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Lessons from Australia's National Electricity Market 1998-2018: the strengths and weaknesses of the reform experience

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Paul Simshauser

Abstract Australia's National Electricity Market (NEM) commenced in 1998 and after two decades it is timely to reflect on the strengths and weaknesses of the reform experience. The centrepiece of NEM reforms was the energy-only wholesale market and accompanying forward markets, and for most of the past 20 years it has displayed consistent economic and technical performance. But missing policies relating to climate change, natural gas and plant exit has recently produced results that have tested political tolerances. The piecemeal and random interventions that are now following are likely to inflame rather than resolve matters, at least over the near term. Network policy failures in the mid-2000s led to sharp regulated tariff increases from 2007 onwards. These policy problems were largely cauterized by 2012 but regulatory timeframes and business inertia meant network tariffs didn't stabilise until 2015. The retail market has been forced to deliver sharply rising prices, and in consequence the problem of rising prices has been conflated with price discrimination; a largely unhelpful development in an otherwise workably competitive market.

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Lessons from Australia's National Electricity Market 1998-2018: the strengths and weaknesses of the reform experience

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March 2019

Abstract

Australia's National Electricity Market (NEM) commenced in 1998 and after two decades it is timely to reflect on the strengths and weaknesses of the reform experience. The centrepiece of NEM reforms was the energy-only wholesale market and accompanying forward markets, and for most of the past 20 years it has displayed consistent economic and technical performance. But missing policies relating to climate change, natural gas and plant exit has recently produced results that have tested political tolerances. The piecemeal and random interventions that are now following are likely to inflame rather than resolve matters, at least over the near term. Network policy failures in the mid-2000s led to sharp regulated tariff increases from 2007 onwards. These policy problems were largely cauterized by 2012 but regulatory timeframes and business inertia meant network tariffs didn't stabilise until 2015. The retail market has been forced to deliver sharply rising prices, and in consequence the problem of rising prices has been conflated with price discrimination; a largely unhelpful development in an otherwise workably competitive market.

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1. Introduction

Australia's National Electricity Market (NEM) formed part of a world-wide electricity industry microeconomic reform experiment which as Pollitt (2004) notes, commenced in Chile in 1982. The NEM, which covers the eastern and south eastern states of Australia[2], reached its 20th birthday in December 2018. The centerpiece of the NEM reform is the wholesale market, an energy-only gross pool with a real-time spot market and forward derivatives market – the former coordinating scheduling and dispatch, the latter tying the economics of the physical power system to Resource Adequacy and new capacity. By virtually any metric, for most of the past two decades the wholesale market has been *a marvel of microeconomic reform*[3]. A vast oversupply of generation plant was cleared, unit costs plunged, plant availability rates reached world class levels, requisite new investment flowed when required, investment risks were borne by capital markets rather than captive consumers, and reliability of supply – in spite of an energy-only market design – has been maintained with few exceptions thanks to a very high Value of Lost Load (VoLL); at A$14,500/MWh[4] it is amongst the highest in the world.

However, over the past two years the wholesale market has struggled to maintain prices within politically tolerable limits, and one region (South Australia) experienced a black system event. Causes can be traced to i). adverse effects of climate change policy discontinuity, which punctured new plant investment continuity; ii). sudden and uncoordinated exit of coal plant at-scale, driven by climate change policy discontinuity; and iii). turmoil in the adjacent market for natural gas, which would otherwise provide the transitional fuel and shock absorbers required for coal plant exit at-scale (Simshauser, 2019a).

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[1] Written for the *Handbook on the Economics of Electricity*.

[2] Queensland, New South Wales, Victoria, South Australia, Australian Capital Territory and Tasmania.

[3] I should acknowledge Danny Price (Frontier Economics) for this description, which was contained in one of his recent speeches.

[4] $14,500 is in fact the Market Price Cap. Estimates of the Value of Lost Load are considerably higher but for the purposes of this research, VoLL is used.

The NEM wholesale market is *attempting to transition without the transitional fuel*, and without a united & synchronized climate change and energy policy architecture. Indeed, the climate change policies that have existed were poorly designed in that they tended to collide with the NEM design by breaking essential links between investment requirements and system operations via certificate side-markets and more recently, via off-market government intermediations (Simshauser, 2019b).

Transmission & Distribution Networks across NEM regions are subject to economic regulation based on Littlechild's (1983) incentive-based *'RPI-X'* approach. While considerable variation exists amongst NEM regions, network performance has been marked by (somewhat ironically) *policy-based* Averch & Johnson (1962) gold plating. The Regulatory Asset Base of combined networks servicing NEM customers surged from A$32 billion in 2004 to $93 billion in 2018 while aggregate demand tracked sideways[5]. Underlying policy problems were cauterized by 2012, but business inertia and time lags between regulatory determinations meant network tariffs did not alter from their sharply rising trajectories until 2015.

Retail markets have been forced to deliver this bad news to customers through sharply rising retail prices. Retail markets followed the British approach to Full Retail Contestability, albeit with different NEM regions adopting contestability and price deregulation at different timeframes, which in turn were driven by local political constraints. As with the wholesale market, the NEM's contestable retail markets have by-and-large been successful; although as with Great Britain, more recently consumer groups and politicians have conflated the problem of rising electricity prices with price discrimination – a largely unhelpful development. The term *'loyalty tax'* for sticky customers made its media *cameo* in 2018 and the policy of re-introducing regulated tariff caps soon followed. Unfortunately for the market, at the time of writing both the Commonwealth Government and Victorian State Governments had drafted re-regulation legislation.[6]

One of the more interesting aspects of the Australian market model, if not a dry aspect, are the governance arrangements. First and foremost, although the 'N' in NEM stands for National, energy and energy policy is the domain of State Governments, not the Commonwealth Government. Historically, vertical monopoly Electricity Commissions were developed, owned and operated by the respective State Governments. Given the power system was built up around state borders, the fact that Australia has a centrally coordinated competitive *National* market at all is remarkable given the political coordination required in its establishment. From an institutional design perspective, the functions of rule-making, regulation and market operations are strictly separated amongst three entities; the Australian Energy Market Commission (AEMC), the Australian Energy Regulator and the Australian Energy Market Operator (AEMO), respectively. Policymaking and ultimate oversight of the energy industry occurs through a body known as 'COAG Energy Council' (Council of Australian Governments – Energy Council) comprising the Energy Ministers from each State Government and the Commonwealth Minister.

In contrast to energy policy, climate change policy is the domain of the Commonwealth Government. Unfortunately, the democratic Labor and conservative Liberal parties have been unable to identify common ground for decarbonizing Australia's CO_2 intensive power system for almost two decades (with the core of disagreement occurring within the Liberal party itself). As with the USA and Canada, whenever the Commonwealth has misaligned climate change policies with Australia's international commitments (e.g. most recently, the Paris Agreement), piecemeal State Government policy activity emerges to fill the void demanded by business and stakeholders, but the design of these policies has frequently been incompatible with the NEM's wholesale market design.

[5] See Simshauser & Akimov (2019).

[6] The policy was originated by the Commonwealth (in a highly politicised manner) and largely driven by an inquiry by the Australian Competition & Consumer Commission (ACCC). The view taken by the ACCC in their draft and final reports were erroneous and inconsistent with the economics of price discrimination. The Commonwealth Government sought to implement a regulated price cap regime, it was not supported by other state and territory governments (with the exception of Victoria – which sought to do so in its own right), and the rule-making body, the Australian Energy Markets Commission (AEMC) which is accountable to all State, Territory & Commonwealth Energy Ministers, formed an entirely (and justifiably) different view, and advised against the proposed change.

The purpose of this article is to review the NEM's performance over the past two decades, and to highlight the strengths and weaknesses of the Australian reform experiment. This article is structured as follows; Section 2 provides a brief background to Australian energy market reform. Section 3 reviews the governance structure while Section 4 examines industrial organization in the NEM. Section 5-7 then analyse the performance of the wholesale market, regulated networks and retail markets, respectively. Section 8 presents strengths and weaknesses of the Australian approach to energy market reform. Conclusions follow.

2. Background to Australian Electricity Market Reforms

Prior to the 1990 reforms, vertically integrated monopoly electricity utilities were public assets built-up within state boundaries. *State Electricity Commissions* were non-taxpaying entities, responsible to their State Government owners vis-à-vis system planning, investment, system operations, reliability of supply and tariffs. As with many vertical utilities around the world, during the 1980s and early-1990s the status of the monopoly power generation industry in South-Eastern Australia[7] was bordering on critical; New South Wales had invested in so much baseload capacity that it would take more than 20 years to clear, while Victoria's excess baseload plant investments adversely affected that State's Credit Rating.[8] Electricity tariffs were substantially above competitive levels and consequently, the requirement for, and objectives of, microeconomic reform were clear.

Microeconomic reform of Australia's power industry can be traced back to 1991 when the Commonwealth Government initiated a national inquiry via one of its economics agencies, the Productivity[9] Commission. What evolved was a recommendation to restructure, deregulate and establish a 4-state interconnected grid covering east and south-eastern Australia; viz. Queensland (QLD), New South Wales (NSW), Victoria (VIC) and South Australia (SA).[10] The island state of Tasmania (TAS) would later be interconnected by an undersea HVDC cable. Western Australia and the Northern Territory could not be connected due to geographical distances.

This reform would create Australia's National Electricity Market or *NEM*. Co-operation amongst participating State Governments was essential, and was successfully achieved. Australian reforms were largely inspired by the British & Wales electricity market template. There were four key steps to reform:

1. State-owned monopoly Electricity Commissions were 'corporatised' (i.e. commercialised). These entities became businesses incorporated under Australian Corporations Law, were given a commercial mandate and profit motive, and subsequently exposed to a taxation equivalence regime.

2. Corporatised monopoly utilities were then vertically restructured into three segments; generation, transmission and distribution/retail supply, within existing state boundaries. The credit standing of each business was also simulated *'as if'* the firm was non-government owned, which removed any perceived benefit that may otherwise arise in transacting and raising capital. This corporatisation process proved to be a critical step in levelling the playing field and removing any residual unfair advantage that would otherwise exist.

3. Competitive segments of generation and retail supply were horizontally restructured into a number of rival entities within each region.

[7] The exception to this was the Queensland Electricity Commission, which at that time had the 5th lowest electricity prices in the world. See Booth (2000).
[8] Following a serious down-grading, a Labor Victorian State Government was virtually forced to privatise its newest power station as a result.
[9] The Productivity Commission was actually then known as the Industry Commission.
[10] In 1992, the Federal Government established a committee to investigate a national competition policy framework. The committee handed down its blueprint for the implementation of a formal competition policy in August of 1993, with the report becoming known as 'The Hilmer Report', after the committee chairman, Professor Fred Hilmer. See Hilmer (1995).

4. Businesses were privatised but the timing of this final stage varied considerably across NEM due to regional political agendas. VIC privatised its electricity businesses in the late-1990s, SA followed in the early-2000s, QLD privatised its retail supply businesses (in the Southeast corner) in 2007 and after a number of failed attempts, has since resolved to retain the balance of the industry in public ownership (including transmission, distribution, and two rival generation business with ~60% market share). NSW privatised its merchant generation and retail supply businesses in the early-2010s and sold half of the regulated network businesses in the mid-2010s in spite of a bitter partisan campaign between the two major political parties, Labor and Liberal. In TAS, the industry remains publicly owned.[11]

It is notable that the NEM inherited a high-quality and oversupplied stock of monopoly-built utility-scale plant at inception, and thus gains from exchange via a competitive energy-only gross pool and associated forward derivatives market would be material. Table 1 contrasts the NEM's commencing generation fleet with a modelled 'optimal plant mix'. Note that the NEM was substantially *overweight* base plant, with around 4100MW of excess supply – located mainly in the states of VIC and NSW. Intermediate plant was roughly even, while peaking plant was *underweight* by 1600MW. The system was oversupplied in aggregate by around 2600MW against a then optimal plant stock of ~30,600MW and a coincident system maximum demand of about 25,000MW. The market value of the structural faults at the time were ~$5 billion or 13% of the (then) $44 billion NEM generating portfolio.

Table 1 - NEM generating plant portfolio balance in 1998

NEM 1997/98	Optimal (MW)	Actual (MW)	Portfolio balance (MW)
Baseload	20,400	24,500	4,100 *overweight*
Intermediate	2,000	2,100	100 *overweight*
Peaking	8,200	6,600	-1,600 *underweight*
Total	30,600	33,200	2,600 *oversupplied*

Source: Simshauser (2008)

3. Industrial Organisation

Before the wholesale market commenced, it was necessary to restructure state-owned monopoly Electricity Commissions. Accordingly, during the 1990s the four vertical utilities in QLD, NSW, VIC and SA[12] were restructured into 16 portfolio generators[13], 5 transmission entities and 15 distribution/retail supply[14] entities around state/NEM region boundaries. Over time, industrial organisation would depart from this original NEM blueprint through three dimensions; vertical boundaries, horizontal boundaries and geographic lines.

Initially, the 15 incumbent (i.e. franchise) Retailers were stapled to a host monopoly Distribution Network. This 'retailer-distributor model' was common to Great Britain and Australia at reform onset which, as Helm (2014, p.2) explains, was *'the best that could be done at the time'* due to the difficulty of splitting such complex business interfaces, and, it ensured retail supply businesses had substantial asset backing.

But horizontal boundaries would be altered; the lack of scope economies and vastly different risk profiles meant all distribution networks in the NEM (and in Great Britain) would divest their retail

[1111] As an aside, privatisation of the industry (historic decisions and future possibilities) remains highly politically contentious in all jurisdictions.

[12] Tasmania is somewhat complicated by the fact that it only joined the NEM in 2006, and for a range of reasons including scale, remained a largely monopoly/monopsony regional market.

[13] This included 4 portfolio generators in QLD, 4 in NSW (including Snowy Hydro), 5 in VIC, 3 in SA and 1 in TAS.

[14] This included 2 in QLD, 6 in NSW, 1 in the ACT, 5 in VIC and 1 in SA (and from 2005, 1 in TAS).

supply businesses. These downstream structural separations were 'value-driven' investor events.[15] While a seemingly benign development, being stapled to a Distribution Network meant a Retail business was credit-wrapped by the investment-grade rating of very substantial regulated 'poles & wires' businesses. Separation of Retail from Networks meant the presence of investment-grade credit had been withdrawn from the merchant market in a two-step process. First, through the withdrawal of government ownership, and second, through the separation of Retailers from investment-grade monopoly Network Networks. This would later have profound implications for industrial organisation.

Electricity supply is among the most capital-intensive industries in the world and understanding capital flows is therefore very important. Why is the presence of investment-grade credit important for the merchant/deregulated market for generation plant? Credit metrics applied to project financings, an historically dominant source of capital for capital-intensive new power generating equipment, were tightened by project banks from *ca.*2004 in direct response to prolonged periods of low prices, generator economic losses and episodes of *'missing money'* (see Section 5) in various energy markets around the world.[16] As a result, timely investment in new plant would require the involvement of an investment-grade credit-rated entity, either as principal investor or as the underwriter of long-dated Power Purchase Agreements (PPAs). This was an entry hurdle not envisaged by policymakers or academics during market design phase. Changes in credit parameters and applied by risk-averse project banks was not unique to Australia – it was a characteristic of energy markets around the world (see Finon, 2008; 2011). Accordingly, changes to industrial organisation would follow.

1. The 15 incumbent Retailers lacked scale[17] and progressively consolidated horizontally to remain competitive – and this occurred amongst both privatised retailers, and amongst government-owned Retailers. Indeed, the States of QLD and NSW consolidated their own retail supply businesses from nine down to just four prior to, or during, privatisation processes in 2007 and 2011 respectively.[18] By 2011, three 'incumbent' Retailers emerged in the NEM from a long-line of government privatisations, Merger and Acquisition events. Curiously, State Governments, the Commonwealth Government and Australia's competition regulator waived these horizontal mergers and privatisations through – prioritising *proceeds* and *ownership* over market *concentration* and *competition*.

2. Re-integration became a visible trend as the three incumbent Retailers pursued reverse vertical integration with merchant generation, thus becoming known as *'the Gentailers'*. Furthermore, forward integration became a dominant strategy amongst incumbent merchant generators – many of which now form large vertical businesses in their own right. A further 15-20 new entrant retailers formed the competitive fringe. Somewhat ironically, most policymakers view vertical re-integration, not horizontal consolidation, as the unwelcome development.

Opposition to vertical boundary changes appears amongst a majority of regulators and policymakers in the NEM.[19] Their *a priori* reasoning is vertical acquisitions collide with the NEM blueprint, may reduce forward market liquidity, and in turn adversely impact *'balances of competition'*. By this logic, vertical integration was presumed to be anti-competitive. However, and to be perfectly clear on

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[15] That is, stock markets were consistently under-valuing the combined distributor-retail businesses. In all cases, sum-of-the-parts valuations revealed structural separation would result in better Total Shareholder Returns.
[16] Especially the USA, UK and Australia. For further details, see Joskow (2006), Finon (2008), Simshauser (2010) or Nelson & Simshauser (2012).
[17] In the Australian utilities sector, investment-grade credit notionally commences with firm earnings of $100 million or greater. Hence scale is not unimportant from a credit rating perspective.
[18] There were originally three franchise retailers in Queensland and six in New South Wales. In Queensland, Origin Energy and AGL Energy purchased the retail businesses. In New South Wales, Origin Energy and Energy Australia purchased the retail businesses.
[19] See for example AER (2011) and in the case of Great Britain, see Ofgem (2014).

this, with the exception of bottleneck infrastructure[20] the weight of theoretical and empirical evidence on vertical integration overwhelmingly concludes the opposite (see Cooper et al. 2005; Lafontaine & Slade, 2007; Mansur, 2007; Joskow, 2010; Simshauser et al. 2015).[21] To the extent that market power issues occasionally arise in the NEM, their common underpinnings are horizontal power, not vertical power – something which seems to have bedevilled the Australian Competition and Consumer Commission (ACCC).

4. Governance of Australia's NEM

The NEM officially commenced in December 1998 but from 2006, governance arrangements underwent a structural change of their own with policy, rule-making, regulation and market operations strictly segregated:

- Policy – Energy Ministers from each NEM State and the Commonwealth form the members of the Council of Australian Governments Energy Council (i.e. COAG Energy Council);

- Rule-making – the Australian Energy Market Commission (AEMC) operate on behalf of COAG Energy Council as the market rule-making entity and policy advisor, and has established an open-source platform for doing so;

- Regulation – the Australian Energy Regulator enforces wholesale and retail supply Rules, and is the economic regulator of the NEM's regulated networks; and

- Market operations – the Australian Energy Market Operator (AEMO) is the Independent System Operator.

    - More recently[22], an Energy Security Board (ESB) was inserted above the three market institutions (i.e. AEMC, AER and AEMO) for a time-limited period in an attempt to assist policy co-ordination following the black system event in SA. The ESB comprises the heads of the AEMC, AER and AEMO, and an independent Chair and Deputy Chair.

A defining characteristic of Australia's NEM is its *'open source'* approach to rulemaking, in which the AEMC consistently attempts to capture the wisdom of the crowd, that is, from market participants, capital markets, consumer groups and industry stakeholders. Under Australia's NEM rules, the system operator, the regulator, any market participant, investor, consumer group, interested entity or individual can originate a rule change. The AEMC is the institution charged with running a politically independent Rule Change process in a manner consistent with the National Electricity Objective[23] and does so using a conventional policy development cycle incorporating i). an initial issues paper, ii). a formal public consultation processes, iii). draft determination subject to a further round of consultation, and iv). final determination. There are four channels to originate a Rule Change:

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[20] An electricity transmission line linking generation and retail load is an example of bottleneck infrastructure.

[21] Vertical integration is an organisational form of last resort that occurs in response to non-trivial market frictions and in most circumstances, is welfare enhancing – even when horizontal issues take on a considerable importance. Once the long list of explicit and implicit assumptions underpinning standard economic models are relaxed, boundary changes are likely when firms face hazards associated with asset specificity, incomplete markets, bounded rationality, asymmetric information and regulatory & policy uncertainty. When non-trivial hazards exist in relation to ex ante investment commitment and the ex post performance of highly specific assets, vertical integration will invariably achieve *'more adaptive, sequential decision-making procedures'* than anonymous spot and forward market transactions, especially as market conditions change (see Williamson, 1973).

[22] In an earlier market review by Australia's Chief Scientist on behalf of COAG Energy Council, one recommendation was to add an Energy Security Board. In my view, it grinded against the structural separation but given the black system event in SA, COAG Energy Council had little choice but to endorse the recommendation. Of course, the black system event had nothing to do with policy coordination – it was strictly a matter of System Operations.

[23] That is, to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to: price, quality, safety and reliability and security of supply of electricity.

1. Normal Rule Change: the AEMC initiates its policy development cycle within 4 months of receiving a Rule Change Request and must complete its process within 6 months (i.e. 10 months in total);

2. Expedited Rule Change: can be made within just 8 weeks. However, a prerequisite to this channel is the existence of a (*typically prior*) formal consultation process either by a proponent or by the AEMC;

3. Fast-Track Rule Change: where no prior consultation exists, a rule change can be originated and policy development cycle completed within 3 months, but with the prerequisite that a genuine threat to power system security or reliability exists.

   - It is worth noting that AEMO has sole responsibility for real-time system security, but is not responsible for Resource Adequacy (i.e. system reliability and associated Resource Adequacy is delivered through the NEM's very high VoLL and the forward markets). However, AEMO can initiate Emergency Trader Provisions if short-term Resource Adequacy is likely to compromise system security. AEMO also benefits from NEM Rule 4.3.1 which states amongst other things that the System Operator should *"initiate action plans to manage abnormal situations or significant deficiencies which could reasonably threaten power system security"*. Deficiencies are noted without limitation, viz. i). power system Frequency and/or voltage operating outside the definition of a satisfactory operating state, and ii). actual or potential power system instability.

4. Market Development Rule Change: the AEMC can propose a Rule Change to COAG Energy Council, which in turn would have the effect of originating a rule change. For clarity, the AEMC cannot propose a rule change to itself.

The AEMC assesses any Rule Change against *statutory objectives* (viz. the five AEMC Commissioners are bound by these statutory objectives including, above all, *'the long-term interests of consumers'*). A common criticism that I hear – including from Energy Ministers, Senior Officials, consumer groups, lobby groups and (non-market facing) renewable project developers/investors – is the slow speed of change vis-à-vis the NEM Rules. Conversely, I rarely hear such complaints from the capital-intensive market-facing participants who have made large investment commitments in plant and retail systems based on their understanding of market rules, nor from sophisticated debt and equity capital market participants who ultimately fund these market-facing participants. These latter groups may not like the outcome of various Rule changes, but they value the politically independent rule-making process and the stability of the NEM Rules (noting that the problem of climate change policy is *not* the domain of the AEMC or the Rules).

Most Rule processes are completed within 9-12 months. And while there is considerable evidence of NEM Rule change processes of urgency being the subject of delay, what virtually all stakeholders *do not observe* is the cause of delays. In almost every case, delays can be traced to COAG Energy Council – when the form of an AEMC Rule Change is materially altered in the legal drafting stage (viz. over-reach by a jurisdiction trying to achieve some 'additional policy objective'), all prior consultation process previously undertaken by the AEMC are no longer relevant. Consequently, under its statutory responsibilities, AEMC Commissioners are obliged to re-initiate the policy development cycle once again. Observable rule-making process delays have an uncanny correlation with the level of interest and decision making-authority by COAG Energy Council and their Senior Officials – of which I have first-hand experience[24]. In an outlier example, a Fast Track Rule Change, which should have taken 3 months to complete, took 3½ years to implement because of *over-reach* by a particular State Government attempting to deliver tangential policy outcomes.

[24] The Author was the Director-General of the Queensland Department of Energy and Water Supply and the Queensland Government's Senior Official for COAG Energy Council from 2015-2017.

5. Wholesale Market

As noted at the outset, for most of the past two decades the economic and technical performance of the NEM's wholesale market has been exceptional in that following reform, costs reduced, prices fell to competitive levels, plant oversupply was cleared and the NEM's reliability criteria of *'no more than 0.002% lost load'* was met (see Simshauser, 2005; 2014). One could conclude with considerable justification that the reform objectives of enhancing productive, allocative and dynamic efficiency were achieved.[25] Indeed, the NEM design was widely regarded as a template for power system reform (see IEA, 2005; Warren, 2019).

But recent performance of Australia's wholesale market has been tarnished by a black system event in SA (Australia's first system collapse in since 1964), with spot & forward electricity prices surging outside of politically tolerable levels. To be clear, the NEM market design remained faithful with prices reflecting resource costs. Key problems have been sequential supply-side shocks; i). poor design and discontinuity of climate change policies; ii). gas market shortages, and iii). uncoordinated coal plant exit at-scale without adequate notification periods, because of i) above. As this Section explains, the NEM is attempting to *transition without the transitional fuel*, and without the climate change policies that should guide any transition (Simshauser & Tiernan, 2019).

5.1 Institutional design

The NEM is somewhat unique amongst restructured electricity market designs due to its single real-time platform comprising a mandatory energy-only *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). Prices are cleared under a uniform first-price auction clearing mechanism, and a single Independent Market Operator coordinates all regions and all spot markets; and again somewhat uniquely, without any formal day-ahead market[26] or centrally determined capacity mechanism (see Riesz et al. 2015). Future plant capacity is guided by the NEM's forward markets; derivative contracts are traded both on-exchange and Over-The-Counter (OTC) and have historically exhibited turnover of 300+% of physical trade, albeit with considerable variation between seasons and regions. Reliability (i.e. Resource Adequacy) is thus driven by future price expectations and underpinned by an extremely high VoLL of \$14,500/MWh – the level of VoLL having a direct relationship with the reliability objective function; to ensure *no more than 0.002% lost load*.

5.2 Historic market prices

For most of the past two decades, spot prices spanned a relatively tight range. From 1998-2015, annual spot prices averaged \$40/MWh (i.e. ~US\$28/MWh[27]) with a P90 - P10 range of \$27 - 57/MWh (US\$18.90 - 39.90/MWh). These spot prices were underpinned by Australia's low coal coal-fired generation fleet. Figures 1-2 present historic average spot prices (6-month resolution) in nominal and real 2018 dollars, and contrast these with the Average Total Cost (ATC) of the incumbent coal fleet, and estimated New Entrant Cost[28] relevant at the time. There are four things worth noting in Figures 1-2:

1. Spot prices experienced two major excursions. The first (2007-2008) coincided with Australia's east coast millenial drough. Apart from adverse effects on hydro plant, drought conditions were so severe that some coal-fired generators were forced to mothball units due to cooling water shortages (urban drinking water being prioritised from affected dams). The second (2017-2019) persisted at the time of writing due to coal plant *exit at-scale* (see Section 5.4) and turmoil in the adjacent market for natural gas (see Section 5.5).

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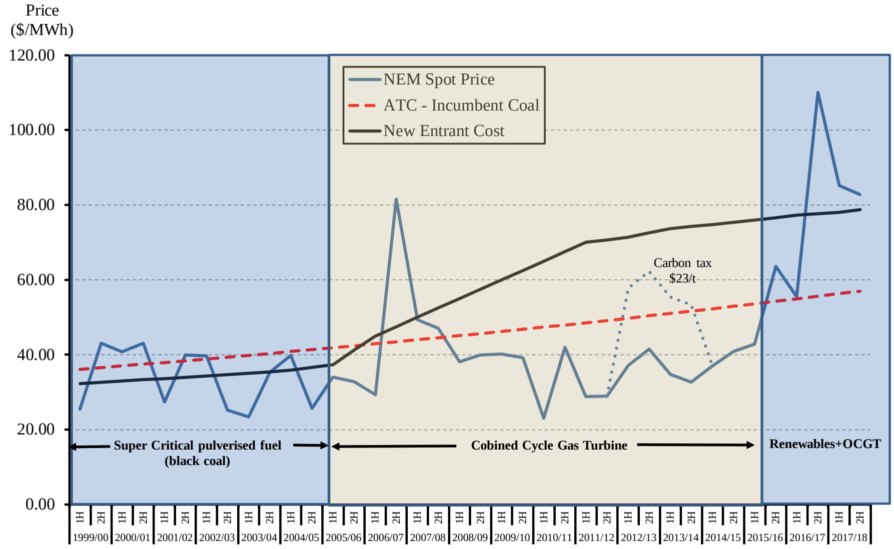
[25] Performance improvements included average cost, price, plant availability, and reserve margins (see Simshauser, 2005). In more recent research, the wholesale market was one of the few areas of the electricity market that was performing well (see for example Nelson & Orton, 2016; Simshauser, 2014). From mid-2016 however, market performance deteriorated significantly.
[26] Although as MacGill (2010) points out, the Market Operator does produce a very transparent 40hr pre-dispatch forecast which is continuously updated.
[27] I use a AUD to USD exchange rate of \$0.70.
[28] Average Total Cost and New entrant Cost data from Simshauser (2019a).

2. The New Entrant Cost series in Figures 1-2 exhibits a steep incline from 2005-2012 which coincides with a shift in the benchmark entrant technology, from coal to gas, and in line with expectations of a carbon constraint. Domestic gas prices rose sharply following a series of LNG export commitments, which had the effect of linking domestic gas prices with the seaborne market rising from \$3/GJ to \$9/GJ (~US\$2.21 to US\$6.85/MMbtu) over the period 2005-2012. By 2016, the cost of renewables had fallen considerably and even after accounting for intermittency (by way of an OCGT), became the new benchmark entrant.

3. While not captured in Figures 1-2, the marginal running cost of the NEM's coal-fired fleet is now beginning to rise; legacy coal supply agreements at a number of marginal coal plants across QLD and NSW have been progressively expiring, and replacement contracts are now based on the 5500kcal coal futures contract (export price ex-Newcastle, north of Sydney). International thermal coal prices are materially higher (currently ~US\$90/t) than legacy contract prices (historically ~A\$30-40/t).

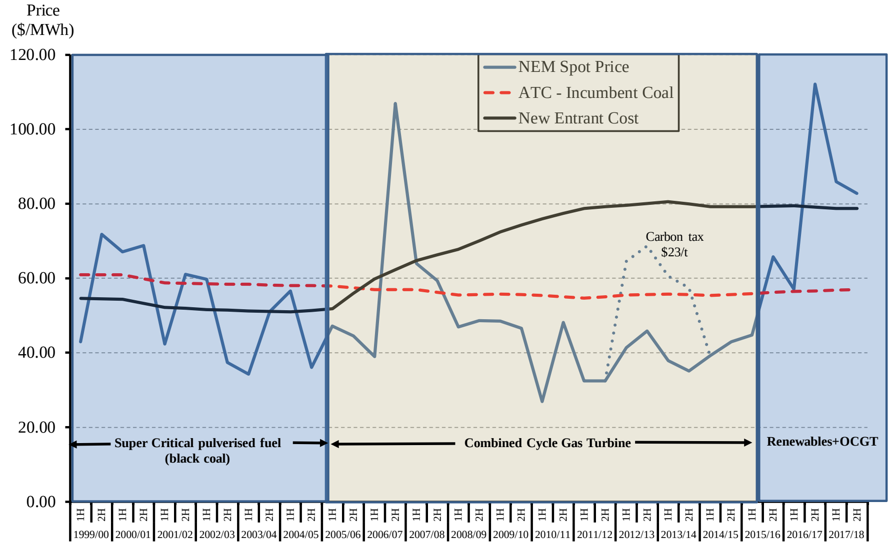
4. Australia had a carbon price from 2012-2014, but the (democratic)Labor Government's policy was short-lived following a bitter general election campaign in which the carbon price (labelled the *'great big tax on electricity'* by the (conservative) Liberal Opposition) formed centre stage. A core election commitment, the incoming Liberal Government dismantled the policy within 9 months.

Figure 1 - 20-year NEM Spot Prices vs Incumbent Coal and New Entrant Cost: 1999-2018 (nominal)



Source: AEMO, ABS, Simshauser (2019a).

Figure 2 - NEM Spot Prices vs Incumbent Coal and New Entrant Cost: 1999-2018 (constant 2018 $)



Source: AEMO, ABS, Simshauser (2019a).

5.3 Reliability & Reserve Plant

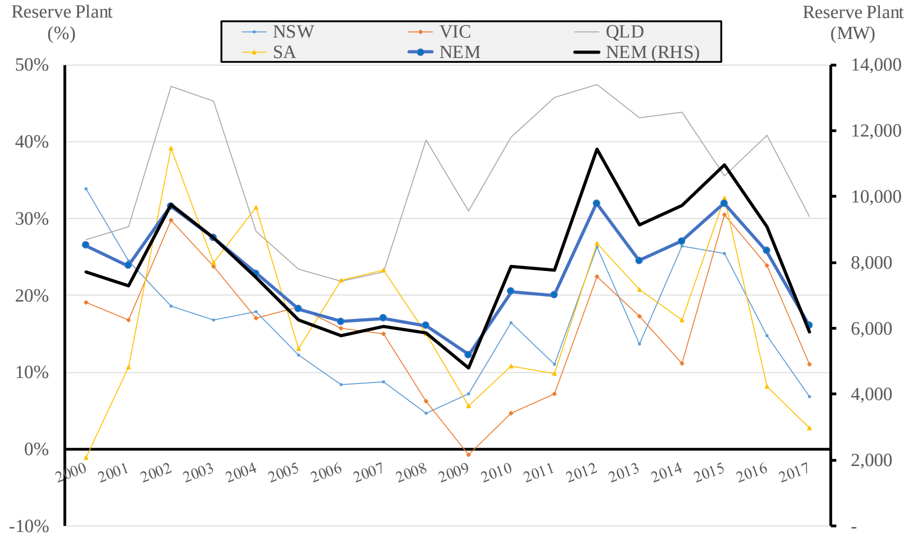
From a Resource Adequacy perspective, the NEM's Reliability Panel sets the criteria and reviews overall power system performance. The reliability criteria has been achieved with few exceptions. NEM outage analysis by Grattan (2019) covering the period 2009-2019 identified that only 0.1% of system minutes lost related to generation plant shortfalls – the balance arising from a black system event in South Australia[29] (1.6%), transmission plant outages (0.7%) and distribution network outages (97.7%).

Figure 3 presents NEM reserve plant based on nameplate capacity (which has the effect of overstating the apparent Reserve Plant *cf.* thermal de-rating during summer peak periods). More important however are Year-on-Year changes in reserve plant. During the transition from monopoly to competitive market, QLD (1998), SA (2000) and VIC (2001) experienced supply disruptions but these were legacy issues, not market design issues (noting the NEM commenced in 1998). In response, market-based supply-side additions commissioned in 2002-2004 were swift, as Figure 3 illustrates.

In 2009, VIC experienced supply disruptions following a very material jump in maximum demand and coincident lags to peaking plant capacity additions. These events coupled with the 2007-2008 price cycle, and the (then) looming expectation of a CO_2 Emissions Trading Scheme, led to a large number of gas-fired capacity additions from 2009-2012 as Figures 6-7 later reveal. However as this capacity was commissioned, NEM aggregate demand contracted (for the first time in history) throughout 2010-2015. Australia's 20% Renewable Energy Target would also force more plant into the market (through an adjacent certificate 'side-market') and combined this led to reserve plant margins increasing materially. These conditions would eventually weigh heavily on spot electricity prices and culminate in aged coal plant *exit at-scale* (see Section 5.4). This coal plant exit procession produced a sharp run-down in reserve plant, which is visibly noticeable from 2015 onwards.

[29] The SA black system event was not a Resource Adequacy / Reliability problem, but a system security issue (i.e. an unstable system in which a voltage collapse led to plant disconnecting, with the rate of change of frequency falling faster than supply and demand resources could respond to.

Figure 3 - NEM Reserve Plant (2000-2017) Nameplate vs Maximum Demand



Source: ESAA, AEC.

5.4 The NEM's episode of economic losses and exit at-scale

A known theoretical characteristic of energy-only markets is *missing money* and risks of timely plant entry (see Cramton & Stoft, 2006 amongst others[30]). While the NEM's very high VoLL and associated contract markets have ensured Resource Adequacy, the energy-only market design has meant the economic consequences of oversupply are amplified. These have been further compounded by the presence of a poorly designed 20% Renewable Energy Target (i.e. use of 'certificate' side-markets).

By combining underlying annual cost and price data from Figure 1 with thermal generation output, an estimate of economic losses (including a subcomponent of missing money) over time can be established – which is presented in Table 2. To be clear, Table 2 excludes Ancillary Services revenues (typically < 0.5% of system revenues) and hedge contract premiums (nominally ~3-7% above spot prices). These are important caveats; but these limitations aside the estimated economic loss is $4 billion over the period 1999/00 – 2017/18 against the current capital stock of 46,000MW with an estimated value of ~$49.7 billion.[31]

[30] See also Neuhoff et al. 2004; de Vries, 2004; de Vries et al. 2008; Bushnell, 2005; Roques et al. 2005; Joskow, 2008; Finon, 2008; Simshauser, 2008; Joskow, 2013; Nelson & Simshauser, 2012; Cramton, Ockenfels & Stoft, 2013; Green & Staffell, 2016; Keay, 2016.

[31] Depreciated optimised valuation estimates are based on hydro plant at $1500/kW, coal plant at $1000/kW, CCGT and Solar plant at $1500/kW, Wind at $2000/kW and OCGT plant at $500/kW. Applying these statistics to the NEM's existing plant equates to $49.7 billion.

Table 2 - Generator economic losses

Year	ATC ($/MWh)	NEM Price ($/MWh)	Shortfall ($/MWh)	Generation (TWh)	Missing Money ($ Billions)
2000	35.75	33.36	-2.40	162.9	-0.3
2001	36.52	41.79	5.27	168.8	0.8
2002	37.31	33.63	-3.67	171.9	-0.6
2003	38.11	32.49	-5.62	175.8	-0.9
2004	38.93	29.29	-9.63	182.8	-1.6
2005	39.76	32.71	-7.06	186.0	-1.2
2006	40.62	33.17	-7.45	188.9	-1.2
2007	41.49	55.22	13.73	194.7	2.4
2008	42.39	48.26	5.88	197.8	1.0
2009	43.30	39.11	-4.19	197.4	-0.7
2010	44.23	39.46	-4.76	192.8	-0.8
2011	45.18	31.96	-13.22	187.4	-2.2
2012	46.15	28.83	-17.32	184.9	-2.8
2013	47.14	39.61	-7.53	174.0	-1.2
2014	48.16	33.78	-14.37	168.2	-2.1
2015	49.19	39.60	-9.59	173.4	-1.5
2016	50.25	54.06	3.81	172.9	0.6
2017	51.33	77.10	25.77	169.8	3.9
2018	52.43	82.61	30.18	166.5	4.4
Total	46.09	36.06	-10.03	1,278.1	-4.0

Source: AEMO, ESAA, AEC, Simshauser (2019a).

While the aggregate result in Table 2 is -$4 billion of economic losses, note between 2009-2015 (shaded area) it was ~$11.3 billion – a direct result of plant oversupply.[32] This period induced uncoordinated coal plant *exit at-scale* over the period 2012-2017 as outlined in Table 3. Initial closure events (i.e. 2012-2015) were benign as NEM spot prices and Table 2 tend to indicate; they were warranted on economic grounds (i.e. oversupply) and consistent with climate change policy objectives (i.e. lower emission entrants causing the oversupply).

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

Simshauser (2019a)

However, the final two plant exits in Table 3 were material, uncoordinated and occurred with little warning. The 540MW Northern Power Station, the last coal-fired plant in the NEM's SA region, announced it would close in mid-2016. With spot revenues declining and plant costs rising (i.e. falling availability and utilisation) closure became the dominant strategy. Two months later,

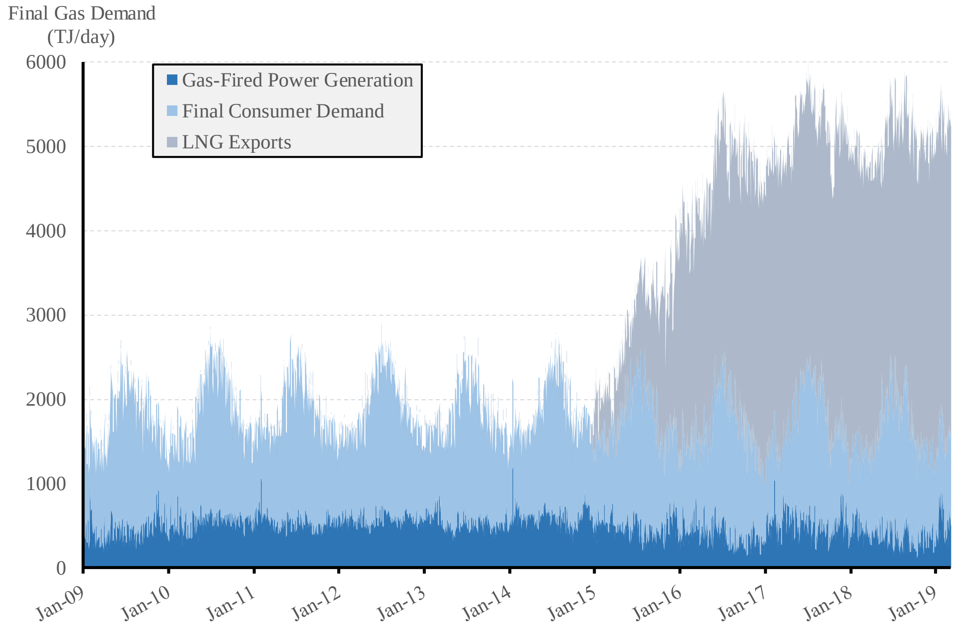
[32] Untangling missing money from within the economic loss is a difficult task, but my own prior estimates of VoLL were considerably higher than $14,500/MWh. In Simshauser (2008) the estimate was $24,500/MWh vs. the then VoLL of $10,000/MWh.

unexpectedly, the 1600MW Hazelwood Power Station in the adjacent VIC region (and 20% market share) announced it would close in April 2017, i.e. less than 5 months' notice. Closure was driven by mounting capital re-investment requirements ($400 million) relating to plant safety. The Northern Power Station exit is an example of *first mover disadvantage*. While Northern Power Station would eventually close 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. These uncoordinated exits in 2016-2017 pushed spot electricity prices to multi-year highs and contributed to (but were not the cause of) supply disruptions in SA (2016, 2019) and VIC (2019). The NEM was about to commence its transition in earnest, but would be forced to do so without its historically cheap and abundant *transitional fuel* – natural gas.

5.5 Transitioning without the transitional fuel: gas market shortfalls

Central to current market conditions in the NEM is the dire state of the Australian east coast market for natural gas. Following very large coal seam gas discoveries in QLD (i.e 40,000+PJ, or 6,500+Mboe of 2P Reserves discovered), three large LNG export plants were commissioned in 2014-2016, resulting in a 3-fold increase in final Australian east coast gas demand (see Simshauser & Nelson, 2015; Grafton et al. 2017; Billimoria et al, 2018). This change in aggregate final demand is illustrated in Figure 4 (daily resolution) over the period 2009-2018. Note that there are three market segments identified, i). Gas-Fired Power Generation, ii). Final (domestic) Consumer Demand, and iii). LNG Exports, which commence from late-2014.

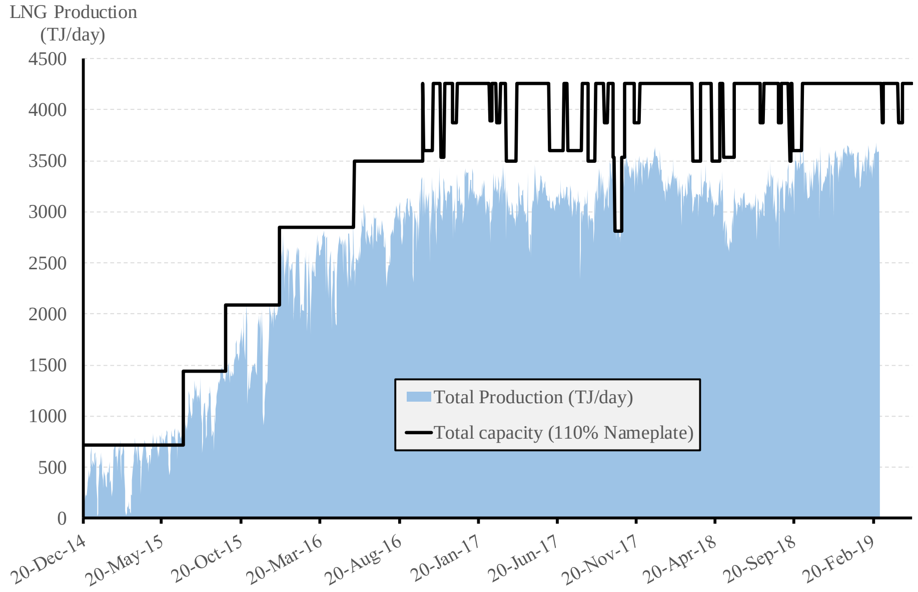
Figure 4 - Expansion in aggregate demand for natural gas (TJ/day, 2009-2018)



Source: GMAT.

What Figure 4 does not capture is the under-utilisation of new LNG export plant capacity, and the consequential pressure this has placed on the domestic gas market. Domestic gas prices had historically cleared at $3 - 4/GJ (i.e. ~US$2.21 - 2.96/MMbtu) under both short and long-dated contracts. But the advent of LNG export terminals linked the $3/GJ domestic market to a highly volatile $8 - $12/GJ netback (~US$5.91 – 8.87/MMbtu) seaborne market. And because excess LNG capacity had been built, marginal supplies in the domestic consumer market are forced to compete with sunk LNG export capacity – with domestic prices now clearing at (or above) the seaborne market range. Figure 5 presents the ramp-up and ongoing LNG plant capacity (2014-2018, daily resolution) and contrasts this with actual production. The extent of the visible market shortfall in Figure 5 (i.e. at least 1 full LNG train, or about 250-300 PJ/a) is very material – noting that aggregate domestic market demand is only 600PJ/a.

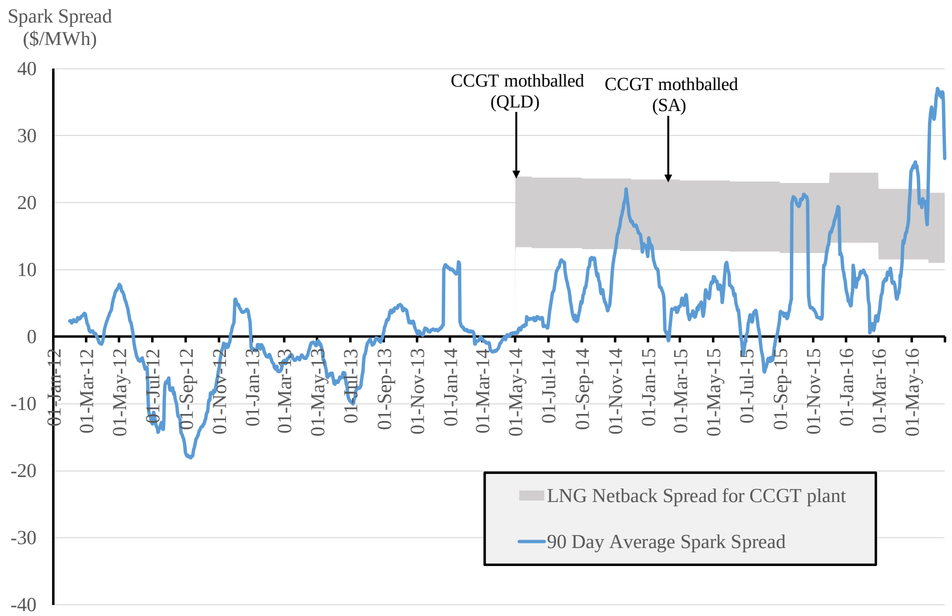
Figure 5 - Australian East Coast LNG Export Capacity vs LNG Production



Source: GMAT.

With gas prices surging, legacy long-dated gas supply agreements held by generators (and struck at the pre-LNG prices of \$3 - \$4/GJ) became more valuable as an export feedstock during the low spot price period of 2009-2015. As Figure 6 illustrates, Spark Spreads from 2012-2015 were generally negative and well below that which could be sustainably achieved by mothballing a CCGT plant, and on-selling the gas to LNG exporters under medium term agreements. Consequently, many gas generators forward-sold their gas to LNG producers and temporarily exited the spot electricity market – unaware of looming coal plant *exit at-scale* from 2016–2017 onwards. When these plant returned to market, their marginal costs were based on export-linked short-term gas prices. This would also have crucial implications for new plant entry, as Section 5.6 explains.

Figure 6 - NEM Spark Spread (2012-2016)



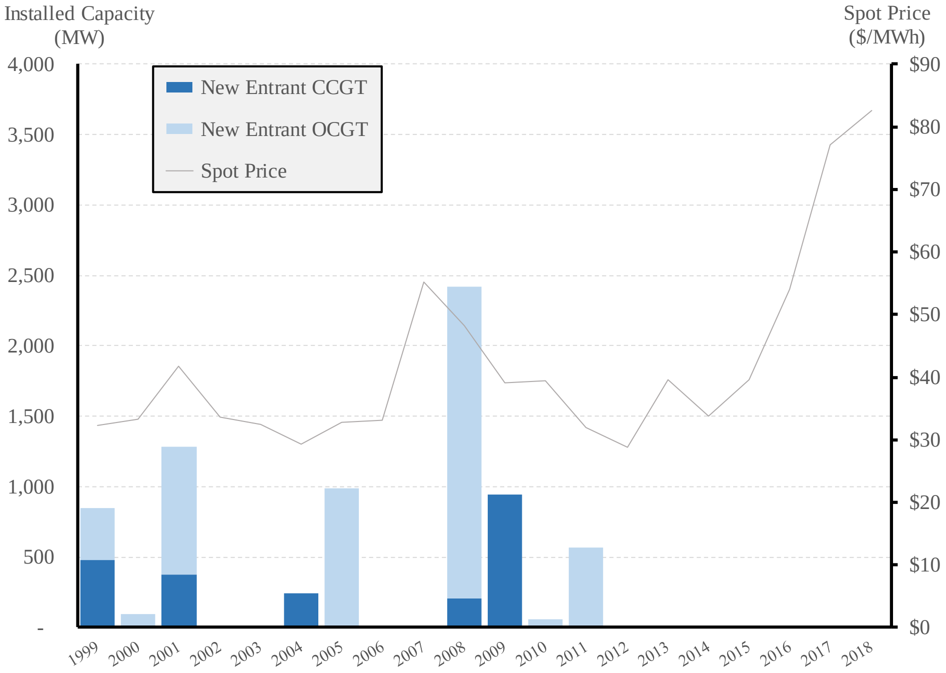
Source: GMAT, Simshauser (2019a).

5.6 Entry and investment commitments: 1999-2018

Recall from Figures 1-2 that spot prices spiked above the cost of entry during 2017-2018. A striking feature of the current electricity price cycle was the absence of gas turbine *proposals*, let alone gas plant *entry*. Gas plant entry was subject to critical hold-up for reasons outlined in Section 5.5.

During previous electricity price cycles (e.g. 2007-2008, driven by east-coast Australia's millennium drought) more than 5000 MW of gas-fired generation plant entered the coal-dominated NEM as Figure 7 illustrates. In the 2017-2019 cycle, there was no gas plant entry, and as noted above many gas-fired generators forward-sold their long term, low cost gas supplies to the chronically short LNG export industry during the *electricity price lull period* unaware that multiple, uncoordinated coal plant exit was imminent.

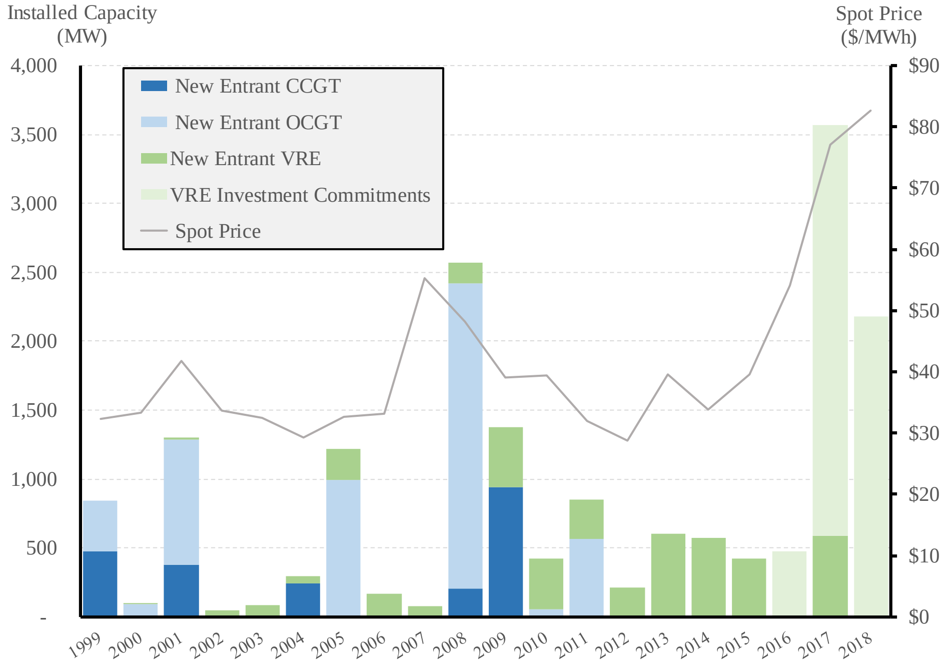
Figure 7 - New entrant gas-fired plant (1999-2018)



Source: ESAA, AEC, AEMO.

The entrant of choice in the Australian market has therefore switched to Variable Renewable Energy (VRE), principally wind and solar PV. Their material and timely reduction in entry costs along with an undersupplied 20% Renewable Energy Target helped drive a cyclical investment boom as Figure 8 notes. Figure 8 builds on Figure 7 by adding in commissioned new entrant VRE plant, and irreversible VRE investment commitments (i.e. projects that have reached financial close and are now under construction).

Figure 8 - New entrant plant (1999-2017) and investment commitments (2017-2018)



Source: ESAA, AEC, AEMO, CEFC.

While VRE plant has seen record levels of investment, the majority of plant is under construction and at the time of drafting in early 2019, is yet to make a dent in prevailing spot and year-ahead forward contract prices. As Figure 21 later reveals, there appears to be a tightening link between average spot electricity and average spot gas prices.

5.7 Market Power in the NEM

Central to the literature on energy-only markets is the matter of generator market power. Because there are no capacity payments, for an energy-only market to reach equilibrium it must have a high VoLL. In real-time, participants are unable to optimise the number of VoLL events. Actions by regulatory authorities and System Operators compound matters by frequently suppressing legitimate price signals (de Vries, 2003; Wen et al. 2004; Finon & Pignon, 2008; Joskow 2008, Spees et al., 2013; Hogan, 2013, Leautier, 2016). Energy-only markets are therefore rarely in equilibrium, and this creates risks for the continuity of timely investment to ensure the administratively determined reliability criteria is met (Bidwell & Henney, 2004; Cramton & Stoft, 2006; de Vries & Heijien, 2008; Hirth et al. 2016). In the circular calibration of reliability standards and a high VoLL, the risks and ability to distinguish market power events are compounded (Roques et al, 2005; Besser et al, 2002; Oren, 2003; Cramton & Stoft, 2006; Joskow 2008; Simshauser, 2008).

In the NEM, the Australian Energy Regulator routinely investigates all price spikes above $5000/MWh with the intent of monitoring competitive behaviour and compliance with the market Rules. Because there are no capacity payments, NEM generators are free to bid their output at prices up to VoLL, with competitive forces regulating the extent of *economic withholding* of capacity. As outlined in Table 2, the NEM has generally been characterised by intensely competitive prices – especially over the periods 1999-2006 and 2009-2015.

Across the NEM's four major regions of QLD, NSW, VIC & SA from 1999-2018 (i.e. "80 region years"), there have been eight notable episodes of *economic withholding of capacity* (and no doubt countless other minor episodes). However, half of these events merely reduced the economic losses outlined in Table 2. Table 4 outlines the year, participant, portfolio size (MW), region and the (regional) average spot price relevant to the year in which the economic withholding of generating capacity occurred. Axiomatically, each case involved a large *horizontal* market participant.

Table 4 - NEM Market Power Events (1999-2018)

Year	Participant	MW	Region	Spot Price (nominal $)	Est. ATC (regional)	Spot - ATC
1999	Tarong Energy*	1900	QLD	$53.17	$35.00	$18.17
2000	TXU	1280	SA	$59.27	$40.75	$18.52
2001	Loy Yang Power	2000	VIC	$44.57	$38.52	$6.05
2003	Enertrade*	2610	QLD	$37.79	$38.11	-$0.32
2008	Macquarie Generation*	4600	NSW	$41.66	$42.39	-$0.73
2008-10	AGL Energy	1280	SA	$59.93	$48.30	$11.63
2013-14^	CS Energy*	4440	QLD	$41.21	$47.14	-$5.93
2013-14^	Stanwell*	3854	QLD	$41.21	$47.14	-$5.93
2017	Stanwell*	3854	QLD	$95.41	$51.33	$44.08

* Government Owned ^Incl. Carbon Price $23/t

From a policy perspective, each *withholding event* triggered a response. Responses came in the form of i). competition via new entry, ii). regulatory, via Rule change (e.g. bidding in good faith rule, five-minute settlement rule), iii). in the case of government trading enterprises, intervention by government owners, iv). litigation by the Australian Energy Regulator for a Rule breach, or v). longer term changes in policymaker attitudes and therefore subsequent policy adjustment. [33]

There are two further points worth noting with respect to transient market power events in the NEM. First, in all but one case participants were *not* vertically integrated. And in the vertical case the source of market power was horizontal scale of the generator (privatised by the SA government), not vertical boundaries. Second is the prevalence of market power events involving Government-Owned generators.[34] As Grattan (2018) explain in their analysis of market power events covering the coal plant exit period, the NEM is *'mostly working'*.

5.8 VRE and South Australia

An article on the NEM would be incomplete without reference to the special case of SA and the market implications of a sharply rising VRE market share, i.e. > 50% VRE. By way of brief background, in 1997 Australia established the world's first Renewable Portfolio Standard. Commencing at *'2% renewables by 2010'*, the market share target was lifted to *'20% renewables by 2020'* following a general election in 2007. The national renewable energy policy required all liable Retailers to submit sufficient 'Renewable Energy Certificates' each year to meet progressively higher targets. As an aside, the 20% target will be comfortably met by 2020.

[33] Table 4 does exclude a recent event relating to AGL Energy's bidding behaviour in NSW following their acquisition of the 4600MW Macquarie Generation coal portfolio during the mid-2010s – a line of inquiry which had emerged at the time of writing in Mountain & Percy (2019). The issue here was not the typical withdrawal of capacity to very high spot prices, but a soft parallel shift of their supply curve from ~$20/MWh to ~$50/MWh. However, while Mountain & Percy (2019) interpreted the shift as market power abuse, it appears a more widespread structural shift of the aggregate black coal supply function which has been well documented by AEMO (2018), investigated by Australian Energy Regulator and ACCC, and consistent with sharp changes in the 6000 kcal Coal Futures prices. As a result, crucial components of the Mountain & Percy (2019) analysis (relating to coal supply constraints and marginal coal costs) is contentious.

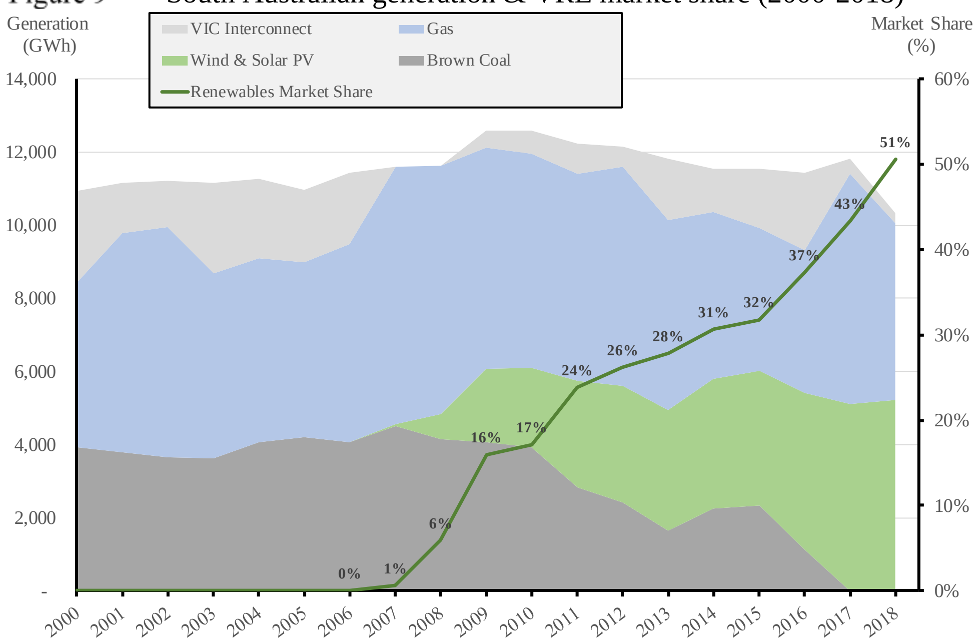
[34] That transient market power has been exercised more frequently in QLD can be explained by the fact that it is the region with i). the least vertical integration (i.e. a market dominated by generators with long positions), and ii). the highest reserve margins (Figure 3) and consequently economic losses and the missing money subset tends to be amplified (Table 2).   For most of the NEM's history, QLD has been a major net exporter of power to the south and this has produced large reserve margins. With a surplus of low-cost generating plant, economic losses and missing money is likely to be more prevalent. Conversely, because the supply-side is dominated by a small number of large (state-owned) portfolio generators, economic withdrawal of capacity is plausible, profitable and in order to avoid extended periods of economic losses, somewhat necessary – noting that not all episodes have actually produced an economic rent. Importantly however, from a policymaker perspective market power events have never been sustained without a response. That is, economic withholding on the supply-side has invariably been met by new entrants, policymaker intervention, or a NEM Rule change.

Inadequate thought went into how the certificated scheme design might be refined and improved[35] when it was expanded from 2% to 20%, and in the event the existing 2% legislation was largely rolled-over intact. In the event the scheme collided with the NEM's wholesale market design - disconnecting entry decisions from the NEM's forward markets. One direct consequence of this was the world class wind resources in SA would attract a disproportionate amount of investment because of the existence of the certificate side-market, and further compounded by *off-market investments* (i.e. sub-national governments writing off-market CfDs to acquit their own intra-state renewable aspirations; the Australia Capital Territory wrote a series of CfDs in the SA region, yet their own load is located within the NSW region – a region dominated by scheduled plant, thus leaving SA with more VRE plant). As Figure 9 explains, between 2006 and 2018 VRE plant market share in the 'loosely interconnected' SA NEM region would rise from 0% to 51% (wind dominating at 42 percentage points). By comparison, the large and more strongly interconnected regions of QLD, NSW and VIC would be greatly under-weight renewables, each with less than 8% VRE market share.

Compounding matters for SA were its small system size (3100MW peak demand, 12.5TWh energy demand) and very poor load factor (0.45 – a very *peaky* power system). Indeed, SA is by far the smallest of the NEM's four main regions with an underlying base load of just ~1100MW, and as indicated above, limited interconnection to the adjacent VIC region.

With an influx of wind generation, the SA region experienced so-called *merit order effects* from as early as 2011 (see Forrest & MacGill, 2013; Cludius et al. 2014; and Bell et al. 2017). Consistent with literature in the field, merit order effects eventually reverse (see Gelabert et al. 2011; Nelson et al. 2012) with coal plant forced to withdraw. SA lost all coal plant generating units over the period 2012-2016 as Figure 9 illustrates (see also Table 3).

Figure 9 - South Australian generation & VRE market share (2000-2018)



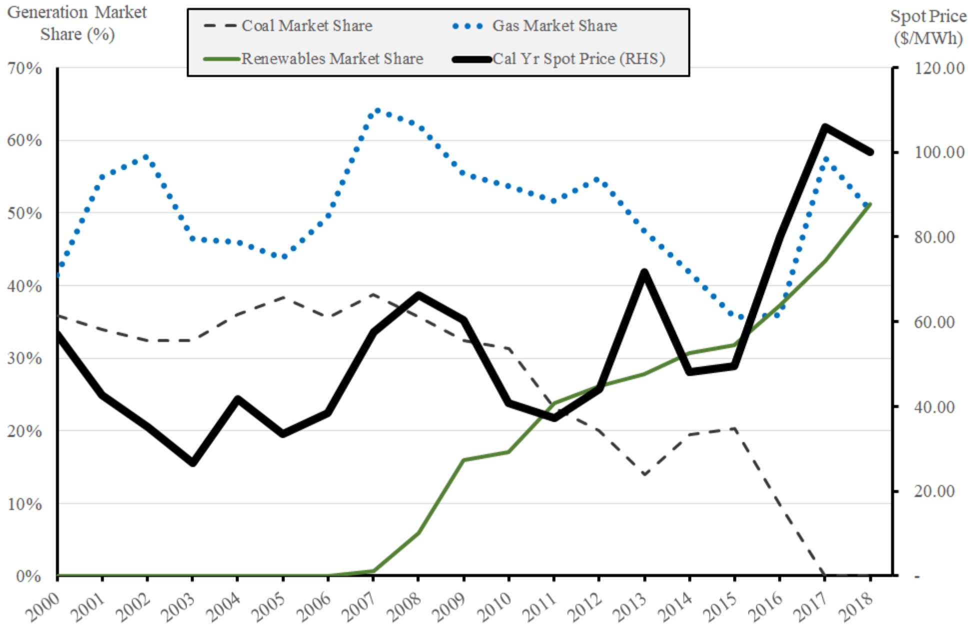
Source: AEMO

Once VRE annual market share rose above ~25%[36] coal plant operations became increasingly uneconomic. By the time VRE exceeded ~35% (in 2016), the coal fleet exited, and gas-fired

[35] A national target was thought to deliver the target at least-cost, but this ignored other system integration costs from high concentrations in certain geographical areas.
[36] This occurred in 2012 with an average VRE market share of 26%, maximum VRE for a single day was 68%, and more than 20 days were higher than 50% market share.

generation plant provided an expensive *shock-absorber* given gas price dynamics outlined in Section 5.5. The sharp rise in spot prices is illustrated in Figure 10.

Figure 10 - SA generation market share vs. Spot Price[37] (Cal Years 2000-2018)



Source: AEMO

Although SA was visibly changing from a synchronous, dispatchable coal and gas resource-based system to one comprising an increasing and dominant level of asynchronous, stochastic wind and solar PV resources, AEMO maintained the same levels of Frequency Contingency services (i.e. 6 second, 60 second and 5 minute spinning reserves), and had reduced the levels of Frequency Regulation and Black Start services in prior periods[38]. Furthermore, AEMO maintained a practice of global procurement of Frequency Control Ancillary Services (FCAS) across NEM regions (rather than localising some minimum level of FCAS).[39] These practices, coupled with a changing plant mix and *how AEMO chooses to define* what constitutes a credible contingency were crucial elements that would exacerbate any supply-side shock.

At 4:18pm on 28 September 2016, SA experienced a black system event[40]. A severe storm cell with wind speeds of 190-250km/h moved through the State and damaged two transmission lines, causing a series of voltage dips over a two-minute window. In real time, SA System Demand was 1826 MW, and system dispatch configuration comprised 330MW gas-fired generation, 883MW wind generation and 613MW imports through the VIC-SA Interconnector – the latter notably operating at close to its rated capacity during the storm event.

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[37] Spot prices in 2013 and 2014 have been adjusted downwards by $23/t x 0.6t per MWh to remove the effects of the CO_2 Tax. The actual spot prices were $69.75/MWh and $61.71/MWh respectively.

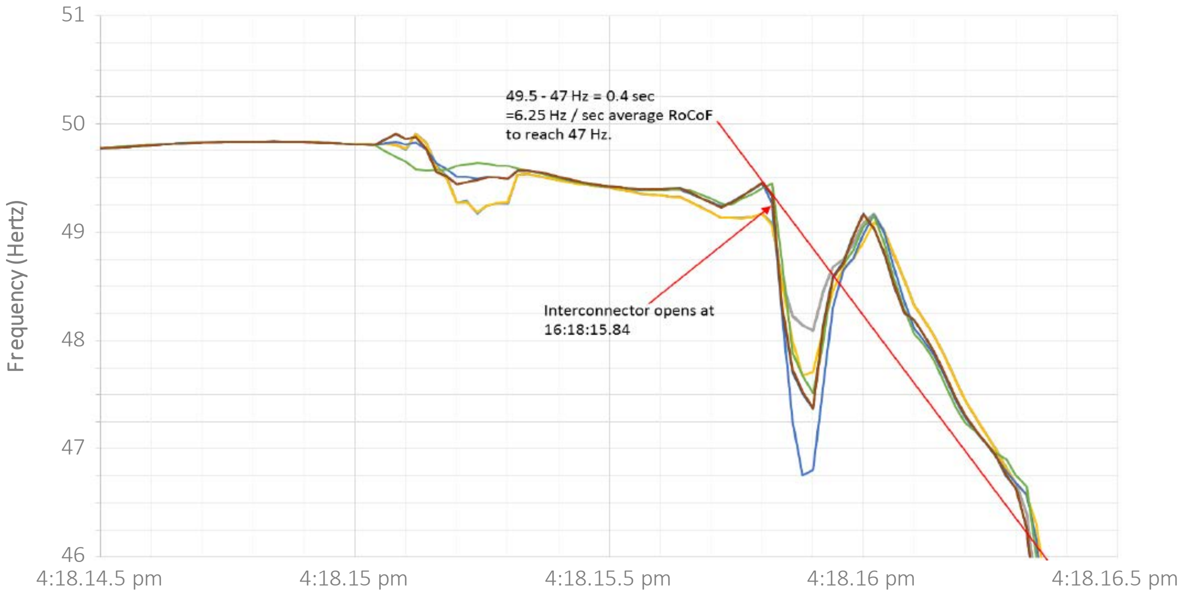
[38] In my prior role as a Director-General of the Queensland Department of Energy and Senior Official to COAG Energy Council, I had argued for a review of FCAS quantities (viz. an increase in regulated FCAS demand, and a localisation of some component of that demand) from April 2017. It appears AEMO failed to anticipate predictable impacts of a changing generation mix. In a note to stakeholders on 3 October 2018, AEMO advised that *"Regulation FCAS volumes have not been revised for many years, over which time significant system changes have occurred; less governor-based frequency support and increased penetration of intermittent generation are most notable"*. Regulated FCAS quantities were set in 2004 when the NEM had no intermittent renewable resources. It seems obvious this would be inadequate for regions such as SA, which by 2018 had > 50% intermittent resources. The note to stakeholders followed a series of material security events, the most recent being in August 2018 relating to primary frequency control (which put at risk the stability of two entire NEM regions including the largest, NSW).

[39] In the NEM, FCAS is determined dynamically in each 5-minute interval (viz. based on the single largest contingency event, loss of the largest generator, for example). FCAS is also procured "globally" across regions subject to network constraints. In periods of higher variability, FCAS regulation procurement automatically rises from the typical set point of 130MW to as much as 230MW (in 60MW increments) to maintain Frequency. Threshold quantities of FCAS Regulation and FCAS Contingency (including 6 second, 60 second and 5 minute spinning reserves which typically equate to about 990MW in aggregate) remained static as VRE increased.

[40] For full details see https://www.aemo.com.au/Media-Centre/AEMO-publishes-final-report-into-the-South-Australian-state-wide-power-outage.

As a result of the voltage dips, a group of wind turbines operating at ~450MW disconnected from the grid (nb. an unknown fault ride-through issue[41]). In response, power imported across the main VIC-SA Interconnector, already operating at close to full load, surged from 613MW to 890MW (i.e. > 250MW above rated capacity) and within 0.6 of a second, protection systems tripped the interconnector offline. At this point SA was islanded from the balance of the NEM. Following the combined loss of ~450MW wind generation and ~600MW VIC Interconnector flows, contingent capacity from indigenous dispatched plant (330MW) and Under Frequency Load Shedding resources were simply inadequate to arrest the decline in Frequency – noting that the time lapse of the events spanned 2 seconds, at 4:18:15pm as Figure 11 illustrates. When combined with FCAS (Frequency Regulation and 6 second Frequency Contingency), Under Frequency Load Shedding can generally arrest a Rate of Change of Frequency (RoCoF) of ~3.5Hz per second. But notice in Figure 11 that the estimated RoCoF was closer to 6.25Hz per second.

Figure 11 - Frequency and Rate of Change of Frequency (various measurement points)



Source: AEMO

How AEMO had configured the SA power system just prior to the Black System event was intriguing; the cyclonic conditions and 190+ km/h winds were forecast in advance. Noting the existence of s4.3.1 of the NEM Rules (per Section 4), power system operations immediately prior to material weather events in the NEM's northern region of QLD are always configured differently. QLD has a long, skinny network spanning several thousands of kilometres, and the far north of the State will typically experience 2-3 cyclones per annum – some of which can be expected to cross the network. The long-standing practice of grid owner (Powerlink) and System Operator (AEMO) in periods prior to cyclones crossing land is to invoke a greater reliance on local dispatchable generation either side of the weather event (i.e. dispatchable generation plant in the North is constrained-on, out of *merit order*) thus reducing reliance on intra-connector flows from the South in the event of a contingency. Why SA wasn't similarly configured during their 1-in-50 year storm remains a mystery. To be clear, the black system was a *system security* event, not a *Resource Adequacy* event. That is, there was more than adequate available generating capacity within the SA region.

AEMO undertook a review and made a series of changes, and the SA government stepped into the market and contracted a 100MW Tesla Battery to provide Fast Frequency Response, and added ~300MW of fast-starting Gas Turbine plant ahead of the looming 2018 and 2019 summer periods (given the potential impacts of combined coal plant exits of Northern and Hazelwood Power Stations,

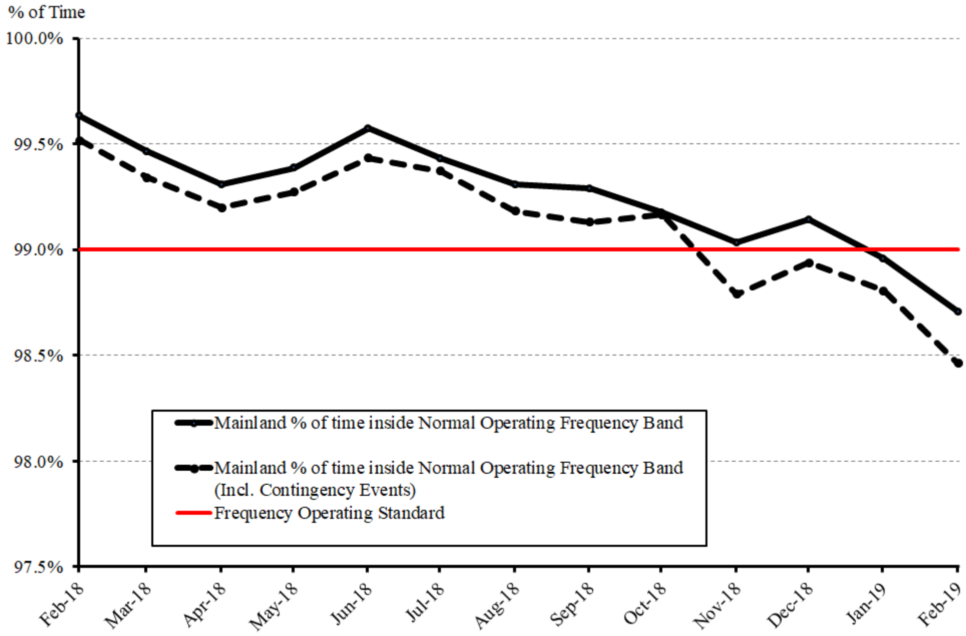
[41] The fault related to control systems configurations, which triggered disconnection after two minutes of continuous voltage dips – which in hindsight, the wind farms should have been able to ride through).

the latter in the adjacent VIC region). The Battery has thus far proven to be highly effective in supplying (and moderating the cost of) Frequency Control Ancillary Services.

5.9 Ongoing challenges for NEM Frequency

The Normal Operating Frequency Band in the NEM is 50Hz +/-0.015Hz, and system Frequency is to be maintained within that Band for > 99% of time. With more VRE plant entering (per Figure 8), NEM Frequency has become increasingly volatile. AEMO continued to hold FCAS quantities constant, at roughly 130MW of Frequency Regulation and ~990MW of combined Regulation and Contingency (spinning reserve) resources. AEMO's position on FCAS finally changed in early-2019 when Frequency fell outside the Normal Operating Band's '99% threshold' (see Figure 12). Frequency Regulation has now been increased to ~200MW and remains under active review along with the quantity of Frequency Contingency services. The direction of FCAS volumes was, in my view, predictable and long overdue.

Figure 12 - System Operations inside Normal Frequency Band (% of time)



Source: AEMO

6. Networks and Network Regulation

The Transmission and Distribution (T&D) networks servicing the NEM's 10 million business and residential customers are regulated by the Australian Energy Regulator in rate cases of five years' duration. The form of regulation is based on Littlechild's (1983) incentive-based *RPI-X*, with annual regulated revenue caps derived by a traditional building block approach. Within the revenue cap, there is an ability to rebalance tariffs amongst consumer segments within limits, beyond which specific regulatory approval is required.

The form of tariffs for end users varies considerably. For households and small businesses, a conventional two-part tariff applies (i.e. fixed rate, variable rate) with the fixed rate ~20% and the variable rate ~80% of revenue. For large Commercial & Industrial customers, conventional three-part tariffs (i.e. fixed, variable and demand charge) are generally used.

Capital deployed by Distribution networks tends to be dominated by residential segment peak loads. Conversely, adoption of rooftop solar PV has been prolific in the residential sector; Australia has among the highest rooftop PV take-up rates in the world. And this matters because solar PV systems greatly reduce energy (kWh) demand, but in certain regions only marginally impact peak (kW) demand (for example, see Simshauser, 2016). Consequently, two-part tariffs dominated by a volumetric variable charge are not well suited vis-à-vis rate stability. But while the economic justification for reforming residential tariff structures is (in my opinion) compelling, the political economy of doing so has proven almost impossible thus far. The inevitability of *losers* from tariff reform requires expending considerable political capital – and only policymakers in the Australian Capital Territory[42] have been prepared to take on such political risks.

6.1 Network performance

Network policy, network regulation and overall network performance has been amongst the most contentious aspects of Australia's energy market reforms – especially during 2007-2015. This period coincided with an enormous increase in the combined T&D Regulatory Asset Base as Figure 13 later illustrates. Key policy and regulatory decisions underpin this including i). erroneous policy decisions by the State Governments of QLD and NSW to tighten reliability standards in 2004 (following severe network-related blackouts in the capital cities of Brisbane and Sydney); ii). the decision to revalue network assets in the mid-1990s before market start; and iii). a policy decision by all State Governments in 2006 that had the effect of making network regulation *formulaic*, which amongst other things eliminated the ability of the Australian Energy Regulator (AER) from pursuing Regulatory Asset Base (RAB) write-downs (the absence of any *regulatory threat* being a clear deficiency vis-à-vis incentives of the firm).

By way of brief background, until 2006 Distribution Networks were regulated by State Government regulatory authorities[43]. From 2006 the AER took over network regulation from the State-based regulators. Evidently lacking trust in the new regulator, State Government Senior Officials attempted to minimise the risk of regulatory error by hard-wiring a surprising number of variables which otherwise require considerable professional judgment. This had the consequence of constraining the AER when undertaking regulatory determinations. By way of specific example;

- Regulated returns are determined by estimating a fair Weighted Average Cost of Capital (WACC) using the Capital Asset Pricing Model (for equity returns), and BBB rated 10-year corporate bonds (for debt returns). When the regulator attempted to make determinations in 2008 during the middle of the *Global Financial Crisis*, Australian credit markets had largely closed and the market for Australian 10-year corporate bonds literally disappeared. The regulator was then forced to use international proxies, which set excessively high debt returns[44]; and

- *any* capital invested by a network over and above the 5-year regulatory allowance could be automatically rolled into the RAB at the next regulatory reset without any prudency or efficiency review (see Grant, 2016).

What followed was predictable, and was predicted – Averch & Johnson (1961) gold plating, which when combined with excessive returns produced sharply rising network tariffs. Figure 13 presents the combined Regulatory Asset Base (RAB) of T&D networks servicing NEM customers (bar chart, LHS axis) and contrasts this with non-coincident NEM Maximum Demand (line chart, RHS axis) over the period 2006-2017. Notice the combined T&D RAB increased from ~$40 billion to $90 billion (+125%) whereas Maximum Demand had increased by only 11%. Network utilisation rates have consequently plunged. The aggregate Distribution network utilisation rate in particular has fallen from 0.59 to 0.45, with networks in NSW and QLD exhibiting large falls of 0.51 to 0.34, and 0.60 to 0.48, respectively.

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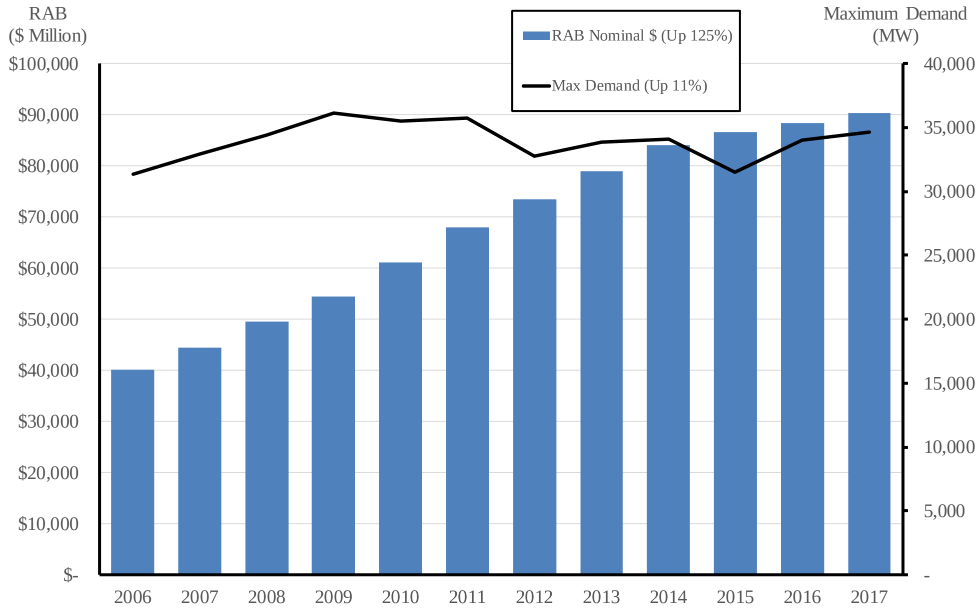
[42] The Australian Capital Territory is pursuing a household demand tariff, under an opt-out regime. From a wholesale market perspective, the Australian Capital Territory is a small sub-region of the NSW region. However, it has its own distribution network and retail market.
[43] The Queensland Competition Authority (QCA), the New South Wales Independent Pricing & Regulatory Tribunal (IPART), The Essential Services Commission of South Australia (ESCOSA) and so on.
[44] I specifically recall the then Chief Executives of Energex and Ergon in the early 2010's being embarrassed by the return levels in WACC determinations applying to their businesses. They were also at pains to point out that any future determination will be ~250 basis points (bps) lower. By the time the AER completed their Determinations in 2015, they were 400bps lower.

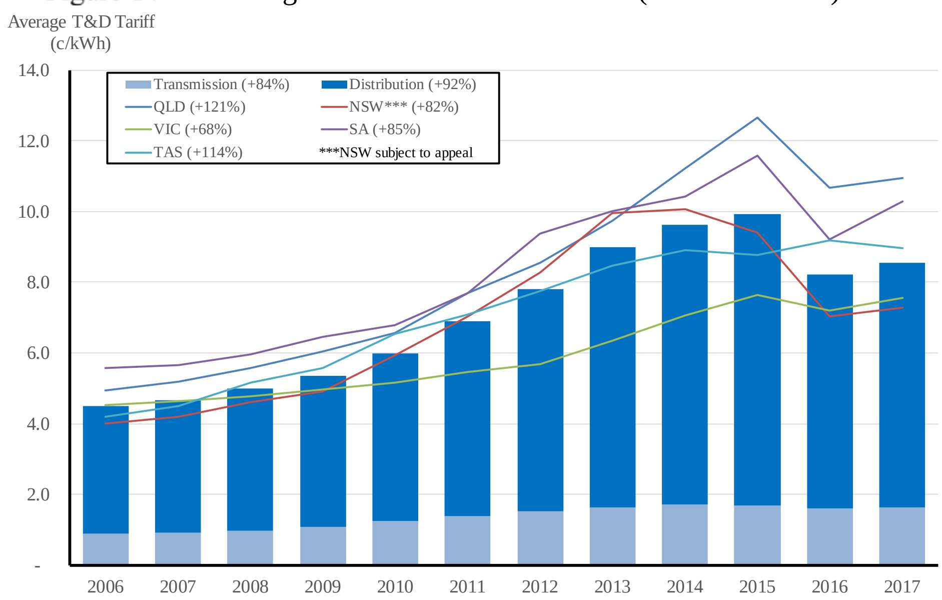
Figure 13 - Combined T&D RAB (in nominal dollars) vs Maximum Demand 2006-2017



Source: AER, ABS.

Figure 14 presents a simplified Average T&D Network Tariff for each region (line series) and in aggregate (bar series). Note the nominal average network tariff has increased by 91%, from 4.5c/kWh to 8.5c/kWh with considerable variation amongst regions. This data series has been constructed by dividing aggregate T&D revenues by T&D energy delivered, and as a result masks the rich variation of tariffs by consumer segment.

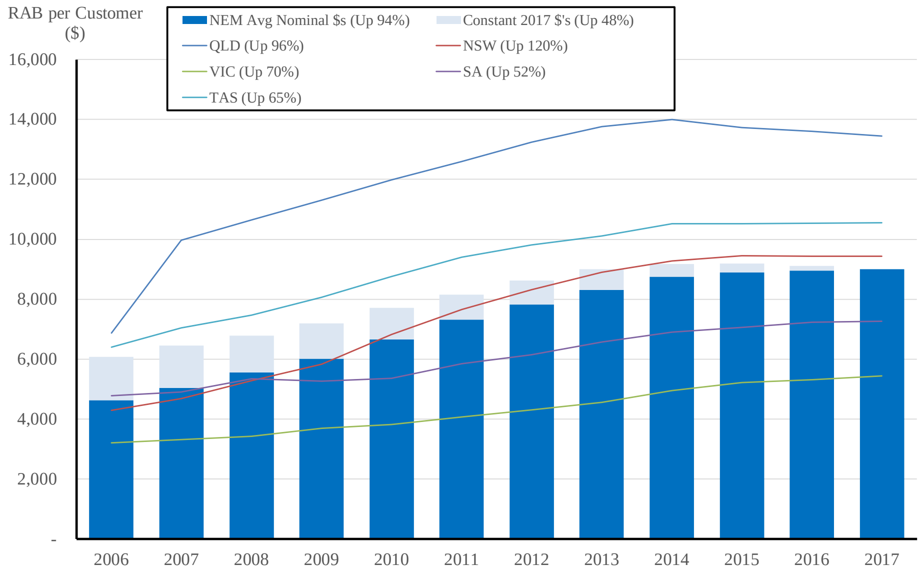
Figure 14 - Average Network Tariff 2006-2017 (nominal dollars)



Source: AER, ABS.

Figure 15 presents $RAB per Customer Connection by region (line series) and in aggregate (bar series – in both nominal and constant 2017 dollars). Notice the sharp increase in QLD (up 96%) and NSW (up 120%).

Figure 15 - RAB per Customer Connection (nominal dollars)



Source: AER, ABS.

6.1 Regulatory & policy response

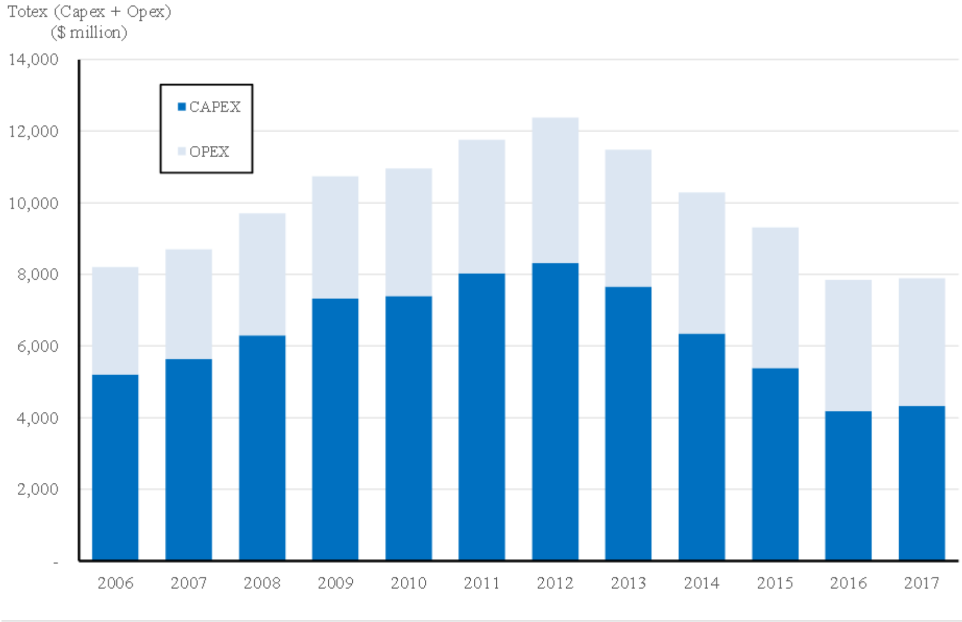
Once the effects of a tightened reliability standard became clear to regulators and policymakers, along with the fact that demand growth had stalled, a series of material policy & regulatory changes would follow. Both QLD and NSW abandoned their tightened reliability criteria – essentially reverting back to a probabilistic approach (rather than deterministic). The AER maximised the low interest rate environment and pushed allowable WACCs in each Determination down from 2015 – with returns falling from ~10% to ~6%, and more recent one Determination in the mid-5% range as illustrated in Figure 16.

Figure 16 - Regulated Returns (5 Year Determinations made over the period 2002-2018)

Source: AER, ACCC.

The AER also adopted a hard line on Capital Expenditure (Capex) and Operating Expenditure (Opex) allowances, routinely rejecting as much as 30% of that proposed by network companies. Figure 17 illustrates the sharp reductions in Total Expenditure or Totex (i.e Capex and Opex).

Figure 17 - Allowable Totex in constant 2017 dollars



Source: AER

Two outstanding network policy issues that remain are i). given dramatic falls in network utilisation, how this excess capacity should be treated[45]; and ii). the efficiency of network tariff design - especially at the household level given sharply rising levels of Distributed Energy Resources.[46] On the latter, the nature of the current regulatory system means that the regulator and distribution companies have tended to focus on the Revenue Cap, not the efficiency of tariff structures.[47]

7. Retail Market

Competition in the retail segment formed a key component of Australia's energy market reforms, and was based largely on Great Britain's approach to contestability (see Littlechild, 2016). Specifically, in the period leading up to market start, incumbent distribution/retail supply companies held a monopoly franchise over their customer base, but this franchise would diminish gradually. To ensure an orderly transition to a competitive market, retail electricity market contestability was phased in over a timetable comprising 4-6 Tranches of consumers (starting with the largest customers) and spanning a 4-8 year window. The final tranche of customers (i.e. residential) had added policy scaffolding in the transition to a fully contestable market – a 'regulated tariff cap' – retained as a transitional measure until the so-called *mass market* was deemed to be *workably competitive*. The mass market would be deemed workably competitive by reference to measures such as i). consumer awareness of their ability to switch supplier; ii). number of rival retailers; iii). array of products and the depth of discounting; iv). customer switching rates; v). market share of incumbent Retailers, vi). number of customers remaining on the default tariff, and so on.

In Great Britain, retail competition commenced in the early-1990s with the residential/household segment made contestable in 1999, and residential price controls removed (i.e. price deregulation) in 2002 (Littlechild, 2016). NEM contestability varied by region; VIC 1994-2002; NSW 1996-2002; QLD 1998-2007; and SA 1998-2003. Residential segment price deregulation occurred in 2009, 2014, 2016 and 2013 respectively (Simshauser, 2018).

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[45] See Simshauser (2017) and Simshauser & Akimov (2019).

[46] See Simshauser (2016).

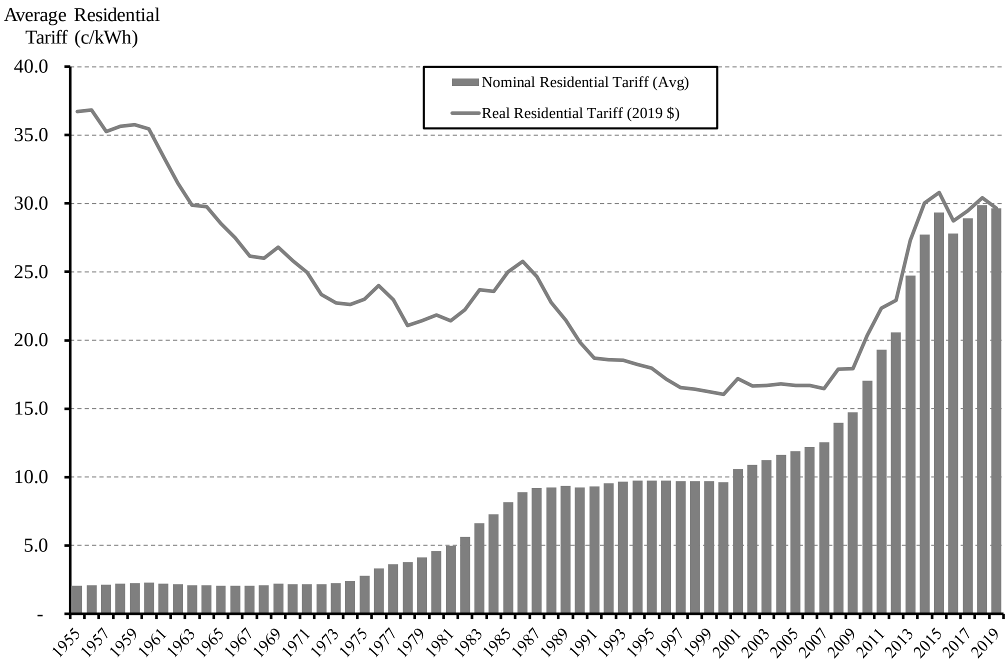
[47] A series of 2012 Rule changes removed the formulaic approach to network regulation, and replaced them with descriptions of the factors the AER needed to take into account, and placed obligations on the AER to explain how they had done so. In retrospect, while this was sensible from an economic regulatory perspective, the replacement of formulas with words laid the ground work for (excessive) legal challenges. The tendency of (or some would argue, abuse by) network businesses to so ultimately led to a COAG Energy Council decision to abolish Limited Merits Review.

As Section 7.1 reveals, the experience of consumers over the period 2007-2015 has been characterised by sharply rising electricity tariffs after a period of price stability. Rising prices, driven by network and wholesale prices (per Sections 5-6 above) have tended to mask the successes of retail competition in the NEM; the number of competitors, the array of products, discounts available, competitor rivalry, customer switching rates and reductions in the number of Default Tariff customers have all progressively intensified over time. But as with Great Britain, the evolution of price discrimination has become a political target – erroneously conflating the problem of rising prices (and some poor practices by certain Retailers) with price dispersion.

7.1 Retail Tariff Increases

To understand the problem of rising final consumer prices in Australia, Figure 17 presents Average Retail Tariffs from 1955-2019 in nominal and real terms using QLD data as the reference. As with all NEM data there is variation by region, but the trend is largely consistent.

Figure 18 - Queensland Average Residential Electricity Tariff (1955-2019)



Source: Simshauser (2018).

It took 45 years of technological advancement, scale economies and microeconomic reform from 1962-2007 to drive real tariffs from 30c/kWh down to 16c/kWh. Policy errors would unwind those gains in eight years (2007-2015). Three distinct drivers were responsible for tariff increases, viz. network policy failure[48] (2007-2015, see Section 6), environmental schemes[49] (2011-2017) and wholesale prices (2017-2019, see Section 5). These pricing effects were sequential, and cumulative.

Compounding matters were the timing; the sharp run-up in household electricity tariffs occurred in the post-Global Financial Crisis era of low consumer price inflation, low productivity, low wages growth and in some jurisdictions coincident record-high house prices. Unsurprisingly (and understandably), and as with Great Britain, electricity prices and retail electricity markets became a

[48] In relation to network policy failure, in the 2004 summer Southeast Queensland experienced a series of extreme weather events which produced three severe episodes of distribution network-related load-shedding. These were a political disaster because Energex, a government-owned distribution network company, had aggressively reduced operating and capital expenditures in prior periods to raise productivity and returns (as requested by Shareholding Departments). An inquiry into the blackouts recommended a change in planning standards, from stochastic to deterministic, which produced a form of Averch & Johnson (1962) gold-plating. The huge expansion in the capital base commenced soon after, with network tariffs more than doubling from 2007-2013 (Simshauser, 2017).

[49] Four environmental schemes impacted tariffs from 2011-2017. To be clear, each scheme was trivial but combined they aggravated network-driven tariff increases. Schemes included i). solar Feed-in Tariff (Nelson et al 2012); 20% Renewable Energy Target which was separated into two, viz. ii). small-scale and iii). utility scale (MacGill 2010) and iv). the carbon tax from 2012-2014. At their peak, environmental schemes added 15% to an already sharply rising tariff.

cost of living *focus event* for consumer groups and politicians (see Littlechild, 2014; Waddams Price & Zhu, 2016; He & Reiner, 2017; Simshauser & Tiernan, 2019).

7.1 Price Discrimination the Target

As with Great Britain, there has been nothing politically contentious about the overall performance, and success, of the Commercial & Industrial retail market segment. However, as with Great Britain, recent performance of the NEM's residential retail market has been the subject of a highly charged and politicised debate which deteriorated badly over the period 2016-2019. For the first time in a generation, an Australian Prime Minister became involved in what has traditionally been a State Government responsibility. And unfortunately, two separate issues were conflated; rising prices and price discrimination (see Simshauser, 2018, and also Littlechild, 2017 on Great Britain). Rising prices are indeed a problem, including rising network charges (2010-2015) and wholesale price dynamics (2017-2019). But price discrimination is not; and the difficulty for policymakers is that misdiagnosing price discrimination for policy treatment may make some household considerably worse off, and leave residential consumers as class no better off (Simshauser, 2018).

When contestability commences in the residential segment, prices commence a natural drift from a regulated uniform (two-part) tariff to discriminatory prices. A regulated price cap is initially retained as a proxy *safety-net* for inactive household consumers as the market shifts from single monopoly provider to competitive market. This regulated *Default Tariff* forms a price-to-beat. Rival and new entrant retailers entering a franchise service area will offer *discounts* off the incumbent's Default Tariff in order to poach customers. Incumbent Retailers are forced to construct their own discounted matching-products in response. Discounts off a Default Tariff are thus a central design feature of a contestable retail electricity market.

The success of Full Retail Contestability (i.e. household segment) is inextricably linked to expected gains from switching. Gains to household consumers are expressed as a "percentage discount off[50]" an existing Default Tariff. When the mass market is deemed *workably competitive* the requirement for an independent regulator to set a regulated Default Tariff cap no longer exists. Incumbent Retailers – who retain an obligation to supply[51] in their former franchise area – must ensure that their Default Tariff (and associated levels of service) is available at all times.

When retail prices are deregulated, the number of rival suppliers will expand rapidly because a key business risk (i.e. regulatory risk) has in theory been removed.[52] In addition, Retailers segment the residential market into multiple sub-segments[53] and product bundles are then constructed to target those discrete sub-segments. Consequently, with the number of rival Retailers expanding and consumer sub-segments multiplying, the number of products – and discounts –proliferates.

Certain *'Reviews'* of residential retail market practices and performance in Australia and in Great Britain have pointed to price discrimination as a key policy problem; suggesting the practice produces *unfair prices* and *'loyalty taxes'* for disengaged customers who do not switch supplier regularly (see Littlechild, 2016; Simshauser, 2018). But price discrimination is unremarkable in economics, is a predictable outcome of rising competition and is frequently welfare enhancing. Price discrimination is pervasive throughout the economy and forms a vital means by which non-trivial joint fixed and sunk costs are efficiently recovered by firms, especially in capital-intensive or 'heavy' industries (see Dana, 1998; Levine, 2002; Elegido, 2011; Littlechild, 2017).

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[50] British research revealed only 19% of consumers preferred wanted to stop discounts being expressed in percentage terms (*cf.* dollar savings). In addition, he strongest driver of customer activity is the size of anticipated gains from switching – *not* the simplicity of offers available. See for example IPART (2013); Littlechild (2016); Waddams Price & Zhu (2016); He & Rainer (2017); Simshauser (2018); Flores & Waddams Price (2018).

[51] This is usually a condition of their retail licence.

[52] In the NEM there are now thought to be three tiers of retailers; 1st Tier incumbents (i.e. the Big 3), 2nd Tier Retailers being highly successful new entrants (most of which are also vertically integrated), and a 3rd Tier being boutique, sub-scale, new entrants.

[53] For example, 1) affluent urban professionals, 2) budget conscious families, 3) pensioners, 4) socially conscious households; 5) time-poor families; and 6) tech-savvy households.

Nonetheless, *perceptions of fairness* inevitably arise when a menu of tariffs emerge and deviate from an historic uniform price (Dana, 1998). Deeply discounted tariffs are popular while high Default Tariffs are derided by consumer groups (and in a rising price environment, with some justification). Regardless, their existence produces adverse media and political *focusing events* in which ill-advised claims of forcing Retailers to shift all customers en-masse to the cheapest tariff can be expected (see He & Rainer, 2017; Littlechild, 2017; Simshauser, 2018). Implementation of such a policy would of course see cheap tariffs disappear overnight. As an aside, the business segment of electricity markets exhibits extensive *second- and third-degree* practices yet are never questioned by policymakers.

It is worth briefly reviewing some of the NEM retail market metrics to highlight the overall performance of the market (in spite of the network and wholesale market cost pressures).

7.2 Competitive health of the retail market

Customer switching is frequently used as a headline measure of the health of contestable residential electricity markets. Switching rates in NEM regions have typically averaged 16-22% per annum, which compares favourably to other Australian industry switching rates (see Table 5).

Table 5 - Industry comparison of customer switching rates

Industry	Switching Rate (%)
NEM Electricity	23.5
NEM Gas	15.9
Broadband	15.0
Mobile Phones	13.0
Pay Television	12.0
Insurance	12.0
Airlines	10.0
Banking	8.0
Health	4.0
Superannuation	4.0

Sources: Simshauser (2014, 2018).

Detailed historic data for the main NEM regions is presented in Table 5.

Table 6 - NEM Electricity customer switching by Region (2007/08-2017/18)

Fin Year	SE QLD	VIC	NSW	SA
2007/08	20.3	22.4	10.2	18.3
2008/09	20.7	25.4	10.9	15.0
2009/10	23.3	25.9	12.8	13.9
2010/11	25.3	27.1	14.0	18.6
2011/12	21.2	26.8	17.3	22.1
2012/13	18.1	28.7	20.1	22.0
2013/14	17.0	27.3	15.2	18.3
2014/15	16.7	26.6	15.9	16.0
2015/16	16.8	24.6	16.9	16.3
2016/17	22.1	27.4	18.6	16.5
2017/18	32.2	29.0	20.0	20.4
5Yr Avg	21.0	27.0	17.3	17.5

Source: AEMO

Another residential market metric that requires continual monitoring by policymakers is so-called *'rusted-on'* customer numbers, i.e. customers who have never switched and remain *rusted-on* to incumbent retailer Default Tariffs. Table 7 presents *rusted-on* customer results for the primary NEM regions:

Table 7 - Year of reform and market customers vs. 'rusted-on' customers

Region	Full Retail Contestability (Year)	Price Deregulation (Year)	Total Customers	Default Customers	"Rusted-on" Customers (%)
SE QLD	2007	2016	1,317,957	226,018	17.0
NSW	2002	2014	3,534,894	813,000	23.0
SA	2003	2013	864,876	121,000	14.0
VIC	2002	2009	2,807,280	281,000	10.0
		Total NEM	8,525,006	1,441,018	16.9

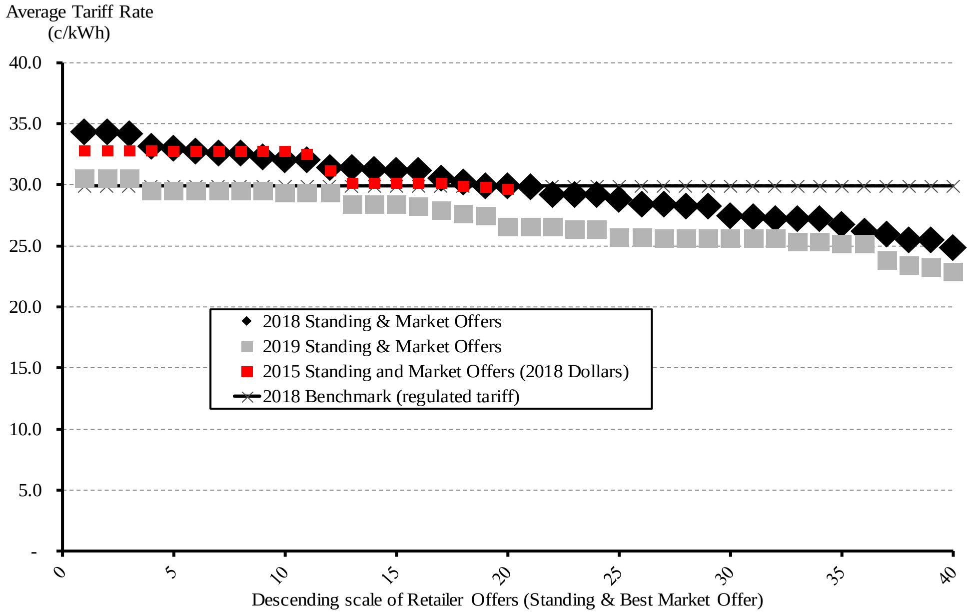
Source: Simshauser, 2018.

Table 7 notes Victoria is the oldest of the deregulated markets (2009) with the lowest number of rusted-on customers (10%). After deregulating in 2016, 17% of Southeast Queensland customers are rusted-on. These results compare favourably to the British Market, which has about 33% of rusted-on customers after Full Retail Contestability in 1999 and price deregulation in 2002 (Littlechild, 2016; He & Reiner, 2017).

The final matter of interest is the extent of price dispersion, and for this Figure 19 presents data from the QLD region – ideally suited for such analysis because Regional QLD is a regulated monopoly (and is still subject to a regulated price based on the South East QLD cost inputs) whereas Southeast QLD is a fully contestable and deregulated market (thus enabling a direct comparison of a competitive and regulated market, which is unique by global standards). Figure 19 presents four discrete data series:

1. The 2018 Regulated Tariff (applied to Regional QLD customers and based on the common QLD region wholesale price, and Southeast QLD Network charges, and a suitable retail supply cost allowance);
2. Southeast QLD competitive offers in 2015 *prior* to deregulation – i.e. when QLD's Regulated Tariff acted as a tariff cap in the contestable Southeast QLD corner (as well as the regulated price to regional QLD customers) inflated to 2018 dollars;
3. Southeast QLD competitive offers in 2018 *after* deregulation; and
4. Southeast QLD competitive offers in 2019 (nb. the 2019 Regulated Tariff was 29.6c/kWh, ~0.8% lower than the 2018 Regulated Tariff rate of 29.9c/kWh – see Figure 18).

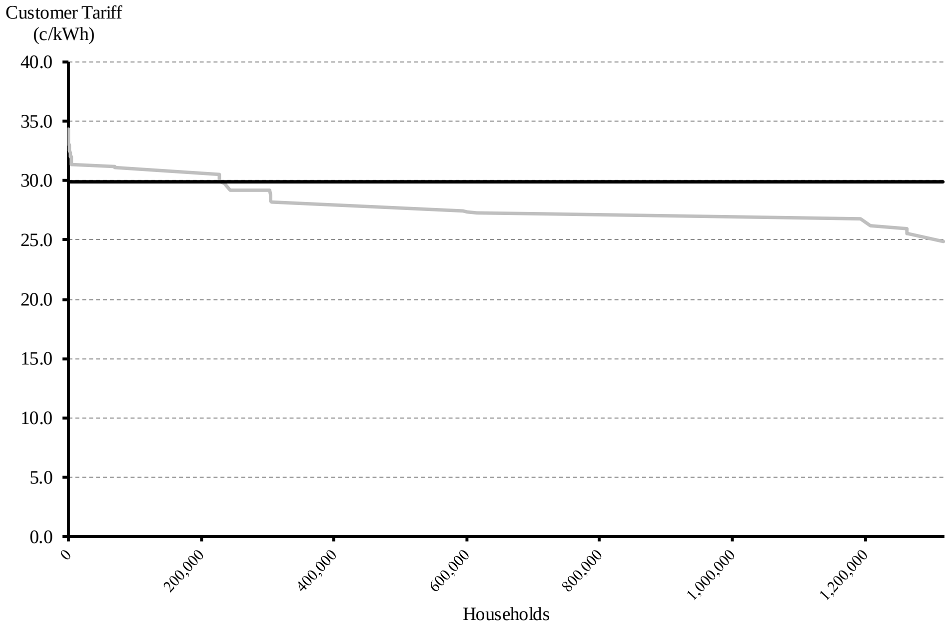
Figure 19 - Tariff dispersion: pre- and post-deregulation tariffs vs Benchmark



Source: Simshauser (2018), AER.

Figure 19 and the data behind it provides important insights for the competitive retail market. First, following deregulation of Southeast QLD in 2016, the number of rival retailers expanded from 12 to 20 by 2018, and the number of Default Tariffs and *routine discounts* offered by rival retailers expanded from 24 to 40+. Second, the dispersion of tariffs increased in line with general findings of the literature, i.e. falling either side of the regulated rate. But to be clear, about 1.1 million out 1.3 million Southeast QLD households were on a lower tariff than the Regulated Tariff as Figure 20 notes (and as a class, Southeast QLD households in aggregate were paying 7% less than the regulated rate, albeit with ~200,000 households paying more than the regulated rate – see Simshauser, 2018). Third, by 2019 competition had forced high-end Default Tariffs closer to the counterfactual Regulated Rate, with deeper discounts also being exhibited.

Figure 20 - 2018 Distribution of Southeast QLD households by tariff



Source: Simshauser (2018).

On balance, one can conclude that the deregulated retail electricity market is performing well. The *Standing* or Default Tariffs of retailers, which Table 7 and Figure 20 confirm is limited to a relatively small percentage of customers, has received a disproportionate level of political attention, and policy solutions of re-regulating prices through a Price Cap is unlikely to end well for those consumers active in the market (in the medium term) as retailers progressively re-adjust their market segmentations and profit strategies.

This is not to suggest the retail market is operating without fault; vulnerable rusted-on customers represent a misallocation problem (i.e. low income households are on a tariff designed for an inelastic segment), and discounts are no longer anchored to a common price. Both of these matters are serious policy problems that require further work by Retailers and policymakers, respectively.

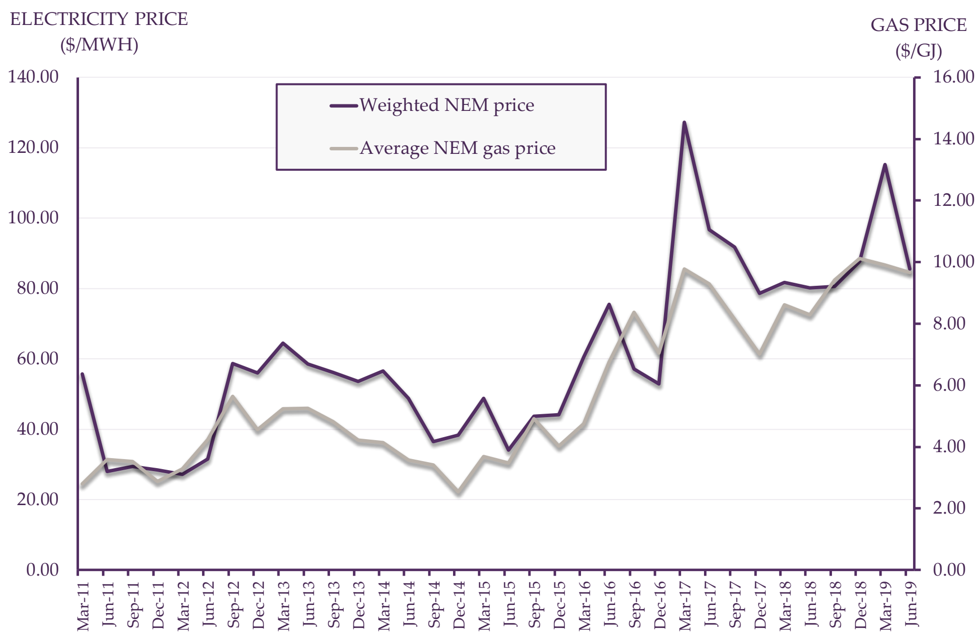
8. The Strengths & Weaknesses of Australia's Energy Market Reforms

In light of the recent problems emerging in Australia's NEM, it is easiest to start with a review of weaknesses. There have been a series of reform weaknesses which stem from policy failures. With the benefit of hindsight, these include the following:

1. The lack of a clear gas market and **LNG export capacity policy** architecture prior to LNG investment commitments in 2010-2012. Emphasizing the benefit of hindsight, LNG export licencing should have restricted to the availability of 'booked' 2P Reserves above that required to service the domestic market for natural gas. This *missing policy* needed to be

coordinated at the national level because no individual jurisdiction is able to reasonably assess, on a cost-benefit basis, east coast Reserves adequacy. Gas shortages (Fig. 5) on Australia's east coast remain an unresolved problem, and the impact on electricity price is evident as the 34 Quarterly data points in Figure 21 illustrate (nb. correlation of 0.88). Forward resolution needs to turn to prospective measures on new supply, rather than retrospective policy intervention which may inflame perceptions of *sovereign risk*.

Figure 21 - Quarterly Average: NEM Spot Price vs NEM Gas Price



Source: Grattan (2019), AEMO.

2. Policy discontinuity and design errors vis-à-vis **climate change policy**, and a general lack of a united climate & energy policy architecture. At least four Australian Prime Ministers have lost their leadership through a two-decades long *climate change policy war* with both sides of politics suffering equally. This *missing policy* has adversely affected investment continuity in the NEM, and remains a live problem at the time of writing. Furthermore, the policies that do exist, such as the expanded 20% Renewable Energy Target amongst an array of others (see Simshauser & Tiernan, 2019) were incompatible with the NEM design in that investment was largely disconnected from forward markets – instead, investment was being driven by side-markets. This problem risks being further compounded by the rising use of government-initiated CfDs; while highly effective at encouraging new capacity to meet various policy objectives (e.g. navigate *missing policies* relating to climate change etc), government-initiated CfDs are incompatible with the NEM design (Simshauser, 2019b). Whether the NEM's wholesale market design needs to change to suit CfDs, or alternate mechanisms need to be found to suit the NEM design, is an open question.

3. **Plant exit policy**, and coal plant exit in particular, could have been better managed in the NEM if the gas market had been functioning properly. But regardless of this, or perhaps because of it, transparency around exit timing needed to be greatly improved. This *missing policy* has been *semi-resolved* by way of a Rule Change that requires continuous disclosure of plant exit timing (referred to as the 3-year closure Rule). However, looking forward, each State Government should have a well-rehearsed plant exit policy; the closure of the 1600MW Hazelwood Power Station (20% VIC market share) over 6 consecutive trading days with 5-months' notice did not represent an orderly exit. In the event, annual wholesale spot market turnover rose from $7.7 billion to $17.2 billion either side of the Hazelwood exit. In hindsight, some component of Hazelwood's required $400m capital expenditure program

could have been taxpayer- (or electricity consumer-) funded, on a cost-plus basis so as to ensure an orderly exit and provide the market with more time to adjust given predictable entry lags. Such a policy should not be interpreted nor designed to prevent an exit decision per se, and above all, should avoid outcomes that lead to ‘costs being socialised and profits being privatised’. It should be a contingent policy, used judiciously to facilitate orderly exit, and only applied in critical circumstances.

4. **Competition policy**; with the benefit of hindsight, the Commonwealth Government, State Governments and the ACCC allowed an excess of horizontal M&A events. State Governments sought to maximise privatisation sale proceeds, and in my view the ACCC over-diagnosed *vertical* integration, and under-diagnosed more adverse *horizontal* aggregations.

5. **The over-diagnosis of price discrimination** by various agencies and governments is likely to adversely impact a component of NEM reforms that has generally performed well. This is not to suggest the retail market is without fault; clear weaknesses include the lack of jurisdictional coordination over the timing deregulation events across NEM regions (i.e. lack of synchronisation), how Retailers deal with vulnerable customers on Default Tariffs, and the lack of a common anchor for advertised product discounts. But a policy of re-instating a regulated price cap will not solve the underlying problem of affordability, a point in economics that the AEMC has also recently noted.

6. While NEM governance has certain unique advantages (e.g. strict segregation amongst market institutions), in the absence of a formal binding agreement to meet certain policy objectives, **COAG Energy Council** ultimately becomes a weakness of NEM governance in that it requires multiple State and Territory Governments (and multiple political parties), and the Commonwealth, to agree to material policy change. Furthermore, State Governments have de-skilled their Energy Departments over time (notably, there are virtually no specialist Energy Departments remaining. In most jurisdictions, the former Department of Energy now forms part of a broader mega-departmental structure, with the Departmental Secretary or Director-General spread thinly across the long list of line responsibilities). It is worth noting that during the 1990s, ‘competition payments’ from Commonwealth to State Governments were used to encourage a united approach to policy and reform objectives.

7. **Network Regulation** in the NEM proved to be a weakness throughout the period 2004 to 2015. Critical errors were made by certain State Governments vis-à-vis reliability standards, and the Rules from 2006-2012 were too *formulaic* to respond to the unique conditions of the Global Financial Crisis. These two conditions proved to be devastating for network prices as the charts in Section 6 illustrated.

The strengths of the Australian reform experience could be summarised as follows:

1. The NEM’s **energy-only, gross pool market design,** very high VoLL **and associated market for forward derivatives** has delivered Resource Adequacy and withstood a wide array of economic and technical conditions. Market failures can generally be attributed to *missing policies* of LNG export capacity, climate change and plant exit, design errors of renewable schemes, and the application (or lack thereof) of competition policy vis-à-vis initial privatisation events.

2. The NEM’s core **governance structure and approach to open-source Rulemaking** has had the beneficial effect of minimising misguided political interference, and ensured Rule changes have *purposefully* thought through economic trade-offs. For example, the strict segregation between AEMC (i.e. Rulemaking body) and AEMO (System Operator) means Rule changes which enhance system operations and spot prices efficiency can be weighed against any efficiency losses that might arise in forward markets and in turn, how capital markets interact

with the energy market. Moreover, the segregation between the AEMC and AER has the effect of separating Policy Advice and Rulemaking that follow such advice (AEMC functions) from the entity which enforces compliance with Rules, and acts as industry economic regulator (AER functions). The evidence on these separations is that capital markets have had confidence in the market and market institutions to back required investment. It is however noteworthy that interference by the Commonwealth Government has been rising, ironically due to market failures associated with *the missing policies* and the misdiagnosis of price discrimination (i.e. weaknesses 1, 2, 3 and 5 above).

3. While I have argued that State Governments and the ACCC have allowed too much horizontal aggregation, the same institutions have allowed (or been forced by courts to allow) **capital markets to determine vertical business boundaries**. Specifically, it was the capital markets that initiated the dis-aggregation of Retail businesses from Distribution Network businesses, and also the re-integration of Generation with Retail. This has reduced the cost of capital in both the regulated and merchant segments.

4. Competition in the NEM's **Retail Markets** has generally performed well, especially in the industrial segment. Rising electricity prices and associated affordability for certain household segments are indeed a problem, but to be clear these relate to sequential rises in Network prices, (weakness 7 above) and wholesale prices (caused by *the missing polices*, weaknesses 1, 2 and 3 above).

9. Conclusion

This article has provided a background to Australian energy market reform experience, and explained the critical importance of reform sequencing. The review of industrial organization in the NEM highlighted that the reform blueprint was eventually altered by the capital markets, which had a preference for aligning (and mitigating) the risk characteristics of merchant businesses through vertical integration, and isolating regulated from merchant business units. The performance of the wholesale market revealed an institutional design that remained largely true to its objective function of enhancing productive, allocative and dynamic efficiency. But this high-performing energy-only market design with its high VoLL and associated forward markets could not navigate market failures associated with what I have described as *the missing policies*, relating to LNG export capacity, climate change policy discontinuity and design errors, and disorderly coal plant exit at-scale.

The review of the NEM's regulated networks revealed major historic policy failures, specifically coincident (and coincidental) misguided changes to reliability standards in QLD and NSW along with an initial *formulaic* approach to network regulation when professional judgement was required. Notably, both policy changes were instituted without a formal policy development cycle, and the unintended consequences have severely damaged the network sector.

The final two sections covered the Retail Market, which was on balance argued to have operated well, and the strengths and weaknesses of the Australian reform experience.

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