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Oakley Greenwood

Estimates of the Long Run Marginal Cost for Electricity Generation in the National Electricity Market

A Report for the Australian Energy Market Commission

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1. Introduction

NERA Economic Consulting (NERA) and Oakley Greenwood (OGW) have been asked by the Australian Energy Market Commission (the Commission) to apply a perturbation methodology to estimate the long run marginal cost (LRMC) for wholesale generation in the National Electricity Market for 2005-06, 2006-07, 2008-09, 2009-10 and 2011-12. These estimates therefore extend the analysis that had been undertaken as part of our earlier study to benchmark NEM wholesale prices against estimates of the LRMC, to provide a complete series of estimates for the LRMC using the perturbation methodology.[1]

As in our earlier study, the estimates of the LRMC are provided for each NEM region except for the Tasmanian region. Tasmania has not been considered in our analysis because of the complexities involved in adequately representing the hydro dominant conditions in the perturbation approach. In addition, the original MEU proposal also recognised that Tasmania is a special case and should be excluded from the proposed new rule change.

Finally, to ensure easy comparison of these additional LRMC estimates with our earlier results, we set out in this report all of our earlier estimates in addition to our estimates of the LRMC using the average incremental cost approach.

The remainder of the report is structured as follows:

- section 2 provides a brief overview of the perturbation methodology used to estimate LRMC; and
- section 3 outlines the results of the analysis including investigating the underlying drivers of the observed outcomes.

The appendix provides further details on the assumptions used to estimate LRMC.

[1] See NERA Economic Consulting and Oakley Greenwood, (2012), *Benchmarking NEM Wholesale Prices against Estimates of Long Run Marginal Cost*, A report for the AEMC, 12 April.

2. Methodology for Estimating Long Run Marginal Cost

In this report we apply the perturbation methodology to estimate LRMC for wholesale generation in the NEM for the period 2005-06 to 20011-12. In our earlier study we only used the perturbation methodology to produce estimates of the LRMC for 2007-08 and 2010-11, and used an average incremental cost methodology to estimate LRMC for those and the remaining years in the period being considered.

This chapter provides a brief description of the perturbation methodology used to produce the additional estimates of LRMC, and describes some additional modelling considerations that arose over the course of the study. In addition, we provide some comments on the interpretation of estimates of the LRMC. A more detailed explanation of the methodologies we have used to produce estimates of the LRMC is set out in our earlier work.[2]

2.1. The perturbation approach

LRMC is the cost of serving a permanent incremental change in demand in a market, assuming all factors of production can be varied. Importantly, because the LRMC is a long run concept, it takes into account that firms have the option of expanding capacity to meet an increase in demand.

The perturbation approach is a commonly used methodology to estimate LRMC. The approach 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; and
4. Calculating the 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.

The effects of a permanent increase in demand are twofold. First, there is a need to invest in capacity expansion *sooner* than would have otherwise been the case, and second there are associated increased operating costs to service this increased demand. The LRMC estimate using the perturbation approach is the difference in the present value under the two scenarios, i.e, the present value of capacity expansion and operating costs without the incremental increase in demand and the present value of capacity expansion and higher operating costs with the incremental increase in demand,.

In markets with lumpy and infrequent capacity expansion investments (such as electricity wholesale markets), LRMC would be expected to rise and fall in line with the deviation between actual demand and the timing for new investment. If electricity demand is at or

[2] Kemp, A., Chow, M., Thorpe, G., (2011), *Estimating Long Run Marginal Cost in the National Electricity Market: A Paper for the AEMC*, 19 December, Sydney.

close to existing generation supply capacity, the LRMC of meeting an additional unit of demand will be high as it reflects the imminent capital expenditure on a new generator which would be required to meet additional demand. However, when there is significant spare generation capacity, an increase in demand can be met by using existing capacity in the short term and there is no immediate need to invest in generation capacity. That is, the LRMC is lower where there is spare capacity because additional capacity is not needed until the spare capacity is utilised.

The advantage of the perturbation approach over alternative methodologies for estimating the LRMC is that it is able to account for complex interactions including opportunities to optimise investment and operating costs across years, network constraints and interactions with external constraints such as renewable targets, through the use of electricity market models.

2.2. Modelling considerations

The perturbation methodology uses expectations about future demand and supply capacity needs to determine what the cost of satisfying an increment (or decrement) of electricity demand will be. This means that applying the perturbation methodology to estimate LRMC for historic years required us to reconstruct market conditions and future expectations as they would have been understood at the time. This includes both expectations of demand and capacity expansions, and also any potential policy changes that might influence demand and supply outcomes (e.g. the expected introduction of a renewable energy target or carbon emission scheme).

The reconstruction of market conditions inevitably requires judgement about the information available to market participants at the time, and what weight was placed on that information. Where possible we have relied on data published in the Statement of Opportunities by the Australian Energy Market Operator (AEMO) for each year. The relevant modelling assumptions used included forecast electricity demand, estimated capital costs of new generation, generation fuel costs, carbon prices and renewable energy targets. The detailed model assumptions and inputs that we have used are set out in Appendix A.

Throughout the period that we considered there was considerable uncertainty about the government’s likely approach to introduction of a renewable energy target and a carbon emissions scheme. We believe that these uncertainties could have impacted on investment risk hurdles applied by investors and premiums embedded in wholesale contract prices through the period but these are not reflected in the AEMO data. As a result the LRMC values presented here are potentially low. On the other hand , developments in coal seam gas technology and planned investments in liquid natural gas facilities in Queensland have also made forecasting new entrant gas prices difficult. The impact of lower cost associated ramp gas on gas fuel prices for existing generators is also likely to have contributed to lower wholesale prices but only in the short term. These policy uncertainties highlight the difficulty in estimating LRMC and why, in practice, any estimate of the LRMC is inherently dependent on the assumptions used in the analysis.

Finally, in estimating LRMC using the perturbation methodology for the additional years it became apparent that the assumptions about the expected timing of the expansion of the renewable energy target (RET) from the existing Mandatory Renewable Energy Target (MRET) had a large influence on the results. Intuitively, as the renewable energy target is increased, it creates an obligation for increased investment in renewable generation. Higher renewable generation defers investment in thermal generation that would have otherwise been needed to satisfy future demand. As the main renewable energy technology, wind has very low operating costs (essentially only variable maintenance cost) and an increasing renewable target displaces dispatch from thermal generation further reducing costs. Deferring thermal generation lowers the present value cost of generation investment, which, when demand is perturbed, has the effect of reducing the estimated LRMC – at the expense of higher retail prices needed to recover the cost of renewable certificates that fund the higher capital cost of wind As a consequence, expectations of the timing for the introduction of the RET, and so a large increase in the renewable energy target compared to the MRET, was found to have a large influence on the estimates of LRMC.

We judged that uncertainty about the timing and magnitude of a future RET was significant in 2006-07 and 2007-08. We therefore applied two different assumptions about the timing and size of the renewable energy target in those years.

2.3. Interpreting the LRMC results

Estimating LRMC for any market is an inexact science. As we have explained above, and in our earlier studies, it requires consideration be given to a large number of assumptions and inputs, including expectations about future demand, generation capacity expansion and all of the associated costs. This highlights that different estimates of the LRMC will be produced depending on the assumptions made.

In addition, any modelling framework is itself an approximation of the factors relevant to the operation of a market. To the extent that there are additional influences on market outcomes not captured within the modelling framework, then actual market outcomes can differ from those predicted from a model. Relevantly, unanticipated electricity demand and generation supply changes, for example due to weather related outages or other unintended generation or network failures, can have a significant impact on outturn wholesale market prices. These influences cannot be predicted and so taken into account within the modelling frameworks used.

As a consequence, observing deviations between actual wholesale market prices and estimates of LRMC provide a helpful input for an investigation on potential exercise of market power. Actual market prices that are *persistently* and *significantly* above LRMC provides a signal that further and deeper analysis is required to determine whether observed deviations of wholesale price over a sufficiently long period:

- are a response to unanticipated changes in underlying demand and supply conditions, ie, flooding or significant transmission network outages, and so are representative of the market providing price signals to equate supply and demand in the short term, and create incentives for new generation in the long term;
- reflect inaccuracies or uncertainties in the assumptions underpinning the estimates of LRMC; or
- can only be explained by an exercise of market power.

That said a simple investigation of deviations in actual prices from estimates of LRMC is only one factor relevant to a consideration of the potential exercise of market power. Consideration of barriers to entry and exit are also important, as higher prices are expected to create incentives for new investment in generation capacity, which itself places downward pressure on market prices.

In reviewing differences between estimates of LRMC and actual prices a number of considerations should be kept in mind, namely:

- we have been conservative in our approach to estimating LRMC, particularly in relation to the inclusion of investment risk premiums that investors would have likely applied given uncertainty about renewable and carbon price policy. In our earlier work the sensitivity of LRMC estimates to the cost of capital was examined.
- LRMC is inherently a long term measure and our comparison with annual spot and contract market prices is relatively arbitrary to assist with an assessment of market power. Using longer time frames for calculating spot or contract market prices allow short-term fluctuations to be smoothed out.
- considering the behaviour of spot prices on a half hour by half hour basis is only relevant to assess if the market rules governing half hourly operation are facilitating or hindering efficient dispatch behaviour. While in aggregate inefficient dispatch outcomes and associated spot prices might provide an indication that market power is being exercised, simply considering half hourly behaviours cannot provide any insight as to whether resultant prices and behaviours *persist* and so might be evidence of inappropriate exercise of market power.
- the inability to store electricity and the relative size of daily fluctuations in demand and the size of generating units means that the single clearing price of the NEM spot market is inherently volatile. This volatility can be exacerbated by market behaviours including behaviour, which if sustained, could lead to prices above LRMC and accordingly provide evidence of the exercise of market power.
- further, the degree to which short term behavior is linked to an exercise of market power varies between market designs and as a result considerable care needs to be taken in making comparisons between different markets.
  - While there is commonly an objective to deliver a total price that is efficient and aligns with LRMC, some markets provide a form of guarantee of part of the price via a capacity payment or impose contracting restrictions on the participants.
  - While there are many alternative energy market designs, in general where a capacity payment is part of the design, the energy price would be expected to more closely track the short run cost of generation and so be more amendable to review on a half hour by half hour basis. This price is commonly referred to as the ‘SRMC’ although strictly speaking it is only the variable cost of supply. Relevantly, it should be distinguished from the SRMC of meeting demand which must also account for risks of supply shortfall as demand approaches supply, which is the basis for the NEM energy price in the absence of an alternative capacity payment guarantee.
  - Short term behaviour which deliberately sets out to withhold capacity and physically reduce supply or to leave no option other than high priced capacity will obviously lead to increased half hourly prices. As noted earlier, an analysis of these events is valuable in informing market design and both market and regulatory risk and the role of financial instruments for both supply and demand side participants in the market. However, by definition short term analysis can only inform short term issues.

Individual half hour prices above LRMC are an inherent and essential feature of the NEM. Similarly, years with a seasonal average price above LRMC are inherent in the market design, as are years with seasonal average prices below LRMC. We believe that an annual average comparison is the shortest period for which comparison is useful but is then only an indication as it is still short of the investment lead time and can be influenced by factors such as annual weather cycles. Analysis conducted for this work has shown variations aligned with daily weather, network capability, drought and most recently with external policy drivers such as the impact of renewable energy targets and general economic conditions.

The quantitative analysis shows that actual prices over a period of time have been below conservative estimates of LRMC, particularly in more recent years. It is on this basis we have concluded that our analysis supports a conclusion that there is no evidence of the exercise of market power as it has been defined. This conclusion is reached notwithstanding that, particularly in the South Australian region, there was a period of price above LRMC and that in certain circumstances there may have been examples of behaviours that *if they persisted* could have provided evidence of market power. In reaching this conclusion we make no comment on the design of the market rules and associated financial mechanisms (contracts) under which the behaviours occurred. Finally, we note that lifting the assumptions that make the calculated LRMC conservative, for example by applying higher risk premiums (ie, a higher WACC), would reduce the extent that we observed prices exceeding LRMC.

Finally, regarding the interpretation of the LRMC estimates under the MRET and LRET assumptions, the estimates under the two schemes will differ depending on the extent to which a particular region is expected to contribute towards the renewable generation capacity expansion to meet the target. Consequently, the difference between the two estimates reflects the degree of uncertainty inherent in predicting LRMC during these periods. In regions that are not expected to have a significant contribution towards the particular RET the uncertainty is lower and therefore each estimate is more closely aligned.

3. Estimates of the LRMC using the Perturbation Methodology

This chapter sets out our results of applying the perturbation methodology to estimate LRMC for the period 2005-06 to 2011-12. To facilitate comparison with our earlier results, we have reproduced our estimates of LRMC obtained applying the average incremental cost methodology, and our calculations of actual average annual wholesale prices and contract prices.

3.1. General Observations

The additional estimates of LRMC produced through application of the perturbation methodology are consistent with the estimates set out in our earlier study, and in particular the estimates produced through application of the average incremental cost methodology. As a consequence, the additional estimates of LRMC when compared with the calculated spot and contract market outcomes continue to support a conclusion that there is no evidence of market power as it has been defined in this work. This conclusion is supported by the following:

- within each of the NEM regions considered, spot prices do not deviate persistently from LRMC estimates;
- interpretation of prevailing market demand and supply conditions indicate that when prices were either above and below the calculated LRMC the direction of the deviation was consistent with the market conditions at the time; and
- for the South Australian region in particular, while observed spot prices were above estimates of LRMC in some years, none were persistently above the estimates.

As anticipated, the application of a lower renewable energy target assuming the continuance of the MRET, led to higher estimates of LRMC across all regions. The difference in LRMC between the two renewable energy target assumptions considered is greatest in South Australia and Victoria, where the majority of renewable generation investment is expected.

Since 2009-10 the LRMC estimates produced from the perturbation methodology increase significantly and then decrease in 2011-12. This is consistent with declining need for new and existing thermal generation:

- in the AEMO estimates over the period, initially there were increasing estimated costs of new entrant generation and gas costs followed by a fall in capital costs in 2010-11. It is notable that the AEMO used different external advisors to estimate new entrant costs in the final year, who applied a different methodology to estimate costs, which, when combined with different assumptions about future exchange rates may have contributed to the different cost outcomes. This further highlights the difficulty in developing estimates of LRMC; and
- reducing forecast future demand combined with a fixed renewable trajectory.

Finally, across the NEM, observed wholesale prices recently have been trending downward relative to the LRMC estimates. As we observed in our earlier report, such an outcome is unlikely to be viable for the wholesale generation sector for an extended period of time. The modelling presumes that new investment will occur in response to wholesale price signals and therefore shows delayed and initially underutilised thermal generation, which progressively sees increasing utilisation and rising prices over the medium term, in addition to the carbon price impact, as prices more closely align with the LRMC of electricity production.

The rest of this chapter outlines the results of comparing spot prices and LRMC estimates for the regions of the NEM considered in our analysis. While this study has not involved a further detailed consideration of reasons underpinning the observed differences between spot prices and estimates of LRMC we provide some commentary on the possible reasons underpinning the observed differences. We refer readers to our earlier study for a more detailed explanation of these differences.

3.2. Queensland

The additional estimates of LRMC produced from applying the perturbation methodology are consistent with our earlier estimates. Indeed, the perturbation estimates of LRMC trended steadily higher from $42/MWh in 2005-06 to $63/MWh in 2011-12, with a peak of $67/MWh in 2010-11 – Figure 3.1, Table 3.1.

Figure 3.1
Queensland Weighted Average Prices Compared with LRMC

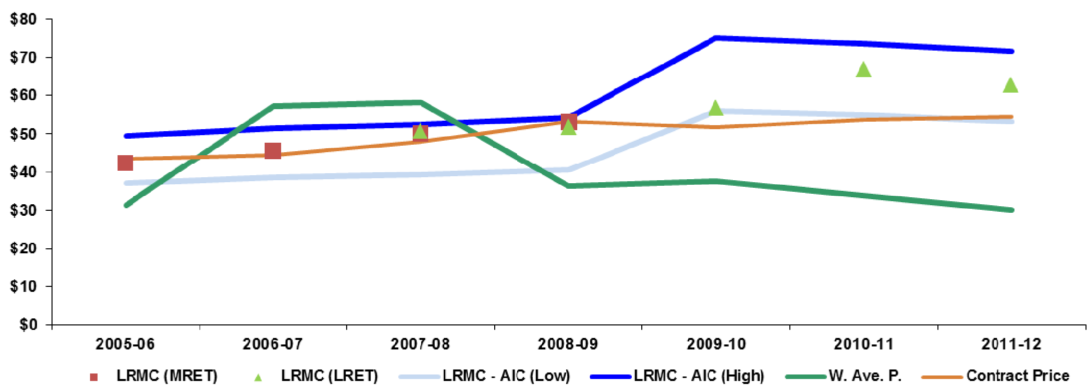

Table 3.1
Long Run Marginal Cost, Spot and Contract Prices for Queensland ($/MWh)

	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12
LRMC (perturbation)							
- MRET	$42	$46	$50	$53			
- LRET			$51	$52	$57	$67	$63
LRMC (average incremental cost)							
- Low	$37	$38	$39	$41	$56	$55	$53
- High	$49	$51	$52	$54	$75	$74	$72
W. Ave. Price	$31	$57	$58	$36	$37	$34	$30
Contract	$43	$44	$48	$53	$52	$54	$54

The years where actual prices had the largest deviation from LRMC are during 2006-07 and 2007-08 where actual prices exceed LRMC estimates, and from 2008-09 onwards where actual prices fall below LRMC estimates.

In 2006-07 and 2007-08, there are several circumstances that would be expected to deliver deviations, specifically:

- high spot prices in the early months of 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; and
- in winter 2007, a combination of record winter peak demand and reduced availability of coal fired generators in NSW as a result of flooding contributed to a number of high price events.

The data also reveals that higher annual spot prices in 2006-07 and 2007-08 were driven by higher prices across much of the year (not only over peak), consistent with a temporary reduction in supply capacity associated with drought impacting on generator availability.

Average observed prices in 2009-10, 2010-11 and 2010-11 are considerably lower than the LRMC estimates. There are a number of possible explanations for these observed differences, namely:

- 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[3]. These forecasts had a sharp increase in price from 2008-09 to 2009-2010. Differences in gas price expectations might therefore explain some of the observed difference in average observed prices compared with the modelled LRMC outcomes. The impact on the LRMC estimates arises from fuel prices affecting the expected future generation investment profile in both the base and incremental cases, which can influence the estimates of the LRMC. We anticipate (based on average incremental cost analysis described in our earlier report) that if gas prices had been kept at 2008-09 prices, then the lower LRMC estimate would have fallen to around $42/MWh, rather than $56/MWh. Lower expectations about gas prices might have been due to continued availability of relatively cheap 'ramp gas' associated with the development of LNG facilities in Queensland; and
- continuing expansion in generation capacity since July 2009. This is considerably faster than the growth in demand but is typical of the lumpy investment pattern in the industry.

The perturbation approach using the MRET and LRET assumptions provides results for the Queensland region that are broadly consistent– Figure 3.3. This result reflects the relatively more limited role Queensland plays in satisfying renewable energy targets. As a consequence a higher renewable energy target has little impact on the LRMC estimates for this region.

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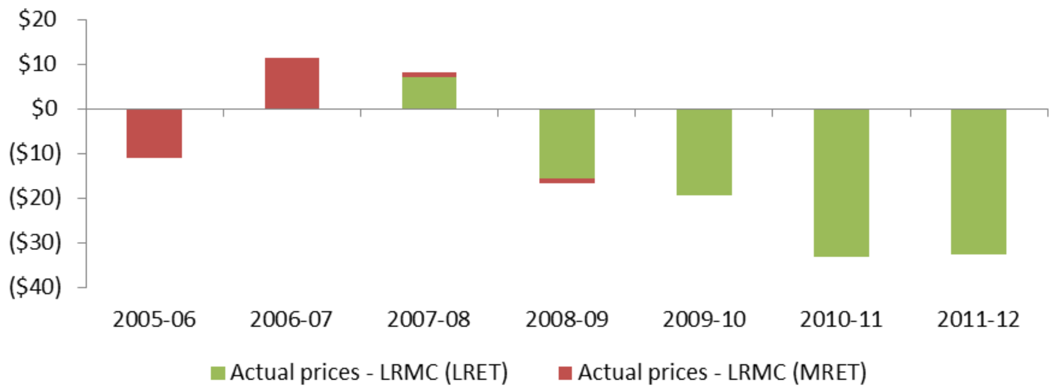
3 ACIL Tasman, (2009), *Fuel Resource, New Entry and Generation Costs in the NEM*, April.

Figure 3.2
Queensland difference between actual volume weight price and LRMC estimated using the perturbation methodology



3.3. New South Wales

As with the Queensland region, the additional estimates of LRMC produced by application of the perturbation methodology are consistent with our earlier estimates of LRMC. The perturbation estimates of LRMC for New South Wales trended steadily higher from $42/MWh in 2005-06 to $60/MWh in 2011-12, with a peak of $66/MWh in 2010-11 - Figure 3.3, Table 3.2.

Figure 3.3
New South Wales Weighted Average Prices Compared with LRMC

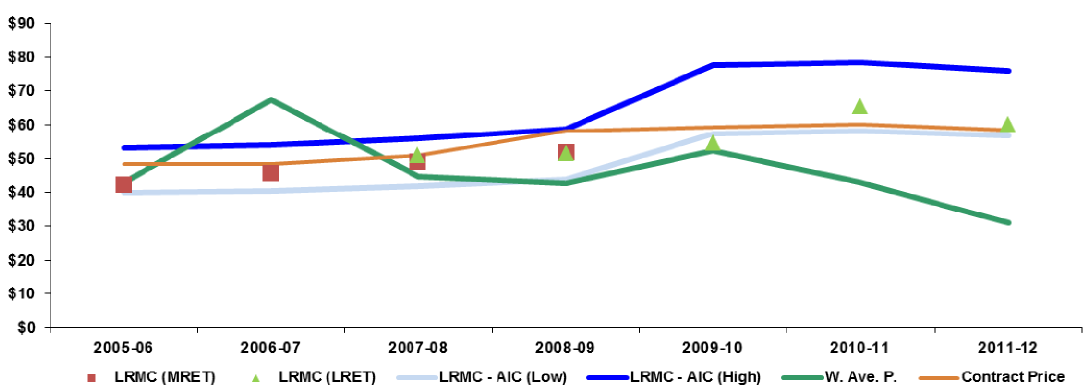


Table 3.2
Long Run Marginal Cost, Spot and Contract Prices for New South Wales ($/MWh)

	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12
LRMC (perturbation)							
- MRET	$42	$46	$49	$52			
- LRET			$51	$52	$55	$66	$60
LRMC (average incremental cost)							
- Low	$40	$40	$42	$44	$57	$58	$57
- High	$53	$54	$56	$59	$77	$78	$76
W. Ave. Price	$43	$67	$45	$43	$52	$43	$31
Contract	$48	$48	$51	$58	$59	$60	$58

Looking at conditions in the market over the period considered, there are a number of explanations for prices being observed to deviate from the LRMC estimates. Specifically, in 2006-07:

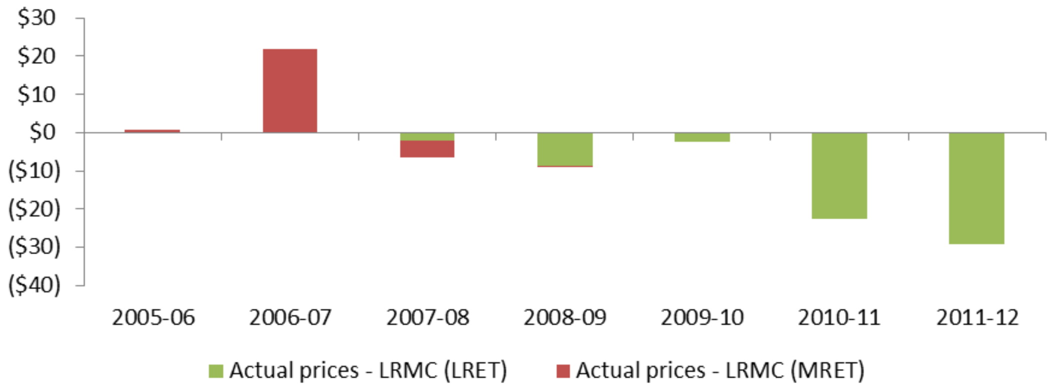
- continuing drought impacted on electricity supply capacity; and
- a significant price event in June 2007, resulting from a combination of high winter demand combined with restricted supply capacity due to drought, and short term electricity production restrictions in the Hunter Valley due to localised flooding, led to the volume weighted spot price in June 2007 to be significantly higher when compared to other periods.

These conditions are similar to those affecting prices in Queensland over the same period, although the price deviation did not persist to the same extent into 2007-08 as was observed in the Queensland region.

Observed prices in 2009-10, 2010-11 and 2011-2012 are lower than the estimates of LRMC, (specifically 9, 26 and 46 per cent lower than the lowest LRMC estimated, respectively). Electricity demand in 2010-11 and 2011-12 is generally lower than demand in previous years, which would be expected to reduce average prices when compared to expectations based on forecast load.

As with Queensland, estimates of LRMC using the perturbation methodology are similar regardless of the renewable energy target assumptions used – Figure 3.5. This reflects the expectation that less renewable generation investment will likely occur in New South Wales as compared to other regions to satisfy the renewable energy target. This outcome is consistent with observed patterns of renewable generation investment, which are focused in the southern regions where there are higher quality wind resources.

Figure 3.4
New South Wales difference between actual volume weight price and LRMC estimated using the perturbation methodology



3.4. Victoria

The additional estimates of LRMC for Victoria, produced by application of the perturbation methodology are consistent with our earlier estimates of LRMC. The perturbation estimates of LRMC trended steadily higher from \$49/MWh in 2005-06 to \$61/MWh in 2011-12, with a peak of \$66/MWh in 2010-11 - Figure 3.6, Table 3.4.

Figure 3.5
Victoria Weighted Average Price Compared with LRMC

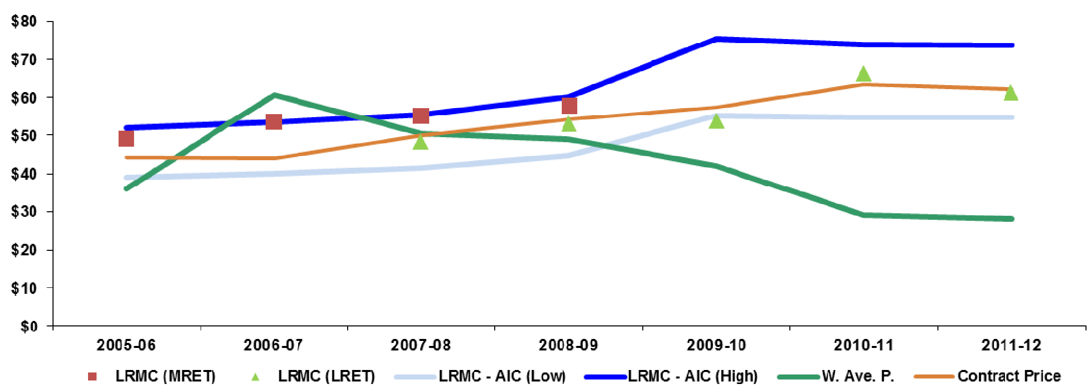


Table 3.3
Long Run Marginal Cost, Spot and Contract Prices for Victoria ($/MWh)

	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12
LRMC (perturbation)							
- MRET	$49	$54	$55	$58			
- LRET			$48	$53	$54	$66	$61
LRMC (average incremental cost)							
- Low	$39	$40	$42	$45	$55	$55	$55
- High	$52	$53	$55	$60	$75	$74	$74
W. Ave. Price	$36	$61	$51	$49	$42	$29	$28
Contract	$44	$44	$50	$54	$57	$63	$62

As with the other regions, in 2006-07 actual spot prices were at its highest compared to the estimates of LRMC. The high spot prices during 2006-07 are 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,[4] leading to price spikes and an interruption of around 2,600MW of customer load.

Spot prices in 2009-10, 2010-11 and 2011-12 are lower than the estimates of the LRMC, (specifically 31, 47 and 49 per cent lower than the lowest LRMC estimated, respectively). The observed Victorian region spot prices in 2010-11 and 2011-12 were considerably below the LRMC estimates. These outcomes are consistent with observations that:

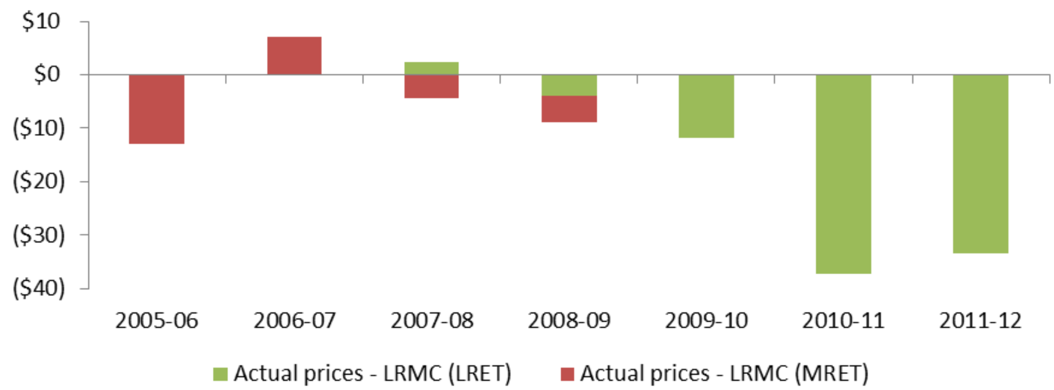
- 2010-11 and 2011-12 saw substantially less time at high demands compared with previous years, which would be expected to have a significant dampening effect on market prices; and
- a large amount of wind generation had come online from 2009-10 to 2011-12 placing further downward pressure on spot prices.

The LRMC estimates for the Victoria region using the LRET and MRET assumptions highlight the influence of different renewable energy targets on the LRMC estimates. The LRMC estimate for 2007-08 using the LRET assumptions was $7/MWh lower than when the MRET assumptions were used. In 2008-09, the difference was slightly lower at $5/MWh – Figure 3.7. The difference in the LRMC estimates in Victoria highlights the impact a higher

[4] The Snowy region was abolished from July 2008

renewable energy target has on renewable generation investment, and so on the subsequent need for thermal generation investment.

Figure 3.6
Victoria difference between actual volume weight price and LRMC estimated using the perturbation methodology



3.5. South Australia

Historically, South Australia has tended to have the highest and most volatile prices of the regions in the NEM, largely due to limited low cost coal-fired generation, high levels of wind generation and limited interconnection to other regions.

The additional estimates of LRMC for South Australia, produced by application of the perturbation methodology are consistent with our earlier estimates of LRMC. The perturbation estimates of LRMC were relatively flat through the period, increasing from $60/MWh in 2005-06 to $64/MWh in 2011-12, with a peak of $73/MWh in 2010-11 – Figure 3.8 and Table 3.4.

Figure 3.7
South Australia Weighted Average Prices Compared with LRMC

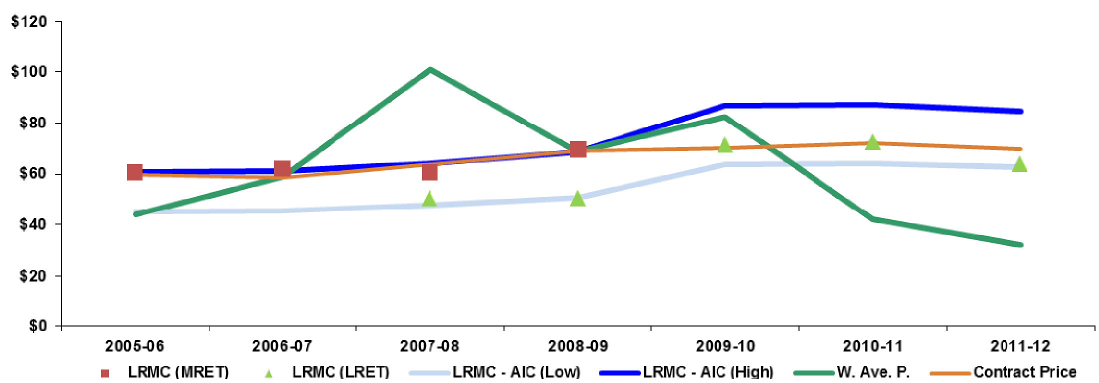


Table 3.4
Long Run Marginal Cost, Spot and Contract Prices for South Australia ($/MWh)

	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12
LRMC (perturbation)							
- MRET	$60	$62	$61	$70			
- LRET			$51	$51	$72	$73	$64
LRMC (average incremental cost)							
- Low	$45	$45	$48	$51	$64	$64	$63
- High	$61	$61	$64	$69	$87	$87	$85
W. Ave. Price	$44	$59	$101	$69	$83	$42	$32
Contract	$60	$59	$64	$69	$70	$72	$70

High average annual spot market prices in 2007-08 were heavily influenced by high spot prices in March 2008, where prices exceeded $5000/MWh for 26 half hourly periods. These high half-hourly prices were associated with:

- South Australia experiencing an unprecedented 15 day heat wave over this period; and
- the capacity of the interconnector at high price times was the lowest level over the period reviewed, thereby limiting electricity flows from Victoria and creating significant price separation.

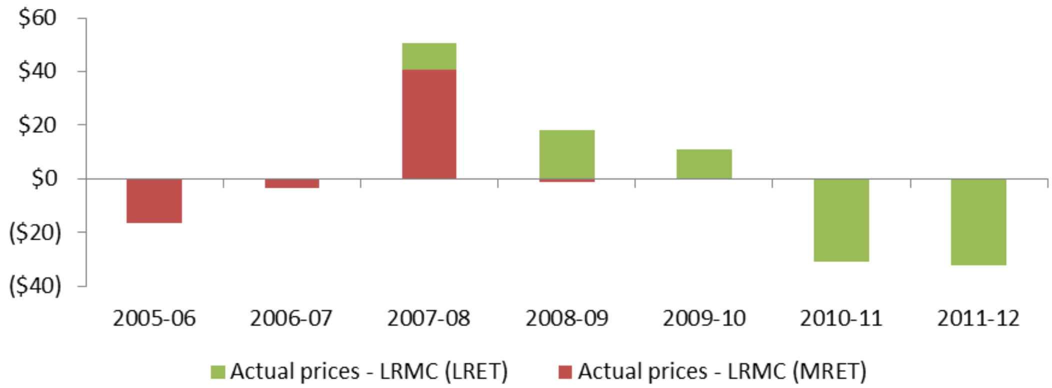
High prices in 2009-10 were also influenced by an extraordinary high demand period. In November 2009, South Australia recorded its most severe heat wave on record. This period saw prices exceeding $5,000/MWh for 14 trading intervals in mid-November, with 13 being at the market price cap. In addition high temperatures in February 2010, were associated with prices exceeding $5000/MWh for 9 trading periods.

Since 2009-10 spot market prices in South Australia have lowered. This is likely being driven by two main factors, namely:

- a growth in wind generation capacity, which has had a depressing effect on wholesale prices, exaggerated by the high incidence of negative prices in the region, a result of negative bidding by wind and by baseload generation rebidding at the floor price to continue to be dispatched at times of high wind and low demand; and
- warmer winters and milder summers across the region.

The estimates of the LRMC using the perturbation approach and with the MRET and LRET assumptions are broadly consistent with the high and low estimates of LRMC obtained using the average incremental cost approach. That said, South Australia does have the most significant variation between the LRMC estimates under the assumption of the LRET and MRET. In 2007-08, the higher LRET assumptions result in a LRMC estimate that is $10/MWh lower than when the MRET assumptions are used. For 2008-09 the difference is $19/MWh – Figure 3.9. The difference in the LRMC estimates under each set of renewable energy target assumptions reflects the influence of the target on renewable generation investment in South Australia.

Figure 3.8
South Australia difference between actual volume weight price and LRMC estimated using the perturbation methodology



Appendix A. Modelling Assumptions and Inputs

This section sets out the market modelling assumptions that have been used to estimate the LRMC for the using the perturbation approach. Our approach to developing these assumptions involved undertaking a detailed review of material from the relevant years, including both material prepared as input for other electricity market studies and, wherever possible, publicly available market information.

The perturbation approach calls for estimates of LRMC for each year to be based on the expectation of future market conditions, as the market participants would reasonably have anticipated them, at the time. Accordingly for each annual estimate, data from that year was used in the modelling.

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 the reality at the time. Consequently, for each year, care has been taken to ensure that the model reflected, to the extent practical, the prevailing market arrangements. This allows the increase in capital and operating costs due to the increase in demand, and so estimate 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, (2005-2011), Electricity Statement of Opportunities (ESOO); and
- KPMG Econtech, (2010), Economic Scenarios and Forecasts for AEMO – 2009 Update, 11 February.

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

A.1. Carbon Prices and Renewable Energy Targets

Over the study period a number of policy changes and uncertainties around future renewable energy targets and carbon prices made it difficult to determine the basis on which investment decision were made at each point in time. There were a number of key events that contributed to this uncertainty, in particular:

- in 2001 the MRET was launched, requiring 9,500GWh of renewable energy by 2010;
- in 2004 the National Emissions Trading Taskforce (NETT) was established and a review was conducted (the Tambling Report) which recommended that the MRET be expanded from 9,500 GWh by 2010 to 20,000 GWh by 2020. However, soon after, the Government

White Paper,'Securing Australia's Energy Future', concluded that a 'significant economic cost' would be imposed on the economy if it were to be expanded;[5]

- in late 2004, a NETT progress report to Ministers first floats the notion of a 'soft start' ETS applying to the stationary energy sector;
- in late 2008 the Federal Government released a draft ETS design to be commenced in mid-2010;
- in May 2009 the Federal Government announces a delay to the start of the ETS, pushing it back to 2011;
- in August 2009 the expanded RET legislated a target of 20,000 GWh of renewable energy by 2020, known as the LRET; and
- in April 2010 Federal Government announces further delay in start of ETS to 2013.
- On 24 February 2011 the Federal Government announces that the Carbon Tax will be introduced on 1 July 2012.
- On 1 July 2012 the Carbon Tax is introduced.

A.1.1. Renewable Energy Target Assumptions

For each year in the study it was necessary to have a reasonable estimate of the renewable energy target that was expected at that point in time. For the early years of the sample period, from 2005-06 to 2008-09, Australia's renewable energy target was 9,500GWh, under the MRET. The Enhanced Renewable Energy Target or Large Scale Renewable Energy Target (LRET) was announced in 2009 and set a target of 20 per cent by 2020 essentially requiring an extension of 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 uncertainty around renewable energy policy was also compounded by speculation about future carbon pricing.

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

In light of the policy development over the sample period, the study assumed the MRET applied for the years 2005-06 and 2006-07 and the LRET for the years 2009-10 to 2011-12. In the intervening years both renewable energy target scenarios were modelled to reflect the uncertainty at the time.

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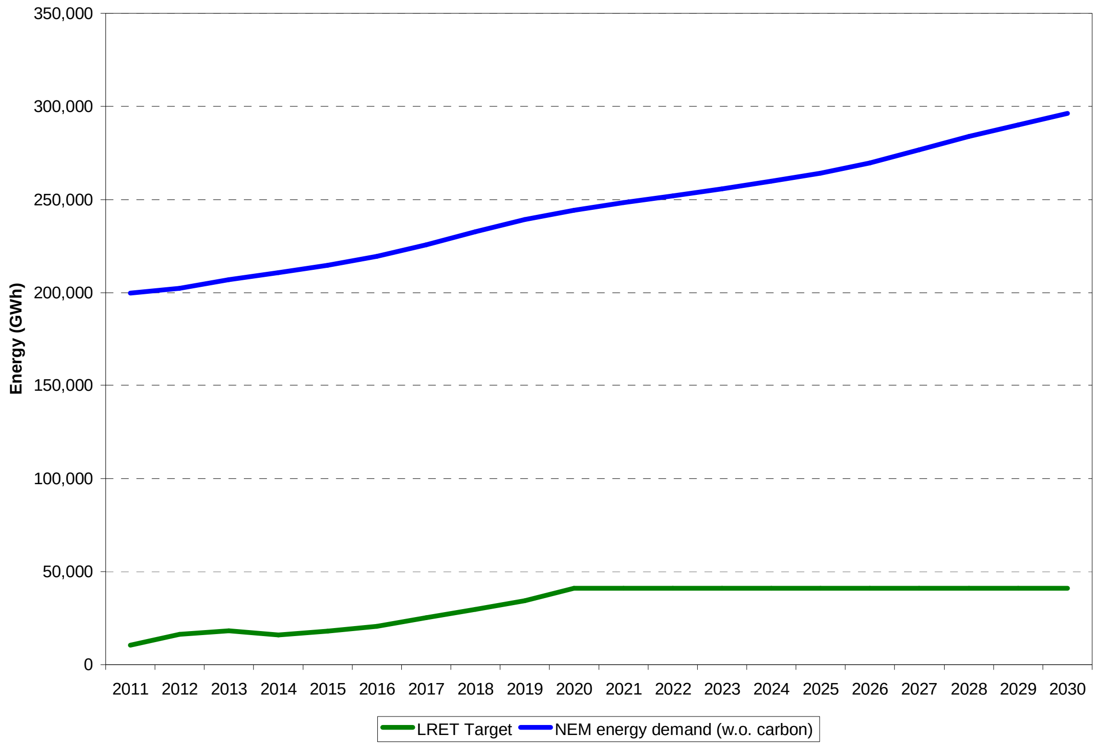
[5] MRET Review Panel 2003, Renewable Opportunities: A Review of the Operation of the Renewable Energy (Electricity) Act 2000, September, Canberra

Figure A.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.

An important assumption in the modelling of the renewable energy targets is that renewable energy investment is driven solely by the respective renewable energy target and not by any market forces. This assumption is based on the fact that most (large scale) renewable energy sources are still not cost competitive with conventional courses. This means than in the perturbation approach, when the increment in demand is applied, the extent of renewable energy investment does not change, and therefore, the change in the investment profile needed to meet the increment in demand is met only by conventional generation.

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

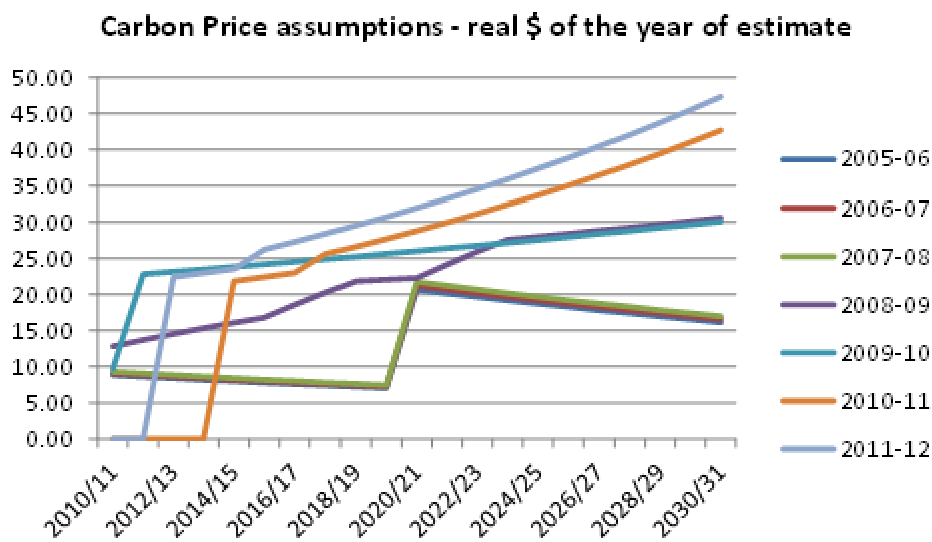
A.1.2. Carbon Price Assumptions

Realistic carbon price assumptions needed to be included into the modelling to reflect expected future market conditions and therefore obtain accurate LRMC estimates for each year. Over the sample period, we found that assumptions about future carbon prices changed dramatically.

While during the periods the LRMC estimates are being produced for a carbon price had not been introduced, the expected introduction of a carbon price would still have had an impact on LRMC estimates through its effect on the expected future cost of operating a power plant.

To the extent practicable, the estimates used in this study are broadly consistent with the profiles used in the SOO/ESOO reports from the respective years, as well as the expectation around future carbon price policy in each year. Early conjecture about carbon prices (for the first three years studied) were for quite low values and included forecasts of constant price (in nominal terms). In particular,

- For the years up to and including 2007-08, in order to reduce fluctuations in LRMC estimates arising from our carbon price assumptions, we chose a relatively conservative schedule where the carbon price commenced in 2010-11, where the price was set to a nominal $10/t with no escalation (meaning a fall in real terms) and then increased to $22/t in 2020-21. This is conservative in the sense that LRMC would have been higher had we worked with the alternatives that assumed an increase throughout the (current) decade;
- For the 2008-09 analysis we adopted the profile used in the ESOO, commencing at $13.5/t and escalating;
- For the 2009-10 analysis we used $10/t for the first year and then $24 from 2010-11/t with an escalation of 4 per cent in real terms, reflecting the soft start option as had been proposed in December 2008;
- For 2010-11 we assumed a significant delay to the start of carbon price reflecting the policy hiatus at the time but with an initial price in excess of $20/t; and
- For 2011-12 we assumed that the market accepted the starting price of $23/t rising for three years (the current schedule) and then moving to the Treasury forecast of $29/t.



A.2. 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 SOO/ESOO. In the modelling these estimates were used to produce estimates of the future demand to be met. The annual energy demand (sent out) forecasts for the years 2005-06 to 2011-12, as used in the analysis, are set out in Table A.1 to Table A.5 and maximum demand forecasts, as measured by the 10% Probability of Exceedance (POE), in Table A.6 to Table A.10.

Beyond the years estimated in the ESOO, the values were extrapolated out for an additional 10 years, to make a total of 20 years, using an escalation rate based on the final years of the ESOO forecast.

A.2.1. Annual Energy Demand

Table A.1
Queensland Annual Energy Served (GWh) – 10 Year Forecasts

	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12
2005-06	48,487						
2006-07	50,715	49,387					
2007-08	52,866	51,785	51,058				
2008-09	54588	53,771	53,129	52,194			
2009-10	56,130	55,667	55,109	53,943	51,503		
2010-11	57,529	57,418	57,355	55,909	53,677	53,487	
2011–12	59,176	59,266	59,389	57,826	56,609	55,601	52,802
2012–13	60,944	61,249	61,730	59,465	58,182	58,733	55,854
2013–14	62,614	63,042	63,764	61,364	60,028	62,182	59,005
2014–15	64,281	64,927	65,672	63,173	61,665	65,510	62,659
2015–16		66,816	67,790	65,139	63,233	68,657	66,042
2016–17			69,913	67,211	64,927	70,425	68,187
2017–18				69,422	66,690	71,851	69,594
2018–19					68,454	73,729	71,370
2019–20						75,606	73,519
2020–21							75,667

Table A.2
New South Wales Annual Energy Served (GWh) – 10 Year Forecasts

Year of Forecast	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12
2005-06	72,740						
2006-07	74,100	74,240					
2007-08	75,820	75,600	75,710				
2008-09	77,130	76,840	76,900	75,480			
2009-10	78,440	78,160	78,000	76,120	75,470		
2010-11	79,870	79,380	78,890	76,280	76,030	77,720	
2011–12	81,540	80,960	80,060	76,760	76,510	80,098	75,735
2012–13	82,990	82,290	81,520	77,820	77,920	81,187	77,527
2013–14	84,520	83,790	82,900	78,420	78,350	81,657	78,301
2014–15	85,890	85,190	84,330	78,900	79,590	83,241	79,212
2015–16		86,680	85,990	80,020	81,720	84,983	81,083
2016–17			87,540	80,450	83,250	86,389	82,271
2017–18				81,260	84,670	87,468	83,369
2018–19					86,100	88,705	84,528
2019–20						90,962	86,022
2020–21							87,745

Table A.3
Victoria Annual Energy Served (GWh) – 10 Year Forecasts

Forecast Year	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12
2005-06	46,342						
2006-07	46,675	46,716					
2007-08	47,263	47,336	47,599				
2008-09	47,505	47,591	46,468	47,449			
2009-10	48,092	46,975	46,362	44,393	46,895		
2010-11	48,880	46,971	47,085	43,941	47,127	48,186	
2011–12	49,340	47,097	47,713	43,667	47,781	49,399	48,314
2012–13	49,905	47,983	48,574	42,574	48,630	50,202	49,766
2013–14	50,405	48,530	49,293	43,115	48,836	49,817	50,771
2014–15	51,133	49,286	50,086	43,939	49,361	49,886	50,964
2015–16		50,223	50,955	44,843	50,171	50,045	51,421
2016–17			51,919	45,833	51,083	50,772	52,468
2017–18				46,696	51,559	51,566	53,058
2018–19					52,037	51,993	53,743
2019–20						52,544	54,640
2020–21							55,732

Table A.4
South Australia Annual Energy Served (GWh) – 10 Year Forecasts

Forecast Year	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12
2005-06	11,628						
2006-07	11,542	12,331					
2007-08	11,808	12,070	12,631				
2008-09	11,916	11,990	13,064	13,140			
2009-10	12,070	12,095	13,212	13,255	14,145		
2010-11	12,580	12,283	13,410	13,218	14,668	14,307	
2011–12	12,768	12,487	13,628	13,348	14,717	14,824	14,543
2012–13	12,931	12,678	13,834	13,762	15,291	14,982	14,839
2013–14	13,114	12,854	13,989	14,045	15,572	15,020	15,150
2014–15	13,340	13,075	14,160	14,391	15,841	14,788	15,204
2015–16		13,296	14,323	14,570	16,186	14,989	15,444
2016–17			14,495	14,951	16,505	15,119	15,783
2017–18				15,296	16,723	15,239	15,948
2018–19					16,931	15,356	16,309
2019–20						15,512	16,438
2020–21							16,694

Table A.5
Tasmania Annual Energy Served (GWh) – 10 Year Forecasts

Forecast Year	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12
2005-06	10,387						
2006-07	10,335	10,339					
2007-08	10,562	10,463	10,221				
2008-09	10,701	10,594	10,418	10,202			
2009-10	10,898	10,841	10,661	10,483	10,704		
2010-11	11,027	10,981	10,781	10,179	10,965	11,334	
2011–12	11,177	11,135	10,927	10,440	11,258	11,482	11,204
2012–13	11,345	11,291	11,087	10,592	11,357	11,518	11,443
2013–14	11,490	11,430	11,205	10,493	11,397	11,491	11,506
2014–15	11,323	11,705	11,470	10,409	11,076	11,536	11,556
2015–16		11,880	11,653	10,103	11,331	11,573	11,599
2016–17			11,771	10,218	11,719	11,750	11,778
2017–18				10,362	11,789	11,811	11,849
2018–19					11,856	11,878	11,923
2019–20						11,960	12,026
2020–21							12,135

A.2.2. Maximum Demand

Table A.6
Queensland 10% POE Demand (MW) – 10 Year Forecasts

	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12
2005-06	9,046						
2006-07	9,510	9,675					
2007-08	9,998	10,138	9,981				
2008-09	10,426	10,585	10,435	10,042			
2009-10	10,824	10,975	10,850	10,516	10,074		
2010-11	11,210	11,347	11,273	10,976	10,535	10,524	
2011–12	11,580	11,724	11,687	11,450	11,128	10,948	10,612
2012–13	11,962	12,107	12,135	11,869	11,537	11,469	11,233
2013–14	12,354	12,503	12,527	12,250	11,979	12,204	11,840
2014–15	12,723	12,914	12,916	12,648	12,353	12,812	12,553
2015–16		13,325	13,340	13,095	12,714	13,411	13,189
2016–17			13,764	13,535	13,098	13,918	13,679
2017–18				13,988	13,482	14,324	14,044
2018–19					13,892	14,676	14,462
2019–20						15,129	14,953
2020–21							15,315

Table A.7
New South Wales 10% POE Demand (MW) – 10 Year Forecasts

	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12
2005-06	14,080						
2006-07	14,420	14,750					
2007-08	14,900	15,120	15,020				
2008-09	15,310	15,500	15,500	14,860			
2009-10	15,750	15,970	15,930	15,180	15,375		
2010-11	16,250	16,460	16,350	15,530	15,666	15,657	
2011–12	16,700	16,930	16,760	16,020	16,122	16,169	15,827
2012–13	17,110	17,370	17,220	16,390	16,448	16,544	16,121
2013–14	17,560	17,810	17,670	16,750	16,801	16,927	16,440
2014–15	18,130	18,240	18,110	17,120	17,045	17,322	16,781
2015–16		18,700	18,420	17,490	17,439	17,714	17,121
2016–17			18,800	17,840	17,860	18,101	17,470
2017–18				18,230	18,271	18,493	17,837
2018–19					18,692	18,884	18,207
2019–20						19,266	18,587
2020–21							18,960

Table A.8
Victoria 10% POE Demand (MW) – 10 Year Forecasts

	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12
2005-06	10,119						
2006-07	10,367	10,234					
2007-08	10,635	10,473	10,026				
2008-09	10,850	10,683	10,124	10,525			
2009-10	11,097	10,819	10,297	10,592	10,346		
2010-11	11,356	10,990	10,515	10,753	10,702	10,783	
2011–12	11,573	11,163	10,720	10,940	10,838	11,103	10,994
2012–13	11,793	11,415	10,940	11,151	11,231	11,372	11,370
2013–14	12,001	11,627	11,173	11,354	11,404	11,461	11,646
2014–15	12,218	11,837	11,370	11,552	11,546	11,673	11,869
2015–16		12,076	11,582	11,809	11,743	11,990	12,062
2016–17			11,794	12,054	11,995	12,174	12,296
2017–18				12,320	12,227	12,421	12,542
2018–19					12,566	12,699	12,815
2019–20						12,930	13,113
2020–21							13,404

Table A.9
South Australia 10% POE Demand (MW) – 10 Year Forecasts

	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12
2005-06	3,378						
2006-07	3,481	3,441					
2007-08	3,565	3,506	3,311				
2008-09	3,644	3,609	3,421	3,408			
2009-10	3,728	3,680	3,483	3,470	3,500		
2010-11	3,854	3,730	3,522	3,510	3,540	3,530	
2011–12	3,938	3,778	3,592	3,467	3,570	3,630	3,570
2012–13	4,018	3,824	3,684	3,562	3,660	3,670	3,630
2013–14	4,098	3,866	3,799	3,624	3,760	3,720	3,700
2014–15	4,186	3,916	3,838	3,694	3,850	3,730	3,780
2015–16		3,984	3,919	3,766	3,940	3,780	3,840
2016–17			3,994	3,851	4,050	3,860	3,920
2017–18				3,927	4,130	3,880	3,960
2018–19					4,190	3,940	4,030
2019–20						4,010	4,090
2020–21							4,170

Table A.10
Tasmania 10% POE Demand (MW) – 10 Year Forecasts

	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12
2005-06	1,364						
2006-07	1,386	1,456					
2007-08	1,413	1,486	1,405				
2008-09	1,443	1,505	1,431	1,445			
2009-10	1,463	1,537	1,464	1,483	1,442		
2010-11	1,490	1,557	1,481	1,510	1,490	1,523	
2011–12	1,509	1,579	1,503	1,626	1,534	1,550	1,519
2012–13	1,530	1,601	1,527	1,650	1,554	1,561	1,561
2013–14	1,554	1,621	1,544	1,668	1,566	1,563	1,583
2014–15	1,559	1,657	1,579	1,706	1,535	1,576	1,599
2015–16		1,680	1,604	1,733	1,574	1,588	1,613
2016–17			1,622	1,754	1,630	1,617	1,643
2017–18				1,776	1,647	1,633	1,661
2018–19					1,664	1,649	1,679
2019–20						1,668	1,702
2020–21							1,726

A.2.3. Scaling Factors

In addition, because the NEM forecasts for maximum and annual energy 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 ESOO/SOO scaling factors were applied throughout the analysis to do this conversion.

A.3. Generating capacity

The modelling framework determines the new generation entry required to satisfy expected future electricity demand, given information on existing plant, planned plant retirements and new plant investments. For the estimates produced in each year, we include all new generation projects that had reached the committed status at the time, as defined by the AEMO, as well as the generators that are scheduled for retirement. Each year these schedules are provided by the AEMO in the SOO/ESOO.

A.4. 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 20 year forecast for fuel costs changed significantly between 2007-08 and 2008-09 reflecting the change in expectations around future gas prices as a result of the development of LNG facilities in Queensland from late 2013. In the short term there is expected to be a decrease in the price of gas as a result of additional supply of gas during the commissioning phase of the LNG export facilities. The additional gas prior to plant commissioning is commonly referred to as 'ramp gas'.[6]

Table A.11 shows the gas price assumptions for each state for each year. The prices are quoted at value for the start and the end of the 20 year period (in real dollars of the starting year) used for estimating LRMC values. In the modelling, for the intervening years, a linear interpolation was applied to estimate the gas price for each year.

Table A.11
Gas price assumptions for each state ($/GJ delivered)

	QLD		NSW		VIC		SA		TAS	
Year	Year 0	Year 20	Year 0	Year 20	Year 0	Year 20	Year 0	Year 20	Year 0	Year 20
2005-06	3.29	3.89	4.20	4.22	3.31	4.23	3.90	4.66	4.50	4.65
2006-07	3.28	3.89	4.00	4.22	3.30	4.23	3.90	4.66	3.60	4.65
2007-08	3.26	3.89	3.60	4.22	3.30	4.23	3.90	4.66	3.60	4.65
2008-09	3.90	6.23	4.57	6.93	3.94	6.33	4.67	6.83	4.46	6.43
2009-10	4.50	5.64	5.50	6.87	4.55	6.44	5.40	7.42	5.28	7.17
2010-11	4.96	6.60	5.47	7.76	4.82	7.81	5.44	8.55	5.29	8.24
2011-12	4.88	5.64	5.63	6.87	4.73	6.44	5.59	7.40	5.46	7.17

A.5. Generator capital costs

The capital cost of new entrant plant was based on SOO/ESOO forecasts. In general the AEMO updated these costs each two years. In order to fill the missing values and avoid step jumps in the forecasts we conducted a linear interpolation between the existing estimates. Towards the end of the sample period the AEMO commissioned a different advisor to develop capital and operating cost estimates – we have used these values, as developed by the advisors at the time, but note that one reason for the fall in LRMC towards the end of the sample period is lower cost forecasts, and particularly capital costs.

Regarding the weighted average cost of capital (WACC), we adopted only a single and relatively conservative estimate, broadly in line with the estimate employed by the AEMO. We recognise that this approach tends to give a lower LRMC than might have been the case if a WACC that might be value more in line with investor requirements, where a higher WACC is used to incorporate a risk premium. Values for selected key technologies are summarised in Table A.12 below.

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[6] 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 A.12
Generator capital costs ($/kW)

Year	CCGT	OCGT	Wind
2005-06	850	600	2250
2006-07	952	652	2373
2007-08	1050	703	2490
2008-09	1222	847	2539
2009-10	1386	985	2585
2010-11	1386	901	2500
2011-12	1125	822	2500

A.6. New entrant coal

The modelling assumed that no investment would be made in coal fired generation because of uncertainty around future carbon pricing. If coal was believed to be as an option, the calculated LRMC values would be expected to be lower.

A.7. 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.

A.8. Capacity contribution of intermittent generation

We assumed wind (as the primary intermittent generation technology that emerged in the results) would contribute 3 per cent of installed capacity at peak times in the NEM. This value is broadly consistent with reliability assessments by the AEMO. However, we are focussing on changes in capital and operating expenditure as a result of increments in demand, therefore, the particular level used is not critical as the same level would be present in both the base and perturbed cases in each year and thus highly unlikely to change the technology mix between the two cases.

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