Climate and electricity policy integration – Is the South Australian electricity market the canary in the coalmine?

The South Australian region of the Australian east-coast National Electricity Market (NEM) has undergone profound change over the past fifteen years. The Renewable Energy Target (RET) and premium solar feed-in tariffs (PFiT) have resulted in substantial additions to the electricity generation stock. From a standing start, around 1.5 GW and 0.5 GW of wind and solar capacity has been added to the system respectively. Historical peak regional demand is only 3.5 GW. Generators that provide firm capacity are being retired or mothballed due to the merit-order effect, higher gas prices and recently declining demand. Historical average annual spot prices provide little incentive for the replacement of the capital stock. Forward contract prices are rising, placing financial pressure on industrial users of energy. It is clear that little consideration has been paid to the interaction between an energy-only market design and the overlay of climate change policies such as the RET. To avoid extreme pricing volatility and possible security of supply issues, it is vital that Australia urgently review its energy market frameworks to ensure they are better integrated with climate change policies.

Keywords: climate change; renewables; energy-only markets; market design
JEL Codes: D04, D47, Q40, Q41, Q48

1. Introduction

South Australia is a region of the east-coast Australian National Electricity Market (NEM). The NEM is an energy-only gross pool electricity market in which prices are formed under a uniform first-price auction clearing mechanism – put simply, prices during ‘off-peak’ periods tend to reflect short-run marginal costs of power generation, while prices at ‘peak’ periods can increase by around 25,000% to over \$13,000 per megawatt-hour (MWh). In theory, this allows heavy capital costs to be recovered over the business cycle. Participants manage this market volatility by entering into financial market contracts.

The state of South Australia is at the frontline of how to incorporate large volumes of renewable energy, while maintaining reliability and system security, given issues related to renewable intermittency in an energy-only market. Wind generation comprises around one-third of total electricity load and approximately one-quarter of all residential properties has installed embedded solar PV generation. In a market with a peak load of approximately 3 to 3.5 GW, renewable generation capacity is around 2 GW, but at times of peak demand the system is reliant upon an ageing fleet of gas-fired generators and a relatively small interconnector to the neighbouring Victorian region. Synchronous generation capacity is relied upon for reliability purposes but the value of ‘energy’ (fuel) in non-peak times is effectively zero as wind and distributed solar have been substituted for gas and coal.

The policy objective underpinning the creation of the NEM in the 1990s related to improvements in capital allocation and pricing efficiency (see Hilmer, 1993 for the original ‘blueprint’ for energy-market reform). From the early 2000s, it became clear that the NEM reform process had not adequately considered community expectations around anthropogenic greenhouse gas emission reductions and the development of new generation technologies. A 20% Renewable Energy Target and Premium Feed-in Tariffs (PFiT) were established that created non-electricity market incentives for adding substantially to the stock of generation capacity. Pollitt and Haney (2013, p. 9) make the salient observation that when markets such as the NEM were liberalised, ‘competitiveness was the overriding priority. Today, competitiveness, energy security and decarbonisation are the three main energy policy priorities’.

This article explores the dynamics in the South Australian market and finds that decarbonisation-related policy objectives for the South Australian electricity system are unachievable with continued reliance upon an energy-only market. This is due to pricing outcomes being inconsistent with real-world constraints including: financing new generation infrastructure; customer preferences in relation to stable pricing; and the inability of intermittent renewable generation to provide ‘firm’ contract pricing. In the long-run it is obvious that an ‘energy-only’ market makes little sense in a system with very high penetration of renewables given that the energy (sun, wind etc) is free. It is recommended that policy makers urgently review the NEM and its governance and institutional frameworks to ensure consistency with climate-change objectives. The article is structured as follows: Section 2 outlines how the South Australian market has evolved and discusses emerging issues related to reliability concerns; Section 3 explores why optimal investment decisions are not forthcoming even with impending potential shortages; while policy recommendations and concluding remarks are provided in Section 4.

2. The evolution of the South Australian electricity market

At the time of market start in the late 1990s, South Australia had approximately 740 MW of coal and 1680 MW of oil/gas/diesel generation capacity. Peak load was around 2,200 MW. Investment decisions in new generation capacity were driven by increasing peak load and market fundamentals for the first few years of the market’s operation. There was almost no large-scale renewable generation and very few distributed generation facilities.

In 2001, the Commonwealth Government introduced a Mandatory Renewable Energy Target (MRET). This policy was expanded in 2009 to a 20% Renewable Energy Target (RET) and subsequently split into a Large Scale Renewable Energy Target (LRET) and Small-Scale Renewable Energy Target (SRES) in 2010. In the late 2000s, various state governments also introduced PFiT policies for installers of distributed solar PV generation. The end result of these policy decisions was the provision of material subsidy support for investment in both large-scale and distributed renewable energy generation. Almost no attention was paid to the interaction of these policy decisions with the ‘energy-only’ electricity market design. Policy makers were largely confident that demand would continue to increase which would offset any adverse impacts of the increase in renewable energy generation capacity.

South Australia experienced relatively rapid investment in large-scale renewable generation. While the 20% RET was a national policy, South Australia’s wind resource was superior to neighbouring states and project planning policies were more supportive. At the time of writing, total installed capacity of large-scale wind is approximately 1,400 MW and a further 110 MW is under construction. There has also been rapid growth in small-scale embedded generation. Around one in four households in South Australia have installed premise-based solar PV. Total solar PV distributed generation capacity is around 600 MW. Figures 1 and 2 shows the additional large-scale and small-scale generation capacity added to the system since the late 1990s respectively.

Figure 1: Large-scale generation capacity added to the South Australian market since late 1990s

Source: ESAA (annual reports)

Figure 2: Distributed generation capacity added to the South Australian electricity system

Source: Clean Energy Council (2015)

Figure 1 shows that around 1.2 GW of new thermal capacity and 1.5 GW of wind capacity has been added to the system since the late 1990s. When combined with the *c.a.* 600 MW of embedded generation shown in Figure 2, around two-thirds of the new capacity in the South Australian system is some form of intermittent renewable energy. Figures 1 and 2 are instructive because they collectively demonstrate that around 2 GW of the 3.2 GW of capacity additions have been driven by renewable policy interventions implemented *externally* to electricity policy.

The other dynamic at play within the South Australian market is declining grid-based electricity demand. The maximum demand registered within the SA region was recorded in FY11 and since then peak demand has fallen by 17.4% (AER, 2015, p. 27). Energy-demand has also fallen across Australia due to the closure of some industrial manufacturing, improved energy efficiency, price elasticity responses to higher grid-based tariffs and a relatively high currency. Australian electricity demand and the ‘grinding down’ of official forecasts is shown in Figure 3.

Figure 3: Electricity demand – actual and forecasts (by year of forecast)

Source: AEMO (2015) and Nelson and Orton (2016)

So where do these historical trends leave South Australia today? The system’s peak demand is likely to be in the order of 3,000 MW to 3,300 MW (depending upon summer weather) with average load in the order of 1,500 MW and a ratio of peak to underlying of up to 2.4 (esaa, 2015). In FY15, wind generation in South Australia represented 29% of total registered capacity and supplied 37% of total electricity consumption. At times during FY15, wind generation alone was up to 109% of underlying South Australian electricity demand. In fact for 30 of the 8760 hours of FY15, wind was producing more than South Australia’s energy requirements, necessitating the export of surplus energy to Victoria (the neighbouring region). In FY15, around 7% of South Australia’s total energy consumption was sourced from distributed solar PV. At lunchtime on Boxing Day 2014, embedded solar PV generation produced 36% of the total state load (AER, 2015).

At times of peak demand, renewable generation was sometimes very low, necessitating the use of ageing thermal power stations within South Australia and the Heywood interconnector to Victoria. The Australian Energy Market Operator (AEMO) estimates that only 10% of wind capacity and 31% of solar capacity in South Australia can be relied upon at times of peak summer demand as there is a degree of non-coincidence between embedded solar PV output (middle of the day) and system peak demand (late afternoon and early evening) (AER, 2015, p. 30-31).

The characteristics of the power stations, and the change in the generation mix within South Australia have placed extreme pressure on the operation of the ‘energy-only’ market. Thermal generators have historically been relied upon for their capacity at times of peak demand and for their contribution to the management of system frequency but their output has declined. Across the country, capacity factors have plunged. Overarching NEM capacity utilisation fell from 54% in 2009 to 47% in 2014. Generators are expected to be available for dispatch to ensure reliability but they are remunerated on the basis of the energy they produce. And it is the value of this energy which is gradually being eroded by the substitution of coal and gas for wind and solar with their inherent ‘free energy’ characteristics, and declining grid-based energy demand.

The impact of this gradual energy substitution effect has been significant retirement and mothballing announcements from the owners of the incumbent ageing and inflexible thermal fleet: Alinta has announced the retirement of the 540 MW Northern and 200 MW Playford coal-fired power stations effective in 2016; Unit 2 of the Pelican Point CCGT facility has been mothballed with 249 MW available on a 48 hour recall; and the 480 MW Torrens Island A station is due to be mothballed from 2017. Interestingly, at the same time that such plant is being mothballed and retired, a new wind farm is under construction with the Hornsdale project scheduled for commissioning in 2016. The only additional firm capacity being added to the system is the upgrade of the Heywood interconnector with Victoria, from 460 MW to 650 MW. The end result of these announcements on supply availability for 2017 is shown in Figure 4.

Figure 4: Peak SA system demand and supply by generation type

Source: Compiled with data from ESAA annual reports and AER (2015). Distributed solar generation is accounted for ‘behind the meter’ reducing net demand from the grid

Figure 4 shows that the 2017 supply mix for South Australia is substantially different from that of 1998. The left and middle bars show the contrast between the *c.a.* 2.5 GW peak load system in 1998 reliant upon coal and gas/oil/diesel and the 2017 *c.a.* 3 GW peak load that is to be serviced without coal but instead by wind, expanded interconnection services and gas/oil/diesel generation. Assuming all wind is considered ‘firm’ and available at times of peak demand, there is plenty of system reserve and reliability should not be compromised. However as noted earlier, the system operator, AEMO, allows for only around 10% of registered wind capacity to be considered ‘firm’. The right bar of Figure 4 shows that with such a constraint imposed, peak demand is likely to exceed combined generation and interconnection capacity. In other words, without further investment in generation or transmission interconnection, system security is likely to be compromised (particularly during interconnector outages)¹.

3. Intractable investment - due to a lack of energy and climate policy integration?

The impending system security crisis in South Australia has created pricing conditions that appear, at first glance, to create incentives for new investment in firm and flexible gas-fired generation capacity. The physical characteristics of systems with high penetrations of large-scale intermittent renewables are complementary to investment in flexible gas-fired generation. However, it is the design of electricity markets, not physical parameters, which create investment incentives. Figure 5 shows historical average annual spot prices in the South Australian region and flat contract prices for 2016-2018 (as at January/February 2016).

Figure 5: Average annual spot pricing and futures pricing in South Australia

Source: AER (2015), esaa, EPRI, AGL data. Future operating costs for CCGT are estimated from electricity forecasting data and ACIL Allen technology and fuel cost estimates published by AEMO.

¹ Outages due to interconnector issues have occurred in the recent past. See <http://www.abc.net.au/news/2015-11-02/electricity-interconnector-fails-power-blackouts-south-australia/6904062> as an example. Accessed on 24 March 2016.

Figure 5 contrasts historical and futures pricing for the South Australia market with the Long-Run Marginal Cost (LRMC) of a new combined cycle gas turbine, historically discounted by inflation from current levels. While investment decisions are based upon complicated load-weighted pricing outcomes which reflect the unique nature of the generation technology, it is worth noting that average revenue in the South Australian market has been economically insufficient to justify the construction and operation of a CCGT². Only six of the sixteen years since 1998 have produced average pricing outcomes consistent with investment in a new flexible CCGT plant³. As Nelson et al (2010) noted, the baseload and intermediate plant investment since the NEM's start has only been economic due to its incorporation in large integrated retail facing businesses.

While it is true that futures pricing is effectively valuing the scarcity articulated in Figure 4, three years of 'above average' contract revenue is hardly sufficient to justify investment in new generation infrastructure with long lived asset lives⁴. Even before considering the lack of climate and electricity policy integration, the existing literature highlights the dilemma associated with new investment based upon pricing outcomes such as those shown in Figure 5 – a phenomenon known as the 'missing money' problem (see Simshauser, 2008; Simshauser, 2010; Nelson and Simshauser, 2013; Simshauser, 2014). The demand for grid electricity throughout the design life of a new thermal power station is also somewhat uncertain, and will be influenced by economic conditions for energy-intensive manufacturing as well as demand-side product developments including distributed generation and energy storage technologies.

In theory, where aggregated discrete units of capacity (e.g. a 200 MW open-cycle gas turbine unit) exceed demand, prices are generally reflective of the short-run marginal cost (SRMC) of the marginal unit required to meet demand. However, where demand is met with the highest-cost final marginal unit, prices exceed SRMC outcomes, thereby allowing generators to recover their heavy fixed costs. This also facilitates new investment by providing pricing signals for additional capacity requirements. Where overinvestment occurs, prices do not allow for the recovery of fixed costs preventing further overinvestment occurring. Over the course of a business cycle it was expected that demand growth would absorb such overinvestment⁵.

In other words, volatility is effectively the economic means by which 'energy-only' markets provide revenue adequacy for an 'optimal' generation mix. But with the introduction of very low SRMC renewable generation via climate-related public policies such as the RET, volatility must become extreme to ensure capital costs of firm complementary thermal generation or battery storage technologies can be recovered. Edenhofer et al (2013, p. 519) summarise this point well: *'lower average prices caused by higher renewable energy penetration lead to a reduction of overall capacity, which in turn increases the frequency of scarcity events and respective scarcity prices. According to theory this will bring the market back to the long-term equilibrium in which long-run average costs and average revenues are balanced for all capacities and where, as a direct result, the capacity level is efficient.'*

² Based upon current capital costs and \$6.00 per GJ gas pricing (see EPRI, 2015 for more information).

³ Open-cycle gas turbines and lithium-ion battery storage options could also be considered but at current technology prices would be more costly than CCGT. As the analysis is utilising flat underlying contract data, CCGT costing is more suitable given its higher utilisation rates, relative to an OCGT.

⁴ The emergence of an LNG-export industry in Gladstone has increased demand for east-coast gas supplies threefold within three years (see Simshauser and Nelson, 2015). This has increased the pricing required in wholesale electricity markets to make gas generation economic. It has also increased the running cost of incumbent steam gas boiler plant to be available at times of low wind and solar generation.

⁵ In reality, demand grows steadily but supply comes on in lumps.

And this brings us to a critical point: extreme volatility, which is required for an energy-only market with high penetration of renewables, is inconsistent with real-world constraints and community expectations. Riesz et al (2016) find that the NEM would require a market price cap of between \$60,000 to \$80,000 per MWh for revenue adequacy if the system was supplied by 100% renewable energy. This is between four and six times greater than the current market price cap. It is hard to gauge why extreme volatility would be desirable given the high and known fixed-cost nature of renewable energy. In simple terms, it is difficult to justify continued reliance upon an energy-only market in an environment where the cost of energy is zero (i.e. sun, wind) but the cost of developing capacity to produce the energy is high and fixed.⁶ Under these conditions it is uncertain how new renewable capacity could be successfully financed because intermittent generators are generally unable to sell forward contracts (which provide some revenue certainty) and high market pricing events may coincide with low rather than high output from intermittent renewables.

Continued use of an ‘energy-only’ market while pursuing high proportions of renewable energy for climate change-related public policy purposes is likely to be unacceptable to generation financiers and retailers; customers; and governments. Simshauser and Nelson (2013) demonstrate that the ‘merchant’ model is dead in relation to power generation investment. As an alternative to merchant transactions, investors require project proponents to enter into Power Purchase Agreements (PPAs) with credit-rated counterparties (retailers) to facilitate the provision of project debt. In systems with high renewable penetrations, retailers would be required to manage extreme short-term price volatility risk while entering into long-term PPA contracts with generation counterparties. It is almost inconceivable that banks would provide finance to new projects via either the merchant or PPA model if costs are largely fixed but revenues can fluctuate 80,000% in half an hour. In other words, real-world financing constraints would prevent investment in new capacity in an energy-only market with very high proportions of renewable energy.

Extreme volatility is also likely to be unacceptable to customers and governments. Customers will increasingly be exposed to some of the same dynamics playing out in South Australia and noted in Figure 5. Pricing outcomes in South Australia have created significant concerns for individual businesses and peak business bodies (see Potter, 2015). Governments will also be concerned about the impacts of volatility on both business customers and households, given the nature of electricity as an essential service (see Simshauser and Nelson, 2014). Indeed the perceived risk of policy intervention to ease cost pressures for energy users when energy-only markets exhibit such volatility presents a further barrier to investment. In a market with very high proportions of large-scale renewable energy, extreme price volatility and the exit of firm generation capacity (that can provide hedging cover) may become a challenge for financing the deployment of new and innovative retail products and services, unless alternative tools for managing wholesale market exposure risks are developed.

⁶ ‘Energy’ pricing effectively prices the marginal unit of energy to reflect the cost of providing the last unit of capacity, which has a low utilisation rate.

4. Public policy recommendations and concluding remarks

So where does all this leave South Australia and the broader NEM? It is imperative that Australian policy makers integrate climate change and electricity policy. In 2015, Australia committed to reducing greenhouse gas emissions by 26-28% relative to 2005 levels by 2030. More importantly, Australia, like other nations, committed to reducing emissions in a manner consistent with limiting global warming to 2 degrees Celsius above pre-industrial temperatures, requiring substantial decarbonisation of the electricity system. Such a commitment implies a ‘carbon budget’ of around 10 gigatonnes (Gt) of emissions between now and 2050 and a 45% reduction in emissions by 2030 (see Climate Institute, 2015 for calculating the budget; and Adams et al, 2015 for an economic analysis of such a target). To meet these commitments, it will be necessary for significant further investment in zero-emissions power generation. At present, the most foreseeable policy commitment is a significant expansion of investment in renewable energy.

Real-world integration of climate change and electricity policy will be required for policy to succeed against objectives of: reliability; affordability; and reduced greenhouse gas emissions (see Simshauser, 2014 for a good description of this policy *trilemma*). In our view, it is time for Australian policy makers to revisit the Hilmer reforms of the 1990s and reconsider the design and governance institutions of the NEM to incorporate legitimate government public policy goals related to reducing emissions and increasing the proportion of renewable energy within the east-coast electricity system⁷. Revisiting the Hilmer reforms is not as simple as abandoning the ‘energy-only’ market design in favour of a ‘capacity’ market (see McDonald-Smith, 2015 and MrArdle, 2015 as examples of discussion of ‘energy-only’ and ‘capacity’ markets in the Australian context). Rather, a root-and-branch review of energy market design and governance is required – to consider how best to decarbonise Australia’s electricity supply across the generation, transmission, distribution and retail components of the supply chain while maintaining supply security, efficient pricing and appropriate risk allocation. It is essential that the governance arrangements for energy markets are well equipped to respond to evolving customer preferences, community standards and technology development⁸. The technology-led transformations of other sectors, such as telecommunications, may prove instructive to develop an appropriate governance and regulatory structure for energy supply.

Importantly, the review must include a transition to a new wholesale pricing model that reflects the very high-fixed cost nature of technologies required for the electricity system to decarbonise. Abandoning the current ‘energy-only’ market for immediate adoption of an alternative (such as a capacity market) would ignore the nature of *transition* from high-emitting sources of electricity, such as coal, to renewables, battery storage and other low-emission technologies. Longer-term, the profile of a system powered by 100% renewable energy is likely to require some form of market that values capacity, as it is the generation capacity that allows ‘free’ renewable energy to be harvested and subsequently transmitted to homes and businesses as grid-connected electricity⁹.

The current trajectory of climate and electricity policy puts Australia on a long-term collision course with real world financing constraints and customer expectations in relation to stable pricing outcomes being unmet. If Australia persists with an energy-only market, it is likely that

⁷ Australian policy makers recently undertook a review of governance arrangements for Australian energy markets (Vertigan et al, 2015). The words ‘climate change’ and ‘renewable’ occur twice in the 113 page report. The reviewers were not tasked with assessing climate change and renewable policy integration in their consideration of governance arrangements.

⁸ Some stakeholders argue that even relatively simple energy market rule changes often take several years to implement, with reform outpaced by technology and customer changes.

⁹ It may well be that in the long-term, end-use customers will pay for capacity and not energy. Distributors are already shifting their tariffs towards capacity based payments. Within a decarbonised system with high penetration of renewables, customers will seek to purchase capacity that allows for ‘free’ renewable energy to be produced and consumed via and within networks.

aspects of the South Australian experience may be replicated in other regions with the market price cap in the NEM needing to lift to between \$60,000 and \$80,000 per MWh. In a practical sense, this means that new electricity generators will receive little revenue for most of the year with their high fixed costs recovered through a handful of extreme pricing periods¹⁰. Investors would undoubtedly balk at investments with such extreme pricing risk causing new investment to become intractable. This would result in public policy goals in relation to affordability, reliability and improved environmental outcomes being compromised. Accordingly, it is inevitable that further reform of the NEM must occur.

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¹⁰ In other regions in the NEM, barriers to exit will require thought by policy makers to facilitate conditions conducive to further renewable energy investment. However, even with such barriers overcome by complementary policy (see Jotzo and Mazouz, 2015 as an example), investors will increasingly question the suitability of 'energy-only' markets to deliver adequate revenue to justify commitment to new generation capacity.

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