Electricity Market Implications of a Least-Cost Carbon Abatement Plan: An Australian Perspective

Several least-cost planning studies have suggested a significant shift away from coal toward gas, renewables and potentially nuclear in the long term. Using a Cournot gaming model to analyze the ramifications that market power in Australia’s concentrated market may hold for a transition to a low-carbon electricity sector suggests that the substantial influence on price outcomes of some players will need to be fixed before we can have faith in the least-cost carbon abatement strategy.

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I. Context

Long-term carbon abatement from the electricity sector typically involves transition over time from a fossil fuel-dominated generation mix (more often coal) to a low-carbon mix. Least-cost planning of electricity (Stoll, 1989) that gained prominence in the 1980s and 1990s had taken a backseat during electricity market development of the 1990s. However, a resurgence of carbon abatement in the past 10–15 years in some countries including Australia has seen a renewed interest in least-cost carbon...
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A "carbon-aware" least-cost planning approach to electricity generation has been a useful aid to carbon policy development in Australia including the mainstay for an Energy White Paper over the last few years (Department of Industry, 2013). A number of technology policy papers produced by the government bodies and power industry groups since 2006 (CSIRO, 2013; ROAM Consulting, 2010; McKinsey, 2008; CRA International, 2007; MMA, 2007; Frontier Economics, 2006) also relied on the least-cost planning approach in one form or another. CSIRO’s publication in December 2013 under the aegis of the Future Grids Forum (CSIRO, 2013) analyzes a number of technology, demand, and carbon abatement scenarios for the period leading up to 2050. Across the CSIRO scenarios, the electricity sector is projected to achieve greenhouse gas emission reduction of 55–89 percent below 2000 levels by 2050, which is reasonably consistent with the currently legislated national greenhouse gas emission reduction target of 80 percent below 2000 levels by 2050.

CSIRO’s least-cost analysis predicts that wholesale electricity unit costs would increase from approximately $60/MWh in 2013 to between $113/MWh and $176/MWh in 2050 (all figures in this article are given in Australian dollars). It also predicts that nuclear power may provide a cost-effective way to reduce emissions and lower costs by $34/MWh in the long run (relative to a “no nuclear” scenario). Similar analyses have been performed by ROAM Consulting (2010) as part of the federal government’s initiatives in the Energy White Paper. McKinsey (2008) had produced a comprehensive abatement cost curve for the Australian power sector displaying many cost-effective measures including demand-side response. In the wake of the serious greenhouse gas emissions reduction policy debates that started in 2005, a number of power industry lobbies and the Australian government produced a number of supporting policy analyses (CRA International, 2007; MMA, 2007; Frontier Economics, 2006) that also relied on least-cost planning and yielded the initial estimates of marginal cost of carbon, impact on the coal industry and the relative importance of various clean technologies.

II. Market Issues Not Captured in a Least-Cost Analysis

While the least-cost planning studies have indeed been useful in setting a “competitive benchmark” against which an informed policy debate can, and did, take place, questions around two major issues have not been addressed by such analyses:

A. Market power in an imperfectly competitive market

To begin with, how well a least-cost capacity expansion and dispatch sit with the current market design, even absent any carbon impost. As in other electricity market jurisdictions, there have been divergent views in Australia on this fundamental issue. On the one hand, market power allegations have been leveled against some of the dominant generation companies in Australia since the early days of the Australian National Electricity Market (NEM), as has probably been best documented by Booth (2003), including the fact that the LRMC of new generation
at the time (2001–2002) was $34/MWh – well below the NEM average price of circa $44/MWh, despite the market having a significant reserve margin.¹

Prices in South Australia in particular have been a contentious issue, with annual average prices varying between $30/MWh and $156/MWh between 1998 and 2013, without a fundamental shift in demand–supply balance over these years. In fact, price variations have been so stark in this region that the contribution of a carbon tax in July 2012 has not been felt as a major price shock.²

On the other hand, the regulatory response has been relatively benign, with NECA (2001) largely dismissing the initial claims of market power abuse. Although there has been a Market Power Rule Change Proposal instigated by the Major Users Group in more recent years, the policy response from the Australian Energy Market Commission in its Final Determination (NEM, 2013) again has been lukewarm: ‘‘The Commission considers that analysis of market outcomes in Queensland, New South Wales, and Victoria does not support a conclusion that there is or has been substantial market power in those regions of the NEM. . . . With regard to South Australia, the Commission considers it is not clear as to whether substantial market power has existed in that region to date. The Commission however considers there is insufficient evidence to support the likely exercise of substantial market power in the current market environment.’’

B. Price volatility

Price volatility is an integral part of electricity markets, especially in an ‘‘energy-only’’ market (EOM) such as the NEM that relies solely on pool price volatility to signal the need for new generation capacity including peaking generation capacity. While a least-cost plan in theory can capture some of the aspects of volatility arising from uncertainties in demand, random outages of generators, transmission lines, etc. – these do not adequately cater for all sources of volatility seen in a market, nor does it reflect how such price risks are built into financial investment decisions. A reserve margin constraint that typically features in (deterministic) least-cost planning may not necessarily be met in a real-life electricity market because the investment risk may be deemed too high by commercial investors. Indeed a continuation of non-market based ‘‘reserve trader’’ arrangement in the NEM suggests that such non-market interventions were necessary to ensure there is adequate level of reserve capacity in the market. Therefore, the assumption of a certain level of reserve margin automatically being delivered will not necessarily be seen in a market place.

Retailers are mostly at the receiving end of the price volatility and need to find a way to manage these price risks through commercial contracts including inter alia ‘‘caps’’ and two-way hedges. The efficiency and liquidity of a financial market in such products is just as important to ensure there is a viable retail business to support a least-cost plan. Since an energy-only market such as the NEM exhibits relatively extreme form of spot price volatility ranging from a price floor of AUD (–) 1000/MWh to a price cap of AUD 13,100/MWh, the market may be deemed to be ‘‘too risky and unreliable’’ absent an efficient financial market. This is often a recipe for vertical integration for generation and retail companies to effectively manage these risks – a trend that has certainly been conspicuous in the NEM and has received considerable attention from the Australian Competition and Commerce Commission lately.³ Contrary to the previous point we made regarding the lack of commercial appetite for peaking investment, presence of
vertical integration may actually mean in some cases overinvestment in peaking generation as part of an entry-deterrent behavior. Again, decision-making on new generation may in essence be driven by price volatility to promote vertical integration that may mark a departure from the one predicted by a least-cost plan. Finally, price volatility would be significantly impacted by large-scale entry of wind and solar generation. Intermittent renewables form a significant part of long term generation portfolio for deep (60% or more) carbon emissions cuts, especially in the event baseload nuclear and/or carbon capture and storage (CCS) technologies are not allowed. The inherent uncertainty in supply of intermittent renewable energy presents a level of price volatility risk that has not been seen in the NEM to date. In South Australia that has seen the highest level of penetration of wind (about 30% of the total capacity to date), an increase in peak price volatility has already been observed. However, as wind/solar penetration escalate over the years in other regions, there is expected to be a disproportionate level of increase in price volatility that will have significant ramification for new investment as well as vertical integration which in turn may affect market concentration. These dynamic interactions are not captured in a least-cost clean generation mix but are fundamental issues that need to be addressed to develop a market-centric view of new generation development.

C. Sovereign risk, policy uncertainty and other issues

Apart from these two, there are of course a raft of other issues, not the least of which is around sovereign risk and policy uncertainty that may also dampen investment in the power sector.

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The policy uncertainty surrounding carbon and renewable policies in Australia has already caused significant nervousness for investors and financiers to a point that has in some quarters been labeled as “investment paralysis” (Nelson et al., 2010).

The literature on these market issues – both in the academic journals as well as in the form of industry reports and reviews – is not as rich as its least-cost utility planning counterpart. Nevertheless, there is a more recent and growing recognition of the importance of these issues. Some of the initial analyses including (ROAM Consulting, 2010; CRA International, 2007; MMA, 2007) included a market-based analysis in addition to a least-cost plan, although these did not delve into the issue of market implication of a least-cost plan that we have discussed here. Mountain (2013) has more recently presented a qualitative analysis of the impact of wind power on electricity market (power) specifically focusing on South Australia. Twomey and Neuhoff (2010) presented the first general theoretical framework to assess the role played by intermittent generation on market power. There have been more recent exploration of uncertainties associated with intermittent generation in Dai and Qiao (2013). Our previous work in the (South) Australian context ( Chattopadhyay and Alpcan, 2014) demonstrated that as wind generation typically drops during the summer peak, it may provide ample opportunity for dominant generation companies (gencos) in a concentrated market to raise prices above competitive level. This is particularly true because significant surplus capacity during off-peak periods can depress prices to very low levels, including negative price events. Also receiving some attention has been the second issue of price volatility, including an increase in volatility caused by wind/intermittent generation (Gil and Lin, 2013; Morales et al., 2011). The third issue around impact of
policy uncertainty has been partly addressed in Majumdar and Chattopadhyay (2011), which estimates that the market impact of such uncertainty in Australia around carbon policy has already been in the $1–2 billion range (or 10–20 percent of annual wholesale market revenue) per year. CSIRO (2013) has also analyzed this issue more recently and concluded that the cost of policy uncertainty may be on average 17 percent.

The remainder of this article presents a high-level analysis of long-term generation development in the NEM. We have used a deterministic least-cost planning model in conjunction with a Cournot gaming model to discuss the market implications of a least-cost plan.

III. Analytical Framework to Assess Market Implications

In order to assess the market implications of a least-cost generation plan, we have used a multi-period Cournot model that can replicate market behavior of gencos that is influenced by market concentration and relative costs. The core model may be represented as a quadratic programming (QP) optimization problem, as has been discussed in our prior research publications (Chattopadhyay and Alpcan, 2014; Chattopadhyay, 2004a,b).

As we have discussed in Chattopadhyay (2004a), the optimization problem (1)–(3) presents a “single optimization problem for all the gencos... however, the individual genco profit maximization problems are implicit in this single optimization.” The model captures the capacity withholding behavior typically exhibited by gencos in an oligopolistic market where generators attempt to withdraw generation to keep prices above marginal cost. The model calculates the Cournot–Nash equilibrium (CNE), given a capacity expansion plan. The model parameters – specifically the linear demand equation parameters – are calibrated against actual dispatch/price outcomes using 2011/2012 data for the NEM, following a calibration procedure discussed in CRA International (2007). The calibration step is essential to ensure that the demand (as well as other model parameters (e.g., contract level of gencos) are set to a level that is reflective of the market realities and the model can reliably reproduce actual price outcomes.

Once the calibrated demand curves are obtained, we have simulated the market implications of a least-cost low-carbon capacity plan for different levels of market concentration to develop insights into the ramifications of market power in a low-carbon power system.

The Cournot model may also be used to replicate a perfectly competitive market by simply dropping the last term of the objective function (1) that represents dead-weight losses associated with market power (Chattopadhyay, 2004b). We can therefore replicate the marginal cost prices corresponding to a least-cost capacity plan using essentially the same model without considering such dead-weight losses.

Finally, the basic model (1)–(3) can easily be extended to include nodal representation of electricity markets (Chattopadhyay, 2004b), multiple time periods (or “load blocks”) within a year (Chattopadhyay, 2004a), and also volatility of intermittent (wind) generation (Chattopadhyay and Alpcan, 2014)—we have used all of these features to replicate operation of the NEM. In particular, we have considered a five-zone representation of the NEM including the interconnection capacity limits across the regions, and we have considered the volatility of wind power generation using Monte Carlo
simulation that samples wind availability from a historical distribution of wind power in NEM regions. A fuller description of the model as well as details of these extensions are included in references (Chattopadhyay and Alpcan, 2014; Chattopadhyay, 2004a,b), and are not repeated here.

IV. Results and Discussions

In this section, we have presented some of our findings on the market implications of a least-cost plan. Figure 1 shows a typical least-cost low-carbon capacity plan for the Australian NEM wherein the coal generation, and hence emission intensity of the pool, steadily declines over the years. As gas and renewable generation increases, it adds to system costs comprising both capital and operating costs, which are captured well by the least-cost optimization model. The cost increase is relatively small in the short term (2015–2020) as emission intensity drops marginally from 0.9 t/MWh to 0.75 t/MWh by 2020, but the cost increments are much more significant post-2020 and for the period up to 2030 during which a coal-dominated system makes the transition to a lower carbon state. The cost increase is highest for the period 2030–2050, as the need for large-scale expensive baseload clean technologies becomes pivotal to meeting deep emissions cuts.

We have first simulated a “perfectly competitive” or “PERF COMP” scenario by dropping the dead-weight loss term in equation (1) as discussed in the preceding section for both peak and off-peak load conditions in the NEM. We have then considered two market concentration scenarios, namely:

(a) High Market Power scenario wherein we assume the current vertically integrated scenarios continues till 2050 with proportional addition of capacity to the current portfolios held by gencos. In other words, we assume that the market concentration remains at a high level, with all of the new low-carbon capacity being apportioned to the existing portfolios; and

(b) Low Market Power scenario wherein we double the number of market participants.

Figures 2 and 3 show mean peak (highest 600 hours) and off-peak prices (the remaining 8,160 hours) for the three scenarios for the near term/CURRENT (2015), mid-term/TRANSITION (2020–2030), and LONG-TERM (2031–2050). Peak
prices in the NEM are already quite high, at around $150/MWh, and the High Market Power scenario would largely maintain prices at the same level. If anything, prices drop slightly in the long term with high penetration of wind in some states (e.g., South Australia and New South Wales). There is a stark difference in peak prices across High Market Power and PERF COMP for the CURRENT period. To some extent it highlights the market power concerns that have been expressed since the beginning of the NEM operation (e.g., Booth, 2003), but admittedly the simplified least-cost dispatch modeling probably also underestimates the true volatility of peak prices to some extent. Over the years, perfectly competitive prices rise significantly to reflect the high cost of low-carbon generation. As a significant cost of carbon implies the relative costs among competing gencos are closer and we assume the market concentration remains the same, there is no further increase in peak prices in the LONG TERM, albeit it still remains considerably above the PERF COMP prices.

The gap in off-peak prices for the market power and PERF COMP scenarios is also significant, albeit generally much lower, which is reflective of the significant level of surplus capacity in the system. Prices for the High/Low Market Power scenario in the LONG TERM is in fact lower than that of the PERF COMP counterpart. This is largely due to the presence of intermittent generation that encourages dominant gencos to depress prices below competitive level during off-peak hours and to withhold capacity/generation during peak hours. This behavior is consistent with observed market prices and our analysis of the South Australian market (Chattopadhyay and Alpcan, 2014).

Figure 4 compares volatility of peak prices measured as the standard deviation of peak prices across 500 samples of wind generation. Put differently, depending upon availability of wind during peak hours, prices may vary significantly. Variability of prices would obviously increase with higher penetration of wind over the years. As the figure demonstrates, volatility of peak prices would increase significantly from A$5/MWh or lower in CURRENT years to $20–30/MWh in the LONG TERM, although we do not find any definitive correlation between...
market power and peak price volatility.

The findings of our numerical simulations is significant in that:

a. It firstly confirms in a way that the current market structure leads to a peak price outcome that is possibly very significantly above where competitive prices should be;

b. Secondly, simulation results show that peak prices will continue to remain high although transition to a low-carbon state would not appreciably change prices from its current level; and

c. The results also show that the variability of peak prices will, however, increase by a factor of four to five regardless of the market concentration as share of intermittent generation increases.

These findings are alarming because, as Table 1 summarizes the outcomes for the High Market Power scenario, a combination of high and volatile peak prices would be a major concern for retailers and generators alike.

In fact, there is a more serious but arcane message in these results. A high and volatile price outcome may call into question the practicability of achieving the low-carbon capacity plan in the first place. If prices are too high arising from high market concentration, there is no major incentive for the incumbent gencos to invest in low-carbon technologies other than, of course, subsidy-driven technologies. The Australian NEM has in fact seen very little market-driven initiative toward low-carbon power generation. Artificially high power prices would discourage consumption to a point of making some of the electricity intensive industries uncompetitive in the global market – there is some evidence of it already in the form of some of the smelters closing down in recent years. If the volatility of peak prices increases over the years, it will be more of a concern for new investors as well as for retailers/consumers. It is a concern for new investors because of the unpredictability of return on its investment. It is also a concern for retailers because a four- to five-fold increase in peak prices would probably mean a similar order-of-magnitude of increase in premiums for financial products such as “cap contracts” to hedge against such volatility. It would be a significant burden for smaller retailers that are not part of the three vertically integrated players – potentially encouraging them to exit and add to the trend of vertical integration.

In order to highlight the ill effects of extreme market power, we have constructed three additional cases with varying technology mix and market concentration, namely:

A. No_Abatement, i.e., no carbon reduction and the current market concentration continues;

B. 80_PCT_NO_NUKE which achieves 80 percent reduction in carbon by 2050 without nuclear and once again assuming the current market concentration continues; and

C. 80_PCT_NO_NUKE which also achieves 80 percent carbon reduction but uses nuclear as the primary baseload technology that accounts for 25 GW of nuclear addition by 2050. The least-cost capacity expansion plan with nuclear is marginally cheaper (<5%) compared to its “No

| Table 1: High Market Power Scenario: Mean and Standard Deviation of Peak Prices: LONG-TERM vs CURRENT |
|-----------------|-----------------|
| **LONG TERM**   | **CURRENT**     |
| Mean            | 142             | 149             |
| Std Dev         | 19              | 4               |

Figure 5: Comparison of No Abatement and Abatement Scenarios (With and Without Nuclear)
Nuclear counterpart. In this scenario, we assume all nuclear capacity will be under a single ownership, which adds considerably to market concentration.5

Figure 5 shows a comparison of average prices over 2015–2050 for the three scenarios. Prices for both 80 percent reduction scenarios are much higher than No_Abatement, as one would expect. However, the average market prices for the 80_PCT_NUKE is found to be significantly higher than the 80_PCT_NO_NUKE counterpart despite the former having a lower underlying system cost. In other words, the effect of a higher market concentration can completely dominate the cost effects. Such price outcomes may once again distort investment signals and may jeopardize the move to a low carbon economy.

V. Summary and Concluding Remarks

Least-cost generation planning taking into account carbon constraints has been a useful aid to policymaking in many countries, including Australia. A number of such studies by federal and state governments in Australia as well as those sponsored by the power industry suggested a significant shift away from coal toward gas, renewables, and potentially nuclear in the long term.

However, the current market realities suggest that the market is highly concentrated with three major vertically integrated players, where prices have frequently stayed significantly above a competitive/least-cost benchmark. In this article, we have analyzed the ramifications of market power that may arise in such a concentrated market and the implications such outcomes may hold for transition to a low-carbon electricity sector in Australia.

In order to analyze these issues, we have relied on a multi-year nodal Cournot model following (Chattopadhyay, 2004a,b). The model is augmented with a Monte Carlo simulation engine to capture the impact of variability in wind generation following our earlier work in (Chattopadhyay and Alpcan, 2014). The model is implemented for the Australian NEM for 2015–2050. It uses a least-cost capacity expansion plan as an input and generates expected price outcomes for these years for different levels of market concentration as well as a perfectly competitive regime.

There are three key messages that emerge from the results of our Cournot and perfect competition model simulations, namely:

a. There is a significant gap in the near term between what is predicted by the Cournot model, calibrated to actual market price outcomes, and the competitive benchmark – especially for the peak period. This should be a significant concern because such peak prices can have distortionary impacts, including a reluctance on the part of incumbent gencos to invest in capital-intensive low-carbon generation;

b. If we assume that the current level of market concentration continues till 2050, peak prices according to our model results will continue to remain high although peak prices do not rise above their current level in any year and in fact drop slightly in later years as the volume of intermittent generation increase significantly, with the effect of reducing prices. As a low-carbon power system incurs heavy costs, our competitive scenario also predicts prices to go up sharply over the years and the gap by 2050 is smaller compared to 2015, albeit market prices continue to be well above its competitive benchmark. This again reiterates our major concern that gencos who can significantly influence price outcomes to keep it well
above their costs, will not necessarily be interested to invest in cleaner and expensive forms of generation; and

The results also show that the variability of peak prices will however increase by a factor of four to five regardless of market concentration as share of intermittent generation increases. This is an outcome that should concern new investors and retailers alike. In effect, the upshot of a least-cost carbon abatement strategy in a concentrated market is that prices may remain higher than competitive prices and worse – they may become substantially more volatile.

These findings do not obviate the need for least-cost planning. It, however, shows that if the market has an inherent distortion, with some players having a substantial influence on price outcomes, these issues need to be fixed first before we can have faith in the least-cost carbon abatement strategy. As the experimentation with carbon pricing in the recent years in Australia has shown, adding a carbon price has merely added to wholesale electricity prices without a proportionate decrease in carbon emissions (Chattopadhyay, 2013). A least-cost generation expansion plan, in the same vein, is unlikely to be effective because there will be no major incentive for incumbent gencos and a volatile and uncertain electricity market is unlikely to attract new investors to put in tens of billion dollars in clean generation.

References


National Electricity Code Administrator (NECA), 2001. Investigations into the Events of 7 and 8 February, Australia.


Endnotes:

1. Also, some of the dominant generators were alleged to carry out maintenance of major units during high-demand periods that led to sustained high spot price events that contributed significantly to high average price outcomes. R.R. Booth of Bardak Ventures also made a major submission to the Australian Energy Regulator in 2002 titled “Are Price Spikes Good for You?” that contains some of these findings which is available on Australian Energy Regulator. Website: http://www.aer.gov.au/sites/default/files/Bardak%20Group%20-%20Submission%20to%20Regulatory%20Test%20Discussion%20paper%20-%20August%202003%20-%20AttachmentAlso, the report by Burns and Roe Worley (BRW), Loy Yang Power Unit 2: Technical investigation, 2001, examined the legitimacy of a forced outage claimed by Loy Yang – one of the major coal generators in Victoria that led to a number of price spikes. In particular, these reports by Booth and BRW document investigation among other things into the shutdown of a 50 MW generating unit in Australia that led to extremely high prices for two days in Victoria and South Australia.

2. The standard deviation of annual average spot prices in South Australia from 1998/1999 to 2011/2012, i.e., prior to the introduction of carbon tax, has been AUD 32.68/MWh. In comparison the carbon-related cost increase is lower at approximately AUD 21/MWh which is calculated as the carbon tax of $23/ton X pool emission intensity of 0.9 ton/MWh.

3. For instance, ACCC has recently blocked an acquisition of a major coal generator in New South Wales by AGL, a vertically integrated generator-retailer. ACCC noted that the “…the acquisition would be likely to prevent sufficient vigorous competition with AGL, Origin and Energy Australia, who already have 85 percent of the overall retail market in NSW and 95 percent of the mass market, and would have a combined share of 70 to 80 percent of electricity generation capacity or output in NSW if the acquisition proceeded. … In addition, had the acquisition proceeded, AGL would have become the largest generator in each of NSW, Victoria and South Australia. The ACCC remained concerned about the likely competitive impact of the proposed acquisition in one or more of the wholesale electricity markets in these regions.” Cited from: http://www.accc.gov.au/media-release/accc-opposes-agls-proposed-acquisition-of-macquarie-generation

4. That said, average competitive prices around $30–40/MWh has been consistently reported in a number of studies, including (CSIRO, 2013; ROAM Consulting, 2010; McKinsey, 2008; CRA International, 2007; MMA, 2007; Frontier Economics, 2006). Since Australian coal-based gencos enjoy abundantly available cheap coal resources with short-run marginal costs in the range of $3–15/MWh for vast majority of its power stations, any underestimation of PERF COMP prices is unlikely to change the broad outcomes of this study.

5. We would like to note that in reality nuclear power may in fact have little flexibility to exercise market power because of its inherent limitation to change output and also potential regulatory restrictions and government ownership of these facilities. It should therefore be seen as a hypothetical scenario. Nonetheless, it is useful to understand how market power may distort investment signals for all new entrants, including low-/zero-carbon technologies.