UNIVERSITAT DE BARCELONA

Essays on Regulation, Liberalization and Privatization in Energy Markets

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PhD in Economics

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A Maria del Pilar

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1. Introduction

Electricity is of strategic importance to the development of an economy in several aspects. It is a key input of production for several industries and it allows providing services which are essential to the welfare of consumers such as lighting and communications, it represents the 24% of the energy consumption by households and 21% by industry (Eurostat, 2017; IEA, 2018b). The component of electricity generation represents between the 23% to 58% percent of the final price paid by consumers (EC, 2019).

The production of electricity is related with exploitation of natural resources and environmental sustainability. In 2018 the power sector accounted for nearly two-thirds of emissions growth and only coal-fired electricity generation accounted for 30% of global CO_2 emissions (IEA, 2018a). The conversion of generation facilities to low emission technologies is an essential condition for abating the current rate of greenhouse gases emissions. These and other important considerations place the institutional design of the electricity generation activity at the core of the environmental and energy policy debates around the world.

In the 1980s and 1990s, the electricity industry experienced important market-oriented reforms in response to a combination of political, ideological, economic and technological factors (Jamasb et al., 2017). One of the principal objectives of this rearrangement of the industry was increasing efficiency with respect to the old statist model. In the case of electricity generation, there are two key elements of the reform program aimed for encouraging productive efficiency: i) the introduction of competition and ii) private participation (Newbery, 1997). According to the rationale of the reforms, profit maximization behavior of private agents together with the competition between firms would work as a mechanism to transfer to the final consumers the reduction of costs (Vickers and Yarrow, 1988; Joskow, 1998).

After more than thirty years after the start of the wave of reforms, it is possible to find markets with different levels of progress in terms of the two key aspects mentioned above. In relation to competition, it should be noted that in several electricity generation markets in which this element has been introduced, market power issues have been evidenced (Joskow et al., 2008).[1] Regarding privatization, the percentages of participation of public companies in electricity generation supply remain important in several markets, even in those pioneer countries in the implementation of economic liberalization programs.[2] Figure 1 presents the participation of state owned generation assets in OECD and G20 countries.

The general motivation of this research is to explore the effects of the coexistence of public and private companies on the allocative efficiency of the supply of electricity. In particular, this thesis investigates from an empirical perspective to what extent the distinction between private and public companies is relevant to understand the competition in the wholesale electricity generation markets. I apply several econometric techniques and theory advances in industrial organization branch on data of the firms of the Colombian market.

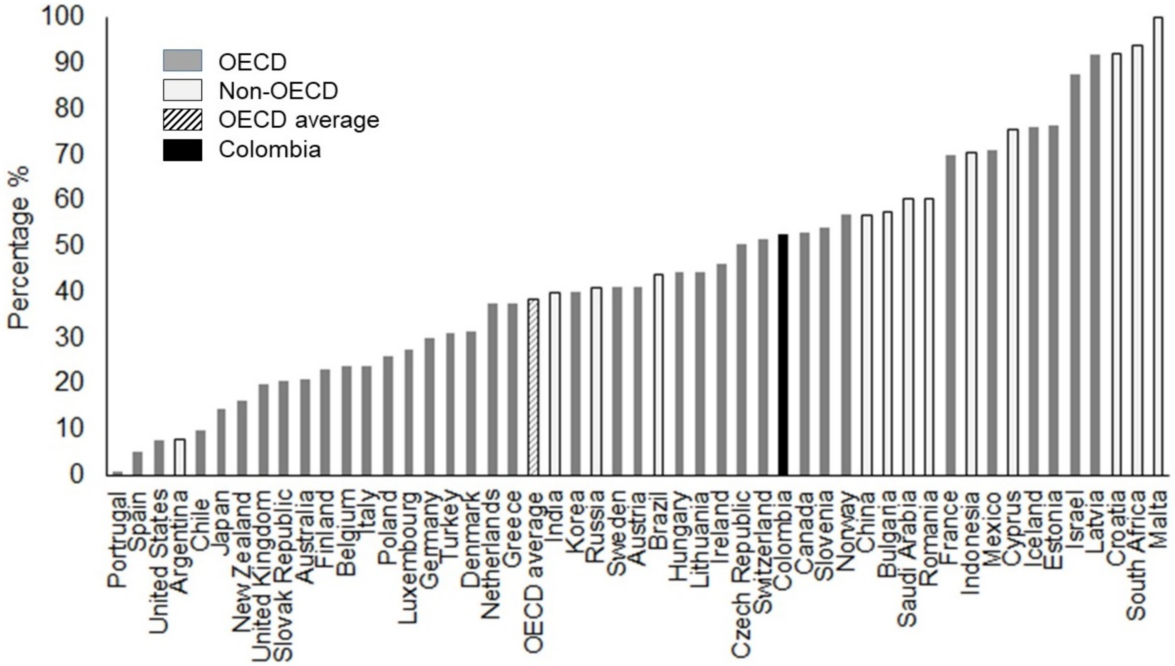
The case of the Colombian electricity market is suitable to study this issues for four reasons: i) It is an oligopoly in which private and public companies compete under the same rules. ii) The most important firms in the Colombian electricity sector are mature organizations, with a conventional business vision. In fact, many of these companies belong to transnational capital that carry out activities in several continents. iii) The market setting have a conventional design similar to other liberalized electricity markets. It operates as a multi-unit uniform-price auction. iv) There is available information with daily and even hourly resolution of the generation market variables. I consider that these are key elements for justifying the external validity of the results.

This thesis presents three essays that aim to answer three questions related to the interaction between competition in electricity markets and their ownership structure. Chapter 1 addresses the question: Do the switch from public to private management have impacts in the bidding strategy of specific generation assets? Chapter 2 explores the question: Do public and private generation companies respond the same to the incentives

[1] After the seminal empirical studies of Green and Newbery (1992) and Wolfram (1999), market power issues of various kinds was identified in many wholesale electricity markets. The concern for this issue was exacerbated during the first half of the 2000s after serious blackouts occurred in recently liberalized markets (California, Chile and Brazil). Several authors found a relationship between the existence of market power and the California electricity market crisis (Puller, 2007; Wolak, 2003; Borenstein et al., 2002) .

[2] Privatization is not an indispensable condition for liberalization. In theory, public companies may also be subject to competition incentives (Jamasb and Pollitt, 2005). In several jurisdictions, as a result of liberalization reforms, public and private firms coexists and compete under the same regulatory conditions. Clò et al. (2017) documented that public ownership is still relevant in the electricity industry in Europe. Prag et al. (2018) reported different levels of public ownership shares of electricity generation capacity within OECD and G20 countries, ranging from state monopoly to almost complete privatization.

Figure 1.1.: Public ownership of electricity generation



Source: Prag, RÃűttgers and Scherrer (2018). OECD document, SOEs and the Low Carbon Transition, based on OECD data and World Electric Power Plant Database. I made the computation for Colombia using the information of installed capacity available in the web page of the market operator XM.

to relax competition? Chapter 3 focuses on the question: Do private companies have a greater propensity to establish coordination relationships in comparison to public firms?

In the first chapter of this thesis I evaluate the impact of privatization on the bidding of electricity units participating in a liberalized wholesale electricity market. The results of this evaluation contribute to better understand whether privatization is the right decision in an environment of imperfect competition.

Mixed oligopoly models have analyzed from a theoretical perspective, markets in which public, private and / or mixed companies coexist and compete under conditions of limited competition in the same relevant market.[3] Many of the conclusions of these models arise from adopting different assumptions for private and public firms. The most

[3]The main concern of this group of studies has focused on the level of optimal privatization (De Fraja and Delbono, 1989; Fershtman, 1990; Matsumura, 1998), the role that public companies can play as an instrument of economic policy (Harris and Wiens, 1980; Beato and Mas-Colell, 1984; Cremer et al., 1989; Brandao and Castro, 2007; Bel and Calzada, 2009) and the compatibility of incentives between company managers and objectives from both private and public companies (Fershtman and Judd, 1987; Barros, 1995)

common of these assumptions are: i) Private firms are profit maximizers and public firms are welfare maximizers (I will refer this as behavioral difference); ii) Private companies achieve greater productive efficiency than public companies (I will refer this as performance difference). However, most of the empirical exercises intended to find differences between public and private firms are focus on the performance issue and are carry out in non-competitive contexts as pure public versus pure private monopoly (La Porta and Lopez-de Silanes, 1999; Frydman et al., 1999; Megginson and Netter, 2001; Bel et al., 2010) or mixed delivery system (Bel and Rosell, 2016) .

In this essay I adopt a policy evaluation approach to estimate the impact of changes from public to private management on the bidding prices of electricity generation units. I use information of bidding prices of the Colombian wholesale electricity market and exploit the changes of management of generation units documented in the period 2006 - 2018. The methodologies and results presented in this thesis contributes to the literature of mixed oligopoly because they place special emphasis on the behavioral differences between private and public companies and studies a field expierence in which they compete in the same relevant market. To the best of my knowledge, few papers have adopted this approach (Barros and Modesto, 1999). The empirical evidence resultant from the policy evaluation method is aligned with the theoretical predictions of comparative statics arising from the behavioral differences of mixed oligopoly models.

The second chapter of this dissertation proposes a methodology in order to find differences between the reactions of private and public firms when they face incentives to exercises unilateral market power. Several common events in the electricity industry such as transmission restrictions, the concentration of generation property within specific areas, the non-storage capacity of electricity and the low elasticity of demand, provide opportunities to exert market power (Joskow, 1997; Borenstein, 2002) . That is why this issue has been widely studied and discussed theoretically (von der Fehr and Harbord, 1993; Newbery, 1998; Wilson, 2002; Fabra et al., 2006) and empirically (Green and Newbery, 1992; Wolfram, 1998, 1999; Borenstein et al., 2002; Hortaçsu and Puller, 2008) . The novel element of this essay in relation to this strand of the literature is accounting for the distinction between private and public companies regarding competitive behavior.

An important question that remains unsolved of chapter one is whether the changes in the pricing strategies caused by privatization are due to the exercise of market power. That is why in chapter two I make use of the empirical techniques developed in the literature on electricity markets, in particular the model proposed by McRae and Wolak (2009) to identify the market power mitigation effect of public firms in the Colombian market. This technique draws on information about individual bids (willingness to sell) available in the electricity markets organized as a multi-product auction. I apply this methodology to the Colombian wholesale electricity market for the period 2005 to 2014.

The main contribution of this chapter is to develop an empirical model for the analysis of the differences between private and public firms in terms of their incentives to exercise market power in a multi-unit auction framework. Overall, this methodology is implementable to any multi-product, uniform price auction in which the competitors' bids and marginal costs are observable. In addition, as far as my knowledge goes, this is the first study that attempts to identify heterogeneous behavior of private and public companies in relation to incentives to exercise market power in electricity generation activity. The results of this study suggest that there are marked differences between private and public firms in their exercise of unilateral market power. I found that the prices of public companies do not respond to incentives to increase market power while those of private companies do, although less than expected by profit maximization models. This supports the hypothesis of the market power mitigation effect of the public firms.

In chapter three we go beyond the analysis of the study of unilateral market power and consider the coordinated strategic behavior as object of research.[4]

From a general perspective, the conventional wisdom in collusion theory is that transparency facilitates collusion (Ivaldi et al., 2003). However, in the specific case of wholesale electricity markets, to date, different opinions persist among academics studying this issue. On the one hand, those skeptical about the effectiveness of information concealment argue that the complexity of the bidding process of electricity markets makes difficult implicit coordination. In addition, they claim that the availability of data of market outcomes allow to several stakeholders undertake studies examining whether implicit tacit collusion or other type of strategic behavior is occurring (Wolak, 2009) . On the other hand, those who are against transparency argue that the immediate and detailed disclosure of information on market outcomes is not a necessary element to ensure rational and competitive behavior. They also claim that, transparency may facilitate the exercising of unilateral market power and maintaining collusion (von der Fehr, 2013).

However, there is little empirical evidence to discard any of the arguments presented above.[5] As far as we know, the only paper empirically studying the specific problem of

[4]This chapter reports partial results of a co-authored project with Miguel Espinosa (Assistant Professor at the Department of Economics and Business, Universitat Pompeu Fabra and Affiliated Professor at the Barcelona GSE) and Rocco Macchiavello (Department of Management, London School of Economics and Political Science).

[5]Bolle (1992) proposes a supply function equilibrium model with instantaneous production and con-

transparency and coordination in electricity markets is the study of Brown et al. (2018)

Chapter 3 investigates from an empirical perspective the role of disclosure information in the stability of informal coordination agreements.[6] Particularly, this chapter focuses in the economic effects of the announcement and the put into effect of a non-transparency policy implemented in the Colombian wholesale electricity market in 2009.

We propose an identification strategy for isolating the effect of a coordinating relation from the confusion factors related with unilateral market power. The characteristics of the reform of the transparency policy allow to link the simple announcement of the policy change with the collapse of a coordinated strategy of private firms in a repeated interaction context. In this aspect, our approach is similar to the study of the impact of the entry of purely financial players in electricity markets presented by Mercadal (2019). This author relates the anticipation responses of generation firms with deviations from the static Nash equilibrium. We use several empirical tools to assess the impact of the simple announcement of a modification in the transparency conditions on the average bidding price of private firms. We present a empirical analysis of the average bidding price data over August 2008 - July 2009.

This chapter contributes to the literature of electricity markets design documenting and studying for the first time a quasi-natural experiment of change in transparency conditions. The findings and methodology of this paper also contribute to the empirical literature on informal self-enforcement relationships between firms. The rationale of distinguishing between the effects of the announcement and the effect of the occurrence of a determinant fact may be applied in several contexts to identify the existence of informal self-enforcement relations in a context of repeated interaction. Chapter three documents an economically and statistically significant decrease in bidding prices by private firms during the period between the announcement and the implementation of the policy. We interpret these findings as suggestive evidence of the existence of an informal coordination relation between private firms in the Colombian wholesale electricity market.

sumption and stochastic fluctuations of demand as in the case of electricity markets. Staiger and Wolak (1992) investigates theoretically the reaction of collusive pricing in the framework of capacity constraints and demand uncertainty. On the side of empirical studies in this branch of the literature there are two important papers. Fabra and Toro (2005) use a time series Markov-switching model for analyzing the properties of the collusive strategy of several firms in the Spanish electricity market. Puller (2007) study the pricing pattern of firms during the existence of the California wholesale electricity market. He finds that several firms raised prices above the unilateral market power. However, these prices did not reach the joint monopoly price.

[6] In this thesis we will refer to market transparency as the ability of firms to observe market outcomes and the prices and sales of their competitors.

2. Private management and strategic bidding behavior in electricity markets

2.1. Introduction

In this paper I adopt a policy evaluation approach based on double difference (or difference-in-difference) techniques to test the hypothesis that the bidding prices of generation units change following a shift from public to private management. I draw on bidding data and information concerning changes in management structures for the period 2006 to 2017 in the Colombian wholesale electricity market.

The objectives of this paper are twofold. First, it seeks to contribute to empirical evidence on the effectiveness of reforms adopted in the electricity sector in the 1990s. The aim here is to determine whether privatization is the right decision in an environment of imperfect competition. Specifically, this study approaches privatization as a public policy program and assesses the effect of a shift to private management on the competitive behavior of electric power generators. I seek to answer the question: Is the price bidding of generation units more aggressive after switching from public to private management? Second, this study seeks to provide new insights into how private and public enterprises compete in an oligopolistic environment. Specifically, I wish to determine whether the empirical evidence is coherent with the theoretical models that study competition between private and public firms and those that study imperfect competition in electricity markets.

In relation to the first of these objectives, it should be noted that privatization was first adopted as an instrument for market liberalization in the electricity industry during the reforms implemented in the 1990s. Several authors have studied the relationship between market-oriented reforms and privatization, both theoretically (Sappington and Stiglitz, 1987; Shapiro and Willig, 1990; Tirole, 1991; Roland, 2002) and empirically

(Lopez-de Silanes et al., 1997; Frydman et al., 1999; La Porta and Lopez-de Silanes, 1999; Megginson and Netter, 2001).

Tirole (1991) concluded that a competitive market structure must necessarily precede privatization. The argument is that although private firms pursue cost reduction, they do not pursue a higher level of competition because this reduces their market power and, hence, their profits. In the specific case of electricity generation services, once the possibilities of scope economies with other segments of the production chain and scale economies had been ruled out, competition was introduced and privatization served as a tool for ownership separation and the entry of new competitors (Green and Newbery, 1992; Newbery, 2005). And, moreover, once the reforms had produced markets based on competition and price signals, the implicit promise of privatization was a reduction in electricity generation costs. Furthermore, such a reduction would offset the strategic component of potential unilateral market power.

Accordingly, thanks to the reforms, the final consumer observes more cost representative prices, and the overall efficiency of the sector improves (Joskow, 1998). However, after more than 30 years of liberalization and privatization experiences, market power issues of various kinds have been identified in many electricity markets (Joskow et al., 2008). This paper gathers empirical evidence to establish whether private management has effectively promoted more competitive price bids, where "competitive" is understood to mean more cost reflective, and not necessarily lower, price bids.

As for the second objective, it is worth stressing that the question studied herein bridges two branches of literature: that of mixed oligopoly theory, which studies how private and public companies interact in an environment of imperfect competition; and that of empirical studies of comparison between public and private firms, which examine the consequences of privatization in the framework of the wave of the reforms of utilities in the 1980s and 1990s.

The main concerns of the mixed oligopoly literature have been (1) the optimal level of privatization (De Fraja and Delbono, 1989; Matsumura, 1998); (2) the role of public enterprises as an instrument of economic policy (Beato and Mas-Colell, 1984; Cremer et al., 1989); and (3) the incentive compatibility between the objectives of corporate managers and shareholders of both private and public firms (Barros, 1995). However, few papers have concerned themselves with the empirical differences in strategic behavior in a mixed oligopoly environment (Barros and Modesto, 1999).

On the other hand the empirical literature of comparison between state-owned and privately-owned firms has mostly focused in their relative performance regarding efficiency and profitability (Frydman et al., 1999; La Porta and Lopez-de Silanes, 1999). These studies aims to investigate whether the processes of privatization have been successful in transforming former state owned enterprises into more efficient and more competitive private enterprises (Megginson and Netter, 2001). However, in the majority of cases these studies make comparisons without taking account if the form of production is a natural monopoly or if the activity is subject to regulation. This paper contributes to the literature because its approach adopt two novel elements. First, it is more focused in behavioral differences and allocative efficiency than in performance differences and productive efficiency. Second, it compares the behavior of private and public firms in an environment in which they compete in a daily basis in the same relevant market.

This study aims to establish whether there is any coherence between the empirical evidence and the behavioral differences of public and private companies as identified by mixed oligopoly models. It seeks to verify the congruence of the data with theoretical predictions made about the bidding behavior of the firms, according to their forward contract positions in the market (Newbery, 1998; Green, 1999). This paper focuses on the behavioral changes related to the switch of management from public to private, a question examined by only a few papers to date. Although previous studies have focused on the impact of the implementation of reforms in the electricity industry from a policy evaluation perspective when taking a double difference approach (Fabrizio et al., 2007; Davis and Wolfram, 2012), none of them have addressed the potential effects of private management on bidding prices in an environment of imperfect competition.

The rest of this paper proceeds as follows: the second section describes the main features of the Colombian wholesale electricity market and the introduction of private management structures the country's electricity generation. The third section explains the theoretical background underpinning the identification strategy used. The fourth presents a general description of the data set, delineates the identification strategy and discusses the suitability of the double difference methodology. The fifth section presents the results of the application of the double difference analysis to the price bids of the generation units that switched from public to private management. In this section, I also perform several robustness checks for different econometric alternatives. The final part summarizes the results and presents my conclusions.

2.2. Institutional context

2.2.1. Colombian electricity market reforms

To understand how the Colombian electricity generation market is structured, we need a clear overview of its institutional framework and of the direction taken by the sector's reforms implemented in the mid-1990s. The institutional structure of the Colombian electricity sector clearly reflects the spirit of the 1991 Political Constitution and Laws 142 and 143 enacted in 1994. The Constitution adopted a new model of economic development which, among other major features, opened up the public service sector to private investment, establishing as basic principles, free entry and the introduction of competition where possible. Based on this mandate, the electricity generation and retailing segments were defined as competitive, while its transmission and distribution services were defined as natural monopolies subject to regulation.

Electricity Law 143 of 1994 structured the sector's generation activities around a wholesale electricity market, organized in the form of a pool, in which generators are able to sell their energy output via bilateral forward contracts or directly on the spot market. The Colombian energy spot market operates as a first-price multi-product auction. Generators report a bid price per block of energy offered to the market operator. The aggregate supply curve is then constructed by organizing the generation units in merit order (from the cheapest to the most expensive). The equilibrium price is the minimum bid price at which the total demand for electricity can be met. All generators bidding a price below the equilibrium price are dispatched and all are paid the marginal price that clears the market. Electricity producers must bid a daily price for each of the generation units they have. For each hour of the day, the market operator determines the price that balances the supply from the generators with total demand, and the units that will be dispatched. Forward contracts between generators and traders, or those entered into directly with final customers, are permitted. This system serves as a hedging tool against market risk. The positive or negative differences between the contracted quantities and the quantities generated by each agent are settled at the spot price.

2.2.2. Transition from public to private management

As mentioned above, Public Service Law 142 and Electricity Law 143 ushered in reforms to promote private enterprise in the electricity industry. The changes in the management structures in the generation units studied herein can be accounted for in terms of privatization processes and the ending of power purchase agreements (PPAs). Privatization in the form of the sale of stakes in, or the transfer of assets from, public enterprises was not exclusive to the energy sector. Private management policy formed part of other structural reforms oriented at opening up the Colombian economy. Privatization programs were also initiated in manufacturing, natural gas, fuel distribution, water sanitization and the banking industries. This, added to the separation of the activities of vertically integrated public companies in the electricity industry, triggered a series of sales of generation assets. At the same time, central and municipal governments attracted private investment for generation services via the signing of PPAs.

The main privatization sales of Colombian generation services occurred in two waves: The first in the 1990s, before the period of analysis considered in this study, and the second in the mid-2000s. The latter were related to the liquidation processes of the vertically integrated companies that had already transferred their assets to other activities and in which only the assets of the generation segment remained to be disposed of. At the beginning of the period of analysis, in 2006, the total installed capacity of the Colombian generation market was 13.313 MW. At the end of the period of analysis, in 2017, it was 16.689 MW.

In 2007, the Pacific Energy Company (EPSA) became the new owner of the Prado Hydroelectric Power Plant (46 MW). This asset had previously been owned by the public company, Gestion Energetica (GENSA). In 2008, the Colombian Investment Company, Colinversiones (later CELSIA), acquired the assets and energy contracts of the Las Flores Thermoelectric Power Plant (160 MW), previously under the control of the public company, GECELCA. On June 30, 2010, the municipality-owned firm EMCALI sold 92% of the shares of the thermal unit Termoemcali I to the new private partners, TE Holdings Colombia S.A.S (owned by the Infrastructure Fund Colombia Ashmore I) and Maguro Ltd. The reason given by EMCALI for making this sale was to enable it to make the necessary investments in drinking water and sanitation infrastructure.

Although privatization continued in the distribution segment, only one new privatization was made in that of electricity generation in the years up to 2016. The Canadian fund, Brookfield, acquired 57.6% of Isagen which had been the property of the national government. The government's argument for selling off Isagen was to raise funds to finance third-generation road projects. Isagen is Colombia's second largest generator, accumulating a total installed capacity of 3,032 MW, of which 2,732 MW are hydraulic and 300 MW are thermal technologies. As for the PPAs, in 1995 the state-owned firm CORELCA signed a PPA for the sale of the energy from the Termobarranquilla 3, Termobarranquilla 4 and TEBSA units. In 2006, the rights of the PPA were transferred to the state-owned firm GECELCA due to the restructuring and liquidation of CORELCA. Under the PPA contract, GECELCA was made responsible for the commercial management in the wholesale electricity market of the energy generated by the aforementioned units, although the property infrastructure remained the concern of the private firm TEBSA. On April 21, 2016 the PPA was terminated and TEBSA began to participate in direct sales in the wholesale energy market.

Based on these changes, it is apparent that the transition from public to private management of the generation units analyzed herein was part of a general restructuring of the entire economic development model, in which the generation activity was just a modest part. Moreover, the reasons offered for the privatization or the change in management often differed and included such arguments as an attempt at restructuring firm processes, funding strategic assets or terminating the PPAs. As such, these privatizations can be considered exogenous to the interactions of competition in the wholesale market and to the productive performance of these units. Table 2.1 lists the generation units that have passed from state to private control in the twelve-year period of 2006 to 2017.

Given the processes of privatization and divestiture, the resulting ownership structure of the main generation companies operating in Colombia is heterogeneous in terms of the private or public nature of the main shareholders. The Colombian generation stock has a high proportion of publicly owned or mixed companies that are under the control of public entities.

2.3. The mixed oligopoly model

This section presents various theoretical predictions of the effects of private magement on bidding strategies in electricity markets. I base my analysis on the extrapolation of behavioral and cost assumuptions from mixed oligopoly studies to a simple model of best response in the context of oligopoly competition in the electricity market.

Models of mixed oligopoly necessarily entail adopting different assumptions for private and public firms. There are two basic types of difference, and several models combine them both: Namely, 1) Behavioral differences, i.e. differences in the objective function of the firms. In most cases, the mixed oligopoly models assume that private firms aim to maximize profits while the objective function of public (or mixed) firms is to maximize social welfare; 2) Costs differences, i.e. differences in productive efficiency. Typically, it is assumed that private firms operate at lower costs than public enterprises.

Table 2.1.: Privatized Generation Units 2006-2017

Date	Unit	Technology	Installed Capacity (MW)	From State Owner	To Private Owner
August 2007	Hidroprado	Hydro	56	GENSA	EPSA
August 2007	Prado IV	Hydro	5.7	GENSA	EPSA
November 2008	Termoflores	Thermal, Gas fired, combined cycle	150	GECELCA	COLINVERSIONES
June 2010	Termoemcali I	Thermal, Gas fired, combined cycle	213	EMCALI	Holdings Col., Ashmore I, and Maguro LTD
January 2016	Calderas	Hydro	26	ISAGEN (57.6% Ministry of Finance)	ISAGEN (57.6% Brookfield Fund)
January 2016	Miel	Hydro	396	ISAGEN (57.6% Ministry of Finance)	ISAGEN (57.6% Brookfield Fund)
January 2016	Jaguas	Hydro	170	ISAGEN (57.6% Ministry of Finance)	ISAGEN (57.6% Brookfield Fund)
January 2016	San Carlos	Hydro	1.240	ISAGEN (57.6% Ministry of Finance)	ISAGEN (57.6% Brookfield Fund)
January 2016	Sogamoso	Hydro	820	ISAGEN (57.6% Ministry of Finance)	ISAGEN (57.6% Brookfield Fund)
January 2016	Termocentro	Thermal, Gas fired, combined cycle	300	ISAGEN (57.6% Ministry of Finance)	ISAGEN (57.6% Brookfield Fund)
April 2016	Termobarranquilla 3	Thermal, Gas fired, simple cycle	64	GECELCA	TEBSA
April 2016	Termobarranquilla 4	Thermal, Gas fired, simple cycle	63	GECELCA	TEBSA
April 2016	TEBSA	Thermal, Gas fired, combined cycle	791	GECELCA	TEBSA

Source: own elaboration

From these different assumptions, opposite effects on pricing strategies and, hence, on competition, can arise.

The analysis for profit maximizing firms builds on the theoretical arguments proposed by (Wolak, 2000; McRae and Wolak, 2009). Assuming the firm has previously sold an amount of energy q_i^c at a fixed price p_i^c by forward contracts, the profit function is defined by the following expression:

$$\pi_i = p_i^{RD}(q_i)(q_i - q_i^c) + p_i^c q_i^c - C_i(q_i)$$

where π_i is the profit of the firm *i*, $p_i^{RD}(.)$ is the inverse residual demand function of firm *i*, q_i is the quantity sold by firm *i* and $C_i(.)$ is the total cost function of firm *i*. Note that the market clearing price and the total cost are functions of the quantity. Given that in electricity markets demand is necessarily equal to supply, at equilibrium the residual demand of firm *i* is equal to the total quantity produced by this firm: $RD_i = q_i$. From the first order conditions of the profit maximization problem, we can then obtain the following expression for the price:

$$p^{RD}(q_i) = \frac{\partial C_i(q_i)}{\partial q_i} \underbrace{- \frac{\partial p^{RD}(q_i)}{\partial q_i}(q_i - q_i^c)}_{\text{strategic element}} \tag{2.1}$$

This is the best response of a profit maximizing firm. The first term on the right-hand side of this equation is the marginal cost and the second term is the strategic component. The latter is equal to the interaction of the inverse of the slope of the residual demand curve and the net forward contract position of the firm. Thus, the greater the amount of energy sold by the firm through fixed price forward contracts, the lower the incentive to increase the spot price. It should be noted that in cases where the generator is in a short position, it has the incentive to exercise market power to reduce the price. This is the expected behavior of a private firm which, according to the mixed oligopoly assumptions, is profit maximizing.

Next, the welfare maximizing assumptions for public firms (which typify mixed oligopoly theory) are extrapolated to this simple model of electricity markets and the results compared to equation 2.1 so as to highlight the difference between private and public enterprises. The welfare function is the sum of the consumer surplus and the firms' profits:

$$W = \underbrace{\int_0^Q p\big(x(q_0)\big)\,dx - p(x)\sum_{j=0}^{N}(q_j - q_j^c) - \sum_{j=0}^{N} p_j^c q_j^c}_{\text{Consumer Surplus}} + \underbrace{\sum_{j=0}^{N}\big(p(x)(q_j - q_j^c) + p_j^c q_j^c - C_j(q_j)\big)}_{\text{Industry Profits}}$$

where $p(x)$ is the inverse demand function, Q is the equilibrium total quantity and the other variables are as described above. For convention's sake, we identify the variables of the public firm using the sub-index 0. The first three terms are the consumer surplus and the remaining are the sum of industry profits. Note that the sum of the income from the spot price and forward markets is simply a transfer from consumers to producers. Thus, this expression can be simplified to:

$$W = \int_0^Q p\big(x(q_0)\big)\,dx - \sum_{j=0}^{N} C_j(q_j)$$

From the first order conditions of the maximization of this welfare function, the following expression can be obtained for the price :

$$p(Q) = \frac{\partial C_0(q_0)}{\partial q_0} \tag{2.2}$$

This equation indicates that the best response for a welfare maximizing firm is to apply the marginal cost pricing rule. This result is coherent with the findings of Beato and Mas-Colell (1984) who demonstrated theoretically that a public firm is able to restore market efficiency by applying this pricing rule.

Equations 2.1 and 2.2 allow two potential effects of the change from public (welfare maximizing) to private (profit-maximization) management to be identified: the behavioral and the cost effects.

In the case of the behavioral effect (marginal costs being equal), the comparison of equations 2.1 and 2.2 leads to the conclusion that more cost reflective pricing (though, recall not necessarily lower pricing) is achieved by public enterprises. Note that the difference between equations 2.1 and 2.2 is the strategic component. The sign of this component depends on the difference between the total quantity produced by the firm (q_i) and its total forward contract commitments (q_i^c). Moreover, the strategic component is relevant only if the slope of the residual demand is steep enough, that is, if the new manager has sufficient market power. Hence, as far as the behavioral effect is concerned, the sign of the effect of the change from public to private management will depend on the contracting levels of the firms and their market power. For high (low) contracting levels, a negative (positive) effect is expected. The greater the market power enjoyed by the firm, the greater the magnitude of these effects.

In the case of the cost effect (assuming identical behavior of both private and public firms), the canonical assumption of mixed oligopoly models of a more cost effective performance of private firms, i.e. $\frac{\partial C_j}{\partial q_j} < \frac{\partial C_0}{\partial q_0}$, leads to the conclusion of a pro-competitive effect of private management that necessarily entails lower equilibrium prices. [1] In this scenario, the effect of switching from public to private management would be expected to lead to a decrease in price bidding.

In subsection 2.4.2., I explain the strategy for disentangling these effects and in section 2.5 I present the results.

2.4. Empirical analysis

2.4.1. Data

I assess the impact of private management on the bidding prices of generation units in Colombia by using data from the wholesale electricity market. The data set contains the daily observations of 65 generation units, owned by 25 generation firms, during the period January 2006 to December 2017. Note I only include the generation units that bid prices in the wholesale electricity market.[2] In addition, there are several units that ceased to operate and others which started operations during the period of analysis. Hence, the data constitute an unbalanced panel of 348.331 observations.

Information about daily price bids, commercial availability and sales in forward contracts (requisite information for computing the forward contract level of the unit's owner) was extracted from the website of the Colombian wholesale electricity market operator, XM. Information about changes to the administrative structures of the generation units (see table 2.1) was extracted from press releases and the websites of the current

[1] Several theories seek to disentangle the source of the cost discrepancy between private and public firms. Such studies are oriented towards examining regulated private firms (Shapiro and Willig, 1990), the effects of transition from centrally planned to market-based economies (Roland, 2002; Tirole, 1991) and the role of transaction costs on the production of private and public firms (Sappington and Stiglitz, 1987). Similarly, a large number of studies have been devoted to finding empirical evidence for this discrepancy. Although the evidence is contradictory, many of these studies identify improvements in performance following privatization (Frydman et al., 1999; La Porta and Lopez-de Silanes, 1999; Megginson and Netter, 2001).

[2] Small units (generation capacity less than 20MW) are incorporated automatically as base generation.

owners. As a time varying control variable, an estimation of the marginal costs of the generation units was used. I assume an accounting approach similar to that assumed in previous studies in the field of electricity markets (Green and Newbery, 1992; Wolfram, 1998, 1999; Borenstein and Bushnell, 1999; Borenstein et al., 2002; Wolak, 2000; Fabra and Reguant, 2014). I computed the marginal costs of thermal plants taking into account their technical parameters (heat rate), fuel costs and fuel transportation costs. The sources of the information and more detailed information concerning the assumptions for the calculation and imputation of these costs are presented in appendix A.3. It is important to bear in mind that these computations may contain some measurement error given that we approximate the fuel costs to references prices, and the cost per unit in the actual fuel supply contracts may be different.

For hydroelectric generation units, a marginal cost equal to zero is assumed. Even when this assumption may appear to be unrealistic, the use of unit fixed effects and date fixed effects in the estimation ensures I can control for time invariant heterogeneity and common time variant factors. The validity of the result relies on the assumption that the expectation of the time variant heterogeneity component of the marginal costs is zero. Table 2.2 highlights the main descriptive statistics of each of the variables included in the model.

2.4.2. Identification strategy

This paper examines private management from the perspective of the evaluation of policy impact. The differences-in-differences methodology with staggered adoption undertakes a comparison of treated and non-treated (control) groups before and after policy intervention in a context in which the date of treatment may vary by unit. Specifically, in this paper, the generation units that switched from public to private management make up the treated group while the public generation units constitute the control group. The estimation of the impact of private management on bidding prices, using this methodology, relies on the assumption that the average change between pre- and post-treatment periods on bidding prices of the units that remained public throughout the period is an unbiased estimator of the average change in bidding prices of the treated units had they continued to be managed by public companies. This in turn entails that the unobserved time variant heterogeneity of the estimation model is uncorrelated with the switch in management structures. A major concern in the application of double differences is the possibility that treatment and control groups may differ in their pre-existing character-

Table 2.2.: Variables in the econometric model

Variable	Units	Obs	Mean	Std. Dev.	Min	Max
Bid Price (b)	Pesos/KWh	348331	403.32	451.98	37.06	22552.48
Logarithm Bid Price ($Ln(b)$)	Ln(Pesos/KWh)	348331	5.51	1.01	3.61	10.02
Marginal Costs (C)	Pesos/KWh	348331	40.32	49.93	0.00	443.90
Daily Commercial Availability (A)	GWh	348331	30.14	24.04	0.00	75.22
Daily Forward Contracts (F)	GWh	348331	14.81	13.22	0.00	52.10
Index of contracting (IC)	Percentage	343860	51.78	23768.57	0.00	1.33E+07
Indicator of under contracting (L)	Dummy	343860	0.88	0.33	0.00	1.00
Indicator of over contracting (H)	Dummy	343860	0.12	0.33	0.00	1.00
Control Group						
Variable	Units	Obs	Mean	Std. Dev.	Min	Max
Bid Price (b)	Pesos/KWh	277288	401.53	449.75	37.06	22552.48
Logarithm Bid Price ($Ln(b)$)	Ln(Pesos/KWh)	277288	5.51	1.01	3.61	10.02
Marginal Costs (C)	Pesos/KWh	277288	41.97	50.55	0.00	443.90
Daily Commercial Availability (A)	GWh	277288	30.24	25.57	0.00	75.22
Daily Forward Contracts (F)	GWh	277288	14.99	13.89	0.00	52.10
Index of contracting (IC)	Percentage	273227	65.05	26664.41	0.00	1.33E+07
Indicator of under contracting (L)	Dummy	273227	0.85	0.36	0.00	1.00
Indicator of over contracting (H)	Dummy	273227	0.15	0.36	0.00	1.00
Treated Group						
Variable	Units	Obs	Mean	Std. Dev.	Min	Max
Bid Price (b)	Pesos/KWh	71043	410.31	460.51	40.57	12387.83
Logarithm Bid Price ($Ln(b)$)	Ln(Pesos/KWh)	71043	5.53	1.01	3.70	9.42
Marginal Costs (C)	Pesos/KWh	71043	33.91	46.87	0.00	420.11
Daily Commercial Availability (A)	GWh	71043	29.76	16.83	0.00	69.70
Daily Forward Contracts (F)	GWh	71043	14.10	10.13	0.00	35.91
Index of contracting (IC)	Percentage	70633	0.45	0.67	0.00	155.98
Indicator of under contracting (L)	Dummy	70633	0.98	0.13	0.00	1.00
Indicator of over contracting (H)	Dummy	70633	0.02	0.13	0.00	1.00

Source: XM - Colombian Market Operator

istics resulting, in this instance, in different bidding price strategies even if the former had not undergone private managed. Specifically, generation units may differ in two key features: i) technological characteristics, such as fuel type, installed capacity and potential for supplying auxiliary services; and ii) the forward contract exposure position of the unit's owner. Different initial conditions with regard to these characteristics could account for the different time paths of the treatment and control groups, rather than the switch to private management. In order to address this concern, in the base line estimation, I apply matching methods in order to pair observations from the treatment group with similar observations in the control, given several observable initial characteristics. First, the criteria for considering the plants in the treated and control groups as similar need to be established. Rosenbaum and Rubin (1983) proposed calculating the probability of being treated conditional on the individuals' pretreatment observable characteristics and, then, using this probability (propensity score) as criteria for matching observations. In the framework of this research, I calculate the propensity score with a cross-sectional probit model:

$$Pr\big[T_i = 1|X_i\big] = \Phi\big(X_i^T \beta\big)$$

where $Pr\big[T_i = 1|X_i\big]$ is the probability of switching from public to private management conditional to the observable variables, T_i is a dummy that takes the value of 1 if the unit was switched to private management during the period of analysis and 0 otherwise, $\Phi(.)$ is the cumulative distribution function for the standard normal and X_i is a set of key pretreatment observable characteristics: the type of fuel used by the unit, the potential for supplying an automatic generation control service, the installed capacity, the expected daily amount of energy which the unit can supply in hydro critical conditions, and the average contract position of the firm in the years 2005 and 2006, prior to any privatization process analyzed in this study.

Having calculated the propensity score, I considered as control group those units that did not switch to private management and lie in the common support region, i.e. the public plants for which the probability of their being privatized is positive, according to the probability distribution associated with the propensity score model. The observations of units that did not switch management to private and are outside the common support were dropped. In the robustness checks subsection (2.5.2.), I examine the results of the estimation without applying propensity score matching and using more stringent matching criteria, such as nearest neighbor.

As stated above, the first objective of this empirical analysis is to establish whether private management has a significant effect on the bidding price and, if so, its magnitude. The second objective is to identify the drivers of the potential changes by exploiting information about forward contracts in the Colombian wholesale electricity market. Finally, the paper explores the features of the dynamic effect of privatization, understood as the duration, trend and variability of the impact over time. In order to tackle the first objective of this paper, i.e. to establish the net average effect of privatization on bidding prices, I propose estimating the following two-way fixed effects linear regression model:

$$b_{it} = \beta_0 + \beta_1 D_{it} + \sum_{k=2}^{N} \beta_k x_{it}^k + \gamma_i + \sigma_t + \epsilon_{it} \tag{2.3}$$

where b_{it} is the level or logarithm of the daily bidding price submitted by unit *i* in the day *t*; D_{it} is a dummy variable that takes the value of 1 when unit *i* is privately managed on the day *t*; x_{it}^k is a vector of time variant heterogeneous variables, in this case the marginal cost;γ_i is a generation unit fixed effect that controls for non-observable time invariant heterogeneity; and σ_t is a date fixed effect which controls for the common time variability. Finally, ϵ_{it} is the generation unit time-varying error, which is assumed to be uncorrelated with D_{it} and the vector X_{it}. Note that in the base line estimation, the control group consists of the public generation units; hence,D_{it} takes the value of one after unit *i* switched to private management. The parameterβ_1 represents the double difference effect of the change from public to private on price bids. The logarithmic specification of the dependent variable facilitates interpretation of this parameter as a percentage change.

Second, section 2.3 argued that the behavioral effect on the bidding strategy of a change in management depends on the capacity of private managers to use their market power. To capture this heterogeneity, the treatment group is split in two subgroups: i) The first includes the units that changed to being a large private incumbent and ii) the second includes the units that changed to being a new private competitor in the market. Note that the management changes affecting the first group entail an increase in market concentration while those affecting the second decrease it. Hence, the distinction between the two subgroups is based on the presumption that large private incumbents increase their market power with a change of management while new competitors do not.

In order to capture these differences in behavioral reaction due to market power, I propose estimating the following two-way fixed effects linear regression model:

$$b_{it} = \beta_0 + \beta_1 D_{it} \cdot Big_{it} + \beta_2 D_{it} \cdot New_{it} + \sum_{k=3}^{N} \beta_k x_{it}^k + \gamma_i + \sigma_t + \epsilon_{it} \tag{2.4}$$

where Big_{it} is a dummy variable that takes the value of 1 when unit *i* is privately managed by a big incumbent private firm on the day *t* and zero otherwise. New_{it} is a dummy variable that takes the value of 1 when unit *i* is privately managed by a new competitor in the market in day *t* and zero otherwise. The remaining variables have the same meaning as in equation 2.3.

Third, to identify the coherence of the effect of private management due to behavioral changes and the theoretical predictions presented in section 2.3., it should be borne in mind that in the case of the Colombian market the information about the forward contract position of the electricity generator is observable for the econometrician. This makes it possible to identify two different impacts of private management (parameters) corresponding to the different requirements of forward contracts. To capture any differences, I created two dummy variables corresponding to high and low levels of forward contracting, i.e. the dummy variable L_{it} (H_{it}), takes the value of one if the owner of the unit has a low (high) level of forward contracts, and zero otherwise . In order to consider the forward contracting position of a firm as low or high, I calculate an indicator for the level of contracting based on the hourly information of forward contracts and commercial availability. For each day, I calculate the sum for the 24 hours of forward contracts and commercial availability.

$$F_{jt} = \sum_{h=1}^{24} F_{jth}$$

$$A_{jt} = \sum_{h=1}^{24} \sum_{i=1}^{N_j} A_{ijth}$$

where F_{jth} is the amount of energy committed in forward contracts in in hour *h* of day *t*, for firm *j*. A_{ijth} is the commercial availability of unit *i* owned by firm *j* in hour *h* of day *t*. N_j is the number of units owned by firm *j*. I calculate the index of contracting IC_{jt} of firm *j* in day *t*, as the ratio between daily forward contracting and the daily sum of commercial availability:

$$IC_{jt} = \frac{F_{jt}}{A_{jt}}$$

This can be interpreted as the fraction of the daily commercial availability of a firm that is committed to forward contracts. I consider the contracting position of a firm as high (low) when the value of the IC_{jt} of firm *j* is greater (less) than the average IC_{jt} of private firms prior to the first period of treatment. Here, this value is 0.26. Subsequently, I apply each of these contract position dummies to the treatment dummy, replacing the unique treatment variable for its interactions with each of the contract position dummy variables. Accordingly, I estimate the following two-way fixed effects model:

$$b_{it} = \beta_0 + \beta_1 D_{it} \cdot L_{it} + \beta_2 D_{it} \cdot H_{it} + \sum_{k=3}^{N} \beta_k x_{it}^k + \gamma_i + \sigma_t + \epsilon_{it} \tag{2.5}$$

where L_{it} is the low contracting position dummy, H_{it} is the high contracting position dummy,x_{it}^k is a vector of observed time variant variables that can affect the price bids of unit *i* on day *t*: marginal costs and forward contracting. The remaining variables are the same as in equation 2.3. Table 2.2 shows that the IC_{jt} for the control group presents notable outliers. These outliers are attributable to the extremely low values of the denominator. For this reason, I opt to exclude the observations for which the A_{jt} is less than 5% of the maximum A_{jt} for firm *j*, that is, I exclude the observations if $A_{jt} < 0{,}05 \cdot \max_t(A_{jt})$.

Concerning the validity of the results of the models estimated in equations 2.3, 2.4 and 2.5, a key assumption is the lack of significant changes in marginal costs or in the strategic component due to time variant unobservable heterogeneity attributable to other events that might alter the relative bidding behavior of the firms around the time they switched to private management. Specifically, a major El Niño event occurred between November 2014 and May 2016. [3] This period coincides with two shifts in management structure: the sale of ISAGEN shares and the finalization of the PPA signed with the TEBSA. In the following sections, I present evidence to show that the occurrence of this event does not invalidate the results.

2.4.3. Parallel trends

As discussed above, the correct identification of the effect of a management switch using the double difference estimator relies on the assumption that the average bidding prices of public generation units in post-private management periods are an unbiased estimator

[3]The drop in rainfall caused by the El Niño phenomenon has a significantly negative impact on the availability of hydro generation resources. This translates into significant price changes on the wholesale energy market.

of the average bidding prices of the privatized units had they not been privatized. Given the impossibility of obtaining data for this counter-factual, statistical testing of this assumption is not feasible. However, the recent literature on the use of double differences performs statistical tests of parallel trends in the dependent variable between treatment and control groups prior to the intervention. To do likewise, I compare the bidding price of public generation units with the average bidding price of the units that were privatized prior to this change (treated before treatment - TBT group).

First, I carry out a graphical analysis to identify any marked differences. The graphs in figure 2.1 show the monthly average bid (panel a) and bid logarithm (panel b) for both the control and treatment groups prior to private management. Both series are noisy and it is not possible to identify clear differences between the time trends of each group simply by inspection. As for the potential effect of the 2014-2016 El Niño event, no clear break can be identified in the differences presented by the two series during this period.

Second, I implement a fixed effects regression, taking as independent variables the interactions of the linear and quadratic time trends and dummies for the control group and the TBT group, i.e.:

$$b_{it} = \beta_0 + \beta_1^T D^T \cdot T + \beta_2^T D^T \cdot T^2 + \beta_1^{NT} D^{NT} \cdot T + \beta_2^{NT} D^{NT} \cdot T^2 + \gamma_i + \epsilon_{it}$$

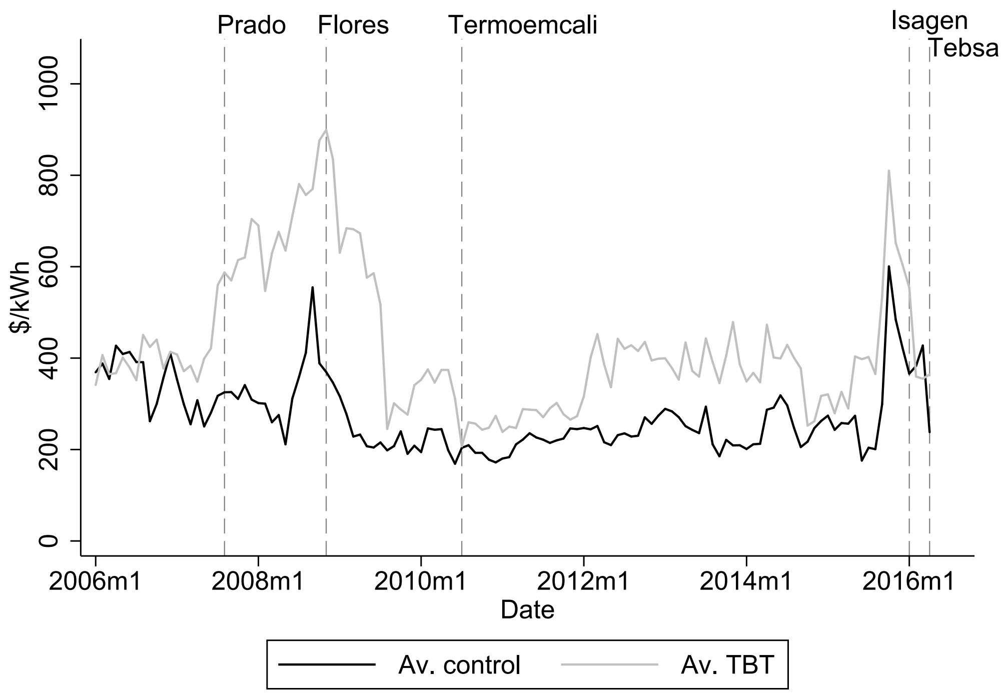
where T is the linear time trend, D^T is a dummy variable that takes the value of 1 when unit *i* is in the group of units that are to be private managed ; D^{NT} is a dummy variable that takes the value of 1 when unit *i* is in the group of non-switched units that remain public throughout the period of analysis and the remaining variables are the same as in equation 2.3. Later, I tested the null hypothesis: Ho: $\beta_1^T = \beta_1^{NT}$ and Ho: $\beta_2^T = \beta_2^{NT}$. Table A.1 in appendix A.1 shows the results.

The coefficients for both interactions point to a very uncertain estimation and the test for equality of coefficients indicates that there is no statistical evidence of differences between the two groups.

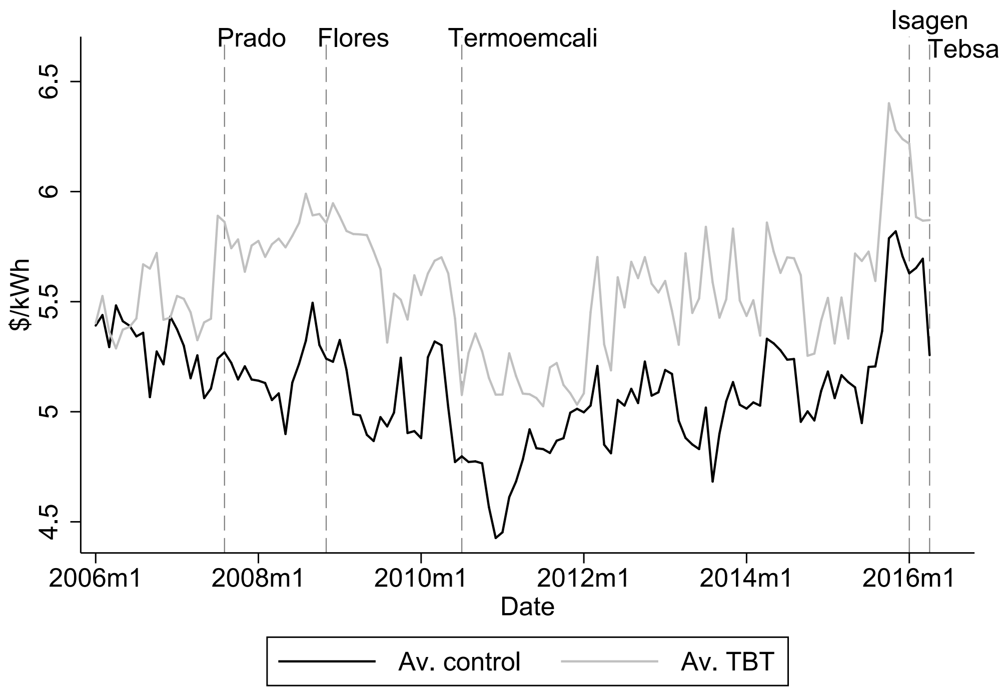
Finally, given that the parallel trend assumption should be met in relation to the moment of application of the policy and that I have different dates for the switch in management structures, I checked the relevance of differences between the treatment and control groups for the 72 months prior to the treatment date. I adopt a monthly version of the approach suggested by Galiani et al. (2005). This involves performing a two-way fixed effect estimation of the panel data, including dummy variables for each group (control and TBT), for each lag period. In this case, I estimated a coefficient for each group for

Figure 2.1.: Time series treatment and control groups

(a) Bids



(b) Bids logarithms



Source: Data from XM - Elaboration: Author.

the 72 months prior to the change to private management. The model estimated is:

$$b_{it} = \beta_0 + \sum_{l=1}^{72} \beta_l^T D_l^T + \sigma_t + \gamma_i + \epsilon_{it} \tag{2.6}$$

where D_l^T is a dummy variable that takes the value of 1 when the unit i is in the group of units that are going to switch from public to private and the day t is in the l month previous to the switch to private. The remaining variables have the same meaning as in equation 2.3. For this regression it was necessary to drop the treated observations in the post-treatment period. Figure 2.2 presents the results of the test for the differences of non-switched and switched to private groups, for each lag of the month to the treatment date.

Overall, it is only possible to reject the null hypothesis of a difference equal to zero in less than 10% of the months prior to treatment. As for the potential effect of the El Niño event, the pretreatment period is sufficiently long to capture differences in the series before and after the onset of the 2014-2016 event. The onset of the El Niño phenomenon is around 14 to 17 months prior to changes in the management of ISAGEN and TEBSA. There are no major changes in the differences observed between the treated and control groups in the months coinciding with this El Niño event. This suggests that the climatic event did not influence the difference in average bidding prices between the control and treatment groups. Based on these results, the assumption of parallel trends of the treatment and control groups seems reasonable.

2.5. Results

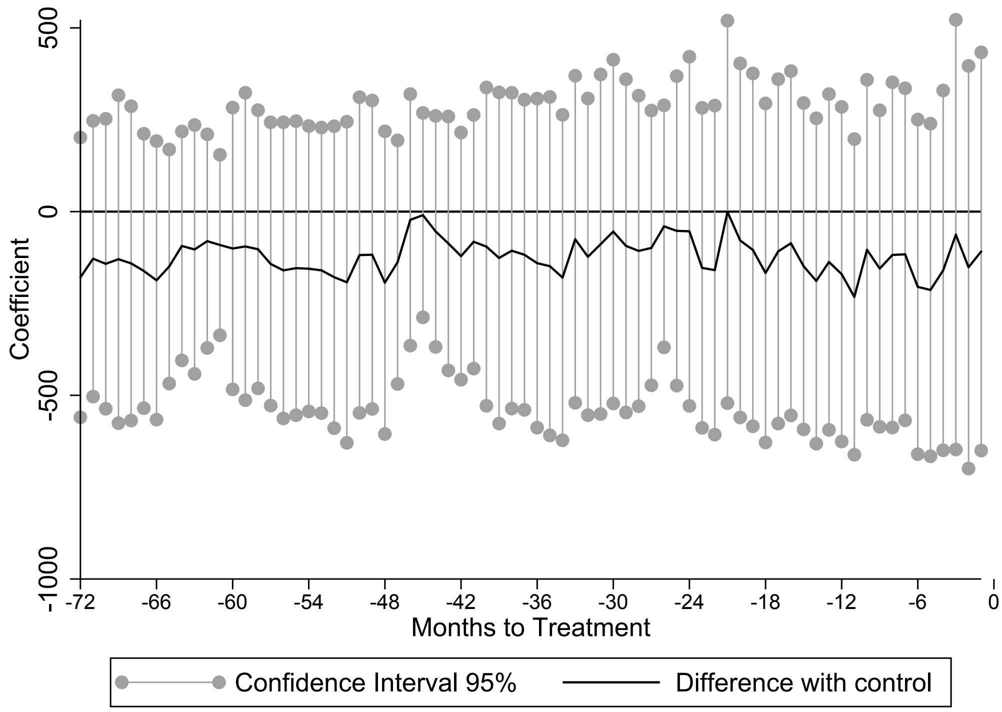
2.5.1. Baseline estimation

In this section the double difference models described in subsection 2.4.2 above are applied to the data set for the wholesale electricity market in Colombia. Given the large number of time controls applied, I adopted the procedure for estimating high-dimensional fixed effects models proposed in Correia (2017). Table 2.3 displays the results of the baseline estimate of the models in expressions 2.3 and 2.4.

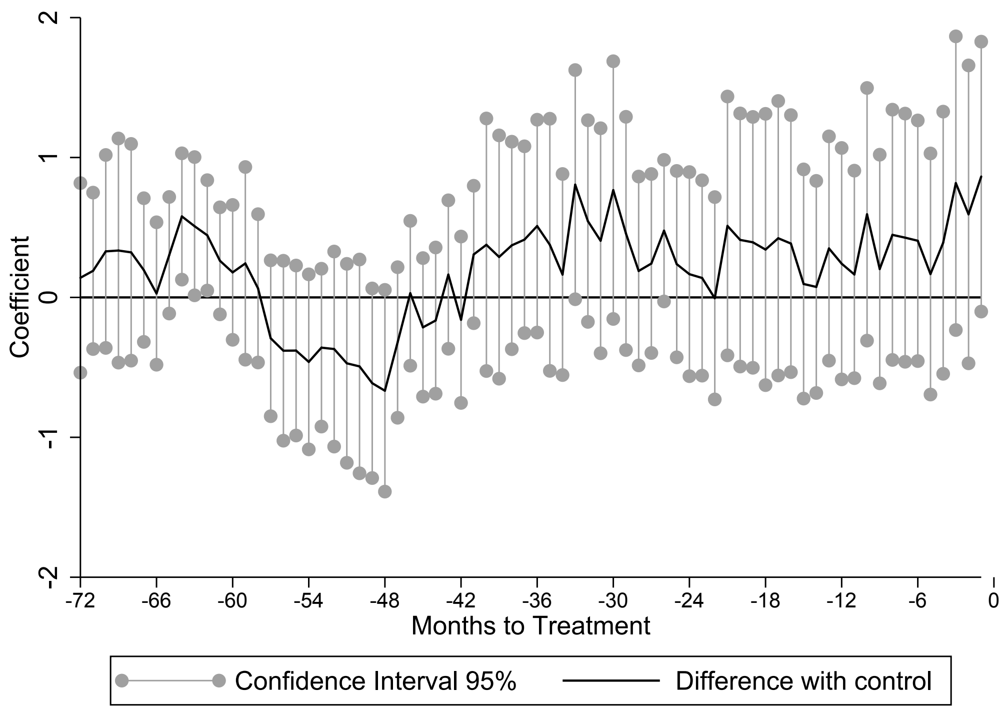
It is evident that the general effect of switching to private management on price bids is economically important but highly uncertain. For all the treated generation units I found an increasing effect around the 20% of the bidding price. However, when distinguishing between the changes to large incumbents and those to new competitors, a marked

Figure 2.2.: Parallel trends in pre-treatment months

(a) Bids



(b) Bids logarithms



Source: Data from XM - Calculations and elaboration: Author.

positive economic impact on the bidding strategy of the latter group can be observed. This impact reaches around the 90% of increase of the bidding price. The effect of the entry of new private competitors is economically non-significant and highly uncertain, the percentage increase in the bidding price related with it is around 3%. These results suggest that the strategic component related to market power matters.

In relation to the dynamic effects of private management, I explored the duration, trend and stability of the impact around the time of the switch from public to private management. To do so, I created a treatment dummy variable for each of the 24 months before and after the change in management structure, according to the following modification of the model proposed in expression 2.3:

$$b_{it} = \beta_0 + \sum_{l=-24}^{24} \alpha_l (D_{it} \cdot Z_{itl}) + \sum_{k=1}^{N} \beta_k x_{it}^k + \gamma_i + \sigma_t + \epsilon_{it} \tag{2.7}$$

where α_l is the average impact l months before (or after) private management, Z_{itl} is a dummy that takes the value of one if unit i in moment t switched to private management l months before (or after). The remaining variables and parameters are the same as those in equation 2.3. The results of the estimation of this model for the logarithm of the bidding price are presented in figure 2.3. [4]

In the estimation that does not discriminate between large incumbents and new competitors, a clear positive jump can be seen in the month of the switch to private management, which is statistically significant for the first three months. After this, the effect slowly decreases and even becomes negative after 15 months. This suggests that although the average impact of the shift from public to private management is positive and statistically significant in the short run (first three months), this impact decreases in the long run and exhibits a clear decreasing trend over time.

These results can be interpreted in relation to the hypothesis that privatization may yield cost savings because of the greater efficiency achieved in the management of operations and contractual negotiations by private companies. The changes associated with these factors can be expected to be gradual, stable and, eventually, to reach a point of exhaustion. Assuming that privately managed firms expect to become net sellers of energy,[5] the pattern presented in figure 2.3 is congruent with the hypothesis of an initial counter-competitive strategic impact that is gradually offset by the greater cost reduc-

[4] The results for the bidding price as dependent variable are presented in panels a, b and c of figure A.2 in appendix A.2.

[5] Note the average IC_{it} for private firms during the analysis period is 0.37.

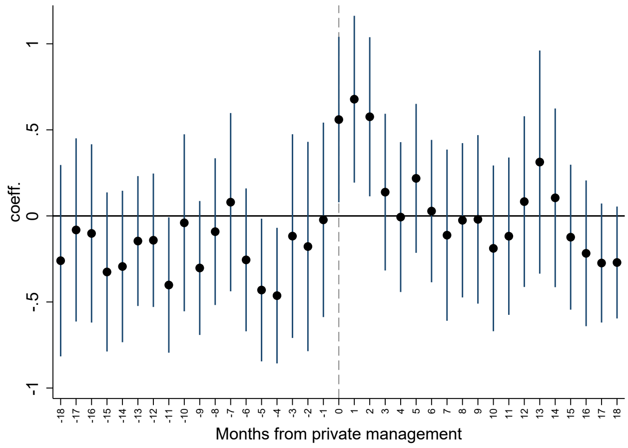
Table 2.3.: Impact of private management - Bid price and Logarithm

	(1) Bid	(2) Bid	(3) Bid	(4) Bid	(5) Ln (Bid)	(6) Ln (Bid)	(7) Ln (Bid)	(8) Ln (Bid)
Change to	86.730				0.183			
Private	(68.794)				(0.119)			
Ch. to P.		339.560***		358.829***		0.653***		0.642***
Small to big		(88.854)		(59.207)		(0.162)		(0.117)
Ch. to P.			-30.361	-4.622			0.014	0.029
New comp.			(42.538)	(53.015)			(0.106)	(0.111)
Marginal Costs	-2.414***	-1.847	-2.794***	-2.332**	-0.007***	-0.007***	-0.008***	-0.007***
	(0.846)	(1.110)	(0.870)	(0.882)	(0.002)	(0.002)	(0.002)	(0.002)
Unit FE	Y	Y	Y	Y	Y	Y	Y	Y
Date FE	Y	Y	Y	Y	Y	Y	Y	Y
N	90874	54683	81409	90874	90874	54683	81409	90874
R-sq	0.360	0.360	0.441	0.368	0.556	0.539	0.593	0.560

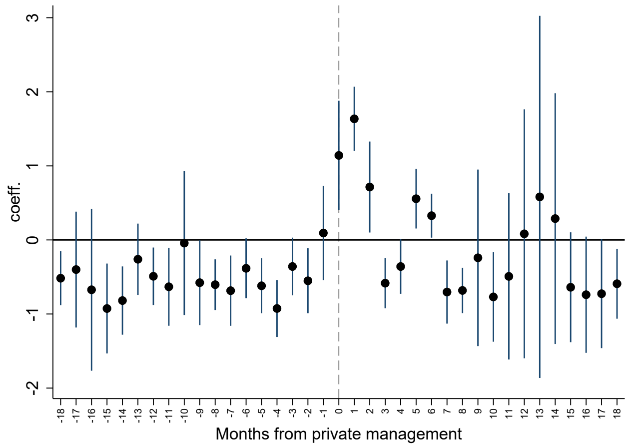
Note: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%).
Standard errors in parentheses clustered by generation unit.

Figure 2.3.: Dynamic effects of private management

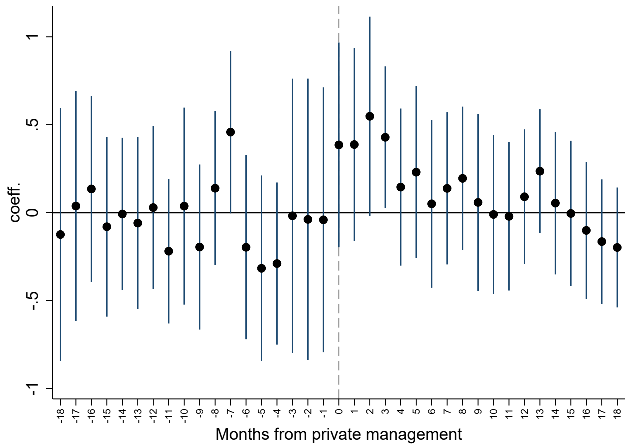
(a) All



(b) Big Incumbents



(c) New competitors



Source: Data from XM - Calculations and elaboration: Author.

tions implemented by the private manager. This scenario supports the hypothesis that both components are relevant for explaining the differences in bidding prices between private and public enterprises.

However, this narrative presumes that firms managed privately expect to achieve positive net sales of energy on the wholesale market. For this reason, I performed additional estimates corresponding to two different impacts depending on the level of forward contracting (low or high) of the owner of the generation unit. In this way, I am able to verify the coherence of the results with the predictions of equations 2.1 and 2.2 discussed in section 2.3. Table 2.4 shows the results of the estimation of the model applied to specific situations in which the private owners of the treated units have low or high forward sales, as stated in expression 2.4 in subsection 2.4.2.

In the case of firms with low levels of forward contracting , columns 1 and 5 in table 2.4 show an economically significant positive effect with low levels of uncertainty. When the treatment group is split between large incumbents and new competitors, although I found the expected effect for both subgroups, that of the former was greater and less uncertain than the effect of the latter.

According to these results, when producers face low levels of forward contracting, the privatization of generation units leads to an increase in bidding prices. These results are consistent with the theoretical predictions of the model of incentives to exercise market power proposed by Wolak (2000, 2003).

In contrast, in the case of situations of high levels of forward contracting, a negative net average effect of private management on bidding prices can be detected. This is economically relevant with low levels of uncertainty for the whole sample and the subgroups of large incumbents and new competitors.

Given these results, we incorporate the level of forward contracting in the analysis of duration, trend and stability of the impact for the 24-month period either side of the switch to private management. Thus, I interacted the variables of low (L_{it}) and high (H_{it}) levels of contracting with the lags/leads (Z_{itl}) both 24 months before and after the change in management structure, according to the following modification of the model expressed in equation 2.5:

$$b_{it} = \beta_0 + \sum_{l=-24}^{24} \alpha_l^L (D_{it} \cdot Z_{itl} \cdot L_{it}) + \sum_{l=-24}^{24} \alpha_l^H (D_{it} \cdot Z_{itl} \cdot H_{it}) + \sum_{k=1}^{N} \beta_k x_{it}^k + \gamma_i + \sigma_t + \epsilon_{it} \quad (2.8)$$

where α_l^L is the average impact l semesters after (or before) private management with low levels of contracting, α_l^H is the average impact l semesters after (or before) private management with high levels of contracting. x_{it}^k is a vector of time variant observed variables that are not common to all the units: marginal costs and forward contracting. The remaining variables are the same as those in expression 2.5. I perform this estimation for the whole sample and for the sub-samples of large incumbents and new competitors. Figure 2.4 presents the results for the estimation of the logarithmic model.[6]

Regarding the estimation for the whole sample, in the months previous to the switch to private management there is no a clear differences in the pattern of bidding between low and high forward contracting episodes. After private management, the coefficients for low contracting locate systematically in the positive region and the coefficients for high contracting locate in the negative region.

The bidding pattern corresponding to days of low levels of contracting locates in the positive region immediately after the change to private management. As in the estimation of the model in expression 2.7 (which does not consider forward contracting), the first three months of private management present positive coefficients with low levels of uncertainty. In the case of bids made during days of high forward contracting, it is evident that following the change to private management the coefficients locate in the negative segment. Although the first four months are uncertain and close to zero, in subsequent months these coefficients present more markedly negative values. When the sample is split between the large incumbents and new competitors, two different patterns are observed and it is evident that the general pattern observed in panel a of figure 2.4 is driven by that of the new competitors.

Prior to private management, the first subgroup shows negative differences with respect to the control group, especially on days of low levels of forward contracting. During the first three months of private management, the bids jump to reach positive and statistically significant values for both high and low forward contracting positions. During the first nine months of private management, the bidding strategy in both forward contracting positions seems to follow the same pattern. After the ninth month, the coefficients no longer present a clear pattern. In contrast, the group of new competitors present an unequivocal pattern of different bidding strategies depending on the forward contracting position. As predicted by the theory of incentives to exercise market power, private managers increase their bids when their contract obligations are low and decrease their bids when contract obligations are high. These results indicate that the firms' level of

[6]The results for the model with bids as the dependent variable are presented in panels d, e and f of figure A.2 in appendix A.2. Although the results are more uncertain, the model presents the same patterns as those of the logarithmic model.

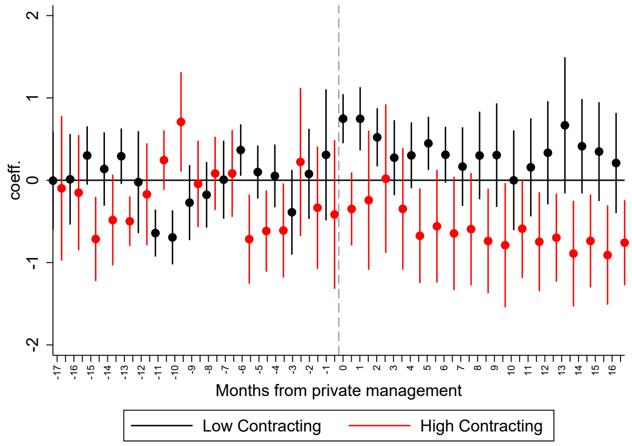
Table 2.4.: Impact of private management and forward contracts

	(1) Bid	(2) Bid	(3) Bid	(4) Bid	(5) Ln (Bid)	(6) Ln (Bid)	(7) Ln (Bid)	(8) Ln (Bid)
Ch. to P./C. Low	177.05*				0.38**			
	(86.57)				(0.15)			
Ch. to P./C. High	-190.52*				-0.46***			
	(100.66)				(0.15)			
Ch. to P./C. Low		402.67***		419.91***		0.76***		0.75***
Small to big		(111.19)		(83.43)		(0.18)		(0.13)
Ch. to P./C. High		-149.42*		-155.92*		-0.34**		-0.33**
Small to big		(77.23)		(80.51)		(0.13)		(0.14)
Ch. to P./C. Low			78.57	91.69			0.29	0.29
New comp.			(100.89)	(98.14)			(0.22)	(0.22)
Ch. to P./C. High			-210.89	-189.40			-0.57**	-0.54**
New comp.			(175.82)	(174.82)			(0.26)	(0.26)
Contracts Low	61.59	76.43	66.99	60.11	0.30	0.35	0.31	0.30
	(68.00)	(65.97)	(58.61)	(60.68)	(0.20)	(0.20)	(0.19)	(0.19)
Marginal Costs	-2.93***	-2.25**	-3.33***	-2.84**	-0.01***	-0.01***	-0.01***	-0.01***
	(0.93)	(0.90)	(1.04)	(1.01)	(0.00)	(0.00)	(0.00)	(0.00)
Unit FE	Y	Y	Y	Y	Y	Y	Y	Y
Date FE	Y	Y	Y	Y	Y	Y	Y	Y
N	89607	53484	80174	89607	89607	53484	80174	89607
R-sq	0.36	0.34	0.44	0.36	0.56	0.53	0.59	0.56

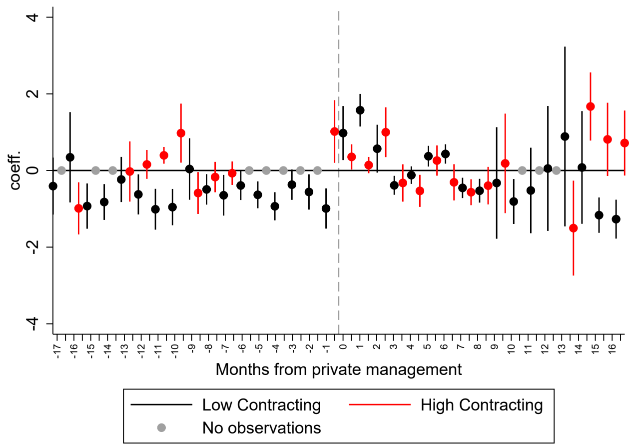
Note: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%).
Standard errors in parentheses clustered by generation unit.

Figure 2.4.: Dynamic effects and forward contracts

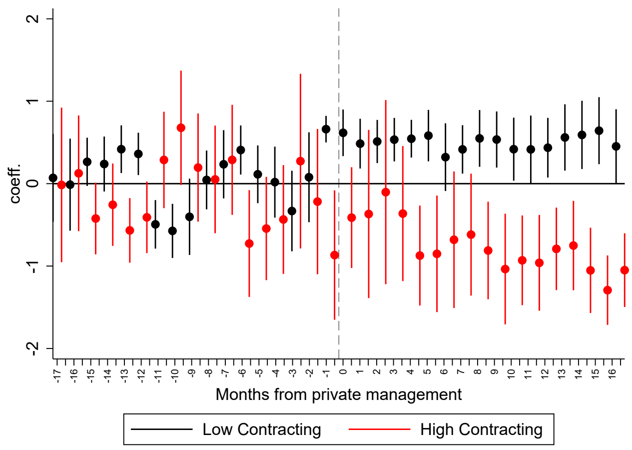
(a) All



(b) Big Incumbents



(c) New competitors



Source: Data from XM - Calculations and elaboration: Author.

forward contracting is a key element in understanding the bidding strategy of privately managed firms and the differences in relation to the bidding behavior of public firms. In addition, these findings allow me to clarify the explanation for the patterns found in figure 2.3 and the hypothesis of initial counter-competitive effects and subsequent cost reduction attributable to the change to private management.

The findings in table 2.4 and panels a and c of figure 2.4 show that the pattern found in figure 2.3 reflects the composite effect of two strategies: The bidding behavior on days of low levels of forward contracting and the behavior on days of high levels of forward contracting. These results support the hypothesis that the reduction in average bidding prices several months after the switch to private management can be attributed to strategic behavior rather than to a reduction in costs.

Given the rigorous time fixed effect controls applied to the estimations, the fact that the reduction in bidding price is well explained by high levels of forward contracting is inconsistent with the hypothesis that the driving factor of the decline in bid prices following private management is the gradual reduction in costs. It should be noted that the estimated magnitude of the increase in bidding prices for days of low levels of contracting — c. 38% — and that of the decrease for days of high levels — c. 46% — are economically significant. It is implausible that such changes are attributable to a cost difference generated by improvements in the operative management of the units and a more efficient negotiation of fuel contracts. Studies that evaluate the impact of the implementation of liberalization on productive performance in electricity markets suggest that effects of this type are modest. Fabrizio et al. (2007) assessed the impacts of liberalization on the efficiency of thermal power plants in the US. They found efficiency gains from liberalization of around 3 to 12% for labor and non-fuel inputs. Davis and Wolfram (2012) evaluated the impacts of liberalization on the operating performance of nuclear plants in the US. These authors conclude that deregulation and consolidation are associated with a 10% increase in operating performance, achieved primarily by reducing the duration of reactor outages. Cicala (2015) found a fall of around 12% in the price paid for coal by deregulated generation firms after the end of cost-of-service regulation.

In contrast, the evidence found after incorporating the information of forward contracting is consistent with the theory of incentives to exert market power in electricity markets outlined in section 2.3. This predicts that the coefficient should exhibit opposite signs in different contract positions.

2.5.2. Robustness Checks

The results presented above may, however, be dependent on the particular specification of the econometric model employed. In this section I present several estimations to test the impact of changes in these specifications. Overall, the qualitative results of the model seem to be robust to the different changes. First, I estimated the model under the assumption of random unobserved heterogeneity. I performed a generalized least squares regression applying fixed effects for every week of the sample with robust standard errors clustered by unit. The results are shown in table A.2 in appendix A.2. Second, in addition to propensity score matching, another strategy for controlling for pre-existing time invariant characteristics is to allow for the inclusion of time invariant observable control variables that may lead to different time paths for the treatment and control groups. Bernardo (2018) performed an estimation of a Prais-Winsten pooled regression model which assumes an autoregressive process of order 1 and heteroscedasticity in the error term. Although this specification may be biased by unobserved time invariant heterogeneity, it allows time invariant observable control variables or initial conditions to be included, which may lead to different time paths for the treatment and control groups. I performed this type of estimation avoiding the use of the propensity score matching but including the following control variables: the type of fuel of the unit, the potential for supplying an automatic generation control service, the installed capacity, the daily amount of energy that the unit can supply in hydro critical conditions and the average contract position of the firm in the years 2005 and 2006, prior to any switching process from public to private management analyzed in this study. The results are shown in table A.3 in appendix A.2.

Third, in the baseline estimation, I applied a matching method, using as pairing criteria the common support resulting from the propensity score matching procedure. I performed several checks employing with this methodology. First, I estimated the whole sample again but ignored the results of the propensity score matching. The results for the estimation of models of expressions 2.3 and 2.4 are presented in table A.4 in appendix A.2. The results for the dynamic effects of the switch to private management are presented in figure A.3 in appendix A.2. The second robustness check related to the matching methodology concerns the estimation model of the propensity score. I repeated this estimation using a logit model to calculate the propensity score. The matching results were identical. Likewise, I performed the estimation of the propensity score using all the data as a pooled data panel. (The results can be consulted in table A.5 in appendix A.2). As a third check, I modified the criterion in order to match the observations of the treatment and control groups. Instead of using the common support of the propensity score, I considered the nearest neighbor algorithm. This seeks to identify the control observation with the closest propensity score for every privatized unit. The observations that are not matched can then be dropped. The results using the nearest neighbor criterion to select the control group are shown in table A.6 in appendix A.2. Fourth, price bid information is available for private and public firms, which means other control groups may be considered, such as: i) any units owned by the central government that did not change managers during the time analyzed; ii) any units that did not change their managers during the time analyzed regardless of their ownership type. I took these unit sets as control groups and repeated the parallel trend tests and the baseline estimation. The results are presented in figure A.1 in appendix A.2. For both sets of unit, the parallel trend tests indicate that this is a reasonable assumption. The results of the estimation of the models in Equations 2.3 and 2.4 when using these different control groups are shown in tables A.8 and A.8 in appendix A.2. I also performed an estimation of the dynamic effects of the switch to private management for both samples. The results are presented in figures A.4 and A.5 in A.2, respectively. The results of the checks described above were robust and similar to the baseline estimation.

Finally, for the baseline estimation, I performed fixed effects estimations with robust standard errors clustered by each generation unit. However, Bertrand et al. (2004) showed that serial correlation in double difference applications may distort the inference, even using robust standard errors. In order to explore the possibility of serial correlation issues provoking false positive effects in units and periods in which switching to private management did not occur, I performed several placebo tests. To check the potentially significant results on non-treated plants, I dropped the observations of treated units and applied a fictional random treatment to the non-treated sample according to different probabilities of fictional treatment (25, 50 and 75%). Later, I estimated the impact for each of the probabilities assigned. The date of treatment is random and differs for each unit. The results of the estimation are shown in table A.9 in appendix A.2. As expected, for samples in which fictional treatment is applied with probabilities of 50 and 75%, the interest coefficients are not statistically significant at conventional confidence levels. In the case of a fictional treatment being applied with a probability of 25%, statistically significant coefficients are obtained. Although opposite signs (negative) to those found in the baseline estimation are exhibited, this result warns of a potential problem of over-rejection of the null hypothesis. In order to check the robustness of the baseline estimation against this potential inferential problem, I allowed for arbitrary variancecovariance matrix within units. Athey and Imbens (2018) suggest that, in the context of difference in difference settings with staggered adoption, the clustered bootstrap variance estimator is conservative. I estimated the models specified in equations 2.3 and 2.4 applying fixed effects for every week of the sample and block-bootstrapping methods. The results are shown in table A.10 in appendix A.2. The statistical significance of the coefficients and the extent of uncertainty in the inference are similar to those in the baseline estimation. This is an indication that the inference in the baseline estimation is not affected by marked biases. However, given the data's long time dimension, the results of the difference-in-differences estimations performed in this paper should be treated with caution.

The results presented in this section suggest that the baseline estimation presented in subsection 2.5.1. is robust to different sample alternatives and other specifications of the model. However, given the data's high number of time periods I should stress that serial correlation biases of the standard error estimates may well arise.

2.6. Conclusions

In this paper, I have undertaken a policy evaluation of the impact of the switch from public to private management structures of electricity generation units on the bidding strategy of firms in the Colombian wholesale electricity generation market. This empirical exercise has sought to address two goals: i) a determination of the net average impact on price bids and ii) an analysis of the coherence of the empirical evidence with the theory of incentives to exercise market power in electricity markets in a mixed oligopoly framework. I drew on daily information on bidding strategies and assumed the switch to private management of several units as being an exogenous decision in order to perform a double difference analysis, in which the public units are the control group and those switching to private management constitute the treatment group.

The positive impact of private management was found to be statistically significant for situations in which the firms faced short forward contract positions, while for those facing long positions, the results are also statistically significant, but the sign of the effect is negative, and the magnitude of the coefficients are economically relevant. These findings are intuitive with regards to the model of incentives to exercise market power in the electricity market. I analyzed the dynamics of the impact of the switch to private management on bid pricing and found that the pattern of the impacts presents a decreasing effect on days of low forward contracting and an increase on days of high forward contracting. These effects are sudden following the change of management, with high variability and no clear tendency to disappear.

Given the magnitude of the impact, the link between the marginal costs of electricity generation and time invariant factors, and the empirical evidence that contradicts the hypothesis of the better cost performance of public enterprises compared to that of private firms, these findings are suggestive of a relevant change in strategic behavior when the units are switched from public administration to private management. These findings suggest that private firms are sensitive to the incentives to exercise market power, while public enterprises are less sensitive.

This empirical finding is coherent with the mixed oligopoly theory, which in line with the assumption of welfare maximizing behavior deduces that public firms apply the marginal cost pricing rule. This is not surprising in the case of electricity generation in Colombia given that the Ministry of Energy sits on the management boards of the majority of public generation firms. The price of electricity is the subject of intense political debate and one that can have a vital impact on the welfare of consumers and the competitiveness of energy intensive industries.

However, there are alternative explanations that lie outside the scope of the present paper. Hortaçsu and Puller (2008) observed that small sellers formulate less refined bid strategies than big firms and Hortaçsu et al. (2019) found that firm size and manager education improves the sophistication of firms' strategies. Extrapolating this finding to privately and publicly managed firms, the trend towards the strategic profit maximization bids of firms that are privatized can be interpreted as a possible effect of the better bidding skills of privately managed firms. Few empirical studies to date have sought to disentangle the effects of private management in an environment of oligopolistic competition. This is understandable given that the change in management of generation units is unusual and because the number of individual units in a sample is intrinsically limited by the nature of oligopolistic market structures. Although more empirical studies of the impact of privatization on competition are necessary, the evidence presented in this paper offers clear insights regarding the changes in competitive behavior following the shift to private management.

3. Mixed oligopoly and market power mitigation

3.1. Introduction

A key concern in any discussion about privatization are the benefits that might accrue to society from public firms. Their advocates claim they can be used as economic policy instruments. In mixed oligopoly markets (i.e., markets in which private and public firms compete), some economists and policy-makers claim that public enterprises are able to mitigate market power through more competitive pricing or what we refer to hereinafter as "regulatory intervention".[1]

The mixed oligopoly literature has analyzed the strategic interaction between public and private firms in non-perfect competitive markets in order to establish what, in theory, are the welfare effects of privatization. Several studies employing such models have concluded that full privatization is not recommendable because it can have counter-competitive effects in the market and lead to subsequent increases in terms of dead-weight loss (De Fraja and Delbono, 1989; Matsumura, 1998). These conclusions arise from the assumption that the objective function of public firms and mixed firms differs from that of private firms. In most cases, mixed oligopoly models assume that private firms aim to maximize profits while the objective function of public (or mixed) firms is to promote social welfare.

However, it is not possible to know *a priori* what the objective function of a public firm is, it being dependent on various questions related to the government's ultimate goals and on the institutional structure. Given this ambiguity, and its obvious importance in determining the effect of private and state ownership on competition, the behavioral difference between these two types of firm is a matter that merits empirical analysis.

The possibility of conducting such analyses in regulated industries has been enhanced

[1] In this paper, public firms are understood to be those in which national or local governments have a majority shareholding and control over their management.

greatly over the last three decades thanks to the improved availability of data and the diversity of market reforms. As a result of these two developments, it is now possible to address empirically the key questions underpinning the mixed oligopoly model namely: Do public and private firms behave the same when faced with equivalent incentives? Indeed, the empirical analysis of the differences in the way in which private and public firms exercise their market power should provide us with interesting insights.

In this paper, I address the strategic pricing of public and private firms from an empirical perspective in order to determine how they exercise their market power. To do so, I apply models of unilateral market power in electricity markets to a framework in which strategic firms (private) compete with competitive companies (public). Specifically, I extend the analysis of the incentive to exercise market power (IEMP), as proposed by McRae and Wolak (2009), to the case of two different types of firm with disparate behavior facing the same strategic incentives. This technique draws on information about individual bids (willingness to sell) available in the electricity markets organized as a multi-product auction. I apply this extended methodology to the Colombian wholesale electricity market.

In addition to its relation with the mixed oligopoly models, this paper lies at the intersection of other two different strands of the literature: i) The empirical studies of comparison of efficiency of public and private firms and ii) the works on the estimation of market power in electricity markets.

To date the empirical studies of efficiency of public and private firms have focused primarily on the differences in the performance (or productive efficiency) of public and private monopolies (La Porta and Lopez-de Silanes, 1999; Frydman et al., 1999; Megginson and Netter, 2001; Bel et al., 2010). One relevant exception is the paper of Seim and Waldfogel (2013) which is specifically focused in uncover the goals implicit in the decisions of public enterprises. They estimate an spacial model of demand based on information of Pennsylvania's state liquor retailing monopoly. They found that the actual store network is much more similar in size and configuration to the welfare maximizing configuration. My research is also focus in disentangle differences in the goals of public firms in comparison with private, but it differentiates from the study of Seim and Waldfogel (2013) because it analyze a field experience in which private and public companies compete in the same relevant market, while these authors investigate the goals of a public monopoly. To the best of my knowledge, only the paper of Barros and Modesto (1999), in a study of the Portuguese banking sector, has focused on the differences of public and private firms that compete in the same relevant market.

On the other hand, the economic literature examining the problem of market power in electricity generation markets is extensive. Here, we can identify three main groups of empirical model based on the methodological approach employed. The first approach is based on the direct or indirect estimation of Lerner indexes or mark ups (Wolfram, 1999; Wolak, 2003). The second group of studies seeks to determine the market power of the agents, making simulations from the equilibrium conditions that emerge from the economic models of oligopoly (Green and Newbery, 1992; Wolak, 2000; Sweeting, 2007; Hortaçsu and Puller, 2008; Bushnell et al., 2008). The third approach involves the use of structural econometric models to estimate functional or behavioral parameters (Wolfram, 1998; Wolak, 2007; Reguant, 2014).

Although several techniques for estimating market power in electricity markets have been proposed, few studies aim to distinguish differences in competitive behavior between heterogeneous types of firms. Regarding this aspect, my approach is related to the studies of Hortaçsu and Puller (2008) and Hortaçsu et al. (2019) who examined the bidding behavior of firms in the Texas electricity spot market and found differences in the competitive strategies between big and small firms. Concerning the methodological approach, as mentioned above, my empirical implementation is similar to the estimation model proposed by McRae and Wolak (2009).

The main contribution of this paper is to develop an empirical model for the analysis of the differences between private and public firms in terms of their incentives to exercise market power in a multi-unit auction framework. This methodology provides a new analytical tool that serves to clarify the effect of mixed (private-state) ownership on competition. Overall, this methodology is applicable to any multi-product, uniform price auction in which the competitors' bids and marginal costs are observable.

The empirical analysis performed in this article suggests that there are marked differences in the way private and public firms exercise their unilateral market power, supporting the hypothesis of the latter's market power mitigation. The results indicate that the public firms do not price strategically on the spot market. Moreover, partial evidence was found of profit-maximization behavior on the part of private firms and of bidding under the marginal cost pricing rule on the part of public firms. These results are coherent with the behavioral structure of mixed oligopoly models.

The rest of this paper is divided into five sections. The second outlines the characteristics of the Colombian wholesale electricity market and the structural problems presented by this market that need to be taken into account to obtain a more appropriate identification of the behavioral parameters this study is interested in. Section three explains the theory underpinning the incentives faced by profit-maximizing firms to exercise unilateral market power and stresses the differences in this regard with the behavior of firms that do not act strategically. This section also sets out the empirical approach adopted in seeking to identify the behavioral differences between private and public firms. Section four presents the data, the results of applying the empirical approach proposed to this market and, finally, it reports several robustness checks on multiple econometric choices. The final section summarizes the results and concludes.

3.2. The Colombian market and mixed competition

This section outlines the main features of the Colombian electricity generation market that allow it to be classified as a mixed oligopoly and describes the main elements of this market that need to be taken into account when examining problems of market power.

For a market to be considered a mixed oligopoly, it must satisfy three conditions: i) the market must be liberalized, i.e. the price is determined by the competing bids made by the producers; ii) public, private and mixed firms must compete in equal conditions, i.e. there are no discrimination rules; and iii) the conditions of competition in the market are not perfect, i.e. there are high levels of concentration.

As regards the first condition, since the introduction of the Public Utilities Act (Act 142 of 1994) and the Electricity Act (Act 143 of 1994), the generation of electricity in Colombia has been organized in a wholesale electricity market centralized in a pool scheme. Generators can sell their energy by long-term bilateral contracts with other agents or directly in the day-ahead energy exchange. This exchange operates as a multi-product, uniform first-price auction, in which each generator reports to the market operator a price bid (or willingness to sell) for each generation unit. With this information, and according to the demand forecasts, the market operator establishes the merit order and defines the market clearing price (spot price) for every hour of the day. This feature provides verification that the Colombian wholesale energy market is neither price-regulated nor a cost-based pool and that it obeys the conditions of competition among producers.

Second, with respect to the coexistence of private and public companies in the Colombian generation market, it is important to highlight that although the spirit of the Colombian electricity sector reform in the early nineties was to promote private entrepreneurship, the activity has a high proportion of public or mixed firms under government control. Table 3.1 shows market shares in the Colombian wholesale electricity market for 2014. The second column reveals that four of the seven leading firms were state controlled in that year. According to this information, the ownership structure of the leading generation firms operating in Colombia during the period of analysis was heterogeneous in terms of the private or public nature of their major shareholders.

Table 3.1.: Market shares in Colombian electricity market - 2014

Firm	Majority Shareholding	Electricity Generation (gWh)	%	Cumulative %
EMGESA	Private	13691	21%	21%
EPM	Public	13626	21%	42%
ISAGEN	Public	10609	16%	59%
GECELCA	Public	7508	12%	71%
COLINV.	Private	6711	10%	81%
AES	Private	3982	6%	87%
GENSA	Public	2436	4%	91%
Others		5764	9%	100%
Total		64328	100%	100%
HH				1422

Source: XM - Market Operator

Finally, as regards the third condition, i.e. the level of competition and concentration in the market, the levels of concentration of electricity generation activity in Colombia correspond to those of a moderate oligopoly, according to the merger guidelines of the US Department of Justice. Table 3.1 presents the participation of the six leading generation companies in the Colombian generation market. In addition to the above features, there are several other traits of the Colombian wholesale electricity market that need to be considered in order to characterize the unilateral market power of electricity generators properly.

i Colombia's generation supply is mainly produced by hydroelectric and thermoelectric resources. In the case of the country's hydro technology, it should be borne in mind that Colombia's rain regime is subject to the effects of El Niño and La Niña events. During the former, dry weather conditions have a negative impact on the contribution of hydroelectric resources, while the opposite occurs during La Niña events. In addition, the annual rain regime fluctuates between dry (December, January and February) and wet (April, May and June) seasons. Daily information of the river flows that feed the main hydro units is available. As for the country's thermal technology units, these are primarily gas and coal fired. The gas market in Colombia is organized as a bilateral contract scheme. The price of Colombia's main gas well was regulated during the period analyzed in this paper. Likewise, the fees for using the gas transport pipes are regulated according to a mixed scheme which takes into consideration both capacities and volumes. Information about the heat rates of each thermoelectric plant is available. Table 3.2 highlights the importance of large hydro plants and thermoelectric units.

Table 3.2.: Generation by type of resource - 2013 and 2014

	Generation (gWh)			
Type	December 2013	December 2014	Growth	Share 2014
Hydro	3622	3707	2%	68 %
Thermal	1370	1474	8%	26 %
Small Units	300	305	2%	6%
Cogeneration	32	45	41%	1%
Total	5323	5531	4%	100%

Source: XM - Market Operator

ii Most energy transactions are performed through long-run, fixed-price forward contracts. Since physical dispatch is centrally coordinated, bilateral forward contracts work as financial hedges against spot prices (Garcia and Arbelaez, 2002). Table 3.3 shows the total energy traded during 2013 and 2014 in the electricity generation market. It distinguishes between transactions conducted through fixed-price forward contracts and direct transactions in the day-ahead energy exchange. In the Colombian case, the amounts sold by each agent via forward contracts are observable ex-post. Thus, the net forward market position of the firms can be computed.

iii Finally, the rules of the Colombian electricity exchange market allow only one valid bid-price to be made per unit for each 24-hour period. For each unit participating in the central dispatch, the bid consists in one bid-price that remains valid for the whole day and 24 quantities (commercial availability), that is, one for each hour of the day. The generators report these day-ahead bids in the market clearing period. Regardless of the fact that the market clears every hour (in order to account for differences in demand and in availability of non-centrally dispatched generation resources), the

Table 3.3.: Energy sales by trade mechanism - 2013 and 2014

	Generation (gWh)			
	2013	2014	Growth	Share 2014
Spot Market	14949	15507	4%	18%
Forward Contracts	71374	69846	-2%	82%
Total	86323	85352	-1%	100%

Source: XM - Market Operator

generator can only bid one price and cannot change any part of its bid during the whole day. This restriction has considerable implications as regards incentives to exercise market power. This point is explained in detail in sub-section 3.3.1.

3.3. Theoretical background and identification

3.3.1. The incentives to exercise market power

This subsection examines the theoretical background to the analysis of the IEMP of both profit-maximizing and non-strategic firms and the implications of certain features of the Colombian wholesale electricity market regarding the identification approach. The literature focused on electricity markets has proposed various empirical techniques for estimating market power (Green and Newbery, 1992; Wolfram, 1998, 1999; Borenstein et al., 2002; Wolak, 2003; Bushnell et al., 2008; Hortaçsu and Puller, 2008; Reguant, 2014). A common element in the most relevant papers conducting analyses of this type is that the estimation strategy is based on the first order condition of the profit maximization problem. In general, these order conditions make it possible to express the optimal price or bid as the sum of a cost component plus a strategic component. Specifically, this paper opts to adopt the model proposed by Wolak (2000) and McRae and Wolak (2009). These authors developed a methodology for estimating the IEMP based on a simple model of profit-maximizing firms that have ex-ante forward contract obligations in a residual demand setting. In this context, the IEMP is the ability to change the spot price when withdrawing output with the aim of maximizing profits. In a theoretical study, Allaz and Vila (1993) showed that when profit-maximizing firms sell a large share of their output via forward contracts with fixed prices, they have less incentive to increase prices on the spot markets.

According to McRae and Wolak (2009) model, assuming the generator has previously sold an amount of energy q_{ih}^{c} at a fixed price P_{ih}^{c} by forward contracts, the profit function of the generation firm *i* in the hour *h* can be defined by the following expression:

$$\pi_{ih} = P_h(DR_{ih})(DR_{ih} - q^c_{ih}) + P^c_{ih}q^c_{ih} - C_i(DR_{ih})$$

where π_{ih} represents the profits of the firm *i* in the hour *h* in the electricity market, P_h is the spot price, DR_{ih} is the residual demand of the firm *i* in the hour *h*, and $C_i(DR_{ih})$ is the cost function of the firm *i*. From the first order condition, the following expression is obtained:

$$P_h(DR_{ih}) = \frac{\partial C_i(DR_{ih})}{\partial DR_{ih}} \underbrace{- \frac{\partial P_h(DR_{ih})}{\partial DR_{ih}}(DR_{ih} - q^c_{ih})}_{\text{strategic element}} \tag{3.1}$$

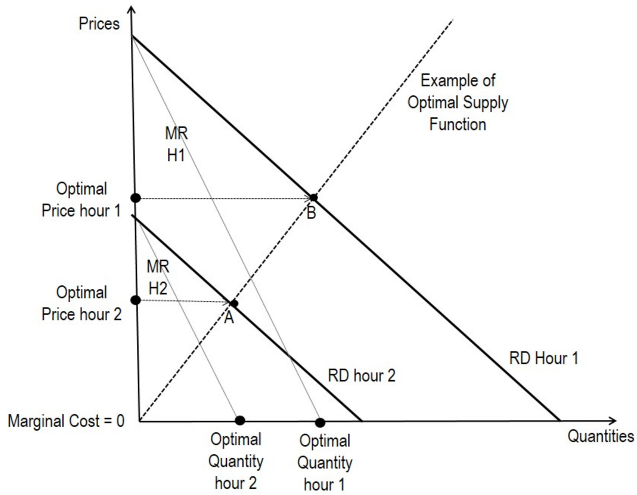
It should be borne in mind that at the point of market equilibrium, the residual demand of firm *i* in hour *h* ,DR_{ih} , is equal to the total quantity produced by that firm in this hour, therefore $\frac{\partial C_i(DR_{ih})}{\partial DR_{ih}}$ is the marginal cost of firm *i* in hour *h*. This is the first term of the right-hand side of equation 3.1. The second is the strategic element, i.e. its IEMP, which is equal to the interaction of the inverse of the slope of the residual demand curve and the firm's net position in the forward contracts market. This interaction is the optimal margin of a profit-maximizing firm. Thus, the more energy sold by the firm through fixed-price forward contracts, the less the incentive to increase the spot price. Note, however, that in cases in which the generator has an energy deficit relative to its contractual commitments, it has the IEMP by reducing, as opposed to incrementing, the spot price (McRae and Wolak, 2009).

Given the design of the Colombian wholesale electricity market, the daily bid constraint limits the generator's ability to make the precise bid that will maximize its profit function each hour. The generation firm must choose a unique price in order to maximize its expected daily profits. This means it cannot bid a continuous supply function that intersects the maximum profit points, given the different realizations of the residual demand. Thus, hourly IEMPs are not necessarily the same as daily incentives. By way of example, figure 3.1 presents the case in which a firm has only one generation unit and it has to bid one unique price for two periods.

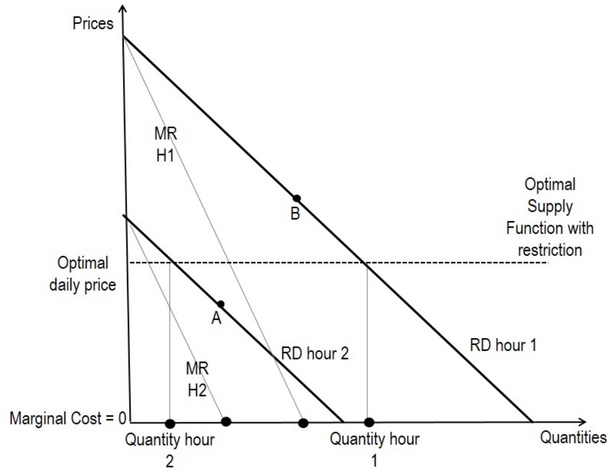
To address this problem, here, I propose a daily measurement of the IEMP. The problem the generator faces is that of designing a set of daily bids $Sit = \{s_{i1t}, s_{i2t}, \cdots, s_{ijt}, \cdots, s_{iNt}\}$, where s_{ijt} is the daily bid price on day *t* for the energy of unit *j*, owned by firm *i* and *N* is the number of units that the this firm *i* is able to bid. These bids are ordered from lowest to highest, so that they maximize the expected daily profit π_{it} which

Figure 3.1.: Daily-bid restriction and optimal bidding strategy

(a) Optimal decision no restricted generator



(b) Optimal decision restricted generator



Source: Own elaboration.

In this example, we assume that marginal costs are equal to zero. For each hour of the day, there are different residual demand functions (RD hour 1 and RD hour 2) and therefore different marginal revenue functions (MR H1 and MR H2). If the generator could bid an ordered pair (price, quantity) for each hour, it would choose point A for hour 2 and point B for hour 1. The generator chooses the quantities for which the marginal revenue is equal to the marginal cost. In the case in which the generator can bid a supply function, it would bid a function similar to the dotted line in panel (a). Once the generator is restricted, it has to find an optimal price for two periods. So it will bid the price that maximizes the sum of the RD in hour 1 and the RD in hour 2. Panel (b) shows the case when the generator is restricted. Here, it is possible to see that the optimal price under the restriction is lower than the unrestricted optimal price in hour 2 (on-peak period). Conversely, the optimal price under the restriction is higher than the unrestricted optimal price in hour 1 (off-peak period).

is the sum of the hourly profits π_{ith}. If we adopt a residual demand approach, in which the competitors' bids are given, the generator should choose the bids that clear the market in the 24 hours of day *t*, constrained by the capacity of its own units and the market clearing price rules. Let $\pi_{it}(S_{it})$ be the daily profits of firm*i* on day *t*; let DR_{ith} be the residual demand of firm *i* on day *t* at hour *h*; and, let S_{it} be the set of bids made by firm *i* during day *t*. When considering forward contracts, the profit maximization problem of the firm can be stated as:

$$\max_{S_{it}} \pi_{it}(S_{it}) = \max_{S_{it}} \left[\sum_{h=1}^{24} \Big(p_{th}\big(DR_{ith}(S_{it})\big)\big(DR_{ith}(S_{it}) - q^c_{ith}\big)\Big) + \sum_{h=1}^{24} p^c_{ith} q^c_{ith} - \sum_{h=1}^{24} C_{it}\big(DR_{ith}(S_{it})\big) \right]$$

Subject to the capacity constraints and the non-negativity conditions:

$$0 \leq q_{jith} \leq \overline{q_{ji}}$$

If the restrictions are not binding, the first order conditions of this problem are:

$$\sum_{h=1}^{24} \left[\frac{\partial p_{th}}{\partial s_{ijt}} \big(DR_{ith}(S_{it}) - q^c_{ith}\big) \right] + \sum_{h=1}^{24} p_{th}\big(DR_{ith}(S_{it})\big) \frac{\partial DR_{ith}(S_{it})}{\partial s_{ijt}} - \sum_{h=1}^{24} \frac{\partial C_{it}\big(DR_{ith}(S_{it})\big)}{\partial DR_{ith}} \frac{\partial DR_{ith}(S_{it})}{\partial s_{ijt}} = 0$$

Given the residual demand approach and the market clearing price rule, the equilibrium price of the market (or marginal price) is $p_{th} = min(s_{i1t}, s_{i2t}, \cdots, s_{ijt}, \cdots, s_{iNt})$ such that:

$$DR_{ith}(s_{imt}) = \sum_{j=1}^{m} q_{imt}$$

If the plants are ordered by merit, this means the spot price is equal to the bid of the generator's marginal plant, $p_{th} = s_{imt}$, if plant *m* clears the market in hour *h*. This in turn implies that $\frac{\partial p_{th}}{\partial s_{imt}} = 1$. In addition, in line with previous studies in the literature (Reguant, 2014), I assume that the residual demand of hour *t* is a function of the bid of unit *m* that is marginal in this hour *h*, but not of the bids of the other units. This entails that the derivative of the residual demand of hour *h* with respect to the bids of the plants that are not marginal in that hour is equal to zero, i.e $\frac{\partial DR_{ith}(s_{imt})}{\partial s_{ijt}} = 0$ where $m \neq j$ and that the derivative of the price of hour *h* with respect to the bids of the plants that are not marginal in that hour is equal to zero i.e $\frac{\partial p_{th}}{\partial s_{ijt}} = 0$ if unit j is not marginal .

Note that the set of potential bids that the generator is able to bet is limited by the daily bid constraint. If the day has 24 periods with different residual demands, the generator owns *N* plants and $N < 24$, then in at least $24 - N$ periods the generator will not be able to choose the exact bid that clears the market in the profit-maximizing point of each hour. In fact, the generator is compelled to clear the market with the bid of one unit, let s_{imt}, for several hours of the day. Hence, if the unit *m* is marginal in hours *h* and *h+k*, it means that $p_{th} = p_{t(h+k)}$. In this way, every hour can be linked to a marginal plant *m*. Considering all of the above, if $\mathcal{H}_{ijt}$ is defined as the set of hours of the day t where the unit j is marginal (and the unit j is owned by the firm i), the first order condition can be expressed as:

$$\sum_{h\in\mathcal{H}_{ijt}} (DR_{ith}(s_{ijt}) - q^c_{ith}) + s_{ijt} \sum_{h\in\mathcal{H}_{ijt}} \frac{\partial DR_{ith}(s_{ijt})}{\partial s_{ijt}} - \sum_{h\in\mathcal{H}_{ijt}} \frac{\partial C_{it}}{\partial DR_{ith}} \frac{\partial DR_{ith}(s_{ijt})}{\partial s_{ijt}} = 0$$

The optimal bids for the unit *j* s^*_{ijt} for a private firm should be such that:

$$s^*_{ijt} = \frac{\sum_{h\in\mathcal{H}_{ijt}} \frac{\partial C_{it}}{\partial DR_{ith}} \frac{\partial DR_{ith}(s_{ijt})}{\partial s_{ijt}} - \sum_{h\in\mathcal{H}_{ijt}} (DR_{ith}(s_{ijt}) - q^c_{ith})}{\sum_{h\in\mathcal{H}_{ijt}} \frac{\partial DR_{ith}(s_{ijt})}{\partial s_{ijt}}}$$

If we assume the marginal cost of unit *j* to be constant during the day *t*, the optimal bid of a daily profit-maximizing firm can be expressed s^*_{ijt} as:

$$s^*_{ijt} = c_{ijt} + \frac{-\sum_{h\in\mathcal{H}_{ijt}} (DR_{ith}(s_{ijt}) - q^c_{ith})}{\sum_{h\in\mathcal{H}_{ijt}} \frac{\partial DR_{ith}(s_{ijt})}{\partial s_{ijt}}} \tag{3.2}$$

where c_{ijt} is the constant marginal cost of the unit *j*. The second term on the right-hand side of equation 3.2 is a weighted version of the inverse of the semi-elasticity of the residual demand. This is the IEMP of a firm that maximizes daily expected profits. I compute the daily IEMP of the firms for the daily model according to this expression.

From a behavioral perspective, strategic firms will take the IEMP into account in their pricing, whereas non-strategic firms will not. But, what type of behavior can be expected from public firms seeking to mitigate market power? Here, the theoretical literature on mixed oligopolies offers an appealing response. Beato and Mas-Colell (1984) demonstrate that public firms are able to restore market efficiency by applying the marginal cost pricing rule in a mixed oligopoly model in which public firms compete with private firms, where the former are welfare maximizing and the latter are profit maximizing. Hence, if public firms are implementing market power mitigation schemes, we would expect such firms to apply the marginal cost pricing rule or, at least, we would expect the impact of the strategic element in prices to be less important than it is for private firms.

What, therefore, are our expectations regarding public firms in the specific case of Colombia? In this country, market power and marked rises in wholesale electricity prices are a major concern for authorities, consumers and stakeholders alike. Leading industrial consumers tend to be well organized and exert pressure on the government calling for energy cost reductions. At the same time, the Ministry of Energy and Mines sits on the board of several of the leading public electricity generation companies. As a result, there are potential incentives for public firms and mixed firms under government control to exert market power mitigation. In the empirical section of this paper, I cluster the a latter - i.e. mixed firms under government control - with public firms.

In summary, when private firms behave strategically, the interaction between the slope of residual demand and the net financial position has an impact on price bids. In contrast, when public firms exert market power mitigation, they have no IEMP, i.e. their prices are not affected by this interaction and are primarily explained by the marginal cost.

3.3.2. Identification strategy and estimation

In this section, the differences in the incentives of private and public firms to exercise market power are addressed from an empirical perspective. The model presented adopts the estimation methodology proposed by McRae and Wolak (2009), but includes the interaction between the firms' type of ownership and their IEMP. The extension of this model to establish these differences in incentives is based on expression 3.2 for private companies.

First, we need to consider that the estimation of the opportunity costs of using hydro power resources involves dynamic components that do not necessarily correspond to the first order conditions raised in expression 3.2. For this reason, the estimations presented in this paper only use data from situations in which the firms' marginal power plants use thermal technology. However, the importance of hydroelectric generation in this market is useful later on when having to refine the identification strategy in order to address endogeneity issues.

Second, it should be borne in mind that expression 3.2 does not consider any source of uncertainty. However, we ought to recognize that the bidding firm cannot be certain about the residual demand curves it faces throughout the day. On the one hand, it cannot be certain about the realization of total market demand; and, on the other, it does not know in advance the supply functions of its competitors. McRae and Wolak (2009) argue that although a supplier cannot be certain about the market demand and supply of its competitors, it can have a very good idea of the possible realizations of the residual demand curves, due to factors such as the characteristics of each generation unit owned by the supplier's competitors, the specific rules of the market and the high frequency of the market. This means that the ex-post evaluation of the second term on the right-hand side of expression 3.2 is a good approximation to the expected incentives to exercise market power even in an uncertainty framework. Furthermore, Hortaçsu and Puller (2008) proved that when the residual demand is additively separable in an elastic component and a stochastic component, the company's supply strategy $S_i(p)$ is a better response function for any possible realization of the residual demand, so that the ex-post realization of expression 3.2 is also an optimal strategy.

In this paper, these sources of uncertainty, will be considered assuming that the stochastic shocks of the demand and supply functions of other competitors are both additively separable in a similar way to the approach taken by Hortaçsu and Puller (2008). It is assumed that the total demand can be expressed as the sum of a deterministic elastic component and a stochastic shock, i.e. $D_{th}(p) = \widehat{D}_{th}(p) + \nu_{th}$, where $D_{th}(p)$ is the total demand in the hour h in the day t. In the same way, we assume that the aggregate supply of a firm's rivals can be expressed as the sum of a deterministic elastic component and a stochastic shock $Q_{-ith}(p) = \widehat{Q}_{-ith}(p) + \upsilon_{-ith}$. This allows the residual demand to be expressed as the sum of a random component and a deterministic elastic component. By definition, the residual demand function of the firm i is the difference between the total demand and the aggregate supply of its competitors, i.e. $DR_{ith}(p) = D_{th}(p) - Q_{-ith}(p)$, which implies that it can be expressed as $DR_{ith} = \widehat{DR}_{ith} + \epsilon_{ith}$, where $\widehat{DR}_{ith} = \widehat{D}_{th}(p) - \widehat{Q}_{-ith}(p)$ and $\epsilon_{ith} = \nu_{th} - \upsilon_{-ith}$.

Additionally, as will be seen below, the marginal cost estimates of the units considered are based on the technical characteristics and prices of the observable inputs. However, there may be unit characteristics and random shocks common to all plants that are not observable to the econometrician and which have an effect on marginal costs. Therefore, in this paper it is assumed that the marginal costs of each unit can be expressed as the sum of the marginal cost estimate based on the technical parameters, an individual heterogeneity component and a time effect common to all the units, i.e. $c_{jt} = \widehat{c}_{jt} + \mu_j + \varphi_t$.

Thus, as a first approximation, I estimate the following two-way fixed effects linear regression model:

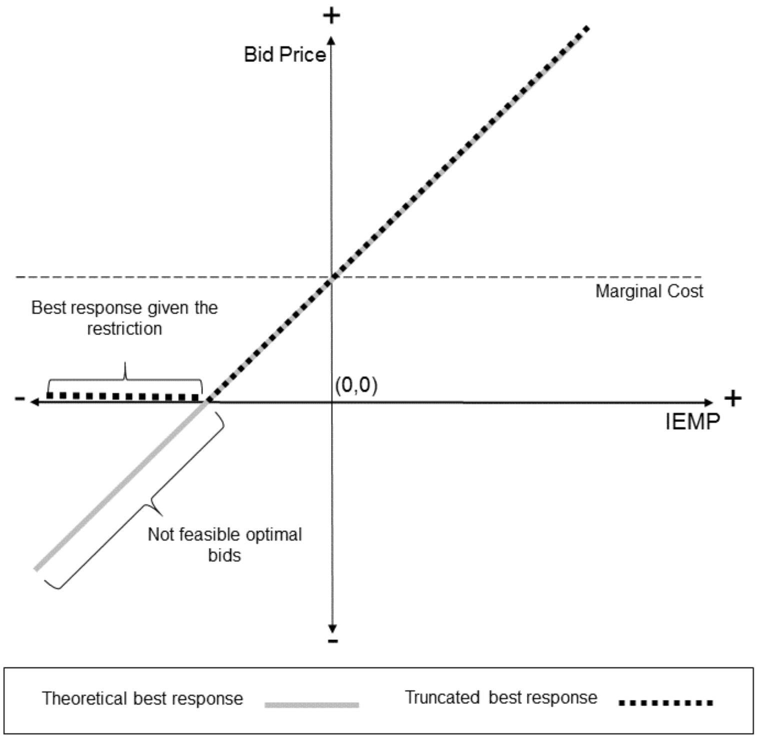
$$p^*_{ijt} = \beta_0 + \theta(\widehat{c}_{ijt}) + \alpha_{pri}(D^{pri}_j * \widehat{IEMP}_{ijt}) + \alpha_{pub}(D^{pub}_j * \widehat{IEMP}_{ijt}) + \mu_j + \varphi_t + \varepsilon_{it} \quad (3.3)$$

where P^*_{ijt} is the bid of firm *i*, for its marginal unit *j* in the day *t*, $\widehat{c_{ijt}}$ is the estimation of the marginal cost of unit *j* in the day *t*, $\widehat{IEMP}_{ijt}$ is the estimation of the incentive to exercise market power for a profit- maximizing firm (the empirical estimation of of the second term of the left-hand side of expression 3.2, for company *i* in the day *t* during the hours in which the unit *j* was marginal, D^{pub}_j is a dummy variable that takes the value of 1 when the unit *j* is owned by a firm *i* under state control and 0 otherwise. D^{pri}_j is a dummy variable that takes the value of 1 when the unit *j* is owned by a private firm *i* and 0 otherwise. μ_j and φ_t represents unit and temporal unobserved effects, respectively. The term of disturbance ε_{it} contains the unobservable shocks in hourly demands and hourly aggregated supply of competitors, i.e. $\varepsilon_{it} = \frac{-\sum_{j=m}(\nu_{th} - \upsilon_{-ith})}{\sum_{j=m}\frac{\partial DR_{ith}(s_{ijt})}{\partial s_{ijt}}}$. β_0, θ, α_{pub}, α_{pri} are the parameters to be estimated. These model is similar to the application developed by McRae and Wolak (2009), however, in the present paper, heterogeneous effects are introduced for public and private companies. I estimate this model by ordinary least squares (OLS) with standard errors clustered by unit.

It should be borne in mind that P_{ijt} is the price-bid of unit *j* when the latter is marginal. The first order condition expressed in equation 3.2 is not valid when the unit *j* is not marginal. This means the panel data only contain information about those plants that were marginal during at least one hour in the day. Likewise, in the case of the residual demand approach, the marginal price bid of firm *i* is equal to the spot price, that is, $p_{th} = s^*_{imt}$, if unit *m* is marginal in hour *h*. However, given the discontinuity and ladder shape of the supply and residual demand functions, this does not always occur in the real market. Therefore, there are two alternatives regarding the dependent variable of the model presented in 3.3 : Either the spot price when unit *i* clears the market or the price bid of the marginal unit of each firm. Since the last alternative allows a greater number of observations to be used (and unit j does not need to clear the market), it can be considered the most appropriate option.

It should not be forgotten that in the Colombian wholesale electricity market there are no negative price bids. This means that when private firms have an excess of forward contract commitments and the absolute value of the IEMP is greater than the marginal cost, the bidding rule according to expression 3.2 cannot be applied. The best response in such cases is to bid prices equal to zero. Figure 3.2 presents the potential effects of this restriction. It represents the bidding rule of expression 3.2 in the Cartesian space IEMP - Bid-Price.

Figure 3.2.: Non-negative price restriction



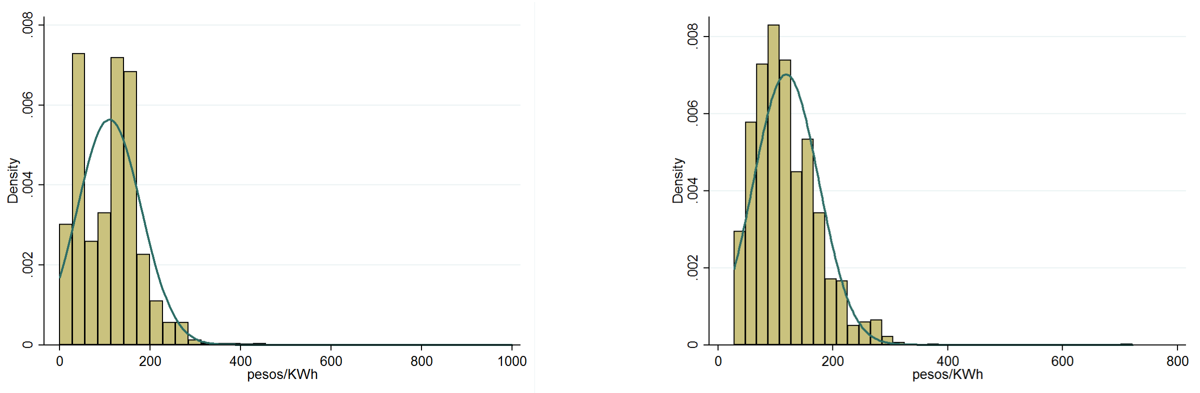
Source: Own elaboration.

The continuous gray line represents the optimal bidding rule according to expression 3.2 in the Cartesian space (Bid-Price, IEMP). Note that this rule only is feasible for bids greater than zero. The segment of the grey continuous line below the x-axis represents the non-feasible bids. The dotted black line represents the best response of the generators given the non-negative price restriction. For potential positive values of the price it overlaps with the non-restriction theoretical response, but for potential negative not feasible values of the price-bids it overlaps with the x-axis

Given this restriction, and according to the mixed oligopoly model, the distribution function of the marginal bid-price for private firms is expected to be asymmetric and truncated in zero. Figure 3.3 shows the histograms of the marginal bids for private and public firms and it is possible to observe a truncation in zero in the distribution of both.

Figure 3.3.: Marginal price histograms

(a) Private (b) Public



Source: Data from XM - Calculations and elaboration: Author.

In order to address this issue, in addition to the OLS methods, I estimated the two-way fixed effects model in expression 3.3 using the following Tobit model:

$$P^{*}_{ijt} = \begin{cases} P^{**}_{ijt} & \text{if } P^{**}_{ijt} \geq 0 \\ 0 & \text{if } P^{**}_{ijt} < 0 \end{cases}$$

where P^{**}_{ijt} is a latent variable:

$$P^{**}_{ijt} = \beta_0 + \theta(\widehat{c}_{ijt}) + \alpha_{pri}(D^{pri}_{j} * \widehat{IEMP}_{ijt}) + \alpha_{pub}(D^{pub}_{j} * \widehat{IEMP}_{ijt}) + \mu_j + \varphi_t + \varepsilon_{ih}$$

and

$$\varepsilon_{ih} \sim N(0, \sigma^2)$$

Addressing the truncation of the price-bid variable using a Tobit model entails making more rigid assumptions: It is necessary to assume normality and constant variance of the unobservables ε_{it}. However, the Tobit model solves potential problems of bias and inconsistency in the OLS estimations in a context of censored variables.

Third, as for the stochastic components of the residual demand, these can be generated by demand shocks or by shifts in the competitors' supply function. It is reasonable to assume that the shocks of the demand ν_{th} come from unexpected consumer reactions which lie completely beyond the firms' control. However, endogeneity concerns could arise with regards to shifts in the competitors' supply function, υ_{-ith}. These shifts may be caused by unforeseen changes in the costs of rival firms or by unforeseen impacts in their strategic incentive. Clearly, this second component, because it depends on the strategic interaction of the competing firms, poses a problem of endogeneity. The IEMP results from the expectations that various firms have about the behavior of their rivals. According to the bid rules of the wholesale energy market, the competitors' bids must be made simultaneously. Thus, for generator A to estimate its residual demand curve, it has to form an expectation about its rivals' bid prices, however, at the same time, the bid prices of these rival firms will depend on their estimations of the residual demand curves which in turn will be dependent on their expectations regarding generator A's bid prices. Hence, if we assume that the strategic component is not an important driver of shifts in the competitors' supply function, estimation by ordinary least squares is valid. If this, however, is not the case, we need to address this issue using instrumental variable methods.

I address this specific problem here by performing estimates that consider instruments for the IEMP whose variation arises either from demand shocks or exclusively from the competitors' cost component (both of which are unrelated to the strategic component). The literature on market power estimation in an environment of differentiated products recommends using the observed characteristics of the products supplied by rival firms in order to obtain the optimal instruments for a specific product (Berry et al., 1995). By analogy, in the framework of the electricity market, I opt to use as instruments variables that are unrelated to the rival's strategic component but which at the same time have effects on their supply function, that is, factors associated with shifts in the costs of rival firms.

Specifically, I consider three instruments: i) a weekend day dummy variable is used in order to capture demand shocks; ii) the inflows of the rivers feeding the rivals' main hydraulic generation units are used to account for changes in the marginal costs of the leading competitors - the exogenous nature of this variable is evident given its dependency on natural phenomena; and, iii) the competitors' full commercial availability, i.e. their generation capacity on specific days. Note, however, that the greatest changes in this last variable are motivated by the scheduled or unscheduled unavailability of the plants and by the highly variable contribution of the smaller base-load generation units.

In the framework of the instrumental variables approximation, I implement two types of model; first, an estimation of the two-way fixed effects proposed in expression 3.3 and, second, a more rigorous structural interpretation of the profit-maximization restricted to one bid per day from each unit. If the marginal cost and IEMP components are measured correctly, under a structural interpretation of the profit-maximization model, the empirical analogue of the first order condition should not include the constant and fixed effects that do not appear in equation 3.2. Note that for private companies, the inclusion of these terms would allow them to bid prices above or below the marginal cost independent of residual demand and their contractual position, that is, for reasons independent of their IEMP. As far as public companies are concerned, the additional fixed effects would allow level-shift deviation, which implies violating the marginal cost pricing rule. [2]

I propose estimating the parameters α_{pub} and α_{pri} by implementing a linear generalized method of moments (GMM) model. Assuming valid and relevant instruments, I can use the orthogonality conditions of the instruments and the first order condition of the daily profit maximization problem presented in expression 3.2 in order to construct the moments conditions. The orthogonality conditions imply that:

$$E\big[Z'_{ijt}\varepsilon_{it}\big] = E\Big[Z'_{ijt}\big[P^*_{ijt} - \theta(\widehat{c}_{ijt}) - \alpha_{pri}(D^{pri}_j \cdot \widehat{IEMP}_{ijt}) - \alpha_{pub}(D^{pub}_j \cdot \widehat{IEMP}_{ijt})\big]\Big] = 0 \quad (3.4)$$

Alternatively, if I use the margin as the dependent variable, which means dropping the estimation of θ and assuming it is equal to 1, the orthogonality conditions can be written as:

$$E\big[Z'_{ijt}\varepsilon_{it}\big] = E\Big[Z'_{ijt}\big[\underbrace{(P^*_{ijt} - \widehat{c}_{ijt})}_{\text{Margin}} - \alpha_{pri}(D^{pri}_j \cdot \widehat{IEMP}_{ijt}) - \alpha_{pub}(D^{pub}_j \cdot \widehat{IEMP}_{ijt})\big]\Big] = 0 \quad (3.5)$$

[2] I owe this observation to an anonymous referee

The parameters can now be estimated using the empirical analogue of these moments conditions.

The econometric exercises proposed here seek empirical evidence for the impact of the IEMP of private and public companies on their own bid prices according to the predictions of the mixed oligopoly model. Three specific hypotheses are analyzed:

i Hypothesis 1 (H1): Given the same incentives, the exercise of market power by state-owned and private firms differs.

ii Hypothesis 2 (H2): Public firms (do not) exercise market power as non-strategic agents, i.e. they apply the marginal cost pricing rule.

iii Hypothesis 3 (H3): Private firms exercise market power taking into account the strategic element.

First, note that testing the null hypothesis, $\alpha_{pri} = \alpha_{pub}$ in 3.3 is consonant with the rationale that the exercise of market power of state-owned and private firms is equal given their incentives. If private firms behave as profit maximizers and public enterprises implement market power mitigation schemes, depending on the ownership of each enterprise, the interaction of the slope of residual demand and the net forward contract position will impact differently on their respective bidding strategies.

In the case of the second hypothesis, if public firms do not behave strategically, we would expect the parameter α_{pub} not to be statistically different from zero, i.e. null hypothesis $\alpha_{pub} = 0$. If public firms exercise regulatory intervention, then their prices will be explained mainly by the marginal cost and they will not be affected by the interaction of the residual demand and the net financial position.

Finally, according to theory, if private companies behave strategically (profit maximizers), we would expect the parameter α_{pri} to be statistically significant and to present a positive sign (being very close to 1 in the case of profit-maximizing firms), i.e. null hypothesis $\alpha_{pri} > 0$ ($\alpha_{pri} = 1$ in the case of profit maximization). If private firms behave strategically, their IEMP has an impact on the firms' pricing. These tests are performed for each of the parameters estimated in the econometric models described above.

In this paper, the empirical approach is applied specifically to the Colombian wholesale electricity market. The section that follows describes the methodological procedure for computing the model's variables, including the IEMP and marginal costs. Finally, the econometric method employed in the estimation is outlined and the most relevant results are presented.

3.4. Empirical Implementation

3.4.1. Data

The hourly and daily data for 21 firms in the Colombian wholesale electricity market were analyzed between 2005 and 2014. To test the three hypotheses (H1, H2, and H3) by estimating the parameters α_{pub} and α_{pri} of the model proposed in expression 3.3, we also need data on marginal costs and on the IEMP. Unfortunately, these variables cannot be observed directly, so we have to rely on indirect estimations.

In the case of marginal costs, an accounting approach is adopted. This is similar to the one employed in previous studies in the field of electricity markets (Green and Newbery, 1992; Wolfram, 1998, 1999; Borenstein and Bushnell, 1999; Borenstein et al., 2002; Wolak, 2000; Fabra and Reguant, 2014). The marginal costs of thermal plants are computed, taking into account the technical parameters of the plants (heat rate), fuel costs, and fuel transportation costs. The sources of the information and more detailed information concerning the assumptions for the calculation and imputation of these costs are presented in appendix A.3. It is important to bear in mind that these computations may contain some measurement error given that we approximate the fuel costs to references prices, and the cost per unit in the actual fuel supply contracts may be different.

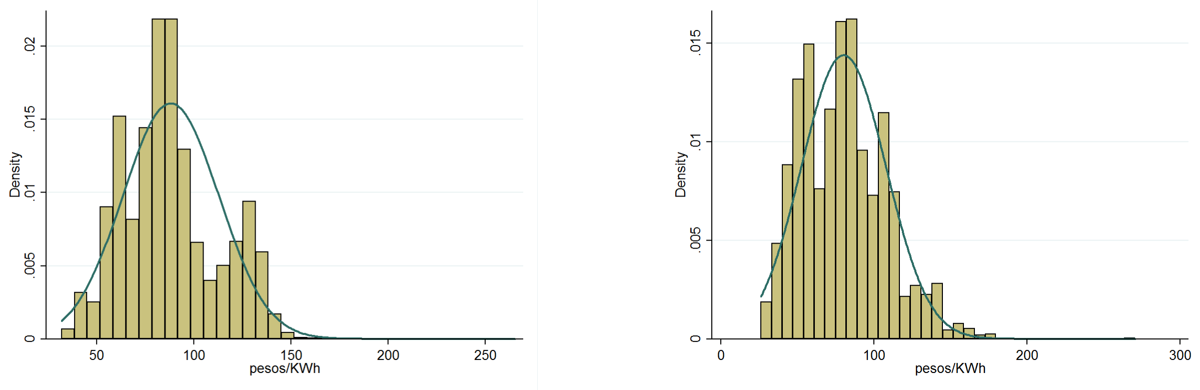
Daily marginal costs were calculated and imputed for 36 thermal plants belonging to 21 firms. Given the small differences in heat rate between publicly owned and private units, there are also no significant differences in the distribution of marginal costs between public and private generation units. Panels (a) and (b) in figure 3.4 present the histograms of the estimated marginal costs for private and public generation units, respectively.

As for the IEMP, recall that this incentive is related to the elasticity of residual demand. Since the Colombian wholesale electricity market allows us to observe the price bids and commercial availability of each plant as well as actual electricity demand, replicating the residual demand of each generator is feasible. The result of this exercise is a decreasing step function of residual demand on which the partial derivative is zero or indeterminate (McRae and Wolak, 2009) . Therefore, to calculate the inverse of the net semi-elasticity of demand, an approximation has to be made to the slope of this function around the market equilibrium price. Wolak (2003) suggests a non-parametric method for calculating the elasticity of residual demand using the points of the function with prices closest to —- both above and below —- the market equilibrium price.

As stated above, a daily version of the IEMP was computed to account for the fact that

Figure 3.4.: Estimated marginal costs

(a) Private units (b) Public units



Source: Data from XM - Calculations and elaboration: Author.

the generators in the Colombian electricity market maximize daily profits as opposed to hourly profits (see subsection 3.3.1). Adopting the methodology proposed by Wolak (2003), the empirical version of the IEMP - i.e. the second term on the right-hand side of equation 3.2 - can be computed as follows:

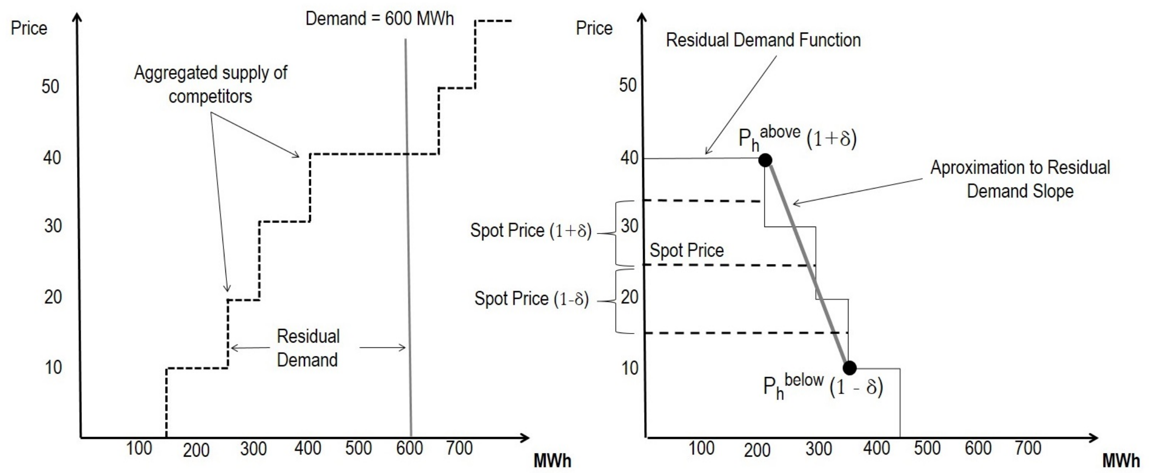
$$\widehat{IEMP}_{ijt} = \frac{-\sum(IG_{ith} - q^c_{ith}|\text{unit } j \text{ is marginal in hour } h)}{\sum(\frac{DR_{ith}(p_{th}\cdot(1+\delta)) - DR_{ith}(p_{th}\cdot(1-\delta))}{p^{above}_{th}(1+\delta) - p^{below}_{th}(1-\delta)}|\text{unit } j \text{ is marginal in hour } h)} \tag{3.6}$$

where $\widehat{IEMP}_{ijt}$ is the incentive to exercise market power on day t for unit j that is marginal during several hours of the day, $p^{above}_{th}(1+\delta)$ is the price of the next step in the residual demand curve above the price $p_{th}\cdot(1+\delta)$, $p^{below}_{th}(1+\delta)$ is the price of the previous step in the residual demand curve below the price $p_{th}\cdot(1-\delta)$, IG_{ith} is the actual ideal generation of producer i in hour h and q^c_{ith} is the quantity of energy committed in fixed price forward contracts. [3] In the Colombian wholesale electricity market this quantity is observable ex post. Finally, I assume a parameter $\delta = 0,05$ (5%). Figure 3.5 illustrates this non-parametric calculation technique. Previous studies using this methodology (Wolak, 2000; McRae and Wolak, 2009) claim that changes in δ do not

[3] From a supply function equilibrium approach (Klemperer and Meyer, 1989), the marginal price bid is the best response of an electricity generating firm given the actions taken by its competitors (as it sets its level of generation and the spot price). This optimal bid price is associated with an optimal generation quantity, so the residual demand of the generator in the equilibrium price should be equal to its ideal generation.

have a marked effect on the outcomes. Among the robustness tests, I computed the $\widehat{IEMP}_{ijt}$ for deltas of 10 and 25%. The main qualitative conclusions remain unchanged.

Figure 3.5.: Calculation technique of IEMP



Source: Data from XM - Calculations and elaboration: Author.

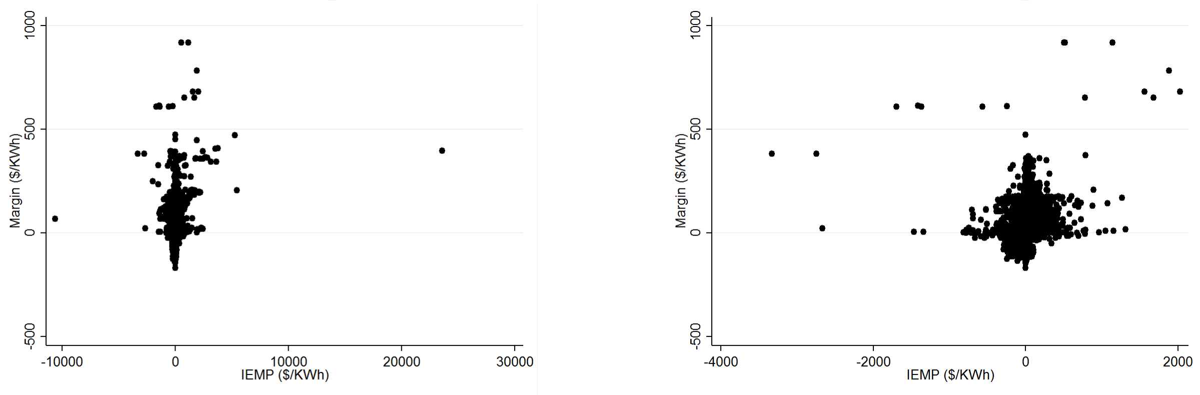
The information about daily price bids, hourly spot prices, hourly ideal generation and hourly sales in forward contracts —- essential details for the computation of the IEMP —- was taken from the website of the Colombian wholesale electricity market operator XM.

A shortcoming of the IEMP calculation technique presented above is that it can yield extreme values due to absolute values close to zero in the denominator of expression 3.6. In fact, in the sample analyzed in this paper, there are extreme values which can reach 2.228 times the interquartile range. Panel a of figure 3.6 presents the scatter plot for the IEMP and the margin $(P^*_{ijt} - c_{jt})$ for the total sample in which extreme outliers are present. In order to address this issue, the sample has been trimmed to exclude the observations corresponding to the 1% lowest values of the denominator of expression 3.6, i.e. the sum of the slope of the residual demand function. Panel b of figure 3.6 presents the scatter plot IEMP vs. margin, after the trimming. Among the robustness tests, several trimming percentile values are tested but they have no major impact on results.

Unlike the situation with estimated costs, some differences in the descriptive statistics

Figure 3.6.: Outliers and trimming of the sample

(a) Total sample (b) Trimmed sample



Source: Data from XM - Calculations and elaboration: Author.

of the IEMP for private and public companies were found. Figure 3.7 shows the distribution of the IEMP of the main electricity generation companies in Colombia, both public and private. Panel a of figure 3.7 presents the box-plot excluding extreme values. In this figure, it can be seen that while private companies, on average, have incentives to exercise market power through price increases, public companies have incentives to bid prices below the marginal cost. In panels b and c of figure 3.7, it can also be seen that the distribution of IEMP of private enterprises has more weight in the right tail, while that corresponding to public firms has more weight in the left tail. This occurs because, on average, the latter have a greater percentage of the energy they sell committed to forward contracts.

Finally, the information about instrumental variables — including daily water inflows and hourly commercial availability — was taken from the website of the Colombian wholesale electricity market operator XM. Table 3.4 highlights the main descriptive statistics of each of the variables included in the model.

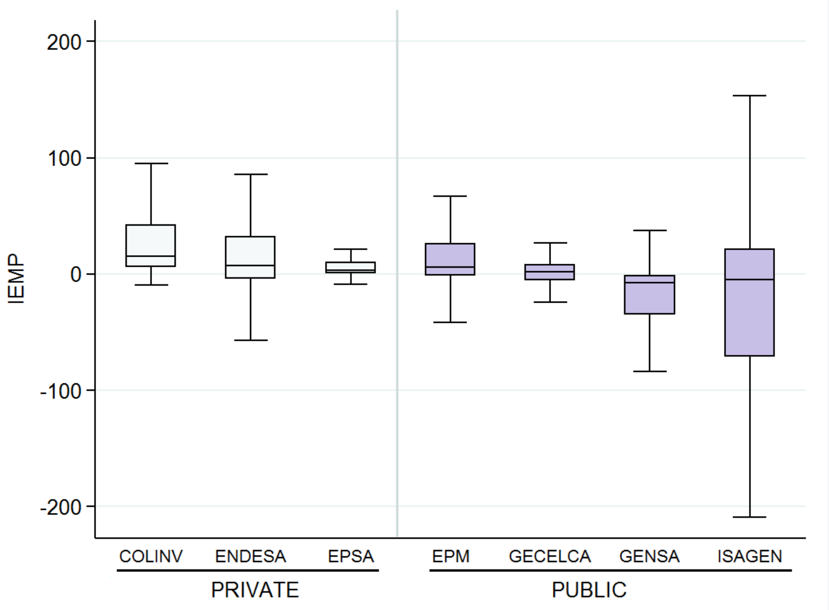
3.4.2. Estimation and results

Two way fixed effects estimations

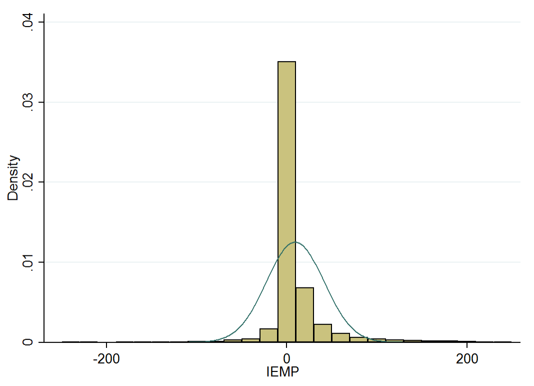
Given the marginal cost estimates for each plant and the incentives to exercise market power of each firm under the assumption of profit maximization, we can now estimate the econometric model of expression 3.3 and test the hypotheses formulated in subsection 3.3.2. In this first approximation, I ignore for the time being the truncation

Figure 3.7.: IEMP of private and public firms

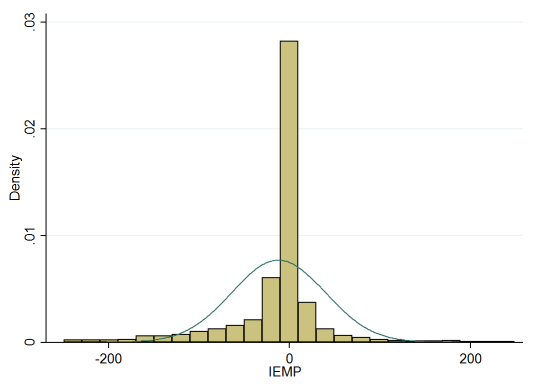
(a) Box-plot



(b) Histogram Private



(c) Histogram Public



Source: Data from XM - Calculations and elaboration: Author.

and endogeneity issues. The estimation of the two-way fixed effects model proposed in expression 3.3 was performed by ordinary least squares (OLS). Table 3.5 presents the results of the estimations. The specifications presented in columns (1), (2), and (3) include monthly fixed effects and generation unit fixed effects. These account for individual characteristics μ_j and temporary shocks φ_t.

In the case of H1, the results in table 3.5 suggest that there are marked differences between private and public firms in their respective exercise of unilateral market power.

Table 3.4.: Variables in the econometric model

Variable and unit	N.Obs	Mean	St. Dev.	Min	Max
Marginal Bid ($/KWh)	20,763	113.90	64.93	0	999.64
Marginal Cost ($/KWh)	20,763	84.52	26.44	26.28	270.73
IEMP ($/KWh)	20,763	-1.17	85.36	-3330.17	2024.58
Rivers inflows of competitors (GWh)	20,763	97.49	45.67	9.91	394.00
Availability of competitors (GWh)	20,763	11.04	1.08	7.38	14.24
Weekend day dummy	20,763	0.24	0.43	0	1
PRIVATE					
Marginal Bid ($/KWh)	11,318	110.08	70.77	0	999.64
Marginal Cost ($/KWh)	11,318	88.09	24.78	31.88	265.19
IEMP ($/KWh)	11,318	12.84	62.93	-663.68	2024.58
Rivers inflow of competitors (GWh)	11,318	98.56	45.36	20.84	394.00
Comercial availability of competitors (GWh)	11,318	11.07	1.18	7.43	14.24
Weekend day dummy	11,318	0.25	0.43	0	1
PUBLIC					
Marginal Bid ($/KWh)	9,445	118.47	56.81	27.87	721.91
Marginal Cost ($/KWh)	9,445	80.23	27.70	26.28	270.73
IEMP ($/KWh)	9,445	-17.95	103.71	-3330.17	1311.18
Rivers inflow of competitors (GWh)	9,445	96.22	46.00	9.91	394.00
Comercial availability of competitors (GWh)	9,445	11.00	0.95	7.38	14.00
Weekend day dummy	9,445	0.24	0.43	0	1

Source: XM - Market Operator

The null hypothesis corresponding to no difference in the coefficients is rejected at conventional levels of statistical significance. As expected, the coefficient for private firms is greater than that for public firms. The coefficient of the interaction of the IEMP with the private dummy is statistically significant at conventional levels in all cases and the magnitude of this coefficient is economically significant, positive and greater than those obtained for public firms.

As regards H2, no statistical evidence is found to reject the null hypothesis of no strategic behavior being shown by public firms. These results support the hypothesis of regulatory intervention by public firms in the Colombian electricity market.

As for H3, the results indicate that the IEMP has an impact on the pricing strategy of private firms. Although there is statistical evidence to reject the null hypothesis of perfect profit-maximization behavior, the coefficient for the private firms presents a positive sign and is statistically and economically significant.[4] According to these results, private firms exercise between 19.3 and 25% of the market power predicted by theory.

[4] I performed a conventional Wald test to verify the null hypothesis: $H_0 : \alpha_{pri} = 1$ for private firms.

Table 3.5.: OLS regression results

	(1)	(2)	(3)
Private IEMP	0.25***	0.20***	0.19***
	(0.06)	(0.06)	(0.06)
Public IEMP	-0.01	-0.04	-0.04
	(0.03)	(0.03)	(0.03)
Marginal Cost	-1.04***	0.76***	-0.34*
	(0.39)	(0.23)	(0.2)
Monthly F.E.	Y	N	Y
Unit F.E.	N	Y	Y
N.Obs	20,763	20,763	20,763
N. Clusters	36	36	36
R-squared	0.36	0.67	0.73
Joint-Sig.	64.95***	100.90***	104.2***
Test No Diff	16.86	12.21	13.34
p-Value	0.000	0.001	0.000
Test PMP	183.74	160.64	190.43
p-Value	0.000	0.000	0.000

Note: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%). SE clustered by unit in parentheses. Test No Diff: $H_0 : \alpha_{pri} - \alpha_{soe} = 0$ and Test PMP(Profit maximization by private firms): $H_0 : \alpha_{pri} = 1$.

In order to check the coherence of the results presented in table 3.5 as regards firm heterogeneity, independent regressions of the bid price on IEMP by firm were undertaken in line with McRae and Wolak (2009). Expression 3.3 was then estimated for the main multi-unit private and public firms. The firms analyzed account for more than 80% of the energy generated and in 89% of hourly periods these same firms set the spot price. The results of these econometric estimations are summarized in table 3.6 for private firms and table 3.7 for public firms.

Table 3.6 shows that the coefficients of the private firms are positive and statistically significant. Even though they differ for each private firm, the coefficient of the pooled regression falls inside the confidence intervals of the regressions for each private firm. In contrast, according to table 3.7, the coefficients of the public firms are not statistically significant and are even negative. These results support the hypotheses of behavioral differences between public and private firms and perfect regulatory intervention by public

Table 3.6.: OLS independent regressions by firm - Private

	ENDESA	COLINV	EPSA
	(1)	(2)	(3)
Private IEMP	0.18***	0.20**	0.19**
	(0.06)	(0.09)	(0.09)
Marginal Cost	2.00***	-1.95	5.90***
	(0.44)	(1.41)	(1.59)
Monthly F.E.	Y	Y	Y
Unit F.E.	Y	Y	Y
N.Obs	2,485	1,531	112
N. Clusters	7	6	-
R-squared	0.38	0.12	0.26
Joint-Sig.	8.839***	2.452***	6.818***

Note: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%). SE clustered by unit in parentheses.

Table 3.7.: OLS independent regressions by firm - Public

	ISAGEN	EPM	GECELCA	GENSA
	(1)	(2)	(3)	(4)
Public IEMP	-0.03*	-0.02	-0.17***	-0.02
	(0.02)	(0.02)	(0.05)	(0.02)
Marginal Cost	-0.87	-0.34	-1.67***	0.56***
	(0.78)	(1.08)	(0.61)	(0.16)
Monthly F.E.	Y	Y	Y	Y
Unit F.E.	Y	Y	Y	Y
N.Obs	1,133	471	3,000	3,634
N. Clusters	-	-	6	4
R-squared	0.04	0.00	0.22	0.02
Joint-Sig.	2.174	0.455	41.49***	14.07**

Note: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%). SE clustered by unit in parentheses.

firms.

The Tobit model results are presented in table 3.8. Although a considerable number of left-censored observations can be made, the model yields a behavioral pattern similar to that resulting from the OLS estimation: i.e. the IEMP is economically and statistically significant for private firms but not for public companies. Given the different interpretation afforded coefficients in the Tobit model, it is impossible to test the coherence of private behavior with profit maximization. However, these results do allow differences in the behavior of private and public firms to be tested. Indeed, this test supports the hypothesis of behavioral differences between public and private firms according to the premises of mixed oligopoly models.

Table 3.8.: Tobit- censored regression model results

	(1)	(2)	(3)
Private IEMP	0.26***	0.20***	0.19***
	(0.05)	(0.05)	(0.05)
Public IEMP	-0.01	-0.04	-0.03
	(0.04)	(0.03)	(0.03)
Marginal Cost	-1.08***	0.83***	-0.23
	(0.41)	(0.26)	(0.23)
Monthly F.E.	Y	N	Y
Unit F.E.	N	Y	Y
N.Obs	20,763	20,763	20,763
N. Clusters	36	36	36
Left-censored	974	974	974
Right-censored	2	2	2
Ps- R-squared	0.04	0.11	0.13
Test No Diff	25.63	18.35	19.08
p-Value	0.00	0.00	0.00

Note: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%). SE clustered by unit in parentheses. Test No Diff: $H_0 : \alpha_{pri} - \alpha_{soe} = 0$

Subsection 3.3.2 sounded a warning about potential problems of endogeneity arising from the interaction of the firms when the strategic component of the shocks of a rival firm's supply function is great. In terms of the elements presented in expression 3.3 , this entails relaxing the assumption that ε_{it} is uncorrelated with the IEMP. Hence, the OLS estimates need to be considered with caution given this potential identification problem.

As stated, to address the issue of endogeneity of the IEMP, I resorted to using instrumental variable techniques. I performed two stage generalized method of moments (GMM2S) in order to estimate the two-way fixed effects proposed in expression 3.3. As instruments I used the contemporary values, the quadratic transformation and the first three lags of the variables described in subsection 3.3.2. i.e. the inflows of the rivers feeding the rivals' firms, the competitors' commercial availability and the weekend day dummy variable.

There are two endogenous variables: the interactions $D_j^{pri}\widehat{IEMP}_{ih}$ and $D_j^{pub}\widehat{IEMP}_{ih}$. In the two way fixed effects model, The first stage equation for these variables is:

$$
\begin{aligned}
D_i^{owner} \times \widehat{IEMP}_{it} = \gamma_0 + \gamma_1 Flows^2_{-it} + \gamma_2(D_i^{pub} \times Flows^2_{-it}) + \gamma_3 Flows_{-it} \\
+ \gamma_4(D_i^{pub} \times Flows_{-it}) + \gamma_5 Flows_{-it-1} + \gamma_6(D_i^{pub} \times Flows_{-it-1}) + \gamma_7 Flows_{-it-2} \\
+ \gamma_8(D_i^{pub} \times Flows_{-it-2}) + \gamma_9 Flows_{-it-3} + \gamma_{10}(D_i^{pub} \times Flows_{-it-3}) + \gamma_{11} Avail^2_{-it} \\
+ \gamma_{12}(D_i^{pub} \times Avail^2_{-it}) + \gamma_{13} Avail_{-it-1} + \gamma_{14}(D_i^{pub} \times Avail_{-it-1}) + \gamma_{15} Avail_{-it-2} \\
+ \gamma_{16}(D_i^{pub} \times Avail_{-it-2}) + \gamma_{17} Avail_{-it-3} + \gamma_{18}(D_i^{pub} \times Avail_{-it-3}) \\
+ \gamma_{19}(\widehat{CMG}_{ijt}) + \psi_{weekday} + \mu_j + \varphi_t + \eta_{it}
\end{aligned}
$$

where the $owner$ can be either private (pri) or public (pub), $Flows_{-it}$ is the sum of inflows of the rivers which feed the reservoirs of the major hydroelectric units of the competitors of agent *i* on day *t* measured in GWh, $Avail_{-it}$ is the sum of the commercial availability of the competitors of agent *i* on day *t* measured in GWh, $\psi_{weekday}$ is the weekend day dummy, μ_j represents unit fixed effects and φ_t are monthly fixed effects. The results of these GMM2S estimations are shown in table 3.9.

In the case of H1, the GMM2S estimations yield qualitatively similar results to those obtained by the OLS regressions. The null hypothesis to the effect that there is no difference in the coefficients of private and public firms is rejected. The coefficients of private firms are positive, statistically significant and greater than those of the public companies.

As for H2, different results are obtained depending on the particular model specification. For the model that ignores individual heterogeneity, the sign of the coefficient for public firms is negative and statistically significant. Conversely, the model that accounts for time and unit fixed effects yields a positive coefficient that is both economically and statistically significant.

Table 3.9.: Two way fixed effects - GMM - results

	(1)	(2)	(3)
Private IEMP	0.99***	0.90***	0.78***
	(0.28)	(0.13)	(0.08)
Public IEMP	-0.65**	0.01	0.27**
	(0.27)	(0.08)	(0.11)
Marginal Cost	-1.29	0.52***	-0.40***
	(0.15)	(0.08)	(0.08)
Monthly F.E	Y	N	Y
Unit F.E	N	Y	Y
N. Obs	15,742	15,742	15,742
N. Clusters	36	36	36
Joint Sig.	43.78***	59.59***	65.76***
Weak Identification			
F first stage Private	92.83	1844.93	617.36
F first stage Public	37.36	7.05	11.4
K-P rk Wald F	7.70	23.84	2.08
Cragg-Donald Wald F	13.58	7.26	6.59
Overidentification			
Hansen J	14.016	22.58	19.69
p-Value	0.78	0.26	0.41
Test Diff	15.81	27.56	8.89
p-Value	0.00	0.00	0.00
Test PMP	0.00	0.59	6.94
p-Value	0.96	0.44	0.01

Note: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%). SE clustered by unit in parentheses. Test No Diff:$H_0 : \alpha_{pri} - \alpha_{soe} = 0$ and Test PMP (Profit maximization by private firms): $H_0 : \alpha_{pri} = 1$. The test statistics for weak identification is the Kleibergen-Paap rk Wald F and the Cragg-Donald Wald F. H0: Instruments are weak. The critical values for two endogenous variables and tweny one excluded instruments are 20.53, 11.04 and 6.10 for 5%, 10% and 20% maximal IV relative bias, respectively, according with Stock-Yogo (2005)

However, it should be noted that these estimations differ quantitatively from those obtained by OLS. The coefficients from the GMM2S estimations yield values of a higher order of magnitude, especially those for the private firms. These results are coherent with the attenuation bias problem in the OLS estimators. Indeed, I found values that are three to five times higher than those obtained when using the OLS estimation. In addition, the value of these coefficients is closer to the expected theoretical value of the the profit maximization models for private firms.

As for H3, note that the specifications including time or unit fixed effects do not allow the null hypothesis to be rejected at any standard level of significance. In the case of the two-way fixed effects model, the hypothesis of profit maximization behavior by private firms cannot be rejected at the 1% significance level.

When testing the adequacy of the instruments, the J-Hansen statistic suggests that the models satisfy the exclusion restriction. As for the potential weakness of the instruments, the F-statistic for each of the endogenous regressors meets the rule-of- thumb threshold of values higher than 10 for the models in columns (1) and (3). Moreover, the Cragg-Donald Wald F-statistic suggests that the GMM2S estimations presented in table 3.9 have a maximum bias, which would not be more than 10% of the bias of the OLS estimations for the models in columns (1) and not more than 20% for the models in columns (2) and (3), according to Stock and Yogo (2002) criteria. Alternatively, the Kleibergen-Paap rk Wald F-statistic suggests that the GMM2S estimations presented in table 3.9 have a maximum bias, which would not be more than 5% of the bias of the OLS estimations for the model in column (2), 20% for the model in column (1) and more than 30% for the model presented in column (3), according to Stock and Yogo (2002) criteria. Although several of the models presented satisfy some of the criteria for discarding the weakness of the instruments as a relevant issue, the results presented in table 3.9 should be considered with caution given that there is no clear consensus regarding the criteria for the detection of weak instruments when the conditional homoskedasticity assumption is not valid.

Structral interpretation

As discussed in section 3.3.2., I adopted a structural interpretation of the first order condition in equation 3.2 when estimating the parameters α_{pri} and α_{pri}. It is assumed that the marginal cost and marginal revenue components are measured correctly. The model presented in column (1) of table 3.9 corresponds to expression 3.4 while the model presented in column (2) corresponds to expression 3.5.

There are no marked differences in the results between the two specifications presented in table 3.10. The GMM2S estimation yields coefficients higher than 1 for private firms. The unilateral profit maximization test is rejected. In the case of public companies, it yields negative and significant coefficients. The test of non-strategic behavior by

Table 3.10.: Structural model - GMM - results

	(1)	(2)
Private IEMP	1.83***	1.76***
	(0.27)	(0.20)
Public IEMP	-1.56***	-1.91***
	(0.29)	(0.34)
Marginal Cost	0.93***	-
	(0.07)	-
N. Obs	15,742	15,742
N. Clusters	36	36
Joint Sig.	210.1***	45.62***
Weak Identification		
F first stage Private	8.04	7.16
F first stage Public	12.96	13.41
K-P rk Wald F	19.84	13.66
Cragg-Donald Wald F	11.08	26.11
Overidentification		
Hansen J	27.95	28.47
p-Value	0.08	0.07
Test Diff	80.07	81.53
p-Value	0.00	0.00
Test PMP	9.78	12.02
p-Value	0.00	0.00

Note: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%). SE clustered by unit in parentheses. Test No Diff:$H_0 : \alpha_{pri} - \alpha_{soe} = 0$ and Test PMP (Profit maximization by private firms): $H_0 : \alpha_{pri} = 1$. The test statistics for weak identification is the Kleibergen-Paap rk Wald F and the Cragg-Donald Wald F. H0: Instruments are weak. The critical values for two endogenous variables and twenty one excluded instruments are 20.53, 11.04 and 6.10 for 5%, 10% and 20% maximal IV relative bias, respectively, according with Stock-Yogo (2005)

public firms is rejected. This suggests that the behavior of public firms is the opposite of that expected of firms that seek to maximize profits. Thus, they increase (decrease) their bids above (below) the marginal cost when there are profit-maximizing incentives to decrease (increase) the price. Given the strong assumptions of the lack of relevance of time-invariant heterogeneity and time-variant common factors, these results must be treated with caution.

In short, the results of the econometric exercises performed here suggest that, in the Colombian wholesale electricity market, private firms are more responsive to their incentives to exercise market power than are public firms. Moreover, there is empirical evidence in support of the hypothesis of regulatory intervention by the latter in the Colombian electricity market. The introduction of structural elements in the identification strategy reveals indications of attenuation bias in the OLS estimators and partial evidence of the profit-maximization behavior of private firms in the Colombian spot market. Overall, this indicates that the private ownership share of electricity generation is not neutral as regards competition.

3.4.3. Robustness checks

The results presented above are dependent on a particular specification of the econometric model regarding such choices as:

i The percentage by which the sample should be trimmed in order to eliminate the IEMP outliers;

ii The lags of the instruments in the first stage of the IV estimations; and

iii The delta (δ) parameter when computing the incentives to exercise market power.

Here, several estimations of the econometric model are run to test different specifications of these choices. Overall, the qualitative results of the model seem to be robust to the different options. First, in the baseline estimation, the sample was trimmed to exclude observations corresponding to the 1% lowest values of the denominator of expression 3.6. Table B.1 in the appendix B.1 presents the estimations when trimming observations corresponding to the 0.1 and 5% lowest values. The OLS estimates of the coefficient of private IEMP yield values that lie within the 95% confidence interval of the baseline estimation. Similarly, the OLS estimates of the coefficient of private IEMP are not statistically significant or are very close to zero. In the case of the GMM2S estimations, even though the coefficients of the private IEMP show lower values for the sample trimmed to the 0.1% lowest values, they are still statistically and economically significant. In the case of the IEMP of public firms , the results remain unchanged.

Second, in the baseline estimation, the first three lags of the river inflows and the commercial availability of the competitors were used as instruments for the GMM2S estimations. I repeated the estimations of this model using the first two and first four lags in the instrumental variable specification. These estimations are reported in table B.2 in the appendix B.1, where they can be seen to be similar to the baseline estimation. Finally, in the baseline estimation, a delta δ parameter of 5% is set in order to take into account the price window when calculating the slope of the inverse residual demand function. The calculation of the IEMP was performed again using δ parameters of 10 and 25% and the estimations were repeated with the same baseline econometric specification. The results are shown in table B.3 in appendix B.1. Although the value of the private IEMP coefficient seems to increase with the delta parameter, these econometric regressions indicate that the most important qualitative conclusions of the baseline estimation remain unchanged.

3.5. Conclusions

In this study, bid price information for the Colombian electricity market has been used to understand differences in the way in which private and public firms exercise market power. Here, the methodology developed by McRae and Wolak (2009) has been extended to deal with firms that do not price strategically. A new interpretation is proposed of the impact of incentives to exercise market power on prices in an effort to obtain evidence of the profit-maximizing behavior of private firms and the adoption of the marginal cost pricing rule by public firms.

Estimations of the semi-elasticity of demand combined with contracting information suggest that the generators analyzed — both state-owned and private — had incentives to exercise market power in association with profit-maximization behavior. An econometric analysis was conducted to find statistical evidence of: i) differences in the impact of incentives to exercise market power on the bids and prices of state-owned and private firms; ii) the non-exercise of market power by public companies in accordance with the marginal cost pricing rule; and iii) the exercise of market power by private firms concordant with profit-maximization behavior. Based on the outcomes of these econometric estimations, two main conclusions can be drawn: first, marked differences exist in the way in which private and state-owned firms exercise unilateral market power - specifically, private generators in the Colombian market are more responsive to IEMP than are public firms; and, second, public firms exercise regulatory intervention in the Colombian electricity markets - that is, they are not responsive to IEMP.

These findings suggest that the ownership regime of firms in Colombia's electricity industry is not neutral as regards the exercise of market power. Moreover, the outcomes reported have important implications for the regulation of electricity markets and the privatization of state-owned firms. First, besides increasing competition, there would appear to be an alternative way to achieve efficiency - namely, the mitigation of market power by state-owned companies. Likewise, regulators need to recognize the nature of ownership within the market they are designing and determine whether public companies implement market power mitigation strategies. Second, the absence of neutrality in the exercise of market power implies that privatization has indirect effects on market competitiveness. This means the government should take into account the possible anti-competitive effects that privatization might have and include these undesirable costs in their valuation of the sales operation of state-owned generation units.

4. Transparency and the value of relational collusive arrangements[1]

4.1. Introduction

The problem of observability posed by Stigler (1964) is a key pillar in the analysis of the role of information in the formation of equilibrium prices in oligopolistic industries. He proposed the idea that coordinated equilibria in repeated games require a mechanism of rewards and punishments in which the possibility of observing deviations is a key element. The lack of transparency, understood as the difficulty of observing the actions of other competitors (imperfect monitoring), makes it more difficult to verify whether the reductions in sales perceived by a particular agent are caused by a deviation by another firm or by an exogenous shock. This, in turn, hinders the decision on when to activate the punishment mechanisms inherent in the agreement. Several seminal papers deepened in the theoretical analysis of this issue (see for instance Green and Porter (1984) and (Abreu et al., 1986)). [2] Although recent theoretical evidence has raised the possibility that transparency makes collusion harder (Sugaya and Wolitzky, 2018), [3] the conventional wisdom is that transparency facilitates collusion.

Despite the relevance of the observability problem, so far there is scarce empirical evidence of the role of information disclosure in the formation or collapse of cartels. In part, this is because collusion is difficult to study in the field. First, the fact that collusive

[1]This chapter is a co-authored paper with Miguel Espinosa (Assistant Professor at the Department of Economics and Business, Universitat Pompeu Fabra and Affiliated Professor at the Barcelona GSE) and Rocco Macchiavello (Department of Management, London School of Economics

[2]Several papers extended the theoretical analysis of the imperfect monitoring issue in the collusion framework (Abreu et al., 1991; Matsushima, 1989, 2001; Sannikov and Skrzypacz, 2007).

[3]These authors show conditions under which cartels obtain greater profits when market outcomes are only private information. They argue that more information allows firms devise more profitable deviations from the collusive agreement. This theoretical ambiguity, reinforces the need to empirically study the effects of transparency policies in market outcomes on firm pricing strategies. Our analysis aims to make contributions in this regard.

agreements are illegal in most jurisdictions, makes the cartels design complex coordination strategies that make detection entangled. Secondly, in several circumstances, the diagnosis of the existence of collusive agreement is based on signals that can also be explained by unilateral market power strategies. These makes that authorities and econometricians can confuse these conditions with other phenomena. A symptom that reflects these difficulties is the fact that most empirical studies that investigate collusion are applied under experimental conditions or use data from cartel cases previously detected by competition authorities. [4] In relation to the specific study of transparency, the paper of Aoyagi and Fréchette (2009) and Harrington Jr et al. (2016) conducted several experiments in order to exploring the relation between communication, market structure and collusion. These authors find that the disclosure of price information can facilitate coordination in the case of the duopoly or when companies are symmetric. Levenstein (1997) studies the previously documented collusion case of bromine U.S producers between 1885 and 1914. This study concludes that some price wars resulted from the imperfect monitoring problems.

This paper investigates from an empirical perspective the role of disclosure information in the stability of informal coordination agreements. We study the economic effects of the announcement and implementation of a non-transparency policy in the Colombian wholesale electricity market in 2009. This measure consisted of increasing from 2 days to 3 months the period between the closing of the electricity market daily auction and the disclosure of the information of bidding prices and sales.

The key element that makes the study of this field experience unique and interesting is the fact that the announcement of the policy was made several days before its effective implementation. The act announcing the policy change was published on January 30, 2009 but the measure took effect since February 6, 2009. This particularity makes it possible to distinguish between the impact of the announcement and the impact of the effective implementation of the non-transparency policy. This distinction becomes very important if we consider the different effects that the mere announcement would have on the behavior of an agent that exercises unilateral market power and the behavior of another involved in an implicit collusion agreement.

In the first case, the firm uses the information on market outcomes to design a pricing strategy that allows it to unilaterally maximize its profits in the current stage of the market. The announcement of the measure does not alter the amount of information that

[4] Some examples of recent studies in this line of research are Hyytinen et al. (2018),Bos et al. (2018) and Igami and Sugaya (2018).

can be used for this purpose, so its bidding strategy would not be expected to change radically.

In a different way, the agents involved in a coordination agreement use the information to verify the abide of the agreement by others members of the cartel and more than maximize the profit in the one shot game, they aim to maximize the expected long-term profits in a repeated interaction framework. The announcement of the measure seriously affects expectations about future profits, since it allows predicting a catastrophic damage in the monitoring mechanism that makes coordination possible. Given this foresight, the companies involved in the agreement realize that detecting deviations from the agreement will be harder. By means of a backwards induction reasoning, it is expected that the cartel members will try to anticipate to opportunistic behavior of other members deviating from the agreement since the moment of the announcement of the policy.

Hence, the distinction between the effect of the announcement and the effect of implementation provides a unique opportunity to isolate the impact of the unilateral strategies from the impact of the coordination strategies.

The empirical analysis of this paper documents an abrupt decrease in bidding prices by private companies, just between the date of announcement and the date of effective implementation of the non-transparency policy. We estimate the magnitude of the bidding price decrease to be between 21% to 33%.

We first present a descriptive analysis of the average bidding price data over August 2008 - July 2009. We present the patterns of the raw time series and perform a test of structural break with endogenous breakpoint date. The simple visual inspection of the raw data suggests a significant drop in bidding prices around the date of the announcement of the policy. Likewise, the structural break tests indicate that the series break point date is located a few days before the implementation date. We estimate several differences-in differences models using the public firms as control group.

The results of these models documents a economically and statistically significant decrease in bidding prices by private firms during the period between the announcement and the implementation of the policy. We rule out several possible explanations for the remarkable decrease in the bidding prices of private firms around the date of the announcement of the no-transparency policy. We interpret these findings as suggestive evidence of the existence of an informal coordination relation between private firms in the Colombian wholesale electricity market.

To explore the possibility that others factors had been the cause of the potential collapse of the informal collusive relation and to quantify the effect of the non-transparency policy on the value of this relation, we estimate a simple structural model based in the work of Igami and Sugaya (2018).

We model the wholesale electricity spot market with a quantity game, in which private firms face a linear residual demand resulting from the supply decisions of a competitive fringe. We use quantitative information of bidding prices from the market operator to estimate the key parameters of the residual demand. We also perform base-engineering estimations of the marginal costs of thermal generation units.

Following the model of repeated interaction in a non-transparency context presented in **?**, we characterize the cartel agreement as a quota system to maximize the collective profits (given the residual demand curve and the firm's cost), and assume the firms use trigger strategies with the threat of reversion to the static Cournot-Nash equilibrium if someone's non-compliance is suspected.

Based on the characterization of the repeated game in two regimes, i) transparency and ii) non-transparency, we computed for each one the incentive compatibility constraint of a representative firm . The results indicate that the collusive agreement would have been sustainable in the periods after the date of the announcement of the non-transparency policy in the counter-factual of continuity of the transparency regime. According to this model the economic quantification of the impact of the non-transparency policy on the incentive compatibility constraint is between -1.54 % and -3.10 % of the annual GDP of the Colombian electricity industry in 2009.

Related Literature. This paper contributes to two strands of literature. Recent papers have focused its attention in the empirical analysis of the mechanisms of emergence or collapse of price coordination mechanisms. Miller and Weinberg (2017) investigates the relation between a sky rocketing increase in retail beer prices and the joint venture of two important competitors in the United States market. They suggest that the joint venture facilitated price coordination. Byrne and De Roos (2019), investigate the channels of initiation of price coordination in the retail gasoline industry. They document that dominant firms creates focal points that triggered market prices coordination. Tadelis and Zettelmeyer (2015) estimated the effect of quality information disclosure using data from large-scale experiment in the auto-mobile auctions. They find that disclosure of quality information facilitates the matching between different types of consumers. Several papers have investigated the issue of collusion detection in the particular context of procurement auctions. Bajari and Summers (2002), Bajari and Ye (2003) and more recently Kawai and Nakabayashi (2018) are good examples.

One important aspect of our paper is that it studies the stability of cartel enforcement and its interaction with the market information transparency in the context of repeated interaction. One important paper adopting a similar approach is the study of Chassang and Ortner (2019). They propose a test of repeated-game collusive behavior in the context of repeated procurement auctions exploiting the theoretical predictions of introducing minimum prices. More oriented to the specific effects of transparency policy, Albæk et al. (1997) study a change in the transparency of prices and discounts of the Danish ready-mixed concrete and a subsequent increase in average prices. Their results suggests that the better explanation of this increase in prices is the facilitation of tacit coordination. Other important reference in this issue, is the recent paper of Lu et al. (2019). It examines the impact of the concealment of the identity of the winner in the outcomes of the B2B auctions. These authors find that the concealment of the identities of the winners is related to a significant increase in the closing price of the auctions. This finding points against the predictions of the conventional theoretical models of transparency and collusion. Our paper contributes to the better understanding of the relation between transparency and coordination in the framework of auctions design because in the case we analyze, we are able to isolate the effect of a coordinating relation form the confusion factors related with unilateral market power. This approach is related to the test of static Nash behavior presented in Mercadal (2019). Like her, we base our test of dynamic coordination in the intuition that, in a repeated game, firms involved in a collusive arrangement respond to the threats from regulatory changes even before they are effectively implemented.

Regarding the second branch of the literature, only few recent papers have focused on providing empirical tools for detecting and quantifying the value of dynamic self enforcement relations. Macchiavello and Morjaria (2015) found empirical evidence of the effort made by flower producers in Kenya to preserve the value of their informal relationships with foreign buyers during negative supply shocks. Blouin and Macchiavello (2019) investigated strategic default on forward sale contracts in the international coffee market and proposed a test to identify it in situations of unanticipated price increases. The findings and methodology of this paper contribute to the empirical literature on informal self-enforcement relationships between firms. The rationale of distinguishing between the effects of the announcement and the effect of the occurrence of a determinant fact may be applied in several contexts to identify the existence of informal self-enforcement relations. [5]

The rest of the paper is organized as follows. In section 4.2 we present a general de-

[5] Our paper is also related with the literature of the design of electricity markets. The majority of this literature is concerned on the unilateral market power more than in coordination strategies. There are few

scription of the Colombian electricity market, we describe the most important features of the institutional framework of the multi-unit auction functioning and we explain in detail the process of issuance of the non-transparency policy as well as the rules embodied in it. Section 4.3 explains the rationale of the test of informal coordination and presents the empirical analysis. Section 4.4 presents the structural model and the quantification of the impact of the non-transparency policy in the value of the informal collusive relation. Section 4.5 concludes and discusses the most important policy implications.

4.2. Industry background

4.2.1. Demand and supply

The wholesale electricity market in Colombia provides energy to the regions connected to the national transmission system. Although these areas only represent 28% of the Colombian territory, 96% of the population inhabits them. In 2009, the average daily electricity of the interconnected system in Colombia was 149.81 GWh and the peak power demand was around 9290 MW. The demand for energy fluctuates at different times of the day. 7 p.m. is the hour of peak demand and 3 a.m. is the hour of lowest demand. Given its location in the tropic, demand does not vary significantly in the different months of the year. Regarding the profile of the electricity supply of the interconnected system in Colombia, in 2009, the share of participation of the different generation technologies over the installed capacity were: 66.7% hydropower, 32.9% thermal generation (20.4% gas-fired, 7.3% coal-fired and 5.2% other fuels) and 0.4% of other small units (cogeneration and wind). With respect to the property characteristics of the generation units, 47% of installed capacity is private owned. The Colombian Electricity Market is a concentrated oligopoly. The calculation of the Herfindahl-Hirschman index of the

papers focused in the issue of market coordination in electricity markets and its implications for market design. Fabra and Toro (2005) use a time series Markov-switching model for analyzing the properties of the collusive strategy of several firms in the Spanish electricity market. Puller (2007) study the pricing pattern of firms during the existence of the California wholesale electricity market. He finds that several firms raised prices above the unilateral market power. However, these prices did not reach the joint monopoly price. As far as we know, the only paper empirically studying the problem of transparency in electricity markets is the study of Brown et al. (2018). These authors find evidence suggesting that important market participants used the information reports for coordinating its bidding strategies. The conditions of the policy change analysed in our document allow us to go beyond the study of how agents use the price offer information in the coordination process and analyze if the the role of the observability in this process.

installed capacity is around 1800. The 4 largest companies accumulate 65% of installed capacity and set the spot price 80% of the time.

In relation to hydro technology, it should be highlighted that Colombia's rain regime is subject to the effects of El Niño and La Niña events. During the former, dry weather conditions have a negative impact on the contribution of hydroelectric resources, while the opposite occurs during La Niña events. In addition, the annual rain regime fluctuates between dry (December, January and February) and wet (April, May and June) seasons.

With regard to gas fired generation, in 2009 there were two types of gas markets for these generation units: i) Primary Market and (ii) Secondary Market. (See Comision de Regulacion de Energia y Gas (CREG) (2009) Page 16). In the Primary Gas Market the gas producers sell long run contracts to the buyers, [6] in the secondary market, the owners of gas contracts have the opportunity to resell the gas to other consumers. The availability of gas in secondary market depends on the amount left after the owners of the contracts have made their consumption decisions. Buyers and sellers agree on the price of gas and the former only pay if they use the gas. The price of this market is not regulated.

Electricity generation represents the largest segment of the gas market. In 2009, it consumed around 535 GBTU per day, which represented 56% of total consumption. The most important gas supply source for Colombian thermal generation is the basin Guajira which is located on the north coast of the country. In 2009, 82% of gas consumption for electricity generation came from that source. [7]

Since September 1995 until August 2013, the Colombian Government regulated the price gas coming from Guajira basin. The regulation consisted in fixing a maximum price of gas. Before the issuance of the public services law in 1994, the price of gas was calculated with base-engineering methodologies and it was indexed to the FOB price of the fuel-oil exported by the national oil public company (ECOPETROL). After August 2013, the price of the gas from Guajira results from the sale process of the wholesale gas market. In the remaining gas sources the price was not regulated.

[6] Most sales are made through Take or Pay contracts. This type of contracts guarantee the delivery of gas specifying the amount, the date and the location of the gas transmission system. No matter if the buyer use or not the gas, it is compelled to pay for the amount committed in the contract.

[7] Information taken from the report of the operation of the Colombian electricity market system and administration of the year 2009 published by the market operator (Expertos en Mercados (XM), 2009).

4.2.2. Institutional setting

The entity in charge of regulating the information transparency conditions in this market in Colombia is the Commission of Energy and Gas Regulation (CREG) and the entity in charge of managing the information related to the market and providing the web platform for access to it is the market operator XM.

The Colombian wholesale electricity spot market is a uniform price multi-unit procurement auction. There is only one pricing node for the whole market, i.e. the same wholesale spot price is paid in all the regions. The suppliers must submit one time per day their bidding program. There are not intra-day balancing markets. The daily bidding program for each generation unit consist in availability declarations for each hour and a unique bidding price (willingness to sell) for the whole day. It must be submitted before 6:00 am of the day before the spot market clears. The units with Installed capacity less than 2 MW are not allowed to bid prices in the auction. These small units account for less than the 5% of the installed capacity. They are considered as load base generation and receive the spot price for the energy that provide to the system. The majority of these small units are run-of-river hydropower plants.

Although only one bidding price is allowed for each unit per day, the Colombian wholesale electricity market clears hourly. The change in the hourly spot price accounts for the change in the availability of the units, the supply shocks of the load base generation and the fluctuation of hourly demand. Once the suppliers have submitted the daily bidding program for each generation unit, the system operator minimizes for each hour the cost of providing energy disregarding the potential restrictions in the transmission network. The spot price is the bidding price of the marginal generation unit necessary for fulfil the demand under no restrictions condition.

This final allocation of production quantities is called ideal dispatch. However, as is frequent in electricity markets, transmission constraints and other contingencies may arise and make infeasible the assignation of the ideal dispatch. The market operator attempt to minimize the costs of the contingencies and reorganizing the assignation to make it compatible with technical constrains. The outcome of this rearrange is called real dispatch. In order to compensate the market participants for the differences between the ideal dispatch and the real dispatch the regulation established a compensation scheme called positive and negative reconciliations.

A positive reconciliation occurs when the real dispatch generation is greater than the ideal dispatch generation for a specific generation unit. According to the regulation in effect in 2009 in Colombia, in these cases, for each unit of additional energy delivered to the market, the generator receives a price equal to the maximum between a cost-based regulated price and the bidding price for the corresponding generation unit.

When the real dispatch generation is less than the ideal dispatch generation, a negative reconciliation arise. According to the regulation in effect in 2009, the generator receives the payment of the spot price for all the energy corresponding to the ideal dispatch. However, for each unit of energy difference between the ideal and real dispatch, it must reimburse to the market operator the average of the spot price and the bidding price of the unit with negative reconciliation.

4.2.3. Description of the policy change

Prior to the policy reform, the transactions information in the Colombian wholesale electricity market was transparent. Two days after the closing of the auction, the information of the bidding program including the identities of the suppliers, the ex-post electricity sold by forward contracts, the quantities of positive and negative reconciliations was published in the web page of the market operator.

During the last quarter of 2008, it was documented an increase in the spot price of the Colombian wholesale electricity market. Although December corresponds to a season with low levels of hydraulic energy, during 2008 there was a rainfall level higher than in former years. This alarmed the regulatory commission and and specially to the central government authorities. The perception of these authorities was that the Colombian electricity market was suffering from anticompetitive practices such as unilateral market power or collusion (Document CREG 005 - 2009, regulation CREG 006 - 2009).

The main authorities of the Colombian electricity sector (Ministry of Energy, CREG and the Public Services Surveillance Authority) held several meetings between December 2008 and January 2009. In one of these encounters in January 6, 2009 was discussed the need to take measures to prevent anticompetitive behaviors in the electricity market. Among other actions, it was proposed to explore legal alternatives to avoid communication between electricity generation companies and carry out direct inspections by the Public Services Surveillance Authority.

Colombian regulators hired to Professor Peter Cramton (University of Maryland) as consultant. According to the documents that complement the resolution that enacted the non- transparency policy, in a presentation on January 24, 2009 he recommended reveal all bids only 90 days after the closing of the auction in order to hinder potential tacit collusion. Following his advice, regulators decided to change information disclosure of bidding prices.

The act was signed on January 30, 2010 but took effect since February 6, 2009. Once the non-transparency policy took effect, the information disclosure delay was extended from two days to three months after the auction. Once the policy was in effect, the only publicly available information two days after the closing of the auction was the spot price. Each plant was also informed whether or not they was awarded in the auction or they had (positive or negative) reconciliations. The argument of the regulation authority for a three month delay in information disclosure was avoiding that the agents could use this information with anticompetitive purposes. The measure also mandated that the generating units kept their bidding programs' information secret. The act did not announce any specified date in which it would change.

Other act (resolution 015 of 2009) complemented the above resolution by making explicit that other entities that had access to the market data for technical reasons, such as transmission network and gas production entities, could not make any information (related to the market) public (before the mandated three month period). Later, resolution 127 of 2009 relaxed some conditions of the non-transparency policy. This act mandated to make public the winners of the auction and those mandated to receive positive and negative reconciliations. It was signed October 2, 2009 and took effect on October 5, 2009 .

These restrictions in information disclosure were in effect until December 4, 2009. Around august 2009 started a El Niño event which lasted until May 2010. As stated above, in Colombia this phenomena provokes a decrease in rainfalls, and therefore a decrease in the supply of hydro-generated electricity. Regulators thought that by making the market more transparent, the agents (generation units, regulators, input producers) could face better this weather shock. The act that interrupted the effect of the non-transparency policy was resolution 159 of 2009. This act dictated that the disclosure of the information on the bidding program would be made two days after the auction, that is, in the same way as in the initial rules scheme. This policy was signed December 3, 2009 and took effect on December 4, 2009. This act also dictated that once the El Niño event ended, the three month non-transparency policy would take effect again.

Finally, once the El Niño event started disappearing, authorities discussed with the stakeholders the convenience of the restriction on information disclosure. Colombian Association of Energy Generators (ACOLGEN) claimed that public information is key to know whether or not agents follow the rules of competition and facilitates the planning and coordination of the market operation. Furthermore, they argued that there is no evidence that restricting information improves efficiency and making public the information makes agents accountable for their actions. On the other hand, the market operator (XM), argued that it was under a reputation risk due to the management of secret information. As well, they recognized that the coordination between different entities involved in the operation of the market was harder than it should be, due to the information restrictions. As a consequence the regulator approved resolution 138 of 2010 on September 17, 2010. This act took effect on 22 September 2010. It reduced the period of information concealment from three to one month. The act did not announce any specified date in which the non-transparency would change or would be reviewed. The table 4.1 summarizes the information restrictions of each of the acts that embodied the non-transparency policy.

4.2.4. Data

In this paper we use two datasets. The first contains detailed information on market outcomes of the Colombian wholesale electricity market from August 2008 to July 2009. This includes the bidding programs submitted by the suppliers to the Colombian day-ahead electricity market, the forward contracts hourly sales of each generation firm, the hourly demand and the daily water intakes of the reservoirs of the most important hydro generation units. This database was constructed with the files available in the web page of the market operator XM.

The second dataset consists of information on input prices and the estimation of marginal costs for thermal generation units. We use a base-engineering accounting methodology to obtain estimations of the marginal cost of the thermal generation units in Colombia. Similar methods has been implemented in the previous literature on electricity markets (Green and Newbery, 1992; Wolfram, 1998, 1999; Borenstein and Bushnell, 1999; Borenstein et al., 2002; Wolak, 2000; Fabra and Reguant, 2014). We computed the marginal costs of thermal plants taking account of the technical parameters (heat rate) of each unit, fuel costs and fuel transportation costs. The details of the calculus are presented in appendix A.3. It is important to bear in mind that these computations may contain some measurement error given that we approximate the fuel costs to references prices, and the cost per unit in the actual fuel supply contracts may be different.

Table 4.1.: Changes in transparency policy

Disposition	CREG24-1995	CREG06-2009	CREG127-2009	CREG159-2009	CREG 138-2010
How long?	13 years, 2 months	8 months	2 months	10 months	2 years, 3 months
Validity	Since 7/24/1995 to 2/06/2009	Since 2/06/2009 to 10/05/2009	Since 10/05/2009 to 12/04/2009	Since 12/04/2009 to 9/22/2010	Since 9/22/2010
Bid Information disclosure	After 2 days	3 months after the last day of the current month	3 months after the last day of the current month	After 2 days	1 month after the last day of the current month
Quantities Information disclosure	After 2 days	3 months after the last day of the current month	After 2 days	After 2 days	After 2 days

Source: Own elaboration

4.3. Detecting the relational collusive arrangement

4.3.1. Announcement vs. implementation

This section explains the rationale of the test of relational collusion and its relation with the case of study analyzed. We exploit a natural experiment in which, as we explained in detail in subsection 4.2.3, the announcement of the non-transparency policy was made several days before the effective implementation of the restrictions on the disclosure of information. The identification strategy is based on the observation that relational contracts and collusive agreements have in common that the agreements are self-enforced due to the expectation of future profits.

From the empirical point of view, it is challenging to identify whether the changes in the pricing strategies observed after a change in the level of information disclosure are due to a potential coordinated strategy. There are confounding factors that prevent establishing a causal link between transparency and the stability of a collusive agreement. In particular, restricted access to to market outcomes may reduce agents' ability to exercise unilateral market power strategies. The lack of information on the rival's bidding prices hinders the calculation of the agents' residual demand and the design of accurate optimal bidding strategies.

Likewise, it is possible that risk averse agents reduce its bidding prices in response to greater levels of uncertainty even if its pricing strategy is unilateral. In this case it would be problematic to identify the nature of the effect of the lack of information. It is hardly possible to distinguish whether the price reduction is caused by higher levels of uncertainty (unilateral) or by the breakdown of a potential collusive agreement (coordinated).

A key important difference between the collusion (coordinated) and unilateral strategy is that the first depends on the expectation of future profits. The collusion is feasible because market interaction is repeated in the future and there is a system of punishments and awards (informal contracting) that refrains the temptation of obtaining high profits in the short run. The agents achieve the collusion equilibrium when, according to this system, the expectation of future benefits of abide the agreement is higher than the one of deviating. On the other hand, by definition, the unilateral market power strategy only considers the expected profits in the current stage of the game.

This difference entails discrepancies in how the agents use the information on market outcomes. Suppliers adopting a unilateral strategy use this information to improve the accuracy and design of an optimal short-term strategy, while the ones involved in a coordination agreement use it to detect deviations and activate the corresponding punishment mechanism (price war). This distinction has consequences in the reaction that these different types of agents will have in front of announcements of future changes in the transparency conditions.

Note that the effects of transparency on unilateral behavior will only manifest after the implementation of the policy. The agents that exercise unilateral market power want the information of market outcomes for refining its best response bidding strategy in the one-shot game. They continue using the market information for this purpose in the period between the announcement of the non-transparency policy and the day it take effect.

On the contrary, the agents involved in a coordinated strategy do not have incentives to wait until the date of the effective information concealment for reacting to the non-transparency policy. The mere announcement that in the future agents will not be able to monitor themselves causes agents to deviate from the collusive agreement and start to play their unilateral strategy. Observability is an essential element in the awards and punishments scheme necessary for making the collusive equilibrium achievable. The transparency on the market outcomes information allows validating compliance with the collusive agreement. The announcement of the information concealment entails that the mentioned punishment-award scheme will hardly work in the future. In this circumstance, the incentive compatibility of the collusion equilibrium, which is based in the expectation of future profits, collapses. Agents anticipate lower profits in the future and realize that their competitors also have greater incentives to deviate. These factors degrade the present value of the relational collusion and trigger a chain of departures from the agreement.

The rationale above, allows us to link the changes in the bidding price strategy that occurred between the announcement and the implementation of the non-transparency policy with a relational contracting test. The distinction between the effect of the announcement and the effect of the implementation allows us to separate the factors of relational collusion from the confounding factors of unilateral market power.

In summary, the fact that the collusive agreement is a relational contract whose compliance depends on the prospects of future benefits allows linking the breaks in the stability of such agreement with the announcement of future adjustments in the conditions of transparency.

In the next section we expose the formal empirical implementation of the relational collusion test and present the most important findings.

4.3.2. Documenting the impact of the policy

Figure 4.1 plots the time series of the average bidding price for private and public owned units, for the period November 1, 2008 - April 30, 2009 detailing three important dates: i) In January 6, 2009 some authorities explicitly manifested inside an inter-institutional meeting their concern with a potential collusive agreement and started to study measures to hinder coordination of the agents (Surveillance); ii) In January 24, 2009 the consultant Peter Cramton recommended to CREG the concealment of bidding program during 90 days after the auction; iii) In February 6, 2009 the transparency act took effect. We plot the series of private and public firms. We use the latter group as control group based in the evidence presented in chapter 1 and 2 of this dissertation. [8] The rationale for assuming this control group is that given that public firms are mitigating market power, it is not expected that they participate in a collusive agreement that may harm seriously the welfare of consumers.

In addition, we present two version of the plot, one for all the units and other only for thermal generation units. We make this distinction because in the next section the information of marginal costs is a key element for computing the value of the collusive relation and we are able to calculate the marginal cost only for thermal units [9]. Hence we consider important to explore the particular effect of the non- transparency policy for this type of units.

Before the beginning of surveillance actions, it is possible to observe a slightly downward trend in the average bidding pricing for public firms and a relatively stable trend for private. The average bidding price was higher for private firms. For the graph with all units the gap between the two series was around the 45% and in the case of thermal units it was around the 40%.

In the period between the surveillance actions and the announcement the average bidding price of private units plummeted around 34% in the case of all units and around 45% in the case of thermal generation. The bidding price of public firms instead, do exhibit an small increase. In both cases, the bidding price gap between the two series shrinks during this period.

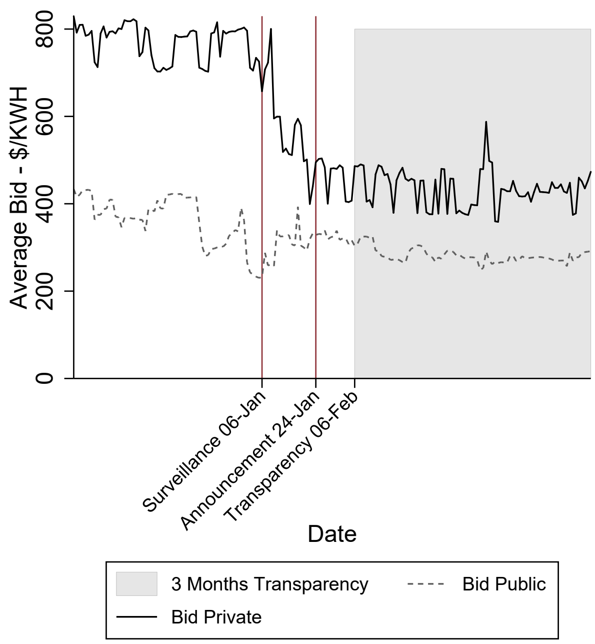
In order to confirm the structural change in the series and avoid the problem of data-mining, we performed time series structural break test with endogenous break point date.

[8] I found that there clear differences in the exercises of unilateral market power between the two types of companies and found evidence of market power mitigation by public firms.

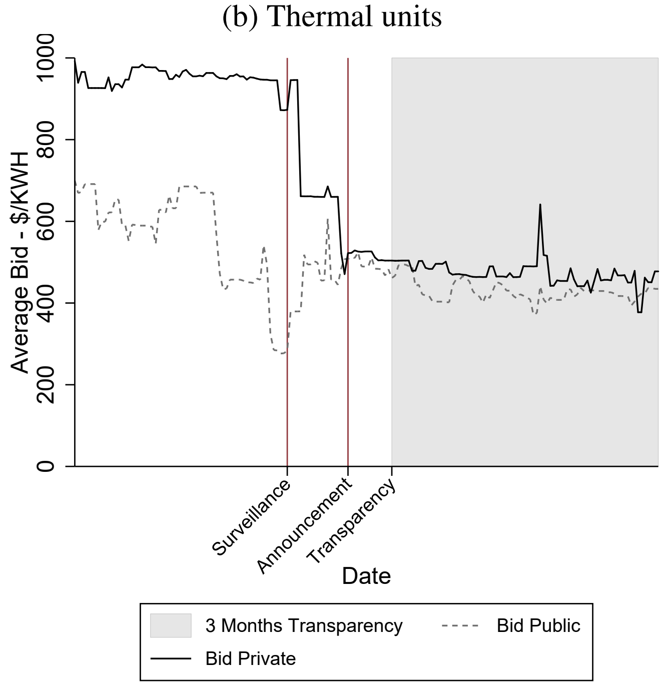
[9] The computation of the marginal cost of hydro-power units is problematic because it is linked with the dynamic opportunity cost of water in electric systems, which is an issue that still unexplored in the context of market power.

Figure 4.1.: Bidding prices time series - Public and private

(a) All technologies units



(b) Thermal units



Source: Data from XM - Calculations and elaboration: Authors.

These test allow to estimate the date of the break point without any a priori knowledge of their timing. We performed the Zivot and Andrews (2002) test for the time series of the average bidding price of private and public firms.[10] As before we consider two samples, all units and only thermal units. In particular we test for a structural break in the intercept of the series.

Figure 4.2 plots the resulting t-statistics and the 1% critical value of the test along the period November 1, 2008 - April 30,2009. A t-statistic less than the critical value is interpreted as an indication of a structural break on the corresponding date. The minimal value of the t-statistic indicates the most probable date of the structural break.

Regarding private owned generation units for both cases, all units and thermal, the most probable date of break point is January 10, 2009. This date This date belongs to the period between the start of the surveillance actions and the implementation of the transparency policy. On the other hand, in both cases, all units and thermal units, the series corresponding to public firms do not show changes as important as in the case of the private series and its most likely break point date is not within the period between the surveillance actions and the announcement of the policy.

The most important empirical suggestions of these patterns are: i) The private firms series had a structural break during the period between the beginning of the surveillance actions and the announcement of the non-transparency policy; ii) after the announcement the average bidding prices of private firms was so much closer to the average bidding price of public units. If we accept the latter as a competitive benchmark, this suggest a more competitive behavior by private firms.

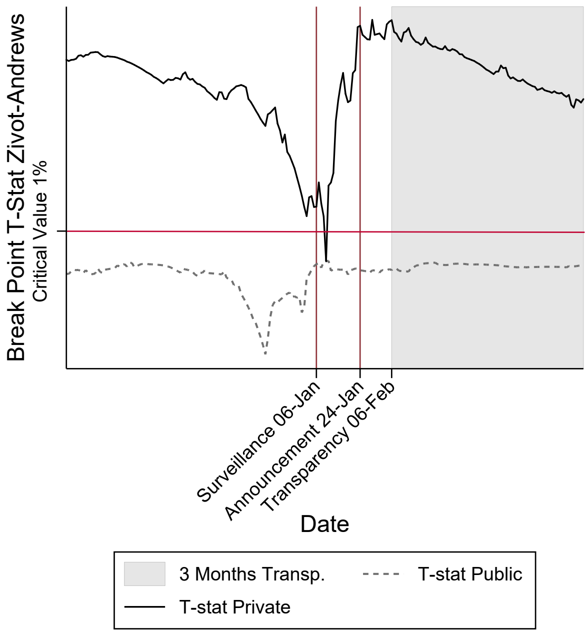
We use difference-in-differences regressions to quantify the impact of both, the anouncement and the effective implementation of the non-transparency policy, controlling for time invariant heterogeneity of units and common seasonal factors. The following regression equation specifies the bidding price and the log bidding price of unit i in the date t according to:

$$\begin{aligned} b_{it} = \beta_0 + \beta_1 \mathbb{1}\{Priv\}_i \times \mathbb{1}\{Announ\}_t + \beta_2 \mathbb{1}\{Priv\}_i \times \mathbb{1}\{Trnsp\}_t \\ + \beta_3 \mathbb{1}\{Priv\}_i + \beta_4 \mathbb{1}\{Announ\}_t + \beta_5 \mathbb{1}\{Trnsp\}_t + \epsilon_{it} \end{aligned} \quad (4.1)$$

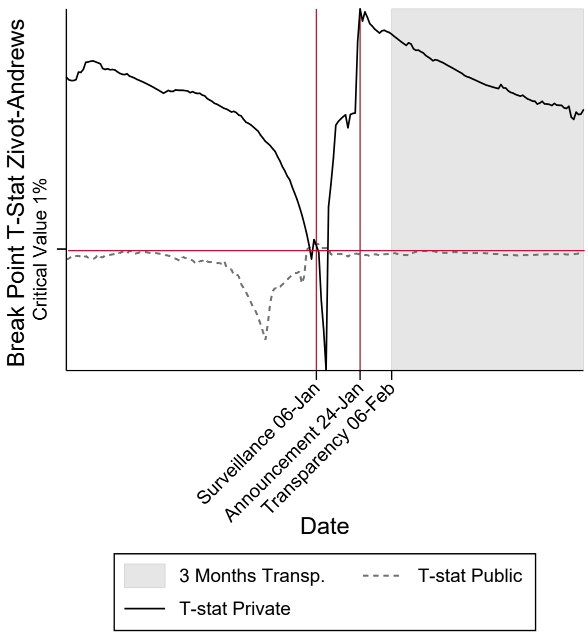
[10]We used the Stata software routine created by Baum (2004)

Figure 4.2.: Zivot and Andrews test - Public and private

(a) All technologies units



(b) Thermal units



Source: Data from XM - Calculations and elaboration: Authors.

$$b_{it} = \beta_1 \mathbb{1}\{Priv\}_i \times \mathbb{1}\{Announ\}_t + \beta_2 \mathbb{1}\{Priv\}_i \times \mathbb{1}\{Trnsp\}_t + \lambda_i + \mu_t + \epsilon_{it} \tag{4.2}$$

Where b_{it} are the bidding price and the logarithm of the bidding price, the dummy variable $\mathbb{1}\{Priv\}_i$ takes the value of one if *i* is private and zero otherwise, the dummy variable $\mathbb{1}\{Announ\}_t$ take the value of one if *t* is a date within the period between the announcement and implementation of the transparency policy and zero otherwise, the dummy variable $\mathbb{1}\{Trnsp\}_t$ take the value of one if *t* is a date after the implementation of the transparency policy and zero otherwise.

We use the data from 6 months prior to the policy implementation and 6 months after. We explore two alternatives for defining the announcement period $\mathbb{1}\{Announ\}_t$: i) In the first alternative we consider dates between the Peter Cramton's talk to regulators (January 24, 2009) and the day in which the policy took effect (February 6, 2009); ii) In the second alternative we consider dates between the beginning of surveillance activities (January 6, 2009) and the day in which the policy took effect (February 6, 2009). In addition, regarding the model in expression (4.1) we control for the reference prices of the inputs of thermal generation units and for the water intakes of the big hydro-power units. Finally, we perform the regressions for the sample with all units and the sample that only includes thermal generation units. Standard errors are clustered at the generation unit level. Table 4.2 presents the regression results for the specification of all units and the first alternative definition of the announcement period (specification 1), table 4.3 for the specification of only thermal units and the first alternative definition of the announcement (specification 2), table 4.4 for the specification of all units and the second alternative (specification 3) and table 4.5 for the specification of thermal units and the second alternative (specification 4). In these tables we present only coefficients related with the interaction of the treatment group with both the announcement and implementation periods. The detailed results are presented in appendix C.1.

For the specification 1 we find a statistically significant decrease in bidding prices of private firms linked with the announcement of the policy around 263 Colombian pesos by kilowatt hour ($COP/KWh). When we use log bidding price as dependent variable , we find a decrease around 33.6% (because $\exp(-0.409) - 1 = -0.336$) but the estimation of the corresponding coefficient is very uncertain. Regarding the effect of the effective implementation of the transparency policy in private firms, the coefficient for $\mathbb{1}\{Priv\}_i \times \mathbb{1}\{Trnsp\}_t$ in this specification is negative and only statistically significant at 10% in the

Table 4.2.: Diff-in-Diff - All Units - Specification 1

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Bid	Bid	Bid	Bid	LnBid	LnBid	LnBid	LnBid
$\mathbb{1}\{Priv\}_i \times \mathbb{1}\{Announ\}_t$	-263.3***	-263.2***	-263.3***	-263.2***	-0.409***	-0.409***	-0.409***	-0.409***
	(92.18)	(92.98)	(92.18)	(92.01)	(0.134)	(0.136)	(0.135)	(0.134)
$\mathbb{1}\{Priv\}_i \times \mathbb{1}\{Trnsp\}_t$	-195.1*	-194.6*	-195.1*	-194.5*	-0.139	-0.136	-0.139	-0.135
	(99.74)	(100.6)	(99.75)	(99.59)	(0.153)	(0.154)	(0.153)	(0.152)
# Observations	17,155	17,155	17,155	17,155	17,155	17,155	17,155	17,155
R-squared	0.100	0.771	0.104	0.768	0.085	0.803	0.086	0.799
Unit FE	NO	YES	NO	YES	NO	YES	NO	YES
Date FE	NO	YES	NO	NO	NO	YES	NO	NO
Inputs Control	NO	NO	YES	YES	NO	NO	YES	YES

Robust standard errors clustered by unit in parentheses
*** p<0.01, ** p<0.05, * p<0.1

case we use the bidding price as left hand side variable.

Table 4.3.: Diff-in-Diff - Thermal Units - Specification 2

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Bid	Bid	Bid	Bid	LnBid	LnBid	LnBid	LnBid
$\mathbb{1}\{Priv\}_i \times \mathbb{1}\{Announ\}_t$	-332.0***	-332.2***	-332.0***	-331.9***	-0.413***	-0.415***	-0.413***	-0.414***
	(116.1)	(117.6)	(116.1)	(115.8)	(0.136)	(0.137)	(0.136)	(0.135)
$\mathbb{1}\{Priv\}_i \times \mathbb{1}\{Trnsp\}_t$	-263.2**	-263.5**	-263.2**	-262.9**	-0.0807	-0.0807	-0.0808	-0.0794
	(113.0)	(114.2)	(113.0)	(112.6)	(0.160)	(0.162)	(0.160)	(0.159)
# Observations	11,315	11,315	11,315	11,315	11,315	11,315	11,315	11,315
R-squared	0.125	0.800	0.132	0.796	0.096	0.818	0.101	0.812
Unit FE	NO	YES	NO	YES	NO	YES	NO	YES
Date FE	NO	YES	NO	NO	NO	YES	NO	NO
Inputs Control	NO	NO	YES	YES	NO	NO	YES	YES

Robust standard errors clustered by unit in parentheses
*** p<0.01, ** p<0.05, * p<0.1

Regarding specification 2 (table 4.3), in all the models the results report statistically significant coefficients for private firms and the announcement of the policy. The absolute bidding price decrease is \$332/KWh corresponding to a 33.8% percent. In relation to the implementation of the policy we also find a negative effect for private firms. The decrease on the absolute bidding price related with the implementation is around \$263/KWh and statistically significant at 5%. In the case of the estimations using log bidding price as dependent variable the coefficient for $\mathbb{1}\{Priv\}_i \times \mathbb{1}\{Trnsp\}_t$ is not significant.

In the case of specification 3 able 4.4) the coefficient for $\mathbb{1}\{Priv\}_i \times \mathbb{1}\{Announ\}_t$

Table 4.4.: Diff-in-Diff - All Units - Specification 3

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Bid	Bid	Bid	Bid	LnBid	LnBid	LnBid	LnBid
$\mathbb{1}\{Priv\}_i \times \mathbb{1}\{Announ\}_t$	-202.1**	-201.9**	-202.1**	-201.8**	-0.349**	-0.349**	-0.349**	-0.349**
	(87.61)	(88.30)	(87.62)	(87.40)	(0.132)	(0.133)	(0.132)	(0.132)
$\mathbb{1}\{Priv\}_i \times \mathbb{1}\{Trnsp\}_t$	-210.2*	-209.5*	-210.2*	-209.4*	-0.168	-0.165	-0.168	-0.164
	(106.2)	(107.1)	(106.2)	(105.9)	(0.160)	(0.162)	(0.160)	(0.160)
# Observations	17,155	17,155	17,155	17,155	17,155	17,155	17,155	17,155
R-squared	0.104	0.771	0.105	0.768	0.086	0.804	0.087	0.800
Unit FE	NO	YES	NO	YES	NO	YES	NO	YES
Date FE	NO	YES	NO	NO	NO	YES	NO	NO
Inputs Control	NO	NO	YES	YES	NO	NO	YES	YES

Robust standard errors clustered by unit in parentheses
*** p<0.01, ** p<0.05, * p<0.1

yields a negative sign coherent with a decrease in bidding prices by private firms linked with the announcement of the transparency policy. The estimated bidding price decrease for private firms related with the impact of the announcement is $202/KWh corresponding to a 29.4% percent. As previous specifications the coefficient for $\mathbb{1}\{Priv\}_i \times \mathbb{1}\{Trnsp\}_t$ is only significant at 10% in the case we use the average bidding price as dependent variable.

Table 4.5.: Diff-in-Diff - Thermal Units - Specification 4

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Bid	Bid	Bid	Bid	LnBid	LnBid	LnBid	LnBid
$\mathbb{1}\{Priv\}_i \times \mathbb{1}\{Announ\}_t$	-213.0*	-213.2*	-213.0*	-212.9*	-0.235*	-0.237*	-0.235*	-0.236*
	(116.0)	(117.3)	(116.0)	(115.6)	(0.134)	(0.135)	(0.134)	(0.133)
$\mathbb{1}\{Priv\}_i \times \mathbb{1}\{Trnsp\}_t$	-275.3**	-275.6**	-275.3**	-274.9**	-0.0909	-0.0910	-0.0910	-0.0896
	(122.4)	(123.6)	(122.4)	(121.9)	(0.165)	(0.167)	(0.165)	(0.165)
# Observations	11,315	11,315	11,315	11,315	11,315	11,315	11,315	11,315
R-squared	0.130	0.800	0.132	0.795	0.099	0.817	0.100	0.811
Unit FE	NO	YES	NO	YES	NO	YES	NO	YES
Date FE	NO	YES	NO	NO	NO	YES	NO	NO
Inputs Control	NO	NO	YES	YES	NO	NO	YES	YES

Robust standard errors clustered by unit in parentheses
*** p<0.01, ** p<0.05, * p<0.1

All the columns of table 4.5 present coefficients for $\mathbb{1}\{Priv\}_i \times \mathbb{1}\{Announ\}_t$ negative and statistically significant at 10% levels for specification 4. The absolute decrease in bidding price of private firms related with the announcement of the information concealment is around \$213/KWh corresponding with a 21.1%. In the case of the effect of the effective implementation of the transparency policy in private firms, the coefficient for $\mathbb{1}\{Priv\}_i \times \mathbb{1}\{Trnsp\}_t$ is only significant at 5% in the case we use the average bidding price as dependent variable.

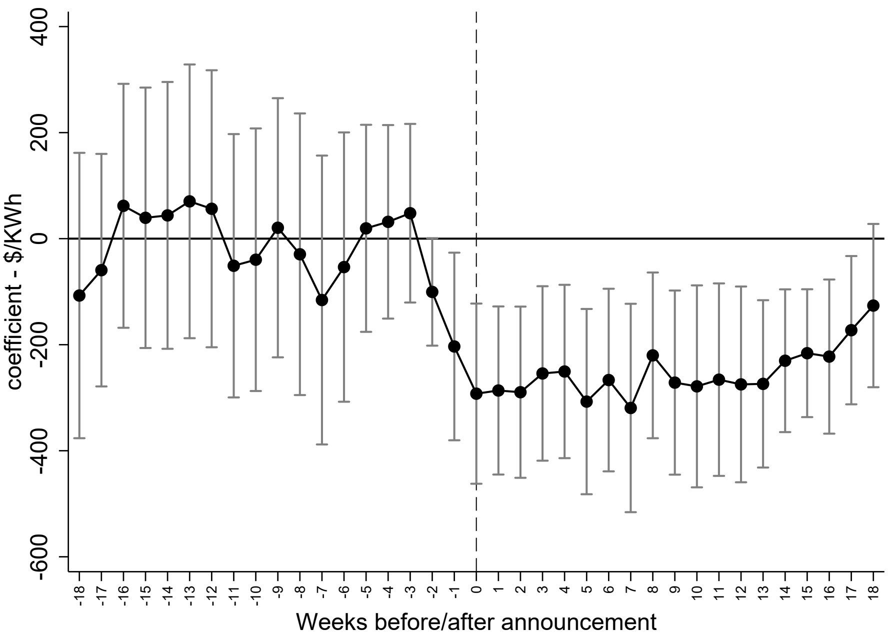
Finally, figure 4.3 presents the result of performing the two way fixed effects model and isolating the private firms' effect by each week of the sample with reference to the date of the announcement of the policy (January 24, 2009). The panel a presents the result for the estimation with all the sample and panel b presents the estimation for the sample that only consider thermal units. There are three important aspects to highlight in these figures. First, we can observe that in the pre-announcement period, with the exception of lags 2 and 1, the coefficients of private firms are not statistically significant. This is suggestive evidence that , at least locally, the parallel trend assumption between the treatment group (private) and the control group (public) is reasonable. Secondly, almost all the coefficients in the post announcement period are economically and statistically significant, even those corresponding with weeks previous to the implementation. Third, two weeks before the announcement (lags 2 and 1) we observe that the coefficient start to decrease. This anticipation effect, suggest that the surveillance actions performed by the government warned to the members of the agreement about future measures oriented to hinder coordination.

There are several important takeaways of the estimates presented above in relation with the aim of detecting an informal coordination relation. The first and most important is that in all the estimates the decrease in bidding prices by private companies related to the announcement of the transparency policy is economically and statistically significant. The coefficients corresponding to this effect remain stable within each of the specifications with the inclusion of fixed effects and covariates related to the inputs of electricity generation. The fact that the R-squared statistic changes radically with the inclusion of these controls and the coefficient remains unchanged is a good signal in relation to a potential omitted-variable bias. A second aspect that should be noted is that, for private companies, the effect of the implementation has a smaller magnitude and is more uncertain than the effect of the announcement. No robust inferences can be drawn from the estimation of the parameters corresponding to the variable $\mathbb{1}\{Priv\}_i \times \mathbb{1}\{Trnsp\}_t$. As argued in the previous subsection, this empirical results are an indication that private companies were involved in a some type of relational coordination contract.

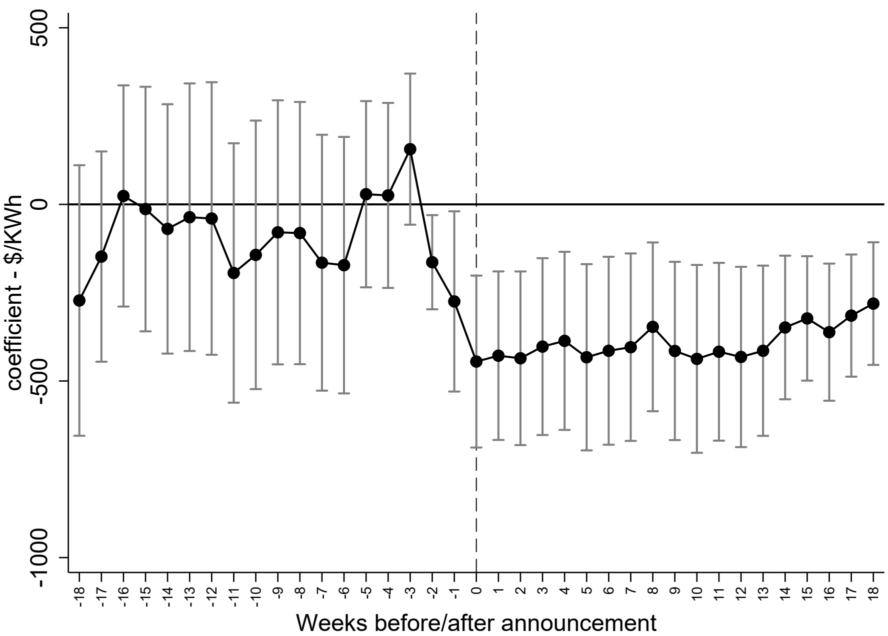
Finally, in relation to the reaction of private companies to the announcement, , we must point out that we find effects with greater magnitudes and with greater strength of

Figure 4.3.: Weekly effect of the announcement in private firms

(a) All technologies units



(b) Thermal units



Source: Data from XM - Calculations and elaboration: Authors.

inference in samples that only consider thermal units. This indicates that the firms use this types of units in order to abide the quota of the informal coordinated agreement.

4.4. Alternative explanations and further evidence

In this section, we present graphical and econometric evidence to determine to what extent the plummet in average bidding prices around the transparency policy date could be explained by other causes. Basically we explore two factors that are crucial for pricing in electricity markets: Forward contracting and cost shocks.

4.4.1. Forward contracting

In electricity markets the incentives to collude or exercise market power depend on the level of the fixed-price forward contracts obligations signed by the firm. The supplier must serve this obligations no matter what the actual wholesale price is. If its forward contract obligations are less than its energy production, the firm is a net seller in the spot market. Hence, an increase in the spot price increases its profits. On the other hand, if its forward contract obligations are greater than its energy production, the firm is a net buyer in the spot market. Hence, an increase in the spot price decreases its profits (Wolak, 2000; McRae and Wolak, 2009). If firms collude to increase prices it is expected that they are net sellers in the spot market, i.e. they should have low levels of fixed-price forward contracts obligations. In this subsection we explore some descriptive statistics of the forward contracting to figure out if private firms in the Colombian wholesale electricity markets are net sellers.

For each day we calculate the sum for the 24 hours of the day of forward contracts and commercial availability.

$$F_{jt} = \sum_{h=1}^{24} F_{jth}$$

$$A_{jt} = \sum_{h=1}^{24} \sum_{i=1}^{N_j} A_{ijth}$$

Where F_{jth} is the energy committed in forward contracts in in the hour h, the day t, for the firm j. A_{ijth} is the commercial availability of the unit i owned by firm j in the hour h of the day t. N_j is the number of units owned by the firm j. We calculate the ratio:

$$IC_{jt} = \frac{F_{jt}}{A_{jt}}$$

It can be interpreted as the fraction of the daily availability of the firm committed in forward contracts.

Table 4.6 present the descriptive statistics of the ratio forward contract/availability for different partitions of the sample. In average private firms commit the 45% of its capacity available in forward contracts. On the contrary, public firms commit almost the 100% of its available capacity. In addition, the distribution of the forward contracting do not show an important change between prior and after the implementation of the policy.

Table 4.6.: Forward contracts descriptive statistics

Group	All	All	Public	Private	Pre-Policy	Post-Policy
Statistic						
Obs	17155.00	14973.00	7308.00	7665.00	7749.00	7224.00
Mean	15.27	0.73	1.00	0.47	0.69	0.77
Std. Dev.	12.92	0.55	0.58	0.35	0.46	0.62
Variance	166.82	0.30	0.34	0.12	0.21	0.39
Skewness	0.29	1.40	1.51	-0.23	0.31	1.74
Kurtosis	1.48	10.82	12.17	1.61	2.70	11.96
Max	38.22	6.21	6.21	1.49	2.29	6.21
Min	0.00	0.00	0.05	0.00	0.00	0.00
Median	10.43	0.67	0.90	0.55	0.68	0.65
P10%	0.00	0.00	0.40	0.00	0.00	0.00
P25%	3.64	0.42	0.55	0.00	0.43	0.42
P75%	29.27	0.97	1.36	0.76	0.95	0.99
P90%	33.01	1.42	1.84	0.88	1.32	1.70

Source: Own elaboration based on data from XM

Figure 4.4 plots the daily average ratio/availability time series. Panel a presents the complete series from January, 2006 to May, 2011 and panel b presents the detail of the series around the implementation of the transparency policy. The series for private firms gravitates around the 40% of forward contract commitment. This exhibits lower percentage of commitment and lower variation than the series of public firms. In panel a it is possible to observe that the level of contracting was relatively stable from 2006 to

2011. In addition, in panel b it is not observed any big alteration of forward contracting for private and public firms around the dates of announcement and implementation of the non-transparency policy.

Given the evidence presented in table 4.6 and figure 4.4 we argue that the forward contract position of private firms is consistent with the willing to increase the spot price, i.e. they are net sellers in the spot market.

4.4.2. Cost Shocks

In this section, we present graphical and econometric evidence to discard marginal costs shocks as the cause of the decrease in bidding prices by private firms around the dates of announcement of the non-transparency policy. We will compare the patterns of the bidding prices and some indicators of the costs of the most important inputs for thermal electricity generation in Colombia: Gas and coal.

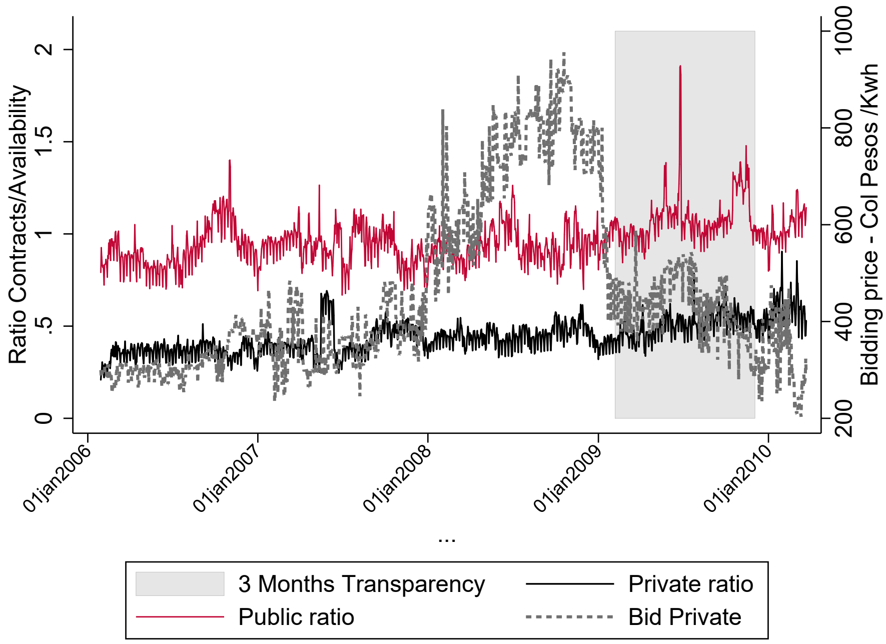
First, we perform the Zivot and Andrews (2002) test for the time series of the input prices. In appendix C.2 we present the time series of bidding prices of gas and coal units for public and private firms parallel to the index of the cost of each of these fuels. In appendix C.2 we also present the figures of the results of the Zivot and Andrews (2002) test for each type of fuel.

Regarding gas fired units, we calculated an index for Guajira regulated cost applying the formula stated in the regulation and converting the resulting price (US dollars/MBTU) to Colombian pesos/Kwh (See details in appendix A.3). The most probable date of break of the series of the public units group and private units group bidding prices series do not coincides with the most probable date of brake of the Guajira Gas Index. Public gas units do not react around the policy implementation. With respect to coal, the FOB export price was computed as the ratio between the total value of coal exportation (in US dollars) and the quantities exported (Tons). Also we converted the resulting price (US dollars/Tons) to Colombian pesos/Kwh (See details in appendix A.3). The series of coal prices show a drop at the middle of October 2008. This date do not coincide with the drop of bidding prices of the private group (January 10th, 2009). The series of the public firms group show a peak around the middle of October 2008 and a drop at the beginning of December 2008. This drops occurs well before the implementation of the no-transparency policy.

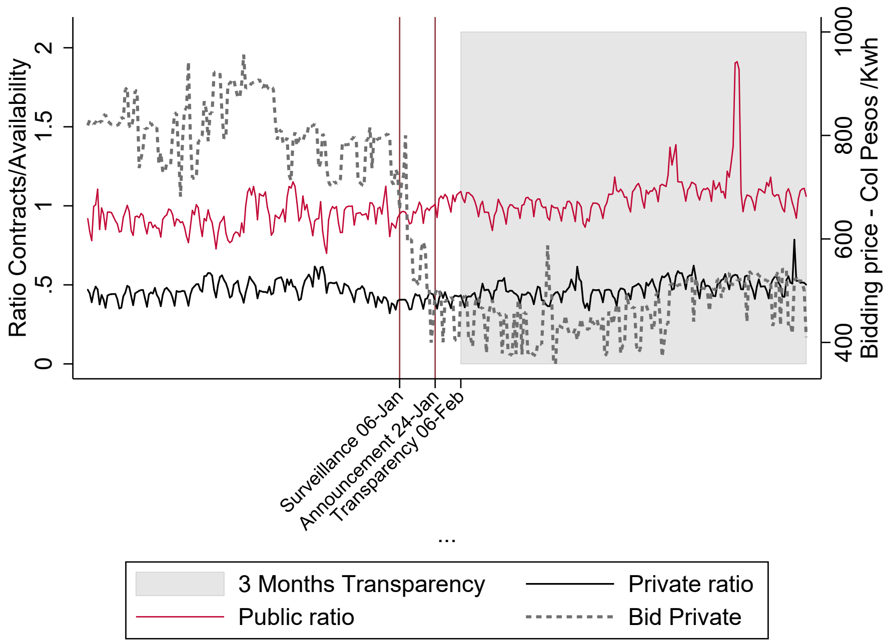
In addition we calculated the margin $(Bid - Mg.Cost)$ for each generation unit. If the increase in bidding prices is explained by shocks in the marginal cost the margin should

Figure 4.4.: Forward contracting - Public and Private

(a) Period January 2006 - May2011



(b) Detail around non-transparency policy



Source: Data from XM - Calculations and elaboration: Authors.

not reflect a decrease previous to the implementation of the transparency policy. Panel a of figure 4.5 presents tha graph of the margin for private and public firms and the average marginal cost. In this figure it is possible to observe that order of magnitude of the fall in bidding prices is much greater than that of the fall in marginal costs. Furthermore, this figure still shows an abrupt fall in the series of the margin of private companies on the dates just before the implementation of the non-transparency policy. Additionally, the mark up of private and public companies was calculated. Panel b of Figure 4.5 shows these series. It is possible to appreciate that the gap between the mark up of both types of firms shrinks just before the implementation of the non-transparency policy.

Finally, we performed difference-in-differences regressions as those specified in expressions (4.1) and (4.2) but using as left hand side variable the margina and the mark up. The resultas are presented in table 4.7 and figure 4.6.

Table 4.7.: Diff-in-Diff - Specification 2 - Alternative LHS variables

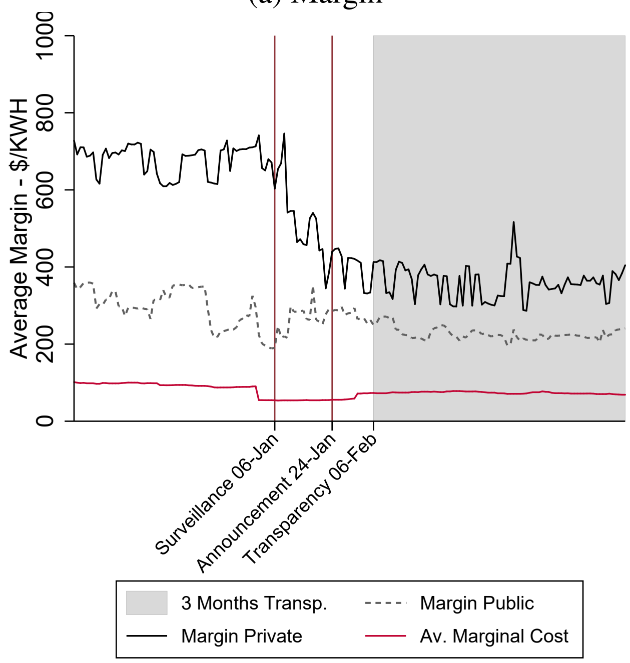
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Margin	Margin	Margin	Margin	Mark Up	Mark Up	Mark Up	Mark Up
$\mathbb{1}\{Priv\}_i \times \mathbb{1}\{Announ\}_t$	-326.8***	-327.1***	-326.8***	-326.8***	-3.334**	-3.338**	-3.334**	-3.333**
	(114.4)	(115.8)	(114.4)	(114.0)	(1.597)	(1.622)	(1.597)	(1.595)
$\mathbb{1}\{Priv\}_i \times \mathbb{1}\{Trnsp\}_t$	-259.7**	-260.5**	-259.7**	-259.9**	-2.327**	-2.346**	-2.323**	-2.335**
	(112.3)	(113.4)	(112.3)	(111.8)	(0.978)	(0.988)	(0.979)	(0.973)
# Observations	11,315	11,315	11,315	11,315	11,315	11,315	11,315	11,315
R-squared	0.112	0.803	0.118	0.799	0.042	0.799	0.055	0.794
Unit FE	NO	YES	NO	YES	NO	YES	NO	YES
Date FE	NO	YES	NO	NO	NO	YES	NO	NO
Inputs Control	NO	NO	YES	YES	NO	NO	YES	YES

Robust standard errors clustered by unit in parentheses
*** p<0.01, ** p<0.05, * p<0.1

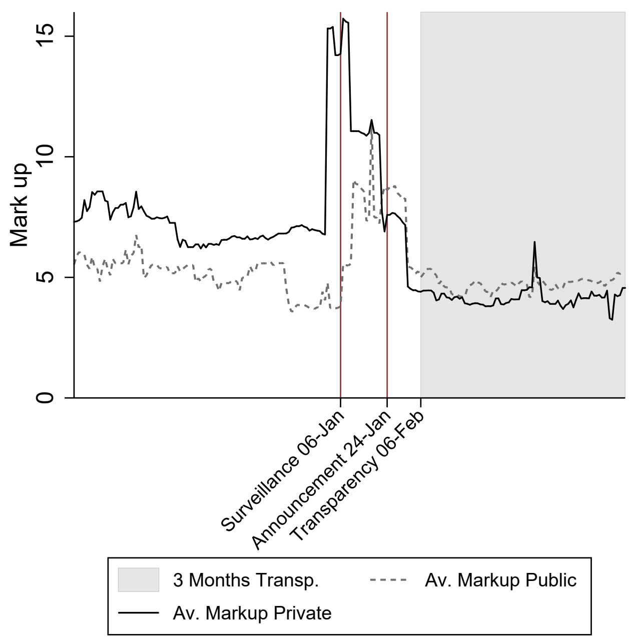
Although the variables in the right hand side of expressions (4.1) and (4.2) have considered the variation in costs, the qualitative results are similar to those obtained in the baseline estimate. This suggests that shocks in marginal costs do not explain the drop in bidding prices of private companies observed just before the implementation of the measure.

Figure 4.5.: Margin and mark up - Public and Private

(a) Margin



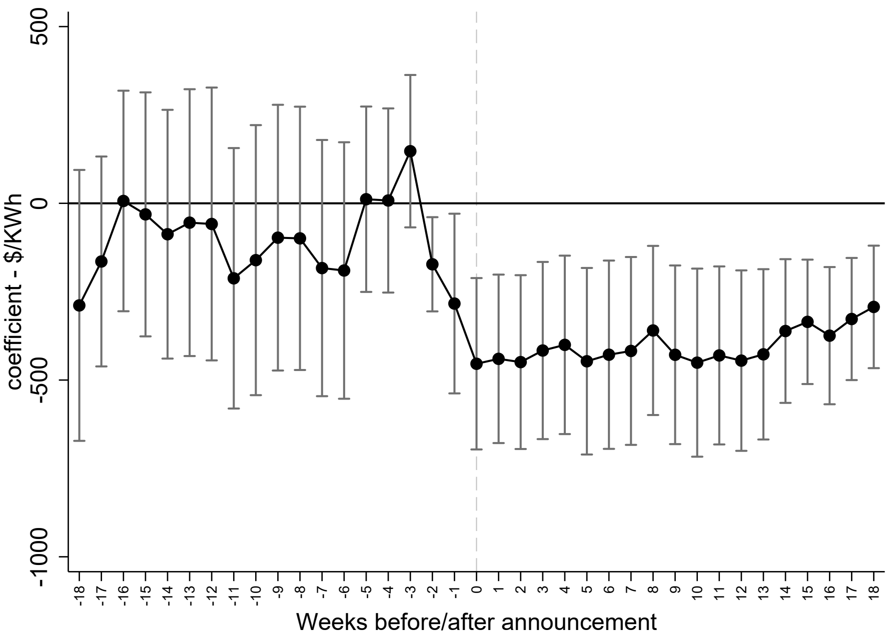
(b) Mark up



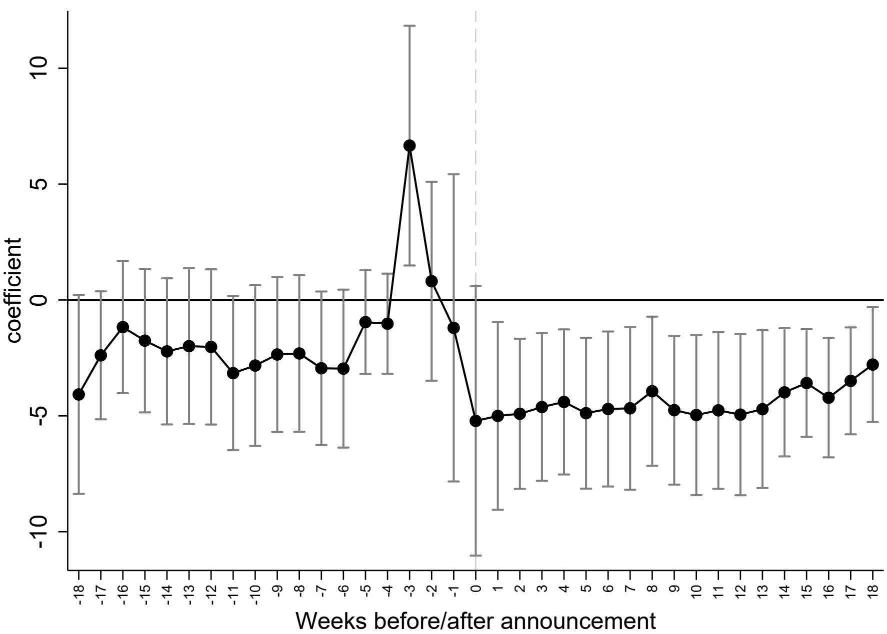
Source: Data from XM - Calculations and elaboration: Authors.

Figure 4.6.: Weekly effect of the announcement - Alternative LHS variables

(a) All technologies units



(b) Thermal units



Source: Data from XM - Calculations and elaboration: Authors.

4.5. Quantifying the Value of the Collusive Agreement

In this section we use a simple structural model for quantifying an upper bound of the value of an hypothetical relational collusion in the Colombian wholesale electricity market. We aim to estimate the incentive compatibility constraint (ICC of abide the agreement in two scenarios: one which transparency and other without transparency. The objective is to compare the impact of the non-transparency policy in the ICC.

In addition the results of this structural analysis allows us to verify whether the breakdown of the potential agreement due to non-transparency policies is consistent with the value of the parameters of the model found using the data of the Colombian electricity market.

The approach adopted in this document is a simplification of the model presented previously by Igami and Sugaya (2018). We use a Cournot model to characterize the equilibrium of each stage of the repeated-game. We assume that the firms in the cartel face a linear residual demand resultant from a competitive fringe. Based on the information on the public companies bidding program and total demand of the system, by means of a ordinary least squares regression, we estimate the parameters of the linear version of the inverse residual demand function. Subsequently, we apply these parameters and the information on marginal costs and forward contracts to the theoretical solutions resulting from the Cournot model. We calculate the profits of the companies at each stage of the game in three situations: i) the firms on the cartel implement the Cournot-Nash competition solution (Unilateral solution), ii) the firms on the cartel comply with the agreement (coordinated solution), iii) one of the agents deviates from the agreement while the others respect it (deviation solution).

Regarding the dynamic solutions, once we have estimated the market outcomes for each stage, we use the repeated game model proposed in Tirole (1988) and Ivaldi et al. (2003) for studying the effects of transparency in the value of the collusive relation. In this model there are random demand shocks and the firms in the cartel are not able to observe the actions of the other members. We find the analytical formula of the incentive compatibility constraint (ICC) of the collusion strategy in this model (No-Transparency dynamic solution). Also, we find the theoretical formula of the ICC in a model with random demand and perfect observability of the actions of the firms in the cartel.

Finally, we impute the profits resulting from the one shot game Cournot model (that is, unilateral solution, coordinated solution and deviation solution) to the ICC of the repeated game model in both regimes, transparency and non-transparency.

4.5.1. The one shot game

Cournot Model - Unilateral Solution. We assume a symmetric oligopoly model, with constant marginal cost and no capacity constraints. In the Colombian electricity market the size of the firms is different. To adopt this feature to the symmetry assumption, we assume that the number of companies in the collusive agreement N is equal to the integer closest to the equivalent number that results from calculating the Herfindahl-Hirschman index for the Colombian electricity generation market in 2009, using the participation in the installed capacity for computing the market shares.

We assume that the N companies in the agreement dispute the remaining market after discounting the supply of a competitive fringe. In this particular case, the competitive fringe corresponds to the load base generation and the production of public companies.

In addition, we theorize that the firms of the cartel can observe the residual demand resultant from discounting the supply of the competitive fringe. In respect to this assumption, previous work in the literature of electricity markets have argued that it is possible to compute accurate marginal cost estimates based on engineering methods (Fabra and Reguant, 2014) . Likewise, due to the high frequency of market interaction between competitors and rigidities imposed by institutional factors, the suppliers in a electricity market are able to figure out reliable approximations to the realization of the residual demand they face (McRae and Wolak, 2009). We consider that although the private firms cannot observe directly the residual demand they will face, the fact that public firms bid prices close to the marginal costs and the availability of base-engineering methods to compute such costs, facilitates the estimation of the parameters of the residual demand that private firms face.

We specify a linear inverse residual demand function:

$$P_t = A_t - \alpha_t Q_t \tag{4.3}$$

Where P_t is the inverse residual demand (Price), Q_t is the total quantity sold by the cartel.

The profit function of each firm is:

$$\pi_{it} = P_t \cdot (q_{it} - f_{it}) + c_{it} \cdot q_{it} \tag{4.4}$$

Where the π_{it} is the the profit of the firm *i*, P_t is the market clearing price, q_{it} is the quantity produced by the firm *i*, f_{it} is the energy committed in forward contracts and c_{it} is the marginal cost of firm *i*.

The best response function of the firm *i* in the Cournot competition model is:

$$q_{it} = \frac{A_t + \alpha_t f_{it} - c_{it} - \alpha_t \sum_{i \neq j} q_{jt}}{2\alpha_t} \tag{4.5}$$

The Cournot-Nash quantity equilibrium of the firm *i* is:

$$q_{it}^{*} = \frac{A_t + N(\alpha_t f_{it} - c_{it}) - \alpha_t \sum_{i \neq j} f_{jt} + \sum_{i \neq j} c_{jt}}{(1+N)\alpha_t} \tag{4.6}$$

We compute the total equilibrium quantity as $Q_{it}^{*} = N q_{it}^{*}$. Replacing this result in (3) we obtain the Cournot-Nash price equilibrium. With this calculations, the base-engineering estimations of the marginal cost and the ex-post observation of the forward contracting we are able to compute the profits of the firm in the Cournot-Nash equilibrium (unilateral solution) π_{it}^{O} replacing all these data in equation 4.4.

Joint Profit Model - Coordinated Solution. In order to obtain the profits of the firm when all the firms abide the agreement, we assume that the cartel maximizes the joint profits of its N members (coordinated solution). We assume symmetric firms. This entails that the market quota is the same for all of them.

The joint profit function is:

$$\pi_t^{C} = P_t \cdot (Q_t^{C} - \sum_{i=1}^{N} f_{it}) + \overline{c_t} \cdot Q_t^{C} \tag{4.7}$$

Where the π_{it}^{C} is the the joint profits of the cartel, P_t is the market clearing price, Q_t^{C} is the quantity produced by the cartel, f_{it} is the energy committed in forward contracts of firm *i* and $\overline{c_t}$ is the average marginal cost between the firms *i*.

The total quantity produced by the cartel is:

$$Q_t^{C*} = \frac{A_t + \alpha_t \sum_{i=1}^{N} f_{it} - \overline{c_t}}{2\alpha_t}$$

Given the assumption of equal quota for all the firms, the quantity produced by each firm is:

$$q_{it}^{C*} = \frac{A_t + \alpha_t \sum_{i=1}^{N} f_{it} - \overline{c_t}}{2\alpha_t N}$$

Replacing the monopoly quantity Q_{it}^{C*} in (3) we obtain the monopoly price. substituting these values, the base-engineering estimations of the marginal cost and the ex-post observations of the forward contracting in (7) we obtain the profits of the firms in the cartel when all of them abide the collusion agreement (coordinated solution) π_{it}^{C}.

Deviation Solution. It is important to keep in mind that the quantity q_{it}^{C*} is not a Cournot-Nash equilibrium in the one shot game. The optimal response of the firm are described by expression (4.5). If others members of the cartel abide the agreement, the best response of the firm *i* can be estimated replacing $Nq_{it}^{C*} = \sum_{i \neq j} q_{jt}$ in (5). this is:

$$q_{it}^{D*} = \frac{A_t + \alpha_t f_{it} - c_{it} - \alpha_t N q_{it}^{C*}}{2\alpha_t}$$

Where q_{it}^{D*} is the optimal quantity supplied by the firm i when others firms j play q_{jt}^{C*}. The total quantity in the market in this deviation scenario is q_{it}^{D}. The total quantity in this deviation scenario is $Q_t^{D*} = (N-1)q_{jt}^{C*} + q_{it}^{D*}$ and replacing in (3) we obtain the market price $P_t^{D*} = A_t - \alpha_t\big((N-1)q_{jt}^{C*} + q_{it}^{D*}\big)$. Replacing all these elements in equation 4.4 we obtain the profit of deviating of the collusion agreement in the one shot game π_{it}^{D}.

Marginal Cost assumption. We obtained base-engineering estimations of the marginal costs of thermal generation units according to the methodology and databases described in subsection 4.2.4. Giving that we perform the calculus for a representative firm, we estimate the profits in the one shot game for three different alternatives of the marginal cost. In the baseline alternative we apply the average daily marginal cost of thermal units. In a second alternative we use the minimum daily marginal cost of thermal generation and in the third alternative we impute the maximum daily marginal cost of thermal.

Residual demand parameters estimation. As stated before, we observe the forward contracts commitments of each firm and we have an base-engineering estimation of the marginal cost of each firm. Hence, for completing the calculus of the profits in each stage of the repeated game, we need an estimation of the parameters A_t and α_t. Note that in the Colombian wholesale electricity market we are able to easily compute the inverse residual demand function of the cartel. We observe the total demand of the electric system, the load base generation and the bidding program of the public firms. However, the resulting function is stepped. In order to obtain the parameters A_t and α_t we perform a lineal approximation by ordinary least squares. We estimate the parameters for each hour of the day and each week of the sample. We use the information of quantities and prices of each elbow of the stepped version of the inverse residual demand function according to the expression:

$$P_{whk} = A_t + \alpha_t Q_{whk} + \epsilon_{whk}$$

Where the index *w* represent each week of the sample, the index *h* represent each hour of the day and the index *k* represent each elbow (each ordered pair *(Bidding Price, Residual demand)*) of the stepped residual demand function. Table 4.8 presents a summary of the results of these estimations.

4.5.2. Repeated-game expected profits.

Once we have calculated for the one shot game i) The profit of the firm *i* in the Cournot-Nash equilibrium (unilateral solution) π_{it}^{O}, ii) the profit of the firm *i* of abiding the agreement π_{it}^{C} and iii) the profit of deviating π_{it}^{D} (the rivals play the cartel solution quantities and the firm *i* plays the best response of the Cournot model), we can apply these result to the repeated game framework.

Repeated-game in the non-transparency regime. In order to model the repeated game in the non-transparency regime, we adopt the Tirole's version Tirole (1988) of the Green-Porter's model Green and Porter (1984). We assume that each firm only observes its own bidding program and sales, but not the others'. With some probability there is a negative demand shock. In this case the members of the cartel have sales as if one of them was breaking the agreement. When the firms are unable to sell its quota, they do not know if there was a negative demand shock or a member of the cartel is cheating. In order to discipline the members of the cartel, each time a firm in the cartel is unable to sell its quota it launch a price war. During the price war each firm plays according to its best response function i.e. the Cournot-Nash equilibrium quantity. Green and Porter (1984) concluded that, even under these restrictive conditions, the tacit collusion equilibrium may arise. The dynamic trigger strategy consist in launching a price war if the firm does not sale its quota and defining the duration of the price war (A number T of periods). For the sake of simplicity we will assume that the price war last forever.

Defining μ as the probability of a demand shock, δ as the discount rate and V^{NTR} as the expected discounted profit if the firm abide the agreement in the non-transparency regime:

Table 4.8.: Summary estimations parameters A_t and α_t

Average by hour Hour	0	1	2	3	4	5	6	7
Constant A_t	256764	205579	180058	177078	233270	399030	499936	615408
Standard Error A_t	13642	11262	9311	9124	12930	29566	42529	54064
Slope (α_t)	-0.056	-0.044	-0.037	-0.037	-0.051	-0.087	-0.108	-0.129
Standard Error α_t	0.005	0.004	0.003	0.003	0.005	0.010	0.014	0.017
Av. # Obs	99	89	85	84	94	112	118	125
Av.R-Squared	0.599	0.604	0.627	0.632	0.589	0.458	0.377	0.341

Average by hour Hour	8	9	10	11	12	13	14	15
Constant A_t	686974	714883	732396	758366	764411	744045	721653	703242
Standard Error A_t	59850	62457	64402	66322	64365	63137	63680	63431
Slope (α_t)	-0.132	-0.132	-0.129	-0.131	-0.137	-0.135	-0.129	-0.124
Standard Error α_t	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017
Av. # Obs	131	134	135	136	136	136	134	133
Av.R-Squared	0.332	0.326	0.323	0.326	0.344	0.339	0.320	0.309

Average by hour Hour	16	17	18	19	20	21	22	23
Constant A_t	697142	739106	931045	985058	935672	841413	661866	370728
Standard Error A_t	62999	64735	79034	83304	77177	67629	51279	21236
Slope (α_t)	-0.124	-0.131	-0.144	-0.148	-0.150	-0.149	-0.135	-0.081
Standard Error α_t	0.017	0.017	0.017	0.017	0.017	0.017	0.015	0.007
Av. # Obs	133	135	139	139	139	138	135	117
Av.R-Squared	0.308	0.325	0.357	0.365	0.371	0.372	0.386	0.549

Source: Own elaboration based on data from XM

Note: For a clearer presentation of the results, the parameters presented were re-escaled according to a residual demand expressed in pesos/MWh. That is, bidding prices P_{whk} were expressed in pesos/MWh and quantities Q_{whk} in MWh.

$$V^{NTR} = (1-\mu)(\pi^C + \delta V^{NTR}) + \mu\Big(\sum_{t=1}^{T} \delta^t \pi^O + \delta^{T+1} V^{NTR}\Big)$$

Where T is the number of periods of the duration of the price war. Given the assumption that the price war lasts forever ($T \to \infty$) we are able to express:

$$V^{NTR} = \frac{(1-\mu)\pi^C + \mu\Big(\frac{\delta}{1-\delta}\Big)\pi^O}{1-(1-\mu)\delta}$$

Defining U^{NTR} as the expected discounted profit of deviating in the non-transparency regime. If the firm cheats:

$$U^{NTR} = (1-\mu)\pi^D + \sum_{t=1}^{T} \delta^t \pi^O + \delta^{T+1} V^{NTR}$$

Given the assumption that the price war lasts forever ($T \to \infty$) we are able to express:

$$U^{NTR} = (1-\mu)\pi^D + \Big(\frac{\delta}{1-\delta}\Big)\pi^O$$

The collusion agreement is sustainable if $V^{NTR} \geq U^{NTR}$, i.e. the incentive compatibility constrain is $ICC^{NTR} = V^{NTR} - U^{NTR} \geq 0$

Repeated-game in the transparency regime. In the transparency regime each firm observes its own bidding prices and sales and the others' bidding prices and sales. With some probability there is a negative demand shock. In this case the members of the cartel have sales as if one of them was cheating. Given the observability of the actions, the firms are able to distinguish between the demand shock and the cheating of others members of the cartel. In this case the members of the cartel know that if they abide the agreement with some probability μ they receive the cartel profit and with probability $(1-\mu)$ they receive the Cournot profit. In order to discipline the members of the cartel, each time a firm cheats its rivals launch a price war.

Defining V^{TR} as the expected discounted profit if the firm abide the agreement in the transparency regime:

$$V^{TR} = \Big((1-\mu)\pi^C + \mu\pi^O\Big)(1+\delta+\delta^2+\delta^3+...+\delta^T)$$

Given the assumption that the price war lasts forever ($T \to \infty$) we are able to express:

$$V^{TR} = \left((1-\mu)\pi^C + \mu\pi^O\right)\left(\frac{1}{1-\delta}\right)$$

Defining U^{TR} as the expected discounted profit of deviating in the transparency regime. If the firm cheats:

$$U^{TR} = (1-\mu)\pi^D + \mu\pi^O + \pi^O(\delta + \delta^2 + \delta^3 + ... + \delta^T)$$

Given the assumption that the price war lasts forever ($T \to \infty$) we are able to express:

$$U^{TR} = (1-\mu)\pi^D + \mu\pi^O + \pi^O\left(\frac{\delta}{1-\delta}\right)$$

The collusion agreement is sustainable if $V^{TR} \geq U^{TR}$, i.e. the incentive compatibility constrain is $ICC^{TR} = V^{TR} - U^{TR} \geq 0$

For computation of V^{TR}, U^{TR}, V^{NTR} and U^{NTR} is necessary to know the parameters μ and δ.

Regarding the value of μ in the Colombian wholesale electricity market, we adopt an heuristic approach and we calculate it as the probability that a private unit in the sample do not generate during each hourly dispatch. We calculate a specific μ_h for each of the 24 hours of the day. However, giving its importance for the sustainability of the hypothetical collusive relation, in the next subsection we calculate upper and lower bounds of the this parameter based on the following two premises : i) in the non-transparency period the agreement is not sustainable and ii) in the period with transparency the agreement was sustainable. We demonstrate that the spectrum of values of μ for which both premises are met in the structural model analyzed is quite broad.

Regarding δ, we adopt parameters previously used in the literature Igami and Sugaya (2018) . We find the solution for the a monthly discount factor of 0.95. We assume that the firms have static expectations and that they use the current value of the parameters for calculating their strategies.

4.5.3. The incentive compatibility constraints.

Once we calculate V^{TR}, U^{TR}, V^{NTR} and U^{NTR} we are able to evaluate the incentive compatibility constraint related with the switching from transparency to non-transparency. We calculate the ICC for two specifications of the model. In a first approach, we do not consider forward contracts. The panel a of figure 4.7 presents the time series of the of the ICC_{TR} and the ICC_{NTR} including the counter-factual, i.e. the ICC_{TR} after February

6th 2009 and the ICC_{NTR} before February 6th 2009. The thickest line represents the corresponding ICC calculated using the the average marginal cost in the corresponding period. The ICC range present the ICC resulting from the imputation of the maximum marginal cost and the minimum marginal cost.

In the second model, we consider forward contracts. As before, we only consider static oligopoly equilibriums which do not violate the non-negativity of the quantities. The panel b of figure 4.7 presents the time series of the of the ICC_{TR} and the ICC_{NTR} in the case we consider forward contracts.

Figure 4.7 clearly shows that the incentive compatibility restriction changes radically when switching from a transparency regime to a non-transparency regime. First of all, it should be noted that in the transparency regime the estimated ICC is greater than zero and hence the collusion relationship is sustainable. On the contrary, in the non-transparency regime the estimated ICC takes negative values, which implies that the collusive agreement is not sustainable.

It is important to note that the ICC in the transparency regime does not show significant valleys nor does it approach to negative values in periods close to the announcement of the non-transparency policy. This indicates that within the framework of the structural model, the variation of the values of the parameters related to marginal costs, residual demand and the perception of the risk of a demand shock μ do not explain a degradation of the value of the implicit collusion relation that could have caused its collapse.

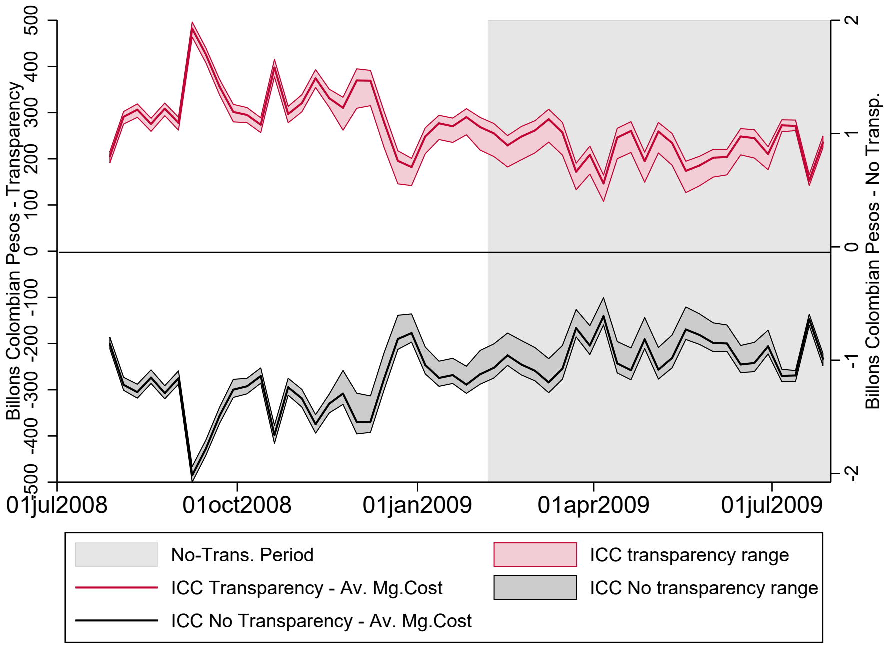
Secondly, the order of magnitude of the value of the ICC also changes significantly with the regime switch. In order to appreciate the variation of the ICC in the non-transparency regime, it is necessary to incorporate another axis with a different scale in Figure 4.7. The order of magnitude of the ICC in the no-transparency regime are expressed in billions of Colombian pesos while in the case of the transparency regime, the order of magnitude reaches hundreds of billions of pesos.

Third, in figure 4.7 it is difficult to observe the difference between the model without forward contracts and the model with forwards. In figure 4.8 we plot the two versions of the model for the average marginal cost. It is possible to observe that the impact of the inclusion of forward contract do not change the most important results of the model. This is because the in average the private firms are net sellers in the electricity in the spot market.

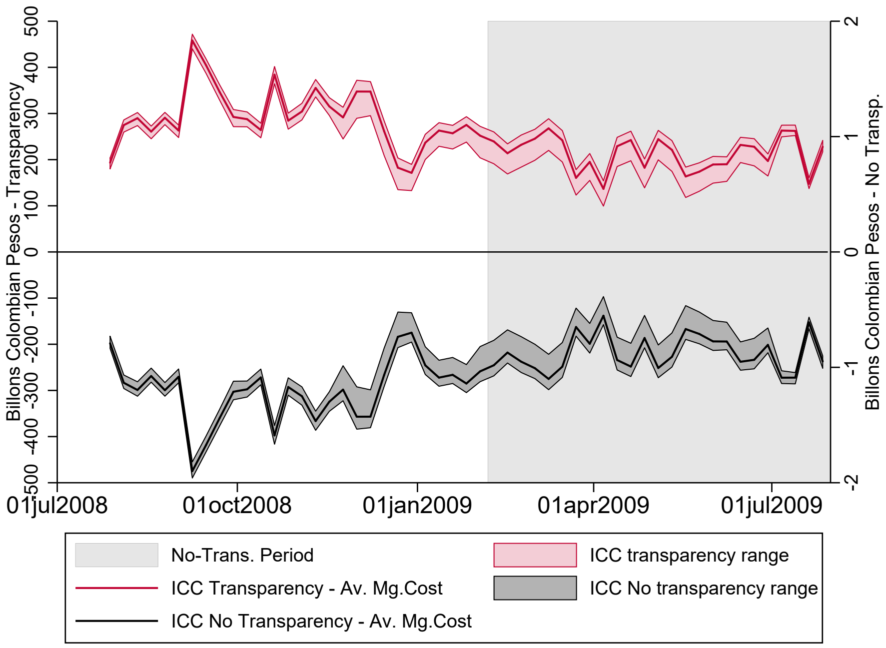
The results presented above are consistent with the hypothesis that the transparency policy had a strong impact on the value of the collusion relationship which was enough to led to the collapse of the agreement, i.e. under the transparency regime the agreement

Figure 4.7.: Incentive Compatibility Constraints

(a) Model without forward contracts



(b) Model with forward contracts



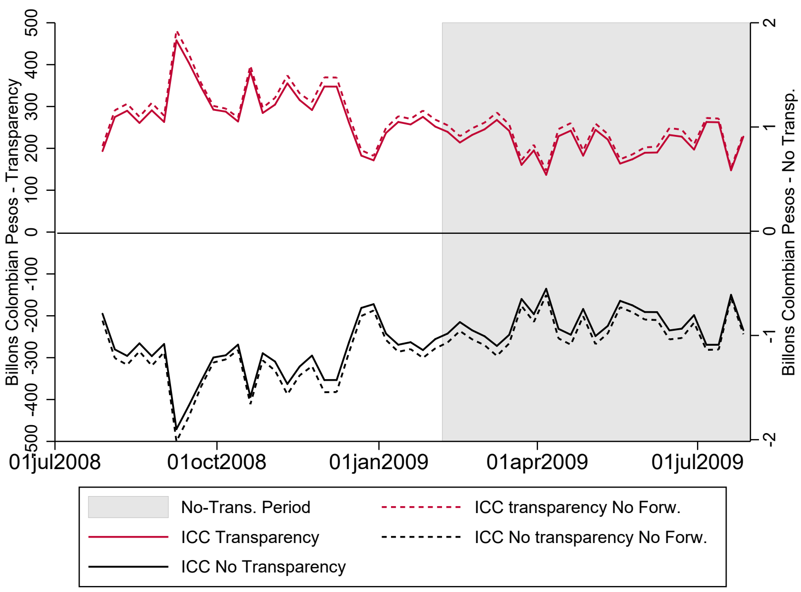
Source: Data from XM - Calculations and elaboration: Authors.

was sustainable and in the non-transparency regime it was not. As was announced in the previous section we found the values of the parameter μ for which both of these premises are met in the structural model.

For finding the upper bound of the parameter μ, we calculated the minimum value that makes the incentive compatibility restriction of the non-transparency regime be greater than zero in at least one of the periods after the announcement of the non-transparency policy, i.e $ICC_{NTR} \geq 0$. This value is 0.99835. For finding the lower bound of the parameter μ, we calculated the maximum value that makes the incentive compatibility restriction of the transparency regime be less than zero in at least one of the periods prior to the announcement of the non-transparency policy, i.e. $ICC_{NTR} \geq 0$. This value is 0.2490. The above entails that for values within the range $[0.2490, 0.99835]$ the change from the transparency to the non-transparency regime causes a flip in the sign of the ICC. We believe that this range is quite wide and that this finding supports the thesis of an implicit collusion relation between private firms.

All these evidence is consistent with the hypothesis of a collapse of a potential collusive agreement due to the announcement of a change in the transparency regime.

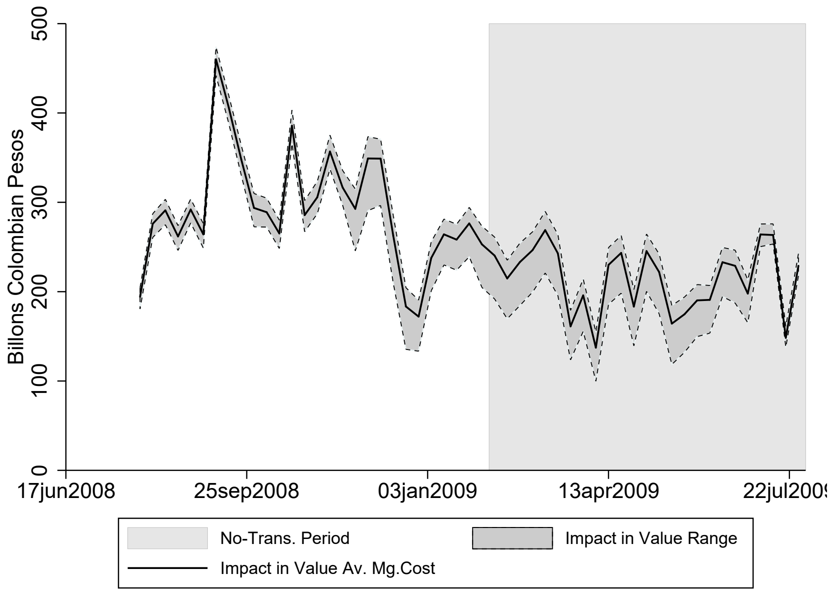
Figure 4.8.: ICC - Model without contracts vs. model with contracts



Source: Data from XM - Calculations and elaboration: Authors.

Finally, we calculate the impact of the transparency policy on the value of the relation as the difference between the ICC with transparency and the ICC without transparency. Figure 4.9 shows the results of this estimation.

Figure 4.9.: Impact of the transparency policy on the value of the relation



Source: Data from XM - Calculations and elaboration: Authors.

According to the parameters estimated for the period post implementation, the impact of the no transparency policy in the value of the relation was between -138.1 and -278.1 billions of Colombian Pesos. These values are equivalent to the -1.54% and -3.10% respectively of the annual GDP of the Colombian Electricity Industry in 2009.

4.6. Conclusions and Discussion

One of the aspects that makes detecting implicit coordination difficult in the field, is the existence of multiple confounding factors from unilateral incentives. In this paper, we study a quasi-natural experiment in the Colombian wholesale electricity market, in which a non-transparency policy, that has an important effect on the value of the informal relation, is announced several days before it takes effect. The possibility of distinguishing between the impact of the announcement and that of the implementation on bidding prices allows us to perform a test to detect implicit coordination agreements. The rationale of this analysis is based on the observation that the mere announcement of the measure has no effect on the current benefits of the firms but on the expectation of future benefits. This allows us to distinguish between a unilateral strategy and a coordination strategy in a repeated game.

The estimation of several specifications of difference in difference models documents a decrease in bidding prices by private companies related to the announcement of the transparency policy. This effect is in a range between the 14% to the 36% and it is statistically significant in almost all the specifications.

Given these results, we constructed a simple structural model with the objective of approaching to a quantification of the value of the implicit coordination agreement and verifying that other elements, such as forward contract levels, marginal costs or residual demand shifts, did not play a definitive role in the hypothetical collapse of this agreement. Our structural model suggest that in post periods the collusive agreement would be sustainable if the transparency policy was not implemented. We quantify the impact of the no-transparency policy on the value of the collusive relation between the -1.54% and -3.10% of the annual GDP of the Colombian Electricity Industry in 2009.

These findings have several important policy implications for the design of competitive wholesale electricity markets. First, our results suggest that high levels of transparency may facilitate informal coordination in electricity markets. Previous empirical studies point out in the same direction. Brown et al. (2018) found evidence suggesting that important market participants used the information reports for coordinating its bidding strategies in Alberta's wholesale electricity market. Second, the case of the Colombian experience indicates that a three-month information information restriction is sufficient to break a potential collusive agreement.

However, there are also powerful arguments against the total concealment of information that should be carefully considered. The concealment of information can make it difficult to coordinate the operation of the electricity market and make it necessary to design confidentiality protocols that ultimately entail higher costs of system administration. Likewise, the non-availability of the information may hinder the surveillance actions by the competition authorities, the academy and other interest groups. Therefore, it seems that an optimal policy of disclosure of information must be placed in the middle between total transparency (as was the case of the Colombian electricity market) and complete concealment.

There are several challenges regarding the design of this policy. In the first place, still it is not clear what variables (prices, quantities, identities, etc.) should be affected by the information concealment. Better insights about what type of information is relevant for achieving coordination equilibria are necessary. Secondly, we do not know what the optimal duration of information concealment should be. Although recent works have studied empirically the mechanisms of emergence or collapse of price coordination (Miller and Weinberg, 2017; Byrne and De Roos, 2019), further research is required in this field to improve the understanding of the role of information in these processes.

5. Conclusions

Explaining how competition works in energy markets is an essential element for designing suitable energy policies to face current global challenges such as energy poverty and climate change. This thesis aims to contribute to the better understanding of these issues by studying from an empirical perspective the implications of the coexistence of private and state owned firms on the allocative efficiency in oligopoly markets.

Chapter 1 of this thesis studied the effect of the switch from public to private management of specific generation units on pricing strategies. In most cases, the mixed nature of ownership in electricity production markets arises from partial privatization processes within the framework of liberalization reforms implemented during the 1980s and 1990s. The logic of these reforms posed that the introduction of competition and the profit maximizing behavior of private agents would result in a cost reduction that would be transferred to the end users. Although there are many empirical studies that deal with the effects of privatization on costs and performance, only few are concerned for other elements necessary for a successful transference of these improvements to the final consumers. In particular, strategic behavior issues may offset the cost savings effect on the final price. This study contributes to the literature on mixed oligopoly by providing new evidence from a policy valuation of the impact of private management which emphasizes in the aspects related to strategic behavior.

In this chapter, we use the information on bidding prices and changes of administration from public to private documented in the Colombian generation market from 2005 to 2018. For estimating the impact of the management changes from public to private, we apply a model of differences in differences with staggered adoption design along with matching techniques. The results of these estimations indicate that although the bidding prices of the units that switched to private administration increased, this effect was transitory. It was also found that the effects of management changes depend on factors such as firm size and forward contracting commitments. When the management of generation assets it is assumed by large private companies with previous presence in the market, the increase in bidding prices is greater than in cases in which the assets change to the management by new entrant private business groups. As for forward contracts, the estimations suggest that the effect of private administration depends on the long or short position regarding contracting hedging. When firms have committed a high proportion of their installed capacity in forward contracts, the switch to private management tends to decrease bidding prices. On the contrary, in the case of low values of the ratio forward contract / installed capacity, I find that the change to private management has an increasing effect on bidding prices.

These findings are aligned with the theoretical predictions of comparative static of mixed oligopoly models about the effect of privatization on pricing strategies. Regarding the policy implications, the results of this chapter suggest that the design of privatization programs that incorporate mechanisms such as mandatory forward contracting levels and restricting the sale of assets only to non-incumbent business groups can mitigate the price increases that private agents would apply when they face opportunities to exercise market power.

In chapter 2 of this thesis, I studied from an empirical perspective the difference between the response of private and public firms against the same incentives to exert unilateral market power. Unilateral market power in wholesale electricity markets has been widely documented in the literature. Many of these studies assume a structural econometric approach and assume a priori that firms aim to maximize profits. Although there is a majority consensus among economists on what is the objective function of private companies (profit maximization), the objective of public companies is so much less evident. In this article I addressed this problem from an empirical perspective. Analyzing the response in the bidding prices of private and public companies to the incentives to exercise market power, I try to figure out whether the two types of companies pursue the same objectives. The main contribution of this document is to provide an analysis framework that serves to clarify the effect of heterogeneous ownership (public-private) on competition in the context of multi-product uniform price auctions.

For the empirical analysis of this chapter I adopted the model proposed by McRae and Wolak (2009). Based on a structural interpretation of the first order condition of the profit maximization problem of electricity generation firms, these authors propose to measures the incentives to exert market power as the semi-elasticity of the net residual demand after deducting the energy committed in forward contracts. I implemented several econometric models in which the dependent variable is the marginal price of each firm and the interest variable is the measure of the incentives to exert market power. The innovative aspects of the econometric specification proposed in this chapter are: i) allowing different coefficients for private and public companies and ii) incorporating instrumental variables analysis to cope with potential endogeneity issues. I applied this methodology to information on the wholesale electricity market in Colombia during the 2005-2014 period.

The results of these estimates suggest that in the Colombian electricity market there are important differences between private and public companies in terms of the exercise of market power. In particular, I found that private companies respond more to incentives to exert market power. Most estimates suggest that public companies behave as if ignoring such incentives. These findings are compatible with the assumptions about the behavior of firms adopted by mixed oligopoly models. An important policy implication that emerges from these results is that the proportion of public/private participation of the ownership in an industry is not necessarily neutral in relation to competition. This calls into question the benefits of the introduction of private initiative in oligopolistic competition environments. Likewise, this implication invites to revisiting the role of public companies as a policy instrument, insofar as they can be used as a competitive benchmarking to promote more aggressive pricing behavior by private companies.

In Chapter 3 we study a regulatory reform in the transparency policy in the electricity market and its link with the sustainability of coordination relationships between private companies. Although the results of the vast majority of theoretical models that have studied the problem of transparency suggest that it facilitates collusion, in the specific case of wholesale energy markets between the experts there are opposite positions in terms of its benefits and disadvantages. To date, there is little empirical evidence that enrich this regulatory policy discussion Brown et al. (2018). This chapter makes a relevant contribution in the field of energy market design because it documents the reactions of private companies to important changes in the transparency policy.

In addition, this chapter proposes a strategy for identifying potential coordination relationships in repeated interaction contexts. The key element of the quasi-natural experiment that makes feasible this identification strategy is the fact that the announcement of the modification of the transparency policy was made several days before its effective implementation. We argue that agents involved in a coordination relationship would react to events that alter the interaction in the repeated game in the future, while agents engaged in a unilateral strategy would only react to changes in information conditions in the present (as in a one-shot game). Based on this premise, we associate the bidding price response to the announcement with a change in the expectations of the rules in future stages of the repeated game and hence with the existence of a coordination relationship. We put forward that this identification strategy can be invoked in other contexts in the empirical literature on detection of collusion agreements and relational contracts.

In this chapter we use information on bidding prices and other outcomes variables of the Colombian wholesale energy market between August 2008 and July 2009. By mean of descriptive statistics, time series models of structural break with endogenous break-point date and regression models of differences in differences, we managed to document a drop between 21% and 33% in the bidding prices of private companies linked with the mere announcement of the policy of non-transparency. We interpret these findings as suggestive evidence of informal coordination relationships between private companies in the Colombian wholesale energy market.

Given these results, we use a simple structural model to estimate an upper bound of the effect of the transparency policy on the firms' valuation of the coordination relationship. In this application we modeled the one-shot game as quantity competition similar to the approach adopted by Igami and Sugaya (2018). We assume that the group of private firms face a residual demand resulting from a competitive fringe. For modeling repeated interaction, we adopted the collusion model in the context of non-transparency proposed by Green and Porter (1984) and Tirole (1988). The results of this structural approach suggest that the impact of the policy on the informal coordination relationship had a magnitude between 1.54% and 3.10% of the annual GDP of the electricity industry in Colombia.

These results suggest that the policy of non-transparency may be effective in hindering the stability of implicit coordination agreements. Still, we believe that giving a certain level of access to information to the academy, competition authorities and interest groups is an important element for the accountability of market participants and administrators. We advocate that a better understanding of the impact of the different aspects of the policy instrument, such as the duration of the information concealment period and the set of variables affected by the measure, is necessary for the design of an optimal transparency policy.

Overall, the evidence presented in the three essays of this dissertation indicates that the distinction between public and private companies may be a relevant aspect for explaining the functioning of competition in liberalized industries.

A. Appendix to Chapter 1

A.1. Parallel trends - figures and tables

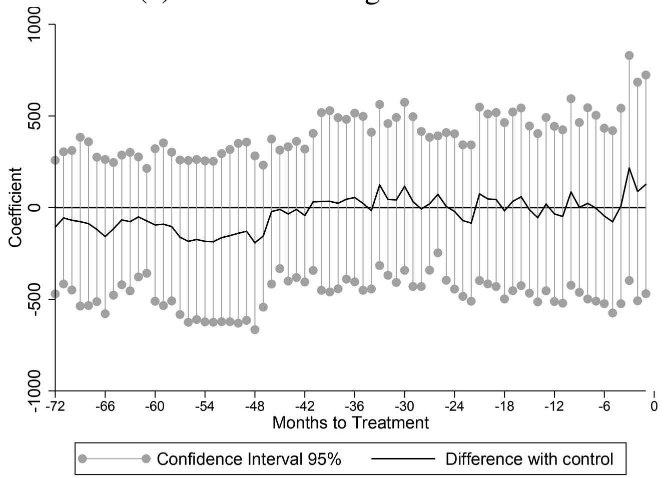
Table A.1.: Quadratic and Linear Trends Equality Test

	Bids		Bids Logarithms	
	Linear	Quadratic	Linear	Quadratic
Linear trend control	-0.0115	-0.142	0.0000118	-0.000465*
	(0.018)	(0.092)	(0.000)	(0.000)
Quadratic trend control		0.0000149		5.44e-08*
		(0.000)		(0.000)
Linear trend TBT	-0.0423	-0.241**	0.0000148	-0.000770***
	(0.076)	(0.078)	(0.000)	(0.000)
Quadratic trend TBT		0.0000247		9.74e-08**
		(0.000)		(0.000)
Observations	93684	93684	93684	93684
Groups	29	29	29	29
F-Statistic Ho: $\beta_1^T = \beta_1^{NT}$	0.16	0.68	0.00	1.02
P-Value	(0.70)	(0.42)	(0.98)	(0.32)
F-Statistic Ho : $\beta_2^T = \beta_2^{NT}$		0.32		1.18
P-Value		(0.58)		(0.29)

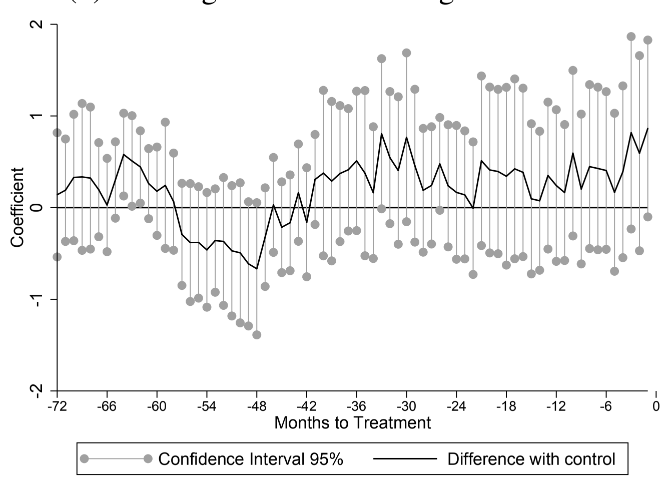
Note: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%).
Standard errors in parentheses clustered by generation unit.

Figure A.1.: Parallel trends alternative control groups

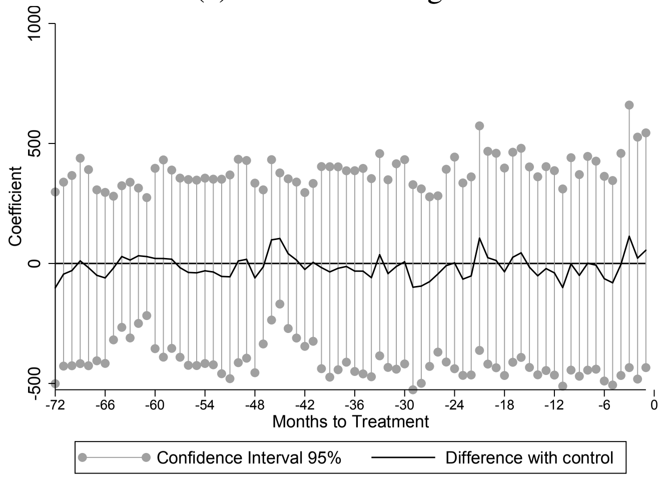
(a) Bids - Central government



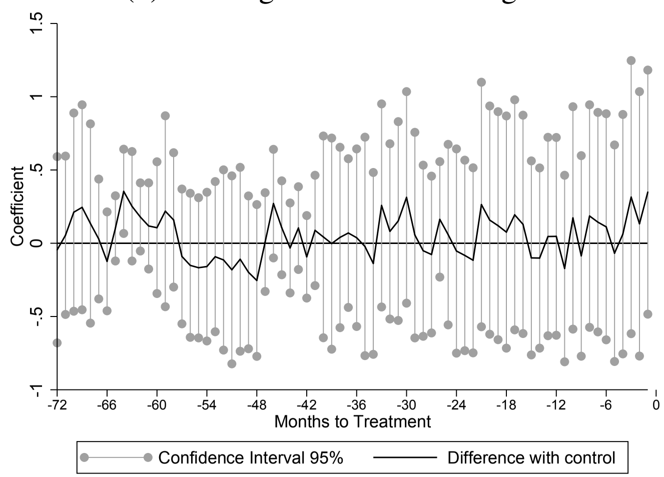
(b) Bids logarithms - Central government



(c) Bids - No change



(d) Bids logarithms - No change



Source: Data from XM - Calculations and elaboration: Author.

A.2. Robustness Checks Tables and Figures

Table A.2.: Random Effects estimator

	(1) Bid	(2) Bid	(3) Bid	(4) Bid	(5) Ln (Bid)	(6) Ln (Bid)	(7) Ln (Bid)	(8) Ln (Bid)
Ch. to Pr.	86.17				0.18			
	(67.23)				(0.12)			
Ch.to Pr. Small to big		354.85***				0.64***		
		(57.92)				(0.12)		
Ch. to Pr. New comp.		-4.89				0.03		
		(51.93)				(0.11)		
Ch.P./C.Low			128.66				0.38**	
			(104.17)				(0.15)	
Ch.P./C.High			-54.59				-0.45***	
			(88.35)				(0.14)	
Ch.P./C.Low Small to big				132.76				0.74***
				(132.99)				(0.13)
Ch.P./C.High Small to big				-18.04				-0.33**
				(90.33)				(0.13)
Ch.P./C.Low New comp.				118.46				0.28
				(115.27)				(0.21)
Ch.P./C.High New comp.				-80.23				-0.53**
				(143.38)				(0.25)
Contracts Low			-133.16	-133.45			0.27	0.269
			(158.97)	(159.83)			(0.20)	(0.19)
Marginal Cost	-2.39***	-2.30***	-1.33	-1.32	-0.01***	-0.01***	-0.01***	-0.01***
	(0.83)	(0.86)	(1.32)	(1.39)	(0.00)	(0.00)	(0.00)	(0.00)
Fuel gas	376.11**	377.64**	346.59**	349.61**	1.40***	1.407***	1.412***	1.427***
	(156.13)	(163.97)	(152.77)	(157.57)	(0.40)	(0.41)	(0.41)	(0.43)
AGC	-171.32**	-150.10**	-148.85***	-146.26**	-0.50**	-0.47**	-0.53**	-0.50**
	(71.69)	(70.19)	(54.96)	(57.13)	(0.23)	(0.22)	(0.23)	(0.22)
Installed Capacity	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
Forward C. 2005/2006	-0.03	-0.06**	-0.03	-0.03	-0.00**	-0.00**	-0.00	-0.00
	(0.02)	(0.03)	(0.03)	(0.03)	(0.00)	(0.00)	(0.00)	(0.00)
Energy critical	-0.00	-0.00	-0.00	-0.00	-0.00	-0.00	-0.00	-0.00
	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
Unit FE	Y	Y	Y	Y	Y	Y	Y	Y
Every Week FE	Y	Y	Y	Y	Y	Y	Y	Y
N	90875	90875	89608	89608	90875	90875	89608	89608

Note: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%).
Standard errors in parentheses clustered by generation unit.

Table A.3.: Prais-Winsten estimator

	(1) Bid	(2) Bid	(3) Bid	(4) Bid	(5) Ln (Bid)	(6) Ln (Bid)	(7) Ln (Bid)	(8) Ln (Bid)
Ch. to Pr.	78.29***				0.12***			
	(22.92)				(0.03)			
Ch. to P. Small to big		107.01***				0.12***		
		(37.80)				(0.04)		
Ch. to P. New comp.		42.27**				0.11***		
		(17.38)				(0.04)		
Ch.P./C.Low			115.32***				0.19***	
			(22.15)				(0.03)	
Ch.P./C.High			-73.44***				-0.11***	
			(15.89)				(0.02)	
Ch.P./C.Low Small to big				134.80***				0.17***
				(34.51)				(0.04)
Ch.P./C.High Small to big				-74.64***				-0.10***
				(16.60)				(0.02)
Ch.P./C.Low New comp.				67.12***				0.27***
				(16.17)				(0.03)
Ch.P./C.High New comp.				-29.37				-0.25***
				(24.73)				(0.05)
Contracts Low			5.95	5.92			0.05***	0.05***
			(5.41)	(5.40)			(0.02)	(0.02)
Marginal Costs	0.19*	0.24**	-0.42***	-0.36***	0.00***	0.00***	0.00	-0.00
	(0.113)	(0.11)	(0.11)	(0.12)	(0.00)	(0.00)	(0.00)	(0.00)
Fuel gas	184.94***	185.59***	247.65***	246.17***	0.80***	0.80***	1.00***	1.01***
	(15.46)	(15.35)	(15.26)	(15.19)	(0.03)	(0.03)	(0.03)	(0.03)
AGC	-162.18***	-157.61***	-154.35***	-149.62***	-0.41***	-0.41***	-0.39***	-0.39***
	(11.31)	(10.66)	(10.43)	(10.01)	(0.03)	(0.03)	(0.03)	(0.03)
Installed Capacity	0.00	0.00	0.00***	0.00***	0.00***	0.00***	0.00***	0.00***
	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
Forward C. 2005/2006	-0.04***	-0.05***	-0.03***	-0.05***	-0.00***	-0.00***	-0.00***	-0.00***
	(0.01)	(0.01)	(0.01)	(0.01)	(0.00)	(0.00)	(0.00)	(0.00)
Energy critical	-0.00***	-0.00***	-0.00***	-0.00***	-0.00***	-0.00***	-0.00***	-0.00***
	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
Unit FE	Y	Y	Y	Y	Y	Y	Y	Y
Every week FE	Y	Y	Y	Y	Y	Y	Y	Y
N	90875	90875	89608	89608	90875	90875	89608	89608
R-sq	0.03	0.03	0.04	0.04	0.07	0.07	0.11	0.11

Note: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%).

Standard errors in parentheses clustered by generation unit.

Table A.4.: Estimation without applying the PSM

	(1) Bid	(2) Bid	(3) Bid	(4) Bid	(5) Ln (Bid)	(6) Ln (Bid)	(7) Ln (Bid)	(8) Ln (Bid)
Change to Private	73.208				0.186			
	(69.707)				(0.118)			
Ch. to P.		365.519***				0.684***		
Small to big		(55.270)				(0.100)		
Ch. to P.		-19.830				0.027		
New comp.		(54.827)				(0.105)		
Ch. to P. Contracts Low			148.654*				0.340**	
			(82.025)				(0.147)	
Ch. to P. Contracts High			-173.705*				-0.405**	
			(98.398)				(0.147)	
Ch. to P. Contracts Low				408.231***				0.735***
Small to big				(86.260)				(0.126)
Ch. to P. Cont. High				-143.152				-0.297*
Small to big				(85.029)				(0.148)
Ch. to P. Cont. Low				58.670				0.232
New comp.				(88.800)				(0.203)
Ch. to P. Cont. High				-163.268				-0.456*
New comp.				(170.931)				(0.255)
Contracts Low			96.168**	89.026**			0.413***	0.401***
			(39.726)	(38.388)			(0.118)	(0.116)
Marginal Costs	-2.046**	-1.968**	-2.415***	-2.328**	-0.006***	-0.006***	-0.007***	-0.007***
	(0.768)	(0.805)	(0.856)	(0.929)	(0.002)	(0.002)	(0.002)	(0.002)
Unit FE	Y	Y	Y	Y	Y	Y	Y	Y
Date FE	Y	Y	Y	Y	Y	Y	Y	Y
N	108406	108406	107139	107139	108406	108406	107139	107139
R-sq	0.359	0.367	0.355	0.362	0.516	0.520	0.516	0.519

Note: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%).
Standard errors in parentheses clustered by generation unit.

Table A.5.: Estimation PSM with pooled data panel

	(1) Bid	(2) Bid	(3) Bid	(4) Bid	(5) Ln (Bid)	(6) Ln (Bid)	(7) Ln (Bid)	(8) Ln (Bid)
Change to Private	86.730				0.183			
	(68.794)				(0.119)			
Ch. to P.		358.829***				0.642***		
Small to big		(59.207)				(0.117)		
Ch. to P.		-4.622				0.029		
New comp.		(53.015)				(0.111)		
Ch. to P. Contracts Low			177.047*				0.383**	
			(86.567)				(0.154)	
Ch. to P. Contracts High			-190.515*				-0.457***	
			(100.656)				(0.148)	
Ch. to P. Contracts Low				419.910***				0.754***
Small to big				(83.434)				(0.128)
Ch. to P. Cont. High				-155.918*				-0.332**
Small to big				(80.508)				(0.137)
Ch. to P. Contracts Low				91.690				0.287
New comp.				(98.139)				(0.217)
Ch. to P. Contracts High				-189.404				-0.535**
New comp.				(174.820)				(0.255)
Contracts Low			61.590	60.105			0.302	0.299
			(67.995)	(60.679)			(0.196)	(0.185)
Marginal Costs	-2.414***	-2.332**	-2.926***	-2.841**	-0.007***	-0.007***	-0.008***	-0.008***
	(0.846)	(0.882)	(0.933)	(1.013)	(0.002)	(0.002)	(0.002)	(0.002)
Unit FE	Y	Y	Y	Y	Y	Y	Y	Y
Date FE	Y	Y	Y	Y	Y	Y	Y	Y
N	90874	90874	89607	89607	90874	90874	89607	89607
R-sq	0.360	0.368	0.357	0.364	0.556	0.560	0.556	0.559

Note: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%).
Standard errors in parentheses clustered by generation unit.

Table A.6.: Estimation with PSM - Near Neighbor

	(1) Bid	(2) Bid	(3) Bid	(4) Bid	(5) Ln (Bid)	(6) Ln (Bid)	(7) Ln (Bid)	(8) Ln (Bid)
Change to Private	71.994				0.181			
	(69.694)				(0.118)			
Ch. to P.		365.383***				0.684***		
Small to big		(55.480)				(0.101)		
Ch. to P.		-21.316				0.022		
New comp.		(54.600)				(0.104)		
Ch. to P. Contracts Low			147.349*				0.336**	
			(82.010)				(0.146)	
Ch. to P. Contracts High			-172.541*				-0.401**	
			(98.245)				(0.147)	
Ch. to P. Contracts Low				408.943***				0.738***
Small to big				(86.449)				(0.126)
Ch. to P. Cont. High				-142.992				-0.297*
Small to big				(84.760)				(0.148)
Ch. to P. Contracts Low				56.172				0.223
New comp.				(88.013)				(0.200)
Ch. to P. Contracts High				-160.750				-0.447*
New comp.				(170.694)				(0.254)
Contracts Low			89.227**	82.424**			0.388***	0.376***
			(39.003)	(37.680)			(0.117)	(0.115)
Marginal Costs	-2.023**	-1.946**	-2.390***	-2.302**	-0.006***	-0.006***	-0.007***	-0.007***
	(0.765)	(0.802)	(0.854)	(0.926)	(0.002)	(0.002)	(0.002)	(0.002)
Unit FE	Y	Y	Y	Y	Y	Y	Y	Y
Date FE	Y	Y	Y	Y	Y	Y	Y	Y
N	109137	109137	107857	107857	109137	109137	107857	107857
R-sq	0.359	0.367	0.354	0.361	0.515	0.519	0.514	0.518

Note: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%).
Standard errors in parentheses clustered by generation unit.

Table A.7.: Alternative Control 1 - Central government

	(1) Bid	(2) Bid	(3) Bid	(4) Bid	(5) Ln (Bid)	(6) Ln (Bid)	(7) Ln (Bid)	(8) Ln (Bid)
Change to Private	222.243**				0.410***			
	(90.650)				(0.123)			
Ch. to P. Small to big		456.831***				0.827***		
		(74.215)				(0.145)		
Ch. to P. New comp.		75.179				0.148		
		(116.992)				(0.183)		
Ch. to P. Contracts Low			318.121***				0.613***	
			(69.675)				(0.098)	
Ch. to P. Contracts High			-214.278*				-0.510***	
			(109.074)				(0.168)	
Ch. to P. Contracts Low Small to big				497.912***				0.894***
				(93.132)				(0.158)
Ch. to P. Cont. High Small to big				-146.487*				-0.312*
				(81.511)				(0.153)
Ch. to P. Contracts Low New comp.				210.892*				0.513*
				(112.433)				(0.240)
Ch. to P. Contracts High New comp.				-238.542				-0.673**
				(187.987)				(0.300)
Contracts Low			17.765	22.307			0.220	0.225
			(88.782)	(70.214)			(0.207)	(0.178)
Marginal Costs	-1.655	-1.680	-2.232*	-2.254	-0.005***	-0.006***	-0.007***	-0.007***
	(0.978)	(1.154)	(1.158)	(1.325)	(0.002)	(0.002)	(0.002)	(0.002)
Unit FE	Y	Y	Y	Y	Y	Y	Y	Y
Date FE	Y	Y	Y	Y	Y	Y	Y	Y
N	54422	54422	54355	54355	54422	54422	54355	54355
R-sq	0.295	0.305	0.303	0.311	0.457	0.464	0.469	0.474

Note: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%).
Standard errors in parentheses clustered by generation unit.

Table A.8.: Alternative Control 2 - No change in property

	(1) Bid	(2) Bid	(3) Bid	(4) Bid	(5) Ln (Bid)	(6) Ln (Bid)	(7) Ln (Bid)	(8) Ln (Bid)
Change to Private	141.435*				0.212*			
	(70.925)				(0.119)			
Ch. to P. Small to big		387.983***				0.666***		
		(35.540)				(0.081)		
Ch. to P. New comp.		69.098				0.079		
		(71.631)				(0.119)		
Ch. to P. Contracts Low			211.000***				0.356**	
			(71.373)				(0.143)	
Ch. to P. Contracts High			-153.576*				-0.336**	
			(85.110)				(0.134)	
Ch. to P. Contracts Low Small to big				427.343***				0.730***
				(42.280)				(0.092)
Ch. to P. Cont. High. Small to big				-123.529*				-0.254**
				(67.859)				(0.114)
Ch. to P. Contracts Low New comp.				141.986				0.251
				(86.355)				(0.201)
Ch. to P. Contracts High New comp.				-147.849				-0.359
				(151.421)				(0.248)
Contracts Low			107.341**	104.491**			0.412***	0.407***
			(47.592)	(46.311)			(0.106)	(0.104)
Marginal Costs	-1.885**	-1.865**	-2.043***	-2.018**	-0.005***	-0.005***	-0.005***	-0.005***
	(0.735)	(0.748)	(0.755)	(0.771)	(0.001)	(0.001)	(0.001)	(0.001)
Unit FE	Y	Y	Y	Y	Y	Y	Y	Y
Date FE	Y	Y	Y	Y	Y	Y	Y	Y
N	167696	167696	165914	165914	167696	167696	165914	165914
R-sq	0.445	0.447	0.448	0.450	0.598	0.600	0.600	0.602

Note: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%).
Standard errors in parentheses clustered by generation unit.

Table A.9.: Placebo tests

	25% Units with placebo				50% Units with placebo				50% Units with placebo			
	(1) Bid	(2) Bid	(3) Ln (Bid)	(4) Ln (Bid)	(5) Bid	(6) Bid	(7) Ln (Bid)	(8) Ln (Bid)	(9) Bid	(10) Bid	(11) Ln (Bid)	(12) Ln (Bid)
Ch. to Pri.	-129.87**		-0.33**		-42.52		-0.12		-61.97		-0.12	
	(52.59)		(0.12)		(59.40)		(0.15)		(66.35)		(0.20)	
Ch.P./C.Low		-146.37**		-0.46**		-54.07		-0.12		0.55		0.09
		(59.41)		(0.21)		(61.13)		(0.18)		(74.44)		(0.24)
Ch.P./C.High		-45.45		-0.09		-27.66		-0.07		-66.45		-0.19
		(49.74)		(0.19)		(60.81)		(0.17)		(59.56)		(0.20)
C. Low		132.87**		0.53***		120.40**		0.48**		105.64**		0.42**
		(50.55)		(0.17)		(51.11)		(0.16)		(42.48)		(0.15)
Marginal C.	-1.98***	-1.99***	-0.01***	-0.01***	-2.18***	-2.32***	-0.01***	-0.01***	-2.28***	-2.44***	-0.01***	-0.01***
	(0.61)	(0.54)	(0.00)	(0.00)	(0.61)	(0.48)	(0.00)	(0.00)	(0.64)	(0.55)	(0.00)	(0.00)
Unit FE	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
Date FE	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
N	63481	62301	63481	62301	63481	62301	63481	62301	63481	62301	63481	62301
R-sq	0.47	0.44	0.49	0.48	0.47	0.43	0.49	0.47	0.47	0.43	0.49	0.47

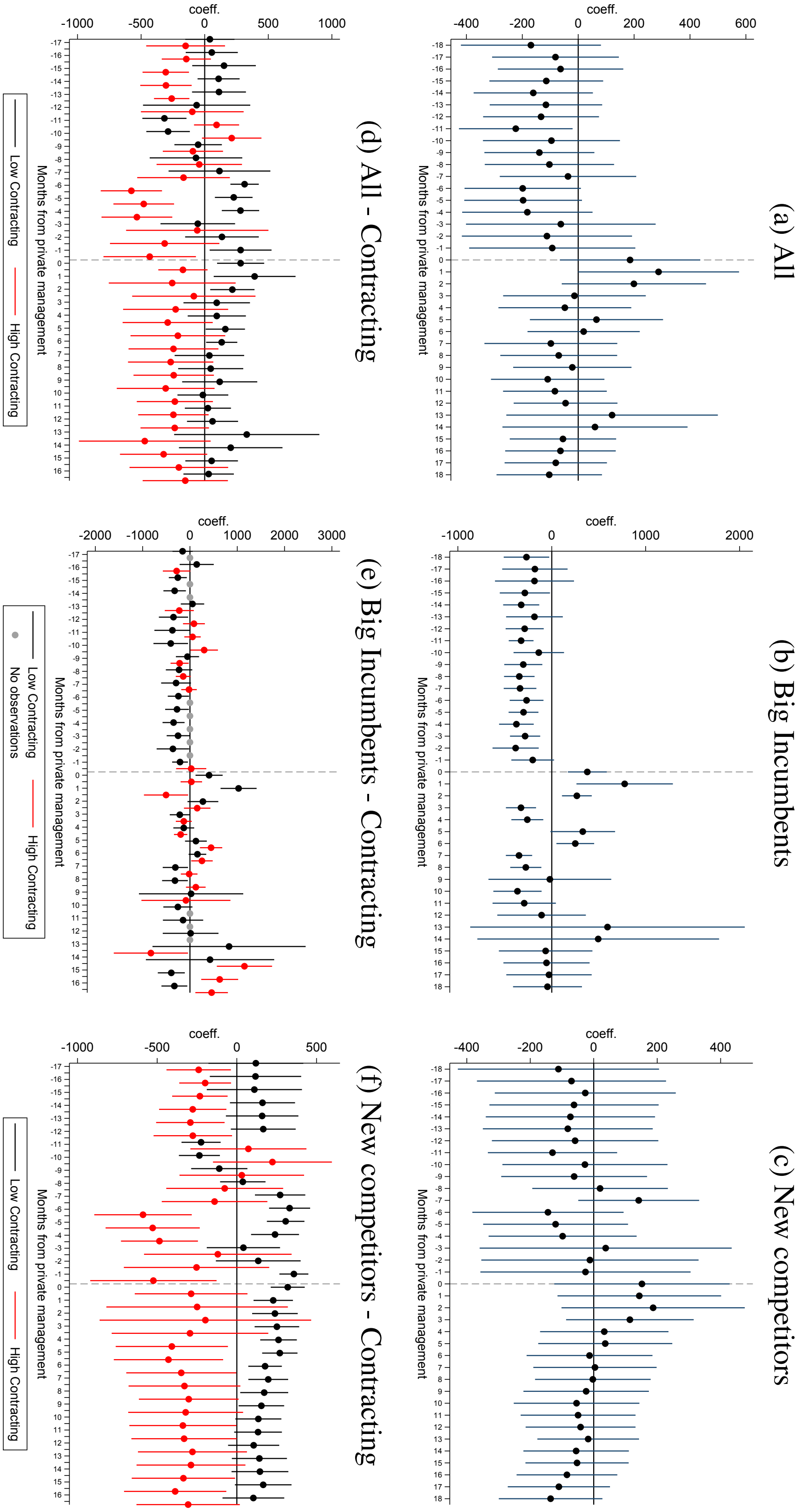
Note: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%).
Standard errors in parentheses clustered by generation unit.

Table A.10.: Results using bootstrapping for standard errors

	(1) Bid	(2) Bid	(3) Bid	(4) Bid	(5) Ln (Bid)	(6) Ln (Bid)	(7) Ln (Bid)	(8) Ln (Bid)
Change to Private	71.994				0.181			
	(69.694)				(0.118)			
Ch. to P. Small to big		358.752***				0.642***		
		(78.784)				(0.247)		
Ch. to P. New comp.		-4.763				0.029		
		(61.960)				(0.143)		
Ch. to P. Contracts Low			176.332*				0.381**	
			(90.780)				(0.149)	
Ch. to P. Contracts High			-189.320*				-0.453***	
			(111.140)				(0.129)	
Ch. to P. Contracts Low Small to big				419.523***				0.753**
				(109.662)				(0.318)
Ch. to P. Cont. High Small to big				-154.960				-0.329**
				(101.109)				(0.168)
Ch. to P. Contracts Low New comp.				91.204				0.285
				(103.888)				(0.237)
Ch. to P. Contracts High New comp.				-188.693				-0.532*
				(174.344)				(0.275)
Contracts Low			59.576	58.109			0.296	0.293
			(78.202)	(71.435)			(0.263)	(0.230)
Marginal Costs	-2.405**	-2.324**	-2.912***	-2.829**	-0.007***	-0.007***	-0.008***	-0.008***
	(0.963)	(0.915)	(0.906)	(1.203)	(0.002)	(0.002)	(0.002)	(0.002)
Unit FE	Y	Y	Y	Y	Y	Y	Y	Y
Week of the sample FE	Y	Y	Y	Y	Y	Y	Y	Y
N	90875	90875	89608	89608	90875	90875	89608	89608
R-sq	0.116	0.126	0.133	0.142	0.189	0.196	0.209	0.215
Bootstrap replications	50	50	50	50	50	50	50	50

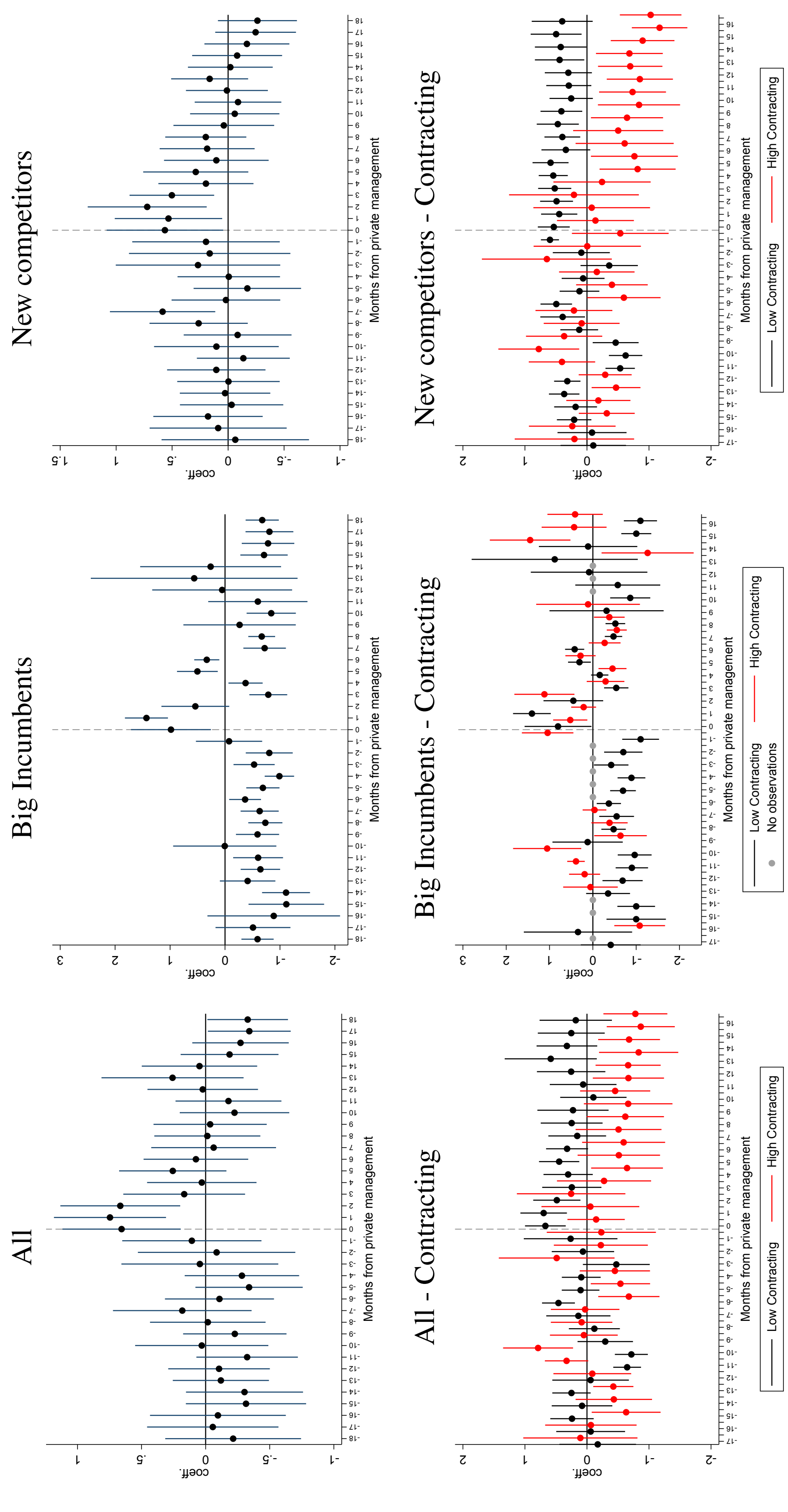
Note: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%).
Standard errors in parentheses clustered by generation unit.

Figure A.2.: Dynamic effects - Bid as dependent variable



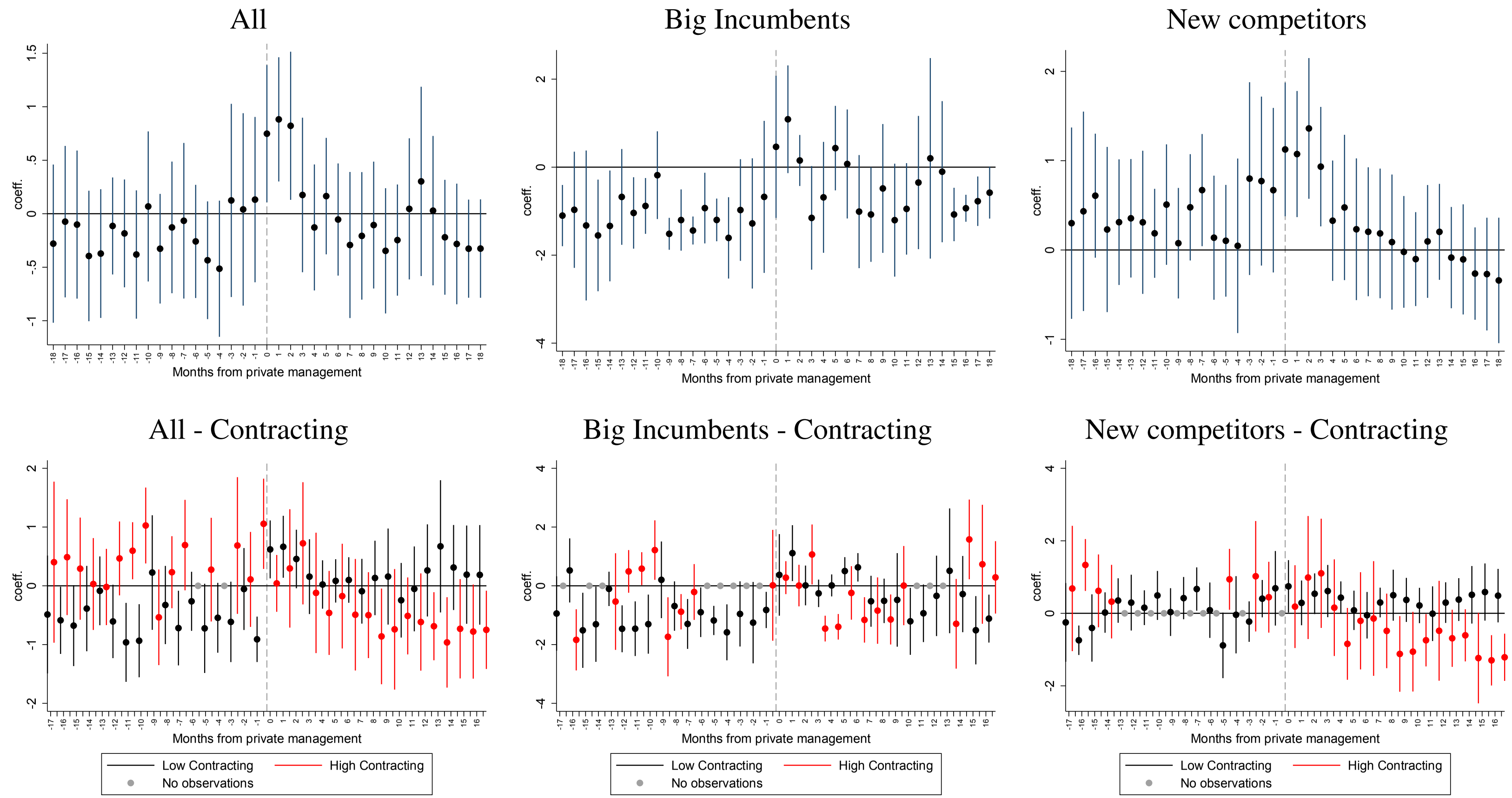
Source: Data from XM - Calculations and elaboration: Author.

Figure A.3.: Dynamic effects - PSM No applied



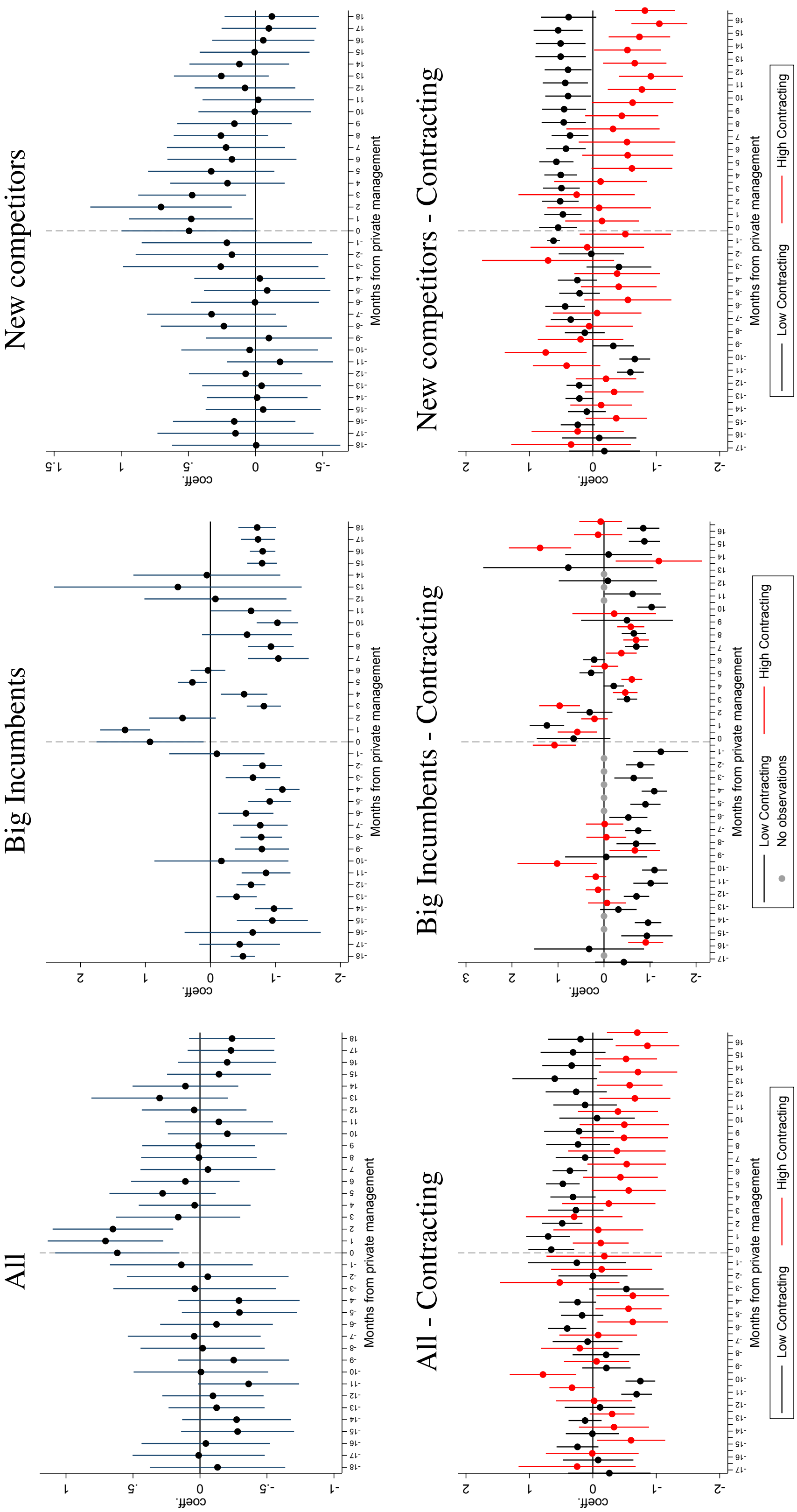
Source: Data from XM - Calculations and elaboration: Author.

Figure A.4.: Dynamic effects - Alternative Control 1 - Central Government



Source: Data from XM - Calculations and elaboration: Author.

Figure A.5.: Dynamic effects - Alternative Control 2 - No change in property



Source: Data from XM - Calculations and elaboration: Author.

A.3. Details of the marginal cost calculus for thermal units

We computed the marginal costs of thermal plants taking account of the heat rate, fuel costs and fuel transportation costs according to the following formula:

$$\underbrace{Exchange\ R._t}_{\frac{COP\$}{US\$}} \times \left[\underbrace{Heat\ R._i}_{\frac{MBTU}{KWh}} \times \underbrace{(Transp.\ fuel\ cost_i + Fuel\ cost_t)}_{\frac{US\$}{MBTU}}\right] = \underbrace{Marginal\ Cost_{it}}_{\frac{COP\$}{kWh}}$$

Where *COP* are Colombian pesos, *MBTU* are one thousand of the British thermal unit, *US* are United States dollars and *KWh* is one kilowatt per hour. The heat rate is a measure of the thermal efficiency of the generation unit. It represents the quantity of fuel measured in *MBTU* necessary to generate one kilowatt per hour.The parameters of the heat rate of thermal electricity generation units were extracted from reports of the Mines and Energy Planning Unit (UPME).

In the case of gas fired units, we use as fuel cost the price of the gas from the basin Guajira which is the most important gas supply source for Colombian thermal generation. Since September 1995 Until August 2013, the Colombian Government regulated the prices of gas coming from this gas source. The regulation consist in imposing a maximum sale price of gas. This maximum price at period t, p_t, is given by the formula $p_{t-1}[index_{t-1}/index_{t-2}]$ where $index_{t-1}$ is the average of the last semester of the New York Harbor Residual Fuel Oil 1.0 % Sulfur LP Spot Price according to the series that was published by the Energy Information Administration of the United States. A period t is defined as semester and it changes 1st February and 1st August of each year [1].This price is given in *US dollars/MBTU*.

From 2005 to 2013 we calculated the Guajira regulated price applying the formula presented above and converting the resulting price *(US dollars/MBTU)* to *Colombian pesos/KWh*. The exchange rate data was obtained from the Colombian central bank (Banco de la RepÃžblica). For the following years to 2013, the weighted average gas price was calculated according to the type of contract, based on information of gas wholesale transactions registered in the web page of the Gas Market Operator in Colombia (BEC).

Consequently, for gas fired units, we take as transportation costs the sum of the fees for the use of each segment of the gas transmission network necessary to take the gas

[1]The formula was established in Act 119/2005 of CREG

from Guajira well to the respective generation units. These fees are regulated by the CREG and are published in regulatory acts (CREG 70 and 125 of 2003).

Regarding the coal fired units, given that Colombia is a net exporter of coal we use the weighted average FOB export price as fuel cost. We computed it as the ratio between the total value of coal exportation (in *US dollars*) and the quantities exported (Tons) according to the data from the non-traditional exports report of the National Department of Statistics (DANE). The price in dollars per ton was transformed to dollars per *MBTU* units, multiplying for a calorific value of the Colombian thermal coal of 1,370 btu per pound (Source: regulation 2009 180507 Colombian Ministry of Energy and Mines). For computing the coal transportation costs, an importation parity approach is adopted. According to this criteria, we estimate it as the road freight transportation fee from the closest importation port to the respective location of the generation unit. These fees were extracted form system of information of efficient costs for road freight transportation provided by the Transportation Ministry of Colombia.

B. Appendix to Chapter 2

B.1. Robustness Checks Tables

Table B.1.: Trimming percentages

	Sample Trimmed at 0.1%				Sample Trimmed at 5%			
	OLS		GMM2S		OLS		GMM2S	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Private IEMP	0.23***	0.14***	0.83***	0.53***	0.39***	0.26***	4.39***	0.80***
	(0.05)	(0.04)	(0.17)	(0.08)	(0.11)	(0.08)	(0.75)	(0.12)
Public IEMP	-0.04	-0.04**	-0.51***	0.27***	0.12	0.04**	-2.24***	0.16
	(0.03)	(0.02)	(0.15)	(0.09)	(0.08)	(0.02)	(0.4)	(0.14)
Marginal Cost	1.2***	-0.31	1.13***	-0.32***	1.16***	-0.33*	0.77***	-0.49***
	(0.17)	(0.21)	(0.09)	(0.09)	(0.17)	(0.20)	(0.20)	(0.06)
Constant	N	Y	N	Y	N	Y	N	Y
Monthly F.E	N	Y	N	Y	N	Y	N	Y
Unit F.E	N	Y	N	Y	N	Y	N	Y
N. Obs	21,189	21,189	15,938	15,938	19,171	19,171	14,777	14,777
N. Clusters	36	36	36	36	36	36	36	36
R-squared	0.70†	0.72	0.49	-0.93	0.70†	0.75	-0.720	-0.326
Joint Sig.	42.39***	6.97***	472.3***	102.8***	22.59***	46.15***	167.2***	29.24***
Weak Identification								
F first stage Private			11.05	228.55			12.13	528.68
F first stage Public			2.86	17.38			3.14	8.95
K-P rk Wald F			3.10	6.25			4.35	15.31
C-D Wald F			7.43	3.35			9.53	7.13
Overidentification								
Hansen J			26.81	23.00			26.56	21.60
p-Value			0.11	0.237			0.115	0.305
Test Diff	15.54	15.37	21.70	2.45	4.09	7.77	65.84	10.24
p-Value	0.00	0.00	0.00	0.12	0.04	0.01	0.00	0.00
Test PMP	210.35	380.83	0.99	32.75	29.85	92.26	20.58	3.03
p-Value	0.00	0.00	0.32	0.00	0.00	0.00	0.00	0.08

Note: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%). SE clustered by unit in parentheses.
Test No Diff: $H_0 : \alpha_{pri} - \alpha_{soe} = 0$ and Test PMP (Profit maximization by private firms): $H_0 : \alpha_{pri} = 1$.
The test statistics for weak identification is the Kleibergen-Paap rk Wald F and the Cragg-Donald Wald F. H0: Instruments are weak.
The critical values for two endogenous variables and twenty one excluded instruments are 20.53, 11.04 and 6.10 for 5%, 10% and 20% maximal IV relative bias, respectively, according with Stock-Yogo (2005). † R-squared for the model without constant.

Table B.2.: GMM2s estimation with 2 and 4 lags

	2 First Lags		4 First Lags	
	(1)	(2)	(3)	(4)
Private IEMP	1.48***	0.74***	1.55***	0.72***
	(0.40)	(0.10)	(0.28)	(0.04)
Public IEMP	-0.77*	0.28	-1.35***	0.17***
	(0.41)	(0.17)	(0.35)	(0.05)
Marginal Cost	1.05***	-0.40***	0.91***	-0.48***
	(0.12)	(0.10)	(0.06)	(0.03)
Constant	N	Y	N	Y
Monthly F.E	N	Y	N	Y
Unit F.E	N	Y	N	Y
N. Obs	17,336	17,336	14,302	14,302
N. Clusters	36	36	36	36
R-squared	$0.40^{\dagger}$	-0.84	$0.13^{\dagger}$	-0.66
Joint Sig.	164.4***	37.29***	540.6***	188.6***
Weak Identification				
F first stage Private	6.39	313.74	37.81	573.99
F first stage Public	2.40	25.61	37.21	6.09
K-P rk Wald F	3.492	2.208	65.17	5.102
Cragg-Donald Wald F	14.08	7.41	9.54	5.75
Overidentification				
Hansen J	24.12	19.56	29.71	24.97
p-Value	0.06	0.19	0.16	0.35
Test Diff	12.56	3.36	26.35	66.84
p-Value	0.00	0.067	0.00	0.00
Test PMP	1.47	6.74	3.70	44.19
p-Value	0.23	0.01	0.05	0.00

Note: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%). SE clustered by unit in parentheses. Test No Diff:$H_0 : \alpha_{pri} - \alpha_{soe} = 0$ and Test PMP (Profit maximization by private firms): $H_0 : \alpha_{pri} = 1$. The test statistics for weak identification is the Kleibergen-Paap rk Wald F and the Cragg-Donald Wald F. H0: Instruments are weak. The critical values for two endogenous variables and twenty one excluded instruments are 20.53, 11.04 and 6.10 for 5%, 10% and 20% maximal IV relative bias, respectively, according with Stock-Yogo (2005). † R-squared for the model without constant.

Table B.3.: Delta parameter 10% and 25%

	$\delta = 10\%$				$\delta = 25\%$			
	OLS		GMM2S		OLS		GMM2S	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Private IEMP	0.39***	0.27***	2.97***	0.91***	0.53***	0.33***	4.00***	1.22***
	(0.10)	(0.07)	(0.48)	(0.10)	(0.15)	(0.08)	(0.82)	(0.19)
Public IEMP	-0.01	-0.04	-2.01**	0.33**	-0.03	-0.07	-3.93***	0.68***
	(0.039)	(0.03)	(0.94)	(0.16)	(0.11)	(0.10)	(0.65)	(0.17)
Marginal Cost	1.20***	-0.34*	0.82***	-0.39***	1.20***	-0.34*	0.84***	-0.48***
	(0.17)	(0.19)	(0.08)	(0.09)	(0.17)	(0.19)	(0.11)	(0.08)
Constant	N	Y	N	Y	N	Y	N	Y
Monthly F.E	N	Y	N	Y	N	Y	N	Y
Unit F.E	N	Y	N	Y	N	Y	N	Y
N. Obs	20,745	20,745	15,724	15,724	20,745	20,745	15,746	15,746
N. Clusters	36	36	36	36	36	36	36	36
R-squared	$0.70^{\dagger}$	0.73	-0.33	-0.74	$0.71^{\dagger}$	0.74	-0.56	-0.72
Joint Sig.	37.63***	25.96***	283.6***	64.84***	30.52***	14.62***	232.7***	32.30***
Weak Identification								
F first stage Private			18.72	1191.55			14.28	465.15
F first stage Public			11.04	2.77			3.14	11.41
K-P rk Wald F			5.07	1.27			3.385	4.945
C-D Wald F			9.87	6.52			9.92	7.84
Overidentification								
Hansen J			27.58	19.39		.	27.52	23.23
p-Value			0.09	0.43			0.09	0.23
Test Diff	12.95	15.45	16.54	6.23	8.39	9.73	52.90	3.38
p-Value	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.07
Test PMP	35.75	98.75	16.95	0.72	9.51	63.89	13.41	1.27
p-Value	0.00	0.00	0.00	0.39	0.00	0.00	0.00	0.26

Note: Statistical significance at standard levels (*** at 1%, ** at 5% and * at 10%). SE clustered by unit in parentheses.
Test No Diff: $H_0 : \alpha_{pri} - \alpha_{soe} = 0$ and Test PMP (Profit maximization by private firms): $H_0 : \alpha_{pri} = 1$.
The test statistics for weak identification is the Kleibergen-Paap rk Wald F and the Cragg-Donald Wald F. H0: Instruments are weak.
The critical values for two endogenous variables and twenty one excluded instruments are 20.53, 11.04 and 6.10 for 5%, 10% and 20% maximal IV relative bias, respectively, according with Stock-Yogo (2005). † R-squared for the model without constant.

C. Appendix to Chapter 3

C.1. Diff-in-diff detailed results

Table C.1.: Diff-in-Diff - All Units - Specification 1

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Bid	Bid	Bid	Bid	LnBid	LnBid	LnBid	LnBid
$\mathbb{1}\{Priv\}_i \times \mathbb{1}\{Announ\}_t$	-263.3***	-263.2***	-263.3***	-263.2***	-0.409***	-0.409***	-0.409***	-0.409***
	(92.18)	(92.98)	(92.18)	(92.01)	(0.134)	(0.136)	(0.135)	(0.134)
$\mathbb{1}\{Priv\}_i \times \mathbb{1}\{Trnsp\}_t$	-195.1*	-194.6*	-195.1*	-194.5*	-0.139	-0.136	-0.139	-0.135
	(99.74)	(100.6)	(99.75)	(99.59)	(0.153)	(0.154)	(0.153)	(0.152)
$\mathbb{1}\{Priv\}_i$	401.5**		401.5**		0.753**		0.753**	
	(178.1)		(178.1)		(0.360)		(0.360)	
$\mathbb{1}\{Announ\}_t$	-60.62***		40.65	40.65	0.0292		0.0955	0.0957
	(22.55)		(27.30)	(27.25)	(0.0823)		(0.0761)	(0.0761)
$\mathbb{1}\{Trnsp\}_t$	-127.4***		-77.68**	-78.28**	-0.246**		-0.216**	-0.218**
	(34.29)		(30.30)	(30.14)	(0.111)		(0.103)	(0.103)
Water Intake			0.142	0.142			-0.000137	-0.000138
			(0.0955)	(0.0955)			(0.000227)	(0.000227)
Coal Price			-0.0191**	-0.0189**			-2.25e-05	-2.22e-05
			(0.00753)	(0.00752)			(1.48e-05)	(1.48e-05)
Guajira Index			0.0834***	0.0835***			7.12e-05*	7.14e-05*
			(0.0249)	(0.0249)			(4.09e-05)	(4.09e-05)
# Observations	17,155	17,155	17,155	17,155	17,155	17,155	17,155	17,155
R-squared	0.100	0.771	0.104	0.768	0.085	0.803	0.086	0.799
Unit FE	NO	YES	NO	YES	NO	YES	NO	YES
Date FE	NO	YES	NO	NO	NO	YES	NO	NO
Inputs Control	NO	NO	YES	YES	NO	NO	YES	YES

Robust standard errors clustered by unit in parentheses
*** p<0.01, ** p<0.05, * p<0.1

Table C.2.: Diff-in-Diff - Thermal Units - Specification 2

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Bid	Bid	Bid	Bid	LnBid	LnBid	LnBid	LnBid
$\mathbb{1}\{Priv\}_i \times \mathbb{1}\{Announ\}_t$	-332.0***	-332.2***	-332.0***	-331.9***	-0.413***	-0.415***	-0.413***	-0.414***
	(116.1)	(117.6)	(116.1)	(115.8)	(0.136)	(0.137)	(0.136)	(0.135)
$\mathbb{1}\{Priv\}_i \times \mathbb{1}\{Trnsp\}_t$	-263.2**	-263.5**	-263.2**	-262.9**	-0.0807	-0.0807	-0.0808	-0.0794
	(113.0)	(114.2)	(113.0)	(112.6)	(0.160)	(0.162)	(0.160)	(0.159)
$\mathbb{1}\{Priv\}_i$	354.9		354.9		0.375		0.375	
	(226.2)		(226.3)		(0.337)		(0.337)	
$\mathbb{1}\{Announ\}_t$	-111.6***		38.40	38.46	-0.117*		0.0829	0.0838
	(29.74)		(37.50)	(37.38)	(0.0623)		(0.0680)	(0.0677)
$\mathbb{1}\{Trnsp\}_t$	-222.5***		-142.6***	-143.1***	-0.534***		-0.426***	-0.427***
	(40.20)		(37.15)	(36.91)	(0.127)		(0.131)	(0.131)
Water Intake			0.118	0.117			0.000113	0.000112
			(0.0916)	(0.0917)			(0.000200)	(0.000200)
Coal Price			-0.0208**	-0.0206**			-2.63e-05*	-2.61e-05*
			(0.00988)	(0.00985)			(1.41e-05)	(1.41e-05)
Guajira Index			0.129***	0.129***			0.000175***	0.000175***
			(0.0345)	(0.0345)			(4.30e-05)	(4.29e-05)
# Observations	11,315	11,315	11,315	11,315	11,315	11,315	11,315	11,315
R-squared	0.125	0.800	0.132	0.796	0.096	0.818	0.101	0.812
Unit FE	NO	YES	NO	YES	NO	YES	NO	YES
Date FE	NO	YES	NO	NO	NO	YES	NO	NO
Inputs Control	NO	NO	YES	YES	NO	NO	YES	YES

Robust standard errors clustered by unit in parentheses
*** p<0.01, ** p<0.05, * p<0.1

Table C.3.: Diff-in-Diff - All Units - Specification 3

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Bid	Bid	Bid	Bid	LnBid	LnBid	LnBid	LnBid
$\mathbb{1}\{Priv\}_i \times \mathbb{1}\{Announ\}_t$	-202.1**	-201.9**	-202.1**	-201.8**	-0.349**	-0.349**	-0.349**	-0.349**
	(87.61)	(88.30)	(87.62)	(87.40)	(0.132)	(0.133)	(0.132)	(0.132)
$\mathbb{1}\{Priv\}_i \times \mathbb{1}\{Trnsp\}_t$	-210.2*	-209.5*	-210.2*	-209.4*	-0.168	-0.165	-0.168	-0.164
	(106.2)	(107.1)	(106.2)	(105.9)	(0.160)	(0.162)	(0.160)	(0.160)
$\mathbb{1}\{Priv\}_i$	416.5**		416.5**		0.783**		0.783**	
	(184.6)		(184.6)		(0.369)		(0.369)	
$\mathbb{1}\{Announ\}_t$	-80.85**		-5.411	-5.105	0.0203		0.0390	0.0398
	(39.58)		(30.86)	(30.81)	(0.0930)		(0.0813)	(0.0813)
$\mathbb{1}\{Trnsp\}_t$	-136.5***		-101.2***	-101.7***	-0.244**		-0.242**	-0.245**
	(37.99)		(31.70)	(31.62)	(0.117)		(0.106)	(0.105)
Water Intake			0.123	0.123			-0.000165	-0.000166
			(0.0916)	(0.0917)			(0.000223)	(0.000223)
Coal Price			-0.0133*	-0.0132*			-1.48e-05	-1.46e-05
			(0.00688)	(0.00688)			(1.48e-05)	(1.48e-05)
Guajira Index			0.0462	0.0465			2.18e-05	2.23e-05
			(0.0317)	(0.0316)			(5.65e-05)	(5.64e-05)
# Observations	17,155	17,155	17,155	17,155	17,155	17,155	17,155	17,155
R-squared	0.104	0.771	0.105	0.768	0.086	0.804	0.087	0.800
Unit FE	NO	YES	NO	YES	NO	YES	NO	YES
Date FE	NO	YES	NO	NO	NO	YES	NO	NO
Inputs Control	NO	NO	YES	YES	NO	NO	YES	YES

Robust standard errors clustered by unit in parentheses
*** p<0.01, ** p<0.05, * p<0.1

Table C.4.: Diff-in-Diff - Thermal Units - Specification 4

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Bid	Bid	Bid	Bid	LnBid	LnBid	LnBid	LnBid
$\mathbb{1}\{Priv\}_i \times \mathbb{1}\{Announ\}_t$	-213.0*	-213.2*	-213.0*	-212.9*	-0.235*	-0.237*	-0.235*	-0.236*
	(116.0)	(117.3)	(116.0)	(115.6)	(0.134)	(0.135)	(0.134)	(0.133)
$\mathbb{1}\{Priv\}_i \times \mathbb{1}\{Trnsp\}_t$	-275.3**	-275.6**	-275.3**	-274.9**	-0.0909	-0.0910	-0.0910	-0.0896
	(122.4)	(123.6)	(122.4)	(121.9)	(0.165)	(0.167)	(0.165)	(0.165)
$\mathbb{1}\{Priv\}_i$	367.0		367.0		0.385		0.385	
	(234.8)		(234.8)		(0.345)		(0.345)	
$\mathbb{1}\{Announ\}_t$	-152.6**		-11.59	-11.12	-0.195**		0.0499	0.0513
	(59.11)		(47.09)	(46.98)	(0.0950)		(0.0890)	(0.0886)
$\mathbb{1}\{Trnsp\}_t$	-239.8***		-167.7***	-168.0***	-0.558***		-0.432***	-0.433***
	(45.50)		(41.60)	(41.57)	(0.128)		(0.138)	(0.137)
Water Intake			0.116	0.116			0.000145	0.000144
			(0.0922)	(0.0923)			(0.000189)	(0.000189)
Coal Price			-0.0149	-0.0147			-2.41e-05	-2.39e-05
			(0.00922)	(0.00922)			(1.54e-05)	(1.53e-05)
Guajira Index			0.0899*	0.0902*			0.000159**	0.000159**
			(0.0459)	(0.0458)			(6.65e-05)	(6.63e-05)
# Observations	11,315	11,315	11,315	11,315	11,315	11,315	11,315	11,315
R-squared	0.130	0.800	0.132	0.795	0.099	0.817	0.100	0.811
Unit FE	NO	YES	NO	YES	NO	YES	NO	YES
Date FE	NO	YES	NO	NO	NO	YES	NO	NO
Inputs Control	NO	NO	YES	YES	NO	NO	YES	YES

Robust standard errors clustered by unit in parentheses
*** p<0.01, ** p<0.05, * p<0.1

Table C.5.: Diff-in-Diff - Specification 2 - Alternative LHS variables

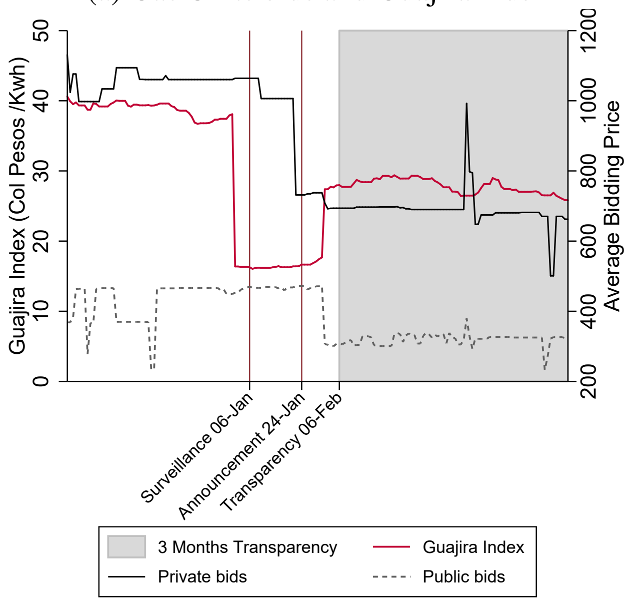
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Margin	Margin	Margin	Margin	Mark Up	Mark Up	Mark Up	Mark Up
$\mathbb{1}\{Priv\}_i \times \mathbb{1}\{Announ\}_t$	-326.8***	-327.1***	-326.8***	-326.8***	-3.334**	-3.338**	-3.334**	-3.333**
	(114.4)	(115.8)	(114.4)	(114.0)	(1.597)	(1.622)	(1.597)	(1.595)
$\mathbb{1}\{Priv\}_i \times \mathbb{1}\{Trnsp\}_t$	-259.7**	-260.5**	-259.7**	-259.9**	-2.327**	-2.346**	-2.323**	-2.335**
	(112.3)	(113.4)	(112.3)	(111.8)	(0.978)	(0.988)	(0.979)	(0.973)
$\mathbb{1}\{Priv\}_i$	342.4		342.4		2.380		2.380	
	(229.1)		(229.1)		(2.602)		(2.602)	
$\mathbb{1}\{Announ\}_t$	-88.62***		34.92	35.03	1.429		-0.518	-0.518
	(29.65)		(36.82)	(36.70)	(0.919)		(1.172)	(1.171)
$\mathbb{1}\{Trnsp\}_t$	-205.8***		-145.1***	-145.4***	-1.354***		-2.665***	-2.660***
	(40.65)		(37.25)	(37.00)	(0.441)		(0.603)	(0.604)
Water Intake			0.120	0.119			0.000208	0.000204
			(0.0917)	(0.0917)			(0.00101)	(0.00101)
Coal Price			-0.0245**	-0.0243**			-0.000115	-0.000113
			(0.00981)	(0.00978)			(0.000121)	(0.000120)
Guajira Index			0.105***	0.106***			-0.00176***	-0.00176***
			(0.0339)	(0.0338)			(0.000620)	(0.000620)
# Observations	11,315	11,315	11,315	11,315	11,315	11,315	11,315	11,315
R-squared	0.112	0.803	0.118	0.799	0.042	0.799	0.055	0.794
Unit FE	NO	YES	NO	YES	NO	YES	NO	YES
Date FE	NO	YES	NO	NO	NO	YES	NO	NO
Inputs Control	NO	NO	YES	YES	NO	NO	YES	YES

Robust standard errors clustered by unit in parentheses
*** p<0.01, ** p<0.05, * p<0.1

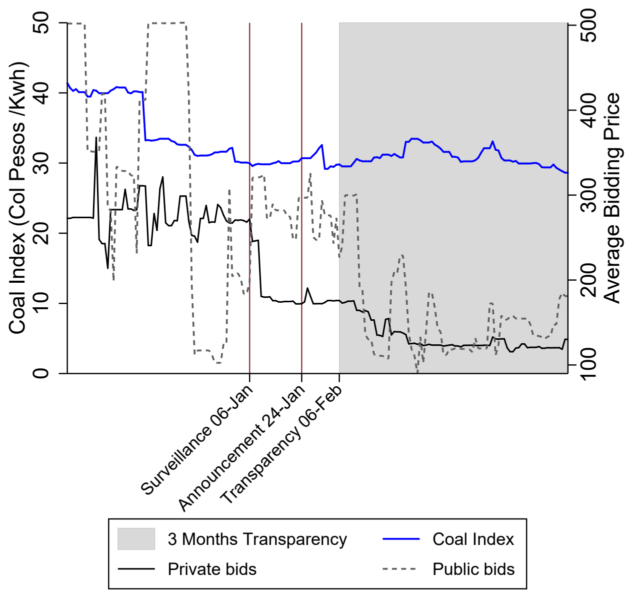
C.2. Discarding competing explanations

Figure C.1.: Thermal inputs and thermal units bids

(a) Gas Units bids and Guajira index



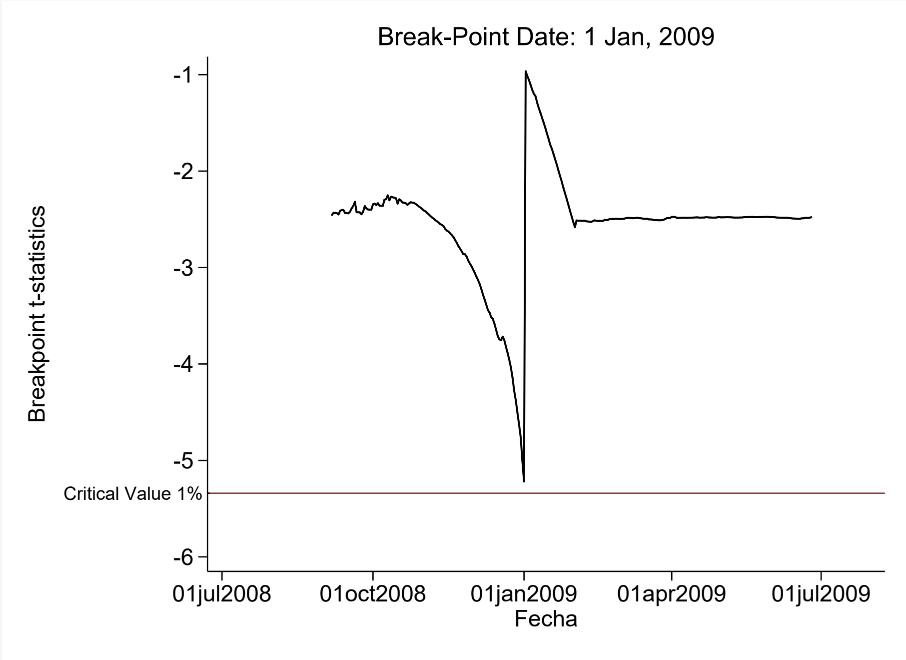
(b) Coal Units bids and Coal index



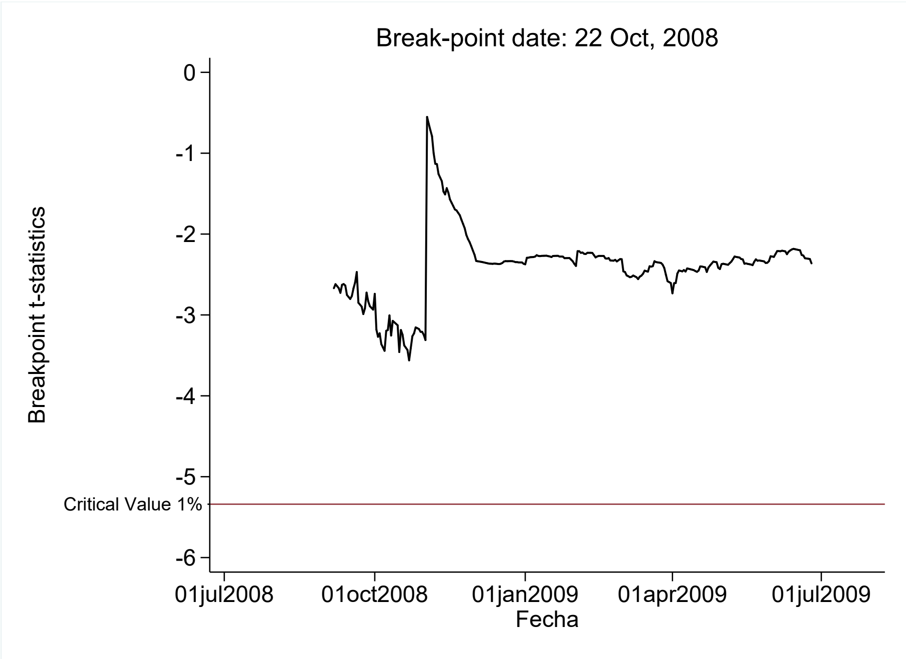
Source: Data from XM - Calculations and elaboration: Authors.

Figure C.2.: Zivot-Andrews test of thermal inputs

(a) Gas - Guajira index



(b) Coal



Source: Data from XM - Calculations and elaboration: Authors.

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