



COAG  
Energy Council

# ENERGY SECURITY BOARD ADVICE

THE NATIONAL ENERGY GUARANTEE

20 NOVEMBER 2017

## Executive Summary

The ESB has provided advice to the Commonwealth government recommending the development of a National Energy Guarantee (Guarantee). The Guarantee would impose two requirements on retailers and other market customers. Firstly, they would have to meet a percentage of their load requirements with contracts that provide dispatchable and/or flexible capacity. Secondly, market customers would be required to meet their load requirements at a certain average emissions level. Both these requirements would be met through market customers' contract positions.

In response to the ESB's initial advice, the Commonwealth Government requested the ESB provide further advice to the Government on the operation of the Guarantee and its impacts on the NEM. Specifically, this second round of advice should assess the mechanism's ability to improve energy affordability and reliability while reducing emissions.

This report contains the analysis requested of the ESB by the Commonwealth Government. As per the Commonwealth Government's request, this work includes detailed electricity market modelling which has had been led by the Australian Energy Market Commission (AEMC or Commission). It is expected that this analysis is an input to discussions at the COAG Energy Council meeting in November 2017.

### The design of the Guarantee

The Guarantee will place a requirement on market customers<sup>1</sup> to simultaneously meet:

- a percentage of their load requirements with contracts that provide dispatchable and/or flexible capacity (the 'reliability requirement'), and
- their load requirements at a certain average emissions level (the 'emissions requirement').

Market customers will fulfil their requirement through the contracts they enter or through the type of generators they invest in directly. It is proposed that the dual guarantees be imposed through the conditions of registration as a wholesale market customer in the National Electricity Rules (NER).

The purpose of the Guarantee is to facilitate the achievement of both energy and emissions reduction policy objectives at the lowest possible cost to consumers. The key elements are:

- the Guarantee is market customer-based, and
- contracting and the contracts market is central to the design of the Guarantee.

### Quantitative assessment of the Guarantee

The Commonwealth government has requested that the ESB provide detailed electricity market modelling of the impact of the Guarantee. It is important to note that the results

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<sup>1</sup> Market customers are those market participants who buy electricity in the spot market, and include retailers and some large users. This definition excludes large and small customers who purchase electricity through a retailer.

from this modelling are not a forecast of the future but rather an indication of what outcomes could be expected using reasonable assumptions. Quantitative assessment outcomes are sensitive to key input assumptions, such as technology costs and fuel prices.

The modelling results show that Guarantee meets the policy objectives of reducing emissions while retaining a reliable system and improving affordability. It does this better than the do-nothing or business-as-usual scenario (BAU).

The Guarantee requires market customers to contract for a certain level of dispatchable generation in the NEM. This can include either thermal generation, or dispatchable renewable generation such as solar thermal or hydro. To the extent that this higher demand for contracts is met from existing capacity, this will increase the proportion of generation capacity contracted (and reduce the proportion uncontracted). This is likely to lead to more competitive bidding in the spot market as generators will bid lower to increase their chances of being dispatched in order to cover their contracted capacity. This results in lower spot prices. If the higher demand for contracts was not able to be met by existing resources due to their physical constraints, the demand would be met from new entrants (particularly fast-start resources), which improves system reliability and reduces the likelihood of extreme spot price events, lowering price volatility.

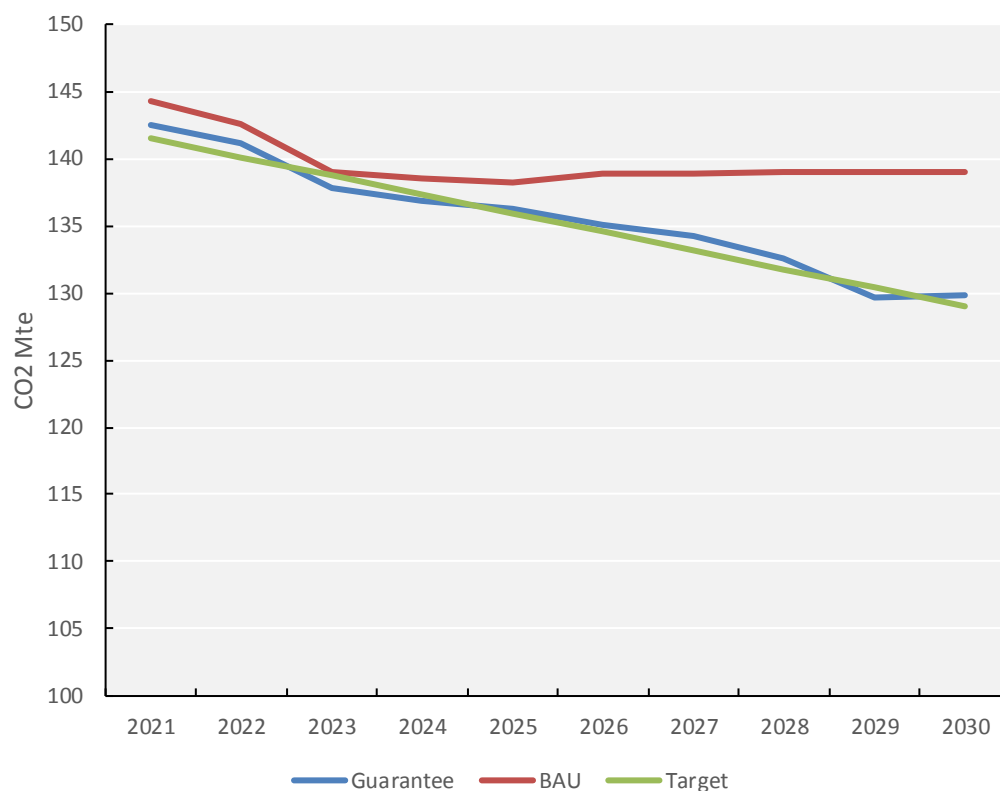
For the purposes of the modelling, the emissions target for the NEM is assumed to be consistent with the Commonwealth Government's stated 2030 emissions reduction target.<sup>2</sup> The Guarantee requires market customers to meet their load requirements within a certain emissions level. In the model, this increases contracting with low-emissions resources providing both certainty for low-emissions generation investment and their cashflows to make that investment viable.

As a result of these requirements, the Guarantee is able to meet the Commonwealth's emissions reduction target under the Paris Agreement, while a do-nothing approach would not be sufficient to meet the 26% goal (Figure 1). Emissions under the BAU scenario do fall, however reflecting the fact that the majority of generation capacity that enters and exits the NEM throughout the 2020-2030 period is already 'committed'. Committed generation is generation that is already planned and so is not specifically incentivised by the Guarantee.

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<sup>2</sup> These are financial years 2020-21 to 2029-30. Any years should be read as financial years for the rest of this document.

**Figure 1 Emissions under the Guarantee and BAU**



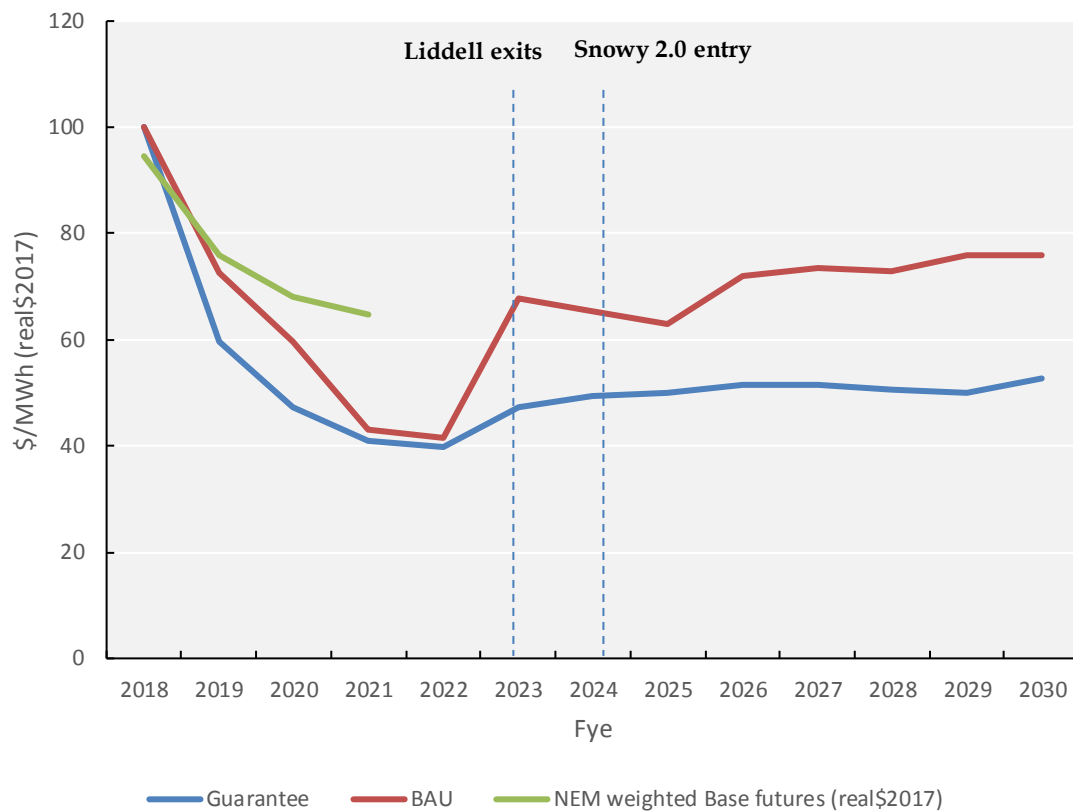
The Guarantee's impact on prices is evaluated for both the wholesale spot prices and retail bill impacts. Wholesale prices provide an investment signal for new generation or for retirement of existing generation, while consumer impacts are best understood through analysis of retail bills.

The steep decline in wholesale prices under both BAU and Guarantee from 2018 to 2022 is due to the committed entry of almost 6,000 MW of renewable capacity across the NEM, principally incentivised by the existing Renewable Energy Target.<sup>3</sup> This price decline is also reflected in the price of baseload futures contracts (Figure 2).<sup>4</sup>

<sup>3</sup> The amount of committed generation is based on market data and Frontier Economics' own analysis, and includes projects under construction, financially closed, or and already committed under the Snowy Hydro expansion, RET, VRET (650MW) and QRET (400MW). Only 460MW of the 7,700MW of committed generation is not built under one of those three schemes.

<sup>4</sup> Price of ASX-traded calendar-year baseload futures contracts, from <https://www.asxenergy.com.au>

**Figure 2** NEM weighted-average wholesale prices (incl. RET certificate costs)



Initially, the reliability requirement leads to more competitive bidding from coal and gas, which reduces prices in the Guarantee somewhat compared with BAU. This difference in bidding has a minimal impact on price differences in 2021-22 as the market becomes oversupplied. Beyond 2022 however, the retirement of Liddell power station reduces supply once again. This results in a sharper increase in prices in the BAU case than the Guarantee, as bidding from existing dispatchable plant is more competitive under the Guarantee. This price jump is similar to recent price increases following the withdrawal of Northern and Hazelwood and highlights that the design of the Guarantee provides for a smoother adjustment to generator exits and avoids a repeat of the price spikes and market dislocation experienced when Hazelwood and Northern were retired.

The average residential bill saving over the 2020-2030 period under the Guarantee is in the order of \$120 per year (in today's dollars) across the NEM relative to BAU, and on average around \$400 lower than the estimated bill for 2017 in each year for the period 2020 to 2030. This saving reflects the reduction in wholesale electricity prices under the Guarantee, due to a combination of lower risk premiums on new capacity investment and more competitive bidding in the spot market. Savings under the Guarantee are robust to changes in assumptions about future demand, future technology costs and future gas prices.

Over the 2020-2030 period, the Guarantee encourages 1,086 MW more dispatchable generation capacity into the system, with this extra capacity used to 'firm up' intermittent renewables (Table 1). This is additional to the 2,543 MW of committed investment in dispatchable generation capacity to 2030 under both BAU and the Guarantee, comprising 2,000 MW through Snowy 2.0, a further 338 MW of pumped

storage hydro, 198 MW in solar thermal and 7 MW in gas peaking plant. No additional dispatchable renewable capacity enters under BAU beyond the committed generation (Table 1). This extra capacity, in combination with better bidding behaviour and a lower risk premium, also contributes to the lower wholesale and retail prices under the Guarantee compared to BAU.

**Table 1 Investment in uncommitted plant (MW)**

	Coal	Gas	Dispatchable renewable (incl. batteries)	Intermittent renewable
BAU	0	263	0	597
Guarantee	0	251	835	3,271

Under both BAU and the Guarantee, the penetration of renewables increases from 2020 to 2030, largely due to higher penetration of intermittent renewables. The increasing renewables' share is greater under the Guarantee due to the emissions obligation. Under the Guarantee, renewables account for 32-36 per cent of output in 2030, depending on assumptions about future demand. These figures include rooftop solar.

### **Next steps**

The COAG Energy Council is being asked to consider approving further work by the ESB on the design of the Guarantee. If there is agreement to this further work the ESB would anticipate undertaking a thorough and comprehensive consultation process with a wide range of industry, consumer and government stakeholders. This process would allow all interest parties to engage in the detailed design of all elements of the policy.

It is anticipated that the ESB would be able to provide a preliminary design approach to Ministers for consideration at the COAG Energy Council meeting scheduled for April 2018 and then a final design recommendation including required legislative and rule changes for approval in July.

It is envisaged that this work would be in conjunction with the work being done by the ESB and the COAG Energy Council to implement the recommendations from the Finkel Review.

# Contents

<b>1</b>	<b>Introduction.....</b>	<b>1</b>
1.1	Current market context.....	1
<b>2</b>	<b>The proposed design of the National Energy Guarantee .....</b>	<b>4</b>
2.1	A market customer-based requirement.....	4
2.2	Reliability requirement.....	4
2.3	Emissions requirement.....	4
<b>3</b>	<b>Quantitative assessment of the Guarantee .....</b>	<b>6</b>
3.1	Modelling assumptions.....	6
3.2	Price impacts.....	12
3.3	Ability to achieve emissions reduction target .....	15
3.4	Investment and retirements.....	16
3.5	Generation output .....	19
3.6	Sensitivity analysis .....	21
3.7	Conclusions from the quantitative assessment .....	27
<b>4</b>	<b>Qualitative assessment of the Guarantee .....</b>	<b>29</b>
4.1	Certainty of achieving policy objectives.....	30
4.2	Technological and geographic neutrality.....	31
4.3	Appropriateness of risk allocation.....	31
4.4	Impact on contract market liquidity.....	32
4.5	Implementation flexibility .....	32
4.6	Adaptability and sustainability .....	33
<b>5</b>	<b>Governance of the Guarantee.....</b>	<b>34</b>
<b>6</b>	<b>Competitive markets and the Guarantee .....</b>	<b>36</b>
6.1	Impact of competition.....	36
6.2	Competition in South Australia.....	37
6.3	A mechanism to limit further market concentration.....	40
<b>7</b>	<b>Next steps .....</b>	<b>44</b>
<b>A</b>	<b>Abbreviations and defined terms .....</b>	<b>46</b>
<b>B</b>	<b>Jurisdictional impacts of the Guarantee .....</b>	<b>47</b>
B.1	Wholesale prices .....	47
B.2	Jurisdictional investments and retirements .....	48
B.3	Impact on generation output by jurisdiction.....	49





# 1 Introduction

On 13 October 2017, the ESB provided advice<sup>5</sup> to the Minister for the Environment and Energy, the Hon. Josh Frydenberg MP, following the Australian Energy Market Operator (AEMO)'s September 2017 report on the risks to reliability in the National Electricity Market (NEM). The Minister for the Environment and Energy had requested advice from the ESB on the changes needed to the NEM and legislative framework such that:

- the reliability of the system is maintained
- the emissions reduction required to meet Australia's international commitments are achieved
- the above objectives are met at the lowest overall costs

In response to the ESB's initial advice, the Commonwealth Government has now requested the ESB provide further advice to the Government on the operation of the National Energy Guarantee (Guarantee) and its impacts on the NEM. Specifically, this second round of advice should assess the mechanism's ability to improve energy affordability and reliability while reducing emissions.<sup>6</sup>

This report contains the analysis requested of the ESB by the Commonwealth Government. As per the Commonwealth Government's request, this work includes detailed electricity market modelling which has been led by the Australian Energy Market Commission (AEMC or Commission).

In preparing this report, the ESB worked with stakeholders to test modelling assumptions and scenarios.

## 1.1 Current market context

### 1.1.1 The challenge of maintaining reliability

The national electricity market (NEM) is moving from large-scale synchronous generation to include non-synchronous, intermittent generation, and from centralised generation to greater amounts of smaller, distributed generation. This change in generation technologies is being driven by:

- declines in the cost of non-synchronous, intermittent generation
- government policies, chiefly the Renewable Energy Target (RET), that have subsidised the uptake of non-synchronous, intermittent generation
- changes in consumer preferences with greater uptake of distributed generation

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<sup>5</sup> See:  
<http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/Energy%20Security%20Board%20ADVICE....pdf>

<sup>6</sup> See:  
<http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/Energy%20Security%20Board%20Modelling%20Letter.pdf>

In relation to cost structures, the cost of renewable technologies is falling. There is also instability and uncertainty regarding key inputs such as gas and coal for thermal generators. Government policies have encouraged more renewable generation which has contributed to the retirement of some thermal generators.

The growth of large-scale intermittent generation is changing how the power system needs to be managed to maintain security<sup>7</sup> and deliver a reliable<sup>8</sup> supply to consumers. These technologies do not generally have the same attributes as the generators that are exiting, such as synchronicity<sup>9</sup> and dispatchability.<sup>10</sup>

### **1.1.2 Australia's emissions reduction policy objectives**

Australia has committed to reducing its emissions by 26-28 per cent on 2005 levels by 2030.<sup>11</sup> As the wholesale electricity generation sector accounts for around one-third of Australia's emissions, meeting our emissions reduction commitments will involve reducing emissions in the electricity sector. Therefore, energy policy and emissions reduction policy are linked.

Achieving Australia's emissions reduction goals at lowest cost to consumers must be done by encouraging new investment in a balanced mix of technologies that address both reliability and emissions reductions. Prices have been rising as a result of the same changes that are causing the system security and reliability concerns.

The principal national mechanism to reduce emissions in the wholesale electricity generation sector currently is the Renewable Energy Target (RET). The RET is a policy mechanism designed to encourage investment in large-scale renewable energy technologies and therefore is more of an industry policy rather than a strict emissions reduction policy. As an industry policy that sits outside the energy market framework, the design of the RET was not focused on working with the risk allocation and incentive mechanisms built into the NEM that align the financial incentives of market participants with the physical needs of the power system.

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<sup>7</sup> A secure system is one that is able to operate within defined technical limits, even if there is an incident such as the loss of a major transmission line or large generator. Security events are caused by sudden equipment failure (often associated with extreme weather or bushfires) that results in the system operating outside of defined technical limits, such as voltage and frequency.

<sup>8</sup> A reliable power system is one which has enough capacity (generation, demand-side and network) to supply customers. That is, a reliable system is one where there is a high likelihood of consumer demand being met. This requires: efficient investment, retirement and operational decisions by market participants resulting in an adequate supply of energy; a reliable transmission and distribution networks, as well as a secure system.

<sup>9</sup> Synchronous generators are synchronised to the frequency of the system and support the stability of the system by working together to maintain a consistent operating frequency and maintain the strength of the system in localised areas of the network.

<sup>10</sup> Dispatchable sources of generation are ones that can be dispatched at the request of the market operator, AEMO, and have their output forecast with a high degree of certainty. The availability of non-dispatchable generation technologies is largely not at the discretion of the party that controls them. Instead, generation is driven by the time of year, weather conditions and time of day.

<sup>11</sup> See:  
<http://www.environment.gov.au/system/files/resources/c42c11a8-4df7-4d4f-bf92-4f14735c9baa/files/factsheet-australias-2030-climate-change-target.pdf>

In interconnected power systems, the amount of electricity being produced from multiple supply sources needs to continuously match the amount of electricity being consumed. Because of the need to co-ordinate supply and demand in real time, the mechanisms for buying and selling electricity at the wholesale level is divided into the following two parts:

- A spot market, which co-ordinates the operation of the power system.
- A hedge contracts market, which pays for capacity, determines market customers' wholesale electricity purchase costs, and allows new investment to be financed.

An individual generator's revenues, and a market customer's costs, are determined by their net exposure to these two markets.

Firm-capacity hedge contracts create a direct link between the needs of the system for capacity in any half-hour period and the financial rewards that accrue to generators from being available and dispatched and the losses or penalties they incur if they are not. The various types of hedge contracts and the payments and receipts flowing from them have this effect because they are linked to the NEM spot prices which reflect the demand-supply balance for each half hour period.

This link between the physical and the financial spot market outcomes is broken under any scheme that provides "certificate" revenue to generators sufficient to impact on financing decisions where the certificates are linked to a type of technology or its emission levels. Any generation capacity that is not financed through a mechanism linked to either spot prices or directly to a customer's load and retail contract, does not have a financial need to be available when the physical system needs it the most.

For a further discussion of the types of contracts used in the NEM, and how entering contracts incentivises generators to be available and thereby deliver reliability of supply to consumers see the AEMC's *Reliability Frameworks Review* Issues paper.<sup>12</sup>

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<sup>12</sup> AEMC, *Reliability Frameworks Review*, Issues paper, 22 August 2017.

## **2 The proposed design of the National Energy Guarantee**

### **2.1 A market customer-based requirement**

The justification for a market customer-based requirement, rather than a requirement on generators or other market participants, is that market customers are the participants in the best position to forecast and acquire the supply necessary to meet consumer demand. Ultimately both the mix of resources required to meet reliability and emissions objectives is a function of consumer demand for grid-based power. Market customers therefore should carry the complementary requirement to acquire a mix of resources on the behalf of their customer demand that allows them to in turn supply electricity that is affordable, reliable and overall complies with national emissions reduction goals.

### **2.2 Reliability requirement**

The ESB's 13 October 2017 advice to the Commonwealth Government proposed the Guarantee include a reliability requirement on market customers to meet a percentage of their load requirements with contracts related to flexible and/or dispatchable resources. These types of resources would need to be further defined, but can broadly be considered as any form of technology, generation, batteries and demand:

- that can respond to a request by the operator to increase or decrease their output over a defined time interval, and
- whose output can be forecast with a high degree of certainty.

This requirement would make clearer the value of being dispatchable, both on the supply and demand side. Maintaining an adequate level of dispatchable resources is necessary for the secure and reliable operation of the power system.

As discussed in Chapter 1, a key factor behind the lack of investment in non-renewable dispatchable generation in the NEM has been the uncertainty about future emissions reduction policies and supporting mechanisms for the electricity sector. The emissions requirement under the Guarantee provides this certainty and therefore may resolve, to a great extent, most of the reliability issues that have arisen during the period of uncertainty.

However, meeting the emissions requirement may not necessarily result in an appropriate amount of low-emissions *dispatchable* resources being in place in each NEM region. The incentive to invest in dispatchable resources is created by the reliability requirement, in combination with existing mechanisms in the NEM. The extra dispatchable capacity will give AEMO more options in how it manages the system to deliver the required level of reliability.

### **2.3 Emissions requirement**

This aspect of the Guarantee has several elements. First, an emissions reduction target for the electricity sector would be set by the Commonwealth Government consistent with Australia's international emissions reduction commitments.

This target would then be translated into an average emissions level (tCO<sub>2</sub>-e/MWh), defined as the amount of carbon dioxide-equivalent (CO<sub>2</sub>-e) emissions divided by the amount of electricity consumption (in MWh).

Market customers would be obligated to meet their load requirements at an average emissions level that does not exceed the specified target of the sector. Retailers would demonstrate they have met their requirements for their overall load, some of which may be contracted and uncontracted.

Market customers that are unable to meet the required average emissions can contract with others that overachieve on their requirements. This would encourage more contracting in addition to the significant volume that currently occurs.

The emissions level of a retailer's load could be determined as the weighted-average of the emissions level of electricity generated under their contracted and uncontracted loads.

In addition to the information contracts currently specify, they could also indicate an emissions level at which amount of electricity would be delivered. The contract would then leave it up to the generator to operate its portfolio of generation units in such a way that the average emissions level is met.

Generation purchased by the market customer from the spot market without a contract would be assigned with the average emissions level of the uncontracted generation capacity available to the market. It is appropriate risk management practice for generators to not contract all of their capacity under firm contracts, to factor in the risk that their plant could experience unplanned outages.

The emissions requirement would be implemented in 2020 in line with when the RET reaches its maximum legislated target for large-scale generation. The Guarantee will be the mechanism to incentivise new generation from 2020. It is anticipated that the detailed design and development of the emissions requirement would begin as soon as there is COAG Energy Council agreement on the approach.

### 3 Quantitative assessment of the Guarantee

The results of quantitative modelling of the wholesale electricity market provides an indication of how wholesale prices, retail bills, emissions levels, and generator investment, retirement and output may change with the implementation of the Guarantee, relative to business-as-usual (BAU) which reflects a 'do nothing' scenario.

The modelling results can also demonstrate how robust the Guarantee is likely to be to changes in input assumptions such as changes in demand or gas prices.

It is important to note that these results are not a forecast of the future but rather an indication of what outcomes could be expected using reasonable assumptions. The quantitative assessment outcomes are sensitive to key input assumptions, such as technology costs and fuel prices, and how generator retirements are determined. Because of this, it is important to compare the relative differences in outcomes between the Guarantee and BAU and to use the sensitivities to test the robustness of these relativities to different assumptions.

#### 3.1 Modelling assumptions

For the purposes of the modelling, the emissions target for the NEM is assumed to be consistent with the Commonwealth Government's stated 2030 emissions reduction target. For the purposes of the modelling, this has been translated to 1,352Mt CO<sub>2</sub>-e of emissions for the period 2021 to 2030, as determined by the Commonwealth Department of Environment and Energy.

In the model, the emissions requirement increases contracting with low-emissions generators, providing both certainty for low-emissions generation investment and their cashflows to make that investment viable.

The Guarantee also requires market customers to contract for a certain level of dispatchable generation in the NEM. This can include either thermal generation, or dispatchable renewable generation such as solar thermal or hydro.

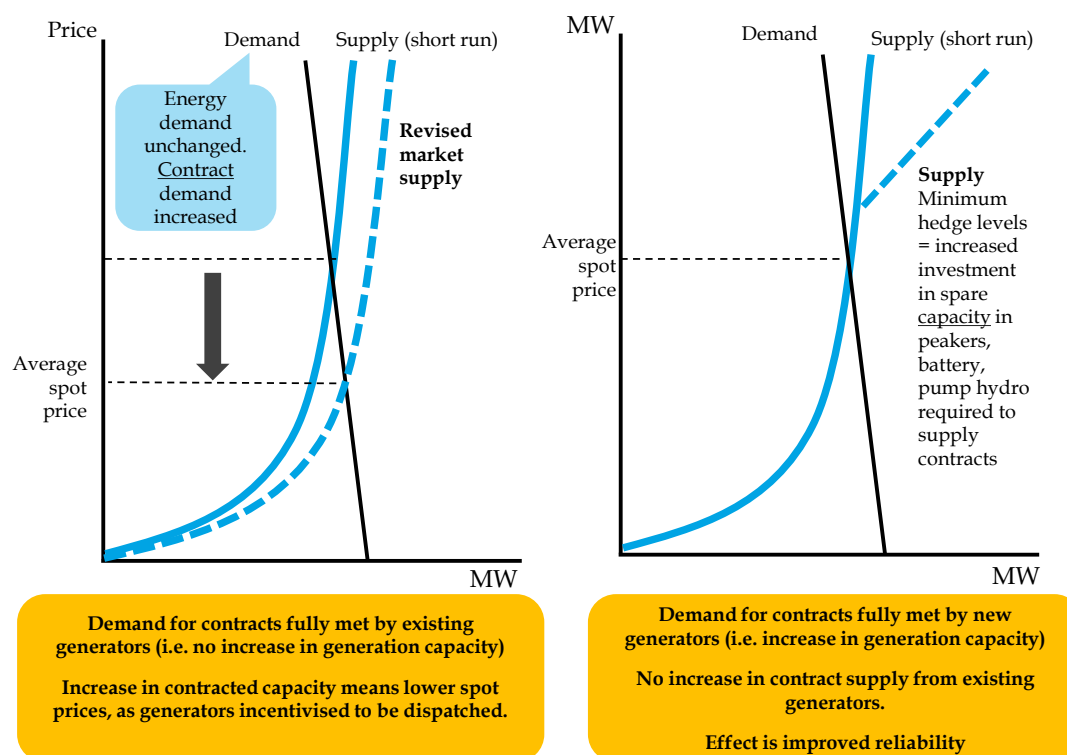
Generators typically do not commit all of their capacity under a firm contract, to account for the physical constraints of their plant. These constraints include the potential for outages at higher plant operating levels and fuel constraints. In addition, market customers' demand for contracts also influences the extent to which a generator's capacity is contracted.

Under the Guarantee's reliability requirement, market customers are required to contract a pre-determined proportion of their forecast load, and some market customers may consequently need to increase the extent of their contracting. To the extent that this higher demand for contracts is met from existing capacity, this will increase the proportion of generation capacity contracted (and reduce the proportion uncontracted). This is likely to lead to more competitive bidding in the spot market as generators will bid lower to increase their chances of being dispatched in order to cover their contracted capacity. This is likely to result in lower spot prices (see left-hand panel of Figure 3.1).

Lower spot prices may be partly offset by higher contract prices due to increased contract demand, but this may, in turn, be offset by the lower risk faced by generators from being able to contract more of their capacity.<sup>13</sup>

If the higher demand for contracts was not able to be met by existing resources due to their physical constraints, the demand would be met from new entrants (particularly fast-start resources), which improves system reliability and reduces the likelihood of extreme spot price events (i.e. lowers volatility); see right-hand panel of Figure 3.1.

**Figure 3.1 Possible market impacts**



It is difficult to predict whether additional contracts will be supplied by existing generation or by new capacity. It is reasonable to assume, for modelling purposes, a mix of each. The modelling assumes that existing dispatchable coal and gas generation will increase contracted levels by five per cent (subject to any physical constraints), and that reserve margins<sup>14</sup> in each region of the NEM and in each year increase by five per cent due to supply from new dispatchable capacity.

Reflecting the technology-neutrality of the Guarantee, the modelling is not prescriptive of the appropriate future mix of dispatchable resources: it could include baseload generation (including hydro and solar thermal) and/or 'firmed up' intermittent generation.

In order to conduct quantitative modelling a number of input assumptions must be made. These include a forecast of what demand levels, fuel prices and technology costs will be in the future. These assumptions rely on judgement. Where possible, the likely

<sup>13</sup> Contracting reduces the volatility of generators' revenues, which lowers generators' financing costs and improves their ability to obtain adequate fuel supply contracts at a lower price compared to remaining uncontracted.

<sup>14</sup> Defined as the level of dispatchable capacity in excess of that needed to meet peak demand.

effects of these assumptions on the modelling results are explained and, where appropriate, these assumptions are tested through conducting sensitivities.

In order to test the relative performance of emissions reduction mechanisms we first need to define the reference case, BAU, against which the Guarantee policy case is compared. The BAU represents a plausible future for the electricity market, in the absence of any further reliability policies or emissions reduction policies being introduced.

The purpose of this modelling is to test the relative effects of a policy for a given set of assumptions on future costs that are uncertain. Although we test the sensitivity of the policy to different cost assumptions, the results of this modelling should not be confused with a prescriptive, central planned future plant mix. The design of the policy should provide appropriate signals and should allow the market to adapt to changes in future costs, particularly where they deviate from modelling assumptions.

**Table 3.1 Base case input assumptions for BAU and the Guarantee**

Assumption	BAU	Guarantee
LRET	33TWh to 2030	
Demand	2017 ESOO Neutral, adjusted See Figure 3.2	
Fuel costs	AEMO NTNDP gas and coal price assumptions	
Technology costs	See Table 3.2	
State RETs	400MW Qld, 650MW VIC already committed, SA EST already committed	
Retirements	Liddell (2023)	
Entry	Snowy 2.0, 2,000MW generation and pump to begin 2023-24	
WACC	WACC under Guarantee + 3% risk premium on all technologies	8.3% pre-tax real
Emissions target	N/A	1,352Mt of emissions over period 2021-2030 (26PC reduction on 2005 by 2030)
Reliability requirement	N/A	Increase in contract levels by 5% Increase in reserve margin by 5%

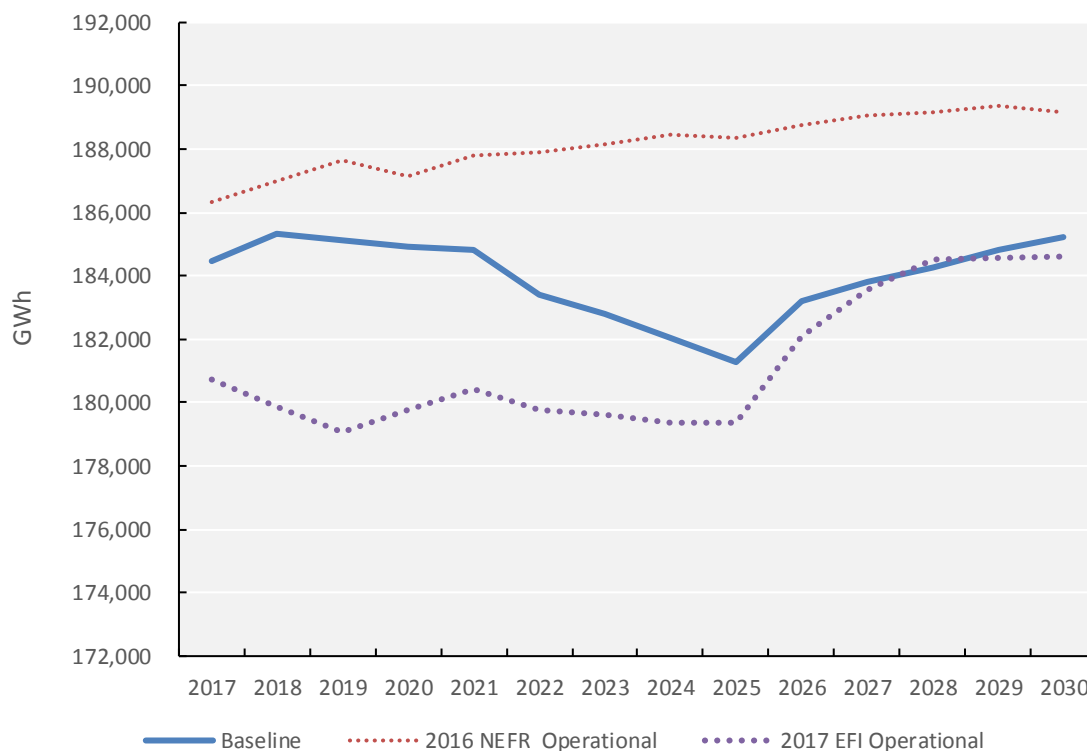
The assumptions under both the BAU and the Guarantee case are:

- The RET is met in 2020 with the scheme ending in 2030.
- Gas and coal costs are from AEMO's 2016 National Transmission Network Development Plan (NTNDP).



- The announced state renewable energy targets in Victoria (VRET) and Queensland (QRET) and the South Australian security target are assumed to only include already committed investment in generation, that is, 400MW of capacity in Queensland and 650MW of capacity in Victoria. This pre-determined entry of generation capacity is referred to below as ‘committed’ capacity. No additional capacity is assumed to be encouraged by these policies.
- Announced generation retirements are assumed to proceed. Liddell is assumed to retire in 2022/23. The Snowy pumped hydro expansion (Snowy 2.0) is included in both the BAU and the Guarantee scenarios entering in 2023/24 with a capacity of 2,000MW (all pump capacity). This represents approximately 355GWh of additional output. This pre-determined entry and exit of generation capacity is referred to below as ‘committed’ capacity.
- Technology costs assumptions reflect in-house estimates based on a database of reported project costs, prices of PPAs, other public estimates of costs ARENA data and stakeholder feedback, and are presented in Table 3.2 for key renewable technologies.
- Two demand profiles are used to ascertain the sensitivity of the modelling results to different assumptions about future demand. One demand profile is from AEMO’s 2017 ESOO Neutral scenario (labelled ‘Baseline’ in Figure 3.2), released in September 2017.

**Figure 3.2 Demand forecasts**



Source: Frontier Economics

Also provided in Figure 3.2 for reference are previous demand forecasts from AEMO's June 2016 NEFR ('2016 NEFR')<sup>15</sup> and AEMO's June 2017 EFI Neutral ('2017 EFI')<sup>16</sup> scenarios. The figure reveals that the baseline demand is forecast to be higher than '2017 EFI' over the decade to 2027, but both demand profiles are similar from the late 2020s.

The following assumptions differ between the Guarantee and BAU:

- In the BAU, the cost of capital is assumed to be 3 per cent higher than under the Guarantee. This premium represents the higher policy risk under the BAU scenario, or, equivalently, a reduction in policy risk with the introduction of a credible, stable policy mechanism. This assumption was based on stakeholder feedback both in terms of the level of the premium and the rationale for inclusion. The impact of the premium is tested in sensitivities to the BAU case.
- The cumulative maximum emissions for the NEM under the Guarantee between 2021 and 2030 is 1,352Mt, consistent with a 26 per cent reduction on 2005-year emissions by 2030.
- In the Guarantee, contracted capacity from existing dispatchable generators are assumed to increase by 5 per cent and reserve margins are assumed to also increase by 5 per cent, compared with BAU.

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[https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning\\_and\\_Forecasting/NEFR/2016/2016-National-Electricity-Forecasting-Report-NEFR.pdf](https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEFR/2016/2016-National-Electricity-Forecasting-Report-NEFR.pdf)

16

[https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning\\_and\\_Forecasting/EFI/2017-Electricity-Forecasting-Insights.pdf](https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/EFI/2017-Electricity-Forecasting-Insights.pdf)

**Table 3.2A Selected levelised cost of energy assumptions<sup>17</sup>**

<b>LCOE (\$/MWh)</b>	<b>Guarantee (no risk premium)</b>	<b>2020</b>	<b>2030</b>	<b>2040</b>
Wind	Maximum	88	77	68
	Minimum	59	52	46
	Average	73	64	57
Solar PV	Maximum	80	61	49
	Minimum	70	54	43
	Average	75	57	46
Solar thermal	Maximum	127	92	65
	Minimum	120	81	57
	Average	123	90	63

**Table 3.2B: Technology costs including premium**

<b>LCOE (\$/MWh)</b>	<b>BAU (3% risk premium on all technologies)</b>	<b>2020</b>	<b>2030</b>	<b>2040</b>
Wind	Maximum	107	94	83
	Minimum	72	63	56
	Average	89	78	69
PV	Maximum	97	74	60
	Minimum	85	65	52
	Average	90	69	56
Solar thermal	Maximum	159	115	81
	Minimum	150	101	71
	Average	154	112	78

Source: Frontier Economics

Assumptions about future demand and technology and fuel costs are a best estimate of the future path of these variables rather than a prediction of what the energy market will look like in the future. To test the robustness of the modelling results to changes in

<sup>17</sup> In both theory and practice, LCOE is not the sole factor for investment decisions, as it fails to account for the value placed on dispatchability. As discussed in Appendix B, dispatchable energy generally is more valuable than intermittent energy. Consequently, comparisons of LCOE between dispatchable and non-dispatchable technologies should be treated with caution.

assumptions about future demand, technology costs and fuel costs, additional modelling scenarios were conducted. The results of additional scenarios for technology costs and fuel costs are provided in section 3.6. Outcomes under a different scenario of future demand are discussed alongside outcomes under the ‘standard’ demand scenario (i.e. ‘baseline’ demand in Figure 3.2).

## **3.2 Price impacts**

### **3.2.1 Wholesale price impacts**

The Guarantee’s impact on prices is evaluated for both wholesale and retail prices. Wholesale prices provide an investment signal for new generation or for retirement of existing generation, while consumer impacts are best understood through analysis of retail bills.

Figure 3.3 reveals NEM-wide wholesale prices are currently much higher than historical levels, reflecting a policy uncertainty-induced freeze in new entrant plant, outside of RET-subsidised generation, combined with withdrawals of Northern and Hazelwood. The steep decline in wholesale prices under both BAU and Guarantee from 2018 to 2022 is due to the committed entry of almost 6,000 MW of renewable capacity across the NEM.<sup>18</sup> This generation is already planned and so is not specifically incentivised by the Guarantee. This price decline is also reflected in the price of baseload futures contracts.<sup>19</sup>

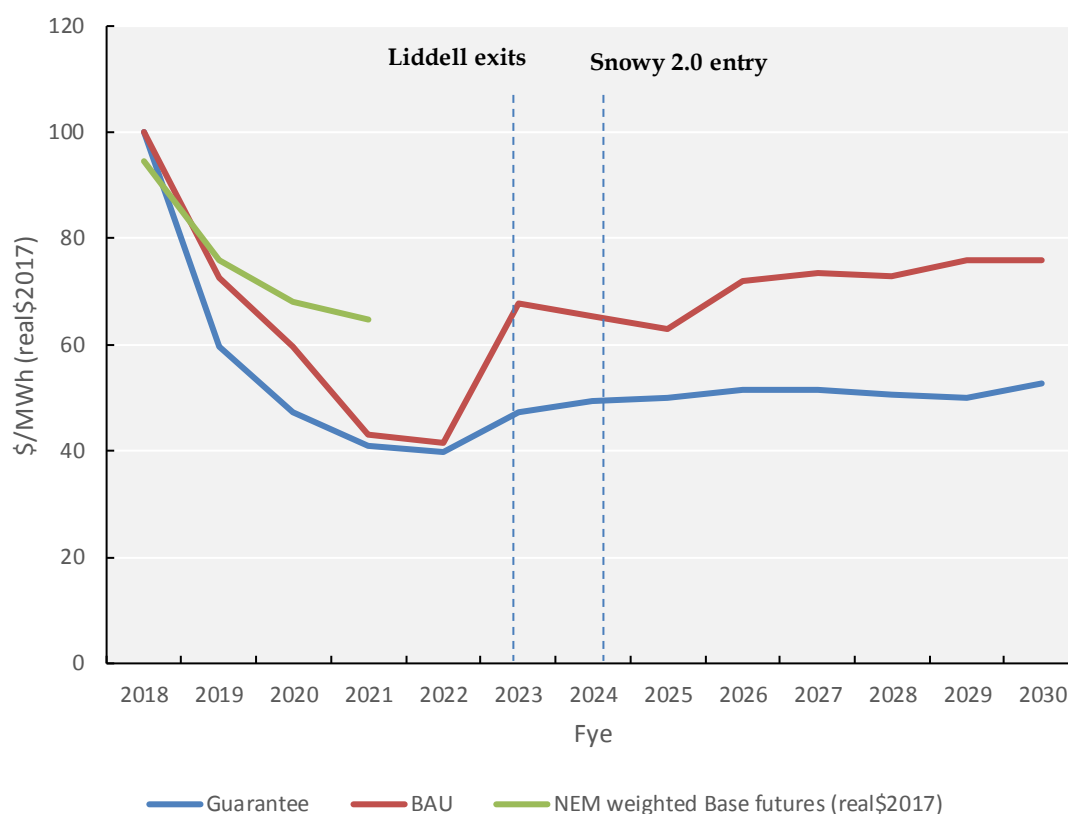
Initially, the reliability requirement leads to more competitive bidding from coal and gas, which reduces prices in the Guarantee somewhat compared with BAU. This difference in bidding has a minimal impact on price differences in 2021-22 as the market becomes oversupplied. In an oversupplied market, higher contracting levels and more competitive bidding has less impact on prices as an oversupplied market is already more competitive than a market with a tight demand/supply balance.

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<sup>18</sup> The amount of committed generation is based on market data and Frontier Economics own analysis, and includes projects under construction, financially closed, or and already committed under the Snowy Hydro expansion, RET, VRET (650MW) and QRET (400MW). Only 460MW of the 7,700MW of committed generation is not being built under one of those three schemes.

<sup>19</sup> Price of ASX-traded calendar-year baseload futures contracts, from <https://www.asxenergy.com.au>

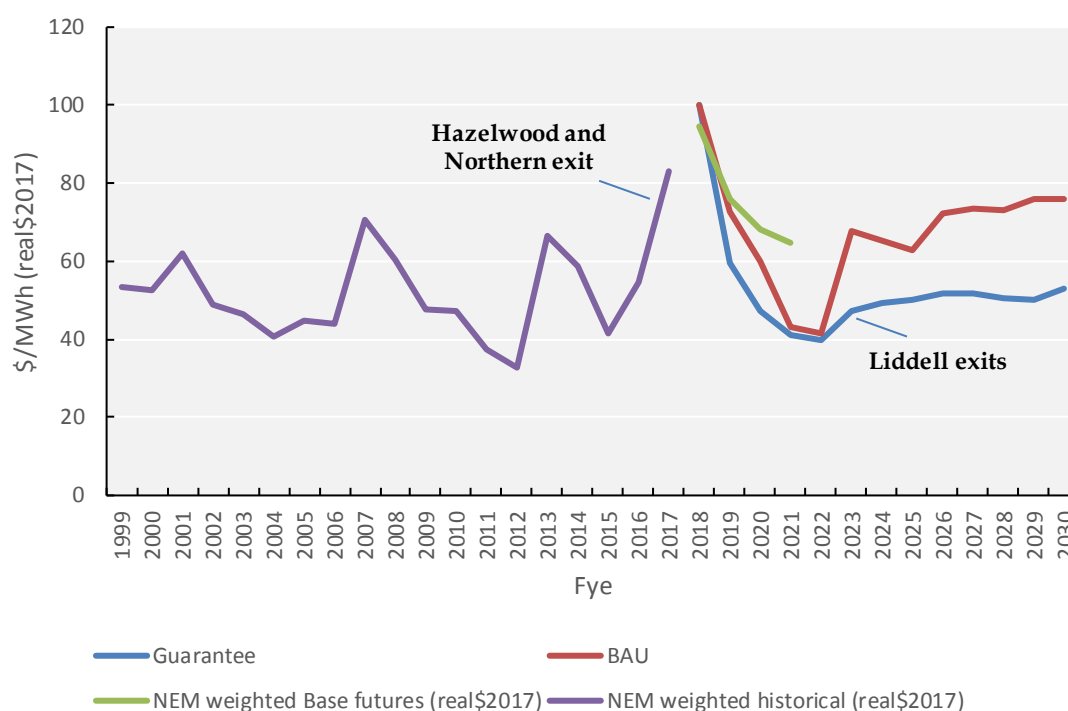
**Figure 3.3 NEM weighted-average wholesale prices (incl. RET certificate costs)**



Source: Frontier Economics

Beyond 2022, the assumed retirement of Liddell power station reduces supply once again. This results in a sharper increase in prices in the BAU case than the Guarantee, as bidding from existing dispatchable plant is more competitive under the Guarantee. This price jump is similar to recent price increases following the withdrawal of Northern and Hazelwood (see Figure 3.4), which leads to a much tighter supply/demand balance. This is less severe in the modelling which assumes perfect foresight and immediate replacement of retiring capacity with new entrant; this result may be more severe in reality for the BAU case if new investment involves a lag.

**Figure 3.4** Historic NEM prices in comparison to BAU and Guarantee case



Source: Frontier Economics

As demand rises over time and there is a greater need for new investment, the impact of a risk premium due to policy uncertainty also contributes to higher prices under BAU compared to prices under the Guarantee.

Wholesale prices by 2030 under the Guarantee (\$53/MWh) are 30 per cent lower than under BAU (\$76/MWh). Over the 2020-2030 period, wholesale prices under the Guarantee are, on average, 23 per cent lower than wholesale prices under BAU. Lower prices under the Guarantee reflect the combination of policy certainty and a more competitive bidding process in the spot market from a higher level of contracting under the Guarantee. The higher the extent of contracting, the greater a generator's incentive to be dispatched. Hence, a near- to fully-contracted generator will bid their contracted capacity in at a lower price than an uncontracted generator, resulting in lower spot prices compared to a situation where generators have more uncontracted capacity.

Furthermore, to the extent the demand for contracts is met by supply of contracts from new entrants, rather than from contracting existing uncontracted capacity, this provides an additional constraint on a generator's ability to set higher market prices.

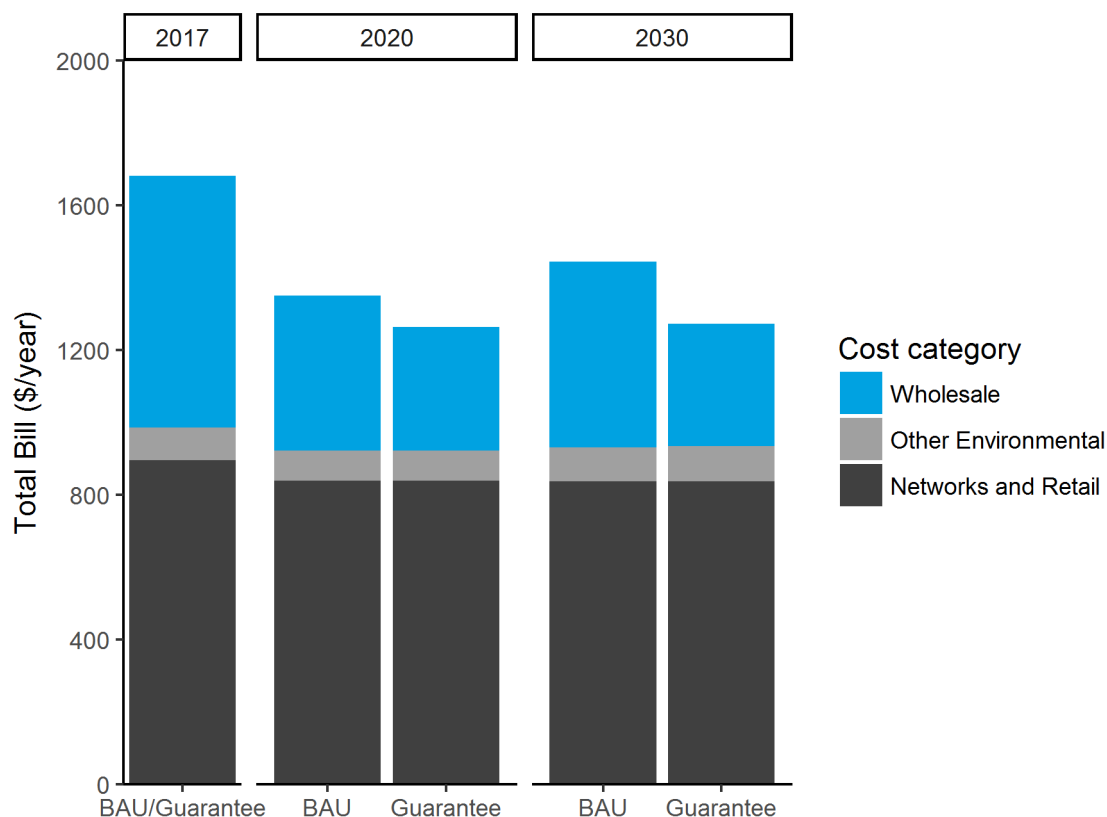
Higher-cost generators that would have been the marginal generator under 'baseline' demand are not dispatched under 'low demand', resulting in lower wholesale prices than under BAU. However, even under the low demand profile, prices fall when the Guarantee is introduced; over the 2020-2030 period, annual wholesale prices under the Guarantee are on average 5 per cent lower than prices under BAU.

### 3.2.2 Retail bill impacts

Retail bill estimates under both the Guarantee and BAU were developed from the AEMC's *Residential Electricity Price Trends 2017*, which estimates bills for residential consumers from financial year 2016 to financial year 2019.

Figure 3.5 shows the modelled range of average NEM-wide residential consumers' annual bills under the BAU and Guarantee in 2020 and 2030. This is compared to the annual expected bill in 2017. The majority of a customer's bill is comprised of network costs, retail costs and the cost of other environmental schemes. The average bill saving from implementing the Guarantee policy, compared to the do-nothing scenario, is around \$120 a year (in today's dollars) for the 2020-2030 period.

**Figure 3.5 Breakdown of retail bills in 2020 and 2030, NEM**



Sources: AEMC; Frontier Economics

Furthermore, annual bills are consistently lower under the Guarantee than current bills, over the 2020-2030 period. For example, average bills under the Guarantee over the 2020-2030 period are around \$400 (in today's dollars) lower than the estimated bill for 2017.

### 3.3 Ability to achieve emissions reduction target

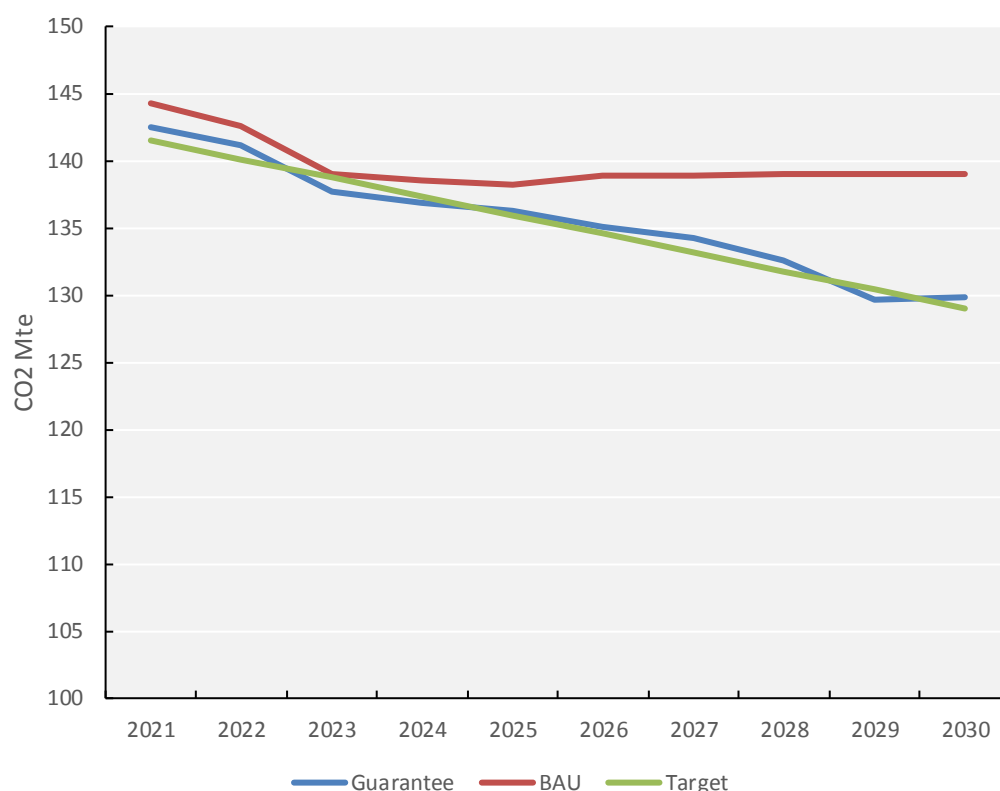
The model imposed a cumulative target for 2021-30 of 1,352Mt consistent with the Commonwealth government's Paris commitments and determined the trajectory that is the least-cost way of achieving the 2030 target over the decade. This resulted in a mostly linear trajectory (see Figure 3.6). Annual emissions produced under BAU and the Guarantee are also shown in Figure 3.6.

Emissions in both cases are projected to fall to 2023, reflecting:

- falling demand forecasts,
- the entry of a large amount of committed renewable energy capacity, and
- the announced closure of Liddell (i.e. exits of committed generation capacity).

The decline in emissions stalls from the early 2020s under BAU once these schemes are met and all committed investments are deployed; the target is not met in this case.

**Figure 3.6 Emissions under the Guarantee and BAU**



Source: Frontier Economics

Emissions continue to fall under the Guarantee due to the emissions requirement. The emissions trajectory modelled for the Guarantee is the least-cost way of achieving the emissions target under the model's assumptions.

In contrast, both BAU and the Guarantee achieve the emissions reduction target under the 'low demand' scenario<sup>20</sup>, as more of the required emissions abatement is delivered through a lower level of demand compared to 'standard' demand, requiring no abatement to be delivered via the entry of uncommitted renewables.

### 3.4 Investment and retirements

The Guarantee is expected to drive differences in the type of new generation investment, compared to BAU. The emissions requirement is expected to incentivise a shift towards lower emissions technologies, while the reliability requirement is expected to incentivise a shift towards dispatchable technologies. Those generators that have both attributes are expected to be highly valued and likely recipients of increased investment focus.

It is worth noting that the modelling, due to time constraints, did not include the potential for upgrades to existing generation assets but in practice this would be

<sup>20</sup> This scenario assumes a 0.5 per cent per annum reduction on the baseline demand profile in Figure 3.2, for each year from 2018 to 2030 (i.e. 'low demand' in 2030 is 6 per cent lower than for 'baseline').



allowed under the Guarantee. Upgrades to existing assets could be a cheaper way of meeting the emissions requirement than building new generation assets. General Electric estimated that upgrading the existing fleet of coal-fired power stations could deliver 19 Mt CO<sub>2</sub>-e of abatement.<sup>21</sup>

Figure 3.7 shows the amount of committed and uncommitted generation capacity that enters and exits the NEM under the Guarantee vs. BAU. The majority of investment throughout the entire period, and particularly earlier in the period, is committed (almost 6,000 MW). As per the definition of ‘committed’ capacity, the amount of capacity that enters and exits is identical under the Guarantee and BAU. In contrast, the amount of ‘uncommitted’ or additional investment that occurs and plant that exits differs between BAU and the Guarantee, and is therefore more informative about the Guarantee’s impact on generation investment.<sup>22</sup>

There is more new capacity installed under the Guarantee than under BAU. For example, around 4,400 MW of new uncommitted capacity enters by 2030 under the Guarantee, compared to 861 MW under BAU (bottom panel of Figure 3.7).<sup>23</sup> Overall, the Guarantee results in extra capacity in the system which both boosts system reliability and lowers wholesale prices under the Guarantee vs. BAU (see Figure 3.3).

The Guarantee’s dual requirements results in greater entry of those technologies that are both low-emissions and dispatchable, compared to BAU. The least-cost mix of new investment under the Guarantee is comprised mostly of wind, followed by large-scale solar PV, batteries and mid-merit gas.

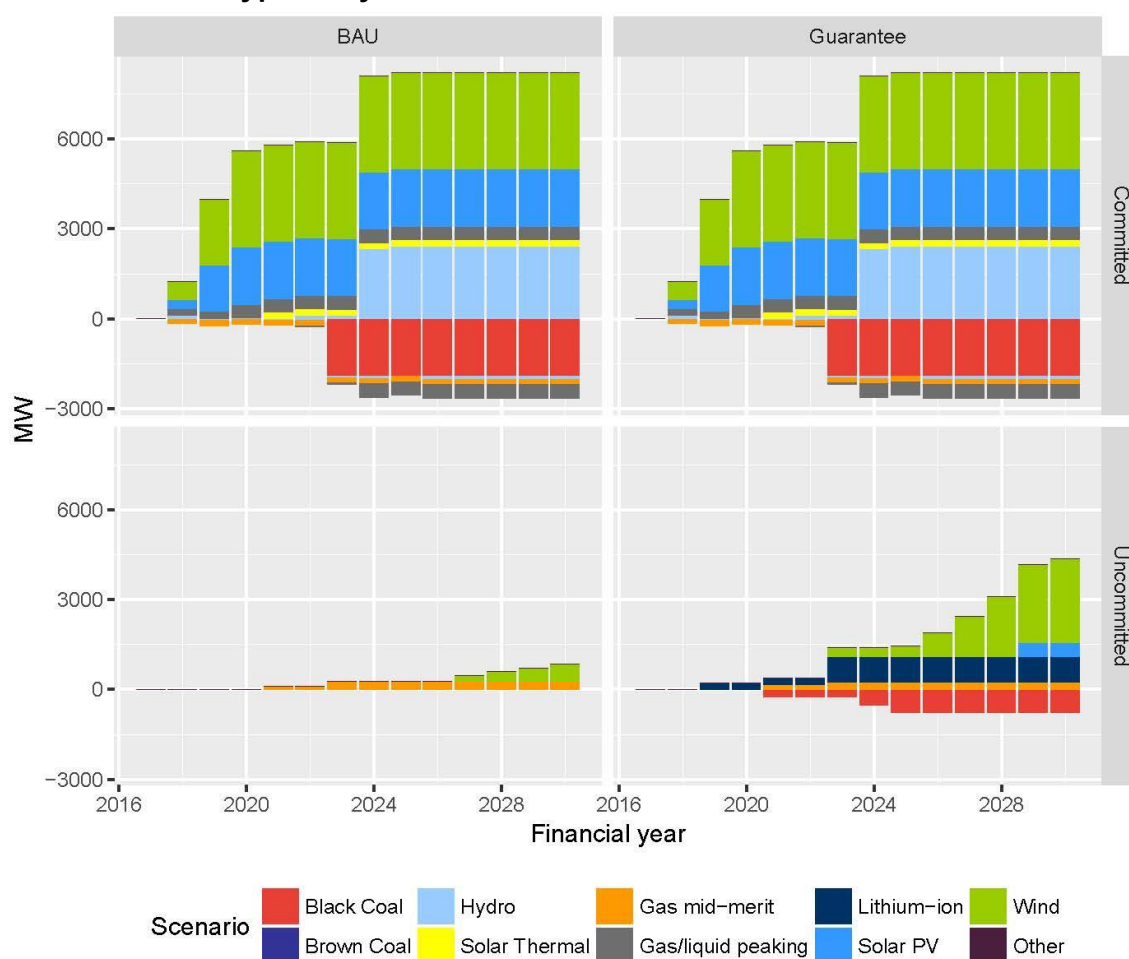
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21 B. Potter, *Cheap new energy and CO<sub>2</sub> cuts right in front of us* – GE, Australian Financial Review, 27 July 2017

22 Committed capacity reflects entry and exit that are not an outcome of the model. Uncommitted investment reflects outputs from the modelling.

23 Figure 3.7 only includes generation investment in the wholesale market, and therefore excludes investment in rooftop solar PV. Investment is represented as positive, exit as negative.

**Figure 3.7 Entry and exit of cumulative generation capacity by technology type and year<sup>24</sup>**



Source: Frontier Economics

Table 3.3 highlights that over the 2020-2030 period, the Guarantee encourages 1,086 MW more dispatchable generation capacity into the system, with this extra capacity used to 'firm up' intermittent renewables. This is additional to the 2,543 MW of committed investment in dispatchable generation capacity to 2030 under both BAU and the Guarantee, comprising 2,000 MW through Snowy 2.0, a further 338 MW of pumped storage hydro, 198 MW in solar thermal and 7 MW in gas peaking plant. No additional dispatchable renewable capacity enters under BAU beyond the committed generation.

**Table 3.3 Investment in uncommitted plant (MW)**

	Coal	Gas	Dispatchable renewable (incl. batteries)	Intermittent renewable
BAU	0	263	0	597
Guarantee	0	251	835	3,271

Source: Frontier Economics

<sup>24</sup> The exit of uncommitted capacity under the Guarantee relates to the mothballing of those units of Gladstone coal power station in operation under BAU (773 MW).

Under a ‘low demand’ profile, there is no additional capacity under BAU and only a very modest amount under the Guarantee. The volume of committed generation capacity is almost entirely sufficient to service demand and meet the reliability and emissions requirements.

### 3.5 Generation output

In addition to showing the path of new investment in generation technologies in the NEM, the modelling can also provide insights into what proportion of generation output comes from different generation technologies.

Table 3.4 shows the output of different generation technologies as a percentage of total output in 2020 and 2030. Under the Guarantee, 36 per cent of generation output in 2030 will come from renewable generation, with four-fifths of this (i.e. 28 per cent of all output) from intermittent renewables. In contrast, under BAU, 31 per cent of output will come from renewable generation (23 per cent from intermittent renewables) in 2030.

**Table 3.4 Output mix (% of total generation) by technology: 2020 and 2030**

Mechanism	Year	Black Coal	Brown Coal	Hydro	Gas	Solar Thermal	Solar PV (incl. rooftop)	Wind
BAU	2020	55%	16%	8%	2%	0%	7%	11%
	2030	48%	16%	8%	5%	0%	12%	11%
Guarantee	2020	57%	16%	8%	2%	0%	7%	11%
	2030	45%	15%	8%	4%	0%	13%	15%

Note: Some years do not add to 100 per cent due to rounding

Source: Frontier Economics

The addition of Snowy 2.0 results in a significant increase in gross hydro output over the 2020-2030 period, but does not increase net output that much (that is, subtracting for the energy used to pump water up the reservoirs). However, the value of this net output increases as the output is able to be dispatched when needed and supports the entry of more intermittent technologies given hydro’s ability to ‘firm’ up the intermittent sources.

Under both BAU and the Guarantee, the penetration of renewables increases from 2020 to 2030, with this increase largely due to higher penetration of intermittent renewables (Table 3.5). As expected, the increase in renewables is greater under the Guarantee due to the emissions requirement. This rising share of renewables occurs at the expense of coal (largely black), which falls from 73 per cent of output in 2020 to 60 per cent in 2030. These figures all include rooftop solar.

These findings are broadly the same under the ‘low demand’ case, though renewables’ share of output under both BAU and the Guarantee (around 30 per cent) is lower than in Table 3.5. Coal’s share of output is correspondingly higher. This is because more of the required emissions abatement is delivered through a lower level of demand compared to ‘standard’ demand, requiring less abatement to be delivered via the entry of ‘uncommitted’ renewables. In 2030, coal’s share of output is around 65 per cent under

both BAU and the Guarantee for the ‘low demand’ case, compared to 60 per cent under the Guarantee.

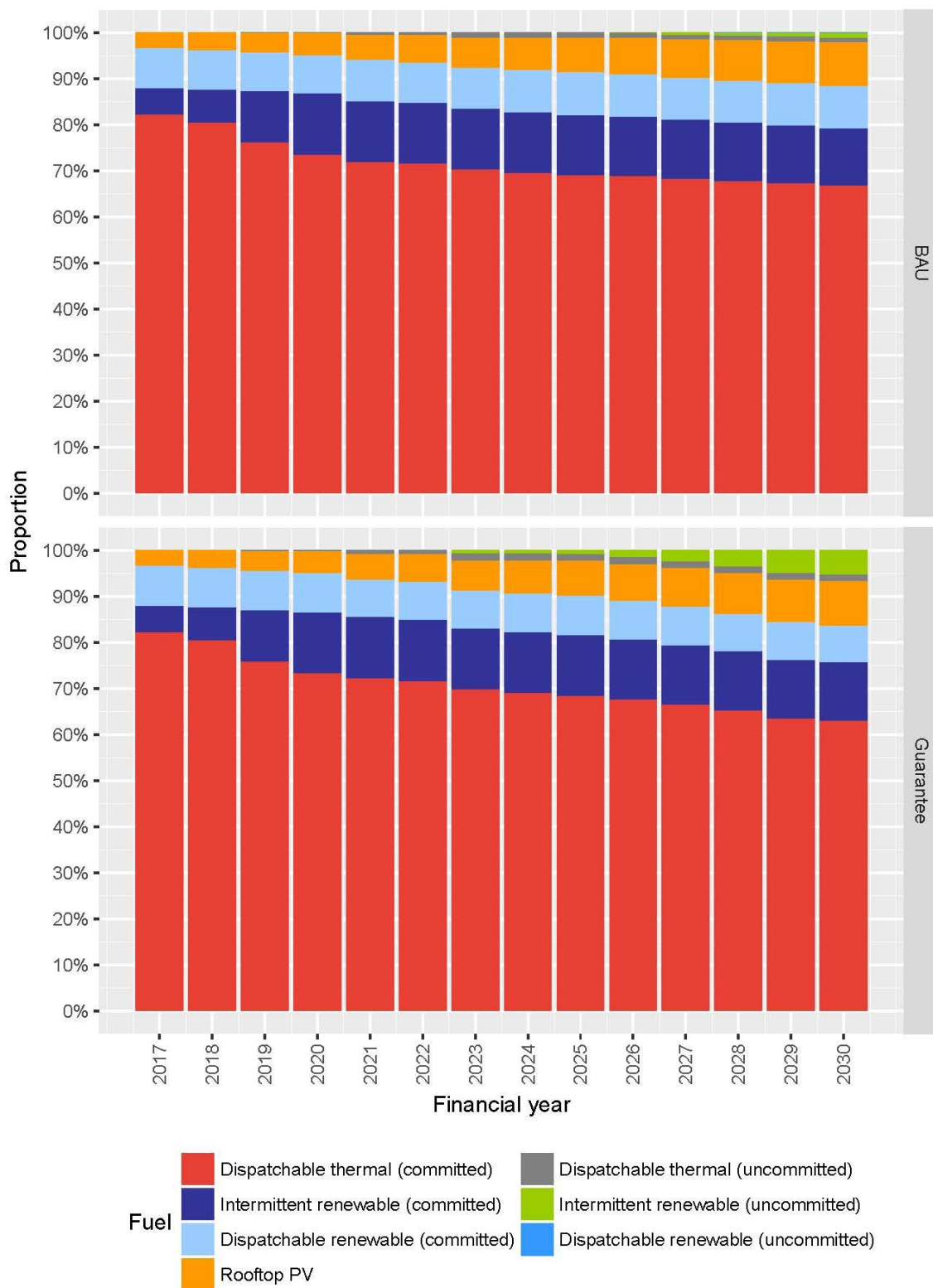
**Table 3.5 Renewable generation output (% of total): 2020, 2025 and 2030**

Scenario	Type of renewable generation	2020	2025	2030
BAU	All	26%	29%	31%
	Intermittent	18%	21%	24%
	Dispatchable	8%	8%	8%
Guarantee	All	26%	30%	36%
	Intermittent	18%	22%	28%
	Dispatchable	8%	8%	8%

Source: Frontier Economics

There is only a modest difference in the output mix between BAU and the Guarantee case, with the differences reflecting the different amounts of uncommitted capacity that enters and exits the NEM under BAU vs. the Guarantee. For example, the proportion of output generated by uncommitted intermittent renewables is zero until 2022, and rises to 5 per cent by 2030 (see Figure 3.8) under the Guarantee, higher than the 2 per cent share in 2030 under BAU.

**Figure 3.8 Output mix by technology type and year**



Source: Frontier Economics

### 3.6 Sensitivity analysis

All modelling requires making assumptions about future outcomes, some of which are highly uncertain. Three variables with the greatest uncertainty about future outcomes are demand, technology costs and fuel costs. The preceding discussion found that

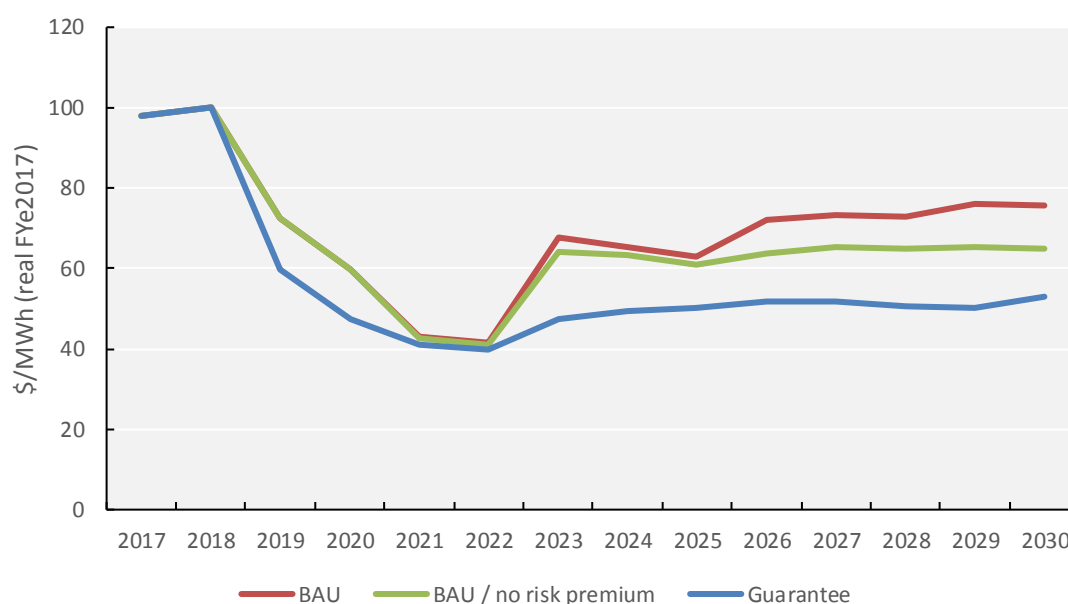
different assumptions around future demand did not change the finding that prices under the Guarantee are lower than BAU. This section assesses whether and how changes in assumptions about the capital cost of renewables and gas prices affect the modelled impacts of the Guarantee on electricity prices, and the investment and output mix.

### 3.6.1 Uncertainty premium

As discussed in section 3.1, the BAU case assumes a risk premium: a 3 per cent increase to the cost of capital, relating to policy uncertainty. No such risk premium exists in the Guarantee case.

The sensitivity of the outputs to this assumption in BAU was tested. Figure 3.9 compares wholesale prices under the Guarantee policy case, BAU without a risk premium, and the BAU with a risk premium discussed throughout this chapter. This implies the majority of the change in wholesale prices between the Guarantee and BAU is driven directly by the Guarantee requirements, as opposed to greater policy certainty as a consequence of the introduction of the Guarantee.

**Figure 3.9 NEM weighted-average wholesale prices (incl. RET certificate costs)**



Source: Frontier Economics

The 'standard' BAU and the BAU sensitivity case assuming no risk premium result in relatively closely aligned wholesale prices until 2022. This is because a substantial portion of the investment is committed regardless of the scenario, meaning that the altered cost of capital does not affect these investment decisions. Prices then start to diverge modestly between the 'standard' BAU and BAU without a risk premium later in the 2020s, to 14 per cent by 2030, as more uncommitted investment occurs.

Nevertheless, the price difference by 2030 is less than half of that between the BAU case (with a risk premium) and the Guarantee policy case. This indicates that the impact of the Guarantee on bidding behaviour plays a greater role than the lowered cost of capital under the Guarantee case, as described in section 3.3.

The effects of a zero risk premium on the BAU for renewable technologies and a three per cent risk premium for thermal technologies were also assessed. The results showed that the wholesale prices were very similar to the BAU scenario to one where there is no premium for all technologies.

Given the relatively small difference to the results explored above, and advice from stakeholders regarding the rationale for the risk premium and its extent, throughout this chapter we have used the BAU including the risk premium to analyse the modelling results.

### **3.6.2 Sensitivity of results to technology cost assumptions**

Electricity models use levelised cost of electricity (LCOE) to choose the least-cost mix of generation technologies. LCOE is useful as it enables a like-for-like comparison of different technologies with differing cost profiles (e.g. the share of fixed costs relative to variable costs). However, it is less useful when comparing dispatchable and non-dispatchable technologies, as it does not account for when output occurs.<sup>25</sup> A wind plant typically has a lower LCOE than a combined-cycle gas plant, but gas may be more valuable than wind once the relatively lower reliability of wind is taken into account.

The technology cost assumptions used in the base case were determined following consultation with industry stakeholders. It is difficult to determine the amount of cost reductions due to underlying cost improvements in the production of the technology, and the impact of different financing structures that may deliver apparently lower LCOEs. This analysis incorporates revised technology cost assumptions based on data provided by ARENA and also tests the impact of different cost levels and trajectories to assess the robustness of the policy approach.

A sensitivity was included to test a future where renewables do not decline in cost as quickly (costs were assumed to be 10 per cent higher by 2030 and 20 per cent higher by 2040), than the corresponding LCOE under the 'standard' Guarantee and BAU scenarios.

A further sensitivity was analysed where the LCOEs of renewables was decreased ('low technology cost' scenario) to capture the potential for a steeper learning curve than that assumed for renewable costs under the standard scenario. In this scenario, LCOEs for renewables were assumed to be 10 per cent lower by 2030 and 20 per cent lower by 2040, than under the 'standard' scenario.

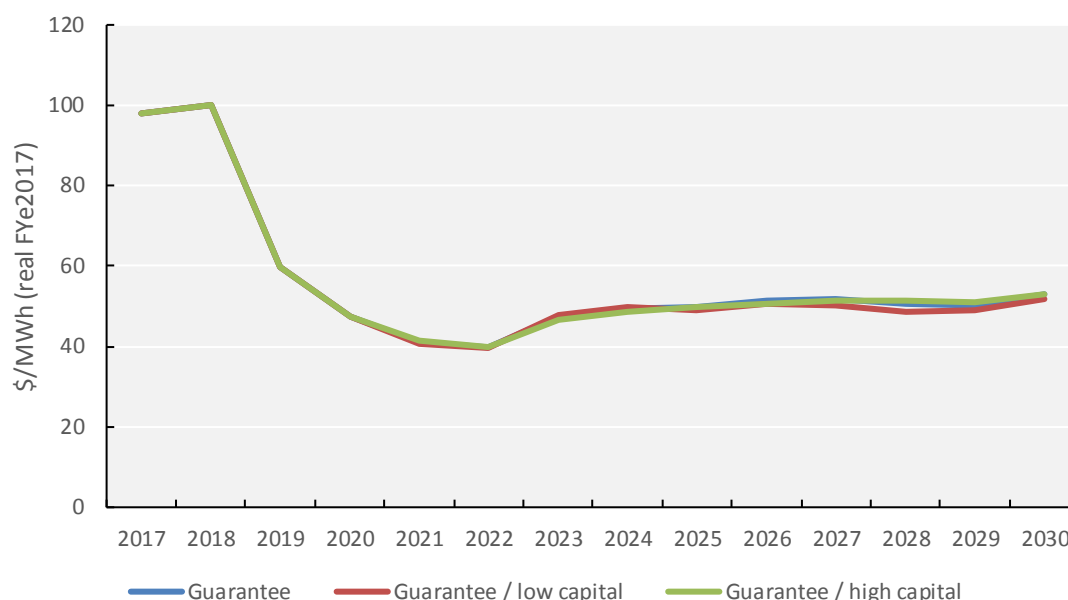
The outcome for wholesale prices is illustrated in Figure 3.10. The figure shows an extremely close alignment in wholesale prices in each of the three technology cost assumption scenarios: an initial steep decline in prices to 2022 driven by the entry of committed capacity, followed by a relatively gradual increase in prices as exits occur.

Wholesale electricity prices in 2030 under low and high technology cost assumptions, compared to the standard technology cost assumptions, are lower under the Guarantee compared to BAU, though the BAU-Guarantee price differential is smallest under the low technology cost assumption.

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<sup>25</sup> The annual capacity factors used to determine LCOE reflect the annual volume of output from that generator, rather than the timing of that output.

**Figure 3.10 Wholesale prices (incl. RET certificate costs) under a range of capital cost assumptions**

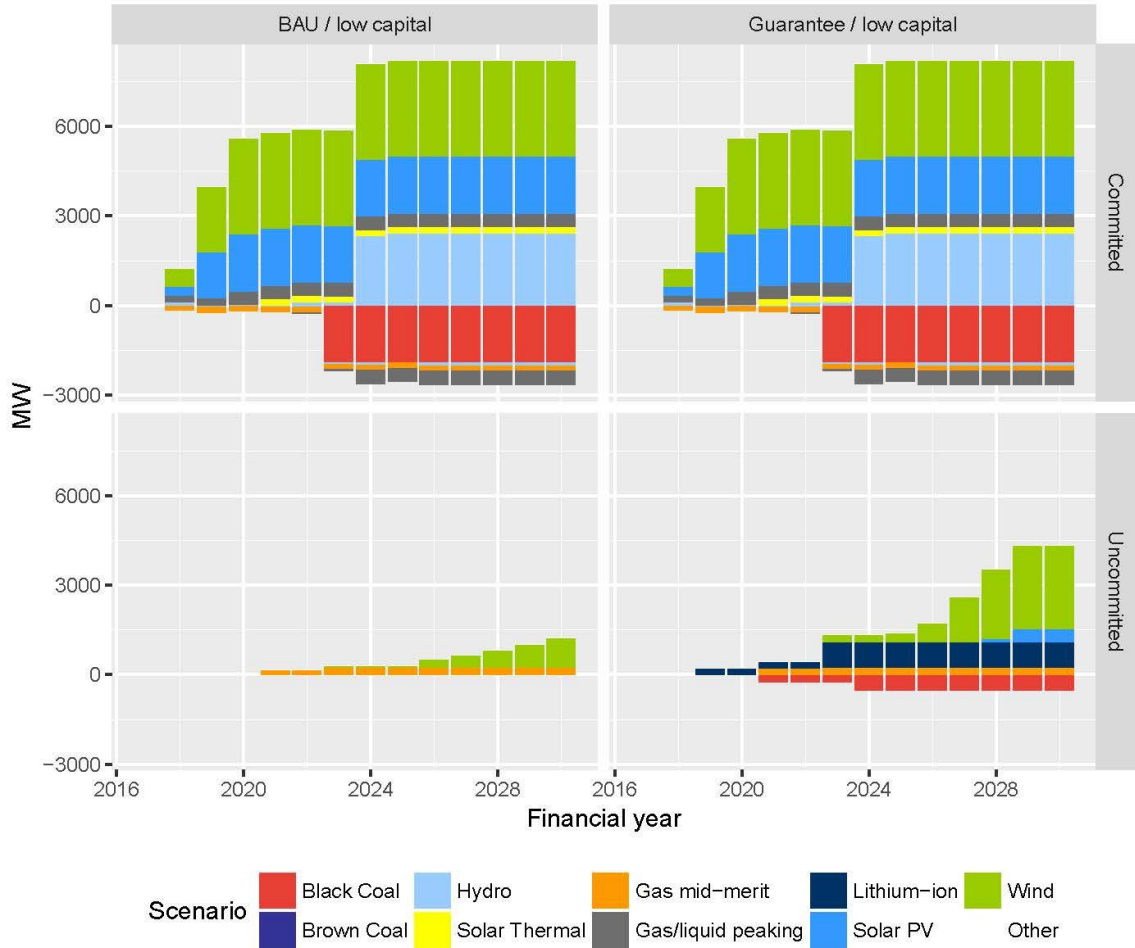


Source: Frontier Economics

Figures 3.11 and 3.12 illustrate the investment mix under the high and low technology cost assumptions, respectively. Both graphs show that the type, timing and extent of entry and exit of generation capacity is broadly the same as under the ‘standard’ technology cost assumption (see Figure 3.7). The low technology cost scenario leads to the same investment mix as the standard scenario as renewables (both intermittent and dispatchable) remain the least-cost technologies. The high technology cost scenario also results in the same investment mix as the increase in renewables costs under this scenario is not sufficient to displace it in the generation merit order.

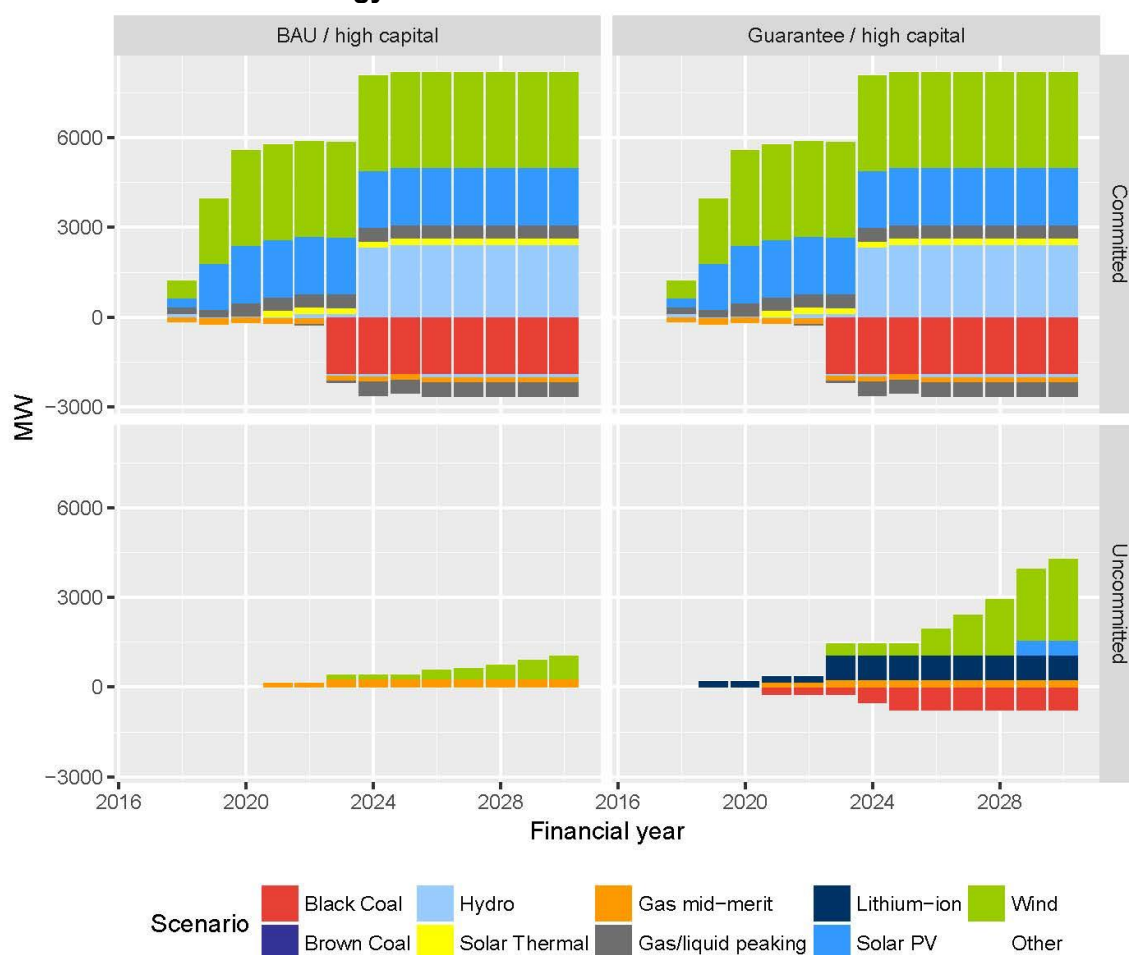


**Figure 3.11      Entry and exit of cumulative generation capacity under low technology costs**



Source: Frontier Economics

**Figure 3.12 Entry and exit of cumulative generation capacity under high technology costs**



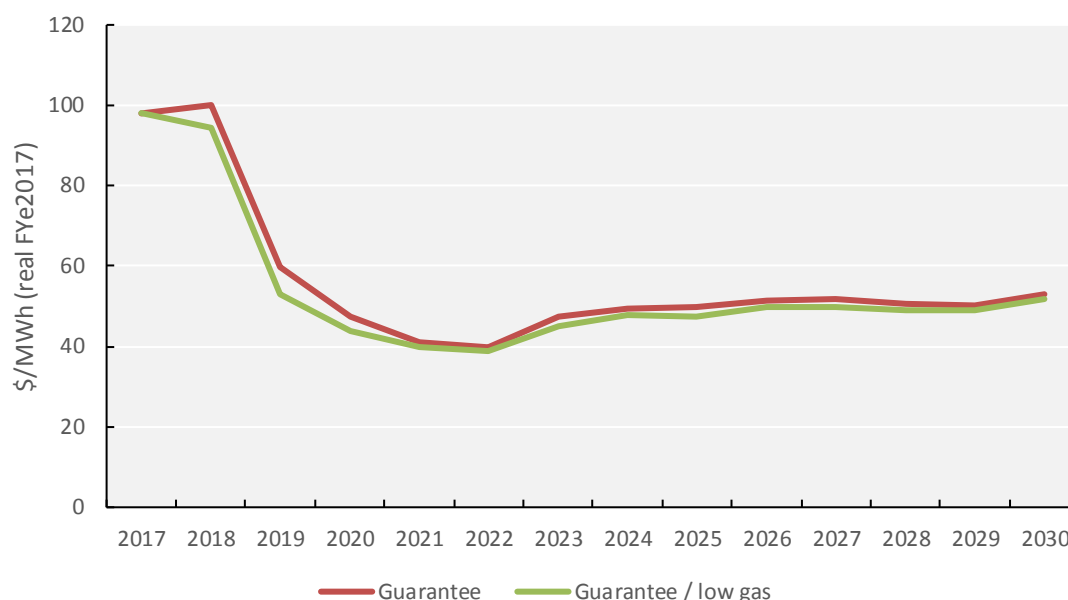
Source: Frontier Economics

### 3.6.3 Sensitivity of results to gas price assumptions

In addition to technology costs, fuel costs are also an important driver of modelling results. In previous AEMC analysis<sup>26</sup> comparing different emissions reductions policies, a lower gas price allows for a period of 'gas transition' where more gas-fired generation is utilised until technology costs fall and become competitive. Since this analysis, expectations around future gas prices have increased and as a result new capacity additions are largely from renewable sources. It was however considered important to test whether a lower gas price may result in different results under a Guarantee policy. Gas prices of \$1/GJ lower than those used in the results outlined in sections 3.2-3.5 were therefore modelled. A \$1/GJ decrease represents an approximately 15 per cent decrease on today's prices. The results of this analysis are presented in Figure 3.13.

<sup>26</sup> AEMC, *Integration of energy and emissions reduction policy*, Report, 09 December 2016.

**Figure 3.13 Wholesale prices (incl. RET certificate costs) under a range of gas price assumptions**



Source: Frontier Economics

The amount, timing and type of investment and retirements were very similar between the two gas price scenarios. In large part this is because much investment is already committed, and a flat demand profile means little additional investment is required, particularly in BAU. Under the Guarantee, the decrease in gas price was not sufficient to substantially replace new renewable and battery investment with gas.

Consequently, lower gas prices do not change the key findings on the Guarantee.

### 3.7 Conclusions from the quantitative assessment

A number of conclusions can be drawn from the quantitative analysis undertaken.

First, the Guarantee policy will meet the emissions reduction goals set by the Commonwealth Government. The modelling shows that emissions can be reduced to 26 per cent below 2005 levels under the Guarantee policy over the period 2021 to 2030 under the standard assumptions. A do-nothing approach will not meet Australia's international commitments.

Second, the Guarantee provides incentives for both more renewable and more dispatchable generation capacity into the market than a do-nothing scenario. The sector can therefore be transformed to meet emissions goals while keeping the lights on for consumers.

Third, the Guarantee lowers wholesale prices and retail bills. The modelling suggests that wholesale prices will be 30 per cent lower under the Guarantee than under BAU by 2030, while customers' retail bills will be in the order of \$120 per year lower under the Guarantee on average. Bills under the Guarantee will also be lower than they are today.

While these modelling results are dependent on the input assumptions used, the sensitivity analysis suggests that the results are not substantially changed with a range of different input assumptions. Under all cases tested, wholesale prices and retail bills

are reduced, investment (if required) is made in dispatchable and renewable generation, and the emissions reduction targets are met, with the introduction of the Guarantee.

## 4 Qualitative assessment of the Guarantee

Following on from the quantitative assessment of the Guarantee in the preceding chapter, this chapter provides a qualitative assessment of the Guarantee. Such an assessment should be made with reference to an assessment framework, which is provided below.

When contemplating the effective integration of energy and environmental policy, it is important to design a mechanism to achieve an emissions reduction objective which is consistent with energy policy objectives<sup>27</sup>. The following principles are important to consider when designing such a mechanism:

- **Certainty of achieving policy objectives** – for mechanisms to be sustainable and effective, they need to be able to meet their objectives in the face of a changing and uncertain future. Without this ability to adapt when the future does not turn out as expected, investors may begin to expect that a mechanism may be changed in light of the actual outcomes, for example if demand is lower than anticipated at the outset of the policy. This can lead to investors not having the confidence to invest in new capacity. A credible and durable compliance framework would also provide greater certainty that both requirements can be, and are being, met.
- **Technology-neutral** – a mechanism that allows the greatest variety of technology options to assist in achieving its policy objectives will help minimise the long term costs to consumers.
- **Geographically-neutral** – a mechanism that is indifferent to where generation technology options are to be located, and allows the locations selected to be an outcome of the trade-off between economic costs and benefits, is likely to minimise costs for consumers.
- **Appropriateness of risk allocation** – a mechanism should allocate risks to those parties best-placed to identify and respond to risks in an efficient manner.
- **Contract market liquidity** – a mechanism that, through its effect on the generation mix, preserves or enhances liquidity in the market for ‘firm’ contracts, will assist participants to manage risks efficiently for the long-term benefit of consumers. Firm contracts are backed by generators that generate when needed by customers and so are more valuable to customers than the ‘non-firm’ contracts offered by generators with intermittent output.
- **Implementation flexibility** – the extent to which a mechanism can be implemented in a manner that automatically adjusts or ‘self-corrects’ in the face of changing demand, cost or other system conditions.
- **Cost estimates and impacts on consumers** – consumer impacts are assessed through wholesale prices, generator investment, retirement and output changes. As these cost estimates and impacts are sensitive to key input assumptions, such

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<sup>27</sup> The Australian Energy Market Agreement (AEMA) is one embodiment of Australia’s energy policy objectives. The objectives of the AEMA include the promotion of the long term interests of consumers with regard to the price, quality and reliability of electricity and gas services.

as demand, fuel prices and generator retirements, it is important to compare the relative differences in outcomes between different sets of assumptions.

- **Adaptability and sustainability of mechanism design** – investors need a level of confidence that policy objectives can be met and that the mechanism for achieving these objectives is sufficiently robust to deal with changes in energy market conditions or policy objectives without succumbing to calls for the mechanism or the policy objectives to be altered or replaced. This requires that the acceptability of outcomes generated by the mechanism should not be predicated on a single view of the future, whether that is a specific demand forecast, relative technology or fuel costs, or the policy objective itself. Rather, investors will need to be satisfied that the mechanism can yield predictable outcomes given different market conditions and policy objectives. Without confidence in the resilience of the mechanism, investment will not be forthcoming and it is likely that neither the emissions reduction nor energy policy objectives will be met.
- **Minimising regulatory burden** – a mechanism’s regulatory burden should be minimised by focusing compliance on only the key information needed to assess and demonstrate compliance with the mechanism, leveraging existing systems and processes for reporting and data collection as far as possible. That is, a mechanism should be designed in a way that minimises the costs of complying with the mechanism whilst achieving the mechanism’s desired policy objectives.

Failing to consider Australia’s energy policy objectives when designing emissions reduction mechanisms is likely to result in higher prices for consumers in the long-run and a less reliable and secure power system than would otherwise be achievable. Conversely, designing the emissions reduction mechanism in a manner that is consistent with governments’ energy policy objectives will contribute to the resilience and longevity of both the emissions reduction policy and its associated mechanism.

## 4.1 Certainty of achieving policy objectives

Both the emissions and reliability requirements embed the policy objectives of emissions reductions and a reliable power system, respectively, into the wholesale electricity price. This provides certainty that the policy objectives would be achieved.

A key challenge for the emissions requirement is uncertainty around future annual energy consumption, as this is used to calculate the annual level of the emissions requirement as follows:

$$\frac{\text{Absolute annual emissions target (tonnes CO}_2\text{)}}{\text{Forecast annual energy consumption (MWh)}}$$

The Guarantee’s reliability objective is that system reliability is consistent with the reliability standard. A greater level of contracting will encourage generators to invest in their plant and offer their capacity into the spot market at their marginal costs to ensure they are dispatched to fund their contractual requirements. Furthermore, the reliability requirement would only bind when expected system reliability levels are considered to be insufficient (e.g. when the reliability standard is projected to be exceeded). This makes it cheaper than other reliability mechanisms that could be used such as a capacity market.

The design of the Guarantee therefore enables it to meet its policy objectives at lowest possible cost, as it has the inherent ability to adapt to changes in forecasts of key parameters (such as demand). On the reliability side, market participants are able to adjust their contract positions to account for changes in their demand forecasts, so the cost of the reliability requirement remains reflective of the value to the system of having that additional reliability.

Subject to further analysis and consultation, it should be possible to establish design elements that provide investor certainty that the mechanisms to achieve the dual requirements would not be changed in light of changes in emissions reduction objectives or system needs. While these goals may change, the mechanism to achieve them will not. This would in turn, promote greater investor confidence to invest in new generation capacity, facilitating the achievement of the policy objectives.

## **4.2 Technological and geographic neutrality**

Technology neutrality is one of the principles crucial to designing effective policy mechanisms that are integrated with the energy market. Technology neutrality means that the widest range of technologies is available to achieve the stated policy objectives. Policies should not favour or subsidise certain technologies over others.

The emissions requirement is technologically-neutral. This means it supports the lowest-cost ways of meeting the emissions requirement, whether that is improving the efficiency of coal generators, fuel switching from coal to gas and/or building renewable energy capacity, even under different assumptions about the future (for example, assumptions about future gas prices or technology costs). The emissions requirement is also geographically-neutral, as the choice of locations for the new generation capacity in the NEM is selected solely on the basis of a cost-benefit trade-off.

The reliability requirement is technologically-neutral, subject to the dispatchability criteria. The obligation is regionally-based reflecting the physical needs and constraints of the system, which limits the extent of its geographic neutrality.

## **4.3 Appropriateness of risk allocation**

The NEM is designed so that generators make investment and retirement decisions based on price signals in the spot and contract markets, and face the outcomes of their decisions. If electricity demand, fuel costs, or other variables are higher or lower than expected, the primary implications for plant profitability are borne by generators, rather than consumers or taxpayers. This is appropriate because generation businesses have the expertise, information and commercial incentives to manage such risks efficiently. In this way, the risk of changes in different variables is appropriately allocated to generators, rather than customers, which helps promote the NEO.

The Guarantee maintains the existing pricing and risk management mechanisms in the NEM for signalling whether new investment is required and whether generators should exit. It does this by maintaining the balance of incentives and risks that ordinarily prevail in the wholesale market. Investors will continue to be responsible for managing risks associated with demand, fuel costs and plant fixed costs diverging from forecast levels.

As the efficacy of the wholesale market price signal is preserved, the allocation of risk between generators and consumers does not change. Generators continue to make investment and retirement decisions based on wholesale spot and contract price signals.

#### **4.4 Impact on contract market liquidity**

Market consumers manage wholesale price and volume risks as a natural part of their business, and are the more appropriate counterparty to generators than governments. Risk-sharing amongst market participants is common practice in the NEM, through the use of forward contracts such as swaps and caps.

The ability to earn certificate revenues, which typically comprise up to two-thirds of generators' overall revenues, has meant the RET has not incentivised intermittent generators to consider the need to 'firm up' their capacity. This lack of incentive is removed under the Guarantee's reliability requirement, as there is no longer a stream of certificate revenues. Intermittent generators would therefore face two choices when contracting:

1. continue to offer PPAs, where the strike price may or may not be sufficient to cover all of the generator's long-run costs, or
2. offer a firm contract (such as a swap), when the costs of firming are lower than the benefits of earning the "dispatchability premium".

In the absence of certificate revenue under the Guarantee, intermittent generators may decide to incur the costs of firming to earn a 'dispatchability premium' under the Guarantee's reliability requirement. By entering firm contracts, these (now dispatchable) generators would be incentivised to be available to the system when it is needed (i.e. at high-priced periods). This reinstates the direct link between the financing mechanism for generation and the physical needs of the system.

Therefore, the Guarantee is likely to promote contract market liquidity in two ways:

1. By requiring retailers to contract with generators in order to meet their emissions and reliability requirements, the Guarantee is likely to increase the demand for contracts.
2. Generators with intermittent output are more incentivised to consider firming up their output due to the absence of certificate revenues. With firmer output, these generators can offer firm contracts, which are more tradeable than PPAs. This is likely to limit the amount of non-firm generation capacity installed in a region, compared to what would occur in the absence of the reliability requirement.

These comments are consistent with the quantitative assessment of the Guarantee's impacts on the generation mix discussed in Chapter 3.

#### **4.5 Implementation flexibility**

Implementation flexibility with regards to the emissions requirement can be achieved through the development of a transparent and mechanistic gateway process to set the trajectory for the emissions requirement.



The Guarantee's design allows retailers and, through its contracts, generators to determine the least-cost generation mix to meet both their reliability and emissions requirements. Competition between retailers ensures retailers are incentivised to meet their dual requirements at the lowest possible cost to consumers, and a credible and durable compliance framework would provide greater certainty that both requirements can be, and are being, met. Furthermore, competition between generators is the process by which the resulting generation mix is least-cost. As discussed in Chapter 6, effective competition in both the retail and wholesale markets is required for the mechanism to achieve its policy objectives at the lowest possible cost to consumers.

#### **4.6 Adaptability and sustainability**

The inherent flexibility of the Guarantee means it is likely to continue to meet its policy objectives even if the policy objectives were to change (e.g. a change in the emissions reduction target). As discussed in Chapter 6, the preferred option in terms of implementation is for the detailed design elements of the mechanism to be included in the National Electricity Law and Rules. This would mean that the mechanism need not change even if emissions reduction policy objectives change. This would make it more sustainable and stable, promoting investor confidence whilst allowing for changes to the mechanism to be considered via the open, transparent and consultative process of a rule change request.

The Guarantee can also be designed in a manner that gives it flexibility to adapt to changing market conditions, such as lower than expected demand or lower than expected costs for new dispatchable renewables.

## 5 Governance of the Guarantee

Assuming that the COAG Energy Council agrees to move to the detailed design phase of the development of the Guarantee, this phase will require coordination between the ESB, Commonwealth and state governments. The detailed design phase will need to contemplate the roles and responsibilities for implementation of the Guarantee. Stable and effective implementation of the Guarantee will provide certainty for market participants about its operation, and allow for long term investment decisions to be made in the electricity sector. Wherever possible, the roles and responsibilities should follow the institutions that already hold the capabilities and infrastructure to implement the relevant functions under the Guarantee.

The proposed governance framework involves COAG/COAG Energy Council agreement through the National Electricity Law. The requirements would form an additional component of the current energy governance framework. There would be joint rules similar to the National Electricity Rules, and the AEMC would be the rule-maker and the AER responsible for compliance for the scheme.

Using this approach, the Commonwealth government would set the emissions reduction target for the electricity sector. In addition, the Commonwealth Government is also responsible for:

- Determining the extent of linkages between Australian emissions reduction mechanisms with similar mechanisms outside Australia. An associated Commonwealth Government responsibility is maintaining the requisite systems and processes for tracking carbon offsets and how they are counted towards meeting Australia's emissions targets.
- The frameworks for measuring, reporting and verifying emissions, in particular through the National Greenhouse and Energy Reporting (NGER) Scheme. Both the NGER Scheme and the registry of offsets are functions administered by the Clean Energy Regulator (CER).
- Defining what is considered an EITE activity for the purposes of being exempt from Australia's emissions reduction mechanisms.<sup>28</sup>

It is anticipated that the Commonwealth Government would need to continue performing these functions under the Guarantee.

Embedding the mechanism into the broader energy governance framework would allow the mechanism to be fully integrated with the broader energy rules. This would maximise consistency between the reliability and emissions requirements, reducing complexity and compliance costs for market participants. The rules framework would:

- translate the target into the retailer requirements
- establish the compliance framework.

In addition, establishing the process for any changes to the mechanisms involved in meeting the requirements within the rules should give market participants more certainty that they will endure beyond any one political term. It will also allow

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<sup>28</sup> These design considerations were discussed in Chapter 2.

participants clarity into how and when revisions to the mechanisms will occur recognising that the design of the mechanism is already flexible to changing market dynamics. Certainty that the policy will last, along with a mechanistic and known approach to any updates, would increase the investor confidence and certainty needed in the electricity sector where the assets are long-lived and the planning horizons are lengthy.

In the case of the emissions requirements, while the target would need to be national, the specific mechanism and proportion of national emissions reductions required would be tailored to the NEM. This would allow a different intensity target and a different mechanism to be established for Western Australia and the Northern Territory if required.

## 6 Competitive markets and the Guarantee

It is important to consider the impact of new regulatory arrangements, such as the Guarantee, on competition in the NEM. In general, the greater the extent of competition amongst market participants, the lower the likely costs to consumers of achieving the Guarantee's policy objectives. Competition in the generation sector influences contract prices and therefore affects the cost to retailers of meeting their requirements under the Guarantee. The greater the effectiveness of this competition, the lower the cost to retailers. In addition, competition in the retail sector influences the cost of the Guarantee to end-consumers. Retail sector competition influences the extent to which the savings to retailers, from competition in generation sector, are passed through to consumers.

The interaction between competition and the Guarantee occurs in three ways:

1. The Guarantee obliges retailers to contract with generators; in some instances, vertical integration (that is, a retailer buying a generator) may be more cost-effective than external contracting. However, this may increase existing market concentration and market power in the retailing and generation sectors.
2. The Guarantee's reliability requirement will increase the incentive on intermittent renewables to 'firm up' their capacity. This could be achieved via contracting between generators. It could also be achieved via horizontal integration (i.e. one generator acquiring another generator), which may have implications for the extent of competition in the generation sector.
3. Subject to further work and consultation, demand-side resources may be eligible which may enhance competition with the generation sector as there would be other options to providing reliability than just contracting for more generation.

Therefore, effective competition in both retailing and generation is required for the Guarantee to achieve its policy objectives at the lowest possible cost to consumers.

This chapter examines the nature of competition in the NEM, distinguishing between the concepts of perfect competition and 'workable' competition. These issues are discussed in the context of indicators of competition in South Australia, a region where competition has been argued to be less workable than for other regions. This chapter then discusses the potential mechanisms that could be imposed in those jurisdictions concerned that the Guarantee could increase market power in that jurisdiction's retail and generation sectors.

### 6.1 Impact of competition

Competition spurs businesses to:

- improve their performance
- develop new products and services and respond to changing circumstances
- offer lower prices and improved choice for consumers<sup>29</sup>

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<sup>29</sup> For a discussion of the development of the NEM, including the injection of competition into the generation and retail sectors, see KPMG, *NEM: A case study in successful microeconomic reform*, a report for the AEMC, December 2013.

One form of competition is perfect competition, where no barriers to entry exist and prices therefore equal short-run marginal cost. Perfect competition is a poor benchmark for the electricity generation sector as barriers to entry exist in the form of high fixed costs. The retail market also has some barriers to entry, though lower than in generation, including a high degree of customer inertia which places incumbents at a competitive advantage over new entrants.<sup>30</sup>

The presence of barriers to entry gives incumbent businesses ‘market power’: the ability to set prices that exceed long-run marginal cost (LRMC). This means customers pay more than would be the case if there was no market power and no barriers to entry (i.e. perfect competition). As long as barriers to entry are not prohibitively high<sup>31</sup>, this market power is transient, as prices that continually exceed LRMC would encourage new entrants, consequently reducing prices. This type of market is ‘workably competitive’ as the threat of new entrants means any market power is transient.

In terms of NEM regions, South Australia and Queensland have been argued as having the potential for non-transient (or ‘substantial’) market power. As discussed below, South Australia has a high degree of market concentration. This, along with wholesale prices that consistently exceed wholesale prices in other regions, means that consideration of the impact of the Guarantee on South Australia will be required.

## 6.2 Competition in South Australia

There are various indicators of the potential existence of market power. Some indicators are based on a comparison of prices against LRMCs, others are based on market shares. In its 2013 rule determination on potential generator market power, the AEMC compared prices against LRMCs and found there was insufficient evidence to support the view that South Australia had substantial market power.<sup>32</sup>

This section presents some standard market share-based indicators of market power, in South Australia’s retail and generation sectors. Figure 6.1 shows that South Australia’s generation sector has a high degree of concentration, with the largest generation business (AGL Energy) having a higher market share (42 per cent) than the largest generator in the other NEM regions (ex-Tasmania).<sup>33</sup>

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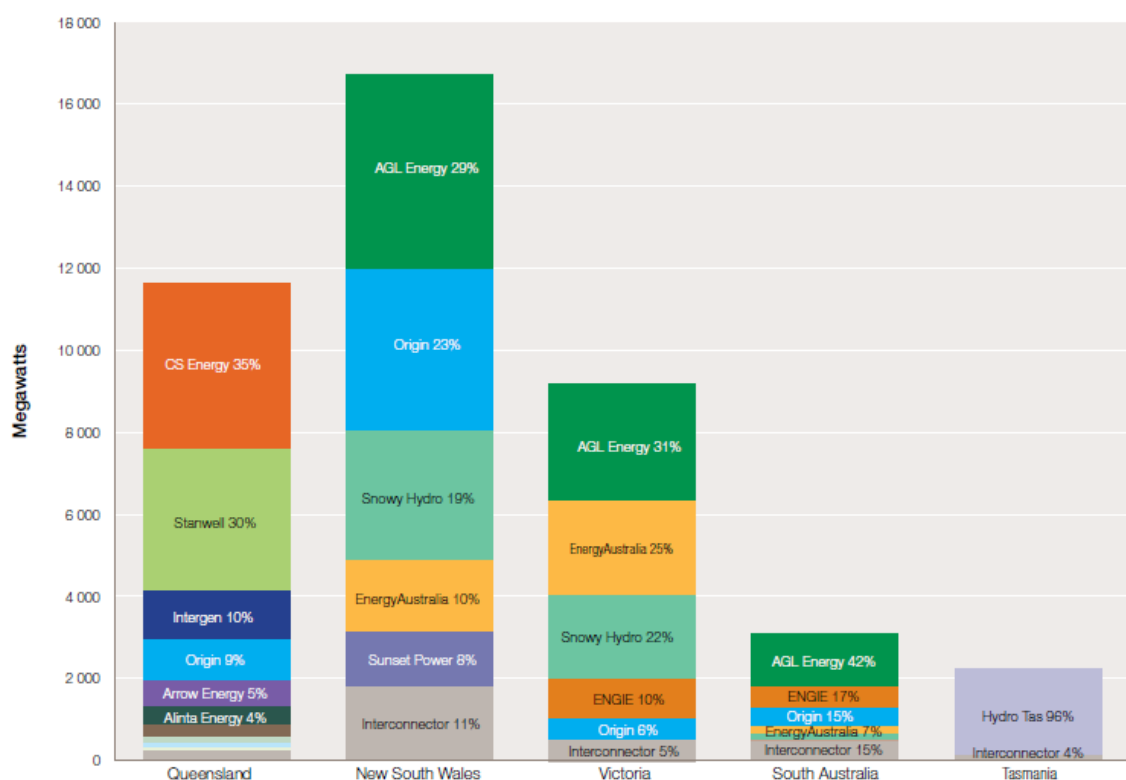
<sup>30</sup> Details on the different types of entry barriers in the retail market, and the impact on retail market competition, are provided in AEMC, *2017 AEMC Retail Energy Competition Review*, Final Report, 25 July 2017.

<sup>31</sup> Markets where entry barriers are prohibitively high result in monopolies. Examples in the electricity sector are the transmission and distribution networks, where very high fixed costs means a rival is unable to offer an alternative network that is price competitive with the incumbent’s network.

<sup>32</sup> AEMC, *Potential Generator Market Power in the NEM*, Final Rule Determination, 26 April 2013.

<sup>33</sup> Wholesale electricity prices in Tasmania are regulated as Hydro Tasmania is a virtual monopolist.

**Figure 6.1 Market shares in the generation sector**



Notes:

Capacity is based on summer availability for January 2017, except wind, which is adjusted for an average contribution factor.

Interconnector capacity is based on observed flows when the price differential between regions exceeds \$10 per MWh in favour of the importing region; the data excludes trading intervals in which counter flows were observed (that is, when electricity was imported from a high priced region into a lower priced region).

Capacity that is subject to power purchase agreements is attributed to the party with control over output.

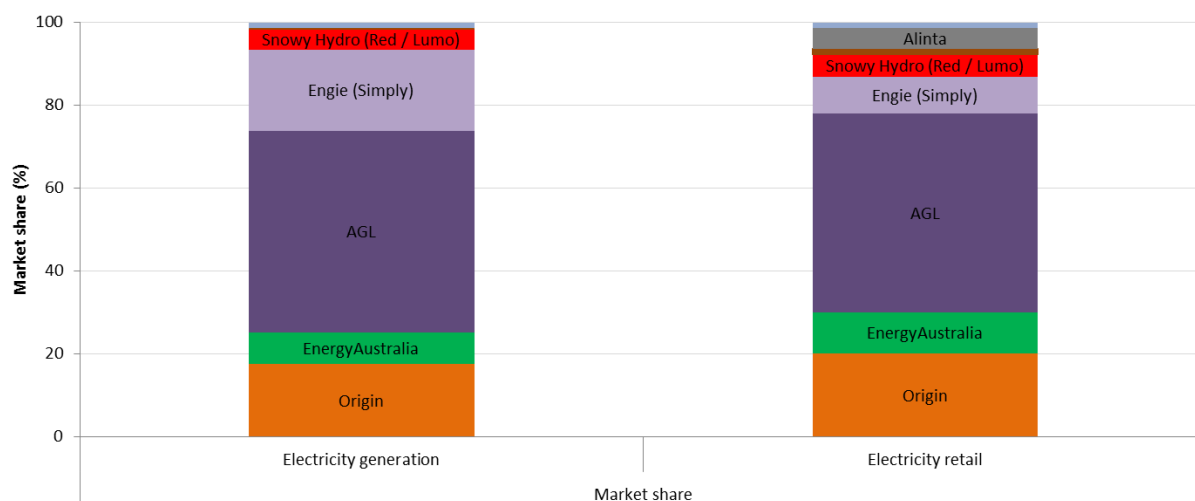
Source: Figure 1.20 in AER, *State of the energy market 2017*, May 2017

Excluding wind and interconnectors and therefore focusing on local dispatchable generators whose capacity financially backs firm contracts, AGL Energy's market share increases to 52 per cent (Figure 6.2, left hand stacked column). The largest three generators comprise almost 90 per cent of South Australia's dispatchable generation sector. In contrast, the largest three generation businesses have a market share of 74 per cent when wind and interconnector capacities are included (Figure 6.1).

South Australia's generation sector is not only concentrated; it is also vertically integrated. For example, AGL's 52 per cent share of South Australia's dispatchable generation sector is almost equal to its retail market share (51 per cent).<sup>34</sup> The largest three generation businesses (AGL, Origin, and ENGIE), with their combined dispatchable generation market share of almost 90 per cent, have a combined retail market share of 80 per cent (Figure 6.2, right hand stacked column). And the five businesses (AGL, Origin, ENGIE, Snowy Hydro, and EnergyAustralia) that supply all of the dispatchable generation capacity comprise more than 90 per cent of South Australia's retail market.

<sup>34</sup> In Figure 6.1, generation market shares are based on summer availability on 31 January 2017, except wind, which is adjusted by an average contribution factor. Retail market shares in Figure 6.2 are based on small customer numbers as at June 2016.

**Figure 6.2 Vertical integration in South Australia**



Source: AER, *State of the energy market 2017*, May 2017

This differentiates South Australia from those NEM regions, like Queensland, where there is a similar degree of concentration in the generation sector but a lower degree of vertical integration.<sup>35</sup>

Of the five ‘gentailers’ that collectively supply all of South Australia’s dispatchable generation capacity (AGL, Origin, EnergyAustralia, Snowy Hydro, and ENGIE):

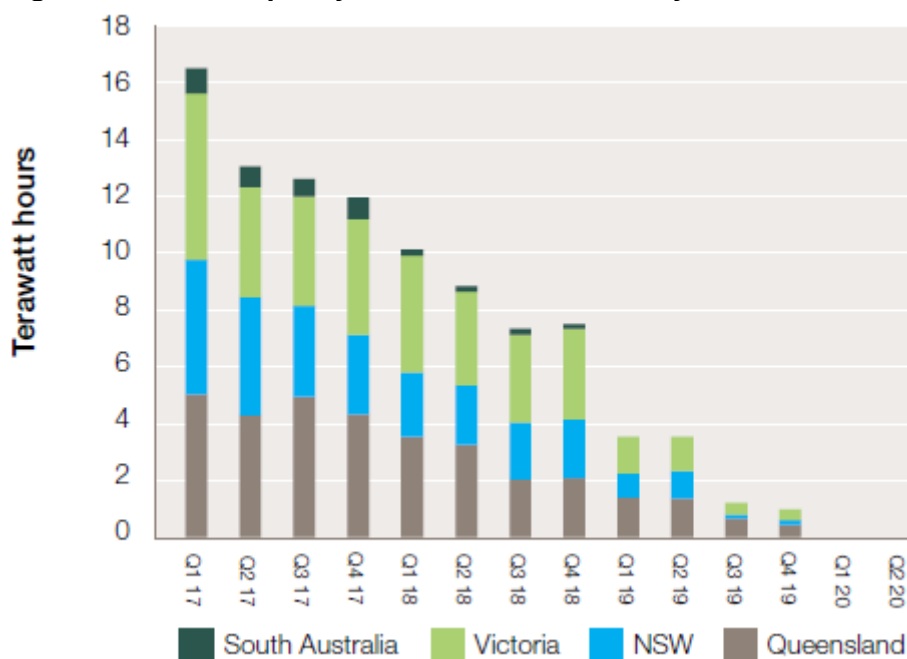
- ENGIE is the only gentailer with a net long position (i.e. generation market share exceeds its retail market share).
- AGL’s net position is close to neutral (i.e. its generation market share is almost equal to its retail market share)
- EnergyAustralia (EA)’s net short position is around the same size as that of Origin’s and Snowy Hydro’s short positions.

Figure 6.2 reveals that, in net terms, ENGIE supplies firm contracts to the other four gentailers, plus Alinta.<sup>36</sup> However, the extent of supply (and demand) is low, as each of the five businesses are highly vertically integrated (i.e. only a small difference exists between generation and retail shares for each business), and Alinta’s retail market share is relatively small. This, combined with South Australia’s lower demand and higher penetration of non-dispatchable generation, explains why South Australia’s contracts market is small and illiquid relative to the other three regional contracts markets in the NEM (see Figure 6.3).

<sup>35</sup> In Queensland, the largest retailer (Origin) had a retail market share of around 35 per cent at June 2016, and a generation market share of only 10 per cent (at January 2017). Furthermore, the largest generator (CS Energy) is not a retailer.

<sup>36</sup> Another source of demand for contracts is from those large C&I customers that buy electricity in the spot market. By size of load, these market customers comprised around 7 per cent of South Australia’s market during 2016/17.

**Figure 6.3 Liquidity in ASX-listed electricity derivatives**



Note: 'liquidity' is defined as the amount, in terawatt-hours, of contracts outstanding as at end-March 2017.  
Source: Figure 1.30 in AER, *State of the energy market 2017*, May 2017

### 6.3 A mechanism to limit further market concentration

In meeting their requirements under the Guarantee, retailers can externally contract and/or internally contract (i.e. vertically integrate) with generators. This optionality is desirable because vertical integration may in some cases be more cost-effective than external contracting. Indeed, the existence of vertical integration in all NEM regions suggests vertical integration in some cases can be, and has been, more cost-effective than external contracting.

However, further vertical integration may exacerbate market concentration especially in those NEM regions, such as South Australia, where a high degree of concentration and vertical integration already exists.

For those jurisdictions concerned about market concentration and market power, there are mechanisms that could be imposed to limit further increases in market concentration in those jurisdictions. There are three broad mechanisms that could be introduced, depending on the market being targeted and the nature of the market concentration:

1. Restrictions on which parties can own, control or operate new generation. This could limit further generation sector horizontal integration in those jurisdictions where the existing degree of horizontal integration is considered excessive.
2. Restrictions on which parties can be a retailer. This is similar to restrictions on the extent of horizontal integration in the generation sector, but for the retail sector.
3. Restrictions on which parties can be both a retailer and own, control or operate generation (i.e. restrictions on cross ownership). This could limit further vertical integration in those jurisdictions where the existing degree of vertical integration is considered excessive.



It is worth noting that these mechanisms can be used by jurisdictions in the context of *any* new mechanism or regulatory arrangement, not just the Guarantee. For example, those jurisdictions considering introducing state-based renewable energy targets and associated mechanisms may wish to consider the need for mechanisms to limit market concentration.

The below discusses the potential design of a generation-based restriction. The suggested mechanism may also be designed and adapted for the retail and generation sectors jointly. As discussed, competition in retailing and generation together deliver low prices for end-consumers, and therefore there may be a need for a mechanism that considers cross-ownership restrictions across these sectors.<sup>37</sup> It is worth noting that the Australian Competition and Consumer Commission's inquiry into the competitiveness of retail electricity markets in the NEM has highlighted vertical integration and generation market concentration as negatively impacting competition in the NEM.<sup>38</sup>

### **6.3.1 Restrictions on generation ownership**

An option that jurisdictions may consider is imposing limits on who may own new generation after some other specified date. This limitation could be triggered where a corporate group owns, controls or operates more than a specified share of generation in a region (termed 'generation market share limitation'). This arrangement is currently in place in the Philippines, under its *Electric Power Industry Reform Act of 2001* (EPIRA).

Control of generation could include control obtained through:

- shareholding or board control of companies that own generation, and/or
- electricity contracts (such as PPAs) that allow a company to direct the timing and amount of generation.

In the context of the Guarantee, control of generation may be obtained by the retailer through the contracts it enters with generators to meet its emissions and reliability requirements.

### **A market share-based limitation**

A metric for the generation market share limitation would need to be developed. This would either be defined in jurisdictional legislation, or the development of the metric could be delegated to the jurisdictional regulator. It is likely that the former option (jurisdictional legislation) would be more preferable in terms of providing certainty to investors and other market participants. The development of the metric would include:

- a definition of 'generation market share'
- the methodology and information required for determining market shares, and

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<sup>37</sup> These comments and considerations have been raised in the context of EPIRA, whose generation-focused market share limitation has been argued as being inadequate to deal with issues of market power arising from vertical integration. For more details, see E. Uy, *Genuine and sustainable reforms in the Electric Power Industry*, presentation to the Emerging Policies Forum II, May 2010.

<sup>38</sup> For more details, see ACCC, *Retail electricity pricing inquiry*, preliminary report, 22 September 2017.

- the specified generation market share in a region which, if and when exceeded, triggers the necessary action required by the relevant corporate group (i.e. the ‘cap’)

The definition of generation market share could be based on either:

- the installed capacity of generation owned or controlled by a corporate group
- the actual share of what is generated by generators owned or controlled by the corporate group over a defined historical period, or
- the availability of the installed capacity over a defined historical period.

The latter two options may better reflect market share as it will take into account differing capacity factors of generators and actual generating patterns. For example, the generation market shares presented in section 6.2 were based on availability on 31 January 2017 (i.e. during summer).<sup>39</sup>

If the metric is applied and a corporate group has breached the relevant cap in the region, it will be prohibited from owning, controlling or operating any new generation in the region. The metric will be applied initially and then re-applied annually to account for changes in generation availability in the region over the year.

The prohibition on owning, controlling or operating new generation could be embodied in generation licences (or jurisdictional regulations or instruments) as a condition of being licensed or authorised to generate in the relevant region.

The jurisdictional regulator would then be responsible for “policing” the limitation. The jurisdictional legislation would specify the penalty for non-compliance.

In addition, a pre-condition of registration of a new generating unit with AEMO could be the confirmation from the jurisdictional regulator that the registration of the new generating unit does not breach any market share limitation on the generator under jurisdictional legislation.

### **6.3.2 Issues for further consideration**

A mechanism to limit potential generator market power requires consideration of various issues related to the mechanism’s design. These issues are:

- Identifying what is “new” generation for the purposes of the limitation
- Considering whether the proposed design should also restrict acquisition of existing generators. This matter is currently covered by section 50 of the *Competition and Consumer Act 2010*, which prohibits acquisitions that would result in a substantial lessening of competition
- The appropriate definition of the market share limitation. As discussed above, there are three broad options in terms of how ‘market share’ is defined

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<sup>39</sup> In contrast, EPIRA based its generation market share limitation on installed capacity. Furthermore, sec. 45 of EPIRA specifies that no company or related group can control more than 30 per cent of the installed generating capacity of a ‘grid’ (akin to a NEM region) and/or 25 per cent of the national installed generating capacity. For more detail on section 45, see: [http://www.lawphil.net/statutes/repacts/ra2001/ra\\_9136\\_2001.html](http://www.lawphil.net/statutes/repacts/ra2001/ra_9136_2001.html)

- Considering whether ‘ownership, control or operation’ needs to be defined. For example, cross-ownership provisions tend to have complex tracing provisions to ensure things owned by various arms of a corporate group are captured by those provisions
- Identifying those jurisdictions that do not have a licensing framework for generation, and understanding how the mechanism would integrate with existing jurisdictional legislation
- Considering the scope, nature and extent of penalties that would apply if a corporate group’s market share exceeds the limitation. Examples of penalties include breach of licence, revocation of generator licence, and a requirement for divestment.

Due to the short timeframes involved in the publication of this report, the following issues have not been fully considered but are included to inform of possible approaches. Their detailed consideration can occur as part of the more detailed design of the Guarantee in the NEL, the NER and detailed procedures, if the COAG Energy Council agrees to move to this phase.

## 7 Next steps

The COAG Energy Council is being asked to consider approving further work by the ESB on the design of the Guarantee. If there is agreement to this further work the ESB would anticipate undertaking a thorough and comprehensive consultation process with a wide range of industry, consumer and government stakeholders. This process would allow all interest parties to engage in the detailed design of all elements of the policy.

It is anticipated that the ESB would be able to provide a preliminary design approach to Ministers for consideration at the COAG Energy Council meeting scheduled for April 2018 and then a final design recommendation including required legislative and rule changes for approval in July.

A timeline and associated consultation stages are provided below for Council's consideration.

Assuming that the COAG Energy Council agrees to move to the detailed design phase of the development of the Guarantee, a suggested timeline for implementation of the Guarantee is provided below.

Date	Action	
2017		
November	COAG Energy Council agrees to progress further work	ESB releases proposed consultation approach and timelines (see below)
2018		
early February	ESB releases proposed Guarantee design paper	The ESB develops further details of design and compliance framework for stakeholder consideration, with the Commonwealth leading consultation on the emissions target, the use of offsets and EITE exemptions.
early March	Public forum on design options	AER, AEMO and AEMC presentations on design elements and stakeholder presentations on different approaches, with the Commonwealth leading consultation on the emissions target, the use of offsets and EITE exemptions.
end of March	Written submissions due on design paper	
early April	ESB provides draft design paper for COAG Energy Council approval	The ESB incorporates stakeholder feedback into paper establishing proposed approach to implementing the Guarantee
mid April	COAG Energy Council approves policy approach	

Date	Action	
May	ESB working papers /workshops on various detail elements of Guarantee design	Stakeholder input requested on detailed design elements in order to develop legislative and rule change requirements
Second half of 2018	ESB releases final design document  Commonwealth releases proposed legislative changes on emissions and NEL	Stakeholder input requested on final design proposal
Second half of 2018	ESB provides final design of the Guarantee for COAG Energy Council approval	Final design includes proposed legislative changes and requirements for new rules and rule changes
Second half of 2018	COAG Energy Council approves final design of the Guarantee	Legislation and rule change implementation begins

It is proposed that a steering committee be developed that could meet monthly to discuss key policy issues and co-ordinate development of legislative framework. This committee could be comprised by:

- ESB Chair
- ESB vice Chair
- AEMC Chair
- AEMO CEO
- AER Chair
- Deputy Secretary of the Commonwealth Government's Department of the Environment and Energy
- Additional Senior Committee of Officials members from jurisdictions

It is also proposed that a technical reference group be established as required on specific topics that could meet at key milestones, to comprise:

- Key industry representatives
- Key consumer representatives
- Energy Consumers Australia
- The Reliability Panel

Assuming that the COAG Energy Council agrees to move to the detailed design phase for the Guarantee, it is envisaged that this work would be in conjunction with the work being done by the ESB and the COAG Energy Council to implement the recommendations from the Finkel Review.

## A Abbreviations and defined terms

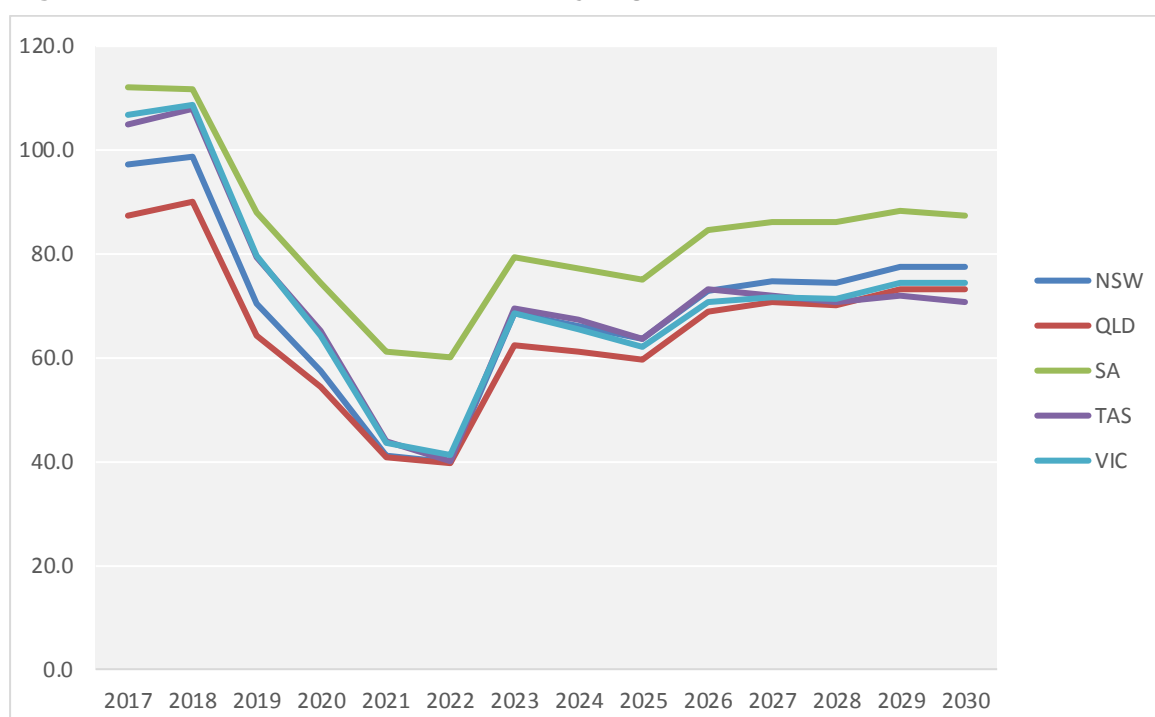
ACCC	Australian Competition and Consumer Commission
ACT	Australian Capital Territory
ACCU	Australian Carbon Credit Unit
AEMA	Australian Energy Market Agreement
AEMC or Commission	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARENA	Australian Renewable Energy Agency
ASX	Australian Stock Exchange
BAU	Business-as-usual
CEFC	Clean Energy Finance Corporation
CER	Clean Energy Regulator
COAG	Council of Australian Governments
EA	EnergyAustralia
EPIRA	The Philippines <i>Electric Power Industry Reform Act of 2001</i>
ESB	Energy Security Board
ESCOSA	Essential Services Commission of South Australia
Guarantee	National energy guarantee
LGC	Large-scale Generation Certificate
LRMC	Long-run marginal cost
Mt	Megatonne (equal to 1 million tonnes)
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
OTC	Over the counter
PPA	Power purchasing agreement
RET	National large-scale renewable energy target currently in place under the <i>Renewable Energy (Electricity) Act 2000</i> (Cth)
SRMC	Short-run marginal cost

## B Jurisdictional impacts of the Guarantee

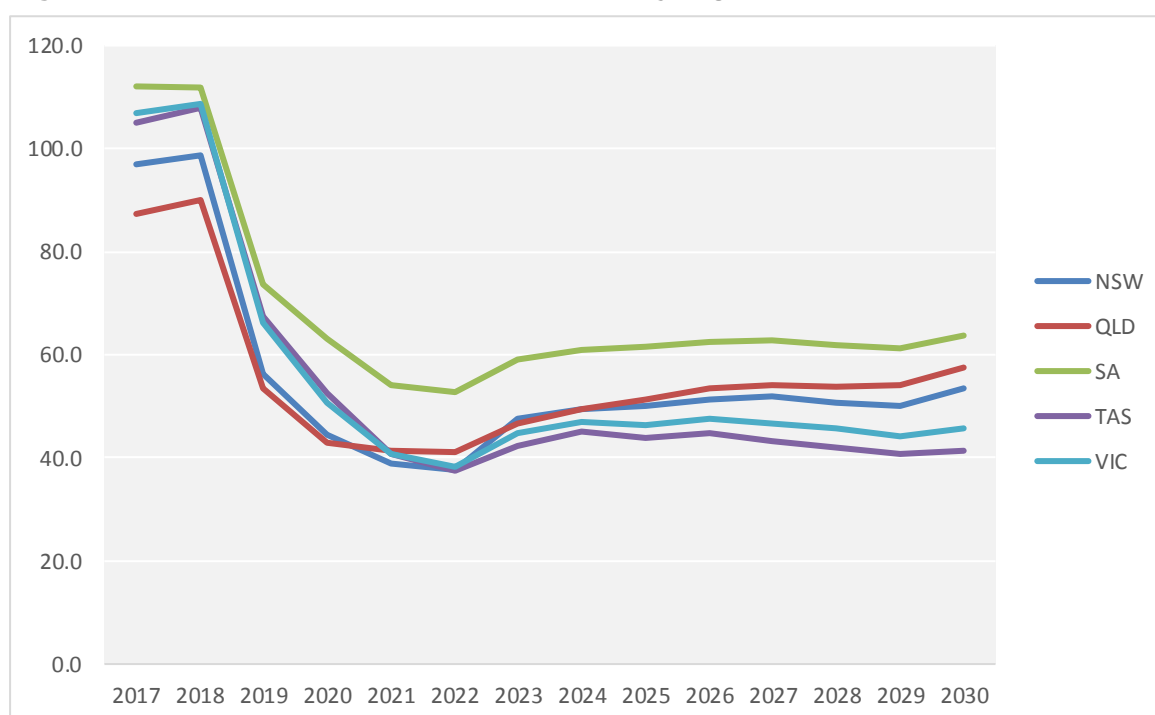
### B.1 Wholesale prices

Wholesale price impacts of the Guarantee compared to BAU do not vary substantially by jurisdiction. Graphs illustrating this are provided in Figures B.1 and B.2, using baseline demand assumptions.

**Figure B.1** BAU Wholesale prices by region



**Figure B.2** Guarantee Wholesale prices by region



In summary, wholesale price outcomes follow roughly the same trends to one another (and the NEM average) in each of the regions in both BAU and under the Guarantee. Wholesale prices under the Guarantee are lower than BAU in every region over the 2020-2030 period.

## B.2 Jurisdictional investments and retirements

The impact of the Guarantee on investment compared to BAU vary by jurisdiction, as illustrated in Table B.1, which shows the amount of uncommitted investment in various generation technologies by 2030.

**Table B.1 Investment of uncommitted plant by 2030 (MW)**

		Coal	Gas	Dispatchable renewable (incl. batteries)	Intermittent renewable
NSW	BAU	0	0	0	0
	Guarantee	0	0	521	866
Qld	BAU	0	0	0	0
	Guarantee	0	0	0	841
SA	BAU	0	263	0	112
	Guarantee	0	251	315	150
Tas	BAU	0	0	0	485
	Guarantee	0	0	0	671
Vic	BAU	0	0	0	0
	Guarantee	0	0	0	742
Total	BAU	0	263	0	597
	Guarantee	0	251	835	3271

Source: Frontier Economics

In summary, under BAU, what little additional investment is required occurs in South Australia (almost all gas mid-merit from the early 2020s) and Tasmania (all wind in the late 2020s).

Additional investment is far more varied across states under the Guarantee. In South Australia, in addition to the gas mid-merit of BAU, significantly more dispatchable capacity is brought into the system, including batteries.

In Tasmania, more and earlier wind generation is invested in. Victoria sees wind investment in the later 2020s, and Queensland wind and solar PV in the late 2020s. The largest amount



uncommitted capacity is invested in New South Wales, with battery investment from the mid-2020s and wind investment late in the decade. These investments are in addition to the 2000 MW of dispatchable capacity from Snowy 2.0.

### **B.3 Impact on generation output by jurisdiction**

The output mix in the Guarantee and BAU by dispatchable/intermittent, thermal/renewable and committed/non-committed generation technologies is provided in Figure B.3.

**Figure B.3** Output of generation by technology type, by year and by jurisdiction

