NERA
ECONOMIC CONSULTING

Projections of Wholesale Energy Costs

A Report for the Australian Energy Market Commission

Review of Retail Electricity Price Trends 2013

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1. Introduction

Each year the Australian Energy Market Commission (the Commission) investigates the outlook for residential retail electricity prices in the National Electricity Market (NEM) and the South West Interconnected System (SWIS) in Western Australia.

As part of its review for 2013, the Commission has engaged NERA Economic Consulting (NERA) to estimate the cost to supply electricity to residential customers in the NEM and the SWIS. For the period from 2012-13 to 2015-16 we have been asked to:

- estimate annual wholesale energy costs[1] using a market modelling methodology; and
- report (and where necessary estimate) wholesale energy costs using the methodologies and assumptions applied by jurisdictional regulators when setting regulated tariffs.

Electricity purchase costs account for the majority of wholesale energy costs, and this has been the focus of our modelling. We have modelled electricity purchase costs for a 'base case' and for five sensitivities to this base case. This report includes a description of the principal assumptions that have underpinned this modelling, and sets out our results.

Other components of wholesale energy costs include: the costs of complying with the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES); market participant fees; and costs for ancillary services. This report also presents our estimates of these costs and their contribution to wholesale energy costs.

At this moment in time a combination of policy and macroeconomic factors are giving rise to considerable uncertainty as to future wholesale market outcomes. In our opinion, the four most significant factors are:

- declining demand for electricity across the eastern states;
- the carbon price and its future trajectory;
- the rise in the penetration of renewable technologies, driven by the LRET and SRES; and
- a potential step change in domestic gas prices on the east coast over the coming decade.

To inform the Commission about the outlook for wholesale energy costs, we have examined the relationship between these drivers of uncertainty and wholesale market outcomes. To this end, our report addresses each of the four identified factors and the relevance of each to future market outcomes.

The remainder of this report is structured as follows:

- **Chapter 2** establishes the current wholesale market context by describing current issues and their implications for energy costs;

[1] Throughout this report we have used the term 'electricity purchase costs' to refer to costs associated with buying electricity to supply a customer's load in the wholesale market. In contrast, we have adopted the term 'wholesale energy costs' to refer to the sum of 'electricity purchase costs' and additional costs associated with the wholesale market (eg, costs of certificate schemes and ancillary services etc.).

- **Chapter 3** describes our methodology for modelling electricity purchase costs, the scenarios that we have modelled, and the principal assumptions that we have adopted;
- **Chapter 4** sets out the results of our modelling of electricity purchase costs;
- **Chapter 5** sets out an estimate of the long run marginal cost to supply customers using a ‘stand-alone’ or ‘Greenfields’ approach;
- **Chapter 6** sets out our approach to estimating LRET and SRES costs, and our projections of these costs;
- **Chapter 7** sets out our estimates of costs associated with market participant fees and ancillary service costs;
- **Chapter 8** sets out estimates of wholesale energy costs for the period from 2013-14 to 2015-16 applied by jurisdictional regulators, supplemented where necessary with our own projections of each relevant cost component; and
- **Chapter 9** concludes by presenting consolidated estimates of wholesale energy costs for residential customers.

In addition:

- **Appendix A** sets out the principal assumptions underlying our market modelling of electricity supply costs;
- **Appendix B** sets out detailed market modelling results in tabular form; and
- **Appendix C** provides an overview of NERA’s wholesale electricity market models.

2. Current Issues in the Wholesale Electricity Market

The Australian electricity sector is currently undergoing a profound structural change due to a combination of policy and macroeconomic factors. In terms of the wholesale electricity sector, there are four principal factors that are driving change and so giving rise to uncertainty, namely:

- **declining demand** for electricity across the NEM;
- **the carbon price** and its future trajectory;
- **increasing penetration of renewable generation technologies**, driven by the LRET and the SRES; and
- **a potential step change in gas prices** in the NEM over the coming decade, brought about by the commencement of an LNG export industry out of Gladstone.

Considered in isolation, any one of these factors has the potential to effect a considerable change in market outcomes. However, in combination these four factors have produced a highly uncertain market environment.

In the context of examining the outlook for the market, the remainder of this section provides an analysis of each factor by describing relevant concepts, the effect on market outcomes to date, and their potential implications for the future.

2.1. Declining demand

In 2008 annual electricity demand across the NEM reached a level of 211 TWh,[2] which was an all-time high. In the following summer Victoria, New South Wales and South Australia all saw record levels of summer maximum demand. At that time, prevailing forecasts were for persistent rises in demand for both energy and capacity into the future. For example, the 2007 Owen Inquiry into electricity supply in New South Wales cited forecasts of: [3]

- 91 TWh of annual energy demand in 2013-14 – a rise of 13 per cent compared with the level in 2006-07; and
- summer maximum demand of 16,990 MW (at the 50 per cent POE) in 2013-14 – a rise of 29 per cent compared with the estimated level in 2006-07.

At that time, a critical concern was whether sufficient generation infrastructure existed, both in terms of energy and capacity, to meet forecast demand.

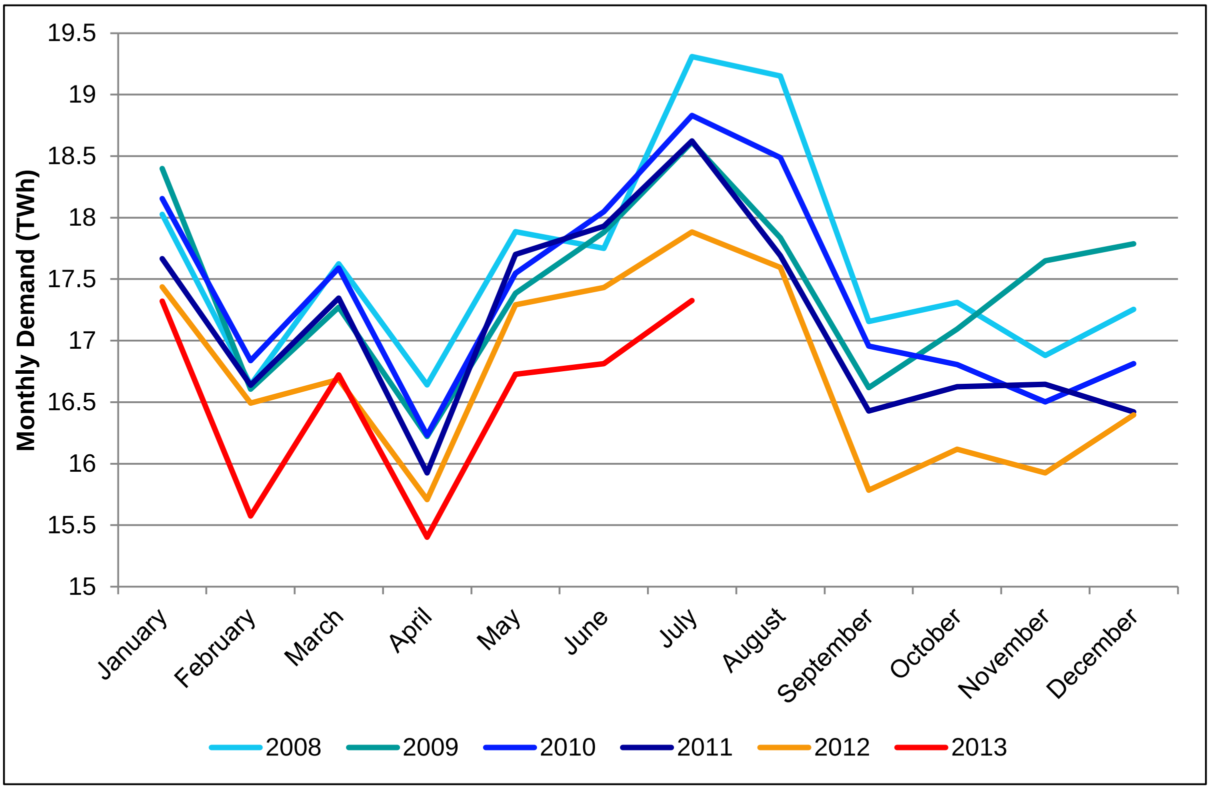
The expected rise in demand for both energy and capacity has not materialised. The level of energy demand reached in 2008 represented the high watermark across the NEM, and

[2] Our analysis of historical demand employs data on ‘total demand plus non-scheduled generation’ as published by AEMO in the MMS database. There are numerous other measures of demand, including those which form the basis of the AEMO assumptions used in our market modelling. This may account for differences between demand values cited in this report and those reported elsewhere.

[3] Professor Anthony D. Owen, “Inquiry into Electricity Supply in NSW,” September 2007.

demand has since fallen in every subsequent year. In 2012 energy demand across the NEM was 201 TWh – a 5 per cent decline versus 2008. The decline does not yet appear to have ended, with levels of energy demand in 2013 still markedly lower than in 2012 – Figure 2.1.

Figure 2.1
Monthly NEM Energy Demand (January 2008 to July 2013)



Source: Demand and Non-scheduled generation data from the MMS database, AEMO.

Declining demand has, to a lesser extent, also been observed in Western Australia, with total demand in the SWIS in 2012 down on levels observed in 2011.

Causes of the decline in demand

The decline in electricity consumption has been particularly surprising, given that Australia has maintained a relatively strong level of economic and population growth over the past few years. The drivers of the decline in electricity demand have been attributed to a range of factors, including:

- the loss of some large industrial loads, such as the Kurri Kurri aluminium smelter;
- a rise in energy efficiency standards, and the use of technologies that reduce demand for electricity sourced from the grid, eg, solar water heaters;
- government policies targeting improvements in energy efficiency (eg, the Energy Savings Scheme in New South Wales, and the Victorian Energy Efficiency Target Scheme);
- a substantial rise in the penetration of rooftop photovoltaic systems (PVs), which provide distributed generation that displaces demand for grid-sourced electricity; and

- a response to substantial and persistent increases in retail electricity prices over the last few years.[4]

2.1.1. Implications of declining demand on electricity costs

As demand for electricity decreases, market outcomes can change considerably. Most notably, spot market prices, which are set based on the marginal cost of supplying another megawatt to the system, can be very sensitive to changes in the level of demand. Changes to the level of demand also affect which generators are dispatched, and in turn other market outcomes.

The persistent decline in demand observed in the NEM since 2008 therefore has considerable implications for the market and for spot prices in particular. In terms of the effect on prices, it is helpful to consider the effect of a change in demand as comprising two parts, namely:

- the *short term* effect on prices, ie, the change in market outcomes holding the available generation profile constant; and
- the *long term* effect on prices, ie, the change in market outcomes when we consider the potential for new generation to be constructed.

In the NEM, prices are set at the cost of the *last and most expensive megawatt* supplied to the region. The producer of this final unit is sometimes termed the ‘marginal generator’. The marginal generator at any given time is therefore a function of the level of demand, and the short run supply curve for electricity, or ‘merit order’.

The short-term effect of a change in demand on prices is therefore straight-forward. A reduction in demand leads to a shift down the merit order and a reduction in price; an increase in demand leads to a shift up the merit order and an increase in price. This short term effect of changes in demand is apparent even at the intraday level, where prices rise and fall in line with daily variation in usage.

The long-term effect of a change in demand on prices is more complex. A permanent reduction in demand can stave off the need to construct new generation capacity. In the NEM, the reduction in demand since 2008 has had the profound effect of deferring the construction of gas fired generation beyond 2020. As a result, a shift to prices being set based on higher cost new-entrant generators has not occurred.

2.2. Carbon price

The Australian government introduced a carbon pricing scheme from 1 July 2012 as part of its Clean Energy Future package.[5] Currently the scheme has two stages:

- a fixed price period concluding on 30 June 2015, with the price starting at $23 per tonne and increasing by 2.5 per cent above inflation in each subsequent year of the fixed price period; and

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4 AEMO, “2013 National Electricity Forecasting Report,” June 28, 2013.

5 See www.cleanenergyfuture.gov.au for further information about the Clean Energy Future package.

- a flexible price commencing 1 July 2015, with prices determined by the market for carbon permits, which will be issued by the government based on an overall cap on emissions from sectors covered by the scheme.

The government has also announced that at the commencement of the flexible price period the carbon pricing scheme will be linked to the European Union Emissions Trading Scheme (EUETS), affording liable entities in Australia the opportunity to use European Union Emission Allowances (EUAs) to meet liabilities under the Australian scheme.[6]

The Climate Change Authority is currently conducting a review so as to determine Australia's emissions target, which will have an influence on expected carbon prices from 1 July 2015.[7]

There is considerable uncertainty as to the very existence of the carbon pricing scheme, because the incoming federal government has indicated its intention to abolish the carbon tax.[8] However, it is currently unclear whether the government will be able to pass legislation to implement its policy.

2.2.1. Implications of the carbon price for market outcomes

Carbon pricing is particularly relevant to the electricity sector in Australia because of the high emissions intensity of the black and brown coal fired power stations of the NEM.

Figure 2.2 shows generation by fuel type in the NEM on a monthly basis from January 2001 to July of 2013, which illustrates that:

- the vast majority of electricity generated in the NEM has historically been produced either by black or brown coal fired generation;
- generation from the Snowy Mountains and Tasmanian hydro-electric schemes accounts for between 5 and 6 per cent of total generation;
- energy generated using modern gas fired technologies – ie, combined cycle gas turbines (CCGTs) and open cycle gas turbines (OCGTs) – has risen to around 12 per cent of total generation; and
- generation from wind farms has risen persistently since the start of the RET and now accounts for between 3 and 4 per cent of total generation.

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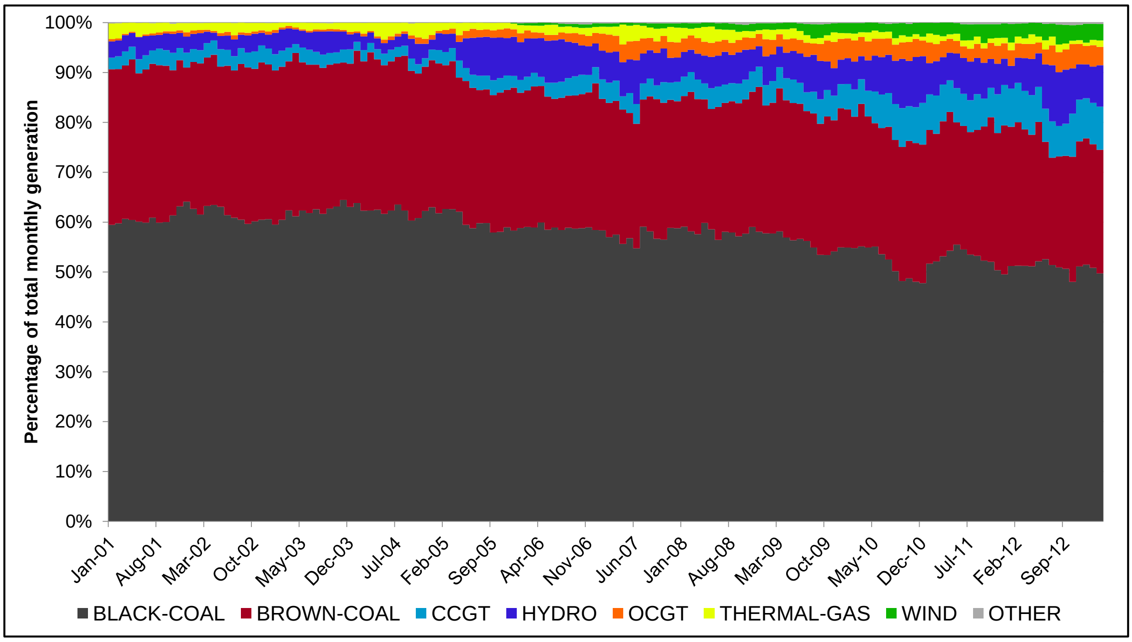
6 See www.cleanenergyfuture.gov.au/international-linking

7 See www.climatechangeauthority.gov.au

8 See www.liberal.org.au/our-plan-abolish-carbon-tax

Figure 2.2
Breakdown of NEM Generation by Fuel Type – January 2001 to January 2013



Source: NERA analysis of generation by unit data from the MMS database, AEMO.

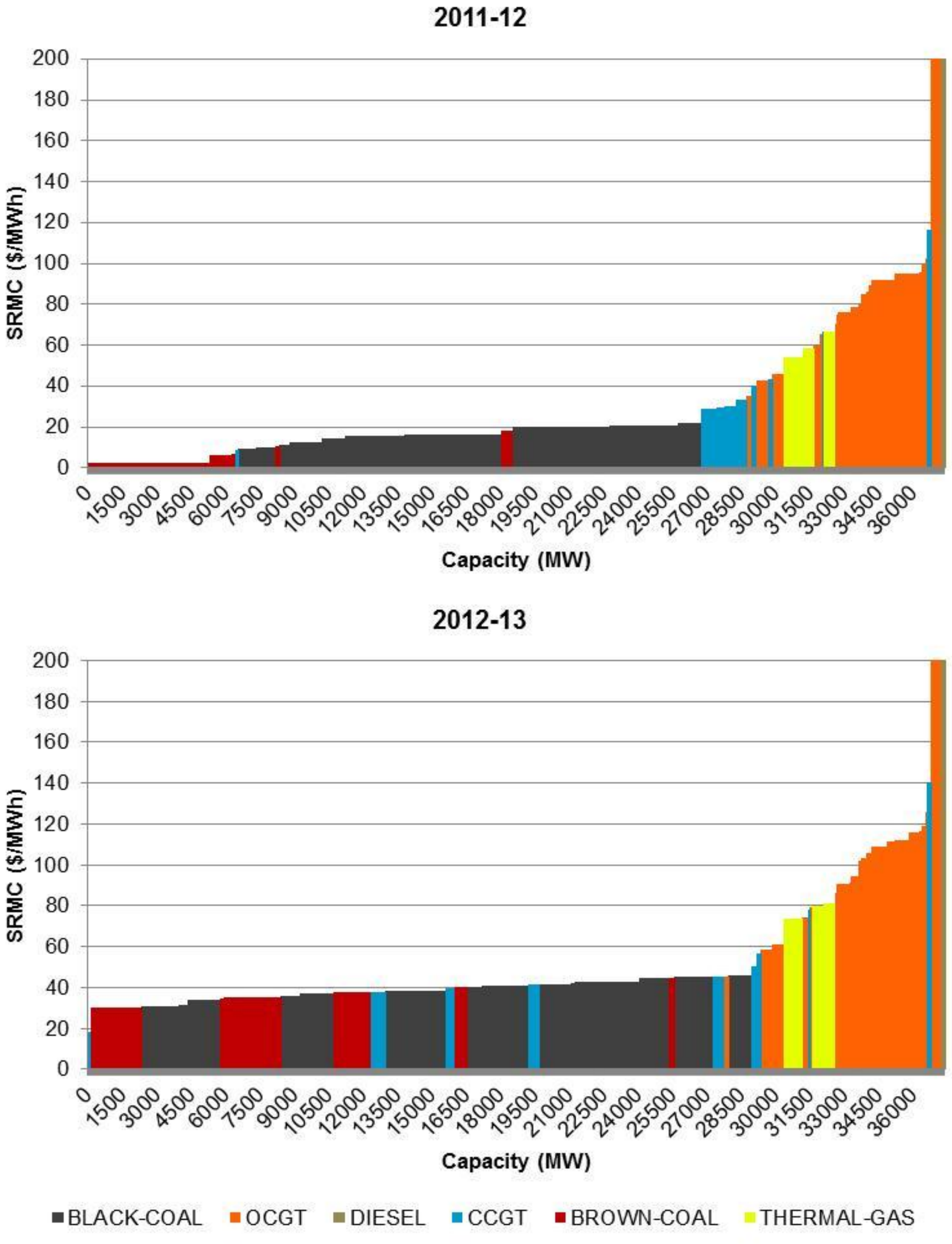
Effect of the carbon price on the merit order

The carbon price increases the operating costs of a generator by an amount equal to the emissions intensity of the generator multiplied by the carbon price. For example, a carbon price of $20 per tonne CO2 will lead to:

- an increase of $20 per MWh for a black coal fired power station with an emissions intensity of generation of 1 t CO2-e/MWh; and
- an increase of $10 per MWh for a CCGT with an emissions intensity of 0.5 t CO2-e/MWh.

Applying this type of analysis to every generator in the NEM can show us how the carbon price has changed the overall short-term cost structure of the market, ie, the merit order. Figure 2.3 provides an indicative analysis of how the carbon price has affected the merit order in the NEM, using modelling assumptions from our base case.

Figure 2.3
Effect of carbon price on the merit order for thermal generation



Note: Fuel costs and emissions factors reflect our base case assumptions.

Immediately before the introduction of the carbon price, the brown coal-fired power stations in the Latrobe valley dominated the bottom of the merit order. These were closely followed by black coal-fired power stations in Queensland and New South Wales, with CCGT and OCGT units located higher in the merit order.

After adjusting for the impact of the carbon price, the operating costs of brown and black coal-fired power stations are somewhat more comparable. However, it is clear that in large part the merit order remains unchanged. In particular, gas-fired generators tend to be higher in the merit order than coal-fired generators. Furthermore, SRMCs for new-entrant gas fired generators remain well above SRMCs for existing coal-fired generators.

Effect of the carbon price on spot price outcomes

We have shown that at the fixed price level of \$23 to \$25 per tonne CO2-e the carbon price has not resulted in a significant change in the merit order. However, the increase in the cost of generating electricity has resulted in an increase in the price for every level of demand.

To illustrate this change, it is useful to compare prices in each region before and after the introduction of the carbon price. Figure 2.3 compares half-hourly demand and prices in each NEM region for two periods, namely:

- the year prior to the introduction of the carbon price, ie, midnight 1 July 2011 to midnight 1 July 2012; and
- the year after the introduction of the carbon price, ie, midnight 1 July 2011 to midnight 1 July 2013.

We have only considered periods where prices are in the range from zero to \$150 per MWh – a band where prices are largely being set based on 'system normal' conditions. In all regions, there is a clear uplift in prices across all levels of demand.

The analysis set out in Figure 2.4 has been intentionally simplified – it does not account for a range of factors, including changes in available generation from one year to the next. Nevertheless, it makes clear the considerable effect that the introduction of the carbon price has had on spot market prices. A future change to the level of the carbon price, be it an increase or decrease, can be expected to have a similarly significant effect.

Figure 2.4
NEM spot prices versus demand – 1 July 2011 to 30 June 2013

Source: NERA analysis of half-hourly demand and spot prices of $0-150 per MWh, as published in the MMS database by AEMO.

2.3. Increased penetration of renewable generation technologies

Retailers have been required to buy renewable energy certificates based on their purchases of wholesale electricity since 2001. This requirement was initially incorporated within the Mandatory Renewable Energy Target (MRET) scheme, which was designed to support an additional 9.5 TWh of generation from renewable sources by 2010.

In August of 2009, the MRET was modified and renamed the Renewable Energy Target (RET), with a significantly greater target of 45 TWh of additional renewable generation by 2020.[9] At that time, generation from both small-scale renewable energy sources, such as rooftop PVs, and large-scale renewable energy generators was covered by the scheme.

In June of 2010, the Commonwealth passed legislation to split the RET scheme into two parts, namely:

- the Large-scale Renewable Energy Scheme (LRES), requiring the surrender of Large-scale Generation Certificates (LGCs); and
- the Small-scale Renewable Energy Scheme (SRES), requiring the surrender of Small-scale Technology Certificates (STCs).

Each of these schemes provides a subsidy to renewable energy technologies, with a view to effecting a transformation of the generation mix over the life of the scheme. In this section we focus on outcomes under the LRET and its implications for wholesale energy costs.

2.3.1. Outcomes under the LRET

Prior to the commencement of the Mandatory Renewable Energy Target in 2001, the only major sources of renewable energy generation in Australia were the Tasmanian and Snowy Mountains hydro-electric systems. By the end of 2012, total generation from large-scale renewable energy sources constructed after 2001 had risen to around 12 TWh – Figure 2.5. This increase can be almost entirely attributed to the RET/LRET, and will accelerate as more renewable facilities come online to meet the target of 41,850 GWh in 2020.

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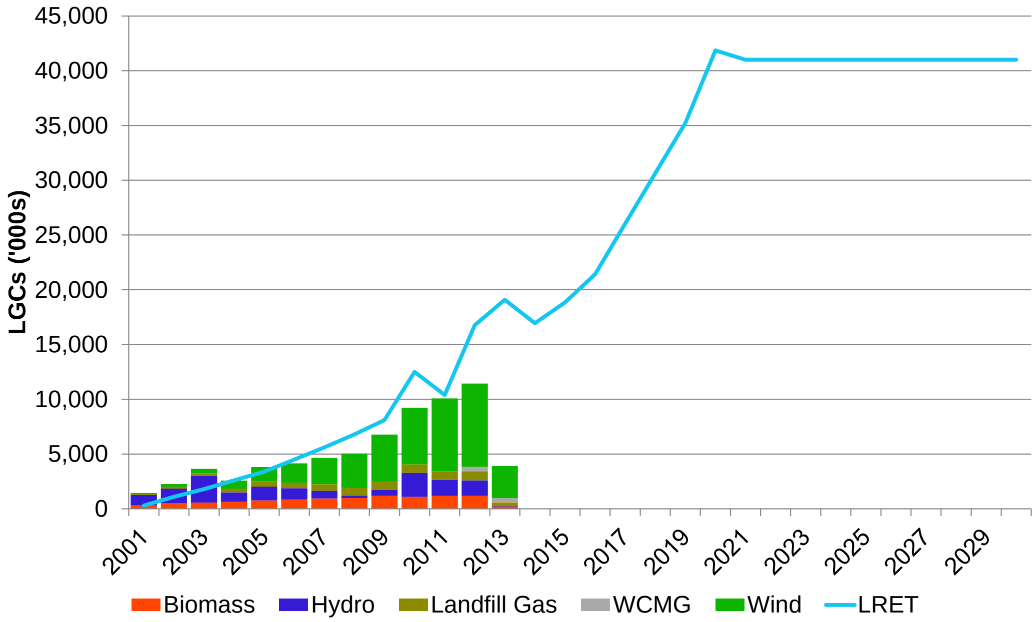
9 Partliament of the Commonwealth of Australia, "Renewable Energy (Electricity) Act 2000," August 2009..

Figure 2.5
Historical creation of LGCs versus the LRET



Source: NERA analysis of REC Registry data, as maintained by the Clean Energy Regulator.

As can be seen in Figure 2.5, the majority of RECs/LGCs are created by wind farms. At the moment, wind farms are the only viable technology that can be constructed on a sufficient scale to meet the LRET. In rough terms, an additional 8 to 9 GW of wind generation capacity is required to meet the LRET target in 2020.

2.3.2. Implications of the LRET for wholesale energy costs

The total return earned by a wind farm[10] is sometimes referred to as its 'bundled revenue', which can be expressed by the formula:

$$Bundled\ Revenue = Spot\ Price\ Revenue + LGC\ Revenue.$$

In the absence of revenue from LGCs – ie, the subsidy that the LRET provides for each megawatt hour of renewable generation – wind farms do not yet earn sufficient revenue from the spot market to cover their costs. The LRET therefore results in the construction of renewable generation capacity that would not otherwise be profitable.

However, once constructed wind farms have a low marginal cost of generation and so will be dispatched ahead of thermal generation. This additional capacity at the bottom of the merit order places downward pressure on spot prices. As wind farms are constructed to meet the LRET, the additional energy that they supply will act to reduce spot prices.

[10] In this section, we focus our analysis on wind as it will form the majority of renewable generation under the LRET. However, our analysis also applies to other forms of renewable generation.

At the same time, the additional revenue earned by wind farms through LGCs must ultimately be recovered from end users of electricity. Costs of complying with the LRET are incurred by retailers and passed on to customers. If these ‘LRET costs’ exceed any reduction in electricity purchase costs then the net effect of the LRET will be to increase costs to consumers.

An important point to emphasise is that the LGC price is inversely related to spot prices, ie, factors that act to increase spot prices will put downward pressure on LGC prices. The bundled price need only be sufficient for a wind farm to recover its costs, and so remains fixed. The formula for the bundled price therefore implies that the LGC price must decrease as spot prices increase.

All else being equal, LGC prices will decrease whenever:

- the level of demand increases;
- prevailing gas prices, or indeed any fuel price, increases; or
- the carbon price increases.

Were spot prices sufficiently high to support investment in renewables even in the absence of a subsidy, the LGC price would tend towards zero.

2.4. Potential step-change in gas prices

The east-coast gas market is currently experiencing a significant structural change driven by the establishment of an LNG export industry, which has the potential to raise prices for domestic gas considerably.

Over the last 20 years, the wholesale gas market in eastern Australia has been characterised by the use of long term bilateral contracts between a small number of gas producers and consumers. The price of gas as a fuel for power generation has been relatively low, because gas-fired generators have had to compete with low-cost coal fired power stations. However, in the next five years the eastern Australian states will see the establishment of large-scale LNG export facilities at the port of Gladstone in Queensland. As existing domestic supply agreements start to expire, the expectation is that new contracts will be struck at considerably higher prices.

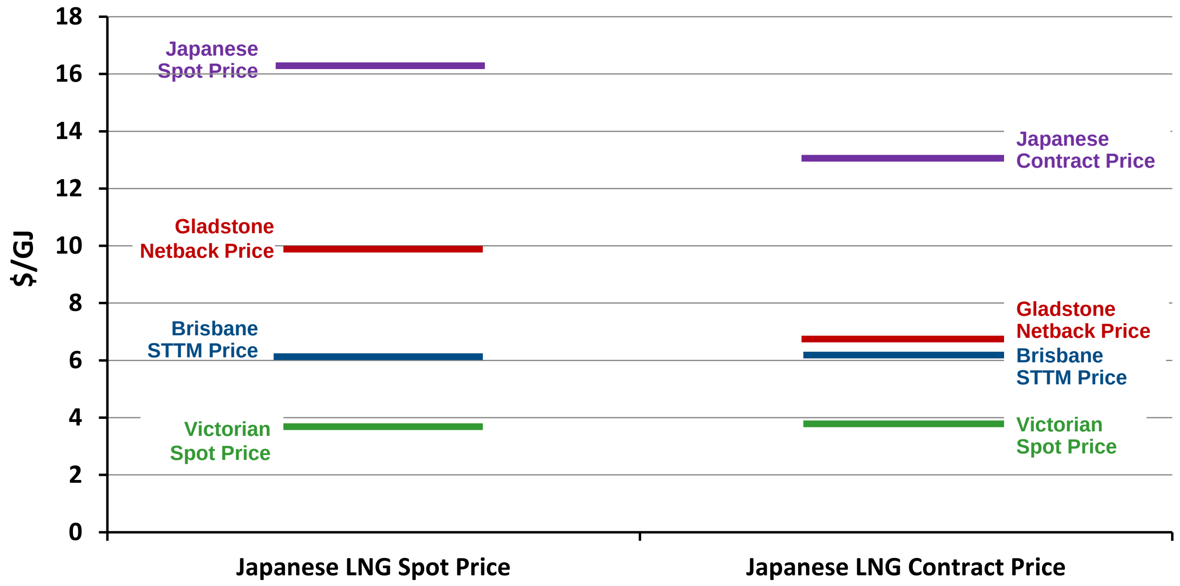
The demand for LNG comes primarily from South Korea and Japan – two countries that have little or no domestic petroleum resources. In these Asian markets, contract prices for LNG have historically been linked to the international oil price. Figure 2.6 illustrates the separation between prices for gas delivered to Japan, both in terms of spot and contract prices, and domestic gas prices on the east coast as represented by:

- the average spot price in the short-term trading market (STTM) at the Brisbane hub; and

- the Declared Wholesale Gas Market (DWGM) in Victoria.[11]

Even after accounting for processing and shipping costs of $4 to $6 per GJ, the prices for LNG delivered to Japan are considerably higher than spot prices in the east-coast market.

Figure 2.6
Indicative analysis of potential Gladstone netback prices



Sources: NERA analysis of BP Statistical Review of World Energy, and DWGM prices published by AEMO. Assumed liquefaction and transport cost of $6 per GJ. STTM and DWGM prices are a simple average of published prices in 2013 up to 30 June.

With the discovery of large reserves of coal-seam gas in the Bowen-Surat and Gunnedah basins, there is now a sufficient volume of gas to support the construction of LNG export terminals. Both Australian and international energy businesses have developed export capabilities, with a view to selling into the higher-priced Asian market. As a result, the opportunity cost of selling gas to domestic customers will rise, in turn leading to a rise in domestic gas prices.

2.4.1. Implications of rising gas prices for the electricity sector

The potential for a rise in domestic gas prices has implications for the entire electricity sector. We have already described that in the presence of a carbon price it is unlikely that any new coal-fired generators will be constructed on the east coast. In this context, gas is the only viable technology for new base-load capacity for the foreseeable future.

The cost of new entrant base-load generation will therefore be based on the cost of gas-fired technologies. As a result, gas prices will be one of the primary determinants of long term

[11] Prices in the DWGM and STTM provide some indication of the prevailing cost of gas on the east coast, but do not necessarily reflect prices for the firm supply of gas under long-term contracts.

electricity prices. The changes occurring to the gas industry are therefore both profound and pervasive – they will have implications across the entire energy sector.

Nevertheless, the decline in demand for electricity is likely to limit the speed at which any potential rise in gas prices translates into electricity spot prices in the NEM. In the absence of demand growth, the shift to gas-fired power stations being the marginal generator may be delayed.

3. Scenario Development and Principal Assumptions

This section describes our methodology for modelling electricity purchase costs, the scenarios that we have modelled, and the principal assumptions that we have adopted.

3.1. Modelling methodology

Our modelling approach consists of three steps, each applied through a different model:[12]

- **Planning Step** – uses PowerPlan to solve for the schedule of new investment in generation capacity required to meet demand and RET requirements in a least cost manner. The output of the model is a schedule of new generation capacity for each region and for each fuel type, to be used as an input to the simulation step.
- **Simulation Step** – uses PowerSim to simulate the hourly operation of the wholesale market. The model estimates prices taking into account the pricing power that generators have at times where available generation is constrained. The output of this phase is a trace of wholesale spot prices.
- **Hedging Step** – uses PowerHedge to apply a hedging strategy to determine the cost incurred by a retailer to supply the load profile of a residential customer.

3.1.1. Calculation of electricity purchase costs

In the absence of hedging, an electricity retailer faces an inherent mismatch between the cash-flows that they *receive* from customers and the cash-flows required to purchase electricity from the spot market. In the short-term, receipts from customers are effectively independent of wholesale market prices, and are therefore fixed. In contrast, the cost of purchasing electricity from the spot market is highly uncertain.

To manage wholesale market risks a retailer typically uses hedging instruments, which trade at a premium to the expected cash-flows accruing to that instrument. Therefore, the degree of spot price volatility that a retailer faces has direct consequences for its cost of purchasing electricity.

To estimate a retailer's wholesale electricity purchase costs it is therefore necessary to consider the costs associated with hedging the loads of that retailer's customers, through the purchase of contracts. This approach is commonly referred to as a 'market modelling approach', reflecting that it seeks to emulate the process directly used by retailers to manage wholesale electricity purchase costs. Inputs to this process are:

- modelled spot prices;
- contract prices, which we have assumed to trade at a 5 per cent premium to the expected cash flows; and
- the load profile to be hedged by the retailer.

[12] A detailed description of NERA's modelling tools is provided in Appendix C.

The specific hedging strategy adopted by a retailer will depend on its expectations of future price volatility and its appetite for risk. However, for the purpose of this analysis – and to allow a comparison across jurisdictions – we have assumed a single strategy is adopted across all regions, whereby a retailer purchases:

- peak and off-peak swaps[13] to cover a fixed proportion of its load on a quarterly basis; and
- caps[14] to cover its remaining load.

3.1.2. Load profile assumptions

To determine regulated residential retail electricity prices, the relevant load profiles are those of residential customers. In our modelling, we have therefore used load profiles based on actual residential load profiles provided to us by the AEMC or, where no such profile is available, the net system load profile for a distribution area that is deemed to be representative of the broader region. In jurisdictions where controlled loads are available to customers, our assumed load profile incorporates a controlled load component, the size of which is based on the relative penetration of controlled loads in that region.

Our assumptions surrounding load profiles are set out in Table 3.1.

Table 3.1
Load profile assumptions for each jurisdiction

NEM Region	Load Profile
Australian Capital Territory	Net system load profile for ACTEWAGL distribution area
New South Wales	Customer load profile data for sub 40 MWh customers in the Ausgrid distribution area provided by IPART
Queensland	Net system load profile for Energex distribution area
South Australia	Aggregated customer load data provide by South Australia Power Networks
Tasmania	Net system load profile for Aurora Energy distribution area
Victoria	Net system load profile for United Energy distribution area

13 An electricity swap is a financial instrument whereby a retailer agrees to pay a generator an amount represented by the difference between the contract strike price and the spot market price, once the spot market price has been determined. The contract is for a particular quantity.

14 An electricity cap contract is a derivative that effectively places a ceiling on the price a retailer pays for electricity. The seller of the cap agrees to compensate the buyer, in circumstances where the spot price exceeds the strike price (usually $300 in the NEM).

3.2. Overview of scenarios

We have modelled a base case and five sensitivities, namely:

- two carbon price sensitivities;
- a reduced LRET sensitivity;
- a low demand sensitivity; and
- a constant gas price sensitivity.

The remainder of this chapter sets out the principal assumptions underpinning our base case, and the changes to those assumptions that give rise to each of the five sensitivities.

3.2.1. Base case

Our base case is centred upon the following principal assumptions:

- **Forecasts of demand** for the NEM have been sourced from the National Electricity Forecast Report (NEFR) 2013 for the medium scenario. Demand forecasts for the SWIS have been sourced from the IMOWA Statement of Opportunities 2013.
- **Fuel price forecasts** have been sourced from the National Transmission Network Development Plan (NTNDP) 2013 fuel price assumptions for the planning scenario. Fuel price assumptions for the SWIS are based on estimates from the NTDNP 2011 modelling adjusted for inflation.
- **Carbon prices** in the base case:
  - follow the legislated fixed price path until 30 June 2015; and
  - move to a price based on the forward price for EUAs from 1 July 2015, as described in section 3.2.2.
- **The LRET** is assumed to remain as legislated – further discussion surrounding our LRET assumptions is set out in section 3.2.3.

Across all modelling we have assumed a pre-tax real discount rate of 10 per cent. All figures are presented in 2012-13 constant dollars unless otherwise stated.

3.2.2. Carbon price sensitivities

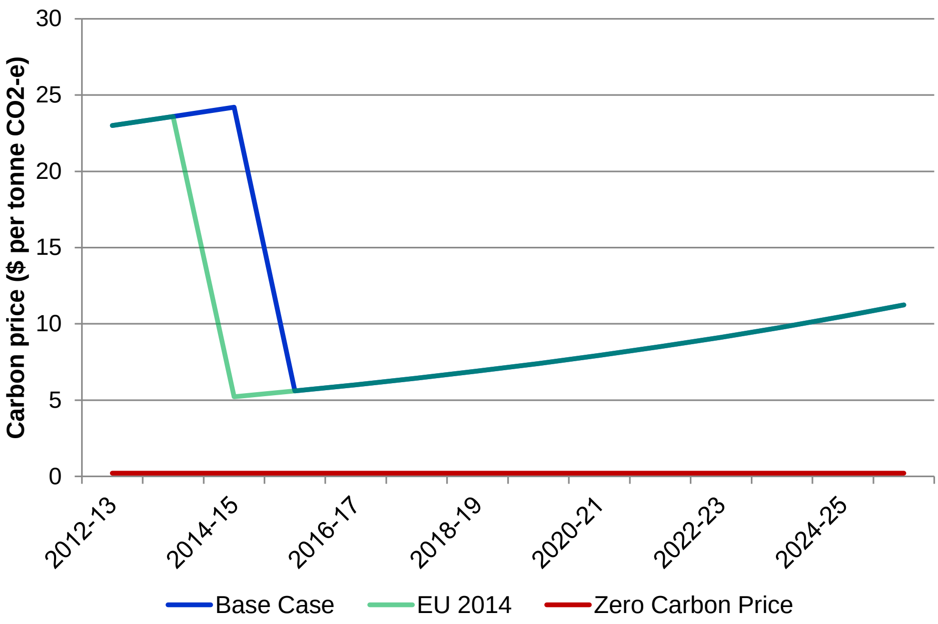
We have modelled two carbon price sensitivities, namely:

- **EU 2014 carbon price sensitivity** – the carbon prices moves from the fixed price to a level matching the EU carbon price on 1 July 2014, ie, one year earlier than in the base case.
- **Zero carbon price sensitivity** – we assume a zero carbon price over the entire modelling period.

The EU 2014 carbon price sensitivity represents the case where the policy announced by the outgoing government is enacted. Prices are assumed to shift to forward prices for EUAs from 1 July 2014, in line with the policy recently announced by the Australian government.[15]

In contrast, we have modelled the zero carbon price sensitivity for the purpose of estimating the 'carbon pass-through', ie, the increase in spot prices attributable to the introduction of the carbon price. The carbon pass-through to spot prices is calculated as the difference between spot price projections under the base case and the zero carbon price sensitivities. The carbon pass-through to electricity purchase costs is similarly defined. Figure 3.1 compares assumed levels of the carbon price for the base case and the two carbon price sensitivities.

Figure 3.1
Carbon price paths assumed in different modelling scenarios



Source: Clean Energy Future scheme; forward prices quoted for EUAs beyond 2016-17 has been interpolated based on discount rate implied by forward curve.

3.2.3. Reduced LRET sensitivity

We have modelled a sensitivity (referred to as the 'Reduced LRET sensitivity') that considers the effect of reducing the LRET to a level equivalent to 20 per cent of total generation by 2020 based on *current* forecasts of demand growth. Major integrated energy businesses have proposed the reduced target as a possible option in light of lower than expected growth in electricity demand. The Climate Change Authority has also considered this proposal as part of the 2012 RET Review.[16]

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15 Rudd, K., and Butler, M., (2013), "Australia to Move to a Floating Price on Carbon Pollution in 2014", *Joint Media Release with the Hon. Kevin Rudd MP Prime Minister, and the Hon. Mark Butler MP Minister for Climate Change,* 16 July, Townsville.

16 Australian Government Climate Change Authority, "Renewable Energy Target Review - Final Report," December 2012.

The LRET sensitivity looks at the effect of reducing the target to reflect a target of 20 per cent of total electricity generation in 2020 based on *current* forecasts of demand. As we have already described in chapter 2, actual demand levels that have materialised since 2008 have been considerably lower than was forecast at that time. It follows that resetting the LRET would result in a considerable reduction in the effective target.

Calculation of the Reduced LRET

We have recalculated the 2020 target using the same approach adopted to calculate the original RET target. This process comprises three steps:

1. **Calculation of 20 per cent of electricity demand in 2020**

   We have calculated that 20 per cent of total electricity demand is equivalent to 48.2 TWh, ie, 20 per cent multiplied by the current forecast annual electricity demand of 241 TWh in 2020.[17]

2. **Adjustments for existing renewable generation and the SRES**

   From the figure of 48.2 TWh, we have then subtracted:

   – 15 TWh to account for generation from renewable generation constructed prior to the start of the RET; and

   – 4 TWh to account for the reduction in the LRET that occurred when small-scale technologies were removed from the scheme.

3. **Additional adjustments for waste coal mine gas**

   Finally, we have made additional adjustments to account for certificate allowances for waste coal mine gas. The result is a target marginally under 30 TWh in 2020.

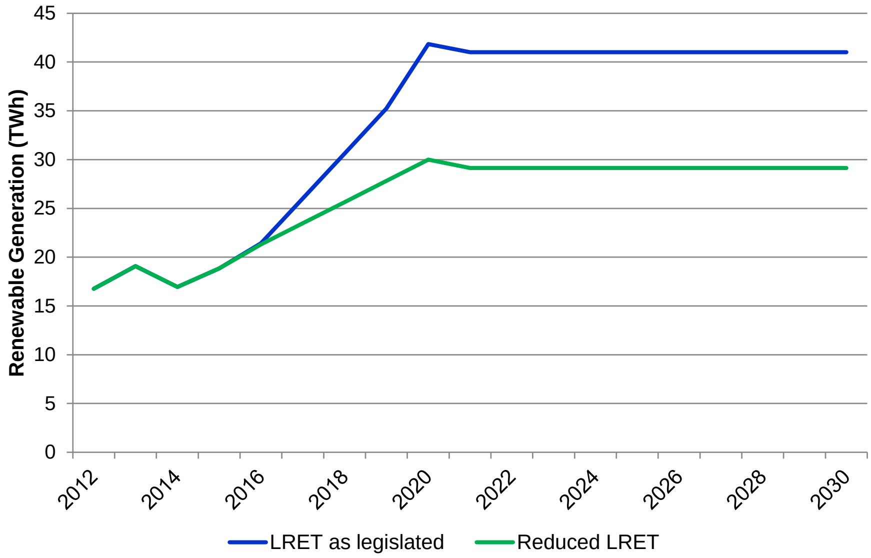
In its current form, the annual targets under the LRET increase each year until 2020, after which the annual certificate target remains constant. To construct the sensitivity where the LRET is reduced requires that we make an assumption about how annual targets prior to 2020 would be affected by the change in the ultimate target.

We have adopted an assumption that the LRET transitions from the target in 2014 to the reduced 2020 target on a ‘straight line’ basis. In addition, we have also imposed a constraint that the new target cannot exceed the current target in any year – an assumption which is material in 2015 due to the profile being convex prior to 2020.

Figure 3.2 compares the resulting level of the Reduced LRET, as modelled in the Reduced LRET sensitivity, to the current LRET.

[17] To calculate the reduced LRET, we have adopted forecasts of annual energy demand on an ‘as-generated’ basis.

Figure 3.2
Assumed levels of the LRET for different modelling scenarios



Source: NERA analysis of the RET, LRET, and SRES schemes.

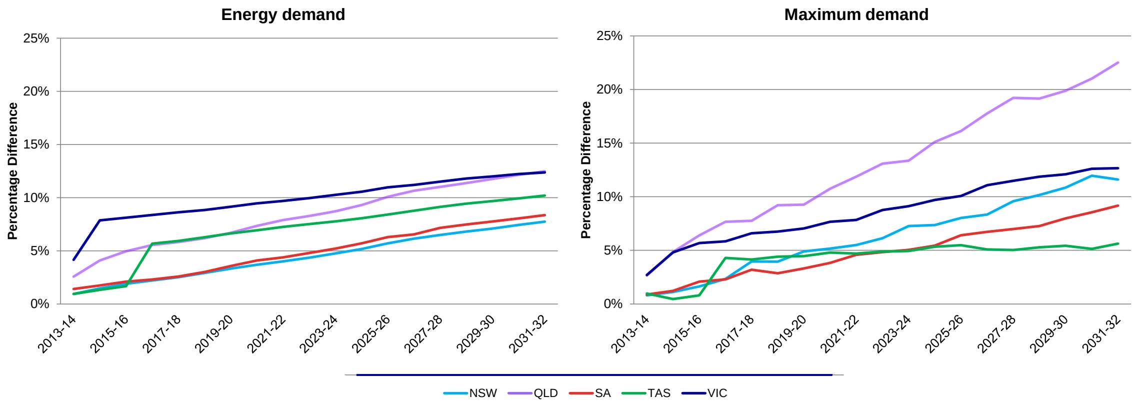
3.2.4. Low demand sensitivity

We have described that actual levels of demand in recent years have consistently been lower than forecast. We have therefore modelled a sensitivity that considers the case where demand levels are based on the low scenario of AEMO's 2013 National Electricity Forecasting Report.

The differences between AEMO's low and medium demand forecasts vary both by region and based on whether the demand is for energy or capacity – Figure 3.3. We observe the following:

- The difference between the medium and low energy demand forecast is greatest in Victoria, particularly prior to 2020. By 2031-32, energy demand in the low scenario is between 7 and 12 per cent lower than in the medium scenario in all regions.
- The difference between the medium and low maximum demand forecasts is greatest in Queensland, where maximum demand is 22 per cent lower by 2031-32. In all other regions except Tasmania, maximum demand in the low scenario is between 8 and 12 per cent lower than in the medium scenario.

Figure 3.3
Differences in demand assumptions – base case and low demand sensitivity



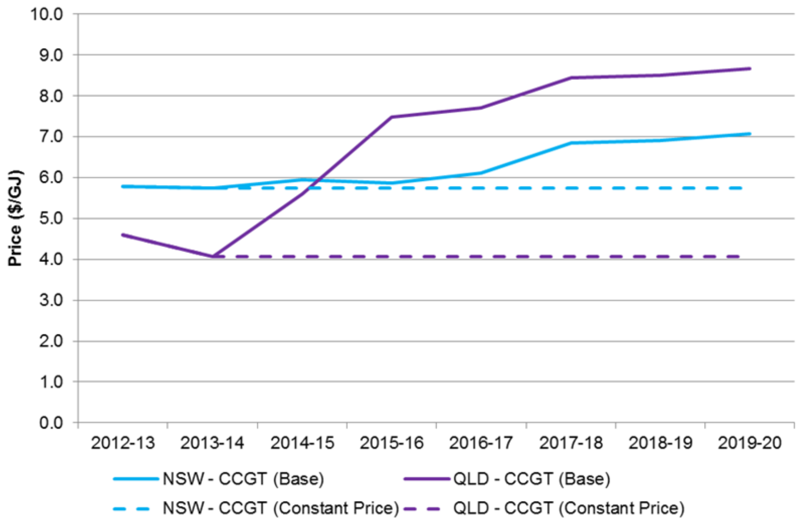
Note: NERA analysis of AEMO NEFR 2013 projections of maximum demand and energy demand.

3.2.5. Constant gas prices sensitivity

We have described the potential for a step change in new-entrant gas prices over the coming years. A relevant question is the degree to which rises in gas prices will affect market outcomes. We have therefore modelled a sensitivity that holds gas prices constant at 2013-14 levels over the entire modelling period. When compared to the base case, this sensitivity provides an indication of the incremental change in wholesale electricity purchase costs resulting from anticipated increases in new-entrant gas prices over the modelling time horizon.

The effect of this assumption on market outcomes varies across regions, because of the different regional forecasts. Figure 3.4 compares gas costs for a new entrant CCGT in both Queensland and New South Wales. The greater rise in gas costs in Queensland in the base case means that the shift to constant gas prices is more significant. Conversely, because the rises in gas prices in New South Wales in the base case are more modest, the effect on new entrant gas prices is less prominent.

Figure 3.4
Effect of constancy assumption on new entrant gas prices



A relevant question is how to treat gas prices for generators that are assumed to have a gas price lower than the new-entrant gas price, ie, those generators that AEMO has assumed have a contract position in the market. For these generators we assume that gas prices move to new-entrant levels once the contract position ends under AEMO's assumptions.

4. Projections of Electricity Purchase Costs

This chapter sets out the results of our market modelling approach to estimate wholesale electricity purchase costs. We first present our results for the base case and then for each of the sensitivities in turn.

4.1. Base case

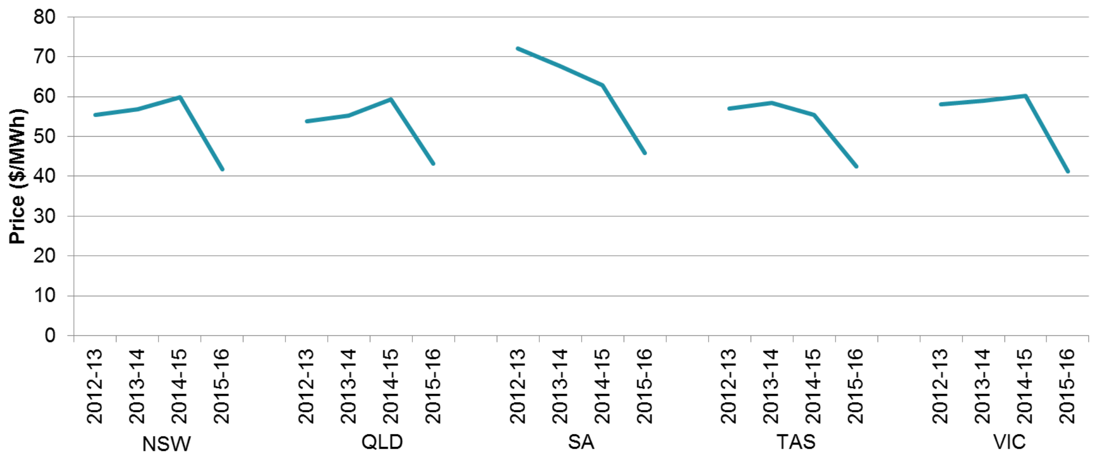
Our projected spot prices and electricity purchase costs for the base case are presented in Figure 4.1 and Figure 4.2, respectively.

Prices across all regions, with the exception of South Australia, rise gradually in 2013-14 and 2014-15 due to:

- assumed rises in gas costs;
- small increases in the carbon price, given the assumption that the fixed price will be retained until 30 June 2015; and
- the firming of total system demand driven predominantly by significant demand growth in Queensland associated with the construction of LNG terminals.[18]

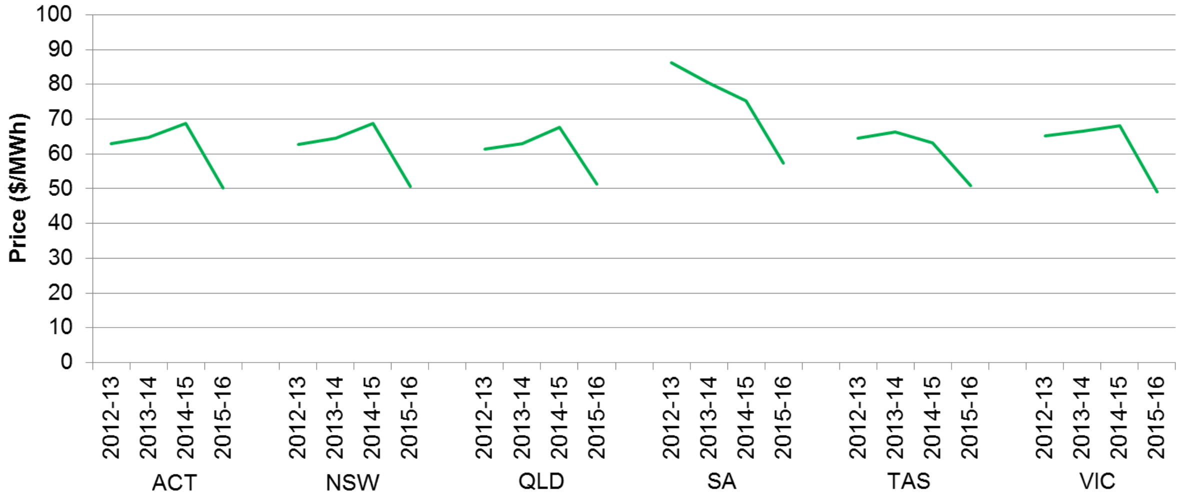
The projected decline in prices in 2015-16 is attributable to a decrease in the carbon price as the fixed price period ends. This is the most significant change in prices over the modelling period.

Figure 4.1
Projected spot prices – base case



[18] AEMO, "2013 National Electricity Forecasting Report."

Figure 4.2
Projected electricity purchase costs – base case



Drivers of outcomes by region

After adjusting for the effect of the carbon price, our projections of electricity purchase costs are relatively low across all regions, with the exception of South Australia. The very high prices in South Australia in 2012-13 and 2013-14 reflect an altered operational schedule for Northern Power station (a 530 MW brown coal fired power station), which continues not to operate during the winter. This has the effect of placing upward pressure on prices. Northern power station is assumed to return to normal operations from October 2014, leading to more moderate prices in South Australia from then onwards.[19]

Across New South Wales, Queensland, Victoria and Tasmania, there is only marginal price separation reflecting the adequacy of existing capacity to meet demand. As a result, outcomes in each of these regions tend to be driven by the same factors, most notably the carbon price and a system-wide firming of demand. There are nevertheless important factors influencing outcomes in each region both over the modelling period and beyond. In particular:

- New South Wales has experienced the greatest decline in demand of any region, and so has a considerable surplus of generating capacity.
- In Queensland, rising gas prices have only a marginal impact over the modelling period because of existing gas contracts (as described in section 3.2.5). However, beyond 2015-16 gas prices are likely to be a principal driver of price outcomes in the region.
- The high emissions intensity of brown coal fired generators in Victoria means that outcomes in this region are likely to be heavily influenced by the carbon price. As a result, we project that Victoria will experience the greatest reduction in spot prices in 2015-16 when the carbon price is assumed to drop.

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[19] Plant operating schedules based AEMO Generator Information (accessed June 2013) – available at http://www.aemo.com.au/Electricity/Planning/Related-Information/Generation-Information.

Electricity purchase costs

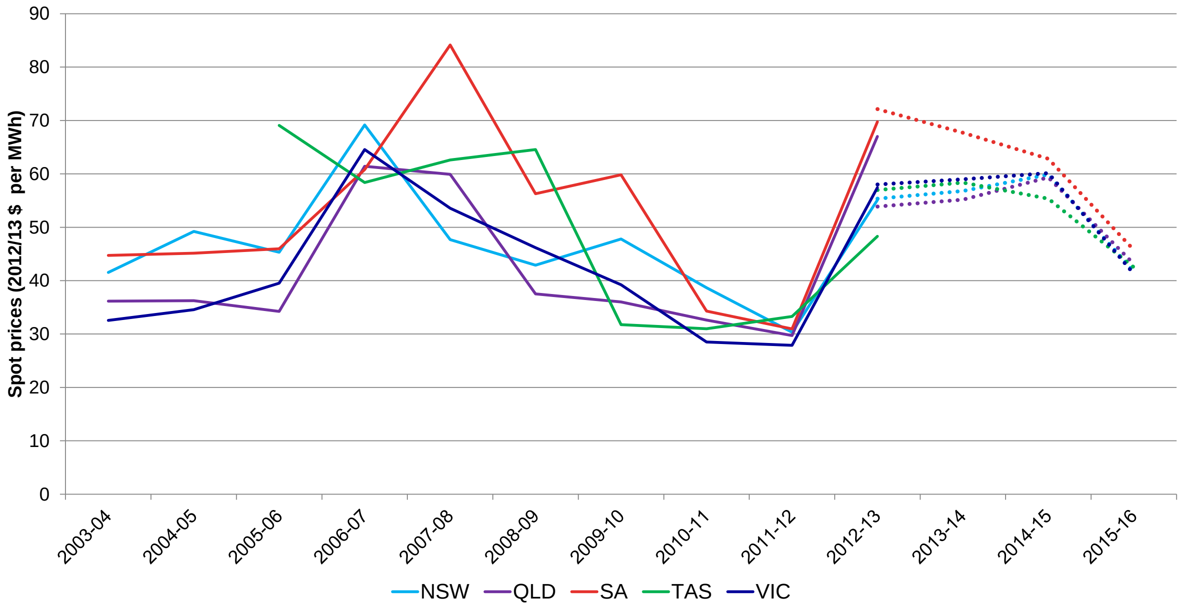
Our projections of wholesale electricity purchase costs exceed our projected spot market prices because of the costs inherent to hedging spot market price volatility. Nevertheless, electricity purchase costs follow a similar profile to spot prices in all regions, and so the drivers of higher spot prices are also drivers of higher electricity purchase costs.

The variation across regions is also influenced by the load profiles that we have adopted for each region. All else being equal, a region with a peakier load profile will have higher wholesale purchase costs than a region with a flatter load profile. For example, whilst spot prices are higher in South Australia, the electricity purchase costs are also higher than in other regions due to the peakier load profile.

Projected spot prices compared to historical outcomes

To place our projections into context, it is helpful to compare our projections with historical price outcomes in the NEM. Figure 4.3 shows historical annual average spot prices by NEM region for the years 2003-04 to 2012-13, as well as our projected spot prices for the base case (indicated by dotted lines).[20] All historical prices have been adjusted for inflation, and are shown in constant 2012-13 dollars.

Figure 4.3
Projected and historical annual average spot prices by NEM region



Sources: NERA analysis of spot prices from MMS database, as published by AEMO; CPI based on All Groups CPI, weighted average of eight capital cities, as published by the Australian Bureau of Statistics.

20 We have modelled spot prices in 2012-13 to compare our results to actual outcomes in that year. Our results differ from actual outcomes because of the inherent limitations of our modelling framework (eg, the inability to capture intra-regional constraints), as well as differences between assumptions and actual inputs (eg, differences in assumed versus actual gas prices, actual outages etc.).

Annual average spot prices have varied considerably over the last decade. From 2003-04 to 2004-05 spot prices in all regions were relatively stable at a level that was likely insufficient to support new-entry into the market. In 2006-07 and 2007-08 prices increased considerably due to a water shortage across the entire NEM. The water shortage reduced generation from hydro-electric plants but, more significantly, limited the supply of cooling water to thermal power stations in Queensland.

From 2008-09, prices have declined considerably across the NEM. In 2011-12, prices in all regions were close to record lows in real terms. The sharp increase in prices in 2012-13 is attributable to the introduction of the carbon price on 1 July 2012, although outcomes in South Australia and Queensland have also been affected by more transient factors.

Our projections for the base case largely reflect a continuation of relatively low prices in the NEM, taking the effect of carbon pricing into account.

4.2. Carbon price sensitivities

This section sets out our results for the carbon price sensitivities, ie:

- the zero carbon price sensitivity; and
- the EU 2014 carbon price sensitivity.

4.2.1. Zero carbon price

Our projected spot prices and electricity purchase costs for the base case and the zero carbon sensitivity are presented in Figure 4.4 and Figure 4.5 respectively.

Figure 4.4
Projected spot prices – base case and zero carbon sensitivity

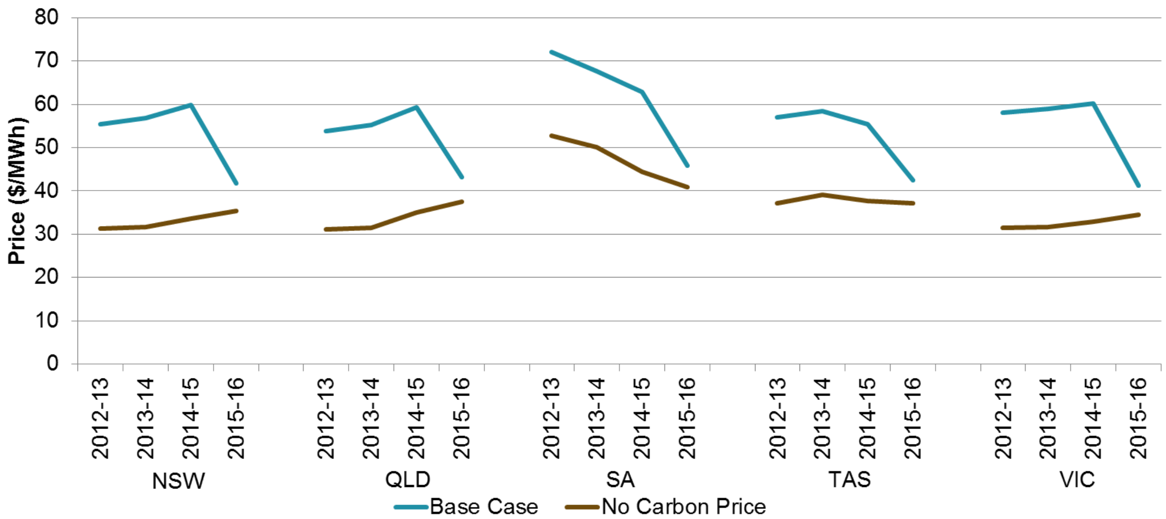
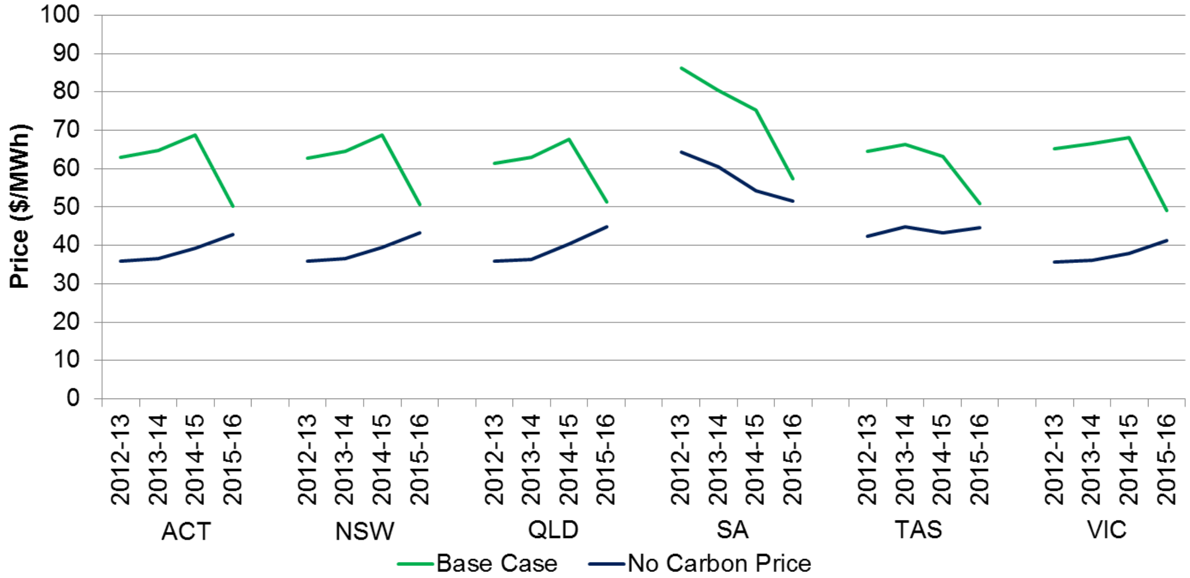


Figure 4.5
Projected electricity purchase costs – base case and zero carbon sensitivity



In the zero carbon sensitivity, prices for New South Wales, Queensland and Victoria rise in each year of the modelling period. The rise is largely driven by the firming of demand across the NEM, but is also influenced by rising gas prices.

We have described that the difference between spot prices in the base case and in the zero carbon price sensitivity is the 'carbon pass-through', ie, a measure of the contribution of the carbon price to spot price outcomes. The carbon pass-through varies by region, but is largely a function of the emissions intensity of generation capacity within a region.

The pass-through is greatest in Victoria at between 115 and 125 per cent, which reflects the high emissions intensity of generation of brown coal fired generators such as Hazelwood and Yallourn. New South Wales and Queensland exhibit a lower carbon-pass through reflecting the use of black coal fired generation in those states.

The carbon pass-through in Tasmania is also considerable, despite the fact that most generation in Tasmania is from hydro-electric plants. The carbon price increases the value of energy in storage which can be exported to Victoria via the Basslink interconnector. As a result, prices in Tasmania shadow the Victorian price to some degree. This emphasises the importance of considering the carbon pass-through based on marginal generation costs, which influence spot prices earned by all generators in the market.

4.2.2. EU 2014 carbon price sensitivity

Our projected spot prices and electricity purchase costs for the base case and the EU 2014 carbon price sensitivity are presented in Figure 4.6 and Figure 4.7, respectively.

Figure 4.6
Projected spot prices – base case and EU 2014 carbon price sensitivity

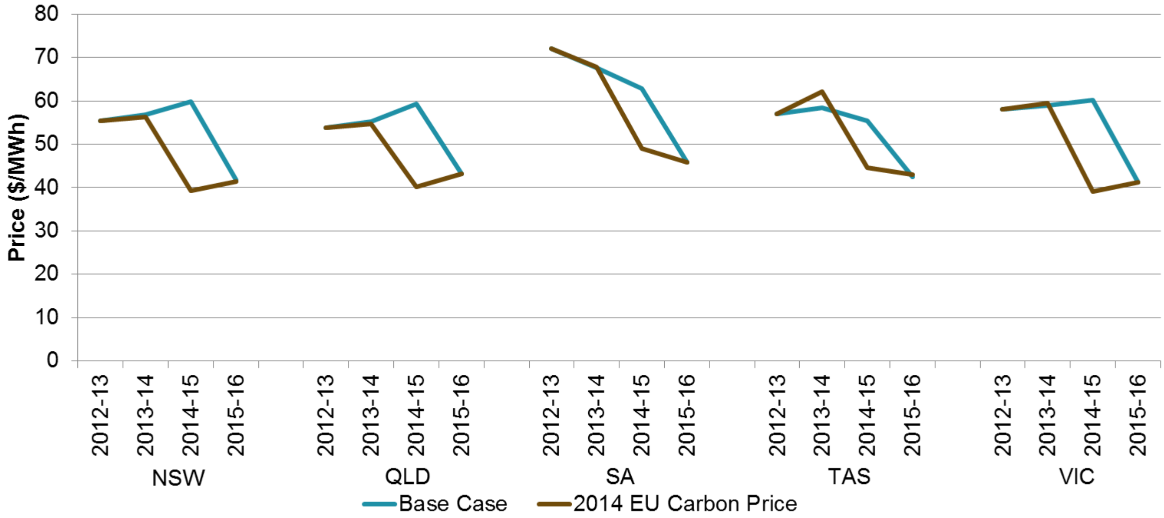
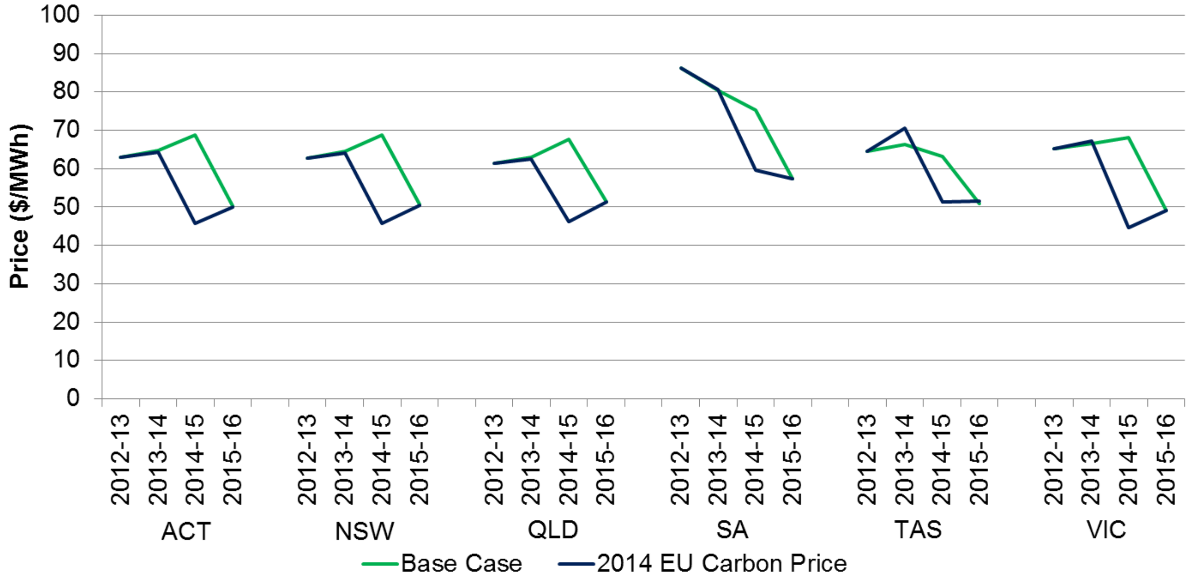


Figure 4.7
Projected electricity purchase costs – base case and EU 2014 carbon price sensitivity



The results in the EU 2014 carbon price sensitivity closely match those in the base case, but with prices in 2014-15 decreasing in line with the reduction in the carbon price. The only exception to this is in Tasmania, where a deferral in the construction of some wind generation capacity results in a small price increase in 2013-14 relative to the base case.

4.3. Low demand sensitivity

This section sets out our results for the low demand sensitivity. Figure 4.8 and Figure 4.9 compare our projected spot prices and electricity purchase costs for the base case and the low demand sensitivity.

Figure 4.8
Projected spot prices – base case and low demand sensitivity

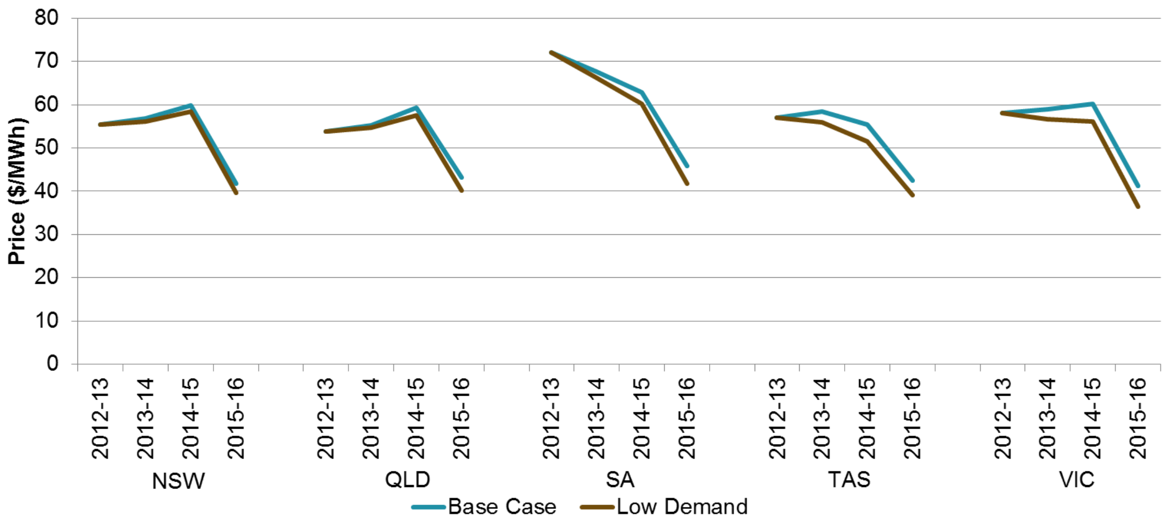
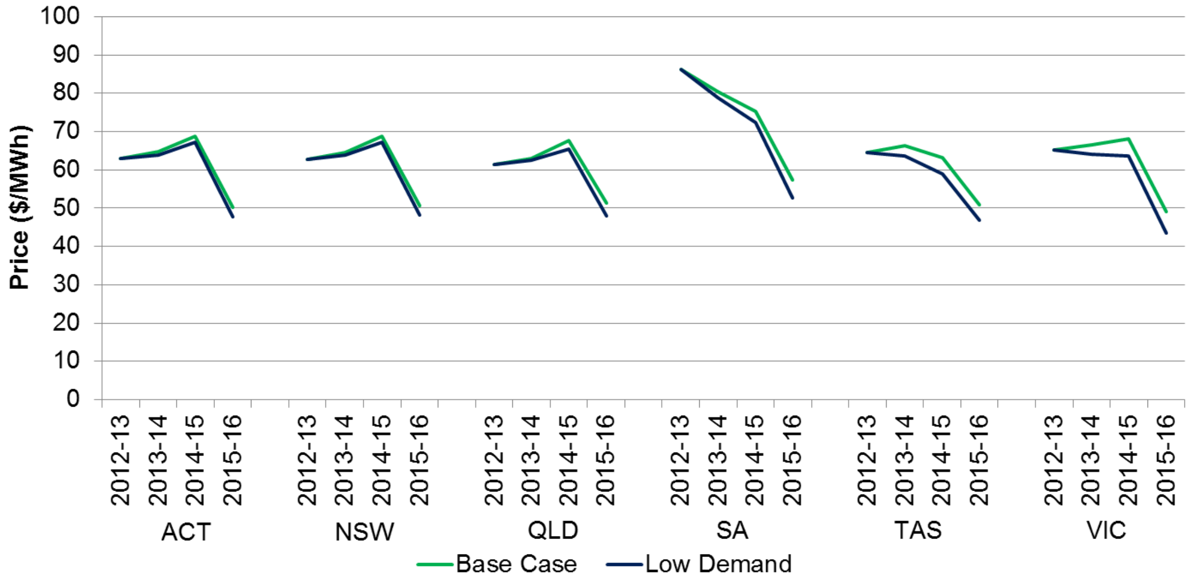


Figure 4.9
Projected electricity purchase costs – base case and low demand sensitivity



As would be expected, prices in the low demand scenario are uniformly lower than in the base case. The difference is relatively small in most regions, but tends to increase over time in line with the growing divergence between demand assumptions in the base case and the low demand sensitivity.

The effect of the low demand assumption on spot prices is greatest in Victoria and Tasmania, driven by the considerable reduction in demand in Victoria. In other states, the effect on prices is far more muted. This can largely be attributed to the low level of demand that is observed in the base case, ie, demand is already at a very low level and so the further reduction has only a limited effect on prices.

4.4. Reduced LRET sensitivity

This section sets out our results for the reduced LRET sensitivity. Figure 4.10 and Figure 4.11 compare our projected spot prices and electricity purchase costs for the base case and the reduced LRET sensitivity.

Figure 4.10
Projected spot prices – base case and reduced LRET sensitivity

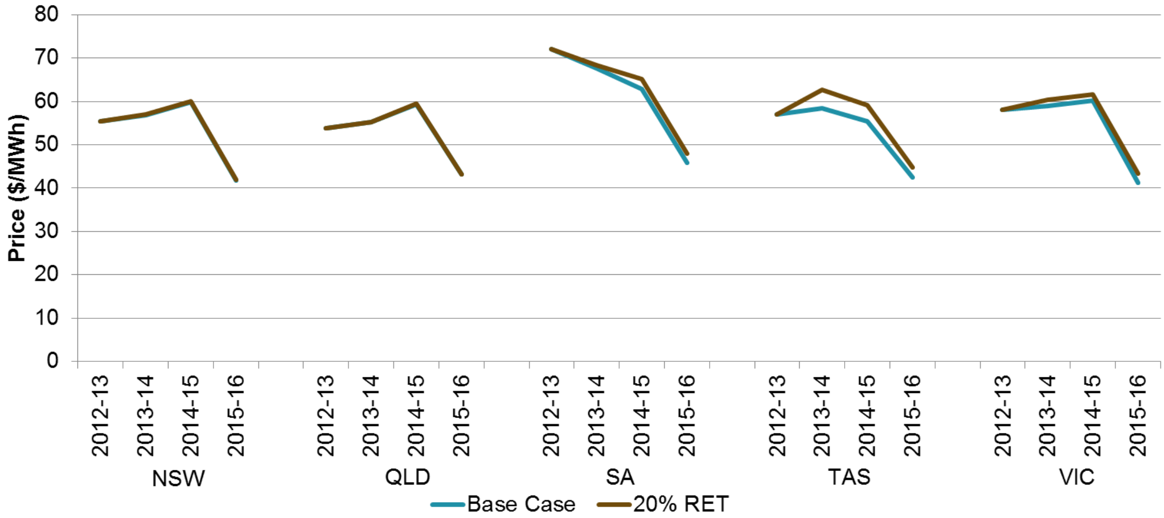
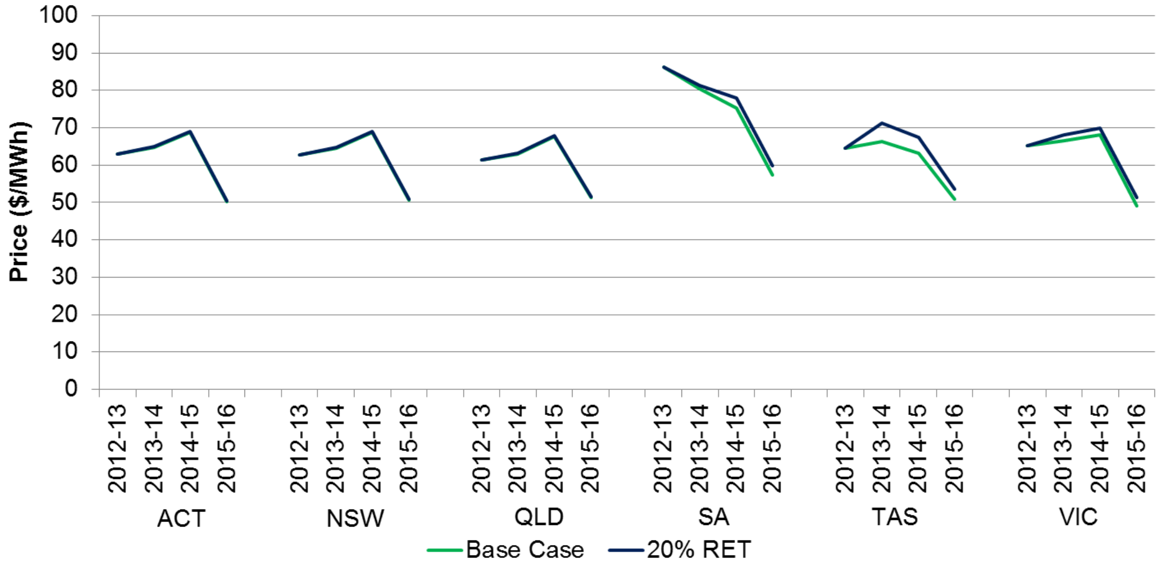


Figure 4.11
Projected electricity purchase costs – base case and reduced LRET sensitivity



Spot prices for the reduced LRET sensitivity are very similar to those under the base case. Prices are marginally higher for the reduced LRET sensitivity on account of changes in the planting of new entrant wind. Small reductions or deferrals of wind investment act to increase demand for thermal generation and so act to increase spot prices, ie, all else being equal the more wind farms that are constructed in a region the lower the spot price. However, our modelling suggests that the increase in spot prices attributable to a reduction in the LRET is limited. In some regions, we project no change in wind generation build over the modelling period and so spot price outcomes are almost identical to the base case.

4.5. Constant gas prices sensitivity

This section sets out our results for the constant gas price sensitivity. Figure 4.12 and Figure 4.13 compare our projected spot prices and electricity purchase costs for the base case and the constant gas price sensitivity.

Figure 4.12
Projected spot prices – base case and constant gas price sensitivity

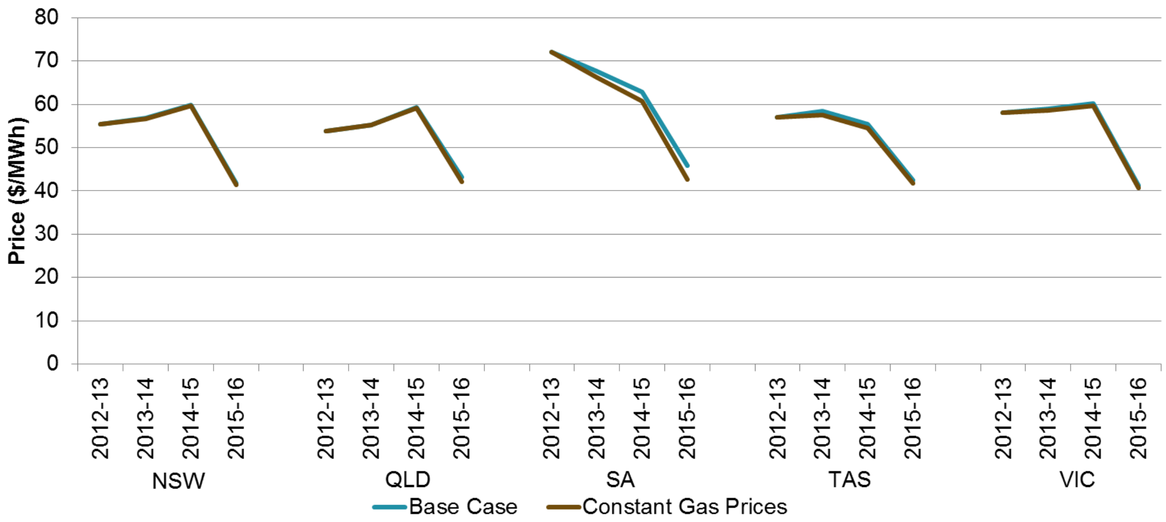
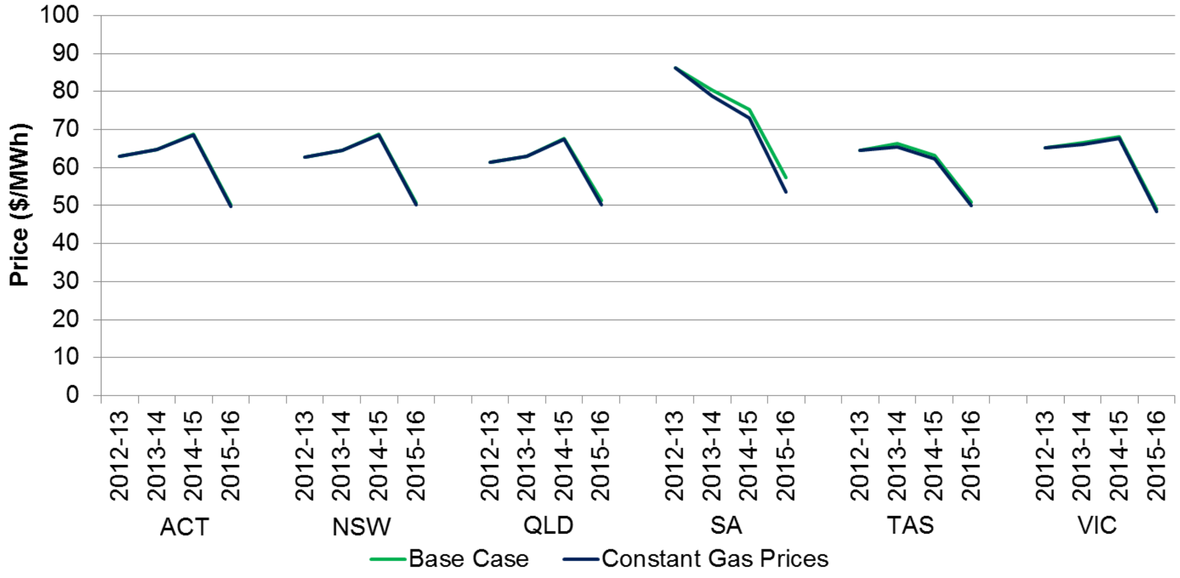


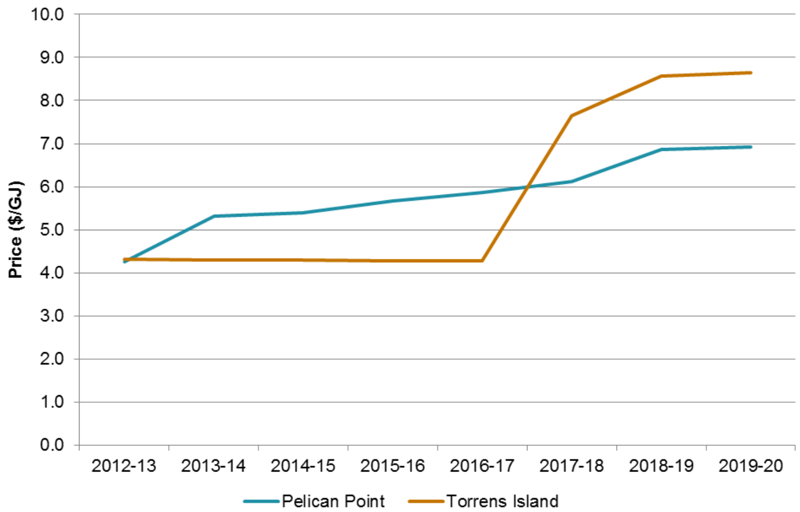
Figure 4.13
Projected electricity purchase costs – base case and constant gas price sensitivity



Spot prices for the constant gas price sensitivity are marginally lower than in the base case. The reason that changes in gas price assumptions do not flow through into prices over the forecasting period is because of the contracting assumptions included in the AEMO fuel price assumptions.

Figure 4.14 shows the influence of AEMO contracting assumptions on fuel prices for two gas fired plants in the South Australian region. Torrens Island is assumed to be under contract until 2016-17, after which it pays a new entrant gas price. In contrast, Pelican Point pays a new-entrant gas price from 2012-13 onwards.

Figure 4.14
Illustration – effect of contracting assumptions on gas prices



Most plants in most regions are assumed to be paying a fixed contract price for part or all of the forecast period, and so the impact of the constant gas price assumption is minimal.

It is important to emphasise that our results do not suggest that gas prices are not important to future price outcomes, but rather that AEMO’s current forecast demand and gas contract assumptions suggest that new-entrant gas prices will have a relatively small impact on spot prices and so wholesale electricity purchase costs over the next few years. However, this scenario outcome is critically dependent on the contracting assumptions in AEMO’s fuel price forecasts, and the likelihood that demand moves in line with forecasts.

5. Estimates of stand-alone LRMC

In addition to our assessment of electricity purchase costs using a market modelling approach, we have also been asked to estimate LRMC using a 'stand-alone' approach. This chapter describes:

- the stand-alone approach we have used to estimate LRMC;
- the specific assumptions that we have adopted; and
- our estimates of stand-alone LRMC for New South Wales, Queensland, South Australia and Victoria.

5.1. Stand-alone LRMC

A 'stand-alone' or 'Greenfields' approach to estimating LRMC assumes that there is no pre-existing generation capacity available to serve prevailing electricity demand. The LRMC is estimated as the average cost of serving an addition to load, for some assumed profile, using the least-cost combination of new-entrant generation.

In practice, applying a stand-alone approach involves:

- developing an optimal mix of generation to supply an existing load and load shape, given assumptions about new entrant capital costs and operating costs; and
- calculating the unit capital and operating cost of the energy supplied by the optimal mix of generation.

The principal feature of the stand-alone approach to estimating LRMC is that it does not incorporate existing generation capacity in calculating the supply cost. In general, new entrant costs will exceed the costs of existing generation, and so a stand-alone approach will tend to provide relatively higher estimates of electricity purchase costs than alternative approaches that incorporate existing generation capacity.

We have implemented this approach for the New South Wales, Queensland, South Australia, and Victoria NEM regions.

5.2. Relevant assumptions

We have adopted assumptions that are consistent with the base case, including:

- customer load profiles;
- carbon prices;
- new entrant technology costs; and
- plant operating parameters, such as thermal efficiencies and auxiliary usage rates.

The input assumptions for the stand-alone calculations are identical to those used for the market modelling approach, save for fuel prices. For the purposes of this exercise, we have been asked to adopt an assumption that new entrant CCGTs pay a delivered price of $7 per GJ for gas in all regions, and that OCGTs pay a 25 per cent premium to this price. This assumption differs from the values that we have used for the market modelling set out in chapter 4.

5.3. Results

Figure 5.1 and Table 5.1 set out our estimates of the LRMC for the New South Wales, Queensland, South Australia, and Victoria NEM regions.

Figure 5.1
Stand-alone LRMC ($7 gas price) versus market based approach

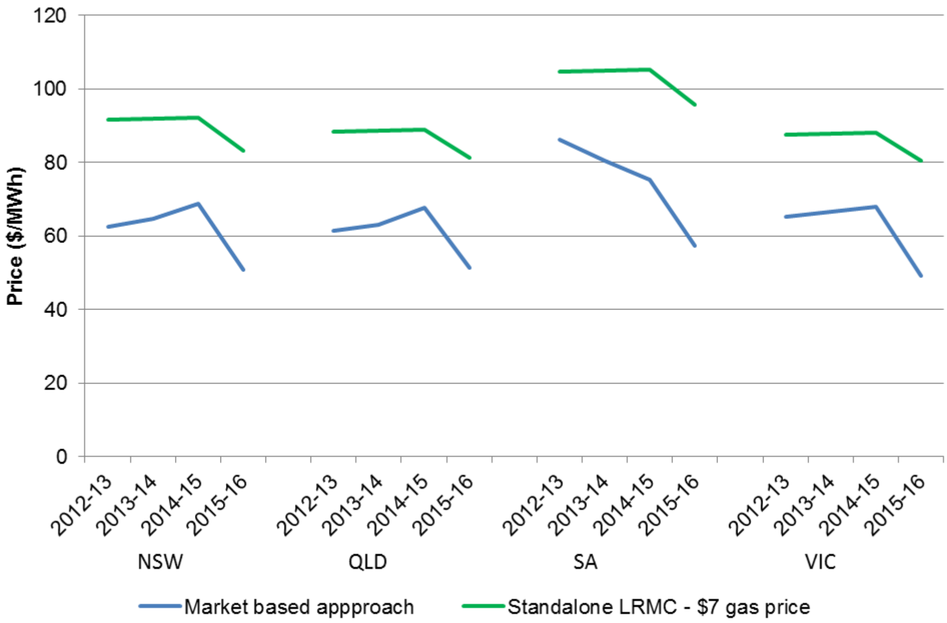


Table 5.1
Stand-alone LRMC ($/MWh) – $7 per GJ gas price

NEM Region	2012-13	2013-14	2014-15	2015-16
VIC	87.5	87.8	88.0	80.4
NSW	91.6	91.8	92.1	83.3
QLD	88.4	88.6	88.9	81.2
SA	104.7	105.0	105.3	95.8

We observe the following:

- In all regions, the estimated stand-alone LRMC remains relatively flat from 2012-13 to 2014-15 reflecting the flat fuel price assumptions in all years. The small increases in the carbon price over this period have a negligible effect on the estimates over this period. This occurs because gas-fired generation technologies have a relatively low emissions intensity and so changes in the carbon price have less of an effect our stand-alone LRMC estimate than on our market-based estimates.

- In all regions, the stand-alone LRMC declines in 2015-16, reflecting a sharp reduction in the carbon price. The decline in the stand-alone LRMC estimate is not as marked as the reduction in the market-based estimate of electricity purchase costs. This is because our stand-alone LRMC estimate assumes new-entrant generation is exclusively gas fired, and so the carbon price is less of a driver than for a market based approach where coal fired technologies are included in the generation mix.
- The stand-alone estimates of the LRMC are consistently higher than our market-based estimates of electricity purchase costs. The market-based approach takes into account prevailing demand and supply conditions within the market – ie, lower demand and surplus capacity both place downward pressure on the cost estimate. In contrast the stand-alone approach, which estimates LRMC solely based on new entrant costs, does not take the current supply-demand balance into consideration. During periods when existing capacity is sufficient to meet prevailing demand, the stand-alone LRMC estimate will therefore include a higher capital cost component compared to the market modelling methodology.

6. LRET and SRES Costs

This chapter sets out our estimates of costs to comply with the LRET and the SRES.

6.1. LRET costs

The LRET creates a liability for retailers to surrender certificates to the regulator in line with purchases of wholesale electricity. Retailers that fail to surrender certificates to match certificate liabilities must pay a ‘shortfall penalty’.

Certificate liabilities are calculated based on the renewable power percentage (RPP) – a value set annually by the Clean Energy Regulator. The renewable power percentage is set based on a fixed (GWh) target, already specified in legislation. Because the target is fixed, the RPP will vary depending on the level of demand – ie, the unitised cost of complying with the LRET is a function of how much demand there is for electricity.

Using the RPP, a retailer’s annual certificate liability is calculated according to the formula:

$$LGC\ Liability = RPP\ \times Wholesale\ Electricity\ Purchases.$$

Retailers face a penalty of $65 for each certificate that they fail to surrender, and this penalty is not tax deductible.

6.1.1. Estimated LRET costs

We have estimated LRET costs on a per MWh basis, by taking the product of projections of the RPP and the LGC price, ie:

$$LRET\ Costs\ = RPP\ \times LGC\ Price$$

We have made projections of the RPP using forecasts of wholesale electricity purchases consistent with our modelling assumptions.

Our projections of LGC prices are outputs of our least-cost planning model. The LGC price can be estimated by considering the marginal value (sometimes called the ‘shadow price’) of the constraint that the LRET must be met, either by surrendering certificates or by paying the shortfall penalty. We have also estimated LRET costs using quoted forward prices for LGCs. Our projected LGC prices for both the base case and the 20 per cent LRET sensitivity are shown in Table 6.1 along with quoted forward prices for LGCs.

Table 6.1
Projected LGC prices by scenario versus forward LGC prices

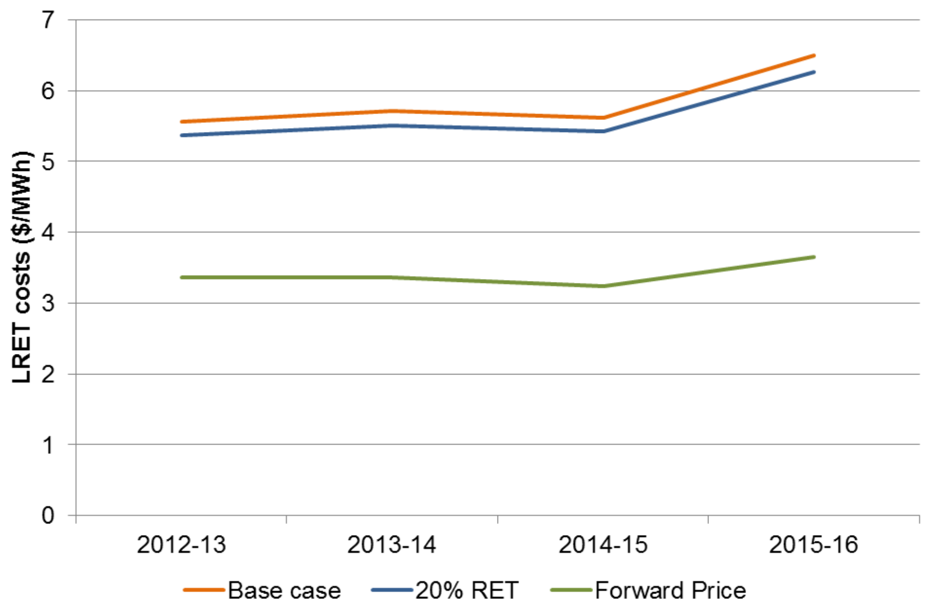
Financial Year	Base	20% RET	Forward price
2012-13	56.16	54.22	33.90
2013-14	58.97	56.93	34.75
2014-15	61.92	59.78	35.62
2015-16	65.01	62.77	36.51

Our projections indicate that LGC prices in both scenarios are relatively similar, but are marginally lower in the Reduced LRET sensitivity. The similarity between results stems from the fact that in all scenarios wholesale market conditions are relatively unfavourable to wind generation investment – the carbon price is low and demand is low compared to installed capacity.

It follows that new wind generation investment is not financially viable without the LRET over the life of the scheme and so LGC prices are relatively high for both scenarios, ie, the additional revenue from LGCs required to support investments in wind farms does not change significantly as the level of the LRET changes.

Based on these assumed prices, our projected LRET costs are set out in Figure 6.1 below.

Figure 6.1
Projected LRET costs by modelling scenario ($ per MWh)



Our projections of LRET costs are relatively flat for the period from 2012-13 to 2014-15, reflecting increases in our modelled LGC prices being offset by a corresponding reduction in the RPP. The increase in LRET costs in 2015-16 is driven by the LRET target increase, which in turn increases the RPP.

Finally, the lower LRET costs under the reduced LRET scenario reflect lower LGC prices, as the RPP is unchanged over the period to 2015-16 due to our assumed gradual transition to the new LRET target level.

6.2. SRES costs

Unlike the LRET, the annual targets for the SRES are not specified in legislation. Instead the targets are set by the Clean Energy Regulator on an annual basis taking into account:

- projections of future installations of small-scale renewable technologies and so the expected creation of STCs in the coming year; and
- any surplus STCs from the preceding year.

Based on this target, the Clean Energy Regulator sets the small-scale technology percentage (STP) that determines the liabilities for individual entities.

The STP then forms the basis of the number of certificates that electricity retailers must purchase and surrender to the Clean Energy Regulator, by way of the formula:

$$STC\ Liability = STP\ \times Wholesale\ Electricity\ Purchases.$$

Like the LRET, liable entities that do not surrender a sufficient number of STCs to meet their liability must pay a shortfall charge of $65 per STC.[21]

6.2.1. Estimated SRES costs

We have estimated SRES costs on a per MWh basis, by multiplying projected values for the STP by an assumed STC price, ie:

$$SRES\ Costs\ = STP\ \times STC\ Price$$

We have assumed values for the STP as published by the Clean Energy Regulator – Table 6.2. These STP values are specified on a calendar year basis, and so to provide an estimate of SRES costs on a financial year basis we have taken the average of the calendar year values (eg, the STP in 2012-13 is the average of the 2012 and 2013 STPs).

Table 6.2
Historical and non-binding future STP values

Year	Required STCs	STP (%)
2011	28,000,000	14.80
2012	44,786,000	23.96
2013	35,700,000	19.70
2014	16,700,000	8.98
2015	15,800,000	8.49
2016*	-	3.97

Source: Data sourced from Clean Energy Regulator website.
** Data for 2016 is only specified by default in the relevant legislation.*

21 The Clean Energy Regulator operates a ‘clearing house’ for STCs that facilitates trades at a fixed price of $40 per STC. We understand that the Regulator will effectively create certificates at the fixed price of $40 to meet demand. Therefore, the shortfall penalty of $65 per STC is in effect $40 per STC.

The uncertainty surrounding future annual STC targets means that the STC price is also uncertain. We have therefore assumed a constant STC price of $38.10, which is the quoted spot price at the time of writing this report.[22] We have assumed that this value remains constant in real terms in each year of the modelling period.

Our projected SRES costs for each year of the modelling period are shown in Figure 6.2 and Table 6.3.

We project that SRES costs decrease in each year of the modelling period. This reflects the decline in the non-binding STPs, as published by the Clean Energy Regulator, over the modelling period. It is important to note that these STP values will be reviewed annually by the regulator and therefore are subject to revision.

Figure 6.2
Projected SRES Costs ($ per MWh)

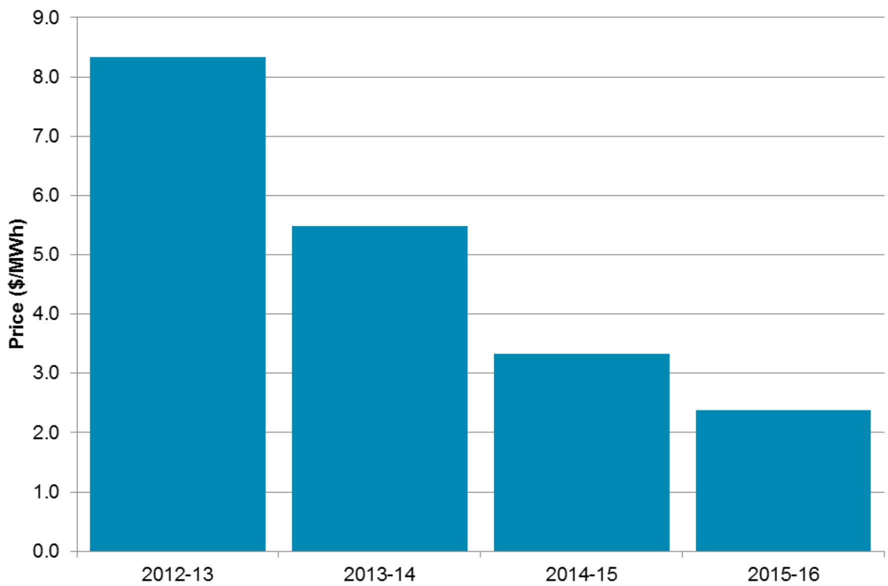


Table 6.3
Projected SRES costs – 2012-13 to 2015-16

Financial Year	STP	Forward Price	SRES Cost
2012-13	21.83%	38.20	8.34
2013-14	14.34%	38.20	5.48
2014-15	8.74%	38.20	3.34
2015-16	6.23%	38.20	2.38

22 STC prices sourced from http://www.cleanenergycouncil.org.au/ as at 9 August 2013.

7. Participant Fees and Costs for Ancillary Services

This chapter sets out our projections of additional costs incurred to supply wholesale electricity, ie, market participant fees and costs for ancillary services.

7.1. Participant fees

The costs incurred by market operators in running the NEM and the SWIS are recovered from market participants. In the NEM, AEMO recovers the following fees:

- fees to maintain the Participant Compensation Fund;
- full retail competition fees;
- National Transmission Planner fees;
- fees collected by AEMO on behalf of the Electricity Consumer Advocacy Panel; and
- other fees incurred by AEMO.

AEMO regularly publishes projections of annual NEM participant fees. We have adopted AEMO's most recent projections to estimate the contribution of market fees to future electricity supply costs for NEM regions. For the SWIS, we have assumed that market fees remain at the current level of $0.85 per MWh (in constant 2012-13 dollars). Our projections of participant fees are set out at Table 7.1.

Table 7.1
Projected participant fees by jurisdiction (2012-13 $ per MWh)

Jurisdiction	2013-14	2014-15	2015-16
ACT	0.36	0.37	0.37
New South Wales	0.36	0.37	0.37
Queensland	0.36	0.37	0.37
South Australia	0.36	0.37	0.37
Tasmania	0.36	0.37	0.37
Victoria	0.36	0.37	0.37
Western Australia	0.85	0.85	0.85

Source: NERA analysis of fees information published by AEMO[23] *and IMOWA*[24].

[23] AEMO, "AEMO Final Budget and Fees 2013-14," May 2, 2013.

[24] Available at http://www.imowa.com.au/n5978.html.

7.2. Ancillary service costs

Ancillary service costs fall into one of the following three categories[25]:

- **Frequency Control Ancillary Services (FCAS)** to maintain the frequency of the system;
- **Network Control Ancillary Services (NCAS)** to ensure that voltage stays within specified tolerances and that flows on interconnectors are kept within short-term limits; and
- **System Restart Ancillary Services (SRAS)** or 'black-start' ancillary services, to enable the system to be re-energised after a shutdown.

AEMO publishes information on ancillary service costs (in nominal terms) for each region on a weekly basis. We have projected future ancillary service costs for each NEM region by taking the average ancillary services costs recoverable from customers (adjusted for inflation) in each region for the period from 1 January 2011 to 1 July 2013.

For Western Australia, we have based our projection on the average ancillary service costs for the SWIS from 1 April 2008 to 1 April 2012. In both cases, we have assumed that costs remain constant over the projection period. Our projections of ancillary service costs for each jurisdiction are presented at Table 7.2.

Table 7.2
Projected ancillary service costs by jurisdiction (2012-13 $ per MWh)

Jurisdiction	2013-14	2014-15	2015-16
ACT	0.67	0.67	0.67
New South Wales	0.67	0.67	0.67
Queensland	0.10	0.10	0.10
South Australia	0.44	0.44	0.44
Tasmania	0.54	0.54	0.54
Victoria	0.19	0.19	0.19
Western Australia	2.12	2.12	2.12

Source: NERA analysis of ancillary services costs published by AEMO.[26]

25 AEMO, "Guide to Ancillary Services in the National Electricity Market," July 1, 2010.

26 Available at *http://www.nemweb.com.au/REPORTS/CURRENT/Ancillary_Services_Payments/*.

8. Jurisdictional Estimates of Electricity Purchase Costs

This chapter sets out our:

- estimates of electricity purchase costs for the period from 2013-14 to 2015-16 as developed by jurisdictional regulators, supplemented where necessary with our own projections; and
- estimates of electricity purchase costs for residential customers in the SWIS based on a stand-alone approach to calculating LRMC.

8.1. Jurisdictional results

In this section, we set out estimates of electricity purchase costs using the methodologies and assumptions applied by jurisdictional regulators in the Australian Capital Territory, New South Wales and Queensland. We have not been asked to consider Tasmania.

Our results come from the following sources:

- For the **Australia Capital Territory** we have reported the energy purchase costs as published by the Independent Competition and Regulatory Commission (ICRC) in its final report regarding retail prices for franchise customers in 2013-14. [27] We have applied the trend from our projections of wholesale electricity purchase costs to establish estimates for 2014-15 and 2015-16.[28]
- For **New South Wales** we have drawn upon the estimates of the cost of energy determined by the Independent Pricing and Regulatory Tribunal (IPART) for its retail price review determination. [29] IPART sets the energy purchase cost allowance – which is the largest component of energy costs – no lower than 75 per cent of the LRMC of generation plus 25 per cent of a market-based purchase cost.
- For **Queensland** we have drawn upon the electricity purchase costs prepared by the Queensland Competition Authority for 2013-14. QCA applies a pure market modelling approach to estimate wholesale energy costs. [30] We have applied the trend from our own projections of wholesale electricity purchase costs to establish estimates for 2014-15 and 2015-16.

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27 Independent Competition and Regulatory Commission, (2013), *Retail Price Adjustment for Franchise Electricity Customers 2013-14,* Final Decision, June, Canberra.

28 The methodology applied by the ICRC can be characterised as a market based approach and is set out in detail in Appendix 4, Independent Competition and Regulatory Commission, (2012), *Retail Prices for Franchise Customers in 2012-14,* Final Report, June, Canberra.

29 Independent Pricing and Regulatory Tribunal, (2013), *Review of regulated retail prices for electricity, 2013 to 2016,* Electricity – Final Report, June, Sydney.

30 ACIL Tasman, (2013), *Estimated energy purchase costs for use by the QCA in its Final Determination on retail electricity tariffs for 2013/14*, February, pp.24-25.

Table 8.1 reports electricity purchase costs for each of these three jurisdictions, supplemented with our own projections as indicated.

Table 8.1
Jurisdictional regulators' estimates of electricity purchase costs

Jurisdiction	2013-14	2014-15	2015-16
Australian Capital Territory	67.3	*71.5*	*52.2*
New South Wales			
Energy Australia	79.88	81.22	69.03
Endeavour Energy	80.59	81.93	69.55
Essential Energy	69.39	70.56	58.83
Queensland			
Energex	69.43	*74.5*	*56.6*
Ergon	64.08	*68.8*	*52.2*

Notes: Values shown in italics have been calculated by NERA adopting the methodology of the regulator.

8.2. Western Australia

For Western Australia we have been asked to estimate electricity purchase costs using a 'stand-alone' long-run marginal cost (LRMC) approach. A stand-alone approach to estimating LRMC assumes that there is no pre-existing generation capacity available to serve prevailing electricity demand. The LRMC is estimated as the average cost of serving an addition to load, for some assumed profile, using the least-cost combination of new-entrant generation.

In practice, applying a stand-alone approach involves:

- calculating the optimal mix of generation to service an existing load and load shape, given assumptions about investment and operating costs, including fuel costs; and
- dividing total operating and fixed costs by the energy supplied.

Our estimates of electricity purchase costs in the SWIS, including the cost of carbon, using a stand-alone LRMC approach are set out in Table 8.2. The values are considerably higher than our results for other regions in chapter 4, largely because of the use of a stand-alone LRMC approach, as compared with a market modelling approach.

Table 8.2
Stand-alone LRMC estimate of electricity purchase costs in the SWIS

	2013-14	2014-15	2015-16
Stand-alone LRMC ($/MWh)	116.5	116.6	107.2
Cost of carbon ($/MWh)	11.6	11.9	2.7

Note: These estimates assume a carbon price in line with our base case assumptions.

We note that we have been unable to obtain a representative load profile for residential customers in the SWIS. In the absence of this information, we have been directed to use the residential load profile for South Australia. We note that the use of a different load profile would affect our results.

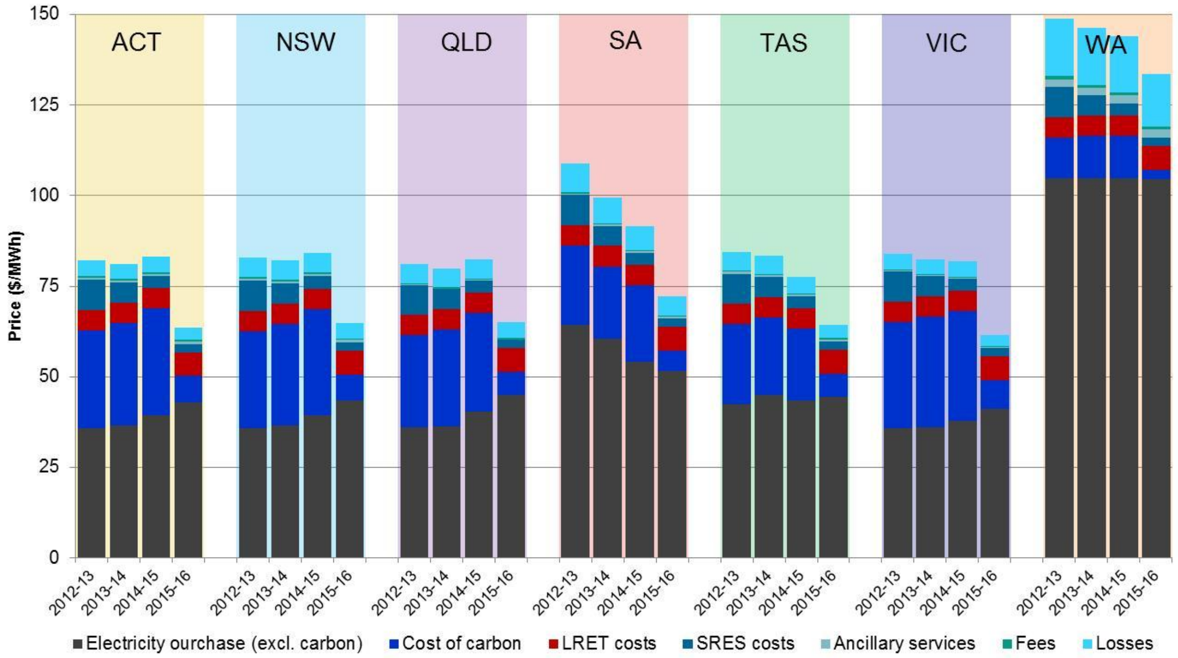
9. Summary of Results

This chapter concludes our report by presenting our consolidated estimates of wholesale energy costs for residential customers for our base case. Additional results for each of the sensitivities are also included in Appendix B.

Up until this point, all results have been presented net of energy losses, ie, as though energy is consumed at the regional reference node. Our consolidated results also include an estimate of the cost of losses in the distribution and transmission network, calculated by multiplying the cost at the regional reference node by an assumed distribution and transmission loss factor.[31] Figure 9.1 and Table 9.1 set out our consolidated results, with total wholesale energy costs broken down into:

- electricity purchase costs (excluding the carbon pass-through);
- the carbon pass-through;
- LRET costs and SRES costs;
- other costs; and
- the cost of distribution and transmission losses.

Figure 9.1
Projections of wholesale energy costs – base case



Note: Estimates of electricity purchase costs for Western Australia are not based on market modelling. We have instead been asked to use our stand-alone LRMC results from chapter 8.

31 Distribution and transmission loss factor assumptions are set out in Appendix A.

Table 9.1
Consolidated results – base case

Year	Electricity purchase costs (ex. carbon)	Cost of carbon	LRET Costs	SRES Costs	Ancillary Services	Participant Fees	Losses	Total
ACT								
2012-13	35.9	27.0	5.6	8.3	0.5	0.4	4.4	82.1
2013-14	36.5	28.3	5.7	5.5	0.7	0.4	4.2	81.2
2014-15	39.3	29.5	5.6	3.3	0.7	0.4	4.3	83.2
2015-16	42.9	7.3	6.5	2.4	0.7	0.4	3.3	63.4
NSW								
2012-13	35.8	26.8	5.6	8.3	0.5	0.4	5.4	82.9
2013-14	36.5	28.1	5.7	5.5	0.7	0.4	5.4	82.2
2014-15	39.5	29.3	5.6	3.3	0.7	0.4	5.6	84.3
2015-16	43.4	7.3	6.5	2.4	0.7	0.4	4.3	64.9
QLD								
2012-13	36.0	25.5	5.6	8.3	0.1	0.4	5.2	81.1
2013-14	36.4	26.6	5.7	5.5	0.1	0.4	5.3	80.0
2014-15	40.4	27.2	5.6	3.3	0.1	0.4	5.5	82.5
2015-16	44.9	6.5	6.5	2.4	0.1	0.4	4.3	65.0
SA								
2012-13	64.2	22.1	5.6	8.3	0.2	0.4	8.1	108.9
2013-14	60.4	20.0	5.7	5.5	0.4	0.4	7.1	99.6
2014-15	54.2	21.0	5.6	3.3	0.4	0.4	6.6	91.6
2015-16	51.7	5.7	6.5	2.4	0.4	0.4	5.2	72.2
TAS								
2012-13	42.5	22.0	5.6	8.3	0.6	0.4	5.1	84.5
2013-14	44.9	21.5	5.7	5.5	0.5	0.4	4.9	83.3
2014-15	43.4	19.8	5.6	3.3	0.5	0.4	4.6	77.6
2015-16	44.6	6.3	6.5	2.4	0.5	0.4	3.8	64.4
VIC								
2012-13	35.8	29.4	5.6	8.3	0.2	0.4	4.4	84.1
2013-14	36.2	30.4	5.7	5.5	0.2	0.4	4.2	82.5
2014-15	37.8	30.3	5.6	3.3	0.2	0.4	4.1	81.8
2015-16	41.3	7.8	6.5	2.4	0.2	0.4	3.1	61.6
WA								
2012-13	104.8	11.3	5.6	8.3	2.1	0.9	15.9	148.9
2013-14	104.9	11.6	5.7	5.5	2.1	0.8	15.8	146.4
2014-15	104.7	11.9	5.6	3.3	2.1	0.9	15.6	144.1
2015-16	104.5	2.7	6.5	2.4	2.1	0.9	14.4	133.5

The modelling sensitivities that we have considered highlight that:

- reducing the LRET to 20 per cent of forecast 2020 demand is projected to marginally increase spot prices and so residential wholesale electricity purchase costs relative to our modelled base-case. These cost increases are not offset by lower projected LRET costs. That said, over the entire period of the LRET scheme reducing the LRET will lower total system generation costs paid by electricity consumers;
- bringing forward the commencement of the EU carbon price to 1 July 2014 will lower projected wholesale electricity purchase costs in 2014-15 by between 18 and 34 per cent, depending on the region; and
- increases in gas prices forecast by AEMO will have a modest impact on wholesale electricity purchase costs over the period to 2015-16 because:
  - under AEMO’s assumption that many gas fired generators are contracted, many generators continue to have lost gas costs over the modelling period; and
  - there are no new entrant gas-fired generators over the modelling period.

Appendix A. Detailed Base Case Modelling Assumptions

This appendix sets out the input assumptions underpinning our market modelling that have not been addressed elsewhere in this report. We present the assumptions in four broad groupings, namely:

- electricity demand;
- fuel cost assumptions;
- operational parameters and costs for existing generators; and
- new entrant fuel prices and technology costs.

We have not included a discussion of our assumptions surrounding the carbon price and the LRET, as we have presented all relevant information in section 3.2.2 and section 3.2.3 of this report.

A.1. Sources of information

We have primarily relied on input assumptions developed and employed by the AEMO. The sources for our principal assumptions including the following:

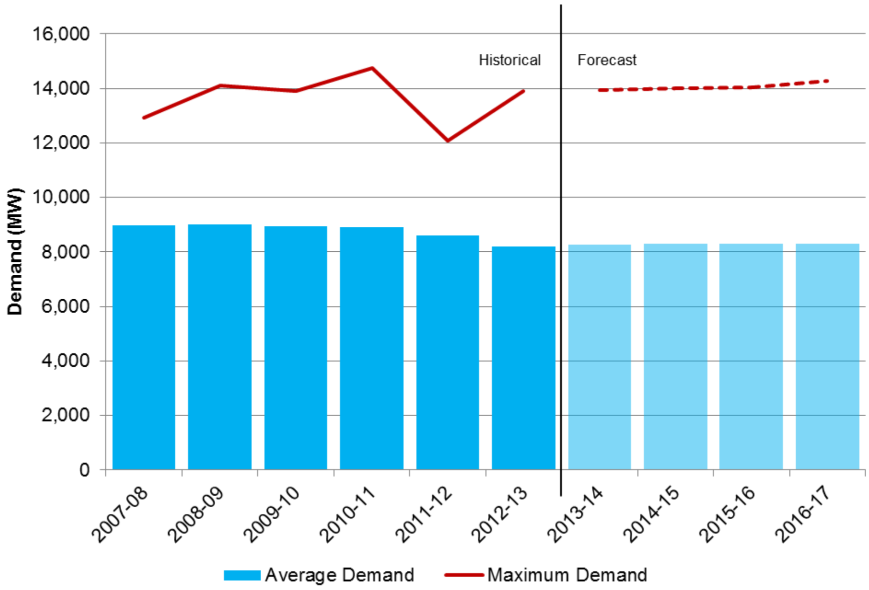
- **Forecasts of demand** for the NEM have been sourced from the National Electricity Forecast Report (NEFR) 2013 for the medium scenario.
- **Fuel cost assumptions** have been sourced from the National Transmission Network Development Plan (NTNDP) 2013 fuel price assumptions for the planning scenario. Fuel price assumptions for the SWIS are based on estimates from the NTDNP 2011 modelling adjusted for inflation. This appendix presents information on gas costs for new-entrant generators, as these are a principal driver of modelling outcomes.
- **Operational parameters and operating costs for existing generators** have been sourced from the NTNDP 2013 assumptions. These include:
  - thermal efficiencies (or ‘heat rates’);
  - emissions intensities of generation;
  - auxiliaries; and
  - variable and fixed operations and maintenance costs.
- **Operational parameters and technology costs for new entrant generators** have been sourced from the AEMO NTNDP 2013.

A.2. Electricity demand

This section sets out our assumptions related to both demand for energy and for capacity (ie, the level of maximum demand) in each region. The level of demand is a key driver of investment in new generation, and decisions to retire existing generating units. AEMO annually publishes its National Electricity Forecasting Report, which presents its forecasts of annual energy demand and maximum demand for each region of the NEM.[32]

For the purposes of this study we have used the 2013 planning scenario forecasts developed by the AEMO and published in June 2013.[33] Figure A.1 through Figure A.5 present historical and projected levels of both average demand[34] and maximum demand for each region of the NEM.

Figure A.1
Electricity demand assumptions – NSW



32 Australian Energy Market Operator, (2013), *National Electricity Forecasting Report – For the National Electricity Market,* June.

33 Ibid.

34 Changes in average demand are equivalent to changes in annual energy demand, but we present average demand values to provide a comparison with the level of maximum demand.

Figure A.2
Electricity demand assumptions – Queensland

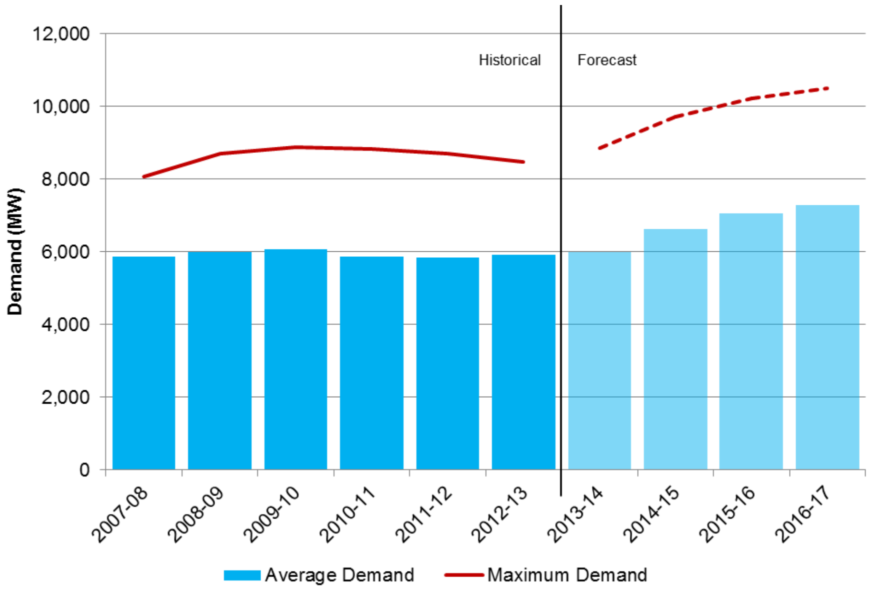


Figure A.3
Electricity demand assumptions – South Australia

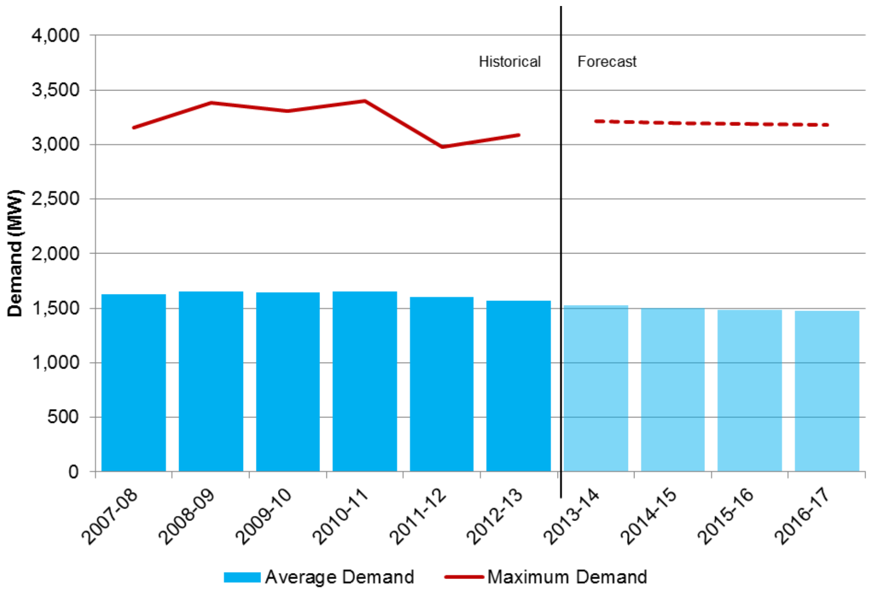


Figure A.4
Electricity demand assumptions – Tasmania

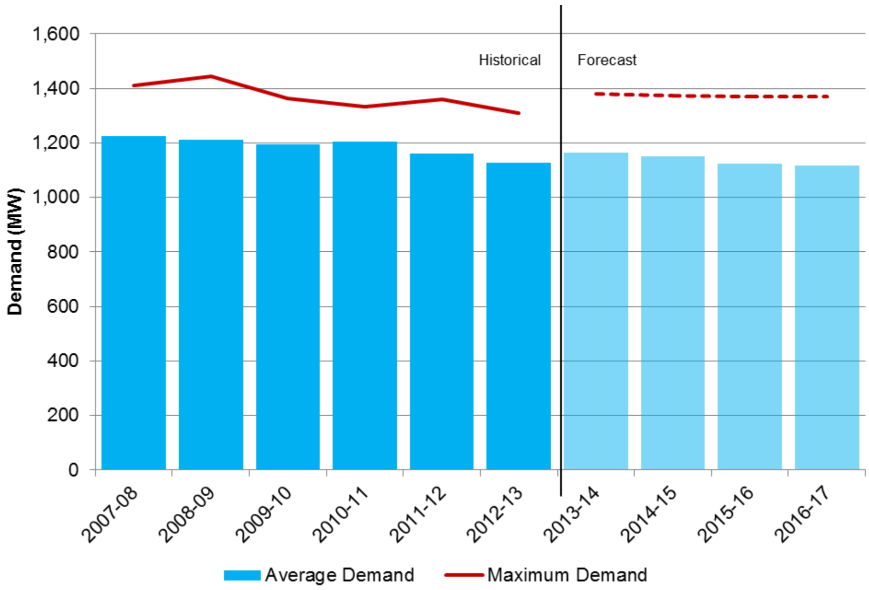
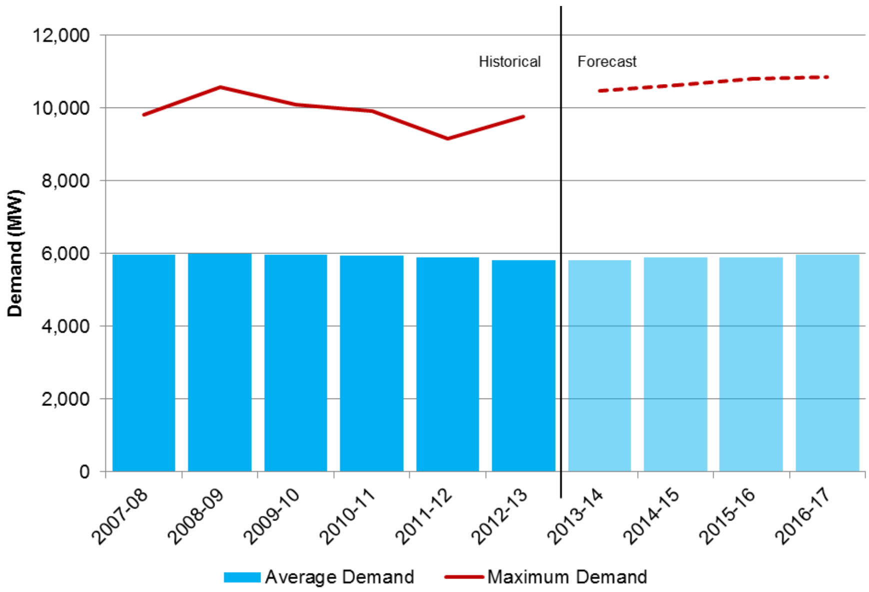


Figure A.5
Electricity demand assumptions – Victoria



Historical annual energy demand peaked in 2008-09 at almost 195 GWh, and has since fallen at an annual rate of approximately 1.2 per cent, reaching a low of 186 GWh in 2012-13.

AEMO's planning scenario projects that demand will not return to 2008-09 levels until 2015-16, with most of the growth in demand being forecast to occur in Queensland. In the longer term, energy demand is projected to rise in each of the larger regions (ie, New South Wales, Victoria and Queensland) but will remain flat or fall in South Australia and Tasmania.

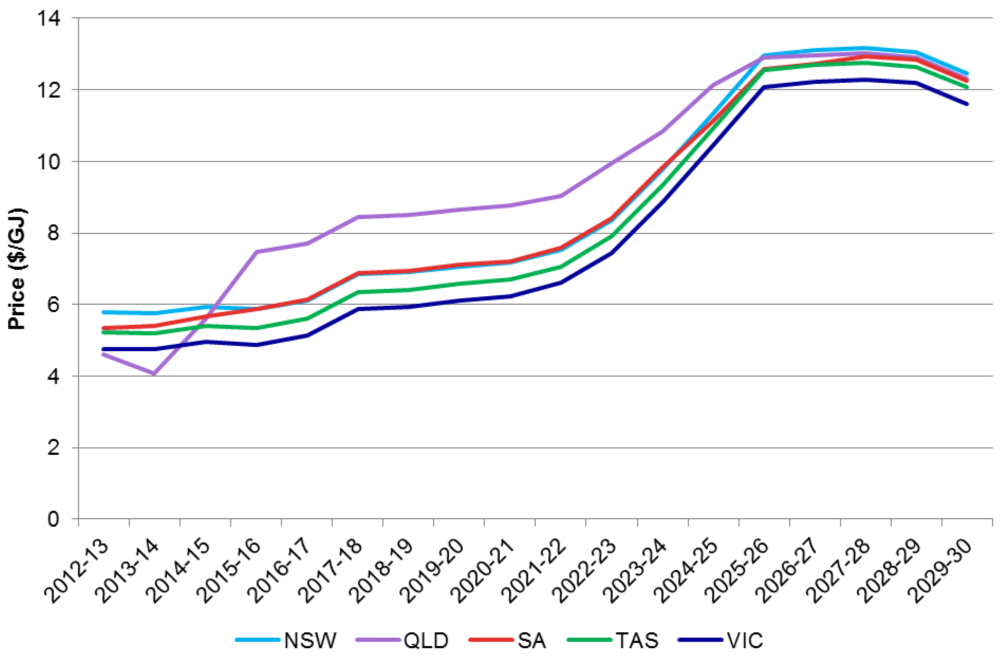
In terms of maximum demand, we make the following observations:

- the highest growth in maximum demand is projected to occur in Queensland, with maximum demand forecast to reach 10,230 MW in 2015-16;
- despite falls in recent years, maximum demand in both New South Wales and Victoria is projected to rise at an average annual rate of 0.8 per cent over the next 20 years; and
- maximum demand in Tasmania and South Australia is projected to be effectively flat over the next 20 years.

A.3. Gas costs for new-entrant generators

We have explained the context surrounding the establishment of an LNG export industry out of the port of Gladstone in Queensland in section 2.4. This explains the considerable rise in gas prices for new entrant generators projected by AEMO, as set out in Figure A.6. These prices are for combined cycle gas turbine (CCGT) units – AEMO's fuel price forecasts assume gas prices for open cycle gas turbine (OCGT) units are uniformly 25 per cent higher that the equivalent CCGT gas price for all regions.

Figure A.6
Assumed Gas Prices for New Entrants (CCGT) by NEM region



AEMO is projecting that east coast gas prices will rise steadily to around $13/GJ in 2026.For our forecasting period (ie, 2013-14 to 2015-16) gas prices are projected to:

- rise most rapidly for new entrant generation in Queensland, from around $4.60 per GJ in 2012-13 to $5.60 per GJ in 2016;
- be steady in Victoria for new entrant generation, remaining around $4.80 per GJ over the course of the modelling period; and
- rise gradually in all other regions.

A.4. Operational parameters and operating costs for existing generators

The set of existing generators that we include within our modelling is based on AEMO's NTNDP 2013 assumptions. We also include directly in the generation planning schedule those generation investments or retirements that have been defined by the AEMO as 'committed'. We have also incorporated assumptions for specific plants that have either been mothballed or are subject to altered operational schedules (eg, operating only in winter months).[35]

For existing generators, we have sourced operational parameters and cost inputs from the NTNDP 2013. These inputs include:

- thermal efficiencies (or 'heat rates');
- emissions intensities;
- auxiliaries; and
- variable and fixed operations and maintenance costs.

Given that this report deals directly with the effect of changes in the carbon price on market outcomes, it is helpful to describe our assumptions about the emissions intensities of specific generators.

A power plant's emissions intensity is the amount of carbon dioxide (or the carbon dioxide equivalent of other greenhouse gases) emitted for each megawatt-hour of electricity it generates. The sensitivity of generation costs to the carbon price is therefore a function of emissions intensity – the higher the emissions intensity, the greater the sensitivity of generation costs to the carbon price.

Each year, AEMO publishes both fugitive and combustion emissions factors as part of the NTNDP modelling assumptions. Based on these figures, AEMO also maintains the Carbon Dioxide Equivalent Intensity Index, which measures the emissions intensity of generation for the NEM on a daily basis.

Figure A.7 shows the emissions intensity of each generator in the NEM grouped by region. The emissions intensity of generation varies significantly by technology type and fuel source. Given the different mix of fuels present in each region, emissions intensity varies across the NEM.

Brown coal fired generation tends to have the highest emissions intensity of all generator types, with an average value of approximately 1.3 tCO2-e/MWh. This is due to the high water content of brown coal and therefore lower efficiency in its combustion. Black coal is a higher quality coal resource and consequently has lower emissions intensity, in the order of 1 tCO2-e/MWh.

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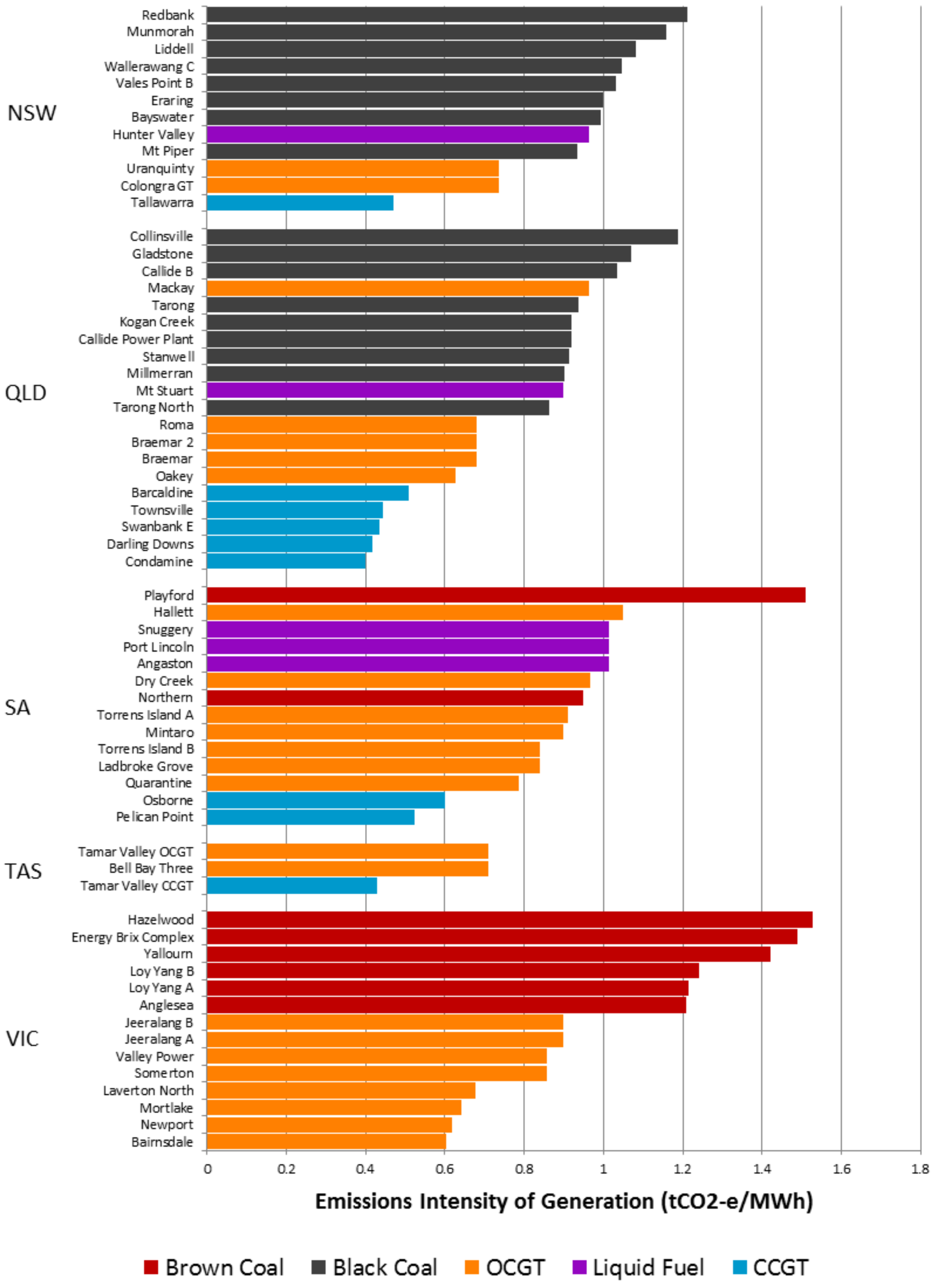
[35] See www.aemo.com.au/Electricity/Planning/Related-Information/Generation-Information.

Gas turbines tend to have lower emissions intensity than a coal fired generator due to the higher efficiency of the combustion process. Furthermore, the higher efficiency of a combined cycle gas turbine means it has a lower emissions intensity than the less efficient open cycle gas turbine – approximately 0.47 tCO2-e/MWh compared to 0.79 tCO2-e/MWh.

On average Victoria has the highest emissions intensity, largely due to the prevalence of brown coal fired generation in the region, most notably Hazelwood – the most emissions intensive generator in the NEM. New South Wales and Queensland have large amounts of black coal fired generation capacity, and so have lower average emissions intensity than Victoria. In contrast, Tasmania has the lowest emissions intensity due to the prevalence of low emissions hydro generation. In South Australia the emissions intensity has been steadily reducing over time due to the expansion of wind generation in the region.

Figure A.7
Emissions intensity of generators across the NEM



A.5. Operational parameters and technology costs for new entrant generators

AEMO publishes assumed capital, fixed, and variable operating costs for new entrant power stations. These projections are developed as part of the annual National Transmission Network Development Plan.[36] The most relevant assumptions for new-entrant generators are set out in Table A.1.

Table A.1
New entrant generation parameters

Technology	Capital Cost ($/MW)	Variable Operations and Maintenance Costs ($/MWh)	Heat Rate (GJ/MWh as generated)
CCGT	1,075,000	4.08	7.05
OCGT	732,000	10.19	10.17
Wind	2,561,625	12.19	Na

For the purposes of this study we have assumed that there is no scope for new entrant coal-fired generation investment over the modelling horizon. Therefore, all new-entrant thermal generation will be gas-fired, either in the form of a CCGT or an OCGT.

A.6. Distribution and transmission loss factors

Table A.2 sets out the assumptions we have made relating to distribution and transmission loss factors.

Table A.2
Combined distribution and transmission loss factors

Region	2012-13	2013-14 onwards	DLF Tariff Assumptions	Transmission Loss Factor
ACT	1.056	1.055	ActewAGL - Low Voltage	Sydney West
NSW	1.070	1.065	Energy Australia as applied by IPART	Sydney West
QLD	1.069	1.073	Energex DLF as applied by QCA	South Pine
SA	1.080	1.077	ETSA - Low Voltage Residential	Torrens Island
TAS	1.064	1.063	Aurora - LV Distribution Network	Georgetown
VIC	1.055	1.053	United Energy - Short sub-transmission DLF	Thomastown
WA	1.119	1.121	Western Power – DLF for A1 Anytime Residential customers	North Perth

36 Australian Energy Market Operator, (2012), *National Transmission Network Development Plan*.

Appendix B. Detailed Market Modelling Results

B.1. Electricity spot prices

Region	Year	Base case	20% RET	No Carbon price	2014 EU Carbon	Constant Gas Prices	Low Demand
NSW	2012-13	55.4	55.4	31.4	55.4	55.4	55.4
	2013-14	56.8	56.9	31.7	56.4	56.7	56.1
	2014-15	59.9	60.0	33.6	39.3	59.7	58.5
	2015-16	41.7	42.0	35.5	41.5	41.3	39.7
QLD	2012-13	53.9	53.9	31.1	53.9	53.9	53.9
	2013-14	55.2	55.2	31.5	54.7	55.2	54.7
	2014-15	59.3	59.5	35.1	40.2	59.1	57.5
	2015-16	43.1	43.3	37.6	43.1	42.2	40.2
SA	2012-13	72.1	72.1	52.7	72.1	72.1	72.1
	2013-14	67.7	68.4	50.2	67.8	66.2	66.3
	2014-15	62.8	65.2	44.4	49.0	60.8	60.3
	2015-16	45.8	48.0	40.9	45.8	42.6	41.7
TAS	2012-13	57.0	57.0	37.2	57.0	57.0	57.0
	2013-14	58.4	62.7	39.2	62.1	57.6	56.0
	2014-15	55.4	59.1	37.7	44.7	54.4	51.5
	2015-16	42.5	44.8	37.1	43.0	41.8	39.1
VIC	2012-13	58.0	58.0	31.5	58.0	58.0	58.0
	2013-14	59.0	60.4	31.7	59.6	58.6	56.7
	2014-15	60.1	61.7	33.0	39.1	59.6	56.1
	2015-16	41.3	43.3	34.6	41.3	40.7	36.4

B.2. Electricity purchase costs

Region	Year	Base case	20% RET	No Carbon price	2014 EU Carbon	Constant Gas Prices	Low Demand
ACT	2012-13	62.9	62.9	35.9	62.9	62.9	62.9
	2013-14	64.8	64.9	36.5	64.2	64.7	63.9
	2014-15	68.8	69.0	39.3	45.7	68.6	67.2
	2015-16	50.2	50.5	42.9	50.0	49.8	47.8
NSW	2012-13	62.6	62.6	35.8	62.6	62.6	62.6
	2013-14	64.6	64.7	36.5	64.1	64.5	63.8
	2014-15	68.8	69.0	39.5	45.8	68.6	67.2
	2015-16	50.7	51.0	43.4	50.4	50.2	48.3
QLD	2012-13	61.5	61.5	36.0	61.5	61.5	61.5
	2013-14	63.0	63.1	36.4	62.5	63.0	62.5
	2014-15	67.6	67.8	40.4	46.2	67.4	65.5
	2015-16	51.4	51.5	44.9	51.4	50.3	48.0
SA	2012-13	86.3	86.3	64.2	86.3	86.3	86.3
	2013-14	80.5	81.3	60.4	80.6	78.8	78.9
	2014-15	75.2	78.0	54.2	59.5	73.0	72.3
	2015-16	57.3	59.9	51.6	57.3	53.6	52.6
TAS	2012-13	64.5	64.5	42.5	64.5	64.5	64.5
	2013-14	66.3	71.3	44.9	70.6	65.5	63.7
	2014-15	63.2	67.4	43.4	51.3	62.2	58.9
	2015-16	50.9	53.5	44.6	51.5	50.0	46.9
VIC	2012-13	65.2	65.2	35.8	65.2	65.2	65.2
	2013-14	66.6	68.2	36.2	67.2	66.2	64.0
	2014-15	68.1	69.8	37.8	44.7	67.6	63.6
	2015-16	49.1	51.4	41.3	49.0	48.4	43.5

Appendix C. NERA's Wholesale Electricity Market Models

NERA has developed a suite of modelling tools to allow for the analysis of a wide number of electricity market questions, including:

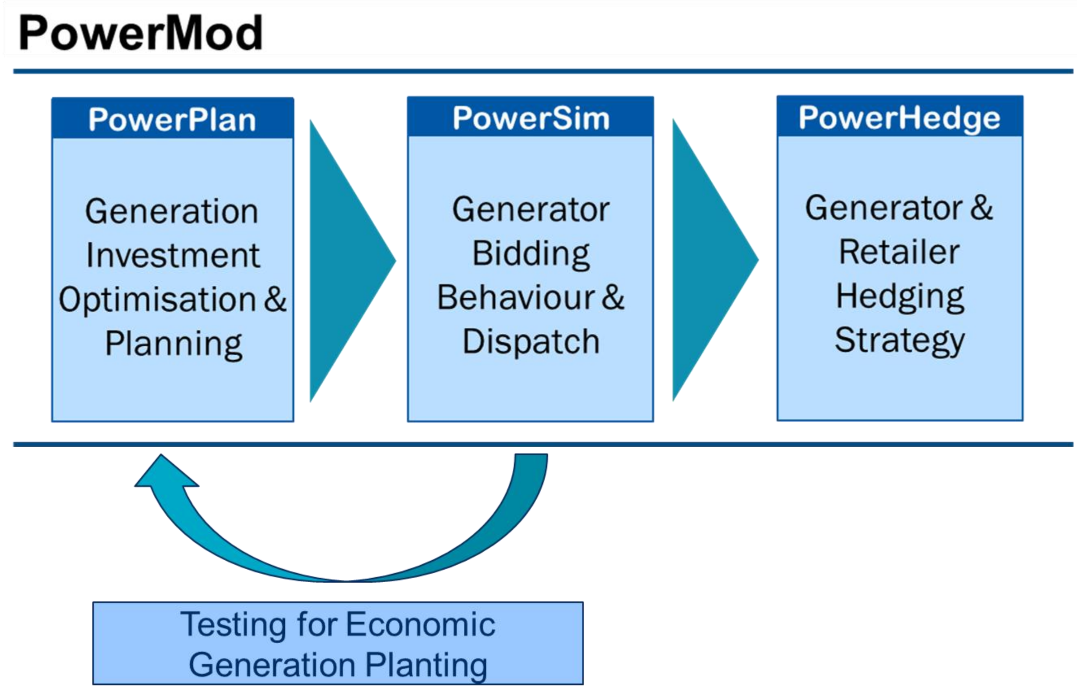
- projecting wholesale electricity market prices;
- forecasting long-term generation capacity expansions to satisfy future electricity demand requirements;
- analysing the long-run and short-run marginal costs of electricity generation;
- analysing evidence of the existence of generator market power;
- analysing the influence of changes in fuel prices, carbon prices, and electricity demand, on generation dispatch and price outcomes;
- analysing changes in the market design, including modifications to the carbon pricing scheme, the renewable energy market, and the introduction of demand response into dispatch mechanisms; and
- analysing the influence on generator emissions and emissions intensity of electricity supply, of changes in government policies and fuel prices.

The suite comprises three distinct but interdependent models, specifically:

- a long-run optimisation model to project generation investment required to satisfy demand, taking account of the Large-scale Renewable Energy Target – **PowerPlan**
- a dispatch simulation model to project individual generation based on short-run marginal costs and strategic bidding behaviour of generators to project wholesale market spot prices – **PowerSim**; and
- a hedging strategy model to project retailer energy costs, applying portfolio theory – **PowerHedge**.

Figure C.1 illustrates the interactions between the models.

Figure C.1: Interaction of NERA's suite of wholesale electricity market models



The model uses linear and integer mixed integer programming techniques to simulate electricity market investment and operation, taking into consideration the specific features of the NEM. The particular features of each model are as follows:

- **PowerPlan** solves by breaking the annual load duration curve into a number of load blocks (typically between 50 and 100 blocks), making decisions as to investment and dispatch to satisfy load in these blocks. This load block or 'timeslice' approach is commonly used in electricity market models to increase the speed of the program, without compromising the rigour of the model outputs. Interactions between PowerPlan and PowerSim ensure that generation investment profiles are 'economic'.

  The key outputs from **PowerPlan** include:

  - the generation investment planning schedule for both thermal and large-scale renewable plants in line with the Renewable Energy Target;
  - projections of renewable energy certificate prices; and
  - estimates of LRMC, applying the perturbation methodology.

- **PowerSim** uses the generation investment profile generated from PowerPlan and solves for generation market dispatch taking into account generator bidding behaviour. Bidding behaviour is explicitly modelled in PowerSim by applying game theory to determine a Nash equilibrium given a set of possible bidding strategies available to generators in each market region.

  The key outputs from **PowerSim** include:

  - the wholesale market spot price for each NEM region, seasonal prices, and peak/shoulder/off-peak prices for each year over the projection period;

    - individual annual generator electricity sent out, hours of dispatch and capacity factors for each plant;
    - total and plant specific emissions, and annual average emissions intensity for electricity supply; and
    - revenue and costs for each plant, in both the short and long-run, and consequent net revenue on an annual and net present value basis.

- **PowerHedge** applies concepts and principles from portfolio theory to calculate optimal hedging strategies for generators and retailers operating within a wholesale electricity market. It combines information on electricity spot prices, obtained from PowerSim in combination with public information on contract prices and electricity demands, to estimate the optimal hedging strategy that minimises retailer and/or generator pricing risks.

  The key outputs from **PowerHedge** include:

    - the optimal hedging strategy for each retailer and/or generator; and
    - projections of energy purchase costs for each retailer.

Relevantly, NERA's suite of electricity wholesale modelling tools has been constructed specifically to address the many market design and policy matters facing the market at this time. As a consequence they are capable of explicitly implementing the perturbation LRMC methodology, and are also extremely flexible to ongoing development and adaptation.

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