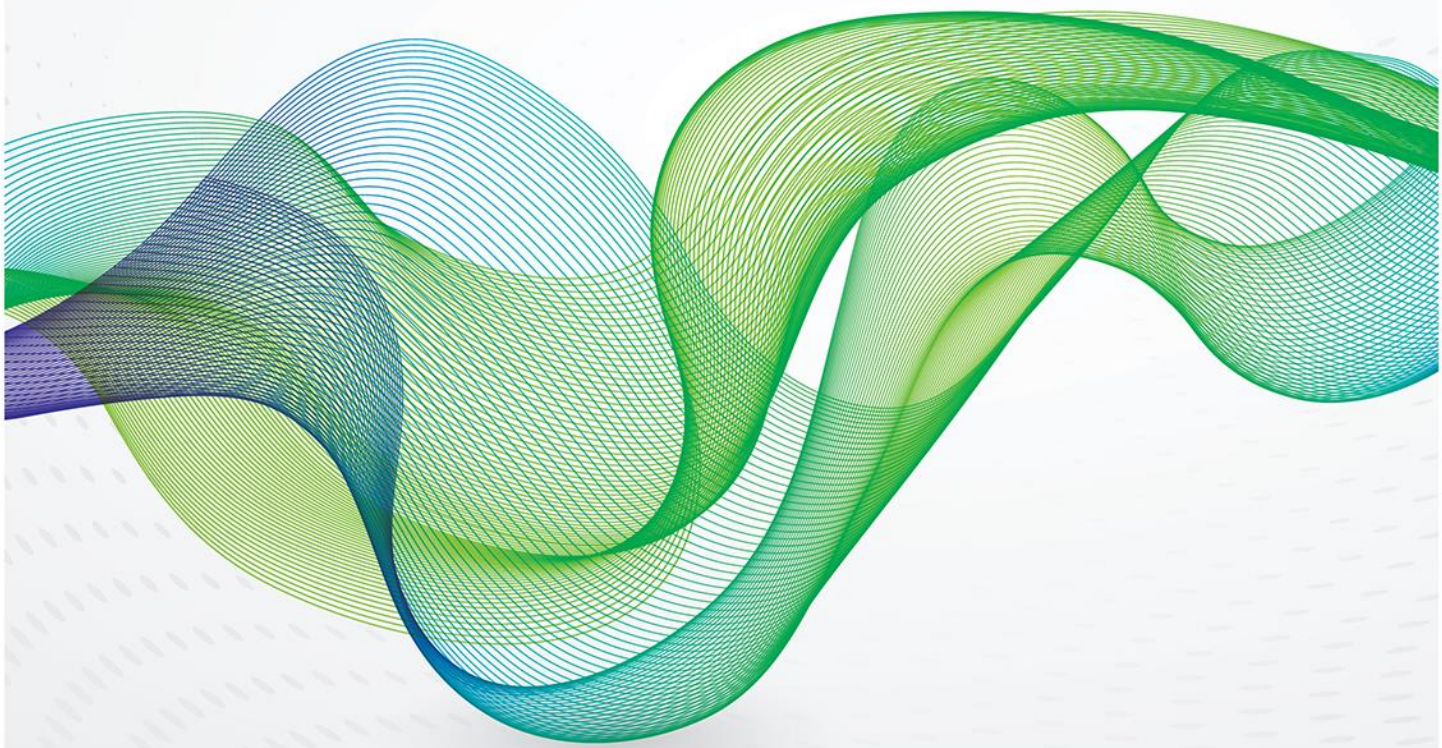
THE OXFORD INSTITUTE FOR ENERGY STUDIES

November 2018

Electricity Sector Transition in the National Electricity Market of Australia:

Managing Reliability and Security in an Energy-Only Market



OIES Paper: EL 31

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ISBN 978-1-78467-122-8

DOI: https://doi.org/10.26889/9781784671228

Electricity Sector Transition in the National Electricity Market of Australia: Managing Reliability and Security in an Energy-Only Market

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Abstract

Australia's National Electricity Market is an important global test case of the impacts of electricity sector transition in a large-scale liberalized energy-only market. The integration of variable and distributed energy resources has provided opportunities for clean, low-cost generation, but has also challenged existing market frameworks and resulted in a debate about the necessity for new designs. The market's delayed and insufficient response to disorderly retirement and the need for certain system services have resulted in government and system operator intervention to bridge the gap. There are difficulties in securing timely new investment under policy uncertainty and integrated capital models. Furthermore, contributions to system services that were previously provided as a consequence of energy provision are not inherently provided by many new-generation technologies. A range of solutions have been proposed to address these challenges, although none to date have harnessed the potential of comprehensive alignment between operational requirements and economic signals. For example, the government's flagship National Energy Guarantee, while providing a new framework for emissions intensity and reliability, did not address the 'missing markets' in energy security. Measures such as forward markets may provide hedging options, but are limited to energy. Centralized commitment could provide operating robustness, but might not be able to provide sufficient transparency of the various electricity value streams, as the experience of international markets shows. Furthermore, while reliability has taken centre stage in the policy discourse, system security is as important in managing a large-scale complex grid with a significant share of asynchronous generation. We argue that an efficient and transparent real-time energy market must reflect the comprehensive operational requirements of electricity dispatch. This necessitates an extension of energy-only design to an 'energy+services' model in which efficient price signals are provided for the 'missing products' necessary for operational security. Clear service specifications provide transparent signals that enable clear price discovery and facilitate competition from new providers and technologies.

[1] This study represents the authors' own work. Any views expressed are those of the authors and do not represent the views of any organization or company. Any errors or omissions remain those of the authors.

Acknowledgements

We would like to thank David Robinson and Malcolm Keay of Oxford Institute for Energy Studies, Bruce Mountain of Victoria Energy Policy Centre, Fernando Lasheras from Iberdrola and Tyson Vaughan and Silvia Piana from Enel Green Power for their robust and detailed comments on the early version of this paper.

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1. Introduction

Australia's National Electricity Market (NEM) is an important global test case of the impacts of electricity sector transition in a large-scale liberalized energy-only market. The growth of utility-scale variable renewable energy (VRE) and distributed energy resources (DER) has changed the operational and market dynamics of the electricity system in the NEM. South Australia, in particular, has been labelled the 'canary in the coalmine' of electricity market transition, with a high penetration of variable renewable and distributed generation. Looking ahead, Australia is expected to become one of the most decentralized electricity markets in the world over the coming decades.

Over the last few years the NEM has faced a number of disruptions, tests, and pressures from an economic, technical, and socio-political perspective. On a technical level, changes to demand, resource availability, and dispatch profiles have required a rethink of operational management of the grid. This is more critical in South Australia, which has only one alternating current (AC) interconnection with the rest of the NEM. Traditionally, thermal generation provided aspects of system security, such as inertia and system strength, simply by virtue of their participation in the market. The provision of these services has declined as thermal units retire and are increasingly pushed out of the merit order stack by low marginal cost renewables. This has necessitated new operational requirements and increased operator intervention to ensure system security. Furthermore, increased penetration of low marginal cost generation has changed pricing dynamics, with subsequent impacts on investment.[2] Variable renewables have also necessitated new approaches to hedging and risk management. For example, the notion of baseload generation becomes less relevant as there is less constant load in the system.

Energy and carbon policy are also increasingly political, with high electricity prices and reliability concerns motivating government intervention. Several attempts to formulate a national carbon policy have also failed to obtain the requisite political support. The government's flagship National Energy Guarantee initiative, after a year of design and consultation, failed to get party approval, and ultimately set off a series of events that resulted in a national leadership change. These issues have led to questions about the appropriateness of existing market frameworks to meet the challenges of the electricity system today and in the future (Finkel et al., 2017). As such, the efficacy of market design at a wholesale and retail level has been subject to policy concerns and reviews.

However, the current market also provides opportunities. Robust and strategic responses to the challenges being faced have the potential to lead to new approaches to the management of the electricity market transition. Regions such as South Australia can act as a test case for the viability of islanded markets with high renewables penetration. The design of their market and regulatory frameworks to ensure the provision of system services could offer learnings for international and regional market design. Furthermore, with current challenges creating commercial opportunities, market response in the form of innovative technology solutions can be observed, such as energy storage and demand response. Thus the identification of successful transition pathways for an island market 'of scale' is of importance and relevance not only to Australia, but also to many major markets around the world.

This paper analyses the challenges that the NEM has been facing as a result of the energy transition and discusses regulatory responses that have been planned. It also explores the pathways forward for the NEM.

The paper is structured as follows. Section 2 outlines the transformational changes taking place in the electricity system, while Section 3 sets out their impacts on the achievement of electricity market

[2] Reliability refers to the ability of generation and transmission capacity to meet consumer demand. Security refers to the ability of the power system to tolerate disturbances and maintain a stable operating state for electricity supply (Finkel at al., 2017).

objectives, pricing signals, and risk management. Section 4 discusses the range of solutions proposed and the pathways for achieving the NEM's reliability and security aims. Finally, Section 5 provides concluding remarks. The Appendix provides an overview of the NEM, including governance, regulatory design, pricing formation, frameworks for reliability and security, and key market participants, as well as approaches to hedging, and portfolio and risk management.

2. The changing dynamics of the electricity system

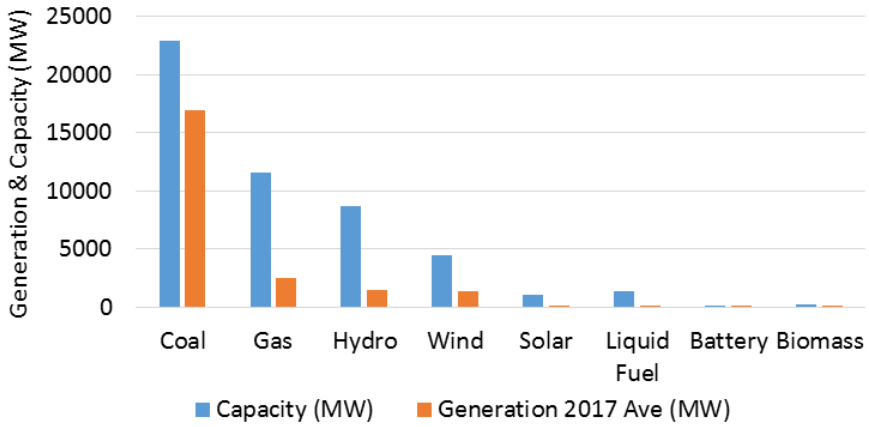
The NEM – Australia's national electricity market – is a large grid connecting the major population centres across the country's east and south coasts. There is also a much smaller interconnected grid in Western Australia (the South West Interconnected System) and an 'archipelago' of smaller grids and systems located in Australia's remote interior.

The NEM is the core focus of this study. It is the longest interconnected power network in the world, extending over 40,000 kilometres and connecting major population centres on the southern and eastern seaboards of Australia (AEMO, 2017i). It has an annual electricity demand of around 200 terawatt hours (TWh) across 9 million customers.[3] The main sources of generation currently in the NEM are coal (23 gigawatts [GW]), gas (12 GW), hydro (9 GW) and wind (4.4 GW) (see Figure 1).

The design of wholesale market is based on an energy-only gross pool, with zonal pricing across five regions delineated by state boundaries. Participants bidding and offering energy and resources on a regional basis are centrally cleared along with frequency control ancillary services (FCAS) via a dispatch optimization engine (AER, 2017) (for a detailed discussion on the basics of market design in the NEM please see the Appendix). While dispatch prices are set every five minutes, the market is settled on a 30-minute basis, with the price set at an average of the six 5-minute intervals within the settlement interval. The Australian Energy Market Commission (AEMC) recently approved a rule change that will align both dispatch and settlement intervals at five minutes (AEMC, 2017b).

At the moment, there is no formal day-ahead or forward dispatch market, although participants are free to contract externally. Market indicators such as pre-dispatch and projected assessment of system adequacy (PASA) provide guidance for market participants with respect to future system conditions, dispatch, and pricing. Regulatory changes to implement organized forward markets are currently being considered by rule makers.

Figure 1: Sources of generation in the NEM (excluding rooftop solar PV), 2017



Note: PV = photovoltaic.
Source: AEMO (2018b)

[3] A detailed map setting out the network and the location of generation stations is set out in the Appendix (Figure A1).

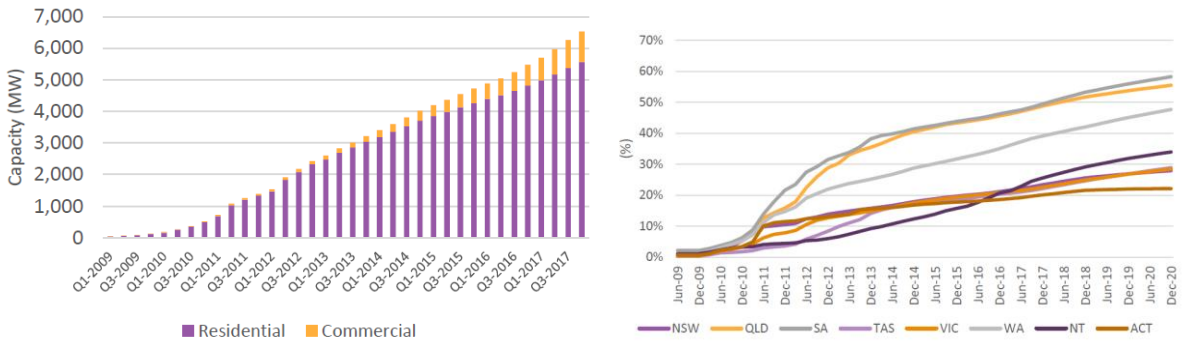
The energy needs of Australian electricity consumers have changed from the perspective of a centrally dispatched system. Since 2010 there has been transformational growth in the installation of distributed rooftop PV, primarily across residential customers, driven in part by government incentives and the avoidance of high retail electricity rates (see Figure 2). As of December 2017, over 7.0 GW of distributed rooftop solar PV capacity was installed in Australia, with rooftop PV penetration rates in excess of 50 per cent in Queensland (ACIL Tasman, 2018; APVI, 2018).

This has resulted in changes to the diurnal patterns of demand that must be met by the centralized market. Operational demand[4] in states such as South Australia at certain times of the year is showing clear 'duck-curve' net demand patterns (see Figure 3) (AEMO, 2018a).

This pattern is expected to become more extreme, based on projections for additional solar PV installations over time driven by commercial and industrial deployment. Expectations are that rooftop solar capacity will exceed 10 GW by 2020 (Green Energy Markets, 2018; Hyland, 2018), with long-term expectations ranging from 20 GW to 37 GW (AEMO, 2017e; CSIRO-ENA, 2017). Australia is expected to become one of the most decentralized systems in the world, with up to 43 per cent of generation capacity located behind the meter by 2040 (BNEF, 2018).

South Australia, in particular, is expected on average to have very low or negative net demand during peak solar generation times and to become a net exporter of generation to other regions. By 2024-25 it is expected that minimum summer operational demand for South Australia will go negative (see Figure 4).

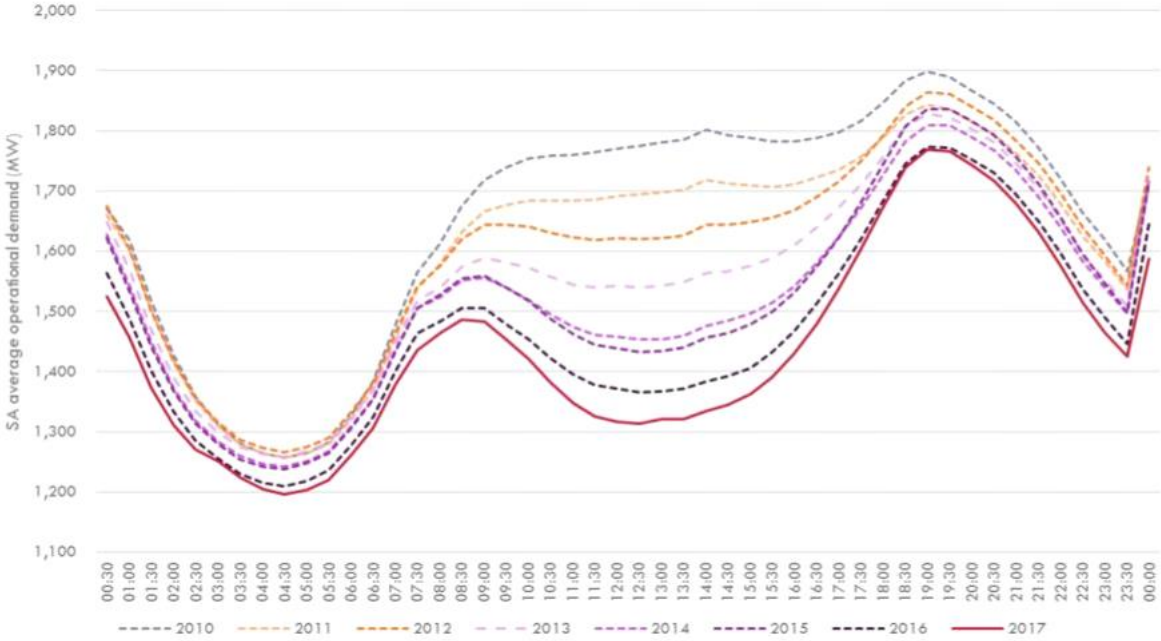
Figure 2: Cumulative rooftop PV capacity (LHS) and residential rooftop penetration (RHS) in Australia



Notes: ACT = Australian Capital Territory; NSW = New South Wales; NT = Northern Territory; QLD = Queensland; SA = South Australia; TAS = Tasmania; VIC = Victoria; WA = Western Australia.
Source: ACIL Tasman (2018).

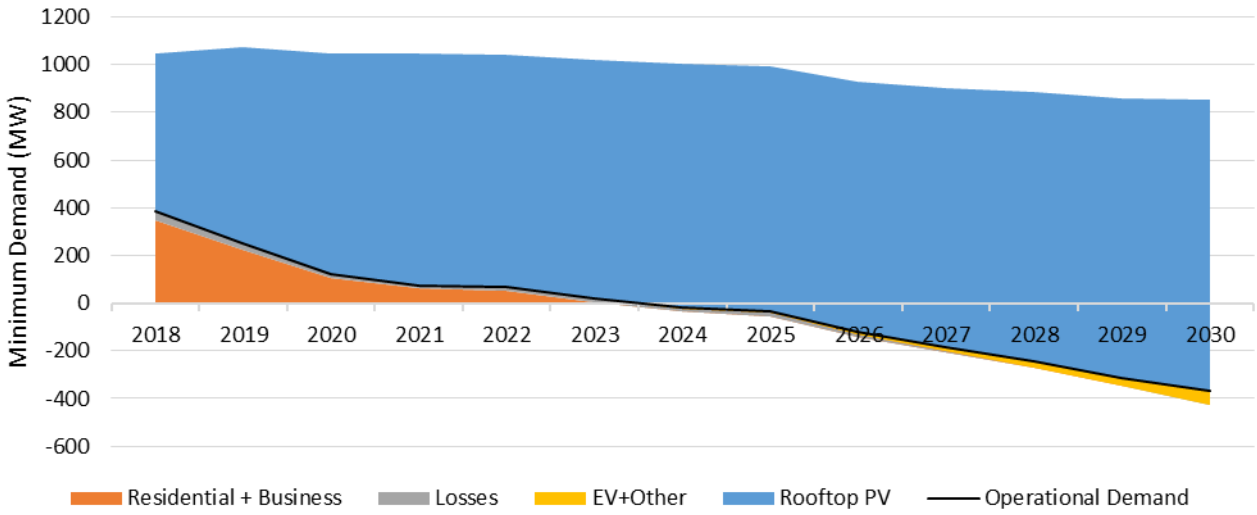
[4] According to AEMO (2018k) Operational Demand in a region is demand that is met by local scheduled generation, semi-scheduled generation and non-scheduled wind/solar generation of aggregate capacity more than 30 MW, and by generation imports to the region, excluding the demand of local scheduled loads.

Figure 3: Operational demand in South Australia



Source: AEMO (2018a).

Figure 4: South Australia minimum operational demand projection



Source: AEMO (2018i).

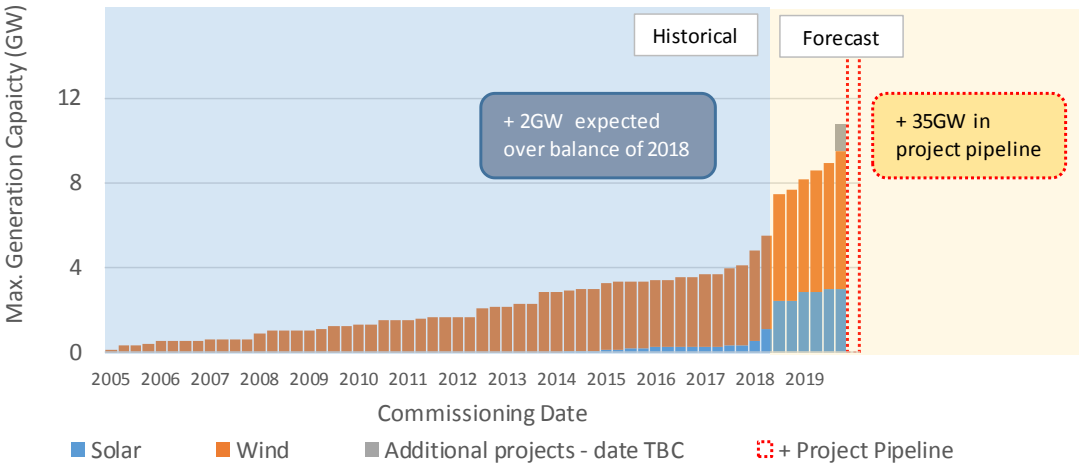
2.1 The buildout of utility-scale renewables

The growth of utility- or large-scale renewables generation has also been remarkable. The Renewable Energy Target (RET) scheme, combined with technology cost reductions, has driven additional investment in over 6 GW of renewable generation capacity over the last ten years (for more on the RET please see the Appendix). The bulk of this buildout to date has been in wind generation, with over 5 GW

of existing and operational capacity in the market (see Figure 5). In recent months, utility-scale solar PV capacity additions have also been strong, with over 600 megawatts (MW) added in the second quarter of 2018, taking total existing capacity to approximately 1 GW.

Further increases in renewables investment are expected across both wind and solar, driven in part by the already low and still decreasing technology costs (Nelson, 2018). The pipeline for solar investment comprises 1.9 GW of committed projects,[5] with an additional 17 GW of proposed projects. For wind, a further 2 GW are committed and an additional 18 GW proposed (AEMO, 2018b). By 2040, modelling from the Australian Energy Market Operator (AEMO) suggests that VRE will be the dominant source of electricity generation in the NEM (AEMO, 2018d) (see Figure 6).

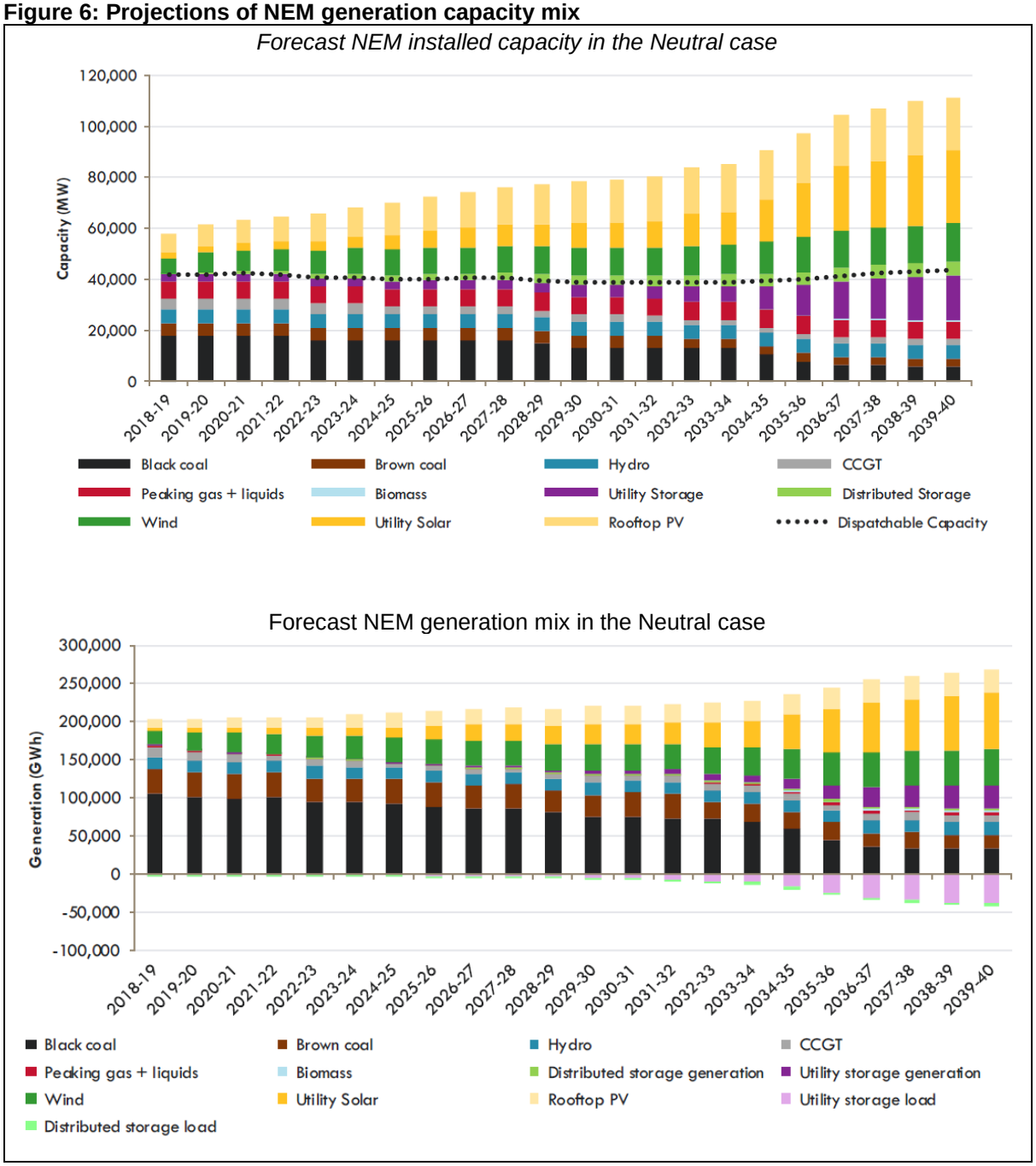
Figure 5: Renewables buildout to date and expected future buildout in the NEM



Notes: Historical capacity is based on AEMO registered capacity; estimated capacity additions based on Integrated System Plan capacity (AEMO, 2018c) and proposed developments sourced from AEMO Generation Information webpage; max. = maximum; TBC = to be confirmed.
Source: Based on AEMO (2018c) and adapted by the authors.

[5] Projects that have received formal commitment for construction or installation.

Figure 6: Projections of NEM generation capacity mix



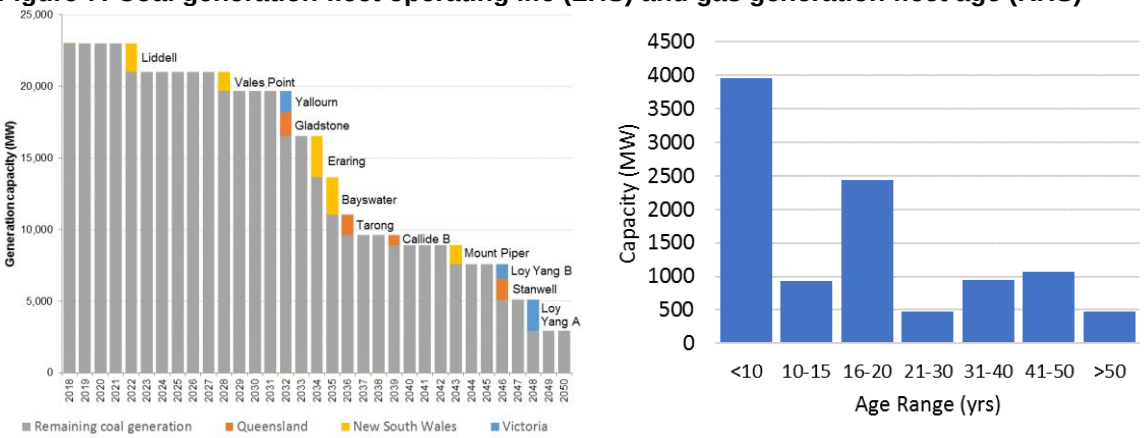
Notes: CCGT = combined-cycle gas turbine; GWh = gigawatt hour.
Source: AEMO (2018d).

2.2 The state of the legacy fleet

In contrast to renewables, the existing coal generation fleet in the NEM is ageing, with over 70 per cent of coal facilities expected to exceed 50 years of full operation by 2040 and be approaching the end of their operating lifetime (AEMO, 2017e) (see Figure 7). The gas fleet is younger, in general, with around 48 per cent of it less than 15 years old.

Since 2012 approximately 5.2 GW of dispatchable coal-fired generation has permanently retired from the market – including in recent years the Northern and Playford power stations in South Australia, and the 1,600 MW Hazelwood power station in Victoria (Nelson, 2018), the latter with less than five months' notice to the market. One of the key risks to the system is that of disorderly generation retirement without sufficient time for the market to respond.

Figure 7: Coal generation fleet operating life (LHS) and gas generation fleet age (RHS)



Sources: AEMO (2017e), AEMO (2018b), Global Energy Observatory (www.globalenergyobservatory.org)

2.3 The energy crisis

In recent times, all three legs of the energy trilemma – affordability, reliability, and sustainability – have been tested in the NEM.

First with regard to affordability, retail electricity prices have increased over the last ten years. Initially retail increases were primarily attributable to higher regulated transmission and distribution charges, but in recent years the wholesale cost of electricity has also increased (see Figure 8), partly resulting from baseload retirements.

Second, a number of security and reliability challenges have also been experienced over the past three years, the most notable of which was a statewide blackout in South Australia on 28 September 2016.[6] This was caused by storms which brought down transmission lines and resulted in voltage instability, affecting wind farms and the South Australia to Victoria interconnector.[7]

Third, from a sustainability perspective, the design of an appropriate emissions regulation scheme has in recent years been hampered by political divisions that have made for a difficult and uncertain policy-making environment. Australia has had a storied history with respect to environmental markets. In 2012, the country established a carbon dioxide (CO_2) emissions trading scheme that was to apply to large emitters (over 25 million tonnes [mt] of CO_2 equivalent [CO_2e] per year), including large thermal generation facilities. That scheme was subsequently abolished on a change of government in July 2014. The Australian Government committed under the Paris Agreement to reduce Australia's greenhouse gas emissions by 26 to 28 per cent from 2005 levels by 2030 (Finkel et al., 2017). To date this has not

[6] Other events included load shedding of customers in South Australia on 1 December 2016 and 8 February 2017, and load shedding of large industrial customers in New South Wales on 10 February 2017.

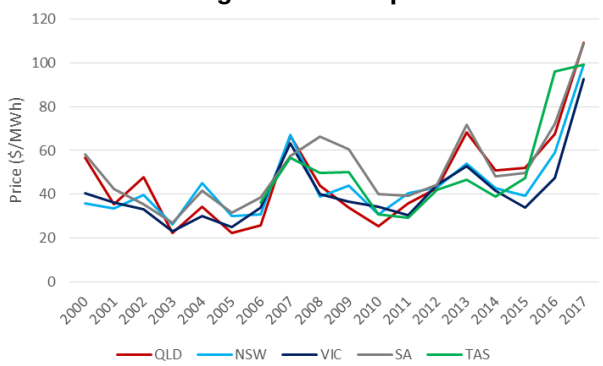
[7] Two tornadoes damaged a single-circuit 275 kilovolt (kV) transmission line and a double-circuit 275 kV transmission line and resulted in nine wind farms in the mid-north of South Australia to exhibit a sustained reduction in power as a protection feature activated. The reduction in wind farm output caused a significant increase in imported power through the Heywood Interconnector to such a level that it tripped the interconnector offline and caused the state-wide black out. Full supply recovery was not complete until 11 October and the market was suspended till that date. For further details see AEMO (2017j).

led to the establishment of any new national emissions regulation scheme, although various guises have been proposed. As a further example of the politically contested nature of energy/carbon policy, the government's flagship National Energy Guarantee failed to gain ultimate political party approval, despite being approved by industry and the Council of Australian Governments (COAG), and was part of a series of events that ultimately led to the replacement of the Prime Minister (Williams, 2018).

This situation has been further compounded by high prices and projected supply shortages in domestic natural gas markets, with the potential for consequent impacts on the reliability and marginal cost of gas-powered generation. While a review of the natural gas sector is outside the scope of this paper, the efficient functioning of the domestic gas market was highlighted by the Finkel review as being important to securing an efficient and reliable electricity system (Finkel et al., 2017).

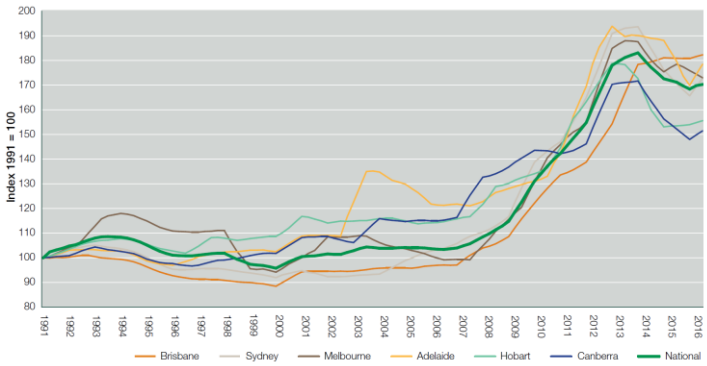
Figure 8: Electricity pricing in the NEM

Average wholesale prices



Note: MWh = megawatt hour.
Source: AEMO (2018b).
Note : $ refers to AUD

Average retail prices



Source: AER (2017).

2.4 The regulatory response

These events have led to a number of policy reviews including: a comprehensive review of the electricity market led by Chief Scientist Dr Alan Finkel (the Finkel review); reviews by regulatory bodies such as the AEMC (on reliability and security frameworks) and the Australian Consumer and Competition Commission (on market competition); and state-based reviews (such as on the retail market structure in Victoria).

There have also been a number of regulatory responses and governmental interventions in response to the crisis:

- The (ultimately unsuccessful) proposal by the Commonwealth Government to establish new reliability and environmental mechanisms via the National Energy Guarantee.
- Market concerns over near-term reliability, which prompted:
  - The market operator to source 1,054 MW of emergency reserves (Reliability and Emergency Reserve Trader reserves) for summer 2017/18 (AEMO, 2017h).
  - The return to service of the previously mothballed 385 MW Swanbank E gas-fired generation facility, owned by a Queensland state-owned independent power producer (IPP) (Department of Natural Resources, Mines and Energy, 2017).
  - Directions by the Queensland government to its state-owned IPP to place downward pressure on wholesale prices (Department of Natural Resources, Mines and Energy 2017).

- A Commonwealth Government-driven initiative to expand the Snowy Hydro scheme by adding 2 GW of pumped hydro capacity, known as Snowy Hydro 2.0.
- A set of energy initiatives by the South Australian government, which involved the buildout of 170 MW of diesel generation facilities, and the subsidized buildout of the world's largest utility-scale battery (100 MW/129 MWh), built by Tesla and owned by Neoen.

3. Challenges to the energy-only design under the energy transition

In the NEM, the recent events and challenges have led some to conclude that the energy-only market is 'broken' and a fundamental redesign is required. Others have argued for a modification of the existing design. However, before we can address solutions, we must first diagnose the specific nature of the problem. This section highlights the specific challenges being faced in the NEM and identifies the degree to which the existing market mechanisms are responding.

3.1 Resource adequacy in uncertain markets

The appropriateness of an energy-only market design versus its alternatives has long been debated – indeed since the introduction of competitive energy markets. The theoretical basis for energy-only markets, established by Schweppe et al. (1988), is the assumption of equilibrium, which is argued to be rare in a practical context (de Vries and Heijnen, 2008; Hirth, Ueckerdt and Edenhofer, 2016). Specifically, concerns have been raised with respect to the ability of the market to incentivize investment to ensure resource adequacy (Cramton and Stoft, 2006). This is compounded by the prospect of political or regulatory intervention supressing legitimate price signals (Simshauser, 2018).

Under a scarcity pricing approach, the market must be allowed to reach scarcity in order to establish pricing signals sufficient to incentivize new investment (Hogan, 2005), which implies that the system is unreliable during those times, with potential load shedding. This is a difficult proposition for electricity given its essentiality and its nature as a core service in modern economies (Nelson, Orton and Chappel., 2017). Energy-only designs can also conflict with the reality of financing capital-intensive assets, making it difficult to meet debt repayment schedules, especially in the absence of long-term contract markets (Simshauser, 2010; Nelson and Simshauser, 2013). This impacts risk appetite and the willingness to make timely investments in new generation under a merchant generator model. Many markets around the world have implemented or are considering implementing additional modules, such as capacity mechanisms, in order to incentivize investment (Peng and Poudineh, 2017; Doorman et al., 2016).

3.1.1 The reliability value of renewables

The concept of reliability in the NEM is intimately connected with the adequacy of the existing resource base to satisfy demand under a variety of conditions, including extreme or 'tail risk' conditions given a 99.998 per cent reliability standard specification.

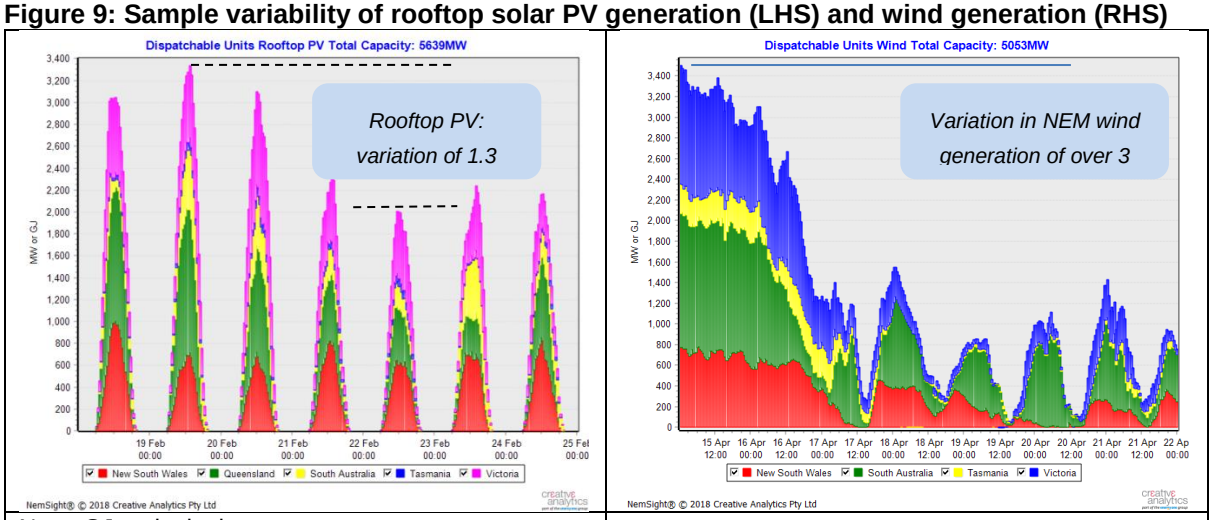
The introduction of VRE and DER brings new challenges to maintaining reliability in the grid. Traditional generation resources are dispatchable, meaning that generator power levels can be controlled and shifted up or down to meet demand. System reserves can also be sized to deal with distinct credible risks, for example the outage of a generation unit or a transmission line.

Wind and solar are by their nature variable, with generation patterns changing according to the availability of the resource. Key issues for resource adequacy include: (i) the need to assess and forecast generation contributions during peak grid demand, over a variety of timeframes; (ii) as much of the solar generation base is distributed, the level of DER generation is itself a determinant of peak grid demand; and (iii) a dispatchable and flexible resource base is thus still required to firm up supply at times when VRE is unavailable.

Patterns of generation for wind and solar can vary on a seasonal basis, but also quite significantly over shorter periods (see Figure 9). An increasingly probabilistic approach is required to understand the range of potential outcomes and reflect the need to account for multiple factors, including:

- variability and uncertainty of the VRE generation base, including correlation between VRE generation and forecasting errors/uncertainties
- variability and uncertainty of demand, especially given DER
- risks to the transmission network
- risks of dispatchable generator outages and de-rating.

Figure 9: Sample variability of rooftop solar PV generation (LHS) and wind generation (RHS)



Note: GJ = gigajoule.
Source: NEMSight (over week of 18 February-2018).

Source: NEMSight (over week of 15 April 2018).

3.1.2 Disorderly retirement and the sufficiency of dispatchable reserves

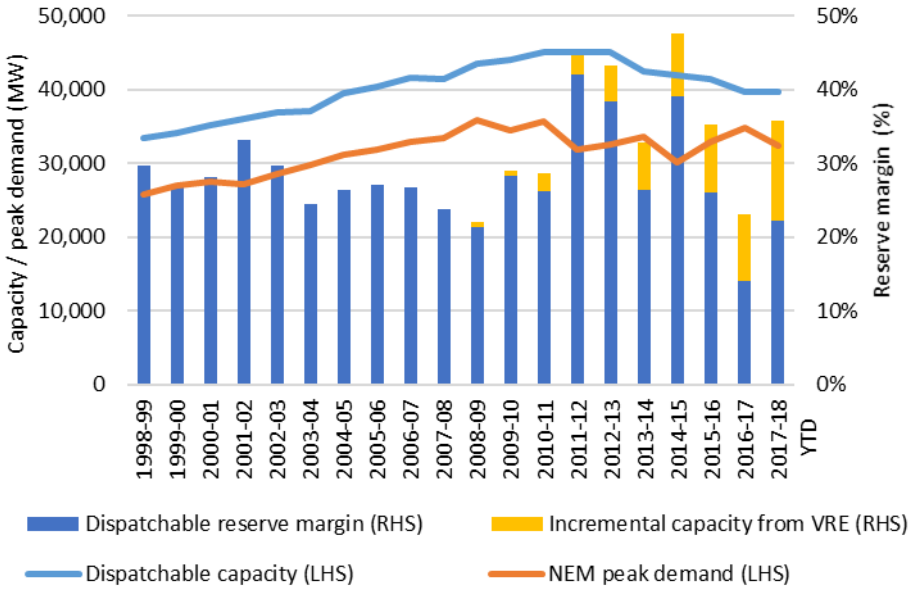
Since 2012 over 4.8 GW of new renewable generation capacity has been brought online across the NEM, driven by in part by environmental and renewable energy policies and subsidies. Over the same period, 5.2 GW of ageing dispatchable coal-fired generation has permanently retired from the market, including in recent years the retirement of the Northern and Playford power stations in South Australia, and the 1,600 MW Hazelwood power station in Victoria (Nelson, 2018).

However, there has been very limited investment in new dispatchable generation– for every MW of coal capacity retired, only 0.5 MW of new dispatchable capacity has been brought online. This compares with a ratio of 1.9 MW of gas investment for every MW of coal retired in the United States (Simshauser, 2018). Total system capacity of all dispatchable generation resources in the NEM has declined from 45.1 GW in 2011-12 to a low of 39.7 GW by 2016-17 (see Figure 10).

On a regional basis, local reliability concerns have been raised in Victoria and South Australia. As part of its 2017/18 summer preparedness plans, AEMO highlighted increased risk of breaching reliability standards in those regions (AEMO 2017b, 2017c).

Retirement of dispatchable plant (especially under timeframes that are insufficient to allow market investment response) is argued to drive a '*disorderly transition'* of the market (Nelson, 2018; Wood and Blowers, 2017) and has prompted a reviews of reliability frameworks and design.

Figure 10: Capacity and reserve margins in the NEM

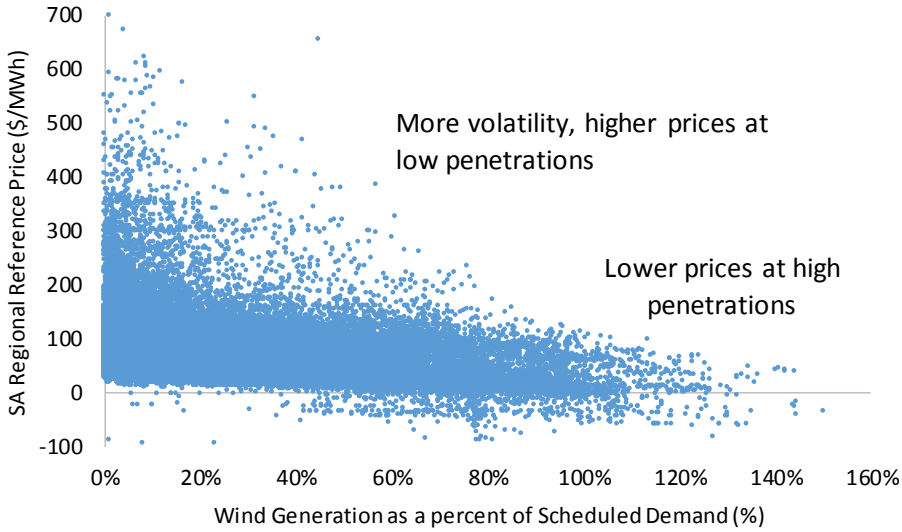


Note: YTD = year to date.
Source: Data sourced from AER (www.aer.gov.au) and adapted by authors.

3.1.3 More renewables = lower average prices but more uncertainty?

Increased renewable capacity in the NEM has changed the pricing dynamics in the market. As variable renewables have very low short-run marginal costs, system prices are likely to be low when renewables are generating, but higher and more volatile otherwise (Nelson, 2016; Wiser et al., 2017; Bushnell and Novan, 2018), especially in the situation where variable renewable generation is subsidized (such as under the RET). The remaining dispatchable generation in the market is thus forced to recover more of its revenue through a reducing number of high price events (Riesz, Gilmore and MacGill, 2016) which adversely affects the economics of existing dispatchable generators (Nelson, 2017). Figure 11 illustrates the relationship between renewables penetration and price in South Australia.

Figure 11: Renewables penetration and market pricing in South Australia, 2014-17



Notes: This analysis covers trading intervals for the period from 1 January 2014 to 1 September 2017, excluding the period of the SA blackout and consequent SA market suspension; 219 outliers with prices above $700/MWh (out of over 60,000 observations) are not shown on this graph, all of which occur at renewable penetrations below 13 per cent. References to $ are to Australian dollar.
Source: NEMWeb (www.nemweb.com.au).

3.1.4 The economics of new dispatchable investment

The scarcity pricing model relies on pricing signals translating into investment or retirement decisions that provide for reliable electricity supply in an efficient manner. Despite concerns over reliability, electricity markets have been in backwardation, that is, the price of electricity for future delivery has been lower than the spot price (the current price of electricity). This is driven, in part, by expectations of over 4 GW of new renewable investment supressing prices (see Figure 12). Looking ahead, wind is anticipated to have the lowest levelized cost of energy (LCOE) in the NEM (Simshauser, 2018; Nelson, 2018). Combined with high gas prices, this has had a negative impact on the economics of new baseload gas-fired generation, which would be expected to 'firm up' renewables.

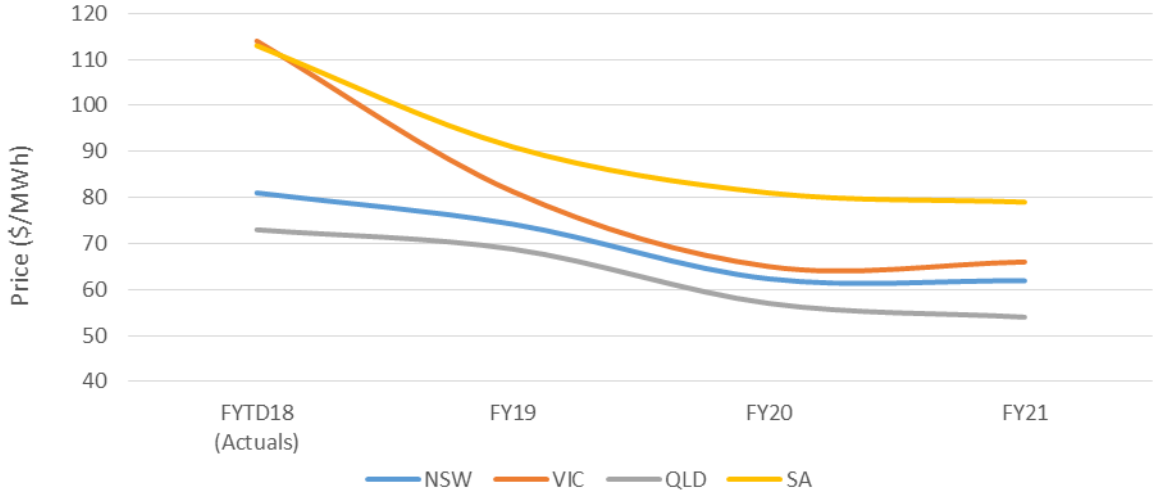
The economics of fast-start generation, such as open-cycle gas turbine (OCGT) or reciprocating engine technology, are also uncertain. While the 'five-minute settlement' rule change is intended to incentivize fast start and flexible forms of generation once active in 2021, the economics of new investment at electricity forward prices had not appeared highly attractive in the intervening period (see Figure 13). Recent secondary market acquisitions of legacy gas portfolios have taken place at AUD 216 per kilowatt (kW), relative to the cost of new generation at AUD 1,000/kW (OCGT) and AUD 1,600/kW (CCGT) (Macdonald-Smith, 2018; AEMO, 2018c). To date, new investment of this form has been measured and has focused on replacing lost capacity rather than adding incremental capacity to the system (see for example AGL Energy, 2017).

New investment has also been more difficult in the context of:

- difficulties in securing long-term gas supply and transport agreements (ACCC, 2017a)
- broader environmental and carbon policy uncertainty (Nelson, Orton and Chappel, 2017)
- assessing the risk of further government intervention
- assessing portfolio impacts – for a merchant player the impact of a new supply source could crowd out and cannibalize its existing assets.

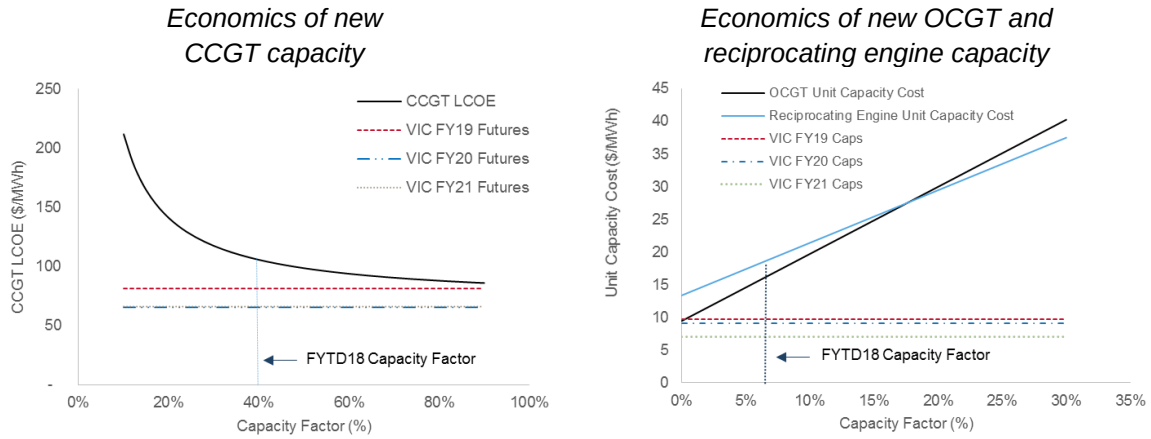
The state of financing markets and capital adequacy can also affect which parties are able to finance new plant. Merchant generators may struggle to obtain attractive project finance, while independent retailers are unable to offer long-term offtake (Simshauser, Tian and Whish-Wilson, 2014; Nelson and Simshauser 2013).

Figure 12: Electricity futures curve



Note: FY = financial year; FYTD = financial year to date.
Source: ASX Energy (www.asxenergy.com.au) as at 7 June 2018. References to $ are to Australian dollar.

Figure 13: Economics of new gas-fired capacity



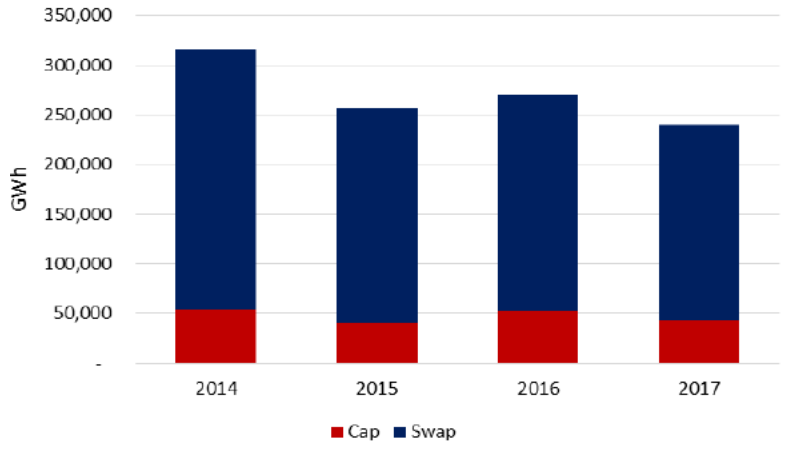
Notes: Electricity caps are a derivative instrument that provide price protection against high prices; see www.asxenergy.com.au/products/overview_of_the_australian_el for further details; CF = capacity factor.
Source: Calculation of LCOE based on approach in AEMO (2018a) using assumptions in AEMO (2018c). References to $ are to Australian dollar.

3.1.5 Contractual liquidity

An active, transparent, and liquid contract market is important for the reliable operation of the market. Due to its variable nature, VRE generation is not able to offer the firm-volume contracts that is typical for exchange-traded products (Simshauser, 2018). Financial innovation is required to allow VRE to participate actively in contract and hedging markets.

A noticeable decline in Australian Stock Exchange (ASX) energy contract liquidity was observed between 2014 and 2017 for cap and swap products, particularly for the New South Wales and South Australia regions (AEMO, 2018a) (see Figure 14). There is no consensus as to the reasons for such a decline. Some have argued that the vertical integration model has driven this decline, as parties are increasingly able to self-hedge, thereby reducing reliance on contract markets for management of their net exposure (Wood and Blowers, 2017). By contrast, assessments by Simshauser, Tian and Whish-Wilson (2014), Mansur (2007) and Bushnell, Mansur and Saravia (2008) suggest that vertical integration does not account for reduced liquidity.

Figure 14: ASX Energy, electricity swap and cap contract volumes



Source: AEMO (2018a).

3.2 The complexities of system security

Managing the stability and security of a large-scale AC system is a complex and multi-faceted operation. Wind and solar PV generation technologies are typically 'asynchronous', which means they are connected to the grid via inverters (which convert DC electricity into grid-compatible AC electricity). This introduces new challenges for system security, but also provides the opportunity for new technologies to resolve the issues.

3.2.1 Near-term concerns for security

Regulatory bodies (AEMO and the AEMC) have identified frequency control and system strength as two near-term priority areas for system security (AEMC, 2017f; AEMO, 2016).

In recent years, the regulation of frequency has become more challenging (see Figures 15 and 16) (Crisp, 2017), driven by:

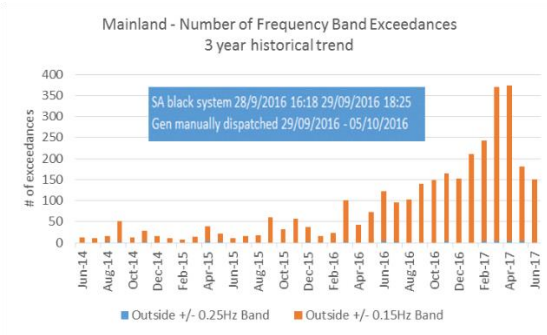
- The retirement of large thermal synchronous generators, which has reduced the level of inertia in the system. Inertia determines the speed at which frequency degrades after a disturbance.[8]
- Larger sources of variability in the system from wind and solar PV.

[8] The rate at which frequency degrades after a system disturbance is known as the 'rate of change of frequency' (ROCOF). If the ROCOF is too high (i.e. frequency degrades very quickly), frequency control ancillary services may not be able to respond effectively to bring frequency back to normal ranges. All else being equal, a system with less inertia will have a higher ROCOF, which could present risks to system security. Further information is www.aemo.com.au/-/media/Files/Electricity/.../Power-system-requirements.pdf.

- A reduction in the amount of governor response from synchronous generation. Governors are feedback control systems at power plants that change power output in response to frequency changes (also termed primary frequency control).

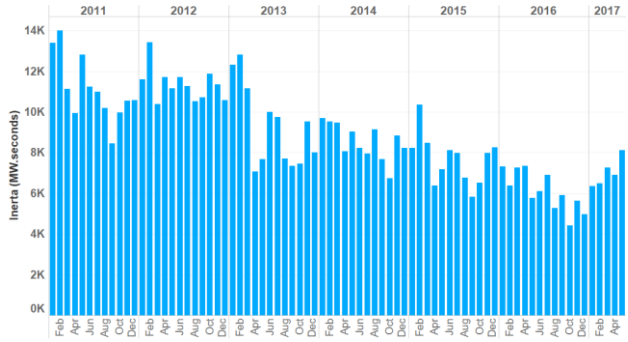
System strength is also a concern for the system in areas with high renewable generation, such as South Australia and western regions of Victoria. System strength is an umbrella term that reflects the ability of the power system to maintain stability after a disturbance (AEMO 2017a; 2017f). System strength is a highly localized issue and varies across parts of the network (see Figure 17). It is determined by the number of synchronous machines connected nearby, and the number of transmission lines or distribution lines (or both) connecting synchronous machines to the rest of the network.

Figure 15: Mainland frequency deviations



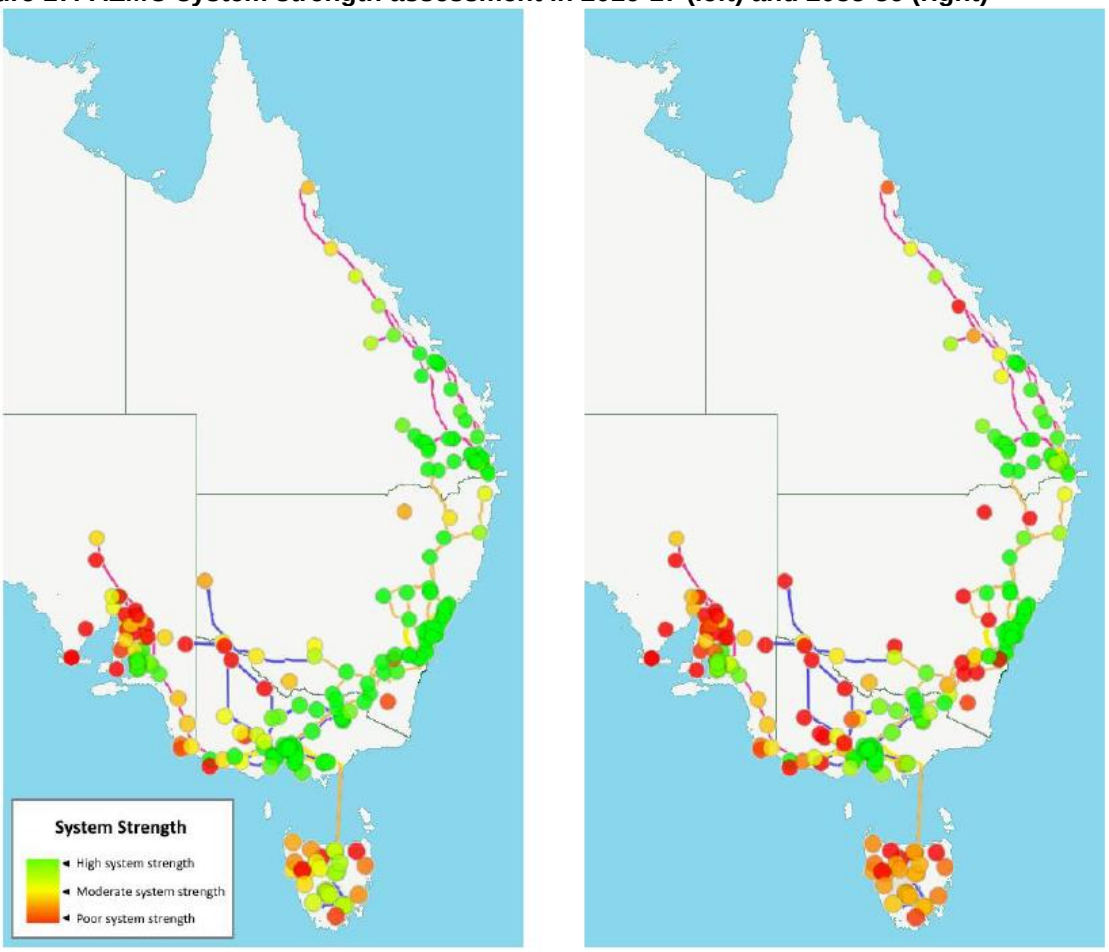
Note: Graph shows number of frequency band exceedences in a three-year historical trend.
Source: AEMO (www.aemo.com.au).

Figure 16: System inertia in South Australia



Source: AEMC (2017f)

Figure 17: AEMO system strength assessment in 2016-17 (left) and 2035-36 (right)



Source: AEMO (2017e).

3.2.3 The value of 'spin' in an AC network

Synchronous units (such as synchronous generators, synchronous condensers, and synchronous motors) provide an inherent contribution to inertia and system strength as a result of their spinning turbine mass. Asynchronous generators do not presently provide significant contributions.

System strength and inertia are both based on 'commitment' rather than 'generation'. This means that the amount of inertia and system strength provided by a synchronous unit depends on whether it is online and synchronized to the system and the turbine is 'spinning'. It is effectively a binary outcome – the unit provides its full contribution to inertia if it is generating and zero if it is not. Its contribution does not scale with the amount of active power being generated.

While services such as inertia can be transferred across AC transmission interconnections, regions such as South Australia are more vulnerable given that it currently has only one AC interconnection with the rest of the NEM (AEMO, 2017g).

Some non-synchronous technologies, such as wind generation or battery systems, can provide a very fast frequency response (FFR), which may be equivalent to an 'emulated' synchronous inertial

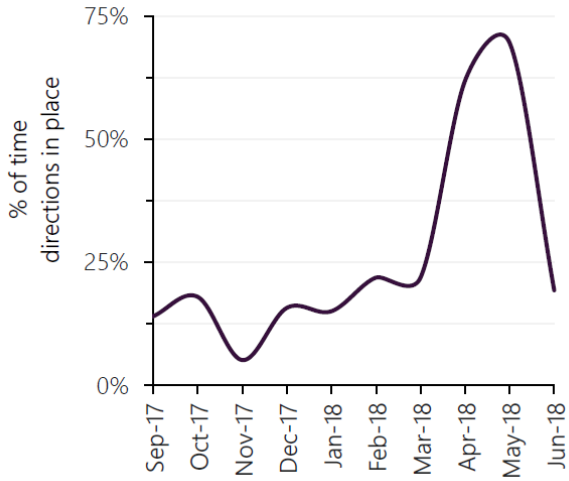
response. Requirements for this 'emulated' response are in place in international markets,[9] and the Finkel review recommended that FFR requirements be incorporated as part of licensing requirements for new asynchronous generation. Trials are have been undertaken to test the functionality and efficacy of these technologies for frequency response (AEMC, 2018b). An example includes the recent trial project that saw the Hornsdale 2 wind farm, an asynchronous and intermittent generation source, provide FCAS into the market.[10]

3.2.3 Increasing intervention in the market

Given concerns around system strength in South Australia, AEMO has imposed operating arrangements for the minimum configuration of synchronous generation that is required to be online in the region (AEMO, 2017f). The minimum increases with the output of non-synchronous generation. If the minimum level is not expected to be met via dispatch, AEMO will intervene in the market to direct generation plant to come online.

In recent months, AEMO has increasingly been required to intervene in the markets, at times when market prices do not provide sufficient incentive for thermal generators to be online (see Figure 18) (AEMO, 2018a). In April and May 2018 in South Australia, directions were in place for the majority of the month in order to maintain sufficient system strength.

Figure 18: Directions for system strength purposes in South Australia



Source: AEMO (2018j).

3.2.4 Security frameworks: Securing efficient, timely investment in system security

Both system strength and inertia were traditionally provided by thermal synchronous generators by virtue of their participation in wholesale markets rather than through designated centralized markets or procurement via contract.

Recent rule changes by the AEMC now designate transmission network service providers (TNSPs) as the entities responsible for providing minimum levels of inertia and system strength. The framework relies upon the identification of gaps in system security requirements by AEMO, which then triggers a

[9] This includes Canada, Saudi Arabia, Brazil, Ontario, and Norway. See Tamrakar et al. (2017).

[10] For further details see https://arena.gov.au/blog/when-the-wind-changes/. Further trials are being considered for the Musselroe wind farm (https://arena.gov.au/assets/2018/03/ARENA-Media-Release_Musselroe-Woolnorth-FCAS-wind-farm-trial-07032018.pdf).

process with the relevant TNSP to resolve the issue.[11] This approach relies upon AEMO having clear, accurate, and fully updated information on the operating plans of generation units. It also emphasizes the need for greater lead times for permanent or temporary withdrawal of capacity from the market.

The rule change is a positive step as it ensures that responsibility for these system requirements is clearly allocated. However, over the longer term there is a broader question of whether a utility regulation framework, based upon asset-based revenue recovery, is the right mechanism to deal with real-time system strength and inertia conditions, or whether a competitive services market is more appropriate. For the former to work, the framework must appropriately incentivize the relevant network operator to canvass the full range of procurement options (including contracting or tendering for the service) and technologies available. The framework must also allow the utility to respond flexibly to changing market dynamics. For example, regulatory processes must envisage the possibility of fast-tracked processes to deal with unplanned generator retirements.

In South Australia, a gap relating to system strength was identified and the resolution process triggered in October 2017. The regional TNSP, Electranet, has announced the buildout of synchronous condensers ('syncons') by 2021 to deal with the issue (see Figure 19).[12] This, however, still leaves the system at risk over the interim period and reliant upon ongoing market intervention by the operator, especially given the upcoming retirement of some thermal units in the state.

Figure 19: Synchronous condenser sites in South Australia

Source: Electranet (www.electranet.com.au)

3.2.5 Future system security considerations

As renewables penetration increases and the legacy synchronous fleet retires, an enhanced suite of services is likely to be required to maintain system security. Additional considerations include:

- Grid forming – frequency is traditionally set by large synchronous generation units by virtue of normal operation. Asynchronous plant in the NEM does not currently provide grid-forming

[11] Similar requirements have also been established in the European Union. Regulation 2017/1485 establishes minimum inertia requirements at the synchronous area level, with transmission system operators required to conduct studies to identify whether the minimum required inertia needs to be established.

[12] Synchronous condensers are effectively electric motors whose shaft is not connected to anything. They can provide multiple services including inertia, system strength, and reactive power.

capability, but research is being conducted on the use of power electronics to set frequency (AEMO, 2018f).

- System restart – currently synchronous generators provide system restart services for the grid. The approach to system restart services will need to be reconsidered in a grid dominated by inverter-based technologies (Kroposki et al., 2017).

3.3 Risk and portfolio management challenges

3.3.1 Managing portfolios in transitioning markets

Changes to demand profile, technology, supply mix, and the operational management of the grid have introduced new hedging and risk management challenges for participants, but also introduce opportunities to adapt and fulfil new needs in the market.

Increasing deployment of rooftop distributed solar is expected to further hollow out demand during the middle of the day. This changes the traditional load profile for retailers and makes firm hedging more difficult (see Figure 20). Wind generation is also expected to add variability to the portfolio. In respect of risk management, these all mean that:

- Retailers that self-hedge will require an increasingly flexible generation fleet that is able to ramp up and down and cycle multiple times a day in line with intraday load changes.
- Retailers that rely on contracts may find the current suite of contractual products that are focused on fixed, firm, and consistent volumes across a period untenable when dealing with a load profile that is increasingly variable.
- Distributed solar generation can also vary significantly based on insolation, so the amount to be hedged also varies.
- Retailers that are power purchase agreement (PPA) offtakers for renewable generation will need to adopt more flexible hedging strategies to account for situations where their net position can change rapidly. For example, wind PPAs provide low-cost energy when generating, but will need reserve generation (or equivalent financial hedging) to deal with generation variability.
- The notion of baseload generation becomes less relevant, as there is less constant usage load in the system.

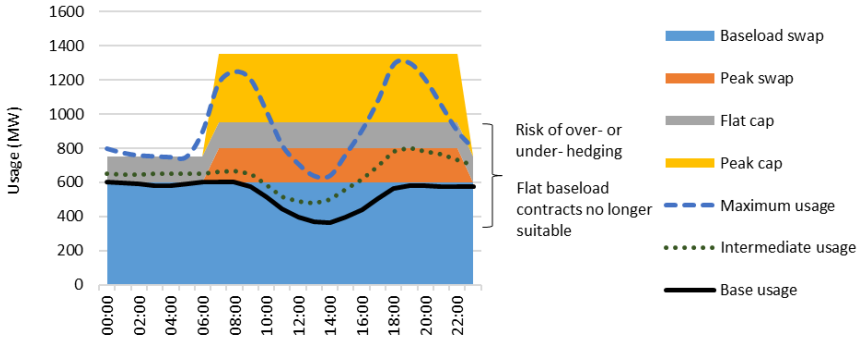
Distributed storage is a potential resource for retailers if they have control and visibility of the resource, but it may introduce further complexity and uncertainty to the load-hedging equation if they lack control or visibility as to how and when these units charge and discharge.

The recent action by certain large electricity consumers to sign ‘corporate PPAs’ is increasingly suggestive of end-consumers exercising individual preferences on supply. This poses a threat to incumbent retailers and generators given the reduced electrical loads, but also offers them opportunities to play a balancing role to ‘firm up’ load when renewable resources are unavailable.

In addition to the above, another problem exacerbates the difficulty of risk management. To maintain system reliability and security, the system operator can sometimes intervene in the market, as for example in South Australia, where directions for system strength have been in place over 60 per cent of the time during April and May 2018. These directions and interventions (if more than just a rare occurrence) can disrupt operating arrangements and thus affect risk management. This is because participants in the market organize their outage, contractual, and fuel procurement arrangements based on their expected generation profiles, retail base and contract positions. Unanticipated directions and interventions in the market by the market operator have the potential to interfere with the way participants organize and manage their own portfolios, operations, and assets. For example, directions to generate may result in generators using more of their gas allocations under gas supply agreements

when they may be seeking to conserve gas. Directions may also interfere with proposed maintenance outages at facilities.

Figure 20: Impact of DER on contracted load and portfolio positions



Source: Adapted from Productivity Commission (2013).

3.4 The effectiveness of the scarcity price signal

3.4.1 Renewable energy policy, contracting, and bidding interactions

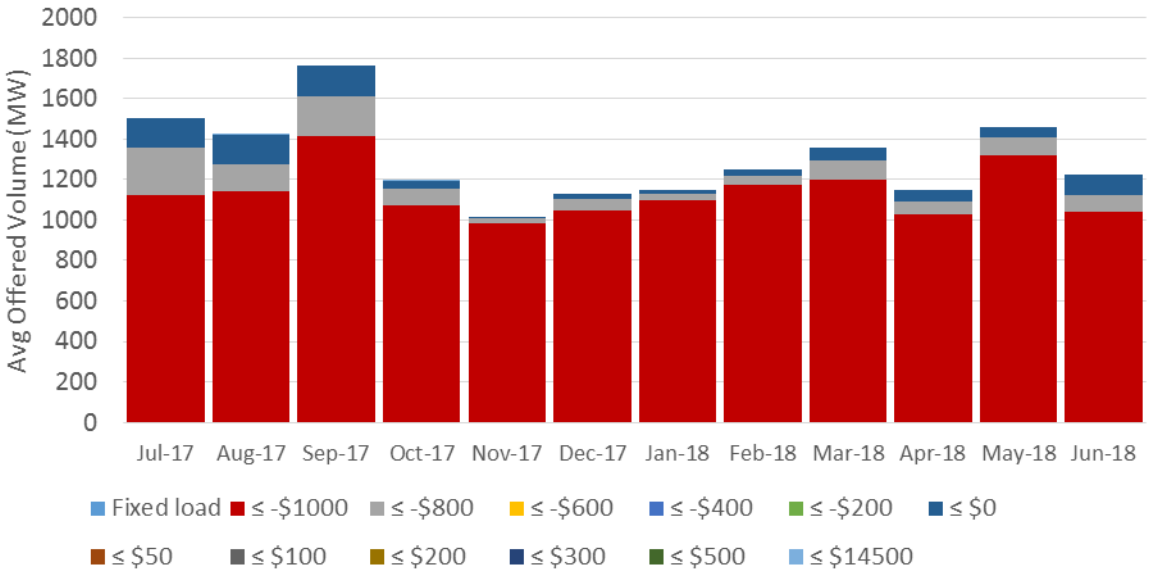
The RET scheme operates through the provision of a generation-based incentive – renewable credits that are based on the actual level of generation (see the Appendix for further detail). By providing a generation-based subsidy to generation units that typically have very low or zero variable costs, VRE can effectively bid a negative short-run marginal cost (SRMC) into the wholesale electricity pool.

Many VRE projects in the NEM are financed via multi-year PPA contracts with a bundled PPA price typically based on the amount of generated (usually as AUD price per MWh of generation sent out). Under this contract form, as the VRE generation unit is effectively hedged from exposure to its local regional reference price (Hirth, Ueckerdt and Edenhofer, 2016; Nelson, 2017), it has an incentive to maximize generation by bidding at levels close to the market price floor of AUD -1,000/MWh[13] rather than at levels that reflect its marginal cost. Thus for periods of high renewable generation, this could result in system prices being systemically well below the effective SRMC of VRE. This could take on increasing relevance to the extent that future renewable investment is financed via PPA.

Figure 21 provides the bidding structure for semi-scheduled variable renewable generation in the NEM over the financial year to date ending 30 June 2018, indicating that most of the available variable renewable capacity is offered at the price floor of AUD -1,000/MWh.

[13] This assumes that the VRE asset owner retains the right to bid the unit.

Figure 21: Variable renewable supply stack in the NEM, FYTD2018



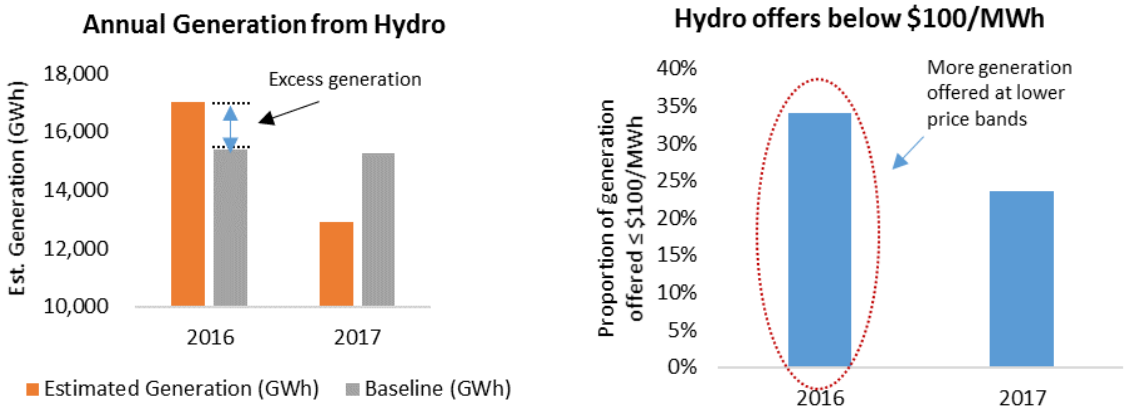
Notes: Total bids adjusted for unconstrained intermittent generation forecasts; data provided from 1 July 2017 to 8 June 2018; $ = AUD.
Source: NEMSight.

3.4.2 RET interactions with hydro generation strategies

The RET scheme also has an impact on existing hydro generation facilities, which are eligible to create large-scale generation certificates (LGCs) for any generation over and above an annual baseline. A year in which a hydro generator decides to generate over and above its baseline is colloquially known as a 'REC year' (ACCC, 2018). Thus the business strategy for hydro generation dams involves calculating the trade-off between the revenue that is expected to be earned from offering energy (either via the pool or contracts) and the revenue that can be earned from the sale of LGCs. Expected precipitation and dam storage levels are also key inputs into the decision as to whether to run a REC year. The decision to run a REC year may impact upon a hydro plant's bidding strategy and the prices and bands in which energy is offered. During REC years, there may be incentives to price energy at cheaper levels, given the potential for revenue from the sale of LGCs. Given that hydro generation makes up 16 per cent of total NEM capacity and is an important source of peak capacity, this could have different impacts on prices depending upon the nature of market interactions (see Figure 22). [14]

[14] For a detailed discussion and analysis of RET impacts on portfolio offers, please see ACCC (2018). Further discussion of hydro generation dynamics in recent quarters is also provided in AEMO (2018j).

Figure 22: Hydro generation bidding interactions



Notes: These graphs present aggregated data; actual generation of LGCs will depend upon the specific baselines set for individual hydro generation facilities as per RET regulations. References to $ are to Australian dollar.
Source: NemSight.

3.4.3 Scarcity pricing and system security: Missing signals

As mentioned previously, variable renewables are likely to depress pool prices given zero marginal costs, prevailing contract structures and interactions with renewable policy. Thermal units in the NEM have positive SRMCs driven by factors that include fuel costs and variable operating expenditure.

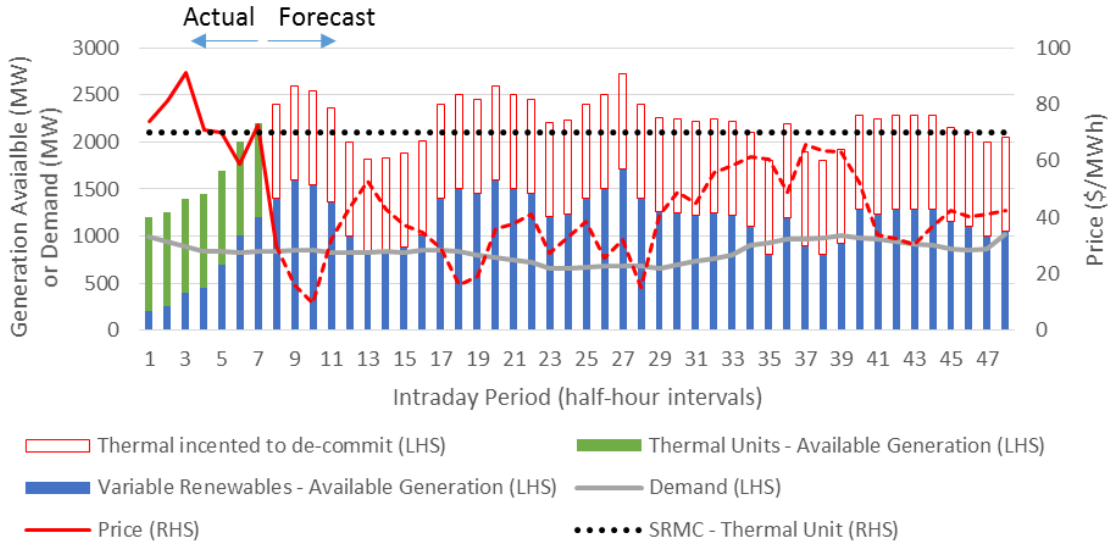
When high levels of variable renewables are being generated in a market, prices are likely to be low and may fall below the SRMC of thermal generators. In this situation, thermal generators may actually be encouraged to de-commit their units. Units that are flexible can withdraw and de-commit in a timely manner based on intraday price forecasts.

Current operating frameworks for system security rely upon having sufficient synchronous resources online in the system, both for inertia and system strength. Current real-time market design does not specifically value either of these services or does not provide any compensation for 'commitment' other than the energy price (Simshauser, 2018). It arguably has the opposite effect of discouraging synchronous units from being online at times when it is most needed for system security.

Figure 23 provides a stylized example of price signals incentivising the de-commitment of thermal units when forecast prices are expected to be below the SRMC. Real-world situations are also likely to incorporate additional complexities, such as the individualized cost of fuel and transport at each facility, start-up/shutdown costs, contract and integrated portfolio positions, and whether an integrated player may also be an offtaker for some of the renewable generation. However, it does illustrate the incentives at play. This situation is being played out in South Australia, with AEMO having to intervene to direct synchronous units to remain online in order to manage system strength.

Furthermore, legacy thermal facilities that are unable to de-commit in a flexible manner may be forced to bear low or negative prices ('thermal stranding') by virtue of their minimum generation requirements and shutdown times, which may exacerbate the risk of disorderly and early retirement.

Figure 23: Incentives to de-commit thermal units

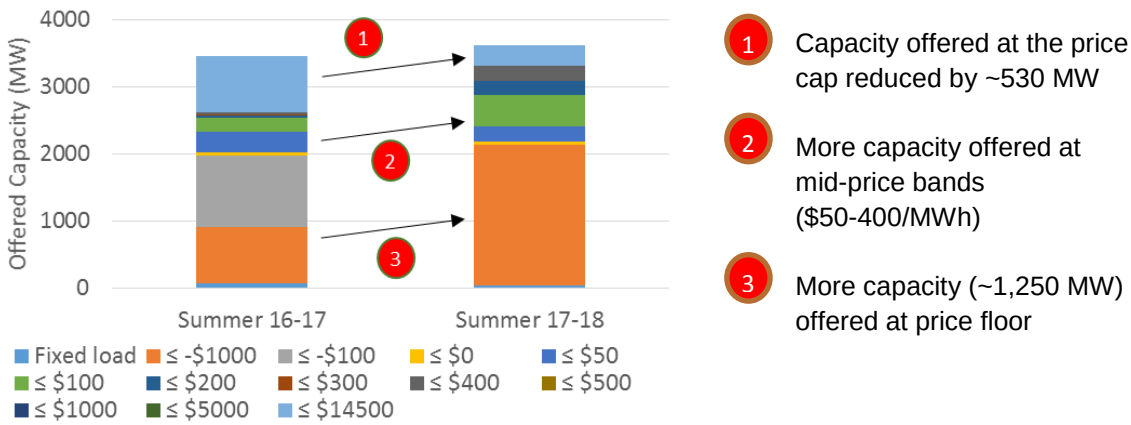


Source: Authors. Note: References to $ are to Australian dollar

3.4.4 Government intervention

The risk of regulatory and political intervention is also an important consideration (Doorman et al., 2016). Governments may seek to intervene in periods of high prices, thus limiting the effectiveness of the price signal. In response to public concerns around electricity unreliability, national, and state governments have sought to intervene in the market through proposals to build or subsidize new generation (South Australia: 170 MW diesel generation and Hornsdale battery; Commonwealth: Snowy Hydro 2.0), or to suppress prices through instructions to government-owned generators (Department of Natural Resources, Mines and Energy, 2017). One particular example of the latter was the direct intervention to require the Queensland government-owned generation company Stanwell *'to offer bids at levels below market price with a view to putting further downward pressure on average wholesale price'* (Stanwell Energy 2017). See Figure 24 for an illustration of bidding patterns over summer 2016 and 2017.

Figure 24: Bidding for the Queensland government-owned generator over summer 2016 and 2017



Notes: Measured over average price bands; $ = AUD.
Source: NEM Sight

3.5 Is the market responding?

The current design relies on market participants responding to scarcity signals. This section examines the nature of the market response and the implications for reliability and security frameworks.

3.5.1 Optimising and reintroducing existing resources

Reflecting concerns over reliability in advance of the 2017/18 summer period, a market response can be observed. While there was no commercially driven investment in new dispatchable capacity (with all new capacity coming from government-led initiatives), markets did respond to the retirement of the Hazelwood power station by reintroducing previously mothballed plant (including Pelican Point CCGT, Swanbank E and Tamar Valley CCGT). However, these capacity additions did not fully offset the loss of the retired units, and the remaining gap was covered by AEMO procuring 884 MW of reliability and emergency reserve trader (RERT) resources as well as government-led capacity investment (see Figure 25).

While nameplate capacity is a relevant metric in assessing resource adequacy, total nameplate capacity is not often available to the market in every interval, given scheduled and unscheduled outages (see Figure 26). The availability of plant is thus important in assessing operational resource adequacy. In the summer prior to its retirement, Hazelwood offered around 1,300 MW of available capacity to the market, on average. On its retirement, the market responded by increasing availability across the remaining commercial fleet in order to limit the net loss of available capacity to around 460 MW. This suggests the market response in this case has primarily been through optimising or reintroducing existing capacity, potentially driven by the tight timeframes involved.

Figure 25: Changes in dispatchable capacity operating in the NEM

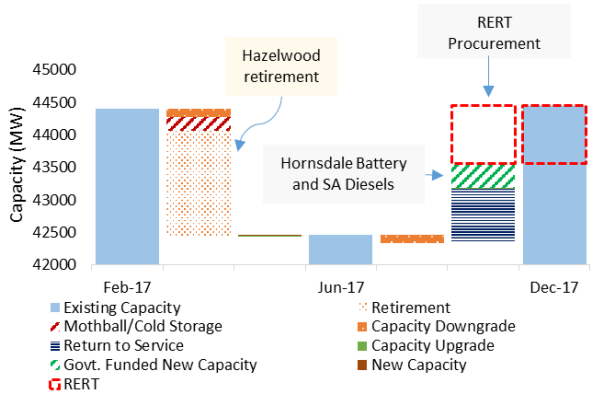
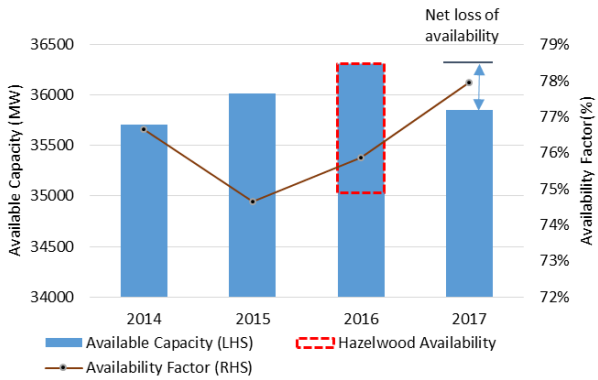


Figure 26: Summer availability and availability factors for dispatchable units



Note: Availability factors calculated as available capacity divided by maximum registered capacity on average across each summer period.
Sources: AEMO (2018b) and NEMSight.

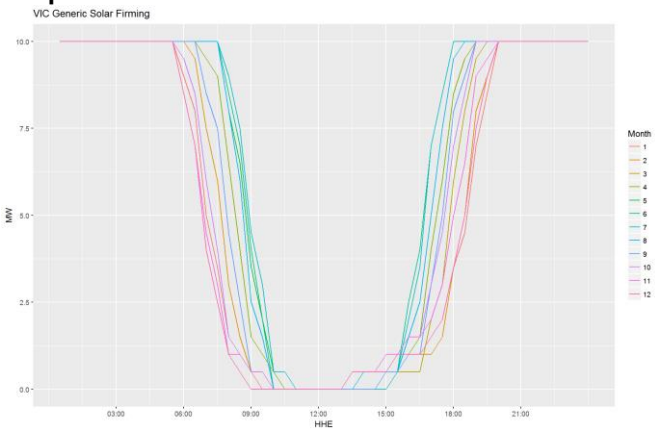
3.5.2 Contractual and market innovation in renewable firming

The market has begun innovating new contractual structures that allow hedging of renewable generation profiles. Participants have been offering firming products that enable better renewables integration with respect to hedging, risk management, and contract market participation (Warren, 2018). Renewable facilities are able to purchase 'firming' contracts, and by combining this with their variable generation can offer firm generation to their customers or offer firm volume contracts to other participants. Dispatchable power sources can provide the 'firming' role in those contracts. Two sets of products have been discussed:

- Solar firming products (Figure 27), developed by energy retailer ERM and brokers TFS Green, replicate the 'inverse shape' of solar generation (Parkinson, 2018). Combining this product with its own generation, a solar generator can offer a firm generation profile. This can be either offered to end consumers, or back onto contract markets as firm contracts.
- Wind firming products (Figure 28), developed by AGL, provide compensation when wind generation is less than the forecasted average generation. The payout is based on the difference between a strike price agreed at inception and the spot price (AEMC, 2018c) The rationale for this product is to allow wind generators to firm up their generation volumes. The product is currently based on total wind generation in a particular state. This means that individual wind farms will have basis risk when their wind patterns are uncorrelated to the state as a whole. However, it is possible that this product could evolve to offer more specific hedges to wind generators.

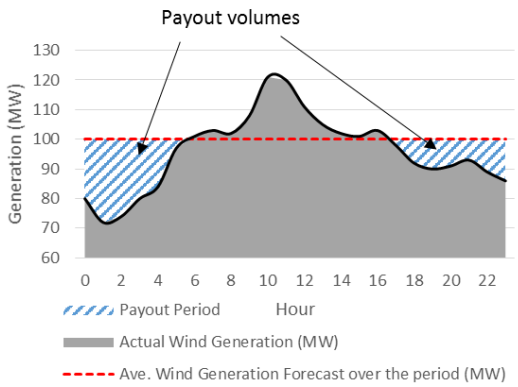
While these products are in their early stages, they provide an example of a market doing exactly as it should – responding to issues and challenges through innovation.

Figure 27: Solar firming product – inverse solar shape



Source: Parkinson (2018).

Figure 28: Wind firming product



Source: AEMC (2018c).

3.5.2 Five-minute settlement and new investment

The five-minute settlement rule change, which comes into place in 2021, will align the settlement interval with the dispatch interval at five minutes and is aimed at providing a clearer price signal. This is expected to incentivize new investment in more flexible forms of dispatchable generation, such as batteries and reciprocating engines. For example, AGL has decided to replace a portion of its retiring OCGT units at Torrens Island with fast-start reciprocating-engine technology at Barkers Inlet, with five-minute settlement being an important driver of the technology choice (AGL Energy, 2017).

The implications for the legacy fast-start fleet are uncertain. Fast-start/peaking capacity in the NEM has traditionally been financed by offering energy cap products. Generators that are unable to respond to a five-minute signal may face difficulties offering insurance-style products, such as caps, in a five-minute market (AEMC 2017b). As such, the role that these facilities play in the generation stack and contract markets will need to adapt. It is possible that these facilities may be able to provide aspects of firming to the market.

3.5.3 Trialling and enabling new technology

There have been a number of successful trials and pilot projects that have opened up new forms of response and service provision in the markets. Most notable are:

- Wind farm participation in ancillary service markets. The Hornsdale 2 wind farm successfully demonstrated the technical ability of variable wind generation to participate in FCAS markets. Future trials aim to establish the economic model for participation. This expands the potential range of service providers for FCAS markets (AEMC, 2018b).
- Australian Renewable Energy Agency (ARENA)-AEMO Demand Response Pilot Project. This established a procurement model for demand response to serve as emergency reserves via an availability and usage fee structure (AEMC, 2018c).
- Virtual power plants (VPPs). While VPPs are already actively provide FCAS (see below), a number of pilot initiatives are underway to develop the business and operational case for VPPs providing a full array of services to the market, including energy provision and additional grid and system security services.
- Grid formation from asynchronous resources. The ESCRI 30 MW battery project in South Australia will be equipped with the first grid-forming inverter in the NEM. Under islanded mode the battery will be able to provide grid-forming services, including setting the reference frequency and reactive power for voltage stability (Electranet, 2018).

Regulatory enablement has also opened up new forms of response:

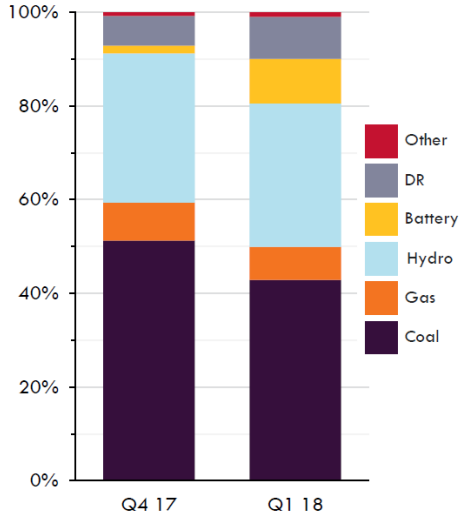
- The Ancillary Services Unbundling rule change in 2016 allowed demand response to participate in FCAS markets. Since the commencement of the new rules in July 2017, around 180 MW of demand response is actively participating in FCAS markets, and together with the Hornsdale battery has changed the supply mix for FCAS (Grover, 2018).[15]
- The construction of the Hornsdale battery, in part funded by the South Australian government, has established the usage case for battery participation in the NEM. The battery has since participated across energy and FCAS markets, and provides additional services, including (i) a 70 MW energy reserve for reliability purposes, and (ii) a special protection scheme that discharges the battery based on interconnector flows, to reduce the likelihood of South Australia islanding from the rest of the NEM (AEMO, 2018h).

Looking ahead, the AEMC's Reliability Frameworks Review has recommended a package of rule change requests, including the establishment of a short-term forward market, a wholesale demand response mechanism, and the introduction of multiple trading relationships at the consumer level (AEMC, 2018c). The AEMC's Frequency Control Frameworks Review reviewed options for frequency services procurement over the long term and potential co-optimization between energy, FCAS, and other system services, as well as fast frequency services. At this stage it did not recommend the establishment of new markets or frameworks, but will continue to work with AEMO to assess system needs. The AEMC also recently completed rule changes to manage the rate of change of power system frequency and power system fault levels, and issued guidelines for generating system models (AEMC, 2018b).

Ongoing pilot projects are important for establishing the technical and economic case for new technologies and forms of response as a precursor to market participation. The removal of regulatory barriers to market participation has also been shown to open up competition and allow new responses to market challenges. Figure 29 illustrates the impact of new technologies and participants on the supply mix of raise FCAS.

[15] The Ancillary Services Unbundling rule change allows aggregated demand response providers to provide FCAS services without being a retailer (www.aemc.gov.au/rule-changes/demand-response-mechanism).

Figure 29: Supply of raise FCAS by fuel type



Source: AEMO (2018l).

4. The solutions plethora and future pathways for the NEM

A number of initiatives have been proposed to respond to the current challenges in the NEM. They range from framework-level changes (such as the National Energy Guarantee and strategic reserve proposals), to enhancements to existing market design (for example, short-term forward markets) and operational frameworks (for example, day-ahead markets). In this section, we provide a brief overview of the proposals and key considerations. Finally, we suggest that an 'energy+services' framework should guide the future development of real-time market frameworks.

4.1 The National Energy Guarantee and strategic reserves

The National Energy Guarantee was proposed by the Energy Security Board in October 2017 to address the dual objectives of (i) meeting reliability objectives, and (ii) achieving an emissions trajectory. It went through a detailed industry and government consultation and design process, with the final design receiving industry, departmental, and COAG support. Ultimately the policy failed to receive final political party approval and was part of a series of events that ultimately resulted in the replacement of the Prime Minister, illustrating the sensitivity of energy/environment issues in the political caucus (Williams, 2018).

The National Energy Guarantee was the latest attempt to reintroduce emissions requirements for electricity generation,[16] setting annual emissions intensity targets for electricity retailers linked with Australia's COP21 commitment of a 26 per cent reduction on 2005 emissions by 2030 (Department of the Environment and Energy, 2018). The reliability element of the policy established procedures around forecasting and identification of reliability gaps, and established market measures and backstop procurement obligations if gaps were identified. This obligation fell short of imposing a mandatory

[16] Post the abolition of the Emissions Trading Scheme, a number of approaches have been proposed to relink electricity generation with carbon emissions. These included the Emissions Intensity Scheme and the Clean Emissions Target.

capacity procurement mechanism. At this stage, it is unclear whether the policy in a current or amended form will be proposed again.

AEMO has also proposed a strategic reserve mechanism that allows it to procure reserves up to one year ahead under a regular tender process based around a standardized reserve product set. Payments for reserves would be structured under a combination of availability, usage, and pre-activation charges. This enhanced strategic reserve mechanism would act as a safety net against reserve inadequacy and allow AEMO to support the system when experiencing short-term issues, such as outages or retirements. Strategic reserves are a capacity mechanism that allows a central authority to procure a portfolio of back-up generating capacity that can be called upon whenever market response is insufficient (Doorman et al., 2016).

An enhanced strategic reserve would begin to introduce elements of a centralized capacity mechanism to the market. The fundamental challenges of capacity markets, however, lies in who determines the capacity obligation, how it is determined, and at what cost (Doorman et al., 2016). This is not a unique response – many international markets have looked or are looking to establish some form of centralized capacity mechanism in response to the reliability question. Most capacity mechanisms are structured to guarantee physical resource addition by addressing the 'missing money' problem (Cramton et al., 2013) and bridging the gap in energy-only markets between short-term price signals and long-term investment (Doorman et al., 2016; Wood, Blowers and Griffiths, 2018).

In most capacity mechanisms, a central authority takes on a more direct role in setting the requirement, while also procuring the required capacity in some mechanisms (capacity auctions and strategic reserves). Some see the role of the central agency as a strength, as it allows clear requirement-setting and better assurance of compliance (Wood and Blowers, 2017; Wood, Blowers and Griffiths, 2018). Conversely, as a non-commercial entity, the incentives of the central agency are indirect and non-pecuniary in nature. A central authority faces no financial penalties for overinvestment or underinvestment, nor is rewarded for striking the right balance. There are potentially strong political pressures to avoid underinvestment and lost-load events. Some argue that this leads to 'risk aversion' and a tendency to over-protect the system – to the detriment of consumer costs and efficiency (Wood, Blowers and Griffiths, 2018; Wood and Blowers 2017; Newbery and Grubb, 2014). As against this, the central party may face criticism or stakeholder pressure from energy market participants if costs are considered inordinate. On both sides, the incentive to act is indirect – the financial implications of decisions are not directly borne by the party itself but by others, typically consumers, either through the costs of overinvestment, or the financial impacts of unreliability caused by underinvestment. In such a mechanism, the direct alignment between the performance evaluation of, and incentives for, centralized decisions takes on increasing importance. A comprehensive performance management and reward-penalty structure would be required to ensure that such decisions are taken within an appropriate incentive framework.[17]

4.2 Enhancements to the energy-only design

In addition to the more fundamental reforms to energy market design, a suite of options are under consideration that keep the core of the existing scarcity pricing regime in place, but modify or add components to the design.

4.2.1 Generator notice of closure

One of the key risks to the system identified by the Finkel review was that the existing market design gives commercial participants flexibility to make decisions around unit additions, availability, and retirements. There are no current obligations to provide prior notice to the market. Allowing large-scale

[17] Billimoria and Poudineh (2018) also suggest a potential alternative approach to resource adequacy, based on enabling consumer price signals for reliability using insurance risk management concepts.

generators to retire with limited notice may not give the market sufficient time to respond commercially – as was arguably the case for the retirement of the Hazelwood power station.

The AEMC has drafted a new rule imposing a three-year notice requirement for ceasing registration as a generator in order to provide better information and clarity to the market (AEMC, 2018d). While the increased notice and transparency in the market is desirable, its implementation requires consideration. For example, a generator may decide to mothball for the medium- to long term or on a seasonal basis, which may avoid being classified as a permanent retirement but have similar outcomes. Furthermore, a generator may continue to be registered but chose not to make itself available. Good faith approaches to generator intentions, which have recently been implemented as part of the 'Bidding in Good Faith' rule change, could be of value in this area (AEMC, 2015b).

4.2.2 Forward markets for energy

Forward and day-ahead markets have also been proposed as an option for improved resource co-ordination and hedging on an operational basis (Finkel et al., 2017). Many jurisdictions around the world have organized short-term forward markets, either on a voluntary exchange-traded basis (for example, United Kingdom), or on a centrally co-ordinated and dispatched basis (for example, United States).

Voluntary exchange-traded market

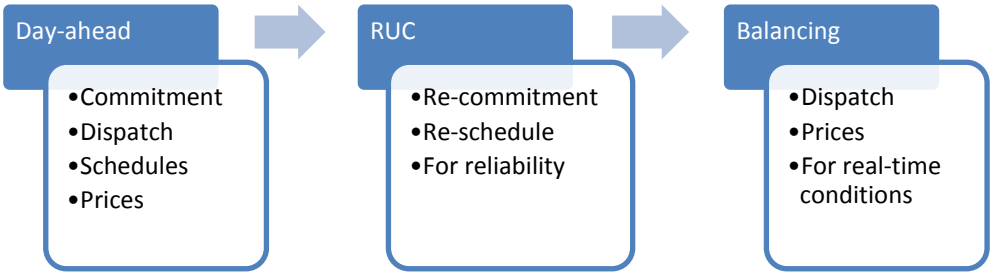
For the former the primary rationale focuses on (i) enhancing risk management options for participants, (ii) better fuel co-ordination for participants, (iii) greater options for hedging and contracting for VRE generators, and (iv) improved market access for demand-side resources (Ausubel and Cramton, 2010). In the NEM, AEMO provides indications of future pricing through the pre-dispatch process. A voluntary forward market would be a natural extension of existing contracting approaches in the market, and it is in this vein that the AEMC has recommended that a rule change on a short-term forward market be proposed (AEMC, 2018c). While this provides additional contracting mechanisms, given the market structure, a forward market lends itself to the same contract liquidity and market issues as longer-term forward markets and measures to maintain liquidity (such as through market making) should also be considered.

Centralized day-ahead dispatch and unit commitment

The centralized day-ahead market approach in the United States is different, typically employing a full network model to economically commit and dispatch participants based on participant offers and bids, and load projections for the day ahead. These are known as a security-constrained unit commitment (SCUC) and security-constrained economic dispatch (SCED). Key elements of the centralized day-ahead design are day-ahead optimization and reliability unit commitment (RUC). As a consequence, the real time becomes a 'balancing market' that deals with differentials against the day-ahead (see Figure 30).

Given the uncertainty and potential changes to operational demand and VRE generation that can occur over short periods of time, a day-ahead time horizon may be too long. CAISO (the California Independent System Operator) has incorporated multiple forward horizons into its commitment and dispatch processes – including day ahead, hour ahead, and 15 minutes ahead (FERC, 2014). This suggests that shorter-term commitment processes may also be required to deal with near-term variability.

Figure 30: Sequence of resource schedule development in the United States



Source: Authors

A key benefit of the centralized approach is that it allows a resource to better 'express its underlying economics' (Cramton, 2017). Resources are able to bid their start-up costs and minimum generation costs (in addition to an energy offer curve), and the dispatch engine produces an optimal outcome taking these costs into account. This contrasts with the NEM design, which requires participants to internalize start-up and minimum generation costs. The centralized structure could be of particular benefit as the optimization engine could also optimize system security requirements, such as system strength and inertia, which are based on commitment (that is, units being online) rather than how much they generate.

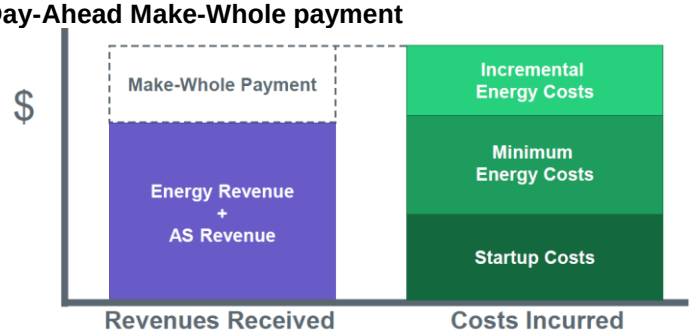
Arguably, AEMO, by having to consistently direct units in South Australia, is already having to run an informal forward residual unit commitment process for system strength. This suggests that an organized, co-ordinated, and systematic approach is a natural extension of what is already happening in the market.

It is, however, important to recognize that in most day-ahead markets the compensation for start-up and minimum energy costs is not handled directly in the dispatch process. These markets adopt an alternative 'out-of-market' compensation regime known as uplift, which compensates providers if energy market revenue is insufficient (Gribik, Hogan and Pope, 2007). For example, ERCOT (Electric Reliability Council of Texas) pays generators a 'Day-Ahead Make-Whole' payment to the extent that their energy and ancillary services revenues are not sufficient to provide revenue neutrality (ERCOT, 2017) (see Figure 31).

Uplift payments are exclusive, complex, non-transparent, and difficult to hedge, and while unavoidable, independent system operators generally look to minimize them (Riesz and Milligan, 2017; FERC, 2014a). Volatile uplift payments may also create financial uncertainty for customers, depress liquidity, mute investment signals, and reduce market efficiency (FERC, 2014a).

For that reason, while elements of an organized market for unit commitment may increasingly be required for operational reasons, and arguably is currently being run in *de facto* form in South Australia, uplift payments would not enable a level of transparency necessary to provide price signalling or affect incentives. Alternative approaches to pricing the required services may be worth considering (see Section 4.4).

Figure 31: ERCOT Day-Ahead Make-Whole payment



Note: AS = ancillary services.
Source: ERCOT (2017).

4.2.3 Dynamic reserves

The traditional approach to scheduling reserves has been based on a set of deterministic rules (Riesz and Milligan, 2017). The intermittent nature of VRE has led to proposals to set reserve requirements and dispatch reserves in a more dynamic way that takes into account this inherent uncertainty (Zhou and Botterud, 2014; Ela Milligan and Kirby, 2011). Under these approaches, the amount of reserves procured varies based on uncertainty from VRE. Initial analysis suggests that use of probabilistic forecasts can contribute to improved system performance and reduced cost (van Stiphout, de Vos and Deconinck, 2017)

The NEM already adopts a dynamic approach to setting regulation requirements based on real-time measurement of time error, which takes into account the variability, uncertainty, and other factors that influence frequency (such as inertia) (Riesz and MacGill, 2013; Riesz and Milligan, 2017). This provides a conceptual model for setting dynamic reserves. The practical implementation, however, is 'relatively coarse' and the level of regulation reserves rarely shifts from the default levels. Thus further adjustments to the dynamic approach based on renewables and demand forecasts may need to be considered.

AEMO has recently released a new Forecast Uncertainty Measure,[18] which assesses the uncertainty in changes to the supply of power in the system. It analyses the risk of changes to variable generation (that is, wind and solar), outages at thermal plants, and demand variations. This could be of use in providing a signal or metric for quantifying the level of dynamic operating reserves required.

4.2.4 Flexibility markets

Flexibility markets are an umbrella term for initiatives that allow different forms of flexible and fast response to access and play a role in the wholesale electricity market, including distribution system connected customers and DER, enablement of demand response in various guises, FFR, and fast-balancing technology (Keay, 2016).

In many respects, the NEM has already made strides towards a 'flexible' market. Movement towards five-minute settlement will create an incentive for timely and flexible generation. The recent Ancillary Services Unbundling Rule also opens up FCAS markets to a wider range of providers, including aggregators. This has enabled VPPs to play a valuable role in the ancillary services market. The System Security Market Frameworks Review has also investigated the potential for FFR services in the NEM (see Figure 32), and included a range of services from:

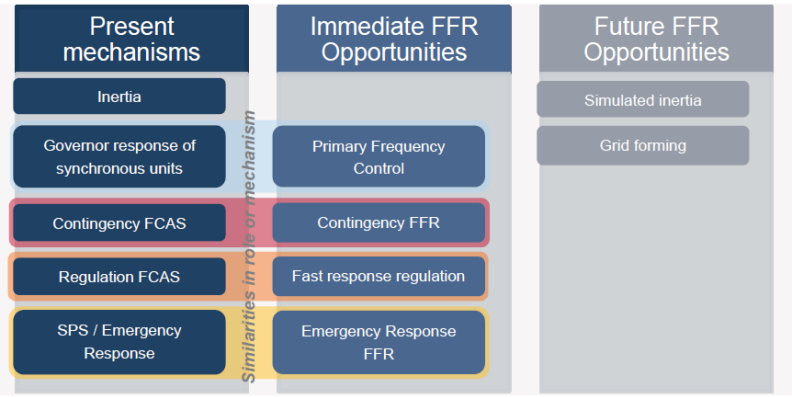
- frequency control (droop response)

[18] For further details on the Forecast Uncertainty Measure please see: www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power_System_Ops/Overview-of-new-method-for-determining-Lack-of-Reserve-V2.docx

- contingency FFR
- fast-response regulation and emergency FFR (AEMO, 2017d).

Attention has also been given to mechanisms that may improve the ability of demand resources and storage to participate in energy markets. The Reliability Frameworks Review has started the process of implementing a wholesale demand response mechanism in the NEM and a mechanism to allow customers to have multiple trading relationships with retailers (AEMC, 2018c). There are also proposals to establish large-scale VPPs that use demand-side resources, including rooftop PV and household battery systems, to provide services to the energy market.

Figure 32: Opportunities for FFR in the NEM



Source: AEMO (2017g).

4.3 Getting the prices right: Towards an 'energy+services' approach

The incorporation of new generation technologies has introduced new operational dynamics to the market. In particular, contributions to certain system requirements such as inertia and system strength were previously provided as a consequence of synchronous energy provision rather than as a specified service. With the increased penetration of asynchronous system resources, these inherent system contributions are reduced.

Hogan (1992, 1998, 2013, 2014) espouses a critical principle of electricity market design – that one should begin with an efficient and transparent real-time energy market that reflects the operational requirements of electricity dispatch. Getting the real-time prices right is critical for all that follows – including forward and long-term markets.

There are currently no economic signals in the NEM for wholesale market participants to provide services such as inertia and system strength in a co-ordinated real-time market. Thus a participant has no incentive to make short-term operational decisions or long-term investment or divestment decisions that take these services into account. These are the 'missing markets' for electricity service (Simshauser, 2018). In the NEM these missing markets include inertia, system strength and, potentially, grid formation. FFR services may also be relevant, as they could impact the level of inertia required in the market (Püschel and Mancarella, 2017). While there are regulatory frameworks for system strength and inertia, these allocate responsibilities to regulated transmission companies. No market frameworks are currently in place for grid formation. In the future, the scope of system services may further expand based on technical and operational requirements.

Given the pace of transition, a proactive approach is required to resolve and mitigate risks as they emerge, and before they become a problem for the system. An economic signalling and incentive system is required to ensure that, in addition to energy, the full scope of system services is provided.

Many regions around the world have an approach that involves an economic disaggregation of energy and services markets (Orvis and Aggarwal, 2017). Separate economic signals are then created for each of these services. In Ireland the DS3 programme is considering a range of system services, including not only a synchronous inertial response service, but also additional services such as dynamic reactive response, FFR, and ramping margin (EirGrid, 2014; Newbery, 2016). A synchronous inertial response product is also being considered in ERCOT in order to provide a minimum level of inertia. Arguably however, AEMO as the operator is already having to run a *de facto* process that directs unit commitment on a residual basis to provide some of these services (AEMO, 2018g).

We propose that market and policy frameworks in the NEM are guided towards an 'energy+services' approach that creates wholesale real-time economic signals for the full range of services required for the comprehensive operation of a modern electricity network. Clear technology-agnostic service specifications and an economic offer process would provide transparent signals that enable clear price discovery. This granularity in services would also encourage new providers and technologies to develop and would guide future new investment. It also allows existing legacy units to capture the full economic benefit of the value they bring to the market, thereby mitigating the risk of disorderly retirement.

Some of the steps towards service definition are already taking place. AEMO has recently released a detailed set of requirements, guidelines, and impact assessments for inertia and system strength,[19] which clarify the nature of the services and the requirements to meet system security. These could form the basis of product definitions for system services.

One of the consequences of this approach is that the revenue mix for market participants may change. Low-cost renewables have the potential to bring down the costs of energy provision, but this may be offset (either partially or fully) by the full value of system costs. The implications of this for consumers and market participants would need to be clearly communicated.

Overall, the NEM currently has gaps between the operational requirements of a complex electricity grid and the specification of services required from the wholesale market. Economic signalling for the full suite of system requirements would allow for these service needs to be met and encourage competition and innovation in delivering them. This requires a shift in thinking from an energy-only mindset to one in which energy and the full suite of system services are valued by participants.

5. Conclusions

The NEM is a case study of a market in transition. Increasing penetration of variable renewable and distributed energy has challenged existing operating frameworks and market design. It has also provided a testbed for new approaches to meeting the reliability and security goals of the market. While reliability (resource adequacy) has taken centre stage in the policy discourse, system security is as important in managing a large-scale complex grid with a significant amount of intermittent renewables. The existing energy price signal has been unable to provide incentives for the full range of services required for secure operation. For example, the disorderly retirement of large synchronous units has introduced security challenges relating to inertia and system strength. While the market has shown adaptability and an ability to respond, the response has not been wholly sufficient in the relevant timeframes. This has required increased operator intervention and direction.

A range of solutions have been proposed, although none to date have harnessed the potential of a comprehensive alignment between economic signals and investment incentives. For example, the government's flagship National Energy Guarantee, while providing a new framework for emissions intensity and reliability, did not address the 'missing markets' in energy security. Measures such as

[19] Please see www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/System-Security-Market-Frameworks-Review for further details.

forward markets may provide hedging options, but are limited to energy. Centralized commitment could provide operating robustness, but might not be able to provide sufficient transparency of the various electric value streams, as the experience of international markets shows.

We argue that while addressing reliability requires an approach that promotes both efficiency and consumer preference, dealing with system security necessitates the extension of market frameworks in the NEM towards an 'energy+services' approach. The economic disaggregation of energy and services markets would create wholesale economic signals for the full range of services required for the operation of a modern electricity network. Separate economic signals are then created for the necessary services, which should include system security services such as inertia, system strength and, potentially, grid formation. Clear service specifications would facilitate transparent signals that enable clear price discovery. This granularity in services would also encourage new providers and technologies to develop, and would guide future new investment. It would also allow existing legacy units to capture the full economic benefit of the value they bring to the market, thereby mitigating the risk of disorderly retirement.

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Appendix

Figure A1: Large-scale map of the National Electricity Market, including generating stations and transmission lines

Source: AER (2017).

Figure A2: Required services in the market

Service description				Supply side		Network						Demand side		
				Centralised generation		Transfer between regions		Transfer within regions	Stabilising devices			Load	Decentralised resources	
System Attribute	Requirement	Service	Spatial level of need	Synchronous generator	Non-synchronous generator	DC interconnection	AC interconnection	Transmission and distribution networks	Grid reactor, grid capacitor, static VAR compensator	Static synchronous compensator	Synchronous condenser [1]	Large industrial, residential, commercial	Solar PV	Battery storage
Resource adequacy	*Provision of sufficient supply to match demand from customers*	Bulk energy	System wide	●	●	➔	➔	➔	○	○	○	●	●	●
		Strategic reserves	System wide	● [2a]	◐ [3a]	➔	➔	➔	○	○	○	●	◐ [3b]	◐ [3b]
	Capability to respond to large continuing changes in energy requirements	Operating reserves	System wide	● [2b]	◐ [3a]	➔	➔	➔	○	○	○	●	◐ [3b]	◐ [3b]
	Services to transport energy generated to customers	Transmission & distribution services	Local	● [4]	● [4]	●	●	●	●	●	●	● [4]	◐	◐
Frequency management	*Ability to set frequency*	Grid formation	Regional	●	◐ [5]	⇨ [5]	●	●	○	○	○	○	○	◐ [5]
	Maintain frequency within limits	Inertial response	Regional	●	◐ [6]	◐ [6]	➔	➔	○	◐ [7]	●	○ [8]	○	◐ [6]
		Primary frequency control	Regional	●	● [9]	➔	➔	➔	○	○	○	●	●	● [9]
		Secondary frequency control	Regional	●	● [9]	➔	➔	➔	○	○	○	●	●	● [9]
		Tertiary frequency control	Regional	●	● [9]	➔	➔	➔	○	○	○	●	●	● [9]
Voltage management	*Maintain voltages within limits*	Fast response voltage control	Local	●	●	●	○	○	●	●	●	●	◐	●
		Slow response voltage control	Local	●	●	●	○	○	●	●	●	●	◐	●
		System strength	Local	●	○	○	⇨	➔	○	○	●	○	○	○
System restoration	*Ability to restore the system*	System restart services	Local	●	◐ [10]	◐ [10]	●	➔	○	○	○	○	○	◐ [10]
		Load restoration	Local	●	●	●	●	⇨	●	●	●	●	◐	◐

1 This includes generators with ability to operate in synchronous condenser mode.
2a While many synchronous generators can provide energy reserves, some less firm technologies (solar thermal or pumped hydro storage) will be limited by the amount of energy storage they include.
2b While many synchronous generators can provide flexibility services, coal generators are limited in their ability to provide such services.
3a Limited by duration for which service can be delivered.
3b Limited by duration for which service can be delivered; existing controllability is limited.
4 The provision of local voltage support from generators and loads can improve the network transport capability near their respective connection points.
5 Grid forming power electronic converters are available and have been proven on small power systems. Development of grid forming converters for large power systems is an emerging area of international research.
6 Some fast frequency response capabilities can provide emulated inertia response, but are not yet proven as a total replacement for synchronous inertia.
7 Static synchronous compensators with energy storage devices are being trialled as an emerging provider of inertial response.
8 Except for load relief.
9 Includes fast frequency response capabilities.
10 System restoration services from variable non-synchronous generators is an emerging area of international research. If they are grid scale, batteries are likely to provide some system restoration support.

Ability to provide service		
●	◐	○
Fully capable	Partial or emerging	Unable
➔	⇨	
Enables delivery	Partial or limited delivery	

Note: Classifications are indicative of the general ability of each technology type. The extent to which technologies can provide each service must be assessed on the specifics of each individual system.

Source: AEMO (2018f)

A. An overview of the National Electricity Market

i. Governance

At a national level the governance of the electricity market on the east coast of Australia is underpinned by a framework agreement between the Commonwealth, state, and territory governments, which provides for a peak policy body known as the Energy Council to be responsible for policy oversight and strategic direction of the National Electricity Market (NEM).

The overarching objective of energy regulation in the NEM is set out in the National Electricity Objective (NEO) 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, reliability, and security"(Government of South Australia, 1996). This objective is interpreted from an entirely economic perspective – it specifically prevents NEM regulators from considering environmental and social objectives in the achievement of the NEO. Environmental and climate policy must be dealt with separately.

Specific governance and regulatory functions are delegated to three agencies with differing responsibilities:

- The Australian Energy Market Commission (AEMC) is responsible for rule making and regulatory reviews of the market.
- The Australian Energy Market Operator (AEMO) is the independent system and market operator responsible for day-to-day operation of the NEM.
- The Australian Energy Regulator (AER) is responsible for regulation and compliance, and as part of its functions sets rates and for regulated transmission and distribution network service providers.

On the recommendation of the Finkel electricity market review conducted in 2017, a new non-legislative governance body known as the Energy Security Board (ESB) has been introduced with responsibility for oversight and review of energy security and reliability (Finkel et al., 2017).

ii. Regulatory design

In the late 1990s, Australian, state, and territory governments agreed to separate their vertically integrated, state-run electricity companies into distinct generation, transmission, distribution, and retail companies. This section describes the framework of how these companies do business.

Wholesale markets

The NEM wholesale market is based on an energy-only gross pool market design with zonal pricing. Participants bidding and offering energy and resources on a regional basis are centrally cleared, along with frequency control ancillary services (FCAS), via a dispatch optimization engine managed by AEMO (AER, 2017).

Retail markets

Retail electricity markets have gradually evolved from a previously regulated model to a market contestable model. Most states have full retail contestability along with fully deregulated electricity pricing (see Figure A3). Under this approach, retailers are able to compete with each other in the absence of price controls and customers can freely switch between retailers (AEMC, 2017a).

Energy retailers typically buy electricity in wholesale markets to be sold to retail customers, combining the cost with network charges. Charges can be flat or varying, but typical retail tariffs insulate the customer from wholesale price volatility (AEMC, 2017a). Retailers typically internalize and manage those risks either through external hedging arrangements (either contract or exchange) or through self-hedging via vertical integration (i.e. ownership of generation assets). As discussed in detail later in this

Appendix, this has been a growing trend in recent years. Many retailers will offer both electricity and gas services, either separately or as part of a bundled package – with some retailers also extending into other services (e.g. internet, mobile phone services).

Figure A3: Energy retail contestability

Jurisdiction	Full retail contestability	Deregulated pricing
Queensland	2007	2016
New South Wales	2002	2014
Victoria	2002	2009
South Australia	2003	2013
Australian Capital Territory	2003	NA

Note: NA = not applicable.
Sources: AEMC (2017a)

Electricity networks – 'poles and wires'

The AER is responsible for economic regulation of electric transmission and distribution networks – termed transmission network service providers (TNSPs) and distribution network services providers (DNSPs). Typically TNSPs and DNSPs operate as regulated monopolies that are subject to economic price regulation by the AER. Each network undergoes a regulatory determination that sets the recoverable rates for a period – typically every five years.

iii. Environmental markets

Australia has had a storied history with environmental markets. In 2012 the country established a CO_2 emissions trading scheme that would apply to large emitters (over 25 mt of CO_2e per year), including a number of large thermal generation facilities.[20] That scheme was subsequently abolished on a change of government in July 2014.

The Australian Government has committed under the Paris Agreement to reduce Australia's greenhouse gas emissions by at least 26 to 28 per cent from 2005 levels by 2030 (Finkel et al., 2017). Electricity generation is a major source of emissions, accounting for around 35 per cent of Australia's national emissions in 2016, and is thus a core sector targeted for decarbonization. To date this has not led to the establishment of any new national emissions regulation scheme, although various guises have been proposed. Carbon emissions and climate change continue to loom large in the national political discourse. A recent illustration of this is the failure to obtain party political support for the government's National Energy Guarantee, despite receiving approval from industry, regulators, and the Council of Australian Governments.

Renewable Energy Target

There is a currently a national Renewable Energy Target (RET) in place that aims to encourage the generation of electricity from renewable sources. The programme is split into a Large-Scale RET and a Small-Scale Renewable Energy Scheme.

The Large-Scale RET sets a target of 33,000 GWh of renewable generation in the NEM by 2020,[21] with interim targets based on a linear trajectory (Clean Energy Council, 2015). Every year retailers have an obligation to generate or purchase large-scale generation certificates (LGCs) equivalent to a certain

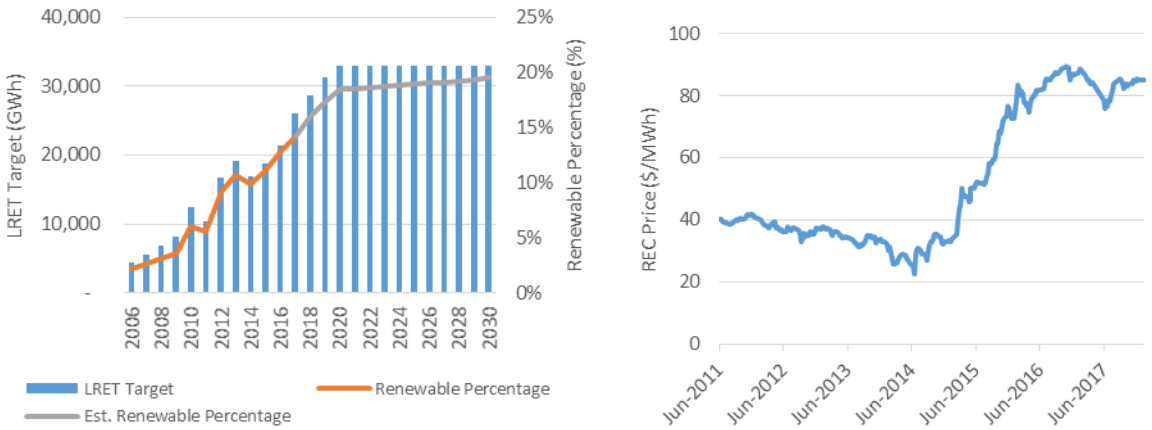
[20] There were also separate attempts between 1997 and 2012 to introduce a federal carbon policy in Australia. See www.cleanenergysummit.com.au/dam/cec/events/aces-2018/presentations/Paul-Simshauser/Paul%20Simshauser.pdf.
[21] In June 2015 the Australian Parliament passed the Renewable Energy (Electricity) Amendment Bill 2015. As part of the amendment bill, the Large-scale RET was reduced from 41,000 GWh to 33,000 GWh in 2020, with interim and post-2020 targets adjusted accordingly.

percentage of their total electricity demand (see Figure A4). The renewable percentage is set annually by the Clean Energy Regulator and for 2018 is set at 16.06 per cent (Clean Energy Regulator, 2018). Retailers can meet their targets through direct ownership of renewable generation assets or through the acquisition of certificates, either via contract or on secondary trading markets. Eligible renewable generation units, including wind, solar (PV and thermal), biomass and hydro technologies, can create one certificate for each MWh of electricity they generate. Existing hydro facilities built before 1997 can create LGCs for any excess electricity they generate above an ascribed 'energy generation baseline'. Under the RET, new renewable projects have typically been financed via a multi-year PPA with a creditworthy entity (Clean Energy Regulator, 2016).

Critics of the scheme point out that it is technology specific and fails to adequately distinguish between low-carbon and renewable resources (Simpson and Clifton, 2014), while Brear et al. (2016) suggest it is a close-to-optimal solution for decarbonization while meeting operational objectives and constraints.

The Small-Scale Renewable Energy Scheme provides an upfront financial incentive (typically in the form of a partial rebate) to individuals and small businesses for the installation of small-scale renewable systems (such as rooftop solar PV). In addition, a net metering scheme is in place that requires the retailer to pay a feed-in tariff (typically ranging from AUD 0.06 to AUD 0.12 per kilowatt hour) to the consumer for any net energy exported to the grid. Some states have legislated minimum feed-in tariff rates (AER, 2017).

Figure A4: Large-Scale RET (LHS) and LGC spot price (RHS)



Note: Estimated renewable percentage calculated as the 2018-30 LRET GWh target as a percent of AEMO forecasted operational demand excluding rooftop solar PV.
Sources: Clean Energy Regulator (2018); Bloomberg

State-based renewables schemes

In addition, certain states have adopted individual renewable energy policies, such as:

- the legislated Victorian Renewable Energy Target (VRET) of 25 per cent by 2020 and 40 per cent by 2025, via a reverse auction scheme that provides revenue certainty to successful projects through a hybrid payment mechanism (fixed payment plus a variable contracts-for-difference payment) (Victorian State Government, 2017)
- the Queensland renewable energy objectives that aim for 50 per cent renewable generation by 2030 (Department of Natural Resources Mines and Energy, 2017)
- the Renewables SA plan aiming to reach a target of 50 per cent renewable generation by 2025 for South Australia; it is unclear how this will be affected by the recent change of government

- an aspirational target of net-zero emissions for New South Wales by 2050
- the target of 100 per cent renewable energy by 2020 in the Australian Capital Territory, underpinned by the contracts-for-difference renewable auction scheme (Simshauser, 2018).

B. Price formation and bidding in the NEM

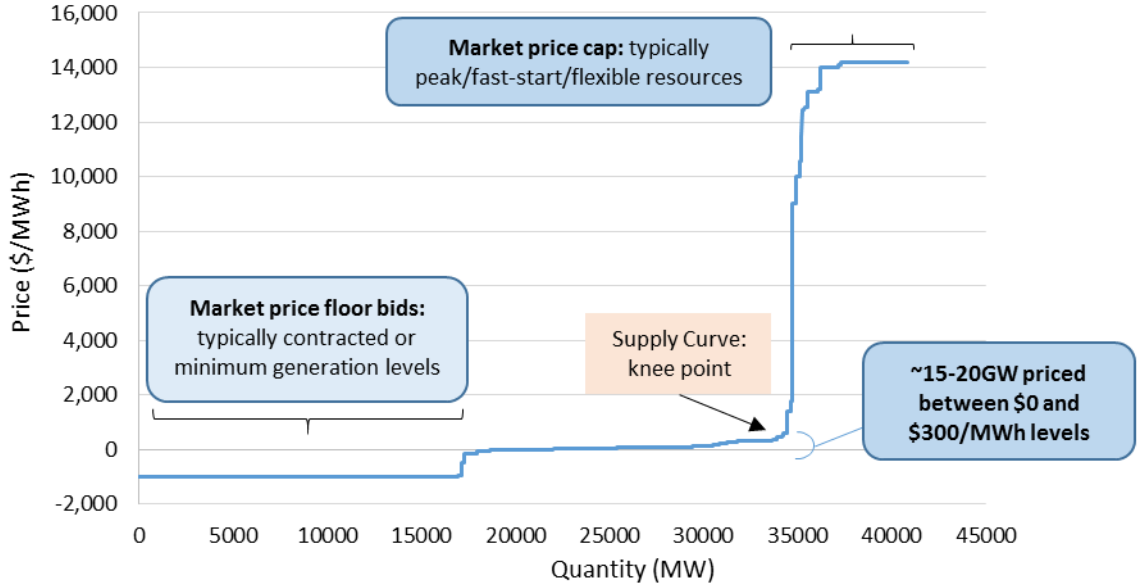
i. Bidding and dispatch

Pricing in the NEM takes place via a security-constrained real-time optimization engine that aims to schedule resources in order to meet demand. Wholesale generators bid to sell electricity through an energy offer curve across ten bid quantity/price bands, with the system cleared through the National Energy Market Dispatch Engine (NEMDE) software that produces binding real-time schedules every five minutes (AEMO, 2017a). The optimization allows for inter-regional dispatch through a series of inter-state transmission lines (known as interconnectors).There are limits to the bid and offer prices for energy. For 2018-19 the market price cap (MPC) is set at AUD 14,500 (increasing annually with inflation), with a constant market price floor (MPF) set at AUD -1,000. While there are rules preventing disorderly bidding and misleading conduct, there is no generalized requirement for generators to bid in line with their costs. NEMDE uses linear programming optimization to solve a five-minute dispatch run taking into accounts bids and offers as well as losses and transmission constraints. Figure B1 shows a sample supply curve for the NEM, and indicates the ‘knee point’ at which the price of offered generation increases by several orders of magnitude towards the MPC.

There is currently no formal day-ahead or forward dispatch market, although participants are free to contract externally. Market indicators such as pre-dispatch and projected assessment of system adequacy (PASA) provide guidance for market participants with respect to future system conditions, dispatch, and pricing. Multiple forecasts are provided by AEMO over a short-term, medium-term, and long-term basis, covering demand, plant, and transmission availability and capacity, and wind and solar generation. In addition, all dispatch outcomes and bids and offers are transparent and publicly available.

Financial transmission rights are available in the form of inter-regional settlement residues, which are auctioned every quarter and may also be traded on secondary markets. Rights are available in respect of flows between all regions of the NEM.

Figure B1: Sample supply curve



Source: NEMWeb (www.nemweb.com.au)

Note: References to $ are to Australian dollar

ii. Semi-scheduled generation

VRE generation resources that have variable output (such as wind and solar PV) are typically classified as semi-scheduled generation.[22] This is able to offer to provide energy in bid bands in the same way as dispatchable generation; however their available offer capacity is limited by the forecasted maximum wind generation potential at the relevant dispatch interval. AEMO has historically forecasted wind and solar using its proprietary systems – the Australian Wind Energy Forecasting System (AWEFS) and Australian Solar Energy Forecasting System (ASEFS). However, a process is underway to allow renewable generation units to substitute forecasts for their own units given, the potential for more granular plant-level forecasts.[23] Based on the available capacity, offered energy bands, prices, and other system factors, NEMDE will provide the semi-scheduled unit with a dispatch target for every five-minute dispatch interval. The implications of imbalances between the dispatch target and actual generation for semi-scheduled participants in the real-time market are set out below.

iii. Unit commitment in the NEM

Many thermal units in the NEM have a minimum generation (MINGEN) requirement that ranges from between 30 per cent and 60 per cent of their normal capacity (ACIL Allen, 2016). This means that these levels must be maintained in order to ensure smooth operation. The NEM's energy offer curve does not allow participants to disaggregate the cost of minimum generation or the cost of starting up a unit.[24] Participants are expected to build these requirements into their energy offers.

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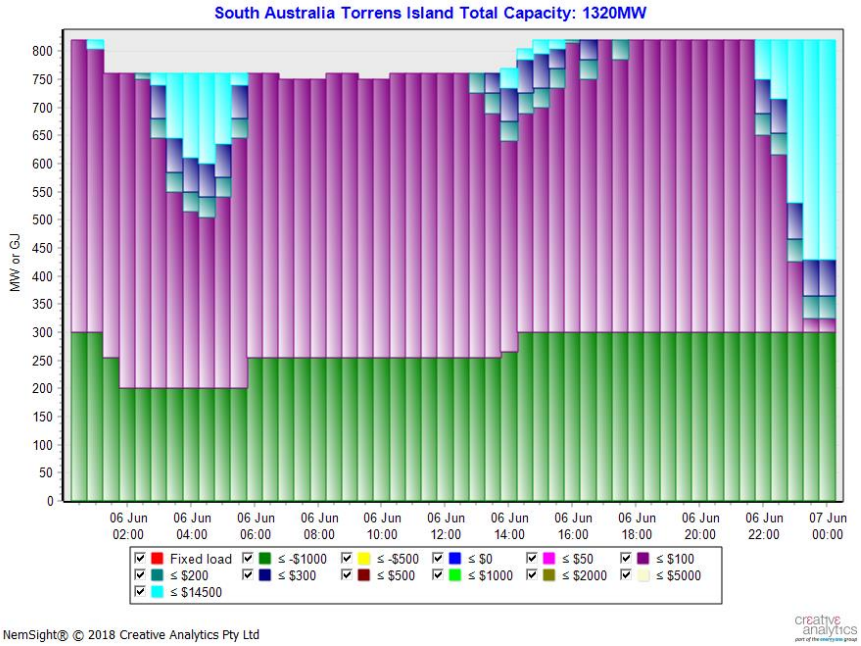
[22] The classification of generation is based on multiple factors, including variability of generation and size, and is assessed at the time of network connection. Prior to the introduction of the semi-scheduled classification, many early wind generation facilities were classified as non-scheduled generation, meaning that those facilities were excluded from central dispatch. A recent rule change proposal to include non-scheduled generation within central dispatch was ultimately unsuccessful. See www.aemc.gov.au/rule-changes/non-scheduled-generation-in-central-dispatch for further details.

[23] See www.aemo.com.au/Stakeholder-Consultation/Consultations/AWEFS-and-ASEFS-Stakeholder-Consultation for further details as it relates to estimated power

[24] This is contrast with many US markets that use a three-part supply offer structure that incorporates start costs, minimum generation costs and an energy offer curve.

As such, these units typically *self-commit* their units into service.[25] In order for a generator to ensure minimum dispatch of its MINGEN requirement, it must bid those quantities at or close to the MPF. See for example Figure B2 for the 1,320 MW Torrens Island power station, with at least 200-250 MW being bid at AUD -1,000/MWh.[26] This way the dispatch of at least the minimum generation level is ensured and the remaining bid bands are priced to recover costs and earn margins. A sample supply stack for an actual dispatch interval is shown in Figure B3. Participants can use contracting strategies outside the pool to earn revenue on minimum generation; however, this is not always possible at all times or in all regions, especially when liquidity is low. Contracting externally may also be difficult if the unit is required for internal hedging as part of an integrated portfolio.

Figure B2: Torrens Island sample bidding structure

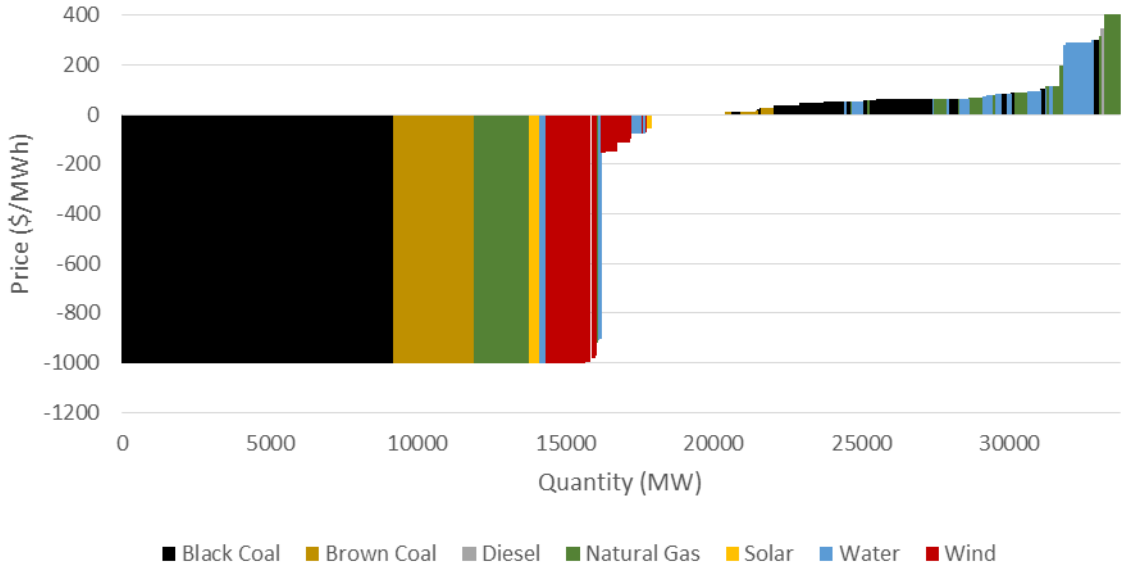


Source: NEMSight.

[25] There is also a dispatch-based commitment process, but this is restricted to fast-start units (with a start time of less than 30 minutes) (AEMO, 2017a) know as fast-start commitment. Units are committed under this process based on an inflexibility profile that takes into account the time required to synchronize, reach, and stay at minimum load, and to shut down. This process also does not disaggregate start costs or minimum generation costs.

[26] In addition, thermal generation that is contracted (either via exchange-traded, over-the-counter [OTC] or other contracts) may also bid close to the MPF in order to 'defend' their contracts.

Figure B3: Sample – NEM supply stack below AUD 400/MWh



Note: Sample supply curve as at 1 June 2018, 8 a.m.
Source: NEMWeb (www.nemweb.com.au).

iv. Ancillary services

In addition, there are eight FCAS markets that are co-optimized with the real-time energy market – six contingency services and two regulation services (AEMO, 2015b). Contingency raise and lower services (6-second, 60-second, and 5-minute) provide localized frequency response to arrest and stabilize frequency following a major drop in frequency. Regulation raise and lower services aim to correct short-term frequency deviations via an automatic generation control (AGC) system. Contingency services are typically sized to manage the loss of the largest generator or load on the system. Participants can offer FCAS across multiple services in up to ten bid bands, with the amount of FCAS procurement set by the market operator. Offers to provide FCAS can range from AUD 0/MWh up to the MPC.

The costs of contingency services are prorated across generation and consumption in the trading interval. The costs of regulation are spread across market participants based on a 'causer-pays' basis. Causer-pays factors are attributed to loads and generation based on their calculated contribution to frequency deviations. Participants that are deemed to contribute to frequency deviations are ascribed a higher factor than those that contribute less or are deemed to assist with frequency deviations. This methodology has come under scrutiny in recent times, with variable renewable generation such as wind facing high FCAS recovery costs (McKenzie and Dyson 2017).

Additional ancillary services (such as for system restart, voltage control, and network support) can be procured by the market operator via contract.

C. NEM frameworks

The core elements of the NEO, as relevant to wholesale market and system operation, thus relate to 'price', 'reliability', and 'security'. For the purposes of this paper it is important to clarify the regulatory distinctions between the concepts of reliability and security, and how each is managed in the NEM. Reliability refers to the ability of generation and transmission capacity to meet consumer demand.

Security refers to the ability of the power system to tolerate disturbances and maintain a stable operating state for electricity supply.

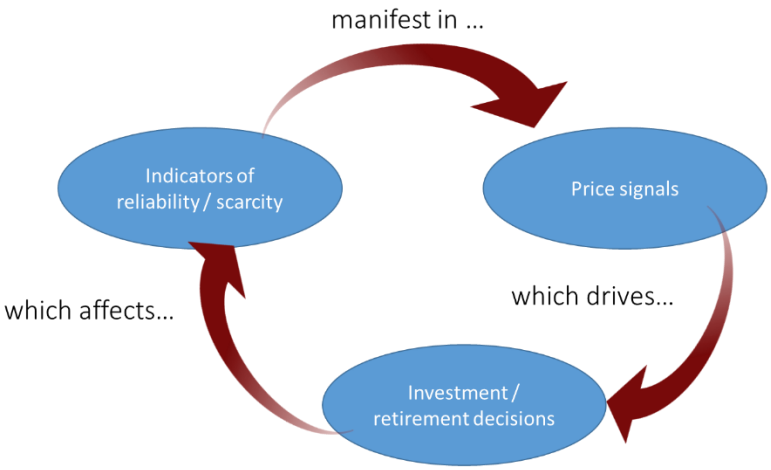
Reliability

In the NEM, reliability is measured as the proportion of total electricity demand that is delivered. The current reliability standard is set at 0.002 per cent of unserved energy (USE) per region or regions per financial year (AEMC, 2013). The reliability standard has an interaction with the reliability settings, which include the MPC, the MPF, and the cumulative price threshold. These settings are reviewed on a periodic basis by the Reliability Panel of the AEMC (AEMC, 2017e). An increase in the level of the reliability standard would likely require a corresponding increase in the level of the MPC, or some other form of generation remuneration, to signal the appropriate level of investment to deliver the higher standard (AEMC, 2017e).

While AEMO as the market operator provides assessments and modelling of the adequacy of the existing resource fleet (generation and transmission) to meet the reliability standard range of demand conditions (AEMO, 2018i; AEMO, 2017c), the energy-only market primarily relies on energy price incentives to drive resource adequacy. MPCs and MPFs are deliberately set at high levels to allow market outcomes to drive investment. The energy-only resource adequacy framework relies on the concept that measures of system reliability will manifest in price signals, which then incentivize decisions with respect to capacity addition or removal (see Figure C1). The design relies on the notion that the effective management of each individual participant's price exposures will provide resource adequacy and reliability over an operational, planning, and strategic horizon.

To the extent that market outcomes are not able to sufficiently deliver resource adequacy, AEMO is able to use 'safety net' powers such as (i) the reliability and emergency reserve trader (RERT) functions to sign contracts with generation or demand resources for either reliability or security purposes, or (ii) 'directions' to order a generator or system resource to act in a particular manner (AEMC, 2010). RERT was used in summer 2017/18 to deal with gaps in system supply-demand balances. In the event that AEMO makes market interventions, an intervention pricing framework applies, which recalibrates zonal prices to remove the impact of intervention.

Figure C1: Reliability design in the NEM



Source: Authors

System security

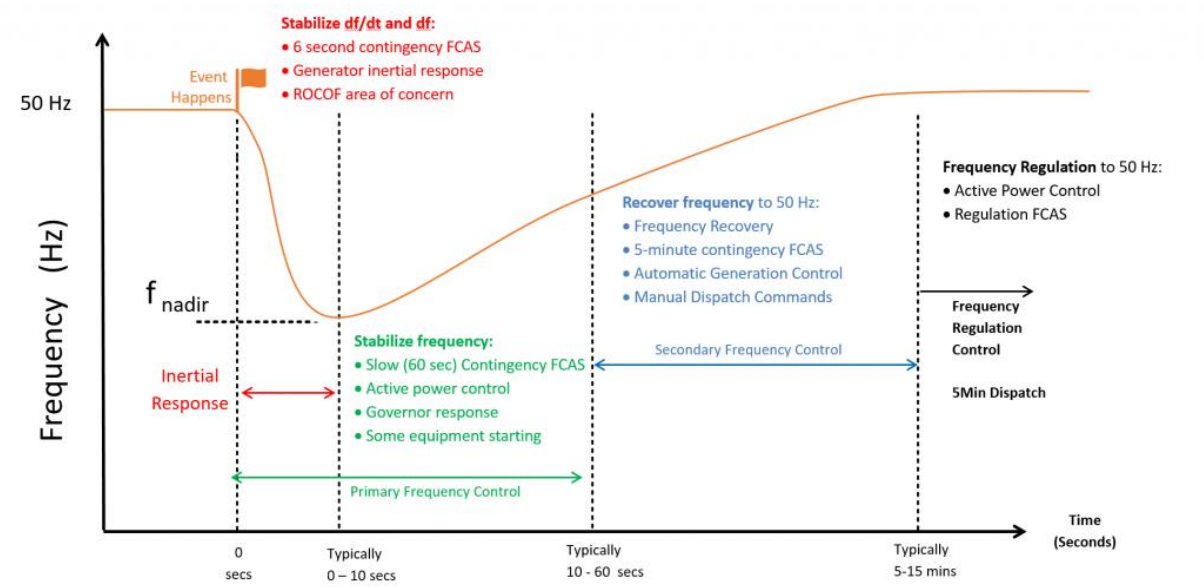
AEMO has the regulatory responsibility for maintaining a secure system and procures the required ancillary services on behalf of the market (AEMC, 2017f). In the NEM the key elements of maintaining

system security include the management of frequency and voltage and the ability to restart the system ('black start') if it there is a blackout.

As outlined in the NEM frequency control ancillary services ("FCAS"): regulation (up and down) services are sourced in order to correct minor deviations in frequency on an ongoing basis. The response to frequency excursions outside these bounds relies upon primary and secondary frequency control via the six contingency FCAS markets to arrest the frequency decline, and then to stabilize and recover the frequency (see Figure C2). The timeframes for these contingency FCAS are set at 6 seconds, 60 seconds and 5 minutes – each with a separate up and down service. In the event that market response is inadequate, AEMO also has the ability to use direct powers to deal with security issues, a capability that has been increasingly used in South Australia in recent months.

Current modes of frequency operation rely heavily on the technical characteristics provided by synchronous generation, including an inherent inertial response to rapid frequency deviations that slows the rate of change of frequency (ROCOF) (AEMO, 2016; Gannon, Swier and Gordon, 2014). If the ROCOF is too high, system disturbances (such as forced outages or intermittency) can exacerbate frequency deviations to a point where current frequency control mechanisms may struggle to arrest, stabilize, and correct frequency.

Figure C2: Frequency contingency response



Note: Hz = Hertz.
Source: Dyson (2017).

D. Market participants and structures

Australia's wholesale and retail electricity markets have been designed as contestable markets. However, since the privatization of retail and generation businesses in New South Wales, Victoria and South Australia in the late 1990s and early 2000s, the market had gradually concentrated through merger and acquisition activity and new investment (Simshauser, 2018). Across the NEM, three large integrated energy companies – AGL, Origin Energy, and Energy Australia (the 'Big Three') – are estimated to collectively own or control 45 per cent of wholesale capacity in the market. Market structures vary across individual regions. Based on ACCC (2018):

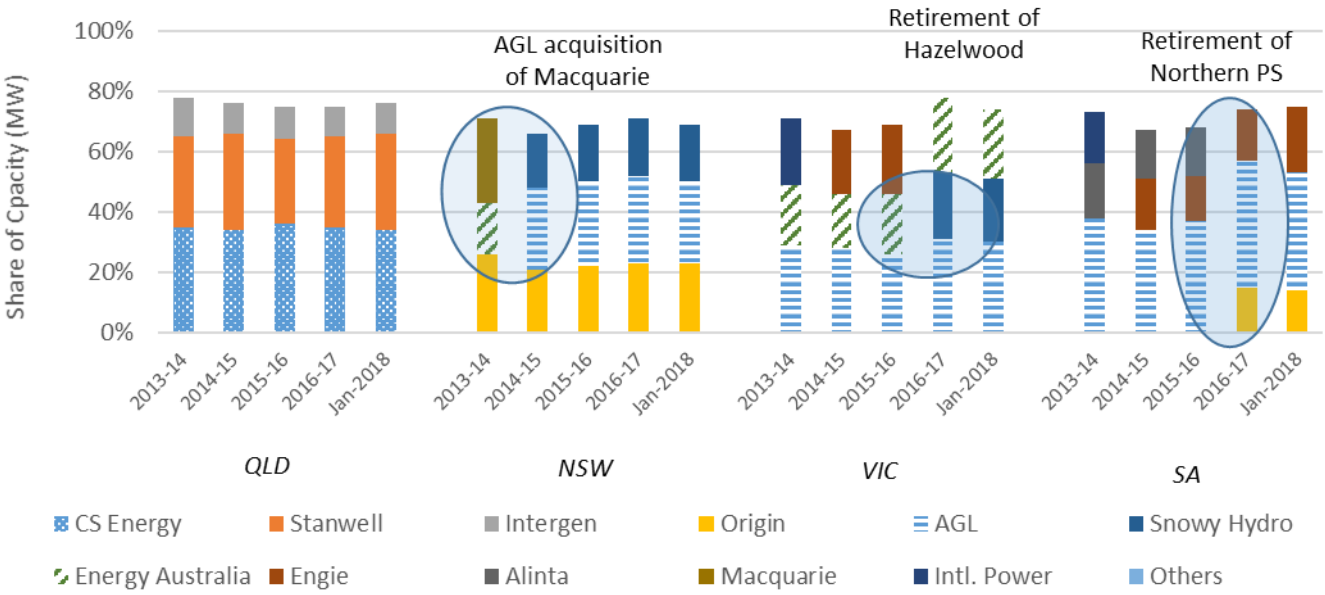
- In Queensland, government generators, Stanwell and CS Energy, together own 66 per cent of capacity.

- In South Australia, three companies, AGL, Origin, and Engie, own 76 per cent of capacity.
- The Big Three collectively own 60 per cent of generation capacity in New South Wales and 58 per cent in Victoria.
- Government-owned generator Snowy Hydro has a significant share of generation capacity in Victoria and New South Wales – 21 per cent and 19 per cent respectively.
- In Tasmania, government-owned IPP Hydro Tasmania owns all of the generation capacity in the state, while retail remains as a government retailer, Aurora Energy.

The spectre of market power has been raised from time to time in the NEM. In 2014-15 a review of the bidding practices of generators in Queensland led to the 'Bidding in Good Faith' rule change.

Figure D1 illustrates the market share of the largest three generators in each state by capacity since 2013-14. In some regions their share has increased, driven in part by capacity retirements. Generators now also face vertical competition in the form of DER and through corporate PPAs, which represent a permanent 'loss of load' to the system, affecting wholesale generators, retailers, and regulated network monopolies.

Figure D1: Generation capacity market share (top three players)



Sources: AER (2014, 2015, 2016, 2017); ACCC (2018).

i. The rise of the second-tier retailer

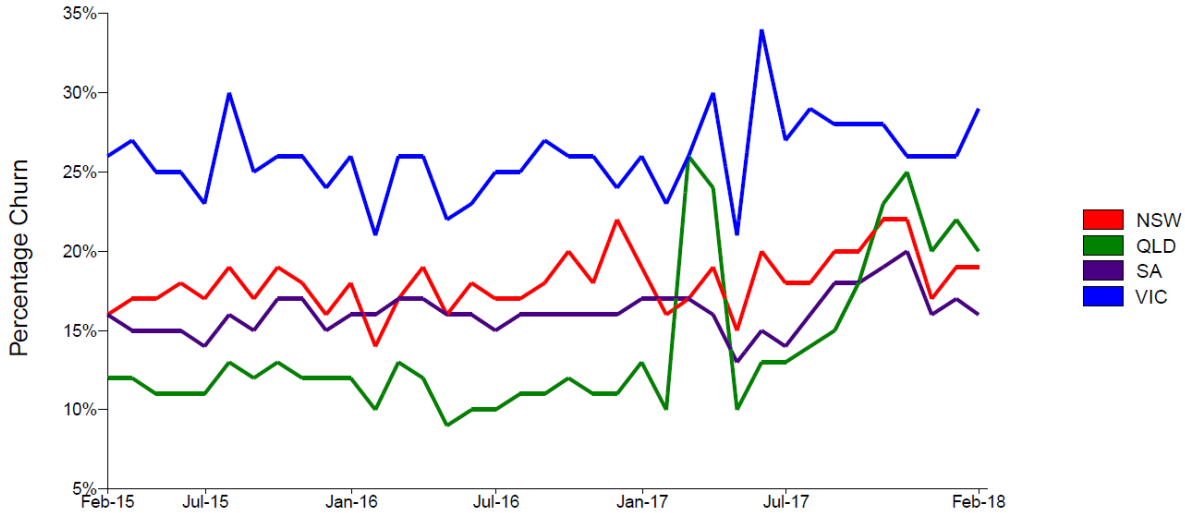
In the retail market, over the last decade the market share held by the Big Three has seen erosion as deregulation and contestability have facilitated the entry of new retailers (known as 'second-tier' retailers). Between 2010 and 2017 the market share held by the Big Three has reduced with second tier retailers now serving 10-14 per cent of the market in certain states (AEMC 2018a; 2017a) (see Figure D2).

Customers switching activity has been high, with some states experiencing churn in excess of 25 per cent in recent times (AEMO 2018d) (see Figure D3).

Figure D2: Retailer market share

Source: AEMC (2018a).

Figure D3: NEM – Annualized small customer switching activity



Source: AEMO (2018e)

ii. Market players and their roles in the NEM

This section provides an overview of the major types of participant in the contestable elements of the NEM – primarily the wholesale and retail markets. It also provides guidance as to commercial imperatives and the impacts of change on each type of business model. Importantly, however, the categorization of players is not intended to be exclusive and indeed participants may have business operations that span multiple models. Furthermore, business activity may also shift between business models over time as part of a deliberate strategic move or as a result of changing market dynamics.

Large vertically integrated energy companies ('Gentailers')

While many of the participants in the NEM exhibit some degree of vertical integration, the Big Three energy companies (AGL, Origin Energy, and Energy Australia) have been considered as the primary proponents of the 'gentailer' model to date (ACCC, 2017b; ACCC, 2018). The Big Three gentailers operate under an integrated approach to energy market supply and delivery. They typically have

diversified portfolios of generation assets with a mix across fuel source, technology, and generation function.

The portfolio mix of location, distribution, technology, and type of generation varies among the Big Three, although generation is typically spread across baseload, intermediate, fast-start, and variable renewable generation (AER, 2017). They also have a large-scale retail customer base that is often closely matched overall to the size of their generation portfolio – although a gentailer may have long or short energy exposures in certain regions or customer segments. These exposures can either be by design or strategy, or shaped by market events.

Generation companies ('Gencos')

Gencos are typified by having a core business model that is focused on the wholesale provision of generation. Key subclasses include:

- Government gencos: Despite the introduction of contestability, a number of generation companies are still owned by national or state governments. While most are typically corporatized entities that ordinarily operate with commercial mandates, governments have used their ownership to implement changes in strategy, which can have an impact upon the market.[27]
- Renewable gencos: these focus primarily on utility-scale renewable generation assets such as wind, solar PV, and hydro. The focus on renewable assets is significant from a business perspective, given the interaction with the RET and other state-based renewable energy schemes. Generation from renewable sources derives value from the energy it sells into the NEM (the 'black' price), but also from the value of the renewable credit that it generates (the 'green' credit). Typically, offtake contracts from renewable generation will aggregate the black and green value into a bundled PPA price, although recently some renewable facilities have disaggregated the 'black' and 'green' value with options to monetize each separately either via long-term contracts or on spot markets.[28] Certain renewable gencos have also begun to vertically integrate themselves with the establishment of retail operations.[29] This potentially creates a need for additional trading, hedging, and risk management functionality to manage exposures, and may involve additional contracting, either in public markets or privately.

While some gencos also have retail operations, they are typically of smaller scale and often have a focus on particular customer types suited to their generation profile. A generation portfolio may also be considered a precursor to retail expansion, where the generator is used to 'anchor' retail contracts.

Energy insurance providers

Energy insurance providers (EIPs) are IPPs that are capable of offering peak supply into the market. These providers have generation that is skewed towards fast-start and flexible units that can start up and ramp rapidly. The flexibility of the asset fleet can allow these providers to capture peak pricing, and by doing so they can offer 'insurance-type' products (such as energy caps and options) into contract or derivative markets to enable other participants to protect themselves from price volatility. An example of a business operating in this model is the government-owned energy company, Snowy Hydro, which

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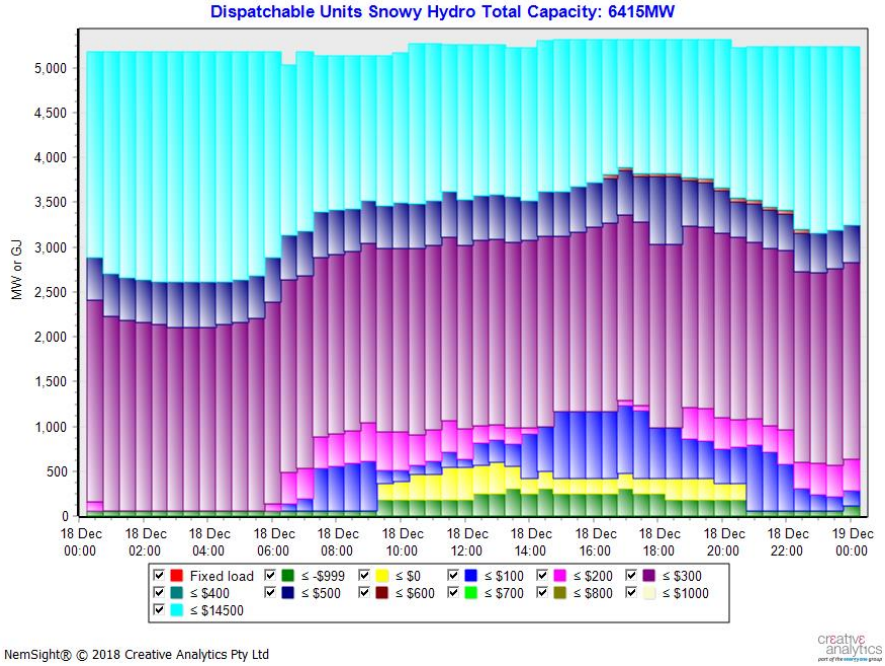
[27] See, for example, the recent Queensland government direction to state-owned IPP Stanwell to undertake strategies to place downward pressure on wholesale prices (Department of Natural Resources Mines and Energy, 2017).

[28] See, for example: (i) Ararat wind farm (240 MW) – output is 40 per cent contracted (via a PPA with the ACT government) with remaining 60 per cent sold on a 'merchant' basis (http://reneweconomy.com.au/ararat-wind-farm-fully-commissioned-supplying-power-to-victoria-and-act-51770/); (ii) Wemen solar farm (110 MW) has been financed and has begun construction on a fully merchant basis (www.cefc.com.au/media/files/cefc-reaches-1gw-solar-milestone-with-finance-across-20-large-scale-solar-projects.aspx); (iii) White Rock wind farm (20 MW) operating on a fully merchant basis (www.allens.com.au/med/pressreleases/pr10may17_01.htm).

[29] See, for example, Pacific Hydro (www.pacifichydro.com.au/).

owns a portfolio of primarily dammed hydropower generation facilities and OCGTs (Snowy Hydro, 2017). Figure D4 illustrates Snowy Hydro's bid stack on 18 December 2017, showing around 80-99 per cent of its available capacity offered at prices above AUD 200/MWh, with around 30-50 per cent being offered at bid bands between AUD 13,000/MWh and AUD 14,200/MWh.

Figure D4: Sample bid stack for Energy Insurance Provider (EIP)



Note: Bid Stack on 18 December 2017.
Source: NEMSight.

Pure play retailers

Pure play or independent retailers operate a retail electricity business without any (or a marginal degree of) vertical integration, that is, ownership of generation assets. With the introduction of retail deregulation and contestability, new retail businesses have formed or entered the energy markets. In the absence of self-hedging through generation ownership, independent retailers generally hedge their price exposure through the contract markets (either exchange traded, or OTC), or alternatively remain exposed to pool price risk. For a pure play retailer the market exposure risks are magnified relative to a gentailer (Tian, 2015). Without appropriate hedging, in the event of high prices a retailer could be exposed to significant costs that it is unable to pass onto consumers. This can result in short-term losses, and challenge the profitability and viability of the business. In addition, independent retailers are reliant on derivative markets for hedging, and can be affected by high contract prices or periods of market illiquidity (ACCC 2017b, 2018). The absence of a net asset base and exposure to retail customer churn limits their ability to enter into long term PPAs (Simshauser, Tian and Whish-Wilson, 2014).

New players and disruptive forces

The competitive dynamic of the NEM is changing rapidly. Technological development and government policy have enabled the entry of new players in the market to compete with existing market participants and/or disrupt existing competitive frameworks, structures, and patterns of demand and supply. Two key disruptors in this vein are on 'the demand side', that is, the customer and energy storage.

The role of the customer or end user of electricity services has changed, and the NEM has already observed pivotal shifts towards the 'prosumer' operating model:

- Distributed energy resources (DER) continue to grow – the NEM now has one of the highest penetrations of rooftop solar PV in the world.
- Initiatives are underway to allow aggregated DER to participate in wholesale markets in an orchestrated manner as virtual power plants (VPPs) (Government of South Australia, 2018), serving as direct competitors against incumbent generation resources.
- Recently certain corporate and industrial customers have executed corporate PPAs with renewable energy projects (PwC, 2017).
- Opportunities are emerging for demand response to participate in wholesale markets, by providing wholesale energy demand response and emergency reserves, and to participate in ancillary service markets.[30]

Thus any analysis of the market must also consider the increasingly active participation of the consumer, not only as an engaged customer, but also as an active competitor providing key components of the market.

The commercialization of energy storage systems, particularly battery energy storage systems, provides a new technological alternative for meeting the reliability and security goals of the market. They have the potential to provide multiple services, including energy, FCAS, and network services. The world's largest grid-scale battery, run by Tesla and Neoen, was installed in South Australia in late 2017. It has already changed market dynamics, taking a 55 per cent share of FCAS revenues in the state (Deign, 2018) and proving to be an important driver of changes to the FCAS supply mix (AEMO, 2018g). Driven by strong expectations of technology cost reductions, battery energy storage deployment in Australia is expected to be close to 6 GW in power output or 2.5 GWh in energy capacity by 2030 (Vorrath, 2018).

E. Hedging, contracting, and integrated portfolio management in the NEM

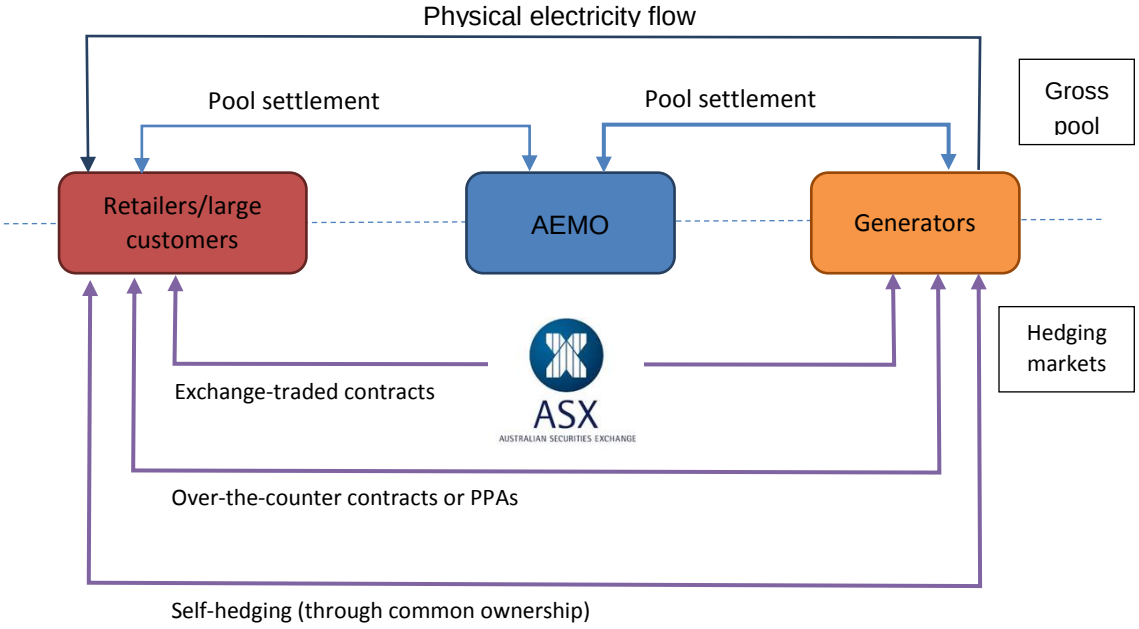
i. Hedging and risk management approaches

Hedging is important in the Australian market as retail customers are typically offered electricity rates that are fixed on an annual basis. Without hedging, a retailer is exposed to the risk of high wholesale prices and price spikes up to the MPC, which may result in exposures that it is unable to pass onto its end consumers. While registered wholesale electricity participants must sell and purchase through the spot pool, they are nevertheless free to structure alternative hedging and risk management arrangements outside of the pool (see Figure E1).

Participants can seek to hedge through contract markets, either via registered futures exchange such as the Australian Stock Exchange (ASX), via OTC derivative contracts, or through bilateral PPAs; or they can 'self-hedge' via internal ownership of generation portfolios.

[30] See, for example: The Ancillary Services Unbundling rule change allows aggregated demand response providers to provide FCAS services without being a retailer (www.aemc.gov.au/rule-changes/demand-response-mechanism). An ARENA-AEMO pilot programme procured 200 MW of demand response emergency reserves (https://arena.gov.au/funding/programs/advancing-renewables-program/demand-response/).

Figure E1: Exposure management in the NEM



Source: Adapted from AEMO (2015a).

ii. The integrated portfolio management model

In recent years the potential for economies of scale and improved risk and portfolio management have provided the rationale for vertical integration across wholesale and retail operations in the NEM – under a business model known as gentailing (AEMC, 2017a).[31] Under the gentailing model a participant will seek to have operations across both the generation and retail subsectors, with the management of financial returns and risk managed on an integrated portfolio basis. Participants have adopted differing degrees of vertical integration. The adoption of an integrated portfolio approach provides for a lower risk of insolvency, lower earnings volatility, and improved capital adequacy (Tian, 2015; Simshauser, 2010; Simshauser, Tian and Whish-Wilson, 2015) relative to 'pure-play' operators. Given retail contestability and the high customer churn, pure merchant generation models are considered unviable in the NEM (Simshauser, 2018; Nelson and Simshauser, 2013).

The ownership of physical generation capacity allows for internal management or self-hedging of exposures to the electricity pool price. This provides additional flexibility and optionality with respect to asset, business, and risk management in the following areas:

- Load shaping. Having control over a physical generation asset can allow for better matching with different customer load profiles. Bidding and operational strategies can be coordinated with the retail load portfolio. Standardized exchange traded products provide limited flexibility to deal with varying customer profiles, while bespoke OTC products that can be tailored may command a premium for that flexibility.
- Flexibility in managing outages (both scheduled and unscheduled). Alternative units can be run to 'cover' the lost generation from outages and minimize net exposure to the pool, or to avoid being forced to purchase contract cover at short notice.

[31] A combination of 'generation and retailing'.

- Fuel management. The Big Three also dominate the gas retail market in Australia, with a total market share of just under 80 per cent (AER, 2017). This market position also provides for scale and leverage in facilitating gas supply and transport arrangements, relative to smaller players.
- Net asset backing and credit worthiness. The ownership of generation assets provides for asset backing that can underpin a credit profile (Simshauser, Tian and Whish-Wilson, 2014). A strong credit profile is an important precondition for long-term offtake contracting, for example via PPAs (Ernst & Young, 2016). A purely retail customer base provides limited asset backing as customers can switch freely between providers. To date, a long-term PPA with a creditworthy offtaker has been a critical element of renewable project financing in Australia, given investor demands for stable, long revenue streams, cashflow stability and downside risk protection (Clean Energy Regulator, 2016; Baker & McKenzie 2014). By providing offtake certainty large gentailers have been able to anchor renewable projects. This positions the gentailer to extract better contract terms and pricing and the ability to sell excess credits onto the market.

Gentailers may nevertheless seek or face net long or short exposures in particular regions and may rely on contract markets to hedge additional risks. A gentailer must weigh the risks of net exposure against the cost of contracting, or generating as relevant. The gentailer model relies on scale in the market to provide flexibility and economies in the management and co-ordination of activities. A sophisticated strategic overlay and risk management strategy is thus required to co-ordinate trading, hedging, operational and other activities.

iii. Traditional hedging of retail load profiles in the NEM

A wide array of hedging and risk management products are available for participants, although the most common and liquid forms are fixed-volume electricity swaps and fixed-volume caps (which provide protection from extreme pool prices). In the NEM, a retailer will typically (though not always) seek to manage the risk associated with load based on categorizations of load held within the portfolio (Productivity Commission of Australia, 2013; Energy Edge, 2017):

- The minimum level of load (typified by a 24x7 commercial or industrial customer base) is hedged using baseload swaps in the contract markets or baseload generators under a self-hedging model.
- Peak-hour levelized loads are hedged via peak swap contracts or self-hedged by mid-merit generators (typified by commercial/industrial customers with daytime loads).
- The maximum load of a retailer is hedged via cap contracts, which essentially provide insurance against high prices, or by running peaking or flexible generation (typified by residential or other variable loads).

It is important to note that this represents a simple and stylized example. Hedging complex large-scale portfolios will utilize a broader and more sophisticated suite of risk management products. Figures E2 and E3 illustrate hedging in contract markets and via the self-hedging model respectively.

Integrated players will also organize their fuel arrangements (commodity and transport) and outage schedules based on the expected generation profile required to match internal retail and contract/hedging portfolios.

Figure E2: Hedging in contract markets

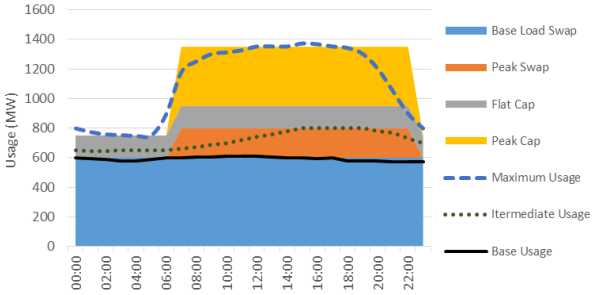
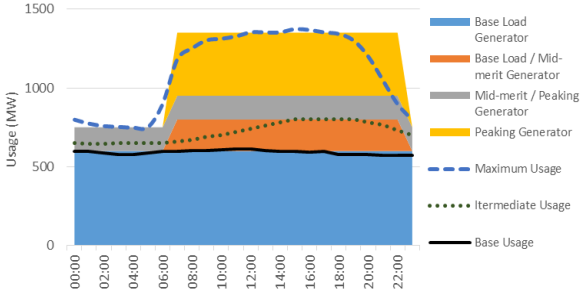


Figure E3: Self-hedging model



Source: Based on Productivity Commission (2013) (illustrative purposes only).