A Structural Model to Evaluate the Transition from Self-Commitment to Centralized Unit Commitment

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Abstract

We introduce a dispatch model of Colombia's independent system operator (XM) in order to study the relative merits of self-commitment vs. centralized unit comment. We capitalize on the transition that took place in 2009 from self-unit commitment to centralize unit commitment and use data from Colombia for the period 2006-2012. In our analysis we simulate a competitive benchmark based on estimated marginal costs, startup costs and opportunity costs of thermal and hydro. We compare the differences between the competitive benchmark and self-commitment for the period 2006-2009 to the differences between the bid-based centralized unit commitment and the competitive benchmark after the transition. Based on these comparisons we estimate changes in deadweight losses due to misrepresentation of cost by bidders and dispatch inefficiency. The results suggest that centralized unit commitment has improved economic efficiency, reducing the relative deadweight loss by at least 3.32%. This result could in part be explained by the observation that, before 2009, there was an underproduction of thermal energy relative to the competitive benchmark and it support the claim that dispatch efficiency has improved after the transition.

Keywords: Electricity Markets, Self-commitment, Centralized Unit Commitment, Economic Efficiency, Market Power.

JEL Classification: Q40, Q42, Q49, L11, L5, L89

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1 Introduction

Since 1993 the Colombian electricity sector went through major restructuring of its overall design. Two central regulatory interventions have affected the centralized planning dispatch and the rules of the Colombian spot market, which operates by receiving day-ahead bids and using those bids for dispatch decisions and calculation of the spot price.[2] Until 2001 the spot market, organized as an energy exchange, required generating units (plants) to self-commit generating capacity and submit hourly energy price offers along with declaration of their maximum generating capacity for each of the next day 24 hours. Using these bids, the system operator (XM) would determine the least cost generation dispatch to satisfy demand on an hour by hour basis, ignoring transmission constraints, and determined the hourly wholesale price, as the price offered by the marginal plant (that is the highest cost plant needed to meet demand). This hourly market clearing price was used to compensate all dispatched generating units. This mechanism amounts to running an hourly uniform price auction for energy (see below for details) and subsequently handling transmission constraints through an out of market balancing mechanism. After 2001, the *Comisión de Regulación de Energía y Gas* (CREG)[3] determined that only one price should be offered for the next 24 hours in which the plants were committed – see CREG-026 (2001).

In 2009 CREG[4] realized the possibility of productive inefficiencies of the existing market design due to the heterogeneity of generating technologies comprising hydro and thermal generating units, with very different cost structures. In particular such inefficiencies could arise from the non-convex cost structure of thermal generating units, since their startup and shut down costs were not explicitly accounted for in the dispatch optimization. The economic and engineering literature has extensively discussed the fact that in the presence of non-convexities, self-committed uniform price auctions with energy only offer prices can lead to productive inefficiencies.[5] From the suppliers' perspective, thermal units face an unnecessary risk when restricted to submit energy only offer prices since if a unit is dispatched, the market clearing price would need to be sufficiently high to compensate for startup costs. On the other hand,

[2] Thus, 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 the energy consumption and production among market participants. To be consistent with standard local terminology, we will follow the usual practice in Colombia and refer to the market and its price as "spot market" and "spot price", respectively.

[3] Colombia's energy regulatory agency.

[4] Document CREG – 011 (2009), Resolución 051 (2009) and subsequent modifications.

[5] Sioshansi, O'Neill and Oren (2008), (2008b), (2010), O'Neill, Sotkiewicz, Hobbs, B.F., Rothkopf, and Stewart, (2005).

turning off thermal plants that are already running and turning on a lower marginal cost unit could result in inefficient production due to ignoring startup costs.[6]

Following recommended international best practices and academic literature, the CREG undertook a redesign of the spot market and centralized energy dispatch. In broad terms the market became a pool, with multipart bids and centralized unit commitment. More precisely, generating units are now required to separate their offers into variable and quasi-fixed costs (startup and shut down). In this way generators now submit "complex bids" consisting of three parts hourly bids for the next 24 hours (1) Variable cost bid (the same for the next 24 hours), (2) Startup and shut down cost (the same for a three month period) and (3) maximum available capacity (a different value for each hour). Using this information the system operator determines the least cost generation needed to satisfy demand on an hour by hour basis, setting the market clearing price as the price offered by the marginal plant. Ex post the system operator determines which of the dispatched plants cannot recover their fixed costs given the energy market clearing price over the 24 hour period. Such plants are paid a "make whole payment" in addition to their energy sales revenues, which enables them to recover their fixed costs. Clearly, this centralized unit commitment approach solves the inefficiency issues but raises (or reinforces) new incentive problems. See, for instance Sioshansi, Oren and O'Neill (2010), Sioshansi and Nicholson (2011).

While in a well-designed centralized unit commitment the system operator can determine the most efficient dispatch, the auction mechanism used to solicit generator data, upon which the market clearing prices and settlements are based, may compel generators to overstate costs.[7] This incentive to overstate costs is also true of self-commitment in an energy exchange, but complex bids allow for further strategic behavior. There are no theoretical studies with clear-cut results that rank the performance of one design relative the other, so the question remains an empirical one.[8] This study proposes a structural model of the dispatch to evaluate empirically the ultimate benefits (if any) of the 2009 regulatory intervention in Colombia. This paper is a follow up paper to Riascos, Bernal, de Castro and Oren (2016) in which we use econometric techniques to address the problem of economic efficiency and provide

[6] Sioshani, Oren and O'Neill (2010) provide a stylized example which shows that self-commitment in an energy exchange can result in inefficient production of energy even if generators are price takers. This is a phenomenon due only to non-convexities in the cost structure of some generating units. See page 169, Table IV.

[7] A well designed centralized unit commitment requires a rich set of technological parameters to calculate the efficient dispatch but due to the way plants report their bids, efficiency losses may persist even under truthful biding. For example a single price bid for all 24 hours can be interpreted as the average marginal cost, but this would result in an inefficient dispatch. Allowing for multipart price bids that can vary hourly may improve efficiency, provided that generators use the multipart format to reflect their true cost structure.

[8] See Sionashi and Nicholson (2011).

evidence of increased exercise of market power by generators after the transition to centralized-unit commitment. In contrast to that paper, here we use an explicit model of the dispatch that better represents the actual production and pricing decisions based on economic conditions (demand, costs, etc.) and plants technological restrictions. This approach allows us to quantify more precisely the relative merits of centralized unit commitment in terms of economic efficiency[9]. Under uniform pricing and short-run inelastic demand, economic efficiency corresponding to social welfare maximization is equivalent to minimizing production costs.

2 The problem

In this section we briefly explain the Colombian spot market design before and after the regulation of 2009 and the most important features of resolution 051 of that year.[10] We focus on the domestic market (national market) and ignore the international exchanges with Venezuela and Ecuador. 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 national market is appropriate.

The spot market and energy dispatch prior to Regulation 051 (i.e. before 2009) can be summarized as follows. There are three relevant points in time: the day ahead (economic dispatch), the real time dispatch (real dispatch) and the day after (ideal dispatch). The main features of the economic dispatch are:

a) Plants submit two-part offers: a minimum price at which they are willing to generate during the next 24 hours along with their maximum generating capacity for every hour of the next 24 hours.
b) Plants inform the Independent System Operator (ISO) about the fuel and plant configuration that should be used for solving the unit commitment problem.
c) The system operator estimates the hourly demand for the following 24 hours.
d) Generators submit basic technical characteristics of plants (ramp model for thermal plants, minimum energy operating restrictions $Q_{i,t}^{-}$ for hydro plants, minimum up-time, minimum down-time[11], etc. for thermal plants).

[9] Economic efficiency is, by law, the regulatory agency objective function. See Law 143 (1994), Art. 6.

[10] Unless otherwise stated, in this paper before regulation 2009 means the period in between the regulation of 2001 and the regulation of 2009.

[11] 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 down time).

e) Automatic generation control restrictions (AGC) are given[12].
f) Transmission restrictions are given.
g) The economic dispatch optimizes the following function:

$$\sum_{t=0,\ldots,23} \sum_{i} Pof_i \times p_{i,t}$$

where Pof_i is the price offer of plant i for the next 24 hours and $p_{i,t}$ is the production of plant i in hour t subject to hourly AGC, transmission, demand and technical constrains (ramps), environmental restrictions, etc.

This optimization defines the economic dispatch for every hour. It provides a scheduling plan for generating energy in the next 24 hours. However the prices are determined ex post to account for deviations, on the basis of a separate run referred to as "ideal dispatch".

Real-time production schedules deviate from the day-ahead economic dispatch schedule for various reasons: forecast errors of real-time demand relative to its day-ahead forecast, energy losses, overloaded lines, etc. Therefore, the system operator is required to fine-tune the actual dispatch in real time. Once the real-time generation in the 24 hours has occurred the system operator calculates the ideal dispatch. The ideal dispatch is an ex-post calculation which ignores transmission constraints and is used for settlement purposes. The optimization problem that is solved in the ideal dispatch calculation is the following:

$$\min_{p_{i,t,}} \sum_{i} Pof_i \times p_{i,t}$$

s.t.

$$D_t \leq \sum_{i} p_{i,t} \quad (1)$$

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

[12] Power grids require closely balanced real time generation and load. Thjs is achieved through AGC, which automatically adjusts the power output of generators.

The ideal dispatch forms the basis for calculating the spot price.[13] 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"[14]. We denote this price as MPO_t. The hourly spot price, P_t, is defined as this equilibrium price, $P_t = MPO_t$ (after 2009, the spot price has been modified by an uplift as explained below).

Since the real dispatch turns out to be different from the ideal dispatch, additional side payments are implemented as described below to compensate units that have been operated out of market (e.g. at marginal cost above their offer price).

After the regulation of 2009, the ideal dispatch solves a centralized unit commitment problem. Rather than minimizing the as bid hourly costs of energy, the objective function is set equal to the objective function of the economic dispatch (twenty four hour optimization problem), generators submit complex bids and side payments are introduced. The bids specify a single energy offer price for the next twenty four hours, startup costs and maximum generating capacity for each hour.

Once the optimization problem of the ideal dispatch is solved for the 24 hours, the market price, MPO_t, is calculated as the price bid of the marginal plant that is not saturated. The hourly spot price , P_t , is defined as this market price plus an uplift ΔI , which is defined in the following way.

Let

$$I_i = \sum_{t=1}^{24} p_{i,t} \times MPO_t$$

be the income of plant i according to the ideal dispatch and let

$$C_i = \sum_{t=1}^{24} p_{i,t} \times Pof_i + \sum_{t=1}^{24} Par_i \, s_{i,t}$$

be the generating cost of plant i, where Par_i are startup costs and $s_{i,t}$ is a binary variable indicating it the plant is switch on at time t.

[13] More precisely this is a settlement price since technically speaking there is no spot market.
[14] A plant is saturated when it is operating under inflexible conditions, i.e. when it cannot change its output without violating technical restrictions. For example, a thermal plant in the middle of a startup profile is a saturated plant.

Now let $GI_{i,t}$ be the energy production of plant i at the time when it is saturated (zero otherwise) and RP_i the positive reconciliation price (for the objectives of this study it not relevant to define this price explicitly) 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:

$$DI_i = \sum_{t=0}^{23} GI_{i,t} \times (\max\{MPO_t, RP_i\} - \ MPO_t)$$

The hourly spot price is defined as:

$$P_t = MPO_t + \Delta I$$

Therefore, the spot price guarantees that demand will pay for startup of dispatched plants, and energy production of 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 produced energy (no matter if the plant is saturated or not) and (1) hydro plants reimburse ΔI for each unit of energy produced, (2) thermal plants for which $C_{N,i} \leq I_{N,i}$ reimburse ΔI , and (3) thermal plants for which $C_{N,i} > I_{N,i}$ make no reimbursement.

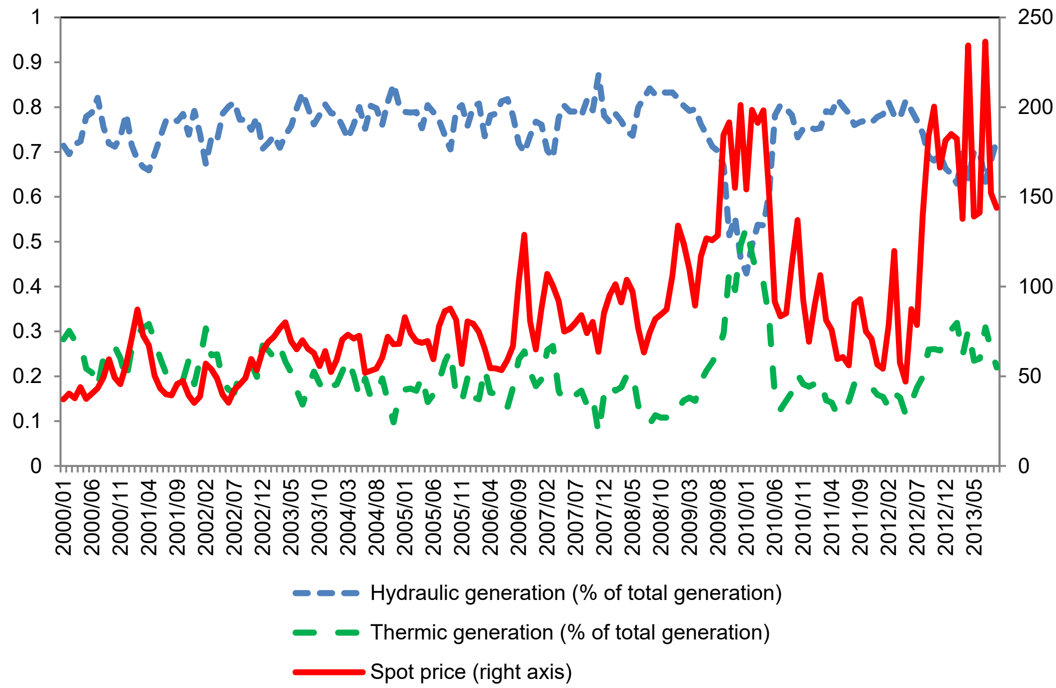
3 Model

The dispatch model we used is explained in the Appendix. A key feature of our methodology is the construction of marginal costs for thermal plants and opportunity costs for hydro plants.

3.1 Marginal and Opportunity Costs

The Colombian electricity sector is a hydro dominated but diversified system. Figure 1 shows a time series of the composition between hydro and thermal generation (as a proportion of total generation) since 2001. The graph also shows the spot price (right axes measured in pesos per kWh).

Figure 1: Mix of hydro and thermal generation and market prices



One of the key variables that we will need to estimate is the marginal costs and opportunity costs of water. We take a pragmatic and standard approach, which is common in the economic literature (Borenstein et.al (2002), Mansur (2008)). The methodology for estimating the marginal costs of plants that use coal and natural gas as their principal fuel is based on: (1) the heat rate of each plant, (2) fuel caloric value, (3) fuel price (P), (4) variable operating and maintenance costs (VOM), and (5) taxes. Then the marginal cost of a thermal plants is:

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

We use a fuel price time series adjusted by caloric value and transport costs from UPME[15] and heat rates are obtained from the power exchange web page for all thermal plants. We used different VOM costs for different technologies, specifically US$5/MWh for gas plants and US$6.9/MWh for carbon plants.

We use the daily official exchange rate (TRM) obtained from *Banco de la República*[16] to express marginal costs in pesos.

[15] UPME refers to the Colombian energy and mining planning department (Unidad de Planeación Minero Energética): http://www.sipg.gov.co/sipg/documentos/precios_combustibles

[16] Central Bank of Colombia.

The opportunity cost of water is one of the most difficult variables to estimate. Hydro plants face a tradeoff between producing now and storing water to produce in the future. In a static one shot game between generators in an organized energy market, the opportunity cost of a hydro generator g producing at time t can be estimated by the maximum price offered by thermal generators that were dispatched at that time (which we denote by $ThermoMPO_{gt}$), thus as a pragmatic estimation of opportunity costs, that only accounts for the present, we use:

$$\widehat{MC_{gt}} = \min\left(ThermoMPO_{gt}, Bid_{gt}\right),$$

where Bid_{gt} is the hydro plant bid at time .

Our structural analysis uses a panel of 50 plants since January 1, 2006 to December 31, 2012, that are responsible for more than 95% of total generation.

3.2 Validation

To test the validity of our model, we simulate the period from June 2010 to October 2012 using real startup costs and bids. Then we compare the resulting market price (MP) with the real market price, as reported by the power exchange. Figures 2 and 3 show the daily and weekly averages of the real versus the simulated market price.

Figure 2: Actual vs. simulated average daily market prices

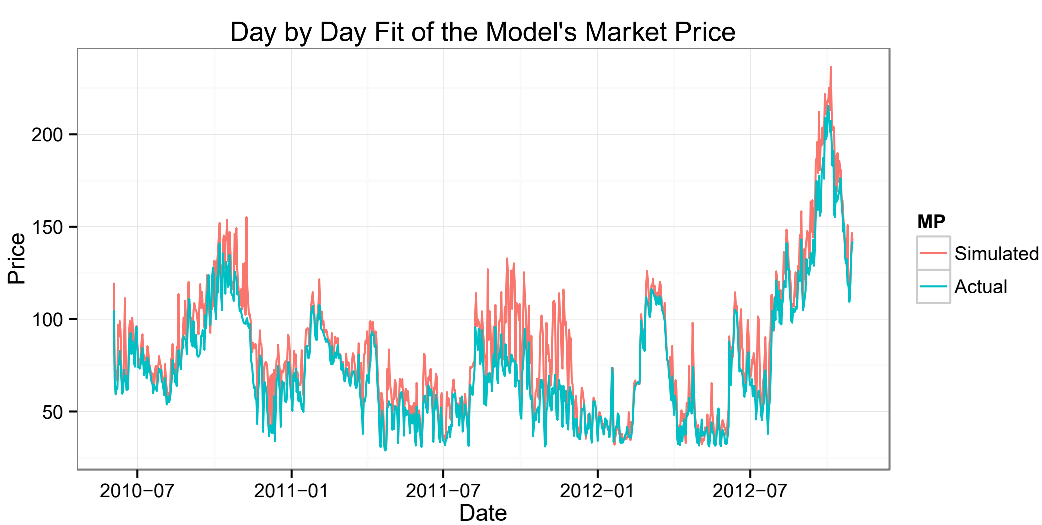
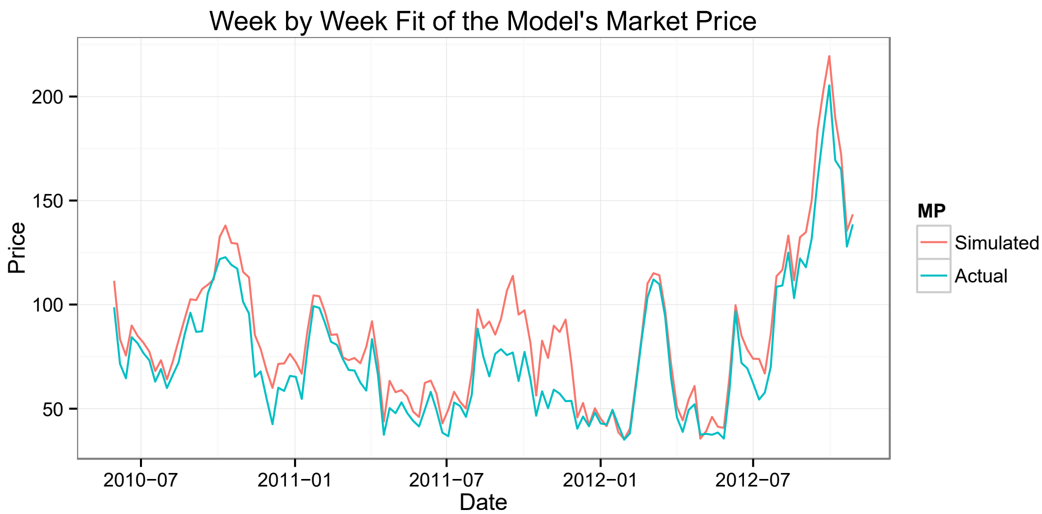


Figure 3: Actual vs. simulated average weekly market prices



As the plots show, there is a good match between the simulated and the real market price. The Table 1 reports a series of measurements on the goodness of fit of the market price generated by our model, relative to the real market price.

Table 1: Goodness of fit measure for simulated market prices

Measure of Error	Daily	Weekly
MAPE	15.43%	14.89%
MPE	-14.69%	-14.63%
MAE	10.42 COP	10.10 COP[17]
RMSE	14.73 COP	12.76 COP

Figure 4 and and Table 2 show the fit of our model in terms of total costs.

[17] COP means Colombian Pesos (Colombian official currency).

Figure 4: Actual vs. simulated average weekly production cost

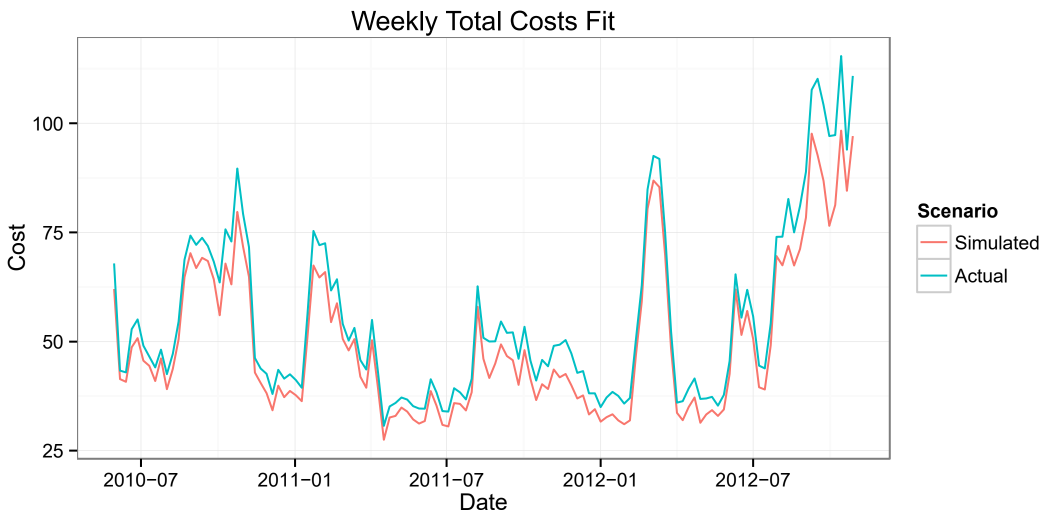


Table 2: Goodness of fit measures for simulated production cost

Measure of Error	Daily	Weekly
MAPE	14.23%	9.49%
MPE	14.23%%	9.49%
MAE	1.00e+9 COP	5.34e+9 COP
RMSE	1.04e+9 COP	6.26e+9 COP

It is interesting to note that our model overestimates actual market prices and underestimates total costs. One of the reasons for this discrepancy could be that in the actual dispatch performed by the exchange there are a number of complex rules which exclude generators deemed inflexible from participation in the price setting.

In the next section we will simulate a benchmark competitive market based on estimated true costs (rather than bids) and compare it with the real market. We have two options when analyzing the real market: use the actual dispatch based on historical data, or use simulated dispatch after feeding our model with the real bids and start-up costs. We select the second option, since as noted before, there is a small bias in our model with respect to the realized outcomes and in absence of detailed information regarding the causes of that distortion, we believe that the estimate of relative efficiency will be more reliable using a consistent model for the competitive benchmark simulation and the bid based simulation.

4 Results: Competitive Benchmark vs Bid-based simulation

We perform three simulations: (1) The competitive benchmark for the whole period of study. (2) The simulated real scenario before 2009, result of using our structural model of the dispatch under self-unit commitment and (3). The simulated real scenario after 2009, result of using our structural model of the dispatch under centralized-unit commitment. To be more precise:

- The competitive benchmark for the whole period of study is constructed in the following way. For the whole period of study we have marginal and opportunity costs of all plants as estimated above. For the period after 2009, under centralized unit commitment, we have reported startup costs. To construct our competitive benchmark we estimated what would have been the startup costs before 2009, the Appendix contains this methodology. Now, using marginal costs and startup costs for the whole period of study, assuming the latter are good estimates of real startup costs, we plug in these value in our dispatch model for centralized unit commitment. We take the output of the model as our competitive benchmark.

- The simulated real scenario before 2009 is constructed as follows. We first simulate an hourly uniform auction using the reported energy bids. Then we determine which of the dispatched plants are saturated. This is done by calculating the dispatch with the full 24 hour model. The MPO is then determined as the price of the cheapest non saturated dispatched plant (according to the uniform auction). This is our model for self-unit commitment and hourly optimization for the period before 2009.

- The simulated real scenario after 2009 uses our full model of the dispatch under centralized unit commitment explained in the Appendix. It uses reported energy bids and startup costs to calculate the MPO.

Finally, to calculate the Market Price (MP) we add an uplift to the MPO that compensates the losses of generators that could not fully cover their start-up costs. This is done for the competitive benchmark and the simulated real scenario after 2009.

Hydro and Thermal Generation

We calculate the participation of hydro and thermal generation in the production of energy, both for the competitive and real scenarios. Figures 5 and 6 present the weekly participation across time in percentages.

Figure 5: Share of hydro energy of total weekly generation

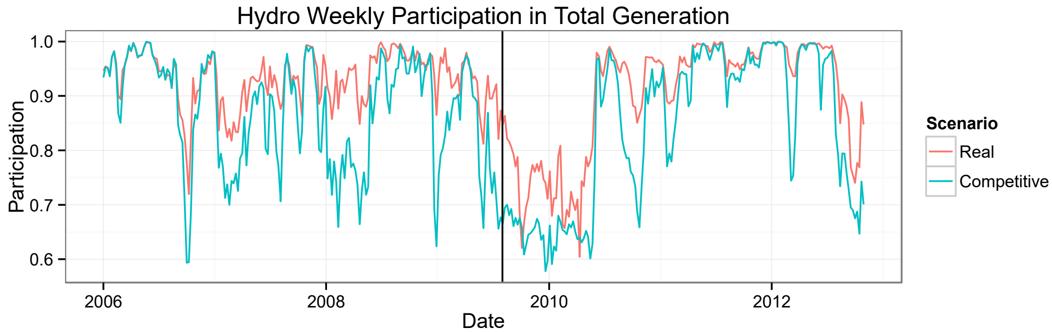
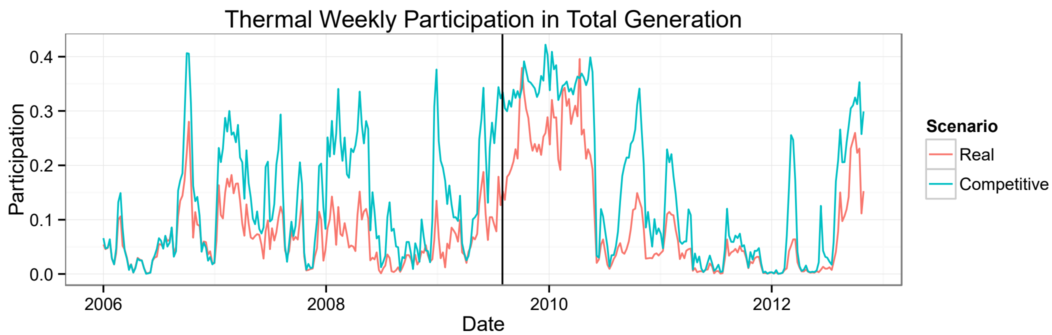


Figure 6: Share of thermal energy of total weekly generation



Note that with respect to the perfect-competition scenario, thermal generations have been under-producing, and hydro generators have been over-producing. The reason is that, historically, thermal generators have over-bid, and so the optimization algorithm has allocated less power production to thermal units than what is optimal. Figure 7 presents the weekly excess hydro supply with respect to perfect competition, clarifies the previous claim.

Figure 7: Weekly excess hydro generation relative to the competitive benchmark

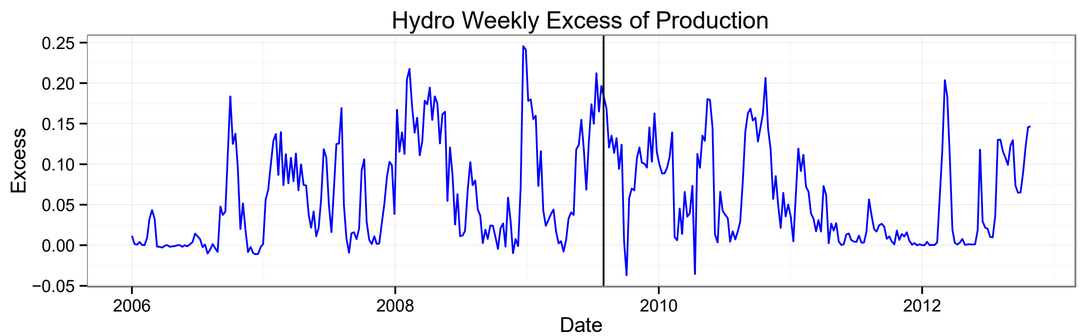


Table 3 presents the average participation over years, before and after the 2009 reform. It is always the case that hydro participation in the Real Scenario is greater than in the Competitive Scenario. The reform seems to have had an effect in diminishing this excess of production.

Table 3: Annual shares of Hydro vs. Thermal energy production

Year	Thermal Participation		Hydro Participation		Hydro Excess
	Real	Competitive	Real	Competitive	
2006	6.29%	8.16%	93.71%	91.84%	6.29%
2007	8.43%	14.74%	91.57%	85.26%	8.43%
2008	5.09%	13.96%	94.91%	86.04%	5.09%
2009 BR	8.00%	17.35%	92.00%	82.65%	8.00%
2009 AR	23.93%	34.41%	76.07%	65.59%	23.93%
2010	14.48%	22.73%	85.52%	77.27%	14.48%
2011	3.28%	5.78%	96.72%	94.22%	3.28%
2012	5.96%	11.72%	94.04%	88.28%	5.96%

Table 4 below presents corresponding results if we exclude a period of unusually high fuel prices (August 2009-February 2010).

Table 4: Annual shares of Hydro vs. Thermal energy production excluding period of very high prices

Reform	Thermal Participation		Hydro Participation		Hydro Excess
	Real	Competitive	Real	Competitive	
Before	6.84%	13.17%	93.16%	86.83%	6.84%
After	4.73%	9.69%	95.27%	90.31%	4.73%

4.1 Economic Efficiency

In order to determine the efficiency of the energy market we first calculate the total costs of production in both the competitive and the real world scenario. The competitive and real total costs of any given day are:

$$CompetitiveCosts = \sum_{t=1}^{24} \sum_{g \in G} q_{gt}^{C} p_{gt} + \sum_{t=1}^{24} \sum_{g \in T} u_{gt}^{C} s_{gt}$$

$$RealCosts = \sum_{t=1}^{24} \sum_{g \in G} q_{gt}^{R} p_{gt} + \sum_{t=1}^{24} \sum_{g \in T} u_{gt}^{R} s_{gt}$$

where q_{gt}^{C} and q_{gt}^{R} denote the quantity produced at time t by generator g in the competitive and real scenario, respectively; u_{gt}^{C} and u_{gt}^{R} are binary variables that indicate whether generator g was started at time t; finally, p_{gt} and s_{gt} indicate variable production costs and start-up costs. Note these are the estimated marginal costs, i.e. the costs that were used in the competitive scenario simulation, and not the costs that were actually bid by generators.

Figures 8, 9 and 10 presents the weekly total costs corresponding to the actual dispatch and competitive benchmark. We also include separate plots for the thermal and hydro generation.

Figure 8: Total weekly costs for the actual dispatch vs. competitive benchmark

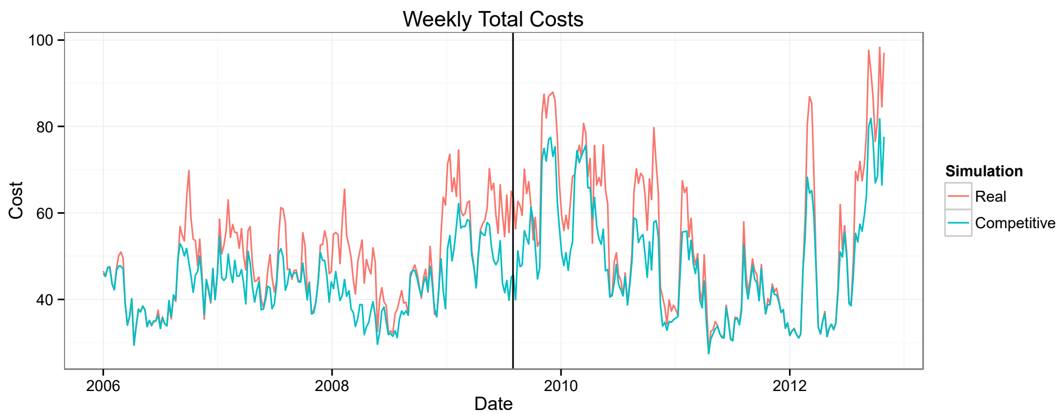


Figure 9: Total weekly costs for thermal generation in the actual dispatch vs. competitive benchmark

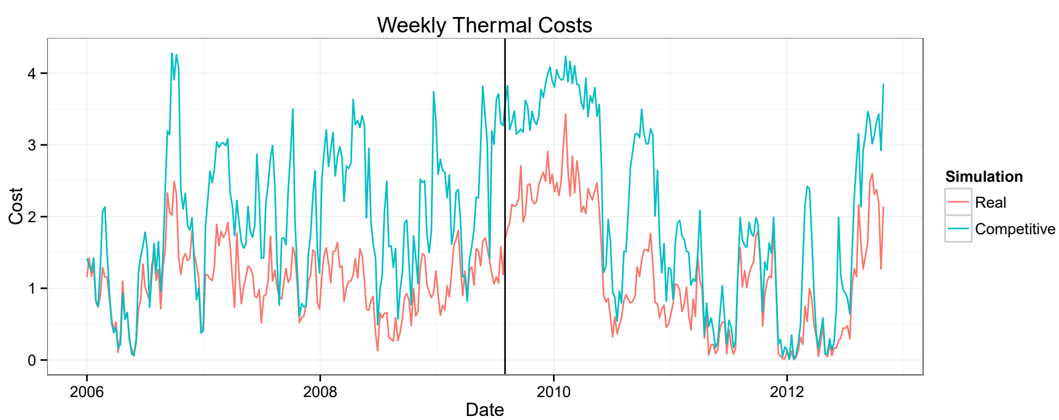
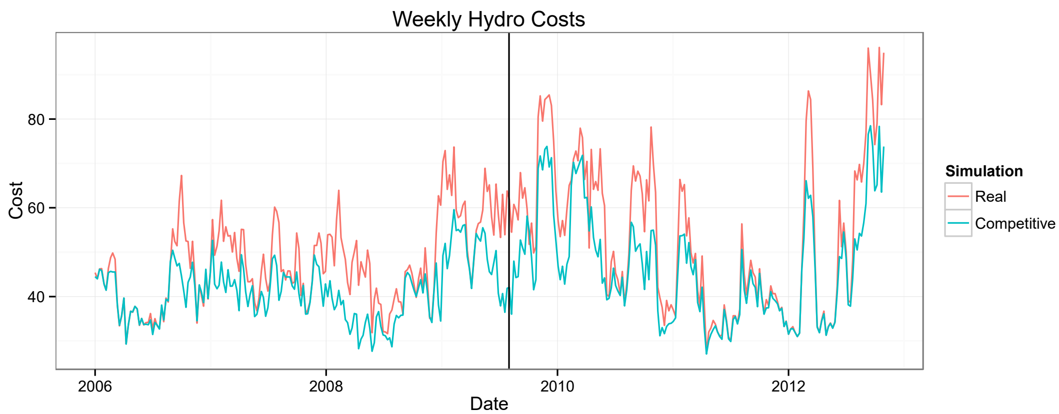


Figure 10: Total weekly costs for hydro generation in the actual dispatch vs. competitive benchmark



As can be noted, total costs are greater in the simulated real scenario than in the competitive benchmark. The reason is that the competitive total costs are optimal, that is, demand cannot be satisfied at a lower cost. The real scenario, on the other hand, is optimal given the bids of the generators, which differ from marginal costs.

Tables 5 and 6 below present the total generation costs (in billions of COP) for different time periods, decomposed into hydro and thermal energy.

Table 5: total generation costs

Year	Hydro Costs		Thermal Costs		Total Costs	
	Real	Competitive	Real	Competitive	Real	Competitive
2006	2611.63	2238.48	65.46	114.25	2677.09	2352.72
2007	2702.40	2356.39	60.79	101.48	2763.19	2457.87
2008	2753.11	2405.24	56.64	102.70	2809.75	2507.94
2009 BR	1607.79	1399.93	34.07	59.31	1641.86	1459.24
2009 AR	1173.60	1009.73	24.97	45.41	1198.57	1055.15
2010	2647.67	2292.25	61.99	108.23	2709.66	2400.48
2011	2485.44	2158.17	60.67	106.26	2546.11	2264.43
2012	2127.43	1867.51	53.11	91.10	2180.55	1958.61

To measure the efficiency of the market we calculate the deadweight loss due to bid that differ from marginal costs. For any given period, this deadweight loss is calculated as

$$DW_P = RealCosts_P - CompetitiveCosts_P.$$

A bigger deadweight loss means a less efficient market. Because we do not want our efficiency measure to depend on the energy produced on a given period, we calculate the deadweight loss ratio:

$$DWR_P = \frac{RealCosts_P - CompetitiveCosts_P}{CompetitiveCosts_P}.$$

Figure 11 below presents the weekly deadweight loss ratio across the period that we are considering.

Figure 11: Deadweight loss ratio for different periods

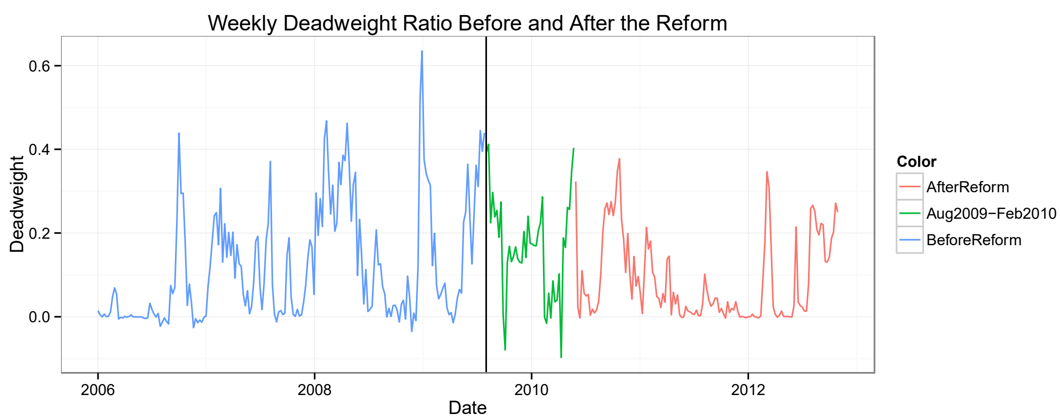


Table 6 below presents the average weekly deadweight loss ratio for different time periods.

Table 6: Average weekly deadweight loss ratios

Year	2006	2007	2008	2009BR	2009AR	2010	2011	2012
Deadweight	3.87%	10.90%	17.95%	18.70%	19.04%	14.69%	4.23%	10.26%

Table 7 presents the average results across the periods in each regime excludinge the period of very high fuel prices (August 2009-February 2010). We observe that weekly deadweight loss ratio decrease after the reform.

Table 7: Average weekly deadweight loss ratios with exclusion of a period of very high fuel prices

Reform	**Before**	**After**
Deadweight	12.12%	8.80%

To validate the significance of the above result we perform a mean difference t-test between the weekly deadweights before and after the reform with

$$H_0: \overline{DW}_{Before} = \overline{DW}_{After}$$

$$H_a: \overline{DW}_{Before} > \overline{DW}_{After}$$

Which results in: T statistics = -2.4668 and P-value = 0.007087

T at a 1% confidence level we can conclude that the weekly deadweight loss of the market decreased after the reform, which is evidence of more efficient energy production.

5 Conclusions

The economic and engineering literature has extensively discussed the fact that in the presence of non-convexities, self-committed uniform price auctions with energy only offer prices can lead to productive inefficiencies. From the suppliers' perspective, thermal units face an unnecessary risk when restricted to submit energy only offer prices since if a unit is dispatched, the market clearing price would need to be sufficiently high to compensate for startup costs. This paper capitalizes on the recent transition in Colombia from self-commitment to centralized unit-commitment (transition that took place in October 2009) to empirically evaluate the relative economic efficiency under the two regimes. For doing so we introduce a structural model of the dispatch to estimate the benefits (if any) of the 2009 regulatory intervention in Colombia. Our results which compare the relative deadweight loss due to misrepresentation of costs by bidders and dispatch inefficiency, suggest that centralized unit commitment has improved economic efficiency. The observed relative deadweight loss reduction of at least 3.32% can be explained in part be by the fact that, before 2009, there was an underproduction of thermal energy relative to the competitive benchmark and that inefficiency was corrected after 2009.

This paper is a follow up paper to Riascos, Bernal, de Castro and Oren (2016) in which we use econometric techniques to address the problem of economic efficiency and provide evidence of increased exercise of market power after the transition to centralized unit commitment. Taken together these results suggest that, although centralized unit commitment may have improved economic efficiency, the mechanism used to elicit generators data, upon which the market prices and settlements are based, may compel generators to act strategically so that the efficiency gains are not passed on to the end users of electricity.

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Appendix A: Dispatch model

In this section we provide a detailed description of our model of ideal dispatch. The model is cast as a mixed integer linear program. We also highlight the main differences with the ISO ideal dispatch model.

a) Nomenclature

- t =0,1,…,23; denotes one of the 24 hours of the day.
- i denotes a plant.
- $p_{i,t}$ is the power provided by plant t during hour t.
- $p_{i,t}^{soak}$ is the power provided by plant t during hour t and start-up phase.
- $p_{i,t}^{des}$ is the power provided by plant t during hour t and desynchronization phase.
- $u_{i,t}$ is a binary variable indicating if unit i is up in period t.
- $s_{i,t}$ is a binary variable indicating if unit i is started in period t.
- $h_{i,t}$ is a binary variable indicating if unit i is stopped in period t.
- $u_{i,t}^{soak}$ is a binary variable indicating if unit i is in the start-up phase.
- $u_{i,t}^{disp}$ is a binary variable indicating if unit i is in the dispatch phase.
- $u_{i,t}^{des}$ is a binary variable indicating if unit i is in the shut-down phase.
- n_{i}^{soak} represents the number of hours during the start-up phase (since start-up until output is at the technical minimum.
- n_{i}^{des} represents the number of hours during shut-down phase (from a technical minimum to shut-down).
- n_i is the minimum up-time of unit i.
- f_i is the minimum down-time of unit i.
- $Pof_{i,t}$ is the the price bid of plant i for hour.
- Par_i is the startup costs.
- D_t is the estimated total domestic demand for hour t.
- $P_{i,t}^{min}$ and $P_{i,t}^{max}$ are the minimum and maximum generating capacity respectively.[18]

b) Ramp model

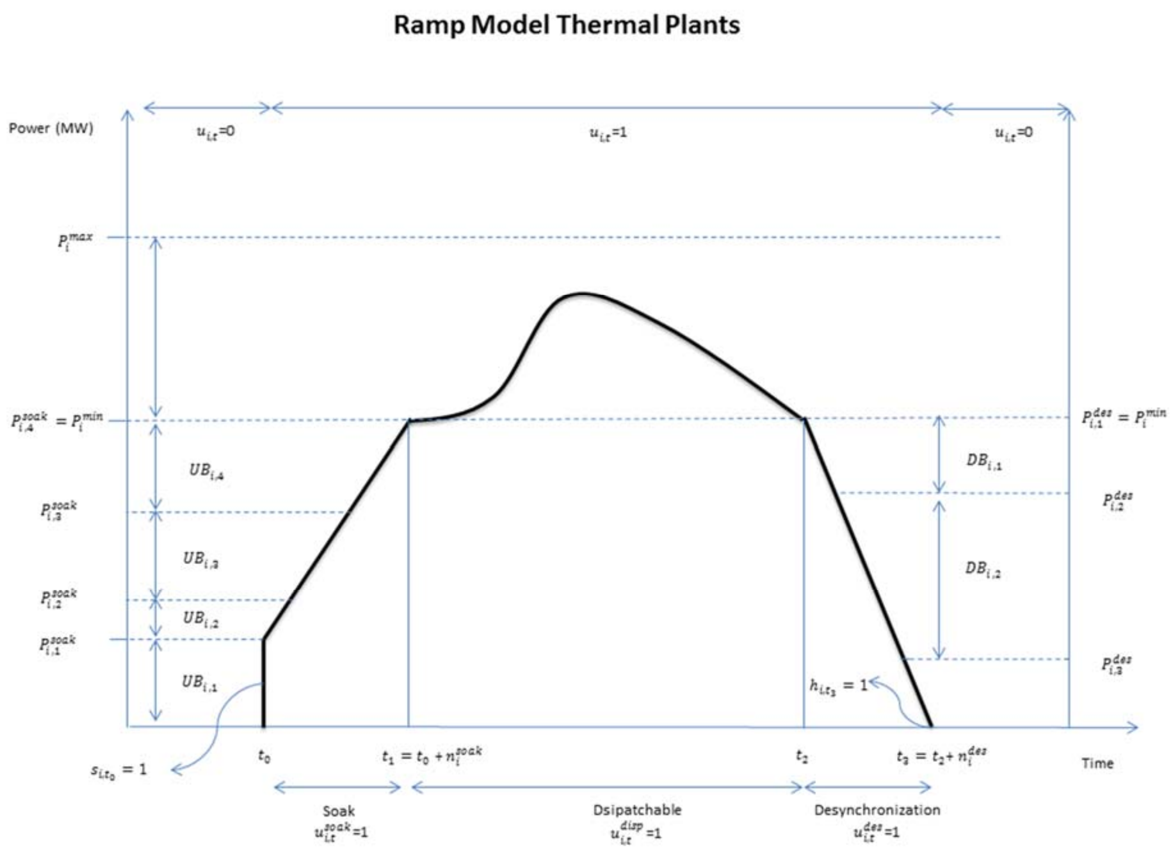
The ramp model is similar to Simoglou et.al (2010). We assume that thermal units follow three consecutive phases of operation: (1) soak or start-up phase (from zero to technical minimum), (2) dispatchable (when output is between the technical minimum

[18] For thermal plants the minimum and maximum is independent of t. For hydro it is zero for most plants except for those that are constrained by environmental requirements that may depend on t.

and maximum feasible power output) and (3) de-synchronization phase (when output is below the technical minimum and just before shut-down).

In the soak phase, the power output follows a block model. In the dispatchable phase we assume an affine model for power. In the de-synchronization phase we assume a block model.

Figure A-1: Ramp model of a thermal plant



c) Optimization problem

The ideal dispatch is the solution to the following optimization problem. It is a mixed integer linear program.

Objective function

$$\min_{p_{i,t},p_{i,t}^{soak},p_{i,t}^{disp},p_{i,t}^{des},s_{i,t},h_{i,t},u_{i,t},u_{i,t}^{soak},u_{i,t}^{disp},u_{i,t}^{des}} \sum_{t=0,\ldots,23} \sum_{i} Pof_i \times p_{i,t} + Par_i s_{i,t}$$

s.t.

Output feasibility

Feasible output:

$$D_t \leq \sum_i p_{i,t} \quad (1)$$

Soak phase:

Soak phase starts immediately following start-up[19]:

$$\sum\nolimits_{\tau=t-n_i^{soak}+1}^{t} s_{i,\tau} = u_{i,t}^{soak} \quad (2)$$

Let $\{UB_{i,s}\}_{s=1,..,n_i^{UB}}$ be the ramp up blocks during soak phase, then:

$$P_{i,s}^{soak} = \sum\nolimits_{j=1}^{s} UB_{i,s}$$

is the power provided by plant i, and period s following start-up . Then, during soak phase, the power output of the unit is constrained by:

$$\sum\nolimits_{\tau=t-n_i^{soak}+1}^{t} s_{i,\tau} P_{i,t-\tau+1}^{soak} = p_{i,t}^{soak} \quad (3)$$

Dispatch phase

We simplify the current model by assuming linear up and down ramp constraints:

$$p_{i,t} \leq \frac{UR + b \times p_{i,t-1}}{a} + N(u_{i,t}^{soak} + u_{i,t}^{des}) \quad (4)$$

$$p_{i,t} \geq \frac{-DR + c \times p_{i,t-1}}{d} - N(u_{i,t}^{soak} + u_{i,t}^{des}) \ - Nh_{i,t} \quad (5)$$

---

[19] We make two simplifications with respect to the Colombian ISO ideal dispatch model. We only consider one type of start-up (as opposed to a cold, warm, or hot, start-up) and we only consider one type of configuration per plant (i.e., a fixed ramp per plant). Not sure what ramp has to do with configuration.

Here N is a sufficiently large parameter.[20]

De-synchronization phase

The de-synchronization phase starts before shut-down:

$$\sum_{\tau=t+1}^{t+n_i^{des}} h_{i,\tau} = u_{i,t}^{des} \quad (6)$$

Let $\{DB_{i,s}\}_{s=1,..,n_i^{DB}}$ be the ramp down blocks during the de-synchronization phase and

$$P_{i,DesynchHours(g)-s+1}^{des} = \sum_{j=1}^{s} DB_{i,j}$$

be the power provided by plant i s periods after desynchronization is started. Then, during the de-synchronization phase the power output of a unit is constrained by[21]:

$$\sum_{\tau=t+1}^{t+n_i^{des}} h_{i,\tau} P_{i,t+1-\tau+n_i^{des}}^{des} = p_{i,t}^{des} \quad (7)$$

Minimum up time

Plants are constrained to be up for n_i periods after they are started up:

$$\sum_{\tau=t-n_i+1}^{t} s_{i,\tau} \leq u_{i,t} \quad (8)$$

Minimum down time

Plants are constrained to be down for f_i periods after they are shut down:

$$\sum_{\tau=t-f_i+1}^{t} h_{i,\tau} \leq 1 - u_{i,t} \quad (9)$$

Power Output Constraints

$$p_{i,t} \geq p_{i,t}^{soak} + p_{i,t}^{des} + P_i^{min} u_{i,t}^{disp} \quad (10)$$

[20] We have approximated the ISO model for the dispatchable region. The ISO model is based on maximum and minimum power variations depending on the level of outputs (segments model called Model number 2 by ISO). Our model for the dispatchable region is a special case of ISO's model number 3 used by some plants as an alternative to model 2. This discussion is esoteric and should probably be removed.

[21] This is a simplification of the current Colombian dispatch model on two dimensions. We do not consider an alternative shut down ramp whenever output is not at the technical minimum. What is the second dimension?

$$p_{i,t} \leq p_{i,t}^{soak} + p_{i,t}^{des} + P_i^{max} u_{i,t}^{disp} \quad (11)$$

$$p_{i,t} \leq p_{i,t}^{soak} + p_{i,t}^{des} + P_i^{max} u_{i,t}^{disp} + \left(P_i^{min} - P_i^{max}\right) z_{i,t+n_i^{des}} \quad (12)$$

Equation (12) constrains the plant to produce the minimum power just before starting the de-synchronization sequence.

Logical status of commitment

The following are restrictions required for the transition of the binary variables:

$$u_{i,t} = u_{i,t}^{soak} + u_{i,t}^{disp} + u_{i,t}^{des} \quad (13)$$

$$s_{i,t} - h_{i,t} = u_{i,t} - u_{i,t-1} \quad (14)$$

$$h_{i,t} + s_{i,t} \leq 1 \quad (15)$$

Boundary conditions

$$s_{i,-n_i+1}, s_{i,-n_i+2,\dots}, s_{i,0} \text{ given.}$$

$$h_{i,-f_i+1}, h_{i,-f_i+2,\dots}, h_{i,0} \text{ given.}$$

where all variables represent observed variables of the real dispatch of the previous 24 hours.

Appendix B: Construction of startup costs

Before 2009, startup costs were not reported by generators. In order to overcome this difficulty, we used reported startup costs after 2009 and fuel prices to estimate startup costs before 2009. To do so we first calculated the most common operating fuel type by plant (as shown in Table B-1).

Table B-1: Fuel types for different units

Generator	Startup 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 cost (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 are the only plants that can use both types of fuel.

Fuel prices are reported in 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 2009-2012 period. Since fuel costs have a six month frequency we used a local regression model to construct daily fuel cost data. For an appropriate fit of the LOESS model we use a smoothness parameter of $\alpha = 0.3$. With the LOESS fit we construct a new database with the price of fuel for each plant, with 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 startup 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 fit 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.

Table B-2 presents these results[22]. For 12 generators the restriction on the coefficients β_g^T was binding.

Figure B-2: Goodness of fit for startup cost estimation

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

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