ESSAYS ON COMPETITION IN ELECTRICITY MARKETS

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By

Ricardo Javier Bustos Salvagno, M.A.

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Ricardo Javier Bustos Salvagno, M.A.

Dissertation Advisor: Ian Gale Ph.D.

Abstract

The first chapter shows how technology decisions affect entry in commodity markets with oligopolistic competition, like the electricity market. I demonstrate an entry deterrence effect that works through cost uncertainty. Technology's cost uncertainty affects spot market expected profits through forward market trades. Therefore, incentives to engage in forward trading shape firms' decisions on production technologies. I show that high-cost but low-risk technologies are adopted by risk-averse incumbents to deter entry. Strategic technology adoption can end in a equilibrium where high-cost technologies prevail over low-cost but riskier ones. In the case of incumbents who are less risk-averse than entrants, entry deterrence is achieved by choosing riskier technologies. The main results do not depend on who chooses their technology first.

Chapter two examines the Chilean experience on auctions for long-term supply contracts in electricity markets from 2006 to 2011. Using a divisible-good auction model, I provide a theoretical framework that explains bidding behavior in terms of expected spot prices and contracting positions. The model is extended to include potential strategic behavior on contracting decisions. Empirical estimations confirm the main determinants of bidding behavior and show heterogeneity in the marginal cost of over-contracting depending on size and incumbency.

Chapter three analyzes the lag in capacity expansion in the Chilean electricity market from 2000 to 2004. Regarded as a result of regulatory uncertainty, the role of delays in the construction of a large hydro-power plant has been overlooked by the literature. We argue that those delays postponed projected investment and gave

small windows of opportunity that only incumbents could take advantage of. We are able to retrace the history of investments through real-time information from the regulator's reports and a simple model enables us to explain the effect of those delays on suggested and under-construction investments.

INDEX WORDS: Technology adoption; Entry deterrence; Forward markets; Chile; Long-term contracts; Auctions; Electricity; Regulation; Investment lag

This thesis research is dedicated to my parents and grandparents.

It would not have been possible without them.

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CHAPTER 1

TECHNOLOGY ADOPTION UNDER STRATEGIC FORWARD TRADING

1.1 INTRODUCTION

In commodity markets, we usually find competition in both the spot market and the forward market. The spot market can be identified with a short-term market, where the physical product itself is sold, while the forward market refers to a long-term contract market where production is sold in advance. There are two main ways in which forward trading can affect spot competition. First, it allows risk-averse firms to hedge risk and increase production in the spot market (Sandmo, 1971). Second, it can foster competition in oligopolistic spot markets even without uncertainty when firms engage in forward trading for strategic reasons (Allaz and Vila, 1993).[1] The nature of the strategic incentive is key in this paper.

In a two-period setting - where in the first period there is forward market competition and in the second period there is spot market competition - a firm has an incentive to sell a portion of its future production in advance. By selling forward, the firm is committing to a larger spot market production which, all else equal, reduces the competitor's market share. Since all firms face the same incentives, producers engaged in forward competition produce (and sell) more in the spot market than in

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[1]The strategic use of forward trading under oligopolistic competition starts with the seminal papers of Allaz (1992) and Allaz and Vila (1993). I will provide a more extensive literature review at the end of the paper, after main results are presented.

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the case when forward contracts are not available. As a result, spot prices are closer to the competitive level when the amount of forward sales increases.[2]

Recognizing the strategic impact of forward trading on spot market competition, it is relevant to ask about the effect of technology decisions. In commodity markets with forward transactions it is usually assumed that technologies do not have an effect on competition. Nevertheless, since each technology implies a specific level of cost uncertainty, technology adoption has an impact on risk-averse firms' expected payoff by changing hedging and strategic incentives to sign forward contracts.

An incumbent's technology choice can make entry less attractive to potential competitors, but an incumbent firm must balance cost volatility against the entry deterrence effect, especially if the incumbent is risk-averse. I show that technology choice allows incumbents to deter entry by adopting technologies with specific levels of cost volatility. When all firms are equally risk-averse, entry deterrence strategies can inefficiently bias technology adoption: technologies with higher expected cost but less risky are preferred over lower expected cost ones (Proposition 1.4.1). By choosing a safer technology the incumbent is committing to be tough in the forward market by selling forward. If the incumbent is less risk-averse than the entrant and there is enough difference in cost volatility between technologies, the incumbent is able to deter entry by adopting riskier technology (Proposition 1.4.2) even if expected marginal costs are the same for both technologies.

I consider an oligopolistic market for a homogenous good in which firms compete in quantities. First, firms choose their production technologies from an existing menu, each one with a known distribution of marginal costs, with perfect commitment. Second, firms sign observable forward contracts. Third, uncertainty is resolved, production is delivered and firms compete in the spot market. The model includes uncer-

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[2]I will describe this effect more fully in section 1.2.

tainty about production cost and risk aversion, which allows hedging and strategic reasons to determine jointly a firm's position in the forward market. Larger variance in production cost increases price volatility in the spot market, changing firms' incentives to trade forward. The direction of the change depends on the interaction between hedging and strategic effects. In short, my base model follows the original line of Allaz (1992) and my main contribution consists of including entry and endogenizing the technological decisions of all firms.

Technology choice can have important effects. A market dominated by low-risk technologies leaves less room for the development of newer but initially riskier technologies. The analysis can be applied to electricity generation or wholesale natural gas markets where homogeneous non-storable goods are traded forward, mostly under oligopolistic competition. For example, green-energy technology adoption can be blocked by strategic considerations. It is also possible to end in a situation where riskier technologies are preferred to reduce competition, amplifying the effect of random shocks over market variables.[3]

The basic model is described for n firms but to simplify the exposition, the main results are obtained for one incumbent and one entrant. I will consider three extensions of the above model: $n>1$ incumbent firms, alternative timing decisions, and competition in prices instead of quantities. Adding more incumbents just changes the likelihood of finding different accommodating equilibria. Changing the time line does not modify the main conclusions, but competition in prices instead of quantities makes deterrence more difficult.

Section 1.2 presents the basic model. Section 1.3 discusses the simplest case of a monopolist not facing any potential entrant. This case presents a benchmark

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[3]The issue becomes increasingly more relevant as in many places policymakers have required power distribution companies to contract for new supplies to mitigate resource adequacy concerns. For example: Brazil, Chile, Peru, Colombia, New Zealand, Illinois.

against which to compare a successful entry deterrence strategy. In section 1.4 entry is included. By considering different levels of the incumbent's risk aversion I obtain different entry deterrence strategies. Section 1.5 discusses extensions of the model. Section 1.6 provides a review of the related literature. Section 1.7 concludes and summarizes. Proofs are available in the Appendix A.

1.2   BASIC MODEL FOR n INCUMBENT FIRMS

Let us assume the following time line. In the first period all incumbent firms choose the technology they will use to produce. After the incumbents choose their technologies, but before they sign forward contracts, a potential entrant observes this technology decision and decides to enter or not.[4] If the entrant decides to participate in the market, then she also adopts a technology from the same set. In the second period, before competing in the spot market, firms can sign observable and enforceable forward contracts.[5] Finally, uncertainty about technology's cost is resolved before production is delivered and firms compete in the spot market. As a result, the amount of forward trading will be a function of cost volatility and the expected level of competition in the spot market. The time-line decision sequence is pictured in Figure 1.1.

Figure 1.1: Time line

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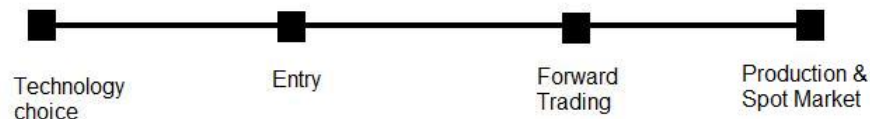
[4]The alternative case where the entrant chooses technology first or at the same time as the incumbents is developed as an extension of the basic model in section 2.5.

[5]A forward contract is a commitment to sell or buy at a pre-specified price that calls for delivery of the good in a future period.

In terms of information, there is full public information about costs, forward contracts and production decisions. All strategic variables are observable. Also, there is no discounting between periods and there are no costs in signing a forward contract. All of the above is common knowledge.[6]

In the next subsections I describe in detail how the agents interact in each period.

1.2.1 SPOT MARKET

There are n identical firms competing à la Cournot in a spot market for a single homogeneous non-storable good. The demand, for the sake of simplicity, is linear.[7] In this way, the inverse demand function would be $p_s = a - bX$, where $X = \sum_{j=1}^{n} x_j$, and x_j is the quantity produced by firm j. Both a and b are positive parameters. From now on I will assume $b = 1$.[8] Marginal cost is labeled by m_k for firm k and $a > m_k$ for any k. The quantity of forward contracts signed before spot market interaction by firm k is f_k and their price is p_f.

Firm k's profits in the spot market are given by:

$$\pi_k = p_s(X)(x_k - f_k) - m_k x_k + p_f f_k \tag{1.1}$$

The total quantity produced by firm k is x_k, so the amount sold at the spot price is $x_k - f_k$. The amount f_k has been contracted at price p_f. A positive value of f_k means the firm sold part of the production in advance, while a negative value of f_k indicates the firm bought production in advance. Thus if the firm bought in advance, the firm will sell at the spot price a quantity larger than x_k. Otherwise, the firm

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[6]These assumptions allow us to focus on the strategic interaction between technology adoption and entry deterrence. For a discussion about observability of forward contracts, see Hughes and Kao (1997).

[7]Allaz and Vila (1993) solve the nonlinear case of demand and cost with no significant change in their results. Here I have not considered nonlinearities.

[8]In case the parameter b affects a result I will point it out. Nevertheless, all the proofs in Appendix A consider the possibility of any positive value for b.

will sell less than x_k at the spot price. In financial terms, a firm that takes a "long position" is buying production in advance (buying forward), while a firm that takes a "short position" is selling production in advance (selling forward).[9]

Marginal revenue is $p_s - (x_k - f_k)$. Compared with $f_k = 0$, a positive amount of forward trading $f_k > 0$ creates a parallel shift up of the marginal revenue curve thereby augmenting the incentive to increase spot market output. The marginal revenue curve now intersects the inverse demand curve at $x_k = f_k$, as it can be seen in Figure 1.2. If $x_k < f_k$, marginal revenue is higher than price and the firm is a net buyer hence she benefits from a reduction in price caused by expanding x_k. Observe that marginal revenue does not depend on the contract price p_f.[10]

Figure 1.2: Effect of forward trading on marginal revenue curve

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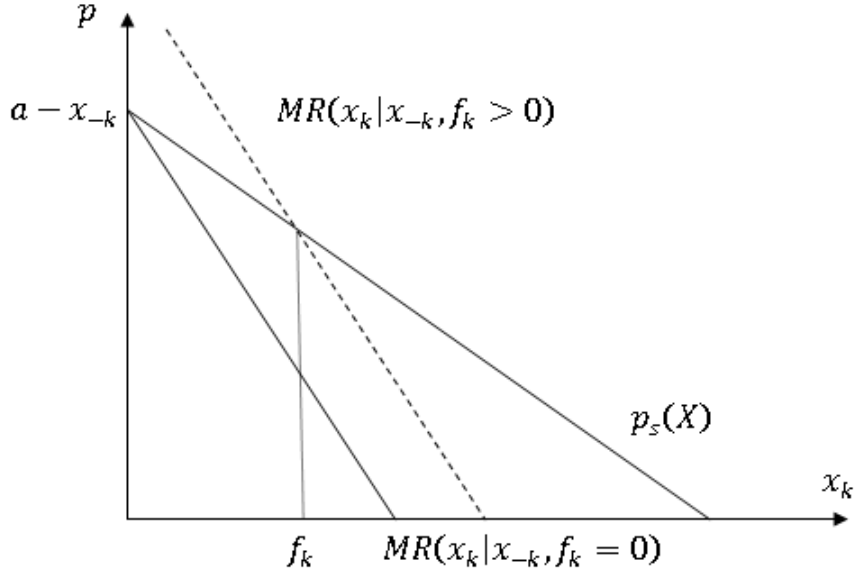
[9]In case the amount of forward sales is larger than the amount of physical production, those forwards are purely financial transactions without physical delivery. The shorter trader can settle his position by paying the spot price.

[10]The equilibrium in the spot market is not a function of p_f since revenue from forward market is already sunk at this moment.

The profit function can be expressed differently as:

$$\pi_k = [p_s(X) - m_k]x_k + [p_f - p_s(X)]f_k \tag{1.2}$$

This way it is possible to separate profits coming from spot market production (first term on the RHS) and profits that come from forward trading (last term on the RHS). Maximizing (1.2) with respect to x_k, yields the reaction function for firm k.

$$x_k(x_{-k}) = \frac{a - m_k - \sum_{j \neq k}^{n} x_j + f_k}{2}$$

The key point here is that the reaction function is increasing in f_k and is affected by other producers' contracts only through their expected production levels, x_j. This means that regardless of competitors' production levels, selling forward pushes the reaction curve out and reduces competitor's residual demand.

Solving for the unique equilibrium in the spot market, we obtain:

$$x_k = \frac{a - nm_k + \sum_{j \neq k}^{n} m_j}{(n+1)} + \frac{nf_k - \sum_{j \neq k}^{n} f_j}{(n+1)} \tag{1.3}$$

$$p_s = \frac{a + \sum_{k=1}^{n} m_k}{n+1} - \frac{\sum_{k=1}^{n} f_k}{n+1} \tag{1.4}$$

The first part of the RHS in (1.3) and (1.4) is the usual result from Cournot competition with heterogenous costs. The second part is the forward market interaction.[11] Due to the change in the reaction curves of producers that choose trade forward, a positive amount of forwards (sell forward) lowers the spot price while a negative amount (buy forward) raises it.[12] In sum, the result of the forward market will affect spot market competition.

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[11]With symmetric amounts of forward contracts $f_k = f_j = f$, each firm's spot output expands by $\frac{f}{n+1}$ while spot price falls by $\frac{n}{n+1}f$.

[12]Allaz and Vila's framework is characterized by a setting without uncertainty and Cournot competition that leads to firms only selling forwards. In my setting, firms will be able to sell or buy forward depending on risk aversion and cost volatility levels. However x_k and p_s are constrained to be always positive.

1.2.2 FORWARD MARKET

There are producers willing to trade forward and speculators or arbitrageours willing to sign those forward contracts.[13] Both producers and speculators participate in the forward market by taking out contracts. These contracts can be purely financial transactions or can call for a physical delivery of the good.[14] Before spot market interaction, producers sign forward contracts with speculators. If producers sell forward, speculators buy forward and vice versa. In the spot market, all the production is delivered and producers and speculators close their positions.[15] Speculators obtain profits from the difference between the forward price and the spot price. They are assumed to earn zero profits due to free entry and exit. For this reason, they are indifferent about different levels of forwards.[16] I will assume that speculators are risk-neutral. As Allaz (1992) shows, in such a case, the forward price in equilibrium is an unbiased predictor of the future spot price.[17]

We have assumed that firms do not know the value of their marginal cost until they are about to produce the good for the spot market. At the moment of signing forwards, firms just know the expected values of their payoffs. The attitude toward risk will be a key feature for firm strategic interaction. I will assume a simple form for

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[13]The literature on forward trading uses "speculators" to label agents who sign forward contracts with producers, but in other markets - like the power market - these agents can also be retailers.

[14]In the Allaz and Vila (1993) model it makes no difference whether to adopt a physical or financial view of forward contracts as long as firms compete in quantities in the spot market. In this paper there will be cases where physical delivery is not possible because the amount of forward trade exceeds the quantity produced in equilibrium.

[15]All agents must close their positions at the spot market. With physical delivery, those agents who bought forward receive the good from those who sold forward. If there is not physical delivery, those who sold forward must pay the spot price to those who bought forward.

[16]They act competitively so there are no arbitrage opportunities.

[17]The expected payoff of speculator i that signed forward contracts g_i are $E[(p_s - p_f)g_i]$, where the expectation is taken with respect to the random cost parameter. Such assumptions allow us to focus on the producers' side, in a partial equilibrium setting.

the firm's payoff function that accounts for this feature, in the spirit of Allaz (1992):[18]

$$\Pi_k = E[\pi_k] - \frac{\lambda_k}{2} Var[\pi_k] \qquad (1.5)$$

where λ_k is the constant degree of risk aversion of firm k. A risk-neutral firm has $\lambda_k = 0$. Substituting profits π_k from (1.2) into (1.5) we obtain the expected payoff function for forward and spot markets. Risk-neutral speculators give a forward price as an unbiased predictor of the future spot price, so $p_f = E(p_s)$. Then, expected payoff for firm k is:

$$\Pi_k = E[(p_s - m_k)x_k] - \frac{\lambda_k}{2} Var[\pi_k] \qquad (1.6)$$

where the marginal cost m_k is a random variable due to cost uncertainty.[19]

Each firm will maximize (1.6) by choosing an amount of forward contracts, recognizing (1.3) and (1.4).[20] As a result, the amount of forwards is a function of technology, risk aversion and number of competitors.

The effect of signing forward contracts on the expected payoff is shown in equation (1.7) and has three components. The first effect is the direct result of the own forward trade over the own production in the spot market. The second is Allaz and Vila (1993)'s strategic effect where the incentive to sell forward reduces competitors' production. The last effect is the result of spot market uncertainty so firms have an incentive to hedge the risk by forward trading.

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[18] I use a mean - variance payoff function for the risk-averse firm, with constant absolute risk aversion. This kind of function has a central role in modern theories of portfolio selection and asset pricing.

[19] The expected payoff of a risk-averse firm have four components, the expected payoff in the spot market, the variance of the profit in the spot market, the variance from signing forwards, and the covariance between profits in both markets: $Var[\pi_k] = Var[(p_s - m_k)x_k] + Var[(p_f - p_s)f_k] + 2Cov[(p_s - m_k)x_k, (p_f - p_s)f_k]$.

[20] A complete description of producers' and speculators' optimizing decisions can be found in Allaz (1992).

$$\frac{\partial \Pi_k}{\partial f_k} = E\left[\underbrace{\frac{\partial x_k}{\partial f_k}(p_s - x_k - m_k)}_{\text{Direct effect}} - \underbrace{\left(\sum_{j \neq k}^{n} \frac{\partial x_j}{\partial f_k}\right) x_k}_{\text{Strategic effect}}\right] - \underbrace{\frac{\lambda_k}{2}\frac{\partial Var[\pi_k]}{\partial f_k}}_{\text{Risk-hedging effect}} \qquad (1.7)$$

There are different situations to consider. First, assume the firm is risk-neutral, $\lambda_k = 0$, so the net effect of f_k on Π_k depends on size and direction of the strategic and the direct effect. If $f_k > 0$, the direct effect is negative and the strategic effect is positive. A firm selling forward reduces its own expected payoff through the direct effect.[21] Ceteris paribus, a larger amount of forwards increases spot quantities and reduces the spot price. However, a firm can increase the expected payoff through the strategic effect by reducing competitors' production in the spot market, as the reaction function shifts out. If $f_k < 0$, both effects are negative. The sign of the strategic effect changes because buying forward increases competitor's production in the spot market.

Second, assuming a risk-averse firm, the risk-hedging effect depends on the source of uncertainty. Demand uncertainty does not have the same effect than cost uncertainty. In order to explain this feature, the next section describes the source of uncertainty.

1.2.3 TECHNOLOGY ADOPTION

I will introduce uncertainty in a different fashion from Allaz (1992), where there is demand uncertainty.[22] Since the purpose of this paper is to address how the strategic interaction in forward and spot competition shapes technology decisions, I assume that firms face cost volatility. This is a common feature in energy markets. For

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[21] The first order condition of maximizing profits in the spot market is equal to $p_s - x_k - m_k = -f_k$.

[22] Demand uncertainty is dominant in this literature of forward trading besides the work of Hughes and Kao (1997) and Downie and Nosal (2003).

example, power is a non-storable good, which makes electricity prices particularly exposed to fuel price volatility and to surges caused by temporary imbalances between demand and supply.[23] Unstable political situations can have a similar effect.[24] Since I have not included capacity constraints, this kind of uncertain supply just changes the expected level of cost.

Demand uncertainty and cost uncertainty yield different incentives in the forward market. Under demand uncertainty, risk-averse firms will hedge the risk by selling forward. They sell part of the production in advance at a fixed price. Under cost uncertainty, the mechanism is different. By selling forward, the firm would be increasing the risk exposure by ending with more production in the spot market. Instead, by buying forward the firm decreases production in the spot market and, consequently, reduces risk exposure. As Hughes and Kao (1997) explained, since production is made after uncertainty is resolved, sequential rationality implies that profit maximizing decisions at the spot market will be made as in the risk-neutral case. Then, forward contracts can be used to buy production back before uncertainty is resolved and partially undo spot market decisions.

Considering cost volatility, in equation (1.7) the risk-hedging effect will be negative is the firm sells forward (a positive amount of forwards will increase variance) and positive if the firm buys forward (a negative amount of forwards will reduce variance). Then firms can increase the expected payoff by taking long positions in the forward market. However, that will make the strategic effect negative. In order to find the final impact on expected payoffs I need to impose some structure on the cost function.

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[23]Production of hydropower is affected by water availability in several countries (e.g. Brazil, Norway, Chile, New Zealand).

[24]Russia - Ukraine gas disputes since 2005 have occasioned supply disruptions in many European nations, increasing natural gas cost volatility.

All technologies will be characterized by their marginal cost mean and variance. The marginal cost m_k is equal to $c_k + \theta_k$. θ_k is a random variable with mean 0, variance σ_k^2 and a symmetric distribution.[25] A riskier technology will have a larger variance. Technology adoption will consider not only the expected marginal cost c_k but also the volatility level given by σ_k^2. It is assumed that $0 < c_k + \theta_k < a$, for all k. In short, firms adopt an existing technology from a non empty set, considering its characteristics in terms of expected marginal cost and variance.[26]

I will simplify the set of available technologies by assuming there are only two levels of risk. A technology r with $\sigma_r^2 = \sigma^2 \neq 0$ and a technology s with $\sigma_s^2 = 0$. The first one is the risky technology and the second is the safe or zero risk technology. All firms, incumbents and entrant, have the opportunity to choose the same technology.

In terms of expected marginal cost c_k, I will assume that $c_r \leq c_s$. The safer technology has an expected marginal cost at least as high as the riskier one.[27] This assumption allows to understand how decisions are made when there is a trade off between uncertainty and expected marginal cost.

If we consider a situation where there is no forward trading, due to the convexity of profits in costs, a risk-neutral firm will prefer to adopt a riskier technology over a safer one.[28] A risk-averse firm will adopt the safer technology only if cost volatility

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[25]The assumption of a symmetric distribution is made to simplify the covariances calculation.

[26]Adopting a technology assumes perfect commitment with it. For example, in investment projects where environmental permissions are needed and obtained after extensive studies, moving from one technology to another could be highly expensive.

[27]For example, in power generation, hydroelectric dams have a low marginal cost when there are plenty of rains but a higher volatility, due to the possibility of a draught. Coal plants have a higher expected marginal cost but low volatility about it.

[28]This is called "relative output variation effect" by Creane and Miyagiwa (2009).

is high enough to overcome the convexity effect.[29] With a forward market, forward purchases can hedge cost uncertainty so the likelihood of risk-averse firm adopting a riskier technology increases. However, competition in the forward market depends also on strategic incentives to sell forward. In sum, it is possible to define two different channels through which technology adoption affects expected payoffs: a direct effect due to the convexity of profits in costs that favors riskier technologies and an indirect effect through forward trading.

1.3 RESULTS UNDER NO THREAT OF ENTRY

In order to present how the forward-spot interaction works with endogenous technology adoption, I start with the case of no threat of entry.[30] This section considers two extreme situations. First, I go through the case where there is no hedging incentive for forward trading. This case characterizes the behavior of a risk-neutral firm. Second, I explain the case with no strategic incentive to sign forward contracts. This case describes the incentives of a single risk-averse firm.

1.3.1 WITHOUT HEDGING INCENTIVE

Suppose that all the firms are risk-neutral so there are no hedging reasons to sign forward contracts. The problem then collapses to the one considered in Allaz and Villa (1993) where $\lambda_k = 0$. In other words, equation (1.7) reduces to only direct and strategic effects. Firm i maximizes expected payoff (1.6) with respect to f_i to obtain

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[29]For example, under our setting and assuming $Var(\theta^2) = 0$, a risk-averse monopolist's expected payoff will be: $\frac{(a-m)^2}{4} - \frac{\lambda\sigma^2}{2}\frac{(a-m)^2}{4}$. In this case expected payoff is convex in cost m if and only if $\lambda\sigma^2$ is below 2.

[30]This case gives a benchmark to compare with the entry deterrence case.

the reaction functions in the forward market.

$$f_i(f_{-i}) = \frac{(n-1)(a - nm_i + \sum_{i \neq j}^{n}(m_j - f_j))}{2n} \qquad (1.8)$$

Forwards are strategic substitutes in this case because by selling forward a firm is reducing the residual demand of the competitors in the spot market.

The optimal amount of contracts each firm will sign is:

$$f^* = \frac{(n-1)(a - nm_i + \sum_{i \neq j}^{n} m_j)}{(n^2 + 1)} \qquad (1.9)$$

Selling forward is a "tough investment" in the sense that it lowers the rival's output, all else equal, so firms will over-invest in forwards when they compete in quantities.[31] Then, as Allaz and Vila (1993) showed, producers will sign forwards to improve their situations on the spot market, even without uncertainty.

Equilibrium expected payoffs, assuming $m_i = m$, $\forall i$, are:

$$E[\Pi^*] = \left[\frac{(n^2 + n)(a - m)^2}{(n^2 + 1)^2(n + 1)} \right] \qquad (1.10)$$

It can be verified that a positive amount of forwards reduces equilibrium expected payoffs.[32] As Allaz and Vila (1993) pointed out, firms engaged in forward competition produce more than in the case when forward markets are not available. Their best response functions give a positive amount of forward contracts, but equilibrium payoffs end up lower. It is a prisoner's dilemma type of situation.[33]

In this situation, firms will choose the risky technology because (1.10) is convex in cost m. This decision will not affect incentives to forward trading because firms are risk-neutral. In terms of technology adoption, we have the same result as without

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[31]If they compete in prices, forwards are strategic complements. It is optimal to buy forward as is shown in Mahenc and Salanie (2004).

[32]Cournot profits are equal to $\frac{(a-m)^2}{(n+1)^2}$ and are bigger than (1.10).

[33]As a result, there is a competitive effect of forwards - in terms of price being closer to marginal cost - on the spot market equilibrium.

forward trading because there is no indirect effect of technology on expected payoffs. In terms of expected payoffs, firms are worse off because of their strategic incentive to sell forward.

1.3.2 WITHOUT STRATEGIC INCENTIVES

Assume now we have only one firm producing in the market. There is no competition nor threat of entry so no strategic effect in equation (1.7). If this monopolist is risk-neutral, $\lambda_k = 0$, the direct effect is the only effect in (1.7). As a result, the optimal amount of forwards signed by a risk-neutral monopolist is zero. Assuming the monopolist's expected marginal cost is m_m and σ^2 its variance, expected payoff from (6) is:

$$\Pi_m = \frac{(a - m_m)^2 - (f_m)^2}{4} \tag{1.11}$$

Only $f_m = 0$ maximizes the expected payoff. In terms of technology adoption, the risk-neutral monopolist will choose risky technology because the expected payoff is convex in costs. This is the same result as in the case without forward market.

Introducing risk aversion makes the monopolist willing to sign forward contracts to hedge the risk in case he chooses the risky technology. The spot market solution is the same as in (1.3) and (1.4), but for $n = 1$. In the forward market, the monopolist will sign a negative amount of f_m: the monopolist buys forward. As Hughes and Kao (1997) state, without a strategic effect the negative hedge risk effect dominates under cost uncertainty.

$$f_m = -\frac{(a - m_m)\lambda_m \sigma^2}{(2 + \lambda_m \sigma^2)}$$

The monopolist is buying his own production in advance. He is creating a demand for his own spot output. At the spot market, the speculators must close their positions.

If the monopolist buys in advance more than what is produced in the spot market, there is not physical delivery and speculators will have to pay the spot price to the monopolist. Since buying forward decreases spot output, the monopolist ends up increasing the spot price.[34]

The constant risk-averse parameter λ_m and cost variance σ^2 become important together. I will refer to them together, using the term "impact of cost volatility". It tells how much the cost variance of a technology impacts a risk-averse firm. The monopolist buys more forwards the higher the impact of cost volatility, that is, due to more risk aversion or higher cost variance.[35]

There is an increasing relationship between the monopolist's expected payoff and the level of impact of cost volatility. The reason behind this result is that higher $\lambda\sigma^2$ increases forward purchases. The monopolist hedge the risk buying forward and as a result, spot price increases.

In terms of technology adoption, a risky technology will increase the hedging reason to buy forward.[36] Then, the monopolist's expected payoff is increasing in $\lambda_m\sigma^2$. If this is true, the monopolist will always choose the risky over the safe technology. In case of risk-neutrality, because of payoff's convexity in costs; and in case of risk aversion, because of the risk-hedging incentive to buy forward.

However, for low levels of impact of cost volatility, the direct effect in (1.7) can exceed the risk-hedging effect and the payoff's convexity. In that situation, the monopolist will prefer not to participate in the forward market, sign zero amount of forwards

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[34]Mahenc and Salanie (2004) mention evidence of powerful producers that tend to buy forward to sustain spot prices.

[35]In the finance literature, $\lambda\sigma^2$ is the risk premium or expected excess of return of an ex-ante efficient portfolio. The larger the risk premium of the benchmark portfolio, the bigger is the incentive to buy forward.

[36]A negative amount of forwards reduces production in the spot market, but spot production never becomes negative no matter the level of cost uncertainty.

and choose the risky technology. In case the monopoly has to participate in the forward market, he will choose technology s. The next proposition states the technology adoption condition for a risk-averse monopolist without entry.

Proposition 1.3.1 *A risk-averse monopolist who faces no threat of entry will choose the risky technology if and only if the impact of cost volatility is high enough and he signs a non-zero amount of forwards.*

Proof: See Appendix.

The exact conditions of Proposition 3.1 can be found in the Appendix but here it is easier to focus on the simple case where $c_r = c_s$ in order to abstract from differences in expected marginal costs. If the riskier technology has a low impact of cost volatility, the best option for the monopolist is to choose the riskier technology and does not sign any forward contract. He will still prefer the riskier over the safer one due to the convexity of profits, and the hedging incentive is not high enough to overcome the direct effect of forwards reducing the expected payoff by distorting spot market decisions. However, if the monopolist signs a non-zero amount of forwards, the best option in that case is the zero risk technology.[37] Once the uncertainty is sufficiently high, the hedging incentive is big enough and the monopolist can increase his expected payoff by choosing the riskier technology. Since the monopolist faces no strategic incentive to sell forward, using technology options with more risk means higher payoffs by buying forward.

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[37]This hold for any positive value of $\lambda_m \sigma^2$ below 0.733.

The introduction of potential competition changes the incentives of the incumbent firm and technology choice becomes a strategic decision. If both firms were risk-neutral, we would be in the Allaz and Vila case, where firms sign forwards only for strategic considerations. There would be entry if the entry fixed cost, $K > 0$, is affordable and both firms will share the market equally. The technology adopted will be the risky one due to profit's convexity in cost. A more general result can be found when we deal with risk aversion among firms.

1.4.1 If all firms are equally risk-averse

Consider the case where the firms have the same level of risk aversion and choose the risky technology r. The optimal amount of forward trading for the entrant (f_e) and incumbent (f_i) under the assumption that both choose technology r will be:

$$f^* = \frac{(9 - 14\lambda\sigma^2)(a - c_r)}{(45 + 35\lambda\sigma^2)} \tag{1.12}$$

If the impact of cost volatility is low enough to make $9 - 14\lambda\sigma^2$ positive, both firms will sell forward. The strategic effect is positive and exceeds the negative hedging and direct effects. However, if impact of cost volatility is high enough, both firms will be buying forward.[38] The larger $\lambda\sigma^2$, the hedging effect becomes more important in relation to the strategic and direct effect. It is optimal to buy forward if the impact of cost volatility is large enough. In this case we end with the same result a risk-averse monopolist but softened by competition.

In case the incumbent and the entrant choose different technologies, they will have different incentives in the forward market. If the incumbent chooses the safe

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[38]In the case $b \neq 1$, this condition becomes $9b - 14\lambda\sigma^2$.

technology and the entrant the risky technology, the incumbent will sell forward regardless of $\lambda\sigma^2$ level. His hedging incentive can not exceed the strategic and direct effect. The entrant, in contrast, will buy forward if $\lambda\sigma^2$ is large enough.[39] In case the incumbent choose the risky technology and the entrant the safe one, we have the opposite result.

In terms of aggregate forward trading, the amount of forward sales is always larger that the amount of forward buying if the firms choose different technologies. This means that the spot price decreases due to net forward sales. Only if both firms choose the risky technology and impact of cost volatility is high enough, there will be net forward purchases and spot price will increase.

If both firms choose technology s, expected payoffs are the same as in the risk-neutral case in (1.10). I will denote this payoff level $\underline{K} = \frac{2(a-c_s)^2}{25}$. Figure 1.3 shows the expected payoff of the entrant as the impact of cost volatility increases for different technology choices.[40]

If both firms choose technology r, we know from (1.12) that it is optimal for both firms to decrease their amount of forward sales. This decrease has a positive effect on expected payoffs for two reasons: first, firms do not hurt each other through the strategic effect; and second, the risk-hedging effect increases as forward sales decrease (if $9/14 > \lambda\sigma^2$) or forward purchases increase (if $9/14 < \lambda\sigma^2$). For this reason, $\Pi(c_r, c_r)$ rises with impact of cost volatility. In sum, by choosing the risky technology both firms commit to reduce their incentive to sell forward. This commitment increases their payoff by reducing the strategic effect and increasing their risk-hedging effect. The asymptotic level of $\Pi(c_r, c_r)$ as impact of cost volatility increases is $\frac{3(a-c_s)^2}{25}$ and I will denote it as $\bar{K}$.

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[39] See Appendix for the optimal amount of forward expression in each case.

[40] $\Pi_e(c_i, c_e)$ denotes entrant's expected payoff when the incumbent chooses technology i and the entrant chooses technology e.

Figure 1.3: Entrant's expected payoff with equally risk-averse firms
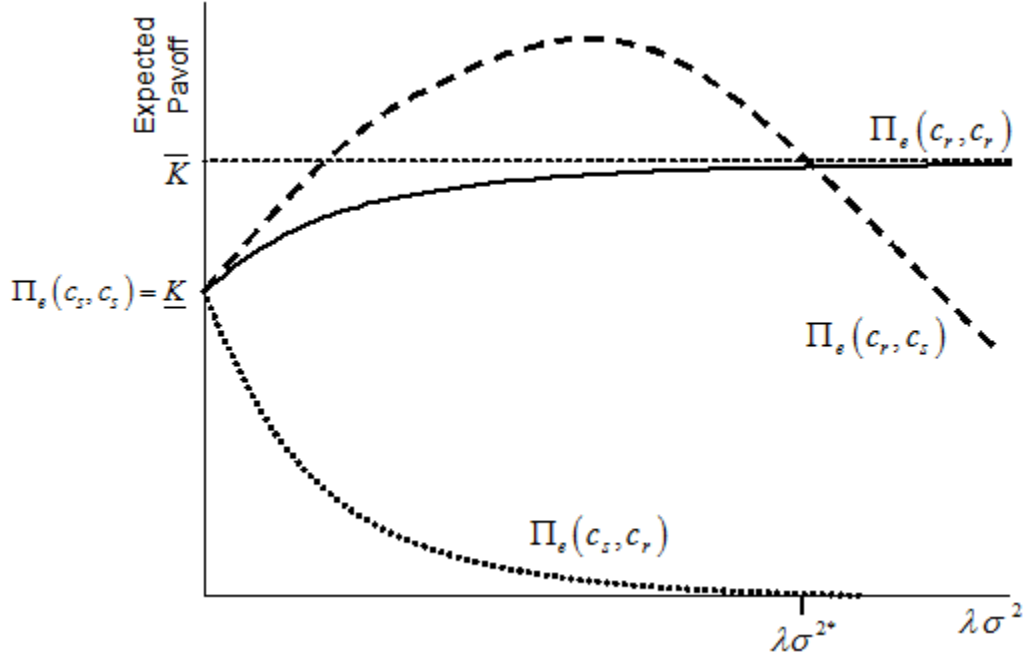
In case the entrant chooses the safe technology and the incumbent the risky one, the entrant will experience an increase in expected payoff if the impact of cost volatility is not too high because the incumbent is committing to reduce his strategic forward sales while the entrant is committing to increase hers. The entrant will strengthen her position in the spot market, while the incumbent will have to face a smaller residual demand in the spot market. However, for large enough values of $\lambda\sigma^2$, the entrant's expected payoff will decrease with the impact of cost volatility due to an increasing negative risk-hedging effect. For this reason $\Pi(c_r, c_s)$ has a concave shape.

If the entrant chooses the risky technology and the incumbent the safe one, the entrant's expected payoff will decrease with the impact of cost volatility. The entrant

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commits to reduce her strategic effect while the incumbent is increasing his forward sales. Not even an increasing risk-hedging effect can overcome the negative strategic effect. $\Pi(c_s, c_r)$ is always decreasing in $\lambda\sigma^2$.

In order to deter a potential entrant, the incumbent must choose a technology that keeps the entrant with small enough payoff so K becomes unaffordable. The only deterrence strategy is to choose the zero risk technology.

The next proposition resumes incumbent's strategies on technology adoption:

Proposition 1.4.1 *A risk-averse incumbent will choose:*
a) the safer technology to deter an equally risk-averse entrant if $\underline{K} < K < \bar{K}$.
b) the safer technology to accommodate if and only if $K \leq \underline{K}$ and the impact of cost volatility is low.
c) the riskier technology to accommodate if and only if $K \leq \underline{K}$ and the impact of cost volatility is high.

Proof: Appendix.

The deterrence equilibrium implies adoption of technology s. There is no room to choose technology r, because it would be advantageous for the entrant to adopt technology s if $\lambda\sigma^2 < \lambda\sigma^{2*}$, and r otherwise. By choosing s, the incumbent is committing to be tough in the forward market. Therefore, deterrence is obtained not because of the higher uncertainty of the technology but because the entrant can not take advantage of choosing a risky technology that will reduce the "curse" of strategic forward selling.

The lower threshold $\underline{K}$ for entry deterrence is decreasing in c_s. Since there is deterrence if the fixed cost of entry is high enough, the larger c_s the easier deterrence can be. Selling forward facilitate deterrence in this case and bias technology adoption into

higher expected marginal cost technologies. If $c_r < c_s$, the incumbent will be willing to choose an inefficient technology with larger expected marginal cost if deterrence is possible. For example, a power generator incumbent will prefer a higher marginal cost but safe technology (i.e. coal) instead of a lower marginal cost but riskier technology (i.e. wind) in order to deter entry.

If deterrence is not possible, the accommodation equilibrium results in (r, r) adoption if the cost volatility impact is above a threshold value, $\lambda\sigma^{2*}$, and (s, s) if it is below. If the cost volatility impact is low, the incumbent will accommodate by sharing the market without any risk. However, if technology r is volatile enough, both firms will benefit from adopting it. In both accommodation equilibria, the incumbent has to share the market equally with the entrant.

1.4.2 If the incumbent is risk-neutral

In this section, I will assume that the entrant is more risk-averse than the incumbent: $\lambda_e = \lambda > 0 = \lambda_i$. [41] There is no loss of generality in assuming that the incumbent is risk-neutral. For the sake of simplicity, I will focus on the case where $c_r = c_s$.

If both firms choose the risky technology, the optimal amount of forwards for each firm is:

$$f_e^* = \frac{(9 - 14\lambda\sigma^2)(a - 3c_i + 2c_e)}{(45 + 70\lambda\sigma^2)} \tag{1.13}$$

$$f_i^* = \frac{9(a - 3c_i + 2c_e) + 7\lambda\sigma^2(3a - 4c_i + c_e)}{(45 + 70\lambda\sigma^2)} \tag{1.14}$$

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[41]Under imperfect credit markets, if entrants have less information about how the local market works (i.e. entrants have to sign contracts with local speculators, there are different regulations, there is a potential capture of the regulator by the incumbents, etc.), banks could limit their access to credit. Banks also could be less eager to lend to entrants because they are less well known than incumbents. In the same line, more experienced companies may have better outside opportunities than their younger competitors. In this way corporate investment can adopt a risk-averse entry into a market. Indeed, Nocke and Thanassoulis (2010) shows that risk aversion can emerge endogenously under credit constraints and diminishing marginal returns to investment.

Equation (1.13) shows that the amount of forward sales of the risk-averse firm can be negative if $\lambda\sigma^2$ is higher than 9/14,[42] while the risk-neutral firm always sells a positive amount of forwards.[43] However, the sum of (1.13) and (1.14) is always positive for any level of cost volatility. This means that the risk-neutral firm is selling more than what the risk-averse firm is buying. In any case, even if they choose different technologies, the incumbent always sells forward because he is risk-neutral. The entrant will sell forward if she chooses technology s or if she chooses technology r and $\lambda\sigma^2$ is low enough.[44]

Figure 1.4 shows the expected payoff of the risk-averse entrant as the impact of cost volatility increases for different technology choices. The entrant's expected payoff $\Pi_e(c_i, c_e)$ is decreasing in impact of cost volatility at all times. Since the incumbent is always selling forward, he always affects negatively entrant's spot market situation through the strategic effect. As higher levels of cost volatility or risk aversion reduce entrant's expected payoff, affording K gets more difficult the higher $\lambda\sigma^2$ is.

If both firms choose the safe technology, again we have the same result of (1.10). In this case I will denote this level of payoff as $\bar{K} = \frac{2(a-c)^2}{25}$. $\Pi_e(c_r, c_r)$ is decreasing in impact of cost volatility, because the entrant reduces her forward sales as $\lambda\sigma^2$ increases while the incumbent is selling forward more and more. Only when $9/14 < \lambda\sigma^2$ the entrant starts buying forward and the level of payoff asymptotically converges to $\frac{3}{4}\frac{(a-c)^2}{25}$. I will denote this asymptotic level $\underline{K}$.

$\Pi_e(c_r, c_s)$ is also decreasing in the impact of cost volatility even when the entrant is also selling forward at any level of $\lambda\sigma^2$. The reason is the larger the impact of cost volatility, the more negative becomes the risk-hedging effect. At low levels of $\lambda\sigma^2$ we

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[42]The same condition as in (1.12).

[43]This holds as long as $c_e \geq c_i$.

[44]See the Appendix for optimal levels of forward trading if firms choose different technologies.

Figure 1.4: Expected payoff of a risk-averse entrant and risk-neutral incumbent
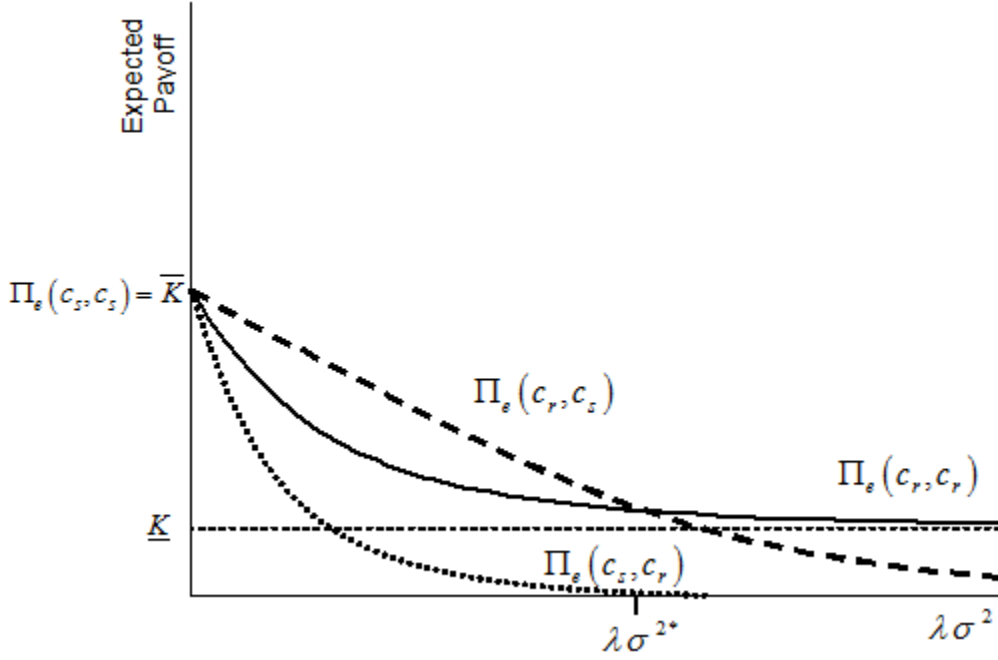
have that $\Pi_e(c_r, c_s)$ is above $\Pi_e(c_r, c_r)$, but for higher levels we have the opposite. Finally, $\Pi_e(c_s, c_r)$ is the lowest payoff as in the case of section 1.4.1.

The next proposition states that even if expected marginal costs are the same for both technologies, a risk-neutral incumbent could adopt the riskier technology to deter entry.

Proposition 1.4.2 *A risk-neutral incumbent can deter a risk-averse entrant by choosing a risky technology if and only if $\underline{K} < K \leq \bar{K}$ and the impact of cost volatility is high enough.*

Proof: See Appendix.

From Figure 1.4 it is clear that the entrant has the incentive to choose the safe technology. The incumbent can use the difference in risk aversion between the firms as an advantage to deter entry. Fixing K at a particular level, there is a level of cost volatility for which K is not affordable and there is entry deterrence. For levels of impact of cost volatility below $\lambda\sigma^{2*}$, there is deterrence if $K > \Pi(c_r, c_s)$ but for higher levels the condition is weaker: $K > \Pi(c_r, c_r)$. In the limit of $\lambda\sigma^2$, this cutoff value of K is equal to $\underline{K}$. If K is above this value, a risky enough technology can deter entry.

Is it possible to deter entry with the zero risk technology? The answer is no. If the risk-neutral firm chooses a zero risk technology, the risk-averse firm's best response is to do the same, giving both the same payoff as if they were both risk-neutral: $\frac{2(a-c)^2}{25}$. If K is higher than this level of payoff, entry is blocked. No matter what a risk-neutral incumbent does, the risk-averse entrant can not afford to enter.

The incumbent will accommodate only if deterrence is not possible because K is not high enough. Again, there are two accommodation equilibria: (s, s) and (r, r). The first is for low cost volatility impact and the second for high cost volatility impact. If the risky technology is not volatile enough or the entrant is not too risk-averse, the incumbent will have to share the market in equal terms with a zero risk technology. Otherwise, he will introduce more risk to take advantage of the entrant's risk aversion. The key value of the impact of cost volatility that separates the accommodation equilibria is $\lambda\sigma^{2*}$.[45]

1.5 EXTENSIONS

In this section I change the basic setting of the model in three different directions. First, I extend the results to n firms. Second, I consider the effect of modifying the

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[45]This threshold value is not the same out of section 1.4.1.

time line, allowing firms to choose their technologies in a different order. Third, I briefly discuss the consequences of firms competing in prices instead of quantities.

1.5.1 GENERALIZATION TO n INCUMBENT FIRMS

Extending to the case of n firms is a continuation of Section 1.2. I assume that all incumbents are identical and have the same incentive to coordinate, choosing the same technology. Hence, they sign the same amount of forward contracts. It is not necessarily a collusive situation. My purpose is to understand the effect on entry of more firms choosing riskier technologies.

Considering the case of all firms being equally risk-averse, it is possible to analyze the effect of more cost volatility on forwards and expected payoffs. As in the two firms case, more cost volatility impact implies more forward buying. Then, firms can increase their expected payoffs by choosing riskier technologies. The expressions for f_e and f_i with n firms can be found in the Appendix.

Equilibria in terms of technology adoption are the same as before: in case of deterrence, (s, s); in case of accommodation, (s, s) for cost volatility impact below $\lambda\sigma^{2*}$ and (r, r) for values above that. Nevertheless, as we increase the number of incumbents, $\Pi_e(c_r, c_s)$ starts falling faster as the cost volatility impact rises. Then, in case of accommodation, the threshold value of $\lambda\sigma^{2*}$ gets smaller and the accommodation equilibrium at (r, r) becomes more likely.

Assuming entry is feasible, an increase in the number of incumbents that choose technology r reduces the entrant's payoff more if she adopts technology s. For this reason, an equilibrium where all choose the riskier technology becomes more likely.

In the case where all incumbents are risk-neutral, incumbents' amount of forward selling is increasing in $\lambda\sigma^2$ while the entrant's is decreasing. The entrant ends buying forward if the riskier technology is volatile enough. Incumbents only sell forward. As in

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the case of risk-averse incumbents, equilibria do not change as n increases. However, $\Pi_e(c_r, c_s)$ falls slower as cost volatility impact rises. In contrast to the above result, the accommodation equilibrium at (r, r) becomes less likely.

1.5.2 DIFFERENT TIME LINE

I will discuss two different time line settings. In order to simplify the argument, I will assume again the case of one incumbent and one entrant. First, suppose the entrant chooses the technology before the incumbent and the latter observes it. After the incumbent adopts a technology, the entrant decides if she will enter or not.[46] Second, suppose the entrant and the incumbent choose their technologies simultaneously, without knowing each other's decision. Then, the entrant decides to enter or not. Keep the previous assumptions about technologies r and s, with the same expected marginal costs but different variances ($c_r = c_s = c$).

ENTRANT CHOOSES TECHNOLOGY FIRST

Let us start with the case of a risk-neutral incumbent and a risk-averse entrant. If the entrant chooses technology s, the incumbent will choose the same technology if cost volatility impact is low enough that deterrence is not possible. If the entrant chooses the riskier technology, the incumbent can deter entry by choosing the safe technology. The entrant will never choose the riskier technology.

In sum, there are several equilibria reported in Table 1.1. If K is higher than $\frac{2(a-c)^2}{25}$, then entry is blocked. If K is below that limit level and $\lambda \sigma^2$ is not high enough to deter entry, technology adoption in equilibrium will be (s, s) and there will be entry. If $\lambda \sigma^2$ is higher but $\frac{3}{4} \left[\frac{(a-c)^2}{25} \right] < K$, there will be entry deterrence.

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[46] The entry fixed cost K is payed once the entry decision is taken, not at the moment of choosing the technology.

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Table 1.1: Equilibria for risk-neutral incumbent

Equilibrium	Accommodation	Deterrence		Blocked
Technologies	(s, s)	(r)		Any
Condition on $\lambda\sigma^2$	Low enough	High enough		Any
Condition on K	$K \leq \left[\frac{2(a-c)^2}{25}\right]$	$\frac{3}{4}\left[\frac{(a-c)^2}{25}\right] < K \leq \frac{2(a-c)^2}{25}$		$\frac{2(a-c)^2}{25} < K$

If all firms are equally risk-averse, the incumbent no longer has any advantage from moving first. The entrant has the same incentives as the incumbent. If he chooses a zero risk technology and K is not high enough, the incumbent can not deter entry. The best response for the incumbent is just to accommodate and adopt the same option.

Table 1.2: Equilibria for equally risk-averse firms

Equilibrium	Accommodation		Deterrence	Blocked
Technologies	(s, s)	(r, r);	(s)	(r)
Condition on $\lambda\sigma^2$	Below $\lambda\sigma^{2*}$	Above $\lambda\sigma^{2*}$	Any	High enough
Condition on K	$K \leq \frac{2(a-c)^2}{25}$		$\frac{2(a-c)^2}{25} < K < \frac{3(a-c)^2}{25}$	$\frac{3(a-c)^2}{25} \leq K$

FIRMS CHOOSE TECHNOLOGY SIMULTANEOUSLY

Here I will focus on pure strategy equilibria. Let us start with the case where the incumbent is risk-neutral and the entrant risk-averse.

If the cost volatility impact is low so $\Pi_e(c_r, c_s) > \Pi_e(c_r, c_r)$, but $\frac{3}{4}\left[\frac{(a-c)^2}{25}\right] < K \leq \frac{2(a-c)^2}{25}$, then there is a deterrence equilibrium: (r, s). Entry is blocked if K is above $\frac{2(a-c)^2}{25}$. Table 1.3 summarizes these results.

If the impact of cost volatility is above $\lambda\sigma^{2*}$ and $\frac{3}{4}\left[\frac{(a-c)^2}{25}\right] < K \leq \frac{2(a-c)^2}{25}$, there is no equilibrium in pure strategies. If the entrant chooses technology s, the incumbent

Table 1.3: Pure strategy equilibria for risk-neutral incumbent

Equilibrium	Accommodation	Deterrence	Blocked
Technologies	(s,s)	(r,s)	Any
Condition on $\lambda\sigma^2$	Low enough	High enough but below $\lambda\sigma^{2*}$	Any
Condition on K	$K \leq \frac{2(a-c)^2}{25}$	$\frac{3}{4}\left[\frac{(a-c)^2}{25}\right] < K \leq \frac{2(a-c)^2}{25}$	$\frac{2(a-c)^2}{25} < K$

will prefer technology r. In that case, the entrant will prefer to move to the same technology as the incumbent, but in that case the incumbent will again prefer to move to technology s. Choosing technology s, is no longer a dominant strategy when impact of cost volatility increases.

If all firms are equally risk-averse, the equilibria depend more on the impact of cost volatility level than in the risk-neutral incumbent case. If K is affordable, there is accommodation. If impact of cost volatility is low, there is a unique pure strategy equilibrium where all firms adopt the zero risk technology. For larger values of $\lambda\sigma^2$, there is another equilibrium where all firms adopt the riskier technology. Table 1.4 summarizes these results.

Table 1.4: Pure strategy equilibria for equally risk-averse firms

Equilibrium	Accommodation		Deterrence	Blocked
Technologies	(s,s)	(s,s); (r,r)	(s,s)	(r)
Condition on $\lambda\sigma^2$	Below $\lambda\sigma^{2*}$	Above $\lambda\sigma^{2*}$	Below $\lambda\sigma^{2*}$	High enough
Condition on K	$K \leq \frac{2(a-c)^2}{25}$		$\frac{2(a-c)^2}{25} < K \leq \frac{3(a-c)^2}{25}$	$\frac{3(a-c)^2}{25} < K$

It is possible to find a pure strategy deterrence equilibrium where both firms choose the safe technology, but only if the impact of cost volatility is below $\lambda\sigma^{2*}$ and $\frac{2(a-c)^2}{25} < K \leq \frac{3(a-c)^2}{25}$. If $\lambda\sigma^2$ is high enough, there is no equilibrium in pure strategies.

In sum, I found that the order of technology adoption is not relevant. Deterrence strategies are the same for all cases where incumbents are as risk-averse as entrants (low-risk technology) and also the same for all the cases where incumbents are less risk-averse (high-risk technology).

1.5.3 Competition in prices

As stated in Mahenc and Salanie (2004), firms competing à la Bertrand on the spot market with differentiated goods results in producers buying forward their own production in equilibrium, under general conditions. In my setting, this means that the strategic incentive changes its direction. Now, both hedging and strategic incentives make firms buy forward. All firms increase their expected payoffs by buying forward. Firms will increase their expected payoffs by adopting riskier technologies.

The advantage of a risk-neutral incumbent over a risk-averse entrant is smaller because choosing the riskier technology does not hurt the entrant's payoff as in quantity competition, where the strategic effect provides an incentive to sell forward.

In order to deter entry, if all firms are equally risk-averse, incumbents can only choose the zero risk technology in order to keep entrant's payoff below K. However, since all firms have the incentive to buy forward, there will be a coordination problem with more than one incumbent.

1.6 Related Literature

There is a large body of literature related to technology decisions and entry. For example, Gilbert and Newbery (1982) analyze incentives of the incumbent to acquire a new technology to deter entry by preemptive patenting. In terms of "raising-the-rival's-costs" strategies, Creane and Miyagiwa (2009) show that an incumbent can

forgo an invention in order to deter entry. I find a similar result where firms choose their technologies strategically, with the caveat that technologies are already available and incumbents only need to choose one. I am focusing on the strategic choice of technology more than on the incentive to introduce a new and/or better one.

In terms of technology decisions, Genc and Thielle (2011) study capacity investments of electricity generators under demand uncertainty that choose asymmetric technologies. In my model, firms can adopt any technology and cost volatility plays a fundamental role. Milliou and Petrakis (2011) introduce timing of technology adoption as a strategic variable. Under Cournot competition, technology adoption occur earlier than under Bertrand competition. I work with Cournot competition but expected results under Bertrand are briefly discussed.

In terms of technology decisions and uncertainty, Maskin (1999) shows that demand uncertainty makes entry deterrence more expensive. Since under demand uncertainty there are scenarios where expanding production is not possible beyond the capacity level, in order to deter entry the incumbent is forced to choose a higher capacity than under certainty. This raises the cost of entry deterrence, making it less likely. My paper shows that, on the contrary, by introducing cost uncertainty in forward trading incumbents can increase their chances of entry deterrence.

Creane and Miyagiwa (2009) also highlights the role of uncertainty in entry deterrence. In their model, a monopoly may forgo the development of a new technology when this technology is distinct from the existing one so that production uncertainty becomes technology-specific. Then the monopoly can deter entry by keeping the existing technology with which the entrant would enter. My approach also emphasizes cost uncertainty but it affects entrant's expected payoff through forward trading.

As was mentioned before, the seminal papers of Allaz (1992) and Allaz and Vila (1993) are the keystone of forward trading and oligopolistic competition. The first

paper separates the strategic effect of forward contracts from the hedging effect in an uncertain setting, showing that these effects can have different signs depending on the assumed conjectural variation. Allaz and Vila (1993) complements the previous paper, showing that the introduction of forward trading enhances spot competition even without uncertainty. Several extensions have considered the limits of their approach. Hughes and Kao (1997) introduce non-observability of forward positions, softening Allaz and Vila's results. Observability of forward commitments is crucial to the strategic effect, but credible disclosure of this information is costly and subject to noise.[47] In a different research branch - one that does not assume uncertainty - Mahenc and Salanie (2004) replace Cournot competition by Bertrand, which ends up softening competition. Firms buy forward instead of selling forward. As Liski and Montero (2006) state, once it is recognized that selling forward contracts is a "tough investment" in the sense that it lowers the rival's profits, all else equal, firms will over-invest in forwards (sell forward) when they compete in quantities but under-invest (buy forward) when they compete in prices.

Empirically, van Eijkel and Moraga-Gonzalez (2010) used data from the Dutch wholesale market for natural gas to show that strategic reasons play an important role in explaining the observed amount of forwards. Wolak (2000) shows evidence of market power mitigation as a result of forward trading in Australia's wholesale power market.

In terms of entry analysis, Green and Newbery (1997) and Newbery (1998) show that if only incumbents can sign forward contracts, there will be entry deterrence by limit price strategies in the UK power sector. In a similar framework applied to

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[47]However, the introduction of technology decisions can make this information inferable. I conjecture that observability of forward positions is not needed, only observable technology choices. It would be expected that technology choices are more observable in many industries than forward positions.

the US, Lien (2000) uses a single large producer with a competitive fringe scheme to show that forward contracts can decrease entry if they are used as a commitment to aggressive behavior. In this setting all players are risk-neutral in a time line where incumbents contract before entry is possible. It is important to stress that my model allows entrants as well as incumbents to sign forward contracts and these contracts are signed after entry has occurred.

1.7 SUMMARY AND CONCLUSIONS

This paper shows how technology decisions are taken under strategic forward trading. I introduce endogenous technology decisions and entry in a complete information forward-spot market game.

With equally risk-averse firms, an incumbent can deter entry by choosing safer technologies. It does not matter if the entrant or the incumbent adopts their technologies first. High-cost but low-risk technology will be adopted instead of a low-cost but riskier one. Taking into account that newer technologies can initially be riskier, this entry deterrence strategy can block their adoption. This could have a lock-in effect. Old technologies continue to be dominant and invention is forgone. Then, the threat of entry can be inefficient in terms of technology adoption if the incumbent firm chooses to switch to a safer - and higher cost - technology just to deter entry.

I also show that entry can be deterred by adopting a sufficiently risky technology if the entrant is more risk-averse than the incumbent. This result remains valid even if the entrant adopts a technology before the incumbent does.

In terms of accommodation equilibria, the entrant adopts the same technology as the incumbent. There is no mix of technologies in equilibrium, a property that can also have a lock-in result.

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Forward markets have been seen as devices to increase competition in spot markets since Allaz and Vila (1993). However, the final result depends heavily on the assumptions made regarding market competition. Introducing cost volatility changes firms' incentives to hedge risk. Firms have an incentive to buy forward instead of selling forward. The strategic effect remains the same, encouraging selling forward if competition is in quantities. Depending on which effect is larger, a firm will set a positive amount of forwards (sell) or negative (buy). If the strategic effect is positive and larger, competition is stronger in the spot market.

Finally, if more incumbents choose the same technology, the accommodating equilibria change. Risk-averse incumbents increase the chances of an equilibrium where all firms adopt the riskier technology. On the contrary, risk-neutral incumbents makes it more likely that all firms end up adopting the zero risk technology.

CHAPTER 2

BIDDING BEHAVIOR IN THE CHILEAN ELECTRICITY MARKET

2.1 INTRODUCTION

One of the main concerns in developing countries is how to acquire new power generation resources to ensure that enough capacity is built in a timely manner and at the least possible cost.[1] The typical obstacles procuring efficient new power generation are finance limitations, spot market volatility and regulatory uncertainty. By providing access to long-term contracts it can be possible to solve part of these problems. Since generation investments involve large capital outlays and financing in developing countries is usually based on project finance, long-term electricity forward contracts provide revenue stability to investors. Also, regulatory uncertainty is reduced by auctioning those long-term contracts.

This paper addresses the Chilean recent experience with auctions for long-term supply contracts (LTC). LTC are forward contracts signed between electricity generators and distributors or large customers in which generators agree to supply power at a fixed price for a long-term period (i.e. from 5 to 15 years). Contracts with distributors were historically under price-regulation by the energy authority. An alternative regulatory scheme is to auction LTC and let average winning bids become final prices for distributors' customers.

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[1]Chile has a power system of 16,900 MW while the single state of California has 67,000 MW. With annual demand growth of 5%, Chile will have to double the existing capacity in about 15 years. (Maurer and Barroso, 2011)

Although LTC auctions are generally seen as a significant improvement in market regulation, there are concerns with auction performance that require careful design. There are also mixed results across countries.[2] For instance, it is not clear how generators determine their bids. To what extent are bids influenced by a generator's own technology or by the expected spot prices? Such distinction is key to determine, for example, how consumer prices should be indexed over time. More generally, there are questions about how competitive these auctions can be in markets with high concentration like Chile. The existence of potential barriers to entry can limit LTC auctions' effectiveness. It is also possible that auctions encourage generators' strategic behavior. For all these reasons understanding bidding behavior is important.

The main goal of this paper is to provide a multi-unit theoretical approach to bidding behavior in Chilean LTC auctions, and determine whether submitted bids can be explained by contracting decisions, production technologies and forecasted spot market prices. Once a model is available it is possible to test theoretical implications with actual data, in particular, looking for heterogenous behavior across firms. To my knowledge, this is the first paper that tests theoretical implications with the Chilean data and analyzes heterogenous behavior across bidders.[3]

I use a model of a divisible good auction in the sense of the Wilson (1979) share auction, adapting a framework developed by Hortaçsu (2002) and Hortaçsu and Puller (2008). It is a first-price sealed-bid discriminatory auction. Generators bid for the right to supply power to a distribution company in a future period. There are two relevant features to highlight in this type of auction: the contracting capacity and the cost of over-contracting of a given generator.

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[2] Moreno et. al. (2010) describe the different experiences of LTC auctions in Brazil and Chile.

[3] Nevertheless, I will not make any assessment about how competitive Chilean auctions have been.

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More important than the physical capacity at the moment of the auction is the contracting capacity. Contracting capacity is the minimum uncommitted capacity a generator has available in order to participate in an LTC auction. It is his own expected generation, considering adverse scenarios (i.e. drought), net of already committed capacity on other contracts.

If a firm bids to supply more than his contracting capacity, it has to face the risk of over-contracting and buying from other generators at the spot market in order to honor his contract. Thus, due to future spot price uncertainty, I explicitly include in the generator's profit function the cost of over-contracting. As a result, firms submit supply functions where the slope becomes steeper for quantities above their contracting capacity. Supply functions have a change in slope because, as quantity supplied increases, generators have to assume riskier forward positions to be closed in future spot markets.

The first part of my analysis considers contracting capacities as given. However, it is possible to have strategic considerations at the moment of choosing contracting capacity.[4] For that reason the basic model is extended to include that possibility. If firms choose their contracting capacities before submitting a bid function, I show there are scenarios were firms choose small contracting positions to behave as a monopolist over the residual demand.

In terms of empirical results, I find evidence that contracting capacity constraints and expected spot price are the main determinants of bidding behavior. I also find heterogeneity across bidders that can be explained by the cost of over-contracting. This cost is larger for small incumbents and entrants. As it would be expected, assuming

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[4]This is possible because a LTC auction is usually performed with years in advance of actual delivery. This feature can not be found in day-ahead power auctions, because capacity is not variable in the short term.

riskier positions for these types of firms is more costly than for larger and diversified generators. Then the idea that LTC auctions would bring more competition to concentrated markets by encouraging entry has to be revisited.

The introduction of LTC auctions replacing price-regulated contracts is novel in the power industry. It has been introduced mainly in developing countries to encourage efficient capacity investment and optimal risk allocation. Brazil started in 2004, followed by Chile in 2005, Peru in 2006 and Panama in 2008. As a recent World Bank study states "Latin America has pioneered the use of auctions to trade long-term products through energy contracts of reliability."[5] In developed countries, the discussion is also focused on how to replace existing generation capacity. In the US, there have been electricity procurement auctions in PJM[6], ISO-NE[7], Illinois, and New Jersey. Other countries, such as UK, and Spain are currently evaluating LTC auctions for their electricity markets.[8]

The Chilean experience is interesting not only because it represents a new case study and provides new data to test our hypothesis, but also because the auctions' results have been somewhat disappointing in terms of capacity expansion and entry in comparison with other South-American countries (Moreno et al, 2010; Maurer

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[5]"Auctions have established a credible market mechanism for the allocation of energy contracts, which in turn play a major role in attracting new generation capacity and also contribute to retaining existing ones. Prices resulting from the auctions have provided an elegant solution to the regulatory challenge of defining what "prudent" costs of generation should be passed on to end-use customers." (Maurer and Barroso, 2011)

[6]Include services in Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

[7]Serves Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.

[8]"...More electricity would have to be auctioned on the longer-term market to make pricing open and attract new entrants. Ofgem says the amount sold in this way remains pitifully low. The regulator is considering forcing companies to trade at least 25% of their power on the longer-term market..." *The Economist*, "Trouble turning up the heat", October 22nd 2011.

and Barroso, 2011). By providing a theoretical approach that fits with the empirical evidence, it is possible to present policy recommendations.

Section 2.2 includes a description of the power market in Chile, its regulation and competition in generation. The main features of the Chilean LTC auctions are described and results are presented. Section 2.3 includes the theoretical approach to understand actual bids. Section 2.4 analyzes the possibility of endogenous contracting decisions. In Section 2.5, empirical evidence is presented. Section 2.6 includes conclusions and summarizes. Tables and proofs are included in Appendix B.

2.2   The Chilean Power System

2.2.1   A brief description

Geographically, there are two main regional power markets: the SIC covering the southern and central areas of the country, and the SING covering the northern part.[9] SIC's generating mix is mainly based on hydroelectric power while SING's is mainly thermal. At SIC, 55% of demand comes from regulated customers while at SING 90% comes from unregulated or "free customers", particularly from the mining industry.[10] SIC is the bigger system with a total installed capacity of $12,488$ MW, serving 90% of the population of the country and SING has 3,964 MW.[11] The electricity generation system has a large installed hydro-generation capacity (35% for the country as a whole, but 45% in SIC), but as demand increases fossil fuels have become more

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[9]SIC (Sistema interconectado Central) and SING (Sistema Interconectado del Norte Grande).

[10]Large consumers are known as free customers because they are free to contract directly with generators for power supply, while regulated customers are supplied by local distribution companies and haven't any direct contact with generators. A consumer is considered large if she demands a capacity of 2 MW or more. Consumers between 0.5 MW and 2 MW can choose to be free customers or regulated customers.

[11]For comparison, the state of Maryland has $12,516$ MW.

important. The generating mix in terms of installed capacity is shown in Table B.1 of the Appendix.

The generation market exhibits high market concentration. In the Appendix, Table B.2 shows installed capacity and Table B.3 market shares of the major generation groups in SIC: Endesa, Colbun, AES-Gener and Guacolda.[12] In 2005, 90% of the installed capacity and 95% of market share was in the hands of these four firms, while in 2011 those percentages were 80% and 83%. The same firms dominated the generation market since the privatization process. Even though recently new firms entered the market, none has more than 3% of SIC physical capacity.

Power regulation in Chile has been an object of study since the 1980s, when a profound market-oriented reform was implemented earlier than even in more developed countries.[13] However, there has been little research on the second wave of reforms implemented after 2004, when LTC auctions were introduced.[14] Caravia and Saavedra (2007) use uncertain supply and risk-averse generators to show that the auction winner is the generating firm that sets the spot market price.[15] Roubik and Rudnick (2009) assume that generators sign forward contracts following an optimal portfolio decision. Since only the spot price uncertainty can be hedged with a LTC, spot price uncertainty is the only relevant variable in generators' decisions. I also found evidence that the expected spot price is one of the main variables that bidders consider, but the cost of over-contracting is relevant too. In a different venue, Lima (2010) develops a single-unit IPV auction model, where each bidder can't fully meet the entire auc-

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[12]Guacolda is the fourth firm in size, but 50% of it belongs to AES-Gener.

[13]As Pollitt (2004) mentions, "Chile's electricity reform has been hailed as a highly successful example of electricity reform in a developing country and a model for other privatization in Latin America and around the world."

[14]See Arellano (2008) for a description of these reforms and the reasons behind them.

[15]In a marginal cost system, like the Chilean one, the firm that sets the spot market price is the one with the most expensive unit of generation in use to balance demand and supply.

tioned demand. He finds that by increasing the number of bidders, expected prices are reduced more than by increasing incumbents' capacity. I don't test this theoretical implication but the number of bidders is only part of the story. If entrants have significantly higher cost of over-contracting, the final effect on power prices is unclear.

2.2.2 REGULATION IN THE POWER MARKET

The Chilean regulation splits the industry into three sectors: generation, transmission and distribution. Transmission and distribution are seen as natural monopolies and remain under price regulation. The regulatory agency is the CNE.[16] Since there are no significant economies of scale in generation, the Chilean law envisioned a competitive environment among generators with open entry.

Generators operate in a spot market and in a forward market at the same time. The spot market works as a short-term market where demand and supply meet instantaneously. The forward market operates as a long-term market where generators and customers contract supply and demand in advance. The spot market is organized by an Independent System Operator (ISO). All generating plants report their operational costs and the operator sets the order of generation following the least cost dispatch. The ISO also audits those operational costs. There is no bidding in the spot market; dispatch is based on audited costs.

A generator acts as two different agents: a producer and a trader. As a producer he will generate power only if the ISO calls him to produce electricity and this depends on his cost of operation or marginal cost. This part of the market works as a price regulated market that mimics perfect competition. Thus, the spot market price is equal to the marginal cost of the most expensive unit of generation in use to balance supply and demand. As a trader, the generator purchases power from the spot

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[16]National Energy Commission (Comisión Nacional de Energía).

market, at the spot market price, to supply his contracts with distributors and large customers.[17] He has to buy from the spot market regardless of whether the ISO calls him to produce electricity or not at that moment.
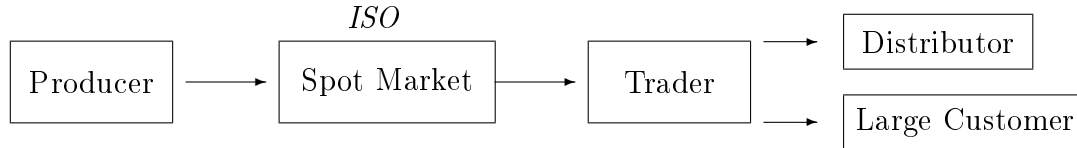
Figure 2.1: Electricity Market

Figure 2.1 summarizes how the market works.[18] Since the producer's role is regulated by the ISO decisions, it will be possible to focus on the trader's role. From the trader's perspective, spot price is an exogenous variable.[19]

2.2.3 CHILEAN LTC AUCTIONS

Until 2005, all contracts with distribution companies for regulated customers had prices regulated by CNE. That year, the government introduced a regulatory reform that replaced contracts under price regulation with LTC auctions with the intention of foster capacity expansion and optimize the risk allocation. According to the new regulations, distribution companies[20] have to contract their entire power demand in advance. Generators bid for the right to supply a distributor's contract. Contracts are allocated among generators through auctions with the following features:

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[17]Neither distributors nor large customers can buy electricity directly from the spot market.

[18]Arrows indicate the direction of electricity sales

[19]In Chile, there are generators who do not hold any contract (pure producers) but there are not pure traders.

[20]There are 5 major distribution groups all along the country - Chilectra, CGE, Chilquinta, EMEL and SAESA - besides smaller distribution companies. In all auctions done so far, these smaller companies joined with one of the 5 major groups in order to make their auctions more attractive to potential bidders.

- Contracts are allocated by minimum price.

- The average weighted winning bid of the auction becomes the power price for all distributors' customers.

- Power prices will remain fixed during the entire length of the contract but they are indexed to input prices chosen by the CNE.[21]

- A publicly known ceiling price is established for each auction by the CNE.

- Auctions have to be done at least 3 years in advance, in order to foster competition among new entrants and incumbents.[22]

- Contracts can not be longer than 15 years.

- The amount of power auctioned does not imply a "take or pay" contract. The amount of power supplied by generators is the one effectively demanded.[23]

Besides what is written in the law, there are some details about how auctions were actually implemented. First, all auctions so far have been first-price sealed-bid auctions. Second, a bidder must pay a small fee to participate in a given auction. This payment gives access to conditions and information of the auctioned power.[24]

Each distributor decides the size and length of each contract to be auctioned. A contract or block of energy can be divided in equal size sub-blocks. For example,

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[21]In practice, the CNE determines which input price can be introduced into the index formula and each bidder establishes the coefficient associated with each input price. So far the CNE has included coal price, diesel price, oil price, natural gas price, liquified natural gas (LNG) price and CPI (consumer price index in US). Indexes are not considered at the moment of the price allocation.

[22]The formal process has to start three years in advance, but the actual auction can be later.

[23]There is an obligation for distributors to release all information about how they calculated their expected demands before the auction in order to reduce generators' uncertainty.

[24]The fee was around USD 2,000 for each distribution company. In comparison with the value of a contract, this fee is meaningless.

distributor X can auction at the same time a block of 1,000 GWh/year divided in 20 sub-blocks of 50 GWh/year and a block of 500 GWh/year divided in 5 sub-blocks of 100 GWh/year.[25] A generator can submit bids with different prices for different sub-blocks in a single block. For these reasons, in a same auction there can be blocks with different characteristics (duration in time, date of initial supply and size).

Due to the heterogeneity in blocks, all five distribution groups coordinate to implement a unique allocation mechanism for each auction. However, they don't sum their demands in a unique supply contract/block. Rather, they coordinate on a single mechanism for different supply blocks that allocates the minimum bid for each block for each distributor. A generator can bid different prices to different blocks and sub-blocks, even if they belong to the same distributor.[26]

Finally, since several contracts with different distributors were auctioned at the same time, in order to foster competition the CNE allowed generators to define a limit for the amount of power that they can win in all the blocks auctioned simultaneously. For example, a generator with a capacity on 1,000 GWh bidding for two different contracts of a 1,000 GWh each, can submit bids for the total amount of each contract but the allocation mechanism will only assign 1,000 GWh to this generator.[27]

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[25]There is some kind of contracting cost for distributors for what it is not optimal to auction smaller sub-blocks.

[26]Appendix B includes an example of an official page to submit bids.

[27]In theory, this allows generators to alleviate their capacity constraints and act similarly across different contracts. For the interest of the current paper, this means that we do not need to consider any relationship between bids submitted to different blocks. We can consider each block independently.

Between October 2006 and July 2011 there were seven auctions for SIC's supply.[28] Table 2.1 summarizes auction results.[29] Prices are in USD/MWh.[30] The average winning price is a weighted average with the weights being equal to the fractions of the individual's quantities submitted in each auction. For a more detailed description of the results, please see Appendix B.

Table 2.1: Results of LTC auctions in SIC

Auction	Size TWh/year	Blocks number	Ceiling P USD/MWh	Winning bid USD/MWh	Bidders number	Unsold portion
Oct-06	12.8	9	62.7	52.7	4	9.3%
Feb-07	1.2	2	62.7	54.5	2	5.5%
Oct-07	14.7	6	61.7	59.8	2	61.3%
Jan-08	9.0	4	71.1	65.8	1	80.1%
Jan-09	8.0	4	125.2	104.3	5	10.6%
Jul-09	0.9	1	125.2	99.5	6	0.0%
Mar-11	2.5	4	95.0	90.3	3	18.4%

Source: CNE

There are three main results to highlight. First, there was no entry until the 2009 auctions, when expected spot prices as well as ceiling prices were higher.[31] Entry of new generators was marginal. Second, prices submitted by generators after 2009 almost doubled those of 2006. Third, bids have been quite close to the ceiling prices

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[28] The first SING auction took place in September 2009 so I will focus only on SIC auctions.

[29] This table includes all auctioned contracts. In case the size of a contract increases in time, I use the amount of power that was used as reference for the allocation in the auction.

[30] Bids are submitted in USD/MWh but prices to regulated customers are converted to Chilean pesos at the proper exchange rate.

[31] Auctions' shares do not change significatively from market shares showed in Table B.3.

in October 2007 and January 2008 when large portions of auctioned contracts didn't receive any bids at all.[32]

The rise in final prices could be explained by different factors. First, it is possible that low-cost power was committed in the first auctions, while the high-cost power was committed in the last ones. Such an explanation is based on technological differences across generation plants. A different explanation is based on capacity constraints. It is possible that as capacity constraints became binding, prices increased. The fact that in 2009 there was power auctioned to be supplied in 2010 gave short time for any capacity expansion if the generator has no power left to supply. Only high-cost plants can be installed in such a short time. Finally, expected spot prices were soaring due to high input prices (i.e. coal, LNG, oil) during this period. In sum, it is an empirical question whether submitted bids can be explained by production costs, capacity constraints and forecasted prices or by strategic behavior.[33] The next section builds up a theoretical approach that will allow us to address these issues.

2.3   THEORETICAL APPROACH

In terms of related literature, multi-unit auctions can be traced back to the seminal work of Wilson (1979).[34] For a literature review on the theoretical and empirical analysis of multi-unit auctions, see Hortaçsu (2011). Along this section I will follow Hortaçsu (2002) and Hortaçsu and Puller (2008) methodology to analyze data on multi-unit auctions.

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[32]The unsold portion of the auction has been positive almost in every auction. This means that some contracts or portions of them did not receive any bid.

[33]It is possible that generators were expecting rises in input prices and for that reason decided not to participate in 2007 and 2008 auction until ceiling price was increased enough. This paper do not account for that dynamic perspective. I will assume each generator submit a bid function for each contract independently of past and future auctions.

[34]Back and Zender (1993), Wang and Zender (2000), Ausubel and Cramton (2002) develop this theoretical framework further.

2.3.1 LINEAR APPROXIMATION FOR BIDS

Before introducing assumptions about bidding behavior I will start describing the available data. From this analysis it is possible to find the best suitable theoretical approach. I will use the data of 7 auctions from October 2006 to March 2011. There were 11 bidders across all auctions. They submitted as bids 319 price - quantities pairs, resulting in an average of 4.1 bids per generator. Each bidder submitted a flat or an upward-sloping supply function. I include in Figure 2.2 an example of an actual bid function.[35] In this case, the generator is willing to supply 900 GWh/year at 50.6 USD/MWh and additional 150 GWh/year at 51.4 USD/MWh.

Figure 2.2: Example of a submitted bid function
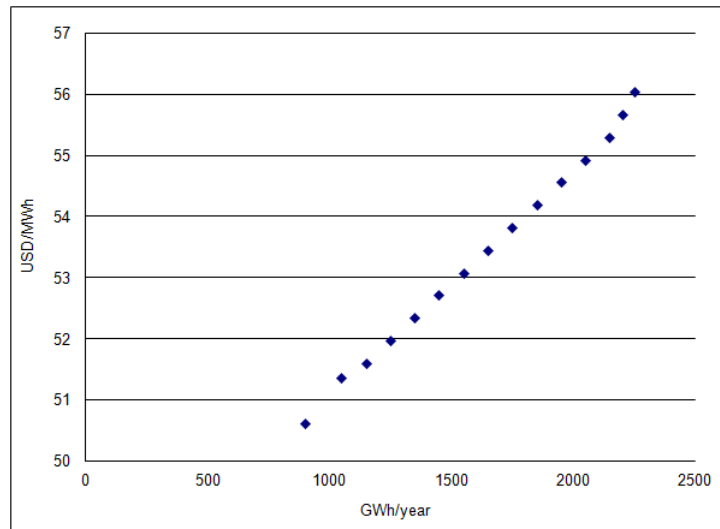
From Figure 2.2 it can be seen that a linear approximation to actual bidding behavior could fit well. For that reason in this section I will approximate the price-quantity pairs submitted by generators by linear and continuous functions. In reality, generators submit non-differentiable step functions. However, Kastl (2008) shows that as the number of steps grows without bound, necessary conditions of bidding behavior

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[35]This schedule was submitted by the largest generator, Endesa, for a contract with the largest distributor, Chilectra, in October 2006.

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in a discrete strategy game converge to the same conditions for equilibrium for a game with differentiable supply schedules.

Now I will describe how I performed the linear approximations. When a distributor auctioned two separate blocks of energy, I separated them as two different contracts.[36] Then I run a linear regression for each bid function in the following way: $p_{ijk} = \beta_{it}q_{ijk} + \alpha_{ik} + v_{ijk}$, where: (p_{ijk}, q_{ijk}) is the j-th price-quantity submitted by bidder i in block k. The parameter β gives the slope, α the price-intercept and v is the error term. Table 2.2 shows the average, minimum and maximum intercept, slope and goodness of fit.[37] There are 57 bid functions.

Table 2.2: Linear approximation to bid functions over i and k (USD/MWh)

	Min	Mean	Max
Intercept	41.91	79.09	128.53
Slope	0.000	0.004	0.048
R^2	0.62	0.95	1

Since the goodness of fit measured by the average R^2 is more than 95%[38], a divisible-good auction model that generates linear supply functions for each bidder as equilibrium bidding strategies would provide a good description of the data. Now it is possible to use the data I obtained from the linear approximations and observe how intercepts and slopes are distributed statistically.[39]

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[36]For example, in October 2006, the largest distribution company Chilectra auctioned 2 blocks: Chilectra 1 with a duration of 11 years and Chilectra 2 with 13 years.

[37]Bid functions with only two points are not included.

[38]Log-normal and exponential approximations do not fit that well.

[39]As Rostek, Weretka and Pycia (2010) mention, a linear approximation finds empirical support in financial, electricity, and other divisible good markets.

There could be unobservable factors that affect price-intercepts between auctions. In order to control for that, Hortaçsu (2002)'s analysis of treasury bill auctions normalizes price-intercepts by dividing them by the resale market price of the securities. In LTC auctions there is not a resale value but we can use the expected spot price at the moment of the auction.[40]

Figure 2.3 shows the distribution of normalized price-intercepts. It can be seen that the distribution has a mode close to one.[41] This last fact suggests that the bid function is determined by the private information of a bidder about expected spot prices.

Figure 2.4 shows the distribution of slopes of the linear approximations to the bid functions.[42] As expected, all slopes are non negative. The heterogeneity in slopes - a large proportion of flat schedules - can be driven by bidder size or available capacity.

In sum, based on the analysis of real auctions' data, my theoretical approach will consider a linear approximation to bid functions, with at least partial private information about expected spot prices and heterogeneity in bidder's size.

2.3.2 A MULTI-UNIT MODEL

This section includes a model that explains under which conditions it is possible to have bidding behavior like that found in Chile's power industry. I will use a divisible good auction in the sense of the Wilson (1979) share auction. It is a first-price

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[40]This expected spot price is based on CNE semiannual estimations (May and October). It considers the expected spot price at the moment contract starts. For a detailed description of what I have used as expected spot prices see Appendix B.

[41]Different normality tests do not reject the null hypothesis that price-intercepts follow a normal distribution (Jarque-Bera test, Shapiro-Francia and Shapiro-Wilk tests). However, the test is very sensitive to any change in the series of expected spot prices used.

[42]A slope of 0.001 indicates that each additional GWh increases the price by one dollar.

Figure 2.3: Distribution of normalized price-intercepts
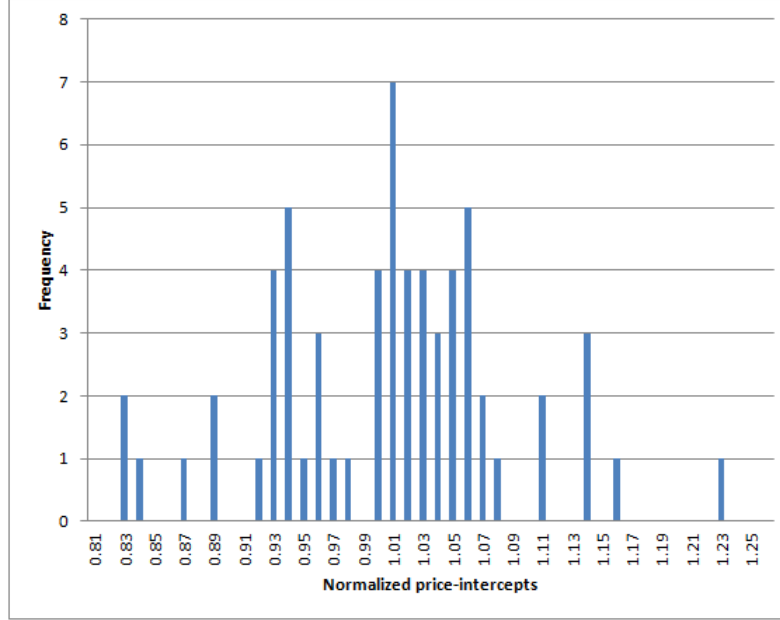
sealed-bid discriminatory auction.[43] I will start assuming the simplest case with independent private values but I will also consider a more general case. Since the expected spot price is a function of all generators' decisions on investment, technologies and contracts, it is possible to have a relevant "common value" component.

Let us assume that there are N risk-neutral power generators.[44] They bid for the right to supply power to a distribution company in the next period. If they win any units, they will have to buy power from the spot market in that period, irrespective of whether they are called by the ISO to generate or not.[45] All generators receive a pri-

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[43]Chilean LTC auctions are all pay-as-you-bid auctions.

[44]Hortaçsu and Puller (2008) show that main results do not change by introducing risk-aversion in this model.

[45]As I mentioned before, the generator has two roles, one as a producer and one as a trader. Here I will refer only to his trader role, submitting bids and signing forward contracts. Within firms usually different units are responsible for those roles.

Figure 2.4: Distribution of slopes of fitted bid functions
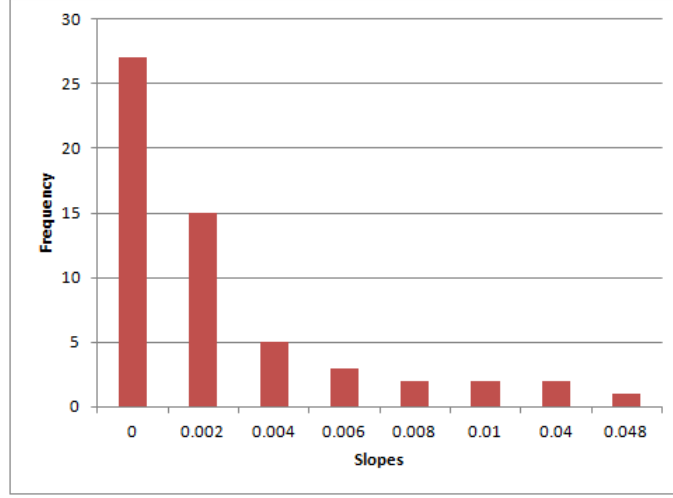
vate signal of the expected spot price, c_i. Spot prices depend on future prices of inputs like coal, natural gas and diesel, but more importantly spot prices at SIC are heavily influenced by the volatility of hydropower generation. Hence all firms have to forecast different scenarios for future spot prices. It is expected that each generator will have different information about their own investment plans and contracting portfolios as well. I assume that c_i is identically and independently distributed according to the cumulative distribution $F(c)$, with density $f(c)$ and it is continuous over $[c_L, c_H]$.

Generators are constrained by installed capacity when they produce electricity. However, installed capacity does not completely constrain the generator when signing a contract with a distributor. The generator (as a trader) can supply the distributor by buying power at the spot market from any other generator that has been called to produce by the ISO at that moment. Also, since auctions are carried years in

advance of the moment of actual delivery, generators have a chance to increase physical capacity or adjust their contract portfolios.[46]

Then what generators have is a sales target or a "contract position" or "contracting capacity" A_i to contract for future supply. Contracting capacity is the minimum uncommitted capacity a generator has available in order to participate in an LTC auction. It is his own expected generation from existing and future plants net of existing contracts with large customers or other distributors. If a firm bids to supply more than his contracting position, it has to face the risk of over-contracting and buying from other generators at the spot market in order to honor his contract. A_i is the contract position at the moment of the auction and I assume generators took it as given. Also, A_i is common knowledge. The heterogeneity across bidders found in Figure 2.4 can be explained by differences in contracting capacity.

It is possible to show a numerical example of a contract decision. Assume three generators, with different technologies of generation. A low cost generator, G_1, with marginal cost of generation equal to 5; a medium cost generator, G_2, with marginal cost of 30; and a high cost G_3 with marginal cost of 50. G_1 and G_2 have an expected production of 100 units each, while G_3 has only 50 units. There are three relevant levels of demand, D, and demand is never larger than 250 units. If $D \leq 100$ units, the spot price is 5. If $100 < D \leq 200$, the spot price would be 30 and if $200 < D \leq 250$ the spot price would be 50. Now, due to price uncertainty, firms may hedge risk with a contract. Assume G_1 and G_2 sign a forward contract with final consumers for 100 units each (the same as the expected production) for a forward price of 30. In this case, no matter what is the spot price, expected profits are positive for both firms. What happens if G_2 signs a contract of 120 units? This generator would be over-

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[46]There have been cases where a generator dropped a free customer's contracts to adjust his overall contract portfolio.

contracted. Under such circumstances, G_2 will have to increase his forward price to obtain the same expected profits as before: 30 for the first 100 units and 50 for the next 20.

Assume generators bid supply schedules that are continuously differentiable with bounded derivatives. $S_i(p) \equiv S(p, c_i, A_i)$ is the bidding function submitted by bidder i, which maps price p into a supply curve given signal c_i and contracting capacity A_i.

I am looking for a Bayesian-Nash equilibrium where bid functions are functions of their private information, c_i. Then, the optimal bidding strategy considers that each bidder forms expectations about the market-clearing price, P^c. In order to define the market-clearing price in the auction, we need a definition for "residual demand function". The total amount of electricity auctioned is $Q = \sum_{i=1}^{N} S_i(P^c)$. Since P^c is the realized market-clearing price under the market-clearing condition, the residual demand is $RD_i(p) = Q - \sum_{j \neq i}^{N} S_j(p)$.

The cumulative distribution function of the market-clearing price is $H(p, S_i(p), A_i)$ from the perspective of firm i, conditional on A_i and the fact that firm i submits a supply schedule $S_i(p)$ while his competitors are playing $S(p, c_j, A_j)$.

$$H(p, S_i(p), A_i) = Pr[S_i(p) \leq Q - \sum_{j \neq i}^{N} S_j(p)] \tag{2.1}$$

In terms of excess of demand (there is an excess of demand at price P^c):

$$H(p, S_i(p), A_i) = Pr[P^c \geq p | S_i] \tag{2.2}$$

The support of the market-clearing price distribution is $[\underline{p}, \bar{p}]$

Not constrained case: $(S_i \leq A_i)$

Consider first the case of a risk-neutral bidder not constrained by contracting capacity $(S_i \leq A_i)$. Ex-post profits are given by the area below the submitted supply curve net of costs at the market-price level:

$$\Pi[S_i(p), p] = \int_0^{S_i(p)} [S^{-1}(q) - c_i]dq$$

$$= \int_0^{S_i(p)} S^{-1}(q)dq - S_i(p)c_i \tag{2.3}$$

At the market-clearing price (ex-post profits):

$$\Pi[S_i(P^c), P^c] = \int_{\underline{p}}^{P^c} S_i(p)dp - S_i(P^c)c_i \tag{2.4}$$

The optimization problem that each non-constrained generator solves symmetrically is:

$$\max_{S_i} \int_{\underline{p}}^{\bar{p}} \Pi[S_i(p), p]dH(p, S_i(p)) \tag{2.5}$$

Integrating by parts:

$$\max_{S_i}\{[\Pi_i(S_i(p), p)H(p, S_i(p))]_{\underline{p}}^{\bar{p}} - \int_{\underline{p}}^{\bar{p}} \Pi'(S_i(p), p)H(p, S_i(p))dp\} \tag{2.6}$$

Setting $S(\underline{p}) = 0$ and considering that $H(\bar{p}, S_i(\bar{p})) = 0$:

$$\max_{S_i} - \int_{\underline{p}}^{\bar{p}} [S_i'(p)(p - c_i)]H(p, S_i(p))dp \tag{2.7}$$

The integrand is a function of p, S' and S.

$$- \int_{\underline{p}}^{\bar{p}} [S_i'(p)(p - c_i)]H(p, S_i(p))dp = F(p, S, S') \tag{2.8}$$

The Euler-Lagrange necessary condition for the (pointwise) optimality of the supply schedule $S_i(p)$ is given by $F_S = \frac{d}{dp}F_{S'}$. In our case this means:

$$H_s(p, S_i(p))[S'(p - c)] = H(p, S_i(p)) + H_p(p, S_i(p))(p - c) + H_s(p, S_i(p))[S'(p - c)] \tag{2.9}$$

The optimal supply schedule is implicitly defined by:

$$p = c_i + \left[\frac{H(p, S_i(p))}{-H_p(p, S_i(p))}\right] \tag{2.10}$$

54

This condition is a mark-up condition, where the generator bids above the expected spot price by an amount determined by the inverse hazard rate of the market-clearing price distribution.[47]

CONSTRAINED CASE: $(S_i > A_i)$

Now it is time to introduce available capacity explicitly in the generator's optimization decision. The ex-post profits for a risk-neutral bidder in this discriminatory auction with available contracting capacity A_i are:

$$\Pi_i[S_i(p), P^c, A_i] = \left[\int_{\underline{p}}^{P^c} S_i(p)dp - S_i(P^c)c_i\right] - \frac{\theta}{2}\left(S_i(P^c) - A_i\right)^2 \tag{2.11}$$

The cost of over-contracting is given by a quadratic expression multiplied by the parameter θ. θ is the marginal cost of over-contracting.

The optimization problem that each generator solves is:

$$\max_{S_i} \int_{\underline{p}}^{\bar{p}} \Pi[S_i(p), p, A_i]dH(p, S_i(p)) \tag{2.12}$$

Integrating by parts we obtain the following:

$$\max_{S_i} - \int_{\underline{p}}^{\bar{p}} [S_i'(p)(p - c_i) - \theta(S_i(p) - A_i)S_i'(p)]H(p, S_i(p))dp \tag{2.13}$$

Solving the Euler-Lagrange condition, and since we are looking for the symmetric equilibrium, we obtain:

$$p = c_i + \left[\frac{H(p, S_i(p))}{-H_p(p, S_i(p))}\right] + \theta(S_i - A_i) \tag{2.14}$$

The bid function's slope is increasing in the marginal cost to over-contracting. This result gives us the following Proposition.

---

[47]The derivative of the pdf of the market-clearing price with respect to the price is negative.

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Proposition 2.3.1 *The optimal bidding strategy for a risk-neutral generator satisfies:*

$$
p = \begin{cases} c_i + \left[\dfrac{H(p, S_i(p))}{-H_p(p, S_i(p))} \right] & \text{if } S_i \leq A_i \\[2ex] c_i + \left[\dfrac{H(p, S_i(p))}{-H_p(p, S_i(p))} \right] + \theta(S_i - A_i) & \text{if } S_i > A_i \end{cases}
$$

Proposition 2.3.1 explains why we can find changes in a bid function's slope. For quantities below contracting capacity, the slope of the bid function is given by the inverse hazard rate. For quantities above contracting capacity, the marginal cost of over-contracting increases the slope.

The Euler equation does not necessarily imply a linear bid function as the one depicted by the data analysis in the previous section. In order to obtain a linear bid function, the inverse hazard rate $\frac{H(p, S_i(p))}{H_p(p, S_i(p))}$ has to be a linear function of the quantity. From now on I will assume the following condition holds, which is adequate to fit our data:[48]

$$
\frac{H(p, S_i(p))}{-H_p(p, S_i(p))} = \lambda(S_i) = \lambda_0 + \lambda_1 S_i \tag{2.15}
$$

If we assume this simple case where the inverse hazard rate is a linear function, Figure 2.5 depicts an example of such a bidding function.[49]

As I mentioned before, since the expected spot price is a function of all generators' decisions on investment, technologies and contracts, it is possible to have a "common value" situation. Instead of a full affiliated value model, it is possible to assume a reduced form specification of a common value model, where the marginal valuations

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[48]Rostek, Weretka and Pycia (2010) shows that if $H(p, S_i(p))$ has a convex support, any distribution that belongs to the class of Generalized Pareto distributions exhibits a linear inverse hazard rate.

[49]In Appendix B it has been included an example of an equilibrium with linear bid functions.

depend on the realization of the market clearing price. The market clearing price is a statistic that aggregates the private information of all bidders. Then, the marginal valuation or cost for the bidder is $(1-\pi)c_i+\pi P^c$, a convex combination of the private signal c_i and the market clearing price P^c. The relative importance of each component is given by π, where $0 \leq \pi \leq 1$. If $\pi = 0$, this collapses to the IPV case. If $\pi = 1$, we have a full CV model, with flat supply functions.[50]

Figure 2.5: Bidding function according to the model
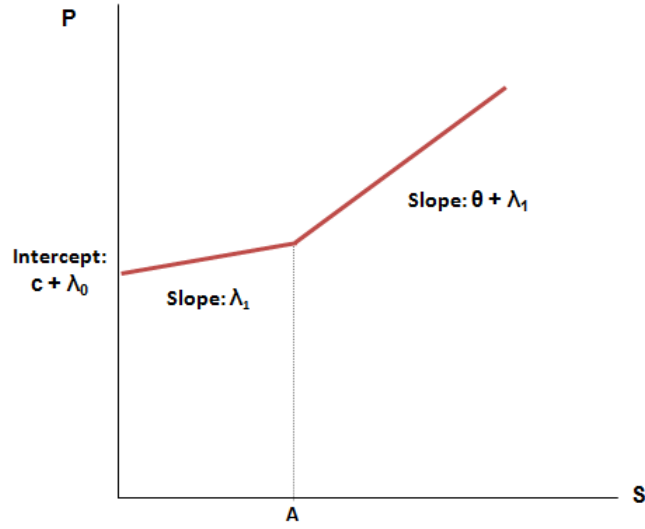
Based on Hortaçsu (2002) and analogous to the previous development, we can set a new optimal supply schedule.

Proposition 2.3.2 *A risk-neutral generator with a common value component, will submit a supply schedule according to:*

$$
p = \begin{cases}
c_i + \frac{1}{1-\pi}\left[\frac{H(p,S_i(p))}{-H_p(p,S_i(p))}\right] + \frac{\pi}{1-\pi}\left[\frac{H_s(p,S_i(p))}{-H_p(p,S_i(p))}\right]S_i & \text{if } S_i \leq A_i \\[4mm]
c_i + \frac{1}{1-\pi}\left[\frac{H(p,S_i(p))}{-H_p(p,S_i(p))}\right] + \frac{\pi}{1-\pi}\left[\frac{H_s(p,S_i(p))}{-H_p(p,S_i(p))}\right]S_i + \theta(S_i - A_i) & \text{if } S_i > A_i
\end{cases}
$$

---

[50]Back and Zender (1993) showed in a CV model that if bidders have constant marginal valuations, they will submit a single price-quantity pair, constituting a flat supply function.

Even with a common value component, it is possible to obtain linear bid functions in equilibrium.[51] The change in slope due to the possibility of over-contracting remains. As can be seen, the above model can give an accurate representation of the actual data.

2.4 Endogenous Contracting Positions

2.4.1 Contracting positions in the data

From the theoretical framework developed above, it is possible to have an approximation to generators' contract capacities. From now on, I will assume that the contract capacity of each bidder, A_i, is equal to the amount of power offered until the bid function's slope changes. In case there is no change in the slope, I will approximate contract capacity by the total amount of power offered for that contract. Then it would be possible to obtain estimates of S-A. This is an important assumption because it allows us to approximate the amount of expected generation net of previous contracts without data on contract positions that would not include strategic considerations.

It is possible to plot these implicit contracting positions and analyze behavior across bidders and auctions. The first result is that there is plenty of heterogeneity across contracts for the same bidder. This could be a result of different contract sizes. For that reason, the Figure 2.6 shows the amount of A in GWh and as a proportion of A/Q for the larger incumbents.[52]

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[51] $\frac{H_s(p,S_i(p))}{-H_p(p,S_i(p))}$ is a constant if the inverse hazard rate is linear.

[52] In the case of the entrants, they generally submitted contracting positions consistent with their installed capacity.

Figure 2.6: Incumbents' contracting positions in GWh/year (1) and as percentage of Q (2).
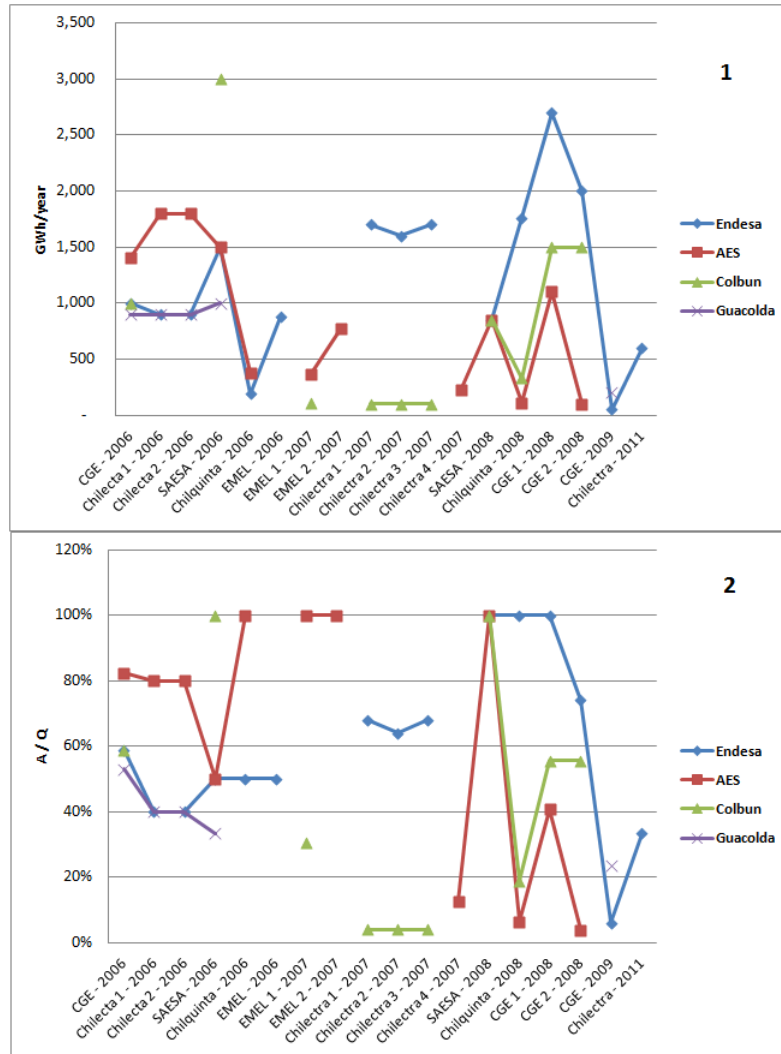
In case of the largest generator, Endesa, available capacity in 2006 auctions is, on average, half of a contract's size. This proportion rises to 68% in 2007 and to 100% in almost all contracts of 2009.[53] In the case of Endesa, there is a homogenous contract position across contracts in each auction. The same can be said about Guacolda's contracting capacity.

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[53]The increase in Endesa's contract position could be explained by a new coal plant in construction since October 2007.

The case of AES-Gener and Colbun is different. Both exhibit more heterogeneity in A as a proportion of size. In particular, it is interesting that Colbun shows very low contracting positions in 2007 in comparison with other auctions and bidders. In 2008 auctions, AES-Gener and Colbun submitted very different contracting positions for contracts with the same distributor.

In July 2009, contracting positions fall for all generators. It is important to remember that this auction was held less than six months in advance of the starting date of the auctioned contract. It is possible that the contract position was already full by then and firms didn't have time to expand it.

In sum, I found plenty of heterogeneity in the estimated values of A. For small generators[54], contracting capacity follows the same pattern as physical capacity, while for some large generators estimated contracting capacity can not be explained by changes in physical capacity. So far contracting positions have been assumed exogenous. However, there is a possibility that A is chosen strategically. The next sub-section endogeneizes the value of A in order to find an explanation for these cases.

2.4.2 Choosing contracting positions

We have seen in the previous section that in October 2007, Colbun and Endesa submitted very different implicit contracting capacities for the same contract. The largest generator Endesa had contracting capacities of 70% of the size of the auctioned contracts while Colbun had only 5%. While Colbun is smaller than Endesa in terms of capacity, it is the second largest generator. Also, in the previous auctions of 2006, Colbun submitted bid functions with larger A and there is no evidence of Colbun committing with other contracts since then. How we can explain this behavior?

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[54]Typically with a few plants and a single generation technology.

In this section I will extend the model of section 2.3 in order to account for potential strategic behavior on A that results in such an asymmetric equilibrium. In order to do so, I assume that firms first choose A and later they participate in an auction. This is a game of two periods where, by solving backwards, the bidding strategy defined in Proposition 2.3.2 is the equilibrium strategy for the last period. I assume a simplified version of the bid function of bidder i: $P = c_i + \lambda + \delta S_i + \theta(S_i - A_i)$ with $S_i \geq A_i$.

Now we need to find the equilibrium strategy for the level of contracting capacity. For the sake of simplicity, I will assume there are only two strategic firms, like in the Endesa-Colbun case, regardless of other non-strategic firms that take their contracting capacity as exogenous. Both strategic firms are large enough to not be restricted on their contracting capacities but they can submit bid functions where A is below their real contracting capacity.[55]

Figure 2.7 shows an example, where firm i can choose between A and A'. These determine supply functions $S(P, A)$ and $S(P, A')$. The lowest price is the same in both cases, P_{min}. In case of rationing, the firm will receive this price for any quantity below A_i. Since firms will participate in a discriminatory first-price auction in period 2, they will choose A in order to maximize the area below the supply curve, with a lowest price P_{min}, net of the expected spot price c_i. The only difference between bid functions is the contracting capacity involved.

For now let us assume both firms are identical in order to provide a symmetric benchmark. In terms of information available at the moment of choosing A, assume that in period 1 firms know the exogenous size of the contract to be auctioned Q and their marginal cost of over-contracting, θ. Regarding the parameter λ, here it

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[55]It is implicitly assumed that there is no cost in adjusting the contract portfolio by subscribing or dropping a forward contract with a large customer to cover the difference.

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Figure 2.7: Comparing different available contracting capacities
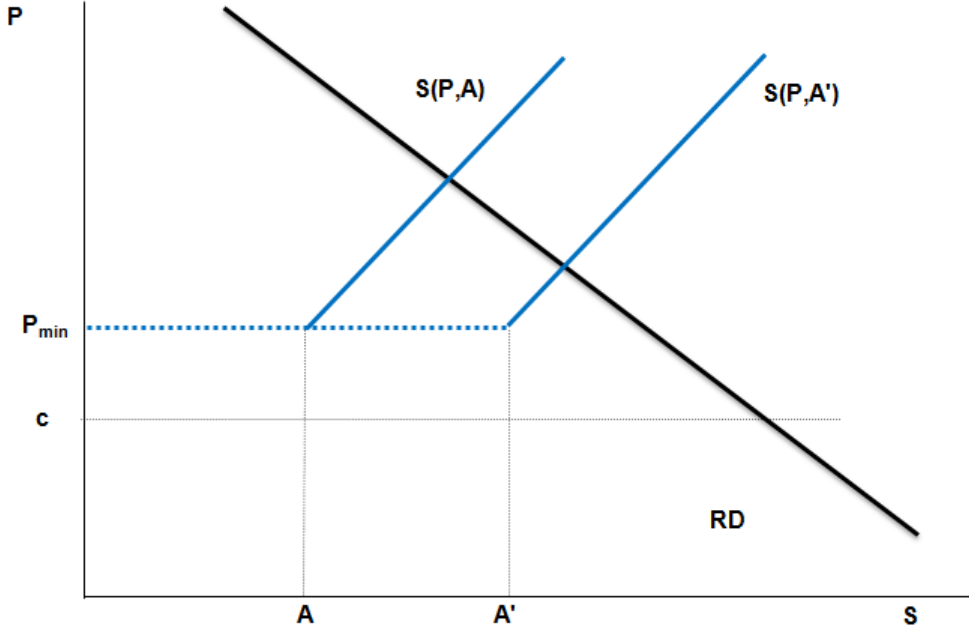
will be a fixed mark-up over the expected spot price. λ is also known in period 1. If we interpret this mark-up as the inverse hazard rate of section 2.3, conditions in the game will change. For that reason I reserve a separate discussion about it in the next section.

Firms will form expectations about expected spot prices. There are two states: high (c_H) and low (c_L). Firm i receives a signal of high expected spot prices with probability ρ and firm j with probability γ.

There will be only two potential levels of residual demand, high or low. The high residual demand for firm i is $Q - \beta P$ while the low residual demand is $Q - \alpha - \beta P$. The residual demand each bidder will have to face depends on the action the rival

firm takes in terms of contracting capacity A. Before analyzing this interaction I need to describe the set of possible actions.

Taking the expected residual demand, bidder i will have to choose a level for A that goes from zero to A_1. If a firm chooses $0 \leq A_i < A_1$ and obtains in the auction a quantity $S \leq A_i$, he will receive P_{min}. For quantities above A_i, he will ask for a higher price, so the slope of the supply function is increasing for $S > A_i$. The higher amount of contracting capacity the firm can choose is at the high residual demand ($\alpha = 0$) with price P_{min}. Then, if firm i chooses the higher amount of contracting capacity, the optimal amount will be $A_i = A_1$.[56] We have two corner solutions and/or an interior solution to the problem of maximizing expected profits by choosing the optimal contracting capacity. Figure 2.8 shows the two corner results with the two possible residual demands.[57]

It is possible to prove that there are no interior solutions to the problem of maximizing expected profits by choosing A. The next lemma shows that any A_i such that $0 < A_i < A_1$ is not optimal under the preceding assumptions.

Lemma 2.4.1 *Assuming two bidders with two states of expected spot prices and two levels of residual demand, a bidder i will have only two optimal levels of contracting capacities: $A_i = 0$ or $A_i = A_1$*

Proof: See the Appendix

The intuition of the proof is the following. Choosing $A = 0$ indicates the bidder is acting as a monopolist over the residual demand. Then if it is not optimal to choose a larger A, $A = 0$ is a superior option to any other $A > 0$ that implies an increasing portion of the supply function. Choosing $A = A_1$ indicates the bidder is acting as a

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[56] Any other amount over this point is not optimal for a risk-neutral firm.

[57] I will assume that both bidders have enough contracting capacity to reach A_1.

price-taker bidder that gets a fixed mark-up over his expected marginal cost. If $A = 0$ is not optimal, then any $A < A_1$ is an inferior option with respect to $A = A_1$. The larger the A, the more fixed mark-up the firm gets. In sum, we have two potential actions, low A or high A as we can see in Figure 2.8.

Figure 2.8: Cases for $A_0 = 0$ and $A_1 > 0$
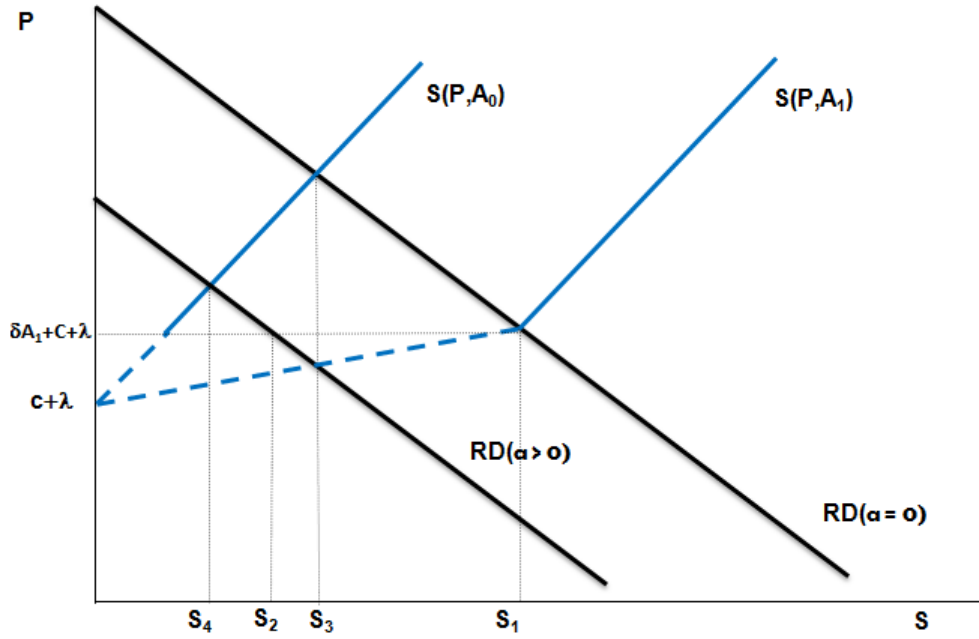
If the residual demand is high, firm i will obtain S_1 if he chooses A_1 and S_3 if he chooses $A_i = 0$. If the residual demand is low, firm i will obtain S_2 if he chooses A_1 and S_4 if he chooses $A_i = 0$. The possible values of S double when we account for the two potential residual levels of expected spot prices. The lowest price in both supply functions is $P_{min} = c_i + \lambda + \delta A_1$ since $S_1 = A_1$.[58]

In order to find the equilibrium strategies each firm will follow, it is important to determine how the decisions of each firm about its own contracting capacity will affect the rival's residual demand. If firm 1 chooses $A = A_1$, residual demand for firm

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[58]In case $\delta = 0$, we have the case of a flat supply function until A. Then $P_{min} = c_i + \lambda$.

2 will be $RD(\alpha > 0)$. By choosing a larger contracting capacity, firm 1 is reducing its rival's market share. If both firms choose $A = 0$, both firms will face a high residual demand, $RD(\alpha = 0)$. If both firms choose $A = A_1$, then both firms will face the low residual demand, $RD(\alpha > 0)$.

Solving this game gives us three Bayesian Nash Equilibria.[59] In what follows and without loss of generality, I will present these equilibria for the case of $\delta = 0$.[60] This includes the case of a flat portion of the supply function. In the Appendix, conditions are shown for the general case.

If we assume complete symmetry between the two bidders, such that $\rho = \gamma$, we will have five cases shown in Figure 2.9. For values of $Q - \lambda\beta(3+2\beta\theta)$ in Case 1 (below βc_L) the BNE is $(A_1, A_1; A_1, A_1)$. Both firms choose the higher level of contracting capacity and both firms end up facing the lower residual demand. The intuition behind this result is based on the size of the residual demand. If the residual demand is small, the best option for both bidders is to submit flat schedules.

For values of $Q - \lambda\beta(3 + 2\beta\theta)$ in Case 5 (above $\alpha + \beta c_H$) the BNE is $(0, 0; 0, 0)$. Both firms choose the lowest level of contracting capacity and both firms end up facing the higher residual demand. Here, since the residual demand is large, both firms will choose to behave as a monopolist over the residual demand.

In case 2, there are two BNE: $(A_1, A_1; A_1, A_1)$ and $(A_1, 0; A_1, 0)$. In case 4, again we have two BNE: $(A_1, 0; A_1, 0)$ and $(0, 0; 0, 0)$. Finally in case 3, the BNE is $(A_1, 0; A_1, 0)$.

The only possibility of an asymmetric result has a firm receiving a signal of high expected spot prices and the rival a signal of low expected spot prices. Under those conditions and if we are in cases 2, 3 or 4, the high-price firm will choose $A = A_1$

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[59]Strategies are define in the following way: in case signal received is high spot price, choose A_H, in case signal is low spot price, choose A_L

[60]Anwar (2007) shows that in an affiliated multi-unit model, there is an equilibrium where bidders with constant marginal valuations submit flat price schedules.

Figure 2.9: Cases for BNE if $\rho = \gamma$
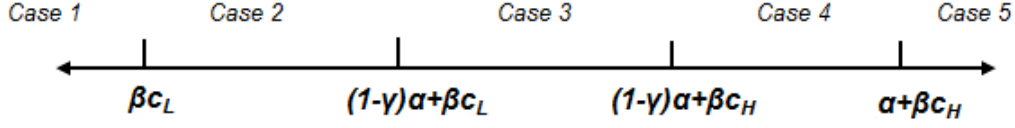
and the low-price firm will choose $A = 0$. If Colbun was expecting low spot prices and Endesa high spot prices, this result can explain their behavior in 2007 auction. Indeed, submitted prices were lower for Colbun than for Endesa, while in previous auctions the situation was the opposite.

If $\rho < \gamma$, we have two additional cases as is shown in Figure 2.10.[61] Under this assumption, we are more likely to have an asymmetric equilibrium.

Figure 2.10: Cases for BNE if $\rho < \gamma$
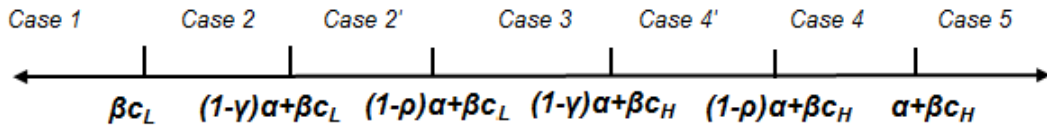
Here we are interested in asymmetric equilibria where firms choose different contracting capacities. So far I have assumed both firms are identical. I will consider two different kind of asymmetries: size and cost of over-contracting.

First, in the case of size asymmetries, I will assume firm 1 is larger than firm 2 and in case they choose $A > 0$, $A_1 > A_2$, i.e. $A_1 = A_2 + \epsilon$ where $\epsilon > 0$. This means

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[61]Figure 2.10 shows the cases if $\gamma - \rho < \frac{\beta}{\alpha}(c_H - c_L)$

that in case firm 1 chooses A_1, firm 2 has to face a residual demand $Q - (\alpha + \epsilon) - \beta P$. Under these assumptions there is only one asymmetric BNE, which is described in the following proposition.

Proposition 2.4.1 *Assuming firm i can choose a bigger contracting capacity than firm j, $A_i = A_j + \epsilon$ where $\epsilon > 0$ and $\rho = \gamma$, there is only one asymmetric equilibrium where firm i always chooses the lowest contracting capacity, $(0, 0)$, and firm 2 chooses the highest $(A_1, 0)$, if the difference in contracting capacities ϵ is large enough.*

Proof: See the Appendix

In this case the large firm chooses to play as the monopolist over the residual demand and the small firms chooses to play as a price-taker if both receive a signal of high expected spot prices. This does not explain the Endesa-Colbun case because the largest firm (Endesa) was the one choosing the largest contracting capacity.

A different kind of asymmetric BNE can be found if we assume different marginal costs of over-contracting θ between firms instead of differences in size.

Proposition 2.4.2 *Assuming firm i has a larger marginal cost of over-contracting than firm j, $\theta_i > \theta_j$ and $\rho = \gamma$, there is an asymmetric equilibrium where firm i always chooses the highest contracting capacity (A_1, A_1) and firm j always chooses the lowest $(0, 0)$, if the difference in the marginal cost of over-contracting, $\theta_1 - \theta_2$, is large enough.*

Proof: See the Appendix

This case can explain the 2007 auction. If Endesa had a larger cost of over-contracting, it is possible that Colbun acted strategically and behaved like a monopolist on the expected residual demand by choosing a smaller contracting capacity.[62]

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[62]Similar results can be found in January 2009 auction where the cost of over-contracting rises due to the proximity of delivery in January 2010. AES-Gener and Colbun submitted

MARK-UP AS A FUNCTION OF CONTRACTING CAPACITY

The previous analysis assumes a constant mark-up over the expected spot price λ. In section 2.3 we saw that this mark-up corresponds to the inverse hazard rate and depending on distributional assumptions could be a non-constant value. Decisions on contracting capacity in period 1 affect the mark-up in period 2's auction, but the result of the auction determines this mark-up. Then, λ will be a function of A. In particular, a larger contracting capacity can have a negative impact on the mark-up.[63] In that case, P_{min} will no longer be the same for $S(P, 0)$ and $S(P, A_1)$. It will be lower if the generator chooses A_1. This reduces the incentives to choose a larger A.

In case the relationship between mark-up and contracting position is linear, $\lambda(A) = a - bA$ where $a, b > 0$, Lemma 2.4.1 no longer applies. The optimal action is to choose $A = 0$. For a more general relationship (e.g. quadratic), it is possible to have an interior value $\hat{A}$. In that case, it is possible to replicate the analysis of the previous sub-section, but now with this two optimal levels of A: $(0, \hat{A})$, where $0 < \hat{A} < A_1$.

Since we do not know the exact form of $\lambda(A)$, there is no close form for $\hat{A}$. However, it is possible to recognize that a higher cost of over-contracting will increase $\hat{A}$, under certain parametric conditions. In that case, we will have a similar result as the one stated in Proposition 2.4.2.

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contracting capacities of 8% and 20% respectively for a contract with Chilquinta, while Endesa had a 100% capacity for the same one. However, they also submitted contracting capacities of 40% and 55% respectively for a contract with CGE. The inclusion of a second contract in the extension of the model could explain this result.

[63]Estimations in Appendix B show a negative effect of A over the mark-up.

Once we have a model of bidding behavior it is possible to use the data on bids to estimate unobservable variables like the amount of mark-up. The empirical implementation of (2.10) and (2.14) requires the estimation of $H(p, S(p))$ and its partial derivative for each bidder, in each auction. Unfortunately, the data on LTC auctions from 2006 to 2011 is not enough to estimate the inverse hazard rate by supply function. We have 7 different auctions and only 64 supply functions for 11 bidders.

In this article I will pursue a different goal. By imposing conditions on the inverse hazard rate, I can use the model developed in section 2.3 to estimate the marginal cost of over-contracting, θ, as well as the effect of expected spot price on submitted prices. This is important because we can get an estimate of how important the expected spot price (a variable that depends on the aggregate power system decisions) and the contracting capacity (a variable that depends on physical, technological and commercial decisions of each generator) are to explain submitted prices. I use all pairs of prices and quantities in order to linearly estimate the effect of expected spot prices and over-contracting on submitted prices.

I make two assumptions. First, I will assume the inverse hazard rate is a constant mark-up. This assumption is not as strong as it sounds. The constant mark-up assumption gives a flat bid function until $S = A$ where its slope changes to $\theta > 0$. A flat portion of the bid function is consistent with the rules of the auction. Even if the generator bids an amount A for a price P, the allocation mechanism rations a proportion below A at the same price.[64] Again, I will denote the constant mark-up as λ.

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[64]For example, a bidder i submits a bid of 1,000 GWh for 70 USD/MWh and 500 GWh for 72 USD/MWh for a contract of 1,500 GWh. If bidder j bids 500 GWh for 68 USD/MWh, the allocation mechanism will allocate only 500 GWh at 70 USD/MWh to bidder i.

Second, I will assume as in section 2.4 that the available contract capacity of each bidder, A_i, is equal to the flat amount of power offered until the bid function's slope changes. This assumption does not depend on any condition imposed on the inverse hazard rate.

Although the mark-up is assumed constant, it is a function we don't know. In order to estimate θ we can follow two strategies. First, a parametric estimation by assuming that λ is a polynomial function. Second, a semi-parametric linear estimation can be used if we don't want to impose any structure on it. I will pursue both strategies. The mark-up would be a function of the competitiveness of the auction. For that reason, I include the number of bidders, N, and the size of the contract Q in GWh. Size of blocks and sub-blocks are chosen by distributors so they are exogenous to generators. I estimate the following equation, for i bidders, j units, t auctions.

$$P_{ijt} = C_t + \beta\lambda_{it} + \theta(S - A)_{ijt} + \alpha_i + \mu_j + \eta X_{jt} + \varepsilon_{ijt} \qquad (2.16)$$

The endogenous variable is the submitted price, P, which includes modulation factors. Among the exogenous variables, $S - A$ is calculated as the amount offered over the contract capacity. In order to account for size I create a second variable (in percentages) that normalizes $S - A$ by the physical capacity of the generator.[65] C is the expected spot price at the moment of the auction, based on information provided by CNE.[66] Fixed effects by generator are captured by α_i

In order to account for heterogeneity across distributors, I include a dummy variable for each distributor μ_j. There is heterogeneity across contracts too. For that

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[65]As physical capacity I use the on-firm energy of each plant as it is calculated by the Independent System Operator. On-firm energy is power that can be generated in dry periods and it is a relevant capacity measure in systems with large portions of hydropower.

[66]Appendix B includes a detailed description of it. I have tried different scenarios for expected spot prices with the same results in terms of significance.

reason I also include two other regressors in X: the duration of the contract in years and the time left for physical delivery in weeks. It would be expected that longer contracts would be more coveted by bidders and a shorter time left for delivery would raise the cost of over-contracting.

Table 2.3 shows summary statistics for the main variables in the regressions. The over-contract proportion, *(S-A)/Capacity*, is particularly high for some small generators. It goes beyond 100% but in average is below 10%. Delivery time goes from 6 months to more than 3 years, but in average is 2 years.

Table 2.3: Summary statistics

Variables	Obs	Mean	Std. Dv.	Min	Max
P	319	80.14	22.99	48.8	128.5
C	319	74.37	16.51	55.0	95.0
A	319	776.83	673.27	23.0	3,000.0
S-A	319	603.36	605.30	0.0	3,500.0
(S-A)/Capacity	319	9.09	18.38	0.0	145.8
Q	319	1,897.87	796.86	150.0	3,000.0
N	319	3.64	1.42	1.0	6.0
Duration	319	12.99	1.48	10.0	15.0
Delivery time	319	109.29	58.90	26.3	169.7

2.5.1 RESULTS

Table 2.4 shows the estimations for two parametric specifications: linear and polynomial of grade two. The regressor $S - A$ is in GWh (not normalized by physical capacity) and in % (normalized by physical capacity). In both specifications, the variables that affect significatively (and positively) the bidding price are the expected spot price C and the over-contracting quantity $S - A$. The expected spot price has

Table 2.4: Parametric Approach

Variable	Linear		Polynomial	
	In GWh	In %	In GWh	In %
C	1.198***	1.202***	1.133***	1.139***
	0.158	*0.148*	*0.16*	*0.15*
$S - A$	0.002**	0.186***	0.002**	0.184***
	0.001	*0.026*	*0.001*	*0.026*
N	0.431	0.451	4.385	4.266
	1.095	*1.03*	*2.713*	*2.552*
Q	0.000	0.000	0.004	0.005
	0.001	*0.001*	*0.004*	*0.004*
N^2			-0.947	-0.915
			0.556	*0.523*
Q^2			-0.000	-0.000
			0.000	*0.000*
Delivery	0.002	0.000	-0.062	-0.062
	0.058	*0.054*	*0.067*	*0.063*
Duration	-0.068	-0.012	-0.13	-0.072
	0.355	*0.334*	*0.373*	*0.351*
Constant	-7.252	-8.382	4.369	2.857
	21.616	*20.339*	*23.073*	*21.697*
Obs	319	319	319	319
R^2 adjusted	0.925	0.933	0.926	0.934

(*) p < 0.05, (**) p < 0.01, (***) p < 0.001.

a coefficient ranging between 1.13 and 1.2. The cost of over-contracting is around 2 USD/GWh.[67]

Table 2.4 also uses the normalized regressor $S-A$, that shows the over-contracting quantity as a percentage of the physical capacity. Results are almost identical, but here the cost of over-contracting is in terms of capacity percentages. Contracting one

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[67]This value is significatively below the 3.8 USD/GWh shown in Table 2.2 as an average of all linear approximations to the submitted bidding functions.

percentage point over the physical capacity implies an increase of 185 USD/GWh in the submitted price. Considering that some firm are over-contracted for more than a 100%, the total cost of over-contracting can be particularly high.

In the polynomial regression, delivery time and duration have a negative effect on prices as expected but they are not significant. The effects on prices of the number of bidders and the size of the contracts are also not significant, but the number of bidders become significant in higher degree polynomials.

Table 2.5: Parametric Approach with different polynomials

Variable	Grade 3		Grade 4	
	In GWh	In %	In GWh	In %
C	1.107***	1.115***	1.067***	1.049***
	0.155	0.145	0.178	0.166
$S - A$	0.002***	0.185***	0.002**	0.186***
	0.001	0.025	0.001	0.025
N	-42.308***	-42.328***	44.128	55.936
	10.005	9.359	42.026	39.14
N^2	14.703***	14.642***	-38.767	-45.381*
	3.356	3.139	23.883	22.244
N^3	-1.401***	-1.386***	11.477*	12.937*
	0.313	0.292	5.466	5.091
N^4			-1.002*	-1.109**
			0.416	0.387
$Delivery$	0.009	0.012	0.131	0.132
	0.068	0.064	0.093	0.087
$Duration$	-0.068	-0.002	-0.288	-0.226
	0.363	0.339	0.373	0.347
$Constant$	44.676	43.475	-6.208	-9.906
	23.798	22.254	30.916	28.792
Obs	319	319	319	319
R^2 adjusted	0.931	0.939	0.932	0.941

(*) $p < 0.05$, (**) $p < 0.01$, (***) $p < 0.001$.

It is possible that above parametric specifications are not capturing the mark up λ if the polynomial has a different structure. Table 2.5 shows results for polynomials

of degree three and four. The cost of over-contracting does not change significatively. The coefficient of C gets closer to one as we increase the degree of the polynomial. This could mean that a more flexible specification for the mark-up can give better estimations for this coefficient. Also, the effect of the number of firms is negative and statistically significant at the average value of N in polynomials of higher degree.[68]

We have mentioned that a second strategy is to follow a semi-parametric estimation. Robinson (1988) showed that despite the presence of a nonparametric component as λ, θ can be estimated. In my setting λ is considered a nuisance function and I proceed to estimate a partially linear model.[69] Results are depicted in Table 2.6.

Semi-parametric estimations are less precise but they allow for more flexible modeling strategies. The coefficient of expected spot price is close to 0.9. The cost of over-contracting is identical to the polynomial specification.

In sum, under different specifications we can assert three main results. First, the expected spot price and the cost of over-contracting are the main determinants of submitted prices. Second, expected spot prices have a close one-to-one relationship with submitted prices. Third, the marginal cost of over-contracting is around 185 USD per percentage point of physical capacity.

Figure 2.4 shows that there is plenty of heterogeneity across bidders. It is a relevant question if the cost of over-contracting is different across groups of bidders. I present results in Table 2.7 for the linear and the polynomial of grade two specification, but only for a group of generators. The group includes the four largest incumbents (Endesa, AES-Gener, Colbun and Guacolda). These are the historical incumbents of

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[68]It is possible to choose the best specification by cross validation. Since results are very similar across all polynomials, I prefer to show them all.

[69]I use a constant normal kernel density estimator. Bandwidth was selected from Silverman (1986) for the optimal smoothing of a normal random variable's density.

Table 2.6: Semi-parametric estimation

Variable	Robinson's Estimation	
	In GWh	In %
C	0.888*	0.898**
	0.331	*0.403*
$S-A$	0.002**	0.185***
	0.001	*0.024*
Delivery	0.000	0.000
	1.36	*1.268*
Duration	-0.128	-0.101
	0.384	*0.358*

(*) $p < 0.05$, (**) $p < 0.01$, (***) $p < 0.001$.

the industry. It is expected that the cost of over-contracting of incumbents or big generators would be lower than the average generator.

Table 2.7: Parametric estimation for incumbents

Variable	Linear		Polynomial	
	In GWh	In %	In GWh	In %
C	1.19***	1.19***	1.162***	1.158***
	0.152	*0.152*	*0.155*	*0.155*
$S-A$	0.001	0.162	0.001	0.164
	0.001	*0.087*	*0.001*	*0.087*
Obs	264	264	264	264
R^2 adjusted	0.921	0.921	0.92	0.92

(*) $p < 0.05$, (**) $p < 0.01$, (***) $p < 0.001$.

From Table 2.7 we can see that the marginal cost of over-contracting for incumbents is below the average value in Tables 2.4, 2.5 and 2.6, and is not even significant. The cost of over-contracting is a bigger constraint for smaller incumbents and entrants. Table 2.8 introduce an interaction between $(S-A)$ and a dummy variable

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for the top four incumbents. As it can be seen, the cost of over-contracting is significant for entrants but not for the top 4 incumbents. It is possible that entrants face a riskier scenario in case of winning a LTC. Since they usually relay in a few units of production, any eventuality (i.e. drought, earthquake, accident) can drive the entrant into bankruptcy.[70]

Table 2.8: Parametric estimation with incumbents' interactions

Variable	Linear		Polynomial	
	In GWh	In %	In GWh	In %
C	1.199***	1.198***	1.132***	1.134***
	-0.154	-0.149	-0.155	-0.151
$S - A$	0.010***	0.189***	0.010***	0.186***
	-0.002	-0.028	-0.002	-0.027
$(S - A) * Inc$	-0.009***	-0.023	-0.009***	-0.018
	-0.002	-0.089	-0.002	-0.089
Obs	319	319	319	319
R^2 adjusted	0.929	0.933	0.930	0.934

(*) $p < 0.05$, (**) $p < 0.01$, (***) $p < 0.001$.

The cost of over-contracting is related to the slope of the bid function. The average slope of bid functions remain constant between October 2006 and Feb 2009. When the time lag to start supplying the contracted amount of power is reduced to less than 6 months, average slopes jump from 1.9 USD/GWh to 19 USD/GWh. As an important part of available capacity was committed in previous auctions and there was no time left to install new plants, it is to be expected that there would be a rise in the cost of over-contracting. This rise increases bid functions' slopes. Once time to delivery increases back, slopes fall down. However, in my estimations I couldn't find any evidence of delivery time as a significant explanatory variable of prices. An

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[70]The biggest entrant in the 2008 auction, Campanario, went into bankruptcy in 2011 after several months of negative cash flow due to high spot prices and not enough own production to supply for its LTC.

alternative explanation could be that in this auction we have three entrants and one small incumbent. Since the marginal cost of over-contracting is higher for entrants and small generators, the average slope is higher in that auction relative to others. Similar results can be found if we perform an estimation by submitted schedule.[71]

2.6 SUMMARY

LTC auctions for power have become a new instrument to encourage investments in generation and to reach a correct risk allocation. Since 2005, generators in Chile have to compete in public auctions for the right to supply electricity to customers formerly under price regulation. Long-term contract auctions imply different incentives than widely known short-term or day-ahead auctions. This article provides a multi-unit model to understand bidding behavior, as well as to estimate the main determinants of submitted prices. This is the first theoretical approach that fits the actual Chilean data. In particular, it is the first that considers the divisible-good dimension of LTC auctions.

From my estimations, the key variables explaining bidding behavior are expected spot prices and generator's contracting capacity. There is an almost one-to-one relationship between expected spot prices and submitted prices. This is an important fact for contract indexation. Indexation should take into account the expected spot price, not individual generators' technology. As a policy recommendation, it would be beneficial to increase the time between the moment of the auction and the moment of physical delivery, not necessarily because a shorter time would increase prices, but

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[71]In Appendix B, Table B.5 shows that contracting capacity has a negative effect on the difference between price-intercepts (estimated by linear approximations in section 2.3.1) and expected spot prices. This effect is larger for non-incumbents in Table B.6.

because increasing the time to deliver would make generators think more in terms of expected spot prices than short-term fluctuations.

Our approach allows us to estimate the marginal cost of over-contracting. We have calculated that the cost of over-contracting is around 185 USD per percentage point over generator's physical capacity. Also we have found that this cost is more important in smaller generators and new entrants. This is a point to keep in mind about the impact of entry.

Estimations of contracting capacity seem to follow physical capacity in the majority of the cases. Nevertheless, in some auctions we found large incumbent firms who show very reduced contracting capacities. This behavior can be explained by strategic choices of contracting capacities. A generator can commit to a smaller size to act as a monopolist over the expected residual demand.

This paper was written without considering the dynamic implications of having sequential auctions. It is an important feature because the contracting decisions of today will impact the contracting decisions of tomorrow. A firm that contracts a positive amount of electricity in period t will face a more constraining situation in $t + 1$. Since results are public, this information is available for competitors and they will behave accordingly. In LTC auctions there is a caveat. Since auctions are usually performed with years in advance, a generator has a higher incentive to expand capacity after winning a contract. Then the optimal contract position increases. The final effect is unclear and remains to be explored in future research.

CHAPTER 3

"RALCO IS COMING": INVESTMENT DELAY IN THE CHILEAN POWER MARKET

3.1   INTRODUCTION

From 2000 to 2004 there was a lag in generation investment in the Chilean power market. The capacity expansion was below the medium-run average during this period. Part of the literature argues that regulatory uncertainty explains it. In the current paper we try a different explanation. We argue that the main reason for this investment lag is the announcement of a new large unit of generation that was unexpectedly delayed several times over the period. In a market with indivisible investments, like the power market, a large investment will reduce the overall level of investment before and after a "big unit" starts operating. We make the point that the normal lag in capacity investment was amplified by the delay in a big unit's entry.

The big investment we refer to is a hydro-power plant named Ralco. Ralco was a project of the largest generator, Endesa. Its size was about 10% of total installed capacity in 2000. We argue that the delay of Ralco modified incentives of competitors' projects, resulting in an ex-post investment lag. In a simplified investment model, delays can have a "leapfrogging effect". If the delay is large enough to make profitable a unit before the big unit starts operating and the time-to-build restriction is not binding, a unit that was originally scheduled after the big unit will be rescheduled to enter before it. In this context, a unit leapfrogs ahead of the big unit. If the delay is not large enough to increase investment returns in order to move a unit forward or

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the time-to-build restriction is binding, no units will be scheduled before the big unit and the investment lag is more harmful.

Additionally, time restrictions due to the short-time announcement of Ralco's delays generated small windows of investment opportunity. We argue that this gave an advantage to incumbents, which were the only ones able to take the opportunity fast enough. Under such conditions, opportunities for potential entrants were reduced in a highly concentrated market like the Chilean one.[1]

This paper makes three relevant contributions. First, we compile information not previously systematized on capacity expansion from 1998 to 2004, and we present this information in a way that helps to understand better the evolution of the investments. Using real-time information from the regulator's semestral reports, we are able to trace back in detail the story of Ralco's delays and its relationship with other projects. The regulator's information about expected spot prices as well as suggested and under-contraction plants is the best public information available in the market. Second, using an ex-ante approach we are able to distinguish a period of investment lag from a period of lack of investment. We find that the period under analysis falls under the first category. Finally, we explain how these delays could increase incumbents' investment advantage. Opportunities for investment before Ralco's announced operation were seize only by incumbents because they have comparatively shorter time-to-build requirements or more accurate information about the market situation.

Historically, the largest proportion of installed capacity in Chile was based on hydro-power due to natural resource endowments. Most capacity expansion was based on thermal generation once natural gas was able to be imported from Argentina in 1995. Ralco, the last big hydro-power plant built since the natural gas arrival,

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[1]There was no relevant entry until several years later when the circumstances and the regulation had changed.

started construction in 1999. It was set up to start producing in April 2002 but it finally went into operation in September 2004. From 2000 to 2004 we say there was a "quiet period" in terms of investment in generation. In May 2004, the Argentinean government abruptly decided to reduce its natural gas exports, and since 2005 natural gas was no longer a reliable input for electricity generation in Chile. The main goal of this paper is to explain the investment lag during the quiet years, before the natural gas restrictions.

In the Chilean literature, there has been plenty of analysis of the natural gas arrival (Fischer and Serra, 2004) and the origins of a shortage during the 1998-99 drought (Chumacero, Paredes and Sanchez, 2000; Diaz, Galetovic and Soto, 2000), as well as the effect of the natural gas crisis after 2004 (Arellano, 2008). However, there has been less attention on the quiet years. Arellano (2008) attributes a lack of investment in the period to regulatory uncertainty. We do not find evidence of lack or absence of investment but rather an investment lag that is not related to regulatory uncertainty. Galetovic, Olmedo and Soto (2002) introduce a methodology using public data to evaluate the likelihood of a power shortage from 2002 to 2004. They found a small probability of shortage. We also use public data from the regulatory authority to trace back the investment path over the period. To our knowledge, there has not been any other work that includes a detailed description of the capacity expansion over that period.

This paper is related to the literature on investments in oligopoly and entry deterrence. Capacity investments that can deter entry can be found in Spence (1977, 1979), Dixit (1980), Eaton and Lipsey (1981) among others. A fixed sunk cost investment reduces a firm's marginal cost, making it a tougher competitor and reducing competitors' expansion without rising rivals' costs. In any case, this requires the incumbent's commitment to a course of action. In the Chilean case, the announcement of a new

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unit can be a strong commitment once the regulatory authority consider it to be under-construction on an official report. We will see in detail the regulator's role in the announcement of a new plant.

In this paper, however, we also stress the importance of the time until the investment is ready to operate. We argue that lag on capacity investment can be explained by a large sunk investment plus several delays in its construction. Bar-Ilan and Strange (1996) shows how the existence of a period of time to earn income after an irreversible sunk investment has been made can result in different investment patterns due to uncertainty. Our paper is also related to Eaton and Lipsey (1980), where the durability of capital can be used as a barrier to entry. As a result, the incumbent chooses to extend or reduce the durability of capital, away from the cost-minimizing solution. Instead of a period of capital durability, we have a time-to-build period for a large sunk investment that affects the incentives to entry. Pacheco-de-Almeida and Zemsky (2003) studied the effect of time-to-build on strategic investment under demand uncertainty. In this paper we are not saying there is a strategic use of the investment size or the time-to-build to deter entry. However, we stress the negative effect of a large investment's delay on the likelihood of entry.

Section 3.2 includes a description of the Chilean Power Market. Section 3.3 describes power regulation in Chile from 2000 to 2004 and its relationship to capacity investment. Section 3.4 analyzes aggregate investment behavior and the evolution of relevant prices. In Section 3.5 we set up a simple model of investment and describe how Ralco's delays affected the investment pattern during the period. Section 3.6 summarizes and includes policy recommendations. Tables and secondary figures are included in Appendix C.

3.2 Chilean Power Market

Geographically, there are two main regional power markets: the SIC covering the southern and central areas of the country, and the SING covering the northern part.[2] There is no connection or overlap between systems. SIC is the bigger system, with a total installed capacity of 12,488 MW, serving 90% of the population of the country.[3] SIC's generating mix is mainly based on hydro-power while SING's is mainly thermal.[4]

Due to the geographic characteristics of the Central and South part of Chile, under normal weather conditions, hydro-power represents more than 60 percent of SIC total generation.[5] Water resources can be stored to generate power at a later date. For this reason, SIC's spot price is heavily influenced by the opportunity cost of water: using water to generate today or leave it for a future period. Also, water shortages can produce power outages, increasing spot market uncertainty.

The evolution of SIC's technology mix since the mid 90s can be understood in terms of actual generation.[6] By 1995, 70% generation was based on hydropower and 30% on coal. After an international agreement with Argentina in 1995, imported natural gas became a major source for power generation due to its low marginal cost, medium investment cost and short time-to-build. While the SIC was expanding natural gas generation, the most severe drought in thirty years occurred during 1998-

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[2]There are other smaller and isolated systems in the South: Aysen and Magallanes.

[3]As a matter of comparison the state of California has 67,500 MW of installed capacity

[4]In terms of demand, 60% of SIC's demand comes from regulated customers, residential and commercial mainly, while at SING 90% comes from large customers, particularly from the mining industry.

[5]Installed hydro-generation capacity is 35% for the country as a whole, but 45% in SIC.

[6]Capacity and actual generation does not necessary coincide due to hydrology fluctuation and demand volatility. Figure C.1 in the Appendix shows generation by technology between 1996 and 2009.

1999. For the first time oil-based generation became important to replace hydro-power for a short period.[7]

After the 1998-1999 drought, natural gas became the most important thermal source of generation until 2004. It would have continued to be so but an unexpected energy crisis in Argentina impacted in the Chilean systems when restrictions over natural gas exports started in May 2004. This restriction reached over 50% of the Chilean demand in 2005, becoming even worse with time.[8]

New plants based on natural gas were stopped due to input uncertainty. Existing natural gas plants were adapted to use oil instead, which explains the growth of generation based on oil after 2006. A new drought in 2007-2008 was overcome basically with a demand reduction and oil-based generation. In sum, there have been three relevant supply shocks in the system that determined the current technology generation mix: the introduction of natural gas in 1996, the drought of 1998-1999 and the natural gas crisis of 2004.

The generation market exhibits high market share concentration.[9] Figure C.3 in the Appendix shows shares of installed capacity and sales by the major generation groups in SIC from 2000 to 2005: Endesa, Colbun, AES-Gener and Guacolda.[10] During this period, more than 90% of the installed capacity and the contract market was in the hands of the top four firms. Considering sales under contract, the Herfindahl Index for the top four firms was 2,905 in 2005.

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[7]500 MW in diesel turbines were installed by generators in less than a year.

[8]Restrictions as a percentage of total natural gas imports are depicted in Figure C.2 in the Appendix.

[9]The literature (Pollit, 2004; Fischer and Serra, 2004; Arellano, 2008) showed concerns about the degree of concentration in the generation market.

[10]Guacolda is the forth firm in size, but it is important to stress that 50% of it belongs to AES-Gener.

3.3 Power Regulation in Chile

The Chilean Electricity Market is separated into three sectors: Generation, Transmission and Distribution. Transmission and Distribution are seen as natural monopolies and remain under price regulation. Considering that there are no significant economies of scale in generation, the law envisioned a competitive environment among generators with open entry. The decision of investment is completely decentralized and all firms are privately owned. Each generator decides the timing, size and technology of a new unit, depending on price signals. The National Commission of Energy (CNE) is the regulatory authority.

Generators operate in a spot market and in a forward market at the same time. The spot market works as a short-term market where demand and supply meet instantaneously. The forward market operates as a long-term market where generators and customers contract supply and demand in advance. In the next sub-sections we will describe the regulation over both markets during the period under study.[11]

3.3.1 Spot market

The spot market is organized in Chile by an Independent System Operator called CDEC.[12] All generating plants report their operational costs and the CDEC audits them. The CDEC sets the order of generation following the least cost of dispatch. It is a model of centralized power dispatch, independent from the forward market.[13]

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[11]In March 2004 and May 2005 there were two significative regulatory reforms (Short Law I and II) but they are not relevant for our period of analysis.

[12]Centro de Despacho Economico de Carga.

[13]As Arellano (2008) argues, the regulation of the spot market tries to simulate a perfectly competitive market. This system is different from a day-ahead auction like in California where each firm bidding to supply power submits an upward-sloping supply schedule for each hour while purchasers bid downward-sloping demand schedules.

The spot price mechanism in the Chilean system follows a peak-load pricing scheme. There is a power price and a capacity charge.[14] The marginal cost of generation is the power price and it is equal to the most expensive unit of generation in use to balance demand and supply, taking into account transmission constraints and energy losses.[15] The capacity charge, instead, is given by the lowest capital cost of a generation unit to supply the peak of demand and it is calculated by the CNE. The power price covers the variable costs, while the capacity charge is an annual payment that it is allocated proportionally to the "on-firm" capacity of each plant.[16]

In sum, spot prices indicate the short-term marginal cost of electricity generation, plus the opportunity cost of installing peak capacity. In theory, it gives the appropriate signal for an optimal operation of the spot market and an optimal decentralized investment decision to supply a growing demand. Given the absence of economies of scale, the peak-load pricing scheme allows for a variety of generating units with different sizes, marginal costs and technologies to balance supply and demand. By the end, the customer pays a price for the power she consumes and a different price for the capacity she demands at the peak hours.

[14]In power markets, setting a price equal to marginal cost is not sustainable. A generator selling at marginal cost would not earn enough return without a capacity charge, since power demand has high demand and low demand states each day. For example, a diesel turbine that generates only on peak-demand periods and has the highest marginal cost will not be profitable without a capacity charge.

[15]In case of any shortage, the spot price is equal to a "failure cost" calculated by the CDEC. The failure cost is based on consumer willingness to accept compensation for a planned outage of a particular magnitude.

[16]On-firm capacity is the amount of power that a unit can effectively generate. For a hydro-based unit it considers dry periods. For a thermal-based unit it considers periods of maintenance. It is a relevant capacity measure in systems with large portions of hydro-power.

3.3.2 Forward market

The purpose of forward contracts is to hedge spot market risk.[17] There is uncertainty about future spot prices that are subject to excess of capacity, potential entrants with lower generation costs, hydrologic volatility, etc. A forward contract reduces the risk a new plant has to face and it is sometimes a prerequisite for financing new units.

Forward contracts can be signed with distribution companies, for customers under price regulation, and with large firms or large consumers (with installed demand over 2 MW) also known as "free customers". Free customers can contract directly with generators for power supply, while "regulated customers" are supplied by local distribution companies and can not have any direct contact with generators. Generators are free to sign as many forward contracts with free or regulated customers as they want. Neither distribution companies nor free customers have access to the spot market.

Until 2005, forward contracts with distribution companies or regulated contracts only specified duration and quantity. Price was regulated, called "node price", and no other contract condition could be included for any party.[18]

The regulated price is the sum of the regulated price of distribution (price that covers the distribution company investment and operation), the node price of power, the node capacity charge and the relevant transmission charge (that covers transmission operation and investment). The transmission charge and the regulated price of distribution are calculated every four years and remain constant during the period. The node price of power and the capacity charge are determined for six months every

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[17]We will not consider potential strategic behavior on the forward market. Since forward contracts with power distributors were price regulated during this period, and the spot market is coordinated by the CDEC, there was no room for strategic forward trading.

[18]The Short Law II approved in 2005 introduced mandatory auctions for long-term power supply contracts between distributors and generators. Power prices remain fixed during the entire length of the contract but indexed to input prices chosen by the CNE. The capacity charge remains regulated.

April and October. In the calculation of node prices, the CNE uses all the available information from the generation market to forecast future spot prices. This is the best information available in the market.

Figure 3.1 summarizes the regulation of the generation market. The direction of the arrows indicates the power generation of generator G_i into the spot market and the purchases from the spot market to supply his forward contracts.

Figure 3.1: Spot and Forward Market
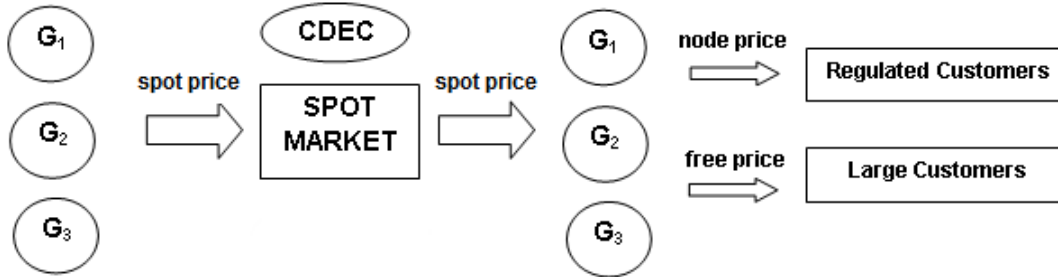
SIGNALS FOR INVESTMENT IN REGULATED PRICES

The CNE determines the node price in two steps. The first step is to calculate a "theoretical price" of power as the average forecasted spot price over different scenarios and a capacity charge as the capital cost of a diesel turbine. The sum of both prices comprise a "monomial price". The second step consists in comparing the monomial price with the average price for free customers.[19] The monomial price is required to lie within a band of +/- 10% of the average free price.[20] If the node price is out of the band, it is adjusted until it reaches the lower or upper limit band.[21]

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[19]It is the average for the last four months previous to the node price calculation. All generators inform their average price per free contract to the CNE.

[20]In March 2004 the width of the band was reduced to +/- 5%.

[21]This adjustment used to be applied to the entire monomial price, but with the reform of 2004 (Short Law I), only the theoretical price of power is corrected in case of being required, while the capacity charge remains without any change.

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Formally, the node price of power or theoretical price is the expected spot price of power. In order to calculate it, the CNE has to forecast demand and supply, as well as input prices. In terms of supply, the CNE designs an "investment plan" for the next 10 years. The CNE determines the investment plan schedule for generation and transmission that minimizes the total cost of supply. This total cost is the present value of investment, operation and potential rationing[22] for the next ten years. The investment plan considers the estimated demand and the present state of existing units of generation as well as units under construction. There are also "suggested" units that are needed to balance supply with expected demand. If a suggested plant appears in the investment plan, this is a signal that there is enough room for capacity expansion, and it is the best information a new project can use. CNE's investment plan indicates that new units are introduced the moment they are profitable in the system. The investment plan is an indicative plan, not a mandatory requirement.

Once the optimal investment plan has been designed, the CNE calculates the expected marginal costs of the system for the next 48 months.[23] This is an average weighted price considering all the potential hydrologic conditions that occurred in the previous 40 years. Marginal costs of generation are calculated taking into account expected prices of fuel as well as the economic value of water resources.

Finally, the node peak capacity charge reflects the annual marginal cost of increasing system capacity assuming a specified reserve margin. It reflects the capital and operating costs including a 10% of return over capital of a diesel turbine.

All the information about CNE estimations is public and it is the best information an entrant can have about expected spot prices and forecasted capacity expansion. By

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[22]The estimation allows for power outage scenarios. In case of a shortage, the power price is equal to the cost of rationing in the simulation.

[23]Estimations are run for the next ten years, but the node price only takes into account the first four.

using the information provided by CNE's reports we can retrace agents' expectations about prices and capacity expansion at the moment.[24]

In order to account for expected prices we can look at regulated and free prices. It is important to highlight that node prices and free prices follow a similar pattern. We know that the node price can be adjusted if it is too far away from the average free price. But also, some free contracts are indexed to the node price. In Appendix C we present a Granger causality test to determine how regulated, non-regulated and spot prices affect each other. Using quarterly data from April 1995 to October 2004 we find out that monomial node prices Granger cause monomial free prices but not the reverse. Also, one of the main factors that affect the spot price is the availability of inflow energy from water resources. In sum, free prices follow node prices. If generators are contracting at prices that follow the node price, the information used to calculate the node price should be accurate enough about their own expectations. Then, by using information from node price reports we can analyze the investment incentives of the period.[25]

3.4   Aggregate Investment and Prices from 2000 to 2004

We define an investment lag as a situation in which ex-post capacity expansion is below the medium-term average during a particular period of time, but where all the ex-ante required investments were made. This period of time is established as the necessary time-to-build a new generation plant: two to three years.[26] It is important to

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[24]It is a common practice in the Chilean industry to use CNE's reports as an input for forecasting. For example, Galetovic, Olmedo and Soto (2002) use information provided by CNE's reports in 2001 to analyze the probability of power shortages in the system.

[25]Before Ralco's delays there was little concern in the market about the possibility of CNE miscalculations in the investment plan. This plan didn't miss the real path of capacity expansion by much.

[26]This was the average time-to-build an expansion unit during the period under study.

separate the definition of investment lag from lack of investment. Lag of investment is a delay in projected investments that are not required for the expansion of the system, while lack of investment is a deficit in the required amount of investment. The differences between both phenomena are important. In a situation of investment lag there is no problem associated with the expansion of the required capacity. In the case of a lack of investment, there is a problem and in order to avoid future deficits it could be necessary to implement policies to reduce the gap between required and realized investment.[27]

In Figure 3.2 we plot expected additional capacity in a five-semester horizon according to the CNE's reports. Additional capacity is separated into suggested and under-construction. Suggested capacity indicates that the system is requiring an expansion. It can be seen that there was little expected capacity expansion in the next five semesters, in reports from April 1999 to April 2000. Due to an over-capacity situation in the previous years, the system did not require more investment. Only in October 2000 do we have the first signal of an investment lag: no under-construction units but a small suggested one. Even though there was a lag in capacity investment, there was not a significant deficit in the required expansion of the system. This situation does not correspond to a lack of investment. A different case can be found in 2005. Due to natural gas restrictions, the system was requiring an expansion in capacity. This was signaled by a large suggested capacity in CNE's reports.

Even if we consider a different horizon[28], the lack of investment in 2005 remains, but the investment lag disappears as we move to a longer horizon. There is no investment lag if we consider the average investment for a longer period than the regular

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[27]We define the required level of capacity expansion to the level that allows balancing demand and supply.

[28]Figure C.5 in the Appendix included expected additional capacity for four, eight and ten semesters.

Figure 3.2: Expected additional capacity in a five-semester horizon
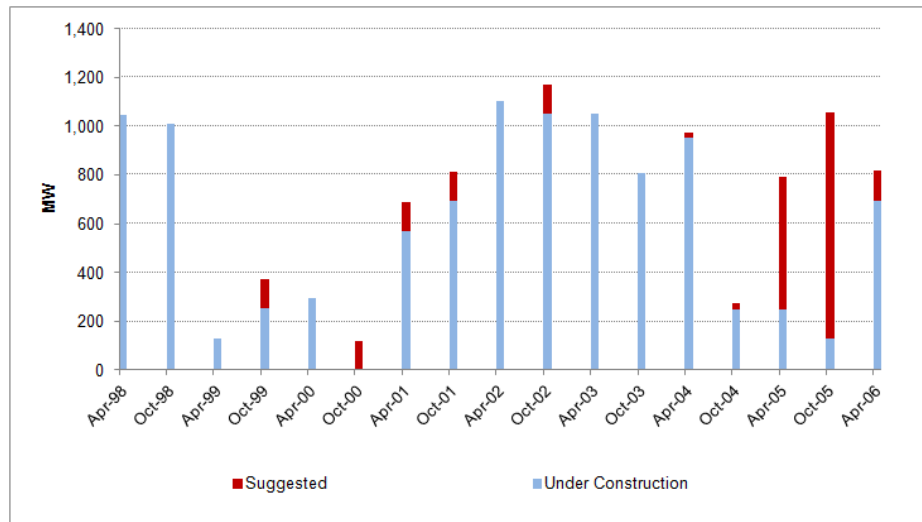
time-to-build. Instead, a lack of investment remains because it affects the long-term investment average.

In Figure 3.3 we can see this investment lag in aggregate terms. From 1996 to 1999, we have an expansion of thermal capacity based on natural gas. After the drought in 1998-1999, we have a different scenario with no significant expansion in installed capacity until Ralco in 2004. After Ralco, there is no relevant expansion until 2007. In systems that largely depend on hydro-power generation, it could be not possible to separate a situation of investment lag from a case of lack of investment with an ex-post perspective. For example, ex-post, there was a power shortage in 1998-1999 not due to lack of capacity but due to hydrologic conditions. Ex-ante, the investment situation was good in 1998.[29] Also, in Figure 3.3, we cannot distinguish ex-post between the

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[29]In fact there was, in a broad sense, a situation of over-capacity investment. Firms were running to have ready their natural gas units as soon as possible. There were units originally scheduled for 2001 that were in operation by 1999.

investment lag in 2000-2003 from the lack of investment in 2004-2006. For this reason, an ex-ante approach based on real-time information is the adequate methodology to separate them.

Figure 3.3: Capacity expansion by technology in SIC
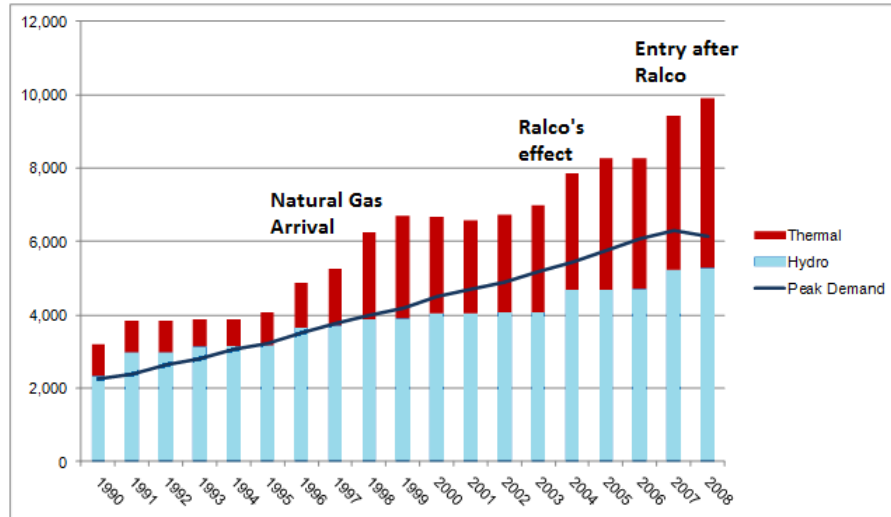
Source: CNE

Arellano (2008) refers that from 2000 to 2003 there was a "lack of investment over that period as the system capacity increased in average 75 MW per year in the face of 245 MW in maximum demand". We do not observe in Figure 3.3 a precarious situation in terms of peak demand and capacity. The reserve margin was above the pre-natural-gas period.[30] Also, when we include Ralco and calculate the annual investment average between 2000 and 2004, we get 234 MW. Then, there is no evidence of lack of investment.

As would be expected, prices and investment are related. However, we can not infer a lack of investment from ex-post prices. A good hydrologic situation can reduce prices in a situation of absence of investment but a bad hydrologic period can rise prices

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[30]Galetovic, Olmedo and Soto (2002) showed that the likelihood of a power shortage was over-estimated during 2000 and 2001.

even with over-capacity installed. Figure 3.4 shows the series for spot prices, node power price and average free price.[31] From 1996 to 1999 node prices were decreasing, but due to hydrologic conditions the spot price was above it. In 1999 spot prices and node prices had very different patterns and we will talk about it later. After 2000, a period of good hydrological years began.[32] The availability of hydro generation drove down the spot price, below node prices. Despite the investment lag, this situation did not rise prices because of the hydrological conditions.[33] In 2005, we have a spike in spot prices due to the natural gas crisis when this input was replaced with oil.

Generators' returns during the period were good, mainly due to the positive difference between forward prices and spot prices.[34] Average returns over fixed assets for Endesa, AES-Gener and Pehuenche (owned by Endesa) before 1998 were 9.9%. Due to the severe drought, average returns from 1998 to 2000 were 2.2%, but Endesa faced high negative returns in 1999. From 2001 and until 2005, average returns were 9.4%. The low spot prices during the period and the high returns of hydro-power generators like Pehuenche can be explained by the good hydrologic situation of the moment. In sum, we found high returns, node prices above spot prices, but no investment nor entry.[35]

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[31]Spot price is the average marginal cost in a trimester. The node price is the power price without the capacity charge and includes the +/-10% band adjustment. The free price is the inferred average free price from the band adjustment at the moment the CNE determines the node price.

[32]There is a close relationship between the hydrologic situation and the evolution of prices as we found in our VAR analysis. In Figure C.4 in the Appendix we show the series for inflow energy and the historic average for the last 40 years. It can be seen that between 2000 and 2005, the hydrologic conditions were good enough to have low spot prices.

[33]As we saw in Figure 3.3, peak demand did not react to the apparent capacity shortage mentioned.

[34]Figure C.6 in the Appendix shows the annual returns over fixed assets for generators from 1995 to 2005.

[35]Regarding potential entrants, we have information about two potential new firms during the period of 2000 to 2005. Pacific Hydro, a Norwegian generator, asked for environmental permission for a hydro-power plant of 240 MW in June 2002. This project was never approved

Figure 3.4: Evolution of prices in SIC, in USD/MWh.

Source: CNE
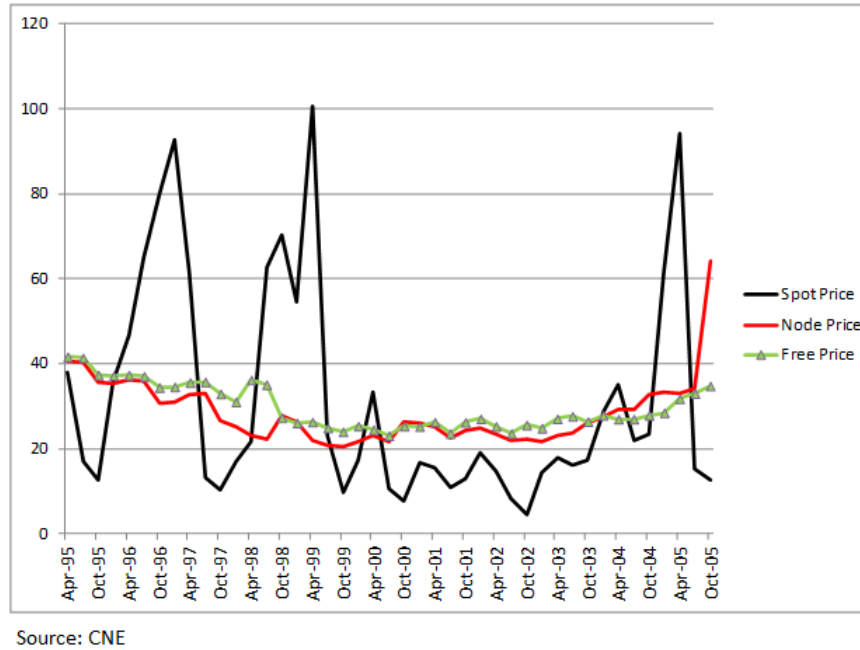
Part of the literature blames the investment lag on regulatory uncertainty. Arellano (2008) points to a regulatory change in 1999. Electricity companies in Chile are financially responsible for any supply failure in a contract, unless it cannot be attributed to the company. Then, if the regulatory authority declares "force majeure" or an accident, the company is not responsible for it. Before 1999, generators were not required to compensate their customers under contract if a drought was more severe than the driest year in record, 1968. However in July 1999, the regulation

because the own firm canceled it. Only in February 2004, when Ralco was about to start operating, Pacific Hydro asked for the permission again and got it in September 2004. The unit, hydroelectric La Higuera, was not operative until 2010. A second potential entrant was Campanario. They have a project of 390 MW base on natural gas that asked for environmental authorization in October 2003. Ralco was not delayed anymore after that point. It was approved in July 2004 and became operative in 2007.

was modified and a drought can not be considered as force majeure anymore. Arellano(2008) emphasizes that incentives to invest in hydroelectric plants and generator's interest to contract with distribution companies were significatively reduced with this change.[36] However, the investment lag in thermal generation cannot be explained by this change. Natural gas and coal plants were not affected by this change in regulation. Also, in case of a drought, a thermal unit with a contract at the node price will not be affected, unless it is over-contracted.[37] Not even delays in Ralco can be explained by this regulatory change, because Ralco was already under construction at that moment.

A second source of regulatory uncertainty would be the calculation of the node prices.[38] During the 1998-1999 drought, the CNE was criticized because the node price didn't react when spot prices were spiking. We saw the different patterns in Figure 3.4. This could mean that the marginal cost expected by the authorities and thus the nodal price level were below those expected by the industry. It is true that there were periods with relevant differences between real marginal costs and CNE's projections, particularly in 1999. However, as it can be seen in Figure C.7 in the Appendix, there are not large differences between real and estimated marginal costs in the medium-run.

In terms of differences between nodal prices and real marginal costs, it is important to highlight that the node price is considering the medium and long-term price of power, beyond short-term shocks. There are moments when the node prices are below the real marginal costs and moments when they are above. The simple averages of

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[36] The node price calculation would not be including this kind of uncertainty.

[37] Figure C.6 in the Appendix shows that during the severe drought of 1998-1999, the only generators with positive returns were the thermal ones: AES-Gener and ESSA.

[38] Additional sources of uncertainty, like the discussion of regulatory reforms finally implemented in 2004 and 2005, do not seem to provide enough evidence for Ralco's delays or being enough to deter entry.

these two prices are not that different. For example, if we take the difference between the average spot price and the average node price between April 1998 and April 2006, the difference is only 3.4 USD/MWh, while the difference between April 2002 and April 2006 was -0.4 USD/MWh. In sum, the industry's expectations do not seem to be that different from the regulator's.

3.5 THE INVESTMENT DECISION: STORY OF RALCO

This section presents a simple model of investment, with a focus on the main determinants of a generator's investment decision. The model is built in order to replicate investment in a decentralized power market in which capacity expansion is based on a standard unit.[39] This framework will allow us to analyze the effect of an unanticipated delay of a big generation unit. The story of Ralco can be used as an example to show how the change in its schedule affected other units in the system. We trace back the story of Ralco using node price reports prepared by the CNE every April and October. Those reports correspond to a picture of the system's forecasted future.[40]

We assume there is an aggregate demand function that grows over time denoted by $D(p, t)$. We will omit the hourly and daily variation in the demand and will focus only on the monthly average. Given this simplification, the expansion of the installed capacity can be supplied by a standard unit. The standard unit has the lowest levelized cost[41], a capacity equal to K, a variable cost equal to zero and no depreciation. Under the above assumptions, the generator's problem is when to invest and not the size of the unit. The capital cost is equal to r.

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[39]This simplification allow us to focus on a single technology.

[40]Appendix C includes a detailed description of the CNE's investment plans.

[41]Levelized cost is the lifetime discounted cost of a unit expressed in cost per unit of energy produced. In the case of Chile, this unit was a combined cycle gas turbine of 332 MW in the period under study according to the CNE reports.

Given the structure of the supply, the market price is given by $\hat{p}(t)$ that solves $D(\hat{p}(t), t) = n(t)K$, where $n(t)$ is the number of units installed up to t.[42]

We will assume that each firm can install only one unit. There is an infinite number of potential firms. Under this assumption there are multiple Nash equilibria in pure strategies but all with the same property: each unit has an expected return equal to the capital cost r.[43] The intuition is as follows. If the return is lower than r then it is better not to install the unit. If a firm has a return higher than r then it is profitable for the next (previous) firm, the one scheduled just after (before), to deviate and bring forward (delay) his unit.

Let us assume that the increment in demand over time is just a parallel shift, that is $D(p, t + \tau) = D(p, t) + E * \tau$ for some positive constant E and for all τ, t and p. Under this assumption, in equilibrium, the units are installed at a regular pace. Figure 3.5 shows an example of this equilibrium.

Figure 3.5: Steady state case

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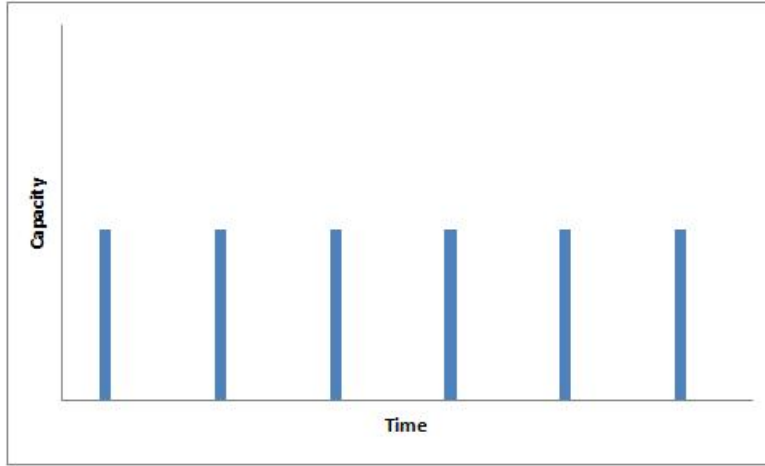
[42] If we include different units with variable cost different from zero there will be a more complex supply curve, but the main result will not change because we are working with only one block of demand.

[43] In Appendix there is a more formal development of the results presented in this section.

Let us call this equilibrium the "steady state" case. There are several examples of this case in the CNE reports. It is possible to find this path of investment using the development unit of the system.[44] In Figure 3.6 we show CNE's expected path of investment between 2003 and 2008, in the October 1999 report.

Figure 3.6: Steady state case in the October 1999 report, suggested units
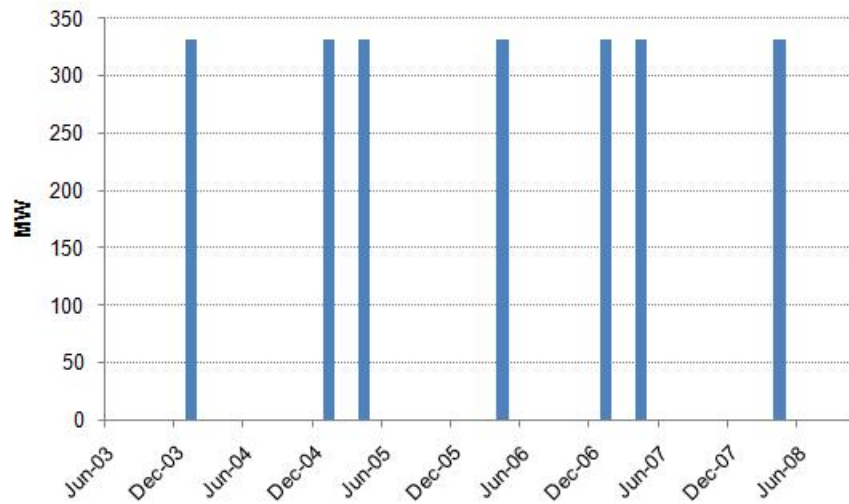
As one can see in Figure 3.6, the investment process can be approximated by the "steady state" case mentioned before. This similarity is not unexpected. The investment plan is created using a more complex model but with similar assumptions to the model presented here. Even though reality could differ from this suggested path, the steady state case is a relevant starting point in order to understand agents' expectations about future investment.

We need to make an important remark about this simple model. In the model, the schedule of the future units is determined at time zero because there is no uncertainty in technology or demand. In reality there are three different kind of projects at each period t. The first group includes projects that were under construction at t, that is, projects that are sunk for today's decisions. We use the term "under-construction

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[44]This is not including diesel turbines or small hydro-power generators.

projects" to refer to them. The second group are the projects that are committed today and scheduled to be ready for some moment in the future. Let us call them "contingent projects". The third and last group includes projects that can be ready in the distant future, so long away that it is not optimal to commit now to their construction. Those are the "suggested projects".

The difference between these three groups of projects can be found in variables like time-to-build and planning horizon. Time-to-build is how much time is needed between the decision to build and the starting date of the operations. It determines a lower bound for the completion of contingent projects. Any of these projects cannot be scheduled to start operating before the required time-to-build. The second limit is the planning horizon. It tells how far in the future is optimal (or credible) to schedule a project. Given the uncertainty about demand, relevant prices, or other shocks to the system, it is not optimal to commit now to projects in the distant future. Beyond that point in the future, the potential gain of committing now (that consists in reducing the incentives of other agents to invest close to the committed operational date) is lower compared with the potential cost of having to follow an investment plan if there are significant changes in the system's variables. In sum, there is a horizon of time when the cost of a riskier commitment is higher than the potential gains. That determines an upper limit for contingent projects.

A relevant source of heterogeneity across agents is the difference in time-to-build. The agent with a lower time-to-build will have a competitive advantage over others in scheduling a project in the near future. In our model without delays, this advantage is relevant only in the beginning of the game because all future projects are scheduled at

time zero.[45] In the case with delays, this advantage can make an important difference. We will return to this particular point later.

Now let's see the effect of a big unit, a unit with a capacity higher than the standard ones. We assume no strategic behavior from the generator's big unit by fixing the date of its operation and letting the other firms allocate their units. Moreover, we assume that the decision about the operational date of the big unit is based in different reasons than the standard projects. That is, the big unit schedule will be considered as an exogenous decision for the system. The idea behind this assumption is to keep aside the decision of the big unit and focus on the response of the other agents. Taking the big unit schedule as given, Figure 3.7 depicts an equilibrium with a big unit. An example of this case can be also found in CNE's October 1999 report, before Ralco's delays started. Figure 3.8 shows the big unit case. Between 2001 and 2003 no standard units were considered.

Figure 3.7: Big unit case
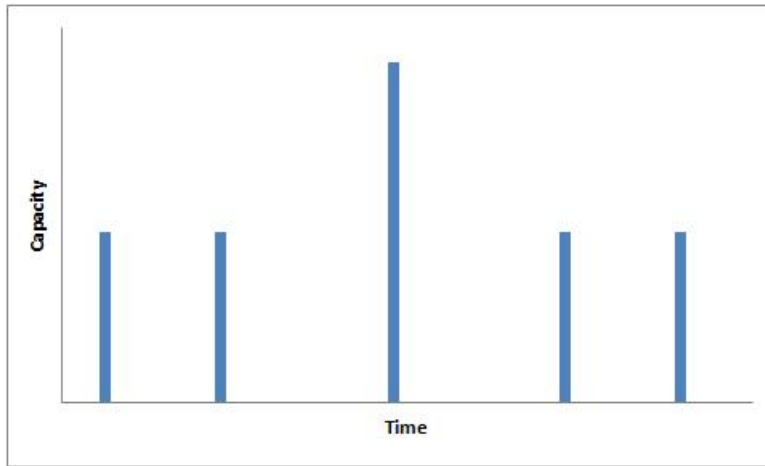
There are two qualitative differences between the steady state and the big unit cases. First, while in the big unit case there are significative gaps around the big

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[45]In the model where we include the difference between contingent and suggested projects, time-to-build affects the contingent projects.

Figure 3.8: Big unit case in October 1999 report
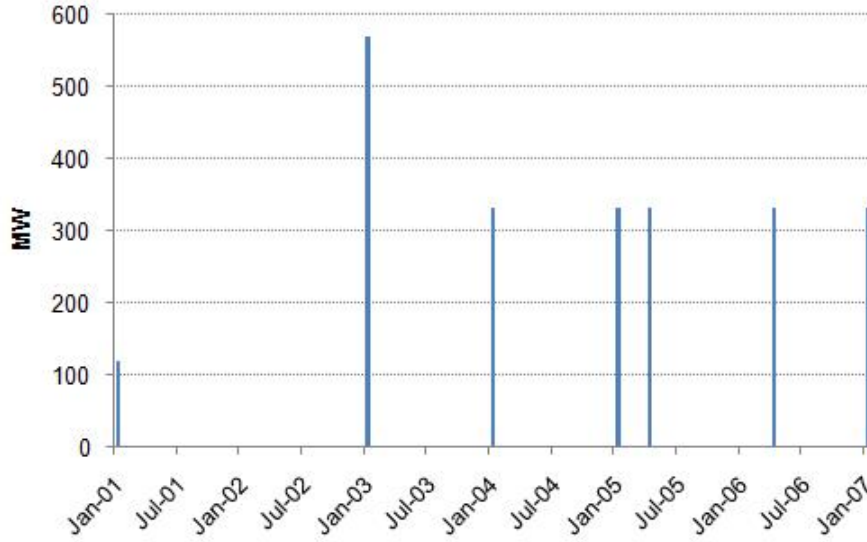
unit, the medium term average investment is not affected. That is, if we calculate the moving average with an appropriate range (for example two and a half years) this moving average investment is not affected by the presence of a big unit. There is an investment lag but not a lack of investment. Second, the existence of this big unit reduces the room for new units to enter and, therefore, new competitors in the market.

Let us now introduce the possibility of a big unit's delay. Figure 3.9 shows the big unit's delay before other units can be rescheduled.

The relevant question here is what is the effect of such a delay on other units, in particular to the unit that was supposed to enter after the big unit.[46] Given our assumptions, the only relevant variable for the price, and therefore the returns, is the

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[46] We work under the assumption that all the units schedules before the big one are under-construction units. Once under construction, it is not possible to speed it up.

Figure 3.9: Big unit delay
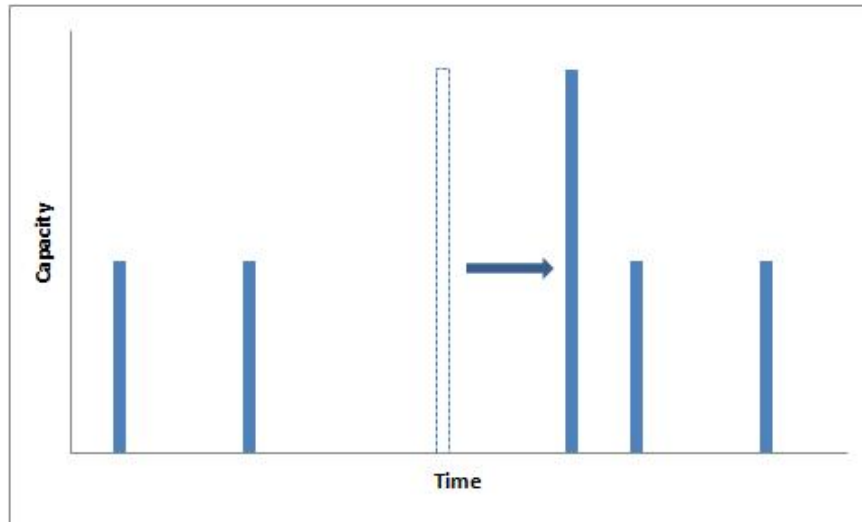
installed capacity. If the delay of the big unit is up to the unit scheduled after it, then
the price after the big unit's entry does not change, because the aggregate investment
at this time has not changed. The only relevant deviation is the possibility that this
latter unit decides to bring forward its starting date and operate before the big unit
enters. This is profitable when the gap between the big unit and the previous unit
is large enough after the delay. In order to analyze when this is profitable, let's start
with two extreme cases. First, the delay is marginal, and second, the delay is long
enough to have the big unit scheduled almost at the same time as the next unit in
the previous equilibrium.

If the delay is marginal, there is no incentive to bring forward the entry of a unit
before the big one. If the delay is significant so the big unit is close enough to the unit
scheduled after it, then the later will have a gap large enough in order to shift and

obtain the appropriate return.[47] Given that the potential return of a unit that shifts before the big unit is increasing in the time delayed of the latter, there is a critical time where the optimal decision changes.

In a more general result, the first possibility is that the delay is large enough to make it profitable for the unit that was scheduled after the big unit to reschedule its entry before the big unit. We will call this case a "leapfrog effect". The shift is profitable if the return of the rescheduled unit is equal or greater than r and the reschedule is feasible. This last restriction requires two conditions. The first one is that the rescheduled unit was not under construction. The second one is related to the time-to-build mentioned previously. If the unit is under construction or the desirable reschedule time is before the required time-to-build, then the reschedule is not feasible.

In case the shift is not profitable or feasible the scheduled time is maintained. There is a reduction in the gap between the big unit and the next one. If there are no changes other than the delay in the big unit, the return on capital for the unit after the big one is still r. In this case, there could be an investment lag. Given the delay in the big unit's entry, and if no other unit is rescheduled, the investment moving average will decrease before the big unit's entry.

If there is a leapfrog effect, then there could be an advantage for units with shorter time-to-build. It is possible to assume that incumbents' units have a shorter time-to-build. There are two reasons that justify this thesis. First, if there is learning by doing associated with some pre-investment task, for example in order to obtain an environmental permission, an incumbent's project has an edge. The second one is

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[47]See Appendix C for details.

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the possibility of incumbents having private information about changes in under-construction units and the ability of forecasting those delays in a better way.[48]

Roughly speaking, if the big unit's delay happens in a situation when the time-to-build constraint is binding, then we will have a trade off between an investment lag and the entry of new competitors in the market. In terms of market structure they will have different results. On one side, an incumbent's unit can reduce/eliminate the investment lag faster with a shorter time-to-build but will not leave any room for entrants with a longer time-to-build. On the other side, a large enough investment lag can give the opportunity for entry in a concentrated market.[49]

After we have provided a simple characterization of a big unit's effect on the pattern of investment, we are able to analyze the delays exhibited by Ralco during its construction, and identify what effects were the most relevant in each case. First of all, we need to clarify the assumption that these delays were not part of strategic behavior of Ralco's owner. We do not have any evidence to sustain the possibility of Endesa's strategic behavior. In contrary, there is evidence of conflict with local indigenous communities over the use of the area where Ralco was about to be build (Aylwin, 2002).[50]

We will focus on the change between two consecutive CNE's reports. The initial one, when the delay was not included, and the final one, where the delay was included. In CNE's investment plan there is a separation between plants under-construction and suggested plants. There is a relevant difference with our previous classification

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[48] Galetovic, Olmedo and Soto (2002) mentioned information in the private sector about Ralco's delay in 2001, before it appeared in the CNE report.

[49] As Spence (1979) pointed out "constraints on growth and the timing of entry put firms in asymmetric positions with respect to investment". These asymmetries are induced by the history of the market.

[50] Looking at the history of Ralco, there was only one delay when Endesa was the generator that filled the investment gap by an own unit, as we will see. In all the other delays, there were other incumbents that made the unit's investment.

in the model: contingent plants. A contingent plant is one that was not scheduled in the initial report but appeared under construction in the next report. In the case of suggested plants, these are units that represent the optimal investment plan from the regulator's point of view. They are a relevant signal of room for investment in the short and medium term. Suggested plants can be understood as a lack of required projects to balance expected supply and demand.

1. First delay: April 1999 - October 1999

   The first relevant delay of Ralco happened between the reports of the year 1999. There was a seven months delay from the original date of June 2002. Given the time between the announcement of the delay and the starting day, this case exhibits a leapfrog effect, as is shown if Figure 3.10. Ralco is the dark blue unit.

Figure 3.10: Delay between April 1999 and October 1999.
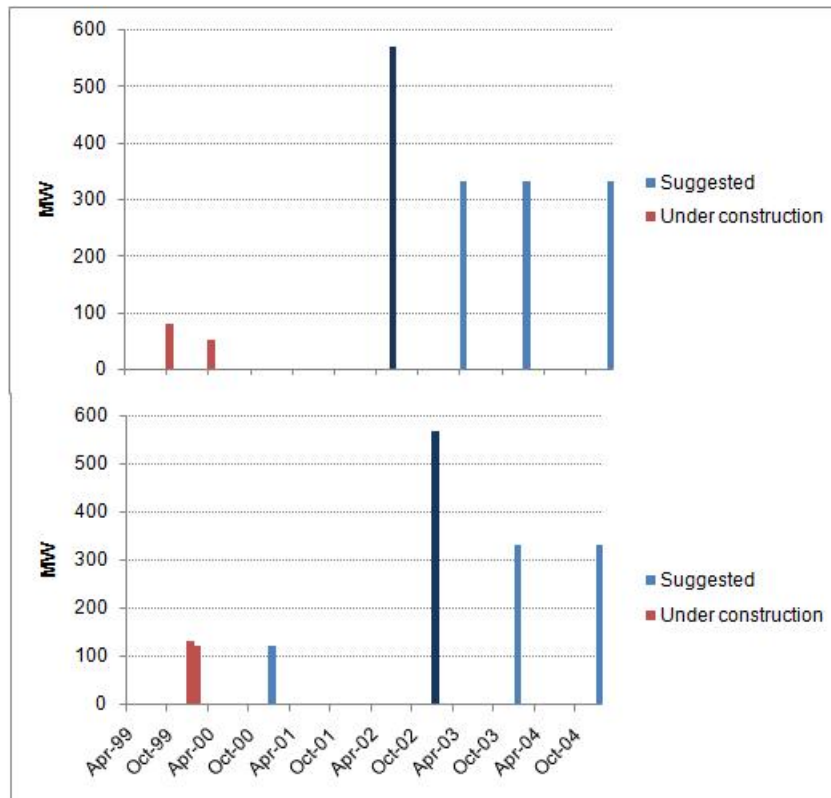
As a result of the delay, two new plants were scheduled before Ralco. One under-construction and one suggested. The under-construction one was Taltal, a gas turbine (GT) owned by Endesa.[51] The suggested unit was another GT with the same characteristics of Taltal.

2. Second delay: October 1999 - April 2000

The second relevant delay was after the October 1999 report and it postponed Ralco for six more months beyond January 2003. Here the delay gave room again for a new unit before Ralco. The CNE suggested to close the cycle of a combined cycle gas turbine (CCGT) on April 2003.

Between these two reports there were two changes that are important to high-light. The first one is the change of the second GT of 120 MW from suggested to under-construction. In the final report this plant was the second unit of the Taltal project. This indicates that this was the project that the CNE had in mind at the moment of suggesting a GT of 120 MW in the initial report. The second change is the introduction of a suggested CCGT before Ralco. This CCGT was not only a suggested unit but one with a label: Taltal CCGT. The CNE labeled a suggested unit with the name of an incumbent's project. This decision could have an effect on potential entrants' decisions. It should be different to have an anonymous suggested project that one with an ongoing project with environmental approval. In the later case the project is not an open space for any entrant but something closer to an under-construction unit. Looking ex

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[51]Taltal is the first unit of a multi-unit project developed by Endesa. It asked for an environmental approval on November 1997 and it was approved on December 1998. The full project involved a combined cycle gas turbine (CCGT) with two units of 120 MW each one, and a total installed capacity of 370 MW when the cycle was closed.

Figure 3.11: Delay between October 1999 and April 2000.
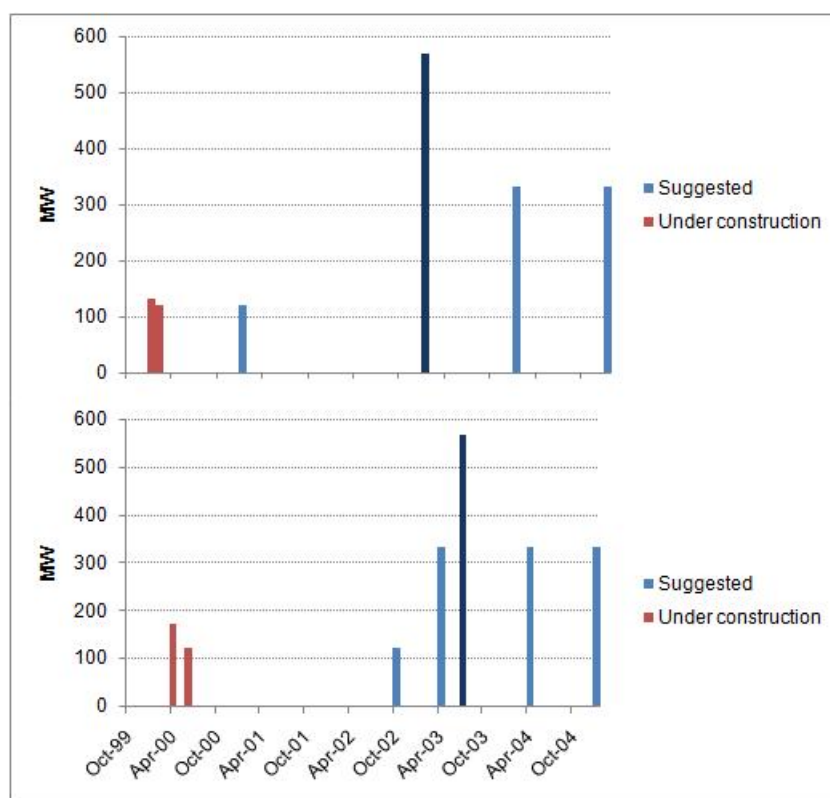
post, the fact that the project has not been developed so far, makes one wonder what could have been the effect on entry if this unit would have been kept as an anonymous suggested unit.

3. Third delay: April 2001 - October 2001

The third relevant delay was closer to Ralco's final operational day. The delay implies six months from the previous date of July 2003. The effect was a leapfrog of a small suggested investment after Ralco (an interconnection of 205 MW)

replaced by two small units on 2002.[52] Additionally, Ralco got closer to the CCGT scheduled for April 2004.

Figure 3.12: Delay between April 2001 and October 2001.
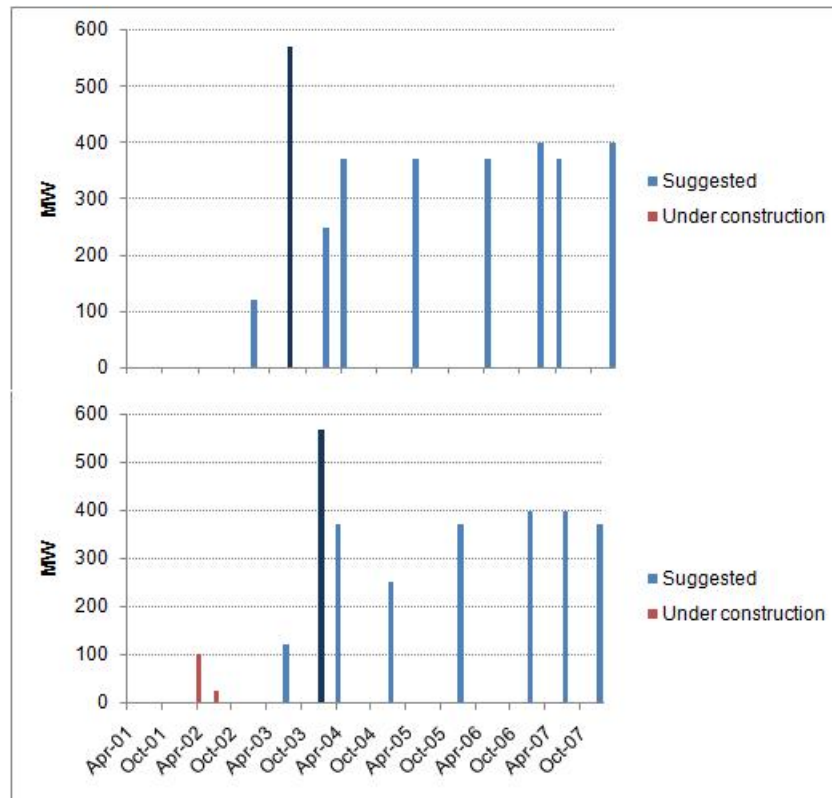
In this delay and the following one, it is possible to see more clearly the effect of time-to-build. The announcement of Nehuenco 9B was made between the two CNE's reports and the unit was operational in less than a year. In order to start building Nehuenco 9B, Colbun had to get an environmental approval. Here it is important to highlight two points. First, the date when Colbun asked for the approval was the same month of the final report, the one that reveals another significant delay in Ralco. Second, the project was approved by the environmental authority in just four months.

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[52] The biggest of these units, Nehuenco 9B, was a GT owned by Colbun, another incumbent in the market.

4. Fourth delay: April 2002 - October 2002

   In the middle of 2002, another six months of delay were announced and the final
   date was settled on July 2004.

Figure 3.13: Delay between April 2002 and October 2002.
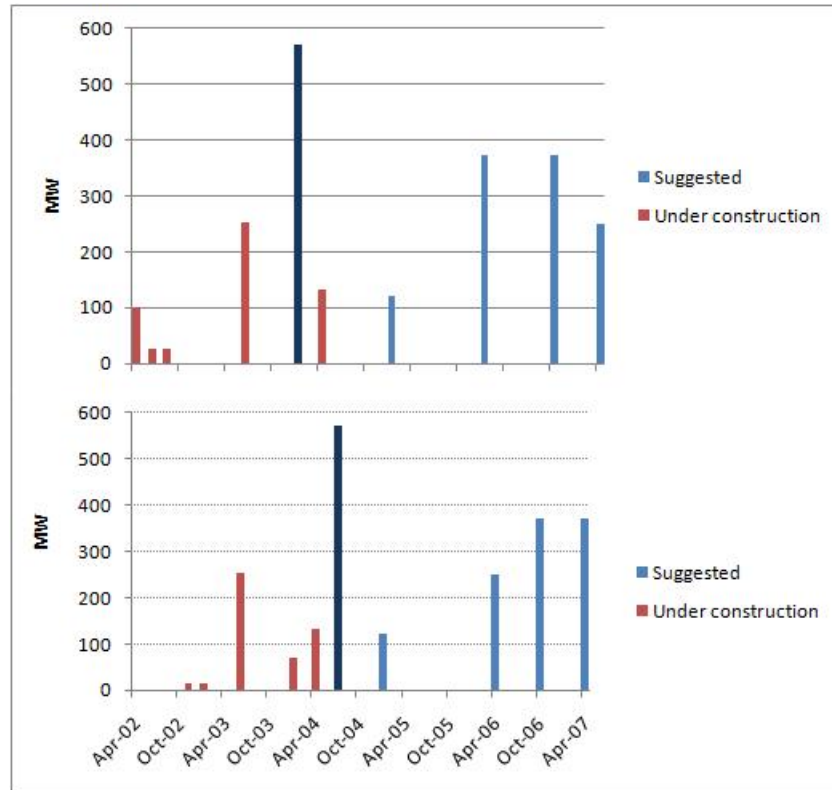
   There was one unit scheduled after Ralco (the finishing of Colbun CCGT for
   April 2004) which date was kept even with Ralco's final delay. Again some
   under-construction projects were incorporated, operational in a relatively short
   term, two years from the report date.[53]

In sum, the investment lag we found from 2000 to 2004 is the result of a combi-
nation of two effects: first, the schedule of the big unit, Ralco; second the leapfrog

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[53]Three small units owned by the firm Arauco were included here. Arauco is a paper mill
who has power capacity for their own use, releasing residual power in case they have any.

effect due to Ralco's delays. It is possible to see how some of Ralco's delays left room only for projects that were able to be put in operation really fast. There was room for investment because CNE's reports were signaling the necessity of an additional unit every time Ralco was delayed, but this room was relatively short with the exception of the first delay.

3.6 SUMMARY

Chile's generation market had an uneven path of expansion in the last 30 years. Historically based on hydro-power generation, the arrival of imported natural gas in 1995 allowed capacity to expand fast enough to cope with a growing demand. The Argentinean gas crisis changed investment incentives, as did regulation after 2005. There has been little attention on the period between 2000 and 2004. Even though there were optimal conditions for new projects (and generators), this was a period of lag in projected investment. By analyzing this period we are able to shed light on the investment incentives in the Chilean power market and the reasons behind a capacity expansion mainly based on incumbents' investment.

Part of the literature blames regulatory uncertainty for the investment lag. In this paper we show that an alternative and more plausible explanation for the lag in investment is Ralco's repeated construction delays. By collecting the data used in node price calculations performed by the CNE, we are able to show that Ralco's delays did not leave many windows of opportunity for other projects. We cannot assess if Ralco's owner, Endesa, was behaving strategically in terms of delaying Ralco to deter entry, but in any case, the result was an incumbent's advantage. The only projects that could take the opportunity of Ralco's delays were from other incumbent. Without commenting on the efficiency of this result, we can assess that this incum-

bent's advantage can explain why the historically high concentration in the market was not reduced in this period.

Due to good hydrological years, there was little public awareness about the effect of this investment lag on prices. Capacity was expanding slowly but spot prices were below contract prices. The unexpected gas crisis changed completely the scenario in the years afterwards. Interestingly, if Ralco had been ready in time, more units based on natural gas would had been introduced and the impact of gas shortages would have been larger.

It is important to understand the incentives of capacity expansion. Even though a new regulatory framework was introduced in 2005, there are some lessons to consider for similar circumstances in the future. In 2008, the two largest incumbents in a common enterprise, Endesa and Colbun, asked for environmental permission to build the largest hydro-based plant in Chile. The project is Hidroaysen, with a size of 20% the SIC's installed capacity. It is the largest hydro-power plant since Ralco. The environmental permission was granted in 2011 and it was original scheduled to be operational in 2015 but due to several delays now it is scheduled to start in 2020.[54] Uncertainty about Hydroaysen can have an impact on other generators' projects as Ralco had in terms of investment lag and incumbents' advantage.

There are some policy recommendations to consider after the above analysis. In order to give room for investment uncertainty, it would be useful that the CNE reports alternative scenarios in the investment plan, in particular when large investments are involved. The CNE has to choose one scenario to determine the node price, but it is possible to report sensitivity analysis. In the same fashion, it is preferable to keep as anonymous as possible all suggested plants. Entrants can be deterred if the CNE

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[54]In May 30th of 2012, Colbun announced the project was on freeze due to regulatory uncertainty about the transmission line that is necessary to build in order to connect Hydroaysen with the SIC.

includes suggested plants which are publicly known as ongoing incumbents' projects. Finally, for a better understanding of where generators' revenues come from and to what extent it is profitable to expand capacity strategically, it would be useful to have separate accounting information about spot market revenues and contract market revenues.

Proof of Proposition 1.3.1

The monopolist's expected payoff will be:[1]

$$\Pi_m = \frac{(a-m_m)^2 - (f_m)^2}{4} - \frac{\lambda_m}{2}\left[\frac{8(a-m_m)^2\sigma^2 + \mu^2}{32^2} + \frac{\sigma^2 f_m^2}{4} + \frac{(a-m_m)\sigma^2 f_m}{2}\right]$$

$$(A.1)$$

The first term is the expected payoff in the spot market. The second term is the impact of volatility on the total expected payoff.[2]

The first order condition of maximizing the expected payoff is:

$$-\frac{f_m}{2} - \frac{\lambda_m \sigma^2}{2}\left(\frac{f_m}{2} + \frac{a-m_m}{2}\right) = 0 \tag{A.2}$$

The payoff differential for a monopolist between choosing technology r versus technology s comes from:

$$\Pi_m(c_r) - \Pi_m(c_s) = \frac{(a-c_r)^2}{4b(2b+\lambda\sigma^2)}\left[\frac{(\lambda\sigma^2)^3}{2} + (\lambda\sigma^2)^2 - \lambda\sigma^2\right] + \frac{(a-c_r)^2 - (a-c_s)^2}{4b}$$

Assuming $c_r = c_s$, the only relevant component deciding the sign of this expression is the term in brackets. This term can be reordered to obtain the condition that r is

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[1] In addition to σ^2 being the variance of the shock θ, the variance of θ^2 is μ^2. As the distribution of θ is assumed symmetric, the covariance between θ and θ^2 is zero.

[2] From (1.6) we know that the first component inside the brackets is the variance of profits in the spot market. The second component is the variance in forward market's profits, and the third is the covariance between the two previous components. It is possible the see that moving to $f_m < 0$, the monopolist has an incentive to buy forward if the third component prevails.

preferred if $\lambda\sigma^2 > \sqrt{3} - 1$. If $\lambda\sigma^2$ is high enough, the payoff differential is positive.

$\square$

Proof of Proposition 1.4.1

The proof has two parts. The first part shows that if the both firms choose the same technology, the entrant would prefer to choose technology r over s. Then, $\Pi_e(c_r, c_r) > \Pi_e(c_s, c_s)$. The second part shows that the entrant has no incentive to deviate if the incumbent adopts technology s: $\Pi_e(c_s, c_s) > \Pi_e(c_s, c_r)$.

If both firms choose the riskier technology, expected payoff for the entrant will be $\Pi_e(c_r, c_r) = A(c_r, c_r) - \frac{\lambda\sigma^2}{2} B(c_r, c_r) - \frac{\lambda\mu^2}{162b^2}$, where:

$$A(c_r, c_r) = \frac{[a - c_r - b(f_i + f_e)][a - c_r + b(2f_e - f_i)]}{9b} \tag{A.3}$$

$$B(c_r, c_r) = \frac{(2a - 2c_r + bf_e - 2bf_i)^2 + 36b^2 f_e^2 + 12bf_e(2a - 2c_r + bf_e - 2bf_i)}{81b^2} \tag{A.4}$$

In this case, $f_i = f_e$ and correspond to equation (1.12). Replacing above and assuming $c_r = c_s = c$:

$$A(c_r, c_r) = \frac{(3b + 7\lambda\sigma^2)(a - c)^2(54b + 21\lambda\sigma^2)}{(45b + 35\lambda\sigma^2)^2 b} \tag{A.5}$$

$$B(c_r, c_r) = \frac{(a - c)^2(135b)^2}{81b^2(45b + 35\lambda\sigma^2)^2} \tag{A.6}$$

Now, considering that all firms adopting technology s means that $\Pi_e(c_s, c_s) = \frac{2(a-c)^2}{25b}$, the difference $\Pi_e(c_r, c_r) - \Pi_e(c_s, c_s)$ is equal to:

$$\frac{(a - c)^2[2450(\lambda\sigma^2)^2 + 3825b\lambda\sigma^2]}{50b(45b + 35\lambda\sigma^2)^2} + \frac{\lambda\mu^2}{162b^2} \tag{A.7}$$

Such a difference is always positive for any volatility level, as we wanted to show.

Next, if the incumbent chooses the zero volatility technology but the entrant deviates to the risky one, payoff became $\Pi_e(c_s, c_r) = A(c_s, c_r) - \frac{\lambda\sigma^2}{2} B(c_s, c_r) - \frac{\lambda\mu^2}{162b^2}$. The optimal

amount of forwards for each firm will be:

$$f_i(c_s, c_r) = \frac{(9b + 4\lambda\sigma^2)(27b + 45\lambda\sigma^2)(a - c)}{[1215b^2 + 1188b\lambda\sigma^2 + 20(\lambda\sigma^2)^2]b} \tag{A.8}$$

$$f_e(c_s, c_r) = \frac{(9b - 20\lambda\sigma^2)27b(a - c)}{[1215b^2 + 1188b\lambda\sigma^2 + 20(\lambda\sigma^2)^2]b} \tag{A.9}$$

Replacing in $A(c_s, c_r)$ and $B(c_s, c_r)$:

$$A(c_s, c_r) = \frac{(1458b^2 + 2754b\lambda\sigma^2 + 380(\lambda\sigma^2)^2)(a - c)^2(729b^2 + 1215b\lambda\sigma^2 - 160(\lambda\sigma^2)^2)}{9b[1215b^2 + 1188b\lambda\sigma^2 + 20(\lambda\sigma^2)^2]^2}$$
$$\tag{A.10}$$

$$B(c_s, c_r) = \frac{4(a - c)^2(729b^2 + 1215b\lambda\sigma^2 - 160(\lambda\sigma^2)^2)^2}{81b^2[1215b^2 + 1188b\lambda\sigma^2 + 20(\lambda\sigma^2)^2]} \tag{A.11}$$

Now, replacing in $\Pi_e(c_s, c_s) - \Pi_e(c_s, c_r)$ we obtain that this difference is always positive, as we wanted.

In terms of equilibria, the deterrence equilibrium is reached when K is high enough so the incumbent can deter entry by choosing technology s. As $\lambda\sigma^2$ goes to infinity, $\Pi_e(c_r, c_r) = \frac{3(a-c)^2}{25b}$. If K is such that $\frac{2(a-c)^2}{25b} < K < \frac{3(a-c)^2}{25b}$ then the incumbent chooses technology s and entry is deterred.

When K is not as high, there exists a $\lambda\sigma^{2*}$ where above that cost volatility impact value, $\Pi_e(c_r, c_r) \geq \Pi_e(c_r, c_s)$[3]. Below $\lambda\sigma^{2*}$ the accommodation equilibrium is (c_s, c_s) and above is (c_r, c_r).

$\square$

Proof of Proposition 1.4.2

A risk-averse entrant will choose technology s versus technology r, causing the incumbent to choose r, if $\Pi_e(c_r, c_s) - \Pi_e(c_r, c_r) > 0$. The risk-averse entrant's expected payoff can be decomposed into two separate terms, profits at the spot market $A(c_i, c_e)$ and

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[3]Assuming $b = 1$, $\lambda\sigma^{2*} = 5$

variance of profits $B(c_i, c_e)$, so from (1.6) $\Pi_e(c_i, c_e) = A(c_i, c_e) - \frac{\lambda\sigma^2}{2}B(c_i, c_e) - \frac{\lambda\mu^2}{162b^2}$.

Then the difference in payoff from choosing technology r versus s is:

$$\Pi_e(c_r, c_s) - \Pi_e(c_r, c_r) = A(c_r, c_s) - A(c_r, c_r) - \frac{\lambda\sigma^2}{2}\left[B(c_r, c_s) - B(c_r, c_r)\right] \quad \text{(A.12)}$$

Considering that the marginal costs of the both technologies are equal, $c_i = c_e = c$, A is equal to:

$$A(c_i, c_e) = \frac{[a - c - b(f_i(c_i, c_e) + f_e(c_i, c_e))][a - c + b(2f_e(c_i, c_e) - f_i(c_i, c_e))]}{9b} \quad \text{(A.13)}$$

From (1.13) and (1.14) we have the amount of forwards each firm signs if both choose the technology r.

$$f_i(c_r, c_r) = \frac{(9b + 21\lambda\sigma^2)(a - c)}{(45b + 70\lambda\sigma^2)b} \quad \text{(A.14)}$$

$$f_e(c_r, c_r) = \frac{(9b - 14\lambda\sigma^2)(a - c)}{(45b + 70\lambda\sigma^2)b} \quad \text{(A.15)}$$

If the entrant chooses s instead, the amount of forwards changes to:

$$f_i(c_r, c_s) = \frac{9b(a - c)}{(45b + 4\lambda\sigma^2)b} \quad \text{(A.16)}$$

$$f_e(c_r, c_s) = \frac{(9b + 4\lambda\sigma^2)(a - c)}{(45b + 4\lambda\sigma^2)b} \quad \text{(A.17)}$$

As mentioned in the main text, the entrant sells more forwards when choosing technology s. Replacing this expression in A we get that the difference in A is:

$$A(c_r, c_s) - A(c_r, c_r) = \frac{(a - c)^2[9b(18b + 4\lambda\sigma^2)}{b(45b + 4\lambda\sigma^2)^2}] - \frac{(a - c)^2[(9b + 21\lambda\sigma^2)(18b + 7\lambda\sigma^2)]}{b(45b + 70\lambda\sigma^2)^2}$$

$$\text{(A.18)}$$

It is possible to check that $A(c_r, c_s) - A(c_r, c_r) > 0$ unless $\lambda\sigma^2$ is large. Spot market expected payoff is larger for the entrant selling more forward contracts. However, as cost volatility impact rises, the risk-averse firm could improve her expected payoff buying forward. For this reason, eventually $A(c_r, c_s)$ becomes smaller than $A(c_r, c_r)$ as cost volatility impact grows.

Additionally,

$$B(c_r, c_s) = \frac{(2a - 2c + bf_e - 2bf_i)^2 + 9b^2 f_e^2 - 6bf_e(2a - 2c + bf_e - 2bf_i)}{81b^2} \quad \text{(A.19)}$$

$$B(c_r, c_r) = \frac{(2a - 2c + bf_e - 2bf_i)^2 + 36b^2 f_e^2 + 12bf_e(2a - 2c + bf_e - 2bf_i)}{81b^2} \quad \text{(A.20)}$$

Coming back and replacing A and B in the expression for the difference in expected payoffs, it is possible to obtain the condition for an entrant to prefer technology s over technology r

$$18b(18b + 4\lambda\sigma^2)(45b + 70\lambda\sigma^2) + 225b\lambda\sigma^2(45b + 4\lambda\sigma^2)^2 > \quad \text{(A.21)}$$

$$(18b + 42\lambda\sigma^2)(18b + 7\lambda\sigma^2)(45b + 4\lambda\sigma^2)^2 + 36b\lambda\sigma^2(45b + 70\lambda\sigma^2)^2 \quad \text{(A.22)}$$

From (A.21-A.22) it is possible to obtain $\lambda\sigma^{2*}$. Below this value, the entrant's best response to $c_i = c_r$ is to adopt the zero risk technology. This means that every value of $\lambda\sigma^{2*}$ below 22.35 (assuming $b = 1$) sets the incentives of the entrant in line to choose the zero risk technology.[4] Recall that $\lambda\sigma^{2*}$ in Proposition 1.4.1 was 5.

Now that we have set the conditions for an entrant's technology choice, in order to close the proof of Proposition 4.2 we need to state that higher $\lambda\sigma^2$ reduces entry opportunities. The entry deterrence condition is:

$$K > \Pi_e(c_r, c_s) = \frac{(a - c)^2(162b + 18\lambda\sigma^2)}{(45b + 4\lambda\sigma^2)^2} - \frac{\lambda\mu^2}{162b^2} \quad \text{(A.23)}$$

Taking the derivative of $\Pi_e(c_r, c_s)$ with respect to $\lambda\sigma^2$ it is possible to check that it is always negative. So higher levels of $\lambda\sigma^2$ makes deterrence easier. Even if $\lambda\sigma^2$ is large

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[4]As b rises, $\lambda\sigma^{2*}$ is higher.

enough to make the entrant's switch to a risky technology, above $\lambda\sigma^{2*}$, this deterrence effect continues. Then entry deterrence is possible by choosing riskier technologies if $K > \Pi(c_r, c_r)$. In the limit when $\lambda\sigma^2$ goes to infinity, this cutoff value of K is equal to $\frac{3}{4}\frac{(a-c)^2}{25b}$.

In the case of accommodation, condition (35-36) determines if the equilibrium will be (c_s, c_s) for cost volatility impact below $\lambda\sigma^{2*}$ or (c_r, c_r) for values above it.

$\square$

Case of n incumbent firms

Assuming $c_r = c_s = c$, if all firms choose the technology r, the optimal amount of forwards is equal to:

$$f^* = \frac{[(n+1)^2(n-1)b - (n^2+2n-1)2\lambda\sigma^2](a-c)}{[(n^2+1)(n+1)^2b + (n^2+2n-1)\lambda\sigma^2(n^2+1)]b} \qquad (A.24)$$

This is just a generalization of (1.12). It can be checked that f^* is decreasing in volatility.

Assuming now that incumbents are risk-neutral, the optimal amount of forwards appears in (A.25) and (A.26).

$$f_e^* = \frac{(n+1)[(n+1)^2(n-1)b - 2\lambda\sigma^2(n^2+2n-1)](a-c)}{b(n^3+n^2+n+1)[n(n^2+2n-1)\lambda\sigma^2 + b(n+1)^2]} \qquad (A.25)$$

$$f_i^* = \frac{(n-1)[(n^4+n^3+n^2+3n+2)(n^2+2n-1)\lambda\sigma^2 + (n+1)^2b(n^3+n+2)](a-c)}{(n^2-n+2)b(n^3+n^2+n+1)[n(n^2+2n-1)\lambda\sigma^2 + b(n+1)^2]}$$
$$\qquad (A.26)$$

Tables

Table B.1: Installed Capacity in MW by Technology, December 2010

Technology SIC	Installed Capacity [MW]	Installed Capacity [%]
Hydro with a dam	3,768.1	31.8%
Hydro without a dam	1,573.7	13.3%
Coal / Petcoke	1,354.4	11.4%
Natural Gas	2,721.0	23.0%
Oil	2,050.4	17.3%
Biomass	217.0	1.8%
Wind	160.5	1.4%
Total Capacity SIC	11,845.1	100.0%
Technology SING	**Installed Capacity [MW]**	**Installed Capacity [%]**
Hydro without a dam	14.9	0.4%
Coal / Petcoke	1,137.8	31.8%
Natural Gas	2,073.9	58.0%
Oil	348.2	9.7%
Total Capacity SING	3,574.9	100.0%

Source: CNE

Table B.2: Capacity installed by Generator

Generating Groups	Capacity in 2005		Capacity in 2011	
	MW	%	MW	%
Endesa	4,171.73	50.3%	5,107.45	40.9%
AES-Gener	1,160.37	14.0%	1,682.68	13.5%
Colbún	1,840.40	22.2%	2,555.17	20.5%
Guacolda	304.00	3.7%	608.00	4.9%
Others	811.80	9.8%	2,534.59	20.3%
Total SIC	8,288.30	100.0%	12,487.89	100.0%

Source: CNE

Table B.3: Market Share by Generator

Generating Groups	Sales in 2005		Sales in 2011	
	GWh	%	GWh	%
Endesa	13,999.47	40.9%	17,495.75	40.5%
AES-Gener	6,978.58	20.4%	5,944.27	13.8%
Colbún	9,564.65	27.9%	10,431.13	24.2%
Guacolda	2,083.82	6.1%	3,820.23	8.9%
Others	1,611.96	4.7%	5,471.47	12.7%
Total SIC	34,238.48	100.0%	43,162.83	100.0%

Source: CNE

Description of auction results

I use the data of seven auctions between October 2006 and March 2011. The first group of auctions started in October 2006, where all the five main distribution companies auctioned around 12,800 GWh/year. It was an important amount of power, almost half of distributor's total sales in 2005. All auctioned blocks of power started in 2010 with different lengths (from 10 to 15 years). Since not all the power auctioned was allocated in the first auction, the process continued with a second auction in January and February of 2007. There were no new generators participating in the auction, only the major incumbents: Endesa, AES-Gener, Colbún and Guacolda.[1]

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[1]Seven other firms pay the fee to participate, but they eventually didn't submit any bid.

In the second set of auctions, only the three major distributors participated: Chilectra, Chilquinta and CGE, summing a total of 14,700 GWh/year. The first auction was in October 2007 and a second one was held in January 2008 for the uncovered part of the first. All blocks had a duration longer than 10 years but they started in different dates: half in 2010 and half in 2011. From the total auctioned, only 5,700 GWh/year were allocated at an average price of 59.8 USD/MWh and all in contracts starting in 2011. It is important to stress that only Endesa, Colbún and AES-Gener participated in this set of auctions.

The third group had its first auction in January 2009 and a second in July 2009. Power auctioned in this set corresponded to the sum of previous uncovered supply. The total power auctioned was 8,010 GWh/year for contracts starting in 2010 for 12 to 15 years length. In terms of entry, two new firms participated in the first auction[2] and four new firms in the second[3].

The latest auction was in March 2011, where Chilectra and Chilquinta auctioned contracts from 11 to 14 years, starting in 2013, 2014 and 2015. The total amount auctioned was 2,450 GWh. Only Endesa and ENEL participate. It was the first time for this last generator, even though his firms Puyehue and Panguipulli have been in the Chilean power system for a long time.

Expected spot price calculation

By definition, C should be the long-term price generators' expect to pay when they retire electricity from the spot market to supply their contracts. It is similar to the long-term cost of providing for his contracts. If a generator is bidding in 2006 for a contract that starts in 2010 and ends in 2020, C should be the estimation of

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[2]Campanario and Electrica Monte Redondo (EMR). The first one generates power from natural gas and oil while the second generates it from wind.

[3]EMR, Norvind, Electrica Puntilla (EEP) and EMELDA. Norvind has wind generators, EEP has hydropower and EMELDA natural gas and oil based production.

future prices between 2010 and 2020. The long-term price of generation is called "cost of development"(CD).[4] The CD is calculated as the power price needed to finance a plant whose marginal cost of generation is determining the spot price. In Chile it is calculated for a coal-fueled power plant.[5] Then, the cost of development is highly influenced by the cost of a coal plant. Chile is a net importer of coal and it is a price-taker on the international market.

Expected coal prices for 2010 and on got more volatile since 2006. Figure B.1 shows that in October of 2006, the CNE was expecting coal prices of 75 USD/Ton in the long term. One year later, this expected price rose to 93 USD/Ton with a hike in 2010 to 109 USD/Ton. By October 2008 expectations kept rising. The long-term coal price was close to 150 USD/Ton. The financial crisis reduced the demand for coal and also expected coal prices in October 2009. By October 2010, long-term price was around 120 USD/Ton.

Figure B.1: Expected coal prices by CNE's report

Source: CNE

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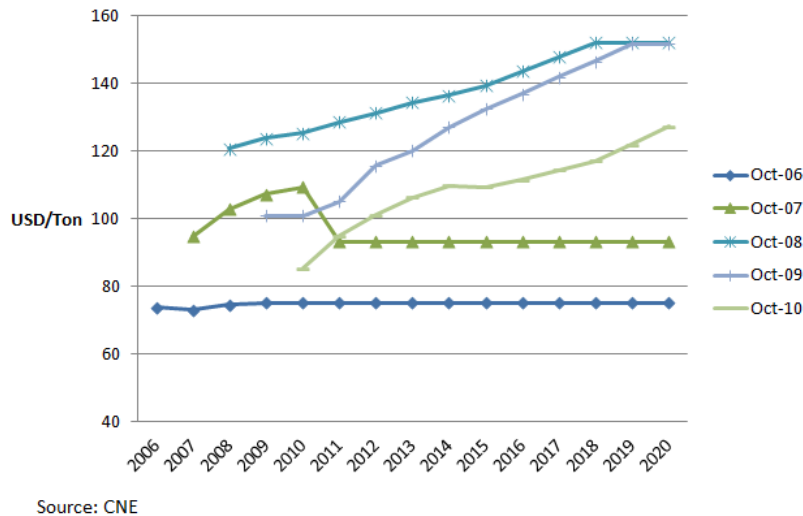
[4]Also called "levelized cost" in part of the literature.

[5]Before 2005 it was calculated based on a natural gas plant. Since there are no current imports of natural gas, power development is now based on coal. Other technologies like LNG are still more expensive.

Table B.4: Cost of Development Estimations

USD/Ton	USD/Kw	CD
75	1800	55.86
75	1850	56.72
75.83	1850	57.03
93.15	1850	63.55
121.89	1850	74.35
121.89	2000	76.94
139.2	2000	83.44
140	2500	92.35
150	2000	87.5
150	2500	96.12
120	2000	76
120	2500	84.84

Prepared based on information provided by CNE

Table B.4 shows the estimation of CD for different prices of coal in USD/Ton and investment cost in USD/Kw.

Coal prices are not the only one determinant of C. At the spot market, demand is satisfied in order of marginal cost. The first plants that are dispatched are based on hydro-power or wind-power, which have marginal cost close to zero. The second plants are based on thermal power, natural gas (if any) and coal. If demand is high enough, plants based on diesel are dispatched. Diesel is usually used on peak hours but if the demand is consistently over supply, the cost of generating with diesel becomes de spot market price. Then, if the generators were expecting a situation of tight supply in a particular year, expected spot prices would be higher than CD. This is important because by the beginning of 2008 the CNE received reports of potential tight supply in 2010. Then, contracts which started in 2010 would be affected by an expected spot

Figure B.2: Expected spot prices in 2010 in CNE reports

Source: CNE
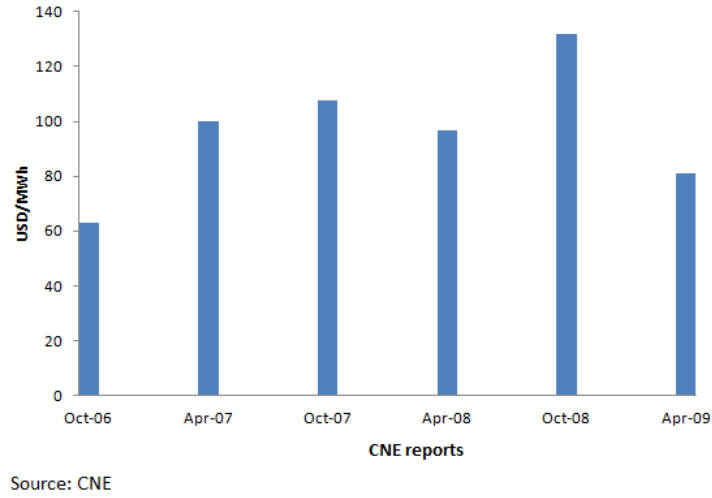
price above the estimated CD. Figure B.2 shows how expected spot prices for 2010 were rising before April 2009.

In order to account for this effect, I use the semiannual forecasts of spot prices performed by the CNE in April and October. Those forecasts are calculated based on simulations of the system's operation in the next four years, considering the expected price of fuel, the economic value of water resources, demand estimates and hydrological conditions over the past 40 years.

In sum, I use four scenarios: an optimistic and a pessimistic one based only on CD estimations, and an optimistic and a pessimistic scenario that accounts for a situation of tight supply in 2010. Main results in estimations do not change.

How generators submit their bids

The way each generator have to submit his bids is shown in Figure B.3. This is an example taken from Chilquinta's contract in 2009. Chilquinta is the third largest distributor and it was auctioning a contract for 1,760 GWh per year. The contract was divided in 16 sub-blocks of 110 GWh each one. In the first part of the sheet, the generator has to declare what sub-blocks he is bidding for, individually or combinatorially. In the second part of the sheet, he has to specify the price in US/MWh for each individual sub-block or combination declared in the previous section.

Figure B.3: How generators submit their bids

Estimations by schedule

Table B.5: Effect of A on mark-up for all schedules

	Linear	Grade 2	Grade 3
A	-0.005*	-0.005*	-0.005*
N	4.864***	1.702	-32.463*
Q	-0.001	-0.001	-0.002
N^2		0.443	11.487*
N^3			-1.057*
Constant	-3.829	0.796	32.482*
Obs	63	63	63
R^2	0.403	0.408	0.463

(*) p < 0.05, (**) p < 0.01, (***) p < 0.001.

Table B.6: Effect of A on mark-up for non-incumbents

	Linear	Grade 2	Grade 3
A	-0.020***	-0.019***	-0.018**
N	3.441**	25.156	-122.39
Q	0.003	0.001	0.001
N^2		-2.44	31.28
N^3			-2.48
Const.	1.548	-41.22	165.09
Obs	22	22	22
R^2	0.725	0.759	0.781

(*) p < 0.05, (**) p < 0.01, (***) p < 0.001.

Proofs of section 2.2.4

Lemma 2.4.1

In order to prove that there are only two optimum levels of contracting capacity A, we first need to define quantities and prices under the different residual demand scenarios. From Figure 2.8 we know there are four possible levels of S. Since $P_{min} = c_i + \lambda + \delta A_1$, we have that:

$$S_1 = A_1 = \frac{Q - \beta(c_i + \lambda)}{1 + \beta\delta} \tag{B.1}$$

$$S_2 = \frac{Q - \alpha - \beta(c_i + \lambda)}{1 + \beta\delta} \tag{B.2}$$

$$S_3 = \frac{Q - \beta(c_i + \lambda)}{1 + \beta(\delta + \theta)} \tag{B.3}$$

$$S_4 = \frac{Q - \alpha - \beta(c_i + \lambda)}{1 + \beta(\delta + \theta)} \tag{B.4}$$

The profits at A_1 for firm i depend on expected residual demand. If residual demand is high then bidder i will offer S_1 and profits will be $\Pi(c_i + \lambda + \delta A_1, A_1) = \lambda(Q - \beta(c_i + \lambda + \delta S_1))$. If residual demand is low then bidder i will offer S_2 and payoffs will be $\lambda(Q - \alpha - \beta(c_i + \lambda + \delta S_2))$.

From the auction game we know that the positive slope portion of the bid function is $P = c_i + \lambda + \delta S_i + \theta(S_i - A_i)$. Then, if $A = 0$, $P = c_i + \lambda + (\delta + \theta)(S_i)$. If residual demand is high, $S = S_3$ and profits will be $\Pi(P, 0) = \lambda S_3 + \frac{S_3 - A_0}{2}(P - (c_i + \lambda_i + \delta A_1))$. If residual demand is low, $S = S_4$ and profits will be $\Pi(P, 0) = \lambda S_4 + \frac{S_4 - A_0}{2}(P - (c_i + \lambda_i + \delta A_1))$.

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Now, let us assume there is a level of $A = \hat{A}$ where $0 < \hat{A} < A_1$. In that case, the price for a residual demand that intersects the bid function above $\hat{A}$ would be $P = c_i + \lambda + \delta\hat{S} + \theta(\hat{S} - \hat{A})$. Then:

$$\hat{S} = \frac{Q - \alpha - \beta(c_i + \lambda + \theta\hat{A})}{1 + \beta(\delta + \theta)}$$

Profits from $\hat{S}$ will be:

$$\Pi(P, \hat{S}) = (P_{min} - c_i)\hat{S} + \frac{1}{2}(\hat{S} - \hat{A})(P - P_{min})$$

Maximizing this profits with respect to A will give us the optimal amount of contracting capacity as an interior solution. From the first order conditions we get that there is an extreme point. However, this is a minimum according to the second order conditions.[6] What we have is that, under our assumptions, it is never optimal for a firm to choose a level of A different from 0 or A_1.

Symmetric equilibria

Before finding conditions for an asymmetric equilibrium, I need to define conditions for a symmetric equilibrium. Equations B.1 to B.4 define the four cases of quantities supplied depending on the choose of A and the level of residual demand. When we introduce the additional dimension of two levels of expected spot prices, we have eight cases. Profits associated with each case are defined as Π_{ml} for spot price m and case l.

It is possible to establish relationships between profits. First, $\Pi_{m3} < \Pi_{m1}$ if:

$$Q < c_m\beta + \lambda\beta + \frac{2\lambda\beta(\delta + \theta)[1 + \beta(\delta + \theta)]}{\theta - 2\delta\beta(\delta + \theta)[1 + \beta(\delta + \theta)]} \tag{B.5}$$

If $\delta = 0$, this condition collapses to $Q < c_m\beta + \lambda\beta[3 + 2\beta\theta]$.

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[6] $\hat{A} = A_1 - \lambda\beta(1 + \beta\theta)$ if $\delta = 0$.

Second, $\Pi_{m4} < \Pi_{m2}$ if:

$$Q < c_m\beta + \lambda\beta + \alpha + \frac{2\lambda\beta(\delta + \theta)[1 + \beta(\delta + \theta)]}{\theta - 2\delta\beta(\delta + \theta)[1 + \beta(\delta + \theta)]} \tag{B.6}$$

If $\delta = 0$, this condition collapses to $Q < c_m\beta + \lambda\beta[3 + 2\beta\theta] + \alpha$.

Firm i receives a signal of high expected spot prices with probability ρ and firm j receives a signal of high expected spot prices with probability γ. If firm 1 chooses $A = A_1$, residual demand for firm 2 will be $RD(\alpha > 0)$. If both firms choose $A = 0$, both firms will face a high residual demand, $RD(\alpha = 0)$. If both firms choose $A = A_1$, then both firms will face the low residual demand, $RD(\alpha > 0)$. Considering these assumptions, expected profits will have the following form:

- For the case of firm i choosing $A = A_1$ if signal c_H and $A = A_1$ if signal c_L and firm 2 choosing $A = A_1$ if signal c_H and $A = A_1$ if c_L:

$$U_i(A_1, A_1; A_1, A_1) = \rho\gamma\Pi_{H2} + (1 - \rho)[\gamma\Pi_{L1} + (1 - \gamma)\Pi_{L2}]$$

- For the case of firm i choosing $A = 0$ if c_H and $A = 0$ if c_L and firm 2 choosing $A = 0$ if c_H and $A = 0$ if c_L:

$$U_i(0, 0; 0, 0) = \rho[\gamma\Pi_{H3} + (1 - \gamma)\Pi_{H4}] + (1 - \rho)\Pi_{L3}$$

- For the case of firm i choosing $A = A_1$ if c_H and $A = 0$ if c_L and firm 2 choosing $A = A_1$ if c_H and $A = 0$ if c_L:

$$U_i(A_1, 0; A_1, 0) = \rho\gamma\Pi_{H2} + (1 - \rho)\Pi_{L3}$$

Figure 2.9 define five cases from four cutting values. Equations (B.5) and (B.6) give the cutting values for cases 1 and 5. The other two come from the next condition:
$\gamma\Pi_{m1} + (1 - \gamma)\Pi_{m2} > \gamma\Pi_{m3} + (1 - \gamma)\Pi_{m4}$ if:

$$Q < c_m\beta + \lambda\beta + (1-\gamma)\alpha + \frac{2\lambda\beta(\delta+\theta)[1+\beta(\delta+\theta)]}{\theta - 2\delta\beta(\delta+\theta)[1+\beta(\delta+\theta)]} \tag{B.7}$$

In order to sustain $(A_1, A_1; A_1, A_1)$ as a BNE we need that (B.7) is true for c_L.[7] $(0,0;0,0)$ as a BNE needs that (B.7) is not true for c_H.[8] Finally, the third symmetric BNE is $(A_1, 0; A_1, 0)$. The condition for it is:[9]

$$\beta c_L < Q - \lambda\beta - \frac{2\lambda\beta(\delta+\theta)[1+\beta(\delta+\theta)]}{\theta - 2\delta\beta(\delta+\theta)[1+\beta(\delta+\theta)]} < \alpha + \beta c_H \tag{B.8}$$

Proposition 2.4.1

The only difference between firms is the size of the maximum contract position they can choose: $A_1 = A_2 + \epsilon$ where $\epsilon > 0$. If $\delta = 0$, the cutoff values of Figure 2.9 change from $(1-\gamma)\alpha + \beta c_m$ to $(1-\gamma)(\alpha+\epsilon) + \beta c_m$. If $A_1 - A_2$ is large enough, it is possible to have an asymmetric equilibrium where the big firm firms plays $(0,0)$ and the small firm plays $(A_1, 0)$. The condition for such BNE is: $Q + \lambda\beta[3 + 2\beta\theta]$ has to be between $\alpha + \beta c_H$ and $(1-\gamma)(\alpha+\epsilon) + \beta c_H$. This means that:

$$\epsilon > \frac{\gamma}{1-\gamma}\alpha$$

Proposition 2.4.2

The only difference between firms is the cost of over-contracting θ. In this case I assume $\theta_1 > \theta_2$. Then, if the difference is large enough we can have the following condition if $\delta = 0$.

$$Q - \lambda\beta(3 + 2\beta\theta_1) < \beta c_L$$

$$\alpha + \beta c_H < Q - \lambda\beta(3 + 2\beta\theta_2)$$

If this is true, we can have an asymmetric equilibrium where firm 1 chooses (A_1, A_1) and firm 2 chooses $(0,0)$.

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[7]If $\delta = 0$ this means $Q < \beta c_L + (1-\gamma)\alpha + \lambda\beta[3 + 2\beta\theta]$.

[8]If $\delta = 0$ this means $Q > \beta c_H + (1-\gamma)\alpha + \lambda\beta[3 + 2\beta\theta]$

[9]If $\delta = 0$ this means $\beta c_L < Q + \lambda\beta[3 + 2\beta\theta] < \beta c_H + \alpha$.

Example of bid function equilibrium

Following the guess-verify-technique for equilibrium presented in Hortaçsu (2002), it is possible to show an example of a bid function equilibrium for a given probability distribution of the private signal.

Starting with the case where $S_i \leq A_i$, assume two bidders and a true supply function: $S(p, c_i) = \alpha + \beta p + \gamma c_i$, where $\alpha, \beta > 0$ and $\gamma < 0$. The first step is to guess a linear bid function: $s(p, c_i) = a + bp + dc_i$, where a, b and d are functions of α, β and γ. Now, let us impose a parametric probability distribution to the private signal c. Assume $F(c) = e^{-\lambda c}$. Then the pdf of the market clearing price is $H(p, S(p)) = e^{-\lambda \frac{Q-a-bp-S}{d}}$ and the inverse hazard rate is $\frac{\lambda b}{d} < 0$.

The next step it to substitute in the optimality condition and equate coefficients:

$$S(p, c_i) = \alpha + \frac{\gamma}{\lambda} + \beta p + \gamma c_i$$

$$p(S, c_i) = \frac{1}{\beta}[S - \alpha - \frac{\gamma}{\lambda} - \gamma c_i]$$

In case $(S_i > A_i)$:

$$p(S, c_i, A_i) = \frac{1}{\beta}[(1 + \beta\theta)S - \alpha - \frac{\gamma}{\lambda} - \gamma c_i - (\mu + \beta\theta)A_i]$$

Causality between prices

Table C.1: VAR Granger Causality

Dependent variable: NPMA		
Excluded	Chi-sq	Prob.
FPM	13.86967	0.01650
MGC	22.54805	0.00040***
All	40.42350	0.00000***
Dependent variable: FPM		
Excluded	Chi-sq	Prob.
NPMA	24.01664	0.00020***
MGC	4.01058	0.54790
All	28.50116	0.00150
Dependent variable: MGC		
Excluded	Chi-sq	Prob.
NPMA	3.09350	0.68560
FPM	2.00539	0.84840
All	4.43280	0.92570

We perform a VAR estimation including input prices (coal and oil), hydrologic conditions (inflow energy) and macroeconomic variables (inflation and USD exchange rate). We use a lag of five quarters, where serial correlation is minimize. Since both endogenous variables FPM (monomial free prices) and NPMA (monomial node prices) have a unit root, we follow Toda and Yamamoto (1995) procedure to test for Granger causality. NPMA and FPM have the same order of integration (one), we test for cointegration and we find both variables are cointegrated. This indicates the existence of

Granger causality, but not the direction of it. When two time-series are cointegrated, there must be Granger causality between them - either one-way or in both directions.

Table C.1 shows the VAR Granger Causality results for FPM, NPMA and MGC (spot prices). We can not reject the hypothesis that NPMA Granger causes FPM. Also, we cannot reject that MGC Granger causes NPMA. In sum, we find out that free prices follow node prices and spot prices depend on exogenous hydrologic variables.

Ralco in CNE's investment plans from 1999 to 2004

We start our revision of the investment plan in the April 1999 report even though Ralco is present in previous reports. After the Argentinean natural gas was available, there was a first wave of investment in CCGT plants based on natural gas.[1] Since these plants were developed and installed without considering the effect of Ralco, it is useful to leave them out of our story.[2] In the October 1998 report, according to the information provided by Endesa, Ralco was scheduled to be ready in April 2002. By the April 1999 report, Ralco was delayed a few months, to June 2002. However, this does not change the big picture: after Ralco, the CNE only suggested investments in CCGT units, the long-run unit of the system at the moment. For all the above reasons, we use April 1999's report as a starting point for our analysis.

The investment plan forecasted by the CNE in April 1999 is in Table C.1. Before Ralco, there were two small hydro-power plants under construction, while after it we find the expansions plants on natural gas.

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[1] CCGT is a combined cycle gas turbine

[2] These plant were: Nueva Renca, property of AES-Gener (formerly Gener), operative in 1997 with installed capacity of 379 MW; San Isidro, property of Endesa, operative in 1998 with 379 MW; Nehuenco, property of Colbun, operative in 1998, with 368.4 MW.

Table C.2: April 1999's report

Operative in	Plant name	Technology	Capacity MW	Situation.
$Oct - 99$	Peuchen	Hydro	79.0	Under construction
$Apr - 00$	Mampil	Hydro	52.0	Under construction
$Jun - 02$	Ralco	Hydro	570.0	Under construction
$Apr - 03$	CCGT NG	Thermal	332.4	Suggested

In the next report we have the first significant delay in Ralco's operation date. It was delayed seven months and now is expected on January 2003. Given this delay, the CNE included two new units before Ralco in the optimal investment plan. The first unit is an under-construction one, Taltal GT, while the second one is a suggested unit.[3] Suggested expansion units after Ralco remained the same.

Table C.3: October 1999's report

Operative in	Plant name	Technology	Capacity MW	Situation.
$Jan - 00$	Peuchen	Hydro	79.0	Under construction
$Jan - 00$	Mampil	Hydro	52.0	Under construction
$Feb - 00$	Taltal GT	Thermal	120.0	Under construction
$Jan - 01$	GT	Thermal	120.0	Suggested
$Jan - 03$	Ralco	Hydro	570.0	Under construction
$Apr - 03$	CCGT NG	Thermal	332.4	Suggested

By April 2000's report, we have another delay of six months in Ralco. The new starting date was July 2003. This delay gave space for a new unit on October 2002. Now the suggested unit of the previous report was replaced by a unit under construction (Taltal's second turbine), while the new suggested unit is the Taltal CCGT

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[3]GT is a gas turbine.

project with an additional 120 MW.[4] Again, after Ralco there are suggested expansion units.

Table C.4: April 2000's report

Operative in	Plant name	Technology	Capacity MW	Situation.
Apr − 00	Mampil	Hydro	52.0	Under construction
Apr − 00	Taltal 1 GT	Thermal	120.0	Under construction
Jun − 00	Taltal 2 GT	Thermal	120.0	Under construction
Oct − 02	Taltal CCGT NG	Thermal	120.0	Suggested
Jul − 03	Ralco	Hydro	570.0	Under construction
Apr − 03	CCGT NG	Thermal	332.4	Suggested

In October 2000's plan a new project is introduced: an interconnection between SIC and SING.[5] The project was suggested for the year 2006 but the interconnection remains a project even today.

Table C.5: October 2000's report

Operative in	Plant name	Technology	Capacity MW	Situation.
Oct − 02	Taltal CCGT NG	Thermal	120.0	Suggested
Jul − 03	Ralco	Hydro	570.0	Under construction
Jan − 04	Interconnection SING	Inter	250.0	Suggested
Apr − 04	CCGT NG	Thermal	332.4	Suggested

April 2001's report has no relevant changes with respect to the previous one. The completion of the Taltal project remains as the unique suggested unit before Ralco. After Ralco, we find two new suggested projects in the long term. The first one is another interconnection, now with Argentina, while the second one is a hydro-power project, Neltume. Both are still under project status. They have never been under construction.

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[4]In fact, the CCGT was never ended.

[5]At the time, SING had excess of capacity in thermal units.

Table C.6: April 2001's report

Operative in	Plant name	Technology	Capacity MW	Situation.
Jan − 03	Taltal CCGT NG	Thermal	120.0	Suggested
Jul − 03	Ralco	Hydro	570.0	Under construction
Jan − 04	Interconnection SING	Inter	250.0	Suggested
Apr − 04	CCGT NG	Thermal	332.4	Suggested

In October 2001 we find another important delay for Ralco. An additional six months were needed and the new starting date became January 2004. Again, the investment plan needed to fill the gap with an additional unit. In this case the unit is GT 9B Nehuenco, property of Colbun. This unit was under construction and was scheduled for April 2002. A small hydro-power run-of-the-river plant was added too (Chacabuquito). The suggested completion of the Taltal project is still before Ralco and it was also delayed six months.

Table C.7: October 2001's report

Operative in	Plant name	Technology	Capacity MW	Situation.
Apr − 02	9B Nehuenco TG	Thermal	100.0	Under construction
Jul − 02	Chacabuquito	Hydro	25.0	Under construction
Jul − 03	Taltal CCGT NG	Thermal	120.0	Suggested
Jan − 04	Ralco	Hydro	570.0	Under construction
Apr − 04	CCGT NG	Thermal	332.4	Suggested
Jan − 05	Interconnection SING	Inter	250.0	Suggested

In April 2002's report we find the effect of the previous delay in Ralco's construction. Given the room for a new unit before Ralco, covered by the suggested finishing of Taltal, a new project appeared: a CCGT in Quillota. This project was developed by Colbun and it got the environmental authorization in March 2001 for two open

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cycle units for a total capacity of 240 MW. In October 2001 Colbun incorporated a change in the project, increasing the capacity by 130.7 MW by closing the CCGT in April 2004. Given that the new project filled the capacity requirements before Ralco, the finishing of Taltal was postponed until January 2005. The same happened with the interconnection project.

Table C.8: April 2002's report

Operative in	Plant name	Technology	Capacity MW	Situation.
Apr − 02	9B Nehuenco TG	Thermal	100.0	Under construction
Jun − 02	Chacabuquito	Hydro	25.0	Under construction
Aug − 02	Energia Verde	Thermal	25.0	Under construction
Jul − 03	Quillota GT	Thermal	253.5	Under construction
Jan − 04	Ralco	Hydro	570.0	Under construction
Apr − 04	Quillota CCGT GT	Thermal	130.7	Under construction
Jan − 05	Taltal CCGT NG	Thermal	120.0	Suggested
Jan − 06	CCGT NG	Thermal	332.4	Suggested

In October 2002 we find the last delay in Ralco's project. It is again a six months delay, setting the operation in July 2004.[6] In this report there were three projects of Arauco Generacion, units Cholguan, Licanten and Valdivia, incorporating almost 100 MW into the system. The delay in Ralco was covered by these projects and the finishing of the Quillota CCGT.[7]

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[6]The first units of Ralco started operating on September 2004.

[7]It is important to highlight that Arauco is paper mill who has power capacity for their own use, releasing residual power in case they have any.

Table C.9: October 2002's report

Operative in	Plant name	Technology	Capacity MW	Situation.
$Nov-02$	Cholguan	Thermal	15.0	Under construction
$Jan-03$	Licanten	Thermal	13.0	Under construction
$Jun-03$	Quillota GT	Thermal	253.5	Under construction
$Jan-04$	Valdivia	Thermal	70	Under construction
$Apr-04$	Quillota CCGT GT	Thermal	130.7	Under construction
$Jul-04$	Ralco	Hydro	570.0	Under construction
$Jan-05$	Taltal CCGT NG	Thermal	120.0	Suggested
$Apr-06$	Interconnection SING	Inter	250.0	Suggested
$Oct-06$	CCGT NG	Thermal	332.4	Suggested

The new investment plan in April 2003 presented no major update. There was just a small delay in Cholguan, Licanten and the finishing of the Quillota CCGT projects.

Table C.10: April 2003's report

Operative in	Plant name	Technology	Capacity MW	Situation.
$Apr-03$	Cholguan	Thermal	15.0	Under construction
$Apr-03$	Licanten	Thermal	13.0	Under construction
$Jun-03$	Quillota GT	Thermal	253.5	Under construction
$Jan-04$	Valdivia	Thermal	70	Under construction
$Jul-04$	Quillota CCGT GT	Thermal	130.7	Under construction
$Jul-04$	Ralco	Hydro	570.0	Under construction
$Jul-06$	Interconnection SING	Inter	250.0	Suggested
$Apr-07$	CCGT NG	Thermal	332.4	Suggested

October 2003's plan showed another delay in Licanten and an expansion in Arauco. Two issues are worth pointing out: first, the delay in the interconnection SING-SIC until October 2008; and second, the entry of geothermal projects in the suggested investment plan.

Table C.11: October 2003's report

Operative in	Plant name	Technology	Capacity MW	Situation.
Mar − 04	Valdivia	Thermal	70	Under construction
Apr − 04	Licanten	Thermal	13.0	Under construction
Apr − 04	Arauco exp	Thermal	24.0	Under construction
Jun − 04	Quillota CCGT GT	Thermal	130.7	Under construction
Jul − 04	Ralco	Hydro	570.0	Under construction
Jul − 06	CCGT NG	Thermal	332.4	Suggested

April 2004's report includes the first under-construction project scheduled after Ralco.[8] This project, Candelaria, is a thermal based unit. Once uncertainty about Ralco's final date disappeared, smaller projects were introduced, as would be expected.

Table C.12: April 2004's report

Operative in	Plant name	Technology	Capacity MW	Situation.
May − 04	Quillota CCGT GT	Thermal	130.7	Under construction
Jul − 04	Ralco	Hydro	570.0	Under construction
Jul − 05	Candelaria	Thermal	250.0	Under construction
Apr − 06	Coya	Hydro	25.0	Suggested
Oct − 07	V region	Hydro	65.0	Suggested
Jan − 08	La Higuera	Thermal	155.0	Suggested
Apr − 08	CCGT NG	Thermal	332.4	Suggested

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[8]It is true that in the April 2002 plan there was a project after Ralco, but this one was the completion of a CCGN, not a new project

Model

Let's assume an aggregate demand function that grows over time and it is denoted by:

$$Q = A_0 + \alpha t - BP$$

where $A_0, \alpha, \beta > 0$. As time t increases, there is a parallel shift at an equal rate in the demand. The standard unit has a capacity given by K. Since variable cost is zero and there is no depreciation, at each moment, the market price is given by $P(t) = \frac{A_0}{B} - n(t)\frac{K}{B}$, where the $n(t)$ is the number of units installed up to t.

If a generator invests in one unit at time t, there is an interval of time Δt between two consecutive units where the market price is the same. This condition is given by:

$$\frac{A_0 + \alpha t}{B} - \frac{Q}{B} = \frac{A_0 + \alpha(t + \Delta t)}{B} - \frac{Q + K}{B}$$

$$\Rightarrow \Delta t = \frac{K}{\alpha}$$

Now, the condition for the units to have a return equal to r is the same as having a present discount value PV equal to zero with r as the discount factor. Let's use a continuous time approach in order to simplify the algebra and obtain the exact return r. The present value is:

$$PV = \int_0^\infty P(t) e^{-rt} dt - K$$

We know that in equilibrium the evolution of prices look the same by intervals of Δt, so we can rewrite it as:

$$PV = \sum_{I=0}^{\infty} \left[\int_0^{\Delta t} P(t) e^{-rt} dt \right] e^{-r\Delta tI} - K$$

Let's denote by P_0 the price just after the unit is installed. Then, the price after the unit's installation is given by an increase at rate $\frac{\alpha}{B}$. We need to calculate P_0. Working with the previous expression we get:

$$PV = \sum_{I=0}^{\infty} \left[\int_0^{\Delta t} \left[P_0 + \frac{\alpha}{B} t \right] e^{-rt} dt \right] e^{-r\Delta tI} - K$$
$$= \sum_{I=0}^{\infty} \left[P_0 \left[\frac{1}{r} - \frac{e^{-r\Delta t}}{r} \right] + \frac{\alpha}{Br} \left[\frac{1}{r} - \frac{[1+r\Delta t]e^{-r\Delta t}}{r} \right] \right] e^{-r\Delta tI} - K$$

Setting PV equal to 0:

$$PV = 0 \Rightarrow P_0 \left[\frac{1}{r} - \frac{e^{-r\Delta t}}{r} \right] + \frac{\alpha}{Br} \left[\frac{1}{r} - \frac{[1+r\Delta t]e^{-r\Delta t}}{r} \right] = K \left[1 - e^{-r\Delta t} \right]$$
$$\Rightarrow P_0 = rK - \frac{\alpha}{Br} + \frac{K}{B} \frac{e^{-r\frac{K}{\alpha}}}{1-e^{-r\frac{K}{\alpha}}}$$

So we have the expression for the price after the investment in a standard unit.

Next we will focus on the big unit case. Assume for the sake of simplicity that the big unit has the same characteristics as the standard unit but a capacity equal to D times the standard unit's $(D > 1)$. Let's normalize the time by defining time zero at the moment when the unit scheduled before the big unit enters, and this unit is already under construction. This way we know that the price at that moment is P_0. The question is when it is optimal for the next standard unit to be installed given the big unit schedule.

Let us start with the most simple case, where the big unit is installed at time zero, that is, at the same moment as the previous unit.[9] Then the next standard unit is installed at time $\frac{DK}{\alpha}$, the price at that moment will be P_0 and the return will be r. It is easy to see that for any time the big unit is installed between 0 and $\frac{DK}{\alpha}$, the return of this standard unit will remain on r if it is installed at $\frac{DK}{\alpha}$. So the question is if it is possible to get a higher return by entering before the big unit. The next standard unit, the one entering at $\frac{(D+1)K}{\alpha}$, it is not affected by the possible shift of the unit under study, because the price at that moment will not be affected. So we assume an initial situation where the BU is scheduled in a time when the next standard unit has no incentive to deviate and shift before the big unit. This is our initial equilibrium.[10]

Now we consider the case of a delay in the big unit. Let t_{BU} be a new schedule for the big unit (BU). Given the structure of the problem, we need to focus on $t_{BU} \in \left[0, \frac{DK}{\alpha}\right]$. As we said before, if $t_{BU} \leq \frac{DK}{\alpha}$ then the next standard unit still has a return equal to r if it keeps the schedule time at $\frac{DK}{\alpha}$, because the accumulated investment is the same. Following the same logic as in the equilibrium without a BU, there are no incentives to move its entry marginally ahead. So the maximum return that the unit can obtain by installing after the BU is r. Let's see the return for installing before the BU.

In the case where the standard unit is moved ahead of the BU, we know that the price at $\frac{DK}{\alpha}$ is still P_0, because the total investment up to this point has not changed. In the period between the entry of the standard unit and the BU, the only investment

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[9] This is an extreme point and we are stressing the assumption of the previous standard unit as under construction.

[10] Formally, there are multiple equilibria depending on the order of investment, but in all cases firms earn r.

is the standard unit.[11] After the BU enters, the price shifts down by $\frac{DK}{B}$. After $\frac{DK}{\alpha}$ we start again with the steady state case, where the expected return is r. So we can write the return for investing at t^* between 0 and t_{BU} as:

$$PV(t^*) = \underbrace{\int_{t^*}^{t_{BU}} \left[P_0 + \frac{\alpha}{B}t \right] e^{-r(t-t^*)}dt}_{Before\ BU} + \underbrace{\int_{t_{BU}}^{DK/\alpha} \left[P_0 + \frac{\alpha}{B}t - \frac{DK}{B} \right] e^{-r(t-t^*)}dt}_{After\ BU} + \underbrace{Ke^{-r(DK/\alpha-t^*)}}_{After\ \frac{DK}{\alpha}} - K$$

Evaluating at t_{BU} equal to $\frac{DK}{\alpha}$, which is the upper bound, it is easy to see that the present value with t^* equal 0 is strictly positive, because the second integral is zero and by the definition of P_0 the return is higher than r, or the PV is strictly positive. On the other extreme, if t_{BU} is zero, then the only possible value for t^* is zero too, and the return is below r, because the PV is negative.

Given that we are maximizing a continuous function, $PV(t^*)$, in a compact set, $t^* \in [0, t_{BU}]$ a solution exists, and the value function is continuous. Then given that we have one case where the solution gets a return higher than r and the other lower than this threshold, there exists a value t_{BU}^* where the standard unit can get exactly r if it shifts before the BU.

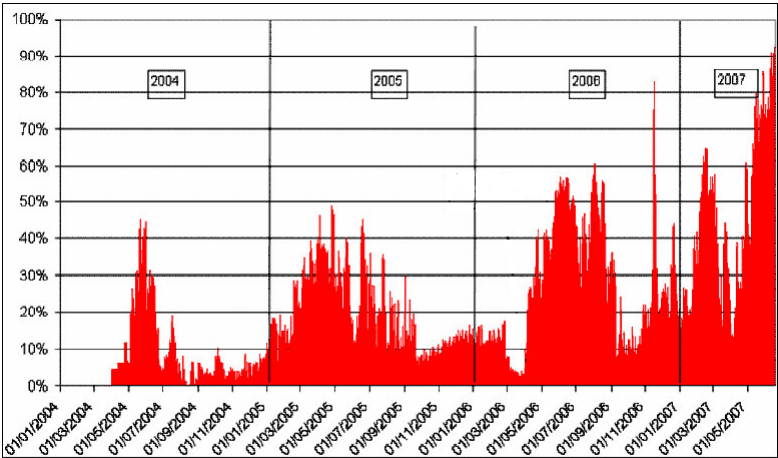[11]Remember the normalization of the time we did before.

Figures

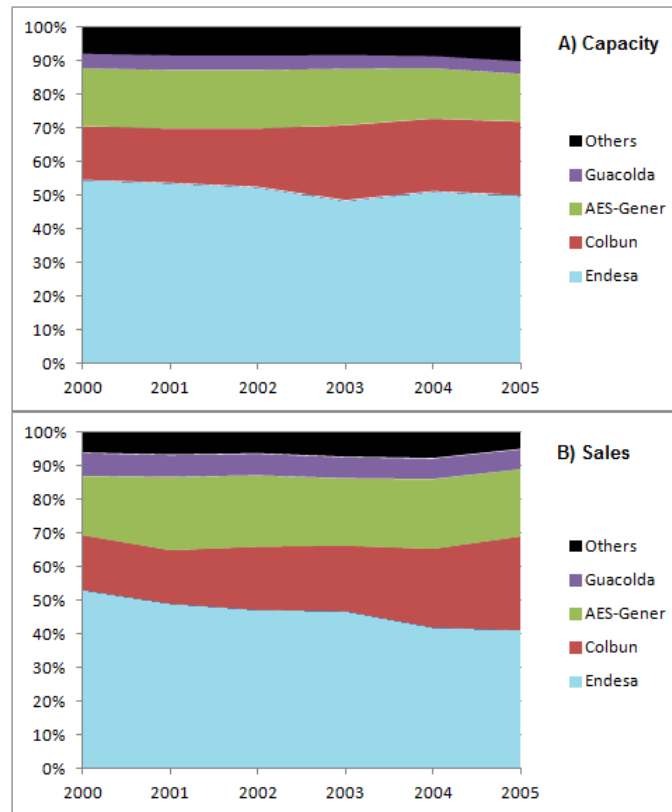Figure C.1: SIC generation in % by technology, from 1996 to 2009
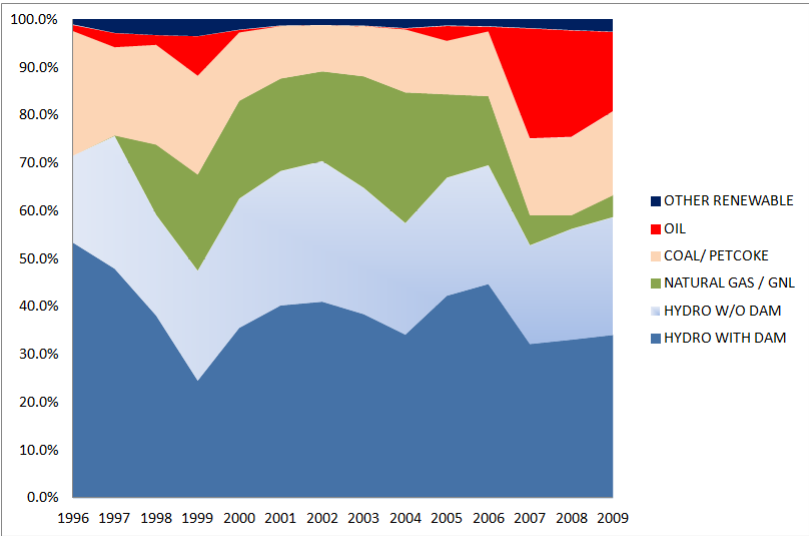
Source: CDEC-SIC

Figure C.2: Natural gas restrictions as a percentage of total imports
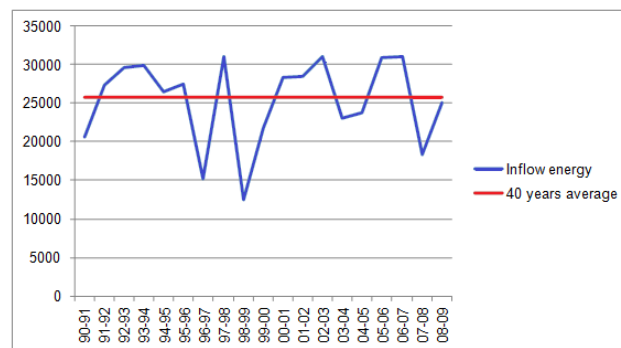

Source: CNE

Figure C.3: Market shares in terms of capacity (a) and sales (b), from 2000 to 2005

Source: CNE, CDEC-SIC

Figure C.4: SIC's Hydrologic situation over time

Source: CNE

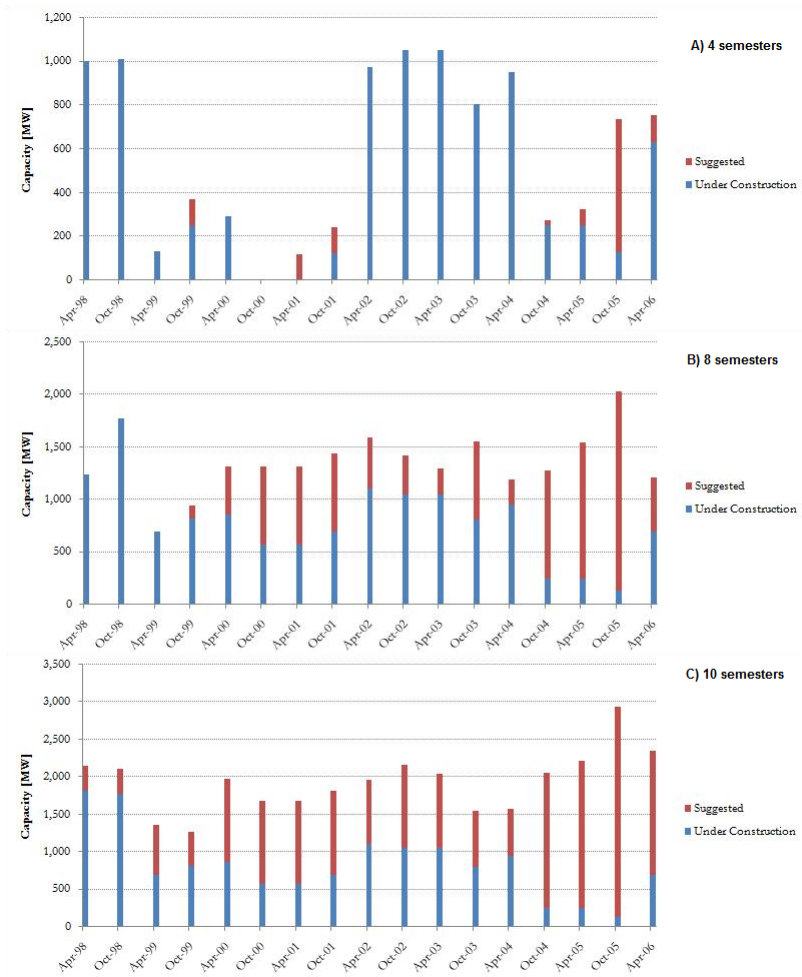Figure C.5: Expected additional capacity in four semesters (A), eight semesters (B) and ten semesters (C).

Figure C.6: Annual returns over fixed assets from 1995 to 2005.
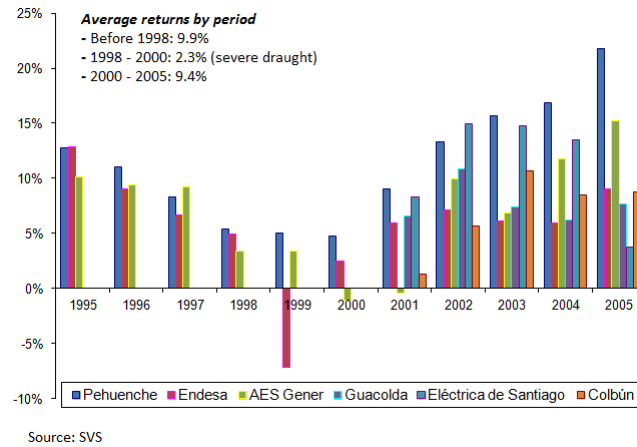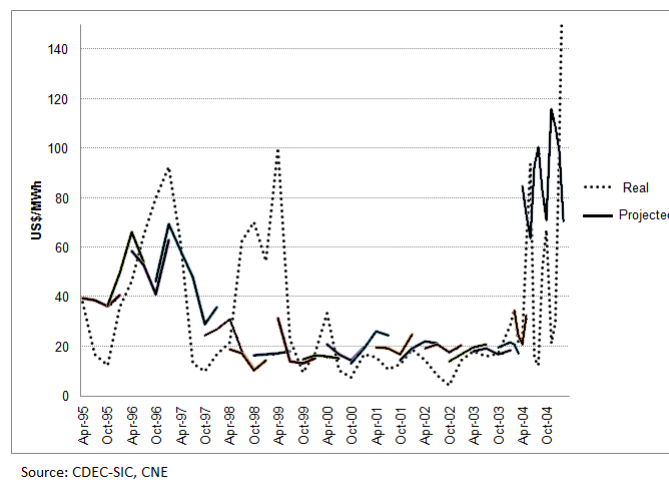

Figure C.7: Real and nine-months projected marginal cost by CNE's report. Values in three month average.

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