2017 Residential Electricity Price Trends Report

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

December 2017

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1 Introduction

The Australian Energy Market Commission (AEMC) is currently undertaking the 2017 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. 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 2016/17 to 2019/20. 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 and ancillary services costs 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 2016/17 to 2019/20. 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 2016 Residential Electricity Price Trends report. The methodology 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.

Appendix A through Appendix E presents Frontier's detailed supply-side input assumptions. Appendix F presents more detailed modelling results at regional level.

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[1], 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 an 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

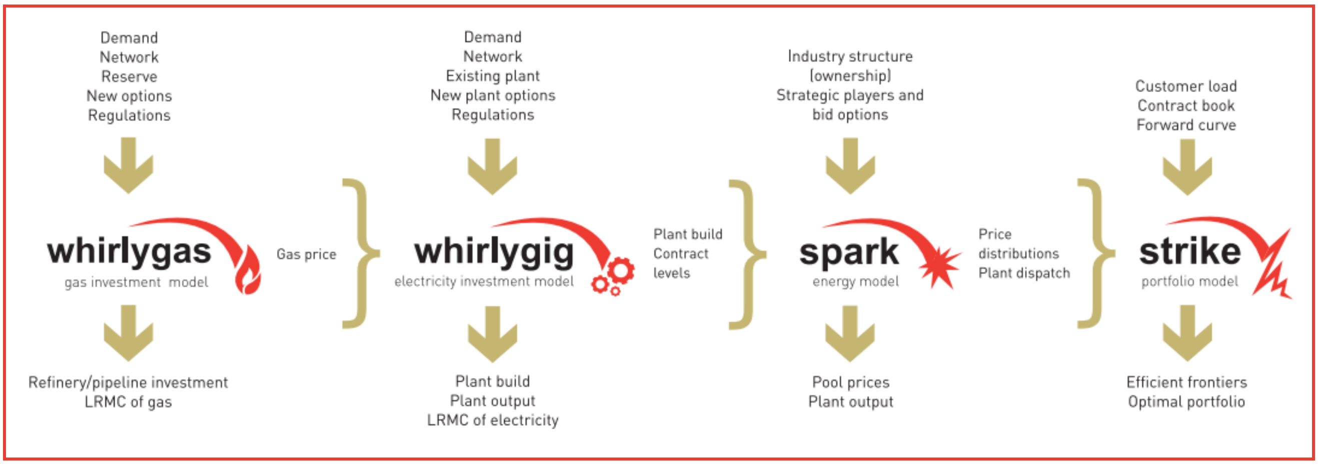
1 Metalytics is a resource economics consultancy that works closely with Frontier Economics.

behaviour as a model *output* rather than an *input*. The model determines the 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, the 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.[2] 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 captured in the modelling approach. Key to this is ensuring that the

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2 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.

assumed customer load shape is correctly correlated to an accurate distribution of possible pool price outcomes. Given these inputs – accurately correlated spot 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 financial hedges – swap and cap products – are available at an assumed 5 per cent premium[3] 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.[4]

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

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3 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#

Our more recent analysis continues to indicate that an assumed 5 per cent contract premium is reasonable.

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

- 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
- 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.

We note that that on the 9th June 2017, the Treasurer of Tasmania issued a Wholesale Electricity Price Order[5] decreeing the wholesale electricity price to be at $83.79/MWh in 2017/18. This will affect the Tasmanian electricity retail tariff. However, we have continued to model Tasmanian wholesale electricity prices using our approach described above, which we consider to be a better reflection of the true economic cost drivers. Nevertheless, price trends that take account of the Wholesale Electricity Price Order can be calculated by using the wholesale price of $83.79/MWh in place of our calculated market-based electricity purchase cost.

2.3 Estimating costs of complying with the Renewable Energy Target

In addition to advising on wholesale electricity costs for the period 2016/17 to 2019/20, 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).

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5 Treasurer of Tasmania, *Wholesale Electricity Price Order*, 9th June 2017.

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 tend to 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 and also provides something of a floor: 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 cost (and risk) of holding cost 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.

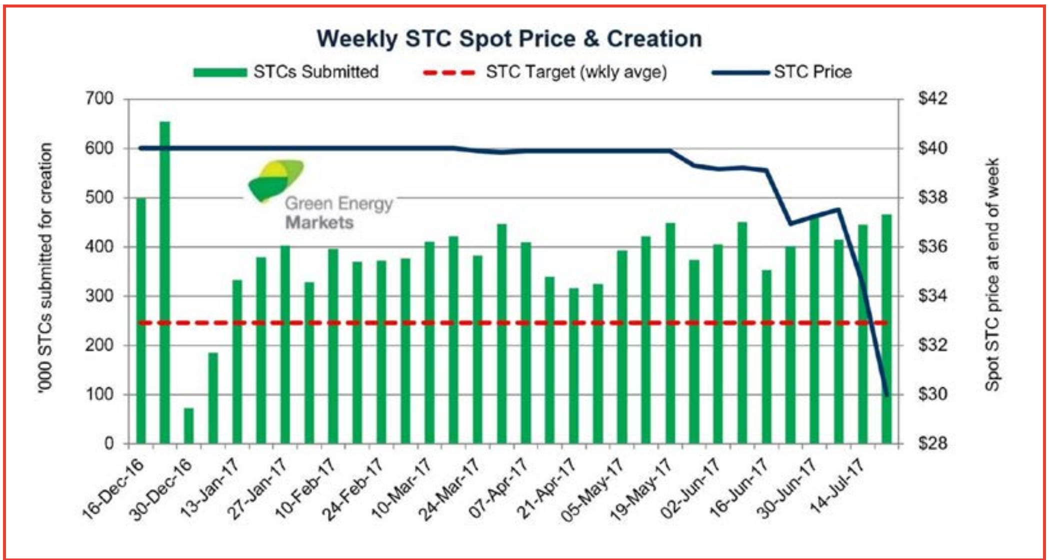
Cost of STCs

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 note that STC prices have recently fallen from the longer-term level of $40/STC, as shown in Figure 2. We expect that this is driven by a short-term surplus of STCs increasing the cost of holding STCs until they can be redeemed in the STC Clearing House. Price reductions like this have been observed in the past, but have typically been relatively short-lived.

Figure 2: Current STC market prices



Source: Green Energy Markets website. Viewed on 31st July 2017. 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,[6] 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.

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

Approach to estimating ancillary services costs

To estimate the future cost of ancillary services we extrapolate based on the past 4 years of ancillary service cost data published by AEMO for each region of the NEM and the SWIS.

The exception to this in ancillary services costs in South Australia. In South Australia, these costs have increased materially over the last 12 months or so (likely driven by the closure of Northern Power Station). However, the battery that is being built in South Australia is intended to address these higher ancillary services costs. For this reason, we have excluded ancillary services costs for 2016/17 in South Australia and based on estimate of the future cost of ancillary services in South Australia on average prices from 2013/14 to 2015/16.

2.5 Losses

We base loss estimates on information on transmission and distribution losses published by the market operator.[7]

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[7] 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
- jurisdictional government policies

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 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

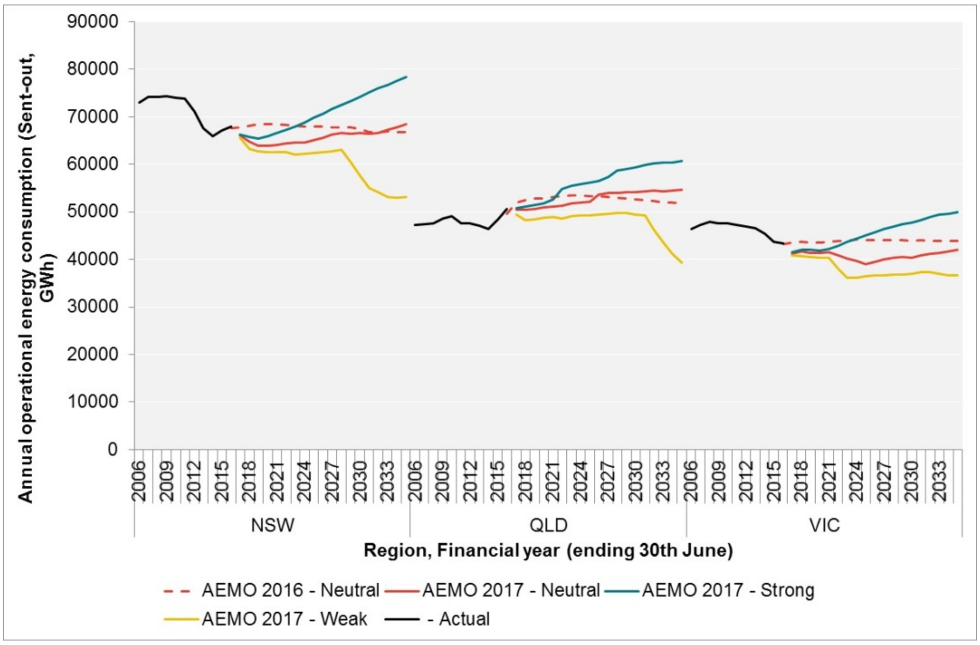
System load shapes are only required for the NEM, where we use a market-based approach. In the SWIS, where we use a stand-alone LRMC approach, we only need a residential load shape.

The system load shapes that we use for each NEM region are based on historical data from 2015/16. This half-hourly profile is scaled to forecast energy and peak demand taken from AEMO's 2017 Electricity Forecasting Insight (AEMO 2017 EFI).[8]

In the scenarios that we model we use each of the Neutral, Weak and Strong demand forecasts from the AEMO 2017 EFI. Figure 3 (NSW, Victoria and Queensland) and Figure 4 (SA and Tasmania) show the annual energy forecasts from AEMO's 2017 and 2016 forecasts. Note the two charts are on different scales due to the different sizes of the regions.

Over the market modelling period, which ends at 2019/20, energy consumption in the Neutral forecast is expected to fall (NSW and SA), or remain flat (Queensland and Victoria), with the exception of Tasmania. In fact, compared to the 2016 forecast, the 2017 Neutral forecast has generally lower energy consumption for NSW, Queensland and Victoria throughout most of the 2020s. In the Strong case, there is higher energy consumption growth forecast, but most of the growth occurs after 2019 or 2020. In the Weak case, energy consumption is expected to remain flat or decline gradually in most regions until industrial closures lead to sudden drops in levels.

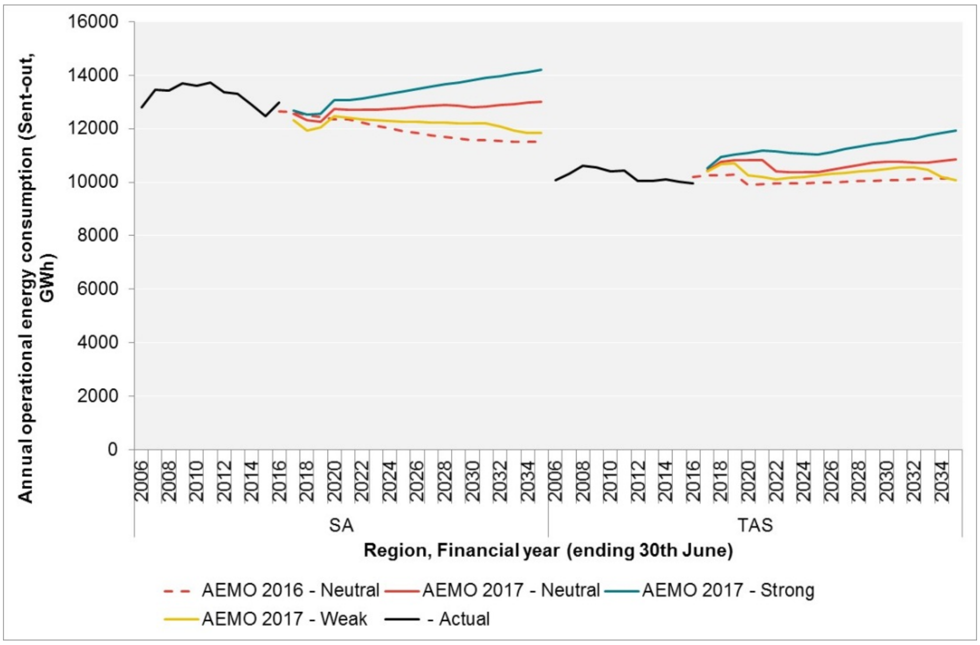
Figure 3: AEMO demand forecasts (NSW, Victoria and Queensland)



Source: AEMO 2016 NEFR and AEMO 2017 EFI

8 AEMO, *Electricity Forecasting Insights*, For the National Electricity Market, June 2017. Available here: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Electricity-Forecasting-Insights

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



Source: AEMO 2016 NEFR and AEMO 2017 EFI

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 distribution area. We use data for 2015/16, which is the most recent financial year available.

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.[9]

[9] 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.

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.

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 combined renewable output of the LRET target (33 TWh/year), the ACT renewable auction scheme (1.9 TWh/year) and hydro production (14TWh/year), in percentage terms, for each of the three demand scenarios we consider. We have calculated renewable output both with and without SRES.[10] The results of our calculations are set out in Table 1.

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10 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 to both the numerator and the denominator.

Table 1: Percentage renewable energy generation

Scenario	Total national demand (GWh)	GWh of renewable energy excl. rooftop PV	GWh of Rooftop PV	% of renewable energy dispatched (excl. SRES)	% of renewable energy dispatched (incl. SRES)
Low demand	198,716	48,900	11,462	24.61%	28.72%
Medium demand	205,024	48,900	12,028	23.85%	28.07%
High demand	210,815	48,900	12,604	23.20%	27.53%

Source: AEMO 2017 EFI, AEMO WEM ESOO 2017 and Frontier Economics Analysis

3.4 Government Policies

Recently various state governments have introduced their own energy policies aimed at either increasing renewable generation or providing system security. This section discusses the extent to which we have incorporated the state policies in the modelling. It is worth noting that the details of some of the policies are still unclear at the time of finalising this report. Therefore, we have modelled the policies using the most up-to-date public information available to us as of the end of October 2017.

3.4.1 South Australia

The South Australian government has introduced a suite of significant market reform policies following the state-wide black out in late September 2016.

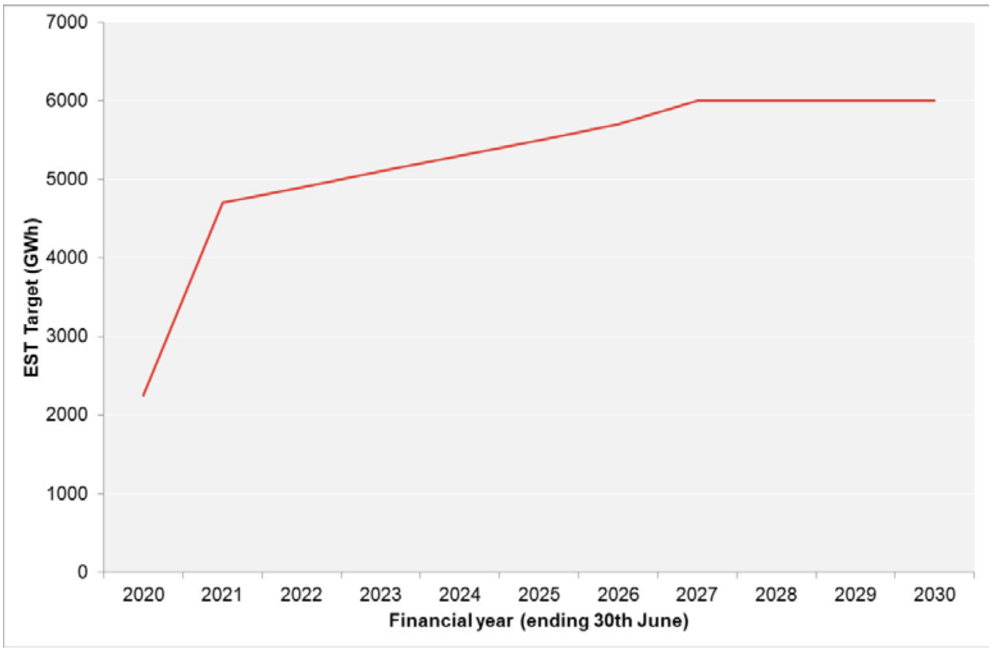
Energy Security Target (EST)

This scheme is designed to increase dispatchable electricity generation in SA by improving the economics of eligible generators, who will be able to create one certificate for each MWh of electricity generation. The certificate will then be purchased by retailers. The price of the scheme is capped at $50 per certificate. [11]

[11] Department of the Premier and Cabinet, *Energy Security Target, Stakeholder Consultation*, http://www.dpc.sa.gov.au/__data/assets/pdf_file/0014/18113/Energy-Security-Target-Stakeholder-Consultation.pdf, p2

The government has announced that the commencement of the scheme has been delayed until January 2020.[12] However, it is unclear whether (or how) the government plans to adjust the previously announced annual target to account for the new commencement date. In our modelling, we have retained the target in the original consultation paper[13], but shifted it back by two years. Hence the modelled target will increase from 4,500 GWh initially to 6,000 GWh before 2029/30, as shown in Figure 5. Given the scheme runs only for half a year in financial year 2019/20, we have halved the initial target in that year. Currently it is unclear if any banking and borrowing is allowed. We have assumed a borrowing limit of 10% and unlimited banking.

Figure 5: SA energy security annual target



Source: Frontier Economics

Similar to the LRET, the EST will impact final retail prices in two ways. First, the certificate price received by SA eligible generators (including gas-fired) will reduce their opportunity cost of dispatch, which will likely reduce the SA

12 Department of the Premier and Cabinet, http://www.dpc.sa.gov.au/what-we-do/services-for-business-and-the-community/energy-resources-and-supply/south-australias-energy-supply-and-market/energy-security-target

13 Department of the Premier and Cabinet, *Energy Security Target, Stakeholder Consultation*, http://www.dpc.sa.gov.au/__data/assets/pdf_file/0014/18113/Energy-Security-Target-Stakeholder-Consultation.pdf, p3

wholesale pool prices if the generators pass through the cost reduction. While the reduction in wholesale pool prices will lower retail prices, there is a countervailing effect of retailers passing through certificate costs to end consumers. In our modelling, we have assumed that the SA gas generators will pass through the entire cost saving from the EST certificates in their bids.

Government load contracted to new generators

The SA government also announced that it will contract its government load to new electricity generators.[14] In August 2017, it was announced that the government load would be supplied by the Aurora Solar Project, a 150 MW solar farm that was expected to start operation in 2020.[15] Given the construction of the project is expected to start in 2018, we have assumed that it will not be fully operating during the current price trend period (ending in 2019/20) and have not included this project in our market price modelling.

Government owned emergency backup generator

The SA government has announced that it will build a government owned emergency gas generator to be used during times of emergency.[16] We have assumed the generator will have a capacity of 200 MW according to AEMO's June 2017 Energy Supply Outlook.[17] This generator is assumed to be operational in January 2018 in our modelling. Given the public information indicates that it will only be used at time of emergency, we have assumed that it will bid at the market price cap and hence will not be dispatched unless there would be a physical shortfall of energy.

Utility scale battery storage

In early July 2017 it was announced that Tesla would build a 100 MW/129 MWh grid level battery before summer 2017/18.[18] Currently the detailed operation of the battery, in particular the proportion that would be used in energy trading, and its related operating protocol, is unclear. Information based on the government's website suggests that it will primarily be used for supplying FCAS and provide

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14 SA Government, *Our Energy Plan,* http://ourenergyplan.sa.gov.au/assets/our-energy-plan-sa-web.pdf, p6

15 http://www.abc.net.au/news/2017-08-14/solar-thermal-power-plant-announcement-for-port-augusta/8804628

16 Ibid, p4

17 AEMO, *Energy supply outlook,* June 2017,

https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2017/2017-Energy-Supply-Outlook.pdf, p24

18 http://www.abc.net.au/news/2017-07-07/sa-to-get-worlds-biggest-lithium-ion-battery/8687268

emergency backup if required.[19] For this modelling, we have assumed that the battery will not trade regularly on the energy market and have not included the battery in our market price modelling.

3.4.2 Victoria

Victorian Renewable Energy Target (VRET)

In June 2016, the Victorian government announced the VRET scheme which aims to generate 25% of Victoria's electricity from Victorian renewable resources in 2020 and 40% in 2025. This target includes generation from rooftop PV.[20] According to the consultation paper published by the Department of Environment, Land, Water and Planning, 20% of the generation contracted will be from large scale solar projects.[21] We have also been advised by the jurisdiction that the generators under the VRET will not enter the market until after 2020/21, and hence will not be eligible for creating LGC certificates. While the VRET generators do not directly affect the market prices between 2016/17 and 2019/20, they have an indirect impact on generation investment and retirement. To the extent that state sponsored renewable schemes will reduce future pool prices and can make investment in new renewable from the private sector less attractive, they will likely lead to higher LGC prices, as renewable projects from the private sector would require a higher subsidy than otherwise to recover their cost. Therefore, we have included the VRET generators in our long-term investment modelling.

Table 2 shows the assumed generation to be contracted under the VRET up to 2025. Currently there has been no firmly announced annual generation target, apart from the above reference to 25% and 40% energy generation for 2020 and 2025 respectively. Therefore, we have adopted the following assumption regarding the VRET target:

- The **total generation targets** for calendar years 2020 and 2025 are calculated by multiplying Victoria's annual generation by 25% and 40%, respectively. Strictly speaking, the estimate of Victoria's annual generation used to determine the total generation targets should be a modelled outcome, as generation will depend on investment in the NEM, including the VRET plant themselves. While the retirement of Hazelwood in early 2017 might significantly reduce the amount of Victorian generation in the short term, the

[19] http://ourenergyplan.sa.gov.au/battery.html

[20] Department of Environment, Land, Water and Planning, Victorian Renewable Energy Auction Scheme, Consultation Paper, p2

http://www.delwp.vic.gov.au/__data/assets/pdf_file/0005/351572/Consultation-paper-Victorian-renewable-energy-auction-scheme.pdf

[21] ibid, p4

large amount of renewable investment under the VRET would make Victoria a net exporter after 2020, especially after the retirement of Liddell in NSW in 2022/23. Therefore, when calculating the total generation targets we assume that Victoria's annual generation consists of total Victorian energy consumption plus an assumed constant net export at 7 TWh per year. Consumption here includes AEMO's forecast rooftop PV output. The **total utility level targets**, which are to be met by utility-scale generation, are obtained by subtracting forecast rooftop PV from the total generation targets. We have calculated the total utility level targets based on the AEMO 2016 NEFR Neutral scenario as the percentage target was announced when the AEMO 2016 NEFR forecast was available. If we used the AEMO 2017 EFI forecast, the total utility level targets would be slightly lower due to the lower forecast for Victoria electricity consumption.

- The total utility level targets for other years are calculated by applying a linear growth path and assuming the target for calendar year 2017 starts at 0 GWh.
- We have assumed that all existing and committed hydro and wind farms in Victoria can contribute to this the total utility level targets.
- The **final VRET generator target** for each calendar year is obtained by subtracting existing and committed renewable from the total utility level target for that year.
- In our modelling, we have assumed that the VRET generators are not operational until after 2019/20, based on the feedback from the jurisdiction.

Table 2: VRET target

Calendar year	Total generation (native + rooftop PV + 7TWh export) (GWh)	Total generation targets (GWh)	Total utility level targets (GWh)	Existing and committed renewable generation (hydro + wind + solar) (GWh)	VRET solar (GWh)	VRET wind (GWh)
2018	53,307	4,484	2,896	6671	0	0
2019	53,475	8,969	7,152	7980	0	0
2020	53,814	13,453	11,388	8806	516	2,066
2021	54,244	15,233	12,902	8806	819	3,277
2022	54,633	17,013	14,406	8806	1,120	4,480
2023	55,128	18,793	15,903	8806	1,420	5,678
2024	55,568	20,572	17,398	8806	1,719	6,874
2025	55,880	22,352	18,895	8806	2,018	8,072

Source: Frontier Economics analysis based on AEMO NEFR 2016 forecast

Victorian Energy Storage Initiative

The Victorian government has announced that it will fund a grid level battery which will be operational by January 2018.[22] We have incorporated the battery in our modelling and assumed it to be 40 MW/100 MWh based on information from AEMO.[23] Given the size of the Victorian electricity market (peak demand in excess of 8,500 MW) and its interconnection with three other regions, the inclusion of the battery is not expected to significantly impact on the annual average pool price forecast.

3.4.3 Queensland

The Queensland Department of Energy and Water Supply has recently published the final report by the Renewable Energy Expert Panel, which investigated the Queensland government's renewable energy objective of reaching 50% renewable energy generation by 2030.[24] Renewable projects under a 400 MW reverse auction, which is expected to be completed in 2020, will be part of the pathway. Currently there is no concrete plan for projects after 2020 yet. We have assumed that all such projects, including those under the 400 MW reverse auction, will begin operation after 2019/20, and hence will not directly impact on the market price between 2016/17 to 2019/20. Similar to the VRET, the 50% Queensland renewable energy pathway is incorporated in our long-term investment modelling due to their impact on generation investment and retirement, as well as the LGC prices.

While the final report of the Renewable Energy Expert Panel has investigated different pathways, we have adopted the linear pathway,[25] but have adjusted the figures to reflect the AEMO 2017 EFI forecast. This leads to a similar path for Queensland utility level renewable investment, starting from 0 GWh in 2020 and ending in 14,529 GWh in 2030. We have assumed that this energy will be split evenly between utility Solar PV and wind.

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22 Department of Environment, Land, Water and Planning, https://www.energy.vic.gov.au/batteries-and-energy-storage

23 AEMO, *Energy supply outlook,* June 2017,

https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2017/2017-Energy-Supply-Outlook.pdf, p 24

24 Renewable Energy Expert Panel, *Credible pathways to a 50% renewable energy target for Queensland, Final Report,* 30th November 2017

https://www.dews.qld.gov.au/__data/assets/pdf_file/0018/1259010/qreep-renewable-energy-target-report.pdf

25 ibid, p74

3.5 Frontier Economics' supply side inputs

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

3.5.1 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 publishes information on the capacity of existing and committed generation plant in the NEM over the next two years.[26]
- AEMO publishes the National Transmission Network Development Plan (NTNDP), and supporting documents, which include a range of technical and cost input assumptions.[27]
- AEMO publishes information on marginal loss factors for generation plants.[28]

These various reports released by AEMO could be used in our electricity market modelling. However, there are a number of reasons why we consider some of 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 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

26 AEMO, http://www.aemo.com.au/Electricity/Planning/Related-Information/Generation-Information

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

28 AEMO, https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Loss-factor-and-regional-boundaries

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).

3.5.2 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 exports and higher export prices.

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 6 for each region. 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 uses AEMO's high demand forecasts and assumes that additional LNG export opportunities mean that LNG net-back prices remain the opportunity cost of supplying gas domestically.
- 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.

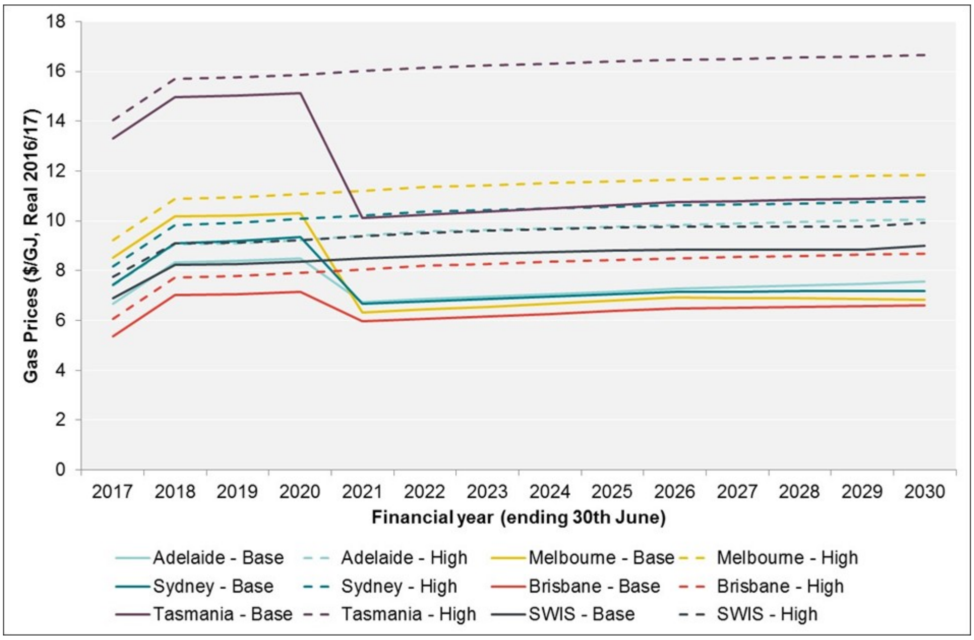
Our Base case forecasts are higher than long-term historical prices. This reflects the tight supply-demand balance, and the observation that the LNG net-back price can reflect the opportunity cost of supplying gas to the domestic market in those circumstances. The increase in the forecast gas price from 2016/17 to 2017/18 reflects the step increase in the World Bank's forecast of Japan LNG prices, relative to actual Japan LNG prices in 2016/17. The forecast reduction in gas prices in 2020/21 reflects a modelled increase in gas production capacity at this point. With this additional gas supply, the supply-demand balance is less tight, and the cost returns to cost of production rather than LNG net-back prices. There is a slight increase (in real terms) in this over the period to 2029/30.

The differences in prices at different points in eastern Australia reflects differences in transport costs. In the period to 2019/20, the differences reflect the different costs of transporting gas from Wallumbilla. In the period after 2020/21 the differences in transport costs lessen because there is a modelled increase in gas production capacity both in Victoria (for transport to nearby demand centres) and in Queensland.

The High case forecasts are higher, largely as a result of the assumptions that the supply-demand balance remains tight over the period to 2029/30 (so that the LNG net-back price remains the opportunity cost of supplying gas to the domestic market) and that the Japan LNG price is higher.

We would note that there are risks and uncertainties associated with these results. 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. Or if demand for gas decreases more than expected, or more new supply becomes available, or if Japan LNG prices fall, gas prices could be lower.

Figure 6: LRMC of gas by for key demand centres ($2016/17) – Base and 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.

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.

Over the modelling period the coal prices are forecast to decline significantly for coal mines that are export exposed. This is due to the forecast reduction in Australian export coal prices by World Bank.[29] We note that the declines in export coal prices forecast by the World Bank are also reflected in forward prices for Newcastle coal and other public forecasts of international coal prices.

In the high case, we assumed that the export coal prices are 10% higher than the base case.

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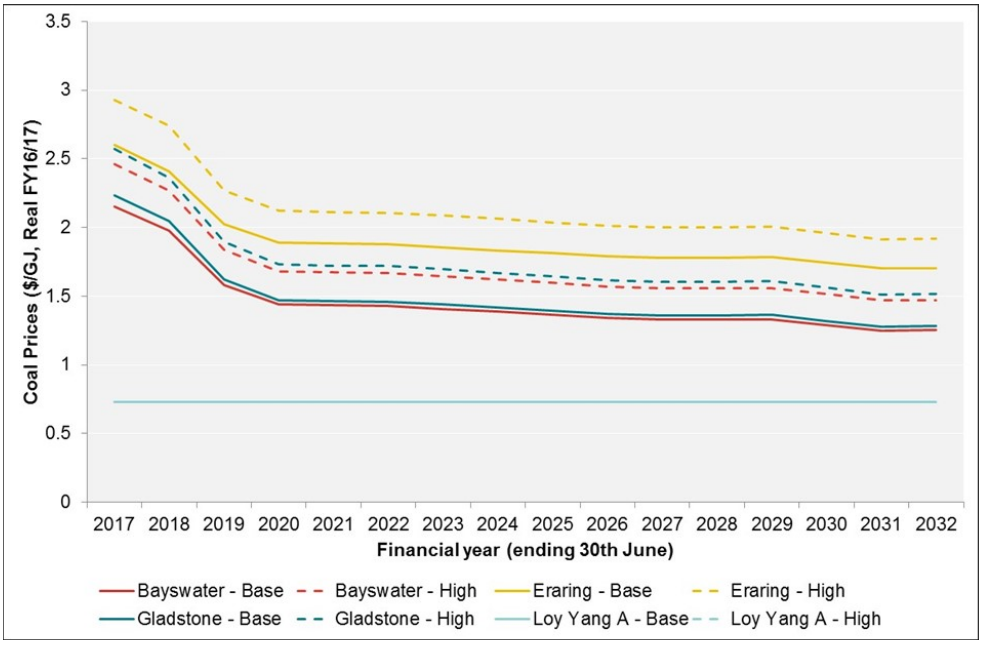
[29] World Bank, *Commodity Market Outlook,* April 2017, available at:

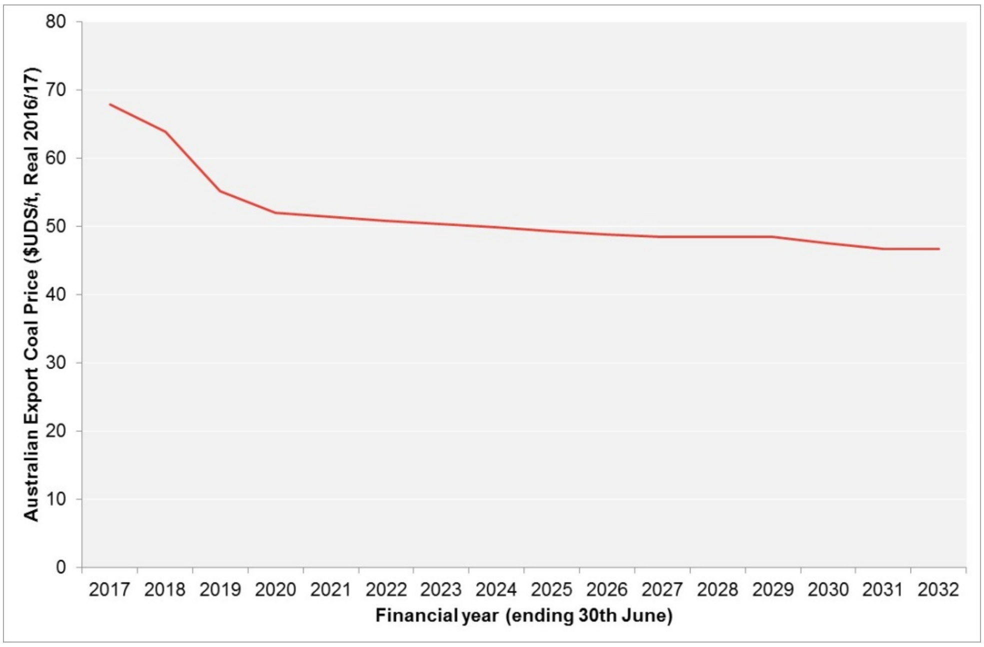
http://pubdocs.worldbank.org/en/662641493046964412/CMO-April-2017-Forecasts.pdf

Figure 7: Coal prices for representative generators ($2016/17) – Base (solid) and High (dashed) cases



Source: Frontier Economics

Figure 8: Australian export coal price forecast ($2016/17 in USD dollars)



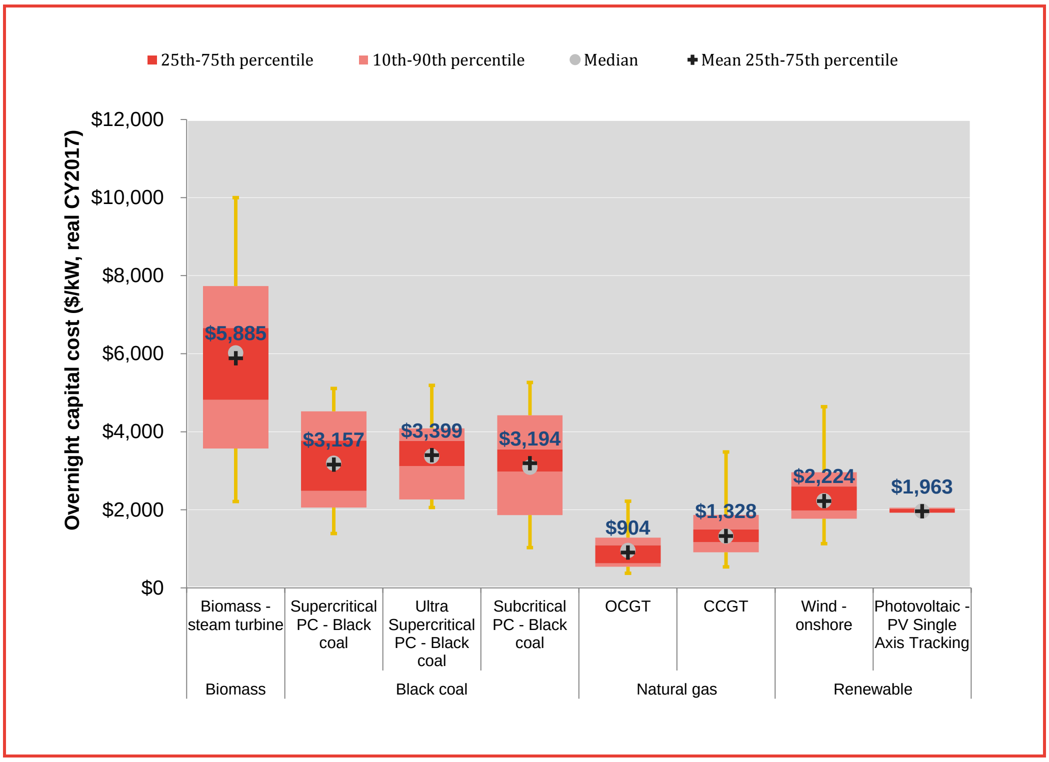
Source: World bank Commodity Markets Outlook, April 2017 and Frontier Economics Analysis

3.5.3 Capital Costs

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 25th to 75th percentiles). The range of estimates and the final number used in the modelling are shown in Figure 9. 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 9: Current capital costs



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 $3,878/kW in the SWIS, compared to $3,157/kW in the NEM. 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

3.5.4 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. 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 NTNDP.[30] Table 3 Shows the capacity factors by NTNDP zone used in our modelling.

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

Table 3: Wind capacity factor by tranches

NTNDP Zone	T1	T2	T3	T4
CAN	36.39%	34.26%	32.78%	29.56%
CVIC	39.49%	35.86%	33.82%	31.57%
LV	39.49%	35.86%	33.82%	31.57%
MEL	39.49%	35.86%	33.82%	31.57%
NCEN	36.39%	34.26%	32.78%	29.56%
NNSW	36.39%	34.26%	32.78%	29.56%
NQ	36.37%	32.00%	32.00%	28.22%
NSA	41.26%	38.17%	35.30%	30.83%
SESA	41.26%	38.17%	35.30%	30.83%
SWNSW	37.39%	35.26%	33.78%	30.56%
SWQ	37.37%	33.00%	33.00%	29.22%
TAS	43.00%	41.33%	35.82%	29.41%

Source: AEMO NTNDP and Frontier Economics Analysis

Solar capacity factors by NEM sub-region

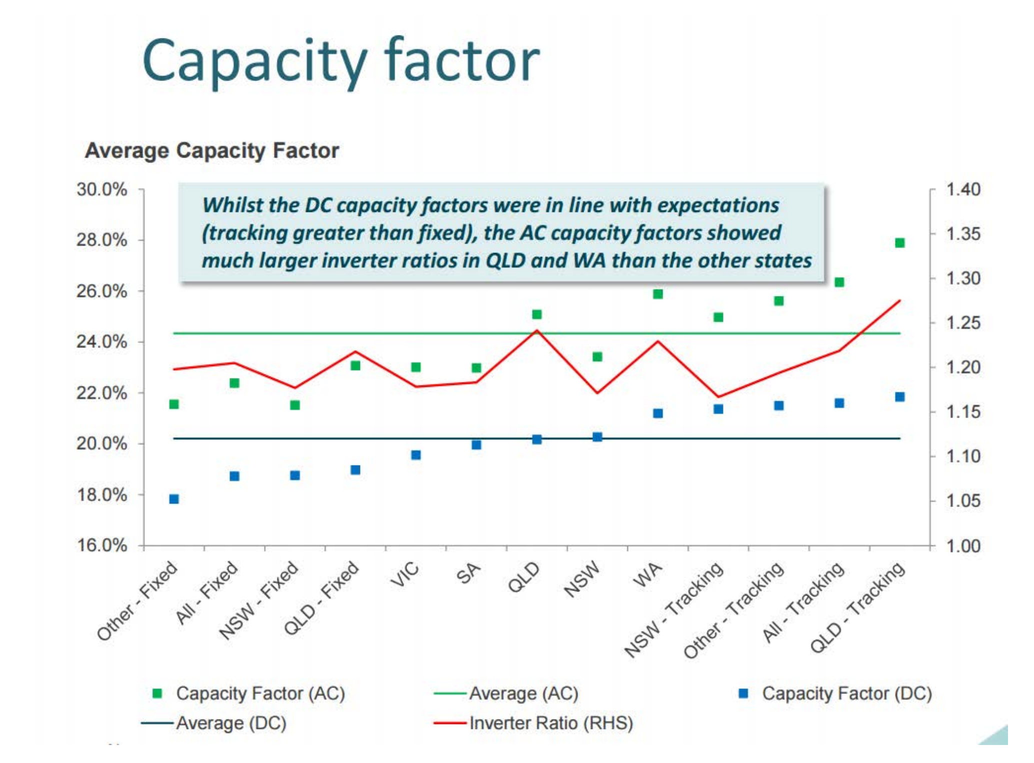
The average annual capacity factors for solar plants in the NEM vary depending on the location of the plant. Accurately capturing the annual average capacity factor of solar plants is important – this is because the annual capacity factor is the primary driver of long-run marginal cost. In our modelling, we will apply capacity factors based on ARENA data, as shown in Figure 10. For NSW, this implies a capacity factor of 21.54% for Fixed and 25.1% for tracking (on AC basis). For Queensland, the corresponding figures will be 23.09% and 27.95%. Table 4 shows the capacity factors by region for utility level solar PV.

Table 4: Solar capacity factor

Region	Fixed-Plate	Single-Axis Tracking
NSW	21.54%	25.10%
QLD	23.09%	27.95%
SA	21.06%	24.54%
VIC	21.10%	24.58%

Source: ARENA Large Scale Solar PV Competitive Round EOI Data and Frontier Economics Analysis

Figure 10: Actual capacity factor EOIs from ARENA



Source: ARENA Large Scale Solar PV Competitive Round EOI Data

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.

3.6 Change in Existing and Committed Capacity

3.6.1 Plant retirements and mothball assumption

In recent years, the NEM has experienced a period of suppressed demand growth. At the same time, there has been a large amount of new renewable generation entering the market. These outcomes have contributed to low wholesale prices and low profitability for a number of generators prior to financial year 2016/17. 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 or mothballed in the NEM, consistent with the generation capacities reported by AEMO. 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 earlier years.[31]

We have made the following retirement and mothballing assumption for the modelling period according to AEMO's generation information in all cases

- Generation retirement
  - Hazelwood: from April 2017

[31] 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#

- Smithfield: from financial year 2017/18
- Two units of Torrens Island Power Station: from financial year 2019/20[32]

- Generation Mothballing
  - One unit of Pelican Point until 2017/18[33]
  - Swanbank E until Q1 2018[34]

3.6.2 Committed new entrant

While we have incorporated existing and committed generation information from AEMO's generation information list, there are many renewable projects that have either started construction or achieved financial close, yet have not been listed as committed projects on AEMO's generation information as of June 2017.[35] To ensure that we incorporate generation capacity that is likely to come online during our modelling period, we have done extensive research on project websites and included in our modelling those projects that have either started construction, or have reached financial close. These projects are double checked against the "New Developments" sheet in AEMO's generation information before they are included in our model. Table 5 to Table 8 list the committed new entrant during the modelling period. We have not included committed entrant smaller than 30 MW as they are likely to be classified as non-scheduled and do not form part of the operational demand.

Figure 11 shows the cumulative capacity of committed new entrants during the modelling period. A significant amount of renewable capacity of over 2,800 MW is expected to enter the NEM by financial year 2018/19 (as well as a small amount of new peaking generation), which will have a suppressing effect on the wholesale pool prices across the NEM.

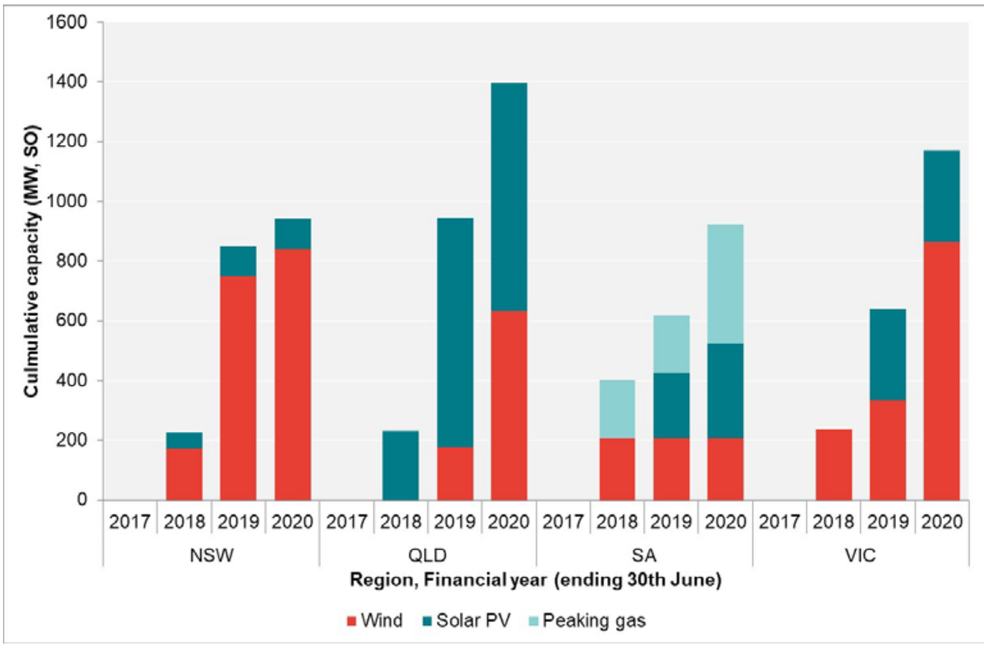
32 https://www.agl.com.au/about-agl/media-centre/article-list/2017/june/agl-announces-development-of-$295m-power-station-in-sa

33 http://www.abc.net.au/news/2017-03-29/engie-announces-40-million-dollar-upgrade-of-sa-pelican-point/8396092

34 http://statements.qld.gov.au/Statement/2017/6/4/swanbank-e-power-station-fires-up-again

35 Many of them appear as "New Developments" and have a "full commercial use date" in AEMO's generation information.

Figure 11: Committed generation capacity during the modelling period



Source: Frontier Economics analysis of AEMO generation information and Project website data.

Note we exclude projects less than 30MW

Table 5: Committed Projects after 2016/17 - NSW

Project name	Fuel	Capacity (MW)	Starting financial year	Source
Parkes Solar Farm	Solar	54	2017/18	AEMO Generation Information, "Summer/winter scheduled capacity"
White Rock Wind Farm	Wind	175	2017/18	AEMO Generation Information, "Summer/winter scheduled capacity"
Manildra Solar Farm	Solar	48	2018/19	AEMO Generation Information, "Summer/winter scheduled capacity"
Bodangora Wind Farm	Wind	113	2018/19	https://www.infigenenergy.com/bodangora/
Sapphire Wind Farm	Wind	270	2018/19	http://www.sapphirewindfarm.com.au/
Silverton Wind Farm	Wind	199	2018/19	https://www.agl.com.au/about-agl/how-we-source-energy/renewable-energy/silverton-wind-farm
Crookwell 2 Wind Farm	Wind	91	2019/20	http://www.environment.act.gov.au/energy/cleaner-energy/next-generation-renewables

Source: AEMO Generation Information (5th June 2017) and Frontier Economics analysis of project website

Table 6: Committed Projects after 2016/17 - Queensland

Project name	Fuel	Capacity (MW)	Starting financial year	Source
Clare Solar Farm	Solar	136	2017/18	AEMO Generation Information, “Summer/winter scheduled capacity”
Hamilton Solar Farm	Solar	57.5	2017/18	AEMO Generation Information, “Summer/winter scheduled capacity”
Whitsunday Solar Farm	Solar	57.5	2017/18	AEMO Generation Information, “Summer/winter scheduled capacity”
Collinsville Solar Farm	Solar	42.5	2018/19	http://ratchaustralia.com/collinsville/about_collinsville.html
Darling Downs Solar Farm	Solar	110	2018/19	https://www.apa.com.au/about-apa/our-projects/darling-downs-solar-farm/
Kidston Solar Farm	Solar	50	2018/19	http://www.genexpower.com.au/the-kidston-solar-project-phase-one-50mw.html
Lilyvale Solar Farm	Solar	100	2018/19	http://www.lilyvalesolarfarm.com.au/project
Ross River Solar Farm	Solar	116	2018/19	http://rossriversolarfarm.com.au/the-project/
Sun Metals Solar Farm	Solar	125	2018/19	http://statements.qld.gov.au/Statement/2017/5/17/210-new-jobs-as-sun-metals-solar-powers-north-queensland-clean-energy-boom
Mount Emerald Wind Farm	Wind	180.5	2018/19	AEMO Generation Information, “Summer/winter scheduled capacity”
Coopers Gap Wind Farm	Wind	453	2019/20	https://www.agl.com.au/about-agl/how-we-source-energy/renewable-energy/coopers-gap-wind-farm

Source: AEMO Generation Information (5th June 2017) and Frontier Economics analysis of project website

Modelling assumptions

Table 7: Committed Projects after 2016/17 – South Australia

Project name	Fuel	Capacity (MW)	Starting financial year	Source
Hornsdale Wind Farm 2	Wind	100	2017/18	AEMO Generation Information, “Summer/winter scheduled capacity”
Hornsdale Wind Farm 3	Wind	109	2017/18	AEMO Generation Information, “Summer/winter scheduled capacity”
Bungala Solar Farm	Solar	220	2018/19	AEMO Generation Information, “Summer/winter scheduled capacity
Barker Inlet	Gas	210	2019/20	https://www.agl.com.au/about-agl/media-centre/article-list/2017/june/agl-announces-development-of-$295m-power-station-in-sa
Tailem Bend Solar Farm	Solar	100	2019/20	http://www.snowyhydro.com.au/news/sa-solar-investment/

Source: AEMO Generation Information (5th June 2017) and Frontier Economics analysis of project website

Table 8: Committed Projects after 2016/17 - Victoria

Project name	Fuel	Capacity (MW)	Starting financial year	Source
Ararat Wind Farm	Solar	240	2017/18	AEMO Generation Information, “Summer/winter scheduled capacity”
Gannawarra Solar Farm	Wind	50	2018/19	AEMO Generation Information, “Summer/winter scheduled capacity”
Karadoc Solar Farm	Solar	90	2018/19	http://www.overlandsunfarming.com.au/sun-farms.html Capacity from AEMO generation Information, “New Development”
Wemen Solar Farm	Solar	88	2018/19	http://www.overlandsunfarming.com.au/sun-farms.html Capacity from AEMO generation Information, “New Development”
Yatpool Solar Farm	Solar	81	2018/19	http://www.overlandsunfarming.com.au/sun-farms.html Capacity from AEMO generation Information, “New Development”
Kiata Wind Farm	Solar	31	2018/19	https://www.windlab.com/kiata-wind-farm-begins-construction/
Mount Gellibrand Wind Farm	Wind	66	2018/19	AEMO Generation Information, “Summer/winter scheduled capacity”
Stockyard Hill Wind Farm	Wind	536	2019/20	http://www.stockyardhillwindfarm.com.au/sites/default/files/pdf/05-17/OEL%20Media%20release%20SHWF%20sale%2020170508.pdf

Source: AEMO Generation Information (5th June 2017) and Frontier Economics analysis of project website

3.7 Scenarios considered in the modelling

The modelling considers a Base case and three other scenarios, as listed in Table 9.

Table 9: Summary of scenarios

	Scenario	LRET	Demand scenario	Fuel
1	Base case	33,000 GWh by 2020	AEMO EFI 2017 Medium	Mid-range forecast
2	Low Demand	33,000 GWh by 2020	**AEMO EFI 2017 Low**	Mid-range forecast
3	High Demand	33,000 GWh by 2020	**AEMO EFI 2017 High**	Mid-range forecast
4	High Fuel	33,000 GWh by 2020	AEMO EFI 2017 Medium	**High forecast**

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 4.2 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 12. Figure 12 shows the market-based electricity purchase costs for each distribution area that we consider, for each load shape that we consider (that is, standard load and controlled load), and for each year to 2019/20. For the purposes of comparison Figure 12 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 and the ACT).

As can be seen from Figure 12, 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. The withdrawal of the 1,600 MW capacity of Hazelwood, with its low SRMC, has a large impact on the pool prices in the NEM, leading to large pool price increases across the NEM in 2017/18.
- **Suppressed demand:** The AEMO 2017 EFI shows either flat or declining demand in most NEM regions between 2016/17 and 2019/20, 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 renewable investment over the period to 2019/20, driven by the Renewable Energy Target and additional schemes such as the ACT renewable auction and ARENA funding. Investment in wind and solar generation in 2017/18 and 2018/19 is committed investment. Committed investment in these two years amounts to over 2,800 MW of additional renewable generation capacity across the NEM, as well as around

200 MW of additional peaking generation. In 2019/20 our modelling suggests that significant further investment in renewable generation will occur due to the LRET scheme. Combined with additional committed new entrants in 2019/20, this amounts to additional renewable generation of close to 2,000 MW in the NEM in the base case, as well as around 200 MW of further peaking plant. The additional generation capacity over these years from 2017/18 to 2019/20 has the effect of lowering prices, especially in financial year 2018/19.

- **Fuel prices:** During the modelling period, the gas prices across all NEM regions are expected to increase from 2016/17 to 2017/18 and then remain relatively flat until 2019/20. Coal prices are forecast to decrease over the modelling period for export exposed coal mines due to the expected decline of Australian export coal prices. While rising gas prices in 2017/18 will contribute to an increase in electricity wholesale prices in that year, from 2018/19 onwards, flat gas price and declining coal prices tend to result in lower wholesale electricity prices.
- **South Australian EST:** The certificate price of the South Australian EST improves the economics of eligible generation in SA, effectively reducing their SRMC. In our modelling, we have assumed the eligible generation in SA passes through the reduction in their SRMC through their bid into the NEM. Since the EST is projected to be operational in calendar year 2020,[36] we have incorporated its effect for the second half of financial year 2019/20. Assuming SA generators pass through their saving in SRMC, this contributes to the reduction in SA pool prices in 2019/20 and, through the interconnectors, also contributes to a reduction in pool prices in other regions.

The effect of these drivers is to cause the electricity pool prices to increase in 2017/18 due to an increase in gas prices and Hazelwood retirement. The prices are expected to fall from 2018/19 when the coal prices begin to fall and large amount of renewable investment enter the market.

We note that while our Base case represents the most likely combination of inputs for the modelling period, there is risk that one or more of our inputs will turn out to be different from the forecast, which could lead the actual price trend to be different to what we forecast. In particular, the forecast downward trend in the 2018/19 wholesale pool prices might not arise due to any of the following factors:

- Demand turns out to be much stronger than AEMO's forecast, or extreme weather conditions (among other things) causes very peaky demand during summer or winter.

[36] http://ourenergyplan.sa.gov.au/energy-security-target.html

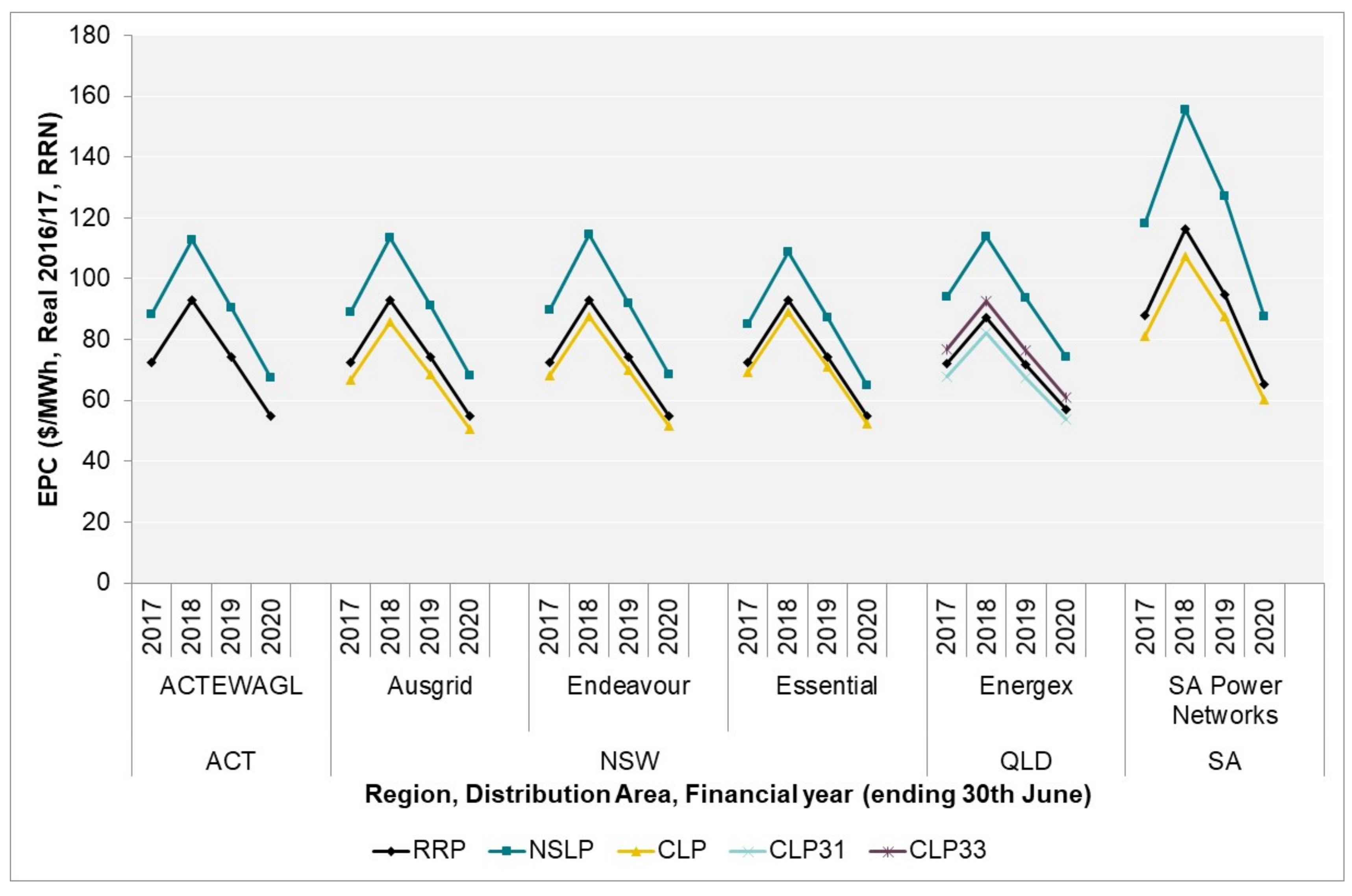
- Gas prices keep rising after 2017/18 and coal prices do not fall after 2017/18.
- The committed new entrants we have assumed to enter the market from 2018/19 fail to become operational in time due to construction delay; or there is significantly less new entrant in renewable generation compared to our modelling due to factors such as policy change or uncertainty
- There is significant change to the operation of EST as we currently understand it, or the SA gas generators do not pass on the saving in SRMC.

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.

Table 10 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.

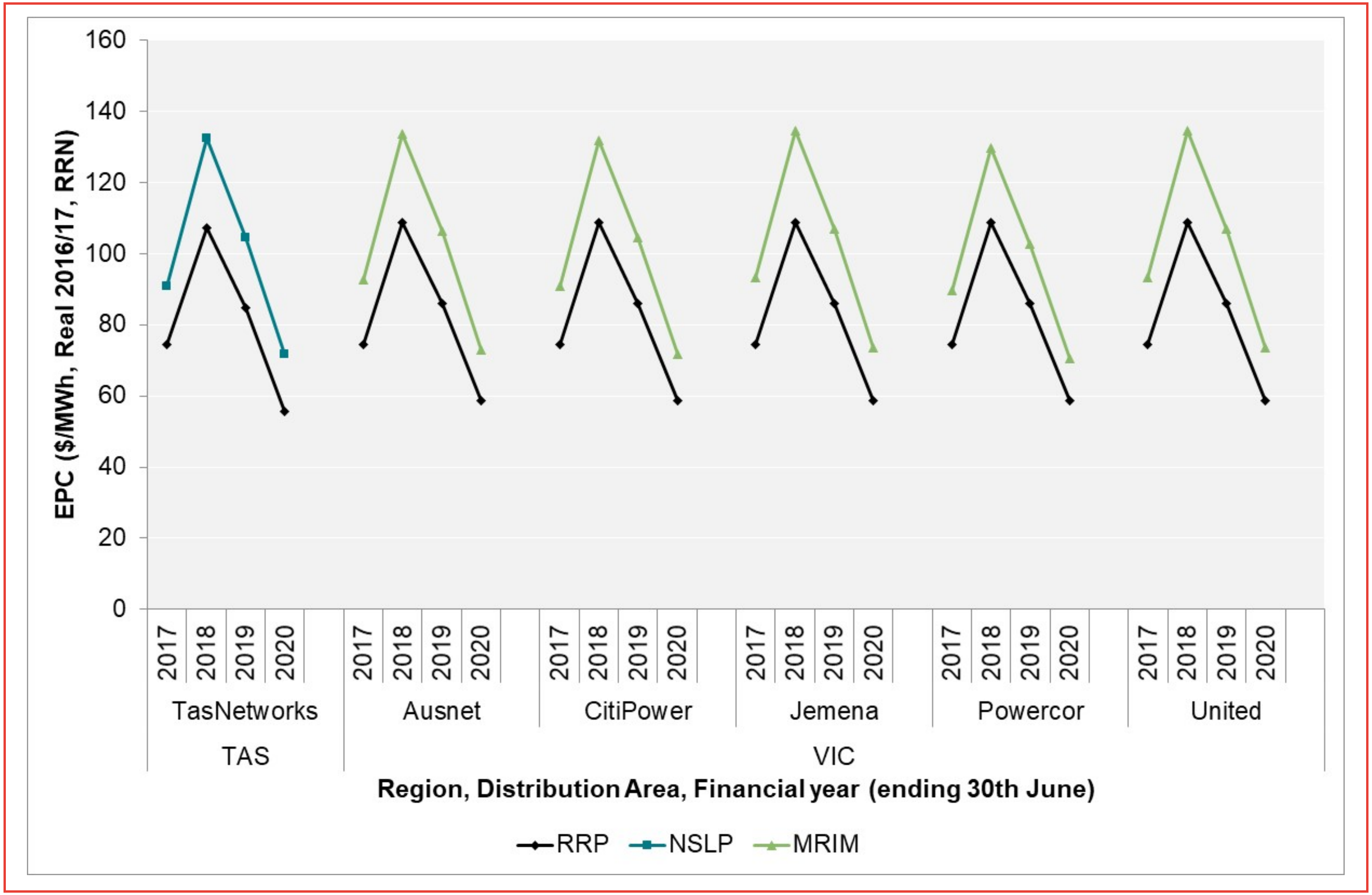
Figure 12: Market-based electricity purchase cost results for ACT, NSW, Queensland and South Australia – Base case



Source: Frontier Economics

Results – wholesale electricity costs

Figure 13: 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 pool and contract prices in Victoria, rather than Tasmania.

Table 10: 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 Hazelwood, fuel prices and new renewable entrant. Retirement of Hazelwood and rising gas prices in 2017/18 leads to an increase in pool prices across the NEM. Steady gas and declining export coal prices, mild demand forecast and new renewable investments in 2018/19 then lead to reduction in pool prices afterwards.
High Demand	We model AEMO's Strong demand forecasts in this scenario. This results in forecast electricity prices that are higher than the Base case forecasts in all regions in all 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 and the easing pressure on fuel prices.
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 all 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.
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 the rise in electricity pool prices in 2017/18 is less pronounced. When demand is lower, gas is less likely to be marginal and hence the impact of higher gas prices and Hazelwood retirement is reduced.

4.2 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.

Plant retirements

As discussed in Section 3.6.1, we have incorporated announced actual plant retirement and mothballing assumptions on the market in all scenarios. Our modelling also forecasts retirement of existing generation plants where demand and supply conditions mean that the least cost outcome is for a given plant to close. Given the recent retirement of Hazelwood and the announced retirement of Liddell after 2021/22, the demand and supply balance has tightened sufficiently during the period from 2016/17 to 2019/20 that no further modelled retirement occurs in this period except for the Low Demand scenario. In the Low Demand case our modelling suggests that one unit of both Yallourn and Tarong will retire in 2019/20. As well as low demand, this is driven by the assumed commencement of VRET and the Queensland 50% renewable energy pathway from 2020/21 in our investment modelling.

The retirement forecasts have regard to the forecasts of power station fixed and variable operating costs that are included in our modelling. For each existing generation plant in the NEM, the estimates for fixed and variable operating costs are those published by AEMO for the NTNDP. 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 averages rather than annual values that reflect maintenance cycles is unlikely to result in material differences.

New investment

Figure 15 presents the total new investment (modelled plus committed) across the NEM for all scenarios. Investment results by each region are shown in Figure 16 (Base case and High Fuel), Figure 17 (High Demand and Low Demand). Everything else held constant, new investment will tend to reduce pool prices.

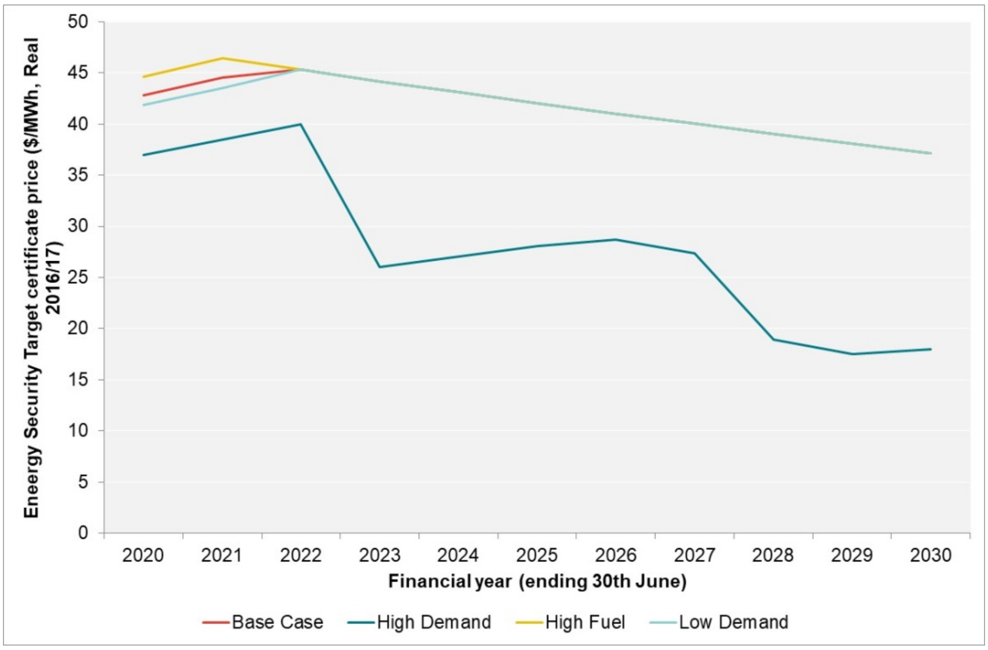
In 2017/18 and 2018/19 our modelling includes investment in committed new wind generation and solar generation. This committed investment does not vary between the Base case and the three scenarios. New uncommitted investment in our modelling is assumed not to be an option until 2019/20 (on the basis that there would be a two-year lead time for uncommitted investment to become fully operational). In 2019/20 our modelling suggests that there will be significant investment in wind generation in all scenarios.

New wind investment results across all cases are very similar. There are approximately 750 to 800 MW of modelled wind investment across the NEM in financial year 2019/20. In the Low Demand scenario, there is slightly more investment in wind (by approximately 50 MW across the NEM) than the Base case. The results for the Low Demand case appear slightly counter-intuitive, as one would expect there would be less wind investment relative to the Base case. Indeed, this is the outcome we see over the medium term, with less investment in wind generation in the Low Demand scenario than the Base case during the 2020s. The different outcomes we see in 2019/20 are really about the timing of investment in wind generation. In the Low Demand scenario, we see retirement of coal-fired plant in Victoria and Queensland in 2019/20, which provides the opportunity for more and earlier investment in wind generation.

In all scenarios, there is no modelled thermal investment until 2019/20, except for in SA in the High Demand scenario. While the retirement of Hazelwood has tightened the supply-demand balance, the suppressed level of demand and the large amount of both modelled and committed renewable entrant means that new thermal investment is not needed before the 2020s.

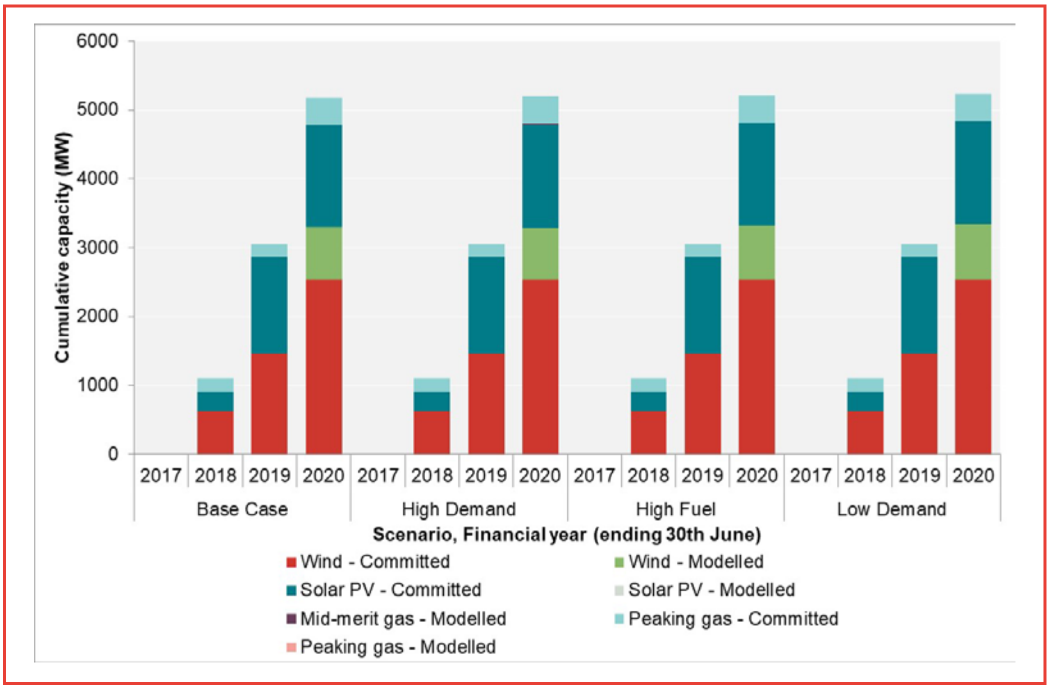
Figure 14 shows the EST certificate prices in South Australia. Compared to the Base case, the certificate price is cheaper in the High Demand scenario as less subsidy is required to run gas generation. It is more expensive in the High Fuel scenario as a larger subsidy is needed to encourage gas generators to run. The Low Demand scenario is slightly lower than the Base case as the result of two countervailing drivers. On the one hand, lower demand means that SA gas needs a higher subsidy to displace imports from the interconnectors. However, the retirement of black and brown coal generators in 2019/20 in the Low Demand scenario means that there will be less import into SA, *ceteris paribus*. In this scenario the second effect dominates so the cost of the subsidy is relatively less than the Base case.

Figure 14: Energy Security Target certificate price



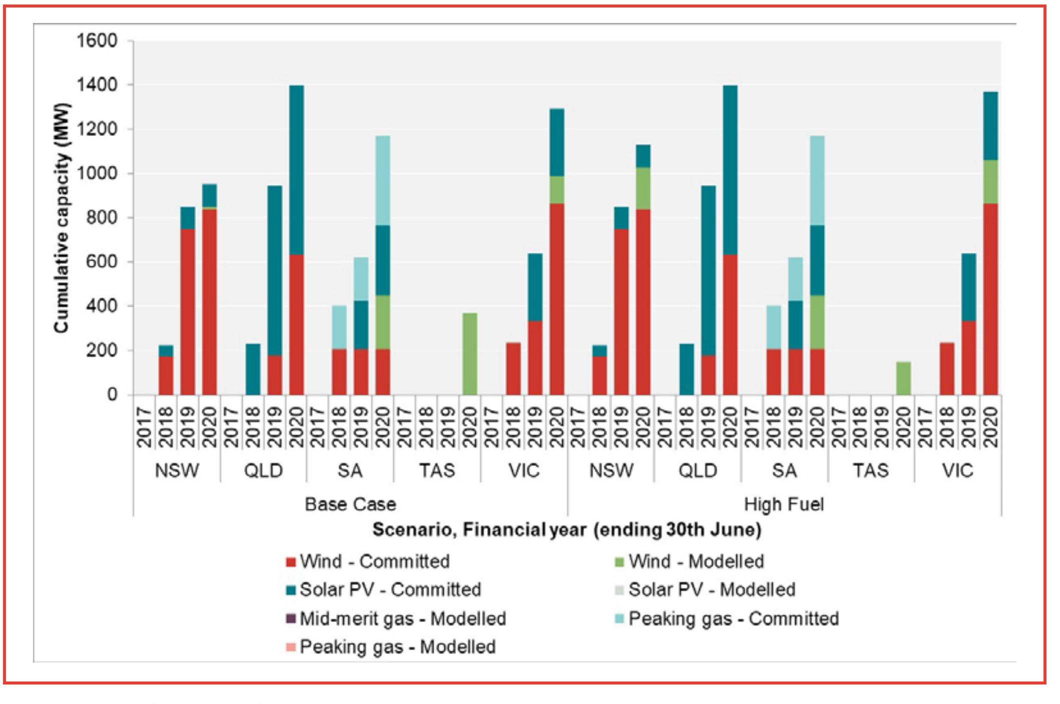
Source: Frontier Economics

Figure 15: Cumulative new investment by scenario – NEM total



Source: Frontier Economics

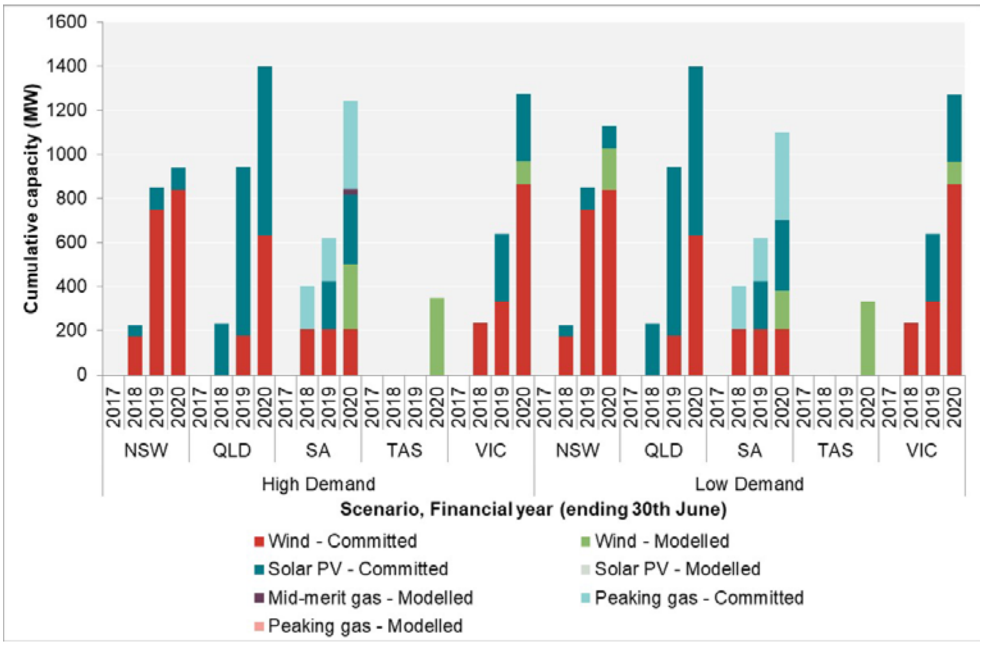
Figure 16: Cumulative new investment by regions – Base case and High Fuel



Source: Frontier Economics

Results – wholesale electricity costs

Figure 17: Cumulative new investment by regions – High Demand and Low Demand



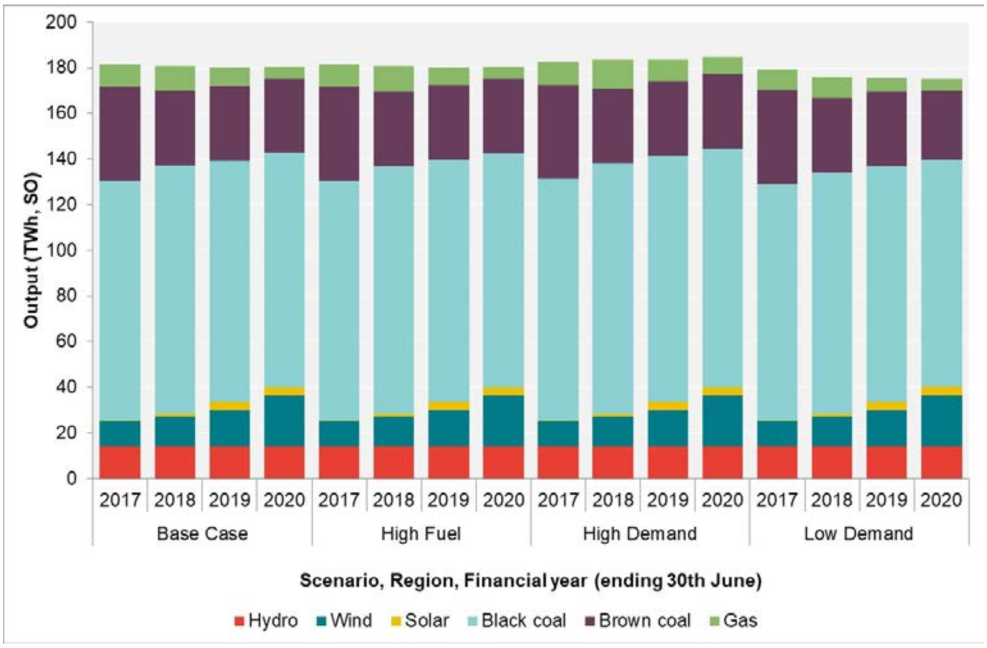
Source: Frontier Economics

Dispatch

Power station dispatch in aggregate for the NEM for the Base case and each of the three 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 2019/20, with the results shown by fuel type.

In all cases the retirement of Hazelwood in March 2017 leads to the reduction of brown coal generation in Victoria after the first year. 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 and Low Demand scenarios where demand is either flat or decreasing.

Figure 18: Annual dispatch in all scenarios

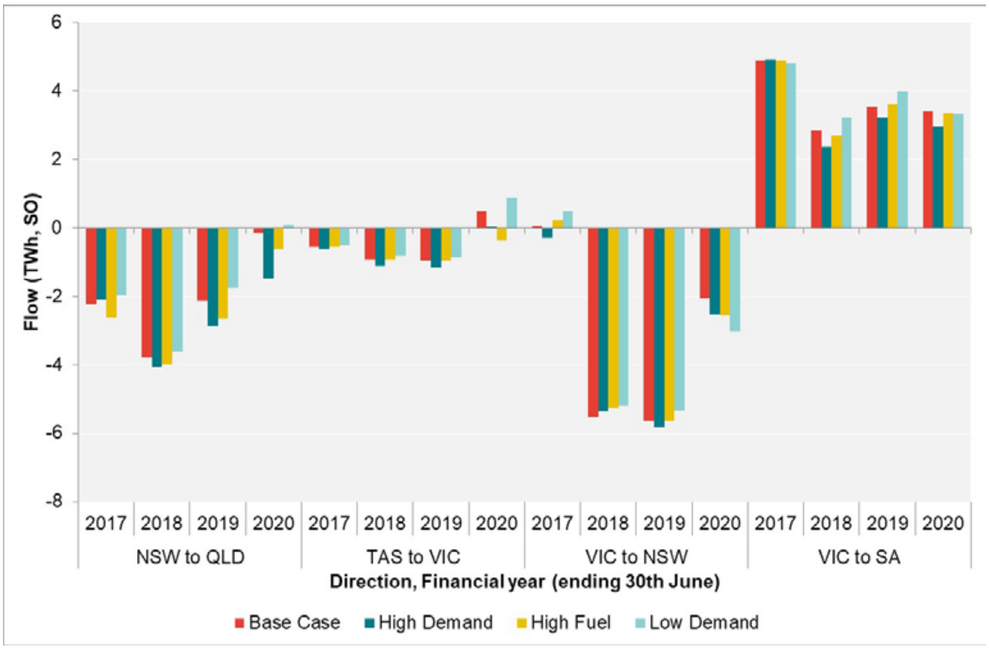


Source: Frontier Economics

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, and are heavily influenced by the retirement of Hazelwood. 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 and 2018/19, as Hazelwood generation is replaced by NSW black coal generation. Victoria's dependence on export from the northern region is reduced in 2019/20 when new investment in renewable becomes available in the southern regions.

Figure 19: Net interconnector annual flows between the NEM regions



source: Frontier Economics

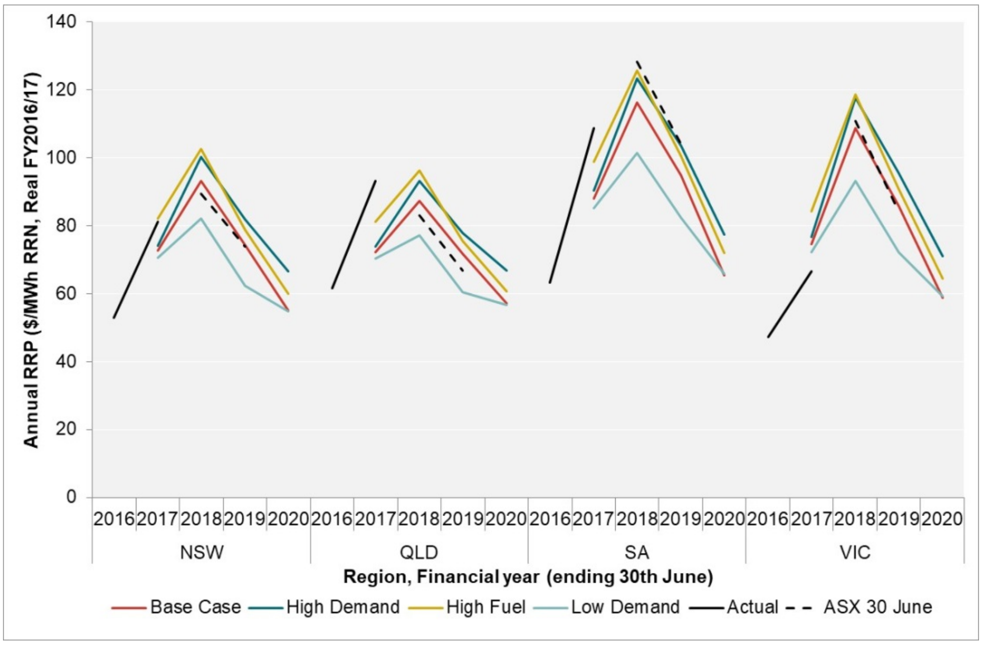
Pool prices

Forecast pool prices for the Base case and each of the three 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 base swap prices as of 30th June 2017. All prices are at the regional reference node, in real 2016/17 dollars, and the ASX Energy flat swap prices have been adjusted to real financial year 2016/17 dollars and to remove an assumed contract premium of 5 per cent.

In the Base case the 2016/17 pool prices (both actual and modelled) have increased significantly relative to 2015/16. This was mainly driven by the retirement of Northern in SA at the end of 2015/16, rising gas prices in 2016/17 and the closure of Hazelwood after March 2017. The annual average pool prices are forecast to increase further in all regions in 2017/18 following the retirement of Hazelwood and some further increases in gas prices. From 2018/19, however, the pool prices are forecast to fall, mainly due to the large amount of recent committed renewable projects coming online (See Section 3.6.2), the forecast flattening of gas prices and the forecast falling export coal prices. The declining trend is expected to continue in 2019/20 as more renewable (committed or modelled to meet the LRET) generation is predicted to enter the market and the fall in coal prices is forecast to continue. The South Australian EST will also likely help reduce pool prices in 2019/20, especially in SA and Victoria, assuming the SA gas generators will competitively pass through the reduction in their SRMC.

The wholesale price trends in the other three scenarios are very similar to that in the Base case due to similar trends in the key drivers. In the High Demand scenario, while the level of demand in all years is higher, the trend in demand growth is similar to that in the Base case, resulting in higher price levels than the Base case in all years. The High Fuel scenario is similar to the High Demand case. Although the level of fuel prices are higher, their trend is similar to the base case during the modelling period, resulting in higher levels of pool prices than the Base case. In the Low Demand scenario, the suppressed demand level in 2017/18 means that the effect of gas price increases is mitigated by gas being marginal less often. Hence, there is a much smaller increase in pool prices from 2016/17 to 2017/18.

Figure 20: Pool price forecasts and ASX futures prices – All scenarios ($/MWh annual average prices, real $2016/17)



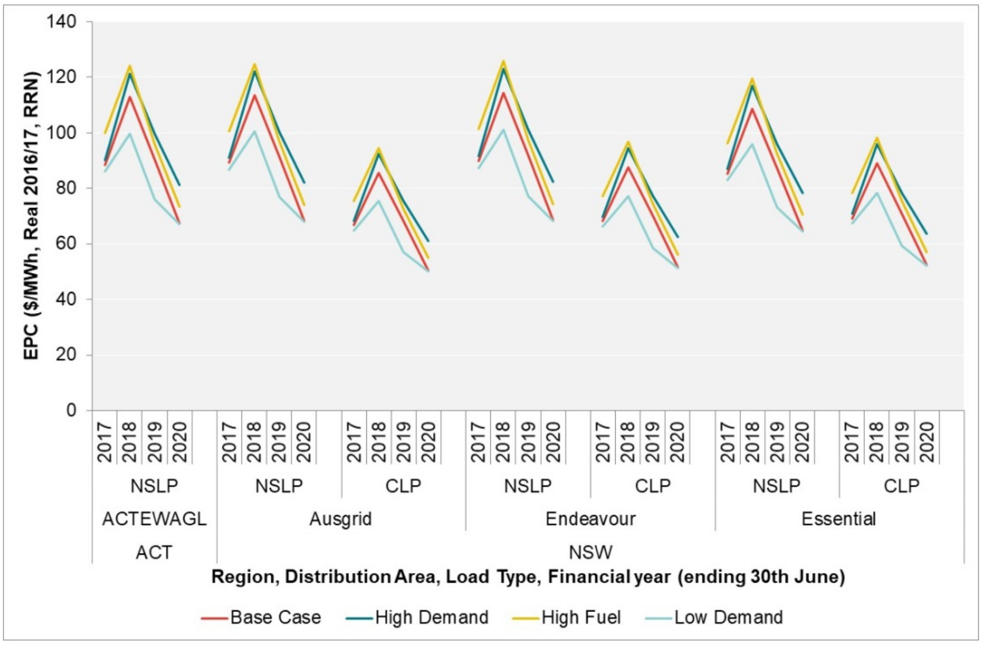
Source: Frontier Economics

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 2016/17 dollars.

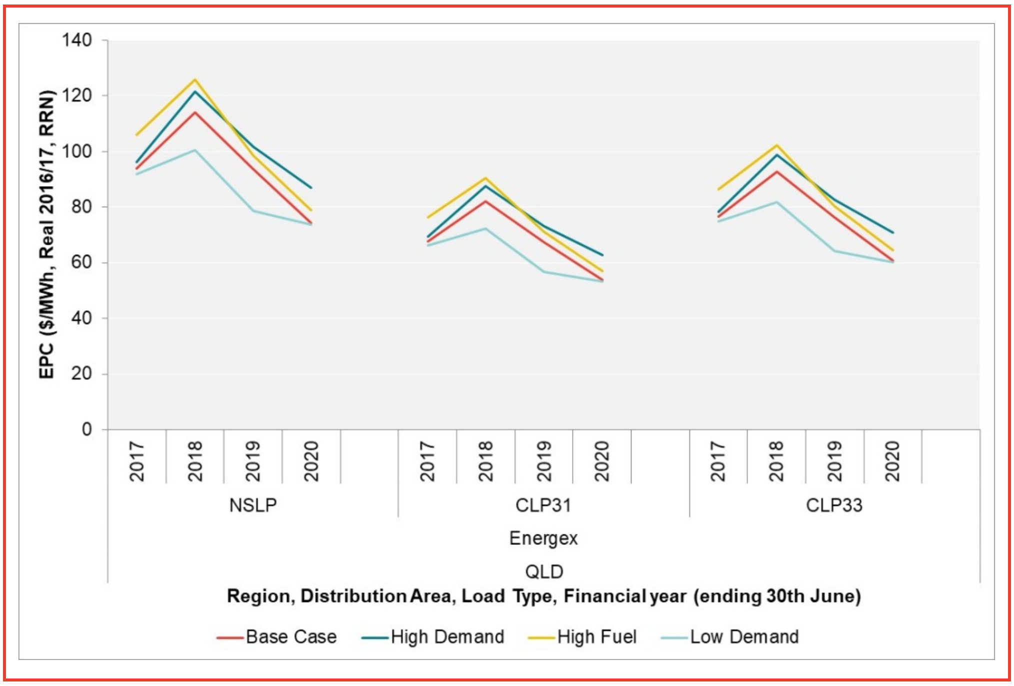
As discussed in Section 4.1.1, the market-based electricity purchase costs reflect two key drivers: forecast spot prices and residential load shapes. Since the residential load shapes are assumed to be constant over the forecast period and between scenarios, the residential load shapes do not drive trends 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



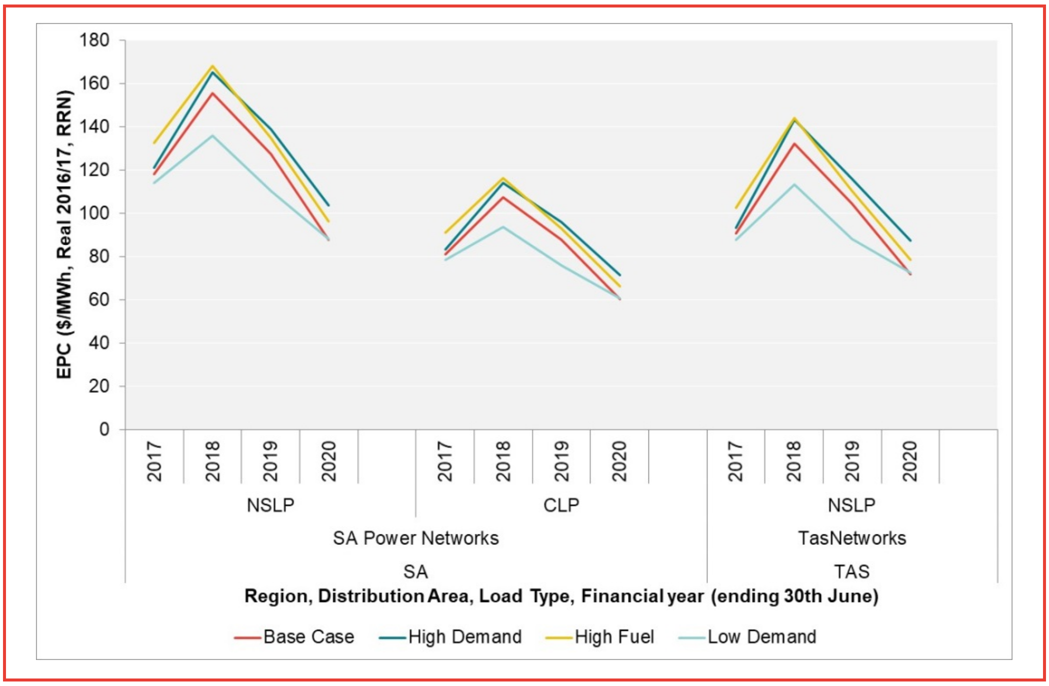
Source: Frontier Economics

Figure 22: Electricity purchase cost results for Queensland



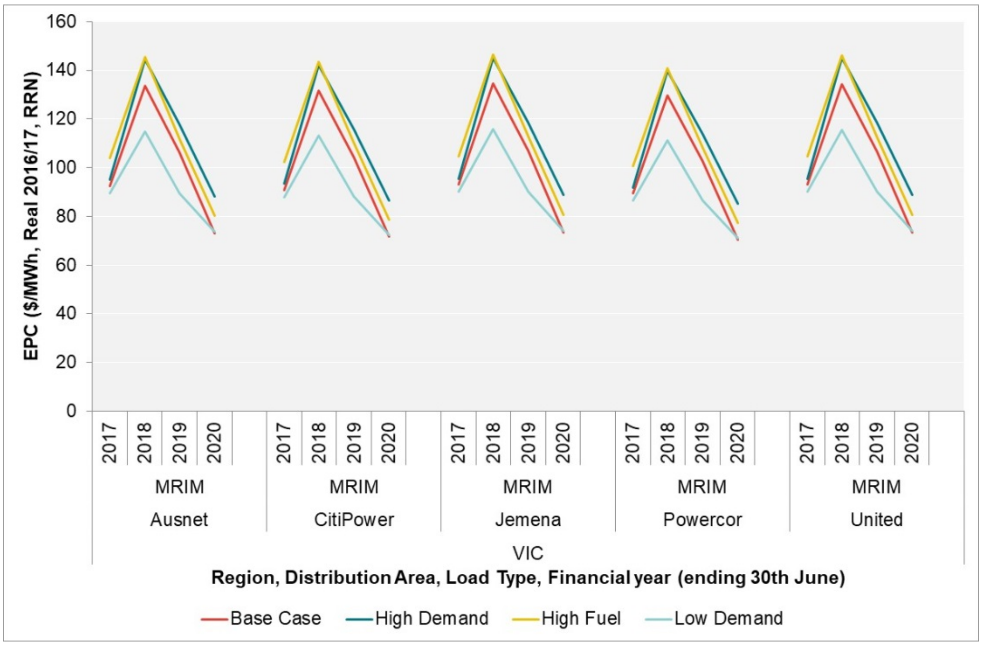
Source: Frontier Economics

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

4.3 Stand-alone LRMC of electricity

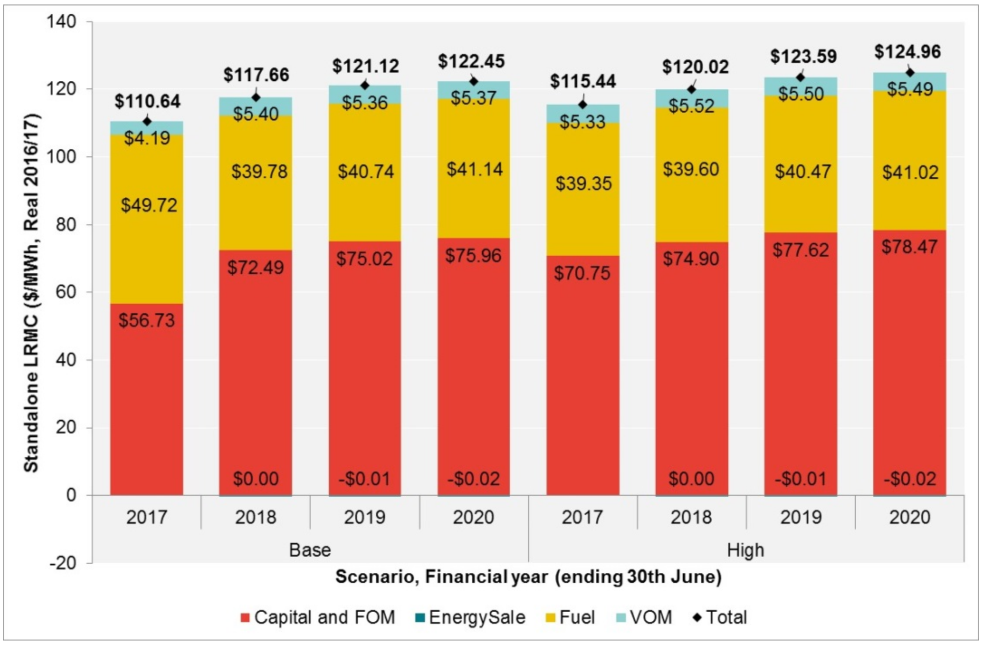
This section presents the results of our modelling of the stand-alone LRMC for the SWIS. Stand-alone LRMC results are presented for the Base case and the High Fuel case. The High Demand case and the Low Demand case are not relevant under the stand-alone LRMC approach because under the stand-alone LRMC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

For the current modelling, the Public Utility Office in WA supplied half-hourly load traces that differ in each modelled financial year. From 2017/18, the trace becomes peakier due to the increased rooftop PV output, which has led to negative demand in some half-hours. Because we are modelling the cost of a retailer serving a standalone retail load, as opposed to the actual system load, we have assumed that negative demand reflects sales to the market at the average 2016/17 STEM price of $52.73/MWh. This sales revenue is treated as a negative cost in the LRMC.[37]

[37] One could also model the retailer building a battery, or sell the negative energy at the half-hourly price when the negative consumption occurs. We note that the impact on the final results is negligible as even in 2019/20, the amount of negative energy still accounts for less than 0.2% of annual consumption.

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 2019/20, including the breakdown of the stand-alone LRMC into capital and fixed operating and maintenance costs (FOM), fuel costs, variable operating and maintenance (VOM) costs, and the energy sale costs (negative).

Figure 25: Stand-alone LRMC results – Base case and High Fuel



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. In the Base case, the standalone LRMC increases from 2016/17 to 2017/18 due to the forecast increase in gas prices. In fact, as the investment mix can be completely rebuilt in the standalone LRMC, there is a switch from gas only fuel mix in 2016/17 to gas plus coal in 2017/18. As shown in investment results (Figure 26) and dispatch outcomes (Figure 27). The fuel mix switch leads to an increase in capital cost and a reduction in fuel costs in 2017/18, as coal plants with more expensive capital but cheaper fuel costs are built. The overall effect, however, is an increase in total costs. The High Fuel scenario has a similar trend, except in 2016/17 there was already coal in the fuel mix due to the higher starting gas price level.

From 2017/18 to 2018/19, there is a further increase in standalone LRMC as the load shape becomes peakier, as shown in Table 11. A peakier load shape leads to more investment in peaking capacity, hence increase the capital cost of serving the residential load. This can be seen in Figure 26, where there is more OCGT built in the investment mix from 2017/18 to 2018/19.

Table 11: Load factor of standalone demand trace

Financial year	Load factor
2016-17	29.99%
2017-18	30.00%
2018-19	28.48%
2019-20	28.30%

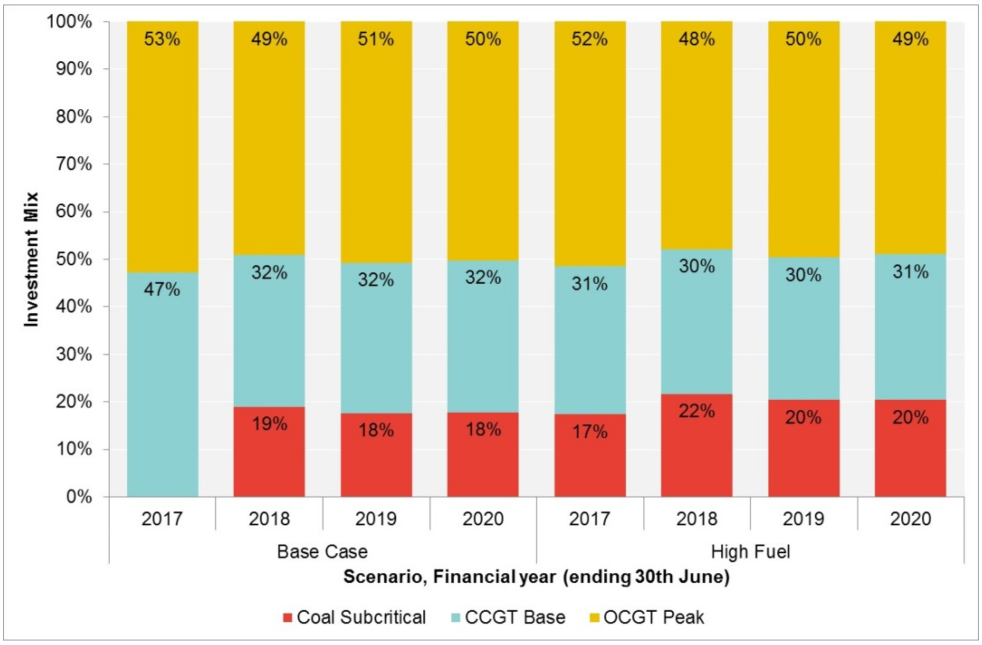
Source: Frontier Economics analysis of PUO load shape

Table 12 summarises the key trends that drive outcomes in the Base case and the High Fuel case.

Table 12: High level trends in the stand-alone LRMC, by scenario

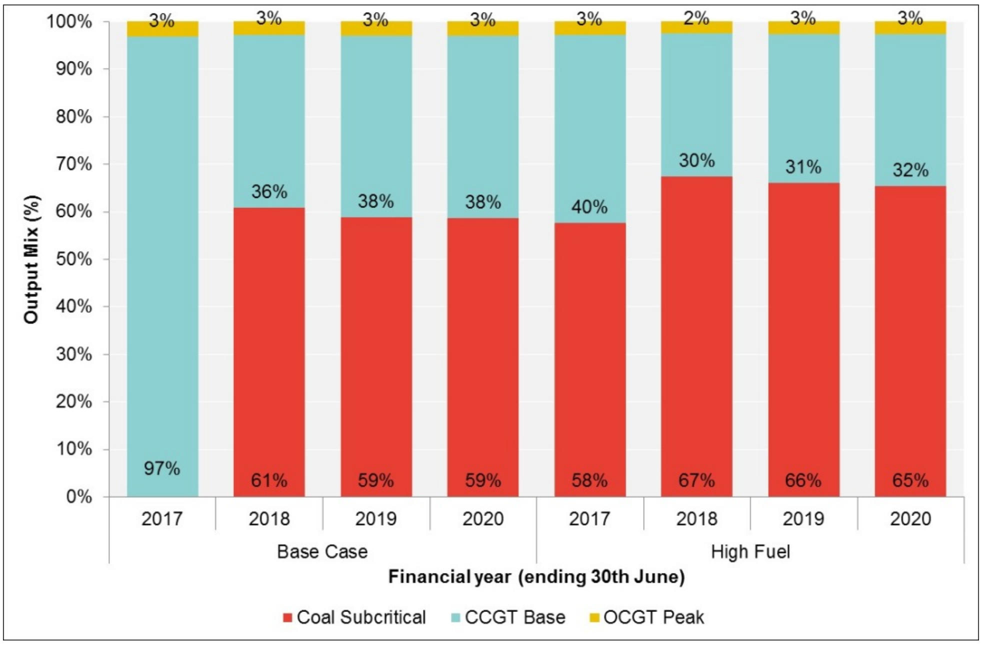
Region	Key trends
Base case	The standalone LRMC increases from 2016/17 to 2017/18 due to an increase in the gas price. There is a switch in fuel mix from gas only in 2016/17 to building coal in 2017/18. The standalone LRMC increase further in 2018/19 as the load shape becomes peakier and more OCGT capacity is built to meet peak demand. From 2018/19 to 2019/20 the standalone LRMC remains reasonably flat.
High Fuel	Similar trend to the Base case. Standalone LRMC in 2017/18 increases due to higher gas price and in 2018/19 due to peakier load shape. From 2018/19 to 2019/20 the standalone LRMC remains reasonably flat.

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



Source: Frontier Economics

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



Source: Frontier Economics

5 Results – other cost estimates

In addition to advising on wholesale electricity costs for the period 2016/17 to 2019/20, 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 13 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 13: Renewable power percentages

Financial Year	RPP (% of liable acquisitions)
2016-17	13.49%
2017-18	14.93%
2018-19	16.36%
2019-20	17.78%

Source: Clean Energy Regulator with Frontier Economics adjustment.

Modelled LGC certificate cost

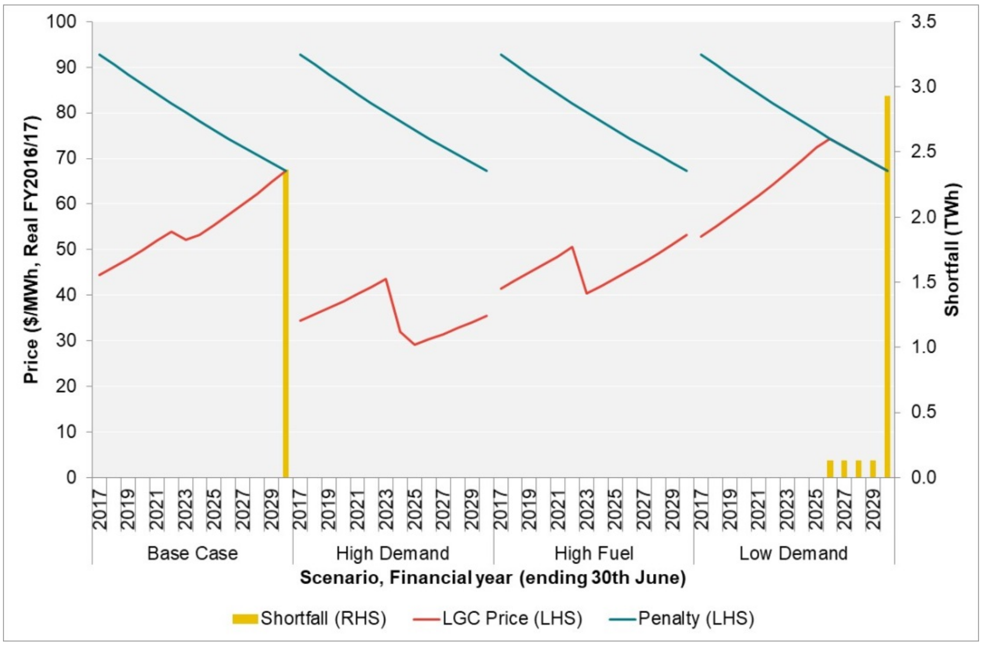
Our modelled LRET certificate costs are summarised in Figure 28. Figure 28 shows, for the Base case and each of the three scenarios, the LRET penalty (which falls in real terms over time), the shortfall in meeting the LRET (if there is one) and our estimate of the LRMC of meeting the LRET.

In the Base case, our estimate of the LRMC of meeting the LRET is around $45-50/MWh over the modelling period. The LGC costs rises further to slightly above $54/MWh before dropping to close to $52/MWh in 2022/23, after which it continues to rise to approximately $67/MWh in 2030. The kink in 2022/23 is due to both the limit of inter-temporal borrowing being reached and the expected retirement of Liddell. The higher electricity pool prices after Liddell's retirement means a smaller subsidy is required to recover the cost of new renewable plant. Since a large amount of renewable generation (in addition to LRET) is expected to enter the market under both the VRET and the Queensland 50% renewable energy pathway, this will likely put downward pressure on pool prices, leading to higher LGC 'subsidies' required for new renewable entrants that contribute to the LRET. In fact, in the Base Case, our modelling shows a small amount of shortfall in LRET occurs in 2030. We note that this modelled shortfall amount is very small, roughly equivalent to an 80 MW wind farm operating for 10 years. In reality, this may be avoided if the actual investment path diverges slightly from our modelled prediction due to factors such as faster capital cost reduction or different demand forecast, etc.

In both the High Demand and High Fuel scenarios, our modelled LRMC of LGC certificates follows similar trends to the Base case, although the levels of LGC certificate in both scenarios are lower than the base case. This is because in both scenarios, higher pool prices mean a smaller subsidy is required to recover the cost of new renewable plant.

In the Low Demand case, our estimate of the LRMC of meeting the LRET is higher, and there is a larger shortfall against 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.

Figure 28: Modelled LRET outcomes by scenario

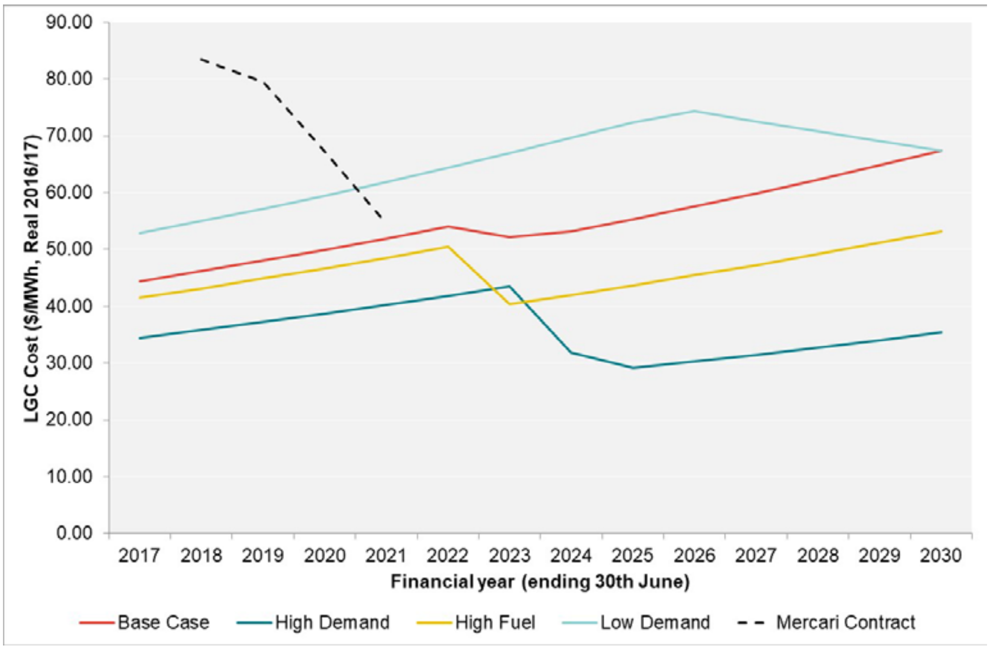


Source: Frontier Economics

Our modelled LGC costs differ quite significantly from the contract prices for LGCs reported on Mercari, as shown in Figure 29. The Mercari contract prices are shown as on the 8th November 2017, except for the FY2017 price, which was obtained on 30th June 2017, and have been converted to real 2016/17 dollars. Figure 29 shows that the contract prices for LGCs have generally been around $70-80/MWh for the period to 2019/20, but the prices decrease sharply afterwards to close to $45/MWh in 2020/21, which is similar to our base case forecast.

The difference arises as we model the LRMC of the LGC certificate, which reflects the subsidy required to build the marginal renewable plant to meet the LRET, whereas the high contract prices in the early years is more likely to be caused by a few retailers who are purchasing LGC certificates to cover their shortfall in the short run. In fact, the current contract prices – at nearly $80/MWh – is unlikely to reflect the LRMC of meeting the LRET. At the current pool price of over $70/MWh, this would imply a total black plus green cost of nearly $150/MWh, which is significantly higher than the levelised cost of a wind farm.

Figure 29: Modelled LGC *vs.* contract prices



Source: Mercari data and Frontier Economics analysis

Retailer cost of meeting the LRET

Table 14 shows the LRMC of the LGC certificate (RRN basis, real $2016/17) from our modelling, and compares with the forward prices for LGCs as reported on Mercari on 30th June 2017. 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 14: LGC cost estimate ($/certificate, RRN basis, real $2016/17)

Financial Year	Base Case	Low Demand	High Demand	High Fuel	Mercari forward prices
2016-17	$44.38	$52.89	$34.41	$41.50	$79.88
2017-18	$46.16	$55.00	$35.79	$43.16	$83.49
2018-19	$48.01	$57.20	$37.22	$44.88	$79.44
2019-20	$49.93	$59.49	$38.71	$46.68	$67.21

Source: Frontier Economics

Based on the estimates of LGCs costs in Table 14, and RPPs, the LRET cost to residential consumers is presented in Table 15.

Table 15: LRET cost ($/MWh, RRN basis, real $2016/17)

Financial Year	Base Case	Low Demand	High Demand	High Fuel	Mercari forward prices
2016-17	$5.99	$7.13	$4.64	$5.60	$10.77
2017-18	$6.89	$8.21	$5.34	$6.44	$12.47
2018-19	$7.85	$9.36	$6.09	$7.34	$12.99
2019-20	$8.88	$10.58	$6.88	$8.30	$11.95

Source: Frontier Economics

5.1.2 SRES

Table 16 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 2019, and the assumption that the STP remains constant after this at the level from 2019.

Table 16: Small-scale technology percentages

Financial Year	STP percentage
2016-17	8.35%
2017-18	7.54%
2018-19	7.79%
2019-20	7.52%

Source: Frontier Economics

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

Based on these inputs, Table 17 contains the estimated SRES costs. These are higher in earlier years due to the higher STP percentages and higher real STC cost.

Table 17: SRES cost ($/MWh, RRN basis, real $2016/17)

Financial Year	SRES cost
2016-17	$3.34
2017-18	$2.94
2018-19	$2.97
2019-20	$2.79

Source: Frontier Economics

5.2 Retail pass-through of Energy Security Target costs

Currently we do not yet know the exact pass-through mechanism of the EST in South Australia, and assumed that it would similar to the LRET. We have calculated the "EST retail percentage" based on the current known EST target over AEMO EFI neutral forecast. This is shown Table 18. Note that we have halved the original assumed financial year 2019/20 target, as the scheme is expected to commence in January 2020.

Table 18: Assumed 'EST retail percentage"

Financial Year	AEMO Native forecast – EFI 2018 neutral (GWh)	EST Target	"EST Retail Percentage"
2016-17	12,629	0	0.0%
2017-18	12,396	0	0.0%
2018-19	12,359	0	0.0%
2019-20	12,839	2250	17.5%

Source: Frontier Economics Analysis of EST Stakeholder consultation paper

Combining this with the modelled certificate prices as in Figure 14, the calculated pass-through of EST for each scenario is shown in

Table 19: EST retail pass-through ($/MWh, Real 2016/17)

Financial Year	Base Case	Low Demand	High Demand	High Fuel
2016-17	0	0	0	0
2017-18	0	0	0	0
2018-19	0	0	0	0
2019-20	$7.51	$7.34	$6.48	$7.82

Source: Frontier Economics

5.3 Market fees and ancillary services costs

5.3.1 Market fees

Table 20 shows our estimated market fees on an RRN basis in real 2016/17 dollars. These estimated market fees are based on budgets published by AEMO.

Table 20: Market Fees ($/MWh, RRN Basis, real $2016/17)

Financial Year	Region	Market fees
2016-17	NEM	$0.34
2016-17	SWIS	$0.95
2017-18	NEM	$0.37
2017-18	SWIS	$0.90
2018-19	NEM	$0.35
2018-19	SWIS	$0.90
2019-20	NEM	$0.31
2019-20	SWIS	$0.90

Source: Frontier Economics

5.3.2 Ancillary services costs

Table 21 shows our estimated ancillary service cost on an RRN basis and in real 2016/17 dollars.

These estimated ancillary services costs are based on the historic average ancillary services costs in each region over the period 2013/14 to 2016/17.

The exception to this in ancillary services costs in South Australia. In South Australia, these costs have increased materially over the last 12 months or so (likely driven by the closure of Northern Power Station). However, the battery that is being built in South Australia is intended to address these higher ancillary services costs. For this reason, we have excluded ancillary services costs for 2016/17 in South Australia and based on estimate of the future cost of ancillary services in South Australia on average prices from 2013/14 to 2015/16.

More generally, 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 21: Ancillary service cost ($/MWh, RRN basis, real $2016/17)

Financial Year	Region	Ancillary service costs
2016-17	QLD	$0.16
2016-17	NSW	$0.45
2016-17	ACT	$0.45
2016-17	VIC	$0.18
2016-17	TAS	$0.58
2016-17	SA	$0.50
2016-17	SWIS	$1.86
2017-18	QLD	$0.16
2017-18	NSW	$0.45
2017-18	ACT	$0.45
2017-18	VIC	$0.18
2017-18	TAS	$0.58
2017-18	SA	$0.50
2017-18	SWIS	$1.86
2018-19	QLD	$0.16
2018-19	NSW	$0.45
2018-19	ACT	$0.45
2018-19	VIC	$0.18
2018-19	TAS	$0.58
2018-19	SA	$0.50
2018-19	SWIS	$1.86
2019-20	QLD	$0.16
2019-20	NSW	$0.45
2019-20	ACT	$0.45
2019-20	VIC	$0.18
2019-20	TAS	$0.58
2019-20	SA	$0.50
2019-20	SWIS	$1.86

Source: Frontier Economics

5.4 Loss factors

The loss factors for each distribution area are reported in Table 22 and Table 23.

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 22: Transmission loss factors

State	Area	2016/17	2017/18
ACT	ActewAGL	1.0176	1.0479
NSW	Ausgrid	1.0055	1.0054
NSW	Endeavour Energy	0.9962	0.9952
NSW	Essential Energy	1.0261	1.0237
QLD	Energex	1.0132	0.9952
SA	SA Power Networks	1.0041	1.0044
TAS	TasNetworks	1.0295	1.0479
VIC	Citipower	1.0008	1.0020
VIC	Jemena	1.0024	1.0143
VIC	Powercor	1.0083	1.0143
VIC	Ausnet	1.0015	1.0054
VIC	United Energy	0.9962	0.9987
WA	Western Power	1.0401	1.0395

Source: Frontier analysis of AEMO data

Table 23: Distribution loss factors

State	Area	2016/17	2017/18
ACT	ActewAGL	1.0508	1.0482
NSW	Ausgrid	1.0581	1.0548
NSW	Endeavour Energy	1.0673	1.0649
NSW	Essential Energy	1.0815	1.0795
QLD	Energex	1.0578	1.0560
SA	SA Power Networks	1.0980	1.1050
TAS	TasNetworks	1.0335	1.0351
VIC	Citipower	1.0400	1.0419
VIC	Jemena	1.0449	1.0438
VIC	Powercor	1.0698	1.0686
VIC	Ausnet	1.0689	1.0618
VIC	United Energy	1.0544	1.0507
WA	Western Power	1.0415	1.0403

Source: Frontier analysis of AEMO data

Appendix A – Supply-side input assumptions; macroeconomic inputs

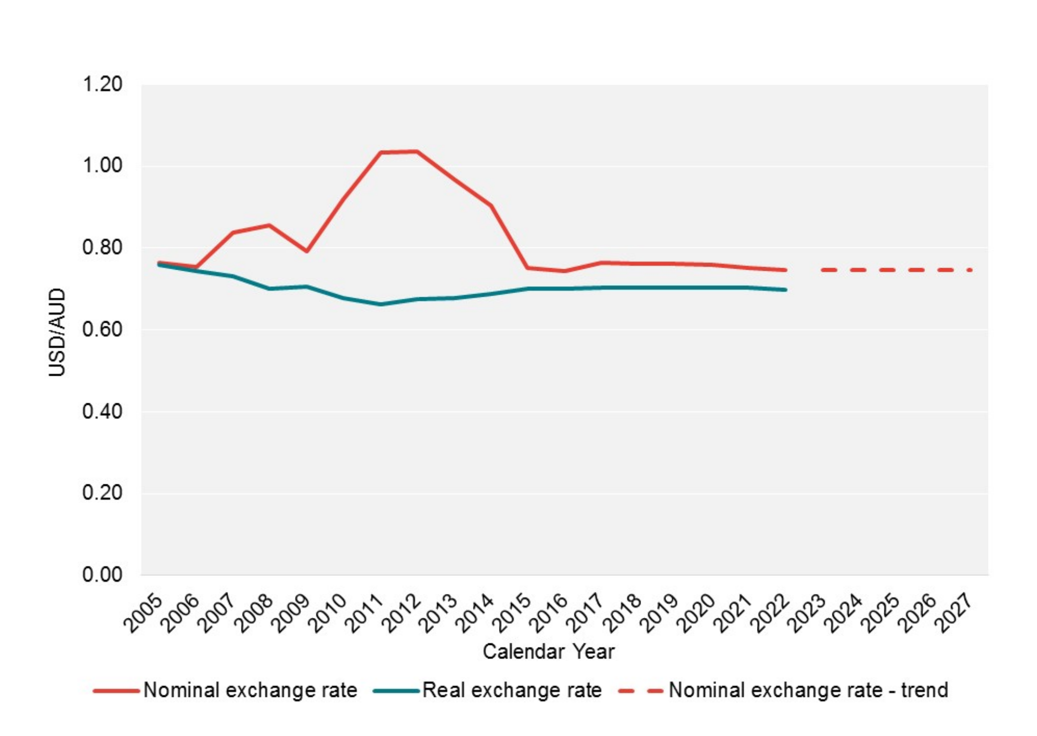
There are a number of macroeconomic input assumptions that are used in developing the input assumptions set out in this report. For consistency, the same macroeconomic input assumptions have been used throughout this report.

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.[38] This data includes historic nominal and real exchange rates, as well as forecasts of nominal and real exchange rates out to 2022. For nominal exchange rates, for which we require an exchange rate forecast beyond 2022, we have assumed that the exchange rate will remain at the 2022 forecast level for the remainder of the modelling period. Exchange rates for the US dollar are shown in Figure 30 and exchange rates for the Euro are shown in Figure 31.

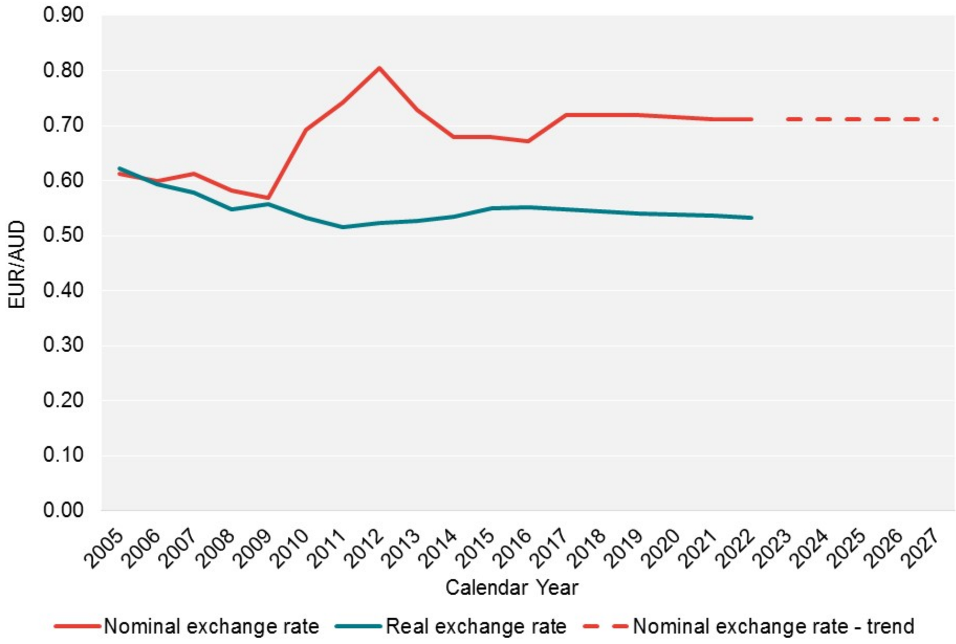
38 We use the most recent available data. At the time of our analysis this was the April 2017 World Economic Outlook. Available at: https://www.imf.org/external/pubs/ft/weo/2017/01/weodata/index.aspx

Figure 30: Exchange rates (USD/AUD)



Source: International Monetary Fund, World Economic Outlook Database, April 2017.

Figure 31: Exchange rates (Euro/AUD)



Source: International Monetary Fund, World Economic Outlook Database, April 2017.

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. 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 2016 – 0.04 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 2016 – 1.29 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 2016 will continue into the future.

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.[39]

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:

39 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 2016/17 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 energy 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 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 9. The range of cost estimates that covers the 10th to 90th percentile of cost estimates is shown by the pale red "boxes", and the range of cost estimates that covers the 25th to 75th percentile of cost estimates is shown by the dark red "boxes".

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 for technologies that are built less frequently, for which there tends to be a broader distribution of estimates.

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.

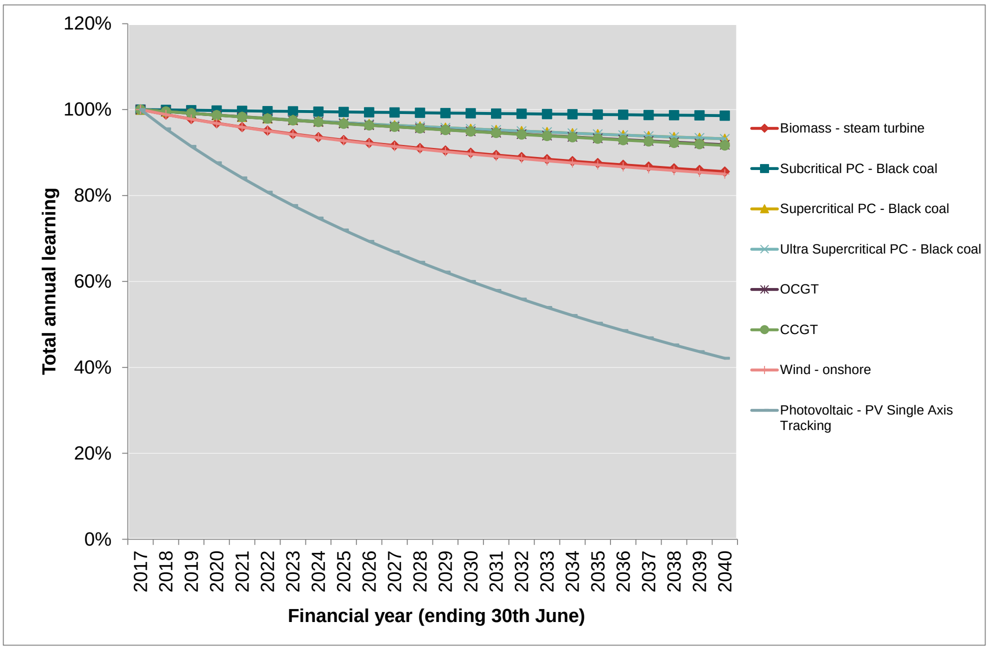
Estimates of capital costs over the modelling period

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 32.

Figure 32: Learning curves

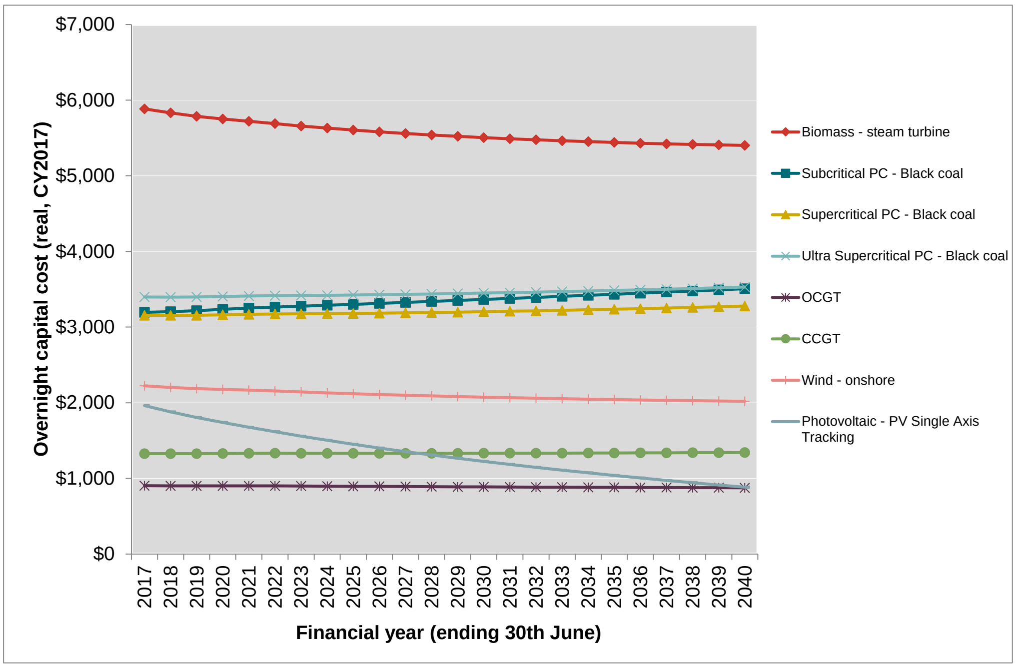


Source: Frontier analysis based on various sources

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 33.

As seen in Figure 33, the capital costs for 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. 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 PV costs fall significantly over the modelling period. 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 33: Forecast capital costs for coal generation plant



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 2016/17 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.

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.

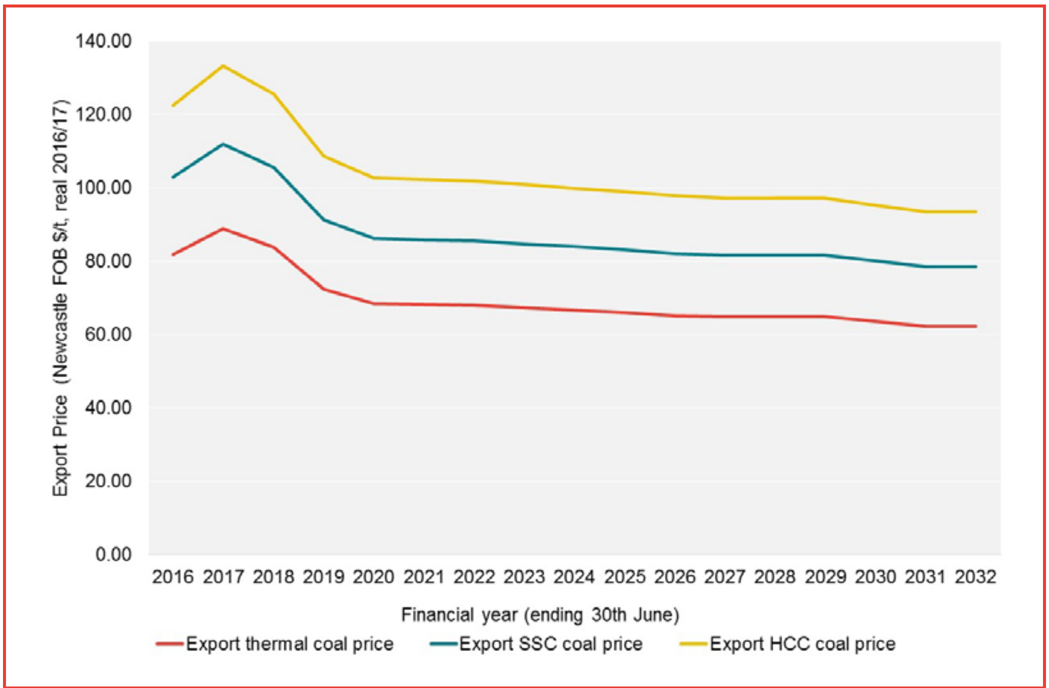
The **first step** for calculating the net-back price of coal is a forecast of the export price of coal. It is this export price that determines the revenue that a coal producer will earn by exporting coal.

The export prices that we have used to calculate the net-back price of coal are from quarterly forecasts released by the World Bank.[40] The World Bank provides

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

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.[41] 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 34.

Figure 34: Export coal prices ($2016/17)



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 34 are for coal of a particular quality. For instance, the export thermal coal price shown in Figure 34 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.

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

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.

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.[42] We have incorporated this additional cost of coal production in our coal price forecast for all Victorian coal plant. We have used the price that reflects the higher royalty rate for the full financial year 2016/17, but this will have no material effect on our modelling wholesale electricity prices for 2016/17 since brown coal generation rarely marginal and so does not set the wholesale electricity spot price.

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 an option to export) the net-back price of coal for the coal mine.

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

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

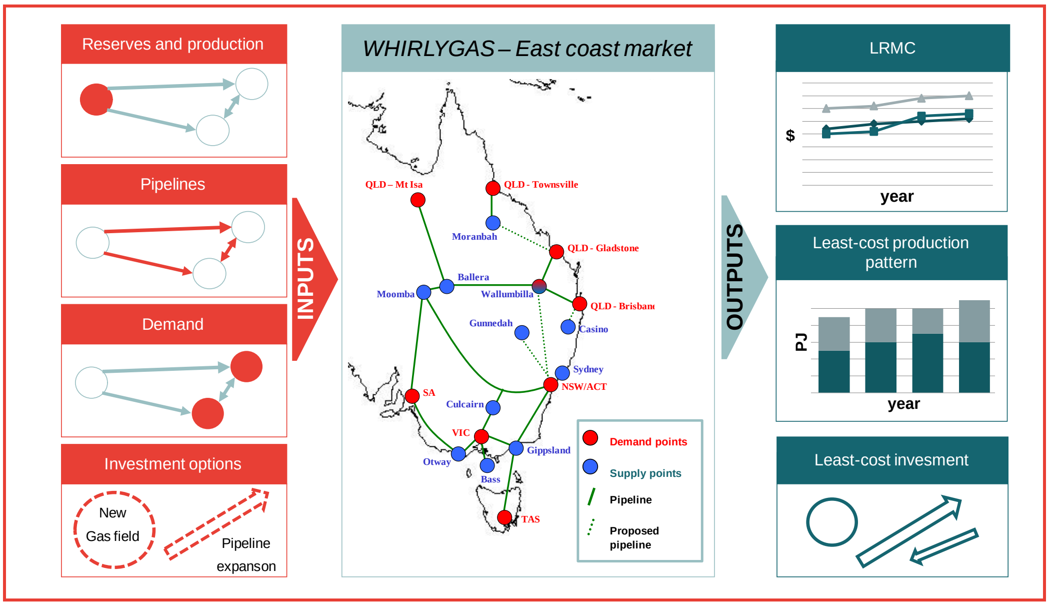
We estimate the cost of gas supplied to gas-fired power stations based on the marginal opportunity cost of gas.

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 35.

Figure 35: *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

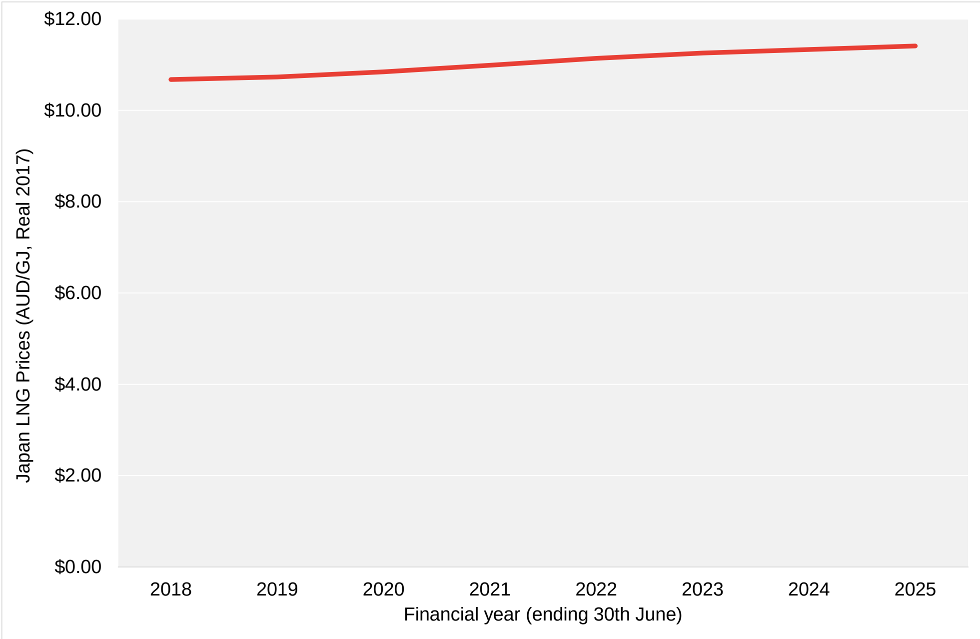
As with our coal forecasting work, opportunity cost is important to our gas forecasting work. The reason that opportunity cost is relevant to assessing the cost to gas producers of supplying gas to gas-fired generators is because the producers may well be foregoing alternative markets for that gas. For 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.[43] The World Bank provides annual forecasts of the Japanese LNG prices out to 2025 (as well as a price forecast for 2030). 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 36.

43 http://www.worldbank.org/en/research/commodity-markets

Figure 36: Japan LNG prices ($2016/17)



Source: World Bank, Commodity Price Forecast, April 2017.

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.

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.

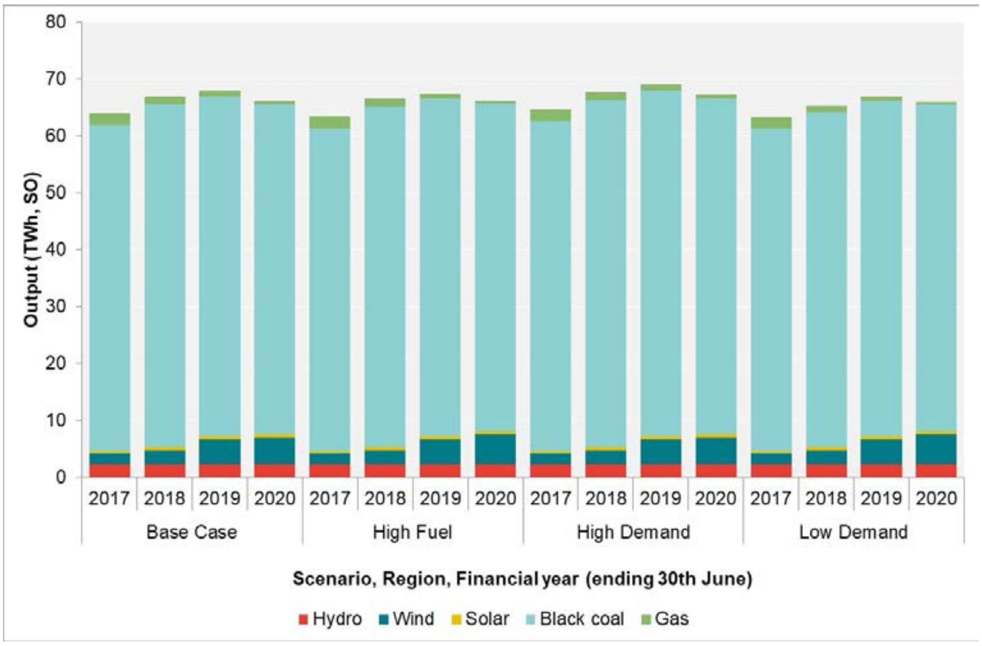
Results – other cost estimates

Appendix F – Regional modelling results

F.1 – Annual dispatch results

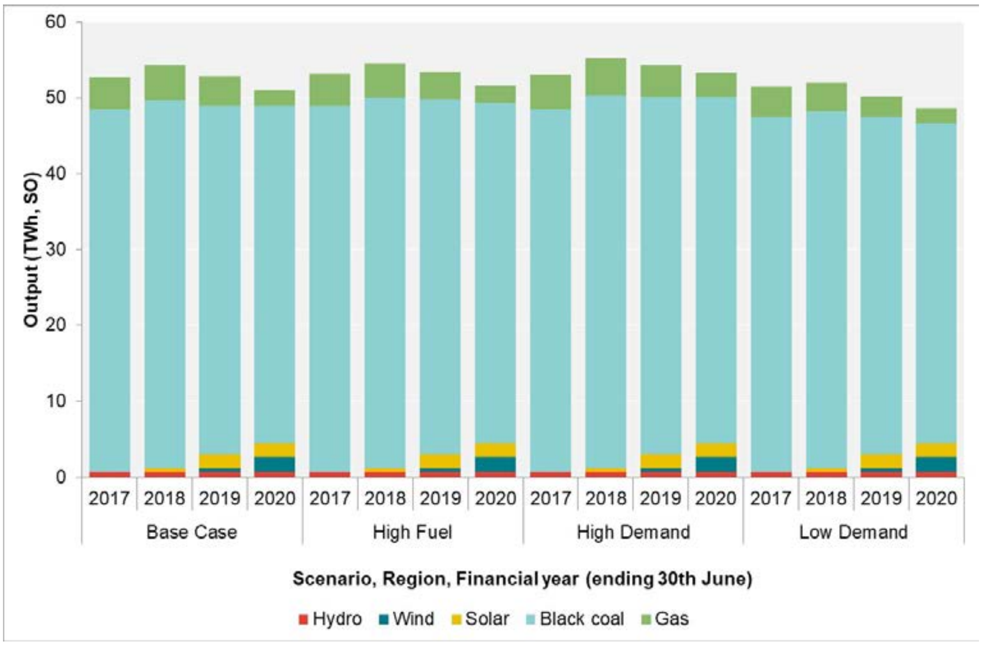
In Section 4.2, annual NEM dispatch results were presented for each Scenario. This appendix provides these annual results for each NEM region.

Figure 37: Annual dispatch results for each scenario - NSW



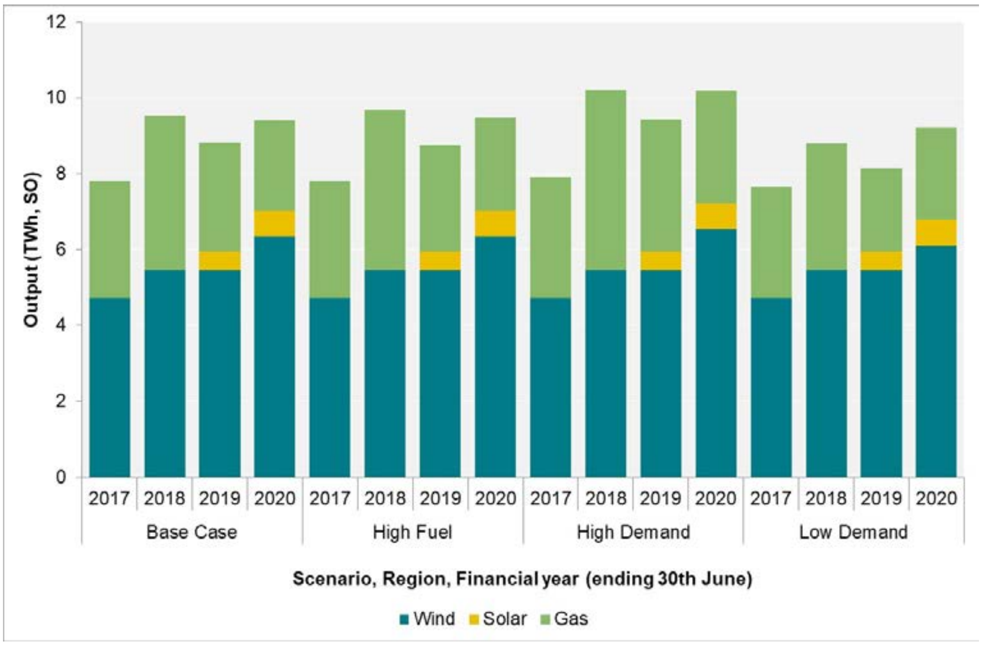
Source: Frontier Economics

Figure 38: Annual dispatch results for each scenario - QLD



Source: Frontier Economics

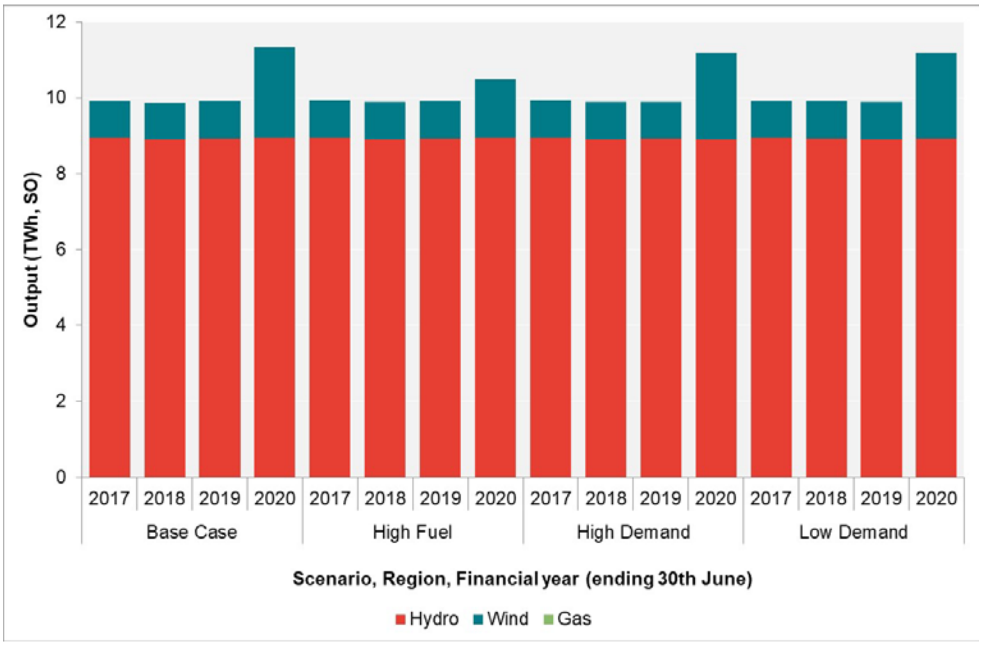
Figure 39: Annual dispatch results for each scenario - SA



Source: Frontier Economics

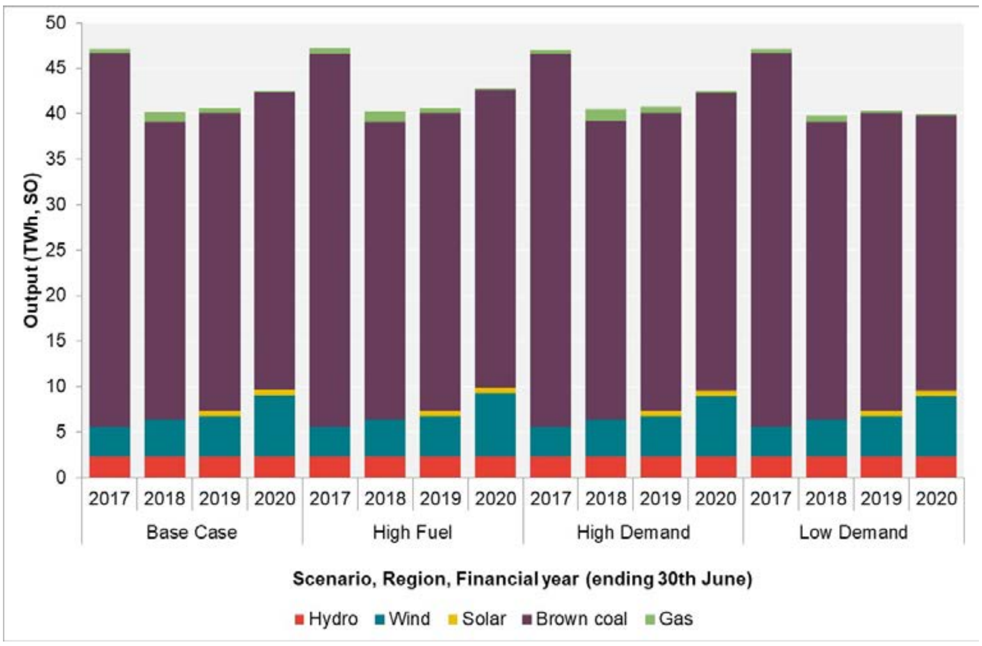
Results – other cost estimates

Figure 40: Annual dispatch results for each scenario - TAS



Source: Frontier Economics

Figure 41: Annual dispatch results for each scenario - VIC



Source: Frontier Economics

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
EFI	Electricity Forecasting Insight
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
EST	Energy Security Target
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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