Griffith UNIVERSITY
Griffith Business School
Queensland, Australia

Centre for Applied Energy Economics & Policy Research: Working Paper Series 2020-04

Is the NEM broken? Policy discontinuity and the 2017-2020 investment megacycle

Paul Simshauser[§a] and Joel Gilmore[♣]
May 2020

Abstract
The recent history of Australia's National Electricity Market (NEM) from 2012-2017 has been problematic with sudden coal plant closures, a tight domestic gas market and sharply rising electricity prices. The supply-side response that followed from 2017-2020 was an investment megacycle – 12000MW of plant commitments comprising $20+ billion across 105 projects – most of them Variable Renewables. Problems emerged including entry lags, connection delays, system Frequency careering outside normal bands, failing system strength, rising Frequency Control Ancillary Service costs and increasing Operator interventions in the security-constrained dispatch process. Market institutions were caught out. Yet instead of identifying and addressing urgent problems, a suite of market redesign proposals emerged which focus on future investment and Resource Adequacy. In this article, we analyse recent NEM performance and find all pressing issues relate to real-time power system security, not Resource Adequacy, and reflect a Rate of Change problem stemming from record levels of simultaneous (asynchronous) new entry. Resolution requires establishment of 'missing markets' to restore power system resilience. Fundamental market redesign is a distraction – it may well become necessary but there is no united agreement as to why this is the case nor when it is required. As it stands, no reform proposal comes even close to resolving the NEM's existing, and pressing, problems.

Keywords: Renewables, energy markets, investment cycles
JEL Codes: D24, G31, L94.

♣ Policy Innovation Hub, Griffith Business School, Griffith University.
♠ Research Associate, Energy Policy Research Group, University of Cambridge.

Centre for Applied Energy Economics and Policy Research

1. Introduction

For most of its 23-year history, Australia's National Electricity Market (NEM) has been a marvel of microeconomic reform. Prices fell to efficient levels, oversupply gradually cleared, the Reliability Standard of '*no more than 0.002% Lost Load*' was met with *very few* exceptions and risks of erroneous investments were allocated to investors rather than captive franchise consumers.

The NEM's recent history, specifically 2016/17-2019/20, has been problematic with sharply rising prices, a Variable Renewable Energy (VRE) investment bubble and failing power system resilience. Three key elements preceded the 2017-2020 period. To summarise briefly, contracting demand from 2010-2015 and overinvestment in the plant stock in prior periods led to material excess capacity and a procession of coal plant exits. Second, the natural gas market went into an export-driven deficit from 2014-2017 following the development of 3 x LNG export terminals when realistically, only two should have proceeded. Third, Australia's 20% by 2020 Renewable Portfolio Standard was the subject of policy discontinuity during 2011-2015, and VRE investment flows were 'punctured' leaving a shortened investment window to meet the Target.

Combined, these established near perfect conditions for an awkward investment megacycle. Crystallising the start of the problem-phase was a black system event in the NEM's South Australian region in September 2016, as its market share of renewables approached 50%. Details of these events and the sharp rise in wholesale electricity prices that followed have been examined in detail in Simshauser (2019a, 2019b) and so we do not propose to repeat the analysis here. Our interest is in the *investment megacycle* that followed.

A large supply-side response to sharply rising prices is evidence of a market at work. But the volume of activity comprising the investment megacycle became a problem of itself, and it is not until this activity is analysed that this becomes clear. The scale of investment was material enough to register on the Reserve Bank of Australia's radar, becoming visible in national economic data (de Atholia, Flannigan and Lai, 2020). As a highly capital-intensive, resource-based and geographically dispersed economy, it is not immediately obvious that this was a good thing – the last time electricity investments registered attention in national economic data, distribution networks were being gold-plated (Plumb and Davis, 2010; Simshauser, 2019a).

Post-entry market conditions sparked a wave of market reform proposals to fundamentally alter the NEM's real-time gross pool, zonal market design including the so-called 'post-2025 market design'. Yet despite the abundance of reform proposals there is surprisingly little evidence, and certainly no united agreement, on what problem actually exists.

To be sure, our subsequent analysis reveals the existing NEM design *must* be altered to restore power system resilience. Our concern is reform proposals are responding to symptoms and beliefs, rather than underlying problems and evidence.

The purpose of this article is to analyse market performance and the 2017-2020 investment megacycle in particular. Placing the fallout from an investment megacycle into context is important – not every deviation in the pre- and post-entry environment warrants a policy response, let alone policymaker attention.

Our analysis shows the 2017-2020 investment megacycle was significant by any metric. Over the NEM's ~23 year history (1998-2020), 206 utility-scale new entrant plant comprising 28,147 MW of coal, gas and renewables reached Financial Close with an aggregate investment value of AUD$52.6 billion[1]. The surprising statistic is how much activity occurred during 2017-2020 – virtually half of the NEM's historical investment commitments, viz. 12,148 MW (43% of the total) with an aggregate value of $21.5 billion (41%) across 105 (51%) projects, including 63 utility-scale solar PV and 32 wind projects.

The NEM's post-entry environment presents as a *Rate of Change* problem. Underlying causes of the megacycle can ultimately be traced to continuous reviews of Australia's Renewable Portfolio Standard of 20% by 2020. By the time the industry had 'clear air' on a revised renewables policy (i.e. in 2015/16) only four years remained to meet the Target which caused Certificate prices to spike. With spot electricity prices simultaneously surging for unrelated reasons the bundled (i.e. spot electricity + Certificate) price created *gold rush* conditions. The market overshot creating an excess entry result. A thorough understanding of how Australia's Paris Commitment is to be met should be of unquestionable interest to policymakers in order to avoid an encore performance in 2027-2030.

The central implication of the NEM's post-entry environment and the *Rate of Change* problem are those relating to power system Security. We find far less evidence of Resource Adequacy problems which might otherwise necessitate a fundamental market redesign. The practical evidence is that 105 power projects entering *en-masse* caused a visible deterioration in power system Frequency, failing system strength and a sharp rise in Market Operator interventions to deal with new and emerging modes of power system failure. Resolution does *not* require a market redesign; it requires identification and establishment of missing markets, and their establishment is evidently quite urgent.

This article is structured as follows: Section 2 provides a review of relevant literature. Section 3 introduces our modelling framework. Section 4 examines NEM performance and Section 5 catalogues the fallout from the 2017-2020 investment megacycle. We examine the underlying cause in Section 6. Policy implications and concluding remarks follow.

2. Review of Literature

There are two streams of relevant literature, (i). on energy-only markets, and (ii). on climate change policy discontinuity in Australia.

2.1 On energy-only markets

An extensive literature exists on whether electricity markets, and energy-only markets in particular, are capable of delivering an adequate plant stock and meet reliability constraints given the predominance of fixed and sunk costs. Economic theory and power system modelling has long demonstrated organised spot markets can clear demand reliably and provide suitable investment signals for new capacity (Schweppe et al. 1988). But theory and modelling is based on equilibrium analysis with unlimited market price caps, limited political and regulatory interference, and by deduction – largely equity capital-funded generation plant able to withstand elongated 'energy market business cycles' (Simshauser, 2010; Arango and Larsen, 2011; Cepeda and Finon, 2011; Bublitz *et al.*, 2019).

Of central concern is *missing money,* a concept formally introduced by Cramton and Stoft (2005, 2006) describing inadequate net revenues *cf.* expected returns. Peaking plant are thought to be particularly susceptible given manifestly random revenues in organised spot markets (Doorman, 2000; Besser, Farr and Tierney, 2002; Stoft, 2002; Peluchon, 2003; Roques, Newbery and Nuttall, 2005; Hogan, 2005; Simshauser, 2008; Finon, 2008; Finon

[1] Expressed in constant 2020 dollars. AUD$1.00 = US$0.65, €0.60 and £0.54

and Pignon, 2008; Joskow, 2008; Spees, Newell and Pfeifenberger, 2013; Cramton, Ockenfels and Stoft, 2013; Bajo-Buenestado, 2017; Keppler, 2017; Milstein and Tishler, 2019). Actions by regulatory authorities and Market Operators compound matters by suppressing legitimate price signals (Joskow, 2008; Hogan, 2013; Spees, Newell and Pfeifenberger, 2013; Leautier, 2016). Furthermore, many energy markets have been unable to deliver the optimal mix of derivative instruments required to facilitate efficient plant entry, specifically, long-dated contracts sought by risk averse project banks (Joskow, 2006; Chao, Oren and Wilson, 2008; Meade and O'Connor, 2009; Howell, Meade and O'Connor, 2010; Caplan, 2012; Meyer, 2012; Nelson and Simshauser, 2013; Newbery, 2017, 2016; Grubb and Newbery, 2018; Bublitz *et al.*, 2019).

Collectively, these characteristics are thought to create risks for timely investment required to meet power system Reliability Standards (Bidwell and Henney, 2004; Cramton and Stoft, 2006; de Vries and Heijnen, 2008; Roques, 2008; Hirth, Ueckerdt and Edenhofer, 2016). The key issue is whether plant will arrive on a timely basis, or in response to a crisis (Simshauser, 2018).[2]

High levels of VRE is thought to complicate matters because of 'side-markets' subsidies (Joskow, 2013; Newbery, 2016; Simshauser, 2018b). VRE merit order effects, which may be sustainable through 'side-markets' may therefore pose even greater challenges to Resource Adequacy, implying capacity markets or *strategic reserves* may become essential (Hach and Spinler, 2016; Höschle *et al.*, 2017; Bublitz *et al.*, 2019; Milstein and Tishler, 2019).

Despite this, with few exceptions Australia's energy-only gross pool has produced a consistent stream of investment as Fig.2 subsequently reveals. Three variables have been particularly important in this regard, i). an historically tight nexus between the NEM's very high Market Price Cap of $14,700/MWh and the Reliability Standard of *no more than 0.002% lost load*, ii). the existence of non-negative forward market premiums above spot prices, and iii). industrial organisation and vertical integrated investments as a means to deal with the unusually high financial hazards associated with ex-ante capital-intensive peaking plant commitments and ex post performance (Simshauser, 2010, 2020b; Simshauser, Tian and Whish-Wilson, 2015). While innovation in financial markets is typically measured over decades or centuries as Newbery (2020) notes, ironically the NEM successfully originated ~60 long-dated Power Purchase Agreements (PPA) to facilitate optimal financing conditions for VRE entry over the 2017-2020 cycle (see Section 4.1). So-called "super peak" and "inverse solar/solar firming" shaped swap contracts are also now available from a small but growing number of providers.

Perhaps counterintuitively, real-time energy-only markets also have many attractive features for managing systems with high shares of VRE (Henriot *et al.*, 2013; Riesz, Gilmore and MacGill, 2016). They provide very sharp price signals for performance at critical times including demand-side response and flexible resources if and when required (Galetovic, Munoz and Wolak, 2015). In contrast, capacity markets necessarily require arbitrary definitions of "capacity" which will become increasingly problematic for markets with high VRE, short-term energy storage, flexible loads and firm supply delivered through diversified VRE portfolios. Indeed, capacity payments do not necessarily correlate well with performance, leading to a misallocation of costs (Olsina *et al.*, 2014; Byers, Levin and Botterud, 2018).

[2] Concerns over Resource Adequacy are compounded by the fact that large segments of real-time aggregate demand are price-inelastic and unable to react to scarcity conditions, and similarly in the short run, supply is inelastic because storage remains costly (Batlle and Pérez-Arriaga, 2008; Cramton and Stoft, 2008; Finon and Pignon, 2008; Roques, 2008; Bublitz *et al.*, 2019).

2.2 On climate change policy discontinuity in Australia

Australia has been unable to establish a united energy and climate change policy architecture – instead industry and consumers have been forced to navigate a two-decades long climate policy war between Australia's two main political parties, the conservative Liberal Party, and social democratic Labor Party (Byrnes *et al.*, 2013; Molyneaux *et al.*, 2013; Nelson *et al.*, 2013; Freebairn, 2014; Garnaut, 2014; Apergis and Lau, 2015; Nelson, 2015; Simshauser, 2018a; Simshauser and Tiernan, 2019). Two policy mechanisms have been the subject of discontinuity, i). Australia's Renewable Portfolio Standard and ii). Emissions Trading (Jones, 2010).[3]

Australia introduced the world's first Renewable Portfolio Standard after passing legislation in 2000 (Jones, 2010; MacGill, 2010). An obligation of '2% by 2010' was placed on electricity retailers and mobilised by tradeable Certificates (Jones, 2009; Simshauser and Tiernan, 2019). The target was comfortably met four years ahead of schedule (Buckman and Diesendorf, 2010).

With Australia's international CO_2 commitments known, and the absence of credible matching policy, State Governments filled the policy vacuum – as occurred in the US and Canada (Jones, 2014; Schelly, 2014). From the early-2000s State Governments began to mandate higher Targets for their own jurisdictions as the Commonwealth's Emissions Trading policy stalled (Nelson *et al.*, 2013; Cludius, Forrest and MacGill, 2014; Jones, 2014; Simshauser, 2018a). Work simultaneously commenced on a State-based National Emissions Trading Scheme (Nelson *et al.*, 2010; Simshauser and Tiernan, 2019). The 2007 Commonwealth election thus elicited two commitments from Australia's political parties; the incumbent conservative government's 15% Clean Energy Target and the social democratic opposition's greatly expanded renewable target of '20% by 2020'. A united position existed on an Emissions Trading Scheme (Jones, 2010; Apergis and Lau, 2015; Simshauser, 2018a).

Australia's 2% by 2010 Renewable Portfolio Standard and associated certificate side-market had trivial impacts on the NEM's organised spot market, but expanding the scheme to 20% (without any adjustment) revealed a number of design flaws which Buckman and Diesendorf (2010) explain in some detail. For our purposes, the most critical were initial inclusion of rooftop solar PV which overwhelmed volumes and de-stabilised the policy, and the use of a fixed volumetric target of 44TWh rather than a genuine 'percentage of demand' Target (Jones, 2010; Byrnes *et al.*, 2013; Forrest and MacGill, 2013; Bell *et al.*, 2015; Simshauser, 2018a; Simshauser and Tiernan, 2019). Compounding matters, two-yearly reviews of the Renewable Portfolio Standard produced visible stop-start investment cycles (Fig.2).

Of special importance to our analysis was the "Warburton Review" of the Renewable Portfolio Standard, initiated after the 2013 Commonwealth election. The new government initiated an unscheduled review aimed at reducing the fixed volume target after energy demand contracted (following the 2008 Global Financial Crisis). Given contracting aggregate demand, the Standard was moving closer to a 25-30% target cf. the 20% policy design. Forcing VRE capacity into an increasingly oversupplied and unstable wholesale electricity market with Certificate costs levied on consumers was occurring at a time when residential electricity tariffs were rising sharply due to gold-plating of networks (Cludius, Forrest and MacGill, 2014; Garnaut, 2014; Nelson, Reid and McNeill, 2015; Bell *et al.*,

---

[3] On 20 November 1997 Australian Prime Minister Howard announced that the Commonwealth would work with the State Governments to "set a mandatory target for electricity retailers to source an additional two per cent of their electricity from renewable energy sources by 2010" and "Australia also believes that an international emissions trading regime would help minimise costs of reducing emissions. (see Parliament of Australia at: http://parlinfo.aph.gov.au/parlInfo/search/display/display.w3p;query%3DId%3A%22chamber%2Fhansardr%2F1997-11-20%2F0016%22 – accessed April 2020).

2017). In the end, the Standard was scaled-back to 33TWh (Biggs, 2016) but not before VRE investment flows were punctured (Simshauser, 2018a, 2019b; Simshauser and Tiernan, 2019). Figure A1 (Appendix I) illustrates legislated changes to the Renewable Portfolio Standard.

On emissions trading, formal policies had been developed and discarded in 1999-2001, 2005-2006 and in 2007-2010 (Simshauser and Tiernan, 2019). In late-2010 a minority Labor Government emerged from the 2010 Commonwealth election, revived an earlier policy that had been discarded only months earlier and legislated a $23/t fixed carbon tax from July 2012 as a precursor to an Emissions Trading Scheme (Garnaut, 2014; Wild, Bell and Forster, 2015). The policy was abandoned in 2014 following a change of government. Three further ETS policy attempts occurred in 2016, 2017 and 2018 but were discarded by the right of the conservative Liberal party. In all, from 1999-2018 seven formal attempts at an Emissions Trading Scheme were initiated with no tractable policy emerging (Simshauser and Tiernan, 2019).

3. The benchmark cost of entry in the NEM

In order to make sense of investment patterns and market performance over time, a suitable new entrant benchmark is required. The PF Model, a dynamic multi-period post-tax discounted cash flow model, has been specifically designed for this purpose by solving for multiple generating technologies, business combinations and financing structures, simultaneously determining the unit cost, debt-sizing and post-tax equity returns. First-stage outputs are similar to levelised cost estimates but with a level of detail well beyond conventional Levelised Cost of Electricity Models because corporate financing constraints and taxation variables are co-optimised. Model logic is presented in Appendix II.

The benchmark entrant has changed over time as technology costs, exchange rates, fuel costs and perceptions of CO_2 emissions liabilities varied. These changes are examined in considerable detail in Simshauser & Gilmore (2019) and so we do not propose to repeat the analysis here. To summarise, Supercritical Coal plants dominated until 2007, Combined Cycle Gas Turbines (CCGT) formed the benchmark through to 2017, from which time a combination of Wind[4] + Open Cycle Gas Turbines (OCGT) dominates while gains from exchange exist. Table 1 provides relevant data for conventional plant over six relevant reference years and Table 2 provides a time series for Wind.

[4] Solar PV is excluded from this comparative analysis due to the nature of its output (i.e. being limited to daylight hours) and the extensive implied backup costs. Wind on the other hand, while stochastic, operates continuously and is well suited to 'backup' by an OCGT during low-wind/high-price conditions. A more sophisticated analysis may comprise a portfolio of wind, solar and other firming technologies, i.e. OCGT and battery storage. See Simshauser & Gilmore (2019), Simshauser (2020a) and also footnote #6.

Table 1: Technology Assumptions 1998-2020

Technology	Capex	Installed Capacity	Generating Units	Unit Heat Rate	Unit Fuel Cost	Capacity Factor	Fixed O&M Cost	Variable O&M	Capital Works	Auxillary Load	Carbon Intensity
	($/kW)	(MW)	(MW)	(kJ/kWh)	($/GJ)	(%)	($/MW/a)	($/MWh)	(%)	(%)	(t/MWh)
Incumbent - 1998											
Black Coal	1,000	1,000	2	10,000	1.10	90.0%	52,500	1.00	0.25%	7.50%	0.92
2004 Inputs											
Black Coal	1,400	1,000	2	9,500	0.70	90.0%	45,000	-	0.25%	7.00%	0.86
CCGT	1,000	400	1	7,000	3.00	70%	8,000	4.00	0.05%	3.00%	0.40
OCGT	700	300	2	11,300	3.00	10%	3,078	7.71	0.05%	1.00%	0.60
2007 Inputs											
Black Coal	1,500	1,000	2	9,500	2.00	90.0%	48,000	1.00	0.25%	7.00%	0.86
CCGT	1,250	400	1	7,000	3.00	70%	9,000	4.00	0.05%	3.00%	0.40
OCGT	875	300	2	11,300	3.50	10%	3,315	8.31	0.05%	1.00%	0.60
2012 Inputs											
CCGT	1,275	400	1	6,965	6.00	70%	9,500	7.00	0.05%	3.00%	0.36
OCGT	893	300	2	11,300	7.00	10%	3,751	9.40	0.05%	0.00%	0.60
2018 Inputs											
CCGT	1,500	400	1	6,930	8.50	70%	10,000	7.00	0.05%	3.00%	0.36
OCGT	1,050	300	2	11,300	10.00	10%	4,350	10.90	0.05%	1.00%	0.60
2020 Inputs											
CCGT	1,500	400	1	6,930	9.00	70%	10,769	7.00	0.05%	3.00%	0.36
OCGT aero	1,250	240	4	10,500	10.00	10%	4,570	11.45	0.05%	1.00%	0.50

Source: Simshauser & Gilmore (2019).

In Table 2, we have collated live capital costs from 67 of the NEM's 81 wind projects over the period 2000-2020 and matched these data with capital markets swap rates for 7-year money and estimated Project Finance credit spreads (for a $/kW analysis of wind and solar PV in real 2020$, see Fig.18).[5]

Table 2: Wind New Entrant Cost Data (2000-2020, nominal dollars)

Wind	Capex	Fixed O&M Cost	Variable O&M	7 Yr Swap Rate	PF Spread*	PF Debt**	Assumed Refi Rate***	Equity Returns
	($/kW)	($/MW/a)	($/MWh)	(%)	(bps)	(%)	(%)	(%)
2000	1,667	31,630	2.10	6.78	140	8.18	7.43	12.0
2001	1,813	32,262	2.14	5.87	140	7.27	7.23	12.0
2002	2,143	32,907	2.19	6.00	140	7.40	7.30	12.0
2003	1,957	33,566	2.23	5.51	140	6.91	7.50	12.0
2004	1,893	34,237	2.27	5.98	140	7.38	7.50	12.0
2005	1,828	34,922	2.32	5.77	145	7.22	7.50	12.0
2006	2,569	35,620	2.37	6.12	148	7.61	7.50	12.0
2007	1,964	36,333	2.41	6.77	217	8.94	7.50	12.0
2008	2,353	37,059	2.46	6.61	427	10.88	7.50	12.0
2009	2,344	37,800	2.51	5.45	433	9.78	7.50	12.0
2010	2,708	38,556	2.56	5.72	275	8.47	7.50	12.0
2011	2,343	39,327	2.61	5.32	321	8.53	6.97	12.0
2012	2,711	40,114	2.66	3.90	382	7.71	6.31	12.0
2013	2,088	40,916	2.72	3.87	310	6.98	5.70	12.0
2014	2,325	41,735	2.77	3.61	251	6.12	5.23	12.0
2015	2,325	42,569	2.83	2.72	280	5.52	4.73	12.0
2016	2,485	43,421	2.88	2.32	291	5.23	4.50	12.0
2017	2,114	44,289	2.94	2.65	199	4.64	4.50	10.0
2018	1,930	45,175	3.00	2.65	197	4.62	4.50	10.0
2019	1,855	46,078	3.06	1.47	217	3.65	4.50	10.0
2020	2,049	47,000	3.12	0.80	236	3.16	4.50	10.0

* Project Finance Spreads (PF Spreads) are set to 40bps above the BBB-rated bond spread.
** Project Finace Debt (PF Debt) is comprised of the 7 Year Interest Rate Swap and PF Spread.
*** The assumed Refinancing Rate (Refi Rate) is modelled as a collar around 4.5 - 7.5%.

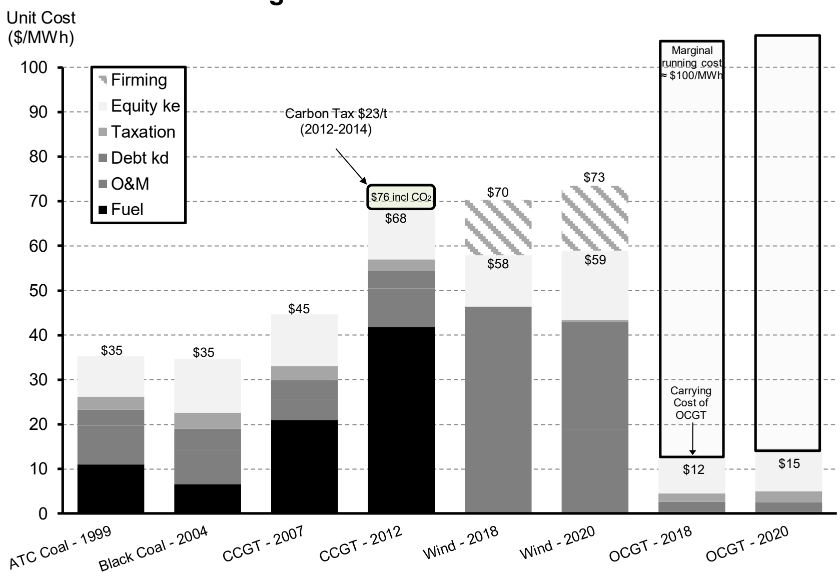
Source: BNEF, Reuters, RBA, Simshauser & Gilmore (2019).

PF Model results are presented in Fig.1. Note 2012 isolates impacts of the (defunct) $23/t CO_2 tax – we exclude these in all subsequent analyses. Wind results for 2018 and 2020

[5] The average credit spread for Project Financings has been 1.92% with a tenor of 6.9 years. Early projects typically secured long-dated money (i.e. 10-12 year facilities) but more recent projects gravitate to 5-year money. For PF spreads over time, we have priced these at 40 basis points (bps) over BBB corporate bond spreads for modelling purposes. This seems to align reasonably well with our private data on Project Finance credit spreads.

comprise two components, i). underlying run-of-plant cost estimates of $58 and $59 respectively, and headline results including “firming[6]” at $77 and $81 – with firming derived from the carrying cost of OCGT plant (in 2018 and 2020) of $12 and $15, respectively.

Figure 1: PF Model New Entrant Costs



4. Is Australia’s NEM Broken?

Strains on Australia’s NEM during 2016/17-2019/20 were very significant. A black system event, sharply rising wholesale (and therefore consumer) prices, large deviations in power system Frequency, project connection lags, unexpectedly large variations in Marginal Loss Factors and new modes of power system failure emerged in the post-entry environment. One could be forgiven for concluding Australia’s NEM had broken. Some argue it has.

But apparent market underperformance, deviations and market frictions in the post-entry environment need to be catalogued and diagnosed carefully to ensure policy proposals target underlying (and agreed) problems rather than respond to transient symptoms, ‘outlier’ events and second-order issues. Fundamental policy changes or market redesign would involve mass disruption, create new and unanticipated problems, and generate sizable transaction costs which are notoriously difficult to quantify ex ante. Above all, experience with fundamental policy change and market redesign here and abroad translates to years of stalled *“merchant”* investment commitment – and may (ironically) ultimately require central intervention[7]. In Sections 4-5 we review NEM parameters with a view to identifying market frictions worthy of policymaker attention.

4.1 On investment in new plant

A persistent concern with the energy-only market design is whether Resource Adequacy can be maintained over time. Grubb & Newbery (2018, p.5) summarised the precursor to central intervention in Great Britain’s energy-only market as follows:

> *To the unavoidable economic uncertainties— associated not only with future market conditions but also the likely level, timing and frequency of scarcity pricing—was added political uncertainty. Investment requires some confidence in the future*

[6] Supercritical Coal and CCGT are both dispatchable plant whereas Wind is intermittent making direct comparison problematic. However, a Wind generator (producing energy) combined with a fast-start OCGT plant (providing dispatchable capacity, but only when required) provides a more meaningful comparison. However, this combination relies on gains from exchange in organised spot markets. For further details see Simshauser (2020a).

[7] As one Reviewer noted, centrally coordinated long-term contracts for capacity and for VRE will stimulate investment under such conditions.

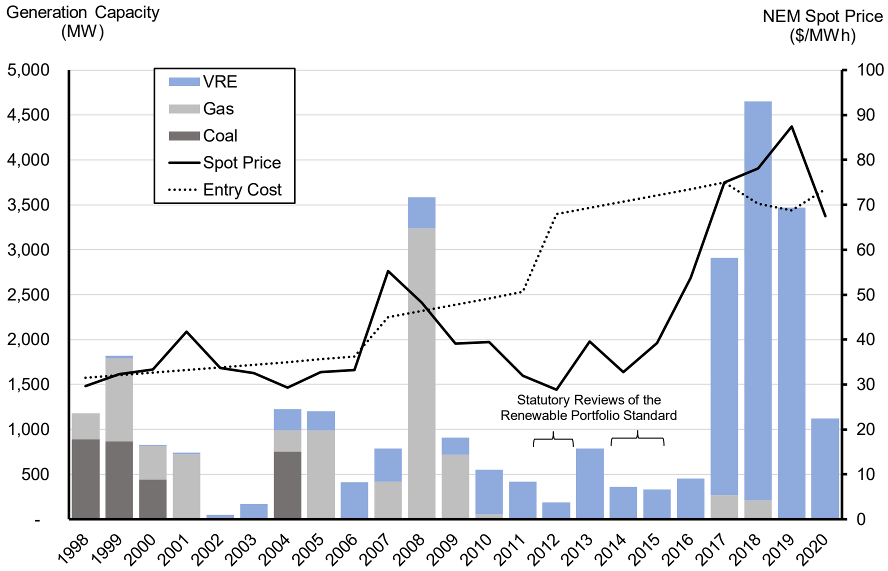
> *political landscape and the determinants of the wholesale electricity price, which one could at least plausibly estimate or hedge. However, UK energy policy had been in turmoil for most of the post-1997 period when the Labour Party came to power, with arguments over the role of coal, gas, renewables, and especially nuclear power. There were four Energy White Papers from 2003–2011. The lack of any futures market combined with these multiple and often inestimable economic and policy uncertainties clearly deterred new investment in the UK's energy-only market…*

While the Australian experience regarding political interventions and policy discontinuity have obvious parallels to Great Britain (Section 2.2), practical out-workings have been different. Unlike Great Britain, the NEM's core market design has remained entirely stable over its 23-year history and in consequence, aggregate investment in generation capacity has been very significant. To be clear, VRE investment flows were 'critically punctured' (2013/14-2015/2016) but not eliminated, as Fig.2 illustrates.

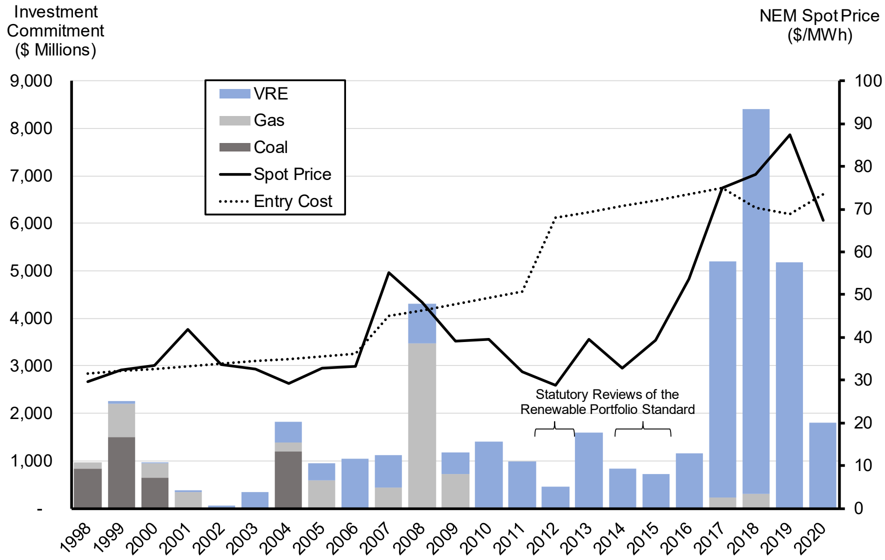
By way of background, the NEM's opening plant stock in 1997/98 comprised ~33,000MW of generating capacity producing 141TWh per annum. By 2020, the generation fleet had expanded to 55,000MW with 205TWh production. New capacity additions of 28,147MW were committed from 1998-2020. Fig.2 data illustrates a healthy relationship between investment commitment (LHS axis) and price (RHS axis).

Figure 2: Generation plant commitments 1998-2020

2a – Capacity (MW)



2b – Investment ($ Millions)



Source: ESAA, Company Reports, BNEF.

Most non-VRE investments have been merchant and facilitated by industrial organisation. For example, vertical utilities have been responsible for ~75% of all gas-fired plant entry (Simshauser, 2020b). The surprising feature of the 2017-2020 megacycle has been the number of long-dated, ~10+ year, Power Purchase Agreements originated to facilitate VRE plant entry, and the number of purely merchant (i.e. spot exposed) entrants. Approximately 79% of VRE projects in the megacycle were PPA-contracted, with the remaining 21% fully 'Merchant' or spot exposed (nb. a large number of PPA-contracted projects were also purposefully oversized to acquire residual spot market exposures). Our dataset contains 60 PPAs with 58% written by utilities – most of these presumably in response to the 2020 Renewable Portfolio Standard – and the remaining 42% split between Corporate PPAs (17%) and Government CfDs (25%). Evidently, Renewable Portfolio Standards are capable of driving financial market innovation and contract efficiency.

It is worth noting a sizeable proportion of NEM investments in Fig.2 qualified for Certificates in 'side markets' (Simshauser, 2018b). Prima facie this is distortionary vis-à-vis the energy-only market design. But Australian side markets have merely priced a carbon externality (an otherwise 'missing market' in the NEM) by various mechanisms (see Simshauser & Tiernan, 2019). Furthermore, Australian side-markets are transparent, liquid and commodity-based in nature (i.e. there are no guaranteed prices or fixed payment streams). Consequently, Certificate side-markets carry considerable price and volume risk in their own right (as Fig.19 later illustrates) with investment error borne by power project counterparties, not captive franchise consumers. Moreover, side markets will continue – VRE Certificates are ultimately a CO_2 derivative and a form of CO_2 currency – and the efficiency of markets means they will ultimately become fungible with Australian Carbon Units – used by utilities to acquit legislative requirements, and by corporates to acquit their obligations to institutional investors (i.e. voluntary/ESG) given the absence of formally binding sectoral targets in Australia.

Fig.2 confirms substantial investment but says little with respect to investment timing, which we address in Section 4.2.

4.2 On investment timing

Like most global market designs, the NEM has provided an effective platform for investing in new generation, and as Fig.4-6 subsequently reveal, with high levels of Reliability.

Several US jurisdictions have organized Capacity Markets which, to generalize, arrange auctions for firm capacity or demand response three years ahead in order to meet administratively determined Reliability Standards and Reserve Margins.

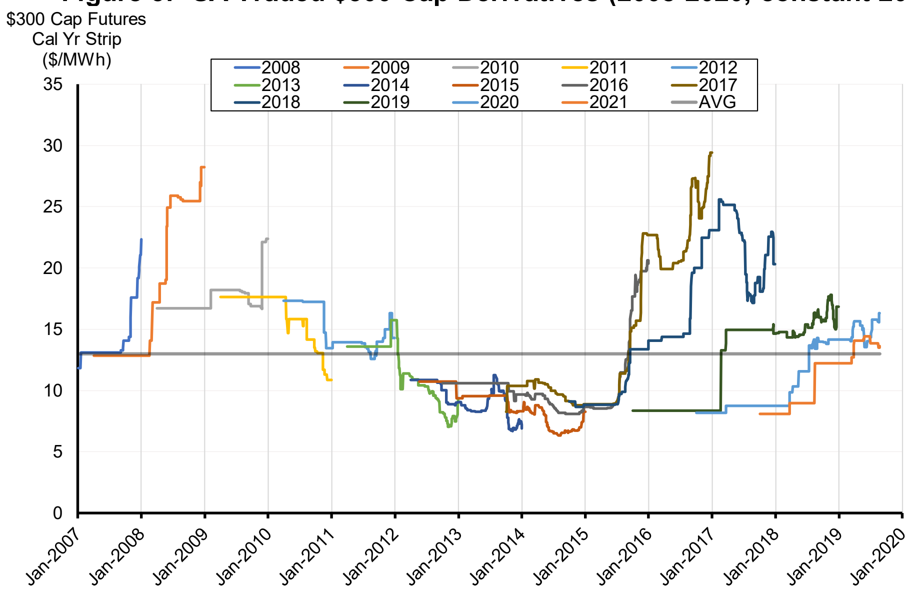
The NEM does not have an organized Capacity Market. But it does have organized and liquid (i.e. ~350% of physical) forward derivatives markets for Swaps and Caps (the latter being a Capacity-market equivalent). Put another way, an administratively determined Capacity Reliability Mechanism seeks to maintain a certain level of reserves, while the NEM's equivalent is the $14,700/MWh Market Price Cap (and the Retailer Reliability Obligation[8]) which guides investment commitments[9]. The NEM's forward markets are the quintessential link between physical (spot market) requirements, investment requirements and Resource Adequacy given the NEM's Reliability Standard of *not more than 0.002% Lost Load*.

A common concern raised by Australian policymakers and institutions is that, with rising levels of VRE, peaking plant may operate as little as a few hundred hours per year – and by deduction presume such plant cannot be economic. For a stand-alone peaking plant reliant on spot markets for revenue, this is no doubt correct. But this overlooks historically equivalent conditions and the practical evidence, viz. $10.4 billion (8456MW) of investment in gas-fired generation.

Peaking plant are not reliant on operating hours to generate revenue. Revenue is derived from the spot market, forward markets (with ~30% premiums[10] ex post) and crucially, industrial organisation. NEM forward markets have a relatively short tenor (i.e. 3 years and are most actively traded 18 months out) and consequently tends to *guide* rather than *underwrite* investment (to be sure, as practitioners we consider fundamental power system planning to be the critical determinant of investment commitment). More important for peaking plant are the various forms of industrial organization by matching such capacity with stochastic retail loads (Simshauser, 2020b) or stochastic generation (Simshauser, 2020a). Firms then actively internalize Cap value in longer tenors within integrated portfolios, and sell residual capacity into forward markets. And as Figure 3 illustrates – the average value in forward markets over the business cycle has been ~$13/MWh, which aligns reasonably well with our $14.50/MWh estimate of the new entrant cost of an OCGT plant with *'zero'* run-hours.[11]

[8] This mechanism, when triggered, requires Retailers to accumulate firm contracts and/or physical capacity equivalent to their Peak Demand at 50% Probability of Exceedance.
[9] Note that all mechanisms fail if exit-driven shortfalls are not projected in advance.
[10] Historically, traded Caps delivered ex post premiums of ~30% (time averaged) over the cycle (and negative premiums ex post one-year-in-ten). This is an expected outcome given the nature of the instrument, viz. an insurance product connected to the NEM's very high Market Price Cap of $14,700/MWh.
[11] The point here is that 'under Cap revenues' are capable of making up the difference when run hours are not zero.

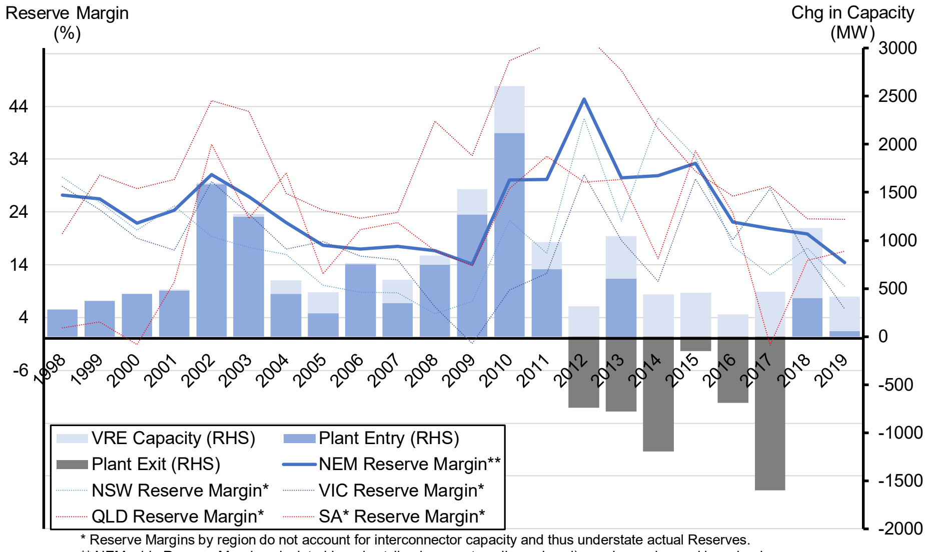
Figure 3: SA Traded \$300 Cap Derivatives (2008-2020, constant 2020\$)



Source: Simshauser, 2020a.

With this background, we analyse the responsiveness of the NEM's aggregate plant stock in Fig.4. The LHS-axis measures VRE-adjusted Reserve Margins (%) and RHS-axis measures plant entry and exit (total MW). As an aside, the NEM-wide (stylized[12]) Reserve Margin exhibits a -0.49 correlation with spot prices, as one might expect.

Figure 4: Reserve Margins, Plant Entry & Plant Exit 1998-2019



* Reserve Margins by region do not account for interconnector capacity and thus understate actual Reserves.
** NEM-wide Reserve Margin calculated here is stylised across two dimensions i). maximum demand is a simple sum-of-the-regions maximums rather than coincident demand, and ii) generation is aggregated without any adjustment for interconnector constraints. 5.5% of Solar and 8% of Wind capacity contribute to the Reserve calculation.

Source: ESAA, AER, AEMO, BNEF.

An important insight from Fig.4 is changes to aggregate capacity from 2012-2017. Note NEM-wide Reserves increased sharply from 2009-2012 as new gas plant commitments (2007-2009 – see Fig.2a) were progressively brought into service (and almost simultaneously, NEM demand began to contract 2010-2015). The sharp rise in Reserve Margins led to falling spot (Fig.2) and forward (Fig.3) prices, which in turn triggered an exit procession (Tab.3), the effects of which are clearly visible in Fig.4. Ultimately Reserve

[12] The Reserve Margin adjusts for the firmness of VRE, but treats the plant stock as if a perfect transmission system exists.

Margins returned to historical levels. The exit speed of the final two plants in Tab.3 was problematic – its implications discussed in some detail in Simshauser (2019b).

Table 3: NEM Coal Plant Exit (2012-2017)

Coal Plant	Capacity (MW)	NEM Region	Exit (Year)	Enter (Year)	Age at Exit (Years)	Warning (Months)	Notice Date	Closure Date
Swanbank B	500	Qld	2012	1972	40	23.6	26-Mar-10	27-Mar-12
Playford*#	240	SA	2012	1960	52	6.9	7-Oct-15	8-May-16
Collinsville	180	Qld	2013	1972	41	5.9	1-Jun-12	1-Dec-12
Munmorah~	600	NSW	2013	1969	44	0.0	3-Jul-12	3-Jul-12
Morwell	195	Vic	2014	1958	56	1.0	29-Jul-14	30-Aug-14
Wallerawang~	1000	NSW	2014	1978	36	0.0	1-Nov-14	1-Nov-14
Redbank	151	NSW	2015	2001	14	0.0	31-Oct-14	31-Oct-14
Anglesea	150	Vic	2016	1969	47	3.6	12-May-15	31-Aug-15
Northern#	540	SA	2016	1985	31	6.9	7-Oct-15	8-May-16
Hazelwood	1600	Vic	2017	1967	50	4.8	3-Nov-16	1-Apr-17
Total / Average	5156			1972	42.5	5.2		

* Mothballed in 2012

\# Original notice 11 June 2015 with planned closure date of March 2018

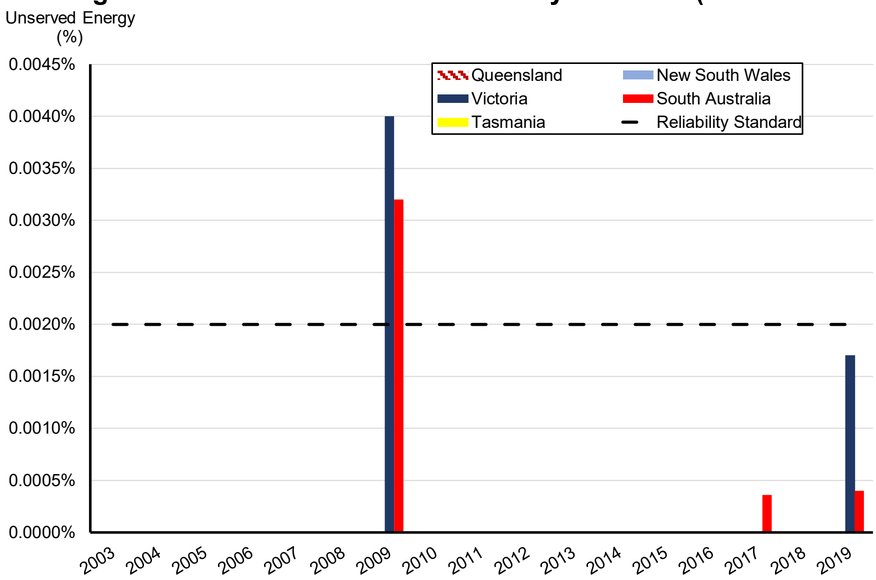
~ Mothballed, Notice was therefore immediate

Source: Simshauser & Tiernan (2019).

4.3 On reliability of supply

The 'NEM Reserve Margin' in Fig.4 implies a perfect transmission system exists, whereas in practice interconnectors bind during peak demand events. The State-based Reserve Margins in Fig.4 adopt the other extreme and assume no interconnection (and therefore present an excessively conservative view). Nonetheless, this view implies Resource Adequacy constraints in 2000, 2009 and 2017 (and tight conditions in 2019). Of these, 2009 was material but largely driven by a very significant (weather-driven) increase in VIC and SA maximum demand, with coincident network limitations binding within VIC and in TAS (Rai et al 2020). As Fig.5 illustrates, this is the *only* occasion where the NEM's Reliability Standard (*0.002% Lost Load*) was breached.

Figure 5: NEM Lost Load vs Reliability Standard (2002/03-2019/20)



Source: Reliability Panel.

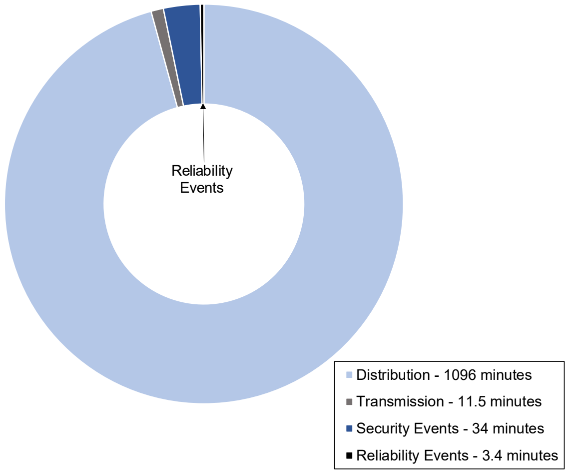
More recent episodes of Lost Load (2017, 2019) are a product of the speed of coal plant exit, and entry lags as Section 5.5 later explains. These were unforecastable events – the Market Operator was not predicting a breach of the Standard in the three-year period leading up to coal plant exits in 2016/17 (and to be clear, nor did any other marker participant – including forward markets as Fig.8 subsequently reveals). Conversely, closer to real time Emergency Trader Provisions were activated in a manner consistent with the

NEM design.[13] Centralised capacity procurement would *not* have resulted in different outcomes (absent costly and erroneous ex ante over-procurement).

The NEM's investment signals therefore appear to have operated exactly as intended. A separate question is whether the current Reliability Standard is appropriate. The 0.002% Lost Load Standard was set with regard to minimising total costs to consumers given the marginal cost of supply and consumers' Value of Lost Load[14]. Both the Standard and the Market Price Cap required to achieve it have been regularly reviewed. The Market Price Cap has increased over time, but until recently no changes have been recommended by the NEMs Reliability Panel. In March 2020, the Energy Security Board recommended a (non-trivial) tightening to *0.0006% Lost Load*. This was largely driven by concerns around current sensitivities to the existing 0.002% Standard (i.e. potential long-tail). Shifting to 0.0006% would ordinarily require a radical recalibration of the Market Price Cap – from $14,700/MWh to c.$40,000/MWh – but in this instance a medium term out of market Reserve is to be procured by the Market Operator.

It is notable that the overwhelming majority of supply interruptions occur at the distribution network level (1096 minutes) as Fig.6 notes. And, interruptions relating to power generation are dominated by real-time Security events (34 minutes) rather than Resource Adequacy (3.4 minutes). We shall return to Security of Supply in Section 5.

Figure 6: Sources of supply interruptions (2009-2019)



Source: Reliability Panel.

4.4 On the efficiency of wholesale prices

Wholesale price rises from 2016/17 were acute, unexpected and adversely impacted a wide array of consumers. Section 1 outlined initial triggers, viz. coal plant exit, a tight gas market and entry lags. But, as Figs.7-8 illustrate, prices largely reflect market fundamentals (albeit amplified by a transient market power event in early-2017[15]).

---

[13] An important feature of the NEM is the ability of the Market Operator to step-in and procure additional Resources if the Reliability Standard is forecast to be breached. These emergency powers have been utilised over time, and have served the market well. Under the Rules, they are triggered up to 9-12 months in advance if forecast Lost Load is expected to breach the Reliability Standard. Sources of supply are typically Demand Response (closing the gap between the Value of Lost Load and the Market Price Cap) and out-of-market emergency generation packs (e.g. diesel gensets).

[14] From a power system planning perspective the overall objective function is to minimise

$$VoLL\ x\ Lost\ Load + \sum_{i=1}^{n} c(R)\ |\ VoLL\ x\ Load\ Load + c(\hat{R}) = 0,$$

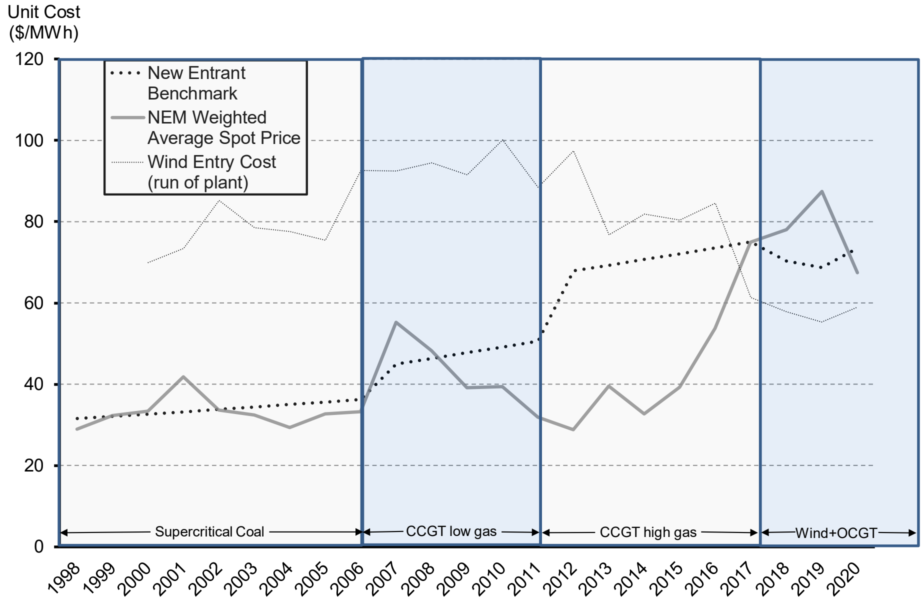
where $VoLL$ is the Value of Lost Load and where $c(R)$ is the cost generation plant, and $c(\hat{R})$ is the cost of peaking plant capacity. Provided these conditions hold, it can be said there is a direct relationship between the Reliability Standard and the Market Price Cap. An alternate expression where reliability criteria is based on Loss of Load Expectation is $LoLE = CONE/VoLL$, where CONE is the cost of new entry. For an excellent discussion on the relationship between a Market Price Cap and Reliability criteria, see (Zachary, Wilson and Dent, 2019).

[15] See Australian Energy Regulator, 'State of the Energy Market 2018' at page 113 (esp. Figure 2.27).

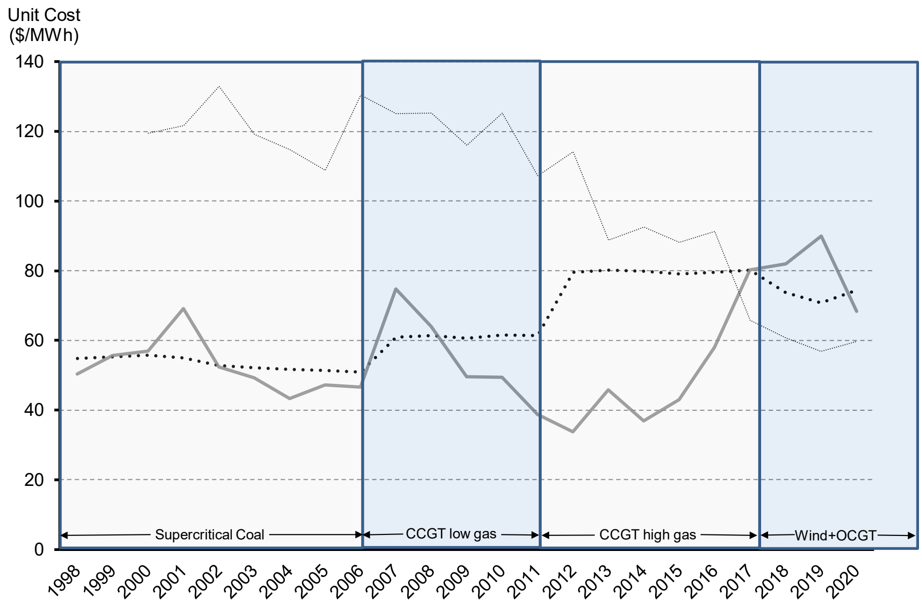
In order to analyse the efficiency of wholesale prices, suitable comparative benchmarks are required. Results from Fig.1 have been transposed to a timeseries and compared against annual spot prices and wind entry costs (Tab.2) in nominal and constant 2020 dollars (Fig.7). Prices, while rising sharply from their 2013/14 lows, do not reveal sustained excursions above the cost of entry. Indeed, as Fig.2 aptly illustrated, each excursion above benchmark was met with a sizable supply-side response.

Figure 7: New entrant cost vs Spot Prices (1998-2020)

7a - Nominal Dollars



7b - Constant 2020$



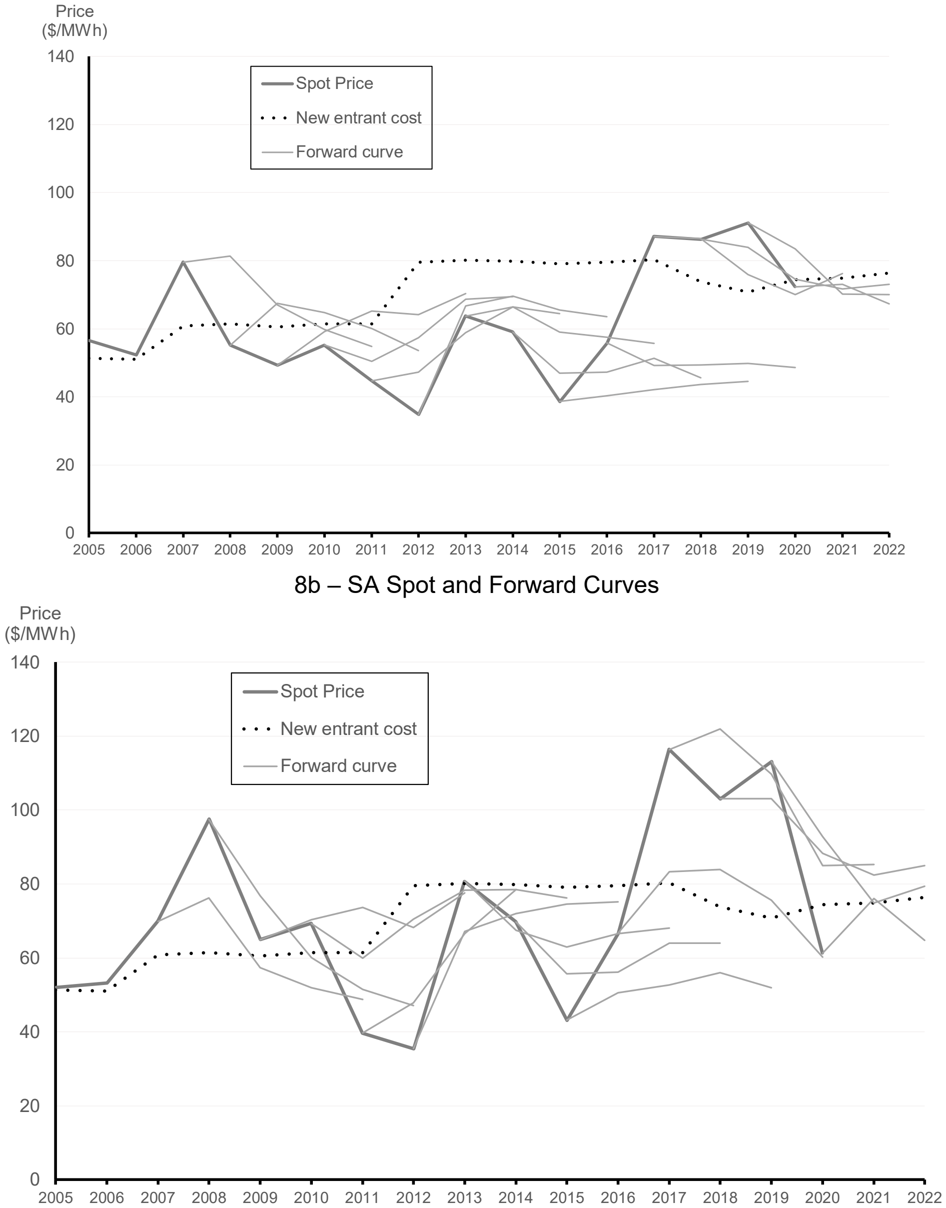
Source: Simshauser & Gilmore (2019), AEMO, ABS.

NEM Spot (Fig.7b) and Forward (Fig.8) prices have largely followed the pattern of market imbalances (Fig.4) and are mean reverting, exhibiting elongated business cycles typical of energy markets generally (see Pindyck, 1999; Simshauser, 2010; Arango and Larsen, 2011; Cepeda and Finon, 2011; Bublitz *et al.*, 2019). Fig.8 presents (baseload) forward curves from two NEM regions by way of example. Forward markets missed the rapid coal closures which caused the surge in spot prices from 2016-2018, and from 2018 the forward curves (in backwardation) continuously drifted sideways – the reasons for which are examined in Section 5.5 – but trend towards the new entrant cost.

Figure 8: Spot and Forward[16] Price Curves 2005-2022 (constant 2020$)

8a – NSW Spot and Forward Curves

8b – SA Spot and Forward Curves



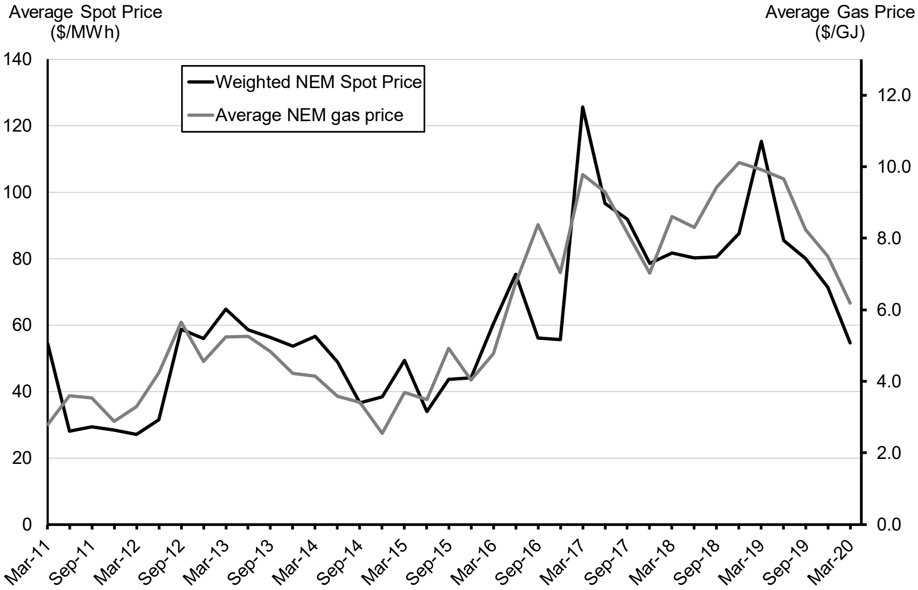
Source: AEMO, SFE, ABS.

Fig.7-8 confirm prices have not been maintained beyond the cost of entry but says little of the allocative efficiency in between peaks. To analyse relative allocative efficiency, Fig.9 contrasts Quarterly Average Gas prices with Quarterly Average Spot Electricity prices. Once again, we do not identify sustained variations with the correlation over time being 0.89.

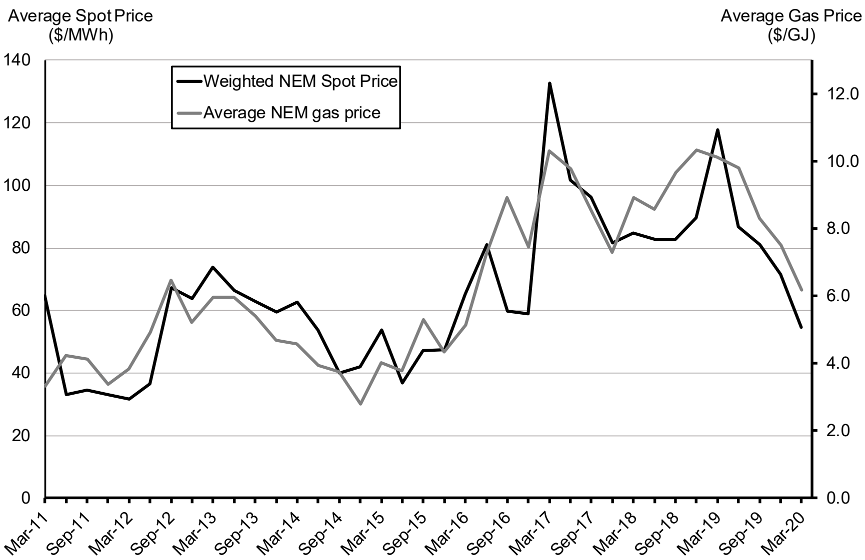
[16] Note price data in these Figures are CO2-inclusive from 2012-2014.

Figure 9: Quarterly Average Gas vs Electricity Prices

9a – Nominal Dollars



9b – Constant 2020 Dollars



Source: AEMO, ABS.

To be sure, electricity prices over 2017-2020 are high in absolute terms relative to recent history but this reflects sudden coal plant closures, falling market imbalances and rising underlying resource costs rather than a failure of the market to efficiently price supplies. Furthermore, forward prices (Fig.8) have consistently trended downwards given new investment commitments – reinforcing our view that investors are making rational (and efficient) decisions.

4.5 Summary

To summarise, new investment commitments in the NEM have totalled $52.6 billion, with forward markets pricing capacity over the cycle and – at least based on the evidence – delivering capacity on a timely basis with the Reliability Standard having been met with few exceptions. Prices have largely reflected underlying resource costs with excursions above entry benchmarks routinely met by a wall of supply-side investments.

The Market Operator has stepped into the market 2017-2019 and used Emergency Trader provisions in response to near-term concerns vis-à-vis Resource Adequacy. The SA Government similarly stepped in following the pace of coal plant exit. One should be cautious pointing to this as evidence of a market design failure. Firstly, use of these provisions was necessary due to the speed of unforecasted coal plant closures as Fig.4 and Fig.8 illustrated (and the absence of an exit policy – see Simshauser 2019b), entry lags (see Section 5.5) and tangential policy interventions (Section 7). Furthermore, Emergency Trader provisions are a fundamental component of the NEM market design – if they had failed, there may then be a basis for claiming a market failure.

The NEM's good news ends at this point.

5. The 2017-2020 Investment Megacycle: Consequences

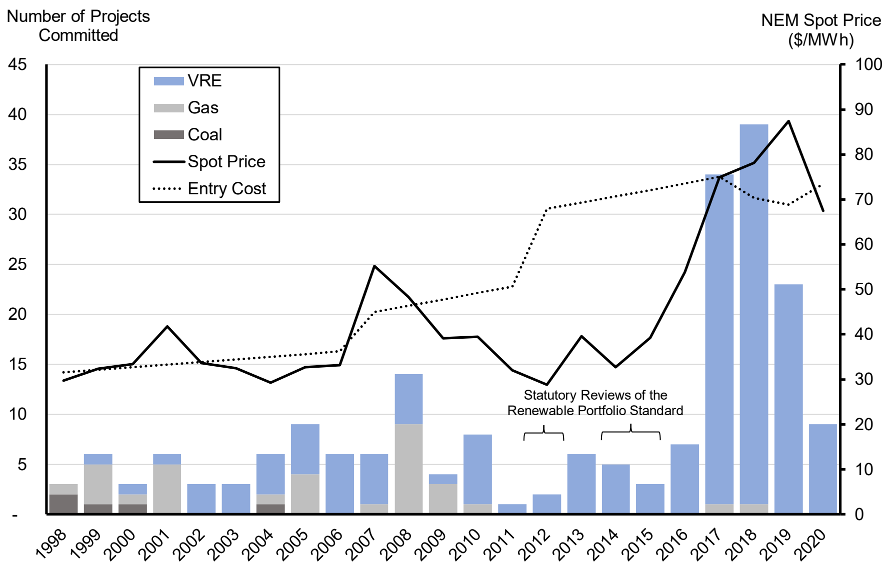
Recall from Fig.2 that 2017-2020 prices induced a sizeable supply-side response. Australian energy markets are not foreign to an *excess entry result.* Indeed, as Armstrong et al. (1994) explain it is quite common in homogeneous commodity markets. What was unusual about Australia's 2017-2020 cycle was the source and pattern of investment. Traditional utilities accounted for just 15% of direct VRE investment commitments and only 58% of underwriting efforts by way of Power Purchase Agreements (PPA). The balance of investments were by Developers (48%) and Superannuation/Pension Funds (36%) with a surprising ~20% of VRE developments being *"purely merchant"* (spot exposed) – a product of very high spot prices and falling VRE entry costs as Fig.20 subsequently reveals.

5.1 Project Numbers

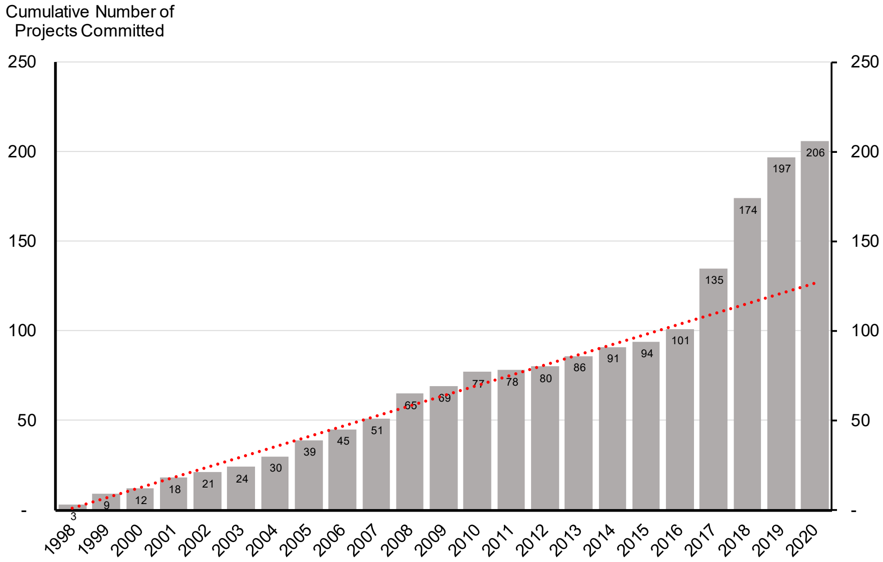
The data in Fig.2 did not reveal the extraordinary number of investment commitments. By historic standards, 2017-2020 could only be described as a cyclical boom, as Fig.10 reveals. Note in Fig.10b that the cumulative count for projects by 2016 was 101 with a relatively steady trajectory (see trend line) over the period 1998-2016. From 2017 the number of project commitments exploded with, as Fig.20 subsequently reveals, supranormal profits driving excess entry.

Figure 10: Absolute number of utility-scale projects

10a – Number of Investment Commitments



10b – Cumulative Number of Investment Commitments



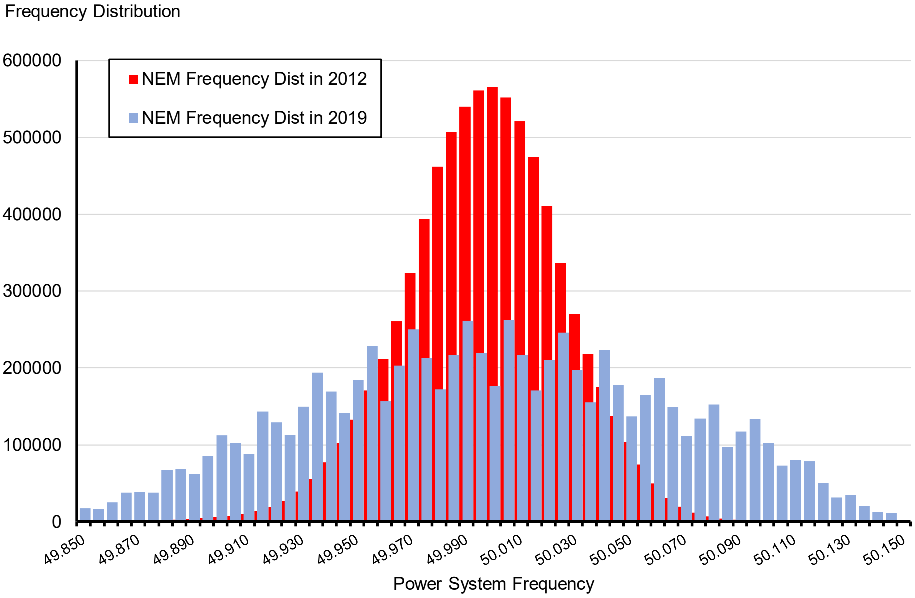
From 1998-2016, the 5-region NEM connected an average of 5.3 power projects per annum. Over the next three years, power project connections increased by 602% to 32 projects per annum. Ex ante, when 105 utility-scale developments reach irreversible investment commitment in the space of four years in a power system the size of the NEM, it is beyond belief that all will present as sound economic and engineering power projects, ex post. Significant investment mistakes in retrospect can be expected in *gold rush* conditions. Investment mistakes did occur, amplified by network connection lags, network congestion and voltage instability necessitating ex post remedial capital expenditure due to failing system strength. As following sections reveal, the *Rate of Change* evidently proved too much for many NEM parameters.

5.2 On Security of Supply

In hindsight, the speed of entry (i.e. 105 projects in 4 years) was striking. If there was one set of parameters that stands out from all others in pointing to a broken market in the context of trying to digest this dramatic Rate of Change, it is the deteriorating performance of the NEMs *security of supply* (viz. maintaining Frequency 50Hz, and voltages +/-10%). With the rapid entry of VRE projects and gradual reductions in the supply of Primary Frequency Response, the Market Operator is encountering new modes of failure, contingent events previously considered non-credible, and failing system strength – particularly in the renewables-rich SA Region.

Fig.11 contrasts the distribution of power system Frequency in 2019 with 2012. As coal plant began to close (i.e. from 2012-2017), the distribution of power system Frequency began to deteriorate, with marked acceleration from 2016 onwards. By 2019, the variation in Frequency was more than 200% of the 2012 result.

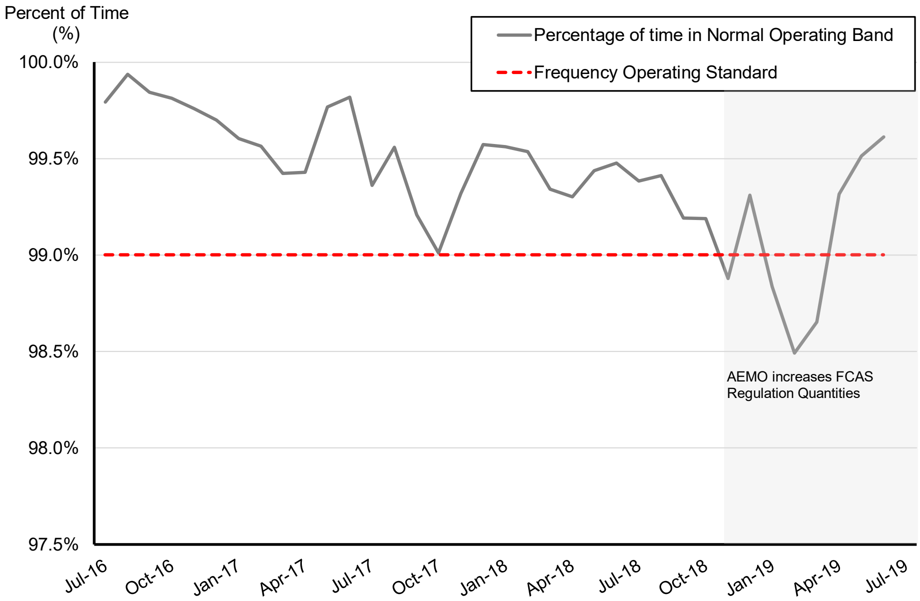
Figure 11: Distribution of NEM Frequency (4 second data 2012 vs 2019)



Source: Reliability Panel

The NEMs Normal Operating Band is 50Hz +/-0.15Hz, and the Frequency Operating Standard specifies the power system should be maintained within this Band >99% of time. Midway through 2018/19, Frequency careered outside the Standard as Fig.12 illustrates.

Figure 12: Frequency vs Frequency Operating Standard



Source: AEMC

Yet, the deterioration in Frequency and transient breach of the Frequency Operating Standard merely reflected changes in system resources[17]. The administratively determined level of demand for Frequency Regulation services had historically been set to ~130MW with Frequency Contingency Services typically comprising a further 620MW under most system conditions (i.e. a total of 750MW and equivalent to an n-1 FCAS suite). Frequency Regulation quantities had been set in 2004 when the NEM had virtually no VRE. Quantities were (*finally*) reviewed from 3 October 2018 (Simshauser, 2019a) and based on Fig.12 data, it would seem not before time. A non-trivial increase in Frequency

[17] Including some generators that detuned governors in response to conflicting regulatory signals.

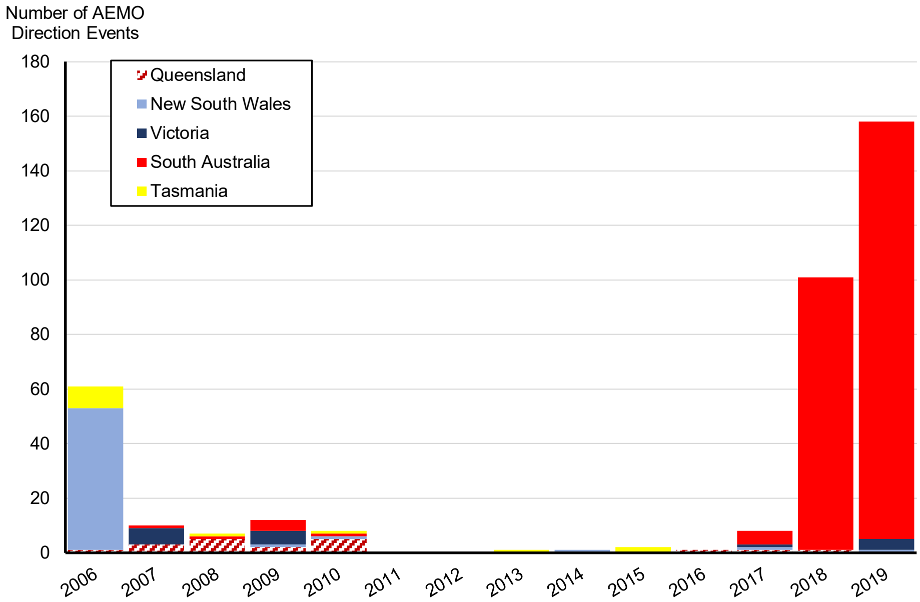
Regulation would follow, rising from 130MW to 220MW (and at times to as much as 350MW).

To be clear, no Rule or regulation prevented an earlier revision of necessary quantities[18], and as more VRE enters we should anticipate rising FCAS quantities and new FCAS services to deal with new risks – by way of example, the n-1 suite will ultimately be surpassed by forecast uncertainty as a more probable mode of failure.

5.3 On failing system strength

Sharply rising levels of asynchronous VRE and the consequential demise of synchronous coal generators in the renewables-rich SA region has had adverse implications vis-à-vis power system strength. As a direct consequence of this, the NEM has seen a continuous rise in market interventions by the Market Operator as Fig.13 illustrates. In 2019 there were 158 Directions – 153 of these related to system strength in the SA region (i.e. AEMO 'constraining on' synchronous gas-fired generators during typically high wind / low to moderate demand conditions). Failing system strength has also presented itself in Western Victoria (Nov-2018) and Far North Queensland (Mar-2020).[19]

Figure 13: Number of AEMO Interventions



Source: Reliability Panel.

The Market Operator is now being forced to intervene in the NEM on an almost daily basis, which some argue is evidence of NEM market failure. This is not correct. It is necessary to distinguish between electricity market design failure, and missing markets. In our view, this is a clear-cut case of a missing market (i.e. unpriced system strength services vis-à-vis inertia and voltage stability). Alternate market designs would not reduce the number of interventions – only identification, pricing and scheduling of the relevant services and constraints will. In SA, the lowest cost solution proved to be the installation of three

[18] The NEMs Frequency Operating Standard does not place any specific requirement or limitation on AEMO as to how Frequency should be maintained *within* the normal band – AEMO are in effect free to select the appropriate mix and quantity of services to procure. Currently, this includes Frequency Regulation and three forms of Frequency Contingency Services (i.e. 6 second, 60 second, 5 minute). Apart from increasing the quantity of FCAS Regulation, AEMO have not chosen to augment their Services. The authors sponsored a Rule Change to add Fast Frequency and Operating Reserves to the FCAS suite – see Section 7.

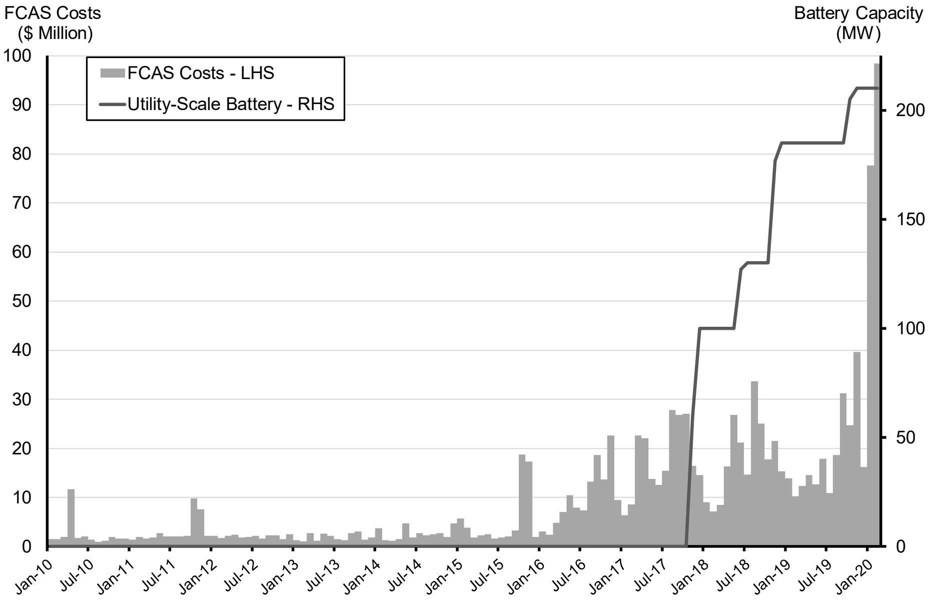
[19] For further details, see Reliability Panel AEMC, (2020), "2019 Annual Market Performance Review", Reliability Panel Publication, Sydney. Available at https://www.aemc.gov.au/market-reviews-advice/annual-market-performance-review-2019

synchronous condensers (as regulated assets[20]) which once commissioned are expected to immediately remove the need for the SA Directions in Fig.13.

5.4 On Frequency Control Ancillary Services (FCAS)

Perhaps unsurprisingly, a corollary to Section 5.3-5.4 is an increase in FCAS market prices (i.e. spot markets for Frequency Regulation, and 6 second, 60 second and 5 minute Frequency Contingency). Monthly FCAS costs are highlighted in Fig.14, and are dominated (on a proportionate basis) by one of the smallest regions (SA – following the exit of the last coal plant). To generalise, FCAS costs tend to rise in the peak wind production season (i.e. July-Sep) when asynchronous wind generation is highest and consequently, synchronous thermal generation is lowest.

Figure 14: NEM FCAS Costs 2010-2019



Source: AEMO, BNEF.

But the rise in FCAS prices also triggered a supply-side response following the initial (and, evidently, warranted) rapid intervention by the SA Government with their underwriting of the 100MW / 135MWh Tesla Battery. Battery Storage investments have since streamed into the market, with aggregate capacity now approaching typical FCAS Regulation quantities. Battery response times are measured in milliseconds, and this capability can, should, and at times is, used. However, there is currently no market for FCAS Fast Frequency Response which would otherwise improve system 'resilience' to new modes of failure, including low inertia conditions – it is a *missing market*.

5.5 On connection lags

From 2018-2020, the NEM baseload forward curve was in persistent backwardation, but the front end of the curve seemed to continually 'drift sideways' as Fig.8 illustrated. Forward markets had assumed, erroneously, that apart from scheduled construction lags new entry would be frictionless and therefore prices would fall. That assumption proved manifestly wrong. Entry frictions beyond construction lags exceeded all expectations.

Stock analysts at Bank of America Merrill Lynch undertook a project-by-project analysis of total observed development delays and showed an average 'additional' entry lag of 33 weeks (7½ months) per Tab.4. Parallel analysis by ARENA (2020) and Australia's Clean Energy Finance Corporation across 14 utility-scale solar PV projects found an average

[20] Not all missing markets warrant the transaction costs associated with organised spot markets, while in others instances an organised market exchanger may fail due to inadequate competition.

additional entry lag of 38 weeks (~8½ months) compared to original construction schedules. Central to lags was the rapidly changing Network Connection process. Furthermore, post-connection R2 validation commissioning testing (i.e. ensuring actual performance equates to pre-connection modelled performance) would constrain output levels below maximum practical output – in the case of the ARENA sample - for an *additional 28 weeks* on average.

Table 4: Observed Delays of Development Projects under construction in the NEM

Source: Bank of America Merrill Lynch[21]

Grid connection has never been easy, and nor should it be given the consequence of error. Following the 2016 black system event in SA (sparked by 4 wind farms failing to meet s5.3.4A Generator Performance Standards), a *'do not harm'* clause was added to the Rules which required all new connecting generators to undertake a *Full Impact Assessment* with a special focus on system strength (s5.3.4B of the Rules). Networks and the Market Operator simply weren't ready for Rule change implementation – and project proponents, Original Equipment Manufacturers and Project Banks were all caught out as a result.

Physical system models were being refined *on the fly*, and under the new Rule multiple iterations of connection studies were being undertaken while modelling capacity and

[21] See Low and Yang, (2019), "The National Electricity Market (NEM): the capacity bomb is still coming", *Bank of America Merrill Lynch*, Australian Utilities Equity Research, 2 October 2019.

precision attempted to catch up with physical realities – all of which contributed to the results in Tab.4 and in ARENA (2020). Networks and the Market Operator were using different models which produced different results, adding to confusion.

In the classic case, a VIC region solar PV project could not connect until it had installed a Synchronous Condenser – a c.$20m capital cost incurred post-financial close. Other projects connected but faced binding production caps for 6-12 month windows which adversely affected revenue streams and debt servicing capacity – the most well-known case involving five VRE projects in a rhombus-shaped area of remote western Victoria and remote southwestern NSW, which subsequently became known as *'the Rhombus of Regret'*.

Unintended consequences would follow. Investment commitment and Financial Close had historically occurred on the strength of a 'draft' s5.3.4A letter of approval and a draft Network Connection offer (the former being a pre-condition of the latter) with Final documents negotiated during construction. The prospect of incurring greatly increased construction costs post-Financial Close, or facing elongated binding production caps while Full Impact Assessment studies were resolved, meant Project Banks altered their conditions precedent – rather than drafts, Banks would now require *final* s5.3.4A, s5.3.4B approvals, and final Network Connection Agreements *before* Financial Close.

For all new projects, a sizeable barrier to entry had just been erected.

In practical terms, developed projects now needed to be held in suspended animation for a period of ~6 months while Connection Agreements, Generator Performance Standards (s5.3.4A) and Full Impact Assessments (s5.3.4B) were completed. The process involves a complex four-way negotiation process between project proponent, Original Equipment Manufacturer (OEM), Network and Market Operator (and suite of expert advisors). Above all, it necessarily brings forward very sizeable components of detailed project design work involving material non-refundable capital expenditure prior to Financial Close – capital costs which used to be incurred post-Financial Close.

'Queueing' along the Connection *supply chain* was a predictable outcome as limited resources within Networks, the Market Operator, OEMs and even within the independent expert engineering advisory firms reached breaking point. Indeed, in our discussions with one of the wind turbine OEMs, almost 75% of their internal global grid connection experts were working on Australian projects, despite representing less than 10% of their worldwide order book, due to the complexity of the NEM's new connection Rules.

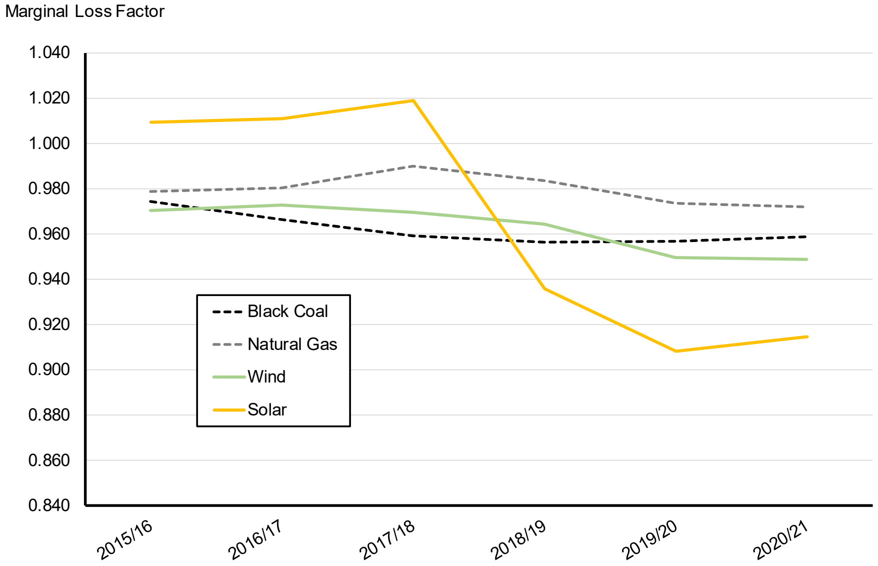
During the roughly 6-month period of 'project suspended animation', project sponsors are exposed to changes in equipment pricing, exchange rates, the cost (and availability) of capital, and the PPA underwriting the entire project. These are material risks, the reasons for which are axiomatic, and several instances of near-committed projects collapsed when time-sensitive capital or PPAs were 'pulled'. To compound matters, newly established projects were being subjected to new constraints as AEMO's modelling capabilities improved. Even high value, flexible assets such as Batteries were caught up in Connection lags[22].

[22] As practitioners, the authors were involved in a 25MW / 52MWh Battery Project and among the first to be exposed to a Full Impact Assessment under s5.3.4B of the Rules. The process was initiated on 23 May 2019 and was completed on 7 May 2020. Fortunately, an interim result issued late-Sep-19 allowed Battery connection from Oct-2019. The Network & the Market Operator couldn't agree on what scenarios to test, used different models which generated different results, and, frustratingly, the Network's Model couldn't initially integrate a battery. After a series of adjustments, the Full Impact Assessment initially indicated that the adjacent (13-year old) wind farm presented a system risk and was exposed to a marginal production cap. Six months later, Modelling results gave both the Battery and the Wind Farm a clean bill of health (i.e. it was evidently a modelling input issue – no change to plant was required).

5.6 Variations in MLFs - Marginal Loss Factors

VRE investor surveys reveal the most significant perceived risk to be shocks to Marginal Loss Factors (MLFs) ascribed to NEM generators (ARENA, 2020). MLFs, the static estimate of each individual generator's marginal network losses, are revised each year by the Market Operator. Variations in MLFs have historically been modest; for example the black coal fleet MLF has averaged 0.95+/-0.02 (Fig.15). However, a number of recent VRE investments have been subjected to dramatic MLF variations. This matters because Total Revenue = [Price x Quantity x MLF]. Fig.15 illustrates fleet-average MLF variations from 2016-2021 – the impact of the megacycle is most evident with the solar PV fleet-average falling from 1.0189 to 0.9081 – a change of more than 10 percentage points.

Figure 15: Generation Fleet MLFs, weighted by Installed Capacity



Source: AEMO

But the extent of these variations needs to be put into context. Of the 105 development projects committed in the cyclical boom, 2645MW or less than 30% of new projects were materially adversely affected by an MLF change (i.e. which we define as an MLF falling below 0.90). As Table 5 notes, 64% were solar projects. Interestingly, the traditional market-facing energy utilities who actively trade in the NEM's spot, forward and retail markets had virtually no exposure (~3%) *because* they all have an acute understanding of site-selection and MLF risk. Conversely, the new breed of non-traditional NEM VRE investors – who do not have large in-house development and trading teams, and no history of exposure to adverse MLF movements, viz. Pension Funds – are disproportionately represented (59%). The balance of adversely affected projects are owned by a small number of VRE Developers[23] (38%) as Tab.5 illustrates.

Table 5: Generating Capacity Materially Adversely Impacted by MLFs in 2020/21

	Wind	Solar	Total	*Owner*
Developer	-	993	993	*38%*
Pension	878	688	1,567	*59%*
Incumbent Utilities	75	11	86	*3%*
Total	953	1,692	2,645	
Wind/Solar	*36%*	*64%*		

Source: AEMO, BNEF, AEC, Company Reports.

[23] Most VRE developers faced minimal adverse effects. In discussions with a Partner from one of the Big 4 advisory firms, their analysis showed that across 20 developers, only 2 were materially adversely affected (and were evidently affected across more than 1 project).

While variations in MLFs have adversely impacted a number of VRE investors, this is a matter of producer surplus – consumer welfare is unaffected. Some have argued that variations in MLFs are a form of market failure and left uncorrected, will result in higher hurdle rates in future and sharp curtailment in VRE investment commitments (and point to current downward trends). More recently the AEMC has argued this is evidence of a need to shift to nodal prices.

We find both lines of argument unconvincing. The NEM comprises 55,000MW of generating capacity with over 400 generator connections. Adversely affected projects comprise 2645MW of generating capacity at ~30 (mostly very remote) sites, with an overrepresentation of solar PV connecting into 33kV and 66kV networks. These projects represent less than 5% of the plant stock and 30% of cyclical boom investment commitments. We noted at the outset that when 105 projects are committed in the space of four years in a long, skinny network like the NEM, it is beyond belief that all will present as sound economic and engineering propositions – significant mistakes in retrospect will be made.

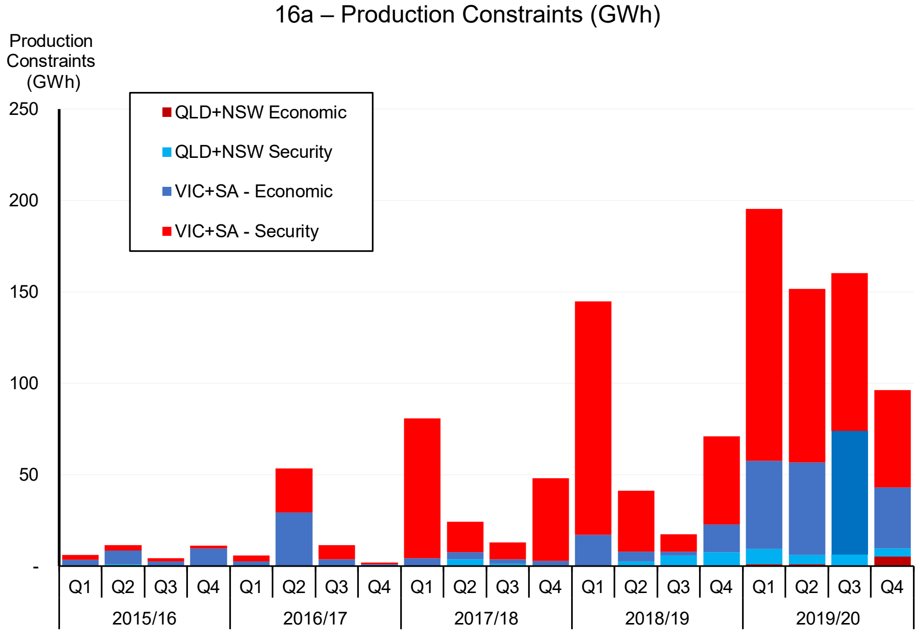
Proposals to move to average loss factors emerged. Unsurprisingly, the AEMC did not see fit to alter the MLF process – instead opting to maintain market stability and a methodology consistent with the laws of physics. However, the Rate of Change and asymmetric information regarding i). a lack of transparency over rival projects and ii). the absence of any MLF sensitivities, undoubtedly amplified the extent of investment mistakes in retrospect.

5.7 Security-Constrained Dispatch and Economic Curtailment

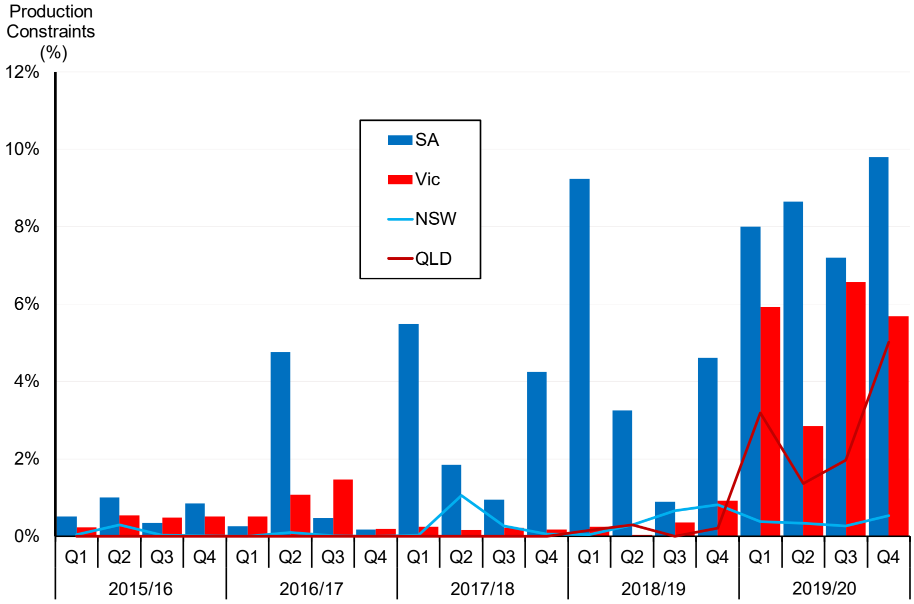
The culmination of issues in Sections 5.1-5.6 meant certain projects would face dispatch constraints and in addition, economic curtailment given production correlation between technologies within certain geographies. We have analysed the production constraints facing the NEM's Wind fleet from 2015/16-2019/20 (Fig.16). Any production constraint with spot prices above \$5/MWh has been classed as a 'Security' constraint, whereas lost production when prices were below \$5/MWh has been classed as 'Economic' curtailment. SA and VIC regions dominate total lost wind production (and note an equivalent analysis of Solar PV would presumably reveal material constraints in QLD).

Figure 16: Wind Production Constraints 2015/16-2019/20

16a – Production Constraints (GWh)



16b – Production Constraints (%)



Source: AEMO

In the SA region, lost Wind fleet production has risen from ~1% per annum (2015/16) to around 7% per annum (2019/20), with Security Constraints comprising the dominant (~¾) share. Over time as system strength issues are resolved, one would expect these to be relaxed, but economic curtailment is likely to rise and in most instances this will be an efficient outcome.

5.8 Refinancing Task

A summary of investment commitments undertaken over the NEM's history and during the 2017-2020 megacycle is presented in Tab.6. As a percentage of NEM history, the four-year cyclical boom produced 12,148MW (43%) of new installed capacity, $21.5 billion (39%) of committed capital across 105 projects committed, and 51% of total NEM project connections.

Table 6: NEM Investment Commitments (1999-2020)

	1999-2020			2017-2020		
2020$	Capacity (MW)	Investment ($ million)	Projects (No.)	Capacity (MW)	Investment ($ million)	Projects (No.)
Coal	2,953	6,910.8	5	-	-	-
Gas	8,456	10,372.4	32	480	522.0	2
Wind	9,552	22,893.0	81	5,227	10,581.7	32
Solar	6,479	11,045.7	70	6,151	10,138.7	63
Other*	706	1,356.0	18	290	247.0	8
Total	28,147	52,577.9	206	12,148	21,489.3	105

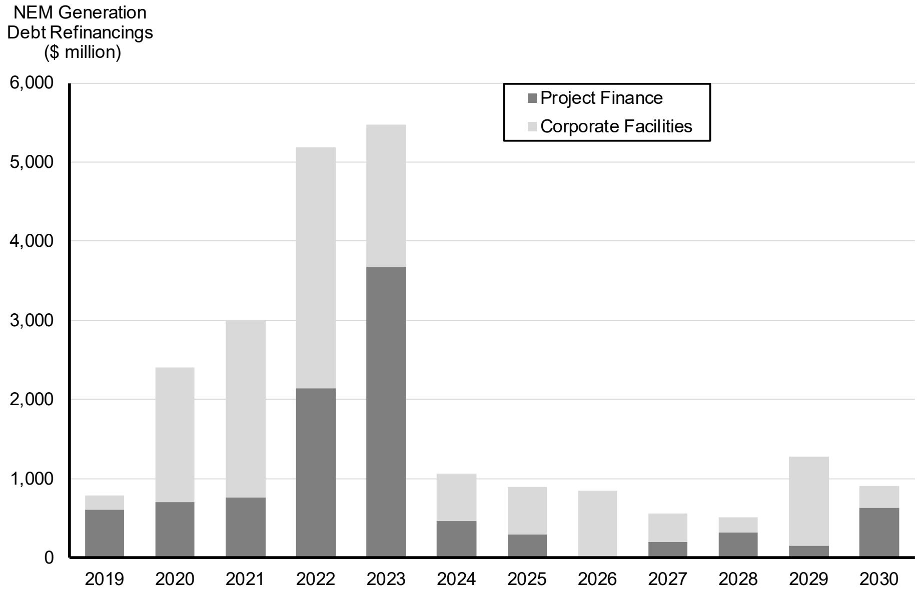
Sources: ESAA, AEC, BNEF, Company Reports. Excludes Return to Service of 120MW Smithfield OCGT.

*Other includes battery storage, hydro, mini-hydro, biomass and landfill gas.

2017-2020's $21.5 billion investment commitment comprised $9.9 billion in debt capital with an average tenor of 6.9 years, and median tenor financing dominated by 5-year money (by global standards, a relatively short tenor). In addition to project debt facilities, there is an additional $12.9 billion in corporate facilities from traditional (non-regulated) merchant energy utilities.

Figure 17 presents the aggregate industry refinancing task. Evidently, Australian bankers will be especially busy in 2022-2023. Between now and 2025, 84% of VRE project debt ($8.4b) and 74% of corporate debt ($9.6b) needs to be refinanced - $17.9b in total. And with a strange twist of irony, policymakers have decided to conduct a 'post-2025 market design program' and commit to the design by the end of 2021 – just as the refinancing task commences in anger. Any fundamental change is likely to be highly problematic and almost certainly create a string of liquidity events.

Figure 17: NEM Refinancing Task 2019-2030



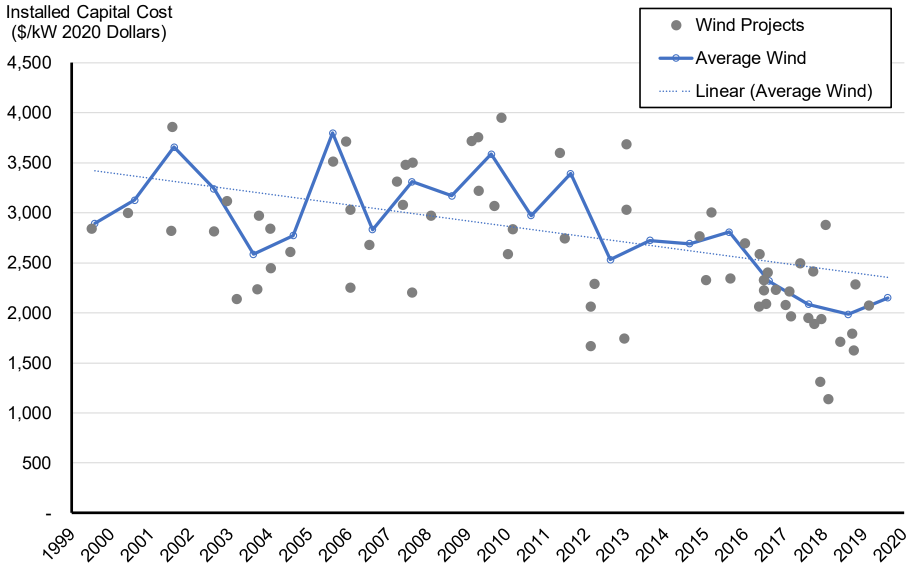
Sources: Company ASX announcements, websites & media releases, Bloomberg, RenewEconomy.

6. Cause of the megacycle

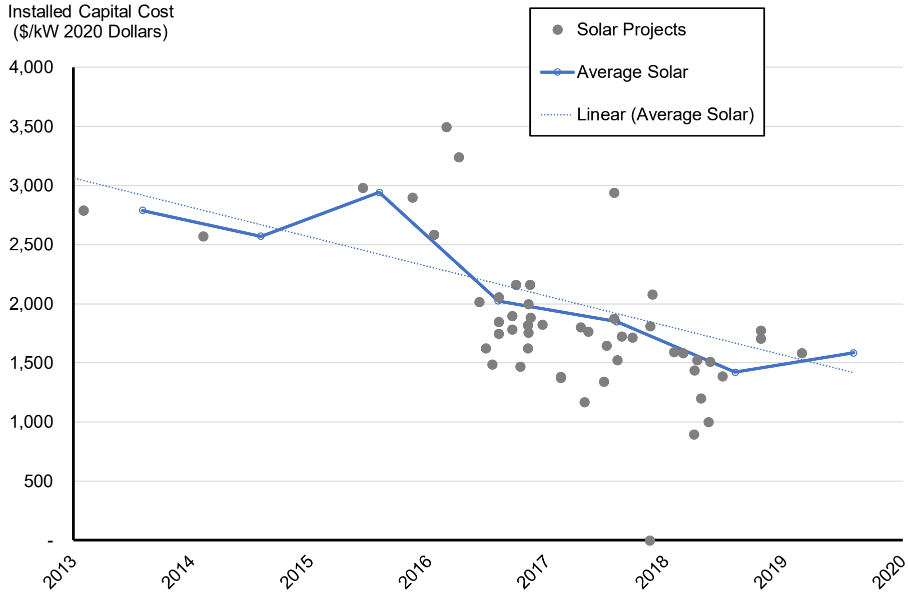
Business cycles are normal. The NEM's 2017-2020 cycle was not. It was driven by many things going wrong, and all at once. Uncoordinated coal plant exit, rising gas prices, a market power event aggravating price rises, and crucially, an undersupplied but rapidly closing window to meet a 20% Renewable Portfolio Standard by 2020. For good measure, VRE entry costs plunged from 2016 (Fig.18) which no doubt added to *gold rush conditions* and the excess entry result.

Figure 18: Capital Cost of NEM VRE Projects (Constant 2020$)

18a - Wind



18b - Solar



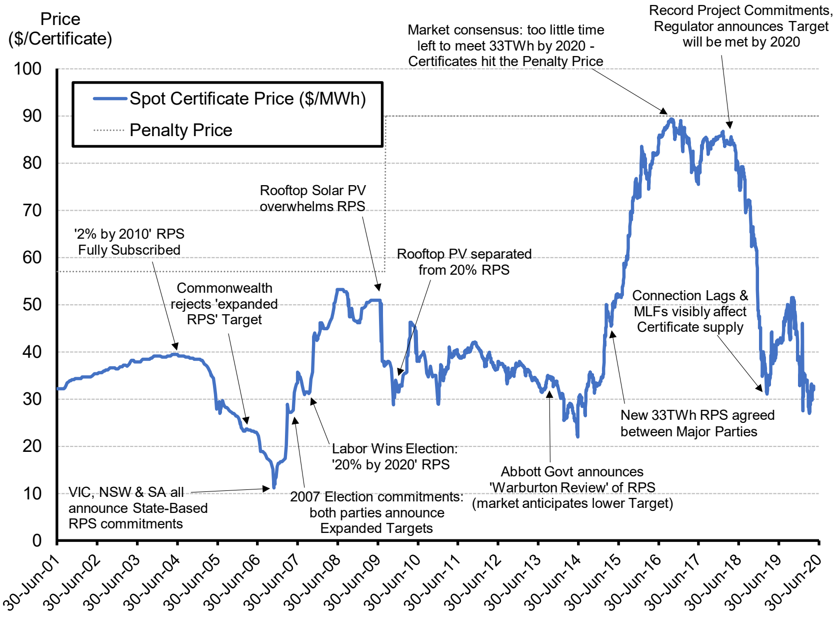
Source: ESAA, BNEF, ABS, Company Reports.

Coal plant exit and rising gas prices had the effect of driving spot and forward electricity prices above benchmark entry levels (Fig.2, Fig.8). A market power event in QLD amplified these conditions – in the very short run many aspects of the power system are inelastic – demand is unresponsive, capacity is fixed and storage is costly. But in the long run supply and demand are very elastic and in response, 31 QLD solar PV projects (49% of NEM solar project commitments) comprising 2300MW of capacity were committed under boom conditions (and 180MW of smelter load exited).

But in our view, the central driver of the megacycle can be traced to 20% Renewable Portfolio Standard policy discontinuity. It had been the subject of continuous review throughout the early 2010s. By the time the policy was finally "settled" in 2015/16, only four years remained to meet a sizable 20% target after years of stalled investment under uncertainty (recall from Fig.2 that statutory reviews had punctured the flow of investment).

Certificate prices surged to the penalty cap of $90/MWh (Fig.19) just as spot and forward electricity prices were surging to their record highs.

Figure 19: Renewable Portfolio Standard Certificate Prices

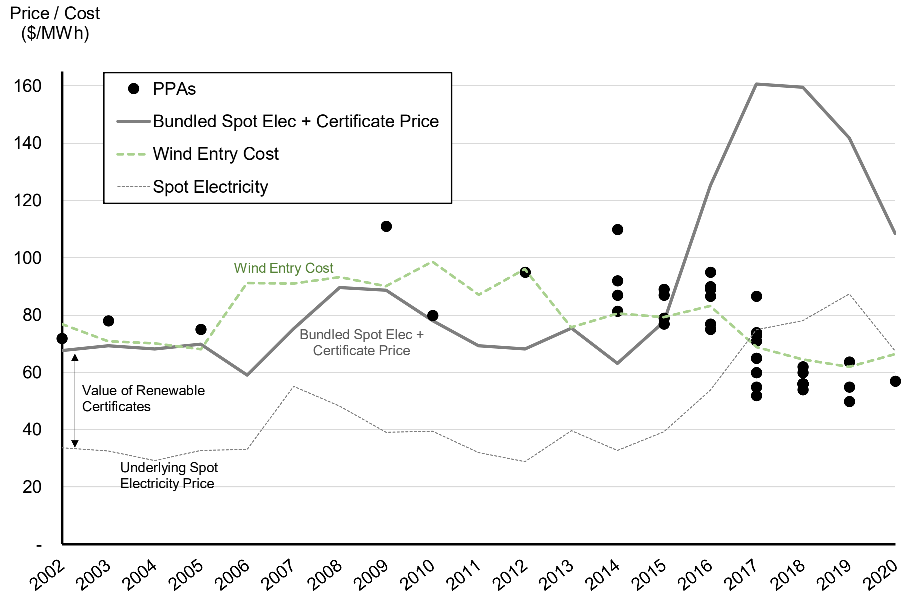


Source: Simshauser (2018), GFI.

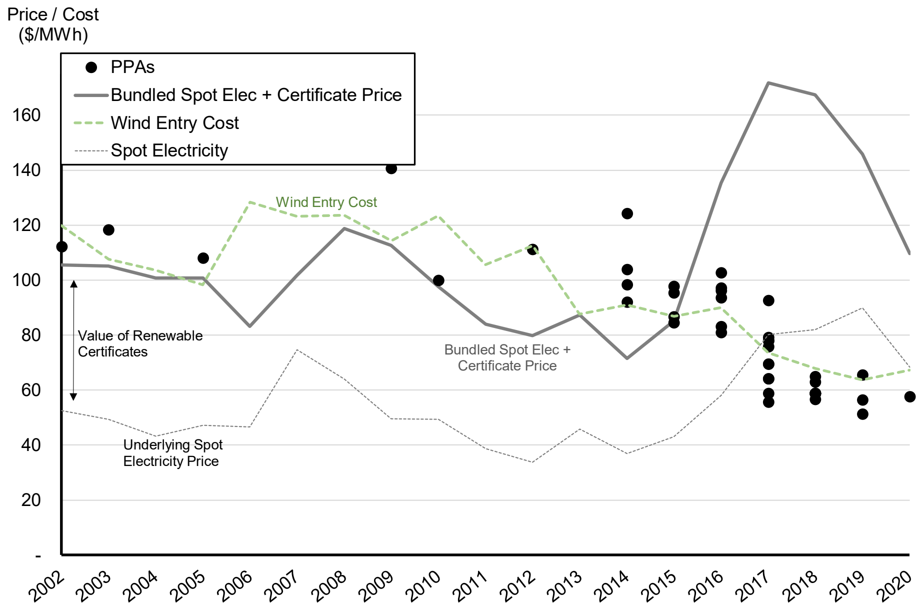
By 2017, the market was confronted with underling forward electricity prices of ~$80-90/MWh and renewable Certificate prices of ~$80-90 – collectively totalling $160+/MWh (Fig.20). At the same time, falling technology costs presented the market with sizable supranormal profits. As Fig.20 indicates, from 2016-2020 *gold rush conditions* emerged. With supranormal profits, an excess entry result comprising 105 projects was the unfortunate outcome. To be sure, many projects beyond the 105 entrants failed to enter – project supply 'vastly exceeded' the shrinking 20% Renewable Portfolio Standard window, and so PPA prices also fell rapidly as Fig.20 illustrates (with many US, EU and Southeast Asian institutional investors holding identical investment mandates that required contracted revenues/PPAs as a precondition to commitment).

Figure 20: Bundled Prices vs Wind Entry Costs & PPA prices (2002-2020)

20a – Nominal Dollars



20b – Constant 2020 Dollars



Sources: AEMO, GFI, BNEF, Company Reports.

One of the notable underperformers in our list of 2017-2020 entrants was dispatchable capacity. Of the 12147MW of new plant capacity, only 600MW[24] of gas and 210MW of Battery Storage was commissioned – most of this in SA where it was desperately needed. No plant was developed in QLD, consistent with its current level of structural oversupply. In NSW, the 120MW Smithfield Gas Turbine was returned to service and in VIC, a 30MW battery was commissioned. Why so little dispatchable capacity committed in NSW and VIC?

Firstly, forwards for $300 cap contracts trended downwards to below our estimated $14.50/MWh for new entrant OCGT plant. Furthermore, the System Operator was not projecting a breach of the NEM's Reliability Standard (with the exception of a 2019

[24] This includes 120MW at Smithfield, which has been excluded from most calculations as it was a mothballed Cogen plant which has been Returned to Service as a peaking gas turbine.

'scenario' which presumed delayed return to service of two plants on extended outages in the Vic region in 2019/20). While Reserve Levels have fallen, this is not inconsistent with history (and entirely consistent with the megacycle). Therefore, a lack of new dispatchable capacity does not represent a market failure per se.

However, this does not mean future problems will not occur. Historically, the NEM's large vertical utilities have been responsible for 75% of all investments in new gas-fired generation plant. In 2017 the ACCC flagged an informal 20% (regional) generation market share threshold, and the desirability of non-integrated new entrant generators in NSW, VIC and SA. In response, the Commonwealth Government, with no history of market intervention in the NEM's (then) 22 year history, launched an 'Underwriting Scheme' for new dispatchable generation (and at the time of writing, was the subject of an Auditor-General Review on the grounds of process, or lack thereof). The scheme was closed to Australia's Big 3 utilities and we suspect their two largest integrated rivals. The Commonwealth also introduced their so-called 'Big Stick' legislation which threatens utilities with forced divestments along with other intrusive interventions.

All of the NEM's utilities have advanced gas-fired generation projects but have evidently (and understandably) been hesitant to commit. Compounding matters is another of the NEM's largest vertical utilities, the government-owned Snowy Hydro, which has semi-committed to a 2000MW pumped-storage hydro (nb noting a requisite $2 billion transmission line augmentation and site environmental approvals are unresolved) which casts a long shadow over the NSW - given the size of the project. And finally, the VIC Government has cast a shadow of its own by committing to underwriting a very large portfolio of new VRE plant by way of government-initiated Contracts-for-Differences (4500MW of VRE capacity in aggregate by 2025). Out of market CfD transactions make investing in merchant plant in VIC extremely problematic.

7. Policy Implications

From our analysis of the NEM's 2017-2020 megacycle, what problems did we identify? The first point to note is that rising prices are a symptom, not a problem. Prices are driven by resource costs, supply-side structural inadequacies, or both. Structural inadequacies in the NEM, including falling reserve margins and market power events, have only ever been transient and supply-side responses have been marked - $52.6 billion to be precise. We found no evidence of persistent economic rent and NEM average spot prices from 2016-2020 of $76/MWh equal average entry costs ($76/MWh per Fig.7). Over the NEMs history (1998-2020) average spot prices ($56/MWh) compare favourably to average NEM entry costs of $64/MWh as Fig.7 aptly illustrated[25]. Only by lowering resource costs (fuel, capex, maintenance) can electricity prices fall further.

On Resource Adequacy and investment in new capacity, if anything we found irrational exuberance and an excess entry result fuelled by *gold rush conditions* (Fig.20) rather than underperformance. The NEMs organised spot and forward markets and high Market Price Cap ($14,700, amongst the highest in the world) have consistently guided corrections (i.e. favourably) to structural imbalances – Fig.4 provided the practical evidence and illustrated the patterns of entry (28,000MW) and exit (5000MW), while Figure 8 showed the mean-reverting pattern of spot and forward electricity prices.

The 2017-2020 asset allocation was heavily dominated by VRE. Of the 12,148MW of new capacity, just 810MW was dispatchable (Fig.2, Tab.6). VRE-adjusted Reserve Margins have decreased as coal plants exited but will begin to rise again as the full fleet of investment commitments progresses through construction and enters into service.

[25] We should also point out that contract premiums and earnings from FCAS close a majority of this gap (Caps trade at ~30% premium, peak swaps at ~15%, base swaps at ~2% and FCAS amounts to ~$0.75/MWh).

Forward $300 cap prices have also declined (Fig.3) and consequently it is not entirely obvious that the NEM is underweight dispatchable capacity (although granted, against a new and surprisingly conservative 0.0006% Reliability Standard, some out-of-market Reserves will become necessary in some regions).

But any under-representation of investment in dispatchable capacity is a policy choice, not a market design issue per se. In 2017, the ACCC made clear its view on incumbent expansion with scant regard to the economics of peaking plant and its relationship to industrial organisation, viz. ex ante investment commitment and ex post performance. The Commonwealth Government responded through its generation Underwriting Scheme. Both the view[26], and the policy, are misguided. Dispatchable capacity is best matched with stochastic retail load (see Simshauser, 2020b), stochastic merchant generation or holders of the relevant PPA output (Simshauser, 2020a). Entities with stochastic assets and investment grade balance sheets to match are the large vertical incumbents and have been responsible for most (~75%) of the NEMs gas plant investments. If large incumbents with all the incentives to invest in firming capacity are constrained by a regulator or deterred by policy, is it really surprising dispatchable capacity is underweight?

Conversely, large vertical incumbents invested minimally in VRE – just 15% of the 12,000MW committed. What the market needs is 'clear air' – cancelling the Underwriting Scheme, and the Vic CfD scheme for that matter. VIC VRE targets are entirely appropriate and States would be wise to proceed with their own decarbonisation policies and regimes in the absence of a unified Commonwealth position. But the CfDs path is inconsistent with the NEM design. With CfDs, no NEM entity takes ownership of the stochastic VRE output (unlike bilateral PPAs), and therefore no market entity is motivated to 'firm' the output by investing in dispatchable plant (see Simshauser, 2019c).

Rising levels of zero marginal cost VRE plant is not a policy problem either – after all, zero marginal cost VRE are merely replacing one of the world's lowest marginal running cost coal fleets, and that ultra-low cost coal fleet did not deter (28,000MW and $52.6b of) entry. Ultimately the aggregate supply curve continues to be upward sloping. The SA region is well beyond 50% VRE and exhibited all the conditions necessary for investment as the 2017-2020 cycle demonstrated. All market forecasting agencies that we are aware of (e.g. Aurora, EY-Roam, Jacobs, Acil Allen, Frontier Economics) and academic studies (e.g. Simshauser, 2018b; Marshman *et al.*, 2020) show an energy-only market remains tractable with rising VRE given a Market Price Cap of $14,700 and Reliability Standard of 0.002%. In a remarkably detailed modelling effort which included FCAS markets, Marshman et al (2020) show some out-of-market peaking capacity may become necessary when aggregate VRE output approaches 60%, but not before. This is still some way off for Australia's NEM.

Market performance has been presented throughout this article in the context of an enormous number of simultaneous project commitments – 105 as Fig.10 illustrated. While forward project numbers may well remain elevated (*cf.* historic trends associated with the construction of very large, centralised base load generation investments) we should not anticipate sustained megacycle-levels of activity. Investment trend data in Fig.2 and Fig.10 confirms this to be the case as the 20% Renewable Portfolio Standard '2020 window' closed. This tends to suggest connection lags (Tab.4) and MLF shocks (Fig.15) will also recede and therefore do not warrant policy attention.

- Connection times will presumably shrink as firms become more familiar with the s5.3.4B process, and PSCAD Models of Networks become more refined.

[26] We should note our commentary here in no way relates to the ACCC's assessment and identification of problems associated of horizontal scale, but rather, its views on vertical practices. See Simshauser (2020b).

- MLF shocks, while unfortunate for the ~2645MW of affected projects, can be minimised in future through greater transparency of the status of (anonymised) rival projects by location[27], and provision of location loss factor sensitivities on a fee-for-service basis – clearly, the Market Operator has every incentive to do so without explicit policy intervention.

In the course of this research, we formed a view that power system security (Fig.11-12), power system strength (Fig.13) and FCAS market service coverage (Fig.14) are the central market problems. We consider their resolution to be of utmost urgency. As this became clear to us, we submitted two Rule Change proposals to the AEMC with a view to introducing new FCAS markets for i). Fast Frequency Response and ii). Operating Reserves. The Market Operator also submitted a Rule Change proposal vis-à-vis Primary Frequency Response.[28] We expect these will provide the Market Operator with new weapons to restore some, but not all, elements of the NEM's faltering resilience.

This leaves system strength. Although organised spot markets are our inherent bias, they are costly to administer. We are of the view that some level of pre-emptive investment in system strength services should be Administratively Determined to cope with inevitable forecasting errors and newly identified modes of failure with the default or benchmark solution being synchronous condensers.

VRE production curtailment is not a problem but a symptom of market economics (i.e. negative prices or investment congestion), security-constrained dispatch, or both. The former warrants not a second of policymaker time or attention, and the latter should be an outcome of Administrative Decisions relating to system strength. The tyranny of distance with system strength solutions means some remote generators may never avoid curtailment, and that is likely to be efficient.

Long run market re-design proposals for the NEM, including a shift from zonal to nodal pricing and from real-time to day-ahead markets, remain intriguing but are a distraction. They are also widely considered amongst investors and utilities to be the best way to halt generation investment *'dead in its tracks'*. The reason for this is axiomatic – a major redesign of the market creates a transition period where any contract must straddle two completely different market environments – bounded rationality, ambiguity and uncertainty must ultimately lead to a merchant investment freeze. Ironically, such conditions are probably worse than ongoing random interventions.

To be sure, we see merit in an ahead market for system security services where the Market Operator otherwise faces constraints with intervention times. Operating Reserves also necessarily involve reserving capacity ahead of some future (uncertain) need. However, we see no economic justification for shifting the spot electricity market to a day-ahead platform. As for nodal pricing, its superior performance relative to a zonal model is unquestionable but dispatch inefficiencies of just $3-15 million per annum[29] have been identified through disorderly bidding and pale into insignificance to NEM market turnover of $19,500 million per annum. Disorderly bidding has virtually no effect on end-consumer pricing, and a shift to dramatically more nodes risks Balkanising the NEMs liquid zonal hedge markets – the quintessential market that guides investment, facilitates retail

[27] Indeed, Rule changes were proposed by multiple parties (and consolidated) to address this issue. See https://www.aemc.gov.au/rule-changes/nem-information-project-developers

[28] Unfortunately, Primary Frequency Response was implemented as a 'mandatory requirement' without reserved headroom thereby mis-pricing a valuable service and in consequence, failing to address the underlying problem of declining system security resources. We are not aware of any work undertaken to identify the efficient level of the service required.

[29] See AEMC (2013) 'Transmission Frameworks Review Final Report' at Section 8.4.2.

competition and 'grounds' consumer pricing. As a long skinny network with a history of market power events, it is not entirely obvious that nodal will outperform zonal due to the transaction costs of the change, especially if the hedge market is damaged.

And for those querying locational investment signals, Pension Funds (59%) and Developers (36%) whose site selection was a mistake in retrospect (Tab.5) have been allocated with a commensurate MLF as a perennial reminder of their decision. The lesson is laid before all to see, and learn from.

8. Conclusion

Most global electricity market designs have been reasonably successful to date at delivering reliable supply, including Australia's energy-only gross pool. The NEM design and its associated forward markets have evidently achieved what it was designed to do – the Reliability Standard has been met with few exceptions (Fig.5), prices reflect underlying resource costs (Fig.7), and capacity investment has consistently flowed when required (Fig.4 & Fig.7). Further, the NEM's Emergency Trader provisions functioned when coal plant closure rates accelerated (noting exit notification periods were a form of market failure in their own right and the subject of subsequent policy change).

Globally, no loosely interconnected electricity market has been forced to deal with the VRE market shares observed in South Australia, or the relative Rate of Change experienced by the NEM. We consider FCAS markets for Fast Frequency Response, Operating Reserves, and System Strength to be of utmost urgency. These services were a joint product of coal plant output and were therefore previously unpriced, but their shortfall following the changeover from synchronous to asynchronous plant has since led to daily Market Operator interventions.

In our view, these missing markets need to be procured on a probabilistic basis because *n-1 contingencies* are gradually being surpassed by new modes of failure, some visible and other yet to be revealed. Synchronous Condensers, the default solution to system strength, or alternative emerging technologies need to be originated on a proactive basis to locations where grid stability may be at risk under conditions of rapid plant closure or entry. By being *one step ahead*, future system security disruptions could be minimised. In our view, the risks are asymmetric and the cost of over-investment is less than the cost of under-investment.

None of our analysis pointed to an alternate market design that might have improved outcomes. Nodal pricing, capacity markets, and day-ahead markets are of course well proven in various jurisdictions[30]. So too is driving on the right-hand side of the road. For better or worse, Australia has a left-hand road network and a zonal, real-time energy-only electricity market design. Changing to a right-hand road network would allow Australian consumers to access a vastly greater pool of vehicles. But changing Australia's road network mid-stream would involve breathtaking transaction costs. In the case of Australia's NEM, changing design mid-stream will impact $52.6b of generation commitments, freeze merchant generation plant investment, frustrate each and every retail and wholesale contract spanning the event, and, will almost certainly induce liquidity events in an already complex refinancing task (Fig.17).

Indeed, critical to the functionality of the power system as a whole is maintaining the confidence of both debt and equity capital markets if requisite future investment in generation and network plant is to occur. Capricious and random interventions by government to support particular generation projects heightens perceptions of sovereign

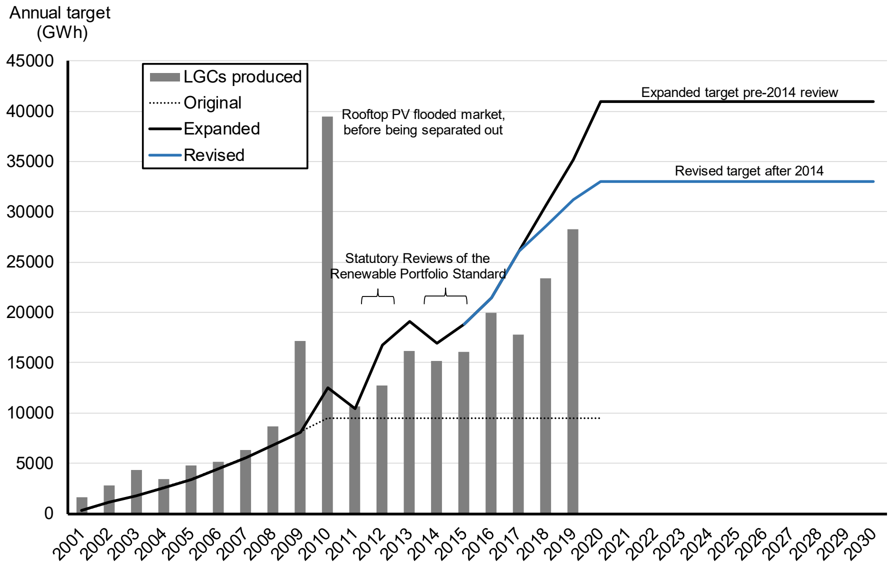
[30] Although few markets have been exposed to NEM exit conditions (especially 2016-2017) and a Rate of Change experienced by the NEM in 2017-2020.

risk, not to mention a long history of producing higher overall systems costs and welfare losses. As perceptions of sovereign risk heighten, investment discontinuity is predictable.

Glossary

ABS	Australian Bureau of Statistics
ACCC	Australian Competition & Consumer Commission
AEC	Australian Energy Council (successor to ESAA)
AEMC	Australian Energy Market Commission (NEM Policymaking body)
AEMO	Australian Energy Market Operator (NEM Market Operator)
AER	Australian Energy Regulator
ARENA	Australian Renewable Energy Agency
AUD	Australian Dollar
BNEF	Bloomberg New Energy Finance
CCGT	Combined Cycle Gas Turbine
CfD	Contract-for-Difference
ESG	Environmental, Social and Governance
ESAA	Energy Supply Association of Australia
FCAS	Frequency Control Ancillary Services
Hz	Hertz (50Hz in Australia)
MLF	Marginal Loss Factor (network loss ascribed to each connection point)
MW	Mega Watt
MWh	Megawatt hour
NEM	National Electricity Market
NSW	New South Wales (NEM Region)
OCGT	Open Cycle Gas Turbine
OEM	Original Equipment Manufacturer
QLD	Queensland (NEM Region)
PPA	Power Purchase Agreement
SA	South Australia (NEM Region)
Solar PV	Solar Photovoltaic
TAS	Tasmania (NEM Region)
TWh	Terrawatt hour
VIC	Victoria (NEM Region)
VRE	Variable Renewable Energy (i.e. wind and solar PV)

APPENDIX I – Figure A1 Changes to Australia's Renewable Portfolio Standard



APPENDIX II – PF Model Overview

In the PF Model, costs increase annually by a forecast general inflation rate (CPI). Prices escalate at a discount to CPI. Inflation rates for revenue streams π_j^R and cost streams π_j^C in period (year) *j* are calculated as follows:

$$\pi_j^R = \left[1 + \left(\frac{CPI \times \alpha_R}{100}\right)\right]^j \text{, and } \pi_j^C = \left[1 + \left(\frac{CPI \times \alpha_C}{100}\right)\right]^j \qquad (1)$$

The discounted value for α_R reflects single factor learning rates that characterise generating technologies.

Energy output q_j^i from each plant (*i*) in each period (*j*) is a key variable in driving revenue streams, unit fuel costs and variable Operations & Maintenance costs. Energy output is calculated by reference to installed capacity k^i, capacity utilisation rate CF_j^i for each period *j*. Plant auxillary losses Aux^i arising from on-site electrical loads are deducted.

$$q_j^i = CF_j^i . k^i . (1 - Aux^i) \qquad (2)$$

A convergent electricity price for the *i^th^* plant $(p^{i\varepsilon})$ is calculated in year one and escalated per eq. (1). Thus revenue for the *i^th^* plant in each period *j* is defined as follows:

$$R_j^i = \left(q_j^i . p^{i\varepsilon} . \pi_j^R\right) \qquad (3)$$

In order to define marginal running costs, the thermal efficiency for each generation technology ζ^i needs to be defined. The constant term '3600'[31] is divided by ζ^i to convert the efficiency result from % to kJ/kWh. This is then multiplied by raw fuel commodity cost f^i. Variable Operations & Maintenance costs v^i, where relevant, are added which produces a pre-carbon short run marginal cost. Under conditions of externality pricing CP_j, the CO_2 intensity of output needs to be defined. Plant carbon intensity g^i is derived by multiplying the plant heat rate by combustion emissions $\dot{g}^i$ and fugitive CO_2 emissions $\hat{g}^i$. Marginal running costs in the *j^th^* period is then calculated by the product of short run marginal production costs by generation output q_j^i and escalated at the rate of π_j^C.

$$\vartheta_j^i = \left\{\left[\left(\frac{\left(3600/\zeta^i\right)}{1000} . f^i + v^i\right) + \left(g^i . CP_j\right)\right] . q_j^i . \pi_j^C \middle| g^i = \left(\dot{g}^i + \hat{g}^i\right) . \frac{\left(3600/\zeta^i\right)}{1000}\right\} \qquad (4)$$

Fixed Operations & Maintenance costs FOM_j^i of the plant are measured in \$/MW/year of installed capacity FC^i and are multiplied by plant capacity k^i and escalated.

$$FOM_j^i = FC^i . k^i . \pi_j^C \qquad (5)$$

Earnings Before Interest Tax Depreciation and Amortisation (EBITDA) in the *j^th^* period can therefore be defined as follows:

$$EBITDA_j^i = \left(R_j^i - \vartheta_j^i - FOM_j^i\right) \qquad (6)$$

Capital Costs (X_0^i) for each plant *i* are Overnight Capital Costs and incurred in year 0. Ongoing capital spending (x_j^i) for each period *j* is determined as the inflated annual assumed capital works program.

---

[31] The derivation of the constant term 3600 is: 1 Watt = 1 Joule per second and hence 1 Watt Hour = 3600 Joules.

$$x_j^i = c_j^i . \pi_j^C \qquad (7)$$

Plant capital costs X_0^i give rise to tax depreciation (d_j^i) such that if the current period was greater than the plant life under taxation law (L), then the value is 0. In addition, x_j^i also gives rise to tax depreciation such that:

$$d_j^i = \left(\frac{X_0^i}{L}\right) + \left(\frac{x_j^i}{L-(j-1)}\right) \qquad (8)$$

From here, taxation payable (τ_j^i) at the corporate taxation rate (τ_c) is applied to $EBITDA_j^i$ less Interest on Loans (I_j^i) later defined in (16), less d_j^i. To the extent (τ_j^i) results in non-positive outcome, tax losses (L_j^i) are carried forward and offset against future periods.

$$\tau_j^i = Max(0, (\, EBITDA_j^i - I_j^i - d_j^i - L_{j-1}^i). \tau_c) \qquad (9)$$

$$L_j^i = Min(0, (\, EBITDA_j^i - I_j^i - d_j^i - L_{j-1}^i). \tau_c) \qquad (10)$$

The debt financing model computes interest and principal repayments on different debt facilities depending on the type, structure and tenor of tranches. There are two types of debt facilities – (a) corporate facilities (i.e. balance-sheet financings) and (2) project financings. Debt structures include semi-permanent amortising facilities and bullet facilities.

Corporate Finance typically involves 5- and 7-year bond issues with an implied 'BBB' credit rating. Project Finance include a 5-7 year bullet facility requiring interest-only payments after which it is refinanced with consecutive amortising facilities and fully amortised over an 18-25 year period (depending on the technology). The second facility commences with a tenor of 7-12 years as an amortising facility set within a semi-permanent structure with a nominal repayment term of 18-25 years. The decision tree for the two tranches of debt was the same, so for the Debt Tranche where DT = 1 or 2, the calculation is as follows:

$$if\ j \begin{cases} > 1, DT_j^i = DT_{j-1}^i - P_{j-1}^i \\ = 1, DT_1^i = D_0^i . S \end{cases} \qquad (11)$$

D_0^i refers to the total amount of debt used in the project. The split (S) of the debt between each facility refers to the manner in which debt is apportioned to each tranche. In the model, 35% of debt is assigned to Tranche 1 and the remainder to Tranche 2. Principal P_{j-1}^i refers to the amount of principal repayment for tranche T in period j and is calculated as an annuity:

$$P_j^i = \left(\frac{DT_j^i}{\left[\frac{1-(1+(R_{Tj}^Z + C_{Tj}^Z))^{-n}}{R_{Tj}^Z + C_{Tj}^Z}\right]} \Bigg|_{z} \begin{cases} = VI \\ = PF \end{cases} \right) \qquad (12)$$

In (12), R_{Tj} is the relevant interest rate swap (5yr, 7yr or 12yr) and C_{Tj} is the credit spread or margin relevant to the issued Debt Tranche. The relevant interest payment in the j^{th}

period (I_j^i) is calculated as the product of the (fixed) interest rate on the loan by the amount of loan outstanding:

$$I_j^i = DT_j^i \times (R_{Tj}^z + C_{Tj}^z) \qquad (13)$$

Total Debt outstanding D_j^i, total Interest I_j^i and total Principle P_j^i for the i^{th} plant is calculated as the sum of the above components for the two debt tranches in time *j*. For clarity, Loan Drawings are equal to D_0^i in year 1 as part of the initial financing and are otherwise 0.

One of the key calculations is the initial derivation of D_0^i (as per eq.11). This is determined by the product of the gearing level and the Overnight Capital Cost (X_0^i). Gearing levels are formed by applying a cash flow constraint based on credit metrics applied by project banks and capital markets. The variable γ in our PF Model relates specifically to the legal structure of the business and the credible capital structure achievable. The two relevant legal structures are Vertically Integrated (VI) merchant utilities (issuing 'BBB' rated bonds) and Independent Power Producers using Project Finance (PF).

$$iif\ \gamma \begin{cases} = VI,\ \frac{FFO_j^i}{I_j^i} \geq \delta_j^{VI} \forall\ j \ \left| \frac{D_j^i}{EBITDA_j^i} \geq \omega_j^{VI} \forall\ j \ \right| FFO_j^i = \left(EBITDA_j^i - x_j^i\right) \\ = PF, Min\left(DSCR_j^i, LLCR_j^i\right) \geq \delta_j^{PF}, \forall\ j \ \left| DSCR_j = \frac{\left(EBITDA_j^i - x_j^i - \tau_j^i\right)}{P_j^i + I_j^i} \right| LLCR_j = \frac{\sum_{j=1}^{N}\left[\left(EBITDA_j^i - x_j^i - \tau_j^i\right).(1+K_d)^{-j}\right]}{D_j^i} \end{cases} \qquad (14)$$

Credit metrics[32] (δ_j^{VI}) and (ω_j^{VI}) are exogenously determined by credit rating agencies and are outlined in Table 3. Values for δ_j^{PF} are exogenously determined by project banks and depend on technology (i.e. thermal vs. renewable) and the extent of energy market exposure, that is whether a Power Purchase Agreement exists or not. For clarity, FFO_j^i is 'Funds From Operations' while $DSCR_j^i$ and $LLCR_j^i$ are the Debt Service Cover Ratio and Loan Life Cover Ratios. Debt drawn is:

$$D_0^i = X_0^i - \sum_{j=1}^{N}\left[EBITDA_j^i - I_j^i - P_j^i - \tau_j^i\right].(1+K_e)^{-(j)} - \sum_{j=1}^{N} x_j^i.(1+K_e)^{-(j)} \qquad (15)$$

At this point, all of the necessary conditions exist to produce estimates of the long run marginal cost of power generation technologies along with relevant equations to solve for the price $(p^{i\varepsilon})$ given expected equity returns (K_e) whilst simultaneously meeting the constraints of δ_j^{VI} and ω_j^{VI} or δ_j^{PF} given the relevant business combinations. The primary objective is to expand every term which contains $p^{i\varepsilon}$. Expansion of the EBITDA and Tax terms is as follows:

$$0 = -X_0^i + \sum_{j=1}^{N}\left[\left(p^{i\varepsilon}.q_j^i.\pi_j^R\right) - \vartheta_j^i - FOM_j^i - I_j^i - P_j^i - \left(\left(p^{i\varepsilon}.q_j^i.\pi_j^R\right) - \vartheta_j^i - FOM_j^i - I_j^i - d_j^i - L_{j-1}^i\right).\tau_c\right].(1+K_e)^{-(j)} - \sum_{j=1}^{N} x_j^i.(1+K_e)^{-(j)} - D_0^i \qquad (16)$$

The terms are then rearranged such that only the $p^{i\varepsilon}$ term is on the left-hand side of the equation:

Let $IRR \equiv K_e$

$$\sum_{j=1}^{N}(1-\tau_c).p^{i\varepsilon}.q_j^i.\pi_j^R.(1+K_e)^{-(j)} = X_0^i - \sum_{j=1}^{N}\left[-(1-\tau_c).\vartheta_j^i - (1-\tau_c).FOM_j^i - (1-\tau_c).\left(I_j^i\right) - P_j^i + \tau_c.d_j^i + \tau_c L_{j-1}^i).(1+K_e)^{-(j)}\right] + \sum_{j=1}^{N} x_j^i.(1+K_e)^{-(j)} + D_0^i \qquad (17)$$

32 For Balance Sheet Financings, Funds From Operations over Interest, and Net Debt to EBITDA respectively. For Project Financings, Debt Service Cover Ratio and Loan Life Cover Ratio.

Griffith UNIVERSITY
Griffith Business School
Queensland, Australia

The model then solves for $p^{i\varepsilon}$ such that:

$$p^{i\varepsilon} = \frac{X_0^i}{\sum_{j=1}^{N}(1-\tau_c).P^{\varepsilon}.\pi_j^R.(1+K_e)^{-(j)}} + \frac{\sum_{j=1}^{N}\left((1-\tau_c).\vartheta_j^i+(1-\tau_c).FOM_j^i+(1-\tau_c).\left(I_j^i\right)+P_j^i-\tau_c.d_j^i-\tau_c L_{j-1}^i).(1+K_e)^{-(j)}\right)}{\sum_{j=1}^{N}(1-\tau_c).q_j^i.\pi_j^R.(1+K_e)^{-(j)}} + \frac{\sum_{j=1}^{N} x_j^i.(1+K_e)^{-(j)}+D_0^i}{\sum_{j=1}^{N}(1-\tau_c).q_j^i.\pi_j^R.(1+K_e)^{-(j)}} \qquad (18)$$

Centre for Applied Energy Economics and Policy Research

9. References

Apergis, N. and Lau, M. C. K. (2015) ‘Structural breaks and electricity prices: Further evidence on the role of climate policy uncertainties in the Australian electricity market’, *Energy Economics*, 52(October), pp. 176–182. doi: 10.1016/j.eneco.2015.10.014.

Arango, S. and Larsen, E. (2011) ‘Cycles in deregulated electricity markets: Empirical evidence from two decades’, *Energy Policy*, 39(5), pp. 2457–2466. doi: 10.1016/j.enpol.2011.02.010.

ARENA (2020) *Insights From t he First Wave of Large-Scale Solar Projects in Australia*. Sydnet.

de Atholia, T., Flannigan, G. and Lai, S. (2020) ‘Renewable Energy Investment in Australia’, *Reserve Bank of Australia Bulletin*, (March), pp. 36–46.

Bajo-Buenestado, R. (2017) ‘Welfare implications of capacity payments in a price-capped electricity sector: A case study of the Texas market (ERCOT)’, *Energy Economics*, 64, pp. 272–285. doi: 10.1016/j.eneco.2017.03.026.

Batlle, C. and Pérez-Arriaga, I. J. (2008) ‘Design criteria for implementing a capacity mechanism in deregulated electricity markets’, *Utilities Policy*, 16(3), pp. 184–193. doi: 10.1016/j.jup.2007.10.004.

Bell, W. P. *et al.* (2015) ‘Wind speed and electricity demand correlation analysis in the Australian National Electricity Market: Determining wind turbine generators’ ability to meet electricity demand without energy storage’, *Economic Analysis and Policy*, 48, pp. 182–191. doi: 10.1016/j.eap.2015.11.009.

Bell, W. P. *et al.* (2017) ‘Revitalising the wind power induced merit order effect to reduce wholesale and retail electricity prices in Australia’, *Energy Economics*, 67, pp. 224–241. doi: 10.1016/j.eneco.2017.08.003.

Besser, J. G., Farr, J. G. and Tierney, S. F. (2002) ‘The political economy of long-term generation adequacy: Why an ICAP mechanism is needed as part of standard market design’, *Electricity Journal*, 15(7), pp. 53–62. doi: 10.1016/S1040-6190(02)00349-4.

Bidwell, M. and Henney, A. (2004) ‘Will Neta ensure generation adequacy’, *Power UK*, 122(April), pp. 10–26.

Biggs, C. (2016) ‘A resource-based view of opportunities to transform Australia’s electricity sector’, *Journal of Cleaner Production*, 123, pp. 203–217. doi: 10.1016/j.jclepro.2015.12.006.

Bublitz, A. *et al.* (2019) ‘A survey on electricity market design : Insights from theory and real-world implementations of capacity remuneration mechanisms’, *Energy Economics*, 80, pp. 1059–1078. doi: 10.1016/j.eneco.2019.01.030.

Buckman, G. and Diesendorf, M. (2010) ‘Design limitations in Australian renewable electricity policies’, *Energy Policy*, 38(7), pp. 3365–3376. doi: 10.1016/j.enpol.2010.02.009.

Byers, C., Levin, T. and Botterud, A. (2018) ‘Capacity market design and renewable energy: Performance incentives, qualifying capacity, and demand curves’, *The Electricity Journal*. Elsevier, 31(1), pp. 65–74. doi: 10.1016/j.tej.2018.01.006.

Byrnes, L. *et al.* (2013) ‘Australian renewable energy policy: Barriers and challenges’, *Renewable Energy*, 60, pp. 711–721. doi: 10.1016/j.renene.2013.06.024.

Caplan, E. (2012) ‘What drives new generation construction?’, *The Electricity Journal*, 25(6), pp. 48–61.

Cepeda, M. and Finon, D. (2011) ‘Generation capacity adequacy in interdependent electricity markets’, *Energy Policy*, 39(6), pp. 3128–3143. doi: 10.1016/j.enpol.2011.02.063.

Chao, H. P., Oren, S. and Wilson, R. (2008) ‘Reevaluation of vertical integration and unbundling in restructured electricity markets’, in *Competitive Electricity Markets*, pp. 27–64. doi: 10.1016/B978-008047172-3.50005-2.

Cludius, J., Forrest, S. and MacGill, I. (2014) ‘Distributional effects of the Australian Renewable Energy Target (RET) through wholesale and retail electricity price impacts’, *Energy Policy*, 71, pp. 40–51. doi: 10.1016/j.enpol.2014.04.008.

Cramton, P., Ockenfels, A. and Stoft, S. (2013) ‘Capacity market fundamentals’, *Economics of*

Energy & Environmental Policy, 2(2), pp. 1–21.

Cramton, P. and Stoft, S. (2005) ‘A Capacity Market that Makes Sense’, *The Electricity Journal*, 18(7), pp. 43–54.

Cramton, P. and Stoft, S. (2006) *The Convergence of Market Designs for Adequate Generating Capacity with Special Attention to the CAISO ’ s Resource Adequacy Problem*. 06–007.

Cramton, P. and Stoft, S. (2008) ‘Forward reliability markets: Less risk, less market power, more efficiency’, *Utilities Policy*, 16(3), pp. 194–201. doi: 10.1016/j.jup.2008.01.007.

Doorman, G. L. (2000) *Peaking capacity in restructured power systems*. Norwegian University of Science and Technology.

Finon, D. (2008) ‘Investment risk allocation in decentralised electricity markets. The need of long-term contracts and vertical integration’, *OPEC Energy Review*, 32(2), pp. 150–183. doi: 10.1111/j.1753-0237.2008.00148.x.

Finon, D. and Pignon, V. (2008) ‘Electricity and long-term capacity adequacy: The quest for regulatory mechanism compatible with electricity market’, *Utilities Policy*, 16(3), pp. 143–158. doi: 10.1016/j.jup.2008.01.002.

Forrest, S. and MacGill, I. (2013) ‘Assessing the impact of wind generation on wholesale prices and generator dispatch in the Australian National Electricity Market’, *Energy Policy*, 59, pp. 120–132. doi: 10.1016/j.enpol.2013.02.026.

Freebairn, J. (2014) ‘Carbon Price versus Subsidies to Reduce Greenhouse Gas Emissions’, *Economic Papers*, 33(3), pp. 233–242. doi: 10.1111/1759-3441.12082.

Galetovic, A., Munoz, C. M. and Wolak, F. A. (2015) ‘Capacity Payments in a Cost- Based Wholesale Electricity’, *The Electricity Journal*, 28(10), pp. 80–96. doi: http://dx.doi.org/10.1016/j.tej.2015.10.011.

Garnaut, R. (2014) ‘Resolving Energy Policy Dilemmas in an Age of Carbon Constraints’, *Australian Economic Review*, 47(4), pp. 492–508. doi: 10.1111/1467-8462.12087.

Grubb, M. and Newbery, D. (2018) ‘UK electricity market reform and the energy transition: Emerging lessons’, *Energy Journal*, 39(6), pp. 1–25. doi: 10.5547/01956574.39.6.mgru.

Hach, D. and Spinler, S. (2016) ‘Capacity payment impact on gas-fired generation investments under rising renewable feed-in - A real options analysis’, *Energy Economics*, 53, pp. 270–280. doi: 10.1016/j.eneco.2014.04.022.

Henriot, A. *et al.* (2013) *Market Design for Large Scale Integration of Intermittent Renewable Energy Sources*, *Cigre Wg C5-11*. Available at: http://c5.cigre.org/Members-Area/WG-C5-11-Market-Design-for-Large-Scale-Integration-of-Renewable-Energy-Sources-and-Demand-side-Management.

Hirth, L., Ueckerdt, F. and Edenhofer, O. (2016) ‘Why wind is not coal: On the economics of electricity generation’, *Energy Journal*, 37(3), pp. 1–27. doi: 10.5547/01956574.37.3.lhir.

Hogan, W. W. (2005) *On an ‘Energy Only’ Electricity Market Design for Resource Adequacy*, *Cener for Business and Government - John F. Kennedy School of Government*. Available at: https://ferc.gov/EventCalendar/Files/20060207132019-Hogan_Energy_Only_092305.pdf.

Hogan, W. W. (2013) ‘Electricity scarcity pricing through operating reserves’, *Economics of Energy and Environmental Policy*, 2(2), pp. 65–86. doi: 10.5547/2160-5890.2.2.4.

Höschle, H. *et al.* (2017) ‘Electricity markets for energy , flexibility and availability — Impact of capacity mechanisms on the remuneration of generation technologies’, *Energy Economics*, 66, pp. 372–383. doi: 10.1016/j.eneco.2017.06.024.

Howell, B., Meade, R. and O’Connor, S. (2010) ‘Structural separation versus vertical integration: Lessons for telecommunications from electricity reforms’, *Telecommunications Policy*, 34(7), pp. 392–403. doi: 10.1016/j.telpol.2010.05.003.

Jones, S. (2009) ‘The future of renewable energy in Australia: A test for cooperative federalism?’, *Australian Journal of Public Administration*, 68(1), pp. 1–20. doi: 10.1111/j.1467-8500.2008.00606.x.

Jones, S. (2010) 'The national renewable energy target: An example of post-machiavellian policy-making?', *Australian Journal of Public Administration*, 69(2), pp. 165–177. doi: 10.1111/j.1467-8500.2010.00678.x.

Jones, S. (2014) 'Flirting with Climate Change: A Comparative Policy Analysis of Subnational Governments in Canada and Australia', *Journal of Comparative Policy Analysis: Research and Practice*. Routledge, 16(5), pp. 424–440. doi: 10.1080/13876988.2014.942570.

Joskow, P. L. (2006) *Competitive electricity markets and investment in new generating capacity*. 06–009.

Joskow, P. L. (2008) 'Capacity payments in imperfect electricity markets: Need and design', *Utilities Policy*, 16(3), pp. 159–170. doi: 10.1016/j.jup.2007.10.003.

Joskow, P. L. (2013) 'Symposium on "capacity markets"', *Economics of Energy and Environmental Policy*, 2(2), pp. v–vi.

Keppler, J. H. (2017) 'Rationales for capacity remuneration mechanisms : Security of supply externalities and asymmetric investment incentives', *Energy Policy*, 105(September 2016), pp. 562–570. doi: 10.1016/j.enpol.2016.10.008.

Leautier, T. O. (2016) 'The visible hand: Ensuring optimal investment in electric power generation', *Energy Journal*, 37(2), pp. 89–109. doi: 10.5547/01956574.37.2.tlea.

MacGill, I. (2010) 'Electricity market design for facilitating the integration of wind energy: Experience and prospects with the Australian National Electricity Market', *Energy Policy*, 38(7), pp. 3180–3191. doi: 10.1016/j.enpol.2009.07.047.

Marshman, D. *et al.* (2020) 'Performance of Wholesale Electricity Markets with High Wind Penetration', *Energy Economics*, In-Press.

Meade, R. and O'Connor, S. (2009) *Comparison of long-term contracts and vertical integration in decentralized electricity markets*, *Comparison of Long-Term Contracts and Vertical Integration in Decentralised Electricity Markets*. RSCAS 2009/16.

Meyer, R. (2012) 'Vertical economies and the costs of separating electricity supply - A review of theoretical and empirical literature', *Energy Journal*, 33(4), pp. 161–185. doi: 10.5547/01956574.33.4.8.

Milstein, I. and Tishler, A. (2019) 'On the effects of capacity payments in competitive electricity markets : Capacity adequacy , price cap , and reliability', *Energy Policy*, 129(November 2018), pp. 370–385. doi: 10.1016/j.enpol.2019.02.028.

Molyneaux, L. *et al.* (2013) 'Australian power: Can renewable technologies change the dominant industry view?', *Renewable Energy*, 60, pp. 215–221. doi: 10.1016/j.renene.2013.05.009.

Nelson, J. and Simshauser, P. (2013) 'Is the Merchant Power Producer a broken model?', *Energy Policy*, 53, pp. 298–310. doi: 10.1016/j.enpol.2012.10.059.

Nelson, T. *et al.* (2010) 'Delayed Carbon Policy Certainty and Electricity Prices in Australia*', *Economic Papers*, 29(4), pp. 446–465. doi: 10.1111/j.1759-3441.2010.00084.x.

Nelson, T. *et al.* (2013) 'An analysis of Australia's large scale renewable energy target: Restoring market confidenc', *Energy Policy*, 62, pp. 386–400.

Nelson, T. (2015) 'Australian Climate Change Policy - Where To From Here?', *Economic Papers*, 34(4), pp. 257–272. doi: 10.1111/1759-3441.12114.

Nelson, T., Reid, C. and McNeill, J. (2015) 'Energy-only markets and renewable energy targets: Complementary policy or policy collision?', *Economic Analysis and Policy*, 46(2015), pp. 25–42. doi: 10.1016/j.eap.2015.04.001.

Newbery, D. (2016) 'Missing money and missing markets: Reliability, capacity auctions and interconnectors', *Energy Policy*, 94(January), pp. 401–410. doi: 10.1016/j.enpol.2015.10.028.

Newbery, D. (2017) 'Tales of two islands – Lessons for EU energy policy from electricity market reforms in Britain and Ireland', *Energy Policy*, 105(June 2016), pp. 597–607. doi: 10.1016/j.enpol.2016.10.015.

Newbery, D. (2020) *Capacity Remuneration Mechanisms or Energy-Only Markets? The case of*

Belgium's market reform plan. Energy Policy Reserach Group, University of Cambridge. Available at: https://www.eprg.group.cam.ac.uk/wp-content/uploads/2020/03/D.-Newbery_Comment_24Mar2020.pdf.

Olsina, F. *et al.* (2014) 'Reliability payments to generation capacity in electricity markets', *Energy Policy*. Elsevier, 73, pp. 211–224. doi: 10.1016/j.enpol.2014.05.014.

Peluchon, B. (2003) 'Is investment in peaking generation assets efficient in a deregulated electricity sector?', in *Research Symposium on European Electricity Markets*, pp. 1–8.

Pindyck, R. S. (1999) 'Long-run evolution of energy prices', *Energy Journal*, 20(2), pp. 1–27. doi: 10.5547/issn0195-6574-ej-vol20-no2-1.

Plumb, M. and Davis, K. (2010) 'Developments in utilities prices', *RBA Bulletin*, December, pp. 9–17. Available at: http://www.rba.gov.au/publications/bulletin/2010/dec/bu-1210-2a.html.

Riesz, J., Gilmore, J. and MacGill, I. (2016) 'Assessing the viability of energy-only markets with 100% renewables: An Australian National Electricity Market case study', *Economics of Energy and Environmental Policy*, 5(1), pp. 105–130. doi: 10.5547/2160-5890.5.1.jrie.

Roques, F. A. (2008) 'Market design for generation adequacy: Healing causes rather than symptoms', *Utilities Policy*, 16(3), pp. 171–183. doi: 10.1016/j.jup.2008.01.008.

Roques, F. A., Newbery, D. M. and Nuttall, W. J. (2005) 'Investment Incentives and Electricity Market Design: the British Experience', *Review of Network Economics*, 4(2), pp. 93–128. doi: 10.2202/1446-9022.1068.

Schelly, C. (2014) 'Implementing renewable energy portfolio standards: The good, the bad, and the ugly in a two state comparison', *Energy Policy*, 67, pp. 543–551. doi: 10.1016/j.enpol.2013.11.075.

Simshauser, P. (2008) 'The dynamic efficiency gains from introducing capacity payments in the national electricity market', *Australian Economic Review*, 41(4), pp. 349–370. doi: 10.1111/j.1467-8462.2008.00512.x.

Simshauser, P. (2010) 'Vertical integration, credit ratings and retail price settings in energy-only markets: Navigating the Resource Adequacy problem', *Energy Policy*, 38(11), pp. 7427–7441. doi: 10.1016/j.enpol.2010.08.023.

Simshauser, P. (2018a) 'Garbage can theory and Australia's National Electricity Market: Decarbonisation in a hostile policy environment', *Energy Policy*, 120(June), pp. 697–713. doi: 10.13140/RG.2.2.34021.91367.

Simshauser, P. (2018b) 'On intermittent renewable generation & the stability of Australia's National Electricity Market', *Energy Economics*, 72(May), pp. 1–19. doi: 10.1016/j.eneco.2018.02.006.

Simshauser, P. (2019a) *Lessons from Australia's national emlectricity Market 1998-2018: the strengths and weaknesses of the reform experience*. EPRG Working Paper 1927, Energy Policy Research Group, University of Cambridge. Available at: https://ideas.repec.org/p/cam/camdae/1972.html.

Simshauser, P. (2019b) 'Missing money, missing policy and Resource Adequacy in Australia's National Electricity Market', *Utilities Policy*, 60, p. 100936. doi: 10.1016/j.jup.2019.100936.

Simshauser, P. (2019c) 'On the Stability of Energy-Only Markets with Government-Initiated Contracts-for-Differences', *Energies*, 12(13), p. 2566. doi: 10.3390/en12132566.

Simshauser, P. (2020a) *Merchant renewables and the valuation of peaking plant in energy-only markets*. EPRG Working Paper 2002, Policy Research Group, University of Cambridge. doi: 10.13140/RG.2.2.25864.98563.

Simshauser, P. (2020b) *Merchant utilities and boundaries of the firm : vertical integration in energy-only markets*. EPRG Working Paper 2008, Policy Research Group, University of Cambridge.

Simshauser, P., Tian, Y. and Whish-Wilson, P. (2015) 'Vertical integration in energy-only electricity markets', *Economic Analysis and Policy*, 48, pp. 35–56. doi: 10.1016/j.eap.2015.09.001.

Simshauser, P. and Tiernan, A. (2019) 'Climate change policy discontinuity and its effects on Australia's national electricity market', *Australian Journal of Public Administration*, 78(1), pp. 17–36. doi: 10.1111/1467-8500.12328.

Spees, K., Newell, S. A. and Pfeifenberger, J. P. (2013) ‘Capacity markets - Lessons learned from the first decade’, *Economics of Energy and Environmental Policy*, 2(2), pp. 1–26. doi: 10.5547/2160-5890.2.2.1.

Stoft, S. (2002) *Power System Economics: Designing Markets for Electricity*. Wiley.

de Vries, L. and Heijnen, P. (2008) ‘The impact of electricity market design upon investment under uncertainty: The effectiveness of capacity mechanisms’, *Utilities Policy*, 16(3), pp. 215–227. doi: 10.1016/j.jup.2007.12.002.

Wild, P., Bell, W. P. and Forster, J. (2015) ‘Impact of Carbon Prices on Wholesale Electricity Prices and Carbon Pass-Through Rates in the Australian National Electricity Market’, *The Energy Journal*, 36(3), pp. 137–153.

Zachary, S., Wilson, A. and Dent, C. (2019) *The integration of variable generation and storage into electricity capacity markets*. arXiv:1907.05973 [math.OC]. Available at: http://arxiv.org/abs/1907.05973.