AUSTRALIAN ENERGY COUNCIL

Dr Ann Palmer
Committee Secretary
Select Committee into Fair Dinkum Power
Department of the Senate
PO Box 6100
Parliament House
CANBERRA ACT 2600

15th February 2019

Submitted online to:
https://www.aph.gov.au/Parliamentary_Business/Committees/Senate/Fair_Dinkum_Power/FairDinkumPower

Dear Dr Palmer,

Terms of Reference

Thank you for inviting the Australian Energy Council (the "**Energy Council**") to make a submission to the Senate Select Committee into Fair Dinkum Power's ("**the Committee**'s") Terms of Reference.

The Energy Council is the industry body representing 23 electricity and downstream natural gas businesses operating in the competitive wholesale and retail energy markets. These businesses collectively generate the overwhelming majority of electricity in Australia, sell gas and electricity to over ten million homes and businesses, and are major investors in renewable energy generation.

Introduction

The benefits of competitive markets are without question. Since the introduction of competition in the wholesale electricity market in 1998 and the retail markets progressively since 2002, these competitive market structures have been able to deliver least cost outcomes for consumers. Markets have continued to evolve since their establishment and market participants have developed innovative product offerings and solutions. Unfortunately government policy uncertainty over the past decade has hobbled further retail product development and capital investment in the wholesale market, and the Energy Council is keen that any recommendations made by the Committee will have a positive return on investment, and be tangible and enduring.

To this end the Energy Council would like the Committee to note that it has considered the likely changes to the National Electricity Market's ("**NEM**'s") structure as a result of technology and policy changes, and recently commissioned a report by Rajat Sood of Frontier Economics,[1] a copy of which is appended to this submission. In addition, last year the Energy Council commissioned KPMG to consider long-term market design principles,[2] and that report is appended also.

[1] Sood, R., *NEM Structure in Light of Technology and Policy Changes*, 13th December 2018, available at: https://www.energycouncil.com.au/media/14945/20181213-final-report-advice-on-nem-structure-in-light-of-technology-change-stc.pdf
[2] KPMG, *Electricity Market Design Principles – Identifying long-term market design principles to support a sustainable energy future for Australia*, 19th April 2018, available at: https://www.energycouncil.com.au/media/12077/market-design-principles-final-report-180419.pdf

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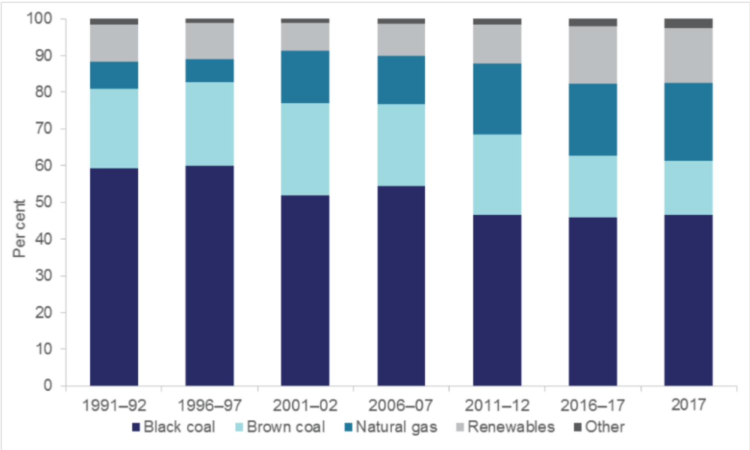
Discussion

There is no doubting that Australia's power system is in transition, as the proportion of variable renewable energy supply increases and aging conventional generation reaches the end of its economic life and retires. While the closure of large generation units such as Hazelwood Power Station in Victoria (1,600MW) attracts significant media attention, in reality the change in generation mix does not occur as a single well-defined event or a series of such events. Instead the displacement of conventional generation has occurred gradually, as shown in the graph from the *Australian Energy Update 2018*.[3]

Figure 3.5: Australian electricity generation fuel mix



Thus it is important for the Committee to consider the interaction of all sectors of the generation mix, including, but not limited to:

- small, distributed generation "behind the meter" (in the form of photovoltaic cells and batteries);
- large-scale renewable generation (such as wind farms and solar farms);
- small, conventional generation such as diesel and natural gas generators (which may or may not be configured as an aggregated array); and
- large-scale conventional generation, such as gas-fired generators and high-efficiency low-emissions coal-fired power.

In addition, the increasing availability and use of storage in the form of grid-scale batteries and pumped hydro will also need to be considered.

The Energy Council therefore advocates that the Committee consider the interaction between these sectors and how market efficiency can best be encouraged. As a first step, market efficiency may be improved by providing better signals between the different generation sources and demands, for example to ensure that customers receive advice on the overall market supply & demand balance, and in return provide the market with knowledge of their intentions. It is also important to ensure that different technologies receive the same market signals, to ensure that innovation is fostered and development is as efficient as possible.

Of course if customers are participating in the market, even in a limited way and with modified market signals, their contributions will need to be directly comparable with those of other generation sources, and it is important for the Committee to consider the reliability of consumer-provided energy services in its deliberations.

While reliability in this context generally refers to the power system within the NEM and the ability of the market to count on small generation when it is needed, being connected at the distribution system level rather than the transmission system level, having significantly more connections than large generators, and finally being in proximity to the general public indicates that these types of small installations may have higher risk, and the Energy Council therefore recommends that the Committee consider the electrical safety of these installations and their ongoing compliance with relevant standards. As an example, in its report on the 25th August Separation Event,[4] AEMO observed that of the sampled behind-the-meter photovoltaic systems installed after the introduction of the new Australian standard, AS4777.2-2015 *Grid Connection of Energy Systems via Inverters – Inverter Requirements*, around 15% of the installations in Queensland and 30% in South Australia did not provide the over-frequency reduction capability required by the standard.[5]

[3] Figure 3.5, p.22, Department of the Environment and Energy, *Australian Energy Update 2018*, August 2018
[4] Australian Energy Market Operator, *Final Report – Queensland and South Australia System Separation on 25 August 2018*, 10th January 2019
[5] Ibid., p.6

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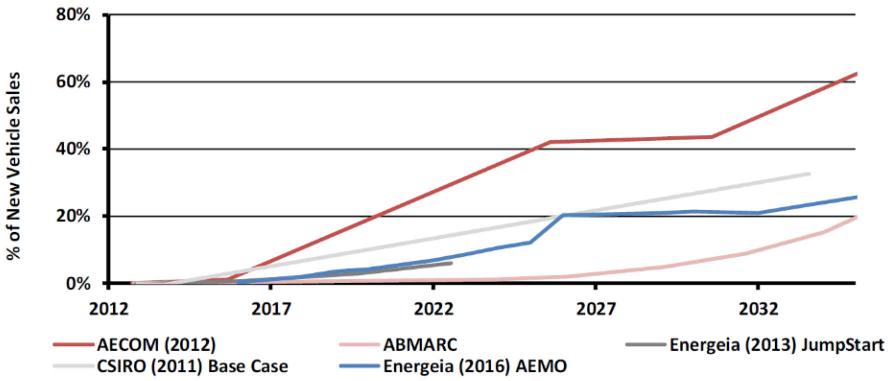
The integration of consumers in the broader market also raises questions about the equitable treatment of the different market segments. The Energy Council believes the remit of the Committee should be such that it considers the issues of cross-subsidisation between different market segments, and the appropriate tariff structures for different market segments' distribution network utilisation.

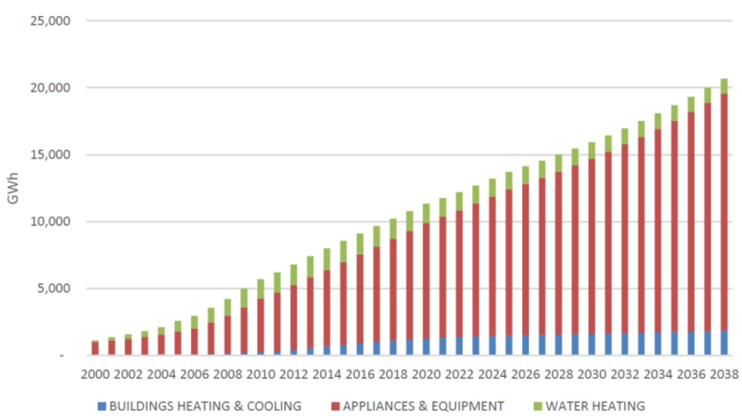
In addition to the transition which is currently being witnessed, technology change will continue. As an example there are differing views as to the uptake of electric vehicles within Australia over the next ten years, as shown in the graph, taken from the *Australian Electric Vehicle Market Study*.[6]

Figure 44 – Selected Historic Australian PEV Uptake Forecasts



Therefore considering the penetration of electric vehicles and their effects on consumer supply and demand profiles will be an important consideration for the Committee. It will also be important for the Committee to consider the complementary sides of likely technology changes, being technology changes which affect electricity generation (such as the increasing size of wind turbines, and the use of micro-inverters with photovoltaic panels), as well as technology changes which will affect demand. As an example, under a moderate scenario, 20TWh of residential energy savings are expected over the next 20 years, as shown in the graph, taken from *Energy Efficiency Impacts on Electricity and Gas Demand to 2037-38*.[7]

Figure 14: Residential GEMS Savings by End-Use Type, Moderate Scenario



Technology changes will not be limited to appliance efficiency improvements and new generation sources. As homes become "smarter", old appliances are replaced with internet-connected devices, and new appliances such as home speakers and smart watches become commonplace, the opportunity for more localised supply and demand control exerted either by consumers, service providers or artificial intelligence become more likely scenarios, and the Energy Council recommends that the Committee considers these types of futures in its deliberations, and ensures that different technologies receive the same market signals.

These sorts of changes will change the nature of the customer relationship with retailers, and third parties such as demand response aggregators may increasingly interact with consumers. It is important that when considering the regulatory reforms necessary, the Committee reviews the roles of these different entities and, most importantly, ensures that customer protections are maintained.

[6] Energeia, *Australian Electric Vehicle Market Study prepared for ARENA and CEFC*, May 2018, Figure 44, p.53,
[7] Strategy. Policy. Research, *Energy Efficiency Impacts on Electricity and Gas Demand to 2037-38: Final Report*, 1st June 2018, Figure 14, p.30

Conclusion

In conclusion, the Energy Council supports the work of the Committee and believes that its Terms of Reference should be broadened to consider the interaction between smaller generators and consumers, and larger generators and consumers. The additional matters the Committee should consider have been set out in this submission, but for ease of reference a summary is appended.

Any questions about this submission should be addressed to the writer, by e-mail to Duncan.MacKinnon@energycouncil.com.au or by telephone on (03) 9205 3103.

Yours sincerely,

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Appendix
Additional Terms of Reference

In addition to the Terms of Reference initially set out for the Committee, the Energy Council recommends including the following:

1. The reliability of consumer-provided energy services;
2. The interaction between customer participation and the National Electricity Market to maximise efficiency, and the need for market signals to be uniform and bidirectional;
3. The effects of increasing consumer generation on the distribution network, including electrical safety;
4. The ongoing compliance of behind-the-meter installations with relevant standards;
5. Cross-subsidisation between the different market segments, and the appropriate distribution network tariff structures;
6. The effect of electric vehicle uptake on consumer supply and demand profiles;
7. Likely technology developments which will affect electricity generation;
8. Likely technology developments which will affect demand;
9. The future of artificial intelligence and remote operation on consumer demand profiles;
10. The role of retailers and third parties such as demand response aggregators; and
11. How customer protections will be proposed to be maintained.

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NEM STRUCTURE IN LIGHT OF TECHNOLOGY AND POLICY CHANGES

REPORT FOR THE AUSTRALIAN ENERGY COUNCIL
PREPARED BY RAJAT SOOD, FRONTIER ECONOMICS

13 DECEMBER 2018

CONTENTS

EXECUTIVE SUMMARY

Policy-makers and regulators have recently raised concerns about high prices in Australia's National Electricity Market (NEM). This report discusses technological, policy and structural developments in the energy sector that are underway or are likely to take place over the next decade and considers their implications for the likely future structure, conduct and performance of the NEM. In particular, this report considers whether changes in technology, market architecture and the supporting infrastructure could over time address concerns that policy-makers and regulators have raised about wholesale market bidding, contracting, vertical integration and pricing outcomes.

The NEM has traditionally exhibited a combination of characteristics that differentiate it from many other markets in the economy. These characteristics are:

- Generating plant has tended to be large and expensive to build, which has made it hard for smaller players to participate;
- Electricity demand is highly unresponsive to real-time prices; and
- To maintain a secure power system, electricity supply needs to equal demand at all times.

Taken together, these features imply that wholesale prices can be very volatile depending on physical supply/demand conditions, which in turn draws greater scrutiny on the size of each player's portfolio.

These features also mean that when new plant enter the system or retiring plant leave, average prices can suddenly collapse or jump, respectively, reflecting the marked implications of changes in the industry supply-demand balance. Customers have recently experienced the latter phenomenon following the exit of the Northern and Hazelwood power stations – in both cases, wholesale prices went from very low levels to well above the long run average in the space of weeks or months. Similar outcomes could occur again in future if other large fossil-fuel generators were to close as renewable plant continue to enter the NEM in response to Commonwealth and State renewable energy targets (RETs). The price impact of large plant exits is illustrated in a stylised manner in **Figure 1** below.

Given the essential nature of electricity to citizens and businesses in the modern economy, these types of abrupt shifts naturally cause public consternation and draw the attention of policy-makers. Many of the relatively interventionist measures proposed to date are directed at addressing what policy-makers perceive to be competition problems that stem from the current environment.

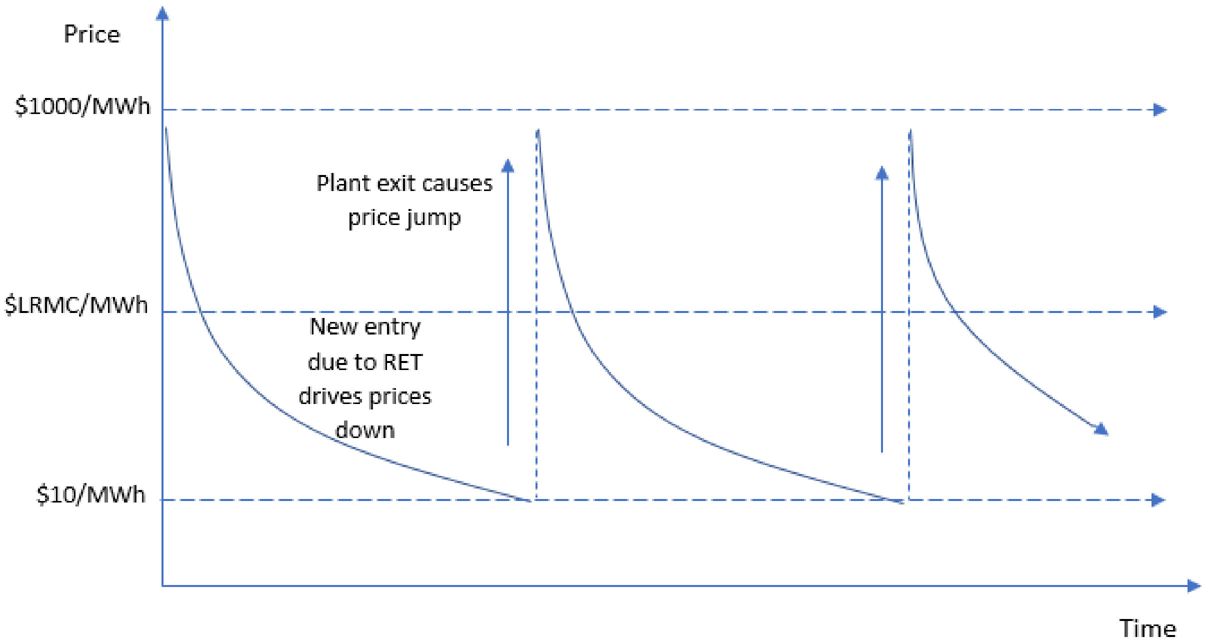
However, recent and upcoming changes to electricity generation and storage technology, market architecture and supporting infrastructure are likely to mitigate not only these medium-term price cycles in the NEM, but also the scope for generators to instigate short-term price spikes – thereby overcoming much of the impetus for the kinds of interventions that have been put forward. The types of changes that have already been forthcoming or are likely to occur over the next few years are as follows:

- The availability of renewable plant in much smaller increments and reflecting much smaller scale efficiencies than traditional generators, and the much shorter lead times for commissioning such plant. These developments will make it easier for small non-vertically-integrated retailers and business customers to sponsor the entry of new plant.
- Substantial reductions in the costs of utility-scale solar thermal plant and battery storage, in particular.
- More transmission investment across the NEM to reduce network constraints and facilitate the movement of power from 'renewable energy zones' to demand centres.

- Detailed changes to the operation of the NEM to reduce strategic bidding incentives and promote dispatchable demand response from smaller customers.
- A new obligation on generators to notify the market of their intention to exit three years in advance of doing so.
- Smarter metering and energy management systems combined with further increases in rooftop PV and distributed batteries to increase the real-time ability of demand to respond to high wholesale prices.
- The possibility of a liquefied natural gas (LNG) import terminal in the southern part of the NEM, helping to diversify fuel supplies and increase competitive discipline on existing gas suppliers.

This combination of technological, economic and policy-driven changes is likely to have a very significant effect on participant short- and longer-term decision-making and on medium-term price cycles.

Figure 1: Recent RET-driven price-cycle dynamics

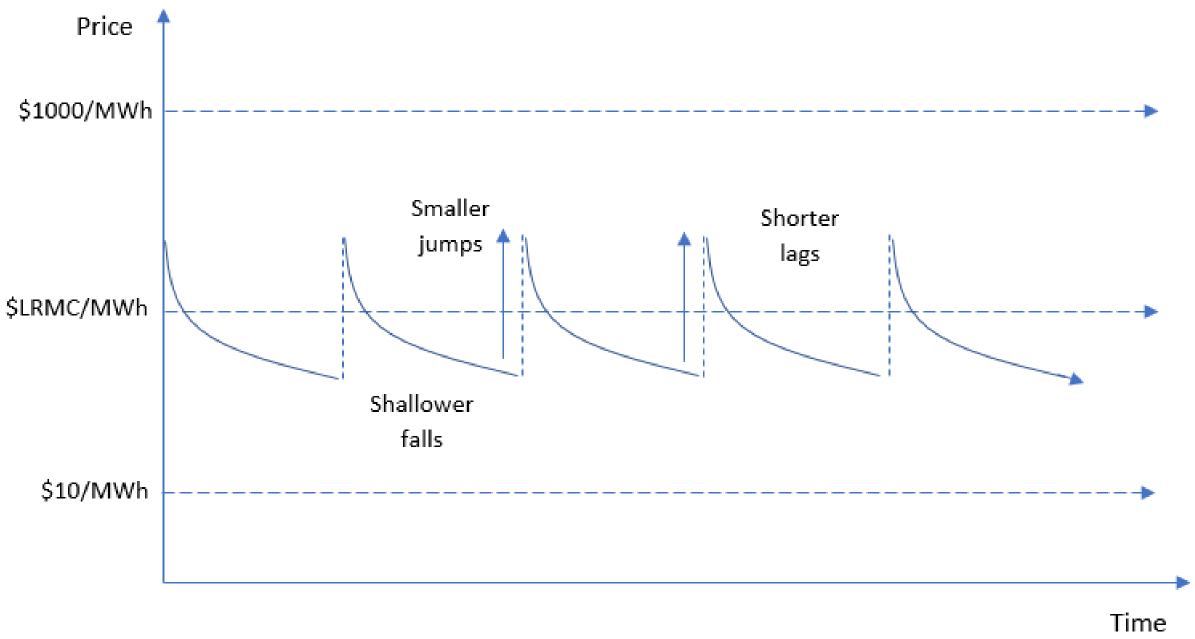


Source: Frontier Economics

As a result of the greater scope for existing and new investors to finance and develop small additions of generating plant, the abruptness and amplitude of medium-term price cycles is likely to diminish. These price cycles are likely to shift over the next decade from the familiar pattern shown in **Figure 1** towards cycles that appear more like those in **Figure 2** below.

In addition, short term price volatility is likely to reduce, as the wider adoption of battery storage and greater participation of scheduled demand response increase the ability of demand response to attenuate price spikes and other changes such as the impending move to 5-minute participant settlement and deeper transmission interconnection impose tighter discipline on participant bidding behaviour.

Figure 2: Future RET-driven price cycles in the NEM



Source: Frontier Economics

Overall, these developments are likely to offer three major benefits from the perspective of policy-makers and regulators:

- The first is that they should help smooth wholesale price volatility in both the short term and in the medium to longer term;
- The second is they should reduce the advantages of the vertically-integrated 'gentailer' business model; and
- The third is that they should encourage more competitive behaviour in the NEM wholesale market and thereby lead to more efficient and cost-reflective dispatch and pricing outcomes.

In this way, the analysis in this report is directly relevant to whether interventions of the type that have been proposed are likely to be worthwhile.

These developments are also broadly consistent with the satisfaction of the National Electricity Objective (NEO), although only the third is directly relevant. Reduced price volatility may or may not promote the NEO in itself, but is expected to be a consequence of behaviours that would promote the NEO – namely, more efficient participant decisions about energy usage and investment, and more cost-reflective bidding. Similarly, reduced advantages for the gentailer business model may not promote the NEO directly, but could increase competition by lowering entry barriers.

1 INTRODUCTION

This report has been prepared by Rajat Sood, consultant at Frontier Economics, for the Australian Energy Council (AEC). This report discusses the implications of technological and policy changes in the energy sector for the likely future structure, conduct and performance of Australia's National Electricity Market (NEM). The report considers whether changes in technology and energy infrastructure combined with forthcoming modifications to the NEM design could over time organically address concerns that policy-makers and regulators have raised about wholesale market bidding, contracting, vertical integration and pricing outcomes both recently as well as at various times since the commencement of the NEM. As well as helping to address policy-maker and regulator concerns, these technological and other developments should enable to market to better meet the National Electricity Objective (NEO)[1] – which is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:

- price, quality, safety and reliability and security of supply of electricity
- the reliability, safety and security of the national electricity system.

This report is arranged as follows:

- Chapter 2 summarises concerns raised by the Australian Competition and Consumer Commission (ACCC or Commission) in its Retail Electricity Price Inquiry (REPI) final report and subsequently by the Federal Government in its recent consultation paper on electricity price monitoring and responses.
- Chapter 3 attempts to discern the specific underlying economic features of the NEM that do not apply to most other markets and appear to have given rise to the concerns of policy-makers and regulators.
- Chapter 4 briefly summarises our literature review on recent and expected future changes in technology and outlines key policy and other expected changes to the operation of the wholesale market.
- Chapter 5 explains the implications of changes in technology, market architecture and the supporting infrastructure for the underlying drivers of policy-makers' concerns about the NEM wholesale market and how the changes are likely to lead to policy-makers' concerns dissipating over time.
- Appendix A Energy-only wholesale market operation – provides a brief explanation of how energy-only markets such as the NEM are designed to remunerate investors for their fixed and sunk costs and provide incentives for investment in an optimal mix of plant.
- Appendix B Literature review – contains the most salient findings from our literature review of historical and expected future technology changes and costs.

1 *National Electricity Law*, section 7.

2 CONCERNS RAISED BY POLICY-MAKERS AND REGULATORS

2.1 Background

Policy-makers and regulators have recently been expressing concerns about prices in the wholesale and retail electricity markets that appear to them to be excessive. In the retail market, the primary concern appears to be that customers who are either unable or unwilling to vigilantly monitor retailer offers pay far higher tariffs than are available and that this ‘loyalty tax’ feeds into retailers’ profits. In the wholesale market, the key concerns appear to revolve around the bidding and contracting behaviour of the large incumbent generators, including the vertically-integrated ‘gentailers’. The large generators are seen as engaging in and benefitting from the exercise of some form of market power, both by increasing wholesale spot and contract prices as well as potentially by withholding the supply of hedge contracts that are regarded as a necessary input to retailing.

This report focuses on the concerns raised by policy-makers and regulators about the *wholesale market*, as well as how the wholesale market can influence the retail market through vertical integration. The report seeks to identify the underlying reasons for policy-maker and regulator concerns, and the extent to which these underlying causes are likely to be overcome or addressed by expected technological and other structural or market design changes over the next decade. I note that similar concerns have been expressed by policy-makers and regulators at various times since the commencement of the NEM. For example, in 2001, in response to a number of price spikes in the wholesale market, the then National Electricity Code Administrator made an application to the ACCC for authorisation of changes to the National Electricity Code seeking to prohibit bids that “have the purpose, or have or are likely to have the effect, of materially prejudicing the efficient, competitive or reliable operation of the market”.[2]

This chapter outlines the concerns raised by the:

- ACCC in its Retail Electricity Pricing Inquiry (REPI) final report of June 2018;[3] and
- Commonwealth Government in its Electricity price monitoring and response legislative framework Consultation paper (Consultation paper) of October 2018.[4]

2.2 ACCC REPI

The ACCC’s REPI raised concerns about both wholesale market concentration and vertical integration.

[2] See NECA Code Change Panel, *Generators’ bidding and rebidding strategies and their effect on prices*, Volume 1 Report, September 2001, available at: https://www.accc.gov.au/public-registers/authorisations-and-notifications-registers/authorisations-register/nec-rebidding-code-changes.

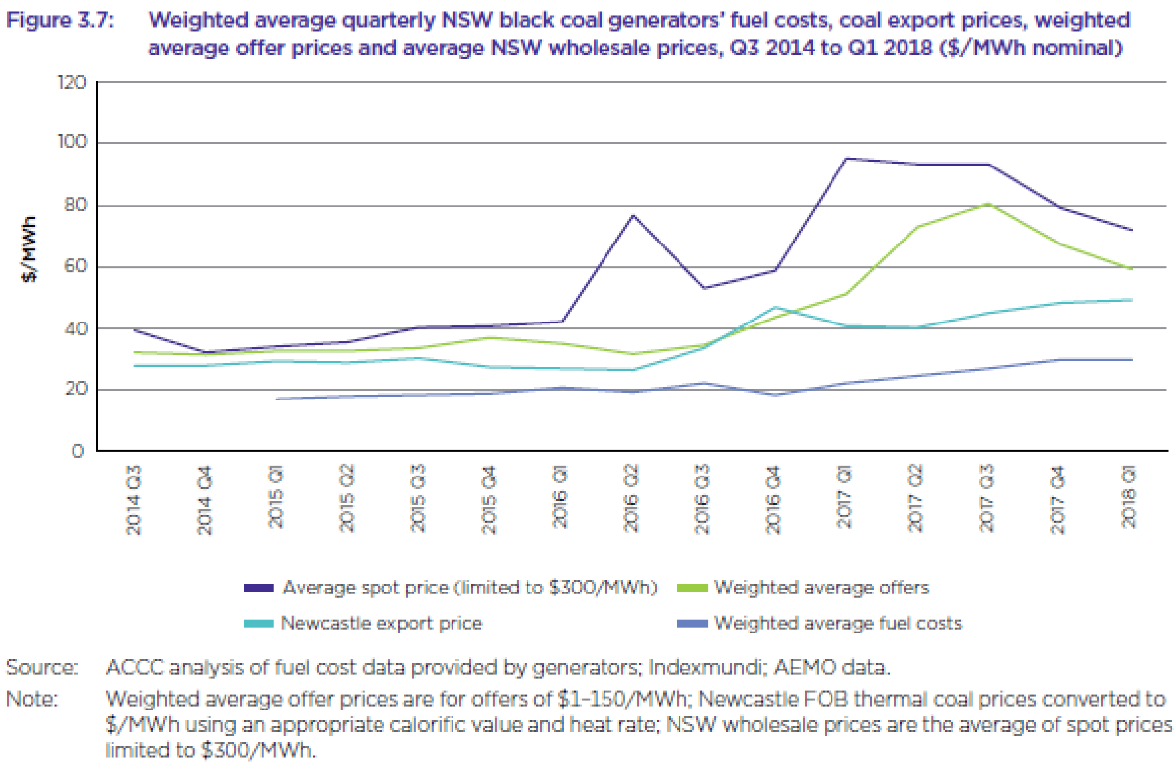
[3] ACCC, *Restoring electricity affordability and Australia’s competitive advantage, Retail Electricity Pricing Inquiry – Final Report*, June 2018 (ACCC REPI), available at: https://www.accc.gov.au/regulated-infrastructure/energy/electricity-supply-prices-inquiry/final-report.

[4] The Australian Government the Treasury, *Electricity price monitoring and response legislative framework, Consultation paper*, October 2018 (Consultation paper), available at: https://treasury.gov.au/consultation/c2018-t337042/.

2.2.1 Wholesale bidding

The ACCC did not find evidence of the large generators systematically engaging in output-withholding behaviour to 'spike' wholesale prices.[5] However, the report included some discussion about coal-fired generators in New South Wales and Queensland experiencing higher fuel costs in recent times and increasing their offer prices by more than the Commission considered necessary to reflect those cost increases.[6] See **Figure 3** and **Figure 4**, reproduced from chapter 3 of the REPI.

Figure 3: NSW black coal generator bidding



Source: ACCC REPI, p.68.

[5] The ACCC said: "[T]he key cause of higher wholesale prices is less related to discrete instances of market power being used to spike the price and more driven by a subtle and sustained 'lift' in prices that can be attributed in part to a lack of competitive constraint." See ACCC REPI, p.96.

[6] It is not clear why the ACCC chose to focus on the differences between black coal generator offer prices and contract fuel costs rather than the Newcastle export price, which better reflect the opportunity cost of black coal and from which offer prices show much smaller divergences.

Figure 4: Queensland black coal generator bidding

Figure 3.8: Weighted average quarterly Queensland black coal generators' fuel costs, coal export prices, weighted average offer prices and average Queensland wholesale prices, Q3 2014 to Q1 2018 ($/MWh nominal)

Source: ACCC REPI, p.69.

The Commission concluded:[7]

> The ACCC considers that the overall widening between NSW and Queensland black coal generators' offer prices and their fuel costs is likely to be a product of a lack of competitive constraint and the highly concentrated market structure in Queensland.

These concerns did not extend to the bidding behaviour of gas-fired generators:[8]

> The ACCC also considered how gas generators' average offer prices related to their fuel costs. Average gas generators' offers increased from $30–50/MWh (depending on the region) in early 2015, to around $90/MWh in early 2018. In Victoria, NSW and South Australia, average offers were generally above fuel costs by $10–15/MWh in the earlier periods, however fuel costs and average offers tended to increase together and converge by late 2017.
>
> Unlike black coal, the ACCC's analysis indicates that gas generators' average offers at cost-related price bands tended to increase in line with their fuel costs, which to an extent appear linked to (gas) market prices.

The REPI also highlighted instances of generator bidding behaviour and dispatch outcomes in different NEM regions before and after certain market structural changes and policy interventions as a means of demonstrating the apparent influence of these factors. For example, following the closure of the Hazelwood power station in March 2017, the ACCC commented that both AGL and Origin Energy began shifting significant capacity of their Bayswater and Eraring power stations, respectively, into higher price bands from December 2016. Both participants at least partly reversed these increases from about October 2017 onwards.[9] Similar behaviour by AGL in relation to Pelican Point had followed the closure

[7] ACCC REPI, p.69.

[8] ACCC REPI, p.71.

[9] ACCC REPI, p.77.

of the Northern power station in South Australia in May 2016. The ACCC also observed that the Queensland Government's direction to Stanwell in July 2017 to "place downward pressure on prices" appeared to show a 'stark effect' on Stanwell's bidding behaviour from around that date.

The ACCC concluded its findings on generator bidding behaviour as follows:[10]

> Following the closure of Hazelwood, the behaviour of particular NSW black coal generators appears to be a result of both increases in fuel costs (and fuel supply issues in parts of 2017) and outcomes from an environment where generators can and appear to have acted in a relatively unconstrained manner. This lack of competitive pressure is of concern to the ACCC, particularly given the critical need for a sufficient level of competition in this market to drive affordable electricity prices.
>
> The concentrated nature of the South Australian market has clearly contributed to high price outcomes in that region, particularly when supply conditions in the region have been tight. When supply has been improved, through the return of Pelican Point as well as the introduction of the Hornsdale Power Reserve, there has been downward pressure on prices in the region.
>
> In terms of the Queensland black coal generators, the ACCC considers that analysis of the available information indicates that, in the absence of the direction by the Queensland Government to place downward pressure on wholesale prices, there is very limited constraint on the bidding behaviour of Queensland's black coal generators.

In response, the ACCC made a number of recommendations in relation to the wholesale electricity market including:

- Prohibition on any acquisition or arrangement that would raise a participant's market share above or beyond 20 per cent (Recommendation 1)
- General market manipulation rule – to prevent fraudulent or misleading behaviour intended to distort or manipulate prices, mainly in the future and especially under the NEG (Recommendation 3)
- Australian Government to enter into 'low fixed-price' offtake contracts for the 'later years' of new generation projects that meet certain criteria (Recommendation 4)
- OTC contract disclosure obligation (Recommendation 6)
- Market-making obligations on vertically-integrated firms in South Australia (Recommendation 7)

The question for policy- and rule-makers of the NEM has always been whether trying to regulate what Justice French in 2003 called the exercise of 'transient market power'[11] is worth the cost. The key risk of, say, capping generator bids is that if the regulator gets it wrong and sets the cap too low, generators could choose to withhold their output altogether, potentially leading to load shedding (or blackouts). This would then require the regulator or another party to conduct an in-depth audit to establish whether the generator's reason for not offering its output into the market was genuine. This would constitute a very intrusive, laborious and error-prone process.

Ultimately, the ACCC did not recommend specific market power mitigation rules, echoing the 2013 assessment of the AEMC that such rules "would address the symptoms rather than the underlying cause of market power."[12] The ACCC instead supported structural solutions, although it did recommend a general prohibition on market manipulation in a similar form to the prohibition that applies to gas supply hubs.[13]

10 ACCC REPI, p.87.

11 *Australian Gas Light Company v ACCC (No 3)* [2003] FCA 1525 (19 December 2003), at para 453. See: http://www.australiancompetitionlaw.org/cases/agl.html.

12 ACCC REPI, p.96.

13 ACCC REPI, pp.96-98.

2.2.2 Vertical integration

Chapter 5 of the REPI focused on concerns surrounding wholesale contracting trading in the NEM and the effect of vertical integration. The ACCC highlighted concerns that:

- Vertical integration provides gentailers with cheaper access to wholesale power than smaller retailers; and
- Vertical integration has reduced contract liquidity and lessened the ability of (standalone) participants to effectively manage their risk.

While recognising the efficiency benefits of vertical integration and the variety of ways in which 'liquidity' can be defined and has changed over time, the ACCC nonetheless expressed concern about the prospects of standalone retailers.[14]

The ACCC also sought and examined 'transfer prices' for gentailers – the prices that gentailers effectively price wholesale energy to their own retail arms – and found that:[15]

> The majority of vertically integrated businesses calculate a transfer price based on what they could sell the same electricity for in contracts with third parties. In an economic sense, the retail arms of vertically integrated businesses are paying the 'opportunity cost' of the business's generation capacity. The retailer will therefore be incurring a wholesale electricity cost comparable to a standalone retailer contracting through the market. In these circumstances, the economic benefits of vertical integration are largely accruing to the wholesale arm of the business.

I make three observations on this comment. First, setting transfer prices based on opportunity cost suggests that gentailers are treating standalone retailers on an equal basis to their own retail arms and not seeking to foreclose on rivals. Second, if one were to focus on competition as a process rather than as a situation, one would presumably seek to encourage other participants to make efficiency-enhancing changes (such as vertical integration) so as to promote competition between a larger number of more efficient competitors and raise the likelihood that those efficiencies will be sustainably passed on to consumers through lower retail prices. Third, suggesting that gentailers should pass on a greater share of the efficiency benefits from vertical integration to their own retail customers than to standalone retailers seems inconsistent with recommendations aimed at increasing the viability of the standalone retailer business model.

2.3 Commonwealth Government Consultation Paper

The Commonwealth Government's recent Consultation paper builds on the Government's announcement of 20 August 2018 that it would task the ACCC with, *inter alia*, monitoring wholesale bidding and contract market liquidity in the NEM and provide for enforcement remedies. The list of potential remedies included imposing wholesale contract market-making obligations beyond South Australia and ordering asset or business divestiture.[16]

The Consultation paper seeks comment on how 'prohibited conduct' ought to be characterised in wholesale bidding and contracting. The proposed prohibition in relation to wholesale bidding and conduct is stated as follows:[17]

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14 ACCC REPI, pp.111-114.

15 ACCC REPI, p.125.

16 Consultation paper, p.2.

17 Consultation paper, p.4.

> An electricity generator must not, when making a bid or offer to dispatch electricity, act fraudulently, dishonestly or in bad faith with the purpose of distorting or manipulating prices.

The Consultation paper goes on to describe the objective of the prohibition and seek feedback on two hypothetical examples:

> The objective of this limb is to prevent conduct in the wholesale spot market (in the case of the NEM) or other form of wholesale market (outside the NEM) which is anti-competitive and can lead to an increase in prices which flows through to end consumers. The relevant conduct could involve bidding, or could involve non-bidding behaviour, such as a decision to supply or withhold supply.
>
> The Government is considering how best to distinguish between behaviour which takes advantage of periods of high prices (which, over time, should be a signal to investors) and behaviour which seeks to manipulate or distort prices in a way not intended by the design of the relevant wholesale market.
>
> Stakeholder feedback is sought on the hypothetical example below, including under what circumstances of this sort of conduct should or should not be captured by a prohibition:
>
> • Generator A schedules discretionary maintenance on a power plant to occur during a peak period in order to increase the market price, and increase the revenue received by the other power plants owned by Generator A.
>
> Another hypothetical example that may represent conduct that could be prohibited is where:
>
> • Gentailer A continually bids in significant capacity at a low price in times of relatively low demand incurring significant losses in doing so for a sustained period of time; and
>
> • Gentailer A's purpose is to ensure that a Gentailer B (a rival), which cannot incur the same losses and must bid at a price sufficient to cover its costs, is unable to be dispatched and is driven from the market.
>
> This limb is not intended to interfere with the design and operation of the relevant wholesale market. For example, the NEM wholesale spot market permits rebidding in good faith as it can allow market participants to respond to changing market conditions. Similarly, transient instances of market power can act as a market signal for more investment, stimulating competition.

2.4 Implications for the NEO

One overarching interpretation of the competition concerns expressed in the REPI and the Government's Consultation paper is that even though new generation entry has occurred in the past in response to high wholesale prices, existing generators and gentailers can have and exercise excessive market power, such that prices are higher than they would be otherwise.

To the extent these concerns are supported by recent market outcomes, they would similarly suggest that the NEM is failing to satisfy the NEO. As noted above, the NEO refers to the promotion of efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:

- price, quality, safety and reliability and security of supply of electricity
- the reliability, safety and security of the national electricity system

If participants operating in the wholesale market wield excessive market power, then it is unlikely that investment in the NEM will be efficient, or that consumers face prices that reflect the lowest sustainable costs of delivering reliable and secure power.

The subsequent chapters explore whether, leaving aside the merit of these concerns, technology and other changes over the next decade are likely to address the underlying drivers of these concerns, and in so doing, help the NEM to better satisfy the NEO.

3 KEY FEATURES OF THE NEM AND THEIR IMPLICATIONS

This chapter of the report attempts to discern the underlying economic features of the NEM that differentiate it from textbook models of competitive markets and many real-world markets operating in the economy. In my view, it is the outworkings of these features that have likely contributed to the policy-maker and regulatory concerns discussed in the previous chapter. The discussion in this chapter will provide a suitable context for analysing the implications of emerging and future changes to electricity technology, policy and structure for the future prevalence of the issues that have raised concerns about the market.

3.1 Nature of generation infrastructure

Electricity generating plant has traditionally exhibited a range of features that differentiate it from the supply-side characteristics of many other markets:

- Generators tend to have relatively low operating or variable costs[18] and relatively high fixed costs that are typically largely unavoidable or 'sunk' once an investment has been made.
- Generation plant has traditionally exhibited strong economies of scale, in that the average total cost of output from a given technology tends to fall (in declining order of magnitude):
  - As unit capacity size increases;
  - As the number of units in a power station increases; and
  - As the number of power stations in a portfolio increases.
- Generation plant has traditionally exhibited discreteness or 'lumpiness' of investment options, in that it has only been possible to make investments in certain minimum increments.
- The development of new generating plant has generally involved long lead times. Like other forms of large-scale infrastructure, such as transport and mining infrastructure, it takes considerable time for proponents to obtain planning and environmental consents, secure project financing, and undertake site preparation, development and commissioning.

3.2 Energy-only market design

The NEM is one of the relatively few 'energy-only' wholesale electricity markets around the world. As discussed in Appendix A, an energy-only market is one where investors in electricity supply assets are remunerated solely through the supply of power to the wholesale market at prevailing spot prices and voluntary derivative contracts settled against spot price outcomes. Unlike many markets elsewhere, the NEM does not incorporate a separate capacity market or 'mechanism' that provides investors with a

[18] In this report, the operating or variable cost of production of a generator is assumed to be a single number that excludes start-up costs and any dispatch inflexibilities. This is often referred to in the industry as a generator's short-run marginal cost (SRMC) of production.

separate stream of revenue to help recover the fixed and sunk costs of their plant. There are good reasons to expect an energy-only market to deliver more efficient outcomes than two-market designs.[19]

Nevertheless, the absence of a separate capacity mechanism in the NEM is a significant feature due to the high fixed and sunk costs that generators have traditionally exhibited. In order to recover these fixed costs in an energy-only market, the spot price must be able to at least occasionally rise above the variable cost of the plant with the highest variable costs in the market in order to enable that plant (traditionally, a gas peaking plant) to recover its fixed costs. When this happens, other generators with lower variable costs (such as coal, hydro-electric and many other renewable plant) also receive a price on their output in excess of their variable costs and a contribution towards their fixed costs. If the spot price is higher or remains high longer than necessary to enable existing generators to recover their total (fixed and operating) costs, this provides an incentive to investors to develop more plant. Conversely, if the spot price is insufficient to enable existing generators to recover their fixed costs, investors receive an incentive to not develop more plant and some existing plant may be partly or wholly shut down or ‘mothballed’ until conditions improve (see Part 1 of Appendix A).

The ability of new generation proponents to make investments on the basis of wholesale price signals and physically connect to the grid at minimal cost is a key design feature of the NEM, and it has the effect of placing new entrants on a similar footing to most new entrants elsewhere in the economy. That is, new entrants face relatively low barriers to investment, facilitating a timely investment response to prevailing and expected future periods of high prices. This ‘open access’ model of network connection is not commonplace in electricity markets elsewhere – in part, due to the conflicts that can arise between open access and the operation of separate capacity mechanisms (see Box 1).

[19] For example, see ACCC REPI, p. 41 and Wood, T., Blowers, D., and Griffiths, K. (2017). *Next Generation: the long-term future of the National Electricity Market*. Grattan Institute. (Grattan Institute Next Generation report), pp. 31, 36-37. See: https://grattan.edu.au/report/next-generation-the-long-term-future-of-the-national-electricity-market/.

Box 1: Open access

Unlike many electricity markets elsewhere, the NEM embodies an ‘open access’ philosophy to generation investment, connection and dispatch. New generators are permitted to seek connection to the transmission (or distribution) system and pay only the direct or ‘shallow’ costs of connection. Generators are not required to contribute to the cost of the existing grid or to any network expansions or extensions that they themselves do not request. The *quid pro quo* for open access is twofold. First, generators have no right to be dispatched in accordance with their position in the dispatch merit-order (which arranges participant bids and offers from lowest to highest and selects the cheapest first) and will typically have their output limited if and when applicable network constraints bind. Second, transmission network augmentation is determined in a centralised manner on the basis of an overall system cost minimisation criterion that place no value on the dispatch of individual generators *per se*.

By contrast, the Western Australian wholesale electricity market and most markets in the United States do not allow generators to connect without meeting various technical requirements and paying ‘deep’ augmentation costs. In these markets, generators seeking connection need to wait for the system operator to perform power flow analysis to ascertain the effect of the new generator on transmission constraints. This leads to a connection ‘queue’ being formed, which – combined with higher connection charges – imposes considerable delays and costs on new entry.

Part of the reason for the connection and queuing policies adopted in such markets is the role of separate capacity mechanisms. If the system operator is relying on a specific generator to be dispatched at peak times to meet demand, the system operator needs to be confident that the network will not constrain the output of that generator under peak loading conditions. This particular issue does not arise in the NEM because generators are not paid for their output unless and until they are dispatched, and transmission planning is undertaken on the basis of ensuring that sufficient energy will be available – from any generator anywhere across the NEM – to meet demand across the system to the extent necessary to satisfy the NEM reliability standard (see below).

3.3 Highly inelastic demand and the need for a MPC

Another key feature of the NEM and most other electricity markets to date has been the highly unresponsive or ‘inelastic’ nature of real-time electricity demand. Very few electricity customers participate directly in the wholesale market, although some have arrangements with retailers to curtail demand at times of high spot prices.[20] Most customers face retail prices that tend to involve flat usage-based charges. Even when customers face time- or demand-based tariffs, the applicable rates typically do not change in line with prevailing spot market outcomes. Yet the secure operation of a power system requires, *inter alia*, the maintenance of a stable system frequency, which in turn requires electricity supply to precisely equal demand at all times. Indeed, if there is insufficient supply to meet demand for even a few moments, there may be no price at which the market will clear. In these circumstances of ‘market failure’, the market and system operator will be required to shed load involuntarily and set a

[20] For example, AGL has a commercial agreement in place with the Tomago smelter that gives AGL flexibility to manage its customer load during plant outages in exchange for Tomago receiving commercial benefits. See: https://www.agl.com.au/about-agl/media-centre/asx-and-media-releases/2017/february/agl-and-tomago-agreement-in-place-to-curtail-electricity.

price for the remaining transactions that are able to take place. For these reasons, the NEM incorporates a market price cap (the 'MPC', formerly the 'Value of Lost Load' or 'VoLL'), at which the spot price is set if supply cannot meet demand. The MPC is presently $14,500/MWh, which is well above the operating costs of any plant in the NEM.

The MPC is set at a level designed to ensure that generators – particularly peaking generators – are able to recover both their variable and fixed costs over those short periods when supply is insufficient or barely sufficient to meet demand. This is designed to encourage enough generation investment to ensure that periods of involuntary load shedding are relatively rare. Specifically, the NEM reliability standard is a maximum level of unserved energy (USE) in a region of 0.002 per cent of the total electricity demanded in that region for a given financial year.[21] The higher the MPC is set, the more generation and demand response is likely to be viable and hence the less involuntary unserved energy could be expected to result. In order to achieve this objective, the MPC is reviewed by the AEMC Reliability Panel every four years.

In equilibrium, an energy-only market in which participants behave in a price-taking (highly competitive) manner should not only yield levels of unserved energy and installed generation capacity consistent with meeting the NEM reliability standard at least cost, it should also produce an efficient technology mix of plant (see Part 2 of Appendix A).

3.4 Pricing and structural implications of NEM features

The unique features of the NEM as an energy-only electricity market have hitherto differentiated it from most other markets in the economy in relation to its implications for both pricing outcomes (in the short and longer terms)[22] and structural (contracting and integration) outcomes.

3.4.1 Short term pricing implications

In the very short term, even small deviations from pure price-taking conditions can result in large (transient) price spikes. Under pure price-taking, the wholesale spot price should remain relatively low (at or below the variable costs of peaking plant) unless load shedding is occurring. However, at times of very high market demand, if even one or a small number of generators refrain from offering all of their available output or raise their offer prices towards the MPC, the spot price may spike several orders of magnitude above pure price-taking levels. This is a point frequently made by the Australian Energy Regulator (AER) in its reports of conditions when NEM spot prices exceed $5,000/MWh.[23]

This extreme sensitivity of wholesale prices to supply and demand is a phenomenon that is not widely observed in any other substantial market in the economy. In general, the ability and incentive for a

[21] See: https://www.aemc.gov.au/energy-system/electricity/electricity-system/reliability.

[22] 'Longer term' here refers to a period of months or years, which may not be sufficient for traditional forms of supply-side capacity to be augmented or commissioned. This differs from the economic concept of the 'long run', in which all inputs are flexible.

[23] For example, in relation to high prices in Victoria and South Australia on 19 January 2018, the AER said: "On 19 January maximum temperatures in Melbourne and Adelaide exceeded 40°C, leading to high demand for electricity and forecast high prices. While demand for electricity was high in both the South Australian and Victorian regions, it was not near record levels. In South Australia the spot price reached $11 864/MWh at 2.30 pm, $13 408/MWh at 3 pm, $5413/MWh at 5 pm and $5332/MWh at 6 pm. The spot price exceeded $5000/MWh only once in Victoria, reaching $10 152/MWh at 2.30 pm. The vast majority of capacity in both regions was priced in very low price bands, a small amount in very high price bands and almost no mid-priced capacity. As a result, small increases in demand at the top end of low priced capacity had the potential to lead to high prices. This was essentially the major contributing factor behind the high price outcomes." See AER, *Electricity spot prices above $5000/MWh, Victoria and South Australia, 19 January 2018*, 20 March 2018, available at: https://www.aer.gov.au/wholesale-markets/market-performance/prices-above-5000-mwh-19-january-2018-vic-and-sa.

generator to strategically withhold potential output increases with the size of the participant's portfolio, as the size of the revenue 'payoff' from higher prices increases.

Other electricity market designers have responded to the risk of this type of behaviour by imposing bidding rules or caps of one form or another. However, Australian designers have long resisted these types of measures for several reasons:[24]

- Bid-capping rules are intrusive and complicated to design and apply, and raise the risk that they could deter investment if set too low.
- Many of the markets in which these rules are imposed have two-market designs, such that the risk of deterring investment is mitigated through the returns available from a separate capacity market.
- If barriers to new generation entry are relatively low, then new entrants will respond to higher prices by investing sooner and driving prices down.
- Structural solutions – namely, horizontal disaggregation – are preferable to behavioural conditions. This view was restated by the ACCC in the REPI (see section 2.2.1 above).
- Since NEM start, market designers have been hopeful that increased demand-side response could mitigate generators incentives to engage in non-price-taking behaviour in the energy-only NEM.

Regarding the last of these points, the ACCC made the following comments in its 1997 National Electricity Code Authorisation determination:[25]

> The other aspect that must be developed in conjunction with action on structure is the need to develop demand side flexibility. The larger the demand uncertainty faced by generators relative to capacity, the more likely it is that all generators will have an incentive to bid aggressively because they face the prospect of being left out of the market during that trading period. However, the responsiveness of the demand side is likely to increase in the longer term.

3.4.2 Longer term pricing implications

The second way in which the features of the NEM have traditionally differentiated its pricing outcomes from other markets is that even under conditions of highly competitive bidding, periods of relatively elevated and depressed average wholesale prices can persist for extended periods – often, several years. This is due to the characteristics of electricity supply infrastructure and electricity demand discussed above:

- ***Low operating and high fixed and sunk costs*** – which contribute to barriers to entry and exit.
- ***Strong economies of scale*** – imply that in an environment in which demand is rising only gradually, it will often be efficient to wait longer to invest than in the absence of these economies.
- ***'Lumpiness'*** – means that the market may experience alternating periods of insufficient and excess supply, with the short run operating profits of plant oscillating from much higher-than-necessary to recover fixed costs to zero.[26]

[24] For example, see AEMC, *Final Rule Determination, Potential Generator Market Power in the NEM*, 26 April 2013, available at: https://www.aemc.gov.au/rule-changes/potential-generator-market-power-in-the-nem.

[25] ACCC, *Applications for Authorisation, National Electricity Code*, 10 December 1997 (ACCC Code Authorisation), p.103, available at: https://www.accc.gov.au/public-registers/authorisations-and-notifications-registers/authorisations-register/national-electricity-code-mark-i.

[26] Electricity economist, Steve Stoft provides the following example: if baseload plant can only be built with a capacity of 1000 MW and peakers can only be built with a capacity of 100 MW, then if peak demand in the market is 7,750 MW, for an assumed set of costs and load profile, the optimal plant mix is six baseload plant and 19.75 peakers. In this context, he says, "Building 19 peakers would result in supply being short of demand for a duration 4 times greater than is optimal (2.5% instead of 0.62%), and this would cause peakers to over-recover fixed costs by a factor of four. These high profits would entice the entry of another peaker which would drop short-run profits to zero. This would stop entry as demand grew. With free entry and the uncertainties of a real market, short-run profits would average out to the level of fixed costs. But lumpiness would prevent the right

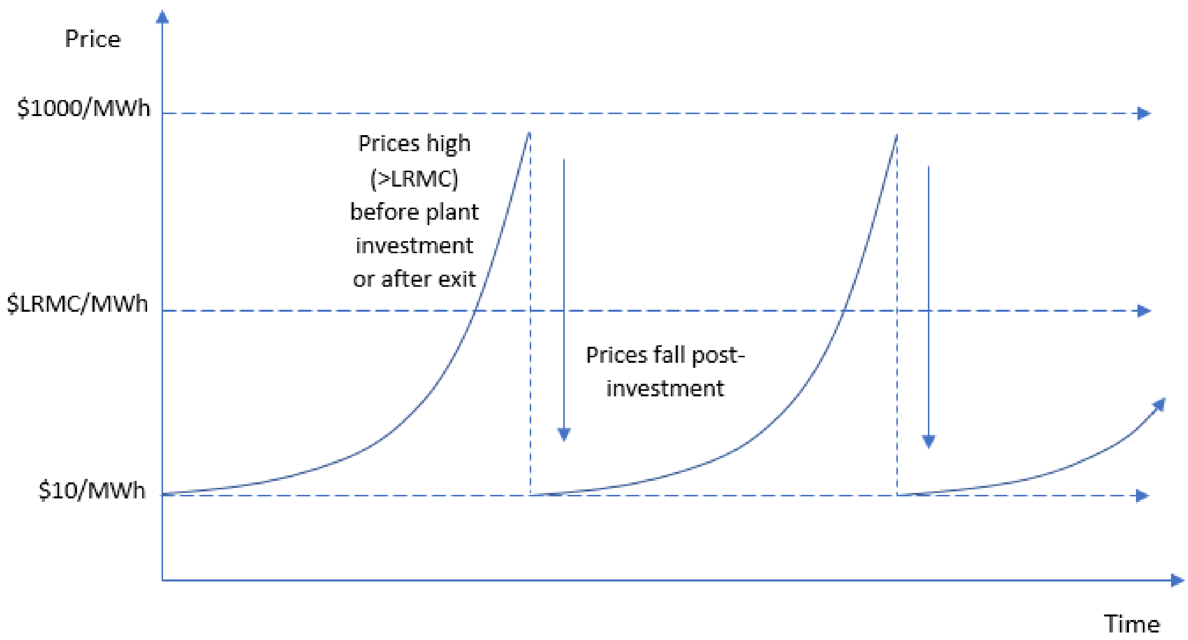
- ***Long lead times*** – the longer it takes to commission new plant, the longer that periods of insufficient supply may persist. Conversely, plant can be mothballed or retired relatively quickly, which can limit the duration of periods in which excess supply persists.
- ***Inelastic demand*** – while not almost completely inelastic as in the short run, electricity demand is still relatively inelastic in the longer term, contributing to sustained periods of high or low prices.

Taken together, these factors mean that prior to a generation investment being made (or after a major plant has been retired), average spot prices will tend to be higher than the long run equilibrium average price; and prices will be lower than the long run equilibrium in the period following an investment.

Figure 5 below shows how an energy-only market such as the NEM can exhibit a multi-year ‘cycling’ of average spot and contract prices under historically conventional conditions of rising demand and no major plant exits:

- In the period (which may be several months or years) prior to a new generation investment, average prices will be above the long run marginal cost (LRMC) of supplying market demand;
- Immediately after a large lumpy investment, average prices will be below LRMC; and
- If demand is rising over time, prices should gradually rise back towards and beyond LRMC.

Figure 5: Conventional price cycles in an energy-only market



Source: Frontier Economics

In the more recent scenario we have been observing in the NEM of RET-driven investment helping to trigger sporadic major plant exits, the dynamics of price-cycles are almost reversed, appearing more as they do in **Figure 6**.

(fractional) number for peakers from being built, and this would cause some inefficiency.” See Stoft, S., *Power System Economics, Designing Markets for Electricity*, IEEE Press 2002, p.131.

Figure 6: Recent RET-driven price-cycle dynamics

Source: Frontier Economics

It is important to note that given traditionally characteristic strong economies of scale, lumpiness and long lead times for generation development, such cycling of average prices is perfectly consistent with competitive and efficient participant behaviour and market outcomes.[27] However, the amplitude of such cycles can be exacerbated where existing participants are not pure price-takers and where barriers to entry to new generation investment are high, such as under the following circumstances:

- If incumbent generators have a high market share (as a result of benefitting from economies of scale), they may have a reduced incentive to invest because the subsequent 'collapse' in wholesale prices can substantially curtail their expected returns (although, in reality, incumbents in the NEM have invested with reasonable alacrity in the past and continue to do so).[28]
- Even new entrants might not find it worthwhile to invest given that entry requires high sunk costs to be incurred and can cause post-entry prices to fall significantly.
- The post-entry fall in prices also means that customers have a reduced incentive to invest in generation or demand-side response (DSR) themselves, because other customers who do not contribute to the new investment also benefit from lower prices (free-rider effects).

The recommendations in the ACCC's REPI and proposals in the Government's Consultation paper – and more generally, the sense that ordinary competition law is believed to be unsuitable and sector-specific rules for the NEM are necessary – seem to reflect a degree of frustration with the performance of the energy-only market, particularly over these longer time periods.

[27] For example, agricultural markets – in which producers (farmers) typically behave in a pure price-taking manner – can exhibit volatile 'cobweb' patterns of prices and volumes due to lags in the adjustment of supply (crops) to demand. See: https://en.wikipedia.org/wiki/Cobweb_model.

[28] See Part 2 of Appendix A on the drivers for the Somerton and Hallet OCGT plant.

3.4.3 Structural implications

The in-built short- and longer-term volatility of wholesale prices in an energy-only market such as the NEM has its own implications for the way market participants choose to structure their businesses.

Generators and retailers operating in the NEM are typically exposed to complementary risks:

- Generators are exposed to the risk that the (volatile) wholesale prices they are paid for their output may not be sufficient to finance their fixed and sunk costs and earn a reasonable profit; while
- Retailers and large customers are exposed to the risk that the price they pay for wholesale power will exceed the typically fixed[29] price they receive, respectively, from their customers or for their output.

The complementary nature of these risks mean that generators and retailers engage in either or both the following risk allocation activities:

- ***Purchase or sale of financial derivative contracts*** – that are settled against regional spot prices. NEM participants usually enter derivative contracts to hedge (rather than extend or speculate on) their natural spot price exposures. Accordingly:
  - Since generators have a natural long[30] exposure to the spot price, generators generally sell derivative contracts to hedge or offset their natural exposure.
  - Likewise, since retailers and large industrial customers have a natural short exposure to the spot price, these parties typically purchase derivative contracts to offset their natural exposure.
- ***Vertical integration*** – to provide an internal or 'physical' hedge against spot price risk. Vertical integration can consist of any of the following:
  - Acquisition of existing generation or retail assets
  - Establishment or development of new generation or retail assets or activities
  - Acquisition of rights to the outputs or cash flows of generation or retail activities, such as through Power Purchase Agreements (PPAs).

A key advantage of vertical integration over contracting is that vertical integration avoids or reduces the transaction costs associated with a generator or retailer/large customer needing to negotiate or trade derivative contracts on a regular basis to hedge its spot price exposures. Such costs can include:

- Operating and maintaining (as large) a trading team
- Meeting additional prudential requirements or providing additional credit support to counterparties
- Potentially paying higher prices for hedging due to significant counterparties or potential counterparties 'holding-up' contract (re)negotiations.

As noted in section 2.2.2 above, the ACCC in its REPI report acknowledged that vertical integration could offer efficiency benefits.

The remainder of this report considers the extent to which recent and forthcoming changes to technology, market architecture and the supporting infrastructure are likely, over time, to minimise the differences between the NEM and other more 'normal' markets that have given rise to the concerns recently expressed.

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[29] 'Fixed' in this context refers to fixed with respect to the wholesale electricity price.

[30] 'Long' in this context refers to financially benefitting from a rise in the price of the underlying commodity (here, wholesale electricity). 'Short' has the opposite meaning.

4 TECHNOLOGY AND POLICY CHANGES

This chapter outlines the nature of changes to technology, market architecture and structural features of the NEM that are occurring or can be reasonably anticipated over the next decade.

4.1 Changes to generation & storage infrastructure

The previous chapter discussed the technical and economic characteristics of traditional electricity generation infrastructure that have contributed to short- and longer-term price volatility in the NEM. This section discusses how many of these characteristics have changed and are likely to continue changing and the likely implications for the future plant mix of the NEM.

More detail on existing generating plant types and sizes, likely future trends in plant technology and cost characteristics, and the potential future NEM plant mix is provided in Appendix B.

4.1.1 Historical trends in plant technologies, unit and station sizes

The S&P World Electric Power Plants Database (WEPP) database[31] is a worldwide inventory of generator technology investment decisions from 1960 to the present day. The WEPP provides interesting insights into historical trends in centralised generation investment around the world.

Focussing on 5 key countries (Australia, Canada, the United States, Germany and China), some of the most salient features are:

- Coal-fired and gas steam turbines, and to a lesser extent, hydro power stations are the largest generators built in each of countries examined, with unit sizes in Australia in the 250-750 MW range and station sizes of at least 500 MW.
- The number of coal-fired power stations built in developed countries has decreased in recent years.
- In Australia and the USA, coal-fired generator sizes have been falling, with the trend flat or mixed elsewhere.
- The trend in coal plant unit sizes appear to be falling in Australia and Canada, while rising in China and mixed elsewhere.

Appendix B provides more details.

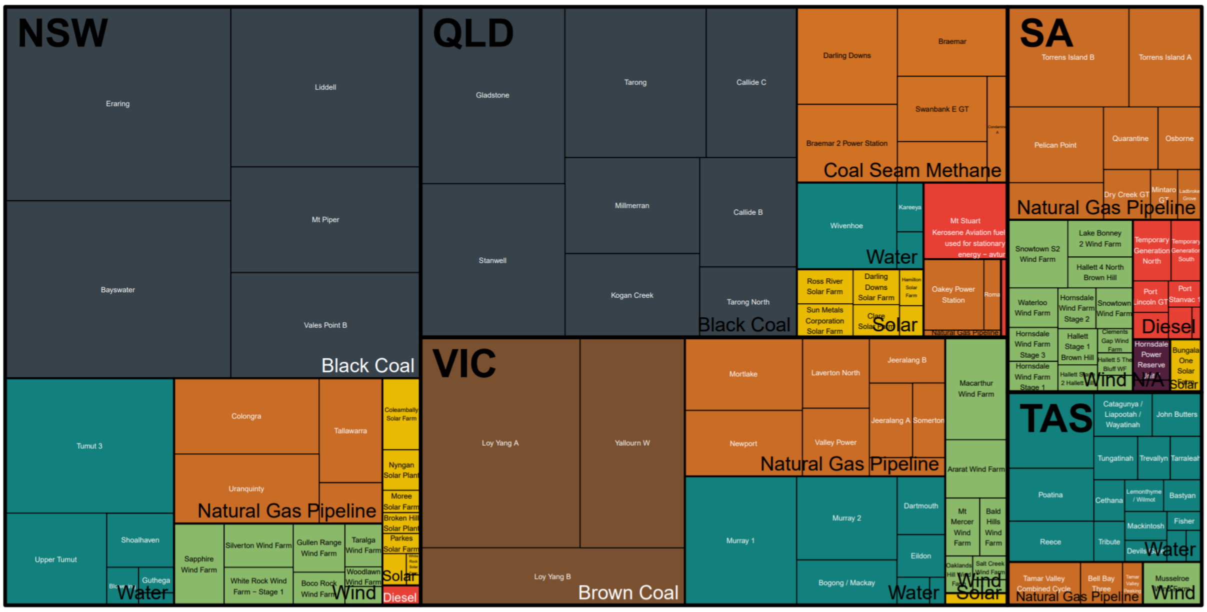
4.1.2 Current large-scale generation mix in the NEM

In spite of several recent coal-fired generator retirements, large coal-fired power stations in New South Wales, Queensland and (to a lesser extent, after the closure of Hazelwood) Victoria dominate the NEM energy mix, with the remaining generation stock consisting of smaller stations fuelled by gas, wind, solar and liquid fuels (**Figure 7**). The current dominance of coal plant is even more pronounced when considering relative output shares of different plant (**Figure 8**).[32]

[31] S&P Global Market Intelligence World Electric Power Plants Database – see: https://www.platts.com.es/products/world-electric-power-plants-database.

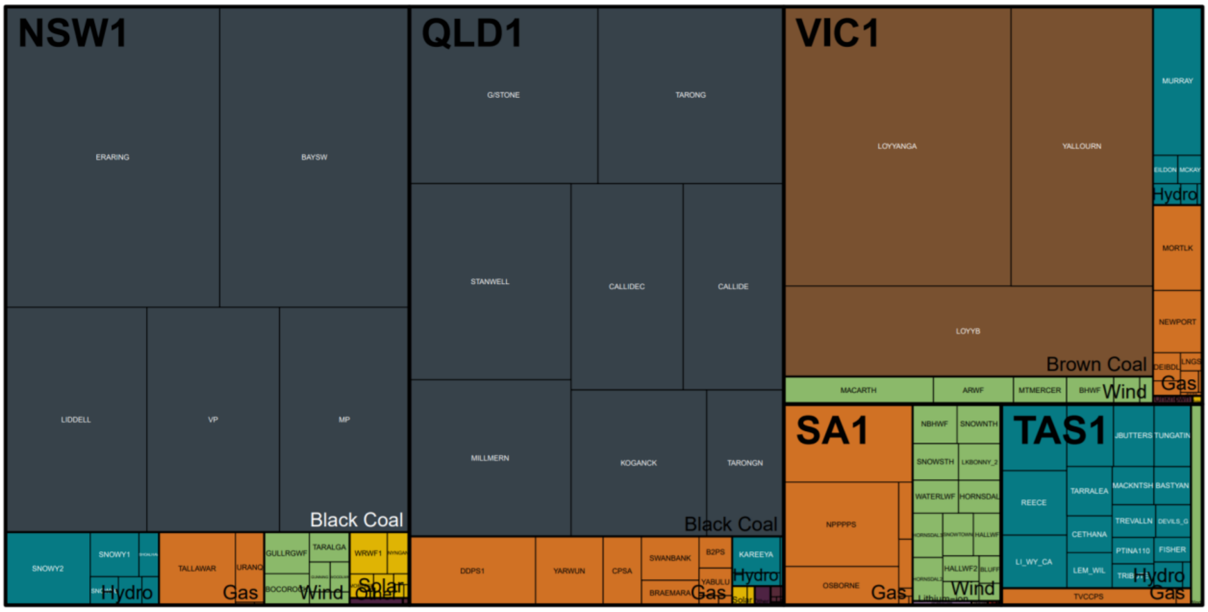
[32] Both Figures have been reproduced from Appendix B.

Figure 7: NEM station capacity by region and fuel type



Source: Frontier Economics analysis of AEMO data (generation information 2 November 2018)

Figure 8: NEM station output by region and fuel type



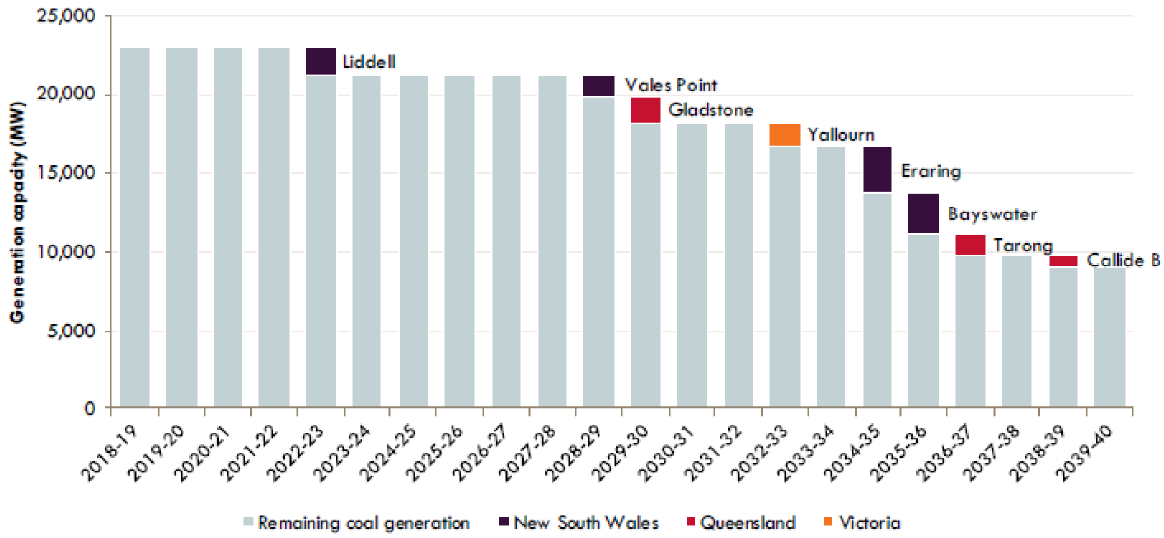
Source: Frontier Economics analysis of AEMO data (MMSDM)

Projected coal-fired plant retirements

Despite its present dominance of the NEM plant capacity and output mix, the overall level of coal-fired generation capacity has peaked and is likely to diminish in future decades due to ongoing plant retirements. **Figure 9** below shows the current stock of NEM coal-fired power stations and when they are due to be decommissioned according AEMO's Integrated System Plan (ISP).[33] Substantial retirements are due in the 2030s, and are unlikely to be replaced with new coal. In our view, it is possible that some of these retirements (e.g. Yallourn) may be brought forward into the 2020s.

Figure 9: AEMO ISP projections of coal-fired power station retirements

Figure 2 **NEM coal-fired generation fleet operating life to 2040, by 50th year from full operation or announced retirement**



Source: AEMO ISP, p.22.

4.1.3 New energy technologies and costs

New energy technologies include all of the following types of infrastructure:

- Large-scale wind plant
- Rooftop solar PV units
- Solar thermal plant
- Small-scale ('behind the meter') and large-scale (grid-connected) storage, including batteries and pump storage
- Energy management systems.

As discussed in the ACCC REPI report, virtually all additions to the NEM's stock of generation in recent years have involved renewable plant. The REPI notes that:[34]

> Of around 2500 MW of new generation investment over the past six years, well over 90 per cent has been in renewables. Since 2013, no material thermal generation has been added to the market.

The pace of investment in renewable generation has increased since the resolution of the Commonwealth RET in mid-2015:[35]

[33] AEMO, *Integrated System Plan for the National Electricity Market*, July 2018 (ISP), Figure 2, available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan.

[34] ACCC REPI, p.46.

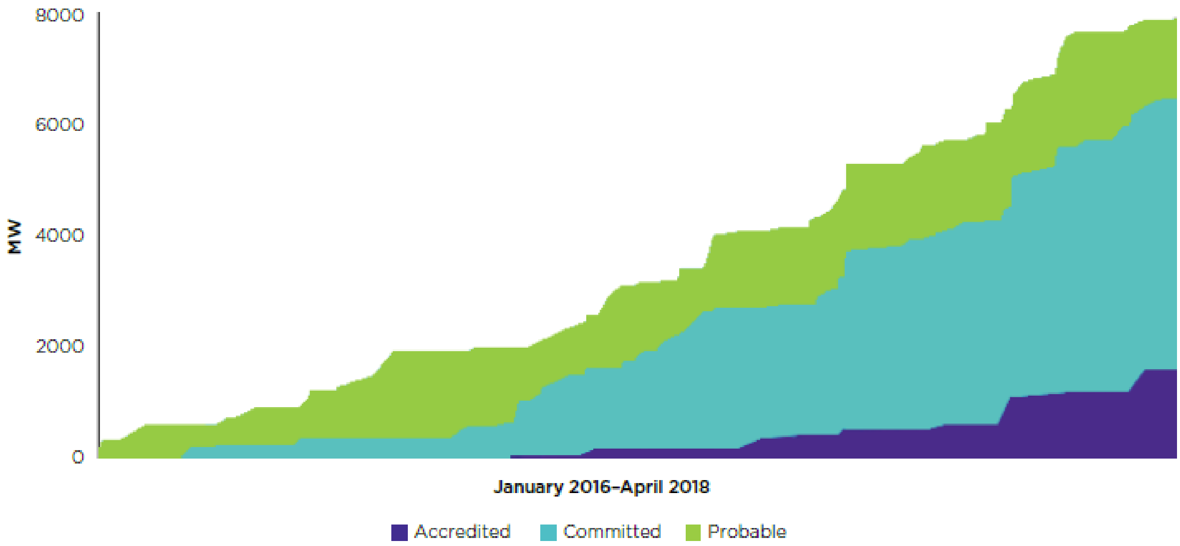
[35] ACCC REPI, p.46.

> As at March 2018, nearly 90 per cent of the 4400 MW of committed generation investment coming into the NEM is either wind (2032 MW) or solar PV (1877 MW).30 A similar percentage of the 45000 MW of proposed projects in the NEM are also renewables (39 per cent wind, 38 per cent solar and 11 per cent hydro), with the remainder mostly gas plant.

See also **Figure 10** below.

Figure 10: Recent trend in renewable energy project developments

Figure 2.5: Renewable energy project developments from January 2016 to April 2018



Source: Clean Energy Regulator.

Source: ACCC REPI, p.46.

Evidence on lumpiness and scale economies for new technologies

A 2015 study by CO2CRC[36] found that lumpiness and economies of scale for renewable technologies are far less significant than for large fossil-fuelled power stations. This lack of both features applies at both the unit level and the overall plant or station level.

For example, wind turbines investigated in the study consist of 3 MW turbines, with farm sizes of 50 MW and 200 MW, reflecting the availability of much smaller capacity increments than traditional technology types. Further, wind exhibited fairly modest economies of scale by the standards of traditional fossil-fuelled plant, as demonstrated by the following plant costs:

- Capital cost (sent-out):
  - 50 MW: $2,550 / kW
  - 200 MW: $2,450 / kW
- Operating and maintenance (O&M) cost (per annum):
  - 50 MW: $60 / kW
  - 200 MW: $55 / kW

[36] Wiley, D., Neal, P., Ho, M. 2015, Fimbres Weihs, G., Australian Power Generation Technology Report, CO2CRC, CSIRO, ARENA, Office of the Chief Economist (Federal Department of Industry and Science) and anlecr&d (CO2CRC et al (2015)). See Appendix B.

These figures indicate that potential investors in wind generation face relatively weak incentives to invest in large and expensive projects, and hence are likely to face fewer financing and other barriers to investing.

CO2CRC also evaluated solar PV at residential (5 kW), commercial (100 kW) and utility-scale (10 MW and 50 MW) sizes, with utility-scale plant assessed with fixed, single-axis and dual-axis mounts. In all cases, economies of scale were again fairly limited:

For fixed module mounting:

- Capital cost (sent-out):
  - 5 kW: $2,100 / kW
  - 100 kW: $1,950/ kW
  - 10 MW: $2,400 / kW
  - 50 MW: $2,300 / kW
- O&M cost (per annum):
  - 5 kW: $30 / kW
  - 100 kW: $30 / kW
  - 10 MW: $30 / kW
  - 50 MW: $25 / kW

For utility-scale dual-axis module mounting (which offers the highest capacity factors):

- Capital cost (sent-out):
  - 10 MW: $3,600 / kW
  - 50 MW: $3,400 / kW
- O&M cost (per annum):
  - 10 MW: $45 / kW
  - 50 MW: $40 / kW

This relatively wide spread of available capacity increments combined with gently-declining slopes of renewable energy average cost curves is likely to promote the recent trend of smaller, geographically diverse and independently-owned renewable power stations (see below). This, in turn, will help reduce the importance of existing retail market positions in helping to support or underwrite new capacity additions, thus lowering barriers to entry and expansion.

Projected changes in new technology costs

Generation

Recent research produced by the CSIRO highlights the falling costs of new generation technologies.[37] Hayward & Graham (2017) developed cost projections for a range of both conventional and new technologies out to 2050 taking into account 'learning effects' – which reduce deployment costs – and modelled costs under two scenarios: 2 degrees (formerly 450 ppm) and 4 degrees (550 ppm) warming. Selected projections for the latter scenario are provided below (see also Appendix B). As the figures show, less developed renewable technologies (solar PV and solar thermal) are still expected to benefit

[37] Hayward, J.A. and Graham, P.W. 2017, *Electricity generation technology cost projections: 2017-2050*, CSIRO, Australia (Hayward & Graham (2017)), available at: https://publications.csiro.au/rpr/download?pid=csiro:EP178771&dsid=DS2.

from substantial learning effects and cost reductions over time. However, given the relative maturity of wind technology, the unit costs of wind are not expected to fall significantly.

Figure 11: Solar thermal, wind and solar PV cost projections

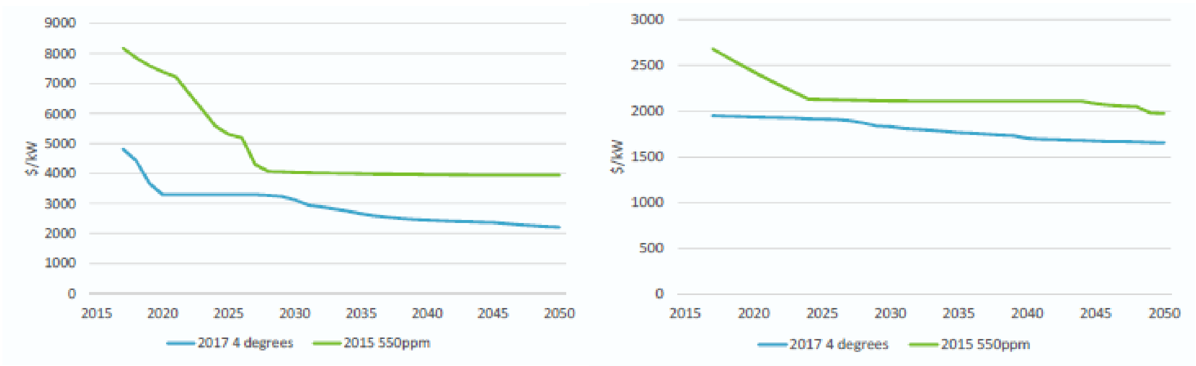


Figure 3-3: Solar thermal with 6 hours storage (left) and wind (right)

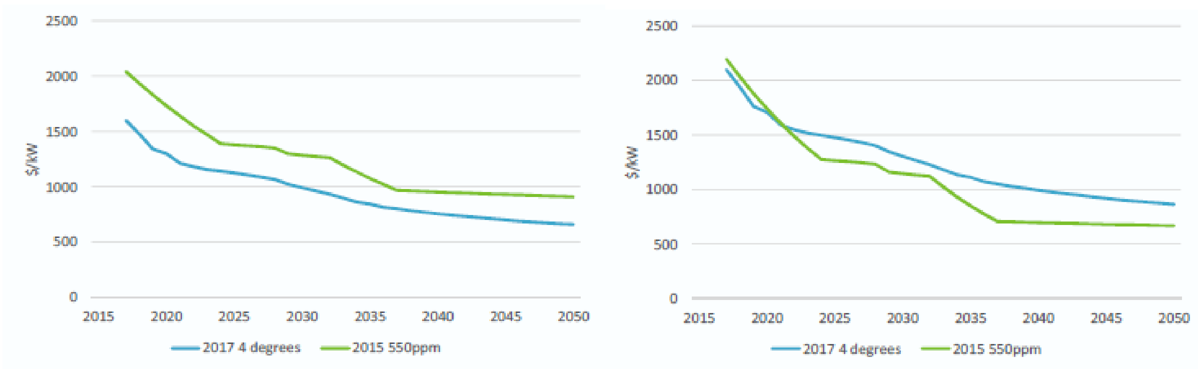


Figure 3-4: Rooftop solar photovoltaics (left) and large scale solar photovoltaics (right)

Source: Hayward & Graham (2017), p.9.

The cost projections for rooftop solar PV and batteries (see below) were updated in 2018 in Graham et al (2018).[38] See also Appendix B.

Traditional generation technologies were not expected to not exhibit anything like the same cost reductions.

[38] Graham P.W., Wang D., Braslavsky, J., and Reedman L.J. 2018. *Projections for small-scale embedded technologies, Report for AEMO*, CSIRO, Australia (Graham et al (2018)), available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2018/Projections-for-Small-Scale-Embedded-Technologies-Report-by-CSIRO.pdf.

Batteries

Battery storage is projected to benefit from continued learning-based cost reductions in the near term. Of all the technologies discussed, storage is the most modular, has very short lead times and economic lifespan, which reduces long term investment risk and lowers barriers to investment.

Hayward & Graham (2017) also projected future costs of batteries, finding even more rapid reductions were likely than previous bullish forecasts (see **Figure 12**). While battery costs are projected to fall rapidly and substantially, balance of plant costs (referring to the required parts of the station excluding the battery itself) are significant and benefit less from learning. This will slow overall cost reductions of the technology.

Figure 12: Battery-only cost projections: 2017 update and previous projections, 2017 $A

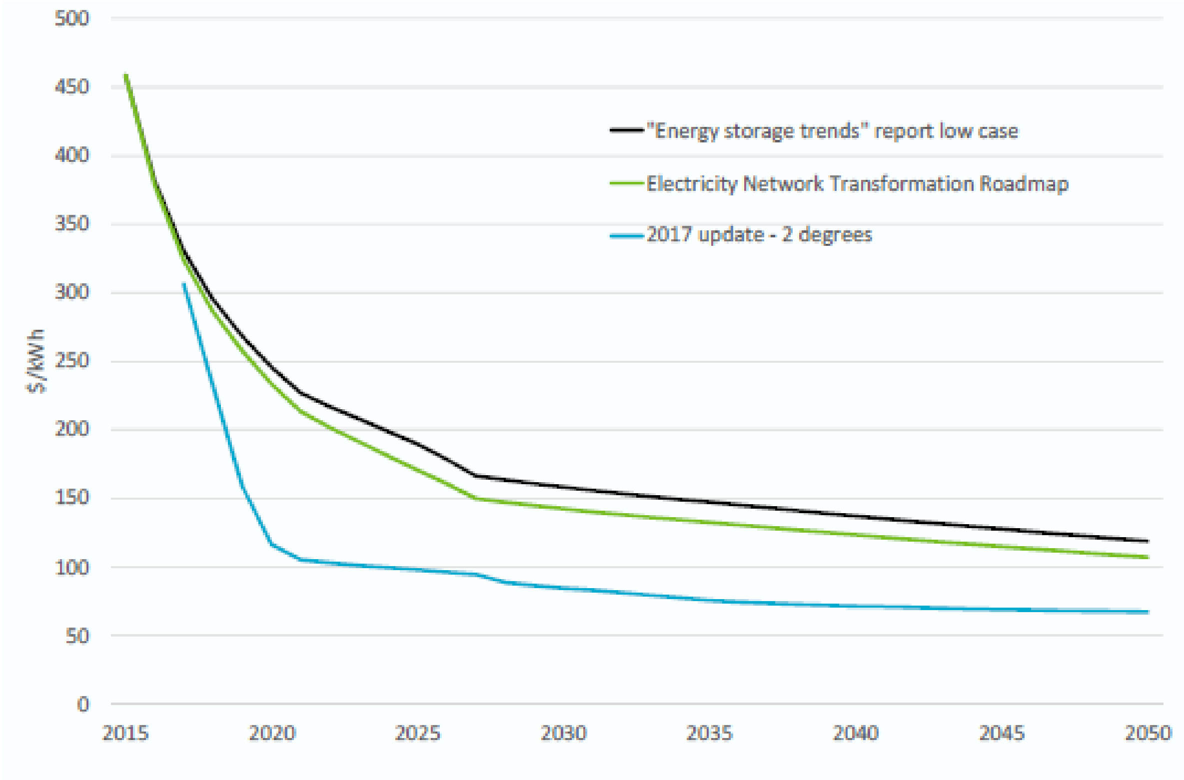


Figure 3-12: Comparison of battery only cost projections: 2017 update and previous projections, 2017 AUS dollars

Source: Hayward & Graham (2017), p.14.

CSIRO published updated cost projections for batteries – including balance of plant costs – in 2018.[39] See also Appendix B.

4.1.4 Projected changes in generation plant mix

The trends discussed above suggest that reductions in costs, economies of scale and lumpiness of generating plant will continue to occur over the next decade. However, these reductions will largely be driven by an ongoing shift in the *types* of technology investors favour, rather than taking place within

39 Graham et al (2018).

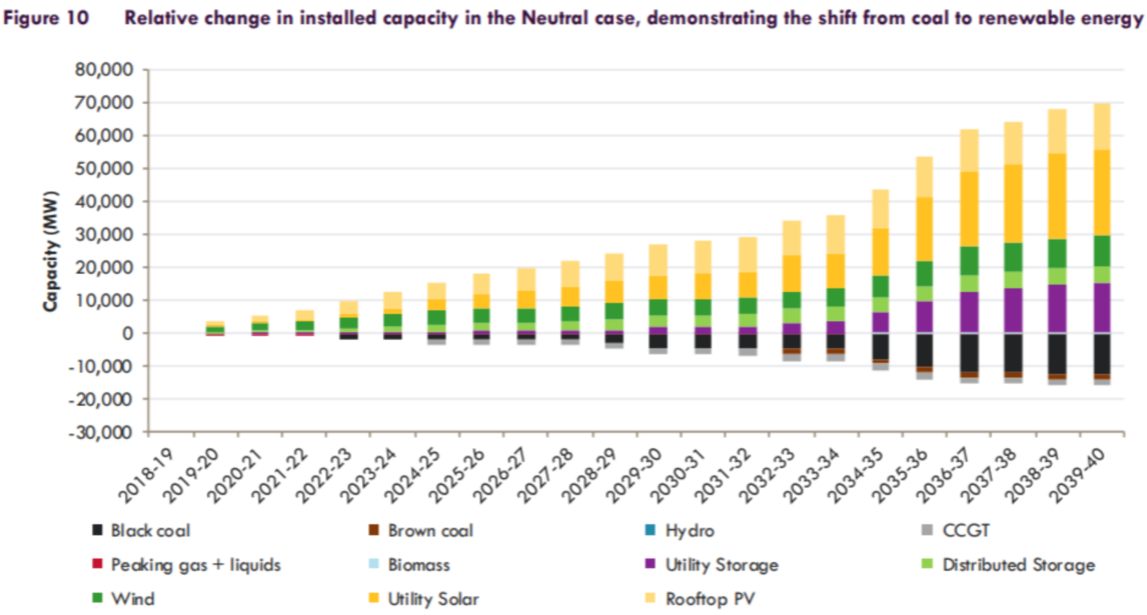
traditional types of generation. In short, new plant investment is likely to exhibit the following changes in characteristics relative to historical patterns of plant development – new plant will tend to reflect:

- Renewable and storage technologies rather than fossil-fuelled technologies; and
- Smaller economies of scale and smaller capacity increments, which combined with shorter development lead-times should result in more 'right-sized' and timely additions to the stock of plant than previously.

Having regard to changing generation cost structures and trajectories of demand growth, federal and state environmental policies and their financing implications, and planned transmission expansions (see below), generation investment in the NEM and the overall NEM plant mix is likely to be substantially different in a decade's time than it is now. Investment in new coal-fired power stations and more generally steam turbines is unlikely to be substantial. As in recent years, generation investment is likely to be dominated by many relatively small utility-scale wind and solar projects, with a continuing steady uptake of residential solar PV. In addition, it is likely that a substantial quantity of battery storage will be required, even if Snowy 2.0 proceeds.

Figure 13 reproduces Figure 10 from AEMO's ISP, which shows the relative changes in installed capacity in the 'Neutral' planning scenario relative to the present generation mix over the next 20 years. It highlights the growth in both rooftop PV and utility solar (solar thermal), as well as the ongoing growth of wind, and the beginnings of significant investment in distributed and utility-level storage.

Figure 13: AEMO ISP projections of changes in plant mix



Source: AEMI ISP, p.38.

4.2 Transmission expansion

As noted in Box 1: transmission expansion in the NEM has traditionally been undertaken according to an overall system cost minimisation criterion. This criterion has been applied by jurisdictional transmission businesses on a project-by-project basis. However, following from the recommendations of the 2017 Finkel Review,[40] AEMO published its initial ISP in July 2018.

The ISP recommends a large number of transmission investments in three tranches, depending on how urgent AEMO considers them to be. The first tranche (Group 1) comes at a cost of $450-650 million and includes:

- Increase transfer capacity between New South Wales, Queensland, and Victoria by 170-460 MW.
- Reduce congestion for existing and committed renewable energy developments in western and north-western Victoria.
- Remedy system strength in South Australia.

The second tranche (Group 2) is designed to be completed by the mid-2020s to support new ‘renewable energy zones’ or ‘REZs’ and consists of:

- New transfer capacity between New South Wales and South Australia of 750 MW (RiverLink).
- Increased transfer capacity between Victoria and South Australia by 100 MW.
- Increased transfer capacity between Queensland and New South Wales by a further 378 MW (QNI).
- Connecting renewable energy through the above developments.
- Coordinating distributed energy resources (DER, primarily solar PV and batteries) in South Australia.

The third tranche (Group 3) is designed to support REZs and system reliability and security and is to be undertaken by the mid-2030s and beyond.

4.3 Better access to wholesale prices via the internet, ‘smart’ software and DER optimisation

Developments in communications technology have enabled tariffs and services previously restricted to large energy consumers to be offered to the mass market. Type 4 (‘smart’) meters measure electricity consumption at periodic intervals (typically 30 minutes) and remotely report readings, removing the need for manual meter reads. Smart meters were rolled out in Victoria between 2009 and 2015 under state regulations[41] and are gradually being installed in other NEM regions principally via opt-in and new-and-replacement meter policies. Smart meters enable network businesses and retailers to set tariffs with more sophisticated and cost-reflective charging bases than anytime consumption.

The AEMC made a rule change in late 2014 that imposed more prescriptive obligations on distribution networks to set cost-reflective network tariffs.[42] As a result, most distribution networks now offer optional time-of-use and maximum demand tariffs to residential and small business customers, and many businesses are moving to mandatory or opt-out assignment of cost-reflective tariffs to new customers, as well as existing customers installing or changing solar PV or battery units.[43]

[40] *Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future*, Commonwealth of Australia 2017 (Finkel Review), Recommendation 5.1, p.124.

[41] See: http://www.smartmeters.vic.gov.au/about-smart-meters/reports-and-consultations/advanced-metering-infrastructure-cost-benefit-analysis/2.-background#.

[42] AEMC, *Rule Determination, National Electricity Amendment (Distribution Network Pricing Arrangements) Rule* 2014, 27 November 2014, available at: https://www.aemc.gov.au/rule-changes/distribution-network-pricing-arrangements.

[43] AEMC, *Economic Regulatory Framework Review, Promoting Efficient Investment in the Grid of the Future*, 26 July 2018, section 7.3.2 and Table 7.2, pp.110-112, available at: https://www.aemc.gov.au/markets-reviews-advice/electricity-network-economic-regulatory-framew-1.

Importantly, for the purposes of this report, traditional time-of-use (ToU) and demand (and even critical peak pricing or CPP) tariffs do not necessarily imply a greater elasticity of real-time wholesale electricity demand. Rather, tariffs aimed at signalling times of peak demand in advance will tend to *reduce* actual electricity demand at the relevant times, rather than increase the *sensitivity* of demand to real-time wholesale prices.

That said, communications technology has increased economic opportunities for customers to provide real-time demand-side responses via alerts or autonomous controls or systems. On a residential level, several networks are offering incentives to install devices that enable them to control customer air-conditioner thermostats remotely[44] during peak events. To date, the emphasis on residential product offerings has focussed on times of network peak events rather than wholesale market peak events, but this has started changing following recent rule changes to promote competition in metering[45] and the contestability of distributed energy services.[46] On a commercial level, offerings of demand-side management hardware and software services attempt to minimise businesses' costs by optimising the timing of flexible loads, predicting wholesale price spikes, and initiating demand-side responses during peak periods. An example of these offerings is GreenSync's PeakResponse product.[47] In addition:

- ERM offers a pool price pass-through contract for consumers with an electricity bill spend of over $30,000 per annum;[48] and
- Amber offers a pool price pass-through contract for residential consumers, presently only in New South Wales.[49]

Falls in the price and increases in the energy density of chemical battery storage have made electricity storage products financially and/or practically feasible for some customers to install in their homes or businesses. Industry reports suggest that residential battery storage install rates almost quadrupled from about 6,000 systems in 2016 to around 23,000 systems in 2017.[50] Further, all the mainland NEM states have now announced battery subsidy schemes offering several thousand dollars of benefit per unit and with an overall target of nearly 100,000 installations. On the other hand, AEMO has recently revised down its battery forecasts in its 2018 Electricity Statement of Opportunities (2018 ESOO)[51] in light of recent reductions in wholesale electricity prices – see **Figure 14**.

[44] See: https://www.geelongadvertiser.com.au/news/geelong/powercor-energy-partner-program-offers-financial-incentive-for-airconditioning-control/news-story/2aaf7d403b9d4779de3ad7bd01912191 and https://www.ergon.com.au/network/manage-your-energy/incentives/peaksmart-air-conditioning.

[45] See: https://www.aemc.gov.au/rule-changes/expanding-competition-in-metering-and-related-serv.

[46] See: https://www.aemc.gov.au/rule-changes/contestability-of-energy-services.

[47] See: https://greensync.com/solutions/greensync-pr/.

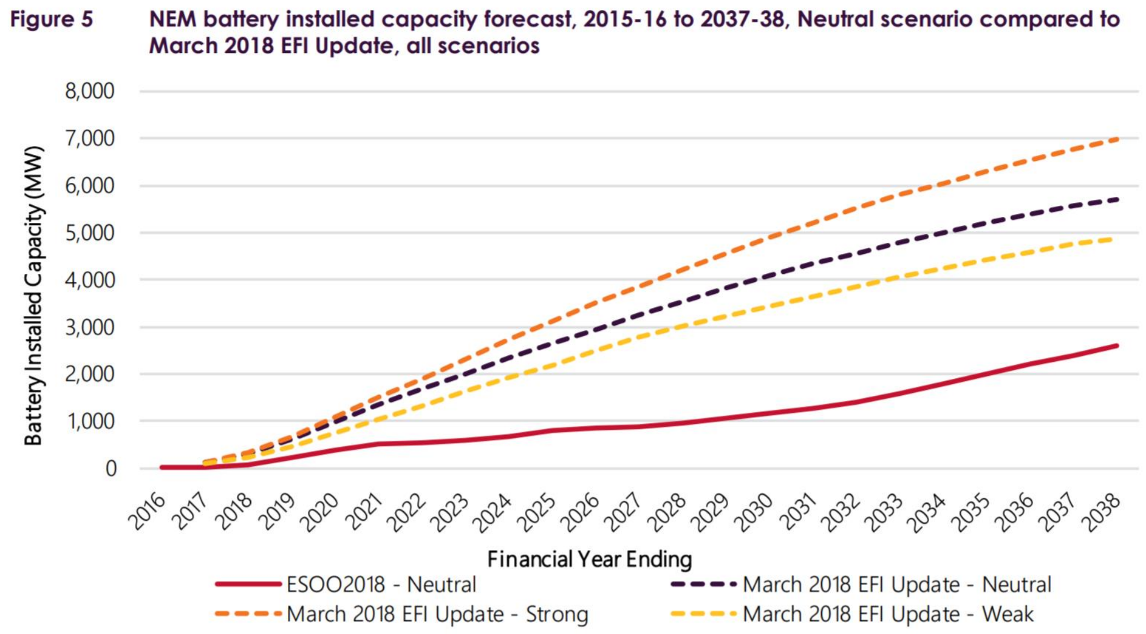
[48] See: https://ermpower.com.au/business-energy/energy-products/.

[49] See: https://www.amberelectric.com.au/.

[50] See: http://www.sunwiz.com.au/index.php/2012-06-26-00-47-40/73-newsletter/434-australian-battery-markettrebles-in-2018.html

[51] AEMO, *2018 Electricity Statement of Opportunities, A report for the National Electricity Market*, August 2018 (AEMO 2018 ESOO), available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities.

Figure 14: AEMO 2018 ESOO forecast of NEM battery installations



Source: AEMO 2018 ESOO, p.28.

Several businesses and governments have trialled Virtual Power Plant (VPP) programs, which enable registered wholesale market participants with control over a number of distributed generation and/or storage products to optimise operation of the systems in response to wholesale and or network price incentives. Notable examples of VPP schemes include the South Australian Government/Tesla VPP[52] and various retailer/independent offerings of AGL, Simply Energy and Reposit Power.

At a regulatory and market design level, work is progressing between Energy Networks Australia (ENA), AEMO and distribution networks on arrangements for the future improved optimisation of distributed energy resources (DER), such as small-scale solar PV, battery storage and 'behind-the-meter' energy management systems. The AEMO and ENA's recent Open Energy Networks consultation paper[53] describes three broad long term options for enabling the dynamic coordination of DER in the power system. These options involve real-time dispatching of 'active' (controllable) DER in such a way as to maximise the value of the energy and ancillary services DER can provide without violating network security constraints, as well as better utilising DER as an alternative to network capex. While both the preferable model and the specific actions necessary to implement it are as yet uncertain, it is likely that regulatory changes will be required at some stage to enable the full value of falling DER costs and rising DER capability and penetration to be harnessed.

[52] See https://virtualpowerplant.sa.gov.au/virtual-power-plant.

[53] AEMO and ENA, *Open Energy Networks, Consultation Paper*, 15 June 2018, available at: https://www.energynetworks.com.au/open-energy-networks-consultation-paper.

4.4 Three-year notice of generator closure

On 8 November 2018, the AEMC made a final rule that requires large electricity generators to provide at least three years' notice to the market before closing.[54] The rule change was based on one of the recommendations in the Finkel Review.[55]

The AEMC considered that the provision of this advanced information will help market participants respond to possible future shortfalls in electricity generation, such as by building replacement capacity in a more timely manner. In so doing, it will eliminate incumbents' informational advantage over other parties as to when new generation investment may be viable. This should reduce the risks of entry and promote wholesale competition.

4.5 5-minute settlement

In November 2017, the AEMC made a final rule to change the settlement period for the electricity spot price from 30 minutes to five minutes, starting on 1 July 2021.[56] The delay of over three and a half years was provided to mitigate the costs and risks associated with implementation.[57]

The implications of moving to 5-minute settlement for policy-makers' concerns are discussed in the following chapter.

4.6 Demand response mechanism

The Finkel Review found that demand response plays a relatively small role in the NEM and recommended that the COAG Energy Council should direct the AEMC to undertake a review to recommend a mechanism that facilitates demand response in the wholesale energy market.[58]

In the REPI, the ACCC recommended the development of a demand response mechanism for the NEM to enable third parties who are not retailers to offer demand response directly into the wholesale market, "given its potential to constrain the pricing of generation businesses, limit the need for additional generation and lead to lower prices."[59]

In its final report for the Reliability Frameworks Review, the AEMC supported the development of a rule change to implement a mechanism that would enable demand response aggregators to be treated on an equal footing with generation.[60] On 31 August 2018, the Public Interest Advocacy Centre (PIAC), Total Environment Centre and the Australia Institute submitted a rule change request to implement a wholesale demand response mechanism.[61] Subsequently, the AEC submitted its own proposed rule

[54] AEMC, *National Electricity Amendment (Generator three year notice of closure) Rule 2018*, 8 November 2018, available at: https://www.aemc.gov.au/rule-changes/generator-three-year-notice-closure.

[55] *Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future*, Commonwealth of Australia 2017 (Finkel Review), Recommendation 3.2, pp.87-97.

[56] AEMC, *Rule Determination, National Electricity Amendment (Five Minute Settlement) Rule 2017*, 28 November 2017 (AEMC 5-minute settlement determination), available at: https://www.aemc.gov.au/rule-changes/five-minute-settlement.

[57] AEMC 5-minute settlement determination, p.vi, 17 and chapter 7.

[58] Finkel Review, Recommendation 6.7, p.148.

[59] ACCC REPI, p.204.

[60] AEMC, *Final Report, Reliability Frameworks Review*, 26 July 2018 (AEMC Reliability Frameworks Review), available at: https://www.aemc.gov.au/markets-reviews-advice/reliability-frameworks-review

[61] Public Interest Advocacy Centre, Total Environment Centre and the Australia Institute, *Wholesale Demand Response Energy Market Mechanism: Rule Change Request*, 31 August 2018, available at: https://www.aemc.gov.au/rule-changes/wholesale-demand-response-mechanism.

change supporting the development of demand response, which the AEC says could provide many of the benefits of the PIAC et al rule change, but at significantly lower costs.[62] Then on 30 October 2018, the South Australian Government submitted a third, related rule change request that would allow third parties to offer wholesale demand response into the wholesale market as well as set up a separate wholesale demand response market.[63]

The AEMC has published a consultation paper on all three rule change proposals.[64] Given the support a demand response mechanism has received from the ACCC, AEMC and the COAG Energy Council, it is likely that something of this nature will be implemented in the next two to three years.

4.7 LNG import terminals

AGL is one of several parties considering building a LNG import facility on the east coast of Australia. AGL's proposed facility is at Crib Point on Western Port Bay in Victoria.[65] The Crib Point terminal would utilise a floating storage and regassification unit (FSRU) which stores the liquid gas and could allow between 12 to 40 LNG ships per year to resupply the FSRU with LNG. AGL anticipated that the first deliveries of LNG could occur in early 2020. However, the Victorian government recently decided to conduct a full environmental assessment for the project, which at the least would likely delay commissioning beyond this date.[66]

If the Crib Point project or one like it were to proceed, it would enable LNG to be supplied from overseas or elsewhere in Australia, providing more certain supply and greater price competition for east coast gas supplies.

[62] Letter from Sarah McNamara, Chief Executive Officer, Australian Energy Council, to John Pierce, Chair, Australian Energy Market Commission, "Demand Response Mechanisms", 18 October 2018, available at: https://www.aemc.gov.au/rule-changes/wholesale-demand-response-register-mechanism.

[63] Letter from The Hon Dan van Holst Pellekaan MP, Minister for Energy and Mining to John Pierce, Chair, Australian Energy Market Commission, "Proposed Rule change – Demand Response Mechanisms", 30 October 2018, available at: https://www.aemc.gov.au/rule-changes/mechanisms-wholesale-demand-response.

[64] AEMC, Consultation Paper, Wholesale Demand Response Mechanisms, 15 November 2018, available at: https://www.aemc.gov.au/rule-changes/wholesale-demand-response-mechanism.

[65] See: https://www.agl.com.au/about-agl/how-we-source-energy/crib-point-project.

[66] See: https://www.theaustralian.com.au/business/mining-energy/agl-energys-plan-to-import-gas-at-crib-point-faces-delay/news-story/110f34f2e3d69d539f43bd42aec359e9.

5 IMPLICATIONS OF TECHNOLOGY AND OTHER CHANGES

Chapter 3 explained how certain key features of the NEM likely contributed to short and longer term price outcomes that have attracted the attention of policy-makers and regulators. Chapter 4 outlined a range of technology and market design changes affecting the NEM that can be reasonably anticipated over the next decade. This chapter brings together the themes explored in the previous two chapters by examining the implications of the expected technology and other changes for future market conduct and outcomes in coming to a view on whether the factors underlying policy-makers' historical and recent concerns are likely to persist over the next decade and beyond.

This chapter proceeds by examining the potential influence of the technology and other changes discussed in chapter 4 on the features of the NEM that I believe have driven policy-makers' concerns laid out in chapter 3. Specifically, this chapter considers how various forms of technology and other policy and market changes will likely affect those features of the NEM that together have led to high and prolonged sensitivity of wholesale prices to demand and supply conditions (and thereby the benefits of vertical integration) – these features being:

- The nature of generation technology – as exhibiting high fixed and sunk costs, large economies of scale, 'lumpiness' and long lead-times
- The energy-only design of the NEM, combined with
- Highly inelastic nature of real-time wholesale electricity demand.

5.1 Expected changes in generation technology and costs

As discussed in Appendix B and summarised in chapter 4, it is likely that over the next decade, generation technology will move more rapidly in the direction it has been moving over the decade – towards more renewable generation capacity and storage and away from conventional fossil-fuelled generation. As a consequence, new electricity generation in particular is likely to exhibit:

- ***Less irreversibility (or 'sunkness')*** – some plant types (such as batteries and micro-generators) will be smaller and more portable than traditional fossil-fuelled turbines, and many new technology plant have shorter asset lives. Both of these factors will tend to reduce barriers to entry and exit.
- ***Weaker economies of scale*** – renewable generation and battery storage technologies exhibit much smaller average unit cost declines with larger unit and plant sizes than traditional technologies, making it efficient to invest at a smaller scale – and sooner – than previously would have been optimal.
- ***Reduced lumpiness*** – renewable generation and battery storage technologies are available in much smaller increments than fossil-fuelled units, making it possible to take advantage of smaller economies of scale to invest sooner than otherwise and without creating the same capacity overhang and 'price collapse' effects as the commissioning of new generators created in the past.
- ***Shorter lead times*** – enabling quicker market reactions to high demand conditions.

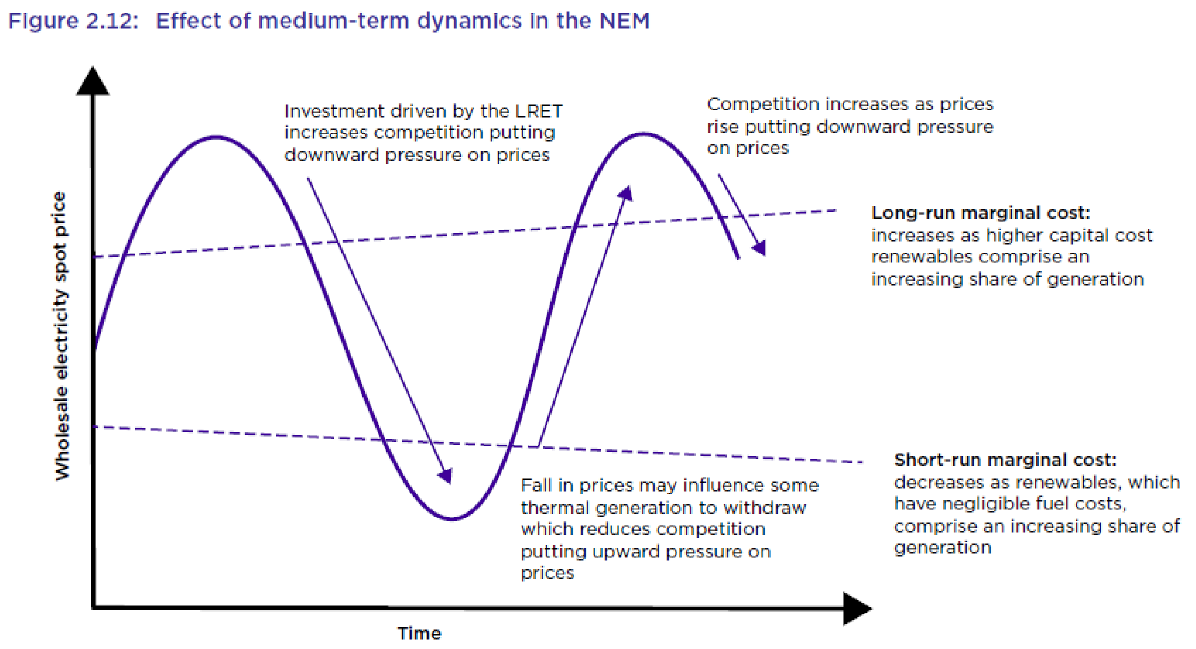
All of these factors are likely to encourage faster and smaller-sized market responses to periods of relative undersupply than has previously been the case. They should also help reduce the importance of (i) existing retail market positions and (ii) fear of price collapse effects in developing new capacity additions, thus lowering barriers (such as they are) to entry and expansion.

The impact of such changes has already been evident following the closure of the Northern and Hazelwood power stations in South Australia and Victoria, respectively. While the South Australian Government has instigated a number of supply-side investments itself, elsewhere, the investment response to date has been largely driven by market responses to high wholesale prices and the existing Commonwealth RET.[67]

Further, less irreversible or shorter-lived generation and storage that can be commissioned without long lead times could encourage faster market responses to high prices.

The likely future effect of these changes can be shown using a similar stylised approach to the price-cycling phenomenon shown in **Figure 5**. In this context, I note the following figure from the AEMC's 2017 Residential Price Trends report[68] (as adapted from the Grattan Institute's Next Generation report[69]) and reproduced by the ACCC in the REPI (**Figure 15**). This figure purports to show contemporary NEM price-cycle dynamics.

Figure 15: Cycle of wholesale prices in the energy-only NEM with the RET



Source: AEMC 2017 Residential Price Trends report, Figures 1 and 3.3, pp.v and 23; ACCC REPI, Figure 2.12, p.53.

The Grattan / AEMC figure appears to be based on an expectation of minimal future changes to generation technology and costs across the dimensions highlighted above – investment cost reversibility, economies of scale, lumpiness and development lead times. If these aspects of generation technologies and costs change over the next decade in ways that appear likely, NEM price-cycle dynamics in both the short term and the medium to longer term could change considerably.

67 See: https://www.energycouncil.com.au/analysis/tracking-ret/.

68 AEMC, *Final Report, 2017 Residential Electricity Price Trends*, 18 December 2017, available at: https://www.aemc.gov.au/markets-reviews-advice/2017-residential-electricity-price-trends.

69 Grattan Institute Next Generation report, Figure 3.1, p.17.

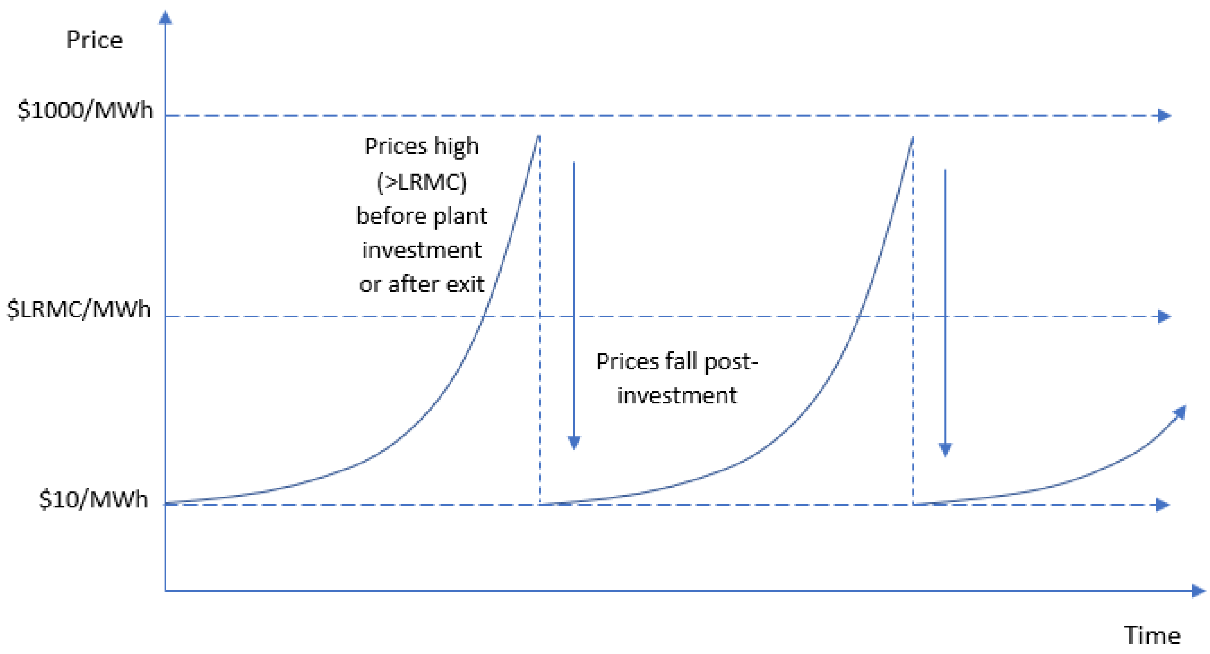
5.1.1 Implications for short term price dynamics

Wholesale prices *may* become more volatile in future (as suggested by the Grattan / AEMC figure) over short time horizons to the extent that the proportion of intermittent generation capacity increases and is not complemented by storage and/or more real-time demand response. If very little demand response emerges, then short term prices could become more volatile than they are now. However, given the market design (section 5.2) and technological moves (section 5.3) supporting greater real-time demand response and less strategic generator bidding behaviour, it is quite likely that short term prices could eventually become *less volatile* than they are presently.

5.1.2 Implications for medium to longer term price dynamics

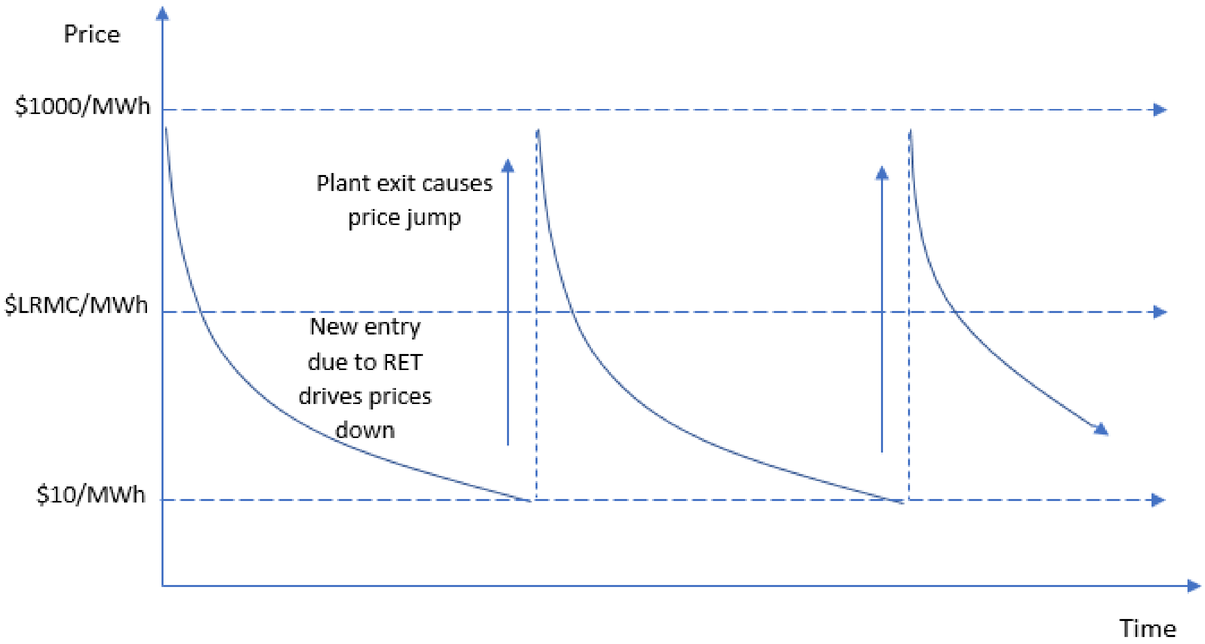
The expected changes to generation technology discussed in chapter 4 could reduce the amplitude of medium to longer-term price cycles. Recall the historical NEM price-cycles presented in **Figure 5** and **Figure 6**, reproduced below in **Figure 16** and **Figure 17**, respectively.

Figure 16: Conventional price cycles in an energy-only market



Source: Frontier Economics

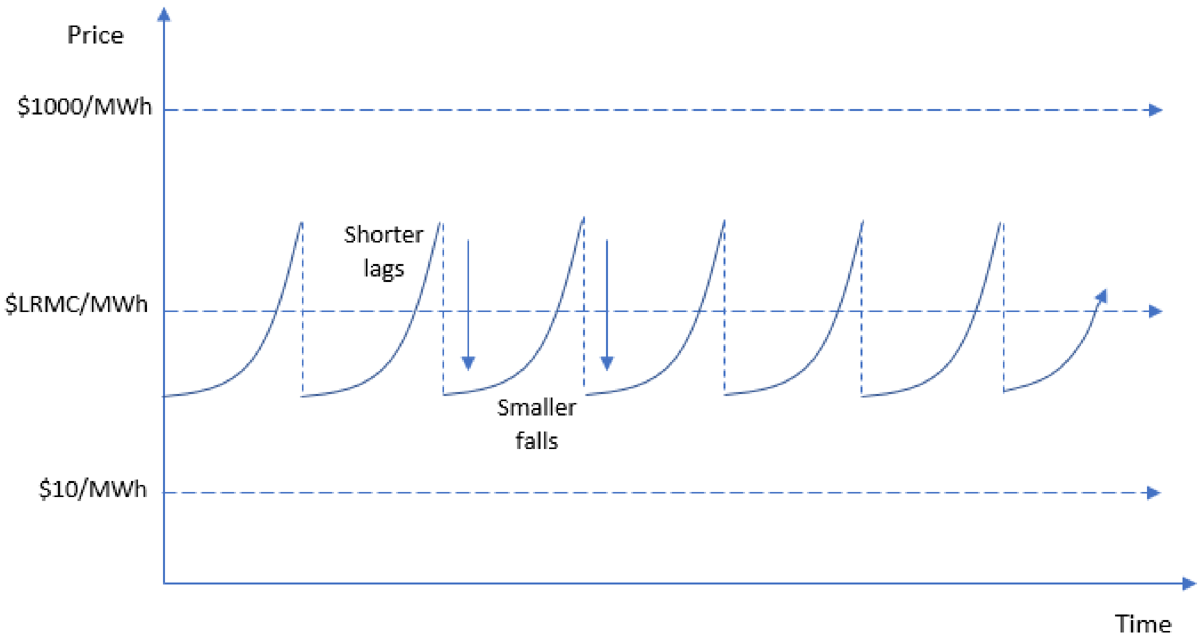
Figure 17: Recent RET-driven price-cycle dynamics



Source: Frontier Economics

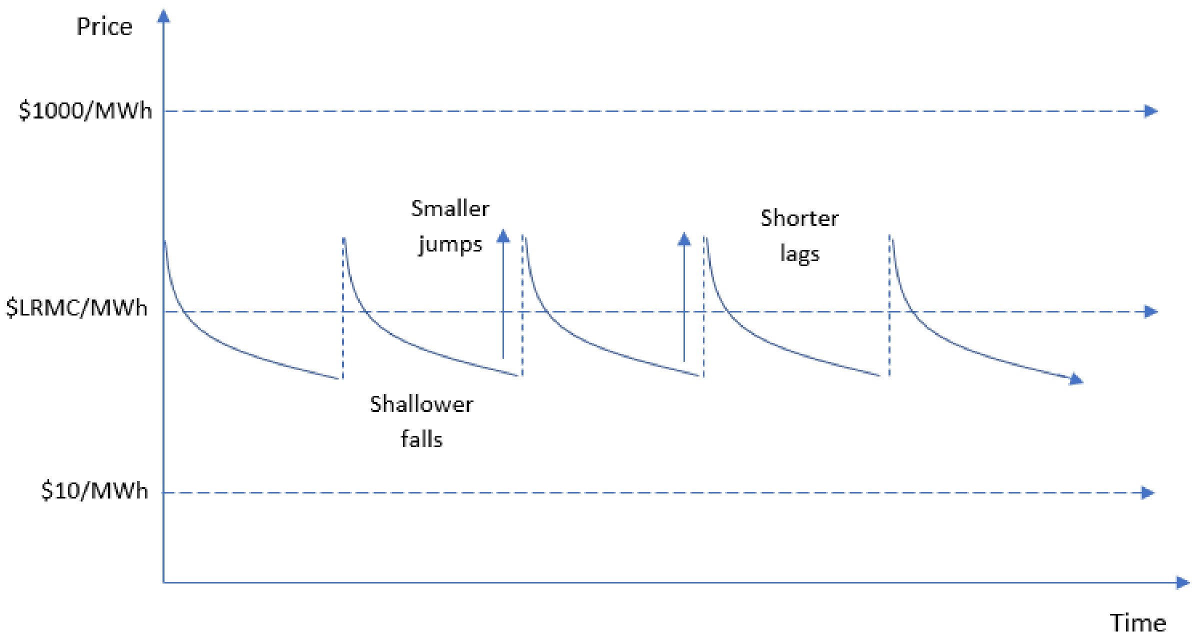
In my view, medium to longer-term price cycles are likely to shift over the next decade towards cycles that appear more like those in **Figure 18** and/or **Figure 19** below.

Figure 18: Future conventional price cycles in the NEM



Source: Frontier Economics

Figure 19: Future RET-driven price cycles in the NEM



Source: Frontier Economics

To the extent that electricity demand grows and plant exits are limited or delayed, price cycles should resemble those in **Figure 18**. The smaller scale of potential generation investment means both that:

- Incumbents face less of a 'price collapse' deterrent to investing in a timely manner; and
- New entrants face reduced financing and other barriers to generation investment.

Both of these factors should mean that investment happens more promptly and in smaller increments than has historically been the case. The result is a flatter price cycle over the medium to longer term.

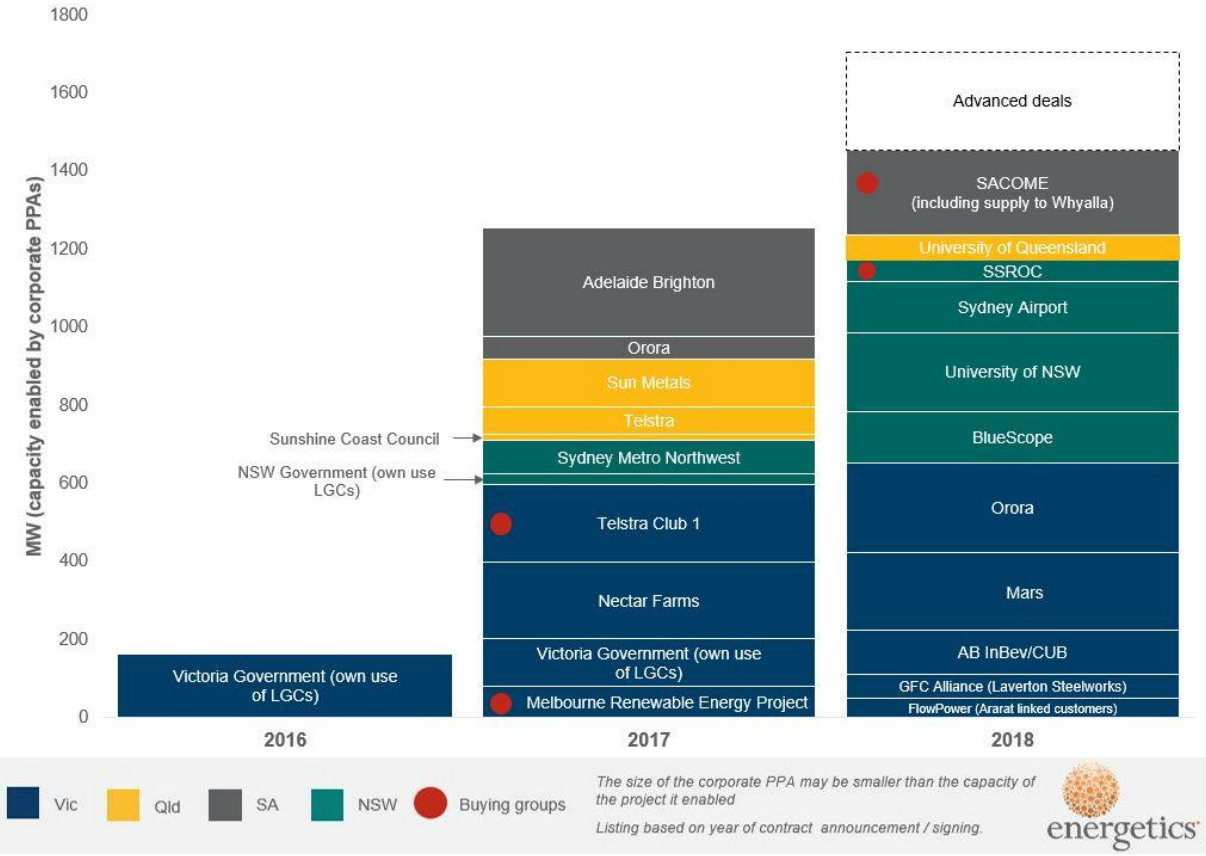
In the perhaps more likely scenario that coal-fired generators gradually continue to exit the market and renewable energy targets drive a sizeable proportion of all new generation investment, future price cycle dynamics could more resemble those in **Figure 19**. The recently-imposed requirement for a three-year notice of closure combined with the shorter lead times for new generation technology investments should mean that wholesale prices do not rise as much following a plant exit as they did following the departure of Hazelwood because investors will have time to anticipate and invest in advance the closure. Further, the three-year notice requirement may encourage plant owners to err on the side of bringing forward closures to avoid the risk of being obliged to run their plant when wholesale prices drop to very low (circa 2015) levels. This should mean that other things being equal, wholesale prices do not fall to as low levels prior to a plant exit as they did prior to the closure of Northern and Hazelwood.

5.1.3 Implications for the benefits of vertical integration

Changes in generation technology and costs should also limit the benefits of vertical integration, particularly the importance of large retail positions in sponsoring or underwriting new generation investment.

Strong evidence for the proposition that economies of scale and lumpiness are not presenting barriers to end-customer investment in renewable technologies is provided by data on recent power purchase agreements (PPAs). There is an emerging trend of corporate energy consumers signing PPAs directly with generators on much smaller scales than has historically been typical in the NEM. **Figure 20** illustrates recent public corporate PPA deals in the NEM from 2016 to 2018. These PPAs enable prospective wholesale market entrants with projects in the hundreds or even tens of MW to contract their output to one or several customers, rather than selling to an existing retailer or building a retail portfolio. In signing long term PPAs, financers are willing to accept high debt-to-equity ratios, lowering the weighted average cost of capital (WACC) for the prospective entrant and increasing the economic viability of the project. Direct contracting in this manner reduces barriers to entry for prospective market participants and diminishes the benefits of vertical integration – see also section 5.1.3.

Figure 20: Corporate renewable energy PPA deals



Source: Energetics corporate renewable energy PPA deal tracker https://www.energetics.com.au/insights/knowledge-centres/corporate-renewable-ppa-deal-tracker/

It is clear that many such investments are being made in reliance on some form of renewable subsidy program – whether the Commonwealth RET, or the Victorian or Queensland RETs (VRET and QRET, respectively) – rather than price signals from the energy-only market alone. However, a substantial amount of investment in addition to that motivated by RETs will be required by 2030 to meet the NEM reliability standard, and such investments will need to be driven by wholesale market signals.

One interpretation of the PPA evidence is that heralds the beginning of the end for the advantages of the gentailer business model. While it is unlikely that business consumers sponsoring new small-scale renewable plant via PPAs are presently bypassing the need to contract with a retailer for hedging services (who in turn would need to own or contract with flexible suppliers), this may become more realistic in the future.

Over the next decade, for the reasons discussed in sections 5.2 and 5.3, smaller consumers are likely to have much greater access to the following:

- Battery storage to help manage troughs in energy supply from remote or local intermittent renewable generation
- Energy management technology and service providers to facilitate more flexible demand response to both weather conditions and owned or contracted intermittent renewable plant output and
- Wholesale market rewards for scheduled demand response.

This does not mean that consumers will bypass retailers entirely, but that retailing could become a narrower function focussed on providing settlement and billing services. That is, the need for retailers to offer wholesale price hedging to consumers could lessen and the benefits of vertical integration could decline as a consequence. To the extent this occurs – and the extent remains uncertain at this stage – this could mitigate competition concerns about vertical integration.

5.2 Expected changes in market design and structure

Chapter 4 discussed two key changes to market design that are expected over the next few years or have been foreshadowed by the AEMC. The first is the planned move to 5-minute settlement in July 2020 and the second is the AEMC's intention (following the Finkel Review recommendation) to introduce a demand response mechanism. Both of these changes could reduce short term volatility in wholesale prices. Chapter 4 also discussed the prospect of a major push for investment in transmission expansions across the NEM, driven by the ISP, and also the prospect of a new LNG import terminal. These developments are also discussed below.

5.2.1 ISP transmission expansions

If Group 1 and 2 projects proceed over the next few years as the ISP recommends, then assuming modest demand growth, the NEM is likely to experience fewer inter-regional constraints than it does at present. Fewer constraints mean that generators, demand-side response and storage in different locations will be able to compete more effectively to discipline prices in a given region. Given that the ACCC has consistently adopted state-based market definitions in its competition analysis, a reduced incidence of inter-regional constraints should help alleviate regulator and policy-maker concerns over regional wholesale concentration and contract liquidity levels.

5.2.2 Effect of 5-minute settlement

The move to 5-minute settlement will likely change the nature of bidding incentives. With no assurance that they will remain dispatched beyond a 5-minute period, generators responding to a spike in spot prices will have stronger incentives to incorporate any start-up costs in their offer prices. On its own, this could raise the volatility of spot prices. To the extent that generators become less willing to offer cap contracts, retailers will need to raise retail tariffs to help compensate for the higher hedging costs and risks they will be forced to manage.

On the other hand, larger and relatively slower-to-respond coal- or even most gas-fired generators could face weaker incentives to engage in strategic behaviour to raise prices – to the extent this incentive remains following the AEMC's late rebidding rule change[70] – because any resulting increase in prices may not persist for long enough to make such conduct worthwhile.

[70] See https://www.aemc.gov.au/news-centre/media-releases/new-rules-for-last-minute-electricity-market-rebid.

5.2.3 Effect of demand response mechanism

Assuming the adoption of changes to the market arrangements to promote greater demand response (particularly, scheduled demand response), along the lines of either of the proposals discussed in section 4.6, the extent of real-time demand response is likely to increase in the future. This should increase the real-time responsiveness or elasticity of electricity demand with respect to the wholesale price – see also section 5.3 below.

5.2.4 Access to alternative fuel sources

As discussed in section 4.7, AGL is one of several parties considering building a LNG import facility on the east coast of Australia. If the Crib Point project or one like were to proceed, it would enable LNG to be supplied from overseas or elsewhere in Australia, providing more certain supply and greater price competition for east coast gas supplies.

Access to an alternative source of gas at internationally-traded prices should, other things being equal, lead to less medium-term volatility in gas prices and hence less medium-term volatility in wholesale electricity prices to the extent that gas generation remains marginal at peak demand times. This is likely to be the case over the next decade.

5.3 Expected changes to demand elasticity

Leaving aside changes to the market design or rules, section 4.3 explained how improvements in communications technology and metering have increased economic opportunities for customers to provide real-time demand-side responses via alerts or autonomous controls or systems. Further, the scope for much improved DER optimisation could help ensure that DER is applied to whatever purpose – wholesale or network demand response – offers the greatest benefits. At times of peak system demand (and given the likely infrequency of constraints on distribution networks), this is likely to be electricity demand that is more responsive to wholesale prices. Over time, these developments should result in a more elastic wholesale demand for electricity.

A more elastic real-time demand for electricity will help reduce price volatility in the short term in two key ways:

- First, real-time demand that is more responsive to wholesale prices will reduce the price impact and hence ‘payoff’ to generators of a given size from withdrawing or pricing-up their capacity to spike prices, relative to the incentives for such behaviour that might otherwise prevail. Further, new entrant retailers will have access to similar physical hedging options as large gentailers do now (i.e. new entrants can pick and choose a ‘right-sized’ physical generation hedge to match their small loads), with the result that financial hedge premiums should reflect efficient risk allocation rather than any market power.
- Second, even where generators largely behave as price-takers, more elastic real-time wholesale demand should reduce the extent to which wholesale prices spike in the event of events such as unexpectedly high system peak demand and/or sudden major plant outages.

Even with a relatively modest degree of real-time demand responsiveness, both the incentives on generators to engage in strategic bidding and even the need for a MPC to enable the spot market to clear can diminish. These developments would help bring the NEM more into line with other markets in the economy and potentially reduce policy-makers’ and regulators’ concerns about the efficient and competitive functioning of the electricity sector.

5.4 Implications for the achievement of the NEO

The developments discussed in this chapter are likely to offer three major benefits from the perspective of policy-makers and regulators:

- The first is that they should help smooth wholesale price volatility in both the short term and in the medium to longer term;
- The second is they should reduce the advantages of the vertically-integrated 'gentailer' business model; and
- The third is that they should encourage more competitive behaviour in the NEM wholesale market and thereby lead to more efficient and cost-reflective dispatch and pricing outcomes.

These developments are also broadly consistent with the satisfaction of the NEO, although only the third is directly relevant. Reduced price volatility may or may not promote the NEO in itself, but is expected to be a consequence of behaviours that would promote the NEO – namely, more efficient participant decisions about energy usage and investment, and more cost-reflective bidding. Similarly, reduced advantages for the gentailer business model may not promote the NEO directly, but could increase competition by lowering entry barriers.

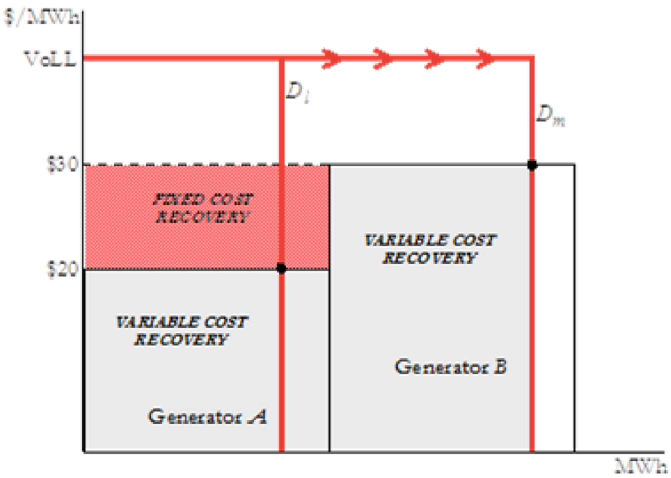
A ENERGY-ONLY WHOLESALE MARKET OPERATION

Part 1 – Fixed cost recovery

Figure 21 and **Figure 22** below illustrate the concept of fixed cost recovery in an energy-only wholesale electricity market graphically. Assume two generators (A and B) utilise different technologies. Generator A is a coal-fired plant used for baseload supply and has a relatively low variable cost of supply. Generator B is a gas-fired plant used for peaking supply and has a relatively high variable cost of supply. Demand is a sideways "L-shape" since demand is perfectly inelastic for prices below the MPC.

At times of low demand (Dl) only Generator A is selected to run (in line with least-cost dispatch) and hence the spot price is set at $20/MWh. Since this is equal to Generator A's variable costs, this generator is recovering only its variable costs of supply.

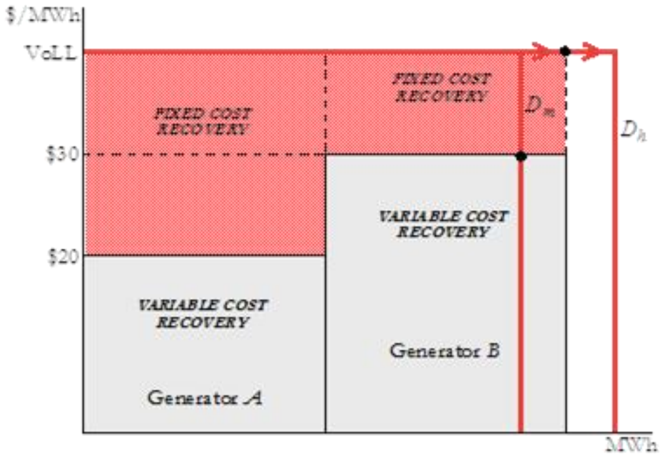
Figure 21: Recovery of fixed costs during times of medium demand



Source: Frontier Economics

At times of medium demand (Dm) both Generator A and B are selected to run and hence price is set at $30/MWh. Since $30/MWh is greater than Generator A's variable cost of $20/MWh, during times of medium demand Generator A recovers both its variable costs and some contribution towards its fixed costs. Since $30/MWh is equal to Generator B's SRMC, this generator is recovering only its variable costs of supply.

Figure 22: Recovery of fixed costs during times of high demand



Source: Frontier Economics

At times of high demand (Dh), where demand outstrips supply, price will approach the MPC and thus both generators will recover their variable costs of supply and some contribution towards their fixed costs.

Part 2 – Optimal plant mix

The energy-only market design is not only intended to yield consistent levels of unserved energy and installed generation capacity, it can also produce an efficient technology mix of plant. In a theoretically ideal (fully-competitive) energy-only market in which all generators bid at their avoidable operating costs, for a given:

- MPC
- mix of available generation technologies (with differing cost and operating characteristics) and
- shape or 'profile' of load,

the market should produce:

- the optimal technology mix and timing of generation investment as well as the optimal operation of these generators, together ensuring that long-run total costs of meeting load are minimised and
- a path of market prices that results in this optimal mix of plant – based on optimal dispatch – perfectly recovering all generators' total costs (fixed and variable) over time.

The precise conditions necessary for this outcome are not borne out in practice due to a range of real-world market imperfections and failures. For example, it ignores generator start-up costs, which are typically material for conventional thermal generators (such as coal and gas-fired plant) but are not typically factored into estimates of operating cost.

Nevertheless, it is illustrative to describe how in theory an energy-only market seeks to ensure the efficient mix and operation of generation plant, as well as cost recovery for that efficient mix of plant.

Different types and technologies of generating plant have different fixed and variable costs. 'Baseload' plant, such as coal-fired generators, tend to have relatively high fixed costs and relatively low variable costs. This structure of costs means that it is efficient for them to operate at high capacity for a large proportion of the time. ‘Mid-merit’ plant such as combined cycle gas turbines (CCGTs) tend to have moderate fixed and variable costs, making it efficient for them to operate for a moderate proportion of the time. ‘Peaking’ plant, such as open-cycle gas turbines (OCGT), tend to have relatively low fixed costs and relatively high variable costs. This structure of costs means that it is efficient for them to operate for a small proportion of the time, such as during hot or cold weather when electricity demand is high.

As noted above, for efficient plant to recover their full costs in an energy-only market, the wholesale spot price must be able – and expected – to rise above the operating cost of all technologies of plant from time to time, to enable each plant type to recover its fixed (as well as variable) costs:

- When the spot price rises above the operating cost of baseload plant, baseload plant earn ‘infra-marginal’ rents that contribute towards the recovery of their fixed costs.
- When the spot price rises above the operating cost of mid-merit plant, both peaking and mid-merit plant earn infra-marginal rents that contribute to the recovery of their fixed costs.
- When the spot price rises above the operating cost of peaking plant, all plant (baseload, mid-merit and peaking) earn infra-marginal rents that contribute to the recovery of their fixed costs.

The level and shape or ‘profile’ of demand over time will – in combination with generator and demand-side bids – influence how often and for what duration the spot price lies above or below the operating costs of various plant. The expected level and profile of the spot price will over time influence which plant are likely to be profitable and enter or exit the market.

Figure 23 below provides a stylised illustration of how energy-only markets signal an efficient plant mix. The top panel shows the total cost, per MWh, of three generation technologies at different operating capacity factors. The y-intercept denotes fixed cost and the slope of the line denotes variable cost. Depending on the duration of operation, each technology is at some point least-cost in $/MWh terms (ie it lies on the dotted red line). These ‘screening curves’ can be used to determine the optimum plant mix for a given shape of load.

Taking as given the target maximum annual magnitude of unserved energy, it is possible to derive the optimal proportion of time that each plant should run and the resultant optimal level of installed capacity of each plant from the middle panel.

Under the assumptions of a fully-competitive market, the:

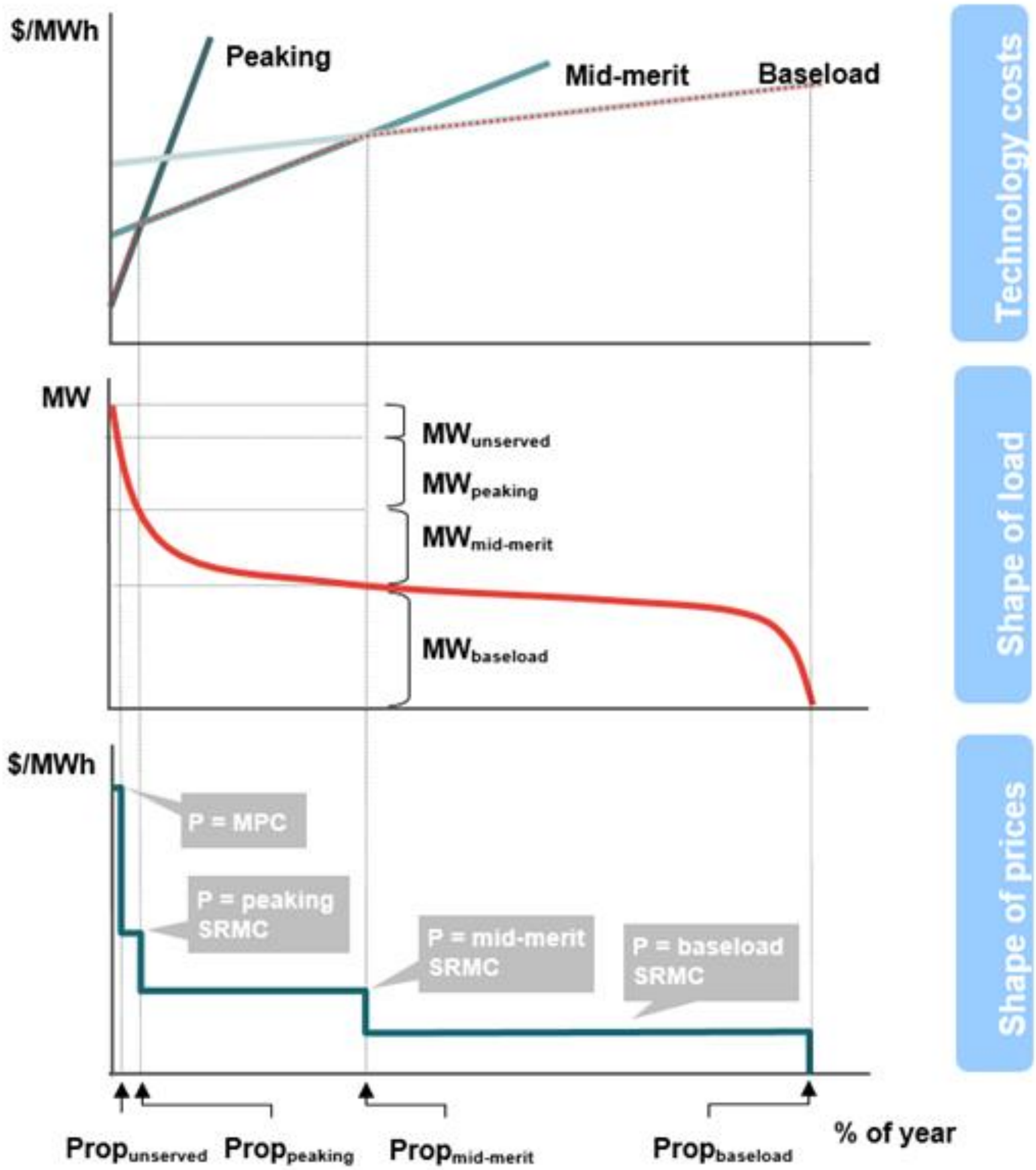
- optimal duration of unserved energy, combined with the
- optimal plant mix and operation given technology costs and the shape of load,

can be used to derive an optimal price-duration curve as per the bottom panel.

This resultant price-duration curve is sufficient to ensure that all technologies in the optimal mix can recover their total costs (variable and fixed) over time. Each technology recovers only its variable costs when it is setting the price (i.e. it is the marginal generator). Each technology recovers both its variable and a portion of its fixed costs when the market price rises above its variable cost. This means that:

- The most expensive generation technology recovers its fixed costs only when it is required to be dispatched meet demand, or during periods of unserved energy when the market price is equal to the MPC.
- All other generation technologies in the optimal mix also rely on MPC prices at these times to ensure they fully recover their fixed costs. For example, a baseload unit will recover some of its fixed costs when a mid-merit plant is marginal and setting the price, but will not recover all its fixed costs unless the optimal duration of MPC prices occurs.

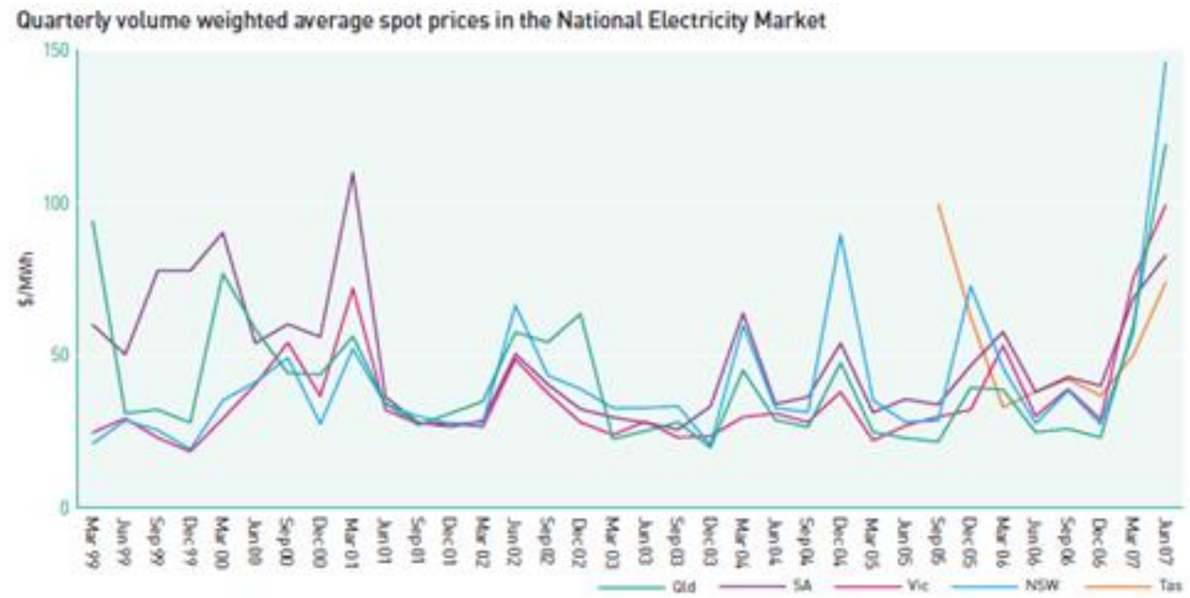
Figure 23: Technology costs, optimal plant mix and price-duration curve



Source: Frontier Economics

Investment in unsubsidised (non-renewable) generation have generally reflected the predictions of energy-only market theory. When the NEM commenced, there was considerable coal baseload capacity in Victoria but limited gas peaking capacity (although Snowy Hydro's plant played this role to some extent). Through the course of several hot summers, when demand and spot prices in Victoria and South Australia rose sharply for short periods of time (see **Figure 24**), investors realised that while additional baseload plant would not be viable, lower fixed cost peaking plant that would only operate for a few days or weeks a year could be profitable. The result was the development of the gas-fired Somerton OCGT in Victoria and the gas/diesel Hallett OCGT in South Australia.

Figure 24: NEM spot prices 1999-2007



Source: AER, State of the Energy Market 2007*, Figure 2.9, p.90.*

B LITERATURE REVIEW

Part 1 – Historical trends in generation technology in the NEM

World Electric Power Plants Database

The S&P Global Market Intelligence World Electric Power Plants Database[71] (WEPP) is a worldwide inventory of electric power generating units. This database can be used to examine historical trends in centralised generation investment around the world. Entries in this database include information about unit sizes, station sizes, construction year, operating status, technology, fuel type and location.

This report uses the WEPP data to investigate trends in generator technology investment decisions from 1960 to the present day. To obtain a subset of projects of interests, we perform some basic filtering prior to presenting the following results. Our filtering methodology is as follows:

- We select five significant countries of interest, including Australia.
- We consider the most common fuels utilised in Australia, including coal, gas, water (hydro), solar and wind.
- We only consider power stations greater than or equal to 30MW in size. Many projects in the database are embedded (decentralised), which we consider separately in the following section. We use a 30MW minimum station capacity as a heuristic to filter out decentralised projects which would otherwise skew results.

The following figures show distributions via box-and-whisker plots[72] of station size by technology and country (**Figure 25**) and unit size by technology and country (**Figure 26**) in five year periods. We aggregate projects by fuel type, but split gas into technology categories of steam turbine and 'other', as there is a distinct step change in the size of steam turbine gas generators compared to other gas generator technology types[73]. For stations with units built in different years, we attribute the modal (most frequent) year of unit construction to the station[74].

From **Figure 25**, it is clear that coal-fired and gas steam turbines, and to a lesser extent, hydro power stations are the largest generators built in each of countries examined. Most remarkably in Australia, coal-fired power stations have consistently dominated other fuel groups – small coal-fired power stations in Australia are comparable in size to large power stations of other fuel types.

The number of coal-fired power stations built in developed countries has decreased in recent years, likely due to a combination of the following reasons:

- Flattening or falling demand in the selected countries other than China
- Carbon pricing or abatement risk, leading to investment in low-carbon emitting substitutes

[71] See: https://www.platts.com.es/products/world-electric-power-plants-database

[72] The methodology for calculating elements of the box and whiskers is known as Tukey's methodology. The elements of the box include 25th, 50th and 75th percentiles. The whiskers represent the most extreme values falling within the 25th/75th percentiles plus/minus the interquartile range (IQR), which is the difference between the 75th and 25th percentile. Outliers include any values more extreme than the 25th/75th percentiles plus/minus the IQR.

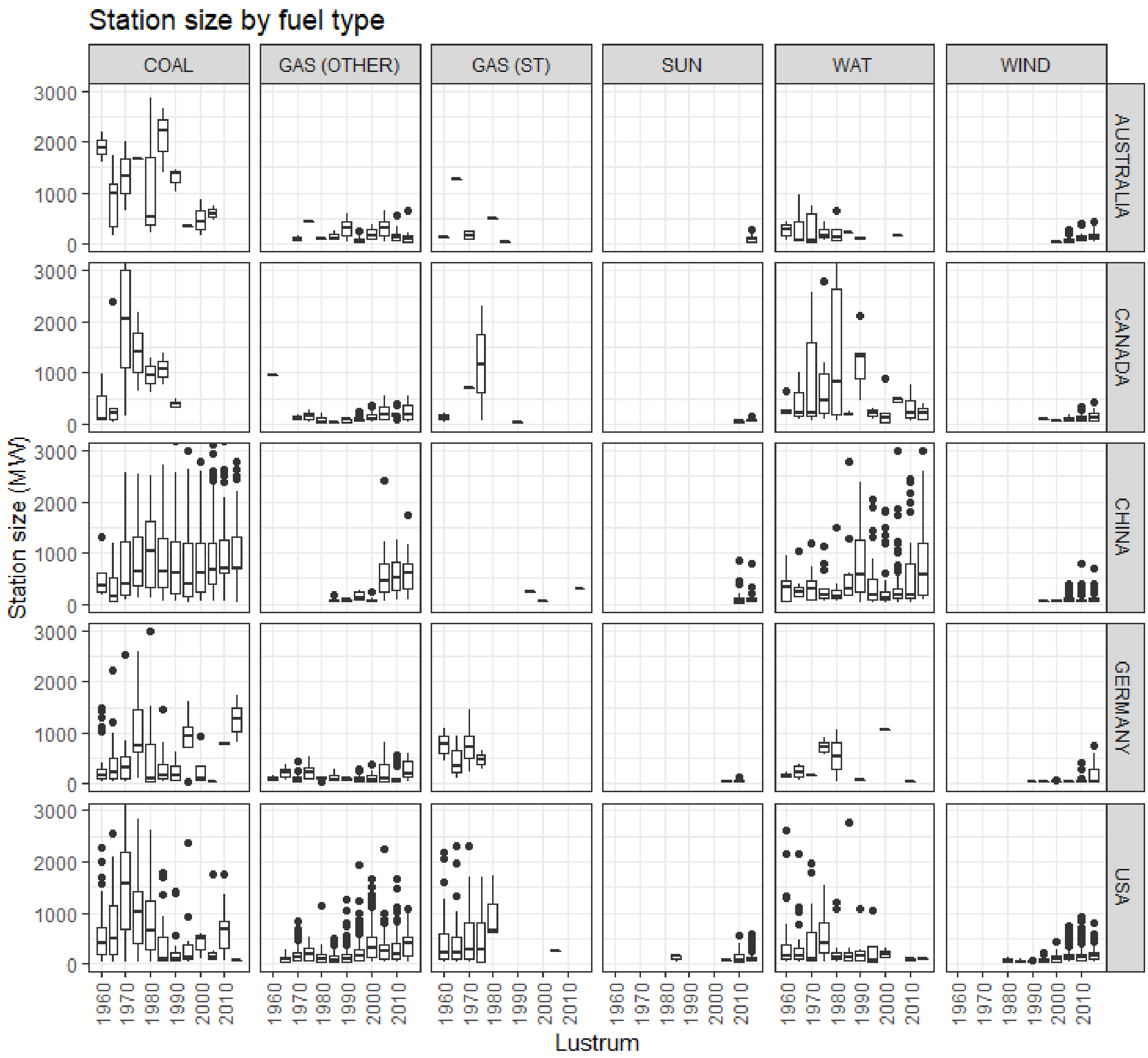
[73] There are a large number of possible configurations for gas-fired power stations with similar unit/station size characteristics. (footnote)The relatively new single shaft combined cycle configuration (both prime-movers attached to a single shaft) has favoured larger units, explaining recent increases in size in the US and China

[74] This explains several data points seemingly missing from **Figure 25** from data in **Figure 26**.

- Requirements for flexibility in systems with increasing variable renewable energy (VRE) – coal-fired power stations (large steam turbines) are generally slow to respond to rapid changes in demand and supply conditions.

In Australia and the USA, coal-fired generator sizes have been falling. The size trend for coal stations is flat in China and mixed in Germany.

Figure 25: Station size by fuel type



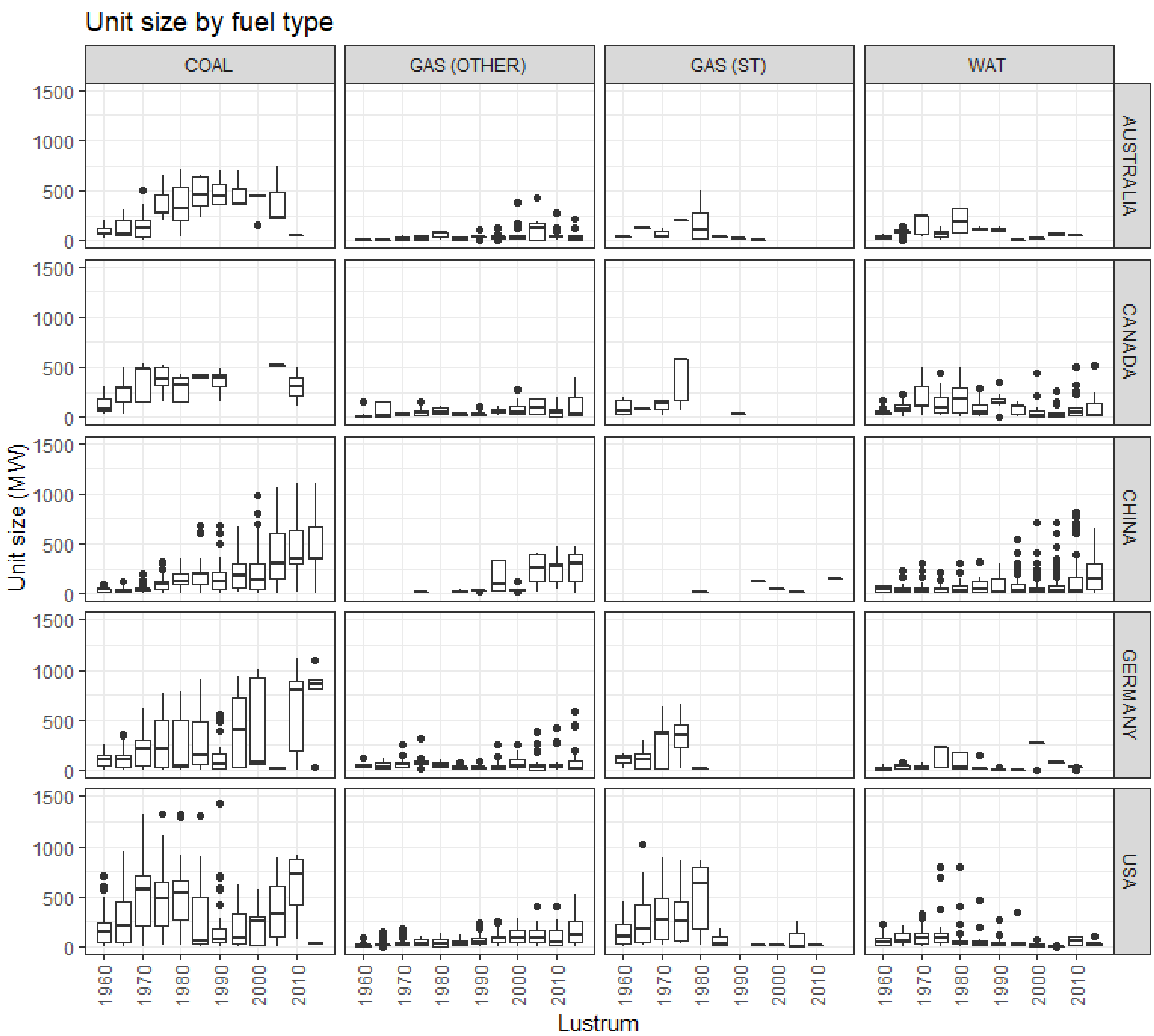
Source: Frontier Economics analysis of WEPP data

Figure 26 illustrates trends in unit sizes for the same fuels/technologies and countries. We omit solar and wind fuels in this figure, as these technologies are aggregated to station size in the database.[75] As is the case with station sizes, steam turbine units (coal-fired and separately presented gas-fired units) are among the largest. However, both gas-fired steam turbines and coal units have fallen out of favour

[75] Likely due to the fact that PV panels are typically measured in hundreds of watts and wind turbines in single-digit MW; inclusion of each individual panel and/or wind turbine would make the database very large.

in recent years, likely due to the reasons highlighted above. The trend in coal plant unit sizes appear to be falling in Australia and Canada, but rising in China and mixed elsewhere.

Figure 26: Unit size by fuel type

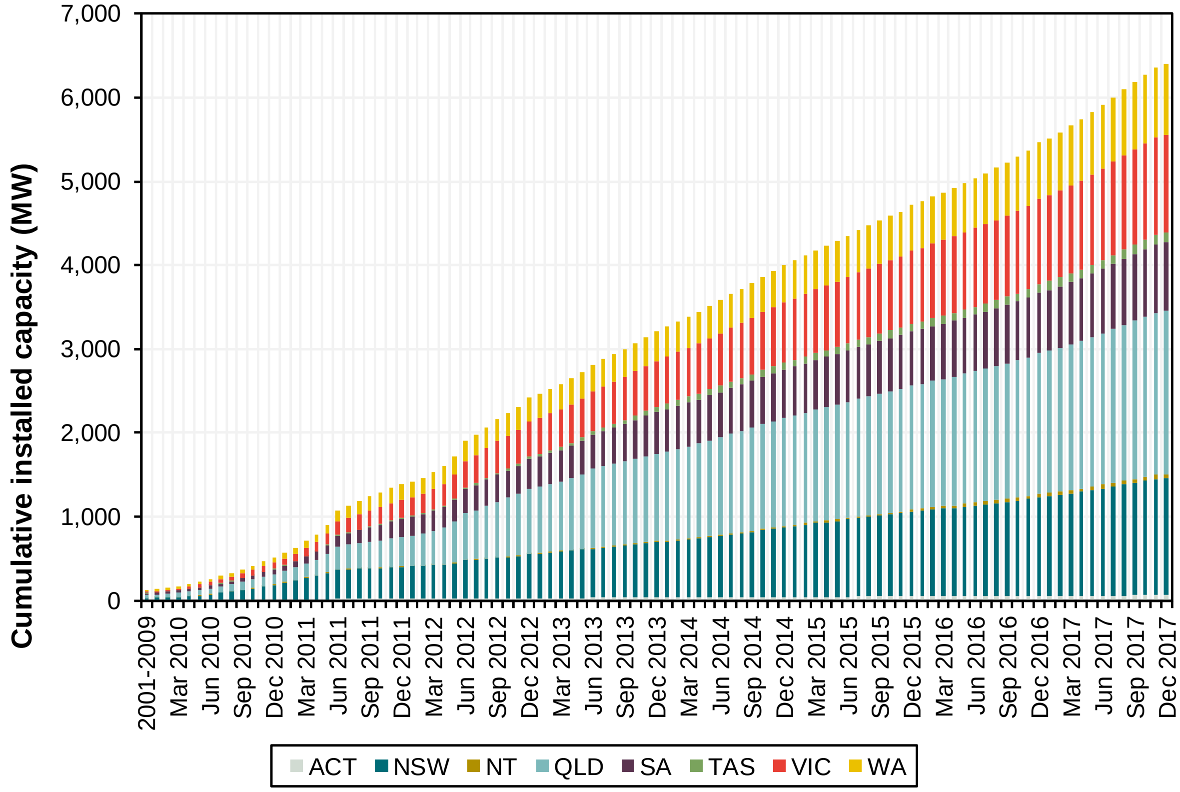


Source: Frontier Economics analysis of WEPP data

Distributed generation

From early 2010, residential rooftop solar PV installations in Australia have steadily increased in both number and size, as illustrated in **Figure 27** and **Figure 28**. The technology's popularity increased around this time due to generous federal and state government subsidies in the form of the RET, generous state-based "premium" feed-in tariffs, and underlying technology costs falling as more and more systems were installed. The financial attractiveness to customers of installing solar PV was and remains enhanced by an implicit cross-subsidy in network and retail pricing, with fixed and sunk network costs being recovered from customers through variable charges. This means that customers who install solar PV (and thereby reduce their grid-sourced consumption) are able to avoid paying for network costs that are no longer avoidable in an economic sense. The AEMC documented this issue in detail in its network pricing rule change determination.[76] Since the early 2010s, jurisdictional feed-in tariffs have become far less generous, but network cross-subsidies remain significant as cost-reflective network tariffs apply to relatively few residential customers.

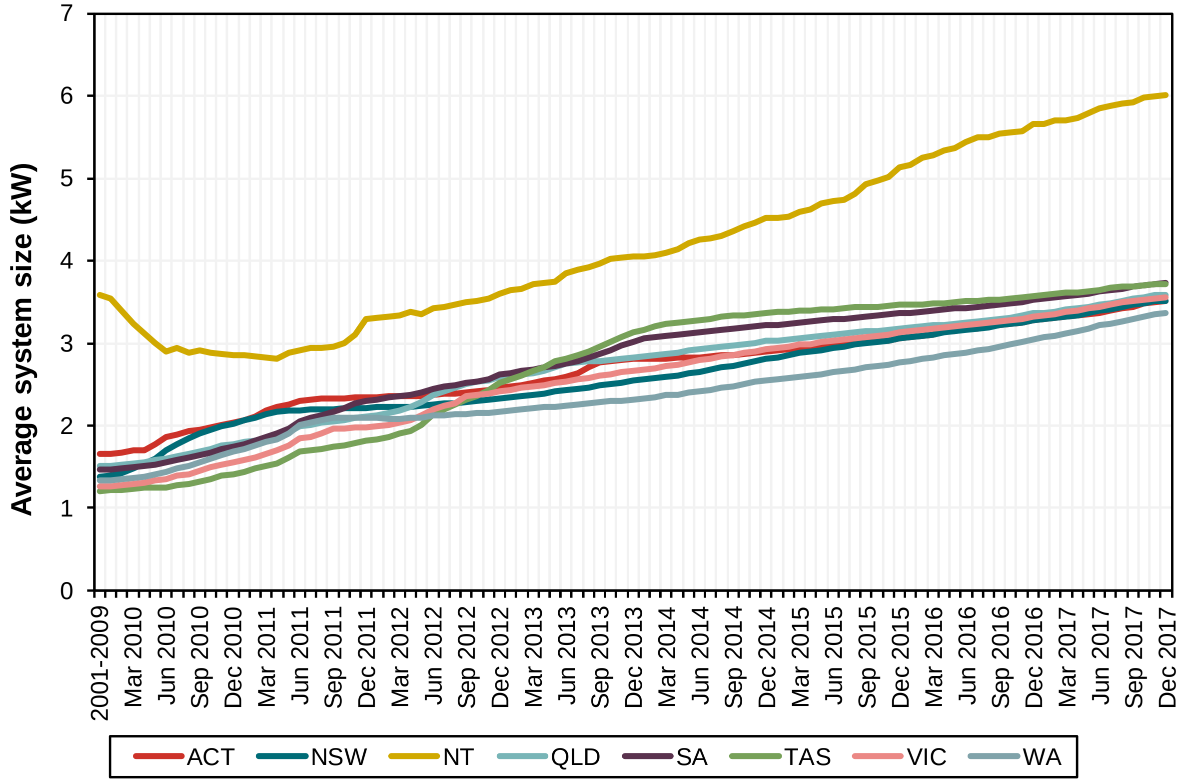
Figure 27: Rooftop PV uptake in Australia



Source: Frontier Economics analysis of CER data

[76] AEMC, *Rule Determination, National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014*, 27 November 2014, section 4, available at: https://www.aemc.gov.au/rule-changes/distribution-network-pricing-arrangements.

Figure 28: Average rooftop PV system size in Australia over time



Source: Frontier Economics analysis of CER data

With around 6.3GW of residential rooftop PV at the end of 2017, the technology contributes materially to meeting demand in most NEM regions. An analysis of AEMO's estimated actual rooftop PV generation data[77] suggests that from 1 October 2017 to the end of October 2018, it has generated around 7.8TWh, around 4 per cent of NEM operational demand of approximately 192TWh.

Current state of centralised generation technology in the NEM

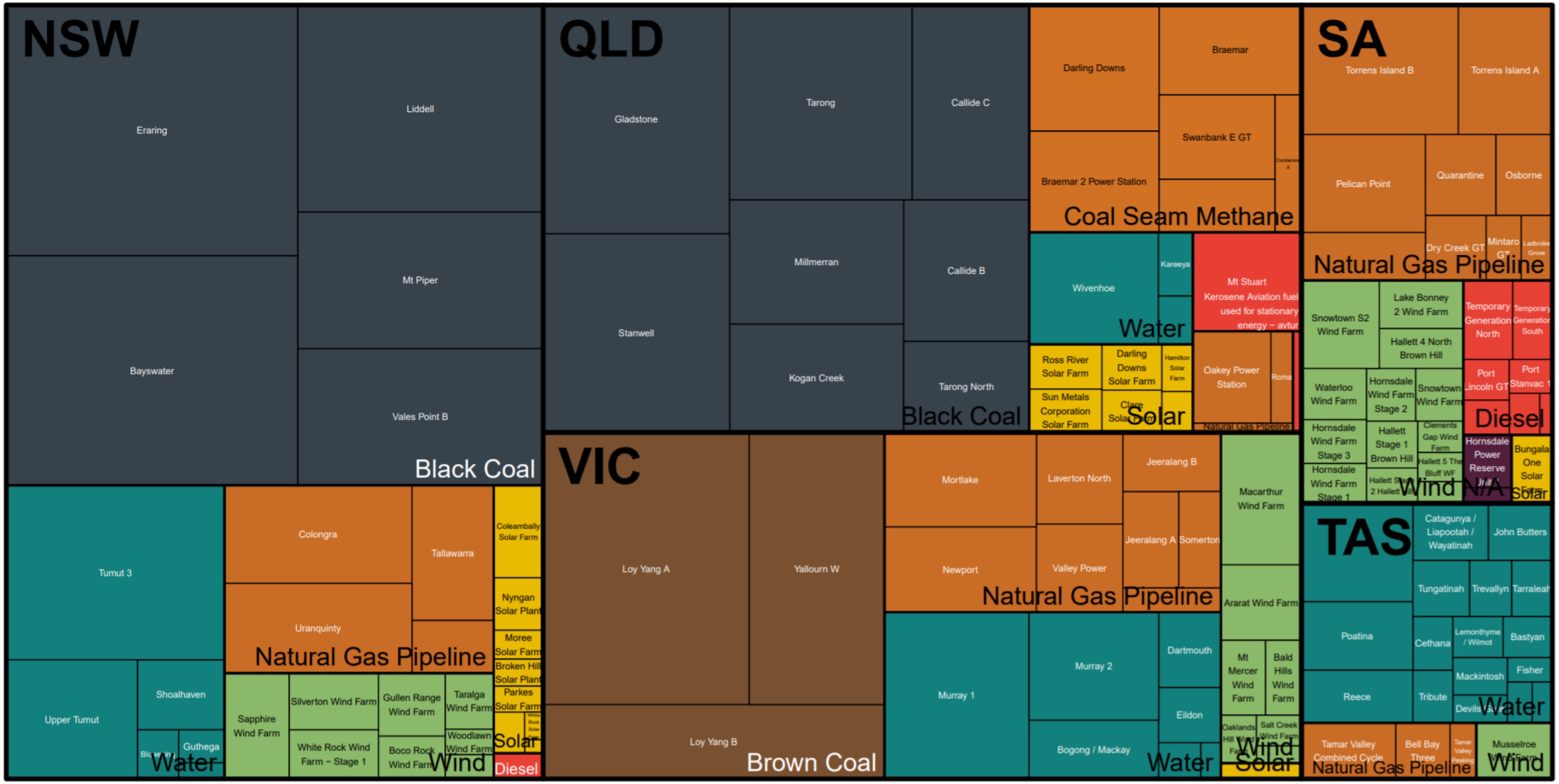
The result of the station investment path illustrated in **Figure 25** is presented in **Figure 29**, which shows the relative size of each NEM station grouped by region and fuel type. The area of each station box reflects the relative capacity of the station, and the same is true for aggregations of stations into fuel types and regions (e.g. the capacity of Queensland generation is slightly larger than Victoria, as the QLD box is slightly bigger than the VIC box). Large, coal-fired power stations in New South Wales, Queensland and (to a lesser extent, after the closure of Hazelwood) Victoria dominate the energy mix, with the remaining generation stock consisting of smaller stations fuel by gas, wind, solar and liquid fuels.

Figure 30 charts the same stations by region and fuel type on an output basis. Generally, coal and gas generators with the lowest SRMCs will operate for most of the year, higher SRMC gas generator output will fluctuate with demand, VRE is limited by available renewable resources, and high SRMC peaking power stations will only operate for a few hours in the year. The result of these operating patterns is that

[77] Available at: http://nemweb.com.au/REPORTS/ARCHIVE/ROOFTOP_PV/ACTUAL/.

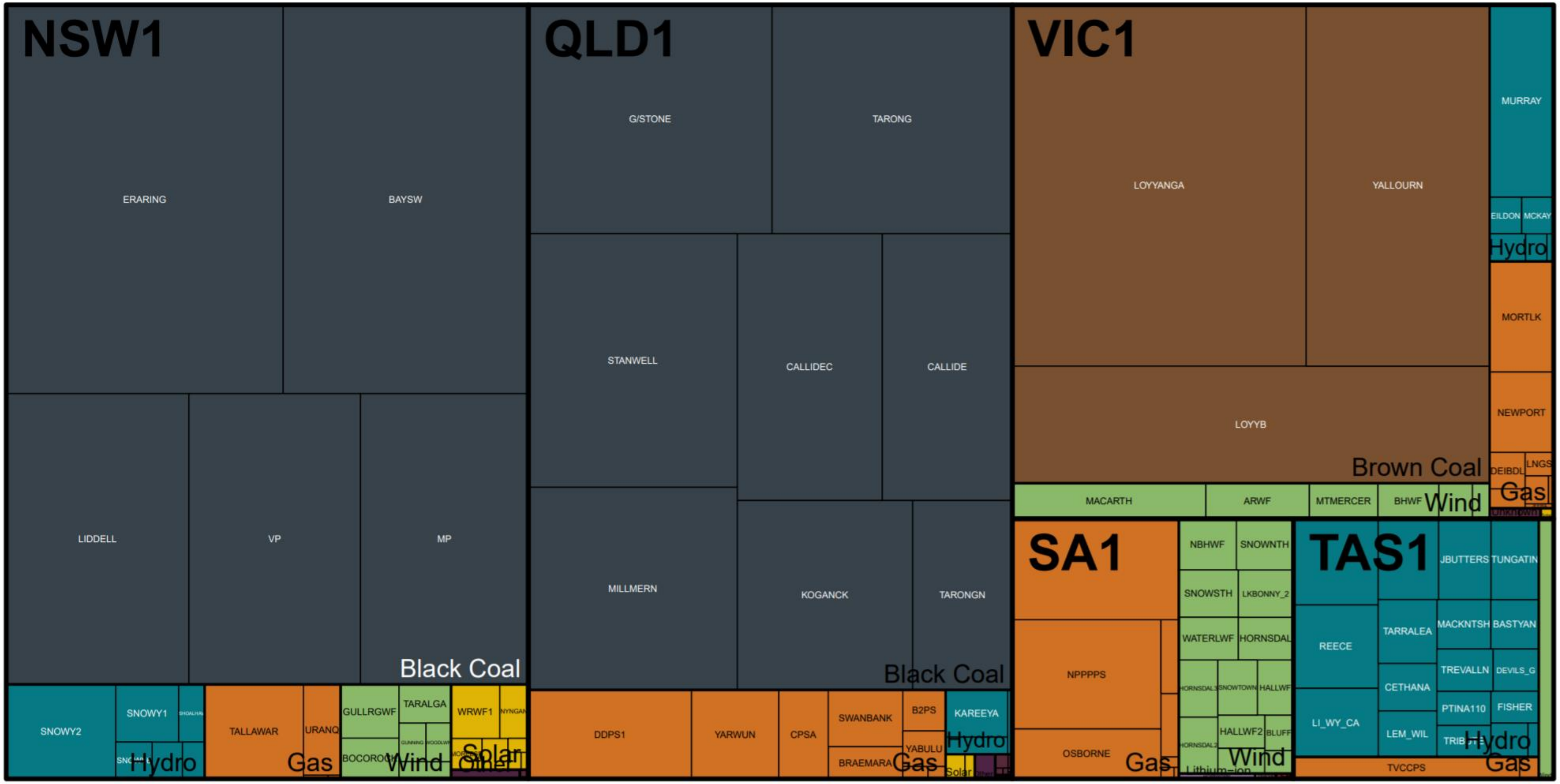
actual output in the NEM is dominated by black and brown coal from New South Wales, Queensland and Victoria.

Figure 29: NEM station capacity by region and fuel type



Source: Frontier Economics analysis of AEMO data (generation information Nov 02 2018 - https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information)

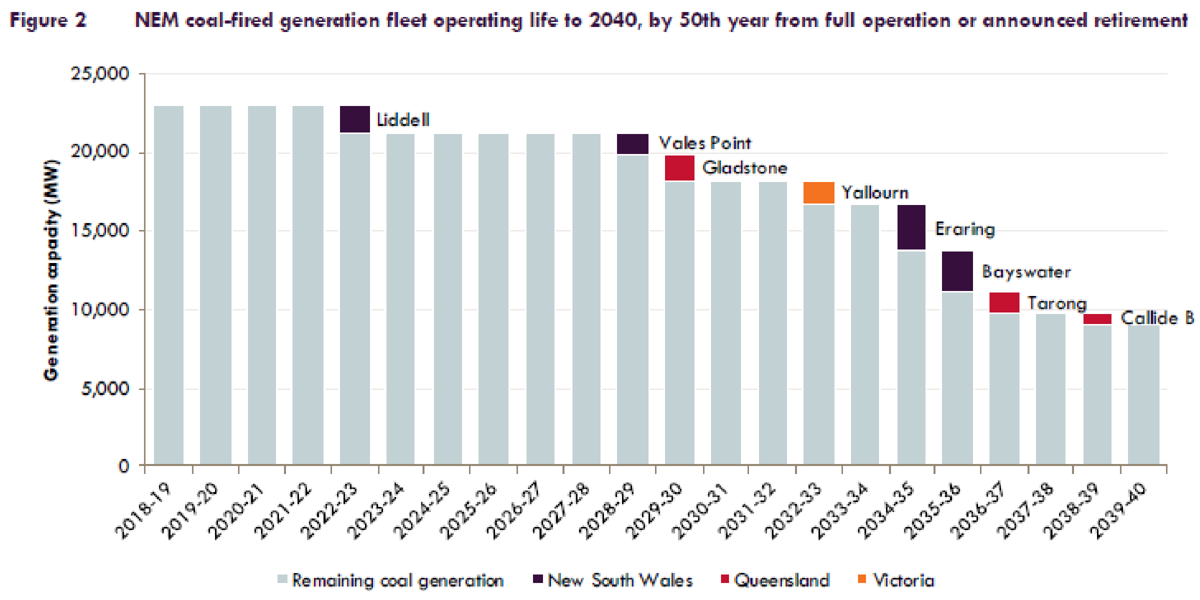
Figure 30: NEM station output by region and fuel type



Source: Frontier Economics analysis of AEMO data (MMSDM)

Despite its present dominance of the NEM plant capacity and output mix, the overall level of coal-fired generation capacity has peaked and is likely to diminish in future decades due to ongoing plant retirements **Figure 31** below shows the current stock of NEM coal-fired power stations and when they are due to be decommissioned (either when announced or after 50 years assumed). Substantial retirements are due in the 2030s, and are unlikely to be replaced with new coal. It is possible that some of these retirements (e.g. Yallourn) may be brought forward into the 2020s.

Figure 31: AEMO ISP projections of coal-fired power station retirements



Source: AEMO ISP, p.22

Part 2 – Future cost projections

CO2CRC et al, Australian Power Generation Technology Report (2015)

While the cost data in the CO2CRC et al (2015) report[78] were considered "significantly out of date" by the CSIRO in its 2017 update (see below), the CO2CRC et al (2015) report is a much more detailed document than the 2017 update and contains some useful information on unit sizes and economies of scale, particularly for renewable plant of different technologies. In particular, it highlights that renewable generators are typically available in much smaller unit sizes than traditional generators.[79]

- Wind turbines investigated in the study consist of 3 MW turbines,[80] with farm sizes of 50 MW and 200 MW – exhibiting fairly modest economies of scale:[81]
  - Capital cost (sent-out):
    - 50 MW: $2,550 / kW
    - 200 MW: $2,450 / kW
  - Operating and maintenance (O&M) cost (per annum):
    - 50 MW: $60 / kW
    - 200 MW: $55 / kW
- Solar PV is evaluated at residential (5 kW), commercial (100 kW) and utility-scale (10 MW and 50 MW) sizes, with utility-scale plant assessed at fixed, single-axis and dual-axis mounts – also exhibiting limited economies of scale:[82]
  - For fixed module mounting:
    - Capital cost (sent-out):
      - 5 kW: $2,100 / kW
      - 100 kW: $1,950/ kW
      - 10 MW: $2,400 / kW
      - 50 MW: $2,300 / kW
    - O&M cost (per annum):
      - 5 kW: $30 / kW
      - 100 kW: $30 / kW
      - 10 MW: $30 / kW
      - 50 MW: $25 / kW

78 Wiley, D., Neal, P., Ho, M. 2015, Fimbres Weihs, G., *Australian Power Generation Technology Report*, CO2CRC, CSIRO, ARENA, Office of the Chief Economist (Federal Department of Industry and Science) and anlecr&d (CO2CRC et al (2015)).

79 CO2CRC et al (2015), p.17.

80 The CO2CRC et al report notes that average size of onshore wind turbines being installed continues to increase (p.49). While the report anticipates that offshore turbines will increase in capacity to 10-20 MW per turbine over time, it notes that onshore turbines are expected to be limited to 3-5 MW due to logistical and construction requirements (p.53). The report notes that, "Offshore wind has been developed at commercial scale globally in shallow waters. No resource maps have been developed for offshore wind in Australia. This is in part due to the narrowness of the continental shelf." (p.232)

81 CO2CRC et al (2015), p.115.

82 CO2CRC et al (2015), p.234.

- For utility-scale single-axis module mounting (which offers higher capacity factors):
  - Capital cost (sent-out):
    - 10 MW: $2,850 / kW
    - 50 MW: $2,700 / kW
  - O&M cost (per annum):
    - 10 MW: $40 / kW
    - 50 MW: $35 / kW
- For utility-scale dual-axis module mounting (which offers the highest capacity factors):
  - Capital cost (sent-out):
    - 10 MW: $3,600 / kW
    - 50 MW: $3,400 / kW
  - O&M cost (per annum):
    - 10 MW: $45 / kW
    - 50 MW: $40 / kW

- Solar thermal is investigated as a single 125 MW plant with 6 hours of direct two-tank molten storage.[83]
- Nuclear plant is investigated at a 1,100 MW unit size.[84]
- Baseload fossil fuel unit sizes are generally assumed to be no greater than 500 MW, irrespective of the specific technology (pulverised coal, integrated gasification combined cycle and natural gas combined cycle). However, ultra-supercritical pulverised coal is included in the study at 650 MW for comparison purposes.[85]

CSIRO: Hayward & Graham (2017)

More recent research produced by the CSIRO highlights the falling costs of new generation technologies.[86]

Hayward & Graham (2017) developed cost projections for a range of both conventional and new technologies out to 2050 taking into account 'learning effects' – which reduce deployment costs – of the following nature:

- Rapid learning during the early stages of a new technology's development
- Declining rates of learning as the technology increases its market share – due to established engineering and thermodynamic limits on the size of strength of components or theoretical maximum energy conversion efficiency.
- Except for solar photovoltaic generation and battery storage – which "do not appear to have a strongly settled set of underlying material components".[87] For these technologies, Hayward &

[83] CO2CRC et al (2015), p.233.

[84] CO2CRC et al (2015), p.236.

[85] CO2CRC et al (2015), p.225.

[86] Hayward, J.A. and Graham, P.W. 2017, *Electricity generation technology cost projections: 2017-2050*, CSIRO, Australia (Hayward & Graham (2017)).

[87] Hayward & Graham (2017), pp.5-6, says, "While silicon panels are currently the dominant solar photovoltaic technology, there are a number of alternative materials being explored where significant progress is being made in achieving efficient energy

Graham (2017) apply their high historically observed learning rate indefinitely: "In practice, this means these technologies can achieve steeper cost reduction curves for longer than other technologies."[88]

- No learning-based cost reductions are applied to mature technologies, but a small fixed annual decline is applied across their cost inputs to reflect general productivity growth.

Hayward & Graham (2017) develop cost projects based on two scenarios:

- 2 degrees' warming (formerly 450 ppm); and
- 4 degrees' warming (formerly 550 ppm).

In the 2 degrees scenario, stronger policy action results in faster deployment and learning-based cost reductions in carbon capture and storage (CCS). However, CCS is generally deployed at a lower level than in the CSIRO's 2015 projections due to the unexpectedly large fall in projected renewable costs – particularly rooftop solar PV and solar thermal – since 2015. The new assumption about ongoing learning for solar PV along with cost reductions observed since 2015 contributed to this outcome. The solar thermal cost reductions were informed by the 150 MW South Australian Aurora project due for completion in 2020, which helped to 'restore confidence' in solar thermal projections after initial optimistic cost projections were disappointed due to the diversion of investment funds towards solar PV and wind. Wind also experienced some cost reductions compared to the 2015 projections.

Battery cost projections are largely derived from the deployment and learning effects produced by a separate transport model. Cost projections have nearly halved since the projections incorporated in the ENA Transformation Roadmap. However, the 'balance of plant' costs remain very significant.

While making a number of caveats around their calculation and use, Hayward & Graham (2017) publish conventional levelised cost of energy estimates to illustrate the effect of changes in projected capital costs since 2015. They go on to refer to other modelling which shows that the need for the deployment of intermittent renewable plant to be complemented by 'firming' capacity commences as the variable renewable share in a market rises beyond 40 per cent. From 40 to 60 per cent renewable capacity share, the modelling favoured installing batteries as a complementary technology, whereas 60 per cent, open-cycle gas turbines (OCGT) were required. By the time 90 per cent variable renewable generation is reached in 2050, the following approximate complementary capacity was required for each kW of variable renewable plant:

- 0.75 kW of batteries and synchronous condensers
- 0.4 kW of flexible dispatchable capacity (e.g. OCGT).

By 90 per cent variable renewable share, wind had suffered a 17 per cent reduction in capacity factor and solar PV had suffered a 39 per cent reduction due to the need to 'spill' excess energy production. They note that, "However, the increasing losses to the capacity factor does not significantly increase the total cost of generation because, over time, the cost of capital has also fallen to offset this effect."

While this research does not directly discuss declining economies of scale and lumpiness, it can be inferred from the inherent nature of rooftop solar PV and the relatively small sizes of wind and solar thermal plant.

conversion and in different systems for installing the solar conversion system (Jacoby, 2016) (Fraunhofer ISE, 2015). This could mean improvements not only in the panel but in the installation and balance of system costs. Similarly, alternative battery chemistries and configurations also continue to be explored with no obvious limit on what might be achieved (Miller, 2017)."

[88] Hayward & Graham (2017), p.6.

Figure 32: Comparison of 2017 4-degrees and 2015 550ppm scenario costs, 2017 $A sent-out basis

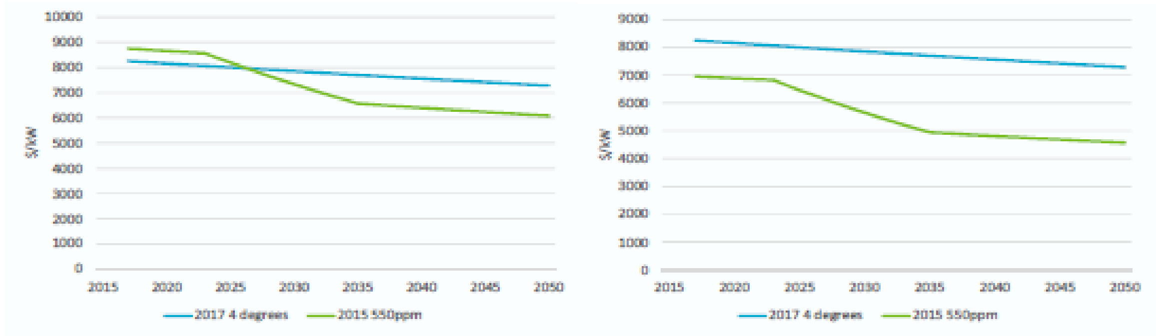


Figure 3-1: Brown coal with CCS (left) and black coal with CCS (right)

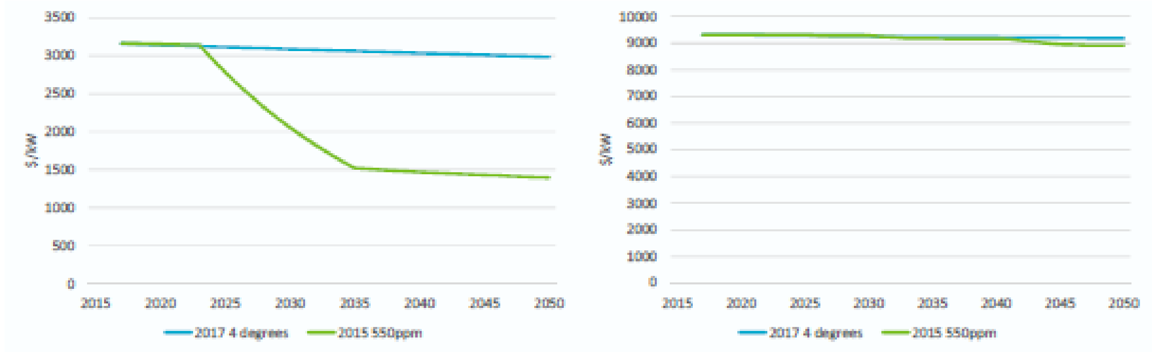


Figure 3-2: Gas with CCS (left) and nuclear (right)

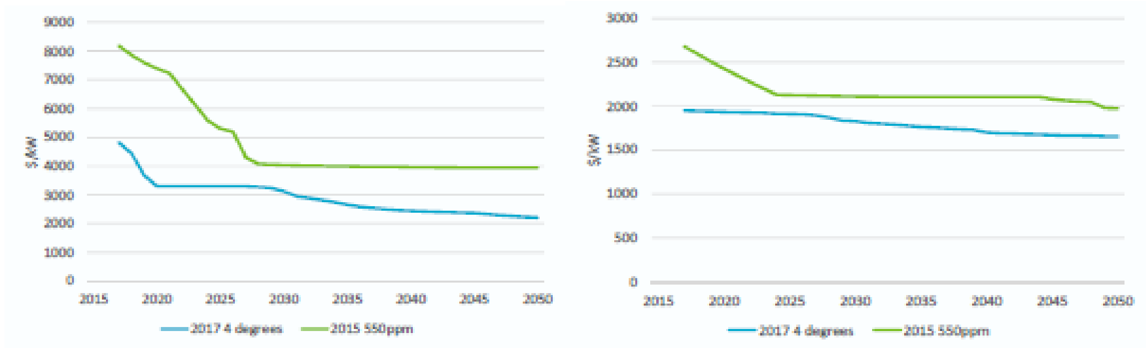


Figure 3-3: Solar thermal with 6 hours storage (left) and wind (right)

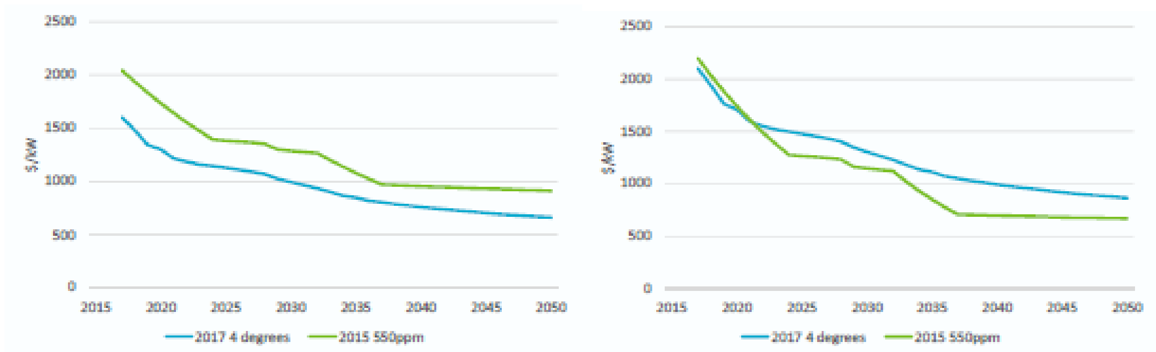


Figure 3-4: Rooftop solar photovoltaics (left) and large scale solar photovoltaics (right)

Source: Hayward & Graham (2017), p.9.

Figure 33: Comparison of 2017 2-degrees and 2015 450ppm scenario costs, 2017 $A sent-out basis

Source: Hayward & Graham (2017), p.10.

Figure 34: Battery-only cost projections: 2017 update and previous projections, 2017 $A

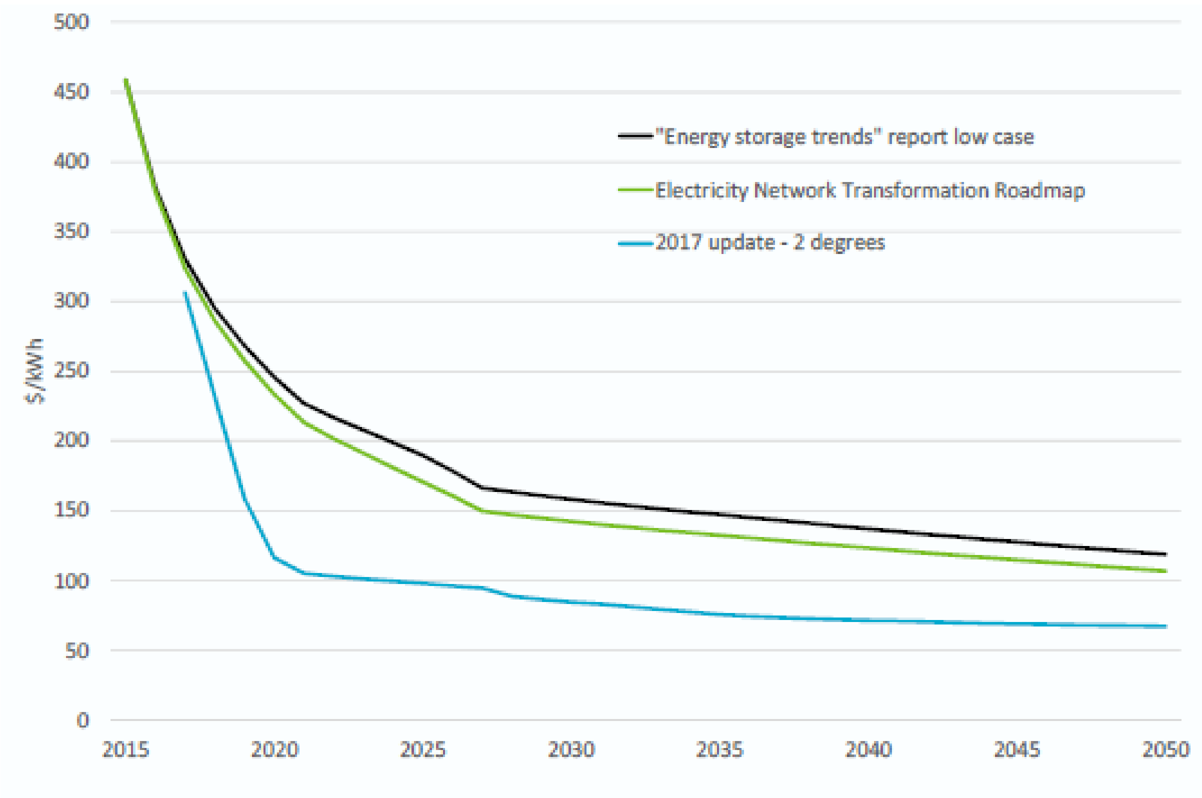


Figure 3-12: Comparison of battery only cost projections: 2017 update and previous projections, 2017 AUS dollars

Source: Hayward & Graham (2017), p.14.

Figure 35: Previous CSIRO and other publicly available electricity generation technology cost projections for 2030

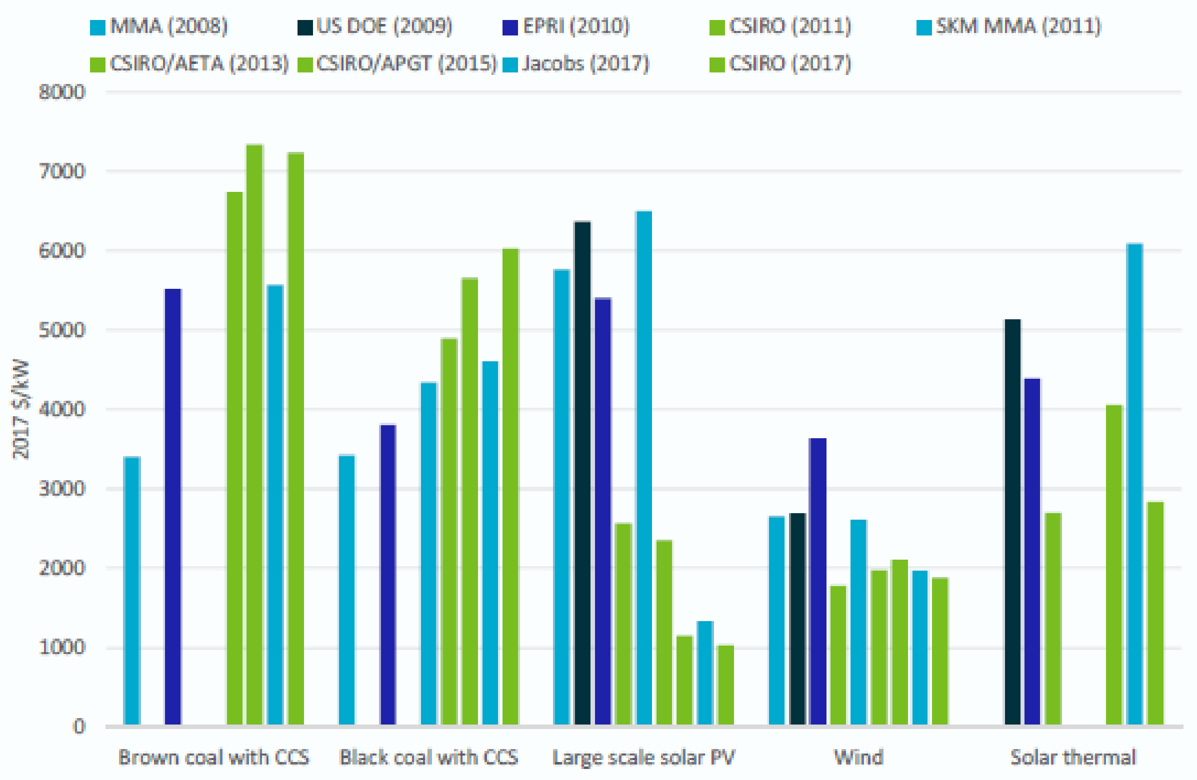


Figure 3-13: Previous CSIRO and other publicly available electricity generation technology cost projections for 2030

Notes: All CSIRO projections are shown in green with earliest starting on the left where available. The 2015 APGT was written by EPRI with cost projections provided by CSIRO. Similarly, AETA was written by the Bureau of Resources and Energy Economics and consultants. MMA, SKM MMA and Jacobs represent a reasonably continuous projections team with changes to their trading name. Consequently their projections are all shown in blue with earliest projections starting on the left where available.

Source: Hayward & Graham (2017), p.16.

Figure 36: Conventional levelised cost of electricity estimates

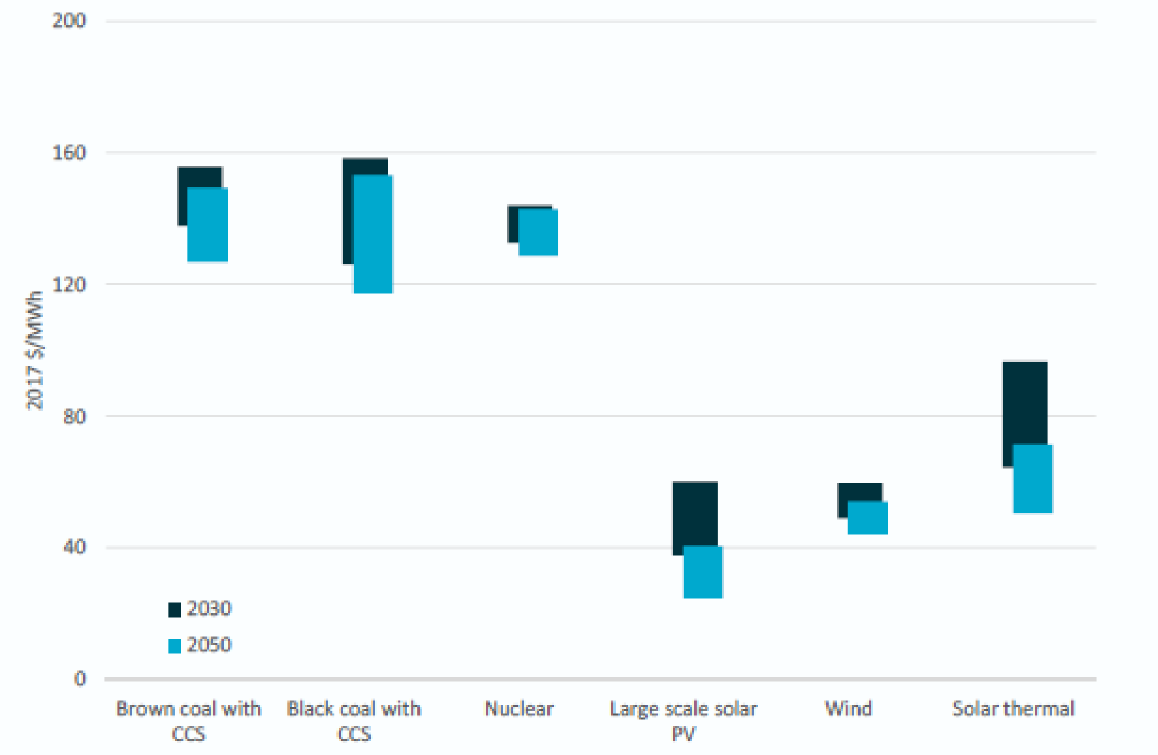


Figure 4-1: Conventional LCOE estimates for selected technologies

Table 4-1: High and low values for key LCOE assumptions

	Capacity factor (%)		O&M 2050 ($/MWh)		Fuel 2050 ($/MWh)	
	Low	High	Low	High	Low	High
Brown coal with CCS	85	85	17	21	15	25
Black coal with CCS	85	85	14	17	25	49
Nuclear	85	85	12	15	11	22
Large scale solar PV	19	32	5	6	0	0
Wind	35	42	6	7	0	0
Solar thermal	40	55	12	17	0	0

Source: Hayward & Graham (2017), p.18.

CSIRO: Graham et al (2018)

The CSIRO recently produced a report providing projections for small-scale embedded technologies, focussing on solar PV panels, batteries and electric vehicles.[89]

This report models three scenarios – Moderate, Slow and Fast – with solar PV and battery (and balance of plant or BOP) cost assumptions for the Moderate scenario largely drawing from the 4 degrees warming scenario in Hayward & Graham (2017). Charts representing both technologies' costs under the three scenarios are reproduced below.

Figure 37: Assumed solar PV capital costs

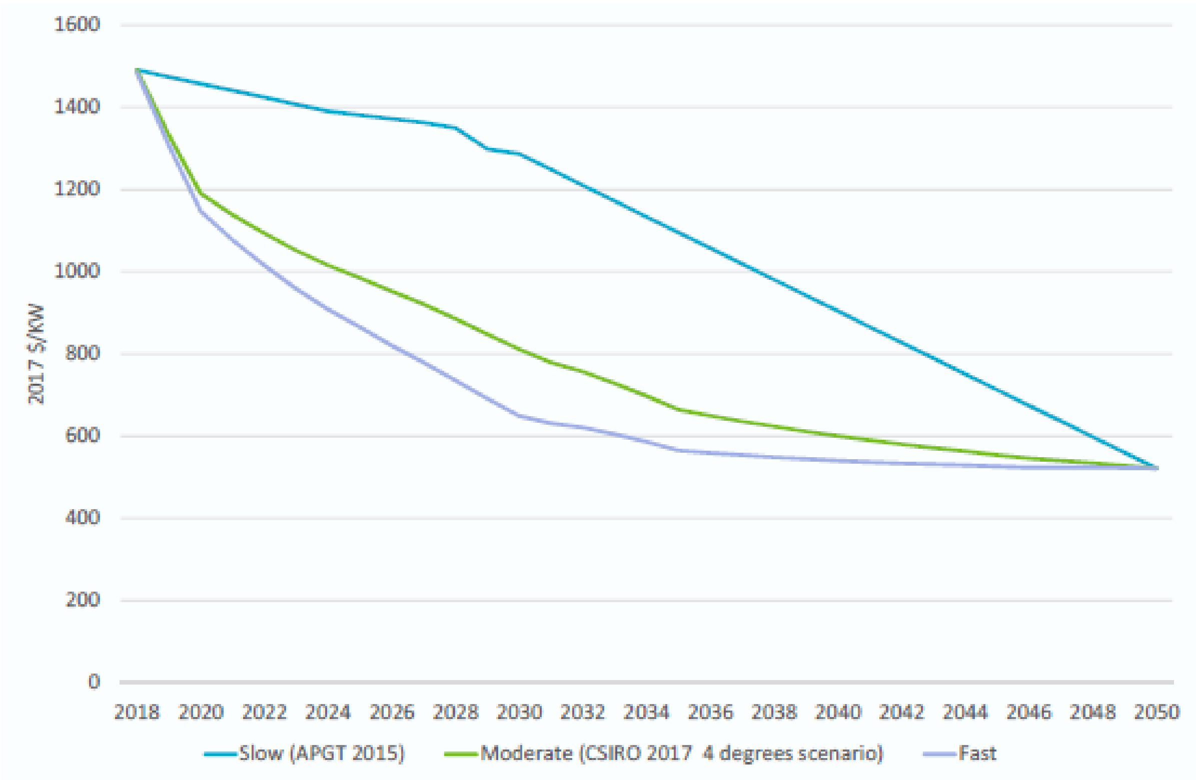


Figure 4-1: Assumed capital costs for rooftop and small-scale solar installations by scenario

Source: Graham et al (2018), p.23.

[89] Graham P.W., Wang D., Braslavsky, J., and Reedman L.J. 2018. *Projections for small-scale embedded technologies, Report for AEMO*, CSIRO, Australia (Graham et al (2018)). The report was published in June 2018.

Figure 38: Assumed battery and BOP capital costs

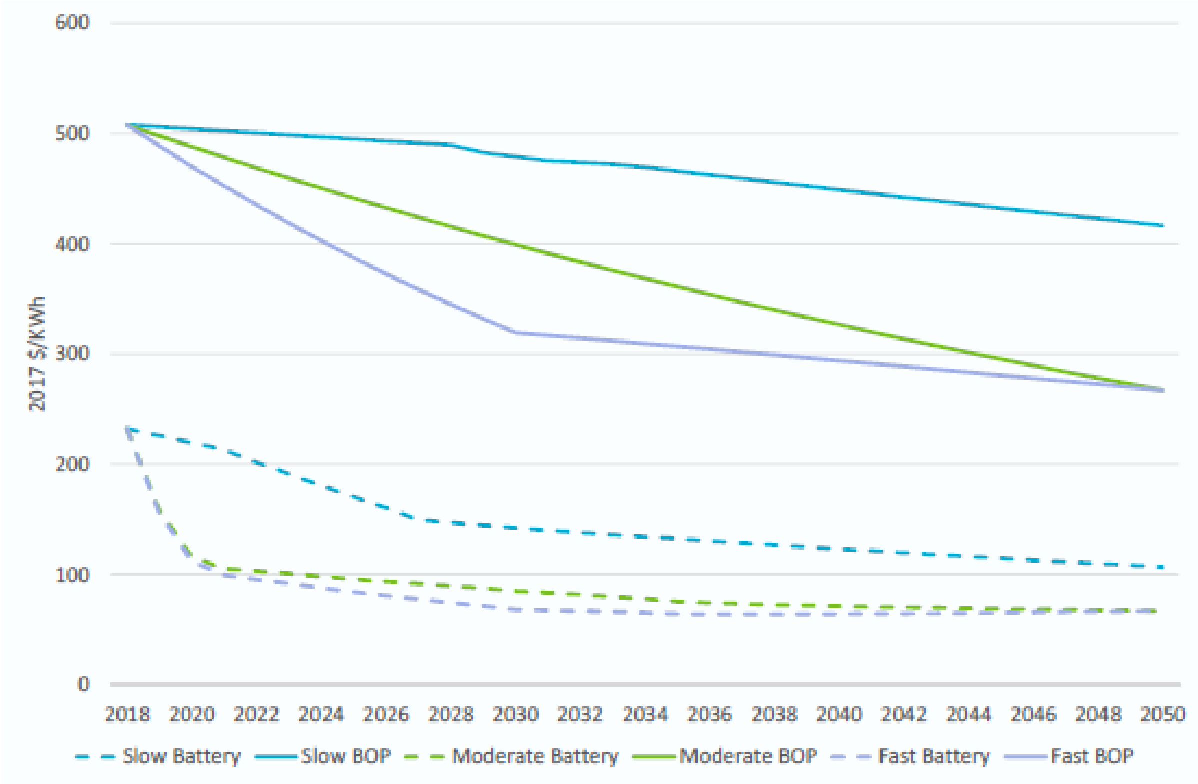


Figure 4-2: Assumed capital costs for battery storage installations by scenario

Source: Graham et al (2018), p.24.

Other key assumptions made in the report are:

- Relevant government subsidy policies for small-scale renewables are the Small-scale Renewable Energy Scheme (SRES) and the Victorian and Queensland Renewable Energy Targets (VRET and QRET). Feed-in tariffs are assumed to continue to be based on the wholesale cost of power.[90]
- Smart tariff structures gradually apply to a larger proportion of customers. In the Moderate scenario, 25 per cent of residential customers face smart tariffs by 2030 and 50 per cent by 2050.Customers facing smart tariffs are assumed to optimise battery usage to minimise grid usage at peak times.[91]

The modelling in the report does not appear to incorporate any technical ‘static’ limits on solar PV exports to the grid.

As a result, Graham et al (2018) came up with national and jurisdictional projections for the adoption of the following technologies across three scenarios:

- Residential rooftop solar PV
- Commercial rooftop solar PV (10 kW to 100 kW)
- Commercial solar PV (above 100 kW) – behaving as non-scheduled generation below 30 MW
- Residential batteries

[90] Graham et al (2018), pp.19-20.

[91] Graham et al (2018), pp.28-30.

- Commercial batteries
- Standalone power systems (SAPS) and
- Electric vehicles

The aggregate size of commercial batteries, and numbers of SAPSs and EVs are expected to be relatively low over the next decade.

To the extent small-scale embedded technologies are adopted, and the manner in which adoption occurs, is likely to have implications for the ability of generators in the wholesale market to influence prices by withholding output. This is discussed in chapter 5 above.

Part 3 – ISP projections

Background to the ISP

Following from the South Australian system black event of 26 September 2016,[92] the 2017 Finkel Review commissioned by the COAG Energy Council recommended that AEMO should have:[93]

> …a stronger role in planning the future transmission network, including through the development of a NEM-wide integrated grid plan to inform future investment decisions. Significant investment decisions on interconnection between states should be made from a NEM-wide perspective, and in the context of a more distributed and complex energy system.

In response to this recommendation, AEMO published its initial ISP in July 2018. The ISP is a cost-based engineering optimisation plan that forecasts the overall transmission system requirements for the NEM over the next 20 years. The ISP takes a range of cost inputs combined with system security and reliability considerations, expressed Commonwealth and State Government policies, to identify transmission investments that will minimise system costs in a number of scenarios. In the ISP's 'Neutral' planning scenario, the lowest cost replacement for this retiring capacity and energy is expected to involve a portfolio that includes solar (28GW), wind (10.5 GW) and storage (17 GW and 90 GWh), complemented by 500 MW of flexible gas plant and transmission investment.[94]

Transmission projections

The ISP recommends a large number of transmission investments in three tranches, depending on how urgent AEMO considers them to be – these tranches are described as follows:

- **Group 1: Near-term construction to maximise economic use of existing resources** – for immediate action to:
  - Increase transfer capacity between New South Wales, Queensland, and Victoria by 170-460 MW.
  - Reduce congestion for existing and committed renewable energy developments in western and north-western Victoria.
  - Remedy system strength in South Australia.

  Cost: $450-650 million

[92] See: https://www.aemo.com.au/Media-Centre/AEMO-publishes-final-report-into-the-South-Australian-state-wide-power-outage.

[93] Finkel Review, Recommendation 5.1, p.124.

[94] ISP, p.5.

Group 2: Developments in the medium term to enhance trade between regions, provide access to storage, and support extensive development of 'renewable energy zones' (REZs) – to initiate now for implementation by the mid-2020s to:

- Establish new transfer capacity between New South Wales and South Australia of 750 MW (RiverLink).
- Increase transfer capacity between Victoria and South Australia by 100 MW.
- Increase transfer capacity between Queensland and New South Wales by a further 378 MW (QNI).
- Efficiently connect renewable energy sources through maximising the use of the existing network and route selection of the above developments.
- Coordinate DER in South Australia.

Group 3: Longer-term developments to support REZs and system reliability and security – for the mid-2030s and beyond.

Generation projections

AEMO's ISP generation plant projections were based on a range of modelling assumptions, including for generator build costs. According to the ISP, build cost assumptions were derived from Hayward & Graham (2017), coupled with AEMO internal analysis.[95] Accordingly, it is unsurprising that the ISP projections tell a similar story to the CSIRO analysis. For the sake of completeness, the ISP's build cost projections to 2029-30 for the 'Neutral' scenario are reproduced in **Figure 39** below.[96]

Figure 40 reproduces Figure 10 from the ISP, which shows the relative changes in installed capacity in the Neutral planning scenario relative to the present generation mix over the next 20 years. It highlights the growth in both rooftop PV and utility solar (solar thermal), as well as the ongoing growth of wind, and the beginnings of significant investment in distributed and utility-level storage.

[95] AEMO ISP, Table 2, p.27.

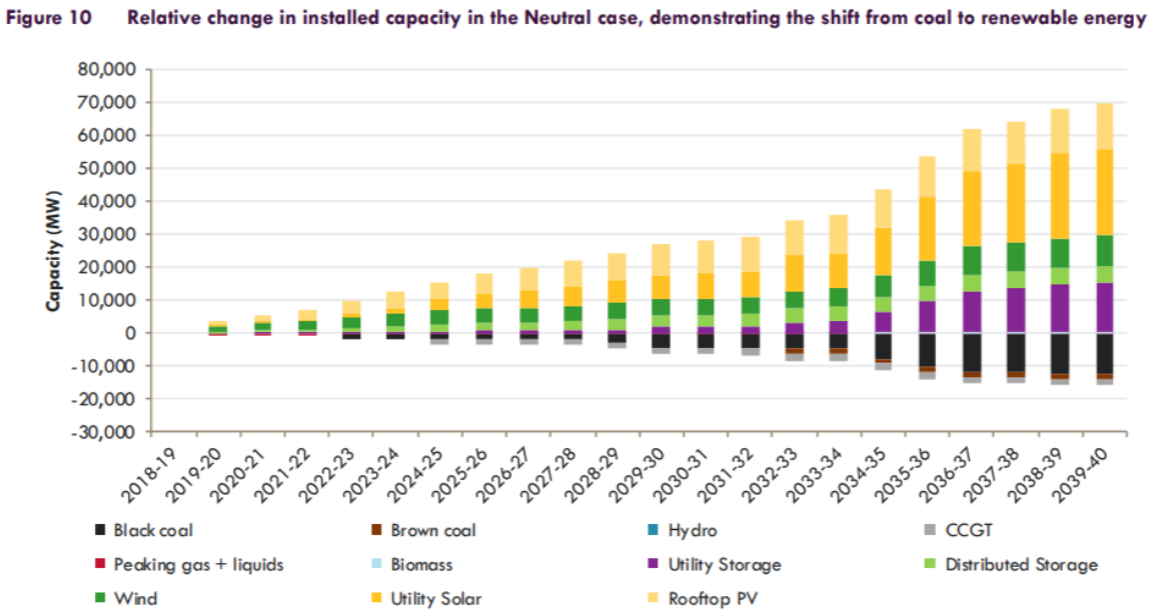
[96] AEMO, *2018 ISP Assumptions workbook*, 17 July 2018, 'Build cost' tab, available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/ISP-database

Figure 39: AEMO ISP – Neutral scenario – build costs ($/kW) real 2017 dollars

Neutral	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
Biomass	$ 3,779.15	$ 3,770.82	$ 3,757.65	$ 3,755.92	$ 3,752.78	$ 3,752.78	$ 3,752.78	$ 3,752.78	$ 3,752.78	$ 3,752.78	$ 3,752.78	$ 3,752.78	$ 3,752.78
CCGT	$ 1,500.68	$ 1,500.66	$ 1,500.66	$ 1,500.41	$ 1,500.30	$ 1,499.99	$ 1,499.69	$ 1,499.39	$ 1,499.11	$ 1,498.46	$ 1,497.45	$ 1,496.49	$ 1,495.56
OCGT	$ 1,019.61	$ 1,014.51	$ 1,009.44	$ 1,004.39	$ 999.37	$ 994.37	$ 989.40	$ 984.45	$ 979.53	$ 974.63	$ 969.76	$ 964.91	$ 960.09
Single-axis Tracking Solar PV2	$ 1,952.05	$ 1,733.25	$ 1,634.67	$ 1,492.50	$ 1,421.39	$ 1,363.01	$ 1,316.62	$ 1,270.06	$ 1,228.59	$ 1,183.76	$ 1,148.26	$ 1,081.55	$ 1,033.69
Solar Thermal Central Receiver (6 hrs storage)	$ 4,434.41	$ 3,677.62	$ 3,299.20	$ 3,299.20	$ 3,299.20	$ 3,299.20	$ 3,299.20	$ 3,299.20	$ 3,296.30	$ 3,137.48	$ 3,031.77	$ 2,905.32	$ 2,835.99
Wind	$ 1,945.06	$ 1,940.42	$ 1,933.93	$ 1,924.78	$ 1,921.10	$ 1,908.58	$ 1,901.27	$ 1,899.67	$ 1,899.10	$ 1,899.01	$ 1,898.92	$ 1,898.77	$ 1,875.96
Pumped Hydro (6hrs storage)	$ 1,386.11	$ 1,379.18	$ 1,372.29	$ 1,365.42	$ 1,358.60	$ 1,351.80	$ 1,345.04	$ 1,338.32	$ 1,331.63	$ 1,324.97	$ 1,318.35	$ 1,311.75	$ 1,305.19
Large Scale Battery Storage (2hrs storage)	$ 1,480.18	$ 1,313.14	$ 1,208.39	$ 1,166.77	$ 1,143.42	$ 1,120.72	$ 1,099.36	$ 1,078.22	$ 1,057.30	$ 1,036.78	$ 1,008.10	$ 986.98	$ 967.01
Black Coal (HELE)	$ 3,268.42	$ 3,263.89	$ 3,249.43	$ 3,233.50	$ 3,233.50	$ 3,233.50	$ 3,233.50	$ 3,233.50	$ 3,233.50	$ 3,233.50	$ 3,233.50	$ 3,233.50	$ 3,233.50

Source: AEMO, 2018 Integrated System Plan Modelling Assumptions workbook, 'Build cost' tab.

Figure 40: ISP projections of changes in plant mix



Source: AEMO ISP, p.38.

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Electricity Market Design Principles

Identifying long-term market design principles to support a sustainable energy future for Australia

A report for the Australian Energy Council

19 April 2018
kpmg.com.au

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This report provides a summary of KPMG's findings during the course of the work undertaken for the Australian Energy Council under the terms of KPMG's engagement letter. This report is provided on the basis that it is for the Australian Energy Council and is to be made public only in accordance with the terms of engagement.

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Executive summary

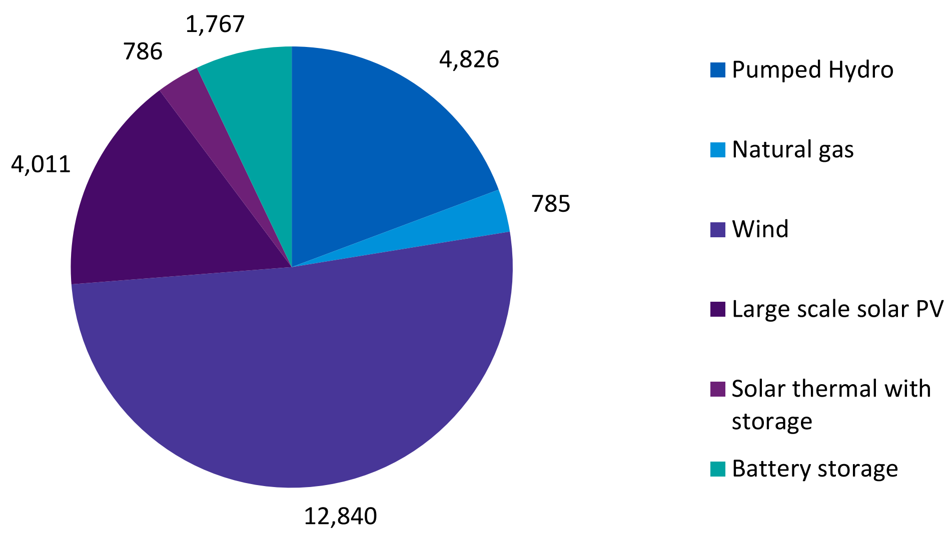
The Australian Energy Council (AEC) has asked KPMG to provide advice on long-term market design principles that support a sustainable energy future for Australia and allow the assessment of potential market design changes.[1] We have also been asked to examine various market mechanisms intended to improve power system security and reliability, and undertake a high level review of these against the principles.

The nature of the challenge

Decreasing wind and solar technology costs, along with government emissions reduction policies, are driving the transformation of the Australian electricity sector. The scale of new investment required through this transition to 2030 is shown in Figure 1. Around $23 billion of expenditure in generation resources alone is expected to be required in the National Electricity Market (NEM) and $2 billion in the Western Australian Wholesale Electricity Market (WEM).

Investors, including customers investing in demand-response, require confidence in the market framework to underpin their decisions. Without confidence, capital for new investment will require higher returns or not be readily available. Policy uncertainty affects affordability – an increase in the cost of capital by 1% is estimated to increase the required annual revenue sought by investors by around 10%.[2]

Figure 1: New generation investment requirement ($m)3



[1] The AEC represents major electricity and downstream natural gas businesses operating in competitive wholesale and retail energy markets.
[2] Based on the difference between a 10% and 11% required return over a 25 year asset life, adjusted for inflation.
[3] Australian Energy Council website.

Market design principles

How do we evolve the current electricity market design to meet these challenges? As the electricity system incorporates new technologies with different physical and technical properties, we need to consider how to evolve the market design to reflect these changes and meet the National Electricity Objective.[4]

Change in any market is inevitable. What is important is this occurs in a way that is well understood and provides both investors and customers with confidence to make long term decisions. A robust market design framework with established and accepted principles is a necessary part of this.

Our recommended principles for wholesale electricity market design are shown in Table 1.

Table 1: Market design principles

Market design principles		
Principle 1	Competition and market signals	Participants responding to market signals in a competitive environment tends to promote better outcomes for consumers than centralised planning.
Principle 2	Risk allocation	Markets that allocate risk, costs and accountability for decisions to those best placed to manage them promote efficient outcomes.
Principle 3	Competitive neutrality	Markets that are technology neutral and do not favour one technology or business model over another encourage consumer needs to be met at the lowest cost and promote innovation.
Principle 4	Clear and durable rules	Markets that are durable across a range of credible future scenarios, and establish a clear and consistent set of rules, provide participants with the confidence to make decisions.
Principle 5	Information asymmetries	For competitive markets to work as intended, market participants need accurate and timely information to make decisions. Without this, they will not be confident they are competing on a level playing field.
Principle 6	Cross-market integration	Costs to consumers will be minimised when markets complementary to energy, such as ancillary services and emissions, are designed in a way that is consistent with the price discovery mechanism for electricity.

These principles reflect the view that an effectively competitive wholesale electricity market, where participants make investment and operational decisions based on market signals, will provide consumers with the energy services they demand at the lowest possible cost.

Market design principles should endure through time and guide market development as the electricity sector evolves.

A useful way of applying the principles is to break down a market mechanism or policy into components. Design choices for each component can then be assessed against the principles. To do this it can be beneficial to start by framing the analysis as questions, such as:

- What services is the mechanism valuing and pricing?[5]
- Is the design of the mechanism clear and easily understood?

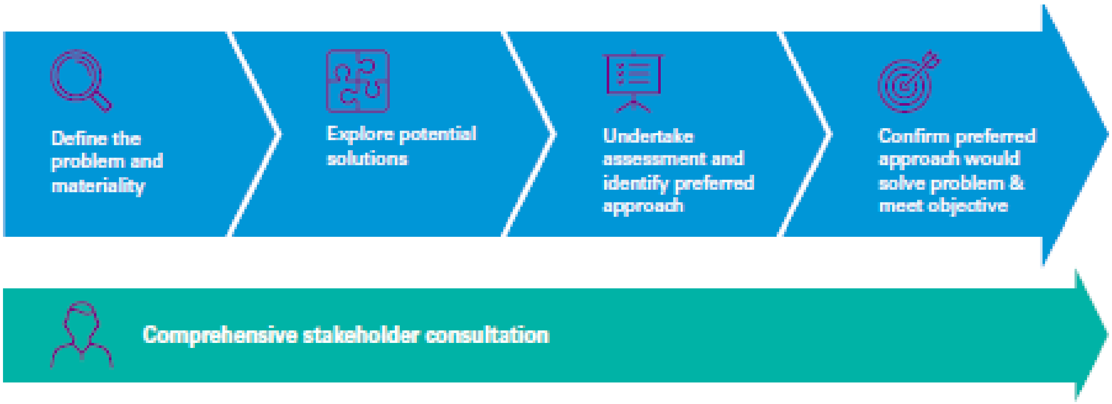
[4] The National Electricity Objective is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to – price, quality, safety, reliability, and security of supply of electricity; and the reliability, safety and security of the national electricity system.
[5] Services could include, inertia, fast frequency response, generator ramping capability, system restart and network control ancillary services.

- What is the role of non-market facing entities and when does decision making pass from the investor and participant to the market operator?[6]
- What is the role of forecasting in the operation of the mechanism and who is exposed to the risk of inaccurate forecasts?
- How will the mechanism affect the hedge contract market?

Good outcomes for consumers requires good regulatory practice

Principles are one aspect to market design – how the principles are applied is equally important. Fundamental electricity market reform requires an integrated and well-structured policy development process, as illustrated in Figure 2.

Figure 2: Good regulatory practice



Electricity is a vital input to the Australian economy. Wholesale electricity market rules can have a material impact on the efficiency of the electricity sector, as they are the 'goal-posts' within which market participants make investment and operational decisions.

Prior to considering potential solutions and applying an assessment framework, it is critical to understand the problem to be solved and whether it is likely to persist. Not doing so risks solving the wrong problem or a non-existent problem.

An effective process involves comprehensive stakeholder consultation. Facilitating industry participation in market reform processes creates a sense of ownership, which is essential for successful outcomes. Ultimately, the outcomes for consumers from market reforms will be enhanced when participants understand, adapt their behaviour and embrace the change.

Understanding the problem

Variable renewable energy is creating new challenges for a power system designed around coal, natural gas and hydro. Events in South Australia and New South Wales in 2016 and 2017 have raised the public profile of electricity supply and focussed attention on the functioning of the National Electricity Market.

The wholesale electricity market design must deliver a secure, reliable and affordable supply of electricity with a decreasing emissions intensity. To do this it needs to ensure that the right investments are made across the supply chain, at the right time and at least cost.

[6] Non-market facing entities include transmission and distribution networks, and the services they could provide to the wholesale electricity market, such as inertia through synchronous condensers.

There are two factors under the current National Electricity Market design that could impede this outcome:

- Lack of integration of emissions reduction policy into the wholesale electricity market, which is delaying new investment due to policy uncertainty; and
- Not identifying and pricing all services necessary to incorporate increased variable renewable energy into the power system, such that market participants can respond to these price signals and provide services like inertia, ramping and fast frequency response.

Reliability is different to security

While the public commentary has sometimes indicated otherwise, the National Electricity Market has performed well in terms of the **reliability of wholesale electricity**. In 2016/17, the market achieved a reliability level of 99.9996% - above the standard of 99.998%.[7]

Notwithstanding this, recent events have resulted in a **public perception** that there is a reliability problem or that one will emerge with the growing penetration of variable renewable energy. This needs to be addressed by all stakeholders to **regain customer trust** and investor confidence.

Maintaining system security – or the ability to operate the system within defined technical limits – appears to be the current challenge facing the market. In 2016/17 there were 11 instances of the system being operated outside its secure limits for greater than the maximum allowable time of 30 minutes under the Frequency Operating Standard.[8]

Maintaining system security has become more complex as variable renewable energy, such as wind and solar, form a greater proportion of the energy mix. Issues around system security are currently being addressed through a range of initiatives.[9]

The policy landscape is complex

By our count there are a total of 46 policies or initiatives being considered, with 16 focussed on reliability, eight on security, 16 on emissions reduction and six on affordability. Responsibility for these is spread across the Energy Security Board, the Australian Energy Market Commission, the Australian Energy Market Operator, the Commonwealth Government and state governments.

Governments and energy market institutions will pursue initiatives and changes to the market framework in line with their respective functions and responsibilities. To minimise cost and complexity it is important for all bodies to identify and evaluate the multiple interactions and interdependencies, and provide a coherent and consistent market reform pathway.

To assist in framing the role of proposed market reforms, Figure 3 places eight market mechanisms currently under consideration on a matrix categorised by the time horizon over which they act – operational or investment – and whether the mechanism primarily acts to address system security or reliability.[10] It shows the mechanisms that have been topical recently generally have reliability as their key objective.

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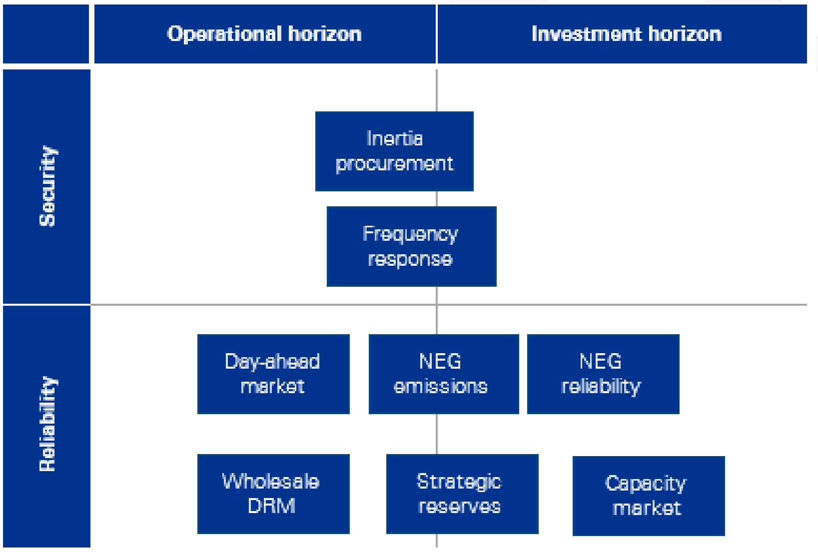
[7] AEMC Reliability Panel, Annual Market Performance Review 2017 (2018)
[8] AEMC Reliability Panel, Annual Market Performance Review 2017 (2018)
[9] Over the past 12 months, a lot of work has been undertaken on security issues, culminating in a number of rule changes around managing power system security, fault levels and inertia that have recently been finalised and are being implemented.
[10] Decisions on the operational horizon support day-to-day operation of the market, while those on the investment horizon are related to major capital investments.

Figure 3: Categorisation of wholesale market mechanisms



Preliminary review of market mechanisms against the principles

Our preliminary review of the above market mechanisms against the principles is summarised in Table 2, which also includes the constrained access reforms in the WEM.

We note where development work is being undertaken on these mechanisms, the design process is generally at an early stage and therefore our findings could change.

Table 2: High-level review of policies against the principles

Market Mechanism	Primary objective	Summary of review
NEG emissions guarantee	Reduce emissions/ enhance reliability	The emissions guarantee is still at an early stage, but could be developed in a way that is consistent with the market design principles. Key uncertainties include the impact on ASX hedge contracts and increased transaction and compliance costs, which can be expected to increase barriers and reduce competition.
NEG reliability guarantee	Enhance system reliability	Similar to the emissions guarantee, the reliability component is still at an early stage of development. It could be designed to flag to participants the types of services required and allow a market response. Long trigger times will result in a proxy capacity market and may undermine private investment.
Capacity market	Enhance system reliability	Subject to the specific design, a capacity market is unlikely to be consistent with the market design principles because investment risk is generally transferred from market participants to consumers through a central decision-making body. Consumers are not best placed to manage this risk.
Day-ahead market	Enhance system reliability	There are many different types of day-ahead market designs. Subject to the problem definition, a voluntary exchange-traded market could be developed in a way that adds value to participants if it facilitates more flexible hedge contracting.

Market Mechanism	Primary objective	Summary of review
Strategic reserve	Enhance system reliability	For an energy-only market design to be sustainable in the current environment, a credible 'safety net' is required. However, a strategic reserve with long lead times undermines a market response and transfers risk to consumers. Any design needs to be well considered, including whether adjustments to the existing Reliability and Emergency Reserve Trader framework would meet the policy objective.
Wholesale Demand Response Mechanism (DRM)	Enhance system reliability	A wholesale DRM has been considered multiple times since the start of the NEM. A wholesale DRM that makes payments for demand reduction is theoretically sound but complex to implement in practice. The high price cap in the NEM should provide a strong incentive for participants to develop demand response capability.
Inertia and frequency response	Enhance system security	The changing energy mix in the NEM is driving the need for the market to explicitly procure new services to support system security. As variable renewable asynchronous generators displace thermal plant in the energy mix, inertia drops and the system becomes more vulnerable to contingencies. Markets to price inertia and faster frequency response will support the efficient supply of these services.
WEM constrained access	Reliability	Constrained access supports an efficient allocation of network congestion and will likely provide better opportunities for generators to connect to the network. Transitional arrangements may be implemented to recognise existing network access rights.

Contents

1 Introduction

1.1 A changing energy mix

Changes in relative technology costs between fossil fuel and renewable energy capacity is shifting the generation mix of the Australian electricity sector. Coal-fired generation is retiring and being replaced by wind and solar capacity. While this transformation has been supported and accelerated by government policies, wind and large-scale solar are becoming competitive with traditional thermal plant on a levelised cost of energy basis.[11]

With renewables occupying a growing proportion of the energy mix, these technologies are creating new challenges for a power system designed around coal and gas-fired generators. At the same time, customers are seeking to become more active participants in the market through the use of distributed generation, battery technology and demand-response. Recent events in South Australia and New South Wales in 2016 and 2017 have raised the public profile of electricity market policy and the performance of the National Electricity Market (NEM). Because of this, a number of processes have been initiated to consider how the NEM may need to adapt.[12]

The Chief Scientist of Australia, Dr Alan Finkel, was commissioned in 2016 by the Commonwealth Government to conduct an independent inquiry into the future operation of the NEM. The review attempted to provide guidance on the rapid changes taking place in the electricity market and alleviate growing concerns surrounding the integration of renewable technologies into the grid. On completion, the review recommended several reforms aimed at four key outcomes: increased security, future reliability, rewarding customers and lower emissions.

Electricity is an input into most goods and services produced by the Australian economy. Accordingly, the performance of the economy is inextricably linked to the efficiency of the electricity sector. Wholesale electricity costs account for around 42% of residential customer electricity bills.[13] KPMG modelling has shown that a 10% increase in the cost of generating electricity reduces economic output by $4.2 billion per annum, with the export sector being the most affected.[14] Policies that result in inefficiencies in the electricity sector have far-reaching consequences for all Australians.

Wholesale electricity market rules can have a material impact on the efficiency of the electricity sector given they are the 'goal-posts' within which market participants make long term investment and short term operational decisions. As such, changes to the market design must be assessed against a clear set of market design principles designed to achieve an unambiguous overarching objective.

To this end, our report on wholesale electricity market design principles prepared for the Australian Energy Council (AEC) is a timely addition to the debate, providing the industry with a robust framework for considering future design changes.

[11] International Renewable Energy Agency, *Renewable Power Generation Costs* (2017)
[12] For example, the Independent Review into the Future Security of the NEM, the Australian Energy Market Commission's Reliability Frameworks Review and the Australian Energy Market Operator's Integrated System Plan.
[13] Australian Energy Market Commission, *Residential Electricity Price Trends Report 2017 - Information Sheet* (2017), p. 2.
[14] KPMG, *The National Energy Guarantee, Pricing and the Australian economy* (2017).

1.2 Scope and purpose of the report

To prepare for a number of forthcoming consultations on wholesale electricity market design, the AEC asked KPMG to provide its members with an understanding of:

- critical wholesale electricity market elements of the Finkel Review, including (but not limited to) strategic reserves, day-ahead markets and demand response; and
- The National Energy Guarantee (NEG) proposed by the Energy Security Board (ESB).

The AEC's aims for the project are as follows:

- Identify long-term market design principles that would support a sustainable energy future for Australia.
- Articulate the arguments for and against various market mechanisms intended to improve power system security and reliability, and make recommendations for future market design.
- Establish the appropriate principles to assess the Finkel Review's recommendations as they relate to market design and wholesale market issues.
- Identify the most appropriate principles for the ESB's proposed dual guarantees, considering the guarantees' implications and opportunities.

The primary purpose of this report is to help the AEC and its members better understand and assess changes to the electricity market frameworks that have been proposed or are currently being consulted on. The focus is on the NEM, while also covering relevant aspects of the Wholesale Electricity Market (WEM) in Western Australia.

1.3 Our approach to the task

Our approach to the scope of work is as follows:

- **Chapter 2**: Provides an overview of the current reform environment, including recent market events, and the policies and market mechanisms that have been proposed in response.
- **Chapter 3**: Establishes an assessment framework, including a set of market design principles to help frame policy discussions.
- **Chapter 4**: Reviews market mechanisms that have been proposed to meet security, reliability and emissions reduction objectives and tests them against the principles in the assessment framework. The following mechanisms were reviewed:
  - National Energy Guarantee (emissions);
  - National Energy Guarantee (reliability);
  - capacity markets;
  - day-ahead markets;
  - strategic reserves;
  - wholesale demand response mechanisms;
  - inertia and frequency control markets; and
  - Western Australia constrained access.
- **Chapter 5**: Outlines areas for further analysis.
- **Appendix A**: Sets out a detailed overview of policy proposals underway in the Australian electricity market.

- **Appendix B**: Provides a high-level overview of how select mechanisms have performed in international markets.
- **Appendix C:** Sets out a summary table of current policy proposals including categorisations and responsible parties.

1.4 Defining key terms

Terms that are not well defined can lead to misunderstanding and confusion. Notwithstanding certain terms can be contentious and difficult to define, for the purpose of this report we have defined key energy market terms as follows:

- **Reliability:** Reliability is having sufficient generation, demand side response, and interconnector capacity in the system to generate and transport electricity to meet consumer demand.
- **Security:** Security is operating the power system within defined technical limits even if there is an incident, such as the loss of a major transmission line or large generator.
- **Dispatchable generation:** Dispatchable generation refers to sources of energy or load that can respond to instructions to increase or decrease output or usage under normal operating conditions.
- **Variable Renewable Energy (VRE):** VRE is renewable energy generation that fluctuates in response to its fuel source, but is predictable with some degree of accuracy.
- **Investment horizon:** The investment horizon is the length of time required to conceptualise, develop, finance and execute major capital projects that support the operation of the market.
- **Operational horizon:** The operational horizon is the length of time required to conceptualise and execute decisions that support the day-to-day operation of the market.

2 Current situation

The purpose of this chapter is to describe the current situation, including recent events that have led to a range of policy initiatives, policy proposals and debates on wholesale electricity market design.

Additional detail on the policy initiatives and implementation timeframes is included in Appendix A.

2.1 Understanding the problem

A critical piece of any market design process is a body of analysis that clearly defines the problem to be solved. Although KPMG has not been asked to analyse and define the problem as part of this scope, we consider some discussion around the issues facing the market, and how these can be categorised is important context for this report.

Australia is navigating a structural transformation of the generation mix. Around 4,200 MW of coal-fired generation has exited and over 2,000 MW of wind and large scale solar PV has entered the NEM since November 2013. The market is simultaneously in an investment and disinvestment phase, which is unprecedented in its history.[15]

To add to the challenge, the current synchronous generation capital stock is being replaced by asynchronous technology and, given the pace of change, it is not surprising the power system is facing challenges.[16] We make the observation that any structural change generally results in a period of instability as new technologies and systems and processes are developed and implemented.

The International Energy Agency (IEA) focussed on the rapidly evolving Australian energy system in their recent 2018 country policy review, noting the complexity of the task at hand. The IEA observe that uneven growth in renewables entering the system, driven by state policies and falling costs, has prevented holistic system integration. To better coordinate the transition, the IEA recommend several key actions, including the development of a stable energy and climate policy framework.[17]

As discussed throughout this report, the issues facing the NEM are multi-faceted and can be categorised as:

- **Security**: Operating the power system within defined technical limits even if there is an incident, such as the loss of a major transmission line or large generator.
- **Reliability**: Having sufficient generation, demand side response, and interconnector capacity in the system to generate and transport electricity to meet consumer demand.
- **Affordability**: Regaining Australia's electricity cost competitiveness and delivering electricity at the lowest possible cost to consumers.
- **Sustainability**: Reducing the carbon-dioxide emissions produced by the electricity sector in line with Commonwealth and state and territory government emission reduction targets.

[15] AEMO, "Generation Information Page", *National Electricity Market,* accessed 13 March 2018, https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information
[16] Synchronous and asynchronous generators have different physical properties, with asynchronous generators not contributing the levels of inertia or system strength that most synchronous plant, such as coal and gas, provide.
[17] IEA, *Energy Policies of IEA Countries – Australia 2018 Review* (2018), p. 14.

The complexity of solving these issues is reflected in the range and scope of policies and mechanisms proposed by the energy market institutions and governments outlined in section 2.4.

2.2 Recent NEM performance

With respect to reliability, the NEM has to-date appeared to perform well as the market navigates the structural change discussed above. Aside from a few hours over the last decade, there has been sufficient supply of energy to meet demand.[18] Further, the Australian Energy Market Operator (AEMO) is not currently forecasting the reliability standard to be breached over the next 10 years under base case assumptions, although it notes that a material reduction in capacity or increase in summer maximum demand will change this assessment.[19] AEMO is also not currently forecasting material growth to peak demand.[20]

When considering the problem definition, and in particular whether the NEM has a reliability issue, it is illustrative to note that over 97% of supply disruptions since 2007 were due to distribution network issues. Of the remainder, only 0.24% were due to a reliability shortfall.[21] We also note that reliability in the NEM pre-2007 has also been within the reliability standard of 0.002% of unserved energy.

Reliability is an explicit economic trade-off, such that higher levels of reliability will increase consumer bills. If additional capacity or demand response is procured as a 'safety net' for low probability events, these costs will be faced by consumers.

When considering the recent load-interruption events we note the following:

- **South Australian system black (September 2016)**: Caused by an 'act of God' event that resulted in system security being breached and the cascading tripping of generation and network capacity.
- **South Australian involuntary load shedding (February 2017)**: Caused by extreme weather, AEMO short-term wind and demand forecasting inaccuracy and unplanned generator outages, resulting in a reliability shortfall.
- **New South Wales Tomago aluminium smelter demand response (February 2017)**: Caused by extreme weather and unplanned outages, resulting in a reliability shortfall and AEMO instructing Tomago smelter to interrupt some of its load.

Separate to reliability, the market is currently facing a system security challenge. The number of AEMO market interventions has increased in the last 12-18 months due to system security issues in South Australia (not scarcity of energy or frequency control ancillary services).[22] These interventions have predominately been to increase the number of synchronous units (in this case gas-fired generators) online to minimise constraints on output from low cost wind generation due to system security concerns during periods of high wind farm output.[23]

2.3 Future outlook

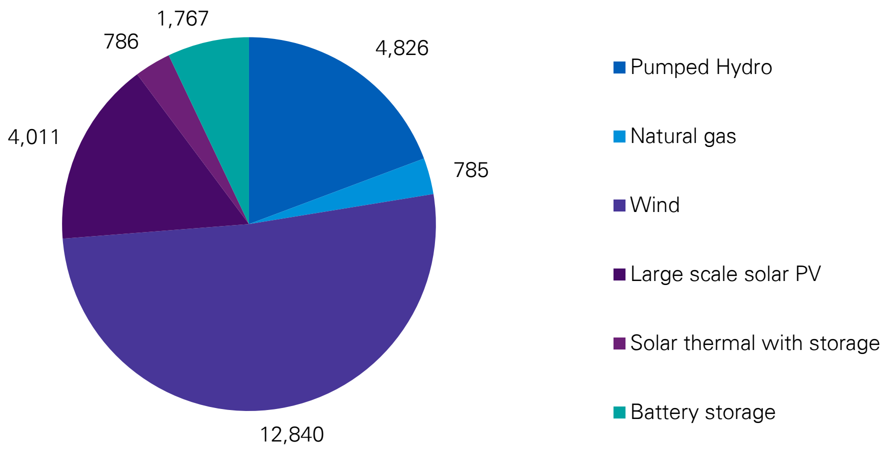
Changes in technology costs and government emissions reduction policies are driving the transformation of the Australian electricity generation mix. The sheer scale of new investment required through this transition to 2030 is shown in Figure 4. Around $23 billion of capital expenditure

[18] AEMC, *Reliability Frameworks Review: Issues paper* (2017), p.104
[19] AEMO, *Electricity Statement of Opportunities* (2017)
[20] AEMO, *2017 Electricity Forecasting Insights*, (2017)
[21] AEMC, *Reliability Frameworks Review: Interim Report* (2017), p.53
[22] ibid., p.229
[23] AEMO, *South Australian System Strength Assessment* (2017)

in generation resources alone is expected to be required in the east coast NEM and $2 billion in the Western Australian Wholesale Electricity Market.

Investors require confidence in the market regulatory framework to underpin their investment decisions. Without confidence, capital for new investment will require higher returns or not be readily available. Uncertainty will affect affordability – KPMG estimates that an increase in the cost of finance by 1% would increase the required annual revenue sought by investors by 10%.[24]

Figure 4: New generation investment requirement ($m)[25]

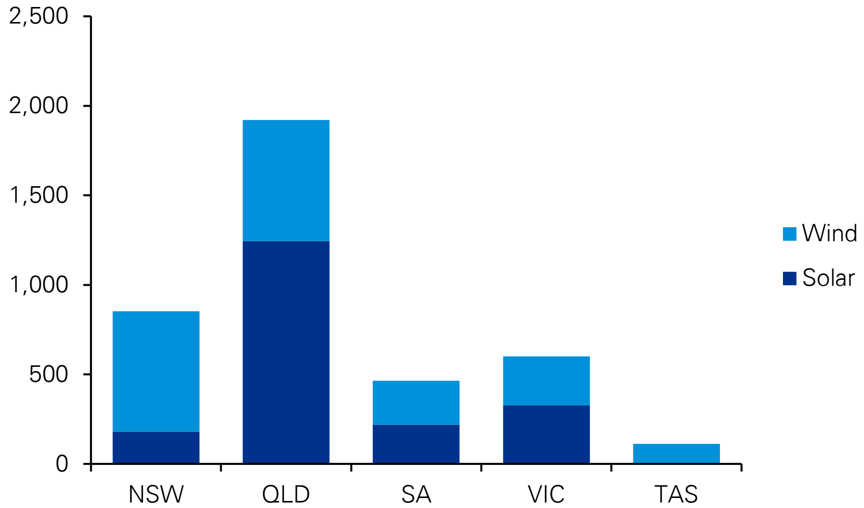


Over 3,500 MW of new wind and solar is either under construction, committed or at an advanced stage of proposal, as shown in Figure 5. Nearly 2,000 MW alone will enter the Queensland region. If publicly announced projects are included, the proposed capacity increases to around 30,000 MW.

Such a large volume of new capacity entering the market over such a short time period will likely result in changes to power flows on the system, altering how AEMO operates the system and potentially resulting in new security and reliability challenges.

Some of the effects on the power system are already being seen through AEMO's draft marginal loss factors for 2018/19, with reductions of around 10% in North Queensland at some connection points.[26]

Figure 5: Investment in new generation capacity (MW) [27]



[24] Based on the difference between a 10% and 11% required return over a 25 year asset life, adjusted for inflation.
[25] Australian Energy Council website
[26] AEMO, *Draft marginal loss factors: FY 2018-19* (2018)
[27] AEMO, "Generation Information Page"

2.4 The policy landscape is complex

To address the challenges in the wholesale electricity market, several policy proposals, mechanisms, and initiatives have been proposed or undertaken, including the:

- Independent Review into the Future Security of the NEM (the Finkel Review);
- Energy Security Board's NEG; and
- Australian Energy Market Commission (AEMC) Reliability Frameworks and System Security reviews, plus associated rule changes.

Table 3 categorises and maps the policies and initiatives underway in the market. As can be seen, responsibility is spread between the Commonwealth Government, ESB, state governments, the AEMC and the Australian Energy Market Operator (AEMO). To provide an understanding of what the initiatives are attempting to achieve, we have categorised the proposed changes as having either a reliability, security, affordability or emissions reduction objective.

By our count there are a total of 46 policies or initiatives being considered, with 16 of these focussed on reliability, eight on security, 16 on emissions reduction and six on affordability. Although some of the policies have multiple objectives or the objectives may not be clear, we have sought to allocate what we consider to be the primary objective of each proposal.[28] We also note that some of the AEMC rule changes, such as 5-minute settlement, have recently been completed – these have still been included given they form an important part of the changing policy environment.

Governments and the energy market institutions will pursue changes to the market framework in line with their respective functions and responsibilities. To minimise cost and complexity it is important for all bodies to identify and evaluate the multiple interactions and interdependencies, and provide a coherent and consistent market reform pathway.

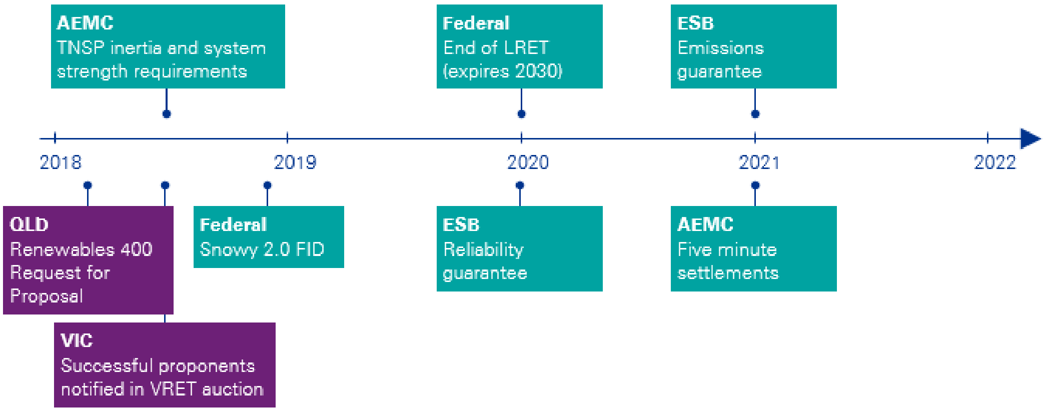
Table 3: Count of energy policy proposals by objective and organisation

	Security	Reliability	Emissions reduction	Affordability	Total
C'wlth	0	1	0	0	**1**
ESB	0	5	1	0	**6**
AEMC	3	4	0	1	**8**
AEMO	4	1	0	0	**5**
SA	0	3	1	2	**5**
QLD	1	1	6	3	**11**
VIC	0	0	5	0	**5**
TAS	0	1	3	0	**4**
Total	**8**	**16**	**16**	**6**	**46**

[28] A detailed breakdown of the categorisation is in Appendix C.

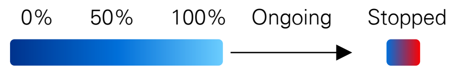
Figure 6 shows a timeline of key events. New system security obligations on transmission network service providers, the subject of recent AEMC rule changes, come into effect mid-2018. Also in the near term, outcomes from the Queensland and Victorian government renewable energy auctions are expected to be known, along with whether Snowy 2.0 will reach final investment decision (FID). As we reach 2020, the large-scale renewable energy target (LRET) is expected to be met and the NEG would become operational if implemented, while 5-minute settlement goes live in 2021.

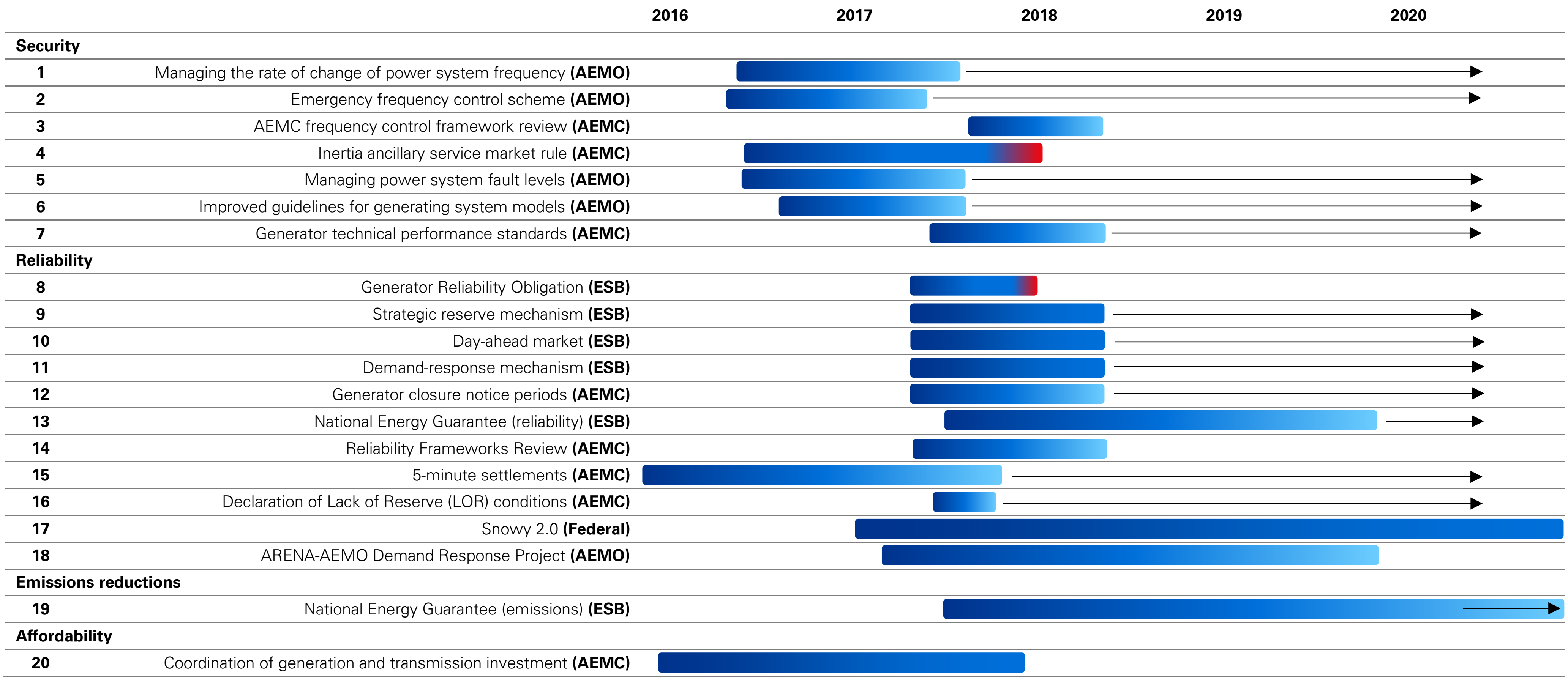
Figure 6: High level timeline of key events



Sections 2.5 and 2.6 summarises the timeframes for all processes currently on foot. As can be seen, most processes or implementation timeframes are expected to continue out to 2020 and in some instances beyond (where there is not a clear decision or implementation date).

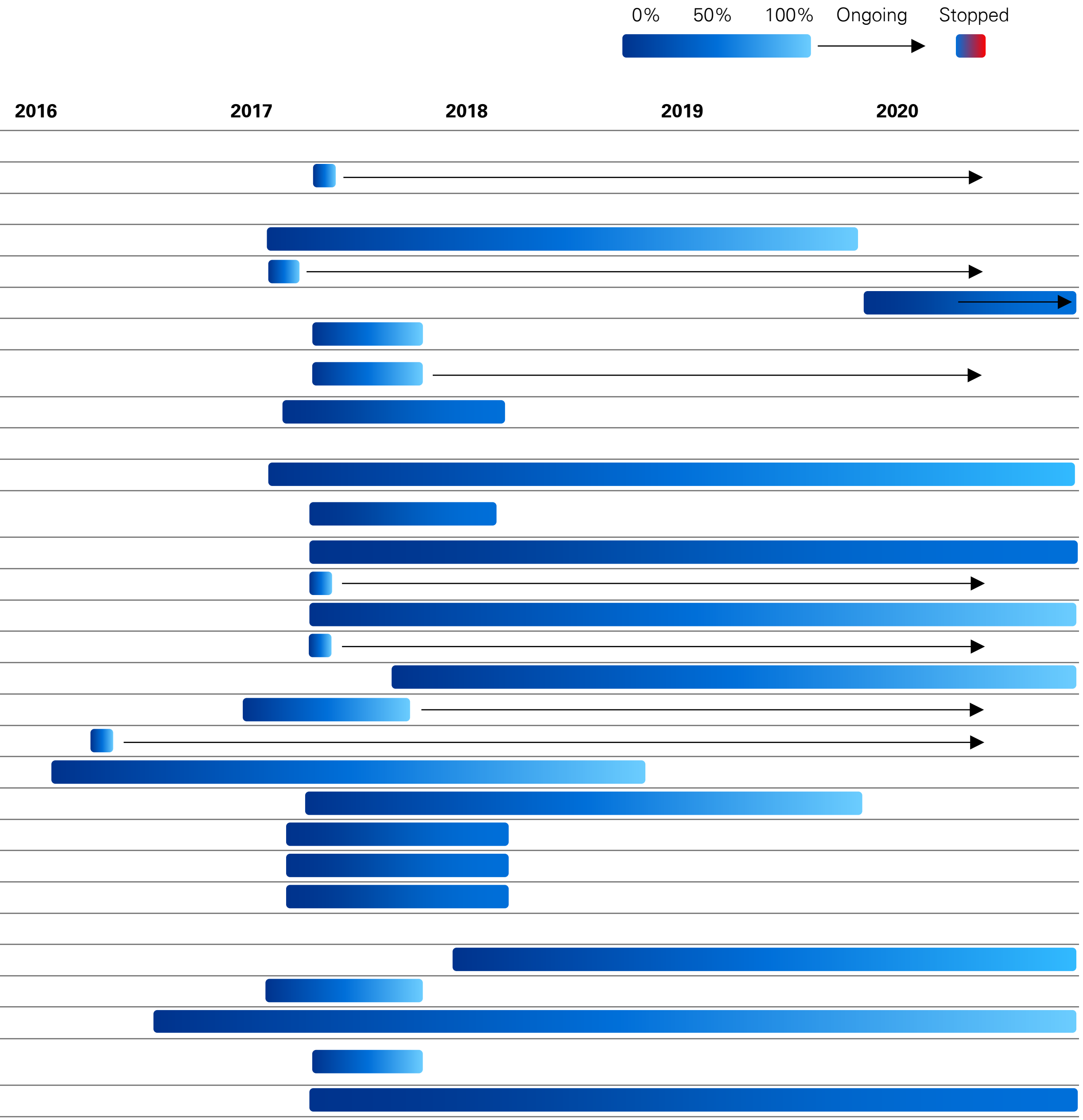
2.5 Federal and market body policies





2.6 State-based policies

Security	
21	Establishment of the Queensland Energy Security Taskforce **(QLD)**
Reliability	
22	New state-owned gas power plant **(SA)**
23	Local powers over the national market **(SA)**
24	Energy Security Target **(SA)**
25	Returning the Swanbank E-gas fired power station to service **(QLD)**
26	Improving the process of large-scale project facilitation, planning and network connections. **(QLD)**
27	Implement pumped hydro capacity in Tasmania **(TAS)**
Emissions reductions	
28	Battery storage and renewable technology fund **(SA)**
29	Investigate the restructure of Queensland Government owned generators, and the establishment of a 'Clean Co' **(QLD)**
30	Powering North Queensland Plan **(QLD)**
31	Confirmation of the 50% Renewable Energy Target by 2030 **(QLD)**
32	Renewables 400 **(QLD)**
33	Advocating for a stable, integrated national climate and energy policy **(QLD)**
34	Victorian Renewable Energy Auction (VREAS) **(VIC)**
35	The *Climate Change Act (2017)* **(VIC)**
36	TAKE2 Pledge Program **(VIC)**
37	New Energy Jobs Fund (NEJF) **(VIC)**
38	Renewable Energy Action Plan **(VIC)**
39	A 'future state' national electricity market **(Hydro Tas)**
40	Tarraleah Power Scheme redevelopment **(Hydro Tas)**
41	Gordon Power Station upgrade **(Hydro Tas)**
Affordability	
42	Funding the Solar Bonus Scheme **(QLD)**
43	New generation for more competition **(SA)**
44	South Australian gas incentives **(SA)**
45	Directing Stanwell Corporation to undertake strategies to place downward pressure on wholesale prices **(QLD)**
46	Implementation of the Queensland Gas Action Plan **(QLD)**



2.7 Most market mechanisms focus on reliability

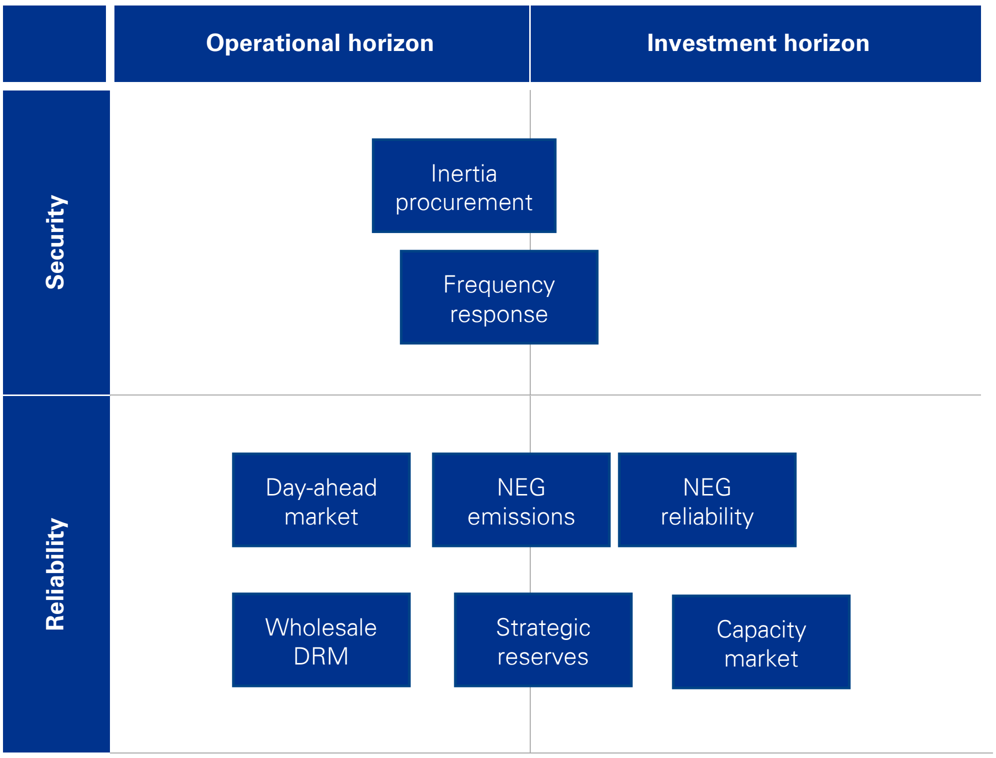
Figure 7 places the eight market mechanisms evaluated in this report (see Section 1.3 and Chapter 4 for a description of each mechanism) on a matrix categorised by the time horizon over which it acts – investment or operational – and the primary objective it is intended to achieve – system security or system reliability. As can be seen, most of the mechanisms currently being discussed are designed to promote system reliability.

The NEG reliability and emissions guarantee, capacity markets and strategic reserve all act on the investment horizon. This is because these mechanisms send signals to participants that primarily influence their decisions on whether to build, return from storage, expand or retire capacity from the market. The NEG emissions guarantee and strategic reserves could also influence operational decisions, as would a wholesale DRM and day-ahead market.

The mechanisms focussing on security are inertia procurement and frequency response. These markets primarily act on the operational horizon, although inertia and Frequency Control Ancillary Services (FCAS) markets can provide longer term investment signals for wholesale market participants or network service providers in terms of the type of capacity to invest in.

Figure 7 highlights a theme in energy policy development that security is a short term operational matter, while reliability is a longer term investment matter. Of course, the two concepts are interrelated – all new generation will have a reliability and security impact, the extent of which is determined by the type of technology. By transparently pricing the security services required by the market, investors will take these revenue streams into consideration when analysing the value of different generation technologies and making an investment decision.

Figure 7: Categorisation of wholesale market mechanisms



2.8 Western Australia

The primary focus of this report is the NEM given the large number of policy proposals and processes underway. However, a number of reforms are also being progressed to consider wholesale market changes to the WEM.

The WEM covers the South West Interconnected System (SWIS) and is a different market design to the NEM's energy-only market, where generators are only paid for the energy they produce. The WEM has a capacity mechanism, which is designed to provide sufficient capacity to meet forecast demand. It also has a day-ahead market, which allows participants to trade around their net contract position, and an on-the-day balancing market.

The WEM has facilitated a significant oversupply of capacity, with an estimated surplus of around 23% in 2016/17.[29] The annual cost of this excess capacity is about $116 million and has led to proposed reforms to the WEM design.[30] The wholesale market reforms are as follows:

- **Reserve Capacity Mechanism (RCM)**: Considers the manner in which the capacity price and capacity volume are determined for generators and demand side management providers in order to reduce the surplus generation capacity.
- **Constrained network access**: Considers accommodating a constrained network access model, including the introduction of facility bidding.

The previous Western Australian electricity market reform program recommended the introduction of a capacity auction to replace the current administrative process for procuring capacity under the RCM. Amendments to the Market Rules were made by the Minister for Energy on 31 May 2016 to implement new arrangements to improve the capacity supply-demand balance before the introduction of a capacity auction design. However, the current Western Australian Government has asked the PUO to review the Reserve Capacity Mechanism to determine if a move to a capacity auction remains an appropriate approach. The PUO will provide its advice to the Minister in September 2018.[31]

On 23 August 2017, the Minister for Energy announced that legislation would be introduced in 2018 to adopt a framework of constrained access to Western Power's electricity network. Constrained network access is expected to promote simpler access to the grid. However, implementation will require changes to the network connections and access regime applying to Western Power, as well as changes to the WEM. Constrained network access is expected to go-live in October 2022.[32]

Further discussion of constrained access is set out in section 4.9.

[29] We note excess capacity fell to 14% in 2017/18 and 4% in 2018/19.
[30] AEMO, *2017 Electricity Statement of Opportunities for the Wholesale Electricity Market* (2017), p.61
[31] Public Utilities Office, *Improving Reserve Capacity pricing signals – alternative capacity pricing options* (2018)
[32] Public Utilities Office, *Improving access to Western Power's network – Information Sheet* (2018)

3 Assessment framework

An assessment framework guides decision making by establishing a common, rigorous approach to assessing proposed changes to the energy regulatory framework. It keeps a market design process focussed on meeting the overarching objective in a particular way.

Wholesale electricity market complexity necessitates a robust assessment framework to guide the analysis and mitigate the risk of bad policy decisions, while promoting industry confidence and understanding in the change process.

This chapter sets out our assessment framework, including market design principles.

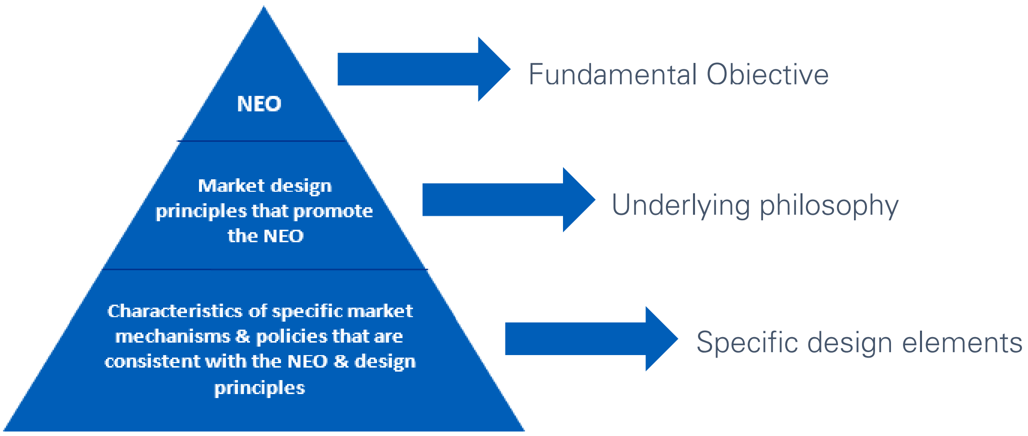
3.1 Assessment framework structure

To be a useful tool, an assessment framework needs to outline a fundamental objective for the analysis and a set of principles for achieving that objective. The principles are representative of a shared understanding and philosophy on how the objective should be achieved and provide additional guidance when undertaking the assessment. As long as the underlying philosophy does not change, an assessment framework should endure through time as the industry evolves.

The assessment framework developed for this report is made up of three core elements, which are shown in Figure 8 as a hierarchical relationship. The highest point in the pyramid is the overarching objective that guides wholesale electricity market design: the National Electricity Objective (NEO). The mid-tier is a set of market design principles that promote the NEO, and at the base of the pyramid are characteristics of specific design elements that promote both the NEO and principles.

Under this approach the top two tiers of the pyramid should be sufficiently robust to endure through time. This is particularly important in an industry with an estimated capital stock in the billions and asset lives that can be over 40 years. With such long-lived assets, investors need certainty as to how changes to the regulatory framework or 'goal posts' will be assessed. The base of the pyramid represents particular characteristics of market mechanisms being considered and, as these are inherently more specific, provide further guidance on design choices.

Figure 8: Assessment framework as a hierarchical relationship



3.2 Overarching objective

The overarching objective for our assessment framework is the NEO. The NEO is set in the National Electricity Law and must be the basis upon which potential amendments to the national electricity arrangements are assessed by the Council of Australian Governments Energy Council (Energy Council) and the energy market institutions.[33]

The NEO is an efficiency objective and is defined as follows (emphasis added):[34]

The National Electricity Objective is to promote ***efficient investment in, and efficient operation and use of****, electricity services for the long term interests of consumers of electricity with respect to – price, quality, safety, reliability, and security of supply of electricity; and the reliability, safety and security of the national electricity system.*

The NEO is structured to drive market design decision-making in a way that supports the:[35]

1. allocation of electricity services[36] to market participants who value them the most, typically through price signals that reflect underlying costs;
2. production of electricity services at the lowest possible cost through employing the least-cost combination of inputs; and
3. ability of the market to readily adapt to changing supply and demand conditions, relative technology costs, and the services required for a reliable and secure market over the long-term by achieving outcomes 1 and 2 over time.

We note the NEO aims to maximise efficiency across a range of parameters, including price, security, reliability and safety. Efficiency is defined for the purposes of this report as the wholesale electricity market providing the electricity services required to meet consumer demand, at the time they are required, and at the lowest possible cost.

Historically wholesale electricity market design has been focussed on maximising efficiency with respect to price through reforms to promote competition. In recent times the focus has shifted to maximising efficiency with respect to reliability and security, as well as price. This has been driven by new technologies and the changing energy mix, and recent events in South Australia and New South Wales discussed above.

3.3 Is the NEO the right objective?

KPMG has not been asked to consider whether the NEO is the ‘right’ objective. However, we make the following observations:

- Market design decision-making is enhanced by having a single, unambiguous objective focussed on efficiency, as an efficient market is one that generally promotes affordability.
- The discipline to justify how market design changes will enhance efficiency in the long term interests of consumers limits short-term reactive decision-making.

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[33] The five energy market institutions are the Australian Energy Market Commission, the Australian Energy Market Operator, the Australian Energy Regulator, Energy Consumers Australia and the Energy Security Board.
[34] *National Electricity (South Australia) Act 1996*, Schedule, s.7
[35] These three outcomes are referred to as allocative, productive and dynamic efficiency, respectively, in the economic literature.
[36] Electricity services include energy, demand response, inertia, frequency control or other ancillary services.

- Expanding the NEO to introduce multiple, and potentially conflicting, objectives will not automatically solve the issues currently facing the NEM.[37]
- Solving our current challenges requires, at a minimum, two key actions so that the private sector can confidently make new investment decisions:
  1. Long-term bipartisan political support on emissions reduction targets; and
  2. A mechanism to reduce electricity sector emissions at the lowest cost for consumers.

3.4 Market design principles

Market design principles represent the underlying philosophy that guides how the fundamental objective will be achieved. When there is more than one pathway to achieving an objective, principles determine which path is taken.

Our recommended principles for wholesale electricity market design are shown in Table 4 below.

We recognise there will always be challenges and trade-offs when applying principles to a market design process. Examples of these challenges are discussed in Section 3.4.2. Notwithstanding this, an assessment will be more robust when starting from first principles and, if required, moving away from these by making explicit trade-offs. Not having a set of principles to act as a map to guide the design process risks unintended consequences.

In addition, having policy makers explain how principles have been applied aids understanding, transparency and stakeholder support for the reforms.

Table 4: Wholesale electricity market design principles

Proposed wholesale electricity market design principles		
Principle 1	Competition and market signals	Participants responding to market signals in a competitive environment tends to promote better outcomes for consumers than centralised planning.
Principle 2	Risk allocation	Markets that allocate risk, costs and accountability for decisions to those best placed to manage them promote efficient outcomes.
Principle 3	Competitive neutrality	Markets that are technology neutral and do not favour one technology or business model over another encourage consumer needs to be met at the lowest cost and promote innovation.
Principle 4	Clear and durable rules	Markets that are durable across a range of credible future scenarios, and establish a clear and consistent set of rules, provide participants with the confidence to make decisions.
Principle 5	Information asymmetries	For competitive markets to work as intended, market participants need accurate and timely information to make decisions. Without this, they will not be confident they are competing on a level playing field.
Principle 6	Cross-market integration	Costs to consumers will be minimised when markets complementary to energy, such as ancillary services and emissions, are designed in a way that is consistent with the price discovery mechanism for electricity.

3.4.1 Philosophy behind the principles

The principles reflect the view that an effectively competitive wholesale electricity market, where participants make investment and operational decisions based on market signals, will provide consumers with the energy services they demand at the lowest possible cost. In this context,

[37] Having multiple objectives leads to more subjective judgment and debate on how to evaluate and resolve the inherent trade-offs in attempting to meet all objectives.

effective competition is defined as a market where firms are generally price takers, entry and exit of participants occurs, and there are firms engaging in rivalrous behaviour.

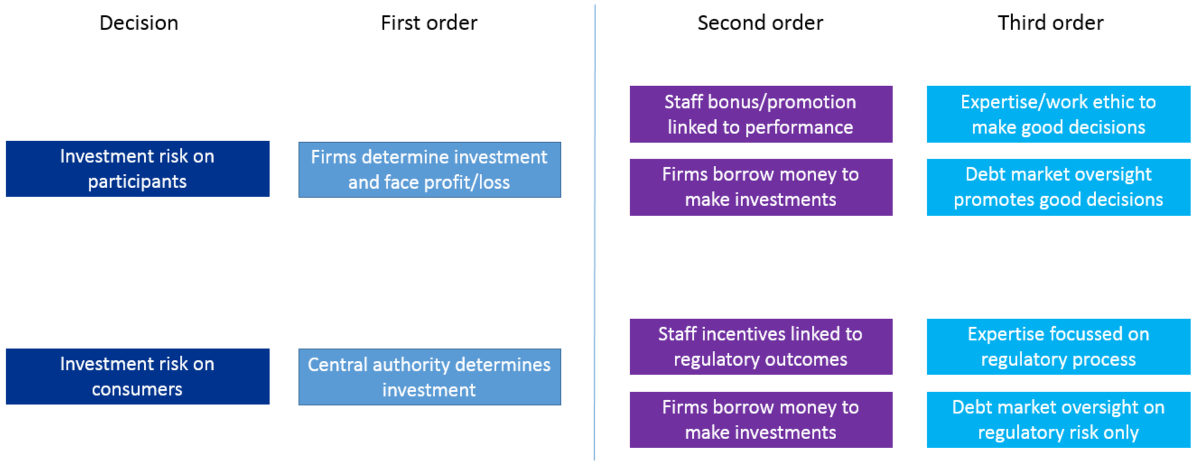
Under this approach, market participants determine how they operate their assets, what they will invest in and when. They also determine when to temporarily or permanently retire existing assets. The rationale for this approach is primarily one of risk allocation and the positive second and third order effects that arise from allocating risk to the private sector in this way.

As shown in Figure 9, by placing the risk of investment decisions on the private sector, managers and staff have a commercial incentive to develop the expertise to make prudent decisions by effectively managing risk. Additionally, firms that finance assets face oversight from debt markets, which provides another level of due diligence on a proposed investment.

In contrast, when investment risk is placed on consumers through governments or their agencies, a regulatory process is run to procure a pre-defined amount and type of energy services. In this scenario, firms' incentives naturally become linked to outcomes from the regulatory process. Firms' expertise will be focussed on maximising outcomes from the regulatory 'game' and debt market due diligence will be narrowed to assessing regulatory risk, as opposed to the commercial viability of the investment.

Further discussion on each of the principles is below.

Figure 9: Second and third order risk allocation effects



Principle 1: Firms responding to market signals in a competitive environment tend to promote better outcomes for consumers than centralised planning

The future is inherently uncertain and forecasts of the future inevitably wrong. Any number of variables can change that will alter preferences, incentives, behaviour and future market outcomes.

Participants in a competitive market are constantly competing to make investment and operational decisions that meet customer needs and maximise profit in an uncertain environment.[38] To do this, they source the best information and expertise possible and put in place management practices to reduce risk to acceptable levels and respond to change.

Centralised planning and economic regulation stands in contrast to a competitive market. Under this approach, a static view of the future needs to be taken at a point in time and investment occurs based on this. Because the assessment is made by a government or its agency, there is a natural tendency to take a conservative view. If the assessment of the future turns out to be incorrect, which will

[38] IEA, *Lessons from Liberalised Electricity Markets* (2005), p.23-25

inevitably be the case, the additional cost of unnecessary investment in generation capacity or demand response is borne by consumers, not the private sector.[39]

While the process of competition can sometimes appear disorderly, market participants responding to competition and market signals generally results in lower costs for consumers compared to centralised planning. As the electricity industry navigates this structural change, it is arguably more important than ever that the market is organised in a way that is dynamic and facilitates innovation.

Principle 2: Markets that allocate risk, costs and accountability for decisions to those best placed to manage them promote efficient outcomes

Allocation of risk to parties best placed to manage it is a common economic principle. The principle is based on the premise that the party in the greatest position of control of the risk, or the party that possesses the best ability to manage a particular risk, has the best opportunity to reduce the likelihood of the risk eventuating or to control the consequences of that risk if it arises.[40]

In the wholesale electricity market, parties best placed to manage risk are those that own and control the assets, and face the benefits from managing risk well and the costs from managing risk badly.

A market design that moves risk to other parties reduces the incentive for participants to make prudent decisions. Without an overarching behavioural risk minimisation incentive in place, market outcomes will become less efficient, at a cost to all consumers.

Appropriate risk allocation is particularly important in a sector with high capital expenditure and long-lived assets. The future is and always will be uncertain. Private businesses with commercial incentives employ resources, techniques and frameworks to reduce risk to acceptable levels when making decisions. They plan for a wide range of scenarios in the long term and narrow down their investment choices as time to make an investment decision approaches. Maximum flexibility is provided for through this process so that a business can be responsive to changing market dynamics.

Making investment decisions around technology type, size, location and timing in an uncertain and risky environment is the speciality of private businesses.

Principle 3: Markets that do not favour one technology or business model over another encourage consumer needs to be met at the lowest cost and promote innovation

A market design that does not favour one technology or business model over another will allow firms, through the process of competition, to innovate and develop offerings that best meet the changing needs of consumers.[41]

Rules around technologies and business models that are explicitly or implicitly prescriptive put a dampening effect on innovation and provide established players with an advantage over new entrants, stifling competition. Additionally, government intervention, either directly or indirectly, should be carefully considered, as it risks deterring private investment.

Where a negative externality, such as carbon dioxide emissions, needs to be addressed, costs tend to be lower for consumers if this is done through a price signal to internalise the cost of environmental damage, rather than the market design being skewed toward particular technologies over others.[42]

[39] ibid., p.31
[40] Productivity Commission, *Public Infrastructure, Inquiry Report No. 71* (2014), p.125
[41] Productivity Commission, *Shifting the Dial: 5 year Productivity Review* (2017), p.161
[42] ibid., p.162

Principle 4: Markets that are durable across a range of credible future scenarios, and establish a clear and consistent set of rules, provide participants with the confidence to make decisions

Investments in electricity generation assets are worth hundreds of millions of dollars and can have lives past 40 years. To make these types of decisions, equity and debt markets need confidence that the fundamental market design – how electricity is priced and traded – will not materially change in response to populist sentiment at a particular point in time.[43]

The NEM was implemented in 1998/99 after an eight year design process that began in 1991.[44] The market will soon be approaching 20 years of operation and has provided participants with a platform from which to make operational decisions and longer term investment and retirement decisions.

While there has been constant change to the NEM design since its inception, the process is well understood by participants and the fundamentals have remained the same. Maintaining this clarity and durability is crucial towards retaining investor confidence in the market.

Principle 5: Information asymmetries should be minimised so market participants have confidence they are competing on a level playing field

For competitive markets to work as intended, market participants need accurate and timely information to make decisions. Without this, participants will not be confident they are competing on a level playing field and may exit or not enter the market.[45]

Information provision includes transparency of hedge contract trading as well as spot market data. Hedge contracts are an important mechanism used to manage price risk in the spot market for both generators and large users[46] and can be traded bilaterally and on the ASX. A liquid ASX hedge contract market is an important component of promoting competition because it is anonymous and provides a transparent forward price curve, which is a key decision making tool for market participants.

Another aspect to information asymmetry is complexity. Where a market design is complex it can be more difficult for participants to understand and assess risk. Invariably larger organisations with more resources will likely be better at evaluating risk and opportunities in complex environments than smaller organisations, potentially creating a barrier to entry or expansion and reducing competition.

Principle 6: Costs to consumers will be minimised when markets complementary to energy, such as emissions, are designed in a way that is consistent with the price discovery mechanism for electricity.

Costs faced by consumers will be minimised when the mechanism to reduce carbon dioxide equivalent emissions from the electricity sector is congruent or works with the price discovery mechanism in the wholesale electricity market.[47]

If the emissions reduction mechanism reduces the efficacy of the price signal in the wholesale electricity market, which is a critical piece of information used by participants to make decisions, then participants will lose confidence in the market and not invest.

[43] IEA, *Liberalised Electricity Markets*, p.60-61
[44] KPMG (AEMC), *National Electricity Market – a case study in successful microeconomic reform* (2015)
[45] Reserve Bank of Australia, *Promoting Liquidity: Why and How?* (2008), p.6
[46] Productivity Commission, Electricity Network Regulatory Frameworks – Inquiry Report (2013), Appendix C
[47] IEA, *Managing interactions between carbon pricing and existing energy policies* (2013), p.29

An emissions reduction mechanism that is well integrated into the wholesale electricity market allows market participants to continue making operational and investment decisions in response to price signals, which also reflect the emissions constraint.

The same concept applies for ancillary services markets, day-ahead markets and strategic reserves. These mechanisms must be designed in a way that does not damage the efficacy of the price signal for wholesale electricity in the spot market.

3.4.2 Real world challenges to applying the principles

There are often challenges when applying a set of design principles to 'real world' markets, particularly when an outcome may be economically efficient, but also results in wealth transfers and creates a large gap between 'winners' and 'losers' of a design change.

For example, allocating risk to parties best placed to manage it translates into a 'cost-to-cause' framework where participants that create costs for the system are required to incur those costs. However, this can create barriers to entry or expansion that negatively impact competition, and trade-offs will need to be made to balance these principles.

Another challenge can be complexity. A market can be theoretically designed to deliver economically efficient outcomes and meet the principles. But it may become so complex that market participants do not support the design change or, if the design is implemented, participants do not understand the risks and opportunities, and the reform fails.

As discussed above, best-practice market design starts with an overarching objective and principles to meet the objective. All principles should be applied to the issue at hand holistically. Where one or more of the principles cannot be met, trade-offs should be explicitly consulted on and made with a comprehensive understanding of the costs and benefits.

An assessment will be more robust when starting from first principles and, if required, moving away from these by making explicit trade-offs. Not having a set of principles to act as a map to guide the design process risks unintended consequences.

3.5 Questions to help apply the principles

Applying a set of high level principles to market design problems can be inexact. To help with the assessment and to identify the impacts of any mechanism, it can be useful to start by framing the analysis as questions.

We have listed a number of generic questions below that could assist in this regard:

- What services is the mechanism valuing and pricing?
- Is the design of the mechanism clear and easily understood?
- What is the role of non-market facing entities and when does decision making pass from the investor and participant to the market operator?
- What is the role of forecasting in the operation of the mechanism and who is exposed to the risk of inaccurate forecasts?
- How will the mechanism affect the hedge contract market?

3.6 Application of the principles to the WEM

The statutory objectives of the WEM are:[48]

- Promote the economically efficient, safe, and reliable production and supply of electricity and electricity-related services in the SWIS.
- Encourage competition among generators and retailers in the SWIS, including by facilitating efficient entry of new competitors.
- Avoid discrimination in that market against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or that reduce overall greenhouse gas emissions.
- Minimise the long-term cost of electricity supplied to customers from the SWIS.
- Encourage the taking of measures to manage the amount of electricity used and when it is used.

We consider the principles in section 3.4 are consistent with the objectives of the WEM as, similar to the NEO, they are focussed on economic efficiency, cost minimisation and the promotion of competition.

3.7 Market design characteristics

Market design characteristics provide further granularity when assessing specific mechanisms. If the market design characteristics are consistent with and promote the principles and objective, then it can be easier to apply the assessment framework to technical aspects of market design.

For example, one characteristic of strategic reserves is the period of time over which the market operator can procure the reserves. A procurement period that is as close as possible to the forecast reliability shortfall will keep most of the investment risk with market participants and continue to promote Principle 2 – Risk Allocation.

A useful way of applying the principles is to break down a market mechanism into individual components. Design choices for each component are assessed against the principles. The ones that best meet the principles then become the market design characteristics.

Market design characteristics are discussed further as part of our assessment of market mechanisms in Chapter 4.

3.8 Good regulatory practice

Principles are one aspect to market design – how the principles are applied is equally important. Fundamental electricity market reform requires an integrated and well-structured policy development process.

An example of best-practice market design is shown in Figure 10. Defining the problem, materiality and whether it is likely to persist, as well as gaining agreement on this among stakeholders, is the most important part of the process. If this does not occur, issues can remain unsolved or solutions can be developed to solve the wrong issue.

[48] See clause 1.2.1 of the market rules: https://www.erawa.com.au/cproot/18794/2/Wholesale%20Electricity%20Market%20Rules%2027%20March%202018.pdf

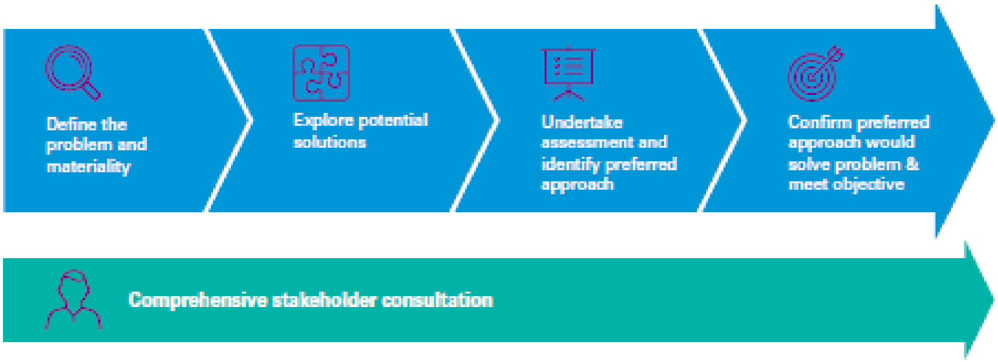
Equally important is how an assessment of the options is undertaken. If the assessment approach and overarching objective is ambiguous or contradictory, identifying and agreeing on a preferred solution will be challenging.

While the NEO is set in the National Electricity Law, there is not a defined set of principles to guide how the Energy Council and market institutions should apply the NEO.[49] Having a well-defined framework to compare various market mechanisms and policies may reduce ambiguity around how policy makers and the energy market institutions make decisions. It may also promote consistency with how the NEO is applied over time.

A useful first step in this regard could be AEC members adopting a common set of principles, informed by this report, to use as the basis for responding to proposals and rule changes. As part of this, the AEC could convene workshops with the Energy Networks Association and consumer groups to seek feedback and broaden the adoption of the principles across all industry stakeholders. Support from a wide range of energy sector stakeholders may encourage the Energy Council or the AEMC to formally establish a set of principles for achieving the NEO.

AEC members and industry stakeholders could adopt a common set of principles to use as the basis for responding to policy proposals and rule changes. Leadership in this area may encourage the formal establishment of principles by the Energy Council or AEMC.

Figure 10: Best-practice market design starts with a clear problem



Failure to follow a deliberate market design process can result in risks that range from wasting time and resources by not solving the issue at hand, to making an existing problem worse or introducing reforms that fail. Successful market design also requires thoughtful consideration of all second and third order consequences, from the wholesale market to the contract market, networks, and retail customers.[50] For instance, a change to the framework might solve an issue in the wholesale market, but could result in reduced retail market competition and higher overall costs for consumers.

Throughout the market design process it is important that comprehensive stakeholder consultation is undertaken. No organisation has all the information required to make good decisions, and public consultation processes facilitate information exchange between the decision-maker and industry, as well as between industry participants themselves. Consultation processes help bring stakeholders along on the market design journey.

[49] We note the AEMC has published a guide to applying the energy market objectives, which sets out their approach to analysing rule changes and reviews, and can be found on the AEMC website.
[50] A recent example could include the second and third order effects of generous residential solar PV feed-in-tariffs. The objective of stimulating the uptake of solar PV was met, but a number of issues ranging from the overall cost of the schemes, how these were recovered and required network augmentation were experienced.

4 Review of wholesale electricity market mechanisms

This chapter reviews the market mechanisms set out below and their objectives under a common, simple to understand framework. We also undertake a preliminary review of the mechanisms against each of the principles presented in section 3. The overview of the mechanisms and review against the principles is done at a high level to illustrate how the principles can be used to undertake an assessment. However, further detailed work on the design of the mechanisms needs to be undertaken for an assessment against the principles to be complete and conclusive.

The following wholesale market mechanisms are considered:

1) National Energy Guarantee (emissions);
2) National Energy Guarantee (reliability);
3) Capacity markets;
4) Day-ahead markets;
5) Strategic reserves;
6) Wholesale demand response mechanisms;
7) Inertia markets;
8) Frequency response markets; and
9) Constrained access in the WEM.

4.1 National Electricity Market – status quo

Before reviewing the market mechanisms, we first undertake a high level review of the NEM against the principles, which is shown in Table 5.

Table 5: Review of the National Electricity Market against the principles

Principle	Preliminary review
Competition and market signals	The NEM wholesale market is a gross pool, energy-only market where participants make investment and operational decisions in response to market signals. The current design includes and co-optimises energy and ancillary services markets. Separate to the NEM, privately organised financial hedge contract markets are used by participants to manage price risk and place a value on capacity (through cap contracts). While there are concerns around growing vertical integration and concentration in some regions, the NEM is generally seen to be a workably competitive wholesale electricity market, as long as there is access to competitively priced hedge contracts for non-integrated retailers and other market customers.

Principle	Preliminary review
Risk allocation	Risk around investment and operational decision-making predominately sits with market participants. Generators are not paid for capacity, they are only paid for the electricity generated at their respective regional reference node (which is net of auxiliary and transmission network losses). Generators have a strong incentive in the form of the market price cap to build or contract with sufficient capacity to meet their expected demand.
Competitive neutrality	The NEM is designed to be competitively neutral in terms of participants' business models and technology neutral in terms of the types of technologies that can participate in the market, subject to meeting regulatory standards that promote the safe and secure operation of the power system. This sentiment is stated in the market rules. Section 3.1.4(a)(3) of the National Electricity Rules is an explicit market design principle that seeks to avoid any special treatment with respect to different technologies used by market participants for the wholesale trading of electricity and ancillary services. As new technologies are developed and enter the NEM, it is good practice to review the regulatory framework and, if required, make changes to avoid unintended bias. Government policies outside of the NEM can act on the market and drive outcomes that are not competitively or technology neutral. The LRET is an example of a policy that favours specific types of technologies.
Clear and durable rules	The NEM wholesale market is generally well-defined, with the framework set out through transparent rules and procedures. The market has so-far proven to be robust over time and through economic cycles since its commencement in 1998/99. Fragmentation between federal and state bodies on emissions reduction policy is presenting challenges to the NEM and increasing complexity for participants and investors.
Information asymmetries	Information asymmetry needs to consider the NEM wholesale spot market, as well as the hedge contract market. Information transparency in the NEM is promoted through the energy market institutions regularly publishing substantial amounts of raw data and numerous analytical reports across short and longer duration timeframes. Transparency in the contract market has reduced in recent years with the cessation of the Australian Financial Markets Association electricity derivative contract survey. However, we understand this survey will be recommencing in 2018.
Cross-market integration	There is currently no integrated emissions reduction mechanism in the NEM, with the LRET acting outside of the electricity spot market.

4.2 National Energy Guarantee (emissions)

This section discusses and reviews the emissions requirement of the NEG.[51] We note that the NEG is effectively two different mechanisms and we have hence examined them separately here.

4.2.1 Policy objective

The policy objective of the emissions requirement is to provide incentives to electricity market participants such that "the average emissions level of the electricity they sell to consumers supports Australia's international **emission reduction commitments**, as set by the Commonwealth Government".[52]

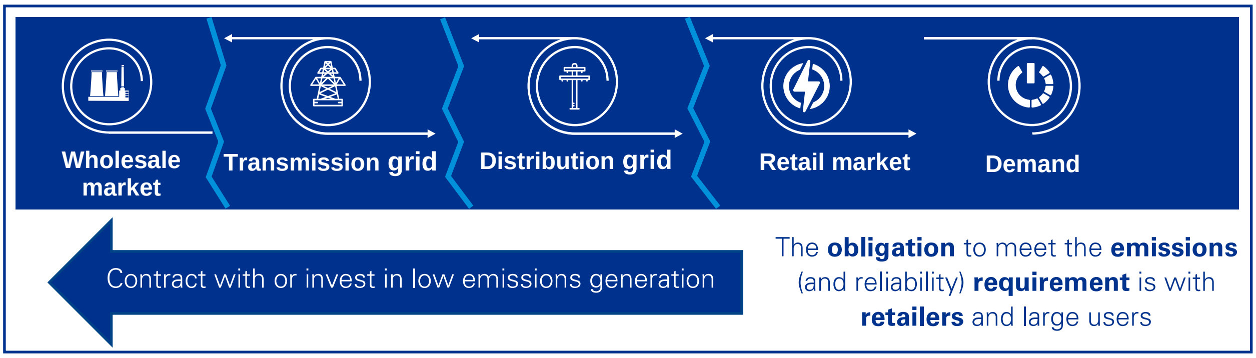
[51] ESB, *National Energy Guarantee: Draft design consultation paper* (2018), p.15
[52] ibid., p.10

4.2.2 How the emissions guarantee is expected to work

In order to achieve a predefined emissions per megawatt hour (MWh), retailers will be required to contract with or invest in generation capacity or demand response. The ESB uses the term 'retailers' to refer to entities registered by AEMO as a 'Customer' under the National Electricity Rules.[53]

The mechanism places the emission reduction obligation on the retail sector of the supply chain, as opposed to the obligation being confined to the wholesale segment through electricity generators. This is shown in Figure 11.

Figure 11: National Energy Guarantee obligations



A difference with the NEG emissions requirement and other emissions reduction mechanisms is that a stand-alone property right is not created, such as a 'unit' of carbon dioxide emissions or a 'certificate' of low emissions energy. It appears that the low emissions component will not be able to be explicitly valued and exchanged in response to price signals (although shadow prices may emerge in the form of premiums on contracts for low emissions generation sources).

Calculating a retailer's emissions intensity

Retailers will be required to meet their demand from a portfolio of generation and contracts with an average emissions intensity at or below the target emissions intensity set by the Commonwealth Government. The calculation of a retailer's load will be the number of MWh recorded by AEMO as being purchased by the retailer on the spot market in the relevant compliance year.

Retailers manage their electricity purchases in a number of different ways, including through bilateral and over-the-counter (OTC) contracts, ASX exchange-traded contracts and spot market purchases. To calculate the emissions intensity of a retailer's electricity purchases the following factors will need to be determined:

- Emissions intensity of bilateral, OTC and ASX contracts; and
- Emissions intensity of any spot market purchases.

The ESB is proposing that a registry be created to match the actual generation and emissions from power stations with the retailers they have entered into contracts with. The ESB acknowledges that this will likely be a complex task due to the large number of contracts held and traded by retailers at different points in time.

Setting aside the task of tracking all contracts held by retailers, there is also the challenge of assigning an emissions intensity to each contract, which may be backed by multiple generation sources within a portfolio, and monitoring compliance.

[53] The Commonwealth Government is considering exempting Emissions Intensive Trade Exposed industries from complying with the emissions requirement.

The ESB notes that standardised stapled security type contracts could emerge with a specified emissions intensity per MWh stapled to OTC or ASX traded contracts. The emissions intensity in this case would be representative of the average emissions intensity of a portfolio of generation over a specified time. Records would need to be maintained of the emissions produced for each MWh of the relevant plant so the emissions intensity could be verified.

Some contracts will not have an emissions intensity attached to them. For example, ASX contracts and those sold between retailers and generation businesses or intermediaries where the generation source is not specified. Also, some retailers and large users will be purchasing wholesale electricity from the spot market. For these situations, an emissions intensity will need to be deemed.

4.2.3 Market design characteristics and dependencies

Market design characteristics associated with the emissions guarantee include:

- how the emissions target is expressed over time, whether this is as an emissions intensity as currently proposed, or absolute emissions;
- whether generators create a property right that can be sold to entities to meet their emissions requirement, facilitating efficiencies of trade and allowing separate revenue streams from the energy and low emissions property rights to be realised by generators;
- whether the obligations to reduce emissions fall directly on the demand-side (retailers and end-users) or the supply-side (generators) of the market;
- what happens if the retailer defaults and exits the market (does the liability transfer to the retailer of last resort?);
- potential exemptions from meeting emissions guarantee obligations and the resultant cost implications for remaining participants; and
- governance arrangements associated with establishing and administering the scheme.

Each of these design decisions will result in different outcomes and the trade-offs should be considered against an assessment framework and market design principles.

4.2.4 International experience

We are not aware of international emissions reduction mechanisms similar to the NEG.

The NEG appears unique in that obligations are placed on retailers to contract in a certain way with generators to meet the emissions target. Most international frameworks develop a transparent market for electricity generators or retailers to meet their obligations at the lowest cost in response to transparent price signals.

4.2.5 Review against the principles

Table 6 undertakes a preliminary review of the emissions guarantee against the principles.

Table 6: Review of the emissions guarantee against the principles

Principle	Preliminary review
Competition and market signals	Competition may be reduced if the emissions guarantee is implemented in a way that is complex and results in high transaction and compliance costs. Competition could be reduced if the design has the effect of limiting or preventing trading of ASX hedge contracts. Competition may be impeded if emissions liability deficits are not able to be freely exchanged with those with emissions liability surpluses in response to price signals.

Principle	Preliminary review
Risk allocation	The allocation of risk for investment and operational decisions remains with market participants, who are best placed to manage them. Placing the burden of meeting the guarantee on retailers may be administratively more complex than on generators, both in terms of tracking contracting arrangements and increasing prudential requirements (if prudential requirements are higher for OTC contracts vis-a-vis ASX hedge contracts). It may also be less costly for generators to manage the risk of the emissions guarantee.
Competitive neutrality	The emissions guarantee appears to be technology neutral in terms of providing incentives to all low emissions technologies. However, the current design may preclude existing business models where the energy and certificates can be sold separately. This may restrict innovation and the ability to meet customer needs at the lowest cost. It could also remove the possibility of renewable generators selling ASX contracts if the ASX contracts have a deemed emissions intensity, because they may have a lower premium to zero emissions contracts.
Clear and durable rules	The emissions guarantee will need to demonstrate it is consistent with the operation of the spot market, contract market, retail market and reliability guarantee with sufficient governance and legislative arrangements.
Information asymmetries	Where the emissions guarantee focuses contract trading in the bilateral and OTC markets in lieu of the ASX, information asymmetries around contract prices and volumes may increase. This could reduce competition and market confidence.
Cross-market integration	The emissions guarantee will drive demand for contracts from particular generation sources. These generators will bid into the spot market in line with their short run marginal cost, which should preserve the efficacy of the price signal in the NEM across the energy and ancillary services markets. The impact on the contract market and whether it will reduce liquidity appears to be the key issues with the emissions guarantee.

4.3 National Energy Guarantee (reliability)

This section discusses and reviews the reliability requirement of the NEG.[54]

4.3.1 Policy objective

The objective of the reliability guarantee, as defined by the ESB, is to "make clearer the value of being dispatchable, both on the supply and demand side".[55] The ESB states that maintaining an adequate level of dispatchable resources is necessary for the secure and reliable operation of the power system. However, the ESB states the reliability guarantee will not address the provision of services such as system strength, inertia, ramping and flexibility, which are required for a secure system.

In summary, the policy objective of the reliability guarantee, as the name suggests, is to promote the **reliable operation of the system** by providing for a minimum level of dispatchable resources.

4.3.2 How the reliability guarantee is expected to work

The reliability guarantee, as currently articulated, is only designed to come into effect if AEMO forecasts that the reliability standard will not be met. It can be considered a 'safety net' that allows AEMO to procure specific types of resources in response to a forecast shortfall.

[54] ibid., p.31
[55] ibid., p.31

The ESB has set out a number of steps it sees as forming the reliability guarantee, which we summarise below:

- **Forecasting and updating the reliability gap**: AEMO will forecast whether the reliability standard in each NEM region will be met over the period and update these forecasts over time.
- **Market response**: If a reliability gap is forecast, market participants will have an opportunity to respond before the reliability guarantee is triggered. A response will entail investing in new capacity or offering additional capacity to the market.
- **Triggering the requirement**: The reliability guarantee will be triggered if a response is not forthcoming. This will require retailers to make investments or enter into contracts with 'dispatchable' resources that cover their share of peak demand to alleviate the reliability gap.
- **Procurer of last resort**: If retailers do not meet their requirement by the compliance date, it is proposed that AEMO will have the power to procure resources.

We note it appears the ESB's intention is provide the market with the opportunity to address any forecast gap and therefore to avoid the reliability guarantee being triggered. In this way, the reliability guarantee is similar in intent to the Australian Domestic Gas Security Mechanism (ADGSM) implemented by the Commonwealth Government in 2017. The ADGSM was established to intervene in the gas market if forecasts show a shortfall in domestic gas supply. However, market participants are expected to respond to resolve any shortfall prior to the intervention being required.[56]

Two key differences between the reliability guarantee and ADGSM stand out. For the ADGSM:

- a Minister of the Commonwealth Government makes the final decision to intervene in the market, not AEMO or another government agency or institution; and
- the Minister is expected to consult widely before making the decision, including with energy market bodies and government agencies, industry participants and other government ministers.

Due to the nature of the intervention, and potential costs imposed on gas market participants, it may not have been deemed appropriate for this decision-making to be delegated.

4.3.3 Market design characteristics and dependencies

If the reliability guarantee is implemented and triggered, it could result in costs on market participants and wealth transfers to suppliers of dispatchable resources from those required to contract with them. To avoid inefficient outcomes, two key design decisions need to be understood:

- **AEMO's forecasting methodology**: It will be important to have absolute transparency around AEMO's forecasting methodology, along with a robust consultation process to develop the input assumptions. Ideally, an independent assessment should be undertaken by a third-party if a reliability shortfall is forecast, simply because forecasting by its nature is uncertain and no one has perfect foresight of the future.
- **Pricing framework**: Will there be obligations on AEMO to meet the reliability guarantee at an efficient cost (which is well defined and linked to the reliability standard) and transparency around these arrangements? A mechanism will need to be implemented to ensure the 'insurance' procured by AEMO through the reliability guarantee does not come at any cost to consumers.
- **Time horizon**: There is a natural tension between applying the trigger at a longer horizon, which provides the market operator with certainty that a response will ensue, to a shorter horizon, which provides more time for the market to respond in line with the most up-to-date information. In any

[56] See: https://www.legislation.gov.au/Details/F2017N00050

case, there should be clear parameters established around how the mechanism is triggered such that industry participants are able to anticipate AEMO's likely decision.

A number of dependencies emerge when considering the reliability guarantee:

- **Investment incentives**: If suppliers of dispatchable resources know that AEMO can trigger a mechanism to force retailers to contract with them, how will this affect their incentives to contract ahead of time? Also, how will this affect incentives to accurately reveal capacity information to AEMO's forecasting processes?
- **Reliability and Emergency Reserve Trader (RERT)**: Would the reliability guarantee effectively replace the RERT? AEMO is able to contract for reserve capacity under the RERT up to 10 weeks ahead of a projected shortfall.

  Prior to a recent AEMC rule change AEMO could contract up to nine months ahead. The lead time was shortened to provide the market with more time to respond to forecast shortfalls and minimise the likelihood AEMO crowds out potential market based arrangements, including retailers procuring demand response from their customers.[57]

  The reliability guarantee can be seen as similar to the RERT, but with retailers having the first opportunity to enter contracts ahead of AEMO. If this is the policy intent, it may be administratively simpler and lower cost to implement the reliability guarantee through the existing RERT framework, rather than developing a new one.

4.3.4 International experience

We are not aware of reliability mechanisms similar to the NEG in international markets, in terms of requiring retailers to contract with dispatchable resources. The closest framework would be a capacity market whereby retailers (also known as load serving entities) are required to purchase sufficient capacity to meet their forecast peak demand. Capacity markets are discussed in Section 4.4.

4.3.5 Review against the principles

Table 7 is a preliminary review of the reliability guarantee against the principles.

Table 7: Review of the reliability guarantee against the principles

Principle	Preliminary review
Competition and market signals	Competition will likely be reduced if the reliability guarantee results in independent retailers having to contract with their vertically integrated competitors, instead of purchasing contracts anonymously on the ASX or through a combination of Power Purchase Agreement with a VRE generator, spot risk and demand response. Competition may be reduced if the reliability guarantee is implemented in a way that is complex and results in high transaction and compliance costs.
Risk allocation	How risk is allocated will depend on the lead time for triggering the reliability guarantee. A longer lead time is more likely to result in forecast errors and the guarantee being triggered when not required, but could encourage more resources to enter the market. This will pass risk and costs onto consumers. A shorter lead time will place more risk on industry participants, who are best placed to manage it.
Competitive neutrality	The reliability guarantee will require retailers to invest in or contract with generation sources that will help meet the requirements of the guarantee. However, we note VRE generators may be able to participate in the reliability guarantee market if they have firming capability, such as batteries, gas, or hydro.
Clear and durable rules	The reliability guarantee will need to demonstrate it is consistent with the spot market, contract market, retail market, and emissions guarantee.

[57] AEMC, *Reliability Frameworks Review: Issues Paper*, p. 92

Principle	Preliminary review
Information asymmetries	Where the reliability guarantee focuses contract trading in the bilateral and OTC markets, information asymmetries around contract prices and volumes will likely increase. This may negatively impact competition and market confidence, as participants will not know whether they are paying a price comparable with their competitors.
Cross-market integration	We have not identified issues associated with integrating the reliability guarantee with the emissions guarantee, energy market or ancillary services markets. The key issue appears to be how the emissions and reliability guarantees are integrated into the contract market, and whether they will reduce liquidity as contracts become less standardised.

4.4 Capacity market

The NEM is an 'energy-only' wholesale electricity market design where generators are only paid for the energy they produce. Key parameters, such as the market price cap and cumulative price threshold, are set such that market participants have the right profit incentives to build sufficient capacity to achieve the reliability standard of 99.998% of demand. In an energy-only market, participants make the decision of how much capacity to build and when, and take this risk.

The alternate approach to organising the trade of electricity and achieving a targeted level of reliability is through a capacity market. Under this type of market design, generators are paid for making capacity available for the market operator to dispatch. In a capacity market a central authority determines how much capacity is required in the future. If the capacity is never used the market participant generally still receives payment with the risk and the cost paid for by consumers.

4.4.1 Policy objective

The policy objective of a capacity market is the same as an energy-only market – to meet a **reliability standard** in an efficient manner over the **operational** and **investment** horizon.

As discussed above, a capacity market can be seen as a more regulated approach to an energy-only market. While there are many types of capacity markets, the key distinction is that the model relies on an administrative forecast of demand and subsequent transfer of investment risk to consumers.

4.4.2 How a capacity market works

While no two capacity markets are alike, they generally have the following characteristics:

- A reliability standard is established by government and/or regulator.
- The reliability standard is translated into a planning requirement to meet forecast peak demand plus a reserve margin above this.
- A process, such as an auction, is run by a market operator to identify and attract resources (capacity and demand response) to meet the reliability standard and reserve margin.
- There is an obligation on the market operator *or* Market Customers (those that purchase electricity through the spot market) to purchase this capacity to meet their peak demand.

Another form of capacity market has been implemented in Ireland, where a Reliability Option is auctioned. Winners of the auction receive an annual payment for the contracted capacity, but also enter into a one-sided contract-for-difference. In the event that market prices exceed a set strike price, generators are obliged to pay the excess. This provides insurance to consumers against high prices whilst also signalling appropriate scarcity.[58]

Capacity markets generally co-exist alongside a day-ahead market (although this should not be seen as a mandatory requirement) and an on-the-day energy and ancillary services market. As a result, it is common for resource providers cleared in the capacity auction to be required to offer into the energy or ancillary services markets, ensuring that these services are physically available when needed.

4.4.3 Market design characteristics and dependencies

Key elements of a capacity market are as follows:

- **Demand curve**: Administratively set demand curves are established and overlaid with bids from resource providers to solve the capacity auction. Demand curves can be vertical (perfectly inelastic) or curved. The design can materially impact the capacity price.
- **Delivery period**: The delivery period is the period of time over which a capacity provider is obligated to make its capacity available to the market (e.g. annual, seasonal, monthly, etc.)
- **Forward period**: The forward period is the period of time between which an auction occurs and the start of the delivery period. Forward periods can range from a few days before the start of a month to up to 15 years. The forward period may also specify differing contract term lengths of a full year, calendar quarters or monthly blocks and thus signal those periods where capacity is of more or less value. The longer the forward period the more competition is likely to be present in an auction, although the potential for demand forecast errors increase.
- **Definition of the capacity product**: Differentiation can occur between the operational capabilities of capacity products, e.g. start times, ramp rates, etc.
- **Supply curve**: Key considerations in the supply curve are the treatment of wind and solar capacity resources and their contribution to setting and achieving the reliability setting.

Settlement in capacity markets can occur in the following ways:

- **Bilateral**: Settlement occurs directly between capacity resource providers and market customers.
- **Wholesale and retail**: Payment is made by the market operator at the auction clearing price to all capacity resources cleared in auctions. Costs associated with capacity payments are passed on to Market Customers. Retailers recover these costs through their tariffs to customers.

When considering capacity market design there are a number of dependencies that also need to be considered:

- **Price caps in the real-time energy market**: If the expectation is that generators recover their fixed costs through capacity payments, price caps in the energy market should be reviewed.
- **Nodal pricing**: Early capacity mechanisms did not reflect transmission constraints, resulting in local capacity shortages and reliability issues. Transmission constraints need to be reflected in the capacity market design.
- **Day-ahead markets**: Most capacity markets have a 'must-offer' obligation into the energy or ancillary services markets to ensure that the committed capacity is available when needed. This is generally implemented through a day-ahead market (discussed in Section 4.5).

[58] Newbery, D.M., *Designing an electricity wholesale market to accommodate significant renewables penetration: Lessons from Britain* (2017), p.9

4.4.4 International experience

We have examined learnings from capacity markets in Germany, France, the United States, Great Britain and Alberta (Canada). Key findings are discussed below, with further detail in Appendix B.

Capacity markets that have been implemented in the United States (US) and Great Britain are immature relative to the NEM. The NEM commenced in 1998/99, while the first capacity auctions occurred:[59]

- PJM (US) in **2007/08** for a three year forward period.
- MISO (US) in **2013/14** for a two month period.
- ISO-NE in **2010/11** for a three year period.
- NYISO in **2006/07** for a 2-30 day period.
- Great Britain in December **2014** for a one year period.

From our research it became clear that most jurisdictions that have implemented capacity markets did so in response to an *expected* 'missing money' problem and not in response to multiple reliability standard breaches.[60] The argument is generally that increasing penetration of renewable energy results in lower average energy prices and therefore reduced ability for peaking plants to recover their costs, eventually resulting in a breach of the reliability standard. However, we did not find this outcome had occurred, rather it was an *expectation* that led to capacity markets.

The missing money problem arises when the market price cap is not set sufficiently high to compensate peaking generators required to run for a few hours a year to meet peak demand. Often the market price cap is set too low due to political pressure to avoid high wholesale electricity prices and price volatility, even though an effective contract market facilitates management of this risk.

Capacity market experience has been mixed, particularly with respect to inducing cost-effective entry and exit of capacity. Published studies argue that almost all new investment in capacity in the US was constructed under a long term contract or through vertical integration, with only 2.4% in 2013 and 4.8% in 2014 being built for sale into the capacity market.[61] However, another study challenges this finding, claiming 60% of the capacity was market funded and the residual was privately funded.[62]

When considering international case studies it is important to understand the local energy mix and other key factors. The US capacity markets have substantial nuclear, coal and gas-fired generation, and wind and solar penetration levels of less than 10%.[63] In contrast, systems that support a high penetration of large-scale renewable energy, such as South Australia (~40%), Denmark (~40%), Texas (~18%) and Germany (~26%) have done so without capacity markets.[64] Germany considered a capacity market as part of its 'Power Market 2.0' reforms, but did not proceed due to concerns around distortions and costs, instead introducing a strategic reserve.[65]

4.4.5 Review against the principles

Table 8 undertakes a preliminary review of capacity markets against the principles.

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[59] Jenkin, T., Beiter, P., Margolis, R., *Capacity payments in restructured markets under low and high penetration levels of renewable energy*. NREL (2016), p.4

[60] The missing money problem occurs when revenues from the sale of energy and ancillary services are insufficient to compensate generators to invest in capacity to meet a reliability standard.

[61] CRA, A case study in capacity market design and considerations for Alberta (2017), p.37

[62] ibid,. p.37

[63] ibid,. p.17

[64] IEEFA, *Power-industry transition, here and now* (2018)

[65] Jenkin, Beiter, and Margolis, *Capacity Payments in Restructured Markets*, p.31

Table 8: Review of capacity markets against the principles

Principle	Preliminary review
Competition and market signals	Wholesale market competition is dependent on the forward period. The longer the forward period, the greater the certainty and lower the risk for new entrants. However, the investment risk is greater for consumers. Capacity markets can support retail competition because, depending on the design, they are able facilitate the competitive procurement of capacity for electricity retailers, on a non-discriminative basis.
Risk allocation	Capacity markets place investment risk onto consumers because a central authority is required to forecast the level of demand to be procured. If demand forecasts persistently turn out higher than actual demand, which is the likely outcome as the central authority is accountable to governments and can be expected to forecast conservatively, consumers pay for capacity that is not required. In the WEM capacity market it has been estimated that the market has a 23% oversupply which costs consumers $116 million in 2016/17.[66]
Competitive neutrality	The capacity market design influences the technologies that can participate. Short forward periods and delivery periods favour incumbent generators or new entrants with low fixed costs (i.e. diesel generators). The product definition can also be used to target specific technologies. For example, the WEM has historically over-rewarded demand-side technologies prior to the recent reform process.[67]
Clear and durable rules	International experience has shown that capacity market rules are subject to change by regulators depending on the outcomes. Demand curves, forward periods and delivery periods, product definition, market power mitigants, and other parameters can be adjusted to skew outcomes.
Information asymmetries	Capacity markets can be designed to minimise information asymmetries.
Cross-market integration	Capacity markets can be integrated with emissions reduction mechanisms and ancillary services markets.

4.5 Day-ahead markets

A day-ahead market trades electricity (or the rights to electricity) for a whole day or specific periods within a day. For example, a day-ahead market might clear through an auction at 2pm before the start of a 24 hour period that begins the following day at 4am. This section also covers what we refer to as 'prompt' markets, which facilitate the trade of electricity contracts up to a week out from dispatch.

4.5.1 Policy objective

Day-ahead markets aim to improve system **reliability** over the **operational horizon** by providing the market operator with greater transparency on near future availability of electricity generation. Depending on the design, they may provide participants with a mechanism to optimise contract participants up to dispatch, promoting efficiency.

4.5.2 How a day-ahead market works

Broadly, there are two types of day-ahead markets:

[66] Western Australia Public Utilities Office, *Final Report: Reforms to the Reserve Capacity Mechanism* (2016), p. 3
[67] ibid., p. 7

- **US-style**, market participant-to-market operator design, which aims to provide sufficient information for the reliable operation of the system; and
- **European-style**, participant-to-participant design aimed at facilitating contracts between market participants.

While there are a number of key differences, both approaches support reliability through imposing financial incentives on participants to fulfil day-ahead contract positions in the real time market. For example, if a generator has sold 100 MW in the day-ahead market, but only generates 80 MW in the real-time market, it will be required to pay the market operator for the 20 MW at the real time price (which could be high if the market is short).

In the NEM, AEMO is provided with operational information on generators' expectations for the following day through the pre-dispatch process. While the pre-dispatch process is not financially binding on participants, there is an opportunity cost associated with a generator not being online when the market price is high. As a high market price should correlate with high demand for capacity, generators in the NEM face an incentive to be online when the market operator requires them, even if they are not fully contracted.

US-style day-ahead market

Under a US-style day-ahead market, the transaction occurs between market participants and the system operator, and assists the system operator to schedule the market. Key objectives are to:[68]

- Provide technical and cost information to the system operator through financially binding operating schedules and technical operating parameters for the following day;
- Provide market participants with financially binding schedules to support physical unit commitment; and
- Allow market participants to provide information to system operators to schedule cross-border flows between different regional markets (not relevant for the NEM).

In the US-style mechanism, generators submit unit-level bids for their entire generation portfolio. From this, the market operator runs an auction to establish financially binding schedules for the day. Participants settle against the day-ahead price, with deviation quantities between the day-ahead and real-time markets settled in the real-time balancing market.

European-style day-ahead market

The European-style day-ahead market allows participants to optimise their portfolios continuously on a participant-to-participant basis, as opposed to the US-style approach which is between participants and the market operator. There are a number of timeframes around when this can be done, from day-ahead auctions for electricity delivered on an hourly and half hourly basis, to a prompt market that facilitates trading of exchange products up to a week ahead.[69]

If generators trading in the day-ahead market cannot deliver the supply they have sold, they will be exposed to the price in the real-time market. This places additional financial risk on generators and creating an incentive to 'guarantee' bids though back-up capacity or contracts with other generators. In effect, a day-ahead market attempts to increase the contracting levels of generators close to dispatch in order to create an explicit financial obligation.

The objective of European-style markets is to:

[68] AEMC, *Reliability Frameworks Review: Interim Report*, p. 160
[69] See: https://www.apxgroup.com/trading-clearing/apx-power-uk/

- Concentrate liquidity at a certain point in time (i.e. day-ahead to a week out), providing participants with greater confidence in market depth and the prices observed;
- Allow market participants to optimise contract positions closer to dispatch or hedge against the spot market; and
- Provide information to the market ahead of dispatch through contract prices.

In the European markets, the system operator does not rely on information from the day-ahead market to operate the system and settlement occurs through private exchanges.

4.5.3 Market design characteristics and dependencies

Typical market design characteristics for day-ahead markets are as follows:

- **Type**: Whether the most appropriate design is the US-style with active system operator participation or European-style which facilitates participant-to-participant trade.
- **Participation**: Most day-ahead markets are voluntary. Mandatory participation generally only applies when resources are being paid under a capacity market.
- **Type of commitment**: The type of commitment depends on whether deviations from the day-ahead market schedules are financially settled in the real-time market or whether they are an obligation to physically generate or use electricity.
- **Locational**: The degree to which locational elements of the electricity system are taken into account. A day-ahead market design that accounts for transmission system constraints and produces operationally feasible schedules is a nodal day-ahead market.
- **Settlement**: How settlement between the day-ahead market and real-time market occurs.

When considering a day-ahead market design, the following dependencies need to be considered:

- The relationship between the price cap in the day-ahead market and real-time market, and any market power considerations;
- The type of design, whether the market is continuously traded on an exchange or an auction at a point in time;
- Incentives to allow the prices in the day-ahead market to converge with the real-time market so that any price differences can be efficiently arbitraged away;
- Interactions with the contract market, such as whether some hedge contracts will be settled against the day-ahead market instead of the spot market, and whether this is likely to split contract market liquidity; and
- Governance arrangements, including the most appropriate organisation to run the market.

4.5.4 International experience

We have examined learnings from day-ahead markets in Texas and Great Britain. Key findings are discussed below, with further detail in Appendix B.3.

Texas implemented a voluntary, financially binding day-ahead market as part of the implementation of a nodal market. It primarily provides a platform to hedge transmission congestion costs ahead of the operating day, as well as price volatility in the real-time market.

Market participants in the Great Britain market have access to independent day-ahead power exchanges, which provide a mechanism to hedge one hourly and half hourly blocks of electricity day-ahead, as well as longer dated products up to a week-ahead.

4.5.5 Review against the principles

Table 9 is a preliminary review of a day-ahead market against the principles, while Box 1 discusses how a European-style day-ahead market could add value to market participants in the NEM.

Table 9: Review of day-ahead markets against the principles

Principle	Preliminary review
Competition and market signals	Day-ahead markets can support wholesale and retail market competition, as they are able to support the competitive procurement of capacity, on a short-term basis, by electricity retailers.
Risk allocation	US style day-ahead markets where outcomes are financially binding transfer risk from market participants to consumers if the market operator over forecasts demand and the real time price is lower than the day-ahead price. European style day-ahead markets aim to concentrate the exchange trading of contracts at a specific point in time to concentrate liquidity. They also provide flexibility around the short term trading of electricity contracts.
Competitive neutrality	Day-ahead markets can be designed to be technology neutral. Day-ahead markets can support greater participation of demand response through the forward certainty provided.
Clear and durable rules	Depending on the design, day-ahead markets can be complex or simple. Day-ahead market design factors include: US or European-style, mandatory/voluntary, firm or non-firm scheduling, locational or non-locational, and simple or complex bidding. Consistency and integration with the real time market and any capacity market also needs to be considered.
Information asymmetries	Day-ahead markets can be designed to minimise information asymmetries through greater information being published ahead of dispatch.
Cross-market integration	Day-ahead markets can be integrated with emissions reduction mechanisms and co-optimised with ancillary services markets.

4.6 Strategic reserves

Strategic reserves are capacity reserved for use by the market operator in emergencies if a market response to a forecast capacity shortfall fails to eventuate. They are procured and dispatched outside of the merit order (out-of-market).

4.6.1 Policy objective

Strategic reserves are designed as last resort mechanisms that can be used by a market operator to prevent load-shedding should market participants fail to respond. This helps to provide a safety net if the market fails to deliver the targeted level of **reliability**. Strategic reserves primarily influence **investment incentives**, but can also impact **operational** outcomes.

4.6.2 How strategic reserves work

The Finkel Panel recommended that:

> "Consideration should be given to the suitability and desirability of an out of market Strategic Reserve mechanism. This could involve equipping AEMO with the power to contract for a targeted level of capacity that would be held in reserve outside of the market. If implemented, this policy should be designed as an enhancement or replacement to the

existing reliability safety net measure, the Reliability and Emergency Reserve Trader (RERT) mechanism …"[70]

The strategic reserve envisaged by the Finkel Review involves the market operator obtaining capacity outside of the market – i.e. via a mechanism other than the fundamental mechanism underpinning the spot market.

As identified in the Finkel Review, the NEM already operates a form of strategic reserve through the RERT. RERT is a mechanism that allows AEMO to set up a panel of capacity providers (both generation and demand response), in cases where it is predicted that the market will not meet the reliability standard.

Other forms of strategic reserves involve the government directly procuring reserve capacity to dispatch in times of market emergencies and procuring demand-side capacity through an auction process.

For emphasis, payments for strategic reserves are not made through the spot market but rather in parallel to, or outside of the market. The use of strategic reserves therefore represents an intervention in, or override of, the market.

4.6.3 Market design characteristics and dependencies

Key considerations for strategic reserves are:

- whether generation capacity is owned by the government or contracted to capacity providers (either generation or demand management);
- whether strategic reserves exist as a temporary or permanent mechanism;
- the timeframes under which strategic reserves can be procured; and
- the conditions under which the reserve market can be procured and triggered.

4.6.4 International experience

We have examined learnings from strategic reserve markets in Germany, Texas and Belgium. Key findings are discussed below, with further detail in Appendix B.2.

Germany's Federal Parliament legislated to create a capacity reserve in June 2016 as part of a broader market reform. The capacity reserve contains power plants which are not part of the regular power market and have a total capacity of 5% of the average maximum demand, costing between €130 million to €260 million.

The ERCOT market contains an Emergency Response Service mechanism (ERS) which dispatches demand response and distributed energy resources in response to anticipated supply shortages. The ERS mechanism works by generating a demand curve, based on an annual expenditure limit of US$50 million, rather than by estimating the total capacity needed. Effectively, this sets in place a 'budget' for the procurement of capacity, which is maximised within the cost constraint.

Similar to the NEM's RERT, Belgium's system operator Elia has strategic reserves in its energy-only market to avoid capacity shortfalls and to maintain reliability, procuring capacity in periods of supply emergencies. As a number of nuclear and gas plants were mothballed, or out of the market, this mechanism was introduced in 2014 to aid in managing reliability during winter months.

[70] Finkel, A. et al., *Independent Review into the Future Security of the National Electricity Market*. Commonwealth of Australia (2017), p.200.

4.6.5 Review against the principles

Table 10 is a preliminary review of strategic reserves against the principles.

Table 10: Review of strategic reserves against the principles

Principle	Preliminary review
Competition and market signals	If market participants anticipate that a strategic reserve will be triggered too aggressively, the private sector may not invest in the resources required to meet an identified reliability gap. This would undermine the overarching objective of the market to facilitate efficient private investment to meet expected demand. For strategic reserves to support market competition, strict rules must be in place to inhibit the use of strategic reserves in all but emergency situations.
Risk allocation	Strategic reserves place investment risk onto consumers, as a central authority is tasked with determining the amount of reserve to be maintained. If too high a level is set, consumers will pay for generation capacity they will not use in most cases. Strategic reserves act like insurance in this manner, as a premium is paid irrespective of use.
Competitive neutrality	Strategic reserves can be designed to be technology neutral. Strategic reserves can support participation of demand response through one way of gaining forward contracting certainty.
Clear and durable rules	A key factor to a strategic reserve being applied in a consistent manner is the conditions under which a strategic reserve can be utilised. As discussed above there must be clear and consistent rules in place for the conditions of use to avoid private investment decline in generation capacity.
Information asymmetries	Information about strategic reserves should be, and typically are, made public to the market so that participants can make decisions in full knowledge of the existence of the strategic reserve.
Cross-market integration	A strategic reserve can be integrated with an emissions reduction mechanism and ancillary services markets.

4.7 Wholesale demand response mechanism

Demand response involves consumers, or loads, altering their level of consumption in response to prices signalled to them. These prices can be signalled via retail prices, network charges or through the wholesale market. A wholesale DRM facilitates demand response through the wholesale market, potentially by allowing demand response providers to offer the service into the market in a manner akin to generation capacity.

4.7.1 Policy objective

The objective of a wholesale DRM is to facilitate increased uptake of demand response resources and, more broadly, to meet a given level of demand at the lowest cost. A DRM primarily contributes to **reliability** and influences decision-making on the **operational horizon**.

4.7.2 How wholesale demand response works

A wholesale DRM works by allowing demand response services to be 'offered' into the market as a service in a manner akin to generation capacity. Demand response resources are therefore included in the dispatch process explicitly – their cost is compared with the cost of dispatching generation. If the demand response is part of the least-cost dispatch solution, then the market operator will dispatch the demand response services.

We note that a wholesale DRM is not essential to allow demand response to participate in the market. The current energy-only design of the NEM already allows responsive loads to benefit by reducing exposure to high spot prices and, if they wish, can be scheduled and cleared against the spot price and included in dispatch. However, this approach may have challenges and create risk and uncertainty for market customers, as they are exposed to the variability of the spot price. A DRM might help to overcome these risks, but there is also the potential for the design to create an oversupply compared to an efficient level of DRM, which would increase cost for consumers.

The Finkel Review recommended the COAG Energy Council direct the AEMC to undertake a review to recommend a mechanism that facilitates demand response in the wholesale energy market; and that this review should be completed by mid-2018 and include a draft rule change proposal for consideration by the COAG Energy Council.[71] We understand the AEMC and AEMO are considering a wholesale DRM with the ESB, who will coordinate the market bodies' response.

4.7.3 Market design characteristics and dependencies

Key considerations for wholesale market DRM are:

- how the quantum of demand response is measured and verified, noting that the mechanism must continually determine a 'what if' value, i.e. what would the customer's consumption have been but for the decision to respond;
- the interaction with the retail price levied on the customer;
- the cost and complexity of implementing the DRM; and
- the degree to which there may already be existing, implicit incentives for customers to adopt demand response.

4.7.4 International experience

We have examined learnings from wholesale DRMs in Texas and the US (PJM). Key findings are below, with further detail in Appendix B.3.

Wholesale DRM is procured in the Texas system by ERCOT as part of its Emergency Response Service (ERS) discussed above.

Since 2000, demand participation has existed in some form in the US PJM market as a way of paying loads for curtailment during emergency conditions. Around 15,000 MW of demand response cleared in the forward capacity auction for the 2015/16 delivery year.

4.7.5 Review against the principles

Table 11 is a preliminary review of wholesale DRM against the principles.

Table 11: Review of wholesale DRM against the principles

Principle	Preliminary review
Competition and market signals	A wholesale market DRM can be seen as a means to allowing more demand response to participate in the market. It could be argued that the current rules make it too difficult for demand response to participate in the market, limiting the degree of competition between these services and other forms of generation.
Risk allocation	There are risks associated with demand response services gaming their baselines to improve the price that they receive. These risks are borne by consumers, unless satisfactory mechanisms can be put in place to police gaming of baselines.

[71] Finkel, *Independent Review*, Recommendation 6.7

Principle	Preliminary review
Competitive neutrality	We would argue that a wholesale DRM is not technology neutral – in effect, demand response services receive special treatment, as the mechanism does not treat generation and loads on equal terms. To do so, would require that loads simply face a spot price, such as is the case under the current rules.
Clear and durable rules	It is possible to create a set of clear and consistent rules that underpin a wholesale DRM. Notwithstanding, rules for determining baselines often become complex and unwieldy as has been demonstrated in other markets around the world.
Information asymmetries	There are no material information asymmetries under a wholesale DRM that have been identified in terms of bidding and dispatch outcomes. The key information asymmetry is between the DR customer and the buyer of the service, and goes to the difficulty of measuring and verifying demand reductions.
Cross-market integration	A wholesale DRM is consistent with the principles of an integrated emissions reduction mechanism and co-optimisation of energy and ancillary services markets.

4.8 Inertia and frequency response markets

Inertia

Traditional synchronous generation providers are typically based on moving parts.[72] These moving parts have an inherent physical attribute – inertia – which is defined as the tendency of movement to continue in the absence of an opposing force.[73]

Inertia in the electricity grid has traditionally been provided as a by-product of generation capacity, as traditional sources of power typically involve a moving component (i.e. spinning turbines). The benefit of inertia is demonstrated when a generation source goes offline. The inertia inherent in the system slows the rate at which frequency drops, providing a time buffer for other generation sources to come online and bring the frequency up to the required level.

Frequency Control Ancillary Services

Frequency Control Ancillary Services (FCAS) support the secure operation of the market by ensuring frequency is managed within safe parameters.

Frequency refers to the speed at which current alternates in an Alternating Current (AC) network, such as the NEM. In Australia, this frequency is 50 Hz. It is critical this level is maintained within parameters to support the safe operation of any equipment connected to the network.

4.8.1 Policy objective

As FCAS and inertia markets relate to frequency control, the objective of these mechanisms is to **support system security**. FCAS and inertia markets aim to incentivise market participants to invest in and provide these services to support the operation of the market. They can therefore act on both the **investment and operational horizon**.

[72] Generally spinning turbines, although wind turbines also provide inertia
[73] Wirfs-Brock, J., "IE Questions: What Is Inertia? And What's Its Role In Grid Reliability?", *Inside Energy,* 2015, http://insideenergy.org/2015/06/15/ie-questions-what-is-inertia-and-whats-its-role-in-reliability/

4.8.2 How inertia and fast frequency response markets work

Inertia

As variable renewable energy sources are increasingly introduced to the grid, the reliance on inverters results in no mechanical inertia contribution to the system.[74] The following four inertia market mechanisms offer potential solutions:[75]

TNSP provision

TNSP provision has been noted as being the most likely option to provide the targeted level of inertia through network support agreements or providing inertia through synchronous condensers owned by the TNSP. Key factors to key consider are:

- financial incentives to minimise associated costs;
- consistency where TNSPs are accountable for the outcomes of their networks; and
- the ability to localise system strength where required.

Generator obligation

This option places an obligation on generators to provide inertia. Whilst simple to conceptualise, if a defined level of required inertia is provided to a generator, this is likely to result in over-supply at times of low demand. Limiting the obligation to centrally dispatched generators may also be ineffective at times when there is little centrally dispatched generation in the system.

AEMO contracting

Similarly to TNSP sourcing, AEMO contracting can provide certainty for investment, while also allowing for flexibility in sourcing and dispatch. However, as AEMO does not have clear financial incentives like TNSPs, it may be difficult to develop criteria by which AEMO could assess competing offers.

Market sourcing

This option forms a spot market for inertia provision, however it is not clear if a liquid secondary market would develop to manage price risk. Further, the physical properties of inertia make it difficult to incorporate into existing dispatch mechanisms.

FCAS

FCAS is sourced from markets operating in parallel to the wholesale energy market, with FCAS and wholesale electricity being optimised simultaneously to minimise total cost.

There are two types of FCAS:

- Regulation raise and lower services, used to correct minor changes in frequency; and
- Contingency fast (6 second), slow (60 second), and delayed (5 minute) raise and lower services, used to respond to larger deviations in power system frequency, typically as a result of contingency events such as the tripping of a large generator or load.

Changes by the AEMC in November 2016 have unbundled the provision of energy and ancillary services. This change allows ancillary-only service providers to enter the market, allowing both generation and demand-side response to provide FCAS services.

[74] ibid., p.3

[75] AEMC, *Final Report – System Security Market Frameworks Review* (2018), p.34

Recent price trends have incentivised market participants to install equipment to enable participation in the FCAS markets. The cost of delivering ancillary services to the market has increased from $2 million per week to in 2012 to $4.45 million per week in 2017. [76] This increase is largely attributed to increases in the cost of regulation services. As these services are procured through a market mechanism, this is reflective of a market signal for new participants into the market.

4.8.3 Market design characteristics and dependencies

Key considerations for inertia and fast frequency response markets are:

- recognising that inertia and fast frequency response services may be provided by different parties over time:
  - in the short term, inertia may be provided by existing generators;
  - in the long term, inertia may be provided by anyone who can build and maintain a synchronous condenser;
  - fast frequency response services may be provided by new entrants that do not participate in the wholesale market;
- inertia and fast frequency response are, to some degree, substitutes for one another and so a market design should consider *both* these services simultaneously, rather than each one in isolation; and
- the decline in the level of inertia is a problem that grows each time a synchronous generator retires – the solution must consider not only the need for new sources of inertia, but how policies can make use of, or preserve, existing sources of inertia.

4.8.4 International experience

We have examined learnings from inertia and frequency response markets in Great Britain and the Texas system managed by ERCOT. Key findings are below, with further detail in Appendix B.3.

To protect against drops in system frequency, National Grid in Great Britain has numerous services that market participants can offer into. One of these services is enhanced frequency response, which requires a <1 second response time to 100% proportionate active power output, compared to 10–30 seconds for mandatory and firm frequency response.

ERCOT procures four frequency control services: regulation reserves are deployed immediately in response to changes in system frequency, responsive reserves must respond within 10 minutes of a significant deviation event, and non-spinning reserves must have a response less than 30 minutes.

4.8.5 Review against the principles

Table 12 is a preliminary review of inertia and fast frequency response markets against the principles.

Table 12: Review of inertia and fast frequency response markets against the principles

Principle	Preliminary review
Competition and market signals	Creating markets for these new, unpriced services will ensure the services are provided to the market. Making TNSPs responsible for the provision of some of these services may be acceptable where the services have characteristics of a natural monopoly, i.e. large fixed costs with low ongoing variable costs.

[76] AEMC, *Interim Report*, p.49

Principle	Preliminary review
Risk allocation	TNSP provision, the generator obligation, and AEMO contracting all place the risk of over-investment on consumers. Under these options, if the central authority persistently over-estimates the need for inertia and fast frequency response, consumers will pay for the excess quantity of these services. This may not be the case where market sourcing is used. However, we note that there is a minimum amount of inertia/frequency response required to maintain system security at all times – this cannot be determined by the market, and so would be determined by a central authority under all options. Notwithstanding, the level of services above this minimum level could be determined by the market.
Competitive neutrality	Markets for these new services are a technology neutral solution. However, the other models put forward to obtain these services, such as TNSP provision or the 'generator obligation' options may not be technology neutral. For instance, the TNSP provision option may favour the use of synchronous condensers over other technologies.
Clear and durable rules	The rules for the mechanisms to obtain these services appear to be clear and consistent.
Information asymmetries	The generator obligation option may create some information asymmetries. Large generators, who can use their own portfolio assets, have an informational advantage over smaller generators, who may have to contract with larger generators to meet the obligation.
Cross-market integration	All of the options can be integrated with emissions reduction mechanisms.

4.9 Western Australia – constrained access

On 23 August 2017, the Western Australian Minister for Energy announced that legislation would be introduced in 2018 to adopt a framework of constrained access to Western Power's electricity network.

The current WEM arrangements are based on an *unconstrained* transmission network design. This network design is based on existing generation having firm access to the transmission network under system normal conditions and, in order to maintain firm access, potentially requiring expensive network augmentation prior to the connection of additional generation.[77]

An unconstrained network design, while providing certainty to generators, results in an overbuilt congestion-free network, which will eventually increase customer costs. An efficiently built network will have some level of congestion. Accordingly, the WEM plans to move to a NEM style constrained access regime by 2022, in order to promote a simpler connection process and more efficient outcomes.

Under constrained access, generators compete for access to the network through the real time wholesale market, with dispatch subject to network constraints to maintain system security. This provides an economically efficient means for the allocation of network capacity to generators based on their offer prices, and is expected to reduce the cost of new generators connecting to the grid.

4.9.1 Policy objective

The objective of introducing constrained access is to reduce costs and therefore enhance customer affordability. By allowing an efficient level of congestion through constrained access, new generators will be able to connect at a lower cost.

The PUO expects the reforms will reduce the time and cost to connect to Western Power's network, reducing barriers to entry and improving access to the network for newer generation technologies, particularly renewables.[78]

4.9.2 How constrained access is expected to work

The PUO is proposing the following approach to implementing constrained network access for the WEM:[79]

- No generator will have a guaranteed right to export electricity into Western Power's network. Firm access rights will not be grandfathered beyond some transitional arrangements (see below). This means any terms and conditions in existing network access contracts that grant, or purport to grant, rights to export electricity up to a maximum amount (when the network is operating under system normal conditions) will need to be subordinated to the operation of market dispatch, or otherwise overridden.
- All new connections to the Western Power network will be on a constrained basis. This means generators can be constrained-off (or constrained-on) by the activities of other users. No generator will be afforded firm access to the network under any circumstances.

[77] Firm access means that a generator is guaranteed access the transmission network for a specified capacity under system normal operating conditions.
[78] Public Utilities Office, *Improving access to Western Power's network – Implementing a constrained network access regime* (2018), p. 3
[79] ibid., p.5-6

- Terms and conditions in existing network access contracts that are inconsistent with a framework for constrained access will be modified accordingly. For example, contractual provisions that allow generators to transfer and / or relocate capacity between connection points will have no effect.

We also note these reforms may be supported by transitional arrangements for existing generators that recognise the investments these participants have made based on the existing regulatory framework. To inform a decision on required transitional arrangements to implement constrained access, the PUO is investigating the impacts on generators through market modelling.

The PUO is also investigating a form of rolling priority access to the reserve capacity mechanism on a first come, first served basis, where new entrant generators would have lower priority for 10 years. This is to provide a period of confidence to existing generators and to discourage new generators from locating in congested locations.

4.9.3 Market design characteristics and dependencies

Changes to the WEM to adopt a security-constrained market design will also be required. Existing WEM systems were designed on the basis that network congestion would rarely occur and the current approach of manual intervention during congestion events is unlikely to handle a higher incidence of network congestion in the future. Other changes to the design of the WEM include:[80]

- the introduction of facility bidding for all market participants;
- co-optimisation of energy and ancillary services; and
- implementation of 5-minute dispatch.

4.9.4 International experience

Most markets around the world, including the NEM, have a system of constrained access. This approach recognises that it would be inefficient to build a network with sufficient capacity to allow all generation to be dispatched, and that at some point the cost of building additional network outweighs the cost of congestion. In other words, there is an efficient level of network congestion.

In the NEM, generators are "constrained off" when there is congestion on the network, and so they cannot access the wholesale market price. In other markets internationally, generators have financial rights which effectively provide them with compensation when they cannot access the market price due to network congestion.

4.9.5 Review against the principles

Table 13 is a preliminary review of WA constrained access reforms against the principles.

Table 13: Review of WA constrained access reforms against the principles

Principle	Preliminary review
Competition and market signals	Constrained access supports increased wholesale market competition as new generators face lower barriers to connect to the grid.
Risk allocation	The allocation of risk sits with generators under the constrained access model. New entrant generators can take actions to manage this risk such as decisions on where to locate, taking into account grid conditions and the likelihood of congestion. Provision of rolling priority access for incumbents over new entrants for 10 years correctly allocates congestion risk with the causer of the congestion (i.e. new entrants).

[80] ibid., p.11

Principle	Preliminary review
Competitive neutrality	Constrained access supports competitive neutrality as under this framework all generators will have equal access to being dispatched in the WEM.
Clear and durable rules	As seen in the NEM, which has been in operation since 1998/99, constrained access can be implemented in a way that market participants can understand and which are adaptable over time to changes supply, demand and market structure.
Information asymmetries	Constrained access can be implemented in a way that minimises information asymmetries through the publication of transmission network constraints and generator bids. This information allows market participants to analyse and simulate likely constraints and congestion.
Cross-market integration	Constrained access can be implemented in a way that supports emissions reduction policies and ancillary services markets, as has occurred in the NEM.

5 Areas for further analysis

Australia's wholesale electricity markets are navigating a transition driven by changing relative technology costs and the need to reduce emissions. Enhancements to the NEM will likely be required for the market to adapt and a number are currently underway or proposed.

A key finding of our report is that the approach to changing the market design should follow a deliberate and well-structured process encompassing comprehensive stakeholder consultation (see section 3.8). If this does not occur, there is a risk that solutions are developed and implemented to solve the wrong problems or key stakeholders are not brought on the journey and frustrate reforms.

Facilitating industry participation in market reform processes creates a sense of ownership, which is essential for successful outcomes. Ultimately, market reforms will be enhanced when industry participants understand, adapt their commercial behaviour and embrace the change.

This chapter sets out our recommendations for further analysis.

5.1 Areas for further analysis

Our report has established a best-practice process for market design, developed an assessment framework, reviewed policy proposals, and tested various wholesale market mechanisms against the design principles in Chapter 3.

A critical piece of the design process is detailed analysis of issues facing the NEM, resulting in a set of clearly defined problems. Without this there is a risk the current solutions-focussed debate continues. We have posed a number of questions to guide analysis to help build on this report.

01 What services does the spot market need to price and participants need to procure for a reliable and secure system into the future?

The role of the spot market is to supply and price the services required to operate the power system in a secure and reliable state, in the long-term interests of consumers. Since commencement, the NEM has priced energy and frequency control ancillary services. A number of other services, such as inertia, have been supplied as a function of the predominant type of generation technology.[81] These services deliver value to customers and the market broadly.

As new technologies emerge and the generation mix changes, do new services need to be defined, priced and procured by the market operator on behalf of consumers? If the services required by the market operator to operate a secure and reliable system are transparently defined, then participants responding to price signals can be expected to meet this demand.

New services that may be required by the market include:

- Inertia;

[81] For example, inertia can be thought of as a positive externality – it was provided as an inherent characteristic of thermal generators for the benefit of all system users and the market operator.

- Dispatchable capacity;
- Fast frequency response; and
- Ramp-rate capability.

02 When is the appropriate time for operational and investment decision making and control to transfer from market participants to AEMO?

The current NEM design places investment decision making on market participants and only transfers operational decision making to the market operator five minutes ahead of dispatch. Prior to this point market participants can rebid their capacity between fixed price bands in response to changing conditions and new market information.

Some of the mechanisms discussed in Chapter 4 transfer decision making to the market operator earlier than currently occurs. For example, a mandatory, US style, day-ahead market can financially bind generators 12 to 16 hours ahead of dispatch, while a strategic reserve market could allow a market operator to procure capacity a number of years ahead of dispatch.

Through the market design process it is important to consider the implications of transferring decision making to the market operator and how this influences risk allocation and incentives for market participants. This could lead to trade-offs between certainty and efficiency.

03 Would wind and solar forecast accuracy increase if these market participants were responsible for providing energy forecasts to AEMO?

Forecasts of output from wind and solar over the operational horizon are key inputs into the NEM pre-dispatch process, as they provide information to market participants and AEMO on the resources available to meet demand. As forecasting becomes more challenging with the increased penetration of variable renewable energy generators, consideration could be given to ways of enhancing forecasting accuracy.

Forecasts of large-scale wind and solar generation for NEM pre-dispatch and dispatch are currently undertaken by the market operator. Forecasting is inherently difficult and no one organisation has all of the information or expertise. Market participants may have better information on expected generation through experience gained developing and operating their assets, as well as specialist in-house expertise.

The Victorian Declared Wholesale Gas Market (DWGM) operated by AEMO is a case in point. In the DWGM market participants forecast demand, which is used by AEMO for gas scheduling. The underlying philosophy is that market participants, in particular retailers, are better placed to predict their customers' gas demand than AEMO. However, because AEMO is responsible for operating the system in a secure state, it also undertakes whole-of-system demand forecasts and has an ability to override market participants' demand forecasts, subject to a transparent methodology.[82]

[82] AEMO, *Demand Override Methodology*, 16 July 2013

04 What market mechanisms could be considered to reduce the risk of VRE generators selling medium to long term hedge contracts?

An important aspect of facilitating efficient outcomes in an energy-only spot market such as the NEM is a liquid contract market. Generators and market customers enter into hedge contracts to manage spot price volatility. Without an effective contract market, the energy-only gross pool NEM design is unlikely to be sustainable.

As VRE generation makes up a greater proportion of the energy mix, the supply of hedge contracts offered into the market will likely reduce. This is because a mismatch is created between renewable energy generators with a variable fuel source and demand from retailers and large users for firm hedge contracts. If a VRE generator sells a firm hedge contract and its wind or solar plant is not generating, it will be exposed to the spot price of up to $14,200/MWh.

A European-style exchange-traded market for electricity contracts could provide a way to manage this risk through facilitating greater short term trade between VRE generators and dispatchable generators. Such a market would enhance the scope for VRE generators to manage volume risk associated with selling longer term OTC/ASX hedge contracts, through an ability to cap risk by buying back contracts on a short-term basis in response to wind/solar forecasts. It could also be used to facilitate the trade of demand-response contracts.

This type of market would in effect facilitate VRE generators becoming 'synthetic' firm generators and, if successful, increase the supply of longer term hedge contracts. The market could be established by the ASX offering short-term contracts, a new platform developed by industry participants or implemented by AEMO through an AEMC rule change. For this type of market to be successful, industry will need to coordinate and lead the design process, and play an active role in supporting trading liquidity.

Appendix A: Review of policy proposals

The purpose of this appendix is to review the wholesale electricity market elements of the various policy initiatives underway in a succinct, easy to understand manner. This will cover the many reviews, recommendations, and proposals underway in the market, focussing primarily on the:

- Independent Review into the Future Security of the National Electricity Market (the Finkel Review);
- ESB National Energy Guarantee (NEG);
- AEMC Reliability Frameworks and System Security reviews, and associated rule changes; and
- State and federal government initiatives.

A.1 Finkel Review recommendations

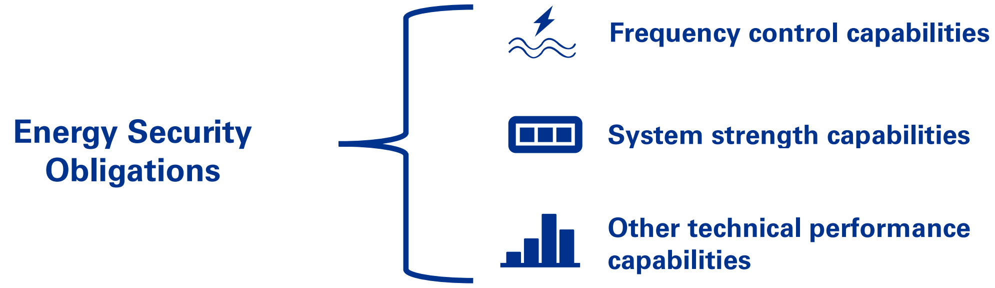
A.1.1 Overview of Finkel Review

Following the South Australian system-black event in 2016, Australia's Chief Scientist, Dr Alan Finkel, was commissioned to conduct an inquiry into the state of the electricity sector and provide recommendations for its future. The results of the inquiry form what is known as the Finkel Review[83], which encompasses a wide range of suggested reforms across several areas. The key recommendations, and the implementation status of them, is outlined in the following section.

A.1.2 Energy Security Obligations

The reform areas of the Energy Security Obligations for the NEM are summarised below in Figure 12.

Figure 12: Outline of Energy Security Obligations



[83] Finkel, *Independent Review*

What is the objective?

System security refers to the resilience of the electricity sector to unexpected perturbations, and is commonly linked to concepts such as synchronous generation and system inertia. With higher levels of renewable electricity, which does not possess inherent inertia, system security is reduced and there is a higher risk of faults. These reforms are aimed at strengthening this security by creating new mechanisms for promoting frequency control capabilities, system strength capabilities, and other technical performance capabilities.

Linkages with other policies

There are no direct links between this policy and others underway in the Australian electricity market.

Table 14: Energy Security Obligations – frequency control

#	Initiative	How it will work?	Who?	Why?	When?
1	Managing the rate of change of power system frequency[84]	• AEMC Rule change to require TNSPs to make minimum levels of inertia available when needed. • TNSPs will be able to contract with third-party providers of alternative frequency control services to provide inertia substitutes. • AEMO will be able to utilise the provided inertia network services under specific circumstances to maintain power system security.	NSPs, ISPs, Generators, Registered Participants and AEMO	Security	July 2018: Development and publication of methodology to determine inertia by AEMO is due. July 2019: TNSPs must address any declared shortfall in inertia.
2	Emergency frequency control scheme[85]	• AEMC Rule change to establish a framework for reviewing current and emerging power system frequency risks and managing emergency frequency events. • The new rules also establish a protected contingency event which allows AEMO to manage the system at all times using ex ante operational solutions and limited generation and load shedding.	AEMO, NSPs, Registered Participants, System Security Coordinator, Generators	Security	April 2018: Completion of a power system frequency review by AEMO is due, with a review at least every two years.
3	AEMC frequency control framework review[86]	• The AEMC is continuing its assessment of the appropriate design of an inertia market mechanism. • In particular, it is considering issues associated with primary frequency control, frequency control ancillary services, and distributed energy resources (DER)	NSPs, Generators, AEMO	Security	March 2018: AEMC Draft Report on Frequency control framework is due.
4	Inertia ancillary service market rule[87]	• AGL proposed a rule change to introduce a market based mechanism for the provision of inertia above the minimum obligations on TNSPs. • The AEMC has determined that the introduction of such a mechanism is not appropriate at this point in time.	TNSPS, Generators, AEMO	Security	February 2018: AEMC Final Determination passed.

[84] AEMC, *Rule Determination: National Electricity Amendment (Managing the rate of change of power system frequency) Rule 2017* (2017)
[85] AEMC, *Rule Determination: National Electricity Amendment (Emergency frequency control schemes) Rule 2017* (2017)
[86] AEMC, *Progress Update: Frequency control frameworks review* (2017)
[87] AEMC, *Rule Determination: National Electricity Amendment (Inertia Ancillary Service Market) Rule 2018* (2018)

Table 15: Energy Security Obligations – system strength capabilities

#	Initiative	How it will work?	Who?	Why?	When?
5	Managing power system fault levels[88]	• The AEMC is introducing regulatory arrangements to require network service providers (NSPs) to maintain system strength above key levels at key locations in the power system. • AEMO will be required to develop system strength requirement procedures and a system strength impact assessment. Where a system strength shortfall exists, TNSPs will be required to procure system strength services. • The rule also imposes a new requirement on connecting generators to 'do no harm' to the security of the power system.	Generators, TNSPs, ISPs, Registered Participants, AEMO	Security	July 2018: Development and publication of methodology for determining system strength requirements by AEMO is due. July 2019: TNSPs must have system strength services to meet shortfalls.

Table 16: Energy Security Obligations – other technical performance capabilities

#	Initiative	How will it work?	Who?	Why?	When?
6	Improved guidelines for generating system models[89]	• AEMC Rule change to expand the application of existing model data provisions in the NER to apply to additional types of participants and the plant they operate. • AEMO is required to set out in its power system model guidelines what model data must be provided by participants and the specific circumstances or conditions under which that model data will be required.	NSPs, prospective system restart ancillary services (SRAS), network support and control ancillary services (NCAS), AEMO.	Security	July 2018: Development and publication of revised guidelines for generating system models by AEMO is due.
7	Generator technical performance standards[90]	• AEMC Rule change to introduce a number of access standards for connecting generators and amending the process for negotiating performance standards. • Access standards include voltage control and reactive power provision, disturbance ride through, system strength, active power control and remote monitoring and control; • It is important to note that this rule change is limited to technical performance standards. A process for a further comprehensive review is being considered by the Energy Security Board.	Generators, NSPs and AEMO	Security	April 2018: Draft Determination expected. July 2018: Final Determination due.

[88] AEMC, *Rule Determination: National Electricity Amendment (Managing power system fault levels) Rule 2017* (2017)
[89] AEMC, *Rule Determination: National Electricity Amendment (Generating System Model Guidelines) Rule 2017* (2017)
[90] AEMC, *Rule Determination: National Electricity Amendment (Generating System Model Guidelines) Rule 2017* (2017)

A.1.3 Generator Reliability Obligation

The Generator Reliability Obligation (GRO) would impose new obligations on variable renewable energy (VRE) generators connecting to the NEM and is aimed at ensuring reliability is maintained. We note the ESB expects the GRO to be superseded by the reliability guarantee of the NEG[91].

What is the objective?

Placing reliability obligations on generators aims to counterbalance increasing intermittency in the grid as a result of renewable energy technologies.

Linkages with other policies

This policy is linked with the following policy developments:

- National Energy Guarantee (reliability) – Section A.2.2.

Table 17: Generator Reliability Obligation

#	Initiative	How will it work?	Who?	Why?	When?
8	Generator Reliability Obligation[92]	• Regional reliability assessments would be undertaken to determine the minimum dispatchable capacity for each region • This would inform any requirements for new generators.	Generators, retailers, Registered Market Participants, and AEMO	Reliability	The ESB expects the GRO to be superseded by the reliability guarantee of the NEG.

A.1.4 Strategic reserve mechanism

Strategic reserve is an out-of-market mechanism intended to act as an enhancement or replacement to the Reliability Emergency Reserve Trader (RERT). This is linked to the AEMC's Reliability Frameworks Reviews, as well as the ARENA-AEMO demand response trial.

What is the objective?

AEMO has proposed the need for a strategic reserve, similar to the existing RERT and AEMO/ Australian Renewable Energy Agency (ARENA) demand response procurement mechanisms to address brief, but extreme periods in the NEM.[93]

Linkages with other policies

This policy is linked with the following policy developments:

- AEMC Reliability Frameworks Review – Section A.3.1; and
- ARENA-AEMO demand response project – Section A.4.2.

[91] ESB, *National Energy Guarantee*
[92] AEMC, *Consultation Paper: National Electricity Amendment (Generator Technical Performance Standards) Rule 2017* (2017)
[93] AEMO, *Advice to Commonwealth Government on Dispatchable Capability* (2017), p 20.

Table 18: Strategic reserve mechanism

#	Initiative	How will it work?	Who?	Why?	When?

9	Strategic reserve mechanism[94]	• Demand response and peaking generation would be procured ahead of time and used to avoid load shedding, but would only be enabled during periods of scarcity pricing.
		• AEMO is considering two options for the strategic reserve:
		  • Procure fixed quantities of fixed reserve based on an assessment of shortfalls in demand in the market; or
		  • allocate a fixed budget to the scheme, with the maximum possible quantity of reserves to be purchased within that budget.
			AEMO, NSPs, Generators	Reliability	Mid-2018: AEMC and AEMO are considering with ESB to coordinate the market bodies' response on this issue.

A.1.5 Day-ahead market

The Finkel Review considered that the ability for AEMO and NEM participants to contribute to short-term reliability could be enhance through greater forward transparency of supply conditions provided by a day-ahead market.[95]

What is the objective?

Broadly, the Finkel Review considers that a day-ahead market would provide reliability benefits, although it does note that most characteristics of day-ahead markets in the US and Europe can be found in the NEM's pre-dispatch process and the contract market.

Linkages with other policies

This policy is linked with the following policy developments:

- AEMC Reliability Frameworks Review – Section A.3.1.

Table 19: Day-ahead market

#	Initiative	How will it work?	Who?	Why?	When?
10	Day-ahead market[96]	• Consideration of a day-ahead market is being progressed through the AEMC's Reliability Frameworks Review.	AEMO, Generators	Reliability	Mid-2018: AEMC and AEMO are considering with ESB to coordinate the market bodies' response on this issue

A.1.6 Demand response mechanism

Demand response involves consumers temporarily changing their usage of electricity at times of peak demand in response to signals to do so. The Finkel Review considered that DRM designs in New York and Texas might be appropriate for the NEM.[97]

[94] ibid., p.18
[95] Finkel, *Independent Review*
[96] AEMC, *Interim Report*, p.155
[97] Finkel, *Independent Review*

What is the objective?

Demand response is used to improve reliability and reduce wholesale prices by avoiding load shedding, and has the potential to provide system security benefits.

Linkages with other policies

This policy is linked with the following policy developments:

- AEMC Reliability Frameworks Review – Section A.3.1; and
- ARENA-AEMO demand response project – Section A.4.2.

Table 20: Demand response mechanism

#	Initiative	How will it work?	Who?	Why?	When?
11	Demand response mechanism [98]	• Consideration of a DRM is being progressed through the AEMC's Reliability Framework Review and ARENA-AEMO demand response trial will help to inform work on facilitating demand response.	AEMO, Retailers	Reliability	Mid-2018: AEMC and AEMO are considering with ESB to coordinate the market bodies' response on this issue

A.1.7 Generator closure notice periods

The Finkel Review recommended that all large generators provide at least three year's notice prior to closure and AEMO should maintain a register of long-term expected closure dates for large generators.

What is the objective?

It is anticipated that by 2035, 68 per cent of coal-fired generators will have reached the end of their life and are unlikely to be replaced with like-for-like generation assets.[99]

This could be problematic as the NEM transitions towards a new paradigm of two-way electricity flows and greater levels of VRE, particularly if generators retire with shorter notice than the time it takes for new capacity to be planned, financed and constructed. The Finkel Review considers this could have implications for system security and reliability issues.

Linkages with other policies

This policy is linked with the following policy developments:

- AEMO Integrated System Plan.[100]

[98] AEMC, *Interim Report*, p.101
[99] Clean Energy Council and Energy Networks Australia, *2016 Electricity Gas Australia* (2016)
[100] AEMO, *Integrated System Plan Consultation* (2017)

Table 21: Generator closure notice periods

#	Initiative	How will it work?	Who?	Why?	When?
12	Generator closure notice periods[101]	• AEMO is preparing drafting to amend the NER to require large generators to provide at least three years notice prior to closure and retirement of the generation asset. • Consultation will be considered as part of the AEMC's Reliability Frameworks Review. • AEMO will also set out information including announced closures, as part of its Integrated Systems Plan which is currently being developed.	Generators, AEMO	Reliability	2018: Consultation on the rule change is expected to commence.

A.2 National Energy Guarantee (NEG)

A.2.1 Overview of the NEG

The National Energy Guarantee was proposed by the Energy Security Board in October 2017, as a means to support the provision of reliable, secure, and affordable electricity whilst also meeting Australia's international commitments in the Paris Agreement. Rather than the Clean Energy Target (CET) recommended as part of the Finkel Review, the NEG was the Government's preferred option moving forward. The original concept incorporated two key mechanisms: an emissions guarantee, and a reliability guarantee. This would place an obligation on retailers to source electricity that met certain standards, either through contracting or other means.

A consultation paper on the NEG was released by the Energy Security Board on 15 February 2018[102], which outlined in more detail the workings behind the two key mechanisms, as well as providing more detail on other factors such as governance and effects on contract markets.

A.2.2 Reliability guarantee

The reliability guarantee sets an obligation retailers to meet any forecast shortfalls in reliability through contracting additional eligible capacity. This will build upon existing contract markets in the NEM in order to decrease the complexity of integration.

What is the objective?

With an increasing penetration of intermittent renewables on the grid, there have been increasing concerns regarding the effect this is having on reliability and security in the NEM. Mandating a reliability standard for retailers will alleviate this issue, and the increased liquidity of the contract market as a result of contracting additional capacity aims to put downwards pressure on electricity prices.

Linkages with other policies

This policy is linked with the following policy developments:

- AEMC Reliability Frameworks Review – Section A.3.1; and
- Generator Reliability Obligation – Section 0.

[101] ibid., p.30
[102] ESB, *National Energy Guarantee*

Table 22: National Energy Guarantee (reliability)

#	Initiative	How will it work?	Who?	Why?	When?
13	Reliability guarantee[103]	• AEMO will forecast shortfalls in reliability for given regions of the NEM, informing retailers if they fail to meet the predetermined standard. • Retailers will have a fixed amount of time to prove they have contracted enough eligible capacity to overcome the shortfall. • If the shortfall has not been alleviated by a given date, AEMO are required to procure resources to fill the gap at any cost to the retailer. • The increase in contracted capacity should increase competition and put pressure on electricity prices.	Retailers, AEMO	Reliability	February 2018: Consultation paper released by the ESB outlining a reliability guarantee. End of 2019: Reliability guarantee expected to take effect.

A.2.3 Emissions guarantee

The emissions guarantee as part of the NEG aims to integrate climate policy with energy policy through its emissions guarantee. Retailers would be required to meet an emissions intensity standard set by the Government that aligns with Australia's Paris Agreement objective.

What is the objective?

Given Australia's commitments at the Paris Agreement to a 26-28% reduction in emissions by 2030, there is a need for a transformation in the electricity sector. Whilst previous schemes such as the Renewable Energy Target aimed to incentivise the uptake of renewables, its failure to be integrated with current energy policy decreased investor confidence in the long-term survivability of certificate schemes.

Linkages with other policies

There are no direct links between this policy and others underway in the Australian electricity market.

Table 23: National Energy Guarantee (emissions)

#	Initiative	How will it work?	Who?	Why?	When?
14	Emissions guarantee[104]	• A retailer's emissions intensity will be calculated in a given compliance year, accounting for unknown contracted intensities with standardised values. • Retailers can meet the emissions intensity targets through contracting with low-carbon sources of energy or demand management. • The emissions intensity trajectory will be set by the Federal Government initially for ten years, with targets only adjustable every five years. • State-based renewable schemes will count towards meeting the targets.	Retailers, AEMO, AER	Emissions reductions	February 2018: Consultation paper released by the ESB outlining a reliability guarantee. End of 2020: Emissions guarantee expected to take effect.

[103] ibid., p.31
[104] ibid., p.15

A.3 AEMC rule changes and reviews

As the entity primarily responsible for the introduction of Rule changes and reviews, the AEMC is a key player in the introduction of new policies and regulations into the electricity market in Australia. Several Rule changes and reviews undertaken through the AEMC have been outlined in Section A.1 as part of the implementation of the Finkel Review, including:

- managing the rate of change of power systems;
- emergency frequency control scheme;
- AEMC frequency control framework review;
- inertia ancillary service market rule;
- managing power system fault levels;
- improved guidelines for generating system models; and
- generator technical performance standards.

In addition to these rule changes, the AEMC are also undertaking several other reforms, including:

- the AEMC Reliability Frameworks Review;
- 5-minute settlement in the wholesale market;
- changing the declaration of Lack of Reserve (LOR) conditions; and
- reviewing the coordination of generation and transmission investment.

This section investigates the context surrounding these additional reforms.

A.3.1 Reliability Frameworks Review

The review is aimed at providing a holistic assessment of the changes required to existing market and regulatory frameworks to maintain reliability in the NEM, as the electricity system transforms to accommodate more VRE generation. An interim report was published by AEMC on 17 December 2017[105], and submissions regarding the report were due on 6 February 2018. A Directions Paper for stakeholder consultation is due to be published on 27 March 2018.

What is the objective?

The growth of intermittent renewables and events such as the load shedding in South Australia and NSW in February 2017 have called the current frameworks surrounding reliability into question. The hope is that this review will provide a better understanding of how to best tailor the reliability frameworks of the NEM to support its transition into higher renewables.

Linkages with other policies

This policy is linked with the following policy developments:

- Demand response mechanism – Section A.1.5;
- strategic reserve mechanism – Section A.1.4;
- Generator Reliability Obligation – Section 0;
- National Energy Guarantee (reliability) – Section A.2.2;

[105] AEMC, *Interim Report*

- declaration of Lack of Reserve (LOR) conditions – Section A.3.3; and
- ARENA-AEMO demand response project – Section A.4.2.

Table 24: Reliability Frameworks Review

#	Initiative	How will it work?	Who?	Why?	When?
15	Reliability Frameworks Review[106]	• AEMC exploring whether variances in demand forecasting can be better managed through the forecasting process, or alternatively whether there are ways to rely less on forecasts. • The AEMC have expressed concern that information on the contract market is not widely available. • Strategic reserve is recommended to alleviate failures to meet the reliability standard, and an investigation into whether further enhancements to the RERT, or a separate strategic reserve are required. • The AEMC is examining ways in which the value associated with demand response can be better captured by third parties. • Day-ahead markets were considered, although European-style markets are similar to the current NEM, and US-style markets would take significant resources to introduce, albeit improving reliability.	AEMO, Generators	Reliability	December 2017: Interim report published February 2018: Submissions due March 2018: Directions Paper due to be published

A.3.2 5-minute settlement

The AEMC recently introduced new rules to align dispatch and financial settlement periods in the NEM to five minutes. This will reduce the time interval for financial settlement from 30 minutes to five minutes.

What is the objective?

Differences in dispatch and settlement timeframes are sending inefficient price signals to market participants. Generators and large users are being incentivised by price signals that can be up to 25 minutes after the physical energy system needs a response, reducing incentives for investment in more flexible technologies and leading to potentially inefficient bidding behaviours by participants.

Linkages with other policies

There are no direct links between this policy and others underway in the Australian electricity market.

Table 25: 5-minute settlements

#	Initiative	How will it work?	Who?	Why?	When?
16	5-minute settlements[107]	• AEMC Rule change to amend the definition of a trading interval to a five minute period. • The spot price will no longer be the time-weighted average of dispatch prices across a 30 minute timeframe and will instead be done on a five minute basis. • Type 1-3 meters, as well as Type 4 meters at transmission network or distribution connection points where the financial responsible market participant (FRMP) is a Market Generator or Small Generation	Registered Market Participants, Generators, Small Generation Aggregators, AEMO.	Reliability	December 2017: Transitional arrangements commenced. July 2021: Rule commences.

[106] ibid.
[107] AEMC, Rule Determination: National Electricity Amendment (5-Minute Settlement) Rule 2017 (2017)

#	Initiative	How will it work?	Who?	Why?	When?
		Aggregator, will need to record and provide five minute data from 1 July 2021.			

A.3.3 Declaration of Lack of Reserve (LOR) conditions

The AEMC made a final rule promoting short-term reliability by making declarations of a lack of reserve more flexible and transparent. Making these declarations more available aims to promote a market response in order to address shortfalls in capacity in order to minimise the risk of load shedding.

What is the objective?

Declarations of lack of reserve is the primary mechanism by which AEMO can communicate the risk of load shedding in a region. AEMO considered that the definitions of lack of reserve were not appropriate for identifying power system risks, and did not encompass a range of risk scenarios that could eventuate in high peak demand times.

Linkages with other policies

This policy is linked with the following policy developments:

- Strategic reserve mechanism – Section A.1.4; and
- AEMC's Reliability Frameworks Review – Section A.3.1.

Table 26: Declaration of Lack of Reserve (LOR) conditions

#	Initiative	How will it work?	Who?	Why?	When?
17	Declaration of Lack of Reserve (LOR) conditions[108]	• AEMO will develop and publish reserve level declaration guidelines that outline the criteria for lack of reserve conditions. • AEMO will declare any lack of reserves under these new guidelines to the market in order to promote a response.	Registered Market Participants, AEMO	Reliability	January 2018: New LOR framework in place.

A.3.4 Coordination of generation and transmission investment

The AEMC is in the process of conducting a review into the drivers that could impact on future transmission and generation investment. Provided the conclusions of a stage 1 report published on 18 July 2017, the review has progress into stage 2, which aims to outline options for improving the coordination of investment.

What is the objective?

There is increased uncertainty surrounding federal emissions policy, coupled with the replacement of thermal generation by variable renewables and the uptake of distributed energy resources. It is essential that new transmission and generation infrastructure is equipped to cope with these changes, and investigating the coordination of this investment is part of this process.

Linkages with other policies

There are no direct links between this policy and others underway in the Australian electricity market.

[108] AEMC, Rule Determination: National Electricity Amendment (Declaration of Lack of Reserve Conditions) Rule 2017 (2017)

Table 27: Coordination of generation and transmission investment

#	Initiative	How will it work?	Who?	Why?	When?
18	Coordination of generation and transmission investment [109]	• Options recommended through the review process may be implemented through various Rule changes.	Generators, TNSPs	Affordability	March 2018: Options Paper due.

A.4 Federal, state, and other policies

Factors including international emissions obligations, concerns over energy reliability, and changes in Government policy have led to a series of policy initiatives launched over the past 18 months. Each of these initiatives is aimed at delivering on one or more of the following overarching objectives:

- Stabilisation of wholesale electricity prices in the NEM;
- increasing renewable energy generation;
- providing additional storage capacity; and
- increasing system security and reliability.

A.4.1 Snowy 2.0

Snowy 2.0 is a proposed expansion to the existing Snowy Mountain Hydroelectricity scheme. The original Snow Hydro Scheme, built between 1949 and 1974 consists of 16 dams, 145 km of tunnelling, 80 km of pipes and aqueducts, and is one of the largest infrastructure projects ever undertaken in Australia.[110]

Using Pumped Hydroelectric Energy Storage (PHES), Snowy 2.0 is planned to increase generation capacity by 2000 MW (50%), and provide 350,000 MWh of energy storage. The project has progressed past the feasibility study stage and a final investment decision is currently being evaluated.[111] As part of the Department of Environment and Energy Climate Review, the Australian Government has invested up to $8 million towards Snowy Hydro's feasibility study on expanding pumped hydro storage in the Snowy Mountains, as part of its policy package aimed at reducing emissions to meet Australia's clean energy targets, and facilitate the efficient integration of renewable energy into the electricity grid.[112]

What is the objective?

As the generation mix of the NEM changes towards the use of more VRE sources, the ability of the NEM to incentivise investment in additional dispatchable generation has diminished.[113] Snowy 2.0 meets a market need for quick-start, dispatchable energy; providing additional reliable generation to the NEM. Additionally, Snowy 2.0 is located close to the two main load centres of Sydney & Melbourne, and uses existing water storages, removing the need for additional dam construction.[114]

[109] AEMC, Approach Paper: Coordination of generation and transmission investment (2017)
[110] Snowy Hydro, "Snowy 2.0", accessed 06 February 2018, http://www.snowyhydro.com.au/our-scheme/snowy20/
[111] ibid.
[112] Commonwealth of Australia, Department of Environment and Energy, *2017 Review of Climate Change Policies* (2017), p.27
[113] AEMO, *Advice to Commonwealth*, p.2
[114] Snowy Hydro, "Outcomes of the Feasibility Study", accessed 06 February 2018, http://www.snowyhydro.com.au/our-scheme/snowy20/outcomes-of-the-study/

Table 28: Snowy 2.0

#	Initiative	How will it work?	Why?	When?
19	Snowy 2.0[115]	• A Feasibility Study demonstrated technical and financial feasibility has been met to a suitable standard, and a defined planning process has been generated.	Reliability	Late 2018: Financial Investment Decision due. 2024: First power generation expected.

A.4.2 ARENA–AEMO demand response project

The ARENA-AEMO demand response project is a three year trial, initiated to make available 200 MW of capacity across the NEM, using the principle of demand response.

Demand response capacity aims to reduce discretionary usage during peak times, rather than building additional generation and transmission infrastructure, which are only used at full capacity on days of peak demand.[116]

Co-funded by ARENA ($28.6 million) and the NSW Government ($7.2 million), the demand response project has invested a total of $35.8 million across 8 different initiatives across Australia, with 143 MW of the total 200 MW to be made available during Summer 2017/18.[117]

What is the objective?

Electricity infrastructure, across generation, transmission, and distribution has been designed and built to meet maximum network demand, which is only reached a few times a year. The safe and voluntary reduction of this demand at peak times can significantly improve the reliability of the NEM, helping to avoid load-shedding blackouts and reduce the impacts of pricing spikes at times of peak demand.

Table 29: ARENA-AEMO demand response project

#	Initiative	How will it work?	Why?	When?
20	ARENA–AEMO demand response project[118]	• 10 pilot initiatives that incentivise avoiding or limiting electricity use in peak demand times have been invested into. • Each pilot initiative works off the same principle of voluntary reduction by consumers and associated compensation.	Reliability	Summer 2018: 143 MW available. December 2020: End of initiative.

A.4.3 South Australia's Our Energy Plan

Created in response to a number of energy security and reliability issues in 2016, the $550 million South Australian 'Our Energy Plan' was announced in March 2017, and contains a number of initiatives targeted at improving energy reliability, affordability and increasing the use of renewables.[119]

[115] ibid.
[116] Australian Renewable Energy Agency, "Australians demand secure, reliable energy this summer. ARENA and AEMO are responding" (2017), accessed 08 February 2018, https://arena.gov.au/blog/demand-response-3/
[117] Australian Renewable Energy Agency, "Demand Response: Helping to secure the grid by December 2020" (2017), accessed 08 February 2018, https://arena.gov.au/funding/programs/advancing-renewables-program/demand-response/
[118] ibid.
[119] Government of South Australia, *Our Energy Plan* (2017), p.7

What is the objective?

South Australia has a high reliance on VRE, with 39.2% of its electricity generated by wind, and 9.2% by rooftop solar PV systems.[120] This, alongside coal generation shutdown in recent years, has resulted in a lack of on-demand, dispatchable electricity to the grid, and price-spikes at times of high demand. The South Australian 'Our Energy Plan' was created in response to these challenges in network reliability and electricity prices.[121]

Table 30: South Australia's Our Energy Plan[122]

#	Initiative	How will it work?	Why?	When?
21	Investing in renewable energy with battery storage	• A $150 million Renewable Technology Fund was established by the State Government to invest in renewable energy projects that incorporate a storage component. • The first project funded under this plan was the 100 MW Neoen Energy/ Tesla wind farm and battery in Jamestown, South Australia. • A second initiative was announced in February 2018, outlining a plan for a rollout of 50,000 home solar and battery systems across South Australia, forming a 250 MW 'virtual power plant'. • The South Australian Government is assisting the program though a $2 million grant, and access to a $30M loan facility through the Renewable Technology Fund. • Further projects are under consideration, including solar thermal, biomass, hydrogen energy and pumped hydro.	Emissions reductions	November 2017: Tesla battery operational. 2019: Virtual power plant trial ends and installation in private properties begins.
22	Increasing state-owned generating capacity	• Hybrid gas/diesel generators have been connected to the grid at two temporary locations in South Australia. • These generators will operate on diesel for the peak demand seasons of 2018 and 2019, providing up to 276 MW of generation and extra inertia to stabilise local power suppliers.	Reliability	November 2017: Hybrid generators operational
23	Greater power over national market operators and privately owned generators	• The South Australian Government has legislated powers to the Minister for Energy to be able to direct AEMO to control flow on the South Australian-Victorian interconnector; and the ability to direct generators to operate. • The intention of these powers is to be used as a last-resort if the NEM is not acting in South Australia's best interest. • South Australia will now require all proposed generation projects over 5 MW to include power system security services as part of their projects in South Australia.	Reliability	April 2017: Government powers implemented
24	New generation for more competition	• The South Australian Government has tendered 75% of its electricity needs over the next 10 years. • This tender process has resulted in a $650 million, 150 MW Solar Thermal plant being built at Port Augusta, contracted to supply 100% of the South Australian Government's electricity needs. The maximum price paid for this electricity will be $78/MWh.	Affordability	2020: Completion of Port Augusta plant expected
25	South Australian Gas incentives	• The Plan for Accelerating Exploration (PACE) grants have been increased by $24 million to incentivise companies to further exploit South Australia's natural gas reserves. • A new PACE Royalties Return Scheme will provide 10% of royalties to landowners whose property overlies a	Affordability	March 2017: First round of PACE Gas grants announced.

[120] AEMO, *South Australian Electricity Report* (2017), p.30
[121] Government of South Australia, *Our Energy Plan* p.7
[122] ibid., p.4

		petroleum field brought into production, further incentivising exploration and production in South Australia.		December 2017: Second round of PACE Gas grants announced.
26	Energy Security Target	• South Australia's self-sufficiency will be increased through compelling retailers to source a percentage of energy from local generators. • Energy security target expected to transition to an Emission Intensity Scheme (EIS) or Lower Emissions Target (LET) depending on national policy. • Current developments from AEMO and FInkel Review implementations have allowed for a deferral of the target.	Reliability	2020: Energy Security Target expected to start

A.4.4 Queensland's Powering Queensland Plan

The Powering Queensland plan invests a total of $1.16 billion across 11 key initiatives to place downward pressure on energy prices, increase system security and availability; and increase the use of renewable energy.[123]

What is the objective?

Similarly to the South Australian 'Our Energy Plan', the Powering Queensland Plan has been formed in response to a number of challenges in the NEM, namely high electricity and gas prices, low system security, low gas availability, and a lack of an integrated national energy and climate policy.[124]

Table 31: Queensland's Powering Queensland Plan[125]

#	Initiative	How will it work?	Why?	When?
27	Funding the Solar Bonus Scheme.	• The cost of the Solar Bonus scheme will be removed from Queensland electricity bills for the next three years, and a delegation reissued to the Queensland Competition Authority to set the 2017-18 prices in line with the reduced rates. • It is expected that this action will limit the bill increase for a typical regional household to around 3.3%, and place downward pressure in 2018-19, and 2019-20. • The cost for this initiative is estimated at $770 million.	Affordability	15 February 2018: All battery installation and additional generation past this date is covered.
28	Returning the Swanbank E-gas fired power station to service.	• The Queensland Government will direct Stanwell Corporation[126] to return its 385 MW Swanbank E power station to service over the peak summer period.	Reliability	December 2017: Swanbank E returned to service
29	Directing Stanwell Corporation to undertake strategies to place downward pressure on wholesale prices.	• Direction will be given to Stanwell to alter bidding strategies in the NEM with the aim of placing downward pressure on electricity prices.	Affordability	December 2017: Direction given by Queensland Government

123 Queensland Government Department of Energy and Water Supply, *Powering Queensland Plan* (2017), p.1
124 ibid., p.1
125 ibid.
126 Stanwell Corporation is a Queensland Government owned corporation, and the state's largest electricity generator.

#	Initiative	How will it work?	Why?	When?
30	Investigate the restructure of Queensland Government owned generators, and the establishment of a 'Clean Co'.	• In order to improve market outcomes, a recommendations will be provided on restructuring Government owned generators. • Establishment of a Clean Co. generator will allow for operation of Queensland's existing renewable and low-carbon assets. • Clean Co. will also be responsible for developing new renewable energy projects.	Emissions reductions	Early 2018: Advice provided to Queensland Government.
31	Powering North Queensland Plan	• $150 million will be allocated to developing strategic transmission infrastructure in North and North-West Queensland to support a clean energy hub (subject to feasibility study). This has the potential to unlock up to 2000 MW of renewable energy projects in the region. • $100 million of equity will be invested into SunWater, along with reinvestment of dividends to deliver works to ensure the Burdekin Falls Dam continues to meet design standards. • A further $100 million will be invested to support the funding of a 50 MW hydro-electric power station at Burdekin, subject to the completion of a business case.	Emissions reductions	September 2017: Expressions of interest closed. September 2017: Feasibility study released
32	Confirmation of the 50% Renewable Energy Target by 2030.	• The 50% capacity target will be achieved through several mechanisms, including Renewables 400 and Clean Co. • Further schemes are likely in order to meet the target by 2030.	Emissions reductions	-
33	Renewables 400	• Reverse auction of 400 MW of renewable energy into the market, with priority to projects that support local jobs and businesses. • Additional process to secure 100 MW of energy storage prior to 2020.	Emissions reductions	Early 2018: Shortlisted proponents invited to submit binding bids
34	Improving the process of large-scale project facilitation, planning and network connections.	• Network connections will be ensured through work between Queensland Government, Powerlink, and Energy Queensland. • The Queensland Government has established a centralised web portal to provide integrated information for renewable energy project proponents. • Development of best practice guidance material for project planning and development.	Emissions reductions	Late 2017: Online web portal established.
35	Establishment of the Queensland Energy Security Taskforce	• A taskforce will be mobilised to develop an energy security plan for the State. A preparedness plan was developed for Summer 2017-18, mapping out steps to ensure Queensland's system remains secure in the short term. This will investigate hydro and pumped storage capacity, transmission infrastructure in North/North-West Queensland, and expanding interstate connectors. • The taskforce will also develop a demand management and energy efficiency strategy to help Queenslanders manage their power bills and to better manage peak demand, improving the resilience of the grid. • Further the taskforce will provide advice to the Queensland Government and the NEM on long-term market design, taking into account the outcomes from the Finkel Review.	Security	Summer 2018-19: Next summer preparedness plan due.
36	Implementation of the Queensland Gas Action Plan	• The Queensland Government released a tender for gas development in the Surat Basin, involving 58 sq.km, on the provision that the gas is sold on the Australian market.	Affordability	September 2017: Second tender released.

#	Initiative	How will it work?	Why?	When?
		• The Government released another similar 396 sq. km for gas development under similar conditions.		Early 2018: Preferred tenders expected to be announced.
37	Advocating for a stable, integrated national climate and energy policy.	• The Queensland Government will continue advocating for a stable and more integrated national climate and energy policy to ensure emission reduction commitments are met and to support clean energy investment.	Emissions reductions	-

A.4.5 Victorian Renewable Energy Target (VRET)

In June 2016, the Victorian Government committed to a renewable energy generation target of 25% by 2020, and 40% by 2040.[127] This was legislated in the Victorian Parliament through the *Renewable Energy (Jobs and Investment) Act 2017* (Vic), formalising the target along with a package of other policy reforms.

What is the objective?

In addition to providing a platform for increasing their commitment to sustainable energy, the VRET was developed by the Victorian Government to also respond to increasing electricity prices, and to deliver higher investor certainty in the region. By establishing a plan to bring forward investment in renewable energy projects in Victoria, the VRET aims to secure Victoria's electricity supply along with the creation of thousands of jobs.[128]

Table 32: Victorian Renewable Energy Target (VRET)[129]

#	Initiative	How will it work?	Why?	When?
38	Victorian Renewable Energy Auction (VREAS)	• Bids from renewable energy projects were submitted under a formal Request for Proposal (RFP), including a request for up to 550 MW of renewable energy and 100 MW of large-scale solar-specific projects. • Successful proposals will be awarded a 'Support Agreement' by the state to ensure certainty. • Proponents will be paid through a mix of fixed-price and a variable contract-for-difference payment. • The agreement will last for 15 years. • The 2017 auction has closed.	Emissions reductions	February 2018: Auction proposals due July 2018: Successful proponents notified
39	The *Climate Change Act (2017)*	• The *Climate Change Act (2017)* provides a legislative foundation for establishing emission reduction targets to achieve VRET. • Interim targets, Climate Change Strategies, Pledges, and Adaption Action Plans are required every five years	Emissions reductions	February 2017: Climate Change Bill passed
40	TAKE2 Pledge Program	• The TAKE2 pledge program encouraged community engagement with reducing emissions. • Business, individuals, and other organisation can pledge to reductions through an online portal.	Emissions reductions	June 2016: TAKE2 program established.

[127] Department of Environment, Land, Water and Planning (Victoria), *Renewable Energy (Jobs and Investment) Bill 2017* (2017) p.1
[128] ibid., p.1
[129] Department of Environment, Land, Water and Planning (Victoria), "Victoria's renewable energy targets", accessed 01 March 2018, https://www.energy.vic.gov.au/renewable-energy/victorias-renewable-energy-targets

#	Initiative	How will it work?	Why?	When?
41	New Energy Jobs Fund (NEJF)	• A $20 million New Energy Jobs Fund (NEJF) was established to support Victorian-based renewable projects. • Funding is available through three annual grant rounds from 2016 – 2018.	Emissions reductions	March 2018: Third grant round closed
42	Renewable Energy Action Plan	• The plan will invest $146 million in order to support sector growth, empower communities and consumers, and modernise the energy system. • $48.1 million will go towards renewable energy certificate purchasing. • $15.8 million will go towards smart solar and battery microgrid initiatives. • $25 million will go towards grid-scale battery storage facilities by Summer 2018.	Emissions reductions	July 2017: Renewable Energy Action Plan released.

A.4.6 Hydro Tasmania's Battery of the Nation

Hydro Tasmania is Australia's largest generator of renewable energy, producing 9,000 GWh annually from a 2,600 MW network of 30 power stations and more than 50 dams.[130] Expansion of this program is intended to provide significant contribution into the NEM, and provide a large energy storage system that can be relied upon alongside intermittent renewable generation on the grid. Additionally, this will provide energy security for Tasmania, as well as boosting the state's economy.

What is the objective?

The Battery of the Nation aims to alleviate concerns surrounding energy reliability in the NEM by providing a large energy storage system through the use of pumped hydro technology. In addition to helping with the decarbonisation of the NEM, the project will also work to lower national and local electricity prices.

Table 33: Hydro Tasmania's Battery of the Nation[131]

#	Initiative	How will it work?	Why?	When?
43	A 'future state' national electricity market	• Hydro Tasmania is analysing and modelling how the National Electricity Market (NEM) might evolve in the future. • Early analysis shows that Tasmania's superior wind resource, existing hydropower assets and untapped pumped hydro potential can deliver a future that's clean, reliable and affordable, at a time when Australia needs reliable, large-scale dispatchable generation.	Emissions reductions	Early 2018: Outcomes to be announced
44	Increasing the pumped hydro capacity in Tasmania	• An extensive assessment process across Tasmania is being completed. • Key regions and specific sites will be shortlisted to take to the next stage of study. • Up to 2,500 MW of capacity is expected to be delivered under this process.	Reliability	Early 2018: Outcomes to be announced

[130] Hydro Tasmania, "What we do", accessed 06 February 2018, https://www.hydro.com.au/about-us/what-we-do
[131] Hydro Tasmania, "Battery of the Nation", accessed 06 February 2018, https://www.hydro.com.au/clean-energy/battery-of-the-nation

#	Initiative	How will it work?	Why?	When?
45	Tarraleah Power Scheme redevelopment	• Suitable options for redesign of the Tarraleah Power Scheme are being assessed. • The redesign could boost production by 200 GWh each year, and extend the station's operating life by 80 years. • A feasibility study will be conducted for the chosen redesign option.	Emissions reductions	Early 2018: Outcomes to be announced
46	Gordon Power Station upgrade	• To maintain environmental flows to the Gordon River, Hydro Tasmania are currently running an existing large turbine at low load, which is not efficient. • Hydro Tasmania are looking at a solution to more efficiently generate power from the environmental water flow released to the Gordon River.	Emissions reductions	Early 2018: Outcomes to be announced

Appendix B: International experience

The purpose of this appendix is to review international examples and experience with the various market mechanisms outlined in this report. These market mechanisms are:

- National Energy Guarantee (emissions);
- National Energy Guarantee (reliability);
- Capacity markets;
- Day-ahead markets;
- Strategic reserves;
- Wholesale demand response mechanisms; and
- Inertia and fast frequency response markets.

B.1 Capacity markets

	Germany
Why	Germany considered a capacity market as part of its 'Power Market 2.0' reforms, however did not proceed to implementation, rather relying on a strategic reserve mechanism and market-based reforms.[132]
How	N/A
Outcome	A capacity market was rejected for three reasons: • sufficient levels of existing capacity; • a perception that capacity markets distort existing energy-only markets; and • cost effectiveness.[133]

[132] Clean Energy Wire, "Germany's new power market design" (2016), accessed 10 February 2018, https://www.cleanenergywire. org/factsheets/germanys-new-power-market-design,
[133] Jenkin, Beiter, and Margolis, *Capacity Payments in Restructured Markets*, p.31

France	
Why	Due to forecasted medium-term shortages, and peak demand growing at a higher rate than average demand, France introduced a capacity market mechanism in 2017.[134] Peak demand has a large impact on price volatility, and is primarily a function of winter temperatures – when the temperature decreases by 1 degree Celsius, consumption increases by 2400MW at peak.[135]
How	Following the ex-post model, energy retailers in France are obligated to purchase capacity certificates to cover their estimated level of consumer demand.[136] The total system need is assessed after the fact, and if retailers in aggregate supply enough certificates to cover demand, rebalancing occurs, and if not enough capacity is supplied, retailers must pay an imbalance settlement.[137]
Outcome	As this capacity market was only implemented in 2017, it is currently too early to make a historical determination of the effectiveness of the policy.

PJM	
Why	The current capacity market in the PJM is known as the Reliability Pricing Model (RPM) design, which was introduced in 2007 after eight years of a previous capacity market design.[138] It was designed to fix the revenue issues of the previous model, which did not provide sufficient incentive for new investment in generation.[139]
How	The central agency forecasts demand over a 3-year time horizon, when the first capacity auction takes places. From this point, further auctions take place in each successive year, enabling generators to trade capacity if their circumstances change.[140] To receive revenue for their auctioned capacity, generators must bid into the energy market. Unlike an energy-only market, electricity does not have to be dispatched for suppliers to receive payment, rather a commitment is made to supply energy during emergency periods under a capped price.[141]
Outcome	The Reliability Pricing Model has improved the incentives for new generation in the market, but still suffers from some issues regarding mismatches in price due to artificial suppression and inadequate performance incentives.[142]

Great Britain	
Why	The UK Government introduced a capacity market in 2014 as part of its Electricity Market Reform policy. The policy is intended to incentivise investment in sustainable, low-emission generation at least cost to consumers, while maintaining reliability.[143] Up to 20% of existing generation capacity is expected to close in the UK, replaced by VRE generation. Modelling conducted by the UK Government indicates that left unchecked, up to 2.5M homes could be affected by load-shedding blackouts.[144]

[134] RTE Réseau de transport d'électricité, *French capacity market* (2014), p.4
[135] FTI Consulting, *Assessment of the impact of the French capacity* (2016), p.1
[136] ibid., p.3
[137] ibid., p.35
[138] Bowring, J.E., "The Evolution of the PJM Capacity Market: Does it Address the Revenue Sufficiency Problem?" in *Evolution of Global Electricity Markets, ed.* Sioshansi, F.P (2013), p.236
[139] ibid., p.236
[140] PJM, *RPM 101 Overview of Reliability Pricing Model* (2017), p.17
[141] ibid, p.6
[142] Bowring, *PJM Capacity Market*, p.253
[143] Ofgem, "Capacity Market (CM) Rules", accessed 08 February 2018, https://www.ofgem.gov.uk/electricity/wholesale-market/market-efficiency-review-and-reform/electricity-market-reform/capacity-market-cm-rules
[144] Department of Energy & Climate Change (UK), *Annex C - EMR Capacity Market Design and Implementation Update* (2012), p.4

Great Britain	
How	Similarly to the PJM Capacity Market, the UK Capacity Market uses the ex-ante auction model. The first auction takes place four years out from generation date (T-4), followed by a second auction undertaken six months from generation date. The first three auctions have been run, however the first year of delivery under the Capacity Market will occur in 2018.[145]
Outcome	The latest T-4 Capacity Market auction cleared at a record low price of £8.40/kW, exhibiting a significant shift away from coal-based generation, with nearly 8GW of existing coal stations missing out on capacity. Existing gas and nuclear, plus new interconnectors and decentralised energy are filling the gap, as the UK grid transitions to a power system with decreasing dependence on large-scale power generation.[146]

Alberta, Canada	
Why	In November 2016, the Government of Alberta announced the transition of its energy-only market to a combined energy and capacity market. The transition was announced in response to a number of factors, most of which are analogous to the NEM, namely price instability, certainty of revenue for new generation capacity, and supporting the transition of Alberta's generation mix towards the use of more renewables.[147]
How	Currently under development, the Government of Alberta has delegated the design of the capacity market to the Alberta Electric System Operator (AESO). AESO is currently undertaking a market design process with the first iteration of the proposed design released in January 2018.[148] While the proposal as a whole is still in an early draft stage, and subject to significant further revision, the overview of the first iteration may provide insight into how a similar market may be designed in Australia. The proposed design currently contains the following features, as of February 2018: • Forecast demand is estimated by AESO, based on forward-looking probabilistic resource adequacy modelling, and a resource adequacy standard. • The forward capacity auction will be held three years in advance, as a uniform price, sealed bid, single round auction. The delivery period will be for one-year running from November to October. • Two rebalancing auctions will be held at 18 and 3 months prior to the delivery period. These rebalancing auctions allow suppliers to offer buy-out bids and incremental sell offers to the market.[149]
Outcome	It is expected the market design process will take up to three years from November 2016, and the capacity market is expected to be in place by 2021.[150]

B.2 Strategic reserves

Germany	
Why	In June 2016, the German Federal Parliament legislated to create a capacity reserve as part of a broader market reform. This was carried out to ensure efficient generation and the security of supply as the German electricity market makes the transition to renewable power.[151]

[145] D Yiakoumi & A Rouaix, *Understanding the new Capacity Market implemented in the UK* (2016), p.8
[146] KPMG UK, *Capacity Market auction results* (2018), p.1-2
[147] AESO, "Capacity Market Transition", accessed 08 February 2018, https://www.aeso.ca/market/capacity-market-transition/
[148] AESO, *Alberta Capacity Market* (2018), p.1
[149] ibid., p.2-5
[150] ibid., p.1
[151] Clean Energy Wire, "Germany's new power market design"

Germany	
How	The capacity reserve contains power plants which are not part of the regular power market, and have a total capacity of 4.4GW – five percent of the average maximum demand. It has been noted that these reserves will only be used when "all market-based options in the market are exhausted".[152] The total capacity will be tendered in tranches, with the first tender of 1.8 GW of capacity until 2019 released to the market in 2017. Due to this process, the total cost for the procured capacity is unclear, though it is expected to cost between €130-260M.[153]
Outcome	It has been estimated that the grid fee increase due to the strategic reserve will be in the range of 0.028 to 0.055 cent/kWh.[154]

ERCOT	
Why	The ERCOT market contains an Emergency Response Service mechanism (ERS) which dispatches demand response and distributed energy resources in response to anticipated supply shortages. The estimated load required is procured via a clearing-price auction, and paid on the basis of load reduction provided when the ERS is active.[155] The ERS is the successor to the Emergency Interruptible Load Service (EILS), introduced following a load-shedding event in 2006; the first since the inception of ERCOT. In 2012, the EILS mechanism was expanded to allow participation by distributed energy resources, and was re-named as the ERS.[156]
How	The ERS mechanism works by generating a demand curve, based on an annual expenditure limit of US$50M, rather than by estimating the total capacity needed. Effectively, this sets in place a 'budget' for the procurement of capacity, which is maximised within the cost constraint. The total funds are distributed across three annual auctions, based on the risk of an emergency event occurring in the given period. Participants in the auction are paid to curtail their availability in the event of an emergency, similar to the way in which demand response capacity providers are compensated. However, participants in the ERS do not receive further payments if their capacity is called upon under the ERS. To limit participants from consuming less prior to being dispatched via the ERS (to limit their exposure to high prices), the ERS imposes financial penalties if usage is less than stated baselines. This effectively limits the ERS system from responding the market price signals, ensuring it remains an out-of-market-response.[157]
Outcome	The ERS operates in a similar fashion to the ARENA-AEMO demand response project, as both target only demand response, though the procurement structure differs.

Elia (Belgium)	
Why	Similarly to the NEM's RERT, Belgium's system operator, Elia has strategic reserve in its energy-only market to avoid capacity shortfalls and to maintain reliability, procuring capacity in periods of supply emergencies. As a number of nuclear and CCGT plants were either mothballed, or out of the market for differing reasons, this mechanism was introduced in 2014 to aid in managing reliability during winter months.[158]

152 ibid.
153 ibid.
154 ibid.
155 AEMC, *Interim Report,* p.256
156 ibid., p.257
157 ibid., p.258
158 ibid., p.260

Elia (Belgium)	
How	Each year by 15 November, Elia calculates the strategic reserve requirement using probabilistic modelling to estimate the shortfall for the winter months. If a requirement is identified, reserves are procured through a competitive tender process.[159] There are two types on capacity reserves under Elia's Strategic Reserve mechanism: • Strategic Generation Reserve (SGR); and • Strategic Demand Reserve (SDR). SGR is delivered by generational capacity – to limit market distortion; SGR is limited to generators that are mothballed, or completely shutdown. SDR is delivered by two types of demand response, which both require demand to curtail to a target level, either via a 'drop by' target (i.e. demand is to *drop by* a defined target); or a 'drop to' target (i.e. demand is to *drop to* a defined target). SGR providers are compensated to cover expenses incurred in keeping generating units available, as well as for the energy dispatched. SDR providers are paid an availability payment, and an activation payment.
Outcome	Elia has noted that changes to the methodology used in the calculation of strategic reserve requirement have arisen from stakeholder consultation.[160]

B.3 Day-ahead markets

ERCOT	
Why	ERCOT was originally focused on bilateral trades with zonal congestion management, and retail competition. However, due to increasing cost of real-time re-dispatch for transmission congestion management and volatile zonal prices, ERCOT began planning to move to a nodal market from 2003, to support the introduction of a day-ahead market.[161]
How	Generators firstly submit either an energy-only bid; or a three-part bid outlining incremental energy cost, no-load cost and start-up cost. ERCOT then uses the granular information relevant to the physical operation of the system, to assist in scheduling the system dispatch for the day ahead, optimising both energy and ancillary services on a daily basis. Market participants with load are financially obligated to procure ancillary services. Awarded ancillary services are also physically binding.[162]
Outcome	The absolute difference between day-ahead and real-time energy prices in ERCOT was $7.44 per MWh in 2016, a decrease of 8% from the previous year and showing a continued improvement in performance of the market.[163]

PJM	
Why	A day-ahead energy market was introduced into the PJM in 2000, in order to develop financial schedules that are physically feasible for operators.[164] Additionally, it provides price certainty to participants in the market through forward energy pricing, price sensitive demand bids, increment offers, decrement bids, and up-to-congestion transactions.[165]

[159] ibid., p.260
[160] Elia, "Adequacy study for Belgium: The need for strategic reserve for winter 2018-19" (2017), accessed 16 February 2018, http://www.elia.be/en/about-elia/newsroom/news/2017/20171130_Strategic-reserve-for-winter-2018-19
[161] AEMC, *Interim Report,* p.255
[162] ibid., p.255
[163] Potomac Economics, *2016 State of the Market Report for the ERCOT Electricity Markets* (2017), p.vii
[164] PJM, *Overview of the Energy Market* (2016) p.7
[165] ibid., p.8

PJM	
How	Participants purchase and sell energy at a binding Locational Marginal Price (LMP), which consists of a system energy price, congestion price, and loss price.[166] Any generator that is a PJM generation capacity resource with an RPM Resource Commitment must submit a bid schedule regardless of availability.[167] After the daily period closes, PJM calculates the schedule based on the bid offers using a least-cost, security constrained resource commitment for each hour of the following day, incorporating reliability and reserve requirements.[168]
Outcome	PJM average day-ahead cleared supply in 2017 was 130,912 MW, compared to an average of 92,481 MW real-time cleared supply, and the average price difference between the two markets was -$0.06 per MWh in 2017.[169] The Market Monitoring Unit (MMU) recommended in their 2017 State of the Market report that market rules should explicitly require offers into the day-ahead market to be competitive (i.e. the short run marginal cost of the units).[170]

Great Britain	
Why	The EPEX SPOT UK Power Auction is a day-ahead mechanism introduced originally under APX Power UK in 2000 as Britain's first independent power exchange.[171] There are three primary mechanisms within the day-ahead market: an hourly auction, a half-hourly auction, and a prompt market.[172] The prompt market allows for continuous trading on a market up to a week out from delivery, the hourly auction consolidates liquidity a day before delivery, and finally the half-hourly auction is conducted at 15:30 the day before delivery and allows for tailoring and refining loads.[173]
How	The day-ahead hourly auction is an hourly double-sided blind auction, meaning that buyers and sellers enter anonymous orders for each hourly period.[174] Bids can be entered for a singular hour or in blocks, and there is a minimum price of -500 GBP per MWh and a maximum of 3000 GBP per MWh for any hourly offer (single or consecutive).[175] Orders are processed and matched through comparing the supply and demand of bids the day before delivery for every hour of the following day.[176] The half-hourly auction works in a similar fashion, but offers half-hour contracts for trading and matching.[177]
Outcome	The day-ahead market has continued to grow year-on-year, expanding 15.2% from 2017 to 2018.[178] In February 2018 alone, 4,440,080 MWh were traded on the market in the UK. The majority of this trading still occurs through the hourly day-ahead auction, although the half-hour auction grew 35% in 2017.[179]

[166] PJM, *PJM Manual 11: Energy & Ancillary Services Market Operations* (2017) p.17
[167] ibid. p.17
[168] ibid. p.17
[169] Monitoring Analytics, *State of the Market Report for PJM* (2017), p.118
[170] ibid. p. 99
[171] epexspot, "EPEX SPOT in the UK" (2017), accessed 13 March 2018, https://www.apxgroup.com/trading-clearing/apx-power-uk/
[172] ibid.
[173] ibid.
[174] epexspot, "APX Power UK – Auction" (2017), accessed 13 March 2018, https://www.apxgroup.com/trading-clearing/auction/
[175] ibid.
[176] ibid.
[177] epexspot, "UK Half Hour Day-Ahead 15:30 Auction" (2017), accessed 13 March 2018, https://www.apxgroup.com/trading-clearing/uk-half-hour-day-ahead-1530-auction
[178] epexspot, "French and UK Day-ahead Markets Grow Year-on-Year" (2018), accessed 13 March 2018, https://www.epexspot.com/en/press-media/press/details/press/French_and_UK_Day-ahead_markets_grow_year-on-year
[179] ibid.

B.4 Wholesale DRM

ERCOT	
Why	As part of its Emergency Response Service (ERS), demand response services can be dispatched to anticipate load-shedding events.[180] The ERS is the successor to the Emergency Interruptible Load Service (EILS), introduced following a load-shedding event in 2006; the first since the inception of ERCOT.[181] In 2012, the EILS mechanism was expanded to allow participation by distributed energy resources, and was re-named as the ERS.[182]
How	Demand response services are procured through generating a demand curve with an annual expenditure limit of US$50M across three periods, with allocation determined by the likelihood of an emergency event in that period.[183] The market enables several types of demand response. Load Resources (1,400 MW participating) can be deployed if frequency falls below a threshold level, and a capacity resource can be paid for availability during system shortages (400 MW participating).[184]
Outcome	ERCOT have attempted to introduce load in its energy market dispatch, although participation remains low.[185] This is restricted by current rules which require a 5-minute dispatch response time, do not allow aggregators to participate without representation through a retailer, and forbid the provision of ancillary services for resources with minimum or maximum run times.[186]

PJM	
Why	Since 2000, demand participation has existed in some form in the PJM as a way of paying loads for curtailment during emergency conditions.[187] Moving forward, the market has evolved to allow demand response to provide capacity, ancillary services, and energy.[188]
How	Demand response (DR) options are split into three categories in order to prevent displacing generation with resources that have lower availability.[189] Limited DR has the lowest availability, followed by Extended Summer DR, and Annual DR, both of which must be available for an unlimited number of interruptions during their respective delivery periods.[190] PJM can then place limits on the amount of procured resources of each category.[191]
Outcome	PJM has experienced a successful and rapid deployment of demand response through allowing aggregators to participate directly in the market, and compensating demand resources in a similar fashion to generation.[192] 15,000 MW of demand response cleared in the forward capacity auction for the 2015/16 delivery year.[193]

[180] AEMC, *Interim Report*, p.256
[181] ibid. p.257
[182] ibid. p.257
[183] ibid. p.257
[184] Brown, T., Newell, S.A., Oates, D.L., Spees, K., *International Review of Demand Response Mechanisms* (2015), p.39
[185] ibid. p.45
[186] ibid. p.45
[187] ibid. p.47
[188] ibid. p.47
[189] ibid. p.50
[190] ibid. p.50
[191] ibid. p.50
[192] ibid. p.48
[193] ibid. p.48

B.5 Inertia and fast frequency response

Great Britain	
Why	To protect against drops in system frequency and given their obligation to control frequency at a level of 1% within the nominal frequency of 50.00 Hz, National Grid have numerous services that market participants can offer in compensation.
How	Mandatory frequency response is generally a condition of connection, and can be bid on by generators, which receive payments for making a unit available in frequency response mode. Firm frequency response (FFR) services are procured through a monthly online tender process open to all providers, and are paid on an availability basis with additional payments for dispatch. Enhanced frequency response is an additional service which requires a <1 second response time to 100% proportionate active power output, compared to 10 – 30 seconds for mandatory and firm frequency response. Other services offered include frequency control by demand management (FCDM), reserves, fast reserves, short-term operating reserves (STOR), and reactive power services.
Outcome	Although a wide range of frequency response services are available, there have been recommendations for reform of the ancillary services market. The current areas of concern include transparency in service provision, the participation of interconnectors, and barriers to entry for synthetic inertia providers.

ERCOT	
Why	Significant planned additions of renewables have created volatility in supply, meaning there is a need for additional fast-responding dispatchable generation in ERCOT.[194] To maintain system frequency, four services are procured – up regulation, down regulation, responsive reserves, and non-spinning reserves.[195]
How	Regulation reserves are deployed immediately in response to changes in system frequency, responsive reserves must respond within 10 minutes of a significant deviation event, and non-spinning reserves must have a response less than 30 minutes.[196] ERCOT establishes an Ancillary Services Plan in the day-ahead market that outlines ancillary obligations of Qualified Scheduling Entities (QSEs) for each hour of the following day.[197] QSEs must then submit their bids and offers on the market, meeting obligations through self-supply, bilateral trades, or purchases from ERCOT. [198]
Outcome	Ancillary service requirements decreased from 5,300 MW in 2015 to 4,900 MW in 2016, spread across all service provisions, and prices for services have remained low due to a lack of shortages.[199] Real-time co-optimisation of energy and ancillary services has been recommended to improve efficiency, as currently only day-ahead markets are co-optimised.[200]

[194] Apex CAES, "ERCOT Market" (2012), accessed 14 March 2018, http://www.apexcaes.com/caes/ercot-market
[195] ibid.
[196] Argonne National Laboratory, *Survey of U.S. Ancillary Services Markets* (2016), p.8
[197] ibid. p.9
[198] ibid. p.9
[199] Potomac Economics, *State of the Market*, p.34
[200] ibid. p.42

Appendix C: Policy categorisation

The purpose of this appendix is to lay out the current policies and initiatives in a table that provides an indication of the responsible party and the objective of the policy, with regards to security, reliability, affordability, and emissions reductions.

Table 34: Categorisation of policies and initiatives

#	Policy/Initiative	Party responsible	Objective
1	Managing the rate of change of power system frequency	AEMO	Security
2	Emergency frequency control scheme	AEMO	Security
3	AEMC frequency control framework review	AEMC	Security
4	Inertia ancillary service market rule	AEMC	Security
5	Managing power system fault levels	AEMO	Security
6	Improved guidelines for generating system models	AEMO	Security
7	Generator technical performance standards	AEMC	Security
8	Generator Reliability Obligation	ESB	Reliability
9	Strategic reserve mechanism	ESB	Reliability
10	Day-ahead market	ESB	Reliability
11	Demand response mechanism	ESB	Reliability
12	Generator closure notice periods	AEMC	Reliability
13	National Energy Guarantee (reliability)	ESB	Reliability
14	Reliability Frameworks Review	AEMC	Reliability
15	5-minute settlements	AEMC	Reliability
16	Declaration of Lack of Reserve conditions	AEMC	Reliability
17	Snowy 2.0	Federal	Reliability
18	ARENA-AEMO demand response project	AEMO	Reliability
19	National Energy Guarantee (emissions)	ESB	Emissions
20	Coordination of generation and transmission investment	AEMC	Affordability
21	Establishment of the Queensland Energy Security Taskforce	QLD	Security
22	New state-owned gas power plant	SA	Reliability
23	Local powers for the national market	SA	Reliability
24	Energy Security Target	SA	Reliability

#	Policy/Initiative	Party responsible	Objective
25	Returning the Swanbank E-gas fired power station to service	QLD	Reliability
26	Improving the process of large-scale project facilitation, planning, and network connections	QLD	Emissions reductions
27	Implement pumped hydro capacity in Tasmania	TAS	Reliability
28	Battery storage and renewable technology fund	SA	Emissions reduction
29	Investigate the restructure of Queensland Government owned generators, and the establishment of a 'Clean Co.'	QLD	Emissions reductions
30	Powering North Queensland Plan	QLD	Emissions reductions
31	Confirmation of the 50% Renewable Energy Target by 2030	QLD	Emissions reductions
32	Renewables 400	QLD	Emissions reductions
33	Advocating for a stable, integrated national climate and energy policy	QLD	Emissions reductions
34	Victorian Renewable Energy Auction (VREAS)	VIC	Emissions reductions
35	The Climate Change Act (2017)	VIC	Emissions reductions
36	TAKE2 Pledge Program	VIC	Emissions reductions
37	New Energy Jobs Fund (NEJF)	VIC	Emissions reductions
38	Renewable Energy Action Plan	VIC	Emissions reductions
39	A 'future state' national electricity market	TAS	Emissions reductions
40	Tarraleah Power Scheme redevelopment	TAS	Emissions reductions
41	Gordon Power Station upgrade	TAS	Emissions reductions
42	Funding the Solar Bonus Scheme	QLD	Affordability
43	New generation for more competition	SA	Affordability
44	South Australian gas incentives	SA	Affordability
45	Directing Stanwell Corporation to undertake strategies to place downward pressure on wholesale prices	QLD	Affordability
46	Implementation of the Queensland Gas Action Plan	QLD	Affordability

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