EMPIRICAL ASSESSMENT OF MARKET POWER IN THE ALBERTA WHOLESALE ELECTRICITY MARKET

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ABSTRACT

This paper develops an index to measure a firm's strategic behaviour in the Alberta electricity market. A firm-behaviour parameter is extracted from price-cost margin data by distinguishing a firm-behaviour effect and a demand-elasticity effect. Although strategic firms withheld capacity during the sample period of 2003-2004, when price was above marginal cost, evidence suggests that it is more likely that firms priced competitively than that they used unilateral market power pricing given an inelastic residual demand faced by strategic firms.

Keywords:
Market power - Electricity market - Wholesale - Firm behaviour - Alberta

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1. INTRODUCTION

In the early 1990s, several countries began to unbundle regulated electricity monopolies into generation, transmission, distribution and retail companies. Transmission and distribution services remained regulated but generation and retail services were opened for competition. Both wholesale and retail electricity markets were created.

In some cases, the newly created markets, in California and the United Kingdom for example, experienced difficulty mainly because of poorly designed market rules and the strategic behaviour of generators. Market power issues became more and more important in the determination of the success of deregulated electricity markets. The issue of how to measure and deal with market power in the wholesale electricity market caught the attention of academics.

In Alberta, the question of how to measure and mitigate market power has become increasingly important. For example, Frayer and Goulding (2005) addressed the issue of the coming expiration of holding restrictions regulations on the purchase of Power Purchase Arrangement (PPA) capacity[1]. They suggested tests to detect market power. But this methodology was nothing more than measuring the concentration of the market and the price-cost margin of the peaker. Regulators in Alberta still do not have useful and workable tools to understand, measure and take action on market power issues.

Several methods of measuring market power have been developed recently for the other electricity markets around the world, especially those in the United States. Borenstein, Bushnell, and Wolak (2002) simulated a perfectly competitive market and compared the price outcomes with actual market level data in order to measure the market inefficiency in the California market. They found that, during the summer period of 2000, electricity consumers in California paid $6.94 billion more in comparison with the same period in 1999. More than $4 billion of this was determined to be a result of the exercise of market power. Bushnell and Saravia (2002) and Mansur (2001) adopted similar methodologies when they assessed the competitiveness of the New England market and the Pennsylvania-New Jersey-Maryland (PJM) market.

Using a different method, Puller (2002) was able to reassess the market power in California with firm level data. He found that firm conduct is relatively consistent with a Cournot pricing game during the period 1998–1999.

In this paper, the theoretical method comes from Puller (2002), although the model may appear different. In various electricity markets, market rules and market set-ups can be dramatically different and so adapting a theoretical method to a specific market can be very difficult. The intention of this paper is to develop a competitiveness index specifically for the Alberta market through a simple and standard economic approach. This paper, to my knowledge, is the first of this kind to target the Alberta market.

The analysis indicates that, during the sample period, firms in Alberta were more likely to price competitively than to use unilateral market power pricing. Moreover, firms had higher price-cost margins during the off-peak season. The reason for this unusual off-peak pattern will be explained in detail later in this paper.

In Section 2, I briefly introduce how the Alberta wholesale electricity market works. In Section 3, I briefly review what market power in the electricity market is and how researchers model it. In Section 4, 5, 6 and 7, I develop a theoretical model to measure market power in

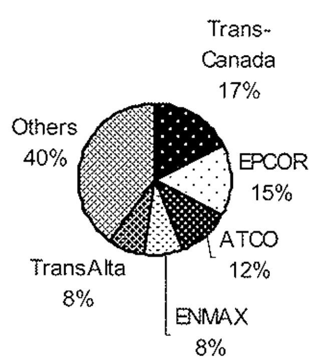
[1] See Section 2 for reference.

Alberta. In Section 8, I describe how the data were obtained. In Section 9, the method used to estimate the model and the results from the estimation are presented. In Section 10, I conclude the paper and point out improvements that could be made in the future.

2. THE ALBERTA WHOLESALE ELECTRICITY MARKET

The Alberta Electric Utilities Act was proclaimed in 1995 and went into effect on January 1, 1996. In order to diversify the control of regulated plant output, Power Purchase Arrangement (PPA) was used and a PPA auction was completed in July 2000. A 20% PPA holding restriction was implemented. Through PPAs, some generating firms in Alberta own the right to offer electricity to the market even though they do not own the underlying assets. Unsold PPAs were held by the Balancing Pool (BP) and strip contracts were used to sell the offer rights part by part to market participants through consecutive Market Achievement Plan (MAP) contracts. In the calculating of market shares and the modeling of market power, it is the offer rights that matter. Among generation firms in Alberta, five have a relatively large market share. The rest of the generating firms are very small, with a market share of no more than 2-3% each. Counting only coal-fired plant and gas-fired plant offer rights, TransCanada, EPCOR, ATCO, ENMAX and TransAlta have 17%, 15%, 12%, 8% and 8% market shares, respectively (Figure 1).

Figure 1. Market Share



In this paper, the generation firms in Alberta are divided into two groups. One group contains the five largest firms. These firms are called strategic firms. The other group contains the small generating companies. These firms are non-strategic firms or the competitive fringe. I assumed that non-strategic firms bid competitively. I also removed hydro, wind and biomass capacities, if any, from the five largest firms and assigned these capacities to the competitive fringe since their cost is more opportunity-cost, which is totally different from the marginal-cost structure of coal- and gas-fired units. The demand faced by strategic firms is called residual demand. Total demand, in the short run, is nearly perfectly inelastic and any elasticity of residual demand comes from the elastic supply of the competitive fringe. When the market is tight, residual demand can be very inelastic and strategic firms can raise market price to earn extra profit for all their infra-marginal output.

In Alberta, generators can have a maximum of seven blocks to bid into an hourly, uniform-price auction, and form a merit order. Following the merit order, generators obtain the right to supply power to the electricity grid. The size of the bidding blocks and even the price of each block can be changed through energy restatement and locking restatement. Importers and exporters are forced to be price takers by the market rules during the 2003–2004 sample period. This is because imports and exports are generally scheduled one hour in advance and cannot effectively respond to inter-hour market dispatches. In other words, trading of electricity between Alberta and other jurisdictions is completely inelastic within any hour once the trading hour begins. Therefore, generators in Alberta essentially face a demand net of imports and exports.

Wholesale electricity price in Alberta was capped at $1000/MWh (megawatt hour) during the sample period to limit the exercise of market power.

3. Market Power in the Electricity Market

The general definition of market power in economics is the ability to profitably alter prices away from competitive levels. Harvey and Hogan (2001, Page 3) have provided a market power definition for the electricity market: "market power is the ability to withhold production on some units in order to increase market prices and profit more from production on other units."

Exercising market power can be very complicated in the electricity market, especially when the electricity networks are constrained. Generally speaking, there are two methods employed by generators when exercising market power: physical withholding and financial withholding. Unfortunately, in most cases, it is impossible to distinguish between the two strategies, since generators are free to exercise market power by reducing output or increasing price. Sheffrin (2001) found only one example in the California market where a generation company shut down a plant in order to exercise market power. In Alberta, energy restatement and locking restatement make exercising market power through financial withholding much easier. In this paper, only financial withholding is considered.

Market power can distort choices and create deadweight welfare loss. The market equilibrium is inefficient. Moreover, uneconomic dispatch will fail to allocate social resources economically and so waste some of these resources[2]. Exercising market power may also hurt the fairness of the market and create unwarranted wealth transfer. Therefore, measuring market power and taking appropriate actions are important tasks for both academic researchers and market-regulating agencies.

Stoft (2002) pointed out that exercising market power is not viewed as antisocial behaviour but as simply a rational form of market behaviour that usually leads to an inefficient outcome. Although sustained market power abuse warrants corrective actions, I suggest making new entry easy and allowing competition to do the heavy lifting. Well-designed market rules, which can reveal true cost and demand preferences, may be better solutions than direct regulation and investigation.

The modeling of market power in the electricity market helps clarify the factors that control the exercise of market power and provides important information for market design. Common measures of market power, such as the Herfindahl-Hirschman Index (HHI) and Lerner Index, are unreliable and fail to consider the behaviour of strategic firms. Stoft (2002)

[2] Higher marginal cost units run while lower marginal cost units exercise market power by withholding.

pointed out that the HHI provides almost no guidance when used in a power market. Although the Lerner index is a reasonable indicator of market power in most markets, it offers little information, provides little insight into the style of competition and fails to explain if a high price-cost margin is a result of less competitive behaviour or a less elastic residual demand.

This paper breaks price movements down into a cost effect, a demand-elasticity effect and a firm-behaviour effect. I address the shortcomings of the above common measures, starting with the modeling of the rational behaviour of the market participants in the next section.

4. THE ECONOMIC MODEL

A static, one-shot quantity-setting game played by strategic firms is assumed in this paper. A quantity-setting game is assumed because there is no firm that could set the price by supplying the entire market. Strategic firms choose a single-period output to maximize profit without intertemporal considerations about the effect of this period's behaviour on future profit. In Alberta, strategic firms bid every hour and the hourly pool price is greatly influenced by trading activities, plant outages and demand shocks, which are highly uncertain. Thus the pool price is volatile and difficult to forecast, even for the next several hours. It is impossible to determine, then, any time length that strategic firms might consider to maximize profits. Although a static model may not exactly match the reality in Alberta, it is probably the best approximation.

In Alberta, strategic firms sell their product in the real time market and/or through forward contracts. Since firms selling their product in the forward market have less incentive to exercise market power, product sold forward does not count as infra-marginal output. Forward sale data at the firm level are not publicly available and omission of forward sales will underestimate the market power exercised by those firms that sell forward.

Strategic firms may offer their capacity in the ancillary services market. Any capacity committed to ancillary services should be included in the infra-marginal output, although no electricity is generated. Unfortunately, data on ancillary services are not publicly available either and I will not consider them in this paper. This treatment may overestimate the market power exercised by the strategic firms.

Net imports should be counted as the infra-marginal output of the firm. But the import-export data at the firm level are not publicly available. Fortunately, the biggest player on the inter-province tieline has no physical assets in Alberta and the activities of the rest of the players on the tieline are negligible. Therefore, the omission of the trading activities of the strategic firm is expected to produce negligible bias in the market power analysis.

Let D_t be the total demand for electricity in Alberta, $NIMP_t$ be the net imports of electricity to Alberta, and Q_t be the total electricity supply of all the firms in the territory of Alberta. Then we have:

$$Q_t \equiv D_t - NIMP_t. \tag{1}$$

Let Q_{1t} be the supply of competitive fringe, Q_{2t} be the supply of strategic firms, and DR_t be the residual demand. Then we have:

(2) $$Q_t \equiv Q_{1t} + Q_{2t}, \text{ and}$$

(3) $$Q_{2t} \equiv DR_t.$$

Let π_{it} be the profit of firm i at time *t*, $p(Q_{2t})$ be the inverse residual demand function, q_{it} be the output of firm i at time *t*, and $C_{it}(q_{it})$ be the total cost of firm i at time *t* when output q_{it} is produced. Then we have:

(4) $$\pi_{it} = p(Q_{2t})q_{it} - C_{it}(q_{it}), \text{ and}$$

(5) $$Q_{2t} = \sum_{j=1}^{N} q_{jt}.$$

Assume there are N strategic firms playing a quantity game with a capacity constraint.

(6) Define $$\frac{dC_{it}(q_{it})}{dq_{it}} = c_i(q_{it}),$$

where $c_i(q_{it})$ is the marginal cost of generator i with output q_{it}.

Then the generating firm's problem can be written as:

(7) $$\underset{q_{it}}{Max} \;\; \pi_{it} \;\; s.t. \; q_{it} \le cp_{it},$$

where cp_{it} is the capacity limit of generator i at time *t*.

The Lagrangian for this problem has the following form:

(8) $$L = \pi_{it} + \lambda_{it}(cp_{it} - q_{it}) = p(Q_{2t})q_{it} - C_{it}(q_{it}) + \lambda_{it}(cp_{it} - q_{it}).$$

The first order condition with respect to q_{it} is:

(9) $$p(Q_{2t}) + q_{it}\frac{dp(Q_{2t})}{dQ_{2t}}\frac{\partial Q_{2t}(q_{it}, q_{-it})}{\partial q_{it}} - c_i(q_{it}) - \lambda_{it} = 0,$$

where λ_{it} is the shadow value of additional capacity when the capacity constraint is binding, so that

(10) $$\lambda_{it} = 0 \text{ when } q_{it} < cp_{it}, \;\; \lambda_{it} \ge 0 \text{ when } q_{it} = cp_{it}.$$

Define $\gamma_{it} = \frac{\partial Q_{2t}(q_{it}, q_{-it})}{\partial q_{it}}$ as the behavioural parameter. γ_{it} measures the effect of changing firm i's output on the total output of the strategic firms.

The above first order condition becomes:

$$(11) \qquad p(Q_{2t}) + q_{it} \frac{dp(Q_{2t})}{dQ_{2t}} \gamma_{it} - c_i(q_{it}) - \lambda_{it} = 0$$

Solving for γ_{it} from the above first order condition yields:

$$(12) \qquad \gamma_{it} = \frac{p(Q_{2t}) - c_i(q_{it}) - \lambda_{it}}{-q_{it} \frac{dp(Q_{2t})}{dQ_{2t}}}.$$

γ_{it} as a continuous variable could serve as a general index for the competitiveness of an electricity market. γ_{it} ranges from 0 to ∞ with higher values signalling greater market power. Intuitively, γ_{it} is the price-cost margin, $p(Q_{2t}) - c_i(q_{it})$, adjusted for scarcity rent, λ_{it}, and then divided by infra-marginal output, q_{it}, and the negative value of the price-output slope of strategic firms, $\frac{-dp(Q_{2t})}{dQ_{2t}}$. For example, when a strategic firm has idle capacity (λ_{it}=0), produces small output and faces very elastic demand but can still maintain a high price-cost margin, the behaviour of this firm is believed to be less competitive. The following three special cases in Section 5, 6 and 7 may be observed in calculating γ_{it}.

5. Perfect Competition Outcome

When a market is characterized as perfectly competitive, any increase in the output of an individual firm should have virtually no impact on market price and total market output, i.e.,

$\frac{\partial p_t}{\partial q_{it}} = \frac{\partial Q_{2t}(q_{it}, q_{-it})}{\partial q_{it}} = 0$, which implies that $\gamma_{it} = 0$.

The above first order condition becomes:

$$(13) \qquad p_t - c_i(q_{it}) - \lambda_{it} = 0.$$

This means that price equals marginal cost or that the price-cost margin purely reflects the scarcity rent when firms run out of capacity.

6. Cournot Solution Outcome

In the Cournot competition framework, each firm maximizes its profit based on the assumption that the quantity produced by other firms is invariant with respect to its own quantity decision.

The above condition could be expressed as

$$\gamma_{it} = \frac{\partial Q_{2t}(q_{it}, q_{-it})}{\partial q_{it}} = 1 \tag{14}$$

and the first order condition becomes:

$$p(Q_{2t}) + q_{it}\frac{dp(Q_{2t})}{dQ_{2t}} - c_i(q_{it}) - \lambda_{it} = 0\,. \tag{15}$$

The above equation illustrates that a strategic firm will produce electricity at a level for which the extra profit, by producing an additional unit of output, $p(Q_{2t}) - c_i(q_{it}) - \lambda_{it}$, is exactly offset by the loss on all the outputs due to the decrease of electricity price, $q_{it}\frac{-dp(Q_{2t})}{dQ_{2t}}$.

7. Tacit Collusion Outcome

Electricity markets can be characterized as a frequent interaction of players and relatively transparent rivals' information. New entry to the market is constrained because of the time needed to build and investment decisions under uncertainty. Hence the electricity market is conducive to collusion among generating firms. Perfectly collusive pricing is joint-monopoly pricing. Generators may determine their interdependence and unite to maximize the profit of a group of generators, sharing the profit thereafter. If the group of $N > 1$ dominant generators possess symmetric features[3], which are characterized by $\gamma_{it} = \frac{\partial Q_{2t}(q_{it}, q_{-it})}{\partial q_{it}} = N$, the above first order condition will be:

$$p(Q_{2t}) + q_{it}\frac{dp(Q_{2t})}{dQ_{2t}}N - c_i(q_{it}) - \lambda_{it} = 0\,. \tag{16}$$

In Alberta, strategic firms are not symmetric, at least in terms of market shares. If we assume features other than the size of firms are symmetric, then it is possible to have γ_{it} fluctuating between 3 and 8.

Hypothesis tests could be carried out in order to establish if the underlying data suggest $\gamma_{it} = 0$, $\gamma_{it} = 1$ or $\gamma_{it} > 3$, implying the existence of perfect competition, Cournot

[3] Assuming firms have the same size, same \$/MWh cost structure and earn the same \$/MWh profit.

competition or collusive pricing, respectively. I argue that, as a continuous variable, γ_{it} serves as a meaningful index for the general competitiveness of the electricity wholesale market.

8. DATA

The five strategic firms in Alberta are TransCanada, EPCOR, ATCO, ENMAX and TransAlta. Data for the actual generation and marginal cost of each generating unit of the strategic firms are needed. The hourly pool price, demand, and export and import data are also needed in order to estimate the model.

Hourly pool price data and the actual hourly output of each generating unit can be found at the AESO website[4]. Output of all the units for which a strategic firm possesses offer rights is summed up to form the output of the firm. Strip contracts are not counted because there is no information about which company actually supplied the outputs recorded on the AESO website. TransCanada owns the Genesee #2 and Sheerness #2 strip contracts. Enmax owns the Genesee #1 strip contract. The omission of these strip contracts may result in a slight overestimation of the market power exercised by TransCanada and Enmax. The MacKay River cogeneration and Genesee #3 plants are not included because they entered the market in late 2004 and initial commissioning operations are not conducive to the exercising of market power. Operating data for ATCO's Scotford Upgrader are also not recorded at the AESO website. Scotford is used to supply steam and electricity for the oil sands project, and it is likely that Scotford seldom produced electricity for the grid during our sample period.

Measuring each unit's marginal cost is very difficult. Assumptions and estimations are necessary. The marginal cost of each generating unit at every hour includes:

1) Fuel cost
2) Variable operating and maintenance (O&M) cost
3) Transmission tariff

Technical characteristics of all the strategic firms' units are available at the firms' websites. The key factor in calculating fuel cost is heat rate. The heat rate (GJ/MWh) measures the conversion rate from the heat content of the fuel to the amount of electricity produced. It is determined by the unit capacity, age of the unit and the technology that was used, such as open-cycle, combined cycle, super high pressure or sub-critical operation. The estimated heat rates are listed in Table 1. The fuel cost ($/MWh) of generators is obtained by multiplying the heat rate by the fuel price, where fuel price is in units of $/GJ. Daily natural gas prices are available at the NGX website. The coal price in Alberta is relatively stable and $0.5/GJ was used in this paper. Variable O&M costs are estimated, based on the operating characteristics of the generators. All gas-fired units are assumed to have $0.5/MWh variable O&M cost except Sturgeon #1 and #2 at $1.5/MWh. All coal-fired units are assumed to have $1/MWh variable O&M cost except Wabamun #1 and #2 at $1.5/MWh. The low end of the variable O&M cost is used to reflect the O&M cost that actually affects the unit's dispatch decision. The variation of minus or plus ten dollars for the marginal cost is examined later in the paper.

[4] http://ets.powerpool.ab.ca/

The transmission tariff includes loss charge, interconnection charge, operating reserve charge and regulated generating unit connection charge. The loss charge equals the location-specific loss factor multiplied by the pool price for every MWh of output generated, where the location-specific loss factor is determined by the AESO and is available at the AESO website. The interconnection charge and operating reserve charge are determined by the AESO and are applicable to all the generators' output without discrimination. The specific figure is also available at the AESO website[5].

Table 1: MCR[6], and Heat Rate

Generating Unit	Type	Maximum Continuous Rating (MW)	Estimated Heat Rate (GJ/MWh)
BearCreek	Combined Cycle Cogeneration	82.5	9
Carseland	Cogeneration	90.5	9
Redwater	Cogeneration	46.5	9
Sundance #1	Coal	286.5	11
Sundance #2	Coal	288	11
Sundance #3	Coal	370	11
Sundance #4	Coal	365.5	11
Sundance #5	Coal	367.5	11
Sundance #6	Coal	406	11
Battle River #3	Coal	151.5	13
Battle River #4	Coal	159.5	13
Battle River #5	Coal	380	13
Rossdale #8	Open-cycle	67	15
Rossdale #9	Open-cycle	71	15
Rossdale #10	Open-cycle	71	15
Joffre #1	Cogeneration	474	7
Muskeg River	Cogeneration	200	7
Poplar Hill #1	Open-cycle	47	11
Primrose #1	Cogeneration	85	9
Rainbow #1	Open-cycle	26	11
Rainbow #2	Open-cycle	40	11
Rainbow #3	Open-cycle	21	11
Rainbow #5,	Cogeneration	49.5	9
Rainbow Lake #1	Cogeneration	52.5	9
Sturgeon #1	Open-cycle	10	25
Sturgeon #2	Open-cycle	8	25
Valley View #1	Open-cycle	45	11
Keephills #1	Coal	387.5	11
Keephills #2	Coal	386.5	11
Wabamun #4	Coal	279.5	13
Suncor	Cogeneration	445	7
Wabamun #1	Coal	61.5	15
Wabamun #2	Coal	58	15

[5] http://www.aeso.ca/transmission/211.html

[6] MCR (Maximum Continuous Rating) shows the maximum output that a unit can produce continuously. MCR decreases in the summer months. Using constant MCR in this paper overestimates the market power exercised by the strategic firms.

The regulated generating unit connection charge is $365/MW per month and only applies to those units built within the regulated regime and specified in the Alberta Electric Utilities Act (1998). The amount is minute and was ignored in the marginal cost calculation in this paper. The marginal cost of the unit is assumed to be constant up to the capacity of the unit.

Any outages of the generating unit are treated as unavailable instead of as withholding, because shutting down the unit to exercise market power is very rare and imposes a future start-up cost. Obtaining the marginal cost of the generating units is not the end of the story, since it is each firm's marginal costs, rather than the marginal costs of generating units, that are required. The firm's marginal cost is set as the highest marginal cost of all the running generating units of the firm. In some circumstances, the firm's higher marginal cost unit runs while lower marginal cost units may still have idle capacity. The higher marginal cost is used as the firm's marginal cost. Because the firms may be involved in dynamic optimization, the shadow cost of the operating constraint has to be considered in this case. The only problem with using higher marginal cost is that a higher marginal cost unit may operate in order to maintain network security under a Transmission Must Run (TMR) contract. If this is the case, generators are paid separately, independent of the real time price. This situation may mean an underestimation of the market power exercised by the firm.[7]

Whether or not the firm still has excess capacity is determined by comparing the firm's output to 95% of the collective Maximum Continuous Rating (MCR) of the firm's running units. For example, the firm is modeled to collect a scarcity rent when its output reaches 95% of the firm's capacity of running units. Therefore the estimated λ_{it} reflects how much extra revenue that firm could collect if the firm could produce one more unit of output from the running units' capacity.

Cogeneration units in Alberta make the estimation of the firm's marginal cost extremely difficult. From our sample data, we frequently found that some units had a marginal cost much higher than the pool price but still ran at nearly full capacity. This makes the price-cost margin negative. Cogeneration units generate electricity and steam at the same time. All the steam and part of the electricity are sold to the customer directly and are paid for separately, regardless of the pool price. In some cases, cogeneration units look like they are losing money, because we do not have sufficient information about the revenue for other products, such as steam. In this paper, we set all negative price-cost margins at zero. Puller (2002) estimated the California model with the negative price-cost margin untouched. In comparison with California, cogeneration plants in Alberta make up a relatively larger portion of installed capacity, mostly due to oil sands industry operations. Consequently, negative price-cost margin appears more frequently in our sample data and brings significant, underestimated bias to the market power estimation. Setting all negative price-cost margins at zero may improve the accuracy of the estimation.

In measuring marginal cost, I ignored start-up cost and the shadow cost of the operating constraints, such as the minimum stable output constraint and the ramping constraint.[8] For example, the pool price of some hours at off-peak time could be significantly lower than the marginal cost we calculate for this paper. On December 20, 2004, all the electricity in Alberta

[7] Several units in Alberta occasionally ran under a TMR contract, but the output is small. TMR data are not publicly available but could be accessed by related regulating agencies.

[8] For example, when system demand increases very quickly, slow ramping units cannot produce enough electricity in such a short time to satisfy the increased demand, though providing additional electricity is profitable. We say that the slow ramping units have a high shadow cost of the ramping constraint.

was free between 1:00am and 5:00am (HE2 to HE5). Generators are constrained by minimum stable output and would rather sell their output free than shut down the unit and incur a start-up cost in the future. As another example, high price spikes are often found between 6:00am and 10:00am (HE7 to HE10) and 4:00pm and 6:00pm (HE17 to HE18) because some generators cannot ramp up quickly enough to keep pace with the increase in demand and an expensive generator must run to satisfy the load. During these periods, the marginal cost of the firm includes the shadow cost of the operating constraints. The marginal cost calculation used in this paper is seriously flawed for these periods.

In order to avoid these problems, I use only 1:00pm to 2:00pm (HE14) data to estimate our model. Demand between 11:00 am and 4:00pm (HE 12 to HE16) is high enough and the start-up cost constraint is generally not applicable during these hours. Load is nearly flat during these 5 hours. I choose the middle hour (HE14) because generators have ample time to finish the initial ramp-up of 6:00am–10:00am (HE7 to HE10) and also have ample time to prepare for the next ramp-up of 4:00pm–6:00pm (HE17 to HE18). By using only this particular hour each day, we can most reasonably calculate the firm's marginal cost and reflect the firm's actual optimization problem.

Tables 2 and 3 present summary statistics on the price-cost margin at HE14 for the set of strategic firms. The second columns show the percentage of the observations for which there exist a positive price-cost margin and the firm's unused capacity. The percentages are overestimated because the capacities offered in the ancillary services market are counted as withholding. The third to sixth columns show the summary statistics of the price-cost margin when only the observations with a positive price-cost margin and unused capacity are considered. The price-cost margin identified above does not reflect scarcity rent, since firms still have capacity that could produce output profitably. Theory suggests that a price-taking firm in a perfectly competitive market should fully use its capacity when price is higher than its marginal cost.

Strategic firms withhold capacity 11% to 58% of the time. This suggests firms exercise market power. ENMAX has a relatively low percentage (11% to 22%) because only two base-load coal fired plants are counted as the assets for which ENMAX possesses the offer rights.

Comparing the results with those in the California market, which has percentages of 78% to 100%, it appears that the Alberta market is more competitive than the California market.

The sensitivity of the above analysis to the calculation of the firms' marginal cost is also checked. When marginal cost, minus or plus ten dollars, is used, similar results appear, although some figures do increase and others decrease.

Comparing the five strategic firms for 2003 and 2004, the data illustrate that 2004 had lower price-cost margins and lower percentage withholdings. Figure 2 plots the average price-cost margin for 2003 and 2004. The figure may be astonishing to the analysts in the industry. The off-peak season has an overwhelmingly higher price-cost margin than peak season. In this paper, I consider the peak season to be January, February, November and December. The rest of the year is treated as off-peak season.

In the next section, we will measure firm behaviour based on residual demand and price-cost margin. Behavioural parameters of the strategic firms are estimated.

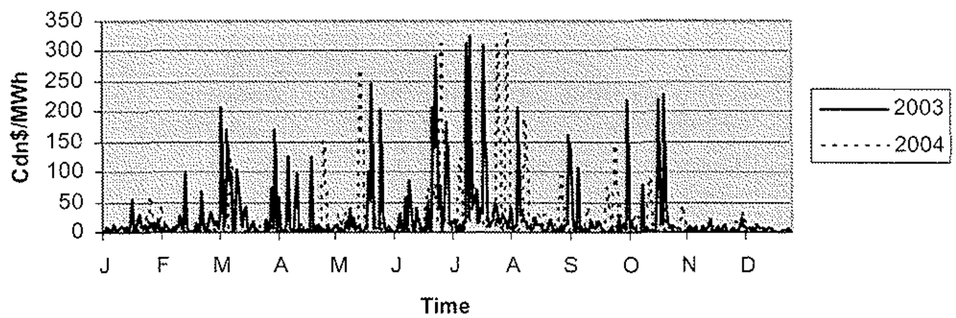
Table 2: Price-Cost Margin, 2003

Firm	% of observations with positive price-cost margin and unused capacity	Price-Cost Margin			
		Mean	Median	Standard Deviation	Maximum
TransCanada	37%	64.58	18.37	98.27	507.96
EPCOR	41%	58.32	39.95	65.38	415.19
ATCO	41%	65.59	21.56	98.43	526.06
ENMAX	22%	72.32	46.28	81.68	392.28
TransAlta	58%	52.13	17.61	85.14	513.53
All 5 Firms	40%	60.73	27.28	86.80	526.06

Table 3: Price-Cost Margin, 2004

Firm	% of observations with positive price-cost margin and unused capacity	Price-Cost Margin			
		Mean	Median	Standard Deviation	Maximum
TransCanada	39%	36.10	12.65	69.85	396.72
EPCOR	33%	62.00	49.84	77.90	441.78
ATCO	38%	37.82	11.23	73.45	415.11
ENMAX	11%	37.68	34.21	31.73	184.5
TransAlta	56%	33.20	17.14	60.00	405.06
All 5 Firms	35%	40.45	18.17	68.18	441.78

Figure 2. Average Price-Cost Margin



9. ESTIMATION OF THE MODEL AND ESTIMATION RESULTS

Recall the first order condition:

$$p(Q_{2t}) + q_{it}\frac{dp(Q_{2t})}{dQ_{2t}}\gamma_{it} - c_i(q_{it}) - \lambda_{it} = 0. \quad (11)$$

Equation (11) illustrates that strategic firms exercise market power in order to raise the price-cost margin adjusted for the scarcity rent when they have more infra-marginal output, q_{it}, and operate on an inelastic residual demand. It is worth mentioning that a high price-cost margin does not necessarily reflect that firms behave less competitively. It is possible that the firm behaves more competitively and, at the same time, enjoys a higher price-cost margin. By estimating equation (11) and identifying the parameters, we can gain important insights into the behaviour of strategic firms in the Alberta market.

In addition to the data we obtained in the previous section, we need to know $\frac{dp(Q_{2t})}{dQ_{2t}}$ in order to estimate equation (11). In Alberta, five strategic firms compete with each other for the residual demand, which is the total inelastic demand minus the supply of the competitive fringe. The elasticity of residual demand comes from the elasticity of supply of the competitive fringe. The slope of the competitive fringe supply has the same magnitude but the inverse sign of the slope of residual demand that strategic firms face. The relationship can be written as:

$$\frac{dp(Q_{2t})}{dQ_{2t}} = -\frac{dp_t}{dQ_{1t}}, \quad (17)$$

where $Q_{2t} \equiv DR_t$, $p(Q_{2t}) = p_t$ = Hourly Pool Price.

The competitive fringe supply is modeled as:

$$\ln Q_{1t} = \beta_0 + \beta_1 \ln p_t + \beta_2 \ln pgas_t + \beta_3 Dm_t + \beta_4 Dw_t + \varepsilon_t, \quad (18)$$

where $pgas_t$ is the gas price at the time t and Dm_t is a dummy variable for the peak season. $Dm_t = 1$ when t is in January, February, November and December. Dw_t is a dummy variable for weekdays. $Dw_t = 0$ when t is in Saturday, Sunday and statutory holidays. The reason for using gas price is to catch the cost condition of fringe supply. The coal price does not enter the function because the coal price changes little and the pool price is normally set by gas-fired generators. The reason for using a dummy variable for the peak season is to reflect the reservoir level and outage features of the competitive units. Demand on weekdays is much higher than on weekends and statutory holidays. This feature is captured by dummy variable Dw_t. The above model assumes a constant supply elasticity with respect to the pool price.

Using the fringe supply model, we have

(19) $$\frac{dp(Q_{2t})}{dQ_{2t}} = -\frac{dp_t}{dQ_{1t}} = -\frac{p_t d\ln p_t}{Q_{1t} d\ln Q_{1t}} = -\frac{p_t}{Q_{1t}\beta_1}.$$

The first order condition, equation (11), can be written as

(20) $$p_t - q_{it}\frac{p_t}{Q_{1t}}\frac{\gamma_{it}}{\beta_1} - c_i(q_{it}) - \lambda_{it} = 0.$$

In this paper, I will use an average behaviour parameter γ_i and average shadow value of additional capacity λ_i for each firm, across all time periods, which are consistent with Puller (2002). The following can then be obtained:

$\lambda_{it} = \lambda_i, \gamma_{it} = \gamma_i$ for all t, i = 1 to 5 representing TransCanada, EPCOR, ATCO, ENMAX and TransAlta, respectively.

Estimate residual demand and strategic supply together, giving

(21) $$\ln Q_{1t} = \beta_0 + \beta_1 \ln p_t + \beta_2 \ln pgas_t + \beta_3 Dm_t + \beta_4 Dw_t + \varepsilon_t, \text{ and}$$

(22) $$p_t - c_i(q_{it}) = q_{it}\frac{p_t}{Q_{1t}}\frac{\gamma_i}{\beta_1} + \lambda_i DCAP_{it} + u_{it},$$

where $DCAP_t$ is a dummy variable. $DCAP_t$ = 0 when firms still have unused capacity and $DCAP_t$ = 1 otherwise. u_{it} is an error term.

Since we have six related equations (one residual demand and five strategic supplies), OLS equation by equation estimation would lose information and would not be efficient.

In this paper, I will use the seemingly unrelated regression method (SUR) to estimate the above equations and improve efficiency. Since the price level p_t and firm level output q_{it} are determined simultaneously with residual demand Q_{1t} and the price-cost margin $p_t - c_i(q_{it})$, respectively, instrumental variable estimation is adopted to deal with this endogeneity. I will use the net import level at 1:00pm–2:00pm (HE14) and total system demand at

12:00pm–1:00pm (HE13) as instruments for both p_t and q_{it}. The two instrumental variables are believed to be independent of the error terms and highly correlated with both p_t and q_{it}, so they make ideal instruments. The method is essentially Three-Stage Least Squares (3SLS).

In this paper, I view each observation as an independent event and treat the disturbances accordingly. I assume that disturbances are correlated for any particular observation and uncorrelated across observations.[9] This treatment is also supported by the data selection method used in this paper that the data set contains only one observation for each day.[10]

Tables 4 and 5 illustrate the estimation results for 2003/2004 and peak season/off-peak season. Peak season (β_3) and weekdays (β_4) signal higher fringe supply and are statistically significant at the 1% level of significance. Fringe supply is lowered by higher gas prices. The relationship (β_2) is statistically significant at a 5% level of significance.

The hypothesis of Cournot pricing is rejected with all the data sets of 2003, 2004, peak season and off-peak season, even at a 1% level of significance[11]. It is unlikely that generation firms exercised unilateral market power during our sample period.

For 2003 and 2004, fringe supply was relatively inelastic with the elasticity (β_1) of 0.079 and 0.063. This figure is lower than California (0.15 to 0.19), indicating a less elastic residual demand faced by strategic firms in Alberta. Residual demand in Alberta is more elastic during the off-peak season than during the peak season. The residual demand elasticity is statistically not different from zero during the peak season, even at a 50% level of significance. Facing such an inelastic residual demand, all five firms behave reasonably and their behaviour parameters (γ_i) during the peak season are not significantly different from zero at a 50% level of significance. This suggests that, during the peak seasons in 2003 and 2004, the Alberta market was highly competitive and the market outcome approached perfect competitive pricing.

Behavioural parameters (γ_1 and γ_3) of TransCanada and ATCO are statistically not different from zero at about a 10% level of significance in 2004 and off-peak season. This suggests that the behaviours of TransCanada and ATCO are nearly perfectly competitive in those periods.

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[9] For instance, disturbance in one strategic firm's supply at any particular hour is correlated with a disturbance in any of the other four strategic firms' supplies and residual demand at this particular hour, but not any disturbance 24, 48, 72, ... hours ago.

[10] I checked the case when general first order correlation among disturbances is considered. $\varepsilon_t = R\varepsilon_{t-1} + v_t$ is then allowed, where $\varepsilon_t, \varepsilon_{t-1}$ and v_t are 6x1 vectors. R is a 6x6 matrix. The general case of a vector autoregressive model with no restrictions on the R matrix is implemented. Therefore, all 36 $\rho_{i,j}$ s in the matrix R and the coefficients in the six equations are estimated simultaneously using Maximum Likelihood Method. The result is similar with the result using 3SLS although the magnitude of the estimated parameters becomes smaller. Estimated behaviour parameters are within the range of 0 to 0.135.

[11] Hypothesis is $\gamma_i = 1$.

Table 4: Estimation Results for 2003 and 2004

	2003			2004		
	Statistics of Estimated Parameters			Statistics of Estimated Parameters		
	Coefficient	Standard Error	P-Value	Coefficient	Standard Error	P-Value
β_0	8.123	0.057	0.000	8.110	0.075	0.000
β_1	0.079	0.015	0.000	0.063	0.019	0.001
β_2	-0.202	0.026	0.000	-0.107	0.044	0.016
β_3	0.081	0.010	0.000	0.068	0.014	0.000
β_4	0.044	0.008	0.000	0.038	0.010	0.000
γ_1 / β_1	0.114	0.053	0.033	-0.024	0.059	0.682
γ_2 / β_1	1.371	0.079	0.000	1.019	0.081	0.000
γ_3 / β_1	0.646	0.238	0.007	-0.153	0.252	0.545
γ_4 / β_1	2.343	0.120	0.000	2.336	0.146	0.000
γ_5 / β_1	0.736	0.147	0.000	0.566	0.182	0.002
λ_1	1.853	0.743	0.013	0.459	0.637	0.471
λ_2	-4.018	1.420	0.005	10.891	1.353	0.000
λ_4	4.064	1.001	0.000	5.457	1.137	0.000
	Hypothesis Test $\gamma_i = 0$			Hypothesis Test $\gamma_i = 0$		
	Test Value	Standard Error	P-Value	Test Value	Standard Error	P-Value
γ_1	0.009	0.004	0.038	-0.002	0.004	0.683
γ_2	0.109	0.020	0.000	0.064	0.021	0.002
γ_3	0.051	0.020	0.010	-0.010	0.016	0.550
γ_4	0.186	0.035	0.000	0.146	0.048	0.002
γ_5	0.058	0.015	0.000	0.036	0.016	0.028
	Hypothesis Test $\gamma_i = 1$			Hypothesis Test $\gamma_i = 1$		
	Test Value	Standard Error	P-Value	Test Value	Standard Error	P-Value
γ_1	-0.991	0.004	0.000	-1.002	0.004	0.000
γ_2	-0.891	0.020	0.000	-0.936	0.021	0.000
γ_3	-0.949	0.020	0.000	-1.010	0.016	0.000
γ_4	-0.814	0.035	0.000	-0.854	0.048	0.000
γ_5	-0.942	0.015	0.000	-0.964	0.016	0.000

Table 5. Estimation Results for Peak Season and Off-Peak Season

	Peak Season			**Off-Peak Season**		
	Statistics of Estimated Parameters			Statistics of Estimated Parameters		
	Coefficient	Standard Error	P-Value	Coefficient	Standard Error	P-Value
β_0	8.424	0.056	0.000	7.980	0.080	0.000
β_1	-0.011	0.018	0.561	0.090	0.023	0.000
β_2	-0.120	0.033	0.000	-0.119	0.035	0.001
β_4	0.036	0.009	0.000	0.041	0.012	0.001
γ_1/β_1	0.085	0.052	0.105	-0.010	0.051	0.052
γ_2/β_1	1.864	0.111	0.000	0.903	0.070	0.000
γ_3/β_1	0.398	0.207	0.056	-0.425	0.228	0.064
γ_4/β_1	3.814	0.220	0.000	1.780	0.105	0.000
γ_5/β_1	0.526	0.149	0.001	0.274	0.150	0.069
λ_1	0.086	0.326	0.793	2.896	1.014	0.005
λ_2	-2.818	0.944	0.003	5.448	1.401	0.000
λ_4	-6.348	1.028	0.000	7.786	0.966	0.000
	Hypothesis Test $\gamma_i = 0$			Hypothesis Test $\gamma_i = 0$		
	Test Value	Standard Error	P-Value	Test Value	Standard Error	P-Value
γ_1	-0.001	0.002	0.568	-0.009	0.005	0.093
γ_2	-0.020	0.034	0.559	0.081	0.021	0.000
γ_3	-0.004	0.007	0.564	-0.038	0.024	0.105
γ_4	-0.041	0.070	0.558	0.160	0.041	0.000
γ_5	-0.006	0.010	0.557	0.025	0.014	0.086
	Hypothesis Test $\gamma_i = 1$			Hypothesis Test $\gamma_i = 1$		
	Test Value	Standard Error	P-Value	Test Value	Standard Error	P-Value
γ_1	-1.001	0.002	0.000	-1.009	0.005	0.000
γ_2	-1.020	0.034	0.000	-0.919	0.021	0.000
γ_3	-1.004	0.007	0.000	-1.038	0.024	0.000
γ_4	-1.041	0.070	0.000	-0.840	0.041	0.000
γ_5	-1.006	0.010	0.000	-0.975	0.014	0.000

In other periods, behaviour parameters (γ_1 to γ_5) are between 0.009 and 0.186 and are statistically significant at a 10% level of significance. Therefore, the hypotheses of perfectly competitive behaviour are rejected[12]. It is more suitable to describe the behaviours of these firms as within the range between perfect competition and the exercising of unilateral market power. The firms' behaviours are more consistent with competitive pricing than unilateral market power pricing. Among the five firms, ENMAX has the highest behaviour parameter, signalling the least competitive behaviour among all the strategic firms. ENMAX has only the low cost Keephills #1 and #2 in its portfolio (Genesee #1 Strip Contract is not included) and the price-cost margin of ENMAX is much higher than that of any other strategic firm. If ENMAX withholds capacity, although less frequent than the other firms, its behaviour parameter could be large. In 2003, 2004, peak season and off-peak season, the estimated shadow value of additional capacity is between -\$6.348/MWh and \$10.891/MWh. These figures are very small, compared with average \$73/MWh pool prices. These figures are also much lower than California's \$25.251 to \$57.508/MWh. These figures strongly suggest that the Alberta market is oversupplied during the sample period and send a clear signal not to build.

ENMAX during the peak season, EPCOR during the peak season and EPCOR in 2003 possess negative shadow value of additional capacity that is not consistent with the profit maximization model. This may reflect a minor inaccuracy in ENMAX and EPCOR's strategic behaviours. Although the two firms had positive price-cost margin, they could earn more profit by further withholding some capacities to the point where their profit functions are maximized and the shadow value of additional capacity approaches zero. However, given the high volatility of pool price and small magnitude of the negative value, the two firm's strategic performances were reasonable.[13]

Comparing the results of peak season and off-peak season, the behaviours of the strategic firms were more competitive during the peak season. The possible reason for this is that the Alberta market is oversupplied during the sample period. Off-peak demand is low and, theoretically, the market price could be very low. The off-peak pattern found in this paper indicates that the market price was highly resistant to additional decreases below a certain level. During the off-peak season, coal-fired thermal units set the price more frequently than during the peak season. Compared with gas plants, coal-fired plants are characterized by small variable cost and large fixed costs. Theoretically, in a competitive electricity market, all the generators should bid their marginal costs, which are equal to the variable cost in this paper's setup. Fixed cost will be covered through a scarcity rent. The off-peak pattern detected in Alberta suggests that firms may consider fixed cost recovery of the coal-fired generators and may engage in a certain degree of collusion. If this bidding strategy continues, consumers in Alberta will have to pay more for every MWh of electricity but will have fewer times of black-out.[14]

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[12] Hypothesis is $\gamma_i = 0$.

[13] Discrete offered capacity may also, in part, explain the negative shadow value of additional capacity.

[14] See Stoft (2002) for reference.

10. CONCLUSION

Understanding market power and identifying the factors that contribute to market power abuse are the first steps in operating an efficient electricity market. Policy-makers and regulators need to consider the magnitude and source of market power when designing market structure, rules and trading practices. This paper analyzes market power issues broadly and develops a helpful index to measure the extent of market power in Alberta. In the sample years 2003 and 2004, Alberta firms behaved within the range of competitive pricing and unilateral market power pricing. Although strategic firms withheld capacity when price was above marginal cost, their behaviours were more consistent with competitive pricing given an inelastic residual demand that they faced. This paper also finds that, in Alberta, firms are more likely to exercise market power during the off-peak season.

The intent of this paper is to illustrate the method of analyzing market power in Alberta. The accuracy of the calculation is constrained by the use of public data. Regulating agencies could improve the measurement dramatically by using data that are not publicly available, such as generators' derate data[15], ancillary service data, outage data, generator cost data, firm level import-export data, strip contract output, forward contract volume and prices, TMR contract output and prices, etc.

The Alberta market faces possible refinement. In the future, imports and exports may be possible to set price. Day-ahead market and even capacity market may be implemented. These all provide new challenges in measuring and understanding market power. The price level, reservoir level and even temperature level in neighbouring jurisdictions may have to be considered in the future when modeling market power.

Finally, the results in this paper may underestimate market power for several reasons already identified, though the magnitude is not significant. Biases may also be created by the extremely volatile pool price in Alberta, although the use of data from HE14 may eliminate some of these biases. Future efforts need to be made to improve the methodology when market prices are volatile. Although the biases may render the measurement inaccurate, by using the same methodology and comparing the results over time, the behaviour parameters will provide consistent inference about market power.

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[15] Derate happens when a generator declares part of the installed capacity unavailable.

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