From first place to last: Australia's policy-induced energy market death spiral

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Abstract

Microeconomic reforms that established Australia's National Electricity Market during the 1990s were extensive. State-owned Electricity Commissions were vertically and horizontally restructured, and many of the restructured businesses were privatised. A mandatory gross pool market was established to facilitate competition amongst generators and retailers, and quickly became one of the best performing wholesale electricity markets in the world. Networks remain regulated under unresponsive 5-year rate cases with flat-rate tariffs persisting, while inflexible 'subsidy schemes' proliferated and forced generation plant entry into an already oversupplied market. End-use electricity tariffs have since doubled. Misguided and overlapping policy failures are primary causes.

Keywords: Microeconomic reform, electricity markets.

JEL Codes: D04, D47, L11 and L94.

1. Introduction

From 1994, State Electricity Commissions were vertically separated into generation, transmission, distribution and retailing with the intent of forming a National Electricity Market (NEM).¹ Generation and retail were further horizontally restructured to create competing entities while monopoly transmission and distribution networks were subjected to revenue regulation. The NEM and its accompanying institutions formally commenced in 1998. This structural progression is illustrated in Appendix I.

By 2005 capacity oversupply, which plagued the east coast from the late-1980s, was largely cleared, plant availability increased sharply to world best practice, electricity prices were falling, investment in new equipment flowed seamlessly, and system reliability criteria was met in all years (Simshauser, 2005). As the IEA (2005) observed, Australia had executed one of the best microeconomic reforms of a power system in the world. But by 2014, things looked different. Utility stock analysts at investment bank UBS analysed tariff changes from 2007-2013 across a range of countries. From a rate-of-change perspective, the NEM was the worst performer. How did the NEM slip from first place to last so quickly? The short answer is energy policy failure.

The objective of energy policy is to (1) ensure the security of energy supply; (2) with supplies delivered at minimum cost; (3) subject to an environmental constraint. Each of these policy objectives collides. Policymakers must continuously trade-off each at the expense of others. In general terms, a security of supply threshold is of paramount importance (i.e. as an essential service, failure is devastating for politicians).² Cost minimisation in Australia has been delivered through competition policy, viz. restructuring monopoly generators and creating a mandatory gross pool market with a real-time uniform first-price auction clearing mechanism. Retail-level

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¹ Covering East Coast Australia. Western Australia and Northern Territory were too remote for electrical interconnection. See www.aemo.com.au for a detailed background on the design and operation of the National Electricity Market.

² Power systems are not built for 100% reliability. The NEM uses 'no more than 0.002% unserved load'.

competition was similarly delivered through restructuring and contestability. Competition was not practical for poles and wires infrastructure so revenue regulation was deployed. Additionally, government businesses have been progressively privatised. Finally, environmental objectives have been delivered through Renewable Energy Targets and largely transient greenhouse policies such as the ill-fated carbon pricing framework, Solar PV capital subsidies, subsidised Solar PV Feed-in Tariffs and other temporary State-based emission abatement schemes.³

An excessive and uncoordinated focus on the first and third of these objectives, coupled with the inertia of energy policy (even when it becomes clear more damage is being done than good) has come at the expense of the cost minimisation objective function. There is no other credible explanation of the NEM's collapse in performance.

Many of the policy failures identified in this article have been amplified by unprecedented contractions in energy demand. But energy demand has contracted because of price increases arising from policy failures. The purpose of this article is to review key developments in the NEM, and to outline necessary surgery to remedy the situation. This article is structured as follows; Section 2 reviews recent trends in electricity price and demand. Section 3 reviews network infrastructure while Section 4 reviews power generation. Policy implications follow.

2. Electricity Price and Demand

A suitable starting point is to review the tariff analysis undertaken by Utility stock analysts at UBS.⁴ Figure 1 presents the data for 19 countries, Australia is ranked 14th.

Figure 1: 2013 Residential Electricity Tariff (USD)

In 2007, Australia had the second lowest electricity prices in the world.⁵ Based on the change in tariffs from 2007-2013 (per Figure 2) Australia is the worst performing market. This outcome is being driven by rising Network Costs, and, Taxes/Levies – both of which are driven more by policy and regulation than markets. In contrast, the increase in the cost of Energy & Supply – a

³ These include state-based renewable targets, the QLD Gas Electricity Certificate scheme, the NSW Greenhouse Gas Abatement scheme, and various State-based energy efficiency certificate schemes.

⁴ I am indebted to UBS Securities Australia Utilities Stock Analyst David Leitch and his international colleagues for providing me with their underlying data and analysis.

⁵ See Simshauser, Nelson and Doan (2011 at p.72).

competitive segment – has increased only marginally in nominal terms (and has decreased in real terms, even after accounting for AUD appreciation).

Figure 2: Change in Tariffs 2007-2013 (USD)

From 2007-2013, retail tariffs doubled. This rapid doubling of tariffs was forecast at least as far back as 2009 by AGL in a Working Paper titled ‘The Boomerang Paradox’.⁶ Residential tariffs and total electricity load from 1990-2014 are presented in Figure 3 along with annual load forecasts prepared from 2010-2014.⁷ 2010 was the first year in Australian electricity industry history that demand contracted, and it took time for central forecasts to adjust.

Figure 3: NEM final demand 1990-2020f

Source: AEMO, esaa, AGL Energy Ltd.

⁶ A peer-reviewed version of Working Paper No.17 ‘The Boomerang Paradox: how a nation’s wealth is creating fuel poverty – and how to defuse the cycle’ was subsequently published in *The Electricity Journal* in 2011. See Simshauser, Nelson & Doan (2011).

⁷ The Australian Energy Market Operator produces an annual load forecasts. See www.aemo.com.au for details.

The magnitude of tariff changes ultimately impacted final electricity demand. This is reflected in Figure 4 which presents Year-on-Year growth in load and real tariffs (note the inverse axis on the RHS).

Figure 4: Year-on-Year growth in final electricity demand vs. (real) residential tariffs (1991-2014)

These conditions and the policies that have driven them have induced the early stages of an *Energy Market Death Spiral*, a term AGL Energy Working Paper No.31⁸ introduced to the Australian energy industry in June 2012, and was in turn drawn from US energy economist Craig Severance (2011, p13):

The unspoken fear of all utility managers is the “Death Spiral Scenario”. In this nightmare, a utility commits to build new equipment. However, when electric rates are raised to pay for the new plant, the rate shock moves customers to cut their kWh use. The utility then raises its rates even higher – causing a further spiral as customers cut their use even more... In the final stages of that death spiral, the more affluent customers drastically cut purchases by implementing efficiency and on-site [solar PV] power, but the poorest customers have been unable to finance such measures... (Severance, 2011, p.13).

In this article, ‘considerable ink’ is devoted to examining causes and remedies of Network Cost increases since they dominate the cost increases in Figure 2. The analysis that follows does not examine privately-owned Victorian Network businesses because their performance has been comparatively favourable.⁹ It is the policies and productivity of the seven government-owned network businesses in QLD and NSW that form the focus of Section 3. For clarity, the impacts of the overinvestment in Solar PV driven by inert and overlapping federal government policy (i.e. capital subsidies) and state government policy (i.e. Feed-in Tariff subsidies) are not examined. An article of this size could not do justice to such a vexed area of energy policy.

3. Network Infrastructure

It is difficult to overstate network policy failure in QLD and NSW from 2004. The capital cities of both states experienced severe security of supply events in FY04. Both State Governments reacted by tightening network planning policy and reliability standards in 2004. New five-year

⁸ A peer reviewed version of Working Paper No.31 appeared in *Australian Economic Review*. See Simshauser and Nelson (2014).

⁹ See Mountain and Littlechild (2010) for a comparison of privatised Victorian networks with government-owned NSW networks.

rate cases would commence from *ca.* 2007 in which the ‘tightened policies’ would take effect. The capital investment that followed was breathtaking, and had a predictable effect on tariffs. The progression of events in NSW is documented in Hill (2014) and so for the purposes of this article Queensland will be the focus noting that ‘*while a different fuse was lit, the same powder keg exploded*’.

3.1 **Energex: summer 2004**

A series of distribution network-related blackout events occurred in Southeast Queensland (SEQ) in January, February and March of 2004. In prior reporting periods, Energex, a Queensland government-owned electricity distribution company, was encouraged to lift profits and dividends to owners. Capital and operating expenditures were reduced including, amongst other initiatives, trimming vegetation removal expenditures and a thinning of line maintenance crews.

Weather conditions in early-2004 were severe. In late January, five storms hit Brisbane in just seven days. The extent of vegetation damage to network lines was extensive – at one point 330,000 households were without power. Cutbacks in line crews in prior periods meant restoration times were badly delayed.

Just as the system was restored in February, the hottest weather in a decade prevailed and Queensland’s first episode of ‘latent peak demand’ from residential air-conditioner installations in prior periods was revealed.¹⁰ Then in March, ‘an east coast low’ weather pattern delivered three days of near-cyclonic winds and rain, thus repeating the events of January.

Left to their own devices with instructions from policymakers to fix the problem, there is no doubt in my mind that the then Board and Executive of Energex would have, with the support of regulatory authorities, taken the appropriate actions within the bounds of good engineering and economic practice. If that was allowed to occur, this article would be 2000 words shorter. However, media coverage of blackouts was understandably extensive. In isolation, each blackout event was problematic. Taken collectively it was a “*PR disaster*” for Energex and a State Government held accountable by media and the public.¹¹ The Government reacted accordingly and “an Inquiry” was formed. However, as Helm (2014, p.4) observed in relation to a British Energy Market Inquiry being held at the time of writing:

The trouble with Inquiries is that they engender the expectation that something will be done... Inquiries beget further interventions. Further interventions beget more unintended consequences. These beget more interventions. Eventually the results are so complicated and unsatisfactory that radical options start to gain traction...

Many sensible recommendations flowed from the inquiry. The recommendation to shift away from “probabilistic risk-based” network planning to a “deterministic N-1” approach was not. It was shorthand for “eliminate outage risk” whatever the cost. This recommendation – accepted by Queensland policymakers, enforced by regulators, and delivered by Queensland networks without any real evidence that aggregate distribution system outage rates had jumped outside tolerable

¹⁰ Household air-conditioner penetration rates had been rising sharply for years but the quantity of installations was unknown. Hot weather in February 2004 provided the practical evidence of installed units. We now know that in 2001 36.3% of SEQ homes had an air-conditioner and that by 2004 this had increased to 47% (*ca.* 750,000 a/c units installed). By 2013, 74% of SEQ households had an air conditioner (*ca.* 1.85 million a/c units installed). Almost a quarter of SEQ homes have 3 or more air conditioning units. Outside the Brisbane metro area but within SEQ, 76% of Gold Coast residents, 61% of Sunshine Coast residents, and 84% of Ipswich residents have an air-conditioner. The latest household survey indicates 79% of the population will have an air-conditioner by 2018.

¹¹ Of these, hot weather blackouts were highly damaging. When poles and wires are brought down by storm conditions, residential customers are generally sympathetic. When the skies are perfectly clear on a sweltering Brisbane summer day, security of supply events are difficult for consumers to understand. To make matters worse, in many locations when transformer fuses blew, it was replaced but within hours had blown again, plunging thousands of households back into blackouts (a sign of under-investment).

limits¹² – would result in a wave of capital spending unparalleled in Queensland energy industry history. Figure 5 illustrates the sharp change in network capital expenditure from 2005 onwards.

Figure 5: Queensland Network Capital Expenditure – 1979-2013¹³

3.2 NSW & QLD Network Investments & Productivity

At roughly the same time, NSW policymakers embarked upon a similar tightening of network reliability standards following blackouts in the Sydney CBD in late-2003, which unleashed an equivalent wave of capital expenditure in that state.¹⁴ The combined spending on monopoly poles and wires in QLD and NSW from 2004/05-2012/13 is presented in Figure 6. The aggregate value of network assets (bar series, LHS Axis) is contrast with non-coincident aggregate System Peak Load (line series, RHS Axis). Total network assets more than doubled from \$27.6 billion to \$60.8 billion. Peak demand increased, and to be clear, an increase from 21,273MW to 23,699MW is significant and would require substantial capital expenditure – but *ceteris paribus*, would not require the asset stock to double.

¹² While outage duration and frequency rates were elevated, they remained inside expected tolerances.

¹³ Figure 5 notes that capital expenditure jumped from about \$500m per annum (2014 dollars) during 1979-1999 to about \$2.5bn per annum from 2007 onwards. There was no doubt a legitimate increase in capital expenditures due to population growth, increases in air-conditioner installations and rising peak loads. There was also a non-trivial element of correcting for 'underspending' in prior years. Queensland also experienced its' largest wage escalation period from 2007-09. Other factors that might otherwise explain a surge in capex over the 2005-2013 appear to be absent or benign. For example, although the price of copper doubled in 2005, it has since been consistently lower including in 2008 when it halved. The Australian dollar has increased in value from 2005 (albeit with a 6 month deviation from September 2008). A subsequent Queensland Government Inquiry was held in 2011 into rising network prices. The Network Businesses recommended to the Inquiry that security standards should be changed, and if accepted, would result in \$1.5bn in capital expenditure savings. See Electricity Network Capital Program Review 2011 (available at http://www.business.qld.gov.au/_data/assets/pdf_file/0018/9117/ENCAP_Review_Final_Report_3_new.pdf)

¹⁴ In September 2003, a fire in an underground substation led to a complete blackout of Sydney's CBD at 5.30pm, bringing Australia's largest city to a standstill. More than 50 high-rise buildings were impacted and in some cases people trapped in high-rises lifts for 4 hours or more. Power was largely restored by the following morning. This led to a similar tightening of network reliability standards in NSW.

Figure 6: Network Assets vs. Peak Demand (QLD and NSW Combined)

Given these results, a collapse in network capital productivity is predictable. In theory, absent technological innovation capital productivity should run roughly sideways. In the case of the Australian economy capital productivity dropped by -13.1 points from 2004/05-2012/13 due to the ‘mining and resources boom’ and will presumably rebound from 2015 as investment tappers and productive capacity come on-stream. In contrast, the combined capital productivity of Government-Owned Networks dropped -54.3 points (QLD by -50.5, NSW by -57.6) with little prospect of a market-driven rebound. Note the gap between the Australian economy and regulated Government-Owned monopoly networks is 41.2 percentage points. While not illustrated in Figure 7, Victorian networks have dropped by only half this amount. The bars in Figure 7 measure the GWh delivered per \$1 million invested, in nominal dollars.

Figure 7: Network Capital Productivity 2005-2013

Labour productivity statistics are little better. Australian economy labour productivity has averaged 1.0-1.5% per annum (i.e. +11% cumulative increase). Networks decreased by 19.5% following a marked improvement in QLD in 2012/13. A 30.5 percentage point gap exists between regulated network monopolies and the Australian economy.

Figure 8: Network Labour Productivity 2005-2013

The outcome of these policy settings has been network tariff increases at multiples of the general inflation rate. A potential solution is examined in Section 5.

4. Power Generation

The competitive market for power generation faces vastly different problems – generation prices have decreased in real terms as explained in Section 2. The competitive market has been distorted by the other primary variable in Figure 2 – Taxes/Levies (viz. subsidy schemes).

Electricity industry reforms were primarily initiated to resolve generation sector performance. The extent of plant under-performance and excess-capacity in the early 1990s, along with how reforms corrected this situation from 1994-2004 is documented extensively in Simshauser (2005) and so I will not reproduce detailed analysis here. To summarise, the NEM inherited an excellent albeit under-performing stock of utility-built (gold-plated) plant at market start. Gains in productivity would always be significant once competitive pressure was revealed. In the early-1990s, excess capacity was substantial with reserve plant margins of 35+% in all regions (vs. optimal of *ca.* 15%). Wholesale transfer prices were above efficient levels, and power station fleet availability was *ca.* 80-85%.¹⁵ By 2005, excess capacity had been largely cleared, wholesale prices were at efficient levels and fleet availability had risen to 90+%. In short, the NEM's wholesale market started out brilliantly. Three problems would emerge, however.

First, the NEMs wholesale market design as a mandatory 'energy-only' gross pool is a particularly tough market to operate in under ideal conditions.¹⁶ Reasons for this have been well

¹⁵ Queensland was the exception with fleet availability of 90%. Further, the three 350MW unit power stations (i.e. 1400MW Tarong, 700MW Callide and 1400MW Stanwell) quite literally set the 'world benchmark' for power plant availability at *ca.* 94-95%.

¹⁶ In energy-only markets, generators are only paid when they produce electricity – which makes investment in peaking plant particularly hazardous. Other market designs incorporate 'capacity markets' or reliability mechanisms, in which power stations are also paid for their 'available capacity'. In such markets, spot market price caps are set at much lower levels.

documented in prior editions of this Journal (see Simshauser 2006, 2008) and the power system modelling results can be condensed down to a single chart – Figure 9 – which presents the competitive average spot price and compares this with average system cost for each NEM region. The dynamic partial equilibrium model¹⁷ that produced these results assumes a perfect transmission system, an optimal plant mix, with plant operating in an intensely competitive market with perfect information.¹⁸ Note each region in Figure 9 has an average unit cost of *ca.* \$41/MWh¹⁹ vs. competitive spot prices of just \$23-28/MWh. Consequently, cost recovery ranges from 57-66%. This is a well-known phenomenon in energy economics literature referred to as ‘the missing money’ and raises questions of whether resource adequacy and a least-cost plant mix can be practically achieved in ‘energy-only’ markets.²⁰

Second, credit metrics applied by project finance banks, an historically dominant source of capital for new generating equipment, were tightened dramatically from *ca.* 2004. This was in direct response to episodes of ‘the missing money’. As Joskow (2006) noted in the US, from 1997-2005 about 230,000MW of generation capacity was added or acquired, most of which was Merchant Plant relying on project finance. By 2005, fully 123,000MW was in financial distress or bankrupt (Finon, 2008). Nelson and Simshauser (2013) noted that in Australia, 10 project financed generators were sold or restructured due to financial distress while Steed and Laybutt (2011) observed the NEM’s \$50 billion merchant generation fleet (i.e. the fleet of power stations operating in the competitive wholesale electricity market) had incurred economic losses of \$6 billion over the decade to 2010. Consequently, it is no longer possible to obtain project finance for a merchant power plant (Nelson & Simshauser, 2013).²¹

¹⁷ The NEMESYS Model is documented in Appendix I in Simshauser (2008).

¹⁸ The model also ensures an optimal number of blackouts. This assumption has the effect of inducing the maximum tolerable ‘Value of Lost Load events’ - that is, where spot prices hit the (then) regulated price cap of \$10,000/MWh - without violating the model’s reliability constraint.

¹⁹ The NEM-wide result of \$38.96 reflects the substantially lower reserve plant margin required (given the assumption of a perfect transmission system).

²⁰ See Bidwell and Henney (2004) or Finon (2008) for an excellent discussion on resource adequacy and a least-cost plant mix in energy-only markets.

²¹ Any new plant requires the involvement of an investment-grade credit-rated entity either as principal investor or as the underwriter of long-dated Power Purchase Agreements (PPAs) – an entry barrier not envisaged by policymakers during market design phase had thus been applied by risk-averse project finance banks (Simshauser, 2010). This is not unique to Australia. A study of 98 power generation projects built in 2011 by Caplan (2012, p.55) found that, ‘...the construction of new power plants necessitates stable long-

Third – and amplifying the first and second issues – overlapping and uncoordinated environmental policies such as the 20% Renewable Energy Target²² provide subsidies to qualifying plant. Under conditions of demand growth, a bifurcated market can, in theory, work. Under conditions of demand contraction and a market designed for entry and not exit, it creates certain problems.

Each environmental scheme had noble objectives but were invariably inflexible and did not form part of an integrated energy market design. On the contrary, as Nelson, Reid and O'Neill (2014) explain in detail, the schemes collide with the market design. Consequently, problems identified in Figure 9 become worse, not better. Figure 10 identifies why this is the case. In Figure 10 power system peak and off-peak demand (d_p and d_o) is illustrated along with pre-scheme aggregate supply curve (s – which is the power station supply curve) in a market where consumers face a final retail 'flat-rate' tariff (p_{ac}), which is based on average Total Electricity System (i.e. power stations, transmission, distribution, retail) costs. A low emissions plant subsidy scheme is introduced which shifts the aggregate supply curve to the right (s_1). Scheme subsidies must be recovered from consumers so final retail tariffs rise from p_{ac} to p_{ac}^* and quantities consumed reduce from q_p and q_o to q_{p^*} and q_{o^*} . In the wholesale market, it can be seen that, ceteris paribus, wholesale prices will fall²³ in line with reduced quantities (with square markers identifying changes in wholesale auction clearing prices).

Figure 10: Aggregate demand and supply with and without subsidy schemes

Given the subsidy schemes, it is worth reviewing how new plant has entered the NEM. This is illustrated in Figure 11 by allocating each new plant to one of two categories: (1) purely merchant investments or (2) policy induced (i.e. subsidised) plant. Plant developed by government-owned corporations have been added to the second category – representing investments that, based on

term financial arrangements. Long-term contracts and vertically integrated utility ownership of generation are the predominant means of supporting new capacity...

²² Queensland's 13% Gas electricity Certificate scheme had a similarly adverse effect on the electricity market. However, the QLD GEC scheme has resulted in \$65 billion of economic investments in upstream (gas exploration and production) and downstream (gas pipelines and LNG export facilities) investments.

²³ The energy economics literature contains two conflicting views on the impact on electricity prices arising from Renewable Energy Targets. One school of thought is that a so-called 'merit-order effect' exists. Taking wind farms as an example, even though the average cost of wind generation is ca.\$80/MWh, its marginal running cost is close to zero and thus enters at the bottom of the merit order (see Figure 10). The merit-order effect suggests that adding zero marginal cost plant to the aggregate supply curve will drive down wholesale spot prices and that these savings will be passed on to consumers – and – more than offset the costs of subsidising the high average cost wind generation (see for example Sensfuß et al. 2008; McConnell et al. 2013). The alternate view is that this is a static analysis and fails to take into account the reaction functions of rival generators, and that prices must ultimately rise to entry costs of thermal plant (as intermittent sources cannot deliver security of supply given the current state of battery technology). Thus even if there was a merit-order effect, it would be transient (see for example Felder, 2011; Nelson, Simshauser and Nelson, 2012; Edenhofer et al. 2013). The practical evidence from Australia supports the latter view. South Australia for example has the highest levels of wind generation, and also has the highest wholesale electricity prices because thermal generators have withdrawn.

my experience, could not have been banked by the private sector at the time.²⁴ Two timeframes have been used, pre-2004 and post-2004 to coincide with changes in the market for project finance outlined above. Note up to 2004 merchant plant investments dominate entry. From 2004 entry has been overwhelmingly subsidised.

Figure 11: Basis of entry in the NEM 1997-2013

Source: esaa, AGL Energy Ltd.

Despite policy intent, subsidy schemes had the effect of distorting an already tough wholesale market and produced a poor allocation of scarce capital. The extent is revealed in Table 1 which has been constructed using the static partial equilibrium model contained in Simshauser (2014), NEM final demand for 2013/14, and in the treatment of renewables, drawing on the methodology contained in Martin and Diesendorf (1983), and more recently Bushnell (2010) and Simshauser (2011).

Table 1: Structural supply-side imbalance in the NEM - 2013/14

NEM Plant -Incl. schemes	Optimal (MW)	Actual (MW)	Structural Imbalance (MW)		Capital Cost (\$/kW)	Total Capital (\$ Million)
Base	19,800	25,100	5,300	<i>overweight</i>	2,000	10,600
Intermediate	3,700	5,700	2,000	<i>overweight</i>	1,200	2,400
Peak	14,200	13,700	(500)	<i>underweight</i>	850	(425)
Renewable	2,800	3,000	200	<i>overweight</i>	2,500	500
Total	40,500	47,600	7,100	<i>oversupply</i>		13,075

A predictable oversupply ensued. Renewables policy had an inflexible design predicated on continuous demand growth. In Table 1, the optimal plant stock of 40,500MW includes 19,800MW of base plant and 2,800MW of renewables (given policy targets). Actual plant is higher in all categories except peaking duties with the market in aggregate oversupplied by 7100MW. Using overnight capital costs (\$/kW) outlined in Table 1, the marginal value of structural faults equates to \$13,075 million.²⁵ Figures 12-13 reveal that this policy-engineered oversupply is producing an increasingly unsustainable wholesale market, while the value of

²⁴ Callide C is the exception because the general market view is that it was both an economic, and necessary, investment.

²⁵ The value of excess capacity is based on the 'marginal value' of any imbalance using current replacement costs. The reason for using this approach becomes clear when Table 2 is introduced. For clarity, a depreciated optimised valuation reduces the \$13.075 billion result to about \$5.2 billion.

consumer-funded subsidies (i.e. wealth transfers) continues to rise. Figure 12 traces NEM power station utilisation rates. Ironically, they are now below the pre-reform levels.

Figure 12: NEM Power Station Utilisation Rate – 1955-2013

Source: Simshauser & Nelson (2013).

Figure 13 compares six-monthly NEM average spot prices to *generalised* long run marginal cost estimates. From 1999-2010, ‘the missing money’ amounts to \$6.2 billion²⁶ which is consistent with Steed and Laybutt’s (2011) estimate of \$6.0 billion. Extending the calculation to 2014, ‘the missing money’ swells to \$14.7 billion and helps to explain how AGL acquired 4640MW of privatised NSW base load thermal plant (with a replacement value of \$11.6 billion and depreciated optimised value of \$3.3 billion) for just \$1.5 billion.

Figure 13: NEM Spot Price vs. Long Run Marginal Cost

Source: aemo; Simshauser, Molyneux & Shepherd (2010); Simshauser & Aryaratnam (2014)

²⁶ The missing money = $\sum_{t=1}^n (p^t - c^t) \cdot q^t$ where p is the volume-weighted spot price in the NEM, c is the cost of entry and q is energy generated in each period, t . These calculations overlook the important role that contracts play and the risk premiums that generally exist in forward market transactions, and so ‘the missing money’ estimates are somewhat overstated.

If the market had been left to its own devices, structural imbalances would be different. In Table 2, all non-merchant plant contained in Figure 11 has been removed and the partial equilibrium model re-run – as if subsidy schemes never existed. A surprising result is revealed – the market is balanced and the over-capitalisation has been reduced from \$13,075 million to just \$3,175 million.²⁷ As an aside, the value of policy-induced investments in Figure 11 amounts to \$10,608 million.

Table 2: Structural supply-side imbalance in the NEM in 2013/14 without policy-induced plant

NEM Plant	Optimal	Actual	Structural Imbalance	Capital Cost	Total Capital
-No schemes	(MW)	(MW)	(MW)	(\$/kW)	(\$ Million)
Base	20,800	23,500	2,700 <i>overweight</i>	2,000	5,400
Intermediate	3,700	3,900	200 <i>overweight</i>	1,200	240
Peak	14,300	11,400	-2,900 <i>underweight</i>	850	-2,465
Total	38,700	38,800	100 <i>oversupply</i>		3,175

5. Policy prescriptions

The common thematic thus far is that electricity market policy interventions have frequently done more damage than good (despite their initial intentions). The issues facing generation are longer term in nature whereas elevated network tariffs require a more direct intervention. To understand what can be done with QLD and NSW Networks, the Energex business will be used by way of example noting that the principles can be generalised to other state-owned network businesses. For reasons which become apparent, privatisation of Government-Owned businesses is a crucial component of the subsequent policy prescription.

5.1 Network Infrastructure

In 2004/05, Energex had a balance sheet of \$5.6 billion. By 2012/13 it was almost \$12 billion and by 2015 it will be \$13.5 billion. This rising “Regulated Asset Base” or RAB represents the asset value approved by the regulator, and is in turn a direct (and crucial) input variable when determining the level of regulated network tariffs. As Crawford (2014) explains, about half the value of network tariffs are driven by the approved RAB.²⁸ Given sharp increases in Energex’s RAB – from \$5.6 billion to \$13.5 billion – network tariffs have also increased sharply – from 5-6 c/kWh to *ca.* 15 c/kWh.

QLD households reacted to rising electricity tariffs by reducing electricity consumption. Energex revenues are regulated, so when consumption volumes dropped, network tariffs increased the following year to offset prior period volumetric losses. The tariff increases resulted in another round of consumption volume declines, leading to yet another round of tariff increases. To aggravate matters – considerably – overlapping federal and state subsidy policies resulted in Solar PV investments well above the efficient level – 1-in-4 detached SEQ houses now have Solar PV, further compounding volumetric losses while subsidy costs compounded the next round of tariff increases. Under these conditions, it is easy to see how network tariffs have increased rapidly, and, have become unstable. An *‘energy market death spiral’* is clearly more than a theoretical possibility.

Solving these issues requires non-trivial asset impairment (i.e. given the capital productivity issues identified in Figure 7) with the structural design of tariffs modified to better reflect cost-causation (i.e. to reduce tariff instability). Given limited growth in aggregate demand, there are no other obvious solutions. However, and to be perfectly clear on this, *any asset impairment requires direct owner intervention, not regulatory intervention.* That is, since the problem of

²⁷ This analysis is of course a theoretical exercise, and in practice, even if the schemes did not exist in the first place, some of the investments would have *eventually* proceeded due to spatial constraints within the NEM.

²⁸ That is, through the return of, and return on, the Regulated Asset Base.

QLD and NSW network overcapitalisation can be clearly traced back to state government policy failures 10 years ago, it is those same owners of assets that should incur the asset impairment – and then privatise the network businesses ‘*in clean health*’.

The Australian Energy Regulator (AER) does not currently possess the power or authority to ‘strand’ approved Network RABs. Nor should they acquire such powers for policy-induced overcapitalisations driven by unwarranted changes to reliability standards. If ‘approved RAB stranding’ capability was acquired by the AER, it would create a ‘dynamic inconsistency problem’ and have unintended consequences across all network businesses in all regions.²⁹ Such a material policy change would adversely impact debt and equity capital market risk premiums – an outcome which is be entirely predictable. As Section 5.4 subsequently reveals, time inconsistency has already resulted in unnecessary capital market risk premiums creeping into the Australian power generation asset class. Consequently, to the extent that government owned network asset impairment is considered desirable, it should be initiated by Government Owners, and, immediately prior to a committed privatisation event.

The miracle of the network ‘RAB Multiple’ can facilitate such a process because when regulated network businesses are privatised, history shows that a ‘profit on sale’ is almost always achieved. Any profit on sale would reduce (or even eliminate) apparent shareholder losses arising from an asset impairment. That is, privatisation can help mute the adverse effects of impairment.

5.2 The Miracle of the Network ‘RAB Multiple’

Over the past 15 years there have been 42 energy network asset transactions (privatisations, Mergers & Acquisitions) totaling \$50.3 billion in value, and with few exceptions, a profit on sale was generated. From a capital markets perspective, an important transaction metric is the “RAB Multiple” achieved on sale date. The RAB Multiple is the asset sale price divided by the approved RAB.³⁰ In theory, RAB Multiples should be exactly 1.0x. That is, when a regulated asset is sold, if the regulatory system was working perfectly and the assets were being run efficiently, asset exchange would occur at the same value as the RAB, with no gain or loss on sale. However, as Figure 14 reveals over the past 10 years, despite tariffs being calibrated against the RAB, network assets have transacted at an average RAB Multiple of 1.33x (not 1.0x).³¹ That is, a business with a RAB of \$10 billion will, on average, exchange hands for \$13.3 billion resulting in a \$3.3 billion profit on sale. The x-axis of Figure 14 lists Australian assets transacted (date and nominal value in \$m) and the y-axis measures the relative asset transaction value for each \$100 of RAB. So for example, the first transaction is the Dampier-Bunbury Pipeline (DBP). It sold in August 2004 for \$1,680m which represented \$120 for each \$100 of RAB – giving a RAB Multiple of 1.20x.

Some of the profit on sale (or *RAB Premium*) is explained by unregulated revenues³², but most is explained by the fact that purchasers identify additional value when government-owned assets are privatized (via allowed ‘Operating Expenses’ versus what can be achieved in practice, and via the allowed ‘Cost of Capital’ versus taking greater risks than regulated benchmarks assume). This is a well-known economic phenomenon underpinned by asymmetric information.

²⁹ Crawford (2014) also notes that it would break a regulatory compact.

³⁰ For example, if a network is sold for \$13 billion and has an RAB of \$10 billion, then the RAB Multiple is $\$13b/\$10b = 1.3x$.

³¹ While there have been 42 transactions in total, RAB data is only available for the most recent 19 transactions.

³² Many network businesses have highly profitable side-businesses that are “unregulated” and therefore don’t form part of the RAB. In my discussion with Australian Utility Stock Analysts, in some cases almost half of any RAB Premium (i.e. above 1.0x) can be attributed to unregulated business revenues.

Figure 14: RAB Multiples from August 2004-August 2014

Source: JP Morgan Australia.

5.3 Overcapitalised Network Privatisation

Based on historic transaction metrics, if Energex was privatised Queensland Treasury might expect sales proceeds of 1.33x RAB (i.e. 1.33x \$13.5 billion = \$17.96 billion). A windfall profit of \$4.46 billion would be generated on sale – the “RAB premium”. Supporting this acquisition price is a network tariff of roughly 15c/kWh comprising a fixed charge of 59.4 cents per day and variable rate of 12.64 c/kWh. The fixed charge produces 20% of network revenues and the variable charge earns the remaining 80%.

The \$13.5 billion RAB comprising \$8.1 billion of debt and \$5.4 billion of equity and the apparent RAB Premium of \$4.46 billion is represented by the first bar in Figure 15 (time period t-1, LHS axis) while the tariff supporting the RAB is represented by the (straight) line series starting in period t-1 and running through to period t+5 (RHS axis).

Figure 15: Privatisation Theory for Overvalued Network Assets

There is, in my opinion, a difficulty with this RAB premium. If network assets are to be privatised, due diligence undertaken by sophisticated Institutional Investors will uncover four issues:

- Public data reveals the network is overcapitalised;
- Public data reveals energy demand has been contracting;
- Published network tariffs have more than doubled and are driving demand contraction (i.e. Demand Response through energy efficiency and subsidised solar PV); and
- Published tariffs are dominated by variable charges and have become “unstable” – each price rise further exacerbates Demand Response.

Institutional Investors invariably have Investment Committees that screen assets prior to committing funds. Among the last hurdles is not a quantitative metric, but a qualitative one based on the professional judgement of committee members – the “*is this too good to be true?*” test. There is a risk that capital markets will assess QLD and NSW network RAB’s as vulnerable to future stranding risk due to the extent of overcapitalisation. Whether this occurs through policy intervention, or by way of a death spiral, is not the point. Either way, RAB Multiples of 1.33x may not apply in their current overcapitalised form.

State Governments, as owners, have the opportunity to ‘pull two levers simultaneously’ to maximise welfare due to the fact that ratepayers are also taxpayers. Therefore, per Figure 15:

- Government owners can voluntarily impair the RAB and write-down the equity component by *ca.*30% (\$3 billion) such that the total RAB falls from \$13.5b to \$10.5 billion (see second bar in Figure 15);

- b) Government owners then reduce network tariffs to the impaired RAB, which results in a 19% tariff cut in period t (see ‘permanent tariff reduction ~ 19%’ in Figure 15). Households (i.e. taxpayer/ratepayers) face these reduced network tariffs in perpetuity;³³
- c) To help stabilise the newly reduced network prices, reorganise the pricing structure by introducing a demand charge (\$/kW) and reducing the variable charge (c/kWh). Consequently, in period t, the recalibrated network tariff would be comprised of a fixed charge (20%), variable charge (20%) and demand charge (60%) – which in theory should better reflect ‘network cost causation’; and
- d) Consistent with our ongoing advice to governments, ensure households installing Solar PV systems also install a smart meter and default to a demand tariff.³⁴

These actions would rectify an element of electricity tariffs inefficiencies and, given revenue regulation, would produce more stable network prices over time.³⁵ By implication, this would reduce revenue volatility to new asset owners.³⁶ Combined, this should optimise any RAB Multiple (\$10.5bn x 1.33 = \$13.97bn). With these metrics, sale proceeds of \$13.97bn are above the original (pre-impairment) network capital outlay of \$13.5bn in any event.

Network labour productivity is gradually being dealt with (see Figure 8). Future capital expenditure is being wound back as well. And clearly, reliability standards need to revert back to a probabilistic risk-based (i.e. outcomes-based) approach. But the primary QLD and NSW Network problem, sunk capital, needs to be dealt with and absent sharp growth in energy demand can only be remediated by asset impairment. Better this occur by State Government intervention and as part of an asset privatisation than by regulatory intervention. The latter would clearly create a time inconsistency problem and introduce debt and equity capital risk premiums previously unseen in the regulated network asset class in Australia.

To be sure, these outcomes cannot be achieved without asset privatisation. If a state government simply impairs the asset, reduces network tariffs and does not privatise the asset, lower tariffs (and higher gearing ratios) will adversely impact state government income, and audited balance sheet capacity. It is the presence of a ‘RAB premium’ (i.e. the additional value identified by private investors) upon a privatisation event that bridges this gap.

Even if my assessment of RAB premiums is understated, and buoyant capital markets deliver a 1.33x RAB Multiple on an unimpaired \$13.5bn asset – taxpayer/ratepayer welfare will be no worse off under either scenario. Whether taxpayer/ratepayers receive sale proceeds of \$17.96bn without asset impairment, or impair assets to \$10.5bn and receive a combination of sale proceeds (\$13.97bn) and a 19% discounted network tariffs, the welfare of taxpayer/ratepayers is identical. However, a 1.33x RAB Premium on overcapitalised network assets has a risk of being illusory, and, households prefer network tariff discounts (i.e. money in their own pocket). At worst, asset impairment remedies grave policy errors in QLD and NSW – errors that consumers have been paying for ever since. And ironically, unwinding that error through discounted network tariffs will produce a broadly progressive distribution of benefits.³⁷

³³ This reduction would equate to approximately 10% at the retail level since generation and retail charges comprise *ca.* 50% of a household bill.

³⁴ This was a key outcome arising from the ‘Smart Grid Smart City’ project funded by the Federal Government.

³⁵ It would also ensure that households dominated by peak loads (i.e. households with air-conditioners and/or solar PV units) face tariffs that better match network costs to network benefits (cost-causation).

³⁶ The above actions would establish a level of investor confidence that I believe will otherwise be lacking in any network sale process. It would have the effect of reducing network assets’ susceptibility to the “*is this too good to be true*” test (from an ‘investment committee’ perspective). I also believe this would maximise the RAB multiple.

³⁷ As Nelson et al. (2012) explain, income and consumption are positive correlated but are far from perfectly correlated, and when electricity volumes are used to collect quasi taxes, the result is a regressive outcome. Consequently and by deduction, any reduction in network tariffs will produce a broadly progressive outcome and enhance welfare.

5.4 Generation

Structural issues facing the wholesale market are: (1) extensive oversupply, (2) *barriers to exit*³⁸, (3) low wholesale spot prices and (4) inflexible policies subsidising plant entry. Does it actually matter that policy-induced plant entry is engineering an acute oversupply and delivering low wholesale prices³⁹ and a rising ‘scheme subsidy’ pool? After all, at face value this is just a series of wealth transfers from incumbent thermal plant to consumers (via lower wholesale prices) and from consumers to low-emission plant (via subsidies identified in Figure 10) while progressing towards a lower emissions plant fleet.

It matters for three reasons.

1. How do principal investors or underwriters of new renewable plant get comfortable making long-dated irreversible commitments when industry fundamentals have deteriorated? The market is already oversupplied with falling ‘real’ electricity prices. Marginal debt and equity capital commitments (in the world’s most capital-intensive industry) will thus become ever-more reliant on green subsidies that, as Nelson et al. (2014) explain, have been reviewed six times and undergone material policy change on three occasions in 10 years!⁴⁰ At the very least, the cost of capital will increase as Nelson et al. (2013) demonstrate.
2. The NEM’s 28,800MW thermal fleet provides 82% of underlying energy⁴¹ and more importantly, the rapid response to intermittent generation (ensuring real-time security of supply). Yet as Figure 16 reveals 26.4% of that fleet is within its ‘design life’. Put another way, 73.6% of the thermal fleet is operating beyond its intended design life.
3. While Table 1 noted the NEM is 7,100MW oversupplied, *ca.*3000MW of gas plant is likely to shift from active operating duties to virtual ‘*power station museums*’ over the next few years as new LNG terminals raise the price of domestic gas to very high levels. This will render many gas-fired generators largely uneconomic outside of critical event days.

³⁸ Nelson, O’Neill and Reid (2014) discuss four barriers to generation plant exit in some detail. While they attribute policy uncertainty as the more problematic, I consider their second barrier – the cost of site remediation – as the more critical. The issue here is that it costs ca.\$100-300 million to remediate a site, and a small fraction of this to mothball a plant. The option value of plant recall makes this a reasonably rational choice for owners. But the ability to recall the plant with notice (say 2-3 months) casts a downward financial shadow on forward market prices and in part makes new renewable plant investment intractable.

³⁹ Before analysing the wholesale market, one must always unpack transient issues from structural or more enduring issues. Figure 13 clearly demonstrated that spot prices in FY14 were under pressure. While falling demand played a part, ironically, the withdrawal of policy has created a distortion. The change in Federal Government in September 2013 was expected to result in the carbon pricing framework being repealed from FY15. Since hydroelectric plants benefit from carbon-inclusive wholesale prices they ‘over-produced’ during FY14 (i.e. maximised production in spite of rather obvious hydrological limitations) in order to maximise profit. Then, just as hydro capacity readjusted output levels in FY15, delays to Liquefied Natural Gas (LNG) export projects in QLD produced a very large surplus of natural gas forcing fuel prices down in gas spot markets. At the time of writing, gas-fired generators were maximising production. Of course, as LNG plants reach capacity, gas-fired generators will virtually retreat from the market altogether.

⁴⁰ This of course raises the rather obvious corollary, dynamic inconsistency. When perceptions of ‘policy uncertainty’ become enshrined due to erratic, opportunistic or unpredictable changes by regulators or policymakers, firms will act rationally in response (see for example Kydland and Prescott, 1977; Taylor, 1985. As Simshauser (2014) noted in relation to the RET, firms expect the 20% renewable target in 2020 to be modified, and so they have slowed their renewable plant investment commitments. Now so little time is left to meet the fixed volumetric target that policymakers will almost certainly be forced to adjust the policy downwards.

⁴¹ Thermal plant in QLD, NSW, VIC and SA produced 166 TWh out of total generation of 185 TWh. See esaa (2014).

Figure 16: Cumulative Age of the NEM's Thermal Plant Stock

Source: Schumacher (2014), esaa, AGL Energy Ltd.

How these factors interact is difficult to predict. At one level, the rapidly advancing portfolio age of thermal plant should help alleviate structural oversupply through retirements – after all, more than 5000MW of plant in Figure 16 is now more than 40 years old. And when combined with the uneconomic gas-fired plant capacity, the current oversupply could eventually unwind quite quickly. But the transitional period is likely to be protracted, and it is difficult to reconcile how the more intensive maintenance associated with aged plant will be delivered in an environment more likely to be characterised by maintenance cut-backs (i.e. due to low spot prices).

In the meantime, forcing additional capital-intensive, subsidised and intermittent renewable plant into an already overcapitalised power system with declining demand makes little economic sense. When coincident barriers to exit are added, it casts doubt over the durability of the NEM design and Australian energy policy. The theory of energy-only markets (i.e. spot electricity markets in which generators are only paid when they produce, with no payments made for plant availability) involve a particularly long list of explicit and implicit assumptions. But the practical evidence is that the design cannot withstand extensive policy collision – energy-only markets appear to be failing in various jurisdictions where complementary schemes have been legislated (e.g. UK, France, Germany, Spain, Texas). Indeed, the weight of academic literature points to a market design ‘*on death row*’ – at least in its pure form.⁴²

That said, and to be clear, in the short to medium term there is no threat to the security of supply. But in the long run, if conditions are not corrected the problem will move beyond the immediately affected equity investors and enter a new phase encompassing project banks – which raises an entirely new dimension to the problem. Bank finance is responding pre-emptively. Prior to 2006, credit spreads on Australian power plants debt were 20 basis points (bps) *below* global average (i.e. 113bps vs. 133bps). By 2013 Australian power project finance spreads were 25 basis points *above* global average (i.e. 287bps vs. 262bps) with demonstrably shorter tenors (masking the extent of the differential).⁴³ This impacts the economics of replacement plant investment and incumbent plant cash flows as they refinance.

⁴² Simshauser & Ariyaratnam (2014) survey some of the relevant academic literature at p.153.

⁴³ For details of credit spreads, see Simshauser (2014) and especially Table 3.

Investment in renewables to meet policy targets has become intractable (Nelson et al, 2014). Policy-induced over-investment in the NEM can only be curtailed by realigning subsidy schemes with a more efficient allocation of resources and a sustainable endpoint. While this is a long run problem, the NEM's energy-only market design is an increasing part of the overall problem and changing institutional design will take no less than five years – probably longer to cleanse a majority of forward market contracts. Recent changes to Britain's energy-only market demonstrated 'an investment blackout' ensues until new institutions are understood and implemented. Policy reviews therefore should not be unnecessarily delayed. To be clear, the 'mandatory gross pool' component of the NEM is important, well-functioning, and should be retained. Forcing all generators to compete for real-time output through a centralised exchange maximises transparency and static productive efficiency. But subsidy schemes need to be reassessed, the NEM design and options for capacity/reliability mechanisms reviewed – all with the intent of ensuring the generation market is durable under a range of conditions.

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Appendix I: Industry Structure

Figure A1: Vertical Separation

Prior to vertical structural separation, the State-Owned Electricity Commissions were integrated businesses comprising Generation, Transmission, System Operations, Distribution and Retailing functions. Electrons (denoted $-e$ in Figure A1) are manufactured by Generation with System Operations sending dispatch instructions to power stations to meet instantaneous demand. The electricity is transported in bulk and at high voltage through the Transmission System to various bulk supply points or demand nodes around the State. The electricity is then reduced in voltage and distributed to consumers through the Distribution Network. The Retailing function issues bills and collects cash (\$) on behalf of the industry segments. Figure A1 shows how State Electricity Commissions were vertically restructured into Generation, Transmission and System Operations, and finally, Distribution Networks and Retail.

Figure A2: Horizontal Separation

In Figure A2, notice that the former monopoly generator has in this instance been horizontally separated into five rival generators. Similarly, Retail has been horizontally restructured into three rival retailers (stapled to a Distribution Network, thus creating a retail franchise with each customer segment eventually made contestable according to a set timetable).

Figure A3: NEM Institutional Design

Figure A3 sets out the institutional market design. The delivery of electricity to customers, that is, from the point at which the energy (kWh) departs the generator terminals and is delivered via the transmission and distribution network, remains a regulated monopoly. The wholesale market, where generators and retailers interact, is coordinated by the Australian Energy Market Operator (AEMO). Hedge activity is not coordinated by AEMO – it occurs in the over-the-counter derivatives market and through the Sydney Futures Exchange. In Figure A3, the blue arrows represent regulated money flows, while the grey arrows represent competitive money flows.