A Comparison of Ex Ante versus Ex Post Vertical Market Power: Evidence from the Electricity Supply Industry*

by

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This paper provides a prospective and retrospective quantitative assessment of the impact of a passive vertical integration between a large electricity retailer and a large electricity generator in the Australian National Electricity Market (NEM). We adapt a standard model of fixed-price forward contracting behavior by an electricity retailer before and after the acquisition of a share of a baseload electricity generation plant to determine the likely change in its contracting behavior. Using bid and market outcome data during the three years leading up to the acquisition, we estimate the change in bidding behavior of the generation unit owner from the change in its fixed-price forward contract obligations brought about by the acquisition. This change in bidding behavior is used to compute a prospective change in each half-hourly wholesale price during the pre-acquisition period. Because this acquisition was allowed to take place, we also use market-clearing prices of wholesale electricity in the four states of Australia in NEM at that time and the price of the marginal input fuel during the pre-acquisition and post-acquisition time periods to compute a variety of treatment effects estimates of the impact of this acquisition. We find fairly close agreement between the prospective and retrospective quantitative impact of the acquisition on wholesale prices. In both methodologies find a significant increase in wholesale electricity prices associated with the acquisition, which emphasizes the importance of taking into account the extreme susceptibility of short-term wholesale electricity markets to the exercise of unilateral market in any competition analysis in this industry.

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1 Introduction

Re-structuring of vertically-integrated electricity supply industries has typically involved the horizontal separation of the monopolist's generation and retailing assets, vertical separation of transmission from generation and retailing, and the requirement that each retailer offer an open-access tariff to charge competitors for the use of its local distribution network. The goal of the vertical separation process is to provide all participants in the potentially competitive segments of the industry—generation and retailing—with equal access to the bottleneck portions of the industry—the transmission and distribution networks. Horizontal separation in the generation and retailing segments was intended to create the initial conditions necessary for vigorous competition. Several countries also separated retailing from generation because of a belief that vertical integration did not involve any potential gains in productive efficiency and separation was preferable to integration to avoid potential anti-competitive concerns.

In several countries, this vertical separation has been challenged by industry incumbents. In the UK, a number of large generation companies serving the England and Wales market integrated downstream into electricity retailing. In New Zealand, integration between generation and retailing has left the industry virtually fully integrated with five main participant generator-retailers. A similar structure has been in place since the start of the market in Spain, with Endessa and Iberdrola, the two largest generation unit owners also being the largest retailers. These industry structures raise the question of whether in the absence of a regulated retail price vertical integration enhances the ability of the combined entity to exercise unilateral market power.

This paper provides both an ex ante and ex post quantitative assessment of the impact of vertical integration on market outcomes in Australian National Electricity Market (NEM). Until April 2004, there was very little vertical integration in the NEM, although a few retailers owned peaking generation plants and some generators have retail arms aimed at large industrial users. In 2003, the largest energy retailer in the state of Victoria, Australia Gas Light Company, known as AGL, proposed to acquire a stake (as part of a consortium) in the largest base-load generator in the Victoria, Loy Yang A (LYA). Concerned about potential anti-competitive harm as well as the idea that this might be a first step in a wave of vertical acquisitions, the competition authority, the Australian Competition and Consumer Commission (ACCC), challenged the acquisition. The merging parties successfully overcame this challenge and effective April 1, 2004 control of LYA was transferred to the consortium in which AGL held a 35 percent stake. A pre-condition to the acquisition was that AGL would give Court enforceable undertakings that it would not be involved in the day-to-day bidding and contract trading of LYA with representation only at the Board of Directors level. That is, the acquisition would be a *passive* one.

To parties unfamiliar with the susceptibility of wholesale electricity markets to the exercise of unilateral market power, this acquisition would not seem to raise competitive concerns.[1] If the broad geographic market of the eastern Australian states of New South Wales, Queensland, South Australia and Victoria was accepted, both the electricity generation and retailing sectors were not at levels of concentration that would

[1] The evidence on vertical integration with state-level regulation of retail electricity prices in the United States has involved complete mergers with active control. See Mansur (2003) and Bushnell, Mansur and Saravia (2005) for a description of these results that suggest vertical integration can have pro-competitive impacts. It is important emphasize the role of explicit state-level retail price regulation, something that did not exist in Victoria at the time of the acquisition, in delivering these results.

normally raise concerns under typical merger guidelines.[2] In addition, the potential anti-competitive consequences of vertical integration are controversial at the best of times, let alone a partial ownership in a moderately concentrated market. Add to that the passiveness of the acquisition, and the usual mechanisms by which anti-competitive harm could arise – namely, raising rivals' costs and foreclosure – may not be available to the acquirer.[3] These reasons alone may indicate that such an acquisition should not command significant regulatory attention.

However, in this paper, we provide a novel theoretical argument that it is the very passiveness of the acquisition along with the particular characteristics of wholesale electricity markets that could make this type of acquisition a significant competition concern. Using bid and market outcome data over the pre-acquisition time period from January 1, 2000 to June 30, 2003 and a model of expected profit-maximizing bidding behavior with fixed-price forward contracts from Wolak (2000 and 2003a), we provide prospective assessment of the likely magnitude of the increase in wholesale electricity prices that would result from this acquisition. We then use pre-acquisition versus post-acquisition market outcome data to perform several retrospective treatment effects analyses of the impact of the acquisition on wholesale electricity prices in the Australian NEM. These results are similar in magnitude to the ex ante predictions from our analysis based on the pre-acquisition bid and market outcome data, suggesting that the ACCC's concerns with the vertical combination were justified.

[2] Gans (2007) provides a modification of concentration measures to take into account potential issues associated with vertical integration. With either a broad or narrow geographic market definition, such concentration would not have increased as AGL would have remained a net buyer in the market post-acquisition.

[3] A number of legal commentators raise concerns about the notion that vertical integration is a competitive concern even in highly concentrated markets. However, a recent literature, has suggested that concentration is a factor in allowing integrated companies to engage in foreclosure activities. See Rey and Tirole (2007) for a recent survey and de Fontenay and Gans (2005) for a general model in an oligopolistic environment.

The remainder of the paper proceeds as follows. Section 2 develops a simple model that demonstrates that a passive vertical acquisition provides the acquiring electricity retailer with a non-contractual natural hedge against fluctuations in the wholesale price of electricity. This causes the retailer to reduce its demand for fixed-price forward contracts for electricity which in turn reduces the total volume of such contracts held by generators. The reduced fixed-price forward contract obligations of generation unit owners, increases their incentive to exercise unilateral market power in the short-term wholesale electricity market, which is raises the equilibrium spot market prices feeding back into higher wholesale prices overall.

Section 3 describes the procedure we use to quantify the extent to which LYA and other generation unit owners are able to raise short-term wholesale electricity prices because of the reduced forward contract obligations that result from the acquisition. We apply the implicit function theorem to the first-order conditions from expected profit-maximizing bidding behavior for a pre-specified quantity of fixed-price forward contract obligations to derive an expression for the change in the generation unit owner's bids into the short-term market as a result of change in its daily fixed-price forward contract obligations. Using an estimate of the likely reduction in LYA's fixed-price forward contract obligation derived from the model in Section 2, we compute the change in its expected profit-maximizing the bid curve for each half-hour period of our pre-acquisition period. The intersection between this counterfactual bid curve and the actual residual demand curve faced by LYA gives an estimate of the counterfactual post-acquisition price

Section 4 presents the results of this calculation for each half hour of our sample period from January 1, 2000 to June 30, 2006. We find a prospective price increase between 15% and 20%, depending on the half-hour period of the day, for all years in our sample as a result of the change in the unilateral expected profit-maximizing bidding behavior of LYA because of our predicted reduction in its fixed-price forward contract obligations as result of the acquisition. These estimated percent price increases from the acquisition justify the concerns raised by the ACCC.

Section 5 attempts to determine whether the price increases from the acquisition implied by the prospective analysis reported in Section 4 actually occurred using half-hourly market-clearing wholesale electricity prices from the states of Victoria, New South Wales, Queensland and South Australia for the period April 1, 2003 to April 1, 2005. Treatment effects estimation procedures are used to determine whether wholesale electricity prices in Victoria and throughout the NEM and were significantly higher following the acquisition. We employ a number of different controls for the underlying time trend in wholesale electricity prices that would have occurred in the absence of the acquisition. For all of these controls we find evidence consistent with the acquisition leading to a statistically significant increase in wholesale electricity prices on the order of the magnitudes found in the prospective analysis reported in Section 4.

Section 6 discusses the implications of these results for desirability of allowing significant vertical integration between electricity generation and retailing. We argue that in an electricity supply industry without explicit retail price regulation, as is the case in the NEM,[4] vertical integration can increase the opportunities for generation unit owners

[4] From January 13, 2002 onwards all retail customers in Victoria had Full Retail Competition (FRC), meaning that they could choose their retail electricity supplier from a number of competitors. There is

to raise wholesale electricity prices and ultimately retail electricity prices. This paper provides both a theoretical rationale for policy concern regarding passive vertical acquisitions in electricity markets and ex ante and ex post empirical verification of the significance of this concern. Although there are a number of caveats associated our analysis and these conclusions, we hope that our paper will cause antitrust and competition authorities to turn a more skeptical eye to vertical combinations between generation and retailing in electricity supply industries where retail prices are not subject to explicit cost-of-service regulation.

2 Passive Vertical Acquisitions and Forward Contracting by Electricity Retailers

To study the impact of a passive vertical acquisition on the contracting behavior of the acquiring electricity retailer, we adapt a model of the interaction of forward and spot market outcomes in electricity from Powell (1993). A key feature of this model is that electricity retailers are risk averse. The magnitude of short-term electricity price volatility in the NEM documented in Wolak (1999) and the level of price bid cap on the wholesale market ($AU 10,000/MWh since April 2002 and $AU 5,000/MWh before that), combined with the fact that virtually all electricity in Australia is sold to final consumers at retail prices that do not vary with half-hourly wholesale prices all imply that some degree of risk aversion by electricity retailers seemed justified. With average wholesale prices of $AU 30/MWh during our pre-acquisition sample period, even a small fraction of the half-hour periods during the year with wholesale prices close to $AU

requirement for retailers to set prices below a maximum retail tariff, but the regulator recognizes the need for allow headroom above the cost-of-service price for retail competition to develop. By June 30, 2005, it is estimated that approximately 45% of Victoria customers had switched retailers.

10,000/MWh will quickly bankrupt a retailer selling at fixed retail price (set to recover this average wholesale price) that does not have virtually all of its final demand covered with fixed-price forward contracts.

We designate retailers with index w and generators with index j (where $-w$ and $-j$ stand for retailers and generators other than w and j respectively). The model focuses on the operation of the market forward and spot markets in a given half-hourly time period, i. We assume that in this time period, the market demand for electricity, QD_i is known with certainty and that consumers pay a regulated price, P. The short-term market or spot price of electricity at time i is p_i. It is determined by the independent system operator (ISO) equating the demand for electricity with the supply as defined by the bid curves submitted by generators for that time period. While the actual settled spot price will depend upon transmission constraints and line losses, we ignore features of actual wholesale electricity markets because they do not impact the general conclusions we draw from our analysis. In addition, incorporating these aspects of wholesale electricity markets considerably complicates our modeling effort. For similar reasons, we assume that generator j has a constant marginal cost, C_j, and fixed capacity, k_j, while retailer w has no production costs (besides wholesale energy costs) or capacity limits, just an inelastic demand, q_{wi}.

Following Powell (1993), the only source of uncertainty in this model is the realized short-term market price, p_i. We assume there is a random shock, ε, to the spot price with compact support (because of the bid price floor and cap in the NEM), expected value of 0 and variance of σ^2.[5] The expected spot price is $E[p_i]$. The forward price of electricity is f_i. We assume: (1) that retailers are risk averse (with mean-variance utility[6]) while generators are risk neutral;[7] and (2) that forward markets are sufficiently liquid so that in any period, $f_i = E[p_i]$. The rationale for this equality is that if there was a forward market premium, energy traders would find it advantageous to sell electricity in the forward market and buy it back in the short-term market, and if there was a forward discount they would find it advantageous to buy electricity in the forward market and sell in the short-term market. These attempts by traders to arbitrage temporal price differences cause the forward price to equal the expected spot price.

We adopt the following standard timing for analyzing the joint contract and spot market equilibrium:

1. Given f_i, retailers and generators choose their contract quantities, QC_{wi} and QC_{ji}.
2. Given QC_{ji}, generators chooses their spot market strategy (i.e., based on their residual demand).

This is the timeline of Newbery (1998), Green (1999) and Powell (1993) for the case where generators are unable to collude in the contract or spot markets. The residual demand of a generator j, $DR_{ji}(p_i)$, is the difference between the market demand QD_i and the aggregate willingness to supply curve of all generation unit owners during period i

[5] We could also assume that retail demand is stochastic. This will add notation but does not fundamentally alter our results.

[6] If profit is π_{wi}, the retailer's utility function takes the form $E[\pi_{wi}] - \frac{1}{2}\lambda Var[\pi_{wi}]$ where λ is a coefficient of absolute risk aversion. This may differ from retailer to retailer but for notational simplicity, as we only focus on a single retailer below, the subscript is omitted.

[7] All we need to assume is that generators are less risk averse than retailers. This is very likely to be an empirically valid assumption as forward contract premia in electricity are rarely negative (Powell, 1993).

besides firm *j*, $SO_j(p_i)$ which is computed using the half-hourly bid supply curves of all other generations unit owners besides firm *j*. Mathematically, $DR_{ji}(p_i) = QD_i - SO_j(p_i)$.

2.1 Stand-alone Generators

We begin by considering the situation where generator *j* is a stand-alone entity and is not owned by any retailer. Generation unit owner *j*'s variable profits (excluding fixed costs) are:

$$\pi_{ji} = \underbrace{(DR_{ji}(p_i) - QC_{ji})(p_i - C_j)}_{j\text{'s Spot Profits}} + \underbrace{(f_i - C_j)QC_{ji}}_{j\text{'s Contract Profits}} \qquad (1)$$

The first term in (1) is the variable profits from short-term market participation and the second term is the variable profits from long-term contract sales. Because the first term in (1) depends on QC_{ji} and is multiplied by the short-term wholesale price, p_i, as discussed in Wolak (2000 and 2003a), the expected profit-maximizing bid of the generation unit owner will depend on QC_{ji}. In this next section, we will use this assumption to compute how generation unit owner *j*'s expected profit-maximizing bid curve will change as a result of having less fixed-price forward contract obligations. As discussed in Wolak (2000 and 2003a), if a generation unit owner has more fixed-price forward contract obligations, it will bid to set lower short-term prices. We assume that the retailer recognizes that its forward contracting decision impacts both the mean and variance of the distribution of short-term prices. Specifically, $\frac{\partial E[p_i]}{\partial QC_{wi}} < 0$ and $\frac{\partial \sigma^2}{\partial QC_{wi}} < 0$; increases in the retailer's forward contract quantity reduces the mean and the variance of short-term prices

We are now in a position to determine a retailer's demand for fixed-price forward contracts. Retailer *w*'s objective function is:

$$U_{wi} = (P - E[p_i])q_{wi} + (E[p_i] - f_i)QC_{wi} - \tfrac{1}{2}\lambda\left(q_{wi} - QC_{wi}\right)^2 \sigma^2 \tag{2}$$

where q_{wi} is the retailer's demand for wholesale electricity to serve its retail customers in period i. The first-order conditions for retail w's optimal forward contract choice is:

$$\frac{\partial U_{wi}}{\partial QC_{wi}} = E[p_i] - f_i - \frac{\partial E[p_i]}{\partial QC_{wi}}\left(q_{wi} - QC_{wi}\right) + \lambda\left(q_{wi} - QC_{wi}\right)\sigma^2 - \tfrac{1}{2}\lambda\left(q_{wi} - QC_{wi}\right)^2 \frac{\partial \sigma^2}{\partial QC_{wi}} = 0 \tag{3}$$

Thus, the retailer's demand for contracts comes from: (a) any discount associated with contracting (the first term); (b) its desire to mitigate the spot market power of generators (the second term); (c) its aversion to risk (the third term); and (d) its desire to reduce short-term price volatility (the last term). Of course, this first motive will not be present, in equilibrium, between the forward market and short-term market because of the actions of traders described above. Thus, (3) can be re-written:

$$\underbrace{f_i - E[p_i]}_{=0} = \underbrace{-\left(\tfrac{\partial E[p_i]}{\partial QC_{wi}} - \lambda\sigma^2 + \tfrac{1}{2}\lambda(q_{wi} - QC_{wi})\tfrac{\partial \sigma^2}{\partial QC_{wi}}\right)}_{>0}(q_{wi} - QC_{wi}) \tag{4}$$

Imposing the forward/spot market arbitrage condition, $f_i = E[p_i]$ implies that, *expected utility maximizing retailers will be fully hedged* (i.e., $QC_{wi} = q_{wi}$). This outcome is consistent with the publicly-stated hedging strategies of the retailers in the NEM at the time of proposed acquisition.

2.2 Post-Acquisition

Consider a situation where a single retailer, *w*, purchases a share, α, of generator *j*. Because this acquisition is passive, generator *j*'s behavior in terms of bidding and contracting will not be controlled by retailer *w*'s preferences. However, retailer *w*'s behavior will change. Specifically, its variable profit function becomes:

$$
\begin{aligned}
&\pi_{wi} + \alpha\pi_{ji} \\
&= (P - p_i)q_{wi} + (p_i - f_i)QC_{wi} + \alpha\left(\left(DR_{ji}(p_i) - QC_{ji}\right)(p_i - C_j) + (f_i - C_j)QC_{ji}\right)
\end{aligned} \tag{5}
$$

These profits have variance of:

$$
\begin{aligned}
Var[\pi_{wi} + \alpha\pi_{ji}] &= (q_{wi} - QC_{wi} + \alpha QC_{ji})^2\sigma^2 \\
&- 2(q_{wi} - QC_{wi} + \alpha QC_{ji})\alpha Cov[p_i, DR_{ji}(p_i)(p_i - C_j)] + \alpha^2 Var[DR_{ji}(p_i)(p_i - C_j)]
\end{aligned} \tag{6}
$$

Solving the optimal forward contracting problem for the retailer can become far more complex under these conditions. Consequently, we adopt here a simplifying assumption, namely, that DR_{ji} is not a random variable from the retailer's perspective and so is independent, in particular, of p_i. This assumption states that generator *j*'s dispatched market load in every period is known or does not vary.

We believe this is a reasonable simplifying assumption to make in the present context. LYA is a baseload generator with a capacity factor over our sample period in excess of 0.90 and for all but one year of our sample its annual capacity factor is above 0.95.[8] Therefore, LYA's dispatched output for a given half-hour period of the day is likely to be predictable with a high degree of precision, so that the wholesale price risk component of the overall profit risk faced by AGL in a half-hour period should swamp the quantity risk associated with LYA's output during that half-hour period. Appendix A presents a comparison of the half-hourly coefficient of variation of the Victoria price and LYA's half-hourly output for each year from January 1, 2000 to June 30, 2003. We find that the coefficient of variation of the half-hourly price is always several times larger than this same variable for LYA's half-hourly quantity, and in many half-hours for each of the years, the price risk (as measured by the coefficient of variation) is more than ten times

[8] The capacity factor of a generation facility is defined as the total amount of megawatt hours (MWh) produced over certain time period divided by the nameplate capacity of the generation unit times the number of hours in that time period. Capacity factors are typically reported on an annual basis.

larger than the quantity risk. Therefore, to simplify our theoretical analysis we assume the quantity risk borne by the retailer having a stake in a generator is zero and although we recognize that in reality this quantity risk is nonzero and it may marginally impact the retailer's demand for fixed-price forward contracts.

Given this, retailer *w*'s demand for contracts is now the solution to:

$$\begin{aligned}\max_{QC_{wi}} &(P - E[p_i])q_{wi} + (E[p_i] - f_i)QC_{wi} \\ &+ \alpha\left(\left(DR_{ji}(p_i) - QC_{ji}\right)(E[p_i] - C_j) + (f_i - C_j)QC_{ji}\right) \\ &- \tfrac{1}{2}\lambda\left(q_{wi} - QC_{wi} - \alpha\left(DR_{ji}(p_i) - QC_{ji}\right)\right)^2 \sigma^2\end{aligned} \tag{7}$$

Note that, by the envelope theorem, there the impact on *j*'s profits through the spot price effect does not factor in *w*'s contracting choice. The first-order condition is:

$$\begin{aligned}&\underbrace{f_i - E[p_i]}_{=0} \\ &= -\left(\tfrac{\partial E[p_i]}{\partial QC_{wi}} - \lambda\sigma^2 + \tfrac{1}{2}\lambda\left(q_{wi} - QC_{wi} - \alpha\left(DR_{ji}(p_i) - QC_{ji}\right)\right)\tfrac{\partial\sigma^2}{\partial QC_{wi}}\right)\left(q_{wi} - QC_{wi} - \alpha\left(DR_{ji}(p_i) - QC_{ji}\right)\right)\end{aligned} \tag{8}$$

Notice that there are two impacts of the acquisition on retailer *w*'s demand for contracts. First, because some of those contracts are held by generator *j*, payments on those contracts are partially returned. However, given the competitive contract market, this has no net effect on the quantity chosen by retailer *w*. On the other hand, retailer *w* is now partially hedged; reducing the variance of their profits. The ownership stake is a perfect substitute for explicit contracts. Indeed, from (8), it can be seen that:

$$QC_{wi} = q_{wi} - \alpha\left(DR_{ji}(p_i) - QC_{ji}\right) \tag{9}$$

Retailer *w* is fully hedged but does not necessarily use contracts to achieve this. Instead, if generator *j* is not fully hedged (i.e., if $DR_{ji}(p_i) > QC_{ji}$), the demand for contracts will decrease.

Note, however, that the level of hedging by other retailers will be unchanged. They will continue to be fully hedged. Thus, the total amount of hedge contracts in the industry will fall by:

$$\Delta_i \equiv \alpha\left(DR_{ji}(p_i) - QC_{ji}\right) \tag{10}$$

This is the level of the *natural hedge* that retailer *j* achieves from the acquisition.

This illustrates the first-order behavioral impact of the acquisition; that is, passive acquisitions change the behavior of the acquirers even if they have no explicit ability to impact the behavior of the acquired firm or other firms. However, the anti-competitive effect comes from what this change means for wholesale prices. In particular, if the reduction in the quantity of hedge contracts sold by a generation unit owner caused by the reduction in the retailer's demand for contracts leads the generation unit owner to bid to set higher prices, this should result in higher prices after the acquisition. In the next section we describe our methodology for calculating prospective changes in wholesale prices based on counterfactual changes in the quantity of fixed-price forward contracts sold by baseload generation unit owners.

2.3 Relationship to the Literature

It is worthwhile at this point to relate the above model to the literature on vertical integration. That literature, without exception (to our knowledge), considers such integration as active. In so doing, the anti-competitive harm from vertical integration comes from the potential softening of downstream price competition or bargaining effects that lead to foreclosure (Hart and Tirole, 1990; Rey and Tirole, 2007; de Fontenay and Gans, 2005). Here, however, the main impact of integration is to facilitate a reduction in the effectiveness of forward contract markets in constraining generator market power in the short-term wholesale market. This arises because of its passive nature rather than a change in the behavior of the acquired firm towards the acquirer's rivals.

O'Brien and Salop (2000) do illustrate how passive acquisitions can lead to anti-competitive effects in horizontal mergers. Basically, while a (passive) acquisition does not alter the pricing behavior of the acquired firm it does alter the acquirer's incentives to price aggressively as they now internalize the effect of this on the profits they accrue from their subsidiary. Here, we model passive acquisition in much the same way; however, the internalization effect is not present as the acquirer is in a different vertical segment to the acquired firm. Instead, the acquirer receives something valuable from the acquisition – a natural hedge – and this causes it to substitute away from explicit contracting with generators. In electricity, that change has an impact on prices. As such, the model here is really one specific to the electricity industry and to industries where forward contracts play a role in constraining market power. Nonetheless, it does reinforce the O'Brien and Salop insight that passivity does not provide an unequivocal defense against accusations of potential anti-competitive harm.

2.4 Calculating the Natural Hedge

To begin, it should be noted that LYA's registered capacity is 2000 MW, however, their average half-hourly capacity utilization has historically on the order of 1900 MW. In addition, in public disclosures the future owners of LYA claimed that they would aim to hedge 75 percent of this half-hourly output. This suggests that the level of the natural hedge AGL would gain would be α x 0.25 x 1900 MW = α475 MW or 166.25 MW at an α = 0.35 ownership stake.

In actuality, however, this type of 'back of the envelope' calculation misses an important effect: that if the natural hedge causes AGL to reduce its contracting with LYA (as is possible), this will raise LYA's uncontracted position which, in turn, raises AGL's natural hedge. It is relatively straightforward to resolving the circularity. Suppose that if AGL's natural hedge is NH, it will plan to reduce its contract cover with LYA by γNH (where $0 < \gamma < 1$). Now suppose that LYA's uncontracted capacity is currently 475 MW (consistent with a 75% contracted strategy). Then the natural hedge is the implicit solution to the equation:

$$0.35\,(475 + \gamma \mathrm{NH}) = \mathrm{NH}$$

or

$$\mathrm{NH} = 166.25/(1-0.35\gamma)$$

Notice that this NH ranges from approximately 166 MW when $\gamma = 0$ to 256 MW when $\gamma = 1$. The lower bound corresponds to a situation where LYA's contract position remains unchanged post-acquisition whereas the upper bound corresponds to a situation where it bears the full impact of any reduction in demand from AGL. The reality is likely to be some intermediate value.

Given the range of possible intended and likely levels of the natural hedge, we use the above calculations as an indicator of the order of magnitude of potential reductions in contract positions of generators post acquisition. First, even if AGL were to reduce its contract cover by NH, it is not certain that this reduction would translate fully into the reduction in contract positions held by baseload generators. Speculators and generators in other states may choose to unwind their contract holdings or retailers may choose to expand their positions. However, these are extremely risky strategies for these market participants to pursue given the price effects of the acquisition that we estimate. Further evidence of the perceived risk of this strategy is that generation unit owners from neighboring states are reluctant to sell fixed-price forward contracts that clear against prices in states where they do not own generation capacity. Second, it is not clear what the distribution of reduced contract holdings will be across generators. It is unlikely that the entire reduction would be with LYA although some proportionate reduction across baseload generators is more plausible. Nonetheless, we argue that an analysis focusing on a single generator is indicative of the potential effects that may arise as a result of the acquisition studied here and may underestimate the magnitude of the price increase for the reasons discussed in Section 4.

3 Ex Ante Estimation the Spot Price Impact of Acquisition

The model in the previous section demonstrates that a passive vertical acquisition of a share of a baseload generation facility is likely to cause the acquiring retailer to reduce its demand for fixed-price forward contracts by between 166 MW to 256 MW. In this section, we use the model of expected profit-maximizing bidding behavior of a supplier in a wholesale electricity market with fixed-price forward contract obligations developed in Wolak (2000 and 2003a) to derive an estimate of the change in a supplier's daily bidding behavior as a result of a reduction in its fixed-price forward contract obligations.

For each day during the period January 1, 2000 to June 30, 2003 we compute 48 counterfactual half-hourly bids curves for LYA associated with a lower level of fixed-price forward contract obligations for that day. We then compute the counterfactual half-hourly market price and quantity of electricity sold by LYA for this reduced level of fixed-price forward contract obligations by intersecting the actual half-hourly residual demand curve faced by LYA with its half-hourly counterfactual bid curve. The *ex ante* predicted impact of the acquisition is the percent difference between the annual mean of the counterfactual half-hourly price and the annual mean of actual half-hourly price.

We first describe how the assumption of expected profit-maximizing bidding behavior for a given level of fixed-price forward contract obligations is used to derive the change in bidding behavior that results from a change the supplier's vector of daily fixed-price forward contract obligations. We then describe how to compute the counterfactual market outcome implied by the change in bidding behavior implied by supplier's lower level of fixed-price forward contract obligations. Finally, we present a comparison of the mean counterfactual and mean actual prices for each half-hour of the day for the period January 1, 2000 to June 30, 2003.

3.1 Computing Counterfactual Bids from Expected Profit-Maximizing Bidding Behavior

Each day generation unit owners in the National Electricity Market (NEM) of Australia submit their willingness to supply electricity from the generation units they own for all 48 half-hour periods of the following day to the National Electricity Market Management Company (NEMMCO). These bid functions are weakly increasing step functions giving a supplier's willingness to provide electricity from its generation units in that half-hour as a function of the market price. The NEM market rules require that the system operator choose which units operate and how much they operate by minimizing the as-bid costs of meeting demand at each location in the transmission network taking into account the capacity of the national transmission network and the impact of transmission losses in moving the electricity from where it is produced to the where it is ultimately consumed. These generation unit-level bid functions and dispatch levels are publicly available.[9]

The NEM chooses the least as-bid cost of meeting the demand for electricity at all locations in the transmission network and sets prices for the four states of southeastern Australia in the NEM--Victoria (VIC), New South Wales (NSW), Queensland (QLD) and South Australia (SA)--that account for transmission losses.[10] If there are no constraints in the transmission network, these prices differ only because of the transmission losses associated with moving power between the four states. For example, if electricity is flowing from Victoria to the South Australia and there are no transmission constraints between these two regions, the price in Victoria will be less than the price in South Australia because all energy produced in Victoria is being paid the same price, but the amount flowing from Victoria to South Australia incurs transmission losses before it arrives in the South Australia. Transmission losses across regions are typically less than 5 percent, meaning that price differences between regions less than 5% are very likely to reflect only transmission losses.

More substantial price differences across regions are caused by constraints in the transmission network which prevent generation units with lower priced bids from being

9 All bid and market outcome data is available the day after the market operates at http://www.nemmco.com.au.

10 Transmission losses account for the fact that a supplier injecting 1 MWh of energy at its location in the transmission network will result in less than 1 MWh of energy arriving at the location in the transmission network where it is consumed. As a general rule, the greater the distance between the location the energy is injected and the point at which it is consumed, the greater are the transmission losses. Another factor impacting the magnitude of transmission losses is whether a generation unit is located in a generation-rich or generation-poor region of the transmission network. Those units located in more generation-rich regions experience greater transmission losses. The NEM accounts for these transmission losses by inflating the bid prices of suppliers located far away from the point where the energy is being consumed and those located in generation rich areas to reflect the fact that 1 MWh of energy injected by these units will result in less than 1 MWh delivered at the point this energy is withdrawn.

dispatched because of their location and cause units with higher bid prices to be dispatched because of their location. This occurs when there is insufficient transmission capacity across the states of Australia to transfer all of the lower-priced energy from one state into another state. For example, even if after controlling for the impact of transmission losses, an additional 100 MWh of energy from Victoria would be cheaper to use in South Australia than a 100 MWh of additional energy produced from units within South Australia, NEMMCO may not be able to use all of this 100 MWh from Victoria if the amount of available transmission capacity between these two regions is less than 100 MW. Under these circumstances, NEMMCO will have to reduce the price in Victoria to limit the amount of output taken from generation units there and increase the price in South Australia to increase amount of energy supplied from generation units in South Australia. Although the impact of these transmission constraints can be incorporated into our model of expected profit-maximizing bidding behavior, in order to take a conservative approach to assessing impact of the acquisition on market prices, in computing the counterfactual prices we assume that bids from all generation units in all four Australian states compete with bids from LYA regardless of the amount of unused capacity in the transmission network.

We now discuss our model of expected profit-maximizing behavior in a bid-based wholesale electricity market that forms the basis for computing our counterfactual bids for LYA. In the NEM, each trading day is composed of 48 half-hour long load periods. The trading day begins with the half-hour from 4:00 am to 4:30 am and ends with the half-hour from 3:30 am to 4:00 am following day. The day before the start of the trading day, suppliers submit up to ten bid prices and up to 480 half-hourly quantity increments for each generation unit they own. An electricity generation plant is typically composed of multiple generation units or gensets. For example, Loy Yang is a 2000 MW facility composed of four generation units each with 500 MW of capacity. Consequently, LYA submits bid curves of this form for each half-hour of the day for each of its four generation units. This implies that LYA sets up to 40 bid prices and 1920 half-hourly quantity increments each trading day.

We require the following notation to present our methodology for computing the change in LYA's bidding behavior as a result of change in its forward contract obligations:

- QD_i: Total market demand in load period i, (i = 1, ..., 48)
- $SO_i(p)$: Amount of energy all other firms besides LYA are willing to supply to the market in load period i at price p
- $DR_i(p) = QD_i - SO_i(p)$: Residual demand faced by LYA in load period i (specifying the demand faced by LYA at price p)
- QC_i: Contract quantity for load period i for LYA
- PC_i: Quantity-weighted average (over all hedge contracts signed for that load period and day) contract price for load period i for LYA.
- $\pi_i(p)$: Variable profits of LYA at price p, in load period i
- $SL_{ij}(p,\Theta)$: Bid function of genset j owned LYA for load period i giving the amount it is willing to supply from this unit as a function of the price p and vector of daily bid parameters Θ
- Q_{ij} = total amount produced from unit j during load period i
- $Q_j = (Q_{1j}, Q_{2j}, ..., Q_{48j})$ = vector of daily outputs from genset j
- C_j = the variable cost of producing output from genset j
- $SL_i(p,\Theta) = \sum_{j=1}^{J} SL_{ij}(p,\Theta)$ = total quantity bid in by LYA at price p during load period i.

Let ε_i equal the shock to LYA's residual demand function in load period i (i = 1,..., 48). Re-write this residual demand function in load period i accounting for this demand shock as $DR_i(p,\varepsilon_i)$. The residual demand shock reflects uncertainty in both total system demand and the offers of all other suppliers at the time LYA submits its bids to the wholesale market the day before the trading day. Collect these 48 half-hourly demand shocks into the vector $\varepsilon = (\varepsilon_1, \varepsilon_2, ..., \varepsilon_{48})$.

Define $\Theta = (p_{11}, ..., p_{JK}, q_{1,11}, ..., q_{1,JK}, q_{2,11}, ..., q_{2,JK}, ..., q_{48,11}, ..., q_{48,JK})$ as the vector of daily bid prices and quantities submitted by LYA. There are K increments for each of the J gensets owned by LYA. The NEM rules require a single bid price, p_{jk}, to be set for each of the k = 1,..., K bid increments for each of the j = 1,..., J gensets owned by LYA for the entire day. However, the quantity, q_{ijk} made available to produce electricity in load period i from each of the k = 1,..., K bid increments for the j = 1,..., J gensets owned by LYA can vary across the i = 1,..., 48 load periods throughout the day. The NEM rules specify the value of K as 10, so the dimension of Θ is $10J + 48\times10J$. LYA owns four gensets so $J = 4$.[11]

The market clearing price p for load period i is determined by solving for the smallest price such that the equation $SL_i(p,\Theta) = DR_i(p,\varepsilon_i)$ holds, which we denote by $p_i(\varepsilon_i,\Theta)$. This price depends on both realization of ε_i and the value of Θ, because it is determined by the intersection of the realized residual demand curve and the bid curve of LYA for load period i. Note that, $SL_{ij}(p(\varepsilon_i,\Theta),\Theta) = Q_{ij}$, meaning that the amount produced by genset j in load period i is equal to the quantity bid by genset j in load period i at the market price during period i.

In terms of this notation, the realized variable profit for LYA given the vector of bid parameters for the day, Θ, and the vector of half-hourly forward contract quantities for the day $QC = (QC_1, QC_2, ..., QC_{48})$ is:

[11] Figure 4.1 of Wolak (2003a) provides a graphical illustration of how the constraints on price and quantity bids required by the NEM rules impact the ability of suppliers to alter their half-hourly supply curves across the trading day.

$$\Pi(\Theta,\varepsilon)=\sum_{i=1}^{48}\left(DR_i(p_i(\varepsilon_i,\Theta))p_i(\varepsilon_i,\Theta)-(p_i(\varepsilon_i,\Theta)-PC_i)QC_i-\sum_{j=1}^{J}C_jSL_{ij}(p_i(\varepsilon_i,\Theta),\Theta)\right) \quad (11)$$

To economize on notation in what follows, we abbreviate $p_i(\varepsilon_i,\Theta)$ as p_i, even though it depends on both ε_i and Θ. LYA's best-reply bidding strategy is the vector, Θ, that maximizes the expected value of $\Pi(\Theta,\varepsilon)$ (taken with respect to the joint density of ε) subject to the constraints that all bid quantity increments, q_{ijk}, must be greater than or equal to zero for all load periods, *i*, gensets, *j*, and bid increments, *k*, and that for each genset the sum of bid quantity increments during each load period is less than the capacity, CAP_j, of genset *j*. All daily price increments must be greater than −\$9,9999.99/MWh and less than \$5,000/MWh before April 1, 2002 and less than \$10,000/MWH after April 1, 2002, where all dollar magnitudes are in Australian dollars (\$AU). All of these constraints can be written as a linear combination of the elements of Θ.

In terms of the above notation, LYA's expected profit-maximizing bidding strategy can be written as:

$$\max_{\Theta} E_{\varepsilon}\left[\Pi_d(\Theta,\varepsilon)\right] \text{ subject to } b_u \geq R\Theta \geq b_l \quad (12)$$

where $E_\varepsilon[.]$ is the expectation with respect to the joint distribution of ε. The first-order conditions for this optimization problem are:

$$\frac{\partial E_{\varepsilon}\left[\Pi_d(\Theta,\varepsilon)\right]}{\partial\Theta}=R'\lambda-R'\mu \quad (13)$$

$$R\Theta \geq b_l\,,\; b_u \geq R\Theta \quad (14)$$

$$\text{if } (R\Theta-b_l)_k>0, \text{ then } \mu_k=0 \text{ and } (R\Theta-b_u)_k<0, \text{ then } \lambda_k=0 \quad (15)$$

where $(X)_k$ is the k^{th} element of the vector X and μ_k and λ_k are the k^{th} elements of the vectors of Kuhn-Tucker multipliers, μ and λ.

If all of the inequality constraints associated with an element of Θ, say p_{jk}, are slack, then the first-order condition reduces to:

$$\frac{\partial E_{\varepsilon}\left[\Pi(\Theta,\varepsilon)\right]}{\partial p_{jk}}=0 \tag{16}$$

For out sample period, all of the daily bid prices associated with LYA's gensets over the sample period lie in the interior of the interval (-9,999.99,5,000) before April 1, 2002 and the interval (-9999.99,10,000) after April 1, 2002, which implies that all bid prices satisfy the first-order conditions given in (16) for all days, gensets, j, and bid increments, k. For this reason, we can use the first-order conditions for daily expected profit maximization with respect to LYA's choice of the vector of daily bid prices to compute the change in its bid prices as a result of a change in its vector of daily forward contract quantities, QC.

LYA operates 4 units during sample period and each of them has bid 10 increments, which implies 40 first-order conditions hold as equalities for each day of our sample. These first-order conditions imply that the daily bid price vector is a function of the vector of daily forward contract quantities, QC. Using the implicit function theorem, we can then compute the matrix of partial derivatives of the vector of daily bid prices with respect to QC for each day. Multiplying this matrix by the change in QC that results from the acquisition yields our predicted change in the vector of daily bid prices.

It is not possible to use the first-order conditions with respect to the bid quantity increments to compute the change in the vector of daily quantity bids that results from the acquisition because for a number of load periods throughout the day for virtually all days on our sample several bid quantity increments are zero and/or the sum of the ten bid quantity increments for that load period is equal to the capacity of the genset. As noted in Wolak (2004), when either of these conditions holds for a bid quantity increment, the best that can one can do is infer the sign of the partial derivative of the daily expected profit function with respect to this bid quantity increment. Thus, we are unable to apply the implicit function theorem to derive the expected profit-maximizing bid quantity response to a change in the value of *QC* for LYA. Therefore, we compute LYA's 48 counterfactual daily bid curves that result from a lower value of *QC* under the assumption that all of its half-hourly bid quantity increments for the day do not change. Only the vector of daily bid prices are allowed to change as a result of the hypothesized change in *QC*.

Although this assumption is necessitated by the fact that the Kuhn-Tucker multipliers in (15) are not observed, we do not believe it significantly impacts our counterfactual market price results. Because LYA has very low variable costs relative to the vast majority of half-hourly market-clearing prices, it operates close to capacity most hours of the year as noted earlier. Consequently, the half-hourly bid quantity choices for each of the four units owned by LYA are often corner solutions with nonzero Kuhn-Tucker multipliers, so that small changes in the daily bid prices for these units are unlikely to cause these corner solutions in the bid quantities to become interior solutions, although the values of the associated Kuhn-Tucker multipliers are likely to change. For these reasons, we believe that for many of the bid increments in a given load period, the expected profit-maximizing bid quantity response to a change in *QC* would be small. It is also important to note that a change in a bid quantity increment for load period i only impacts the supplier's expected profits in that load period, but a change in a bid price impacts expected the supplier's expected profits in all 48 load periods of the day.

Consequently, we would expect any bid price increment to be must more sensitive to changes in QC that any bid quantity increment. We hope to examine the sensitivity of our counterfactual pricing results to the assumption of fixed bid quantity increments in future work.

To make the dependence of QC explicit, we re-write the (40x1) vector first-order conditions for daily expected profit-maximization with respect to Firm LYA's choice of the daily bid price increments as:

$$E_{\varepsilon}\left[\frac{\partial \Pi(\Theta, QC, \varepsilon)}{\partial \theta}\right] = 0, \tag{17}$$

where the vector θ is composed of the 40 bid price increments for the day (4 gensets times 10 bid increments per genset) for the gensets owned by LYA and Θ is vector of bid price and quantity increments for the day. In terms of previously defined notation: $\theta = (p_{11}, ..., p_{JK})'$. The variable QC is the value of the vector of half-hourly forward contract obligations for that day.

Equation (17) and the second-order conditions for expected profit-maximizing bidding behavior imply that the optimal bid price increment for genset s and increment t for that day can be written as $p^*_{st}(QC)$ for all 40 daily bid price increments. Because the NEM rules require bid prices to be fixed for the entire day, each bid price potentially depends on all 48 elements of QC. Let $\theta^*(QC)$ denote the entire (40x1) vector of these optimal daily bid prices. We can write equation (17) in terms of this new notation as:

$$E_{\varepsilon}\left[\frac{\partial \Pi(\theta^*(QC), QC, \varepsilon)}{\partial \theta}\right] = 0. \tag{18}$$

Applying the implicit function theorem to (18), we can compute the 40x48 matrix of partial derivatives of the elements of $\theta^*(QC)$ with respect to the elements of QC as:

$$\frac{\partial\theta^*(QC)}{\partial QC} = \left[E_\varepsilon\left[-\frac{\partial^2\Pi(\theta^*(QC),QC,\varepsilon)}{\partial\theta\partial\theta'}\right]\right]^{-1}\left[E_\varepsilon\left[\frac{\partial^2\Pi(\theta^*(QC),QC,\varepsilon)}{\partial\theta\partial QC'}\right]\right], \quad (19)$$

where we have switched the order of integration and differentiation in computing the matrices of partial derivatives of (18) with respect to θ and QC, respectively. The matrix $E_\varepsilon\left[-\frac{\partial^2\Pi(\theta^*(QC),QC,\varepsilon)}{\partial\theta\partial\theta'}\right]$ has (m, n) element $E_\varepsilon\left[-\frac{\partial^2\Pi(\theta^*(QC),QC,\varepsilon)}{\partial\theta_m\partial\theta_n}\right]$ for m = 1,..., 40 and n = 1,..., 40. The matrix $E_\varepsilon\left[\frac{\partial^2\Pi(\theta^*(QC),QC,\varepsilon)}{\partial\theta\partial QC'}\right]$ has (r, s) element $E_\varepsilon\left[\frac{\partial^2\Pi(\theta^*(QC),QC,\varepsilon)}{\partial\theta_r\partial QC_s}\right]$ for r = 1,..., 40 and s = 1,..., 48. This implies that $\frac{\partial\theta^*(QC)}{\partial QC}$ is (40 x 48) matrix.

Our goal is to obtain a consistent estimate of $\frac{\partial\theta^*(QC)}{\partial QC}$ for each day during our sample period. To do this we compute the estimates of the two matrices in equation (19) using averages of the sample analogues of these magnitudes for B realizations from the distribution of ε. A single element of the vector $\frac{\partial\Pi(\theta^*(QC),QC,\varepsilon(b))}{\partial\theta}$ for residual demand uncertainty realization $\varepsilon(b)$ for the price moment restriction for increment t of genset s is:

$$\frac{\partial\Pi(\Theta,QC,\varepsilon(b))}{\partial p_{st}} = \sum_{i=1}^{48}\begin{pmatrix} DR_i'(p_i(\varepsilon_i(b),\Theta),\varepsilon_i(b))p_i(\varepsilon_i(b),\Theta) \\ +DR_i(p_i(\varepsilon_i(b),\Theta),\varepsilon_i(b)) - QC_i - \sum_{j=1}^{J} C_j\left(\frac{\partial SL_{ij}(p_i(\varepsilon_i(b),\Theta),\Theta)}{\partial p_i}\right) \end{pmatrix}\frac{\partial p_i(\varepsilon_i(b),\Theta)}{\partial p_{st}} - \sum_{j=1}^{J} C_j \frac{\partial SL_{ij}(p_i(\varepsilon_i(b),\Theta),\Theta)}{\partial p_{st}} \quad (20)$$

Note that we are implicitly assuming that the realized profit function is differentiable in the LYP's bid prices and the market-clearing prices. Following the description of our procedure for computing the post-acquisition market-clearing prices, we describe how we smooth the realized profit function to obtain a differentiable realized profit function.

Let A(b) equal the (40x40) matrix that is the sample analogue of the first term in equation (19) for residual demand uncertainty realization $\varepsilon(b)$. The matrix A(b) has representative element $-\frac{\partial^2\Pi(\Theta,QC,\varepsilon(b))}{\partial p_{st}\partial p_{rv}}$, where :

$$\begin{aligned}
&\frac{\partial^2\Pi(\Theta,QC,\varepsilon(b))}{\partial p_{st}\partial p_{rv}} \\
&= \sum_{i=1}^{48}\begin{pmatrix} 2DR_i'(p_i(\varepsilon_i(b),\Theta),\varepsilon_i(b)) + DR_i''(p_i(\varepsilon_i(b),\Theta),\varepsilon_i(b))\,p_i(\varepsilon_i(b),\Theta) \\ -\sum_{j=1}^{J} C_j\left(\frac{\partial^2 SL_{ij}(p_i(\varepsilon_i(b),\Theta),\Theta)}{\partial p_i^2}\right) \end{pmatrix}\frac{\partial p_i}{\partial p_{rv}}\frac{\partial p_i}{\partial p_{st}} - \sum_{j=1}^{J} C_j\left(\frac{\partial^2 SL_{ij}(p_i(\varepsilon_i(b),\Theta),\Theta)}{\partial p_i\partial p_{rv}}\right)\frac{\partial p_i}{\partial p_{st}} \quad (21) \\
&+\begin{pmatrix} DR_i'(p_i(\varepsilon_i(b),\Theta),\varepsilon_i(b))\,p_i(\varepsilon_i(b),\Theta) + DR_i(p_i(\varepsilon_i(b),\Theta),\varepsilon_i) - QC_i \\ -\sum_{j=1}^{J} C_j\left(\frac{\partial SL_{ij}(p_i(\varepsilon_i(b),\Theta),\Theta)}{\partial p_i}\right) \end{pmatrix}\frac{\partial^2 p_i}{\partial p_{st}\partial p_{rv}} - \sum_{j=1}^{J} C_j\left(\frac{\partial^2 SL_{ij}(p_i(\varepsilon_i(b),\Theta),\Theta)}{\partial p_{st}\partial p_{rv}}\right) \\
&-\sum_{j=1}^{J} C_j\left(\frac{\partial^2 SL_{ij}(p_i(\varepsilon_i(b),\Theta),\Theta)}{\partial p_{st}\partial p_i}\right)\frac{\partial p_i}{\partial p_{rv}}.
\end{aligned}$$

Let C(b) equal the (40x48) matrix that is sample analogue of second term of equation (19) for residual demand uncertainty realization $\varepsilon(b)$. The matrix C(b) has representative element:

$$\frac{\partial^2\Pi(\Theta,QC,\varepsilon(b))}{\partial p_{st}\partial QC_h} = -\frac{\partial p_h}{\partial p_{st}} \quad (22)$$

We take *B* draws from the distribution of residual demand uncertainty for each day in our sample according to the following algorithm. One draw is the actual residual demand realization for all 48 half-hours of that day and the remaining draws are the 48 half-hourly residual demand realizations for *B*–1 days from the previous, current, and following month with a daily peak demand closest to the actual peak demand for that day. For the first month of the sample, we use the first three months of sample and for the last month of the sample, we use the last three months of the sample. We experimented with other algorithms for constructing the distribution of daily residual demand curves faced by LYA and found that our results did not appreciably change as long as the value of *B* was chosen to be sufficiently large.

The sample analogues for the matrices in (19) are computed as:

$$SM(A,B) = \tfrac{1}{B}\sum_{b=1}^{B} A(b) \text{ and } SM(C,B) = \tfrac{1}{B}\sum_{b=1}^{B} C(b) \tag{23}$$

where $SM(X,B)$ is the sample mean of $X(b)$ for *B* draws from the distribution of residual demand uncertainty. Let $P(\theta, QC, B)$ equal the estimate of $\frac{\partial \theta^*(QC)}{\partial QC}$ for *B* draws:

$$P(\theta, QC, B) = \left[SM(A,B)\right]^{-1}\left[SM(C,B)\right] \tag{24}$$

Because of the existence of the bid price floor of -9999.99 and the bid price cap of 5000 or 10,000, all of the realizations of $A(b)$ and $C(b)$ are bounded random matrices. Therefore, under suitable regularity conditions, as $B \to \infty$, both $SM(A,B)$ and $SM(C,\mathrm{B})$ tend to their population values given in equation (19) by an appropriate law of large numbers. In this sense, we obtain a consistent estimate of $\frac{\partial \theta^*(QC)}{\partial QC}$. Multiplying $P(\theta, QC, B)$ by our hypothesized change in the vector of daily forward contract quantities, ΔQC, yields the our estimated change in the value of the vector of daily bid prices, $\Delta\theta$:

$$\Delta\theta = \left[P(\theta, QC, B)\right]\Delta QC \tag{25}$$

The counterfactual daily bid price vector then becomes:

$$\theta^c = \theta + \Delta\theta \tag{26}$$

We then compute Θ^c, the counterfactual daily bid price and quantity vector by replacing θ with θ^c in Θ, with no change in the bid quantity increments. The counterfactual market price for load period *i* that results from a ΔQC change in QC is the price at intersection of the actual residual demand realization for that load period with the counterfactual bid curve for that load period. Mathematically, this counterfactual price is equal to the smallest value of p that solves:

$$SL_i(p,\Theta^c) = DR_i(p,\varepsilon_i), \tag{27}$$

which we denote $p_i(\varepsilon_i,\Theta^c)$.

As noted above, this procedure requires the realized profit function for LYP to be differentiable in the bid prices and market-clearing prices. We accomplish by using the flexible smoothing procedure described in Wolak (2003a and 2004) to construct a differentiable approximation to $\Pi(\Theta,C,\varepsilon)$. Let $\Pi^h(\Theta,C,\varepsilon)$ equal the differentiable version of LYA's daily variable profit function indexed by the smoothing parameter h. When h = 0, there is no approximation because, $\Pi^h(\Theta,C,\varepsilon)=\Pi(\Theta,C,\varepsilon)$. Using this smooth, differentiable approximation to $\Pi(\Theta,C,\varepsilon)$, the order of integration and differentiation can be switched in the first-order conditions for expected profit-maximizing bidding behavior to produce the equality:

$$\left.\frac{\partial E_\varepsilon\left[\Pi^h(\Theta,C,\varepsilon)\right]}{\partial\Theta}\right|_{h=0} = E_\varepsilon\left[\frac{\partial\Pi^h(\Theta,C,\varepsilon)}{\partial\Theta}\right]_{h=0} \tag{28}$$

This smooth, differential version of $\Pi^h(\Theta,C,\varepsilon)$ takes the following form. A differentiable residual demand function facing LYA that allows the residual demand uncertainty to impact both the market demand and the bid curves of other suppliers is:

$$DR_i^h(p,\varepsilon_i) = Q_i(\varepsilon_i) - SO_i^h(p,\varepsilon_i) \tag{29}$$

where the smoothed aggregate bid supply function of all other market participants besides LYA in load period i is equal to:

$$SO_i^h(p,\varepsilon) = \sum_{n=1}^{N}\sum_{k=1}^{10} qo_{ink}\Phi\left((p - po_{nk})/h\right) \tag{30}$$

qo_{ink} is the k^{th} bid increment of genset n in load period i and po_{nk} is bid price for increment k of genset n, where N is the total number of gensets in the market excluding those owned by LYA. Because the bid curves of other market participants change daily, the values of qo_{ink} and po_{nk} change on a daily basis. $\Phi(t)$ is the standard normal cumulative distribution function and h is the smoothing parameter. This parameterization of $SO_i^h(p)$ smoothes the corners on the step-function bid curves of all other market participants create a supply function that is differentiable in p for all positive values of h.

This smoothing procedure results in the following expression for derivative of LYA's residual demand function with respect to the market price in load period i:

$$\frac{dDR_i^h(p,\varepsilon)}{dp} = -\tfrac{1}{h}\sum_{n=1}^{N}\sum_{k=1}^{10} qo_{ink}\varphi\left((p - po_{nk})/h\right) \tag{31}$$

where $\varphi(t)$ is the standard normal density function.

This same procedure is followed to make $SL_{ij}(p,\Theta)$ differentiable with respect to both the market price, p, and Θ, the price and quantity bid parameters that make up LYA's willingness-to-supply function. Define $SL_{ij}^h(p,\Theta)$ as:

$$SL_{ij}^h(p,\Theta) = \sum_{k=1}^{10} q_{ijk}\Phi\left((p - p_{jk})/h\right) \tag{32}$$

which implies:

$$SL_i^h(p,\Theta) = \sum_{j=1}^{J}\sum_{k=1}^{10} q_{ijk}\Phi\left((p - p_{jk})/h\right) \tag{33}$$

where it is understood that q_{ijk} and p_{jk} change on a daily basis. This definition of $SL_{ij}(p,\Theta)$ yields the following partial derivatives:

$$\frac{\partial SL_{ij}}{\partial q_{ijk}} = \Phi\left((p - p_{jk})/h\right) \tag{34}$$

$$\frac{\partial SL_{ij}}{\partial p} = \tfrac{1}{h}\sum_{k=1}^{10} q_{ijk}\varphi\left((p - p_{jk})/h\right) \tag{35}$$

$$\frac{\partial SL_{ij}}{\partial p_{jk}} = -\tfrac{1}{h} q_{ijk}\varphi\left((p - p_{jk})/h\right) \tag{36}$$

$$\frac{\partial^2 SL_{ij}}{\partial p_{jk}\partial p} = \tfrac{1}{h^2} q_{ijk}\varphi\left((p - p_{jk})/h\right)\left((p - p_{jk})/h\right) \tag{37}$$

Appendix B computes expressions for the all of the remaining partial derivatives that enter (21) and (22) in terms of the smoothed residual demand curves and LYA bid curves. Proving consistency of the smoothed profit-function version of this procedure for estimating $\frac{\partial \theta^*(QC)}{\partial QC}$ is only slightly complicated by the fact that we must let $h \to 0$ as $B \to \infty$. Because we are only concerned with consistent estimation of the two elements of equation (19), by requiring h to tend to zero sufficiently slow such that $h^2 B \to \infty$ as B $\to\infty$ is sufficient for the smoothed version of $SM(A,B)$ and $SM(C,B)$ tend to their population values given in equation (19), so that we obtain a consistent estimate of $\frac{\partial \theta^*(QC)}{\partial QC}$.

4 Empirical Results

This section first describes the details of the implementation of our methodology for computing counterfactual, post-acquisition wholesale prices for each half-hour over our sample period. We discuss the likely sensitivity of our results to certain modeling assumptions that simplify our analysis. Finally, we present our empirical results that show sizeable and statistically significant differences between the annual half-hourly mean of actual prices and the counterfactual prices for virtually all half-hour periods of the day for all the years in our sample.

4.1 Implementing the Empirical Methodology

For each day of our sample period from January 1, 2000 to June 30, 2003 we use the half-hourly bid, generation unit-level production, forward contract quantities, and market-clearing price data to compute the smoothed values of A(b) and C(b) for a fixed value of *h*. We end our sample on June 30, 2003 because this is the approximate date when public discussions of the acquisition began. To guard against our results being impacted by changes in bidding behavior due to the ongoing analysis of the acquisition, we stopped our sample at this date.

In order to be as conservative as possible in estimating the ability of LYA to raise wholesale electricity prices, we assume that LYP competes in the largest geographic market possible, the entire National Electricity Market (NEM) composed of Queensland, New South Wales, Victoria and South Australia. This means that we include the bid prices and quantity increment bids of all generation units (besides those owned by LYA) in these four states in residual demand curve faced by LYA. This assumption is equivalent to assuming infinite transmission capacity between the four states.

The variable cost of each genset owned by LYA is one piece of information not available from the NEMMECO web-site necessary to compute $A(b)$ and $C(b)$. However, there appears to be general agreement between LYA and other parties that this variable cost is approximately \$AU 4/MWh. These generation units burn "brown coal" that can be surface mined using an automated process. Figure 1 contains photographs of this production process for LYA. The power plant is constructed near the coal deposit and a mechanical device to dig the coal and transport it to the power plant is constructed. Figure 1(a) is a picture of the LYA site which includes a surface mine and nearby generation units. Figure 1(b) is a picture of the mining machine that digs up the brown coal and puts it on a conveyer belt connected to the generation units. Figure 1(c) is a picture of the coal on the conveyer belt. Once constructed, this process runs with little human intervention and at an extremely low variable cost relative to the average price of electricity over our sample period of \$AU 30/MWh. Our analysis uses a value of \$AU 4/MWh for C_j all four gensets owned by LYA. Our results were not sensitive to plausible changes in the value of this variable cost figure.

Our algorithm for drawing residual demand curves for each day in our sample is based on the logic that the peak demand for the day is major determinant of the extent of unilateral market power a supplier expects to exercise during that day. The NEM rule that a supplier's bid prices must remain fixed for all 48 load periods of the day provides further justification for our focus on peak demand in selecting residual demand draws from days from the same and neighboring months with close to the same daily peak demand as the day under consideration. As discussed earlier, to compute draws from the distribution of residual demand uncertainty, we selected values of QD_i, the market demand for load period i, qo_{ink}, the bid quantity increment for load period i and genset n and bid increment k, and po_{nk}, the bid price for genset n and bid increment k for all 48 load periods from the same day, rather than sample independently from load periods within or across days. This was done to preserve the within-day correlation among bid parameters of the LYA's competitors that is likely to exist. We experimented with other residual demand draws selection algorithms such as average daily demand or a weighed sum of minimum and maximum demand and found little difference in our results for a given value of h as long as the number of draws was large enough.

Our analysis uses $B = 25$ and $h = 1$. We found that these values for the number of draws and the smoothing parameter best balanced our need for computational efficiency (because we compute counterfactual prices for every day in our sample) and precision in our estimate of the two matrices in (19). Smaller values of h require larger values of B, but larger values of B significantly increase the time needed to compute our estimate of $\frac{\partial \theta^*(QC)}{\partial QC}$ for each day. Because all bid prices lie between -9999.99 and 5000 (or 10,000) and the average price of electricity during our sample is $AU 30/MWh, a value of $h = 1$, roughly 3.3% of the sample average market price, does not imply a significant amount of smoothing of the step function supply curves.

A final issue with implementing our procedure for computing counterfactual prices is the selection of the vector ΔQC. The analysis in Section 2 uses a single load period-level model, but we are dealing with a daily market with 48 half-hourly periods. Because we expect the slope of the residual demand curve faced by LYA to become more elastic in off-peak periods of the day relative to peak periods of the day, we might expect that elements of ΔQC for the off-peak periods of the day to be less than the elements during the peak periods of the day. However, given its extremely low variable cost, LYA operates as a baseload unit and market participants expect it to run close to capacity during all hours of the day, so it may reduce it forward contract obligations during off-peak hours to take advantage of opportunities to exercise unilateral market power in these load periods as well.[12]

Rather than attempt to fine tune our hypothesized change in the level of fixed-price forward contracts held by LYP on a half-hourly basis, we assume a very simple structure for ΔQC. There are very likely to be ΔQC vectors that yield higher daily average price increases, but to avoid being subject to the criticism that our results are driven by the choice of ΔQC, we take an unsophisticated approach to selecting it. Let $\iota = (1,1,...,1)' \in \Re^{48}$ be a 48x1 vector of 1's and Δqc a scalar. We assume $\Delta QC = \iota(\Delta qc)$. This implies a reduction in LYA's forward contract obligations of Δqc for all half-hours of the day. All of our empirical results use the value of $\Delta qc = -200$ MW. We experimented with values of Δqc between −150 and −250 and obtained qualitatively similar results with larger (in absolute value) values of Δqc associated with larger average price increases.

To compute the counterfactual prices from that result from the acquisition we assume that all of the reduction in the demand for fixed-price forward contracts by AGL as result of the acquisition comes from those sold by LYA. Although we do not believe this outcome is likely, this allocation of the AGL's reduction in its forward contract demand was done to simplify our analysis. Table 1 lists all of the Victoria generation units that existed as of June 2003. There is approximately 5,400 MW of brown coal capacity in Victoria spread among four sizeable generation unit owners. We would expect the reduction in AGL's demand for fixed-price forward contracts to come from all of these suppliers.

[12] Wolak (2003b) found significant opportunities for suppliers to exercise unilateral market power in the California electricity market during off-peak hours of the day for the period June to September 2000.

Our assumption that the entire reduction in AGL's demand for fixed-price forward contracts results in same quantity of reduced sales of forward contracts by LYA may bias our results against a finding of significant price increases as result of the acquisition, because this approach assumes no change in the bidding behavior of the other large brown coal suppliers in Victoria. If the some of the reduction in the demand for fixed-price forward contracts by AGL comes from the remaining baseload suppliers in Victoria, following the logic of Section 3, the expected profit-maximizing price bids of these suppliers would change and the price bids of LYA would change less than if all of reduction the AGL's demand for fixed-price forward contracts demand came from forward contracts sold by LYA. It is unclear which of these two effects dominate in terms of resulting in higher counterfactual prices.

Resolving this question amounts to determining whether reducing the amount of electricity a single generation unit owner with a 20 percent market share is willing to supply at a pre-specified price (by allocating the entire reduction in forward contract demand to that supplier) yields a higher counterfactual price than allocating this same forward contract demand reduction to several suppliers with a total market share of 60 percent. If the single supplier in the first case reduces its willingness to supply by 10 percent, this implies a total reduction in supply to the market at this price of 2 percent. If the suppliers with a total market share of 60 percent each reduce their supply by 4 percent, then the total reduction in supply to the market at this price is 2.4 percent. Therefore, despite the fact that the reduction in the amount supplied by each producer is much less than 10 percent, because this reduction is applied to a larger fraction of total supply, the resulting counterfactual price is higher.

Our analysis can be modified to address any allocation of these fixed-price forward contract obligations among the large baseload suppliers. Consider the case that this forward contract reduction is allocated equally to Loy Yang, Hazelwood and Yallourn, the three largest suppliers in Victoria. Let $SL_i(p,\Theta^L)$, $SH_i(p,\Theta^H)$, and $SY_i(p,\Theta^Y)$ equal, respectively, the bid supply curves of Loy Yang (L), Hazelwood (H), and Yallourn (Y) for load period i, where Θ^K is the daily bid price and bid quantity increment vector for supplier $K = L$, H and Y. For each of these suppliers we could compute the matrix of partial derivatives of their daily bid price vector with respect to their daily forward contract quantity vector and then apply the hypothesized vector of fixed-price forward contract quantity reductions for that supplier to compute the change in each supplier's daily bid price vector. We would then compute the counterfactual post acquisition market prices as the smaller price that solves:

$$SL_i(p,\Theta^{Lc}) + SH_i(p,\Theta^{Hc}) + SY_i(p,\Theta^{Yc}) = DRB_i(p,\varepsilon_i) \tag{38}$$

where Θ^{Kc} is the counterfactual daily bid price and bid quantity increment vector for supplier $K = L$, H and Y that results from that supplier's hypothesized reduction in daily forward contract obligations and $DRB_i(p,\varepsilon_i)$ is the realized residual demand curve faced by these three baseload suppliers. Computing this counterfactual price requires three times the computation effort of our approach and it is unclear is the resulting counterfactual price is higher or lower. This is a topic we plan to explore in future work.

4.2 Empirical Results from Ex Ante Methodology

Let p_{id} equal the actual price for load period i of day d and p_{id}^c the counterfactual price for load period i of day d. To report our results, we compute

$$\overline{p}_i = \tfrac{1}{D}\sum_{d=1}^{D} p_{id} \text{ and } \overline{p}_i^c = \tfrac{1}{D}\sum_{d=1}^{D} p_{id}^c \tag{39}$$

where D is the total number of days in each year of our sample. For 2000, 2001 and 2002 it is the total number of days in the year and for 2003 it is total number of days from January 1, 2003 to June 30, 2003. We also compute the standard deviation of each half-hourly price for each year,

$$\sigma(p_i) = \left(\tfrac{1}{D}\sum_{d=1}^{D} (p_{id} - \overline{p}_i)^2 \right)^{1/2} \text{ and } \sigma(p_i^c) = \left(\tfrac{1}{D}\sum_{d=1}^{D} (p_i^c - \overline{p}_{id}^c)^2 \right)^{1/2} \tag{40}$$

Figures 2(a) plots the values of $\overline{p}_i$ for i = 1,..., 48 for the year 2000 and percentage difference between $\overline{p}_i^c$ and $\overline{p}_i$, which is equal to for i = 1,..., 48. Figure 2(b) plots the values of $\sigma(p_i)$ for i=1,...,48 for year 2000 and the ratio $\sigma(p_i^c)/\sigma(p_i)$ for i = 1,..., 48. These results show a persistent mean price increase between 10 and 25 percent for the majority of half-hour periods (and even higher in several other half-hour periods) as a result of the acquisition and an increase in half-hourly price volatility in most half-hour periods. This price volatility increase is much higher during some half-hour periods. Figure 3(a) and 3(b) through 5(a) and 5(b) present this same information for 2001, 2002 and 2003. These figures tell a similar story. Significant price increases in the 10 to 25 percent range during most half-hours with higher values during some hours are predicted by the acquisition. There is also an increase in price volatility in most half-hour periods, and this increase in price volatility is substantial during some half-hour periods of each year.

The first section of Table 2 presents values of $\overline{p}_i^c$ and $\overline{p}_i$ the asymptotic t-statistic for the null hypothesis that the expected value of $X_{id} = p_{id}^c - p_{id}$ is equal to zero for the year 2000 for all 48 half-hour periods. This asymptotic t-statistic is equal to:

$$Z_i = \frac{\overline{X}_i \sqrt{D}}{\sigma(X_i)} \text{ where } \overline{X}_i = \tfrac{1}{D}\sum_{d=1}^{D} X_{id} \text{ and } \sigma(X_i) = \left(\tfrac{1}{D}\sum_{d=1}^{D} (X_{id} - \overline{X}_i)^2 \right)^{1/2} \quad (41)$$

where D is the total number of days in that year of the sample. The statistic, Z_i is asymptotically distributed as a N(0,1) random variable under the null hypothesis. For all 48 load periods in 2000, we find that the null hypothesis that $E[X_{id}] = 0$, the expected price difference is zero, is rejected at conventional levels of significance and is greater than zero, which provides statistically significant evidence that the mean counterfactual price is higher than the mean actual price for all load periods. The remaining three sections of Tables 2 present the same three numbers for each load period for 2001, 2002 and 2003. For all years and the vast majority of load periods within each year, the mean difference between the counterfactual half-hourly price and the actual half-hourly price is statistically different from zero and positive.

5 Ex Post Analysis of the Acquisition

Because the acquisition was effective April 1, 2004 and we have market outcome data before and after this date we can also perform an ex post analysis of the acquisition using a treatment effects approach. We estimate two distinct treatment effects associated with the acquisition. The first relies on the fact that the highest variable cost generation unit operating during most hours of the year in the NEM is a natural-gas fired generation unit so that by using the daily price of natural gas as our control price, we are account for the impact of input cost differences over time in the price of wholesale electricity in Victoria. The second approach relies on the fact that Victoria has the lowest average wholesale electricity price over our sample period and as a consequence frequently exports electricity to the other four states. During a number half-hours of the year not all of the low-priced electricity available from Victoria producers can be transferred to New South Wales because the interconnection between Victoria and New South Wales is congested and the price in Victoria is determined only by competition among generation unit owners in that state. The second analysis asks if during load periods when congestion between Victoria to New South Wales is likely, Victoria prices are higher relative New South Wales prices after the acquisition.

The sample period for our treatment effects analysis is one year before the acquisition occurred and one year after the acquisition occurred. Increasing the size of the sample period increases the risk that any treatment effect we find may be due to other factors besides the acquisition. Reducing the size of the sample period reduces the precision of any treatment effect we might measure. We settled on a year-long pre-treatment period and post-treatment period to capture the impact of the acquisition on a full year of half-hourly electricity prices.

The data used in the first treatment effects analysis is the half-hourly wholesale electricity price in Victoria in $AU/MWh and the daily natural gas price from the Victoria natural gas wholesale market in $AU per Gigajoule (GJ). A gigajoule is equal to 1.054615 million British Thermal Units (MMBTUs), the standard unit of measure for natural gas sold in the United States. Daily natural gas prices were obtained from the

Vencorp web-site.[13] Vencorp manages the Victorian wholesale natural gas market and sets spot prices on a daily basis. Figure 6 plots the daily natural gas price in Victoria from April 1, 2003 to April 1, 2005 in $AU/GJ and the daily average Victoria wholesale electricity price in $AU/MWh. Figure 7 repeats this plot for the daily average price of electricity in New South Wales. Note the dramatically larger scale for the left axis measuring wholesale electricity prices for the New South Wales graph versus the Victoria graph. During our sample period, the maximum daily average price in New South Wales is more than $AU 1200/MWh and the maximum daily average price in Victoria is approximately $AU 325/MWh.

Figure 8 plots an estimate of the aggregate marginal cost curve as of June 2003 for electricity supplied to the Victoria market that labels the different technologies used to produce electricity. We enter the hydroelectricity capacity at a variable cost of $AU 0/MWh to account for the fact that the incurred cost of producing electricity from a hydroelectric unit is zero. However, we recognize that these units will operate based on the opportunity cost of the water they have behind their turbine. The next collection of generation facilities in the marginal cost curve are the brown coal units. The 2000 MW LYA plant is in this step of curve. The next step of the marginal cost curve accounts for the interconnection capacity from New South Wales. We estimate the variable cost of this step at $AU 15/MWh, which is the variable cost of the black coal units producing electricity in New South Wales.

The final increasing portion of the aggregate marginal cost curve is composed of natural gas-fired generation units with different thermal efficiencies. The idea behind our

13 Daily natural gas price data for Victorian wholesale market can be downloaded from the Vencorp web-site at the link http://www.vencorp.com.au/index.php?sectionID=8246&pageID=8939.

treatment effects analysis is to use natural gas prices as our control variable for input price differences over time. Our two maintained assumptions are that these natural gas price are not be impacted by the acquisition and they adequately control for input cost differences in the price of wholesale electricity over our sample period. It our understanding that the price of brown coal in Victoria and the price of black coal in New South Wales did not noticeably change over our sample period.

If LYA and other baseload brown coal units in Victoria exercise more unilateral market power in the NEM as a result a reduced level of fixed-price forward contract obligations, then we would expect the higher marginal cost natural gas-fired generation units (those lower thermal efficiencies in converting natural gas to electricity) in this aggregate marginal cost curve to be setting the market price more frequently and this will result in a higher wholesale electricity prices. Using the price of natural gas as our control variable accounts for the fact that some of the price changes post-acquisition could be due to changes in natural gas prices and not changes in the thermal efficiency of the highest variable cost unit operating.

Our treatment effects analysis uses a difference-in-difference regression framework separately for each half-hour of the day. Specifically, define the following variables:

- y_{ijd} = the natural logarithm of the price in market *j* during load period *i* of day *d*
- $Post\_Acq_{id}$ = an indicator variable that equals 1 if load period *i* of day *d* is after April 1, 2004 and zero otherwise
- Vic_{ijd} = an indicator variable that equals 1 if the observation for load period *i* of day *d* is from the Victoria wholesale electricity market and zero otherwise
- Vic_{ijd}*$\text{Post\_Act}_{\text{id}}$ = an indicator variable that equals 1 if load period *i* of day d is after April 1, 2004 and the observation is from the Victoria wholesale electricity market.

The subscript j takes on two values, one for the Victoria wholesale electricity market and the other for the Victoria wholesale natural gas market. We run the following regression for each half-hour of the day for our sample period:

$$100 * y_{ijd} = \alpha_i + \beta_{1i} PostAcq_{id} + \beta_{2i} Vic_{ijd} + \beta_{3i} Vic_{ijd} * PostAcq_{id} + \eta_{ijd} \tag{42}$$

Pre-multiplying our dependent variable by 100 converts all of our coefficients to approximate percent changes. Specifically, β_{3i} now becomes the estimated approximate percent change in Victorian wholesale electricity prices that result from the acquisition.

Rather than present a table with the results of the 48 half-hourly regressions, we plot the estimated values of our percent treatment effects from the acquisition, β_{3i}, for each of the 48 half-hour periods, along with the pointwise upper and lower 95% confidence bound on this estimated half-hourly treatment effect. This plot is given in Figure 9 and shows that for all half-hours of the day estimated treatment effect of the acquisition (using the price natural gas in Victoria as the control variable) is between 15 and 30 percent and statistically different from zero. Moreover, the pointwise confidence bounds on these half-hourly estimates contain the vast majority of the ex ante half-hourly estimated percent price increases from the acquisition given Figures 2(a) to 5(a) for 2000 to 2003.

To assess the extent to which these price increases from the acquisition also occurred in New South Wales, the other major population center in Australia, we repeated this treatment effects analysis substituting the logarithm of the half-hourly wholesale electricity price in New South Wales for the one in Victoria as the dependent variable in our 48 regressions. Figure 10 plots these results using the same format as

Figure 9. They are consistent with the view that substantial wholesale electricity price increases associated with the acquisition also occurred in New South Wales.

To provide further evidence that the acquisition enhanced the ability of LYA and other baseload Victoria suppliers to exercise unilateral market power we performed a treatment effects analysis that attempts to measure the differential impact of the acquisition on prices in Victoria versus New South Wales. As noted earlier when there is congestion from Victoria into New South Wales prices in New South Wales are higher than those in Victoria in order to attract sufficient supply from New South Wales to make up for the low-cost supply from Victoria that cannot be transferred to New South Wales because of transmission constraints. To understand this mechanism for exercising unilateral market power by Victoria generation unit owners, consider the following example. Suppose that suppliers in Victoria are willing to provide 1000 MW beyond demand in Victoria to New South Wales at a price of $AU 25/MWh before acquisition and that the price in New South Wales is $AU 35/MWh because the transmission link between these states is only 500 MW. If suppliers in Victoria face less competition after the acquisition, they may be able to raise the price in Victoria to just below $AU 35/MWh which would still prevent suppliers in New South Wales from selling in Victoria but now Victoria generation unit owners would receive a substantially higher price for their sales in Victoria during congested periods. Consequently, one measure of the increased extent of unilateral market power exercised after the acquisition is the extent that prices during congested periods between Victoria and New South Wales are higher in Victoria relative to New South Wales.

During these congested periods, suppliers in Victoria do not face competition from suppliers in New South Wales until their bid prices exceed the highest bid price accepted in New South Wales. Therefore, if suppliers in Victoria are able to exercise more unilateral market power during congested periods in Victoria after the acquisition, then we would expect the ratio between of the price in Victoria to the price in New South Wales during congested periods to be higher after the acquisition. This logic suggests that the appropriate dependent variable for our analysis is the logarithm of the price in Victoria divided by the price in New South Wales. As shown in Figure 8, there is more than 1500 MW of transmission capacity between Victoria and New South Wales. There is relatively a small interconnection between South Australia and Victoria and slightly larger interconnection between Queensland and New South Wales.

Because South Australia and Queensland are not electrically connected to one another except through Victoria and New South Wales, we use the logarithm of the ratio of the prices in these two states as the control variable for the ratio of prices in Victoria and New South Wales during congested periods before and after the acquisition. We are hard pressed to think of a reason why the pattern of the price ratio between South Australia and Queensland would be impacted by the acquisition.

To summarize, the two dependent variables for our model are now: (1) the logarithm of the ratio of the wholesale electricity price in Victoria divided by the wholesale electricity price in New South Wales and (2) the control variable is the logarithm of the price ratio of the wholesale electricity price in South Australia divided by the wholesale electricity price in Queensland. We run the regression given in (42) for each half-hour period in our sample when there is likely to be congestion between

Victoria and New South Wales. Our sample selection rule to determine a half-hour with congestion is if the price in Victoria is less than the price in New South Wales. This is a conservative measure of the likelihood that congestion between these two markets actually exists and is likely to capture hours when there no congestion and the price difference between the states is due to transmission losses only. If we require the price in New South Wales to be more than 5 percent larger than the price in Victoria (a clear indication of congestion and not simply the result of transmission losses), we estimate similar treatment effects in sign and magnitude.

The treatment effect coefficient for these price difference or congestion regression measures the percent increase in the ratio of the price in Victoria relative to the price in New South Wales after the acquisition controlling for all other factors impacting this price ratio pre- and post-acquisition with the ratio of prices in South Australia to Queensland. Figure 11 plots the estimated values of β_{3i} and the pointwise 95% percent upper and lower confidence bounds on the coefficient estimate. For the vast majority of half-hour periods we find an estimated treatment effect that is positive and for many of these half-hour periods it is statistically different from zero, particularly during the high-priced periods of the day. Figure 12 plots the estimated values of β_{3i} and the pointwise 95% percent upper and lower confidence bounds on the coefficient estimate for our model estimated over all half-hours during the sample period of April 1, 2003 to April 1, 2005. As expected the magnitude of these treatment effects is smaller because these regressions includes half-hours the price in Victoria exceeds the price in New South Wales, but the vast majority of these half-hourly treatment effects are positive and statistically different from zero.

These treatment effects are consistent with the view that when the Victoria market is isolated from New South Wales because of congestion, the extent of unilateral market power exercised by suppliers in the Victoria market is higher post-acquisition. The implication of the natural gas price treatment effects results for Victoria and New South Wales is that wholesale electricity prices in these two states are higher post-acquisition, which is consistent with greater exercise of unilateral market power in the NEM post-acquisition.

To estimate an overall average natural gas price treatment effect and an overall congestion price treatment effect, we estimated equation (42) pooled over all half-hour periods, with fixed effects for each half-hour of the day, but a single treatment effect coefficient. For the natural gas price model this overall percent treatment effect coefficient estimate is 20.15 with an estimated standard error (0.53), indicating that average prices across all load periods are 20 percent higher post-acquisition. For the congestion price treatment effect for the sample restricted to half-hours when the price in Victoria is less than the price in New South Wales, the overall treatment effect is 8.48 with an estimated standard error of (0.76). This implies that during periods with congestion the ratio of prices in Victoria divided by prices in New South Wales is 8.47 percent higher. The overall congestion price treatment effect for all half-hours from April 1, 2003 to April 1, 2005 is 7.25 with an estimated standard error of (0.50). These overall results further confirm the existence of large and statistically significant increases in the overall price in the NEM and relative price in Victoria relative to New South Wales during congested periods as a result of the acquisition.

6 Conclusions, Caveats and Directions for Future Research

The role of econometric analysis in predicting the competitive impact of mergers has had mixed success in legal and regulatory domains. Where it has been applied, the pre-dominant purpose has been to assist courts in questions of market definition rather than directly evaluating the potential impact of an acquisition on prices. Moreover, with regard to vertical acquisitions, quantitative assessments have been virtually non-existent.

In this paper, we have demonstrated that, in structured markets, such as electricity, the wealth of data as well as the precise 'rules of the game' allow us to identify both ex ante and ex post the competitive consequences of changes in ownership. Here we examined an acquisition that, using only qualitative assessments, would not have raised concerns. It involved a downstream firm acquiring a (i) partial and (ii) passive stake in an upstream firm that itself was part of a segment that was not highly concentrated. However, a careful formal analysis of how the incentives of all firms in the industry indicated the possibility that the acquisition may materially and significantly raise wholesale prices.

We have taken the opportunity to use the prospective analysis motivated by economic theory to evaluate competitive assessments both before and after that fact for the AGL-LYA acquisition in Australia in 2004. Significantly, the ex post analysis indicates that this acquisition did, in fact, lead to a rise in wholesale prices in the NEM; providing empirical verification for our theory that such acquisitions should be examined closely by competition authorities. In addition, we demonstrated that the evaluation of this theory ex ante, predicted the price increases observed ex post. Consequently, we see this as a validation for the use of econometric techniques tightly linked to theory in the prospective competitive assessment of mergers in ‘data rich’ industries.

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Appendix A

This appendix empirically documents the substantially larger price risk versus quantity risk faced by AGL associated with it acquiring a passive ownership share in LYA. For each half-hour period and each year from January 1, 2000 to June 30, 2003, we compute $CV(p_i)$, the coefficient of variation for the market price in Victoria in load period i as:

$$CV(p_i) = \frac{\sigma(p_i)}{\overline{p}_i}.$$

We also compute the half-hourly mean and standard deviation of LYA's output as:

$$\overline{Q}_i = \tfrac{1}{D}\sum_{d=1}^{D} Q_{id} \text{ and } \sigma(Q_i) = \left(\tfrac{1}{D}\sum_{d=1}^{D} (Q_{id} - \overline{Q}_i)^2 \right)^{1/2}$$

where $Q_i = \sum_{j=1}^{J} Q_{ijd}$ is the total production from all $J = 4$ units owned by LYA during load period i of day d. Define the coefficient of variation for LYA's half-hourly output as:

$$CV(Q_i) = \frac{\sigma(Q_i)}{\overline{Q}_i}$$

and the ratio of these two coefficients of variation as:

$$\text{Ratio}_i = CV(p_i)/CV(Q_i).$$

The first section of Table B-1 contains the values of $CV(p_i)$, $CV(Q_i)$, and Ratio_i for each half-hour period of 2000. For all half-periods during 2000 the ratio of the coefficient of variation for the half-hourly price is more than 5 times the value of the coefficient of variation for LYA's half-hourly output. For a significant fraction of half-hours of the day, this ratio is more than 10 and in several half-hours it is over 50. These same qualitative conclusions hold for the remaining years of the sample, although the minimum daily average value of $Ratio_i$ is smaller than it is in 2000. For the vast majority of half-hour periods in each year, the quantity risk faced by LYA is much smaller than the price risk, where is measured by the half-hourly coefficient of variation for LYA's output and the Victoria market price, respectively. These calculations provide empirical support for our simplifying assumption that AGL faces zero quantity risk associated with its share in LYA.

	2000			2001			2002			2003		
Half Hour Period	**CV of Price in Victoria**	**CV of Loy Yang Quantity**	**Ratio**	**CV of Price in Victoria**	**CV of Loy Yang Quantity**	**Ratio**	**CV of Price in Victoria**	**CV of Loy Yang Quantity**	**Ratio**	**CV of Price in Victoria**	**CV of Loy Yang Quantity**	**Ratio**
1	0.5988	0.1076	5.5639	0.3160	0.1601	1.9742	0.7545	0.1414	5.3361	0.2762	0.0616	4.4855
2	0.6089	0.1055	5.7719	0.3232	0.1603	2.0162	1.0265	0.1383	7.4214	0.2905	0.0653	4.4482
3	0.5726	0.1027	5.5741	0.4172	0.1615	2.5835	0.3000	0.1461	2.0530	0.3093	0.0769	4.0235
4	0.9987	0.1029	9.7011	0.4233	0.1628	2.6006	0.3562	0.1570	2.2683	0.3639	0.0831	4.3814
5	3.0939	0.0999	30.9832	0.4346	0.1667	2.6070	0.3632	0.1642	2.2126	0.4184	0.0866	4.8289
6	4.5891	0.1001	45.8646	0.4740	0.1687	2.8103	0.4317	0.1670	2.5857	0.5037	0.0868	5.7995
7	0.6726	0.0991	6.7841	0.4015	0.1657	2.4238	0.3552	0.1663	2.1354	0.4594	0.0860	5.3402
8	0.6781	0.0970	6.9916	0.3959	0.1662	2.3814	0.4148	0.1660	2.4985	0.5901	0.0826	7.1401
9	0.8680	0.0954	9.0948	0.5098	0.1678	3.0386	0.4091	0.1670	2.4493	0.3894	0.0772	5.0473
10	0.6226	0.0939	6.6299	1.2974	0.1691	7.6726	0.3365	0.1669	2.0162	4.0487	0.0746	54.2710
11	0.5597	0.0920	6.0868	1.2518	0.1696	7.3825	0.3347	0.1668	2.0068	0.3985	0.0746	5.3445
12	0.5832	0.0913	6.3849	4.3800	0.1716	25.5199	0.3061	0.1680	1.8217	0.3502	0.0745	4.6991
13	0.5553	0.0919	6.0446	3.2373	0.1743	18.5778	0.3168	0.1688	1.8763	0.4330	0.0715	6.0568
14	0.5345	0.0995	5.3707	1.1675	0.1747	6.6844	0.3178	0.1687	1.8839	0.5062	0.0716	7.0662
15	0.5505	0.1176	4.6795	3.6955	0.1753	21.0845	0.3426	0.1679	2.0411	0.4033	0.0748	5.3903
16	0.5836	0.1053	5.5399	1.9115	0.1775	10.7705	0.3381	0.1666	2.0294	0.5191	0.0742	6.9962
17	0.5915	0.0905	6.5393	4.1502	0.1776	23.3697	0.3789	0.1659	2.2843	0.6166	0.0738	8.3571
18	0.6151	0.0899	6.8453	3.7363	0.1813	20.6085	0.4129	0.1644	2.5118	0.6622	0.0748	8.8554
19	0.6799	0.1048	6.4894	4.3210	0.1822	23.7149	2.3107	0.1635	14.1300	1.8637	0.0758	24.6021
20	0.7185	0.1058	6.7934	4.7586	0.1838	25.8845	1.0927	0.1630	6.7056	0.8064	0.0760	10.6084
21	0.7768	0.0981	7.9153	4.6904	0.1828	25.6646	0.6011	0.1619	3.7116	1.2281	0.0741	16.5646
22	0.7533	0.0916	8.2235	4.0744	0.1813	22.4723	0.6193	0.1613	3.8390	1.1610	0.0752	15.4326
23	0.8034	0.0895	8.9737	3.7166	0.1827	20.3440	0.6266	0.1610	3.8928	1.2074	0.0746	16.1757
24	0.8451	0.0879	9.6145	4.6457	0.1840	25.2474	0.5919	0.1612	3.6719	1.2542	0.0740	16.9449
25	0.7420	0.0886	8.3719	4.2404	0.1810	23.4288	0.5371	0.1624	3.3071	6.5674	0.0743	88.4132
26	0.7126	0.0935	7.6208	3.3166	0.1784	18.5866	1.1035	0.1616	6.8296	0.5770	0.0726	7.9441
27	2.1180	0.0918	23.0838	3.5275	0.1738	20.2915	1.3743	0.1601	8.5862	0.4588	0.0719	6.3779
28	2.8865	0.0915	31.5498	2.6801	0.1709	15.6836	3.4258	0.1551	22.0924	5.7379	0.0720	79.6930
29	2.5043	0.0935	26.7945	4.2257	0.1696	24.9159	3.2776	0.1504	21.7868	6.2787	0.0714	87.9005
30	2.5373	0.0974	26.0402	0.7732	0.1688	4.5813	1.5950	0.1586	10.0597	2.9960	0.0712	42.0766
31	5.1876	0.0994	52.1783	0.4070	0.1680	2.4225	0.4560	0.1646	2.7699	0.4030	0.0658	6.1206
32	5.2940	0.1039	50.9497	0.4282	0.1681	2.5476	0.3934	0.1658	2.3728	0.3338	0.0654	5.1030
33	5.5594	0.1048	53.0255	0.3322	0.1679	1.9778	0.4081	0.1657	2.4624	0.3298	0.0651	5.0667
34	5.9539	0.1072	55.5290	0.4341	0.1682	2.5812	0.3749	0.1647	2.2766	0.3303	0.0660	5.0008
35	5.8701	0.1063	55.2344	0.3405	0.1675	2.0324	0.3021	0.1638	1.8448	0.3048	0.0654	4.6589
36	5.8664	0.1076	54.5295	0.3189	0.1665	1.9147	0.2738	0.1613	1.6976	0.2869	0.0682	4.2037
37	2.3548	0.1033	22.7868	1.2766	0.1665	7.6681	0.3842	0.1620	2.3711	0.3106	0.0699	4.4416
38	2.6753	0.1039	25.7441	0.3408	0.1738	1.9604	0.3085	0.1613	1.9125	0.2755	0.0712	3.8674
39	4.2301	0.1045	40.4875	0.3124	0.1769	1.7655	0.3290	0.1663	1.9785	0.2510	0.0677	3.7060
40	5.2612	0.1048	50.1908	0.2769	0.1758	1.5750	0.2854	0.1653	1.7272	0.2468	0.0673	3.6671
41	4.9903	0.1064	46.8811	0.3429	0.1671	2.0519	0.2657	0.1644	1.6159	0.2556	0.0714	3.5786
42	3.5103	0.1071	32.7665	0.2904	0.1658	1.7510	0.2580	0.1632	1.5804	0.2574	0.0738	3.4866
43	3.7971	0.1069	35.5069	1.4730	0.1625	9.0642	0.3137	0.1646	1.9058	0.2298	0.0727	3.1616
44	0.9332	0.1052	8.8733	0.2516	0.1575	1.5977	0.3111	0.1622	1.9175	0.2514	0.0780	3.2256
45	0.9027	0.1029	8.7744	0.2759	0.1560	1.7685	0.3067	0.1600	1.9175	0.2670	0.0807	3.3089
46	0.7064	0.1030	6.8588	0.2942	0.1547	1.9017	0.2923	0.1565	1.8674	0.2986	0.0796	3.7533
47	0.6566	0.1057	6.2112	0.3080	0.1525	2.0202	0.2807	0.1523	1.8428	0.3069	0.0722	4.2540
48	0.6110	0.1072	5.6984	0.3133	0.1510	2.0743	0.2681	0.1460	1.8356	0.2855	0.0636	4.4885

Appendix B

This appendix computes all of the partial derivatives in equation (21) and (22)using the smoothed residual demand curves and bid supply curves of LYA. To derive the right-hand side of equation (22), apply the implicit function theorem to the equation used to determine the market-clearing price. This yields the expression:

$$\frac{\partial p_i^h(\varepsilon_i,\Theta))}{\partial p_{jk}} = \frac{\partial SL_i^h(p_i(\varepsilon_i,\Theta),\Theta) \big/ \partial p_{jk}}{\frac{dDR_i^h(p_i(\varepsilon_i,\Theta),\varepsilon_i)}{dp_i} - \frac{dSL_i^h(p_i(\varepsilon_i,\Theta),\Theta)}{dp_i}} \qquad (43)$$

where the derivative of the residual demand curve with respect to price used in this expression is given in equation (31) and the other partial derivatives are given in (34). This expression quantifies, respectively, how the market-clearing price changes in response to changes in the LYA's daily bid prices.

The remaining partial derivatives in equation (21) not defined in the text are listed below. The partial derivative of (43) with respect to bid price increment *v* of unit *r* is:

$$\frac{\partial^2 p_i(\varepsilon_i,\Theta)}{\partial p_{jk}\partial p_{rv}} = \frac{\left(\begin{array}{l} \frac{\partial^2 SL_{ij}(p_i(\varepsilon_i,\Theta),\Theta)}{\partial p_i \partial p_{jk}} \frac{\partial p_i}{\partial p_{rv}} \left(\frac{\partial DR_i(p_i(\varepsilon_i,\Theta),\varepsilon_i)}{\partial p_i} - \frac{\partial SL_i(p_i(\varepsilon_i,\Theta),\Theta)}{\partial p_i} \right) \\ - \frac{\partial SL_{ij}(p_i(\varepsilon_i,\Theta),\Theta)}{\partial p_{jk}} \left(\left(\frac{\partial^2 DR_i(p_i)}{\partial p_i^2} - \frac{\partial^2 SL_i(p_i)}{\partial p_i^2} \right) \frac{\partial p_i}{\partial p_{rv}} - \frac{\partial^2 SL_{ir}(p_i(\varepsilon_i,\Theta),\Theta)}{\partial p_i \partial p_{rv}} \right) \end{array}\right)}{\left(\frac{\partial DR_i(p_i(\varepsilon_i,\Theta),\varepsilon_i)}{\partial p_i} - \frac{\partial SL_i(p_i(\varepsilon_i,\Theta),\Theta)}{\partial p_i} \right)^2} \qquad (44)$$

The partial derivative of (43) with respect to p_{jk} is equal to:

$$\frac{\partial^2 p_i(\varepsilon_i,\Theta)}{\partial p_{jk}^2} = \frac{\left(\begin{array}{c}\left(\frac{\partial^2 SL_{ij}(p_i(\varepsilon_i,\Theta),\Theta)}{\partial p_{jk}^2} + \frac{\partial^2 SL_{ij}(p_i)}{\partial p_{jk}\partial p_i}\frac{\partial p_i}{\partial p_{jk}}\right)\left(\frac{\partial DR_i(p_i(\varepsilon_i,\Theta),\varepsilon_i)}{\partial p_i} - \frac{\partial SL_i(p_i(\varepsilon_i,\Theta),\Theta)}{\partial p_i}\right) \\ -\frac{\partial SL_{ij}(p_i(\varepsilon_i,\Theta),\Theta)}{\partial p_{jk}}\left(\left(\frac{\partial^2 DR_i(p_i)}{\partial p_i^2} - \frac{\partial^2 SL_i(p_i)}{\partial p_i^2}\right)\frac{\partial p_i}{\partial p_{jk}} - \frac{\partial^2 SL_{ij}(p_i(\varepsilon_i,\Theta),\Theta)}{\partial p_i \partial p_{jk}}\right)\end{array}\right)}{\left(\frac{\partial DR_i(p_i(\varepsilon_i,\Theta),\varepsilon_i)}{\partial p_i} - \frac{\partial SL_i(p_i(\varepsilon_i,\Theta),\Theta)}{\partial p_i}\right)^2} \quad (45)$$

The partial derivative of $\frac{\partial SL_{ij}(p_i(\varepsilon_i,\Theta),\Theta)}{\partial p_i}$ with respect to p_i is equal to

$$\frac{\partial^2 SL_{ij}(p_i(\varepsilon_i,\Theta),\Theta)}{\partial p_i^2} = -\tfrac{1}{h}\sum_{k=1}^{10} q_{ijk}\varphi\big((p - p_{jk})/h\big)\big((p - p_{jk})/h\big) \quad (46)$$

The partial derivative of $\frac{\partial SL_{ij}(p_i(\varepsilon_i,\Theta),\Theta)}{\partial p_{jk}}$ with respect to any other bid price increment besides p_{jk} is zero. The derivative with respect to p_{jk} is:

$$\frac{\partial^2 SL_{ij}(p_i(\varepsilon_i,\Theta),\Theta)}{\partial p_{jk}^2} = -\tfrac{1}{h^2} q_{ijk}\varphi\big((p_i - p_{jk})/h\big)\big((p_i - p_{jk})/h\big) \quad (47)$$

Figure 1(a): Surface Brown Coal Mine and Electricity Generation Units

Figure 1(b): Mining Shovel and Transport Facility

Figure 1(c):Transportation

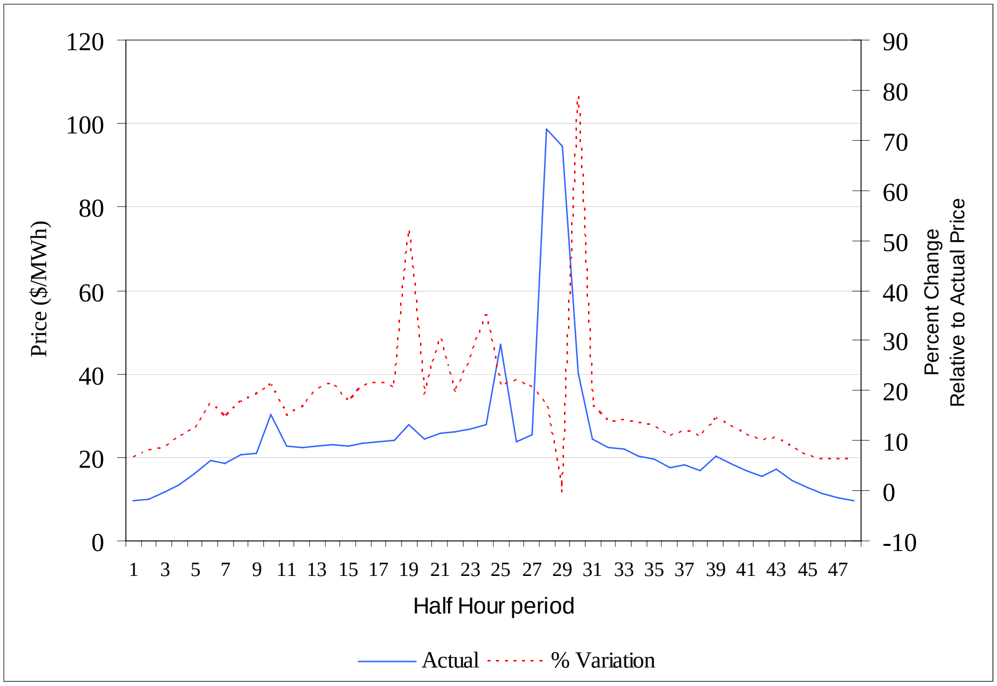

Figure 2(a): Actual Half-Hourly Price and Counterfactual Percent Price Change for 2000

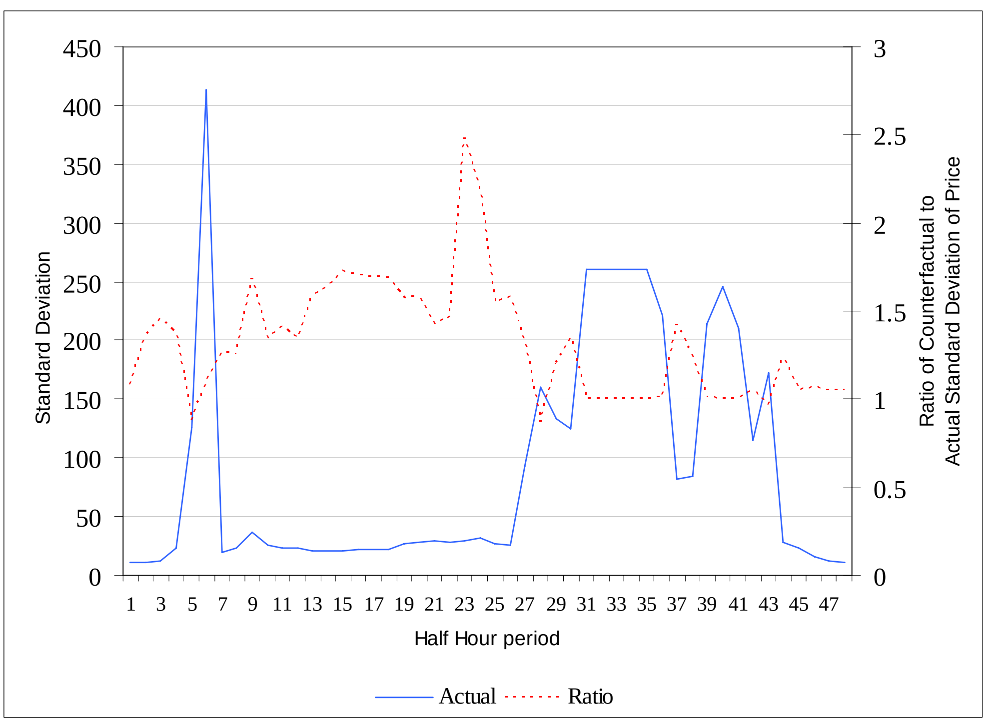

Figure 2(b): Standard Deviation of Half-Hourly Price and Relative Standard Deviation of Counterfactual Price for 2000

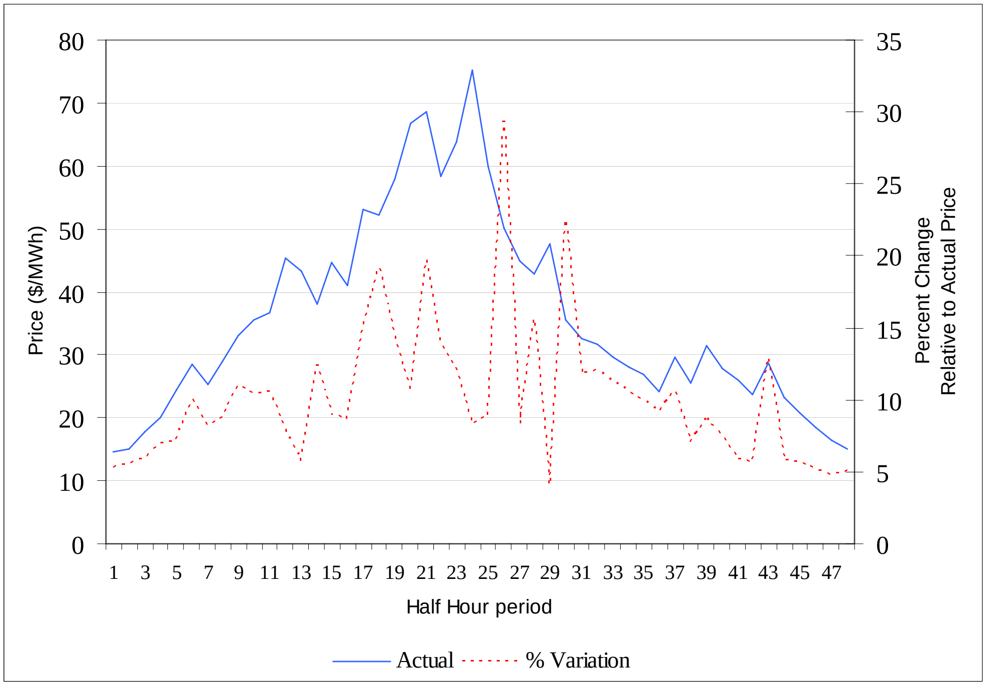

Figure 3(a): Actual Half-Hourly Price and Counterfactual Percent Price Change for 2001

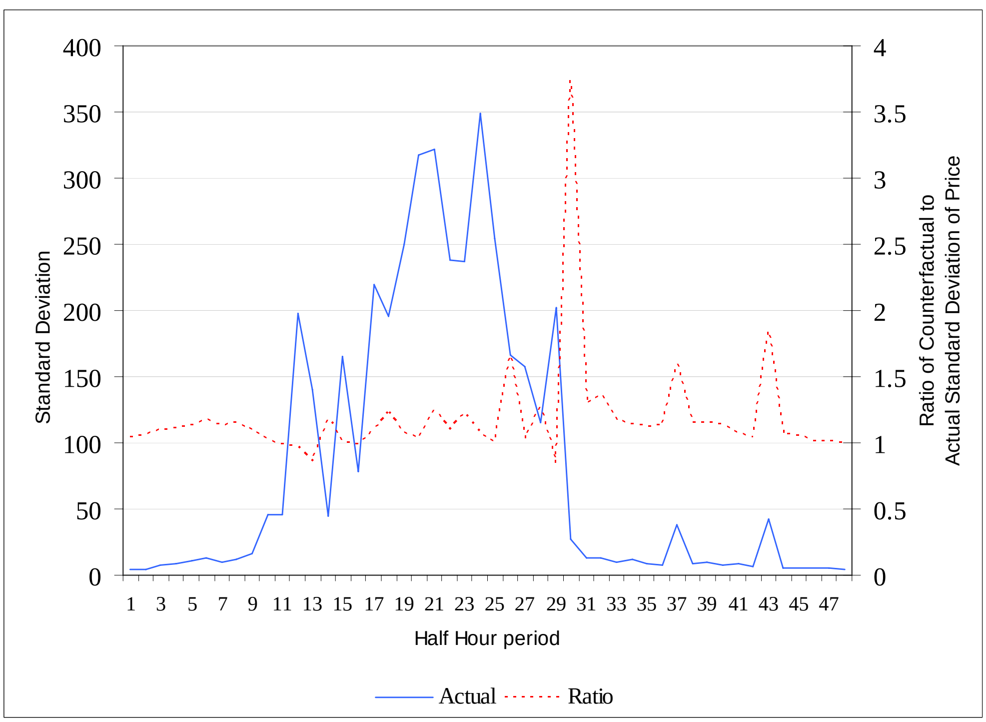

Figure 3(b): Standard Deviation of Half-Hourly Price and Relative Standard Deviation of Counterfactual Price for 2001

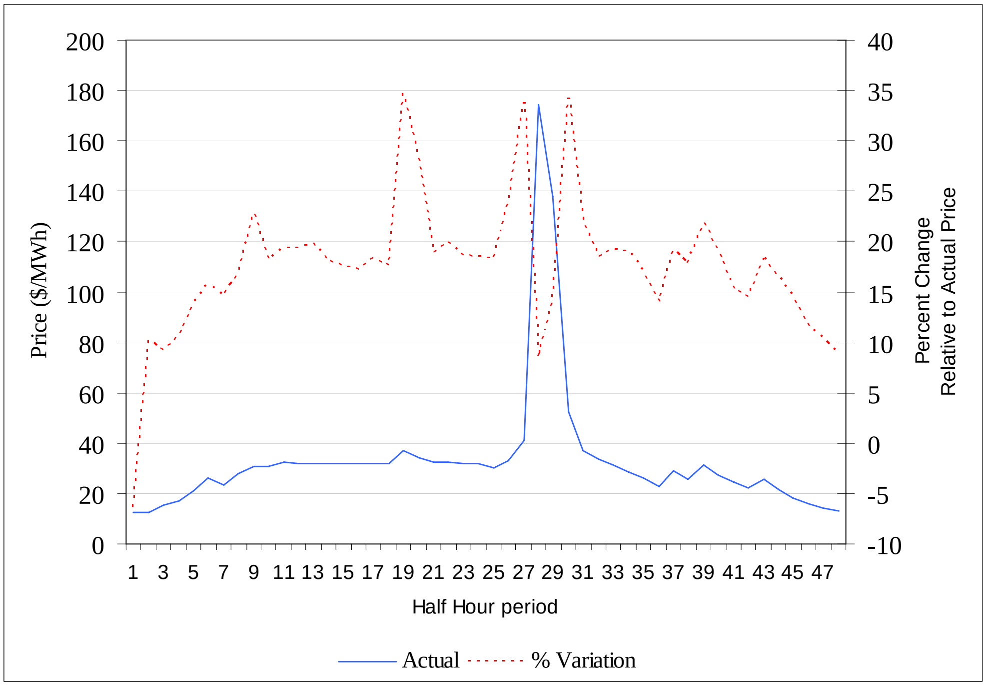

Figure 4(a): Actual Half-Hourly Price and Counterfactual Percent Price Change for 2002

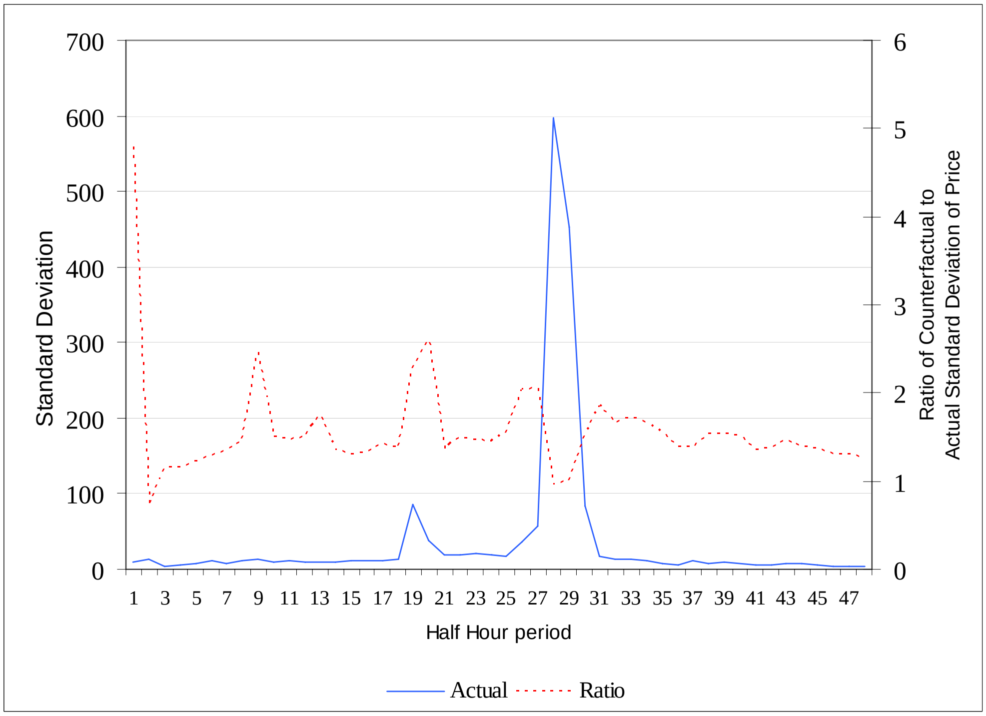

Figure 4(b): Standard Deviation of Half-Hourly Price and Relative Standard Deviation of Counterfactual Price for 2002

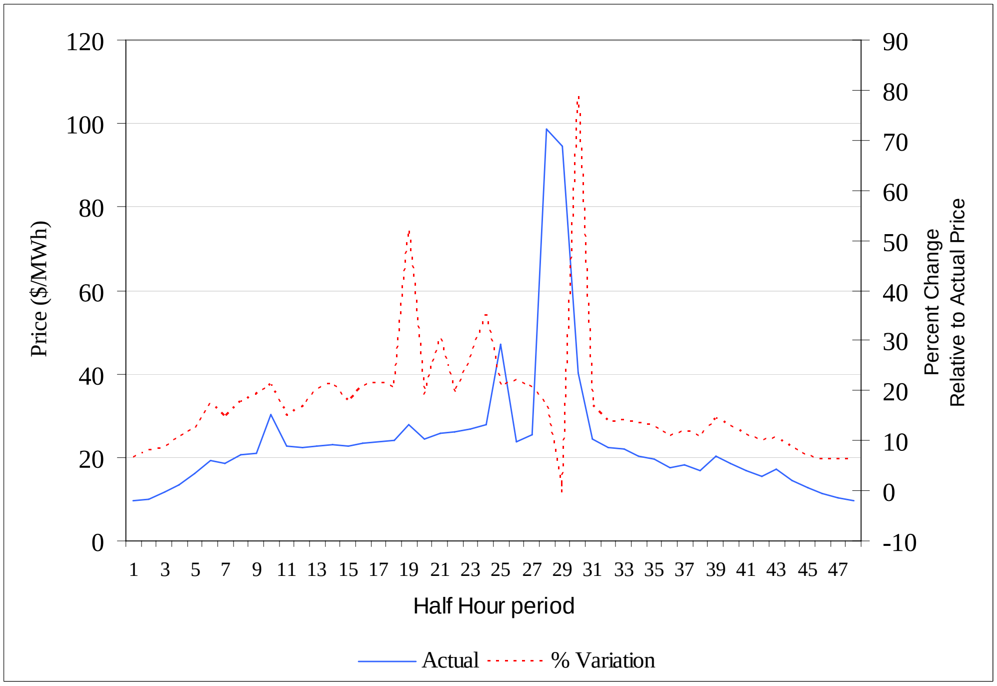

Figure 5(a): Actual Half-Hourly Price and Counterfactual Percent Price Change for 2003

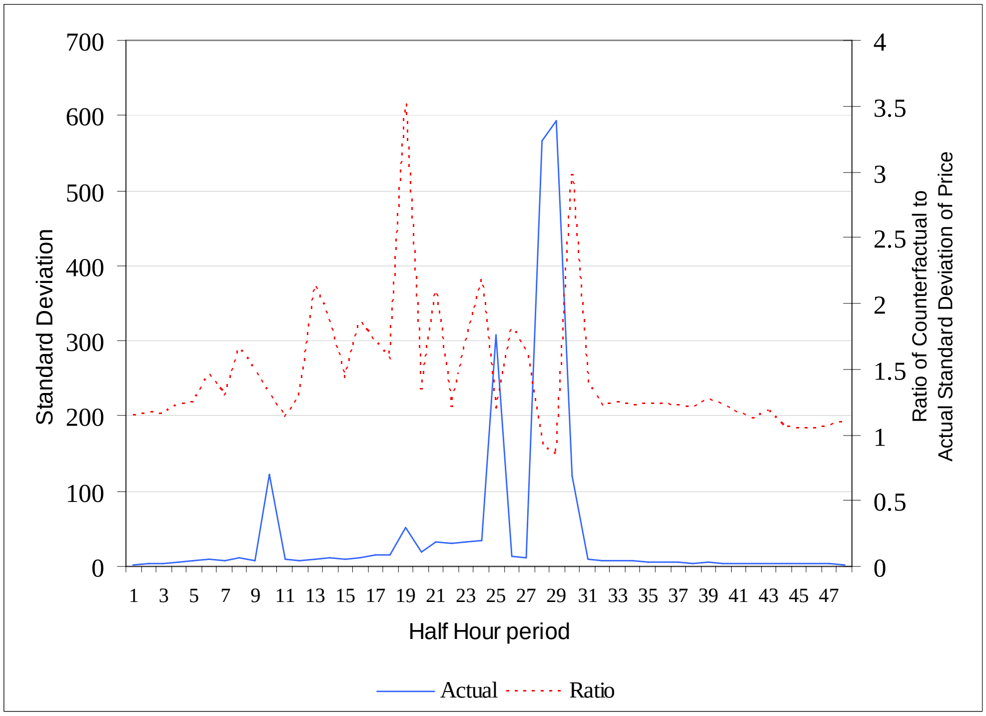

Figure 5(b): Standard Deviation of Half-Hourly Price and Relative Standard Deviation of Counterfactual Price for 2003

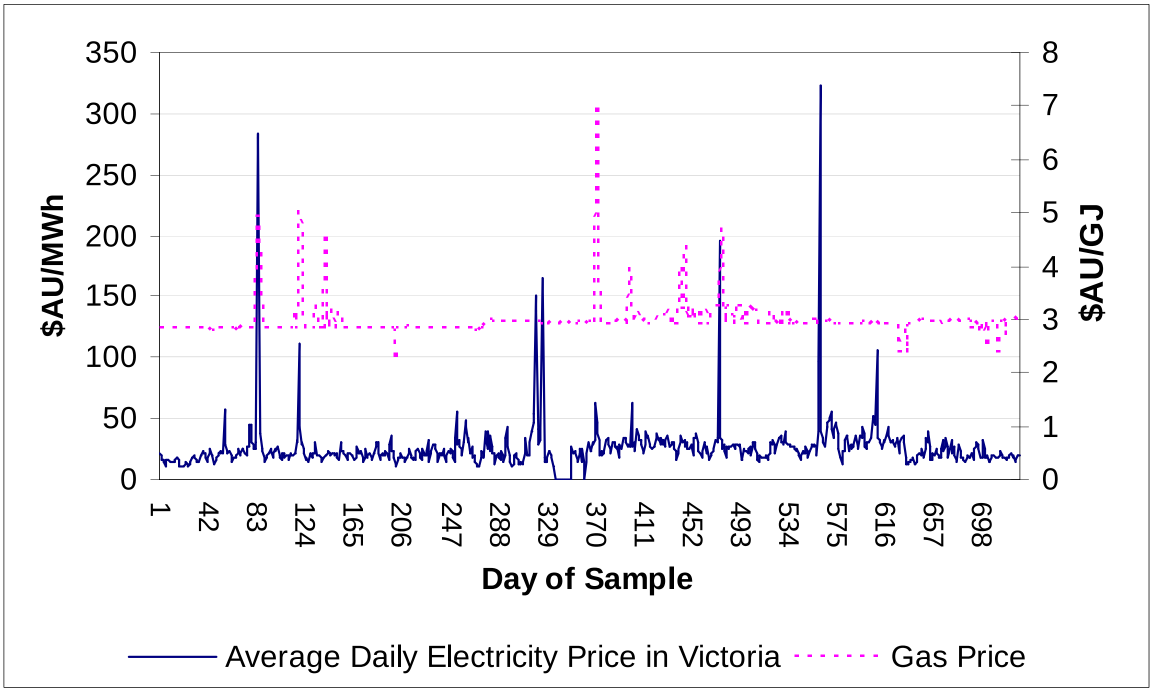

Figure 6: Daily Natural Gas Prices in Victoria and Daily Average Wholesale Electricity Prices in Victoria (April 1, 2003 to April 1, 2005)

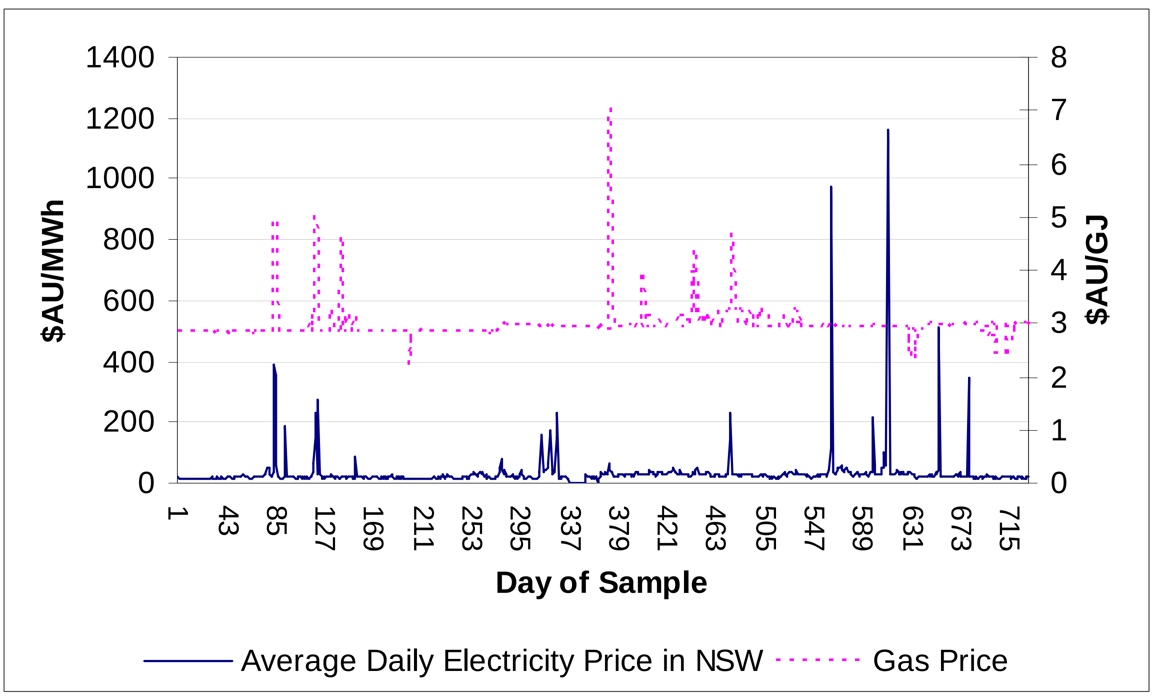

Figure 7: Daily Natural Gas Prices in Victoria and Daily Average Wholesale Electricity Prices in New South Wales (April 1, 2003 to April 1, 2005)

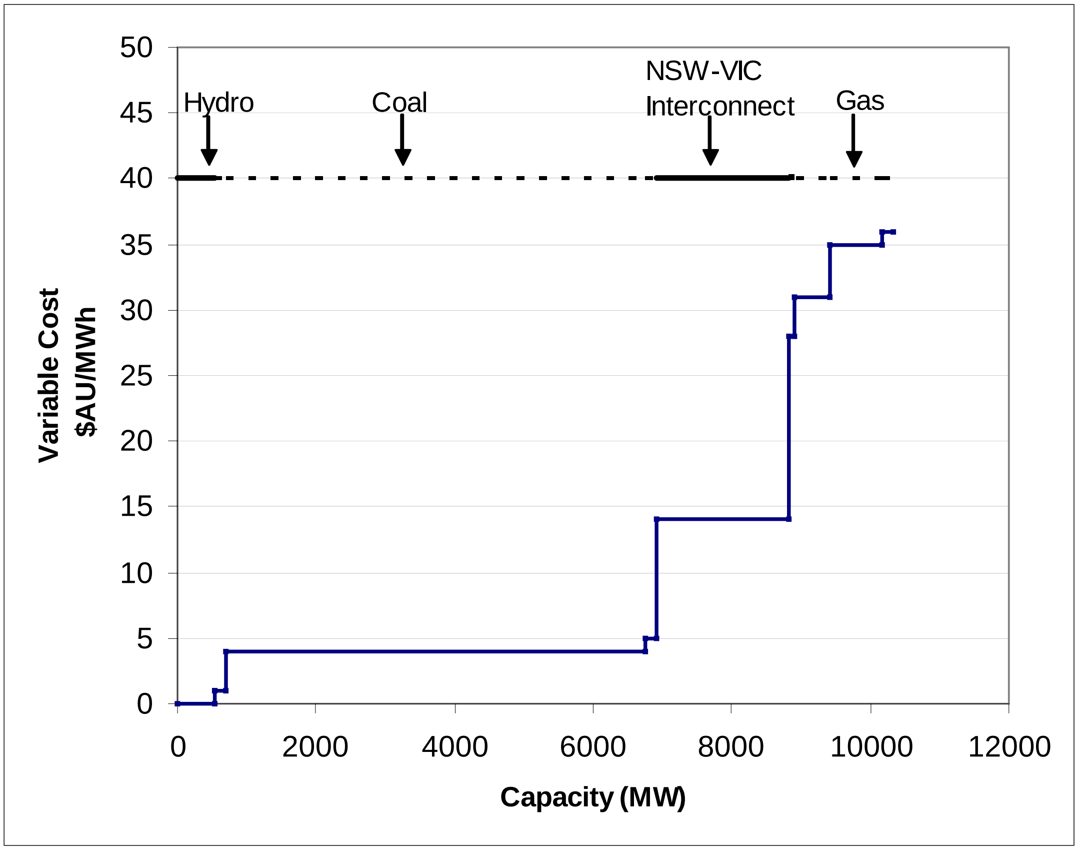

Figure 8: Aggregate Marginal Cost Curve for State of Victoria in June 2003

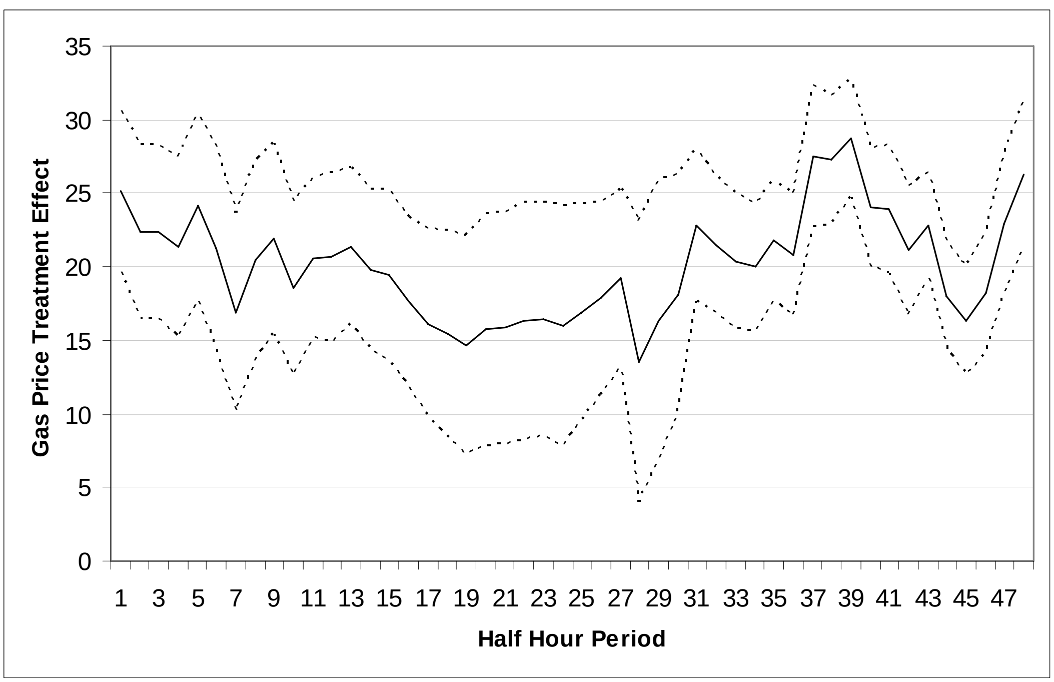

Figure 9: Natural Gas Price Treatment Effect for Victoria Electricity Prices (Percent Price in Increase from Acquisition)

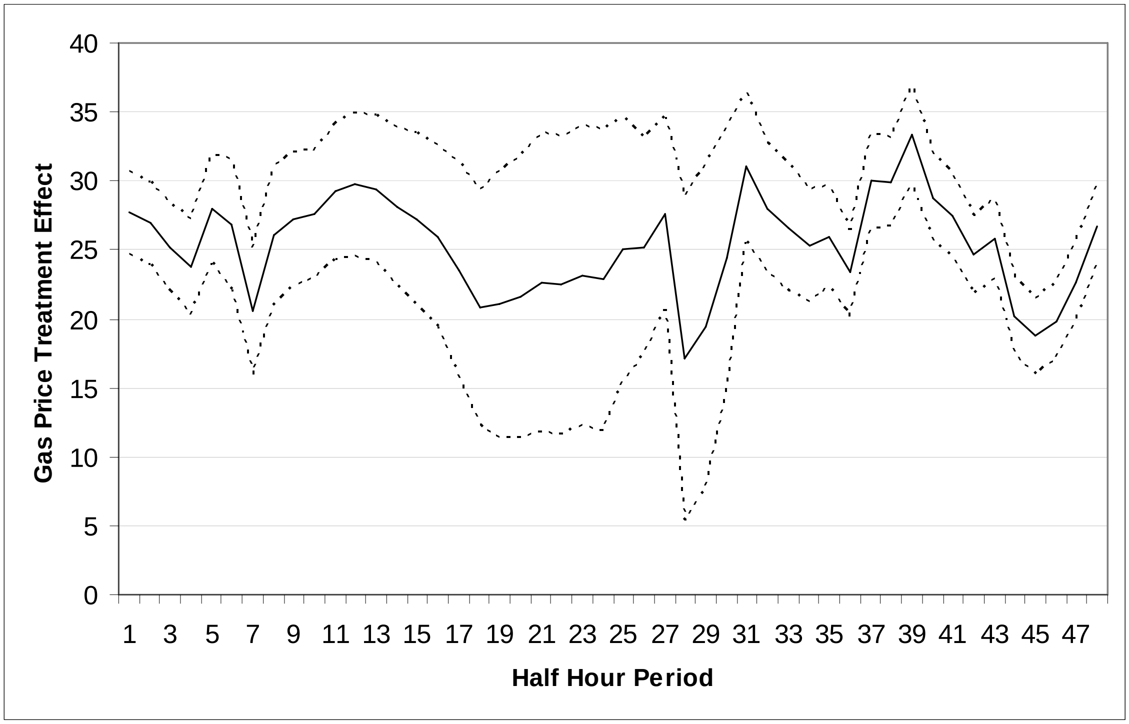

Figure 10: Natural Gas Price Treatment Effect for New South Wales Electricity Prices (Percent Price Increase from Acquisition)

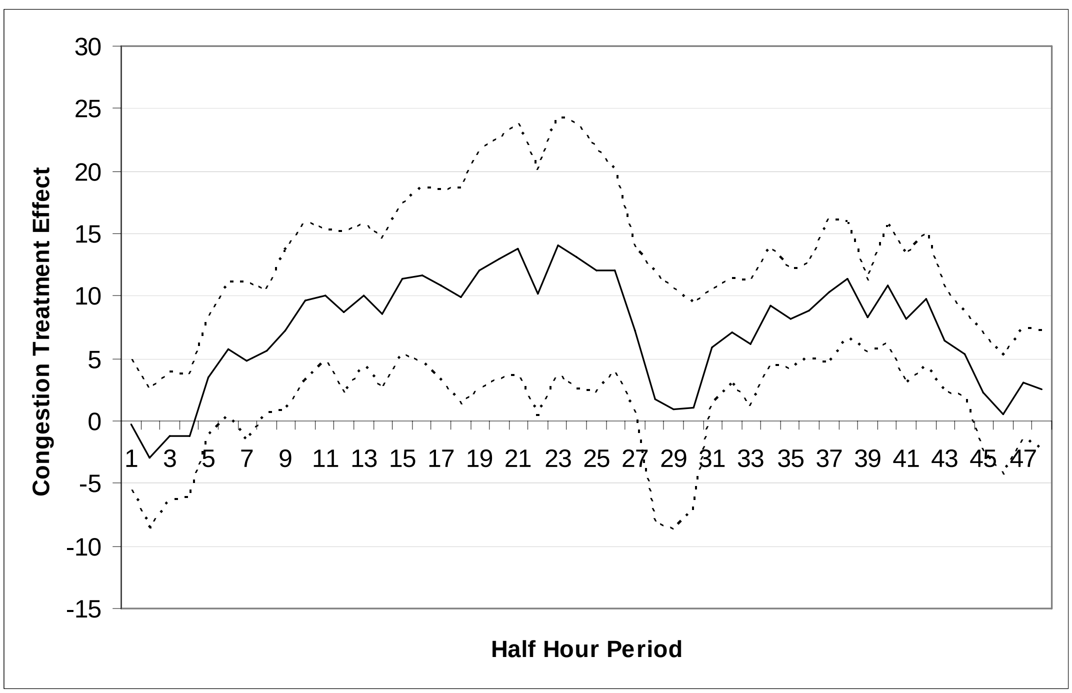

Figure 11: Congestion Price Treatment Effect for Ratio of Price in Victoria to Price in New South Wales for $P_{VIC}/P_{NSW}< 1$ Sample (Percent Increase in Price Ratio from Acquisition)

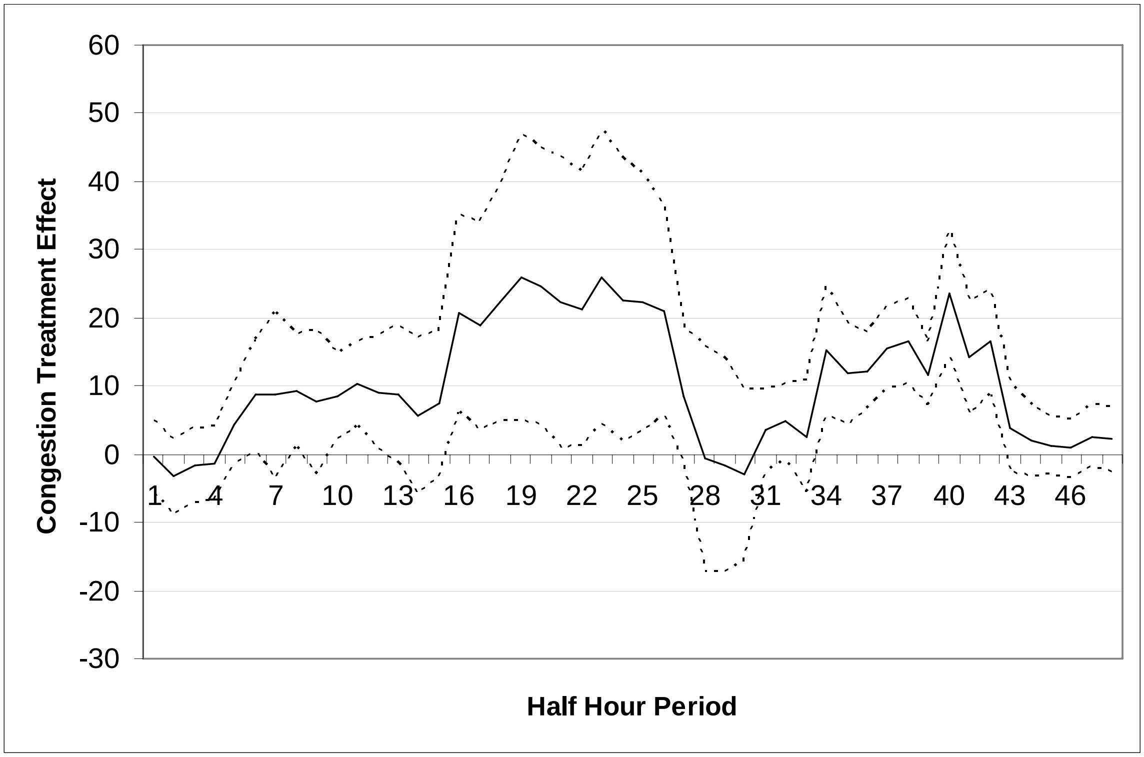

Figure 12: Congestion Price Treatment Effect for Ratio of Price in Victoria to Price in New South Wales for Full Sample (Percent Increase in Price Ratio from Acquisition)

Table 1: Ownership and Generation Capacity in Victoria

Entity (Owner)	Generation plant	Capacity (MW)
Baseload		
SECV	Anglesea, steam coal	150
Loy Yang Power	Loy Yang A, steam coal	2000
Edison Mission	Loy Yang B, steam coal	1000
China Light & Power	Yallourn, steam coal	1450
National Power	Hazelwood, steam coal	1600
Energybrix	Morewell, steam coal	170
Interconnect		
Snowy Interconnect	Vic import capacity	1900
Intermediate		
Duke Energy	Bairnsdale, gas	86
Erarang	Hume, hydro	50
TXU Ecogen	AES Yarra, gas	500
Peak		
Southern Hydro	Various, hydro	498
TXU Ecogen	AES Jeeraling, gas	466
Contact Energy	Valley Power, gas	300
AGL	Somerton, gas	150

Table 2: Actual Half-Hourly Price, Counterfactual Half-Hourly Price and Z-Statistic for Test of Mean Difference

	2000			2001			2002			2003		
	Actual Price ($AU/MWh)	Counterfactual Price ($AU/MWh)	Z	Actual Price ($AU/MWh)	Counterfactual Price ($AU/MWh)	Z	Actual Price ($AU/MWh)	Counterfactual Price ($AU/MWh)	Z	Actual Price ($AU/MWh)	Counterfactual Price ($AU/MWh)	Z
Half Hour Period												
1	17.64	19.39	16.17	14.68	15.46	14.46	12.49	11.71	-0.41	9.48	10.11	14.52
2	17.74	19.82	7.19	14.98	15.81	13.44	12.75	14.06	5.96	10.00	10.79	13.66
3	21.39	24.85	8.34	17.76	18.83	13.07	15.32	16.74	21.19	11.86	12.88	15.82
4	23.02	27.01	7.44	19.96	21.35	14.02	17.35	19.19	20.73	13.32	14.77	13.33
5	40.75	44.48	2.33	24.29	26.03	12.23	20.95	23.85	20.47	16.17	18.18	12.62
6	89.94	102.50	2.75	28.52	31.40	10.93	26.40	30.57	16.02	19.39	22.79	8.22
7	29.70	33.72	7.62	25.23	27.30	14.11	23.49	26.94	16.10	18.45	21.14	11.51
8	34.53	39.78	9.46	28.95	31.50	13.31	27.88	32.59	12.68	20.48	24.10	5.52
9	41.64	46.92	2.55	32.95	36.59	16.10	31.01	38.13	6.15	20.98	25.00	11.18
10	40.86	49.62	9.85	35.48	39.18	17.83	30.93	36.55	14.44	30.30	36.72	2.26
11	40.76	49.45	9.18	36.76	40.64	14.98	32.49	38.77	15.82	22.67	26.07	18.44
12	39.48	47.24	9.03	45.28	48.86	8.49	32.03	38.22	16.12	22.34	26.06	16.57
13	37.90	46.49	7.99	43.33	45.85	2.35	31.66	37.94	12.20	22.61	27.25	4.99
14	37.79	46.73	8.65	37.96	42.68	9.59	31.95	37.73	17.20	23.04	27.98	6.11
15	37.06	46.37	8.08	44.68	48.71	15.37	31.78	37.39	18.22	22.80	26.89	11.31
16	36.90	46.45	8.18	41.12	44.67	11.87	31.77	37.26	17.20	23.50	28.43	5.15
17	36.99	46.82	8.65	53.01	60.94	1.72	32.18	38.08	15.34	23.64	28.81	6.34
18	36.24	45.52	8.08	52.26	62.31	2.11	31.87	37.50	14.81	23.96	28.90	6.12
19	39.33	49.48	8.44	57.80	66.08	1.79	36.97	49.79	2.26	27.74	42.20	1.48
20	38.37	48.47	8.08	66.78	73.86	1.51	33.98	43.47	2.98	24.28	28.96	8.21
21	37.64	47.06	8.51	68.67	82.24	1.78	32.44	38.58	10.27	25.78	33.66	2.99
22	37.29	46.61	8.33	58.35	66.44	1.79	32.22	38.65	8.81	26.06	31.12	5.95
23	37.06	48.48	4.18	63.83	71.51	1.07	32.03	38.01	7.98	26.79	33.89	3.55
24	37.90	49.56	4.93	75.21	81.42	3.91	31.98	37.87	8.52	27.71	37.49	2.76
25	36.52	45.67	7.76	59.92	65.27	3.07	30.47	36.06	9.08	46.98	56.82	2.38
26	36.44	45.60	8.11	50.05	64.78	1.37	33.12	40.98	3.87	23.80	29.07	5.42
27	43.85	54.20	3.22	44.79	48.56	4.62	40.85	54.70	4.26	25.39	30.66	7.66
28	55.60	62.59	3.91	42.93	49.64	2.13	174.13	189.03	2.54	98.64	115.60	1.27
29	53.19	64.76	3.55	47.74	49.71	1.17	138.14	157.48	5.13	94.46	94.25	-0.03
30	49.22	58.67	3.79	35.63	43.67	1.92	52.43	70.43	5.80	40.38	72.26	1.77
31	50.20	56.38	9.39	32.59	36.43	12.05	37.03	45.22	8.28	24.33	28.44	11.70
32	49.20	55.82	8.48	31.73	35.57	8.36	33.79	40.03	10.08	22.32	25.37	15.94
33	46.86	52.48	8.65	29.62	32.94	14.87	31.46	37.48	9.68	21.86	24.94	17.51
34	43.76	48.43	8.54	28.10	31.06	14.67	28.29	33.69	12.16	20.41	23.19	16.83
35	44.39	48.81	9.72	26.85	29.52	18.09	26.05	30.50	14.57	19.71	22.27	15.93
36	37.74	41.37	11.16	24.25	26.48	18.80	22.60	25.79	17.45	17.62	19.56	14.50
37	34.74	41.09	3.40	29.55	32.71	2.62	28.82	34.37	17.76	18.20	20.38	15.55
38	31.47	35.88	4.09	25.47	27.27	10.51	25.47	29.99	16.18	16.97	18.83	18.40
39	50.64	57.10	14.14	31.53	34.26	15.40	31.33	38.20	17.51	20.34	23.24	18.80
40	46.71	51.81	13.35	27.88	29.98	14.52	27.53	32.78	18.30	18.70	21.09	19.11
41	42.19	46.80	7.41	26.05	27.58	12.89	24.59	28.34	19.90	16.82	18.68	19.45
42	32.90	36.42	9.51	23.72	25.06	17.20	22.47	25.72	18.98	15.33	16.88	22.49
43	45.34	50.69	8.65	28.79	32.52	1.97	25.55	30.25	18.99	17.07	18.88	19.15
44	30.75	34.70	7.75	23.18	24.52	16.54	21.61	25.19	19.46	14.51	15.76	22.04
45	26.35	29.16	13.46	20.70	21.88	14.65	18.32	20.98	18.50	12.73	13.63	22.14
46	22.26	24.57	14.22	18.43	19.39	17.17	15.97	17.80	18.72	11.30	12.02	18.92
47	19.08	20.90	15.06	16.30	17.08	16.31	14.19	15.67	17.69	10.33	11.00	17.09
48	17.39	19.08	18.38	14.99	15.74	15.23	13.14	14.30	17.73	9.50	10.09	14.90