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Missing money, missing policy and Resource Adequacy in Australia's National Electricity Market

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JEL Classification D61, L94, L11 and Q40

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May 2018

Abstract
From 2012-2017 more than 5000MW of coal plant exited Australia's National Electricity Market (NEM). The average plant exit notice period was 5.2 months. Exit at scale peaked just as imbalances in the market for natural gas emerged. Compounding matters were Variable Renewable Energy (VRE) plant entry lags due to policy discontinuity in prior periods. By 2016/17, the culmination of coal plant exit, gas market imbalances and VRE entry lags produced more than 20 Lack of Reserve events across the NEM, three blackouts including a black system event in the South Australian region. Spot and forward electricity prices rose to record levels, viz. $90-$130/MWh compared to an historic average of $42.50. In this article, the lead-up to these abnormal trading conditions are traced back to policy decisions a decade earlier in the markets for electricity, natural gas and renewable energy. Lessons for other energy markets undergoing transformation include i). transparency over lumpy plant exit decisions, ii). climate change policy stability, and iii). clear policy limits to gas export capacity vis-à-vis domestic supply.

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1. Introduction

From 1998-2016, Australia's National Electricity Market (NEM) had been a beacon for policymakers seeking to reform an electricity sector. The NEM was unique amongst restructured electricity market designs due to its single, real-time platform comprising a mandatory "gross pool" spot electricity market and eight co-optimised Frequency Control Ancillary Service spot markets, operating across five imperfectly interconnected regions with 5-minute dispatch resolution (MacGill, 2010). A single Independent Market Operator coordinates all regions and all spot markets, and again somewhat uniquely, without any formal day-ahead market[1] or capacity market (Riesz et al. 2015). Forward derivative contracts are traded both on-exchange and Over-The-Counter (OTC) and have historically exhibited turnover of 300-400% of physical trade.[2]

The governance framework is also unique; system operations, market regulation, and market rulemaking/policymaking are strictly segregated between the Australian Energy Market Operator; Australian Energy Regulator and Australian Energy Market Commission[3], respectively. Above all, the NEM's gross pool uniform first-price auction clearing mechanism and associated forward markets have delivered consistent economic performance under a wide range of technical and economic conditions, with Resource Adequacy (i.e. reliability) and security of supply being maintained with very few exceptions (see Appendix I).

In 2016/17 power system conditions deteriorated. The combination of events culminating over prior periods was extraordinary by any standard; the progressive closure of 18% of the NEM's coal fired generators, a domestic gas market that simultaneously went into an export-driven deficit, rebounding energy demand following five years of decline, an absence of new

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[1] Although as MacGill (2010) points out, the Market Operator does produce a very transparent 40hr pre-dispatch forecast which is continuously updated.
[2] See Simshauser, Tian & Whish-Wilson (2015) and in particular Appendix III.
[3] The Australian Energy Market Commission is in turn accountable to "COAG Energy Council" – which comprises the Energy Ministers from the Commonwealth, State and Territory Governments.

gas-fired proposals (let alone new entrants) and renewable plant entry lags due to policy discontinuity.

As a result of this confluence of events, during 2016/17 the market operator issued more than 20 Lack of Reserve notices[4] while the South Australian (SA) region experienced three major blackouts including a total grid collapse – Australia's first black system event since the early 1960s. Base load electricity futures rose to AUD $90-130/MWh[5] – well above the NEM's long run average spot price of $42.50/MWh. And short- to medium-term gas contracts were $9-12+/GJ after having progressively increased from historical long run equilibrium prices of $3-4/GJ as Figure 14 later reveals. The 2017/18 summer was expected to result in more supply shortages. From a consumer perspective this was an energy market in crisis and was treated as such by policymakers. The requisite "Inquiry" followed[6], along with expectations that *something must be done* as Helm (2014, p.4) explains more generally of energy markets and politically-driven Inquiries.

The purpose of this article is to analyse how Australia's NEM deteriorated so quickly, and to draw out policy implications for energy markets. It takes close to a decade to create such a mess, and so the analysis that follows necessarily covers a 10-year window. This article is structured as follows: Section 2 provides a brief review of the literature on energy-only electricity markets. Section 3 analyses the 2009-2015 period leading up to the energy market crisis while Section 4 analyses the unfolding events from 2016-2017. Policy implications and conclusions follow.

2. Review of Literature

In the context of the current analysis, two particular strands of literature are relevant, (i) Resource Adequacy in energy-only markets, and (ii) carbon policy uncertainty in Australia.

2.1 Resource Adequacy in energy-only markets

Resource Adequacy in energy-only markets can be loosely traced back to von der Fehr and Harbord (1995), who noted certain characteristics made merchant generation investment unusually risky, viz. indivisibility of plant capacity, long construction lead-times, lumpy plant entry, investment tenor and policy uncertainty (see also Stoft, 2002; Bidwell & Henney, 2004 and others[7]). Entire editions of academic journals have been devoted to the topic.[8] Doorman (2000), De Vries (2002) and Stoft (2002) were early contributors vis-à-vis the risk of peak plant investment while Peluchon (2003), Roques et al. (2005), Hogan (2005), Cramton & Stoft (2006), Joskow (2006), Finon & Pignon (2008), Simshauser (2008), Finon (2008) catalogue risks to timely entry across Europe, USA and Australia.

In theory, energy-only markets clear demand reliably and provide timely investment signals for requisite new capacity (Schweppe et al. 1988). But energy-only market theories are based upon equilibrium analysis and in practice electricity markets (like other markets) can be off equilibrium for extended periods (de Vries & Heijien, 2008; Hirth et al. 2016). What makes electricity markets of special interest is 1). the capital-intensive nature of the plant stock required to clear largely inelastic demand and the implications for capital flows under disequilibrium, <u>*and*</u> 2). the essential service nature of the commodity and the political economy associated with supply-side shortages.

A long list of explicit and implicit assumptions underpin the energy-only market model – including unlimited market price caps, limited political & regulatory interference, active demand-side participation, perfect forward markets or in the absence of these, a largely equity capital-funded generation fleet able to withstand elongated price cycles. But as these

[4] See ESB (2018).
[5] All financials are expressed in Australian Dollars (AUD) unless otherwise indicated.
[6] The initial response from COAG Energy Council was the establishment of the Finkel Review.
[7] See also Neuhoff et al. 2004; de Vries et al. 2004; Wen et al. 2004; Hogan, 2005; Bushnell, 2005; Roques et al. 2005; Cramton and Stoft, 2006; Joskow, 2006; Simshauser, 2008; Finon, 2008, 2011; Hogan 2013; Cramton, Ockenfels & Stoft, 2013; and Spees et al. 2013.
[8] See for example *Utilities Policy* Volume 16 (2008) and *Economics of Energy & Environmental Policy* Volume 2 (2013).

assumptions are progressively relaxed and market frictions introduced, it can be shown energy-only markets with an administratively determined Value of Lost Load (VoLL) do not have a stable equilibrium (Bidwell & Henney, 2004; Roques, 2008; Simshauser, 2008). Given substantial sunk costs and low marginal running costs, persistent generator bidding at marginal cost in an intensely competitive energy-only market will produce inadequate net revenues – known as the *missing money problem* (Cramton & Stoft, 2006[9]). Participants in energy-only markets are unable to optimise the number of blackout events (i.e. VoLL) that produce stable equilibrium (Cramton et al. 2013), while in addition wholesale price caps can be set too low or over-enforced by regulatory authorities along with actions by System Operators which suppress legitimate price signals (Joskow 2008, Spees et al., 2013; Hogan, 2013, Leautier, 2016 and others[10]).

Furthermore, electricity markets are characterised by several non-trivial market failures. Most hard and soft commodity markets clear under scarcity conditions via a combination of demand-bids and supply-inventories. But in electricity markets, large segments of real-time aggregate demand are price-inelastic and unable to react to scarcity conditions (Cramton & Stoft, 2008, Batlle & Perez-Arriaga, 2008; Roques, 2008; Finon & Pignon, 2008). The supply-side is similarly inelastic in real-time because storage is costly. System Operators must therefore resort to non-price rationing and a regulator is forced to administratively determine VoLL.

High levels of Variable Renewable Energy (VRE) amplifies and complicates matters, because historically such plant have been subsidised in certificate 'side-markets' and priority dispatched (Nelson et al. 2012; Joskow, 2013; Newbery, 2015; Simshauser, 2018). Given negligible marginal running costs, *merit-order effects* arising from VRE became apparent in markets such as Germany as early as 2008 (Sensfuβ et al. 2008) and had been prominent in the SA region of the NEM (Forrest and MacGill (2013; Cludius et al. 2014; Bell et al. 2015; Bell et al. 2017).

Energy-only markets are thus rarely in equilibrium, and this matters because capital-intensive merchant generators face rigid debt repayment schedules. Of itself, this is unremarkable but becomes problematic in the presence of incomplete forward derivatives markets. In consequence, the theory of energy-only markets suffers from an inadequate treatment of how sunk capital is financed (Joskow, 2006; Finon, 2008; Meade & O'Connor, 2009; Caplan, 2012; Nelson & Simshauser, 2013).

Energy-only markets have generally failed to deliver the requisite mix of derivative instruments required to facilitate efficient plant entry (Hansen, 2004; Chao, Oren and Wilson, 2008; Meade and O'Connor, 2009; Meyer, 2012). As Finon (2011) explains, the *canonical model* in deregulated energy-only markets was the Merchant Power Producer, a stand-alone generator that sold its production into spot and short-term forward markets, underpinned by long-dated non-recourse project finance. In the early phases of the global restructuring and deregulation experiment, a vast fleet of merchant plant *was* banked on this basis (Joskow, 2006; Finon, 2008).[11] But recurring economic damage to merchant generator Profit & Loss Statements, a product of *missing money*, began to take its toll on project bank risk tolerances and credit metrics (Simshauser, 2010). By 2005 more than 110,000MW of merchant plant in the US, much of the Australian merchant fleet and some high profile plant in the UK (e.g. Drax) experienced financial distress or bankruptcy (Joskow, 2006; Finon, 2008; Nelson & Simshauser, 2013). Consequently, the *canonical model* became *un-bankable* on a timely basis in the absence of long-term (i.e. 10+ years) contracts. There is now considerable evidence to support the notion that timely plant entry on a purely merchant basis is

[9] See also Neuhoff et al. 2004; de Vries, 2004; de Vries et al. 2008; Bushnell, 2005; Roques et al. 2005; Joskow, 2008b; Finon, 2008; Simshauser, 2008; Joskow, 2013; Nelson & Simshauser, 2013; Cramton, Ockenfels & Stoft, 2013; Green & Staffell, 2016; Keay, 2016.
[10] See also Besser et al. 2002; Oren, 2003;de Vries, 2003; Wen et al. 2004; Batlle & Perez-Arriaga, 2008; Finon & Pignon, 2008.
[11] This included 230,000MW in the US, 13,000MW in Australia and more than 6000MW of new plant in the UK. See Joskow (2006), Finon (2008) and Simshauser (2010) for details.

intractable[12] in energy-only markets (Joskow, 2006; Howell, Meade & O'Connor, 2010; Caplan, 2012; Nelson and Simshauser, 2013).

Long-dated contracts have become a pre-condition for project finance, and while Australia's NEM is noted for favourable forward market liquidity[13], activity spans 3 years – well short of optimal financing that facilitate efficient ex-ante investment commitment, viz. 12-year semi-permanent project debt set within notional 18-25 year structures. Forward markets have failed to calibrate beyond 3 years because competitive Retailers cannot afford to hold hedge portfolios dominated by inflexible long-dated contracts when large components of their customer book switch supplier every 2-3 years. As Figure 11 later illustrates, Commercial & Industrial customers in the NEM had signed, on average, contracts of just 22 months duration just prior to the NEM's looming price cycle. The short-tenor bias of merchant retailers can be traced to excessive retail-level competition, demand uncertainty and risks of being undercut by new entrant retailers with short-dated portfolios (Newbery, 2006 and others[14]).

Three broad remedies are typically suggested to deal with *missing money* viz. (1) introducing capacity markets (Bidwell & Henney, 2004; Simshauser, 2008; Spees et al. 2013; Green & Staffell, 2016), (2) raising VoLL (Newbery, 2006; Finon, 2008; Simshauser, 2010), or (3) increasing Operating Reserves (Hogan, 2005; 2013). Each of these comes with problems; introducing capacity markets represents a *partial reversion* to central planning and grinds against the decision to push market and investment risk away from consumers and to investors in the first place (Leautier, 2016).[15] Raising VoLL compounds the risk of, and inability to distinguish, market power (Roques et al, 2005 and others[16]). And increasing Operating Reserves, which has the effect of expanding volumes and increasing the frequency of 'lower value VoLL events', may suffer similar problems. To be sure, none of these represent a choice between markets and intervention because each involve an administratively-determined variable (Campton et al. 2013).[17]

2.2 Australian carbon price policy discontinuity

While Australia's energy-only NEM operated successfully for the better part of two decades (noting Australia's very high VoLL of $14,200/MWh), this occurred in spite of climate change policy settings. Indeed a "two-decades long" climate change policy war, which commenced in 1997[18], has persisted between Australia's two major parties, the social democratic Labor and conservative Liberal / National coalition, and, within the conservative Liberal party (see Jones, 2009; Nelson et al. 2010; Jones, 2010; Byrne et al 2013; Molyneaux et al 2013; Nelson et al, 2013; Byrne et al. 2013; Freebairn, 2014; Garnaut, 2014; Wagner et al. 2015; Nelson 2015; Apergis & Lau, 2015).

There have been *seven* attempts at a national Emissions Trading Scheme (ETS) over the period 1997-2018. ETS policy development cycles were initiated in 1997-2001 (see AGO,

[12] To be clear, plant will eventually enter on a merchant basis if prices are high enough. But the political economy of such prices makes this problematic.
[13] See for example Chester (2006); Anderson et al. (2007); Howell, Meade & O'Connor (2010); and most recently, Simshauser et al. (2015, Appendix 3 and Figure C.1 on p.54).
[14] See also Green, 2006; Anderson et al. 2007; Finon, 2008; Simshauser, 2010; Howell, Meade and O'Connor, 2010
[15] Hogan (2013) also notes there is no simple way to observe and measure delivery. Conversely, Cramton & Stoft (2008) observe that even if capacity is *overbuilt* as a result of capacity mechanisms, the incremental cost to consumers is small because excess 'peaking plant' is the cheapest form of capacity (viz. an extra 10% of peak capacity may increase consumer costs by say 2%). Additionally, Spees et al. (2013 pp15-16) observe that on balance capacity markets in the US have delivered good results in that they met their objective function, mobilised large amounts of low cost supply including Demand Response, energy efficiency, transmission interconnection, plant upgrades, deferred retirements and environmental retrofits.
[16] See also Besser et al, 2003; Oren, 2003; Cramton & Stoft, 2006; Joskow 2008; Simshauser, 2008.
[17] A higher VoLL involves administratively determining a price cap to meet an administratively-determined reliability constraint. As Joskow (2013) notes, the entire logic of capacity markets starts with administratively-determined reliability criteria and involves administratively determining the quantity required to meet that constraint. And relying on FCAS involves administratively determining spinning reserve quantities in order to meet the reliability constraint. Thus each solution involves some form of administrative judgement, and in all cases, the risk of error – viz. exercise of market power with VoLL (Hogan, 2013); over-investment with capacity markets (Leautier, 2016); or market power and excess reserves with FCAS – is ultimately borne by the customer.
[18] The Howard Government released a broad climate policy strategy titled "Safeguarding the Future: Australia's Response to Climate Change. 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 August 2017).

1999a, 1999b; Nelson et al. 2010; Simshauser & Tiernan 2018), in 2005-2006 via a state-based national ETS scheme (see NETT, 2006; Nelson et al. 2010; Jones, 2014) and again from 2008-2010 (see Buckman & Diesendorf, 2010; Garnaut, 2014). On the fourth attempt the policy development cycle from 2011-2012 was implemented and a carbon tax transitioning to an ETS was implemented from 2012-2014 only to be *killed off* following a general election and change of government in 2013 (see Freebairn, 2014; Wild et al 2015). Three further attempts have since been initiated; an Emissions Intensity Scheme in 2016 (see Simshauser & Tiernan, 2018), a Clean Energy Target in 2017 (see Finkel, 2017; Simshauser 2018) and a National Energy Guarantee from 2018 with this latter policy development cycle still on-foot with tentative bi-partisan support (see ESB, 2018).

Adding to the seven attempts at a national ETS, at the sub-national level two schemes were legislated and operationalised in Queensland and New South Wales from the early 2000s to 2012 due to the absence of an integrated national framework. Both schemes were closed to avoid duplication with Australia's Carbon Tax in 2012, and could not be practically revived when the Carbon Tax policy was shut down in 2014[19] (see Jones 2009; Daly and Edis; 2010; Nelson, 2015; Simshauser, 2018).

Adding to the policy uncertainty has been continuous change in Australia's Renewable Energy Target (RET[20]). The RET was the world's first renewable energy portfolio standard and initially mandated an additional 2% of energy be produced from renewable sources following its announcement in 1997 (MacGill 2010; Buckman and Diesendorf 2010; Byrne et al. 2013; Forrest and MacGill, 2013; Cludius et al. 2014).[21] Legislated in 2000[22] and commencing from 2001, the policy has since been subjected to six major legislative reviews and fundamentally altered on three occasions (Jones 2009; Nelson et al. 2013; Simshauser 2018). A review in 2006 recommended the 9500GWh scheme be expanded and lengthened (Jones 2009; Buckman and Diesendorf 2010; Daly and Edis 2010), in 2008 it was expanded to a 20% Target expressed as 45TWh (Nelson et al. 2010; Byrnes et al. 2013; Cludius et al. 2014), was split into a small (4000 GWh) and large-scale (41TWh) scheme in 2010 due to design flaws (Nelson et al. 2013; Nelson 2015; Simshauser & Tiernan, 2018); and reduced from 41TWh to 33TWh in 2015 (see Simshauser, 2018).

To summarise, there has been seven attempts at an ETS, while the RET has been reviewed six times and fundamentally altered on three occasions. The climate change policy environment impacting Australia's NEM has thus been *discontinuous* at best.

3. The 2009-2015 build-up to energy market conditions in 2016/17

The NEM formally commenced in 1998 although energy-only 'gross pool' markets operated in NEM sub-regions from as early as 1994. Investment decisions for new capacity were, at that point, shifted from former state-owned monopoly Electricity Commissions to the market.

3.1 The starting point: changing entry form - Merchant to Policy-Induced

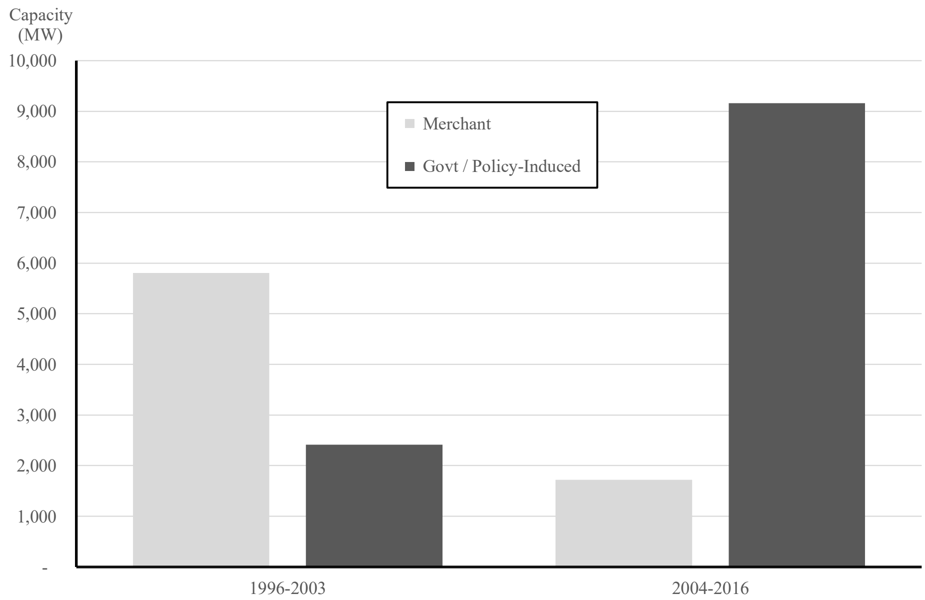
NEM plant entry from the late-1990s experienced two extremes; 1). excess entry of base plant in Queensland, and simultaneously 2). a risk of inadequate peaking plant entry in the Victorian region (i.e. temporal Resource Adequacy problem). Over time, government enterprises and policy mechanisms began to play an increasing role in the type, and the timing, of new plant entry – the latter in response to Australia's international CO_2 emission reduction commitments at Kyoto and later, at the Paris Conference of the Parties. There is no definitive point at which these conditions changed, but for the purposes of the subsequent analysis, 2004 is used as a transition phase in which CO_2-related policy investments became

[19] The Carbon Tax policy was abandoned by the Abbott Government, and at the time, the State Governments of both QLD and NSW were of the same political party. In the case of QLD it is also fair to say that the Gas Electricity Certificate policy had *run its course* for reasons outlined in Section 4.2.
[20] To be clear, Australia's RET is an "electricity" target, unlike the EU RES energy target.
[21] While Australia was the first country to introduce a Renewable Portfolio Standard mechanism, the concept was originally developed in the USA (see Buckman and Diesendorf 2010).
[22] The legislation giving effect to the RET is the *Renewable Energy (Electricity) Act (2000)*.

prominent and coincides with the demise of the *canonical merchant power producer model* discussed in Section 2.1.

Figure 1 allocates NEM generation plant entry into two distinct timeframes – pre- and post-2004 – and split between two entry forms, viz. *"Merchant"* private investment and *"Government / Policy-Induced"*. These latter generators sell their output into the spot electricity market in the same was as *Merchant* but by contrast, have some form of government involvement, either implicit backing – i.e. investments committed by government trading enterprises by way of balance sheet (as distinct from project-) financing, or in most instances, investments by private sector participants which access *tradeable certificates* in a "side-market".[23]

Figure 1: **NEM plant investment– Merchant vs. Government / Policy-induced**[24]



Source: esaa, AEC.

Notice that over the period 1996-2003, almost 6000MW of generation plant entry was *Merchant*. Large capital commitments ($6+ billion) were made in response to perceived supply-side opportunities and the strength of forward price signals. The risk of investment error was allocated appropriately – to the owners of the merchant generator. Notice also that in the 1996-2003 period, *Government / Policy-Induced* entry was relatively small and primarily a response to the 2% Mandated Renewable Energy Target along with some State-sanctioned Power Purchase Agreements on the grounds of Resource Adequacy risks in a newly forming market. The 2004-2016 timeframe exhibits a reversal of entry form – policy inducement became a dominant driver of investment. More than 9000MW of plant was committed whereas pure merchant entry was less than 2000MW.

3.2 Rising plant stock imbalances

Like many markets around the world experimenting with what Pollitt & Anaya (2016) describe as 'game changing polices' to reduce CO_2 emissions, policy-induced entry resulted in a steadily rising structural oversupply and in some regions the emergence of the so-called merit-order effect. The *policy-induced entry form* became prominent from 2010 and would weigh heavily on industry fundamentals.

[23] Side markets include Renewable Energy Certificates under Australia's 20% Renewable Energy Target and other state based schemes, and in some instances direct government contracts structured either as a Power Purchase Agreement or more recently, as Contracts-for-Differences. See Simshauser & Tiernan (2018).

[24] In the period 2004-2016, Government / Policy-Induced plant comprised about 5100MW of conventional plant (dominated by gas-fired generation plant associated with Queensland's Gas Electricity Certificate Scheme), and 4100MW of renewables in response to the RET.

Table 1: NEM Optimal Plant Mix vs Actual Plant Mix in 2010

Operating Duty	Optimal	Actual	Imbalance	Weighting
(Peak load: 35,700 MW)	(MW)	(MW)	(MW)	
Base load plant	25,000	29,000	4,000	Overweight
Intermediate	3,600	6,000	2,400	Overweight
Peak load plant	10,700	10,200	-500	Underweight
Renewables	985	2,200	1,215	Overweight
Aggregate Supply	40,285	47,400	7,115	Oversupplied
Capital stock	\$45,909.70	\$55,248.80	\$9,339.10	Overcapitalised
Source: Simshauser (2010)				

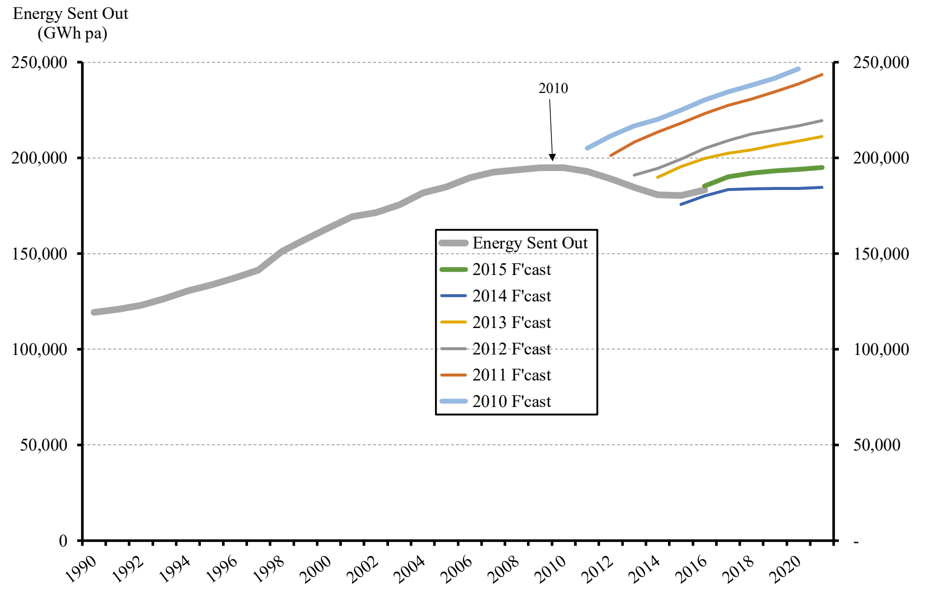
Simshauser (2010)

Table 1 analyses the NEM's 2010 supply-side balance relative to load given the then system-wide maximum demand of 35700MW and energy demand of 200TWh. In a security-constrained dispatch model, the "Optimal" plant stock was determined as 25000MW of base, 3600MW of intermediate and 10700MW of peak duty plant. Additionally, to meet RET policy objectives, about 985MW of renewable plant was required. The "Actual" column shows the incumbent fleet of generators, which exceeded "Optimal" by +7115MW. Notice that oversupply comprised the more capital-intensive base and intermediate duty plant, and thus the capital stock was +\$9,339.1 million overweight just as the RET policy was dramatically increased from 2% to 20%.

3.3 Electricity load growth contracts (the first time in 120 years)

Like many jurisdictions around the world, the Australian power industry can be traced back to the late-1800s. From first power on 9 December 1882, where 8 arc lamps lit up along Queen Street in Brisbane, through to 2010 by which time the 5-region NEM represented one of the largest geographically interconnected grids in the world, the power system experienced positive Year-on-Year load growth. Like most OECD economies NEM growth rates had been slowing from the 1950s onwards. But in 2010, final electricity demand contracted (Figure 2).

Figure 2: **Final electricity demand (NEM Regions) 1990-2016 and 2010-2015 forecasts (net of rooftop Solar PV)**



Source: esaa, AEC, AEMO.

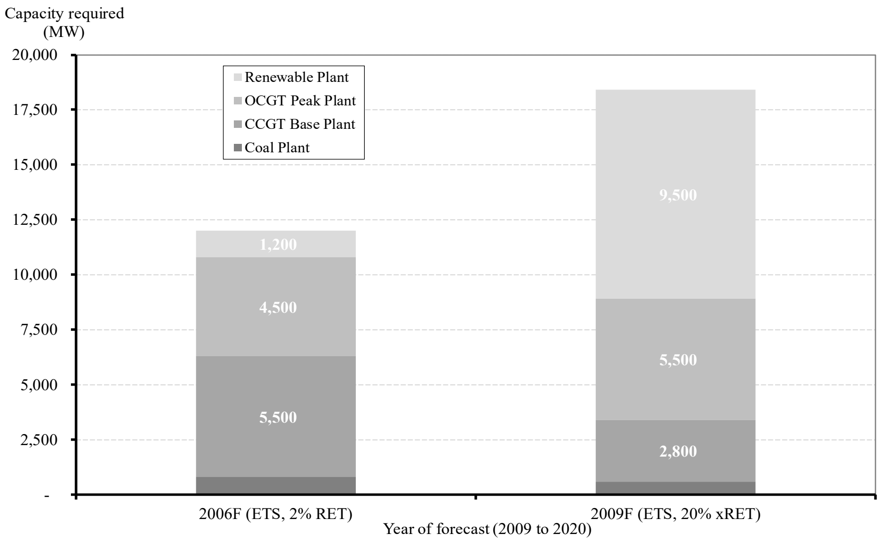
Figure 2 includes central load forecasts undertaken from 2010-2015 – it took some time for industry to moderate forward growth expectations.

3.4 Policy-induced entry into an oversupplied market with contracting demand

Under Australia's 2% renewable energy portfolio standard or RET, qualifying renewable generators could produce a Renewable Energy Certificate (REC) for each MWh they produced. Electricity retailers were allocated a set quantity of RECs to purchase each year and failure to do so was met with a non tax-deductible penalty price of $40/REC or $57/REC after adjusting for corporate taxes (Jones, 2009; Nelson et al. 2013).[25] As Section 2.2 explained, from 2009 the RET policy was greatly expanded from 2% to 20%. To support the policy objective the REC penalty price was raised to $65 or $92/REC after adjusting for taxation.[26]

The investment outlook for renewable plant increased sharply as a result. Figure 3, reproduced from Simshauser (2010), shows two forecasts for plant entry – in 2006 under the 2% RET, and in 2009 after the 20% RET was legislated. Note the expectation in the *Policy-Induced entry form*, from 1200MW to 9500MW. When the 20% RET (or 45TWh target) was devised during the 2-year period leading up to the 2009 legislation, load forecasts anticipated Year-on-Year load growth of 2.3% (per Figure 2). By the time investment commitments were to be made, new plant would enter a market already oversupplied, and a market where load was now contracting for the first time.

Figure 3: **Impact of expanded RET policy on forward investment plans**



Source: Simshauser (2010)

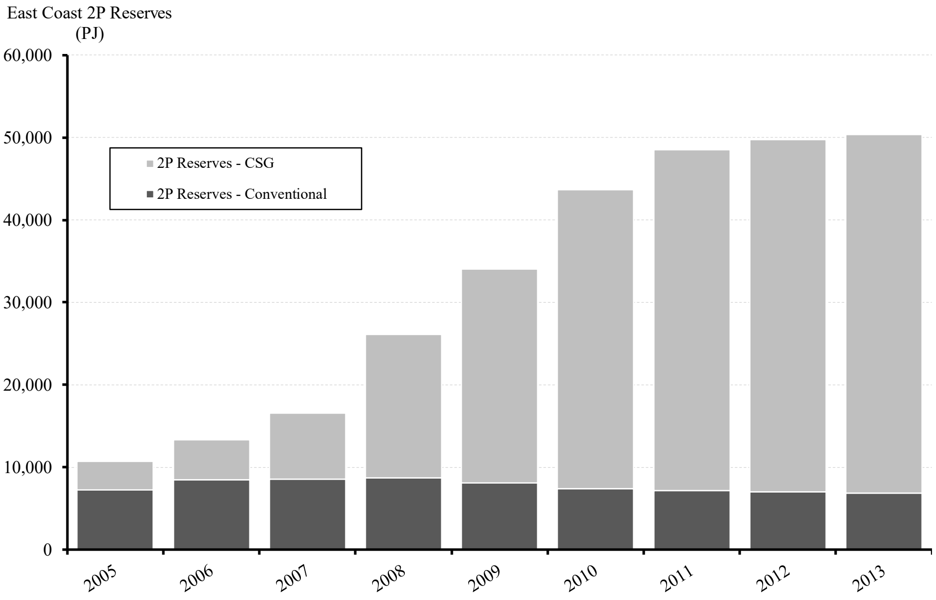
3.5 Compounding matters: large discoveries of cost coal seam gas

Throughout the period in which excess generation capacity was beginning to accumulate, and at a time when Australian final electricity demand was contracting for the first time on record, and in parallel with the expanded RET, discoveries of Proven & Probable (2P) coal seam gas reserves began to rise, sharply, as illustrated in Figure 4.

[25] The opportunity cost of the MRET penalty incorporating the taxation rate of 30% was $57.14, i.e. ($40/0.7).

[26] The legislation was the Renewable Energy (Electricity) Amendment Act 2009. Around the same time, the Renewable Energy Directive (mandating the EU15 achieve 20% renewable energy production by 2020) also entered into force (see Jaraite et al. 2017).

Figure 4: **Build-up of 'Proven & Probable' coal seam gas reserves – 2005-2013**



Source: Simshauser & Nelson 2015

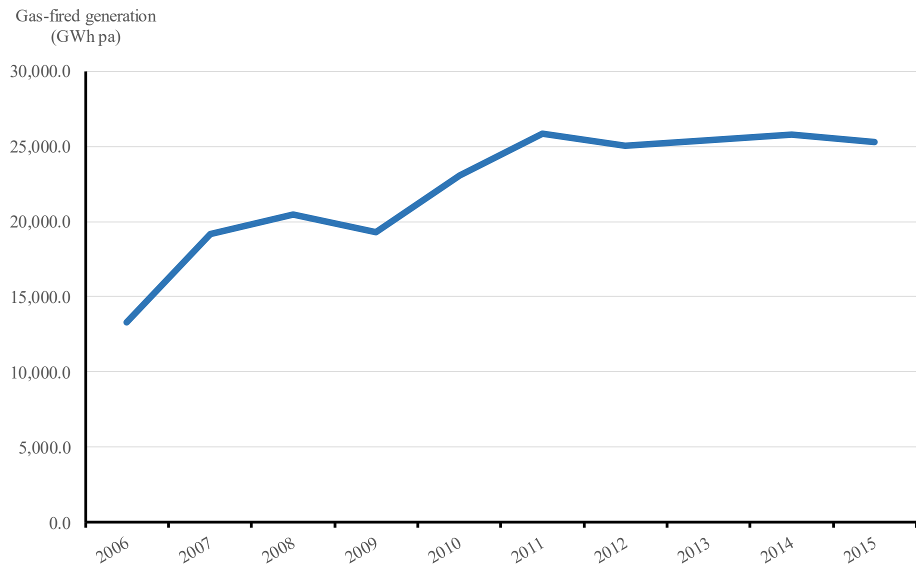
The sheer size of these reserves relative to final east coast gas demand of about 700PJ per annum lead to a monetisation dilemma. Growth in gas demand faced challenges in the short run; *climate change policy wars* meant no clear path existed for gas generation to enter profitably because CCGT plant, even with ultra-low cost Coal Seam Gas (circa $2.50/GJ), faced brutal competition from some of the lowest cost coal-fired generators in the world; the NEM's black and brown coal fleet had marginal running costs of US$3 - US$10/MWh and average total costs of US$30/MWh.[27] Consequently, by 2011 the roughly 50,000PJ of 2P reserves would take more than 70 years to monetise absent some other channel-to-market.[28]

Over the period 2008-2012, three of the major gas producers on Australia's east coast (Shell, Santos and Origin Energy) developed plans for LNG export terminals, each comprising roughly 2 x 250PJ/a plants. The general view was that some consolidation and rationalisation would ultimately occur because if all three projects were to proceed, they would add 1500 PJ/a to Australian east coast gas market final demand of 700PJ/a. The commitment of the 6 x 250 PJ/a LNG trains nonetheless occurred, and would have vital short- and long-run implications for the NEM; in the short run during the period leading up to LNG plant commissioning a certain amount of coal seam gas (i.e. LNG ramp gas) would be temporarily diverted to the NEM's gas turbine fleet. This led to a transient doubling of gas-fired generation output, from an historic market share of 6% to 13%, or 13,300GWh pa to almost 26,000GWh per annum (Figure 5) thus further compounding structural oversupply.

[27] AUD/USD = 0.75

[28] That is, 50,000PJ/700PJ = 71 years.

Figure 5: **Gas-fired generation**



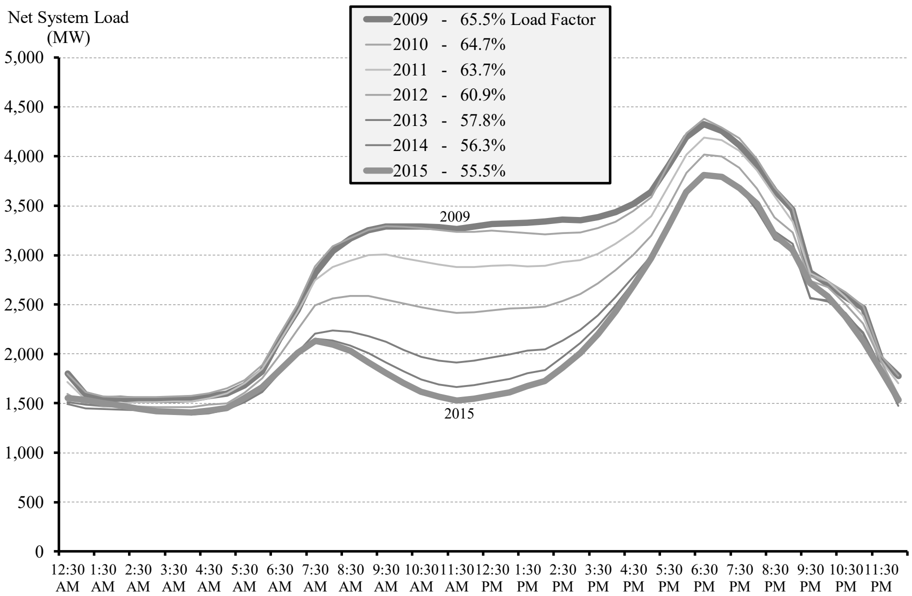
Source: esaa, AEC

The longer-term implications are dealt with later, in Section 4.2.

3.6 Rooftop Solar PV at world record take-up rates

Wholesale market conditions were further weighed down by the rapid take-up in rooftop solar PV. In the QLD and SA NEM regions, installation rates were at world record levels on a per capita basis with 3 in 10 detached households installing rooftop PV systems – and given the size of the Australian housing stock (i.e. marginal housing stock is the second largest in the world at an average 240m^2), marginal installations are typically 5+kW per household. In some distribution network areas, this had the effect of producing the equivalent of the Californian Duck Curve via rooftop PV (rather than utility-scale) as Figure 6 illustrates.

Figure 6: **Impact of rooftop solar PV with take-up rates rising to 3 in 10 detached homes (Southeast Queensland Distribution Network load)**

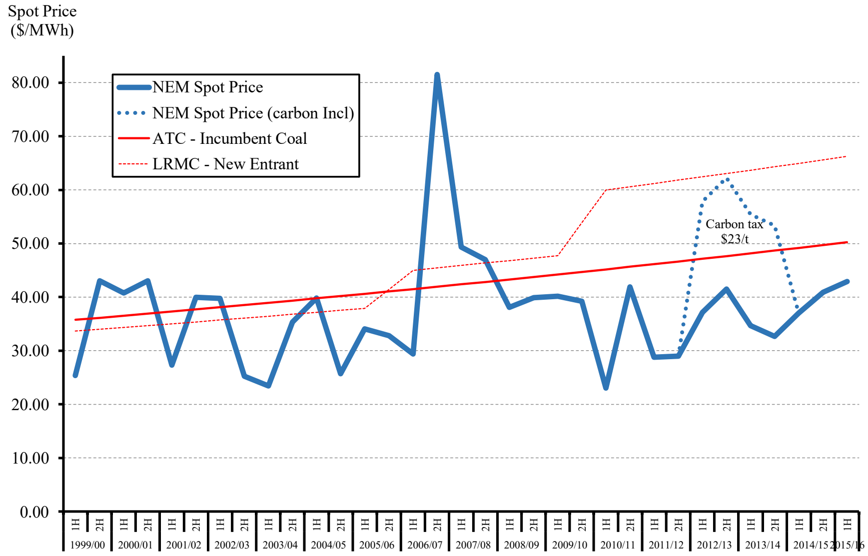


Source: Energex.

3.7 Wholesale prices fall

The impacts of structural oversupply, contracting power system demand, the policy-induced entry form, the build-up of 2P gas reserves & transient surge in gas-fired generation and world-record levels of rooftop solar PV, collectively placed considerable downward pressure on wholesale electricity prices. NEM spot prices (1999-2015, nominal dollars) are presented in Figure 7 and compared to 1). an estimated Average Total Cost (ATC) of the coal-fired fleet and 2). new entrant costs as represented by coal plant (1999-2005) and combined cycle gas turbine plant (2006-2018).

Figure 7: **Nominal spot market prices vs Average Total Cost (Incumbent Coal Plant)**



Source: AEMO, Simshauser (2014).

3.8 *The missing money*

By combining annual spot price and ATC data from Figure 8 with annual generation data for coal and gas-fired generation[29], the quantum of *missing money* over the 2009-2015 period can be estimated (see Table 2). To be sure, Table 2 excludes Ancillary Services revenues (although over this period comprised < 0.5% of system revenues) and any contract premiums – which might add c.5-10% in revenues. These limitations aside, the missing money are c. $11.933 billion. The NEM's coal and gas-fired generation fleet peaked in 2011 at 36500MW, comprising 28150MW of coal and 8500MW of gas plant. The *missing* money for each 1000MW of incumbent capacity was *at least* $300 million over the period 2009-2015 as Table 2 notes.

Table 2: Calculation of missing money for coal and gas-fired generation plant

Year	ATC ($/MWh)	NEM Price ($/MWh)	Shortfall ($/MWh)	Generation (GWh)	Missing Money ($ Billions)
2009	43.30	39.11	-4.19	197,380.7	-0.730
2010	44.23	39.46	-4.76	192,848.5	-0.812
2011	45.18	31.96	-13.22	187,438.1	-2.190
2012	46.15	28.83	-17.32	184,892.2	-2.829
2013	47.14	37.81	-9.33	173,965.5	-1.435
2014	48.16	31.53	-16.62	168,160.4	-2.470
2015	49.19	39.60	-9.59	173,369.7	-1.469
Total	46.09	35.52	-10.57		-11.933

Source: aemo, esaa, Simshauser (2014).

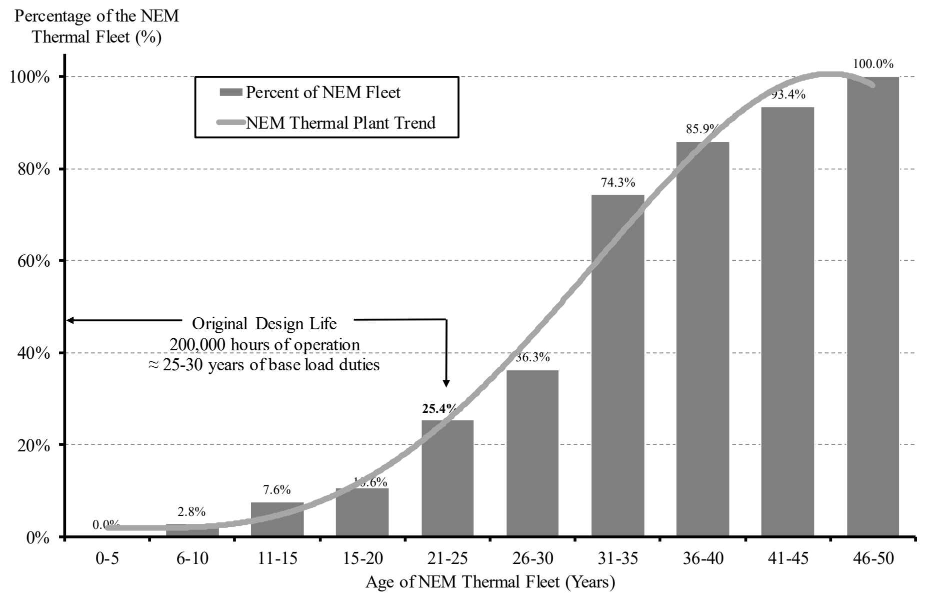
3.9 Combining maintenance cutbacks with aging plant

Like most other power systems amongst OECD countries, the NEM's thermal (i.e. excluding gas turbine) fleet is aging. Entry is now dominated by renewable plant and specifically solar and wind. Figure 8 illustrates the age of the NEM's 26,872MW thermal plant stock. The majority (ca.20,000MW) of the fleet was planned and constructed by State Electricity Commissions, with engineering design lives of ca.200,000 hours of operation (about 25 years of production duties). Of course, most of these machines will have an economic life of 40-50 years – Table 3 later reveals the practical evidence. But the significance of Figure 8 is to

[29] In this calculation, annual generation output was reduced by 7% for auxiliary load and a further 5% for transmission losses.

highlight that 75% of the NEM's thermal plant stock has already surpassed original engineering design lives. If such plant are to maintain high levels of availability, then maintenance expenditure will need to *increase,* not reduce.

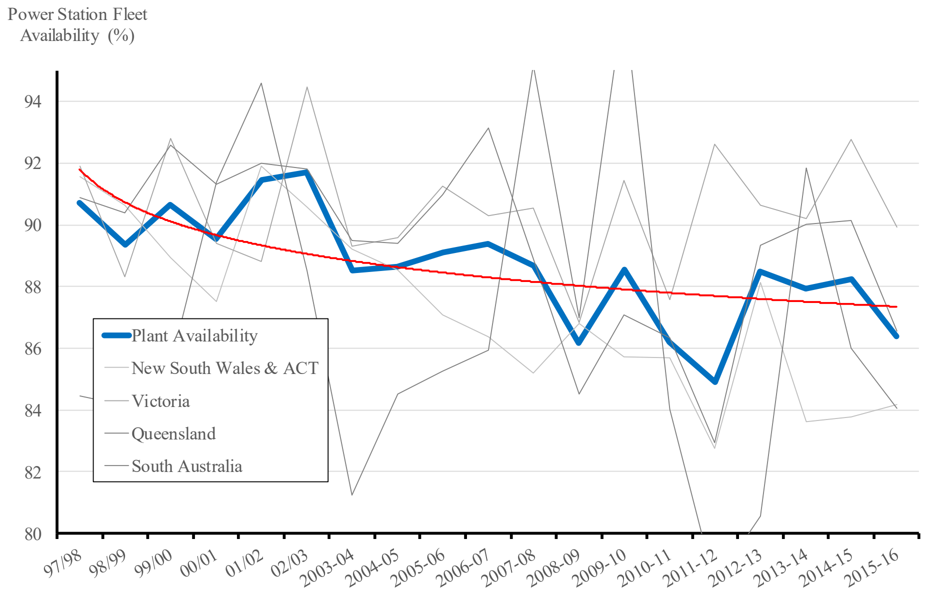
Figure 8: **Cumulative age of the NEM's Thermal Fleet**



Source: ESAA, AEC.

But a predictable outcome in the presence of mounting economic losses (Table 2) is a reduction in planned maintenance expenditures.[30] With maintenance spending cutbacks, plant availability rates would begin to deteriorate in line with the rise in *missing money* as Figure 9 illustrates. This is an economic result, but one that would have implications in 2016/17.

Figure 9: **NEM power station fleet availability from 1997/98 to 2015/16**



Source: esaa, AEC.

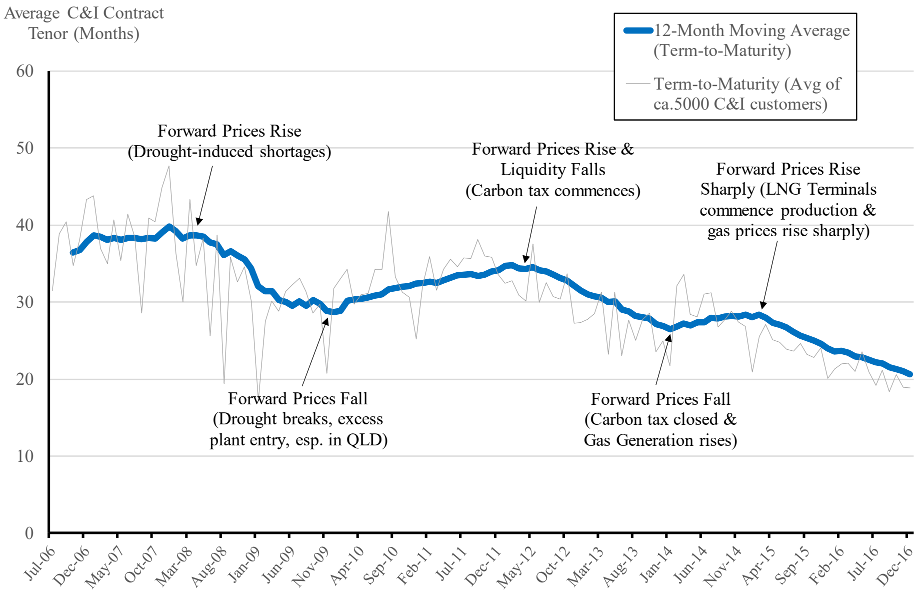
3.10 The C&I Customer Setup

This culmination of events, including gyrations in the market for natural gas and the political market for climate change policy initiatives seemingly led C&I Customers to alter their electricity purchasing practices. Presumably driven by internal procurement teams rather than

[30] By way of simple example, in 2011 the 2000MW Loy Yang Power Station in Victoria's La Trobe Valley delayed an otherwise scheduled statutory overhaul by 12-18 months in order to maintain cash flows in the intervening period. The author was Chairman of Loy Yang from 2009-2011.

treasury teams, contract durations immediately prior to looming price spikes visibly shorten as Figure 10 illustrates. This shortening was material – the average C&I contract tenor had progressively reduced from an average of 38+ months to just 22 months by the end of the data series. This would setup C&I customers for *maximum commodity price exposure* to any upward cycle due the speed of C&I forward purchase maturities.

Figure 10: **NEM average C&I contract tenor: 2006-2016 term-to-maturity**



Source: EnergyAction[31]

By the 2014/15 financial year, NEM power system conditions and the supply-demand imbalances had reached their nadir. From this point, conditions would start to reverse rapidly. Spot and forward prices would then surge to record levels following a series of sudden shocks. For C&I Customers, shortening contract tenor risk would then vest with full force, from 2016/17.

4. 2016/17: exit, LNG entry and renewable policy uncertainty

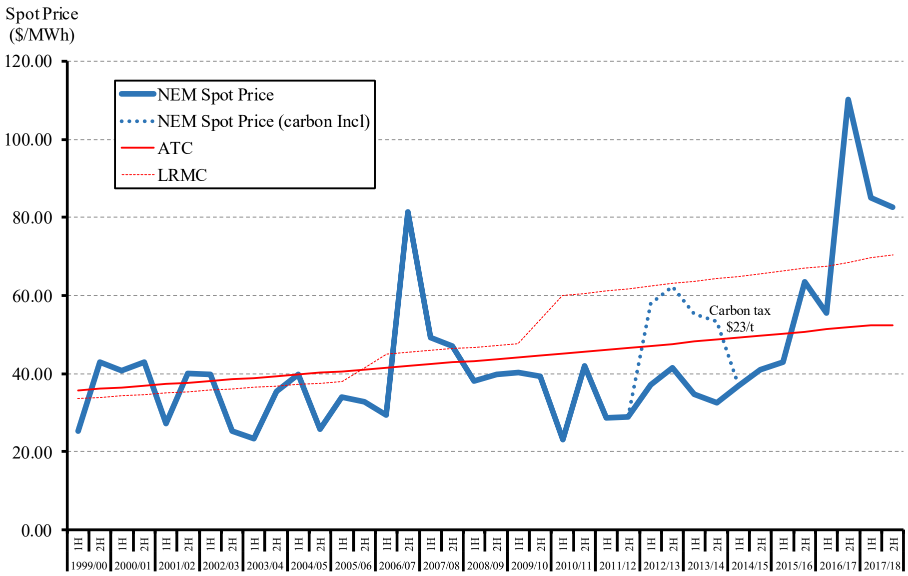
Mounting economic losses (Table 2) meant certain coal generators would hit natural limits to cost cutting and thus exit would become the dominant strategy. Trying to predict the timing of coal plant exit is a thankless task. Tipping points driving exit decisions seem to correlate with large capital re-investment requirements rather than a simple episode of short run revenues failing to cover short run cost. Furthermore, exit decisions are complicated by multiple considerations including 1). immediate losses of uncertain near-term spot market revenues; 2). the risk of *first mover disadvantage;* and 3). the compounding penalty of enormous site rehabilitation costs associated with a coal plant closure decision. Consequently, Australian literature and policy inquiry began to canvas coal plant *barriers to exit* in the NEM (see for example Nelson, Reid & McNeill, 2015; Jotzo & Mazouz, 2015; Parliament of Australia, 2016). Ultimately, what occurred was an uncoordinated exit procession that exceeded market expectation.[32]

It is difficult to define the pivotal moment, but the NEM cycled from record low- to record high-prices over the 2014 (low) to 2017 (high) period, starting with the announced closures of major coal-fired generators in the Southern NEM regions, sharply rising gas prices, and the

[31] Based on approximately 5000 C&I customers. Thanks to Michael Fahey (EnergyAction) for providing this data.
[32] A number of industry professionals have said to this author that the NEM coal plant exit decisions that occurred were predictable. I note that their observations were made 'ex post'! While some of the closures were predictable, I certainly did not anticipate the speed, nor the extent, of the NEM plant closures that ultimately transpired. The practical evidence presented in Section 4 is that the market did not either.

delayed entry of renewables: Figure 11 extends Figure 7 to illustrate the run-up in spot prices from 2H 2015/16.

Figure 11: **Spot market prices vs generator costs 1999-2018**



Source: AEMO, ABS, Simshauser (2014)

4.1 Uncoordinated coal plant exit

From 2012, aging coal plants began exiting the NEM. Initial closures were benign events; plant exits were small relative to total region oversupply, had operated at comparatively low utilisation rates, or had already been mothballed and thus had little impact on spot market prices as Figure 11 indicates. But two plant exits during 2016-2017 in the southern regions of the NEM were material, occurred with little warning and were uncoordinated. Table 3 sets out the NEM coal plant closures from 2012-2017 and notes that 11 coal plants with 5156MW of capacity exited the market with a capacity-weighted average warning period of 5.2 months.

Table 3: NEM coal plant exit

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

The 540MW Northern Power Station, the last coal-fired plant in the NEM's SA Region, announced it would close in mid-2016. The plant had a declining coal resource but more importantly was forced to compete with a large wind fleet, navigate weather-driven *merit-order effects* and a C&I customer base who, ironically, seemed to prefer taking spot exposures than sign medium-term supply agreements with the generator. With spot revenues declining and plant costs rising (falling availability and utilisation) closure became the dominant strategy. The significance of its closure was underestimated - not from a spot market or system reliability perspective, but from a contract market perspective (see Simshauser, 2018b). SA is a small imperfectly interconnected NEM region with a peak load of 3100MW and an underlying base load of 1200MW[33]. Thus the exit of a 540MW base load plant would extract a very material component of SA's primary supply of base load hedge contracts – and in their place were run-of-plant Wind Power Purchase Agreements – far from a perfect substitute. And as Section 4.2 later reveals, immediately preceding this a CCGT plant partially mothballed its capacity to on-sell gas to LNG export markets. Forward prices jumped and crucially, hedge contract liquidity contracted. Over the ensuing 12-month period the SA power system would experience multiple blackouts and a *black system event* in September 2016.

Two months later, the 1600MW Hazelwood Power Station in the adjacent VIC Region announced it would close in mid-2017. The closure arose due to mounting long-dated capital re-investment requirements ($400 million[34]) relating to plant safety. Hazelwood supplied more than 20% of the VIC region, and was thus also a material and coincident plant exit.

Northern Power Station is an example of *first mover disadvantage*. While Northern would eventually exit the market due to declining coal resources, it is not obvious that April 2016 was the optimal closure date given Hazelwood's imminent, but unknown, exit timing.

4.2 LNG entry & CCGT withdrawal

Figure 6 noted gas-fired generation output increased by more than 90%, from 13300GWh in 2006 to almost 26,000GWh in 2014. The 2014 final gas demand on the east coast network was 700PJ/a with gas used in power generation representing about 215 PJ/a or 30% of the aggregate.[35] The east coast's gas supply and demand had taken nearly 50 years reach these levels. During the two-year period 2014-2016, gas demand would triple to 2000PJ/a following the commissioning of three LNG terminals. Details of the LNG terminals are presented in Table 4 and Figure 12 provides historic and forecast final gas demand for context.

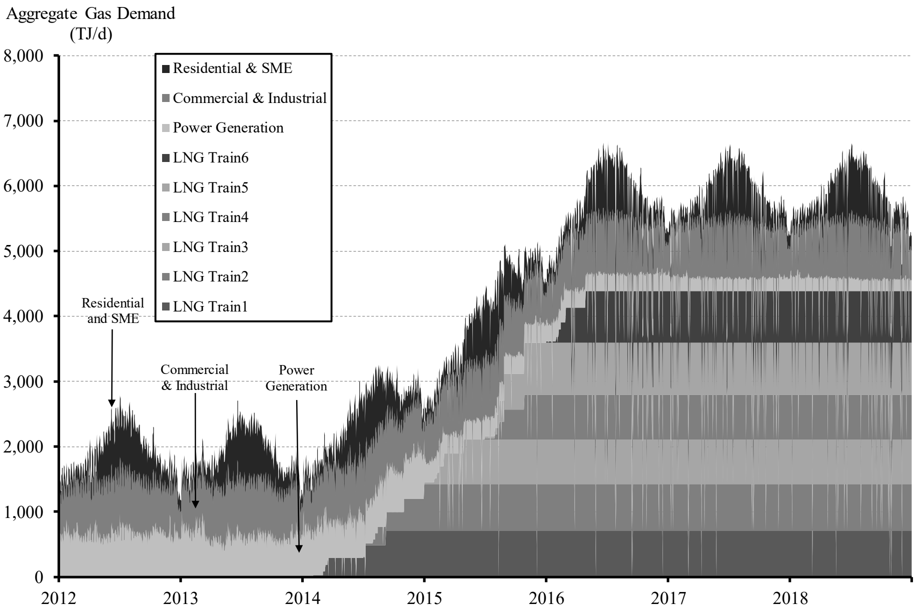
Table 4: Queensland LNG Plant

LNG Project	Domestic Proponent	Project Commitment Date	Nameplate Capacity (PJ/a)	Maximum Capacity (PJ/a)	Contracted Supply (PJ/a)	Comissioning Date Train 1	Comissioning Date Train 2	Investment Commitment
QCLNG	Shell	30-Oct-10	504	549	474	28-Dec-14	5-Jul-15	USD 19.8b
APLNG	Origin Energy	04-Jul-12*	534	575	510	2-Jan-16	6-Oct-16	USD 24.7b
GLNG	Santos	13-Jan-11	463	498	427	27-Sep-15	25-May-16	USD 18.0 b
TOTAL			1500	1622	1411			

*APLNG Train 1 was committed on 28 July 2011. Source: Simshauser (2018), Grafton et al. (2018)

[33] Calculations are based on 2017 SA load data, viz. peak demand of 3059MW and energy demand of 12607GWh. Base load duties have been defined at the 82nd percentile of load given coal plant marginal running costs of $15/MWh and Average Total Cost of $55/MWh, and CCGT plant marginal running costs of $55/MWh and Average Total Cost of $88/MWh.
[34] For details on the Hazelwood re-investment dilemma see http://www.abc.net.au/news/2016-12-01/worksafe-notices-detail-extent-of-repairs-needed-at-hazelwood/8082318.
[35] Commercial & Industrial gas consumption was 290PJ/a, and residential use was 180PJ/a (Simshauser & Nelson, 2015).

Figure 12: **Daily final gas demand 2012-2013 and Forecast gas demand 2014-2018**



Source: Simshauser & Nelson (2015).

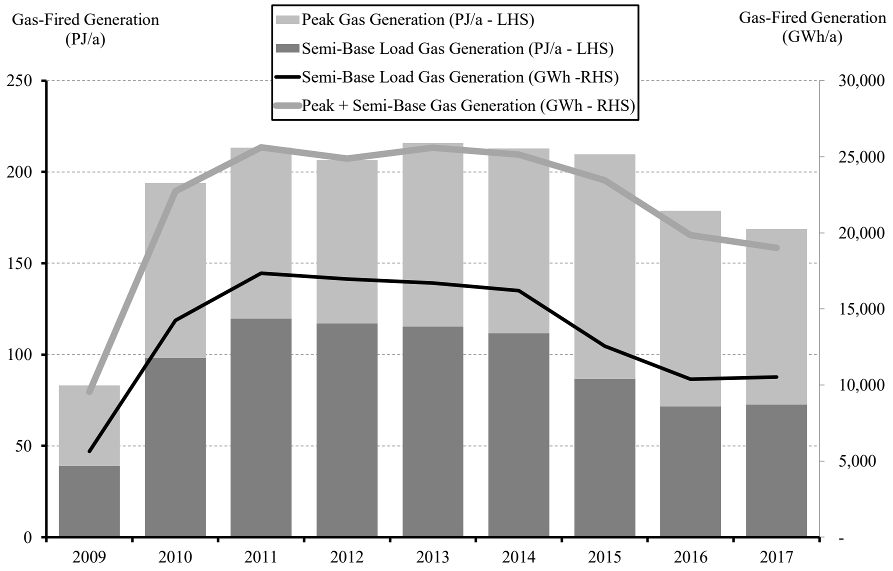
In my opinion, it would be unusual for any mature energy market to experience a three-fold change in demand within a two-year window, and do so smoothly. Just as final gas demand was set to treble constraints emerged on the supply-side – three[36] of five NEM jurisdictional governments and the neighbouring Northern Territory government placed a moratorium on on-shore coal seam gas 'fracking'. Furthermore, just as the LNG terminals were commissioning the oil price collapsed which adversely affected the economics of marginal gas supplies. Boreholes drilled, the lead indicator of future supply, contracted sharply (see Appendix II).

The entry of the three LNG terminals would therefore completely upend eastern Australian gas market dynamics on a sustained basis (i.e. medium- to long-term planning horizon) for three primary reasons;

1. Because LNG entry exceeded supply, a certain amount of gas used in the domestic market would be suddenly re-diverted to LNG export plants to meet certain 'point-to-point contract' export commitments (Grafton et al. 2018). Gas-fired generation peaked over the 2013-2014 period at around 215PJ/a annum. Once LNG Plant began their commissioning cycle, gas used in power generation contracted to 169PJ/a, with semi-base load gas generation reducing from 115PJ/a over the 2013-2014 period to 72PJ/a (down 37%) over the 2016-2017 period (see Figure 13). This contraction in base load gas generation output coincided with the exit of the base load Northern and Hazelwood coal-fired power stations.

[36] NSW, VIC and TAS.

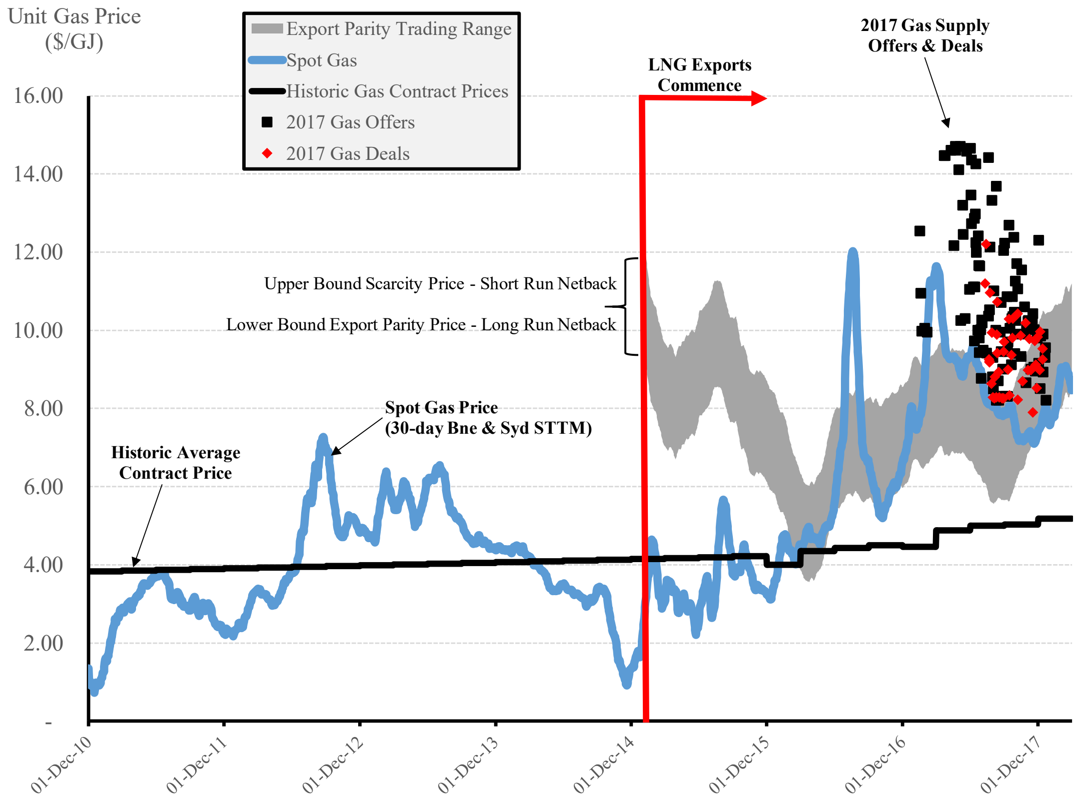
Figure 13: **Gas used in gas-fired power generation (2009-2017)**



Source: EnergyEdge GMAT.

2. Australia's historically low and stable gas prices of $3 - $4/GJ would suddenly link to LNG-netback prices (see shaded area in Figure 14) with forward gas supply contract offers and deals evidently trading from $8 - $12+/GJ as Figure 14 illustrates.

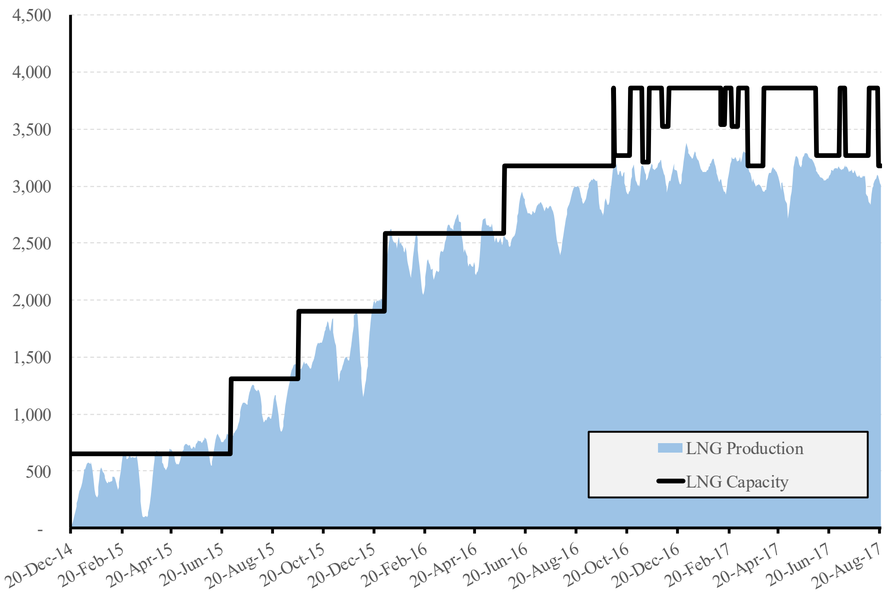
Figure 14: **Australian East Coast Spot and Contract Gas Prices (2010-2018)**



Source: GMAT, ACCC (2018).

3. It had become clear that 3 LNG projects (comprising 6 individual trains, per Table 4) represented *excess entry* and in consequence the gas market would emerge at the end of the LNG commissioning cycle in an elongated state of supply-scarcity as Figure 15 illustrated. As Simshauser & Nelson (2015) explained, the gas market was capable of supporting 4 x 250PJ LNG trains, possibly 5. 6 trains was an *excess entry result*.

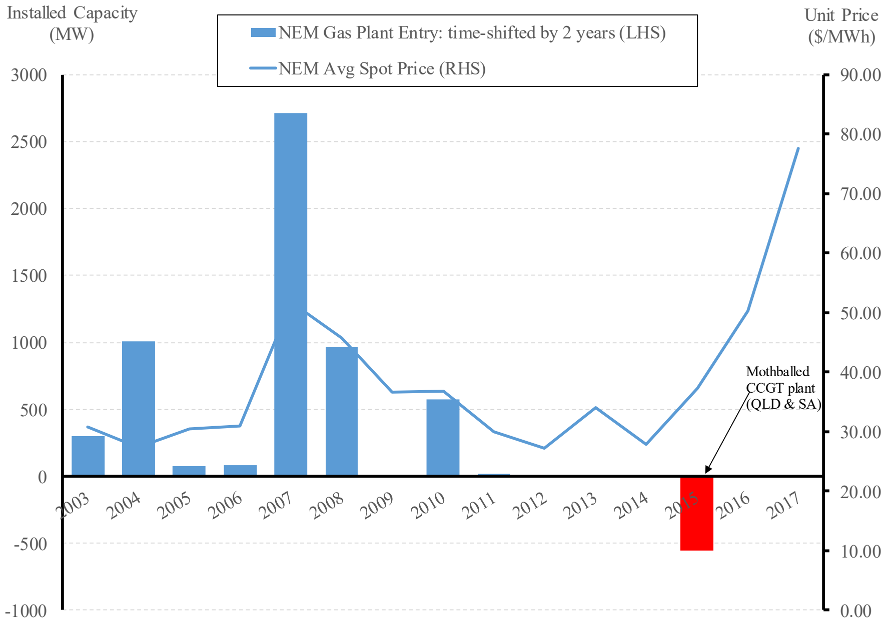
Figure 15: **LNG Plant Capacity vs Production**



Source: GMAT.

A striking feature of the 2016/17 electricity price cycle was the complete absence of gas turbine proposals, let alone entry. Gas plant entry was subject to critical hold-up. The NEM has had prior episodes of high spot electricity (viz. 2007-2008) driven by Australia's millennium drought.[37] During that price cycle, more than 5000MW of gas-fired generation plant entered the coal-dominated NEM (see Figure 16). In the current cycle, prices have risen to much higher levels but rather than entering, semi-base gas-fired generators opted to on-sell long-dated gas supplies to the chronically short LNG export industry during the low spot electricity price periods in 2014-2015 – not knowing that uncoordinated coal plant exits were imminent. Two CCGT plants were, therefore, mothballed in 2015/16. When the Northern and Hazelwood coal plant suddenly exited, CCGT plant struggled to re-enter the market because gas prices had surged beyond economic levels (see Figure 14).

Figure 16: **Gas fired plant entry, and mothballing**



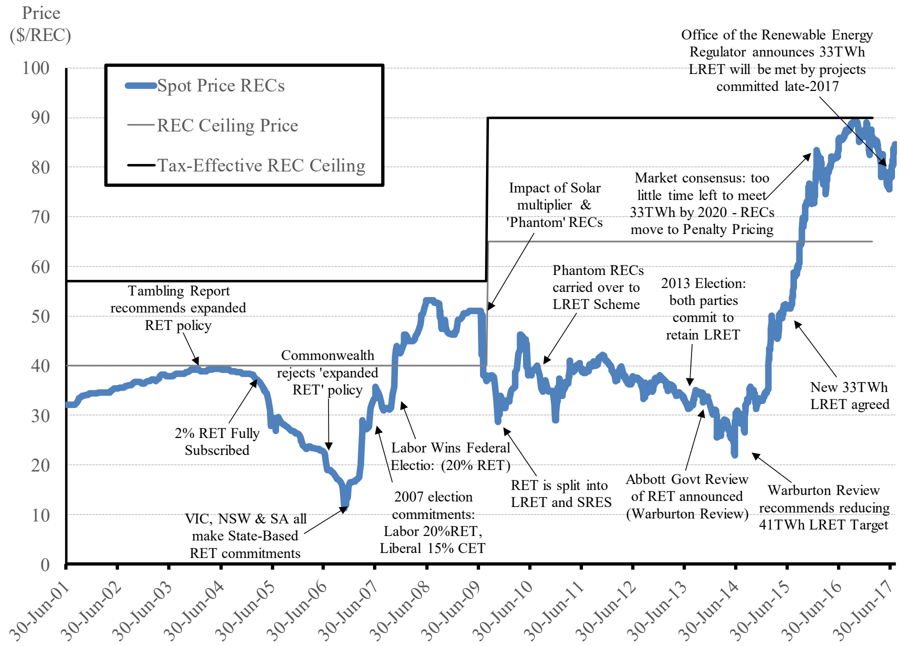
Source: esaa, AEC, AEMO.

[37] During 2007-2008, hydro plant were severely curtailed and in QLD coal plant were forced to mothball due to critical water shortages in dams where coal plant shared with drinking water supplies.

4.3 VRE entry lags

Coal plant exit was driven by *missing money* and the market outlook, viz. contracting demand, expectations of a large policy-induced fleet of VRE plant entry via the 20% Renewable Energy Target (RET) and the other factors outlined earlier. However, the anticipated VRE plant entry experienced non-trivial delay through *policy discontinuity*. Section 2.2 noted the RET had been the subject of six major reviews. Figure 17 illustrates the series of political events and their impact on the prevailing price of Renewable Energy Certificates.

Figure 17: **REC Spot Prices (2001-2017)**



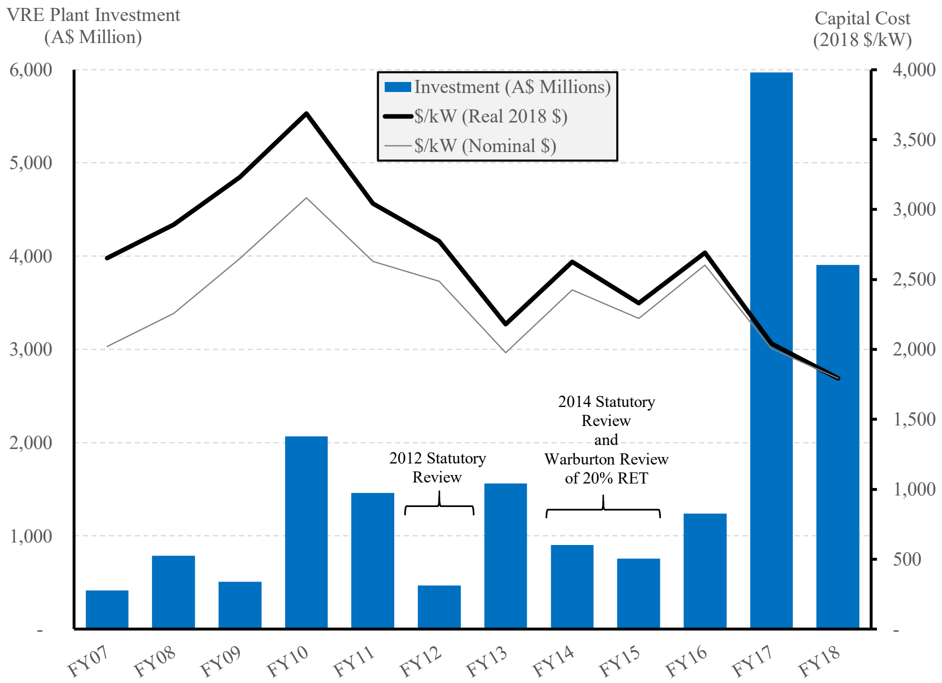
Source: Simshauser (2018)

In 2013 a general election produced a change in the Commonwealth Government, from social democrat Labor to the conservative Liberal/National Coalition. The incoming Abbott Government commissioned yet another (non-scheduled) fundamental review of the RET ('Warburton Review[38]') in February 2014 – the 6th major review of the policy. However, on this occasion the implications were more significant; the Warburton Review's four-person expert panel comprised four highly regarded business people, three of which were outspoken on adverse effects of carbon pricing and RET policies. This set a certain tone as to the likely direction of the policy review within the industry. With the RET fixed at 41TWh and contracting demand, the 20% target was beginning to look closer to 25-30%. This was the narrative adopted when the Review Panel was initiated (Byrne et al. 2013; Nelson, 2015). Consequently, from the moment the panel inquiry and its members were announced, an investment freeze emerged (see Figure 18). The Warburton review released their report on 28 August 2014 and recommended either closing the scheme to entrants, or a variable 20% target (which would equate to 26TWh, a 15TWh reduction from the 41TWh target).

From 2014-2015 wholesale electricity prices were ca.$39/MWh due to the overhang of capacity, and Renewable Energy Certificates traded below $30/REC given policy uncertainty. VRE entry costs had not experienced their more recent rapid downward trajectory (which occurred from 2016 onwards, see Figure 18). Consequently, with wind projects still > $80/MWh and solar PV projects $100+/MWh, investment conditions for VRE had become intractable. For VRE plant to have any moderating effect on the looming and uncoordinated coal plant exits and gas plant withdrawals, it was during this period that investment commitment needed to occur due to construction lags. But as Figure 18 illustrates, a distinct slowdown in investment commitments occurred during FY14-FY16.

[38] Warburton Review available at http://apo.org.au/system/files/41058/apo-nid41058-82456.pdf

Figure 18: **Investment in RET**



Source BNEF, ABS.

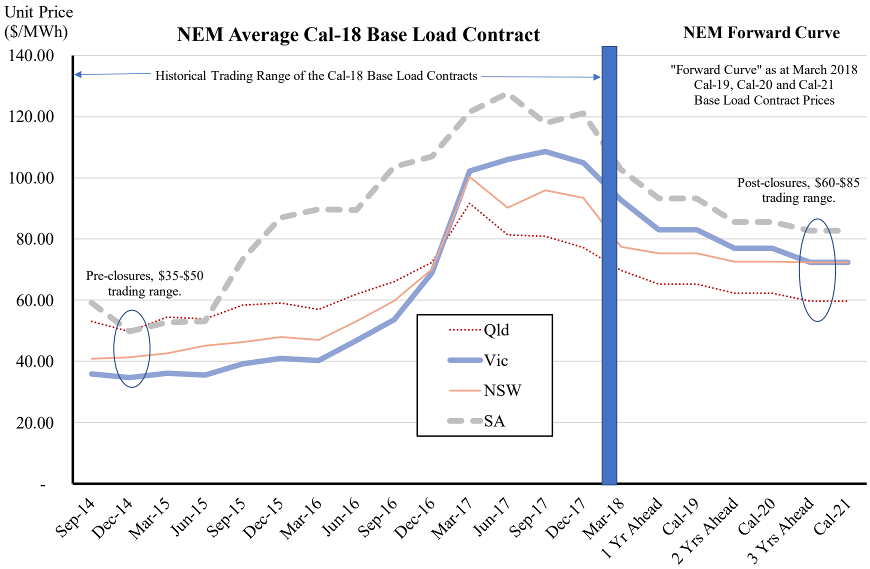
Late in 2014, the major political parties commenced negotiations with the involvement of stakeholders, and a deal was done on 11 May 2015 to scale-back the 41TWh target to 33TWh, with amendments to the RET legislation passed in 23 June 2015. Project development activity was then re-initiated with commitments emerging 12 months later and accelerating in pace to record investment levels in FY17 and FY18, with most of this capacity set to enter in FY19 and FY20.

4.4 Spot and forward prices

The combination of uncoordinated coal plant exit, the commissioning of the LNG terminals, the scarcity of gas supply, declining gas-fired generation output and lagged entry of renewables sent spot and futures prices soaring by historic standards.[39] Figure 18, which has two panels, summarises the evolution of prices by reference to Calendar Year 2018 (Cal-18) base load futures contract prices (LHS panel), and the forward price curve comprising Calendar Year 2019-2021 base load futures prices (RHS panel). Note that the trading range of the Cal-18 instrument was $35-$50/MWh in the period leading up to the NEM's crisis period of 2016/17, whereas the Cal-21 trading range is $60-$85/MWh – the primary difference being the change in the plant mix, underpinned by the profound changes to the market for natural gas.

[39] Adding to the NEMs problems were the ability of remaining coal plant to shadow price the (dramatically) higher marginal running costs of the OCGT plants setting prices, and in the Queensland region, the unexpected but blatant market power abuse by, ironically, a state-owned generator – with tacit supporting behaviour amongst other public and private generators.

Figure 19: **2018 Futures Contracts and 2018 Forward Curve**



Source: GFI.

5. Policy Implications and Concluding Remarks

In May 2018, the front page of *The Australian* newspaper reported a Newspoll survey of voters on which federal party, social democratic Labor or conservative Liberal/National, would best manage energy supply and lower energy prices[40]. That such a poll occurred at all is of concern. When electricity supply persistently makes headlines of national newspapers, the policy that follows will rarely be well considered as Simshauser & Tiernan (2018) explain.

Given the benefit of hindsight, what can be learned from such a mess? It is worth distinguishing problems from properly functioning markets. The NEM's spot and contract markets have operated faithfully[41] throughout the 2016/2017 period in that prices reflected scarcity. The signals, while acute, led to a large supply-side response; by the end of the 2017/18 financial year, Australia's Clean Energy Regulator had recorded 5249MW[42] of VRE committed and under construction with a further 800MW proceeding to financial close. Additionally, the black system event in South Australia, while extraordinary, was a security issue, not a reliability issue, and not one that warrants anything beyond a review of system operations and the dispatch quantities of Frequency Control Ancillary Services given a rapidly changing plant mix.[43]

The NEM's three material policy problems are (i) dealing with uncoordinated plant exit at scale, (ii) climate change policy discontinuity and its impact on investment timing, and the (iii) the general state of the gas market.

5.1 Uncoordinated Exit

When the NEM (and other energy markets like it) was designed load growth was significant and considerable thought went into *plant entry*. In the Australian case at least, it is not obvious that *plant exit* and the post-exit market environment were given much consideration at all because barriers to entry were largely dismantled. In practice, exit decisions at scale are

[40] See "PM's energy plan fails with voters", *The Australian*, 29 May 2018, Page 1. The National Affairs Editor (Simon Benson) of *The Australian* was the author.
[41] Notwithstanding one episode of economic withholding by one generator (see Wood & Blowers, 2018), which in turn was dealt with by policymakers.
[42] Data available at http://www.cleanenergyregulator.gov.au/RET/About-the-Renewable-Energy-Target/Large-scale-Renewable-Energy-Target-market-data#progress
[43] The distinction here is nuanced but critical. It is beyond the scope of this article to review the details of the system collapse, suffice to acknowledge two key issues, 1). Resource Adequacy was not an underlying problem per se in that adequate plant capacity existed, and 2). system operation was suboptimal in that the dispatch of Frequency Control Ancillary Services was insufficient and interconnectors overloaded given the mix of plant available and known volatile weather conditions approaching the region.

uncoordinated for anti-trust reasons, and they have occurred with little warning as Table 3 explained. Uncoordinated and sudden exit at scale produces transient market imbalances and in the NEM raised prices sharply. In most other markets, exit effects are driven by plant entry, and smoothed by inventories and demand bids. In the case of electricity, demand response has been imperfect and the supply-side is largely inelastic in the short run.

As an energy-only market, there is no centrally contracted capacity in the NEM. A Medium Term Projected Assessment of System Adequacy (two-years ahead, weekly resolution) provides information on aggregate supply and forecast demand, but ultimately it is non-binding on participants. The initial response from policymakers on advice from the *Finkel Review* (2017) was to introduce a Three-Year Closure Rule (the Rule Change was under active consideration at the time of writing). This rule would require all power stations above a certain size to nominate their expected closure date to the system operator, and to update any change to this expected closure date immediately (in a manner consistent with the listing conventions and public disclosures associated with stock exchanges).

This is an entirely sensible policy suggestion. The intent of the NEM's proposed Rule Change is to make this disclosure a legally binding obligation, which raises at least two problems; (i) Company Directors have fiduciary duties to *not* trade while insolvent, and (ii) Company Directors also have fiduciary duties to *not* endanger the lives of employees, and clearly with a 40+ year old piece of mechanical and electrical equipment, this cannot be guaranteed three years ahead without occasionally triggering (i) due to extensive capital re-investment required. The Hazelwood example, requiring $400 million of reinvestment, is a case in point.

Would a capacity market alter this dynamic? Perhaps. But it is worth bearing in mind that most power stations in Table 3 would have had a portfolio of forward contracts in place at the time the Board of Directors decided to close the plant, and unwinding these contracts *must* follow any closure announcement otherwise traders are in breach of Australia's "insider trading" laws. And so exit at scale necessarily involves the costly unwinding of forward hedge contracts. Furthermore, as one reviewer pointed out – the first capacity auctions in Great Britain saw a successful CCGT bid fail to enter with the proponents treating the capacity contract as a form of option – and writing off its credit support costs – and an existing coal generator withdrew from a 1-year capacity contact it had previously banked. Ultimately, the combination of (i) and (ii) must surely explain the extraordinary speed of exit of many of the coal plant listed in Table 3 in spite of their forward contract positions.

If publishing expected coal plant closure dates "in good faith" is as much as can be reasonably expected due to Directors liabilities, then the policy gap that needs to be considered is how to moderate the impacts of exit at scale. Forward prices six months prior to the closure of Hazelwood Power Station in VIC were $41.38/MWh (Apr-2016). Forward prices rose to $112.07/MWh (Apr-2017) in the month following plant exit – with the entire 8 x 200MW plant exiting over the course of 6 consecutive trading days. The consumer impact of this price change equates to $3.27 billion in a single year given VIC generation output of 45,250GWh.[44] If the Hazelwood plant required $400 million re-investment but cannot be justified by the firm, and region-wide economic impacts in a single year are multiples of the reinvestment hurdle, then some policy mechanism to fund some fraction of this re-investment could be justified – not with an objective of prolonging a plant which should retire – but to ensure retirement occurs in an orderly fashion. For example, in the Hazelwood case the closure of 4 units in 2017 followed by the closure of the remaining units in 2019 or 2020 would have still produced a surge in prices (albeit not to the same extreme) and provided the supply-side with a reasonable response time.[45]

[44] Prices in all NEM regions were materially impacted, and so NEM-wide (i.e. 180TWh load) consumer impacts are multiples of this figure.
[45] I have written elsewhere that entry times for permitted plant in the NEM including 6 months to reach financial close followed by the following construction periods: 1). 18 months for wind generation, 2). 9 months for solar PV, 3). 9 months for utility-scale battery, and 4). 12 months for gas turbine plant.

5.2 Climate change policy discontinuity

Australian academic literature is littered with research on the effects of *policy discontinuity* after the two decades long climate policy wars. Policy discontinuity has sent mixed signals to utility and renewables investors and created boom-bust investment conditions as illustrated in Figures 17 and 18. Within Australia's federalist system of government, energy policy levers and their real-world implications are generally poorly understood by politicians due to (1) its sporadic relevance to prevailing political agendas, and (2) the sheer complexity of gross pool competitive energy-only markets. Energy policy responsibility is at the State-level, and climate change policy is a Commonwealth responsibility. There are at least a dozen Commonwealth politicians from the conservative side of politics who genuinely believe that what Australia is lacking is a new coal-fired generator.[46]

At the time of writing an integrated energy and climate change policy, known as the National Energy Guarantee (NEG), was being pursued by the full-time politicians dedicated to understanding the NEM, viz. the State and Commonwealth Energy Ministers, with the intent being to enshrine the policy framework into the National Energy Rules (due to the inherent stability of the National Electricity Rules and the robust and non-politicised processes around rule changes). The NEG policy requires retailers to progressively decarbonise their portfolios (Emissions Obligation), and maintain a level of physical or financial forward capacity (Reliability Obligation) at levels consistent with Australia's Paris Agreement and the NEMs reliability criteria, respectively. While the carbon targets will remain the subject of policy discontinuity at the Commonwealth level, the underlying Emissions and Reliability Obligations framework in the NEG can exhibit stability if it can be successfully absorbed by the National Electricity Rules, and this would mark a material step forward for the NEM.

5.3 The market for natural gas

Hindsight is a wonderful thing, but there is no doubting the excess LNG plant capacity built on Australia's east coast both before, and after, the event. It was predicted, and was predictable (see Garnaut, 2014; Simshauser & Nelson, 2015; Grafton et al, 2018). One of the three LNG terminals was known to be inherently short at project commitment. Policy recommendations such as a "National Interest Test" to pre-screen the risk of excess LNG capacity may well have prevented the gas market shortages that now exist. Domestic reservation policies which link export projects with certain domestic supply obligations may also provide a credible forward policy option and appear to work well for Australia's west coast. But such policy cannot be invoked retrospectively without raising genuine soverign risk – which has its own flow-on implications. This also represented an area for further research.

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[46] That a free market has committed $30 billion in generation plant between 2008-2018, without a single coal-fired plant amongst this fleet of new entrants, would seem to suggest otherwise.

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