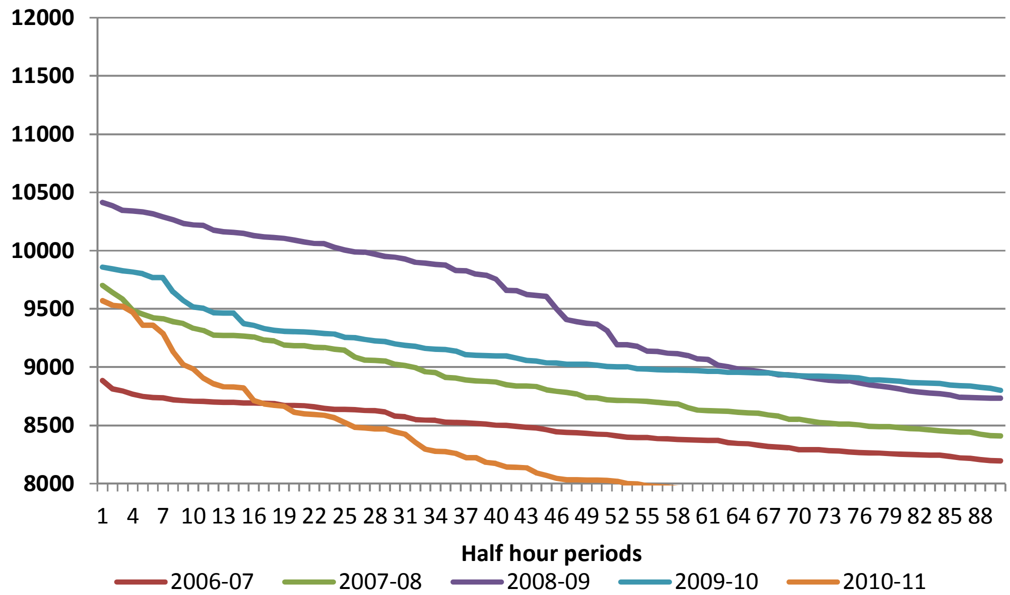
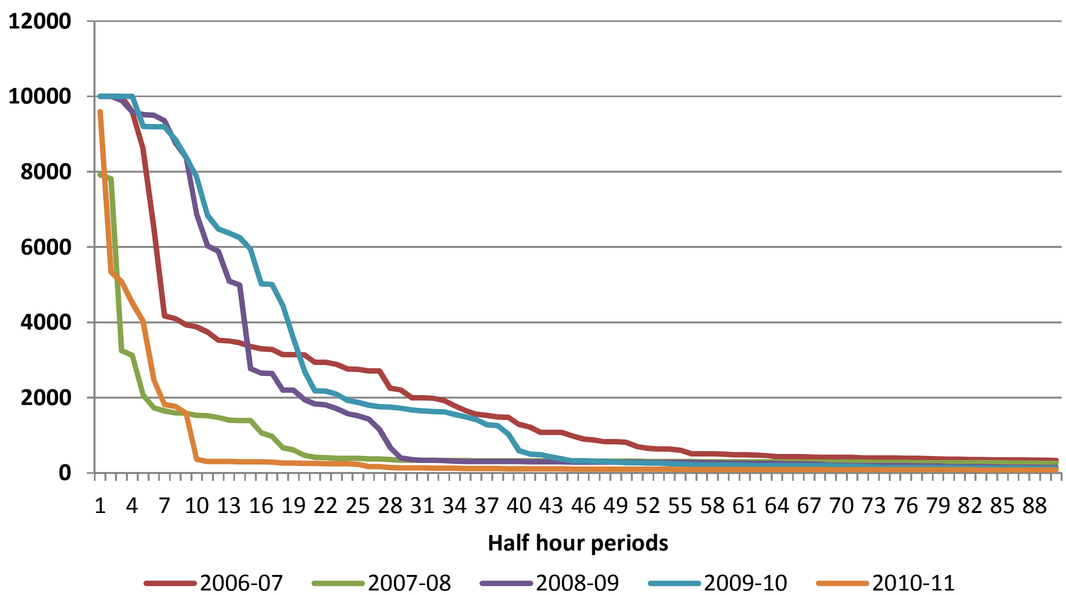


Figure 4.22
Victoria Price Duration Curves – Top 0.5 Per Cent of Price



Spot prices in 2009-10 and 2010-11 were considerably less than the lower estimate of the LRMC range (31 and 47 per cent respectively). The 2010-11 observed figure is also considerably below the modelled LRMC estimate, which itself is towards the upper estimate of the approximate LRMC range.

This outcome is consistent with observations that:

- 2010-11 saw substantially less time at high demands compared with all of the previous seven years. This can be seen in the rapid fall of the "top end" of the load duration curve (Figure 4.21), and would be expected to have had a significant dampening effect on outturn prices. This can also be observed from the rapid fall in occurrence of high prices in the "top end" of the price duration curve; and
- 164 MW of wind generation coming online in October 2009 in Victoria, combined with a further 232 MW of wind generation in South Australia during 2010, placing downward pressure on spot prices.

4.6. South Australia

4.6.1. Overview of results

The actual electricity spot prices for the South Australian region are observed to exceed the upper bound of the LRMC range in 2007-08, and are within the range for the remaining years except for 2010-11 where the price is below all assessments – Figure 4.23, Table 4.5. Indicative region wide contract prices are within the bound between 2005-06 and 2010-11.

Figure 4.23
South Australia Weighted Average Prices Compared with Long Run Marginal Cost

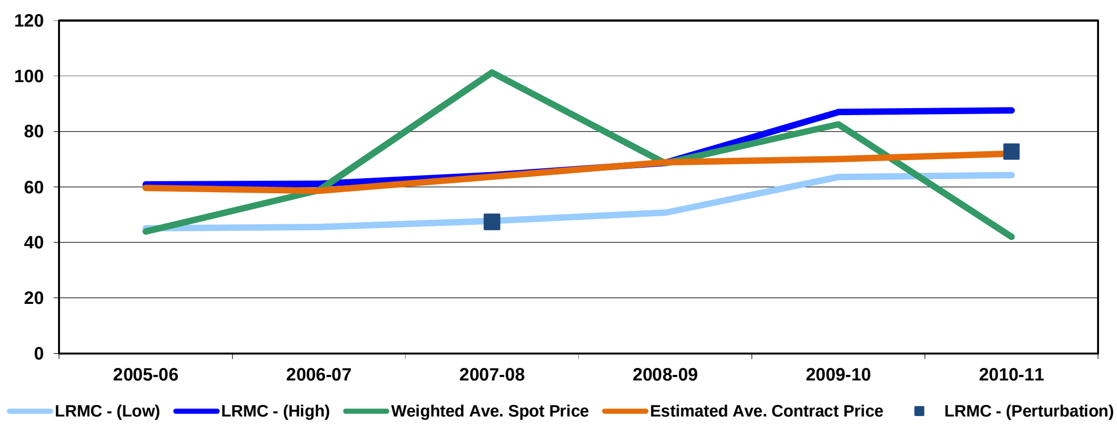


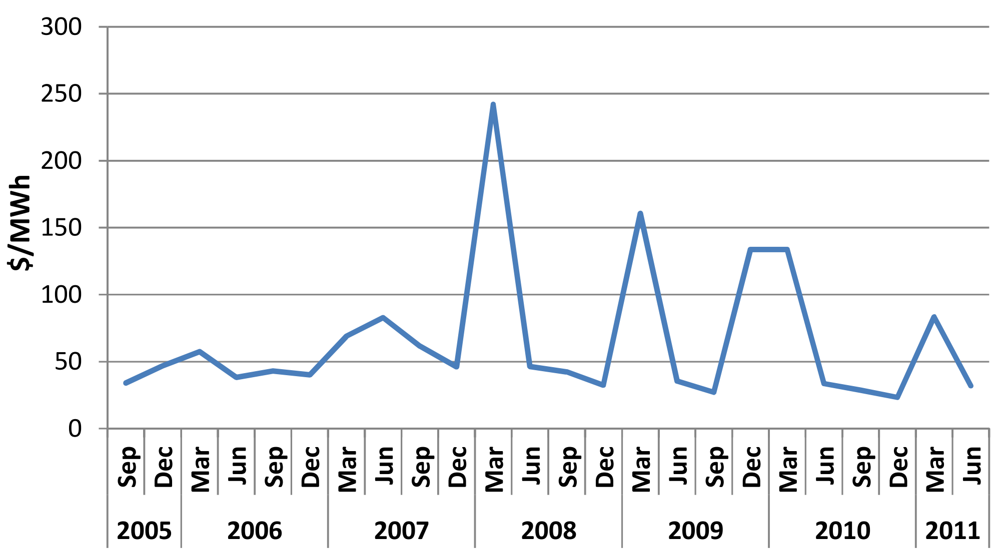
Table 4.5
Long Run Marginal Cost, Spot and Contract Prices for South Australia ($/MWh)

	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11
LRMC (perturbation)			47.4			72.7
LRMC (average incremental cost)						
- upper bound	60.9	61.2	64.3	68.7	87.0	87.5
- lower bound	45.1	45.5	47.8	50.7	63.6	64.2
Volume weighted spot price	44.0	58.8	101.2	68.6	82.5	42.0
Average region wide contract price	59.7	58.6	63.7	68.8	70.1	72.0

4.6.2. Historic price and demand information

Figure 4.24 sets out the historical volume weighted average quarterly prices for the South Australian region for the period from the September quarter 2005 to June 2011. Quarterly prices peaked in the March quarter 2008 at $246/MWh, which remains a record high quarterly price across all NEM regions. This price was driven in particular by high prices over the period of 5 to 17 March 2008, where prices exceeded $5000/MWh for 26 half hourly periods. The March quarter is generally the highest priced quarter (not surprisingly as this covers the majority of the summer period) but the December quarter was also high in 2009-10.

Figure 4.24
Quarterly Volume Weighted Prices, South Australia ($/MWh)



The high price in 2007-08 was driven mainly by the price in the March quarter 2008 at $246/MWh. The price duration curves (Figure 4.25) show that 2006-07 and 2007-08 prices are significantly above the average when compared to other years. This position reversed in 2009-10 and 2010-11 – Figure 4.25.

The price duration curves also show that the high prices were in part a consequence of a small number of peak price periods, because the curve for 2006-07 where average price was almost 42 per cent lower than for 2007-08 sits below the curve for 2007-08. This is consistent with Figure 4.26, which shows 2007-08 with the highest number of periods where prices exceed $5,000/MWh.

In 2007-08 there was a step increase in the number of instances of prices exceeding $5,000/MWh (noting that the market price cap rose from $10,000/MWh to $12,500/MWh in July 2010). The number of these events fell in 2008-09, rose again in 2009-10 and fell back in 2010-11, broadly in line with the changes in annual average price. That said, while there have been a high number of periods of prices exceeding $5,000/MWh, this has not translated into prices consistently exceeding the estimates of LRMC.

Figure 4.25
South Australia Price Duration Curves, 2003-04 to 2010-11

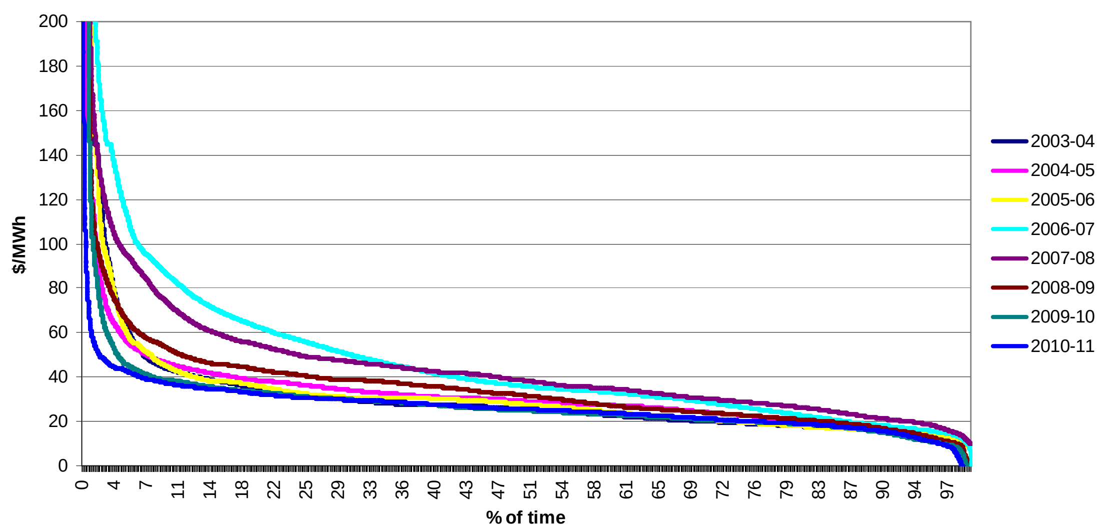
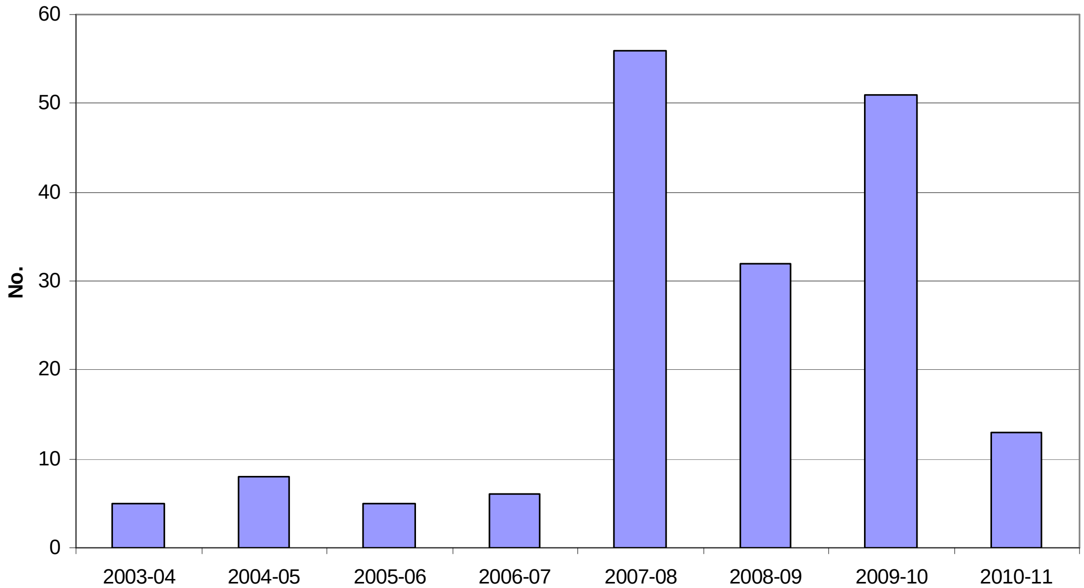


Figure 4.26
Frequency of Half Hourly Price exceeding $5000/MWh, South Australia, 2003-04 to 2010-11



The load duration curves for South Australia are set out in Figure 4.27. The load does not appear to have had a role in the high prices in 2007-08 or the low prices in 2010-11 as the duration curve for those years are broadly similar when compared to other years. Peak demand alone does explain the high prices in 2007-08 or the low prices in 2010-11 either. While peak demand in 2007-08 is higher than previous years, it is lower when compared to subsequent years. In 2010-11 South Australia recorded a record for peak demand of 3,385MW – Figure 4.28.

Figure 4.27
South Australia Load Duration Curves, 2003-04 to 2010-11

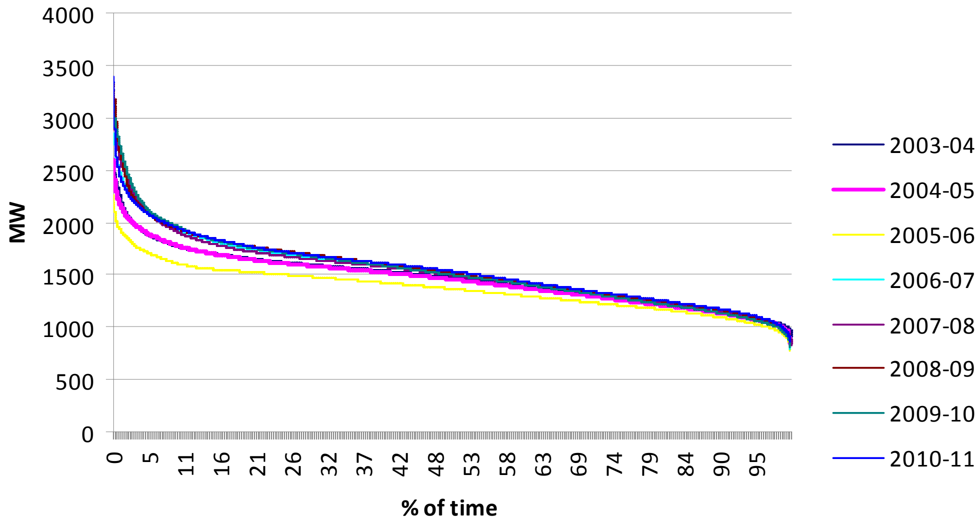
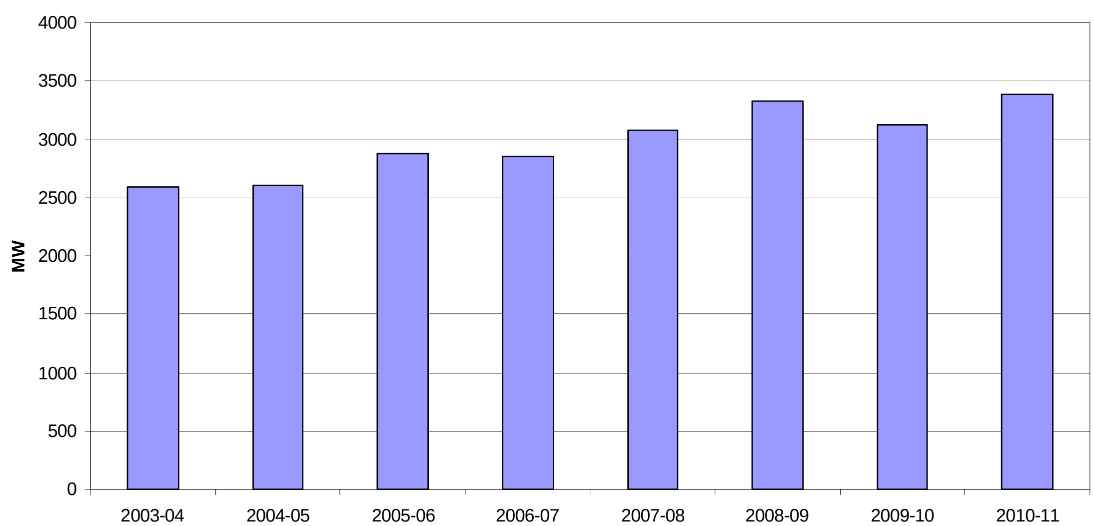


Figure 4.28
South Australia Peak Load (MW)



4.6.3. Discussion of results

The high price in 2007-08 was heavily driven by prices between 5 and 17 March 2008, where prices exceeded $5000/MWh for 26 half hourly periods, approximately half the number of such events for the year. These prices were associated with a number of potentially contributing factors, specifically:

- South Australia experienced an unprecedented 15 day heat wave over this period, which led to record levels of electricity demand; and
- the capability of the interconnector at high price times was the lowest level over the period reviewed, thereby limiting electricity flows from Victoria.

The reduced interconnector capability appears to have played a significant role in 2007-08. Specifically, there were 39 half hourly periods where the price difference between Victoria and South Australia was greater than $9,000/MWh, nearly twice the number in the next highest year (2009-10) – Table 4.6. Limits on transfers between Victoria and South Australian regions at times of high demand are not unusual. However, the average interconnector flow during these periods was 356MW (which compares with an average interconnector flow of 475MW in 2010-11 under similar conditions). In constructing this table, interconnector flow has been taken as the most relevant indicator, although it does assume that the interconnector was being operated to its prevailing capacity when price differences were greatest.

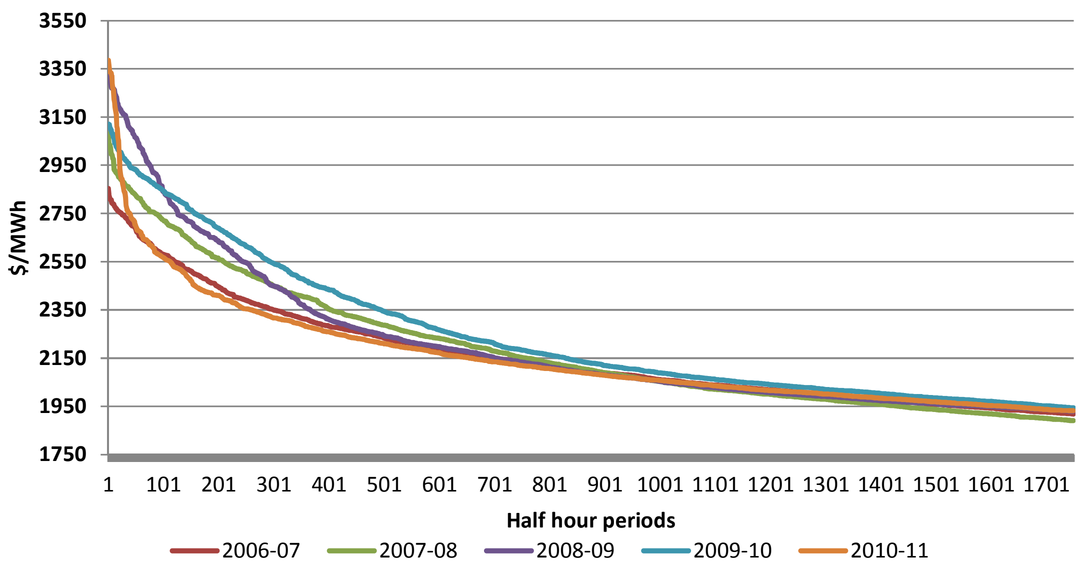
Table 4.6
Price Differences and Interconnector Flows between South Australia and Victoria

Price Difference	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11
> $9,000						
- No. of Events	0	0	39	8	21	5
- Ave Interconnector Flow	-	-	356	397	413	475
> $5,000						
- No. of Events	0	0	50	18	36	9
- Ave Interconnector Flow	-	-	362	380	376	454
> $1,000						
- No. of Events	16	8	53	25	56	14
- Ave Interconnector Flow	362	388	356	373	354	404

Price difference rather than price alone is significant as it indicates lower priced supply was available in Victoria at the time – of course had additional interconnector flows been possible the Victorian price would likely have been higher but the South Australian price lower. It is highly speculative to reconstruct price outcomes for changes in interconnector limits given the complex interactions involved. Nevertheless, in order to explore the possible influence of the interconnector limitation on prices, we examined how prices might have changed if the number of instances of price separation between Victoria and South Australia was not as large as actually observed in 2007-08. If the number of periods with large price differences was reduced by 50 per cent to no more than $1,000/MWh (which would be within the range observed in later years where interconnector flows were higher under these circumstances), then the price in 2007-08 would have been in the order of $85/MWh. The purpose of this comparison is purely to illustrate the potential impact and should not be read as a definitive assessment of the impact of the reduced interconnection capability. We also note that flow (and by implication capacity) has subsequently been rising at times of high prices.

To further understand the drivers on price it is useful to note that the relatively high incidence of demands within 75 per cent of the peak in 2007-08, notwithstanding that 2008-09 and 2010-11 had higher maximum demands – Figure 4.29.

Figure 4.29
South Australia Load Duration Curves – Top 10 per cent of Hours



2007-08 was therefore affected by both relatively high demands and relatively lower interconnector capability (at high demand/price times). Accounting for the higher incidence of price separation and the higher incidence of high demands than would be expected over the long term, it is likely that out turn prices should be expected to be at the upper end or somewhat above the calculated LRMC.

March 2009 also saw high prices, although not to the levels observed in March 2008. High prices in March 2009 were associated with a further period of high temperatures - albeit not as severe as in March 2008. Significantly, price separation from Victoria was less severe at all price levels. For example there were 25 instances where the price in South Australia was more than $1,000 greater than Victoria in 2008-09 compared with 53 in 2007-08.

Interestingly, in 2009-10 the high price end of the price duration curve was similar to 2007-08. However, the low priced end differed in that the 2009-10 values were materially lower leading to a lower annual average price. The growing effect of wind generation on the wholesale price is likely to have impacted on the lower prices in 2009-10 and contributed to a lower annual average price of $82.5/MWh in 2009-10, which was within the range of calculated LRMC. Prices from November 2009 and into January 2010 were again high, reflecting the first ever heat wave in November in South Australia, and saw prices exceeding $5,000/MWh for 14 trading intervals between 10 November and 13 November, with 13 being at the market price cap. Notably, price separation to Victoria was in excess of $9,000/MWh on each occasion but the average interconnector capability was higher at 413MW. In addition high temperatures in February 2010, were associated with prices exceeding $5000/MWh for 9 trading periods between 8 and 10 February.

The price outcomes for 2010-11 are of particular interest because it suggests that demand was lower than for typical years for most of the year and this is consistent with the fewer number of days with maximum temperature over 35 degrees. The lower demand would be expected to place downward pressure on price, in particular fewer high prices. Increasing development of wind generation in South Australia and Victoria would also be expected to reduce price across all time periods but in particular at low demand times. Both of these effects are visible in the 2010-11 results, notwithstanding that 2010-11 saw a record peak demand in South Australia of 3,385MW – Figure 4.28.

4.7. Impact of contracting

Figure 4.30 and Table 4.7 show the costs for each of the NEM region by quarter and year from the quarter of September 2005 to June 2011 of our analysis including indicative region wide contracts. Overall, the estimated energy purchase cost/per MWh, taking into account the observed contract prices and assumed hedging strategy, gradually increases over time in all NEM regions. Contract costs are within the bound of LRMC between 2005-06 and 2010-11 for all NEM regions with the exception of 2009-10 and 2010-11 in the Queensland region where contract costs are below the range. The contract cost is highest in South Australia, due to a combination of higher contract prices and the region's peakier demand profile. In general contract costs peak in the March quarter when demand and contract prices are typically both the highest in all regions considered. Given the assumptions that have had to be made to develop these contract price estimates, we believe that the insights that can be drawn from the estimates are limited. To improve these estimates, we would need to have access to considerably more information about actual market contracting strategies and timing, liquidity, and individual demand profiles. In addition, some consideration would also need to be given to how contract prices are affected by any energy market policy uncertainty that prevailed over the study time period. A number of factors warrant additional comments:

- while there has been growing turnover in contracts, public information about historical contract prices is relatively limited, especially in South Australia where some of the strongest points of concern about price have been raised. This situation has been compounded by increasing vertical integration within the industry meaning that explicit external contracts are not needed to hedge supply costs for much of the demand. In principle, rational market participants might be expected to balance the use of internal resources against further contracting but, once built, there is a substantial sunk cost to the affected businesses and this affect may take considerable time to emerge. Strategic considerations such as management of policy uncertainty would also be expected to impact this balance;

- our analysis has not attempted to examine the situation for individual customers and has been focused on system wide outcomes. As a result any analysis of a system wide contract portfolio would not replicate the position of most customers buying to meet their load shape. Results of system wide analysis will most likely deliver an unrealistically low overall contract price, except for customers with flat load profiles. In principle, secondary trading or bespoke contracts offer the opportunity to adjust profiles but this increases complexity and means standard form contracts and exchanges cannot be used; and

- it is likely that a prudent purchaser will build up a contract portfolio over a number of years as we have assumed. A comparison of the resultant contract price against outturn spot price will therefore be affected by the time lag between contract purchase and year-by-year volatility, and the assumption made in the analysis about how customers stage their contract purchases. Over the longer term it is likely this effect would be "averaged out" but a full analysis if it would require an even longer period of analysis than comparison of spot price against LRMC that we have undertaken in this report. On the other hand purchasers who choose to contract for their total requirement for fixed terms can expect to face lumpy contract prices at each renewal, sometimes higher than outturn spot price and sometimes below – this is more likely in times of policy uncertainty.

The relevant point for this analysis is that, in principle, contract prices should smooth out the year-on-year volatility that is a natural characteristic of the spot price and also in principle should reflect LRMC plus an appropriate commercial risk management premium. In the same way that it is not appropriate to consider spot price in the short term for the purposes of assessing market power, it is important to consider contracting outcomes over sufficient time. The financial market environment in the NEM has matured considerably since the market commenced but, given the changing nature of the market coupled with policy uncertainty in recent years, we consider the results to be indicative. That said the results are broadly in line with the LRMC range and perturbation modelling analysis and so do not indicate that contract prices are inappropriate compared to LRMC.

Figure 4.30
Contract Costs for Each Quarter by NEM region

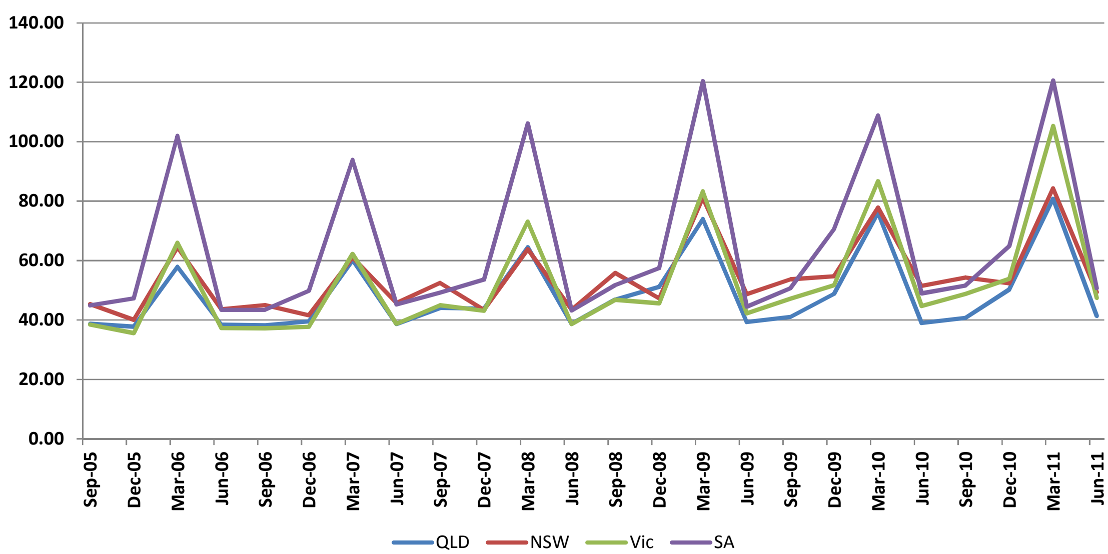


Table 4.7
Yearly Estimated Contract Prices by NEM Region - $/MWh

State	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11
QLD	43.44	44.42	47.98	53.15	51.68	53.69
NSW	48.34	48.38	50.81	58.25	59.39	60.08
Vic	44.24	43.93	49.89	54.27	57.45	63.33
SA	59.70	58.60	63.70	68.84	70.07	71.97

Our conclusion that contracts may only reflect LRMC over a relatively lengthy period is consistent with the role of contracting as a risk management tool that insulates both buyers and sellers from inherently volatile spot outcomes. In the most recent years it is also notable that spot outcomes have been suppressed by an externality in the form of renewable obligations, where the total price of renewables is not seen in the spot price (but clearly is seen in customer net price inclusive of the costs of renewable energy certificates or off take agreements for the purchase of renewable energy). For the time where the renewable obligation is growing and materially impacting spot outcomes, prices below LRMC can be expected, albeit with greater volatility due to the intermittent nature of much of the renewable technology.

Appendix A. Key Modelling Assumptions and Inputs for the Average Incremental Cost Approach to estimate LRMC

This section sets out the assumptions used in this study to estimate LRMC using an approximate approach described in greater detail in chapter 2. Our approach has used several data and parameters sources that are publically available.

The key sources for these parameters and the associated reference materials are:

- ACIL Tasman, (2007*), Fuel Resource, New Entry and Generation Costs in the NEM Report 2 – Data and Documentation*, 6 June;
- ACIL Tasman, (2009), *Fuel Resource, New Entry and Generation Costs in the NEM*, April; and
- AEMO real price and demand data sets.

The ACIL Tasman reports contain the inputs and parameters necessary to calculate variable and annualised capital cost estimates. We have estimated an upper and lower LRMC based on the high and low range of variable and annualised capital costs, as developed by ACIL Tasman. The AEMO website contains real time trading price and demand data sets in half hour intervals from 1998. These were used to estimate the demand load curve for each NEM region for each financial year from 2005-06 to 2010-11.

A.1. Parameters and assumptions used to calculate detailed cost inputs and parameters

A.1.1. Fuel and capital costs

Table A.1 Assumed High and Low CCGT Fuel Costs ($/GJ)

	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11
CCGT – low						
- NSW	$3.00	$3.06	$3.20	$3.27	$4.77	$4.84
- VIC	$2.91	$2.97	$3.11	$3.21	$4.31	$4.43
- QLD	$2.75	$2.81	$2.94	$2.95	$4.65	$4.62
- SA	$3.29	$3.36	$3.51	$3.59	$4.84	$4.95
- TAS	$3.01	$3.07	$3.21	$3.32	$4.75	$4.87
- NEM	$2.99	$3.06	$3.19	$3.27	$4.67	$4.74
CCGT - high						
- NSW	$3.67	$3.74	$3.91	$3.99	$5.83	$5.91
- VIC	$3.56	$3.63	$3.80	$3.92	$5.27	$5.42
- QLD	$3.36	$3.43	$3.59	$3.61	$5.69	$5.64
- SA	$4.02	$4.10	$4.29	$4.39	$5.92	$6.05
- TAS	$3.68	$3.76	$3.93	$4.06	$5.81	$5.95
- NEM	$3.66	$3.73	$3.90	$3.99	$5.70	$5.80

Table A.2 Assumed High and Low OCGT Fuel Costs ($/GJ)

	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11
OCGT – low						
- NSW	$3.75	$3.83	$4.00	$3.92	$5.96	$6.05
- VIC	$3.64	$3.72	$3.88	$3.85	$5.39	$5.54
- QLD	$3.44	$3.51	$3.67	$3.55	$5.82	$5.77
- SA	$4.11	$4.19	$4.38	$4.31	$6.05	$6.19
- TAS	$3.76	$3.84	$4.02	$3.99	$5.94	$6.09
- NEM	$3.74	$3.82	$3.99	$3.92	$5.83	$5.93
OCGT - high						
- NSW	$4.59	$4.68	$4.89	$4.79	$7.28	$7.39
- VIC	$4.45	$4.54	$4.75	$4.70	$6.59	$6.77
- QLD	$4.21	$4.29	$4.49	$4.33	$7.11	$7.06
- SA	$5.02	$5.13	$5.36	$5.27	$7.40	$7.57
- TAS	$4.60	$4.70	$4.91	$4.87	$7.26	$7.44
- NEM	$4.57	$4.67	$4.88	$4.79	$7.13	$7.25

Table A.3 Assumed High and Low CCGT and OCGT Capital Costs ($/kW)

	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11
CCGT - low	$884	$902	$945	$964	$1,231	$1,176
CCGT - high	$1,081	$1,103	$1,155	$1,178	$1,505	$1,438
OCGT - low	$606	$619	$648	$661	$887	$847
OCGT - high	$741	$756	$792	$807	$1,084	$1,035

A.1.2. Plant operating and cost parameters

Thermal efficiency for CCGT and OCGT was assumed to be 50 per cent and between 31 and 32 per cent from 2005-06, respectively.

In addition, the fixed operating and maintenance (FOM) cost and variable operating and maintenance (VOM) cost are shown in the table below. The significant change in the parameter values after 2009-10 reflect a change in assumptions about utilisation as CCGT is assumed to act more as base load generator.

Table A.4 Assumed FOM (MW/year) and VOM ($/MWh)

	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11
CCGT FOM	$11,975	$12,223	$12,800	$13,120	$31,000	$31,775
CCGT VOM	$4.55	$4.64	$4.85	$4.97	$1.05	$1.08
OCGT FOM	$7,016	$7,162	$7,500	$7,688	$13,000	$13,325
OCGT VOM	$7.03	$7.18	$7.50	$7.69	$7.70	$7.89

Other parameters

The post-tax nominal weighted average cost of capital (WACC) is assumed to be 9.25 per cent and 9.48 per cent from 2005-06 to 2008-09 and 2009-10 to 2010-11 respectively. The upper and lower estimates assumed that the WACC was plus or minus 2 per cent from these estimates.

The asset life is assumed to be 30 years for both CCGT and OCGT generation.

A.2. Detailed cost inputs and parameters used to estimate long run marginal costs

This section provides the detailed CCGT and OCGT variable costs and annualised costs assumptions used to calculate the LRMC by financial year and NEM region for both the low and high estimates.

Table A.5 CCGT Variable and Annualised Capital Costs – Low Costs

	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11
Variable Cost						
- NSW	$26.16	$26.70	$27.90	$28.49	$35.38	$35.90
- VIC	$25.52	$26.05	$27.22	$28.06	$32.11	$33.01
- QLD	$24.36	$24.87	$25.99	$26.24	$34.55	$34.32
- SA	$28.22	$28.80	$30.10	$30.83	$35.91	$36.74
- TAS	$26.23	$26.78	$27.98	$28.88	$35.26	$36.15
- NEM	$26.10	$26.64	$27.84	$28.50	$34.64	$35.22
Annualised capital Cost						
- NSW	$85,016	$86,779	$90,876	$92,757	$135,044	$131,170
- VIC	$85,016	$86,779	$90,876	$92,757	$135,044	$131,170
- QLD	$85,016	$86,779	$90,876	$92,757	$135,044	$131,170
- SA	$85,016	$86,779	$90,876	$92,757	$135,044	$131,170
- TAS	$85,016	$86,779	$90,876	$92,757	$135,044	$131,170
- NEM	$85,016	$86,779	$90,876	$92,757	$135,044	$131,170

Table A.6 CCGT Variable and Annualised Capital Costs – High Costs

	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11
Variable Cost						
- NSW	$30.96	$31.60	$33.03	$33.72	$43.01	$43.63
- VIC	$30.18	$30.81	$32.19	$33.19	$39.01	$40.10
- QLD	$28.77	$29.37	$30.69	$30.97	$42.00	$41.71
- SA	$33.48	$34.17	$35.71	$36.57	$43.66	$44.67
- TAS	$31.05	$31.70	$33.12	$34.20	$42.87	$43.94
- NEM	$30.89	$31.53	$32.95	$33.73	$42.11	$42.81
Annualised capital Cost						
- NSW	$138,708	$141,585	$148,269	$151,298	$210,646	$203,394
- VIC	$138,708	$141,585	$148,269	$151,298	$210,646	$203,394
- QLD	$138,708	$141,585	$148,269	$151,298	$210,646	$203,394
- SA	$138,708	$141,585	$148,269	$151,298	$210,646	$203,394
- TAS	$138,708	$141,585	$148,269	$151,298	$210,646	$203,394
- NEM	$138,708	$141,585	$148,269	$151,298	$210,646	$203,394

Table A.7 OCGT Variable and Annualised Capital Costs - Low Costs

	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11
Variable Cost						
- NSW	$50.60	$51.65	$53.98	$53.21	$76.89	$75.92
- VIC	$49.31	$50.34	$52.61	$52.37	$70.31	$70.21
- QLD	$46.99	$47.96	$50.12	$48.86	$75.24	$72.86
- SA	$54.75	$55.89	$58.41	$57.73	$77.97	$77.53
- TAS	$50.75	$51.80	$54.14	$53.97	$76.68	$76.39
- NEM	$50.48	$51.53	$53.85	$53.23	$75.42	$74.58
Annualised capital Cost						
- NSW	$57,102	$58,286	$61,038	$62,266	$87,915	$84,890
- VIC	$57,102	$58,286	$61,038	$62,266	$87,915	$84,890
- QLD	$57,102	$58,286	$61,038	$62,266	$87,915	$84,890
- SA	$57,102	$58,286	$61,038	$62,266	$87,915	$84,890
- TAS	$57,102	$58,286	$61,038	$62,266	$87,915	$84,890
- NEM	$57,102	$58,286	$61,038	$62,266	$87,915	$84,890

Table A.8 OCGT Variable and Annualised Capital Costs – High Costs

	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11
Variable Cost						
- NSW	$60.28	$61.53	$64.31	$63.33	$92.27	$91.04
- VIC	$58.71	$59.93	$62.63	$62.30	$84.22	$84.06
- QLD	$55.87	$57.02	$59.59	$58.01	$90.25	$87.30
- SA	$65.36	$66.71	$69.72	$68.85	$93.59	$93.00
- TAS	$60.47	$61.72	$64.50	$64.25	$92.01	$91.61
- NEM	$60.14	$61.38	$64.15	$63.35	$90.47	$89.40
Annualised capital Cost						
- NSW	$93,920	$95,867	$100,393	$102,387	$142,350	$136,890
- VIC	$93,920	$95,867	$100,393	$102,387	$142,350	$136,890
- QLD	$93,920	$95,867	$100,393	$102,387	$142,350	$136,890
- SA	$93,920	$95,867	$100,393	$102,387	$142,350	$136,890
- TAS	$93,920	$95,867	$100,393	$102,387	$142,350	$136,890
- NEM	$93,920	$95,867	$100,393	$102,387	$142,350	$136,890

Appendix B. Key Modelling Assumptions and Inputs for the Perturbation Approach

This section sets out the market modelling assumptions that have been used for the study. Our approach to developing these assumptions involved undertaking a detailed review of assumptions and inputs used by recent electricity market studies, and wherever possible using publicly available market information for each parameter.

The methodology called for analysis based on the conditions as the market players would reasonably have anticipated at the time. Accordingly studies commencing in 2007 used data from that year and the 2010 study used 2010 era data.

As the analysis is looking for changes in capital and operating costs rather than the spot price, the key requirement is that our base case for each year has a technology mix that is broadly consistent with what would have been expected by participants at the time. This allows the increase in capital and operating costs due to the increase in demand to assess LRMC to occur from a sound base.

The key sources for these parameters and the associated reference materials are:

- Australian Energy Market Operator, (2010), *National Transmission Network Development Plan Modelling Assumptions: Supply Input Spreadsheets*, 23 August;
- Australian Energy Market Operator, (2010), *National Transmission Network Development Plan Demand Forecasts*, 8 June;
- Australian Energy Market Operator, (2010), Electricity Statement of Opportunities (ESOO); and
- KPMG Econtech, (2010), Economic Scenarios and Forecasts for AEMO – 2009 Update, 11 February.

The AEMO data for 2010 was published with reference to a number of market scenarios, which reflect possible differences in economic growth, fuel prices, and energy demand. We have chosen to use Scenario 3[21] which assumes moderate economic growth, moderate oil and gas prices with relatively high domestic gas demand, medium domestic LNG production and new gas supplies in the eastern states.

The capital costs for new plants in Scenario 3 for the 2010 study are approximately the medium for the range predicted across all of the scenarios. In the 2007 SOO scenarios were not presented and we adopted the AEMO costs as the starting point for analysis - although as discussed in the report we recognise that uncertainty about future market conditions will have impacted financial parameters in the costs, for example discount rates used to derive capital costs.

The remainder of this chapter discusses the assumptions and inputs used in greater detail.

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[21] See AEMO, NTNDP Supporting Data Input Data base, <http://www.aemo.com.au/planning/2010ntndp_cd/home.htm>.

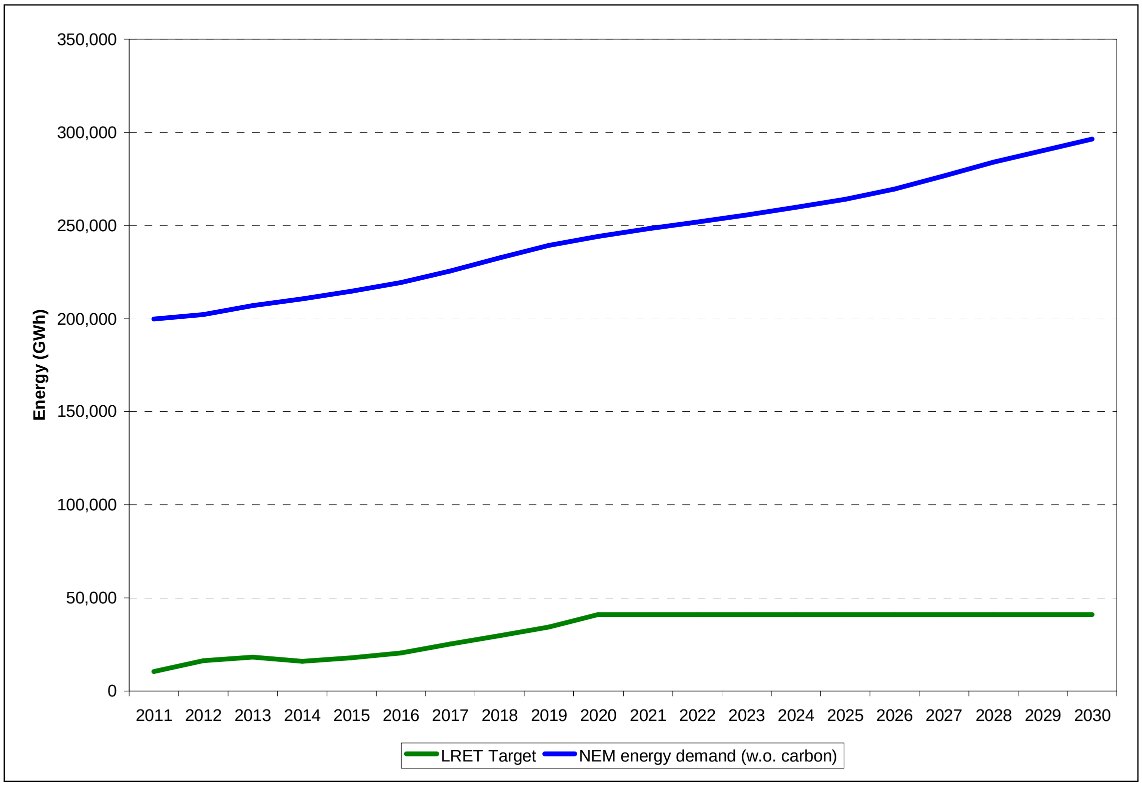
B.1. The renewable energy target

For the study commencing in 2007 it was necessary to choose a reasonable baseline for renewable energy obligations. Australia's initial renewable energy target was for 9,500GWh of new renewable energy to be developed between 2000 and 2010 under a scheme known as the Mandatory Renewable Energy Scheme (MRET). The Enhanced Renewable Energy Target (RET) scheme was announced in 2009 and set a target of 20 per cent by 2020 requiring effectively extending the 9,500GWh target to 45,000GWh by 2020. In the lead up to the announcement of the RET there was considerable uncertainty about the target and also about the future of various state schemes which were already in operation or were emerging at the time. As a result investment and pricing of certificates under the MRET were volatile and it has proven difficult to develop a clear estimate of what market participants would have assumed in NEM trading. However, considerable investment in renewable energy had occurred meeting much if not all of the remaining requirement under MRET. This situation was compounded by speculation about future carbon pricing discussed below.

Fortunately and as noted earlier, the analysis for this current task calls for a robust base in order to ensure the technology in the base case is representative rather than precise amounts. Accordingly for the purposes of this work we have adopted an assumption that the MRET requirement had been fulfilled and that further renewable investment would be driven by the RET, which was subsequently divided in the Larger Renewable Energy Target (LRET) and the Small Renewable Energy Scheme (SRES). We also assumed the various state schemes would result in similar levels of renewable investments for the base case and the case with an increment of demand and would therefore not impact the outcome and as a result were assumed to be encompassed by the uncertainty in the ERET/LRET starting point.

The LRET scheme commenced on 1 January 2011, with the target introduced in line with the schedule set out in Figure B.1 published by the Renewable Energy Regulator.

Figure B.1: Large-scale renewable energy target and total NEM-wide energy demand



Source: ORER website ,http://www.orer.gov.au/new.html#lrettarget.; and AEMO, 2010 NTNDP study, "2010 NTNDP Energy and MD Forecasts.xlsx", see: http://wwww.aemo.com.au/planning/2010ntndp_cd/home.htm.

In setting the requirements in the modelling, we have taken into account existing and committed renewable plant investments and Green Power based renewable energy certificates (RECs).

B.2. Carbon prices

A carbon price scenario has also been included in the market modelling for both years. While at the time a carbon price had not been introduced, the expected introduction of a carbon price would still have an impact on LMRC as this would impact on the expected future cost of operating a power plant. Realistic assumptions need to be included into the model to obtain an accurate LRMC for the years. This means that if the actual expectation of a carbon price at the time is lower than the assumed expectation in the model then this would overstate the LRMC. However, omitting it completely is also likely to omit a factor which would influence LRMC in 2007-08, and would therefore understate LRMC.

Prior to the federal government's announcement about the Clean Energy Package in July 2011 there was uncertainty about carbon pricing although a reasonable confidence that carbon would be priced as a Prime Minister's Task Force had been formed 2006.

For the 2007 cases we have assumed a schedule that is similar to the schedule then being discussed and eventually forming the CPRS schedule which included a soft start in 2010 with

2 years at $10 and then a price of approximately $24/t (2009-10 dollars) incremented at 4 per cent real. This schedule was adjusted to 2007-08 dollars for the study.

For the 2010 case we adopted a schedule that more closely aligns with the schedule ultimately adopted for the Clean Energy Policy which commenced in 2012 but following the same profile as for the 2007 case (that is the "soft start" was dropped.

It is important to note that prior to the introduction of the CPRS

B.3. Committed generation plant new entry and existing plant retirements

The modelling framework determines new generation entry required to satisfy expected electricity demand, given both existing plant and information on planned plant retirements and new plant investments. We include all new generation projects that had reached the committed status, as defined by the AEMO in the NEM at the relevant time for the 2007 and 2010 base case years.

Table B2 lists the existing generating units that had not reached this status for the 2007 ESOO and were therefore excluded from the 2007 case (but included for 2010).

Table B.1
Scheduled and Semi-Scheduled Projects not planned in 2007

Source: OGW/NERA analysis of AEMO, 2010 and 2007 ESOO, published.

Name	Size (MW)	Jurisdiction
Braemar 2	504	Queensland
Condamine	140	Queensland
Darling Downs	315	Queensland
Yarwun	168	Queensland
Mortlake	550	Victoria
Clements Gap	57	South Australia
Hallet 2 Wind Farm	71	South Australia
Hallet 4 Wind Farm	132	South Australia
Lake Bonney 3 Wind Farm	159	South Australia
Waterloo Wind Farm	111	South Australia
Tamar Valley (CCGT and OCGT)	258	Tasmania

A summary of announced retirements in the NEM is set out in below in Table B.2. These were used in the 2007 and 2010 cases.

Table B.2
NEM Retirement Plans

Station	Year	MW reduction	Comment
Munmorah	2015	600	
Playford	2018	240	Assumed but understood to be under review
Swanbank B unit 3	2011	120	
Swanbank B unit	2012	120	Stations fully retired
Mackay GT	2016	27	Subject to review

Source: AEMO, (2010), ESOO, published.

B.4. Marginal loss factors

Marginal loss factors (MLFs) represent the impact of transmission losses from a generator to the relevant regional reference node. They are used to scale regional reference node prices to calculate revenues for generators (and also for customers).

We have used the relevant MLFs as applied by the AEMO, as appropriate for the base years.

B.5. New entrant technology parameters

The new generation entrant technology parameters are based on those developed jointly by AEMO and DRET noted earlier. Values for selected key technologies are summarised in Table B.3 below.

Table B.3
Capital Costs

Technology	Installed capital cost $/kW 2007	Installed capital cost $/kW 2010
Wind (200MW)		2,693
OCGT		947
CCGT		1,302
Geothermal		7,416 (EGS) 7,017 (HSA)
Super critical black coal		2,587
Super critical brown coal		3,452

Note: Installed capital costs are for the NEM in 2020 and are expressed in $2009/10.

Source: AEMO, (2010), 2010 NTNDP: National Transmission Network Development Plan, Supporting Data – Input Database, Input Assumption Tables.

B.6. Fuel costs

The AEMO annually publishes its forecasts of fuel costs for twenty years into the future, for each generating plant within the NEM. These forecasts are developed as part of the ESOO and national transmission planning process and take into account a number of factors including generation fuel type and source, the scope for export of the fuel, transport costs, and the cost of mining, where relevant.

The gas price assumptions result in an increase from $3.50/GJ - $4.00/GJ to approximately $6.00/GJ to $7.5/GJ by FY2020 (in $2009/10) in the NEM with later estimates reflecting expectations of the development of LNG facilities in Queensland from late 2013. This is leading to a slight decrease in gas prices particularly in Queensland as gas is produced in the period leading up to commissioning of the plants, followed by an increase as domestic gas prices progressively shift towards export parity prices. The additional gas prior to plant commissioning is commonly referred to as 'ramp gas'.[22]

A key source of uncertainty about gas price in the NEM is the timing of the expected alignment with a netback price with LNG.

B.7. Electricity demand

The AEMO publishes annual forecasts of total electricity demand and summer/winter maximum demand for each region of the NEM as part of the ESOO. AEMO also develop a range of forecasts for scenarios studied in conjunction with DRET. In addition, AEMO publishes the energy to be supplied by scheduled, semi scheduled and non-scheduled generation, and the contribution expected from non-scheduled generation.

As the demand supplied by the NEM is the demand met from scheduled and semi scheduled and we applied the factors nominated by AEMO in the ESOO to derive these from projections of total demand.

The scheduled peak demand and energy (sent out) forecasts for 2007-08 and 2010-11 used in this study are set out in Table B.4 .

[22] One key difference between LNG plants that use coal seam methane as a feedstock and those that use conventional natural gas is that once the wells are brought into production they effectively must stay in production and this may occur before the facilities that will consume the gas in the long term are complete. The resultant gas production is referred to as 'ramp gas' as it occurs during the "ramp up" period of a project.

Table B.4
2007- 08 NEM Scheduled Peak Demand Forecasts

	10% POE Medium Growth MD (MW)				
	QLD	**NSW**	**VIC**	**SA**	**TAS**
FY2008	9,981	15,020	10,026	3,311	1,405
FY2009	10,435	15,500	10,124	3,421	1,431
FY2010	10,850	15,930	10,297	3,483	1,464
FY2011	11,273	16,350	10,515	3,522	1,481
FY2012	11,687	16,760	10,720	3,592	1,503
FY2013	12,135	17,220	10,940	3,684	1,527
FY2014	12,527	17,670	11,173	3,799	1,544
FY2015	12,916	18,110	11,370	3,838	1,579
FY2016	13,340	18,420	11,582	3,919	1,604
FY2017	13,764	18,800	11,794	3,994	1,622
FY2018	14,203	19,193	12,009	4,061	1,649
FY2019	14,656	19,593	12,227	4,130	1,676
FY2020	15,123	20,003	12,450	4,199	1,704
FY2021	15,605	20,420	12,676	4,270	1,732
FY2022	16,103	20,847	12,907	4,342	1,761
FY2023	16,617	21,282	13,141	4,415	1,790
FY2024	17,146	21,726	13,381	4,489	1,820
FY2025	17,693	22,180	13,624	4,565	1,850
FY2026	18,257	22,643	13,872	4,642	1,881

Note: Data represents financial years (eg, FY2011 is 2011/12)

Table B.5
2010 - 11 NEM Scheduled Peak Demand Forecasts

	10% POE Medium Growth MD (MW)				
	QLD	**NSW**	**VIC**	**SA**	**TAS**
FY2010	10,524	15,657	10,783	3,530	1,932
FY2011	10,948	16,169	11,103	3,630	1,968
FY2012	11,469	16,544	11,372	3,670	1,976
FY2013	12,204	16,927	11,461	3,720	1,983
FY2014	12,812	17,322	11,673	3,730	2,001
FY2015	13,411	17,714	11,990	3,780	2,013
FY2016	13,918	18,101	12,174	3,860	2,042
FY2017	14,324	18,493	12,421	3,880	2,059
FY2018	14,676	18,884	12,699	3,940	2,080
FY2019	15,129	19,266	12,930	4,010	2,106
FY2020	15,749	19,709	13,189	4,066	2,135

Note: Data represents financial years (eg, FY2011 is 2011/12)

Table B.6
2007-08 NEM Scheduled Sent Out Energy Forecasts

	QLD	NSW	VIC	SA	TAS
FY2008	51,058	75,710	47,599	12,631	10,221
FY2009	53,129	76,900	46,468	13,064	10,418
FY2010	55,109	78,000	46,362	13,212	10,661
FY2011	57,355	78,890	47,085	13,410	10,781
FY2012	59,389	80,060	47,713	13,628	10,927
FY2013	61,730	81,520	48,574	13,834	11,087
FY2014	63,764	82,900	49,293	13,989	11,205
FY2015	65,672	84,330	50,086	14,160	11,470
FY2016	67,790	85,990	50,955	14,323	11,653
FY2017	69,913	87,540	51,919	14,495	11,771
FY2018	72,092	89,144	52,825	14,668	11,966
FY2019	74,338	90,777	53,747	14,842	12,164
FY2020	76,655	92,440	54,685	15,019	12,366
FY2021	79,044	94,133	55,639	15,198	12,571
FY2022	81,507	95,858	56,610	15,379	12,780
FY2023	84,047	97,614	57,598	15,563	12,991
FY2024	86,667	99,402	58,604	15,748	13,207
FY2025	89,367	101,223	59,626	15,936	13,426
FY2026	92,152	103,078	60,667	16,125	13,648

Note: Data represents financial years (eg, FY2011 is 2011/12)

Table B.7
2010-11 NEM Scheduled Sent Out Energy Forecasts

	QLD	NSW	VIC	SA	TAS
FY2010	53,487	77,720	48,186	14,307	11,334
FY2011	55,601	80,098	49,399	14,824	11,482
FY2012	58,733	81,187	50,202	14,982	11,518
FY2013	62,182	81,657	49,817	15,020	11,491
FY2014	65,510	83,241	49,886	14,788	11,536
FY2015	68,657	84,983	50,045	14,989	11,573
FY2016	70,425	86,389	50,772	15,119	11,750
FY2017	71,851	87,468	51,566	15,239	11,811
FY2018	73,729	88,705	51,993	15,356	11,878
FY2019	75,606	90,962	52,544	15,512	11,960
FY2020	78,555	92,599	53,069	15,652	12,032

Note: Data represents financial years (eg, FY2011 is 2011/12)

In addition, because the NEM forecasts for maximum demand are presented in “as generated” terms but energy is presented on a “sent out” basis and the NEM scheduling process functions on an as generated basis, it is necessary to convert the energy forecasts to an “as generated basis”. The AEMO publish regional scaling factors for this purpose as shown in Table B.8.

Table B.8
Scaling factors to convert annual energy (GWh) from "sent out" to "as generated"

	QLD	NSW	VIC	SA	TAS
FY2011	1.063	1.058	1.086	1.036	1.001
FY2012	1.060	1.057	1.084	1.035	1.002
FY2013	1.060	1.057	1.079	1.033	1.002
FY2014	1.057	1.057	1.076	1.029	1.002
FY2015	1.057	1.055	1.074	1.029	1.002
FY2016	1.057	1.055	1.073	1.026	1.003
FY2017	1.057	1.053	1.068	1.023	1.003
FY2018	1.056	1.052	1.067	1.023	1.003
FY2019	1.056	1.051	1.067	1.023	1.003
FY2020	1.053	1.051	1.063	1.023	1.003
FY2021	1.053	1.049	1.063	1.024	1.004
FY2022	1.051	1.046	1.059	1.022	1.004
FY2023	1.050	1.044	1.056	1.023	1.004
FY2024	1.049	1.042	1.053	1.023	1.004
FY2025	1.048	1.040	1.053	1.023	1.004
FY2026	1.046	1.047	1.050	1.022	1.004
FY2027	1.045	1.053	1.060	1.023	1.004
FY2028	1.043	1.059	1.070	1.023	1.004
FY2029	1.043	1.059	1.070	1.023	1.004
Average	**1.053**	**1.052**	**1.068**	**1.026**	**1.003**

Source: AEMO, 2010 NTNDP study, "2010 NTNDP Energy and MD Forecasts.xlsx", see: http://wwww.aemo.com.au/planning/2010ntndp_cd/home.htm.
Note: Data represents financial years (eg, FY2011 is 2011/12)

B.8. Capacity contribution of intermittent generation

We assumed wind (as the primary intermittent generation technology that emerged in the results) would contribute 3% of installed capacity at peak times in the NEM. This value is broadly consistent with reliability assessments by the AEMO but because we are focussing on changes in capex and opex as a result of increments in demand the particular level used is not critical providing it does not distort the technology mix in the base case for each year studied.

B.9. Approach to transmission

Finally, the modelling is based on a regional representation of the NEM, which takes into account transmission interconnection capacity and losses between regions.

Interconnectors are represented by linear losses based on an approximation developed from previous analysis of typical flows and marginal loss equations published by the AEMO. This is a simplification needed for the load block form of analysis and is intended to strike a balance between representation of the impact of marginal losses on price outcomes and actual (average) losses impacting physical dispatch.

Table B.9 sets out the key interconnection assumptions we commenced with. Where interconnection capability impacted outcomes we also prepared sensitivities with higher and lower transfer capabilities to assist in explaining outcomes – these are discussed at the relevant points in the main report.

Table B.9
Initial NEM Interconnector Characteristics

Interconnector	From	To	Max Forward (MW)	Max Reserve (MW)	Average Loss Factor
Basslink	TAS	VIC	594	478	0.09
Terannora	NSW	QLD	122	220	0.05
QNI	NSW	QLD	550	1,078	0.05
Murraylink	VIC	SA	220	120	0.025
Heywood	VIC	SA	460	460	0.025
VIC-NSW	VIC	NSW	1,500	1,000	0.12

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