# 18 How do firms exercise unilateral market power? Empirical evidence from a bid-based wholesale electricity market

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## 18.1 Introduction

Empirical examination of the implications of profit-maximizing firm behavior in imperfectly competitive markets is complicated by the fact that the primitives of the economic environment, such as market demand functions and firm-level cost functions, are not directly observable. Moreover, the researcher rarely knows the strategic variables that firms use to influence market prices or often even the details of how market prices are set. As a result, researchers rely on parametric models of market demand, firm-level cost functions, and equilibrium models of strategic interaction such as non-cooperative quantity-setting or price-setting behavior to understand how firms behave in imperfectly competitive markets. Consequently, any conclusions about firm behavior or the extent of market power exercised are conditional on these functional form assumptions and the assumed model of strategic interaction between firms.

We pursue an alternative approach that relies on a data-rich environment where many of these economic primitives are observable and both the strategic variables that firms choose and the exact mechanism that translates these strategic variables into market-clearing prices are known. This economic environment allows us to examine many implications of expected profit-maximizing behavior in imperfectly competitive markets without relying on functional form assumptions for market demand or a specific model of strategic interaction among firms.

To understand the advantages of the approach we pursue, it is useful to review the traditional approach from the perspective of the rapidly expanding literature in what Bresnahan (1989) calls the new empirical industrial organization. This approach uses market-clearing prices and quantities and variables assumed to shift demand and production costs along with three economic and behavioral assumptions to recover estimates of the extent of market power exercised in an imperfectly competitive market.

The three main econometric and behavioral assumptions necessary for validity of the traditional approach are: (1) parametric functional forms for the market demand and firm-level or market-level variable cost functions; (2) a model of firm-level strategic interaction, such as monopoly, quantity-setting competition, or price-setting competition; and (3) profit-maximizing or expected profit-maximizing behavior. Using a cross-section of monopoly newspaper markets, Rosse (1970) was the first to demonstrate that the combination of these three assumptions can allow a researcher to recover the firm's marginal cost function from market-clearing prices and quantities and demand and cost shifters. The results of this modeling effort can then be used to estimate the marginal cost of the highest cost unit of output produced by the firm. This marginal cost equals the market-clearing price if the firm were unable to exercise any market power. Consequently, the difference between the market price and this estimated marginal cost measures the extent of market power exercised.

Porter (1983) applied this basic approach to an oligopolistic industry – nineteenth century railroads. He assumed that actual market outcomes are the result of non-cooperative quantity-setting behavior between market participants. Bresnahan (1981 and 1987) measures the extent of market power exercised in the United States' automobile industry using the assumption of price-setting competition.

All of these studies and many more recent ones employing these techniques rely on an assumed parametric model of demand and a model of competition among firms to derive an estimate of the extent of market power exercised from market-clearing price and quantity data. As has been emphasized by a number of authors, most forcefully by Bulow and Pfleiderer (1983), the estimate of the extent of market power exercised depends on the functional form assumed for the market demand. The assumed model of competition can also exert a substantial influence on the estimate of the extent of market power exercised.

All of these studies quantifying the extent of market power exercised do not explicitly address the question of how firms exercise market power, specifically what factors determine the extent of market power that firms are able to exercise and the amount of market power they choose to exercise. Because the amount of market power exercised is identified from market-clearing prices and quantities (and demand and cost shifters) using the functional form assumed for demand and the assumed model of competition among firms, any conclusions about how firms exercise market power or what factors enhance their ability and incentive to exercise market power are conditional on these two assumptions.

The recent world-wide trend toward introducing bid-based wholesale electricity markets has created an increasing number of data-rich economic environments where it is possible to study how firms behave in imperfectly competitive markets using only the assumption of expected profit-maximizing behavior. Participants in these multi-unit auction markets submit their willingness-to-sell or willingness-to-purchase curves to the market operator and these curves are used to compute market-clearing prices and the quantities bought and sold by each market participant. A willingness-to-sell or willingness-to-buy curve gives the amount of the good a market participant is willing to sell or buy for each possible market-clearing price. If the researcher is willing to assume that a supplier constructs its willingness-to-supply curve to maximize the expected profits that it earns given the offers of its competitors and the bids of demanders, then it is possible to infer a supplier's variable cost function from the bid and offer curves that it and its market participants submit without having to resort to functional form assumptions for aggregate demand or an assumed model of competition among firms.

For the case of a multi-unit auction market, the offers submitted by other suppliers besides the supplier under consideration and the bids of all demanders determine the realized residual demand curve faced by that supplier. For the case that the researcher only has data on market-clearing prices and quantities, the residual demand curve a supplier faces is determined by the functional form assumption for aggregate demand and an assumed model of competition among firms.

For a multi-unit auction market, because a supplier does not know the offers of other suppliers or all demand bids at the time it submits its willingness-to-supply curve, this supplier must construct its offer curve to maximize the profits that it expects to earn given the distribution of residual demand curves that it faces. Wolak (2003a) demonstrates that the assumption that the supplier chooses the form of its offer curve to maximize its expected profits given the distribution of residual demand curves that it faces identifies that supplier's marginal cost function.

Wolak (2003a) applies this logic to a multi-unit auction market for wholesale electricity to estimate generation unit-level variable cost functions without the first two assumptions described above. The information contained in the offer curves submitted by all market participants and the assumption of expected profit-maximizing offer behavior by the supplier under consideration are sufficient to estimate generation unit-level marginal cost functions for a supplier. Wolak (2007) extends this cost function estimation framework to the case of multivariate cost functions in order to quantify the extent to which marginal costs for a specific generation unit in a given half-hour of the day vary with the level of output during that half-hour and during other half-hours of the day. Wolak (2003b) shows that the information contained in the offer curves and demand bids can also be used to compute a measure of the ability of a supplier to exercise unilateral market power.

This chapter uses the framework in Wolak (2003a, 2003b, and 2007) and data on half-hourly offer curves and market-clearing prices and quantities from the New Zealand wholesale electricity market over the period January 1, 2001 to June 30, 2007 to characterize how the four large suppliers in this imperfectly competitive industry exercise unilateral market power. To accomplish this we introduce half-hourly measures of the firm-level ability and incentive of an individual supplier to exercise unilateral market power that are derived from a model of expected profit-maximizing offer behavior in a multi-unit auction market. We then show that half-hourly market-clearing prices are highly correlated with the half-hourly values of the firm-level and across firm-average measures of both the ability and incentive of the four large suppliers in New Zealand to exercise unilateral market power.

We then present evidence consistent with the view that this increasing relationship between the ability or incentive of individual suppliers to exercise market power and higher market-clearing prices is caused by the four large suppliers submitting higher offer prices when they have a greater ability or incentive to exercise unilateral market power. We show that after controlling for changes in input fossil fuel prices and other factors that impact the opportunity cost of producing electricity during that half-hour, each of the four suppliers submits a higher offer price into the wholesale market when it has a greater ability or incentive to exercise unilateral market power.

## 18.2 The New Zealand wholesale electricity market

In October 1996, a wholesale electricity market was formed by the New Zealand electricity supply industry. This market was a contract between market participants – generation unit owners, retailers, and energy traders – that specified how generation units were dispatched and wholesale prices were determined.

Prior to the start of the wholesale market, the transmission and generation sectors were dominated by the state-owned Electricity Corporation of New Zealand ("ECNZ"), which owned and operated more than 95 percent of the total New Zealand electricity generating capacity. ECNZ was broken up in three stages. First, in July 1994, the national transmission grid was separated into a stand-alone State-Owned Enterprise ("SOE") Transpower. In February 1996, before the start of the wholesale electricity market, Contact Energy was formed out of ECNZ generation assets that represented roughly 22 percent of total electricity production. Contact Energy was a stand-alone SOE in competition with ECNZ until it was privatized in 1999. Finally, about the same time as the privatization of Contact Energy, the remainder of ECNZ was split into three competing SOEs: Genesis, Meridian, and Mighty River Power. All three firms, as well as Transpower, remain state-owned during our sample period.

In response to a perceived lack of competition in both the wholesale and retail markets, the Government announced a series of reforms of the electricity supply industry in April 1998. In addition to the final split of ECNZ, these reforms included the forced separation of distribution and retailing businesses. At the time there were more than 40 distribution firms, each with a very high market share in retailing for customers on their networks. The separation of distribution and retail led to rapid vertical integration between the generation and retail sectors, as Contact Energy and the newly formed SOE generators bought the retail businesses from the network owners. Two new privately owned generation and retail firms were created out of the industry reorganization – TransAlta New Zealand and TrustPower – although the former firm disintegrated in 2001.

Since 2001 the industry market structure has been relatively stable. There are five major generation owners: Contact Energy, TrustPower, and the three SOEs, Genesis, Meridian, and Mighty River Power. Each of these generation owners is vertically integrated with a retail business serving a mix of residential, commercial, and industrial users. With the exception of TrustPower, all of these firms have more generation capacity than their average retail load obligation, although there are half-hours during our sample period when each of these retailers has retail load obligations that exceed their sales in the short-term wholesale market.

More than 99% of the energy produced in the South Island comes from hydroelectric sources. There is sufficient generation capacity in the South Island to serve its annual electricity requirements, as well as export a substantial amount of energy to the North Island using a submarine transmission line. Approximately 24.4% of the North Island supply came from hydroelectric sources in 2007, with the remaining 75.6% split between natural gas-fired (44.6%), coal-fired (11.6%), geothermal (13.0%), wind (3.4%), wood (2.1%), and less than 1% from biogas facilities.

Annual electricity consumption for the entire country in the year ending December 2007 was approximately 38.5 Terawatt hours (TWh), with the commercial sector consuming 23.3% of this total, the industrial sector 43.7%, and the residential sector 33.0%. An important aspect of the New Zealand electricity industry is that much of the population resides in the northern part of the North Island in the Auckland metropolitan area, whereas many of the major hydroelectric resources are in the southern part of the South Island. As a result, transmission and distribution accounts for a relatively large fraction of the cost of delivered electricity compared to the rest of the world.

## 18.3 Empirical evidence on how suppliers exercise unilateral market power

This section uses supplier offers, water reservoir levels, and market outcomes to demonstrate a number of empirical regularities in the behavior of the four large suppliers and market outcomes in the New Zealand market. First, summary statistics are presented on the behavior of half-hourly measures of both the unilateral ability and incentive to exercise unilateral market power for each of the four large suppliers. These half-hourly measures of the ability and incentive to exercise unilateral market power are shown to be highly positively correlated with the value of the quantity-weighted average half-hourly market-clearing price.

To demonstrate that this observed positive correlation between the average half-hourly firm-level unilateral ability and incentive to exercise market power and half-hourly market prices is the direct result of market participant behavior, a second line of empirical evidence is introduced. Expected profit-maximizing offer behavior implies that a supplier's half-hourly offer price – the price at which it is willing to sell a pre-specified amount of energy to the short-term wholesale market – should be positively correlated with both its ability and incentive to exercise unilateral market power during that half-hour. Econometric analysis is then used to quantify the empirical relationship between the half-hourly offer price of each supplier and the half-hourly value of an index of that supplier's unilateral ability to exercise unilateral market power (after controlling for other exogenous factors impacting half-hourly market outcomes such as water levels and input fossil fuel prices). Further econometric analysis examines the empirical relationship between the half-hourly offer price of each supplier and the half-hourly value of an index of that supplier's unilateral incentive to exercise unilateral market power. We find that when each of the four suppliers has a greater ability or greater incentive to exercise unilateral market power, they submit substantially higher half-hourly offer prices for a pre-specified quantity of energy.

### *18.3.1 Market outcomes and the unilateral ability and incentive to exercise market power*

Measures of the ability and incentive of a supplier to exercise unilateral market power can be computed on a country or system-wide basis or separately for the North and South Islands using the half-hourly level of demand and the willingness-to-supply curves of all market participants. The form of the residual demand curve that a supplier faces determines its ability to exercise unilateral market power. The inverse of the elasticity of the residual demand curve evaluated at the market-clearing price is one measure of the ability of a supplier to exercise unilateral market power. This inverse elasticity measures the percent change in the market-clearing price that would result from

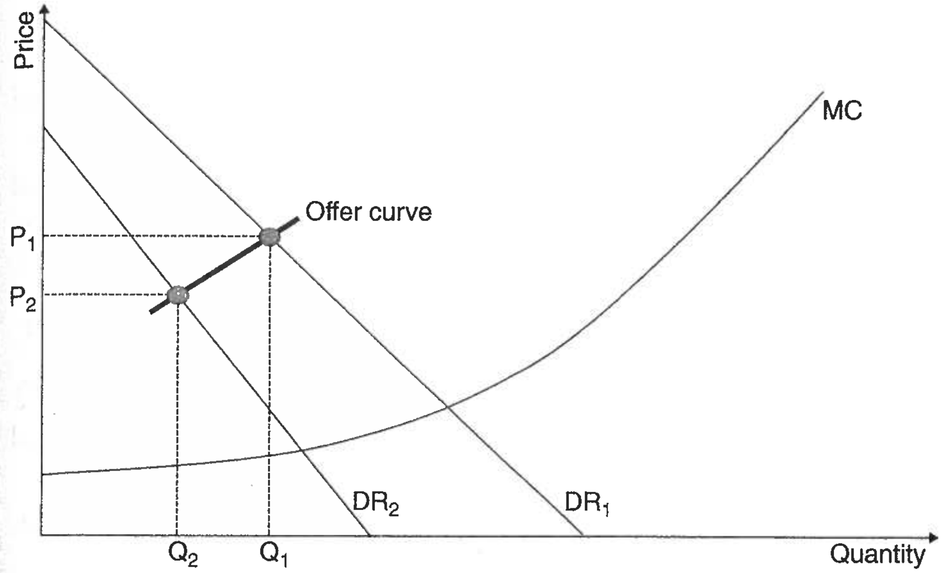


**Figure 18.1** Derivation of offer curve (steep residual demands)

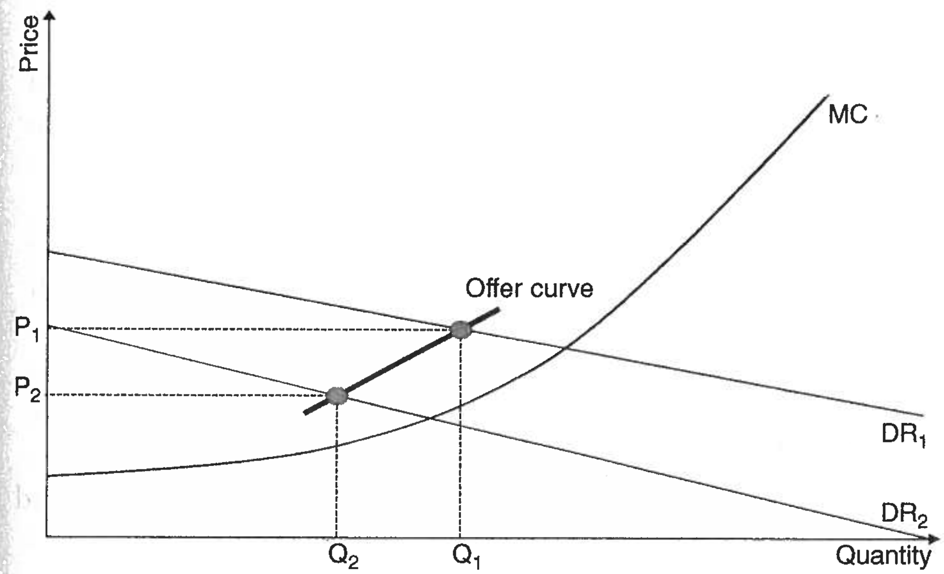


**Figure 18.2** Derivation of offer curve (flatter residual demands)

the supplier producing 1 percent less output than it actually produced during that half-hour period.

Under a simplified model of expected profit-maximizing offer behavior described in Figures 18.1 and 18.2 and discussed in detail in Wolak (2000), this inverse elasticity measure can be directly related to the market-clearing price and the marginal cost of the highest cost unit owned by that supplier operating during that half-hour period.

The logic underlying the construction of the expected profit-maximizing offer curve in Figure 18.1 implies that the point $(P_1,Q_1)$ is the ex post profit-maximizing price/quantity pair for the firm for the residual demand realization $DR_1(p)$ and the point $(P_2,Q_2)$ is the ex post profit-maximizing price/quantity pair for the firm for the residual demand realization $DR_2(p)$. The first-order conditions for ex post profit-maximization for these two residual demand realizations are:

$$(P_1 - C_1)/P_1 = -1/\varepsilon_1 \text{ and } (P_2 - C_2)/P_2 = -1/\varepsilon_2 \qquad (3.1)$$

where $C_i$ (i=1,2) is the marginal cost for supplier i at output level $Q_i$ (i=1,2) and $-1/\varepsilon_i$ (i=1,2) is the inverse of the elasticity of the residual demand curve for that residual demand realization.

Recall that the inverse elasticity is defined in terms of the residual demand curve as:

$$-1/\varepsilon_i = [DR_i(P_i)/P_i]\times[1/DR_i'(P_i)] \qquad (3.2)$$

where $DR_i'(P_i)$ is the slope of residual demand curve i evaluated at price $P_i$, and $DR_i(P_i)$ is the value of residual demand curve evaluated at price $P_i$. Using this definition of the inverse elasticity, the two equations in (1) can be rearranged to equal:

$$P_i = C_i - [DR_i(P_i)/DR_i'(P_i)],\ i=1,2. \qquad (3.3)$$

Equation (3.3) implies that the market-clearing price is equal to the marginal cost of the highest cost unit owned by that supplier operating during that half-hour plus the level of the residual demand curve divided by the absolute value of the slope of the residual demand curve.

Define $\eta_i$ (i=1,2), the inverse semi-elasticity of the residual demand curve i, as:

$$\eta_i = -(1/100)[DR_i(P_i)/DR_i'(P_i)]. \qquad (3.4)$$

This magnitude gives the \$/MWh increase in the market-clearing price associated with a 1 percent reduction in the amount of output sold by the supplier. In terms of this notation, equation (3.3) becomes

$$P_i = C_i + 100\eta_i,\ i=1, 2. \qquad (3.5)$$

Thus, the simplified model of expected profit-maximizing offer behavior implies that higher market-clearing prices should be associated with higher values of the inverse semi-elasticity.

Because offer curves in the New Zealand wholesale market are step functions, residual demand curve realizations do not strictly satisfy the assumptions implied by the simplified model of expected profit-maximizing offer behavior presented there, so that equation (3.5) will not hold with equality. However, the general model of expected profit-maximizing offer behavior implies that when a supplier has a greater ability to exercise unilateral market power as measured by the size of $\eta_i$, the \$/MWh price increase that results from reducing the amount it sells in the wholesale market by one percent, that supplier's offer price is likely to be higher.

Computing the slope of the residual demand curve at the market-clearing price for a step-function residual demand curve requires choosing the output change used to compute the finite-difference approximation to the slope. These output changes should be large enough to ensure that enough price steps on the residual demand curve are crossed so that a non-zero slope is obtained, but not too large that the implied output change is judged as implausible for the supplier to implement. We also want to choose a procedure for selecting the output changes to ensure that the value of the slope obtained is not sensitive to the size of the output changes used to compute it.

Figure 18.3 describes the details of the process we use to compute the slope of the residual demand curve for Firm B for a peak half-hour period in February 2006. Suppose that $Q^* = 901$ MW is the output sold by Firm B at the market-clearing price for this half-hour period of $P^* = \$145$/MWh.[1] We want to approximate the slope of the residual demand curve in the vicinity of $(P^*, Q^*)$. Consider a 10 percent price change window on either side of $P^*$, and look for the closest steps on the residual demand curve to $(P^*, Q^*)$ that lie outside this 10 percent price window. The closest point below $P^*$ that has price less than 0.9 times $P^*$ is (\$129, 969). Call this point $(P_1, Q_1)$. Above $P^*$ the closest point with price greater than 1.1 times $P^*$ is (\$164, 871). Call this point $(P_2, Q_2)$. The slope of the residual demand curve $DR(P^*)$ at $(P^*, Q^*)$ according to this procedure is given by the formula:

$$DR'(P^*) = (Q_1 - Q_2)/(P_1 - P_2) = (969-871)/(129-164) = -2.8 \quad (3.6)$$

[1] All dollar (\$) magnitudes reported in this chapter are in units of New Zealand dollars.

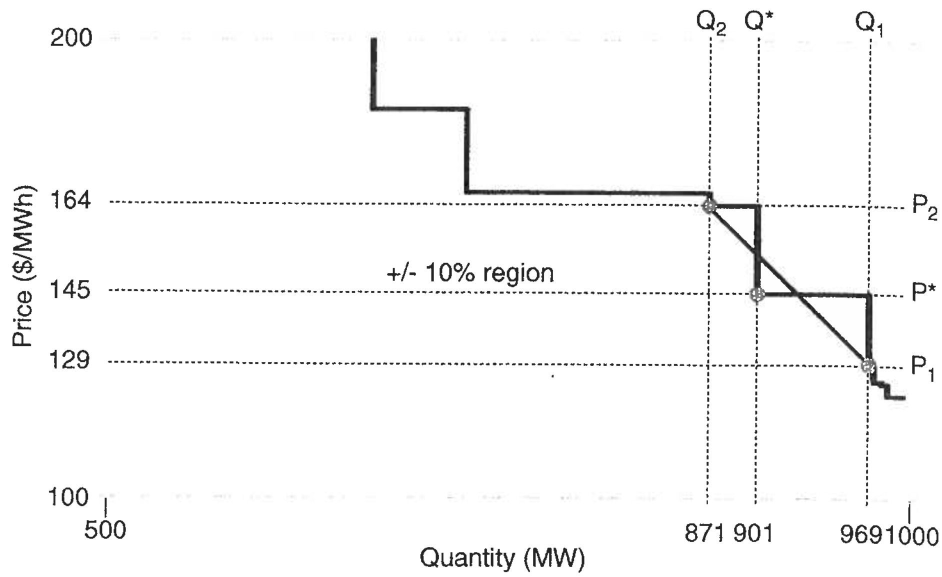


**Figure 18.3** Elasticity calculation for Firm B, peak half-hour period in February 2006

The resulting inverse semi-elasticity at (P*,Q*) for this residual demand curve gives the $/MWh price increase from a 1 percent reduction in output and is equal to:

$$\eta = -(1/100)DR(P^*)/DR'(P^*) = -(1/100)Q^*/\,DR'(P^*) = -(1/100)\ 901/(-2.81) = 3.21 \qquad (3.7)$$

This semi-elasticity quantifies the ability of Firm B to raise prices during this half-hour period by reducing its output by 1 percent. This magnitude implies that if Firm B reduces its output by 1 percent relative to Q* = 901 MW, keeping the offers of all other firms and the level of demand constant, the increase in the market price would be $3.21/MWh.

To compare time series behavior of the inverse semi-elasticities[2] across firms, Figure 18.4 plots the 30-day moving average of the half-hourly values of the inverse semi-elasticities for the four largest firms from January 1, 2001 to June 30, 2007. The half-hourly inverse semi-elasticities follow a very similar pattern across the four firms and certain suppliers have persistently larger values than other suppliers. The maximum value of the smoothed inverse semi-elasticities shown in the

[2] A comparison of the results from calculating the inverse semi-elasticity for the four large suppliers in each half-hour from January 1, 2001 to June 30, 2007, using four different values for the price change window: 1%, 5%, 10%, and 15% can be found in Wolak and McRae (2009).

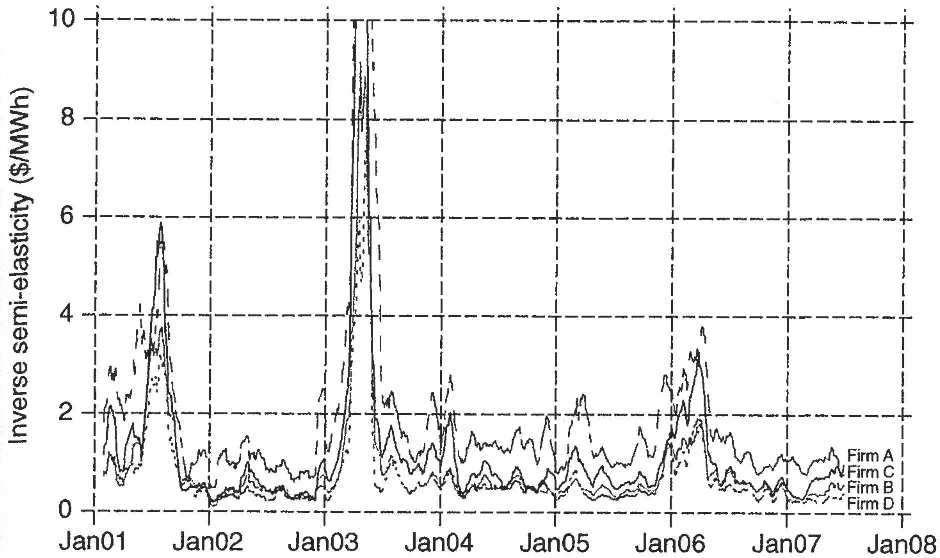


**Figure 18.4** Half-hourly inverse semi-elasticities by firm, 30-day rolling average

figure is 10, with the values for Firm A peaking at close to 20 during early 2003 and the peak values for Firm C for this time period also exceeding 10. Over the entire sample period, Firm A's smoothed inverse semi-elasticities tend to be the highest, followed by Firm C, then by Firm B, and finally by Firm D.

To demonstrate the very close relationship between half-hourly market-clearing prices and the half-hourly ability of the four large suppliers to exercise unilateral market power (as measured by the inverse semi-elasticity of their residual demand curves), Figure 18.5 plots the 30-day moving average of the half-hourly values of the quantity-weighted average of the nodal prices and a 30-day moving average of the half-hourly values of the unweighted average of the four values $\eta_{ihd}$ for Firms A to D, which is equal to $\eta_{hd}(\text{firm}) = \frac{1}{4}\sum_{i=1}^{4} \eta_{ihd}$. Define $p_{hdm}$ as the price at transmission grid node m during half-hour h of day d and $q_{hdm}$ as the total amount of energy injected at transmission node m during half-hour h and day d. Figure 18.5 shows that the time series pattern of $p_{hd}(avg) = \frac{\sum_{m=1}^{M} p_{hdm} q_{hdm}}{\sum_{m=1}^{M} q_{hdm}}$, the quantity-weighted average of the nodal prices for half-hour h of day d, closely tracks $\eta_{hd}(\text{firm})$. During periods when the average index of the ability of these suppliers to exercise unilateral market power is high, the quantity-weighted average of the nodal prices they are paid is also

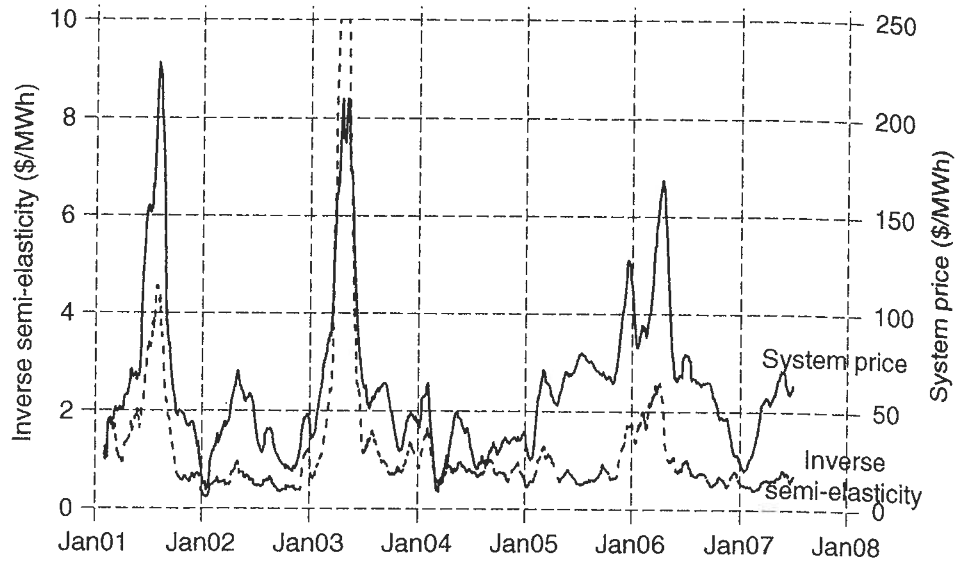


**Figure 18.5** Mean inverse semi-elasticities and system price, 30-day rolling average

very high. Specifically, during mid-2001, early 2003, and early 2006 the average index of the ability of suppliers to exercise unilateral market power is high and the quantity-weighted average nodal price is high. Conversely, during periods when the average index of the ability of these suppliers to exercise unilateral market power is low, the quantity-weighted average of the nodal prices is significantly lower. This occurs during 2002, 2004, and 2005.

Even if a supplier possesses a substantial ability to exercise unilateral market power, it may not submit willingness-to-supply curves that reflect this ability if it has no incentive to exercise unilateral market power. A supplier with fixed-price forward market obligations approximately equal to its sales in the short-term wholesale market has little incentive to exercise unilateral market power, even if it has a substantial ability to do so. This logic suggests that half-hourly measures of the unilateral incentive of each supplier to exercise unilateral market power should be correlated with both market-clearing prices and the level of offer prices that each supplier submits. Wolak and McRae (2009) discuss how fixed-price forward market obligations, either in the form of fixed-price retail load obligations or fixed-price forward contracts, impact the incentive of a supplier to exercise unilateral market power, even if that supplier has a substantial ability to exercise unilateral market power. They show that the inverse semi-elasticity of the net-of-forward market obligation residual demand curve summarizes the incentive a supplier has to exercise unilateral market power.

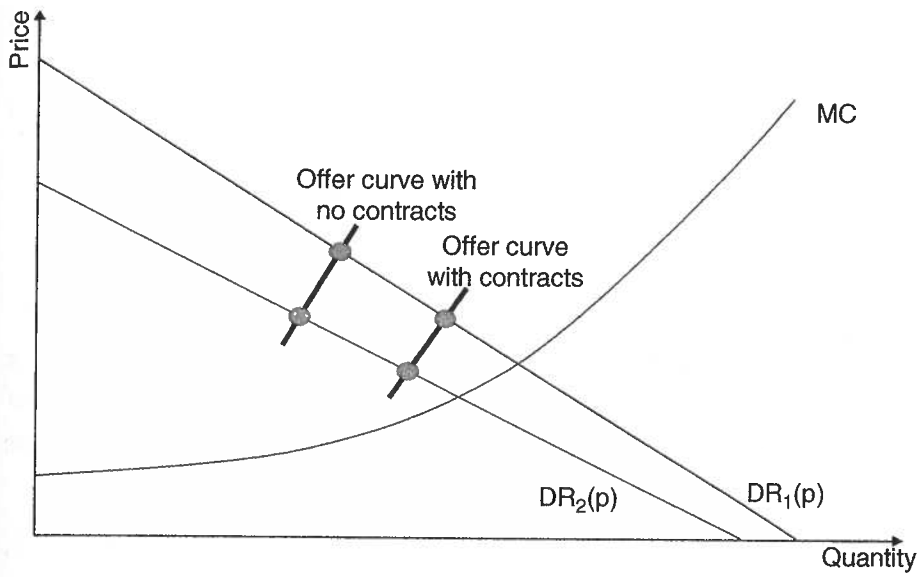


**Figure 18.6** Derivation of offer curves with and without fixed-price contracts

Inverse semi-elasticities for the net-of-forward market obligations residual demand curves can be computed from these inverse semi-elasticities to obtain measures of the incentive (as opposed to ability) of individual suppliers to exercise unilateral market power. Wolak and McRae (2009) demonstrate that under a simplified model of expected profit-maximizing offer behavior, the inverse semi-elasticities of the net-of-forward obligations residual demand curve can be directly related to the market-clearing price and the marginal cost of the highest cost unit owned by that supplier operating during that half-hour period.

The logic underlying the construction of the expected profit-maximizing offer curve with forward market obligations drawn in Figure 18.6 implies that the point of intersection between the offer curve and each residual demand realization is an ex post profit-maximizing price/quantity pair for the firm for each residual demand realization given the forward market obligations of the supplier, $Q_C$. For the two residual demand curve realizations in Figure 18.6, the first-order conditions for ex post profit-maximization for these two residual demand realizations are:

$$(P_1 - C_1)/P_1 = -1/\varepsilon_1^C \text{ and } (P_2 - C_2)/P_2 = -1/\varepsilon_2^C \qquad (3.8)$$

where $C_i$ (i=1,2) is the marginal cost for supplier i at the output level $Q_i$ (i=1,2) and $-1/\varepsilon_i^c$ (i=1,2) is the inverse elasticity of the net-of-forward market obligations residual demand curve for that residual demand realization. The inverse elasticity of the net-of-forward market obligations residual demand curve at price $P_i$ and forward market obligation $Q_C$ is equal to:

$$-1/\varepsilon_i^C = [(DR_i(P_i) - Q_C)/P_i] \times [1/DR_i(P_i)]$$
$$= -1/\varepsilon_i \; [(DR_i(P_i) - Q_C)/DR_i(P_i)]$$

By replacing in equations (3.2) to (3.4) $DR_i(P_i)$ by $DR_i^C(P_i) \equiv DR_i(P_i) - Q_C$ and define $\eta_i^C$ (i=1,2), the net inverse semi-elasticity of the net-of-forward market obligations residual demand curve i, we can find that:

$$P_i = C_i + 100\eta_i^C, \; i=1,2. \tag{3.9}$$

The net inverse semi-elasticity of the net-of-forward market obligations residual demand curve i, is:

$$\eta_i^C = -(1/100)[(DR_i^C(P_i)/DR_i^{C\prime}(P_i)]$$
$$= \eta_i[(DR_i(P_i) - Q_C)/DR_i(P_i)] \tag{3.10}$$

The first equality defines $\eta_i^C$ in terms of the net of fixed-price forward market obligations residual demand curve. The second equality demonstrates that it is equal to the inverse semi-elasticity of the residual demand multiplied by the supplier's exposure to short-term prices. This value of $\eta_i^C$ gives the \$/MWh increase in the market-clearing price associated with a 1 percent reduction in the net position of the supplier, the difference between its short-term market sales and its fixed-price forward market obligations.

Equation (3.9) demonstrates that the simplified model of expected profit-maximizing offer behavior with fixed-price forward market obligations implies that higher offer prices and higher market-clearing prices are associated with higher values of the inverse semi-elasticity of the net-of-fixed price forward market obligations residual demand curve after controlling for the variable cost of the highest cost generation unit in that supplier's portfolio of generation units operating during that half-hour period, $C_i$ in equation (3.9).

To compute the half-hourly value of the inverse semi-elasticity of the net-of-forward market obligations residual demand curve for each of the four largest suppliers, we use the second equality in equation (3.10), with $\eta_i^C$ instead $\eta_i$, which computes this index of the incentive of a supplier to exercise unilateral market power by multiplying the inverse semi-elasticity of the residual demand curve by that supplier's exposure to short-term wholesale prices at the market-clearing price P*, (DR(P*) – $Q_C$), divided by the supplier's short-term market sales, DR(P*). This approach to computing $\eta_i^C$ ensures that the same estimate of the slope of the step-function residual demand curve is used to compute both $\eta_i$ and $\eta_i^C$.

The assumptions required for the validity of the simplified model of expected profit-maximizing offer behavior with fixed-price forward market obligations do not hold because suppliers submit non-decreasing step functions rather than increasing continuous functions as their willingness-to-supply curves. It is important to emphasize that even if the assumptions necessary for the strict validity of the simplified model of expected profit-maximizing offer behavior do not hold, $\eta_i^C$ is still a valid measure of the half-hourly incentive of a supplier to exercise unilateral market power. It equals the $/MWh increase in the market-clearing price that results from a 1 per cent increase in the supplier's net position relative to what it actually had during that half-hour period. As shown in the first equality of equation (3.10), this measure depends on the half-hourly offers of all other suppliers and the supplier's short-term market sales minus its fixed-price forward market obligation.

Figure 18.7 graphs the 30-day moving average of the net inverse semi-elasticities over the sample period of January 1, 2001 to June 30, 2007 computed as described above. For the value of $Q_C$, we use the half-hourly value of the retail load obligation of that supplier. Because there is a small, but sometimes important, fixed-price forward contract market in New Zealand and a small amount of retail load pays a retail price that varies with the half-hourly wholesale price, there is the potential for a small amount of measurement error between the true value of $Q_C$ and the supplier's retail load obligation.

Figure 18.7 demonstrates the mitigating influence of fixed-price forward market obligations on the ability of suppliers to exercise unilateral market power. All of the inverse semi-elasticities of the residual demand curve are reduced significantly in absolute value as a result of multiplying them by the half-hourly value of the net exposure of the supplier to short-term prices, $[(DR_i(P_i) - Q_C)/DR_i(P_i)]$. This net exposure can be negative if the supplier sells less in the short-term market than its fixed-price forward market obligations, $Q_C$. This explains why some of the smoothed values of $\eta_i^C$ are negative for certain suppliers during portions of the sample period.

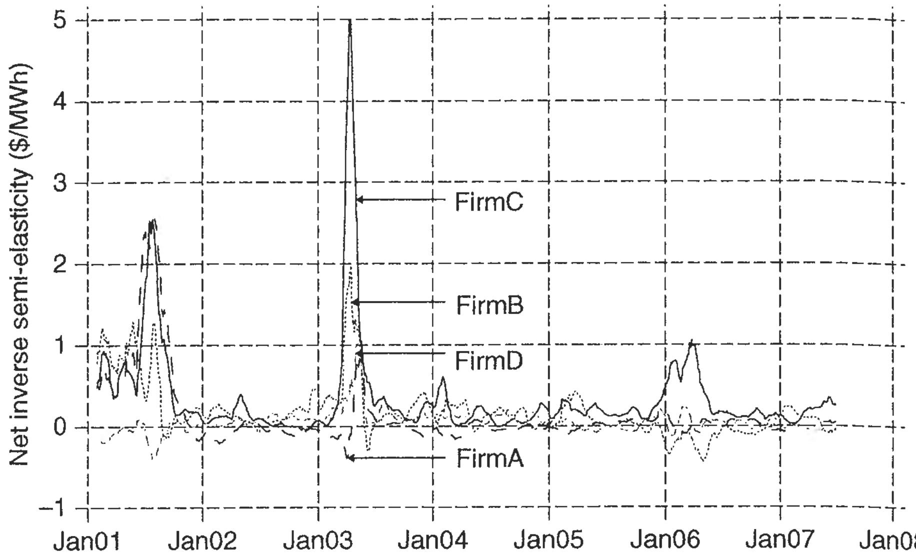


**Figure 18.7** Half-hourly net inverse semi-elasticities by firm, 30-day rolling average

As shown in Figure 18.4, all four suppliers had more than double the ability to exercise unilateral market power in early 2003 relative to mid-2001, as measured by smoothed half-hourly semi-elasticities during the two time periods. Only Firm C translated this larger ability into a large incentive to raise short-term prices as measured by the value of $\eta_i^C$. Consequently, one explanation for the slightly longer period of higher prices that prevailed during mid-2001 is that a larger number of suppliers had a significant incentive to exercise unilateral market power during mid-2001 versus early 2003.

Figure 18.8 plots the 30-day moving average of the half-hourly values of the quantity-weighted average of the nodal prices and a 30-day moving average of the half-hourly values of $\eta_{hd}^C(firm)$. Figure 18.8 shows that the time series pattern of $p_{hd}(avg)$, the quantity-weighted average of the nodal prices for half-hour h of day d, closely tracks the time series pattern $\eta_{hd}^C(firm)$, which is defined analogously to $\eta_{hd}(firm)$. During the half-hour periods when this average index of the incentive of these suppliers to exercise unilateral market power is larger, the quantity-weighted average of the nodal prices is high. Specifically, during mid-2001, early 2003, and early 2006 the average index of the incentive of suppliers to exercise unilateral market power is high and the quantity-weighted average nodal price is high. Conversely, during periods when the average index of the incentives of these suppliers to

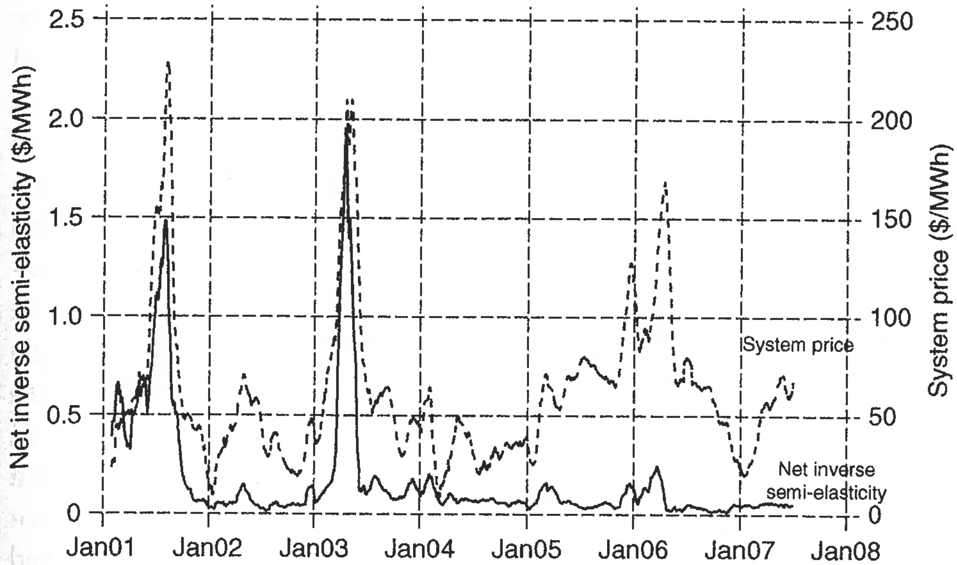


**Figure 18.8** Mean net inverse semi-elasticities and system price, 30-day rolling average

exercise unilateral market power is close to zero, the smoothed quantity-weighted average of the nodal prices is significantly lower. This occurs during 2002, 2004, and 2005.

This section has shown that both the ability and incentive of all four suppliers to exercise unilateral market power are positively correlated with market-clearing prices. The ability to exercise unilateral market power is clearly a necessary condition for a supplier to exercise unilateral market power because a supplier must face an upward-sloping residual demand curve to be able to raise market prices by withholding its output. However, even a supplier with a substantial ability to exercise unilateral market power may not exploit this ability unless it has an incentive to do so. As noted above, the difference between a supplier's short-term market sales and its fixed-price forward market obligations determines the supplier's incentive to exercise unilateral market power.

## 18.4 Offer behavior and ability and incentive to exercise market power

The previous section has demonstrated that the ability and incentive to exercise unilateral market power is very highly correlated with the level of market prices. This section explores the extent to which this relationship is due to suppliers exercising unilateral market power by raising their offer prices (during periods when they have an increased ability and incentive to exercise market power). The theory of expected profit-maximizing offer behavior implies that suppliers exercising all available unilateral market power will submit higher offer prices when they have a greater ability and incentive to exercise unilateral market power. This section provides empirical confirmation for this implication of expected profit-maximizing behavior.

We find that after controlling for differences over days of the sample and half-hours of the day or half-hours of the day during each month of our sample period in an individual supplier's opportunity cost of producing electricity from their generation units, higher values of $\eta$, a supplier's unilateral ability to exercise unilateral market power, are associated with a higher offer price for the quantity of energy dispatched during that half-hour period by that supplier. A similar statement holds for $\eta^C$, a supplier's incentive to exercise unilateral market power. After controlling for opportunity cost differences over time, higher values of this index of the incentive to exercise unilateral market power are associated with a higher offer price for the quantity of energy dispatched during that half-hour period by that supplier. The absolute values of the regression coefficient estimates – associated with the incentive of a supplier to exercise unilateral market power – are uniformly higher for all market participants than the corresponding coefficient estimates for the regressions using the unilateral ability measure. This outcome is consistent with the assertion that the incentive to exercise unilateral market power is a key determinant of a supplier's offer price if it has significant fixed-price forward market obligations, as is the case for all of the four large suppliers under consideration.

As equations (3.5) and (3.9) in Section 18.3 demonstrate, the simplified model of expected profit-maximizing offer behavior by a supplier facing a distribution of downward sloping residual demand curves implies that, after controlling for the opportunity cost of the highest cost generation unit operating during that half-hour period (the term $C_i$ in these two equations), a supplier's offer price at the quantity of energy that it sells in the short-term market should be an increasing function of the value of the inverse semi-elasticity, and increasing in the net inverse semi-elasticity. Although the conditions necessary for the strict validity of the simplified model of expected profit-maximizing offer behavior do not hold for the New Zealand market, we still expect these two implications of the simplified model to hold. Specifically, when a supplier has a greater unilateral ability or incentive to exercise unilateral market power, after controlling for its opportunity cost of selling energy from its highest cost generation unit operating during that hour, the offer price it sets for the amount of energy that it sells in the short-term market should be higher.

Let $P_{jhdm}(\text{actual})$ equal the offer price at the actual level of output sold by supplier j during half-hour h of day d during month of sample m, $\eta_{jhdm}$ the inverse semi-elasticity of supplier j's residual demand curve during half-hour h of day d during month of sample m, and $\eta^{C}_{jhdm}$ the inverse net semi-elasticity of supplier j's net-of-forward-market-obligation residual demand curve during half-hour h of day d during month of sample m. We take two approaches to controlling for differences across half-hours during our sample period in the variable cost of the highest cost generation unit owned by that supplier operating during that half-hour period. The first approach assumes that this variable cost can be different for each supplier for every day during our sample period and each half-hour during the day. The following regressions are estimated for each supplier j:

$$P_{jhdm}(\text{offer}) = \alpha_{dmj} + \tau_{hj} + \beta_j \eta_{jhdm} + \varepsilon_{jhdm}$$
$$\text{and } P_{jhdm}(\text{offer}) = \gamma_{dmj} + \mu_{hj} + \delta_j \eta^{C}_{jhdm} + \nu_{jhdm}, \qquad (4.1)$$

where the $\alpha_{dmj}$ and $\gamma_{dmj}$ are day-of-month d for month-of-sample m fixed effects and the $\tau_{hj}$ and $\mu_{hj}$ are half-hour-of-the-day fixed effects. The $\varepsilon_{jhdm}$ and $\nu_{jhdm}$ are mean zero and constant variance regression errors. Input fossil fuel prices and water levels change at most on a daily basis. Because there is a different fixed effect for each day and month combination during our sample period, these fixed effects completely account for the impact of daily changes in fossil fuel prices and water levels during our sample period on the variable cost of the highest cost generation unit owned by supplier j that is operating during each half-hour period in the day. Consequently, these day-of-sample fixed effects completely control for any differences across days of the sample in input fossil fuel prices and water levels. The half-hourly fixed effects account for differences across half-hours of the day in this variable cost. This strategy for controlling for variable cost changes across half-hours of the sample implies more than 2,400 possible variable cost values over the sample period for each supplier. Multiplying this figure by four implies more than 9,600 possible variable costs of the highest cost generation unit operating during a half-hour that could set the market-clearing price during our sample.

Our second strategy for controlling for the opportunity cost of producing electricity from the highest variable cost unit (operating during half-hour period-of-the-day h during month of the sample m for supplier j) uses different half-hour-of-the-day fixed effects for each month of the sample period. The two equations estimated are:

$$P_{jhdm}(\text{offer}) = \alpha_{hmj} + \beta_j \eta_{jhdm} + \varepsilon_{jhdm}$$
$$\text{and } P_{jhdm}(\text{offer}) = \gamma_{hmj} + \delta_j \eta^{C}_{jhdm} + \nu_{jhdm}, \qquad (4.2)$$

where $\alpha_{hmj}$ and $\gamma_{hmj}$ are half-hour-of-the-day for each month-of-the-sample fixed effects to control for the differences in the opportunity cost of producing electricity from the highest variable cost unit operating during half-hour period-of-the-day h during month-of-the-sample m for supplier j. The $\varepsilon_{jhdm}$ and $\nu_{jhdm}$ are once again mean zero and constant variance regression errors. Because there are 48 half-hour periods in the day and 78 months during our sample period from January 1, 2001 to June 30, 2007, there are $48 \times 78 = 3{,}744$ values of the $\alpha_{hmj}$ and the same number of values of the $\gamma_{hmj}$ for each supplier j. These fixed effects imply that the variable cost of producing electricity from the highest cost generation unit operating during half-hour 12 in month 3 of the sample period can be different from this same variable cost during all other months of the sample period. Moreover, the variable cost of producing electricity from the highest cost generation unit operating during half-hour 12 in month 3 can differ from the variable cost of producing electricity in any other half-hour of any other month of the sample period, including month 3.

These fixed effects allow for a substantial amount of variability in the time path of the variable cost of the highest cost unit operating in the North and South Island of New Zealand during each half-hour of our sample period. There are 3,744 fixed effects for each supplier to account for differences in the variable cost of the highest cost unit in their portfolio operating during each half-hour of the sample period. Multiplying this figure by 4 implies 14,976 different possible variable costs of the highest cost unit operating owned by the four large suppliers that could set prices during our sample period.

The fixed effects in model (4.1) and model (4.2) should be more than sufficient to account for differences in the variable cost of the highest cost generation unit operating during each half-hour of the sample period in the portfolio of generation units owned by each of the four large suppliers. The opportunity cost of producing electricity from hydroelectric generation units should not differ significantly across half-hours of the day or days of the month in a hydroelectric dominated system. The opportunity cost of water depends on current water storage levels and the distribution of future water inflows and outflows. New information about these variables arrives daily, but the best estimates of future inflows and outflows changes slowly as do water storage levels. Our day-of-sample fixed effects are more than sufficient to account for changes in the opportunity cost of water over our sample period.

The variable cost of producing electricity from individual fossil fuel generation units is unlikely to change significantly during individual months of our sample period. It implies that fixed effects that allow these half-hourly variable costs to change each month of the sample period should provide for far more fluctuations in the variable cost of the highest cost unit producing electricity during each half-hour of our sample period than is likely to be necessary to capture the amount of variability that actually exists in these variable costs. Regressions of model (4.1) including the value of the relevant daily fossil fuel price and daily water levels (to account for daily changes in the variable cost of operating fossil fuel generation units and daily changes in the opportunity cost of water) did not quantitatively change any of our results. This outcome is not surprising given the high level of agreement between our estimates of $\beta_j$ and $\delta_j$ using day-of-sample and half-hour-of-the-day fixed effects and different half-hour-of-the-day fixed effects for each month of the sample period.

Table 18.1 presents the estimated values of $\beta_j$ and $\delta_j$ and the estimated standard errors for each of the four suppliers using the day-of-sample and half-hour-of-the-day fixed effects. Table 18.2 presents estimates of the same parameter values for the different half-hour-of-the-day fixed effects for each month of the sample period. The values of $\beta_j$ and $\delta_j$ are positive, precisely estimated and economically meaningful for all regressions. Focusing on the day-of-sample and half-hour-of-the-day fixed-effects model, holding all other factors constant, if the residual demand curve faced by Firm C has an inverse semi-elasticity that is one unit higher, the offer price associated with the amount of output that it sells in the short-term market is predicted to be \$1.41/MWh higher. This is because of the greater ability Firm C

**Table 18.1** ***Dependent variable = offer price at dispatch quantity for supplier j***

| | Firm A | Firm B | Firm C | Firm D |
|---|---|---|---|---|
| $\beta_j$ | 0.46 | 0.56 | 1.41 | 3.81 |
| (s.e.) | (.017) | (.040) | (.031) | (.062) |
| $\delta_j$ | 5.08 | 4.02 | 4.31 | 21.63 |
| (s.e.) | (.108) | (.146) | (.101) | (.335) |

**Note:** Day-of-sample and half-hour fixed effects are included in all regressions.

**Table 18.2** ***Dependent variable = offer price at dispatch quantity for supplier j***

| | Firm A | Firm B | Firm C | Firm D |
|---|---|---|---|---|
| $\beta_j$ | 0.67 | 0.73 | 1.16 | 4.54 |
| (s.e.) | (.020) | (.040) | (.029) | (.064) |
| $\delta_j$ | 7.27 | 3.39 | 3.38 | 22.86 |
| (s.e.) | (.129) | (.154) | (.092) | (.354) |

**Note:** Month-of-sample interacted with half-hour fixed effects are included in all regressions.

has to exercise market power as implied by the inverse semi-elasticity of its residual demand curve.

We compute the half-hourly sample mean and standard deviation of $\eta_{jhdm}$ for each h to demonstrate the economic significance of our estimates of $\beta_j$. Table 5.3 of Wolak and McRae (2009) presents these half-hour-of-the-day means and standard deviations. For example, for Firm C, the standard deviation of $\eta_{jhdm}$ for h=37 is equal to 6.811. This implies that holding the opportunity cost of water and the price of the input fossil fuel constant, a one standard deviation change in the value of $\eta_{jhdm}$ for half-hour number 37 implies a \$9.60/MWh higher offer price and a two standard deviation change a \$19.20/MWh higher offer price according to the parameter estimates in Table 18.1. For Firm A, the mean and variance of the inverse semi-elasticities over the sample period are even higher. The value of $\beta_j$ for Firm A implies that a one standard deviation change in the value of the inverse semi-elasticity of its residual demand curve during half-hour number 23, holding all other factors constant, implies an offer price increase of \$4.50/MWh.

Changes of this magnitude in the value of its inverse semi-elasticity for half-hour number 23 for Firm A during our sample period are not unusual.

For Firm D the value of $\beta$ is significantly higher than it is for all of the other suppliers, on the order of \$3.81/MWh. However, the mean value of the inverse semi-elasticity is the lowest of all of the suppliers and the variance is also the smallest. Nevertheless, the magnitude of $\beta$ for Firm D implies that even for a one standard deviation change in the value of its inverse semi-elasticity, economically significant changes in Firm D's offer price are predicted to occur because of its increased ability to exercise unilateral market power.

The values of $\delta$, the coefficient associated with $\eta^{C}_{jhdm}$, the inverse semi-elasticity of the net of forward market obligations residual demand curve, are substantially larger in absolute value than the corresponding value of $\beta$, the coefficient associated with $\eta_{jhdm}$, for all suppliers. The value of $\delta$ for Firm C implies that if the value of the inverse semi-elasticity of the net forward market obligations residual demand curve for Firm C increases by one unit, then Firm C's offer price for the amount it sells in the short-term market is predicted to increase by \$4.31 because of the substantially greater incentive Firm C has to exercise unilateral market power. Table 5.4 of Wolak and McRae (2009) presents the half-hour-of-day means and standard deviations for $\eta^{C}_{jhdm}$. This table shows that a one unit change in the value of $\eta^{C}_{jhdm}$ is a fairly frequent occurrence. For a number of half-hours of the day, a 3 unit change in $\eta^{C}_{jhdm}$ is less than a two standard deviation change. For example, during half-hour number 37, a two standard deviation change in the value of $\eta^{C}_{jhdm}$ implies a more than \$20/MWh increase in Firm C's offer price.

It is important to emphasize that, different from the case of the inverse semi-elasticity of the residual demand curve, which can only be positive, the inverse semi-elasticity of the net-of-forward-market-obligations residual demand curve can be negative if the supplier's fixed-price forward market obligations exceed the amount of energy that it sells in the short-term market. As shown in Figure 18.7, this was frequently the case for Firm A as well as for Firm B and Firm D during the sample period. The results in Table 18.1 for Firm A imply that, keeping all other factors constant, if a negative value of $\eta^{C}_{jhdm}$ for Firm A becomes larger in absolute value by one unit, Firm A's offer price is predicted to be \$5.08/MWh lower because of its greater incentive to exercise unilateral market power by driving the price down. A one unit change in $\eta^{C}_{jhdm}$ is less than a one standard deviation change for many half-hours of the day. The results in Table 18.1 also imply that – keeping the opportunity cost of water and the price of the input fossil fuel constant – if the value of the inverse semi-elasticity of the net-of-forward-market-obligations residual demand curve facing Firm A increases by one unit, the offer price for the amount of energy it sold in the short-term market is \$5.08/MWh higher because of the greater incentive Firm A has to exercise unilateral market power.

Thus, once fixed-price forward contract obligations are introduced into a wholesale market, suppliers with the ability to exercise unilateral market power can do so either by increasing or decreasing prices. A supplier with a substantial ability to exercise unilateral market power that is net short relative to its forward market obligations (meaning that it has more fixed-price forward market obligations than the amount of energy it sold in the short-term market) has an incentive to exercise market power by driving down the wholesale price, which reduces the cost of closing out its net short position through purchases from the short-term market. The results shown in Tables 18.1 and 18.2 confirm this for logic for all suppliers. Alternatively, when a supplier is long relative to its forward market position, meaning that its sales in the short-term market exceed its fixed-price forward market obligations, a higher value of the $\eta^{C}_{jhdm}$ implies that it will raise its offer price because it has an incentive to use its ability to exercise market power to raise the market-clearing price.

The estimate for $\delta_j$ for Firm D is by far the largest of the five values reported in Tables 18.1 and 18.2. However, as shown in Wolak and McRae (2009), the standard deviations of the inverse elasticity of the net of fixed-price forward market obligations for Firm D are very small in absolute value relative to the values for the other three suppliers. Nevertheless, even multiplying the estimate of $\delta_j$ for Firm D by a one standard deviation change in the value of its inverse elasticity yields predicted offer price changes of more than \$10/MWh for many half-hours of the day. Because the $\eta^{C}_{jhdm}$ for Firm D takes on both positive and negative values during the sample period, there are times when Firm D submits a substantially lower offer price, all other factors held constant, because it has an incentive to use its ability to influence market prices to lower the market-clearing price because its short-term market sales are less than its forward market obligations. Alternatively, when it is long relative to its forward market position, a higher value of the $\eta^C_{jhdm}$ for Firm D implies that it will raise its offer price because it has an incentive to use its ability to exercise market power to raise the market-clearing price.

It is important to emphasize that the goal of our modeling effort is to determine whether higher offer prices are systematically associated with higher values of $\eta_{jhdm}$ and $\eta^C_{jhdm}$ and whether the magnitude of this relationship is economically significant. The results of our analysis presented in Tables 18.1 and 18.2 provide strong confirmation of a positive and economically significant relationship between a supplier's half-hourly offer price and the half-hourly values of $\eta_{jhdm}$ and $\eta^C_{jhdm}$. The magnitude of this relationship is substantially larger for the measure of the incentive to exercise unilateral market power relative to the measure of the ability to exercise unilateral market power. This result is consistent with the logic that a supplier with the ability to exercise unilateral market power must also have the incentive to do so in order to find it expected profit-maximizing to submit offer prices that exploit it.

It is important to emphasize that the regressions (4.1) and (4.2) are predictive regressions in the sense discussed in Reiss and Wolak (2007). As noted above, the economic theory of expected profit-maximizing offer behavior described in Wolak (2003a and 2007) does not imply these regressions yield the precise causal relationship between half-hourly offer prices and the half-hourly indexes of the ability and incentive of market participants to exercise unilateral market power. This fact does not invalidate the interpretation of these regressions as providing predictive statistical evidence consistent with the view that after controlling for the level of input fossil fuel prices and the opportunity cost of water, when any of the four suppliers has a greater ability or incentive to exercise unilateral market power as measured by these indexes, each supplier submits a significantly higher half-hourly offer price and this higher offer price results in a substantially higher market-clearing price.

## 18.5 Do thermal suppliers behave as if they have no ability to exercise market power?

The final piece of evidence in favor of the view that the four large suppliers exercise all available unilateral market power is a test of the null hypothesis that thermal suppliers behave as if they had no ability or incentive to exercise unilateral market power. A supplier that has no ability or incentive to exercise unilateral market power can be expected to submit an offer curve equal to its aggregate marginal cost curve of supplying electricity. The complication with implementing this test for hydroelectric suppliers is that estimating their no-market-power opportunity cost of supplying energy is a massively complex computational problem related to the actual opportunity cost of stored water. However, for fossil fuel suppliers we know that the opportunity cost of producing electricity from their generation units depends on the price of the input fossil fuel, the heat rate of the generation unit, and the variable operating and maintenance cost of the generation unit. Consequently, a fossil fuel supplier with no ability to exercise unilateral market power will submit an offer price for each fossil generation unit equal to the unit's variable cost.

Our test of the null hypothesis that no supplier has the ability or incentive to exercise unilateral market power is based on the simple insight that offer prices of fossil fuel generation unit owners with no ability to exercise unilateral market power should not be predicted by any other factors besides those that impact the variable cost of the generation unit. In particular, if fossil fuel suppliers do not have any ability to exercise unilateral market power, the offer price for the amount of energy they sell into the short-term market should not be impacted by the system hydro storage level. In contrast, if higher offer prices are associated with lower water levels, then this is consistent with a supplier that has the ability to exercise unilateral market power taking advantage of this fact to raise their offer prices and market-clearing prices in response to the incentives that it faces.

To investigate this null hypothesis we regress the offer price for the quantity of energy sold from each fossil fuel generation unit during the half-hour periods of the sample when the unit was available to supply energy on a number of factors that control for the variable cost of producing electricity from this generation unit at different levels of output and daily hydro storage levels in Terawatt-hours (TWh). Let $P_{khdm}$(offer) equal the offer price of the energy sold in the short-term market from fossil fuel generation unit k during half-hour h of day d and month m. Let $Hydro_{dm}$ equal the amount of hydroelectric energy in storage on day d of month m. Let $QINC_{ikdhm}$ equal a set of I(k) dummy variables each of which equals 1 if the dispatch quantity from fossil fuel generation unit k during half-hour h of day d in month m lies in the 10 MW quantity increment i. For each generation unit we take the maximum and minimum output observed during the sample period and divide this range into 10 MW increments. For example, if 250 MW is the lowest output level and 360 MW is the highest output level, then I(k) equals 11, meaning that there are 11 possible 10 MW bins that the supplier could produce in during the sample period. These quantity bins are chosen to account for the fact that the heat rate of fossil fuel units can be different for different output levels. Define $YR_{zdhm}$ as an indicator variable that equals one if half-hour h of day d and month of sample m is in year z, where z=2001, 2002,...2007. Define $MTH_{wdhm}$ as an indicator variable that equals 1 if half-hour h of day d and month-of-sample m is in month-of-the-year w=1, 2, 3..., 12. We estimate the following regression for each fossil fuel unit:

$$P_{khdm}(offer) = \sum_{i=1}^{I(k)} \alpha_{ik}\, QINC_{ikdhm} + \sum_{z=2001}^{2007} \gamma_{zk}\, YR_{zkdhm} + \sum_{i=1}^{I(k)} \sum_{z=2002}^{2007} \theta_{izk} YR_{zkdhm}\, QINC_{ikdhm} + \sum_{i=1}^{12} \delta_{ik}\, MTH_{ikdhm} + \beta_k Hydro_{dm} + \varepsilon_{khdem}. \qquad (5.1)$$

This linear regression controls for differences in the variable cost of fossil fuel units across the 10 MW quantity increments of output levels for the unit (the first summation), across each year of the sample (the second and third summations), and within the months of the year (the fourth summation) in order to assess whether the level of hydroelectric storage provides incremental explanatory power, beyond these variables that control for differences in the generation unit's variable cost of production, in predicting the offer price.

Table 18.3 presents the results of estimating (5.1) for the major fossil fuel units (or, in one case, group of units) operating in the New Zealand market during our sample period. In all cases, the estimated value of $\beta_k$, the coefficient associated with the value of system hydro storage for unit k, is found to be negative and precisely estimated. The null hypothesis that $\beta_k$ is equal to zero is overwhelmingly rejected for all eight units, which provides strong evidence against the null hypothesis that the owners of these fossil fuel units behave as if they had no ability to exercise unilateral market power. The implied change in

**Table 18.3** ***Dependent variable = offer price at dispatch quantity for fossil fuel plant/unit k***

| | Plant 1 | Plant 2 | Plant 3 | Plant 4 |
|---|---|---|---|---|
| $\beta_k$ | −17.40 | −2.34 | −19.61 | −21.13 |
| (s.e.) | (.457) | (.135) | (.340) | (.448) |
| | Plant 5 | Plant 6 | Plant 7 | Plant 8 |
| $\beta_k$ | −8.05 | −24.31 | −11.01 | −24.12 |
| (s.e.) | (.674) | (.377) | (.459) | (.335) |

**Note:** Regressions include year-of-sample fixed effects interacted with generation quantity in 10 MW bins, as well as month-of-year fixed effects. The dependent variable in each regression is the offer price from either a single generation unit, or a group of units.

offer behavior from these generation units as a result of changes in the water level are also economically meaningful. For example, if the value of system hydro storage decreases by 1 TWh, then the offer price for the Plant 6 is predicted to increase by $24.31 and by $24.12 for the Plant 8. The predicted increases in the offer prices for a 1 TWh reduction in the value of system hydro storage for Plant 5 and Plant 7 are roughly half these values. Plant 1 and Plant 3 have predicted offer price increases for a 1 TWh reduction in system hydro storage of $17.40 and $19.61, respectively. Note that the difference between the minimum and maximum system hydro storage levels during our sample period is 3.1 TWh, so these estimates predict very large changes in the offer prices of fossil fuel units for the observed changes in hydrological conditions.

Although these parameter estimates are inconsistent with the hypothesis that these fossil fuel generation unit owners have no ability to exercise unilateral market power, the signs and magnitudes of the estimated values of the $\beta_k$ are consistent with the hypothesis that the owners of these generation units have a significant ability to exercise unilateral market power and that this ability to exercise unilateral market power decreases with the level of system hydro storage. These results are also consistent with the results presented in the previous section which showed that the offer price for the quantity of energy sold in the short-term market by each of the four suppliers is increasing in that supplier's ability and incentive to exercise unilateral market power.

## 18.6 Conclusions about how firms exercise market power

The several lines of empirical inquiry presented in this chapter are broadly consistent with the implications of expected profit-maximizing offer behavior by the four large suppliers in response to the extent of competition they face from other suppliers on a half-hourly basis. This conclusion does not depend on any assumptions about the functional form of aggregate demand in the market or any model of strategic interaction among firms. Because of the data-rich multi-unit auction environment that we study, ex post half-hourly measures of the ability of a supplier to exercise market power using the offers submitted by all suppliers and the level of system demand can be computed without either of these assumptions. We find that each of the four large suppliers submits a higher half-hourly offer price when it has a higher half-hourly unilateral ability to exercise market power. The half-hourly offer price increases predicted by the parameter estimates from our econometric model (for typical changes in the half-hourly ability of each supplier to exercise market power) are economically significant in the sense that the implied offer price increases can be in the range of $10/MWh to $20/MWh during peak periods of the day.

We find even larger (in absolute value) predicted changes in a supplier's half-hourly offer prices in response to changes in its half-hourly incentive to exercise market power for typical changes in the values of these indexes. Our index of the half-hourly incentive of a supplier to exercise market power can be positive or negative, depending on the supplier's exposure to short-term market-clearing prices during that half-hour period. If a supplier is net long – its short-term market sales exceed its fixed-price forward market obligations for that half-hour – then its index of the incentive to exercise market power is positive. If a supplier is short – its sales are less than its fixed-price forward market obligations for that half-hour – then its index of the incentive to exercise market power is negative. Our regression results predict that sizeable increases in the supplier's offer price occur during half-hour periods when this index of the supplier's incentive to exercise market power is large and positive. They also predict that sizeable decreases in the supplier's offer prices occur during the half-hour periods when this half-hourly index of the supplier's incentive to exercise market power is large in absolute value and negative. These results emphasize that the extent a supplier actually exploits a lower degree of competition from other firms depends on the incentive it has to do so, as measured by the degree to which the revenues the supplier receives depend on the short-term market-clearing prices. In addition, how the supplier exploits its ability to influence the short-term market price depends on the sign of its exposure to short-market prices. This result implies that a portion of the high degree of volatility in half-hourly short-term wholesale electricity prices is the result of changes in the sign of the half-hourly incentive of suppliers to exercise unilateral market power. Finally, we provide strong evidence against the null hypothesis that the half-hourly offer curves submitted by owners of fossil fuel generation units are the result of those suppliers behaving as if they have no ability to exercise market power.

Taken together, the empirical results in this chapter demonstrate that although prices in a multi-unit auction wholesale electricity market depend on supply and demand conditions, actual supply conditions depend on the offer curves submitted by market participants to the wholesale market. These offer curves are a direct result of the unilateral expected profit-maximizing actions of suppliers given factors that they are unable to control such as the level of demand at all locations in New Zealand, amount of water inflows to hydroelectric generation units, and the price of fossil fuels and other inputs consumed to produce electricity. Therefore, the ability and incentive of large suppliers to exercise unilateral market power are important determinants of the supply conditions that determine short-term wholesale prices, even after the impact of exogenous factors such as water availability and fossil fuel prices have been taken into account.