NERA
ECONOMIC CONSULTING

Wholesale Electricity Costs in the NEM

A Report for the Australian Energy Market Commission

Advice on Best Practice Retail Price Regulation

19 August 2013

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1. Introduction

The Australian Energy Market Commission (the Commission) has been asked by the Standing Council on Energy and Resources (SCER) to develop a best practice methodology for retail electricity price regulation in the long term interests of consumers.[1] The request forms part of SCER's energy market reform package, which has been designed to further progress reforms to regulated electricity retail pricing as retail market competition develops.

It is within this context that the Commission has asked NERA Economic Consulting (NERA) to investigate the implications of using alternative methodologies to estimate wholesale electricity purchase costs. The investigation of alternative wholesale purchase cost estimation methodologies is to inform the Commission's review of best practice retail price regulation.

Jurisdictional regulators determine regulated retail electricity prices by estimating each of the cost components that are incurred for the supply of electricity to retail customers. These cost components include:

- wholesale electricity purchase costs;
- costs associated with a price of carbon;
- renewable energy target costs, with separate estimation of the cost of complying with the large-scale renewable energy target and the small-scale renewable energy scheme;
- the costs associated with network losses;
- NEM participant fees and ancillary services costs;
- the cost of all relevant jurisdiction's energy efficiency or other programmes;
- transmission and distribution network costs; and
- an allowance for retail operating costs and a retail margin.

The estimate of wholesale electricity purchase costs are a large and important cost component. There are a number of methodologies that are used by jurisdictional regulators to determine a cost allowance for wholesale electricity purchase costs, namely:

- a market modelling approach, which uses estimates of wholesale electricity market prices (based on either modelled spot prices, data on contract prices, or a combination of both) and an associated hedging strategy, to estimate wholesale electricity purchase costs; and
- a long-run marginal cost (LRMC) approach, which uses estimates of the LRMC as the basis for determining wholesale electricity purchase costs.

Both methodologies can be implemented in different ways. For example, there are different approaches to applying a hedging strategy for a retailer. There are also three main methods for estimating the LRMC, namely:

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[1] Standing Council on Energy and Resources, (2013), "Australian Energy Market Commission Reporting on a Best Practice Retail Electricity Pricing Methodology", *Terms of Reference*, May, Canberra.

- a stand-alone or 'Greenfields' approach, which estimates the least cost combination of new entrant generation to supply demand;
- an average incremental cost (AIC) approach, which estimates the least cost combination of generation to satisfy demand over a future time horizon, divided by the incremental change in demand; and
- a perturbation approach, which estimates the cost of bringing forward new generation to satisfy an incremental increase in demand over a future time period.

In addition to implementation differences, each method also requires numerous input assumptions to be made. Choices of methodology and input assumptions can have significant implications for the estimated wholesale electricity purchase costs.

The focus of this study is on the implications for estimated wholesale electricity purchase costs of the choice of methodology used, for the period 2012-13 to 2015-16. We have therefore used a common set of input assumptions, so that the choice of inputs does not influence the results. That said, we have also been asked to qualitatively consider the sensitivity of the results to the demand assumptions.

The remainder of this report sets out our results and observations in detail. It is structured as follows:

- Chapter 2 sets out our detailed modelling assumptions;
- Chapter 3 describes the results of applying a market modelling approach to estimate wholesale electricity purchase costs, and also qualitatively explores the sensitivity of the results to alternative projections of future electricity demand;
- Chapter 4 sets out our estimates of the long run marginal cost for each NEM region; and
- Chapter 5 concludes.

In addition, Appendix A provides a brief description of NERA's suite of wholesale electricity market models, which we have used to apply the alternative methodologies.

2. Detailed Modelling Assumptions

This chapter provides a detailed description of the modelling assumptions used in the development of our ‘base case’ model. This is used to develop both the price forecasts needed to estimate wholesale electricity purchase costs using the market modelling methodology, and to implement the Greenfields, perturbation and average incremental cost methodologies to estimate the LRMC.

We present the assumptions in four broad groupings, namely:

- electricity demand;
- assumed investments and retirements;
- new entrant fuel prices and technology costs; and
- carbon pricing and renewable energy policy assumptions.

2.1. 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.

2.1.1. Energy demand

The Australian Energy Market Operator (AEMO) annually publishes its National Electricity Forecasting Report (NEFR), which presents its forecasts of annual energy demand and maximum demand for each region of the National Electricity Market.[2]

For the purposes of this study we have used the 2013 medium growth scenario forecasts developed by the AEMO and published in June 2013.[3] Figure 2.1 presents annual energy demand for each region of the NEM from 2005-06 to 2031-32 – historical values are indicated by dotted lines.

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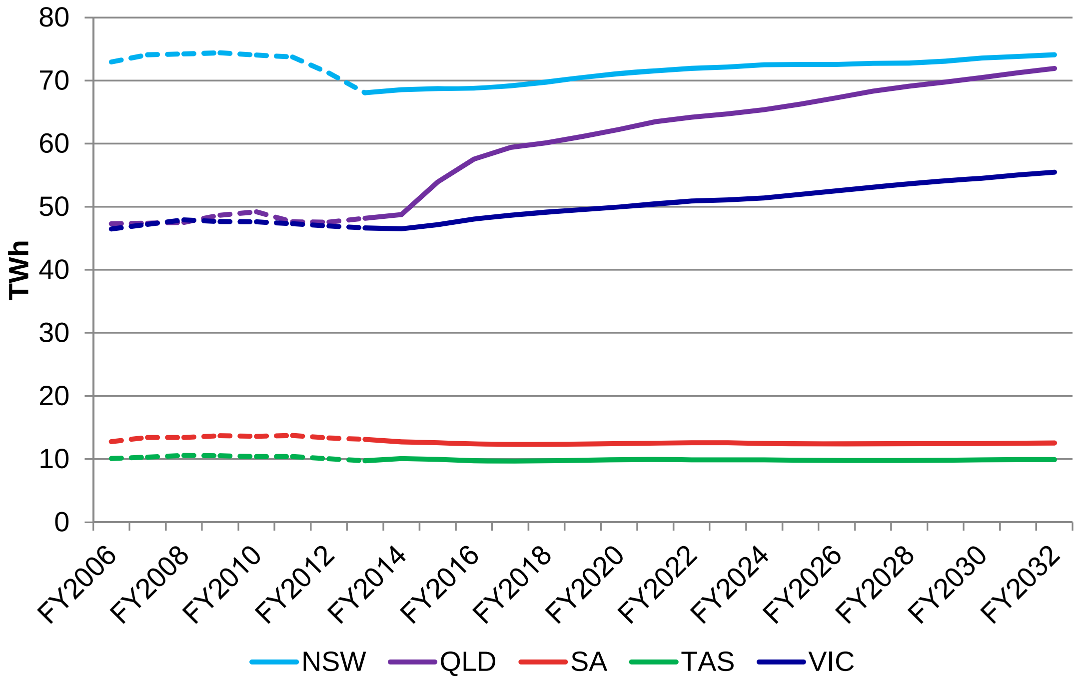
2 Australian Energy Market Operator, (2013), *National Electricity Forecasting Report – For the National Electricity Market,* June.

3 Ibid.

Figure 2.1
Assumed NEM Annual Electricity Demand – Medium Growth Scenario



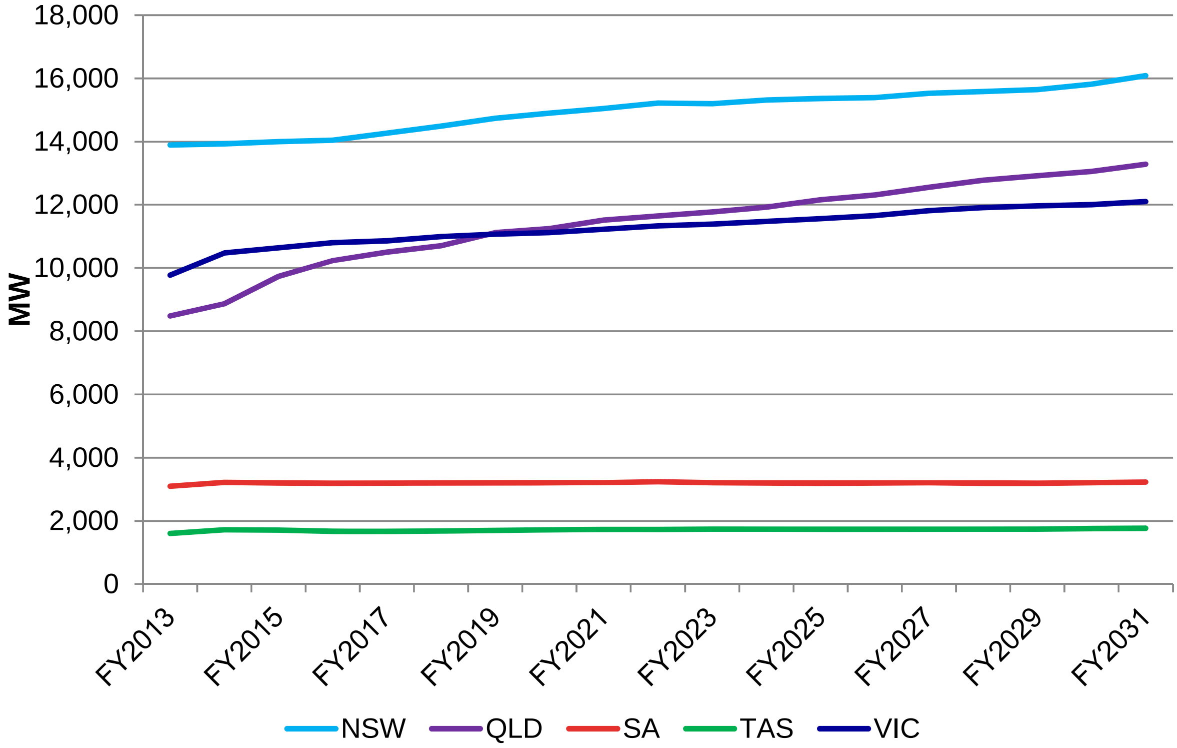
Historic annual energy demand peaked in 2008-09 at almost 195 GWh, and has since fallen at an annual rate of approximately 1.2 per cent. Total demand in 2012-13 was 186 GWh.

AEMO's medium growth scenario projects that demand will not return to 2008-09 levels until 2015-16, with most of the growth in demand being forecast to arise 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.

2.1.2. Maximum demand

Figure 2.2 sets out maximum demand forecasts (at the 10 per cent probability of exceedance (POE) level) for each region. These forecasts show the *annual* maximum demand, be it in winter or summer.

Figure 2.2
Maximum Demand Assumptions – Medium Growth Scenario (10 per cent POE)



There are a number of observations that can be drawn from the maximum demand forecasts, including:

- 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.

2.2. Assumed investment and retirements

Our modelling framework solves for the least cost combination of generation investment and retirement to satisfy projected demand, given assumptions about fuel prices, policy settings such as the renewable energy target and the carbon price, and the structure of the transmission network.

We also include directly in the generation planning schedule those generation investments or retirements that have been defined by the AEMO as 'committed'.[4] Table 2.1 sets out plants that we have modelled as assumed projects as at June 2013.

Table 2.1
Committed Scheduled and Semi-Scheduled New Entrant Projects

Project Name	Size (MW)	Jurisdiction	Scheduled for Completion
Snowtown S2 North	144	South Australia	1 November 2014
Snowtown S2 South	126	South Australia	1 May 2014
Musselroe Wind Farm	168	Tasmania	1 July 2013

Table 2.2 sets out plants that we have modelled as committed retirements as at June 2013.

Table 2.2
Assumed Retirements

Project Name	Size (MW)	Jurisdiction	Scheduled for Retirement
Mackay Gas Turbine	30	Queensland	1 December 2016

2.3. New entrant fuel prices and technology costs

AEMO publishes fuel price projections for both existing and new-entrant generators, as well as 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 (NTNDP).[5]

Critical to our analysis are the costs incurred by new-entrant generators. The remainder of this section summarises the NTNDP assumptions for:

- gas prices for new entrant generators; and
- new entrant technology costs.

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

[5] Australian Energy Market Operator, (2012), *National Transmission Network Development Plan*.

2.3.1. Gas prices for new entrant generators

Gas prices for new entrants are a critical driver of electricity costs in the long-term. Over the last 20 years, the wholesale gas market in Eastern Australia has been characterised by bilateral contracts between a relatively small number of gas producers and consumers.

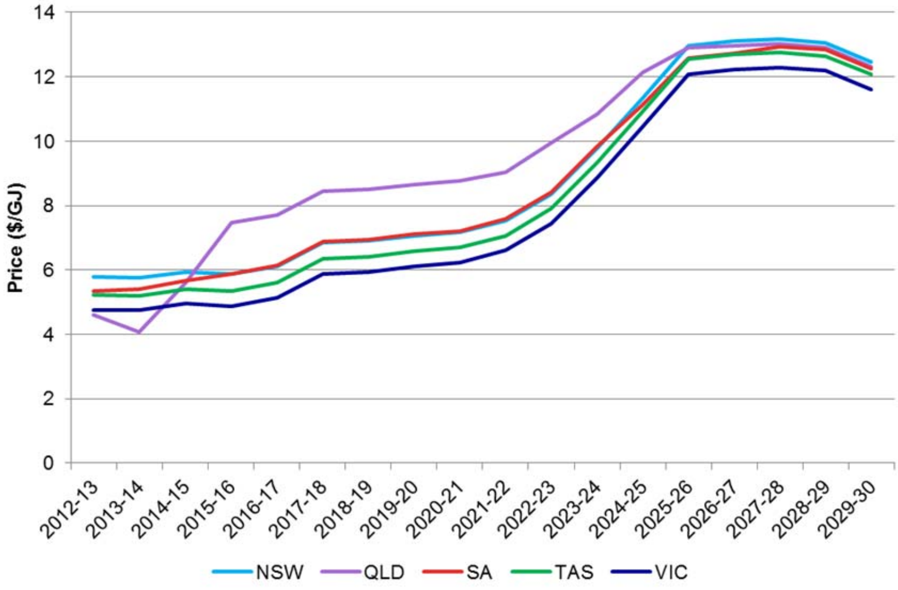
In addition, domestic gas prices have been relatively low in recent years. However, in the next five years the eastern Australian states will see the establishment of large-scale LNG export facilities at the port of Gladstone in Queensland.

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. Even after accounting for processing and shipping costs, LNG prices in Asia are considerably higher than domestic gas prices in the east-coast market.

With the discovery of enormous potential 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.

This context explains the considerable rise in gas prices for new entrant generators projected by AEMO, as set out in Figure 2.3. 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 2.3[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 $7.41 per GJ in 2015-16;
- 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.

2.3.2. New entrant technology costs

AEMO publishes information on the capital costs, operating and maintenance costs, and thermal efficiency rates, as set out in Table 2.3.

6 Source: Australian Energy Market Operator, (2013), *2013 Planning Assumptions – New Entry Generation Data*, 12 June, www.aemo.com.au/Electricity/Planning/Related-Information/2013-Planning-Assumptions.

Table 2.3
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.

2.4. Carbon pricing and renewable energy policy assumptions

The next group of modelling assumptions relate to the influence of government policies to lower carbon emissions by placing a price on carbon and increase renewable generation investment by providing a renewable energy target.

2.4.1. Carbon price

The Australian government introduced a carbon pricing scheme from 1 July 2012 as part of its Clean Energy Future package.[7] 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
- 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.[8]

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.[9]

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

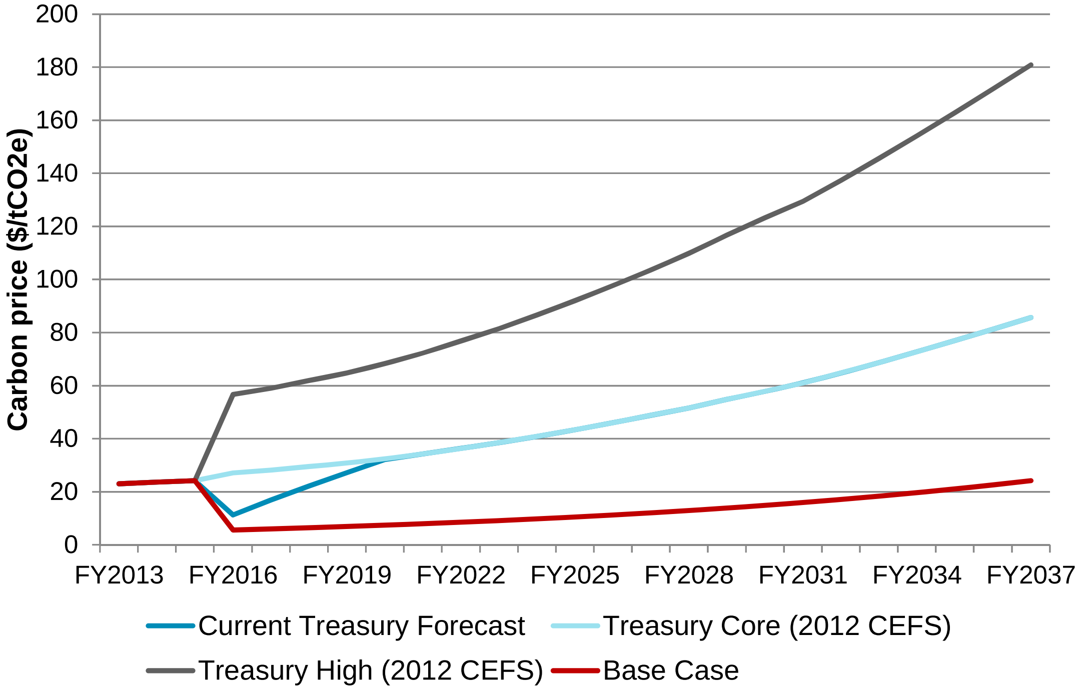
8 See www.cleanenergyfuture.gov.au/international-linking

9 See www.climatechangeauthority.gov.au

Currently, there is considerable uncertainty as to the future of both the trajectory of the carbon price and indeed the very existence of the carbon pricing scheme. The Federal opposition has indicated its intention to abolish the carbon tax if it wins government at the next Federal election.[10] In addition, the government has announced its intention to bring forward the commencement of the flexible pricing period to 1 July 2014.[11]

For the purpose of modelling the base case, we have assumed that the fixed price period continues until 30 June 2015, as set out in the Clean Energy Future Scheme (CEFS) package. We then assume that prices will align with the EUA forward curve – Figure 2.4. This approach conservatively reflects current expectations about future carbon prices.

Figure 2.4
Carbon Price Assumptions – Base case versus assumptions adopted by Treasury[12]



2.4.2. Renewable energy target

The Renewable Energy Target requires large users of electricity (ie, retailers and large industrial users) to buy certificates in line with their purchases of wholesale electricity. In its current form, the Renewable Energy Scheme consists of two separate schemes, namely:

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

11 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.

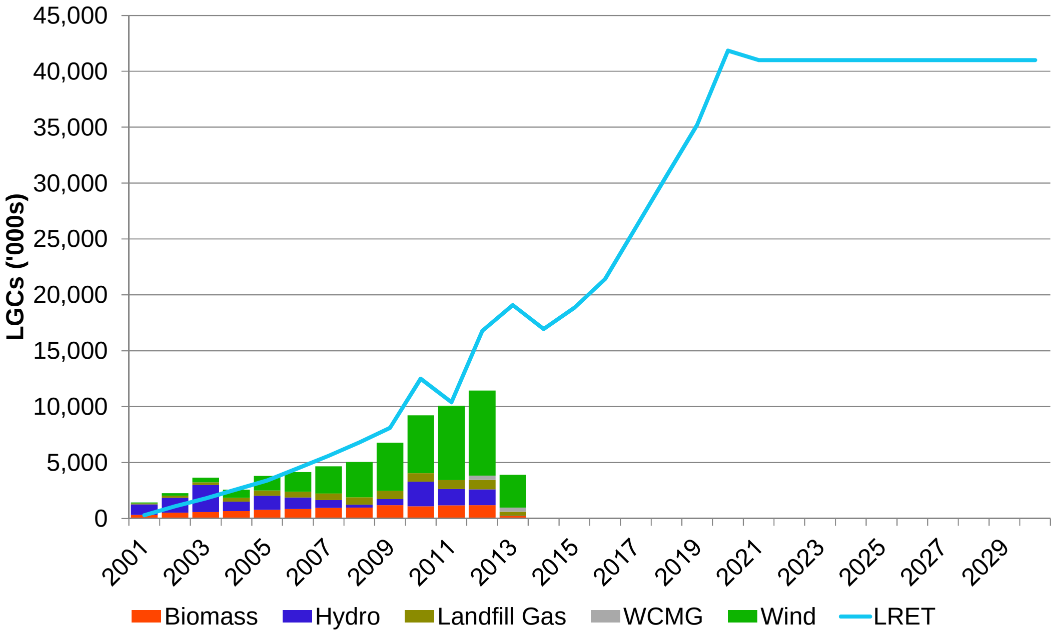
12 Values beyond 2016-17 for the EU forward curve (ie, our base case carbon price) have been interpolated based on a forward discount rate.

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

Each of these schemes is designed to provide support to renewable energy technologies. Investment occurring under the SRES is largely driven by factors other than the wholesale market price (eg, network costs and consumer preferences). Therefore, for the purposes of our modelling, we are primarily concerned with the LRET.

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

Figure 2.5
Large-Scale Renewable Energy Target[13]



Within our modelling, the LRET is an exogenous variable that determines the level of a constraint – the LRET must be met through a combination of surrendering certificates and paying the shortfall penalty. The higher the level of the LRET, the greater the additional costs associated with satisfying the constraint.

13 Source: REC Registry, as maintained by the Clean Energy Regulator.

3. A Market Modelling Approach

This chapter sets out the results of applying our market modelling approach to estimate wholesale electricity purchase costs. Relevantly, this approach is one of a number of approaches that can be classified as a 'market modelling' methodology, reflecting in particularly different methodologies for determining an efficient hedging strategy.

3.1. Modelling methodology

An electricity retailer faces an inherent mismatch between the cash-flows that they *receive* from their customers and the cash-flows required to purchase electricity from the spot market, in the absence of hedging. 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.[14] 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. The inputs that we have used in our market modelling approach include:

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

To determine regulated residential retail electricity prices, the relevant customers are 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 was available, the net system load profile for a distribution area that is deemed to be representative of the broader region.[15]

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

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14 In addition to hedging instruments, retailers can also use long-term power purchase agreements and direct investments in electricity generation so as to manage spot market price risks.

15 We understand that these load profiles were provided to the AEMC as part of its 2013 Retail Price Trends Review.

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[16] to cover a fixed proportion of its load on a quarterly basis; and
- caps[17] to cover its remaining load.

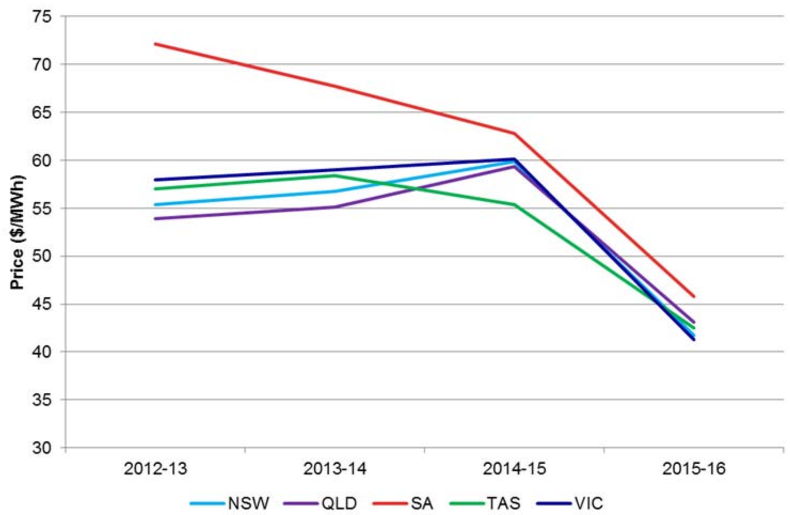
Each of the jurisdictional regulators that use a market modelling approach broadly applies this approach, although there are differences based on the extent that modelled spot prices are used and hedging strategies assumed. In addition, differences emerge between the jurisdictional regulators in terms of the specific assumptions used to forecast wholesale electricity spot prices, the availability of reliable data on small-user load profiles, and the methodology used to determine the optimal hedging strategy.

There are effectively two main steps in the process of estimating the electricity purchase costs for a given load profile: projecting spot prices and determining the electricity purchase costs associated with the load profile based on those spot prices.

3.2. Projected NEM wholesale spot market prices

To forecast wholesale spot market prices, we have used NERA’s electricity market model – PowerMod – with the assumptions set out in Chapter 2. Figure 3.1 and Table 3.1 set out our spot price projections on an annual basis for the period 2012-13 to 2015-16 for each NEM region.

Figure 3.1
Projected Annual Average Spot Market Price Projections by NEM Region



16 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.

17 An electricity cap contract is an option that places a ceiling on the price a retailer pays for electricity. The generator agrees to compensate the retailer, in circumstances where the spot price is greater than the strike price.

Table 3.1
Projected Wholesale Electricity Average Annual Spot Price, by NEM region ($2012-13/MWh)

NEM Region	2012-13	2013-14	2014-15	2015-16
Queensland	53.9	55.2	59.3	43.1
New South Wales	55.4	56.8	59.9	41.7
Victoria	58.0	59.0	60.2	41.3
Tasmania	57.0	58.4	55.3	42.5
South Australia	72.1	67.7	62.8	45.8

In general, our modelled spot prices reflect continuing declines in demand combined with the persistent entry of wind to meet the LRET. Prices across all regions, except 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.

The projected decline in prices in 2015-16 is largely attributable to the shift to the lower carbon price as the fixed price period ends.

The very high prices in South Australia in 2012-13 and 2013-14 reflect the altered operational schedule for Northern power station (a 530 MW brown coal fired power station), which continues not to operate during the winter months because of current low levels of demand. 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.

3.3. Projected wholesale electricity purchase costs

Figure 3.2 and Table 3.2 set out our projections of wholesale electricity purchase costs for the period 2012-13 to 2015-16 for each NEM region and the Australian Capital Territory.[18]

[18] The Australian Capital Territory is part of the New South Wales NEM region, and so we have used modelled New South Wales spot prices for the purpose of estimating its wholesale electricity purchase costs. The difference in purchase costs for the Australian Capital Territory compared to New South Wales reflects different assumed residential load profiles for each jurisdiction.

Figure 3.2
Projected Wholesale Electricity Purchase Costs, by NEM Region

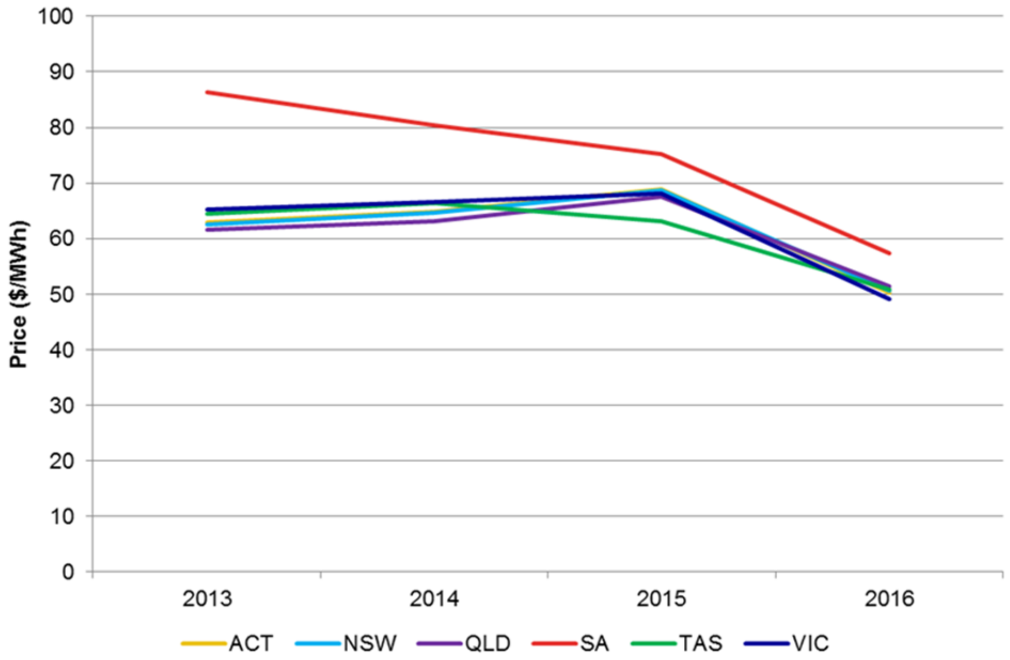


Table 3.2
Projected Wholesale Electricity Purchase Costs, by NEM region ($/MWh)

NEM Region	Distribution Area	2012-13	2013-14	2014-15	2015-16
Queensland	Energex	61.5	63.0	67.6	51.4
New South Wales	EnergyAustralia	62.6	64.6	68.8	50.7
Australian Capital Territory	ActewAGL	62.9	64.8	68.8	50.2
Victoria	United Energy	65.2	66.6	68.1	49.1
Tasmania	Aurora	64.5	66.3	63.2	50.9
South Australia	South Australia Power Networks	86.3	80.5	75.3	57.3

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.

3.4. Sensitivity of the results to forecast demand

We have been asked make a qualitative assessment of the likely sensitivity of our electricity purchase cost estimates to forecast demand. Forecasts of electricity demand, both in terms of energy and capacity, are a fundamental driver of spot prices and so energy purchase costs. In terms of our modelling, the level of demand influences:

- the ‘dispatch profile’, ie, the combination of generation, be it existing or new-entrant, that is dispatched to meet the prevailing level of demand; and
- the ‘investment profile’, ie, the mix of new-entrant generation that is constructed to best meet demand, as well as to satisfy other constraints such as the LRET.

We have adopted the most recent forecasts of electricity demand as released by the AEMO in June 2013. AEMO is forecasting that total electricity demand will increase by an average annual compound rate of 1.9 per cent from 2012-13 to 2015-16. Almost 90 per cent of the increase is accounted for by demand growth in Queensland.

If actual electricity demand growth is lower than these projections, one would generally assume that spot prices would be lower because of a lower-cost dispatch profile, ie, prices being set by plants lower in the merit order. However, whether this will occur in practice depends on the influence of lower demand on the availability of generation capacity. With demand currently at extremely low levels relative to previous highs, further reductions could trigger generation retirements, leading to an *increase* in the spot prices observed.

South Australia provides a good example of this type of phenomenon. Persistent declines in the demand for thermal generation have led to an altered operational schedule for Northern power station. When Northern ceases to operate, prices in the South Australian region rise significantly, even though demand for thermal generation is at a level that is historically very low.

However, if actual electricity demand growth is higher than these projections, spot prices would generally be assumed to be higher than projected, because of a higher-cost dispatch profile.

4. Estimates of the Long Run Marginal Cost

This chapter describes the methodologies that we have employed to estimate the long run marginal cost of electricity generation and sets out our modelling results for each NEM region.

4.1. Modelling methodology

We have been asked to investigate the implications of alternative methodologies for estimating the long-run marginal cost as the basis for determining an allowance for wholesale electricity purchase costs. We have considered three methodologies, namely:

- a Greenfields approach;
- an average incremental cost approach; and
- a perturbation approach.

In the remainder of this section we provide a brief description of our approach to modelling LRMC using each of these methodologies. Relevantly, the implementation of each methodology can differ because of the specific modelling tools used, which can influence the resultant LRMC estimates.

4.1.1. Greenfields approach

A ‘Greenfields’ or ‘stand-alone’ approach to estimate 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 Greenfields approach involves:

- developing an 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 by the optimal mix of generation.

We have implemented this approach using a simple spread sheet model for each NEM region. The assumptions for the customer load shape, generation new entrant costs and new entrant fuel costs are identical to those used for the market modelling approach, as outlined in Chapter 3.

We have also estimated the Greenfields LRMC, both applying a residential load shape (as provided to us by the AEMC), and applying the NEM region load shape. In general, residential load is ‘peakier’, with the NEM region load shape reflecting flatter commercial and industrial loads.

Finally, because this methodology requires each NEM region to be modelled separately, the load cannot be satisfied by generation from other regions.

4.1.2. Average incremental cost approach

An average incremental cost (AIC) approach approximates the LRMC of electricity demand by estimating total future generation and network investment and operating costs required to satisfy forecast incremental changes in electricity demand. In practice this approach involves:

- forecasting average annual and maximum demand for a given load profile over a future time horizon of say 20 years;
- developing a least cost program of generation and network capacity expansion needed to ensure that there is sufficient capacity to support forecast average annual and maximum demand, given the reliability standard; and
- estimating LRMC as the present value of the generation capital and operating costs incurred to supply forecast average annual and maximum demand divided by the present value of the additional demand supplied.

Importantly, the relevant expected costs includes both the capital costs of new generation capacity that is required to satisfy additional electricity demand, plus the operating costs of both existing and new generation to supply the additional electricity demand. In addition, the operating costs include payments of any penalties that might be incurred as a consequence of retailers failing to satisfy the large-scale renewable energy target.[19]

We have implemented this approach using NERA's wholesale electricity market model – PowerMod. In practice, we have estimated the AIC for a particular NEM region as the total wholesale generation capital and operating costs incurred so as to satisfy, forecast average annual and maximum demand for each NEM region. In doing so, we have attributed NEM-wide generation costs to forecast incremental demand in each NEM region, so as to generate an estimate for each NEM region.

4.1.3. Perturbation approach

The final methodology involves estimating LRMC as the change in future generation and network costs as a consequence of an increment or decrement of demand – the perturbation approach. In practice applying the perturbation approach involves:

- forecasting average annual and maximum demand for a given load profile over a future time horizon of say 20 years;
- developing a least cost program of generation and network capacity expansion needed to ensure that there is sufficient capacity to support forecast average annual and maximum demand, given the reliability standard;
- estimating the present value of the generation and network capital and operating costs incurred to supply forecast average annual and maximum demand;

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[19] We do not explicitly include the cost of large scale renewable energy certificates, as these costs are included directly in the capital cost for new wind generation.

- increasing or decreasing both average annual and maximum demand by a small but permanent amount, and recalculating the least cost program of generation and network capacity expansion needed to ensure there is sufficient capacity to support the revised demand forecast;
- estimating the present value of the generation and network capital and operating costs incurred to supply the revised demand forecast; and
- estimating the LRMC as the difference between the present value of the generation and network capital and operating costs divided by the present value of the difference between revised and initial forecast average annual and maximum demand.

We have implemented the perturbation approach using NERA's wholesale electricity market model – PowerMod. The LRMC for a NEM region has been estimated by perturbing demand in the NEM region of interest, and estimating the implications on generation investments across the entire NEM. This process is repeated for each region where an LRMC estimate is required. This directly acknowledges that the marginal impact on future costs can result in changes in generation investments across the entire NEM.

Relevantly, we have estimated the LRMC by perturbing the regional demand trace of each NEM region. As a consequence, the LRMC estimates reflect the marginal change in costs associated with marginal changes in the entire load profile as represented by the regional demand trace.

To understand how changes in demand for a subset of customers within a region and a different load profile influence future generation and network capital and operating costs, the increment or decrement in demand as applied to the relevant demand should reflect the different load profile. As a consequence, the increment or decrement would result in a change to the underlying demand profile with associated implications for the combination of incremental generation investment needed to supply the new load profile. This will result in a different estimate of the LRMC, ie, the LRMC of adding a customer with that demand profile to the system. This methodology would allow a perturbation approach to be used to estimate wholesale electricity purchase costs for different customers within a region.

4.2. Long Run Marginal Cost results

Figure 4.1 through to Figure 4.5 and Table 4.1 set out our estimates of the LRMC for each NEM region applying each of the three methodologies described above.

Figure 4.1
Estimates of the Long-Run Marginal Cost of Wholesale Electricity Supply, Queensland

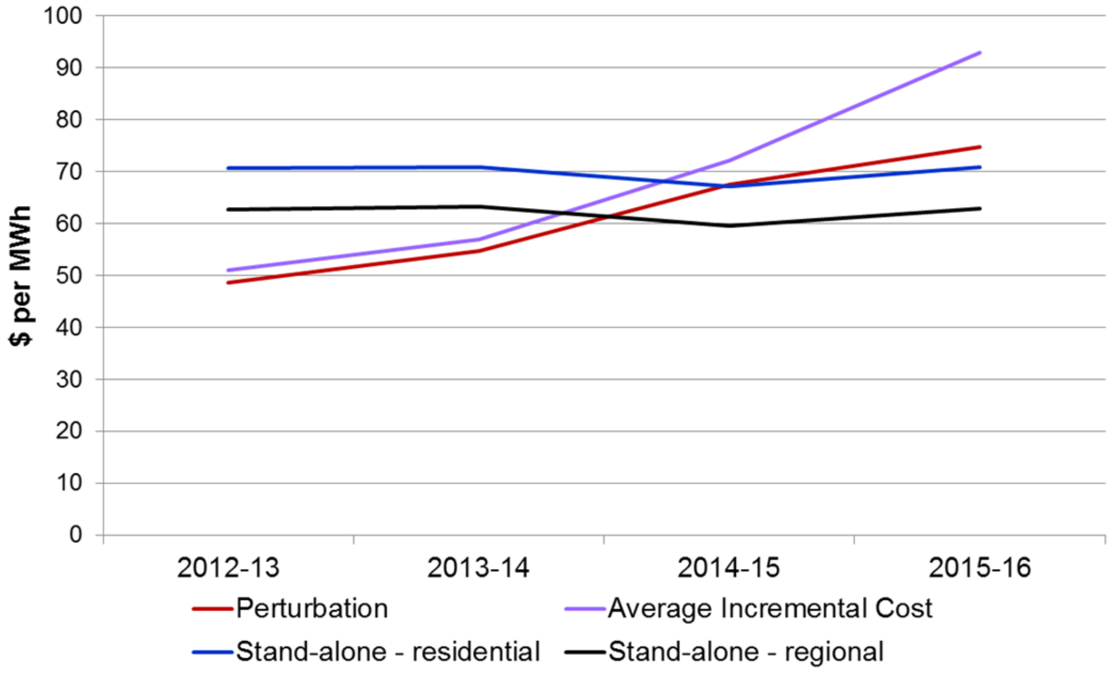


Figure 4.2
Estimates of the Long-Run Marginal Cost of Wholesale Electricity Supply, NSW

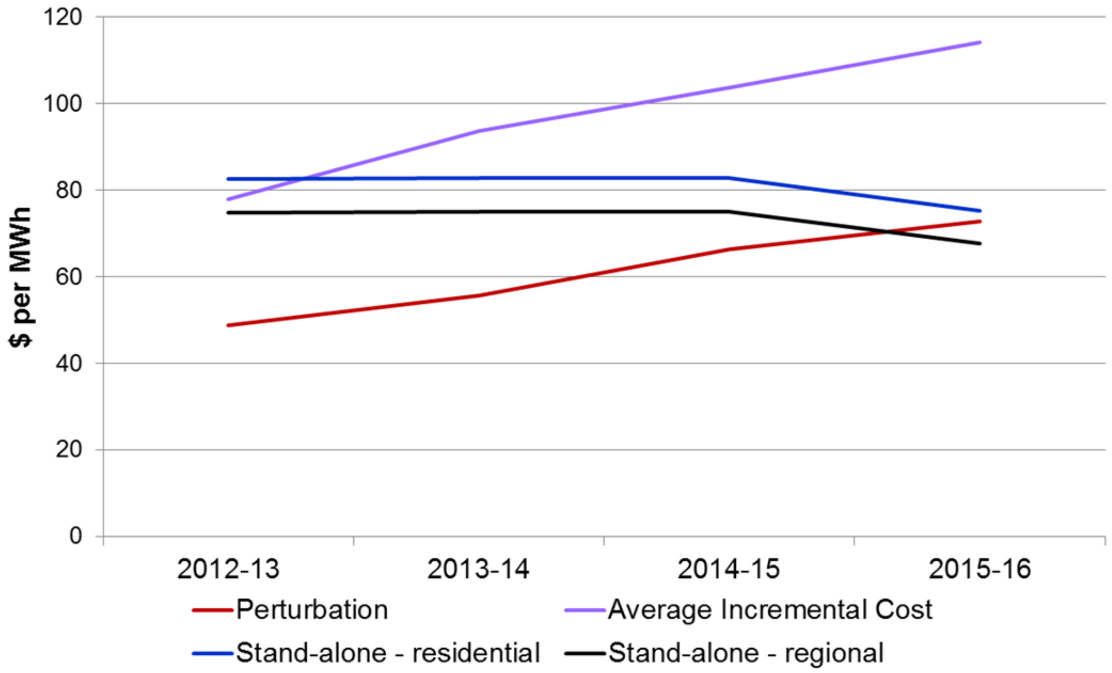


Figure 4.3
Estimates of the Long-Run Marginal Cost of Wholesale Electricity Supply, Victoria

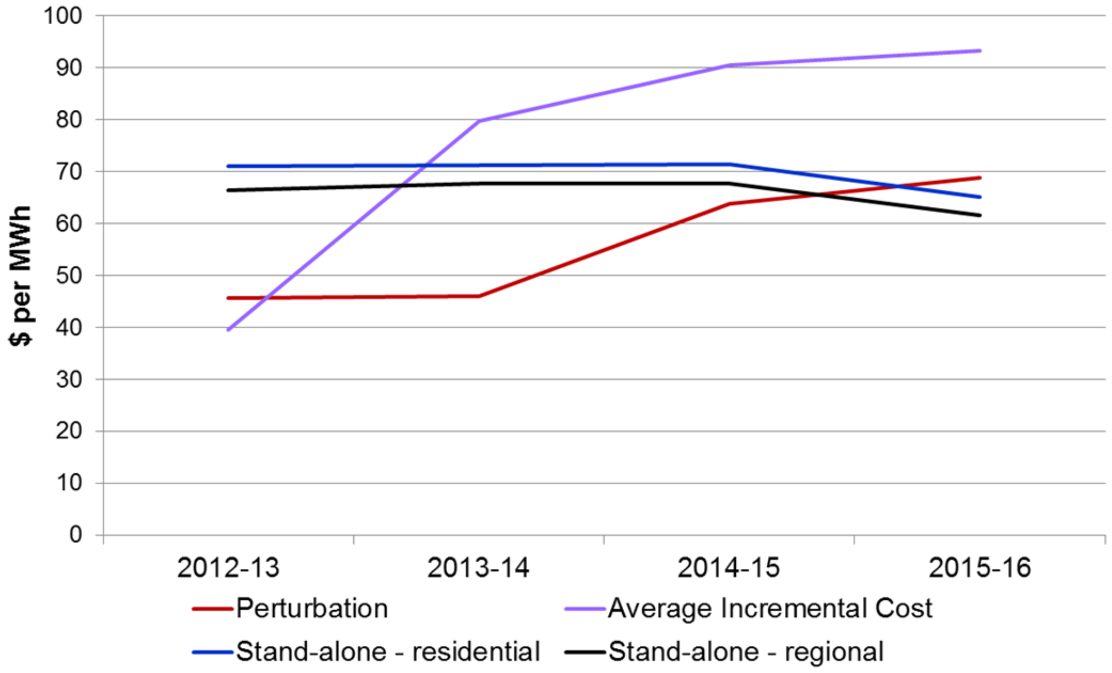


Figure 4.4
Estimates of the Long-Run Marginal Cost of Wholesale Electricity Supply, Tasmania

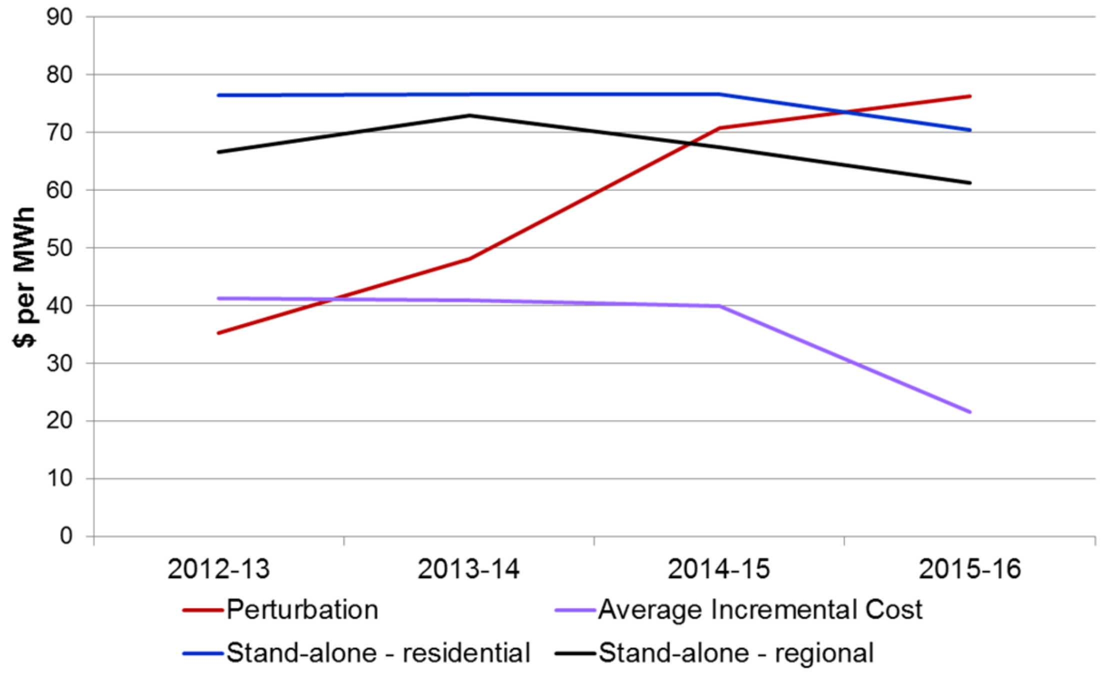


Figure 4.5
Estimates of the Long-Run Marginal Cost of Wholesale Electricity Supply, South Australia

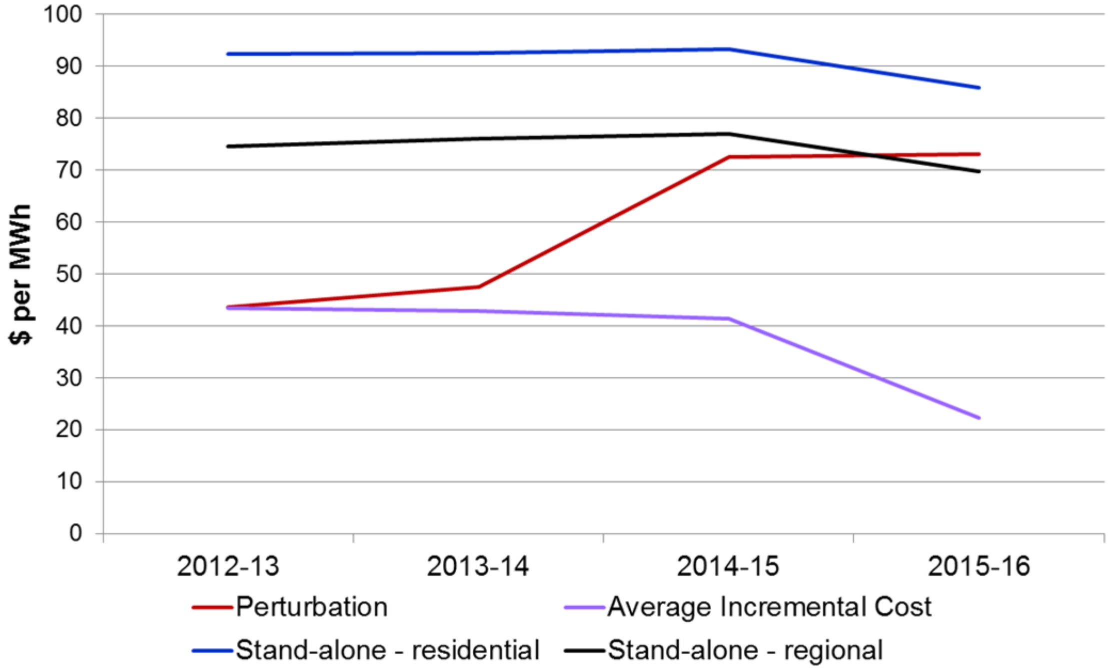


Table 4.1
Estimates of the Long-Run Marginal Cost of Wholesale Electricity Supply, by NEM Region

NEM Region	2012-13	2013-14	2014-15	2015-16
Queensland				
Greenfield				
- Residential Profile	$70.6	$70.8	$67.1	$70.8
- Regional Profile	$62.7	$63.3	$59.6	$62.9
Average Incremental Cost	$51.0	$56.9	$72.2	$92.9
Perturbation	$48.6	$54.8	$67.5	$74.7
New South Wales				
Greenfield				
- Residential Profile	$82.6	$82.7	$82.8	$75.3
- Regional Profile	$74.9	$75.0	$75.0	$67.7
Average Incremental Cost	$77.9	$93.7	$103.7	$114.2
Perturbation	$48.7	$55.6	$66.3	$72.7
Victoria				
Greenfield				
- Residential Profile	$71.1	$71.3	$71.3	$65.1
- Regional Profile	$66.3	$67.6	$67.7	$61.5
Average Incremental Cost	$39.5	$79.7	$90.5	$93.3
Perturbation	$45.7	$46.1	$63.7	$68.9
Tasmania				
Greenfield				
- Residential Profile	$76.5	$76.6	$76.7	$70.5
- Regional Profile	$66.6	$73.0	$67.4	$61.3
Average Incremental Cost	$41.3	$40.9	$40.0	$21.6
Perturbation	$35.3	$48.1	$70.8	$76.4
South Australia				
Greenfield				
- Residential Profile	$92.3	$92.5	$93.3	$85.8
- Regional Profile	$74.6	$76.0	$76.9	$69.7
Average Incremental Cost	$43.4	$42.9	$41.4	$22.2
Perturbation	$43.6	$47.6	$72.6	$73.0

Our estimates of the LRMC for 2012-13 are generally lower than our previous estimates of the 2011-12 LRMC, developed for the AEMC.[20] Although there are a number of reasons this mostly reflects:

- considerably lower carbon price assumptions, particularly over the long term; and
- lower AEMO forecasts of both energy demand and maximum demand resulting in future capital costs being incurred later in the time profile.

The results from applying the Greenfields methodology are generally higher than those resulting from the application of the perturbation and average incremental cost methodologies.[21] The principal reason for this outcome is that the Greenfields methodology determines the least cost combination of *new entrant plants required in a given region* to supply the entire load profile. The fact that new entrant costs will always exceed the cost of using existing generation, combined with an inability to supply incremental demand from *other* regions, means that the total cost will tend to be higher than estimated using alternative methodologies.

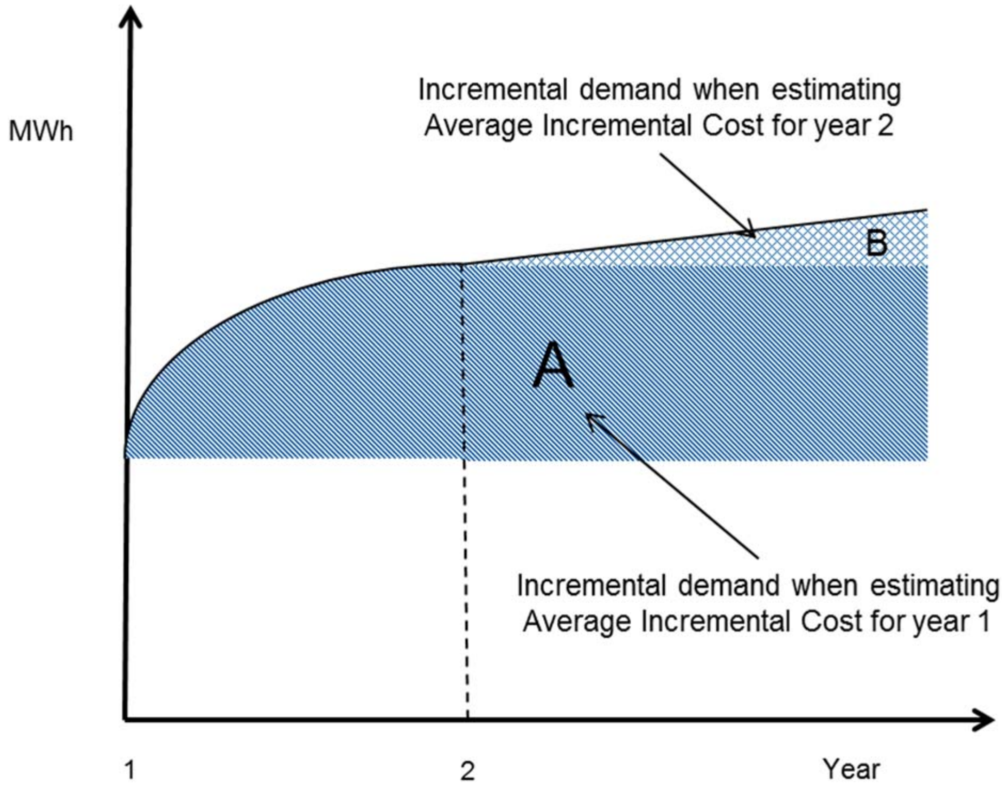
The estimates of LRMC applying the average incremental cost methodology are strongly influenced by forecast incremental demand in each region. For example, the average incremental cost in Queensland increases significantly in 2015-16 because incremental demand growth decreases from 2015-16 and so the present value of the cost of forward generation investments is divided by a smaller present value of demand than in earlier years. This results in the average incremental cost increasing significantly, despite future capital and operating costs not changing significantly between the years for which the LRMC is being estimated.

Figure 4.6 illustrates how significant demand growth in earlier years can decrease the size of the denominator when estimating AIC LRMC in subsequent years. The incremental demand for an AIC LRMC estimate for year 1 is the present value of the increase in demand from year 1, namely the present value of areas A and B. However, the incremental demand for an AIC LRMC estimate for year 2 is the present value of the increase in demand from year 2, namely the present value of area B. The early demand growth in this illustration means that the denominator in the AIC LRMC calculation is significantly higher for the estimate in year 1 compared to year 2. Assuming that future capital and operating costs are similar between the two years, this results in the AIC LRMC estimate being significantly higher in year 2 compared with year 1.

[20] NERA Economic Consulting, and Oakley Greenwood, (2012), "Estimates of the Long Run Marginal Cost for Electricity Generation in the National Electricity Market", *A Report for the Australian Energy Market Commission*, 22 November, Sydney.

[21] That said our estimates of the AIC LRMC for New South Wales are higher than the Greenfields methodology estimates. This likely reflects the growth in generation costs absent commensurate growth in demand in New South Wales.

Figure 4.6
Illustration of the Influence of Demand Growth on Average Incremental Cost LRMC



This effect explains the significant increase in the average incremental cost LRMC estimates, particularly for Queensland, and New South Wales. In Victoria, the low LRMC in 2012-13 reflects forecast decreases in demand in Victoria and so the LRMC estimate converges to the marginal operating costs. The subsequent period increases reflect the costs associated with capital investment required to satisfy the future Victorian region demand growth.

In contrast, the estimates of the average incremental cost LRMC for South Australia and Tasmania converge to operating costs because incremental demand in those regions is forecast to be negative. As a consequence, the only incremental cost attributable to future demand is the operating cost to supply. In other words, there are no average incremental capital costs that arise over our projection period for the region.

The perturbation LRMC for 2012-13 and 2013-14 are consistent with the current wholesale spot market prices. The estimates reflect lower demand and excess existing generation capacity, which leads to a relatively small contribution of long run marginal capital costs to the estimate.

Increases in the perturbation LRMC for 2014-15 and 2015-16 reflect forecast demand growth between 2013-14 and 2015-16 in the Queensland region, which brings forward the need for near term generation investment. As a consequence, when demand is perturbed, the impact on long run marginal capital costs is higher, leading to a higher LRMC estimate.

Finally, the perturbation LRMC results for South Australia and Tasmania rise to be near to Greenfields LRMC estimates in 2014-15 and 2015-16. The increase in both 2014-15 and 2015-16 arises because a small perturbation of demand affects the relative profitability of wind investment compared to payment of the LRET penalty. As a consequence an upwards perturbation of demand:

- marginally increases wholesale electricity spot prices in South Australia and Tasmania; and
- marginally decreases the LGC price, which in combination increases the revenue available to generation in both South Australia and Tasmania; which
- leads to significant wind investment as compared to the base case.

The resultant higher long run marginal capital costs are not offset by the associated decrease in the LRET penalty payments, which affect long run marginal operating costs.

The intuition underlying the rising perturbation LRMC estimates in South Australia and Tasmania reflects the perfect foresight assumption in our generation investment schedule. In other words, small changes to the spot price and LGC price can lead to the financial viability of wind generation investment changing considerably. The resultant increase in the associated capital costs are then factored directly into the LRMC estimate.

4.3. Sensitivity of the results to forecast demand

The relationship between forecast demand and estimates of the LRMC are less direct than for estimates of electricity purchase costs, as discussed earlier in section 3.4. When estimating LRMC the level of demand generally influences the investment profile, ie, the mix of new-entrant generation that is constructed to meet demand, as well as to satisfy other constraints such as the LRET.

The mix of new-entrant generation is strongly influenced by both the forecasts of energy demand and maximum demand. Generally speaking, increases in energy demand without a commensurate increase in maximum demand, will result in the models predicting increases in the use of existing generation. In contrast, increases in maximum demand without any change in average annual demand would likely result in the models projecting increases in peaking generation capacity.

In the NEM the mix of generation needed to satisfy forecast demand is also influenced by the LRET, which provides financial incentives to invest in renewable generation irrespective of changes in demand. That said, the extent that renewable generation investment is predicted by the models will depend on all factors that influence spot prices, including demand.

Both the Greenfields and AIC methodologies for estimating the LRMC will be influenced by demand forecasts. Any change in the associated generation mix towards a higher proportion of generation supplied by higher unit cost generation, will lead to increases in the associated LRMC. It follows that if the demand changes lead to a greater need for peak or renewable generation, then the LRMC will likely rise. Conversely if more base load generation is required, then LRMC estimates will likely fall.

The influence of demand on estimates of the LRMC obtained by application of the perturbation methodology is less clear. If forecast demand is higher in base case scenario, then there is likely to be more generation investment required in the near future, compared to an alternative with lower forecast demand. In this circumstance, perturbing demand would lead to a higher estimate of the LRMC, reflecting that the change in generation costs is discounted by a lower amount. Similarly, if forecast demand is lower in the base case scenario, then the need for new generation investment will be further in the future, and so LRMC estimates would be likely to be lower.

4.4. General observations

Our perturbation LRMC results highlight that:

- with a fixed LRET target, in regions where demand is falling and so there is excess thermal generation capacity, relatively small changes in demand can lead to large changes in renewable generation investment; and
- the opportunity cost of using electricity – as represented by the LRMC – can be high even in regions where demand is falling and there is excess thermal generation capacity, given the influence demand changes can have on the mix of generation investment because of the LRET.

Relevantly, the perturbation LRMC methodology is the only methodology that provides useful insights on the likely changes in opportunity costs for small changes in demand. This is because it takes account of interactions between spot prices and LGC prices as a consequence of a small change in demand, which can influence planned renewable investments. In contrast, the average incremental cost and Greenfields methods are influenced by other factors that mean they are less likely to provide useful insights on the relevant opportunity cost of using electricity in all circumstances.

For example, the average incremental cost methodology does not take into account how marginal changes in demand might influence renewable generation investment given the interaction between spot and LGC prices. As a consequence, it will converge to variable fuel and operating costs for those regions where demand is falling and so there is excess generation capacity.

The Greenfields method has the advantage of being simple to calculate, but does not appropriately account for the current mix of generation supplying demand in a region. It also does not take into account interactions between regions, which might lead to the least cost generation investment to supply changes in demand occurring in an interconnected region.

Finally, we have applied the perturbation methodology to estimate the LRMC for each region using the system load profile prevailing for the region. It is possible to estimate a perturbation LRMC for alternative load profiles, or for segments of the load profile (eg, to estimate a peak or off-peak perturbation LRMC), by applying a perturbation to the load profile or segment of interest. In this way, it would be possible to estimate a perturbation LRMC for a residential load profile, which would be required to estimate wholesale purchase costs for residential consumers for the purpose of setting regulated retail tariffs.

5. Conclusion

The focus of this study has been on estimating wholesale purchase costs and the LRMC for each NEM region for the period 2012-13 to 2015-16. This has allowed us to investigate how the estimates vary according to the choice of methodology used.

Importantly, each methodology is an approximation of the likely wholesale electricity purchase costs because of the need to make assumptions about inputs, as well as the simplifying assumptions that are required to model complex processes such as planting of new generation. The degree to which these assumptions differ from actual market outcomes will determine the extent of deviation between our estimates of wholesale purchase costs and resultant actual wholesale purchase costs.

With these limitations in mind, in theory a market modelling methodology and an LRMC each methodology should produce similar results over the long term. The choice of a particular broad methodology, and the specific modelling assumptions and approach used within any particular methodology adopted, will therefore depend on the particular circumstances and context applying at a given time.

Nevertheless, in our opinion the perturbation methodology is likely to be the most robust of the LRMC methodologies considered because:

- it takes into account the interactions between spot prices, LGC prices and the prevailing level of demand, which the alternative methodologies do not; and
- it appropriately represents the wholesale market demand and supply fundamentals as well as the likely changes resulting from incremental changes in demand, ie, the opportunity cost of using electricity *at the margin*.

In contrast, the Greenfields LRMC does not take into account the current structure of generation capacity and so does not reflect the opportunity cost of using electricity in the prevailing market circumstances. Similarly, the average incremental cost methodology is incapable of appropriately accounting for the influence of demand on renewable generation investment and so will underestimate the LRMC in those regions where there is excess generation capacity and demand is forecast to fall in the future.

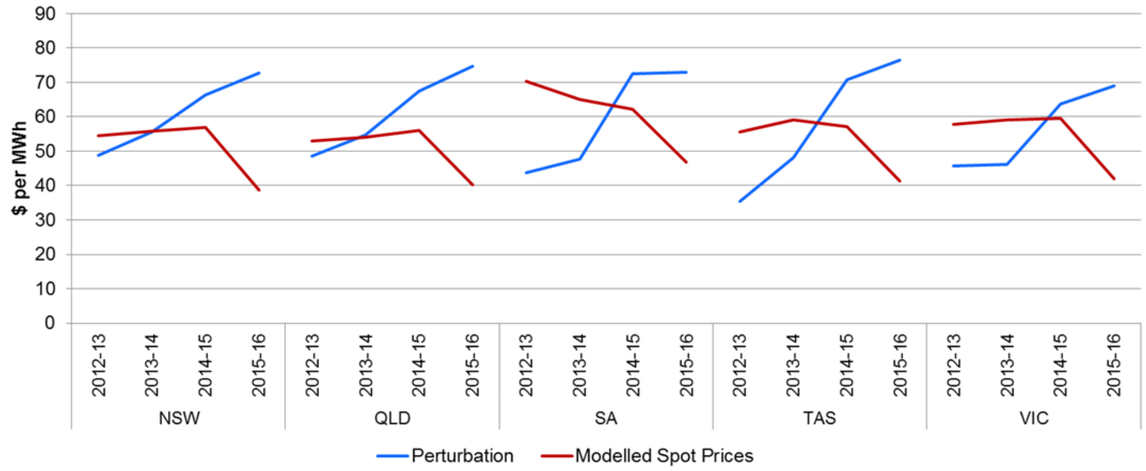
The market modelling approach to estimating wholesale electricity purchase costs has its own implementation challenges, depending on the modelling approach taken to its application. In addition, there are particular challenges relating to choices about:

- the hedging strategy or strategies examined; and
- the relationship between contract prices and spot prices.

Current deviations between wholesale market spot prices and associated wholesale electricity purchase costs and estimates of the LRMC using the perturbation methodology reflect the prevailing wholesale electricity market demand and supply conditions, and the contracting premiums involved.

Figure 5.1 compares the perturbation LRMC with the modelled average annual wholesale electricity spot prices.

Figure 5.1
LRMC estimated via Perturbation versus Modelled Spot Prices, by NEM Region



The results suggest that in each region the perturbation LRMC estimates diverge over the period to 2015-16. This likely reflects the influence of future capital costs on the perturbation results. That is, modelled spot prices are low because of an oversupply of capacity, whereas the modelling horizon for the perturbation approach captures capital investment, albeit discounted, that occurs well into the future.

The perturbation LRMC and spot prices are similar for 2012-13 and 2013-14 for both Queensland and New South Wales. The spot price results are higher for Victoria, Tasmania and South Australia. For Victoria and Tasmania, this likely reflects higher water values from hydro-generation underpinning the spot prices, which are not reflected in the underlying operating costs included in the perturbation LRMC estimate. For South Australia, the deviation between spot prices and estimated LRMC reflects the current operation of the Northern Power station, which is leading to reduced generation capacity during the winter period in South Australia with associated higher prices compared with the underlying market fundamentals reflected in the LRMC estimate.

Finally, while we observe differences in the modelled LRMC estimates and modelled spot prices, in principle these estimates should be broadly similar over the medium to long term. Near term differences reflect prevailing conditions in the demand and supply conditions, which can affect market outcomes.

Appendix A. 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:

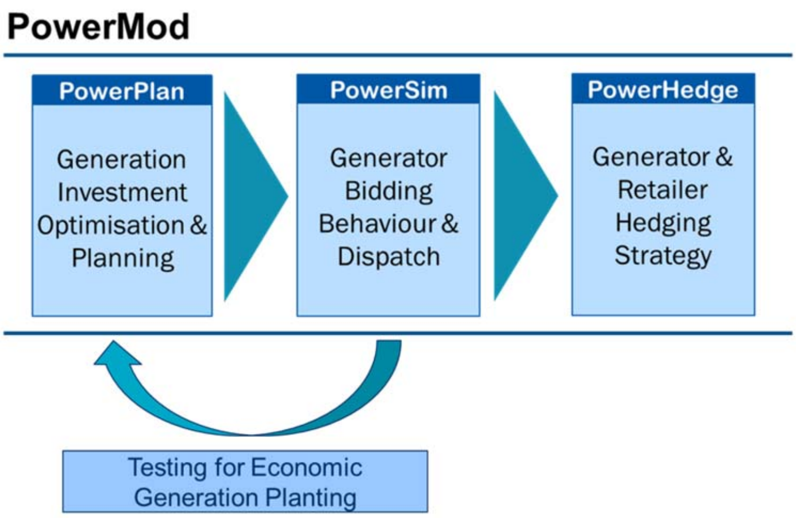
- projecting wholesale electricity market prices;
- forecasting long-term generation capacity expansions to satisfy future electricity demand requirements;
- analysing the long-run and short-run marginal costs of electricity generation;
- analysing evidence of the existence of generator market power;
- 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 related and 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 2.1 illustrates the interactions between the models.

Figure 2.1: Interaction of NERA's suite of wholesale electricity market models



The model uses linear and 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 include:

- **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 or average incremental cost methodologies.

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

  The key outputs from **PowerSim** include:

  - the wholesale market regional reference node 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, duty cycle (ie, hours of dispatch) and capacity factors for each plant;
  - total and plant specific emissions, and average annual 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 portfolio investment theory to develop 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 have been tailored to explicitly implement the perturbation and average incremental cost LRMC methodologies, and they are also extremely flexible to ongoing development and adaptation.

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