Diagnosing and Mitigating Market Power in Chile's Electricity Industry.*

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Abstract

This paper examines the incentives to exercise market power that generators would face and the different strategies that they would follow if all electricity supplies in Chile were traded in an hourly-unregulated spot market. The industry is modeled as a Cournot duopoly with a competitive fringe; particular care is given to the hydro scheduling decision. Quantitative simulations of the strategic behavior of generators indicate that the largest generator ("Endesa") would have the incentive and ability to exercise market power unilaterally. It would do so by scheduling its hydro resources, which are shown to be the real source of its market power, in order to take advantage of differences in price elasticity: too little supply to high demand periods and too much to low demand periods. The following market power mitigation measures are also analyzed: (a) requiring Endesa to divest some of its generating capacity to create more competitors and (b) requiring the dominant generators to enter into fixed price forward contracts for power covering a large share of their generating capacity. Splitting the largest producer in two or more smaller firms turns the market equilibrium closer to the competitive equilibrium as divested plants are more intensely used. Contracting practices proved to be an effective tool to prevent large producers from exercising market power in the spot market. In addition, a more efficient hydro scheduling resulted. Conditions for the development of a voluntary contract market are analyzed, as it is not practical to rely permanently on vesting contracts imposed for the transition period.

JEL Codes: D43, L11, L13, L94
Key Words: Electric Utilities; Market Power; Scheduling of Hydro-Reservoirs; Contracts; Chile's Electricity Industry

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1 Introduction

Chile reformed and restructured its power industry in the early 1980's. Competition among generators was promoted and a 'simulated' spot market was created. Prices in this market were not truly deregulated (except for the largest consumers who chose to enter into contracts directly with generators) but were based in the short-run marginal costs of generators in the system and the associated least cost dispatch. Two decades later, policymakers in Chile are discussing the desirability of further de-regulating Chile's wholesale electricity market. In particular, the simulated spot market that is in place today would be replaced by a real unregulated spot market in which generators would be free to bid whatever prices they choose with competition between generators determining the bids and market clearing prices. One major concern that has been raised regarding this spot market deregulation proposal is that the high degree of concentration in the generation segment would enable incumbent generators to exercise market power, leading to prices far above competitive levels. International experience on restructuring and reforms of the electricity industry on different countries (UK, US, New Zealand and so on) has taught us that this concern is legitimate. First of all, policymakers must realize that the electricity industry is prone to the exercise of market power, as electricity cannot be stored, demand is very inelastic, producers interact very frequently, capacity constraints may be binding when demand is high and thus even a small supplier may be able to profitably and unilaterally increase the market price by withholding supplies from the market. The importance of an adequate number of generating companies that compete in the wholesale market has also been emphasized. For instance, the experience in the UK, has shed light on the market power problems that high concentration may create and during the late 1990s, the government embarked on a program to reduce concentration through divestiture and the encouragement of competitive entry. [1]

This paper examines the incentives to exercise market power that generators would face and the different strategies that they would follow if all electricity supplies in Chile were traded in an hourly-unregulated spot market. The analysis will focus on the impact of such a reform in the biggest Chilean electric system, called the "SIC". Its installed capacity amounts to 6660 MW. Electricity is produced by 20 different generating companies but two economic groups (called Endesa and Gener) control 76% of total installed capacity and 71% of total generation. These firms differ in size, composition of its production portfolio and associated marginal cost functions. Endesa ("Firm 1") owns a mixed hydro/thermal portfolio, concentrates 78% of the systems' hydro reservoir capacity and its thermal capacity covers a wide range of fuel and efficiency levels. Gener ("Firm 2") is basically a purely thermal producer and concentrates the largest fraction of thermal resources in the SIC (46%). Analyzing Chile's sector is especially interesting because a large fraction of its generating capacity is stored hydro. Previous analyses have focused on systems that were either mostly thermal or entirely hydro (e.g. Norway).

Following Borenstein and Bushnell (1999) and Bushnell (1998), Chile's electricity market is modeled as a Cournot duopoly with a competitive fringe. Particular care is given to the modeling of hydro resources, which are not only important because of its large share in total installed capacity and in total generation (61% and 62% respectively in 2000), but because of its impact on the incentives faced by producers when competing. As it will be analyzed in

[1] For more details on the lessons learned from the UK and US experience, see Joskow (2002).

the paper, 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 account that more water used today, means less water is available for tomorrow: the model becomes dynamic rather than static.

Quantitative simulation results suggest that if an unregulated spot market were implemented in Chile, prices could rise far above competitive levels as suppliers, in particular Endesa, the largest supplier, would exercise unilateral market power. The large thermal portfolio owned by Gener, the second largest generator, is not enough for the exercise of market power, as the relevant plants are mostly base load plants. Indeed, Endesa has so much market power and can move prices up so much, that Gener's optimal strategy is to produce at full capacity, profiting from the high prices set by Endesa. Even though Endesa keeps most of its thermal plants outside of the market, the real source of its market power is its large hydro capacity. In particular, it schedules its hydro production in order to exploit differences in price elasticity, allocating too little supply to high demand periods and too much to low demand periods, relative to the competitive equilibrium. This hydro scheduling strategy may be observed no matter what planning horizon is assumed in the model (a month, a year); the only "requirement" is that there is enough "inter-period" differences in demand elasticity. The smaller are the intertemporal differences in demand elasticities, the closer is the hydro scheduling strategy to the traditional competitive supply-demand or value-maximizing optimization analysis' conclusions (i.e. water is stored when it is relatively abundant and released when it is relatively scarce). The importance of hydro resources for Endesa is such that when hydro flows are reduced (as occurs if the hydrological year is "dry"), Endesa loses its market power. Under these circumstances, Gener has incentives to act strategically to increase prices, but the resulting prices are still lower than when Endesa had all of its capacity under normal hydrological conditions. Not surprisingly, alternative assumptions about the elasticity of demand for electricity turned out to be very important, as the more elastic is demand, the less market power can be exercised.

These results suggest that the exercise of market power should be of considerable concern in Chile and that mitigation measures will be needed to prevent market power abuses in the newly deregulated spot market. Different market rules have been implemented as a shield against market power abuses throughout the world. Regulators have relied on elements such as splitting the generating companies into many small firms in order to reduce the degree of concentration of the generation sector (Australia, Argentina), vesting contracts in order to reduce generating companies' incentives to charge high prices (England and Wales, Australia) and continuing regulatory surveillance and threats (England and Wales, United States), among others. Each country / electric power system is different in terms of market structure, size, mix of generating technology and even culture. As a consequence, the experience of another market, even if successful, should not blindly be put into practice elsewhere without first carefully analyzing the individual characteristics of the specific electric power industry subject to reform. The effect of different market power mitigation measures that have been implemented in other restructured electricity markets are also thoroughly analyzed in this paper for the case of Chile's electricity industry. In particular, I analyze and estimate the impact of two different sets of measures that could be implemented to reduce the incentive and ability of the dominant firms to exercise market power in a spot wholesale electricity market in Chile: (a) requiring the largest firm to divest some of its generating assets and (b) requiring the largest firms to enter into fixed price forward contracts covering a large share of their capacity. I compare the new market equilibrium to the competitive equilibrium and to the base model equilibrium, in terms of aggregate levels, allocation of resources, markups and overall welfare (when possible).

The divestiture of some of Firm 1's generating assets, either thermal or hydro storage plants, turns the market equilibrium closer to the competitive equilibrium not only in terms of levels (prices and output) but also in terms of the allocation of resources, as former Firm 1's plants are more intensely and efficiently used and this more than compensates for any reduction in production by the remaining producers with unilateral market power. The application of fixed price forward contracts proved to be an effective tool to prevent large producers from exercising market power in the spot market. In addition, a more efficient hydro scheduling resulted. It is argued that it is not practical to rely permanently on vesting contracts to ensure the development of the contract market as these contracts will eventually expire and if conditions are not given for an appropriate voluntary contracting, market power abusive practices will certainly take place at that time. It is emphasized that the regulation of the industry as a whole (as opposed to the contract market) must provide the incentives for producers and consumers to contract.

This paper is organized as follows: the next chapter reviews the main findings of the literature that are related to the topics covered in the paper. In Chapter 3 I briefly describe the Chilean power industry. In the fourth Chapter I analyze the model that will be the basic tool for the analysis of market power in Chile's electricity industry. Data used to estimate the model are reported in Chapter 5. Quantitative simulations of each generators' strategy and the resulting market equilibrium are estimated under different assumptions in Chapter 6. In Chapter 7, a modified version of the basic model is used to estimate the impact of two sets of mitigation measures. Both a qualitative and a quantitative analysis are done. Chapter 8 concludes.

2 Literature Review

This paper is related to three areas of research: the modeling of electricity markets in order to (ex-ante) simulate strategic behavior after the industry has been deregulated, the analysis of the strategic use of hydro resources to exercise market power and the impact of forward contracting on the incentives producers face to exercise market power.

Three types of model have been used to simulate the strategic behavior of electricity firms. In the supply function equilibrium (SFE) approach, used by Green and Newbery (1992) and Halseth (1998) based on the work by Klemperer and Meyer (1989), the producers bid a supply function that relates quantity supplied to the market price. In the general case, the duopoly supply lies between the competitive and Cournot equilibrium; the range of feasible equilibria is reduced when uncertainty is added to the model.

Green and Newbery (1992) modeled the England and Wales electricity market using the Supply Function Equilibrium (SFE) framework developed by Klemperer and Meyer (1989) as applied to an empirical characterization of supply and demand, designed to match the attributes of the electricity system in England and Wales (making alternative assumptions about the elasticity of demand).[2] They first present simulated values for prices, output

[2] Von der Fehr and Harbord (1993) and Halseth (1998) criticize on theoretical grounds the Green and Newbery (1992) use of the SFE approach.

and welfare for the duopoly case. They found that generators were able to drive prices far above competitive levels, depending on the assumed elasticity of demand, while creating a significant deadweight loss and producing supra-competitive profits for the generators.[3] They then examined the impact of restructuring the industry so that there were five equal-sized firms. In this case, the equilibrium price was significantly lower and close to competitive levels. In order to take account of the effect of potential entry, they examined the effects of entry in the duopoly case under alternative assumptions about the price responses of the incumbents to the entry of generators who acted as price takers. If the incumbents adopted a strategy of not responding to entry by lowering prices, substantial entry was attracted by the excess profits in the system. Eventually entry eroded the incumbents' profits completely, yielding an equilibrium with inefficient expenditures on new generating capacity and high prices. The welfare losses in these cases were very large.

Halseth (1998) used the SFE approach to analyze the potential for market power in the Nordic market. In his model, the supply function is restricted to be linear, with a constant markup over marginal cost. This markup is independent of the particular technology used by the producer but it varies between the different time periods. Asymmetry in production technologies is incorporated through the marginal cost function (each production level is associated to a specific marginal technology (hydro, nuclear or thermal). Due to the importance of hydro production in the Nordic market (it accounts for 50% of annual production), the hydro scheduling issue is explicitly modeled. In particular, annual hydro production is restricted to be less than the annual inflow and the water inflow that is stored between periods has to be within the reservoir capacity. He found that the potential for market power was less than expected due to the fringe's excess capacity. Only two of the six largest producers had incentives to reduce production.[4] Remaining producers did not have incentive to do so. In particular, he found that hydro producers were not interested in reducing its market supply. He argued that since all of its income came from hydro production (with a very low marginal cost), the price increase had to be very large in order to induce it not to use its generating capacity to the full.[5] It should be noted that all the results of this model are reported in annual terms. In particular, he found that hydro generating capacity was used to the full in the year. However, nothing is said regarding how it is allocated throughout the year. This is an important omission because it may be the case that hydro producers do not exercise market power by using less than its hydro capacity but through a strategy that distinguishes between periods of high demand from periods of low demand.

Auction theory has also been used to analyze strategic behavior in the electricity market. Von der Fehr and Harbord (1993) model the UK electricity spot market as a first price, sealed-bid, multiple unit private-value auction with a random number of units. In their model, generators simultaneously bid supply schedules (reflecting different prices for each individual plant), then demand is realized and the market price is given by the offer price of the marginal plant. They argue that producers face two opposing forces when bidding: by bidding a high price, the producer gets higher revenue but a lower probability of being dispatched.

[3] Wolfram (1999) found that prices in the British market had been much lower than what Green and Newbery (1992) predicted.

[4] These two producers are Vattenfall and IVO. The portfolio of the first one is split between hydro (42%), nuclear (48%) and conventional thermal plants (10%). IVO is mostly a thermal producer.

[5] Johnsen et al (1999) concluded from this result that market power cannot be exercised in a market dominated by hydroelectric producers, to what they add, unless transmission constraint binds.

Equilibrium has different properties depending on the demand level. In particular, when demand is low, producers bid a price equal to the marginal cost of the least efficient generator and equilibrium is unique. When demand is high, there are multiple equilibria and the price is equal to the highest admissible price.[6] They remark that some of these equilibria may result in inefficient dispatching: the high cost generator will be dispatched with its total capacity if it submitted the lowest bid, while the low cost generator will be dispatched for only a fraction of it. Finally they argue that their model is supported by the bidding behavior observed in the UK electricity industry from May 1990 to April 1991. In particular, they report that while bids were close to generation cost at the beginning of the period, they diverged thereafter, Even though contracts were in place in the first part of the analyzed period, they argue that contracting practice is not a plausible explanation to the observed bidding behavior because contracts started to expire after the change of pattern took place. The coincidence of the first period with the low demand season (warm weather) and the second with the high demand season (cold weather) makes their model a more appropriate explanation. It should be noticed however that they analyzed a very short period. In order to be really able to separate the contract effect from the high/low demand effect, and in this way to get more conclusive support to their theory, the following seasons should be analyzed.[7]

Finally a third approach that has been used in the literature is to model the electricity industry as a Cournot oligopoly where producers are assumed to bid fix quantities. Andersson and Bergman (1995) simulated market behavior of the Swedish electricity industry after deregulation took place. They assumed a constant elasticity demand function (with an elasticity of demand equal to 0.3 in the main case), constant marginal costs for hydro and nuclear power plants and a non-linear marginal cost function for conventional thermal units. They found that prices would increase and production would be constrained. In particular, they found that the Cournot price equilibrium was 36% higher than the current (base) case and 62% than the Bertrand equilibrium. Markups were not analyzed. They also analyzed the impact of alternative market structures like splitting the largest company in 2 firms of the same size and a merge between the six smallest companies. In both cases equilibrium price was reduced below the base case. Finally they analyzed the impact of increased price responsiveness solving the model for a higher elasticity value (0.6). Since hydro production is modeled on an average basis, nothing is said regarding how resources are allocated within the year (for instance there is no differentiation between peak and off peak periods). In addition, nothing is said regarding how the portfolio of resources is used and how it compares to the base and Bertrand equilibrium cases. This is an important omission given the importance of hydro resources in the Swedish electricity market.

Borenstein and Bushnell (1999) and Bushnell (1998) modeled the California power industry as a Cournot triopoly with a competitive fringe.[8] Cournot producers face a residual demand where must run generation, the fringe's supply and hydro generation in the case of Borenstein and Bushnell (1999) are subtracted from total demand. Marginal cost functions were estimated using cost data at the plant level. A big difference between those articles is given by the treatment of hydro resources: Bushnell (1998) assumes that Cournot producers

[6] Multiplicity of equilibria is given by the fact that both producers want to be the "low bidder" because the received price is the same but the producer is ranked first, and thus output is greater.

[7] Wolfram (1998) analyzes the bidding behavior in the UK and tests the theoretical predictions of the multi unit auction theory.

[8] Their market definitions are slightly different.

use them strategically while Borenstein and Bushnell (1999) assume that they are allocated competitively.[9] In other words, in Bushnell (1998)'s model, hydro producers are "allowed" to store water inflows from one period and use them in another one in order to manipulate prices. As a result, in his model the different periods are not independent and thus the maximization has to be solved simultaneously over the entire planning horizon, as opposed to Borenstein and Bushnell (1999)'s model where each period can be treated independently. Borenstein and Bushnell (1999) use a constant elasticity demand and estimate the model for a range of demand elasticity values (-0.1, -0.4 and -1.0) and six different demand levels. They found that the potential for market power was greater when demand was high and the fringe's capacity was exhausted, making it impossible for the small producers to increase production. In lower demand hours, Cournot producers had less incentive to withhold production because the fringe had excess capacity. In addition they found that the more elastic was demand, the less was the incentive to exercise market power. Finally they analyzed the hydro scheduling issue by allocating hydro production across periods so as to equalize marginal revenue. They found that even though the resulting hydro allocation was very different from the one implied by the peak shaving approach, prices did not change much because as hydro production was moved out from one period, the resulting price increase induces the other large producers and the fringe to increase production. This result is different from Bushnell (1998)'s findings.

Overall, the literature seems to agree on the following conclusions: 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, reduced output 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. In order to say something regarding the role of hydro resources in the exercise of market power, a formal study of the hydro scheduling issue is needed.

The analysis of the hydro scheduling issue is always done following a similar approach: producers maximize their inter-temporal profits subject to certain constraints such as hydro generation being within a range determined by min and max flow constraints and by the availability of water. Then, an assumption is made regarding what sort of strategy producers may choose. Scott and Read (1996), Scott (1998) and Bushnell (1998) used a quantity strategy and the industry was modeled as a Cournot oligopoly. The main difference between their approaches is given by the method they chose to solve the optimization problem. While Scott and Read used a dual dynamic programming methodology (DDP), Bushnell solved the model by searching for the dual variables that satisfied the equilibrium conditions of the model. In particular, Scott and Read used DDP to optimize reservoir management for the New Zealand electricity market over a medium term planning horizon (1 year). They estimate a "water value surface" (WVS) that relates the optimal storage level at each period to the marginal value of water (MVW). The latter is interpreted as the marginal cost of generating at the hydro stations. The schedule of the system is determined by running each period a Cournot model in which the hydro plant is treated as a thermal plant using the WVS to determine the marginal cost of water (i.e. MVW), given the period and the storage level at that period.[10] The Scott and Read approach is rich in details as hydro

[9] In particular, hydro production is allocated over the period using a peak shaving technique.

[10] The water value surface consists on a set of curves, one for each period, which relates the storage level at

allocation for the whole planning horizon is derived as a function of the MVW. However it is computationally intensive, especially when there is more than one producer who owns hydro-storage plants. It is also data demanding as information on water inflows is required on a very frequent basis. Bushnell modeled the Western US electricity market, where the three largest producers had hydro-storage plants. He adopted a dual method to solve the model, treating the marginal value of water multiplier and the shadow prices on the flow constraints as the decision variables. He derived an analytic solution by searching for values of the dual variables that satisfy the equilibrium conditions at every stage of the multi-period problem. In order to solve his model, he simplified it by assuming that demand and the marginal cost functions were linear.[11] The planning horizon was assumed to be one month and the model was estimated for March, June and September. Bushnell (1998) found that firms could profit from shifting production from peak to off peak hours, i.e. from hours when the fringe was capacity constrained to when it was not. In particular, he estimated that hydro production was reduced by 10% (relative to perfect competition) during the peak hours, resulting in more than 100% price increase. Based on the estimated marginal water values for different months, he found that against what it was expected producers did not shift production from months of high demand to months of low demand. He argued "since the market is relatively competitive at least some of the time in each month, strategic firms do not need to reallocate across months in order to find hours in which extra output will have little impact on prices".[12]

The economic literature, both theoretical and empirical, also shows that the more of a generator's capacity is contracted forward at fixed prices, the less market power is exercised in the spot market and the closer the outcome to a perfectly competitive market, in terms of prices and efficiency of output decisions. These results are explained by the change in producers' incentives that is observed as a consequence of contracting practices being introduced. In particular, the more contracted a producer is, the more his profits are determined by the contract price as opposed to the spot market price (see Allaz and Vila (1993), Green (1993), Newbery (1995), Scott (1998) and Wolak (2000)). As a consequence, the firm has less incentive (or no incentive at all in the margin) to manipulate the spot price, as this would have little effect on its revenues. Indeed, for sufficiently high contract levels (when the firm is "over-contracted" [13]) profits are maximized at a price below its marginal cost.[14] Producers' incentive to raise the price is decreasing in the contracted quantity (Newbery 1995). Wolak (2000) and Scott (1998) pointed out that what is really important for the final outcome is the overall level of contracting as opposed to the individual level. In order for contracting practices to mitigate market power, there must be some price responsiveness in demand. In other words, the more inelastic is demand, the less important is the contracting level in

a certain period to the marginal value of water. It is derived recursively. The storage level at the beginning of a certain period is calculated by adding to the end of period storage level a demand curve for release of water (DCR), which is a function of MVW, and subtracting the (expected) water inflows of the period. This is done recursively starting from the end of the planning horizon, resulting on a water value surface. The demand curve for release of water is calculated by running a one stage Cournot model for a representative range of MWVs holding all other inputs constant. The DCR is given by plotting hydro generation versus MWV.

[11] The slope of the demand function was assumed to be constant across periods and set at a level such that the elasticity of demand at the peak forecasted quantity was -0.1.

[12] p.30

[13] A firm is over-contracted when the contracted quantity is more than what the firm can economically produce.

[14] Wolak (2000) uses a very simple framework to illustrate these effects.

producers' incentives to manipulate the price.

While the literature has extensively analyzed the impact that contracting practices have on the "market equilibrium", the same has not happen with respect to their effect on hydro scheduling decisions. Scott (1998) shows that the higher the level of total contracting, the higher is total and hydro generation.[15] He also found a positive relationship between the total level of contracting and the marginal value of water. The effect of contracts on the hydro *scheduling* issue is not explicitly analyzed in his paper. In particular, it is shown that the higher the level of overall contracting, the higher is hydro generation, but it is impossible to know how a particular firm allocates water across periods.[16] For instance, what does the firm do when it is over contracted in one period and under-contracted in the other one?

Even though it is true that given a large forward contract position, the generator would have less incentive to exercise market power, an important issue is whether the contract market will develop or not. In particular the relevant question is why would the producers voluntarily give up to their market power position and sign these contracts?. As Harvey and Hogan (2000) claim "it is clear that generators will understand the incentives and will not be likely to volunteer for forward contracts at low prices that reduce their total profits".[17] An important element in the development of this market will be the price at which the contracts will be signed. Wolak (2000) uses a simple model of the spot market to show that producers will be more willing to participate in the contract market the more elastic is demand for electricity, as the lower spot price is more than compensated by increased sales. However, the elasticity of demand for electricity is usually less than one. He also argues that risk averse agents or regulation may also explain the development of a contract market. Wolak does not explicitly model the contract market and nothing is said regarding how the contracted quantity and prices are set. Allaz and Vila (1993) model the contract and the spot market in a two period setting (contracts are signed in the first period and spot market transactions take place in the second). They showed that producers are willing to sell contracts in an attempt to improve their situations on the spot market. Under these circumstances the contract market develops even in the absence of uncertainty. However, this result strongly depends on the Cournot assumption, as Green (1999) showed. In addition, they showed that if both producers sell contracts simultaneously, a prisoner's dilemma problem emerges. When repeated interaction is added to the model, a reasonable assumption in the case of the power industry, producers should learn after a while and will probably collude and not sell contracts at all.

Green (1999) uses the supply function equilibrium (SFE) approach to model the spot market (assuming linear supply functions) and different conjectures (among them Bertrand and Cournot) to model the contract market. In his model, producers know that by selling contracts, the spot price is reduced while the equilibrium output is increased. They also know that the equilibrium in the spot market could be the same if they had adopted a more aggressive strategy in that market. Green argues that in order to be willing to participate in the contract market they need an additional incentive. He points out two: a change in rival's strategy or a hedging premium. In the particular case of his linear model with risk neutral agents (contract price is equal to expected spot price) each producer's strategy is independent

[15] Over a certain level of contracting hydro generation is greater than in PC.

[16] It is impossible to know the answer to this question because of the way results are reported (hydro generation against total contracting level).

[17] pp.9-10

of his rivals' contract sales. As a consequence, generators with Cournot conjectures sell no contracts in equilibrium, as this does not affect his rival's strategy. Under these circumstances, the contract market would not develop. Green (1999) points out that Allaz and Vila (1993) got a different result because in their model the producers' strategy is given by the quantity offered in the market and this quantity is a negative function of the rival's contract sales. Finally, Green shows that when the buyers are risk averse and thus willing to buy contracts for more than the expected spot price the contract market develops even if producers have Cournot conjectures. The hedging premium is the additional reason the firm needed to enter the contract market.[18]

Powell (1993) also analyzed the impact of risk aversion in the development of the contract market. In particular, he added risk aversion on the part of the buyers to the Allaz and Vila (1993) model. He found that buyers were interested in purchasing hedging contracts, even at a hedging premium, because they wanted to be risk protected but also because of the contracts' "controlling monopoly power" effect. Indeed, Powell showed that the contract market would develop even if the buyers were risk neutral and contracting were costly (contract price > expected spot price); buyers realized that the more contracted generators were, the less market power could be exercised in the spot market, and this was reason enough to contract even at a premium rate. An important element of his model is the contract price and how it is determined. He found that when generators do not cooperate in any market (contract / spot market) the competitive outcome may emerge and full hedging results. However when generators cooperate in one or both markets a price premium and only partial hedging results, being the size of the contract market smaller when generators cooperate only in that market as they use it to pre- commit to a certain output level. Partial hedging is reinforced by the fact that the "controlling monopoly power" effect turns contracts into public goods and each buyer wishes to free ride, reducing demand for contracts.

The contract market may also develop as a result of regulation. When the England and Wales market was deregulated the government put in place a set of contracts between the privatized companies and the RECs. Approximately 87% of National Power and 88% of PowerGen's capacity was covered in the initial portfolio (Green 1994). Green (1999) reported that generators remained heavily contracted after the first set of contracts expired. In particular, greater sales of contracts used to back sales in the competitive market made up for much (but not all) of the fall in the coal contracts.[19] He argues that contract prices have generally been above the pool prices and seem also to have been above the pool prices expected at the time the contracts were signed. This suggests the existence of a hedging premium which producers had been explicitly allowed to charge as part of an agreement to keep wholesale prices below specified levels. Similarly, Wolak (2000) pointed out that generators in the NSW and Victoria markets (Australia) were required to sell hedge contracts to retail suppliers of electricity in a quantity enough to cover their captive consumers' demand. The prices of these contracts were set by the state government at generous levels relative to prices in the wholesale market. The vast majority of these vesting contracts have expired and it seems that many retailers have voluntarily purchased contracts to hedge the spot price risk associate with selling at a fixed price to end consumers. However, voluntary hedging has not been enough

[18] Green (1999) also argues that producers may use contract sales as a commitment device. In particular they would sell contracts to commit to keep output high and spot price low in response to the threat of entry or of regulatory intervention.

[19] See Supplemental Materials for Green (1999) in www.stern.nyu.edu/~jindec/supps/green/green.pdf

to compensate for the expired vesting contracts.

3 Chile's Electricity Industry

Electricity supply in Chile is provided through four non-interconnected electric systems: Interconnected System of Norte Grande (SING) in the north, Central Interconnected System (SIC) in the center and Aysen and Magallanes in the south of the country. Total installed capacity in 2000 amounted to 9713 MW. Due to differences in resource availability, each system generates energy from different sources. While the north relies almost completely in thermal sources, the rest of the country also generates energy from hydroelectric sources and recently from natural gas. The most important source of energy in Chile is hydrological resources. They are concentrated in the central and southern part of the country, which explains why the SIC relies heavily on hydro generation. Fuel resources are not abundant: natural gas and a large fraction of the oil used are imported and Chilean coal is not of good quality. In what follows, all the analysis and estimations will refer to the SIC, the biggest electric system.

The SIC is largest system in the country in terms of installed capacity and concentrates more than 90% of the country's population. Gross generation in 2000 amounted to 29.577 GWh, 37% of which was hydro-reservoir generation, 38% thermal generation and 26% hydro-Run-of-River (ROR) generation. Maximum demand in the year 2000 amounted to 4576 MW (April). The generating sector is highly concentrated: 93% of total installed capacity and 90% of total generation are in hands of three economic groups (Endesa, Gener and Colbun) being Endesa the largest of them (See Table 1). The Hirschmann-Herfindahl index is 3716. In order to simplify the reading of the paper, I will refer to these companies as "Firm 1" (Endesa), "Firm 2" (Gener), and "Firm 3"(Colbun). These three firms differ in terms of size, their generating plants portfolio and the associated marginal cost functions (See Figure 1). While Endesa relies mostly on hydro sources, Gener owns the majority of the thermal plants of the system. Firm 3 has the lowest marginal cost plant, but is also the smallest firm in terms of capacity. Firms 1 and 2 both own low and high marginal cost plants, being this feature more accentuated in the case of Firm 1.[20]

The electricity industry was reformed and restructures in the early 1980's. Competition among generators was promoted, entry into the generation business was opened up to competitors and generators were encouraged to enter into supply contracts with large industrial customers and distribution companies. A spot market was created but generation prices were not "deregulated" in the usual sense of the term, except for the very largest industrial customers who chose to enter into contracts directly with generators.[21] Rather, the system defined a "simulated" perfectly competitive set of spot and forward contract prices. Generators effectively were required to bid their available capacity and associated audited marginal costs into the spot market. The marginal cost of the last generator required to balance supply and demand, taking into account transmission constraints and losses, then determined clearing price, called the Short Run Marginal Cost (SRMC), is given by the marginal cost of the last generator required to balance supply and demand, taking into account transmission constraints and losses. It is calculated by an independent entity, called the "Load and Economic Dispatch Center" (CDEC), according to marginal cost information reported by the generators themselves. Neither distribution companies nor large consumers have access to the simulated spot market. Large consumers are entitled to enter into contracts directly with generators and to freely negotiate the price for electricity. Distribution companies are required to enter into long-term contracts with the generators, at a regulated price, in order to purchase electricity for the supply of their regulated consumers. This regulated price is set every 6 months by the regulatory agency called the National Energy Commission (CNE) and is based on 4-year projections of the nodal prices as determined by the regulator. Forward contract prices have been constrained indirectly by a requirement that they be no higher than 110% and no lower than 90% of the prices charged to large industrial customers who negotiate prices directly with generators. The transmission and distribution segments continued to be regulated based on traditional cost-of-service regulatory principles because of their natural monopoly features. This economic policy was implemented in conjunction with a huge privatization effort, where most of the electricity companies were re-organized and then sold to the private sector.[22] As it was already mentioned, it is currently being analyzed the convenience of implementing a real unregulated spot market in which prices would be set by generators' bid through a competitive process. For a detailed analysis of the Chilean regulation, see Arellano (2001a, 2001b)

4 Theoretical Model

I will estimate an ex-ante model much in the spirit of Green and Newbery (1992), Borenstein and Bushnell (1999) and Bushnell (1998) using real demand and cost data for the year 2000. Following Borenstein and Bushnell (1999) and Bushnell (1998) the industry is modeled as a Cournot duopoly (Firms 1 and 2) with a competitive fringe.[23] The model that is analyzed in this Chapter will be referred to as the "base model".

The portfolio of generation sources is very important; in fact, it defines the way market power can be exercised. The whole idea behind the exercise of market power is to reduce output in order to increase market price. However, the decisions that producers can make are different depending on whether they are in a purely thermal / purely hydro or in a mixed electric system. 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; in this context, market power is exercised by reducing output when rival generators are capacity constrained, which usually corresponds to periods of high demand. A system with hydro-reservoirs, on the other hand, 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

[22] For more information on the privatization process, see Luders and Hachette (1991).

[23] I also estimated the model assuming that the third largest firm (Colbun, "Firm 3") had market power but it turned out that it always ended up behaving as a price taker. In other words, it wasn't big enough to be able to use its resources strategically.

hydro resources over a certain period of time. This (dynamic) scheduling decision is not available to thermal producers.[24] In a purely hydro system producers exercise market power by exploiting differences in demand elasticities in different hours. In particular, they shift production from periods where demand elasticity is high to periods when it is low.[25]

Only water from hydro reservoirs (hydro storage) can be used strategically. Since water from run of the river (ROR) sources can't be stored, it can't be used by producers to manipulate the price. ROR plants will be treated in the model as "must-run" (MR) units except for those ROR plants that are associated to a reservoir system upstream, in which case it will be included as part of the reservoir complex. In the Chilean system, Firm 1 and the Fringe own hydro-reservoir plants. Their hydro capacity amounts to 78% and 22% of total hydro-reservoir capacity respectively. Firm 2 is a purely thermal plant, concentrating the largest fraction of thermal resources in the SIC (46%). See Table 1 for more detailed information. In order to simplify the model as much as possible, I will assume that Firm 1 and the Fringe only have one reservoir complex. They will be made up by the aggregate of individual reservoirs.

The model will determine hydro scheduling by Firm 1. However, since the Fringe also owns a medium size reservoir, it will be necessary to allocate its hydro production in a certain manner. In particular, I will use the Peak Shaving approach. The basic idea is the following: when there are no flow constraints, producers schedule hydro generation so as to equalize the marginal profit that they earn from one more unit of production over the whole period in which the hydro plant is being used. If the market were perfectly competitive, prices would be equalized. If there were market power, then generators would equalize marginal revenues over time. As long as demand level is a good indicator of the firm's marginal revenue, a peak shaving strategy would consist in allocating hydro production to the periods of higher demand.[26] In addition, producers also have to take account of minimum flow constraints, given by technical requirements and irrigation needs, and maximum flow constraints, given by capacity. As a result, hydro production by the fringe was distributed across periods allocating as much as possible (given min/max flow constraints) to every period in order to eliminate or reduce demand peaks.[27]

Cournot producers face a residual demand given by:

$D^R(P_t) = D(P_t) - S^f(P_t) - q_t^{MR} - q_{ht}^{PS}$

where $D(P_t)$ is market demand, $D^R(P_t)$ is residual demand, $S^f(P_t)$ is the Fringe's thermal supply function , q_t^{MR} is must-run units' generation and q_{ht}^{PS} is the Fringe's hydro production from reservoirs distributed across periods according to a Peak shaving strategy.

Each firm's maximization problem is given by:

[24] Notice that even in a perfectly competitive market producers are able to hydro schedule. The difference is that when the market is competitive, difference between on peak and off-peak hours is *reduced*as opposed to when producers exercise market power in which case difference is *enlarged*.

[25] See Johnsen et al (1999), Bushnell (1998) and Halseth (1998).

[26] This is true when using either a linear or a constant price-elasticity demand.

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

Firm 1's Optimization problem

$$\max \sum_t \{P_t(q_t)(q_{1ht} + q_{1Tht}) - CT_1(q_{1Tht})\} \qquad \text{subject to} \tag{1}$$

$$q_{1ThMIN} \leq q_{1Tht} \leq q_{1ThMAXt}\ \forall t \qquad \text{(thermal production min/max constraints)} \tag{2}$$

$$q_{1hMIN} \leq q_{1ht} \leq q_{1hMAXt} \forall t \qquad \text{(hydro production min/max constraints)} \tag{3}$$

$$\sum_t q_{1ht} \leq q_{1htot} \qquad \text{(hydro resources availability)} \tag{4}$$

Firm 2's optimization problem

$$max \sum_t \{P_t(q_t)(q_{2Tht}) - CT_2(q_{2Tht})\} \qquad \text{subject to} \tag{5}$$

$$q_{2ThMIN} \leq q_{2Tht} \leq q_{2ThMAXt} \quad \forall t \ \text{(thermal production min/max constraints)} \tag{6}$$

where:

$P_t(q_t)$ = is the inverse function of the residual demand in period t

q_t = is total production by firms 1 and 2 in period t, (q_t= q_{1t} + q_{2t}),

q_{it}= $q_{iTht} + q_{iht}$is total production by Firm i in period t,

q_{iTht} = total energy produced by Firm i out of thermal plants, period t

q_{1ht}= total energy produced by Firm 1 out of hydro-storage plants, period t

$CT_i(q_{iTht})$= Total Cost function, thermal plants, firm i

$q_{iThMIN(MAX)}$=Minimum (maximum) thermal production, Firm i, period t

$q_{1hMIN(MAX)}$ = Minimum (maximum) hydro production, Firm 1, period t

q_{1htot} = available hydro production for the whole period

t =time period within the planning horizon. The planning horizon of the model will be assumed to be a month and will be divided in 6 sub-periods (t=1,2,..6) of equal length.

Firm 1's Lagrangean is given by:

$$L = \sum_t \{P_t(q_t) * (q_{1ht} + q_{1Tht}) - CT_1(q_{1Tht}) - \lambda_{1t}(q_{1Tht} - q_{1ThMAX}) \tag{7}$$

$$-\alpha_{1t}(q_{1ThMIN} - q_{1Tht}) - \gamma_{1t}(q_{1ht} - q_{1hMAX}) - \delta_{1t}(q_{1hMIN} - q_{1ht})\} - \sigma_1(\sum_t q_{1ht} - q_{1htot})$$

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

$$L = \sum_t \{P_t(q_t)(q_{2Tht}) - CT_2(q_{2Tht}) - \lambda_{2t}(q_{2Tht} - q_{2ThMAX}) - \alpha_{2t}(q_{1ThMIN} - q_{2Tht})\} \tag{8}$$

Where $\lambda_{it}, \alpha_{it}, \gamma_{1t}, \delta_{1t}$ and σ_1 are the Lagrange multipliers for maximum thermal capacity, minimum thermal capacity, maximum hydro capacity, minimum hydro capacity and available hydro flows constraint respectively. They all must be positive. It is important to keep in mind that σ_1 is the only multiplier that is constant over time; 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 are:[28]

$$\frac{\partial L}{\partial q_{1Tht}} = P_t(q_t) + q_{1t}\frac{\partial P_t(q_t)}{\partial q_t} - \frac{\partial CT_1(q_{1Tht})}{\partial q_t} - \lambda_{1t} + \alpha_{1t} = 0 \tag{9}$$

$$\frac{\partial L}{\partial q_{1ht}} = P_t(q_t) + q_{1t}\frac{\partial P_t(q_t)}{\partial q_t} - \gamma_{1t} + \delta_{1t} - \sigma_1 = 0 \tag{10}$$

$$\frac{\partial L}{\partial q_{2Tht}} = P_t(q_t) + q_{2t}\frac{\partial P_t(q_t)}{\partial q_t} - \frac{\partial CT_2(q_{2Tht})}{\partial q_t} - \lambda_{2t} + \alpha_{2t} = 0 \tag{11}$$

These conditions can be reformulated as follows:

$MR_{1t} = c_1 + \lambda_{1t} - \alpha_{1t}$ (9')

$MR_{1t} = \sigma_1 + \gamma_{1t} - \delta_{1t} = \Omega_{1t}$ (10')

$MR_{2t} = c_2 + \lambda_{2t} - \alpha_{2t}$ (11')

where MR_i and c_i are Firm i's marginal revenue and (thermal) marginal cost respectively.

Each firm schedules its production in order to equalize marginal revenue to thermal marginal cost each period (adjusted for shadow prices), as expected (constraints 9' and 11'). In addition, Firm 1 allocates water across time so as to equalize the marginal cost of water (Ω_{1t}) with the cost of producing an additional unit of power from the marginal thermal plant (constraints 9' and 10').[29] This means that 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. The intuition of this 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 hydro production constraints were not binding, 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 cost across periods. Firm 1 peak shaves marginal revenues rather than prices. If thermal and/or hydro min/max capacity constraints are binding, these conclusions still hold but applied to a broader definition of marginal cost / marginal value of water that includes the shadow price of increasing/decreasing installed capacity.

The Fringe solves exactly the same optimization problem solved by Firm 1; the only difference is that $\partial P_t(q_t)/\partial q_{Ft} = 0$ as it 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:

$$P = c_F + \lambda_{Ft} - \alpha_{Ft} \tag{12}$$

$$P = \sigma_F + \gamma_{Ft} - \delta_{Ft} = \Omega_{Ft} \tag{13}$$

Some final remarks regarding the model that will be used to analyze the exercise of market power are in order. First of all, and as the reader has probably noticed, this is a completely deterministic model. 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 real concern, as the former are well

[28] Slackness conditions are not reported.

[29] 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).

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. 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). The longer the planning horizon, the more uncertain are the hydro inflows, and the more important it is to incorporate uncertainty into the model. Secondly, the model lacks dynamic competition elements. This omission is clearly important for this particular industry. 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 yet.[30]

5 Model Parameters

5.1 Supply side

Each firm's marginal cost function was calculated aggregating their thermal plants' marginal cost functions. I assumed that each plant had a constant marginal cost up to its expected capacity level.[31] The constant marginal cost at the plant level (and at the plant "mouth") was calculated as the monthly average of the weekly marginal cost reported by the CDEC. This reported value does not incorporate transmission losses. Since market behavior will be modeled as if all transactions took place at the same geographic node, it is necessary to incorporate the fact that the MC of delivering energy at one node of the system is different from the MC of "producing" energy because a fraction of the energy that is generated in the plant is lost while it is being transmitted to the consumption node. In other words, the marginal cost of a KW produced by a plant located in node A and consumed at node B is "production MC^A" + "transmission charge". In order to incorporate this, I calculated for each plant a "system-equivalent marginal cost" as Production MC x Penalty factor (calculated by the CNE).

Each plant's capacity was adjusted for transmission losses, auto-consumption and average availability.[32] Unfortunately it was not possible to get separate data for scheduled and non-scheduled (non-expected) maintenance periods.[33] Related papers do not adjust for transmission losses that occur within the market but only for those that take place when energy is imported. I think this assumption is not appropriate for the Chilean case. The

[30] The effect of contracts is Chapter 7.

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

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

[33] 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.

distance from North to South in the SIC is approximately 2300 kms. (about 1430 miles) and so transmission losses are likely to be important. In order to take them into account I adjusted capacity by the transmission loss factor. In other words, if maximum capacity is q, then the maximum delivered capacity is q*(1-LF) where LF is the loss factor. Finally since demand will be calculated as the sales of the system, auto-consumption must also be subtracted from total production. I used the last 5 years average for both the transmission loss and auto-consumption factors (4.6% and 2% respectively).

Resulting marginal cost functions are plotted in Figure 2. Notice that both Firms own low and high marginal cost plants, being this feature more accentuated in the case of Firm 1.

5.2 Demand

As it was said before, Cournot producers face a residual demand given by:

$D^R(P_t) = D(P_t) - S^f(P_t) - q_t^{MR} - q_{ht}^{PS}$

Where $D(P_t)$ is market demand, $D^R(P_t)$ is residual market demand, $S^f(P_t)$ is the fringe supply's function (adjusted by transmission losses), q_t^{MR} is must-run units' generation and q_{ht}^{PS} is the hydro production from reservoirs owned by the fringe that is distributed across periods according to a Peak shaving strategy.

5.2.1 *Market demand*:

I constructed a step function representation of April-2000's load curve with 6 discrete load levels (t=1 for the highest load level).[34] The load level of each step was set equal to the average of the loads covered by those hours in the full load profile (see Figure 3).[35] Each load level has an associated price given by the regulated price, which is the price paid by final consumers. This price-quantity point will be referred to as the "anchor point" for each period (Figure 4). Given that there is only one price-quantity observation for each period, it is not possible to directly estimate the market demand function; all that can be done is to assume a functional form and parameterize it using each period's anchor point and an assumption for the price-elasticity of demand for electricity.

Demand is assumed to be linear $D(P_t) = A_t - BP_t$.[36] As a consequence, 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.

The empirical literature has emphasized the importance of price elasticity of demand in the results. In my model, demand elasticity will also turn out to be very important, as Cournot equilibrium will be closer to the competitive equilibrium the more elastic is demand. In addition hydro scheduling will be determined in part by demand elasticity. Estimates of the price elasticity of demand for electricity vary widely in the literature. As Dahl (1993) pointed out, the estimation of price elasticity is sensitive to the type of model used, to the estimation technique and to the data set used. In addition, studies differ on their definition

[34] I chose April because historically it has been the month where the maximum demand of the year takes place.

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

[36] A linear functional form is consistent with the peak shaving criteria that will be used later to allocate hydro generation: periods of high demand are also periods of high marginal revenue.

of short run and long run price elasticity.[37] In lagged adjustment models short run is defined as the 1-year response to a permanent increase in prices. Garcia-Cerruti (2000) using panel aggregate data for selected California counties (1983-1997) estimated that short run price elasticity went from -0.132 to -0.172, while the range for the long run was from -0.17 to -0.19. In the particular case of Chile, Galetovic et al (2001) used a partial adjustment model to estimate the demand for electricity by commercial and residential users. Their estimates of short run (long run) price elasticity were -0.33 (-0.41) and -0.19 (-0.21) for residential and commercial users respectively.[38] Short run estimates of price elasticity are lower when the period in which the consumption pattern may be adjusted is shorter. Wolak and Patrick (2001) looked for changes in electricity consumption due to half hourly price changes in the England and Wales market. They focused on 5 large and medium sized industrial and commercial customers. Not surprisingly, they got much lower estimates of price elasticity. In the water supply industry, which was the most price responsive industry analyzed, price elasticity estimates went from nearly zero (at peak) to -0.27. The steel tube industry was the least price responsive industry, with price elasticity estimates going from nearly zero to -0.007 (there is no indication of the demand level at which the upper estimate was observed). Finally, Dahl (1992) found no clear evidence that the developing world's energy demand were less price elastic than for the industrial world.

Because of the large variation in the price-elasticity estimates, I follow the traditional approach of estimating and reporting the results of the model for different values of elasticity. In particular, the market demand will be estimated for 5 different assumptions of price elasticity of demand E = {-0.1, -1/3, -1/2, -2/3, -1.0}, measured at the anchor point at peak hours. In the main body of the paper I only report results for -1/3 and -2/3.[39] These values may appear to be high compared to some of the estimates reported. However under the assumption that consumers are sensitive to price changes at least until a certain degree, it is not reasonable to assume that consumers will not react to the exercise of market power. In particular, we should expect them to learn, after a while, that the price is higher in certain periods than in others and to adjust their consumption behavior accordingly.[40] This change should mitigate the potential for market power. It is very difficult to explicitly incorporate this demand side reaction to market power into the model. An indirect way of doing it is to assume that the market is more price responsive than short run estimates of price elasticity indicate. Results for the E=-2/3 assumption are reported as a way to illustrate the effect of increasing price-sensitivity of demand. The results for the case of E = -0.1, E=-1/2 and E=-1.0 are reported in the Appendix 1.

[37] Nesbakken (1999) suggested that since there is a lot of individual variation in energy used, estimates based on micro data were more reliable.

[38] As I mentioned before, the regulated price in Chile is fixed for a period of 6 months. During that period, it changes mostly according to he evolution of inflation. This means that the authors did not have much price variation over time. However, since the price that was used to estimate price elasticity was the final price, and since that price includes transmission and distribution charges that vary across consumers according to different parameters, they did have cross-section price variation.

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

[40] See Wolak and Patrick (2001) and Herriges et al (1993) for estimations of elasticity of substitution within the day.

The price elasticity assumption was incorporated in the model through the slope parameter B, which was calculated such that the elasticity at the peak demand level was equal to "E". This implies that I will work with parallel demands ("same slope"). The intercept was calculated so as to fit anchor quantity and anchor price at each demand level (given the calculated slope B).[41] See Table 2 for demand parameters used assuming E = -1/3.

By assuming that market demand is linear and the slope is constant across load levels, I am implicitly assuming that market demand at peak hours is less elastic than demand at off peak hours (at a constant price).[42] Neither the linear demand assumption nor the anchor point chosen had any influence on the results. The main conclusions (even order of magnitudes) were the same when running the simulation assuming that the slope was not constant.[43]

5.2.2 ***Fringe's supply***:

In order to minimize the number of steps that the residual demand faced by Cournot producers have, I decided to use a linear approximation of the Fringe's supply function. This linear function is given by the following expression (see Figure 5):

$$MC_F = \left\{ \begin{array}{ll} 3.66 & for \ \ 0 \leq Q_F \leq 54.9 \ \ MW \\ -114.60441 + 2.156038 Q_F & for \ 54.9 \leq Q_F \leq 58.5 \ MW \\ 11.51217 & for \ 58.5 \leq Q_F \leq 399.9 \ MW \\ -333.526 + 0.8628848 Q_F & for \ 399.9 \leq Q_F \leq 433.7 \ MW \end{array} \right\} \tag{14}$$

5.2.3 ***Must run quantity:***

The plants that have to be dispatched all the time (no matter the price) and thus cannot be used strategically by their owners were designated as "must run" plants. 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. $q^{MR}$was calculated as April 2000's average generation per hour in the case of thermal plants, and in the case of hydro-ROR plants, as the average generation in a normal hydro year calculated according to the Energy Matrix provided by the CDEC.[44]

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

[42] 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.

[43] In the "different slope approach", the slope parameter B was such that the elasticity at every anchor point was equal to "E". Results are reported in Appendix #1. I decided to report in the paper the results for the same slope approach because when using the different slope approach, residual demands intersect on a certain (and relevant) price range making it more difficult to interpret results. Results are almost the same under both approaches.

[44] Since must run plants' production was subtracted from total demand, must run plants were also removed from the set of available units (in other words, they are not included in the aggregated marginal cost function).

5.2.4 *Hydro-reservoir generation by the Fringe* (q_{PSh}).

In order to allocate the hydro-storage generation by the Fringe, I calculated, for each plant, the average generation per month (in this case April) in a normal hydrological year based on the Energy Matrix estimated by the CDEC. This monthly hydro generation was assumed to be total hydro production available for the period. It was allocated over the month according to the peak shaving strategy described before. Minimum and maximum flow constraints were also taken into account. q_{PSh} used to estimate the model is the average hydro generation per hour allocated to each sub-period according to this approach. Since the Fringe owns relatively small hydro-storage plants, the amount of hydro production that can be allocated through a peak shaving approach is also small. Peaks are only slightly reduced and the shape of the "shaved load" curve remains mostly the same. (See Figure 6).

5.2.5 *Residual demand*:

Table 3 summarizes what was subtracted from market demand (April 2000) to get the residual demand faced by the Cournot producers. The shape and position of residual demands faced by Cournot producers is explained by a combination of three elements: the anchor point, the fringe's supply for thermal production and the load curve shape that results after allocating fringe's hydro production through a peak shaving strategy (Figure 7).

5.3 Hydro data

Minimum hydro production per hour is given by technical requirements and by irrigation contracts. Maximum hydro production per hour is determined by technical requirements. Total April's available hydro production is 1118.1 GWh according to the Energy Matrix provided by the CDEC (See Table 4).[45] Fringe's hydro production was allocated according to the Peak shaving strategy, as was explained before. Hydro scheduling by Firm 1 will be a result of the model.

6 Simulation Results

6.1 Competitive equilibrium

As a benchmark case, I calculated the competitive equilibrium. System's hydro-storage production (by the Fringe *and* Firm 1) was allocated according to the peak shaving strategy. The competitive equilibrium was calculated as the quantity - price point where demand (net of hydro production) and the aggregate marginal cost function intersect. The estimated Competitive Equilibrium for E=-1/3 and E=-2/3 are reported in Tables 5 and 6.

Observe that the equilibrium is exactly the same for the first four periods (t=1 to 4) and almost the same for the fifth one. This is a consequence of net demand being the same in those periods, or, in other words, of hydro production being so large that its allocation across the month completely flattens demand in those periods, eliminating (reducing) the peaks. See Figure 8.

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

6.2 Cournot equilibrium

The Cournot-Fringe model was solved with GAMS/CONOPT using an iterative process. I started assuming that each firm produced at the average level observed in April 2000, and then solved for the Cournot equilibrium for Firm 2. Given the resulting production schedule, I solved for Firm 1 and used the resulting Cournot equilibrium as an input for Firm 2's maximization problem. I continued this iteration process until the model converged to a solution for each of the firms.[46] Results are reported in Tables 7 and 8.

Total quantity is smaller than in the competitive model and prices are considerably higher, especially when demand is high (see Figures 9 and 10). Notice that as demand falls, the Cournot equilibrium (price and production) converges monotonically to the competitive equilibrium. The exception is given by the last period when demand is at its lowest level which may be explained by Firm 2 increasingly constraining production as demand falls. The more elastic is demand, the larger is total production and the closer is hydro scheduling to the competitive equilibrium

When demand is at high and medium 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. Firm 2 exercises market power only in the last 2 periods, when demand is low (see Figure 12).[47]

Firm 1 chooses to satisfy demand mainly through hydro production. In particular, it uses *all* the hydro production that is available but allocates it differently than in the competitive model. Firm 1 allocates relatively *less* water to high demand periods and relatively *more* water to the low demand periods (See Figure 11). This hydro allocation enlarges the difference between peak and off-peak periods, as opposed to what is observed under competition. This effect is *smaller* the more elastic is demand.[48] Firm 1's hydro scheduling strategy is consistent with 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 exploits differences in demand elasticity, reducing production when the constraint is binding (and demand is less elastic). Notice that whether or not transmission constraints

[46] 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 (q_1, q_2), marginal cost, marginal value of water and profits. The only exception is given by the 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(q_{1Th}, q_{1h}). 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 MR and MC and that the MR 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 q_{1h} and q_{1th} are averages calculated over 400 different estimations of the model.

[47] 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 2.2

[48] It cannot be argued that the demand assumptions are driving the results. Even though I am implicitly imposing that peak demand is less elastic than off-peak demand (at a constant price) I am not imposing in any way how the water should be allocated across periods. This is just a result of the model.

bind has an impact on the elasticity of the residual demand faced by the Cournot producers as imports/exports of energy take place (or not). My model results show that transmission constraints are not a necessary condition for the exercise of market power by hydro producers. Capacity constraints (supply constraints) will have the same effect. In other words if a hydro producer competes with a thermal producer, the first one may choose to restrict production when the thermal producer is capacity constrained, and to increase production the rest of the time. In this way, one could say that Firm 1 faced a less elastic demand when Firm 2 is capacity constrained. As a consequence, the shifting of hydro production is also the result of Firm 1 exploiting differences in price elasticity.

Firm 1's large hydro capacity is the source of its market power. Accordingly, Firm 1 explicitly schedules its hydro production in order to exploit differences in price elasticity and exercises as much market power as it can. However 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.[49] On the other side, Firm 2's large thermal capacity was not 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.

Firm 1's markups are decreasing as the demand it faces falls and they go from 76% to 66%, with a weighted average of 72% when demand elasticity is -1/3 . The more elastic is demand, the smaller are the Lerner Indices, as expected. Firm 2's markups do not exhibit the same monotone pattern. In particular, the Lerner index is larger during the middle hours (Table 9).[50]

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.[51]

A final question regarding the exercise of market power in this industry is who are the winners and the losers. In order to analyze this issue, I calculated each firm's producer surplus, the consumer surplus and welfare (as the sum of producer and consumer surplus). Results are reported in Table 10.

All of the producers are better off when market power is exercised. 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. Observe that even though it is Firm 1 the one who is really able to constrain production and drive 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

[49] In Chapter 7 I estimate the market equilibrium assuming that Firm 1's thermal portfolio is divested. In particular, I analyze the impact of selling Firm 1's thermal portfolio to two different set of agents: i) a unique producer and ii) many small producers with no market power.

[50] The Lerner index shows market power that is exercised. Since Firm 2 is "capacity constrained", it is probably not exercising market power. Consequently, Firm 2's Lerner index doesn't have an economic meaning during those periods.

[51] The possibility of inefficient dispatching was pointed out by Von der Fehr and Harbord (1993), Borenstein et al (2000) and Wolfram (1998).

higher.[52] Finally notice that the increase in the producer surplus almost compensates the consumer surplus' reduction, keeping welfare loss at a relatively low level.

6.3 Extensions to the Model

In order to evaluate how sensitive these results are to the assumptions used, I re-estimate the model under two different conditions. First, I analyze the effect of a smaller amount of water inflows being available to allocate over the planning horizon. This exercise is motivated by the role hydro resources play in Firm 1's market power. Secondly, it is more realistic to think that Firm 1 may prefer to schedule its hydro production over a longer planning horizon, saving a fraction of the hydropower available in a particular month to be used in a later period. Therefore, the effect of producers maximizing over an entire year rather than a month will be studied.

6.3.1 Cournot equilibrium with reduced hydro inflows.

The model was estimated assuming that the hydrology was "dry" rather than normal. In particular, I assumed that hydro flows were 60% of the flows registered in a "normal" year.[53] Since all hydro flows are assumed to be smaller, the fringe is also smaller and residual demand is relatively less elastic than in the base model. Data used to calculate residual demand are reported in Table 11 while Cournot and Competitive Equilibrium for the E=-1/3 case are in Tables 12 and 13. The results for the E=-0.1, E=-1/2, E=-2/3 and E=-1.0 are reported in Appendix 1.

Hydro flows are just enough to satisfy the minimum hydro production constraint; as a consequence, Firm 1 and the Fringe have little hydro scheduling to do. In particular, the Fringe is not able to schedule its plants differently than running them at minimum capacity. Therefore the shape of the load curve is completely preserved and peaks are not eliminated, just reduced by a very small amount.

Since hydro resources are not abundant as before, thermal capacity is more intensely used, driving prices considerably higher than in the base cases - no matter whether the market is competitive or not. The marginal value of water is also considerably higher as less efficient thermal plants must be dispatched in order to meet demand.

Results reported in Table 13 show that even under these extreme circumstances significant unilateral market power can be exercised. However, while Firm 1's market power has been reduced, Firm 2 now has the incentive and the ability to act strategically by withholding supplies from the market to keep prices from falling further. Prices are lower than when Firm 1's hydro capacity was larger but at the same time, they are still above the competitive equilibrium. Unlike what happened before, prices are increasingly different the lower is demand. How can this be explained? Observe that Firm 1 is capacity constrained when demand is at its maximum level. Therefore, Firm 1 constrains more its thermal production (relative to the competitive equilibrium) the lower is demand. In addition, and contrarily to what was found before, relatively more water is allocated to periods of high demand and

[52] Firm 1's profits are considerably larger than Firm 2's and so in absolute terms, the winner is Firm 1.

[53] Actual values for the 1998/99 year (the driest in the past 40 years) are 55%, 78% and 60% for hydro reservoirs, ROR and total hydro flows, respectively.

relatively less to periods of low demand.[54] Firm 1 behaves like a price taker when demand is high and exercises some market power when demand is low. On the other hand, Firm 2 constrains more its (thermal) production when demand is high.

Firm 2 is still the producer who is benefited the most by the exercise of market power, but similarly to what happens to the remaining producers, its net benefit is smaller than when hydro flows are "normal" (see Table 14). Observe that in relative terms, consumers' loss is smaller (relative to the competitive equilibrium) when hydro flows are reduced as less market power is exercised. Since this more than compensates the smaller increase in the producer surplus, welfare loss is also smaller. The finding that the welfare loss from the exercise of market power is smaller when hydro flows are reduced (as opposed to normal) does not mean that in absolute terms society is also better off. Indeed society is better off when hydro flows are normal than dry, even if market power is exercised.

6.3.2 Hydro scheduling over a longer planning horizon

The model that has been used so far to analyze the exercise of market power in Chile's electricity industry assumed that the hydro producer was able to allocate its hydro production over a 1 month planning horizon. Indeed, the optimization problem solved by Firm 1 in that model, 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. In real life, however, producers usually maximize over a longer time horizon, and thus it is reasonable to expect them to save a fraction of their hydro flows available in a particular month to be used in a later period. An interesting question is whether Firm 1 would follow the same hydro scheduling strategy that was found optimal in the 1-month model if the planning horizon were longer. In particular, would Firm 1 exploit inter-month differences in demand elasticity 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. According to Table 15, this means that hydro production should be shifted from October, November and December to March, January and the winter months (June-August).[55]

There are at least two different approaches 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 1-year version of the model is not available, and therefore many arbitrary assumptions would be needed, I will concentrate on the MVW analysis. A very simple version of a 1-year model is analyzed and estimated in Appendix 2.

The basic idea behind the MVW analysis is the following: given that generators allocate their hydro production in order 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, 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 follow over the year. In

[54] The shadow price of the minimum hydro production constraint is, for the first time, different than zero. In particular, Firm 1 is willing to pay to reduce the lower bound limit when demand is at medium and low levels. Indeed it is willing to pay more the lower is the level of demand. This result is consistent with a producer who is able to exercise market power only when demand is at medium-low levels.

[55] Market demand was parameterized as before, and thus it was assumed that price elasticity was -1/3 at the peak anchor point. Residual demand is not constant throughout the year because must run production and the Fringe's production fluctuates over the different months.

particular, if min/max flow constraints and min/max reservoir capacity constraints are 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 from low MR months to high MR months. If the hydro scheduling strategy that I found that was optimal in the 1-month model is also followed by producers over the year, I should find that: water is cheap (low MVW) in October, November and December and more costly in March, January and the winter months (June-August).[56]

In order to check for this hypothesis, I run the model and calculated the MVW for each month of the year (Table 16). Observe that the MVW fluctuates over the year. Water is more valuable in the first months of the year and less valuable in October, June, July and November. Accordingly, if Firm 1 could reallocate hydro flows throughout the year, it would store a fraction of them in the second half of the year and would use them in the first half of the next year.[57] The MVW is positively correlated to the inter-month differences in demand elasticity suggesting that the hydro scheduling strategy is consistent with the conclusions of the 1-month model, as hydro production would be shifted from low demand elasticity months (low MVW) to high demand elasticity months (High MVW). MVW is also positively correlated to the intra-month variation of demand elasticity (fluctuations of demand elasticity *within* each month). According to this evidence, the hydro producer would choose to "flood" the market not only when average residual demand is relatively more elastic (and hence the market more competitive) but also when the difference between min/max demand and price elasticity across periods is larger, reinforcing the first effect.

Even though the hydro producer has incentive to exploit inter-month differences in demand elasticity, and intra-month demand fluctuations, *the incentive is not strong enough* to completely explain the hydro scheduling strategy over a longer planning horizon. Indeed, the correlation coefficient between average elasticity of demand and the MVW and between intra-month demand fluctuation and the MVW are relatively small (0.24 and 0.26 respectively). Unlike that, the correlation between MVW and the ratio inflows/net demand is very strong (correlation coefficient = -0.93) suggesting that producers store hydro flows and release them across months according to how scarce these flows are relative to demand. This relationship being stronger implies that the value of water and its allocation over the year is mainly explained by a traditional supply-demand analysis (i.e. store water when it is relatively abundant) than by a market power argument (i.e. store water when demand is less elastic).

Why is it that Firm 1 would not schedule its hydro plants in order to exploit inter-month differences in demand elasticity? There are, at least, two possible explanations. First, producers may not need to allocate water from less elastic months to more elastic months in order to exercise market power if they are already able to exercise it within a month. In the 1-month version of the model, I found that Firm 1 exercised market power by constraining its hydro production in periods of high demand, as its rivals were capacity constrained and by using the "stored" water when the market was more competitive (low demand). If there

[56] Winter in the Southern hemisphere goes from June 21st to September 21st. January, February and September coincide with vacation periods. In addition, the first two months are in the middle of the summer. AC use is not spread in Chile.

[57] This simple analysis does not take into account any technical constraint regarding maximum and minimum capacity of reservoirs.

is enough intra-month demand variability, it is more likely that there will be periods in which the producer will be able to release the stored water without a big impact on the market price. The Cournot equilibrium converging each month to the competitive equilibrium as the demand level falls, indicates that the market is competitive a fraction of the time, providing qualitative support to this argument.[58] In order to check for this hypothesis more formally, I estimated a calibrated version of the model assuming that there were *only* inter-month differences in demand elasticity but *no* intra-month demand fluctuation. If it is true that intra-month fluctuations are the reason why Firm 1 does not exploit differences in demand elasticity across months, then the correlation coefficient should be higher. Results are reported in Table 17, column (2). As expected, the correlation coefficient between the elasticity of demand and the MVW is higher but only marginally. At the same time, the relationship between the value of water and its availability (measured by the ratio inflows/net demand) is still very strong. These results suggest that the intra-month demand fluctuation is only a second order explanation to the hydro scheduling strategy followed over the year.

Alternatively, Firm 1 may not have incentive to exercise market power by shifting water from one month to another *because inter-month differences in price elasticity are not big enough.* Remember that the 1-month model, and associated marginal value of water was estimated assuming that the price elasticity of market demand for electricity was -1/3 at the peak anchor point. Even though elasticity of residual demand fluctuates both intra and inter-month as the size of the fringe and must run production varies, it may be possible that this fluctuation is not sufficiently large. In order to check for this hypothesis, I estimated the model assuming that the elasticity of *market* demand was different over the year (but constant within each month).[59] As a result of larger differences in price elasticity (almost ten times), the correlation between the marginal value of water and the average elasticity of demand also increased; the correlation coefficient amounted to 0.88 (Table 17, column (3)). In other words, 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.[60]

Summing up, producers exercise market power 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. This hydro scheduling strategy may be observed no matter what the planning horizon of the model is; the only "requirement" is that there is enough "inter-period" demand variability. The smaller the fluctuation, the closer is the hydro scheduling strategy to the traditional supply-demand analysis' conclusions.

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[58] The correlation coefficient between the price ratio Cournot/Competitive equilibrium and the MVW is -0.72.

[59] It could take one of the following values: -0.1, -0.33, -0.5, -0.67, -1.0. These were randomly allocated to each month.

[60] In order to completely discard that this effect is explained by greater demand fluctuation within each month, I re-calibrated the model, assuming the same inter-month difference in price elasticity but no intra-month fluctuation (Table 2.17, column (4)). The correlation coefficient between the marginal value of water and the average elasticity is almost unchanged.

7 Mitigation Measures

Governments reforming electricity industries have taken different approaches to deal with similar market power problems. When Australia and Argentina de-regulated their power industries, they disaggregated their generation sector into many small firms that were later privatized (or are supposed to be in the case of the remaining state-owned generation companies). On the other hand, the newly formed generation firms were privatized in Chile and UK with large market shares. In the UK, however, firms were privatized with a high level of contracting (National Power with 87% and PowerGen with 88% at the moment of privatization and 72% and 70% respectively after the first set of 1 year contracts expired). Similarly generators in the New South Wales and Victoria markets (Australia) were required to sell hedge contracts to retailers of electricity in a quantity enough to cover their franchise market demand. The prices of these contracts were set by the state at fairly high levels. Finally, regulatory threats have also been used to prevent the exercise of market power: after the UK's regulatory agency threatened National Power and PowerGen to be referred to the Monopolies and Mergers Commission, the producers agreed on a price cap. They also agreed to divest a fraction of their generating capacity to independent producers.[61]

In what follows I analyze two sets of measures that have been relatively successful in other restructured electricity systems and that are feasible to implement in Chile. Since Firm 1's large installed capacity, in particular its control of hydro-storage plants is the source of its market power, it is reasonable to start analyzing the effect of requiring Firm 1 to divest some of its plants.[62] Divestiture of thermal and hydro plants will be analyzed separately. In the first case, I will analyze the impact of transferring Firm 1's thermal plants to a single firm with the potential to exercise market power as well as transferring this capacity to small producers with no market power. Secondly, I will study the effect of dispatching Firm 1's hydro storage plants competitively. In particular, I will calculate the market equilibrium under two alternative assumptions: i) the entire set of hydro storage plants is dispatched competitively and ii) only some of them are. Finally, I will analyze the impact of requiring large generating companies to contract a fraction of their production at fixed prices determined outside of the spot market.

In order to have a quantitative estimation of the real impact of these measures I used GAMS/CONOPT to estimate different versions of the original model, each of them adapted to incorporate one of these mitigation measures. Even though the model results turned out to be sensitive to price elasticity of demand, I only report results for the E=-1/3 case, as the more elastic is demand the less market power can be exercised, and the smaller the need (and the relevance) of mitigation measures.

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[61] For more detail on an international comparison on restructuring and regulation of the electric power sector see Wolak (1999) and ENRE(1997).

[62] Similar exercises were done by Green and Newbery (1992) and Andersson and Bergman (1995). Green and Newbery (1992) estimated what the market equilibrium would look like if the industry were a quintopoly rather than a duopoly. They found that reduction in output, the price increase and the deadweight loss would be considerably smaller. Andersson and Bergman (1995) analyzed the impact of i) splitting the largest company in two firms and ii) a merge between the six smallest generators. In both cases, the market equilibrium was closer to the competitive equilibrium.

7.1 Firm 1's asset divestiture

7.1.1 Full divestiture of thermal plants.

A first alternative of asset divestiture is given by Firm 1 being allowed to keep its entire hydro capacity but required to divest all of its thermal plants. Under these circumstances, hydro scheduling is the only tool Firm 1 has to exercise market power.

Thermal plants may be sold to a single producer or to many small suppliers. Both scenarios will be analyzed. If the entire thermal capacity were sold to a single producer (Firm 3), three producers, a purely "hydro" producer (Firm 1) and two purely thermal producers (Firms 2 and 3) would make up the industry. Newly created Firm 3's installed capacity would be given by former Firm 1's thermal plants. The competitive Fringe would be exactly the same as in the base Cournot model. Alternatively Firm 1's thermal plants may be transferred to many small producers, in which case the industry would be made up by a purely hydro, a purely thermal producer (Firms 1 and 2 respectively) and by a considerably larger competitive fringe as it would also include Firm 1's former thermal plants. In what follows, both cases will be referred to as "Triopoly" and "Duopoly with a larger thermal fringe ("DLTF") respectively. Table 18 reports the resulting distribution of installed capacity.

Marginal cost functions are plotted in Figure 13**.** Firm 1's original marginal cost function is above Firm 2's over almost all the range. Notice that most of the plants that would be sold are less efficient than the ones that the Fringe already had.[63]

While producers in the Triopoly case would face *exactly the same residual demand* that Firms 1 and 2 faced in the base model, the transfer of the thermal capacity to the Fringe in the DLTF case would result on Cournot producers facing *a smaller and more elastic residual demand*. In other words, in the first case, 3 producers (instead of only 2) "share" the same cake, while in the second, the original two producers "share" a smaller cake. The other elements of the model - Firm 1's hydro capacity (and constraints), Firm 2's marginal cost function, must run generation, hydro resources available and hydro generation by the Fringe - remain the same.

The optimization problem to be solved must be adapted to the new circumstances: i) Firm 1 is a purely hydro producer and its only strategic decision is to schedule its hydro plants and ii) the presence of a new producer (Firm 3) in the Triopoly case or a Fringe with a larger thermal installed capacity (DLTF). Each firm's maximization problem is given by:

Firm 1's Optimization problem

$$\max \sum_t \{P_t(q_t) q_{1ht}\} \text{ subject to} \tag{15}$$

$$q_{1hMIN} \leq q_{1ht} \leq q_{1hMAX} \quad \forall t \tag{16}$$

$$\sum_t q_{1ht} \leq q_{1htot} \tag{17}$$

Firms 2 and 3's optimization problem (i=2,3)

$$\max \sum_t \{P_t(q_t)(q_{iTht}) - CT_i(q_{iTht})\} \tag{18}$$

$$q_{iThMIN} \leq q_{it} \leq q_{iThMAX} \quad \forall t \tag{19}$$

[63] Given that the linear approximations used are not exactly the same, results from the different models are not completely comparable

Relevant FOCs:

$$\frac{\partial L}{\partial q_{1ht}} = P_t(q_t) + q_{1ht}\,\frac{\partial P_t(q_t)}{\partial q_t} - \gamma_{1t} + \delta_{1t} - \sigma_1 = 0 \;\; \forall t \qquad (20)$$

$$\frac{\partial L}{\partial q_{iTht}} = P_t(q_t) + (q_{iTht})\,\frac{\partial P_t(q_t)}{\partial q_t} - \frac{\partial CT_i(q_{iTht})}{\partial q_t} - \lambda_{it} + \alpha_{it} = 0 \;\; \forall t,\, i = 2,3 \qquad (21)$$

These conditions can be reformulated as follows:

(20′) $MR_{1t} = \sigma_1 + \gamma_{1t} - \delta_{1t} = \Omega_{1t}$

(21′) $MR_{it} = c_i + \lambda_{it} - \alpha_{it}$

As before, thermal generators produce until marginal revenue equals marginal cost. Firm 1 equalizes marginal revenue to the marginal value of water but this value is no longer linked to thermal marginal cost.[64] The marginal value of water indicates how much total profits would increase by having an additional unit of water available. In the case of a producer with a mixed thermal/hydro portfolio, 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. Therefore, in equilibrium the marginal value of water must be equal to the marginal cost. In the case of a purely "hydro producer" this link no longer exists. In this case, the only way a hydro producer may increase his profits is by changing the hydro scheduling. Under these circumstances, the marginal value of water indicates how much profits would change as a consequence of having *rescheduled* hydro production if an additional unit of water became available.

A priori it is not possible to know what circumstances (triopoly or DLTF model) are more suitable for the exercise of market power. In both of them there are elements that increase market power while others reduce it (number of producers, size of the residual market, price elasticity of demand). In order to analyze this issue, I will focus on two results of the simulation: hydro scheduling and Firms 2 and 3 Lerner Indices.[65]

Results for both models are reported in Tables 19 and 20.[66] Prices are higher and output lower in the Triopoly model than in the DLTF model; both results are in between the base case and the competitive equilibrium (See Figures 14 and 15). Reduction in prices and the increase in total output when compared to the base case, may lead us to, mistakenly, conclude that each Cournot producer exercises less market power.

In Chapter 6 I found that Firm 1 exercised market power by reducing hydro production when demand was high and by increasing it when demand was low (relative to the competitive equilibrium). Exactly the same strategy (and in similar amounts) is carried out when Firm 1 is a purely hydro producer (See Figure 16). Firm 1's ability to exercise market power is reduced but not by much. These results also suggest that Firm 1 exercises more market power in the Triopoly than in the DLTF case.

In the base case, Firm 1 has so much market power, and can drive prices up by so much, especially when demand is high, that Firm 2's optimal strategy is to produce at capacity.

[64] Marginal revenue is equal to the marginal value of water if minimum and maximum hydro production constraints are not binding. Otherwise, min/max hydro production shadow prices must be added.

[65] In the case of Firm 1 there is no thermal marginal cost. Consequently it is not reasonable to talk of markups in the sense of Lerner Indices. This is not a problem. Since Firm 1's only tool available to exercise market power is the scheduling of its hydro-storage plants, it is this variable and not markups what should be the focus of the analysis of Firm 1's market power.

[66] Equilibrium IS unique.

Firm 2 is able to exercise market power only when demand is low. As Firm 1's installed capacity is reduced, Firm 2's relative position in the market is strengthened. As a result, Firm 2 constrains its production (relative to the competitive equilibrium and to the base model) in the intermediate and low demand levels, but it is still profitable to produce at capacity when demand is high (Figure 17). In addition Firm 2 is able to exercise more market power in the Triopoly case, as there is another player who stands up against Firm 1.

Firm 1 exercises (a little) less market power while Firm 2 exercises relatively more. How is it then that total output is higher and prices are lower? The answer to this question is given by the owner(s) of former Firm 1's thermal plants increasing production enormously. As it can be seen in Figures 18 and 19, former Firm 1's thermal plants produce at a considerably higher rate after being divested. This increase is larger the lower is the demand level. It is also larger when the plants are sold to small producers with no market power than when they are sold to a single producer. Under these circumstances, Firm 3 would enjoy some market power and would exercise it at all demand levels except when demand is at its maximum. Even when these thermal plants are used to exercise market power and thus are dispatched at reduced levels relative to the competitive equilibrium, these levels are still considerably larger than when the plants were in Firm 1's hands. Indeed, production is large enough to more than compensate any reduction in production by the other Cournot producers (Figures 15 and 19). Finally, it should be noticed that the allocation is still inefficient but less than in the base model.[67]

Table 21 reports the effect of Firm 1's thermal plants divestiture on total profits. Firms 1 and 2 are worse off after the divestiture of Firm 1's thermal plants. As expected, they are marginally better off in the Triopoly than in the DLTF case. Using Firm 3's profits as a proxy of the equivalent annuity of the amount paid for Firm 1's thermal plants, one can see that Firm 1 is at its best when it controls its original mixed thermal/hydro portfolio. If required to sell its thermal portfolio, it prefers to sell them to a unique seller who enjoys some market power and thus is willing to pay for it. Notice that even though Firm 2's relative position in the market is strengthened as Firm 1 is stripped off its thermal plants, and thus it is able to exercise market power, its profits (and markups) are considerably lower. Firm 2 would still have been better off by taking advantage of Firm 1's original market power.

Summarizing: as a result of the divestiture of its thermal plants, Firm 1's market power is reduced but in no case eliminated. Indeed, Firm 1 retains its hydro capacity, which is the tool it uses to exercise market power. As a result, Firm 1's scheduling of its hydro plants is closer to the efficient allocation but it still exhibits the pattern of "less hydro production when demand is high and more hydro production when demand is low". At the same time, Firm 2 is able to constrain its production, in particular when demand is at medium and low levels. Even though both producers are able to exercise market power - in more or less degree - the market equilibrium (and welfare) is closer to the competitive equilibrium as former Firm 1's thermal plants are more intensely used. This is true even when those plants are sold to a single producer who is able to exercise market power at certain demand levels.

[67] In other words, Firm 2 could produce a fraction of what is currently being produced by the Fringe at a lower marginal cost.

7.1.2 Divestiture of hydro resources

In the previous Chapter, I found that the source of Firm 1's market power is the strategic management of its hydro-storage plants. Accordingly, another policy that may be implemented to mitigate the exercise of market power is to dispatch Firm 1's hydro storage plants *competitively*. Firm 1 may be entitled to keep the property of these plants but to transfer its management to an independent agent such as the CDEC, who is currently in charge of the operation of the system.[68] Under these circumstances, Firm 1 would only be able to use strategically its thermal capacity.

As a result, the industry would be made up by two large thermal producers (Firms 1 and 2) who play Cournot and by a price-taking fringe that owns a small fraction of thermal capacity but the entire hydro capacity of the system. This version of the model will be referred to as "Duopoly with a large hydro fringe" - DLHF. Installed capacity would be distributed among producers as it is reported in Table 22.

Notice that there is a change in the relative position of each firm in the market: the biggest firm in the industry is no longer Firm 1 but Firm 2. Supply and demand side of the model are basically the same as in the base model. The only difference is that in this case the entire system's hydro production from reservoirs is distributed across periods according to a peak shaving strategy (See Table 23).[69] Accordingly, Cournot producers face *a smaller and more elastic residual demand.*[70]

The importance of hydro production is clearly observed in Figures 20 and 21. In the base case, the Fringe owned relatively small hydro storage plants and thus the amount of hydro production that could be allocated through a peak shaving strategy was also small. Peaks were only slightly reduced and the shape of the "shaved load curve" (i.e. total demand - hydro generation) remained mostly the same. In the DLHF model, the entire hydro production is scheduled competitively. In this case, hydro generation is large enough to flatten demand over almost all the period. This means that the shaved load curve is almost flat during a large fraction of the month, eliminating the peaks. Because of the anchors that I used (same price and same slope) this result translates into equal residual demands over the first four periods (Figure 21).

Since Firm 1 does not have hydro resources to allocate across periods, the optimization problem is completely static. There are no interactions between one period and another; each producer treats each period as a different and independent market. Each firm's (i=1,2) maximization problem is given by

$$\max \sum_t \{P_t(q_t)(q_{iTht}) - CT_i(q_{iTht})\} \text{ subject to} \tag{22}$$

$$q_{iThMIN} \leq q_{it} \leq q_{iThMAX} \quad \forall t \tag{23}$$

The solution to this problem is given by six different and independent FOCs for each firm (equations 24 and 24'). In equilibrium each firm adjusts its production rate until marginal

[68] Transferring these plants to many small producers is probably inefficient as the operation of the hydro system would be extremely difficult. In addition, transferring all the hydro plants to a unique producer would not work either as it was analyzed in the Triopoly version of the model.

[69] In this case, a peak shaving strategy consists in allocating more hydro production to the periods of higher demand. Hydro-ROR plants are still assumed to be must run plants.

[70] The residual demand faced by Cournot producers in this case is relatively more elastic than in the base case the higher is the demand level.

revenue equals marginal cost (corrected by shadow prices if appropriate)

$$\frac{\partial L}{\partial q_{iTht}} = P_t(q_t) + (q_{iTht})\,\frac{\partial P_t(q_t)}{\partial q_t} - \frac{\partial CT_i(q_{iTht})}{\partial q_t} - \lambda_{it} + \alpha_{it} = 0 \quad \forall t \tag{24}$$

$$(24\prime)\ MR_i = c_i + \lambda_{it} - \alpha_{it}\ \forall t$$

Results are reported in Table 24.[71] Thermal quantities and prices are the same in the first four periods, a result expected given that after allocating hydro production through a peak shaving strategy, residual demands were the same in those periods (Figure 21).

Producers charge a price that is in between the one that would be charged in a competitive market and in the base model. Prices and total output are considerably closer to the competitive equilibrium. This effect is more significant when demand is at high and medium levels, which are precisely the periods when Firm 1 was able to exercise more market power. The increase in total output is not the result of all producers increasing uniformly its production. On the contrary, observe what happens to the use of thermal capacity, the only resource that can be used strategically in this model. While Firm 1 *increases* the use of its plants, Firm 2 *reduces* it. In a completely "thermal" game, it is Firm 2 and not Firm 1 who really enjoys market power.

Since hydro plants are dispatched competitively, hydro production is larger (with respect to the base case) when demand is high and is smaller when demand is low. Total output increases when demand is at high and medium levels because the increase in hydro production and Firm 1's thermal production more than compensate Firm 2's and the fringe's reduced thermal production (Figures 22-27).

According to Table 25, requiring Firm 1 to dispose of its hydro plants effectively reduces its market power. In fact, the industry reduces its average markup from 61.5% to 40.1%. Reduction in average markup is, however, not a generalized result. Indeed Firm 2 increases its average markup (from 44% to 48%) while Firm 1 reduces it (from 72% to 26%).

Even though Firm 2 is, this time, able to exercise market power, it would have been better off by taking advantage of the greater market power that Firm 1 could exercise when it had all of its capacity. On the other hand, although Firm 1's thermal plants are more intensely used and that profits earned directly from these plants increased by almost 4 times, this is not enough to make up for the (direct) reduction in profits that results from the loss of its ability to schedule its hydro plants unrestricted, as thermal plants represented only 7% of Firm 1's total profits in the base case. Indeed, Firm 1's total profits are only 17% of what it earned in the base case. On the aggregate, however, Firm 1 is not considerably worse off. In fact, when the revenue from the sale of its hydro plants is considered, Firm 1's "adjusted-profits" are only 3% lower than when it had all of its capacity. (Table 26).[72] How is it that prices can go down so much and there be a small effect on Firm 1's profits? The explanation is twofold. On the one hand, prices are lower than in the base case but still higher than what would be observed under perfect competition, as Firm 2 is able to exercise market power. On the other hand, former Firm 1's hydro plants are more intensely used in the periods of high demand, when the price is higher, and less intensely used in the periods of low demand, when the price is lower, as opposed to the hydro scheduling strategy used by Firm 1 when

[71] Equilibrium is unique.

[72] As in the previous exercise I am using the profits earned by the owner of former Firm 1's hydro plants as a proxy of the equivalent annuity of the amount paid for those plants.

it enjoyed market power. As a result, profits earned from former Firm 1's hydro plants are lower than in the base case, but only by 15%, and they are still 20% higher than under perfect competition. This effect along with the increased profits Firm 1 earns from its thermal plants explains the result.

As a final exercise of Firm 1's assets divestiture, I analyzed the impact of requiring Firm 1 to divest only its largest hydro system, "Laja". Under these circumstances, Firm 1 would only be able to strategically schedule 42% of the system's total hydro production as opposed to 87% in the base model.[73] This model will be referred to as "Duopoly with a medium hydro fringe - DMHF". See Table 22 for the resulting distribution of installed capacity.

The most interesting result (Table 27) is how each firm's relative position in the market changes with the demand level. In the base model, we found that Firm 1 was the one that really enjoyed market power, while in the purely thermal game (DLHF), it was Firm 2. In this "in-between" model, both firms seem to enjoy market power, although who can really exercise it varies with the demand level. When demand is at its peak, Firm 1 is the one who constrains its production; Firm 2's optimal strategy is to produce at capacity. Unlike that, in the middle hours, it is Firm 2 the one that enjoys market power; Firm 1's production closely resembles its production in the DLHF model - when its market power was reduced (Figures 22-27).[74]

Summarizing: while the disposal of Firm 1's hydro-storage plants considerably weakens its relative position in the market, Firm 2's is strengthened. Indeed, Firm 2's relative position in the market is the strongest when the entire set of Firm 1's plants is dispatched competitively. Even though Firm 2 is able to effectively exercise market power, the market equilibrium is closer to the competitive equilibrium as total output is considerably larger.

7.1.3 Firm 1's asset divestiture: Comparison and welfare analysis

Alternative forms of Firm 1's asset divestiture have been analyzed. I found that the incentives to exercise market power, even though smaller, are not reduced significantly since Firm 2 is left in a position that enables it to withhold output to keep prices up from the competitive level. As a consequence of its installed capacity being reduced, Firm 1's relative position in the market is weakened while Firm 2's is strengthened. This result is particularly important when Firm 1 is prevented from strategically dispatching its hydro storage capacity, as it is the main tool it has to exercise market power. It is in this case that Firm 2's position is the strongest and exercises the most market power, while Firm 1 exercises the least.

In order to evaluate these policies, a welfare index was calculated as the sum of the producer and consumer surplus (See Table 28). Observe that the four alternatives of asset divestiture are very similar in terms of welfare, the producer surplus and consumer surplus change. If any of these measures were implemented, welfare would be between 2.7 - 3.3% higher than when Firm 1 has its entire capacity and is able to exercise market power (base case) and between 1.0 - 1.5% less than if the market were perfectly competitive.[75] This result

[73] As a consequence of a larger share of hydro production being allocated competitively, the shaved load curve exhibits smaller peaks than in the base model. In fact, during the middle hours, shaved demand is almost constant.

[74] Estimated equilibrium is unique except for Firm 1's production strategy.

[75] The measure of welfare loss used does not take into account inefficiencies that may result from producers allocating resources to maintain their market power, such as lobbying or, more generally, any deterring competition practice. Dynamic elements, such as entry, were not included either. If the high prices that

is explained by a reduction in the producer surplus (between 9 and 15%) and an increase in the consumer surplus (between 14 and 21%) when compared to the base case.[76,77]

Aggregate results across the mitigation measures analyzed being similar does not mean that the different forms of Firm 1's asset divestiture are equivalent. On the contrary, this similarity hides important distributive differences. Firm 1's direct profits are considerably more affected when it is not allowed to schedule its hydro plants strategically; a reasonable result given that its hydro capacity is the source of its market power. However, once revenues from the sales of its assets are taken into account, Firm 1 is almost indifferent between the four different alternatives that have been analyzed. However, Firm 2 and the "initial" fringe are not.[78] Indeed, the reduction in the producer surplus that would be observed if Firm 1's ability to exercise market power were constrained by any of the analyzed measures, would be almost completely explained by the smaller profits earned by Firm 2 and the Fringe. They are certainly not indifferent among the different forms of Firm 1's assets divestiture. They strongly prefer the status quo, and if that is not possible, they prefer the alternative that keeps more market power in the hands of Firm 1 (Triopoly over DLTF and DMHF over DLHF). On the consumer side, exactly the opposite happens. Consumers are better off the less market power can be exercised by Firm 1. Regulatory authorities will have to keep in mind the distributional effects that may take place as a result of each form of Firm 1's asset divestiture.[79]

Requiring the largest producer to divest some of its generating capacity to create more competitors does not eliminate the incentives or the ability to exercise market power, as under those circumstances, both firms are able to constrain their production in different amounts. The main difference in this regard is that Firm 2 holds a stronger position in the market. At the same time, however, market equilibrium is considerably *closer* to the competitive equilibrium not only in terms of levels (prices and output) but also in terms of the allocation of resources. This result is explained by former Firm 1's plants (either thermal or hydro storage) being more intensely and efficiently used, an outcome that should not come as a surprise since a large fraction of the capacity that was kept out of the market by Firm 1 were low-marginal cost plants. The resulting higher (and more efficient) production level more than compensates any reduction in production carried out by Cournot producers.

7.2 Forward contracting

As a final component of the analysis I analyze the impact of contracting practices. I assume that - for reasons that will be later discussed - generators and buyers meet in a contract market and sign contracts for a certain amount of energy and price ("strike price"). In particular,

result from the exercise of market power attract excessive entry as in Green and Newbery (1992) then the welfare loss would be larger.

[76] Given that none of these measures completely eliminates the exercise of market power, the producer surplus is still higher (between 18 and 27%) and the consumer surplus is still lower (between 12 and 17%) than what would be observed if the market were perfectly competitive.

[77] When compared to the base case, welfare only improves slightly as most of the reduction in the producer surplus is compensated by an increase in the consumer surplus. This result is not a surprise given that I assumed that market demand was relatively inelastic (E=-1/3 at the peak anchor point).

[78] By the "initial" fringe I refer to the small producers that were present in the industry before any Firm 1's asset divestiture took place. In other words, it does not include the new owners of former Firm 1's plants.

[79] In order to analyze the convenience of deregulating the system and implementing any of the policies that have been proposed, one should also do a welfare analysis of the current regulation.

I assume that these contracts take the form of "two-way options", i.e. both parties deal with the spot market and the consumer (producer) is compensated for the difference between the spot price (P) and the strike price (W) if P>W (P<W). Contracts are private and are arranged before the spot market meets. After these contracts are signed, both parties (and possibly some others) meet again in the spot market. The contract price may be determined in different ways (by regulators, as a function of the expected spot price, and so on) but once it is set, it is not changed and thus has no direct effect on the spot price.

In order to quantitatively analyze the effect of contracting practices, each firm's objective function must be modified as follows:

$$\max \sum_t \{P_t(q_t)(q_{it} - k_{it}) - CT_i(q_{iTht}) + k_{it}W_{it}\} \quad i = 1, 2 \tag{25}$$

where k_{it} is the contracted quantity and W_{it} is the contracted price. The last term indicates the fixed revenue the firm gets from its contracts. This term has no effect in the solution of the model, as the contracted quantity and price were determined outside the spot market (and before this market meets).

FOCs are:[80]

$$\frac{\partial L}{\partial q_{it}} = P_t(q_t) + (q_{it} - k_{it})\ \frac{\partial P_t(q_t)}{\partial q_{it}} - \frac{\partial CT_i(q_{it})}{\partial q_{it}} = 0 \ \ \forall t \tag{26}$$

$$(26\prime) MR_{it} = c_{it} \ \forall t$$

The producer equalizes marginal revenue to marginal cost, but marginal revenue is not a function of the firm's total production, as before, but only of the level of production that is actually sold in the spot market. Notice that the smaller is this term, the closer is the marginal revenue to the price level, and the closer the "market power" equilibrium to the competitive equilibrium. Equation (26') can be used to analyze the impact of being over (k>q) or under (k<q) contracted. When the producer is under-contracted, the market outcome will lie somewhere between the perfect competition and the no-contract equilibrium. When the producer is over-contracted (k>q), it does not behave as a net seller in the market but as a *net buyer*. In that case, the producer is no longer interested in driving prices up, but instead, it wants to *drive prices down* (and below marginal cost).

The competitive equilibrium will be the benchmark used to calculate the level of contracting at a certain time. In particular, when I say that the contracting level is x% I will mean that the contracted quantity (k) is given by x% of the load that the firm would be expected to generate under perfect competition. This approach allows me to incorporate the fact that the contracted quantity is not constant across the month.[81]

Results for different contracting levels (0%, 50% and 100%) are reported in Tables 29-31. As before, results will be reported for the case in which price elasticity of demand is -1/3.[82] Notice that when k=0 we go back to the original base model and that when the firms

[80] For simplicity I am maximizing over q_{1t} rather than over q_{1ht} and q_{1Tht}. Qualitative results regarding hydro scheduling and thermal/hydro split of production remain the same. I do not report first order conditions for minimum and maximum capacity constraints.

[81] Unfortunately I do not have good information regarding contracting practices in Chile. I only have data on the annual level of contracting but there is no additional information regarding how it is distributed across the year, if there is any particular relationship with capacity, etc.

[82] Conclusions are the same for the remaining cases.

are "fully contracted" (contracting level = 100%) results are very close to the competitive equilibrium.[83]

As expected, the more contracted the firms are, the lower are the prices and markups and the higher is output. In particular, when the firms are "fully contracted" the equilibrium is very close to the competitive equilibrium. In addition, prices tend to be closer to marginal cost as the contracting level increases; indeed when Firm 1 is over-contracted (t=5 for a contracting level of 100%) price is lower than marginal cost as predicted by the theory.

Total production increases with the contracting level, as has also been found in the literature. Two additional results are worth noting. First, notice that as the contracting level increases, Firm 2 loses all the market power that it had before. In the previous Chapter I found that Firm 2 could only exercise market power when demand was low, because in the remaining periods it was capacity constrained. However, when producers sell contracts and the contracted quantity is sufficiently large, Firm 2 cannot exercise market power even in those low demand periods. Secondly, observe what happens to Firm 1's production level. In addition to the fact that it produces more the more contracted it is (Figure 32) there is an important change in the way hydro production is scheduled (Figure 30). There may be two effects in place at the same time. On the one hand, I expect that the more contracted is the firm, the more efficient is its hydro scheduling. I also expect that the firm would allocate more production to those periods when it is over-contracted so as to drive the price down. What we observe is that as the contracting level increases, hydro scheduling is closer to the efficient (competitive) allocation. As a consequence, contracting practices result in gains in both productive and allocative efficiency. In addition, Firm 1 uses (relatively) more water when it is under-contracted (high demand periods) and less when it is over-contracted (when compared to the PC equilibrium). This implies that the contracting practices' "distortion reducing effect" dominates the second effect. Indeed, Firm 1 increases total production when it is over-contracted by relying as heavily as it can on its thermal plants; notice how closely is thermal production to the competitive equilibrium (Figure 32).

Note as well that my results differ from what was found by Scott (1998) regarding the impact of contracting practices on hydro production. He found a positive relationship between hydro production and the contracting level. According to my results, the higher is the contracting level, the closer is hydro scheduling to the optimal allocation, meaning that *more* is produced from hydro sources when demand is high and *less* is produced in low demand periods.

The more contracted the firm is, the higher is the marginal value of water, a result that is consistent with Scott (1998)'s findings for the electricity market in New Zealand (Table 32). The intuition behind this result is the following: the more contracted the firm is, the more it produces and given that the marginal cost function is increasing, the more costly it is to produce. In equilibrium the marginal value of water has to be equal to thermal marginal cost, and thus the more the firm wants to produce, the more valuable is water.

Do contracting practices help to mitigate market power? According to Table 33, the answer is yes. Firm 1's Lerner Indices are notably lower the more contracted the firm is.[84]

[83] Notice that a contracting level of 100% does not mean that contracted quantity = production (k=q). How much the firm will produce at every period is an endogenous variable and thus difficult to predict with certainty at the time contracts are signed.

[84] Notice that the markup is negative for t=5, contracting = 100% indicating that the price is less than the marginal cost. This result is consistent with what we expected for periods when the firm is over-contracted.

This is in line with the role contracts have had in the UK, where according to Newbery (1997) "[they] have turned out to be absolutely critical for introducing competition". By selling contracts, Firms 1 and 2 give up to some or most of their market power. As a result, the production level is closer to the competitive equilibrium and productive and allocative efficiency greatly improve.[85]

These results suggest that generators engaging in forward contracting would greatly reduce their incentives to exercise market power. A related and very important issue is whether the contract market will develop or not. Four different lines of reasoning for the development of the contract market have been discussed in the literature.[86] Wolak (2000) and Allaz and Vila (1993) argued that producers sell contracts in order to improve their situation in the spot market. This argument is probably weak as demand for electricity is relatively inelastic and the result is sensitive to the Cournot assumption. In second place, Green (1999) and Powell (1993) argued that producers might sell contracts, even if this results in their position in the spot market being weakened, if there are risk averse buyers willing to pay a premium in order to be risk protected. Powell (1993) showed that buyers might exhibit strategic behavior and buy contracts, even at a premium price, as a way to prevent producers from exercising market power in the spot market. This result holds even if the buyers are risk neutral. Finally, Wolak (2000), Powell (1993) and Green (1999) showed the role that regulation had in the birth of the contract market in Australia and England and Wales.

A priori it is difficult to know whether the conditions will be appropriate for the development of a voluntary contract market in the post deregulation electricity industry in Chile. At this time, all that can be done is to conjecture. It is clear that in the transition period from the system that is in place today to a deregulated system, regulation that requires retailers to purchase hedge contracts in a quantity enough to cover their monopoly franchise demand may be needed.[87] However, at a certain time, these mandatory contracts will necessarily expire, and if the authority wants to rely on the contract market to prevent producers from exercising market power, it must ensure that conditions will be given for this market to develop.

Green (1999) and Powell (1993) have emphasized the role that risk averse buyers might have in this regard. In order to analyze whether buyers in Chile are risk averse or not, one needs to examine who these buyers are and what do they purchase electricity for. In the case of large consumers who use electricity as an input of production, it is reasonable to expect them to be risk averse, as they usually sell on very thin margins. Accordingly, they would probably be willing to pay a hedging premium for their purchased contracts. Unfortunately the number of large consumers that are entitled to contract with generators is small and

[85] Unfortunately it is not possible to carry out a welfare analysis as it was done in the previous section because that would require too many arbitrary assumptions (risk attitude of the agents, an estimation of the risk premium, estimation of the contract price and expected spot price, etc.)

[86] For more detail, see Chapter 2.

[87] The contracted price will probably not be important for the development of the market but it will certainly have significant distributional effects. There are different approaches that may be used to set the strike price in the vesting contracts. An alternative is to continue calculating the regulated price, using a similar but improved methodology than the one that is used today (currently the regulated price is supposed to be an average of forecasted spot prices in a competitive market). This calculated price could be used as an anchor for the contracts' strike price. For instance it could be used as a price cap or as the middle point in a +/- x% band where the strike price could be allowed to fluctuate. The latter us is less restrictive than directly imposing a price and allows the contracting parties to some degree of negotiation. In addition, if the regulated price were truly a good forecast of the competitive price, as it is supposed to be, the contract price would also be a good proxy.

certainly not enough to guarantee the development of a deep contract market.[88]

A second set of potential buyers of contracts are the distribution companies. How interested these firms are in voluntarily contracting strongly depends on the regulation of the price charged to end-consumers. If they are allowed to completely pass through the "generation" price, it is very likely that they will have no incentive at all to contract. On the other side, if the final price is fixed (and constant) they would face the risk of any spot price change and thus would be more inclined to contract. Forcing distribution companies to contract, for instance by not giving them access to the spot market or by mandating them to contract a certain quantity, may be a dangerous policy. Even though it may result in a deepening (or a development) of the credit market, it may also result in anticompetitive practices at the same time. Think for instance on a distribution company required to be fully contracted and allowed to completely pass through the contracted price to end consumers. If at the same time, and for any reason, generation companies have incentives to contract, distribution companies may feel free to ask for certain "rewards" in order to be willing to sign the contracts. These rewards will most likely come in the form of privileges that go against the development or the functioning of a competitive spot market.[89]

Producers and buyers engaging in contracting practices is an insurance against market power abuses in the spot market, as the more contracted generators are, the closer is the outcome to the competitive equilibrium. Unfortunately, the development of the contract market is not always guaranteed as it has been showed in the literature. If the Chilean authority wishes to rely on the contract market to mitigate market power, it must have to be extremely careful in the incentives the regulation provides for the parties to voluntarily contract. Focusing only in the regulation of the contract market is not only insufficient but also myopic. Vesting contracts will expire sooner or later and at that time, it would be the regulation of the whole industry the one that will be key in providing the incentives to contract. A final warning regarding the importance of appropriate regulation and how much it is desirable to rely on the contract market is given by Powell (1993)'s results: the more opportunities producers have to cooperate, the more partial (as opposed to full) hedging results.

8 Conclusions

Currently Chilean authorities are evaluating the desirability of moving one step forward in the de-regulation process; in particular they are analyzing the costs and benefits of implementing an unregulated spot wholesale electricity market system. Concerns have been raised that this step will make it possible for generators to exercise market power due to the high concentration of generation ownership that the industry exhibits, resulting in significantly higher spot market prices. The incentives and ability of Chilean generators would have to exercise market power were analyzed in this paper. In addition, complementary measures that could be implemented to mitigate market power were evaluated.

The analysis was carried out modeling Chile's electricity industry as a Cournot duopoly

[88] Large consumers in Chile are those whose maximum demand is greater than 2 MW. They amount to a negligible fraction of consumers and 50% of total consumption (more than 30% of it is located inside the distribution companies' franchise market and thus are not really free to choose who to contract with).

[89] This is exactly what currently happens in Chile.

(Firms 1 and 2) with a competitive fringe. The model assumes that both producers own thermal plants but only one of them (Firm 1) also owns hydro-storage plants. These plants turned out to be very important because they allowed the producer to store water (and power) and to allocate it over a certain planning horizon at its convenience. This alternative was not available to Firm 2. There are two elements of the model that should be kept in mind when analyzing its results. First of all, results in general, and the magnitude of distortions in particular, depend on the demand elasticity. The approach taken in this paper was to estimate the model assuming different parameters for the demand elasticity. Because of the importance of this parameter in the final result, more rigorous research in this topic is required for the Chilean case. Secondly, the model has no dynamic elements although a power exchange system is clearly a perfect scenario for repeated competition. It is reasonable to think that this omission results in my model underestimating market power.

Quantitative simulations of producers' behavior showed that if an unregulated spot market were implemented in Chile's electricity industry, generators would have the incentive and the ability to exercise market power, raising prices significantly above competitive levels. In particular, Firm 1 would keep its thermal plants outside of the market and would allocate its hydro resources in order to take advantage of differences in price elasticity of demand; this means allocating too little supply to high demand periods and too much to low demand periods (relative to the competitive equilibrium). As a consequence, differences between peak and off peak periods would be enlarged rather than reduced (as it would be the case if the market were competitive). On the other side, Firm 2 would not be able to use its large thermal portfolio to exercise market power most of the time. In fact, when demand is high, Firm 1 has so much market power and can drive prices up by so much that Firm 2's best strategy is to produce at capacity. Firm 2 is able to constrain its production only when demand is low. Results slightly change when hydro flows are reduced, as it is Firm 2 the one who really enjoys and exercises market power.

Conditions for the exercise of market power are more favorable the more inelastic is demand, an expected result. However, since in this case a generator 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 Firm 1 has to exercise market power by shifting hydro production from one period to another. This result applies no matter the length of the planning horizon assumed in the model.

Two sets of policies that mitigate market power by (a) breaking up the largest generating company through divestiture of generating capacity and (b) by imposing fixed price forward supply contracts on varying amounts of the capacity owned by firms with market power were evaluated. Even though both firms would still be able to exercise a certain degree of market power, the divestiture of Firm 1's assets, either thermal or hydro storage plants, would turn the market equilibrium closer to the competitive equilibrium not only in terms of levels (prices and output) but also in terms of the allocation of resources as former Firm 1's plants (either thermal or hydro storage) would be more intensely used and this would more than compensate any reduction in production by the Cournot producers. The different forms of Firm 1's assets divestiture that were analyzed have a similar effect on aggregate welfare but there are big differences in terms of the change at the firm and consumer level. In particular, the more market power Firm 1 is able to exercise, the better off are Firm 2 and the Fringe and the worse off are the consumers. Regulatory authorities must be aware of the distributional effects that may take place as a result of each form of Firm 1's asset divestiture. The market power mitigation role of contracting practices was also analyzed. I found that the more contracted the firms are, the closer is the market outcome to the competitive equilibrium. In addition, there was an interesting effect in terms of hydro scheduling: the more contracted is the firm, the more efficient is the hydro scheduling, meaning that more water is allocated to periods of high demand and less water to periods of low demand.

Firm 1's asset divestiture and contracting practices bring the market equilibrium closer to the competitive equilibrium. However, requiring firms to contract entails less intervention in the industry structure and in the firms' behavior. After vesting contracts expire (if this is the case) firms would be able to decide whom to contract with and at what price. Contracting practices could even be useful to fulfill other objectives of the Chilean reform like transactions between generating companies and distribution companies being more transparent and a reduction of barriers to entry for new and small producers. Depending on the specific features of contracts (frequency, contracted quantity relative to total demand, etc.) they may increase or reduce barriers to entry to the industry. Newbery (1997) argued that contracts in the UK have been the mechanism for entering the industry with no risk. This has turned out to be an effective disciplinary tool as customers may choose to sign long term contracts with an entrant if the incumbent producers charge high prices. In the case of Chile it has been proposed to require distribution companies to openly bid their contracts and to purchase contracts for a quantity enough to satisfy their captive consumers' demand. The open bidding process should take place 2 years ahead of consumption. In this way, new IPPs would be able to participate in the bid and would have enough time to build a new plant. In order to further reduce barriers of entry, it may be desirable to spread bids (in terms of volume traded) over a period of time; in this way small producers would also be able to enter the industry. Finally, unlike the divestiture of Firm 1 assets, that mainly affected Firm 1, requiring producers to sell contracts in the transition period is probably more "fair" in terms of the impact that it has over the two firms, and thus will be probably easier to implement.

Unfortunately, it is not clear whether or not the contract market will develop. Risk averse consumers willing to pay a premium over the expected spot price, strategic behavior by consumers and the role of regulation in the development of the contract market were conceptually analyzed. Regulation of the contract market, such as the imposition of vesting contracts may be helpful in the transition period. However it is not desirable to rely exclusively on it, as vesting contracts will necessarily expire at a certain time. When that happens producers and consumers must face the right incentives in order to voluntarily contract. In addition, since the contract and spot markets are interdependent, their regulations also are. One must be very careful of the effects of any regulation intended to develop or deepen the contract market as this normative may, at the same time, introduce distortions or incentives to manipulate the price in the spot market. It should be kept in mind that the final goal is not the development of the contract market but a competitive spot market and so more importance must be given to the regulation of the whole industry and the incentives producers and consumers have to voluntarily contract: how are final prices determined, is there a price pass through, how many agents are entitled to engage in voluntary contracting practices, is there a mandate to supply power and so on. Clearly more quantitative research is needed on this subject.

Additional measures that may also be implemented to mitigate market power, like the regulatory threat, the interconnection of the SIC system with the SING system and introducing demand side bidding were not analyzed here. Wolfram (1999) emphasized the importance of the regulatory threat. The basic idea is that a regulatory authority with real power to punish companies who exercise market power (or too much market power) provides enough incentive for the firms to behave competitively (or closer to it). The regulatory threat may also be helpful to prevent producers from cooperating in the contract or in the spot market, a desirable result as cooperation results in only partial (as opposed to full) hedging. Wolfram's argument is similar to Green (1999)'s regarding the role of contracting practices as a commitment device. The interconnection of the SIC system with the SING system has been proposed as a way to reduce the dependence the SIC has on its hydro-storage resources. In addition, by increasing the number of firms and the number of large consumers, competition may also be enhanced. Finally, giving large consumers access to the spot market would introduce demand side bidding. As a result, demand would be more price sensitive and the exercise of market power would be more difficult. This paperes result showed that the more elastic is demand the closer is a welfare index to the competitive level. This calls for bigger efforts to increase the number of customers whose consumption decisions are affected by the spot market price.

Before the regulatory authorities decide to deregulate the price and include some sort of control mechanism to prevent market power abuses, there are two issues that I think should be addressed. First of all, any market power mitigation measure that is introduced attempts to control or influence the spot market's price. As more controls are introduced, the spot market looks less like a real market and more like a centralized market subject to a different form of regulation. The point is then why bother in reforming the price system and move towards a system where prices are market-set if at the end the authority wants to introduce additional controls that prevent the price from being really market based? The authority should introduce these control mechanisms not as a way to continue regulating the price but to get the "market-based" price as close to the competitive price as possible. This leads to a second point: if the current pricing system already sets the price at a level that is close to the competitive level, is it really desirable moving forward to a system where prices are completely market based, even though that entails the risk of market power abuses? In order to answer this question, some previous questions should be addressed: is the current regulatory system pricing at levels that are really close to the competitive equilibrium? If yes, what additional benefits would have to de-regulate prices? Some people mention that the system would gain in transparency . Until now critics have come on qualitative grounds but there are no quantitative estimations on how far or close current nodal price is from the competitive price. In order to analyze the convenience of deregulating the system (and implementing any of these measures), a careful welfare analysis of the current regulation must be done. It is clear that more quantitative work is needed before implementing a power exchange system.

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Tables and Figures

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%
Colbun (Firm 3)	370	0	697	697	1067	34.7%	65.3%	16%
Other	102	403	0	403	504	20.1%	79.9%	8%
Total	2622	886	3151	4037	6660	39.0%	61.0%	100%

Source: CDEC-SIC

Table 2: Demand Estimation, April 2000, Elasticity = -1/3

Demand level	# hours	Anchor quantity MW	Anchor price US$/MW	A	B	Elasticity at anchor point
1	120	4749.7	31.1	6332.9	50.9	0.333
2	120	4329.6	31.1	5912.8	50.9	0.366
3	120	4091.1	31.1	5674.3	50.9	0.387
4	120	3643.3	31.1	5226.5	50.9	0.435
5	120	3270.8	31.1	4854.0	50.9	0.484
6	120	2988.5	31.1	4571.7	50.9	0.530

Table 3: Data to calculate residual demand (MW), Base Model

Demand level	Hydro peak shaving	Thermal must run generation	Hydro ROR Must run generation	Total
1	274.6	14.2	380.3	669.1
2	183.8	14.2	380.3	578.2
3	183.8	14.2	380.3	578.2
4	183.8	14.2	380.3	578.2
5	183.8	14.2	380.3	578.2
6	183.8	14.2	380.3	578.2

Table 4: Hydro Data used to estimate the Base Model

Firm	q^h_{min} (MW)	q^h_{max} (MW)	$q^{\sim h}$ (GWh month)
Firm 1	743.7	2436.1	974.9
Fringe	183.8	489.2	143.2

Table 5: Base Model, Competitive results (E= -1/3)

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	Qtot	Price
1	673.1	944.4	1617.5	2133.1	0.0	2133.1	3750.6	420.5	4839.0	29.4
2	673.1	944.4	1617.5	1802.6	0.0	1802.6	3420.1	420.5	4418.9	29.4
3	673.1	944.4	1617.5	1564.1	0.0	1564.1	3181.6	420.5	4180.4	29.4
4	673.1	944.4	1617.5	1116.3	0.0	1116.3	2733.8	420.5	3732.6	29.4
5	673.1	944.4	1617.5	764.7	0.0	764.7	2382.2	420.1	3380.5	28.9
6	566.2	944.4	1510.6	743.7	0.0	743.7	2254.4	416.6	3249.3	26.0

Table 6: Base Model, Competitive results (E= -2/3)

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	Qtot	Price
1	673.1	944.4	1617.5	2133.1	0.0	2133.1	3750.6	421.5	4840.0	30.2
2	673.1	944.4	1617.5	1802.6	0.0	1802.6	3420.1	421.5	4419.9	30.2
3	673.1	944.4	1617.5	1564.1	0.0	1564.1	3181.6	421.5	4181.4	30.2
4	673.1	944.4	1617.5	1116.3	0.0	1116.3	2733.8	421.5	3733.6	30.2
5	673.1	944.4	1617.5	764.7	0.0	764.7	2382.2	421.3	3381.7	30.0
6	673.1	944.4	1617.5	743.7	0.0	743.7	2361.2	418.4	3357.8	27.5

Table 7: Base Model, Cournot Equilibrium (E=-1/3)

t	qth1 #	qth2	QRth	qh1 #	qh2	QRh	QR	Qthfringe	Qtot	Price
1	133.7	944.4	1078.1	1743.0	0.0	1743.0	2821.3	441.2	3931.3	47.2
2	140.1	944.4	1084.5	1572.0	0.0	1572.0	2656.5	437.5	3672.3	44.0
3	120.3	944.4	1064.7	1472.6	0.0	1472.6	2537.3	434.9	3550.4	41.7
4	122.0	944.4	1066.4	1247.0	0.0	1247.0	2313.4	429.9	3321.5	37.4
5	127.0	867.7	994.7	1094.1	0.0	1094.1	2088.7	426.6	3093.6	34.6
6	131.9	773.6	905.4	995.1	0.0	995.1	1900.6	424.5	2903.3	32.8

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

Table 8: Base Model, Cournot Equilibrium (E=-2/3)

t	qth1#	qth2	QRth	qh1#	qh2	QRh	QR	Qthfringe	Qtot	Price
1	377.7	944.4	1322.1	1768.1	0.0	1768.1	3090.2	429.0	4188.3	36.6
2	376.0	944.4	1320.4	1605.2	0.0	1605.2	2925.6	427.1	3930.9	35.0
3	378.3	944.4	1322.7	1483.6	0.0	1483.6	2806.3	425.8	3810.3	33.9
4	375.8	944.4	1320.2	1262.2	0.0	1262.2	2582.4	423.2	3583.9	31.7
5	379.6	944.4	1324.0	1072.2	0.0	1072.2	2396.2	421.1	3395.6	29.9
6	378.2	944.4	1322.5	932.5	0.0	932.5	2255.0	419.6	3252.8	28.5

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

Table 9: Lerner Indices, Base Model

	E = -1/3		E= -2/3	
T	Firm 1	Firm 2	Firm 1	Firm 2
1	76%	38%	57%	25%
2	75%	41%	55%	26%
3	73%	43%	53%	27%
4	70%	48%	50%	29%
5	68%	48%	47%	31%
6	66%	45%	45%	32%

Table 10: Welfare Analysis
Index (Perfect Competition = 100)

Elasticity	Firm 1's Producer surplus	Firm 2's Producer surplus	Fringe's Producer surplus	Producer surplus	Consumer surplus	Welfare
E = -0.1	242.7	586.0	352.6	319.1	64.0	94.6
E= -1/3	124.0	178.9	145.8	138.3	73.3	95.9
E= -1/2	112.4	131.8	118.5	117.0	82.7	98.1
E= -2/3	107.3	120.6	111.7	110.6	84.9	98.4
E= -1.0	104.0	109.8	105.7	105.4	88.4	99.1

Table 11: Data to calculate residual demand (MW). Model with reduced hydro flows

Demand level	Hydro peak shaving	Thermal must run generation	Hydro ROR Must run generation	Total
1	119.3	14.2	228.2	361.7
2	119.3	14.2	228.2	361.7
3	119.3	14.2	228.2	361.7
4	119.3	14.2	228.2	361.7
5	119.3	14.2	228.2	361.7
6	119.3	14.2	228.2	361.7

Table 12: Competitive results with reduced hydro flows (E= -1/3)

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	Qtot	Price
1	779.2	992.9	1772.1	833.4	0.0	833.4	2605.5	572.6	3420.4	57.6
2	673.1	992.9	1666.0	808.2	0.0	808.2	2474.2	566.0	3282.6	51.9
3	673.1	992.9	1666.0	808.2	0.0	808.2	2474.2	560.6	3277.2	47.2
4	673.1	944.4	1617.5	808.2	0.0	808.2	2425.7	551.5	3219.6	39.4
5	673.1	944.4	1617.5	808.2	0.0	808.2	2425.7	543.3	3211.3	32.3
6	673.1	944.4	1617.5	808.2	0.0	808.2	2425.7	537.0	3205.0	26.9

Table 13: Cournot Equilibrium with reduced hydro flows (E=-1/3)

t	qth1#	qth2	QRth	qh1 #	qh2	QRh	QR	Qthfringe	Qtot	Price
1	614.3	944.4	1558.7	1029.6	0.0	1029.6	2588.3	453.2	3403.2	57.6
2	607.0	944.4	1551.4	826.8	0.0	826.8	2378.2	448.6	3188.4	53.5
3	527.4	944.4	1471.8	787.1	0.0	787.1	2258.9	445.9	3066.5	51.2
4	454.6	944.4	1399.0	743.6	0.0	743.6	2142.6	438.5	2942.8	44.9
5	426.4	944.4	1370.8	743.6	0.0	743.6	2114.4	430.9	2906.9	38.3
6	341.7	902.7	1244.4	743.6	0.0	743.6	1988.0	427.4	2777.1	35.3

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

Table 14: Welfare Analysis, Model with reduced hydro flows Index (Perfect Competition = 100)

Elasticity	Firm 1's Producer surplus	Firm 2's Producer surplus	Fringe's Producer surplus	Producer surplus	Consumer surplus	Welfare
E = -0.1	123.4	147.9	144.6	135.3	77.7	96.7
E= -1/3	107.6	115.4	109.7	110.0	87.1	98.7
E= -1/2	103.7	107.4	103.1	104.4	92.2	99.3
E= -2/3	102.5	105.3	101.4	102.8	93.3	99.4
E= -1.0	101.4	103.2	99.9	101.4	94.5	99.4

Table 15: Demand Indicators

	Total demand (GWh)	Demand - q^{MR} (GWh) *	Inflows (GWh)	Inflows / (demand – q^{MR})	Average Net demand per day (GWh)	Max demand / Min demand	Average Elasticity / Residual Ddand
January	2733.43	2293.80	1058.98	46%	74.0	2.20	0.49
February	2520.23	2139.77	996.86	47%	76.4	1.90	0.47
March	2911.54	2532.46	1333.09	53%	81.7	1.85	0.51
April	2768.74	2484.73	1118.05	45%	82.8	2.00	0.48
May	2885.11	2587.79	1294.28	50%	83.5	1.69	0.45
June	2794.75	2466.61	1561.06	63%	82.2	1.82	0.50
July	2820.53	2487.82	1475.91	59%	80.3	1.79	0.49
August	2799.88	2478.86	1384.18	56%	80.0	1.75	0.49
September	2649.14	2307.95	1262.55	55%	76.9	1.94	0.48
October	2770.69	2399.68	1478.88	62%	77.4	1.93	0.40
November	2751.61	2328.93	1385.07	59%	77.6	1.90	0.40
December	2859.66	2410.97	1279.78	53%	77.8	1.98	0.40

* q^{MR} includes production from must run thermal plants and hydro production from ROR plants.

Table 16: Marginal Value of Water (MVW)

	E = -0.1	E = -1/3	E= - 0.5	E = -2/3	E = -1.0
January	0.00	11.13	11.13	13.91	17.90
February	0.00	11.13	11.13	13.54	17.75
March	0.00	10.62	11.13	13.36	17.75
April	0.00	11.13	11.89	15.78	19.85
May	0.00	9.53	11.13	12.78	17.29
June	0.00	0.00	7.78	11.13	14.21
July	0.00	1.92	10.08	11.13	15.41
August	0.00	6.45	11.13	11.13	15.78
September	0.00	8.47	11.13	11.98	17.03
October	0.00	0.00	9.82	11.13	15.78
November	0.00	2.21	11.13	11.13	17.01
December	0.00	9.88	11.13	14.61	20.28

Table 17: Marginal Value of Water under different price elasticity assumptions.

	MVW				Average Elasticity of residual demand				St dev intra-month elasticity				Inflows/ net demand		
	(1)	(2)	(3)	(4)	(1)	(2)	(3)	(4)	(1)	(2)	(3)	(4)	(1)	(2)	(3)
Jan	11.13	10.08	0.00	0.00	0.49	0.49	0.15	0.15	0.10	0.0	0.03	0.0	46%	110%	46%
Feb	11.13	9.33	17.75	17.25	0.47	0.47	1.36	1.36	0.08	0.0	0.23	0.0	47%	25%	47%
Mar	10.62	8.88	0.00	0.00	0.51	0.51	0.15	0.15	0.08	0.0	0.03	0.0	53%	131%	53%
Apr	11.13	11.13	15.78	15.45	0.48	0.48	0.94	0.94	0.10	0.0	0.19	0.0	45%	35%	45%
May	9.53	7.85	9.53	7.85	0.45	0.45	0.45	0.45	0.06	0.0	0.06	0.0	50%	63%	50%
Jun	0.00	0.00	0.00	0.00	0.50	0.50	0.50	0.50	0.09	0.0	0.09	0.0	63%	84%	63%
Jul	1.92	1.14	1.92	1.14	0.49	0.49	0.49	0.49	0.08	0.0	0.08	0.0	59%	81%	59%
Aug	6.45	5.32	11.13	11.13	0.49	0.49	0.73	0.73	0.09	0.0	0.13	0.0	56%	60%	56%
Sep	8.47	7.02	11.98	11.13	0.48	0.48	0.92	0.92	0.09	0.0	0.16	0.0	55%	45%	55%
Oct	0.00	0.00	11.13	11.13	0.40	0.40	0.72	0.72	0.06	0.0	0.11	0.0	62%	50%	62%
Nov	2.21	1.08	17.01	16.62	0.40	0.40	1.00	1.00	0.06	0.0	0.12	0.0	59%	35%	59%
Dec	9.88	7.90	14.61	14.02	0.40	0.40	0.72	0.72	0.06	0.0	0.09	0.0	53%	44%	53%
Average	6.87	5.81	9.24	8.81	0.46	0.46	0.68	0.68	0.08	0.0	0.11	0.0			
stdev	4.55	4.16	6.93	6.83	0.04	0.04	0.35	0.35	0.02		0.06				
Corr MVW					0.24	0.27	0.88	0.89	0.26		0.77		-0.93		-0.22

Table 18:
Installed capacity in the SIC after full divestiture of Firm 1's thermal plants (MW)

Economic Group	Thermal	Hydro-reservoir	Total
Triopoly			
Endesa (Firm 1)	0	2454	2454
Gener (Firm 2)	1212	0	1212
Firm 3	939	0	939
Fringe	472	697	1169
DLTF			
Endesa (Firm 1)	0	2454	2454
Gener (Firm 2)	1212	0	1212
Fringe	1411	697	2108
Total	2622	3151	5773

Hydro-ROR not included in the table.

Table 19: Divestiture of Firm 1's thermal plants - Triopoly (E=-1/3)

t	qth1	qth2	qth3	QRth	qh1	qh2	QRh	QR	QTh Fringe	Qtot	Price	Ex-Firm 1's thermal
1	0.0	944.4	673.1	1617.5	1620.8	0.0	1620.8	3238.3	431.9	4339.3	39.2	673.1
2	0.0	944.4	572.2	1516.6	1506.6	0.0	1506.6	3023.2	429.4	4030.8	37.0	572.2
3	0.0	920.5	500.7	1421.2	1435.1	0.0	1435.1	2856.3	427.8	3862.3	35.6	500.7
4	0.0	786.6	454.6	1241.2	1301.2	0.0	1301.2	2542.4	424.8	3545.4	33.0	454.6
5	0.0	662.4	454.6	1117.0	1177.0	0.0	1177.0	2294.0	422.0	3294.3	30.6	454.6
6	0.0	568.3	454.6	1022.9	1083.0	0.0	1083.0	2105.8	419.9	3104.0	28.8	454.6

Table 20: Divestiture of Firm 1's thermal plants - DLTF (E=-1/3)

t	qth1	qth2	qth3	QRth	qh1	qh2	QRh	QR	QTh Fringe	Qtot	Price	Ex-Firm 1's thermal
1	0.0	944.4	na	944.4	1712.0	0.0	1712.0	2656.4	1026.3	4351.7	38.9	673.1
2	0.0	944.4	na	944.4	1547.3	0.0	1547.3	2491.7	998.5	4068.5	36.2	673.1
3	0.0 602	944.4 637.03	na	944.4	1428.1	0.0	1428.1	2372.5	978.4	3929.1	34.3	673.1
4	0.0	833.5	na	833.5	1259.6	0.0	1259.6					

Table 25: Lerner Indices

t	Base model Firm 1	Base model Firm 2	DMHF Model Firm 1	DMHF Model Firm 2	DLHF model Firm 1	DLHF model Firm 2
1	76.4%	38.4%	60.2%	45.7%	25.3%	48.5%
2	74.7%	41.2%	55.9%	49.9%	25.3%	48.5%
3	73.3%	43.5%	54.6%	48.5%	25.3%	48.5%
4	70.3%	48.5%	54.5%	48.3%	25.3%	48.5%
5	67.8%	48.2%	54.4%	48.3%	25.2%	48.2%
6	66.0%	45.3%	52.3%	45.8%	27.2%	44.2%

Table 26
Effect of Firm 1's hydro plants divestiture on total profits (E=-1/3)
Index (Base Model = 100)

Model	Firm 1	Firm 2	Fringe	Firm 1 adjusted *
Base	100.0	100.0	100.0	100.0
DLHF	17.1	73.3	215.1	96.7
DMHF	54.9	80.1	158.6	98.0
Perfect Competition	80.7	55.9	68.6	80.7

* Firm 1's profits + Profits the fringe gets from former Firm 1's hydro plants.

Table 27: Partial Divestiture of hydro plants: DMHF model (E=-1/3)

t	qth1#	qth2	QRth	qh1 #	qh2	QRh	QR	Qthfringe	Qtot	Price
1	385.7	944.4	1330.1	859.0	0	859.0	2189.1	432.5	4312.8	39.7
2	380.2	930.3	1310.5	661.5	0	661.5	1972.0	428.0	4091.2	35.8
3	369.5	877.8	1247.3	619.7	0	619.7	1867.0	426.8	3904.0	34.8
4	371.1	871.8	1242.9	612.1	0	612.1	1855.0	426.7	3462.1	34.7
5	367.7	869.7	1237.5	613.5	0	613.5	1850.9	426.7	3091.6	34.6
6	343.8	789.1	1132.9	556.7	0	556.7	1689.6	424.9	2888.1	33.1

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

Table 28: Welfare analysis
(Index, Base Case = 100)

Model	Firm 1*	Firm 2	Fringe **	Producer Surplus	Consumer Surplus	Welfare
Base	100.0	100.0	100.0	100.0	100.0	100.0
Triopoly	79.7 (97.8)	70.8	113.8 (84.0)	88.5	117.7	103.0
DLTF	77.8 (96.6)	68.9	108.1 (77.4)	85.5	120.7	103.0
DLHF	17.1 (96.7)	73.3	215.1 (84.5)	88.5	118.1	103.3
DMHF	54.9 (98.0)	80.1	158.6 (87.9)	91.5	114.0	102.7
Perf. Competition	100.0	55.9	68.6	72.3	136.5	104.3

*In parenthesis Firm 1's profits + profits from former Firm 1's plants. ** In parenthesis profits earned by the former fringe (i.e. *without* including former Firm 1's plants)

Table 29: Cournot Equilibrium, Contracting level = 0% (E=-1/3)

t	K1	K2	qth1#	qth2	QRth	qh1 #	qh2	QRh	QR	Qthfringe	Qtot	Price
1	0	0	133.7	944.4	1078.1	1743.0	0.0	1743.0	2821.3	441.2	3931.3	47.2
2	0	0	140.1	944.4	1084.5	1572.0	0.0	1572.0	2656.5	437.5	3672.3	44.0
3	0	0	120.3	944.4	1064.7	1472.6	0.0	1472.6	2537.3	434.9	3550.4	41.7
4	0	0	122.0	944.4	1066.4	1247.0	0.0	1247.0	2313.4	429.9	3321.5	37.4
5	0	0	127.0	867.7	994.7	1094.1	0.0	1094.1	2088.7	426.6	3093.6	34.6
6	0	0	131.9	773.6	905.4	995.1	0.0	995.1	1900.6	424.5	2903.3	32.8

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

Table 30: Cournot Equilibrium, Contracting level =50% (E=-1/3)

t	K1	K2	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	Qtot	Price
1	1403.1	472.2	454.6	944.4	1399.0	1967.6	0.0	1967.6	3366.5	429.1	4464.4	36.7
2	1237.8	472.2	454.6	944.4	1399.0	1720.1	0.0	1720.1	3119.1	427.2	4124.6	35.1
3	1118.6	472.2	454.6	944.4	1399.0	1541.3	0.0	1541.3	2940.2	425.9	3944.4	34.0
4	894.7	472.2	454.6	944.4	1399.0	1205.4	0.0	1205.4	2604.4	423.4	3606.1	31.8
5	718.9	472.2	454.6	944.4	1399.0	931.3	0.0	931.3	2330.2	421.2	3329.7	29.9
6	655.0	472.2	454.6	944.4	1399.0	758.2	0.0	758.2	2157.1	418.8	3154.2	27.8

Table 31: Cournot Equilibrium, Contracting level =100% (E=-1/3)

t	K1	K2	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	Qtot	Price
1	2806.2	944.4	673.1	944.4	1617.5	2134.7	0.0	2134.7	3752.2	420.5	4841.4	29.3
2	2475.7	944.4	673.1	944.4	1617.5	1804.6	0.0	1804.6	3422.1	420.5	4420.9	29.3
3	2237.2	944.4	673.1	944.4	1617.5	1566.2	0.0	1566.2	3183.6	420.5	4182.4	29.3
4	1789.4	944.4	673.1	944.4	1617.5	1118.4	0.0	1118.4	2735.8	420.5	3734.6	29.3
5	1437.8	944.4	673.1	944.4	1617.5	756.3	0.0	756.3	2373.8	420.3	3372.3	29.1
6	1310.0	944.4	566.4	944.4	1510.8	743.6	0.0	743.6	2254.4	416.6	3249.2	26.0

Table 32: Marginal Value of water (Ω_1)

	Contracting Level		
T	0%	50%	100%
1	11.13	17.13	29.27
2	11.13	17.13	29.27
3	11.13	17.13	29.27
4	11.13	17.13	29.27
5	11.13	17.13	29.27
6	11.13	17.13	25.98

Table 33: Lerner Indices

	Contracting = 0%		Contracting = 50%		Contracting = 100%	
t	Firm 1	Firm 2	Firm 1	Firm 2	Firm 1	Firm 2
1	76.4%	38.4%	53.3%	24.7%	0%	0%
2	74.7%	41.2%	51.2%	25.8%	0%	0%
3	73.3%	43.5%	49.6%	26.7%	0%	0%
4	70.3%	48.5%	46.2%	28.5%	0%	0%
5	67.8%	48.2%	42.8%	30.3%	-1%	0%
6	66.0%	45.3%	38.5%	32.6%	0%	0%

Figures

Figure 1

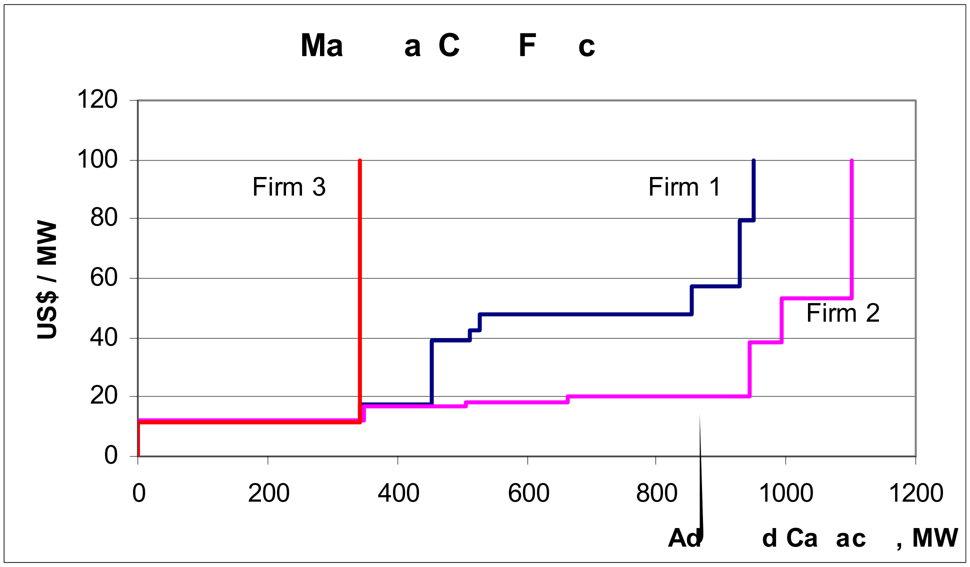


Figure 2

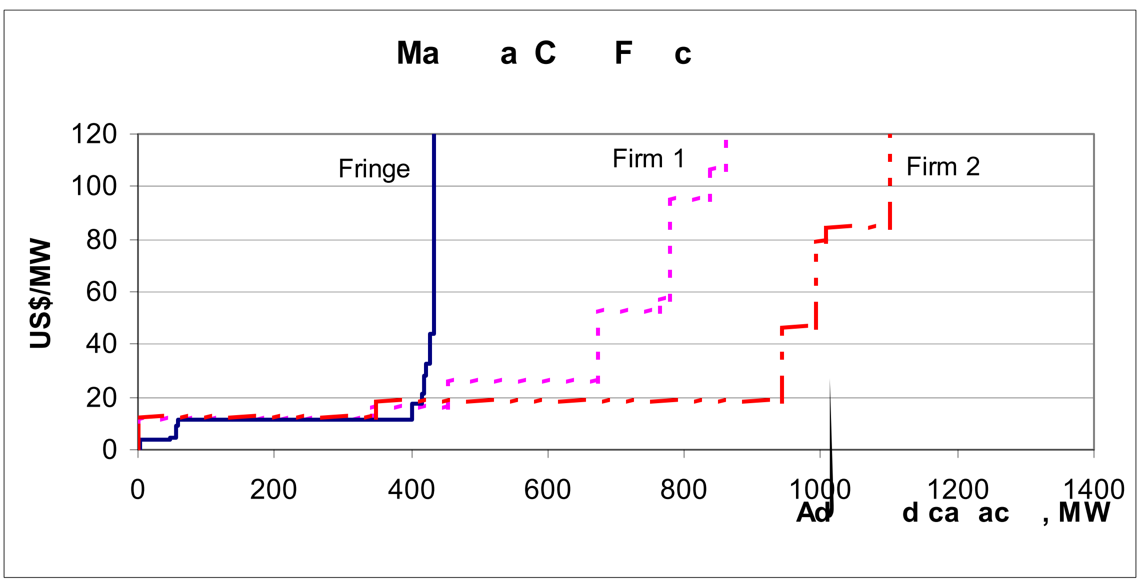


Figure 3

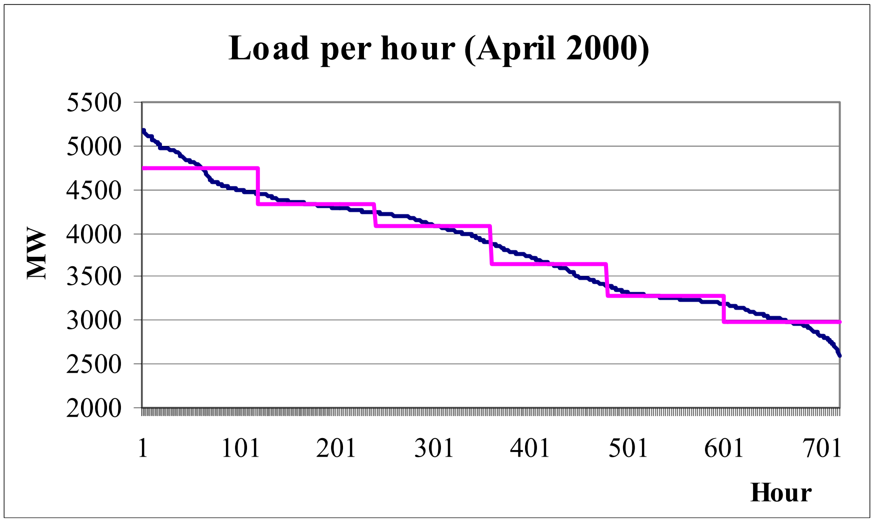


Figure 4

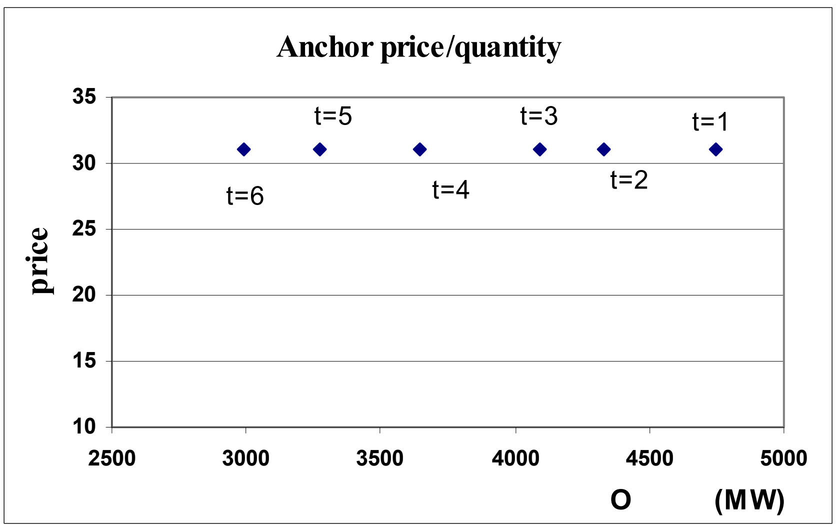


Figure 5

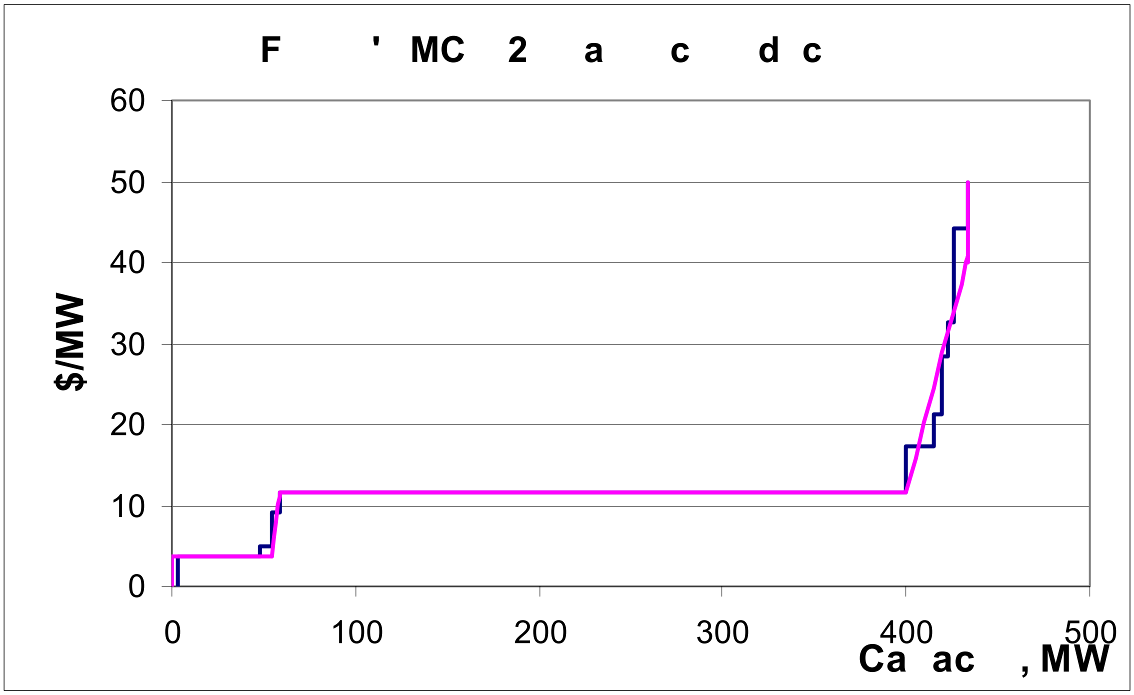


Figure 6

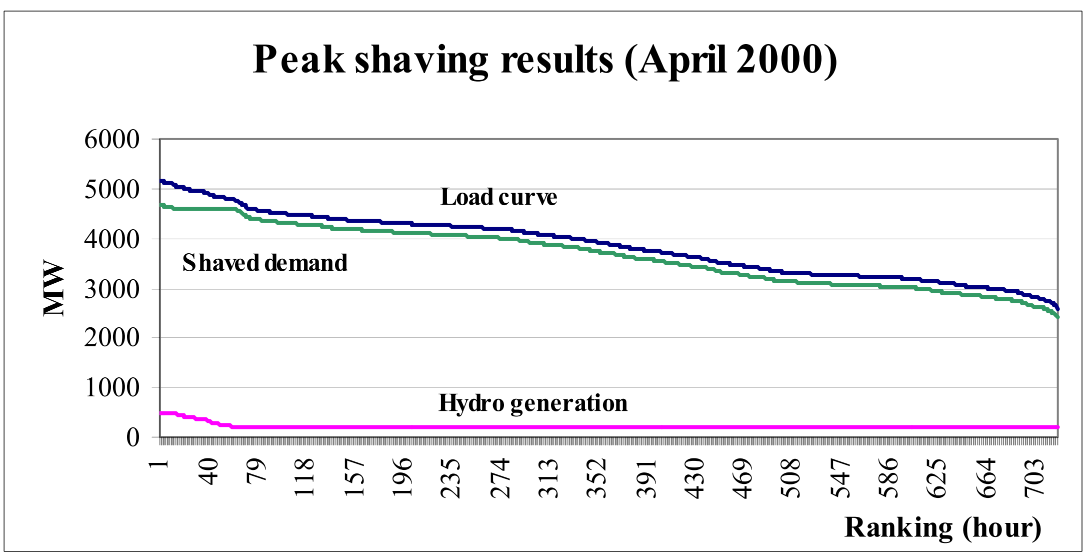


Figure 9

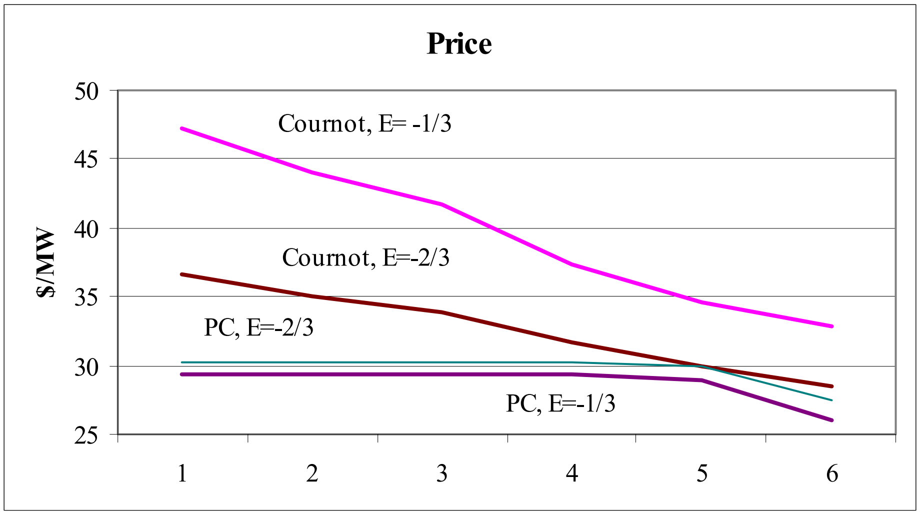


Figure 10

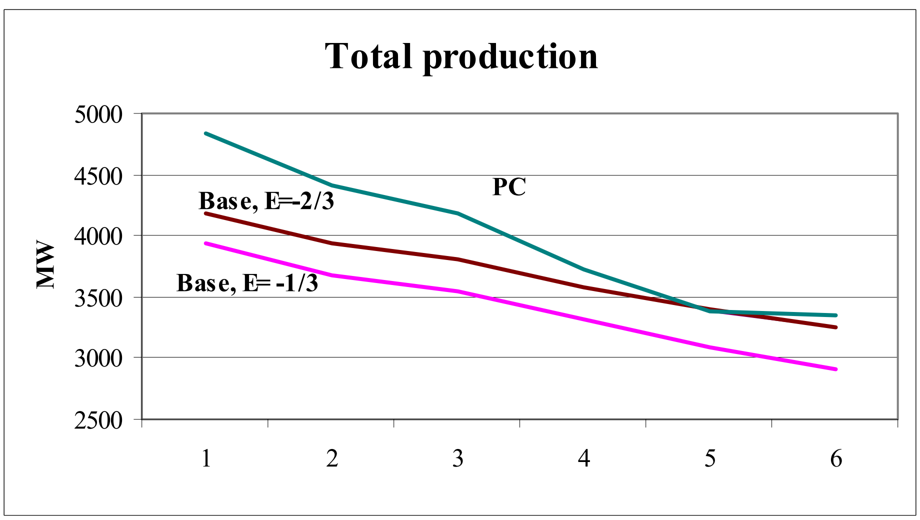


Figure 11

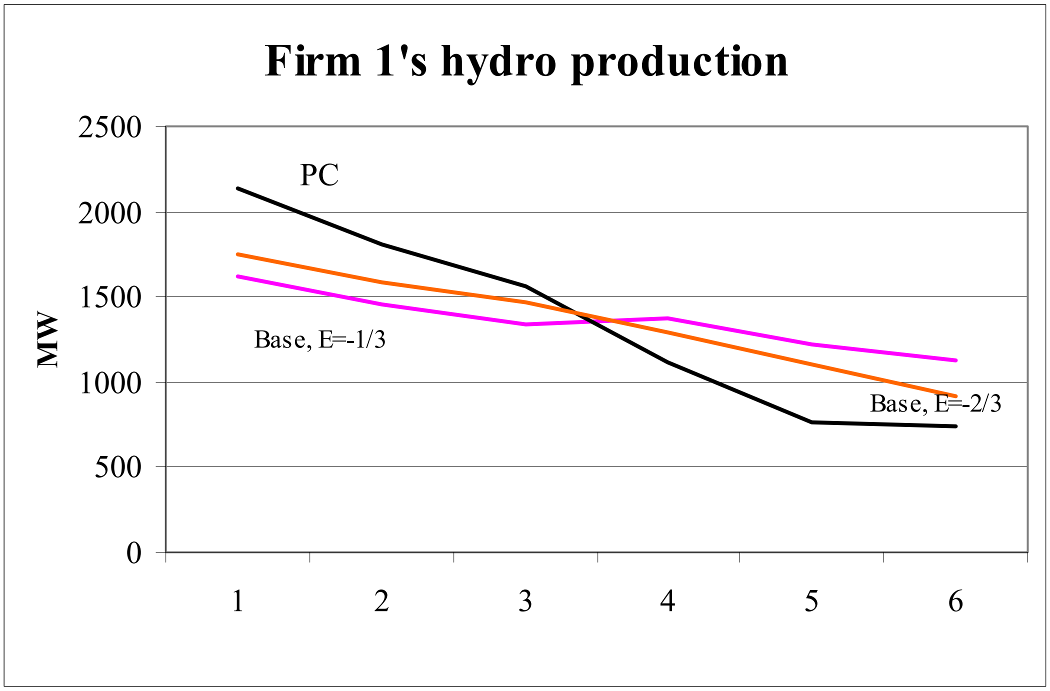


Figure 12

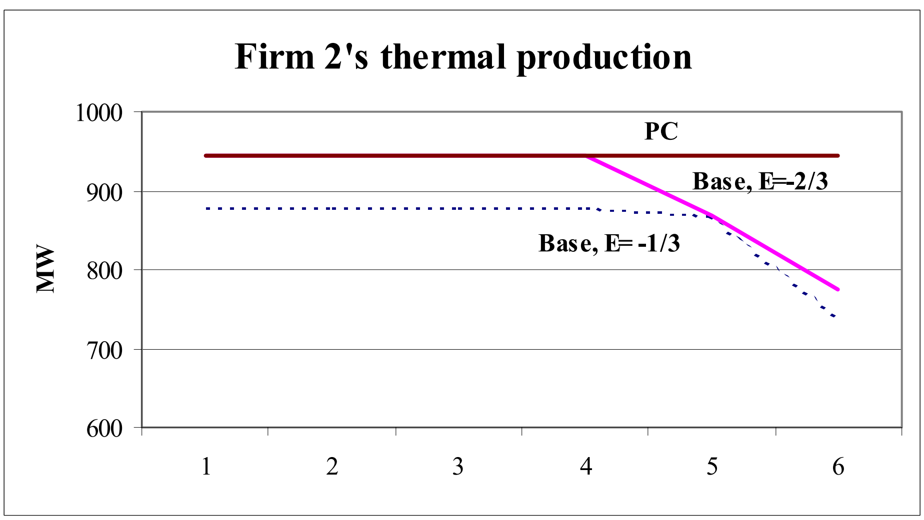


Figure 13

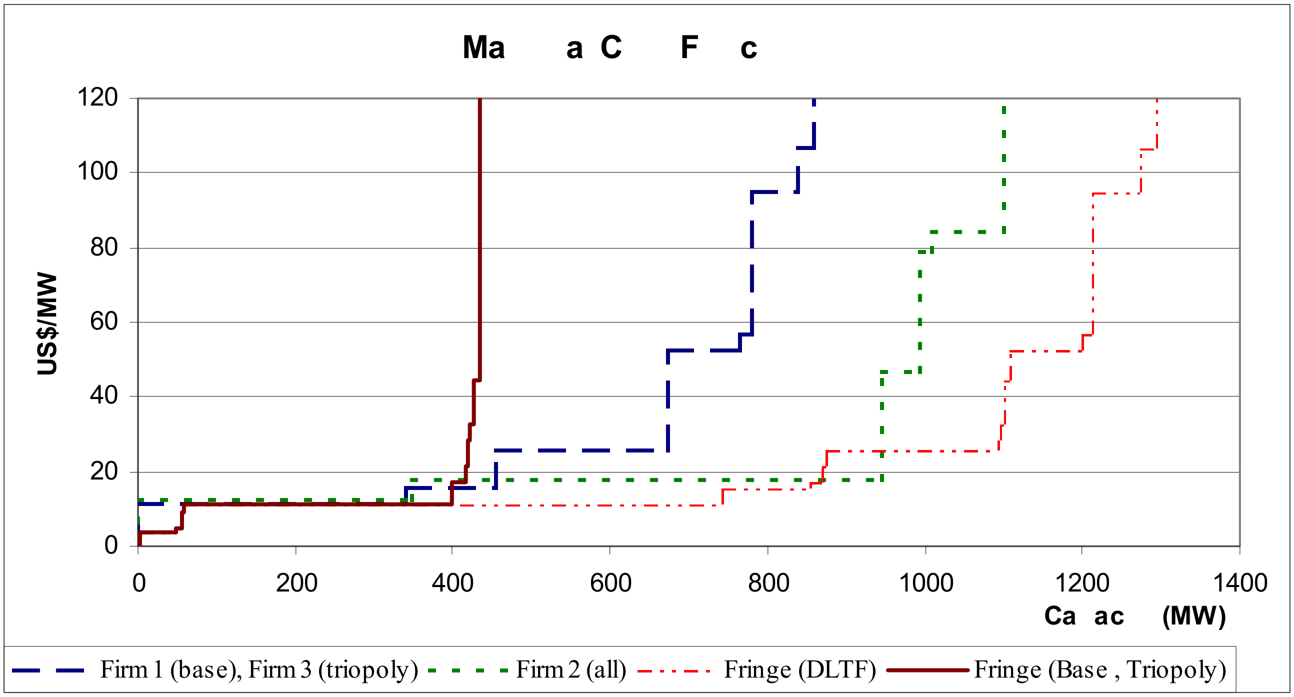


Figure 14

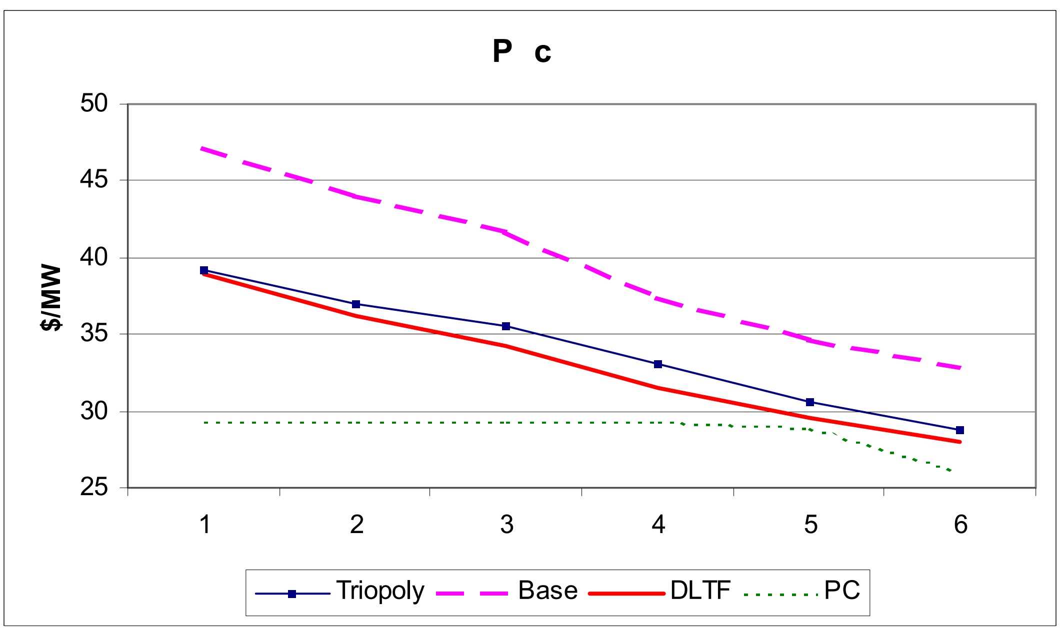


Figure 15

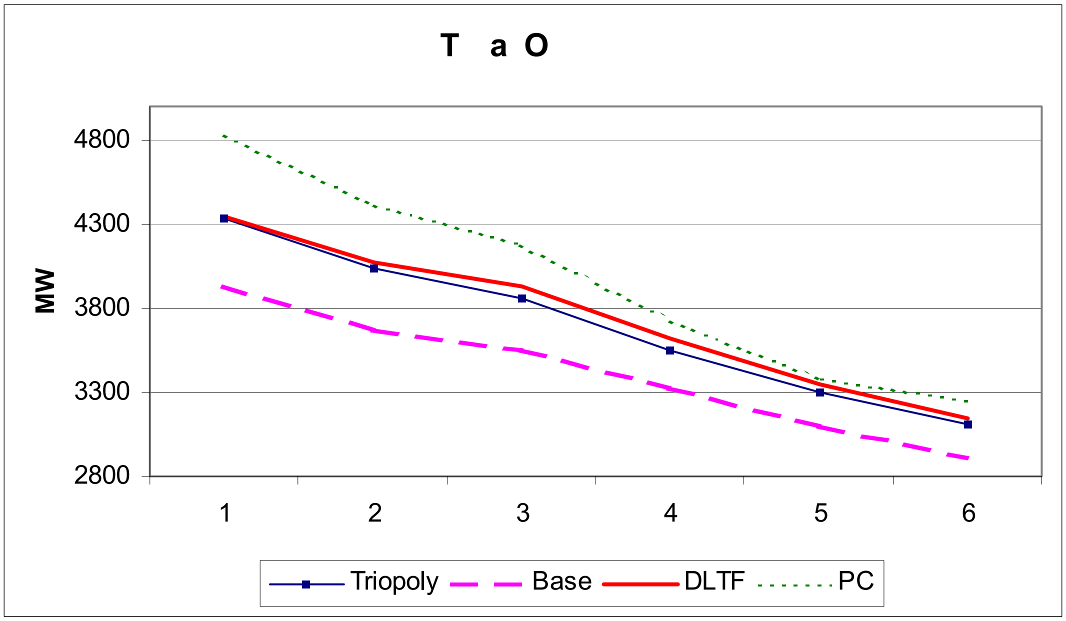


Figure 16

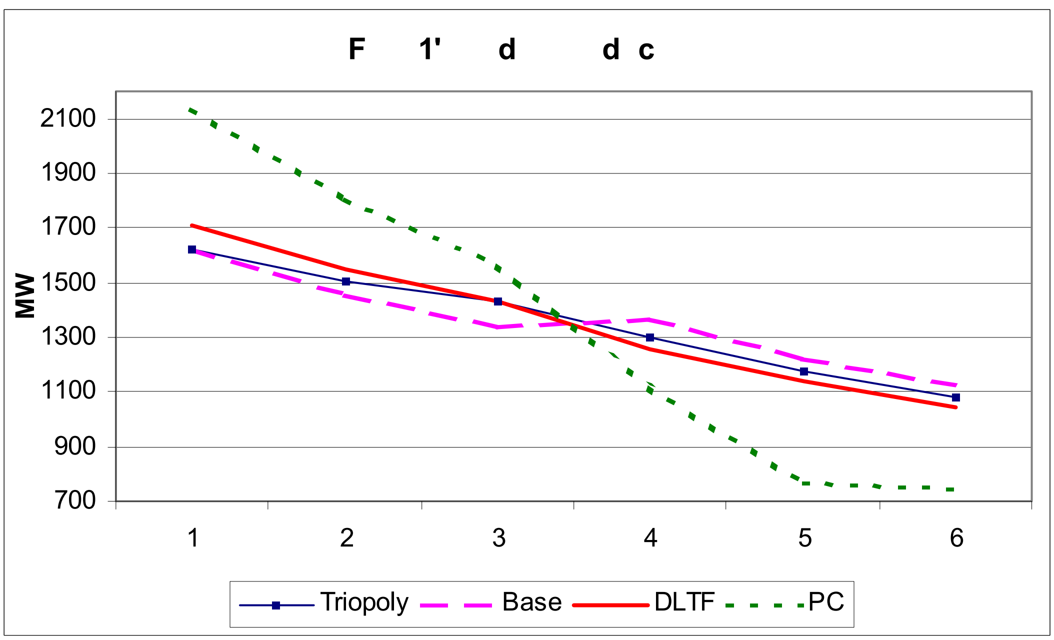


Figure 17

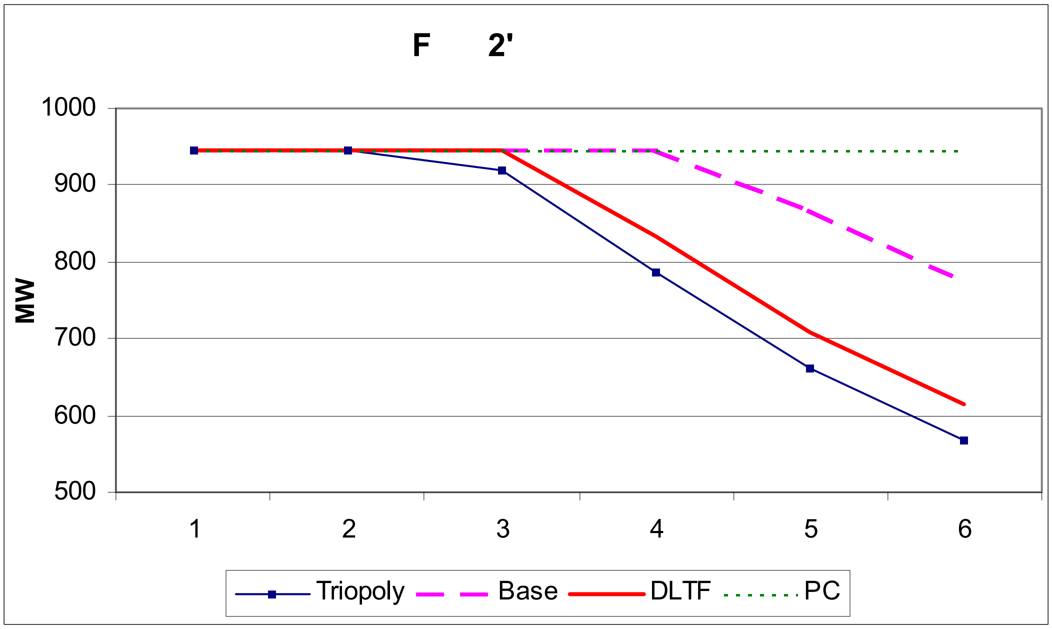


Figure 18

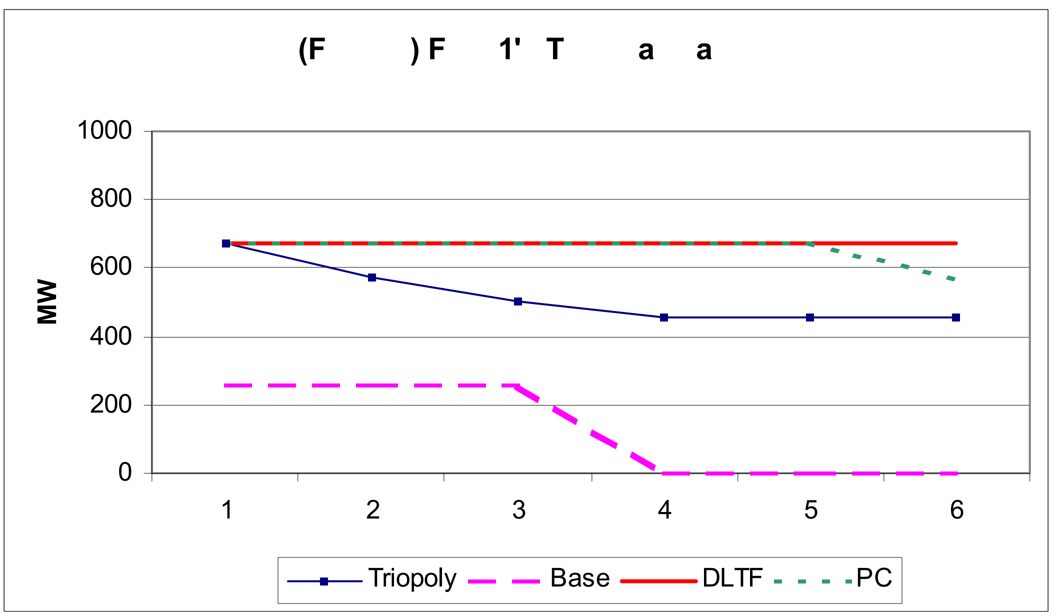


Figure 19

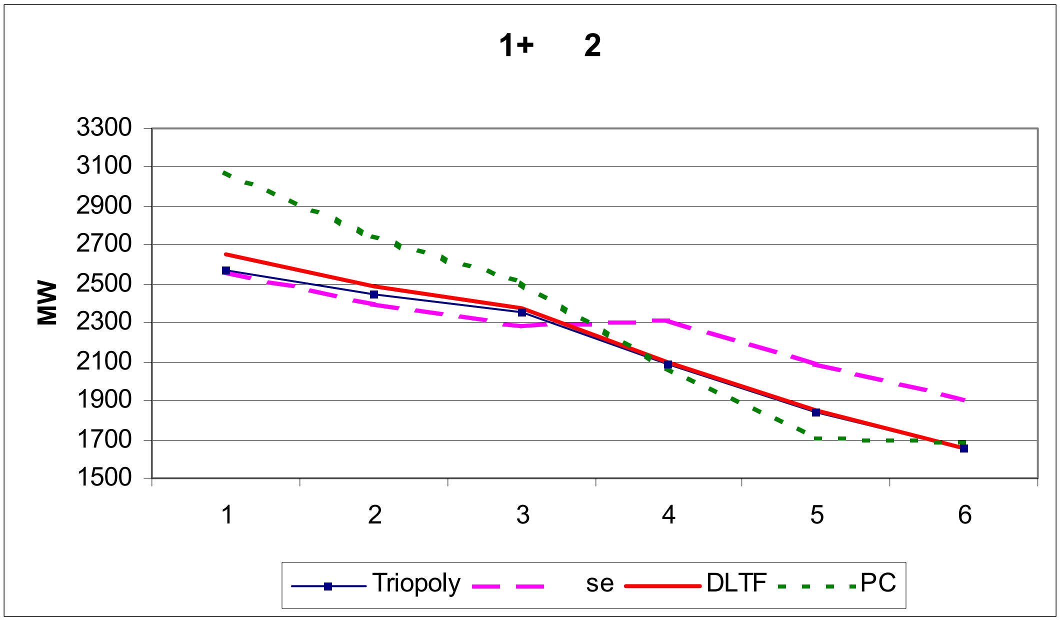


Figure 20

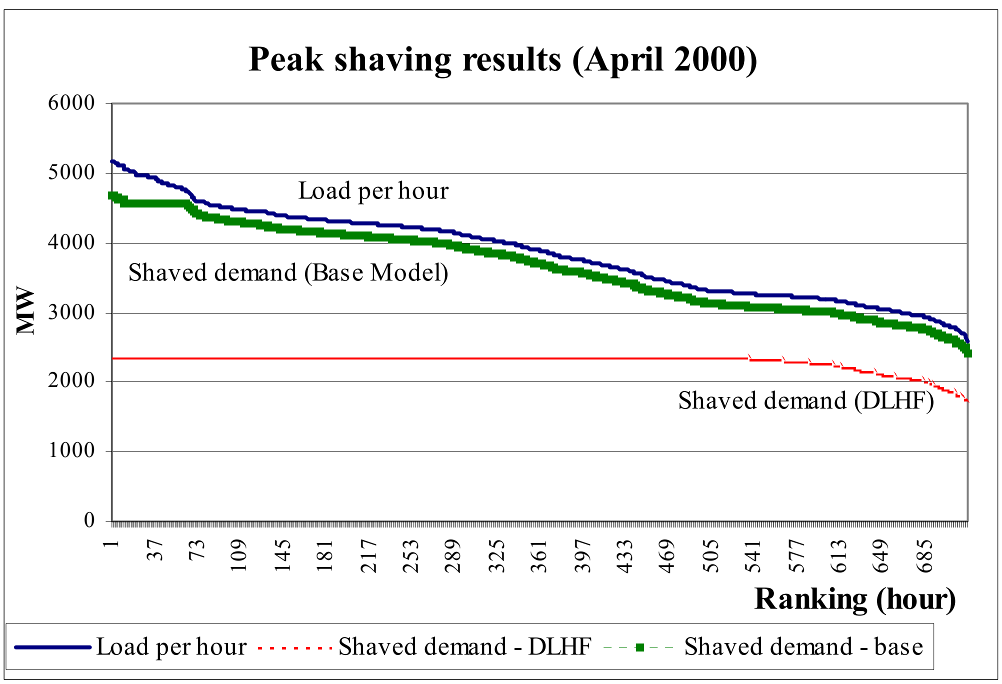


Figure 21

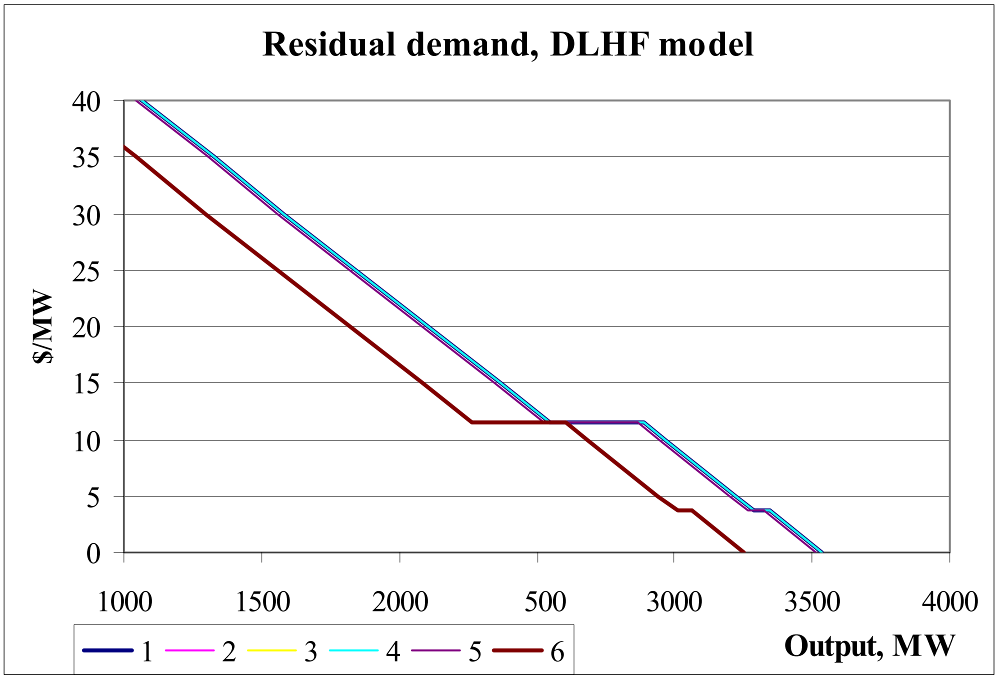


Figure 22

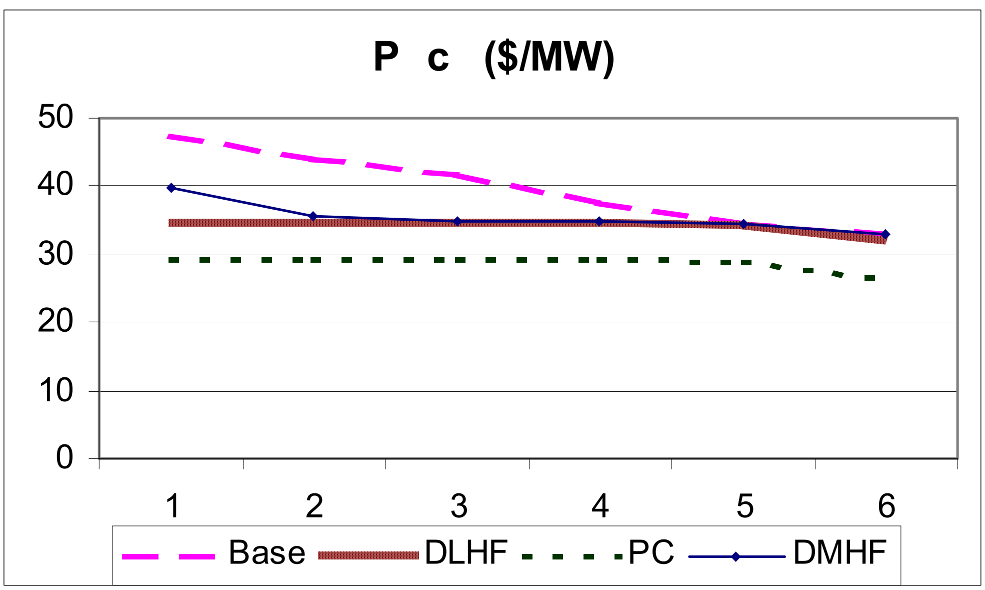


Figure 23

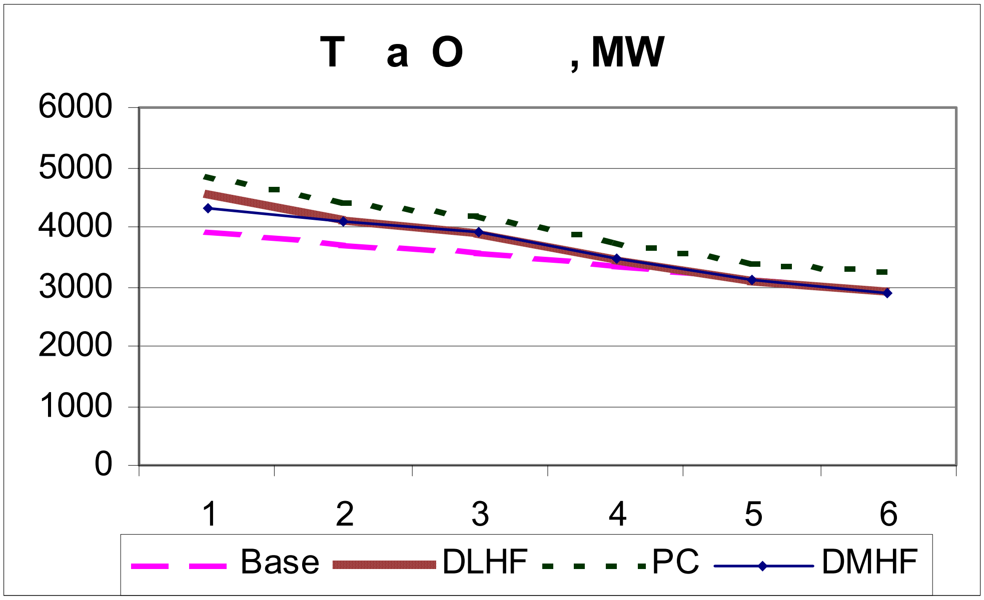


Figure 24

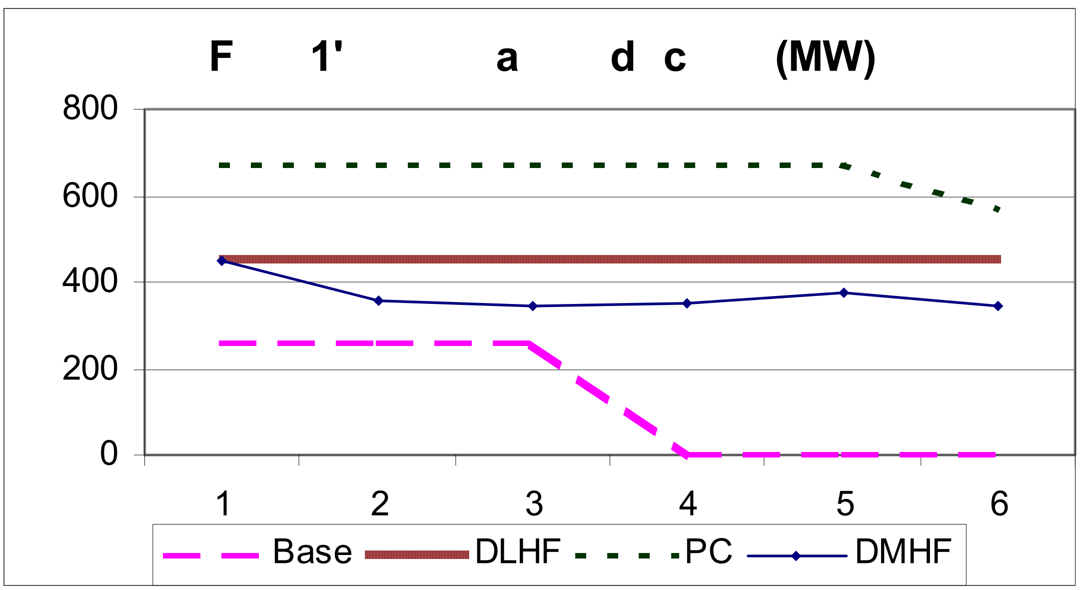


Figure 25

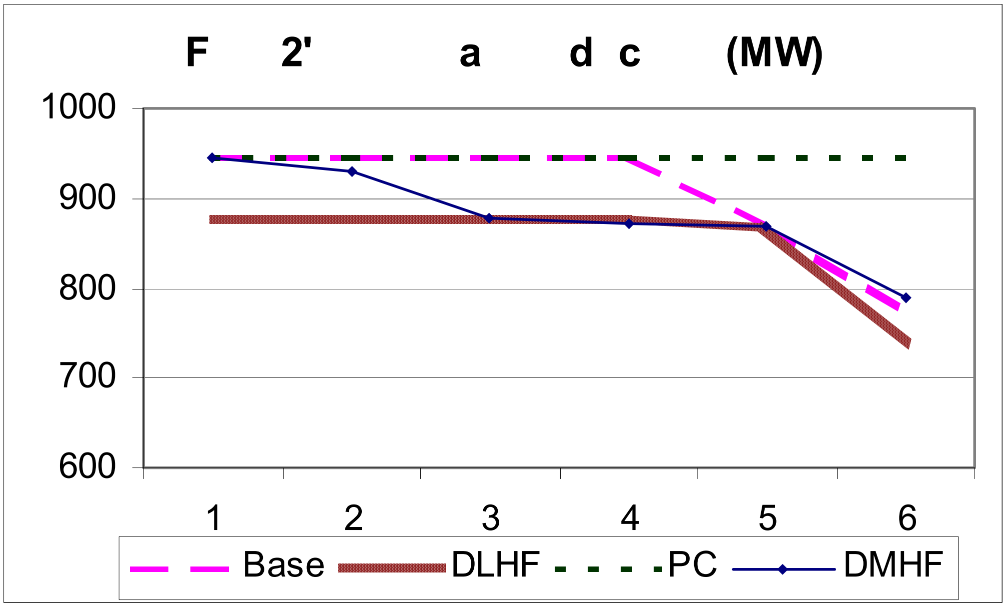


Figure 26

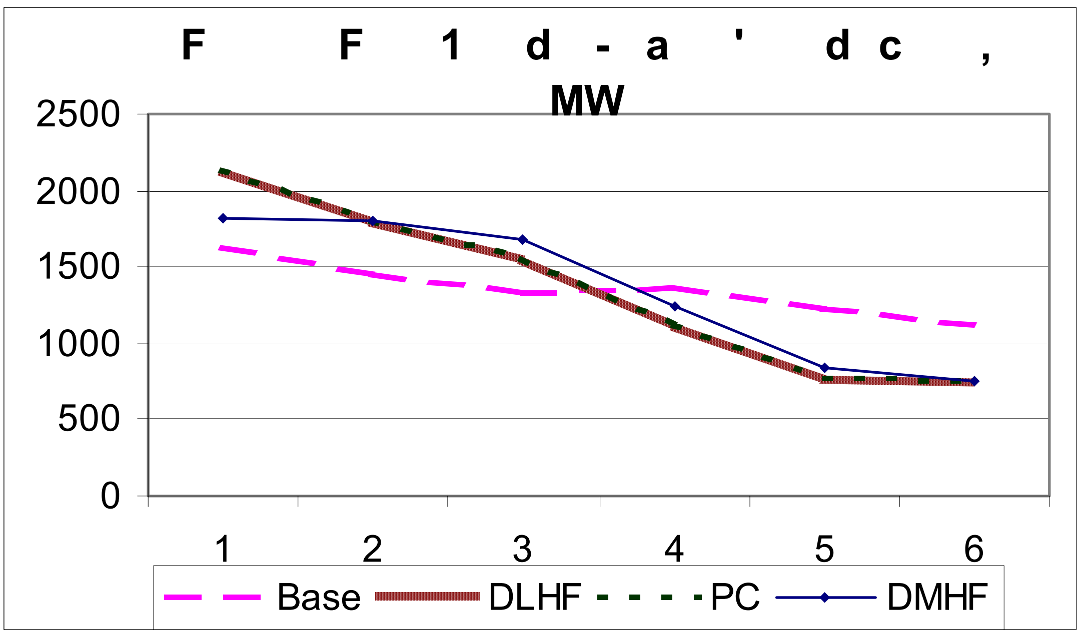


Figure 27

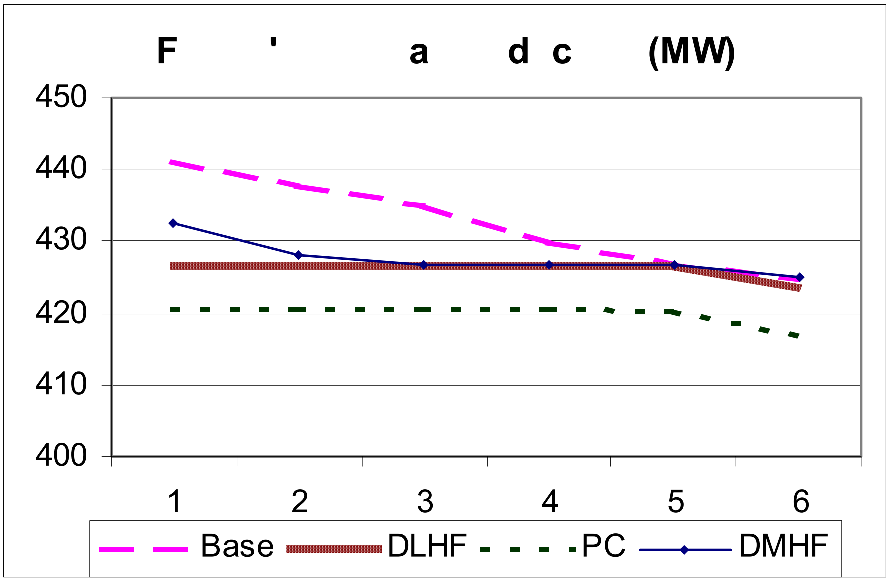


Figure 28

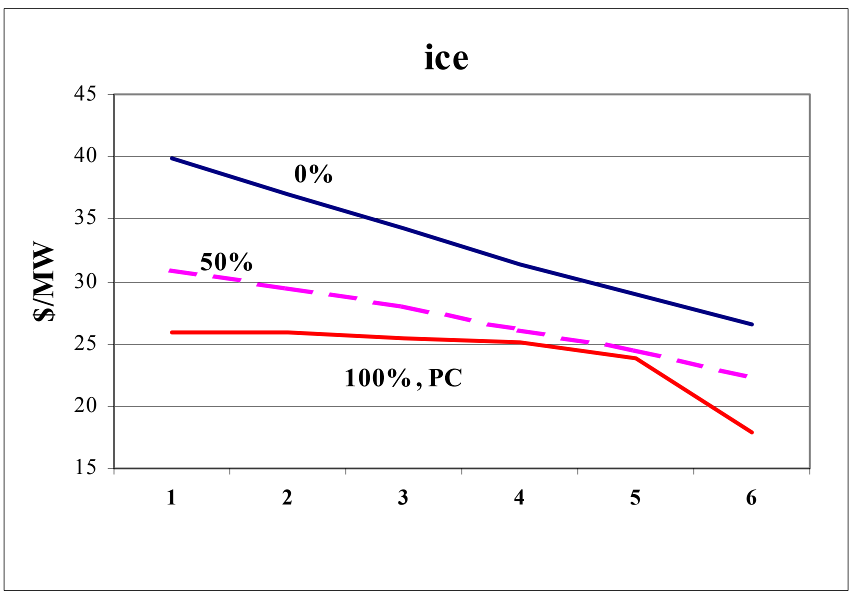


Figure 29

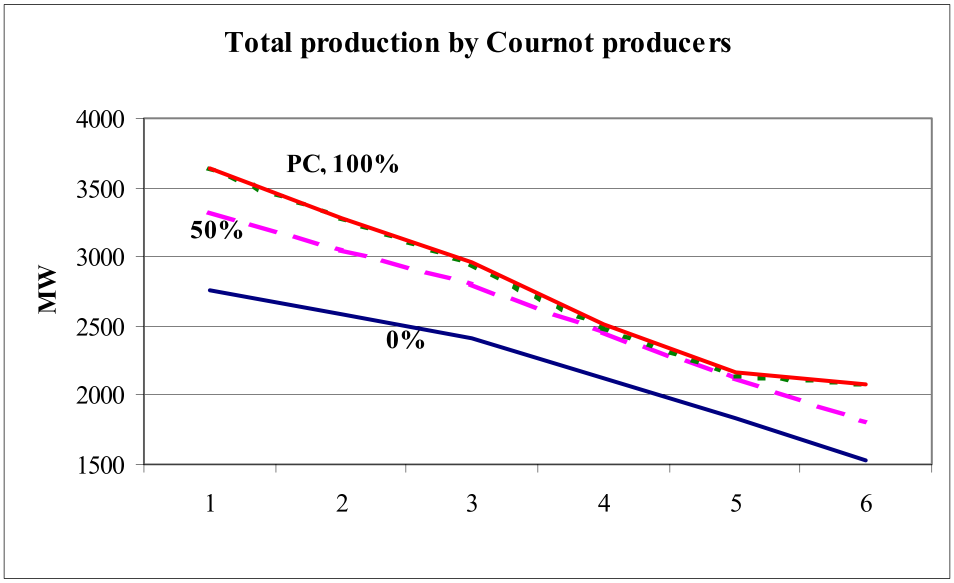


Figure 30

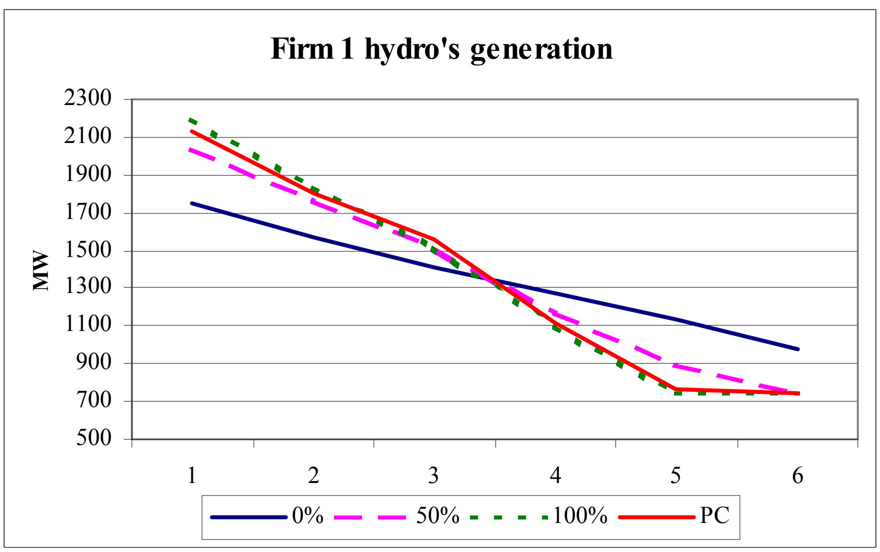


Figure 31

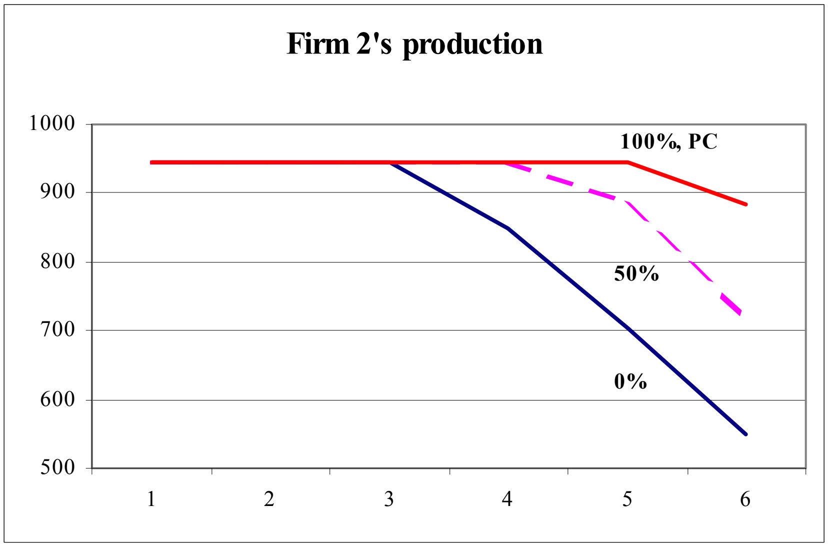
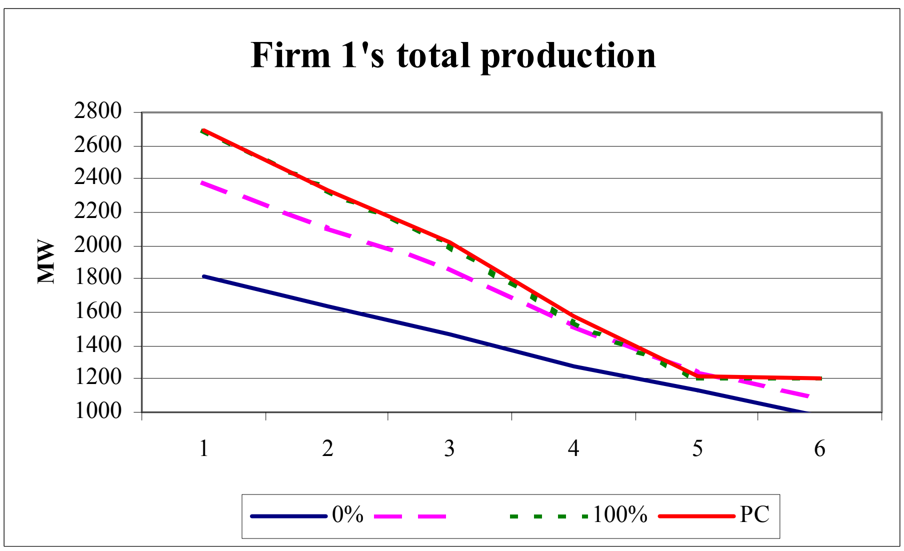


Figure 32



APPENDIX # 1 - TABLES

1. Base Model, Same slope approach

A. Competitive Equilibrium (Same slope approach)

Table A1.1: Competitive equilibrium (E=-0.1)

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	665.94	944.40	1610.34	2133.1	0	2133.1	3743.4	690.03	394.46	2406.49	4827.9	26.0
2	665.94	944.40	1610.34	1802.6	0	1802.6	3412.9	600.43	394.46	1986.36	4407.8	26.0
3	665.94	944.40	1610.34	1564.1	0	1564.1	3174.4	600.43	394.46	1747.87	4169.3	26.0
4	665.94	944.40	1610.34	1116.3	0	1116.3	2726.6	600.43	394.46	1300.08	3721.5	26.0
5	645.03	944.40	1589.43	764.7	0	764.7	2354.1	600.43	394.46	948.48	3349.0	26.0
6	454.60	944.40	1399.00	743.7	0	743.7	2142.7	595.43	394.46	927.52	3132.6	21.7

Table A1.2: Competitive equilibrium (E=-1/3)

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	673.1	944.4	1617.5	2133.1	0.0	2133.1	3750.6	693.9	394.46	2406.49	4839.0	29.4
2	673.1	944.4	1617.5	1802.6	0.0	1802.6	3420.1	604.3	394.46	1986.36	4418.9	29.4
3	673.1	944.4	1617.5	1564.1	0.0	1564.1	3181.6	604.3	394.46	1747.87	4180.4	29.4
4	673.1	944.4	1617.5	1116.3	0.0	1116.3	2733.8	604.3	394.46	1300.08	3732.6	29.4
5	673.1	944.4	1617.5	764.7	0.0	764.7	2382.2	603.9	394.46	948.48	3380.5	28.9
6	566.2	944.4	1510.6	743.7	0.0	743.7	2254.4	600.4	394.46	927.52	3249.3	26.0

Table A1.3: Competitive equilibrium (E=-0.5)

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	673.10	944.40	1617.50	2133.1	0	2133.1	3750.6	694.61	394.46	2406.49	4839.7	29.9
2	673.10	944.40	1617.50	1802.6	1	1803.6	3421.1	605.01	394.46	1986.36	4420.5	29.9
3	673.10	944.40	1617.50	1564.1	2	1566.1	3183.6	605.01	394.46	1747.87	4183.0	29.9
4	673.10	944.40	1617.50	1116.3	3	1119.3	2736.8	605.01	394.46	1300.08	3736.2	29.9
5	673.10	944.40	1617.50	764.7	4	768.7	2386.2	604.69	394.46	948.48	3385.3	29.7
6	673.10	944.40	1617.50	743.7	5	748.7	2366.2	600.79	394.46	927.52	3361.5	26.3

Table A1.4: Competitive equilibrium (E=-2/3)

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	673.1	944.4	1617.5	2133.1	0.0	2133.1	3750.6	694.9	394.46	2406.49	4840.0	30.2
2	673.1	944.4	1617.5	1802.6	0.0	1802.6	3420.1	605.3	394.46	1986.36	4419.9	30.2
3	673.1	944.4	1617.5	1564.1	0.0	1564.1	3181.6	605.3	394.46	1747.87	4181.4	30.2
4	673.1	944.4	1617.5	1116.3	0.0	1116.3	2733.8	605.3	394.46	1300.08	3733.6	30.2
5	673.1	944.4	1617.5	764.7	0.0	764.7	2382.2	605.1	394.46	948.48	3381.7	30.0
6	673.1	944.4	1617.5	743.7	0.0	743.7	2361.2	602.2	394.46	927.52	3357.8	27.5

Table A1.5: Competitive equilibrium (E=-1.0)

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	673.10	944.40	1617.50	2133.1	0	2133.1	3750.6	695.28	394.46	2406.49	4840.3	30.5
2	673.10	944.40	1617.50	1802.6	0	1802.6	3420.1	605.68	394.46	1986.36	4420.2	30.5
3	673.10	944.40	1617.50	1564.1	0	1564.1	3181.6	605.68	394.46	1747.87	4181.7	30.5
4	673.10	944.40	1617.50	1116.3	0	1116.3	2733.8	605.68	394.46	1300.08	3733.9	30.5
5	673.10	944.40	1617.50	764.7	0	764.7	2382.2	605.53	394.46	948.48	3382.2	30.4
6	673.10	944.40	1617.50	743.7	0	743.7	2361.2	603.56	394.46	927.52	3359.2	28.7

B. Cournot equilibrium (Same slope approach)

Table A1.6: Cournot equilibrium **(E=-0.1)**

t	qth1 #	qth2	QRth	qh1 #	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	0.0	944.4	944.4	1612.3	0.0	1612.3	2556.7	500.3	394.46	274.6	3726.1	98.1
2	0.0	944.4	944.4	1447.7	0.0	1447.7	2392.1	488.6	394.46	183.8	3459.0	88.1
3	0.0	944.4	944.4	1328.4	0.0	1328.4	2272.8	480.2	394.46	183.8	3331.3	80.9
4	0.0	854.9	854.9	1149.3	0.0	1149.3	2004.2	467.6	394.46	183.8	3050.0	70.0
5	0.0	730.7	730.7	1025.1	0.0	1025.1	1755.9	458.8	394.46	183.8	2792.9	62.4
6	0.0	636.6	636.6	931.0	0.0	931.0	1567.7	452.2	394.46	183.8	2598.1	56.7

# denotes multiple equilibrium. Values reported are averages over 400 simulations.

Table A1.7: Cournot equilibrium **(E=-1/3)**

t	qth1 #	qth2	QRth	qh1 #	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	133.7	944.4	1078.1	1743.0	0.0	1743.0	2821.1	441.2	394.46	274.6	3931.4	47.2
2	140.1	944.4	1084.5	1572.0	0.0	1572.0	2656.5	437.5	394.46	183.8	3672.3	44.0
3	120.3	944.4	1064.7	1472.6	0.0	1472.6	2537.3	434.9	394.46	183.8	3550.4	41.7
4	122.0	944.4	1066.4	1247.0	0.0	1247.0	2313.4	429.9	394.46	183.8	3321.5	37.4
5	127.0	867.7	994.7	1094.1	0.0	1094.1	2088.8	426.6	394.46	183.8	3093.6	34.6
6	131.9	773.6	905.4	995.1	0.0	995.1	1900.6	424.5	394.46	183.8	2903.3	32.8

# denotes multiple equilibrium. Values reported are averages over 400 simulations.

Table A1.8: Cournot equilibrium **(E=-0.5)**

t	qth1 #	qth2	QRth	qh1 #	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	341.7	944.4	1286.1	1759.9	0.0	1759.9	3046.0	431.7	394.46	274.6	4146.8	39.0
2	341.7	944.4	1286.1	1595.3	0.0	1595.3	2881.4	429.3	394.46	183.8	3888.9	36.9
3	341.7	944.4	1286.1	1476.0	0.0	1476.0	2762.1	427.5	394.46	183.8	3767.8	35.3
4	341.7	944.4	1286.1	1252.1	0.0	1252.1	2538.2	424.1	394.46	183.8	3540.6	32.4
5	341.7	941.5	1283.2	1067.3	0.0	1067.3	2350.5	421.4	394.46	183.8	3350.1	30.1
6	341.7	847.4	1189.1	973.2	0.0	973.2	2162.3	420.0	394.46	183.8	3160.5	28.9

# denotes multiple equilibrium. Values reported are averages over 400 simulations.

Table A1.9: Cournot equilibrium **(E=-2/3)**

t	qth1 #	qth2	QRth	qh1 #	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	377.7	944.4	1322.1	1768.1	0.0	1768.1	3090.2	429.0	394.46	274.6	4188.3	36.6
2	376.0	944.4	1320.4	1605.2	0.0	1605.2	2925.6	427.1	394.46	183.8	3930.9	35.0
3	378.3	944.4	1322.7	1483.6	0.0	1483.6	2806.3	425.8	394.46	183.8	3810.3	33.9
4	375.8	944.4	1320.2	1262.2	0.0	1262.2	2582.4	423.2	394.46	183.8	3583.9	31.7
5	379.6	944.4	1324.0	1072.2	0.0	1072.2	2396.2	421.1	394.46	183.8	3395.6	29.9
6	378.2	944.4	1322.5	932.5	0.0	932.5	2255.0	419.6	394.46	183.8	3252.8	28.5

# denotes multiple equilibrium. Values reported are averages over 400 simulations.

Table A1.10: Cournot equilibrium **(E=-1.0)**

t	qth1#	qth2	QRth	qh1 #	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	454.6	944.4	1399.0	1768.2	0.0	1768.2	3167.2	426.3	394.46	274.6	4262.5	34.3
2	454.6	944.4	1399.0	1603.6	0.0	1603.6	3002.6	425.0	394.46	183.8	4005.8	33.2
3	454.6	944.4	1399.0	1484.3	0.0	1484.3	2883.3	424.1	394.46	183.8	3885.7	32.4
4	454.6	944.4	1399.0	1260.4	0.0	1260.4	2659.4	422.4	394.46	183.8	3660.1	31.0
5	454.6	944.4	1399.0	1074.2	0.0	1074.2	2473.2	421.0	394.46	183.8	3472.4	29.8
6	454.6	944.4	1399.0	933.0	0.0	933.0	2332.0	420.0	394.46	183.8	3330.2	28.9

# denotes multiple equilibrium. Values reported are averages over 400 simulations.

Table A1.11: Lerner Indices

t	E=-0.1 Firm 1	E=-0.1 Firm 2	E=-1/3 Firm 1	E=-1/3 Firm 2	E=0.5 Firm 1	E=0.5 Firm 2	E= -2/3 Firm 1	E= -2/3 Firm 2	E=-1.0 Firm 1	E=-1.0 Firm 2
1	100%	59%	76%	38%	70%	31%	57%	25%	42%	18%
2	100%	65%	75%	41%	68%	33%	55%	26%	40%	18%
3	100%	71%	73%	43%	66%	34%	53%	27%	39%	19%
4	100%	74%	70%	48%	63%	38%	50%	29%	36%	20%
5	100%	71%	68%	48%	60%	40%	47%	31%	33%	21%
6	100%	68%	66%	45%	59%	38%	45%	32%	31%	21%

2. Base Model, Different slope approach

A. Competitive Equilibrium (Different slope approach)

Table A1.12: Competitive equilibrium (E=-0.1)

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	665.94	944.40	1610.34	2133.1	0	2133.1	3743.4	690.0	394.46	2406.49	4827.9	25.98
2	659.02	944.40	1603.42	1802.6	0	1802.6	3406.0	600.4	394.46	1986.36	4400.9	25.98
3	655.09	944.40	1599.49	1564.1	0	1564.1	3163.6	600.4	394.46	1747.87	4158.5	25.98
4	647.72	944.40	1592.12	1116.3	0	1116.3	2708.4	600.4	394.46	1300.08	3703.3	25.98
5	620.67	944.40	1565.07	764.7	0	764.7	2329.7	600.4	394.46	948.48	3324.6	25.98
6	454.60	931.31	1385.91	743.7	0	743.7	2129.6	591.1	394.46	927.52	3115.2	17.92

Table A1.13: Competitive equilibrium (E=-1/3)

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	673.1	944.4	1617.5	2133.1	0	2133.1	3750.6	693.9	394.46	2406.49	4839.0	29.4
2	673.1	944.4	1617.5	1802.6	0	1802.6	3420.1	604.1	394.46	1986.36	4418.7	29.2
3	673.1	944.4	1617.5	1564.1	0	1564.1	3181.6	604.0	394.46	1747.87	4180.0	29.1
4	673.1	944.4	1617.5	1116.3	0	1116.3	2733.8	603.7	394.46	1300.08	3732.0	28.8
5	673.1	944.4	1617.5	764.7	0	764.7	2382.2	602.8	394.46	948.48	3379.4	28.0
6	469.5	944.4	1413.9	743.7	0	743.7	2157.7	600.4	394.46	927.52	3152.6	26.0

Table A1.14: Competitive equilibrium (E=-0.5)

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	673.10	944.40	1617.50	2133.1	0	2133.1	3750.6	694.6	394.46	2406.49	4839.7	29.93
2	673.10	944.40	1617.50	1802.6	0	1802.6	3420.1	604.9	394.46	1986.36	4419.4	29.81
3	673.10	944.40	1617.50	1564.1	0	1564.1	3181.6	604.8	394.46	1747.87	4180.8	29.74
4	673.10	944.40	1617.50	1116.3	0	1116.3	2733.8	604.6	394.46	1300.08	3732.8	29.58
5	673.10	944.40	1617.50	764.7	0	764.7	2382.2	604.0	394.46	948.48	3380.6	29.02
6	551.59	944.40	1495.99	743.7	0	743.7	2239.7	600.4	394.46	927.52	3234.6	25.98

Table A1.15: Competitive equilibrium (E=-2/3)

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	673.1	944.4	1617.5	2133.1	0.0	2133.1	3750.6	694.9	394.46	2406.49	4840.0	30.2
2	673.1	944.4	1617.5	1802.6	0.0	1802.6	3420.1	605.2	394.46	1986.36	4419.8	30.1
3	673.1	944.4	1617.5	1564.1	0.0	1564.1	3181.6	605.2	394.46	1747.87	4181.2	30.1
4	673.1	944.4	1617.5	1116.3	0.0	1116.3	2733.8	605.0	394.46	1300.08	3733.3	30.0
5	673.1	944.4	1617.5	764.7	0.0	764.7	2382.2	604.5	394.46	948.48	3381.2	29.5
6	633.6	944.4	1578.0	743.7	0.0	743.7	2321.7	600.4	394.46	927.52	3316.6	26.0

Table A1.16: Competitive equilibrium (E=-1.0)

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	673.10	944.40	1617.50	2133.1	0	2133.1	3750.6	695.3	394.46	2406.49	4840.3	30.51
2	673.10	944.40	1617.50	1802.6	0	1802.6	3420.1	605.6	394.46	1986.36	4420.1	30.45
3	673.10	944.40	1617.50	1564.1	0	1564.1	3181.6	605.6	394.46	1747.87	4181.6	30.42
4	673.10	944.40	1617.50	1116.3	0	1116.3	2733.8	605.5	394.46	1300.08	3733.7	30.33
5	673.10	944.40	1617.50	764.7	0	764.7	2382.2	605.1	394.46	948.48	3381.8	30.05
6	673.10	944.40	1617.50	743.7	0	743.7	2361.2	601.9	394.46	927.52	3357.6	27.26

B. Cournot equilibrium (Different slope approach)

Table A1.17: Cournot equilibrium **(E=-0.1)**

t	qth1 #	qth2	QRth	qh1 #	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	0.0	944.4	944.4	1612.3	0.0	1612.3	2556.7	500.1	394.46	274.6	3725.9	98.0
2	0.0	944.4	944.4	1426.7	0.0	1426.7	2371.1	496.3	394.46	183.8	3445.6	94.7
3	0.0	944.4	944.4	1295.5	0.0	1295.5	2239.9	491.1	394.46	183.8	3309.2	90.2
4	0.0	860.7	860.7	1091.1	0.0	1091.1	1951.8	484.9	394.46	183.8	3014.9	84.9
5	0.0	738.4	738.4	947.3	0.0	947.3	1685.8	480.7	394.46	183.8	2744.7	81.3
6	0.0	645.7	645.7	838.4	0.0	838.4	1484.1	476.8	394.46	183.8	2539.2	77.9

# denotes multiple equilibrium. Values reported are averages over 400 simulations.

Table A1.18: Cournot equilibrium **(E=-1/3)**

t	qth1 #	qth2	QRth	qh1 #	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	61.2	944.4	1005.6	1815.6	0.0	1815.6	2821.2	441.2	394.46	274.6	3931.5	47.2
2	59.0	944.4	1003.4	1608.1	0.0	1608.1	2611.5	440.0	394.46	183.8	3629.8	46.2
3	49.7	944.4	994.0	1472.7	0.0	1472.7	2466.8	438.6	394.46	183.8	3483.6	45.0
4	31.4	944.4	975.7	1219.2	0.0	1219.2	2194.9	435.5	394.46	183.8	3208.6	42.2
5	21.1	833.9	855.0	1058.6	0.0	1058.6	1913.6	434.0	394.46	183.8	2925.8	40.9
6	9.0	733.3	742.3	949.6	0.0	949.6	1691.9	432.9	394.46	183.8	2703.1	40.0

# denotes multiple equilibrium. Values reported are averages over 400 simulations.

Table A1.19: Cournot equilibrium **(E=-0.5)**

t	qth1 #	qth2	QRth	qh1 #	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	248.6	944.4	1193.0	1882.4	0.0	1882.4	3075.4	431.3	394.46	274.6	4175.7	38.6
2	241.2	944.4	1185.6	1657.7	0.0	1657.7	2843.2	430.5	394.46	183.8	3852.0	38.0
3	242.8	944.4	1187.2	1498.5	0.0	1498.5	2685.7	429.6	394.46	183.8	3693.5	37.1
4	232.2	944.4	1176.6	1213.3	0.0	1213.3	2389.9	427.5	394.46	183.8	3395.6	35.3
5	259.0	871.2	1130.2	977.1	0.0	977.1	2107.3	426.1	394.46	183.8	3111.6	34.1
6	206.6	767.5	974.1	894.8	0.0	894.8	1868.9	425.4	394.46	183.8	2872.5	33.5

# denotes multiple equilibrium. Values reported are averages over 400 simulations.

Table A1.20: Cournot equilibrium **(E=-2/3)**

t	qth1 #	qth2	QRth	qh1 #	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	341.7	944.4	1286.1	1933.0	0.0	1933.0	3219.1	427.5	394.46	274.6	4315.7	35.4
2	341.7	944.4	1286.1	1688.1	0.0	1688.1	2974.2	426.9	394.46	183.8	3979.3	34.9
3	341.7	944.4	1286.1	1523.2	0.0	1523.2	2809.3	426.2	394.46	183.8	3813.8	34.3
4	341.7	944.4	1286.1	1213.8	0.0	1213.8	2499.9	424.7	394.46	183.8	3502.8	32.9
5	341.7	944.4	1286.1	956.4	0.0	956.4	2242.5	423.0	394.46	183.8	3243.7	31.5
6	341.7	848.2	1190.0	809.3	0.0	809.3	1999.3	422.4	394.46	183.8	2999.9	30.9

# denotes multiple equilibrium. Values reported are averages over 400 simulations.

Table A1.21: Cournot equilibrium **(E=-1.0)**

t	qth1 #	qth2	QRth	qh1 #	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	454.6	944.4	1399.0	1969.6	0.0	1969.6	3368.5	424.8	394.46	274.6	4462.4	33.0
2	454.6	944.4	1399.0	1711.2	0.0	1711.2	3110.2	424.4	394.46	183.8	4112.8	32.7
3	454.6	944.4	1399.0	1538.8	0.0	1538.8	2937.7	423.9	394.46	183.8	3939.9	32.3
4	454.6	944.4	1399.0	1215.0	0.0	1215.0	2614.0	422.8	394.46	183.8	3615.1	31.3
5	454.6	944.4	1399.0	945.7	0.0	945.7	2344.6	421.8	394.46	183.8	3344.6	30.4
6	454.6	944.4	1399.0	743.6	0.0	743.6	2142.6	420.7	394.46	183.8	3141.5	29.5

# denotes multiple equilibrium. Values reported are averages over 400 simulations.

Table A1.22**: Lerner Indices**

	E=-0.1		E=-1/3		E=0.5		E= -2/3		E=-1.0	
t	Firm 1	Firm 2	Firm 1	Firm 2	Firm 1	Firm 2	Firm 1	Firm 2	Firm 1	Firm 2
1	100%	59%	76%	38%	71%	32%	62%	26%	48%	19%
2	100%	66%	76%	43%	71%	35%	62%	29%	47%	21%
3	100%	73%	75%	47%	70%	38%	61%	31%	47%	22%
4	100%	79%	74%	56%	69%	45%	60%	36%	45%	25%
5	100%	78%	73%	56%	67%	48%	58%	42%	43%	29%
6	100%	77%	72%	55%	67%	47%	57%	42%	42%	33%

3. Base Model, Same slope approach, Reduced Hydro Flows

A. Competitive Equilibrium (Same slope approach)

Table A1.23: Competitive equilibrium (E=-0.1)

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	860.0	1101.3	1961.3	833.4	0.0	833.4	2794.7	629.9	242.4	952.7	3666.9	107.0
2	779.2	1101.3	1880.5	808.2	0.0	808.2	2688.7	606.1	242.4	927.5	3537.1	86.5
3	779.2	992.9	1772.1	808.2	0.0	808.2	2580.3	596.2	242.4	927.5	3418.9	78.0
4	705.2	992.9	1698.1	808.2	0.0	808.2	2506.3	566.8	242.4	927.5	3315.4	52.6
5	673.1	944.4	1617.5	808.2	0.0	808.2	2425.7	546.2	242.4	927.5	3214.3	34.8
6	535.8	944.4	1480.2	808.2	0.0	808.2	2288.4	536.0	242.4	927.5	3066.7	26.0

Table A1.24: Competitive equilibrium (E=-1/3)

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	779.2	992.9	1772.1	833.4	0.0	833.4	2605.5	572.6	242.4	952.7	3420.4	57.6
2	673.1	992.9	1666.0	808.2	0.0	808.2	2474.2	566.0	242.4	927.5	3282.6	51.9
3	673.1	992.9	1666.0	808.2	0.0	808.2	2474.2	560.6	242.4	927.5	3277.2	47.2
4	673.1	944.4	1617.5	808.2	0.0	808.2	2425.7	551.5	242.4	927.5	3219.6	39.4
5	673.1	944.4	1617.5	808.2	0.0	808.2	2425.7	543.3	242.4	927.5	3211.3	32.3
6	673.1	944.4	1617.5	808.2	0.0	808.2	2425.7	537.0	242.4	927.5	3205.0	26.9

Table A1.25: Competitive equilibrium (E=-0.5)

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	673.1	992.9	1666.0	833.4	0.0	833.4	2499.4	564.0	242.4	952.7	3305.7	50.2
2	673.1	944.4	1617.5	808.2	0.0	808.2	2425.7	558.7	242.4	927.5	3226.8	45.6
3	673.1	944.4	1617.5	808.2	0.0	808.2	2425.7	555.1	242.4	927.5	3223.2	42.5
4	673.1	944.4	1617.5	808.2	0.0	808.2	2425.7	548.4	242.4	927.5	3216.4	36.7
5	673.1	944.4	1617.5	808.2	0.0	808.2	2425.7	542.8	242.4	927.5	3210.9	31.9
6	673.1	944.4	1617.5	808.2	0.0	808.2	2425.7	538.6	242.4	927.5	3206.6	28.2

Table A1.26: Competitive equilibrium (E=-2/3)

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	673.1	944.4	1617.5	833.4	0.0	833.4	2450.9	559.0	242.4	952.7	3252.3	45.9
2	673.1	944.4	1617.5	808.2	0.0	808.2	2425.7	554.5	242.4	927.5	3222.6	42.0
3	673.1	944.4	1617.5	808.2	0.0	808.2	2425.7	551.8	242.4	927.5	3219.9	39.7
4	673.1	944.4	1617.5	808.2	0.0	808.2	2425.7	546.8	242.4	927.5	3214.8	35.3
5	673.1	944.4	1617.5	808.2	0.0	808.2	2425.7	542.6	242.4	927.5	3210.6	31.7
6	673.1	944.4	1617.5	808.2	0.0	808.2	2425.7	539.4	242.4	927.5	3207.5	29.0

Table A1.27: Competitive equilibrium (E=-1.0)

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	673.1	944.4	1617.5	833.4	0.0	833.4	2450.9	553.3	242.4	952.7	3246.5	40.9
2	673.1	944.4	1617.5	808.2	0.0	808.2	2425.7	550.3	242.4	927.5	3218.4	38.4
3	673.1	944.4	1617.5	808.2	0.0	808.2	2425.7	548.5	242.4	927.5	3216.6	36.8
4	673.1	944.4	1617.5	808.2	0.0	808.2	2425.7	545.2	242.4	927.5	3213.2	33.9
5	673.1	944.4	1617.5	808.2	0.0	808.2	2425.7	542.4	242.4	927.5	3210.4	31.5
6	673.1	944.4	1617.5	808.2	0.0	808.2	2425.7	540.2	242.4	927.5	3208.3	29.7

B. Cournot equilibrium, Same slope approach, Reduced Hydro Flows

Table A1.28: Cournot equilibrium (E=-0.1)

t	qth1 #	qth2	QRth	qh1 #	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	486.8	992.9	1479.8	1041.5	0.0	1041.5	2521.2	524.4	242.4	119.3	3407.4	119.0
2	488.9	983.0	1472.0	834.2	0.0	834.2	2306.2	510.0	242.4	119.3	3177.9	106.5
3	455.6	944.4	1399.9	767.8	0.0	767.8	2167.7	502.9	242.4	119.3	3032.3	100.4
4	341.7	944.4	1286.1	743.6	0.0	743.6	2029.7	481.1	242.4	119.3	2872.5	81.6
5	231.8	863.9	1095.7	743.6	0.0	743.6	1839.3	468.2	242.4	119.3	2669.2	70.5
6	137.7	769.8	907.5	743.6	0.0	743.6	1651.1	461.6	242.4	119.3	2474.4	64.8

# denotes multiple equilibrium. Values reported are averages over 400 simulations.

Table A1.29: Cournot equilibrium **(E=-1/3)**

t	qth1 #	qth2	QRth	qh1 #	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	614.3	944.4	1558.7	1029.6	0.0	1029.6	2588.3	453.2	242.4	119.3	3403.2	57.6
2	607.0	944.4	1551.4	826.8	0.0	826.8	2378.2	448.6	242.4	119.3	3188.4	53.5
3	527.4	944.4	1471.8	787.1	0.0	787.1	2258.9	445.9	242.4	119.3	3066.5	51.2
4	454.6	944.4	1399.0	743.6	0.0	743.6	2142.6	438.5	242.4	119.3	2942.8	44.9
5	426.4	944.4	1370.8	743.6	0.0	743.6	2114.4	430.9	242.4	119.3	2906.9	38.3
6	341.7	902.7	1244.4	743.6	0.0	743.6	1988.0	427.4	242.4	119.3	2777.1	35.3

# denotes multiple equilibrium. Values reported are averages over 400 simulations.

Table A1.30: Cournot equilibrium **(E=-0.5)**

t	qth1 #	qth2	QRth	qh1 #	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	662.7	944.4	1607.1	1046.3	0.0	1046.3	2653.4	442.2	242.4	119.3	3457.3	48.0
2	662.7	944.4	1607.1	836.3	0.0	836.3	2443.4	439.0	242.4	119.3	3244.1	45.3
3	618.9	944.4	1563.3	760.9	0.0	760.9	2324.1	437.3	242.4	119.3	3123.1	43.8
4	454.6	944.4	1399.0	743.6	0.0	743.6	2142.6	433.3	242.4	119.3	2937.6	40.3
5	454.6	944.4	1399.0	743.6	0.0	743.6	2142.6	427.7	242.4	119.3	2932.0	35.5
6	454.6	944.4	1399.0	743.6	0.0	743.6	2142.6	423.5	242.4	119.3	2927.8	31.9

# denotes multiple equilibrium. Values reported are averages over 400 simulations.

Table A1.31: Cournot equilibrium **(E=-2/3)**

t	qth1 #	qth2	QRth	qh1 #	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	673.1	944.4	1617.5	1055.0	0.0	1055.0	2672.4	437.1	242.4	119.3	3471.3	43.7
2	673.1	944.4	1617.5	844.9	0.0	844.9	2462.4	434.8	242.4	119.3	3258.8	41.6
3	673.1	944.4	1617.5	743.6	0.0	743.6	2361.1	433.2	242.4	119.3	3156.0	40.3
4	477.5	944.4	1421.8	743.6	0.0	743.6	2165.4	430.4	242.4	119.3	2957.5	37.8
5	454.6	944.4	1399.0	743.6	0.0	743.6	2142.6	426.4	242.4	119.3	2930.7	34.4
6	454.6	944.4	1399.0	743.6	0.0	743.6	2142.6	423.3	242.4	119.3	2927.5	31.7

# denotes multiple equilibrium. Values reported are averages over 400 simulations.

Table A1.32: Cournot equilibrium **(E=-1.0)**

t	qth1 #	qth2	QRth	qh1 #	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	673.1	944.4	1617.5	1055.0	0.0	1055.0	2672.4	432.3	242.4	119.3	3466.4	39.5
2	673.1	944.4	1617.5	844.9	0.0	844.9	2462.4	430.7	242.4	119.3	3254.8	38.1
3	673.1	944.4	1617.5	743.6	0.0	743.6	2361.1	429.7	242.4	119.3	3152.4	37.2
4	607.8	944.4	1552.2	743.6	0.0	743.6	2295.8	426.8	242.4	119.3	3084.3	34.8
5	454.6	944.4	1399.0	743.6	0.0	743.6	2142.6	425.2	242.4	119.3	2929.4	33.3
6	454.6	944.4	1399.0	743.6	0.0	743.6	2142.6	423.0	242.4	119.3	2927.3	31.5

# denotes multiple equilibrium. Values reported are averages over 400 simulations.

Table A1.33**: Lerner Indices**

	E=-0.1		E=-1/3		E=0.5		E= -2/3		E=-1.0	
t	Firm 1	Firm 2	Firm 1	Firm 2	Firm 1	Firm 2	Firm 1	Firm 2	Firm 1	Firm 2
1	78%	51%	55%	32%	46%	25%	38%	21%	28%	16%
2	76%	56%	51%	34%	43%	27%	35%	22%	26%	16%
3	74%	57%	49%	35%	41%	28%	34%	23%	25%	16%
4	81%	70%	51%	40%	38%	30%	31%	24%	25%	18%
5	84%	75%	59%	47%	43%	34%	34%	27%	23%	18%
6	83%	72%	59%	49%	48%	38%	37%	29%	25%	19%

12 Appendix 2: A simple 1-year Cournot Model for Chile's Electricity Industry

The model that was used to analyze the exercise of market power in Chile's electricity industry assumed that the hydro producer was able to allocate its hydro production over a 1 month planning horizon. In addition, in that model no value was given to the water left in the reservoir at the end of the month. Accordingly, even though Firm 1, the hydro producer, was "allowed" by the model to use only a fraction of the water available, incentives pushed more in the direction of using it all.

In real life, however, producers usually maximize over a longer time horizon, and thus it is reasonable to expect them to store a fraction of their hydro flows available in a particular month in order to use them in a later period. An interesting question is whether the hydro scheduling pattern that resulted in the 1-month period model would also be observed when a longer planning horizon is assumed. If so, generators would exploit differences in demand elasticity across months by shifting water from low demand elasticity months to high demand elasticity months. According to the data reported in Table 15, this means that water should be stored in October, November and December and released in April, March, January and the winter months.[90] In the paper I report evidence based on MVW analysis suggesting that Firm 1's incentive to exercise market power by shifting hydro production from one month to another depends on how large are the inter-month differences in demand elasticity/ The smaller the fluctuations, the closer is the hydro scheduling strategy to the traditional competitive supply-demand or value-maximizing optimization analysis' conclusions (i.e. water is stored when it is relatively abundant and released when it is relatively scarce).

The MVW analysis is helpful in that one can draw conclusions regarding how hydro flows would be allocated across months, but it does not provide information regarding the size of the flows that are stored and later released. In addition, it is not possible to compare the market equilibrium when market power is and is not exercised. In order to address these issues, a very simple 1-year model was estimated. This model will still suffer the omission of re-allocation across years but will probably shed lights of the re-allocations that happen within a year.

Given that the estimation of this model was computationally intensive, I had to use many simplifying assumptions. In addition, information on many variables was required but not available; as a consequence, additional assumptions were required.

12.1 The Model

The model is basically the same as the 1-month model. I assumed that there are only *two* periods per month (rather than 6): a high demand period and a low demand period (t=1 and t=2 respectively). Each of them lasts for 360/372 hours. Notice that by reducing the number of periods to only two, I am implicitly reducing the demand variability. Given that Firm 1 is allowed to store hydro flows one month and release them in a later period, a state variable, namely the reservoir level, is introduced. Water inflows are assumed to get to the

[90] Market demand was parameterized as before, and thus it was assumed that price elasticity was -1/3 at the peak anchor point. Residual demand is not constant throughout the year because must run production and the fringe's production fluctuates over the different months.

reservoir at the beginning of each month.

Each period, Cournot producers face a residual demand given by:

$D^R(P_t) = D(P_t) - S^f(P_t) - q_t^{MR} - q_{ht}^{PS}$

where $D(P)$ is expected market demand, $D^R(P)$ is expected residual market demand, $S^f(P)$ is the Fringe's (thermal) supply function (adjusted by transmission losses), q^{MR} is must-run units' generation and q_h^{PS} is the Fringe's hydro production from reservoirs distributed across periods according to a Peak shaving strategy.

Firm 2's optimization problem remains basically the same as in the 1-year model. Firm 1's optimization problem is modified to take account of the reservoir level, and the corresponding minimum and maximum capacity constraints.

Firm 1's Optimization problem

$$\max \sum_t \{P_t(q_t)(q_{1ht} + q_{1Tht}) - CT_1(q_{1Tht})\} \text{ subject to} \tag{27}$$

$$\begin{aligned}
q_{1ThMIN} &\leq q_{1Tht} \leq q_{1ThMAX} \ \ \forall t \text{ (thermal production min/max constraints)} && (28)\\
q_{1hMIN} &\leq q_{1ht} \leq q_{1hMAXt} \ \ \forall t \text{ (hydro production min/max constraints)} && (29)\\
S_m &= S_{m-1} + F_m - q_{1hydrom} \forall m \text{ (Reservoir's level evolution)} && (30)\\
S_{MIN} &\leq S_m \leq S_{MAX} \ \ \forall m \text{ (Reservoir's min/max capacity constraint)} && (31)\\
S_0 &= S_{INI} \text{ (Reservoir's initial level)} && (32)\\
S_{12} &= S_{END} \text{ (Reservoir's level at the end of the year)} && (33)
\end{aligned}$$

where:

m = month index; m = 1,2,..12. m=1 for the first month of the hydrological year assumed.

t = index for each period of 360/372 hours. Since I assumed that there are only two periods per month, t = 1,2, 24. The periods are set in chronological order (t=1 for the high period, month 1; t=2 for the low period, month 1; t=3 for the high period, month 2, and so on).

$Pt(qt)$ = is the inverse function of the *expected* residual demand in period t

Q_t = is total production by firm 1 and 2 in period t, ($Q_t = q_{1t} + q_{2t}$),

$q_{it} = q_{iTht} + q_{iht}$ is total production by Firm i in period t,

q_{iTht} = total energy produced by Firm i out of thermal plants, period t

q_{1ht}= total energy produced by Firm 1 out of hydro-storage plants, period t

$CT_i(q_{iTht})$ = Total Cost function, thermal plants, firm i

q_{iThMIN}= Minimum thermal production, Firm i, period t

q_{1ThMAX} = Maximum thermal production, Firm i, period t

q_{1hMIN}= Minimum hydro production, Firm 1, period t

q_{1hMAX} = Maximum hydro production, Firm 1, period t

q_{1htot} = available hydro production for the whole period

S_m= reservoir level at the *end* of month m, measured in terms of energy.

S_{INI}= initial reservoir level.

S_{END}= end of year reservoir level.

F_m= water inflow *expected* to get to the reservoir at the beginning of month m. Measured in terms of energy.

$q_{1hydro.m}$= total energy produced by Firm 1 out of hydro storage plants, month m. $q_{1hydro.m} = q_{1h(2m-1)} + q_{1h(2m)}$.[91]

The objective function is basically the same as in the 1-month model except for the residual demand, which is in terms of expectation. Constraints (28) and (29) are the same as in the 1-month model and thus need no further explanation. Constraint (30) states that the hydro energy available in the reservoir at the end of each month is equal to the hydro energy available at the end of the previous month plus the water inflows (in terms of hydro energy) received at the *beginning* of the month and less the hydro energy that was produced during the month. Constraint (31) states the minimum and maximum bound for the reservoir level. Finally constraints (32) and (33) are initial and end conditions.[92]

This version of the model takes into the account the incentives Firm 1 has to re-allocate water from one month to another (but always within a year). This is a good assumption for all the Chilean reservoirs except for El Laja (the biggest one) that is so big that its water can be allocated from one year to another. For the moment it is not possible to estimate a model with such a long planning horizon because the information requirements cannot be fulfilled.

This model's treatment of uncertainty is certainly simplistic and incomplete. Only expected values of water inflows and demand per period are considered. Variability is not taken into account because there was no information available. This omission is important, especially with respect to hydro inflows, as hydro producers are likely to manage their reservoirs taking into account the probability of the hydrological year being normal, dry or rainy. Under the current regulation, generators are required to ensure the power supply even under the driest conditions. As a consequence it is reasonable to expect them to manage the reservoirs less aggressively. The exercise of market power is not likely to be the unique goal producers pursue as this model implicitly assumes.

I assumed that the discount rate was equal to zero.

12.2 Model Estimation

The model was estimated under two different market assumptions: i) the market is perfectly competitive and ii) producers are able to exercise market power.

Market demand was assumed to be linear. Each month's slope was calculated such that the elasticity at the peak demand level is -1/3. Anchor quantity to parameterize demand was set to the average load (augmented by spinning reserves) of the highest/lowest 360/372 hours. Anchor price was given by each month's nodal price. Table A2.1 reports the data used to parameterize the market demand and to estimate the residual demand.

Capacity and marginal cost functions are the same as in the 1-month model.

Hydro inflows are given by the average hydro generation per month reported by the CNE for "normal" hydrological year (See Table A2.2). In this sense, water inflows can be interpreted as "expected flows". These inflows were used to allocate hydro production according to a peak shaving strategy, when needed. In the model where Firms 1 and 2 are supposed to be able to exercise market power, I allocated the Fringe's hydro production according to this approach. In this case, I assumed that its water inflows were not large enough to store a portion of them given the min and max production constraints. As a

[91] $q_{1hydrom-1} = q_{1h(t=1)} + q_{1h(t=2)}, q_{1hydrom-2} = q_{1h(t-3)} + q_{1h(t-4)}$, and so on.

[92] The model will be estimated under two versions: with and without constraint (2.21).

consequence, its hydro production per period was calculated by allocating hydro resources over a 1-month time period. When perfect competition is assumed, water inflows of the entire system are allocated according to the peak shaving strategy.

As expected, results of the model turned out to be sensitive to the starting month of the one-year period (i.e. hydro scheduling for the year Jan - Dec was slightly different than for April - March, and so on). The longer the planning horizon, the less important the starting point is. Unfortunately, my data set is too short to further increase the time horizon. In addition I do not have information that could be used to simulate water inflows for a longer period. In an attempt to overcome this problem, I estimated the model and the competitive equilibrium for the 12 possible starting points. I will report results for each estimation and will look for general trends.

I assumed that minimum and maximum capacity of the reservoirs were not restrictive, as I did not have information for many of them. This assumption should not introduce too many distortions as in the past years the reservoir level reached its maximum or minimum capacity only a few times, and most of them took place in very rainy or dry years, and thus in periods in which inflows were different from the ones used to estimate this model.[93]

The reservoir level at the end of the year may be important too, being this another consequence of the short time period used. In order to analyze how important this constraint is, I estimated two versions of the model:

- Reservoir level at the end of the year restricted to be equal to the initial level; in this way, Firm 1 is constrained to use all the water available in the year ("bounded estimation").

- Reservoir level at the end of the year restricted to be within min/max bound limits (Constraint (33) is not included). Firm 1 is implicitly allowed to use only a fraction of the water available for the whole year ("unbounded estimation")

It is worth to mention that even though results from these two versions of the model differ, the differences are rather small. In particular, any change in the amount of hydro production is usually compensated at least in part by a change in Firm 2's thermal production.

12.3 Results

I do not intend to exhaustively analyze the results of this model's simulation, as many of the results are similar, in qualitative terms, to what was found in the 1-month model and additional insights are beyond this paper's reach. I will focus on the question that motivated the estimation of this model: Would Firm 1 store water in low price-elasticity of demand months and release it in high price-elasticity of demand months as it could be extrapolated from the 1-month model? The analysis will be made in comparative terms. In particular, I will compare each month's rate of use of water inflows that results in the Cournot and in the competitive model. Results are reported in Tables A2.3, A2.4, A2.5 and A2.6

The assumption for the reservoir level at the end of the year turned out not to be important, as results from the "bounded" and "unbounded" almost coincide.

The starting month assumption is more important for the competitive equilibrium than for any of the Cournot models estimated. In the latter, the pattern of hydro scheduling is almost always the same (but magnitudes differ), no matter what month was assumed to be

[93] The problem to this argument is that all the observations are from periods in which the management of hydro resources is supposed to have been competitive.

the first. In particular, water is stored in June and July (winter months) and October and November. Water from June and July is completely shifted to August and September, while water stored in October and November is allocated to the first half of the year. In the case of the competitive equilibrium, when the model was estimated assuming that the initial month was any of the first 5 months, all the water available was exhausted in every 1-month period. Results start to change as June and the months in the second half of the year are assumed to be the "initial month", as there is enough water to be stored and used in a later period[94]. In a perfectly competitive industry, water would be stored in the second half of the year, the rainy and melting season, and released in the first half of the next year. This allocation is in line with the availability of hydro production relative to demand as power is "saved" in the periods when it is relatively abundant and it is released when it is relatively scarce.

As I mentioned, a Cournot producer would store power in June, July, October and November. According to these results, it could not be argued that water is allocated from low elasticity months to high elasticity months. Indeed, as Table A2.6 reports, the correlation coefficient between the average price elasticity of demand and the rate of use of available hydro flows is positive, as expected, but relatively small (0.37). Firm 1's hydro scheduling strategy is closer to the conclusions of the traditional competitive supply-demand analysis, where water is stored in those periods in which it is relatively abundant and released when it is relatively scarce. This conclusion is supported by the correlation coefficient between the rate of use of available hydro flows and the inflows/demand monthly ratio (-0.89). See Charts A2.1 and A2.2 for a graphic support of the relative importance of each of the alternative explanations for the hydro scheduling strategy.

In order to understand why Firm 1 does not inter-month differences in demand elasticity, two alternative hypotheses are formally analyzed.

1. *Intra-month differences in demand elasticity are big enough* and water can be allocated within a month in order to exercise market power. In order to analyze this hypothesis, I estimated the model assuming no intra-month differences in demand elasticity and keeping constant inter-month differences. A priori, this explanation does not sound plausible as I assumed that there are only two periods in each month and therefore, demand variability is considerably reduced. If this hypothesis is true, then we should observe that given that producers cannot exploit intra-month demand variability, greater inter-month reallocation should be observed. As it is reported in Table A2.6, column (2), the resulting correlation coefficient between the use rate of available inflows and price-elasticity of demand is still positive, but considerably smaller. At the same time, the correlation with the inflows/demand ratio is still high and thus the relationship strong. Accordingly, intra-month variability seems not to be a good explanation.

2. *Inter-month differences in demand elasticity are relatively small. As a result, the incentive to exploit them is also small.* In order to test for this hypothesis, I estimated the model assuming that price elasticity of market demand was not -1/3 at the peak anchor point, as I did in the previous exercise, but could take different values (E=-0.1, -1/3, -1/2, -2/3, -1.0) which were randomly allocated to each month. Consequently, inter-month variability of price elasticity of demand was 7 times higher. Results are fully supportive of this hypothesis. Indeed, the correlation coefficient is very high (0.95) and it is almost unaffected when no intra-month variability is assumed (column (4)).

[94] In line with this result is the greater standard deviation that resulted in the competitive model.

Observe that the larger are inter-month differences in price elasticity, the more incentives Firm 1 has to allocate its hydro resources in order to exercise market power and the less relevant is the traditional competitive supply-demand analysis in order to understand the hydro scheduling strategy (See Figures A2.3 and A2.4). Preliminary evidence from a 1-year model is in line with the MVW analysis: producers' incentive to exercise market power by shifting water from one month to another depends on how large inter-month differences in price elasticity are. The smaller the difference, the closer is the hydro scheduling strategy to the traditional supply-demand analysis' conclusions (i.e. more water to periods in which water is relatively scarce).

I would like to conclude this analysis by emphasizing that this model is just an attempt to address the issue of hydro scheduling over a longer planning horizon when firms have market power. It is clear that an additional modeling effort is needed in order to have more definitive answers. In particular, it is necessary to improve the treatment of uncertainty and to further increase the planning horizon (in order to reduce the importance of the starting and final points).

Tables Appendix 2

Table A2.1 : Data to estimate residual demand (E=-1/3)

Month	t	Average Load (MW)	Price (US$/MW)	A	B	qPS	qMR
Jan	1	4169.4	31.14	5559.2	44.6	180.7	590.9
Jan	2	3178.6	31.14	4238.1	34.0	137.8	590.9
Feb	3	4008.4	31.14	5344.6	42.9	148.6	566.2
Feb	4	3492.2	31.14	4656.3	37.4	144.0	566.2
Mar	5	4386.8	31.14	5849.1	47.0	489.2	509.5
Mar	6	3439.9	31.14	4586.6	36.8	372.3	509.5
Apr	7	4176.0	31.10	5568.1	44.8	259.9	394.5
Apr	8	3300.8	31.10	4401.1	35.4	137.8	394.5
May	9	4321.9	31.10	5762.5	46.3	406.9	399.6
May	10	3433.8	31.10	4578.4	36.8	137.9	399.6
June	11	4398.8	31.10	5865.1	47.1	489.2	455.7
June	12	3364.4	31.10	4485.9	36.1	387.6	455.7
July	13	4286.3	31.10	5715.0	45.9	489.2	447.2
July	14	3295.8	31.10	4394.4	35.3	313.0	447.2
Aug	15	4224.6	31.10	5632.7	45.3	489.2	431.5
Aug	16	3302.0	31.10	4402.7	35.4	396.4	431.5
Sept	17	4179.9	32.74	5573.2	42.6	489.2	473.9
Sept	18	3178.8	32.74	4238.4	32.4	368.9	473.9
Oct	19	4228.5	37.26	5637.9	37.8	489.2	498.7
Oct	20	3219.6	37.26	4292.9	28.8	322.0	498.7
Nov	21	4298.8	37.26	5731.7	38.5	489.2	587.0
Nov	22	3344.6	37.26	4459.4	29.9	317.4	587.0
Dec	23	4334.2	37.26	5778.9	38.8	489.2	603.1
Dec	24	3353.1	37.26	4470.8	30.0	249.7	603.1

Table A2.2 : Expected water inflows (GWh)

Month	Firm 1	Fringe	Total
January	940.5	118.5	1059.0
February	898.6	98.3	996.9
March	1012.6	320.5	1333.1
April	974.9	143.2	1118.0
May	1091.5	202.7	1294.3
June	1245.4	315.7	1561.1
July	1177.5	298.4	1475.9
August	1054.8	329.4	1384.2
September	953.7	308.9	1262.5
October	1177.1	301.8	1478.9
November	1094.7	290.4	1385.1
December	1004.9	274.9	1279.8

Table A2.3: Cournot model, "bounded version"

Hydro production / hydro production available

Starting month ↓	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Jan	100%	99%	99%	102%	100%	90%	97%	107%	109%	93%	98%	111%
Feb	117%	100%	98%	102%	100%	89%	95%	105%	108%	90%	95%	108%
Mar	115%	113%	98%	102%	100%	88%	94%	103%	106%	89%	94%	107%
Apr	114%	112%	110%	100%	100%	87%	93%	102%	105%	88%	93%	106%
May	113%	110%	109%	112%	100%	86%	92%	101%	103%	87%	92%	105%
Jun	112%	109%	108%	112%	106%	85%	91%	100%	103%	87%	91%	104%
Jul	111%	108%	106%	110%	104%	100%	90%	98%	101%	86%	90%	103%
Aug	109%	106%	105%	109%	103%	97%	104%	97%	99%	85%	89%	102%
Sep	109%	106%	105%	108%	103%	93%	99%	109%	99%	84%	89%	101%
Oct	109%	106%	105%	108%	103%	90%	97%	107%	109%	84%	89%	101%
Nov	106%	103%	102%	106%	100%	90%	97%	107%	109%	100%	87%	99%
Dec	103%	100%	99%	103%	100%	90%	97%	107%	109%	97%	103%	96%

Ratio > 100% → use > monthly inflow, ratio < 100% → use < monthly inflow (water is stored).

Table A2.4: Cournot model, "Unbounded version"

Hydro production / hydro production available

Starting month ↓	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Jan	100%	99%	99%	102%	100%	90%	96%	106%	108%	91%	96%	109%
Feb	117%	100%	98%	102%	100%	89%	95%	105%	108%	90%	95%	108%
Mar	115%	113%	98%	102%	100%	88%	94%	103%	106%	89%	94%	107%
Apr	114%	112%	110%	100%	100%	87%	93%	102%	105%	88%	93%	106%
May	113%	110%	109%	112%	100%	86%	92%	101%	103%	87%	92%	105%
Jun	112%	110%	108%	112%	106%	85%	91%	100%	103%	87%	91%	104%
Jul	111%	108%	106%	110%	104%	90%	90%	98%	101%	86%	90%	103%
Aug	109%	106%	105%	109%	103%	90%	96%	97%	99%	85%	89%	102%
Sep	109%	106%	105%	108%	103%	90%	96%	106%	99%	84%	89%	101%
Oct	109%	106%	105%	108%	103%	90%	96%	106%	108%	84%	89%	101%
Nov	106%	103%	102%	106%	100%	90%	96%	106%	108%	91%	87%	99%
Dec	103%	100%	99%	103%	100%	90%	96%	106%	108%	91%	96%	96%

Ratio > 100% → use > monthly inflow, ratio < 100% → use < monthly inflow (water is stored).

Table A2.5: Competitive model

Hydro production / hydro production available

Starting month ↓	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Jan	100%	100%	100%	100%	100%	92%	96%	101%	102%	92%	100%	113%
Feb	124%	100%	100%	100%	100%	90%	94%	99%	100%	91%	99%	112%
Mar	121%	121%	100%	100%	100%	89%	92%	97%	98%	89%	97%	110%
Apr	120%	120%	108%	100%	100%	88%	92%	96%	97%	88%	96%	109%
May	118%	118%	107%	118%	100%	87%	90%	95%	96%	87%	95%	107%
Jun	117%	117%	106%	118%	107%	86%	90%	94%	95%	86%	94%	106%
Jul	117%	117%	106%	106%	100%	100%	90%	94%	95%	86%	94%	106%
Aug	117%	117%	100%	100%	100%	98%	102%	94%	95%	86%	94%	106%
Sep	117%	108%	100%	100%	100%	96%	100%	105%	95%	86%	94%	106%
Oct	117%	102%	100%	100%	100%	94%	98%	104%	105%	86%	94%	106%
Nov	100%	100%	100%	100%	100%	95%	100%	105%	102%	100%	94%	106%
Dec	100%	100%	100%	100%	100%	95%	99%	104%	104%	96%	104%	100%

Ratio > 100% → use > monthly inflow, ratio < 100% → use < monthly inflow (water is stored).

Table A2.6: Rate of use of Inflows under different price elasticity assumptions.

	Hydro production / Inflows (Bounded version)					Average Elasticity of residual demand				St dev intra-month elasticity				Inflows/ net demand
	PC	(1)	(2)	(3)	(4)	(1)	(2)	(3)	(4)	(1)	(2)	(3)	(4)	
Jan	114%	110%	111%	66%	70%	0.46	0.46	0.14	0.14	0.10	0.0	0.03	0.0	0.39
Feb	110%	106%	106%	138%	137%	0.42	0.42	1.22	1.22	0.05	0.0	0.14	0.0	0.40
Mar	102%	104%	105%	76%	75%	0.47	0.47	0.14	0.14	0.09	0.0	0.03	0.0	0.46
Apr	104%	106%	96%	118%	119%	0.52	0.52	1.02	1.02	0.12	0.0	0.23	0.0	0.40
May	101%	102%	104%	95%	96%	0.43	0.43	0.43	0.43	0.06	0.0	0.06	0.0	0.45
Jun	92%	91%	91%	79%	78%	0.48	0.48	0.48	0.48	0.10	0.0	0.10	0.0	0.56
Jul	95%	95%	96%	80%	81%	0.47	0.47	0.47	0.47	0.09	0.0	0.09	0.0	0.52
Aug	99%	103%	104%	101%	99%	0.47	0.47	0.70	0.70	0.09	0.0	0.14	0.0	0.49
Sep	99%	105%	106%	113%	110%	0.45	0.45	0.87	0.87	0.10	0.0	0.18	0.0	0.48
Oct	90%	89%	90%	98%	97%	0.37	0.37	0.68	0.68	0.07	0.0	0.12	0.0	0.53
Nov	96%	92%	93%	129%	133%	0.38	0.38	0.95	0.95	0.07	0.0	0.14	0.0	0.50
Dec	107%	104%	105%	113%	110%	0.37	0.37	0.69	0.69	0.06	0.0	0.10	0.0	0.45
Average						0.44	0.44	0.65	0.65	0.08	0.0	0.11	0.0	0.47
stdev						0.05	0.05	0.34	0.34	0.02		0.06		0.06
Corr Elasticity	0.11	0.37	0.12	0.95	0.94									
Corr Inflows / Net demand	-0.92	-0.89	-0.73	-0.23	-0.25									

Ratio > 100% → use > monthly inflow, ratio < 100% → use < monthly inflow (water is stored).

Figure A2.1

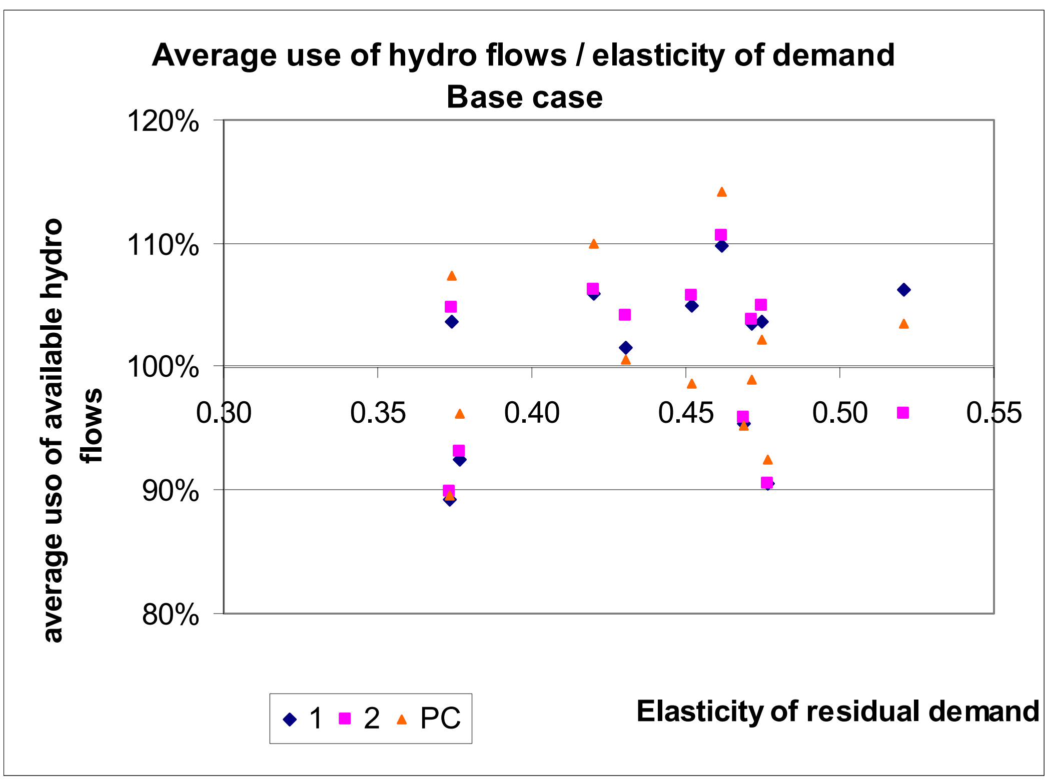


Figure A2.2

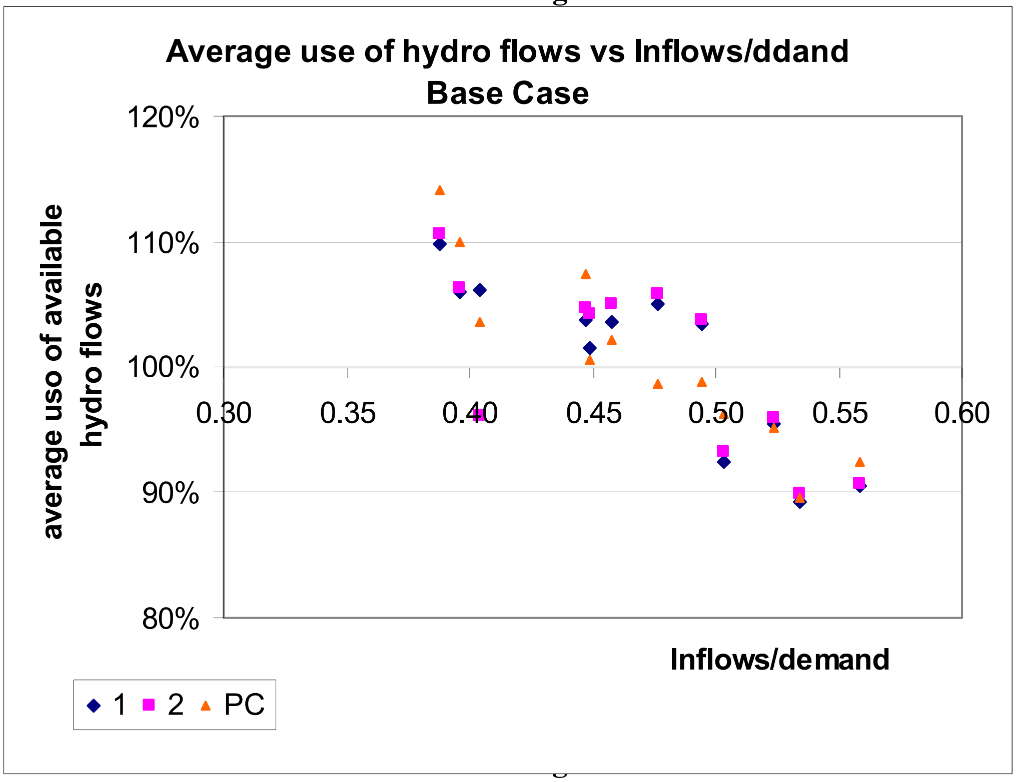


Figure A2.3

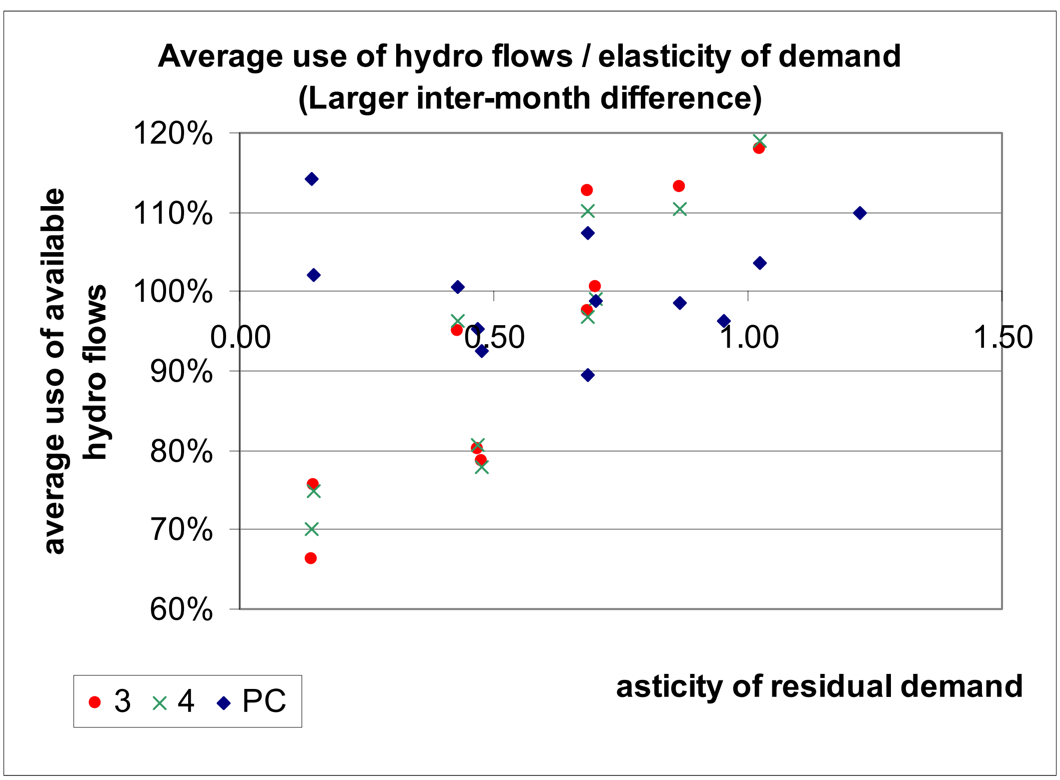
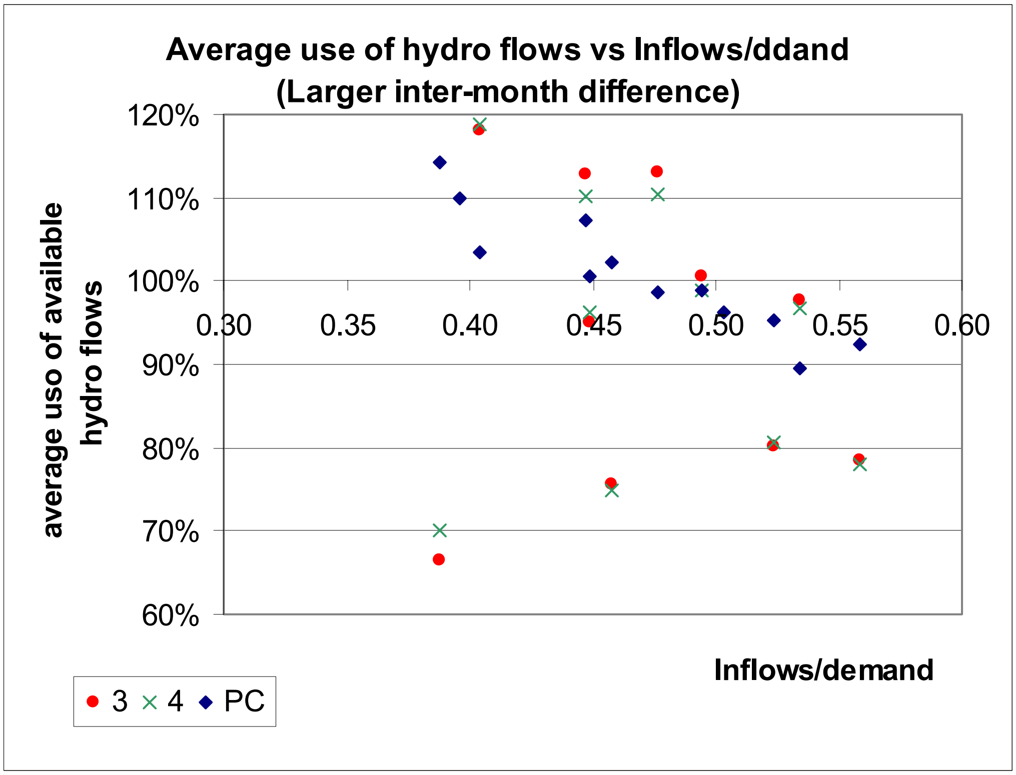


Figure A2.4



Average use of hydro flows vs Inflows/ddand
(Larger inter-month difference)
120%
110%
100%
90%
80%
70%
60%
0.30
0.35
0.40
0.45
0.50
0.55
0.60
average uso of available hydro flows
Inflows/demand
3
4
PC