# Electricity Market Design in a Decarbonised Energy System

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See footnotes at end of text.

## INTRODUCTION

It is arguable that Australia's 'energy-only' National Electricity Market (NEM) is at the vanguard of considering how best to design energy markets to achieve multiple policy objectives. Australia has some of the highest rates of embedded solar PV installations in the world. Furthermore, the South Australian region of the NEM has some of the highest penetrations of non-hydro renewables of any electricity market. The region has a peak demand of around 3,500 MW and installed wind capacity is approximately 1,500 MW. South Australia is connected to other regions of the NEM through the Heywood transmission interconnector that is rated to around 500 MW. 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 electricity demand. Therefore, there is a need for other 'firm' capacity to be available to meet demand when wind and solar PV are unavailable. This capacity is only remunerated when it is needed via the energy it produces. A confluence of factors in South Australia has led to the Australian Government initiating an inquiry into energy policy, led by Australia's Chief Scientist (the 'Finkel' review). South Australia has stagnant underlying electricity demand, high rates of renewables penetration, an ageing thermal generation fleet and reliability issues.[1]

The purpose of this article is to assess whether an 'energy-only' wholesale electricity market design can coexist with a largely decarbonised/renewable energy system, with a particular focus on Australia's NEM. The article is structured as follows: Section 2 outlines a theoretical investigation of how 'energy-only' markets respond when other policy instruments are used to drive investment in new generation capacity; empirical observations of Australia's electricity system are presented in Section 3; with policy recommendations and concluding remarks provided in Section 4.

## A THEORETICAL INVESTIGATION OF 'ENERGY-ONLY' MARKETS

### *Inter-period pricing*

Figure 1 shows a stylised longer-term shift in pricing trends associated with the introduction of renewables and other policies that drive investment in new generation capacity, irrespective of whether demand requires it. The chart on the left shows an 'energy-only' market without the overlay of other policy interventions. Prices rise and fall based upon tightening reserve margins due to increasing demand driving up prices or excess capacity driving up reserve margins respectively. The chart on the right shows how price trends shift in an 'energy-only' market with subsidised renewables. Prices fall to very low levels due to oversupply and low-SRMC renewable generation. Firm thermal generators cannot recover FOM and eventually are removed in a 'disorderly' way, potentially resulting in sustained periods of above LRMC pricing.

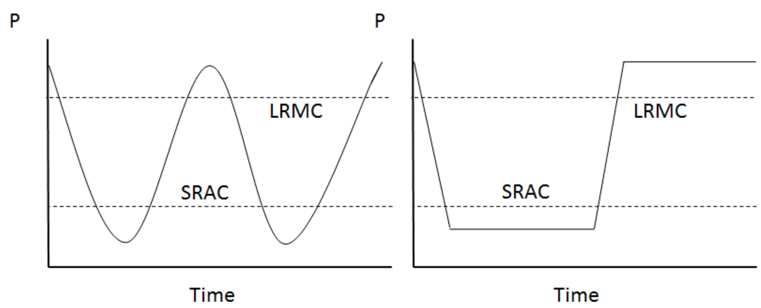

*Figure 1: Change in nature of inter-period pricing events*

### *Intra-period pricing*

Figure 2 shows the stylised impacts of increased renewable penetration on intra-period pricing.[2] As renewables enter the market, they occupy the bottom of the merit-order bid stack and are able to 'bid' into the market at their short-run marginal cost (i.e., effectively zero). For other generators to recover their heavy fixed costs over the business

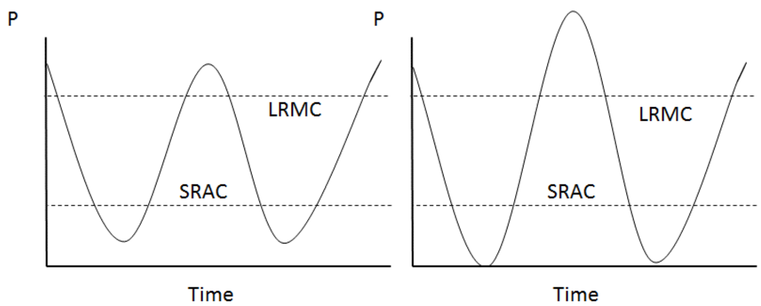

*Figure 2: Change in nature of intra-period pricing events*

cycle, prices at other times must increase significantly. Capital and other fixed costs are recovered over reduced periods of time/demand. Within Australia, estimates have been made in relation to how high the market price cap would need to be for generators to recover their long-run costs in a high-penetration renewable scenario. Riesz et al (2016) concluded an increase from $13,100 per MWh to between $60,000 and $80,000 per MWh would be necessary. In itself, this is not necessarily an issue but it is important to think through how a restructured retail market would function in this environment given the reduced availability of traditional financial derivative products.

## EMPIRICAL OBSERVATIONS OF THE AUSTRALIAN NEM

Australia is arguably one of the best markets to assess the impact of renewables and climate change policy on energy-market design. As noted earlier in this article, South Australia has one of the highest penetrations of renewable energy of any region in the world. Furthermore, Australia is currently unable to secure abatement opportunities from the substitution of coal with gas-fired power generation due to chronic domestic gas supply unavailability.[3] Unsurprisingly, government policy is skewed towards supporting renewable investment as a method of reducing emissions. The Victorian and Queensland governments have established policies to achieve 40% and 50% renewable energy penetration by 2025 and 2030 respectively. These targets are likely to drive abatement towards partially achieving Australia's COP21 commitment to reduce emissions by 26-28% on 2005 levels by 2030.

Figure 3 shows historical pricing within the NEM since its creation in the late 1990s. It is clear that the NEM has produced wholesale pricing that is reflective of relatively efficient dispatch. In most years since its creation, the market has produced pricing outcomes well below that of a new entrant coal or gas-fired plant. It is arguable that this is a reflection of oversupply created by unanticipated declining energy demand, the 'sweating' of existing aged assets and the adding of supply through adjacent climate change policies.

The NEM has not produced pricing outcomes sufficient to incentivise new investment. However, pricing has increased substantially since 2015. Significant withdrawals of aged thermal plant has led to tightening reserve margins. The average prices in 2017 reflect both a resurgence in peak demand and a tighter demand/supply balance. Figure 4 shows forward pricing in Victoria and the increases attributable to the permanent retirement of the 1,600 MW coal-fired baseload Hazelwood power station in March 2017.[4]

Figure 4 effectively demonstrates the inter-period pricing phenomenon established in Section 2. Prices were significantly below LRAC for many years due to oversupply created by flat underlying energy demand and additional supply driven by climate change policies. This resulted in economic pressure being placed upon remaining generators which eventually led to the disorderly withdrawal of the Hazelwood power station. Only six months' notice was provided, well below the notice required to invest in the requisite new firm capacity.[5] Forward pricing has resulted in significant discussion within Australia about prices being 'too high', evidence that realistic political economy of energy prices is perhaps inconsistent with 'energy-only' market design.

The same scenario described above occurred in South Australia in 2015/16. In October 2015,

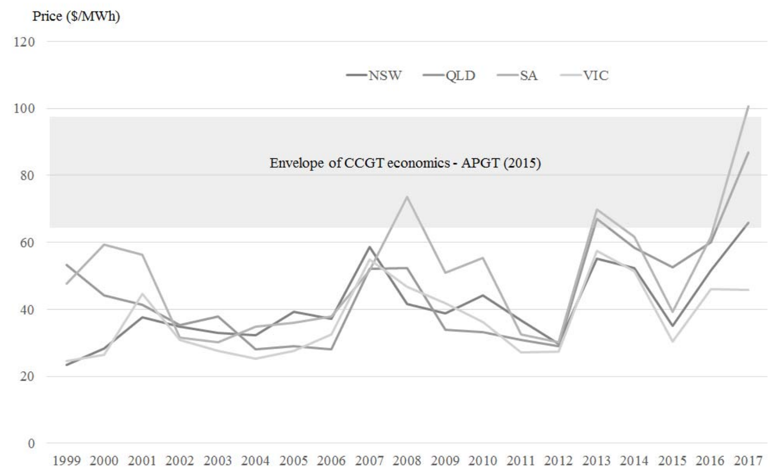


*Figure 3: Historical average wholesale prices in the NEM*
Source: AEMO market data

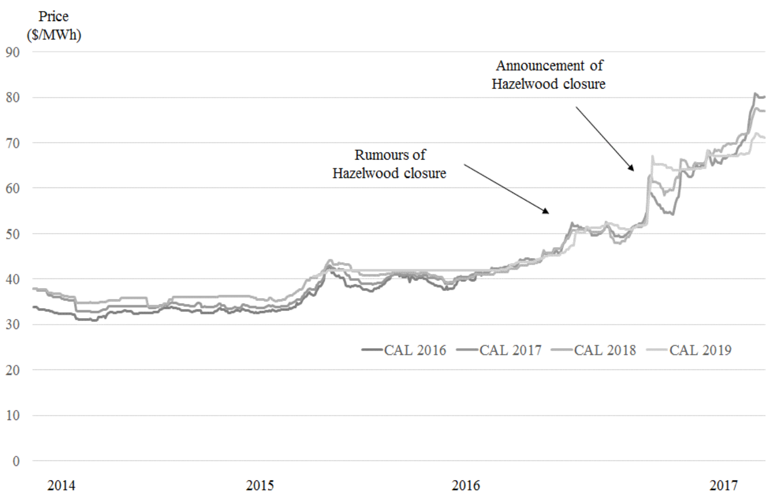


***Figure 4: Victorian forward electricity pricing***
Source: Market data

the owners of the Northern (546 MW) and Playford (240 MW) power stations announced their permanent closure in May 2016.[6] Again, with less than a year of notice, there was no time for new generation to be built (see Nelson and Orton, 2016). Capacity is required to complement the significant penetration of wind generation within the South Australian region. However, 'baseload' coal-fired generation is unsuited to these duties. Figures 5 and 6 provide evidence that lower capacity factor 'firm' plant would be better suited than existing less flexible plant to complement wind generation. The peak/average factor in the South Australian region is 1.89 but if wind is excluded it increases to 2.94. Capacity is required but for much fewer hours of the year. Much of the remaining plant in the South Australian market is unsuited for providing this type of 'flex'.

Wind generation is increasingly reliant upon climate change policy subsidies (Large-scale Generation Certificate: LGC revenue) as it suffers from a 'price penalty' due to its nature as a 'price taker' and coincident generation profile. Figure 7 shows the weighted average spot price in South Australia received by technology type. In every year, wind receives much less revenue due to its inability to generate at times when energy is most valuable (e.g., peak demand times). It is also unable to forward contract by selling forward derivative products. In our view, these issues will become even more evident as more renewable energy enters the market in coming years to achieve the 26-28% emissions reduction target established by the Commonwealth Government.

## POLICY RECOMMENDATIONS AND CONCLUDING REMARKS

### *Addressing inter-period pricing*

Inter-period pricing in 'energy-only' markets is likely to continue to be at odds with the criterion of realistic political economy of energy pricing. Retailers and industrial users of energy cannot forward plan when prices are subdued for a period of time but then rapidly increase due to the 'lumpy' withdrawal of thermal plant. However, an 'orderly' transition to a higher-penetration renewables system can be facilitated within an 'energy-only' market if generators provide sufficient notice of impending closures to allow new complementary capacity to be built. As noted in the subsequent sub-section below, this new investment will likely be lower capacity factor thermal plant in the short-term (e.g., OCGT) or perhaps advanced batteries or pumped hydro style technologies in the long-term. There are a plethora of ways this 'sufficient notice of closure' could be achieved through either plan-

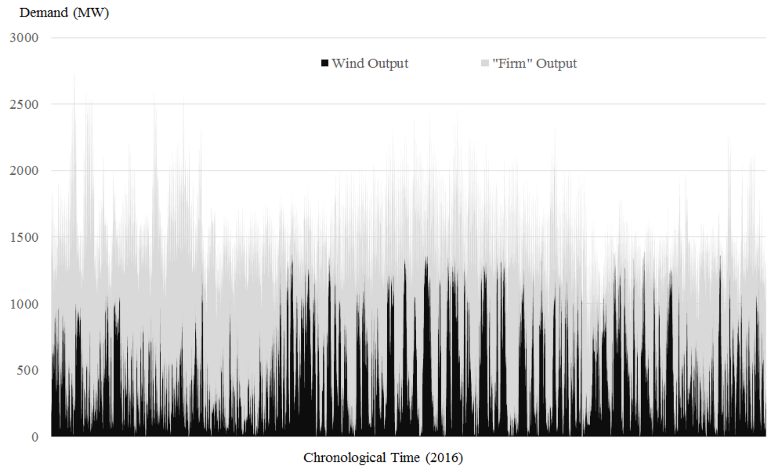


*Figure 5: Output of generation in South Australia chronologically ordered in 2016*
Source: AEMO market data

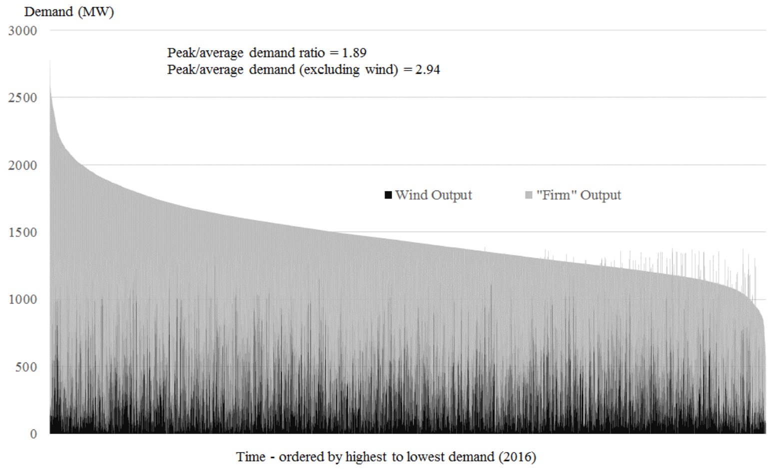


*Figure 6: Output of generation in South Australia ordered by demand points (2016)*
Source: AEMO market data

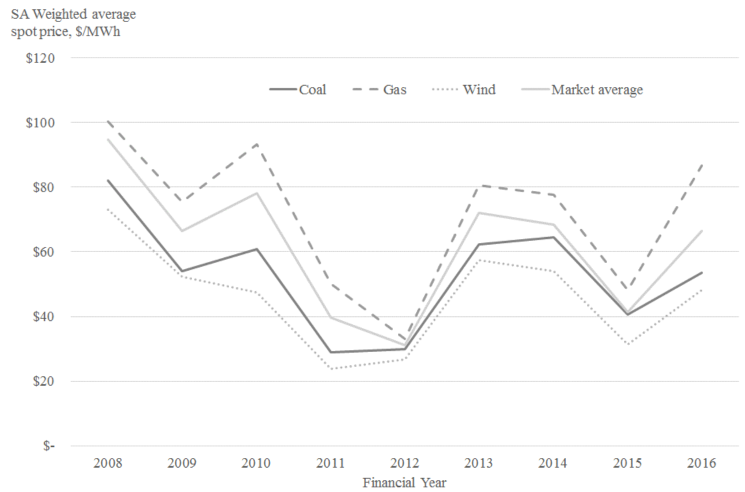


*Figure 7: Weighted average pricing for South Australian generation*
Source: AEMO market data

ning laws or amendments to AEMO generation registration rules. It could also be facilitated through market-based or age-based emission reduction style 'closure' policies (see Jotzo and Mazouz, 2015, for further information).

### *Addressing intra-period pricing and facilitating new investment*

In our view, new investment in capacity is likely to be driven by climate change policies that encourage fuel substitution.[7,8] However, it is important that this new investment is 'dispatchable' and can actively participate in the market. Active participation facilitates the forward contracting of generation and the operation of a competitive downstream restructured retail market (allowing intra-period pricing volatility to be managed).

Rather than creating further distortions on the operation of the electricity market (by implementing capacity markets and the like), it may be preferential for policy makers to alter the design of climate change policies or renewable energy obligations to ensure unintended consequences of climate change policies for 'energy-only' markets are avoided. Intermittent, non-contractible generation (i.e., wind, solar, etc.) could be required to contract with complementary plant such as OCGT, advanced batteries or pumped hydro to create a 'synthetic financial generator', capable of bidding into the spot market and participating in forward derivative markets. This could be achieved through a market mechanism (e.g., 'firm capacity right' certificate which would be required to be stapled to renewable generation facilitating some proportion of the capacity being 'firm') or a generator registration mechanism.[9]

This development is necessary for at least two reasons: it would facilitate retail market innovation and competition by ensuring that sufficient price mitigation hedging tools are available; and it would allow the 'synthetic financial generator' to optimise investment to ensure the right lower capacity factor plant is forthcoming to complement renewables (rather than the sub-optimal use of higher duty incumbent plant that is not suited to such operation). Renewable generators would be better able to participate in the market and be less reliant upon subsidies. There would also potentially be a more transparent 'transfer payment' from non-firm renewable generators to 'firm generators' that provide integration services that are not currently explicitly valued.

## Footnotes

[1] In fact, it was a state-wide blackout on 28 September 2016 that led to the creation of the Finkel review. The blackout was largely caused by an extreme weather event but prompted discussions about whether a different market design or energy mix would have prevented the loss of power.

[2] Intra-period pricing would also be impacted by the choice of climate change policy. For example, in a system with most generators benefiting from Contracts for Difference (CfDs), generators with the highest CfDs will be able to produce at lower prices than those with a lower CfDs. Effectively, the bias is towards the more expensive plants. The impacts of specific climate policy design on energy-markets is therefore worthy of further research.

[3] While east-coast Australia has significant gas reserves, the vast majority of 2P reserves are now allocated for export through a new LNG export industry in Gladstone, Queensland. Simshauser and Nelson (2015) provide a detailed explanation of the events that led to this situation.

[4] See http://www.gdfsuezau.com/media/UploadedDocuments/News/Hazelwood%20Clousure/Hazelwood%20closure%20-%20Media%20release.pdf for further information, Accessed online on 17 February 2017.

[5] Note the specific use of the term capacity rather than energy. The market will continue to need capacity to meet peak demand but less energy due to the introduction of intermittent renewables.

[6] See https://alintaenergy.com.au/about-us/power-generation/flinders-operations for further information. Accessed online on 17 February 2017.

[7] This is irrespective of whether a carbon price (e.g. emissions intensity scheme), direct renewable portfolio obligations or contract for difference policies are pursued.

[8] This effectively solves (albeit temporarily) the limitations of 'energy-only' markets for incentivising new investment.

[9] The market price cap (MCP) will still need to be increased, or more controversially removed, to ensure costs can be recovered and market participants are incentivised to hedge pricing risk.

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