Transition to Centralized Unit Commitment

An Econometric Analysis of Colombia's Experience

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Abstract

This paper attempts to shed light on the relative merits of centralized electricity markets with multipart bids and dispatch using an MIP-based unit commitment optimization approach vs. self-committed markets with linear energy supply curves. We conduct an empirical study of data from the Colombian market, which in 2009 transitioned from a self-commitment paradigm to a centralized unit commitment approach where generators offer a linear supply function for energy along with start-up costs while the commitment and dispatch are determined by the system operator using MIP-based optimization. The results indicate that the transition to centralized dispatch has resulted in productive efficiency gains through a decrease in production costs. However, these gains have not translated into wholesale price decreases; in fact, wholesale prices increased after the change in the dispatch approach. These results suggest that productive efficiency gains have been captured by suppliers through the exercise of market power.

Keywords

Centralized Unit Commitment, Productive Efficiency, Market Power.

1. Introduction

System operators (SO) in electricity markets have the responsibility of balancing supply and demand of electricity at each moment in time, taking into account all of the constraints in the system. One of the most important elements of this task is the dispatch of generators.

There are essentially two ways of determining which generators are to be dispatched in restructured electricity markets. In self-committed markets, generators place bids for energy production and the SO chooses the least-cost producers. In centrally committed markets, generators submit their cost of production and their fixed start-up (and possibly no-load) cost. These fixed costs are taken into account in the optimization problem resolved by the SO and are used to calculate an uplift payment to dispatched generators that does not fully cover their fixed costs through their energy revenues. In contrast, in self-committed markets, generators can only recoup their start-up costs directly through their energy bids.

Of course, efficiency requires that the lowest-cost producers be chosen at each moment in time and that these costs include the generators' start-up costs. Thus, at first glance, centrally committed markets may seem preferable. However, the change in rules also affects the strategic behavior of agents, who may have greater opportunities for misreporting information. Therefore, it is not clear which method is superior.

Indeed, there has been a debate in the literature about this issue. Some authors, such as Ruff (1994), Hogan (1994), Hogan (1995) and Hunt (2002) prefer centrally committed markets. On the other hand, Oren and Ross (2005) show that generators may have incentives to misreport their bids. Wilson (1997) and Elmaghraby and Oren (1999) suggest that self-committed markets may end up being more efficient when bidders' strategic behavior is taken into consideration. Sioshansi and Nicholson (2011) analyze the equilibrium behavior in both designs and show that there are opportunities to misreport in both. Thus, while all SOs in the United States have adopted a design based on voluntary centralized unit commitment for day-ahead markets, so far the theoretical literature has not been able to determine which method is superior. Thus, this important market design question remains an empirical one.

In this paper, we shed some light on the foregoing debate by taking advantage of a natural experiment performed in the Colombian electricity market, where the market design was changed in 2009[1] from a self-committed one to a centrally committed one. We perform a comprehensive analysis of the Colombian market before and after the change and reach two main conclusions. First, the centrally committed market contributed to higher productive efficiency.[2] Second, we find evidence that marginal cost markups and prices after 2009 were also higher than they would have been under the regime before the change, possibly as a result of an increase in exercise of market power by generators. These findings suggest that consumers have not benefitted from efficiency gains and although productive efficiency has increased, the additional strategic flexibility of generators has reduced consumers' surplus; depending on demand elasticity, this could have resulted in reduced social welfare. We show that this is true even if we ignore spot prices and focus only on the average price of bilateral contracts.

This paper is organized as follows. In Section 2, we describe Colombia's electricity market rules before and after 2009. We also describe the unit commitment problem that the system operator XM (Compañía de Expertos en Mercados) solves and how each plant is remunerated. Section 3 contains a description of the data used. The econometric analysis is presented and discussed in Section 4 where we argue that productive efficiency has increased since 2009. Section 5 provides evidence of an increase in market power after 2009 and that efficiency gains were not passed on to consumers through lower prices. Section 6 contains the conclusions.

2. The problem

In this section we briefly explain Colombia's spot market design before and after the implementation of resolution 051/2009.[3] We focus on the domestic market and exclude international exchanges with Venezuela and Ecuador.[4]

Beginning in 2001, Colombia operated a day-ahead market where each generator offered a single bid for energy production for the next 24 hours. The system operator (SO) used these bids to determine which generators would produce. For the spot

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[1] The change was implemented by Resolution 051/2009, enacted by Colombia's energy regulatory agency, the *Comisión de Regulación de Energía y Gas* (CREG).

[2] By this we mean lower total cost of production.

[3] Unless stated otherwise, references herein to "before regulation 2009" means the period from enactment of the 2001 regulation until enactment of the 2009 regulation. In the 2001 reform, CREG imposed the constraint that all bids are to be fixed for the entire day.

[4] The dispatch and spot market in these international exchanges is subordinated to the domestic market which is by far the most important. Hence, from the perspective of this study, focusing on the domestic market is appropriate.

market and energy dispatch prior to Regulation 051 (i.e., before 2009), [5] there are three relevant points in time: day ahead (economic dispatch), real-time dispatch (real dispatch) and day after (ideal dispatch). The main features of the economic dispatch are:

a) Plants submit two-part bids: a minimum price at which they are willing to generate during the next 24 hours along with their maximum generation capacity for each of the next 24 hours.
b) Plants inform the system operator (SO) on what fuel and plants configuration should be used for solving the unit commitment problem.
c) The system operator estimates the following 24 hours total demand for each hour.
d) Basic technical characteristics of plants are taken into account: a ramp model for thermal plants (minimum uptime, minimum downtime[6], etc.), minimum energy operating restrictions for hydro plants, etc.
e) Automatic generation control (AGC) restrictions are taken into account[7].
f) Transmission restrictions are given.
g) Every day, the economic dispatch optimizes the following function:

$$\sum_{t=0,\dots,23} \sum_{i} b_i \times q_{i,t}$$

where b_i is the price bid by plant i for the next 24 hours and $q_{i,t}$ is the production of plant i in hour t subject to hourly AGC, transmission, demand and technical constraints (ramps), environmental restrictions, etc.

This optimization defines the economic dispatch for every hour and provides a scheduling plan for energy generation for the next 24 hours.

Real-time generation sometimes deviates from the planned economic dispatch for a variety of reasons: demand turns out to be slightly different than the demand estimated on the previous day, energy losses, overloaded lines, etc. Therefore, the system operator has to fine-tune the actual dispatch in real time.

[5] The Colombian electricity market is not, in a strict sense, a spot market. The energy price defined in this market is calculated *ex-post* by an optimization program and used to settle energy consumption and production among market participants. To be consistent with standard Colombian terminology, we refer to the market and its price as "spot market" and "spot price," respectively.
[6] Due to technical characteristics, once a thermal plant is started it must be on for a minimum time (minimum up time). The same is true when a thermal plant is shut down (minimum downtime).
[7] Power grids require closely balanced real time generation and load. Automatic Generation Control (AGC) is a system for adjusting the power output of multiple generators based on frequency deviations.

Once the real generation for the 24 hours has occurred, the system operator calculates the ideal dispatch, which is an ex-post calculation used for settlement purposes. The optimization problem solved is the following:

$$\min_{p_{i,t},} \sum_i b_i \times q_{i,t}$$

$$s.t.$$

$$D_t \leq \sum_i q_{i,t}$$

where b_i is the price bid by plant i for the next 24 hours, $q_{i,t}$ is the production of plant i in hour t and D_t is actual demand at time t. Notice that the ideal dispatch is determined through an hour-by-hour optimization problem.

The ideal dispatch forms the basis for calculating the spot price.[8] Once the optimization problem of the ideal dispatch is solved for every hour, the market clearing price is calculated as the price bid by the marginal plant that is not saturated and which is needed to meet demand[9]. We denote this equilibrium price as b_t^m. The hourly spot price P_t is defined as this equilibrium price, $P_t = b_t^m$ (since 2009, the spot price is modified by an uplift as explained below).

Since the real dispatch turns out to be different than the ideal dispatch, side payments are implemented to pay for any differences.[10]

After the regulation of 2009, the ideal dispatch solves a centralized unit commitment problem. Rather than minimizing the hourly costs of generation, the objective function was set as equal to the objective function of the economic dispatch (24-hour optimization problem), generators submit complex bids and side payments were introduced. The bids specify an energy offer price for the next 24 hours, start-up costs for the next three months and maximum generation capacity for each hour in the next 24 hours.

Once the optimization problem of the ideal dispatch is solved for the 24 hours, the equilibrium price b_t^m is calculated as the price bid by the marginal plant that is not

[8] More precisely, this is a settlement price since technically speaking there is no spot market. Following the local usage of the term, we will continue to refer to this as a spot price.
[9] A plant is saturated when it is operating under inflexible conditions; intuitively, when it cannot change its output without violating technical restrictions. For example, a thermal plant in the middle of ramp is a saturated plant.
[10] These are called *reconciliaciones,* both positive and negative.

saturated. The hourly spot price P_t is defined as this equilibrium price plus an uplift, ΔI, where the uplift is defined in the following way.

Let

$$I_i = \sum_{t=1}^{24} q_{i,t} \times b_t^m$$

be the plant's i income according to the ideal dispatch and:

$$C_i = \sum_{t=1}^{24} q_{i,t} \times b_i + \sum_{t=1}^{24} s_i \, u_{i,t}$$

be the plant's i generating cost (assuming truthful bidding), where s_i is plant's i start-up costs and $u_{i,t}$ is a dummy variable that is 1 if the plant is operating in period t and 0 otherwise.

Now let $q_{i,t}^s$ be plant i energy production at the time when it is saturated (0 otherwise) and PR_i the positive reconciliation price[11]. Then the uplift is defined as:

$$\Delta I \quad = \frac{\sum_i \max\{0, C_i - I_i\} + DI_i}{\sum_{t=1}^{24} D_t}$$

where:

$$DI_i = \sum_{t=1}^{24} q_{i,t}^s \times (\max\{b_t^m, PR_i\} - b_t^m)$$

The hourly spot price is defined as:

$$P_t = b_t^m + \Delta I$$

Therefore, the spot price guarantees that demand will pay for the start-up of dispatched plants and energy production by saturated plants. Having defined the spot prices, we now explain the settlements for the various agents. Agents are paid the spot price for any unit of energy produced (regardless of whether the plant is saturated or not) and hydro plants reimburse the ΔI component of the price for each unit of energy

[11] For the objectives of this study, an explicit definition of this price is not relevant.

produced, while thermal plants for which $C_i \leq I_i$ also reimburse the ΔI component of the price and thermal plants for which $C_i > I_i$ make no reimbursement.

3. Data

The Colombian electricity sector is a hydro-dominated but diversified system. Figure *1* shows a time series since 2001 of the share of hydro and thermal generation (as a proportion of total generation). The figure also shows the spot price.

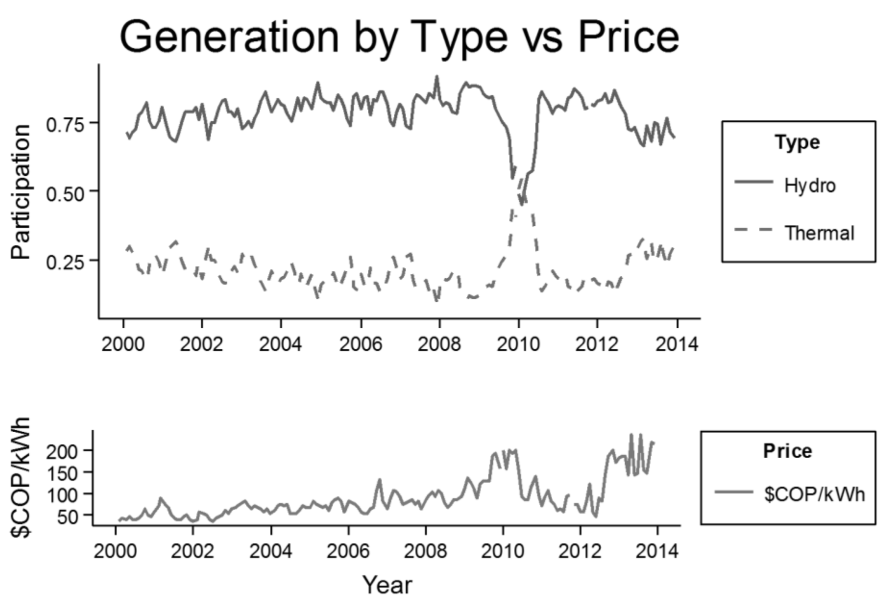

Figure 1: Panel A (upper) shows thermal vs. hydro generation as a proportion of total generation. Panel B (lower) shows the spot price in Colombian pesos per KWh.

Some of the key variables that have to be estimated for the econometric analysis in the next section are the marginal costs and opportunity costs of water. We take a standard, pragmatic approach commonly used in the economic literature (Borenstein et.al. (2002), Mansur (2008)). The methodology for estimating the marginal costs of plants whose principal fuel is coal and natural gas is based on: (1) the heat rate for each plant; (2) fuel calorific value; (3) fuel price (P); (4) variable operating and maintenance costs (VOM); and (5) taxes (CERE and FAZNI[12]). Then the marginal cost of thermal plants is:

$$\text{Marginal Cost} = \frac{\text{Heat Rate}}{\text{Calorific Value}} * \text{P} + \text{VOM} + \text{CERE} + \text{FAZNI}$$

[12] CERE is a tax per unit of generation that redistributes revenues among generators to cover firm energy. FAZNI is a modest tax used to finance energy infrastructure in remote regions of Colombia. Data available from: http://www.alvaroriascos.com/research/data/

We use fuel price time series adjusted by calorific value and transport costs from UPME[13] while heat rates are taken from SO web page for all thermal plants. Also, we use different VOM costs: US$5/MWh for natural gas plants and US$6.9/MWh for coal plants.

The daily official exchange rate (TRM) is from *Banco de la República*[14] is used to express marginal costs in pesos. CERE time series data are obtained from SO databases. FAZNI are calculated by taking into account resolutions CREG 005 (2001) and CREG 102 (2006). These resolutions set FAZNI at 1COP/kWh indexed to the PPI (Producer Price Index) month by month. According to the resolutions, the value is reset to 1COP/kWh in December 2006 and thereafter is indexed to the PPI. The PPI is taken from DANE.[15]

The opportunity cost of water is one of the most difficult variables to pin down. We estimated the opportunity cost of water in one hour as the minimum between the plant's bid price and the marginal cost of the most expensive thermal plant operating during that hour.

Our econometric analysis is based on a panel of 50 plants operating from January 1, 2006 to December 31, 2012, and which are responsible for more than 95% of total generation.

4. Econometric analysis

This section describes an econometric evaluation of the welfare consequences of Resolution 051/2009 using data made available by the *Comisión de Regulación de Energia y Gas* (CREG, the Colombian regulator for electricity markets) and XM (the system operator). The methodology used in this study closely follows the methodology used by (Mansur, 2008) to evaluate the effects of the market restructuring in Pennsylvania, New Jersey and Maryland in 1999. This method is more sophisticated than the standard method used by Borenstein, Bushnell and Wolak (2002), which compares market outcomes with an ideal competitive benchmark that ignores start-up costs. That is, the standard method assumes that whenever a plant has a lower marginal cost than the spot price, it should have been used in the competitive benchmark. However, it may be optimal not to use a plant with a low marginal cost but high start-up costs if it is not required to run for long. Therefore, the standard method

[13] Colombia's energy and mining planning department (*Unidad de Planeación Minero Energética*): http://www.sipg.gov.co/sipg/documentos/precios_combustibles

[14] Central Bank of Colombia.
[15] *Departamento Administrativo Nacional de Estadística*, the official national statistics agency.

overestimates the welfare losses in the actual market. Mansur proposes a dynamic model that produces a more accurate evaluation of welfare losses. This methodology is particularly relevant for our study, since start-up cost is one of the central aspects of Resolution 051/2009.

Specifically, we estimate two models. The first, an output decision model, estimates the quantity of energy produced as a function of price-cost markups in the present, past and future. The actual decision to produce or not will depend on these markups. In order to control for other relevant information that may affect agents' output decisions such as the opportunity costs of water, we carry out two exercises: (1) instrument the spot price using available water resources in rivers (an exogenous variable) and (2) use water resources in rivers as a direct control of the output decision model. Results for the first exercise are reported below and for the second exercise, they are contained in the technical supplement to this article[16]. Our conclusions are robust to these specifications. We calibrated the first model with data before 2009, when the resolution changed the rules, and we used it to simulate the (counterfactual) production that would have been obtained if there was no rule change in 2009.

The second model adapts the methodology described in Mansur's appendix A and estimates prices as functions of demand, controlling also for El Niño and La Niña effects. More details about these procedures and our overall evaluation strategy are given in the next section. This econometric model is a reduced form model that ignores agents' strategic behavior.

Our results indicate that Regulation 51 has improved welfare by reducing production costs. However, the observed prices are higher than the simulated prices that represent the spot price that would have prevailed in the absence of regulation (counterfactual). Moreover, these results do not change when we consider start-up costs. The simulated counterfactual prices and estimated marginal and opportunity costs imply that after Regulation 51 was implemented, markups have increased. This suggests that although dispatch has been more efficient, there has been considerable exercise of market power to the detriment of consumers. In Section 5 we show that this is still the case even if we use contracted prices rather than the spot price.

[16] Available at: http://www.alvaroriascos.com/research/electricitymarkets/

a) Output decisions

Firms' production decisions are estimated using data from before 2009. In this model production predictions are constructed both before (in-sample estimation or model fit) and after the reform (out-of-sample estimation or forecast). In general in a dynamic model, assumptions about how firms create expectations of future prices are important, whereas here we focus on the correlation between future prices and production. Therefore, the model asserts that a firm's current output depends on historical, current, and future price-cost markups (pcm_{it}).

$$pcm_{it} = P_t - c_{it} \quad (1)$$

where i denotes a particular firm, t is the hour of the day, P_t is the spot or simulated price and c_{it} is the marginal or opportunity cost.

Then, output q_{it} before 2009 is specified as:

$$\begin{aligned} q_{it} = \alpha_i + \beta_{1,i} pcm\_pos_{it} + \beta_{2,i} pcm_{it} + \beta_{3,i} pcm_{i,t-1} + \beta_{4,i} pcm_{i,t+1} + \beta_{5,i} \overline{pcm}_{it} \\ + \beta_{6,i} \overline{pcm}_{i,t-24} + \beta_{7,i} \overline{pcm}_{i,t+24} + \gamma_0 niño + \gamma_1 niña + \vec{F} + \varepsilon_{it} \quad (2) \end{aligned}$$

where α_i, are unit fixed effects, $\overline{pcm}_{it}$ is the average markup for the day, pcm_pos_{it} is a binary variable equal to 1 if there was a positive markup for firm i at time t and 0 otherwise and $\vec{F}$ represents fixed time effects (for hours, weekdays and months). Note that specific characteristics like minimum uptimes, minimum downtimes, load costs, start-up cost, ramping rates, etc., do not vary significantly in time and are indistinguishable from the unit fixed effects α_i, which captures all of this variation. To make the model more flexible, all variables except α_i and pcm_pos_{it} are estimated using fifth-order polynomial functions[17]. This model has more variables than Mansur's model in order to adapt the methodology to the Colombian electricity market. First, it includes two indicator variables that are very important for all agents and generating units and that represent El Niño and La Niña phenomena. These variables capture climate changes in the Pacific Ocean that affect precipitation in the country.

To consistently estimate equation (2) using ordinary least squares, it is important that markups are not correlated with the error terms. Since output and markups (prices) are jointly determined in equilibrium, this is most likely not the case. Furthermore, excluding the potential strategic interaction among firms by ignoring output decisions of other firms (other than i) in equation (2), we are potentially omitting variables, which also calls into question the independence of markups and the error term. As a

[17]The online technical supplement to the paper shows that using sixth-degree polynomials is not better than using fifth-degree polynomials.

result estimated coefficients may be biased. We have tried to mitigate some of these potential econometric problems by introducing instrumental variables and reporting the sensitivity analysis for the main results. Below we provide a discussion of these issues. First, in order to get a sense of the model's fit and the role of introducing a more flexible specification, we report estimation results for the model with no polynomials or calendar fixed effects.

Table 1, with neither polynomials nor calendar fixed effects, shows the average coefficient for each variable across all plants, the average standard error and the number of firms (of a total of 46) for which the coefficient is significant at a 95% confidence level. The R^2 of this model is 0.06 and the variables are significant in most of the units evaluated, with the unit fixed effect and El Niño and La Niña phenomenon being key variables in almost all models. Also the coefficient signs of most variables are intuitive. The full model estimation with calendar effects and polynomial has an R^2 of 0.17. Tables 2 and 3 report the same results by resource type. There is a notable difference in coefficients between El Niño and La Niña variables for thermal and hydro plants, which is consistent with our intuition.

Taking into account the high level of concentration in the Colombian electricity market, it is plausible that companies are not behaving as price takers. This is why endogeneity might be a problem in the models above. Even though the analysis has been performed at the unit level, it is possible that companies strategically influence the markup by engaging in price setting and for that reason a final specification of the model is tested using instrumental variables. There are at least three possible candidates for instruments: the maximum energy production capacity, bilateral contracts and water resources in rivers. The first was discarded because of insufficient variability: it didn't change at the hourly level and hardly at all from day to day. The bilateral contracts variable is theoretically very interesting.

Table 1. Summary of Model for All Plants

Plants	Average of Coefficients	Average of Std. Errors	No. of Coefs. Significant(5%)
(Intercept)	4,415,406	46,478	44
pcmpos	913,875	71,499	38
pcm	24,386	2,624	26
pcmminus1	18,964	1,874	32
pcmplus1	16,275	1,879	25
meanpcm	-3,875	2,635	33

Table 1. Summary of Model for All Plants

Plants	Average of Coefficients	Average of Std. Errors	No. of Coefs. Significant(5%)
meanpcmminus24	-6,677	1,530	37
meanpcmplus24	-19,399	1,531	37
nino	-134,881	61,043	43
nina	-125,379	39,182	39

Table 2. Summary of Model for 17 Hydro Plants

Plants	Average of Coefficients	Average of Std. Errors	No. of Coefs. Significant(5%)
(Intercept)	3,479,380	33,612	17
pcmpos	884,697	50,589	17
pcm	21,359	1,741	13
pcmminus1	15,697	1,246	15
pcmplus1	14,146	1,250	16
meanpcm	-3,923	1,293	17
meanpcmminus24	-6,597	648	15
meanpcmplus24	-14,560	648	17
nino	-423,559	42,564	15
nina	-98,842	27,353	17

Table 3. Summary of Model for 29 Thermo Plants

Plants	Average of Coefficients	Average of Std. Errors	No. of Coefs. Significant(5%)
(Intercept)	936,026	12,866	27
pcmpos	29,178	20,910	21
pcm	3,026	883	13
pcmminus1	3,267	627	17
pcmplus1	2,129	629	9
meanpcm	48	1,342	16
meanpcmminus24	-79	883	22
meanpcmplus24	-4,839	883	20
nino	288,678	18,479	28
nina	-26,537	11,829	22

At the moment in time when prices are set, this variable can be taken as exogenous and captures some of the most relevant information for bidding in the day-ahead market. If the firm is "long" on energy then it will be in its interest to bid high, in order to set the price as high as possible. Unfortunately, there are several issues that hinder the use of this instrument. First, the data are not available by unit but by company, eliminating part of the richness of the data. Moreover, there are five units that didn't enter into any contracts and many firms had very few contracts before 2009, reducing the estimation sample substantially. Despite these shortcomings, we performed some tests with the available data. In this case the correlation between the instrument and the markup is 0.3 and the R^2 of the first stage averages 0.12. Nevertheless in the second stage of the estimation we didn't find a good fit. The third variable–water resources in rivers–is also interesting as an instrument. Below we report results for this case.[18]

Figure *2* compares the estimated (in-sample) aggregate supply curve (before 2009) to the observed aggregate supply curve (in-sample).

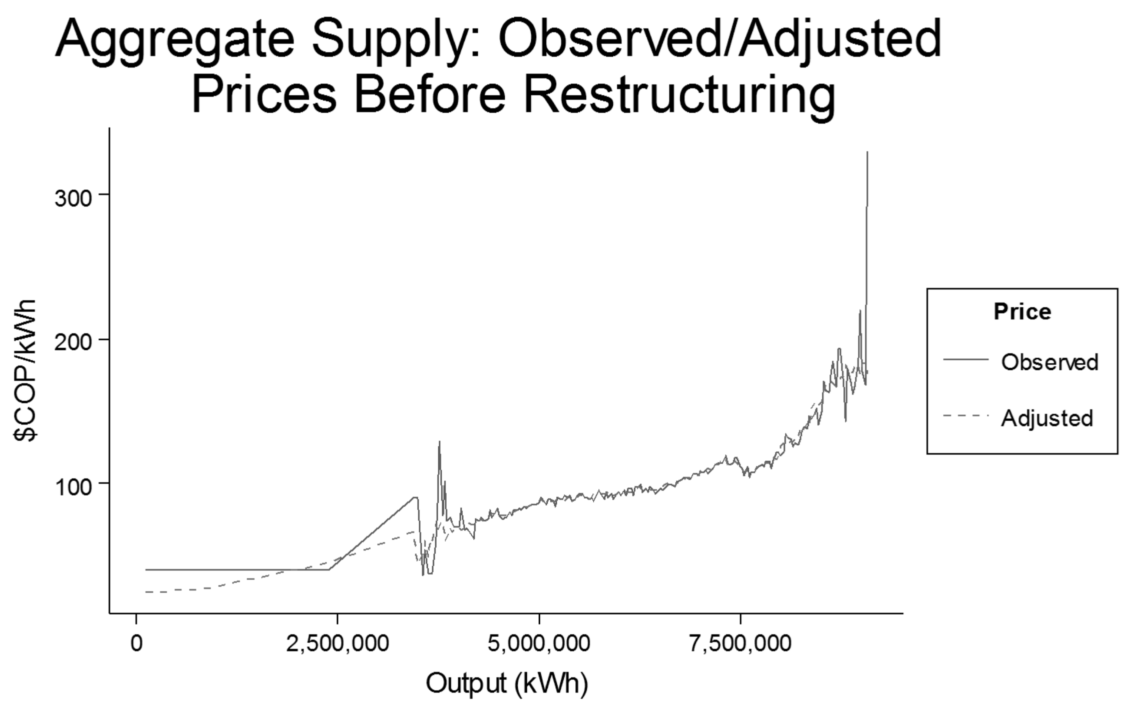

Figure 2: Aggregate supply using observed and adjusted prices

The graph suggests that at least on average, the aggregate fitted (simulated) supply curve is similar to the actual supply curve.

[18] The complete estimation of the model using instrumental variables is described in the technical supplement to this document, which is available at: http://www.alvaroriascos.com/research/electricitymarkets/).

We also run a second exercise in which we estimate the output decision model using water resources in rivers as a covariate rather than as an instrumental variable. The technical appendix to this document shows similar results, particularly in our welfare evaluation of productive efficiency.

b) Prices

As noted in the previous section, the key independent variable is the markup, which is determined by the price. In order to construct a better counterfactual, it must be acknowledged that the reform may have changed the market and consequently the prices. Therefore, following Mansur's appendix A, a counterfactual price $\hat{p}_t$ is simulated for the period after the reform, using the dynamics before the reform.

Here the relationship between prices in the pre-2009 period and aggregate output is examined. The coefficient of aggregate output is allowed to vary by hour-of-day i (and hour-of-day fixed effects are included) and a 10-part piecewise linear spline function (split by decile for each hour) is used. We also control for El Niño and La Niña indicators:

$$P_{i,t} = \alpha_i + \sum_{j=1}^{10} \beta_{i,t,j} D_{i,t,j} + \gamma_0 nino + \gamma_1 nina + e_t \qquad (3)$$

where $D_{i,t,j}$ is zero for every j except when $D_{i,t}$ is in the j-th decile of the empirical distribution of demand for day i in hour t. For this j, $D_{i,t,j} = D_{i,t}$. This function is extremely flexible and fits the pre-restructuring data with an R^2 of 0.92. With these estimated coefficients, a second series of prices is simulated after 2009. As in Mansur's paper, this method requires a common support. The range of demand before 2009 was 2,393,873[19] to 9,107,534 kWh. After 2009, demand increased and the range was 3,828,775 to 9,298,119 kWh. Finally, predicted prices are adjusted to reflect the actual variance observed in the post-restructuring period.

Before 2009, the standard deviation of the unadjusted predicted prices (P_t) (model fit or competitive benchmark) is much lower than that of actual prices (15.37 and 30.73, respectively). In order to increase the variance, we use the residuals from the regression of equation (3) based on the pre-2009 data. First, an AR(1) process is fitted to the residuals:

[19] There were only two values (121,228 and 798,678) below this number.

$$\hat{e}_t = \rho \hat{e}_{t-1} + u_t \ (4)$$

The estimated coefficient is $\hat{\rho} = 0.8$. Then, using a Monte Carlo simulation, we simulate a new series $\hat{e}_t$ by drawing from the sample distribution of u_t. Finally, the error is added to p_t, to get the adjusted predicted prices. We repeat this process 100 times and average the results. Figure 3 shows the observed and simulated aggregate supply function. The figure suggests and upward shift in the supply function consistent with increasing market power since 2009. The following two figures (Figure 4 and Figure 5) show the observed prices and the simulated prices before and after the reform. Notice that the model predicts lower prices even if we compare them to marginal price (Max. Offer) after 2009.[20] These results raise the concern that the spot price increase after 2009 is not due to marginal costs but most likely due to market power.

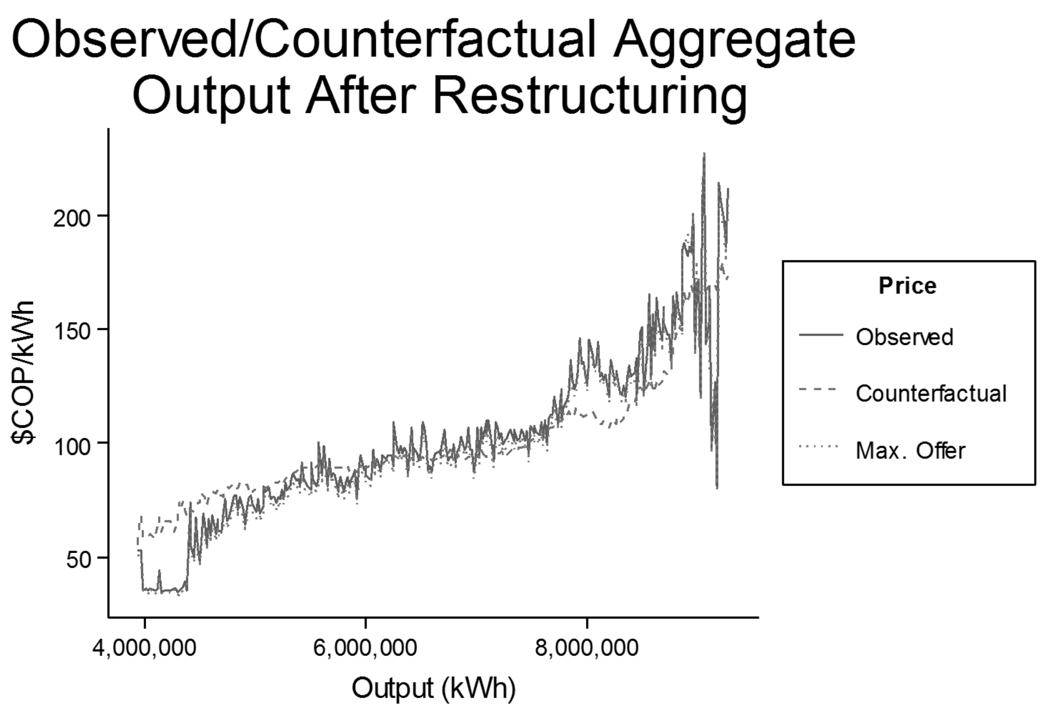

Figure 3: Observed aggregate output and counterfactual aggregate output

For the period before 2009, the simulated prices are close to the observed prices, whereas after the restructuring the volatility is similar but the simulated prices are consistently lower than those observed. This is interesting since, as we will see below in the welfare comparisons, the empirical evidence strongly

[20] Recall that the spot price after 2009 is the marginal price or maximum price offered by the marginal, non-saturated plant dispatched in the ideal dispatch, plus an uplift.

indicates that the new market design based on centralized unit commitment has improved welfare, relative to the counterfactual. Yet the prices we estimate for the counterfactual are lower than those observed, suggesting that exercise of market power has increased.

The next figure (Figure 4) makes it clear that simulated prices are consistently lower than the actual prices (the sample fit before 2009 is almost perfect when averaged by hour and by day; hence the Actual Pre. line cannot be seen in the figure).

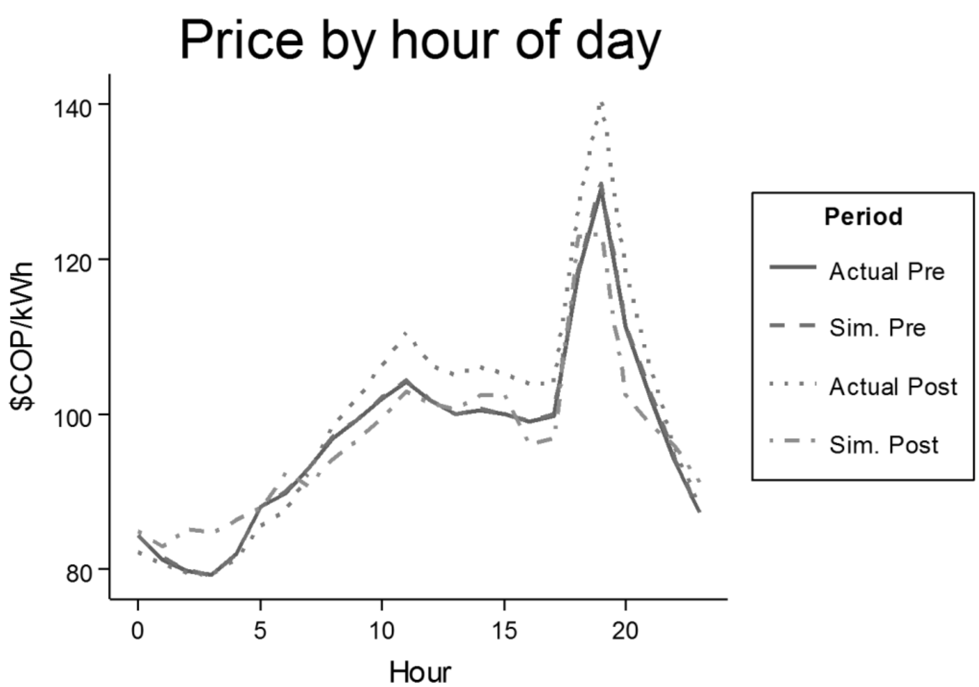

Figure 4: Average observed price by hour before and after reform (Actual Pre, Actual Post respectively) and model adjustment before reform (Sim. Pre) and prediction after reform (Sim. Post)

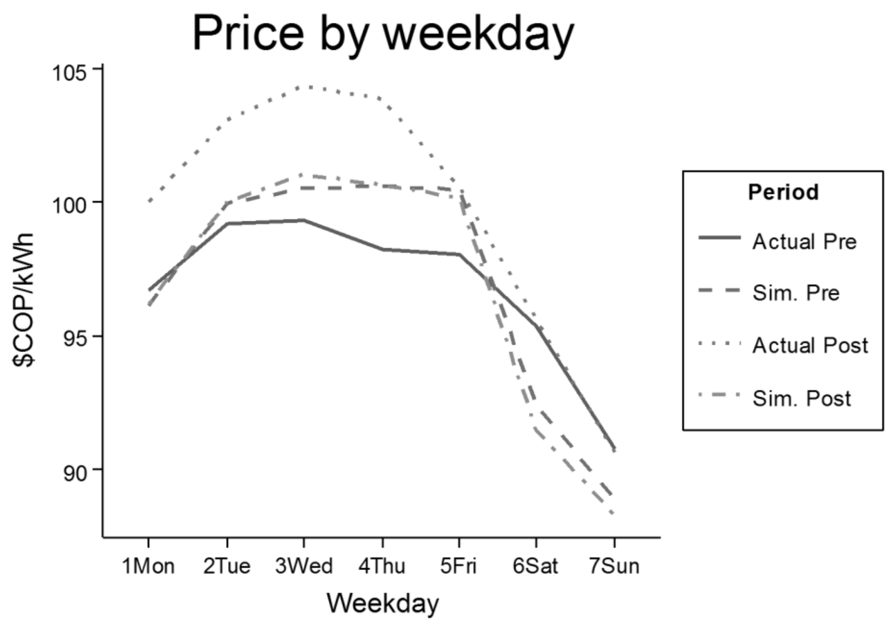

Figure 5: Average observed price by weekday before and after reform (Actual Pre, Actual Post respectively) and model adjustment before reform (Sim. Pre) and prediction after reform (Sim. Post)

c) Counterfactuals

Using the previous two models we perform the following exercise. We use the output decision model estimated from observed markups before 2009 to simulate output (self-unit commitment) after 2009, but using simulated markups. In this case we interpret output as what would have been observed if no regulation had been introduced.

d) Welfare Effects

Welfare effects measurements are based on direct production costs, i.e., variable costs excluding start-up costs. Below we analyze the role of start-up costs in this simulation. Assuming that variable costs are represented by a linear function, the welfare effect of the regulation (deadweight loss) is estimated in the following way:

$$\Delta W = \sum_{t=1}^{T} \sum_{i=1}^{N} c_{it}(q_{it} - \hat{q}_{it}) \qquad (5)$$

where q_{it} is the observed output of plant i during period t, $\hat{q}_{it}$ is the simulated output and c_{it} is the marginal or opportunity cost.

Variable costs

Table 4 reports the results of this evaluation after normalizing aggregate simulated output per hour. To be more precise, the output decision model simulates higher output than actual demand. This could explain why the variable cost of producing energy in the counterfactual could be higher than the actual cost. Hence, we normalize simulated output so that simulated aggregate output supply is equal, hour by hour, to aggregate demand. In Table 4 actual outcomes correspond to observed values for aggregate output and aggregate variable costs. For the counterfactual we report aggregate output (normalized), total variable costs, deadweight loss and dead weight loss share.[21] The results suggest that centralized unit commitment has improved productive efficiency since its introduction.

Table 4. Welfare Implications of Production Inefficiencies

Model	2006-0	2007-0	2008-0	2009-0	2009-1	2010-1	2011-1	2012-1
Actual Outcomes								
Output	48.3	50.0	50.3	29.9	9.2	26.2	52.1	50.6
Total Variable Costs	3205	3556	3253	2534	810	1769	3184	4099
Counterfactual								
Output	48.3	50.0	50.3	29.9	9.2	26.2	52.1	50.6
Total Variable Costs	3552	3864	3463	2711	913	2099	4071	5123
Deadweight loss	-347	-308	-210	-177	-103	-330	-887	-1024
DWL share	-10.84%	-8.67%	-6.44%	-7.00%	-12.70%	-18.66%	-27.87%	-25.00%

Notes: Output is measured in millions of MWh. Total Variable Costs and Deadweight loss are measured in $COP Billions[22].

Start-up costs

As mentioned at the start of this section, for welfare comparisons we have excluded additional costs due to start-up. We find two difficulties in estimating these costs. First, although before 2009 we can count the number of start-ups using generation data (real dispatch), we don't have data for start-up costs (before 2009, plants did not report startup costs); and second, the econometric model, being a linear model, is not tailored for estimating start-ups in the counterfactual. To overcome these difficulties and get a sense of the actual start-up costs and hence a better measure of welfare changes, we estimated start-up costs before 2009 using the methodology reported in the online

[21] Deadweight loss (DWL) share is calculated as welfare change as in equation (5) divided by actual (observed) aggregate variable cost.
[22] A Billion is 10^9.

technical appendix. Then, using real generation, we estimated aggregate (observed) start-up costs before and after 2009; the results are shown in the next table. From Table 5, it is evident that after 2009 start-up costs oscillated between 0.76% and 1.46% of variable costs and before 2009, they ranged from 0.76% and 1.08%. Since we find it difficult to estimate start-up costs in the counterfactual using our model, we assume that the start-up costs after 2009 in the counterfactual were also between 0.76% and 1.08%. We obtain an upper bound on welfare changes due to start-up costs by assuming actual costs of 1.46% after 2009 (for every year) and counterfactual costs of 0.76% for every year. It follows that the welfare gains shown in the previous table, based on variable costs, overestimate the welfare gains of the regulation by less than 0.7% of variable costs per year.

Table 5. Start-up and Variable Costs by Year in Millions of COP

Period	StartUp.Cost	Var.Cost	Proportion
2006.0	34,745	3,211,787	1.08%
2007.0	29,251	3,555,853	0.82%
2008.0	28,490	3,253,060	0.88%
2009.0	19,363	2,533,920	0.76%
2009.1	6,130	809,729	0.76%
2010.1	19,138	1,768,535	1.08%
2011.1	46,458	3,188,179	1.46%
2012.1	45,600	4,121,688	1.11%

5. Market Power and Consumer Welfare

The previous section shows that productive efficiency has risen since the introduction of centralized unit commitment dispatch; it is natural, then, to ask what the impact on aggregate welfare has been. As we described in the previous section, counterfactual (simulated) prices are lower than actual prices, suggesting that even though productive efficiency has increased the benefits may not have been passed on to consumers who have apparently experienced price increases. Moreover, if we assume that aggregate demand is elastic (at least in the long run), it is possible that overall welfare has decreased due to a decline in allocative efficiency. In this section we do not measure the change in consumer welfare but focus on market power to determine if generators have indeed increased their ability to exercise market power after the resolution of 2009.

Figure 6 shows net capacity, average available capacity, average daily generation and monthly average spot price. The graph suggests that there isn't a capacity or firm energy shortage in the Colombian electricity sector although the difference between firm energy and aggregate demand has narrowed. However, while this gap may have an effect on the opportunity costs of water, it should not have a direct effect on thermal plants' behavior unless they exercise market power so as to exploit strategically potential future water shortages and risk-averse behavior by hydro plants. Given the difficulty of determining opportunity costs for hydro plants, which would require a stochastic dynamic programming model, we do not study bid markups for these plants. The point is that these phenomena, in a competitive setting, may affect the relative amount of thermal energy being used and hence the market clearing prices but should not be a determinant of thermal plants' bidding behavior.

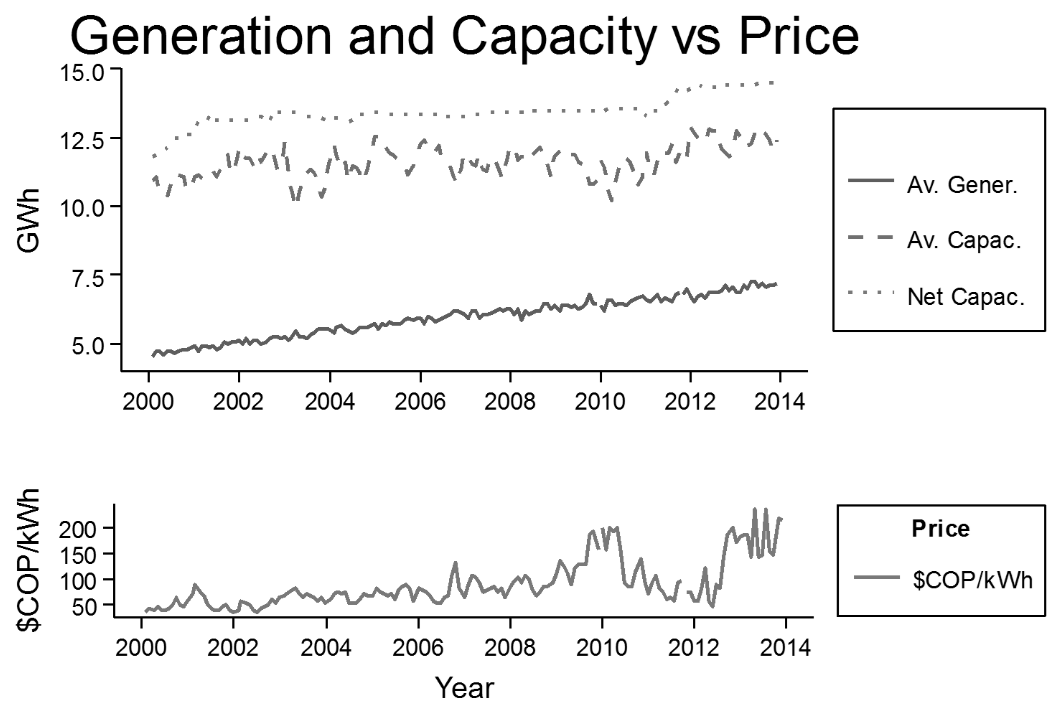

Figure 6: Average daily generation, average daily available capacity, average daily net capacity (upper panel) and average monthly price (lower panel).

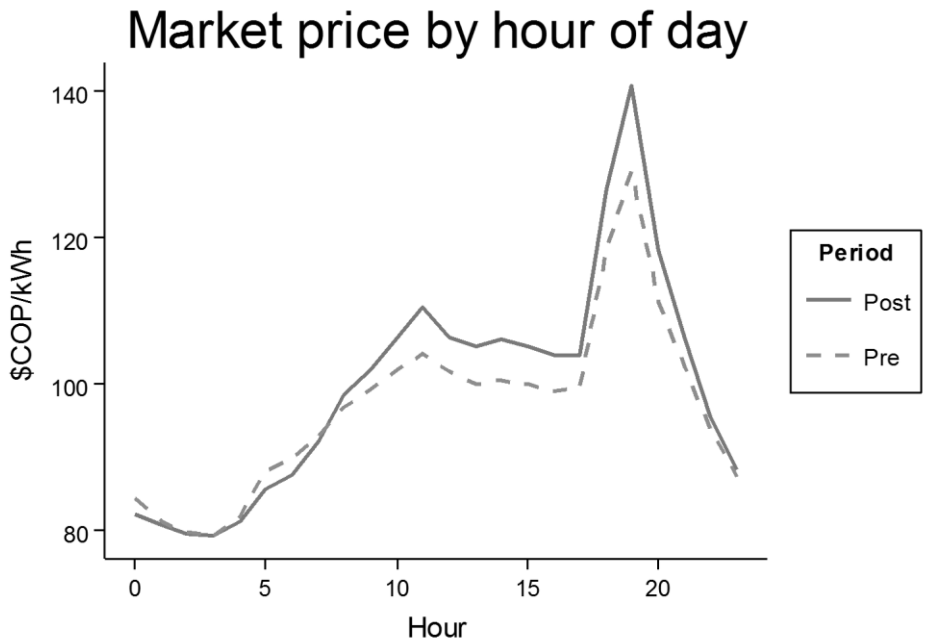

Figure 7: Average observed price by day before and after the reform

The previous section has made the case for the efficiency gains attributable to Resolution 051/2009. We have also noted that the observed spot price is higher relative to what would have happened if Resolution 051/2009 had not been implemented. This suggests that consumer surplus has decreased and, if efficiency has increased, then it must have been the case that that efficiency gains have not been passed on to consumers. We first address our claim regarding market power. Obviously, our statement is based on our determination of marginal costs. Nevertheless, the following set of calculations suggests that the results are quite robust.

We first show our results on bid price markups for dispatched plants.[23] Next we qualify our results based on calculations that take into account some market phenomena that we may be missing in our approach; specifically, periods in which the assumption of a unique operating fuel might result in underestimating the true marginal costs of thermal plants. Furthermore, a period of government intervention may cast doubts on the determination of competitive market outcomes. We address these issues in the last section where we examine the role of contracts in determining consumer welfare.

[23] Similar results hold when we only consider inframarginal bid price markups.

a) Bid Markups

Figure 8 shows the weighted average by capacity of bid markup for dispatched plants before and after 2009.

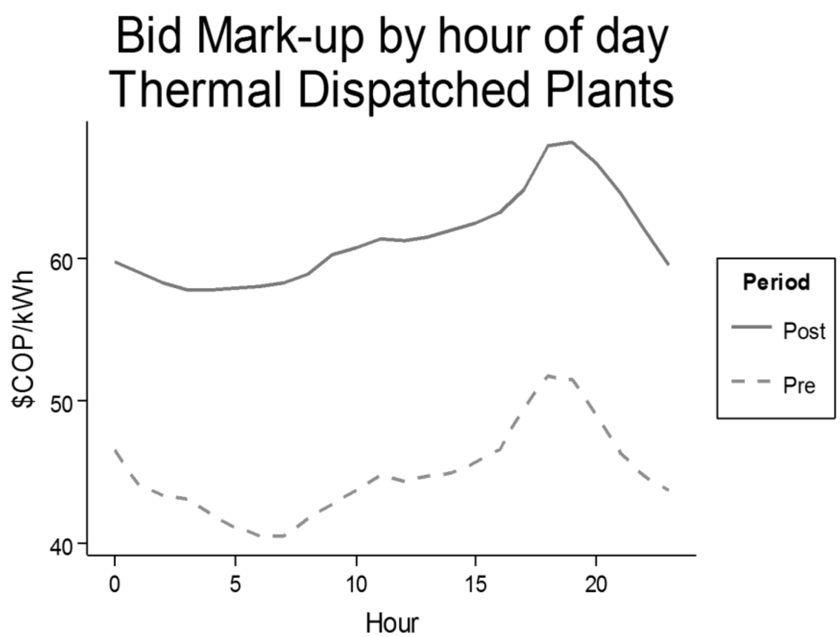

Figure 8: Average bid markup by hour of day, thermal dispatched plants

b) Controlling for plants using liquid fuel

So far, an important simplification in our analysis is the use of only one type of fuel for each thermal plant (the one used in the most common configuration of the plant). In reality this is not always the case since plants change fuels according to their configuration, costs and supply constraints. Of particular importance is the case when plants have used liquid fuels, which are generally more expensive than coal or gas. Therefore, we calculate which plants and in what periods (after 2009) plants used liquid fuels for operation and we omit such periods and these plants from the calculation of bid prices. This procedure will clearly underestimate market power and provide a conservative measure of noncompetitive behavior.

Figure 9 shows how much energy is produced by plants using liquid fuels. Figure 10 shows the recalculated bid markup. The result is robust to PPI inflation (see next subsection).

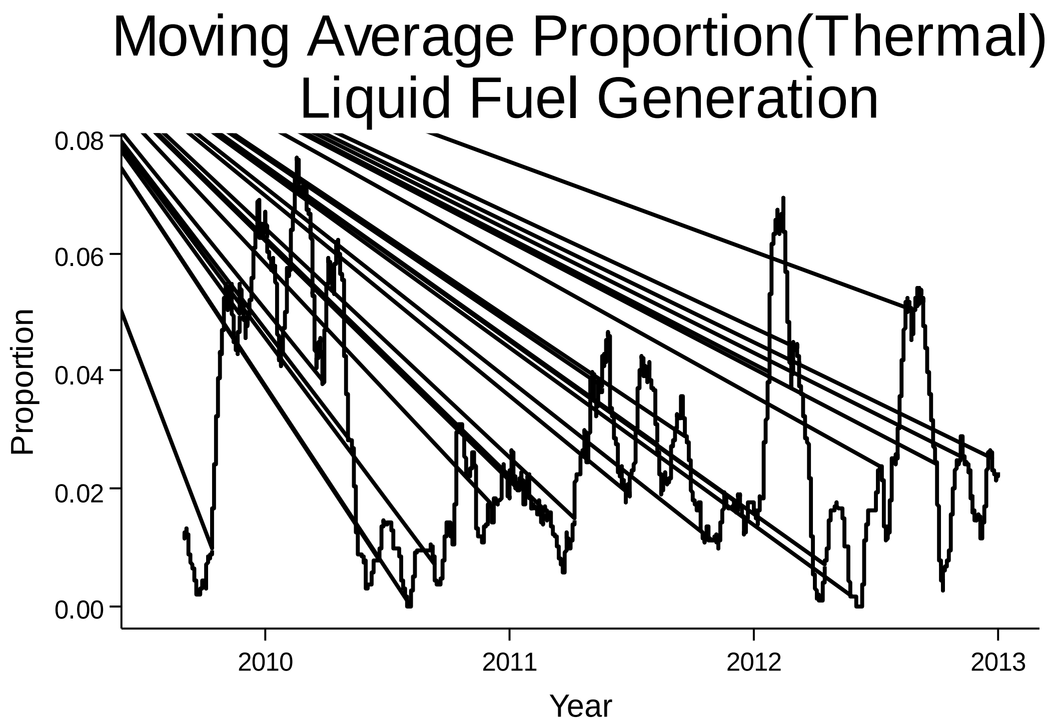

Figure 9: Proportion of thermal generation using liquid fuels, of all thermal generation (moving average)

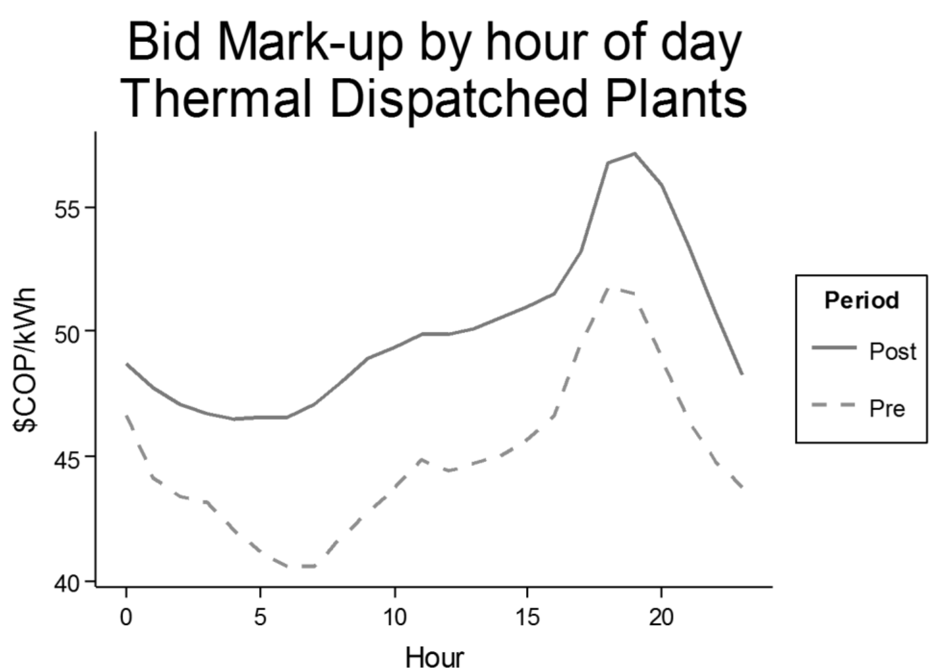

Figure 10: Average bid markup by hour of day, thermal dispatched plants before (Pre) and after the reform (Post).

c) Periods of government intervention and PPI inflation

Finally, market participants have raised concerns regarding a period between 2009 and 2010 in which the government intervened in the market. We take this period as starting on October 2, 2009 (Resolution MME 18-1686) and ending on June 2, 2010 (Resolution CREG 070, 2010). The following figure (*Figure 11*) omits this period and controls for producer's price index inflation.

d) Contracts

Our final calculations take into consideration that there is a significant portion of electricity transactions that take place through bilateral long term contracts so that consumers are not fully exposed to the spot market. Nevertheless, even if the spot price is not the most relevant price and the focus shifts to the price of bilateral contracts, our claims are still indicative of the fact that productive efficiency gains have not been passed on to consumers. First, as the *Figure 12* shows, even though contracted energy constitutes a high proportion of energy demand for the period under study, it is still below 100%. Second, one would expect forward prices to be correlated with the settlement price.

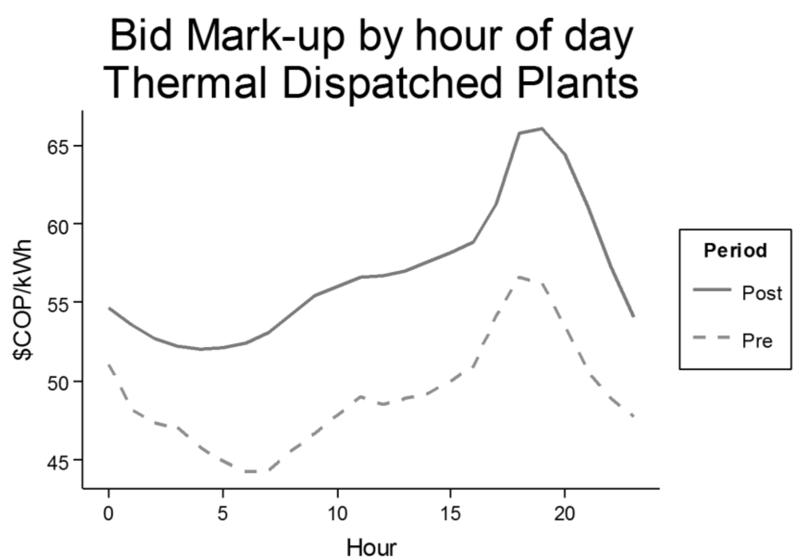

Figure 11: Average bid markup by hour of the day, thermal dispatched plants before (Pre) and after the reform (Post).

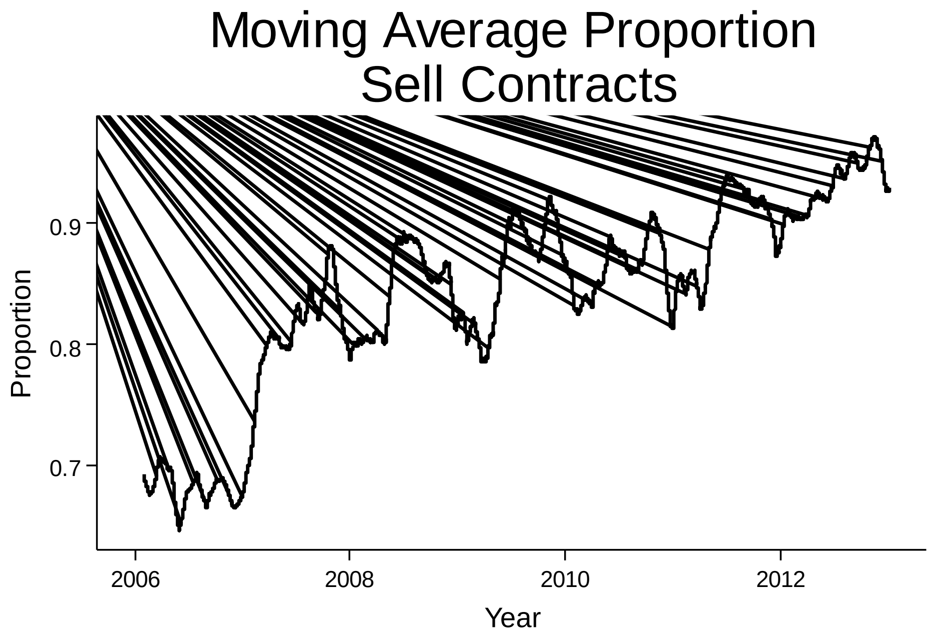

Figure 12: Average level of energy supplied through bilateral contracts.

However, rather than dwelling on the theory of forward prices and their relation to the price of the underlying asset, we examine below the available data regarding the Colombian bilateral contract market. Specifically, the next figure shows the average contract price per month for four different kinds of users: regulated (Ur), unregulated (Unr), intermediaries (Inter) and all users (All). Time series are expressed in December 2012 constant prices. The figure shows that there has been a substantial increase in the average price of contracts since 2009.

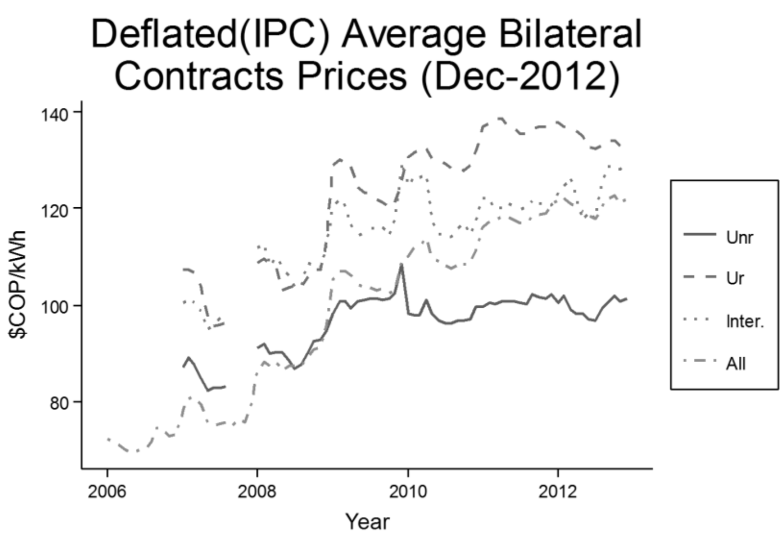

Figure 13: Average prices in bilateral contracts by sector: unregulated (Unr), regulated (Ur), intermediaries (Inter) and all sectors (All)

6. Conclusion

This paper evaluates the effect of Resolution CREG 051/2009 (transition to centralized unit commitment) on the performance of the electricity market in Colombia. We find that productive efficiency has improved since the implementation of the resolution, that is, the total cost of producing electricity has been reduced. This indicates a positive impact of the resolution. On the other hand, we also find that markups have increased since 2009, suggesting an increase in the exercise of market power by producers. This observation is consistent with findings for the United Kingdom and Ireland, which have also implemented centrally committed dispatch through market reforms.

From the two previous points, we conclude that although productive efficiency has increased, the larger share of the efficiency gains were appropriated by the energy producers, rather than passed on to consumers. Our results show that under different model specifications there is evidence supporting the claim that Resolution CREG 051/2009 resulted in a positive welfare effect at least in terms of productive efficiency. This is despite the fact that simulated prices, reflecting what would have happened if the resolution had not been implemented, were lower than the observed ones.

In spite of all the caveats regarding the calculation of marginal prices in our analysis, our results are robust.[24] Our analysis shows that even when accounting for government intervention, when expensive liquid fuels where the rule, there is still a significant increase in markups after 2009, which is reflected in the bids and the resulting spot prices. Furthermore, although most of the energy supplied to retail customers is contracted forward and as such insulated from spot price volatility, both theoretical and empirical evidence suggest that the persistent higher spot prices due to increased markups are correlated with forward contract prices. This, in turn, indirectly results in increased retail prices. Thus, the higher spot prices after 2009 and the observed increase in average forward contract prices present strong evidence that the productive efficiency gains have not benefited consumers.

The question of overall efficiency still remains unclear. If demand is elastic, lower retail prices would have also produced allocative efficiency gains. However, since retail prices have increased it is possible that allocative efficiency decreased by more than the productive efficiency gains, such that social welfare has actually declined since Regulation 51 was implemented.

[24] See "An Evaluation of CREG 051 – 2009 Regulatory Intervention in Colombian Electricity Market." December 19, 2013. Available at http://www.alvaroriascos.com/research/electricitymarkets/

Acknowledgments

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Transition to Centralized Unit Commitment

An Econometric Analysis of Colombia's Experience[1]

(TECHNICAL SUPPLEMENT)

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Introduction

This document is a technical supplement to Riascos et al (2015). See that document for an introduction.

Construction of startup costs

Before 2009, startup costs were not reported by generators. To overcome this difficulty we used reported startup costs after 2009 and fuel prices to estimate start-up costs before 2009. To do so we first calculated the most common operating fuel type by plant (next table).

Generator	Start-up Fuel
TERMOCARTAGENA 1	Gas
TERMOCARTAGENA 2	Gas
TERMOCARTAGENA 3	Gas
MERILECTRICA 1	Gas
PAIPA 1	Coal
PAIPA 2	Coal
PAIPA 3	Coal
PAIPA 4	Coal
PROELECTRICA 1	Gas
PROELECTRICA 2	Gas
TERMOBARRANQUILLA 3	Gas
TERMOBARRANQUILLA 4	Gas
TEBSA TOTAL	Gas
TERMOCANDELARIA 1	Gas
TERMOCANDELARIA 2	Gas
TERMODORADA 1	Gas
TERMOEMCALI 1	Gas
TERMOFLORES 1	Gas
TERMO FLORES 4	Gas
GUAJIRA 1G	Gas and Coal
GUAJIRA 2G	Gas and Coal
TERMOCENTRO 1 CICLO COMBINADO	Gas
TASAJERO 1	Coal
TERMOSIERRAB	Gas

TERMOVALLE 1	Gas
TERMOYOPAL 2	Gas
ZIPAEMG 2	Coal
ZIPAEMG 3	Coal
ZIPAEMG 4	Coal
ZIPAEMG 5	Coal

For each thermal plant we have a six-month frequency series of fuel costs (in US dollars). Each plant, except for GUAJIRA 1 and GUAJIRA 2, uses either coal or gas as its main fuel. GUAJIRA 1 and 2 is the only plant that can use both types of fuel.

Fuel prices are reported as US dollars per Thermal Units (USD/MBTU). Coal and gas prices may differ across plants because of transportation costs and other economic factors. Start-up costs are reported for every thermal generator for the 2008-2012 period. Since fuel costs have a six month frequency we used a local regression model to construct a daily fuel cost data. For an appropriate fit of the LOESS model we use a smoothness parameter of $\propto = 0.3$. With the LOESS fit we construct a new database with the price of fuel for each plant in a daily frequency. Before running the LOESS model we transformed prices and costs to local currency (COP) and used the Producer Price Index (IPP) to deflate both start-up costs and fuel costs. Since the IPP has a monthly frequency, we used a LOESS fit with $\propto = 0.1$ to convert it to a daily series.

Because the prediction horizon is large (daily start-up costs for the period 2006 - 2009) we want to use a simple model that avoids high variance and over fits the data. The econometric specification we used was a linear model of the form:

$$StartUpCost_{gt} = \beta_{g0} + \beta_g^T FuelCost_{gt} + \varepsilon_{gt}$$

Depending on the generator, $FuelCost_{gt}$ represents gas or coal fuel cost. In the case of GUAJIRA 1 and 2, $FuelCost_{gt}$ is a vector with gas and coal fuel costs as its components.

This model is fitted using minimization of the squared error subject to the positivity of the vector β_g^T. This problem can be formulated as a convex optimization problem and can be solved numerically. Whenever β_g^T is strictly positive, we will obtain the OLS solution.

The next table show the results.[2]For 12 generators the restriction on the coefficients β_g^T was binding. The next table reports the results of all other plants.

Generator	R2	Generator	R2
TERMOBARRANQUILLA.3	0.57	TASAJERO.1	0.08
TERMOBARRANQUILLA.4	0.54	TERMOCENTRO.1	0.05
TERMOCARTAGENA.1	0.51	TERMOSIERRAB	0.08
TERMOCARTAGENA.2	0.61	TERMOVALLE.1	0.41
TERMOCARTAGENA.3	0.56	ZIPAEMG.2	0.03
TERMODORADA.1	0.36	ZIPAEMG.3	0.10
TERMOFLORES.1	0.14	ZIPAEMG.4	0.07
GUAJIRA.1	0.44	ZIPAEMG.5	0.13
GUAJIRA.2	0.35	TERMO.FLORES.4	0.05

[2] The complete database can be found at: http://www.alvaroriascos.com/research/data/

General specification output decision model

The following are the estimation results for the general output decisions model, using as instrumental variables water resources in rivers *("Aportes Hídricos")* and ignoring the period of Government intervention.

Summary of model for all Plants

Plants	Average of Coefficients	Average of Std. Errors	# of Significant Coeff. (5%)
(Intercept)	4,007,679	3,983,698	28
Pcmpos	223,576	75,903	30
Pcm	221,546	155,733	7
pcm_2	-276	3,668	3
pcm_3	-30	102	3
pcm_4	0	1	1
pcm_5	0	0	3
pcmminus1	13,062	110,846	2
pcmminus1_2	3,418	1,846	7
pcmminus1_3	61	79	6
pcmminus1_4	-2	1	9
pcmminus1_5	0	0	9
pcmplus1	366,594	136,291	7
pcmplus1_2	1,139	3,664	3
pcmplus1_3	-140	98	5
pcmplus1_4	2	1	5
pcmplus1_5	0	0	5
meanpcm	-3,920,131	973,028	23
meanpcm_2	184,369	53,346	19
meanpcm_3	20,619	5,423	19
meanpcm_4	-762	152	23
meanpcm_5	6	1	17
meanpcmminus24	-2,640,696	775,370	18
meanpcmminus24_2	-466,474	94,388	17
meanpcmminus24_3	-2,171	3,767	23
meanpcmminus24_4	752	185	19
meanpcmminus24_5	-8	2	23
meanpcmplus24	4,169,466	1,208,527	25
meanpcmplus24_2	293,945	69,111	24
meanpcmplus24_3	-9,264	2,455	19
meanpcmplus24_4	-503	123	18
meanpcmplus24_5	8	1	21
Niño	-10,534,695	3,410,290	18
Nina	-4,373,193	2,434,354	27

Plants	Average of Coefficients	Average of Std. Errors	# of Significant Coeff. (5%)
factor(month)2	673,779	1,899,903	22
factor(month)3	1,455,971	1,728,539	23
factor(month)4	2,025,759	2,881,525	22
factor(month)5	3,142,409	4,207,668	19
factor(month)6	3,698,756	4,796,780	26
factor(month)7	1,571,778	4,156,210	21
factor(month)8	-8,870,423	5,752,356	26
factor(month)9	-3,561,142	4,117,038	28
factor(month)10	-8,995,412	3,716,836	22
factor(month)11	-462,391	4,001,576	25
factor(month)12	3,999,440	3,362,153	23
factor(wday)Sunday	3,687,658	2,455,495	21
factor(wday)Monday	-4,249,396	4,210,083	23
factor(wday)Tuesday	-612,219	4,130,158	23
factor(wday)Wednesday	4,465,163	2,739,774	25
factor(wday)Saturday	9,892,300	4,103,528	16
factor(wday)Friday	3,261,587	2,447,297	19

Estimation results when controlling with water resources in rather than using it as an instrument

Summary of model for all Plants

Plants	Average of Coefficients	Average of Std. Errors	# of Coefs. Significant(5%)
(Intercept)	3,540,277	136,346	39
pcmpos	1,489,977	90,796	34
aportesh	0.001	0.004	37
pcm	-18,234	3,687	30
pcm_2	-214	66	19
pcm_3	5	1	22
pcm_4	0	0	18
pcm_5	0	0	16
pcmminus1	1,468	2,997	14
pcmminus1_2	-11	59	17
pcmminus1_3	-1	1	11
pcmminus1_4	0	0	12
pcmminus1_5	0	0	9
pcmplus1	4,063	3,000	22
pcmplus1_2	63	59	21
pcmplus1_3	-2	1	17

Plants	Average of Coefficients	Average of Std. Errors	# of Coefs. Significant(5%)
pcmplus1_4	0	0	14
pcmplus1_5	0	0	13
meanpcm	81,416	6,180	34
meanpcm_2	1,054	279	33
meanpcm_3	-98	16	29
meanpcm_4	1	0	25
meanpcm_5	0	0	27
meanpcmminus24	-24,939	5,044	32
meanpcmminus24_2	-276	247	36
meanpcmminus24_3	74	15	29
meanpcmminus24_4	-2	0	34
meanpcmminus24_5	0	0	30
meanpcmplus24	-33,744	5,004	34
meanpcmplus24_2	-457	247	29
meanpcmplus24_3	74	15	29
meanpcmplus24_4	-2	0	30
meanpcmplus24_5	0	0	32
nino	26,366	76,803	40
nina	38,287	50,973	40
factor(hour)1	-176,838	128,925	5
factor(hour)2	-272,675	129,020	11
factor(hour)3	-284,633	129,186	12
factor(hour)4	-97,688	129,558	9
factor(hour)5	358,485	129,477	16
factor(hour)6	529,176	129,383	16
factor(hour)7	748,314	129,727	22
factor(hour)8	1,089,925	129,978	24
factor(hour)9	1,250,403	130,329	21
factor(hour)10	1,396,710	130,730	22
factor(hour)11	1,510,338	130,723	23
factor(hour)12	1,430,550	130,557	21
factor(hour)13	1,337,770	130,377	21
factor(hour)14	1,340,090	130,276	24
factor(hour)15	1,327,676	130,204	21
factor(hour)16	1,314,480	130,184	22
factor(hour)17	1,421,338	133,467	28
factor(hour)18	2,200,411	137,623	32
factor(hour)19	2,455,786	137,699	29
factor(hour)20	2,238,626	136,427	28
factor(hour)21	1,757,139	131,072	22
factor(hour)22	1,055,596	129,642	17
factor(hour)23	387,855	129,042	13

Plants	Average of Coefficients	Average of Std. Errors	# of Coefs. Significant(5%)
factor(month)2	165,336	88,529	34
factor(month)3	103,830	88,885	39
factor(month)4	4,391	92,623	36
factor(month)5	35,505	104,136	40
factor(month)6	99,739	108,778	36
factor(month)7	139,628	103,307	38
factor(month)8	362,717	111,369	39
factor(month)9	390,913	103,554	43
factor(month)10	45,740	105,907	38
factor(month)11	390,842	107,467	41
factor(month)12	317,349	97,595	39
factor(wday)jueves	810,509	70,663	34
factor(wday)lunes	574,817	71,335	31
factor(wday)martes	783,742	71,125	37
factor(wday)mi?coles	800,219	70,859	38
factor(wday)s?ado	499,695	71,410	33
factor(wday)viernes	775,713	71,025	37

Summary of model for 29 Thermo Plants

Plants	Average of Coefficients	Average of Std. Errors	# of Coefs. Significant(5%)
(Intercept)	763,658	39,500	23
pcmpos	-35,151	24,246	19
aportesh	-.001	.0001	22
pcm	2,627	920	14
pcm_2	0	11	5
pcm_3	0	0	8
pcm_4	0	0	6
pcm_5	0	0	5
pcmminus1	1,462	697	9
pcmminus1_2	-10	9	11
pcmminus1_3	0	0	9
pcmminus1_4	0	0	11
pcmminus1_5	0	0	8
pcmplus1	1,470	697	11
pcmplus1_2	-3	9	13
pcmplus1_3	0	0	10
pcmplus1_4	0	0	9
pcmplus1_5	0	0	8
meanpcm	-1,683	1,179	17

Plants	Average of Coefficients	Average of Std. Errors	# of Coefs. Significant(5%)
meanpcm_2	40	29	19
meanpcm_3	-1	1	18
meanpcm_4	0	0	15
meanpcm_5	0	0	16
meanpcmminus24	8,149	902	20
meanpcmminus24_2	63	24	21
meanpcmminus24_3	-1	0	15
meanpcmminus24_4	0	0	20
meanpcmminus24_5	0	0	17
meanpcmplus24	-1,941	891	20
meanpcmplus24_2	77	24	20
meanpcmplus24_3	0	0	18
meanpcmplus24_4	0	0	21
meanpcmplus24_5	0	0	22
nino	346,172	20,634	25
nina	-43,348	13,866	24
factor(hour)1	-25,861	35,255	1
factor(hour)2	-34,113	35,334	5
factor(hour)3	-37,867	35,486	6
factor(hour)4	-31,067	35,812	7
factor(hour)5	-10,380	35,743	7
factor(hour)6	-6,140	35,665	6
factor(hour)7	10,150	35,942	8
factor(hour)8	33,808	36,119	8
factor(hour)9	43,863	36,355	7
factor(hour)10	55,704	36,615	6
factor(hour)11	67,087	36,566	7
factor(hour)12	56,122	36,467	7
factor(hour)13	53,814	36,359	7
factor(hour)14	66,650	36,276	8
factor(hour)15	74,344	36,229	6
factor(hour)16	83,374	36,250	8
factor(hour)17	124,914	38,060	13
factor(hour)18	222,473	39,800	17
factor(hour)19	234,225	39,552	14
factor(hour)20	192,221	39,092	12
factor(hour)21	138,595	36,736	8
factor(hour)22	91,549	35,814	5
factor(hour)23	45,679	35,360	3
factor(month)2	98,106	24,216	21
factor(month)3	337,558	24,318	27
factor(month)4	184,181	25,528	25

Plants	Average of Coefficients	Average of Std. Errors	# of Coefs. Significant(5%)
factor(month)5	227,888	28,406	25
factor(month)6	165,603	29,290	23
factor(month)7	133,236	28,408	23
factor(month)8	109,974	30,476	26
factor(month)9	222,103	28,349	26
factor(month)10	47,301	29,004	23
factor(month)11	-16,920	29,487	24
factor(month)12	-20,756	26,964	24
factor(wday)jueves	155,717	19,567	18
factor(wday)lunes	130,197	20,179	16
factor(wday)martes	161,397	19,836	22
factor(wday)mi?coles	163,476	19,697	22
factor(wday)s?ado	73,627	20,214	18
factor(wday)viernes	155,904	19,763	22

Summary of model for 17 Hydro Plants

Plants	Average of Coefficients	Average of Std. Errors	# of Coefs. Significant(5%)
(Intercept)	2,776,620	96,846	16
pcmpos	1,525,128	66,551	15
aportesh	.002	.0003	15
pcm	-20,860	2,766	16
pcm_2	-215	55	14
pcm_3	5	1	14
pcm_4	0	0	12
pcm_5	0	0	11
pcmminus1	6	2,300	5
pcmminus1_2	-1	50	6
pcmminus1_3	-1	1	2
pcmminus1_4	0	0	1
pcmminus1_5	0	0	1
pcmplus1	2,593	2,303	11
pcmplus1_2	66	50	8
pcmplus1_3	-2	1	7
pcmplus1_4	0	0	5
pcmplus1_5	0	0	5
meanpcm	83,099	5,001	17
meanpcm_2	1,014	250	14
meanpcm_3	-97	15	11
meanpcm_4	1	0	10

Plants	Average of Coefficients	Average of Std. Errors	# of Coefs. Significant(5%)
meanpcm_5	0	0	11
meanpcmminus24	-33,087	4,142	12
meanpcmminus24_2	-339	223	15
meanpcmminus24_3	75	14	14
meanpcmminus24_4	-2	0	14
meanpcmminus24_5	0	0	13
meanpcmplus24	-31,803	4,113	14
meanpcmplus24_2	-534	223	9
meanpcmplus24_3	74	14	11
meanpcmplus24_4	-2	0	9
meanpcmplus24_5	0	0	10
nino	-319,805	56,169	15
nina	81,635	37,108	16
factor(hour)1	-150,977	93,670	4
factor(hour)2	-238,561	93,686	6
factor(hour)3	-246,765	93,701	6
factor(hour)4	-66,621	93,746	2
factor(hour)5	368,865	93,734	9
factor(hour)6	535,315	93,718	10
factor(hour)7	738,164	93,784	14
factor(hour)8	1,056,117	93,859	16
factor(hour)9	1,206,540	93,975	14
factor(hour)10	1,341,006	94,115	16
factor(hour)11	1,443,251	94,156	16
factor(hour)12	1,374,428	94,090	14
factor(hour)13	1,283,956	94,017	14
factor(hour)14	1,273,439	93,999	16
factor(hour)15	1,253,333	93,976	15
factor(hour)16	1,231,107	93,935	14
factor(hour)17	1,296,424	95,407	15
factor(hour)18	1,977,938	97,823	15
factor(hour)19	2,221,561	98,147	15
factor(hour)20	2,046,405	97,335	16
factor(hour)21	1,618,543	94,335	14
factor(hour)22	964,047	93,828	12
factor(hour)23	342,176	93,682	10
factor(month)2	67,230	64,313	13
factor(month)3	-233,728	64,566	12
factor(month)4	-179,790	67,095	11
factor(month)5	-192,383	75,730	15
factor(month)6	-65,864	79,488	13
factor(month)7	6,392	74,899	15

Plants	Average of Coefficients	Average of Std. Errors	# of Coefs. Significant(5%)
factor(month)8	252,743	80,893	13
factor(month)9	168,810	75,205	17
factor(month)10	-1,561	76,902	15
factor(month)11	407,762	77,980	17
factor(month)12	338,105	70,632	15
factor(wday)jueves	654,792	51,096	16
factor(wday)lunes	444,621	51,156	15
factor(wday)martes	622,345	51,289	15
factor(wday)mi?coles	636,743	51,162	16
factor(wday)s?ado	426,068	51,196	15
factor(wday)viernes	619,809	51,261	15

Welfare Implications of Production Inefficiencies when the output decision model is estimated using water resources in rivers as a covariate.

Welfare Implications of Production Inefficiencies

Model	2006-0	2007-0	2008-0	2009-0	2009-1	2010-1	2011-1	2012-1
Actual Outcomes								
Output	48.3	50.0	50.3	29.9	9.2	26.2	52.1	50.6
Total Variable Costs	4337	4934	4902	3214	1081	2394	4418	4986
Counterfactual								
Output	48.3	50.0	50.3	29.9	9.2	26.2	52.1	50.6
Total Variable Costs	4402	4858	4895	3235	1139	2531	4751	5058
Deadweight loss	-65	76	7	-21	-58	-137	-333	-72
DWL share	-1.50%	1.54%	0.14%	-0.65%	-5.37%	-5.72%	-7.54%	-1.44%

Notes: Output is measured in millions of MWh. Total Variable Costs and Deadweight loss are measured in $COP Billions[3].

[3] A Billion is 10^9.

Estimation of price model using a polynomial of degree 5 and 6

Adding one more degree to the polynomial in the price model does not improve the model. Fewer coefficients are significant.

Degree 5

Summary of model for all Plants

Plants	Average of Coefficients	Average of Std. Errors	# of Coefs. Significant(5%)
(Intercept)	4,007,679	3,983,698	28
pcmpos	223,576	75,903	30
pcm	221,546	155,733	7
pcm_2	-276	3,668	3
pcm_3	-30	102	3
pcm_4	0	1	1
pcm_5	0	0	3
pcmminus1	13,062	110,846	2
pcmminus1_2	3,418	1,846	7
pcmminus1_3	61	79	6
pcmminus1_4	-2	1	9
pcmminus1_5	0	0	9
pcmplus1	366,594	136,291	7
pcmplus1_2	1,139	3,664	3
pcmplus1_3	-140	98	5
pcmplus1_4	2	1	5
pcmplus1_5	0	0	5
meanpcm	-3,920,131	973,028	23
meanpcm_2	184,369	53,346	19
meanpcm_3	20,619	5,423	19
meanpcm_4	-762	152	23
meanpcm_5	6	1	17
meanpcmminus24	-2,640,696	775,370	18
meanpcmminus24_2	-466,474	94,388	17
meanpcmminus24_3	-2,171	3,767	23
meanpcmminus24_4	752	185	19
meanpcmminus24_5	-8	2	23
meanpcmplus24	4,169,466	1,208,527	25
meanpcmplus24_2	293,945	69,111	24
meanpcmplus24_3	-9,264	2,455	19
meanpcmplus24_4	-503	123	18
meanpcmplus24_5	8	1	21

Plants	Average of Coefficients	Average of Std. Errors	# of Coefs. Significant(5%)
nino	-10,534,695	3,410,290	18
nina	-4,373,193	2,434,354	27
factor(month)2	673,779	1,899,903	22
factor(month)3	1,455,971	1,728,539	23
factor(month)4	2,025,759	2,881,525	22
factor(month)5	3,142,409	4,207,668	19
factor(month)6	3,698,756	4,796,780	26
factor(month)7	1,571,778	4,156,210	21
factor(month)8	-8,870,423	5,752,356	26
factor(month)9	-3,561,142	4,117,038	28
factor(month)10	-8,995,412	3,716,836	22
factor(month)11	-462,391	4,001,576	25
factor(month)12	3,999,440	3,362,153	23
factor(wday)jueves	3,687,658	2,455,495	21
factor(wday)lunes	-4,249,396	4,210,083	23
factor(wday)martes	-612,219	4,130,158	23
factor(wday)mi?coles	4,465,163	2,739,774	25
factor(wday)s?ado	9,892,300	4,103,528	16
factor(wday)viernes	3,261,587	2,447,297	19

Summary of model for 17 Hydro Plants

Plants	Average of Coefficients	Average of Std. Errors	# of Coefs. Significant(5%)
(Intercept)	6,274,160	2,110,902	14
pcmpos	177,494	52,842	14
pcm	219,432	134,046	7
pcm_2	-147	3,106	3
pcm_3	-30	96	3
pcm_4	0	1	1
pcm_5	0	0	3
pcmminus1	8,244	93,699	1
pcmminus1_2	3,419	1,349	7
pcmminus1_3	60	73	5
pcmminus1_4	-2	1	9
pcmminus1_5	0	0	9
pcmplus1	372,604	112,530	7
pcmplus1_2	910	3,000	3
pcmplus1_3	-142	90	5
pcmplus1_4	2	1	5
pcmplus1_5	0	0	5

Plants	Average of Coefficients	Average of Std. Errors	# of Coefs. Significant(5%)
meanpcm	-4,166,064	811,405	10
meanpcm_2	186,608	48,112	8
meanpcm_3	20,825	5,275	8
meanpcm_4	-767	150	11
meanpcm_5	6	1	8
meanpcmminus24	-2,570,368	687,972	10
meanpcmminus24_2	-454,765	88,375	9
meanpcmminus24_3	-2,184	3,678	9
meanpcmminus24_4	749	183	9
meanpcmminus24_5	-8	2	9
meanpcmplus24	4,638,543	959,966	10
meanpcmplus24_2	292,823	65,725	9
meanpcmplus24_3	-9,287	2,343	8
meanpcmplus24_4	-500	121	7
meanpcmplus24_5	8	1	5
nino	-9,061,277	2,549,190	7
nina	-3,801,596	1,082,116	9
factor(month)2	-1,078,806	872,550	9
factor(month)3	1,055,318	1,128,999	11
factor(month)4	-1,987,125	1,250,381	10
factor(month)5	-2,003,606	2,221,113	9
factor(month)6	-1,134,915	2,775,908	10
factor(month)7	-1,951,445	2,456,471	10
factor(month)8	-6,820,098	2,443,484	10
factor(month)9	-1,806,498	1,943,902	11
factor(month)10	-5,241,674	2,170,379	11
factor(month)11	920,002	1,539,088	7
factor(month)12	6,291,624	1,725,714	10
factor(wday)jueves	2,133,182	1,818,685	9
factor(wday)lunes	-117,000	1,724,764	7
factor(wday)martes	2,224,530	2,110,956	8
factor(wday)mi?coles	4,428,829	1,881,154	7
factor(wday)s?ado	5,037,533	2,168,961	8
factor(wday)viernes	2,174,832	1,928,379	8

Summary of model for 29 Thermo Plants

Plants	Average of Coefficients	Average of Std. Errors	# of Coefs. Significant(5%)
(Intercept)	-2,266,480	1,872,797	14
pcmpos	46,082	23,060	16

Plants	Average of Coefficients	Average of Std. Errors	# of Coefs. Significant(5%)
pcm	2,114	21,687	0
pcm_2	-130	562	0
pcm_3	0	6	0
pcm_4	0	0	0
pcm_5	0	0	0
pcmminus1	4,817	17,147	1
pcmminus1_2	-1	496	0
pcmminus1_3	0	6	1
pcmminus1_4	0	0	0
pcmminus1_5	0	0	0
pcmplus1	-6,009	23,760	0
pcmplus1_2	229	664	0
pcmplus1_3	2	8	0
pcmplus1_4	0	0	0
pcmplus1_5	0	0	0
meanpcm	245,933	161,622	13
meanpcm_2	-2,239	5,233	11
meanpcm_3	-206	147	11
meanpcm_4	5	2	12
meanpcm_5	0	0	9
meanpcmminus24	-70,328	87,399	8
meanpcmminus24_2	-11,709	6,014	8
meanpcmminus24_3	12	89	14
meanpcmminus24_4	3	2	10
meanpcmminus24_5	0	0	14
meanpcmplus24	-469,076	248,561	15
meanpcmplus24_2	1,122	3,386	15
meanpcmplus24_3	23	112	11
meanpcmplus24_4	-3	1	11
meanpcmplus24_5	0	0	16
nino	-1,473,419	861,100	11
nina	-571,598	1,352,237	18
factor(month)2	1,752,584	1,027,352	13
factor(month)3	400,653	599,539	12
factor(month)4	4,012,884	1,631,144	12
factor(month)5	5,146,015	1,986,555	10
factor(month)6	4,833,671	2,020,873	16
factor(month)7	3,523,223	1,699,740	11
factor(month)8	-2,050,325	3,308,872	16
factor(month)9	-1,754,645	2,173,136	17
factor(month)10	-3,753,738	1,546,456	11
factor(month)11	-1,382,393	2,462,488	18

Plants	Average of Coefficients	Average of Std. Errors	# of Coefs. Significant(5%)
factor(month)12	-2,292,184	1,636,439	13
factor(wday)jueves	1,554,476	636,810	12
factor(wday)lunes	-4,132,396	2,485,319	16
factor(wday)martes	-2,836,749	2,019,203	15
factor(wday)mi?coles	36,333	858,620	18
factor(wday)s?ado	4,854,767	1,934,567	8
factor(wday)viernes	1,086,754	518,918	11

Degree 6

Summary of model for all Plants

Plants	Average of Coefficients	Average of Std. Errors	# of Coefs. Significant(5%)
(Intercept)	664,955,451	182,705,505	20
pcmpos	202,501	75,668	34
pcm	241,055	192,215	4
pcm_2	390	6,454	2
pcm_3	-18	155	5
pcm_4	0	3	3
pcm_5	0	0	4
pcm_6	0	0	1
pcmminus1	-22,908	132,885	1
pcmminus1_2	4,401	4,074	7
pcmminus1_3	63	101	5
pcmminus1_4	-3	2	5
pcmminus1_5	0	0	6
pcmminus1_6	0	0	3
pcmplus1	360,903	179,806	6
pcmplus1_2	6,200	6,589	3
pcmplus1_3	-121	161	3
pcmplus1_4	-1	3	4
pcmplus1_5	0	0	5
pcmplus1_6	0	0	2
meanpcm	-74,215,834	23,964,314	14
meanpcm_2	-9,122,937	2,576,870	10
meanpcm_3	985,354	267,573	14
meanpcm_4	21,661	6,243	9
meanpcm_5	-982	271	13
meanpcm_6	7	2	5

Plants	Average of Coefficients	Average of Std. Errors	# of Coefs. Significant(5%)
meanpcmminus24	543,644,205	141,206,820	17
meanpcmminus24_2	-33,551,707	8,802,862	11
meanpcmminus24_3	-2,667,258	688,950	15
meanpcmminus24_4	182,254	47,524	17
meanpcmminus24_5	-3,384	886	12
meanpcmminus24_6	19	5	15
meanpcmplus24	-246,570,963	72,758,926	9
meanpcmplus24_2	11,363,311	3,530,566	12
meanpcmplus24_3	-856,238	249,238	15
meanpcmplus24_4	13,002	5,831	12
meanpcmplus24_5	88	95	14
meanpcmplus24_6	-1	1	7
nino	-48,133,540	23,124,926	21
nina	-156,416,260	49,669,823	21
factor(month)2	49,556,318	21,389,253	17
factor(month)3	-508,445,892	138,064,913	16
factor(month)4	-254,853,648	67,588,087	17
factor(month)5	-948,846,624	254,967,974	18
factor(month)6	-1,822,642,583	489,043,327	17
factor(month)7	-1,711,537,634	456,370,632	14
factor(month)8	157,442,215	51,410,818	16
factor(month)9	-909,308,476	236,655,727	15
factor(month)10	657,994,400	185,504,766	18
factor(month)11	-801,810,517	215,953,163	19
factor(month)12	253,541,178	82,750,822	13
factor(wday)jueves	218,265,722	62,395,530	9
factor(wday)lunes	-1,415,929,418	369,282,660	14
factor(wday)martes	558,140,082	146,311,960	10
factor(wday)mi?coles	965,240,233	253,385,800	14
factor(wday)s?ado	334,358,136	90,666,606	16
factor(wday)viernes	5,286,609	11,147,052	12