2016 Residential Electricity Price Trends Report

A REPORT PREPARED FOR THE AUSTRALIAN ENERGY MARKET COMMISSION (AEMC)

November 2016

2016 Residential Electricity Price Trends Report

Tables and figures

2016 Residential Electricity Price Trends Report

Figures

Tables

1 Introduction

The Australian Energy Market Commission (AEMC) is currently undertaking the 2016 Residential Electricity Price Trends report. This will be the latest annual residential electricity price trends report prepared by the AEMC at the request of the Council of Australian Government (COAG) Energy Council.[1]

The AEMC's report will set out, in broad terms, the drivers of price movements and trends in residential electricity prices for each state and territory of Australia over the four years from 2015/16 to 2018/19. These drivers and trends are also consolidated to provide a national summary.

1.1 Frontier Economics' engagement

Frontier Economics has been engaged by the AEMC to advise on future trends in residential electricity prices, and the drivers behind them. Specifically, Frontier Economics has been engaged to advise on future trends in the wholesale electricity cost component of residential electricity prices in the National Electricity Market (NEM) and South West Interconnected System (SWIS). The specific cost components for which we are to provide cost forecasts include:

- wholesale electricity costs, estimated using a market based approach for NEM jurisdictions and a long run marginal cost (LRMC) approach in the SWIS;
- network losses;
- market fees for both the NEM and the SWIS;
- the cost impact related to the national Renewable Energy Target (including both the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES)).

Our advice on wholesale electricity costs is to cover the four-year period from 2015/16 to 2018/19. We have been asked to investigate a number of scenarios with regard to demand forecasts and fuel input costs.

1.2 Frontier Economics' previous work

Frontier Economics has advised the AEMC on future trends in residential electricity prices as part of the AEMC's previous price trends reports, including the AEMC's 2015 Residential Electricity Price Trends report. The methodology

1 The COAG Energy Council was previously known as the Standing Council on Energy and Resources.

that we have adopted for this report is the same as the methodology that we have adopted previously. We have updated all of our modelling assumptions since last year's report, although we have generally adopted the same approach to sourcing the modelling assumptions that we use.

1.3 About this report

This report is structured as follows:

- Section 2 presents the approach we use to determine wholesale electricity costs for residential customers.
- Section 3 details the assumptions used in the analysis and the scenarios modelled.
- Section 4 presents our wholesale electricity cost estimates.
- Section 5 covers our other cost estimates.
- Section 6 presents tables of our full results.

Appendix A through Appendix E presents Frontier's detailed supply-side input assumptions.

2 Modelling methodology

This section presents an overview of Frontier Economics' electricity market models and their application to the NEM and SWIS, in order to estimate wholesale electricity costs for residential customers.

2.1 Frontier Economics' modelling framework

Frontier Economics has developed a suite of energy market models that we use to forecast outcomes in the electricity market. Forecasting long term gas prices is undertaken in our gas market model – *WHIRLYGAS*. Coal prices are forecast using our detailed mining cost and netback price models. We forecast wholesale electricity costs using our three electricity market models: *WHIRLYGIG, SPARK* and *STRIKE*. The key features of these models are as follows:

- *WHIRLYGAS* optimises total gas production and transmission costs in the gas market, calculating the least cost mix of existing and new gas production and transmission infrastructure to meet demand. *WHIRLYGAS* provides a forecast of least cost investment and least cost operation of gas production facilities and transmission pipelines and provides an estimate of the LRMC of gas. *WHIRLYGAS* has been structured to incorporate international LNG demand and to produce domestic price forecasts that reflect opportunity costs of exporting gas as LNG.
- Our proprietary coal mine cost models, developed with Metalytics[2], estimate cost based and netback price based estimates for each mine in Australia. These estimates are combined with forecasts of demand for coal to produce price estimates for each power station in the NEM and the SWIS.
- *WHIRLYGIG* optimises total generation cost in the electricity market, calculating the least cost mix of existing generation plant and new generation plant options to meet demand. *WHIRLYGIG* provides a forecast of least cost investment, least cost dispatch and an estimate of the LRMC of electricity. The model can also incorporate policy or regulatory obligations facing the generation sector, such as a renewable energy target, and calculate the cost of meeting these obligations.
- *SPARK* identifies optimal and sustainable bidding behaviour strategy for generators in the electricity market using game theoretic techniques. This is a very important difference between Frontier's approach and that of other analysts. Instead of making arbitrary assumptions about possible patterns of bidding for the purposes of calculating a price, our approach has bidding behaviour as a model *output* rather than an *input*. The model determines the

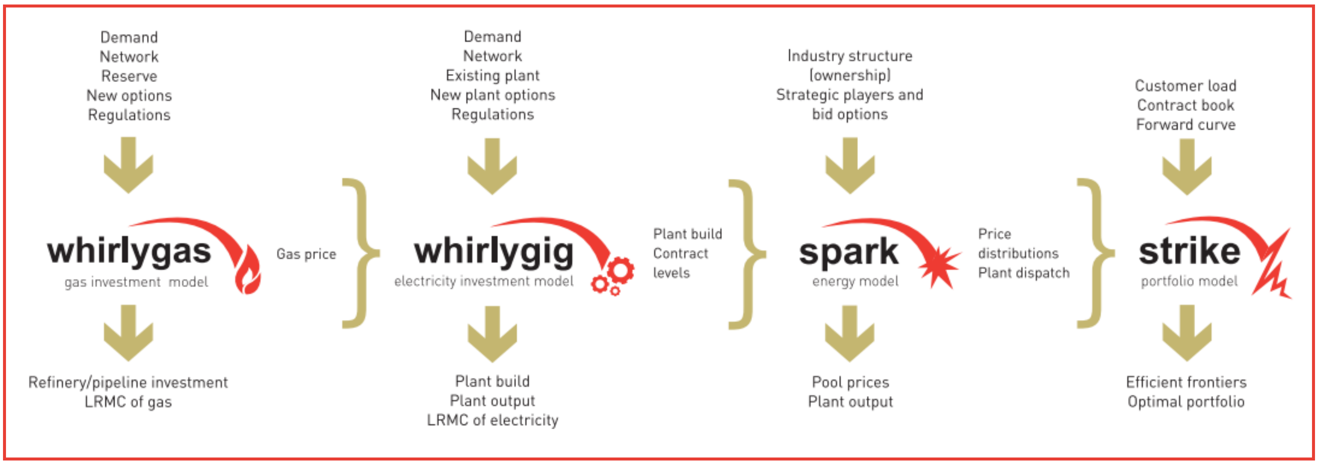
2 Metalytics is a resource economics consultancy that works closely with Frontier Economics.

optimal pattern of bidding by having regard to the reaction by competitors to a discrete change in bidding behaviour by each generator to increase profit (either by attempting to increase price or expand market share). Once the profit outcomes from all possible actions and the reactions to these actions are determined the model finds the equilibrium outcome based on standard game theoretic techniques. An equilibrium is a point at which no generator has any incentive to deviate from because they will be pushed back to this point by competitor responses. *SPARK* provides a forecast of dispatch, which reflects bidding behaviour, and a forecast of electricity prices.

- *STRIKE* is a model that uses portfolio theory to find the best mix (portfolio) of available electricity purchasing options (spot purchases, derivatives and physical products). This model can be used to determine the additional costs of meeting a new load will have on the portfolio effects of a standard retailer and other energy assets (e.g. existing customer base, hedges, power stations, gas contracts, etc.). *STRIKE* uses the output of *SPARK* to provide a distribution of spot (and contract) prices to be used in the optimisation of the suite of purchasing options. *STRIKE* provides a range of efficient purchasing outcomes for all levels of risk.

The relationship between these models is summarised in Figure 1.

Figure 1: Model inputs and outputs



2.2 Estimating wholesale electricity costs

Regulators have typically used one of two approaches to estimating wholesale electricity costs for regulated customers: a stand-alone LRMC approach or a market-based approach. These approaches are discussed in more detail in the sections that follow.

We apply the stand-alone LRMC approach to estimating wholesale electricity costs in the SWIS and a market modelling approach to estimating wholesale electricity costs in the NEM (which includes Queensland, South Australia, New South Wales, ACT, Tasmania and Victoria).

2.2.1 Stand-alone LRMC

The stand-alone LRMC approach reflects the costs that a retailer would face if it were to build and operate a hypothetical least-cost generation system to serve only its retail load (or a relevant subset of its retail load, such as the retail load of regulated customers). Typically, the stand-alone LRMC approach is implemented by assuming that there is no existing generation plant to meet the relevant load: each year, a new hypothetical least-cost generation system is built and operated, and the costs of investment (annualised over the assumed life of the investment) and operation are calculated.

The intuition behind the stand-alone LRMC approach is that the costs that a retailer faces to serve its retail load can be thought of in two ways: either as the costs of purchasing electricity to serve the relevant retail load from the NEM (accounting for the financial hedging contracts that are typically used by retailers to manage risk in the NEM) or as the cost of building and operating generation plant to directly supply the electricity to serve the relevant retail load. The market-based electricity purchase cost considers the first, the stand-alone LRMC considers the second.

Because regulators have typically calculated a stand-alone LRMC each year of a determination period (assuming, in each year, that the investment slate is wiped clean and the retailer will need to invest in a mix of entirely new generation plants) the stand-alone LRMC will, by design, always incorporate both capital and operating costs. In this sense, the stand-alone LRMC is indeed a **long-run** marginal cost: the stand-alone LRMC treats all factors of production as variable and reflects the costs of all factors of production. The same is not true for all approaches to estimating the LRMC of electricity for regulatory purposes.

A major appeal of the stand-alone LRMC is that it is a simple and easily reproduced approach that relies on a minimum of assumptions. A significant drawback is that the approach considers a highly theoretical system (a residential load shape with no existing generators) which can be seen by some stakeholders to hold little relevance to actual electricity markets. On balance, however, the stand-alone LRMC is a useful approach for informing regulatory decisions and has been widely adopted in Australia.

Implementation

The stand-alone LRMC is modelled using *WHIRLYGIG*, assuming that there is no existing generation plant in the system, and a mix of entirely new generation plants must be built in each jurisdiction to meet the load of residential customers in that jurisdiction.

When modelling this hypothetical system, we assume a reserve margin of 15 per cent for the system.[3] A reserve margin of 15 per cent acts as a proxy for the more detailed considerations of reserve that are required in actual markets with pre-existing investments; 15 per cent has been chosen as it reflects a trade-off between prudence and efficiency. Frontier have previously used 15 per cent in our work for the AEMC, the Independent Pricing and Regulatory Tribunal (IPART), the Essential Services Commission of South Australia (ESCOSA), the Economic Regulation Authority (ERA) and the Office of the Tasmanian Economic Regulation (OTTER), and this approach has been subject to extensive consultation from the industry over a number of years.

2.2.2 Market-based approach

The market-based approach to determining the wholesale electricity cost of a representative residential customer involves two steps:

- First, a forecast of market prices is required. In a market-based approach, this forecast of market prices should have regard to the strategic bidding behaviour of market participants and actual supply and demand conditions in the market. The forecast prices need to be correlated to residential load shapes to properly capture the risks faced by retailers in supplying residential customers.
- Second, a forecast of the cost of purchasing electricity to meet the load of a representative residential customer is required. In a market-based approach this forecast of the cost of purchasing electricity should include the cost of purchasing hedging contracts for the purposes of risk management. The forecast cost of purchasing electricity can be based on a forecast of contract prices (typically tied to forecast spot prices) or publicly available contract prices (such as the published prices of ASX Energy contracts).

In order to properly estimate the wholesale electricity cost faced by a prudent retailer, it is important to ensure that the risk of serving a given customer is accurately capture in the modelling approach. Key to this is ensuring that the assumed customer load shape is correctly correlated to an accurate distribution of possible pool price outcomes. Given these inputs – accurately correlated spot

3 In practice, in both the NEM and the SWIS, reserve margins are set as a fixed MW margin that accounts for likely variations in the system load shapes, operational issues and, in the case of the NEM, the diversity of peak demand between different regions of the NEM. Such numbers cannot easily be used as a reserve margin for a residential load shape within the stand-alone LRMC framework. For example, AEMO's reserve margin for NSW is currently -1,564 MW (i.e. NSW has a *negative* reserve margin, reflecting its ability to import from other regions at times of peak NSW demand).

prices and customer loads – a framework for quantifying the trade-off between risk and reward, and ultimately determining an optimal hedging position and associated wholesale supply costs is required.

Our implementation of the market-based approach

The market-based approach is modelled using the following steps:

- *WHIRLYGIG* is used to forecast investment outcomes
- *SPARK* is used to model market price outcomes
- *STRIKE* is used to determine optimal conservative hedging outcomes for residential load shapes. It does this having regard to the load shape, spot price forecast and contract price forecast in each jurisdiction; the optimal conservative hedging outcome can therefore be different in different regions. *STRIKE* uses the forecast spot prices from *SPARK* and assumes that financials hedges – swap and cap products – are available at an assumed 5 per cent premium[4] to forecast spot prices.

Implementation in Tasmania

For the mainland NEM regions, *STRIKE* is used to determine an optimal mix of spot purchases and financial hedges to serve a residential load shape where both the purchases and hedges are at the relevant regional reference node. For Tasmania, where there is no public financial hedge market, OTTER uses an approach based on the market cost of contracts in Victoria adjusted for losses on Basslink:

> The methodology uses published Victorian forward contract prices as the starting variable and makes a number of transparent adjustments to translate these values into Tasmanian contract prices – taking into account expected net energy exports between Tasmania and Victoria.[5]

We have altered our standard approach to more closely mimic this approach by:

- assuming that a Tasmanian residential load shape is hedged *at the Victorian spot price and using Victorian hedge products* to determine an electricity purchase cost at the Victorian node, and

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4 Our consultant's report for the 2015 price trends report includes a detailed discussion of the assumed contract premium. Frontier Economics, *2015 Residential Electricity Price Trends Report*, A report prepared for the Australian Energy Market Commission (AEMC), November 2015. Available at:

http://www.aemc.gov.au/Markets-Reviews-Advice/2015-Residential-Electricity-Price-Trends#

5 See http://www.energyregulator.tas.gov.au/domino/otter.nsf/8f46477f11c891c7ca256c4b001b41f2/0de2f2a45e46402aca257c4a00079a4a?OpenDocument, accessed 9 July 2016.

- adjusting this electricity purchase cost to the Tasmanian node as per forecast losses on Basslink from the relevant *SPARK* model run.

We have adopted this same approach to estimating the market-based electricity purchase cost in Tasmania for previous price trends reports, and we continue to believe that this approach embodies the most accurate market-based approach for Tasmania.

One of the implications of adopting this approach is that the increase in Tasmania electricity prices in 2015/16 that resulted from the outage of Basslink are not reflected in the market-based electricity purchase cost for Tasmania for 2015/16. The immediate reason is that the outage of Basslink did not increase the price of Victorian hedge products. More generally, however, we think that this is a sensible outcome for this price trends report, since residential electricity prices in Tasmania did not increase as a result of the unexpected outage of Basslink. This is because the regulated prices for residential customers were not set with an expectation of the price impact of the outage of Basslink, or to reflect the price impact of the outage of Basslink. In short, the higher wholesale electricity prices in Tasmania caused by the outage of Basslink were not passed through to residential customers.

Contract premiums under the market-based approach

While *SPARK* provides a forecast of spot prices that can be used as an input to *STRIKE*, there is a requirement to make some assumptions regarding financial contract prices. ASX Energy market prices for such contracts do not trade at sufficient levels of liquidity to establish a meaningful price estimate for all jurisdictions over all years of the modelling. Our approach is to assume that financial hedges trade at a 5 per cent premium to our *SPARK* forecasts of spot prices.

This contract premium value – 5 per cent above forecast pool prices – was established based on initial analysis of spot and contract price data over 2006-2007 as part of Frontier Economics' advice to IPART's 2007 retail price determination.[6] The 5 per cent premium has been used in all our work for IPART (the 2007, 2010 and 2013 determinations and annual reviews), in our advice to ESCOSA, in our previous work for the AEMC and elsewhere. We are also aware that a number of businesses use this assumption.

It would be expected that the contract premium would ultimately be related to the expected volatility of spot prices. One reason that volatility in spot prices could increase is an increase in wind generation; for instance. there have been

6 See, for example, Frontier Economics' report for IPART's 2010 to 2013 determination, available at: http://www.ipart.nsw.gov.au/Home/Industries/Electricity/Reviews/Retail_Pricing/Review_of_regulated_electricity_retail_tariffs_and_charges_for_small_customers_2010_to_2013

indications that the increase in wind generation in South Australia have increased price volatility. However, there have been other reasons that price volatility has been high in the NEM (including, notably, the drought during 2007) and our assumption that financial hedges trade at a 5 per cent premium to our *SPARK* forecasts of spot prices has been used without objection during those periods of increased price volatility.

It is certainly the case that recent events – including spot price volatility in South Australia and the closure of Hazelwood – have resulted in an increase in contract prices. At this stage, it is unclear whether this reflects an increase in the contract premium, an expectation that future spot prices will be higher, or both. Given this uncertainty, we continue to use an assumed contract premium of 5 per cent in our modelling.

2.3 Estimating costs of complying with the Renewable Energy Target

In addition to advising on wholesale electricity costs for the period 2015/16 to 2018/19, this assignment also requires us to estimate a range of other electricity-related costs. This section considers the costs associated with complying with the Renewable Energy Target (RET). The RET consists of the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES).

2.3.1 LRET

The LRET places a legal obligation on wholesale purchasers of electricity to proportionately contribute towards the generation of additional renewable electricity from large-scale generators. Liable entities support additional renewable generation through the purchase of Large-scale Generation Certificates (LGCs). The number of LGCs to be purchased by liable entities each year is determined by the Renewable Power Percentage (RPP), which is set by the Clean Energy Regulator (CER).

LGCs are created by eligible generation from large scale, renewable power stations. Small-scale installations less than 100 kW of capacity such as solar water heaters, air sourced heat pumps and small generation units, are not eligible to create LGCs under the LRET. Instead, these small-scale installations are eligible to create certificates under the SRES.

Approach to estimating costs of complying with the LRET

In order to calculate the cost of complying with the LRET, it is necessary to determine the Renewable Power Percentage (RPP) for a representative retailer (which determines the number of LGCs that must be purchased) and the cost of obtaining each LGC.

Renewable Power Percentage

The RPP establishes the rate of liability under the LRET and is used by liable entities to determine how many LGCs they need to surrender to discharge their liability each year.

The RPP is set to achieve the renewable energy targets specified in the legislation. The CER is responsible for setting the RPP for each year. The *Renewable Energy (Electricity) Act 2000* states that where the RPP for a year has not been determined it should be calculated as the RPP for the previous year multiplied by the required GWh's of renewable energy for the current year divided by the required GWh's of renewable energy for the previous year. This calculation increases the RPP in line with increases in the renewable energy target but does not change the RPP to account for any change in demand. Given that forecast electricity demand in the medium case is flat, we expect that the calculation in the *Renewable Energy (Electricity) Act 2000* is likely to be quite close to the RPP set by the Clean Energy Regulator.

Cost of obtaining LGCs

The cost to a retailer of obtaining LGCs can be determined either based on the resource costs associated with creating LGCs or the price at which LGCs are traded.

We use resource costs to estimate the cost of obtaining LGCs. Specifically, the cost of LGCs is estimated on the basis of the LRMC of meeting the LRET. The LRMC of meeting the LRET is calculated as an output from Frontier Economics' least-economic cost modelling of the power system, using *WHIRLYGIG*. The LRMC of meeting the LRET in any year is effectively the marginal cost of an incremental increase in the LRET target in that year, where the incremental increase in the LRET target can be met by incremental generation by eligible generators at any point in the modelling period (subject to the ability to bank and borrow under the scheme). Modelling the LRMC of the LRET in this way accounts for the interaction between the electricity market and the market for LGCs. This includes the impact that a change in the underlying wholesale costs, due to fuel prices movements or other factors, will have on the incremental cost of creating an LGC.

In modelling the LRMC of the LRET, *WHIRLYGIG* is set up on a national level to account for the fact that the scheme is national. This approach ensures consistency between the modelled outcomes in the NEM and the SWIS.

2.3.2 SRES

The SRES places a legal liability on wholesale purchasers of electricity to proportionately contribute towards the costs of creating small-scale technology certificates (STCs). The number of STCs to be purchased by liable entities each year is determined by the Small-scale Technology Percentage (STP), which is set each year by the CER. STCs are created by eligible small-scale installations based on the amount of renewable electricity produced or non-renewable electricity displaced by the installation.

Owners of STCs can sell STCs either through the open market (with a price determined by supply and demand) or through the STC Clearing House (with a fixed price of $40 per STC). The STC Clearing House works on a surplus/deficit system so that sellers of STCs will have their trade cleared (and receive their fixed price of $40 per STC) on a first-come first-served basis. The STC Clearing House effectively provides a cap to the STC price: as long as a seller of STCs can access the fixed price of $40, the seller would only rationally sell on the open market at a price below $40 to the extent that doing so would reduce the expected holding cost of the STC.

Approach to estimating costs of complying with the SRES

In order to calculate the cost of complying with the SRES, it is necessary to determine the Small-scale Technology Percentage (STP) for a representative retailer (which determines the number of STCs that must be purchased) and the cost of obtaining each STC.

Small-scale Technology Percentage

The STP establishes the rate of liability under the SRES and is used by liable entities to determine how many STCs they need to surrender to discharge their liability each year.

The STP is determined by the CER and is calculated as the percentage required to remove all STCs from the STC Market for the current year. The STP is calculated in advance based on:

- the estimated number of STCs that will be created for the year
- the estimated amount of electricity that will be acquired for the year
- the estimated number of all partial exemptions expected to be claimed for the year.

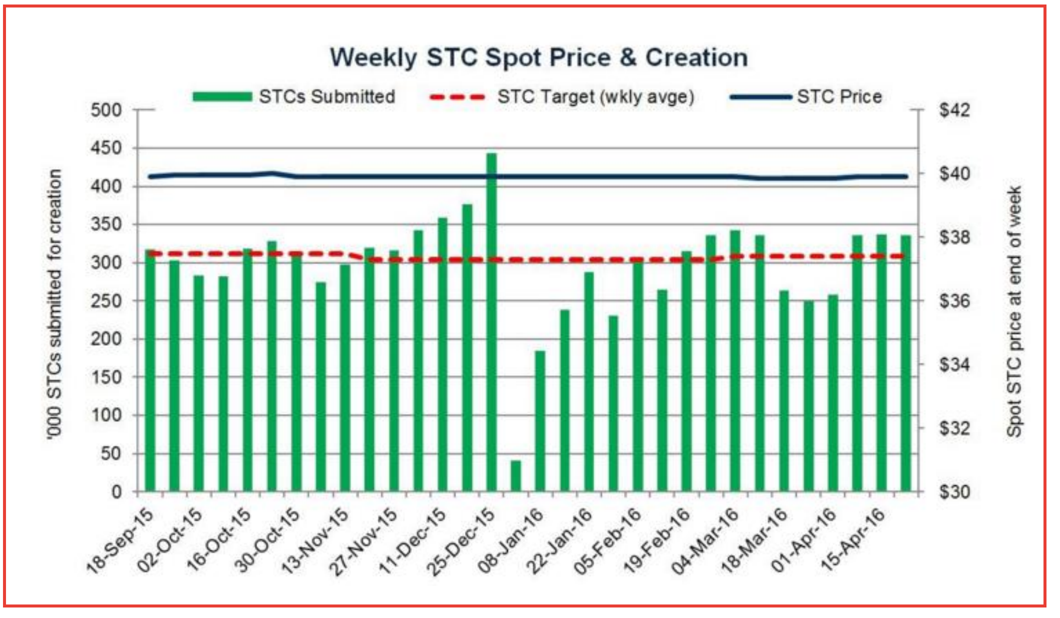
The STP is to be published for each compliance year by 31 March of that year. The CER must also publish a non-binding estimate of the STP for the two subsequent compliance years by 31 March.

Cost of STCs

The cost of STCs exchanged through the STC Clearing House is fixed at $40 (in nominal terms). While retailers may be able to purchase STCs on the open market at a discount to this $40, any discount would reflect the benefit to the seller of receiving payment for the STC at an earlier date. In effect, the retailer would achieve the discount by taking on this holding cost itself (that is, by acquiring the STC at an earlier date).

For these reasons, in estimating the cost to retailers of the SRES, we adopt the STC penalty price of $40/STC fixed in nominal terms. We also note that STC prices are currently trading at, or very close to, the clearing price as shown in Figure 2. Indeed, STC prices have essentially been at the penalty price of $40/STC since around the beginning of 2015.

Figure 2: Current STC market prices



Source: Green Energy Markets website. Viewed on 2 May 2016. Available at: http://greenmarkets.com.au/resources/stc-market-prices

2.4 NEM fees and ancillary services costs

In addition to advising on wholesale electricity costs, this assignment also requires us to estimate the costs associated with market fees and ancillary services costs.

2.4.1 Market fees

Market fees are charged to market participants in order to recover the cost of operating the market.

In the NEM, market fees are based on the operational expenditures of the Australian Energy Market Operator (AEMO). In the SWIS, market fees are based on the costs of AEMO,[7] as well as the costs of the wholesale market related functions of System Management and the Economic Regulation Authority.

Approach to estimating market operator fees

To estimate future market fees for NEM regions, we use AEMO's budgeted revenue requirements and the resulting market fees. For years in which budget forecasts are not available, we hold the final year estimate constant in real terms.

We adopt a similar approach in the SWIS, making use of budget revenue requirements and fees, and holding fees constant in real terms where forecasts are unavailable.

2.4.2 Ancillary services costs

Ancillary services are those services used by the market operator to manage the power system safely, securely and reliably. In the NEM, ancillary services can be grouped under the following categories:

- Frequency Control Ancillary Services (FCAS) are used to maintain the frequency of the electrical system.
- Network Control Ancillary Services (NCAS) are used to control the voltage of the electrical network and control the power flow on the electricity network.
- System Restart Ancillary Services (SRAS) are used when there has been a whole or partial system blackout and the electrical system needs to be restarted.

Similar ancillary services exist in the SWIS.

Approach to estimating ancillary services costs

To estimate the future cost of ancillary services we extrapolate based on the past 5 years of ancillary service cost data published by AEMO for each region of the NEM and the SWIS.

[7] As of 30 November 2015, the market operator functions undertaken by the IMO were transferred to AEMO.

2.5 Losses

We base loss estimates on information on transmission and distribution losses published by the market operator.[8]

[8] For the NEM, see:

http://www.aemo.com.au/Electricity/Market-Operations/Loss-Factors-and-Regional-Boundaries/List-of-Regional-Boundaries-and-Marginal-Loss-Factors-the-2016-17-Financial-Year

For the SWIS, see:

http://wa.aemo.com.au/home/electricity/market-information/loss-factors

3 Modelling assumptions

This section provides an overview of the input assumptions that we use in our electricity market modelling. We use a combination of public sources and, particularly for supply-side inputs, our own estimates.

This section is intended to provide an overview of our approach to developing the required input assumptions, and a high-level summary of the input assumptions that we have used.

The key input assumptions in terms of impact on modelling wholesale outcomes are:

- demand
- carbon and LRET assumptions
- fuel costs
- capital costs.

Each of these key assumptions are discussed below.

Our approach to generating our own estimates of key supply-side assumptions is discussed in more detail in Appendix A through Appendix E.

3.1 Demand

Our modelling approach requires demand data for both the system load in the NEM and the SWIS and for residential load shapes for the different distribution areas across the jurisdictions.

It is important that these system loads and residential loads are correctly correlated. This ensures that market-based electricity purchase cost estimates reflect the costs that retailers face as a result of the correlation between wholesale prices (which reflect the system load) and residential load. We ensure an appropriate correlation by using historical half-hourly data for both the system load and system prices and for the residential load shape.

3.1.1 System load

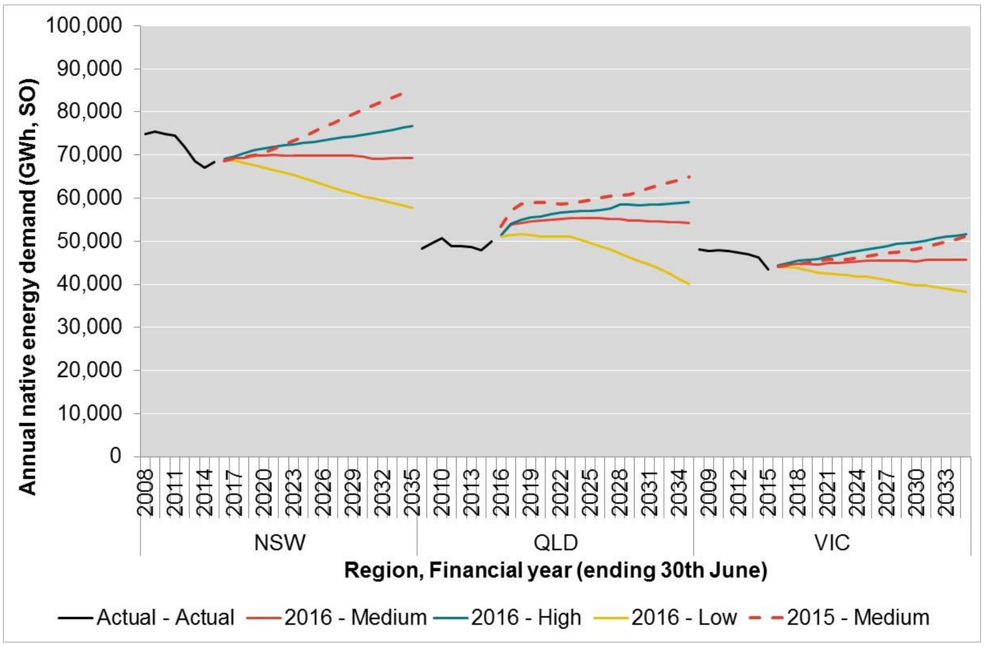
System load shapes are only required for the NEM, where we use a market-based approach. In the SWIS, where we use a stand-alone LRMC approach, we only need a residential load shape.

The system load shapes that we use for each NEM region are based on historical data from 2014/15. This half-hourly profile is scaled to forecast energy and peak demand is taken AEMO's 2016 National Electricity Forecast Report (AEMO 2016 NEFR).[9]

In the scenarios that we model we use each of the Medium, Low and High demand forecasts from the AEMO 2016 NEFR. Figure 3 and Figure 4 shows the annual energy forecasts from AEMO, as well as showing the Medium demand forecast from the AEMO 2015 NEFR for the purposes of comparison. Figure 3 shows the demand forecasts for New South Wales, Victoria and Queensland, and Figure 4 shows the demand forecasts for South Australia and Tasmania (on a different scale).

As can be seen, this year's Medium forecast predicts far less growth in demand than the 2015 Medium case; demand is expected to be lower in both the short and longer term in NSW, Victoria and Queensland. Indeed, in most regions, this year's Medium forecast has annual energy relatively flat over the forecast period in all jurisdictions. In the High case there is moderate demand growth forecast in all regions and in the Low case there are significant reductions in demand forecast in all regions.

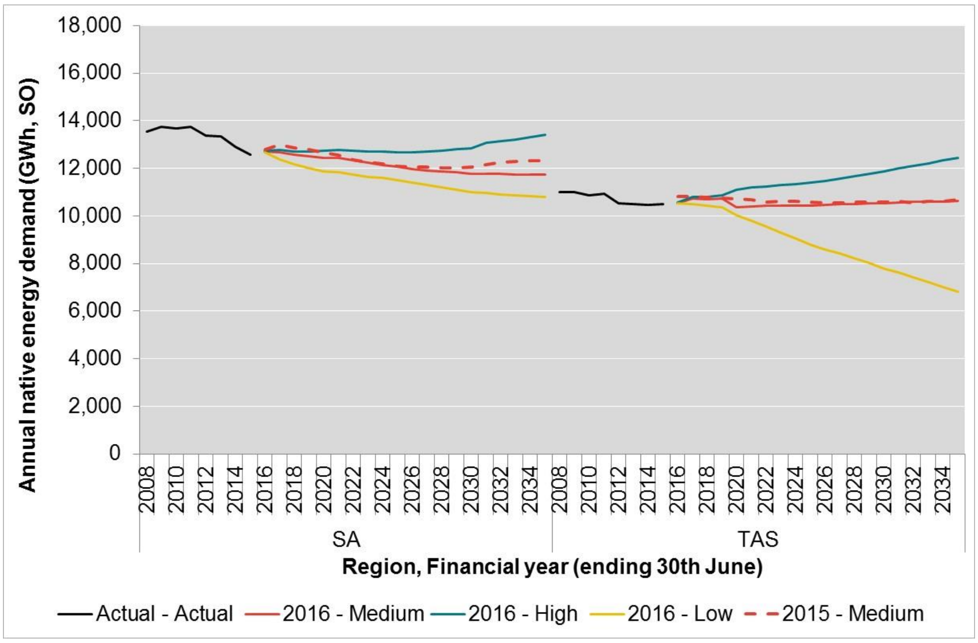
Figure 3: AEMO demand forecasts (NSW, Victoria and Queensland)



Source: AEMO 2016 NEFR and AEMO 2015 NEFR

9 AEMO, *National Electricity Forecasting Report*, For the National Electricity Market, June 2016. Available here: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report

Figure 4: AEMO demand forecasts (South Australia and Tasmania)



Source: AEMO 2016 NEFR and AEMO 2015 NEFR

3.1.2 Residential load shapes

For the NEM, the residential load is based on the half-hourly Net System Load Profile (NSLP), the half-hourly Controlled Load Profile (CLP) and the half-hourly Victorian Manually Read Interval Meter (MRIM) load. AEMO publishes these data sets for each distributor.

With one exception, we use data on residential load data for 2014/15, which is the most recent financial year available. The one exception is Queensland, for which we use data on residential load for 2013/14. The reason that we do not use residential load data for 2014/15 for Queensland is that financial year 2014/15 was characterised by a significant number of instances of high prices occurring at times of high residential demand. The resulting strong correlation between prices and residential load would result in a higher estimate of the market-based electricity purchase cost for the NSLP (and a lower estimate of the market-based electricity purchase cost for the CLP). Our analysis of historical data suggests that 2014/15 was an outlier in Queensland as far as the strength of this correlation is concerned, and our modelling and ASX Energy contract prices indicate that the pricing events that lead to this outcome are not expected to persist over the period to 2018/19. For this reason, we have used data on residential load for 2013/14 for Queensland, because 2013/14 represents a year that is more typical of what we have observed in Queensland.

For the SWIS, where residential load shape data is not publicly available, we use data on the residential load shape that has been provided to the AEMC by the Western Australian Government.

In areas where controlled load exists, it is modelled separately, as required by the AEMC.

For each distribution area, we have normalised the residential load so that the annual energy is 1GWh.[10]

The cost of serving a residential load shape will tend to be higher if the load is peakier (i.e. if its load factor is lower) or if the load and pool prices are positively correlated (such that prices and volumes tend to be high at the same time). However, the importance of load factor and correlation to pool prices varies depending on the approach to estimating the wholesale electricity cost:

- For the stand-alone LRMC approach, the load factor of the residential load shapes is a key driver of the final cost estimate. This is because peakier load shapes require a greater proportion of high LRMC peaking capacity compared to flatter load shapes. For the stand-alone LRMC, the correlation to pool prices is irrelevant as it is a cost-based approach.
- For the market-based approach, both the load factor and the correlation to pool prices drive the estimate of wholesale costs. There is a combined impact where residential consumers demand more electricity when pool prices are high (during the morning, evening peaks and across the day in summer), and less when prices are low (overnight). That is, the peaky, high demand times under the residential load shape are correlated to higher pool price events.

Table 1 shows the load factor between the normalised residential load and the relevant regional pool price for 2014/15 for New South Wales and the ACT, South Australia, Victoria and Tasmania, and

10 The electricity purchase cost and stand-alone LRMC, both expressed in $/MWh, are independent of the volume of energy modelled. The normalisation process ensures that the *shape* of the load remains unchanged.

Table 1: Load factor based on 2014/15 data

Region	Distributor	Profile	Load factor
NSW	ACTEWAGL	NSLP	0.38
	Ausgrid	CLP EA	0.18
		NSLP	0.36
	Endeavour	CLP IE	0.18
		NSLP	0.38
	Essential	CLP CE	0.19
		NSLP	0.51
SA	SA Power Networks	CLP	0.14
		NSLP	0.26
TAS	Aurora	NSLP	0.42
VIC	Citipower	MRIM	0.50
	Powercor	MRIM	0.47
	Jemena	MRIM	0.43
	AusNet	MRIM	0.40
	United	MRIM	0.40

Source: AEMO and Frontier Economics Analysis

Table 2: Load factor based on 2013/14 data

Region	Distributor	Profile	Load factor
QLD	Energex	CLP 31	0.10
		CLP 33	0.13
		NSLP	0.33

Source: AEMO and Frontier Economics Analysis

3.2 Carbon

All modelling cases assume zero carbon prices throughout the modelling period.

3.3 LRET

All modelling cases assume the current LRET target, reaching 33,000 GWh in 2020.

While the LRET target, in gigawatt-hours, remains the same in each scenario, the LRET target in percentage terms (measured as a percentage of total demand) will vary across the scenarios. The reason is that demand varies across the scenarios: with higher demand, the same target in gigawatt-hours equates to a lower percentage target. We have calculated the LRET target, in percentage terms, for each of the three demand scenarios we consider. We have calculated the LRET target both as a stand-alone policy and if we include the SRES and LRET together.[11] The results of our calculations are set out in Table 3.

Table 3: Implied Renewable Energy Target in 2020 (in percentage terms)

Scenario	Total national demand (GWh)	GWh of renewable energy	% of renewable energy dispatched (excl. SRES)	% of renewable energy dispatched (incl. SRES)
Low demand	201,187	33,000	23.36%	27.33%
Medium demand	212,062	33,000	22.16%	26.00%
High demand	218,497	33,000	21.51%	25.27%

Source: AEMO and Frontier Economics Analysis

3.4 Frontier Economics' supply side inputs

This section summarises our approach to developing the supply side input assumptions that we require for our modelling.

11 The implied target excluding SRES is calculated by dividing the sum of the target (33,000 GWh) and forecast dispatch of hydroelectricity (14,000 GWh) by total demand for Australia.

The implied target including SRES adopts the same approach but adds forecast generation from small-scale solar PV (11,000 GWh based on AEMO's latest forecasts) to both the numerator and the denominator.

3.4.1 Sources for modelling assumptions

There are public documents that provide estimates of key supply side input assumptions. In particular, various reports released by AEMO provide a detailed set of cost and technical data and input assumptions that can be used in electricity market modelling:

- AEMO publish information on the capacity of existing and committed generation plant in the NEM over the next two years.[12]
- AEMO publish the National Transmission Network Development Plan (NTNDP), and supporting documents, which include a range of technical and cost input assumptions.[13]
- AEMO publish information on marginal loss factors for generation plants.[14]

These various reports released by AEMO could be used in our electricity market modelling. However, there are a number of reasons why we consider the input assumptions that we have developed are preferable:

- It appears that the most recent input assumptions developed for the NTNDP are not, in all cases, based on the same macroeconomic forecasts. For instance, it appears that the fuel cost forecasts and the capital cost forecasts are based on different assumptions about forecast exchange rates (which are an important determinant of both fuel prices and capital costs).
- The NTNDP does not provide input assumptions for the SWIS. In order to ensure that we develop a set of input assumptions that are entirely consistent (in the sense that they are based on the same methodology and the same underlying assumptions) we have had to develop input assumptions for both the SWIS and the NEM.

Nevertheless, we continue to adopt some input assumptions from various reports released by AEMO. In particular, we adopt input assumptions from various reports released by AEMO where the input assumptions relate to market data collected or generated by AEMO as part of their function as market operator (such as capacities of existing generation plant), where the data is NEM-specific in nature (such as capacity factors for wind plant in various regions of the NEM) or where there is less uncertainty about the input assumptions (including when they relate to technical characteristics of existing generation plant or are not sensitive to changing market conditions).

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12 http://www.aemo.com.au/Electricity/Planning/Related-Information/Generation-Information

13 http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan

14 http://www.aemo.com.au/Electricity/Market-Operations/Loss-Factors-and-Regional-Boundaries

3.4.2 Fuel prices

Frontier Economics' fuel prices are based on modelling and analysis of the Australian gas and coal markets. We maintain a Base case that reflects current estimates of key inputs such as the number of LNG trains and long term export coal and LNG prices. Given the potential for internationalised prices in both coal and gas, we have also developed a high case to provide a set of inputs that can be used to investigate the impact of higher than expected input fuel costs. This high case reflects increased export fuel prices and more east coast LNG trains.

A detailed description of our approach to estimating fuel prices can be found in Appendix D and Appendix E

Gas prices

Gas prices are driven by demand for gas, international LNG prices, foreign exchange rates and underlying resource costs associated with gas extraction and transport.

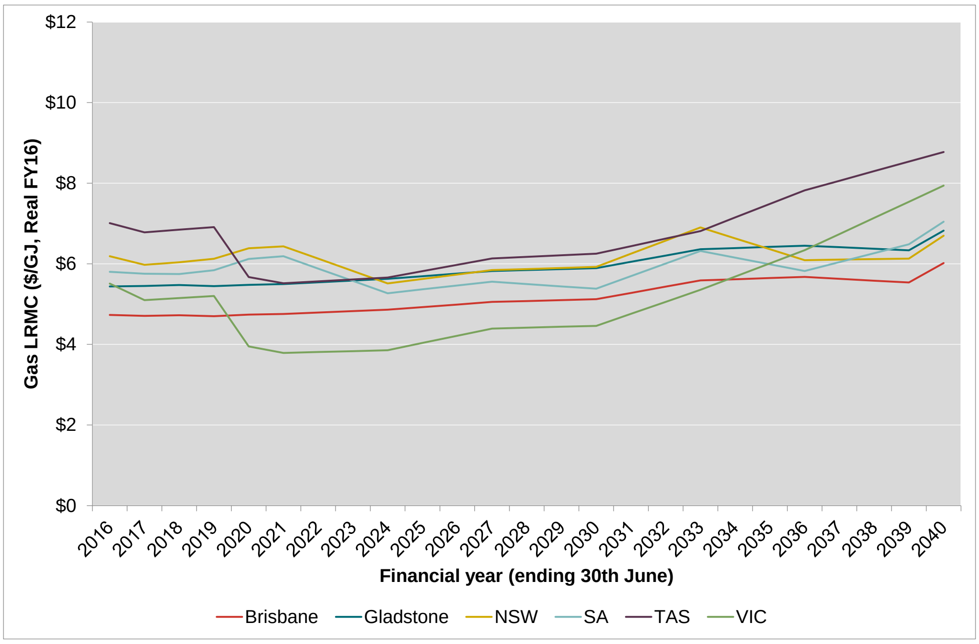
Our Base case and High case forecasts are shown in Figure 5 and Figure 6 for a selection of pricing zones across Australia. There are two key differences between the Base case and the High case:

- Demand: the Base case uses AEMO's medium demand forecasts and assumes that only the existing 6 LNG trains in Gladstone export. The High cases users AEMO's high demand forecasts and assumes that a seventh LNG train in Gladstone is also commissioned and exports gas.
- Cost of supply: the Base case uses our central estimates of gas production and transmission costs. The High case uses a high case estimate of gas production and transmission costs.

Both our Base case and High case forecasts are for relatively moderate gas prices, particularly when compared with some other public forecasts. Our forecasts are begin at prices that are relatively consistent with observed market prices over recent years. Our forecasts then exhibit a general trend towards higher gas prices (in real terms) over the modelling period, but these increases are moderate, particularly in the Base case. We consider that this is consistent with the demand and supply conditions that we incorporate in our modelling. In particular, AEMO are forecasting material reductions in domestic gas demand, which would be expected to reduce the marginal price of gas. Of course there is a significant increase in demand for gas for exporting as LNG, but our estimates suggest that there is sufficient gas available to meet both the domestic gas demand and demand for LNG exports. We also note that we are using much lower forecasts of the global LNG price (resulting in lower netback prices) than would have been the case 12 or 18 months ago.

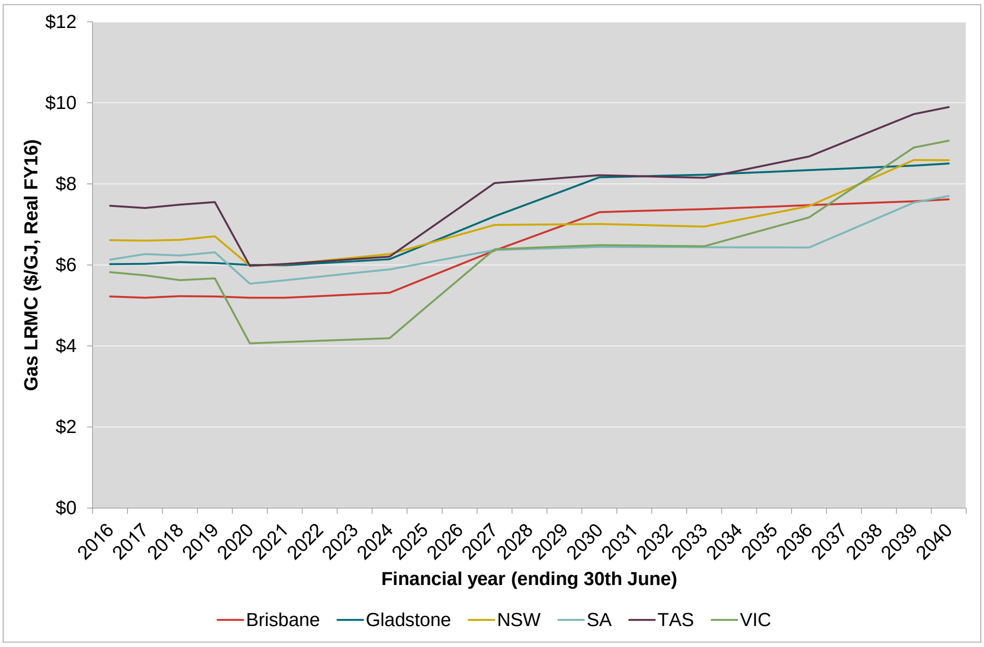
In short, our forecasts suggests that there are sufficient gas reserves and infrastructure in eastern Australia to meet demand without substantial increases in marginal costs of production. However, there are risks and uncertainties associated with this result. In particular, if demand for gas increases, or if there are unexpected problems developing new gas resources (for instance, if undeveloped coal seam gas resources in Queensland prove less economic than expected) gas prices could be higher.

Figure 5: LRMC of gas by for key demand centres ($2015/16) – Base case



Source: Frontier Economics

Figure 6: LRMC of gas by for key demand centres ($2015/16) –High case

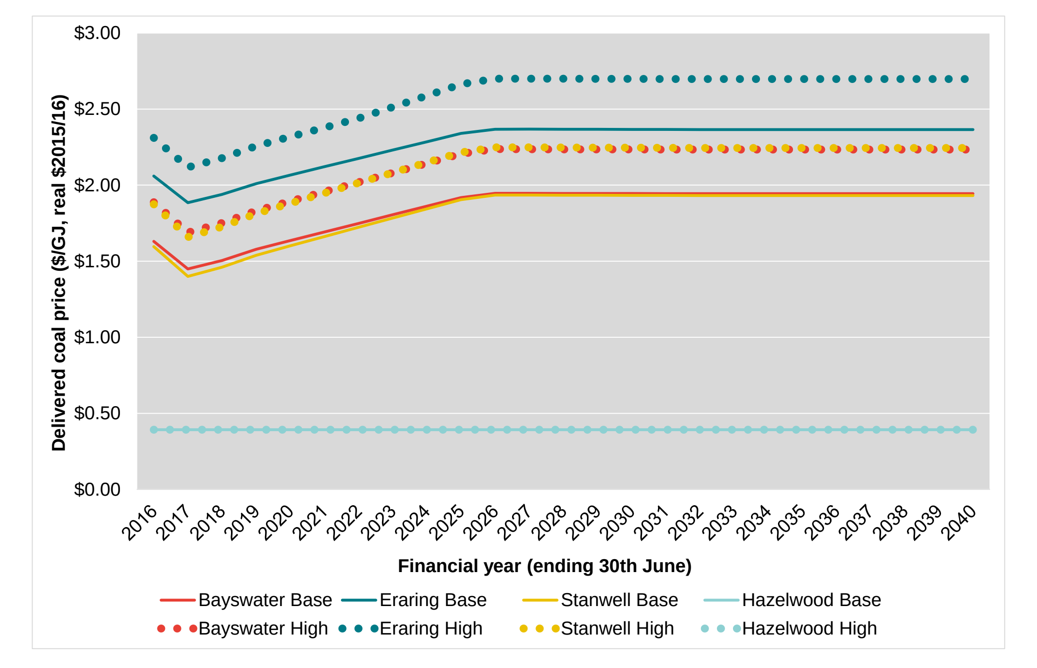


Source: Frontier Economics

Coal prices

Coal prices are driven by demand for coal, international export coal prices (for export exposed power stations), foreign exchange rates and underlying resource costs associated with coal mining. Our Base case (solid line) and high case (dashed line) forecasts are shown in Figure 7 for representative power stations (both export exposed and mine-mouth stations).

Figure 7: Coal prices for representative generators ($2015/16) – Base (solid) and High (dashed) cases



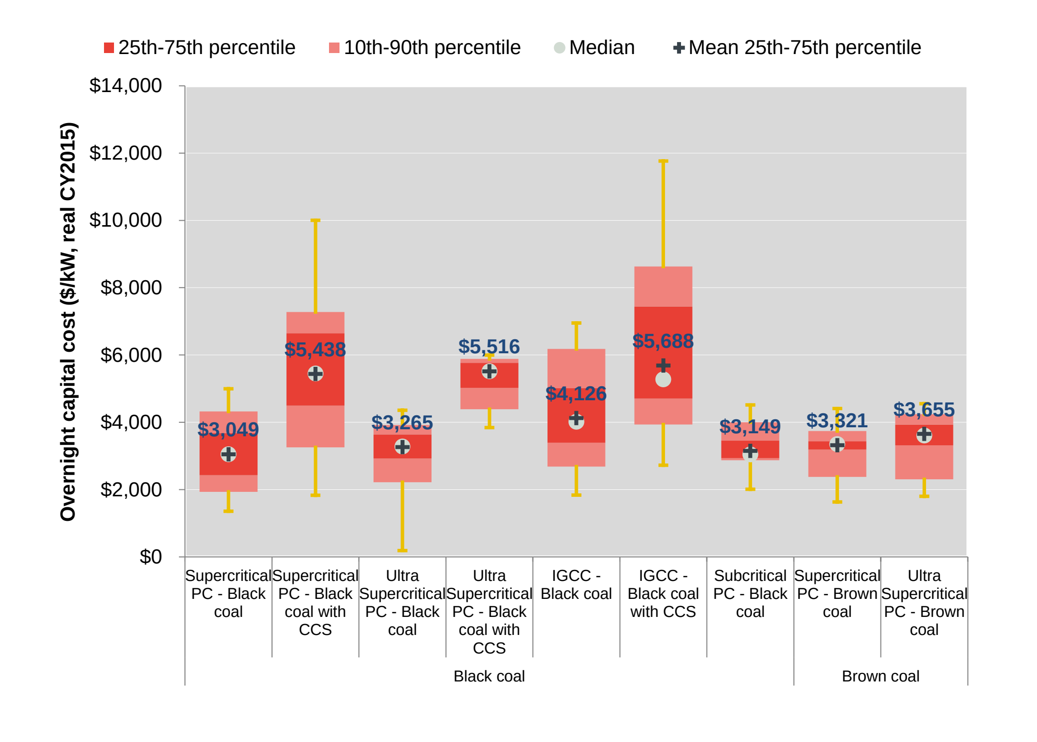
Source: Frontier Economics

3.4.3 Capital

Frontier Economics' capital cost estimates are based on a detailed database of actual project costs, international estimates and manufacturer list prices. A detailed description of our approach to estimating capital costs can be found in Appendix B.

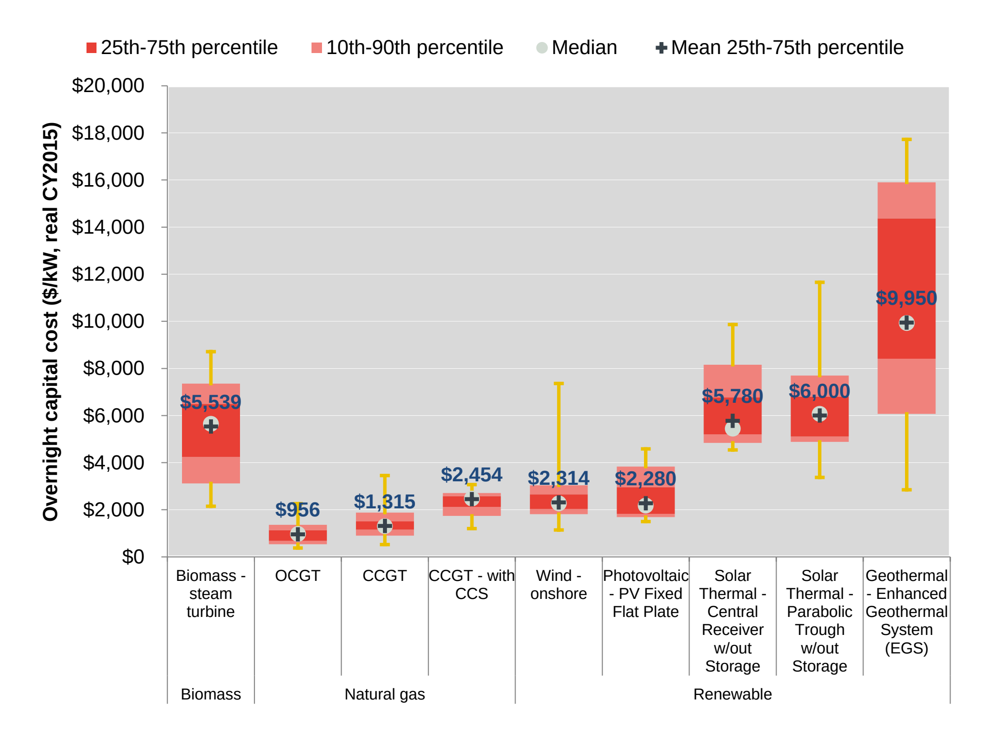
Our approach relies on estimates from a range of sources – actual domestic and international projects, global estimates (for example, from the Electricity Power Research Institute (EPRI)) and manufacturer list prices. These estimates are converted to current, Australian dollars. Our estimate is then taken as the mean over the middle two quartiles of the data (the 25^{th} to 75^{th} percentiles). The range of estimates and the final number used in the modelling are shown in Figure 8 and Figure 9, for thermal and renewable technologies, respectively. The movement of capital cost over time are driven by factors such as real cost escalation of domestic costs (essentially labour), exchange rates and technological improvement. More details on factors that change capital costs over the modelling period can be found in Appendix B.

Figure 8: Current capital costs for coal generation plant



Source: Frontier Economics

Figure 9: Current capital costs for gas and renewable generation plant



Source: Frontier Economics

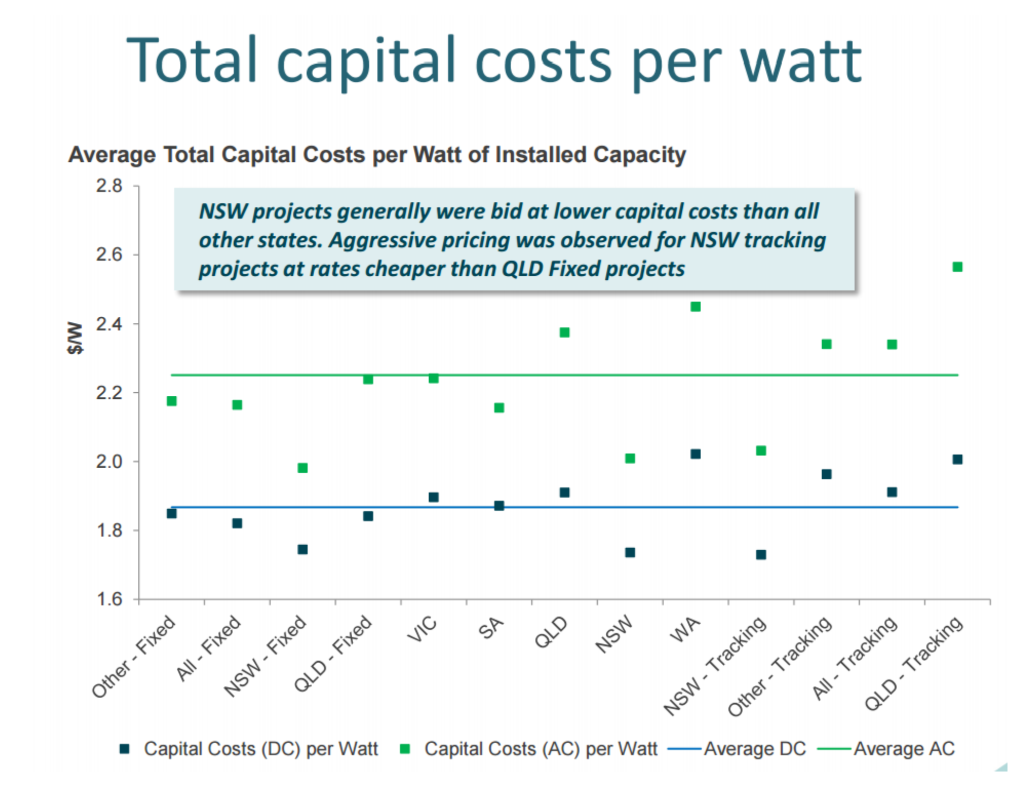
Large scale solar PV capital costs

Frontier Economics' current estimates for large scale solar PV follow the same approach as for all other technologies. Our approach relies on estimates from a range of sources – actual domestic and international projects, global estimates and manufacturer list prices.

Large scale solar PV as a technology is currently experiencing rapid cost reductions and, as such, is subject to significant cost uncertainty. Our estimate of solar PV capital costs have been decreasing in recent years due to a greater proportion of more recent estimates of commissioned solar farms in Australia and abroad. Our estimate for 2016 is $2,305/kW, compared to $2,400/kW in 2015. This estimate is consistent with the expressions of interest (EOI) submitted to ARENA's large-scale solar PV competitive round.[15] As seen in Figure 10, the average capital cost for fixed plate solar PV (in AC, which is closer to our basis) is relatively consistent with our assumption.

15 http://arena.gov.au/files/2016/03/ARENA-Large-scale-Solar-PV-Competitive-Round_EOI-Data-Output_March-2016.pdf

Figure 10: Actual capital costs EOIs from ARENA



Source: ARENA Large scale Solar PV Competitive Round EOI Data

AEMO's 2015 NTNDP applied the capital cost and capacity factor assumptions from Bloomberg New Energy Finance (BNEF)[16]. The BNEF's capital cost assumption of approximately $1,800/kW and their capacity factor assumption of between 15% and 22% is equivalent to those expressed as DC by ARENA. As can be deduced by Figure 10, a capital cost of $1,800/kW in DC is equivalent to approximately $2,200/kW in AC, which is relatively consistent with our assumption.

Our assumed capital cost of $2,305/kW and average capacity factor of 22% results in an LCOE for large scale solar PV of approximately $135/MWh in 2016, reducing to $95/MWh by 2040. The LCOE of wind is in the order of $90/MWh in 2016, and decreases over the modelling period, albeit at a slower rate than solar PV. As the investment in renewable technologies to meet the LRET will occur in the next ten years, and the LCOE of wind remains lower

16 http://www.aemo.com.au/Electricity/Planning/Related-Information/~/media/Files/Electricity/Planning/Reports/NTNDP/2015/2015_08_05%20BNEF%20%20Solar%20PV%20cost%20data.ashx

than that for solar PV in this period, we find it unlikely that further solar PV will be constructed to meet the LRET in our Base case forecast.

3.4.4 Plant retirements

In recent years, the NEM and the SWIS have experienced an unprecedented period of low or, in some cases, negative demand growth. These demand outcomes, as well as ongoing investment in renewable plant, have contributed to low wholesale prices and low profitability for a number of generators. In some cases, generation plant have been removed from the market temporarily (this is often referred to as mothballing or standby outages). In other cases, older generation plant have been retired permanently.

Our modelling incorporates the exit of all generation plant that has been retired in the NEM and the SWIS, consistent with the generation capacities reported by AEMO. We have undertaken our modelling since the announced retirement of Hazelwood power station in Victoria, and have accounted for this retirement in our modelling. Our modelling also incorporates the future exit of plant for which retirement has been announced, such as the retirement of AGL's Liddell power station and Bayswater power station at the end of their respective technical lives. Finally, our modelling will also forecast retirements on a least cost basis, using the same approach that we adopted in our modelling for the AEMC's price trends report in 2015.[17]

3.5 Scenarios considered in the modelling

The modelling considers a Base case and four other scenarios, as listed in Table 4.

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[17] Our consultant's report for the 2015 price trends report includes a detailed discussion of our approach to modelling generation retirement. Frontier Economics, *2015 Residential Electricity Price Trends Report*, A report prepared for the Australian Energy Market Commission (AEMC), November 2015. Available at:

http://www.aemc.gov.au/Markets-Reviews-Advice/2015-Residential-Electricity-Price-Trends#

Table 4: Summary of scenarios

	Scenario	LRET	Demand scenario	Fuel	Baseloader retirement
1	Base case	33,000 GWh by 2020	NEFR 2016 Medium	Mid-range forecast	Northern 2016/17, Hazelwood 2017/18
2	Low Demand	33,000 GWh by 2020	**NEFR 2016 Low**	Mid-range forecast	Northern 2016/17, Hazelwood 2017/18
3	High Demand	33,000 GWh by 2020	**NEFR 2016 High**	Mid-range forecast	Northern 2016/17, Hazelwood 2017/18
4	High Fuel	33,000 GWh by 2020	NEFR 2016 Medium	**High forecast**	Northern 2016/17, Hazelwood 2017/18
5	Hazelwood not retired	33,000 GWh by 2020	NEFR 2016 Medium	Mid-range forecast	**Northern 2016/17**

Source: Frontier Economics

4 Results – wholesale electricity costs

This section presents Frontier Economics' estimate of wholesale electricity costs under the two approaches discussed in Section 2.2: the market based approach and the stand-alone LRMC approach.

4.1 Market-based electricity purchase cost

This section presents the results of our modelling of the market-based electricity purchase cost in each of the NEM jurisdictions. Section 4.1.1 provides a summary of our results and discusses key trends. Section 4.1.2 presents more detailed results.

4.1.1 Summary results and key trends

A summary of the results of our Base case modelling of market-based electricity purchase costs, for each distribution area and load shape, is presented in Figure 11. Figure 11 shows the market-based electricity purchase costs for each distribution area that we consider, for load shape that we consider (that is, standard load and controlled load), and for each year to 2018/19. For the purposes of comparison Figure 11 also shows our forecast of the regional reference price (RRP) that is relevant for each distribution area (for instance, the NSW RRP is relevant for all the distribution areas in NSW).

As can be seen from Figure 11, the trends in the market-based electricity purchase costs are primarily driven by the trends in our pool price forecasts. Key drivers of these trends in our pool price forecasts in the Base case are:

Plant retirement

Retirement of existing generators, especially base load generators with large capacity and low operating costs, will have a significant impact on the pool prices. Northern is retired in our modelling at the beginning of 2016/17 and Hazelwood is retired at the beginning of 2017/18.[18] The withdrawal of 546 MW capacity of Northern and 1,600 MW capacity of Hazelwood, both cheap brown coal generators, has a large impact on the pool prices in the NEM. In 2016/17, South Australian pool prices increase significantly following the retirement of Northern. The retirement of Hazelwood causes the pool prices in Victoria, South Australia and Tasmania to further increase in 2017/18.

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18 In fact, Northern ceased its operation in late May 2016 and Hazelwood is announced to retire by the end of March 2017. We set up our models on a financial year basis and so have assumed these retirements happen at the beginning of a financial year.

Flat demand

AEMO's latest demand forecasts are for demand that is relatively flat over the period to 2018/19 in all jurisdictions (with the exception of Queensland which is forecast to see some modest demand growth). Flat demand, combined with ongoing renewable investment, puts downward pressure on spot prices.

New Investment

There is significant wind investment, and some solar investment, over the period to 2018/19, driven by the Renewable Energy Target. Investment in wind and solar generation in 2016/17 and 2017/18 is committed investment, which amounts to a bit over 1,000 MW of additional generation capacity across the NEM. In 2018/19 our modelling suggests that significant further investment in renewable generation will occur, with around 2,000 MW of additional wind investment across the NEM occurring in that year. The majority of this modelled renewable investment occurs in the southern states – Victoria, South Australia and Tasmania – which have better wind resources and a tighter supply and demand balance after the Hazelwood retirement. The additional generation capacity has the effect of lowering prices, especially in financial year 2018/19.

Flows on the interconnector

The pool prices across the NEM states tend to move closely together when the interconnectors connecting them have not reached their transfer limit. When the energy flow reaches the limit of the interconnector, however, the pool prices between the two regions can separate, with the price typically much higher in the importing region. The retirement of Hazelwood in 2017/18 makes Victoria an importer of energy from the northern regions most of the year. In our modelling, the amount of imports often reaches the limit of the VIC-NSW interconnector, leading to price separation between the northern and southern states. Our modelling results show that in 2017/18, the frequent binding of the VIC-NSW interconnector means that the high prices in the south states are less likely to flow to NSW and Queensland. For this reason, our modelling shows pool prices in the northern regions decreasing in financial year 2017/18.

As explained above, our modelling shows that there will be significant new investment in renewable generation in the southern states in 2018/19. As a result, Victoria will import less from NSW, which leads to the VIC-NSW interconnector binding less often in that year. This means that the prices in the southern and northern states will be more aligned and the higher prices in Victoria will be more likely to flow to NSW and Queensland. Consequently, the prices are predicted to increase in NSW and Queensland, and decrease in the southern states, compared to the level in the previous year.

Flat fuel prices.

All NEM regions experience relatively flat coal and gas prices over the period to 2018/19, which means that the short run marginal cost of generation for coal-fired and gas-fired generators does not change significantly.

The effect of these drivers is to cause the pool prices to exhibit opposite trends in the northern regions (NSW and Queensland) and southern regions (Victoria, South Australia and Tasmania) following the retirement of Hazelwood.

We would note that we would not expect that the trends that we observe over the period to 2018/19 would necessary persist into the 2020s. The key reason is that the different trends in the southern and northern regions are the results of the market responding to the sudden retirement of Hazelwood. When the market adjusts to its new long term equilibrium with new investment responding to the price signals, we would expect that the prices in all regions will return to similar trends. The impact of the Hazelwood retirement, however, will be a permanent increase in the *level* of the pool prices, relative to the state of the world where such retirement did not take place.

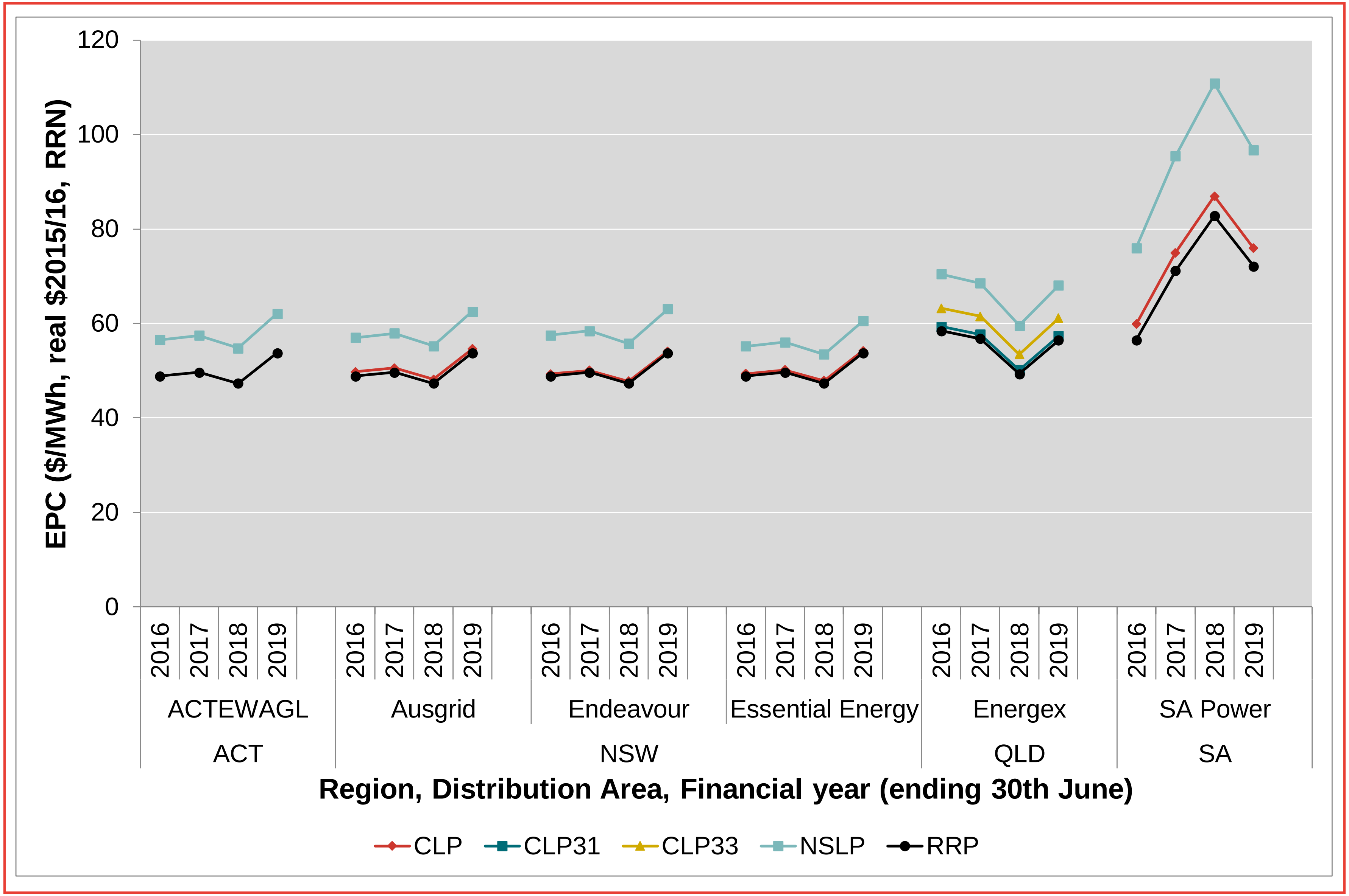
Furthermore, the significant investment in wind generation over the modelling period is a response to the Renewable Energy Target, but we would not expect this same rate of investment to persist in the 2020s (essentially because it is less costly to meet the target by investing earlier than by investing later). At the same time, AEMO's forecasts are for increasing demand over the 2020s (although these increases are much more moderate than AEMO have forecast in previous years). We would expect that these factors, as well as the expected retirement of Liddell, will combine to result in a trend towards some increase in wholesale electricity prices during the 2020s.

There are also other drivers that have affected spot prices in particular jurisdictions. Specifically, we can see the effect that the outage of the Basslink interconnector between Tasmania and the mainland has had on Tasmania's electricity spot prices in 2015/16. We can also see the forecast effect that the retirement of Northern Power Station in South Australia in 2016/17 is expected to have on electricity prices in South Australia from 2016/17.

The other key input into market-based electricity purchase costs – residential load shapes – affects the relative level of the electricity purchase cost between distribution areas and for different load shapes. However, since these residential load shapes are assumed to be constant over the forecast period (and between scenarios), the residential load shapes do not drive trends over time in the electricity purchase cost. The residential load shapes have the following effects on market-based electricity purchase costs:

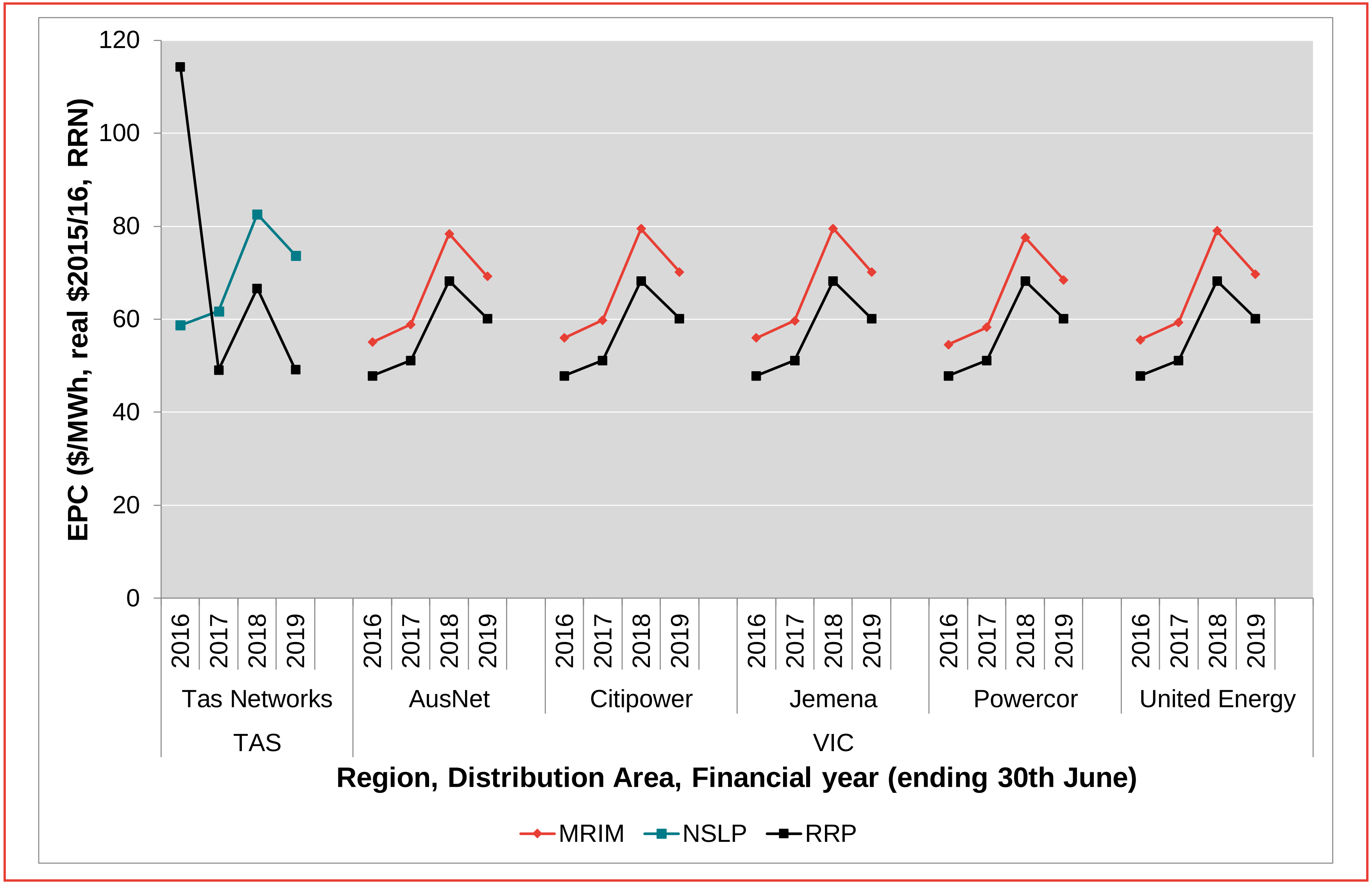
- **Differences between distribution areas**. The different market-based electricity purchase costs in different distribution areas within a single NEM region are driven by differences in the residential load shape in these distribution areas: the peakier the load shape in a distribution area, and the more closely correlated it is to high prices, the higher the electricity purchase costs. This is apparent in New South Wales, for instance, where the load shape of residential customers in the Essential Energy network area is cheaper to serve than the load shape of residential customers in other network areas.
- **Differences between standard and controlled loads**. The different market-based electricity purchase costs for different loads within a distribution area is also driven by differences in the shapes of these different loads, and the correlation of these loads with prices. In each distribution area, the controlled load has a cheaper electricity purchase cost than the standard load, reflecting the fact that controlled load occurs overnight when prices tend to be lower.

Figure 11: Market-based electricity purchase cost results for ACT, NSW, Queensland and South Australia – Base case



Source: Frontier Economics

Figure 12: Market-based electricity purchase cost results for Victoria and Tasmania – Base case



Source: Frontier Economics

Note: As discussed in Section 2.2.2, the market-based electricity purchase cost for Tasmania is based on forecast contract prices in Victoria, rather than Tasmania.

Table 5 summarises the key trends that drive outcomes for the market-based electricity purchase cost in the Base case and in each of the scenarios we have modelled. Table 6 summarises the key trends that drive outcomes for the market-based electricity purchase cost in each jurisdiction.

In the SWIS, the stand-alone LRMC approach leads to fairly stable wholesale electricity cost estimates over the modelling period under both of the modelled scenarios.

Table 5: High level trends in the market-based electricity purchase cost, by scenario

Scenario	Key trends in wholesale pool prices
Base case	General price trends driven by the retirement of brown coal generators in 2016/17 and 2017/18. The price trends differ between the southern regions (Victoria, Southern Australia and Tasmania) and northern regions (NSW and Queensland). Retirement of brown coal generators has the biggest upward pool price impact in the southern regions in 2016/17 and 2017/18. New investments in 2018/19 then lead to reduction in pool prices there. The prices in 2017/18 in the northern regions decrease slightly as the VIC-NSW interconnect binds frequently as the result of large amount of VIC imports. Constrained interconnectors lead to price separation in the NEM. When VIC imports less from NSW in 2018/19 as the results of new investment in the south regions, the interconnector binds less and the higher prices in the south flows into the northern regions more often.
High Demand	We model AEMO's High demand forecasts from 2016/17 in this scenario. This results in forecast electricity prices that are higher than the Base case forecasts in all regions in most years: higher demand means that it is more likely that the marginal, price-setting generator is higher cost, particularly in the short-term before investment can respond to higher prices. The general trend of a market-based electricity purchase cost that falls over time persists, as a result of ongoing investment. The retirement of Hazelwood and strong demand growth leads to new baseload CCGT investment in Victoria and South Australia, which causes the 2018/19 pool prices in these regions to fall below that of Base case level.
High Fuel	We model the same demand levels as the Base case, but higher fuel costs. This results in forecast electricity prices that are higher than the Base case forecasts in all regions in most years. The reason is that the high fuel case has higher prices for gas-fired generators across the NEM and for export-exposed coal-fired generators in New South Wales and Queensland. It is these plant that tend to be marginal plant in the NEM, so we see that prices across the NEM increase broadly in-line with the increase in fuel costs. Without further modelling, it is difficult to disaggregate the effect on prices of the increase in coal prices compared with the increase in gas prices, but it is clear that gas is more likely to be marginal in some regions, particularly South Australia, and coal is more likely to be marginal in other regions, including New South Wales. The pool price in South Australia in 2018/19 is slightly lower than the Base case (by less than $1MWh). This is due to the combined result of slightly more wind investment across the NEM and a small amount of CCGT investment in South Australia (due to the higher operating cost of peakers making baseload investment economical). However, the pattern of prices over the period to 2018/19 is the same as in the Base case.
Low Demand	We model AEMO's Low demand forecasts from 2016/17 in this scenario. This results in forecast electricity prices that are lower than the Base case forecasts in all regions. The general trends in the Low Demand scenario is similar to that in the Base case. The exception is that in NSW the 2018/19 price is lower than the previous year due to depressed level of demand.

Scenario	Key trends in wholesale pool prices
Hazelwood not Retired	This scenario has the same setting as the Base case, except Hazelwood is not retired. It has the same price trend as the Base case in 2016/17 (large increase in Victoria and SA due to Northern retirement, but stable prices in NSW and Queensland). Prices then decrease in 2017/18 and 2018/19 due to the flat demand forecast and new renewable investment to meet the LRET.

Table 6: Summary of jurisdictional price trends

Jurisdiction	Key drivers
New South Wales	Base case electricity purchase cost trends The trends in the electricity purchase cost in the base case reflect the trends in the spot price forecasts for the base case. The trends in the spot price forecasts for NSW in the base case are the following: • Very slight price increase from 2015/16 to 2016/17 – this is a result of the closure of Northern power station in South Australia and, to a lesser extent, an increase in demand in Queensland, with only a small amount of committed wind and solar investment across the NEM in 2016/17. • Price falls in 2017/18 and rises in 2018/19 – In 2017/18 this is due to the large amount of import to Victoria binding the interconnector and leading to price separation in the NEM. In 2018/19 the interconnector binds less as Victoria has more new investment, which causes high southern prices to flow into NSW Trends in other cases The trends in the electricity purchase cost in the other cases reflect the trends in the spot price in the relevant case. The base case trends discussed above also apply in these cases, with the exception that the 2018/19 pool prices decrease in the Low Demand scenario and the prices fall from 2017/18 if Hazelwood is not retired. In addition, however, the following is relevant: • Higher demand results in higher prices. • Lower demand results in lower prices. • Higher fuel prices result in higher prices. • Not retiring Hazelwood result in lower prices.

<table>
<tr><th>Jurisdiction</th><th>Key drivers</th></tr>
<tr><td>Queensland</td><td>
<u>Base case electricity purchase cost trends</u>

The trends in the electricity purchase cost in the base case reflect the trends in the spot price forecasts for the base case. The trends in the spot price forecasts for QLD in the base case are the following:
• Stable between 2015/16 to 2016/17 – the retirement of Northern has little impact on Queensland pool prices due to the distances between SA and Queensland.
• Price trend from 2016/17 to 2018/19 – the price trend is similar to that of NSW, the return of Swanbank in 2017/18 causes a larger decrease in pool prices.

<u>Trends in other cases</u>

The trends in the electricity purchase cost in the other cases reflect the trends in the spot price in the relevant case. The base case trends discussed above also apply in these cases. The only exception is that if Hazelwood is not retired, the prices decrease from 2017/18. In addition, however, the following is relevant:
• Higher demand results in higher prices.
• Lower demand results in lower prices.
• Higher fuel prices result in higher prices.
• Not retiring Hazelwood result in lower prices.
</td></tr>
<tr><td>South Australia</td><td>
<u>Base case electricity purchase cost trends</u>

The trends in the electricity purchase cost in the base case reflect the trends in the spot price forecasts for the base case. The trends in the spot price forecasts for SA in the base case are the following:
• Material price increase from 2015/16 to 2017/18– this is a result of the closure of Northern power station in South Australia in 2016/17 and retirement of Hazelwood in 2017/18.
• Falling prices in 2018/19 – due to the large amount of new investment in the southern regions.

<u>Trends in other cases</u>

The trends in the electricity purchase cost in the other cases reflect the trends in the spot price in the relevant case. The base case trends discussed above also apply in these cases. The only exception is that if Hazelwood is not retired, the prices decrease from 2017/18. In addition, however, the following is relevant:
• Higher demand results in higher prices, with the exception of 2018/19, where the larger amount of investment in wind and CCGT baseload generation in the southern regions causes the price to fall below that in the Base case.
• Lower demand results in lower prices.
• Higher fuel prices result in higher prices, with the exception if 2018/19, when a larger amount of investment in wind and CCGT baseload generation in South Australia causes the price to fall below that in the Base case.
• Not retiring Hazelwood result in lower prices.
</td></tr>
</table>

<table>
<tr><th>Jurisdiction</th><th>Key drivers</th></tr>
<tr><td>Tasmania</td><td><u>Base case electricity purchase cost trends</u>

The trends in the electricity purchase cost in TAS reflect the trends in the spot price forecasts for VIC. This is because the electricity purchase cost in Tasmania is based on forecast contract prices in Victoria. See below for an explanation of the trends in the spot price forecasts for VIC.</td></tr>
<tr><td>Victoria</td><td><u>Base case electricity purchase cost trends</u>

The trends in the electricity purchase cost in the Base case reflect the trends in the spot price forecasts for the Base case. The trends in the spot price forecasts for Victoria in the Base case are the following:

• Material price increase from 2015/16 to 2017/18– this is a result of the closure of Northern power station in South Australia in 2016/17 and retirement of Hazelwood in 2017/19.

• Falling prices from 2018/19 – due to the large amount of new investment in the southern regions.

<u>Trends in other cases</u>

The trends in the electricity purchase cost in the other cases reflect the trends in the spot price in the relevant case. The base case trends discussed above also apply in these cases. The only exception is that if Hazelwood is not retired, the prices decrease from 2017/18. In addition, however, the following is relevant:

• Higher demand results in higher prices, with the exception of 2018/19, where larger amount of investment in wind and CCGT baseload generation in the southern regions causes the price to fall below that in the Base case.

• Lower demand results in lower prices.

• Higher fuel prices result in higher prices.

• Not retiring Hazelwood result in lower prices.</td></tr>
</table>

4.1.2 Detailed results

This section presents the detailed results for the market-based electricity purchase cost for the Base case and each of the three scenarios. We present key modelling results including investment and retirement, dispatch, pool prices and market-based electricity purchase costs.

New investment

Figure 13 presents the total investment across the NEM for all scenarios modelled. Investment results by each region are shown in Figure 14 (Base case and Low Demand), Figure 15 (High Demand and High Fuel) and Figure 16 (Hazelwood not retired). Everything else held constant, new investment will tend to reduce pool prices.

In 2016/17 and 2017/18 our modelling includes investment in committed new wind generation and solar generation. This committed investment does not vary between the Base case and the three scenarios. New uncommitted investment in our modelling is assumed not to be an option until 2018/19 (on the basis that there would be a two-year lead time for uncommitted investment in wind generation). In 2018/19 our modelling suggests that there will be significant investment in wind generation in the Base case and each of the four scenarios.

New wind investment results for the Base case, High Fuel and Hazelwood not Retired case are very similar: in each case our modelling results in around 2,000 MW of new investment in wind generation across the NEM in 2018/19, mostly in Victoria, Tasmania and South Australia. The High Fuel case has a slightly higher overall level of investment. This is driven by the fact that the southern regions have better wind sites and tighter demand and supply balance after the retirement of Hazelwood.

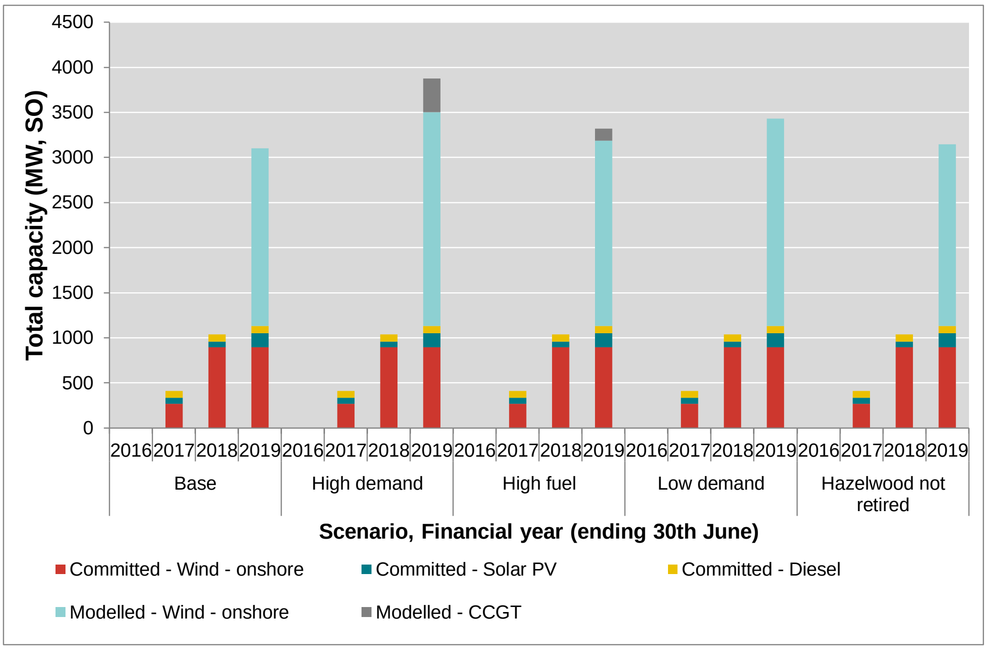
In both the High Demand and Low Demand scenarios, there is more investment in wind (by approximately 300 MW to 400 MW across the NEM) than the Base case. The reason for more investment in the High Demand case is quite straightforward: although wind farms are built to meet the LRET in all scenarios, strong demand growth in the High Demand scenario makes it more attractive to build them earlier. The results for the Low Demand case appears slightly counter-intuitive, as one would expect there be more less wind investment relative to the Base case. Indeed, this is the outcome we see over the medium term, with significantly less investment in wind generation in the Low Demand scenario than the Base case during the 2020s. The different outcomes we see in 2018/19 are really about the timing of investment in wind generation. In the Low Demand case we see retirement of coal-fired plant in Queensland in 2018/19 (see below), which provides the opportunity for more and earlier investment in wind generation in the northern regions. In fact, it can be seen in Figure 14 that relative to the Base case, there is more wind investment in the Low Demand scenario in NSW and Queensland, but less in the southern states.

In the Base case, Low Demand, and Hazelwood not Retired scenario, there is no modelled new thermal investment in 2018/19. While the retirement of Hazelwood has tightened the supply and demand balance, the suppressed level of demand in both scenarios means that new thermal investment is not needed before the 2020s. In fact, in the Base case, new gas generation is only built after the retirement of Liddell (in 2021/22), whereas there is no new thermal generation even at the end of our investment modelling.

In both the High Demand and High Fuel scenarios, however, there is some new CCGT investment in 2018/19. In the High Demand scenario, new CCGT investment occurs in Victoria and South Australia. The combined effect of the Hazelwood retirement and strong demand growth means that new baseload capacity is needed. The High Fuel scenario has the same demand inputs as the

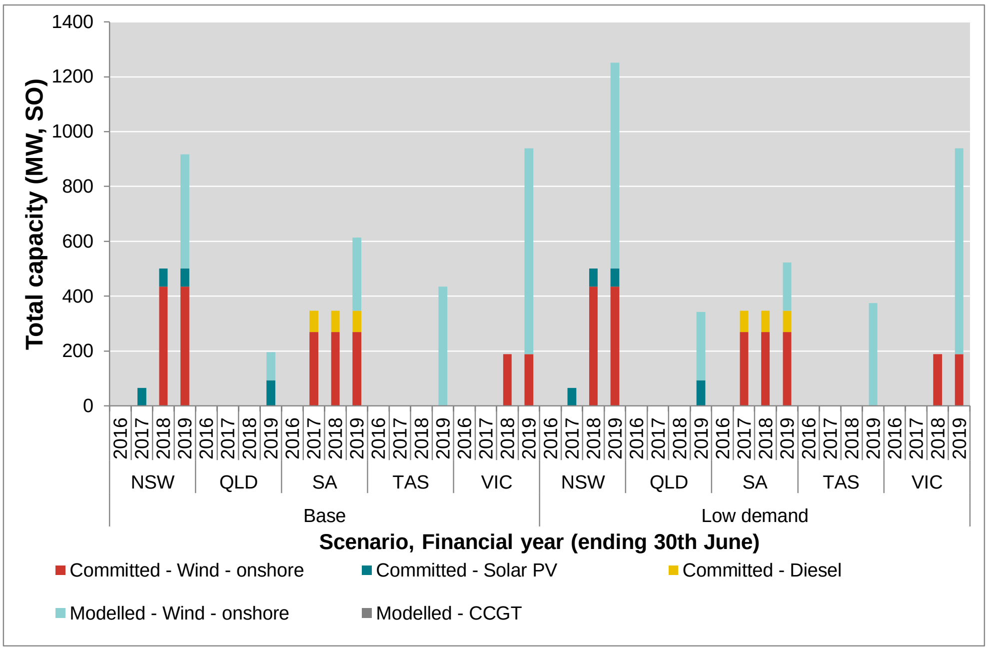
Base case. However, the model predicts that there will be some new CCGT investment in South Australia. This is because with the retirement of Hazelwood, there is less cheap energy for South Australia to import through the interconnectors. This means that South Australia has to run its existing fleet of peaking generators harder, as Northern has already retired in financial year 2016/17. When gas prices are higher, it becomes cheaper to build some new baseload capacity with lower operating costs (i.e., CCGT).

Figure 13: Cumulative new investment by scenario – NEM total



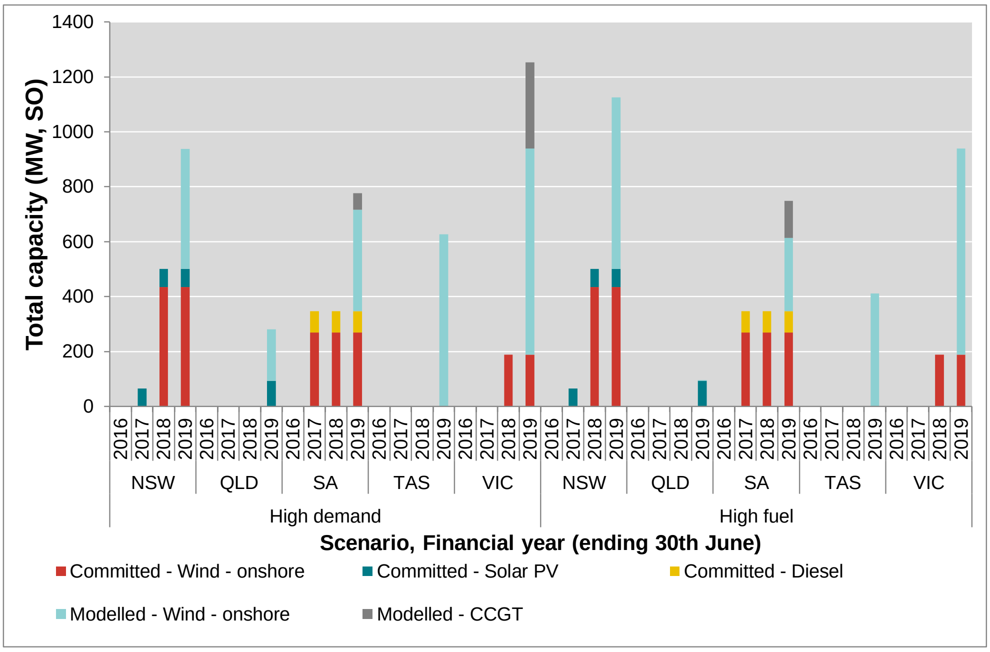
Source: Frontier Economics

Figure 14: Cumulative new investment by regions – Base case and Low Demand



Source: Frontier Economics

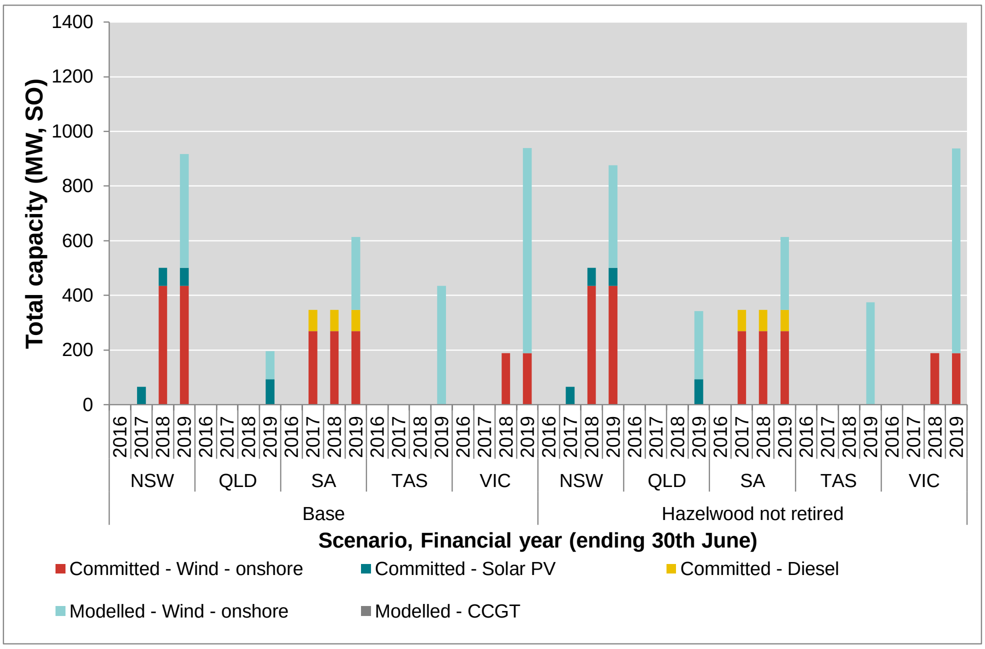
Figure 15: Cumulative new investment by regions – High Demand and High Fuel



Source: Frontier Economics

Results – wholesale electricity costs

Figure 16: Cumulative new investment by regions – Base case and Hazelwood not retired



Source: Frontier Economics

Plant retirements

In the Base case and each of the four scenarios our modelling accounts for announced generation retirement. This information is presented in Figure 17, and is based on AEMO's latest generation information data.[19] The exceptions are that we have assumed that Torrens Island A in South Australia will remain in service, consistent with AGL's recent announcement that it had decided to defer the mothballing of that plant,[20] and we have accounted for the retirement of Hazelwood power station (except for the Hazelwood not Retired scenario), which has been recently announced.

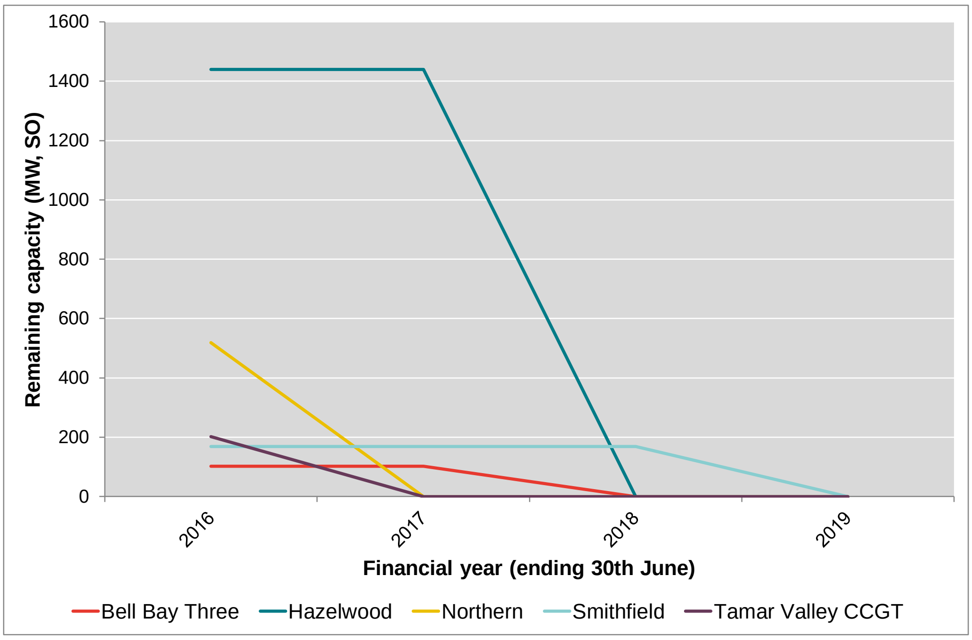
The retirements that affect our modelling over the period to 2018/19 are the retirement of Northern Power Station in South Australia and the Tamar Valley CCGT in Tasmania in 2016/17, the retirement of Hazelwood in Victoria (except

19 AEMO's generation information data does not extend out as far as the retirement date for Bayswater power station, but AGL has announced that it will not extend the operating lives of either Liddell or Bayswater.

20 AGL Press Release, "AGL to defer mothballing of South Australian generating units", 6 June 2016. Available at: https://www.agl.com.au/about-agl/media-centre/article-list/2016/june/agl-to-defer-mothballing-of-south-australian-generating-units

for the Hazelwood not Retired scenario) and Bell Bay Three in Tasmania in 2017/18, and the retirement of Smithfield in NSW in 2018/19.

Figure 17: Assumed retirements in all scenarios (announced)



Source: Frontier Economics

- Hazelwood is not retired in the "Hazelwood not Retired" scenario.

Our modelling also forecasts retirement of existing generation plant where demand and supply conditions mean that it is least cost for particular plant to close. It is only the Low Demand case in which our modelling suggests that additional plant retirements will occur during the period to 2018/19. In the Low Demand case, our modelling suggests that one unit of Tarong Power Station will retire in 2018/19.

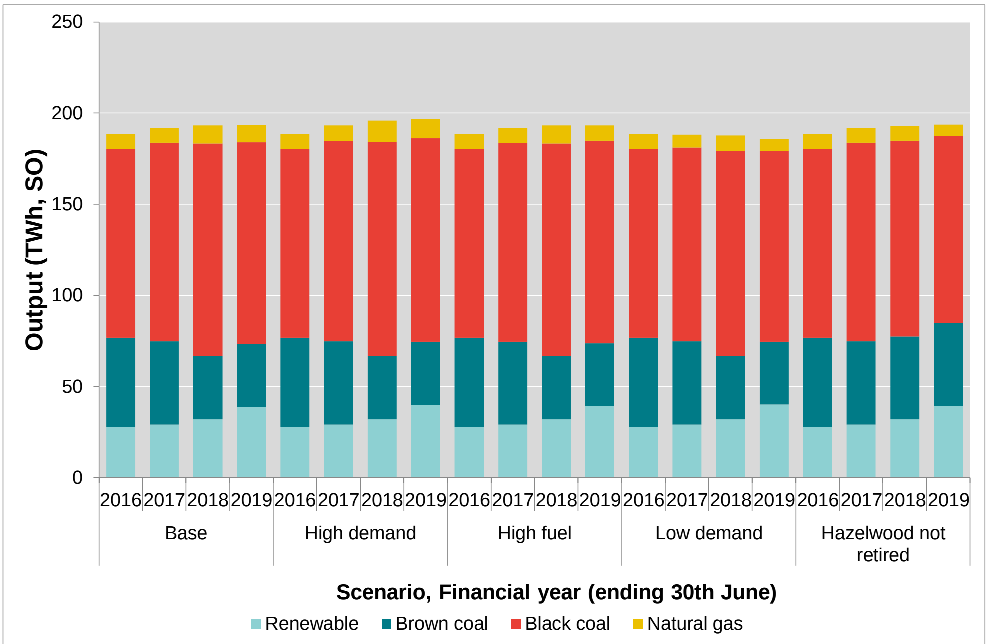
The retirement forecasts have regard to the forecasts of power station fixed and variable operating costs that are included in our modelling. For each of the existing generation plant in the NEM, the data that we use on fixed and variable operating costs are the estimates published by AEMO for the NTNDP. These fixed and variable operating costs published by AEMO are plant specific; in particular, different coal-fired generation plant have different estimates of fixed operating costs. However, the fixed and variable operating costs are static over time; that is, they do not vary from year to year to reflect maintenance cycles. Nevertheless, given that our modelling bases retirement decisions on operating costs over the long term, using static averages rather than annual values that reflect maintenance cycles is unlikely to result in material differences.

Dispatch

Power station dispatch in aggregate for the NEM for the Base case and each of the four scenarios is shown in Figure 18 (dispatch results for each region are shown in Appendix F). NEM dispatch results are shown for each year to 2018/19, with the results shown by fuel type.

In all cases (except for Hazelwood not Retired) and in all regions the retirement of Northern and Hazelwood in 2016/17 and 2017/18 lead to the reduction of brown coal generation over the two years. The reduced output by brown coal is primarily offset by increased gas output in South Australia and Victoria and black coal output from NSW and Queensland. In all scenarios, there is increasing output from renewable generators due to new investment during the modelling period. Extra renewable output displaces black coal and gas generators and the effect is more pronounced in the Base case, High Fuel, Low Demand and Hazelwood not Retired scenarios where demand is either flat or decreasing. Tasmania had significant amount of gas generation in 2015/16 due to the outage of Basslink in the second half of the financial year. The return of the Basslink from 2016/17 means that Tasmania can again rely mostly on renewable output and import from the mainland.

Figure 18: Annual dispatch in all scenarios

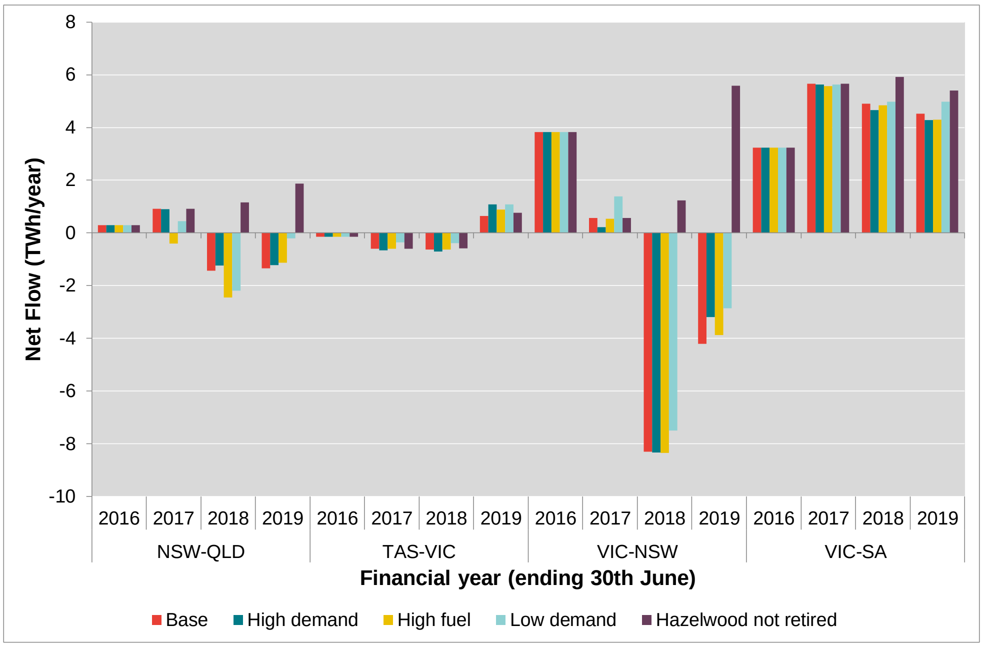


Source: Frontier Economics

Interconnector flows between the NEM regions

Figure 19 shows the net annual interconnector flows between the NEM regions for all scenarios. The flow patterns are similar across the scenarios with Hazelwood retirement, and are heavily influenced by the retirement of Northern and Hazelwood. In 2016/17, the retirement of Northern significantly increases the flow between Victoria and South Australia, which has caused more instances where the interconnectors are constrained, leading to price separation between South Australia and the rest of the NEM. The retirement of Hazelwood in 2017/18 results in less available cheap brown coal generation in Victoria. Therefore, there is less export from Victoria to South Australia and significantly more import from NSW into the southern states in 2017/18, as Hazelwood generation is replaced by NSW black coal generation. The increased southern flow on the VIC-NSW interconnector leads to more instances where it is constrained, which means that there is more likely to be price separation between the northern and southern regions. In 2018/19, more renewable investment in the southern region causes a reduction in Victorian import from the northern states. As a result, the VIC-NSW interconnector binds less and the differences in pool prices between the southern and northern regions are likely to be smaller in 2018/19.

Figure 19: Net interconnector annual flows between the NEM regions



source: Frontier Economics

Pool prices

Forecast pool prices for the Base case and each of the four scenarios are shown in Figure 20. Figure 20 shows the modelled pool prices on a time-weighted, annual average basis. For the purposes of comparison, Figure 20 also shows historic pool prices and ASX Energy flat swap prices. All prices are at the regional reference node, in real 2015/16 dollars, and the ASX Energy flat swap prices have been adjusted to real financial year 2015/16 dollars and to remove an assumed contract premium of 5 per cent.

In all cases and all regions, our modelled pool price for 2015/16 is quite close to the actual pool price for 2015/16. These 2015/16 pool prices already represent a notable increase in the pool prices for 2014/15. This is obviously the case for Tasmania, where pool prices in 2015/16 were affected by the outage of Basslink for much of the second half of the financial year. South Australia also saw significant increases in spot prices from 2014/15 to 2015/16, which was the result of plant retirements and an increasing reliance on wind generation.

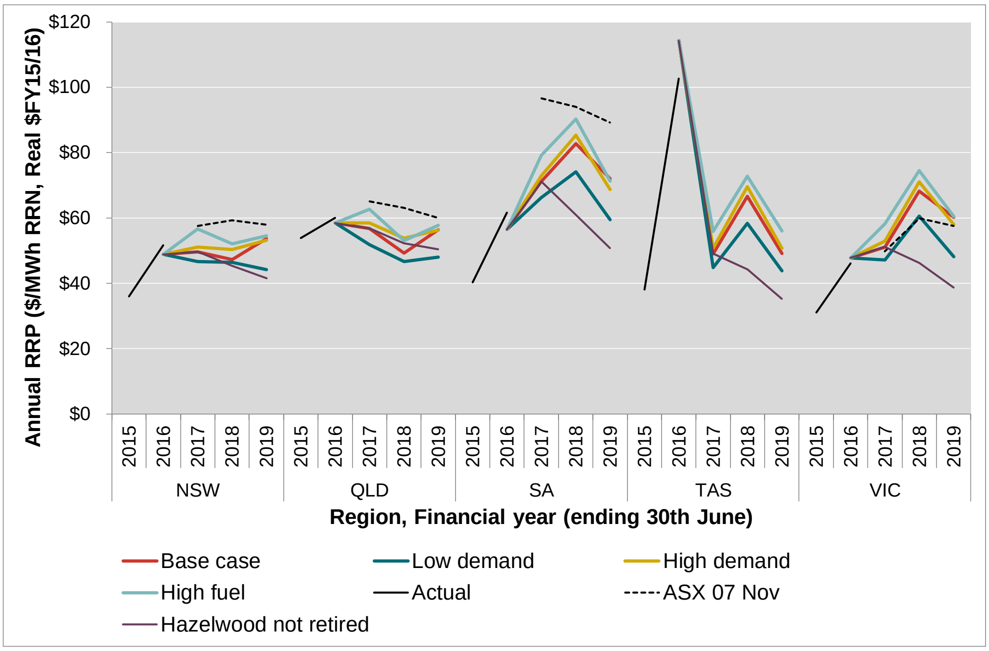
Northern retirement has a significant impact on SA pool prices in 2016/17, leading to a large increase relative to its 2015/16 level in all scenarios. The impact becomes smaller in other regions as one moves further away from South Australia. In the Low Demand scenario, there is actually reduction in pool prices in all regions except South Australia. Tasmania has a significant reduction in its pool prices due to the return of Basslink.

In the four scenarios where Hazelwood is retired, the pool price trends differ between the southern regions (Victoria, South Australia and Tasmania) and the northern regions (NSW and Queensland) from 2017/18. In the southern regions, the retirement of Hazelwood leads to a large increase in pool prices in all scenarios in 2017/18. Pool prices then fall in 2018/19 when new modelled investment adds more supply in these regions. In the High Demand scenario, there is significantly more new investment, particularly in new baseload CCGT units in 2018/19, so that the levels of the pool prices in Victoria and South Australia are slightly lower than in the Base case.

In the scenarios where Hazelwood is retired, in NSW and Queensland, our modelling shows that pool prices might fall slightly in 2017/18, but increase in 2018/19 (except for the Low Demand scenario where the price keeps falling in NSW). As discussed in the previous section, the main driver for this pattern in the northern states is flow on the VIC-NSW interconnector. In 2017/18, large amounts of Victorian imports lead to frequent binding of the interconnector and the higher southern prices due to Hazelwood closure in Victoria does not flow into the northern regions. The new investment in 2018/19, particularly in the southern states, means that they are less reliant on import on the VIC-NSW interconnector. The less frequent binding of the interconnector means that the prices across the NEM states are more aligned in 2018/19. In other words, the prices increase in the northern states and falls in the southern regions relative to their previous year levels.

In the scenario where Hazelwood is not retired, all regions have similar downward price trends from financial year 2017/18 onwards. This is caused by the flat demand forecast and the new renewable investments to meet the LRET.

Figure 20: Pool price forecasts and ASX futures prices – All scenarios ($/MWh annual average prices, real $2015/16)



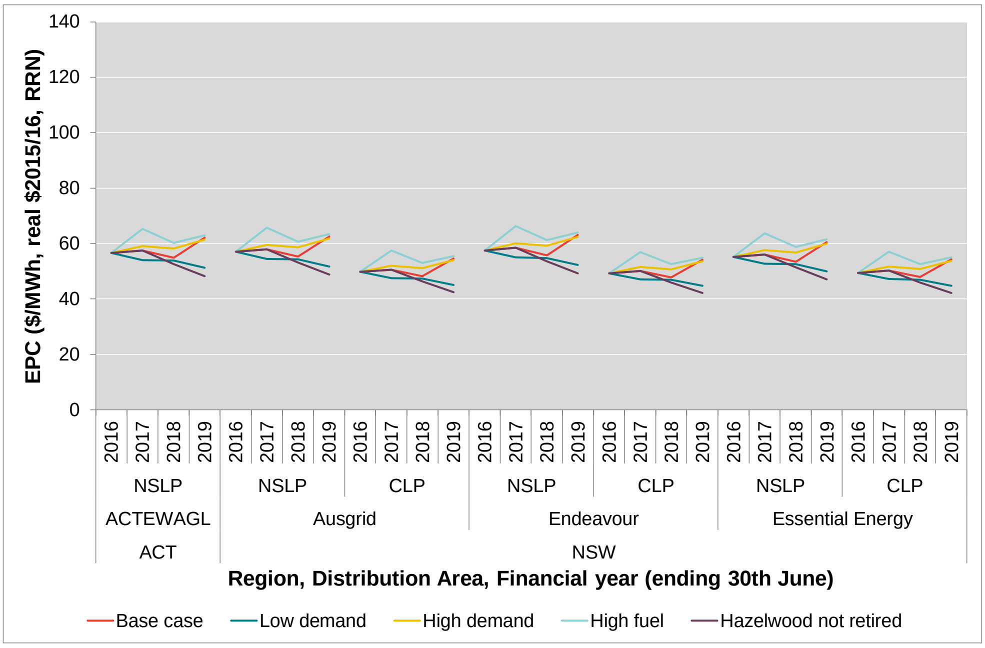
Source: Frontier Economics

Electricity Purchase Cost

The market-based electricity purchase costs for the Base case and each of the three scenarios are shown in Figure 21 to Figure 24. The results are shown in real 2015/16 dollars.

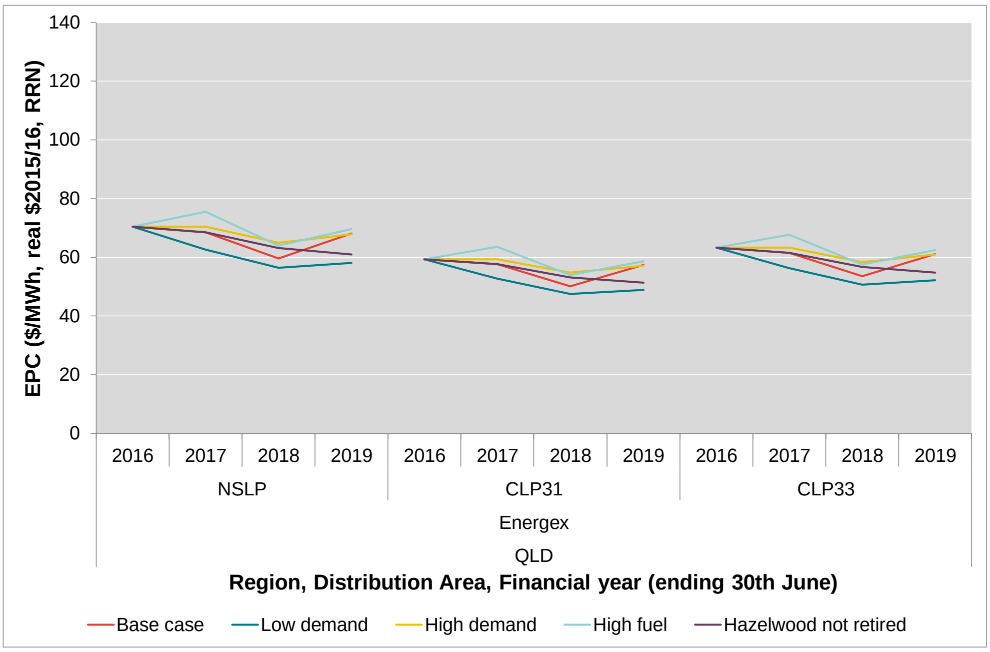
As discussed in Section 4.1.1, the market-based electricity purchase costs reflect two key drivers: forecast spot prices and residential load shapes. Since the residential load shapes are assumed to be constant over the forecast period and between scenarios, the residential load shapes do not drive trends over time or between the scenarios. In other words, trends over the modelling period are driven solely by changes in forecast pool prices.

Figure 21: Electricity purchase cost results for NSW and the ACT



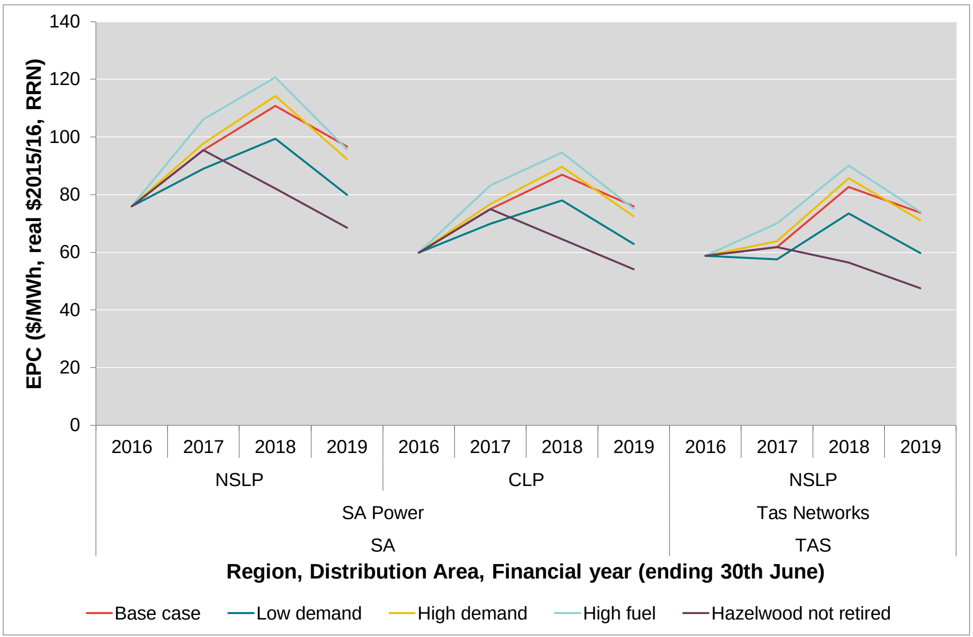
Source: Frontier Economics

Figure 22: Electricity purchase cost results for Queensland



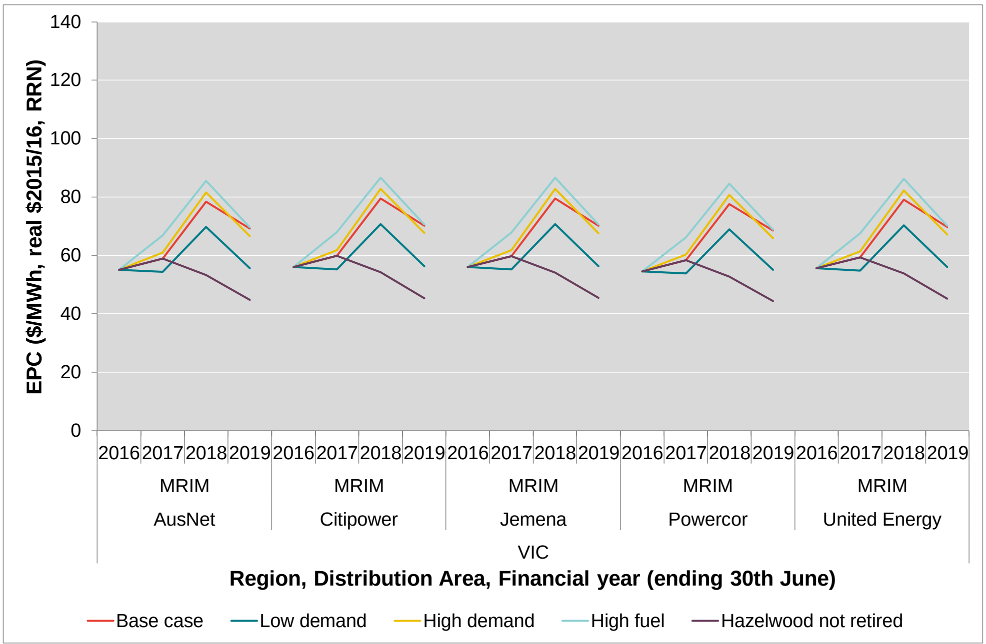
Source: Frontier Economics

Figure 23: Electricity purchase cost results for South Australia and Tasmania



Source: Frontier Economics

Figure 24: Electricity purchase cost results for Victoria



Source: Frontier Economics

4.2 Stand-alone LRMC of electricity

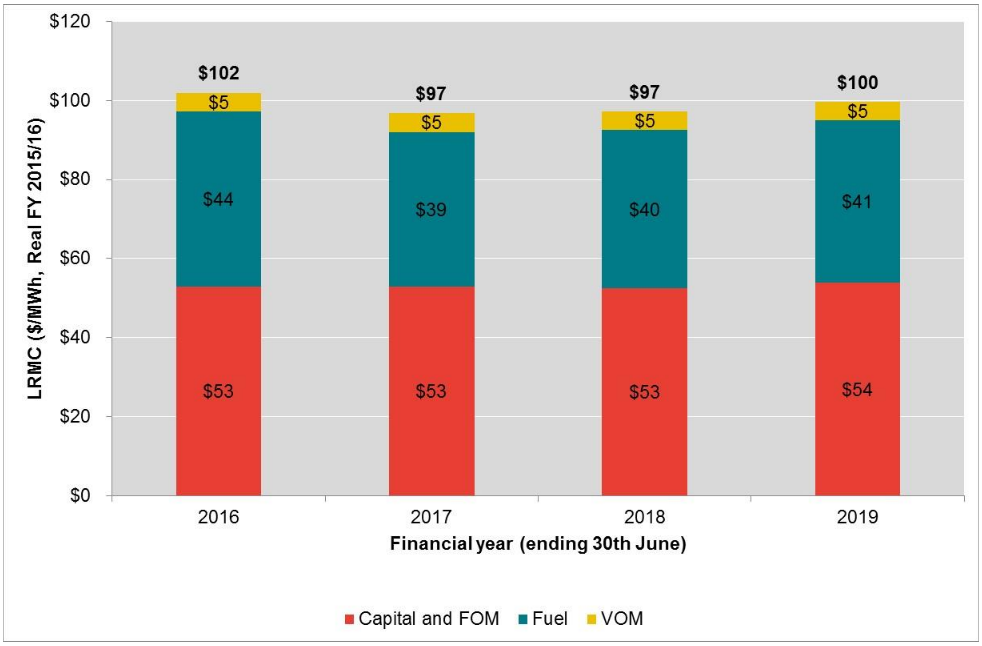
This section presents the results of our modelling of the stand-alone LRMC for the SWIS. Stand-alone LRMC results are presented for the Base case and the High Fuel case. The High Demand case and the Low Demand case are not relevant under the stand-alone LRMC approach because under the stand-alone LRMC approach system demand is not modelled.

Section 4.2.1 provides a summary of our results and discusses key trends. Section 4.2.2 presents more detailed results.

4.2.1 Summary results and key trends

A summary of the results of our Base case modelling of the stand-alone LRMC in the SWIS is presented in Figure 25. Figure 25 shows the total stand-alone LRMC for each year to 2018/19, including the breakdown of the stand-alone LRMC into capital and fixed operating and maintenance costs (FOM), fuel costs and variable operating and maintenance (VOM) costs.

Figure 25: Stand-alone LRMC results – Base case



Source: Frontier Economics

The estimated stand-alone LRMC is driven by the fixed and variable costs of generation technologies and by the peakiness of residential load shapes. Changes over time can only be driven by changes in input costs because residential load shapes are held constant over the modelling period.

There is little change in the estimated stand-alone LRMC over the period to 2018/19. There is a slight increase in capital and FOM costs in 2018/19, reflecting a slight increase in forecast capital costs. There is a decrease in fuel costs over the period to 2018/19, reflecting a forecast reduction in gas prices in the SWIS over the period to 2018/19.

Table 7 summarises the key trends that drive outcomes in the Base case and the High Fuel case.

Table 7: High level trends in the stand-alone LRMC, by scenario

Region	Key trends
Base case	A mix of CCGT and OCGT is built to meet the load shape. The mix of investment and input capital and fuel costs are relatively stable in the SWIS, leading to wholesale electricity costs that are approximately constant in real terms.
High Fuel	A mix of coal, CCGT and OCGT is built to meet the load shape. Building coal plant increases capital costs relative to the Base case and higher gas prices results in higher fuel costs relative to the Base case. The mix of investment and input capital and fuel costs are relatively stable in the SWIS, leading to wholesale electricity costs that are approximately constant in real terms.

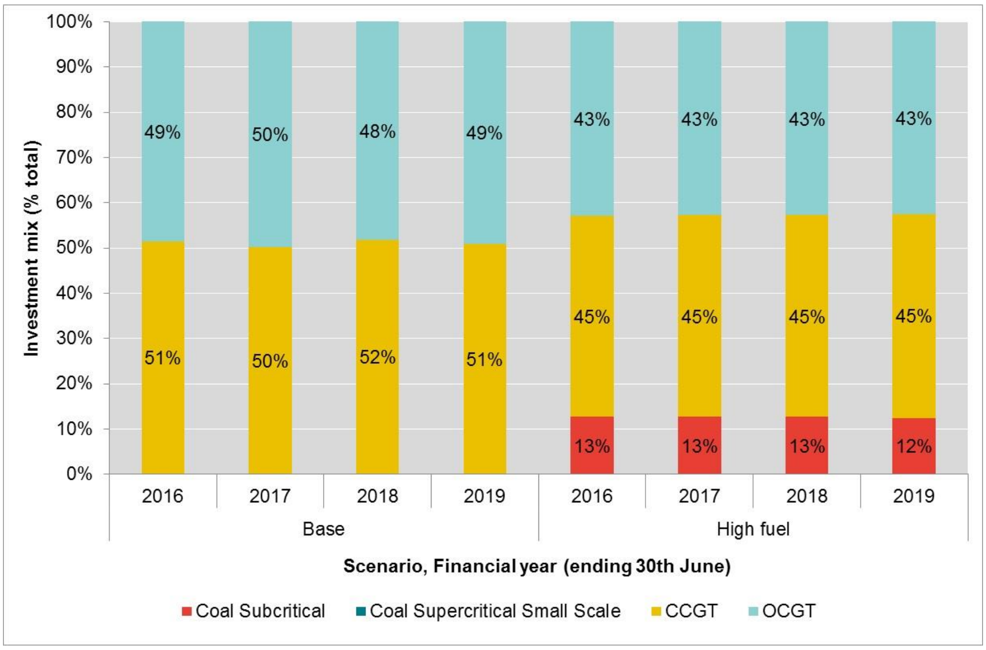
4.2.2 Detailed results

This section presents the detailed results for the stand-alone LRMC for the Base case and the High Fuel case. We present key modelling results including investment, dispatch and stand-alone LRMC.

Investment

Investment to meet the residential load shape in the SWIS, under the stand-alone LRMC, is shown in Figure 26. In the Base case, investment is all gas plant, with a mix of CCGT plant and OCGT plant. In the High Fuel case investment includes some coal plant in place of some of the gas plant. The reason that investment in coal plant occurs in the High Fuel case is that the higher gas price in this case makes investment in coal plant economic.

Figure 26: Stand-alone LRMC investment –Base case and High Fuel case

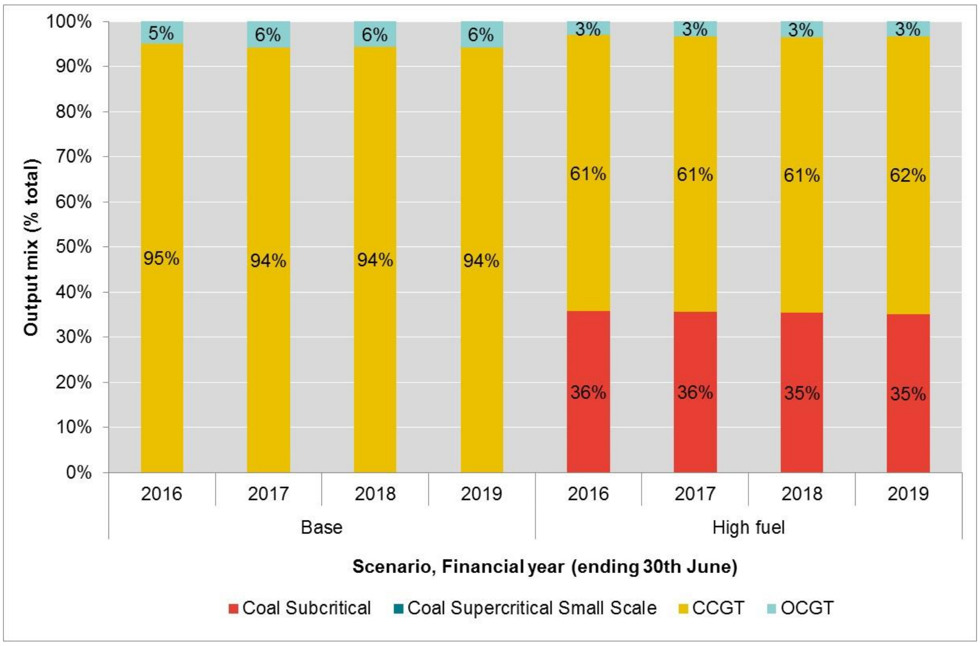


Source: Frontier Economics

Dispatch

Dispatch to meet the residential load shape in the SWIS, under the stand-alone LRMC, is shown in Figure 27. This dispatch is consistent with the optimal investment mix: coal plant or CCGT plant run at baseload and mid-merit to supply most of the electricity to meet the residential load shape, and OCGT plant runs infrequently to meet peak load.

Figure 27: Dispatch – SWIS Base case and High Fuel scenarios



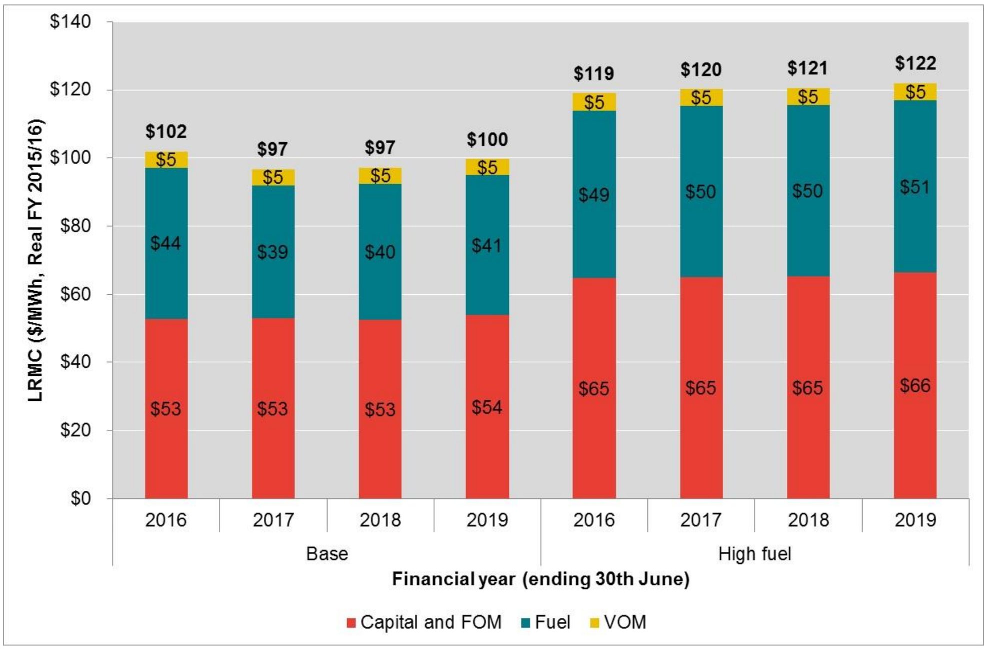
Source: Frontier Economics

Stand-alone LRMC

The stand-alone LRMC for the Base case and the High Fuel case is shown in Figure 28. Figure 28 shows the total stand-alone LRMC for each year to 2018/19, including the breakdown of the stand-alone LRMC into capital and FOM, fuel costs and VOM costs.

The stand-alone LRMC is higher in the High Fuel case – at around $120/MWh as opposed to around $100/MWh in the Base case. The increase is partly due to higher fuel costs and partly due to higher capital and FOM costs. The reason is that in the High Fuel case, it is optimal to incur the higher capital and FOM costs associated with coal plant in order to avoid some of the increase in gas prices in the High Fuel case.

Figure 28: Stand-alone LRMC – SWIS Base case and High Fuel scenarios



Source: Frontier Economics

Stand-alone LRMC estimates, which are around $100/MWh in the Base case, are considerably higher than current observed balancing plus capacity prices in the SWIS. This is consistent with the stand-alone LRMC approach fully reflecting long run marginal costs while the SWIS is currently oversupplied and is consistent with the stand-alone LRMC approach reflecting the cost of the residential load shape as opposed to the system load shape.

5 Results – other cost estimates

In addition to advising on wholesale electricity costs for the period 2015/16 to 2018/19, we are also required to estimate a range of other electricity-related costs. These include the costs of complying with the Renewable Energy Target, NEM fees and ancillary services costs.

5.1 Estimates of cost of the Renewable Energy Target

This section considers the costs associated with complying with the Renewable Energy Target, including both the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES).

Note that our estimate of the cost of the Renewable Energy Target is an estimate of the cost to retailers of complying with their obligations under the Renewable Energy Target, not an estimate of the total economic costs associated with the policy. In other words, we are estimating what it will cost retailers to purchase the certificates that they are required to purchase under the scheme, but we are not estimating the broader economic effects on the electricity market or the economy as a whole of the investments brought about by the scheme. The Renewable Energy Target will have broader economic effects on the electricity market, including changing patterns of investment (renewable plant is built instead of whatever other technology would have been chosen in the absence of the scheme) and potentially bringing about the retirement of some existing generation plant (existing plant can be 'pushed out' of the market by renewable plant).

5.1.1 LRET

Table 8 presents our forecast of the RPPs. These RPPs percentages are based on the current RPP, the announced LRET target and the default adjustment mechanism set out in the regulations, which increases the RPP in line with changes in the LRET target.

Table 8: Renewable power percentages

Financial Year	RPP (% of liable acquisitions)
2016	11.93%
2017	14.12%
2018	16.26%
2019	17.81%

Source: Clean Energy Regulator with Frontier Economics adjustment.

The cost of LGCs is based on our modelling of the LRMC of meeting the LRET. These modelling results are summarised in Figure 29. Figure 29 shows, for the Base case and each of the four scenarios, the LRET penalty (which falls in real terms over time), the shortfall in meeting the LRET (if there is one) and our estimate of the LRMC of meeting the LRET.

Our estimates of the cost of complying with the LRET are used as an input into the AEMC's estimate of retail costs. Therefore, for years where actual retail tariffs are available (2015/16 and 2016/17), it is best to reflect the cost *at the time when the retail tariffs were set*. The retirement of Hazelwood, announced in November 2016, was not known when the 2015/16 retail tariffs were set, and also was unlikely to be taken into account when retailers sets the 2016/17 retail tariffs at the beginning of the financial year. When it becomes publicly known that Hazelwood will retire, and the pool prices are expected to be higher, the cost of LGCs fall as new windfarms requires a smaller amount of subsidy to recover their costs. The drop in our modelled LGC cost reflects the change in people's expectation after the announcement of Hazelwood retirement. They are in fact joined together from two separate model runs. The 2015/16 and 2016/17 results are from the model run where Hazelwood is not retired, reflecting what people expected prior to the November announcement. The results from 2017/18 are from the model run where Hazelwood is retired at the beginning of 2017/18, reflecting people's expectation after the November announcement. The step drop in 2017/18 is consistent with the fact that pool prices are expected to have a step rise in the southern regions following the retirement of Hazelwood.

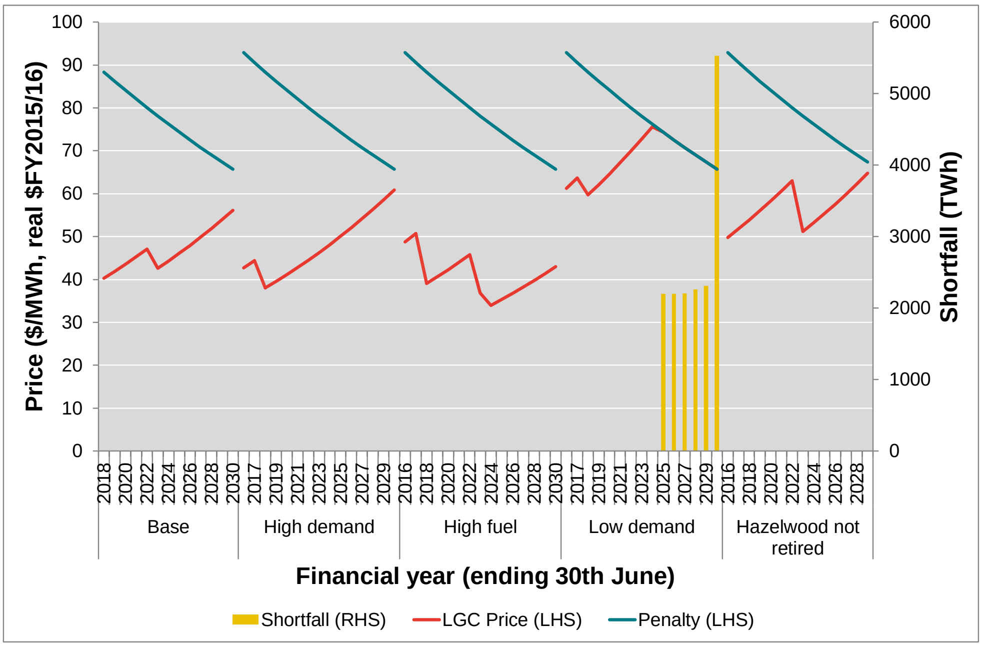
In the Base case, our estimate of the LRMC of meeting the LRET is around $50/LGC prior to the announcement of Hazelwood retirement, drops to around $40/LGC after the announcement, increases over the period to the mid-2020s to slightly below $50/MWh before dropping and then increases over the period to 2030 to around $55/MWh. The reason for the kink in the mid-2020s in the forecast cost is that our modelling finds that the cap for borrowing LGCs is met at that time, which limits the extent to which the LGC price is determined by outcomes at the end of the scheme. As the retirement of Hazelwood and higher pool prices makes it more attractive to build a wind farm, there is no shortfall of the target.

In the High Demand case, our estimate of the LRMC of meeting the LRET is lower. The reason is that higher demand and higher electricity prices diminish the 'subsidy' that is required to make renewable generation economic. In the High Fuel case, our estimate of the LRMC of meeting the LRET is lower for similar reasons: higher fuel costs result in higher electricity prices.

In the Low Demand case, our estimate of the LRMC of meeting the LRET is higher, and there is a material shortfall in meeting the target. The reason is that with falling electricity demand (and lower electricity prices) it is cheaper to pay the penalty than it is to invest in wind generation.

In the scenario where Hazelwood is not retired, the LRMC estimate of meeting the LRET is higher than the base case, reflecting more suppressed pool prices and the larger amount of subsidy required to recover the cost of windfarms.

Figure 29: LRET outcomes by scenario



Source: Frontier Economics

Table 9 shows the LRMC of the LGC certificate (RRN basis, real $2015/16) from our modelling. The LRMC based estimates of LGC permit costs reflect the timing and cost of investment to meet the target, as well as the timing and magnitude of the shortfall against the LRET target (which occurs in the Low Demand scenario). Estimates of the LRMC are lowest in the High Demand and High Fuel scenarios (where pool prices are high) and highest in the Low Demand scenario (where pool prices are low). This demonstrates the inverse relationship between a renewable generators cost recovery from wholesale and LGC sales.

Table 9: LGC cost estimate ($/certificate, RRN basis, real $2015/16)

Financial Year	Base Case	Low Demand	High Demand	High Fuel	Hazelwood not retired
2016	$49.81	$61.20	$42.70	$48.79	$49.81
2017	$51.81	$63.66	$44.42	$50.76	$51.81
2018	$40.26	$59.73	$38.02	$39.09	$53.89
2019	$41.87	$62.12	$39.55	$40.66	$56.04

Source: Frontier Economics

Based on the LRMC of LGC and RPPs, the LRET costs to residential consumers are presented in Table 10.

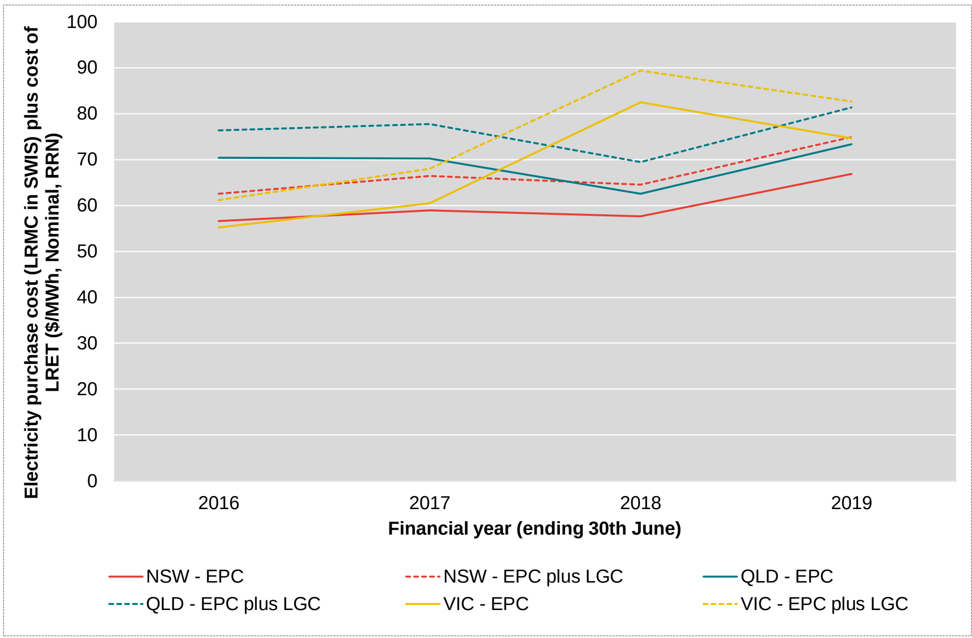
Table 10: LRET cost ($/MWh, RRN basis, real $2015/16)

Financial Year	Base Case	Low Demand	High Demand	High Fuel	Hazelwood not retired
2016	$5.94	$7.30	$5.09	$5.82	$5.94
2017	$7.32	$8.99	$6.27	$7.17	$7.32
2018	$6.55	$9.71	$6.18	$6.36	$8.76
2019	$7.46	$11.07	$7.04	$7.24	$9.98

Source: Frontier Economics

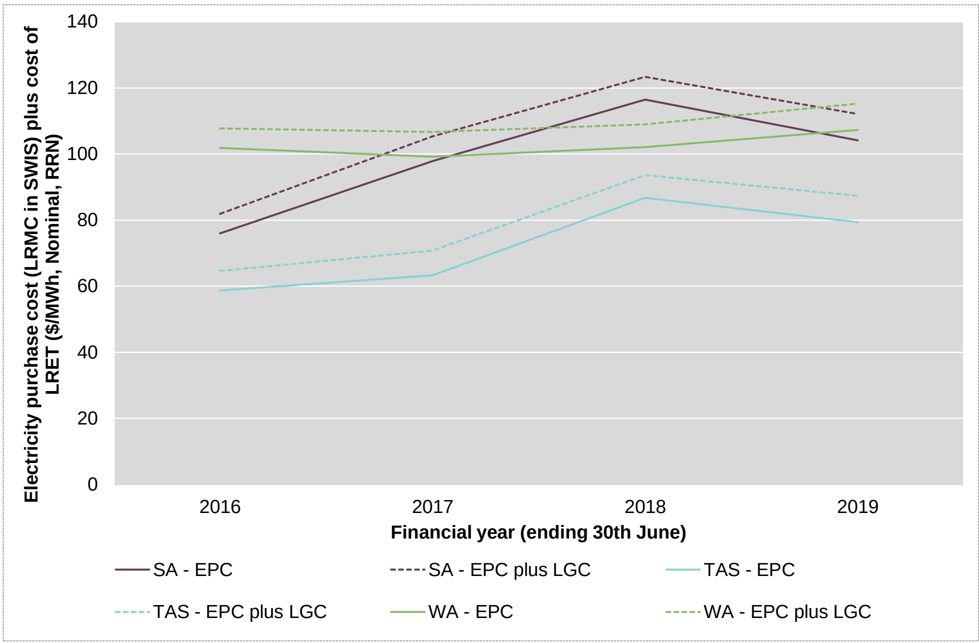
Combining these estimates of the cost of complying with the LRET with the estimates of electricity purchases costs (based on NSLP and MRIM load profiles and stand-alone LRMC for the SWIS) from Section 4, provides the results shown in Figure 30 and Figure 31. The electricity purchase costs for states with multiple jurisdictions are weighted by customer numbers. The figures shown are in nominal dollars.

Figure 30: Cost of LRET plus electricity purchase cost / LRMC – NSW, QLD and VIC



Source: Frontier Economics

Figure 31: Cost of LRET plus electricity purchase cost / LRMC – SA, TAS and WA



Source: Frontier Economics

5.1.2 SRES

Table 11 shows our forecasts of the small-scale technology percentages (STPs). These STPs are based on the forecast STPs published by the Clean Energy Regulator for the period up to calendar year 2018, and the assumption that the STP remains constant after this at the level from 2018.

Table 11: Small-scale technology percentages

Financial Year	STP percentage
2016	10.70%
2017	9.35%
2018	8.67%
2019	8.31%

Source: Frontier Economics

We assumes that the cost of STCs is the penalty price, which is $40/STC in nominal terms.

Based on these inputs, Table 12 contains the estimated SRES costs. These are higher in earlier years due to the higher STP percentages and higher real STC cost.

Table 12: SRES cost ($/MWh, RRN basis, real $2015/16)

Financial Year	SRES cost
2016	$4.28
2017	$3.65
2018	$3.30
2019	$3.09

Source: Frontier Economics

5.2 Market fees and ancillary services costs

5.2.1 Market fees

Table 13 shows our estimated market fees on an RRN basis in real 2015/16 dollars.

These estimated market fees are based on budgets published by AEMO.

Table 13: Market Fees ($/MWh, RRN Basis, real $2015/16)

Financial Year	Region	Market fees
2016	NEM	$0.32
2016	SWIS	$0.50
2017	NEM	$0.34
2017	SWIS	$0.50
2018	NEM	$0.34
2018	SWIS	$0.50

2019	NEM	$0.34
2019	SWIS	$0.50

Source: Frontier Economics

5.2.2 Ancillary services costs

Table 14 shows our estimated ancillary service cost on an RRN basis and in real 2015/16 dollars.

These estimated ancillary services costs are based on the historic average ancillary services costs in each region over the period 2010/11 to 2014/15. It may be that past ancillary services costs are not a reliable predictor of future ancillary services costs; for instance, it may be that the increase in intermittent generation (such as wind farms) increase the need for ancillary services and, therefore, increase ancillary services costs. However, given that ancillary services costs are such a small proportion of the total cost of supplying electricity to residential customers, even a very substantial increase in ancillary services costs is unlikely to have a material impact on retail electricity prices.

Table 14: Ancillary service cost ($/MWh, RRN basis, real $2015/16)

Financial Year	Region	Ancillary service costs
2016	QLD	$0.13
2016	NSW	$0.70
2016	ACT	$0.70
2016	VIC	$0.21
2016	TAS	$0.63
2016	SA	$0.44
2016	SWIS	$1.72
2017	QLD	$0.13
2017	NSW	$0.70
2017	ACT	$0.70
2017	VIC	$0.21
2017	TAS	$0.63
2017	SA	$0.44
2017	SWIS	$1.72
2018	QLD	$0.13
2018	NSW	$0.70
2018	ACT	$0.70
2018	VIC	$0.21
2018	TAS	$0.63
2018	SA	$0.44
2018	SWIS	$1.72
2019	QLD	$0.13
2019	NSW	$0.70
2019	ACT	$0.70
2019	VIC	$0.21
2019	TAS	$0.63
2019	SA	$0.44
2019	SWIS	$1.72

Source: Frontier Economics

5.3 Loss factors

The loss factors for each distribution area are reported in Table 15.

The estimated transmission loss factors (TLFs) for each distribution area are based on the average of reported loss factors for transmission node identifiers for the distribution area that we identify as being locations of customer load. The estimated distribution loss factors (DLFs) for each distribution area are based on reported loss factors for residential customers or low voltage customers.

Table 15: Loss factors

State	Area	TLF	DLF
ACT	ACTEWAGL	1.0176	1.0508
NSW	Ausgrid	1.0055	1.0581
NSW	Endeavour	0.9962	1.0673
NSW	Essential	1.0261	1.0815
QLD	Energex	1.0132	1.0578
SA	SAP	1.0041	1.098
TAS	Aurora	1.0295	1.0335
VIC	Citipower	1.0008	1.04
VIC	Jemena	1.0024	1.0449
VIC	Powercor	1.0083	1.0698
VIC	SP AusNet	1.0015	1.0689
VIC	United	0.9962	1.0544
WA	WA	1.0401	1.0415

Source: Frontier analysis of AEMO data

6 Summary of results

Table 16 through Table 28 summarise each of the components of the cost of supplying electricity to residential customers that we have estimated for this price trends report.

The components that we have estimated are:

- The cost of electricity, which is estimated using either a market-based electricity purchase cost approach (for NEM jurisdictions) or a stand-alone LRMC approach (for the SWIS).
- The cost of complying with the LRET and the SRES.
- Other costs related to the wholesale electricity market, including market fees and ancillary services.
- Electricity losses associated with supplying residential customers, which are represented by the DFL and TFL.

There are also other costs associated with supplying electricity to residential customers, which we have not estimated but which are accounted for in the AEMC's residential price trends report. These other costs include network costs (the costs associated with the use of the transmission network and the distribution network), the costs of energy efficiency schemes and retail operating costs and margins.

Table 16: ACT – ACTEWAGL

	Electricity purchase cost – NSLP ($/MWh, RRN, FY2015/16)	Electricity purchase cost – CLP1 ($/MWh, RRN, FY2015/16)	Electricity purchase cost – CLP2 ($/MWh, RRN, FY2015/16)	Cost of LRET ($/MWh, RRN, FY2015/16)	Cost of SRES ($/MWh, RRN, FY2015/16)	Market fees ($/MWh, RRN, FY2015/16)	Ancillary services ($/MWh, RRN, FY2015/16)	DLF	TLF
Base case									
2015/16	$56.55	-	-	$5.94	$4.28	$0.32	$0.70	1.0176	1.0508
2016/17	$57.45	-	-	$7.32	$3.65	$0.34	$0.70	1.0176	1.0508
2017/18	$54.80	-	-	$6.55	$3.30	$0.34	$0.70	1.0176	1.0508
2018/19	$62.07	-	-	$7.46	$3.09	$0.34	$0.70	1.0176	1.0508
Low Demand									
2015/16	$56.55	-	-	$7.30	$4.28	$0.32	$0.70	1.0176	1.0508
2016/17	$54.02	-	-	$8.99	$3.65	$0.34	$0.70	1.0176	1.0508
2017/18	$53.79	-	-	$9.71	$3.30	$0.34	$0.70	1.0176	1.0508
2018/19	$51.21	-	-	$11.07	$3.09	$0.34	$0.70	1.0176	1.0508
High Demand									
2015/16	$56.55	-	-	$5.09	$4.28	$0.32	$0.70	1.0176	1.0508
2016/17	$59.11	-	-	$6.27	$3.65	$0.34	$0.70	1.0176	1.0508
2017/18	$58.18	-	-	$6.18	$3.30	$0.34	$0.70	1.0176	1.0508
2018/19	$61.41	-	-	$7.04	$3.09	$0.34	$0.70	1.0176	1.0508
High Fuel									
2015/16	$56.55	-	-	$5.82	$4.28	$0.32	$0.70	1.0176	1.0508
2016/17	$65.31	-	-	$7.17	$3.65	$0.34	$0.70	1.0176	1.0508
2017/18	$60.22	-	-	$6.36	$3.30	$0.34	$0.70	1.0176	1.0508
2018/19	$63.01	-	-	$7.24	$3.09	$0.34	$0.70	1.0176	1.0508
Hazelwood not Retired									
2015/16	$56.55	-	-	$5.94	$4.28	$0.32	$0.70	1.0176	1.0508

Summary of results

2016/17	$57.45	-	-	$7.32	$3.65	$0.34	$0.70	1.0176	1.0508
2017/18	$52.62	-	-	$8.76	$3.30	$0.34	$0.70	1.0176	1.0508
2018/19	$48.27	-	-	$9.98	$3.09	$0.34	$0.70	1.0176	1.0508

Table 17: NSW – Ausgrid

	Electricity purchase cost – NSLP ($/MWh, RRN, FY2015/16)	Electricity purchase cost – CLP1 ($/MWh, RRN, FY2015/16)	Electricity purchase cost – CLP2 ($/MWh, RRN, FY2015/16)	Cost of LRET ($/MWh, RRN, FY2015/16)	Cost of SRES ($/MWh, RRN, FY2015/16)	Market fees ($/MWh, RRN, FY2015/16)	Ancillary services ($/MWh, RRN, FY2015/16)	DLF	TLF
Base case									
2015/16	$56.99	$49.74	-	$5.94	$4.28	$0.32	$0.70	1.0055	1.0581
2016/17	$57.90	$50.54	-	$7.32	$3.65	$0.34	$0.70	1.0055	1.0581
2017/18	$55.24	$48.20	-	$6.55	$3.30	$0.34	$0.70	1.0055	1.0581
2018/19	$62.52	$54.61	-	$7.46	$3.09	$0.34	$0.70	1.0055	1.0581
Low Demand									
2015/16	$56.99	$49.74	-	$7.30	$4.28	$0.32	$0.70	1.0055	1.0581
2016/17	$54.45	$47.52	-	$8.99	$3.65	$0.34	$0.70	1.0055	1.0581
2017/18	$54.23	$47.31	-	$9.71	$3.30	$0.34	$0.70	1.0055	1.0581
2018/19	$51.69	$45.05	-	$11.07	$3.09	$0.34	$0.70	1.0055	1.0581
High Demand									
2015/16	$56.99	$49.74	-	$5.09	$4.28	$0.32	$0.70	1.0055	1.0581
2016/17	$59.55	$52.00	-	$6.27	$3.65	$0.34	$0.70	1.0055	1.0581
2017/18	$58.62	$51.17	-	$6.18	$3.30	$0.34	$0.70	1.0055	1.0581
2018/19	$61.86	$54.03	-	$7.04	$3.09	$0.34	$0.70	1.0055	1.0581
High Fuel									
2015/16	$56.99	$49.74	-	$5.82	$4.28	$0.32	$0.70	1.0055	1.0581
2016/17	$65.77	$57.46	-	$7.17	$3.65	$0.34	$0.70	1.0055	1.0581
2017/18	$60.67	$52.98	-	$6.36	$3.30	$0.34	$0.70	1.0055	1.0581
2018/19	$63.45	$55.43	-	$7.24	$3.09	$0.34	$0.70	1.0055	1.0581
Hazelwood not Retired									
2015/16	$56.99	$49.74	-	$5.94	$4.28	$0.32	$0.70	1.0055	1.0581

2016/17	$57.90	$50.54	-	$7.32	$3.65	$0.34	$0.70	1.0055	1.0581
2017/18	$53.06	$46.28	-	$8.76	$3.30	$0.34	$0.70	1.0055	1.0581
2018/19	$48.75	$42.44	-	$9.98	$3.09	$0.34	$0.70	1.0055	1.0581

Table 18: NSW – Endeavour

	Electricity purchase cost – NSLP ($/MWh, RRN, FY2015/16)	Electricity purchase cost – CLP1 ($/MWh, RRN, FY2015/16)	Electricity purchase cost – CLP2 ($/MWh, RRN, FY2015/16)	Cost of LRET ($/MWh, RRN, FY2015/16)	Cost of SRES ($/MWh, RRN, FY2015/16)	Market fees ($/MWh, RRN, FY2015/16)	Ancillary services ($/MWh, RRN, FY2015/16)	DLF	TLF
Base case									
2015/16	$57.52	$49.29	-	$5.94	$4.28	$0.32	$0.70	0.9962	1.0673
2016/17	$58.43	$50.08	-	$7.32	$3.65	$0.34	$0.70	0.9962	1.0673
2017/18	$55.76	$47.77	-	$6.55	$3.30	$0.34	$0.70	0.9962	1.0673
2018/19	$63.07	$54.10	-	$7.46	$3.09	$0.34	$0.70	0.9962	1.0673
Low Demand									
2015/16	$57.52	$49.29	-	$7.30	$4.28	$0.32	$0.70	0.9962	1.0673
2016/17	$54.98	$47.10	-	$8.99	$3.65	$0.34	$0.70	0.9962	1.0673
2017/18	$54.75	$46.88	-	$9.71	$3.30	$0.34	$0.70	0.9962	1.0673
2018/19	$52.20	$44.67	-	$11.07	$3.09	$0.34	$0.70	0.9962	1.0673
High Demand									
2015/16	$57.52	$49.29	-	$5.09	$4.28	$0.32	$0.70	0.9962	1.0673
2016/17	$60.09	$51.51	-	$6.27	$3.65	$0.34	$0.70	0.9962	1.0673
2017/18	$59.16	$50.71	-	$6.18	$3.30	$0.34	$0.70	0.9962	1.0673
2018/19	$62.41	$53.53	-	$7.04	$3.09	$0.34	$0.70	0.9962	1.0673
High Fuel									
2015/16	$57.52	$49.29	-	$5.82	$4.28	$0.32	$0.70	0.9962	1.0673
2016/17	$66.34	$56.93	-	$7.17	$3.65	$0.34	$0.70	0.9962	1.0673
2017/18	$61.22	$52.49	-	$6.36	$3.30	$0.34	$0.70	0.9962	1.0673
2018/19	$64.02	$54.92	-	$7.24	$3.09	$0.34	$0.70	0.9962	1.0673
Hazelwood not Retired									
2015/16	$57.52	$49.29	-	$5.94	$4.28	$0.32	$0.70	0.9962	1.0673

2016/17	$58.43	$50.08	-	$7.32	$3.65	$0.34	$0.70	0.9962	1.0673
2017/18	$53.59	$45.87	-	$8.76	$3.30	$0.34	$0.70	0.9962	1.0673
2018/19	$49.26	$42.10	-	$9.98	$3.09	$0.34	$0.70	0.9962	1.0673

Table 19: NSW – Essential

	Electricity purchase cost – NSLP ($/MWh, RRN, FY2015/16)	Electricity purchase cost – CLP1 ($/MWh, RRN, FY2015/16)	Electricity purchase cost – CLP2 ($/MWh, RRN, FY2015/16)	Cost of LRET ($/MWh, RRN, FY2015/16)	Cost of SRES ($/MWh, RRN, FY2015/16)	Market fees ($/MWh, RRN, FY2015/16)	Ancillary services ($/MWh, RRN, FY2015/16)	DLF	TLF
Base case									
2015/16	$55.17	$49.39	-	$5.94	$4.28	$0.32	$0.70	1.0261	1.0815
2016/17	$56.05	$50.19	-	$7.32	$3.65	$0.34	$0.70	1.0261	1.0815
2017/18	$53.46	$47.87	-	$6.55	$3.30	$0.34	$0.70	1.0261	1.0815
2018/19	$60.56	$54.23	-	$7.46	$3.09	$0.34	$0.70	1.0261	1.0815
Low Demand									
2015/16	$55.17	$49.39	-	$7.30	$4.28	$0.32	$0.70	1.0261	1.0815
2016/17	$52.69	$47.18	-	$8.99	$3.65	$0.34	$0.70	1.0261	1.0815
2017/18	$52.48	$46.98	-	$9.71	$3.30	$0.34	$0.70	1.0261	1.0815
2018/19	$49.98	$44.73	-	$11.07	$3.09	$0.34	$0.70	1.0261	1.0815
High Demand									
2015/16	$55.17	$49.39	-	$5.09	$4.28	$0.32	$0.70	1.0261	1.0815
2016/17	$57.67	$51.63	-	$6.27	$3.65	$0.34	$0.70	1.0261	1.0815
2017/18	$56.76	$50.81	-	$6.18	$3.30	$0.34	$0.70	1.0261	1.0815
2018/19	$59.91	$53.65	-	$7.04	$3.09	$0.34	$0.70	1.0261	1.0815
High Fuel									
2015/16	$55.17	$49.39	-	$5.82	$4.28	$0.32	$0.70	1.0261	1.0815
2016/17	$63.72	$57.06	-	$7.17	$3.65	$0.34	$0.70	1.0261	1.0815
2017/18	$58.75	$52.61	-	$6.36	$3.30	$0.34	$0.70	1.0261	1.0815
2018/19	$61.46	$55.04	-	$7.24	$3.09	$0.34	$0.70	1.0261	1.0815
Hazelwood not Retired									
2015/16	$55.17	$49.39	-	$5.94	$4.28	$0.32	$0.70	1.0261	1.0815

2016/17	$56.05	$50.19	-	$7.32	$3.65	$0.34	$0.70	1.0261	1.0815
2017/18	$51.33	$45.96	-	$8.76	$3.30	$0.34	$0.70	1.0261	1.0815
2018/19	$47.09	$42.13	-	$9.98	$3.09	$0.34	$0.70	1.0261	1.0815

Table 20: Queensland – Energex

	Electricity purchase cost – NSLP ($/MWh, RRN, FY2015/16)	Electricity purchase cost – CLP31 ($/MWh, RRN, FY2015/16)	Electricity purchase cost – CLP33 ($/MWh, RRN, FY2015/16)	Cost of LRET ($/MWh, RRN, FY2015/16)	Cost of SRES ($/MWh, RRN, FY2015/16)	Market fees ($/MWh, RRN, FY2015/16)	Ancillary services ($/MWh, RRN, FY2015/16)	DLF	TLF
Base case									
2015/16	$70.44	$59.33	$63.24	$5.94	$4.28	$0.32	$0.13	1.0132	1.0578
2016/17	$68.51	$57.71	$61.51	$7.32	$3.65	$0.34	$0.13	1.0132	1.0578
2017/18	$59.57	$50.16	$53.50	$6.55	$3.30	$0.34	$0.13	1.0132	1.0578
2018/19	$68.08	$57.35	$61.13	$7.46	$3.09	$0.34	$0.13	1.0132	1.0578
Low Demand									
2015/16	$70.44	$59.33	$63.24	$7.30	$4.28	$0.32	$0.13	1.0132	1.0578
2016/17	$62.64	$52.76	$56.26	$8.99	$3.65	$0.34	$0.13	1.0132	1.0578
2017/18	$56.48	$47.56	$50.73	$9.71	$3.30	$0.34	$0.13	1.0132	1.0578
2018/19	$58.11	$48.93	$52.19	$11.07	$3.09	$0.34	$0.13	1.0132	1.0578
High Demand									
2015/16	$70.44	$59.33	$63.24	$5.09	$4.28	$0.32	$0.13	1.0132	1.0578
2016/17	$70.49	$59.38	$63.28	$6.27	$3.65	$0.34	$0.13	1.0132	1.0578
2017/18	$64.97	$54.72	$58.34	$6.18	$3.30	$0.34	$0.13	1.0132	1.0578
2018/19	$67.83	$57.14	$60.91	$7.04	$3.09	$0.34	$0.13	1.0132	1.0578
High Fuel									
2015/16	$70.44	$59.33	$63.24	$5.82	$4.28	$0.32	$0.13	1.0132	1.0578
2016/17	$75.46	$63.59	$67.74	$7.17	$3.65	$0.34	$0.13	1.0132	1.0578
2017/18	$64.03	$53.93	$57.50	$6.36	$3.30	$0.34	$0.13	1.0132	1.0578
2018/19	$69.64	$58.66	$62.52	$7.24	$3.09	$0.34	$0.13	1.0132	1.0578
Hazelwood not Retired									
2015/16	$70.44	$59.33	$63.24	$5.94	$4.28	$0.32	$0.13	1.0132	1.0578

2016/17	$68.51	$57.71	$61.51	$7.32	$3.65	$0.34	$0.13	1.0132	1.0578
2017/18	$63.14	$53.17	$56.70	$8.76	$3.30	$0.34	$0.13	1.0132	1.0578
2018/19	$60.98	$51.35	$54.77	$9.98	$3.09	$0.34	$0.13	1.0132	1.0578

Table 21: South Australia – SA Power Networks

	Electricity purchase cost – NSLP ($/MWh, RRN, FY2015/16)	Electricity purchase cost – CLP1 ($/MWh, RRN, FY2015/16)	Electricity purchase cost – CLP2 ($/MWh, RRN, FY2015/16)	Cost of LRET ($/MWh, RRN, FY2015/16)	Cost of SRES ($/MWh, RRN, FY2015/16)	Market fees ($/MWh, RRN, FY2015/16)	Ancillary services ($/MWh, RRN, FY2015/16)	DLF	TLF
Base case									
2015/16	$75.98	$59.85	-	$5.94	$4.28	$0.32	$0.44	1.0041	1.098
2016/17	$95.42	$74.95	-	$7.32	$3.65	$0.34	$0.44	1.0041	1.098
2017/18	$110.82	$86.92	-	$6.55	$3.30	$0.34	$0.44	1.0041	1.098
2018/19	$96.67	$75.92	-	$7.46	$3.09	$0.34	$0.44	1.0041	1.098
Low Demand									
2015/16	$75.98	$59.85	-	$7.30	$4.28	$0.32	$0.44	1.0041	1.098
2016/17	$88.99	$69.95	-	$8.99	$3.65	$0.34	$0.44	1.0041	1.098
2017/18	$99.40	$78.04	-	$9.71	$3.30	$0.34	$0.44	1.0041	1.098
2018/19	$79.89	$62.88	-	$11.07	$3.09	$0.34	$0.44	1.0041	1.098
High Demand									
2015/16	$75.98	$59.85	-	$5.09	$4.28	$0.32	$0.44	1.0041	1.098
2016/17	$97.81	$76.80	-	$6.27	$3.65	$0.34	$0.44	1.0041	1.098
2017/18	$114.28	$89.61	-	$6.18	$3.30	$0.34	$0.44	1.0041	1.098
2018/19	$92.22	$72.46	-	$7.04	$3.09	$0.34	$0.44	1.0041	1.098
High Fuel									
2015/16	$75.98	$59.85	-	$5.82	$4.28	$0.32	$0.44	1.0041	1.098
2016/17	$106.09	$83.24	-	$7.17	$3.65	$0.34	$0.44	1.0041	1.098
2017/18	$120.70	$94.60	-	$6.36	$3.30	$0.34	$0.44	1.0041	1.098
2018/19	$95.66	$75.13	-	$7.24	$3.09	$0.34	$0.44	1.0041	1.098
Hazelwood not Retired									
2015/16	$75.98	$59.85	-	$5.94	$4.28	$0.32	$0.44	1.0041	1.098

Summary of results

2016/17	$95.42	$74.95	-	$7.32	$3.65	$0.34	$0.44	1.0041	1.098
2017/18	$82.07	$64.58	-	$8.76	$3.30	$0.34	$0.44	1.0041	1.098
2018/19	$68.49	$54.03	-	$9.98	$3.09	$0.34	$0.44	1.0041	1.098

Table 22: Tasmania – Tas Networks

	Electricity purchase cost – NSLP ($/MWh, RRN, FY2015/16)	Electricity purchase cost – CLP1 ($/MWh, RRN, FY2015/16)	Electricity purchase cost – CLP2 ($/MWh, RRN, FY2015/16)	Cost of LRET ($/MWh, RRN, FY2015/16)	Cost of SRES ($/MWh, RRN, FY2015/16)	Market fees ($/MWh, RRN, FY2015/16)	Ancillary services ($/MWh, RRN, FY2015/16)	DLF	TLF
Base case									
2015/16	$58.71	-	-	$5.94	$4.28	$0.32	$0.63	1.0295	1.0335
2016/17	$61.75	-	-	$7.32	$3.65	$0.34	$0.63	1.0295	1.0335
2017/18	$82.58	-	-	$6.55	$3.30	$0.34	$0.63	1.0295	1.0335
2018/19	$73.71	-	-	$7.46	$3.09	$0.34	$0.63	1.0295	1.0335
Low Demand									
2015/16	$58.71	-	-	$7.30	$4.28	$0.32	$0.63	1.0295	1.0335
2016/17	$57.49	-	-	$8.99	$3.65	$0.34	$0.63	1.0295	1.0335
2017/18	$73.52	-	-	$9.71	$3.30	$0.34	$0.63	1.0295	1.0335
2018/19	$59.67	-	-	$11.07	$3.09	$0.34	$0.63	1.0295	1.0335
High Demand									
2015/16	$58.71	-	-	$5.09	$4.28	$0.32	$0.63	1.0295	1.0335
2016/17	$63.90	-	-	$6.27	$3.65	$0.34	$0.63	1.0295	1.0335
2017/18	$85.62	-	-	$6.18	$3.30	$0.34	$0.63	1.0295	1.0335
2018/19	$71.18	-	-	$7.04	$3.09	$0.34	$0.63	1.0295	1.0335
High Fuel									
2015/16	$58.71	-	-	$5.82	$4.28	$0.32	$0.63	1.0295	1.0335
2016/17	$70.02	-	-	$7.17	$3.65	$0.34	$0.63	1.0295	1.0335
2017/18	$90.03	-	-	$6.36	$3.30	$0.34	$0.63	1.0295	1.0335
2018/19	$73.94	-	-	$7.24	$3.09	$0.34	$0.63	1.0295	1.0335
Hazelwood not Retired									
2015/16	$58.71	-	-	$5.94	$4.28	$0.32	$0.63	1.0295	1.0335

Summary of results

2016/17	$61.75	-	-	$7.32	$3.65	$0.34	$0.63	1.0295	1.0335
2017/18	$56.45	-	-	$8.76	$3.30	$0.34	$0.63	1.0295	1.0335
2018/19	$47.45	-	-	$9.98	$3.09	$0.34	$0.63	1.0295	1.0335

Table 23: Victoria – Citipower

	Electricity purchase cost – MRIM ($/MWh, RRN, FY2015/16)	Electricity purchase cost – CLP1 ($/MWh, RRN, FY2015/16)	Electricity purchase cost – CLP2 ($/MWh, RRN, FY2015/16)	Cost of LRET ($/MWh, RRN, FY2015/16)	Cost of SRES ($/MWh, RRN, FY2015/16)	Market fees ($/MWh, RRN, FY2015/16)	Ancillary services ($/MWh, RRN, FY2015/16)	DLF	TLF
Base case									
2015/16	$55.97	-	-	$5.94	$4.28	$0.32	$0.21	1.0008	1.04
2016/17	$59.80	-	-	$7.32	$3.65	$0.34	$0.21	1.0008	1.04
2017/18	$79.46	-	-	$6.55	$3.30	$0.34	$0.21	1.0008	1.04
2018/19	$70.20	-	-	$7.46	$3.09	$0.34	$0.21	1.0008	1.04
Low Demand									
2015/16	$55.97	-	-	$7.30	$4.28	$0.32	$0.21	1.0008	1.04
2016/17	$55.22	-	-	$8.99	$3.65	$0.34	$0.21	1.0008	1.04
2017/18	$70.76	-	-	$9.71	$3.30	$0.34	$0.21	1.0008	1.04
2018/19	$56.30	-	-	$11.07	$3.09	$0.34	$0.21	1.0008	1.04
High Demand									
2015/16	$55.97	-	-	$5.09	$4.28	$0.32	$0.21	1.0008	1.04
2016/17	$61.78	-	-	$6.27	$3.65	$0.34	$0.21	1.0008	1.04
2017/18	$82.72	-	-	$6.18	$3.30	$0.34	$0.21	1.0008	1.04
2018/19	$67.72	-	-	$7.04	$3.09	$0.34	$0.21	1.0008	1.04
High Fuel									
2015/16	$55.97	-	-	$5.82	$4.28	$0.32	$0.21	1.0008	1.04
2016/17	$68.01	-	-	$7.17	$3.65	$0.34	$0.21	1.0008	1.04
2017/18	$86.66	-	-	$6.36	$3.30	$0.34	$0.21	1.0008	1.04
2018/19	$70.63	-	-	$7.24	$3.09	$0.34	$0.21	1.0008	1.04
Hazelwood not Retired									
2015/16	$55.97	-	-	$5.94	$4.28	$0.32	$0.21	1.0008	1.04

Summary of results

2016/17	$59.80	-	-	$7.32	$3.65	$0.34	$0.21	1.0008	1.04
2017/18	$54.18	-	-	$8.76	$3.30	$0.34	$0.21	1.0008	1.04
2018/19	$45.36	-	-	$9.98	$3.09	$0.34	$0.21	1.0008	1.04

Table 24: Victoria – Jemena

	Electricity purchase cost – MRIM ($/MWh, RRN, FY2015/16)	Electricity purchase cost – CLP1 ($/MWh, RRN, FY2015/16)	Electricity purchase cost – CLP2 ($/MWh, RRN, FY2015/16)	Cost of LRET ($/MWh, RRN, FY2015/16)	Cost of SRES ($/MWh, RRN, FY2015/16)	Market fees ($/MWh, RRN, FY2015/16)	Ancillary services ($/MWh, RRN, FY2015/16)	DLF	TLF
Base case									
2015/16	$55.95	-	-	$5.94	$4.28	$0.32	$0.21	1.0024	1.0449
2016/17	$59.70	-	-	$7.32	$3.65	$0.34	$0.21	1.0024	1.0449
2017/18	$79.50	-	-	$6.55	$3.30	$0.34	$0.21	1.0024	1.0449
2018/19	$70.16	-	-	$7.46	$3.09	$0.34	$0.21	1.0024	1.0449
Low Demand									
2015/16	$55.95	-	-	$7.30	$4.28	$0.32	$0.21	1.0024	1.0449
2016/17	$55.18	-	-	$8.99	$3.65	$0.34	$0.21	1.0024	1.0449
2017/18	$70.71	-	-	$9.71	$3.30	$0.34	$0.21	1.0024	1.0449
2018/19	$56.33	-	-	$11.07	$3.09	$0.34	$0.21	1.0024	1.0449
High Demand									
2015/16	$55.95	-	-	$5.09	$4.28	$0.32	$0.21	1.0024	1.0449
2016/17	$61.79	-	-	$6.27	$3.65	$0.34	$0.21	1.0024	1.0449
2017/18	$82.76	-	-	$6.18	$3.30	$0.34	$0.21	1.0024	1.0449
2018/19	$67.58	-	-	$7.04	$3.09	$0.34	$0.21	1.0024	1.0449
High Fuel									
2015/16	$55.95	-	-	$5.82	$4.28	$0.32	$0.21	1.0024	1.0449
2016/17	$67.87	-	-	$7.17	$3.65	$0.34	$0.21	1.0024	1.0449
2017/18	$86.70	-	-	$6.36	$3.30	$0.34	$0.21	1.0024	1.0449
2018/19	$70.55	-	-	$7.24	$3.09	$0.34	$0.21	1.0024	1.0449
Hazelwood not Retired									
2015/16	$55.95	-	-	$5.94	$4.28	$0.32	$0.21	1.0024	1.0449

2016/17	$59.70	-	-	$7.32	$3.65	$0.34	$0.21	1.0024	1.0449
2017/18	$54.14	-	-	$8.76	$3.30	$0.34	$0.21	1.0024	1.0449
2018/19	$45.39	-	-	$9.98	$3.09	$0.34	$0.21	1.0024	1.0449

Table 25: Victoria – Powercor

	Electricity purchase cost – MRIM ($/MWh, RRN, FY2015/16)	Electricity purchase cost – CLP1 ($/MWh, RRN, FY2015/16)	Electricity purchase cost – CLP2 ($/MWh, RRN, FY2015/16)	Cost of LRET ($/MWh, RRN, FY2015/16)	Cost of SRES ($/MWh, RRN, FY2015/16)	Market fees ($/MWh, RRN, FY2015/16)	Ancillary services ($/MWh, RRN, FY2015/16)	DLF	TLF
Base case									
2015/16	$54.56	-	-	$5.94	$4.28	$0.32	$0.21	1.0083	1.0698
2016/17	$58.29	-	-	$7.32	$3.65	$0.34	$0.21	1.0083	1.0698
2017/18	$77.56	-	-	$6.55	$3.30	$0.34	$0.21	1.0083	1.0698
2018/19	$68.45	-	-	$7.46	$3.09	$0.34	$0.21	1.0083	1.0698
Low Demand									
2015/16	$54.56	-	-	$7.30	$4.28	$0.32	$0.21	1.0083	1.0698
2016/17	$53.82	-	-	$8.99	$3.65	$0.34	$0.21	1.0083	1.0698
2017/18	$68.98	-	-	$9.71	$3.30	$0.34	$0.21	1.0083	1.0698
2018/19	$55.00	-	-	$11.07	$3.09	$0.34	$0.21	1.0083	1.0698
High Demand									
2015/16	$54.56	-	-	$5.09	$4.28	$0.32	$0.21	1.0083	1.0698
2016/17	$60.30	-	-	$6.27	$3.65	$0.34	$0.21	1.0083	1.0698
2017/18	$80.75	-	-	$6.18	$3.30	$0.34	$0.21	1.0083	1.0698
2018/19	$65.97	-	-	$7.04	$3.09	$0.34	$0.21	1.0083	1.0698
High Fuel									
2015/16	$54.56	-	-	$5.82	$4.28	$0.32	$0.21	1.0083	1.0698
2016/17	$66.25	-	-	$7.17	$3.65	$0.34	$0.21	1.0083	1.0698
2017/18	$84.61	-	-	$6.36	$3.30	$0.34	$0.21	1.0083	1.0698
2018/19	$68.82	-	-	$7.24	$3.09	$0.34	$0.21	1.0083	1.0698
Hazelwood not Retired									
2015/16	$54.56	-	-	$5.94	$4.28	$0.32	$0.21	1.0083	1.0698

Summary of results

2016/17	$58.29	-	-	$7.32	$3.65	$0.34	$0.21	1.0083	1.0698
2017/18	$52.77	-	-	$8.76	$3.30	$0.34	$0.21	1.0083	1.0698
2018/19	$44.32	-	-	$9.98	$3.09	$0.34	$0.21	1.0083	1.0698

Table 26: Victoria – SP AusNet

	Electricity purchase cost – MRIM ($/MWh, RRN, FY2015/16)	Electricity purchase cost – CLP1 ($/MWh, RRN, FY2015/16)	Electricity purchase cost – CLP2 ($/MWh, RRN, FY2015/16)	Cost of LRET ($/MWh, RRN, FY2015/16)	Cost of SRES ($/MWh, RRN, FY2015/16)	Market fees ($/MWh, RRN, FY2015/16)	Ancillary services ($/MWh, RRN, FY2015/16)	DLF	TLF
Base case									
2015/16	$55.08	-	-	$5.94	$4.28	$0.32	$0.21	1.0015	1.0689
2016/17	$58.90	-	-	$7.32	$3.65	$0.34	$0.21	1.0015	1.0689
2017/18	$78.38	-	-	$6.55	$3.30	$0.34	$0.21	1.0015	1.0689
2018/19	$69.18	-	-	$7.46	$3.09	$0.34	$0.21	1.0015	1.0689
Low Demand									
2015/16	$55.08	-	-	$7.30	$4.28	$0.32	$0.21	1.0015	1.0689
2016/17	$54.33	-	-	$8.99	$3.65	$0.34	$0.21	1.0015	1.0689
2017/18	$69.72	-	-	$9.71	$3.30	$0.34	$0.21	1.0015	1.0689
2018/19	$55.64	-	-	$11.07	$3.09	$0.34	$0.21	1.0015	1.0689
High Demand									
2015/16	$55.08	-	-	$5.09	$4.28	$0.32	$0.21	1.0015	1.0689
2016/17	$60.93	-	-	$6.27	$3.65	$0.34	$0.21	1.0015	1.0689
2017/18	$81.59	-	-	$6.18	$3.30	$0.34	$0.21	1.0015	1.0689
2018/19	$66.64	-	-	$7.04	$3.09	$0.34	$0.21	1.0015	1.0689
High Fuel									
2015/16	$55.08	-	-	$5.82	$4.28	$0.32	$0.21	1.0015	1.0689
2016/17	$66.93	-	-	$7.17	$3.65	$0.34	$0.21	1.0015	1.0689
2017/18	$85.48	-	-	$6.36	$3.30	$0.34	$0.21	1.0015	1.0689
2018/19	$69.57	-	-	$7.24	$3.09	$0.34	$0.21	1.0015	1.0689
Hazelwood not Retired									
2015/16	$55.08	-	-	$5.94	$4.28	$0.32	$0.21	1.0015	1.0689

Summary of results

2016/17	$58.90	-	-	$7.32	$3.65	$0.34	$0.21	1.0015	1.0689
2017/18	$53.27	-	-	$8.76	$3.30	$0.34	$0.21	1.0015	1.0689
2018/19	$44.74	-	-	$9.98	$3.09	$0.34	$0.21	1.0015	1.0689

Table 27: Victoria – United

	Electricity purchase cost – MRIM ($/MWh, RRN, FY2015/16)	Electricity purchase cost – CLP1 ($/MWh, RRN, FY2015/16)	Electricity purchase cost – CLP2 ($/MWh, RRN, FY2015/16)	Cost of LRET ($/MWh, RRN, FY2015/16)	Cost of SRES ($/MWh, RRN, FY2015/16)	Market fees ($/MWh, RRN, FY2015/16)	Ancillary services ($/MWh, RRN, FY2015/16)	DLF	TLF
Base case									
2015/16	$55.59	-	-	$5.94	$4.28	$0.32	$0.21	0.9962	1.0544
2016/17	$59.35	-	-	$7.32	$3.65	$0.34	$0.21	0.9962	1.0544
2017/18	$79.02	-	-	$6.55	$3.30	$0.34	$0.21	0.9962	1.0544
2018/19	$69.74	-	-	$7.46	$3.09	$0.34	$0.21	0.9962	1.0544
Low Demand									
2015/16	$55.59	-	-	$7.30	$4.28	$0.32	$0.21	0.9962	1.0544
2016/17	$54.83	-	-	$8.99	$3.65	$0.34	$0.21	0.9962	1.0544
2017/18	$70.28	-	-	$9.71	$3.30	$0.34	$0.21	0.9962	1.0544
2018/19	$55.99	-	-	$11.07	$3.09	$0.34	$0.21	0.9962	1.0544
High Demand									
2015/16	$55.59	-	-	$5.09	$4.28	$0.32	$0.21	0.9962	1.0544
2016/17	$61.40	-	-	$6.27	$3.65	$0.34	$0.21	0.9962	1.0544
2017/18	$82.26	-	-	$6.18	$3.30	$0.34	$0.21	0.9962	1.0544
2018/19	$67.17	-	-	$7.04	$3.09	$0.34	$0.21	0.9962	1.0544
High Fuel									
2015/16	$55.59	-	-	$5.82	$4.28	$0.32	$0.21	0.9962	1.0544
2016/17	$67.50	-	-	$7.17	$3.65	$0.34	$0.21	0.9962	1.0544
2017/18	$86.19	-	-	$6.36	$3.30	$0.34	$0.21	0.9962	1.0544
2018/19	$70.11	-	-	$7.24	$3.09	$0.34	$0.21	0.9962	1.0544
Hazelwood not Retired									
2015/16	$55.59	-	-	$5.94	$4.28	$0.32	$0.21	0.9962	1.0544

Summary of results

2016/17	$59.35	-	-	$7.32	$3.65	$0.34	$0.21	0.9962	1.0544
2017/18	$53.78	-	-	$8.76	$3.30	$0.34	$0.21	0.9962	1.0544
2018/19	$45.12	-	-	$9.98	$3.09	$0.34	$0.21	0.9962	1.0544

Table 28: SWIS

	Standalone LRMC ($/MWh, RRN, FY2015/16)	Cost of LRET ($/MWh, RRN, FY2015/16)	Cost of SRES ($/MWh, RRN, FY2015/16)	Market fees ($/MWh, RRN, FY2015/16)	Ancillary services ($/MWh, RRN, FY2015/16)	DLF	TLF
Base case							
2015/16	$101.89	$5.94	$4.28	$0.32	$1.72	1.0401	1.0415
2016/17	$96.76	$7.32	$3.65	$0.34	$1.72	1.0401	1.0415
2017/18	$97.17	$6.55	$3.30	$0.34	$1.72	1.0401	1.0415
2018/19	$99.62	$7.46	$3.09	$0.34	$1.72	1.0401	1.0415
Low Demand							
2015/16	$101.89	$7.30	$4.28	$0.32	$1.72	1.0401	1.0415
2016/17	$96.76	$8.99	$3.65	$0.34	$1.72	1.0401	1.0415
2017/18	$97.17	$9.71	$3.30	$0.34	$1.72	1.0401	1.0415
2018/19	$99.62	$11.07	$3.09	$0.34	$1.72	1.0401	1.0415
High Demand							
2015/16	$101.89	$5.09	$4.28	$0.32	$1.72	1.0401	1.0415
2016/17	$96.76	$6.27	$3.65	$0.34	$1.72	1.0401	1.0415
2017/18	$97.17	$6.18	$3.30	$0.34	$1.72	1.0401	1.0415
2018/19	$99.62	$7.04	$3.09	$0.34	$1.72	1.0401	1.0415
High Fuel							
2015/16	$118.96	$5.82	$4.28	$0.32	$1.72	1.0401	1.0415
2016/17	$120.25	$7.17	$3.65	$0.34	$1.72	1.0401	1.0415
2017/18	$120.55	$6.36	$3.30	$0.34	$1.72	1.0401	1.0415
2018/19	$121.95	$7.24	$3.09	$0.34	$1.72	1.0401	1.0415
Hazelwood not Retired							
2015/16	$101.89	$5.94	$4.28	$0.32	$1.72	1.0401	1.0415

Summary of results

2016/17	$96.76	$7.32	$3.65	$0.34	$1.72	1.0401	1.0415
2017/18	$97.17	$8.76	$3.30	$0.34	$1.72	1.0401	1.0415
2018/19	$99.62	$9.98	$3.09	$0.34	$1.72	1.0401	1.0415

Appendix A – Supply-side input assumptions; macroeconomic inputs

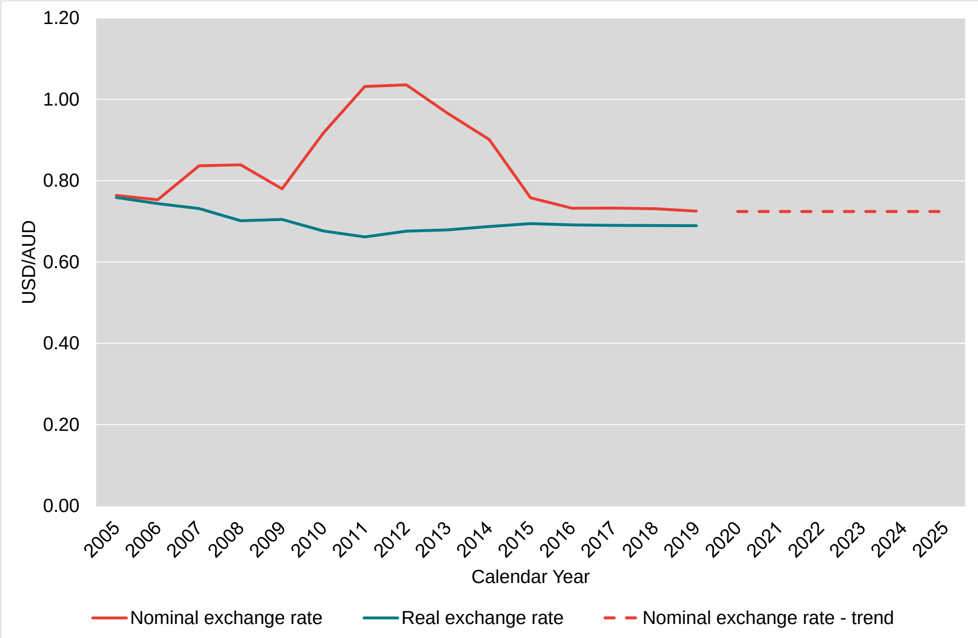
There are a number of macroeconomic input assumptions that are used in developing the input assumptions set out in this report. For consistency, the same macroeconomic input assumptions have been used throughout this report.

A.1 – Exchange rates

As will be discussed in the sections that follow, at various points we make use of both historic and forecast exchange rates and both nominal and real exchange rates. For each of these exchange rates we have relied on data from the International Monetary Fund's World Economic Outlook.[21] This data includes historic nominal and real exchange rates, as well as forecasts of nominal and real exchange rates out to 2020. For nominal exchange rates, for which we require an exchange rate forecast beyond 2020, we have assumed that the exchange rate will remain at the 2020 forecast level for the remainder of the modelling period. Exchange rates for the US dollar are shown in Figure 32 and exchange rates for the Euro are shown in Figure 33.

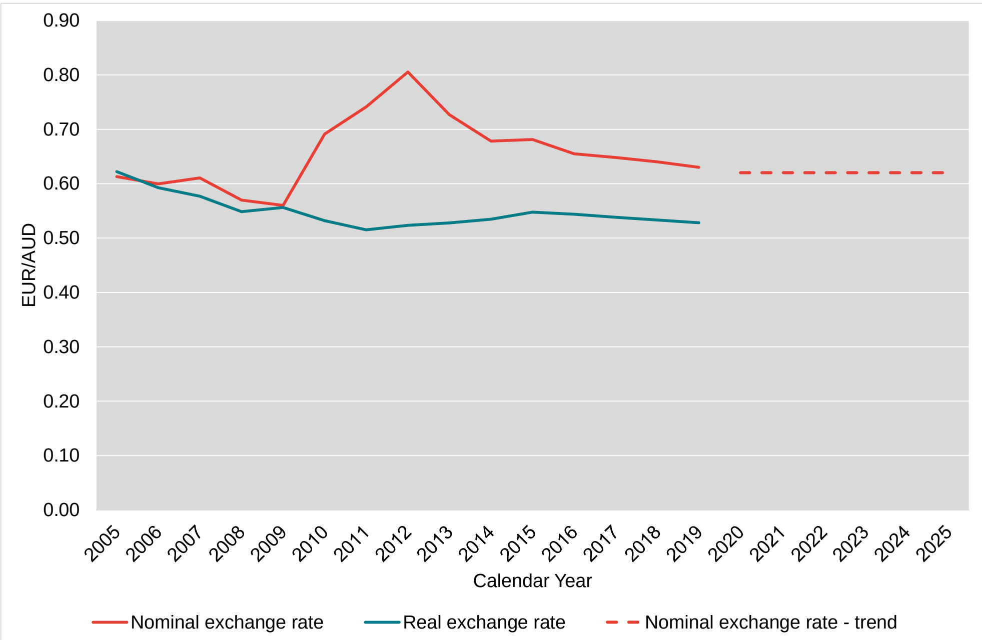
21 We use the most recent available data. At the time of our analysis this was the October 2015 World Economic Outlook. Available at: http://www.imf.org/external/pubs/ft/weo/2015/02/weodata/index.aspx

Figure 32: Exchange rates (USD/AUD)



Source: International Monetary Fund, World Economic Outlook Database, October 2015.

Figure 33: Exchange rates (Euro/AUD)



Source: International Monetary Fund, World Economic Outlook Database, October 2015.

A.2 – Discount rates

We have used different discount rates for different industries. In each case, the discount rate that we have adopted is based on the discount rate determined by IPART as part of their most recent regulatory determination.[22] We have updated relevant parameters used in the calculation of these discount rates to account for current market conditions. Based on this approach, the discount rates that we have used in developing the input assumptions discussed in this report are as follows:

- Electricity generation – 8.3 per cent real pre-tax WACC
- Electricity retailing – 9.53 per cent real pre-tax WACC
- Coal mining – 9.23 per cent real pre-tax WACC
- Gas production – 8.82 per cent real pre-tax WACC
- Gas transmission – 6.7 per cent real pre-tax WACC.

A.3 – Real cost escalation

When forecasting capital and operating costs we need to take account of real cost escalation. This is particularly the case for power station capital and operating costs. To take account of real cost escalation over the forecast period, we adopt the following approach:

- Capital costs are escalated based on the average real increase in the producer price index for domestic goods over the period from 2000 to 2015 – 0.18 per cent per annum.
- Labour costs are escalated based on the average real increase in the labour price index for workers in the electricity, gas, water and waste services industries over the period from 2000 to 2015 – 1.65 per cent per annum.

By adopting this approach we are effectively assuming that the average real increases that we have seen over this period from 2000 to 2015 will continue into the future.

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22 The discount rates provided by IPART as part of their most recent regulatory determinations are set out in our two final reports for IPART's 2013 to 2016 price determination, as well as in IPART's final report. Available here:
http://www.ipart.nsw.gov.au/Home/Industries/Electricity/Reviews/Retail_Pricing/Review_of_regulated_electricity_retail_prices_2013_to_2016
These have subsequently been updated to reflect more recent market data (for instance, in respect of the cost of debt).

Appendix B – Supply-side input assumptions; capital costs

Investors will not commission new generation plant unless they expect to recover the capital costs of building that plant (including an adequate return on their capital). Capital costs of new generation plant are, therefore, relevant to investment decisions in electricity markets, as well as resource costs and electricity prices in the long run.[23]

B.1 – Our approach to estimating capital costs

Our approach to estimating capital costs is a top-down approach: we estimate the capital costs of new generation plant on the basis of a broad survey of reported cost estimates for generation plant of a particular technology.

We implement the top-down approach by making use of our detailed global database of reported capital costs. This global database is populated by publicly available cost estimates from a wide variety of sources, primarily company reports, reports from the trade press, industry and market analysis, and engineering reports. Our database includes estimates of capital costs of specific generation plant that have been commissioned and are operating, as well as capital costs of specific generation plant that are at some stage of planning or construction. Our database also includes estimates of capital costs for generic new generation plant of a particular technology. Our database contains capital cost estimates for a wide range of existing generation technologies that are widely deployed, as well as newer generation technologies that are in various stages of development.

Our database includes reported costs for the principal power stations that have been built, or proposed, in Australia over the past decade. However, the database also has extensive international coverage. For most of the generation technology options that are covered in this report this international coverage is essential, since there has been little or no development activity in Australia for these technologies. Our global database of reported costs is kept continuously up-to-date, so that as new estimates become available they are incorporated in the database.

In order to ensure that the data that we use to estimate capital costs is relevant to current capital costs in Australia, we filter the data in database in the following ways:

23 In contrast, capital costs of existing generation plant are sunk and, therefore, not relevant to economic decisions.

- **Filtering by year**. Our global database includes cost estimates dating back as far as the 1990s and forecasts of future capital costs out to 2050. In order to avoid our cost estimates being affected by changes in technology and learning curves (particularly for the capital costs of some of the newer technologies), we include cost estimates only for projects constructed, or to be constructed, over a narrow range of years. This range varies somewhat from technology to technology; in particular, for technologies for which learning is material we use a narrower range of years.
- **Filtering by country**. Our global database includes cost estimates for a wide range of countries, both developed and developing. In order to avoid cost estimates being affected by significantly different cost structures, we include cost estimates only for projects in OECD economies.
- **Filtering to remove outliers**. In order to avoid our analysis being affected by cost estimates that reflect a particular project that has substantial project-specific cost advantages (or disadvantages), or by cost estimates that reflect a particularly optimistic (or pessimistic) view, we exclude cost estimates that are material outliers.

B.2 – Basis of capital costs

Our estimates of capital costs are intended to reflect the capital costs for a representative generation plant for each of the generation technologies considered in this report.

Our estimates of capital costs include the direct costs of all plant, materials, equipment and buildings inside the power station fence, all labour costs associated with construction, installation and commissioning, as well as owner's costs such as land, development approvals, legal fees, inventories, etc. Our estimates of capital costs do not include the costs of connection to the network, but we have added these connection costs to our capital cost estimates for new generation plant so that the modelled capital cost includes the capital costs 'inside the fence' as well as the cost of connecting to the network.

Our estimates of capital costs are overnight capital costs, expressed in 2015/16 Australian dollars. That is, our estimates do not include interest (or escalation) during construction. These costs are accounted for in the financial model that we use to convert overnight capital costs (in $/kW) into an amortised capital cost (in $/MW/hour) that is used in our electricity market models.

Our estimates of capital costs are expressed in $/kW at the generator terminal (or $/kW GT). Power station auxiliaries (and network losses) associated with the operation of power stations are separately accounted for in our modelling.

B.3 – Estimates of capital costs

Our estimates of current capital costs for each of the generation technologies considered in this report are set out in Figure 34 and Figure 35. Figure 34 deals with coal-fired generation technologies and Figure 35 deals with gas-fired and renewable generation technologies.

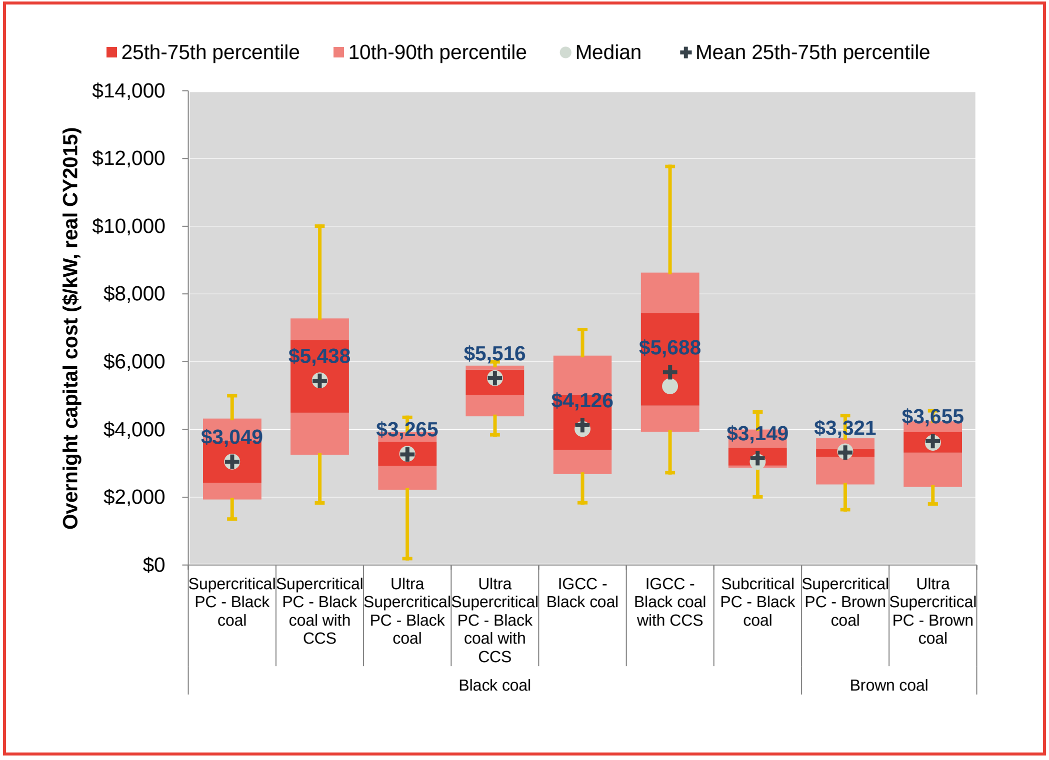
Our estimates of capital costs for each generation technology include a range of individual cost estimates. Even after filtering our global database for relevant countries and years we have a significant number of unique cost estimates for each generation technology. The full range of cost estimates (from lowest cost to highest cost) for each generation technology is shown by the orange "whiskers" in Figure 34 and Figure 35. The range of cost estimates that covers the 10th to 90th percentile of cost estimates is shown by the pale red "boxes" in Figure 34 and Figure 35, and the range of cost estimates that covers the 25th to 75th percentile of cost estimates is shown by the dark red "boxes" in Figure 34 and Figure 35.

Clearly, there are a number of significant outliers in our data – this is seen by the much wider range of costs for the full dataset than for the 10th to 90th percentile. These outliers might arise either because a particular project has project-specific cost advantages (or disadvantages), because a particular estimate of costs reflects a particularly optimistic (or pessimistic) view, or because there are issues with the reported data (for instance, the reported cost may be net of a received subsidy).

While there are outliers, we note that the range for the 25th to 75th percentile is generally reasonably narrow, indicating a reasonable consensus on capital costs for generation plant of that technology. The exception to this is generally for less mature technologies – including Integrated Gasification Combined Cycle (IGCC) and geothermal – for which there is a wide range of estimates of capital costs even within the range of the 25th to 75th percentile.

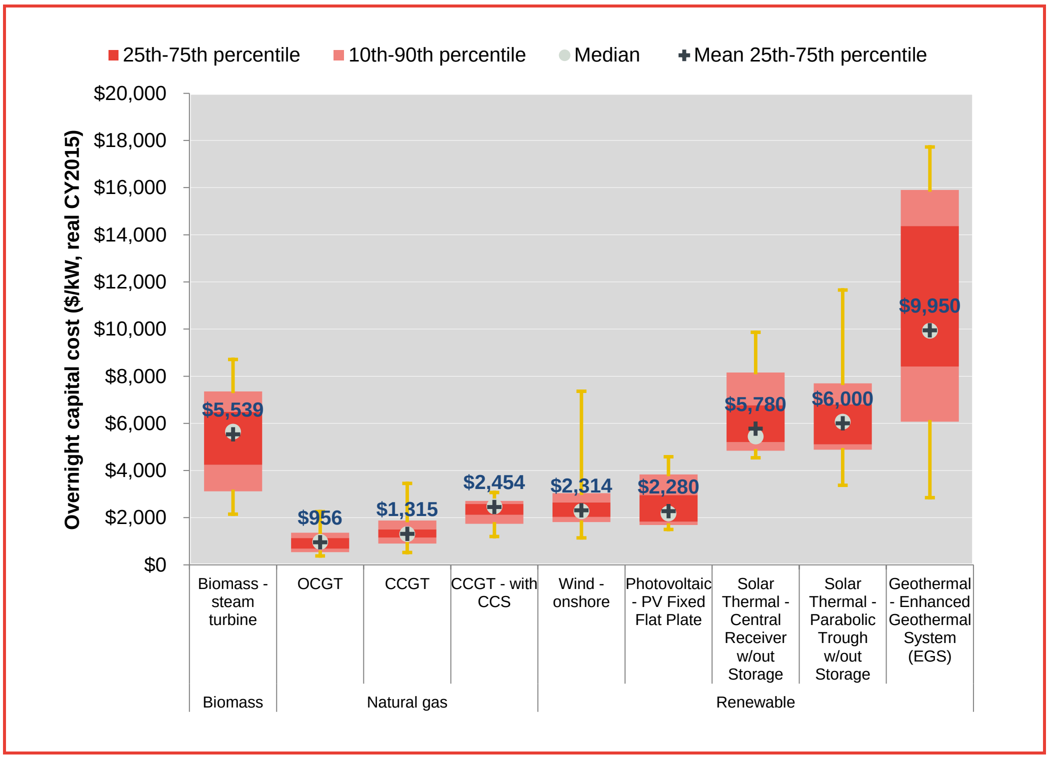
To avoid our analysis being affected by outliers, we estimate current capital costs for each generation technology as the mean of the cost estimates that fall within the 25th to 75th percentile of cost estimates for that generation technology. We note that this mean of the cost estimates that fall within the 25th to 75th percentile is generally very consistent with the median of the full range of data. This suggests to us that using the mean of the cost estimates that fall within the 25th to 75th percentile is a reasonable approach to dealing with outliers.

Figure 34: Current capital costs for coal generation plant



Source: Frontier Economics

Figure 35: Current capital costs for renewable generation plant



Source: Frontier Economics

Estimating capital costs in the SWIS

For all technologies except coal, capital costs in the SWIS are assumed equal to the NEM. However, due to the smaller size of the SWIS market, the optimal unit size for coal technologies is significantly reduced. Specifically, it would not make sense from a system operation perspective to build a 600 MW or larger coal-fired unit in the SWIS, which rules out standard supercritical and ultra-supercritical coal-fired technologies.

To estimate the capital cost of commissioning a new coal-fired power station in the SWIS we have restricted the subset of cost estimates to those with unit sizes approximately half the size of those considered in the NEM. This approach leads to a higher capital cost forecast in the SWIS. For example, supercritical coal is forecast at $3,735/kW in the SWIS, compared to $3,110/kW in the NEM for 2015/16.

We have excluded ultra-supercritical technologies in the SWIS as they require larger unit sizes to achieve the improved efficiencies. It is more likely that less efficient, smaller technologies will be commissioned. We have included a subcritical coal technology in the SWIS with an estimated capital cost of $3,219/kW for 2015/16.

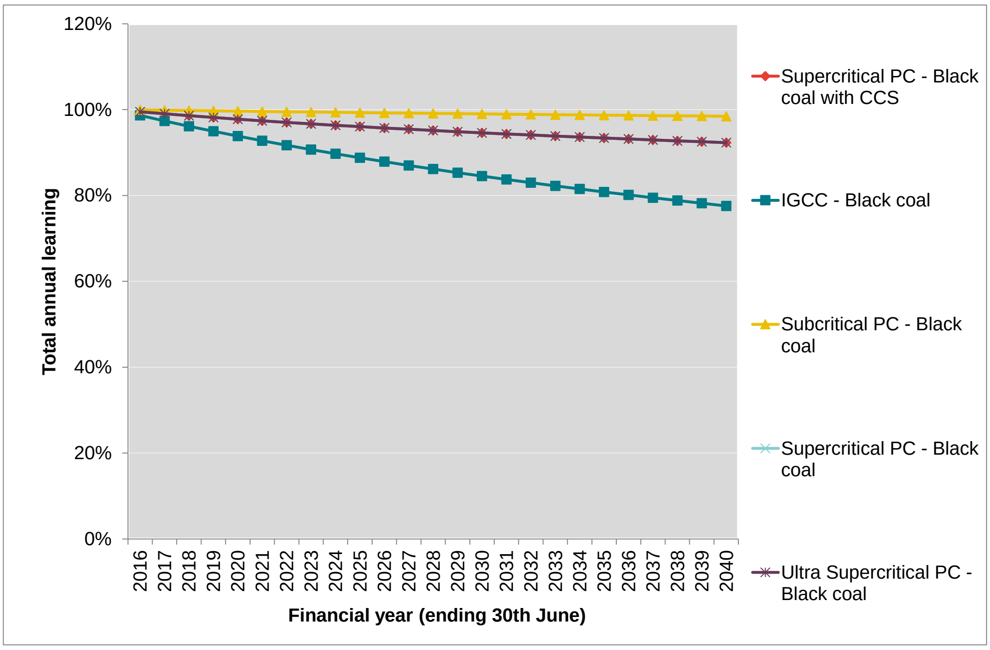
Estimates of capital costs over the modelling period

Since the RET extends to 2030, our modelling of the RET needs to cover at least this period.

This means that we need to develop estimates of capital costs for generation plant that cover this period. Our approach is to use our current estimates of capital costs as the starting point, and vary these estimates over time to account for cost escalation, exchange rate movements and learning curves.

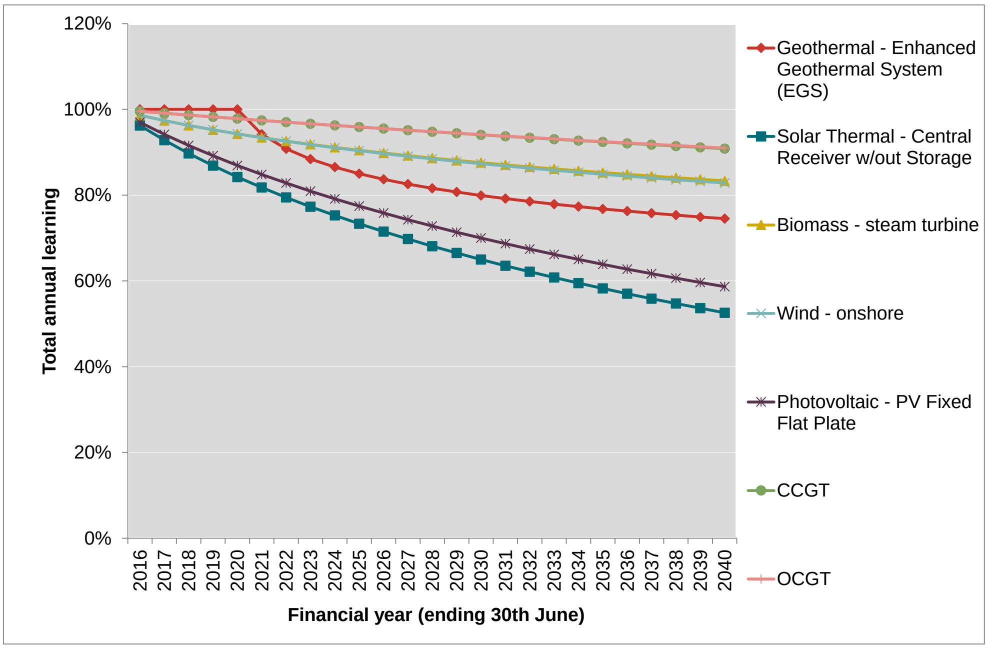
First, we escalate our current estimates of capital costs over the modelling period using the cost escalation discussed earlier to generate a forecast of real increases in the costs of generation plants. Second, we adjust our escalated estimates of capital costs to account for movements in exchange rates, using the exchange rates discussed above. Third, we adjust our estimates of capital costs to account for technological improvements and innovation, through the use of 'learning curves', as shown in Figure 36 and Figure 37.

Figure 36: Learning curves for selected coal generation plant



Source: Frontier analysis based on various sources

Figure 37: Learning curves for gas and renewable generation plant



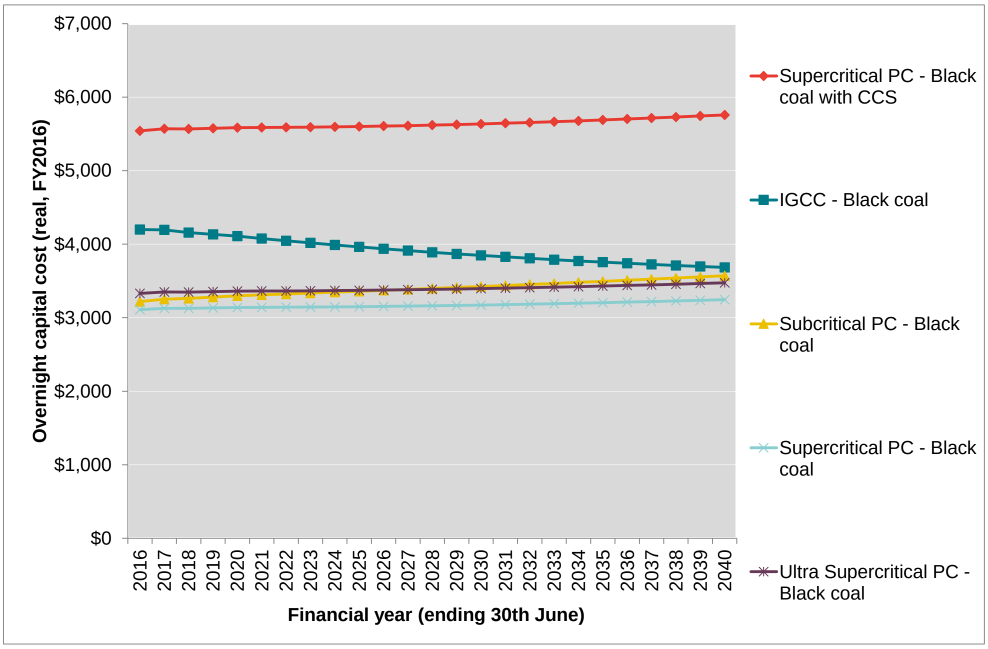
Source: Frontier analysis based on various sources

Taking into account these factors, our estimates of capital costs over the modelling period for each of the generation technologies considered in this report are set out in Figure 38 and Figure 39. Figure 38 deals with coal-fired generation technologies and Figure 39 deals with gas-fired and renewable generation technologies.

As seen in Figure 38, the capital costs for subcritical and supercritical coal-fired generation plants tend to increase over the modelling period. The increasing forecast is the result of the forecast of ongoing real escalation in capital costs and labour costs. The existing coal-fired generation technologies are forecast not to benefit from substantial cost improvements, meaning that, overall, costs increase. As seen in Figure 12, the forecast cost improvements for IGCC technologies outweigh the cost increases, resulting in net cost reductions over the modelling period.

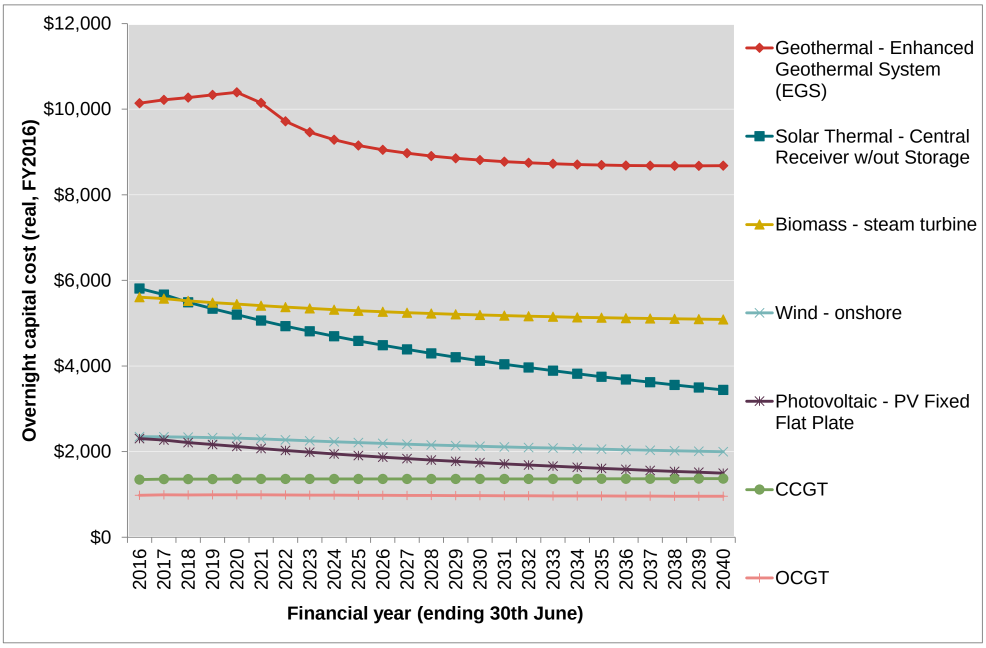
As seen in Figure 39, the capital costs for gas fired and renewable generation plant are more variable over the modelling period. While these generation technologies are subject to increasing costs as a result of real escalation in capital costs, the cost improvements for newer technologies are forecast to be more significant. In particular, solar thermal capital costs fall significantly over the modelling period as the technology is commercialised. Cost reductions for geothermal do not occur until widespread commercialisation is assumed to commence in 2020. In contrast, the expected cost improvements for the established gas fired and renewable technologies – Open Cycle Gas Turbines (OCGT), Combined Cycle Gas Turbines (CCGT), wind and biomass – are more moderate, resulting in more stable costs for these technologies over the modelling period.

Figure 38: Forecast capital costs for coal generation plant ($2015/16)



Source: Frontier Economics

Figure 39: Forecast capital costs for gas and renewable generation plant ($2015/16)



Source: Frontier Economics

Appendix C – Supply-side input assumptions; operating costs and characteristics

There are a range of power station operating costs and characteristics that affect the economics of investment in, and operation of, a power station. These costs and characteristics are required as inputs into our modelling:

- **Fixed operating and maintenance (FOM) costs of new generation plants**. As with capital costs, investors will not commission new generation plant unless they expect to recover the fixed operating and maintenance costs associated with that plant.
- **Variable operating and maintenance (VOM) costs of existing and new generation plant**. The operators of a generation plant will not operate their plant unless they expect to recover the variable operating and maintenance costs associated with operating the plant; if they do not recover these costs, they would do better not to operate the plant.
- **Plant capacity**. Measures the capacity (measured in MW at the generator terminal) of the power station.
- **Equivalent Outage Rate (EOR)**. Measures the equivalent outage rate for the power station, calculated as the sum of full outage hours and the conversion of partial outage hours, to power station full outage hours. Includes planned, forced and breakdown maintenance outages.
- **Maximum capacity factor**. Measures the maximum capacity factor achievable by the power station in any year. The annual capacity factor is measured as the energy production of the power station in the year compared to the total energy production, if the power station operated at full capacity for the full year.
- **Auxiliaries**. Measures the use of energy by the power station. Used to convert plant capacity from a generator terminal (GT) to a sent-out (SO) basis.
- **Heat rate**. Measures the efficiency with which a power station uses heat energy. The heat rate is expressed as the number of GJs of fuel required to produce a MWh of sent-out energy.

C.1 – Our approach to estimating operating costs and characteristics

As with our approach to estimating capital costs (discussed above), our approach to estimating operating costs and characteristics is a top-down approach: we estimate the costs and characteristics for new generation plants on the basis of a broad survey of reported estimates for generation plants of a particular technology.

We implement the top-down approach by making use of our detailed global database of reported operating costs and characteristics. This global database is populated by publicly available estimates from a wide variety of sources, including manufacturer specifications, company reports, reports from the trade press, industry and market analysis, and engineering reports. Our database includes estimates for specific generation plants that have been commissioned and are operating, as well as estimates for specific generation plant that are at some stage of planning or construction. Our database also includes estimates of operating costs and characteristics for generic new generation plant of a particular technology. Our database contains estimates for a wide range of existing generation technologies that are widely deployed, as well as newer generation technologies that are in various stages of development.

Our database includes reported estimates for power stations in Australia and also has extensive international coverage. For most of the generation technology options that are covered in this report this international coverage is essential, since there has been little or no development activity in Australia for these technologies. Our global database of reported operating costs and characteristics is kept continuously up-to-date, so that as new estimates become available they are incorporated in the database.

In order to ensure that the data that we use to estimate operating costs and characteristics is relevant to generation plant Australia, we filter the data in database in the following ways:

- **Filtering by year.** Our global database includes cost estimates dating back as far as the 1990s and forecasts of future operating costs and characteristics out to 2050. In order to avoid our cost estimates being affected by changes in technology and learning curves (particularly for the operating costs and characteristics of some of the newer technologies), we include cost estimates only for projects constructed, or to be constructed, over a narrow range of years. This range varies somewhat from technology to technology; in particular, for technologies for which learning is material we use a narrower range of years.
- **Filtering by country**. Our global database includes cost estimates for a wide range of countries, both developed and developing. In order to avoid cost

estimates being affected by significantly different cost structures, we include cost estimates only for projects in OECD economies.

- **Filtering to remove outliers**. In order to avoid our analysis being affected by estimates that reflect a particular project that has substantial project-specific advantages (or disadvantages), or by estimates that reflect a particularly optimistic (or pessimistic) view, we exclude estimates that are material outliers.

C.2 – Basis of FOM and VOM costs

Our estimates of FOM and VOM costs are intended to reflect the costs for a representative generation plant for each of the generation technologies considered in this report.

Our estimates of FOM and VOM costs include all costs associated with the ongoing operation and maintenance of the generation plant over their expected life. These costs include labour costs as well as materials, parts and consumables. Our estimates of FOM and VOM costs do not include fuel costs or carbon costs, but we separately account for these costs when determining the short run marginal cost of generation plants.

In our experience, there is very little agreement as to what costs constitute **fixed** operating and maintenance costs and what costs constitute **variable** operating and maintenance costs. Economists would typically define fixed operating and maintenance costs as those operating and maintenance costs that do not vary with the level of output of the generation plant and variable operating and maintenance costs as those operating and maintenance costs that do vary with the level of output of the generation plant. In practice, of course, for many operating and maintenance costs there is ambiguity about whether or not they should be thought of as varying with output: for instance, where operating and maintenance costs are related to plant breakdowns, should they be considered fixed or variable? This ambiguity can raise issues in estimating FOM costs and VOM costs: in particular, it is important to ensure that estimates of FOM costs and VOM costs do not double count, or fail to count, any costs. To ensure this, our approach to estimating FOM costs and VOM costs involves the following stages:

- Record total operating costs from each source (including FOM costs and VOM costs). These total operating costs are used to develop our estimates of total operating costs for each generation technology considered in this report.
- Record the proportion of total operating costs that are FOM costs and VOM costs from each source. These proportions are used to develop a single estimate of the proportion of FOM costs and VOM costs for each generation technology considered in this report.

- The proportions of FOM costs and VOM costs are applied to our estimates of total operating costs for each generation technology to develop an estimate of FOM costs and VOM costs for each generation technology.

Our estimates of FOM costs and VOM costs are expressed in 2015/16 Australian dollars. Our estimates of FOM costs are expressed in $/MW/hour at the generator terminal (or $/MW/hour, GT). Our estimates of VOM costs are expressed in $/MWh at the generator terminal (or $/MWh, GT). Power station auxiliaries (and network losses) associated with the operation of power stations are separately accounted for in our modelling.

C.3 – NEM-specific technical characteristics

When modelling new entrant generators in the NEM several additional technical characteristics and constraints are incorporated into the model.

Wind tranches

In order to capture a realistic 'cost curve' for new entrant wind generators that reflects diminishing marginal quality of new wind sites (i.e. an upward-sloping wind supply curve for a given capital cost), our modelling makes use of 4 tranches of wind capacity in each NTNDP Zone, consistent with AEMO's 2015 NTNDP. Each wind tranche has an assumed maximum available capacity in each NTNDP Zone and an assumed maximum annual capacity factor. Capacity factors decline in each wind tranche, resulting in a higher long-run marginal cost for new wind developments as favourable sites are exhausted. The MW availability and associated annual capacity factors for each wind tranche are those applied in AEMO's 2015 NTNDP.[24]

We have made one adjustment to these assumptions for our modelling. The NTNDP assumes that the first tier of wind in Tasmania has a capacity factor higher than all other NTNDP zones. However, we note that existing wind farms have been operating with capacity factors significantly less than other regions. The first tier of wind has therefore been removed in Tasmania to reflect this evidence.

Solar capacity factors by NEM sub-region

The average annual capacity factors for solar plants in the NEM vary considerably depending on the location of the plant. Accurately capturing the annual average capacity factor of solar plants is important – this is because the annual capacity factor is the primary driver of long-run marginal cost. Our

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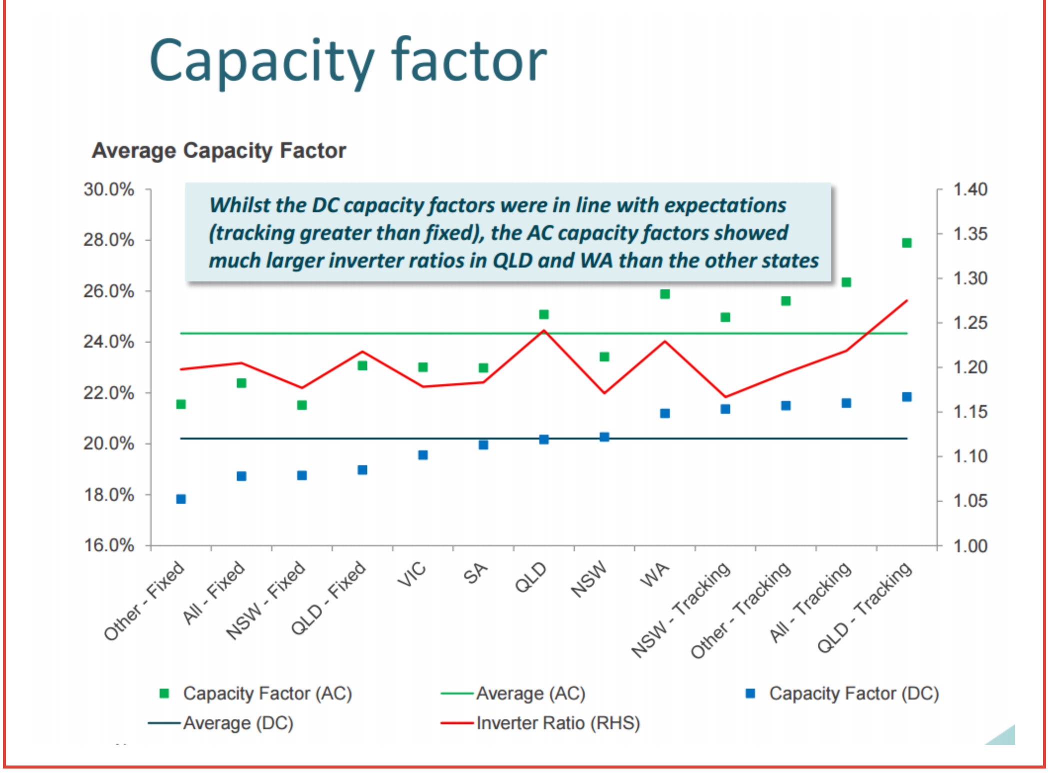
24 http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan

modelling applies the capacity factors for each NTNDP Zone as outlined in AEMO's 2011 NTNDP planning case supply input spreadsheet,[25] and scales these factors to an *average* 22% to reflect technology improvements since this report. This assumption is consistent with the EOI submitted to ARENA's large-scale solar PV competitive round.[26] As seen in Figure 40, the average capacity factor for fixed plate solar PV (in AC, which is closer to our basis) is approximately 22%.

Figure 40: Actual capital costs EOIs from ARENA



Source: ARENA Large scale Solar PV Competitive Round EOI Data

Technology-specific build limits

To capture real-world commercial and technical constraints in commissioning generators over a certain timeframe in the NEM, the modelling assumes a variety of annual and total build limits. Total build limits for each technology by

25 http://www.aemo.com.au/Consultations/National-Electricity-Market/Closed/~/media/Files/Other/planning/0418-0013%20zip.ashx

26 http://arena.gov.au/files/2016/03/ARENA-Large-scale-Solar-PV-Competitive-Round_EOI-Data-Output_March-2016.pdf

NTNDP Zone are those applied in AEMO's 2015 NTNDP. In addition, an annual build limit of 500 MW in each NEM region in each year has been imposed on wind investment. This assumption is necessary to prevent the model attempting to commission an unrealistically large quantity of wind generation in a concentrated area of the NEM in a single year.

Technical characteristics of existing generation plant

In addition to technical characteristics for new entrant generation plants, our market modelling also makes use of technical characteristics for existing generation plant.

The technical characteristics of specific existing generation plants can be difficult to accurately assess. The reason is that these characteristics will not just be affected by the generation technology of the plant, but also by a number of factors specific to the plant including its age, how the plant has been operated over its life and continues to operate, how the plant has been maintained, and the quality of fuel that the plant has burned and continues to burn.

Without specific knowledge of these factors, anything other than generic estimates of the technical characteristics of existing generators is impractical. Rather than rely on generic estimates of these characteristics for existing generators, we have adopted the data used by AEMO in their NTNDP modelling. Given that AEMO engages in stakeholder consultation in developing these assumptions for their modelling, we consider that these assumptions are more likely to reflect the actual technical characteristics of existing generators, than the generic estimates.

Appendix D – Supply-side input assumptions; coal prices for power stations

In order to model outcomes in the electricity market over the period to 2030, we need an estimate of the marginal cost of coal supplied to each existing coal-fired power station, and each potential new coal-fired power station.

This section provides an overview of the methodology that we have adopted for estimating the marginal cost of coal supplied to a power station, and sets out our forecasts of coal prices.

D.1 – Methodology

Our approach to forecasting coal prices is based on determining the marginal opportunity cost of coal for power stations.

Marginal cost of coal

The marginal cost of coal to each power station is the cost the power station would face for an additional unit of coal. The marginal cost of coal to a power station is likely to differ from the average cost of coal to a power station because the average cost of coal will reflect the price of coal under the various long-term coal supply contracts that power stations typically have in place. For instance, a power station that has in place a number of long-term coal supply contracts at low prices would have an average price of coal that reflects these low contract prices. However, if that power station faced higher market prices in purchasing an additional unit of coal, then the marginal cost of coal would reflect these higher market prices.

The reason that we forecast coal prices faced by coal-fired generators on the basis of marginal costs, rather than average costs, is that economic decisions about the operation and dispatch of power stations should be based on marginal costs rather than average costs. For instance, a power station with a low average cost but high marginal cost (as considered above) would reduce its profit if it increased dispatch and recovered its average cost but not its marginal cost: the additional dispatch requires the use of additional coal priced at the market price for coal, and if the revenue from that additional dispatch does not cover this marginal cost, the additional dispatch will reduce total profits.

We base the marginal cost of coal faced by a coal-fired generator on the market price for coal available to that generator. To determine this market price, we ultimately need to construct a demand curve and a supply curve for coal supplied to coal-fired generators. First, however, we need to consider how to assess the costs of supply to coal-fired generators, which we assess on the basis of the opportunity cost.

Opportunity cost of coal

When economists think about cost, they typically think about opportunity cost. The opportunity cost of an activity is measured by economists as the value of the next best alternative that is foregone as a result of undertaking the activity. For instance, the opportunity cost to a home owner of living in their house could be the rent that is foregone as a result of the decision to live in the house.

Opportunity cost is relevant to assessing the cost to coal producers of supplying coal to coal-fired generators because coal producers may well be foregoing alternative markets for that coal in supplying to a coal-fired generator. For instance, a coal producer that has access to the export market may well be foregoing the export price of coal (less any export-related costs) in supplying to a coal-fired generator. In this case, the export price (less any export-related costs) may be relevant to the opportunity cost of supplying coal to a coal-fired generator.

Clearly then, the markets to which a coal producer has access is important in considering the opportunity cost to that coal producer of supplying to a coal-fired generator. We distinguish between two types of coal mine:

- **Coal mines that do not have access to an export market**. Where coal mines do not have access to an export market it is generally as a result of the absence of the infrastructure necessary to transport coal from the mine to port. In many cases these coal mines are co-located with power stations and supply direct to the power stations through conveyors. These power stations are known as mine-mouth power stations. For these coal mines that do not have access to an export market, the coal producer is not foregoing the export price of coal in supplying to a coal-fired generator and, therefore, the export price is not relevant to the opportunity cost of supplying coal to a coal-fired generator. Indeed, for these coal mines, the coal producers' next best alternative is likely to be simply investing its capital in some other activity, so that the opportunity cost of supplying to a coal-fired generator is simply the resource costs of producing coal, including a competitive return on capital.
- **Coal mines that do have access to an export market**. Where coal mines do have access to an export market, this implies that the coal mine has access to the infrastructure necessary to transport coal from the mine to port. These mines may also supply coal to other users, including coal-fired power stations. For these coal mines, in the absence of any export constraints the coal producer is foregoing the export price of coal (less any export-related costs) in supplying to a coal-fired generator and, therefore, the export price (less any export-related costs) is relevant to the opportunity cost of supplying coal to a coal-fired generator. Importantly, for these coal mines, the opportunity cost of supplying to a coal-fired generator is the **value** of exporting coal, which implies that it is necessary to consider both the revenue

from exporting coal and the additional cost of exporting coal. This value is typically known as the net-back price of coal.

It should be noted that simply because a coal mine has access to an export market, this does not mean that the net-back price of coal is the relevant opportunity cost. Indeed, if the net-back price is lower than resource costs, this implies that exporting coal is not the next best alternative (and, indeed, may imply that exporting coal is a loss-making exercise). Rather, the coal producer's next best alternative is likely to be simply investing its capital in some other activity, so that the opportunity cost is the resource costs of producing coal, including a competitive return on capital. In short, for coal mines that do have access to an export market, the opportunity cost of supplying to a coal-fired generator is the higher of resource costs and the net-back price.

Resource costs

Resource costs are the capital and operating costs associated with coal production. In estimating resource costs, our initial focus is on mine-gate resource costs. These are the direct costs associated with all activities within the mine, including mining, processing and loading coal.

Mine-gate costs do not include royalties or transport costs. We also account for royalties and transport costs when estimating the marginal cost of coal, but because transport costs are different for different power stations (depending on their location) we account for transport costs when estimating the marginal cost of coal to each power station.

We separately estimate the following categories of resource costs:

- Upfront capital costs – upfront capital costs are the costs of establishing a coal mine and include costs of items such as pre-stripping, mining equipment, loading equipment, crushers, screens, washeries, access roads, dams, power and other infrastructure. Capital costs for existing coal mines are sunk, and therefore we do not account for these when considering the marginal cost of coal from these mines. Capital costs for new coal mines are not sunk, and therefore we do account for these when considering the marginal cost of coal from these mines.
- Ongoing capital costs – ongoing capital costs are the costs of ongoing investment in a coal mine to replace major equipment and develop new mining areas. Ongoing capital costs for both existing and new mines are not sunk, and therefore we account for these when considering the marginal cost of coal.
- Operating costs, or mine-gate cash costs – cash costs are the costs associated with producing saleable coal from the mine, and include labour costs and other mining and processing costs. Since cash costs of coal mines are

variable, we account for these costs when considering the marginal cost of coal.

- Royalties – are payments to the State Government for the right to make use of the State's coal resources.
- Transport costs – transport costs are the costs associated with delivering coal from the mine-gate to the power station.

These separate elements of resource costs are accounted for, for each coal mine that supplies the domestic market. We have developed a model of resource costs that relate the key characteristics of each coal mine – including strip ratio, overburden and coal quality – to the various categories of resource costs.

Net-back price of coal

In this context, the net-back price of coal refers to the revenue that a coal producer would earn from exporting its coal to the international market, less all of the additional costs that would be incurred by the coal producer as a result of a decision to export the coal rather than sell it domestically, measured at the mine-gate.

As we have seen, the net-back price of coal is relevant to determining the opportunity cost of coal to a coal producer that has access to the export market because the net-back price of coal measures the value that the coal producer would forego if, having produced a unit of coal, it decided to supply that unit of coal to a domestic power station rather than export that unit of coal.

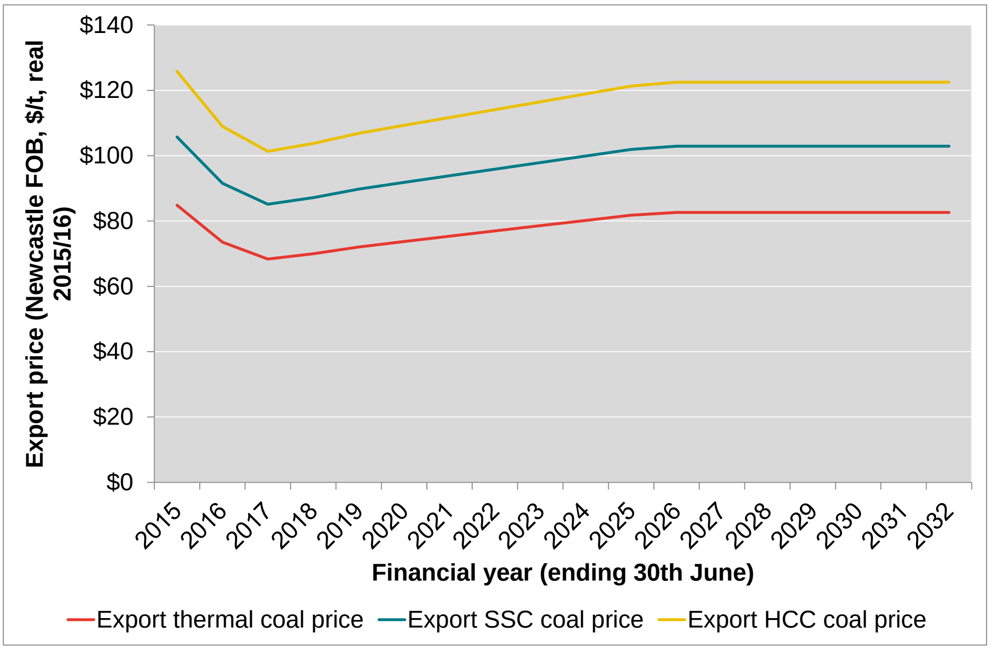
The **first step** for calculating the net-back price of coal is a forecast of the export price of coal. It is this export price that determines the revenue that a coal producer will earn by exporting coal.

The export prices that we have used to calculate the net-back price of coal are from quarterly forecasts released by the World Bank.[27] The World Bank provides forecasts of the export price of thermal coal out to 2025. We have developed consistent forecasts for Semi-Soft Coking Coal (SSC) and Hard Coking Coal (HCC) based on relativities between current thermal, semi-soft and hard coking coal prices out of Newcastle.[28] These export prices, which are in USD/tonne, are converted to AUD/tonne based on the forecast nominal exchange rate set out above. This results in the export prices shown in Figure 41.

27 http://pubdocs.worldbank.org/pubdocs/publicdoc/2016/4/173911461677539927/CMO-April-2016-Historical-Forecasts.pdf

28 https://www.platts.com/IM.Platts.Content/ProductsServices/Products/coaltraderintl.pdf

Figure 41: Export coal prices ($2015/16)



Source: World Bank and Metalytics analysis

The export revenue that a coal producer earns will ultimately depend on the quality of the coal that it produces. The coal prices shown in Figure 41 are for coal of a particular quality. For instance, the export thermal coal price shown in Figure 41 is for coal that meets the benchmark specification of 6,300 cal/kg. For coal that has a different specification, the coal price received by the coal producer will be adjusted according: lower specification coal will receive a lower price and higher specification coal will receive a higher price.

This means that calculating the net-back price of coal requires an estimate of the coal quality for each mine. Coal specifications for export product are generally revealed in company reports or industry publications such as the TEX Report. Many domestic coal calorific values are published in the Register of Australian Mining. In other cases, industry knowledge, the mine's yield and partial pricing signals, provide a reasonable estimate. Our estimates of energy content for domestic thermal coal take into consideration that:

- producers may vary the quality of their product depending on demand from domestic or offshore utilities,
- the quality of the coal being mined may vary through time;
- it may include washery middlings or raw coal which, unprocessed, has little quality consistency.

The **second step** for calculating the net-back price of coal is to estimate the costs that a coal producer will avoid if it does not export coal.

The avoided costs that need to be taken into account in calculating the net-back price of coal are:

- Port fees – we have obtained information on port fees directly from Port Waratah Coal Services and the Newcastle Coal Infrastructure Group. Information on other port charges has come from industry sources and company reports.
- Transport costs – rail costs are calculated using access charges, loading rates and distance travelled.
- Administration and marketing costs – these costs are based on industry estimates.
- The costs of managing exchange rate and counterparty risk – these costs are based on industry estimates.
- Washing costs – these costs are assessed using mine-by-mine information (when available) as well as the mine's yield.

The avoided costs will differ from mine to mine, driven by differences in location, export port and requirements to wash coal. Generally speaking, the avoided costs associated with port fees and transport range from around $8/t to around $23/t, the avoided costs associated with administration, marketing and risk management are around $17/t and the avoided costs associated with washing range from $0/t (for coal mines that do not need to wash their coal) to around $9/t.

The **final step** in calculating the net-back price of coal is to adjust for any differences in yield between coal supplied to the export market and coal supplied to the domestic market.

The yield of a coal mine measures the ratio between tonnes of run-of-mine coal and tonnes of saleable coal. Differences between tonnes of run-of-mine coal and tonnes of saleable coal result primarily from washing: washing improves the quality of coal but reduces the tonnage of coal.

Where a coal mine washes export coal but does not wash domestic coal (or washes the coals to different extents) there will be a difference in yield. This means that a decision to export a unit of coal rather than to sell it domestically will result in a reduction in the tonnes of saleable coal – a higher export price will be received for the higher-quality washed coal, but fewer tonnes will be sold as a result of the washing.

We account for any difference in yield between coal supplied to the export market and coal supplied to the domestic market when calculating the net-back price of coal.

Summary of results

D.2 – Coal price forecasts

In order to model outcomes in the electricity market, we need an estimate of the marginal cost of coal supplied to each existing coal-fired power station, and each potential new coal-fired power station.

This section provides an overview of the methodology that we have adopted for estimating the marginal cost of coal supplied to a power station, and sets out our forecasts of coal prices.

Coal price forecasts for existing mine-mouth power stations

In the case of mine-mouth coal-fired generators, there is no coal region or coal market as such – the cost of coal to mine-mouth coal-fired generators is based simply on the resource cost of the associated mine (on the basis that the coal supplied by the mine has no realistic alternative use).

We have developed estimates of the resource costs of each mine in NSW and Queensland that supplies thermal coal to power stations in the NEM, including each existing mine supplying mine-mouth power stations. These estimated resource costs include ongoing capital costs, cash costs, carbon costs and royalties.

For some mines that supply mine-mouth power stations, there is a real shortage of data on resource costs. This is particularly the case for brown coal mines in Victoria. The problem with these mines is that there has been no investment in new coal mines in these regions for many years, and also no investment in equivalent mines in other regions (in particular, brown coal mines), which means that there is very little up-to-date information on the likely resource costs for mines of this type. For this reason, rather than estimating the cost of coal supplied to power stations from Victoria's brown coal mines on the basis of a detailed estimate of resource costs, we have estimated these costs on the basis of the observed bidding of these power stations. By observing the average price bands in which these power stations have historically bid a material proportion of their capacity, and adjusting these electricity prices to account for the efficiency of the power stations and the power stations' VOM costs, we estimate the cost at which these power stations are supplied with coal.

The Victorian government announced a three-fold increase in the brown coal royalty from 7.6 cents to 22.8 cents per GJ, effective from 1 January 2017.[29] We have incorporated this additional cost of coal production in our coal price forecast for all Victorian coal plant.

29 http://www.premier.vic.gov.au/delivering-a-fair-share-for-victorians/

Coal price forecasts for existing power stations that are not mine-mouth

In the case of power stations that are not mine-mouth, the power station is generally supplied from a coal region in which a number of coal mines supply one or more coal-fired power stations through a network of delivery options (including conveyor, truck and rail). There are two coal regions in the NEM that can be characterised in this way:

- The Central Queensland coal region (in the NTNDP zone, CQ), in which Stanwell and Gladstone power stations are able to source coal from a number of coal mines that also have an export option.
- The Central NSW coal region (in the NTNDP zone, NCEN), which consists of a western region in which Bayswater, Liddell and Mt Piper power stations are located and a coastal region in which Eraring and Vales Point power stations are located. Across this combined region coal can be sourced from a number of coal mines that also have an export option.

Assessing demand and supply in these regions is clearly more complex than doing so for mine-mouth power stations. To determine the cost of coal supplied to coal-fired power stations in these regions, we develop a supply curve and a demand curve for the region.

The supply curve for each coal region is based on the annual capacity of each coal mine to supply thermal coal to domestic power stations and the opportunity cost faced by each coal mine for such supply, where the opportunity cost faced by each coal mine is determined as the higher of the resource cost of supply from the coal mine and (where the mine has option to export) the net-back price of coal for the coal mine.

The demand curve for each coal region is based on an estimate of the annual coal used by coal-fired generators in each region. The annual coal used by coal-fired generators is calculated based on their annual dispatch, adjusted by the heat-rate for the plant.

The marginal opportunity cost of coal in each region is determined by the point of intersection of the demand curve for coal in the region and the supply curve for coal in the region.

Coal price forecasts for new entrant power stations

In addition to considering options for coal supply to all existing coal-fired power stations, it is also necessary to consider the coal supply options to potential new entrant power stations in those regions in which new entrant coal-fired power stations are a possibility. We have estimated capital costs, ongoing capital costs and cash costs for potential new mines in each region in which there are no coal reserves.

The new mine's cash costs are drawn from estimates for existing mines and adjusted to match the average stripping ratios for the relevant region. Labour costs relate to expected volumes, average productivity and the method of mining.

Coal price forecasts for the high case

In addition to our Base case forecasts for coal prices (as discussed above) we have also forecast coal prices for a high case. This case assumes that higher export coal prices are 10% higher than the current World Bank forecasts.

Appendix E – Supply-side input assumptions; gas prices for power stations

In order to model outcomes in the electricity market, we need an estimate of the marginal cost of gas supplied to each existing gas-fired power station, and each potential new gas-fired power station.

This section provides an overview of the methodology that we have adopted for estimating the marginal cost of gas supplied to a power station, and sets out our forecasts of gas prices.

E.1 – Methodology

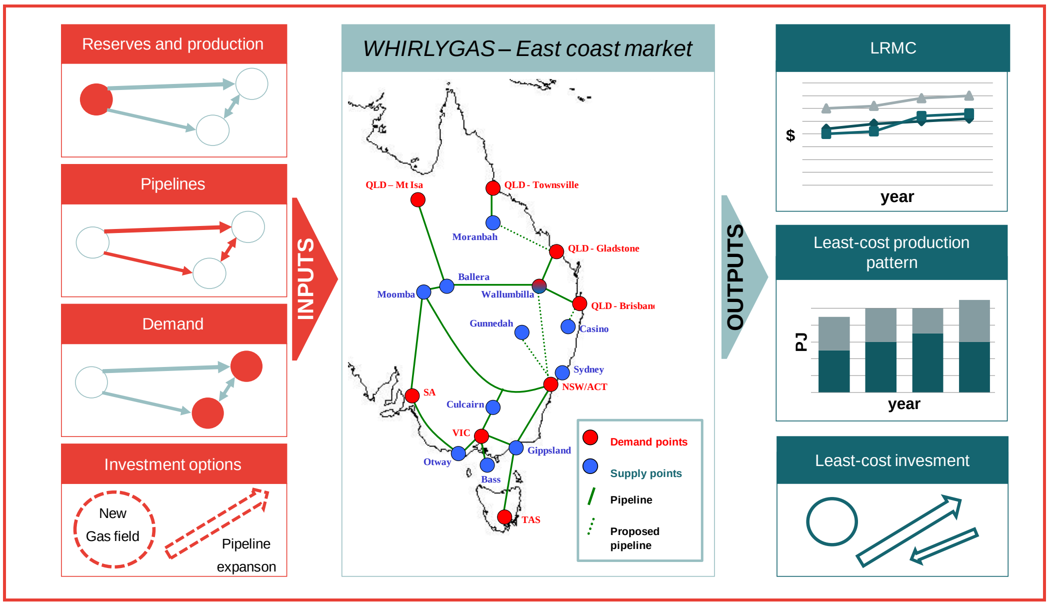
We estimate the cost of gas supplied to gas-fired power stations based on the marginal opportunity cost of gas.

When estimating the marginal opportunity cost of coal, we can do so on a region by region basis, because there is no substantial interconnection between coal supply regions. However, the same is not true of gas: gas regions in eastern Australia are now interconnected through a network of gas transmission pipelines, so that estimating the marginal opportunity cost of gas requires a model that can account for this interconnection. We use our gas market model – *WHIRLYGAS* – for this purpose.

Overview of WHIRLYGAS

WHIRLYGAS is a mixed integer linear programming model used to optimise investment and production decisions in gas markets. The model calculates the least cost mix of existing and new infrastructure to meet gas demand. *WHIRLYGAS* also simultaneously optimises total production and transport costs in gas markets and estimates the LRMC of each demand region in the gas market. A visual summary of the model is provided in Figure 42.

Figure 42: *WHIRLYGAS* overview



Source: Frontier Economics

WHIRLYGAS is configured to represent the physical gas infrastructure in eastern Australia including all existing gas reserves, all existing production plant, all existing transmission pipelines and new plant and pipeline investment options. *WHIRLYGAS* is also provided with the relevant fixed and variable costs associated with each piece of physical infrastructure.

WHIRLYGAS seeks to minimise the total cost – both fixed and variable costs – of supplying forecast gas demand for eastern Australia's major demand regions. This optimisation is carried out subject to a number of constraints that reflect the physical structure and the market structure of the east coast gas market. These include constraints that ensure that the physical representation of the gas supply market is maintained in the model, constraints that ensure that supply must meet demand at all times (or a cost equal to the price cap for unserved gas demand is incurred), and constraints that ensure that the modelled plant and pipeline infrastructure must meet the specified reserve capacity margin.

WHIRLYGAS essentially chooses from an array of supply options over time, ensuring that the choice of these options is least-cost. In order to satisfy an increase in demand over the forecast period and avoid paying for unserved gas demand, *WHIRLYGAS* may invest in new plant and pipeline options. *WHIRLYGAS* may also shut-down existing gas fields and production plant where gas reserves become exhausted, or where they become more expensive than new investment options.

After generating the least cost array of investment options, the model is able to forecast gas production rates and pipeline flow rates, and to provide an estimate of the LRMC of satisfying demand in each demand region in each forecast year. The gas production rates and pipeline flow rates are determined by the least-cost combination of plant and pipeline utilisation that satisfies forecast demand. The LRMC is determined by the levelised cost of the plant and pipelines utilised in meeting a marginal increase in demand at each major demand region. The LRMC is also determined with regard to the scarcity of gas since, for each forecast year, the model considers the trade-offs from consuming gas that is produced from finite gas reserves in that year, as opposed to consuming the gas in other forecast years and in other demand regions (including as LNG exports).

Opportunity costs in WHIRLYGAS

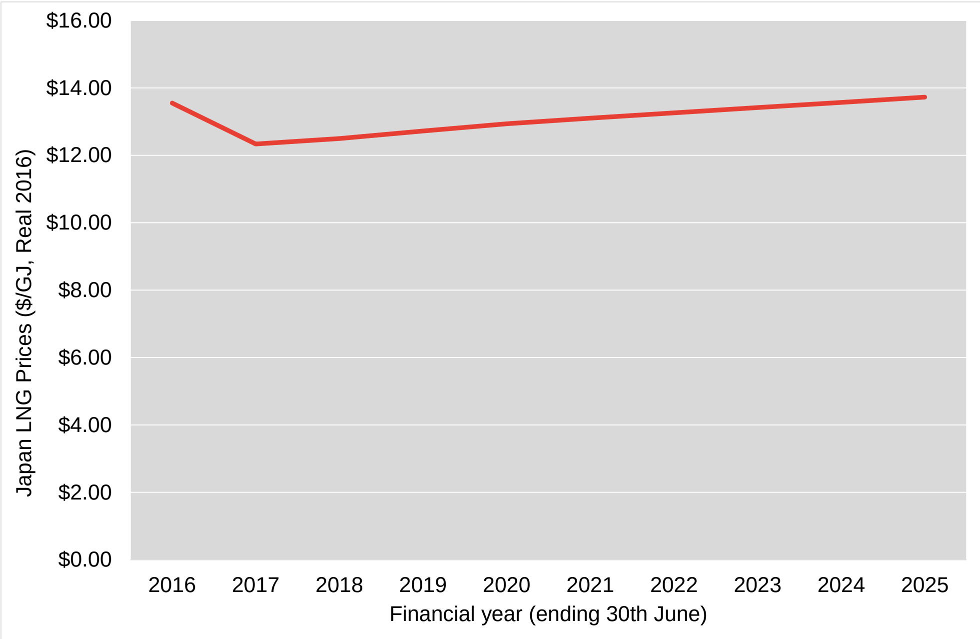
As with our coal forecasting work, opportunity cost is important to our gas forecasting work. The reason that opportunity cost is relevant to assessing the cost to gas producers of supplying gas to gas-fired generators is because the producers may well be foregoing alternative markets for that gas. For instance, a gas producer that has access to the export market may well be foregoing the export price of gas (less any export-related costs). In this case, the netback price may be relevant to the opportunity cost of supplying gas to a gas-fired generator.

The **first step** in calculating the net-back price of gas is a forecast of the export price of LNG. It is this export price that determines the revenue that an LNG exporter will earn by exporting gas.

The export price that we have used to calculate the net-back price of gas is from quarterly forecasts released by the World Bank.[30] The World Bank provides forecasts of the Japanese LNG price out to 2025. These prices, which are in USD/mmbtu, are converted to AUD/GJ based on forecast nominal exchange rate discussed above. This results in the export prices shown in Figure 43.

30 http://pubdocs.worldbank.org/pubdocs/publicdoc/2016/4/173911461677539927/CMO-April-2016-Historical-Forecasts.pdf

Figure 43: Japan LNG prices ($2015/16)



Source: World Bank, Commodity Price Forecast, January 2016.

The **second step** for calculating the net-back price of gas is an estimate of the costs that an LNG exporter will avoid if it does not export LNG.

The avoided costs that need to be taken into account in calculating the net-back price of gas are:

- Shipping costs – estimates of the cost of shipping LNG from Gladstone to Japan are based on industry estimates.
- Liquefaction costs – estimates of the capital and operating costs associated with liquefaction of LNG are based on a Frontier Economics database of these costs.
- Pipeline costs – estimates of the capital and operating costs associated with transmission pipelines are based on the same Frontier Economics database of pipeline costs.
- The costs of managing exchange rate risk – these costs are based on industry estimates.

The **third step** in calculating the net-back price of gas is to adjust for the gas used in liquefaction. This use of gas in liquefaction means that there is a difference in the quantity of gas that can be supplied to the export market and the quantity of gas that can be supplied to the domestic market. Specifically, the use of gas in the liquefaction process means that exporting gas as LNG results in a reduction in saleable quantities relative to supplying gas to the domestic market.

Summary of results

The **final step** in calculating the net-back price of gas is to adjust for the effect of the discount rate on any revenues earned as a result of exporting LNG. If it is the case that the opportunity to export gas as LNG does not arise for several years (for instance because an LNG plant is still under construction, a new LNG plant would need to be constructed, or a relevant shortage of gas supplies to an existing LNG plant does not arise for a number of years) then the potential revenue from exporting this gas as LNG needs to be discounted to account for the time value of money. If gas can be supplied to the domestic market sooner, the effect of this discounting can have a material impact on the effective net-back price of gas.

This discounting is accounted for within *WHIRLYGAS*. As discussed, the model can test whether it is indeed the case that there is sufficient capacity in all required export-related infrastructure to export additional gas as LNG. Where there is a scarcity of liquefaction capacity (as opposed to a shortage of gas reserves or gas production capacity) the opportunity cost for gas producers need not reflect the net-back price. However, where there is a relevant scarcity of gas reserves or gas production capacity to meet LNG exports, the timing of this scarcity is important for determining the effective net-back price of gas.

Model inputs

The key modelling inputs for *WHIRLYGAS* under this approach are:

- gas demand forecasts for each major gas demand region
- gas reserves in eastern Australia
- the relevant costs and technical parameters of existing and new production plant in eastern Australia
- the relevant costs and technical parameters of existing and new transmission pipelines in eastern Australia
- the price of LNG in the Asia-Pacific region.

Model outputs

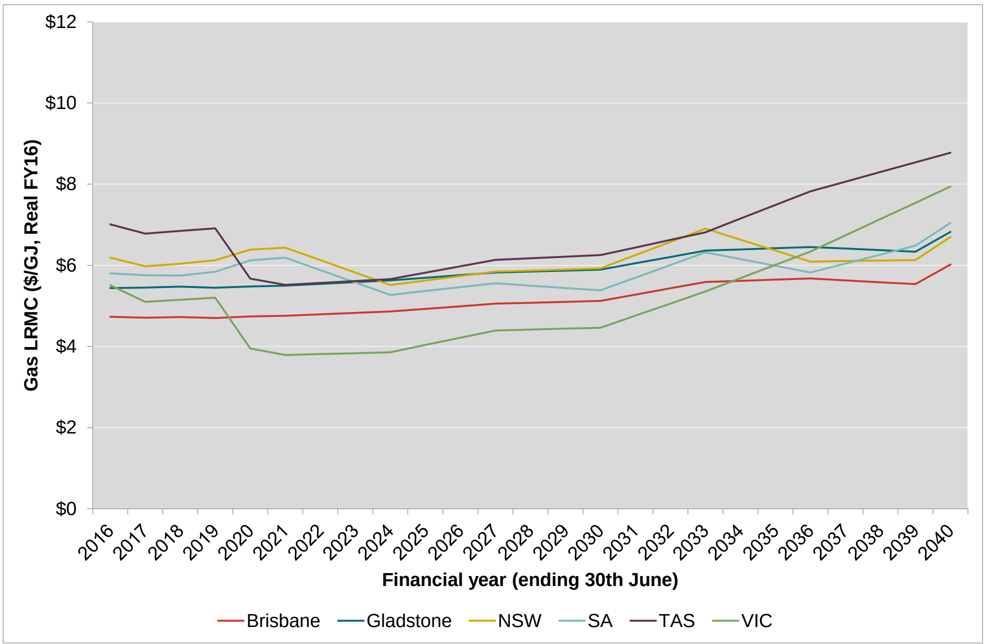
The key modelling outputs for *WHIRLYGAS* under this approach are:

- forecasts of the LRMC of satisfying demand in each demand region
- forecasts of investment in new production plants in eastern Australia
- forecasts of investment in new transmission pipelines in eastern Australia
- forecasts of production rates for existing and new production plants
- forecasts of flow rates for existing and new transmission pipelines
- forecasts of remaining gas field reserves in eastern Australia.

E.2 – Gas price forecasts

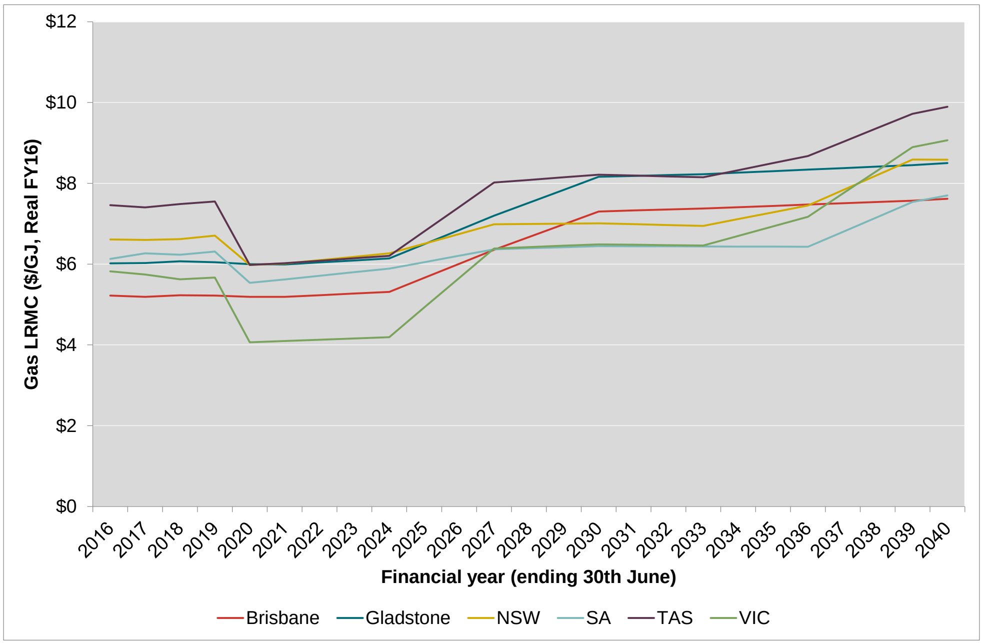
Gas prices are driven by demand for gas, international LNG prices, foreign exchange rates and underlying resource costs associated with gas extraction and transport. Frontier's Base case and high case forecasts are shown in Figure 44 and Figure 45 for a selection of pricing zones across Australia. The Base case incorporates the development of 6 LNG trains at Gladstone, the World Bank's most recent LNG price forecast and our central estimate of production costs for new gas projects in Australia. The high case incorporates the development of 7 LNG trains at Gladstone, a previously higher LNG price forecast from the World Bank and a high case for the production costs for new gas projects in Australia.

Figure 44: LRMC of gas by State capital cities ($2015/16) – Base case



Source: Frontier Economics

Figure 45: LRMC of gas by State capital cities ($2015/16) –High case



Source: Frontier Economics

Gas price forecasts for gas-fired power stations

The LRMC of gas set out above is used in our electricity market modelling as the cost of gas to CCGT plant, which tend to operate on a mid-merit basis at a reasonable capacity factor. OCGT plants, however, tend to operate as peakers at a much lower capacity factor. The cost of gas to an OCGT plant is likely to be higher than the cost of gas to an CCGT plant to the extent that OCGT plants consume gas when prices are higher than average. Our analysis suggests that, at the capacity factor that OCGT plants tend to operate at in the NEM, these plants are likely to face gas costs that are 50 per cent higher than the gas costs faced by CCGT plants in the same region. Based on this, the cost of gas OCGT plants that are used in our electricity market modelling is the LRMC of gas in each NTNDP Zone, increased by 50 per cent.

Gas price forecasts for the high case

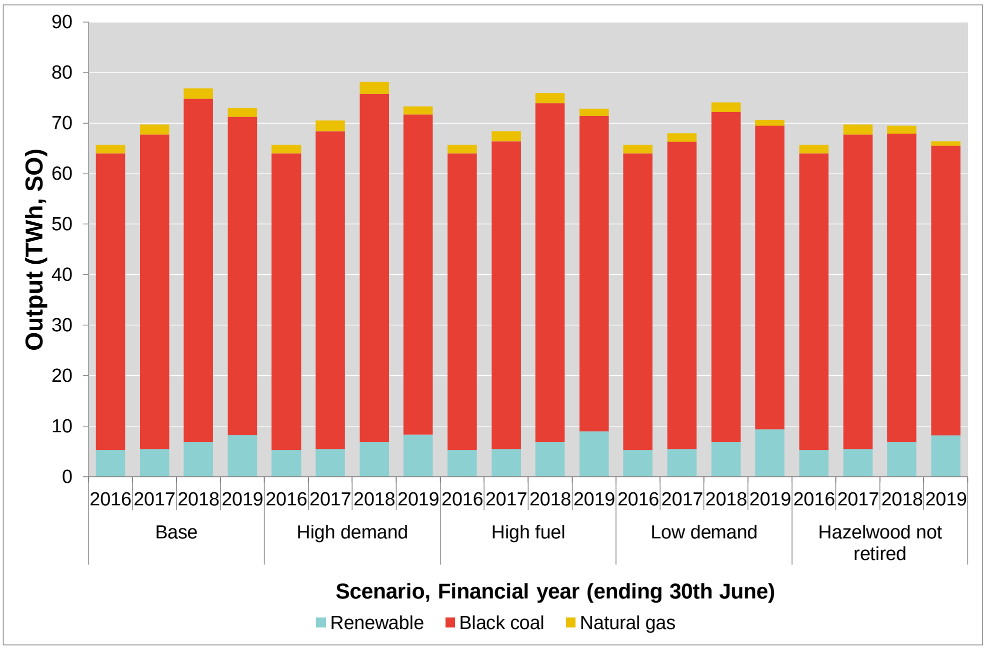
In addition to our Base case forecasts for gas prices (as discussed above) we have also forecast gas prices for a high case. This case applied the high demand scenario from the 2015 NGFR, which has higher domestic gas demand and also assumes the development of a seventh LNG export train at Gladstone. This case also assumes higher domestic gas production costs and that the Asia-Pacific LNG price is higher.

Appendix F – Regional modelling results

F.1 – Annual dispatch results

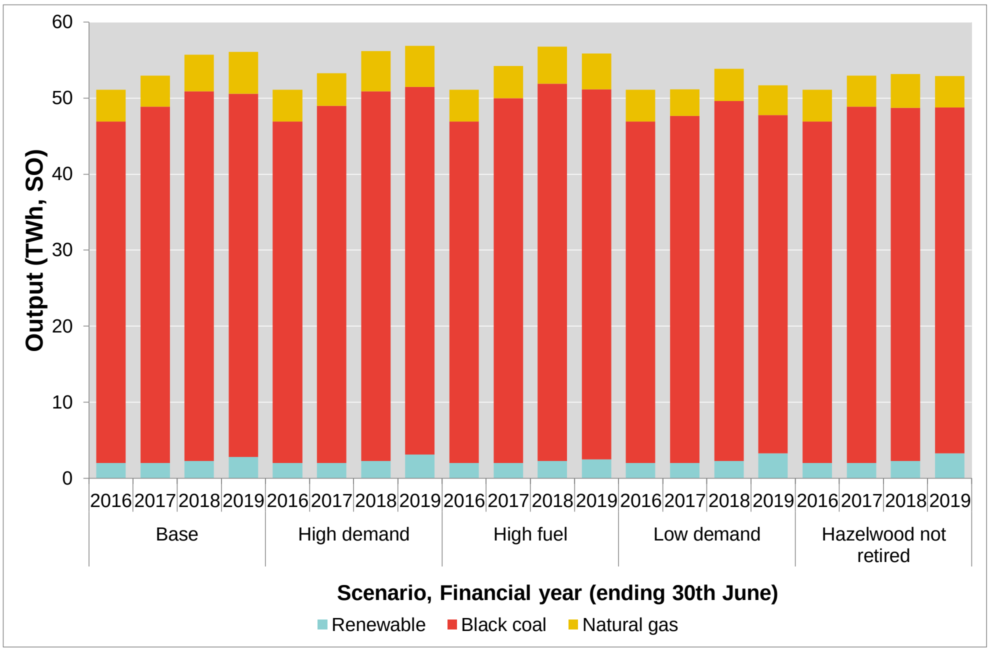
In Section 4.1.2, annual NEM dispatch results were presented for each Scenario. This appendix provides these annual results for each NEM region.

Figure 46: Annual dispatch results for each scenario - NSW



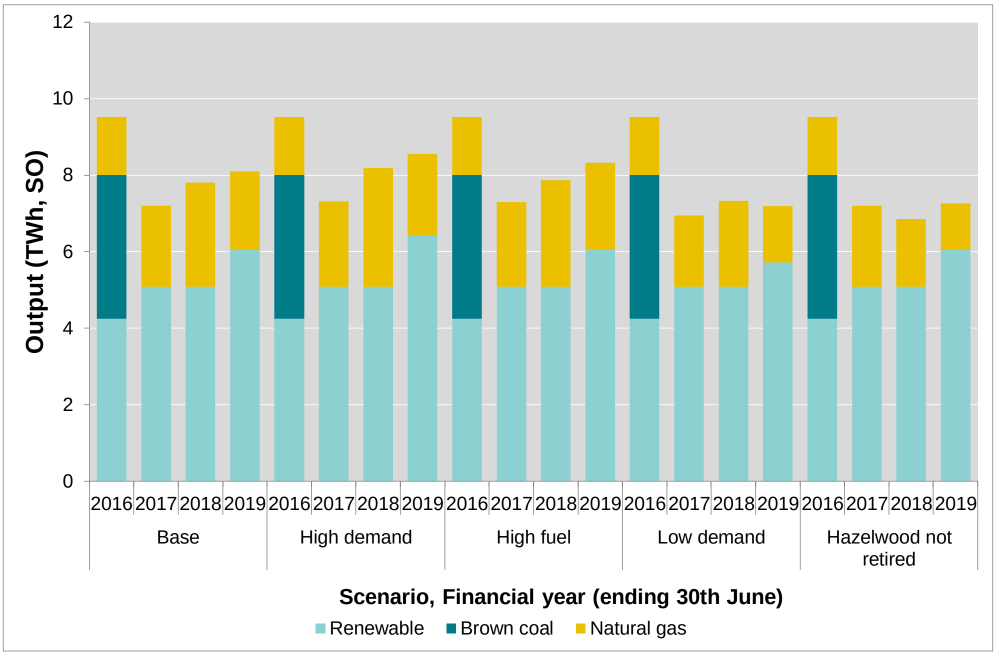
Source: Frontier Economics

Figure 47: Annual dispatch results for each scenario - QLD



Source: Frontier Economics

Figure 48: Annual dispatch results for each scenario - SA

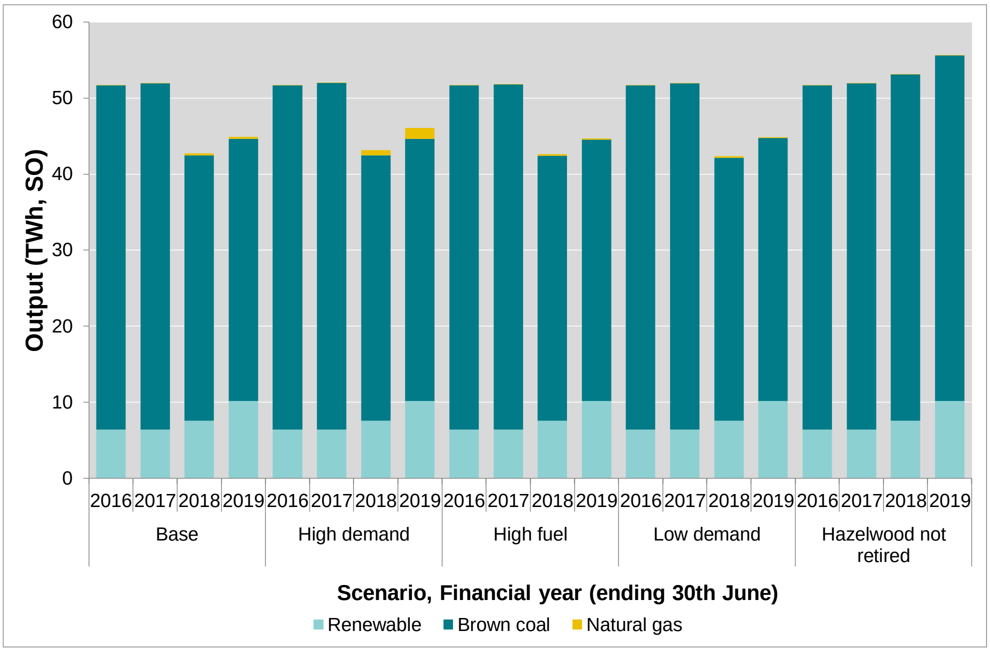


Source: Frontier Economics

Figure 49: Annual dispatch results for each scenario - TAS

Source: Frontier Economics

Figure 50: Annual dispatch results for each scenario - VIC



Source: Frontier Economics

Summary of results

Glossary

AEMO	Australian Electricity Market Operator
BNEF	Bloomberg New Energy Finance
CCGT	Combined Cycle Gas Turbine
CER	Clean Energy Regulator
CLP	Controlled Load Profile
CLP CE	Controlled Load Profile (Country Energy)
CLP EA	Controlled Load Profile (Energy Australia)
CLP IE	Controlled Load Profile (Integral Energy)
COAG	Council of Australian Governments
EOI	Expression of interest
EOR	Equivalent outage rate
EPRI	Electric Power Research Institute
ERA	Economic Regulation Authority
ESCOSA	Essential Services Commission of South Australia
ESOO	Electricity Statement of Opportunities
FCAS	Frequency Control Ancillary Services
FOM	Fixed operating and maintenance costs
GJ	Gigajoule
GT	Generator terminal
GWh	Gigawatt hours
HCC	Hard coking coal
IGCC	Integrated gasification combined cycle
IMO	Independent Market Operator
IPART	Independent Pricing and Regulatory Tribunal
LGC	Large-scale Generation Certificates
LNG	Liquefied Natural Gas
LRET	Large-scale Renewable Energy Target
LRMC	Long run marginal cost
Mmbtu	one million British thermal units

MRIM	Victorian Manually Read Interval Meter
MWh	Megawatt hour
NCAS	Network Control Ancillary Services
NEFR	National Electricity Forecast Report
NEM	National Electricity Market
NSLP	Net System Load Profile
NTNDP	National Transmission Network Development Plan
OCGT	Open Cycle Gas Turbine
OTTER	Office of the Tasmanian Economic Regulator
PV	Photovoltaic
RET	Renewable Energy Target
RPP	Renewable Power Percentage
SO	Sent-out
SRAS	System Restart Ancillary Services
SRES	Small-scale Renewable Energy Scheme
SSC	Semi-Soft Coking Coal
STC	Small-scale Technology Certificates
STP	Small-scale Technology Percentage
SWIS	South West Interconnected System
VOM	Variable operating and maintenance
WACC	Weighted average cost of capital

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