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Simulating market power in the New Zealand electricity market

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The recent Wolak report on the New Zealand electricity market found evidence of substantial market power. The report, an empirical one, was heavily criticised on several aspects of its methodology. We investigate market power in the New Zealand Electricity Market during 2006 and 2008 using an alternative methodology; a computer agent-based model. With this model, we can account for all the substantive criticisms of the Wolak report. Our results are broadly in line with those of Wolak, nonetheless there are significant differences. In particular, our allocation of market rents across periods is very different. We estimate total market rents for 2006 and 2008 to be $2.6 billion.

Keywords: electricity markets; computer agent based models; market power

1. Introduction

In 2009, the New Zealand Commerce Commission released a report by Frank Wolak (2009) analysing market power in the New Zealand electricity market (henceforth NZEM). Wolak concluded that over the seven-year period he studied, market power rents amounted to 4.3 billion dollars. This figure attracted considerable media attention. However, the report's methodology came under considerable criticism. The Electricity Technical Advisory Group (ETAG) released a report a few months after Wolak (ETAG, 2009) summarising 'serious reservations' by commentators regarding the calculation of the rents reported by Wolak. In contrast to Wolak's report, ETAG (2009, p. 40) concluded that 'there is no evidence of sustained or long term exercise of market power'.

Branson (2009) reviews the criticisms raised by ETAG (2009) of Wolak's analysis and dismisses many of these out of hand. However, she strongly agrees that the Wolak report underestimates the opportunity cost of stored water, thus over-estimating the extent of market power. This point was also made by the University of Auckland Energy Centre and University of Auckland Electric Power Optimization Centre (Energy Centre and EPOC) (2009) and Evans *et al.* (2012). Other criticisms include arguments that Wolak failed to properly take transmission constraints and plant availability into account and ignored possible demand responses (Evans *et al.*, 2012), an argument that Wolak overstates the incentives of vertically integrated firms to exercise market power in the New Zealand electricity market (Hogan & Jackson,

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2012), and direct criticism of Wolak's empirical methodology (Evans & Guthrie, 2012).[1] However, to our knowledge no one has yet suggested or attempted to replicate Wolak's work taking into account these criticisms.

In this paper, we estimate market power in the NZEM in an approach parallel to that of Wolak, but using a completely different model. Our aim is not to directly defend or critique the approach taken by Wolak, but to independently compute an estimate of market power in the NZEM, using a model that takes into account all of the substantive criticisms of the Wolak Report. In particular, our model – an agent-based simulation model – carefully computes the opportunity cost of water, includes major transmission constraints, and accounts for plant outages. If we were to find significant market power in this model, that would suggest that the criticisms of Professor Wolak's report do not significantly affect his conclusions, and would provide strong evidence contrary to ETAG's conclusion that there is no evidence of market power in New Zealand.

In principle, it should be straightforward to observe the extent of market power in the NZEM. If firms behave competitively they will submit bids into the market at marginal cost with the market price usually set by the highest cost unit dispatched (Stoft, 2002).[2] The difference between this benchmark and actual prices would then be a measure of market power rents. Marginal costs for thermal generators are generally well-known. However, the marginal costs for hydro generators (those with storage) can vary wildly depending on the opportunity cost of water. If the storage lake is full, and more water is flowing in, there is no value in storing any water for the future, i.e. the opportunity cost of using water now is zero. On the other hand, if there are low inflows to the lake, and a spike in demand is forecast, the opportunity cost of using that water now is the price the hydro generator could have received had it held the water until the demand spike.

In many networks, this opportunity cost of water in a competitive market would be no higher than the marginal cost of the most expensive thermal generator, since the hydro plant merely substitutes for a thermal plant. This is essentially the assumption made by Professor Wolak. However, in New Zealand, the predominance of hydro generation implies that some hydro is necessary to ensure market clearing. In very dry periods, when water storage in all lakes is low, the thermal plants will all already be committed. If a hydro plant uses water in such periods, there may not be enough water in the future to ensure total generation can meet demand. In this case, the future price would be the Value of Lost Load (VOLL) which is usually set at around $10,000 in New Zealand. This VOLL would determine the opportunity cost of water, which is well above the marginal cost of the most expensive thermal plant. Note that such periods give peak thermal plants a chance to recover fixed costs and would be expected in a perfectly competitive market.

As seen above, much of the criticism of the Wolak report was directed at the way Professor Wolak treated the issue of water values for the hydro generators. Since the water values, that the generation firms use to determine their offer stack into the wholesale market, are private knowledge they must be inferred indirectly. During dry year events, Wolak determined that water values should be set equal to the most costly thermal unit since, he argued, there was always spare thermal generation. In our view, and in the view of many others, this does not properly take into account the potential risks and uncertainties surrounding a dry year event. It may well be the case that with hindsight one can infer that hydro generators managed their water too conservatively; however, at the time, hydro operators have to consider a range of

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different scenarios, some of which may lead to very high prices or even forced outages.

Tipping *et al.* (2004) present an econometric model for spot prices in the New Zealand Electricity Market that emphasises the part that marginal water values play in determining prices. They state that 'hydrological factors such as storage levels and inflows, are major drivers of hydro generator behaviour. [...] However marginal water values are assessed internally and are not public knowledge' (Tipping *et al.*, 2004, p. 1).

We use a computer-agent model to simulate spot-prices for the New Zealand wholesale market. In this model, computer agents represent different firms in the NZEM, and search for profit maximising offers in the spot market by trial and error with an algorithm that reinforces profitable actions. Following an approach similar to that advocated by Tipping *et al.* (2004) we model water values as a function of national lake storage levels. In reality, water values reflect price expectations and will be a complicated function of a number of factors including lake levels, expected inflows, expected demand and expected changes in non-hydro plant availability. However, as Tipping *et al.* (2004) and Young *et al.* (2011) show, modelling water values as a simple function of expected lake levels does a surprisingly good job. We use this model to compute competitive benchmark prices for our target years.

The approach we take to model market power in the NZEM accounts for nearly all of the substantial criticisms of the Wolak report. We allow for and estimate the opportunity cost of water. We use a realistic 19 node simplification of the New Zealand grid, which accounts for most major line constraints in the network. We explicitly include plant and line availability in the model as well as making allowance for capacity set aside on the reserve market. In our view this is potentially a more productive approach to analysing the Wolak report. While there has been much criticism of the report, as discussed above, it is not clear how important the various failings identified are. The aim of this paper is to test the robustness of Wolak's conclusions in the light of the critiques levelled against it.

We estimate competitive prices and market rents for 2006 and 2008, the latter being the most recent 'dry year'. The Wolak report covered the time period 2001–2007, including the 2001 and 2003 dry years. We would have preferred to replicate the analysis for these years; however, our transmission dataset was only valid for 2005–2009. As a substitute, we chose to examine the 2008 dry year, which is considered more extreme than the dry year events in 2001 and 2003.[3] Since the market power issues identified by Wolak were most pronounced during these dry year events, 2008 should see even more extreme market power if Wolak were correct. Certainly 2008 provides an ideal testing ground for examining market power determined by low hydro storage levels.

In Section 2 we describe the model. In Section 3 we present the main results. Finally in Section 4 we draw some conclusions.

2. Model

The computer agent-based model we use to model electricity prices in the NZEM is described in detail by Young *et al.* (2011). Here we summarise the key details. The computer agents are firms who own generation assets. Each period the firms offer all their available capacity into the spot market. The firms will typically choose to offer different generation units at different prices. Some of the larger generation units are

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allowed to offer up to four tranches of prices/quantity bids into the market by splitting them into units with smaller capacity. The offer prices are found by trial and error through a reinforcement algorithm. Each period, the firm draws offer prices for each of its generation units from a probability distribution, which is updated at the end of the period using reinforcement payoffs. The market is cleared and profits computed. Actions that return high profits have an increased probability of being played the next round, with the process repeated 1200 times to simulate prices for a single half hour trading period. By the end of the simulation the computer has 'learnt' what price offers will probably yield the best profits given the other firms' likely actions and the simulation ends. The average of the last 100 rounds of prices is computed to establish the simulated price prediction.

The model employs computer agents using the modified Roth and Erev algorithm, with further modifications as suggested by Weidlich (2008). The market is simulated using a 19 node simplified version of New Zealand's 244 node network with electricity flows modelled by a DC flow model with line losses. Demand is assumed inelastic.[4] The solver is a simpler version of New Zealand's market solver, and for given bids, demand, and network parameters, it will output dispatch for each generator, prices at each node, and the flow on each transmission line.

Each plant in our model has a rated capacity, and is allowed to bid one price for that capacity. The modified Roth and Erev algorithm requires a discrete action space, so each plant can bid any price in the set $\{0, 10, 20, \ldots, 1000\}$. If each plant were individually owned, then the modified Roth and Erev algorithm works as follows. Agent i has a propensity function $q_{ij}(t)$, defined as the propensity of agent i to play action j in time t. For example an action could be to offer all capacity to the spot market at a price of \$70/MWh. The propensities are updated each time period according to the following rule,

$$q_{ij}(t+1) = \begin{cases} (1-r)q_{ij}(t) + R(x)(1-\varepsilon) & \text{if } j = k \\ (1-r)q_{ij}(t) + q_{ij}(t)\frac{\varepsilon}{M-1} & \text{if } j \neq k \end{cases}$$

where ε is the experimentation parameter and r is the regency (or forgetfulness) parameter. $R(x)$ is the reinforcement the agent receives from x (here x is the profit and the reinforcement is $R(x) = x$). A high profit from choosing action k means that action is more likely in the future. Given the propensities, the action actually chosen in the next round is probabilistic with the probability of choosing action j equal to

$$p_{ij}(t) = \frac{q_{ij}(t)}{\sum_{k=1}^{M} q_{ik}(t)} \tag{1}$$

In practice, one firm owns many plants, and will construct a profit-maximizing strategy across all plants. Thus, it may be optimal for some plants to make less profit in order to maximize the firm's profit. One way to model this would be to set the firm as the agent, choosing a bid for each plant in its portfolio at each round. However, this approach is impracticable. If each plant has 100 possible actions, then one firm with two plants has 10,000 possible actions and so forth. Computation time rapidly approaches extremes. Weidlich circumvented this problem by introducing a parameter ψ, which is a weighting on how much the plant should consider its own profits versus the firm's profits. The plant remains the agent, but its reinforcement

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payoff now depends on the firm's profit as well. The new formula for the reinforcement payoff is

$$Rf(x) = \psi R(x) + (1 - \psi)\left(\frac{\sum R(y)}{n}\right)$$

where the sum is over all the plants owned by the firm, and n is the number of plants owned by the firm.

Consider a very simple example with two firms A and B who each own 100 MW with demand of 150 MW. The marginal cost of generation is zero. The action space is restricted to {0, 10, 20, …, 100}. Initially, each action is equally likely. Set the initial[5] $q_{ij} = 1000$ for each action j, which is defined to be a bid of \$$j \times 10$. Suppose firm A draws their action from the probability distribution and bids in at \$50/MWh and firm B draws a bid of \$80/MWh. The resulting market clearing price is \$80/MWh with firm A dispatched at full capacity and firm B is dispatched at 50MW. The resulting profit is \$8000/h for firm A and \$4000/h for firm B. The next period propensities for firm A and B are

$$\begin{aligned}
q_{A5} &= (1 - r)1000 + (8000)(1 - \varepsilon) \\
q_{Aj} &= (1 - r)1000 + 1000\frac{\varepsilon}{10} \quad j \neq 5 \\
q_{B8} &= (1 - r)1000 + (4000)(1 - \varepsilon) \\
q_{Bj} &= (1 - r)1000 + 1000\frac{\varepsilon}{10} \quad j \neq 8
\end{aligned}$$

In this example, let $\varepsilon = 0.9$ and $r = 0.1$, so $q_{A5} = 1700$ and for $j \neq 5$ $q_{Aj} = 1000$. Similarly $q_{B8} = 1300$ and $q_{Bj} = 1000$ for $j \neq 8$. Using equation (1) the probability of firm A bidding in next round at \$50/MWh is 14% and the probability of firm B bidding in at \$80/MWh is 12%. Good profit actions are reinforced.

When we simulated prices, we took special care that the electricity network data were as close as possible to those actually realised on any given day. For each day and each period, we searched the Centralised Data Set (CDS) of the NZEM,[6] and any plants that were down for planned or unplanned outages were made unavailable for the computer agent firms to bid into the market. We also updated line capacities if lines were out of service for some reason.[7] Some plants such as geothermal, wind, run of river hydro, or hydro on rivers with minimum flow requirements, are classed as 'must-run'. These are always dispatched in the model with bids of \$0/MWh.[8] We also accounted for plants set aside as spinning reserves, which cannot be dispatched on the spot market, by reducing the capacity of each plant by the average fraction of cleared reserves. We estimated these from the CDS to be 12% of total capacity.

The only contract explicitly included in the model was that held between Tiwai Point Aluminium Smelter. If this were not included, demand from the aluminium smelter would be treated as inelastic, and transmission constraints in the South Island would leave Meridian as an effective monopolist. The agent playing Meridian in our model would then raise prices in the south of the South Island up to the maximum allowed of \$1000/MWh.[9]

The firms in the agent-based model are assumed to have at least some incentive to maximise wholesale profits. All the major firms are vertically integrated. As noted by Wolak (2009) and Hogan and Jackson (2012), vertical integration means that firms have less incentive in the short run to drive wholesale prices up. However as long as they have *some* incentive to push prices up in the spot market the agent-based model should, in principle, be able to simulate prices effectively. The major firms are almost always net sellers onto the spot market. They either sell to large industrial users on real-time contracts or to other smaller firms that are net buyers on the spot market. If there are periods where any of the major firms have an incentive to push down prices on the spot market we would expect the model to fail. The calibration of the behavioural parameters described below should implicitly account for the actual incentives that firms face to maximise spot market revenue. Similarly, although we do not include long-term contracts between generation firms and load, which again may reduce incentives to maximise spot market revenue, they do not eliminate this incentive and, as above, the choice of behavioural parameters accounts for this.

Young *et al.* (2011) describes how the behavioural parameters that describe the computer agents are calibrated using data from the centralised data set (CDS) of the NZEM. Initially, simulated prices are compared to actual prices for different behavioural parameters[10] in an environment where water values are close to zero.[11] Once the behavioural parameters are established, water values are determined as a function of the difference between actual and expected lake storage level. We assume that the behavioural parameters we established for periods where water is plentiful also describe the market when water is valuable. The water value is treated as an unknown effective marginal cost for the hydro generation assets. We then back out the water cost function from observed market prices. We compare simulated and actual prices for different lake levels to estimate the unknown water value curve as a function of relative storage levels.[12] We assume this relationship is robust, that is, we assume this relationship is the same every year, and can be used to calculate counterfactuals. An example of this approach would be to assume a market for a product was described by a Cournot model with constant unknown marginal costs and a linear demand function. If the demand function was known, the actual market price could be used to determine the marginal costs and hence profits. If the market was accurately described by a Cournot model this would give the true costs and profits.[13]

Clearly this approach depends crucially on the credibility of the agent-based model we use here. Agent-based models are a relatively new approach to modelling electricity markets. Nonetheless, they are increasingly seen as a useful way of modelling realistic markets (Weidlich, 2008). The model used here is one of the most complex and realistic agent-based models for electricity markets. Young *et al.* (2011) establish that it simulates prices realistically on all 19 nodes of the simplified New Zealand electricity network across a range of market conditions for the year 2006. As we will see, it performs credibly in 2008 as well. In particular, it performs well during periods when we are confident that the water value is zero; that is, it performs well in periods in which we can accurately estimate all of the marginal costs in the system. The calibrated model performs considerably better then a competitive model where firms submit offers at their marginal cost of generation. The model also simulates prices across a range of demand conditions across a typical day, as well as average weekly prices. The calibration and validation results reported by us in Young *et al.* (2011) gives us confidence that the model will accurately simulate prices for 2008, and that the conclusions we reach will be credible and robust. The parameters we use for this simulation are as follows.

We also use the model to simulate the competitive benchmark for each year by forcing the agents to bid their full capacity at marginal cost. Data on New Zealand

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generators were taken from the New Zealand Market Authority's Generation Expansion Model (GEM).[14] The detailed cost functions we use can be found in Young *et al*. (2011). For thermal generators the marginal cost was computed from representative gas or coal prices. Renewable fuel costs are zero but, like thermals, a small operating and maintenance cost is included in the marginal costs per MW. The hydro marginal costs include the water value as discussed above. The competitive benchmark model is used to establish competitive counterfactual prices assuming the same water value for the hydro assets established from the water value curve. During dry year events we find water values rise considerably higher than Wolak assumed.

Any differences in profit between the two simulations we attribute to market power rents.

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3. Results

Four half-hour prices were simulated for each day, with the starting period for each of the four simulations advanced by one period each day. On 1 January 2008 prices were simulated for periods 4, 16, 28, and 40. On 2 January 2008 nodal prices were simulated for periods 5, 17, 29, and 41, and so forth.

Figure 1 illustrates the simulated weekly average prices for the Otahuhu (OTA) node for the whole of 2008. It can be seen that the simulated price path is similar to actual prices in 2008. Figure 2 illustrates the same weekly comparison for the

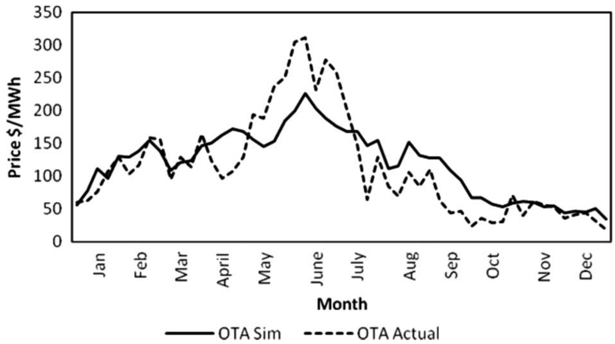

Figure 1. Simulated Otahuhu node weekly average prices for 2008.

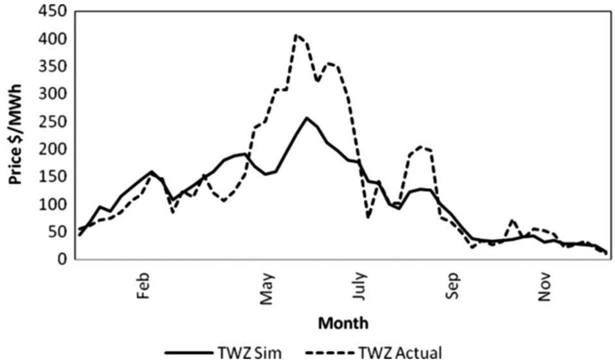

Figure 2. Simulated Twizel node weekly average prices for 2008.

important Twizel (TWZ) node in the South Island. The predicted prices are generally close to observed prices for 2008; however, for both the Twizel and Otahuhu nodes during the period June–July predicted prices are too low. This likely reflects limitations in our water values when lake levels are very low during that period.

Calibrating the water value curve is very time consuming as it involves a large number of simulations. The curves were fitted using approximately 50 points each. For very low lake levels the water level curve, which is exponential, is quite sensitive to the values determined for a handful of points. With hindsight, including more points with low lake levels could have improved the fit for times when prices are very high. Alternatively, the water value curve may not be accurately described by the exponential function we have chosen to use but has more curvature.[15] Estimating the water value curve more accurately is clearly an area for further research. The broad features of the market are reproduced well here for 2008. Figures 3 and 4 illustrate that the agreement is better for 2006. We would not expect that estimating water values using only lake levels for the whole country (and ignoring expected inflows as well as many other factors) will always get the prices exactly right. However, it does get the broad picture right over both years, which gives us confidence that it is a useful model for policy analysis.

We find that the variation in prices during the year is primarily driven by changes in the value of water. Figure 5 illustrates the simulated prices at Otahuhu compared with the water values computed from our water value function for 2008.

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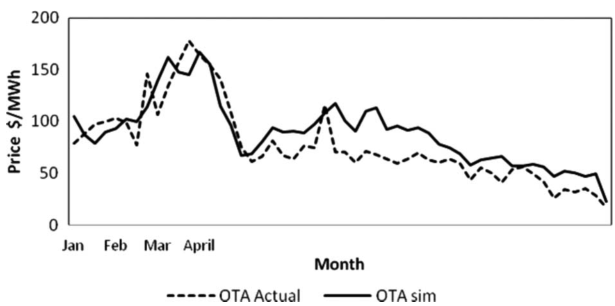

Figure 3. Simulated Otahuhu node weekly average prices for 2006.

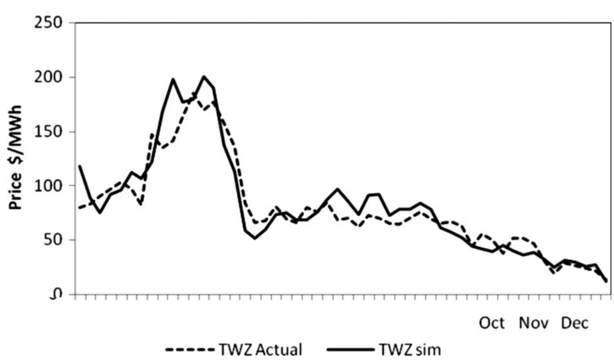

Figure 4. Simulated Twizel node weekly average prices for 2006.

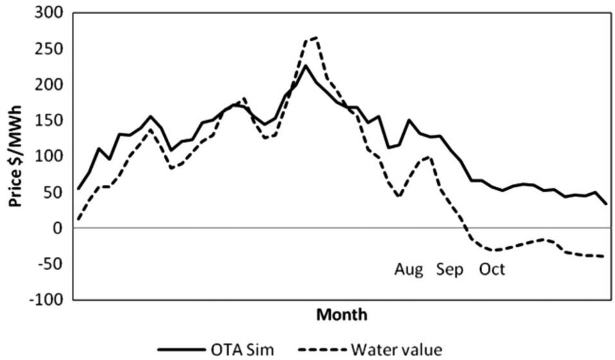

Figure 5. Water values versus actual prices at Otahuhu for 2008.

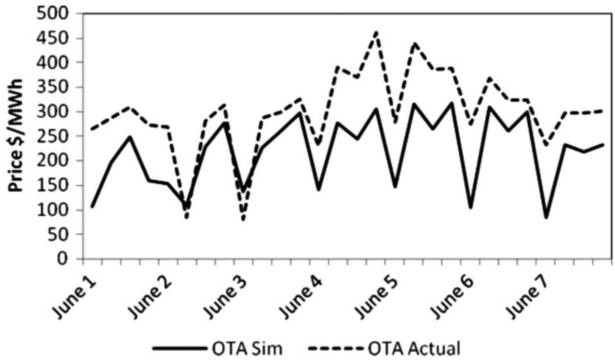

Figure 6. Half-hourly prices (4 per day) from 1 June –7 June 2008.

Note that, at times, the water value can be higher than the average weekly price. This is because when water values are high and demand is low there may be no hydro generation dispatched, aside from must-run generation bid in at zero dollars, and the marginal generator is likely to be a thermal plant bidding in below the water value.

Although we choose here to focus on the average weekly spot prices, it is worth looking in more detail at the hourly prices over the course of a week when water values were high. It will be seen that the average weekly prices conceal considerable variability in prices over the course of a day. During the first week in June, the half-hour simulated prices compare well with the actual prices and capture the variability over the course of the day well.[16] We will return to this point below and argue that it would be difficult to model the variation in prices over the day in a model that assumes no market power.

We turn now to comparing simulated prices to the competitive benchmark. In the competitive benchmark simulation, plants bid in at marginal cost with the hydro marginal costs equal to the value of water plus a small amount covering operating expenses. Figure 7 compares the weekly average computer-agent based model simulation versus the competitive benchmark for Otahuhu for 2008. For reasons of space we cannot report on the results for all 19 nodes, however we have made the full simulation results available for download on the University of Auckland Energy Centre website.[17] In general, we find that simulated prices at all nodes are above the

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competitive benchmark; however, there is some variation. For example North Island mark-ups are typically higher.

We can compute competitive prices and rents at each node by multiplying each nodal price by the demand for each period, and then sum to find the average weekly pattern for both 2006 and 2008. The results are displayed in Figures 8 and 9.

Another key point emerges from these graphs. Market power does not increase dramatically during the period when lake levels are low. On average, it is highest when demand is high.[18] This result is dramatically different to that of Wolak and is a result of us using very different water values to those that Wolak uses. Recall that he effectively uses marginal thermal prices as the opportunity cost of water. If we were to use the same values for water as Wolak did, our simulated prices would be considerably off.

Although our allocation of market rents across periods is different to Wolak (2009), the total rents for the year as a fraction of total revenue are broadly similar. For 2006, where we can make a direct comparison, we find rents that are higher than both of the competitive counterfactuals that Wolak analysed. However, for 2008 we find that market rents are considerably lower as a percentage of total revenue than Wolak found for the comparable dry years of 2001 and 2003 – close to 50% of wholesale market revenue in both cases. Indeed, we argued above that 2008 was, if anything, a more extreme dry year than either of these years. Wholesale market revenue of \$5032 million is considerably higher than either 2001 or 2003, which both saw revenues of around \$3 billion, reinforcing the severity of the 2008 dry year event.

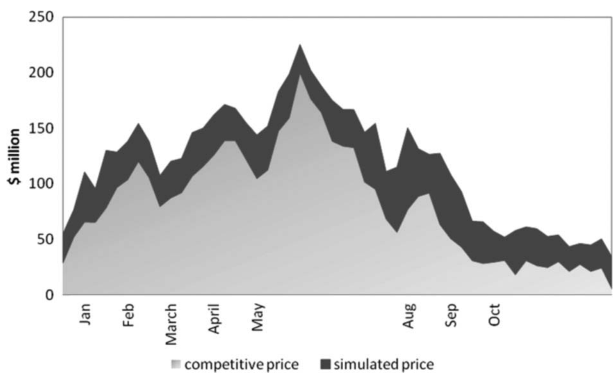

Figure 7. Weekly competitive and simulated prices for 2008 at Otahuhu.

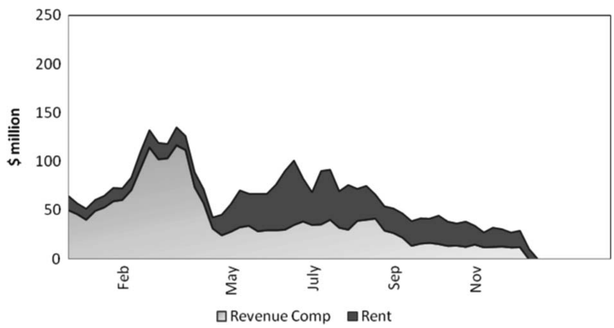

Figure 8. Weekly competitive revenue and rents for 2006.

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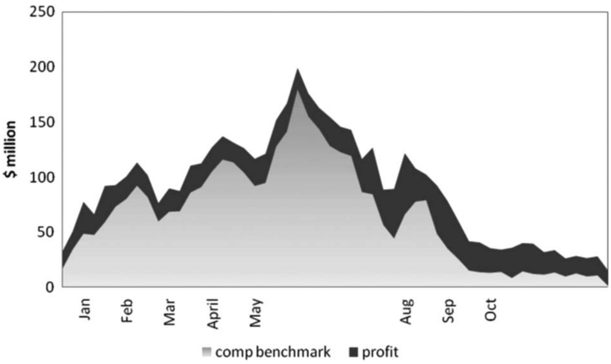

Figure 9. Weekly competitive revenue and rents for 2008.

Another point of interest is that while we find that market rents for 2006 and 2008 are very similar in absolute terms, they are much lower for 2008 as a percentage of total revenue. This again is quite different to Wolak[19] and is a result of our computed water values being considerably higher in 2008. The effective marginal cost of hydro generation for much of 2008 was considerably higher than in 2006. The computer agents found a strategy to push equilibrium prices above cost with the difference between the price and cost varying little as costs increase (holding demand the same). For most situations, the basic Cournot model of market power would lead to similar results.[20]

The focus here is on comparing simulated prices to the competitive benchmark since any errors in simulated prices are likely to be highly correlated with errors in the competitive benchmark, particularly if the errors are due to incorrect water values. As a check, we calculated market rents under the assumption that rents are the difference between actual prices and the competitive benchmark. The results are slightly different, reflecting the fact that, on average, simulated prices are higher in 2006 and lower in 2008 than actual prices.

Another check we made was to run the simulations using a water value curve restricted to be greater than or equal to zero, which restricts the effective marginal cost for hydro to be greater than or equal to \$10/MWh. We found a better fit to prices if we allowed for negative water values,[21] which may reflect the fact that at times firms have no choice about generating hydro if the lakes are very full and more rain is expected. However, we thought it worth checking to see how important this assumption is. It turns out that it makes little difference. For example, for 2008, simulated market revenue is \$4761 million, with market rents of \$1256 million (26% of revenue).

Finally we turn now to examine one aspect of dry year events that can be confusing. Clearly, for most of 2008, prices were well above actual physical marginal costs (that is, ignoring the opportunity cost of water). It is our view that even a perfectly competitive market will take into account the opportunity cost of water. This is very similar to the competitive market for mineral extraction, where even in perfectly competitive markets there will be Hotelling rents as firms take the opportunity cost of allocating mining across different periods into account. In much the same way, competitive firms in a dry year event will take into account the opportunity costs of allocating production of hydroelectricity across different time periods leading to scarcity rents. In theory, in a perfectly competitive market, these

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scarcity rents will encourage entry if too high or exit if too low. On average, they should be just enough to cover fixed costs for the marginal peaking plant and will contribute to fixed costs for other plants.[22] Figure 10 illustrates the competitive prices generated for 2008 under the hypothetical scenario that water is never scarce. In this case the maximum price is that of the marginal thermal unit when demand is high. Frequently, however, the price will be close to zero if there is enough low-cost capacity to cover demand. It can be seen from Figure 10 that these scarcity rents are considerable.[23] One of the key points of difference between the present work and the Wolak report is that Wolak attributes much of these rents to market power.

What we have not considered here is the possibility of entry and exit. It may well be that there are barriers to entry that would lead to less capacity than a perfectly

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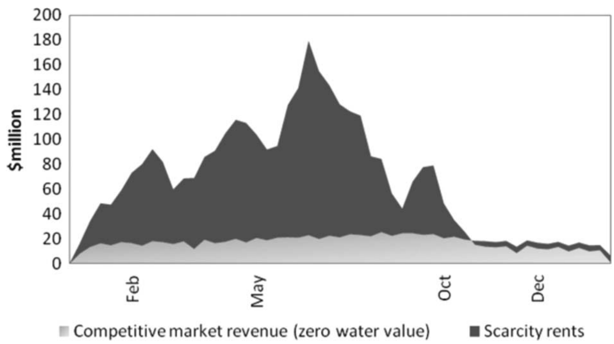

Figure 10. Weekly competitive scarcity rents for 2008.

Table 1. Market rents for 2006 and 2008 using simulated prices.

Year	Simulated Competitive Benchmark Revenue ($million)	% of total	Simulated Market rents ($ million)	% of total	Simulated Wholesale Revenue ($million)
2006	2146	63%	1286	37%	3433
2008	3429	73%	1293	27%	4722
2006 Wolak (2009)*	2330	75%	800	25%	3119

*Average of Wolak's two counterfactuals.

Table 2. Market rents for 2006 and 2008 using actual prices.

Year	Simulated Competitive Benchmark Revenue ($million)	% of total	Market Rents using actual prices ($ million)	% of total	Actual revenue ($million)
2006	2146	70%	898	30%	3045
2008	3429	68%	1605	32%	5032
2006 Wolak	2330	75%	800	25%	3119

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competitive market would produce. This, in turn, would increase the scarcity rent that our competitive benchmark would produce. What we have done here is take the capacity as fixed and simulate a perfectly competitive market with firms bidding in at marginal cost. In reality, a more competitive market would see an increase in capacity as well as marginal cost bidding. Thus, the competitive benchmark should really take this into account and model the actual capacity realised in a competitive market. What this means in practice is ambiguous. On one hand, new capacity could imply lower marginal costs and thus we are underestimating market power rents. On the other hand, new capacity could imply less market power and lower scarcity rents, in which case we are overestimating market power rents.

4. Conclusions

When we embarked on this modelling exercise, our intuition was that accounting for water values properly would result in market rents far lower than those reported in Wolak (2009). Instead, we found market rents similar to those reported by Wolak. However, the distribution of profits over the season and between different years is quite different for reasons discussed above. Given that the results were not what we expected, it is useful to consider critically our approach.

Our methodology relies on using an agent-based model and using accurate cost estimates where possible. We use a simplified 19-node network and a market solver that clears the market based on the offers submitted by the generation firms. We argue that computer agent models have an established track record and that there is a substantial literature that demonstrates that they give credible descriptions of electricity markets (Weidlich 2008; Young *et al.* 2011). To our knowledge there has not been any substantive criticism of this general approach to modelling electricity markets.

Our approach relies on using accurate networks, taking into account line constraints, must-run generation, plant outages, and the reserve market. We think we have accounted for these accurately but there will always be areas where we could improve the model. One example is the way we have accounted for spinning reserves by de-rating all plant capacity by 12%. In the actual market, the reserve and spot market are cleared simultaneously. The agent-based model could be extended to incorporate this; however, it is our view that this would not significantly change the results.[24] Another example where further work would be useful would be to take into account the physical flow restrictions from Taupo into the Waikato hydro chain. We learnt after completing these simulations that flow rates are considerably reduced if the lake level of Taupo falls significantly. Whilst there is always room for improvement, we believe that making these sorts of improvements to the model will not alter our substantive conclusions.

If one accepts the modelling methodology and network data, then calibration becomes a possible area of concern. The calibration exercise determines how successful the agents are in pursuing their profit maximising strategy, and hence how effective they are in exercising market power. After establishing marginal costs, we tune the behavioural parameters to get an accurate fit with prices. Some parameter choices would result in a market with almost no market power, others with considerable market power. Clearly it is very important that generation costs are modelled accurately for the period that the model is calibrated. Young *et al.* (2011) lists in detail the assumptions and the estimated marginal costs of generation for each plant based on data from the New Zealand Electricity Authority. We calibrate the model for periods when water is plentiful and can set the value of water at zero. We then make an assumption that the behaviour parameters do not change as we move into a dry year event. This assumption underlies most agent-based modelling of electricity markets, and we cannot think of a good reason why they may change. However, we accept that this is a possible weakness in our approach. In any case, even if there were very low profits during the periods of water scarcity, that still leaves substantial rents during the periods when water was more plentiful.

Another potential problem is establishing the competitive benchmark, particularly during periods when water values are high. We use the actual lake level data for each year for our modelling simulations. One problem is that these data are based upon actual, historic hydro generation. A competitive market using the same water value curves that we have established would likely generate a different amount of hydro each period, which in turn will change the lake level. Philpot *et al.* (2010) find exactly this when they compute a counterfactual optimal central plan for hydro dispatch for 2005–2007 in the New Zealand market.[25] For much of 2006, the central plan results in 15–20% lower lake levels. If the competitive market followed a similar dispatch to that of the central plan there would be more hydro generation and lower prices when lake levels were low. Hence, our competitive benchmark may have estimated prices that are too high during this period. A possible extension of our model would be to use the lake level counterfactuals that Philpott *et al.* (2010) simulate for the optimal hydro dispatch as the basis for our competitive benchmark. Again, we would not expect our conclusions to alter substantially.

Our analysis finds substantial market power in the New Zealand electricity market. Across the two years we analyse, we estimate total market rents at $2.6 billion. This result is broadly parallel with that of Wolak, despite using a completely different methodology, which addresses nearly all of the substantive criticisms of the Wolak report. This result contrasts strongly with the conclusion of ETAG (2009) that there is no evidence of sustained market power in New Zealand. In our view, it would be very difficult to accurately model prices in the New Zealand Electricity Market without allowing for some market power, even after accounting for the opportunity costs for water.

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Notes

1. The latter argue that Wolak's methodology is flawed and his empirical regression model 'is not identified under ordinary least squares and that even if it were that there is such measurement error that the regression estimates are simply not informative about the utilisation of unilateral market power in New Zealand'.
2. There will also be a small number of hours each year when all capacity is generating and prices are higher than MC of the last plant dispatched. During such times there are competitive scarcity rents that allow peakers to recover their fixed costs (Stoft, 2002).
3. Hunt and Isles (2008) prepared a report for the New Zealand Electricity Commission reviewing the operation of the NZEM during the period leading up to winter 2008 when

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the lake storage level was extremely low. They note that during the period 2 November 2007 to 12 June 2008 national inflow energies were the lowest on record. Cumulative energy inflows were approximately 3800 GWh below the mean. In comparison, 2001 and 2003 saw inflows over the same period of around 2900 GWh and 2200 GWh below the mean respectively.

4. A New Zealand consultancy Castalia (2007) has investigated price elasticity of electricity in New Zealand, and found there was relatively little elasticity, which gives us confidence that this is not a dramatic assumption.
5. The initial value for the starting propensity is determined during the calibration process.
6. The dataset is available on request from the NZ Electricity Authority http://www.ea.govt.nz/industry/modelling/cds/
7. The 19-node simplification is based on the 220 kV lines in the New Zealand network so we do not consider outages in the 110 kV and 66 kV lines.
8. The computer-based agents have no control over their must-run generation. For many hydro plants, the must-run generation will be some fraction of their available generation capacity. The remainder of the capacity is available to the firms to bid into the market in the usual way. Total must-run amounts to around 17% of capacity.
9. The price cap is set at this level to restrict the action space of the computer agents. Allowing much higher bids would increase the numerical complexity and simulation times considerably. Although there is no price cap in the NZ market we note that very recently in a draft decision the NZ Electricity Authority has effectively capped prices on 26 March 2011 at between \$1500–\$3000/MWh.
10. The most important parameters are ε, ψ and r.
11. That is, when lakes are very close to capacity.
12. More details can be found in Young *et al.* (2011). Specifically, we calculate the historical average and variance (using data back to 1990), then calculate a benchmark by computing the mean minus 1.8 standard deviations. The difference between this and the actual water storage level gives the value that we use to compare water storage on different days and years. We model curves for summer and winter separately. The summer curve for summer (1 August to 29 Feb) is $WV = 130 \times \exp(-0.0017 \times D)-45$. For winter, the curve is estimated as $WV = 185 \times \exp(-0.0018 \times D)-28$ where D is the difference between the actual national storage levels and the expected benchmark level (which is similar to 'minzone', which the electricity commission used to monitor risk). Note that at times the water value is negative. In the NZ market, firms must offer in at prices at or above zero so a negative water value is treated as zero marginal cost for water.
13. At the risk of labouring the point, we could have assumed that the market was competitive and concluded that price equals cost and that profits were zero. In comparing the two assumptions (Cornot or Competitive) we would need more information. For example, if there were trading periods where the true marginal costs are known.
14. Information on GEM can be found at http://www.ea.govt.nz/industry/modelling/in-house-models/gem/.
15. Indeed Tipping *et al.* (2004) use a curve that depends on the exponential of D^2, where D is the difference in the lake level and our benchmark lake level described above.
16. The volatility of prices over the day is typically less well captured by the ABM then average prices. At times the ABM model may display more or less variability over the course of a day than actual prices. For example, the following week in June sees very little variability in actual prices whilst the ABM continues to predict similar variability to that seen in the first week in June. Average prices are about right though.
17. http://www.business.auckland.ac.nz/Schoolhome/Research/Researchcentres/EnergyCentre/tabid/1127/Default.aspx
18. Across all half-hourly periods (1460) simulated during 2006 the correlation coefficient is 0.71. For 2008 it is more weakly correlated – the correlation coefficient is 0.5. Mark-up is also higher when demand is high. The correlation coefficient between the mark-up and demand for 2006 is 0.56, for 2008 it is 0.32.
19. Wolak finds that during dry years (where water values would be high in our model) market rents as a percentage of revenue are much higher than wet years.
20. The basic Cournot model marks up costs by a term that depends on the inverse elasticity. As long as this does not change too much as costs change, the result will hold.

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21. Tipping *et al*. (2004) also allow water values to be negative at times.
22. Generation units that have marginal costs below the marginal plant dispatched will also earn competitive rents. See Stoft (2002) for an excellent discussion on these issues.
23. For 2008, scarcity rents total $2453 million which is 52% of wholesale market revenue.
24. Many of our early simulations did not de-rate the plants for the reserve market. De-rating plants for the reserve market improved the accuracy of the model but not dramatically.
25. Which determines water values for a perfectively competitive market.

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