Market Power in Mixed Hydro-Thermal Electric Systems. *

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Abstract

This paper shows that, unlike what has been found in other papers, a hydro reservoir is an effective tool to exercise market power. Its appealing as a tool is enhanced by the fact that there is no need to constrain total hydro production - a practice too easy to detect -; it suffices to distort the intertemporal allocation of hydro production over time. A hydro-producer may increase his profits by exploiting differences in price elasticity of demand across periods, allocating too little supply to less elastic periods and too much to more elastic periods. Differences in price elasticity across periods may result from the combination of a fluctuating market demand and capacity or transmission constraints that bind intermitently. This hydro scheduling decision is only available to hydro producers as thermal generators are not able to "store electric power" and decide when to sell it. It is also shown that total hydro production is not a sufficient indicator of market power being exercised as hydro producers may exercise market power even when all the water available in the\reservoir is used. The real indicator of market power being exercised is the hydro scheduling strategy used

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1 Introduction

This paper shows that, unlike what has been argued in the literature, hydro producers may be able to exercise market power in hydro and mixed hydro/thermal electric systems. Even though hydro producers may attempt to drive prices up by constraining total production- a practice too easy to detect -, they may also use a tool that is not available to thermal producers: the scheduling of their hydro-storage plants' production. Hydro producers may increase their profits by exploiting differences in price elasticity of demand across periods: they allocate too little supply to low price elasticity periods and too much to high elasticity periods, relative to the allocation that would result in a perfectly competitive market. Since this strategy may be used, and be successful, even when all the available hydro flows in the reservoir are used, this paper calls to shift the focus of the analysis of market power in hydro and mixed hydro/thermal power systems from total production to the scheduling of the hydro reservoir plants.

In the past years empirical papers that study market power issues in the power industry have boomed, especially those that attempt to diagnose market power, either ex-ante or ex-post a deregulation process has actually taken place. This behavior has been motivated by the power industry de-regulation wave that has spread throughout the world with different degree of success (UK, many states in the US, Argentina, Colombia, Australia, New Zealand and so on) and most likely by recent experiences regarding the exercise of market power (being California the most notable example).

The analysis of market power in the literature has mostly focused on thermal (or predominantly thermal) systems. This literature seems to agree on the conclusion that more market power can be exercised when the fringe's capacity is exhausted (which usually occurs when demand is high) because this makes the residual demand curve faced by the firms with market power less elastic. The exercise of market power results in high prices and in an inefficient allocation (production costs are not minimized). Results are very sensitive to the elasticity of demand as well as the elasticity of fringe supply. For more details see Green and Newbery (1992), Von der Fehr and Harbord (1993), Andersson and Bergman (1995), Borenstein et al (1996), Wolak and Patrick (1997), Wolfram (1998, 1999), Borenstein and Bushnell (1999), Borenstein et al (2002) and Joskow and Kahn (2002).

Less attention has been given to market power issues in purely hydro or mixed hydro-thermal systems. This omission is probably explained by the presumption that market power cannot be exercised in purely hydro systems because all the water available must be used and, the argument goes, a producer would not benefit from constraining its production in certain hours as this would lower the value of water in future periods (Halseth 1998). However, this presumption is incorrect. As this paper shows, even if the producer is forced to use all the hydro resources that are available in a certain period (say, a month), the producer may still have enough flexibility to decide *when* to use them (i.e. what specific hours within the month). In that case, the producer will choose to allocate its hydro production so as to maximize its inter-temporal profits.

The hydro scheduling issue, probably the most important tool hydro producers have to exercise market power, has not received enough attention in the literature. Even papers that explicitly study market power issues in hydro or mixed hydro/thermal electric systems do not analyze how are hydro resources inter-temporally allocated, but focused almost exclusively on total output and / or total hydro generation (Halseth, 1998; Scott, 1998). Most noticeable exceptions are Bushnell (1998) and Johnsen et al (1999).

This paper shows that a necessary condition for the exercise of market power in mixed thermal-hydro or purely hydro systems is the existence of differences in price-elasticity across periods. If that is the case, then producers schedule their hydro production in order to exploit those differences allocating too little supply to low price - elasticity periods and too much to high price-elasticity periods, relative to the competitive equilibrium. The exercise of market power results by a hydro producer results in price differences across periods being enlarged rather than reduced. This hydro scheduling strategy may be observed no matter how long is the planning horizon assumed in the model (a month, a year); the only "requirement" is that differences in price-elasticity of demand are large enough. The smaller the fluctuation, the closer is the hydro scheduling strategy to the conclusions of the traditional competitive supply-demand or value-maximizing optimization analysis (i.e. water is stored when it is relatively abundant and released when it is relatively scarce). According to this result, the role of price elasticity of demand in the degree of market power that can be exercised in a purely hydro or mixed hydro-thermal systems is not only given by its level, as traditional models of market power point out ("the less elastic is demand, the more market power can be exercised, ceteris paribus") but also by its variability across periods.

Since differences in price elasticity are key to the exercise of market power, it is important to learn where do these differences come from. In the more common setting, a hydro producer faces a residual demand that results from rivals' supply deducted from market demand. As long as market demand is fluctuating (there are peak and off peak periods) and that rivals' capacity constraints are intermittently binding, differences in price elasticity of residual demand across periods should result. In a previous paper, Johnsen et al (1999) showed that market power can only be exercised in hydro systems when there is congestion in the transmission system. They showed that hydro producers may have incentives to withhold capacity when transmission constraints bind because they can later use the remaining water when there are no constraints and the market is less concentrated. My paper shows that their result is just a particular case of the more general result which is the importance of differences in price elasticity in the degree of market power that can be exercised. Indeed, a transmission constraint can be re-interpreted as a rival's capacity constraint because when the line is congested, rivals' located at the other side of the line cannot react to price increases in the local market by increasing their production and their sales to that market.

To illustrate the main results I use a monopoly model of a power industry whose portfolio of generation is made up only by hydro-reservoir plants. The analysis is later extended to a duopolistic industry with a mixed hydro/thermal portfolio of generation. In both cases particular care is given to the hydro scheduling decision. A simulation of the market equilibrium (and producers' strategies) assuming competitive and Cournot equilibrium was carried out using real demand and cost data from Chile's electricity industry (year 2000). Analyzing Chile's power sector is especially interesting because a large fraction of its generating capacity is stored hydro (47%) and its generation segment is highly concentrated. Since capacity constraints are expected to be important, no effort was made to linearize or smooth each producer's marginal cost function. Solving the model with a step-wise marginal cost function imposes some costs (especially in terms of the uniqueness of equilibrium) but the benefits of this modeling choice are greater

The paper is organized as follows: in the next section I use a simple two period model to analyze the incentives a monopolistic hydro producer faces to drive market prices up and the way he may use his hydro reservoir to do that. The model is extended in Section 3 to a duopolistic industry with a mixed hydro/thermal generating portfolio. In the same section, the data used to run a simulation of the model is described and the results are reported. The final Section concludes and gives direction for further research

2 The Model

The whole idea behind the exercise of market power is to reduce output in order to increase market price. However, the available set of strategies that can be used by producers to exercise market power differ between purely thermal and purely hydro or mixed hydro/thermal electric systems. In a purely thermal system, the only decision that can be taken is when to switch on or off a plant and how much to produce at every moment in time. On the other hand, a system with hydro-reservoirs allows producers to store water during some periods and release it in some others; in other words, they are able to "store" power and release it to the market at their convenience. Therefore, hydro producers are entitled to decide not only when to switch on or off their plants and how much to produce, but also to decide *when* they want to use their hydro resources over a certain period of time, subject to minimum and maximum hydro flow constraints. Having hydro resources as a source of electric generation means that firms do not take static production decisions at each moment in time, but that firms have to take into account that more water used today means that less water is available for tomorrow. Accordingly, a hydro producer might use two different tools to exercise market power: the level of its total production and/or the scheduling of its hydro plants. The latter is a more subtle strategy since constraining total hydro production in order to force market prices up is a strategy easier to observe and thus easier to be alleged as anti-competitive. Since it is the "storing of water" feature associated to a reservoir what entitles a hydro producer to schedule his/her hydro plants, this dynamic scheduling decision is not available to hydro-ROR nor thermal producers.

In this section I use a simple two period model to analyze the incentives a hydro producer faces to drive market prices up and the way he may use his hydro reservoir to do that. [1] I assume that market demand ($Q_t(p_t)$) is faced by a unique generator and that its generating portfolio is made up by a hydro-reservoir complex. I further assume that all the water inflows are received at the beginning of period 1 and that the hydro producer is forced to have used all the water that is available at the end of the second period. The latter assumption is not strictly required but is helpful because it means that the monopolist cannot use total hydro production to exercise market power, leaving only the hydro scheduling strategy available. In this way, the analysis is focused on the use of a tool that is only available to hydro producers; no attention will be given to a tool whose use to exercise market power is common knowledge.

The Monopolist maximizes his inter-temporal profits (equation 1) subject to a hydro resources availability constraint (equation 2) as shown by the following optimization problem:

$$\max_{q_1,q_2} \{P_1(q_1)q_1 + P_2(q_2)q_2\} \tag{1}$$

$$\text{subject to } q_1 + q_2 = q_{Tot} \tag{2}$$

[1] Hereafter "hydro producer" will refer to a producer who owns a hydro-reservoir.

where $P_t(q_t)$ is the inverse of market demand, q_t is hydro-production in period t and q_{Tot} is the energy equivalent of the total water inflows that are available to be used in periods 1 and 2 [2]. Market demands in each period are assumed to be independent. Except for the hydro resources availability constraint, this could be thought of as a third degree price discrimination model. Indeed we will see that the results are very similar.

This problem's first order conditions are:

$$P_1(q_1) + q_1 \frac{\partial P_1(q_1)}{\partial q_1} - \sigma = 0 \quad (3)$$

$$P_2(q_2) + q_2 \frac{\partial P_2(q_2)}{\partial q_2} - \sigma = 0 \quad (4)$$

$$q_1 + q_2 = q_{Tot} \quad (5)$$

where σ is the Lagrange Multiplier for the available hydro flows constraint. Notice that this multiplier is constant over time and indicates the marginal value of water (MVW), i.e. how much would profits increase if an additional unit of water (measured in energy units) were available. The MVW may also be interpreted as the marginal cost of water: how much would the monopolist be willing to pay for an extra unit of water.

Equations 3 and 4 may be written in terms of the marginal revenue the hydro producer gets in each period (MR_t) as:

$$MR_1 = \sigma \quad (6)$$

$$MR_2 = \sigma \quad (7)$$

According to equations 6 and 7 the monopolist produces in each period until the marginal revenue is equal to the marginal value of water. Since the MVW is constant over time Proposition 1 can be formulated as:

Proposition 1 *The Monopolist schedules the production of his hydro plants in order to equalize Marginal Revenue over time (equation 8)*

$$MR_1 = MR_2 = \sigma \quad (8)$$

The intuition of this is the following: if the producer uses an additional unit of water to generate power today, profits increase by MR_1.At the same time, there is one unit less of water to be used in the next period and thus profits are reduced by MR_2. In other words, the marginal cost of producing an additional unit in period 1 is given by MR_2. Accordingly in equilibrium, the hydro plant should be scheduled to produce in each period such that marginal revenue is equalized over time.[3]. This result is similar to what we would have found

[2] Additionally a minimum and maximum hydro capacity constraint may be included. The ommission does not change the cualitative conclusions.

[3] If minimum and maximum hydro capacity constraints were included and any of them were binding, marginal revenue would be equalized over time except for a gap given by the shadow price of the binding constraint.

in a third degree price discrimination model; the only difference is that the hydro resources availability constraint restricts the total amount of production (electric power in this case) that can be sold in both markets.

This strategy is different from what a competitive producer would do.

Proposition 2 *A producer with no market power ($\frac{\partial P_t(q_t)}{\partial q_t} = 0$) schedules the production of his hydro plants in order to equalize prices over time.*

$$P_1(q_1) = P_2(q_2) = \sigma \tag{9}$$

Notice that no matter how competitive is the industry, the hydro producer always schedules his hydro plants in order to equalize the marginal profit that he earns from one more unit of production over the whole period in which the hydro plant is being used. Accordingly, a producer with no market power shaves demand in order to equalize prices while a producer with market power equalizes marginal revenues over time. In other words, a hydro producer who is able to exercise market power peak shaves marginal revenues rather than prices.

In order to illustrate more precisely the scheduling of hydro production over time I solve the model for a CES market demand given by $Q_t(P_t) = k_t P_t^{-\varepsilon_t}$ where k_t is a demand parameter and ε_t is the price elasticity of demand (defined as a positive number) .Accordingly, the monopolist's pricing rule is given by equations 10 and 2:

$$P_1\left(1 - \frac{1}{\varepsilon_1}\right) = P_2\left(1 - \frac{1}{\varepsilon_2}\right) = \sigma \tag{10}$$

Example 3 *Constant demands + constant elasticity over time ($\varepsilon_1 = \varepsilon_2$ and $k_1 = k_2$)*

When demand and price elasticity do not fluctuate over time, the competitive producers' and the monopolist's hydro scheduling strategy coincide ($P_1(q_1) = P_2(q_2)$). Accordingly in both cases prices are equalized over periods and no market power can be exercised.

Example 4 *Fluctuating demands + constant elasticity over time ($\varepsilon_1 = \varepsilon_2$ and $k_1 > k_2$)*

Unlike Example 3, $q_1 > q_2$, but it is still true that both the monopolist and the competitive producer schedule their hydro plants in order to equalize prices over time. In other words, the competitive equilibrium and the monopoly equilibrium coincide. Market power cannot be exercised in a hydro system if elasticity is constant over time even when demand fluctuates over time. It is still left to know what happens when there *are* differences in demand elasticity.

Example 5 *Constant demands + different elasticity over time ($\varepsilon_1 > \varepsilon_2$ and $k_1 = k_2$)*

It can be shown that when there are differences in demand elasticity over time the hydro scheduling strategy used by a competitive producer is different from the one used by a monopolist. As Equation 11 shows, the monopolist allocates relatively less supply to the less elastic period (period 2 in Example 5) and relatively more to the more elastic period (period 1).

$$\left(\frac{q_2}{q_1}\right)^{Monopoly} < \left(\frac{q_2}{q_1}\right)^{P\,\mathrm{erf}\,ect\ Competition} \tag{11}$$

It can also be shown that the larger the difference in price-elasticity across periods $(\varepsilon_1 - \varepsilon_2)$, the larger is the distortion -in terms of price and hydro production per period) that results from the monopolist's behavior.

A hydro reservoir allows the producer to shift production from one period to another. When choosing the hydro scheduling strategy the producer realizes that by constraining hydro production in one period, more water will be left available for the other period. If price elasticity is constant over time, the monopolist does not gain anything by distorting the hydro production schedule because the extra revenue that he may earn by constraining production in one period is more than compensated by the lower revenue in the other period, resulting in smaller total profits. On the contrary, when there are differences in demand elasticity, the monopolist is able to increase his profits by shifting production from the less elastic period to the more elastic period. It is no longer true that prices are equalized over time.

This simple model clearly illustrates the mechanic that lies behind the exercise of market power by a hydro producer. Three lessons can be learnt from it:

Proposition 6 *A necessary condition for the exercise of market power in a purely hydro system is the existence of differences in price-elasticity across periods.*

The model shows that the traditional belief that "no market power can be exercised in hydro systems" proves to be true only in cases in which price elasticity of demand is constant over time. Indeed, fluctuating demands does not provide sufficient incentive for a monopolist to exercise market power. The smaller is the difference in price-elasticity of demand across periods, the closer is the hydro scheduling strategy used to the one that would be observed if the market were competitive.

Proposition 7 *A hydro-monopolist exercises market power by exploiting differences in price-elasticity across periods. The monopolist allocates too little supply to the less elastic period and too much to the more elastic periods.*

A hydro reservoir allows the producer to shift hydro production from one period to another. If the reservoir is managed competitively, more would be allocated to periods of high demand and prices would end up being the same over time [4] However if the reservoir is managed by a monopolist, there would be a completely different result. By allocating relatively less to less elastic periods and relatively more to more elastic periods, price differences would be enlarged. This is summarized by Proposition 8.

Proposition 8 *The exercise of market power by a hydro producer results in price differences across periods being enlarged rather than reduced.*

Since price-elasticity of demand must be different across periods for market power to be exercised in a hydro system , it is important to understand where these differences may come from. Fluctuating demands may be one possible explanation, but it depends on the functional form of demand as Example 4 shows. In a more general setting, we could argue that the hydro producer usually faces a residual demand given by the difference between market demand and

[4] Prices would be the same except for shadow prices in case any capacity constraint is binding.

rivals' supply. As long as market demand is fluctuating (there are peak and off-peak periods) and that rivals' maximum capacity is constant (i.e. capacity constraints are intermittently binding) we should expect to observe differences in price-elasticity across time. If this is the case and if conditions are favorable, market power may be exercised.

In order to analyze these issues in the next section the model used will be extended in different ways and simulations of the market equilibrium will be estimated for Chile's electricity industry. The power industry will be modeled as a Cournot duopoly with a competitive fringe (as opposed to the monopoly model used in this section). In addition producers' thermal capacity constraint will play a central role in the results.

3 A Cournot duopoly model for a hydro/thermal power industry

The analysis in the previous section is extended to a duopolistic industry with a mixed hydro/thermal generating portfolio. Later a simulation exercise of the market equilibrium and producers' strategies is carried out using real demand and cost data from Chile's largest electricity system -the Interconnected Central System, SIC- for April 2000.

Analyzing Chile's power sector is especially interesting because a large fraction of its generating capacity is stored hydro and its generation segment is highly concentrated. The Hirschmann - Herfindahl index is 3716. Two economic groups (Endesa and Gener) control 76% of total installed capacity and 71% of total generation. As it is shown in Table 1 and Figure 1, these firms differ in size, composition of their generating portfolio and associated marginal cost functions. Endesa owns a mixed hydro/thermal portfolio, concentrates 78% of the system's hydro reservoir capacity and its thermal capacity covers a wide range of fuel and efficiency levels. Gener is basically a purely thermal producer and concentrates the largest fraction of thermal resources of the industry. . In order to simplify the reading of the paper, I will refer to these companies as "Firm 1" (Endesa) and "Firm 2" (Gener).

3.1 The Model

Following Borenstein and Bushnell (1999) and Bushnell (1998) the industry is modeled as a Cournot duopoly (Firms 1 and 2) with a competitive Fringe.Both producers own thermal plants but only Firm 1 and the Fringe own hydro-reservoir plants. Therefore Firm 1's portfolio is a combination of hydro and thermal plants while Firm 2 is a purely thermal producer. Firm 1 and Firm 2's portfolios are made up only by those plants that may be used strategically.[5] I assume that producers maximize inter-temporal profits over a month with 6 sub-periods of equal length (denoted by t). [6]

Firm 1's Optimization problem is given by

$$\max \sum_{t}^{6} \{P_t(q_t)(H_{1t} + T_{1t}) - CT_1(T_{1t})\} \tag{12}$$

[5] Must Run plants are excluded from Cournot producers' portfolio.

[6] The larger the number of subperiods, the more fluctuation in demand across periods is allowed but the more complicated is the model to solve.

subject to

$$\begin{aligned}
{T_1}^{MIN} &\leq T_{1t} \leq T_{1t}^{MAX} && \forall t && \text{(thermal production min/max constraints)} && (13)\\
{H_1}^{MIN} &\leq H_{1t} \leq {H_1}^{MAX} && \forall t && \text{(hydro production min/max constraints)} && (14)\\
\sum_t^6 H_{1t} &\leq {H_1}^{TOT} && && \text{(hydro resources availability)} && (15)
\end{aligned}$$

Firm 2's optimization problem is

$$\max \sum_t^6 \{P_t(q_t)(T_{2t}) - CT_2(T_{2t})\} \tag{16}$$

subject to

$${T_2}^{MIN} \leq T_{2t} \leq {T_2}^{MAX} \qquad \forall t \qquad \text{(thermal production min/max constraints)} \tag{17}$$

where: $P_t(q_t)$ is the inverse function of the residual demand faced by each Cournot producer in period t and q_t is total production by firms 1 and 2 in period t. Thermal and hydro production by firm i are denoted as T_i and H_i respectively (since Firm 2 doesn't own hydro plants $H_2 = 0$) $CT_i(T_{it})$ denotes Firm i's total cost function. Minimum and maximum capacity constraints are denoted by a superscript MIN / MAX respectively while total hydro inflows available (in energy-equivalent units) is given by ${H_1}^{TOT}$.

The model is mostly the same than the one presented in the previous section except for the Cournot setting and the mixed generating portfolio. In addition, minimum and maximum capacity constraints (equations 13, 14 and 17) were explicitly included this time.

Firm 1's Lagrangean is given by:

$$L = \sum_t \{P_t(q_t)(H_{1t} + T_{1t}) - CT_1(T_{1t}) - \lambda_{1t}(T_{1t} - T_{1t}^{MAX}) \tag{18}$$

$$-\alpha_{1t}({T_1}^{MIN} - T_{1t}) - \gamma_{1t}(H_{1ht} - {H_1}^{MAX}) - \delta_{1t}({H_1}^{MIN} - H_{1t})\} - \sigma_1(\sum_t H_{1t} - {H_1}^{TOT})$$

Firm 2's optimization problem is simpler because it only owns thermal plants. Its Lagrangean is given by

$$L = \sum_t \{P_t(q_t)(T_{2t}) - CT_2(T_{2t}) - \lambda_{2t}(T_{2t} - {T_2}^{MAX}) - \alpha_{2t}({T_2}^{MIN} - T_{2t})\} \tag{19}$$

Where λ_{it} and α_{it},are the Lagrange multipliers for maximum and minimum thermal capacity constraints, γ_{1t} and δ_{1t} for maximum and minimum hydro capacity and σ_1 is the multiplier for the available hydro flows constraint. They all must be positive. It is important to keep in mind that σ_1 is the only multiplier that is constant over time. As in the model of the previous section, it indicates the marginal value of water, i.e. the additional profit Firm 1 would get if an additional unit of water became available.

FOC for Firms 1 and 2 written in terms of Marginal Revenue (MR_i) and Marginal Cost (c_i) are:[7]

[7] Slackness conditions are not reported.

$$
\begin{aligned}
MR_{1t} &= c_1 + \lambda_{1t} - \alpha_{1t} && (20)\\
MR_{1t} &= \sigma_1 + \gamma_{1t} - \delta_{1t} && (21)\\
MR_{2t} &= c_2 + \lambda_{2t} - \alpha_{2t} && (22)
\end{aligned}
$$

As a result, each period both firms schedule their production in order to equalize marginal revenue to marginal cost (thermal and/or hydro), adjusted for shadow prices (constraints 20, 21 and 22). In addition, Firm 1 allocates water across time so as to equalize the adjusted marginal cost of water (denoted by $\Omega_{1t} = \sigma_1 + \gamma_{1t} - \delta_{1t}$) with the marginal cost of producing an additional unit of power from the marginal thermal plant (constraints 20 and 21). In other words, an extra unit of water will be used to generate power until its cost is equal to the cost of the most expensive thermal plant in use.[8] The latter result defines Firm 1's hydro scheduling strategy and mirrors Proposition 8 for a mixed hydro/thermal power system. The intuition for this result is the following: an additional unit of water would replace production from the least efficient thermal plant that is in use and profits would increase by the cost of production that has been saved. If minimum and maximum capacity constraints were not binding ($\gamma_{1t} = \delta_{1t} = \lambda_{1t} = \alpha_{1t} = 0$), then marginal cost and marginal revenue would be constant as the marginal value of water (σ_1) is constant over time. Firm 1 would allocate hydro storage resources in order to equalize marginal revenue across periods. Firm 1 peak shaves marginal revenues rather than prices. If any of the capacity constraints were binding, then these conclusions would still hold but applied to a broader definition of marginal cost and or marginal value of water that includes the shadow price of the capacity constraint that is binding.

The Fringe solves exactly the same optimization problem solved by Firm 1; the only difference is that the Fringe does not have any market power, and thus behaves as a price taker. As a consequence, the fringe uses its plants (thermal and hydro) until the marginal cost (thermal or hydro plants) is equal to the market price (Equations 23 and 24):

$$
\begin{aligned}
P &= c_F + \lambda_{Ft} - \alpha_{Ft} && (23)\\
P &= \sigma_F + \gamma_{Ft} - \delta_{Ft} && (24)
\end{aligned}
$$

Firm 1 and the Fringe's FOC illustrate how different are the hydro scheduling strategies used by a hydro producer who has and has not market power: while the former peak shaves marginal revenue over time, the latter peak shaves prices. In addition the presence of thermal plants does not change the hydro scheduling strategy used. The only new ingredient introduced by thermal plants is that marginal revenue must also be equal to thermal marginal cost.

Some final remarks regarding the models used in this and the previous section to analyze the exercise of market power are in order. First of all, and as the reader has probably noticed, these are completely deterministic models. In particular, hydrological resources, marginal costs and load levels are assumed to be known in advance by the agents. Certainty with respect to thermal marginal cost functions and demand fluctuations should not be a

[8] Notice that Firm 1 allocates its plants (thermal and hydro) efficiently given the total level of production (which is inefficient as the firm produces until marginal cost = marginal revenue < price).

real concern, as the former are well known in the electricity industry and the shape of the load curve has been relatively stable in the past years. Certainty with respect to hydrological inflows is clearly a more arbitrary assumption. The longer the planning horizon, the more uncertain are the hydro inflows, and the more important it is to incorporate uncertainty into the model. In the context of my model, this should not be too problematic either because I assumed that producers maximize over a short time horizon (one month). Notwithstanding that, it would be interesting to learn the impact of hydrological uncertainty in the incentives to exercise market power. Secondly, the models lack dynamic competition elements. This omission is clearly important for this particular industry as in the context of a power exchange system, the producers interact on a very frequent basis providing optimal conditions to engage in (tacit) collusive practices. For instance, producers can easily learn their competitors' strategies, monitor their behavior and credibly threat in case of deviating from the "collusive" strategy. In this sense, the results of the model should be seen as a lower bound of market power. On the other hand, the model does not incorporate the effect of high prices on potential entry or in consumption patterns; accordingly market power might be overestimated. Finally, transmission constraints and contracts were not taken into account. [9]

3.2 Data

The model was estimated using real demand and cost data from Chile's largest electric system, the SIC, for April 2000[10].To simplify notation, the subindex t will be dropped except when its omission may lead to mistakes.

3.2.1 Marginal Cost Functions

Each firm's marginal cost function corresponds to the aggregation of their thermal plants' marginal cost functions. It is assumed that each plant has a constant marginal cost up to its expected capacity level and was calculated as the monthly average of the weekly marginal cost reported by the CDEC (Load and Economic Dispatch Center).[11] Since market behavior is modeled as if all transactions took place at the same geographic node, each plant's marginal cost was adjusted to take account of marginal energy and power losses using the penalty factor (reported by the regulator's office called Comisión Nacional de Energía, CNE). In addition each plant's capacity was adjusted for transmission losses, auto-consumption and average availability using the corresponding 1995-2000 average factor.[12] [13]. Finally a semi linear approximation of the Fringe's supply function is used, in order to minimize the number of steps of the residual demand faced by Cournot producers. Resulting marginal cost functions are plotted in Figure 1**.** Notice that both Firms own low and high marginal cost plants, being this feature more accentuated in the case of Firm 1

[9] For an analysis of the effect of transmission constraints and forward contracting see Arellano (2003).

[10] April has historically been the month in which the annual peak takes place.

[11] Start-up costs were not taken into account.

[12] As it was discussed in Borenstein et al (2000) the use of average availability may underestimate true expected capacity.

[13] Availability figures are high for international standards. This may be due to the way they are calculated: a plant is considered to be available if it doesn't go down when it is dispatched. However plants that are not dispatched but are available are also considered being available. The issue here is that there is no certainty that those apparently available, non-dispatched plants would be effectively available if dispatched. In addition, availability data seems to include maintenance periods, which is a strategic variable.

3.2.2 Hydro data

Firm 1 and the Fringe's individual hydro reservoirs were aggregated into only one for each of them. Minimum hydro production per hour (${H_1}^{MIN}$) is given by technical requirements and by irrigation contracts while maximum hydro production per hour (${H_1}^{MAX}$) is determined by technical requirements. Total hydro inflows available, in energy-equivalent units, (${H_1}^{TOT}$) is given by the average total hydro production that would be observed in April in a normal hydrological year, according to the Energy Matrix provided by the CDEC. As it is reported in Table 2 April's available hydro production is 1118.1 GWh. 87% of it is controlled by Firm 1 and the remaining 13% by the Fringe.[14] .

3.2.3 Residual Demand

Cournot producers (Firms 1 and 2) face a residual demand ($D^R(P)$) given by:

$$D^R(P) = D(P) - S^F(P) - MR - H_F \tag{25}$$

where $D(P)$ is market demand, $S^F(P)$ is the Fringe supply's function, MR is must-run units' generation and H_F is the hydro production from reservoirs owned by the Fringe.

***Market demand*:** As it is shown in Figure 2, I constructed a step function representation of April-2000's load curve with six discrete load levels, each of which is associated to one of the six sub-periods t of the model.($t = 1$ for the highest load level and $t = 6$ for the lowest load level; they will be referred to as the "highest" and "lowest" demand period, respectively). Each sub-period's (quantity, price) anchor point was set equal to the associated average load and the (regulated) price paid by final consumers[15]. Since there is only one price-quantity observation for each period, market demand cannot be directly estimated. In order to parameterize a market demand, a functional form must be assumed. Since results turned out to be independent of the functional form assumed (see Section **3.4**), I report the results of the simulation assuming that market demand is linear ($D(P_t) = A_t - BP_t$) because they illustrate more clearly the different hydro scheduling strategies used by a hydro producer with and with no market power. As a consequence of this assumption, price elasticity increases as the level of production is reduced and the elasticity of demand at the price where the market clears is always higher when there is market power.[16] Demand parameters A and B are closely related to the elasticity assumption. Since estimates of the price elasticity of demand for electricity (ε) vary widely in the literature, I follow the traditional approach of estimating and reporting the results of the model for several values of elasticity. In particular, market demand will be estimated for two different values of ε = {-1/3, -2/3}, measured at the

[14] Since the CDEC does not have and estimation for the Laja system (the largest in the country) I used the observed average generation of that hydro system in April of a normal year.

[15] The observed load per hour was increased by 13% to take account of spinning reserves.

[16] Empirical evidence supports the assumption of price elasticity being a function of the output level as the linear functional form implies. However, evidence is not conclusive regarding whether demand at peak hours is more or less elastic than at off peak hours. Aigner et al (1994) estimated that demand for electricity in the winter was more elastic during peak periods while in the spring/autumn season it was the off peak demand the one that was more price responsive.

anchor point at peak hours. [17] Accordingly, the slope parameter B is calculated such that the elasticity at the peak demand level was equal to "ε" and the intercept A is calculated so as to fit anchor quantity and anchor price at each demand level.[18] Table 3 reports the parameters A and B estimated for market demand when assuming ε = -1/3. Observe that by assuming that market demand is linear and the slope is constant across load levels, it is implicitly assumed that market demand at peak hours is less elastic than demand at off peak hours (at a constant price).

Must run quantity (MR): "Must-Run" plants are those that cannot be used strategically by their owners. They include two small co-generator thermal plants that produce electricity and steam and all the hydro-ROR plants that are not associated to any reservoir system upstream. MR was calculated as the average generation per hour in April 2000 for thermal plants, and in a normal hydro year for the hydro-ROR plants (according to the Energy Matrix provided by the CDEC). As it is reported in Table 3, column 7, MR is constant over the entire planning horizon. Since Must Run plants' production was subtracted from total demand, Must Run plants were also removed from the set of available generation units and excluded from marginal cost functions.

Hydro-reservoir generation by the Fringe (H_F). According to equation 24, the Fringe allocates its hydro production from reservoirs to equalize prices over time (adjusted by minimum or maximum flow constraints' shadow prices if any of them were binding). When market demands are linear, this hydro scheduling strategy consists in allocating as much hydro production as possible (given minimum and maximum flow constraints) to every period in order to eliminate or reduce demand peaks. Total hydro production from the Fringe was allocated across periods according to this "Peak Shaving Approach". [19] H_F used to estimate the model corresponds to the average hydro generation per hour allocated to each sub-period. As Table 3, column 8 reports, the small amount of total hydro production to allocate over the month resulted in the Minimum production constraint being binding almost the entire period. Figure 3 illustrates that as a result, peaks were only slightly reduced and the shape of the "shaved load" curve remained mostly the same.

The shape and position of residual demands faced by Cournot producers is explained by a combination of four elements: the anchor point, the Fringe's supply for thermal production, the load curve shape that results after allocating Fringe's hydro production through a peak shaving strategy and rival's production. Notice that the residual demand faced by both Cournot producers and given by equation 25 is less elastic in the high demand periods ($t = 1, 2$) than in the low demand periods ($t = 5, 6$), at a constant price.

[17] For comparison purposes, I report price elasticity values ("ε") assumed by other authors in their studies of market power in the power industry. A constant elasticity of demand was assumed by Borenstein and Bushnell (1999), estimating the model for ε=-0.1, -0.4 and -1.0 and by Andersson and Bergman (1995) who used ε=-0.3. A linear demand was assumed by Wolfram (1999) with ε=-0.17 at the mean price and quantity and by Bushnell (1998) who assumed ε=-0.1 at peak forecasted price/quantity point.

[18] A similar approach was used by Bushnell (1998).

[19] For more detail on the peak shaving approach see Borenstein and Bushnell (1999).

3.3 Simulation Results

3.3.1 Competitive equilibrium

As a benchmark case, the Competitive Equilibrium was calculated. Since in a competitive industry all the hydro producers would schedule their hydro plants attempting to equalize prices over time, the entire system's hydro-reservoir production (by the Fringe *and* Firm 1) was allocated according to the peak shaving strategy. As Figure 4 illustrates, total hydro production is so large that its allocation across the month almost completely flattens demand and peaks are considerably reduced. Results for ε=-1/3 and ε=-2/3 are reported in Table 4. Observe that the equilibrium is exactly the same in the first four periods (t=1 to 4) and almost the same in the fifth one. This is a consequence of total hydro production being so large that its allocation across the month completely flattens demand in those periods, mostly eliminating the peaks.

3.3.2 Cournot equilibrium

The Cournot-Fringe model was solved with GAMS/CONOPT using an iterative process. [20] Results are reported in Table 5.

Remark 9 *Market power is exercised in Chile's mixed hydro/thermal power industry.*

Comparing Tables 4 and 5, columns 7 and 8, it can be seen that when producers have market power total output is smaller than in the competitive equilibrium and prices are considerably higher

Remark 10 *The less elastic is demand, the more market power is exercised*

Notice in Figure 5 that the difference between the price charged by Cournot and competitive producers is larger the smaller is the elasticity assumption ε.These results are consistent with Cournot producers exercising market power especially when demand level is high and residual demand is less elastic

Remark 11 *More market power is exercised when residual demand is less elastic.*

Figure 5 clearly illustrates that as the demand level falls, the Cournot equilibrium converges monotonically to the competitive equilibrium. The exception is given by the last period

[20] Uniqueness of equilibrium was not investigated theoretically but empirically. In particular, the simulation was solved for 400 randomly chosen starting points. The model always converged to the same aggregated equilibrium: prices, each firm's total production, marginal cost, marginal value of water and profits. The only exception is given by Firm 1's production strategy: even though it is true that the equilibrium for Firm 1's total production is unique, this is not true for its production strategy, i.e. the decision of how much is produced from its thermal and hydro-storage plants(T_1, H_1). Multiplicity of equilibrium is explained by Firm 1 being able to allocate hydro production over time and by marginal cost being constant over relevant intervals of output. Indeed, observe that the FOCs are in terms of Marginal Revenue and Marginal Cost and that the former is a function of total sales and independent of what plants were used. This problem only affects Firm 1 as it is the only one who is able to allocate hydro production over time and that is able to combine thermal and hydro plants to produce a certain output level. I want to remark that in spite of this multiplicity of equilibrium, all the qualitative conclusions hold and magnitudes are very similar. Values reported in the tables for H_1 and T_1 are averages calculated over 400 different estimations of the model.

(t=6) when demand is at its lowest level which may be explained by Firm 2 increasingly constraining production as demand falls. Industry's Lerner Indices (not reported) are consistent with these results; the average markup goes from 64% when demand is a its highest level to 58% in the low demand period[21].

Nothing really new has been said until now. Indeed, this information is not enough to argue that market power is the result of the strategic use of hydro resources. In order to answer these questions we need to know first who is exercising market power.

Remark 12 *The hydro producer (Firm 1) exercises market power by distorting the hydro scheduling strategy.*

By comparing Tables 4 and 5 it is clear that when demand is at high ($t = 1, 2$) and medium ($t = 3, 4$) levels, Firm 1 is the one that really enjoys market power. Indeed, Firm 1 has so much market power and is able to drive prices up by so much that Firm 2's optimal strategy is to produce at capacity.[22] Firm 2 is able to profitably constrain its production and exercise market power only in the last 2 periods, when demand is low (column 4). Firm 2's large thermal capacity proved not to be enough to enable it to exercise market power. Behind this result is the fact that a large fraction of its capacity are baseload plants, which are usually not marginal and thus do not set the market price[23].

Firm 1 chooses to satisfy demand mainly through hydro production. In particular, it uses *all* the hydro production that is available ($\sum_t^6 H_{1t} = H_1{}^{TOT}$) but allocates it differently than in the competitive model (Column 3).As it is clearly observed in Figure 6, Firm 1 allocates relatively *less* water to high demand periods and relatively *more* water to the low demand periods. The former coincides with periods in which Firm 2 is capacity constrained while in the latter is not. This hydro allocation enlarges the difference between peak and off-peak periods, as opposed to what is observed under competition. These results are in line with Propositions 7 and 8. This effect is *smaller* the more elastic is demand[24].

Two important lessons are worth noting:

Remark 13 *Total hydro production over a certain period is not a sufficient indicator of the exercise of market power in electric systems with mixed hydro / thermal portfolios.*

Remark 14 *The relevant indicator of the exercise of market power by a hydro producer is the hydro scheduling strategy used.*

[21] For more details see Arellano (2003).

[22] Strictly speaking, Firm 2 is not producing at capacity as it still has some thermal plants that are not being run. However, the big difference observed between the marginal cost of Firm 2's next available plant and the marginal plant at that demand level (almost \$30) prevents Firm 2 from increasing production. By contrast, Firm 1 has a large capacity at a relatively low marginal cost. See Figure 1.

[23] Based on Producer and Consumer Surplus analysis, it can be shown that all of the producers (Firms 1 and 2 and the Fringe) are better off when market power is exercised. An interesting result is that even though it is Firm 1 the one who exercises market power by constraining production and driving prices up, the real winner, in relative terms, is Firm 2. The reason behind this result is clear: since Firm 2 is capacity constrained when demand is high, its production level is very close to the competitive level but the price is considerable higher. As expected, the less elastic is demand, the better off producers are and the worse off consumers are as more market power can be exercised.

[24] In this case, Firm 1 also exercises market power in a less observable way, namely the use (or more strictly speaking the "no use") of its thermal capacity. Indeed Firm 1 uses, on average, only 15% of its thermal capacity. If Firm 1's thermal portfolio were in a third generator's portfolio, Firm 1 would be more constrained in the exercise of its market power (see Arellano 2003 for a detailed analysis of this scenario).

The important variable is not total hydro production but hydro scheduling. In the case analyzed, Firm 1 used all the hydro resources that were available but it allocated them across periods exactly contrary to what a competitive producer would have done. The importance of the hydro scheduling strategy as an effective tool to exercise market power has not received much attention in the empirical literature. For instance, Halseth (1998) argues that since hydro producers used all the hydro flows that were available in the period it could be argued that they did not exercise market power. He does not investigate if hydro producers are using their hydro scheduling strategy to exercise market power even when using all the water available. [25] Scott (1998) in a somewhat different but related analysis, analyzed the impact of forward contracting on the incentives to exercise market power. He showed that the higher the level of forward contracting, the higher is hydro generation. Since he did not explicitly model the hydro scheduling decision, it is impossible to know how a particular firm allocates water overtime.[26]

As it is argued in Proposition 6, the most important element behind the exercise of market power by a hydro producer is the existence of differences in price-elasticity of demand across periods. In the context of this Section's exercise, these differences come basically from the combination of a market demand which fluctuates over time (coexisting high and low demand periods) and from Firm 2's capacity constraints (supply constraints) that are intermittently binding.

These results, in particular Firm 1's hydro scheduling strategy, extend what has been found in the literature. In their study of the Norwegian electricity market, Johnsen et al (1999) argued that "market power can not be exercised in markets dominated by hydroelectric producers unless there are transmission constraints". The hydro producer constrains its production when the transmission constraint is binding. My model's results show that transmission constraints are not a necessary condition for the exercise of market power by hydro producers. Capacity constraints (supply constraints) have the same effect. Both constraints are just the way differences in price elasticity are materialized. In other words, demand is less elastic either because a transmission constraint is binding or a supply constraint is binding, and the strategy used by a hydro producer to exercise market power will be the same no matter what is behind the differences in price elasticity. In any case, the hydro producer will choose to allocate relatively less supply to periods of low price elasticity of demand and relatively more supply to periods of high price-elasticity of demand (in comparison with the competitive equilibrium).

Remark 15 *There are two sources of inefficiencies in the Cournot equilibrium: low output and inefficient dispatching.*

The Cournot equilibrium is not only inefficient because production falls short the competitive equilibrium production level but also because costs of production are not minimized. In particular, the Fringe is operating plants that are less efficient (higher marginal cost) than the ones that are being withheld by Firm 1 and hydro production is used to increase the difference between peak and off peak periods. The possibility of inefficient dispatching was pointed out by Von der Fehr and Harbord (1993), Borenstein et al (2000) and Wolfram (1998).

[25] Halseth's (1998) conclusion of no market power being exercised may be the result not of the composition of the portfolio but of firms not being big enough.

[26] Results are reported plotting total hydro generation against total contracting level.

3.4 Robustness Checks

There are three assumptions with the potential to change the results just reported: the market demand's functional form, the elasticity assumption ε and the length of the planning horizon. To check for the robustness of the results the model was re-estimated using alternative assumptions.

3.4.1 Market demand functional form

Two different functional forms were used to estimate the model:

Linear Demand, different slope: $D(P_t) = A_t - B_t P_t$ The value of the slope parameter B_t is such that the elasticity at every (quantity, price) anchor point is equal to ε. Results from this "different slope approach" are slightly more difficult to interpret than the reported "same slope approach" because residual demands intersect on a certain (and relevant) price range. Notwithstanding that, conclusions from both approaches are almost the same; even order of magnitudes are similar. As Figure 7 shows it is still true that the hydro producer allocates relatively less supply to the high demand periods and relatively more to the low demand periods and that this hydro scheduling strategy is closer to the competitive equilibrium the more elastic is demand.

CES Demand: $Q_t(P_t) = k_t P_t^{-\varepsilon}$ The model was estimated under two alternative values of ε.(1/3 ; 2/3) Since I assumed the same price-elasticity for all the six periods, differences in price elasticity of the residual demand faced by Cournot producers result from different hydro production from the Fringe (see Table 3, column 8) and from Firm 2's capacity constraint binding intermittently. Figure 7 illustrates that for both values of ε, the hydro scheduling strategy used by the hydro producer to exercise market power exhibits exactly the same pattern: relatively less supply to the low elasticity periods and and relatively more to the high elasticity periods. [27]

3.4.2 Importance of the Elasticity assumption.

As a consequence of the linear demand assumption used in the model, price elasticity increases as the level of production is reduced. In addition the elasticity of demand at the price where the market clears is always higher when there is market power. In order to check for the importance of the implied assumption regarding elasticity, the model was re-estimated for a CES demand under the following three different ε's assumption for the high (t=1,2), middle (t=3,4) and low (t=5,6) demand periods' value differing across periods.

Case	t=1,2	t=3,4	t=5,6
1.	0.5	0.5	0.5
2.	0.4	0.6	0.8
3.	0.8	0.8	0.4

[27] I estimated the model for lower values of ε but results turned out to be unrealistic (prices too high). This should be the result of the traditional problem that Cournot models have when demand is a CES and elasticity is too low. The hydro scheduling strategy still exhibited the same pattern.

The hydro scheduling strategies associated to these cases - plotted in Figure 8- are consistent with the model's results: the larger are the differences in price elasticity across periods, the more distorted is the allocation of hydro production. To see this notice that with a CES market demand, the elasticity of residual demand results from the combination of several elements: the parameter ε, the level of market demand (given by the parameter k_t) and from rivals' capacity constraints. In particular, the smaller is ε and the larger is k_t, the less elastic is residual demand. Accordingly in Case 2, differences in price elasticity of residual demand across periods is maximized as in the high demand periods (t=1,2) k_t 's are high and $\varepsilon_{t\backslash\backslash}$ are at its lowest level while exactly the opposite occurs in the low demand periods. In Case 3, both effects on price elasticity of residual demand tend to compensate to each other: in the high demand periods k_t 's and $\varepsilon_{t\backslash\backslash}$ are high while in the low demand periods k_t 's and $\varepsilon_{t\backslash\backslash}$ are low. Accordingly, in case 3 differences in price elasticity of residual demand across periods are considerably smaller. The distortion introduced by the hydro producer regarding the allocation of his hydro production is larger the larger are differences in price elasticity across periods.

Accordingly, it cannot be argued that the demand assumptions are driving the results. Even though the use of a linear demand implicitly imposes that peak demand is less elastic than off-peak demand (at a constant price), the hydro scheduling strategy - in terms of the hydro producer exploiting differences in price elasticity across periods - remain unaltered when the low demand period is also assumed to have the less price elastic market demand.

3.4.3 Hydro scheduling over a longer planning horizon

The model used in the previous section to analyze the exercise of market power in an electricity industry with mixed hydro / thermal portfolio of generation assumed that the hydro producer allocated its hydro production over a one-month planning horizon. [28] It still needs to be checked if a hydro producer uses the same hydro scheduling strategy to exercise market power when faced to a longer planning horizon. In particular, would Firm 1 exploit inter-month differences in price-elasticity of demand by moving water around? If so, then water should be stored in those months in which demand is less elastic and released when demand is more elastic.

Two different approaches may be used to investigate Firm 1's hydro scheduling strategy over the year: analysis of the marginal value of water (MVW) and a direct estimation of the model assuming that the planning horizon is longer. Since the data set required to estimate a comprehensive one-year version of the model is not available, and therefore many arbitrary assumptions would be needed, I will concentrate on the MVW analysis. Arellano (2003) estimates a simple one-year version of the model, reaching to the same conclusions of the MVW analysis.

The basic idea behind the MVW analysis is the following: given that generators allocate their hydro production to equalize the marginal revenue across periods (subject to capacity and/or production constraints) and that in equilibrium marginal revenue is equal to the MVW (equation 21), it is possible to use the latter to determine the hydro scheduling strategy (when is water stored/ when it is released) that the producer would use over the year . In particular,

[28] Indeed, the optimization problem solved by Firm 1 in that model, implicitly assumed that the water left in the reservoir at the end of the period had no value; accordingly, the incentive to use less water than what is available is reduced as is the market power exercised.

if hydro production min/max constraints (equation 14) were not binding, the MVW analysis would conclude that water inflows are stored in months in which water is cheap (low MVW) and released in months in which water is more expensive (high MVW). In other words, hydro production would be shifted away from low MR months to high MR months.

To analyze the hydro scheduling strategy over a longer planning horizon, I estimated the MVW for each month of the year using different assumptions for inter-month differences in price elasticity of demand. Results are reported in Table 6. Exercise (1) and (2) only differ in how large are inter-month differences in price elasticity of residual demand.[29] To check for the validity of the proposition outlined in this paper, I use the correlation coefficient between each month's average elasticity of residual demand and the associated MVW. If the hydro producer allocates its hydro production by exploiting inter-month differences in demand, i.e. shifting water away from low elasticity months and releasing it in high elasticity months, the correlation coefficient should be positive, and larger the larger are inter-month differences in demand elasticity. As the last row of Table 6 shows, this is precisely what happens. In both exercises the correlation coefficient is positive, indicating that water is stored in those months in which price elasticity is low and released in those months in which price elasticity is high. In addition, this relationship is stronger the larger are inter-month differences in inter-month elasticity of residual demand. These results are consistent with the conclusions of the one-month model regarding how producers schedule their hydro storage plants in order to exercise market power.

Finally, it is interesting to note that the correlation coefficient between the MVW and the ratio hydro inflows/ net demand (an indicator of availability of water relative to demand) is -0.93 and -0.22 for exercises (1) and (2) respectively. This suggests that when inter-month differences in price elasticity are not large enough, the hydro scheduling strategy is mainly explained by a traditional supply-demand analysis; storing water when it is relatively more abundant and releasing it when it is relatively scarce.

Summarizing, the larger are the differences in inter-month price elasticity of demand, the greater the incentive to exercise market power by shifting water from one month to another and the smaller the relationship between the availability of water relative to demand and the value of water. The larger the inter-month difference, the closer is the hydro scheduling strategy to the market power explanation and further from the traditional supply/demand analysis.

Conclusions of the one-month model described in Section 3 proved to be robust to changes in the assumptions used. Neither the linear demand assumption, nor the elasticity parameter nor the length of the planning horizon had any influence on the results. [30]

4 Conclusions

The incentives and the ability a hydro producer would have in a purely hydro and in a mixed hydro/thermal electric system were analyzed in this paper. Using an analytical model and

[29] To completely isolate the effect of *inter-month* differences in price elasticity, both exercises assume that there are no *intra-month* differences. In other words, there are more elastic months and less elastic months but within in each month, all the subperiods' demands are equally elastic. Conclusions are the same when intra-month differences in price elasticity are also assumed.

[30] Results are also robust to changes to the anchor point chosen (not reported).

quantitative simulations of producers' strategies, it was shown that hydro reservoirs are a powerful tool to exercise market power by generators.

Unlike thermal resources, a hydro reservoir allows the producer to store water in some periods and release it in others, implicitly enabling them to shift power across periods. Therefore, hydro producers are entitled to decide when they want to use their hydro resources over a certain period of time. As a result, hydro producers may use two sets of strategies to exercise market power: to constrain total production or to distort the inter-temporal allocation of his hydro resources. This paper shows that hydro producers may increase their profits by exploiting differences in price elasticity, allocating too little supply to periods in which demand is relatively less elastic, and relatively too much to periods with more elastic demand (with respect to the competitive equilibrium). As a consequence, differences between peak and off peak periods are enlarged rather than reduced (as it would be the case if the market were competitive).This strategy may be successful even when all the water available in the reservoir is used.

Accordingly, total hydro production is not a sufficient indicator of market power. Attention should also be paid to the hydro scheduling strategy. This result may seem not to have practical implications as in practice it will be difficult to argue that a producer is or is not exercising market power just by looking at his inter-temporal production decisions, as usually there is no competitive benchmark to compare with. An alternative approach is to look for the incentives to exercise market power rather to anti-competitive practices themselves. This leads us to the price elasticity of demand. and to the double role it plays in this regard. According to this paper's results, a policy maker should look not only at its level but also to its variability across periods.

Conditions for the exercise of market power are more favorable the more inelastic is demand, an expected result. However, since a hydro producer is able to "shift power" from one period to another, there is an additional element that must be looked at when diagnosing market power: the inter-period differences in price elasticity. In particular, the larger the difference of price elasticity of demand across periods, the greater the incentive the hydro generator 1 has to exercise market power by shifting hydro production from one period to another and, accordingly, the further the hydro scheduling strategy to the traditional supply-demand analysis' conclusions.

There are three elements of the model that should be kept in mind when analyzing its results. First, the model has no dynamic elements although a power exchange system is clearly a perfect scenario for repeated competition. Second, even though high margins will likely attract new entrants to the industry, the role of entry is not taken into account .It is reasonable to think that both omissions result in my model underestimating market power. However, they should not have any impact on the strategy used to exercise market power except for how intense it is used. Finally, the model assumes that the hydro producer knows with certainty the size of hydro inflows and their timetable. Hydrological uncertainty is likely to have an important effect on the strategy used by producers to exercise market power. For instance, a hydro producer may choose to store hydro resources as a precautionary strategy (may need to use them later) and not because of market power related reasons.

This paper calls for further research in two topics, whose importance was already mentioned: the effect of hydrological uncertainty on the incentives to use hydro-reservoirs to exercise market power and to extend the model presented in the paper to take account of dynamic issues.

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Table 1: Installed capacity in the SIC (December 2000), MW

Economic Group	Thermal	Hydro-ROR	Hydro-reservoir	Hydro	Total	% thermal	% hydro	% total
Endesa (Firm 1)	939	238	2454	2693	3632	25.9%	74.1%	55%
Gener (Firm 2)	1212	245	0	245	1457	83.2%	16.8%	22%
Other	472	403	697	1100	1571	30.0%	70.0%	24%
Total	2622	886	3151	4037	6660	39.0%	61.0%	100%

Source: CDEC-SIC

Table 2: Hydro Data used to estimate the Base Model

Firm	H_1^{MIN} (MW)	H_1^{MAX} (MW)	H_1^{TOT} (GWh month)
Firm 1	743.7	2436.1	974.9
Fringe	183.8	489.2	143.2

Table 3: Demand Estimation, April 2000, ε = -1/3

t	Average Load (MW) 2	Price (US$/MW) 3	Market Intercept (A) 4	Demand Slope (B) 5	ε (at peak price) 6	*MR* (MW) 7	H_F (MW) 8
1	4749.7	31.1	6332.9	50.9	0.33	394.5	274.6
2	4329.6	31.1	5912.8	50.9	0.37	394.5	183.8
3	4091.1	31.1	5674.3	50.9	0.39	394.5	183.8
4	3643.3	31.1	5226.5	50.9	0.43	394.5	183.8
5	3270.8	31.1	4854.0	50.9	0.48	394.5	183.8
6	2988.5	31.1	4571.7	50.9	0.53	394.5	183.8

Table 4: Base Model, Competitive Equilibrium

Table 4a: ε = -1/3

t	T_1	H_1	T_2	T_F	H_F	Q_t	Price
1	673.1	2133.1	944.4	420.5	274.6	4839.0	29.4
2	673.1	1802.6	944.4	420.5	183.8	4418.9	29.4
3	673.1	1564.1	944.4	420.5	183.8	4180.4	29.4
4	673.1	1116.3	944.4	420.5	183.8	3732.6	29.4
5	673.1	764.7	944.4	420.1	183.8	3380.5	28.9
6	566.2	743.7	944.4	416.6	183.8	3249.3	26.0

Table 4b: ε = -2/3

t	T_1	H_1	T_2	T_F	H_F	Q_t	Price
1	673.1	2133.1	944.4	421.5	274.6	4840.0	30.2
2	673.1	1802.6	944.4	421.5	183.8	4419.9	30.2
3	673.1	1564.1	944.4	421.5	183.8	4181.4	30.2
4	673.1	1116.3	944.4	421.5	183.8	3733.6	30.2
5	673.1	764.7	944.4	421.3	183.8	3381.7	30.0
6	673.1	743.7	944.4	418.4	183.8	3357.8	27.5

Table 5: Cournot Equilibrium

Table 5a: ε = -1/3

t	T_1 # 2	H_1 # 3	T_2 4	T_F 5	H_F 6	Q_t 7	Price 8
1	133.7	1743.0	944.4	441.2	274.6	3931.3	47.2
2	140.1	1572.0	944.4	437.5	183.8	3672.3	44.0
3	120.3	1472.6	944.4	434.9	183.8	3550.4	41.7
4	122.0	1247.0	944.4	429.9	183.8	3321.5	37.4
5	127.0	1094.1	867.7	426.6	183.8	3093.6	34.6
6	131.9	995.1	773.6	424.5	183.8	2903.3	32.8

# denotes Multiple equilibrium. Values reported are averages over 400 different simulations

Table 5b: ε = -2/3

t	T_1 # 2	H_1 # 3	T_2 4	T_F 5	H_F 6	Q_t 7	Price 8
1	377.7	1768.1	944.4	429.0	274.6	4188.3	36.6
2	376.0	1605.2	944.4	427.1	183.8	3930.9	35.0
3	378.3	1483.6	944.4	425.8	183.8	3810.3	33.9
4	375.8	1262.2	944.4	423.2	183.8	3583.9	31.7
5	379.6	1072.2	944.4	421.1	183.8	3395.6	29.9
6	378.2	932.5	944.4	419.6	183.8	3252.8	28.5

# denotes Multiple equilibrium. Values reported are averages over 400 different simulations.

Table 6: Marginal Value of Water under different price elasticity assumptions.

	(1)		(2)	
Month	MVW	Average Elasticity of residual demand	MVW	Average Elasticity of residual demand
January	10.08	0.49	0.00	0.15
February	9.33	0.47	17.25	1.36
March	8.88	0.51	0.00	0.15
April	11.13	0.48	15.45	0.94
May	7.85	0.45	7.85	0.45
June	0.00	0.50	0.00	0.50
July	1.14	0.49	1.14	0.49
August	5.32	0.49	11.13	0.73
September	7.02	0.48	11.13	0.92
October	0.00	0.40	11.13	0.72
November	1.08	0.40	16.62	1.00
December	7.90	0.40	14.02	0.72
Average	5.81	0.46	8.81	0.68
St.dev	4.16	0.04	6.83	0.35
Corr. Coeff	0.27		0.89	

Figure 1

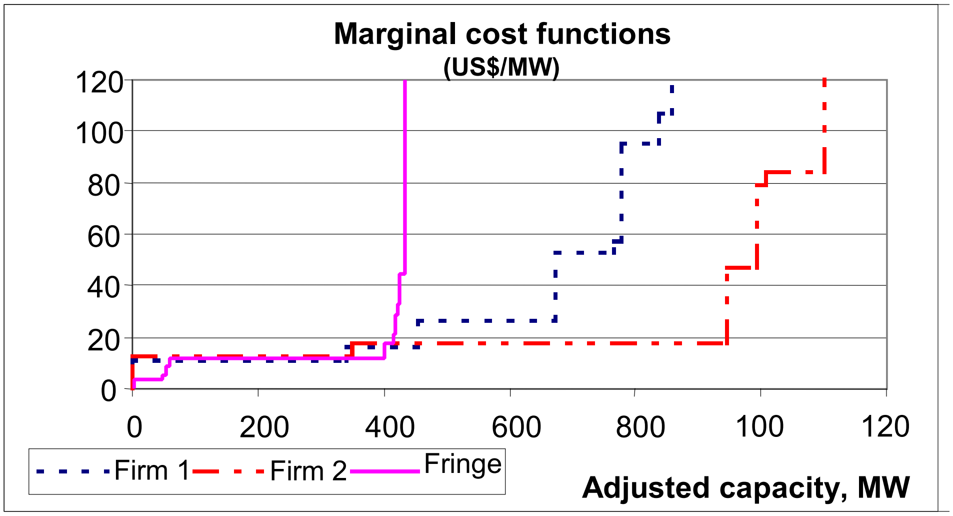


Figure 2

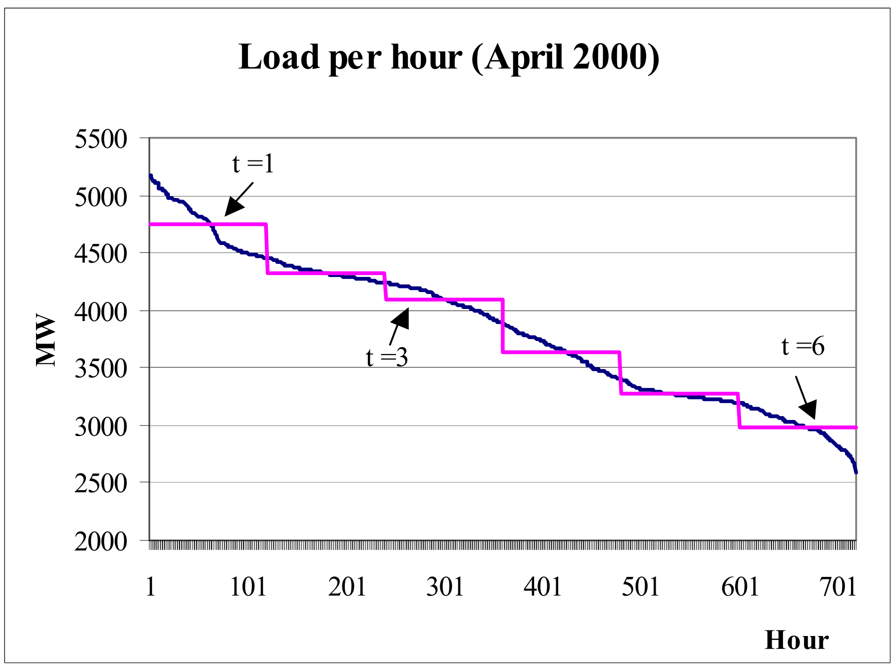


Figure 3

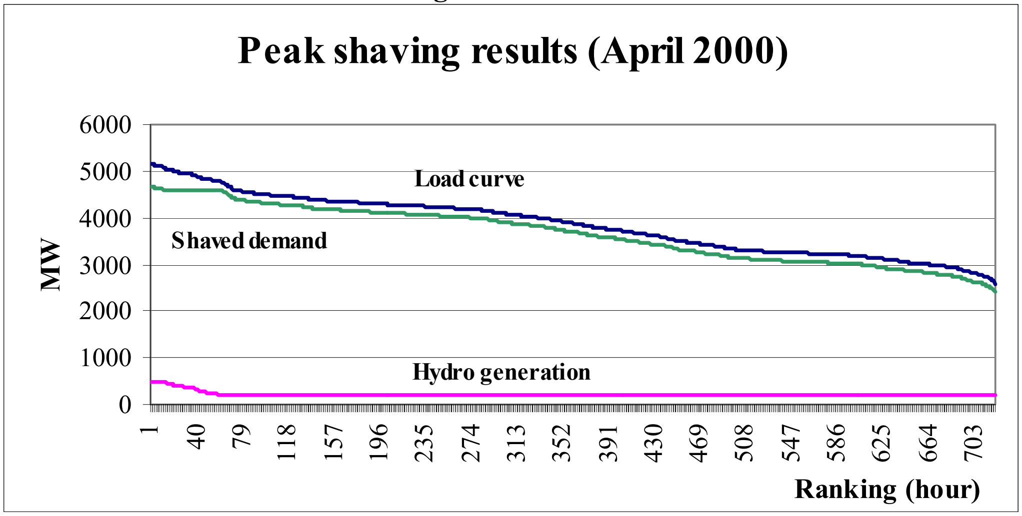
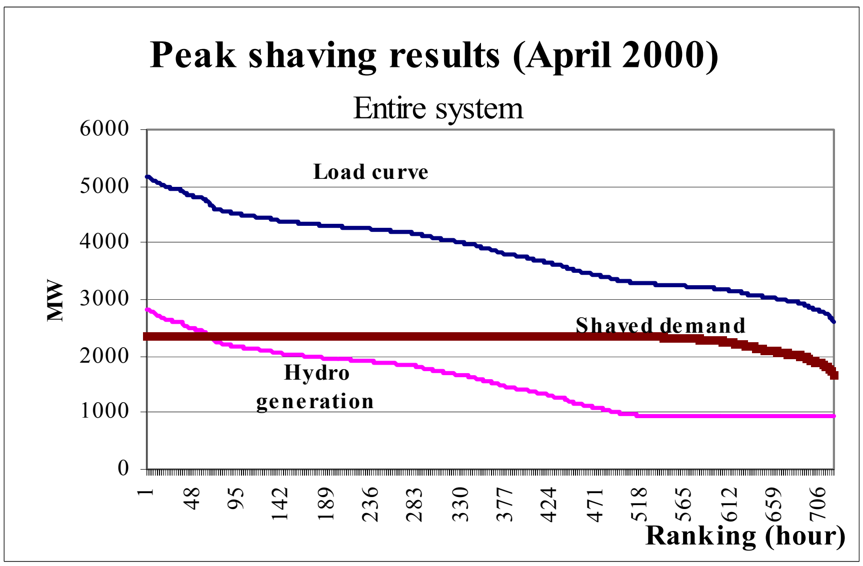


Figure 4



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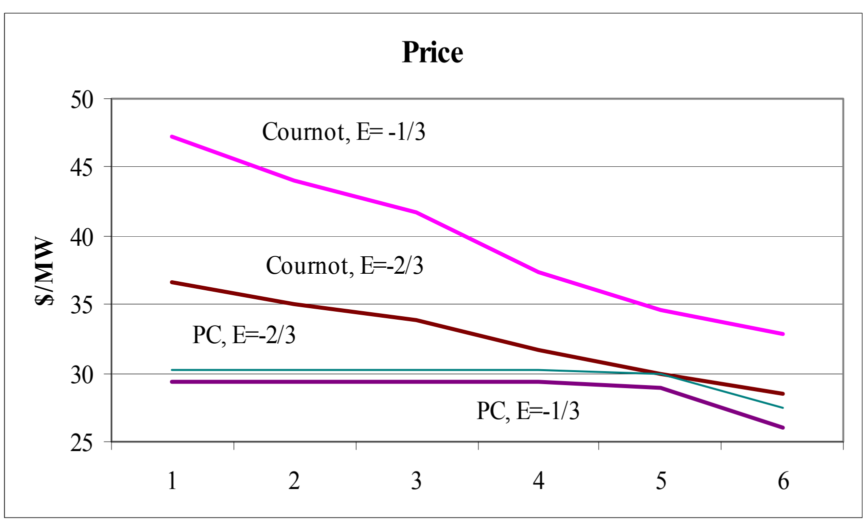

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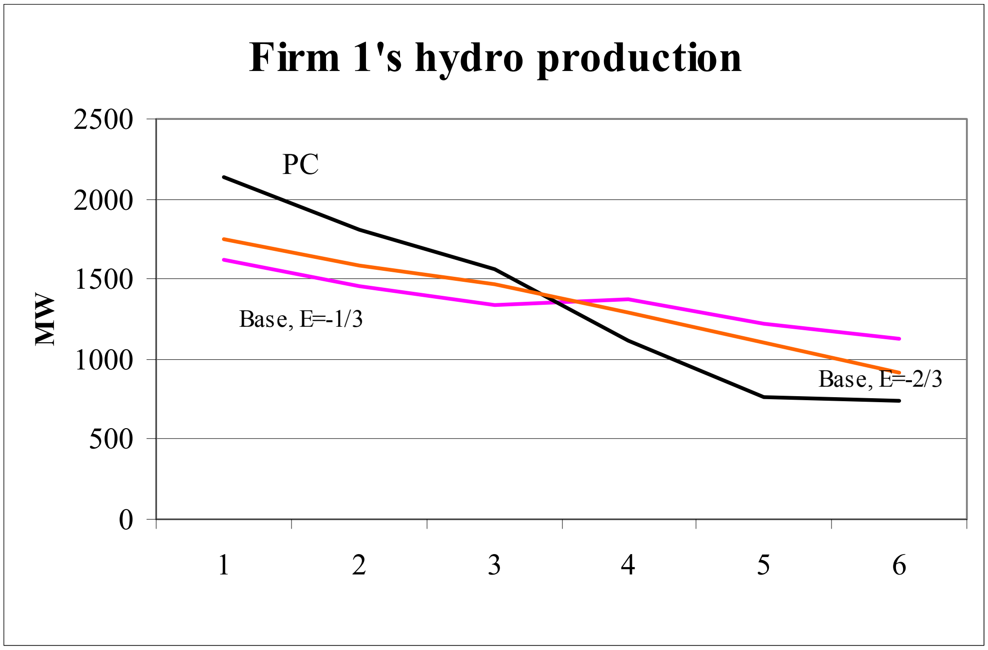

Figure 7
Hydro Scheduling Strategy under different functional forms for Market Demand

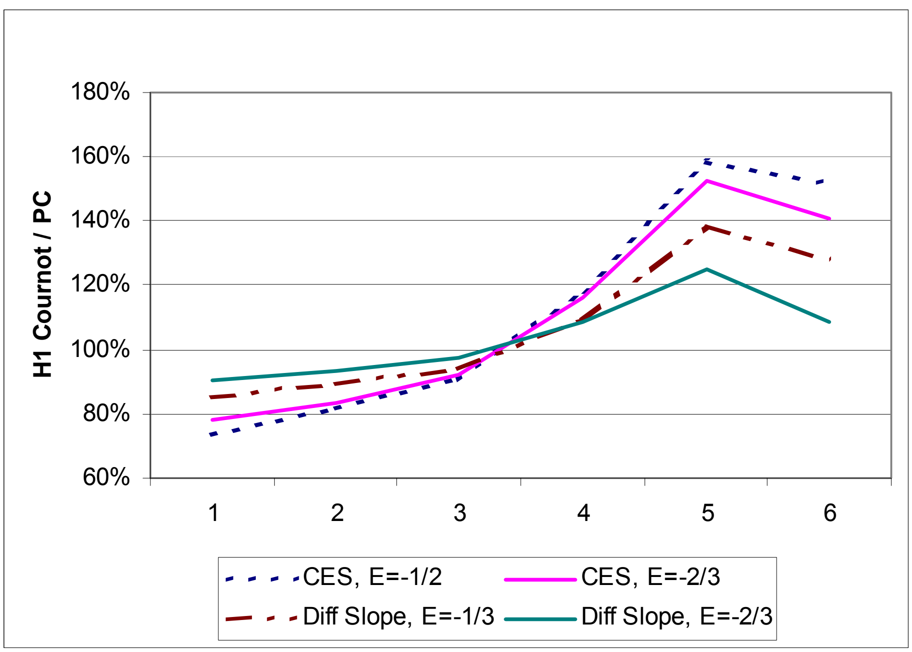

Figure 8
Hydro Scheduling Strategy under different elasticity assumptions