quantil Matemáticas Aplicadas

An Evaluation of CREG 051 – 2009 Regulatory Intervention in Colombian Electricity Market

Final Report for Comments

By

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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's spot market, which operates by receiving day-ahead bids and using those bids for dispatch decision and calculation of the spot price.[1] Until 2001 the spot market, organized as an energy exchange[2], required generating units (plants) to self-commit generating capacity and submit a single hourly energy price offer along with a declaration of their maximum generating capacity for each of the 24 hours.[3] Using these bids, the system operator would determine the least cost generation dispatch to satisfy demand on an hour by hour basis and determined the equilibrium price, or marginal price, as the price bid of the marginal plant (that is the highest cost plant needed to meet demand). This hourly equilibrium price was used to compensate all dispatched generating units. This mechanism amounts to running an hourly uniform price auction for energy. After 2001, the *Comisión de Regulación de Energía y Gas* (CREG)[4] determined that offer prices should be fixed for the entire 24 hours in which the plants were committed – see CREG-026 (2001).[5]

In 2009 the CREG,[6] 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 inefficiency were the result of non-convex cost structures arising from large fixed costs of thermal generating units (startup and shut down costs), that 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 auction 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 pricessince if a unit is dispatched, the equilibrium price would need to be sufficiently high enough to compensate for startup costs. On the other hand, turning off thermal plants already

[1] 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.
[2] See Stoft (2002) for the precise terminology used for power exchange, power pool, etc.
[3] Sometime called simple bids in the literature as opposed to complex bids.
[4] Colombia's energy regulatory agency.
[5] To the best of our knowledge no quantitative assessment has been done of the effects of this regulatory decision.
[6] Documento CREG – 011 (2009), Resolución 051 (2009) and subsequent modifications.

running and turning on a lower marginal cost unit could result in an inefficient production by ignoring startup costs.[7] Following recommended international best practices and academic literature the CREG undertook a redesign of the spot market and centralized energy dispatched. 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 hourly bids for the next 24 hours consisting of three parts (complex bids): (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 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 equilibrium market clearing price as the price bid 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 an uplift 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.

While in a well designed centralized unit commitment dispatch the system operator can determine the most efficient dispatch, the auction mechanism used to solicit generators data upon which the equilibrium prices and settlements are based, may compel generators to overstate costs.[8] 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 vs. the other so the question remains an empirical one.[9] This study proposes several methodologies to evaluate empirically the ultimate benefits of the 2009 regulation.

We focus on the economic effects of the 2009 regulation related to:

1. The economic consequences on the ideal dispatch based on the introduced regulation 051 of 2009. More specifically, the impact on welfare for consumers,

[7] Sioshani, Oren and O'Neill (2010) provide a stylized example which shows that self-commitment in an energy exchange market 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.

[8] A well designed centralized unit commitment dispatch requires a rich set of technological parameters to calculate the efficient dispatch but due to on the way plants report their bids, some of this cannot be possible inferred even under truthful biding. For example a single price bid for all 24 hours, can be interpreted in as the average marginal cost, but this would results in an inefficient dispatch. Allowing for multipart price bids improves efficiency.

[9] See Sionashi and Nicholson (2011).

firm's surplus and economic efficiency.[10] By efficiency we mean the maximization of total surplus, a necessary condition for Pareto efficiency.[11] Under uniform pricing and short run inelastic demand, this is equivalent to minimizing production costs.

2. The efficiency effects of side payments and, in particular, those related to generation of saturated plants.

To address these questions we use three methodologies. (1) A standard descriptive analysis of main variables of interest aided by basic statistical tools. (2) A reduced form econometric model to address question 1 and a full-fledged structural model to simulate a centralized unit-commitment that we use to address question 1.

We found that the electricity is produced more efficiently since 2009, that is, the Resolution 051 contributed to higher efficiency. On the other hand, we found evidence that the mark-ups and the prices after 2009 were also higher than would under the regime before the resolution, possibly as a result of an increasing in market power. We also found out an increase in the number of tests, which might be associated with strategic creation of tests.

This report 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 solves and how each plant is remunerated. Section 3 is a literature review, that describes some of the most important electricity market designs around the world. Section 4 contains a description of the data used, and some descriptive statistics of the Colombia's market before and after 2009. The econometric analysis is presented and discussed in section 5. Section 6 presents the construction of a structural model of the Colombia's electricity market. This model is very close to the actual optimization problem that the system operator XM solves. Section 7 investigates how the Resolution impacted on the use of tests. Section 8 contains the conclusions and a brief list of recommendations.

2. The problem

[10] Economic efficiency is by law, the regulatory agency objective function.

[11] Pareto efficiency refers to a situation in which it is not possible to strictly improve at least one firm's surplus (profits) or aggregate consumer welfare (aggregate consumer's surplus) without strictly reducing at least one firm's surplus or aggregate consumer's welfare.

In this section we briefly explain Colombia's spot market design before and after the regulation of 2009 and the most important features of resolution 051 of that year.[12] We focus on the domestic market (national market) and ignore the international markets with Venezuela and Ecuador. The dispatch and spot market of these international markets 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. Hence, from now on we will ignore variable subscripts representing the national market and assume always that the participation in production or demand from the two international markets is negligible to a first order approximation.

a) Before 2009

Before Regulation 2009 the spot market and energy dispatch can be summarized in the following way. 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 Appendix describes in detail the centralized unit commitment model used in this study. The main features are:

1. Economic dispatch (every day before 8AM):
    a) Plants sent two part bids: 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) on what fuel and plants configuration should be used for solving the unit commitment problem.
    c) System operator estimates the following 24 hours total demand for each hour.
    d) Basic technical characteristics of plants are given (ramp model for thermal plants, minimum energy operating restrictions $Q_{i,t}^{-}$ for hydro plants, minimum up-time, minimum down-time, etc. for thermal plants).
    e) Automatic generation control restrictions (AGC) are given.
    f) Transmission restrictions are given.
    g) The economic dispatch solves every day, the problem explained in Appendix A except for:

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

a. The objective function is replaced by the following:

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

where Pof_i is the price bid of plant i for the next 24 hours and $p_{i,t}$ is the production of plant i in hour t.

b. Additional restrictions to the optimization problem are taken into account. These are AGC and transmission constraints.

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

2. Real dispatch

Following the economic dispatch, real time generation proves sometimes different to the planned economic dispatch for many different reasons: demand turns out to be slightly different than estimated demand in the day ahead, energy losses, overloaded lines, etc. Therefore, the system operator is required to fine tune the actual dispatch in real time. Once the real generation of the 24 hours has occurred the system operator calculates the ideal dispatch. The ideal dispatch is an ex post calculation used for settlement purposes.

3. Ideal dispatch

The ideal dispatch is calculated following the next steps:

- Plants price bid is taken as given.
- Plants fuel and configuration are taken as given.
- ISO calculates real maximum plants capacity.
- ISO uses observed demand rather than estimated demand for the previous 24 hours.
- The ideal dispatch solves for every hour t the following optimization problem:

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

$$s.t.$$

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

where Pof_i is the price bid by plant i for the next 24 hours, $p_{i,t}$ is the production of plant i in hour t and D_t is the forecasted demand at time t.

Notice that the ideal dispatch is an hour by hour optimization problem.

4. Spot price and settlement

The ideal dispatch forms the basis for calculating the spot price.[13] In order to define spot price we need to define what it means for a plant to be saturated. A saturated plant is a plant that is generating at a point at which it cannot fulfill incremental demand (a positive or negative variation of one KW[14]). Once the optimization problem of the ideal dispatch is solved for every hour, the equilibrium price is calculated as the price bid by the marginal plant that is not saturated (i.e., last plant needed to meet demand and is not saturated).[15] We denote this equilibrium 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 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.[16]

b) After 2009

[13] More precisely this is a settlement price since technically speaking there is no spot market. Following the normal usage of the term in Colombian electricity sector we will continue calling this a spot price.

[14] Basically a saturated plant is one such that: (1) It is voluntarily being tested. (2) A hydro plant that is operating at its technical minimum (*mínimo operativo*). (3) A thermal plant which is generating at it technical minimum. (4) A thermal plant that is in soak or deshyncronization phase. A thermal plant that is at its generating at its technical maximum *is not* considered a saturated plant.

[15] Formally called *Máximo Precio de Oferta: MPO*

[16] These are called *reconcialiaciones,* positive and negative.

After the regulation of 2009, the spot market and energy dispatch can be summarized in the following way. There are three relevant points in time: the day ahead (economic dispatch), real time dispatch (real dispatch) and the day after (ideal dispatch).

1. Economic dispatch (every day before 8AM):

   a) Generators submit a three part bid: the minimum price at which they are willing to generate the next 24 hours, they declare their maximum generating capacity for every hour of the next 24 hours and their startup shut down costs (startup and shut down costs are fixed for periods of three months).
   b) Plants inform the ISO on what fuel and plants configuration should be used for solving the unit commitment problem.
   c) System operator estimates the following 24 hours total demand for each hour.
   d) Basic technical characteristics of plants are given (ramp model for thermal plants, minimum energy operating restrictions $Q_{i,t}^{-}$ for hydro plants, minimum up-time, minimum down-time, etc. for thermal plants).
   e) Automatic generation control restrictions (AGC) are given.
   f) Transmission restrictions are given.
   g) The economic dispatch solves every day the problem explained in Appendix A except that it adds additional restrictions: AGC and transmissions constraints.

   This optimization problem defines the economic dispatch for every hour. It provides a scheduling plan for generating energy in the next 24 hours.

2. Real dispatch and ideal dispatch

Following the economic dispatch, real time generation determines the real dispatch in the same way as described before. The next day, the ideal dispatch is calculated following the next steps:

- Plants price bid and startup costs are taken as given.
- Fuel and plants configuration are taken as given.
- ISO calculates real maximum plants capacity.
- ISO uses observed demand.
- ISO solves the problem of Appendix A.

3. Spot price and settlement

Once the optimization problem of the ideal dispatch is solved for the 24 hours the equilibrium price, MPO_t is calculated as the price bid of the marginal plant that is not saturated (last plant needed to attend demand and is not saturated).[17] The hourly spot price, P_t is defined as this equilibrium price plus an uplift, ΔI . The uplift is defined in the following way.

Let

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

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

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

be plant i generating cost.

Now let $GI_{i,t}$ be plant i energy production at the time when it is saturated (zero otherwise) and RP_i the positive reconciliation price then the uplift is defined as[18]:

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

where:

$$DI_i = \sum_{t=1}^{24} GI_{i,t} \times (\max\{MPO_t, RP_i\} - MPO_t)$$

The hourly spot price is defined as:

$$P_t = MPO_t + \Delta I$$

[17] Formally called *Máximo Precio de Oferta.*

[18] For the objectives of this study it not relevant to define this price explicitly.

Therefore the spot price guarantees that demand will pay for startups of dispatched plants, and energy production of saturated plants. Having defined the spot prices we now explain 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. (3) Thermal plants for which $C_{N,i} > I_{N,i}$ make no reimbursement.

Having explained the basic functioning of the market we can now state more explicitly the questions addressed in our subsequent analysis.

c) Questions

We address four main issues related to the way the dispatch is currently designed compared to how it was designed before Resolution 051 of 2009. These are: (1) Total welfare or efficiency. (2) Market power. (3) The distribution of welfare gains between producers and consumers. (4) The role of the spot price and its components: the equilibrium price and the uplift. We now briefly discuss the questions concerning the issues above.

Regarding total welfare (or efficiency) defined as the sum of producers and consumers surplus, we ask whether total welfare has increased or decreased relative to what would have happened in the absence of Resolution 051. The two methodological approaches used in this study, the reduced form econometric analysis and the reduced form analysis of simulated counterfactuals relative to which it makes sense to compare the current welfare.

Market power is basically measured using markups: the difference between the spot price and the marginal costs (in case of thermal plants) or the opportunity costs (in case of hydro plants). We compare markups before and after the implementation ofResolution 051 but most importantly we compare actual markups to markups in the counterfactual simulations.

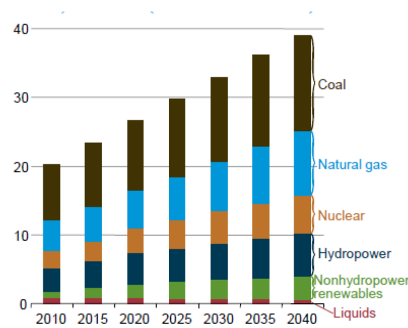
Since total welfare is the sum of producer and consumers surplus it makes sense to decompose the welfare effects of Resolution 051 on producer and consumers surplus. As we'll see total welfare gains may have distributional consequences.

Finally, Resolution 051 is designed to insure thermal plants against losses due to startup costs and compensate for production of saturated plants (nonflexible generation). An important question, however, is whether this mechanism has created perverse incentives for manipulating technical parameters that diminish the benefits of the policy. To address this question we measure the changes in the equilibrium price, how much of the change in the spot price is explained by the uplift, plants voluntary tests, ect.

3. Literature review

a) Introduction

According to the International Energy Outlook 2013, world net electricity generation is expected to increase by 93 percent from 20.2 trillion KWh in 2010 to 39.0 trillion KWh in 2040. Electricity represents an increasing share of the world's total energy demand and is the world's fastest-growing form of energy. World electricity delivered to end users is expected to grow by 2.2 percent per year between 2010 and 2040, as compared with an average growth of 1.4 percent per year for all delivered energy sources. The next figure illustrates the expected electricity composition by energy source.



Source: U.S Energy Information Administration.
http://www.eia.gov/forecasts/ieo/

These developments raise considerable challenges to the energy industry and, in particular, to design of energy markets and efficient mechanisms for the production and pricing of electricity. These challenges have motivated a voluminous literature on unit commitment exploring many dimension of the problem: self vs. centralized unit commitment (Sioshansi, Oren, O'Neill (2010)), objective function (profit maximization vs. cost minimization)(Yan, Stern, Luh, Zhao (2008)) , unit cost functions, technical restrictions (ramps, start-up costs), reserves, reliability constraints and computability issues. This report mainly focuses on the broad characteristics of the dispatch in some relevant markets. Our review summarizes practical experiences around the world and how some of the forefront academic research has made its way in the design of some of these markets, but do not attempt to be an exhaustive one.

We follow two main objectives. First, is to describe the dispatch in the two polar structures of wholesale electricity markets: a decentralized market similar to the current England electricity market and a centralized one such as California electricity market. Second, is to describe the dispatch mechanism of a few countries similar to Colombian electricity market, in terms of complexity, and to some extent composition of energy sources (thermal, hydro, etc.).

b) International Experiences

We describe the most salient features of the US electricity markets focusing on PJM and California and other international markets in Spain, Australia, Ireland and United Kingdom

United States markets

Hellman, et.al (2008) describe the US markets as centralized markets organized into regional transmission organizations (RTOs) and run by independent system operators (ISOs) who are responsible for managing the network and assuring the security of supply. Over 70% of the US demand and about half of the demand in Canada is served through such RTOs while the rest are still served by traditional vertically integrated utilities some of which are members of power pools. In the following we will focus on the RTO/ISO structure which is the most relevant to the Colombian system.

The various ISO markets differ in specific design detail but overall follow common general design principles and tariff that are subject to regulation by the Federal Regulatory Energy Commission (with the exception of ERCOT which is not under FERC jurisdiction). The core design elements of the ISO markets are:

- Financially binding Day Ahead auction market (physical+virtual offers/bids)
- Real-time auction markets for energy balancing.

Bids in the day ahead market consist of three main components: startup cost, no load cost and a multi-segment energy supply function specifying marginal price as function of quantity produced. In addition generation units submit technical parameters such as ramp rate, minimum up time and down time as well as minimum and maximum output levels. The Day Ahead market is cleared for each of the 24 hours in the day ahead using a central security constrained economic dispatch unit commitment optimization algorithm with a DC representation of the transmission network. The quantities and nodal energy prices determined by the unit commitment optimization are financially binding and determine the settlement for the committed energy. However, if the energy revenue for a generator over the committed 24 hour period does not cover its total cost, including startup and no load, then the generator is entitled to bid cost recovery (BCR) in the form of a "make whole" payment for the shortfall. Generators having bilateral agreements with load, who wish to self-dispatch can submit self-scheduling bids specifying quantities along with injection and withdrawal locations which are treated by the optimization as (sell at very low price and buy at very high). Such self-scheduled transactions become price takers in the nodal markets and are not eligible for any "make whole" payments. The day ahead market is open to generators, load serving entities submitting demand bids and to virtual bidders who are financial entities with no generation assets or demand but submit supply or demand bids for the sole purpose of arbitraging between the day ahead prices and real time prices. Often virtual bids are also submitted by generators and load serving entities to hedge their physical positions. Virtual bids must be disclosed as such so that the ISO knows what physical resources are available.

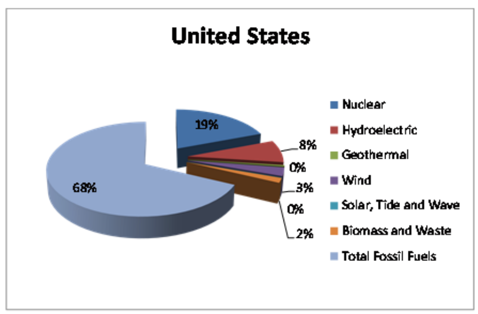
After the close of the day ahead market the ISO runs a reliability unit commitment (RUC) where additional physical resources are committed at minimum load if needed to meet the ISO's load forecast or shortfall in renewables output. A Real Time pre-dispatch market is run every 15 minutes[19] where generation resources and loads can submit bids for deviations from their day ahead commitment and virtual bidder close their open positions from the day ahead market. The real time dispatch is reoptimized every five minutes using the bids from the 15 minutes predispatch with an accurate representation of the AC network and losses, and the real time price is adjusted based on that real time optimization. These prices are used to settle the deviations during the respective five minutes interval from the quantities committed in the day ahead market for that interval, (which are settled at the day ahead price). All the prices are locational (LMP) and can very from bus to bus in the network. The ISO also procures ancillary services, typically regulation and operating reserves, in the day ahead and in the 15 minute market. All (energy and ancillary) markets are typically co-optimized.

Although the ISO markets in the US share these characteristics, they differ in many details (Neuhoff, et.al (2011), pages 15-20). For instance, the California market operates the day-ahead market and calculates prices using an iterative mixed integer optimization model in which linearization of nonlinear AC transmission constraints are generated in each iteration and then a mixed integer linear program commits and dispatches the system. The PJM market instead uses a mixed integer linear-program provided by another vendor. Use of such optimization models rather than Lagrangian relaxation is now the norm in these markets.

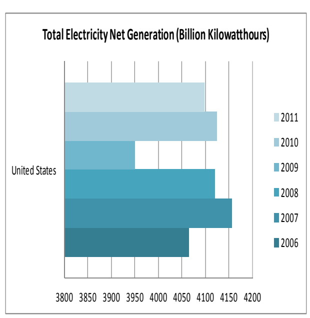
[19] This is a new rule under implementation in compliance with FERC Order 764 which reduces the time interval for the real time auction from hourly to 15 minutes intervals, in order to help renewables participation by improving their forecast accuracy

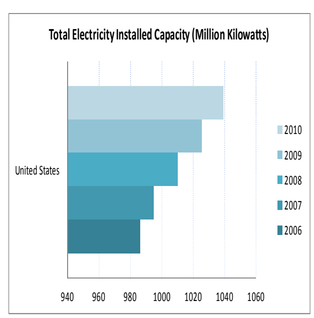
The implementation of locational marginal pricing in the US has proceeded on a regional basis. There are none different ISOs operating RTO in the US and Canada each with its own variant of locational marginal pricing system. Many small but significant differences arise in the different systems, and each ISO often uses in its optimization only approximate representations of its neighboring networks with which it is interconnected through so called "tie lines". Consequently incompatibilities may arise in prices of energy and congestion costs at nearby locations across the boundaries between different ISOs. Such incompatibilities are referred to as 'seams' issues. Barriers to trade across seams have arisen and have proven stubbornly difficult to overcome. As a result, operations within a region have become more efficient, but trade between regions can stagnate or even shrink.

The literature proposes two solutions to this problem. One is integration of regions into a single nodal pricing region with compatible pricing systems and another approach is tighter coordination of nodal pricing in adjacent systems and fuller representation of neighboring networks in the ISOs dispatch and pricing algorithms.



Source: U.S Energy Information Administration, http://www.eia.gov/cfapps/ipdbproject/.





All the ISO markets in the US implement some form of market power mitigation to ensure that the markets are competitive and that no market manipulation takes place. The two prevailing approaches to market mitigation is "conduct and impact" implemented in New England, MISO and NYISO and a structural approach based on "pivotal supplier" screens which is implemented in California, PJM and ERCOT. Both approaches are designed to prevent abuse on market power and when noncompetitive behavior is detected or the potential for such behavior is identified, submitted bids are automatically replaced by “default bid” which are based on cost estimates with a small profit margin.

Energy market Pennsylvania, New Jersey and Maryland (PJM)

PJM is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia. PJM Interconnection coordinates the continuous buying, selling and delivery of wholesale electricity through the Energy Market. Its role as market operator, PJM balances the needs of suppliers, wholesale customers and other market participants and monitors market activities to ensure open, fair and equitable access. PJM has over 700 market participants representing over 58 million people scattered over 211,000 square miles with a peak load of nearly 160 GW. The PJM system has 1365 generation resources with a combined capacity of 180GW.

PJM’s Energy Market operates much like a stock exchange, with the system operator establishing a price for electricity by matching supply and demand.

The market uses locational marginal pricing (LMP) that reflects the value of the energy at the specific location and time it is delivered. If the lowest-priced electricity can reach all locations, prices are the same across the entire grid. When there is transmission congestion, energy cannot flow freely to certain locations. In that case, more-expensive electricity is ordered to meet that demand. As a result, the locational marginal price is higher in those locations.

Locational Marginal Prices (LMP) are the resulting prices associated with a given 5 minute time interval. The LMP values are posted to the PJM external web, eData, and eDataFeed once calculated and are available to participants within 10 minutes of their calculation.

The Energy Market consists of Day-Ahead and Real-Time markets. The Day-Ahead Market is a forward market in which hourly LMPs are calculated for the next operating day based on generation offers, demand bids and scheduled bilateral transactions. The market is cleared using a “mixed integer programming (MIP)” optimization engine that implements security constrained economic dispatch based on the “as bid” cost of energy and reserves. Generation offers consist of startup cost, no load cost and a ten segment supply function. The market clearing optimization handles 1600 generation offers, 20,000 demand bids (fixed or price sensitive) and

60,000 virtual bids at 9500 eligible nodes. The optimization observes constraints on 20,000 transmission lines and 6000 contingencies.

The Real-Time Market is a spot market in which current LMPs are calculated at five-minute intervals based on actual grid operating conditions. Real-time prices are available. PJM settles transactions hourly and issues invoices to market participants monthly.

Additionally, PJM provides a Day-Ahead Scheduling Reserve Market and has a Reliability Pricing Model (RPM) for procuring forward capacity and determining capacity payments. The Day-Ahead Scheduling Reserve Market is a market-based mechanism to procure supplemental, 30-minute reserves on the PJM System. On a day-ahead basis, PJM operators need the ability to schedule sufficient generation so that unanticipated system conditions can be dealt with to preserve reliability during the actual operating day.

PJM currently schedules for this supplemental, 30-minute reserve requirement, Day-Ahead Scheduling Reserve, in both the Day-Ahead Market and the Reliability Analysis. It compensates generators for providing this reserve with day-ahead and balancing operating reserve credits.

The Day-Ahead Scheduling Reserve Market is an offer-based market that will clear existing reserve requirements on a forward basis. The market is designed to create an explicit value for an additional reserve product in the PJM markets on a short-term basis. The market is intended to provide a pricing method and price signals that can encourage generation and demand resources to provide day-ahead scheduling reserves, and to encourage new resources to be deployed that have the capability to provide such reserves.

California

The California wholesale market operates as other commodity exchanges do and is composed of interrelated processes. The market is operated by the California Independent System Operator (CAISO) which is a state governed nonprofit entity that is subject to FERC regulation. The California Market consist of 60,703 MW of power plant capacity (net dependable capacity) and 26,024 circuit-miles of transmission lines, serving a population of 30 million people with 50,270 MW record peak demand (July 24, 2006) and 246 million megawatt-hours of electricity delivered annually. 27,589 market transactions are cleared every day.

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The energy markets (day-ahead, 15 minutes-ahead and real-time) use a full network model that models transmission losses and reactive power load and produces prices at every point in the system. The day-ahead market determines hourly market-clearing prices and unit commitments, analyzes unit must-run needs and mitigates bids if necessary, which produces the least cost energy while meeting reliability needs. The market opens seven days prior to the trade date and closes the day before the trade date. Results are published at 1:00 p.m. The three day-ahead processes are: market power mitigation determination, integrated forward market and residual unit commitment. If any bids fail the market power test, they are mitigated, and the system determines the minimal and most efficient schedule of generation to address local reliability. The integrated forward market (IFM) simultaneously analyzes the energy and ancillary services market to determine the transmission capacity needed (congestion management) and confirm the reserves required to balance supply and demand based on supply and demand bids. It ensures generation plus imports equals load plus exports plus transmission losses and that all final schedules are feasible with respect to the constraints enforced in the full network model as well as 100 percent of the ancillary services requirement. Like at PJM, offers by generators consist of start-up cost no load cost and a multi segment supply function while demand submits either fixed demand or price sensitive demand bids. In additional virtual bidders can submit supply and demand bids. the market clearing in the day ahead market is based on a mixed integer optimization engine (MIP) that implement security constrained unit commitment (SCUC) based on the "as bid" costs and determines financially binding commitments and prices at each location in the network for the next 24 hours. Like in other ISO markets, when forecasted load is not met in the integrated forward market, the residual unit commitment (RUC) process enables the ISO to procure additional capacity by identifying the least cost resources available.

The use of the MIP methodology with its advanced features allows CAISO to deal effectively with a number of market design elements including the co-optimization of Energy and Ancillary Services, a large number of transmission and other security constraints, dynamic Ramp Rates, Forbidden Operating Regions.

The real-time market is a spot market to procure energy (including reserves) and manage congestion in the real-time after all the other processes have run. This market is reoptimized every five minutes to dispatch energy for balancing instantaneous demand, reduces supply if demand falls, offer ancillary services as needed and in extreme conditions, curtails demand.

Day-ahead schedules form the foundation of energy used in real-time along with day-ahead bids and newly submitted real-time bids. The market subjects bids to mitigation tests and the hour-ahead scheduling process, which produces schedules for energy and ancillary services based on submitted bids. It produces ancillary services awards, and final and financially binding intertie schedules.

The real-time unit commitment designates fast- and short-start units in 15-minute intervals and looks ahead 15 minutes. Short-term unit commitment designates short- and medium- start units every hour and looks ahead three hours beyond the trading hour every 15 minutes. In real-time, the economic dispatch process dispatches imbalance energy, or the energy that deviates from the schedule, and energy from ancillary services. It runs automatically and issues dispatches every 5 minutes for a single 5-minute interval. Under certain contingency conditions, the ISO can dispatch for a single 10-minute interval.

The ISO also offers services including mechanisms for entities to obtain and trade congestion revenue rights and engage in virtual bidding activities. All products and services are developed and implemented in full collaboration with stakeholders.

Scheduling coordinators can offer energy into the market from generating units, system units associated with metered subsystems, physical scheduling plants (group of tightly coupled units), participating loads and system resources located outside the ISO balancing area.

As mentioned above, CAISO uses SCUC to run the processes associated with the commitment of Generating Units in DAM and the 15-minute ahead and RTM. SCUC uses a multi-interval Time Horizon to commit and schedule resources and to meet the CAISO Forecast of CAISO Demand in the Market Power Mitigation – Reliability Requirement Determination (MPM-RRD), Residual Unit Commitment (RUC), Short-Term Unit Commitment (STUC) and RTUC, and the bid-in Demand in Integrated Forward Market (IFM).

In the Day-Ahead MPM-RRD, the IFM and RUC processes utilize SCUC which optimizes over the 24 hourly intervals of the next Trading Day. In RTUC, which runs every 15 minutes, SCUC optimizes over 4, 5, 7 and 18 15-minute intervals that span a portion of the current Trading Hour and one to four subsequent Trading Hours.

The Day-Ahead Market Clearing problem includes next-day Generation and Demand

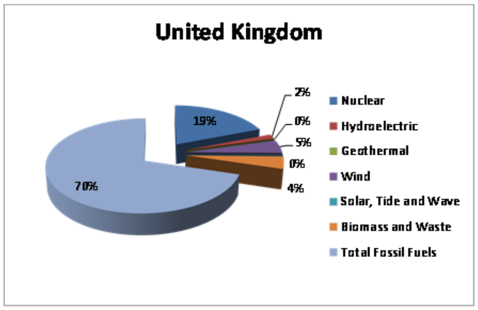
Bids. The objective of the problem is to minimize Energy and Ancillary Services (AS) procurement costs subject to all submitted Energy and Ancillary Services submitted supply bids and transmission constraints. A similar formulation is used to solve the Real-Time Market Clearing problem as well as the Residual Unit Commitment problem. In all cases, SCUC accepts operational data and Bids from resources and power system operating requirements (e.g., Demand forecast, reserve requirements, security constraints, etc.).

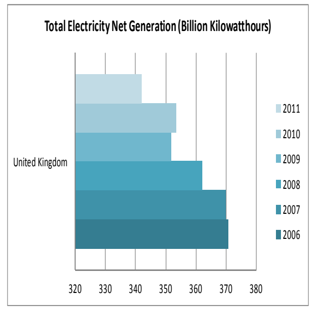
In Real-Time, unit commitment is limited to medium- and fast-start units and the dispatch is initialized from the State Estimator solution or telemetry. The SCUC commits and dispatches resources based on minimum cost as reflected by Bid prices, subject to network constraints.

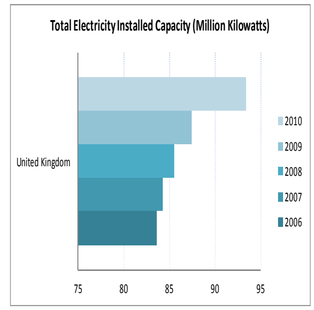
The SCUC adjusts generation, load, import and export schedules and clears Energy Supply and Demand Bids, and AS bids to meet AS requirements, while managing congestion by enforcing linearized transmission constraints, and generating unit inter-temporal constraints. The linearized transmission constraints are identified using AC-based power flow and contingency analysis algorithms based on a Full Network Model (FNM). The FNM includes all CAISO Balancing Authority Area transmission network buses and transmission constraints, and possibly a reduced network representation of the rest of the WECC system. Additionally the SCUC calculates Locational Marginal Prices (LMPs) for Energy, network constraint Shadow Prices and Ancillary Services Marginal Prices (ASMPs) consistent with the AC-based power flow model.

United Kingdom

UK electricity markets have passed by many phases, which can be referred to as public monopoly (until 1990), power pool (1990-2001), New Electricity Trade Arragements - NETA (after 2001) and the Electricity Market Reform, which is currently under final phases of discussion. The next figure shows generating resource composition.







UK's main utility, the Central Electricity Generating Board (CEGB) was privatized in 1990, initiating a series of market-oriented reforms under the orientation of Prime Minister Margaret Thatcher. At the time, CEGB owned all generation and transmission in UK, but in Scotland. CEGB and National Grid were divided in four companies: Nuclear Electric (a public company holding all the nuclear plants), National Power, PowerGen and National Grid Company (NGC).

The privatization was accompanied by the creation of the electricity power pool. This consisted of a centralized day-ahead market that determined the merit order and the wholesale electricity price through the last-price. Additional capacity payments proportional to the loss of load probability (LOLP) were calculated using a negative exponential function of the reserve margin. Also, if transmission constraints prevented a generator its bids from being accepted, this generator would be compensated. The generators submitted bids for 48 half-hourly periods, and could specify ramp and load constraints for each plant. The system marginal price (SMP) was the bid of the most expensive generation set accepted to meet forecasted demand, ignoring transmission constraints. The pool purchase price (PPP) was the sum of the SMP and the capacity payments and paid to the generators if they were dispatched. A generator would receive only the capacity payment for being available, but not dispatched. Buyers in the market paid the pool-selling price, which incorporated to the PPP the uplift. The firms in the market had the software used to determine the allocation of the market, and could manipulate their various parameters and bids to maximize their profits.

Although Newbery and Pollitt (1997) concluded that privatization lead to improvements in efficiency, some allegations of market manipulation were reported. A possible way to manipulate the market would be to declare a plant unavailable and then re-declaring available on the day to collect the capacity payment whose value was calculated using the administrative formula mentioned above. The Office of Electricity Regulation (Offer), the regulatory body for electricity in UK, realized a Pool

Review in 1998 and concluded that the complexities of price formation in the pool allowed market power by participants and recommended a reform.

NETA was implemented in March 2001. The main difference between NETA and the power pool is that under the pool, all generation is centrally dispatched, while under NETA, the plant is self-dispatched.[20] While the pool operated as a uniform price auction, NETA relied on bilateral markets and a Balancing Mechanism (BM). The market participants determine the main part (97%) of all power traded. The BM is run as a discriminatory (pay-your-bid) auction for the residual (about 3%) of the energy not negotiated in bilateral markets.

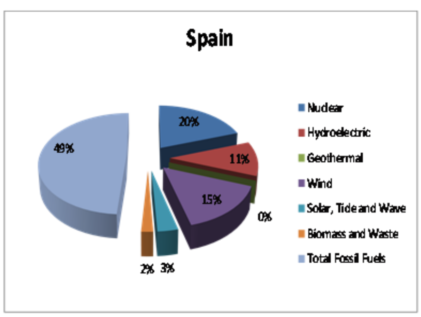
Recently UK's Department of Energy and Climate Change, worried about UK's aggressive commitment to clean energy, decided to propose yet another market transformation. The Electricity Market Reform that is currently in discussion, waiting final deliberation by the parliament, can be summarized, in broad terms, in four main vectors:

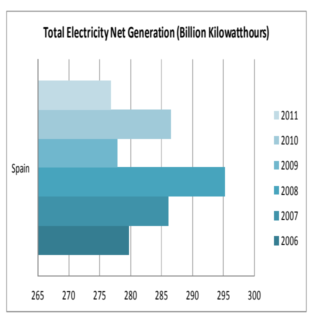
i) Contracts for Difference (CfD)
   — FIT with Contracts for Difference for new low-carbon generation (average pricing)
   — Long-term contracts between generators and government
   — First contracts in 2014 with administratively-set prices
   — Auctions for CfD strike price in 2017
ii) Capacity markets
   — Capacity auctions to be held 4 years in advance to ensure generation adequacy (quantity-based instrument)
   — Resulting capacity payment will be paid by suppliers to generators
   — First auction in 2014
iii) Carbon price floor
   — Tax on fossil fuels based on their average carbon content
   — Provides greater certainty and support to the EU ETS carbon price
   — £15.70/ton in 2013, £30/ton in 2020 up to £70/ton in 2030
iv) Emissions Performance Standards
   — Discourages construction of new unabated coal-fired power stations through an annual limit of CO_2 emissions
   — Limit set at 450gCO_2/kWh

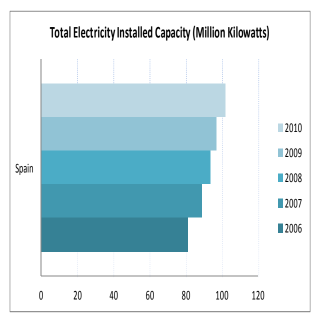
[20] Therefore, UK followed a path in the opposite direction made by Colombia.

Spain[21]

The Spanish electricity market produces between 15MWh and 45MWh hourly. Next figure shows resource composition. Like other electricity markets it can be described as a pool with complex bids and unique procedure that guarantees that dispatched plants can recover their startup costs but, strictly speaking, there are no side payments. Agents in this market must take three decisions: sign financial contracts (private information), bilateral contracts (reported to ISO) and production decisions. In the day ahead market, plants submit complex bids, step functions for every hour (on average 25 steps per unit), representing the willingness to produce at each hour and a 24 hour bid representing a minimum revenues requirement for the day consisting of a variable and a fixed cost. The market operator then runs a 24 hour optimal dispatch optimization problem. For every hour plants are organized based on the offer curves and market operator determines the equilibrium price based on the bid of the most expensive dispatched plant. Then, they evaluate if energy income compensates dispatched plant for startup (fixed and variable) costs. If this is not the case then the plant with the largest deficit is removed from the optimization problem and the optimal dispatched is calculated again. The process (with the same bids) ends once all dispatched plants do not incur in operating loses. This algorithm is not guaranteed to yield and optimal solution, not even to yield a solution. These raise additional problems and we do not discuss in this document.







Australia

Before 1994 the Australian electricity industry consisted on vertically integrated monopolies. Years later, the integrated enterprises were separated and the prevalent monopolies began to be regulated. By year 1993, the first attempts were made for

[21] Reguant (2013).

creating an electricity market The actual NEM operates on the longest interconnected power system that comprises six (6) of the eight (8) states in which is divided Australia. Northern Territory and Western Australia are the only two states that do not receive energy from the interconnection, while the others Queensland, South Australia, New South Wales, Victoria and Tasmania are part of the network. This last state, Tasmania, joined in 2005 with approximately 290 km of submarine power cable through the Basslink HVDC interconnection.

Australian electricity demand on a typical business day (with average temperatures) is about 25 GW. The system is characterized by few hours of peak demand that usually occurs between 7:00 am and 9:00 am and between 4:00 pm and 7:00 pm. The peak moments are not so critical as they occur in each state at different moments, so the supply of each one equilibrates the loads every moment. As the peak moments are not so common, it makes no sense to have a supply excess that is going to be used infrequently. They preferred to assign some responsibilities to a few generators when there are presence of peak demands; furthermore they have encouraged demand side participation, where the consumers decide whether they want to disconnect from the network.

The Australian electricity system is basically a coal-based one as it can be seen from figure below. The generation by black and brown coal (principally from Victoria and South Australia) represents the 80% of total generation. Generation by natural gas represents the 12% and is used basically for the peak demand hours. The 5% of hydro generation is contributed by the Tasmania state where the green activism plays an important role.

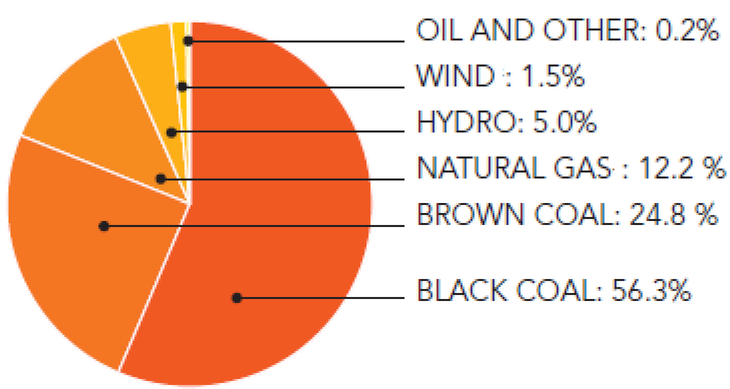


Figure: Generation by Fuel Type.

When the National Electricity Market began operations, it had two entities responsible for its correct development. The National Electricity Code Administrator (NECA), which had to deal with the market rules, and the National Electricity Market Management Company (NEMMCO), which was responsible for the market scheduling and planning matters. From 1 July 2009 NEMMCO ceased operations and its roles and responsibilities were transitioned to the Australian Energy Market Operator (AEMO) which is the actual market operator, not only for electricity but also for the Australian gas market. The market operator functions are prescribed in the National Electricity Law and Rules.

The market is operated as a spot market where supply and demand are matched through a centrally-coordinated dispatch. The formation of the price consists on:

- The generators offer quantities of energy at some specific price every five (5) minutes during the day. AEMO takes these bids and determines the dispatch price, for every five (5) minutes, and also which generators are going to produce.
- A spot price is calculated, for each Australian state, every half hour as the average of the last six dispatch prices. This spot price is the reference that the market operator uses to calculate all the energy transactions.
- In The Rules, a maximum spot price of 12.500 [$/MWh] is set. This figure is called a Market Price Cap and is also used by the AEMO when load shedding is needed to maintain the normal operation of the system. That is, the AEMO considers the system state and assigns the maximum spot price in the nodes and to the generators that are needed to interrupt the service.
- A market floor price is also stated in The Rules as -1.000 [$/MWh]. These limits are updated, if needed, every two years.

Having these, the NEM consists of 288 dispatch intervals and 48 trading intervals (related to the spot price) every day. The generators have to specify the energy they can provide and the price for it. In the NEM there are three (3) types of bids:

- Daily Bids: Have to be submitted before 12:30 pm on the day before to the operation. These bids can be seen in the pre-dispatch forecasts.
- Re-bids: Due to any problems with the generation units or similar causes, the generators can make re-bids up until five (5) minutes before the dispatch. They can change only the volume offered initially, the price must remain unchanged.
- Default-bids: These are the permanent bids that the generators provide; they apply only when no daily bids are made. These bids are confidential because they can reflect the operating base of the generator.

Once the bids are observed by AEMO, it calculates and assigns the generators needed for each period of time. This is done by ordering the bids in an increasing price in order to dispatch the less expensive ones.

AEMO tries to ensure that each NEM participants receive the adequate bills for the electricity consumed and the correct payments for the electricity produced. In order to accomplish these, it calculates the financial liability of each participant day by day and consolidates the transactions collecting the money that has to be paid. This financial settlement operates monthly in arrears and in order to ensure that the consumers are able to pay their dues, AEMO asks for deposit of bank guarantees and security deposits with a credit limit.

If at any moment the limits are violated, AEMO has all the authority to suspend the participant after the required notifications. The participant won't be reinstated unless its required financial position is re-established.

It is important to note that this Australian market is a self-commitment one in which The Rules do not consider startup costs. It is simply organized as a settlement market, where the operator settles all the trades and only cares about the availability of the participants to pay for the dues.

Ireland[22]

The Single Electricity Market (SEM) Program was established to focus on the delivery of a single wholesale electricity market for the island, which in turn has led to the formation of the All-Island Market for Electricity (AIME). SEM started the 1st of November 2007 as a day ahead, dual currency market.

All trade of physical electricity is conducted through the SEM pool and the opportunities for bilateral trading of physical power outside this pool are limited to small scale AER (Alternative Energy Requirement). Compulsory participation is limited to a 10MW minimum threshold; generators below this threshold can choose whether to participate in the pool or be treated as negative demand.

The 'Price Maker' Generators wishing to sell their electricity through the pool are required to submit their Commercial and Technical (dynamic characteristics and availability forecasts) Offer Data to the Market Operator by 10:00 hrs on the day before the relevant trading day (D-1). Under the bidding code of practice generators must bid their short-run marginal cost, (SRMC), including the full opportunity cost of

[22] Conlon (2009)

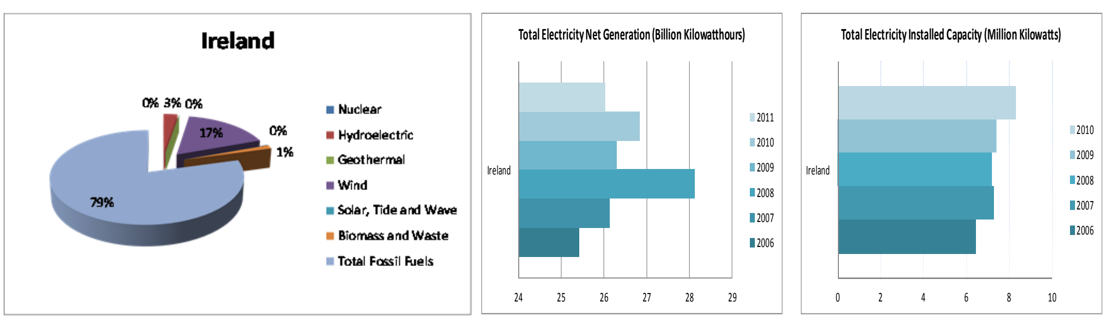
carbon, into the pool (this represents the market shadow price) as well as an uplift element representing start-up and no load costs. Uplifts pays for start up costs, energy produced by saturated plants, no load costs, and so on. It should be emphasized that one of the objectives stated in The Trading and Settlement Code, is to always try to minimize the revenues paid by the concept of Uplifts.

Based on the offer data submitted, the System Marginal Price (SMP) is determined as the SRMC of the marginal generating unit, a single price for each half hour, plus uplift.

As an isolated system, relying heavily on imported fossil fuels, the SMP is particularly susceptible to changes in international fuel prices. The majority of dispatchable generation capacity within the SEM is gas-fired plant, therefore one would expect a significant correlation between SMP and gas price.

The major focus of the market power mitigation strategy has been the imposition of Directed Contracts on all generators with what is considered a significant level of market power, the imposition of a license condition on generators to adhere to a bidding code of practice and the establishment of a Market Monitoring Unit to monitor participants' bidding behavior. The directed contracts mandate that generators with significant market share must enter into forward contracts with suppliers for a specified volume at a price based on a pre-determined formula.

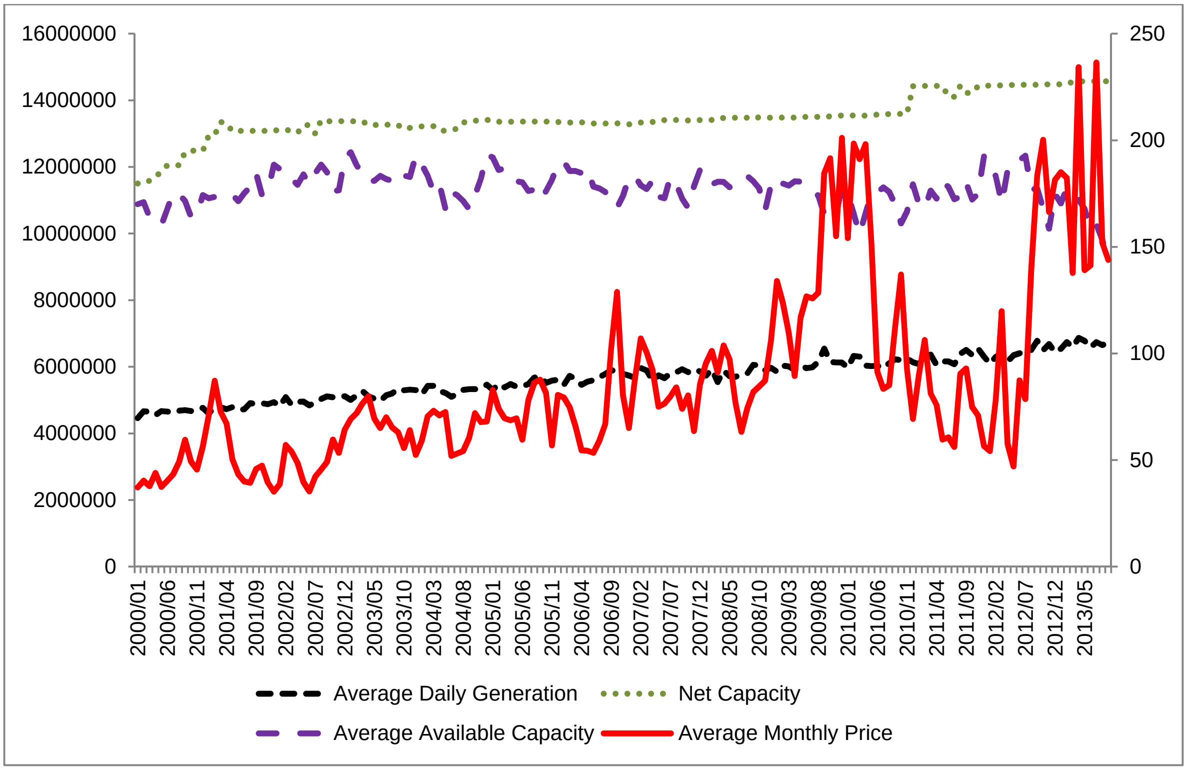
To date ESB Power Generation and NIE Public Procurement Board (a subsidiary of the Viridian Group) have been mandated to enter into directed contracts. Participants may also enter into Non Directed Contracts. The contracts for difference are used as a means to hedging price exposure in the pool. Both sets of contracts are let quarterly via an auctioning process.



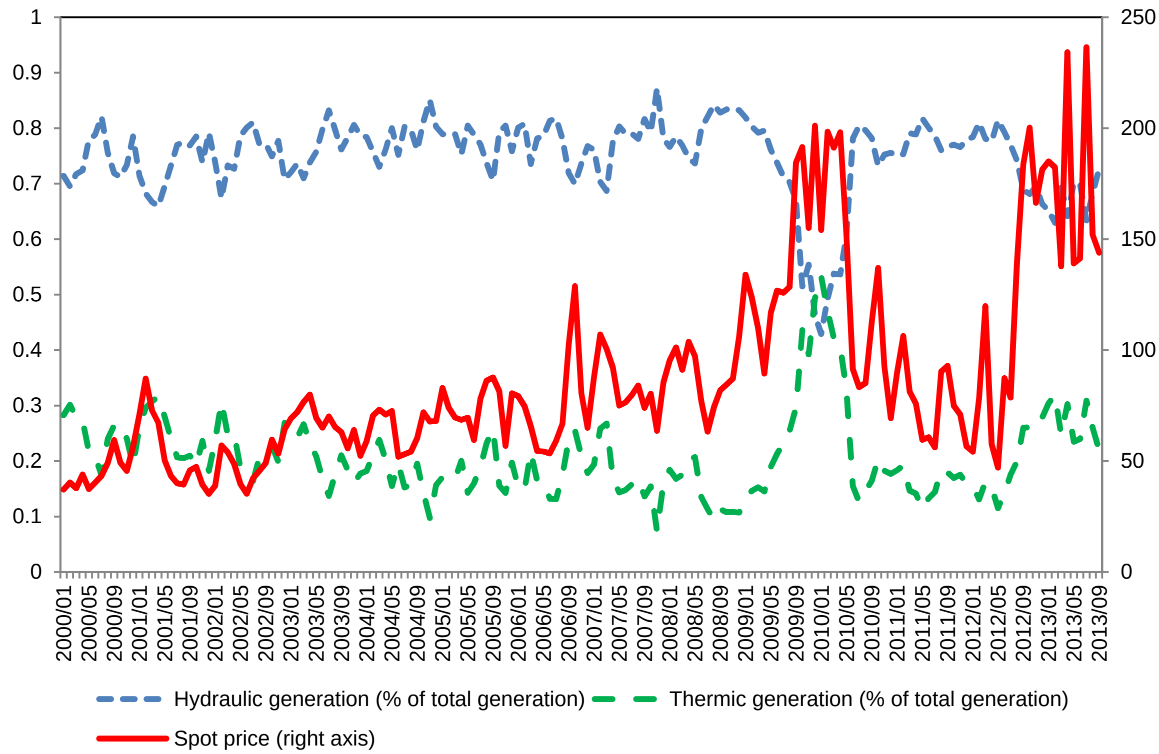
Fuente: U.S Energy Informtion Administration, http://www.eia.gov/cfapps/ipdbproject/. Graphs by the author

4. Data and basic descriptive statistics

The next figure shows net capacity (measured in KW left axis), average available capacity (measured in KW left axis), average daily generation (measured in KWh left axis) and monthly average spot price (measure in KWh right axis). The graph suggests that there isn't a capacity problem in Colombian electricity sector.



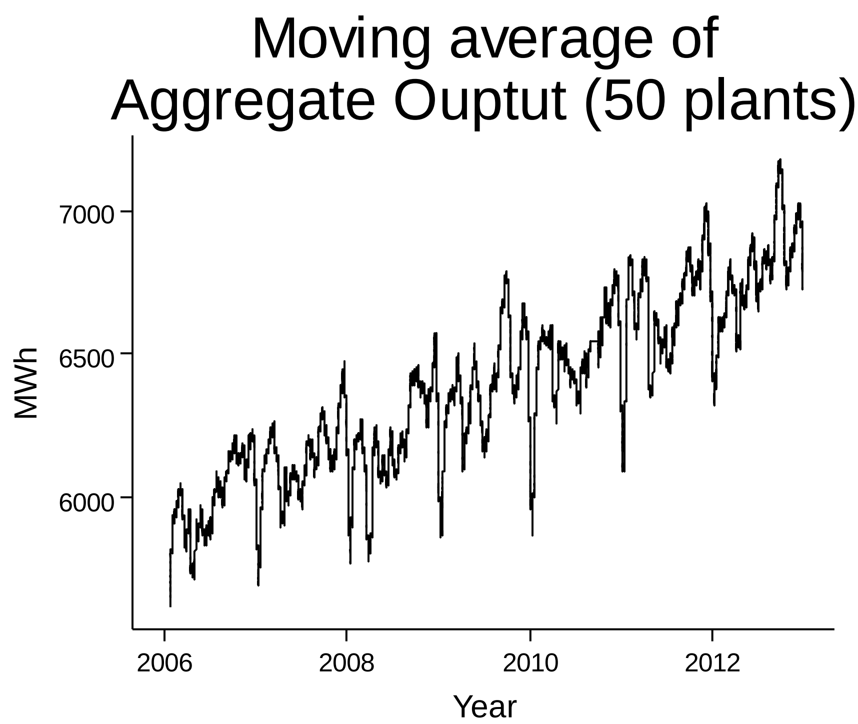
Next graph shows the composition between hydro and thermal generation

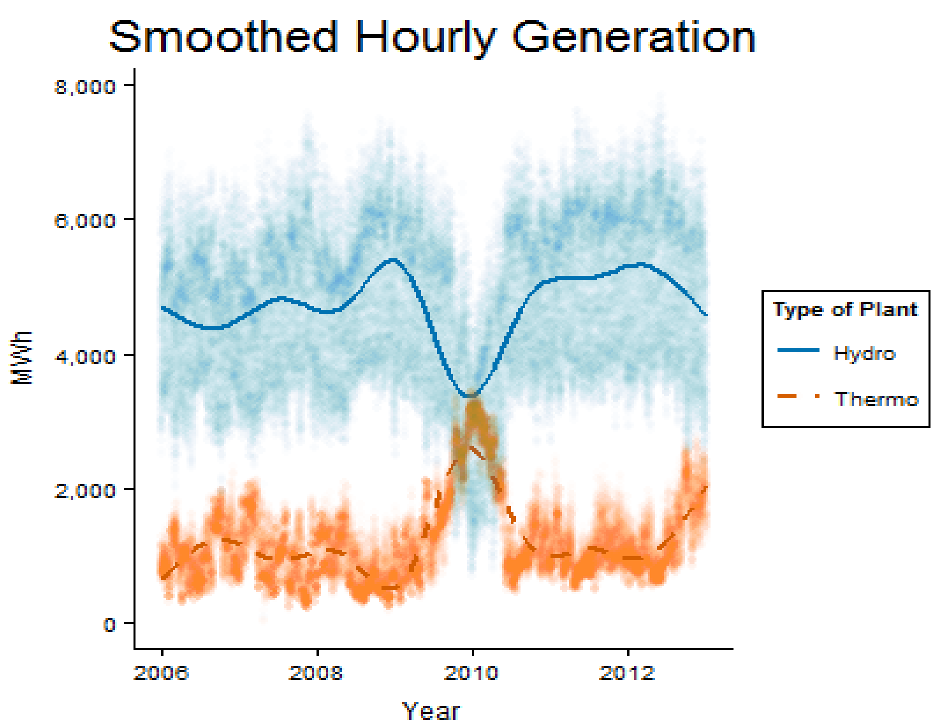


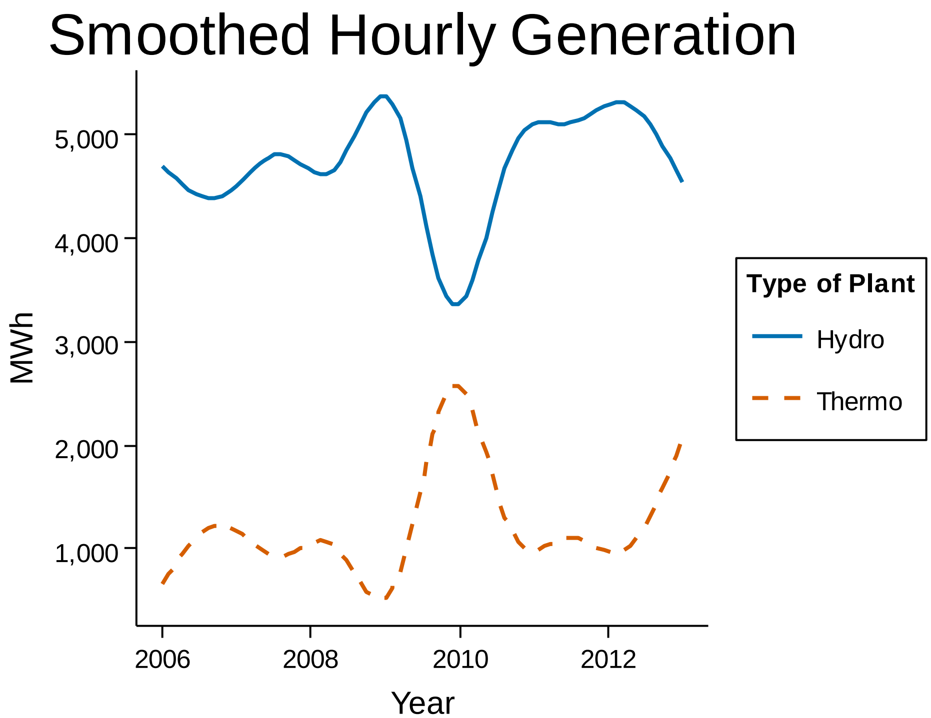
We consider a panel of 50 plants (see Appendix for the list of al plants considered) since January 1, 2006 to December 31, 2012.

a) Output

In our first econometric model, the output decision model, our dependent variable is output per plant. Next figure shows aggregate output of all plants considered for the complete period. The figure illustrates a moving average of 500 hours.


Moving average of
Aggregate Ouptut (50 plants)
7000
6500
6000
MWh
2006
2008
2010
2012
Year

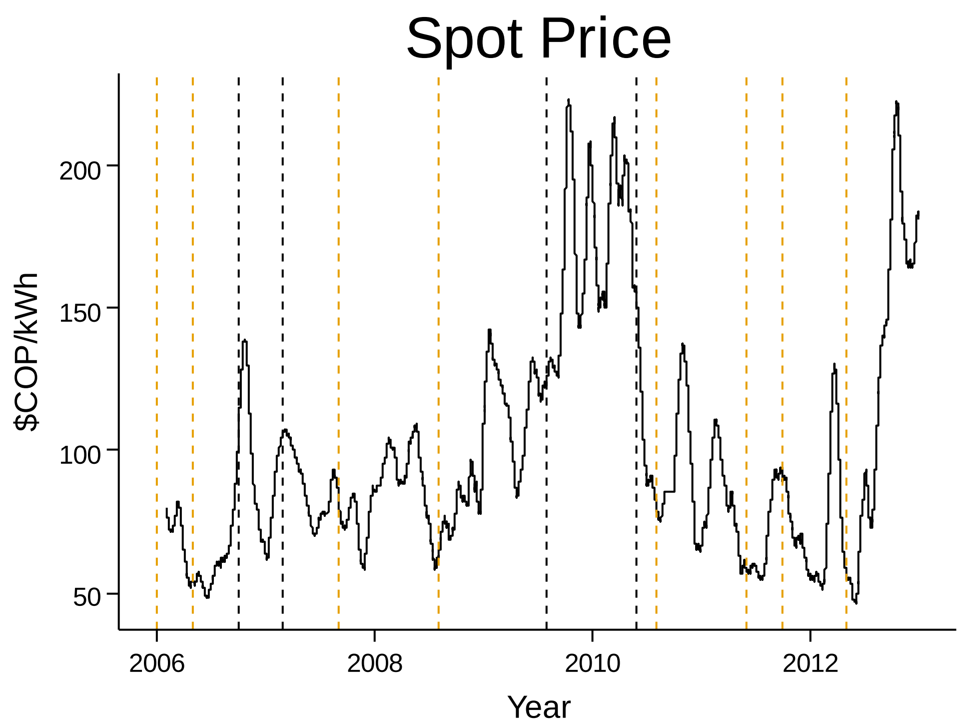

Smoothed Hourly Generation
8,000
6,000
4,000
2,000
0
MWh
2006
2008
2010
2012
Year
Type of Plant
Hydro
Thermo



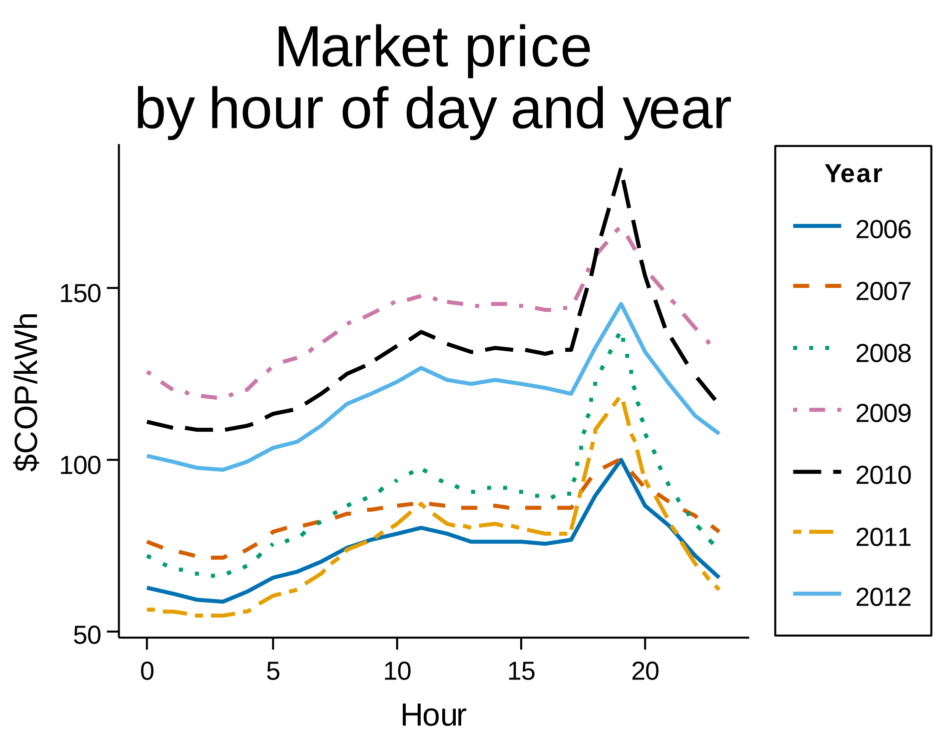
b) Prices

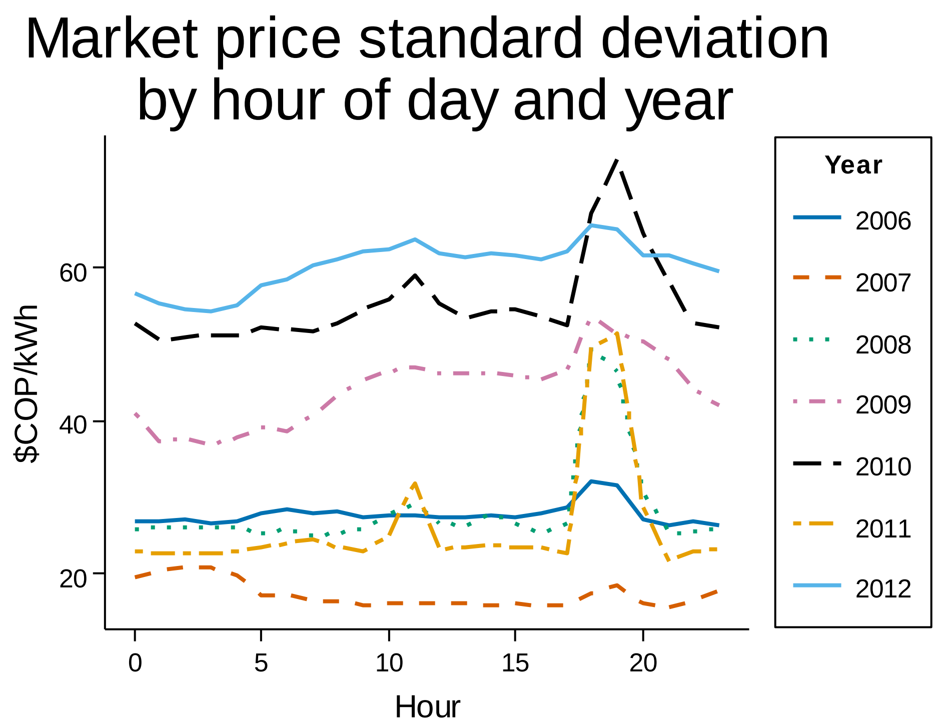
The dependent variables of our econometric model are different transformations of markups. Markups are defined as the observed spot price minus the marginal or opportunity cost of the plant depending on whether it is a thermal or a hydro plant. We first describe graphically the dynamics of the spot price. The next section describes graphically the marginal, opportunity costs and markups (the Appendix explains the methodology for constructing marginal prices and opportunity costs).[23] The next figure shows the moving average (720 hours) of the spot price. Black vertical dotted bands represent El Niño phenomena. Brown vertical dotted lines represent La Nina phenomena.

[23] Price figures and markups are moving averages of 720 hours.

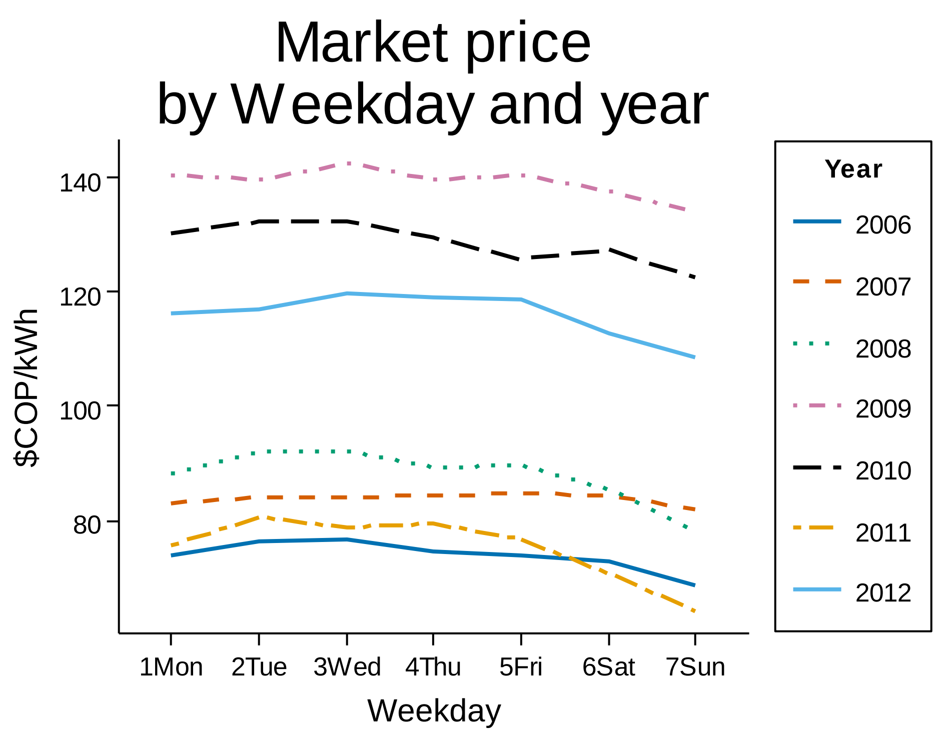


The next two figures show that the spot price has consistently gone up at every hour since 2009. Moreover, its volatility has also gone up substantially.

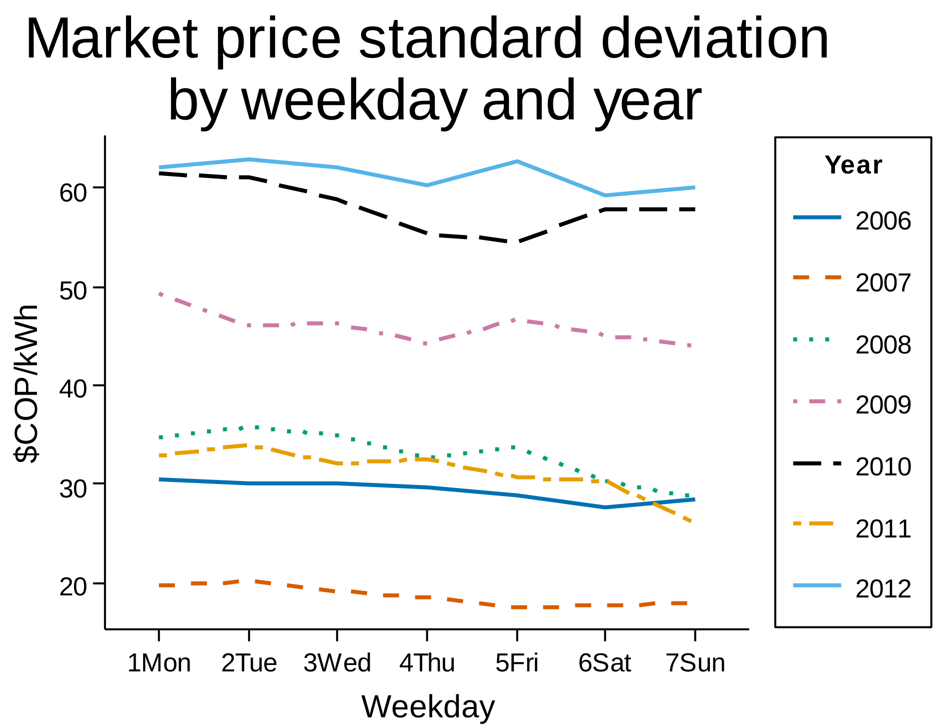


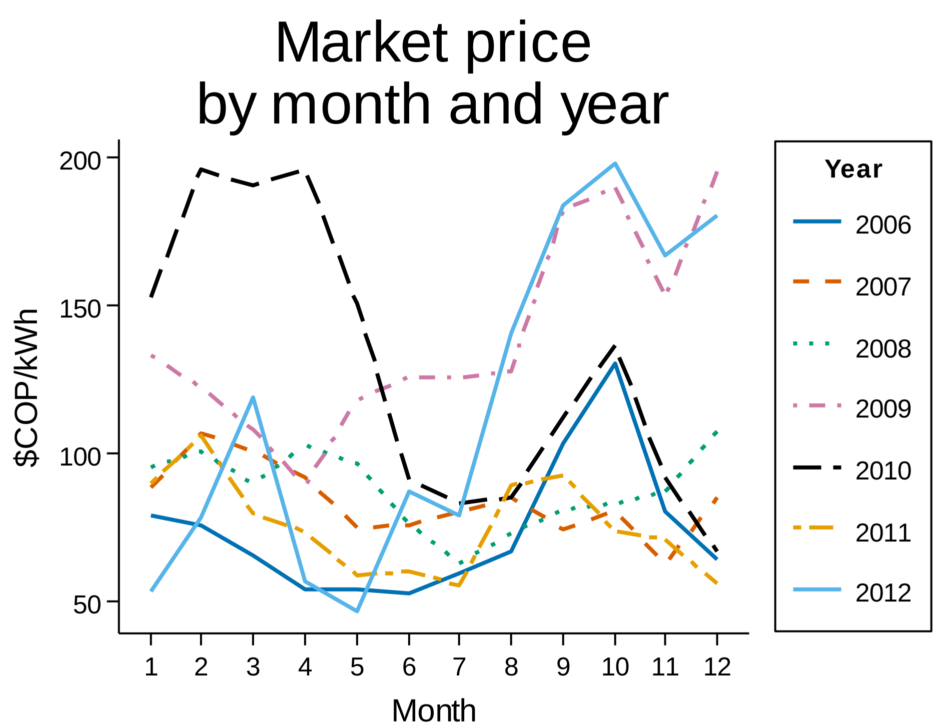


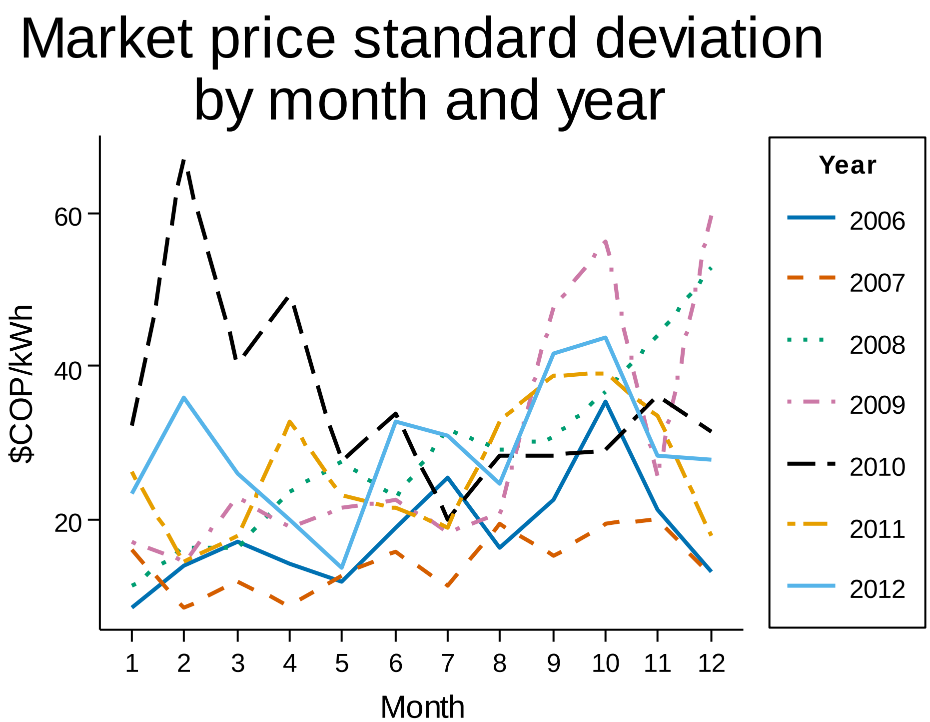
Market price standard deviation
by hour of day and year
$COP/kWh
20
40
60
0
5
10
15
20
Hour
Year
2006
2007
2008
2009
2010
2011
2012



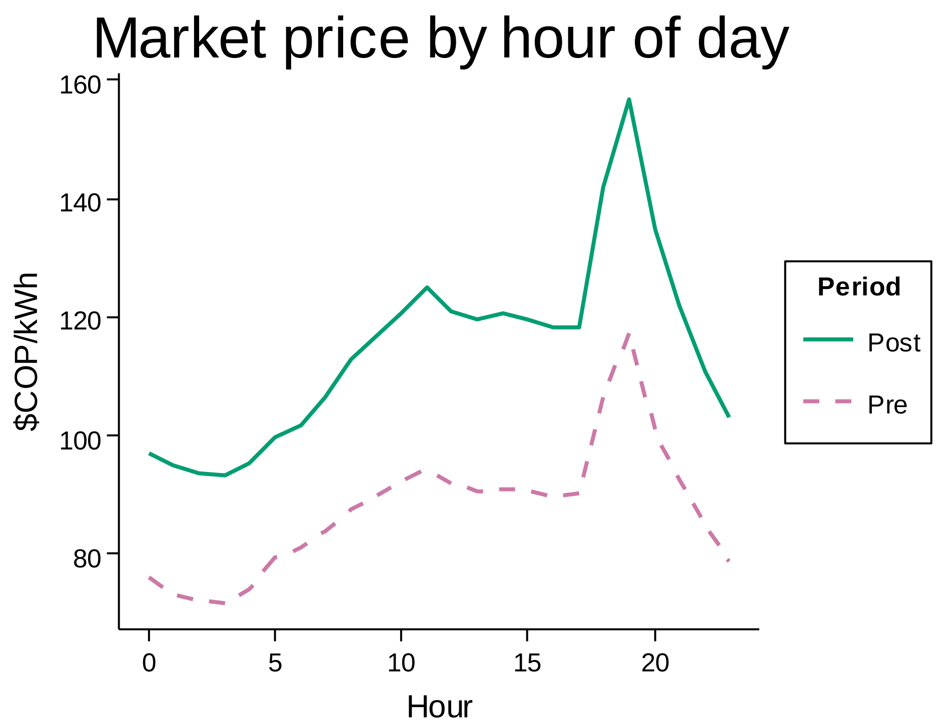
Market price
by Weekday and year
$COP/kWh
80
100
120
140
1Mon
2Tue
3Wed
4Thu
5Fri
6Sat
7Sun
Weekday
Year
2006
2007
2008
2009
2010
2011
2012

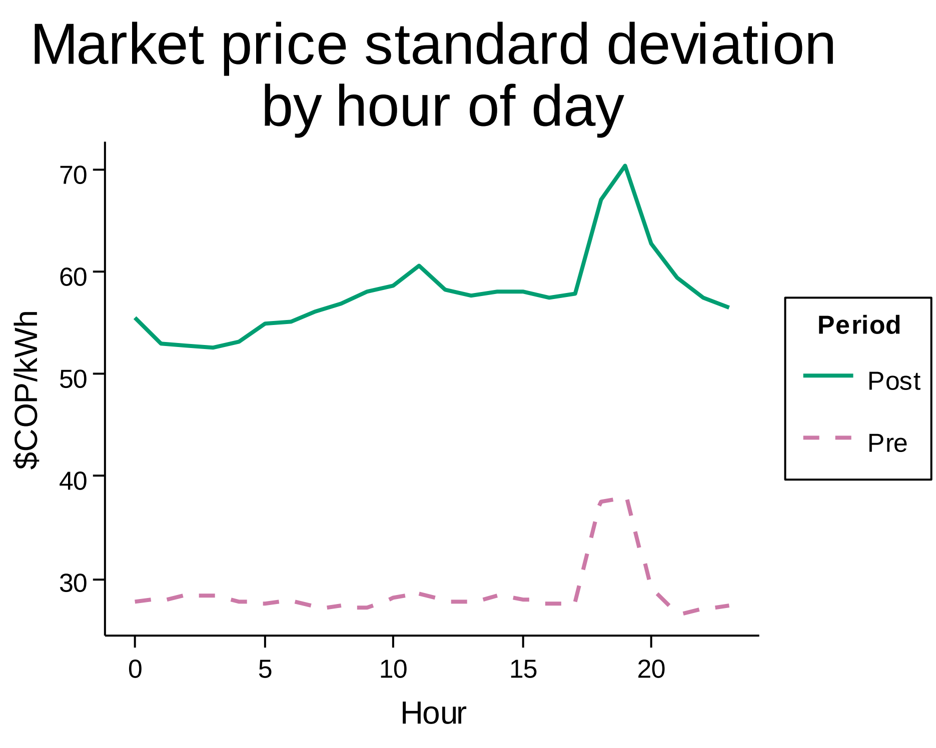

Market price standard deviation
by weekday and year
$COP/kWh
60
50
40
30
20
1Mon
2Tue
3Wed
4Thu
5Fri
6Sat
7Sun
Weekday
Year
2006
2007
2008
2009
2010
2011
2012

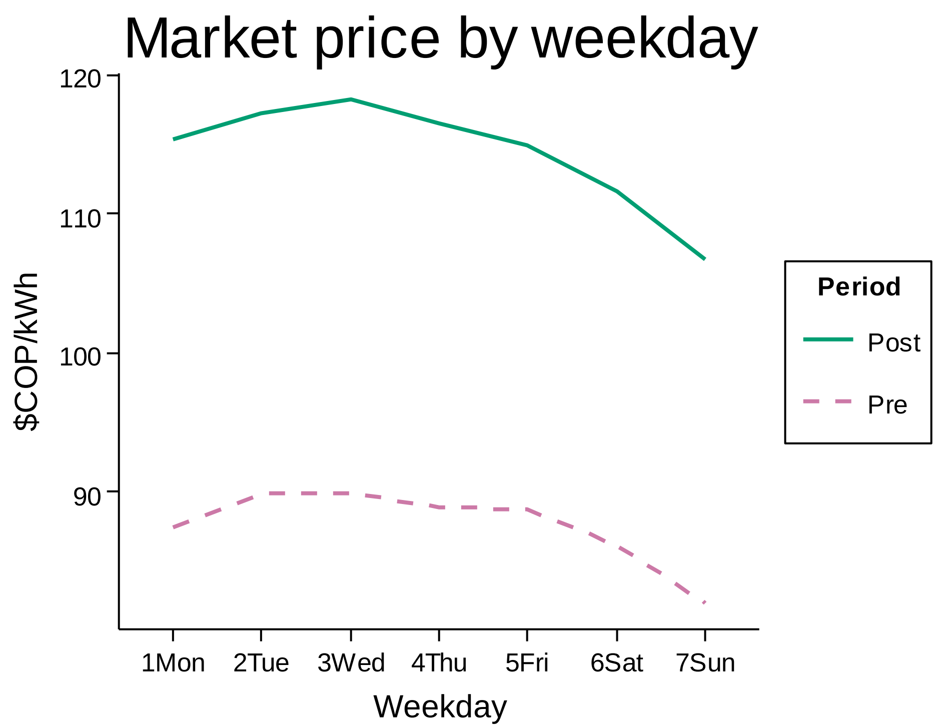

Market price
by month and year
$COP/kWh
200
150
100
50
1
2
3
4
5
6
7
8
9
10
11
12
Month
Year
2006
2007
2008
2009
2010
2011
2012

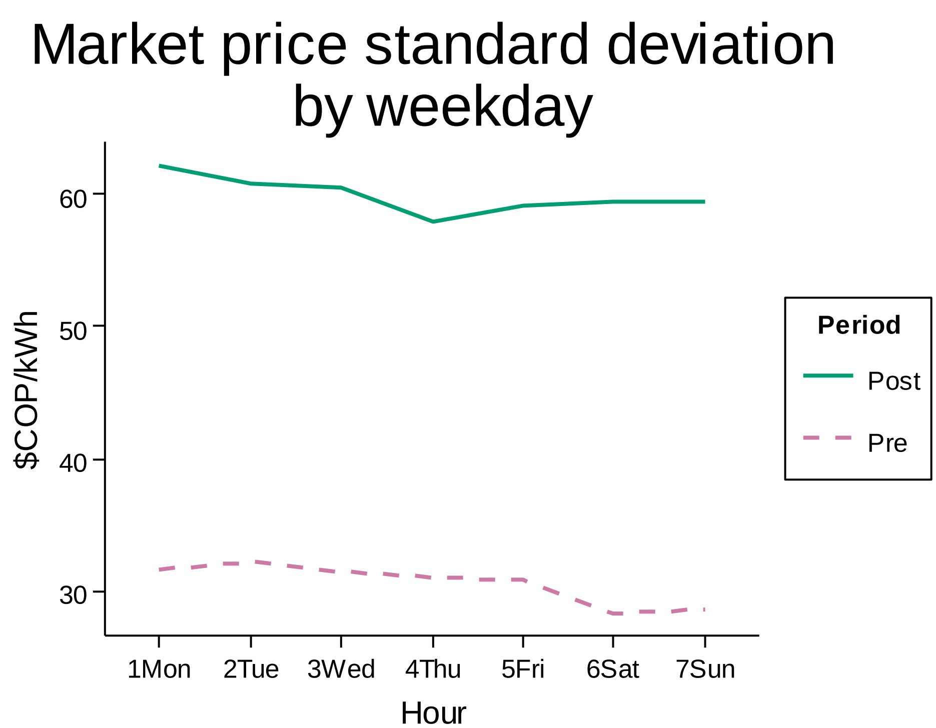


The next four figures display simple averages of spot prices for the period before 2009 (Pre) and after 2009 (Post). In all cases the results suggest that the market price has gone up after 2009 at every hour and the volatility has increased substantially.

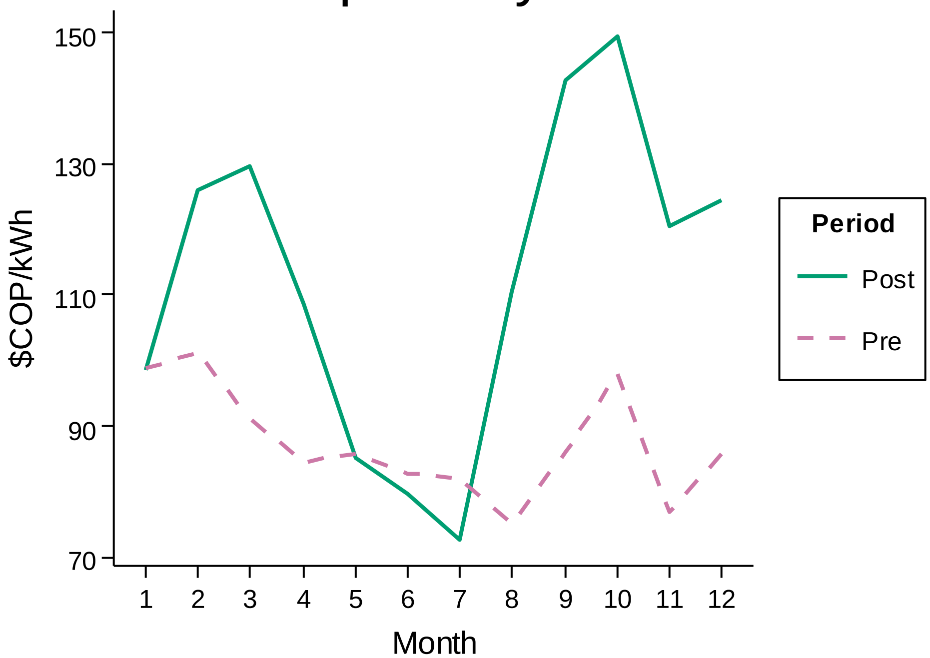

Market price by hour of day
160
140
120
100
80
$COP/kWh
0
5
10
15
20
Hour
Period
Post
Pre


Market price standard deviation
by hour of day
70
60
50
40
30
$COP/kWh
0
5
10
15
20
Hour
Period
Post
Pre

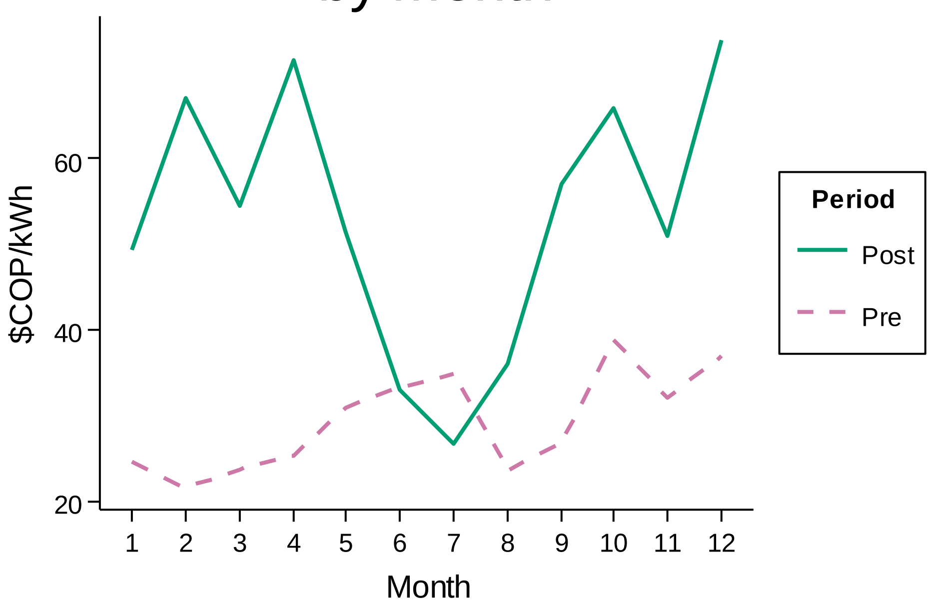

Market price by weekday
120
110
100
90
$COP/kWh
1Mon
2Tue
3Wed
4Thu
5Fri
6Sat
7Sun
Weekday
Period
Post
Pre

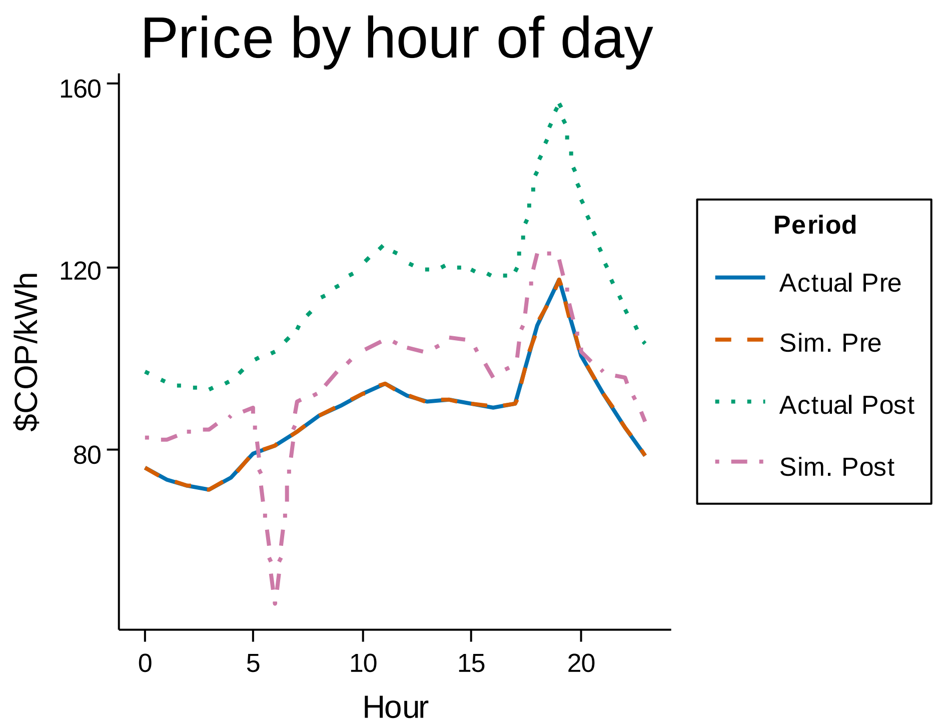

Market price standard deviation by weekday
60
50
40
30
$COP/kWh
1Mon
2Tue
3Wed
4Thu
5Fri
6Sat
7Sun
Hour
Period
Post
Pre

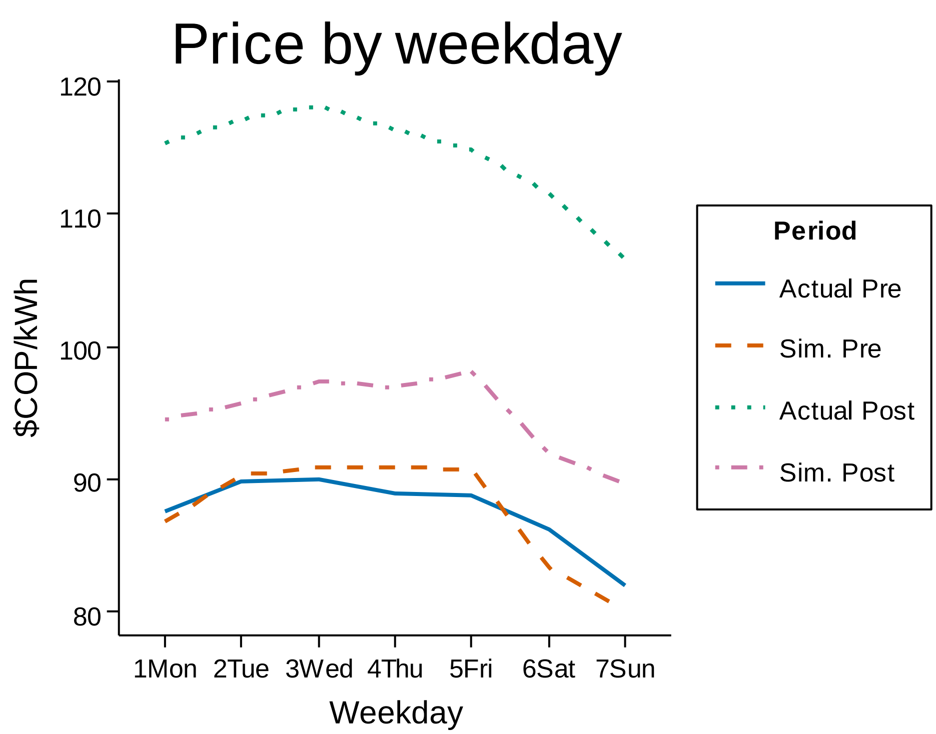
Market price by month

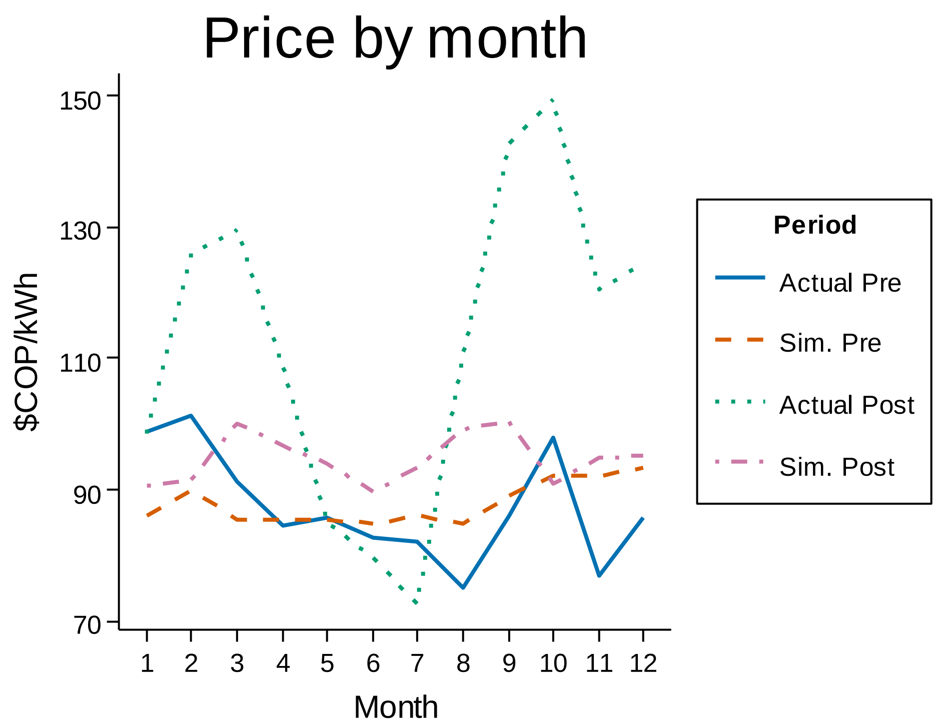


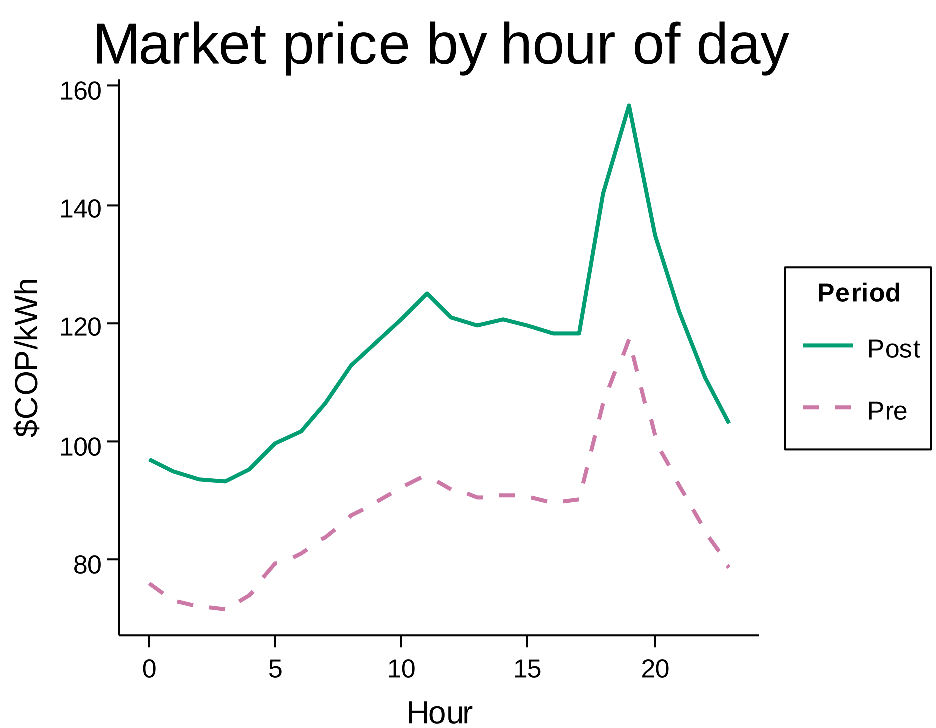
Market price standard deviation by month

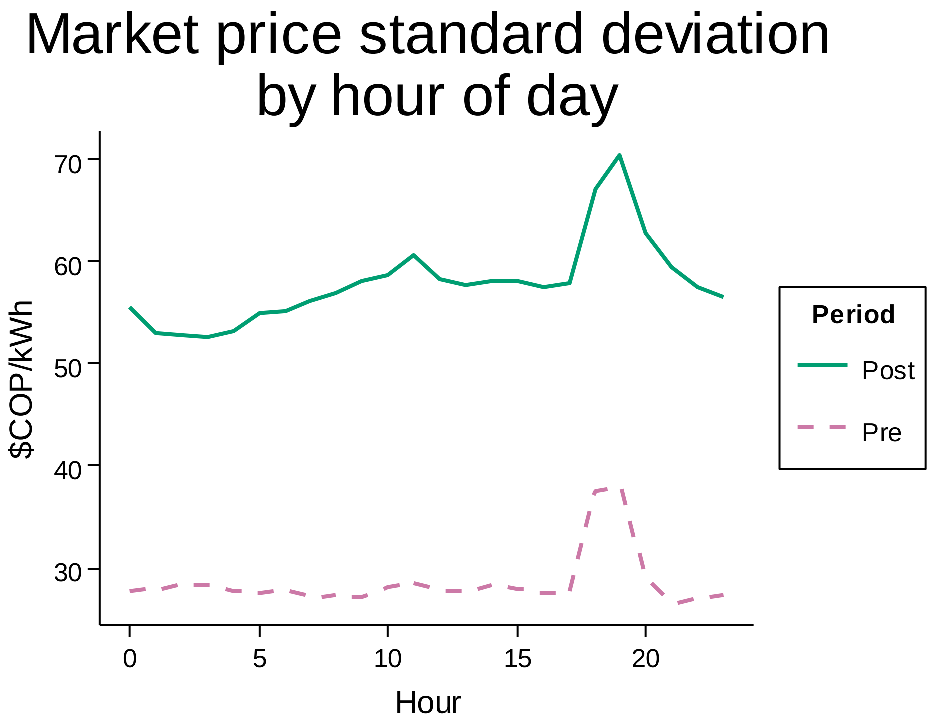


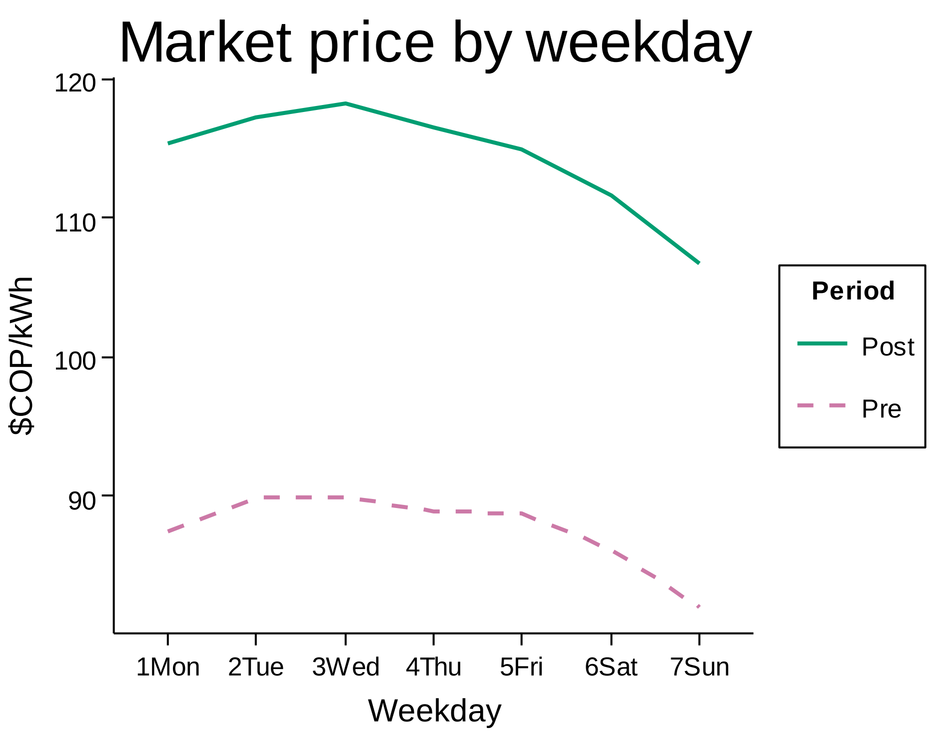

Price by hour of day
160
120
80
$COP/kWh
0
5
10
15
20
Hour
Period
Actual Pre
Sim. Pre
Actual Post
Sim. Post

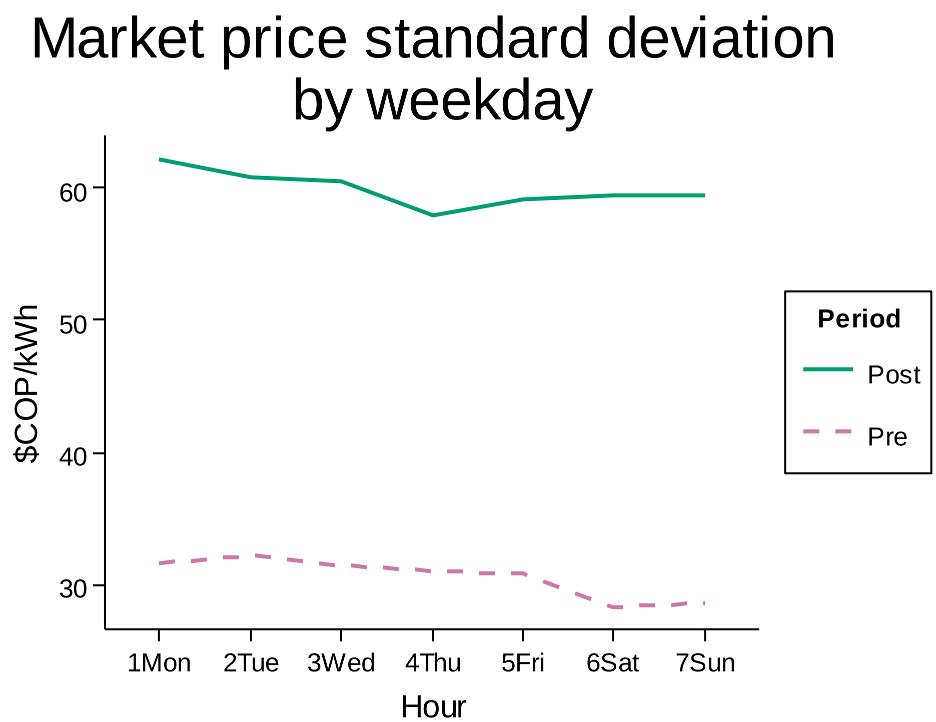

Price by weekday
120
110
100
90
80
$COP/kWh
1Mon
2Tue
3Wed
4Thu
5Fri
6Sat
7Sun
Weekday
Period
Actual Pre
Sim. Pre
Actual Post
Sim. Post


Price by month
$COP/kWh
150
130
110
90
70
1 2 3 4 5 6 7 8 9 10 11 12
Month
Period
Actual Pre
Sim. Pre
Actual Post
Sim. Post

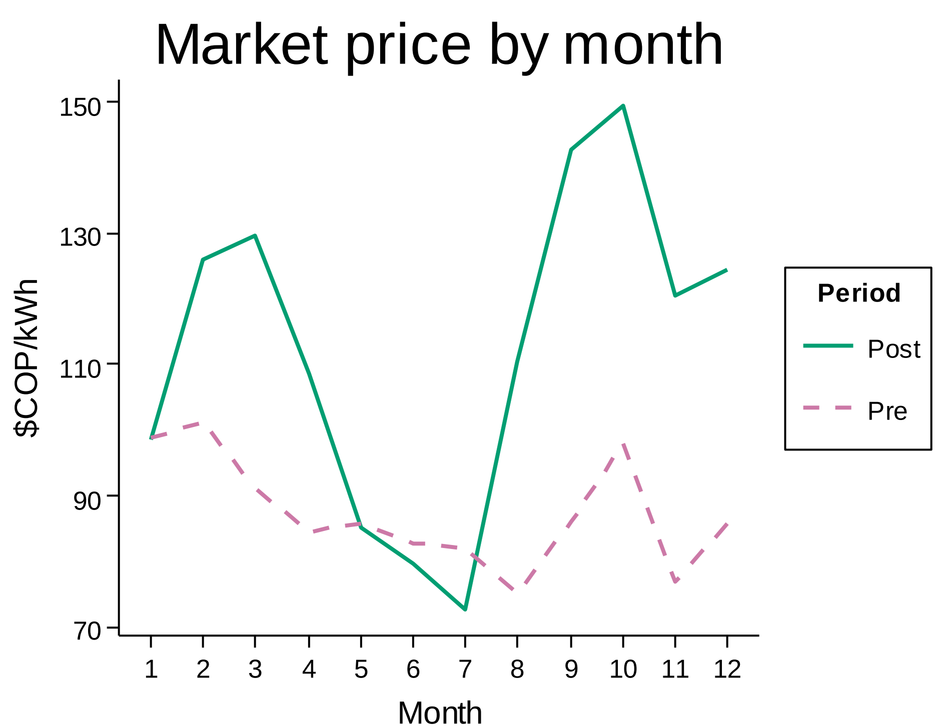

Market price by hour of day
$COP/kWh
160
140
120
100
80
0 5 10 15 20
Hour
Period
Post
Pre


Market price standard deviation
by hour of day
$COP/kWh
70
60
50
40
30
0
5
10
15
20
Hour
Period
Post
Pre

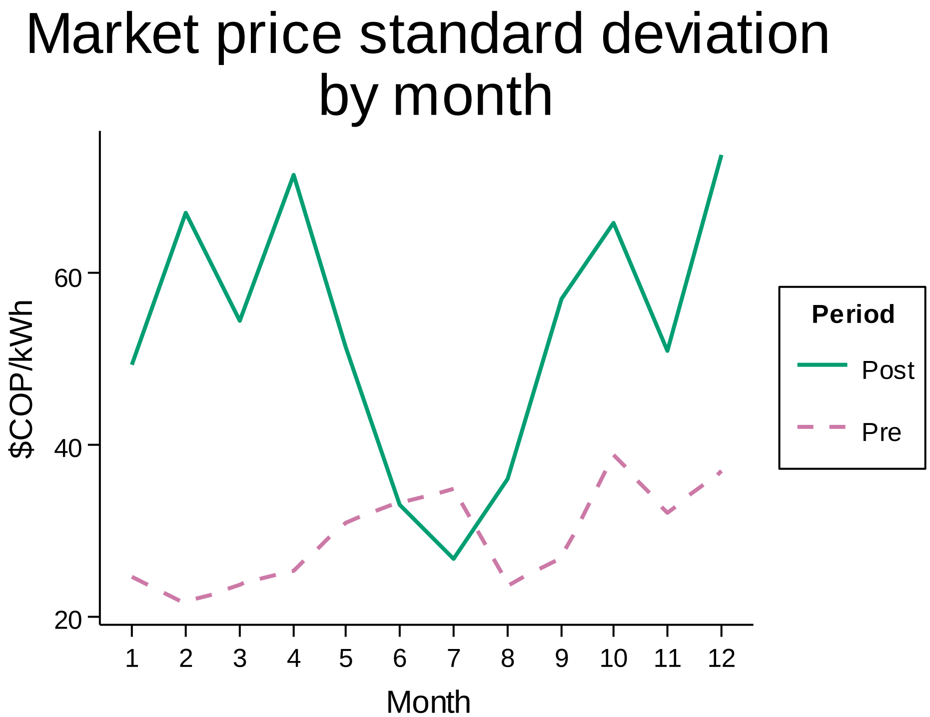

Market price by weekday
$COP/kWh
120
110
100
90
1Mon
2Tue
3Wed
4Thu
5Fri
6Sat
7Sun
Weekday
Period
Post
Pre

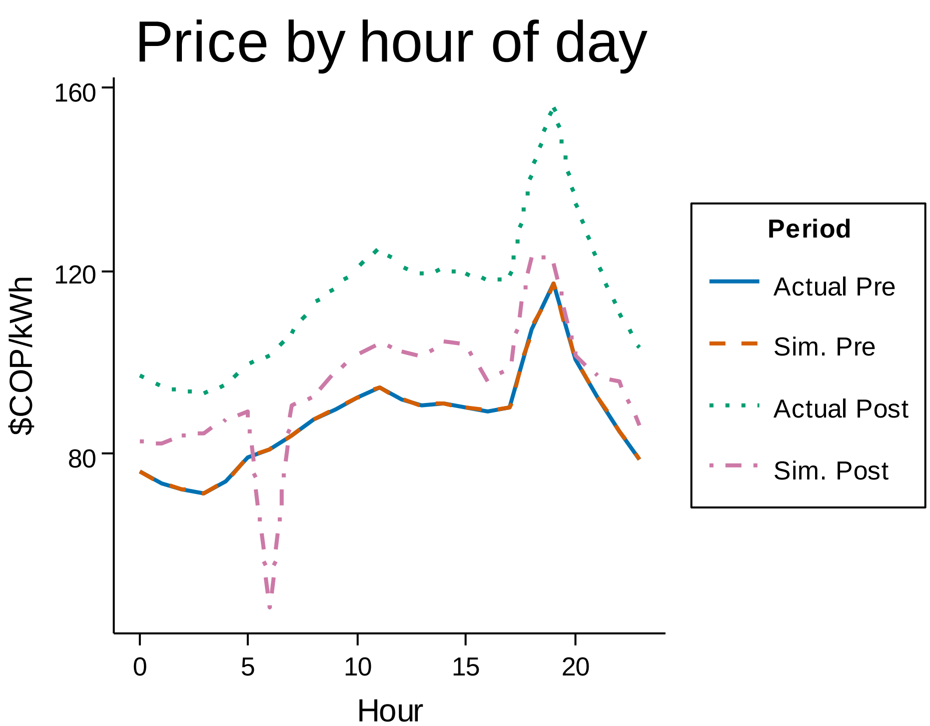


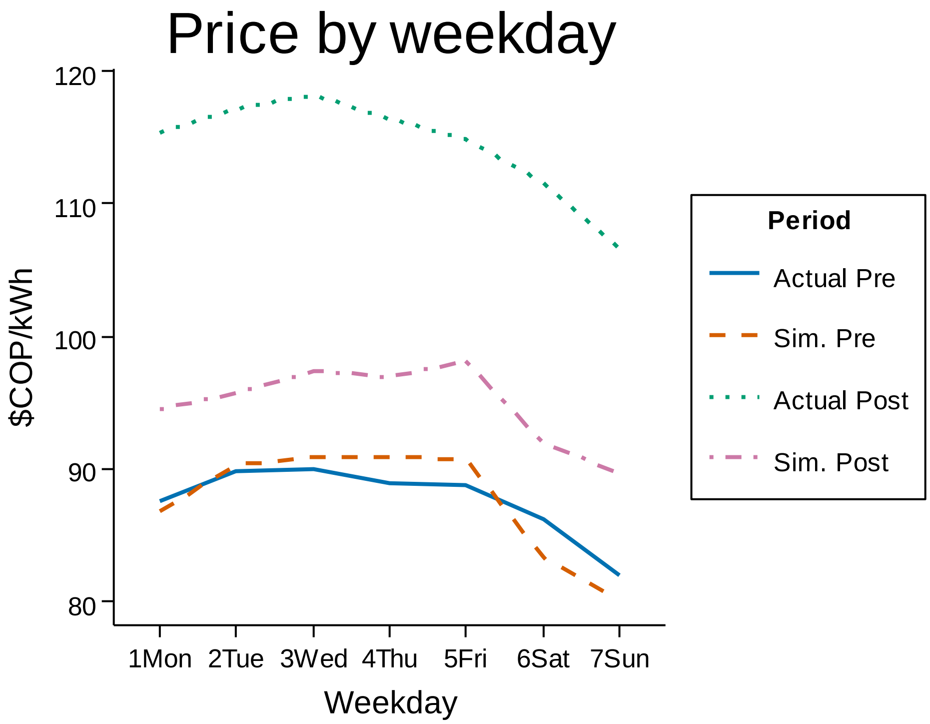
Market price standard deviation
by weekday
60
50
40
30
$COP/kWh
1Mon
2Tue
3Wed
4Thu
5Fri
6Sat
7Sun
Hour
Period
Post
Pre

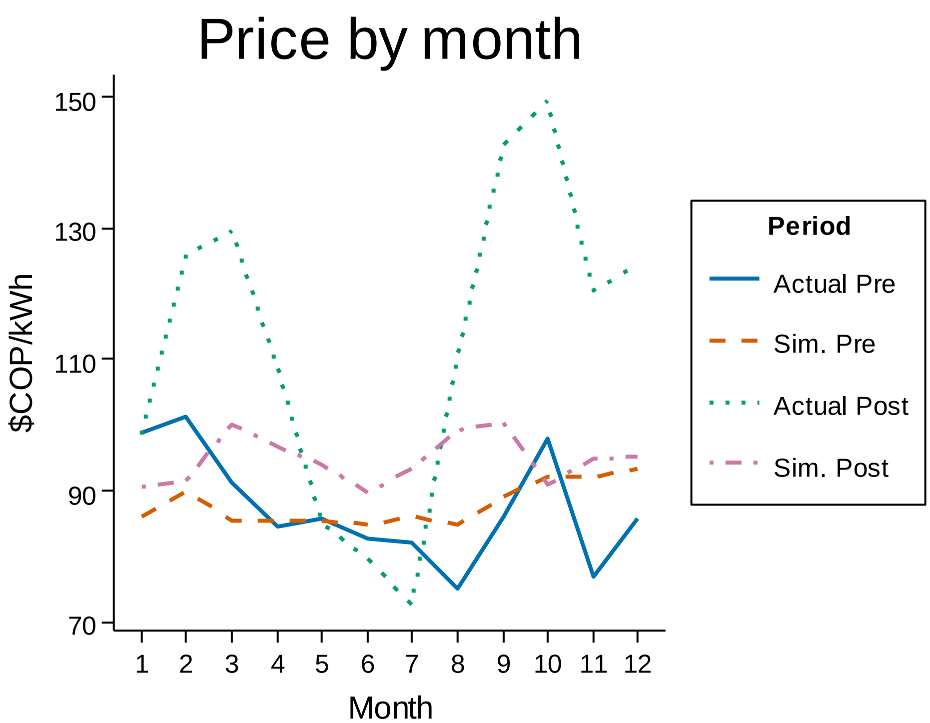


Market price by month
150
130
110
90
70
$COP/kWh
1
2
3
4
5
6
7
8
9
10
11
12
Month
Period
Post
Pre


Market price standard deviation by month
$COP/kWh
20
40
60
1
2
3
4
5
6
7
8
9
10
11
12
Month
Period
Post
Pre


Price by hour of day
$COP/kWh
80
120
160
0
5
10
15
20
Hour
Period
Actual Pre
Sim. Pre
Actual Post
Sim. Post





c) Marginal and opportunity costs

Marginal costs thermal plants

The methodology for estimating the marginal cost of plants that use coal, natural gas, and diesel as their principal fuel consists of:

- Estimate heat rate for each plant (see below).
- Estimate the calorific value of each type of fuel. This is the amount of energy released when a certain quantity of fuel undergoes a process of combustion. For example: [BTU/Pound] for coal, or [BTU/CF] for natural gas (see below).
- Estimate the price of fuel (this is often expressed like [USD/Ton] or [USD/kCF]).
- Estimate variable operating and maintenance costs. The variable operating and maintenance cost are typically in the order of $5USD/MWh.
- Calculate:

$$\text{Marginal Cost}\left[\frac{\$}{\text{kWh}}\right] = \text{Heat Rate} * \frac{1}{\text{Calorific Value}} * \text{Price of the fuel} + \text{VOM cost}$$

Heat rates are taken form XM’s web page for all thermal plants (see figure below).

Unit	Heat Rate MBTU/MWh	FUEL
BARRANQUILLA 3	9,6961	GAS
BARRANQUILLA 3	11,8	FUEL-OIL
BARRANQUILLA 3	11,8	GAS - FUEL OIL
BARRANQUILLA 4	9,9695	GAS
BARRANQUILLA 4	11,8	FUEL-OIL
BARRANQUILLA 4	11,8	GAS - FUEL OIL
CENTRAL CARTAGENA 1	11,1879	COMBUSTOLEO
CENTRAL CARTAGENA 1	11,522	GAS
CENTRAL CARTAGENA 2	11,019	COMBUSTOLEO
CENTRAL CARTAGENA 2	11,8104	GAS
CENTRAL CARTAGENA 3	10,9365	COMBUSTOLEO
CENTRAL CARTAGENA 3	11,522	GAS
FLORES 1	7,3751	GAS
FLORES 1	7,7126	ACPM
FLORES 4B	6,8456	GAS
FLORES 4B	7,646	FUEL-OIL
FLORES 4B	6,99	GAS - FUEL OIL
GUAJIRA 1	9,8036	GAS
GUAJIRA 1	10	COAL
GUAJIRA 1	11,8	GAS -COAL
GUAJIRA 2	9,7038	GAS
GUAJIRA 2	10	COAL
GUAJIRA 2	11,8	GAS -COAL
MERILECTRICA 1	9,601	GAS
PAIPA 1	11,7946	COAL
PAIPA 2	15,3576	COAL
PAIPA 3	10,5281	COAL
PAIPA 4	8,8875	COAL
PALENQUE 3	14,3162	GAS
PROELECTRICA 1	8,1679	GAS
PROELECTRICA 2	8,1679	GAS
TASAJERO 1	9,4628	COAL
TEBSAB	7,3085	GAS
TERMOCANDELARIA 1	10,4868	GAS
TERMOCANDELARIA 1	10,5506	FUEL-OIL
TERMOCANDELARIA 2	10,4914	GAS
TERMOCANDELARIA 2	10,5016	FUEL-OIL
MOCENTRO 1 CICLO COMBIN	7,288	GAS - JET A1
MOCENTRO 1 CICLO COMBIN	7,293	JET A1
MOCENTRO 1 CICLO COMBIN	7,2759	GAS
TERMODORADA 1	9,8238	JET A1
TERMODORADA 1	8,9947	GAS
TERMODORADA 1	9,7755	ACPM
TERMOEMCALI 1	6,9735	FUEL-OIL
TERMOEMCALI 1	6,793	GAS
TERMOSIERRAB	6,2712	GAS
TERMOSIERRAB	6,6727	ACPM
TERMOVALLE 1	6,7581	ACPM
TERMOVALLE 1	6,732	GAS
TERMOYOPAL 2	12,1016	GAS
ZIPAEMG 2	14,623	COAL
ZIPAEMG 3	11,9492	COAL
ZIPAEMG 4	10,5505	COAL
ZIPAEMG 5	9,2574	COAL

Figure: Heat Rate of Thermal Plants.

To estimate the calorific value for each type of fuel we refer to the document "Costos Indicativos de Generación Eléctrica en Colombia" published by the Mining and Energy Planning Unit (UPME) in April of 2005. In this document, they analyze each type of generation, i.e. coal, wind, hydro, natural gas, etc. They divide the Colombian map in nine (9) Interconnected Zones and nineteen Non Interconnected Zones as in Fig. They report the costs and fuel characteristics for each plant by region.

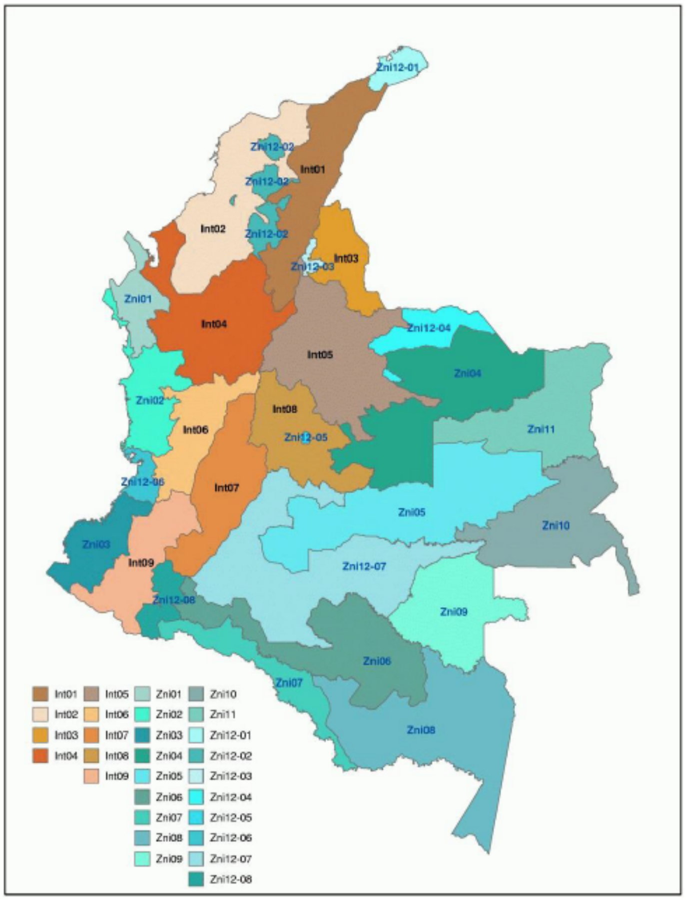


Figure: Regions.

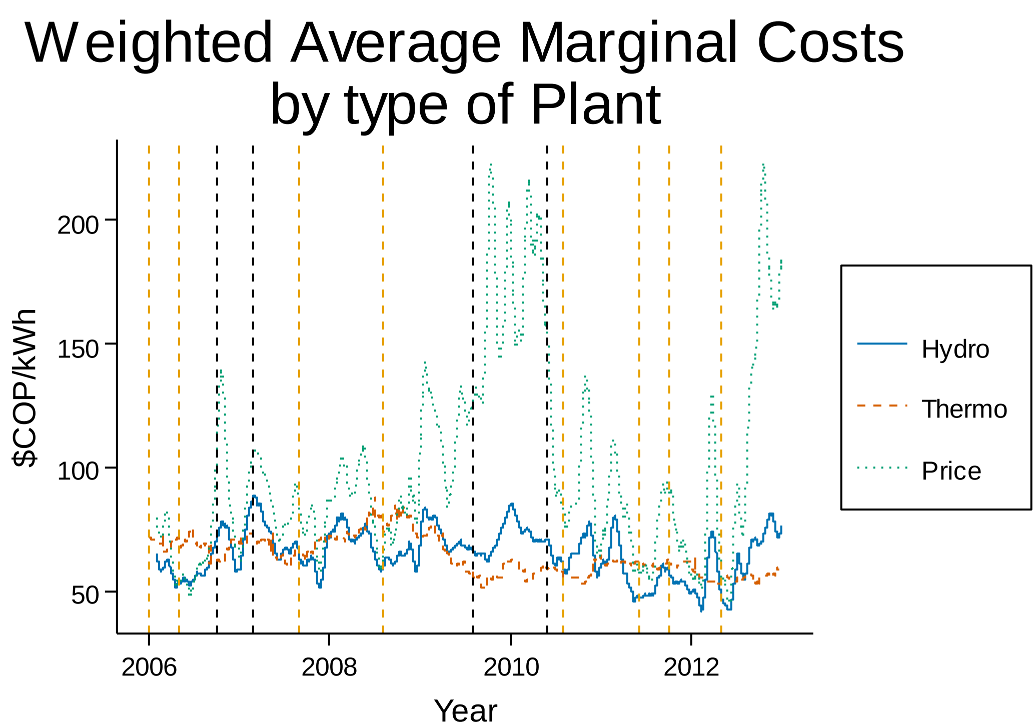
Since these estimates are for year 2005, we construct time series using appropriate variations of the most similar fuel price for which we can find data (the heat rate and calorific values do not change in time). For example for coal, we use international prices, and using their variation over time we construct time series for coal using as base year the estimated prices described in the previous paragraphs.

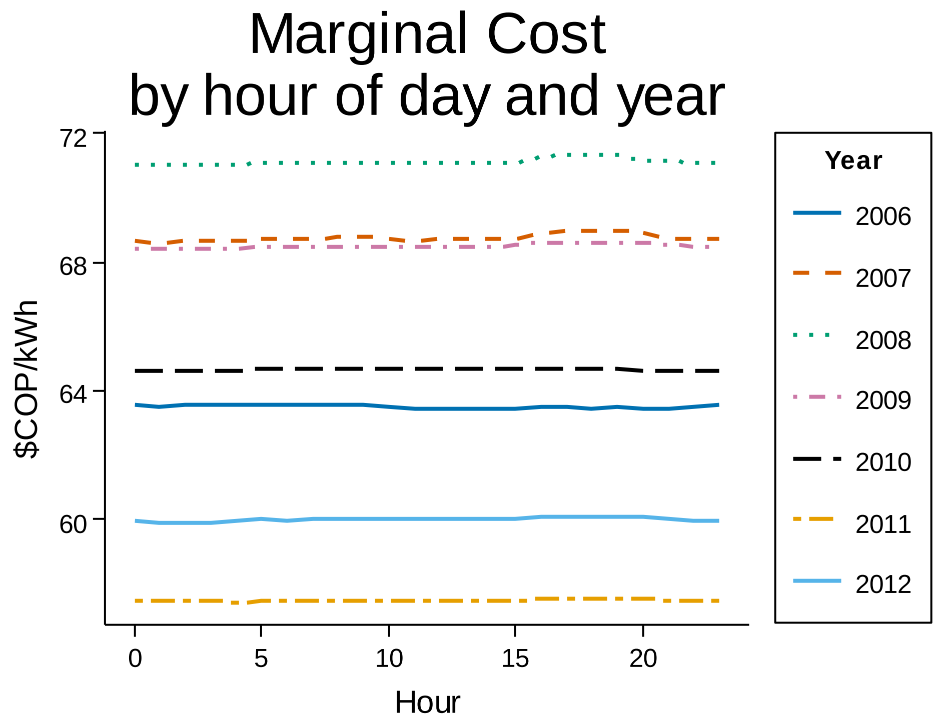
Opportunity cost of water

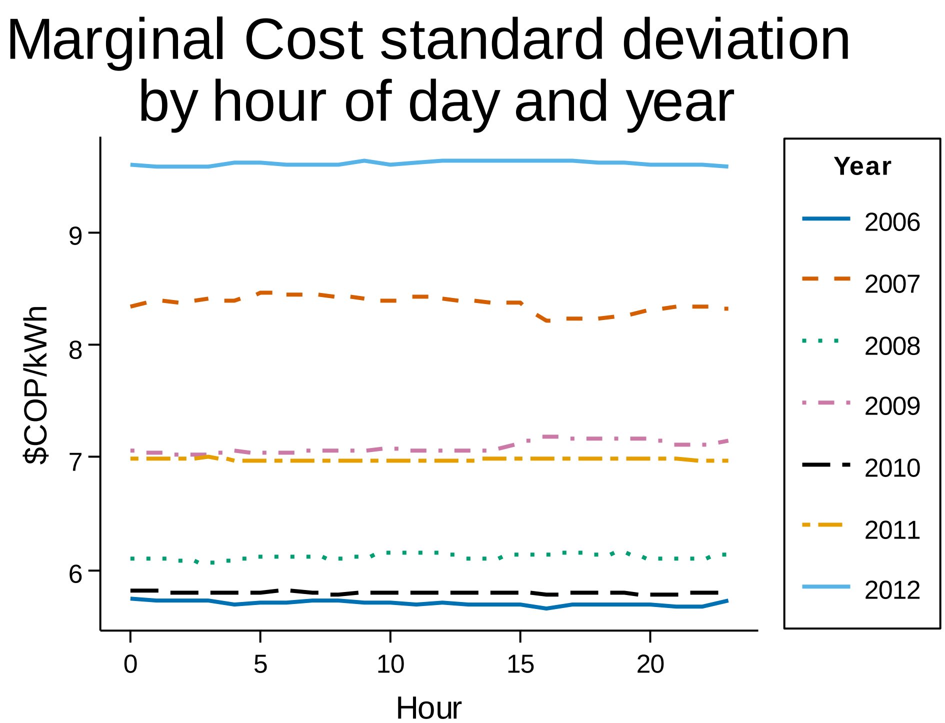
We follow Wolak (2009) and estimate the opportunity cost of water in one hour as the minimum between the plants bid price and the marginal cost of the most expensive thermal plant operating during that hour.[24]

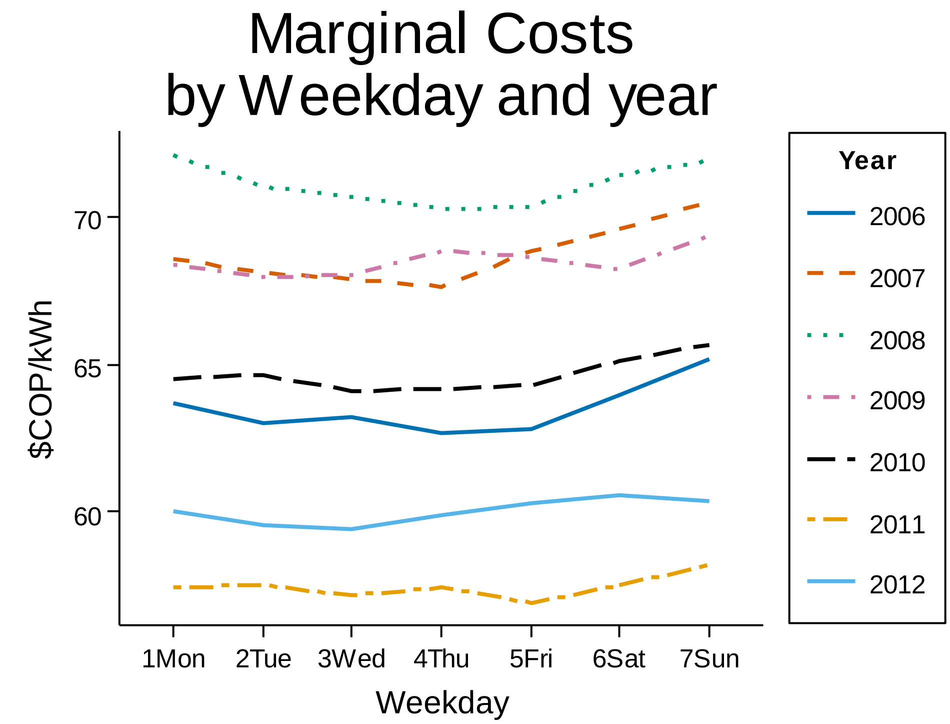
[24] We are also working in another definition of the opportunity cost of water that will be helpful to check the robustness of our results.

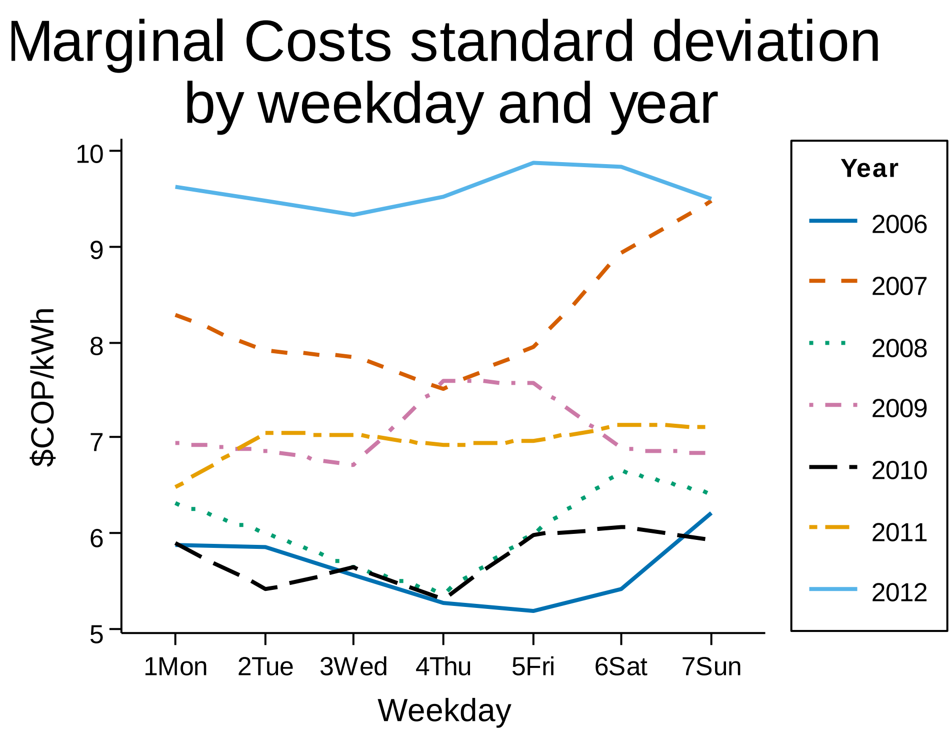
The next two figures show a weighted average of plants marginal costs weighted by maximum capacity. The second figure is the same as the first except for additional lines that represent bands for the period we had either El Niño or La Niña phenomena (the methodology for constructing marginal and opportunity costs can be found in the Appendix). The figures suggest that marginal or opportunity costs have not changed dramatically compared to the spot price. Moreover, there is some evidence that the marginal costs of thermal plants have gone down since 2009. Consistently with these findings, the last figure of this section shows that if anything, markups for thermal and hydro's have gone up.

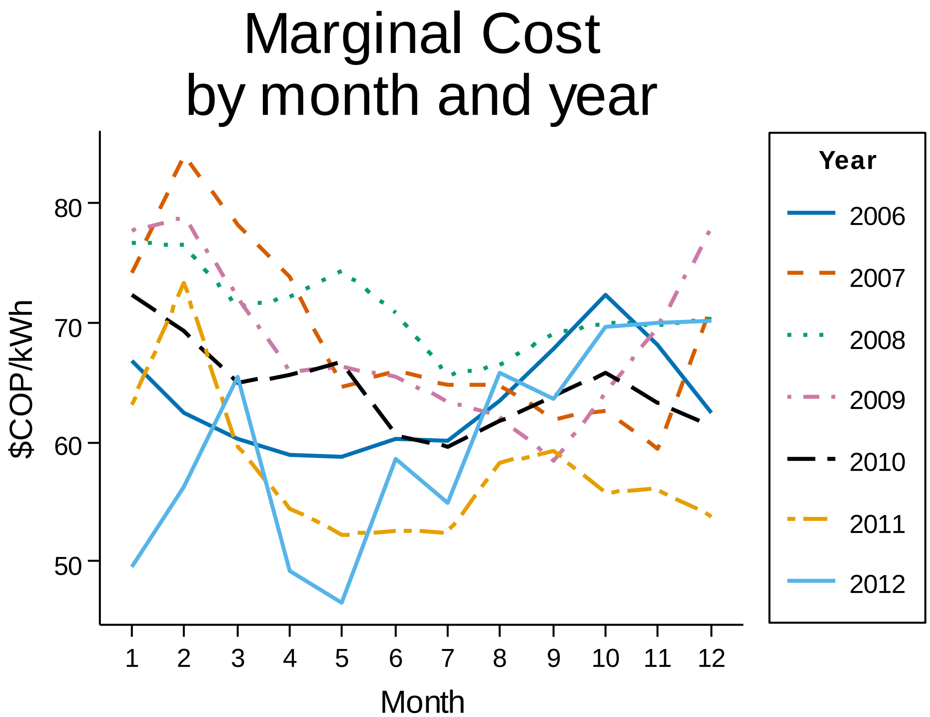


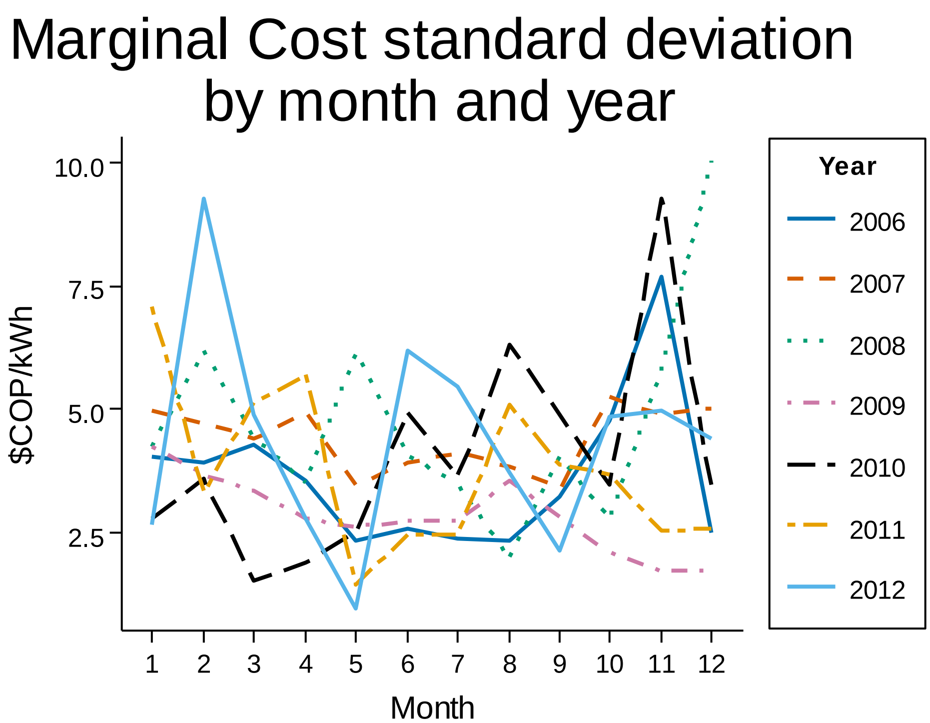

Marginal Cost
by hour of day and year
$COP/kWh
72
68
64
60
0
5
10
15
20
Hour
Year
2006
2007
2008
2009
2010
2011
2012


Marginal Cost standard deviation
by hour of day and year
$COP/kWh
9
8
7
6
0
5
10
15
20
Hour
Year
2006
2007
2008
2009
2010
2011
2012

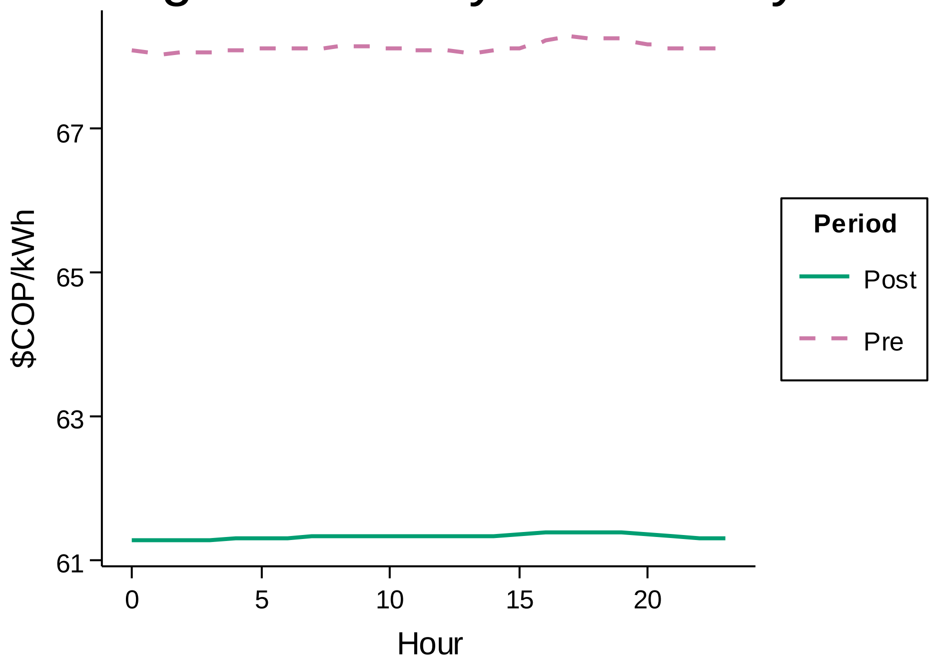

Marginal Costs
by Weekday and year
$COP/kWh
70
65
60
1Mon
2Tue
3Wed
4Thu
5Fri
6Sat
7Sun
Weekday
Year
2006
2007
2008
2009
2010
2011
2012


Marginal Costs standard deviation
by weekday and year
$COP/kWh
10
9
8
7
6
5
1Mon
2Tue
3Wed
4Thu
5Fri
6Sat
7Sun
Weekday
Year
2006
2007
2008
2009
2010
2011
2012

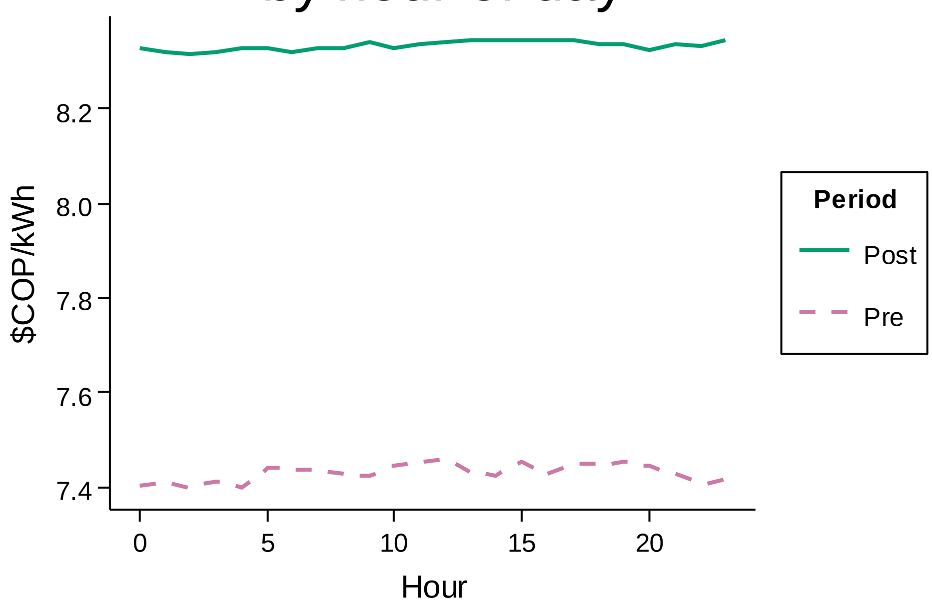

Marginal Cost
by month and year
$COP/kWh
80
70
60
50
1
2
3
4
5
6
7
8
9
10
11
12
Month
Year
2006
2007
2008
2009
2010
2011
2012

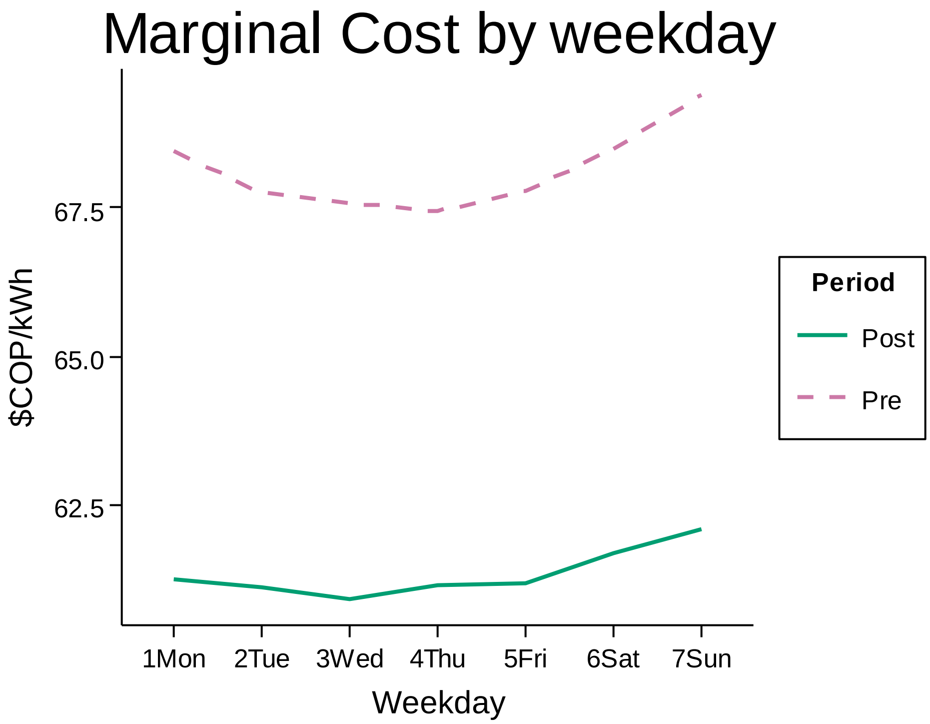

Marginal Cost standard deviation
by month and year
$COP/kWh
10.0
7.5
5.0
2.5
1
2
3
4
5
6
7
8
9
10
11
12
Month
Year
2006
2007
2008
2009
2010
2011
2012

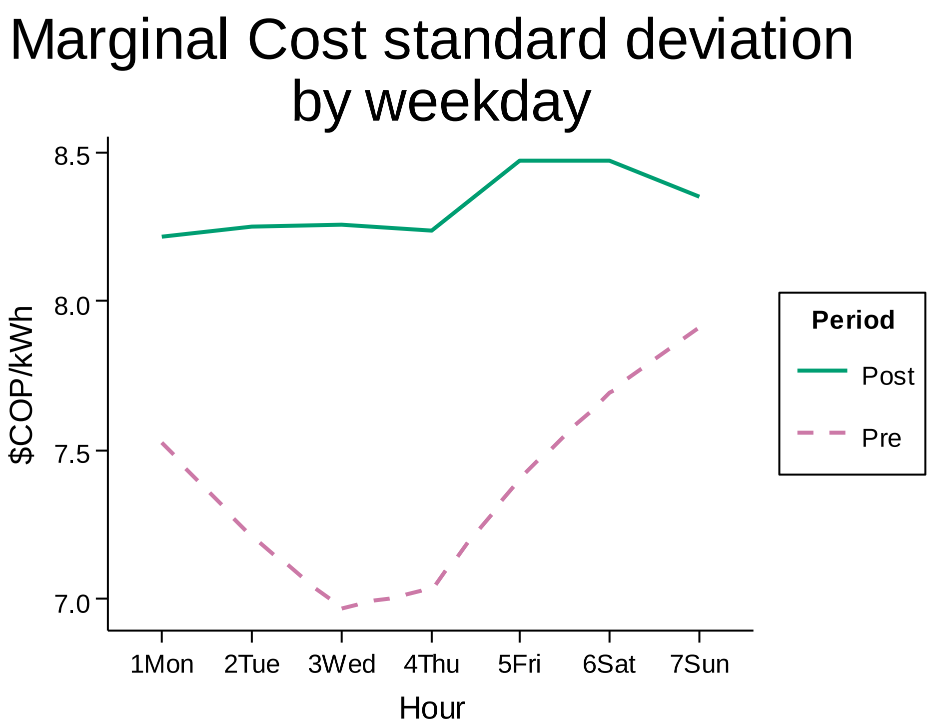
Marginal Cost by hour of day

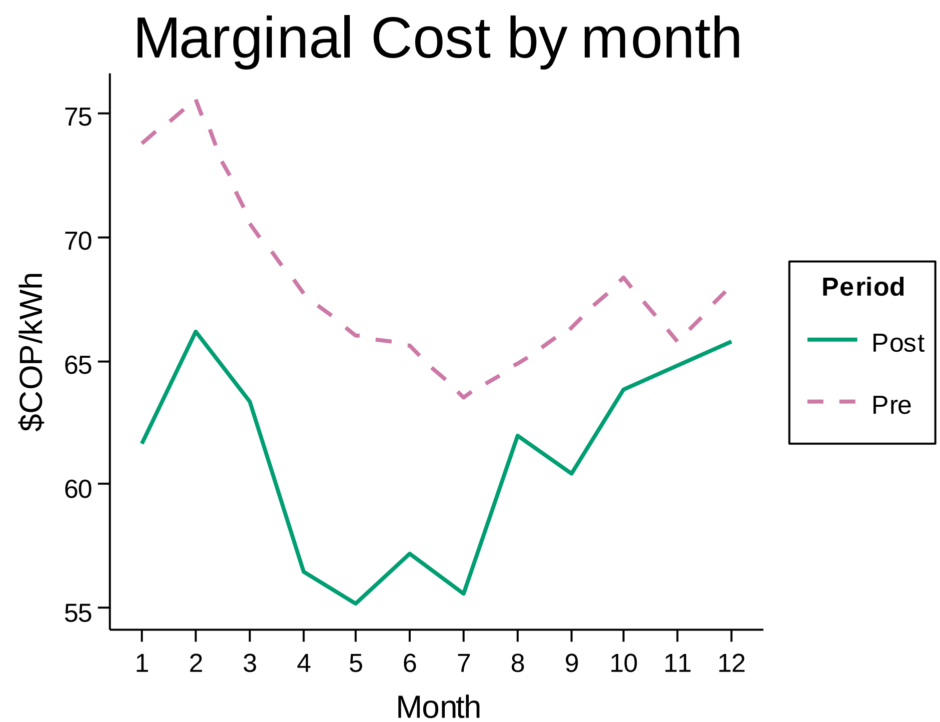


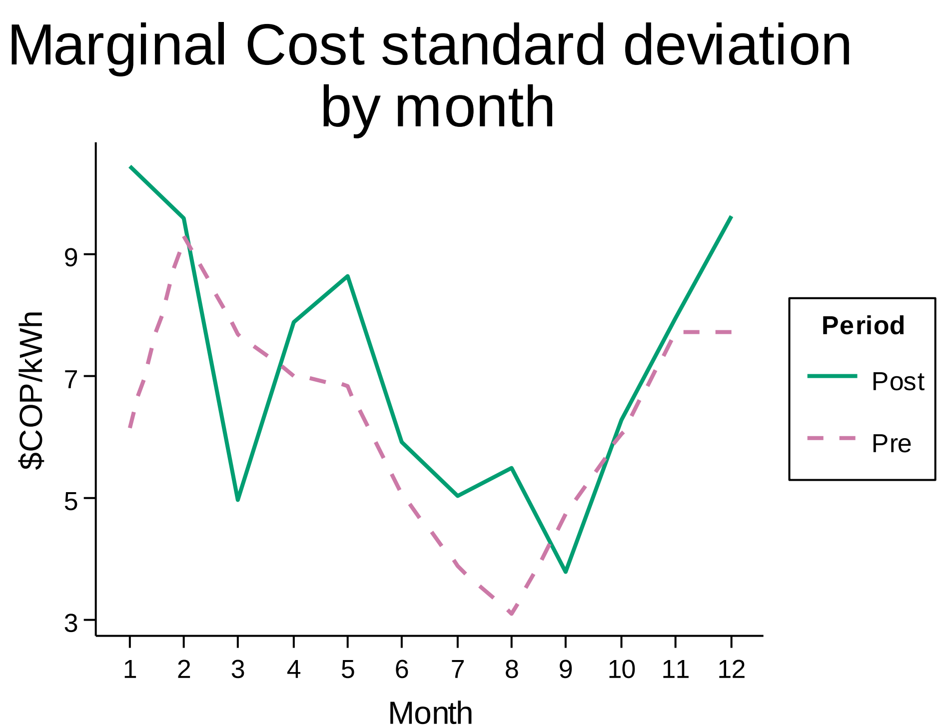
Marginal Cost standard deviation by hour of day



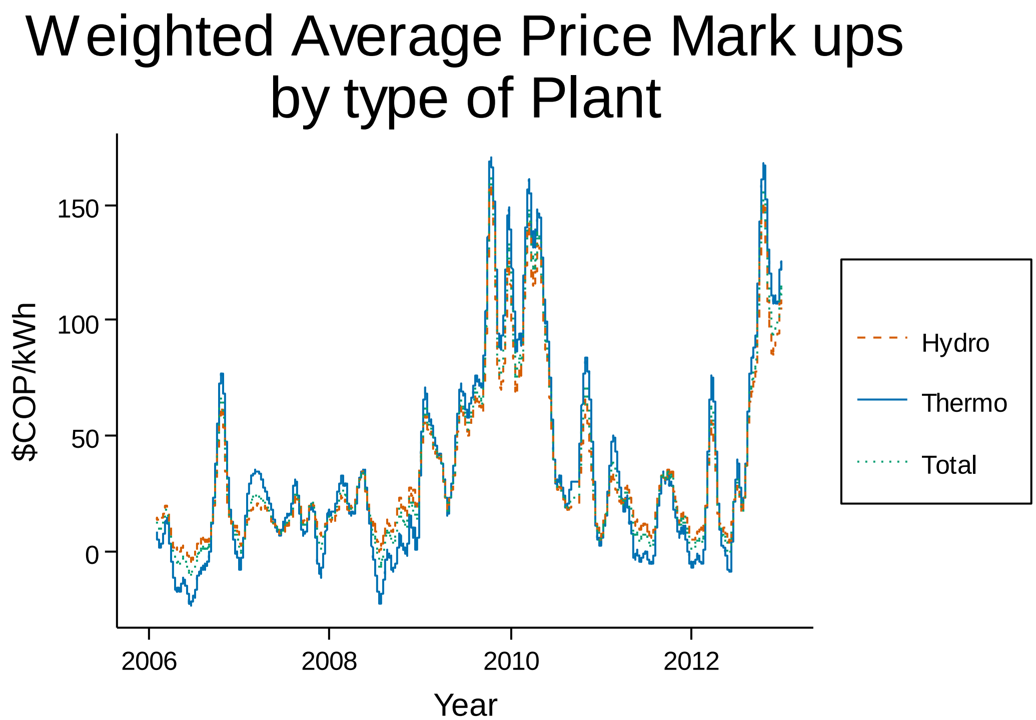

Marginal Cost by weekday
$COP/kWh
67.5
65.0
62.5
1Mon
2Tue
3Wed
4Thu
5Fri
6Sat
7Sun
Weekday
Period
Post
Pre

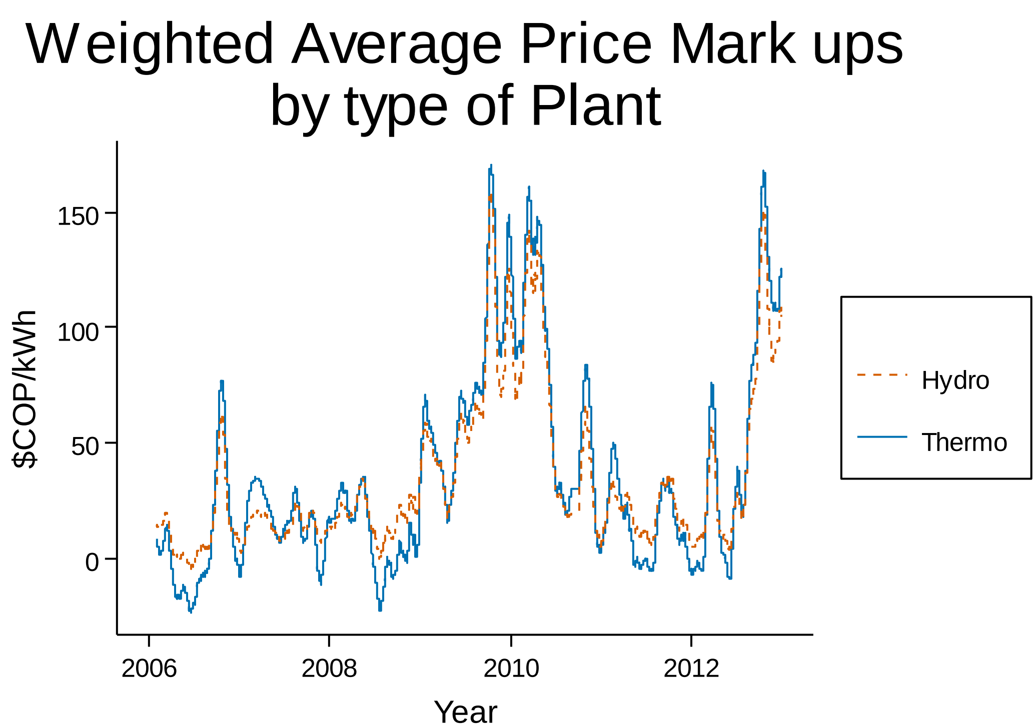

Marginal Cost standard deviation by weekday
$COP/kWh
8.5
8.0
7.5
7.0
1Mon
2Tue
3Wed
4Thu
5Fri
6Sat
7Sun
Hour
Period
Post
Pre


Marginal Cost by month
$COP/kWh
75
70
65
60
55
1 2 3 4 5 6 7 8 9 10 11 12
Month
Period
Post
Pre

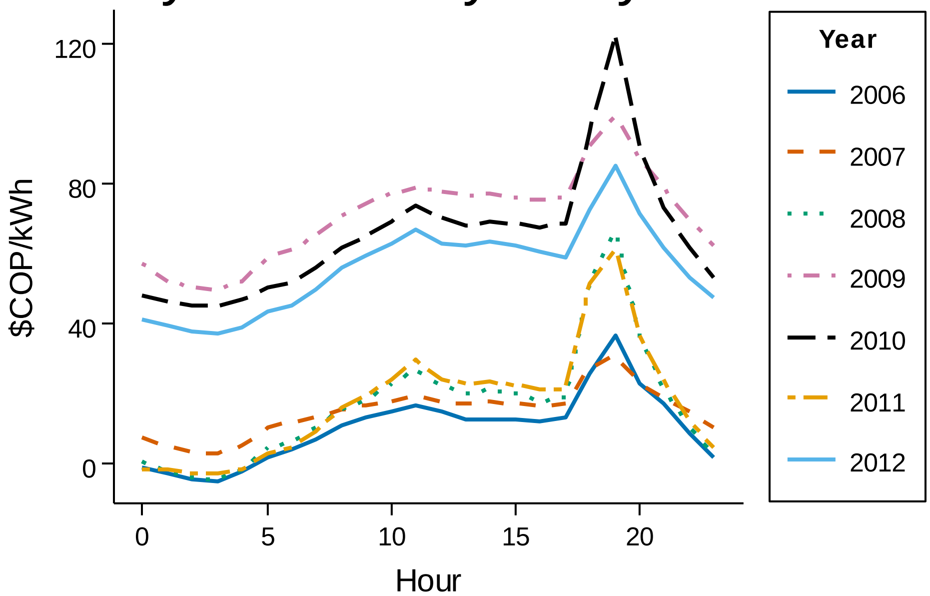

Marginal Cost standard deviation by month
$COP/kWh
9
7
5
3
1 2 3 4 5 6 7 8 9 10 11 12
Month
Period
Post
Pre

d) Markups

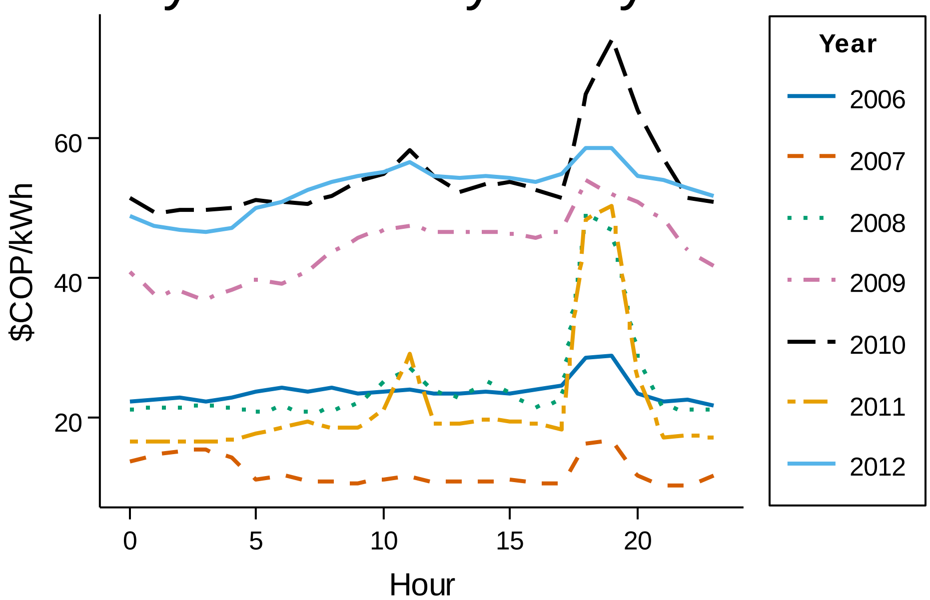

Weighted Average Price Mark ups
by type of Plant
150
100
50
0
$COP/kWh
2006
2008
2010
2012
Year
Hydro
Thermo
Total

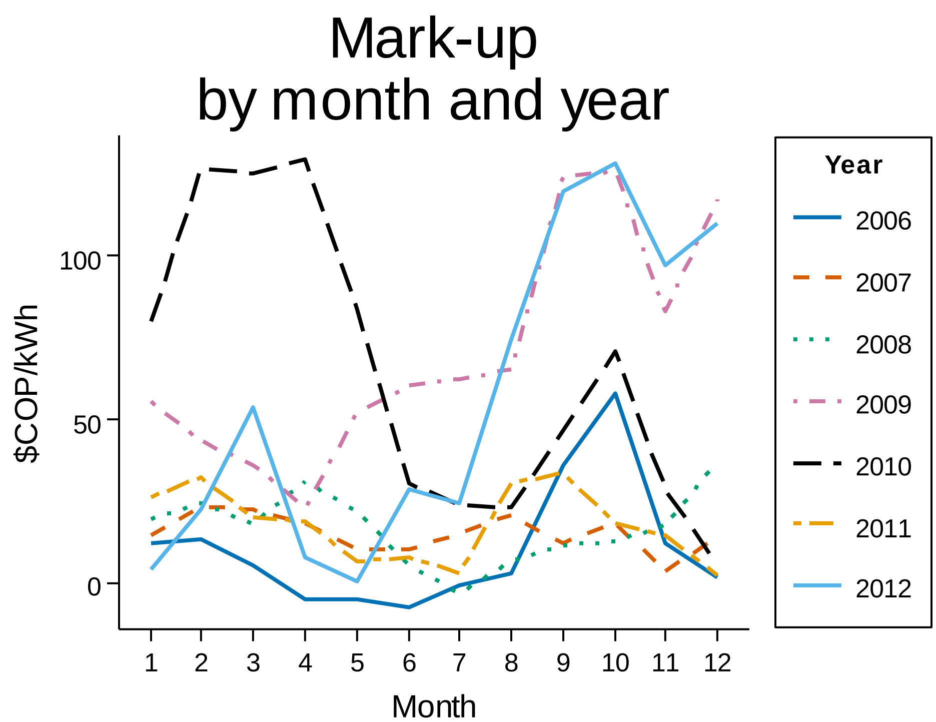

Weighted Average Price Mark ups
by type of Plant
150
100
50
0
$COP/kWh
2006
2008
2010
2012
Year
Hydro
Thermo

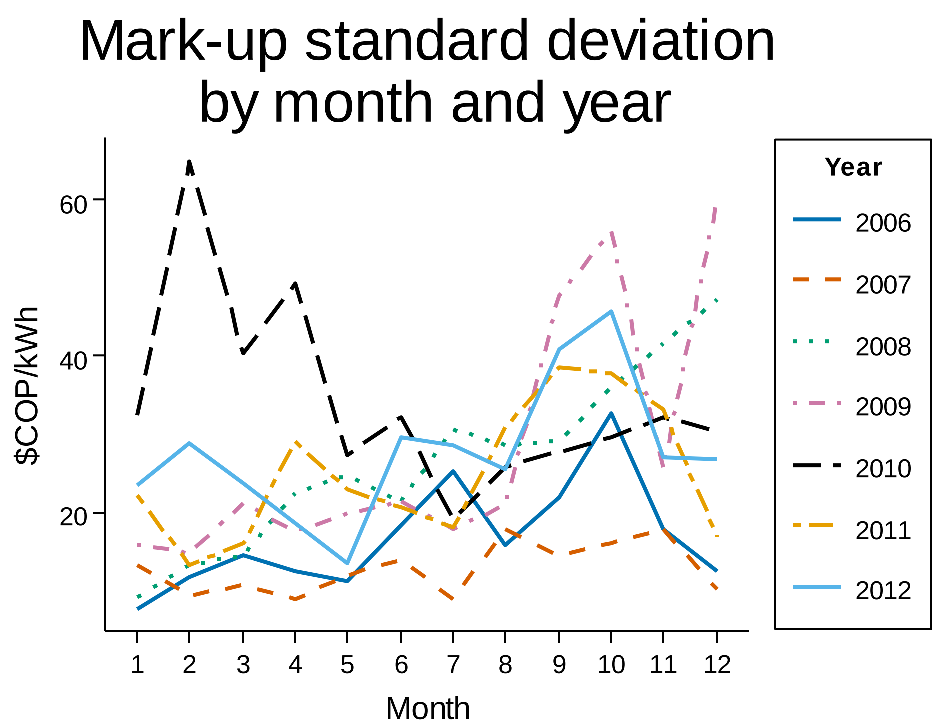
Mark-up by hour of day and year



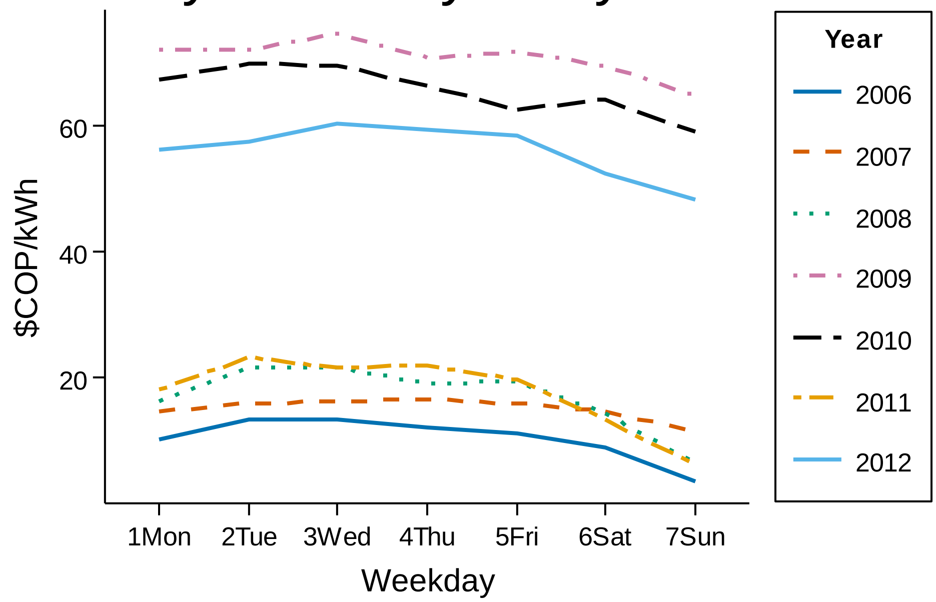
Mark-up standard deviation by hour of day and year



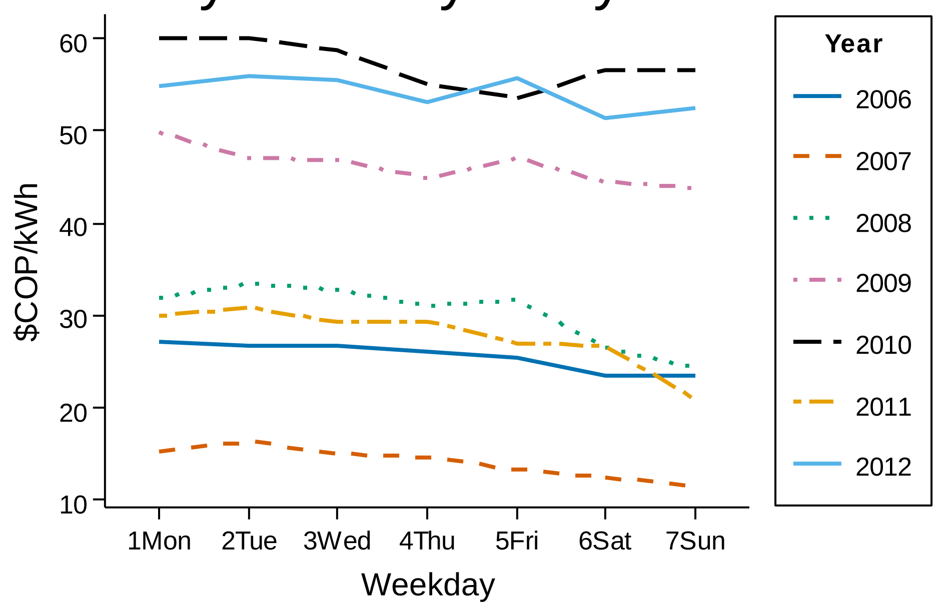

Mark-up
by month and year
$COP/kWh
100
50
0
1
2
3
4
5
6
7
8
9
10
11
12
Month
Year
2006
2007
2008
2009
2010
2011
2012

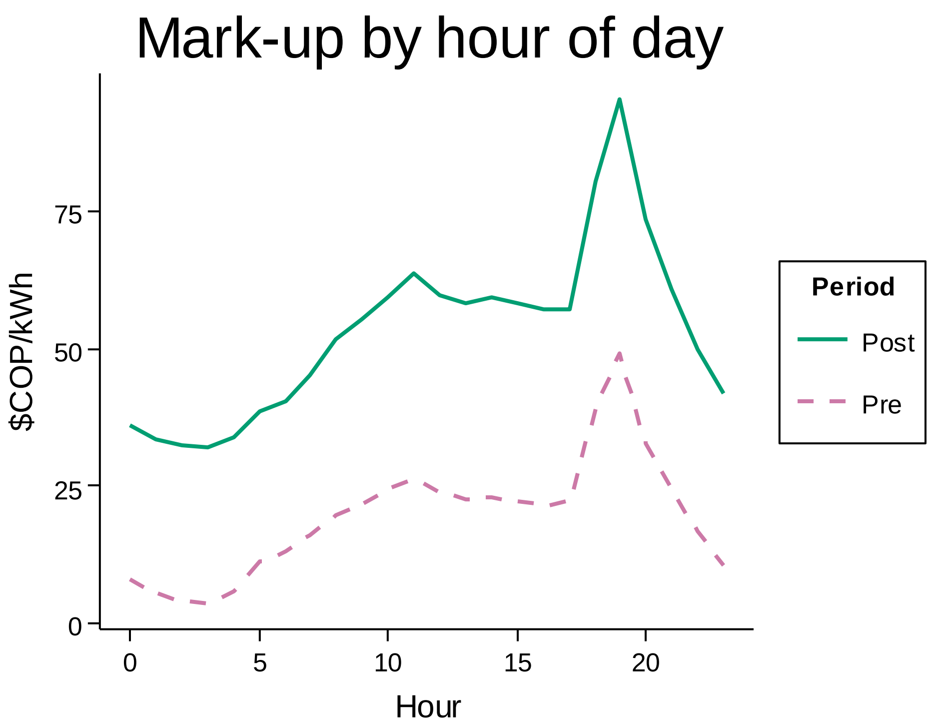

Mark-up standard deviation
by month and year
$COP/kWh
60
40
20
1
2
3
4
5
6
7
8
9
10
11
12
Month
Year
2006
2007
2008
2009
2010
2011
2012

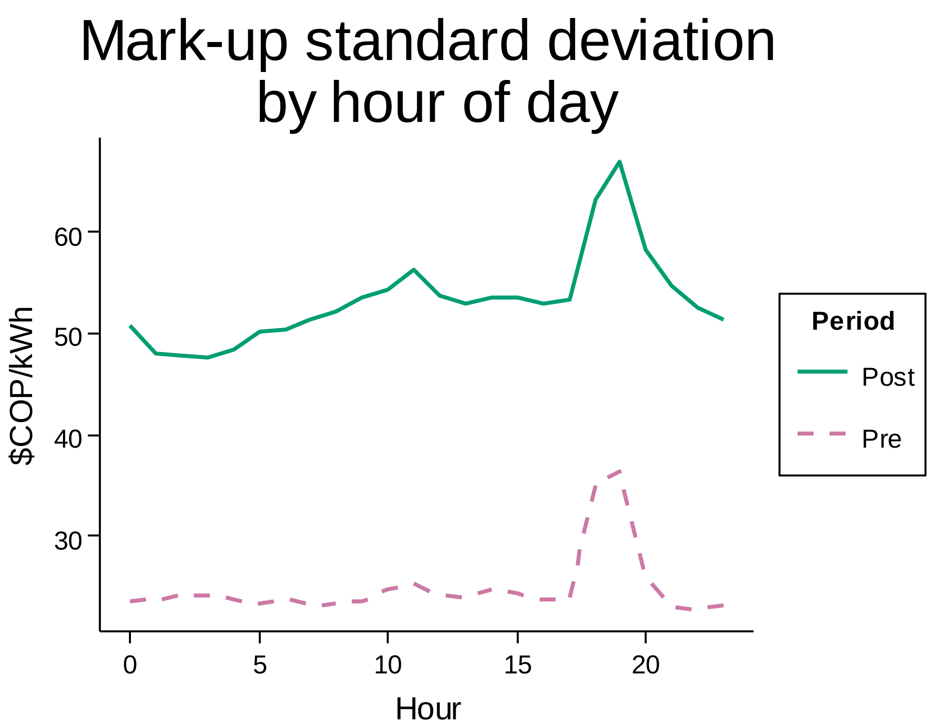
Mark-ups
by Weekday and year

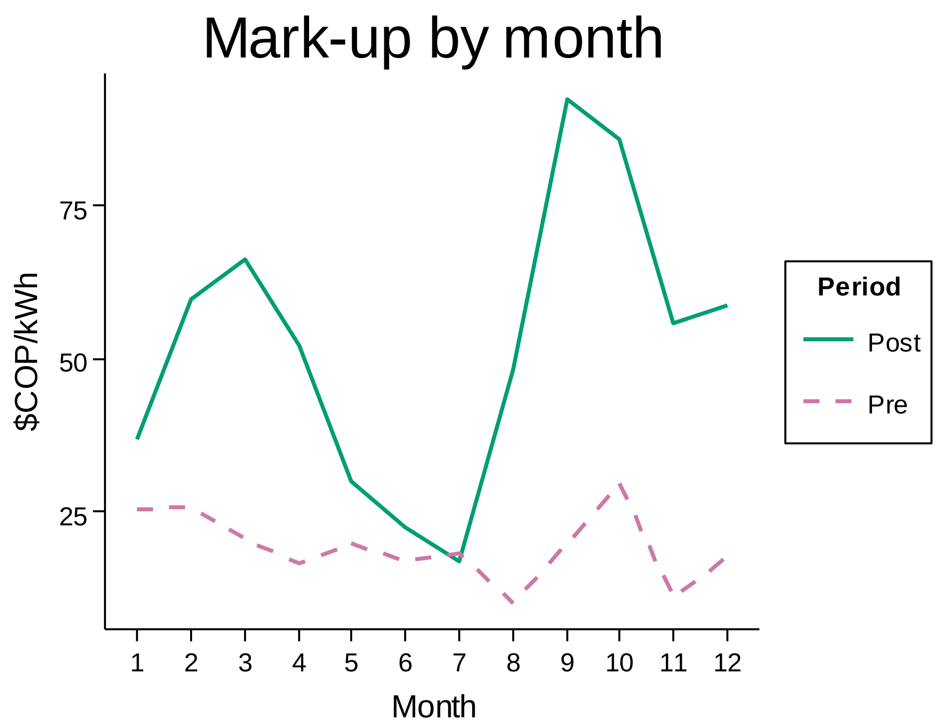


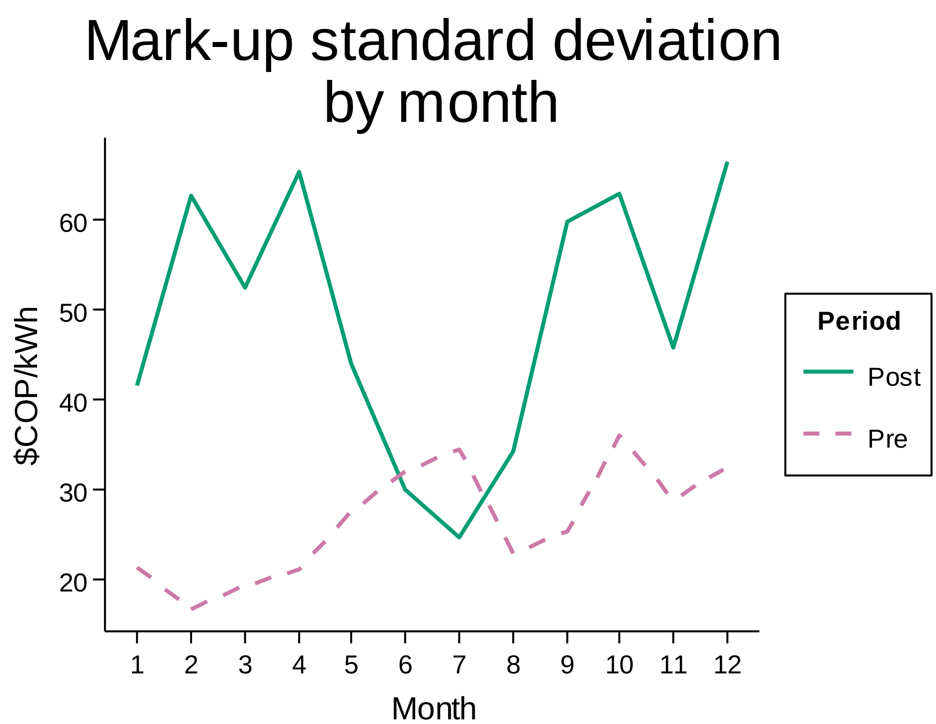
Mark-ups standard deviation
by weekday and year

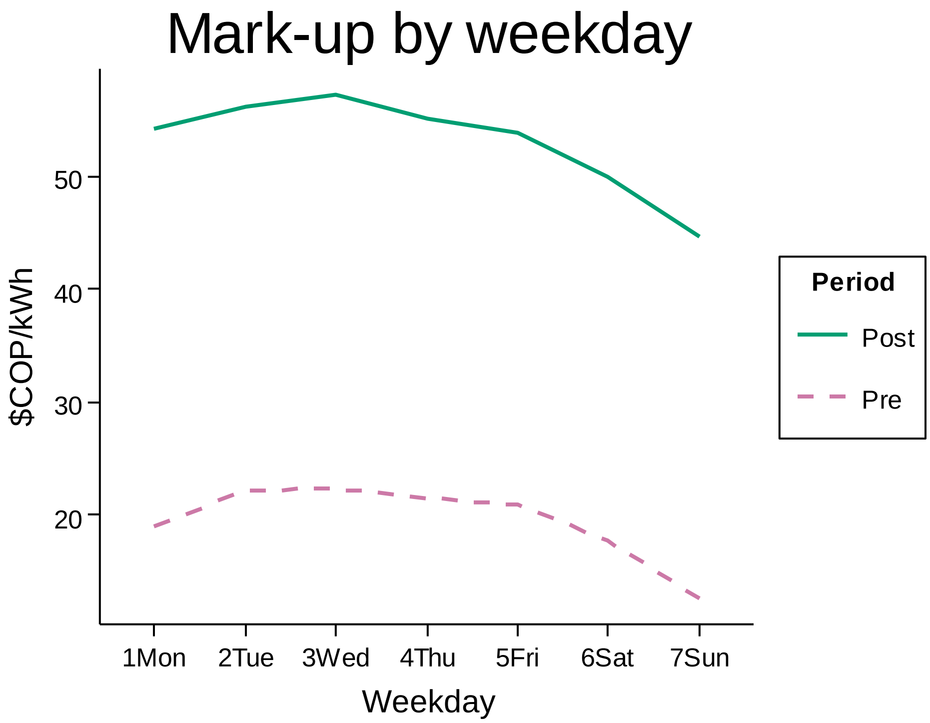


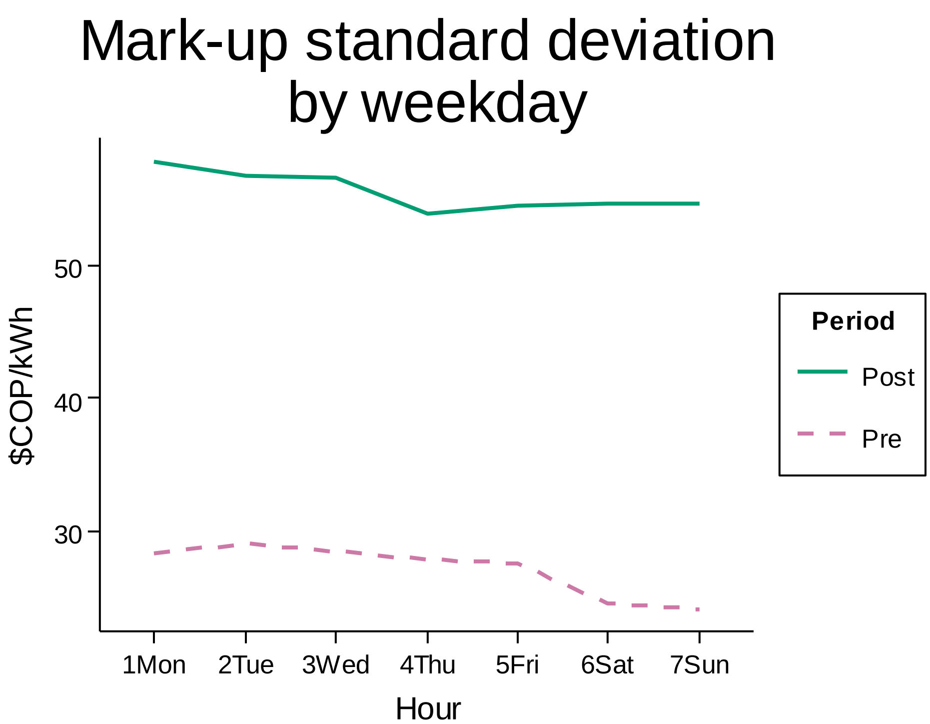

Mark-up by hour of day
$COP/kWh
0
25
50
75
0
5
10
15
20
Hour
Period
Post
Pre


Mark-up standard deviation
by hour of day
$COP/kWh
30
40
50
60
0
5
10
15
20
Hour
Period
Post
Pre


Mark-up by month
$COP/kWh
75
50
25
1
2
3
4
5
6
7
8
9
10
11
12
Month
Period
Post
Pre


Mark-up standard deviation
by month
$COP/kWh
60
50
40
30
20
1
2
3
4
5
6
7
8
9
10
11
12
Month
Period
Post
Pre


Mark-up by weekday
$COP/kWh
50
40
30
20
1Mon
2Tue
3Wed
4Thu
5Fri
6Sat
7Sun
Weekday
Period
Post
Pre


Mark-up standard deviation
by weekday
$COP/kWh
50
40
30
1Mon
2Tue
3Wed
4Thu
5Fri
6Sat
7Sun
Hour
Period
Post
Pre

e) Startup costs

Start-up Costs for the 2008-2009 Period

The figure below shows that weighted average start-up costs tripled (with respect to the value at the end of 2007) in years 2008 and 2009. It is of interest to analyze the reason of this increase.

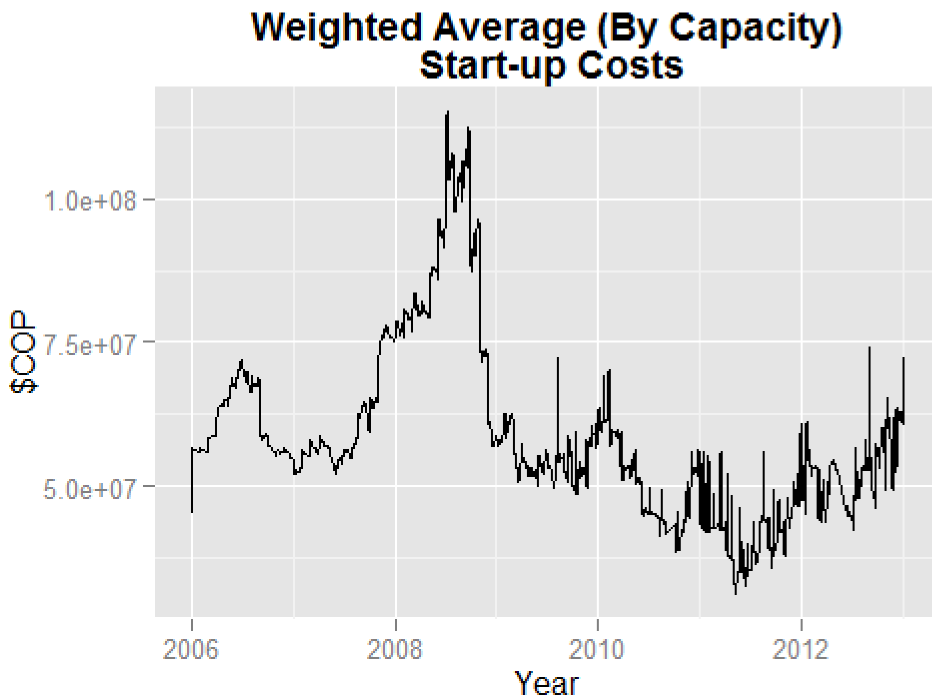
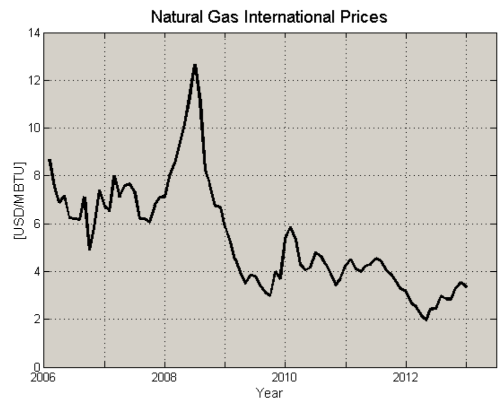
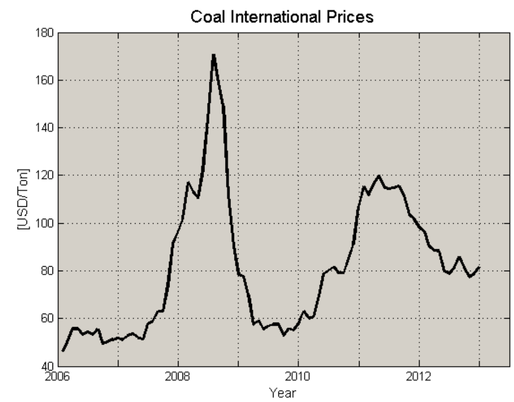
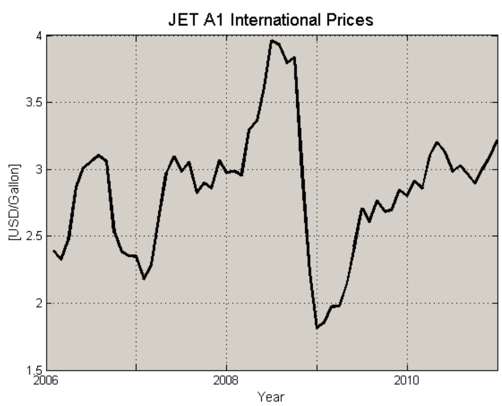


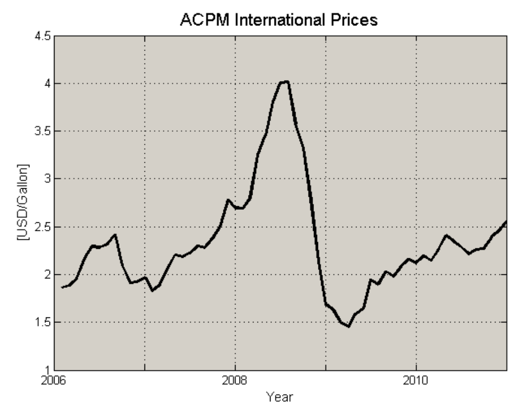
Figure: Start-up Costs for the 2006-2012 period. Before 2009, estimated start-up costs.

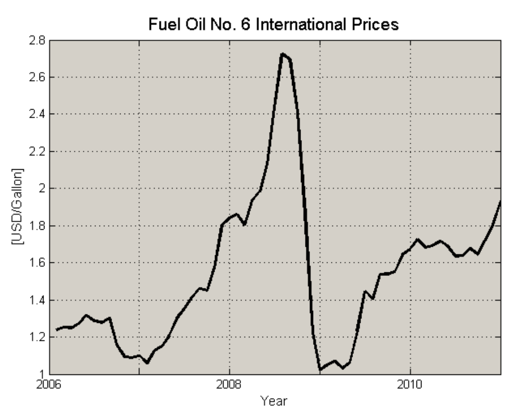
We can observe the behavior of all the fuels we have used to estimate the start-up costs in the figures below. It is clear, thus, that the increase in the costs is highly related to an increase in the fuels used by the thermal plants. Each type of fuel increased the price at the beginning of 2008, peaked in July of 2008 and then decreased dramatically for the beginning of 2009. Fuel prices are correlated to petroleum prices.











During the period 2004-2008 the petroleum price experienced a constant increase. It rose from $40 USD (Brent) in June of 2004 to $147.25 USD (Brent) in July of 2008.

Based on these observations, we can explain the increase in the start-up costs of the thermal plants. The petroleum price dragged the other types of fuel and so the behaviors of all of them were similar.

5. Econometric analysis (self-unit commitment counterfactual)

This section describes an econometric evaluation of the welfare consequences of Resolution 051, 2009, using data made available by *Comisión de Regulación de Energia y Gas* (CREG, the Colombian regulator for electricity markets) and XM (the system operator). This Resolution modified Colombian market from a market of self-commitment to a market with centralized unit commitment in which economic dispatch accounts for startup cost and operational constraints and plants are guaranteed to recover their start-up costs if they are dispatched by 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 PJM 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 might 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 overestimates the welfare losses in the actual market. Mansur proposes a method that takes into account these start-up costs, by estimating a dynamic model and he produces a more accurate evaluation of welfare losses. This methodology is particularly relevant for this study, since start-up cost is one of the central aspects of Resolution 051/2009.

More specifically, we estimate two models. The first model (Output decisions, see section 3.1 below) estimates the quantity of energy produced as a function of price-costs markups in the present, past and future, since the actual decision to produce or not will depend on these markups. We calibrated this model with data before 2009, when the Resolution changed the rules, and used the obtained model to simulate what the production would have been if no rule change had been implemented, i.e., dispatch continued to be based on energy only bids and generators bids continued to be based on marked up marginal cost.

The second model (Prices, see section 3.2) considers an adjustment in prices, taking in account the fact that the Resolution changed the way that the power plants would recover their costs and, therefore, changed the price formation mechanism. For this, we adapt the methodology described in Mansur's appendix A, and estimate prices as functions of demand, controlling also for El Niño y La Niña effects. More details about these procedures and our overall strategy of evaluation are given in the next section. Section 3 contains a detailed description of these methods.

Our econometric model is a reduced form model that ignores agents' strategic behavior. Nevertheless, we perform several sensitivity analysis and alternative model specifications and conclude that results do not change substantially. This suggests that results are robust to an econometric specification that explicitly incorporates agents' strategic behavior.

Results suggest that that the regulation has been welfare improving by reducing production costs even when simulated prices, representing the spot price that would have prevailed in the absence of regulation (counterfactual) are lower than observed prices. Moreover, the result does not change when we consider startup costs. Nevertheless, simulated counterfactual prices and estimated marginal and opportunity costs imply that after the regulation markups have increase suggesting that, although the dispatch has been more efficient, there has been considerable exercise of market power to the detriment of consumers.

The overall strategy is to use the period before 2009 to characterize firms' output decisions and aggregate supply. Using these characterizations we construct a counterfactual for the period after 2009, simulating what would have been firms' output decisions and prices consistent with observed aggregate demand. Since demand is mostly inelastic we assume that electricity demand has been unchanged by the regulation.

Our analysis is composed of the following parts:

a) We model and estimate firms output decisions based on markups and controlling by exogenous variables that are relevant at the firms' level, such as indicators of climate conditions (Niño and Niña events). This is particularly relevant as the hydro generation is very important in Colombia (68% of total generation).

   We estimate this model using data before August 1, 2009 and two measures for the markup. For thermal plants we use the marginal costs estimated using fuel costs, heats rates, etc. and for the hydro plants we use opportunity costs as explained in the Appendix. For prices we use the observed spot price and a simulated spot price that we explain below. Using this information we define markups as the difference between prices (observed spot or simulated) and the marginal or opportunity costs. The first set of prices are named the observed marginal prices, the second set of prices are named the fitted prices (see next item).

Using this model we estimate counterfactual output decisions after 2009. Below we provide our interpretations of this counterfactual.

b) We model pricing behavior using a very flexible aggregate supply curve similar to (Mansur, 2008) and estimate the model using data before 2009. This model is used for two purposes. First, we use it to estimate counterfactual prices after 2009 and second; we estimate fitted prices before 2009.[25]

c) We evaluate welfare losses making three different comparisons depending on the prices we use for estimation before 2009 and the counterfactual we simulate.

a. Output decisions

Firms' production decisions are estimated using data before 2009. Using this model production predictions are constructed both before (in sample estimation or models fit) and after the reform (out of sample estimation or forecast). In general in a dynamic model, assumptions on 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 current output depends on historic, 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:

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

[25] In his framework Mansur (2004) interprets these fitted prices as competitive prices. We do not advocate that interpretation. In our interpretation fitted prices are only useful for performing a sensitivity analysis on our results.

where α_i, are units fixed effects, $\overline{pcm}_{it}$ is the average markup for the day, pcm_pos_{it} is a binary variable equal to *one* if there was a positive markup for firm i at time t and *zero* otherwise and $\vec{F}$ represents hours, weekdays and months fixed effects. Notice that specific characteristics like minimum up times, minimum downtimes, load costs, start-up cost, ramping rates, etc., do not vary significantly in time and are undistinguishable 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. Compared to Mansur's model, more variables were added in order to adapt the methodology to Colombian electricity market. First of all, there are two indicator variables that are very important for all agents and generating units, representing 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. Also by ignoring the potential strategic interaction among firms, by ignoring output decision of other firms (other than i) in equation (2), we are potentially omitting variables which also call into question the independence of markups and the error term. As a result estimated coefficients may be biased. We have tried to mitigate some of these potential econometric problems by introducing instrumental variables and reporting sensitivity analysis for the main results. Below we provide a discussion of these issues. For the moment, to get a sense of the model's fit and the role of introducing a more flexible specification, the next two tables report the estimation results for the model with no polynomials nor calendar fixed effects, and the full specification.

Table 1, with no polynomials nor calendar fixed effects, shows the average coefficient for each variable across all plants, average standard error and the number of firms, out of 46 firms, for which the coefficient is significant at a 95% confidence level.[26] The R^2 of the model is 0.2 and the variables are significant in most of the units evaluated; being the unit fixed effect and El Niño and La Niña phenomenon a key variable in almost all models. Also the coefficients sign of most variables are intuitive. Tables 1.1 and 1.2 report the same results by resource type. There is notable difference in coefficients between El Niño and La Niña variables for thermal and hydroplants which is consistent with our intuition.

[26] Before 2009 we exclude 4 plants: Flores 4 and Porce 3 did not exist and Esmeralda and San Francisco place no bids and therefore, we cannot calculate the opportunity costs for these plants (when opportunity costs for hydro plants are defined as the minimum between the bid and the most expensive thermal plant dispatched).

Table 1.1. Summary of simple model for 29 Thermal Plants

Plants	Average of Coefficients	Average of Std. Errors	# of Coefs. Significant(5%)
Unit fixed effect	774,169	14,810	28
pcmpos	130,251	19,349	25
Pcm	1,460	534	18
pcmminus1	2,170	422	16
pcmplus1	1,719	422	8
meanpcm	-2,670	810	16
meanpcmminus24	4,568	578	26
meanpcmplus24	-2,177	577	21
Niño	228,806	18,131	27
Nina	-28,080	11,672	28

Table 1.2. Summary of simple model for 17 Hydro Plants

Plants	Average of Coefficients	Average of Std. Errors	# of Coefs. Significant(5%)
Unit fixed effect	2,327,243	30,671	17
pcmpos	3,299,761	38,897	17
Pcm	1,047	1,165	13
pcmminus1	8,574	923	15
pcmplus1	8,245	923	15
meanpcm	6,560	1,209	13
meanpcmminus24	-10,389	709	16
meanpcmplus24	-13,791	710	17
Niño	-203,026	41,227	16
Nina	54,984	26,654	15

Table 2 reports the results of the full model. Similar comments apply although now the R^2 of the model is substantially better (approximately 0.3).

Table 1. Simple model estimation. Average over 46 firms

Variables	Average of Coefficients	Average of Std. Errors	# of Coefs. Significant(5%)

Variables	Average of Coefficients	Average of Std. Errors	# of Coefs. Significant(5%)
Unit fixed effect	3,111,768	45,537	45
Pcmpos	3,422,624	58,302	43
Pcm	2,567	1,703	31
pcmminus1	10,751	1,348	31
pcmplus1	9,983	1,348	23
Meanpcm	3,048	2,028	29
meanpcmminus24	-5,311	1,293	42
meanpcmplus24	-15,724	1,292	38
Niño	28,134	59,378	43
Nina	23,310	38,337	43

Notes: The models' average R^2 is 0.20.

Table 2. Summary of flexible model estimation. Average over 46 firms

Variables	Average of Coefficients	Average of Std. Errors	# of Coefs. Significant(5%)
Unit fixed effect	2.27e+06	1.30e+05	44
Pcmpos	2.48e+06	7.57e+04	34
Pcm	-1.13e+04	3.98e+03	24
pcm_2	1.30e+01	6.54e+01	9
pcm_3	5.35e-01	8.90e-01	13
pcm_4	-2.08e-03	5.19e-03	7
pcm_5	1.83e-06	8.90e-06	9
pcmminus1	1.26e+04	2.97e+03	25
pcmminus1_2	-1.05e+02	5.10e+01	20
pcmminus1_3	-1.13e+00	7.15e-01	21
pcmminus1_4	1.09e-02	4.37e-03	24
pcmminus1_5	-2.02e-05	7.71e-06	22
pcmplus1	1.03e+04	2.98e+03	23
pcmplus1_2	-7.40e+01	5.11e+01	19
pcmplus1_3	-7.19e-01	7.20e-01	17
pcmplus1_4	7.03e-03	4.43e-03	17

Variables	Average of Coefficients	Average of Std. Errors	# of Coefs. Significant(5%)
pcmplus1_5	-1.31e-05	7.86e-06	18
Meanpcm	5.65e+04	4.86e+03	31
meanpcm_2	-4.09e+02	1.73e+02	26
meanpcm_3	-9.39e+00	3.94e+00	28
meanpcm_4	1.85e-01	5.26e-02	23
meanpcm_5	-7.16e-04	2.85e-04	25
meanpcmminus24	-1.33e+04	3.65e+03	37
meanpcmminus24_2	3.98e+02	1.52e+02	29
meanpcmminus24_3	-6.79e+00	3.58e+00	31
meanpcmminus24_4	6.43e-02	4.88e-02	25
meanpcmminus24_5	-2.98e-04	2.62e-04	28
meanpcmplus24	-1.17e+04	3.64e+03	36
meanpcmplus24_2	-4.08e+02	1.51e+02	37
meanpcmplus24_3	7.95e+00	3.52e+00	32
meanpcmplus24_4	-1.51e-02	4.77e-02	33
meanpcmplus24_5	-2.99e-04	2.56e-04	34
Niño	7.59e+04	6.80e+04	39
Nina	7.17e+04	4.54e+04	43

Notes: Weekday, hour and month fixed effects are not displayed but were highly significant(full estimation is available in the appendix: Table A1). The models' average R^2 is 0.299. Variables X_# are the terms of the fifth degree polynomial.

b. Prices

As noticed in the previous section, the key independent variable is the markup which is determined by the price. In order to construct a better counterfactual, one has to acknowledge 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. Also we use the in-sample fit of the model to perform a sensitivity analysis.

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 (as well as include hour-of-day fixed effects) and a ten-part piecewise linear spline function (split by decile for each hour) is used. We also control for El Niño and La Niña indicators:

$$p_t = \alpha_i + \sum_{j(i)=1}^{10} D_t + \gamma_0 nino + \gamma_1 nina + e_t \ (3)$$

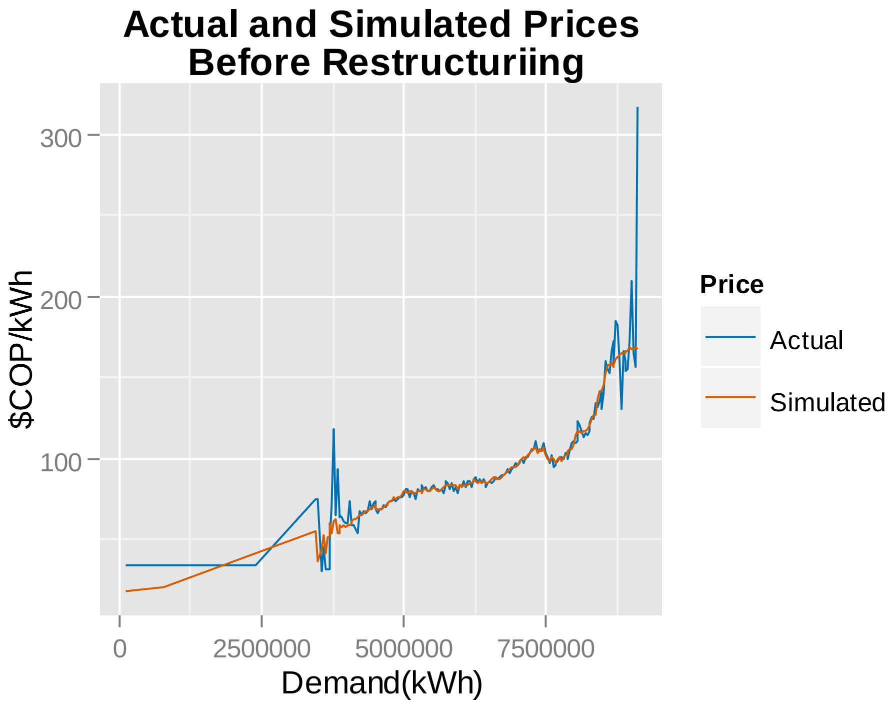
The function is extremely flexible and fits the pre-restructuring data with an R^2 of 0.91. With these estimated coefficients, a second series of prices is simulated after 2009. As in Mansur´s paper, this method requires a common support. The range of demand before 2009 was from 2,393,873[27] to 9,107,534 kWh. The demand increased and the range was 3,828,775 to 9,298,119 kWh after 2009. Finally, predicted prices are adjusted to reflect the actual variance observed in the post-restructuring period.

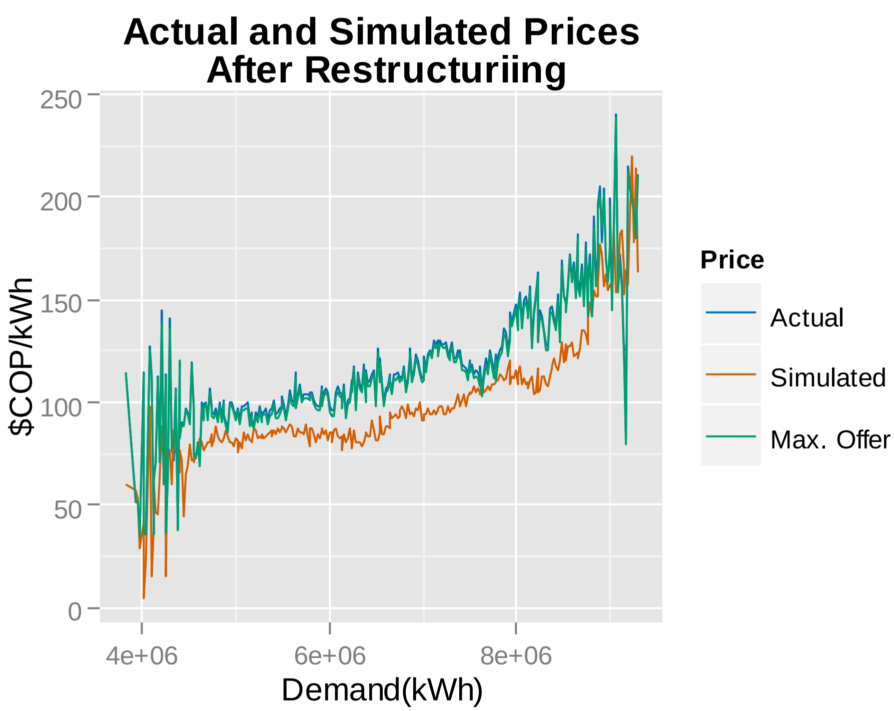
Before 2009, the standard deviation of the unadjusted predicted prices (p_t) (models fit or competitive benchmark) is much lower than that of actual prices (15.37132 and 30.73391, respectively). In order to increase the variance, the residuals from the regression of equation (3) based on the pre-2009 data are used. First, an AR(1) process is fitted for the residuals:

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

The estimated coefficient is $\hat{\rho} = 0.8$. Then, using a Monte Carlo simulation, a new series $\hat{e}_t$ is simulated by drawing from the sample distribution of u_t. Finally the error is added to p_t, to get the adjusted predicted prices. This process is repeated a hundred times and the results are averaged. The following two figures show the real 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 (recall the spot price after 2009 is the marginal price or maximum price offered by the marginal, non-saturated plant dispatched on the ideal dispatch, plus an uplift). Results raise concerns regarding the market power after 2009 suggesting that, the spot price increase after 2009 is not due to marginal costs but, most probably, to market power.

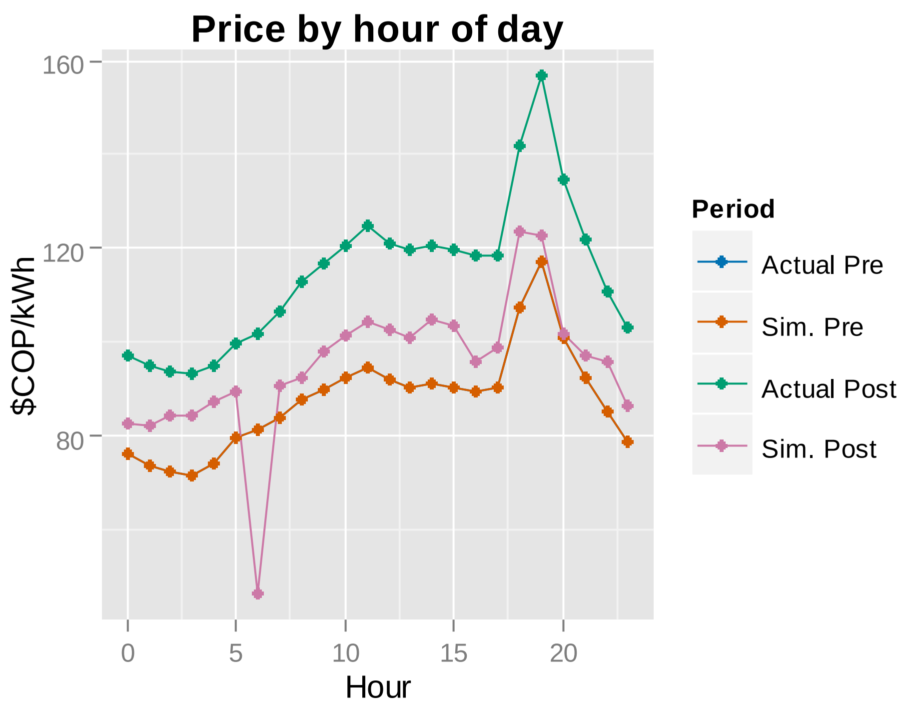
[27] There were only two values (121,228 and 798,678) below.





For the period before 2009, the model simulated prices are close to the real prices, whereas after the restructuration the volatility is similar but the simulated prices are consistently lower. This is very interesting since, as we will see below in the welfare comparisons', all exercises suggest that the new market design based on centralized unit commitment has improved welfare, relative to the counterfactual, even though the prices we are estimating for the counterfactual are lower and most probably, market power has increased.

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



Using these simulated prices for both periods, equations (1) and (2) are estimated again. Once again two versions are shown, the first one with few variables and the second one with full flexibility.

Table 3. Simple model estimation with simulated prices. Average over 46 firms

Variables	Average of Coefficients	Average of Std. Errors	# of Coefs. Significant(5%)
Unit fixed effect	3,852,082	78,963	45
Pcmpos	986,590	94,814	38

Variables	Average of Coefficients	Average of Std. Errors	# of Coefs. Significant(5%)
Pcm	27,065	2,886	24
pcmminus1	21,160	2,087	35
pcmplus1	18,301	2,093	26
Meanpcm	-136	2,910	31
meanpcmminus24	-4,693	1,752	43
meanpcmplus24	-18,663	1,752	43
Niño	-182,242	61,669	37
Nina	19,160	39,232	42

Notes: The models' average R^2 is 0.185.

Table 4. Summary of flexible model estimation with simulated prices. Average over 46 firms

Variables	Average of Coefficients	Average of Std. Errors	# of Coefs. Significant(5%)
Unit fixed effects	3.03e+06	2.86e+05	41
pcmpos	2.56e+05	1.70e+05	20
Pcm	4.64e+04	8.43e+03	19
pcm_2	-4.20e+01	2.07e+02	10
pcm_3	-8.09e+00	4.25e+00	16
pcm_4	5.19e-02	6.75e-02	9
pcm_5	-2.63e-05	3.64e-04	10
pcmminus1	2.61e+04	5.62e+03	21
pcmminus1_2	6.14e+01	1.53e+02	11
pcmminus1_3	-7.55e+00	3.28e+00	16
pcmminus1_4	3.44e-02	5.41e-02	11
pcmminus1_5	7.35e-05	3.05e-04	14
pcmplus1	1.86e+04	5.65e+03	20
pcmplus1_2	9.84e+01	1.54e+02	7
pcmplus1_3	-5.48e+00	3.28e+00	19
pcmplus1_4	2.73e-02	5.42e-02	9
pcmplus1_5	2.63e-06	3.06e-04	14
meanpcm	-1.01e+04	1.96e+04	29
meanpcm_2	1.23e+03	1.25e+03	30
meanpcm_3	-5.12e+00	4.40e+01	25
meanpcm_4	-3.40e-01	8.65e-01	26
meanpcm_5	4.23e-03	7.58e-03	27
meanpcmminus24	1.75e+04	1.71e+04	34
meanpcmminus24_2	-3.06e+03	1.15e+03	35
meanpcmminus24_3	1.20e+02	4.00e+01	37
meanpcmminus24_4	-1.59e+00	7.82e-01	33
meanpcmminus24_5	3.32e-03	6.88e-03	34

Variables	Average of Coefficients	Average of Std. Errors	# of Coefs. Significant(5%)
meanpcmplus24	-1.27e+04	1.73e+04	35
meanpcmplus24_2	-3.57e+02	1.17e+03	32
meanpcmplus24_3	3.39e+01	4.10e+01	31
meanpcmplus24_4	-8.83e-01	8.03e-01	28
meanpcmplus24_5	6.17e-03	7.01e-03	35
Niño	-3.36e+05	7.24e+04	41
Nina	-2.07e+05	4.65e+04	41

Notes: Weekday, hour and month fixed effects are not displayed but were highly significant (full estimation is available in the appendix: Table A2). The models' average R^2 is 0.274. Variables X_# are the terms of the fifth degree polynomial.

Even though some coefficients changed substantially with respect to the actual prices models (tables 1 and 2), El Niño, La Niña and unit fixed effect are still very important. Also notice that R^2 values declined in these models comparatively.

c. Counterfactuals

Using the previous two models we are going to do the following exercises that will lead us to different counterfactuals and welfare estimations.

First let us fix the prices. Simulated prices (in sample or out of sample) and therefore, simulated markups, will be interpreted as self-unit commitment prices/markups. The argument here is that price equation we are estimating with data before 2009 reflects prices that are consistent with the prevailing market design: self – unit commitment.

Before 2009 we estimate two models of output decisions. Using observed markups and fitted markups.

1. For the output decisions model estimated with observed markups, we simulate output decisions using post 2009 observed markups. This simulation is of little importance in itself because it uses a model estimated under self-commitment and simulate it using as inputs markups under centralized unit commitment. Nevertheless, it is useful for the following reason. If the 2009 Regulation had no effect in the market, we would expect that the simulated output would be similar to the observed one after 2009. As reported below, this is not the case and we have an indirect argument for concluding that after 2009 something actually changed in the market.

2. Using the output decisions model estimated using fitted prices, we simulate output after 2009 using simulated (self-unit commitment) markups. This exercise is only of interest for doing sensitivity analysis of our results. In particular we address de robustness of the result to a slightly different price input.

3. We use the output decisions model estimated observed markups to simulate output (self-unit commitment) after 2009 but using simulated markups. In this case we interpret output as the one we would have observed in case no regulation had been introduced (under self-commitment).

d. Instrumental Variables

Taking into account the high concentration of Colombian electricity market, it is plausible that companies are not 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 price setting. That is why a final specification of the model is tested using instrumental variables. There are at least three possible candidates for instruments, the maximum commercial availability, bilateral contracts and "aportes hídricos". The first one was discarded because of insufficient variability: it didn't change at the hour level and scarcely between days. The bilateral contracts variable is theoretically very interesting. At the moment of setting prices it 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 then it will be in its interest to bid high aiming to set the price as high as possible. Unfortunately, there are several issues that hindered the use of this instrument. First of all the data is not available by unit but by company, loosing part of the richness of the data. Moreover, there are 5 units which didn't engage in any contract at all 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. The correlation between the instrument and the markup is 0.3, and the R^2 of the first stage averaged 0.12. Nevertheless in the second stage of the estimation we didn't find a good fit. The third variable "aportes hídricos" is also very interesting as an instrument. Below we report results for this case and more details can be found in the appendix.

e. Welfare Effects

Welfare effects measurements are based on direct production costs, i.e. variable costs, excluding the start-up costs. Below we analyze the role of startup 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:

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

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

Variable costs

Table 5 reports the results of this evaluation. Actual outcomes correspond to observed values for aggregate output and aggregate variable costs. Real prices report also aggregate output and variable costs (deadweight loss and dead weight loss share are not relevant).[28] Results show that post 2009 results are different enough to claim that the Regulation indeed had a notable effect on aggregate output and variable costs.

Results for simulated prices and the "mixed model" correspond to comparisons of observed outcomes after 2009 with the counterfactual explained in the previous section (counterfactuals 2 and 3). The mixed model counterfactual, our best estimation of what would have been unit commitment after 2009 had no resolution been implemented, shows that centralized unit commitment has improved welfare since its introduction. The simulated model provides a way of checking the robustness of the results. Results suggest that welfare has improved since 2011.

[28] Deadweight loss share (DWL share) is calculated as welfare change as in equation 5 divided by actual (observed) aggregate variable cost.

Table 5 exhibits the main results of this econometric assessment of the welfare impact of the Regulation.

Table 5. Welfare Implications of Production Inefficiencies

Model	**2006-0**	**2007-0**	**2008-0**	**2009-0**	**Total Pre.**	**2009-1**	**2010-1**	**2011-1**	**2012-1**	**Total Post.**
Actual Outcomes										
Output	48.5	50.2	50.5	30.0	179.2	22.1	48.0	52.2	50.7	173.0
Total Variable Costs	2,412	2,866	2,936	1,942	10,156	1,369	2,816	2,687	2,874	9,746
Real Prices										
Output	49.0	48.8	49.4	32.8	180.0	25.0	52.0	51.0	56.1	184.1
Total Variable Costs	2,569	2,824	2,880	2,200	10,473	1,646	3,209	2,686	3,361	10,902
Deadweight loss						-278	-394	1	-487	-1,158
DWL share						-20.28%	-13.99%	0.03%	-16.95%	-11.88%
Simulated Prices										
Output	50.9	49.3	50.1	29.3	179.6	21.0	46.4	53.8	56.4	177.6
Total Variable Costs	2,612	2,838	2,848	1,876	10,174	1,334	2,781	2,889	3,263	10,267
Deadweight loss						35	34	-202	-390	-523
DWL share						2.54%	1.21%	-7.52%	-13.56%	-5.37%
Mixed										
Output	49.0	48.8	49.4	32.8	180.0	22.2	47.5	52.9	52.5	175.1
Total Variable Costs	2,569	2,824	2,880	2,200	10,473	1,451	2,890	2,837	3,095	10,273
Deadweight loss						-83	-74	-149	-221	-527
DWL share						-6.05%	-2.64%	-5.56%	-7.68%	-5.41%

Notes: Output is measured in millions of MWh. Total Variable Costs and Deadweight loss are measured in \$COP Billions[29]. Table A3 and A4 show detailed production estimates by unit using the mixed model.

It is important to recall that the dynamic method constructed here, does not impose an equilibrium constraint. However, predicted output is similar to the observed output especially under the mixed model after 2009.[30]

[29] A Billion is 10^9.

Startup costs

As we mentioned at the start of this section, for welfare comparisons we have ignored additional costs due to startups. We find two difficulties estimating these costs. First, although before 2009 we can count the number of startups using generation data (real dispatch) we don't have data for startup costs (before 2009, plants did not report startup costs) and second the econometric model, being a linear model, is not tailored for estimating startups in the counterfactual. To overcome these difficulties and get a sense of the actual startup costs and hence a better measure of welfare changes, we estimated startup costs before 2009 using the methodology reported in the Appendix. Then using real generation we estimated aggregate (observed) startup costs before and after 2009. The next table shows the results. Table 1 shows that after 2009 startup costs oscillated between 1.21% and 1.65% of variable costs and before 2009, between 1.20% and 2.14%. Since we find it difficult to estimate startups in the counterfactual using our model we estimate startup costs after 2009 in the counterfactual to be between 1.2% and 2.14%. Hence we obtain an upper bound on welfare changes due to startup costs by assuming actual costs of 1.65% after 2009 (for every year) and counterfactual costs of 1.21% for every year. Therefore, a lower bound on the welfare gains of the regulation, in terms of startups costs after 2009, is 0.44% of variable costs (per year). It follows that welfare gains calculated in previous table, based on variable costs underestimate the welfare gains of the regulation.

Table 1. Start-Up and Variable Costs by Year in Million COP

Period	**StartUp.Cost**	**Var.Cost**	**Proportion**
2006.0	51,619	2,417,459	2.14%
2007.0	46,229	2,866,409	1.61%
2008.0	61,606	2,935,507	2.10%
2009.0	23,249	1,941,680	1.20%
2009.1	16,517	1,368,602	1.21%
2010.1	35,095	2,815,608	1.25%

[30] Note also that the mixed model predicts better aggregate output than the first exercise (Real Prices model). Also it slightly over estimates aggregate output after 2009. This leans against the welfare of the counterfactual, by requiring to produce more than what is actually observed. Nevertheless, its effect is marginal on our welfare calculation.

Period	StartUp.Cost	Var.Cost	Proportion
2011.1	44,457	2,687,110	1.65%
2012.1	39,660	2,882,408	1.38%

As mentioned before a legitimate question is raised regarding endogenity problems in our specification of the output decision model. The following table reports the welfare results when we estimate the output decision model by instrumental variables using as instruments the volume of water in rivers ("aportes hídricos")

Table 5. Welfare Implications of Production Inefficiencies using Instrumental Variables

Model	2006-0	2007-0	2008-0	2009-0	Total Pre.	2009-1	2010-1	2011-1	2012-1	Total Post.
Actual Outcomes										
Output	48.5	50.2	50.5	30.0	179.2	22.1	48.0	52.2	50.7	173.0
Total Variable Costs	2,412	2,866	2,936	1,942	10,156	1,369	2,816	2,687	2,874	9,746
IV Mixed										
Output	49.9	50.3	50.2	29.0	179.4	22.0	50.0	54.8	52.9	179.7
Total Variable Costs	2,762	3,138	3,128	1,962	10,990	1,436	3,180	3,139	3,199	10,954
Deadweight loss						-67	-365	-451	-325	-1,208
DWL share						-4.92%	-12.96%	-16.80%	-11.31%	-12.39%

f. Conclusion

Results show that under different model specifications there is evidence supporting the claim that Resolution 051 of 2009 of CREG resulted in a positive welfare effect.

This is even though simulated prices, reflecting what would had happened in case the Resolution had not been implemented, predict lower prices than the observed ones. It follows that markups have increased after the regulation suggesting an increase in the exercise of market power. Nevertheless, gains in efficiency due to a better dispatch compensate for the welfare loss due to the exercise of market power.

6. Structural model (competitive benchmark counterfactual)

In this section we introduce the structural model used to evaluate the Resolution. The objective is to lay down a centralized unit commitment formulation that replicates the main features of Colombian ideal dispatch. In other words we construct a model similar to the model used by Colombia's ISO to calculate the ideal dispatch. Since we didn't have access to the official unit commitment model employed by XM we have attempted to replicate it as closed as possible. The model is presented in Appendix A and was programmed and solved using FICO Xpress Optimizaion Suite[31]. Using this model we constructed counterfactuals that represent a competitive benchmarks to supply energy every hour for the period January 1, 2006 to December 31, 2012.

The competitive benchmark has two main versions. In the first version; the competitive all resources dispatch, we use all the resources to service the total demand. In the second version; the competitive thermal dispatch, we factor out hydro generation from total demand and consider the problem of servicing this residual demand using only thermal plants. Both benchmarks rely heavily on our estimation of marginal costs for thermal plants and the opportunity costs for hydro plants. This section is organized as follows: The first section explains in more detail how the counterfactuals are constructed. We then explain how the model was validated. We will argue that the model captures the most salient features of the dispatch and that any differences between the observed ideal dispatch can be explained by simplifications made on the ramping model of thermal plants and boundary conditions used to run the model every day. Section (c) present analogous welfare estimations to those presented in previous section using a reduce form econometric model. Since our structural model is our main evaluation methodology we do further analysis of the welfare calculations to validate their statistical significance. Sections (d) and (e) provide further explanations and intuition of the model and help explain the welfare results of section (c).

[31] Under Academic Partners Program that grants license for full time academics to use Xpress for consulting jobs. See http://exchange.fico.com/dmc.

a) Model and counterfactuals

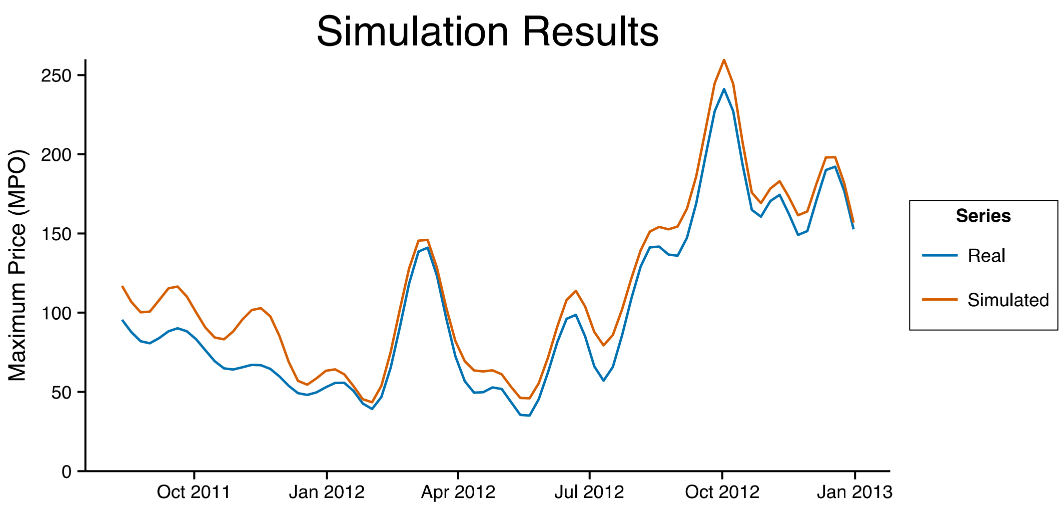
Using the marginal costs of thermal plants, the opportunity cost of water, startup costs and the observed demand for the whole period under study, before and after 2009, we follow the following steps:

- Plug in marginal costs and opportunity costs to the model as if they were agents' truthful bids. All other model parameters are taken identical to parameters in the real world (except for certain approximations, some of them which are discussed in the Appendix).
- The output of the model, dispatch, marginal prices, uplift, spot price are interpreted as a competitive benchmark (first best).
- We measure the difference between the observed dispatch before 2009 and the competitive benchmark after 2009.
- We measure the difference between the observed dispatch and the optimal dispatch after 2009.
- Compare previous two calculations (year by year and for the entire period).

b) Validation

First, we want to determine how good the simulation model is in predicting observed spot prices. To do that, we take the period September 2011 to January 2013 and compare the observed MPO versus the simulated MPO.[32] We plug in into the model actual price bids and reported startup costs. The next graph shows the results (actual and simulated values are smoothed).

[32] This is a long enough period for the validation and also one for which all 50 plants where available to dispatch.



As we see, there is a very good match of simulations to actual MPO. The next table reports a series of measures on the goodness of fit of the simulated data.[33]

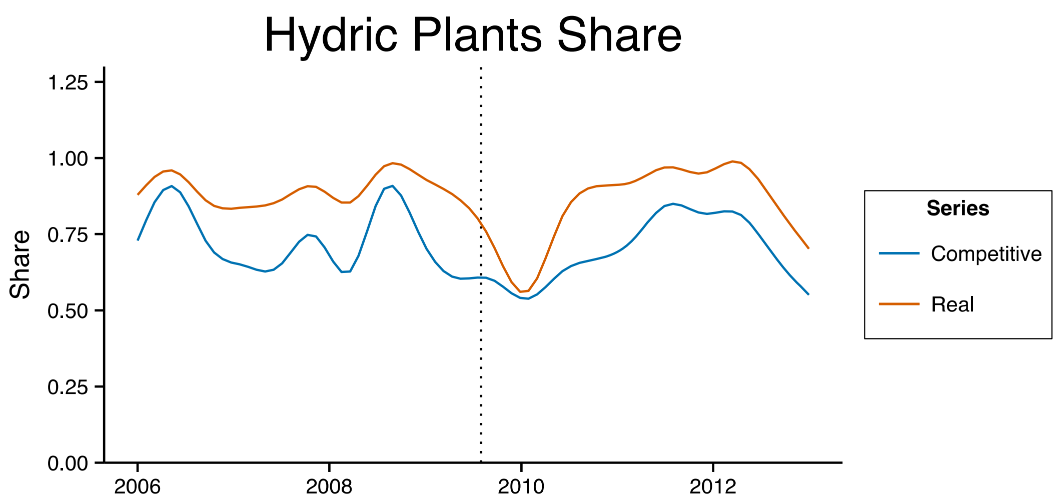
	Value
MAE	**14.73**
MAPE	**11.45%**
MPE	**10.73%**

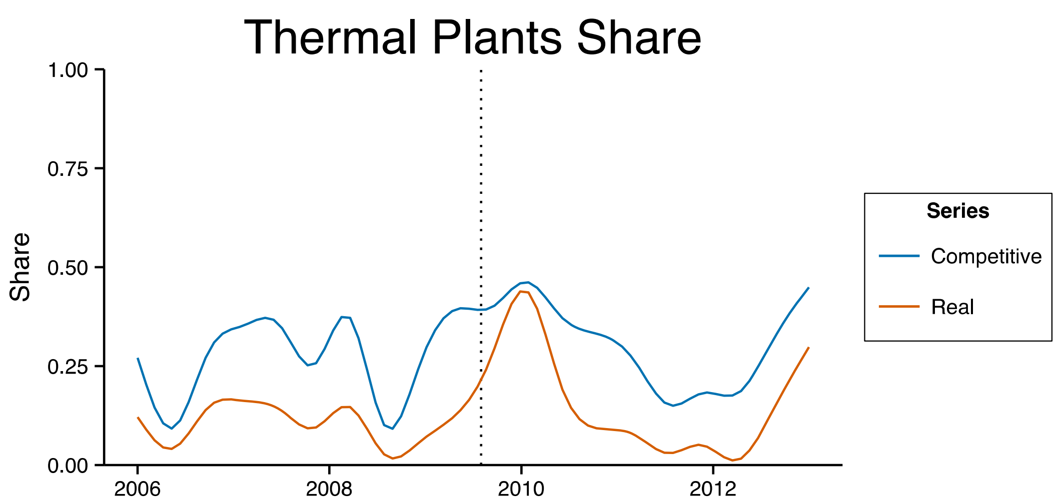
This means that on average, there is an absolute error of 14.73 COP. Absolute relative error normally represents 11.45% of the actual values, and relative error represents 10.73% of the actual value. Since MAPE is close to MPE, we can conclude that error is caused mainly from an upward bias in our simulation, and not from variance in estimation.

33 MAE stands for mean absolute error; MAPE stands for mean absolute percentage error; MPE stands for mean percentage error; RMSE means root mean square error.

c) Output

In order to understand better the results we calculate the share of hydro plants and thermal plants in generation for the 2006-2012 periods and compare it with shares on the all resources competitive benchmark. The two graphs below show real vs. simulated (competitive) shares after smoothing, using cubic smoothing splines.





We observe throughout the 2006-2012 period that hydro generation is higher than the optimal generation suggested by the competitive benchmark, and consequently, thermal generation lower. The dotted line represents the time at which Resolution 051 of 2009 was implemented.

We note that a few months after the reform, thermal generation participation increased towards the competitive ideal, and stayed close to it for a short period. This behavior is similar to the one observed in prices. A few months after the reform, prices decreased and reached competitive spot prices (around the beginning of 2010), but rapidly started diverging from the competitive benchmark.

We also calculate generation shares per year and generation shares before and after the reform for the real world and all resources competitive benchmark.

	Hydro Generation		Thermal Generation	
	Real	Competitive	Real	Competitive
2006	90.53	80.33	9.47	19.67
2007	86.21	66.68	13.79	33.32
2008	92.09	76.94	7.91	23.06
2009	78.35	60.62	21.65	39.38
2010	79.20	63.40	20.80	36.60
2011	94.83	79.11	5.17	20.89
2012	88.4	71.62	11.6	28.38

Generation Shares per Year

	Hydro Generation		Thermal Generation	
	Real	Competitive	Real	Competitive
Before Reform	89.19	72.50	10.81	27.50
After Reform	85.06	69.95	14.94	30.05

Generation Shares After and Before Reform

We see that each year there is a big gap between real generation and competitive (simulated) generation. This gap generally represents more than 10% of total production. If we compare this gap before and after the reform, there is a slight reduction of 2% in the difference between real shares and competitive shares.

d) Markups

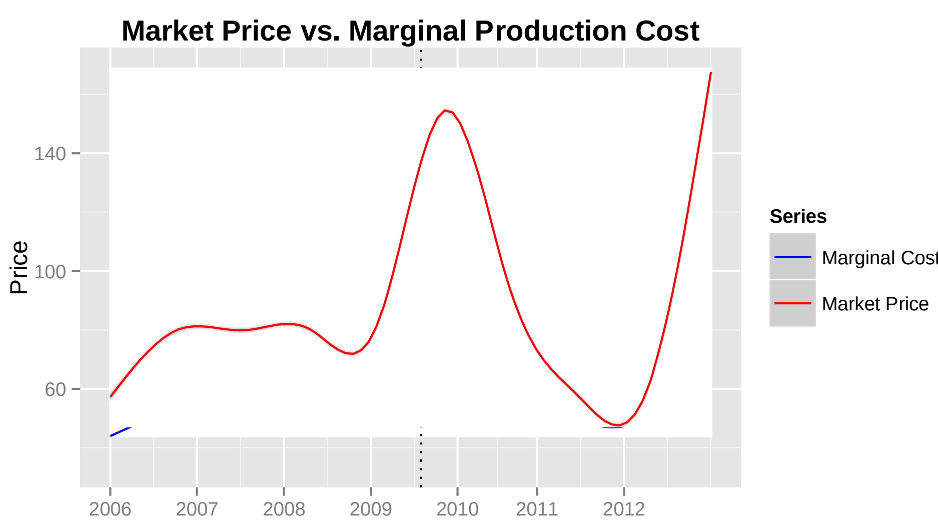
We want to determine if the reform has had any impact on how competitive the energy market is in Colombia, as reflected by plants mark-ups. In order to estimate markups, we use the plants' marginal cost, in the case of thermal units, and the plants' opportunity costs, in the case of hydro units. Both were calculated for the period 2006-2012. Then, we compare them with the actual market price.

Since marginal costs and opportunity costs differ across units, we use a weighted mean as the marginal production cost of the whole industry ($IndustryMC_t$). Weights correspond to energy generation each period.

$$IndustryMC_t = \sum_i \frac{g_{it} MC_{it}}{g_t}$$

where g_{it} is plant i generation at time t, MC_{it} is its estimated marginal cost and g_t is total generation at time t.

The next graph shows the estimated industry marginal cost and actual spot (market) price. We use a locally weighted polynomial regression (LOESS) to draw a smoothing curve for these two series.

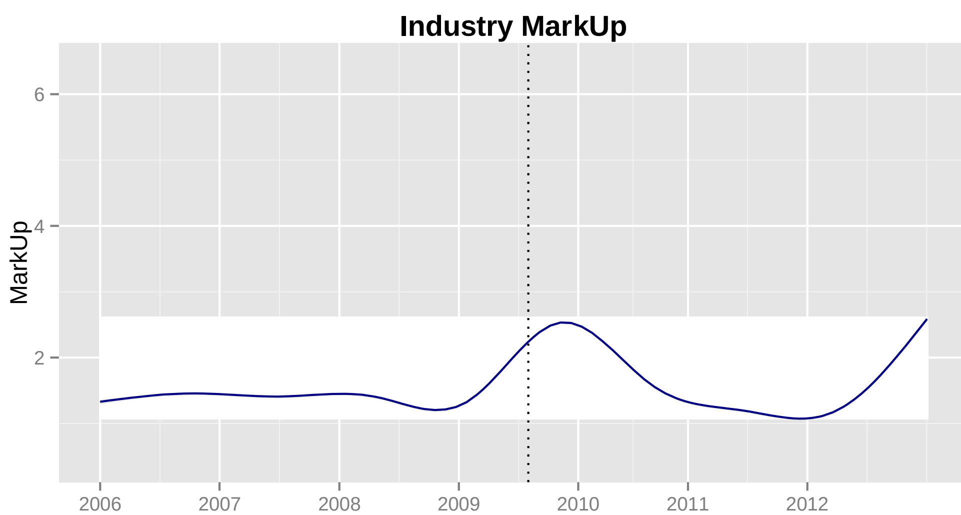


The dotted line represents the time at which the reform was activated. It appears that before the reform, prices had been increasing continuously, and a few months after it, they started to decline until they reached marginal costs just before 2012. The last year, after touching marginal costs, market prices have been increasing substantially. Movements in the marginal price do not explain movements in the market price.

Now we calculate the relative industry's markup ($IndustryMarkUp_t$) defined as market price divided by marginal costs. For a given period:

$$IndustryMarkUp_t = \frac{MarketPrice_t}{IndustryMC_t}$$

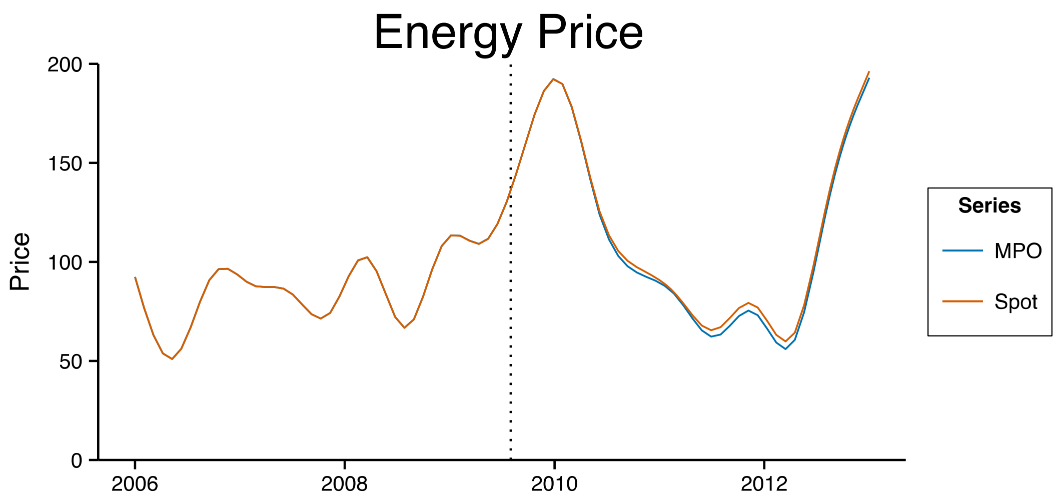
The next graph shows the MarkUp behavior for the 2006-2012 periods.



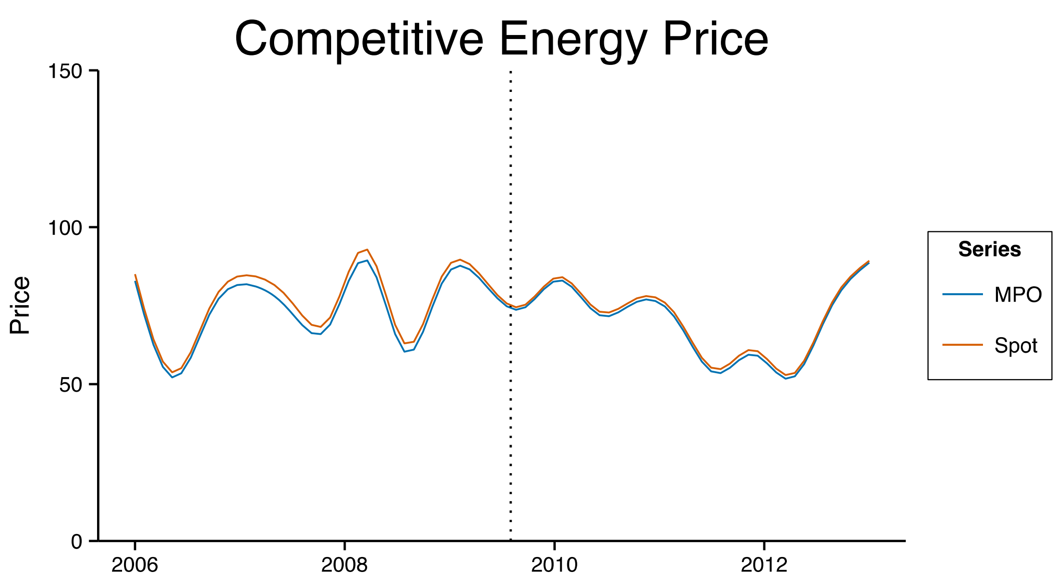
In a perfectly competitive market, the markup should be close to one. We see that before the reform the markup started increasing and kept on increasing until 2010. Then, it declined for two years, becoming similar to the perfect competition benchmark in 2012. Since then, it has been rising again.

e) Observed and simulated competitive prices

The following graph shows observed energy prices (MPO and spot price) for the 2006-2013 period. We use a cubic spline smoother:

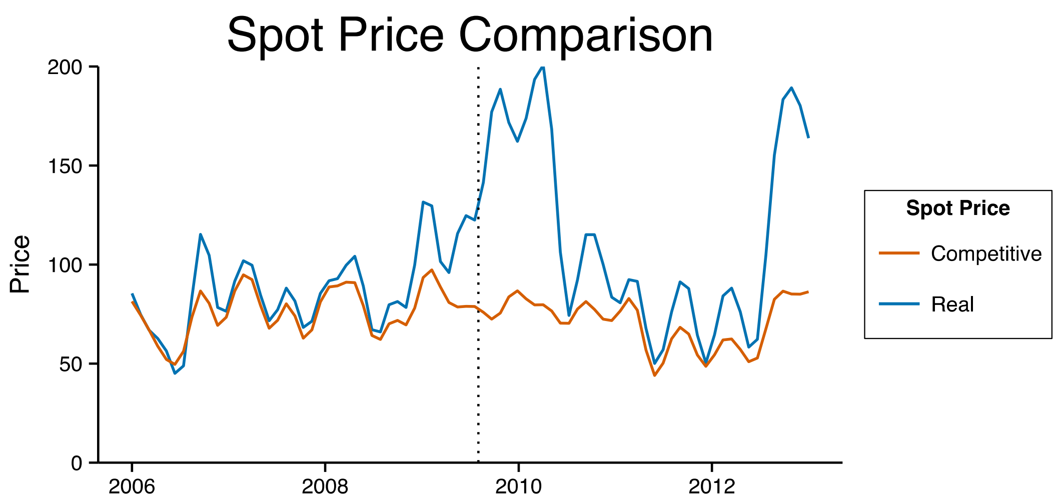


The next figure shows the analogous graph for simulated competitive prices form the all resources competitive benchmark model.



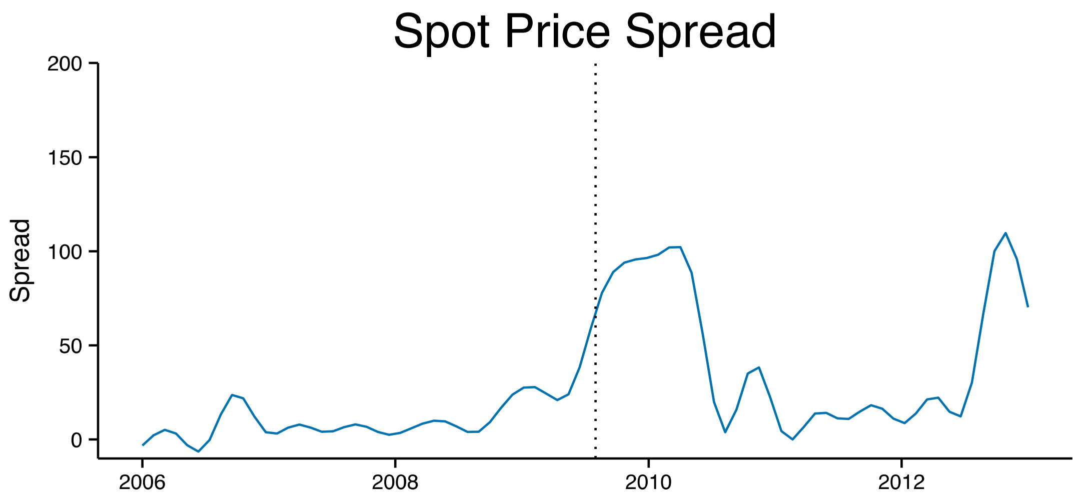
We notice two periods of increasing prices for the observed series. The first one starts a few months before the Resolution is implemented, the second one start after the beginning of 2012. The competitive energy price, which was calculated assuming plants' bids were their marginal costs, does not reflect the increasing behavior in observed prices.

Next figure compares the observed (real) spot price and the simulated (competitive) spot price.



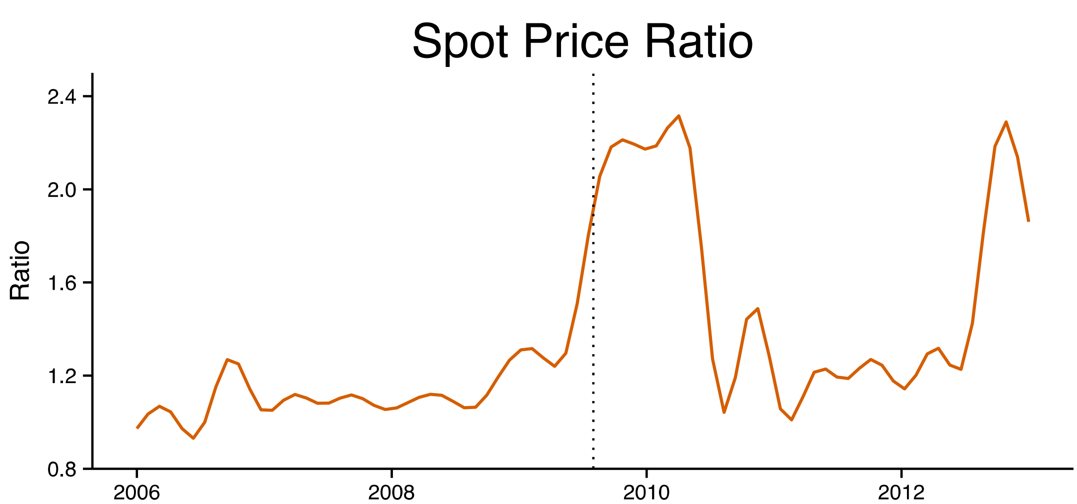
We notice that several fluctuations in the observed spot price are accompanied by fluctuations in the competitive spot price, but competitive spot prices do not follow the same trend as observed prices during the two periods of rapid increase in 2010 and 2012. From this, we can conclude that prices behavior during these two periods cannot be explained by changes in marginal costs.

We graph the spot price gap (or spread), defined as the spread between the observed spot price and the competitive spot price.



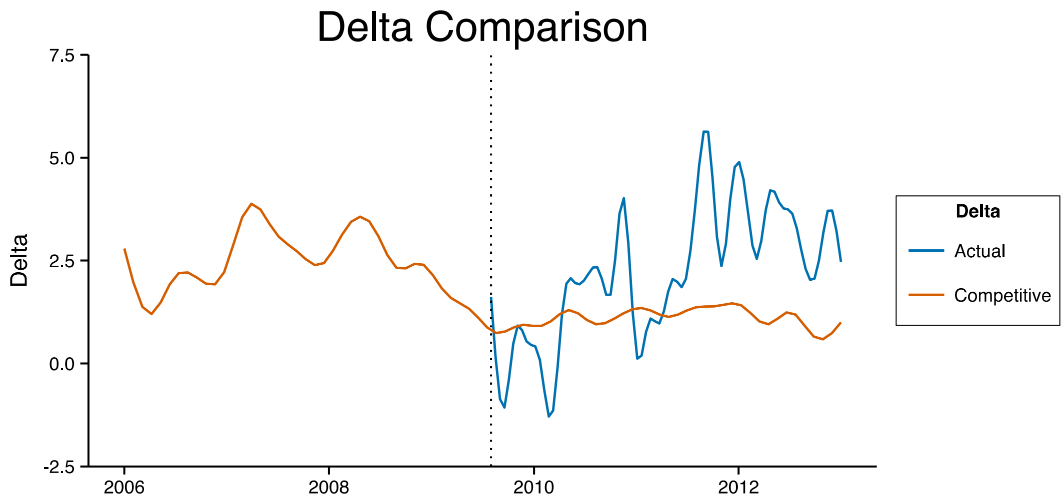
We see that the spot price gap reaches values as high as 100 Pesos at the beginning of 2010 and at the end of 2012. The spot price gap was stable and close to zero during 2006, 2007 and 2008. It rapidly increased in 2009. It fell back and stayed stable until the middle of 2012, when it started to rise rapidly.

The ratio between the spot price and the competitive spot price shows a similar behavior.



Ratios close to one means that prices are close to marginal cost. This is the case for the 2006-2009 periods. In 2010 and 2010, prices reached 2.4 times the competitive price.

Finally, we show the observed delta and the simulated (competitive) delta.



The actual delta is higher than the competitive delta most of the time. This also raises concerns on the efficiency implications of of the observed delta. Recall from previous sections that the uplift depends on startup costs and generation of saturated plants. This results shows that some additional inefficiencies besides plants bids of marginal costs, are due to the revelation of startup costs and thermal plants characteristics that make them less flexible plants and with a higher probability of being compensated for generating as saturated plants. Below we'll comment more on this source of inefficiency and the incentives created by the definition of the uplift.

f) Welfare

We estimated the welfare changes with the Resolution 051 using the same expression used before (eq. 5):

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

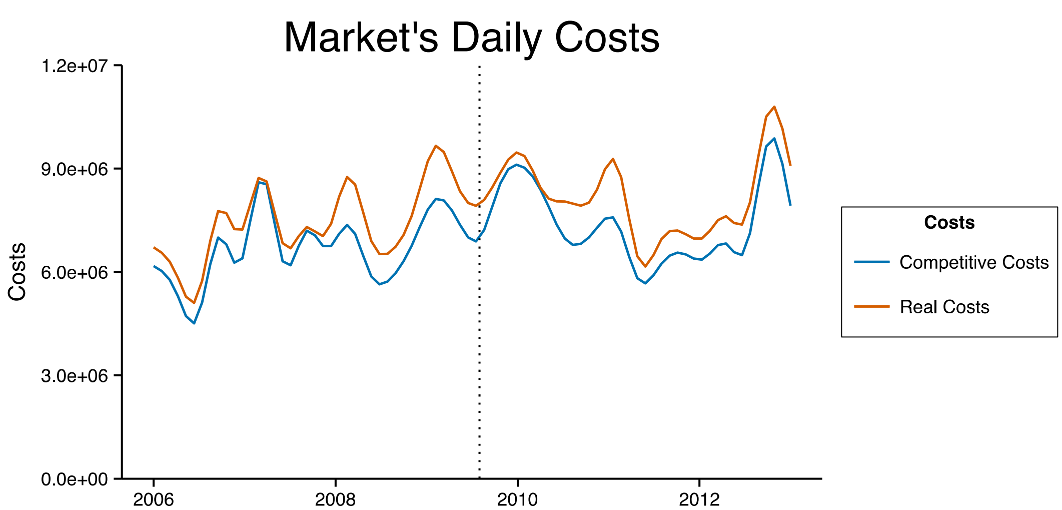
where c_{it} are marginal costs of plant i at time t. And q_{it}, $\hat{q}_{it}$ are real generation and competitive (simulated) generation, respectively.

Another way to look at ΔW is as the deadweight loss in the market from firms not bidding their true marginal costs. Another measure that is going to be useful in analysing deadweight loss is the deadweight ratio

$$DR = \sum_{t=1}^{T}\sum_{i=1}^{N} c_{it}(q_{it} - \hat{q}_{it}) \,/ \sum_{t=1}^{T}\sum_{i=1}^{N} c_{it}q_{it}$$

which represents how big the deadweight loss is in relation to the amount paid to plants for their production. In a competitive market the deadweight portion should be equal to zero.

First, we show actual market's daily costs and competitive daily costs.



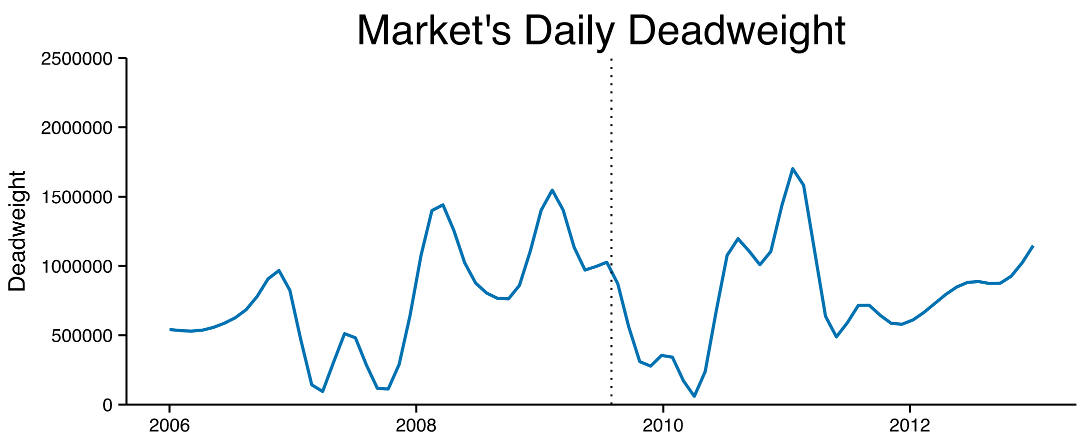
We notice that competitive costs are below real costs, as expected. It's interesting that real costs follow the competitive costs trend. The spread between real costs and competitive costs is a deadweight imposed on the industry as a consequence of market power or inefficiencies in the dispacth. The next graph reflects the daily deadweight in the industry. The results of the model are:

	2006	2007	2008	2009	2010
Real Costs	2353.60	2754.14	2766.21	3235.54	2784.99
Simulated Costs	2120.11	2626.92	2381.08	2902.97	2548.20
Deadweight	233.49	127.22	385.12	332.57	236.79
DW Ratio	9.92%	4.62%	13.92%	10.28%	8.50%

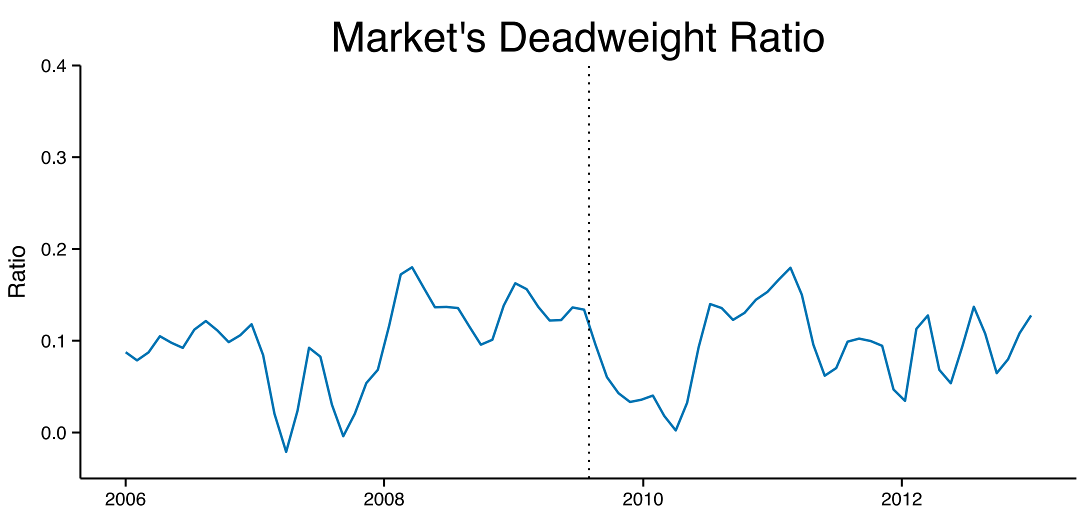
Deadweights for the 2006-2012 period added by year. Total costs and deadweights are expressed in COP Billions

	2006-Reform	Reform-2012
Real Costs	9751.04	9944.84
Simulated Costs	8746.09	9011.77
Deadweight	1004.95	933.07
DW Ratio	10.31%	9.38%

Deadweights before and after the reform. Total costs and deadweights are expressed in COP Billions

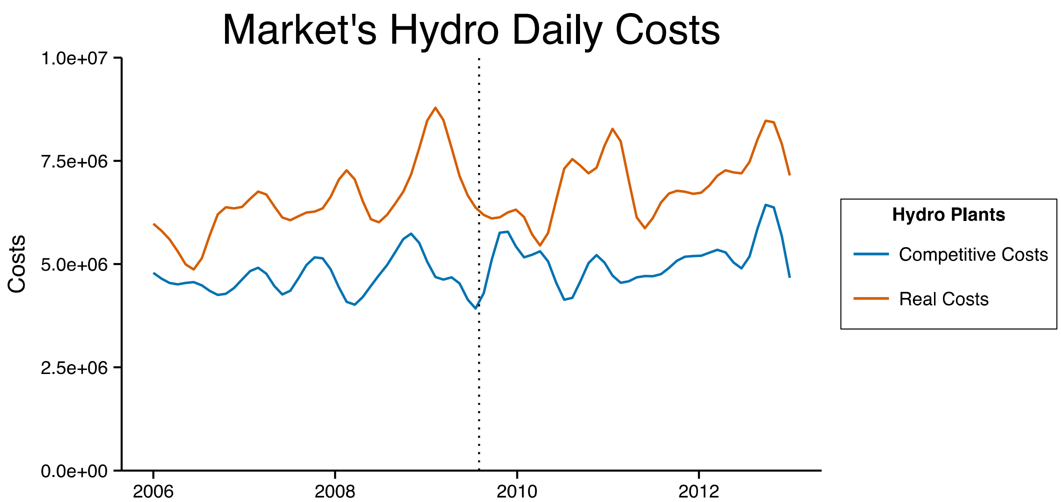


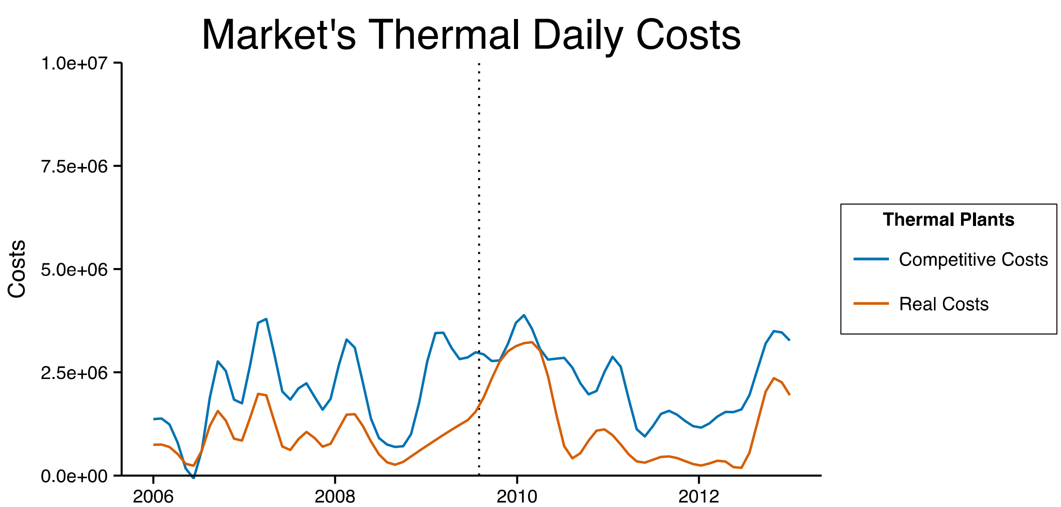
Deadweight is graphed in millions of pesos. This is a quantitative measure of the change in welfare from the actual conditions of the market to a competitive market. This measure is easier to analyse if we compare it with total production. Therefore, we use the deadweight ratio defined above.



Deadweight ratio fluctuates between 0% and 20%, which means that up to 20% of daily production is deadweight on the industry due to the exercise of market power.

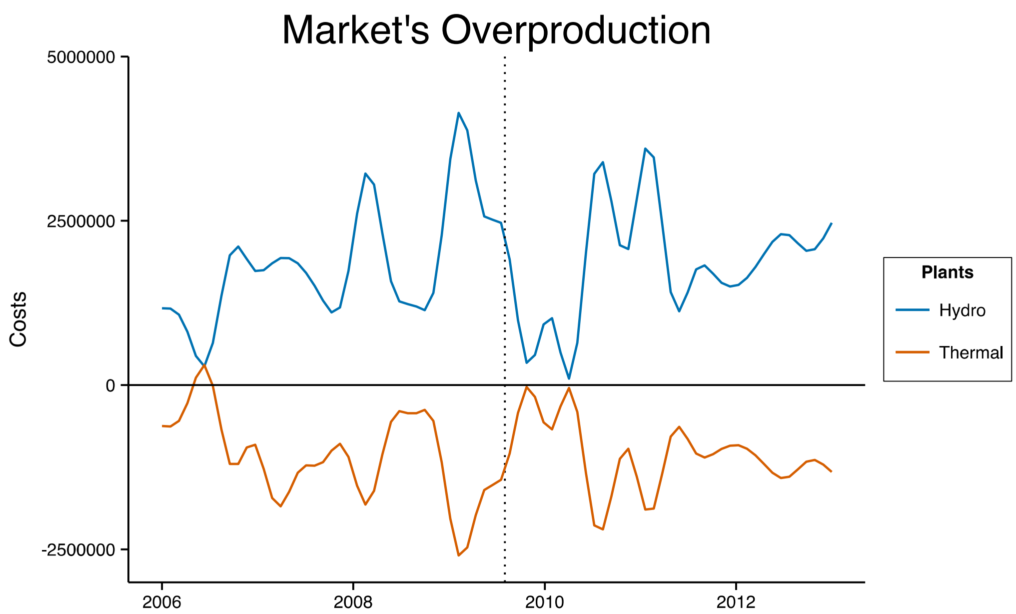
Some interesting insights can be gained from analysing real and competitive costs for thermal and hydro production. We graph the daily market's costs for these two types of generation.



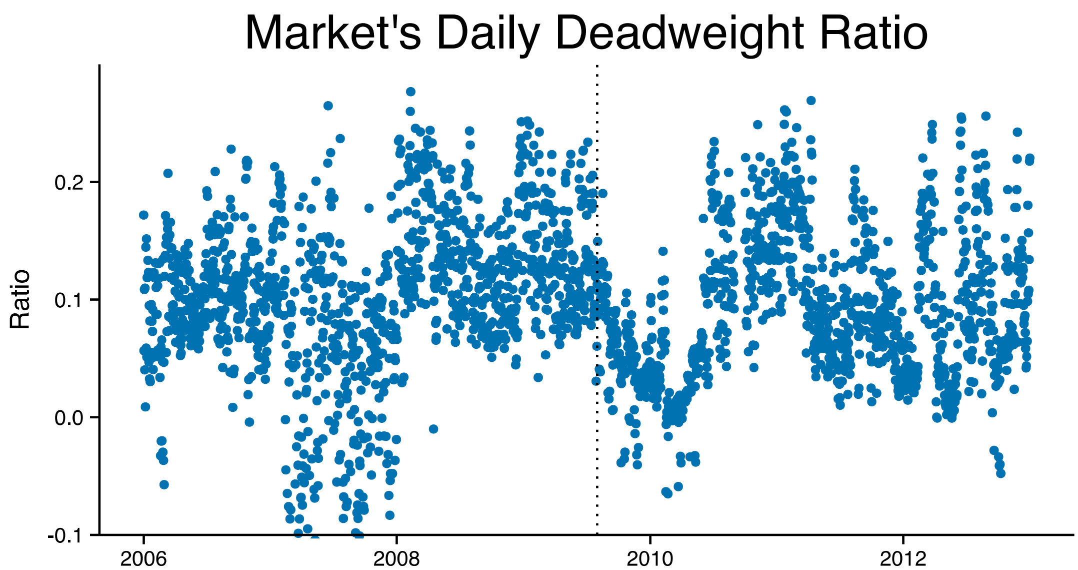


We notice that for hydro production competitive costs are below real costs, but for thermal production, competitive costs are above real costs. This reflects the fact that for the real scenario hydro plants are over-producing and thermal plants are under-producing. An explanation of this phenomenon is that thermal plants are bidding over their marginal costs bymore than what hydro plants are bidding above the opportunity costs (see mark-ups figures), therefore, costs minimization results in excessive hydro production as compared to the competitive scenario while thermal plants produce less than the competitive scenario.

The next graph shows overproduction of hydro plants versus underproduction of thermal plants in millions.



We want to determine if the reform had any effect on deadweight costs. Since we want a measure of deadweight loss relative to production, we will use the daily deadweight ratio. The graph shows observations of this measure across the year.



If we assume independence in the deadweight ratio for daily calculations we can perform a mean difference test. This will determine whether the deadweight ratio decreased after the reform or it did not.

The hypotheses for the test are

$$H_0: DWRatio_{BeforeReform} = DWRatio_{AfterReform}$$

$$H_0: DWRatio_{BeforeReform} > DWRatio_{AfterReform}$$

that is, we want to determine if the Daily Deadweight Ratio was greater before the reform. Using the t-test statistic for a one-sided mean difference test we obtain the following results.

	Before Reform	After Reform	Change
Mean Daily DW Ratio	10.05%	9.02%	-10.28%
Std. Dev Daily DW Ratio	7.70%	6.18%	-19.69%

t-test Statistic	t-test p-value
3.7315	0.000

This means that at a 95% confidence level we reject the null hypothesis and conclude that after the reform there was a decrease in the daily deadweight ratio. The sample estimator for this decrease is of 10.28%.

Another way to express this result is that after the reform the market gained a 10.28% in efficiency, reducing the spread between actual costs and competitive market costs.

Start-up costs

We now address the welfare consequences of start-up costs in the real world and in our competitive benchmark. The next table shows welfare comparisons once we introduce start-up costs. The results show that the actual dispatch is less efficient than the dispatch before the reform when compared to the competitive benchmark.

Year	Real Cost	Simulated Cost	Deadweight	DWRatio
2006	2394.23	2289.21	105.03	4.39%
2007	2803.05	2900.63	-97.58	-3.48%
2008	2853.38	2627.57	225.80	7.91%
2009	3284.39	3115.10	169.29	5.15%
2010	2835.76	2734.62	101.14	3.57%
2011	2804.41	2523.17	281.24	10.03%
2012	3225.77	2963.91	261.87	8.12%

Deadweight and costs are expressed in COP Billions

	Real Cost	Simulated Cost	Deadweight	DWRatio
Before Reform	9962.67	9563.31	399.36	4.01%
After Reform	10238.33	9590.90	647.43	6.32%

Deadweight and costs are expressed in COP Billions

7. Tests

Given that the formula for the uplift has two components: startup costs and production of saturated plants, in this section we address empirical effects of the second component on some observables. Let us recall the saturated production component main determinant:

$$DI_i = \sum_{t=1}^{24} GI_{i,t} \times (\max\{MPO_t, RP_i\} - MPO_t)$$

Independently of RP_i, production of saturated plants is fully insured guarantying that plants will get paid at least the MPO_t. Nevertheless, the incentive for plants to produce under conditions of saturation is not completely clear since technical parameters that define restrictions that determine saturation conditions, also make the plant less flexible for being dispatched when solving the optimization problem. It follows that the question is an empirical one and in this section we try to measure the effects of this component of the uplift on some key variables.

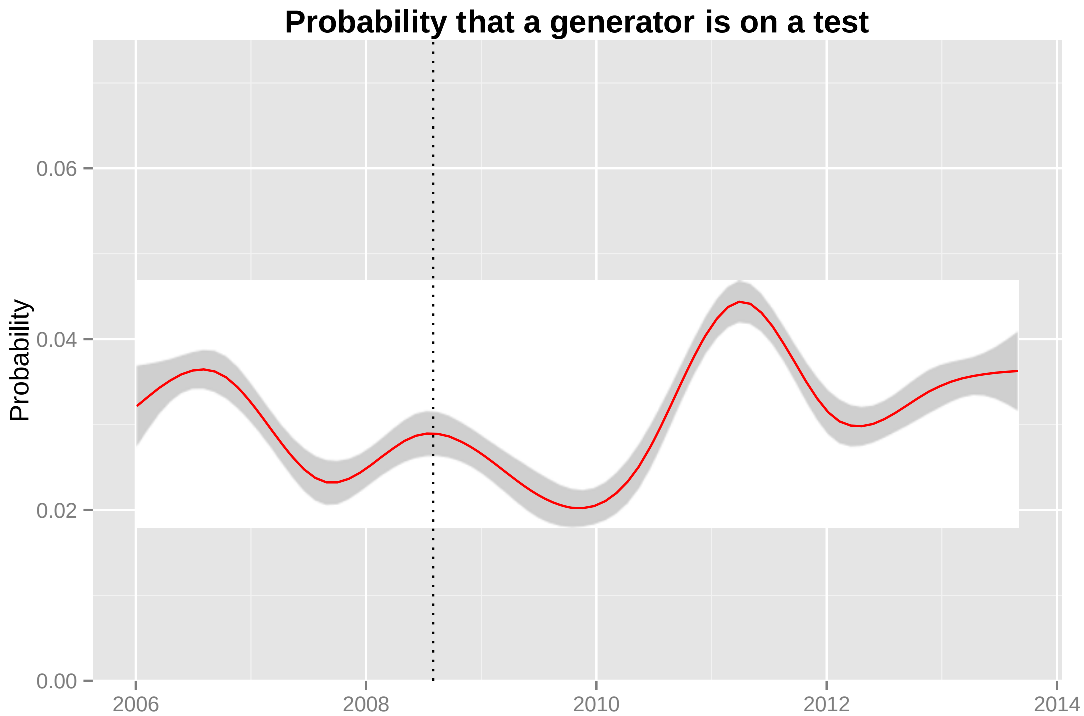
a) Tests

With the 2009 reform plants are paid start-up and energy production costs whenever they perform tests on generators. We want to determine if this has created an incentive for an unnecessary increase in the number and duration of tests.

Probability of being on a test:

First we estimate the probability that in a given hour a firm is in a test. We do this by calculating the empirical probability for each period of 24 hours and then using a LOESS smoother (locally weighted polynomial regression[34]). We present the results graphically.

[34] See Hastie, Tibshirani and Friedman (2009).



The dotted line represents the time at which the reform came into force. During the period 2006-2010, the probability that a generator was doing tests decreased. Starting in 2010, there was a rapid increase in the probability of a test. This probability declined in 2011 but did not recover to the level it had at the beginning of 2010. The last year and a half this probability has been slowly increasing.

Now we calculate the probability that generators were on tests before the reform (starting 2006) and after the reform.

Before Reform	After Reform	Increase
0.02872	0.03332	16.0%

There has been 16% increase in the probability of being on a test after the reform.

We perform a mean difference test to see if the increase in the mean number of periods is statistically significant. Under the null hypothesis that there is no change in means, under the alternative hypothesis there is an increase in the average number of test periods. We obtain the following results using the Welch t-test statistic and we report a 95% confidence interval for the testing increment.

t-statistic	t-Test p-value	95% Confidence Interval
-21.7312	0.000	(14.78%,∞)

At a 95% confidence level we can conclude that there's been a significant increase in the probability that a generator is on tests after the reform.

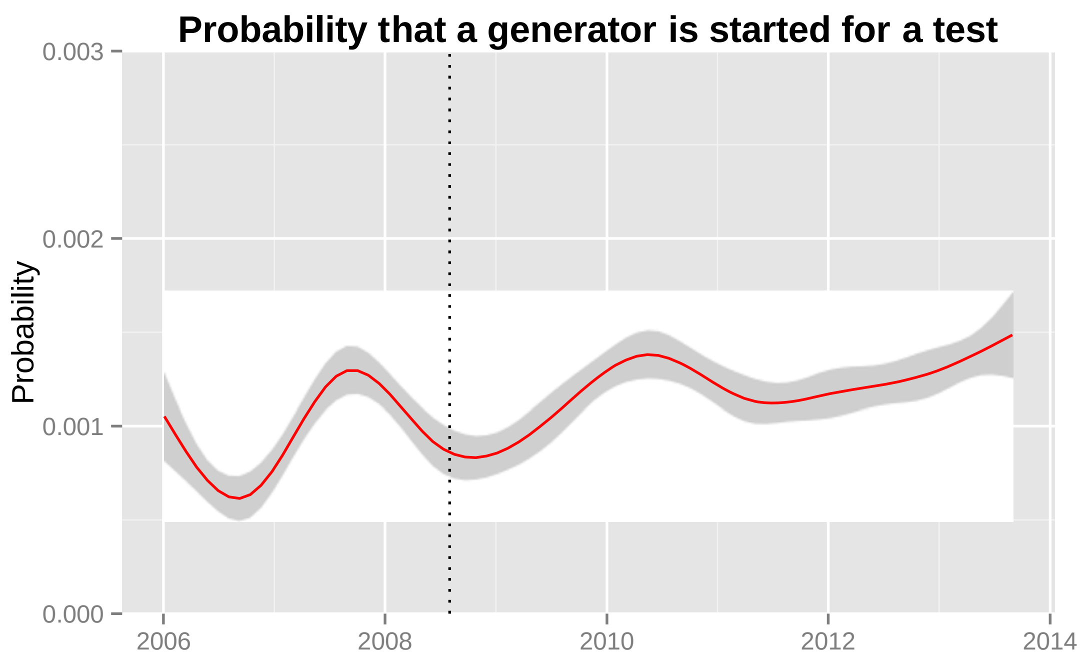
If we perform the same statistical test across the different generators (instead of grouping them as was done in the previous statistical test), then there is statistical evidence that supports, at a 95% confidence level, an increase in the probability of being in a test in 56% of the plants. More information can be found in the Appendix.

Finally, we perform a linear regression of the probability. We use time and a dummy variable that indicates whether the date is before or after the reform as independent variables. We also include their interaction. This will allow us to estimate the probability trend before and after the reform. The results are reported on Table 1 on the appendix.

All coefficients in Table 1 are statistically significant at a 95% confidence level. Before the reform, with each day, the probability of being on a test decreased by $0.987 * 10^{-5}$. After the reform, this probability increased by $0.869 * 10^{-5}$. We conclude, therefore, that there is a negative trend before the reform and a positive trend after.

Probability of starting-up for a test:

We also examine the probability that a generator starts-up for a test. We perform daily empirical estimation of this probability and use an LOESS smoother.



The gray zones represent the standard deviation of the local mean and the dotted line is the time at which the reform came into force. The graph shows a constant increase in the probability of starting up a generator for tests after the reform.

We calculate the empirical probability of starting a generator for a test before and after the reform, there is a 34.61% increase in this probability.

Before Reform	After Reform	Increase
0.0009314	0.001253	34.61%

We also perform a mean difference test to see if the increase in the empirical probability is statistically significant. Under the null hypothesis there is no change in probability, under the alternative hypothesis there is. We obtain the following results using the Welch t-test statistic and we report a 95% confidence interval for the probability increase.

t-statistic	t-Test p-value	95% Confidence Interval
-8.0289	0.000	(27.52%,∞)

We conclude with a confidence of 95% that the probability that a generator starts-up for a test has increased after the reform. This increase has been close to 35%. Performing the same test for each firm, we obtain a statistically significant increase in the probability in 33% of the generators.

We perform again a linear regression of the probability. We use time and a dummy variable that indicates whether the date is before or after the reform as independent variables. We also include their interaction. This will allow us to estimate the probability trend before and after the reform. The results are reported on Table 2 on the appendix.

Coefficients for the trend before reform and for the intercept are significant at a 95% confidence level. Before the reform, with each day, the probability of starting up for a test increased by $5.35 * 10^{-7}$. After the reform, this probability increased by $2.096 * 10^{-7}$ with each day. We conclude, therefore, that there is a positive trend before and after the reform in the probability of starting up for a test. Also, there is no information to conclude that this trend changed with the reform.

b) Conclusion

This section investigate how the use of tests have been affected by Resolution 051. Although tests are considered an instance of inflexibility, their strategic use is different, as we explain below. This motivates the separate consideration.

Tests have the advantage of being temporary and do not suffer from the deterrent of preventing a plant from being dispatched, as is the case with inflexibilities. When a plant is declared in tests, it must run. It is not yet clear, however, that a plant could make money by doing this, since in case of tests, it is only remunerated for actual costs. If the costs are overestimated, however, the companies could make money by declaring it in tests.

We found evidence that the use of tests did increase. This suggests that the strategy described in the previous paragraph may have been employed by some agents.

8. Conclusion and recommendations

This report describes the evaluation of the impacts of the Resolution CREG 051 on the performance of the electricity markets in Colombia.

We found out that economic efficiency has improved since the introduction of the Resolution, that is, the total costs of producing electricity have been reduced. This shows a positive impact of the Resolution.

On the other hand, we also found that mark-ups have increased since 2009, suggesting that there was an increase in the exercise of market power. This observation is consistent with findings for UK and Ireland, which in some phases (see section 3 for details) have implemented centrally committed dispatch as Resolution 051 did.

From the two previous points, we conclude that, although the efficiency has increased, the larger share of the efficiency gains were appropriated by the energy producers, rather than transferred to consumers.

We also detected an increase in the use of tests after the implementation of the Resolution. It is possible that this increase comes from strategic use of tests, with the objective of increasing profits.

Based on these findings, we recommend the following:

a) Execute a deeper study on the possible strategies employed by market participants to manipulate prices under the current rules. Such a study could find out ways to mitigate sources of the market power in the current market design, without the need of substantial modifications in the market rules.

b) Execute a more detailed study on the conditions under which companies are allowed to go in test and be remunerated, with the explicit objective of identifying measures that could curb the generators' possibility of manipulation.

c) While protecting generators against not recovering their startup cost through energy sales should have resulted in more truthful bidding of variable cost, we have not observed a significant decline in energy bids. One possible explanation is the fact that by comparison to centralized unit commitment in

US markets, the bid structure in Colombia under resolution 51 is very simplistic allowing only the bidding of startup cost, one marginal price and technical parameters such as ramp rates and minimum load. By contrast the PJM, CAISO and other US ISOs allow a much richer bid structure that includes no-load cost, 10 segment energy supply curves for each hour, as well as specification of minimum up time and down time, and forbidden ranges for gas turbines. The simplified bid structure in Colombia forces generator to internalize much of the complex structure of their cost and may lead them to overestimate their marginal cost. A richer bid specification that resembles closer the actual cost component could induce more truthful bidding and more efficient dispatch.

d) To the extent that inflated energy bids reflect exercise of market power, it may be appropriate for Colombia to learn from the lessons of the US where current best practices at all ISO include market mitigation and the establishment of *real time* market monitoring entities to assure competitive behavior by market participants. Under such market monitoring practices bids can be replaced by cost based default energy bids when market participants submit bids that are deemed noncompetitive or when market conditions such as congestion or generator's outages create the potential for market power abuse.

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Appendix A: Dispatch model

In this section we give a detailed description of our model of Colombian ideal dispatch. This is a mixed integer linear programing problem. 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 power provided by plant t during hour t.
- $p_{i,t}^{soak}$ is power provided by plant t during hour t and start-up phase
- $p_{i,t}^{des}$ is power provided by plant t during hour t and desynchronization phase.
- $u_{i,t}$ binary variable indicating if unit i is up in period t.
- $s_{i,t}$ binary variable indicating if unit i is started in period t.
- $h_{i,t}$ binary variable indicating if unit i is stopped period t.
- $u_{i,t}^{soak}$ binary variable indicating if the unit i is in the start-up phase.
- $u_{i,t}^{disp}$ binary variable indicating if the unit i is in the dispatch phase.
- $u_{i,t}^{des}$ binary variable indicating if the unit i is in the shut-down phase.
- n_{i}^{soak} number of hours during start-up phase (since start-up until output is at the technical minimum).
- n_{i}^{des} number of hours during shut-down phase (from a technical minimum to shut-down).
- n_i minimum up-time of unit i.
- f_i minimum down-time of unit i.
- $Pof_{i,t}$ the price bid of plant i for hour t.
- N is a big number.
- Par_i is the startup shut down costs.
- D_t is estimated total domestic demand for hour t.
- $P_{i,t}^{min}$ and $P_{i,t}^{max}$ are minimum and maximum generating capacity.[35]
- Parameters of ramping constraint.

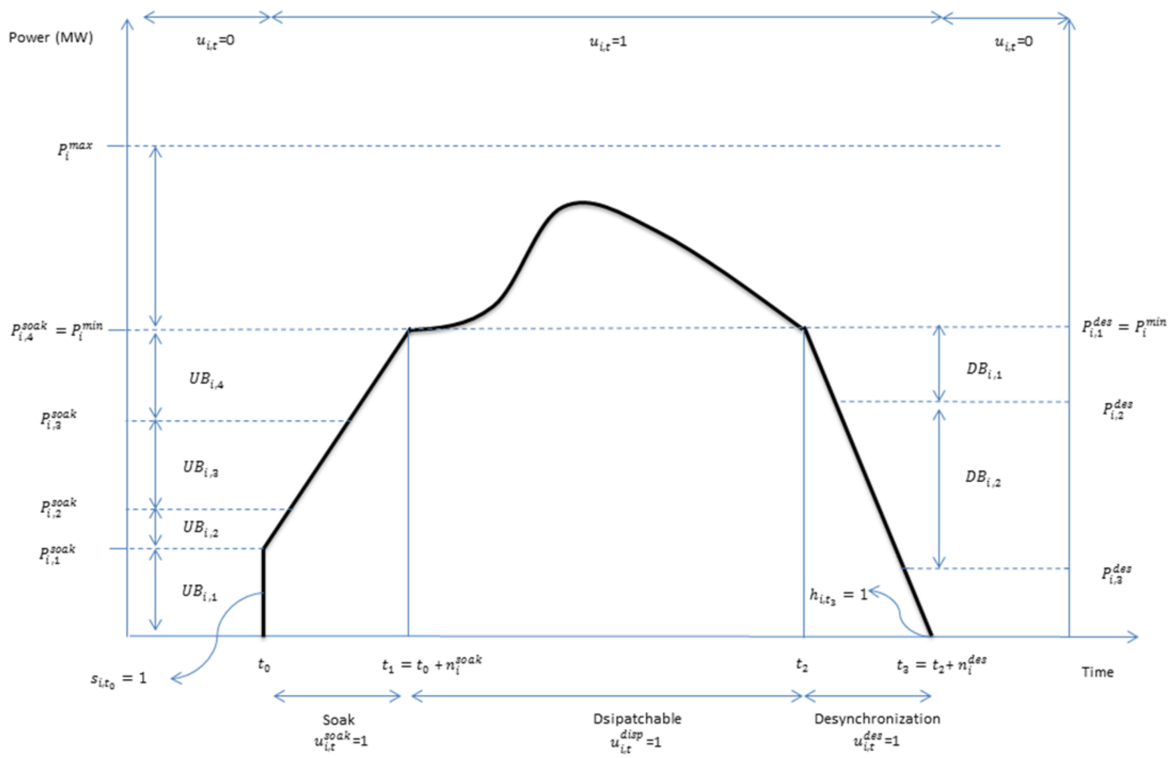
[35] For thermal plants the minimum and maximum is independent of t. For hydro it is zero for most plants except for those that are constrained by environmental requirements that may depend on t.

b) Ramp model

The ramp model is similar to Simoglou et.al (2010). We assume thermal units follow three consecutive phases of operation: (1) Soak or start-up phase (from cero to plants technical minimum power), (2) Dispatchable (when output is between the technical minimum and maximum feasible power output) and (3) Desynchronyzation phase (when output is below the technical minimum and just before shut-down).

In the soak phase power output follows a block model. In the dispatchable phase we assume an affine model for power. In the desynchronization phase we assume a block model.

Ramp Model Thermal Plants



c) Optimization problem

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

Objective function

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

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[36]:

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

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

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

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

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

Dispatch phase

[36] We make two simplifications with respect to Colombian ISO ideal dispatch model. We only consider one type of start-up (as opposed to a cold, warm, hot, star-up) and we only consider one type of configuration per plant (i.e., a fixed ramp per plant).

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

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

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

Here N is a big number.[37]

Desynchronization phase

Desynchronization 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 desynchronization 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 desynchronization phase, power output of the unit is constrained by[38]:

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

Minimum up time

Plants are constrained to be up for n_i periods

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

[37] 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.
[38] This is a simplification of the Colombian current dispatch model on two dimensions. We do not consider an alternative shut down ramp whenever output is not at the technical minimum.

Minimum down time

Plants are constrained to be down for f_i periods

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

Power Output Constraints

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

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

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

Equation (12) constraints the plant to produce the minimum power just before starting desynchronization sequence.

Logical status of commitment

Some restrictions required for a logical transition of the 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

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

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

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

Appendix B: Plants

PLANT	ID	TYPE
ALBAN	101	0
BETANIA	102	0
CHIVOR	103	0
CALIMA	104	0
GUATAPE	105	0
GUATRON	106	0
GUAVIO	107	0
MIEL	108	0
JAGUAS	109	0
LA TASAJERA	110	0
PLAYAS	111	0
PORCE II	112	0
PORCE 3 GENERADOR	113	0
SALVAJINA	114	0
SAN CARLOS	115	0
URRA	116	0
ESMERALDA	117	1
PARAISO GUACA	118	0
PRADO	119	0
SAN FRANCISCO	120	1
TERMOCARTAGENA 1	1001	2
TERMOCARTAGENA 2	1002	2
TERMOCARTAGENA 3	1003	2
MERILECTRICA 1	1004	2
PAIPA 1	1005	2
PAIPA 2	1006	2
PAIPA 3	1007	2
PAIPA 4	1008	2
PROELECTRICA 1	1009	2
PROELECTRICA 2	1010	2
TERMOBARRANQUILLA 3	1011	2
TERMOBARRANQUILLA 4	1012	2
TEBSA TOTAL	1013	2
TERMOCANDELARIA 1	1014	2
TERMOCANDELARIA 2	1015	2
TERMODORADA 1	1016	2
TERMOEMCALI 1	1017	2
TERMOFLORES 1	1018	2
TERMO FLORES 4	1019	2

GUAJIRA 1	1020	2
GUAJIRA 2	1021	2
TERMOCENTRO 1 CICLO COMBINADO	1022	2
TASAJERO 1	1023	2
TERMOSIERRAB	1024	2
TERMOVALLE 1	1025	2
TERMOYOPAL 2	1026	2
ZIPAEMG 2	1027	2
ZIPAEMG 3	1028	2
ZIPAEMG 4	1029	2
ZIPAEMG 5	1030	2

The column named “ID” represents the studies internal identification number for each plant. Column “TYPE” is an attribute representing: “0” if the plant is a hydro generator, “2” if it is a “filo de agua” hydro generator and “2” if it is a thermal generator. Two plants stopped generating the 30th of November, 2011 (thermal plants: Termoflores 2 and 3) and were excluded from the study.[39] Two plants started generating respectively in January 11, 2011 (hydro plant Porce 3) and 12th of august 2011 (Termoflores 4).[40]

[39] At the time most of our quantitative exercises were done we didn’t have the heat rates for Termoflores 2 and 3 so we could not calculate their real marginal costs.
[40] Termocartagena has no bids between June 6, 2006 and April 24, 2008.

Appendix C: Construction of startup costs

Since the Resolution CREG 051 (2009) took effect from August 1st, the start-up-shutdown prices that each thermal plant declares are not available until that date. In order to construct a competitive benchmark (efficiency analysis) and counterfactual (econometric analysis) we need to estimate startup costs before 2009. The methodology we used was the following.

In the first place, we assumed that startup costs are determined by plants characteristics and fuel. Since we have data on what was the configuration used by each plant after 2009 we determined the most used configuration, main fuel type and second fuel type. We took the second fuel type as the one most used for startup. **Table *1*** shows and example of startup costs used.

Table 1: Start-up-shutdown types of fuel.

Plant	Configuration	Type of Fuel
Merilectrica 1	1	Gas
Termocartagena 1	1	Fuel Oil No. 6
Termodorada 1	2	Jet A1
Termocandelaria 1	5	ACPM
Termoemcali	2	ACPM
Zipaemg2	1	Coal

Once we identified the startup costs and type of fuel we used historic international prices for each one. The U.S. Energy Information Administration (EIA) publishes that information in their website. Using these prices we projected backwards the first startup costs (the average of August, Septembre and October 2001), dollar denominated, reported since 2009. Then using the exchange rate we estimated daily startup costs.

Appendix D: Econometric model no instrumental variables

Table A1. Complete model estimation using real prices. Average over 46 firms

Variables	Average of Coefficients	Average of Std. Errors	# of Coefs. Significant(5%)
Unit fixed effect	2.27e+06	1.30e+05	44
pcmpos	2.48e+06	7.57e+04	34
pcm	-1.13e+04	3.98e+03	24
pcm_2	1.30e+01	6.54e+01	9
pcm_3	5.35e-01	8.90e-01	13
pcm_4	-2.08e-03	5.19e-03	7
pcm_5	1.83e-06	8.90e-06	9
pcmminus1	1.26e+04	2.97e+03	25
pcmminus1_2	-1.05e+02	5.10e+01	20
pcmminus1_3	-1.13e+00	7.15e-01	21
pcmminus1_4	1.09e-02	4.37e-03	24
pcmminus1_5	-2.02e-05	7.71e-06	22
pcmplus1	1.03e+04	2.98e+03	23
pcmplus1_2	-7.40e+01	5.11e+01	19
pcmplus1_3	-7.19e-01	7.20e-01	17
pcmplus1_4	7.03e-03	4.43e-03	17
pcmplus1_5	-1.31e-05	7.86e-06	18
meanpcm	5.65e+04	4.86e+03	31
meanpcm_2	-4.09e+02	1.73e+02	26
meanpcm_3	-9.39e+00	3.94e+00	28
meanpcm_4	1.85e-01	5.26e-02	23
meanpcm_5	-7.16e-04	2.85e-04	25
meanpcmminus24	-1.33e+04	3.65e+03	37
meanpcmminus24_2	3.98e+02	1.52e+02	29
meanpcmminus24_3	-6.79e+00	3.58e+00	31
meanpcmminus24_4	6.43e-02	4.88e-02	25
meanpcmminus24_5	-2.98e-04	2.62e-04	28
meanpcmplus24	-1.17e+04	3.64e+03	36
meanpcmplus24_2	-4.08e+02	1.51e+02	37
meanpcmplus24_3	7.95e+00	3.52e+00	32
meanpcmplus24_4	-1.51e-02	4.77e-02	33
meanpcmplus24_5	-2.99e-04	2.56e-04	34
nino	7.59e+04	6.80e+04	39
nina	7.17e+04	4.54e+04	43
(hour)1	-1.02e+05	1.15e+05	3
(hour)2	-1.53e+05	1.15e+05	8
(hour)3	-1.61e+05	1.16e+05	9
(hour)4	-4.49e+04	1.17e+05	10

Variables	Average of Coefficients	Average of Std. Errors	# of Coefs. Significant(5%)
(hour)5	2.86e+05	1.16e+05	16
(hour)6	3.84e+05	1.16e+05	18
(hour)7	5.45e+05	1.17e+05	20
(hour)8	8.14e+05	1.18e+05	21
(hour)9	9.44e+05	1.19e+05	22
(hour)10	1.07e+06	1.19e+05	21
(hour)11	1.17e+06	1.19e+05	22
(hour)12	1.10e+06	1.19e+05	25
(hour)13	1.01e+06	1.19e+05	25
(hour)14	1.03e+06	1.18e+05	23
(hour)15	1.03e+06	1.18e+05	22
(hour)16	1.02e+06	1.18e+05	24
(hour)17	1.10e+06	1.24e+05	26
(hour)18	1.87e+06	1.29e+05	30
(hour)19	2.13e+06	1.29e+05	31
(hour)20	1.85e+06	1.27e+05	31
(hour)21	1.39e+06	1.20e+05	23
(hour)22	8.00e+05	1.17e+05	19
(hour)23	2.83e+05	1.15e+05	13
(month)2	1.58e+05	7.89e+04	34
(month)3	1.38e+05	7.94e+04	39
(month)4	1.37e+04	8.04e+04	42
(month)5	1.31e+05	8.56e+04	41
(month)6	1.28e+05	8.75e+04	38
(month)7	1.33e+05	8.71e+04	37
(month)8	2.85e+05	9.71e+04	38
(month)9	2.42e+05	9.06e+04	38
(month)10	-5.64e+04	8.74e+04	41
(month)11	3.69e+05	8.81e+04	42
(month)12	2.87e+05	8.64e+04	39
(wday)jueves	5.09e+05	6.35e+04	31
(wday)lunes	3.59e+05	6.45e+04	26
(wday)martes	4.81e+05	6.40e+04	37
(wday)miércoles	4.99e+05	6.37e+04	39
(wday)sábado	1.86e+05	6.45e+04	28
(wday)viernes	4.80e+05	6.39e+04	36

Table A2. Flexible model estimation using simulated prices. Average over 46 firms

Variables	Average of Coefficients	Average of Std. Errors	# of Coefs. Significant(5%)
Unit fixed effect	3.03e+06	2.86e+05	41
pcmpos	2.56e+05	1.70e+05	20
pcm	4.64e+04	8.43e+03	19
pcm_2	-4.20e+01	2.07e+02	10
pcm_3	-8.09e+00	4.25e+00	16
pcm_4	5.19e-02	6.75e-02	9
pcm_5	-2.63e-05	3.64e-04	10
pcmminus1	2.61e+04	5.62e+03	21
pcmminus1_2	6.14e+01	1.53e+02	11
pcmminus1_3	-7.55e+00	3.28e+00	16
pcmminus1_4	3.44e-02	5.41e-02	11
pcmminus1_5	7.35e-05	3.05e-04	14
pcmplus1	1.86e+04	5.65e+03	20
pcmplus1_2	9.84e+01	1.54e+02	7
pcmplus1_3	-5.48e+00	3.28e+00	19
pcmplus1_4	2.73e-02	5.42e-02	9
pcmplus1_5	2.63e-06	3.06e-04	14
meanpcm	-1.01e+04	1.96e+04	29
meanpcm_2	1.23e+03	1.25e+03	30
meanpcm_3	-5.12e+00	4.40e+01	25
meanpcm_4	-3.40e-01	8.65e-01	26
meanpcm_5	4.23e-03	7.58e-03	27
meanpcmminus24	1.75e+04	1.71e+04	34
meanpcmminus24_2	-3.06e+03	1.15e+03	35
meanpcmminus24_3	1.20e+02	4.00e+01	37
meanpcmminus24_4	-1.59e+00	7.82e-01	33
meanpcmminus24_5	3.32e-03	6.88e-03	34
meanpcmplus24	-1.27e+04	1.73e+04	35
meanpcmplus24_2	-3.57e+02	1.17e+03	32
meanpcmplus24_3	3.39e+01	4.10e+01	31
meanpcmplus24_4	-8.83e-01	8.03e-01	28
meanpcmplus24_5	6.17e-03	7.01e-03	35
nino	-3.36e+05	7.24e+04	41
nina	-2.07e+05	4.65e+04	41
(hour)1	-7.57e+04	1.18e+05	5
(hour)2	-1.04e+05	1.19e+05	8
(hour)3	-1.07e+05	1.20e+05	8
(hour)4	-1.31e+04	1.23e+05	10

Variables	Average of Coefficients	Average of Std. Errors	# of Coefs. Significant(5%)
(hour)5	2.96e+05	1.23e+05	17
(hour)6	3.65e+05	1.22e+05	16
(hour)7	4.96e+05	1.25e+05	16
(hour)8	7.47e+05	1.27e+05	18
(hour)9	8.47e+05	1.29e+05	18
(hour)10	9.46e+05	1.31e+05	20
(hour)11	1.04e+06	1.31e+05	21
(hour)12	9.77e+05	1.30e+05	22
(hour)13	9.07e+05	1.29e+05	20
(hour)14	9.17e+05	1.28e+05	19
(hour)15	9.20e+05	1.28e+05	19
(hour)16	9.15e+05	1.28e+05	20
(hour)17	9.59e+05	1.43e+05	24
(hour)18	1.62e+06	1.59e+05	25
(hour)19	1.82e+06	1.59e+05	26
(hour)20	1.65e+06	1.53e+05	24
(hour)21	1.27e+06	1.33e+05	22
(hour)22	7.39e+05	1.24e+05	16
(hour)23	2.47e+05	1.19e+05	9
(month)2	1.50e+05	8.09e+04	33
(month)3	-1.55e+05	8.10e+04	43
(month)4	-2.96e+05	8.27e+04	42
(month)5	-4.19e+05	8.92e+04	41
(month)6	-4.92e+05	9.01e+04	41
(month)7	-5.07e+05	8.98e+04	39
(month)8	-4.71e+05	9.98e+04	42
(month)9	-1.77e+05	9.55e+04	39
(month)10	-1.97e+05	9.04e+04	42
(month)11	-4.73e+05	9.18e+04	42
(month)12	-4.42e+05	9.03e+04	42
(wday)jueves	3.00e+05	6.85e+04	32
(wday)lunes	3.51e+05	7.04e+04	26
(wday)martes	3.54e+05	6.93e+04	34
(wday)miércoles	3.36e+05	6.88e+04	38
(wday)sábaado	2.12e+05	7.17e+04	26
(wday)viernes	1.95e+05	7.53e+04	28

Table A3. Production Comparison by plant using the mixed model Pre

Plants	2006.0.act.	2006.0.est.	2007.0.act.	2007.0.est.	2008.0.act.	2008.0.est.	2009.0.act.	2009.0.est.
ALBG	1.76e+03	1.85e+03	2.00e+03	1.79e+03	1.89e+03	1.79e+03	1.03e+03	1.29e+03
CHBG	2.20e+03	2.13e+03	2.01e+03	2.07e+03	2.35e+03	2.26e+03	1.42e+03	1.53e+03
CHVR	4.71e+03	4.19e+03	4.00e+03	3.67e+03	3.76e+03	4.10e+03	1.99e+03	2.58e+03
CLMG	1.69e+02	1.64e+02	1.59e+02	1.57e+02	2.67e+02	2.35e+02	1.45e+02	2.49e+02
GTPE	2.81e+03	2.96e+03	3.57e+03	3.69e+03	4.03e+03	3.72e+03	2.13e+03	2.17e+03
GTRG	2.62e+03	2.75e+03	2.82e+03	2.67e+03	2.37e+03	2.35e+03	1.58e+03	1.65e+03
GVIO	6.10e+03	6.06e+03	5.34e+03	5.20e+03	5.41e+03	5.06e+03	3.43e+03	3.97e+03
HMLG	1.48e+03	1.48e+03	1.46e+03	1.43e+03	1.60e+03	1.53e+03	1.11e+03	1.20e+03
JAGS	7.13e+02	7.73e+02	8.48e+02	7.97e+02	9.79e+02	9.43e+02	4.78e+02	5.22e+02
LTSJ	1.78e+03	1.78e+03	1.79e+03	1.80e+03	1.85e+03	1.86e+03	1.17e+03	1.16e+03
PLYS	1.43e+03	1.49e+03	1.65e+03	1.58e+03	1.55e+03	1.56e+03	9.48e+02	9.44e+02
PRC2	1.92e+03	2.00e+03	2.04e+03	1.92e+03	2.18e+03	2.03e+03	1.14e+03	1.34e+03
SLVJ	1.10e+03	1.19e+03	1.18e+03	1.21e+03	1.57e+03	1.42e+03	7.81e+02	7.96e+02
SNCR	5.93e+03	6.70e+03	7.22e+03	6.69e+03	7.38e+03	7.06e+03	3.99e+03	4.08e+03
URA1	1.30e+03	1.28e+03	1.47e+03	1.34e+03	1.35e+03	1.51e+03	7.74e+02	7.73e+02
PGUG	3.29e+03	3.36e+03	3.57e+03	3.60e+03	4.07e+03	3.85e+03	2.30e+03	2.42e+03
PRDO	1.99e+02	1.90e+02	1.57e+02	1.86e+02	2.73e+02	2.31e+02	1.54e+02	1.82e+02
CTG1	3.27e-01	1.02e+01	1.82e+01	1.70e+01	6.20e+00	1.43e+01	3.70e+01	2.75e+01
CTG2	0.00e+00	1.59e+01	0.00e+00	1.72e+01	1.96e+01	2.37e+01	5.82e+01	3.81e+01
CTG3	9.57e+00	9.05e+00	1.83e+01	1.38e+01	4.84e+00	1.27e+01	7.34e+00	7.47e+00
MRL1	1.26e+02	1.02e+02	5.57e+01	4.99e+01	2.54e+01	6.52e+01	5.29e+00	2.83e+01
PPA1	6.86e+01	4.42e+01	6.27e+01	5.83e+01	0.00e+00	2.43e+01	6.74e-03	2.33e+01
PPA2	2.45e+02	2.54e+02	3.02e+02	3.03e+02	2.81e+02	2.17e+02	1.95e+02	2.50e+02
PPA3	3.01e+02	2.90e+02	2.96e+02	3.45e+02	2.77e+02	2.40e+02	2.61e+02	2.61e+02
PPA4	8.86e+02	8.72e+02	1.00e+03	9.97e+02	7.61e+02	7.37e+02	5.41e+02	6.11e+02
PRG1	5.02e+01	3.97e+01	4.17e+01	3.93e+01	2.17e+01	3.12e+01	8.59e+00	1.35e+01
PRG2	4.98e+01	4.34e+01	4.48e+01	4.46e+01	3.42e+01	3.69e+01	1.17e+01	1.69e+01
TBQ3	4.83e+01	3.26e+01	2.56e+01	2.96e+01	2.57e+01	3.24e+01	5.90e+00	1.39e+01
TBQ4	3.62e+01	3.01e+01	2.40e+01	2.99e+01	2.63e+01	3.04e+01	1.01e+01	9.40e+00
TBST	4.16e+03	3.89e+03	3.89e+03	3.80e+03	3.44e+03	3.65e+03	2.35e+03	2.49e+03
TCD1	1.27e+02	1.68e+02	1.56e+02	1.37e+02	6.13e+00	3.11e+01	2.02e+00	1.26e+01
TCD2	3.45e+01	2.59e+01	8.76e+00	1.97e+01	3.53e+00	1.38e+01	9.70e+00	7.08e+00
TDR1	8.35e+00	1.35e+01	1.44e+01	1.49e+01	1.73e+01	1.75e+01	5.88e+00	9.21e+00
TEC1	1.82e+01	1.52e+01	1.11e+01	1.24e+01	7.95e+00	1.32e+01	6.76e+00	1.04e+01
TFL1	6.45e+02	5.96e+02	5.32e+02	5.94e+02	6.79e+02	5.72e+02	1.21e+02	2.16e+02
TGJ1	2.85e+02	2.10e+02	1.21e+02	2.29e+02	1.70e+02	1.95e+02	2.16e+02	1.74e+02
TGJ2	1.79e+02	1.80e+02	8.96e+01	1.76e+02	1.61e+02	1.51e+02	2.45e+02	1.82e+02
TRM1	2.29e+02	1.97e+02	4.09e+02	3.23e+02	3.13e+01	1.77e+02	7.24e+01	1.24e+02
TSJ1	7.56e+02	7.06e+02	7.62e+02	8.04e+02	6.89e+02	6.30e+02	5.31e+02	5.92e+02
TSR1	1.11e+02	1.82e+02	3.87e+02	2.61e+02	2.35e+02	2.87e+02	2.82e+02	3.24e+02
TVL1	7.51e+01	7.03e+01	1.98e+01	3.78e+01	5.66e+01	5.28e+01	2.94e+01	3.60e+01

Plants	2006.0.act.	2006.0.est.	2007.0.act.	2007.0.est.	2008.0.act.	2008.0.est.	2009.0.act.	2009.0.est.
TYP2	2.01e+02	2.10e+02	1.58e+02	1.71e+02	1.57e+02	1.53e+02	1.37e+02	1.12e+02
ZPA2	5.39e+01	6.97e+01	1.11e+02	6.93e+01	5.06e+01	6.32e+01	2.06e+01	3.69e+01
ZPA3	6.16e+01	7.17e+01	9.65e-02	5.40e+01	1.16e+02	8.09e+01	8.18e+01	6.35e+01
ZPA4	7.05e+01	9.56e+01	7.76e+01	1.23e+02	2.16e+02	1.56e+02	8.96e+01	9.26e+01
ZPA5	1.35e+02	1.66e+02	2.89e+02	1.87e+02	9.00e+01	1.38e+02	8.14e+01	1.11e+02
TOTAL	4.85e+04	4.90e+04	5.02e+04	4.88e+04	5.05e+04	4.94e+04	3.00e+04	3.28e+04

Table A3. Production Comparison by plant using the mixed model Pre

lants	2009.1.act.	2009.1.est.	2010.1.act.	2010.1.est.	2011.1.act.	2011.1.est.	2012.1.act.	2012.1.est.	Total.act	Total.cal
LBG	5.48e+02	7.84e+02	1.72e+03	1.95e+03	1.95e+03	2.14e+03	1.56e+03	2.02e+03	1.25e+04	1.36e+04
HBG	6.13e+02	1.03e+03	1.63e+03	2.18e+03	2.60e+03	2.43e+03	2.19e+03	2.43e+03	1.50e+04	1.61e+04
HVR	1.31e+03	1.75e+03	3.12e+03	3.73e+03	5.34e+03	4.13e+03	4.66e+03	4.30e+03	2.89e+04	2.84e+04
LMG	5.02e+01	1.51e+02	1.84e+02	2.28e+02	2.31e+02	2.35e+02	2.12e+02	2.77e+02	1.42e+03	1.70e+03
TPE	1.10e+03	1.31e+03	2.80e+03	2.93e+03	3.84e+03	3.78e+03	3.38e+03	3.40e+03	2.37e+04	2.40e+04
TRG	1.06e+03	1.23e+03	2.40e+03	2.52e+03	1.99e+03	2.63e+03	2.21e+03	2.64e+03	1.71e+04	1.84e+04
VIO	2.10e+03	2.59e+03	3.84e+03	5.11e+03	4.52e+03	5.91e+03	6.24e+03	6.56e+03	3.70e+04	4.05e+04
MLG	3.10e+02	5.76e+02	1.53e+03	1.54e+03	1.97e+03	1.80e+03	1.47e+03	1.76e+03	1.09e+04	1.13e+04
AGS	2.91e+02	3.89e+02	7.28e+02	8.40e+02	9.71e+02	1.03e+03	8.08e+02	9.89e+02	5.82e+03	6.28e+03
TSJ	5.27e+02	6.35e+02	1.42e+03	1.62e+03	2.14e+03	1.95e+03	1.74e+03	1.70e+03	1.24e+04	1.25e+04
LYS	6.00e+02	5.32e+02	1.12e+03	1.34e+03	1.15e+03	1.57e+03	1.15e+03	1.53e+03	9.61e+03	1.06e+04
RC2	6.28e+02	9.50e+02	1.74e+03	2.05e+03	2.27e+03	2.27e+03	1.88e+03	2.16e+03	1.38e+04	1.47e+04
LVJ	2.37e+02	1.79e+02	1.04e+03	9.05e+02	1.52e+03	1.38e+03	9.90e+02	1.33e+03	8.41e+03	8.41e+03
NCR	2.43e+03	2.69e+03	5.78e+03	6.06e+03	7.63e+03	7.24e+03	6.78e+03	6.87e+03	4.71e+04	4.74e+04
RA1	3.87e+02	7.14e+02	1.30e+03	1.38e+03	1.43e+03	1.42e+03	1.34e+03	1.36e+03	9.35e+03	9.77e+03
GUG	1.49e+03	1.61e+03	3.36e+03	3.56e+03	3.78e+03	4.16e+03	3.66e+03	3.90e+03	2.55e+04	2.65e+04
RDO	3.17e+01	6.08e+01	1.72e+02	1.95e+02	3.03e+02	2.95e+02	1.67e+02	2.49e+02	1.46e+03	1.59e+03
TG1	1.96e+01	7.88e+00	5.47e+01	2.25e+01	4.21e+01	2.73e+01	5.78e+01	4.24e+01	2.36e+02	1.69e+02
TG2	1.02e+02	2.40e+01	1.06e+02	5.50e+01	5.40e+01	6.70e+01	7.34e+01	6.43e+01	4.14e+02	3.05e+02
TG3	0.00e+00	6.92e+00	6.85e+01	1.55e+01	1.10e+02	1.71e+01	7.17e+01	1.47e+01	2.91e+02	9.72e+01
RL1	6.54e+01	5.07e+01	1.35e+01	5.50e+01	7.42e+01	5.07e+01	1.17e+02	6.58e+01	4.82e+02	4.68e+02
PA1	8.66e+01	5.02e+01	1.39e+02	6.52e+01	9.15e+01	2.39e+01	8.59e+01	4.38e+01	5.35e+02	3.33e+02
PA2	2.09e+02	1.39e+02	2.55e+02	2.82e+02	1.23e+02	2.67e+02	2.04e+02	3.41e+02	1.81e+03	2.05e+03
PA3	2.28e+02	1.65e+02	3.93e+02	3.48e+02	1.68e+02	2.93e+02	2.67e+02	3.75e+02	2.19e+03	2.32e+03
PA4	4.28e+02	3.74e+02	9.00e+02	9.04e+02	4.13e+02	9.06e+02	5.12e+02	9.31e+02	5.44e+03	6.33e+03
RG1	9.64e+01	1.94e+01	1.42e+02	3.74e+01	1.92e+02	2.60e+01	2.51e+02	2.29e+01	8.04e+02	2.29e+02
RG2	8.47e+01	2.12e+01	9.38e+01	4.24e+01	1.96e+02	3.07e+01	2.20e+02	2.68e+01	7.35e+02	2.63e+02
BQ3	1.85e+01	8.35e+00	1.45e+02	1.89e+01	6.74e+01	2.19e+01	4.44e+01	2.09e+01	3.81e+02	1.78e+02
BQ4	1.03e+02	9.40e+00	1.21e+02	1.88e+01	5.78e+01	2.22e+01	3.78e+01	2.36e+01	4.17e+02	1.74e+02
BST	2.64e+03	2.07e+03	4.86e+03	3.91e+03	4.04e+03	3.69e+03	4.14e+03	3.82e+03	2.95e+04	2.73e+04
CD1	2.92e+02	2.17e+02	4.03e+02	2.63e+02	2.52e+01	2.18e+01	2.12e+01	2.29e+01	1.03e+03	8.73e+02
CD2	2.26e+02	2.90e+01	3.54e+02	3.41e+01	3.97e+01	1.67e+01	3.10e+01	1.68e+01	7.07e+02	1.63e+02
DR1	2.48e+01	1.52e+01	1.47e+01	2.23e+01	1.06e+01	2.38e+01	2.09e+01	2.39e+01	1.17e+02	1.40e+02

lants	2009.1.act.	2009.1.est.	2010.1.act.	2010.1.est.	2011.1.act.	2011.1.est.	2012.1.act.	2012.1.est.	Total.act	Total.cal
EC1	1.98e+02	2.07e+00	2.65e+02	9.79e+00	7.90e+00	1.23e+01	3.17e+01	1.39e+01	5.46e+02	8.93e+0
FL1	4.06e+02	3.17e+02	9.31e+02	5.42e+02	5.52e+02	5.21e+02	3.62e+02	4.34e+02	4.23e+03	3.79e+0
GJ1	1.90e+02	1.86e+02	5.65e+02	2.60e+02	5.32e+02	2.39e+02	5.09e+02	2.49e+02	2.59e+03	1.74e+0
GJ2	2.81e+02	1.32e+02	4.69e+02	2.14e+02	4.51e+02	1.83e+02	6.70e+02	1.91e+02	2.55e+03	1.41e+0
RM1	4.92e+02	1.59e+02	4.83e+02	3.01e+02	3.31e+02	1.74e+02	5.09e+02	2.18e+02	2.56e+03	1.67e+0
SJ1	4.63e+02	4.12e+02	8.07e+02	8.40e+02	5.23e+02	6.98e+02	7.89e+02	8.49e+02	5.32e+03	5.53e+0
SR1	7.23e+02	1.53e+02	9.82e+02	3.87e+02	5.46e+01	4.73e+02	6.26e+02	5.04e+02	3.40e+03	2.57e+0
VL1	4.25e+02	5.97e+01	5.83e+02	6.27e+01	1.04e+01	5.70e+01	7.13e+01	8.39e+01	1.27e+03	4.60e+0
YP2	9.29e+01	1.16e+02	2.04e+02	1.94e+02	7.60e+01	1.71e+02	1.72e+02	2.11e+02	1.20e+03	1.34e+0
PA2	6.39e+01	6.92e+01	7.13e+01	8.84e+01	2.30e+01	6.81e+01	2.96e+01	5.77e+01	4.24e+02	5.22e+0
PA3	1.23e+02	6.07e+01	2.17e+02	8.54e+01	9.96e+01	6.80e+01	1.16e+02	6.44e+01	8.15e+02	5.49e+0
PA4	1.18e+02	2.07e+01	2.10e+02	1.12e+02	1.02e+02	1.69e+02	1.17e+02	1.52e+02	1.00e+03	9.20e+0
PA5	1.69e+02	1.32e+02	2.69e+02	2.00e+02	3.93e+01	1.65e+02	1.30e+02	1.72e+02	1.20e+03	1.27e+0
OTAL	2.21e+04	2.22e+04	4.80e+04	4.75e+04	5.22e+04	5.29e+04	5.07e+04	5.25e+04	3.52e+05	3.55e+0

Notes: act. Stands for Actual productions and calc. stands for Calculated Production.
Last column named Total is the sum over the entire period including Pre and Post.

Appendix E: Econometric model using instrumental variables

Table 1. Summary of model for all Plants

Plants	Average of Coefficients	Average of Std. Errors	# of Coefs. Significant(5%)
(Intercept)	4,127,231	8,440,041	20
pcmpos	220,439	148,859	32
pcm	106,401	101,960	5
pcm_2	344	2,393	1
pcm_3	-7	45	2
pcm_4	0	0	0
pcm_5	0	0	0
pcmminus1	-14,677	78,777	1
pcmminus1_2	617	2,036	2
pcmminus1_3	11	38	4
pcmminus1_4	0	0	4
pcmminus1_5	0	0	5
pcmplus1	48,052	90,127	1
pcmplus1_2	-1,583	2,230	2
pcmplus1_3	2	39	1

Plants	Average of Coefficients	Average of Std. Errors	# of Coefs. Significant(5%)
pcmplus1_4	0	0	1
pcmplus1_5	0	0	2
meanpcm	369,171	762,694	19
meanpcm_2	-18,641	24,461	16
meanpcm_3	404	697	21
meanpcm_4	-3	10	14
meanpcm_5	0	0	14
meanpcmminus24	-1,846,423	1,025,392	19
meanpcmminus24_2	105,669	47,668	17
meanpcmminus24_3	-2,484	1,168	16
meanpcmminus24_4	24	14	17
meanpcmminus24_5	0	0	11
meanpcmplus24	416,802	854,234	21
meanpcmplus24_2	-10,464	21,192	17
meanpcmplus24_3	209	424	19
meanpcmplus24_4	-2	10	18
meanpcmplus24_5	0	0	19
nino	127,722	2,955,705	21
nina	711,587	1,363,525	23
factor(month)2	2,279,644	2,794,821	20
factor(month)3	780,241	1,670,619	25
factor(month)4	268,855	2,264,863	23
factor(month)5	2,399,932	2,046,864	17
factor(month)6	-124,872	2,512,675	20
factor(month)7	985,527	2,962,831	21
factor(month)8	-297,601	5,276,267	18
factor(month)9	715,229	2,109,867	25
factor(month)10	-1,274,266	4,329,323	23
factor(month)11	28,996	3,523,328	16
factor(month)12	-1,598,508	4,109,303	26
factor(wday)jueves	-917,901	3,535,618	22
factor(wday)lunes	-1,736,005	4,085,562	23
factor(wday)martes	-1,774,808	3,604,594	22
factor(wday)mi?coles	-1,482,513	4,030,002	21
factor(wday)s?ado	584,211	4,037,771	19
factor(wday)viernes	-658,048	3,872,933	22

Mean R-Squared: 0.18

Table 1. Summary of model for 17 Hydro Plants

Plants	Average of Coefficients	Average of Std. Errors	# of Coefs. Significant(5%)
(Intercept)	791,347	3,147,163	10
pcmpos	280,910	92,079	13
pcm	99,448	73,630	4
pcm_2	677	1,521	1
pcm_3	-13	29	2
pcm_4	0	0	0
pcm_5	0	0	0
pcmminus1	-14,575	52,774	0
pcmminus1_2	869	1,162	2
pcmminus1_3	2	23	1
pcmminus1_4	0	0	1
pcmminus1_5	0	0	2
pcmplus1	41,938	64,310	1
pcmplus1_2	-1,265	1,366	2
pcmplus1_3	-5	24	1
pcmplus1_4	0	0	1
pcmplus1_5	0	0	2
meanpcm	247,204	261,087	9
meanpcm_2	10,226	8,544	7
meanpcm_3	-504	266	7
meanpcm_4	7	4	6
meanpcm_5	0	0	2
meanpcmminus24	-305,452	271,740	7
meanpcmminus24_2	4,670	9,790	4
meanpcmminus24_3	-121	265	6
meanpcmminus24_4	1	5	4
meanpcmminus24_5	0	0	4
meanpcmplus24	-216,354	278,228	7
meanpcmplus24_2	8,000	12,206	4
meanpcmplus24_3	-56	210	5
meanpcmplus24_4	0	4	4
meanpcmplus24_5	0	0	5
nino	964,539	1,720,516	8
nina	951,522	798,030	7
factor(month)2	1,487,958	1,070,335	8
factor(month)3	857,443	1,109,629	11
factor(month)4	865,225	1,273,100	11
factor(month)5	2,001,462	1,514,134	5
factor(month)6	487,237	1,503,563	7
factor(month)7	801,126	1,907,864	8
factor(month)8	827,446	2,474,788	6

Plants	Average of Coefficients	Average of Std. Errors	# of Coefs. Significant(5%)
factor(month)9	1,127,426	1,403,901	11
factor(month)10	1,288,889	1,894,891	7
factor(month)11	425,169	1,605,331	5
factor(month)12	-382,174	2,045,779	9
factor(wday)jueves	-566,570	1,125,476	8
factor(wday)lunes	-1,484,795	1,815,507	9
factor(wday)martes	-1,515,532	1,648,630	7
factor(wday)mi?coles	-1,407,539	1,486,644	7
factor(wday)s?ado	601,175	1,393,374	6
factor(wday)viernes	-460,723	1,376,991	8

Mean R-Squared: 0.215

Table 1. Summary of model for 29 Thermo Plants

Plants	Average of Coefficients	Average of Std. Errors	# of Coefs. Significant(5%)
(Intercept)	3,335,884	5,292,878	10
pcmpos	-60,471	56,781	19
pcm	6,954	28,330	1
pcm_2	-334	872	0
pcm_3	7	16	0
pcm_4	0	0	0
pcm_5	0	0	0
pcmminus1	-102	26,003	1
pcmminus1_2	-252	874	0
pcmminus1_3	8	15	3
pcmminus1_4	0	0	3
pcmminus1_5	0	0	3
pcmplus1	6,114	25,817	0
pcmplus1_2	-318	864	0
pcmplus1_3	7	15	0
pcmplus1_4	0	0	0
pcmplus1_5	0	0	0
meanpcm	121,967	501,607	10
meanpcm_2	-28,867	15,917	9
meanpcm_3	908	431	14
meanpcm_4	-10	6	8
meanpcm_5	0	0	12
meanpcmminus24	-1,540,971	753,653	12
meanpcmminus24_2	100,998	37,878	13
meanpcmminus24_3	-2,363	903	10
meanpcmminus24_4	23	10	13

Plants	Average of Coefficients	Average of Std. Errors	# of Coefs. Significant(5%)
meanpcmminus24_5	0	0	7
meanpcmplus24	633,156	576,006	14
meanpcmplus24_2	-18,463	8,986	13
meanpcmplus24_3	265	214	14
meanpcmplus24_4	-2	6	14
meanpcmplus24_5	0	0	14
nino	-836,817	1,235,189	13
nina	-239,936	565,495	16
factor(month)2	791,686	1,724,486	12
factor(month)3	-77,203	560,990	14
factor(month)4	-596,370	991,763	12
factor(month)5	398,470	532,731	12
factor(month)6	-612,108	1,009,112	13
factor(month)7	184,401	1,054,966	13
factor(month)8	-1,125,047	2,801,479	12
factor(month)9	-412,198	705,967	14
factor(month)10	-2,563,155	2,434,431	16
factor(month)11	-396,173	1,917,997	11
factor(month)12	-1,216,334	2,063,524	17
factor(wday)jueves	-351,332	2,410,141	14
factor(wday)lunes	-251,210	2,270,054	14
factor(wday)martes	-259,276	1,955,964	15
factor(wday)mi?coles	-74,974	2,543,358	14
factor(wday)s?ado	-16,964	2,644,398	13
factor(wday)viernes	-197,325	2,495,942	14

Mean R-Squared: 0.155

Table 1. Production Comparison

Plants	2006.0.act.	2006.0.est.	2007.0.act.	2007.0.est.	2008.0.act.	2008.0.est.	2009.0.act.	2009.0.est.
ALBG	1,764	1,839	2,002	1,783	1,889	1,958	1,029	1,111
CHBG	2,202	2,158	2,013	2,133	2,348	2,338	1,424	1,358
CHVR	4,714	4,003	3,998	4,097	3,759	4,021	1,985	2,340
CLMG	169	200	159	228	267	216	145	109
GTPE	2,813	3,440	3,570	3,566	4,031	3,535	2,129	2,001
GTRG	2,618	2,685	2,823	2,643	2,372	2,561	1,584	1,509
GVIO	6,101	5,596	5,340	5,895	5,408	5,519	3,428	3,266
HMLG	1,483	1,509	1,462	1,494	1,597	1,615	1,111	1,034
JAGS	713	821	848	852	979	888	478	456
LTSJ	1,784	1,809	1,790	1,845	1,852	1,870	1,168	1,071
PLYS	1,433	1,546	1,649	1,554	1,548	1,557	948	920
PRC2	1,925	2,020	2,038	2,004	2,182	2,127	1,139	1,132

Plants	2006.0.act.	2006.0.est.	2007.0.act.	2007.0.est.	2008.0.act.	2008.0.est.	2009.0.act.	2009.0.est.
SLVJ	1,096	1,155	1,177	1,221	1,567	1,413	781	828
SNCR	5,928	6,778	7,216	6,862	7,379	7,093	3,991	3,780
URA1	1,298	1,353	1,467	1,376	1,354	1,414	774	750
PGUG	3,293	3,692	3,565	3,623	4,075	3,838	2,299	2,079
PRDO	199	197	157	200	273	237	154	148
CTG1	0	17	18	23	6	15	37	14
CTG2	0	21	0	18	20	23	58	22
CTG3	10	11	18	12	5	12	7	6
MRL1	126	79	56	63	25	63	5	29
PPA1	69	49	63	55	0	30	0	13
PPA2	245	282	302	277	281	277	195	187
PPA3	301	326	296	315	277	283	261	210
PPA4	886	908	1,003	892	761	801	541	587
PRG1	50	38	42	35	22	29	9	21
PRG2	50	43	45	41	34	34	12	24
TBQ3	48	29	26	30	26	32	6	16
TBQ4	36	27	24	29	26	30	10	12
TBST	4,160	4,041	3,895	3,920	3,438	3,631	2,349	2,249
TCD1	127	151	156	148	6	25	2	12
TCD2	35	27	9	19	4	13	10	8
TDR1	8	16	14	16	17	15	6	6
TEC1	18	13	11	12	8	14	7	11
TFL1	645	593	532	558	679	553	121	272
TGJ1	285	238	121	211	170	214	216	133
TGJ2	179	201	90	175	161	170	245	140
TRM1	229	248	409	295	31	159	72	114
TSJ1	756	780	762	777	689	672	531	505
TSR1	111	262	387	328	235	266	282	183
TVL1	75	66	20	54	57	50	29	21
TYP2	201	200	158	186	157	162	137	103
ZPA2	54	76	111	72	51	66	21	27
ZPA3	62	77	0	65	116	78	82	43
ZPA4	71	114	78	107	216	146	90	95
ZPA5	135	182	289	194	90	144	81	79
	48,503	49,915	50,207	50,304	50,485	50,208	29,988	29,033

Table 1. Production Comparison

lants	2009.1.act.	2009.1.est.	2010.1.act.	2010.1.est.	2011.1.act.	2011.1.est.	2012.1.act.	2012.1.est.	Total.act	Total.cal
LBG	548	21	1,723	1,300	1,951	1,871	1,562	910	12,467	10,793
HBG	613	1,430	1,628	2,561	2,603	2,110	2,185	2,714	15,017	16,803

lants	2009.1.act.	2009.1.est.	2010.1.act.	2010.1.est.	2011.1.act.	2011.1.est.	2012.1.act.	2012.1.est.	Total.act	Total.cal
HVR	1,315	796	3,120	2,955	5,338	4,122	4,664	3,652	28,893	25,985
LMG	50	222	184	442	231	496	212	577	1,417	2,489
TPE	1,100	1,497	2,800	2,854	3,845	2,414	3,383	2,988	23,672	22,294
TRG	1,065	0	2,403	1,412	1,986	2,396	2,213	1,807	17,065	15,013
VIO	2,101	4,330	3,840	6,388	4,522	5,327	6,238	6,443	36,978	42,764
MLG	310	141	1,529	1,080	1,972	1,635	1,467	1,053	10,930	9,561
AGS	291	111	728	592	971	786	808	480	5,816	4,986
TSJ	527	83	1,419	946	2,136	1,448	1,738	1,049	12,416	10,121
LYS	600	165	1,123	826	1,154	925	1,154	421	9,609	7,914
RC2	628	1,488	1,735	1,969	2,270	1,645	1,883	1,918	13,800	14,304
LVJ	237	618	1,036	1,249	1,521	1,205	990	1,566	8,406	9,256
NCR	2,431	0	5,784	3,710	7,628	5,974	6,784	2,899	47,142	37,095
RA1	387	1,249	1,297	1,892	1,433	1,358	1,344	1,306	9,353	10,698
GUG	1,486	1,900	3,362	2,863	3,783	2,636	3,660	3,854	25,523	24,484
RDO	32	156	172	267	303	224	167	311	1,456	1,741
TG1	20	224	55	319	42	247	58	357	236	1,217
TG2	102	205	106	306	54	215	73	320	414	1,131
TG3	0	0	68	185	110	292	72	173	291	693
MRL1	65	610	14	863	74	726	117	1,025	482	3,458
PA1	87	2	139	86	92	147	86	107	535	489
PA2	209	19	255	186	123	291	204	245	1,815	1,764
PA3	228	19	393	191	168	303	267	239	2,191	1,887
PA4	428	568	900	833	413	606	512	852	5,444	6,047
RG1	96	164	142	244	192	181	251	268	804	981
RG2	85	119	94	216	196	210	220	197	735	883
BQ3	18	129	145	265	67	311	44	252	381	1,062
BQ4	103	135	121	268	58	269	38	330	417	1,099
BST	2,643	491	4,860	2,417	4,045	3,964	4,137	3,003	29,526	23,716
CD1	292	16	403	480	25	745	21	532	1,032	2,110
CD2	226	175	354	546	40	753	31	550	707	2,091
DR1	25	186	15	262	11	208	21	309	117	1,017
EC1	198	820	265	1,205	8	887	32	1,248	546	4,210
FL1	406	525	931	849	552	611	362	883	4,227	4,844
GJ1	190	474	565	753	532	661	509	789	2,588	3,472
GJ2	281	0	469	421	451	742	670	523	2,546	2,372
RM1	492	716	483	1,249	331	1,123	509	1,466	2,557	5,369
SJ1	463	574	807	806	523	612	789	827	5,320	5,554
SR1	723	446	982	1,547	55	1,979	626	2,102	3,399	7,113
VL1	425	694	583	1,034	10	821	71	1,171	1,271	3,910
YP2	93	4	204	100	76	154	172	88	1,198	997
PA2	64	101	71	305	23	431	30	362	424	1,439
PA3	123	106	217	186	100	154	116	173	815	883

lants	2009.1.act.	2009.1.est.	2010.1.act.	2010.1.est.	2011.1.act.	2011.1.est.	2012.1.act.	2012.1.est.	Total.act	Total.cal
PA4	118	46	210	181	102	294	117	260	1,001	1,242
PA5	169	219	269	350	39	275	130	320	1,203	1,763
	22,093	21,993	48,004	49,960	52,161	54,784	50,740	52,918	352,180	359,114

Appendix F: Results related to section 7

Table 1

$$ProbabilityTest_t = \beta_0 + \beta_1 t + \beta_2 reform + \beta_3 t * reform$$

Coefficients:

	Estimate	Std. Error	t value	Pr(>|t|)
(Intercept)	1.651e-01	3.580e-02	4.611	4.22e-06 ***
t	-9.871e-06	2.632e-06	-3.750	0.000181 ***
reform	-2.634e-01	3.866e-02	-6.813	1.21e-11 ***
t*reform	1.849e-05	2.805e-06	6.591	5.37e-11 ***

Table 2

$$ProbabilityStartUp_t = \beta_0 + \beta_1 t + \beta_2 reform + \beta_3 t * reform$$

Coefficients:

	Estimate	Std. Error	t value	Pr(>|t|)
(Intercept)	-6.332e-03	1.781e-03	-3.555	0.000386 ***
t	5.350e-07	1.310e-07	4.085	4.55e-05 ***
reform	4.370e-03	1.924e-03	2.272	0.023197 *
t*reform	-3.254e-07	1.396e-07 -	2.332	0.019794 *