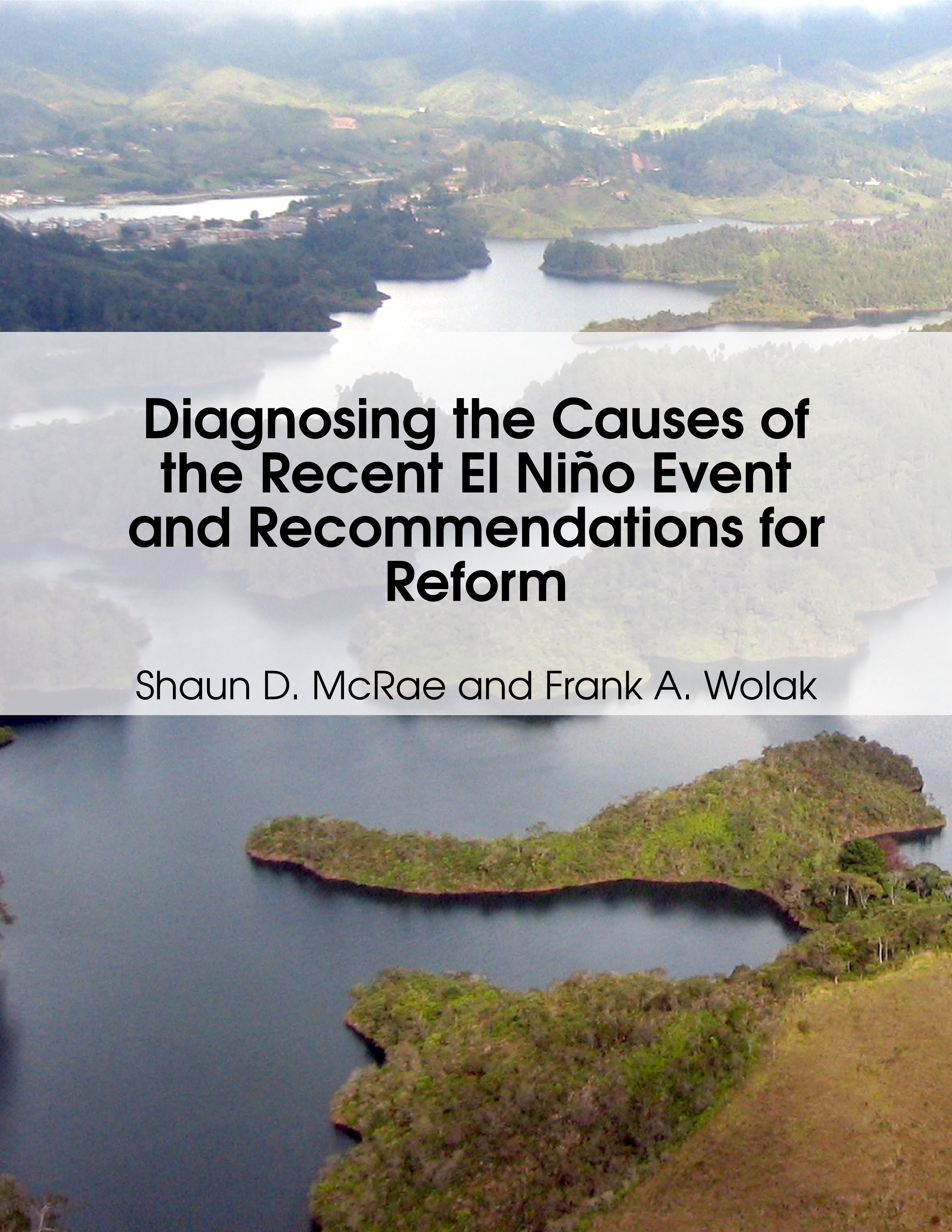

# Diagnosing the Causes of the Recent El Niño Event and Recommendations for Reform

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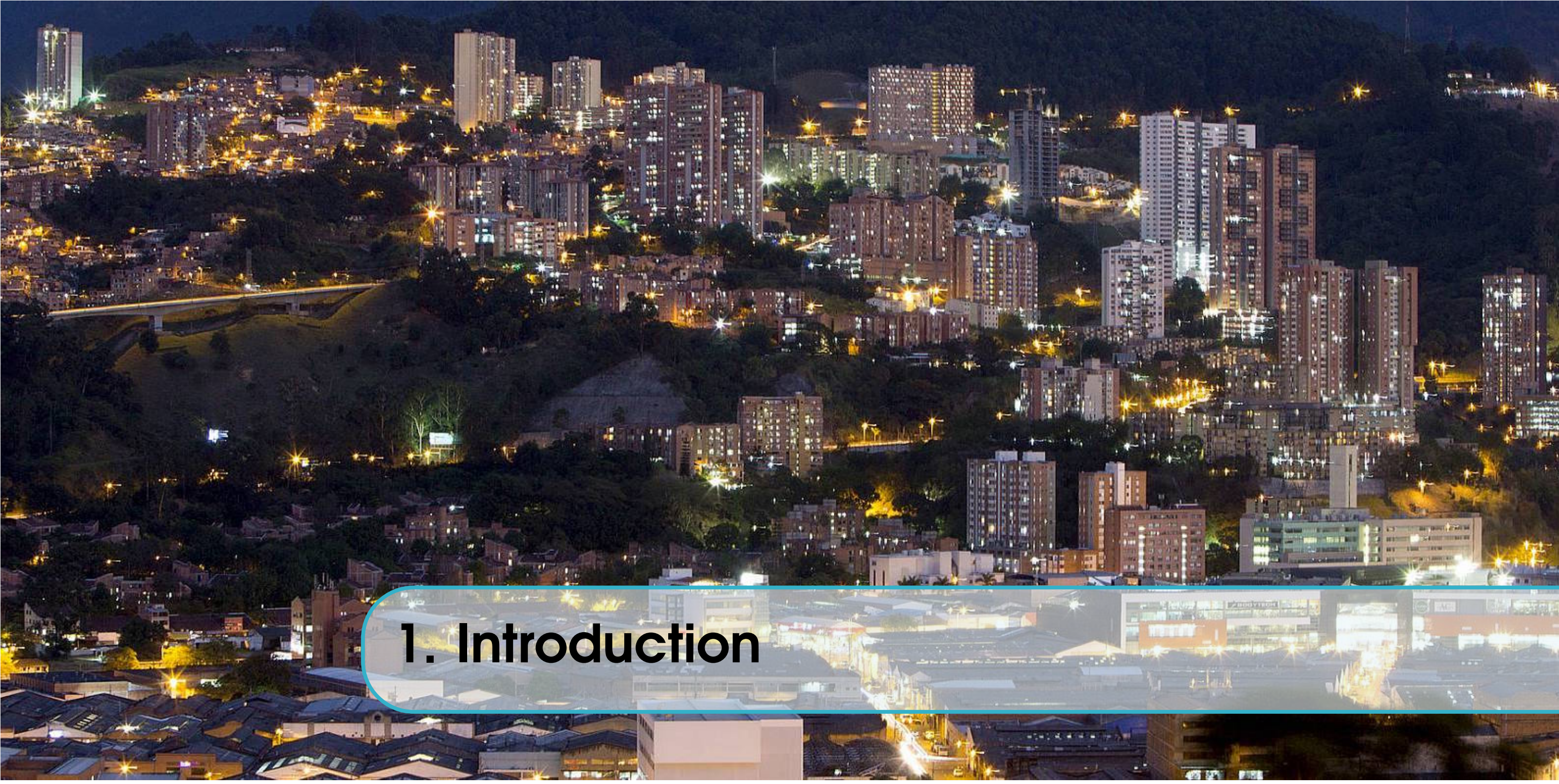
# Contents

# List of Figures

# List of Tables



# 1. Introduction

## 1.1 Purpose of Research

In this report we identify the key drivers of observed market outcomes in the Colombian electricity supply industry during the fourth quarter of 2015 and first quarter of 2016, the time period covered by the most recent El Niño Event. We analyze how effective the market rules and market structure of Colombian electricity supply industry are in managing El Niño Events. The performance of the Reliability Payment Mechanism (RPM) is a major focus of this report because of its designation as the primary mechanism for ensuring an adequate supply of energy at a reasonable price during El Niño Events. We find that the RPM creates a number of perverse economic incentives for supplier behavior, particularly if suppliers have a significant ability to exercise unilateral market power, that works against the RPM mechanism ensuring an adequate supply of electricity at a reasonable price during El Niño Events. We identify several features of the RPM that make it extremely challenging even for a modified version of this mechanism to achieve its goal. We propose an alternative mechanism for ensuring an adequate supply of energy at a reasonable price during El Niño Events that should be straightforward to implement under the current market design in Colombia.

Readers only interested in our assessment of the suitability-to-task of the RPM mechanism and our recommendations for reforming the reliability mechanism and other aspects of the Colombia market can skip to Chapters 9 and 10. These Chapters refer to the relevant analyses of market outcomes in the previous chapters that form the basis for our conclusions and recommendations.

To provide context for assessing the performance of the Colombian market during the 2015-2016 El Niño Event period, we first present a number of analyses of changes in the market structure and market outcomes in the Colombian electricity supply industry over the past decade, and in some cases, since 2000. These analyses are particularly informative because this time period includes the 2009-2010 El Niño Event, which shares many similarities with the 2015-2016 El Niño Event. These analyses reveal a number of stylized facts that form the basis for our assessment of the effectiveness of the market rules and market structure of Colombian electricity supply industry at managing El Niño Events.

## 1.2 Outline of Report

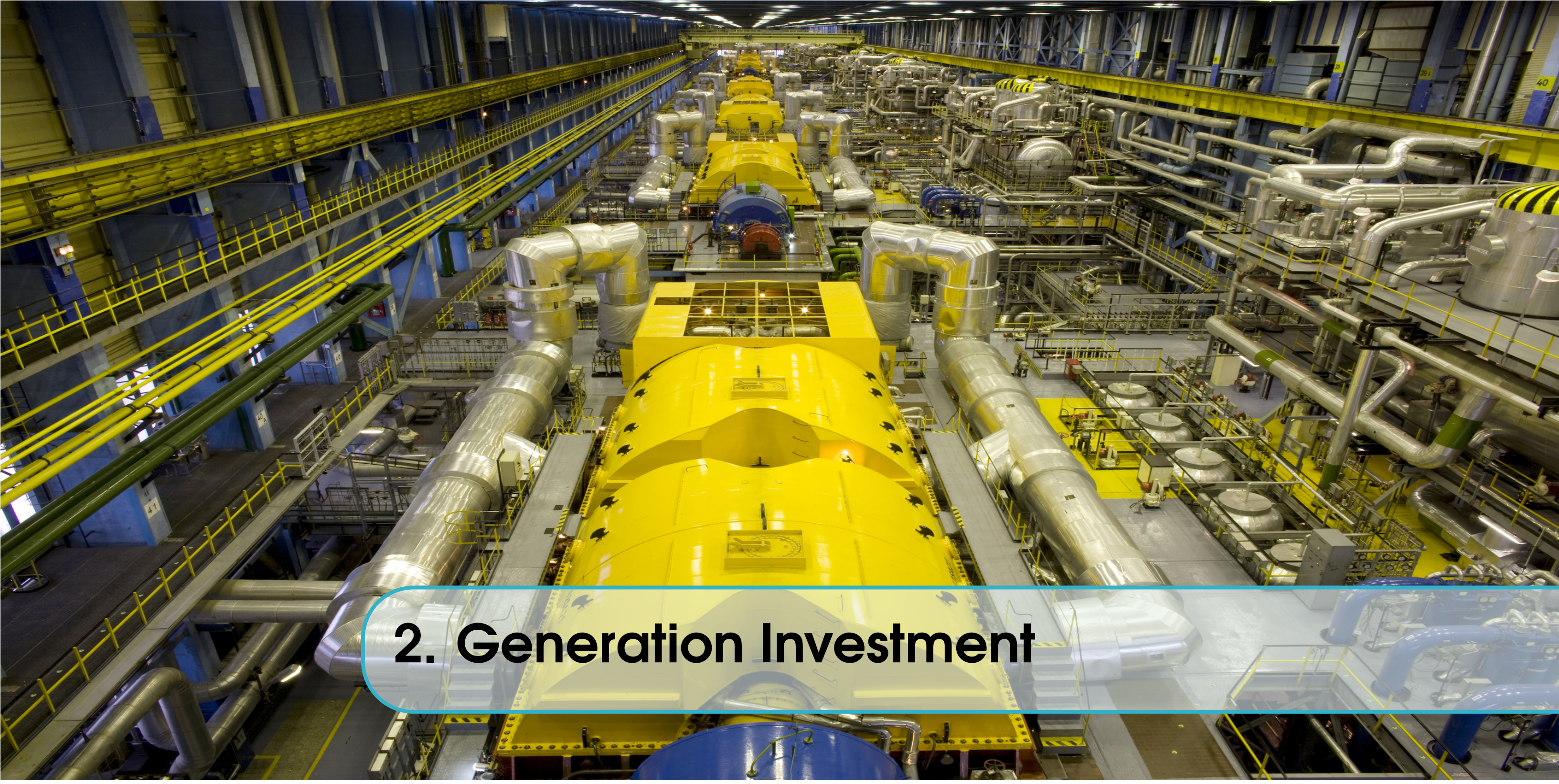
We first present data on the trends in installed generation capacity and Ideal Generation and actual electricity produced by technology. This is followed by trends in the availability of hydroelectric energy and hydroelectric storage capacity with a focus on the two recent El Niño Events. The time series of revenues earned by generation unit owners are then presented broken down by: (1) RPM revenues, (2) Bolsa Market Energy Revenues, (3) Net Firm Energy Refunds (during scarcity periods), (4) Automatic Generation Control (AGC) revenues, (5) Net Positive and Negative Reconciliation Payments, and (6) Start-up Payments. Trends in wholesale market prices and supplier offer prices are then presented. Finally, the behavior of fixed-price forward contract positions in energy and Firm Energy by supplier are presented. We then turn to an assessment of how the ability to exercise unilateral market power has changed over the sample period for the six large suppliers in Colombia. Using two indexes of the ability of an individual supplier to exercise market power, we first demonstrate that even the largest electricity suppliers in Colombia had little ability to exercise unilateral market power throughout our sample period until the end of the third quarter of 2015. We find a massive increase in the ability of the six largest suppliers to exercise unilateral market power during the 2015-2016 El Niño Event. Finally, an assessment of the impact of transmission constraints on market outcomes over the sample period is presented. Here we focus on how the level of positive and negative reconciliations has changed over time and how these payments compare to total Bolsa market revenues over our sample period.

This information provides context for the remainder of the report, which analyzes the performance of the Colombian market during the recent El Niño Event. Although there is no single cause of market outcomes during the fourth quarter of 2015 and first quarter of 2016, we do identify a number of factors that led to these outcomes. Low water conditions in 2013 and 2014, only slightly larger than those during the 2009-2010 El Niño Event, combined with the incentives for supplier behavior created by the structure of the RPM, are important explanatory factors for the poor performance of the industry during 2015-2016 El Niño Event. We then show that the RPM has a number of parameters that are extremely difficult, if not impossible, to set to achieve its desired goal. Setting the level of the Scarcity Price, setting the Firm Energy Value for each generation unit in Colombia and designing the mechanism for penalizing hydroelectric suppliers for low water levels are all extremely challenging tasks. However, each of these parameters of the RPM mechanism can exert an enormous influence on how hydroelectric suppliers decide to use their water both before and during El Niño Events.

We demonstrate that interactions between the fixed-price forward contract obligations of generation unit owners and the firm energy value of the RPM mechanism can create incentives for sudden shifts in supplier behavior. Specifically, depending on the relative values of a supplier's Firm Energy Value, Net Forward Contract Quantity and Ideal Generation, the supplier may switch from wanting to take actions to reduce the Bolsa price to taking actions to increase the Bolsa price. This potential for sudden changes in a supplier's behavior is greatest during periods when it possible that the Bolsa price could be driven above the Scarcity Price and suppliers possess a substantial ability to exercise unilateral market power, as was the case during the 2015-2016 El Niño Event.

Because of the perverse incentives for supplier behavior caused by the RPM and the extreme difficulty in setting values for the parameters of the RPM mechanism to achieve a reliable supply of electricity at a reasonable price during El Niño Events, we propose a simple replacement for the RPM based on a market for standardized forward contracts for energy. This alternative mechanism is straightforward to implement using products currently offered, or that could be offered, by Derivex. This mechanism address the fundamental challenge of the hydroelectric-dominated electricity supply industry that is subject to periodic water availability shortfalls caused El Niño Events—the need for hydroelectric suppliers to re-insure their forward market energy contracts with thermal generation unit owners. We describe a straightforward path for transitioning the existing RPM to an energy contract-based approach to ensuring an adequate supply of energy at a reasonable price during El Niño Events that can be implemented by the regulator.

The report closes with a number of longer-term recommendations for improving the overall efficiency of the Colombian wholesale electricity market. Our major recommendation is to introduce a multi-settlement, locational marginal pricing (LMP)market. This would eliminate the need to have a positive and negative reconciliation mechanism. It would allow more efficient scheduling of combined cycle gas turbine units and coal-fired generation units and more efficient operation of flexible hydroelectric generation units. It can co-optimize the procurement and pricing of AGC and other ancillary services to reduce the cost of these services. It also has the potential to reduce the cost of integrating intermittent wind and solar generation units. Finally, it facilitates the entry of purely financial participants into electricity retailing, which can reduce both wholesale and retail market prices. We recommend increasing the number of offer price and quantity step suppliers are allowed to use to construct their offer curves into the energy and ancillary services markets. We strong support allowing purely financial participants to participate in both wholesale and retail markets for electricity in Colombia.



# 2. Generation Investment

## 2.1 Trends in generation and capacity

This chapter summarizes the behavior of installed generation capacity and the total amount of energy sold as Ideal Generation and Actual Generation over the past fifteen years. Two important stylized facts are revealed. First, particularly since 2010, most of the increase in installed generation capacity has come from investments in hydroelectric generation capacity. Second, despite this trend in new capacity investments, over this same time period the fraction of energy produced from thermal generation units has grown significantly. These two trends have put significant pressure on the RPM mechanism to achieve its stated goal, because the capacity utilization rate of thermal generation units has had to increase above historical levels during non-El Niño periods over this time period to keep up with the growing demand for electricity in Colombia.

Annual electricity generation in Colombia has increased from 41.28 terawatt-hours (TWh) in 2000 to 66.55 TWh in 2015, an average annual growth rate of 3.2 percent, as shown in Table 2.1. Between 2000 and 2009, most of this growth in electricity demand was met by increases in hydro generation, as shown in Figure 2.1. However, this changed after 2010, with demand growth mostly met by increasing thermal generation. As shown in Table 2.1, hydro generation peaked at 48.71 TWh in 2011 and has been lower in every subsequent year. Total Ideal Generation is typically virtually all hydroelectric generation, as shown in Figure 2.2. However, even the share of Ideal Generation coming from thermal generation capacity significantly increased after 2012.

As a result of these two trends, the composition of electricity produced in Colombia has changed since 2000. Between 2000 and 2005, hydro comprised 78.7 percent of total generation. This fell to 71.7 percent of the total between 2012 and 2015. Thermal generation (including a small proportion of thermal cogen plants) made up nearly all of the difference. The only grid-connected, non-hydro renewable generation is the Jepirachi wind farm, which began operations in 2004 and has a capacity of 19.5 MW.[1] Output from this facility comprised just 0.10 percent of total generation between 2012 and 2015.

There was very little expansion in electricity generation capacity between 2002 and 2010, as shown in Figure 2.3. System capacity increased by just 0.24 GW during this period (1.8 percent), compared to the 26.9

[1] http://www.epm.com.co/site/Home/Institucional/Nuestrasplantas/Energ\%C3\%ADa/ParqueE\%C3\%B3lico.aspx

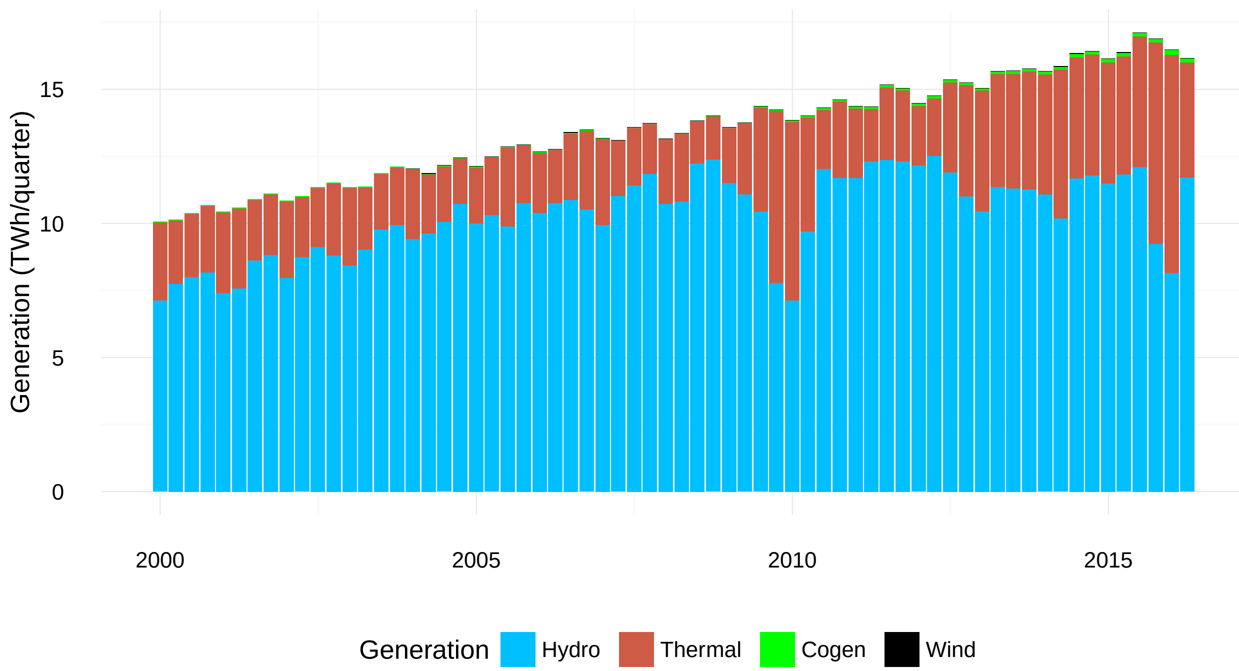



Figure 2.1: Quarterly Actual electricity generation in TWh, by type of generator

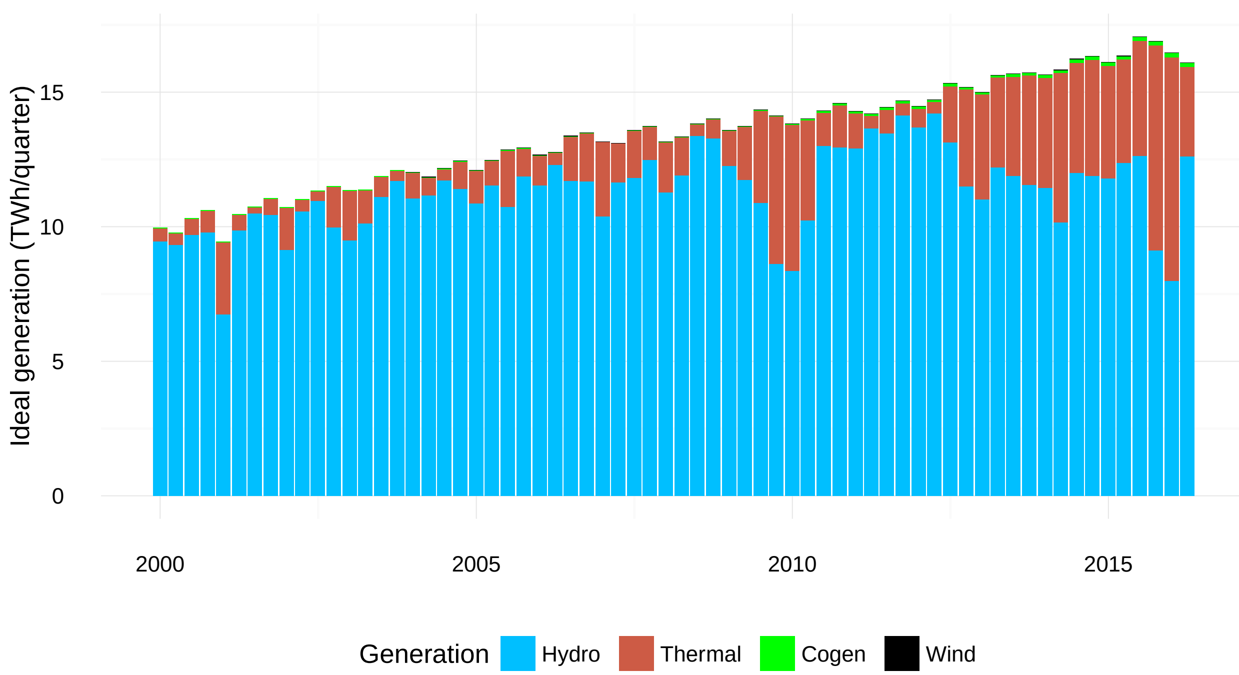



Figure 2.2: Quarterly Ideal electricity generation in TWh, by type of generator

Table 2.1: Annual electricity generation in TWh, by type of generator

| Year | Hydro | Thermal | Cogen | Wind | Total |
|---|---|---|---|---|---|
| 2000 | 31.07 | 10.10 | 0.11 | 0.00 | 41.28 |
| 2001 | 32.44 | 10.51 | 0.10 | 0.00 | 43.05 |
| 2002 | 34.67 | 9.96 | 0.11 | 0.00 | 44.74 |
| 2003 | 37.20 | 9.43 | 0.11 | 0.00 | 46.73 |
| 2004 | 39.85 | 8.54 | 0.12 | 0.05 | 48.56 |
| 2005 | 40.98 | 9.29 | 0.11 | 0.05 | 50.43 |
| 2006 | 42.56 | 9.63 | 0.09 | 0.06 | 52.34 |
| 2007 | 44.24 | 9.26 | 0.07 | 0.05 | 53.63 |
| 2008 | 46.16 | 8.13 | 0.05 | 0.05 | 54.39 |
| 2009 | 40.84 | 14.96 | 0.11 | 0.06 | 55.97 |
| 2010 | 40.56 | 15.97 | 0.22 | 0.04 | 56.79 |
| 2011 | 48.71 | 9.89 | 0.32 | 0.04 | 58.96 |
| 2012 | 47.58 | 11.91 | 0.35 | 0.05 | 59.89 |
| 2013 | 44.36 | 17.42 | 0.35 | 0.06 | 62.20 |
| 2014 | 44.74 | 19.04 | 0.47 | 0.07 | 64.33 |
| 2015 | 44.68 | 21.27 | 0.53 | 0.07 | 66.55 |

percent increase in system output over the same period. Between 2010 and 2016, generation capacity has increased by 2.89 GW. Interestingly, most of this increase (83.0 percent) consists of greater hydro generation capacity, in spite of the decline in total hydro generation over the period. These two facts suggest that the RPM mechanism may not getting the appropriate mix of generation capacity built to provide a reliable supply of electricity at a reasonable price during El Niño Events. Specifically, the significant increase in hydroelectric capacity beginning in 2010 has not led to a reliable increase in hydroelectric generation.

Colombia's thermal generation capacity is composed primarily of natural gas-fired and coal-fired generation capacity, with the vast majority of the new units natural gas-fired. The largest thermal plant in Colombia is Termobarranquilla with a capacity of 903 MW in 2016. The following list summarizes the major changes in thermal generation capacity in Colombia between 2000 and 2016:

- In 2000, the two open-cycle natural gas units at Termocentro were converted to combined-cycle, increasing capacity by 100 MW[2]
- In 2001, the thermal plant La Sierra (Termosierra) added a combined-cycle unit, increasing capacity by 166 MW.[3]
- In 2003, Termoyopal began operations with two gas units (with capacity 20 MW and 30 MW). Three additional units were installed in 2007: El Morro 1 and 2 and Cimarron (20 MW each).[4]
- In 2011, two open-cycle gas turbines at the Termoflores plant in Barranquilla (Flores II and Flores III) were converted to combined-cycle (Flores IV), increasing capacity by 169 MW.[5]

[2] `https://www.isagen.com.co/metaInst.jsp?rsc=infoIn_centralTermocentro\&tituloPag=ISAGEN,\%20Central\%20Termocentro\%20Ciclo\%20Combinado`

[3] `http://www.epm.com.co/site/Home/Institucional/Nuestrasplantas/Energ\%C3\%ADa/Termoel\%C3\%A9ctrica.aspx`

[4] `http://termoyopal.com.co/site/nosotros-_107`

[5] `http://www.celsia.com/Nuestra-Empresa/Generaci\%C3\%B3n-de-energ\%C3\%ADa/Termoel\%C3\%A9ctrica/Zona-Franca-Celsia`

Table 2.2: Generation capacity in GW, as of June 30 each year

| Year | Cogen | Wind | Hydro | Thermal | Total |
|---|---|---|---|---|---|
| 2000 | 0.01 | 0.00 | 8.23 | 4.20 | 12.44 |
| 2001 | 0.01 | 0.00 | 8.68 | 4.46 | 13.16 |
| 2002 | 0.01 | 0.00 | 8.90 | 4.39 | 13.31 |
| 2003 | 0.01 | 0.00 | 8.89 | 4.37 | 13.28 |
| 2004 | 0.02 | 0.02 | 8.89 | 4.23 | 13.16 |
| 2005 | 0.02 | 0.02 | 8.95 | 4.38 | 13.37 |
| 2006 | 0.02 | 0.01 | 8.95 | 4.32 | 13.30 |
| 2007 | 0.03 | 0.02 | 9.02 | 4.34 | 13.41 |
| 2008 | 0.03 | 0.02 | 9.00 | 4.44 | 13.48 |
| 2009 | 0.04 | 0.02 | 9.00 | 4.44 | 13.50 |
| 2010 | 0.04 | 0.02 | 9.03 | 4.46 | 13.55 |
| 2011 | 0.05 | 0.02 | 9.62 | 4.18 | 13.88 |
| 2012 | 0.05 | 0.02 | 9.74 | 4.58 | 14.39 |
| 2013 | 0.06 | 0.02 | 9.86 | 4.51 | 14.45 |
| 2014 | 0.08 | 0.02 | 10.01 | 4.59 | 14.70 |
| 2015 | 0.08 | 0.02 | 10.92 | 4.50 | 15.52 |
| 2016 | 0.08 | 0.02 | 11.43 | 4.90 | 16.44 |

- In 2015, a new 164 MW coal plant in Cordoba (Gecelca 3) was completed.[6]
- In 2016, an additional 160 MW coal unit (Termotasajero II) was added to the Tasajero plant in Norte de Santander.[7]

The observed growth in total electricity generation from 2000 to 2016 in Figure 2.1, combined with limited growth in generation capacity, implies that capacity utilization increased between 2000 and 2016. This growth in capacity utilization appears to be divided into two regimes based on the generation technology that experienced the growth in capacity utilization, as shown in Figure 2.4. The first regime, from 2000 to early 2009, saw steady grow in the capacity utilization of hydroelectric generation units, as shown in Figure 2.4. Following the 2009-2010 El Niño Event until early the 2012, the capacity utilization rate of thermal generation units returned to pre-2009 levels. However, from mid-2012 to mid-2015 the capacity utilization rate of thermal units almost doubled relative to pre-2009 levels to between 40 to 50 percent. The overall capacity utilization rate across generation capacity significantly increased over our sample period, from 37.4 percent in 2000 to 48.8 percent in 2015. As we demonstrate in Chapter 7, this result has implications for the ability of the large suppliers to exercise unilateral market power during El Niño Events.

This "regime shift" in mid-2012 towards higher thermal capacity utilization also appears to be associated with the start of a prolonged period of higher wholesale electricity prices, to levels only seen previously during the 2009-2010 El Niño Event. Figure 2.6 focuses on the time period 2008 to 2016 and presents weekly average Bolsa prices and weekly average capacity utilization rates for hydroelectric and thermal generation units. This figure shows that Bolsa prices from mid-2012 until mid-2015 were often at or above the levels during the 2009-2010 El Niño Event.

It is difficult to explain these higher prices as the result of increased input fossil fuel costs. Figure 2.7

[6] http://www.elheraldo.co/economia/comenzo-operar-gecelca-3-con-una-generacion-de-164-megavatios-217529
[7] http://www.laopinion.com.co/economia/termotasajero-2-entro-nuevamente-en-funcionamiento-108516

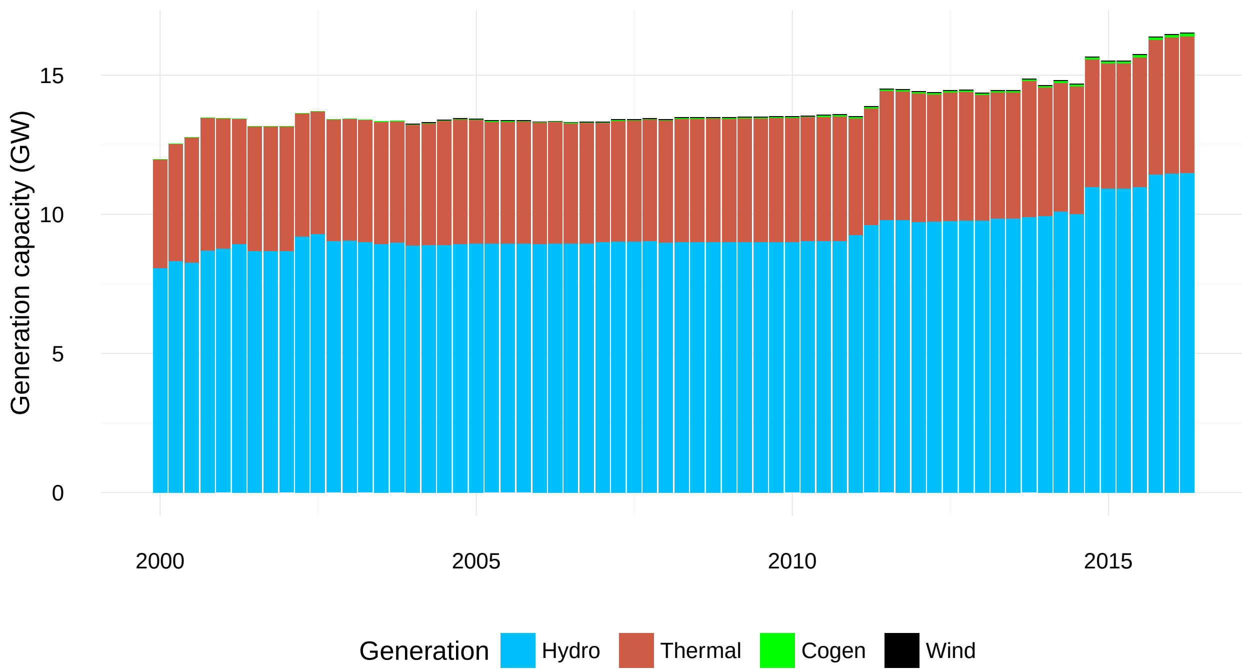



Figure 2.3: Quarterly generation capacity in GW, by type of generator

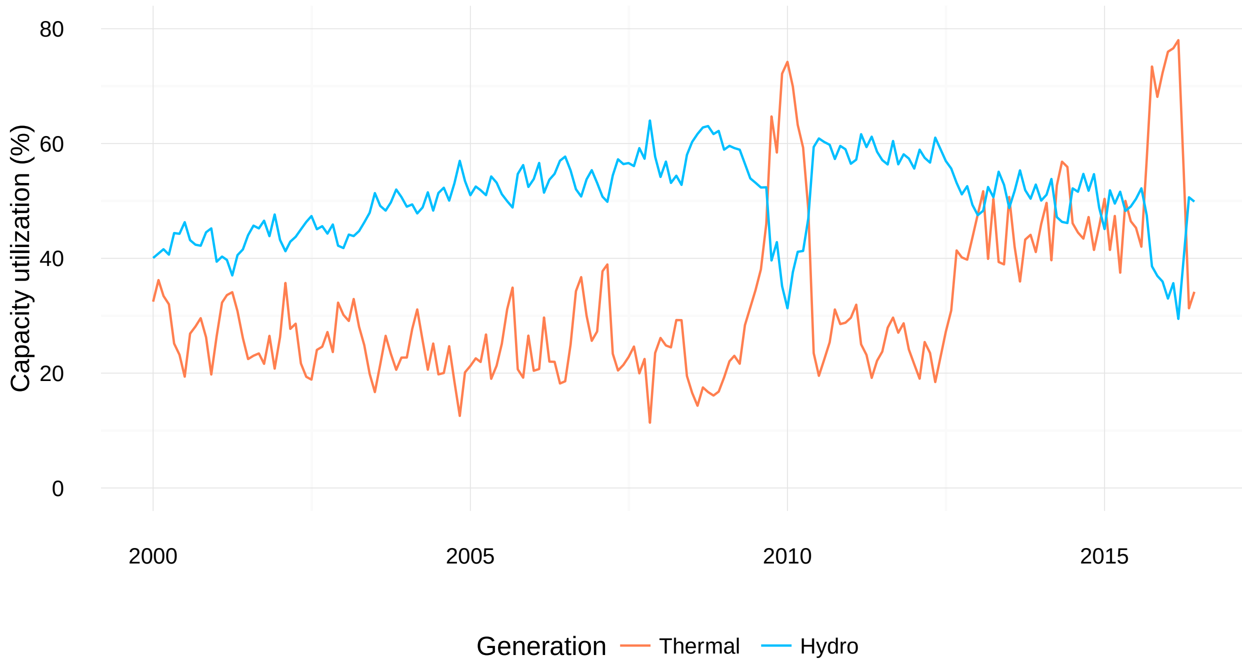



Figure 2.4: Monthly capacity utilization for hydro and thermal generators

plots the Dollar/Colombia Peso exchange rate from 2000 to 2016. This figure shows a steady appreciation of the Colombia Peso from start of the 2009-2010 El Niño Event to mid-2015. Figure 2.8 plots the price of diesel fuel at Barrancabermeja and the US Gulf Coast over this same time period in Colombia Pesos (COP) per million British Thermal Units (MMBTU). Figure 2.9 plots the natural gas prices at Henry Hub and the Guajira and Cusiana locations in Colombia in COP/MMBTU over our sample period. The vertical black line marks the date that the price regulation at Guajira ended. For both diesel prices and natural gas prices, the Peso per MMBTU prices throughout the mid-2012 to mid-2015 period were the same as or at most only slightly higher than they were during the 2009-2010 El Niño period.

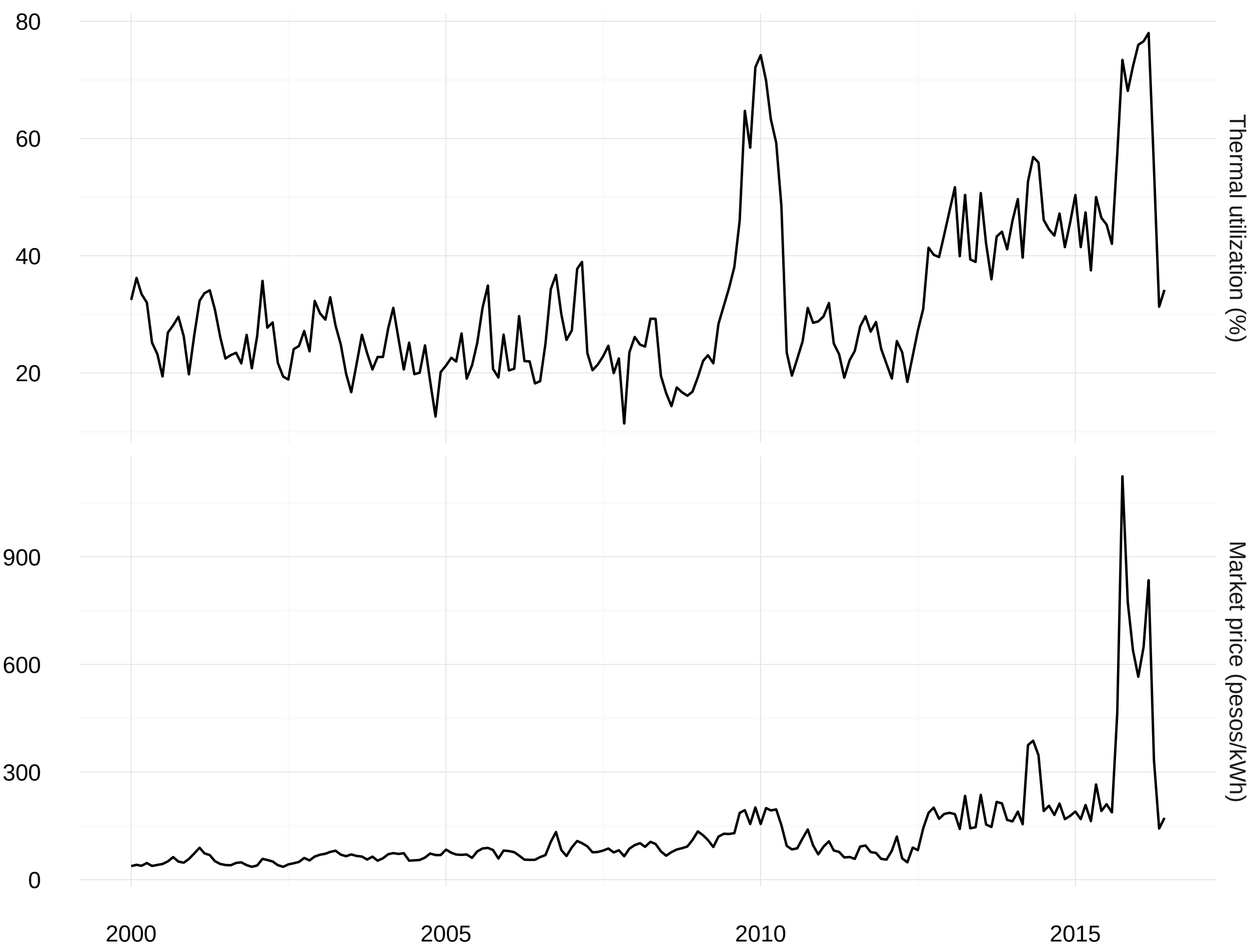
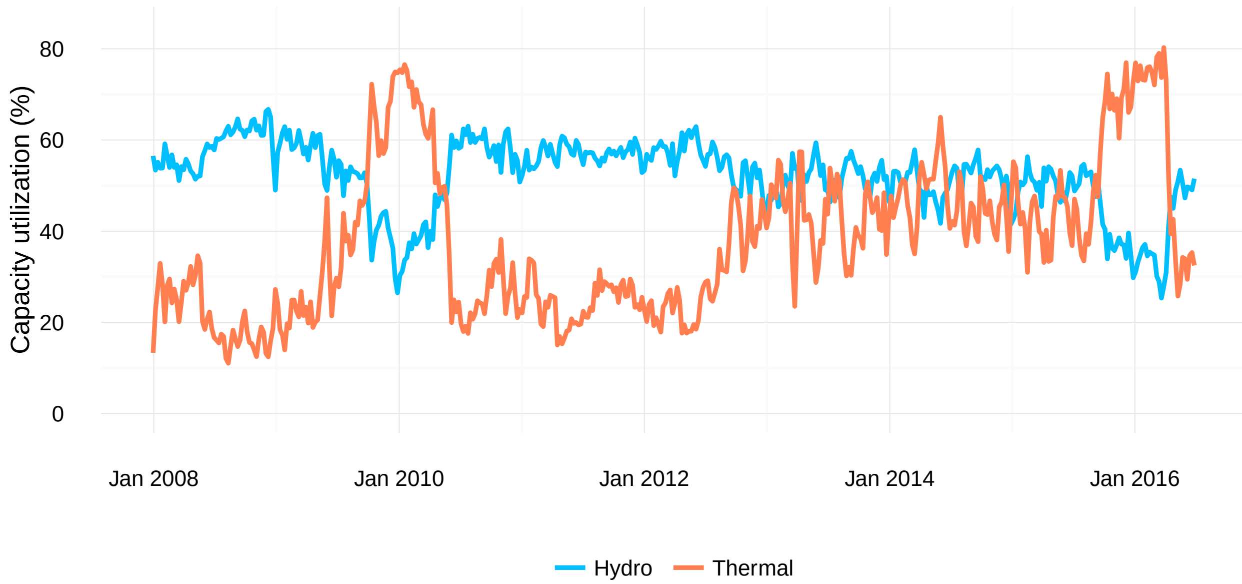



Figure 2.5: Monthly thermal capacity utilization and average market price

Spikes in thermal capacity utilization are associated with higher wholesale electricity prices, as shown in Figure 2.5. This occurred during the El Niño events in 2009–10 and, most notably, in 2015–16. However, the same magnitude spike in the thermal capacity utilization rate in 2015-16 and 2009-2010 led to a spike in Bolsa prices in 2015-2016 that was six times as large as the spike in 2009-2010. This is the first puzzle of the 2015-2016 El Niõo Event relative to the 2009-2010 event. Although natural gas prices in Colombia rose significantly in late 2015, there are a number of reasons to believe these input fossil fuel price increases alone are insufficient to explain the almost tenfold increase in Bolsa prices in late 2015 shown in Figure 2.6. First the price of diesel fuel in Colombia was significantly higher than the price of natural gas and it was



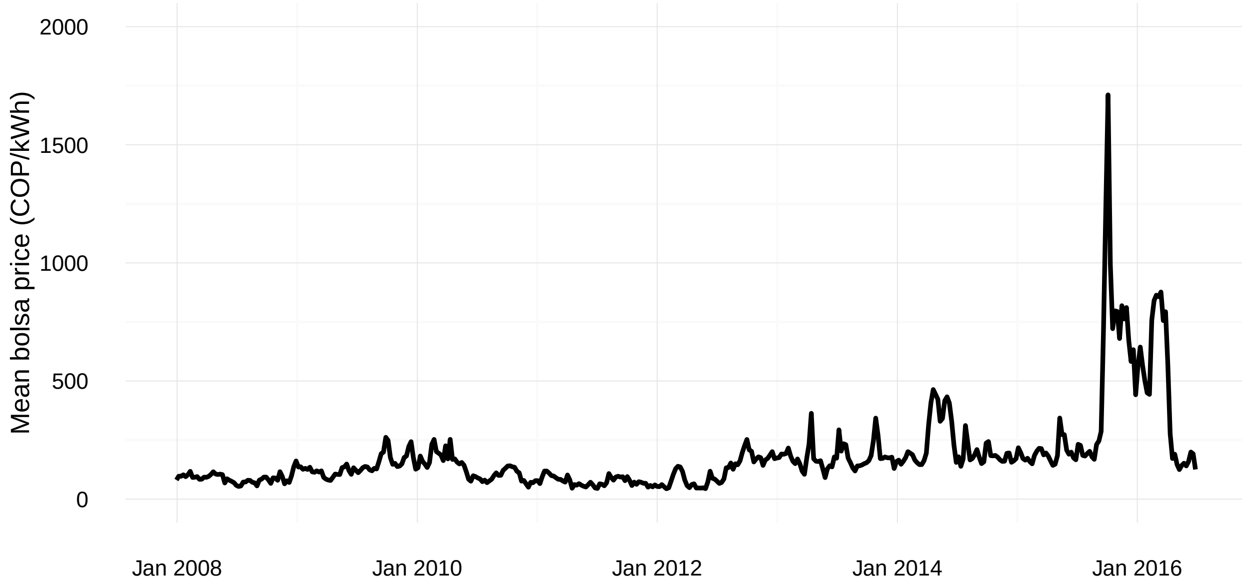




Figure 2.6: Weekly capacity utilization by technology and average bolsa price


Figure 2.7: US Dollar–Colombian Peso exchange rate, 2000–2016

Source: Banco de la República daily representative market exchange rate (TRM) (`http://www.banrep.gov.co/es/trm`).

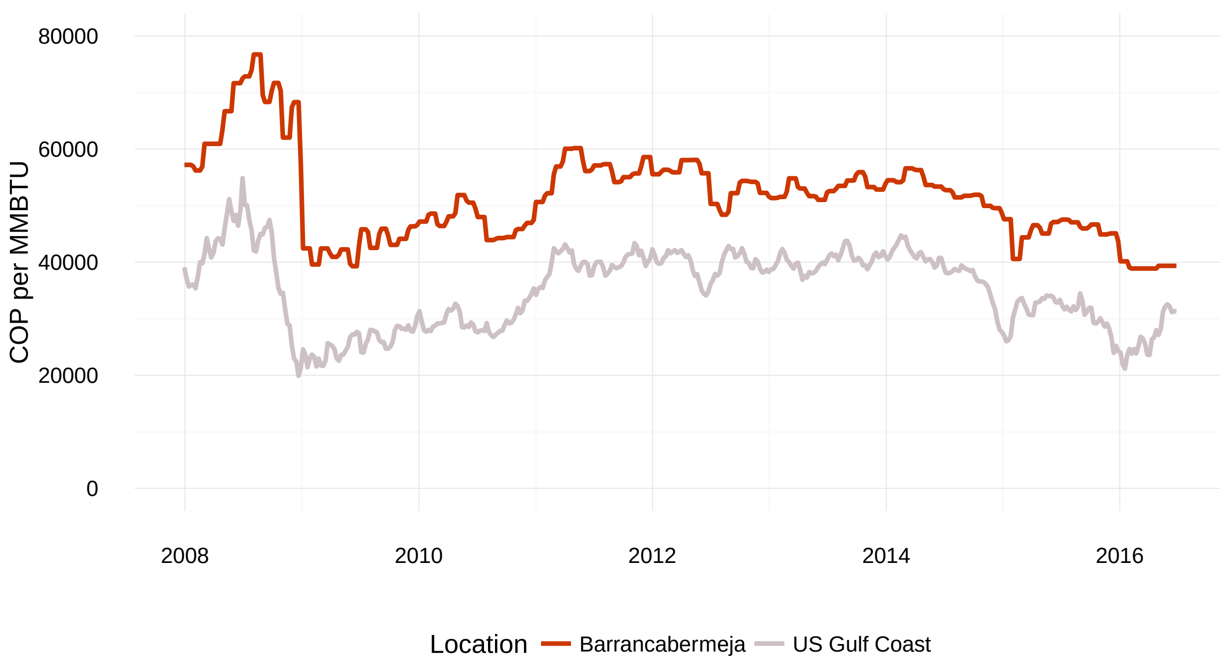



Figure 2.8: Diesel price at Barrancabermeja and US Gulf Coast, 2008–2016

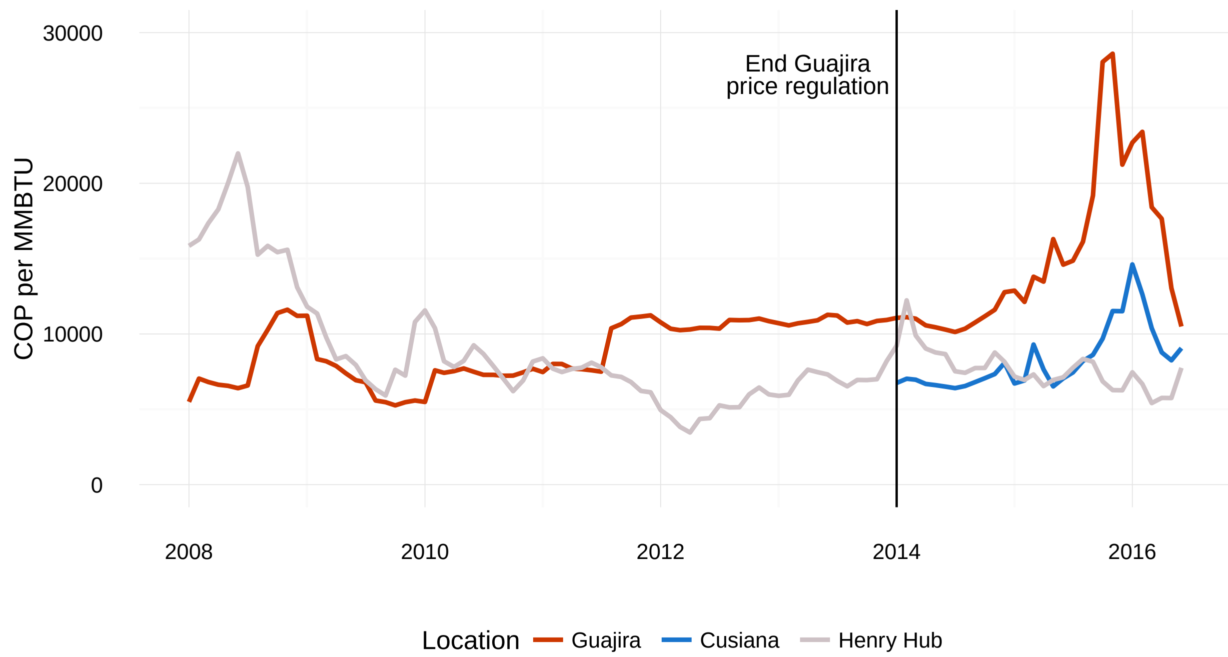



Figure 2.9: Natural gas prices at Henry Hub and major Colombia price points, 2008–2016

falling during much of this time period. Second, as shown in Figure 2.10, diesel and fuel oil were being used to produce some electricity throughout the mid-2012 to mid-2015 time period. Consequently, it is extremely likely that a significant portion of this massive increase in Bolsa prices from mid-2015 forward can be explained by a significant increase in the ability of large suppliers to exercise unilateral market power during this time period relative to the 2009-2010 time period. In Chapter 7, we present strong empirical evidence in favor of this view.

Higher thermal generation during El Niño Events means that fossil fuel consumption is much higher, as shown in Figure 2.10. One puzzling, but notable, difference between the 2009-10 El Niño Event and the 2015-2016 Event is the much greater use of liquid fuels (diesel, fuel oil, jet fuel) during the 2015–16 El Niño Event. Total liquid fuel consumption was 35.11 million MMBTU in the last quarter of 2015 and first quarter of 2016, compared to consumption of 7.71 million MMBTU for the same period in 2009–10. At the same time, natural gas consumption was lower in the recent El Niño event: 65.66 million MMBTU in the last quarter of 2015 and first quarter of 2016, compared to 84.85 million MMBTU for the same period in 2009–10.

The puzzling feature of the fossil fuel use results in 2.10 is the fact that during the 2009-2010 event there were difficulties in obtaining sufficient natural gas and more expensive liquid fuels had to be relied upon. In spite of this experience, less natural gas was consumed during the 2015-2016 El Niño Event than was consumed during the 2009-2010 event. A prudent input fossil fuel procurement strategy given the lower share of thermal capacity in 2015-2016 versus 2009-2010 would entail purchasing more, not less, natural gas because the need for thermal energy was expected to be higher during a future El Niño Event than during the 2009-2010 El Niño Event.

Throughout the remainder of this report statistics are presented at the market participant level. This requires assigning generation assets to specific market participants. Table 2.4 at the end of this chapter

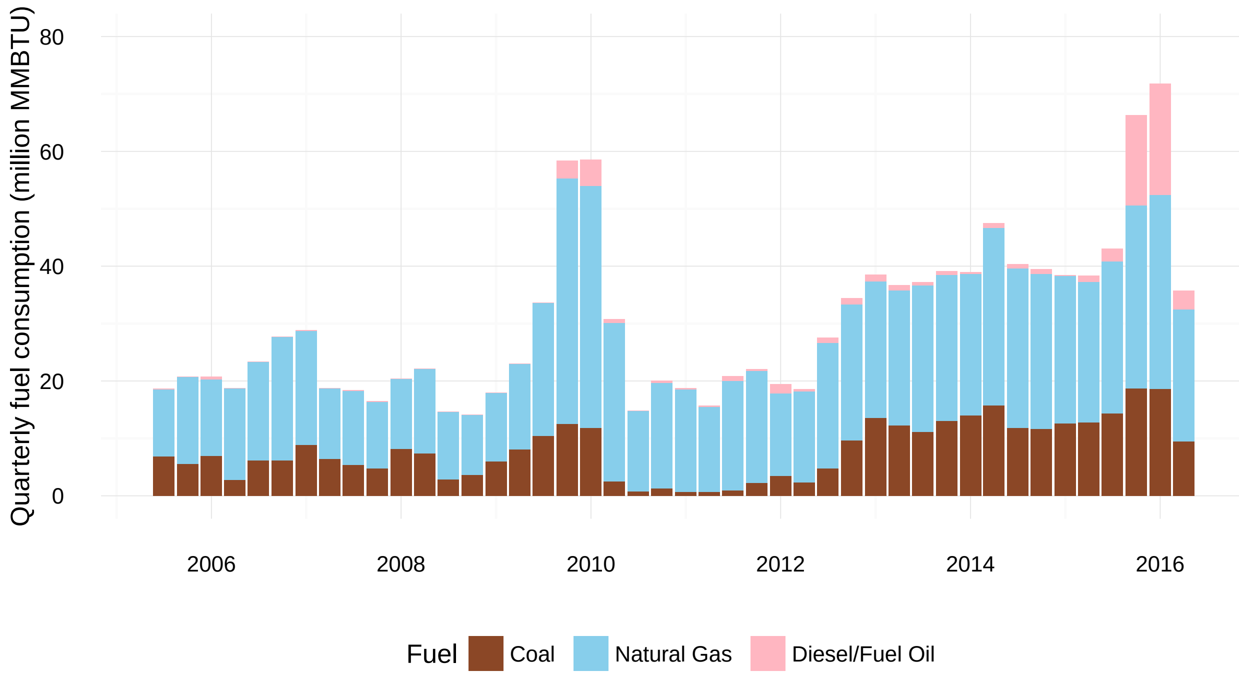



Figure 2.10: Quarterly fuel consumption by thermal generators, 2005–2016

provides a list of these assignments and how they have changed over time. Our general rule was to assign control of a generation unit to a market participant based on which market participant controlled the offers that a generation unit makes into the wholesale market. Table 2.3 presents capacity share information by market participant as of June 30, 2016. The three largest suppliers—EPM, Emgesa, and Isagen—control more than 60 percent of the installed capacity in Colombia. Figure 2.11 presents the Herfindahl-Hirschman Index (HHI) of concentration from 2008 to the present time using the capacity shares of each market participant defined using the information in Table 2.4. The HHI is presented separately for thermal generation capacity, hydroelectric generation capacity, and all generation capacity. The HHI is defined as the sum of the squares of the capacity shares owned by each market participant. Hydroelectric capacity is concentrated in the three largest firms which explains why the HHI for hydroelectric capacity is significantly higher throughout the time period than it is for thermal capacity and all generation capacity. The higher HHI for hydroelectric capacity provides further evidence in favor of our conclusion that when water availability is low there is less competition to supply electricity and the large generation unit owners have a greater ability to raise the Bolsa price by exercising unilateral market power.

Table 2.3: Ownership or control of generation capacity, in GW, as of 30 June 2016

| Firm | Hydro | Thermal | Cogen | Wind | Total | Percent |
|---|---|---|---|---|---|---|
| EPM | 2.99 | 0.54 | 0.01 | 0.02 | 3.56 | 21.48 |
| Emgesa | 3.02 | 0.41 | 0.01 | 0.00 | 3.44 | 20.73 |
| Isagen | 2.73 | 0.26 | 0.00 | 0.00 | 2.99 | 18.02 |
| Celsia | 1.08 | 0.78 | 0.05 | 0.00 | 1.90 | 11.47 |
| SCLEA consortia | 0.00 | 1.22 | 0.00 | 0.00 | 1.22 | 7.34 |
| AES Chivor | 1.00 | 0.00 | 0.00 | 0.00 | 1.00 | 6.03 |
| Gecelca | 0.00 | 0.46 | 0.00 | 0.00 | 0.46 | 2.80 |
| Urra | 0.34 | 0.00 | 0.00 | 0.00 | 0.34 | 2.04 |
| Colgener | 0.00 | 0.33 | 0.00 | 0.00 | 0.33 | 1.98 |
| Gensa | 0.00 | 0.32 | 0.00 | 0.00 | 0.32 | 1.93 |
| Termocandelaria | 0.00 | 0.32 | 0.00 | 0.00 | 0.32 | 1.90 |
| ContourGlobal | 0.00 | 0.21 | 0.00 | 0.00 | 0.21 | 1.28 |
| Other | 0.33 | 0.11 | 0.06 | 0.00 | 0.50 | 3.01 |
| **Total** | **11.48** | **4.97** | **0.13** | **0.02** | **16.59** | **100.00** |

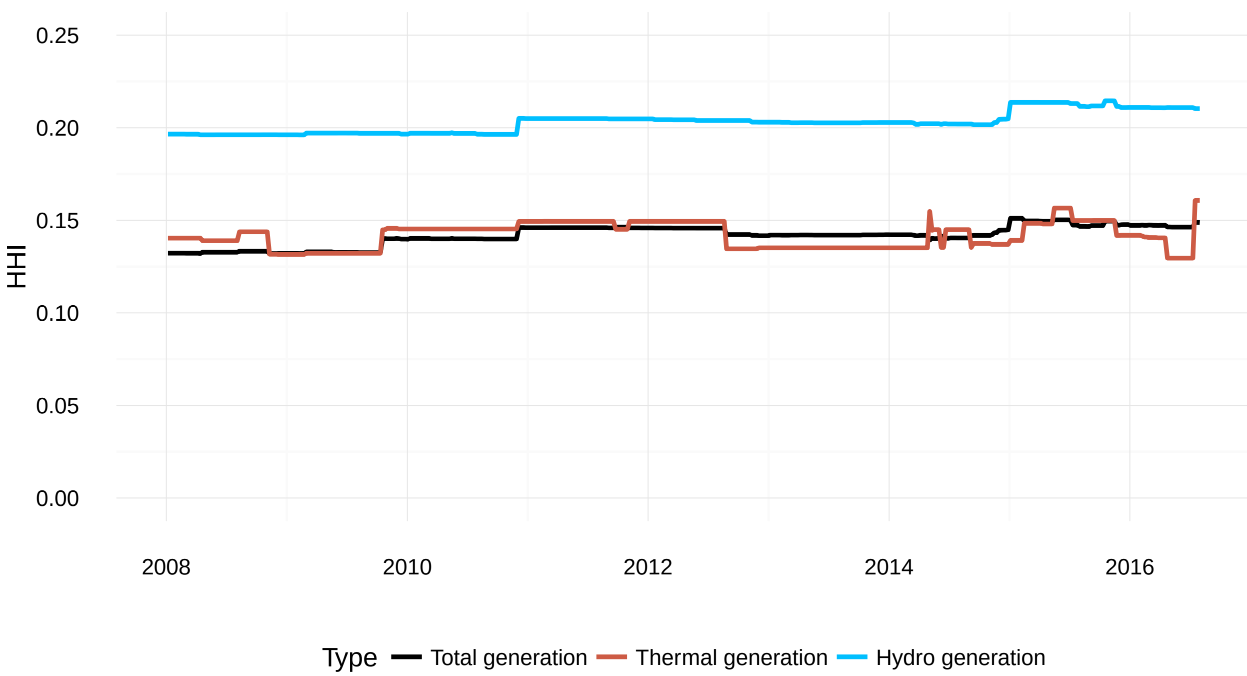



Figure 2.11: Herfindahl-Hirschman index for generation capacity, 2008–2016

Table 2.4: Ownership or control of generation plants larger than 10 MW, 2008–2016

| Firm / plant name | Capacity (MW)[a] | Fuel type[b] |
|---|---|---|
| **Empresas Públicas de Medellín (EPM)** | | |
| Hydro | | |
| Ayurá | 18.0 | |
| Esmeralda | 30.0 | |
| Guatape | 560.0 | |
| Guatron | 512.0 | |
| Insula | 19.0 | |
| La Herradura | 19.8 | |
| La Tasajera | 306.0 | |
| La Vuelta | 12.0 | |
| Niquía | 19.0 | |
| Playas | 207.0 | |
| Porce | 1065.0 | |
| Riogrande | 19.0 | |
| San Francisco | 135.0 | |
| Sonsón | 19.0 | |
| Thermal | | |
| Termodorada[1] | 51.0 | Gas, Jet A1, Diesel |
| Termosierra | 445.0 | Gas, Diesel, Fuel Oil |
| Wind | | |
| Parque Eólica Jepirachi | 18.0 | |
| **Electrificadora de Santander** | | |
| (EPM after 26 February 2009)[2] | | |
| Hydro | | |
| Palmas | 15.0 | |
| Thermal | | |
| Termobarranca[3] | 48.0 | Gas, Fuel Oil |
| Termopalenque[4] | | Gas |
| **Emgesa** | | |
| Hydro | | |
| Betania | 540.0 | |
| Dario Valencia Samper | 150.0 | |
| El Charquito | 19.0 | |
| El Limonar | 18.0 | |
| El Quimbo | 396.0 | |
| Guavio | 1200.0 | |
| Laguneta | 18.0 | |
| Paraíso - La Guaca | 600.6 | |

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| | | |
|---|---|---|
| Salto II | 35.0 | |
| Tequendama | 19.0 | |
| Thermal | | |
| Termocartagena | 187.0 | Gas, Fuel Oil |
| Termozipa | 225.0 | Coal |
| **Isagen** | | |
| Hydro | | |
| Amoyá - La Esperanza | 80.0 | |
| Calderas | 19.9 | |
| Jaguas | 170.0 | |
| Miel I | 396.0 | |
| San Carlos | 1240.0 | |
| Sogamoso | 820.0 | |
| Thermal | | |
| Termocentro | 264.0 | Gas, Jet A1 |
| **Celsia** | | |
| Hydro | | |
| Montañitas | 19.9 | |
| Rio Piedras | 19.9 | |
| Thermal | | |
| Meriléctrica (after 4 August 2008)[5] | 167.0 | Gas |
| Termoflores (Zona Franca Celsia) (after 3 November 2008)[6] | 608.0 | Gas, Diesel |
| **Empresa de Energía del Pacifico** (Celsia after 16 October 2009)[7] | | |
| Hydro | | |
| Alban (Alto Anchicaya and Bajo Anchicaya) | 429.0 | |
| Alto Tulua | 19.9 | |
| Amaime | 19.2 | |
| Bajo Tulua | 19.9 | |
| Calima | 132.0 | |
| Cucuana | 58.0 | |
| Prado | 51.0 | |
| Riofrio | 12.0 | |
| Salvajina | 285.0 | |
| Thermal | | |
| Termovalle (before August 23 2012)[8] | | |
| Cogeneration | | |
| Ingenio Mayaguez | 19.9 | |
| **SCL Energía Activa consortia**[9] | | |
| Thermal | | |

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| | | |
|---|---|---|
| Cimarrón (after October 13 2010) | 20.0 | Gas |
| El Morro 1 and 2 (after October 13 2010) | 39.9 | Gas |
| Termobarranquilla (after 20 April 2016)[10, 11] | 903.0 | Gas, Fuel Oil |
| Termocandelaria (15 May 2015 – 20 November 2015)[10, 12] | | |
| Termovalle (after 13 September 2014)[13] | 205.0 | Gas, Diesel |
| Termoyopal 1 and 2 (after October 13 2010)[14] | 50.0 | Gas |
| **AES Chivor** | | |
| Hydro | | |
| Chivor | 1000.0 | |
| **Gecelca**[*] | | |
| Thermal | | |
| Gecelca | 164.0 | Coal |
| Termoguajira | 300.0 | Coal |
| Termobarranquilla (before 21 April 2016)[11] | | |
| Termoflores (before 4 November 2008)[6] | | |
| **Empresa Urrá**[*] | | |
| Hydro | | |
| Urrá | 338.0 | |
| **Colgener**[18] | | |
| Thermal | | |
| Termotasajero | 328.0 | Coal |
| **Gestión Energética (Gensa)**[*] | | |
| Thermal | | |
| Paipa 1–3 | 171.0 | Coal |
| Paipa 4[15] | 150.0 | Coal |
| **ContourGlobal**[15, 16] | | |
| Thermal | | |
| Termoemcali[17] | 213.0 | Gas, Diesel, Fuel Oil |
| **Pacific Power Generation** | | |
| Thermal | | |
| Proeléctrica | 90.0 | Gas |
| **La Cascada** | | |
| Hydro | | |
| Barroso | 19.9 | |
| El Popal | 19.9 | |
| San Miguel | 44.0 | |
| **Vatia** | | |
| Hydro | | |

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Table 2.4 – *Continued from previous page*

| | | |
|---|---|---|
| Florida 2 | 19.9 | |
| Cogeneration | | |
| Ingenio Providencia | 14.0 | |
| Incauca | 10.0 | |
| **Others / Independent** | | |
| Hydro | | |
| Carlos Lleras Restrepo | 78.0 | |
| Rio Mayo | 19.8 | |
| Thermal | | |
| Termocandelaria (21 November 2015 – 15 July 2016)[12] | 315.0 | Gas, Diesel, Fuel Oil |
| Cogeneration | | |
| Proenca | 19.9 | |

[a] Capacity as at 30 June 2016. Data is from the file "capains0630.txf" from http://www.xm.com.co/Pages/InformacionComercialPublicaSIC.aspx.
[b] Includes all fuels with positive consumption by the plant over the period 2000–2016.
[*] These firms are all or majority-owned by the Colombian government.
[1] This plant was bought by Central Hidroeléctrica de Caldas (Chec) in 2003. EPM bought Chec in 2003.
[2] EPM bought ESSA from the Colombian government in February 2009
[3] This plant will be shutdown in the second half of 2016 (http://www.vanguardia.com/santander/barrancabermeja/364036-luego-de-46-anos-essa-cerrara-termobarranca).
[4] Final appearance in generation capacity list on 30 November 2012, with a capacity of 13 MW.
[5] Merger between Termoflores and Merieléctrica on 5 August 2008. Inversiones Argos (Inverargos) and Cementos Argos swapped 100% of Merieléctrica in exchange for 20% of Colinversiones (later renamed Celsia). http://www.portafolio.co/economia/finanzas/superindustria-aprobo-integracion-termoflores-controlada-colinversiones-merielectrica-313852.
[6] Gecelca (formerly Corelca) had a PPA for electricity from Termoflores. Celsia appears as the market agent on 4 November 2008.
[7] Colinversiones, Inversiones Argos SA, and Banca de Inversion Bancolombia bought the 66.1% holding in EPSA from Gas Natural SDG. Colinversiones later increased its holding to 50.01%.
[8] EPSA had a PPA for electricity from Termovalle. It last appears as the market agent on August 22 2012. The owner of Termovalle at that time was Dorado Group.
[9] This is a group of investors with interests in several thermal generators in Colombia. The investors include Vince Business Corporation (owned by Mercantil Colpatria), Moneda International Inc, Bancard International Investment, and the Americas Energy Fund I administered by SCL Energía Activa (50% SCL Energía and 50% LarrainVial).
[10] The SCLEA group of investors bought the 60.75% shareholding in Termocandelaria Power Limited (TPL) from Tribeca in May 2015 (http://www.portafolio.co/negocios/empresas/tribeca-vende-participacion-termocandelaria-tebsa-30218). TPL is the owner of 57.38% of Termobarranquilla.
[11] Gecelca (formerly Corelca) had a PPA for electricity from Termobarranquilla that ended on April 20 2016.
[12] Superintendencia de Servicios Públicos Domiciliarios took control of Termocandelaria on 21 November 2015.
[13] Kinneas Incorporated (a Panamanian incorporated company) bought Termovalle from Dorado Group in 2014. (http://www.elheraldo.co/economia/superintendencia-de-servicios-toma-posesion-de-termocandelaria-229580). Shareholders in Kinneas include SCLEA, Altra Investments and Mercantil Colpatria.
[14] Consortium of Mercantil Colpatria, Americas Energy Fund, and Altra Investments bought Termoyopal in October 2010 (http://www.dinero.com/negocios/articulo/consorcio-internacional-compra-termoyopal/105973). El Morro and Cimarrón are listed as assets of Termoyopal on its web page (http://termoyopal.com.co/site/nosotros-_107).
[15] Gensa has a PPA for electricity from Paipa 4 that expires in 2019 (http://www.andeg.org/node/14). Paipa 4 is owned by German firm Evonik and ContourGlobal (http://www.bnamericas.com/en/news/electricpower/Maguro-to-buy-additional-stake-in-165MW-Termopaipa-IV).
[16] ContourGlobal bought its 49% shareholding in Paipa 4 from funds associated with Grupo Santo Domingo, in 2006 and 2011.
[17] ContourGlobal and Fondo de Infraestructura Colombia (Ashmore) participated in privatization of Termoemcali, acquiring 62.3% of its shares. ContourGlobal has a 37.3% shareholding and controls and operates the plant (http://www.dinero.com/negocios/articulo/renuncio-presidente-contourglobal-latam/143649).
[18] Termotasajero is owned by Colgener, a Colombian company made up of two Chilean private capital funds associated with Solari family and four Colombian pension funds (Protección, Porvenir, Colfondos, Skandia) (http://www.colgener.com.co/colgener.php?x_sec=1&x_id=1).

# 3. Availability of Hydroelectric Energy

This chapter summarizes the availability of hydroelectric energy since 2000 in terms of both water inflows and water storage levels. We establish three major stylized facts. First, starting in 2011, there has been a continuous decline in total annual water inflows, with annual inflows in 2012 and 2013 only slightly larger than 2009, the calendar year containing the 2009-2010 El Niño Event. Second, annual average reservoir levels are comparable to 2009 and 2010 starting in 2013, two years in advance of the 2015-2016 El Niño Event. These results help explain the significant increase in the capacity factor of thermal generation units in mid-2012. However, these results also raise the question of why the capacity factor of thermal generation units was not even higher from mid-2012 to mid-2015. Finally, the incidence of hydro spill as a fraction of annual hydroelectric energy production in 2014 and 2015 is significantly higher than it was in 2009.

Our analysis is based on the subset of rivers and hydro reservoirs for which data exists since 2000. This is done in order to distinguish changes in hydrological conditions or operating behavior of existing hydro plants from construction of new hydro capacity.[1]

Inflows from the major rivers that feed the hydro reservoirs peaked in April 2011, as shown in Figure 3.1.[2] There is a clear downward trend in this measure of monthly river flows beginning in 2011 that continues until the trough of the 2015-2016 El Niño Event in early 2016.

Figure 3.2 plots aggregate annual inflows. Annual inflows exceeded 40 TWh for each of 2010, 2011, and 2012, with a maximum of 57.1 TWh in 2011. However, for the subsequent three years (2013–2015), annual inflows were below 40 TWh each year. The last time that inflows had been so low for three consecutive years was from 2001 to 2003. Although inflows in 2009 were comparable to inflows in 2013, 2014, and 2015, inflows in 2010, were significantly higher. Consequently, a significant difference between the 2009-2010 El Niño Event and the 2015-2016 event is the sustained period of low annual inflows that preceded the most recent Event.

Hydro reservoir levels are distinct from hydro inflows, in that they depend not only on weather conditions, but also on the offer behavior of all generation unit owners. Between 2005 and 2012, hydro reservoir levels

[1] Hydro reservoirs that are excluded from the analysis are: Urrá, Porce, Miel, Amaní, Topocoro and El Quimbo.

[2] Maximum inflow, for each individual river, is calculated as the highest daily inflow over the period January 2000 to June 2016, in cubic meters per second. The graph shows the aggregate average inflow in cubic meters per second, expressed as a percentage of the maximum inflow for each river.

fell below 50 percent of their maximum on only two occasions: in 2005 and in 2010, as shown in Figure 3.3. However, since 2012, reservoir levels have fallen below 50 percent every year. Daily average reservoir levels in 2013 were the lowest in our sample period, as shown in Figure 3.4. The unusually high inflows during 2011 were reflected in record high reservoir levels in 2011 and 2012. This figure reinforces our earlier point that 2015-2016 El Niño Event was not significantly different from 2009-2010 event in terms of water inflows and water levels during the event period, but the major difference was that the 2015-2016 event was preceded by several years of low water inflows and low water levels. Moreover, as shown in Chapter 2, the thermal share of total generation capacity was higher in 2009-2010 than 2015-2016, so that lower water inflows could be replaced by thermal generation more easily in 2009-2010 versus 2015-2016.

The previous graphs show storage levels and inflows only for the reservoirs that were constructed before 2000. Although there has been a considerable expansion in hydro generation capacity since 2000, Figure 3.5 demonstrates that the new plants have only made a small contribution to aggregate reservoir capacity. Given the growth in overall electricity demand, there has been a fairly consistent decline in the average reservoir storage levels, expressed in days of system load.[3] Average reservoir levels were more than 90 days of system load in 2000 and 2002. This had fallen to about 50 days of system load for 2013–2015. Figure 3.6 plots hydro storage capacity in TWh and hydroelectric generation capacity measured in TWh per quarter (calculated by multiplying the generation capacity in MW by $24 \times 365/4$). Although hydroelectric storage capacity increases from 2010 to 2015, the more rapid increase in hydroelectric generation capacity reinforces the point that much of the increased generation capacity has limited ability to store significant amounts of water relative to existing hydroelectric capacity.

Spill from hydro reservoirs was also relatively high between 2010 and 2012. Figure 3.7 shows that in 2011, water equivalent to 5.9 TWh of electricity generation was spilled from reservoirs, equivalent to 10.0 percent of total generation that year. Unsurprisingly, given the low inflows and high electricity prices, hydro spill has been very low since 2013, although annual spill in 2014 and 2015 was higher than in 2009.

[3]Reservoir storage levels in days of system load are calculated as the daily mean reservoir level, divided by the annual system load, multiplied by 365.

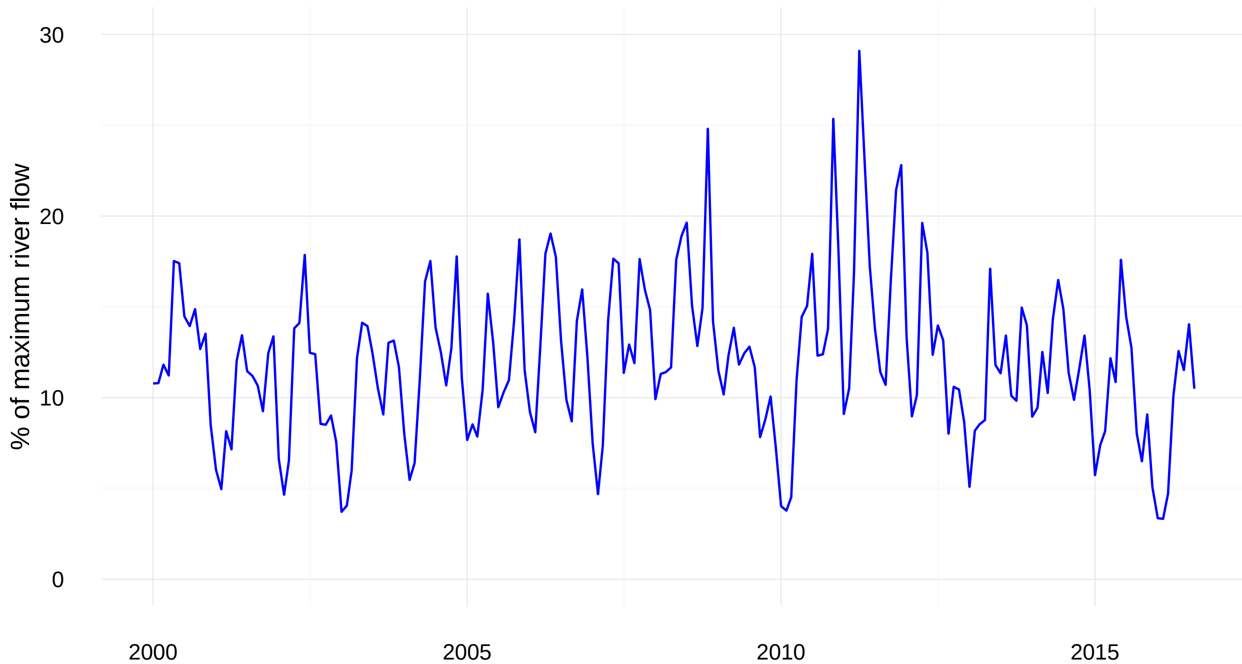



Figure 3.1: Monthly river flows, as percentage of maximum flow, 2000–2016

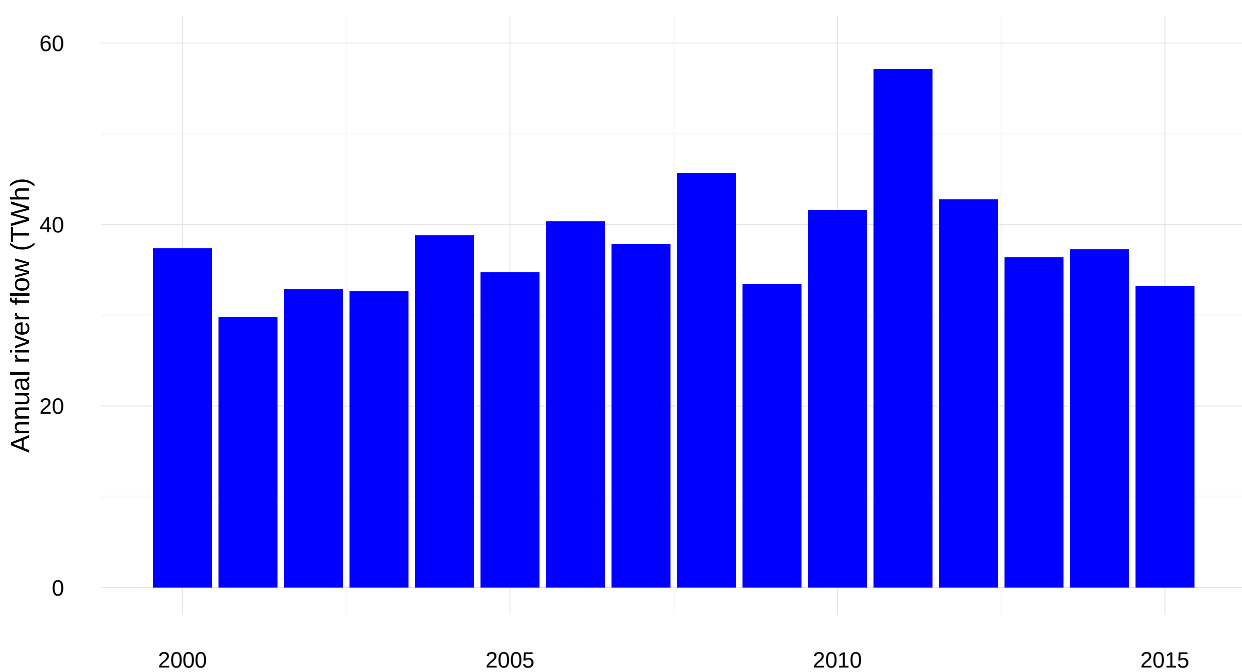



Figure 3.2: Annual river flow, in TWh equivalent, 2000–2015

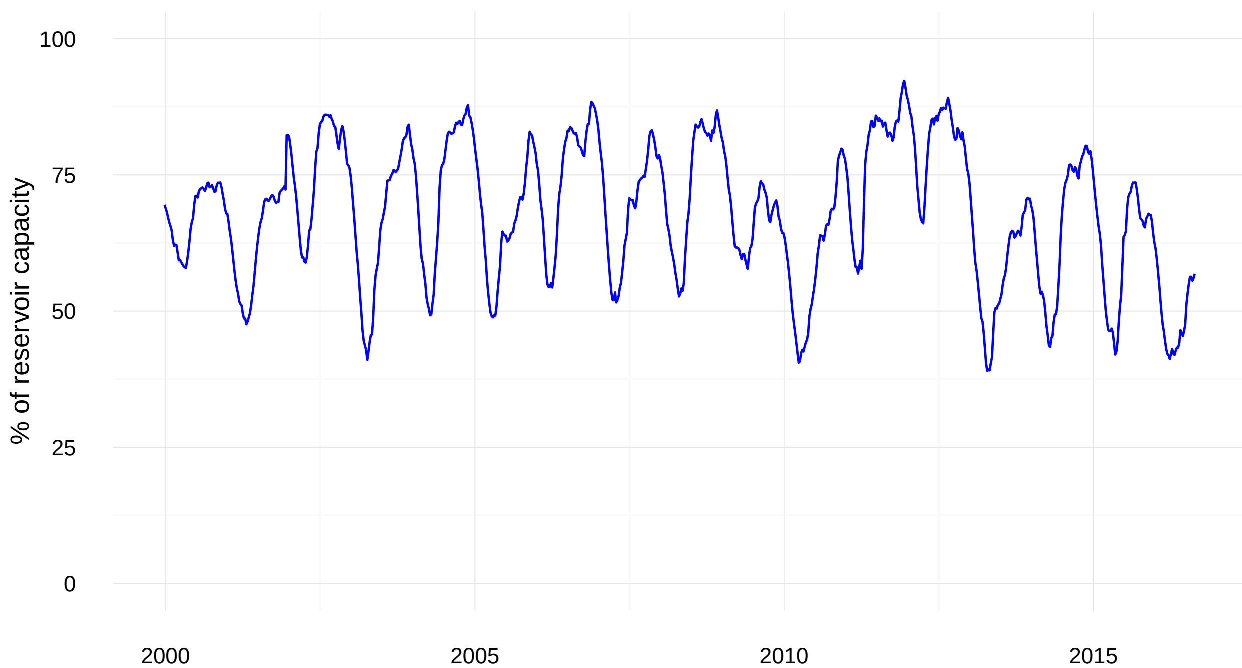



Figure 3.3: Weekly hydro reservoir levels, 2000–2016

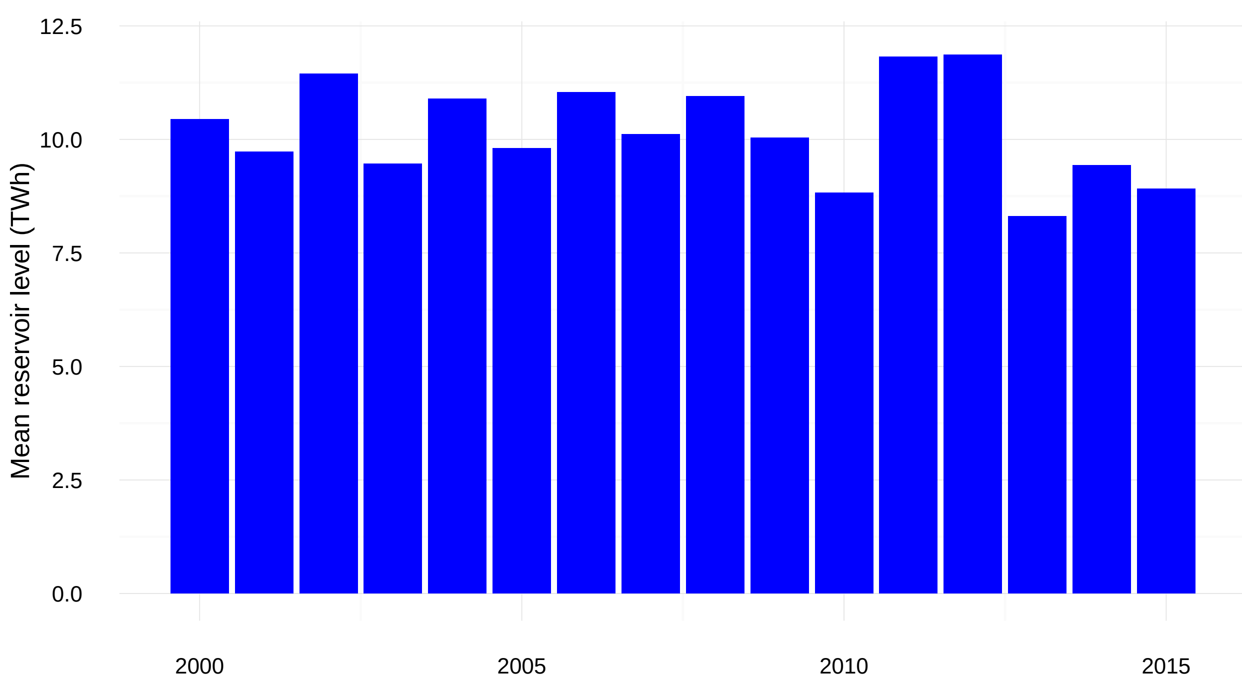



Figure 3.4: Annual average hydro reservoir levels, in TWh, 2000–2015

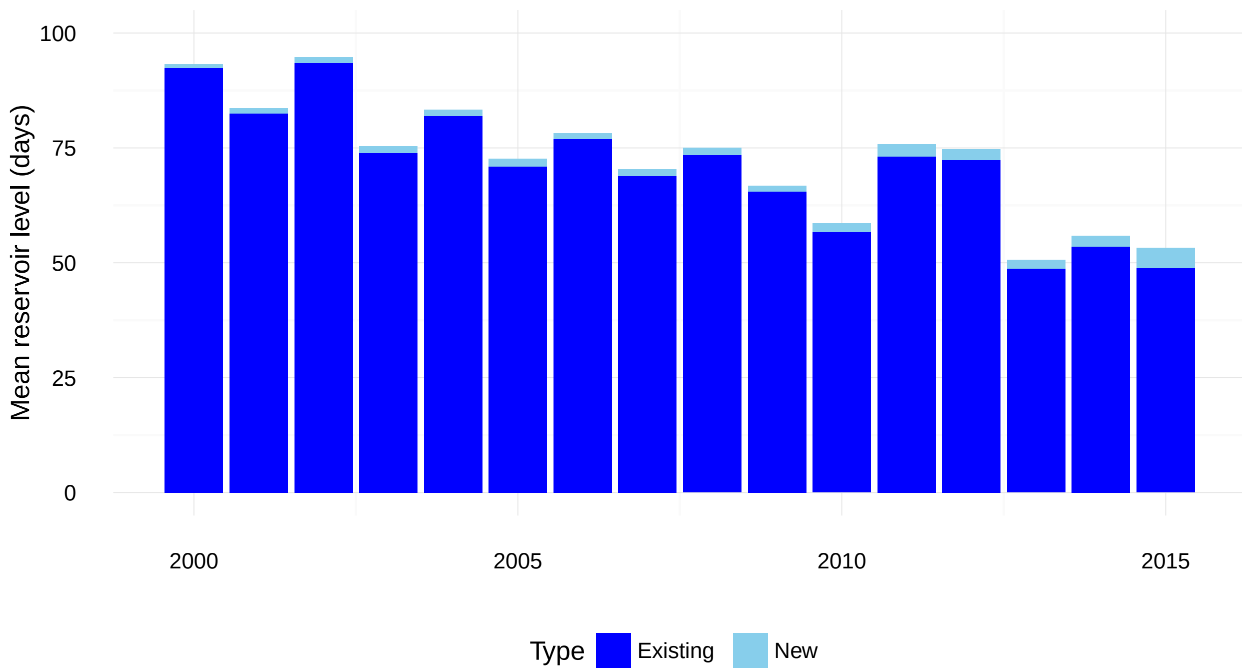



Figure 3.5: Annual average hydro reservoir levels, in days of system load, 2000–2015

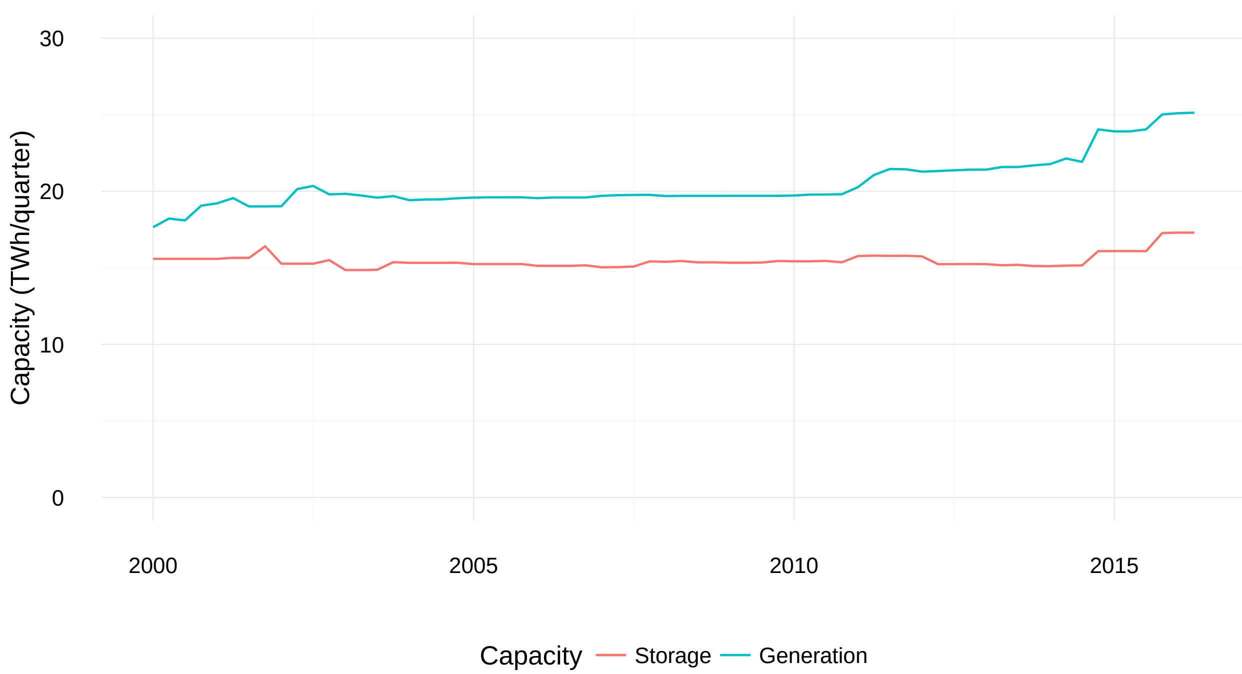



Figure 3.6: Reservoir storage capacity and hydro generation capacity, 2000–2016

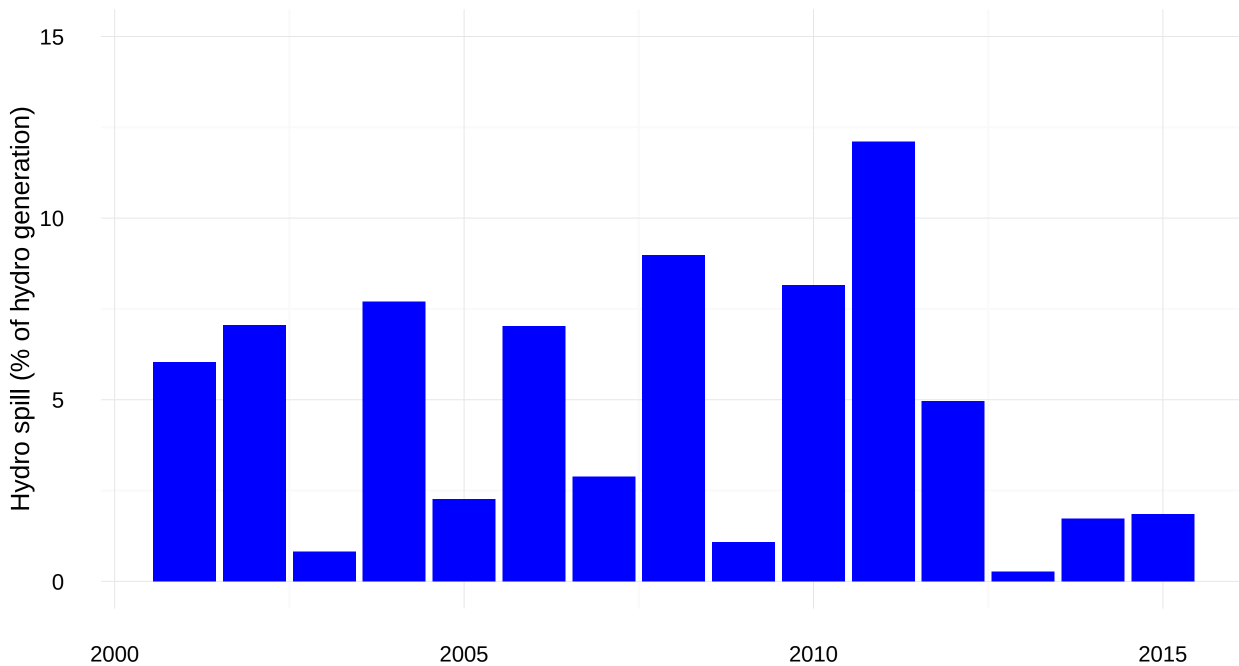



Figure 3.7: Annual spill from hydro reservoirs, 2000–2015

# 4. Reliability Payment Mechanism (RPM)

## 4.1 Firm energy payments

Figure 4.1 shows the quantity of firm energy obligations each quarter, by type of generator.[1] The height of the bar for each color is the quarterly sum of the daily firm energy obligations for that technology and vintage.

The following generators had their firm energy assigned during the first or second firm energy auctions and started generating before July 2016:

- Thermal: Gecelca 3, Tasajero 2, Termoflores 4
- Hydro: Amoyá, Cucuana, El Quimbo, Miel 1, Porce 3, San Miguel, Sogamoso, Carlos Lleras Restrepo

Firm energy obligations assigned to these new entrants is shown in dark blue and dark orange on the figure. The black line on the graph shows the aggregate quarterly demand for electricity.

Figure 4.2 plots the following net revenue components for EPM: (1) Bolsa price generation revenue, (2) Firm Energy Payments, (3) Net Firm Energy Refunds, (4) AGC Services Payments, (5) Net Payments for Reconciliations, and (6) Start-Up Payments. The net revenues shown in the figure are defined as follows:

- Bolsa price generation revenue: for the hours when the Bolsa price is less than the Scarcity price, this is equal to the Bolsa price multiplied by the ideal generation. When the Bolsa price is greater than the scarcity price, this is equal to the Scarcity price multiplied by ideal generation.
- Firm Energy Payments: daily payments for firm energy
- Net Firm Energy Refunds: This is equal to the maximum of the zero and the difference between the hourly Bolsa price and the Scarcity Price times the difference between the hourly value of Ideal Generation and the hourly value of Firm Energy. The Net Firm Energy Refund is non-zero only during scarcity conditions when the Bolsa price is greater than the scarcity price. It is positive or negative depending on the hourly difference between Ideal Generation and Firm Energy. When the generation unit produces more than its Firm Energy Value in an hour this payment is positive, and when it produces less the payment is negative.
- AGC Services Payments: daily payments for providing Automatic Generation Control Services

[1] This data is from the daily settlement files OEFSBMD provided by XM at `http://www.xm.com.co/Pages/InformacionComercialPublicaSIC.aspx`. The figure plots the sum of the variable "OEFD KWH-DIA" for each quarter, broken down by generator type and the new/existing classification.

- Net Payments for Reconciliations: daily net payments for positive and negative reconciliations. Negative reconciliation payments are the foregone Ideal Generation Revenue for units that produce least than their Ideal Generation. Positive Reconciliation payments are the additional revenue that the generation owner receives for providing additional energy from a generation unit beyond its Ideal Generation.
- Start-Up Payments: daily payments to generation units to recover their start-up costs.

Note that these revenues exclude other net revenues a supplier might receive, most notably net payments for energy the supplier has sold through forward contracts. As discussed in Chapter 6, generation unit owners sell a significant fraction of the energy they produce each hour in forward contracts. The relevant opportunity cost of these sales each hour is the Bolsa price, which is why we value each supplier's hourly Ideal Generation at this price. However, the actual revenue earned by a generation unit owner is different from this magnitude because the hourly Bolsa price does not necessarily equal the supplier's quantity-weighted average forward contract price for that hour.

Figure 4.3 reports the same revenue components for Emgesa, Figure 4.4 for Isagen, and Figure 4.5 for Celsia. Several results emerge from these figures. First, the vast majority of revenues are from Ideal Generation sales at a Bolsa price at or below the Scarcity price, although the Firm Energy Payment provides small but steady amount of revenue each quarter to the four suppliers in Figures 4.2 to 4.5. The second result is the fact that the total Net Firm Energy Refund during the 2015-2016 El Niño Event period for all four suppliers except EPM is positive. The third result is that the net reconciliation revenues for these suppliers are typically negative because they receive more negative reconciliations than positive reconciliations. This is not surprising given that all of these suppliers own significant amounts of hydroelectric generation capacity.

Figure 4.6 computes these same revenue streams for all independent thermal generation units. The height of the Firm Energy Payment is a significantly larger fraction of the total height of the revenue bar. Because these are thermal generation units they experience more positive reconciliation than negative reconciliations payments, so they receive net revenues from reconciliation payments. In addition, for these unit owners have negative Net Firm Energy Refunds during the El Niño Event period. Figure 4.7 presents these same revenue streams for all other generation unit owners. The same three conclusions as described in the previous paragraph for Emgesa, Isagen, and Celsia hold for these suppliers.

Figure 4.8 plots the monthly average Bolsa price and the monthly average revenue earned by the entire Colombian generation sector. This COP per KWh magnitude is computed by summing total monthly AGC revenues, all generation in the month valued at the hourly Bolsa price, Firm energy payments, and total monthly Net Reconciliation Payments and dividing by total monthly generation. Note the both Start-Ups payments and Net Energy Refunds net to zero when summed across all market participants. For all but the 2015-2016 El Niño Event period, the difference between the monthly average Bolsa price and the average revenue to the generation sector were not significantly different, although the average revenue was slightly higher during the 2009-2010 El Niño Event and the high water and low Bolas price conditions in 2011. The very large difference between the monthly average Bolsa price and the monthly average revenue during the 2015-2016 Niño Event is the result of the fact that all Ideal Generation is paid the minimum of the Bolsa price and the Scarcity Price and during virtually hours from mid-September until April or 2016 the Bolsa price was above the Scarcity Price.

Figure 4.8 shows that April 2014 was the highest average revenue month and the highest average Bolsa price month since the start of the RPM until the 2015-2016 El Niño Event. A major factor causing the high average revenue during April 2014 was a Scarcity Price at the time of 480 COP per KWh and the fact that the Bolsa price was close to or exceeded the Scarcity Price a number of hours during that month. Figure 4.8 also shows that measured on an average revenue basis, the 2015-2016 El Niño Event was significantly more costly than the 2009-2010 El Niño Event. Although the Scarcity Price in 2009-2010 was slightly higher than it was during the 2015-2016 Event, average revenue in COP per KWh during the 2014-2015 Event was more than 50 percent higher than it was during the 2009-2010 Event. A slightly lower Scarcity Price in 2014-2015 was hit far more frequently in 2015-2016 relative to 2009-2010, in spite of the fact that there were far more Positive Reconciliations for thermal generation units during the 2009-2010 Event versus 2015-2016 Event, as shown 8.2.

The top section of Table 4.1 shows the sum of the six net revenue sources over the period December 1, 2006 to June 30, 2016, for the four largest suppliers. The final column shows the firm energy payments as a percentage of the total revenue. The remainder of the table lists these same components for other thermal generation units. The major result from this table is the significantly higher share of total revenues that these thermal suppliers receive from Firm Energy Payments, compared to the larger suppliers that own both thermal and hydroelectric generation units. As we discuss in Chapter 9, the fact that a number of these thermal generation unit owners earn a significant fraction of their annual revenue from Firm Energy Payments has implications for the financial incentive the unit owner has to provide energy from these units during an El Niño Event.

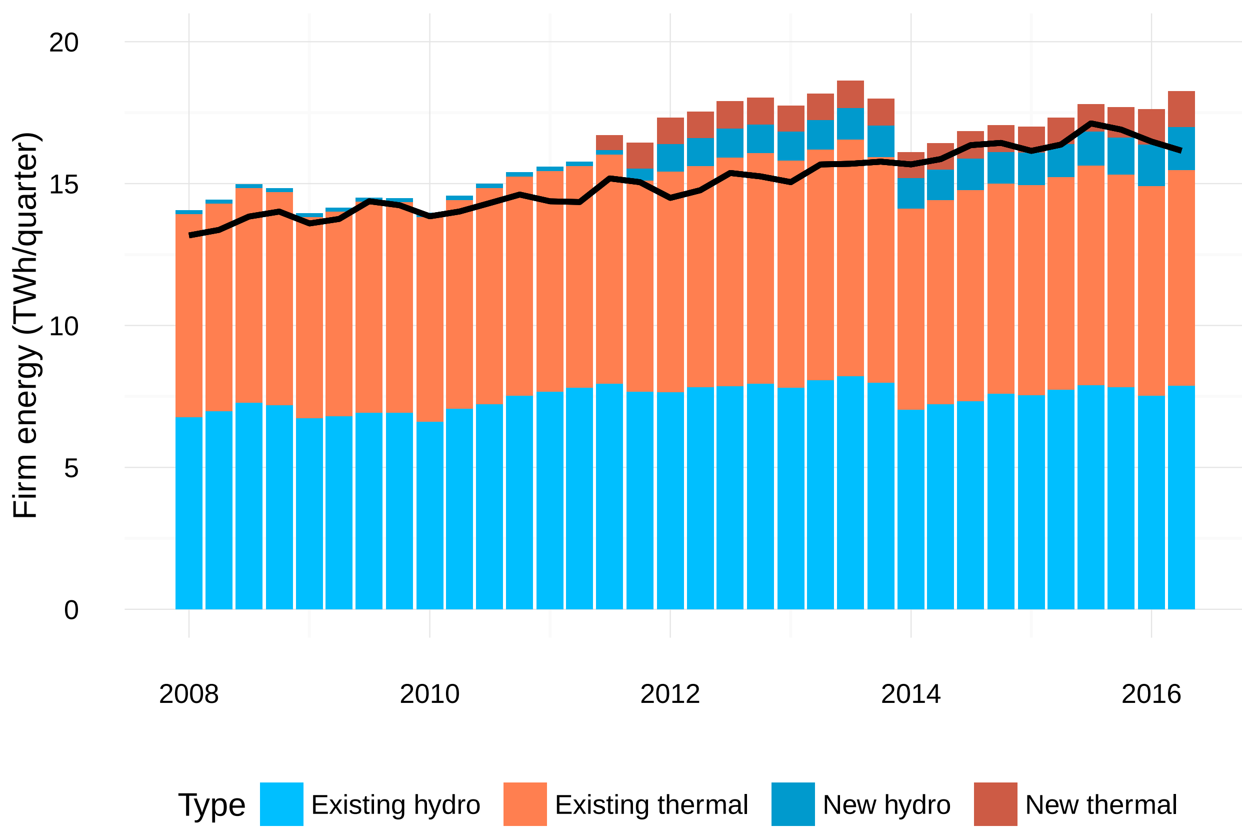



Figure 4.1: Quarterly firm energy quantities, by type of generator

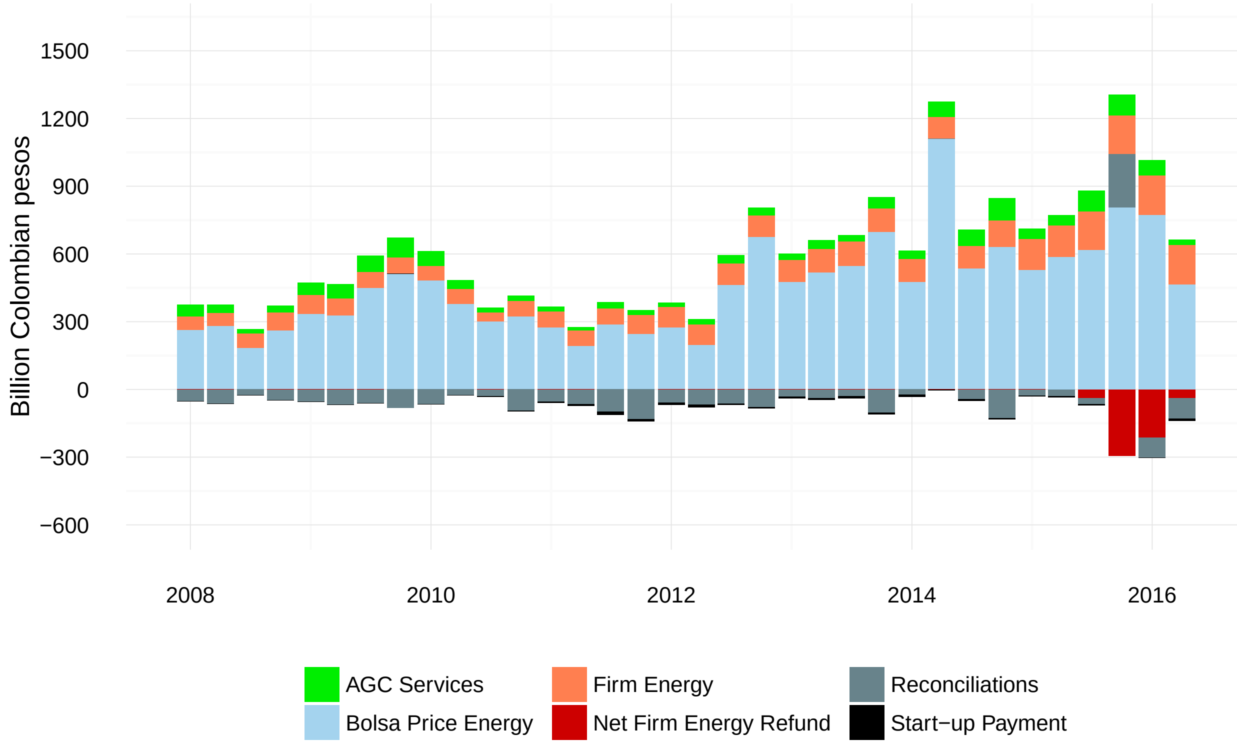



Figure 4.2: Revenue for EPM, assuming energy sold at bolsa price, by quarter

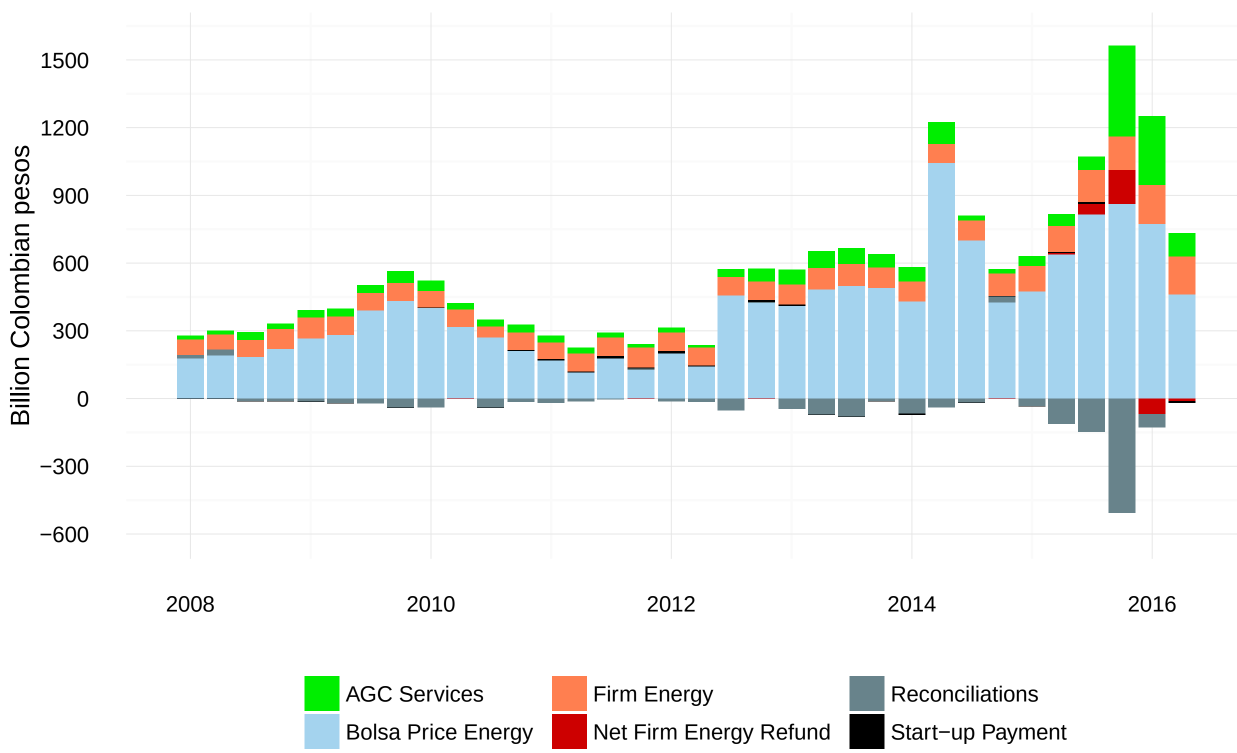



Figure 4.3: Revenue for Emgesa, assuming energy sold at bolsa price, by quarter

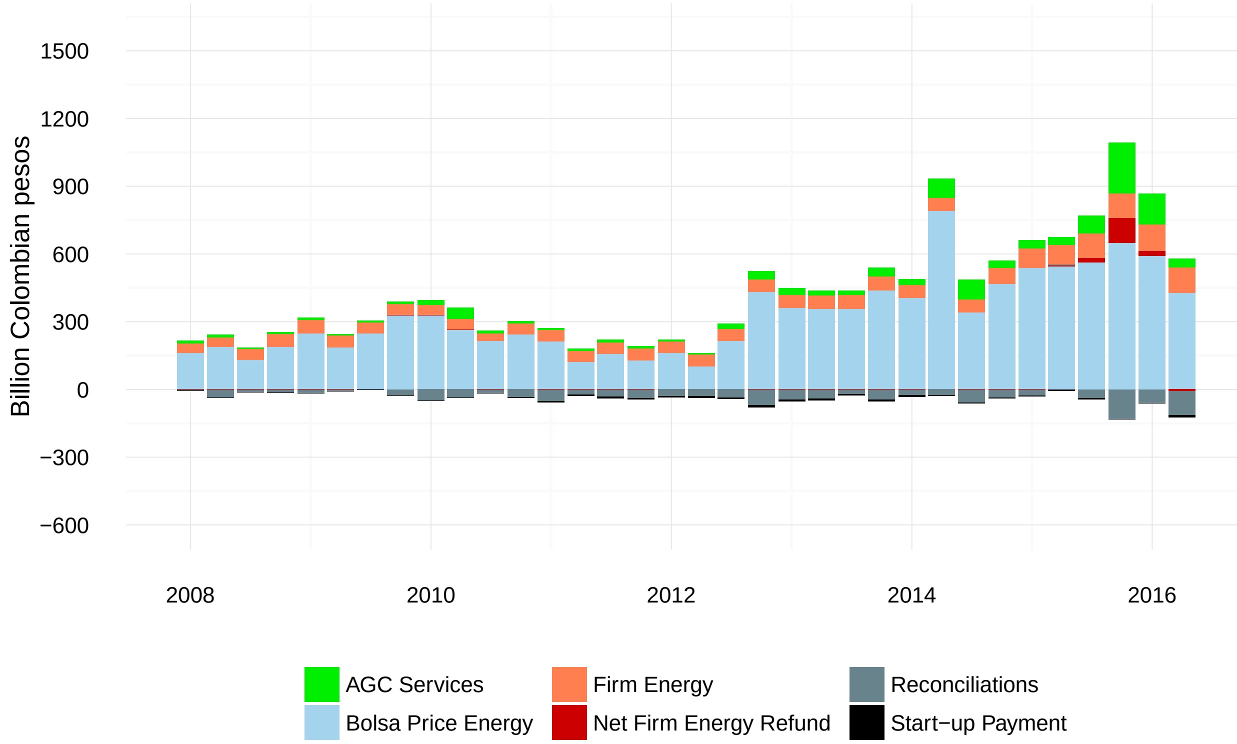



Figure 4.4: Revenue for Isagen, assuming energy sold at bolsa price, by quarter

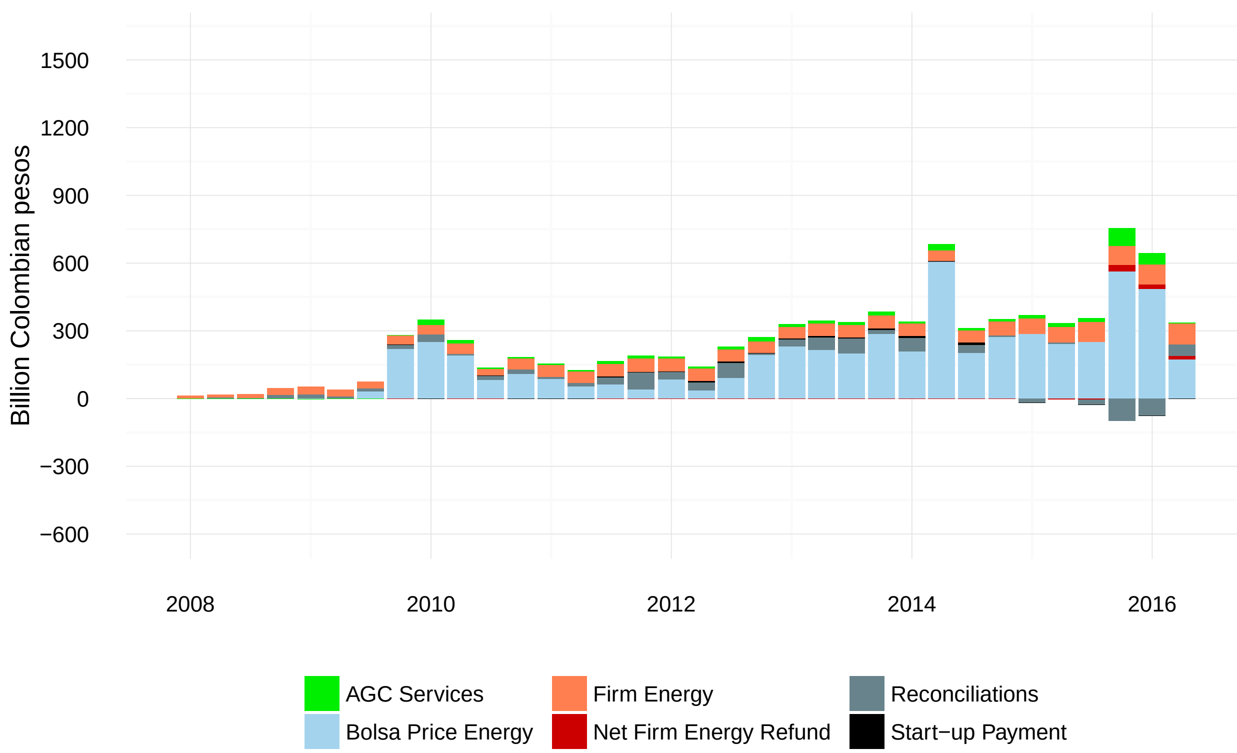



Figure 4.5: Revenue for Celsia, assuming energy sold at bolsa price, by quarter

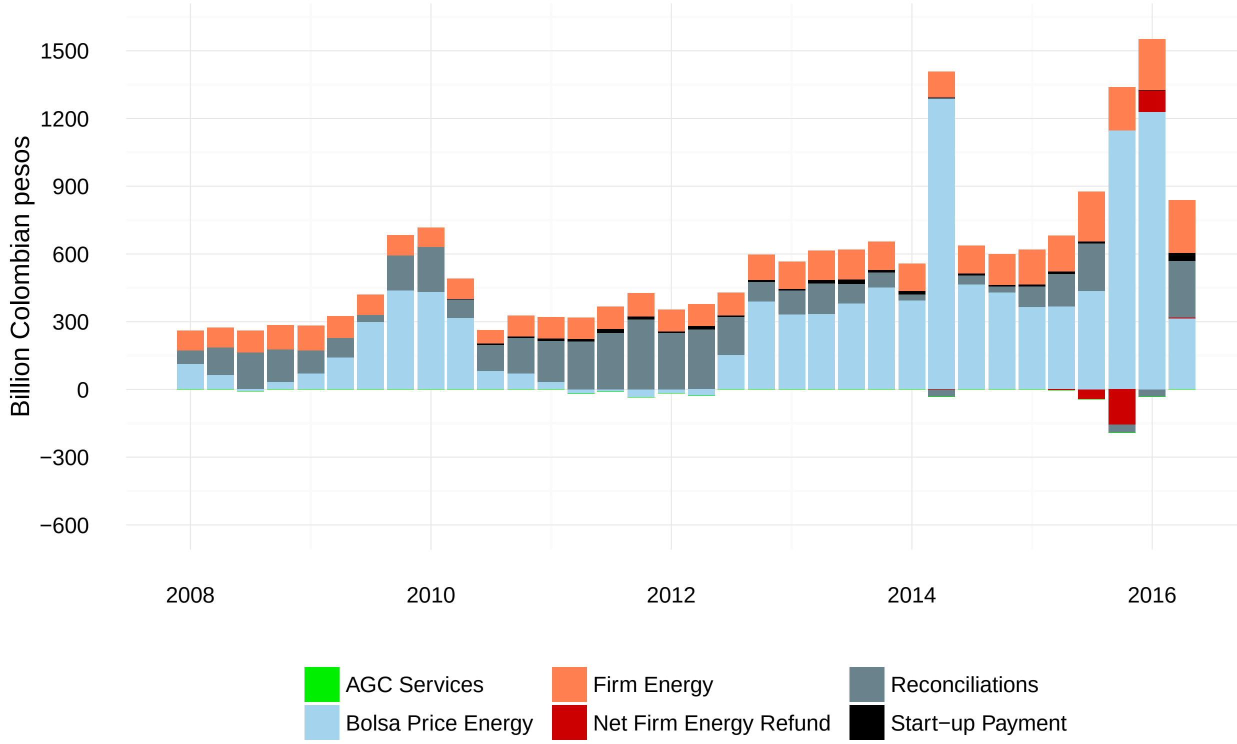



Figure 4.6: Revenue for independent thermal generators, assuming energy sold at bolsa price, by quarter

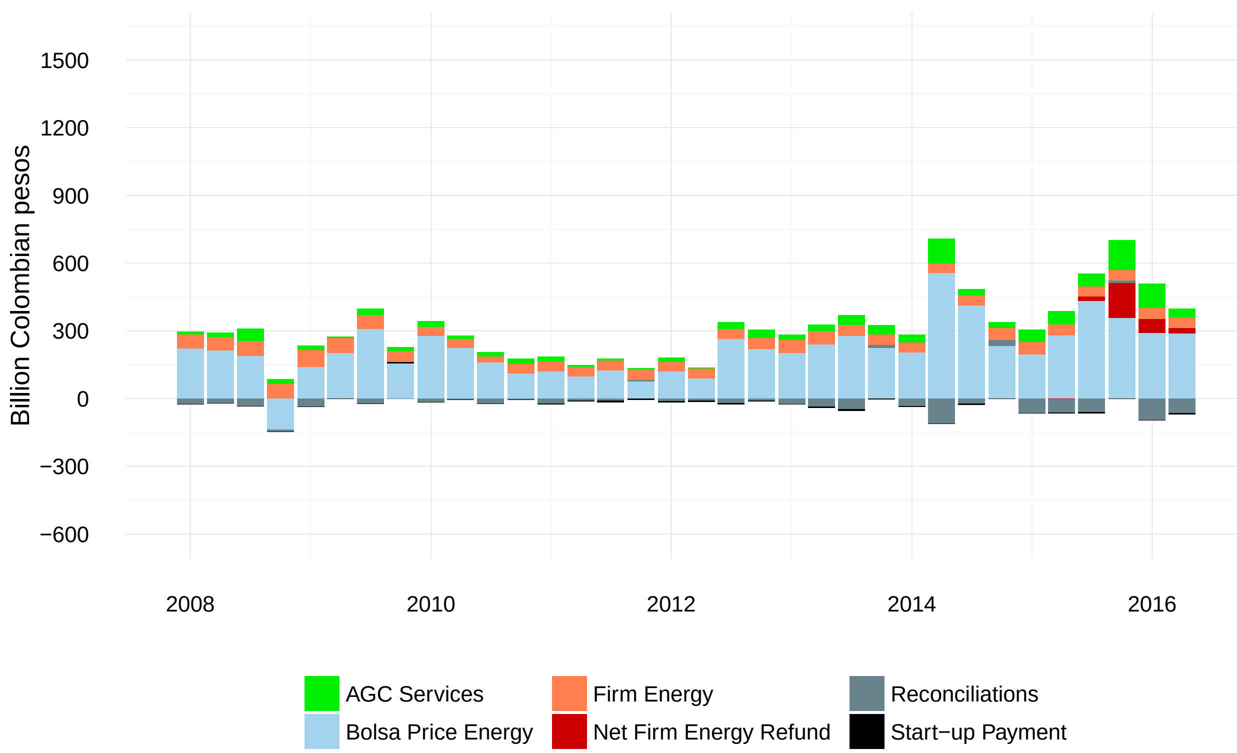



Figure 4.7: Revenue for all other generators, assuming energy sold at bolsa price, by quarter

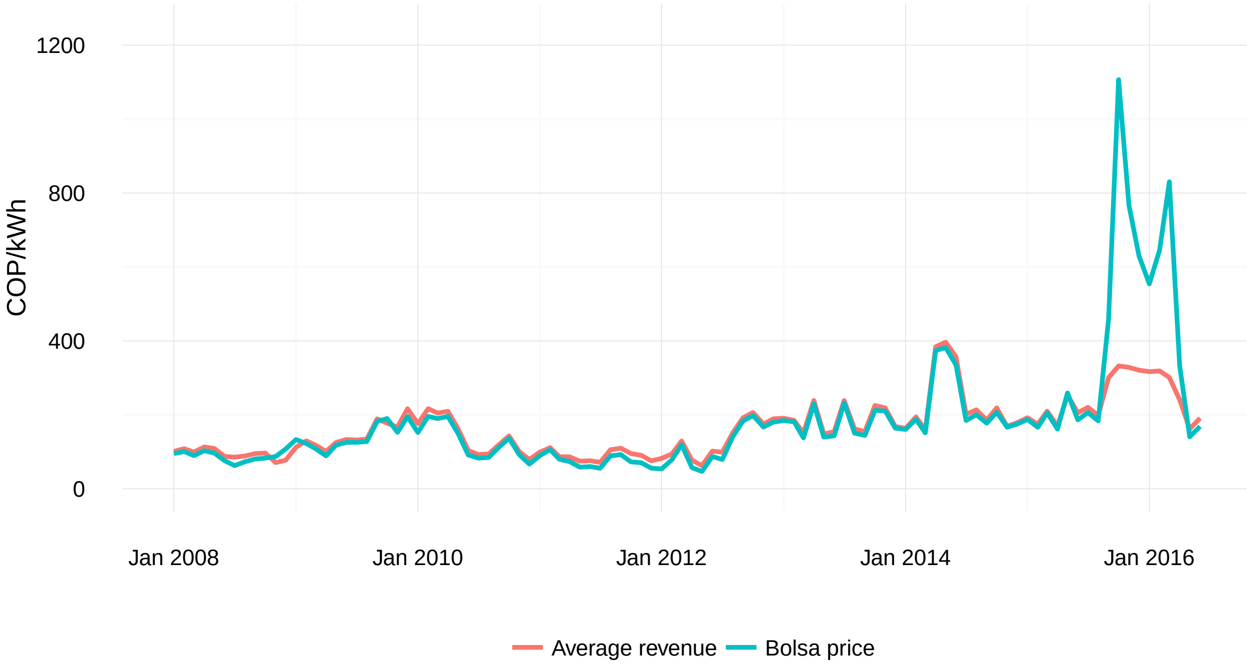



Figure 4.8: Bolsa price and average revenue for all generators, 2008–2016

Table 4.1: Generator revenue (assuming energy sold at bolsa price), December 2006 – June 2016

| Trillion COP | Bolsa Energy | Reconc. | FE Payments | Net FE Refund | Net Start-up | AGC Services | Total | FE % of Total |
|---|---|---|---|---|---|---|---|---|
| **Large hydro and thermal generation firms** | | | | | | | | |
| EPM | 20.37 | -1.88 | 3.56 | -0.58 | -0.17 | 1.71 | 23.00 | 15.48 |
| Emgesa | 17.53 | -1.45 | 3.25 | 0.12 | 0.06 | 2.04 | 21.56 | 15.08 |
| Isagen | 14.92 | -1.25 | 2.29 | 0.15 | -0.13 | 1.19 | 17.16 | 13.32 |
| Celsia | 7.05 | 0.56 | 1.78 | 0.06 | 0.07 | 0.42 | 9.93 | 17.90 |
| **Other thermal generators** | | | | | | | | |
| Gecelca / TEBSA | 7.35 | 3.39 | 2.50 | -0.23 | 0.22 | 0.00 | 13.23 | 18.88 |
| Paipa | 2.81 | 0.01 | 0.64 | 0.05 | -0.01 | 0.00 | 3.51 | 18.28 |
| Termotasajero | 1.32 | 0.25 | 0.37 | -0.08 | 0.00 | 0.00 | 1.87 | 19.68 |
| Termoyopal | 1.03 | -0.01 | 0.05 | 0.13 | -0.01 | 0.00 | 1.19 | 4.42 |
| Termovalle | 0.62 | 0.06 | 0.20 | -0.00 | 0.03 | 0.00 | 0.91 | 22.01 |
| Termoemcali | 0.35 | 0.18 | 0.46 | 0.04 | 0.02 | 0.00 | 1.04 | 43.85 |
| Termocandelaria | 0.34 | 0.23 | 0.58 | -0.03 | 0.01 | 0.00 | 1.13 | 51.44 |
| Proelectrica | 0.27 | 0.47 | 0.18 | 0.01 | 0.01 | 0.00 | 0.93 | 19.45 |
| All others | 11.41 | -1.06 | 1.68 | 0.26 | -0.09 | 1.26 | 13.46 | 12.47 |
| **Total** | **85.37** | **-0.51** | **17.53** | **-0.10** | **0.00** | **6.62** | **108.92** | **16.10** |

# 5. Market Prices and Offers

This chapter studies the behavior of market prices and some of the determinants of market prices. We first explore the extent to which the pre-dispatch Bolsa price that is produced as part of the process of committing generation units to operate differs significantly from the final Bolsa price that is only known at least 30 days after the market actually operates. We then compare the offer behavior of thermal and hydroelectric generation unit owners during the initial stages of the 2009-2019 and 2015-2016 El Niño Events. Finally, we characterize the interaction of water levels and offer price behavior during the mid-2013 to mid-2016 time period. We uncover several puzzles about the relationship between offer price behavior by individual suppliers and water levels that appear to have contributed to the length and severity of the 2015-2016 El Niño Event.

## 5.1 Pre-Dispatch Price versus Bolsa Price

Because it is available immediately after the generation unit commitment decisions have been made by XM, the pre-dispatch price is used by Derivex to clear its futures contracts for energy. Consequently, an important consideration in determining the effectiveness of Derivex futures contracts for hedging Bolsa Price risk is the extent to which pre-dispatch prices differ from the Bolsa price, particularly during scarcity periods.

Figure 5.1 plots the monthly average difference between the pre-dispatch price and the Bolsa price from 2011 until mid-2016. For all but one month, the average pre-dispatch price is greater than the Bolsa price. Only during the middle of 2015-2016 El Niño Event is the monthly average Bolsa price greater than the monthly average pre-dispatch price. This difference was particularly large in October of 2015. Figure 5.2 plots this monthly average difference as a percent of the monthly average price. This plot demonstrates that the monthly average difference between the two prices as a percent of the average monthly Bolsa price has continuously declined since 2011. From mid-2014 onward, the difference in average monthly prices has been less ten percent of the monthly average price. Even during October 2015, this average difference was less than ten percent of the monthly average price.

Table 5.1 presents the annual average Bolsa price, pre-dispatch price and the difference between the two prices for each year from 2011 to 2016. For all years except 2011, this annual average difference is less than 5 percent of the annual average Bolsa price. Taken together these results argue that clearing Derivex contracts against the pre-dispatch price instead of the Bolsa price should not expose suppliers to an excessive amount of unhedged price risk. Moreover, if suppliers insist on clearing their Derivex futures contract positions against the Bolsa price, Derivex could first clear them against the pre-dispatch price and then have true-up once the final Bolsa price is available. The results presented above suggest this would not subject Derivex participants to an excessive amount of revenue risk.

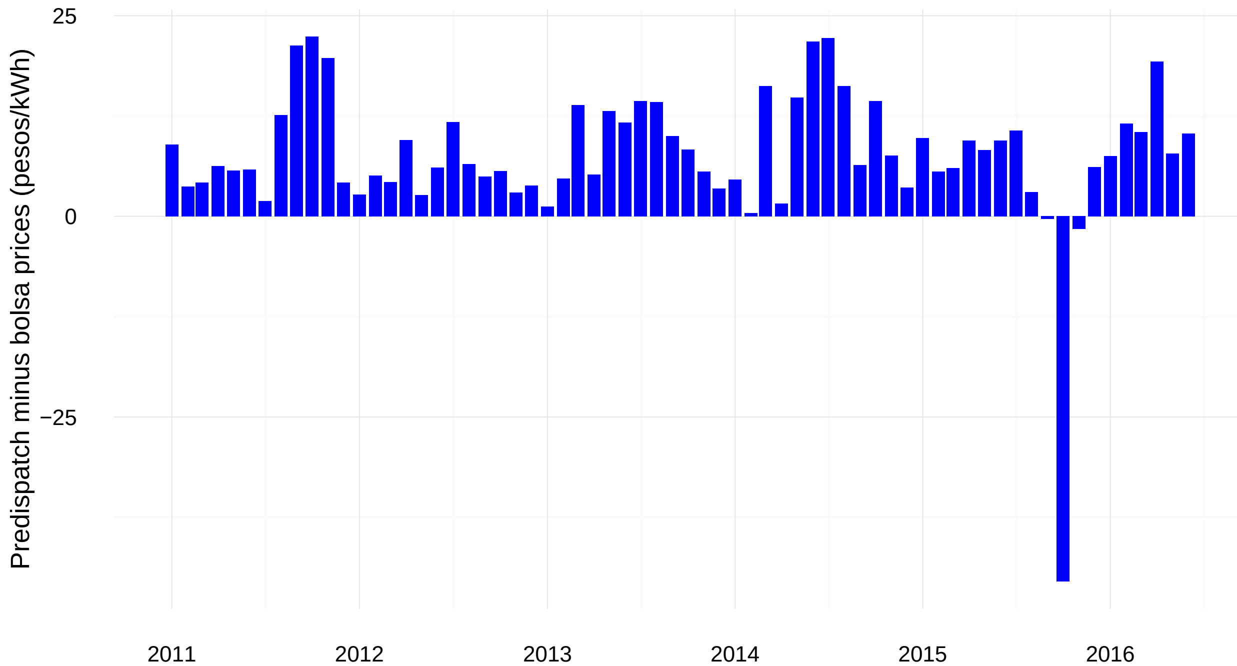



Figure 5.1: Monthly average difference between predispatch and bolsa prices

Table 5.1: Difference between predispatch and bolsa prices (pesos/kWh)

| Year | Bolsa | Predispatch | Difference | Percent |
|---|---|---|---|---|
| 2011 | 78.0 | 87.9 | 9.9 | 12.7 |
| 2012 | 119.3 | 124.8 | 5.5 | 4.6 |
| 2013 | 180.6 | 189.4 | 8.9 | 4.9 |
| 2014 | 228.8 | 239.7 | 10.9 | 4.8 |
| 2015 | 386.5 | 388.1 | 1.6 | 0.4 |
| 2016 | 450.7 | 461.9 | 11.1 | 2.5 |

## 5.2 Offer Prices and Market Prices in 2009 and 2015

This chapter compares the distribution of the ratio of the daily offer price for each generation unit to the Scarcity Price during the two El Niño Event periods to understand what factors led to the significantly higher Bolsa prices during the 2015-2016 period relative to the 2009-2010 period. We find that distribution of the ratio of offer price to Scarcity Price submitted by hydroelectric unit owners during 2015 was very similar to the distribution in 2009. This distribution for thermal generation unit owners had a significantly higher

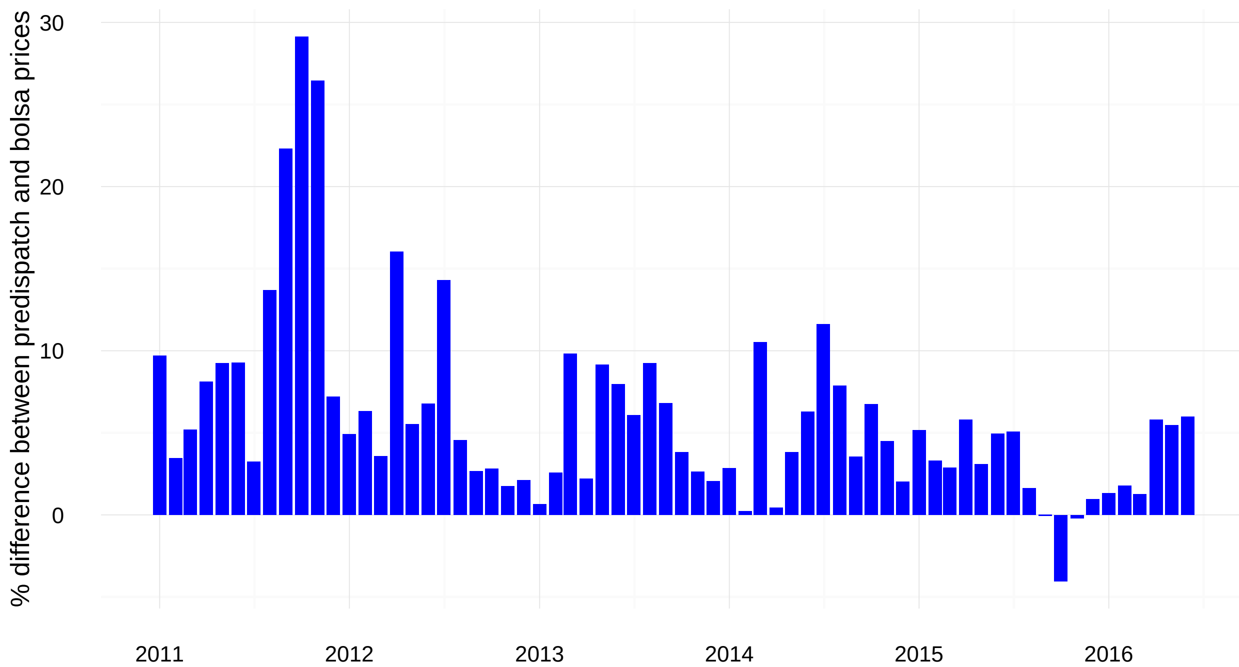



Figure 5.2: Monthly average difference between predispatch and bolsa prices (percentage of bolsa price)

frequency of offer prices that were several multiples of the scarcity price during 2015 versus 2009. This difference in offer behavior by thermal suppliers in 2015 versus 2009 explains why the incidence of Bolsa prices that are multiples of the scarcity price occurred far more frequently in 2015-2016 versus 2009-2010.

Figure 5.3 plots the histogram of the ratio of the accepted offer price divided by the Scarcity Price for 2009 and 2015. Note for all histograms this ratio is capped at 4, so the value of the histogram on the vertical axis at a value of 4 on the horizontal axis indicates the frequency of an offer price to Scarcity Price ratio greater than or equal to 4. The two histograms are remarkably similar, although the 2015 histogram has slightly greater frequency of values of the ratio above 1. Figure 5.4 repeats these two histograms for the case of thermal generation units. These two histograms are significantly different, with the 2015 version having a much greater frequency of values of the ratio greater than 1. This offer behavior by thermal suppliers relative to hydroelectric suppliers during 2015 is puzzling if their goal was to conserve water during this time period. The greater frequency of high offer price ratios for thermal units relative to hydro units implies that the hydro units are more likely to run and thermal units are less likely to run.

Different from 2015, the offer behavior of thermal versus hydroelectric suppliers in 2009 is much more consistent with a water conservation strategy. There is a significantly higher frequency of offer price ratios greater than 1 for the hydroelectric suppliers than for the thermal suppliers. Note the larger point mass at 4 on the hydro-units histogram in 2009 relative to this same point on the thermal-units histogram in 2009. In addition, there is a non-trivial frequency in the 2 to 3 range on the hydro-units histogram in 2009 and a lower frequency in this range for the thermal-units histogram in 2009. This means that hydroelectric units will run less frequently and the thermal units will run more frequently.

Figures 5.5 and 5.6 repeats these two sets of histograms for all offer prices, not just accepted offer prices. The same basic pattern emerges, with the hydroelectric offer price ratio histograms looking fairly similar between 2009 and 2015, whereas the thermal offer price ratio histograms are very different across the two years. Offer price ratios above 1 are far more frequent for the thermal units in 2015 relative to 2009, and offer price ratios above 1 are far more frequent for thermal units versus hydroelectric units in 2015. The opposite result occurs in 2009. High offer price ratios are more frequent for hydroelectric units versus thermal units in 2009. These results support the argument that the histograms of the accepted offer price ratios were not the result of a disagreement between thermal and hydroelectric generation unit owners over whether the hydroelectric units needed to run in 2015. Both the submitted and accepted offer price ratio distributions in 2015 are consistent with a desire to operate hydroelectric generation units instead of thermal generation units during a time period when an El Niño Event appeared to be likely to occur.

Figure 5.7 plots the histogram of the ratio of the hourly Bolsa price to the scarcity price in 2009 and 2015. Consistent with the significantly higher frequency of offer price ratios above 1, the frequency of Bolsa prices above the scarcity price was substantially higher in 2015 relative to 2009 when no Bolsa prices were above the scarcity price. Figure 5.8 plots monthly average Bolsa price and the monthly Scarcity Price from December 2006 when RPM was first implemented through the end of June of 2016.

These figures suggest a failure of the RPM mechanism to provide the appropriate incentives to conserve water and to maintain prices below the scarcity price during the early stages of the most recent El Niño Event in 2015. In the next chapter, we take a deeper look into why this occurred. Our alternative reliability mechanism described in Chapter 10 is designed to prevent eliminate this pattern offer behavior during periods that are suspected to be the start of an El Niño Event.

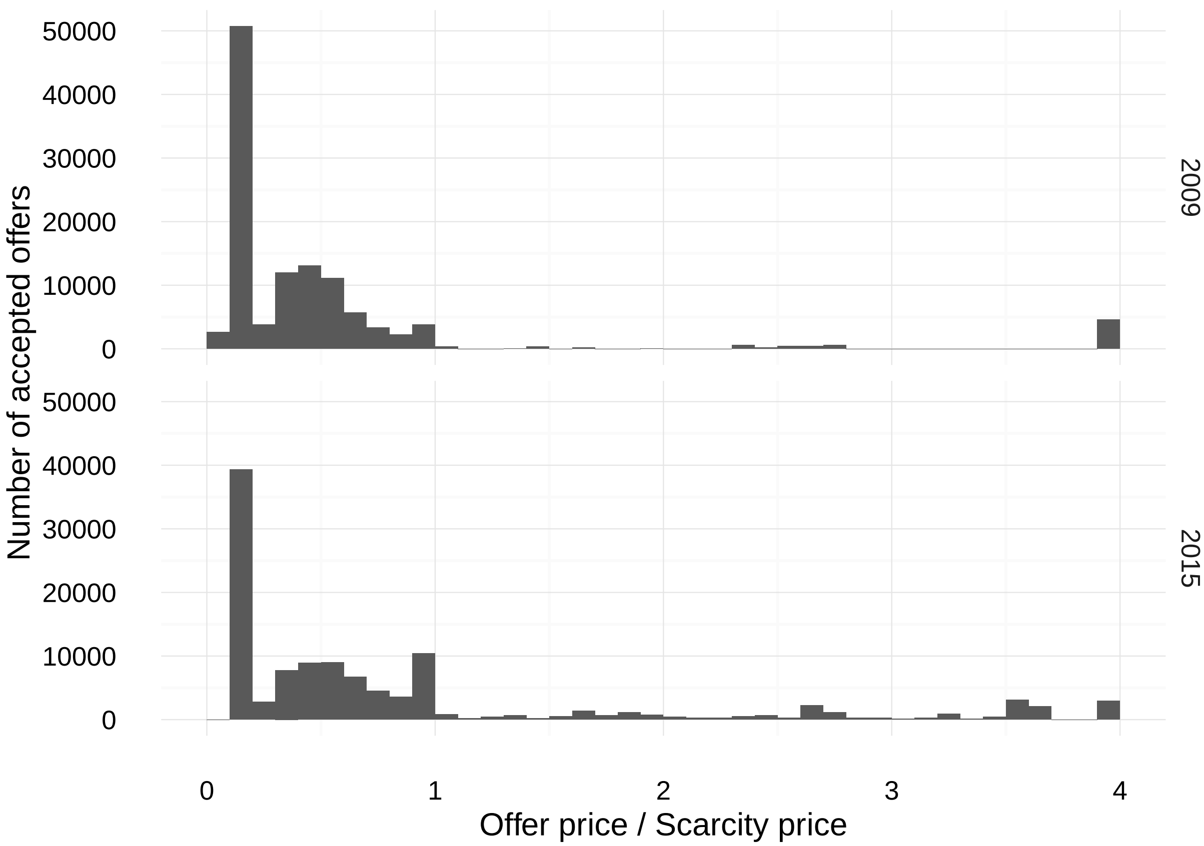



Figure 5.3: Distribution of accepted offers for hydro units, relative to scarcity price

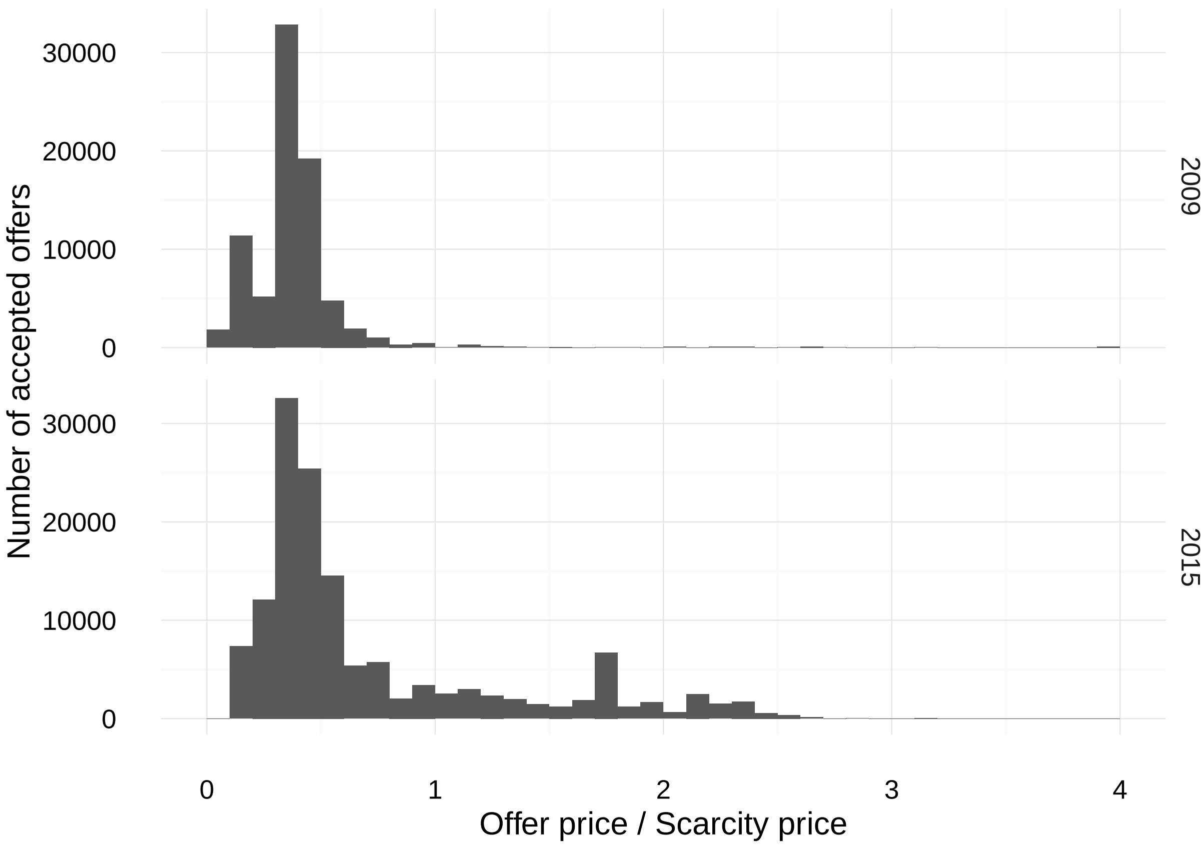



Figure 5.4: Distribution of accepted offers for thermal units, relative to scarcity price

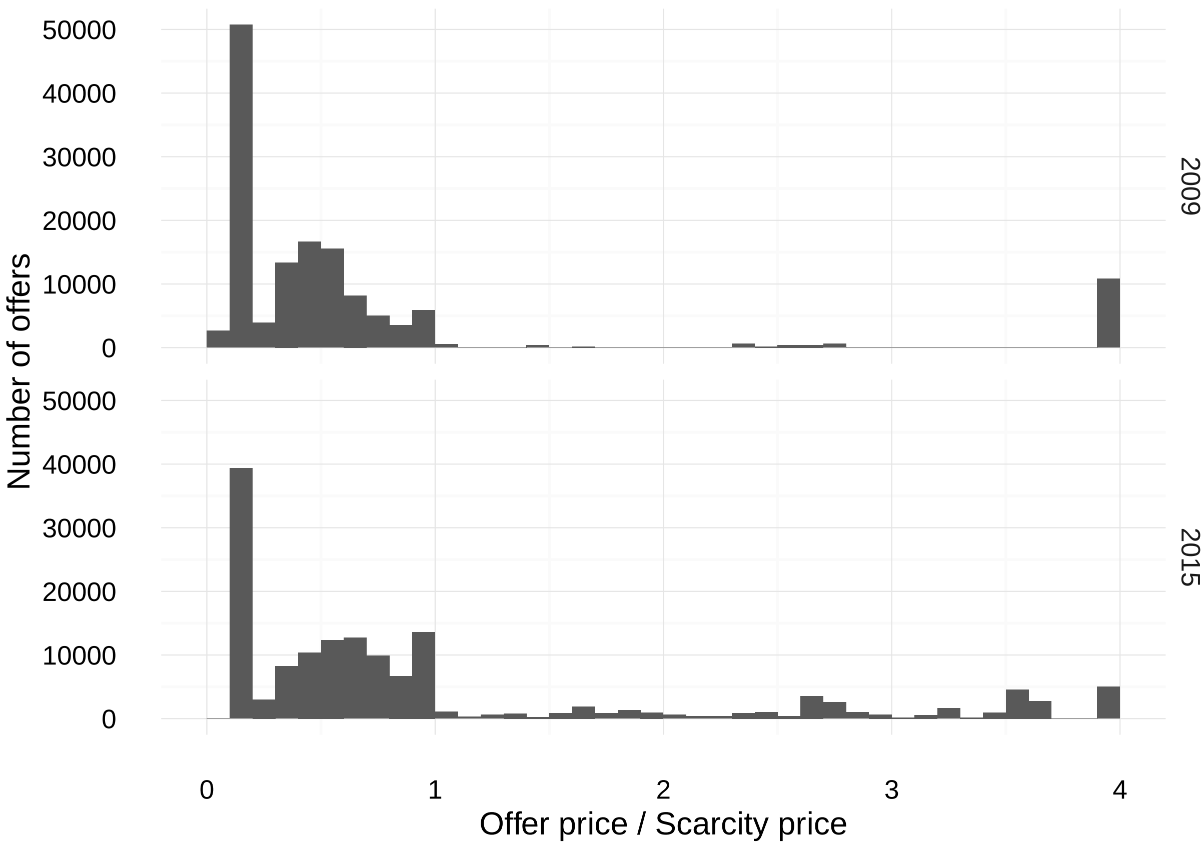



Figure 5.5: Distribution of all offers for hydro units, relative to scarcity price

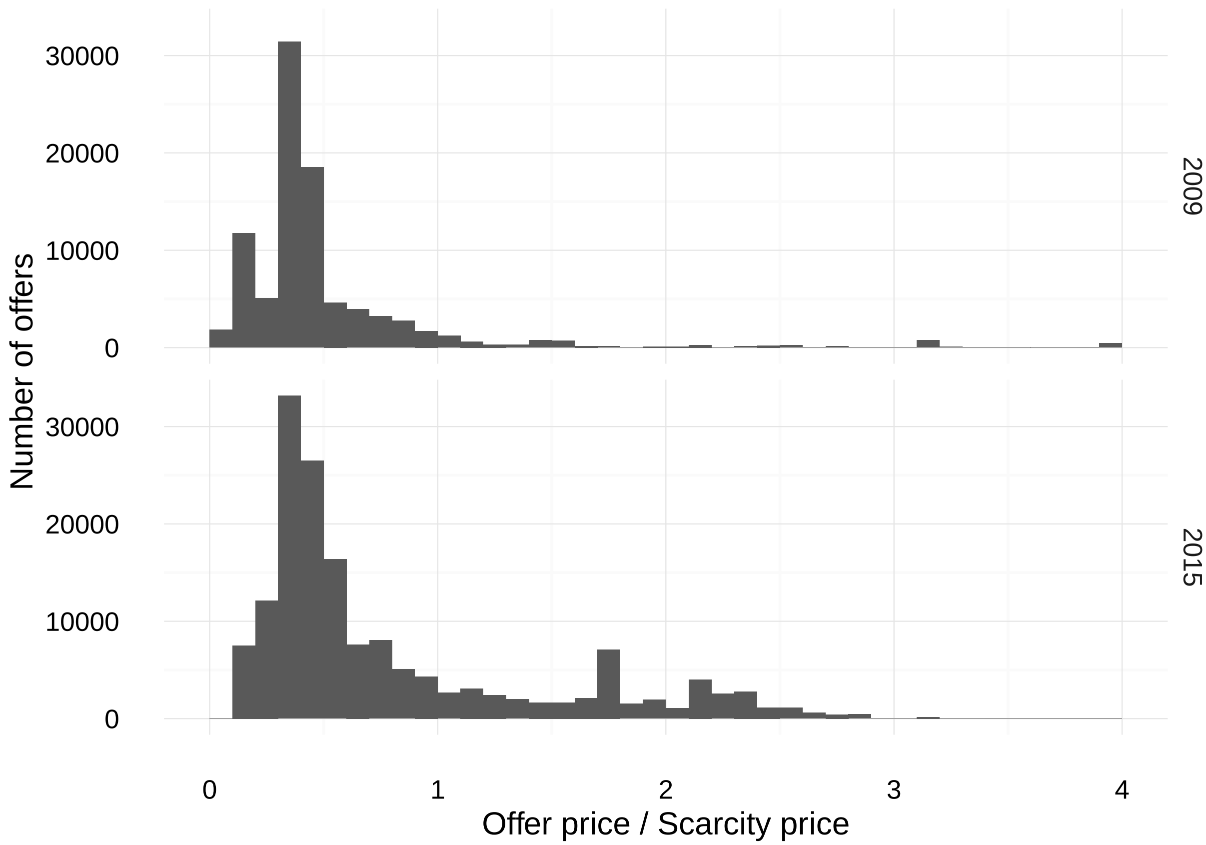



Figure 5.6: Distribution of all offers for thermal units, relative to scarcity price

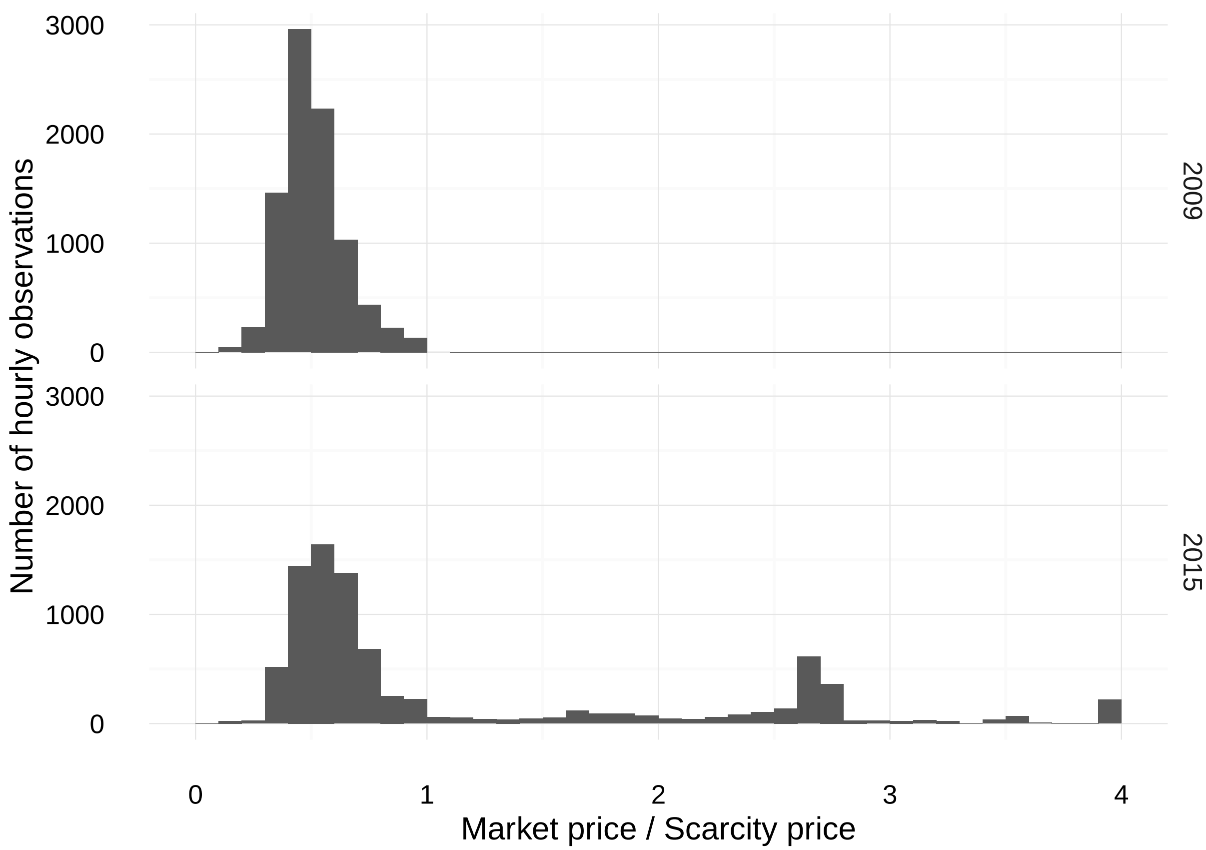



Figure 5.7: Distribution of market prices, relative to scarcity price

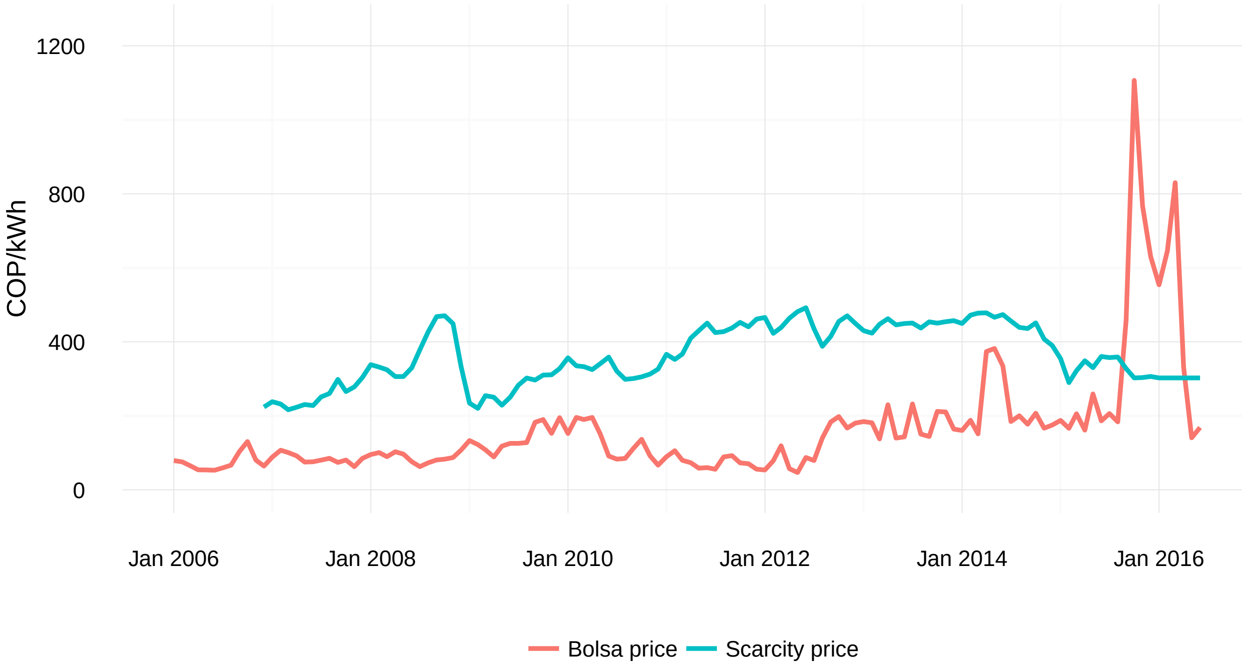



Figure 5.8: Monthly mean bolsa price and scarcity price, 2006–2016

## 5.3 Reliability Payment Mechanism and Offer Prices

This chapter explores the impact of the Reliability Payment Mechanism on the offer behavior of hydroelectric generation units. We find that through mid-September of 2015 the major hydroelectric suppliers did not submit offer prices that were appreciably different from those they submitted in 2013 and 2014, in spite of the fact that during 2015 there was a high probability of an El Niño Event occurring. Consistent with this pattern of offer prices, the output of the large hydroelectric generation units did not appreciably change relative to 2013 and 2014 until after mid-September of 2015. On September 22, 2015 XM issued a market notice declaring low water conditions and a need to conserve water. For all of the major hydroelectric generation units there was discrete increase in their offer prices after that date. Consequently, one question raised by these graphs is why the hydroelectric suppliers submitted the offer prices they did in 2015 before this market notice was issued by XM. Were these unit owners really unaware of the water levels in their own reservoirs and the reservoirs of other hydroelectric suppliers? It is difficult to believe, given their experience with previous El Niño Events, that the hydroelectric unit owners did not know the information contained in the XM notice.

Figure 5.9 is composed of three graphs. The top graph shows the daily reservoir level (dark blue line). Two variables show the minimum reservoir levels: the Lower Minimum Operating Level or MOI (Mínimo Operativo Inferior) shown in the light red line, and the NEP (Nivel ENFICC Probabilístico) shown in the dark red line. If the reservoir levels fall below the NEP for three consecutive days during a Scarcity Period, the offer price for the reservoir is set by formula between the scarcity price and the Value of Lost Load (VOLL)[1]. Furthermore, such an event is considered a failure to guarantee the incremental Firm Energy above the Base ENFICC, and as such the unit owner must refund the incremental Reliability Payments they received.[2] The

[1] Article 4 of CREG Resolution 36 of 2010

[2] Chapter 6 of the Annex to CREG Resolution 61 of 2007, modified by Article 6 of CREG Resolution 137 of 2009.

green line shows the NPV (Nivel Probabilístico Vertimiento), the level at which the reservoir is at risk of spilling water. The middle graph in each block shows the daily offer price for the hydro plant. The bottom graph shows the declared availability of the plant over the 168 hours of each week (black line) and the actual generation during the week (blue bars). These are expressed as a percentage of the nameplate capacity of the plant.

The reservoir level for Guatape is persistently above the MOI and NEP for the entire sample period. The offer prices during the first half 2015 are in fact lower than the values through 2014. There is a spike in June 2015, but they do not jump to a persistently higher level until September 2015. The total availability and the pattern of hydroelectric generation from Guatape is not appreciably different in the first eight months of 2015 relative to the first eight months of 2013 and 2014. Consistent with the timing of the forced outage at Guatape during the recent El Niño EVent, the total offer quantity declines to zero in early 2016.

Figure 5.10 repeats the same three plots for the La Tasajera unit owned by EPM. Not until June 2016 does the water level in this unit fall below its NEP value. The same pattern for offer prices as was observed for Guatape holds for this unit. Except for a spike in late June 2015, offer prices in 2015 were lower than those in 2014. After September 22, 2016 offer prices increased substantially. The pattern and level of output during the first eight months of 2015 was not appreciably different from the pattern of output during the first eight months of 2013 and 2014. Figure 5.11 presents the same three plots for the Jaguas unit owned by Isagen. These three plots each follow the same patterns as the same plot for Guatape and La Tasajera. Not until late June 2016 does the reservoir level for Jaguas fall below the NEP value. Figure 5.12 plots the same three figures for the Miel I unit owned by Isagen. Each of the graphs displays the same features as the previous three graphs, although the reduction in output in 2015 for this unit is more pronounced then for the previous three units. Figure 5.13 plots the same three figures for the Sogamoso unit owned by Isagen. During late 2015 the reservoir level for this unit actually falls below the NEP value. However, the pattern of the offer prices experienced the same rapid increase in late September 2015.

Figures 5.14, 5.15, and 5.16 produce these same graphs for the Pagua, Guavio, and El Quimbo facilities owned by Emgesa. Although the Guavio unit appears to spill water during the third quarter of 2015, the pattern of offer prices, availability, and generation are similar to the units owned by EPM and Isagen. Finally, Figure 5.17 produces the same graphs for the Chivor facility owned by AES Chivor. Water levels in this unit result in spills during the third quarter of 2015 and fall below the NEP during the fourth quarter of 2015. The pattern of offer prices and electricity generated in 2015 relative to the previous two years follows the same patterns as all other hydroelectric generation units.

The pattern of offer prices and hydroelectric generation appears to be common to all of the hydroelectric generation units analyzed in Figures 5.9 to 5.17. Because water inflows and reservoir levels in 2013 and 2014 were similar to those that existed in 2009 and 2010, it is surprising that suppliers did not submit higher offer prices for hydroelectric units in late 2014 and early 2015 in order to conserve water for a likely El Niño Event in late 2015. Moreover, given the declining share of the thermal generation capacity in Colombia during this time period, more conservative use of water would seem to be a prudent response to the low water conditions in 2013, 2014, and early 2015.

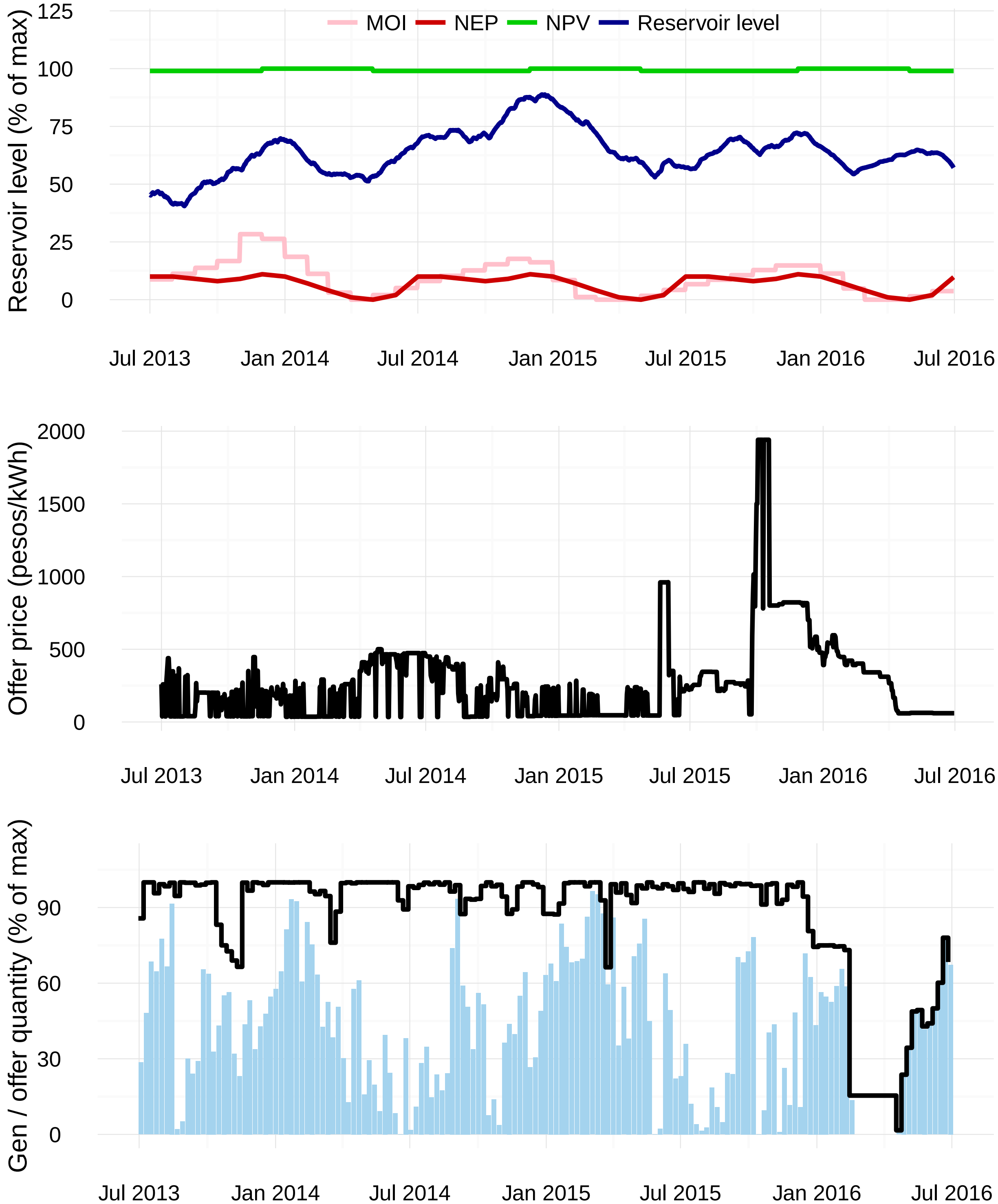



Figure 5.9: Reservoir levels, offers and generation—Guatape (EPM)

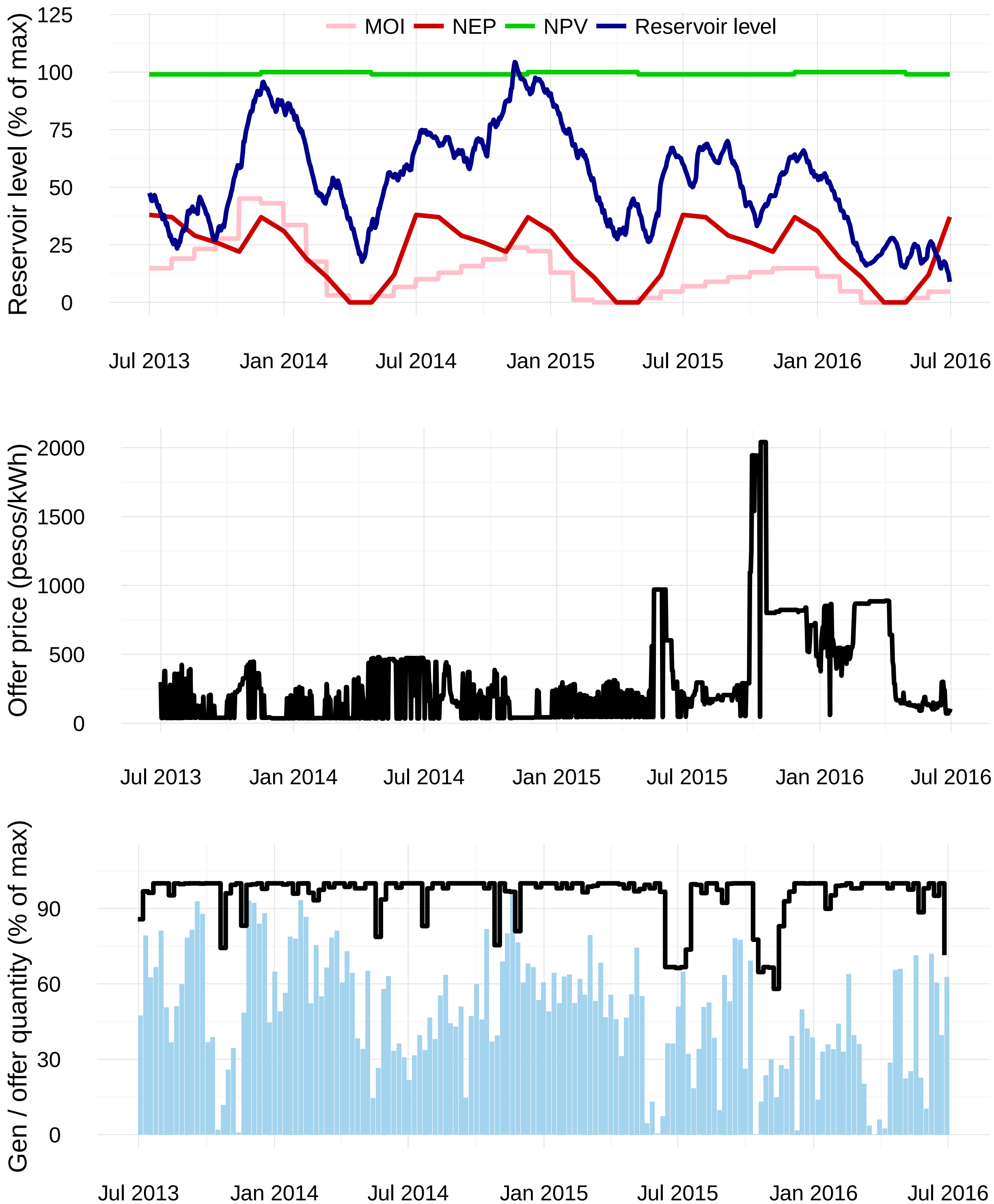



Figure 5.10: Reservoir levels, offers and generation—La Tasajera (EPM)

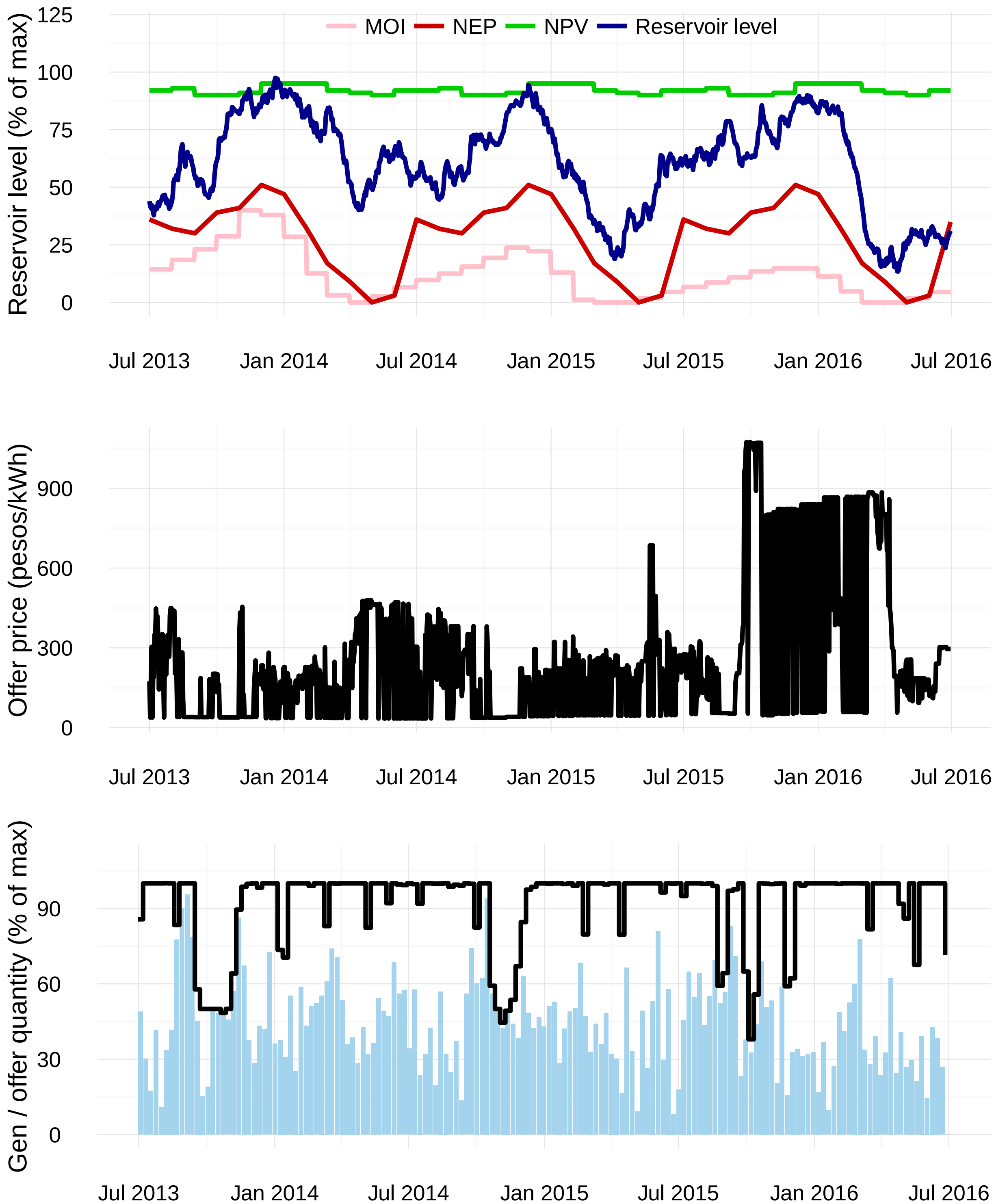



Figure 5.11: Reservoir levels, offers and generation—Jaguas (Isagen)

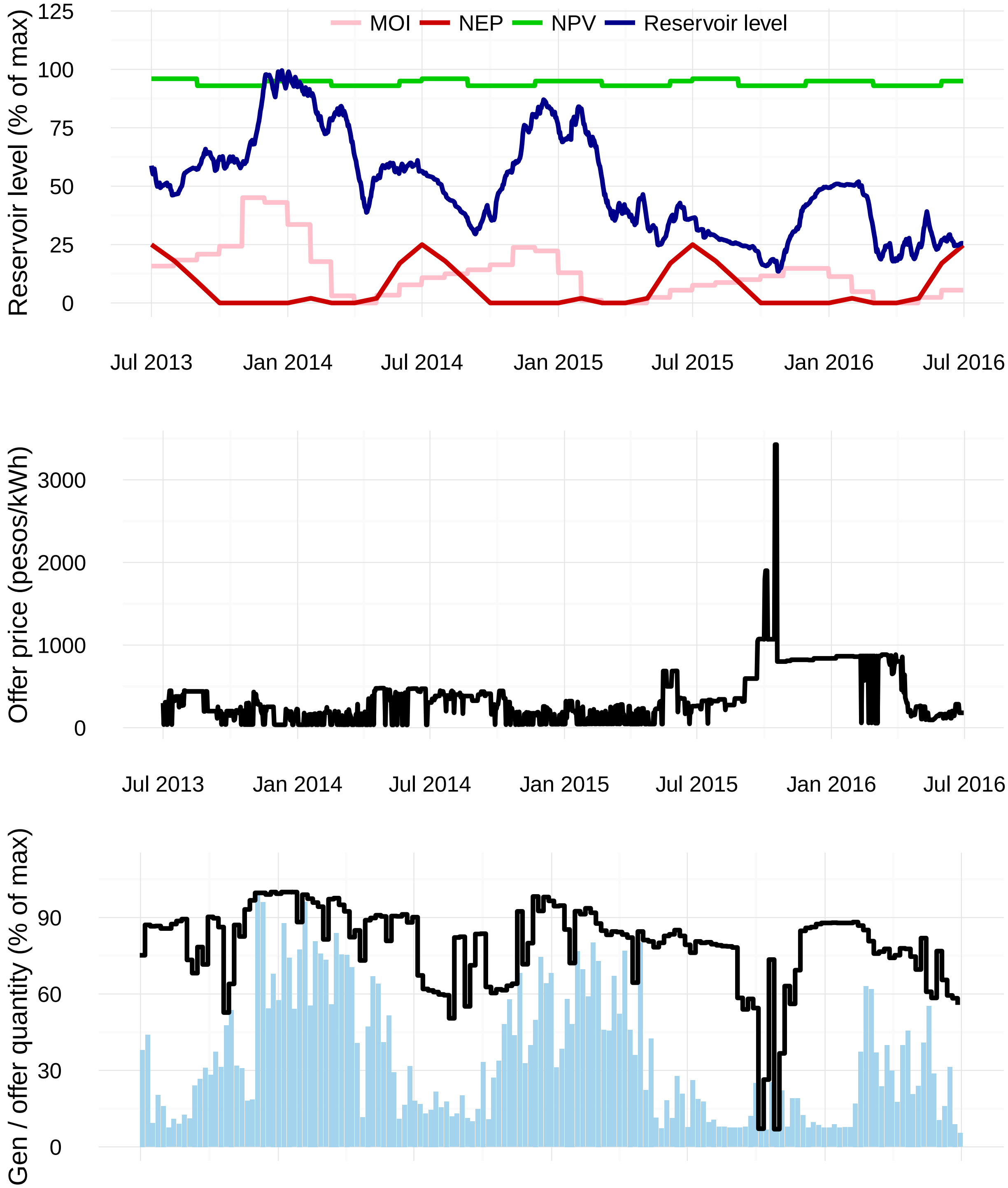



Figure 5.12: Reservoir levels, offers and generation—Miel I (Isagen)

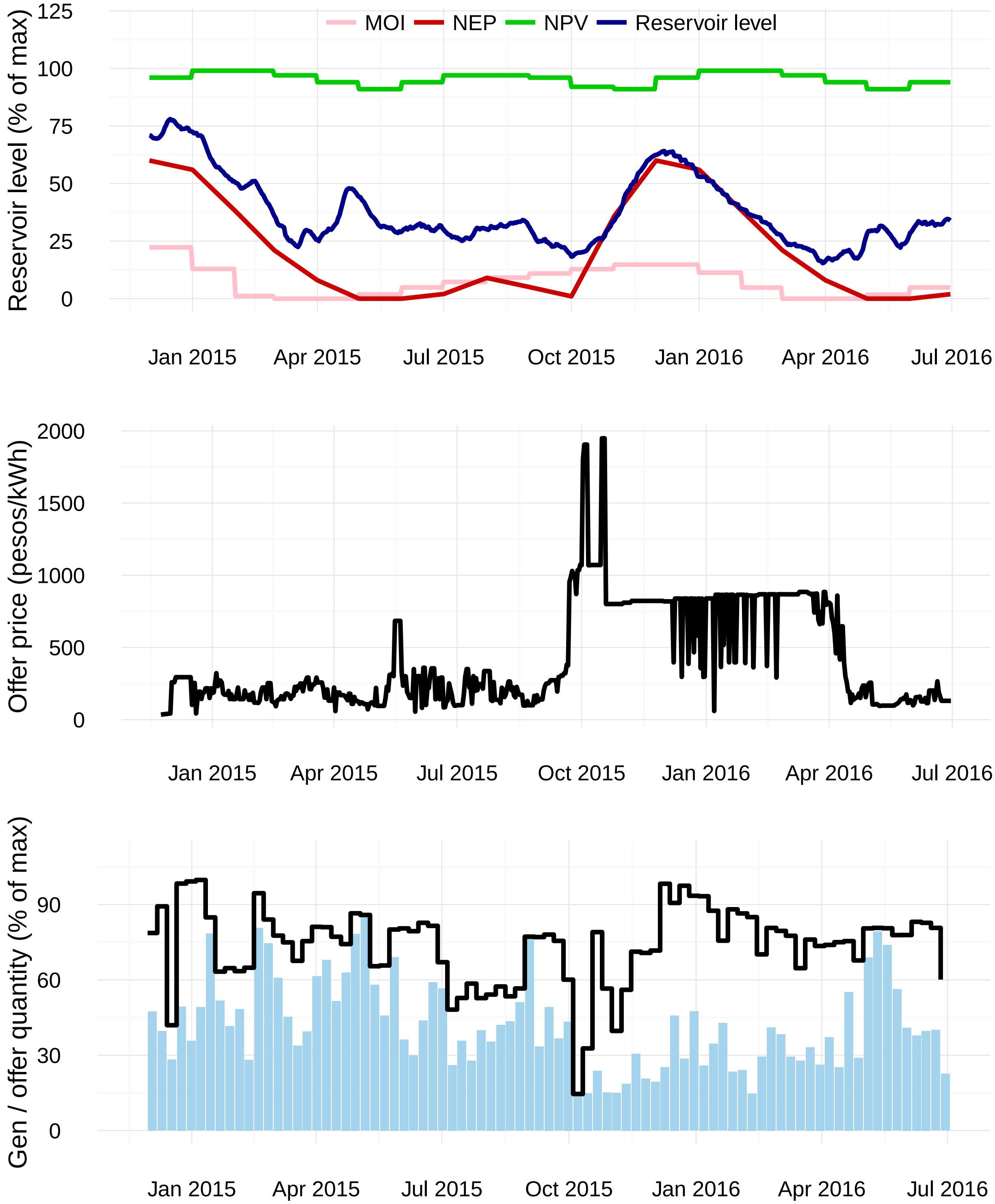



Figure 5.13: Reservoir levels, offers and generation—Sogamoso (Isagen)

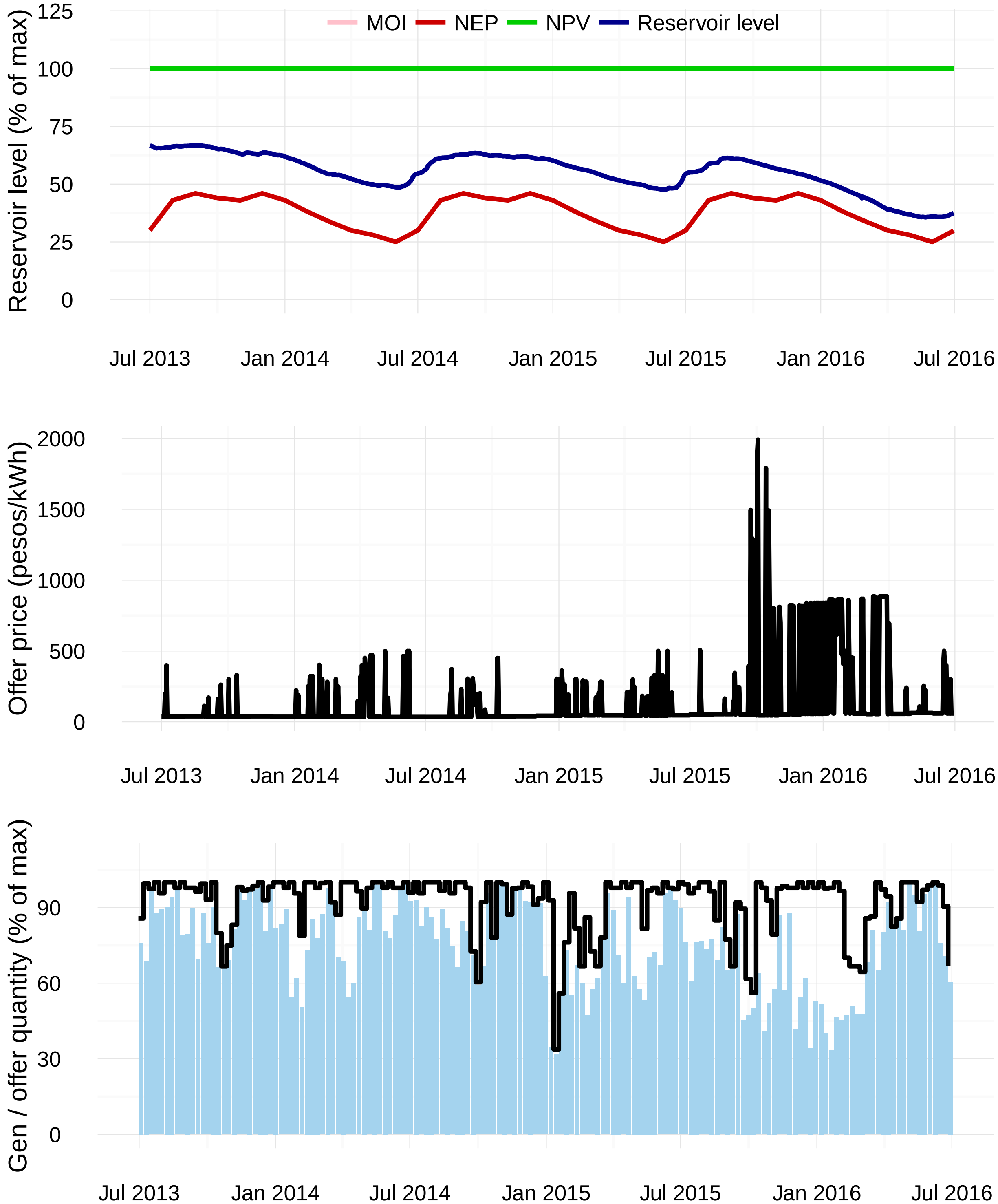



Figure 5.14: Reservoir levels, offers and generation—Pagua (Emgesa)

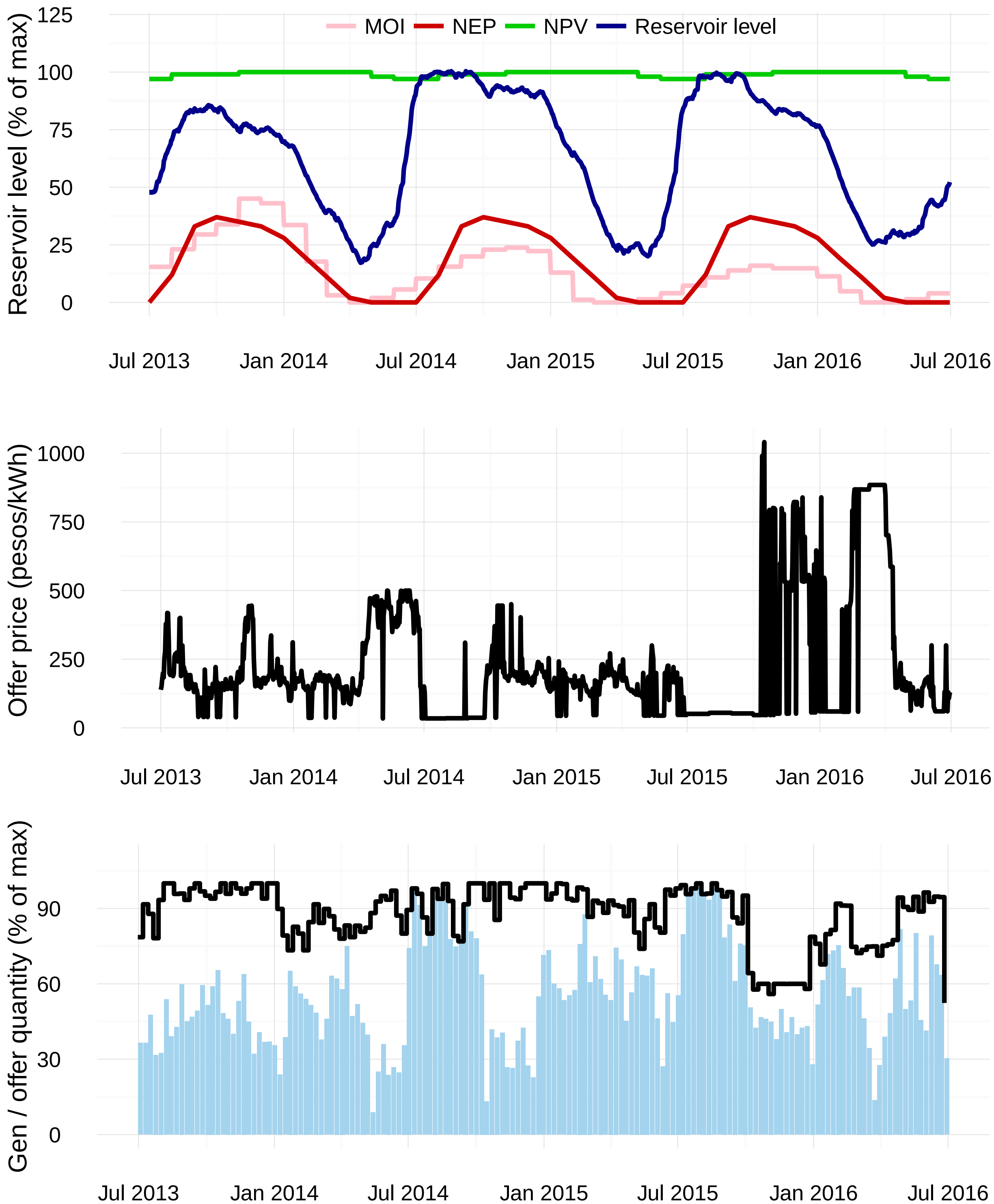



Figure 5.15: Reservoir levels, offers and generation—Guavio (Emgesa)

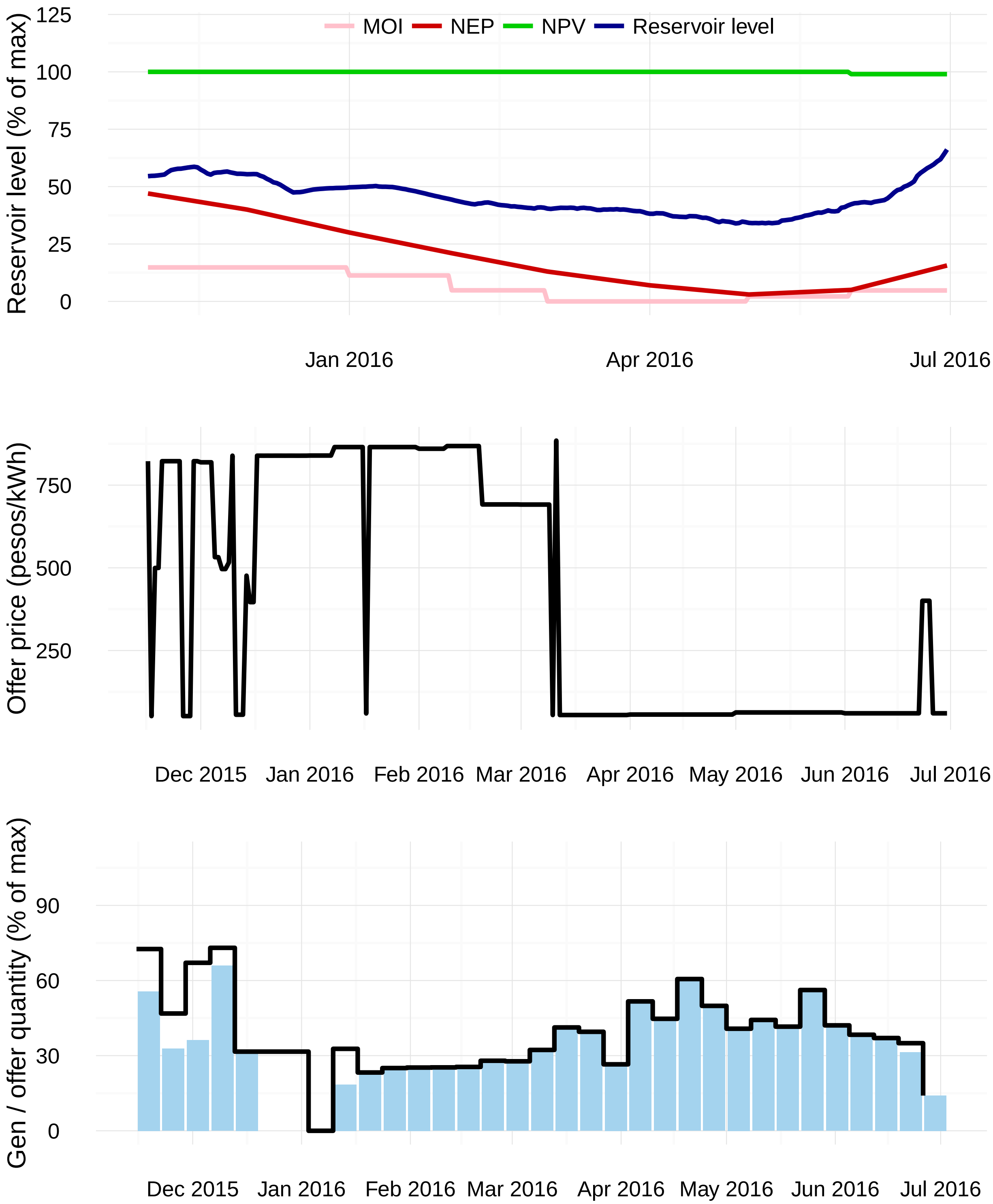



Figure 5.16: Reservoir levels, offers and generation—El Quimbo (Emgesa)

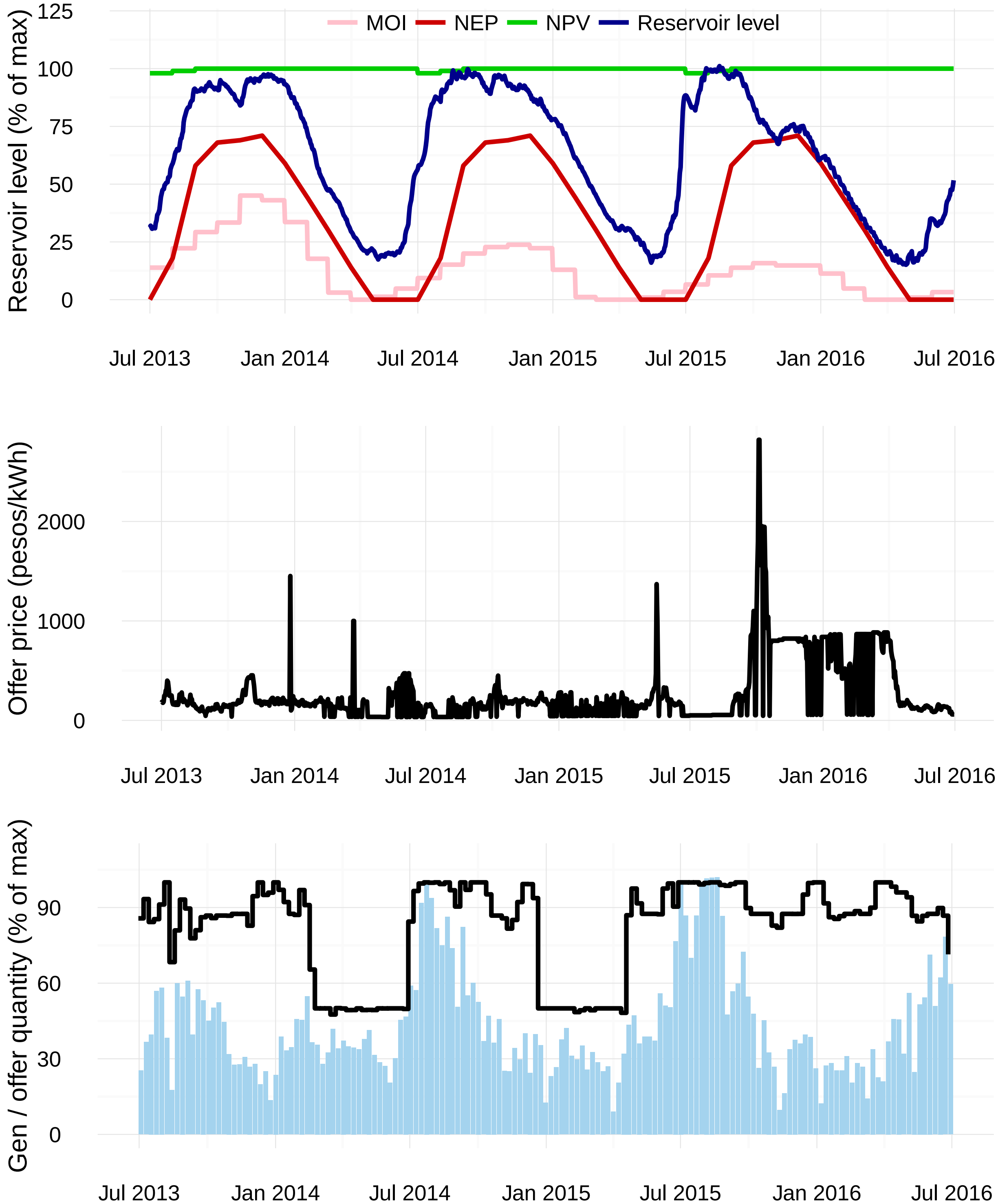



Figure 5.17: Reservoir levels, offers and generation—Chivor (AES Chivor)


# 6. Forward Contract and Firm Energy Positions

This section summarizes the net position of generation unit owners in the forward market from 2008 through 2016. For each supplier we present their total monthly ideal generation, total monthly net forward contract obligations, and their total monthly Firm Energy obligation. We demonstrate that except during El Niño conditions, suppliers tend to have higher values of ideal generation than their fixed-price forward contract obligation. This is referred to as being "net long" on energy. The relationship between a supplier's firm energy quantity and their ideal generation typically differs by technology. Hydroelectric resource owners tend to have hourly Firm Energy Values below their hourly Ideal Generation during normal conditions and thermal generation unit owners tend to have higher hourly Firm Energy Values than hourly Ideal Generation.

Before presenting these summary statistics, we first demonstrate that during normal market conditions, when $P(bolsa) < P(scarcity)$, fixed-price forward contracts for energy are the primary mechanism for ensuring a reliable supply of electricity at a reasonable price for Colombian electricity consumers. We demonstrate that under normal conditions, when a supplier's Ideal Generation for an hour is very close to its net fixed-price Forward Contract Position for that hour, the supplier has very little incentive to raise or lower the Bolsa price by exercising unilateral market power. This result emphasizes the importance of a liquid forward market for energy to the efficient operation of the short-term energy market.

We next demonstrate that during scarcity conditions, when $P(bolsa) > P(scarcity)$, the RPM becomes the primary mechanism for ensuring a reliability supply of electricity at a reasonable price. Moreover, the quantity of fixed price forward contract for energy obligations that a supplier has no longer impacts its incentive to take unilateral actions to raise the Bolsa price.

Finally, we show that the incentive for behavior caused by a supplier's Firm Energy obligation and the net fixed price forward contract position can interact in perverse ways during scarcity conditions and near-scarcity conditions in a manner that works against the RPM mechanism providing a reliable supply of energy at reasonable price during El Niño Events.

## 6.1 Forward Market Positions and Offer Behavior

As documented in Wolak (2000) and McRae and Wolak (2014) a supplier's fixed-price forward contract position impacts its incentive to take actions through the offers it submits to the short-term market to raise or lower the short-term market price. The existence of both fixed-price forward contracts for energy and the RPM with its firm energy quantity complicates this relationship. To see this consider the following expression for a supplier's hourly variable profits:

$$\begin{aligned}\pi_{hk}(P_h(Bolsa)) &= (Q_{hk}(Ideal) - Q_{hk}(Contract)) \times \min(P_h(Bolsa), P_h(Scarcity)) \\ &+ P_{hk}(Contract)Q_{hk}(Contract) + Q_{hk}(Firm)P_h(Firm) \\ &+ [Q_{hk}(Ideal) - Q_{hk}(Firm)] \times \max(0, ((P_h(Bolsa) - P_h(Scarcity))) - C_k(Q_{hk}(Ideal)), \end{aligned} \quad (6.1)$$

where $Q_{hk}(Ideal)$ is supplier $k$'s Ideal Generation during hour $h$, $Q_{hk}(Contract)$ is supplier $k$'s fixed-price forward contract quantity for hour $h$, $Q_{hk}(Firm)$ is supplier $k$'s Firm Energy value for hour $h$, $P_h(Bolsa)$ is the Bolsa price in hour $h$, $P_{hk}(Contract)$ is the quantity weighted average of supplier $k$'s forward contract prices in hour $h$, $P_h(Firm)$ is the price of Firm Energy during hour $h$, and $C_k(Q_{hk}(Ideal))$ is supplier $k$'s variable cost of producing $Q_{hk}(Ideal)$. This expression excludes payments the supplier receives for providing ancillary services and positive and negative reconciliation payments and start-up payments.

If the Bolsa price is less than the scarcity price, Equation (6.1) reduces to the standard variable profit function for fixed price forward contracts given in Wolak (2000) and McRae and Wolak (2014) (except for the addition of the RPM payment $Q_{hk}(Firm)P_h(Firm)$):

$$\begin{aligned}\pi_{hk}(P_h(Bolsa)) &= (Q_{hk}(Ideal) - Q_{hk}(Contract)) \times P_h(Bolsa) \\ &+ P_{hk}(Contract)Q_{hk}(Contract) + Q_{hk}(Firm)P_h(Firm) - C_k(Q_{hk}(Ideal)), \end{aligned} \quad (6.2)$$

This expression makes it clear that unless supplier $k$ sells more in the short-term market than its forward contract position, it has little incentive to use its offers to raise the Bolsa price. If $Q_{hk}(Ideal) < Q_{hk}(Contract)$, then the supplier loses more money the higher is $P_h(Bolsa)$. Consequently, if supplier $k$ is short on energy, so that $Q_{hk}(Ideal) < Q_{hk}(Contract)$, supplier $k$ would like the Bolsa price to be as low as possible. In contrast, if $Q_{hk}(Ideal) > Q_{hk}(Contract)$, then supplier $k$ would like the Bolsa price to be as high as possible. If $Q_{hk}(Ideal) = Q_{hk}(Contract)$, then supplier $k$ is indifferent to the Bolsa price because Equation (6.1) becomes $\pi_{hk}(P_h(Bolsa)) = P_{hk}(Contract)Q_{kh}(Contract) + Q_{hk}(Firm)P_h(Firm) - C_k(Q_{hk}(Ideal))$.

When scarcity conditions occur, so that $P_h(Bolsa) > P_h(Scarcity)$, Equation (6.1) reduces to:

$$\begin{aligned}\pi_{hk}(P_h(Bolsa)) &= Q_{hk}(Ideal)P_h(Scarcity) \\ &+ (P_{hk}(Contract) - P_h(Scarcity))Q_{hk}(Contract) + Q_{hk}(Firm)P_h(Firm) \\ &+ [Q_{hk}(Ideal) - Q_{hk}(Firm)]((P_h(Bolsa) - P_h(Scarcity))) - C_k(Q_{hk}(Ideal)), \end{aligned} \quad (6.3)$$

Note that only the first term on the third line depends on the Bolsa price. This means the incentive a supplier has to use its offers to raise or lower the Bolsa price depends on the value of $Q_{hk}(Ideal) - Q_{hk}(Firm)$. If its hourly Ideal Generation is greater than its hourly Firm Energy Value, then the supplier would like a higher Bolsa price. If its Firm Energy Value exceeds its Ideal Generation, the supplier would like to lower the Bolsa price.

If the $Q_{hk}(Contract) > Q_{hk}(Ideal) > Q_{hk}(Firm)$ then supplier $k$ faces a very perverse set of incentives when submitting its offers into the short-term market. If it can drive the Bolsa price above the Scarcity Price then it would like to take actions to make the Bolsa price as high as possible. If it cannot drive the Bolsa price above the Scarcity Price, then it would like to make the Bolsa price as low as possible. If $Q_{hk}(Firm) > Q_{hk}(Ideal) > Q_{hk}(Contract)$ then supplier $k$ faces another perverse set of incentives when submitting its offers into the short-term market. If it knows that the Bolsa price will not exceed the Scarcity price, then supplier $k$ would like the Bolsa price to be as high as possible. However, if the Bolsa price is above the Scarcity price, then supplier $k$ would like it to be as low as possible.

The other two cases induce a clear set of incentives to lower or raise the Bolsa price, regardless of its value. If $Q_{hk}(Ideal)$ is greater than both $Q_{hk}(Contract)$ and $Q_{hk}(Firm)$ then supplier $k$ wants to use its offers to raise the Bolsa Price. If $Q_{hk}(Ideal)$ is less than both $Q_{hk}(Contract)$ and $Q_{hk}(Firm)$ then supplier $k$ wants to use its offers to lower the Bolsa price. Unfortunately, as we discuss below, the two perverse conditions and the condition that $Q_{hk}(Ideal)$ is greater than both $Q_{hk}(Contract)$ and $Q_{hk}(Firm)$ occurs quite frequently during the 2015-2016 El Niño Event.

Figure 6.1 plots the proportion of hours during each month from January 2008 to June 2016 when the Bolsa price exceeds the Scarcity price. There is a very small frequency during the 2009-2010 El Niño Event and a larger frequency during early 2014. However, during the period October 2015 to April 2015, virtually 100 percent of the hours saw Bolsa prices above the Scarcity Price.

Figure 6.2 shows the net contract position of generators, relative to their total output. The top red line is the mean hourly generation (in GW) for each month. The second green line is the mean net contract position of the generation firms (also in GW) for each month. This is calculated as the sum of contract sales by generators, less the sum of contract purchases by generators, averaged across all of the hours in a month. The bottom blue line is the difference between the generation and net contract position. The aggregate exposure to the Bolsa price, the level of the blue line, is relatively constant from January 2008 to June 2016. As shown below, the exposure to the Bolsa of individual market participants is significantly more variable over this same time period, even changing sign many times.

Tables 6.1 provides summary statistics on the fraction of days each month from October 2015 through March 2016 when scarcity conditions exist and a supplier's daily Net Forward Contract Quantity ($Q_c$ in the Table) is greater than its daily Firm Energy Value ($Q_f$ in the table). The next three lines list the frequency of days when the firm's Ideal Generation ($Q_i$ in the table) satisfies the inequalities listed. For example, for Emgesa in October 2015, on 38.7 percent of the days the interaction between its Firm Energy obligation and its Net Forward Contract Quantity creates the perverse incentive that it would like to raise the Bolsa Price above the Scarcity Price and it would like to lower the Bolsa price if it is below the Scarcity Price. This set of incentives exists for Isagen for 58.8 percent of the days in October 2015. For Isagen this set of incentives exists for a significant fraction of days throughout the October 2015 to March 2016 time period.

Table 6.2 provides analogous summary statistics on the fraction of days each month from October 2015 through March 2015 when scarcity conditions exist and a supplier's daily Firm Energy Value exceeds its Net Forward Contract Quantity. The second perverse set of incentives occurs when $Q_f > Q_i > Q_c$ in the notation described above. In this case the supplier would like to increase the Bolsa price as long as it is below the Scarcity Price, but reduce the Bolsa price as long as it is above the Scarcity Price. For EPM, this event occurs 22.6 percent of days in October 2015. For Celsia it occurs 38.7 percent of the days in October 2015. There are a number of months for several suppliers when these sets of incentives exist.

It is also important to emphasize the significant frequency of days during the October 2015 to April 2015 time period for each supplier when $Q(Ideal)$ is above both $Q(Firm)$ and $Q(Contract)$. Table 6.2 shows that this is a frequent event for EPM, Celsia, and Gecelca throughout this time period. Table 6.1 shows that this is frequent event for Emgesa, Isagen and Chivor throughout this time period. This set of circumstances implies that these firms would like to raise Bolsa price as high as possible, regardless of its value relative to the Scarcity Price.

The results in these two tables argue that if a supplier has a significant ability to exercise unilateral market power, it will use this ability to raise the Bolsa price throughout much of the October 2015 through March 2015 time period. During virtually all of the days during this time period there are several suppliers with a significant incentive to raise the Bolsa price.

## 6.2 Forward Market Positions from 2008 to 2016

This section presents plots of the monthly Ideal Generation, monthly Firm Energy, and Monthly Net Forward Contracts for the six largest suppliers in Colombia for the time period 2008 to 2016. This time period allows us to compare the behavior of these variables during the 2009-2010 and 2015-2016 El Niño Events and several periods of "normal" hydro conditions. Figure 6.3 plots these magnitudes for EPM. During most of the sample period EPM has a monthly value of Ideal Generation that exceeds both its monthly Firm Energy Value and Net Forward Contract quantity. Only during low water conditions does the value of Ideal Generation fall below either the value of monthly Firm Energy or the Net Forward Contract Quantity. This outcome occurred during 2014 and the 2015-2016 El Niño Event. Figure 6.4 presents this same graph for Emgesa. Low water conditions during the two El Niño Events produces values of Ideal Generation less than either the monthly Firm Energy Value and Net Forward Contract Quantity. Figure 6.5 for Isagen is the best graphical illustration of a market participant facing the perverse incentives caused by the interaction of their forward contracts for energy and their Firm Energy Value. For both 2014 and the 2015-2016 El Niño Event, the inequality $Q(Contract) > Q(Ideal) > Q(Firm)$ holds, which implies a unilateral incentive to raise the Bolsa price if it is above the Scarcity Price and lower the Bolsa price if it is below the Scarcity Price. Figures 6.6, 6.7, and 6.8 contain these plots for Celsia, AES Chivor, and Gecelca. Celsia and Gecelca persistently have higher values of $Q(firm)$ than $Q(Contract)$, with $Q(Ideal)$ often between these two values, which implies the other perverse incentive that they would like to raise the price if the Bolsa price is less than the Scarcity Price, but lower the price if it is above the Scarcity price. AES Chivor is often in a position of having $Q(Ideal)$ above both $Q(Firm)$ and $Q(Contract)$, meaning it would like to raise the Bolsa price, regardless of its value.

## 6.3 Hydro and Thermal Offer Prices from 2008 to 2016

General hydrological conditions and the competitive conditions faced by the generation unit owners is likely to impact their offer prices. We expect that when water levels are low, hydroelectric suppliers should submit high offer prices to conserve their water. This decision is also likely to impact the offer behavior of thermal suppliers. By the logic of Section 6.1, if they expect to sell more energy than their forward contract quantity, then they are likely to submit higher offer prices in response to the actions of the hydroelectric generation unit owners. During scarcity conditions they are likely to raise their offer prices in response to the actions of the hydroelectric generation unit owners if they expect to sell more than their firm energy.

Figure 6.9 plots the monthly offer quantity-weighted average of offer prices submitted by hydroelectric generation unit owners and thermal generation unit owners. Each monthly value is equal to

$$p(avg) = \frac{\sum_{d=1}^{D}\sum_{k=1}^{K} p_{dk}(offer)w_{dk}(offer)}{\sum_{d=1}^{D}\sum_{k=1}^{K} w_{dk}(offer)}$$

where $p_{dk}(offer)$ is the offer price for unit $k$ for day $d$ of the month and $w_{hk}(offer)$ is the average offer quantity for unit $k$ during day $d$ of the month. The pattern of these monthly average offer prices are largely consistent with the logic of hydroelectric suppliers conserving water during low water conditions during the 2009-2010 and 2015-16 El Niño events, and during other times primarily running their hydroelectric units. The average thermal offer price is above the average offer price of the hydroelectric units throughout our sample period except during the 2009-2010 and 2015-16 El Niño events. Despite the fact that 2013, 2014, and 2015 were low water inflow years similar to 2009, average hydroelectric offer prices were below average thermal offer prices, indicating a desire by the market to operate hydroelectric units rather than thermal units.

The behavior of two of the large suppliers that own hydroelectric and thermal units are consistent with the pattern of average hydroelectric and thermal offers in Figure 6.9. Figures 6.11 and 6.12 show that EPM and Emgesa have average offer prices for their thermal units above the average offers of hydroelectric units during our sample period except during the 2009-2010 and 2015-2016 El Niño Events. Isagen is the only one of the three large firms that own thermal and hydroelectric units submitting offers during 2013 and 2014 that reflect a desire to conserve water. From mid-2012 onwards, its average thermal offer prices were often below its average hydroelectric offer prices, which is consistent with a desire to conserve water. This graph also shows that Isagen had average offer prices for its hydroelectric units during the 2009-2010 and 2015-2016 El Niño events and in early 2014 above its average thermal offer. Figure 6.14 shows that Celsia also appears to have submitted offers for its thermal and hydroelectric units to conserve water during the mid-2012 to mid-2015 time period. During many of these months its average thermal offer prices were higher than its average hydroelectric offer prices.

EPM's and Emgesa's offer behavior during the 2012 to 2014 time period explains why both suppliers had very low levels of Ideal Generation from their thermal units. Comparing Figures 6.3 and 6.4 to Figures 6.5 and 6.6 over the 2012 to 2014 time period with low water inflows reveals significantly more thermal Ideal Generation from Isagen and Celsia than from either EPM and Emgesa. An outstanding question is why more water was not conserved by EPM and Emgesa during the 2013 and 2014 time period given the low water inflows during that time period. The potential for large amounts of spill by conserving water does not appear to be the case based on Figure 3.7 which shows very little spill in 2013 and the water levels in mid-2013 shown in Figures 5.9 and 5.10 for EPM and Figures 5.14 and 5.15 for Emgesa, which all show significant storage capacity available before the spill level would be reached. Our alternative reliability mechanism is designed to ensure that all hydroelectric suppliers that own thermal generation units behave like Isagen and Celsia during conditions suspected to be the start of an El Niño Event.

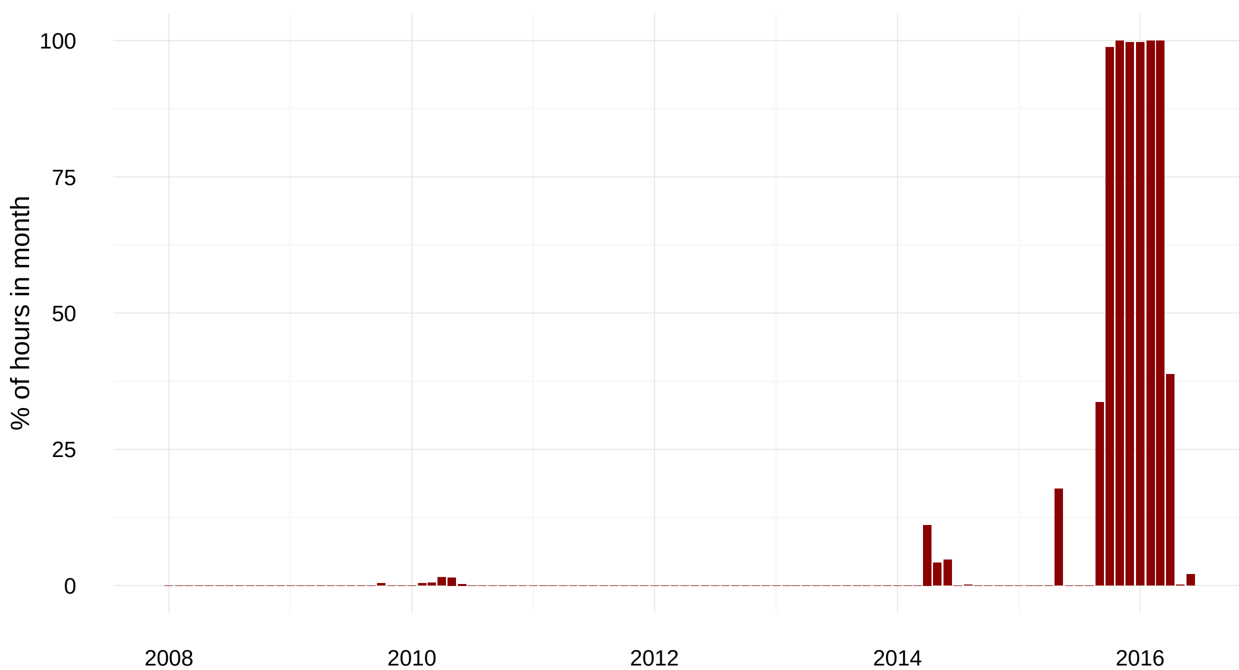



Figure 6.1: Proportion of hours in each month for which bolsa price exceeds scarcity price

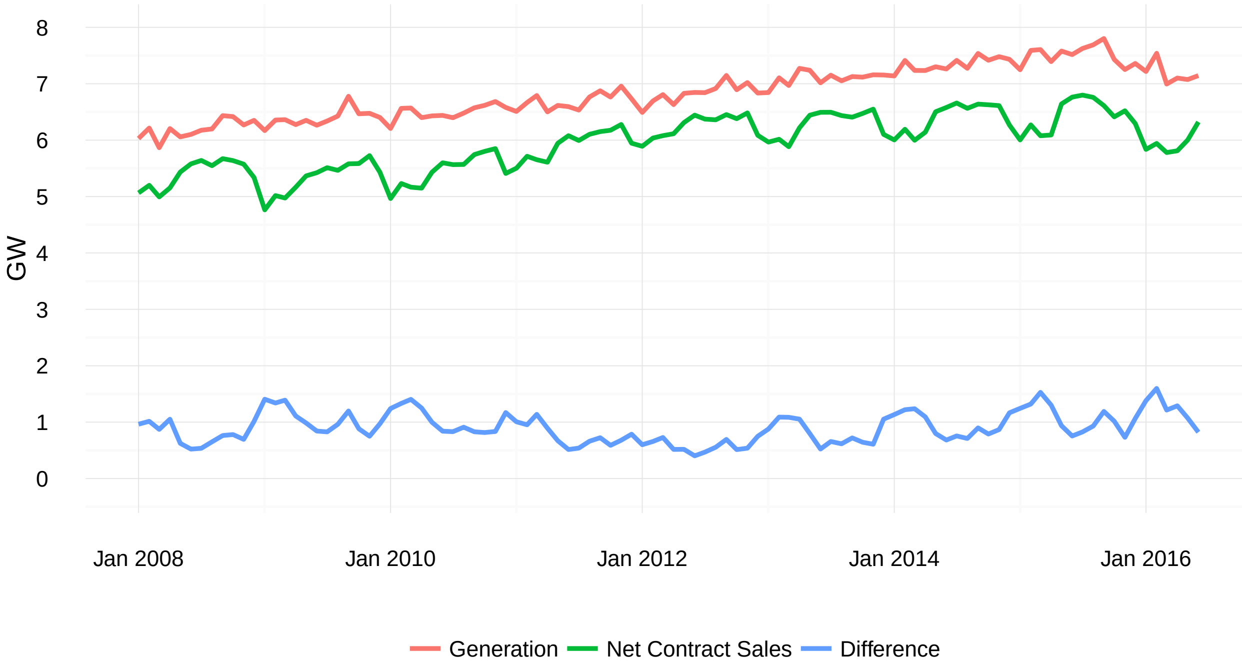



Figure 6.2: Comparison of monthly mean generation and monthly mean contract sales

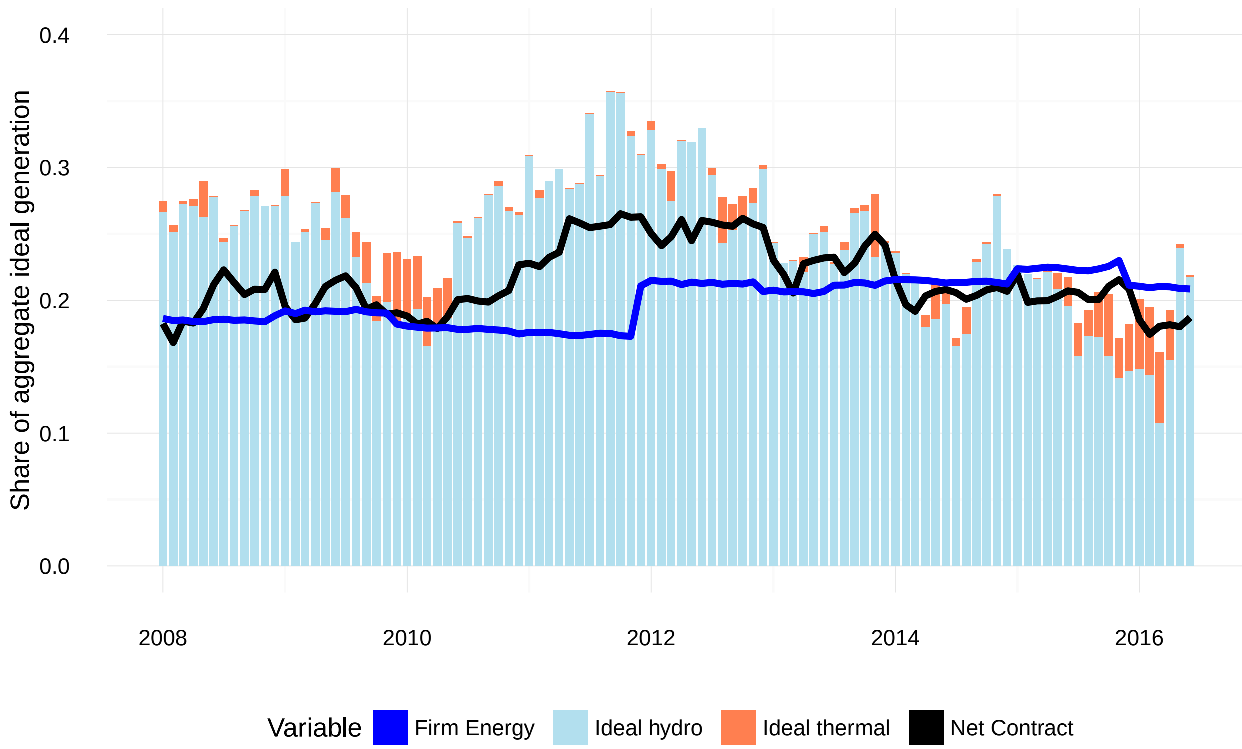



Figure 6.3: Monthly ideal generation, firm energy and contract position—EPM

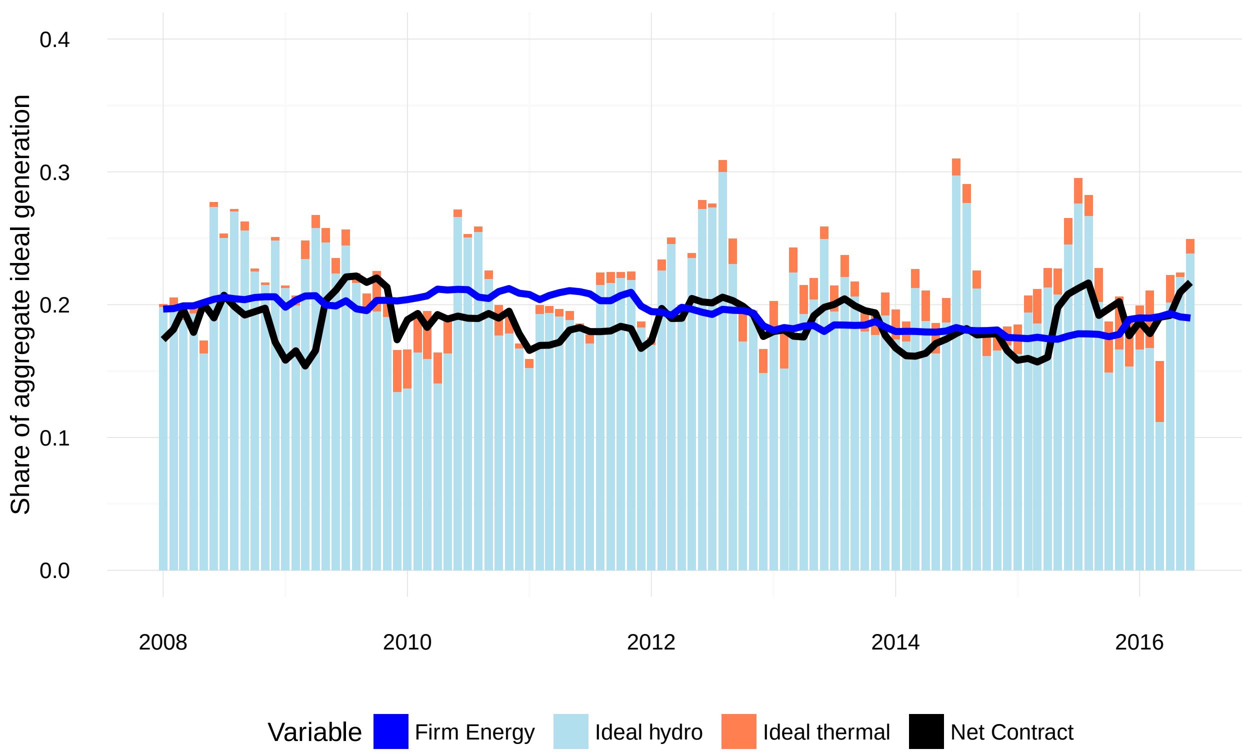



Figure 6.4: Monthly ideal generation, firm energy and contract position—Emgesa

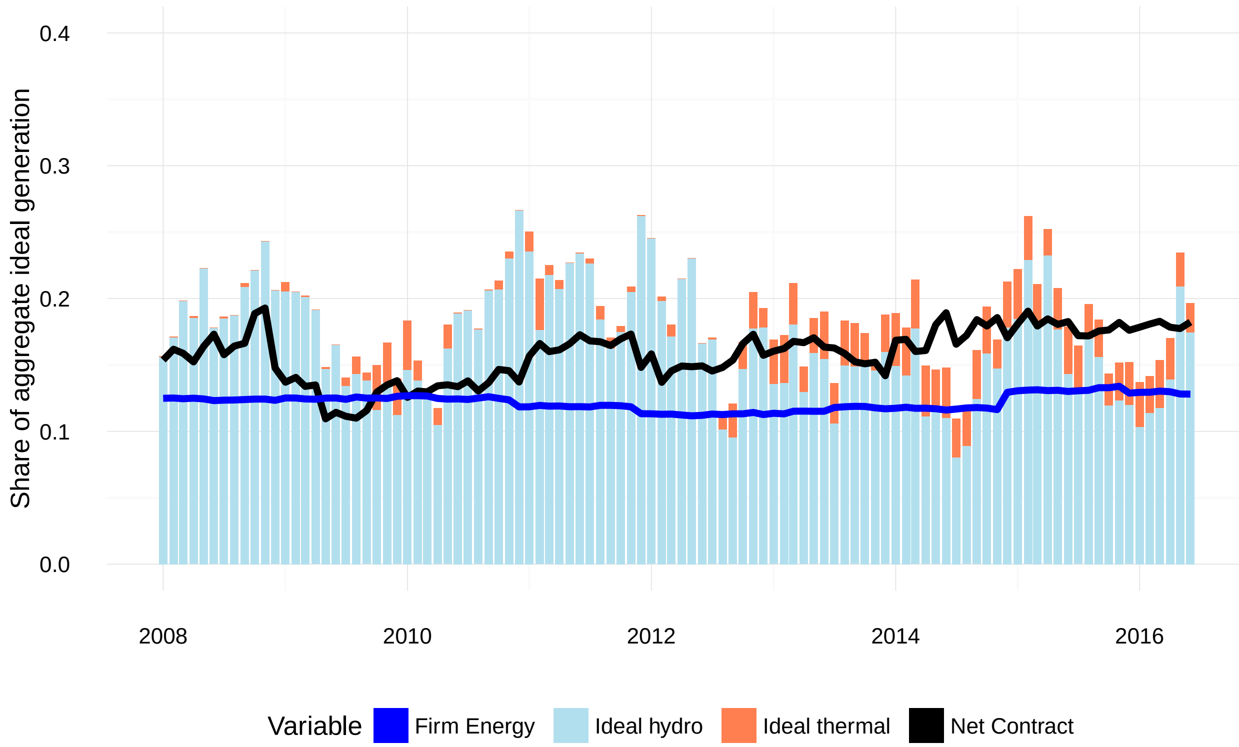



Figure 6.5: Monthly ideal generation, firm energy and contract position—Isagen

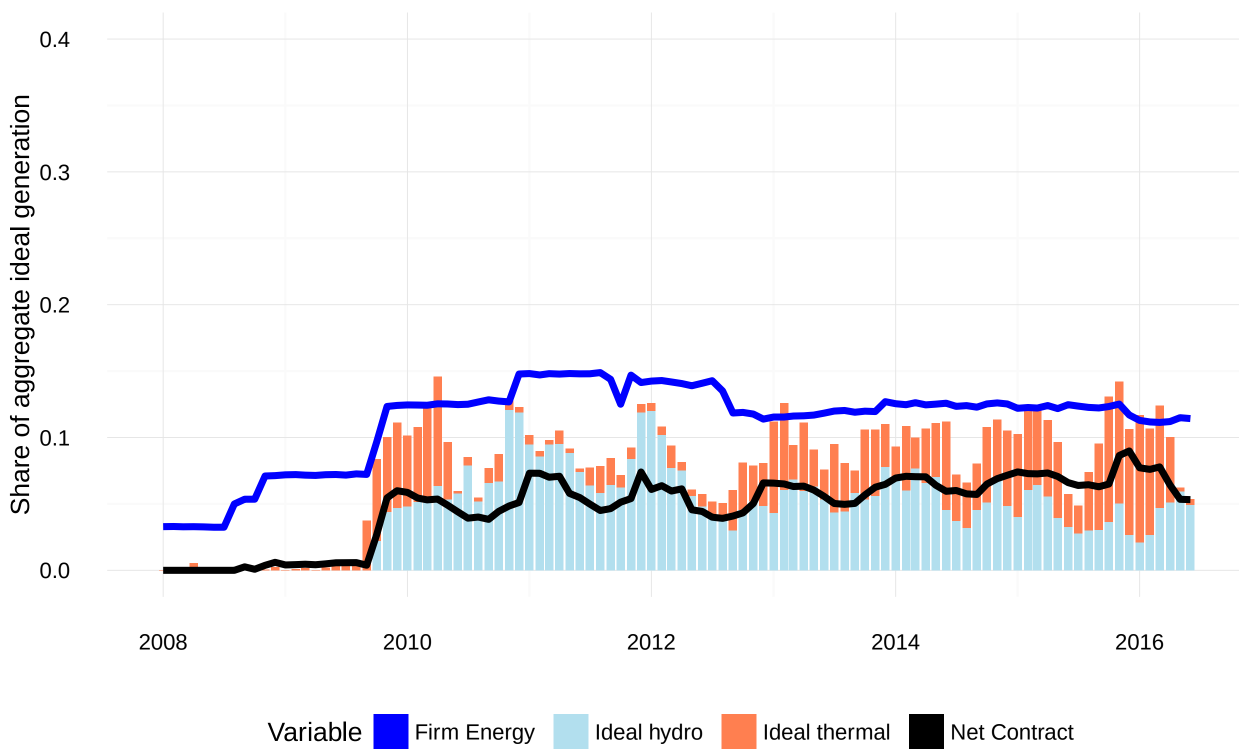



Figure 6.6: Monthly ideal generation, firm energy and contract position—Celsia

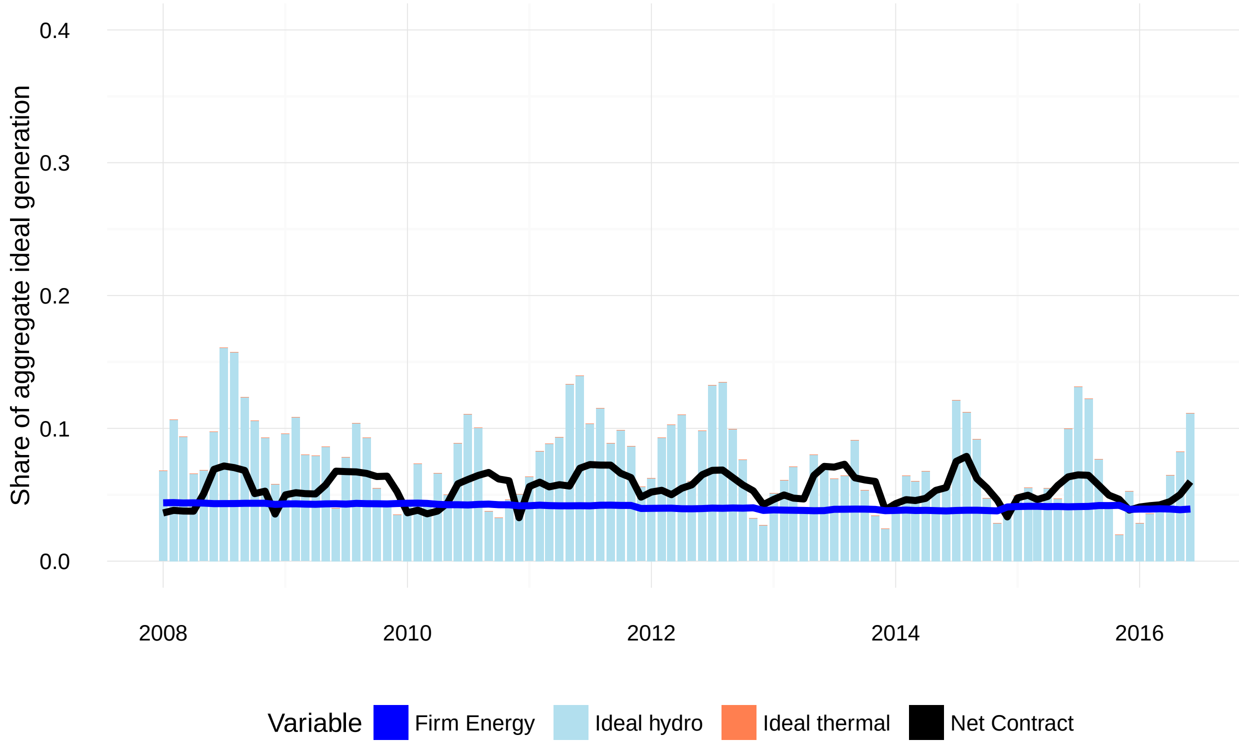



Figure 6.7: Monthly ideal generation, firm energy and contract position—AES Chivor

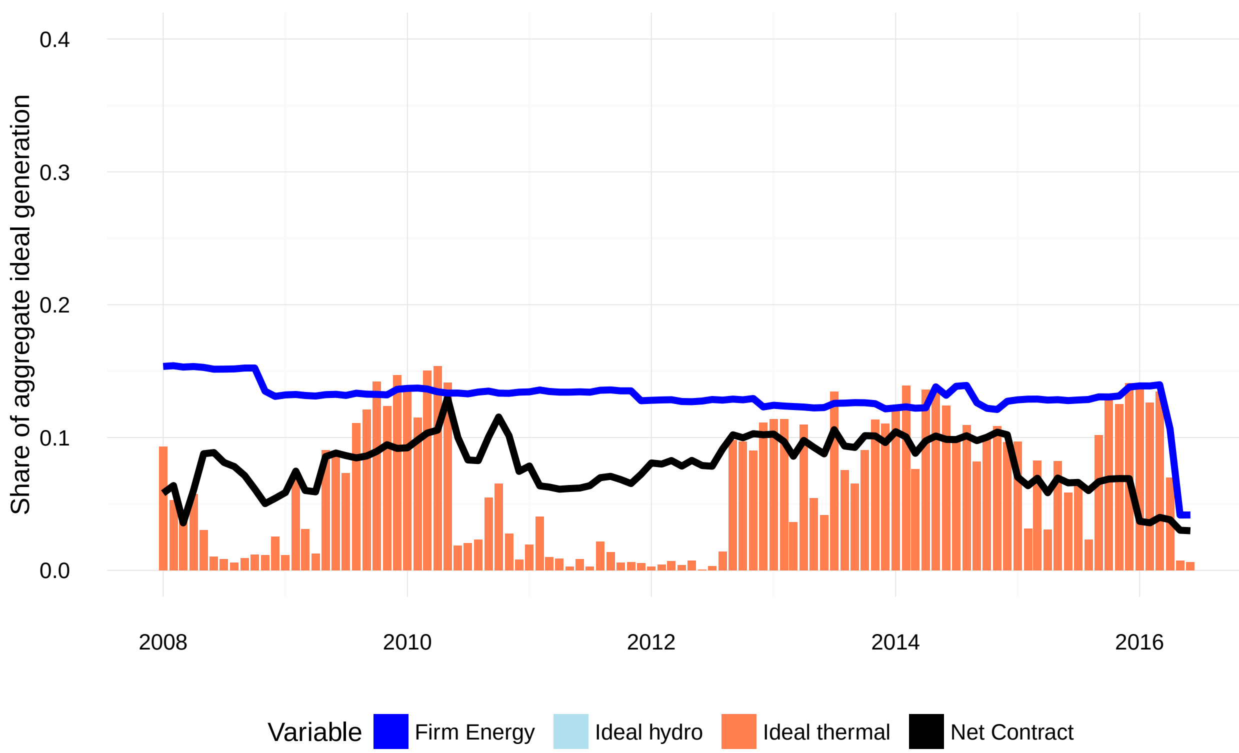



Figure 6.8: Monthly ideal generation, firm energy and contract position—Gecelca

Table 6.1: Relationship between daily firm energy, ideal generation and contract positions, for days in which net contracts exceed firm energy

| Firm | % of days in month for which condition holds | | | | | |
|---|---|---|---|---|---|---|
| | Oct 15 | Nov 15 | Dec 15 | Jan 16 | Feb 16 | Mar 16 |
| $P_b > P_s$ | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| **EPM** | | | | | | |
| $Q_c > Q_f$ | 0.0 | 0.0 | 12.9 | 0.0 | 0.0 | 0.0 |
| $Q_i > Q_c > Q_f$ | 0.0 | 0.0 | 9.7 | 0.0 | 0.0 | 0.0 |
| $Q_c > Q_i > Q_f$ | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| $Q_c > Q_f > Q_i$ | 0.0 | 0.0 | 3.2 | 0.0 | 0.0 | 0.0 |
| **Emgesa** | | | | | | |
| $Q_c > Q_f$ | 100.0 | 100.0 | 0.0 | 12.9 | 0.0 | 48.4 |
| $Q_i > Q_c > Q_f$ | 32.3 | 46.7 | 0.0 | 6.5 | 0.0 | 12.9 |
| $Q_c > Q_i > Q_f$ | 38.7 | 30.0 | 0.0 | 0.0 | 0.0 | 3.2 |
| $Q_c > Q_f > Q_i$ | 29.0 | 23.3 | 0.0 | 6.5 | 0.0 | 32.3 |
| **Isagen** | | | | | | |
| $Q_c > Q_f$ | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| $Q_i > Q_c > Q_f$ | 19.4 | 26.7 | 29.0 | 6.5 | 24.1 | 38.7 |
| $Q_c > Q_i > Q_f$ | 54.8 | 46.7 | 35.5 | 58.1 | 27.6 | 22.6 |
| $Q_c > Q_f > Q_i$ | 25.8 | 26.7 | 35.5 | 35.5 | 48.3 | 38.7 |
| **Celsia** | | | | | | |
| $Q_c > Q_f$ | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| $Q_i > Q_c > Q_f$ | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| $Q_c > Q_i > Q_f$ | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| $Q_c > Q_f > Q_i$ | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **AES Chivor** | | | | | | |
| $Q_c > Q_f$ | 100.0 | 100.0 | 29.0 | 83.9 | 100.0 | 100.0 |
| $Q_i > Q_c > Q_f$ | 38.7 | 23.3 | 9.7 | 29.0 | 34.5 | 41.9 |
| $Q_c > Q_i > Q_f$ | 3.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| $Q_c > Q_f > Q_i$ | 58.1 | 76.7 | 19.4 | 54.8 | 65.5 | 58.1 |
| **Gecelca** | | | | | | |
| $Q_c > Q_f$ | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| $Q_i > Q_c > Q_f$ | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| $Q_c > Q_i > Q_f$ | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| $Q_c > Q_f > Q_i$ | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |

Table 6.2: Relationship between daily firm energy, ideal generation and contract positions, for days in which firm energy exceeds net contracts

| Firm | % of days in month for which condition holds | | | | | |
|---|---|---|---|---|---|---|
| | Oct 15 | Nov 15 | Dec 15 | Jan 16 | Feb 16 | Mar 16 |
| $P_b > P_s$ | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| **EPM** | | | | | | |
| $Q_f > Q_c$ | 100.0 | 100.0 | 87.1 | 100.0 | 100.0 | 100.0 |
| $Q_i > Q_f > Q_c$ | 32.3 | 10.0 | 22.6 | 45.2 | 41.4 | 6.5 |
| $Q_f > Q_i > Q_c$ | 22.6 | 0.0 | 0.0 | 12.9 | 27.6 | 25.8 |
| $Q_f > Q_c > Q_i$ | 45.2 | 90.0 | 64.5 | 41.9 | 31.0 | 67.7 |
| **Emgesa** | | | | | | |
| $Q_f > Q_c$ | 0.0 | 0.0 | 100.0 | 87.1 | 100.0 | 51.6 |
| $Q_i > Q_f > Q_c$ | 0.0 | 0.0 | 54.8 | 58.1 | 82.8 | 9.7 |
| $Q_f > Q_i > Q_c$ | 0.0 | 0.0 | 3.2 | 6.5 | 0.0 | 0.0 |
| $Q_f > Q_c > Q_i$ | 0.0 | 0.0 | 41.9 | 22.6 | 17.2 | 41.9 |
| **Isagen** | | | | | | |
| $Q_f > Q_c$ | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| $Q_i > Q_f > Q_c$ | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| $Q_f > Q_i > Q_c$ | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| $Q_f > Q_c > Q_i$ | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Celsia** | | | | | | |
| $Q_f > Q_c$ | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| $Q_i > Q_f > Q_c$ | 61.3 | 83.3 | 35.5 | 64.5 | 48.3 | 87.1 |
| $Q_f > Q_i > Q_c$ | 38.7 | 16.7 | 38.7 | 35.5 | 34.5 | 9.7 |
| $Q_f > Q_c > Q_i$ | 0.0 | 0.0 | 25.8 | 0.0 | 17.2 | 3.2 |
| **AES Chivor** | | | | | | |
| $Q_f > Q_c$ | 0.0 | 0.0 | 71.0 | 16.1 | 0.0 | 0.0 |
| $Q_i > Q_f > Q_c$ | 0.0 | 0.0 | 41.9 | 3.2 | 0.0 | 0.0 |
| $Q_f > Q_i > Q_c$ | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| $Q_f > Q_c > Q_i$ | 0.0 | 0.0 | 29.0 | 12.9 | 0.0 | 0.0 |
| **Gecelca** | | | | | | |
| $Q_f > Q_c$ | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| $Q_i > Q_f > Q_c$ | 64.5 | 30.0 | 64.5 | 35.5 | 24.1 | 35.5 |
| $Q_f > Q_i > Q_c$ | 35.5 | 66.7 | 35.5 | 64.5 | 75.9 | 64.5 |
| $Q_f > Q_c > Q_i$ | 0.0 | 3.3 | 0.0 | 0.0 | 0.0 | 0.0 |

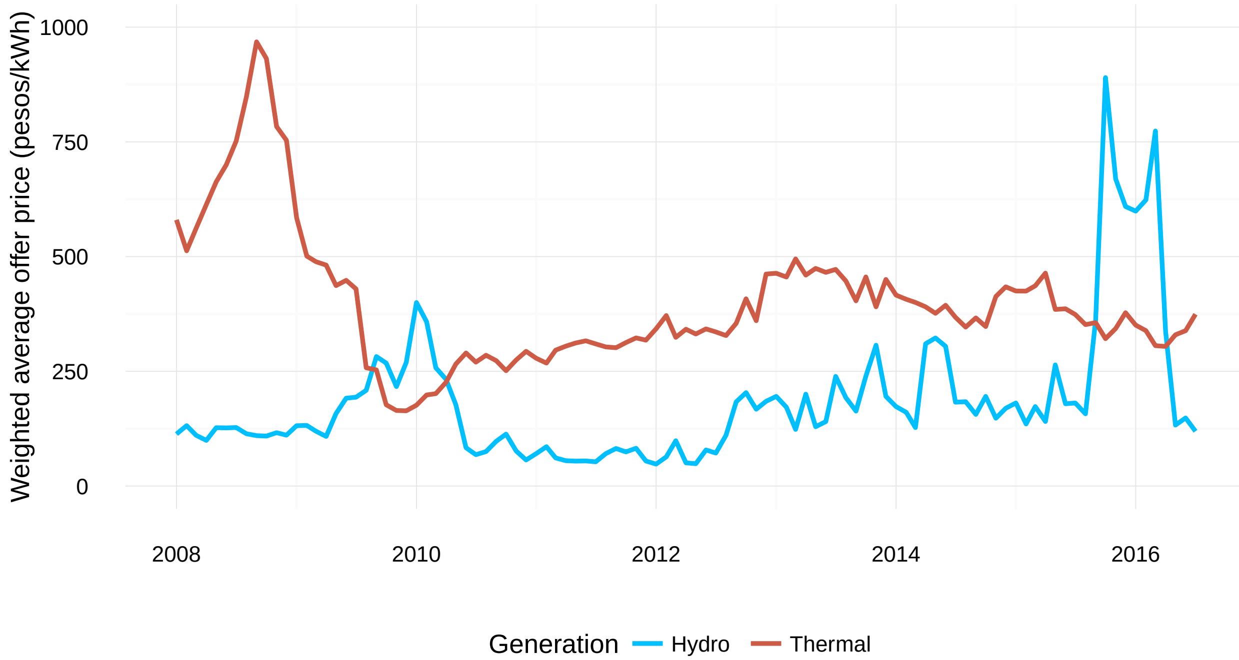



Figure 6.9: Monthly average offers by generation type—local currency

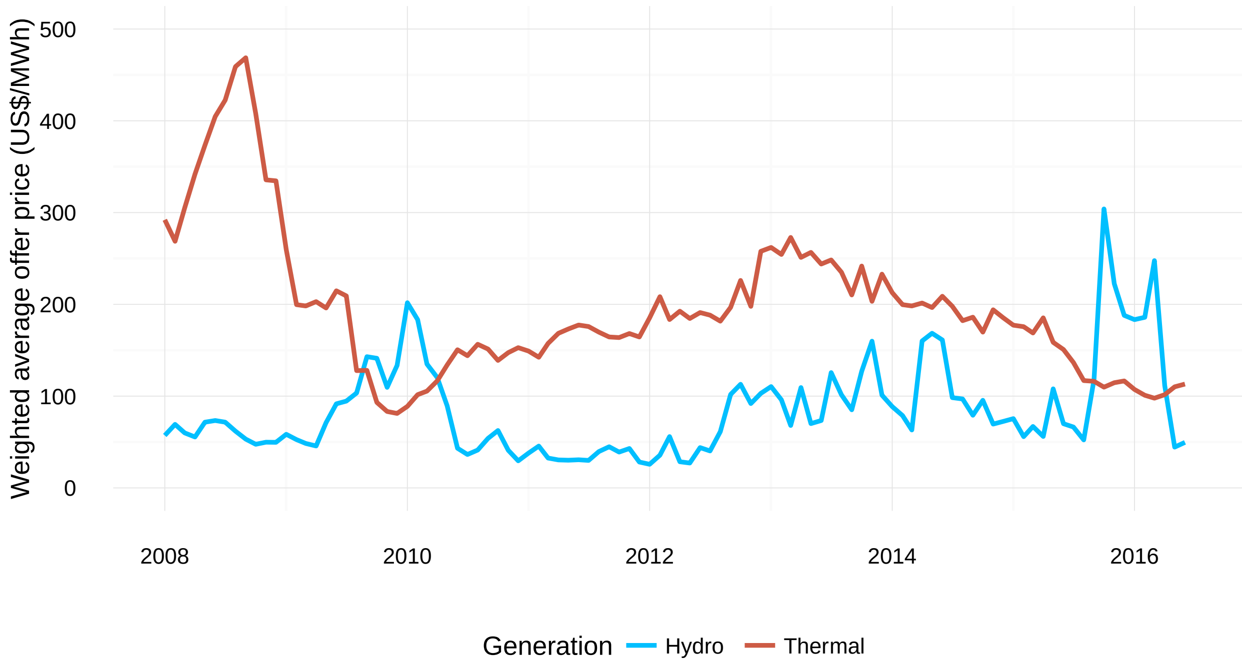



Figure 6.10: Monthly average offers by generation type—US dollars

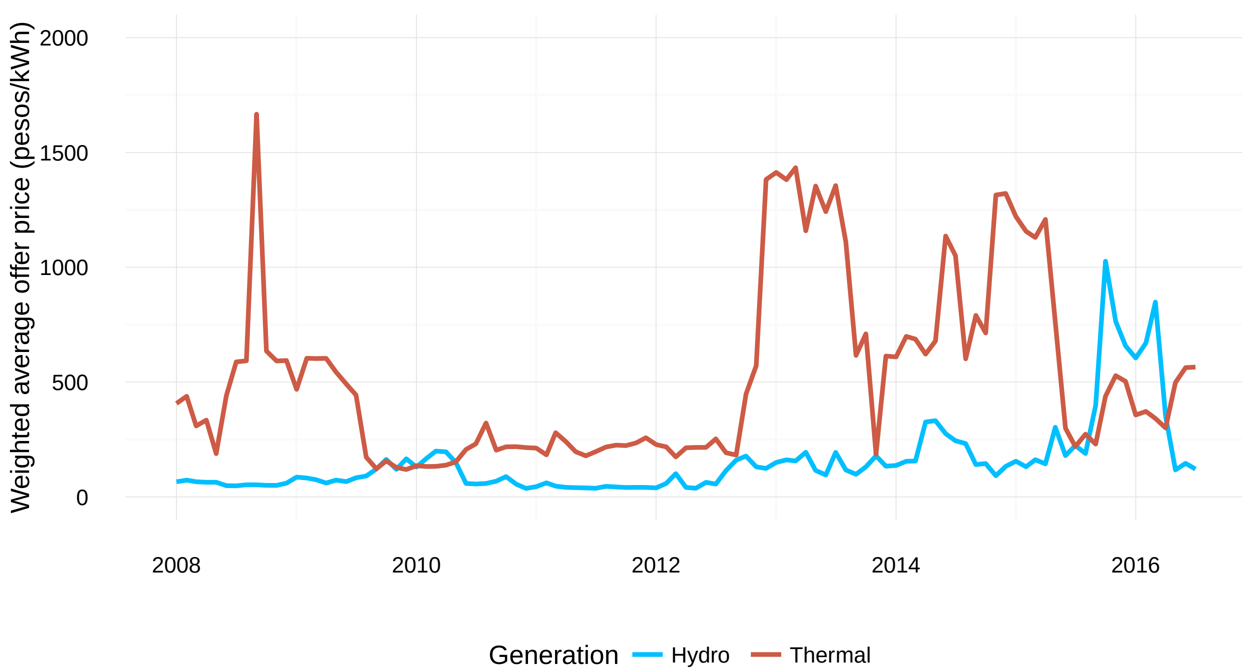



Figure 6.11: Monthly average offers by generation type—EPM

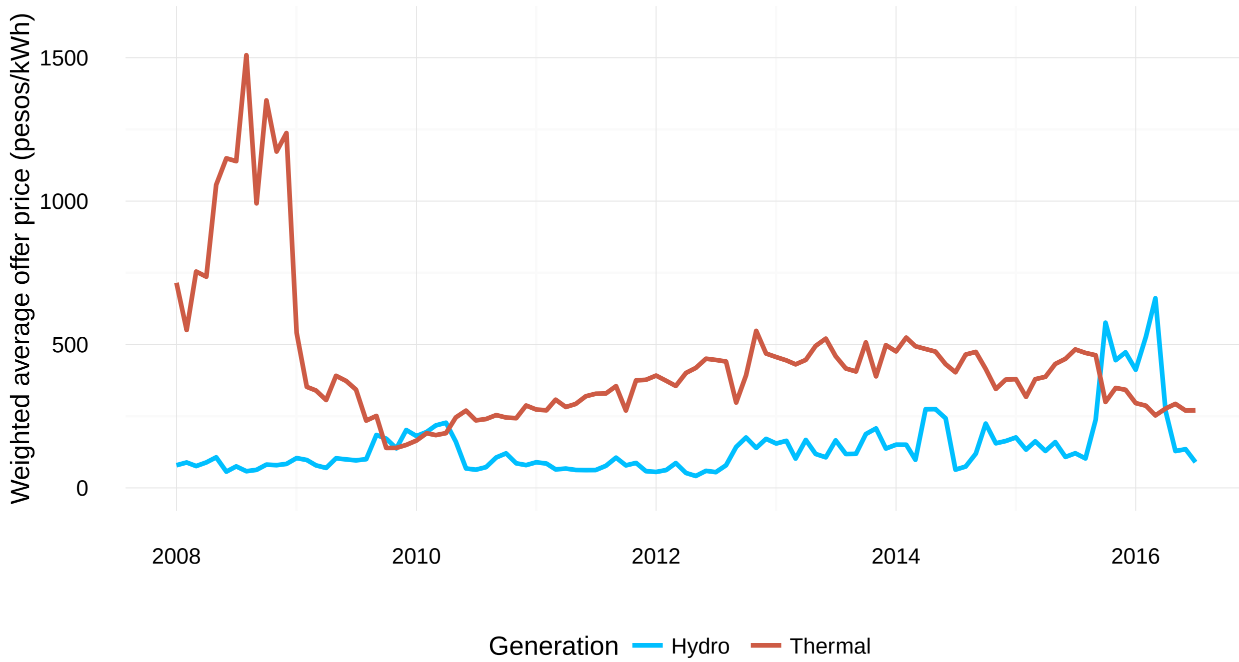



Figure 6.12: Monthly average offers by generation type—Emgesa

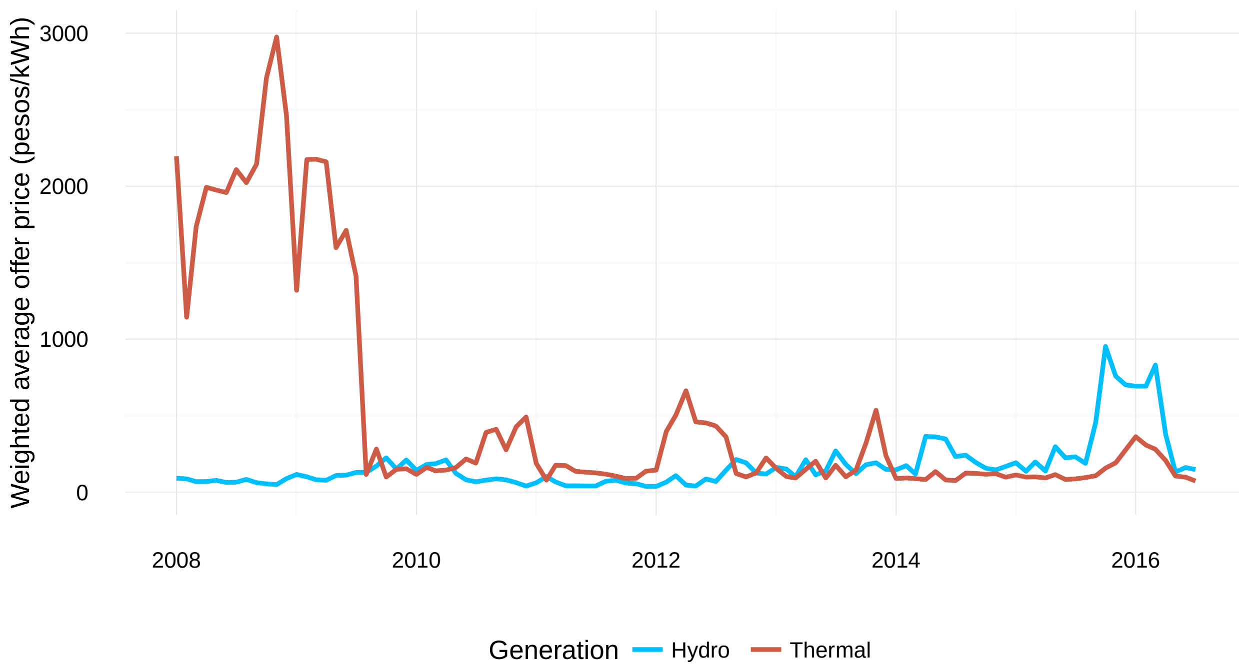



Figure 6.13: Monthly average offers by generation type—Isagen

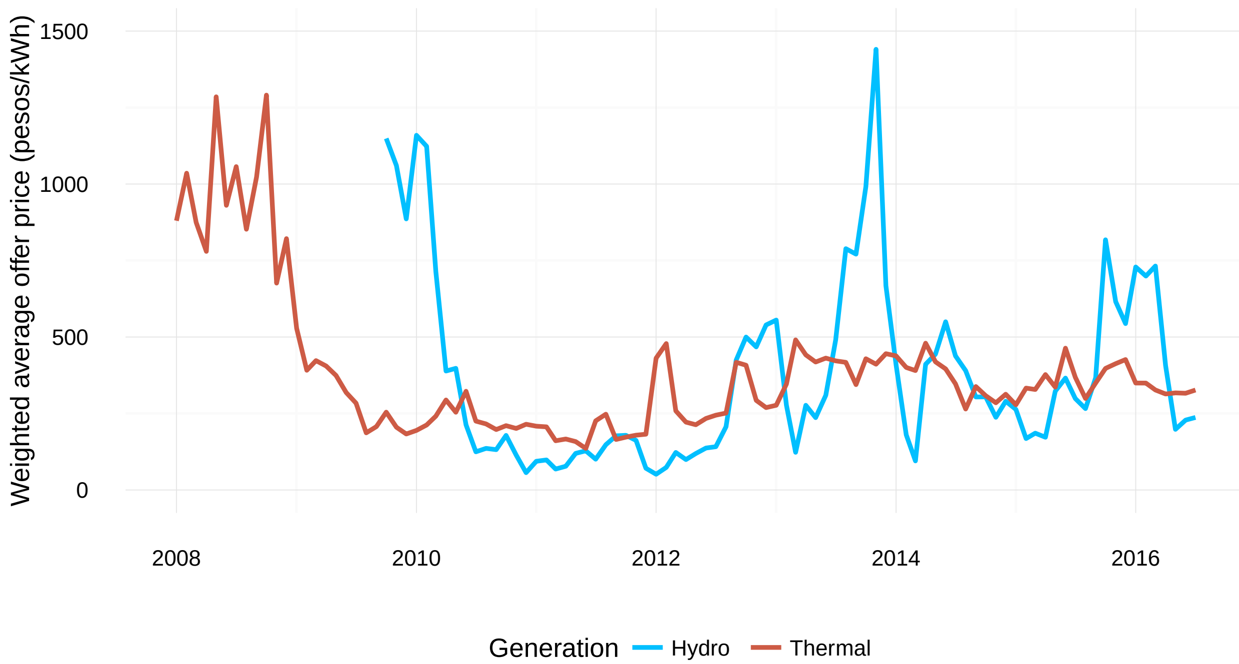



Figure 6.14: Monthly average offers by generation type—Celsia

# 7. Unilateral Market Power

This chapter provides an explanation for the dramatically higher prices during the 2015-2016 El Niño Event relative to the 2009-2010 El Niño Event in spite of the facts shown in Figures 3.1 and 3.2 that the water inflows in 2015 were similar to water inflows in 2009, and as shown in Figure 2.4, the capacity utilization of hydroelectric generation units was similar across the two El Niño periods and the capacity utilization of thermal generation units was only slightly higher during the 2015-2016 period. Our explanation for this difference in market outcomes can be traced to two factors. The first is the significantly smaller fraction of installed capacity available to the market during the 2015-2016 event versus the 2009-2010 event. The second is the massive increase in the ability of the largest suppliers in Colombia to exercise unilateral market power during the 2015-2016 event versus the 2009-2010 event.

## 7.1 Declining Availability Factor

Figure 2.3 demonstrates that virtually all generation capacity additions since 2010 have been hydroelectric generation units. Figure 2.1 demonstrates that electricity generation has continued to grow at steady rate from 2000 to 2016. However, a larger fraction of total generation is provided by thermal units. As shown in the latter third of Figure 2.1, this is particularly true for the post-2010 time period. One explanation for this is shown in Figure 3.6, which shows that the gap between the storage capacity in TWh of Colombia's hydroelectric units and the quarterly energy that can be produced from these generation units has steadily increased since 2010.

Figure 7.10 illustrates the implications of these facts. The black line at the top of the graph is the nameplate capacity of generation units in Colombia from 2008 to the present time. The brown line below it is the total availability of generation capacity in Colombia during the highest demand hour of the week. This is the sum of offer quantities at any offer price during the highest demand hour of that week. The yellow line below the brown line is the total availability during the highest demand hour of the week minus the availability in that hour of the supplier with the largest total availability during that hour. Note that the supplier whose total availability is subtracted from the system-wide availability is not always the same supplier each hour, because different suppliers have the maximum total availability during the different hours of the sample. The blue line that lies below the yellow line before 2014, except for a short time during the 2009-2010 El Niño period, is total system generation during this maximum demand hour of the week. Finally, the red line at the bottom is the positive difference between the blue line and the yellow line. Anytime this event occurs, the supplier with the larger total availability that hour of the week must supply some energy from the generation capacity it makes available or system demand will not be met. A supplier in this position is called "pivotal". As Figure 7.10 demonstrates, starting in 2014, the yellow "Availability N-1" line frequently falls below the blue "Max Demand" line, indicating that the supplier with the largest total availability during that hour has substantial ability to exercise unilateral market power. Specifically, if this supplier is willing to supply only its pivotal quantity of energy, the amount it must supply in order for system demand during that hour to be met, there is no limit to how high it can set the Bolsa price, because its offer must be accepted or demand will not be met given the offers of all other suppliers.

## 7.2 Measuring a Supplier's Ability to Exercise Unilateral Market Power

This section introduces two measures of the ability of a supplier in a bid-based wholesale electricity market to exercise unilateral market power. These measures depend on the hourly willingness-to-supply curves of all producers and the level of hourly demand. Before proceeding with this discussion, we first define unilateral market power and why exercising all available unilateral market power is equivalent to a privately-owned firm serving its fiduciary responsibility to its shareholders.

A market participant is said to possess the ability to exercise market power if it can take unilateral actions to influence the market price and to profit from the resulting price change. The demand side of most electricity markets is composed of many small buyers and the supply side is typically composed of a small number of large sellers. It is also relatively straightforward for a large supplier to withhold output from the short-term market, whereas it is extremely difficult, if not impossible, for a large demander to do this unless it curtails the consumption of the retail customers that it serves. Consequently, the primary market power concern in wholesale electricity markets is from suppliers taking actions to influence market prices.

It is important to emphasize that a supplier exercising all available unilateral market power subject to obeying the market rules is equivalent to that supplier taking all legal actions to maximize the profits it earns from participating in the wholesale market. Moreover, a firm's management has a fiduciary responsibility to its shareholders to take all legal actions to maximize the profits it earns from participating in the wholesale market. Consequently, a firm is only serving its fiduciary responsibility to its shareholders when it exercises all available unilateral market power subject to obeying the wholesale market rules.

A supplier to an auction-based wholesale electricity market submits a willingness-to-supply or offer curve which is composed of a series of offer steps for each pricing period. The length of the step specifies an incremental quantity of energy to be supplied and the height of the step is the price at which the supplier is willing to sell that quantity of energy. The Colombian market has 24 hourly pricing periods each day and suppliers are allowed to submit single price step for the entire day for a generation unit, but different hourly quantity steps for each unit. Figures 7.1 and 7.2 show the final offer curves submitted by Firm 1 and Firm 2 for a single hour. For the lowest-priced offer step, Firm 1 is willing to supply 920 MW at $0.03/MWh and if the market price increases to $60/MWh, it is willing to supply an additional 430 MW, and so on. As the offer price increases, the supplier's cumulative willingness to sell electricity increases along with the offer price, from 920 MW at $0.03/MWh to 1,350 MW at $60/MWh (= 920 MW at $0.03/MWh + 430 MW at $60/MWh). This increasing relationship between the offer price and the supplier's cumulative willingness to sell yields the upward sloping offer curves for each supplier shown in Figures 7.1 and 7.2. Let $S_k(p)$ denote the offer curve of supplier $k$. At each price $p$, this function gives the total quantity of energy that supplier $k$ is willing to sell.

The offer curves from each supplier can be used to construct the aggregate offer curve for any set of suppliers. This is done by calculating the cumulative quantity that the set of suppliers are willing to supply across the relevant range of prices. Let $S_{123}(p)$ equal the aggregate offer curve for firms 1, 2, and 3. In terms the individual offer curves, $S_{123}(p) = S_1(p) + S_2(p) + S_3(p)$, which means that $S_{123}(p)$ at price $p$ is equal to total amount of energy that firms 1, 2, and 3 are willing to supply at price $p$. Figure 7.3 shows the aggregate offer curve for Firm 1 and Firm 2 for the firm-level offer curves shown in Figures 7.1 and 7.2. At a price of \$200/MWh, for example, Firm 1 is willing to supply a total of 1,650 MW and Firm 2 is willing to supply 835 MW. Therefore, the aggregate offer of both firms at a price of \$200/MWh is 2,485 MW. Summing over all suppliers yields the aggregate offer curve given in Figure 7.4.

The Bolsa price is computed by taking the aggregate willingness-to-supply curve and solving for the price where this curve intersects the total demand. Define $S(p)$ as the aggregate willingness-to-supply curve for an hour. It is equal to $S_1(p) + S_2(p) + .. + S_K(p)$, where K is the total number of suppliers in Colombia. Let $QD$ equal the actual real-time demand. The Bolsa price is the solution in $p$ to the equation $S(p) = QD$. An example of this process is shown in Figure 7.5 for the same hour as in Figures 7.1 to 7.4. In this hypothetical hour, the total market demand is 4,400 MW and based on the aggregate offer curve for all the suppliers, the market price has to be at least \$120/MWh for there to be enough supply offers to meet this demand.

This description of the price-setting process allows a graphical description of how suppliers exercise unilateral market power in a bid-based wholesale market, which motivates our two measures of the ability of a supplier to exercise unilateral market power. To analyze the offer behavior of an individual supplier using this graphical framework, the above mechanism can be reformulated in terms of the supplier's own offer curve, the sum of the offers of other suppliers, and the total market demand. Specifically, the price setting equation $S(p) = QD$ can be re-written as: $S_1(p) + S_2(p) + .. + S_K(p) = QD$.

Suppose that we are interested in measuring the ability of supplier $j$ to exercise unilateral market power. This price-setting equation can be re-written as:

$$S_j(p) = QD - (S_1(p) + S_2(p) + ... + S_{j-1}(p) + S_{j+1}(p) + ... + S_K(p)) = QD - SO_j(p),$$

where $SO_j(p)$ is the aggregate willingness-to-supply curve of all firms besides supplier $j$. Define $DR_j(p) = QD - SO_j(p)$ as the residual demand curve facing supplier $j$. The residual demand of supplier $j$ at price $p$ is defined as the market demand remaining to be served by supplier $j$ after the willingness to supply curves of all other firms besides supplier $j$ have been subtracted from the market demand.

Figure 7.6 provides a graphical version of the above calculation of the residual demand for Firm 1 in the same hour. The total market demand is 4,400 MW and the total quantity offered by all suppliers other than Firm 1 is 3,350 MW at \$300 and 2,560 MW at \$50. Therefore, Firm 1's residual demand at \$300 is 1,050 MW (the market demand of 4,400 MW minus 3,350 MW of supply by other generators at that price). Its residual demand at \$50 is 1,840 MW (the market demand of 4,400 MW minus 2,560 MW of supply by other generators at that price). Figure 7.7 shows the residual demand curve resulting from performing this calculation for all possible prices for Firm 1 in this hour. Figure 7.8 combines Firm 1's residual demand curve from Figure 7.7 with Firm 1's offer curve from Figure 7.1. The point of intersection between these two curves defines the market-clearing price.

The residual demand curve that a supplier faces summarizes its ability to impact the market price through changes in its offer behavior, holding the offer behavior of other suppliers constant. A firm can choose to produce any price and generation quantity pair along its residual demand curve. For example, Figure 7.9 shows the residual demand curve for Firm 1 calculated above. The realized price was \$120/MWh and the quantity supplied by Firm 1 was 1,500 MW, which gives Firm 1 generation revenues of \$90,000 in the hour. However, if Firm 1 had reduced the amount of energy it supplied by 15 percent to 1,270 MW, this would have increased the market price to \$250/MWh. This price and quantity combination yields generation revenue of \$158,750, even though Firm 1 supplies less energy to the wholesale market at this substantially higher price.

As shown in Figure 7.9, Firm 1 could have increased the market price by 108% with a reduction in its quantity supplied of 15%. We define the ratio of the potential percentage increase in market price to the percentage reduction in quantity supplied as the inverse elasticity of the residual demand curve. In this case the inverse elasticity is 108/15 = 7.2. Higher values of the inverse elasticity mean that the supplier has greater ability to unilaterally change the market price. As noted above, a supplier's residual demand curve gives the set of feasible price/quantity pairs that it can choose from to maximize its profits. Firms in imperfectly competitive markets often speak of "pricing to take what competition gives them" or "pricing at what the market will bear". These statements can be interpreted as the firm choosing the price/quantity pair along its residual demand curve that maximizes its profits. In this sense, a supplier's residual demand curve shows the trade-off between a higher system price and lower generation quantity for the supplier because of supply responses of its competitors.

We can use this residual demand to define two measures of the ability of a supplier to exercise unilateral market power. The first is called the inverse semi-elasticity of the residual demand curve. Define $\eta_j$ for firm $j$ as;

$$\eta_{hj} = -\frac{1}{100}\frac{DR_{hj}(p_h)}{DR'_{hj}(p_h)}$$

where $DR_{hj}(p_h)$ is the value of firm $j$'s residual demand curve hour $h$ evaluated at the market-clearing price for hour h and $DR'_{hj}(p_h)$ is the slope of firm $j$'s residual demand curve during hour $h$ evaluated at the market-clearing price for hour h. $\eta_{hj}$ is equal to the \$/MWh increase in the market clearing price that would result from supplier $j$ reducing the amount of energy it sells in the short-term market during hour $h$ by one percent. A higher value of $\eta_{hj}$ implies a greater ability of a suppler to exercise unilateral market power. Graphically, the steeper the residual demand curve that supplier $j$ faces during hour $h$, the greater is supplier $j$'s unilateral ability to raise the Bolsa price by withholding output from the market and the larger is $\eta_{hj}$.

The second measure if the frequency that supplier $j$ is pivotal. Supplier $j$ is pivotal is the value of $DR_j(\infty)$, its residual demand at an infinite price, is greater than zero. In words, this means that the value of supplier $j$'s residual demand is positive for all possible prices. Alternatively, given the offers its competitors, supplier $j$ must produce a positive amount of energy regardless of the market-clearing price or system demand will not be met. One measure of the ability of a supplier to exercise unilateral market power is the fraction of hours in some time period when the supplier is pivotal. The higher the frequency that a supplier is pivotal, the greater is the supplier's ability to exercise unilateral market power.

To provide a graphical illustration of the change in a supplier's expected profit-maximizing offer curve when its ability to exercise unilateral market power changes, Figure 7.11 plots the residual demand curve faced by EPM and its offer curve at 6 pm on September 18, 2015, a few days before XM issued the first notice about low water levels on September 22, 2015. Figure 7.12 plots the residual demand curve faced by EPM and its offer curve for 6 pm on September 25, 2015, a few days after day after this notice was issued. Note the very flat residual demand curve faced by EPM on September 18 and the flat offer curve it submitted. On September 25, EPM's residual demand curve became much steeper and its offer curve became much steeper. The Bolsa price on September 25, was several times higher than on September 18, reflecting the much greater ability EPM had to exercise unilateral market power on that day. Figure 7.13 plots these same two curves for 6 pm on October 2, 2015. The residual demand curve during this hour is even steeper than the one at 6 pm on September 25, reflecting an even greater ability to exercise unilateral market power. EPM's offer curve is even steeper during this hour and the Bolsa price is even higher.

Note that residual demand curve for EPM in Figure 7.13 becomes vertical at a quantity greater than zero on October 2, 2015, but it intersects the vertical axis at a finite price on September 18 and September 25.

Therefore, consistent with our definition of a pivotal supplier, EPM is pivotal at 6 pm on October 2, 2015, but not at 6 pm on either of the other days.

This phenomenon is not just confined to EPM. Graphs of the residual demand curves and offer curves for 6 pm of the same days for Isagen and Emgesa are shown in Figures 7.14 to 7.16 for Isagen and Figures 7.17 to 7.19. In all cases, as the supplier's residual demand curve gets steeper, indicating a greater ability to exercise unilateral market power, its offer curve becomes steeper and the Bolsa price increases. Note that both Isagen and Emgesa are also pivotal on October 2, 2015, but they are not pivotal on September 18 or September 25, 2015. Consequently, the inverse semi-elasticity measure and the pivotal supplier measure both indicate that on October 2 at 6 pm, EPM, Isagen and Emgesa possess a substantial ability to exercise unilateral market power. The steepness of their offer curves on those days imply that each of these firms took this knowledge into account in formulating their offer curves for the day.

### 7.2.1 Explaining the Difference between 2009-2010 and 2015-2016

This section uses the two measures of the ability of supplier to exercise unilateral market power to explain the far more extreme market outcomes during the 2015-2016 El Niño Event versus the 2009-2010 Event. Specifically, we find that both measures of the ability to exercise unilateral market power show a massive increase in the ability of the large suppliers in Colombia to exercise unilateral market power starting in October 2015 and lasting through the Spring of 2016. This substantially greater ability to exercise unilateral market power is reflected in the much higher market clearing prices during this time period. As shown in Tables 6.1 and 6.2, during a significant fraction of the days during scarcity conditions, the Firm Energy value of RPM provides large suppliers with an incentive to use their ability to exercise unilateral market power during the scarcity period to raise the Bolsa price much higher than the Scarcity Price.

The top panel of figure 7.20 plots the average weekly value of $\eta_{hj}$ for EPM from January 2008 to June 2016. The middle panel plots the fraction of hours in each week that EPM is pivotal. The bottom panel plots the average weekly value of the highest accepted hourly offer price for EPM. The highest accepted hourly offer price is the highest offer price that has a positive value for Ideal Generation during that hour. Although there is a very small frequency that EPM is pivotal during the 2009-2010 El Niño period, there is very little evidence that EPM had much of an ability to exercise unilateral market power during this time period. Consistent with this evidence, EPM's maximum accepted offer prices only increase slightly during the 2009-2010 El Niño period.

During the 2015-2016 El Niño period there is a massive increase in the average weekly values of $\eta_{hj}$ and an equally large increase in the fraction of hours in the week that EPM is pivotal to almost 60 percent of hours starting in October 2015. This is accompanied by an enormous increase in the maximum accepted offer prices submitted by EPM starting at the same time. The results for Isagen in Figure 7.21 and Emgesa in Figure 7.22 are quantitatively similar to the results for EPM, except that the differences between the unilateral ability measures for the 2009-2010 and 2015-2016 event are more stark. Both Isagen and Emgesa are rarely pivotal and have very small values of $\eta_{hj}$ during the 2009-2010 El Niño Event, and both experience substantial increases in the values of $\eta_{hj}$ starting in October 2015. Again, the maximum accepted offer prices for these suppliers during the 2009-2010 period only increase slightly, whereas they more than quadruple starting in October 2015. Even the smaller firms such as AES Chivor in Figure 7.23 and Gecelca in Figure 7.24 show a similar qualitative pattern, virtually no ability to exercise unilateral market power during the 2009-2010 El Niño Event period and a significant increase during the 2015-2016 period.

Table 7.1 provides a quantitative analysis of the relationship between market prices and our measures of the ability of firms to exercise market power. The table shows the result of regressing the Bolsa price each hour on the mean of the $\eta_{hj}$ across the six major firms, the mean pivotal indicator across the six firms, or the mean pivotal quantity across the six firms. All of the regressions also include very flexible controls for the system load and the month of the sample. These controls account for changes in fuel prices, system demand, and hydrological conditions over our sample period. The first three columns show results for regressions in which the three market power ability measures are included separately. The final column shows the results for a regression that includes all three measures. All of the ability measures have a very precisely estimated positive relationship with the market price, with the exception of the mean pivotal indicator when this is included with the other two measures.

These results are supported by the analysis in Table 7.2. This table shows separate regressions for each of the six major firms. The dependent variable in these regressions is the offer price for the firm each hour, defined as the highest offer price for a unit owned by that supplier with non-zero ideal generation. This is regressed on the firm $\eta_{hj}$ and the firm pivotal indicator. The $\eta_{hj}$ have a very precisely estimated positive relationship with the offer price of each firm, as do the pivotal indicators in four of the six regressions. All of these results provide strong systematic evidence that our measures of market power are capturing the ability of suppliers to raise maket pries.

The results in this section provide strong evidence in favor of the view that the massive increase in market prices during the 2015-2016 El Niño Event period relative to the 2009-2010 period was the result of a tremendous increase in the ability of suppliers to exercise unilateral market power during the 2015-2016 period that was not present during the 2009-2010 period. These results clearly call into question the effectiveness of the RPM as a mechanism for limiting the ability of suppliers to exercise unilateral market power during El Niño and ensure a reliable supply of electricity at a reasonable price.

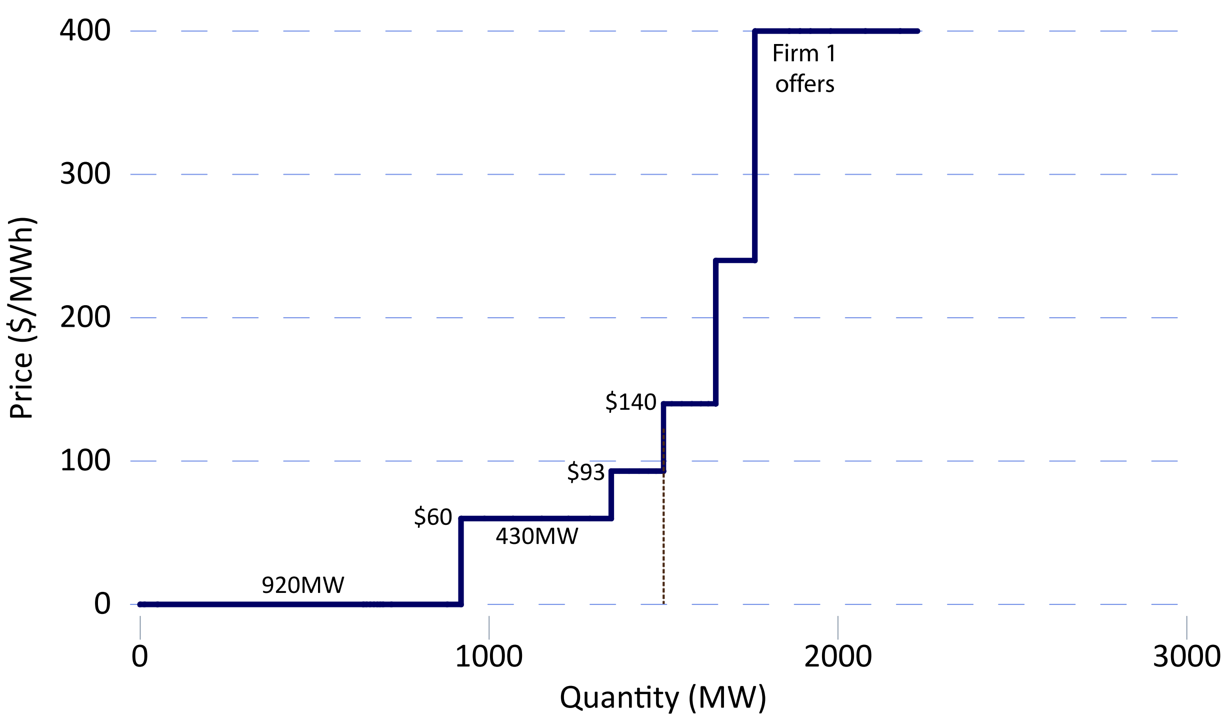



Figure 7.1: Offer curve for Firm 1 for a peak period

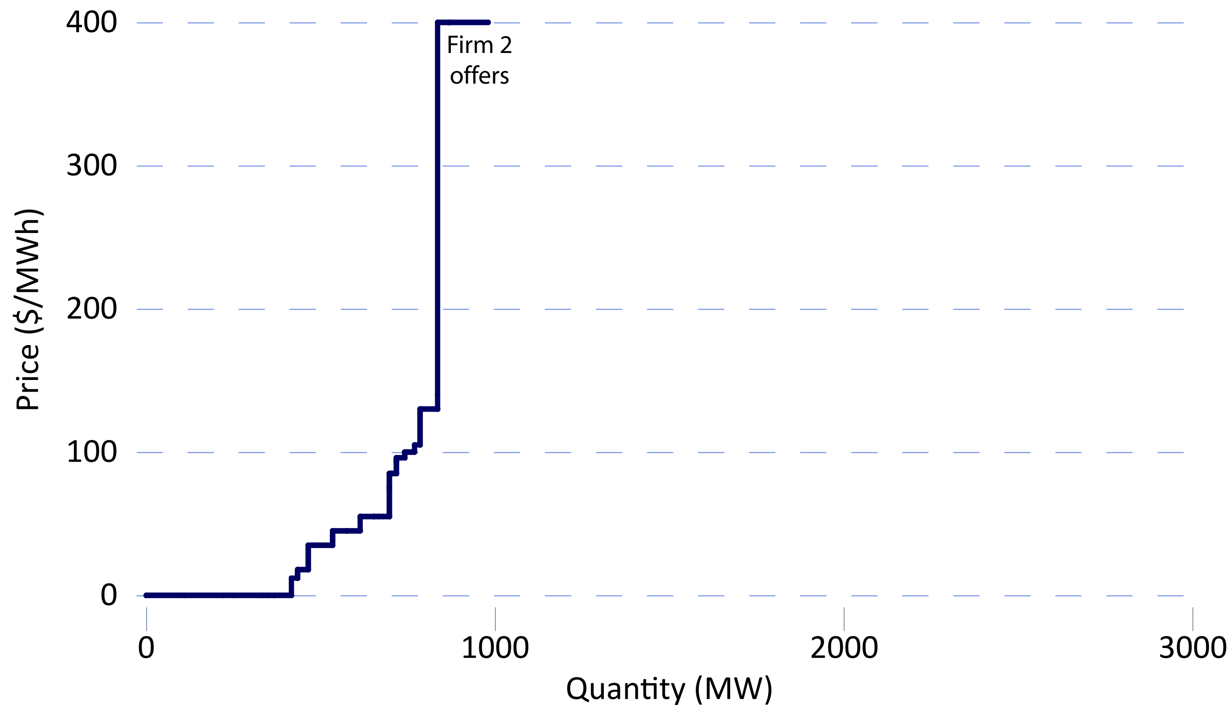



Figure 7.2: Offer curve for Firm 2 for a peak period

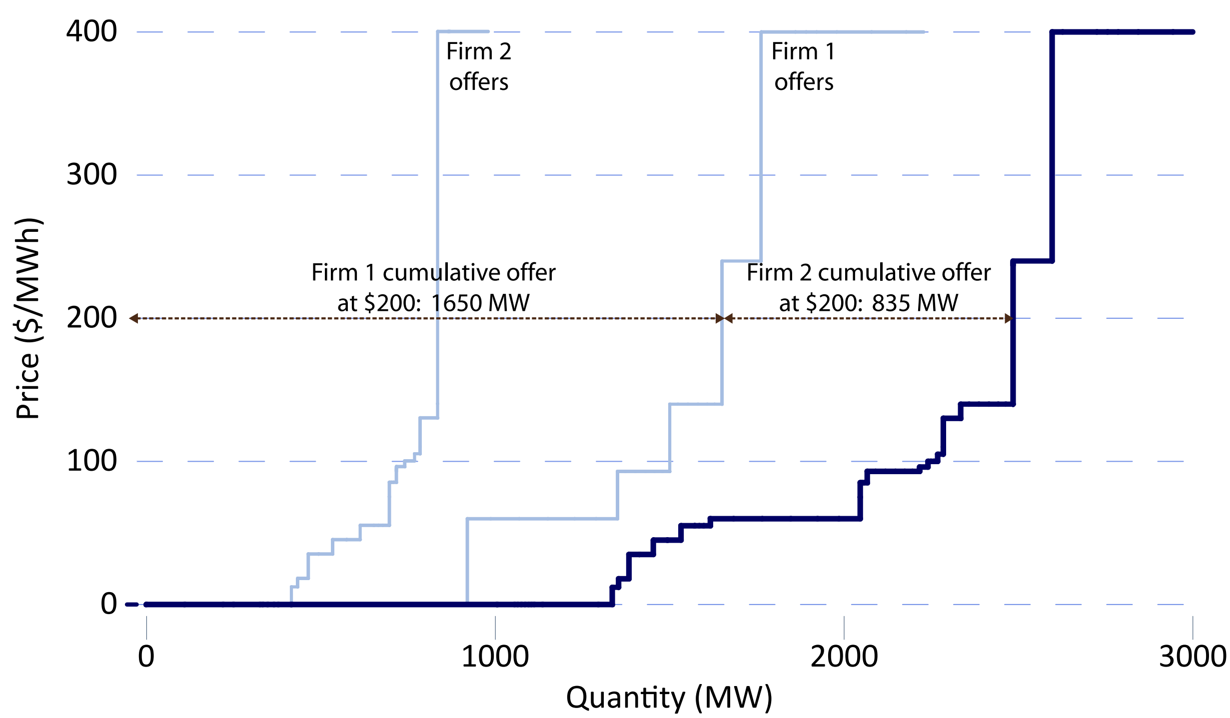



Figure 7.3: Combined offer curve for Firms 1 and 2 for the period

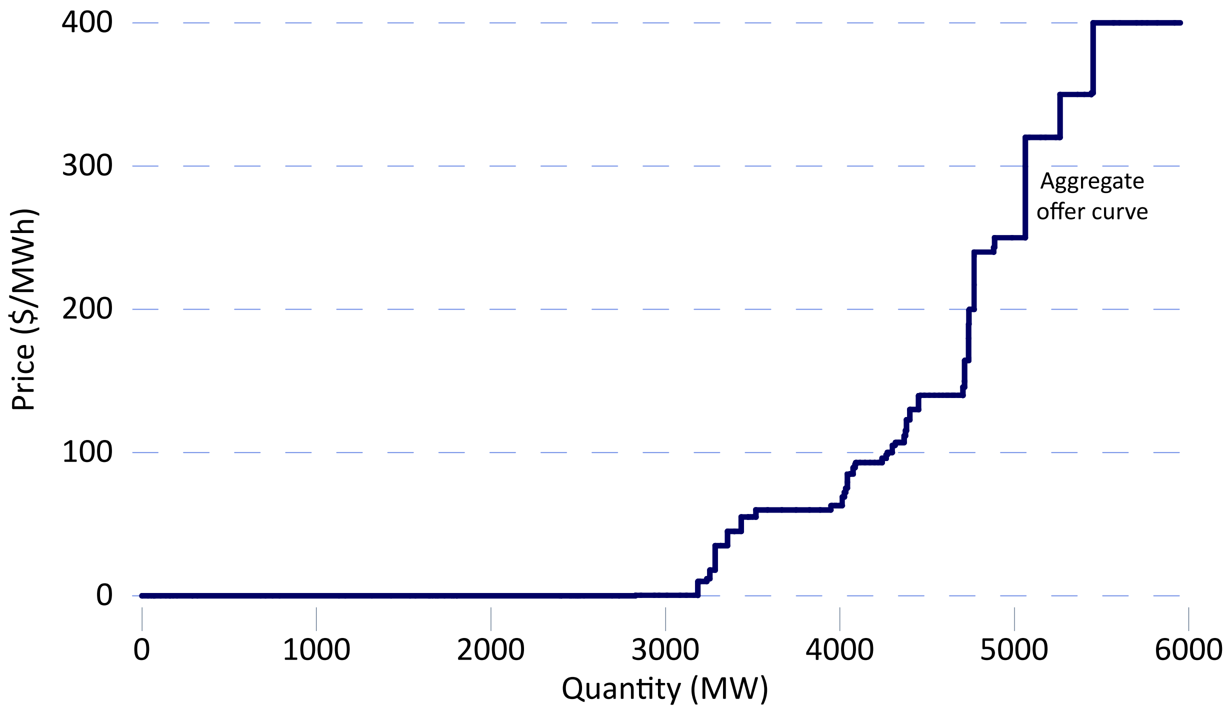



Figure 7.4: Aggregate offer curve for all generators for the period

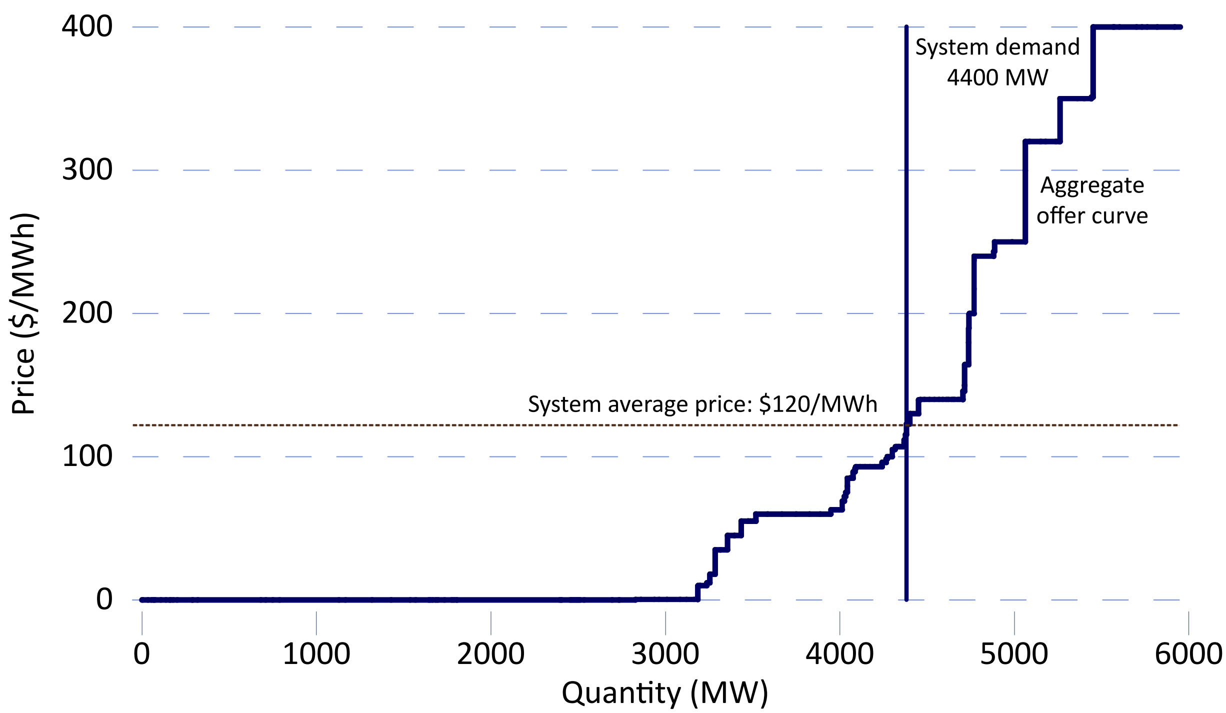



Figure 7.5: Calculation of system price

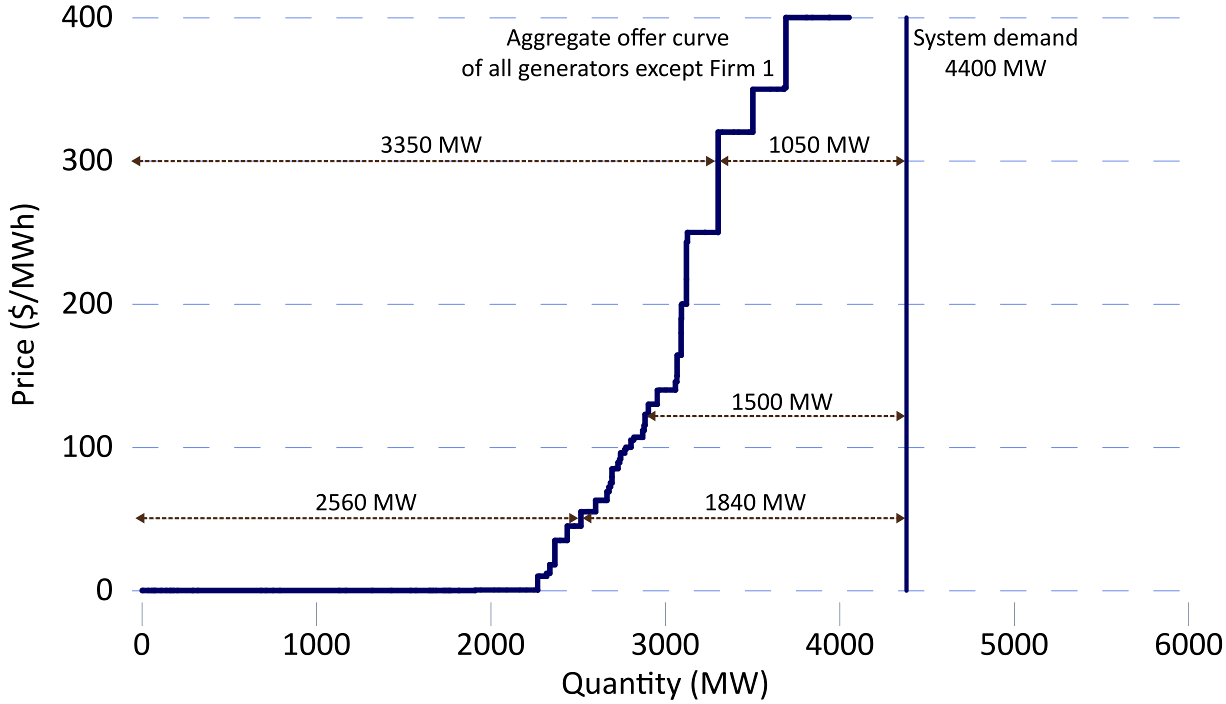



Figure 7.6: Calculation of residual demand for Firm 1

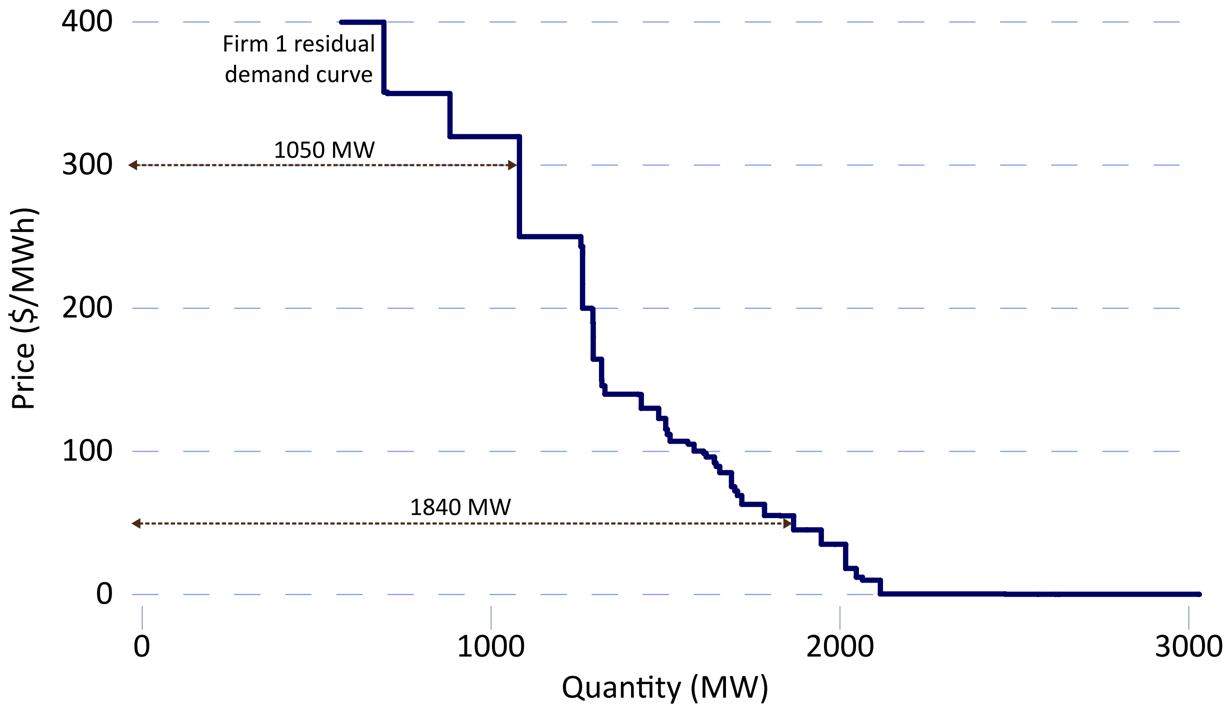



Figure 7.7: Calculation of residual demand for Firm 1

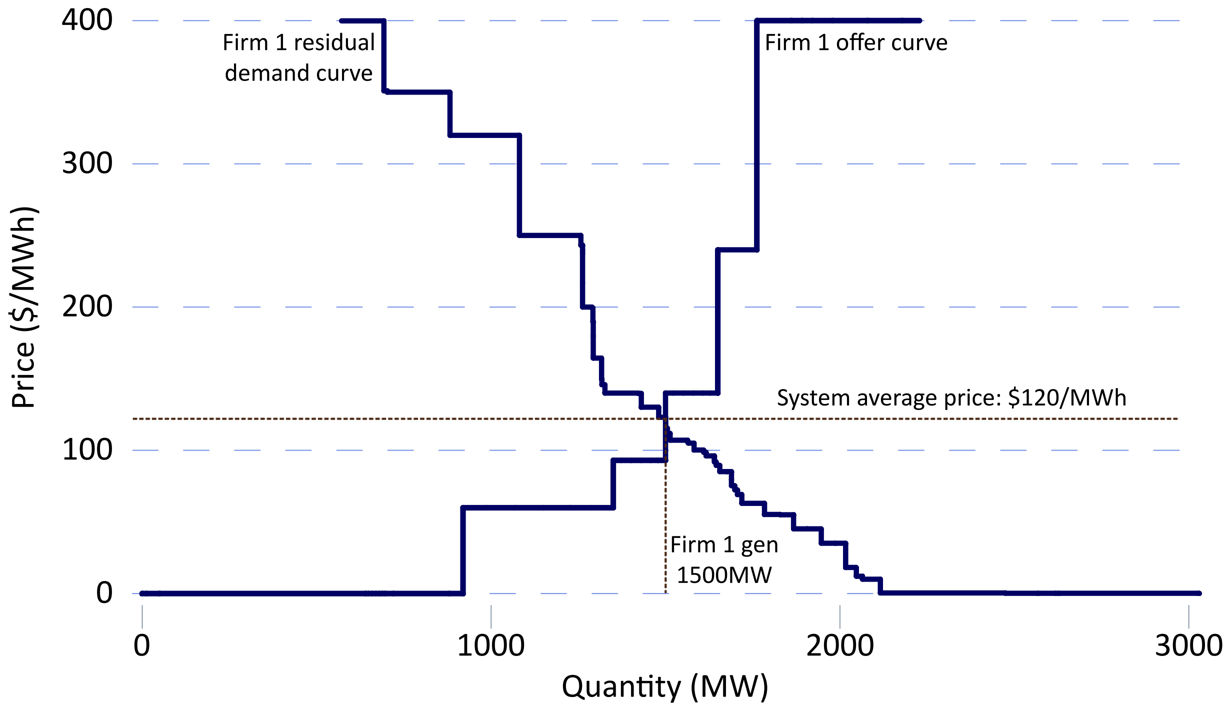



Figure 7.8: Residual demand and offer curve for Firm 1

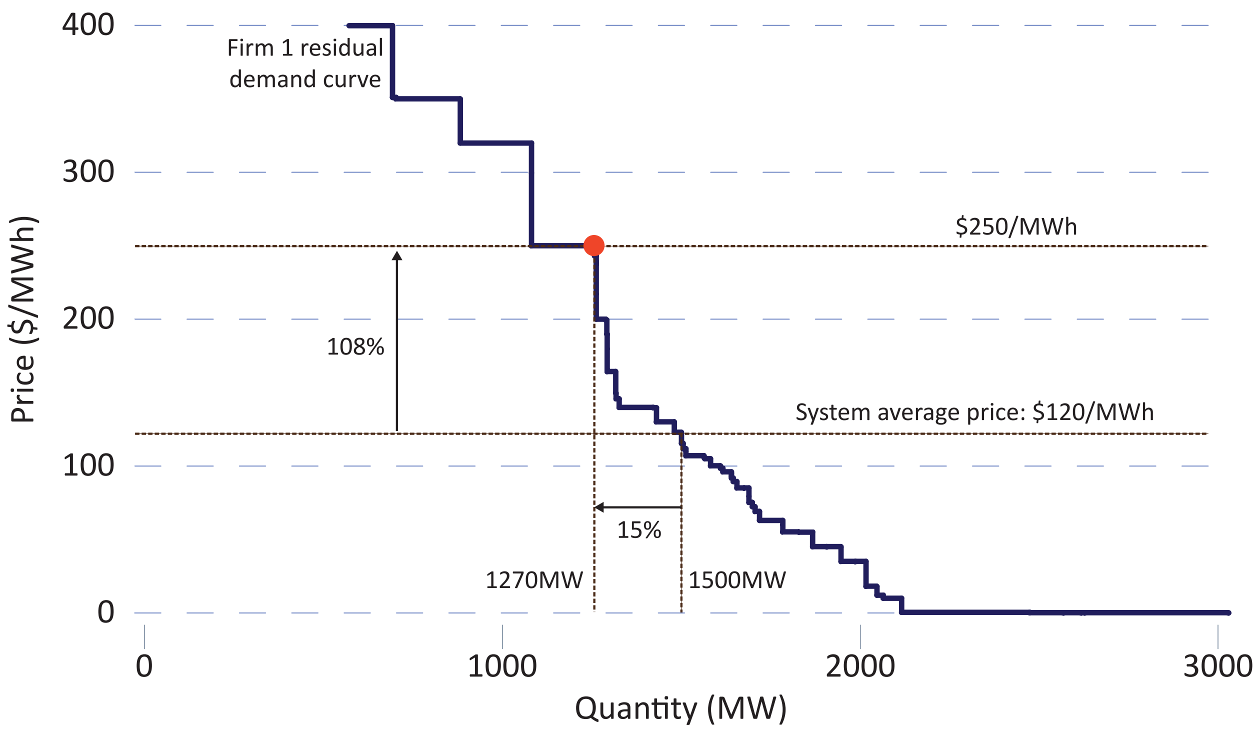



Figure 7.9: Calculation of inverse elasticity from residual demand curve

Table 7.1: Bolsa price and measures of ability to exercise market power

| | Bolsa price (COP/kWh) | | | |
|---|---|---|---|---|
| | (1) | (2) | (3) | (4) |
| Mean $\eta$ | 18.15*** | | | 11.90*** |
| | (6.16) | | | (3.44) |
| Mean pivotal indicator | | 858.22*** | | 200.12 |
| | | (246.13) | | (138.19) |
| Mean pivotal quantity (MW) | | | 1.70*** | 1.26*** |
| | | | (0.21) | (0.18) |
| Hour × year | Y | Y | Y | Y |
| Month-of-sample | Y | Y | Y | Y |
| Gen bin × year | Y | Y | Y | Y |
| Observations | 73,742 | 73,742 | 73,742 | 73,742 |
| Adjusted $R^2$ | 0.84 | 0.86 | 0.86 | 0.87 |

*Notes:* The dependent variable in each regression is the bolsa price in one hour. The three explanatory variables are the hourly mean of $\eta$, an indicator for being pivotal, and the pivotal quantity, across the six largest firms (EPM, Emgesa, Isagen, Celsia, AES Chivor and Gecelca). All regressions include interaction terms for hour-by-year, binned-generation-by-year, and month-of-sample. The generation bins are 50 indicators for the level of aggregate generation.

Table 7.2: Offer price and measures of ability to exercise market power

| | Offer price at dispatch quantity (COP/kWh) | | | | | |
|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) | (6) |
| $\eta$ | 8.81** | 14.18*** | 3.18* | 6.59*** | 5.19*** | 6.55*** |
| | (3.84) | (5.44) | (1.79) | (1.92) | (1.57) | (2.21) |
| Pivotal (0/1) | 442.72*** | 337.58*** | 58.51 | 129.20*** | 123.19*** | −28.29 |
| | (23.07) | (99.58) | (73.09) | (44.95) | (18.34) | (115.87) |
| Generator | Celsia | AES Chivor | Emgesa | EPM | Gecelca | Isagen |
| Hour × year | Y | Y | Y | Y | Y | Y |
| Month-of-sample | Y | Y | Y | Y | Y | Y |
| Gen bin × year | Y | Y | Y | Y | Y | Y |
| Observations | 58,894 | 46,765 | 73,407 | 73,649 | 51,948 | 73,188 |
| Adjusted $R^2$ | 0.63 | 0.75 | 0.70 | 0.76 | 0.44 | 0.72 |

*Notes:* Each column shows a separate regression for each generation firm. The dependent variable is the highest accepted offer price for the generation firm in that hour (the offer at a plant with non-zero ideal generation). All regressions include interaction terms for hour-by-year, binned-generation-by-year, and month-of-sample.

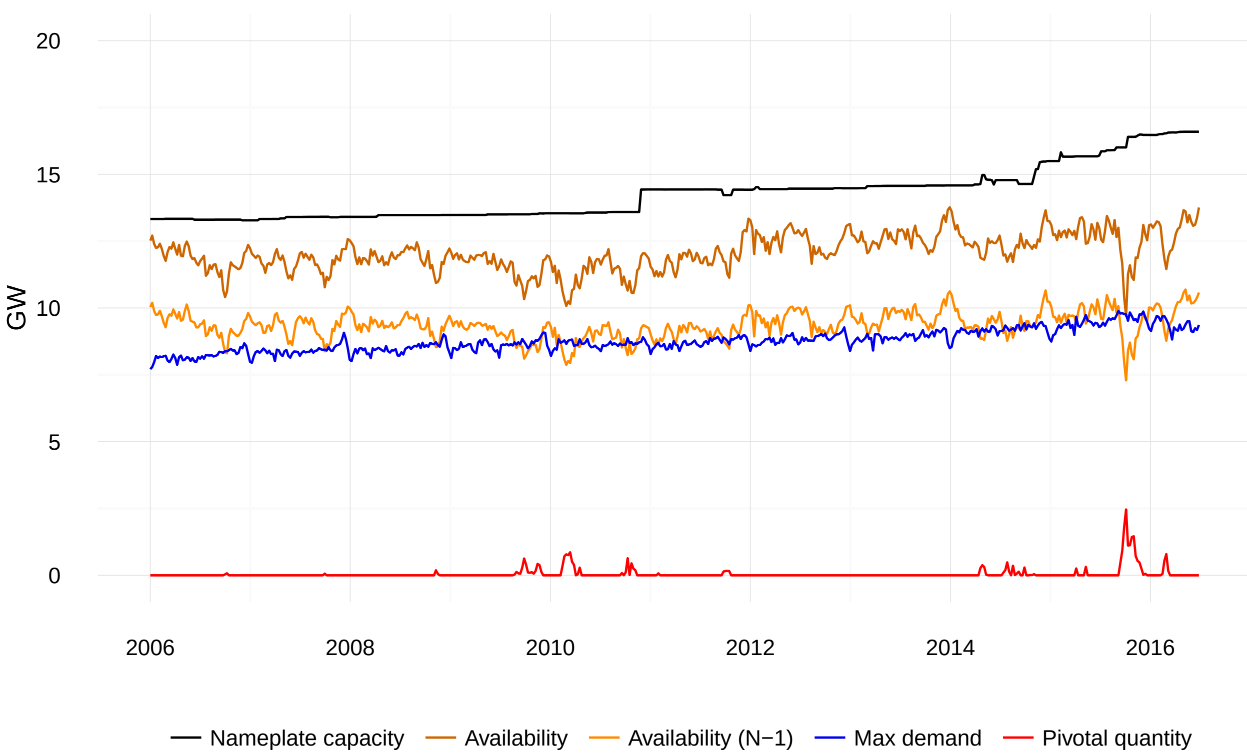



Figure 7.10: Generation availability on highest demand hour of each week, 2006–16

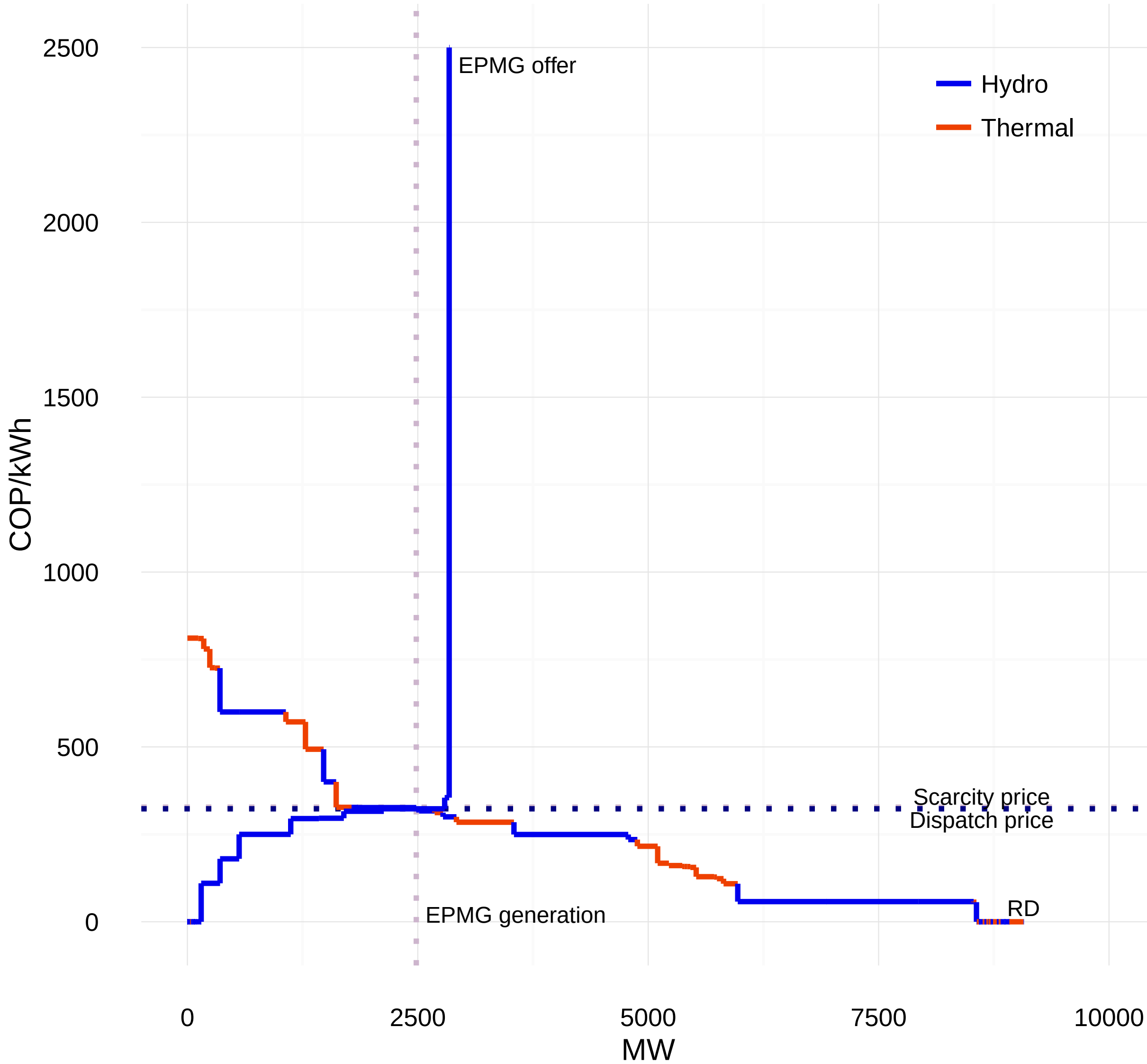



Figure 7.11: Offer curve and residual demand at 6:00PM on September 18, 2015—EPM

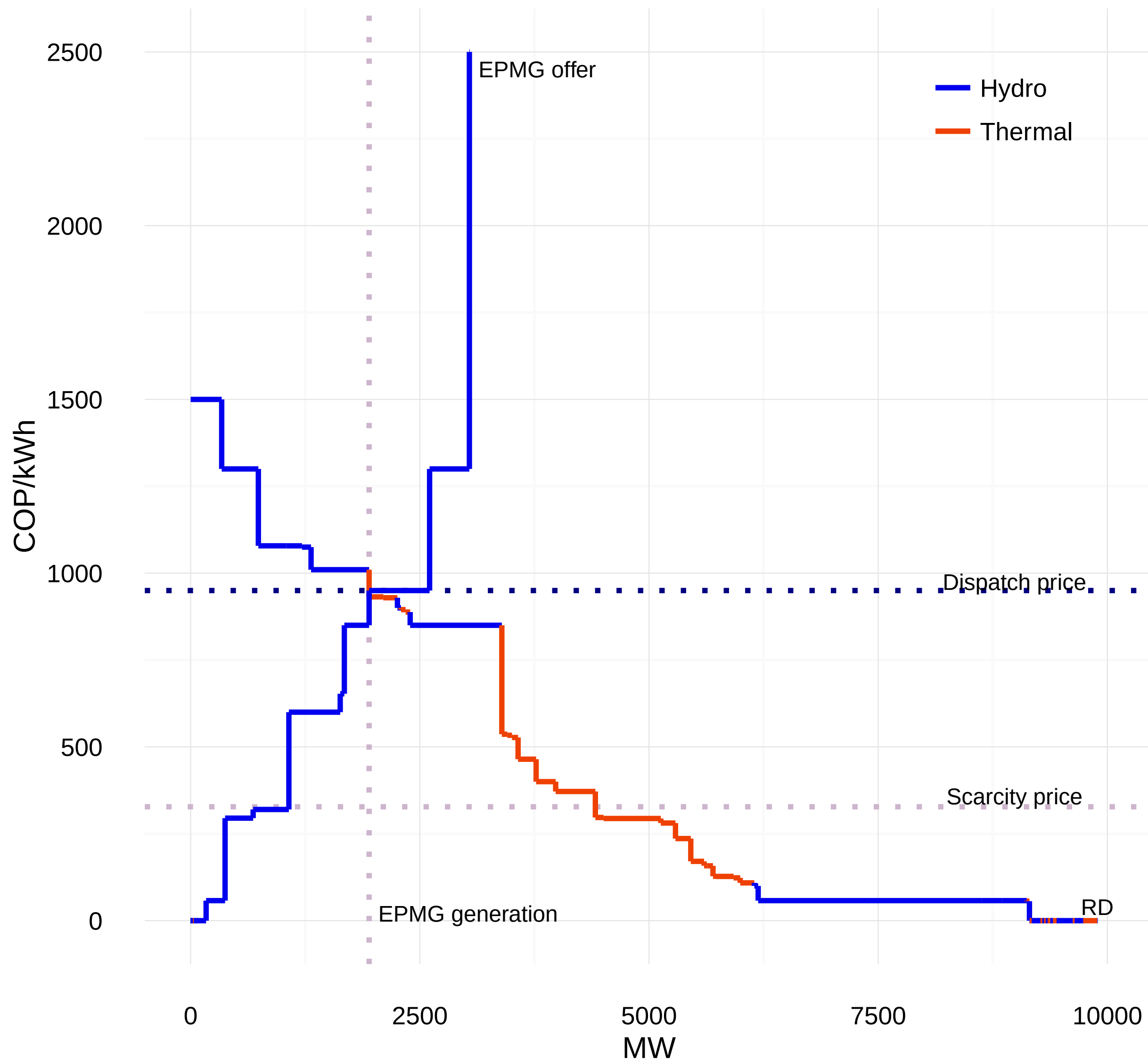



Figure 7.12: Offer curve and residual demand at 6:00PM on September 25, 2015—EPM

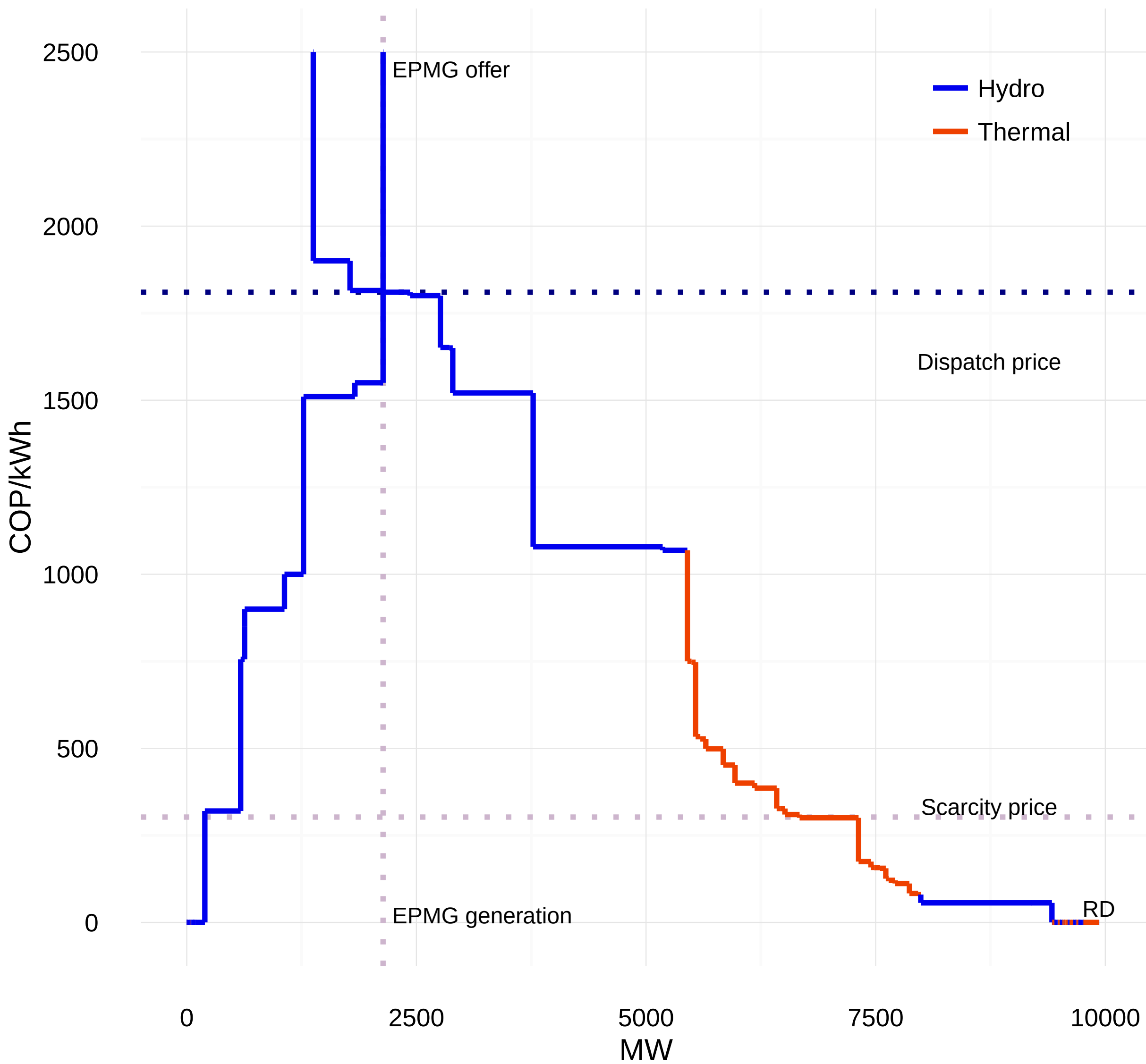



Figure 7.13: Offer curve and residual demand at 6:00PM on October 2, 2015—EPM

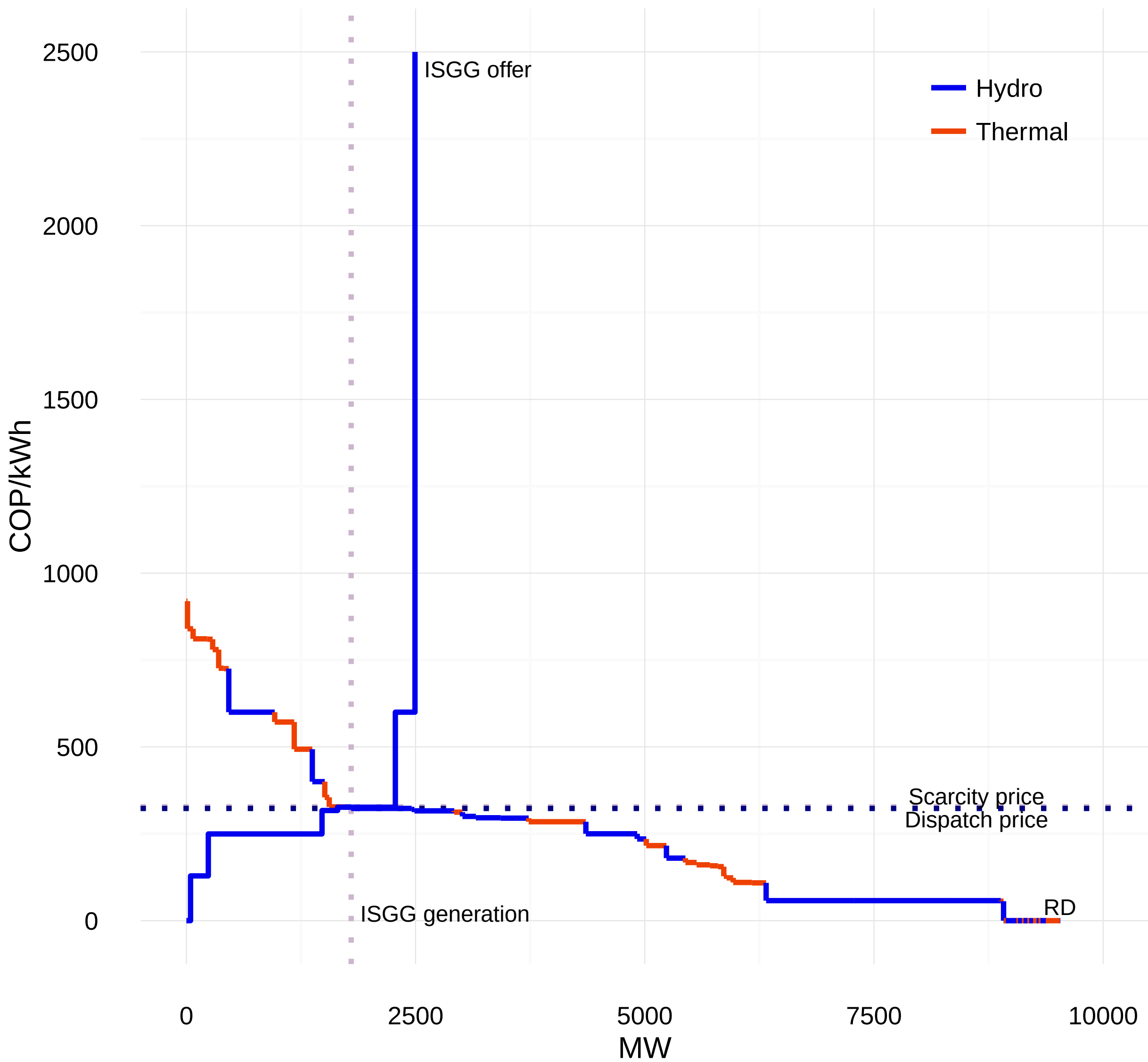



Figure 7.14: Offer curve and residual demand at 6:00PM on September 18, 2015—Isagen

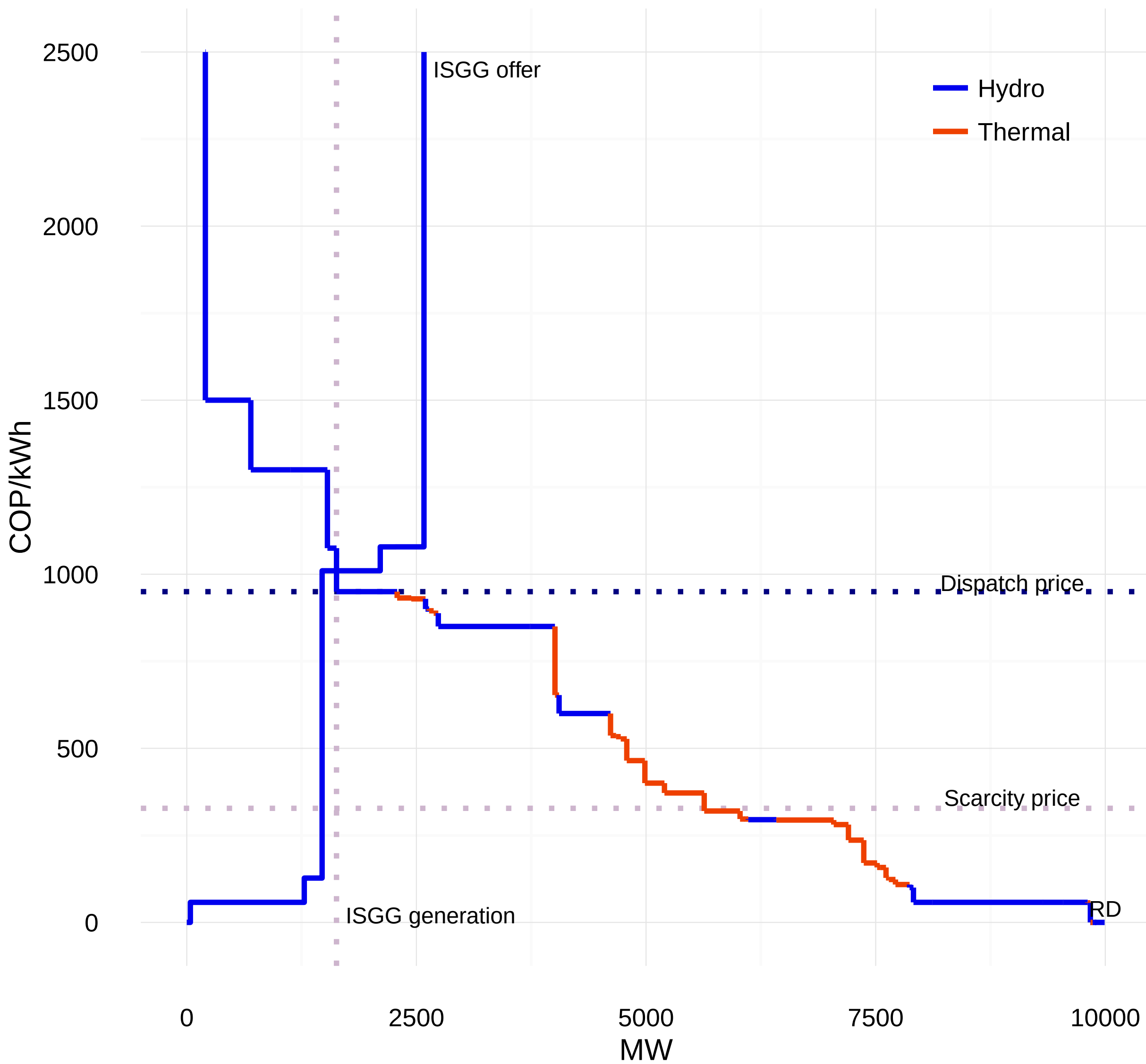



Figure 7.15: Offer curve and residual demand at 6:00PM on September 25, 2015—Isagen

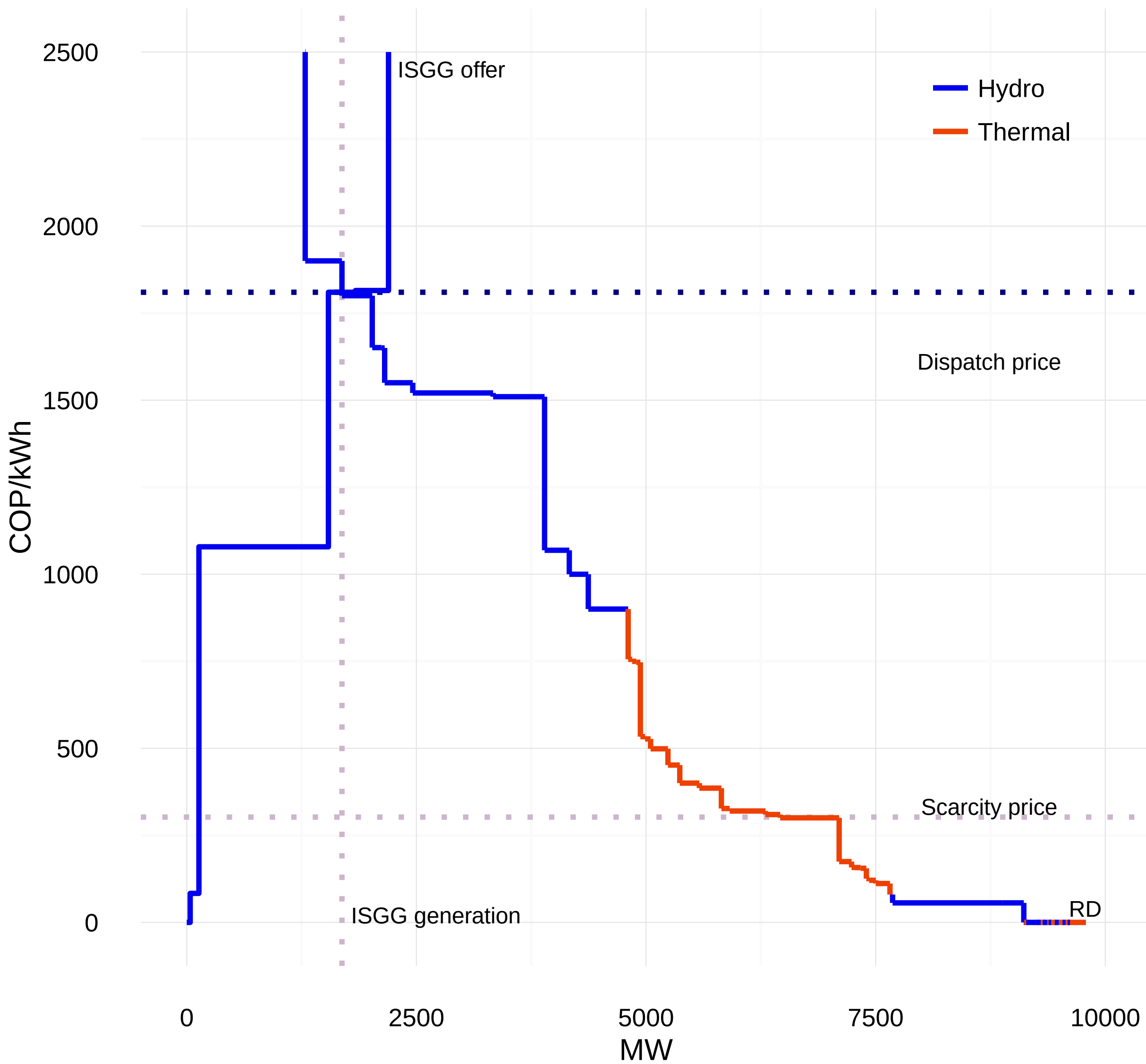



Figure 7.16: Offer curve and residual demand at 6:00PM on October 2, 2015—Isagen

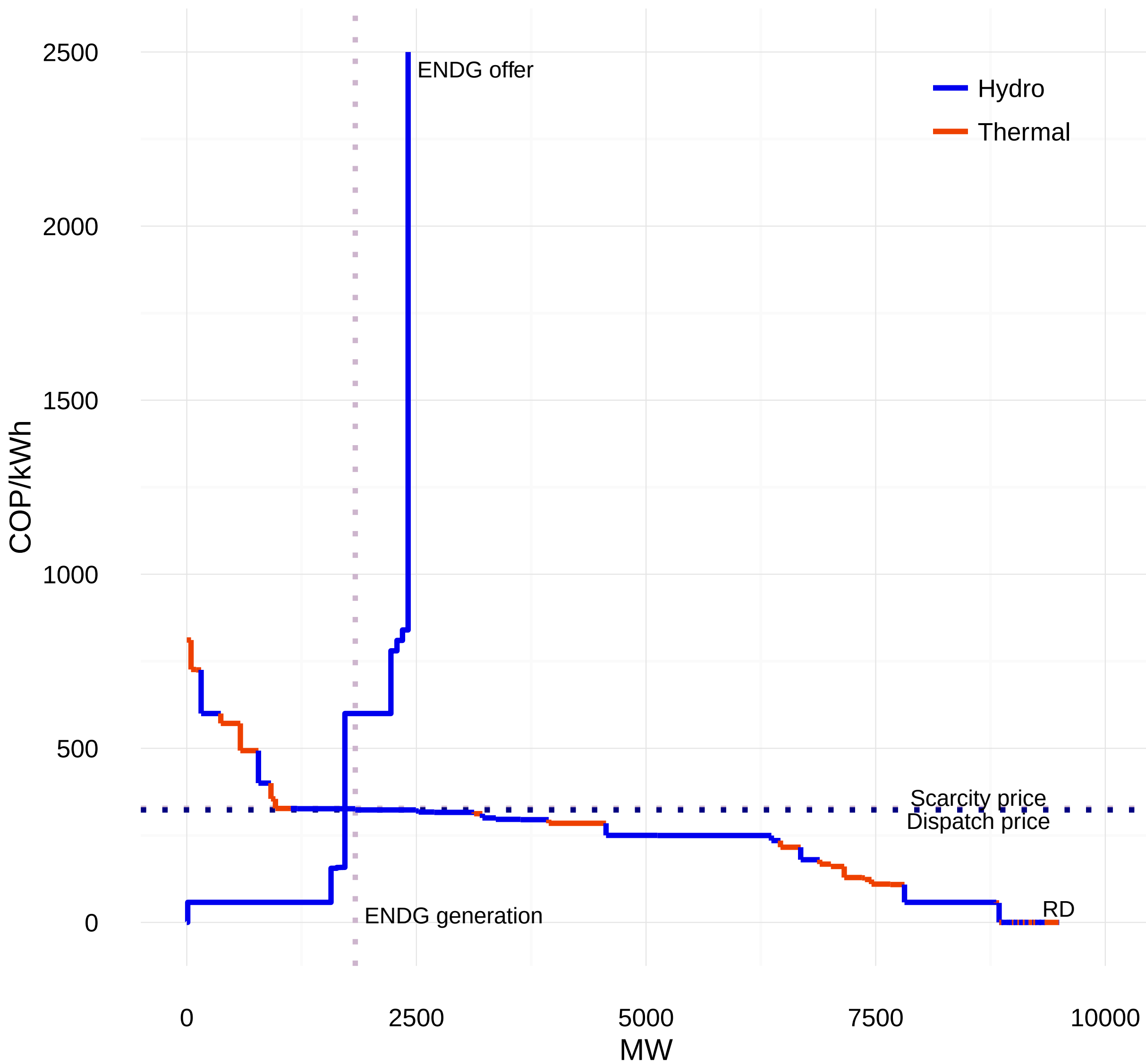



Figure 7.17: Offer curve and residual demand at 6:00PM on September 18, 2015—Emgesa

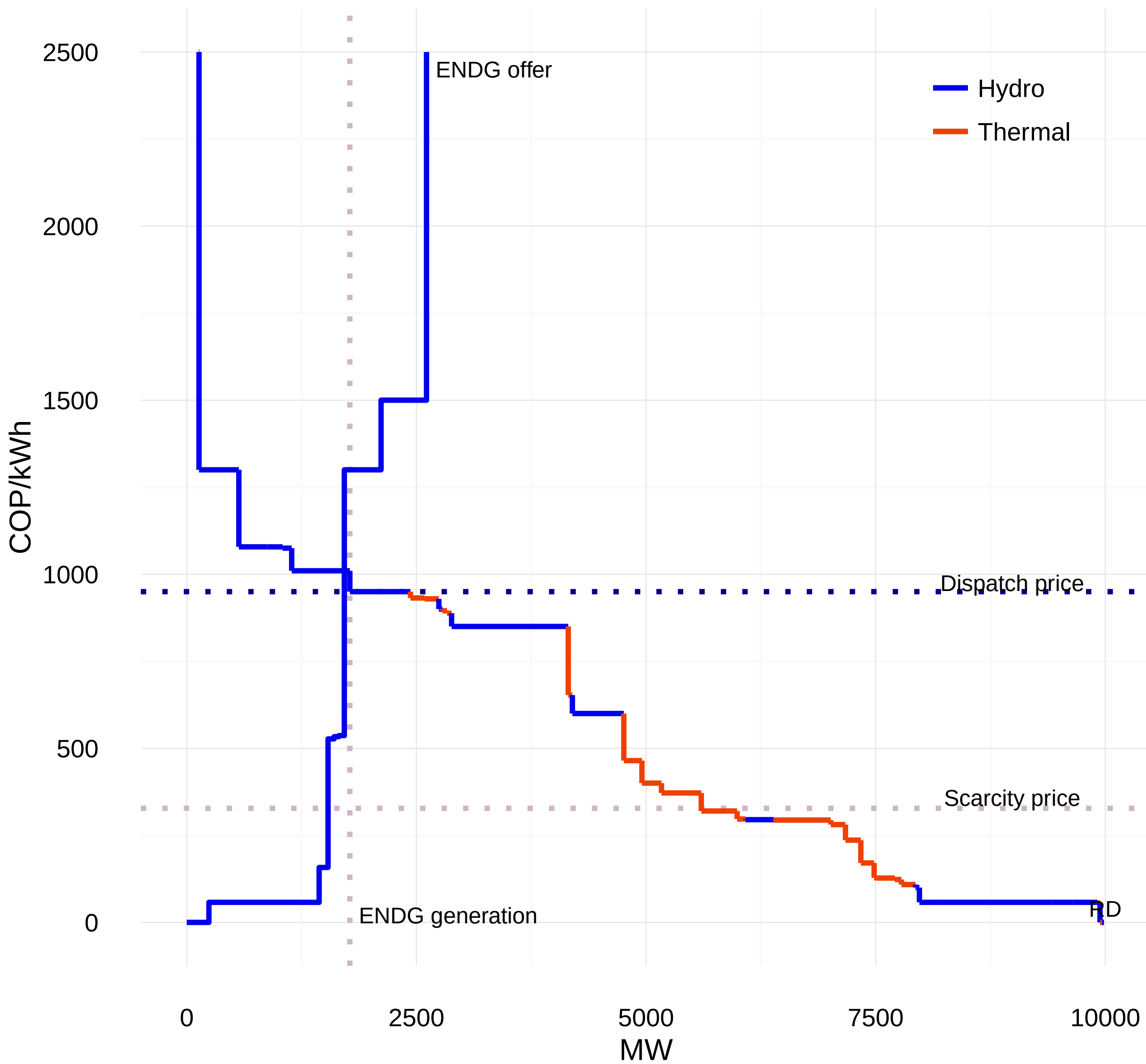



Figure 7.18: Offer curve and residual demand at 6:00PM on September 25, 2015—Emgesa

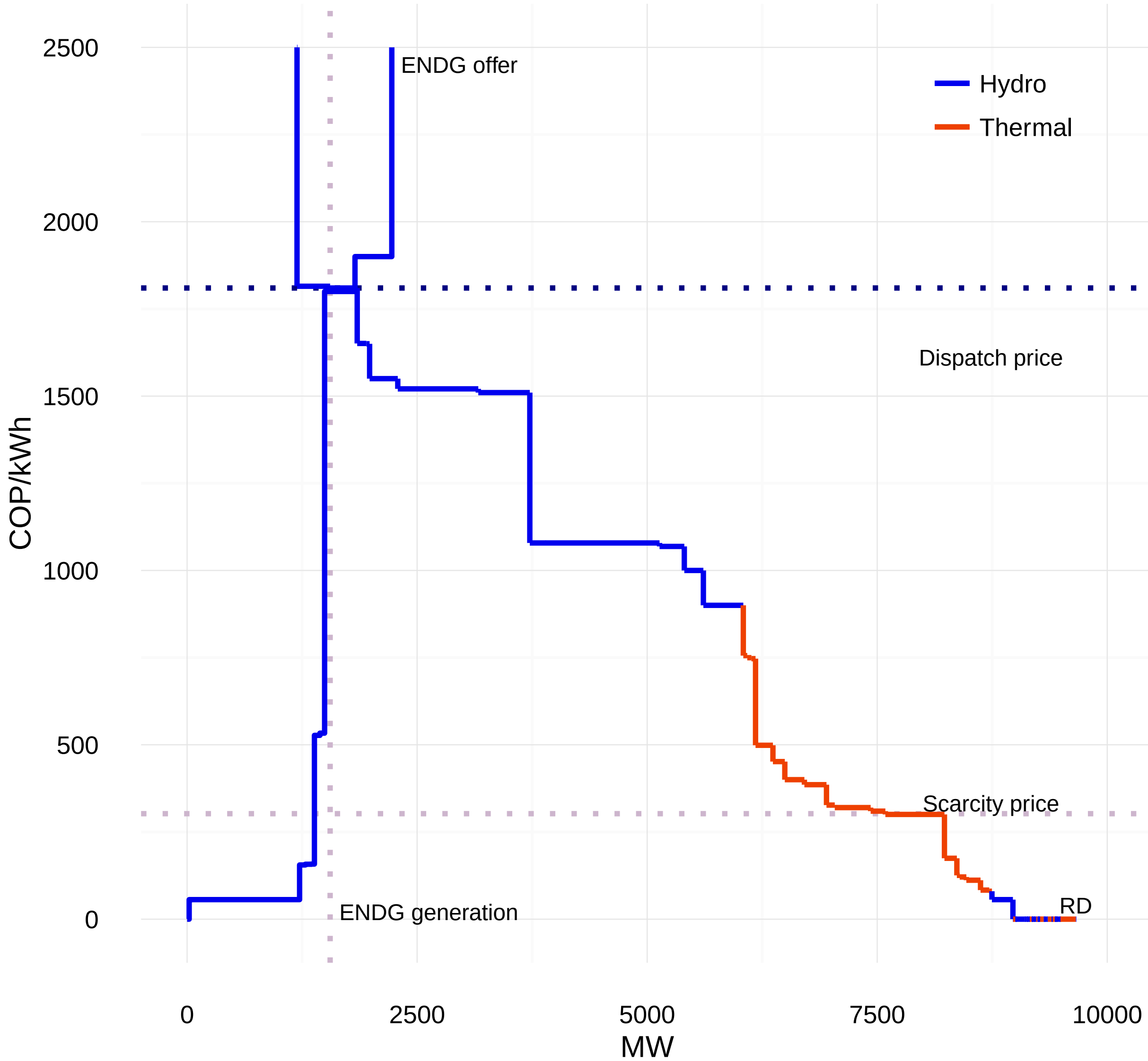



Figure 7.19: Offer curve and residual demand at 6:00PM on October 2, 2015—Emgesa

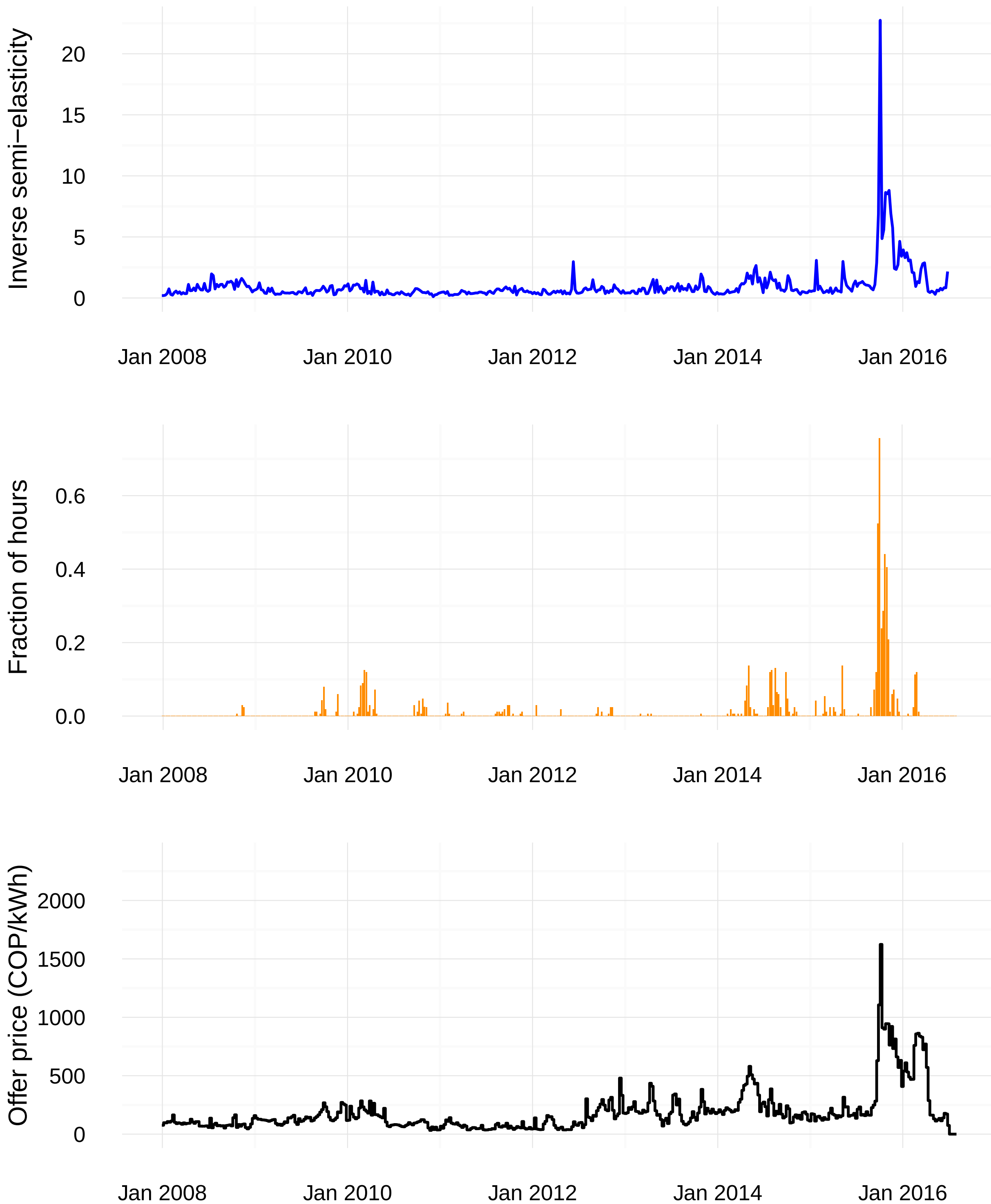



Figure 7.20: Offer prices and market power measures—EPM

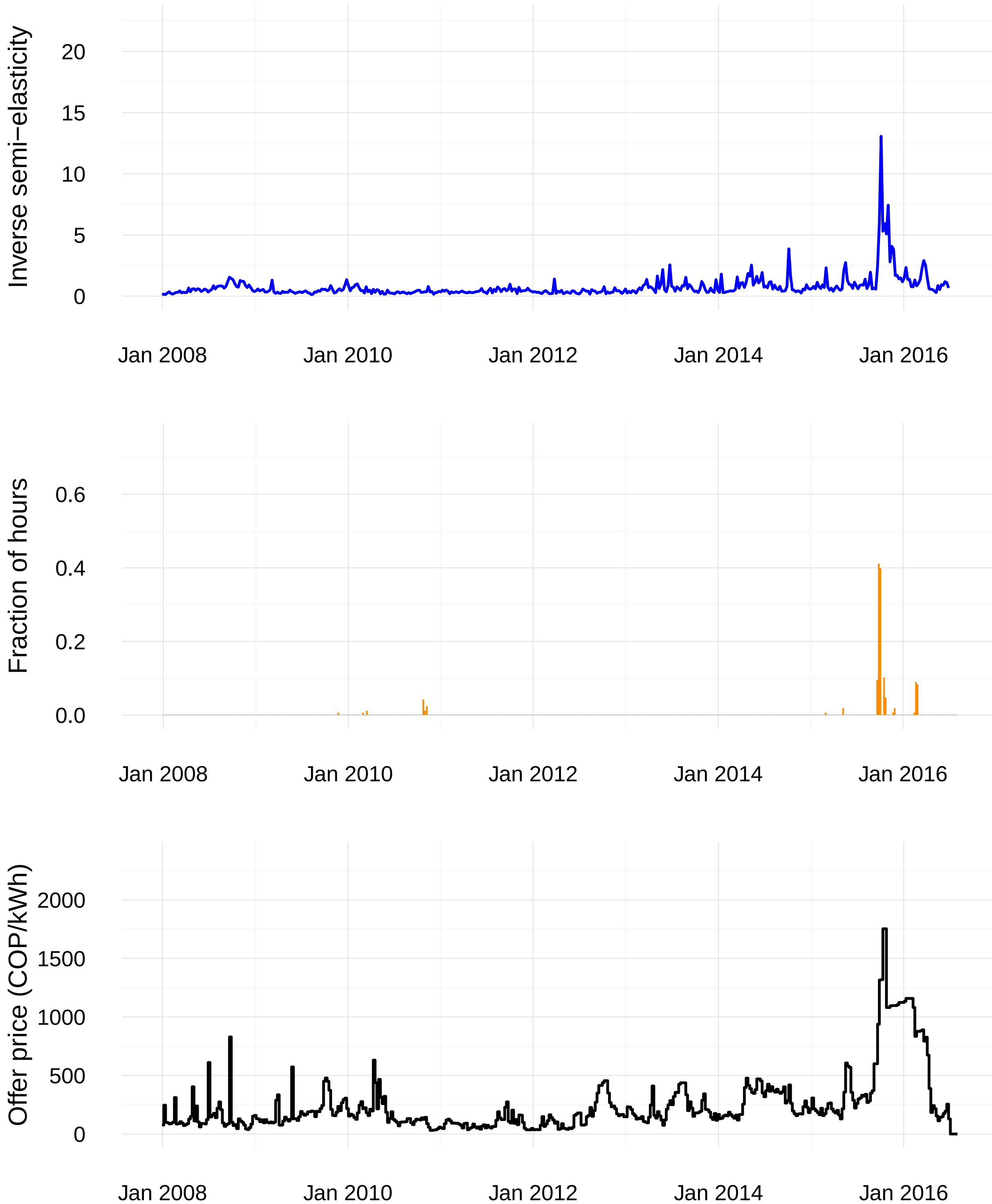



Figure 7.21: Offer prices and market power measures—Isagen

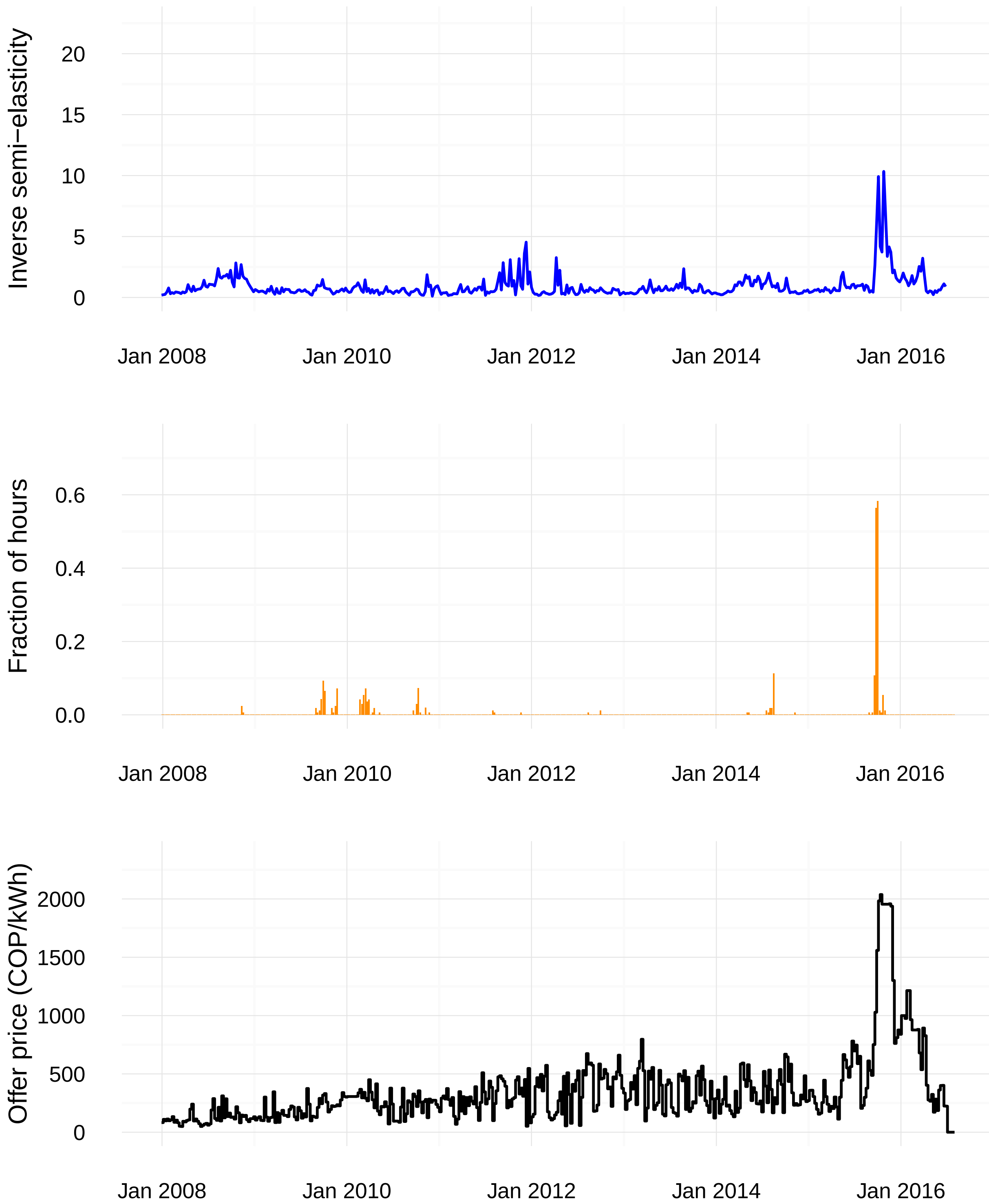



Figure 7.22: Offer prices and market power measures—Emgesa

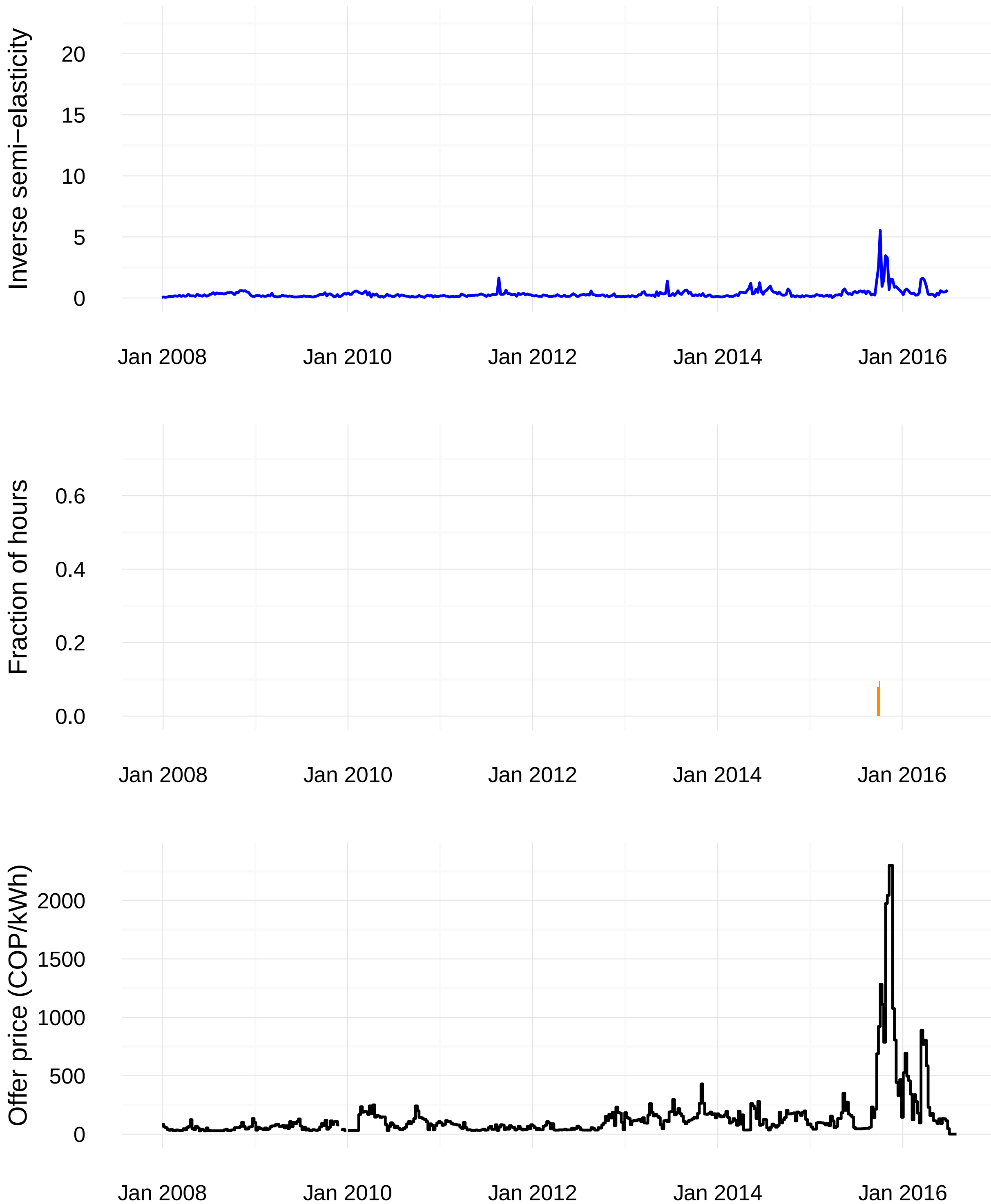



Figure 7.23: Offer prices and market power measures—AES Chivor

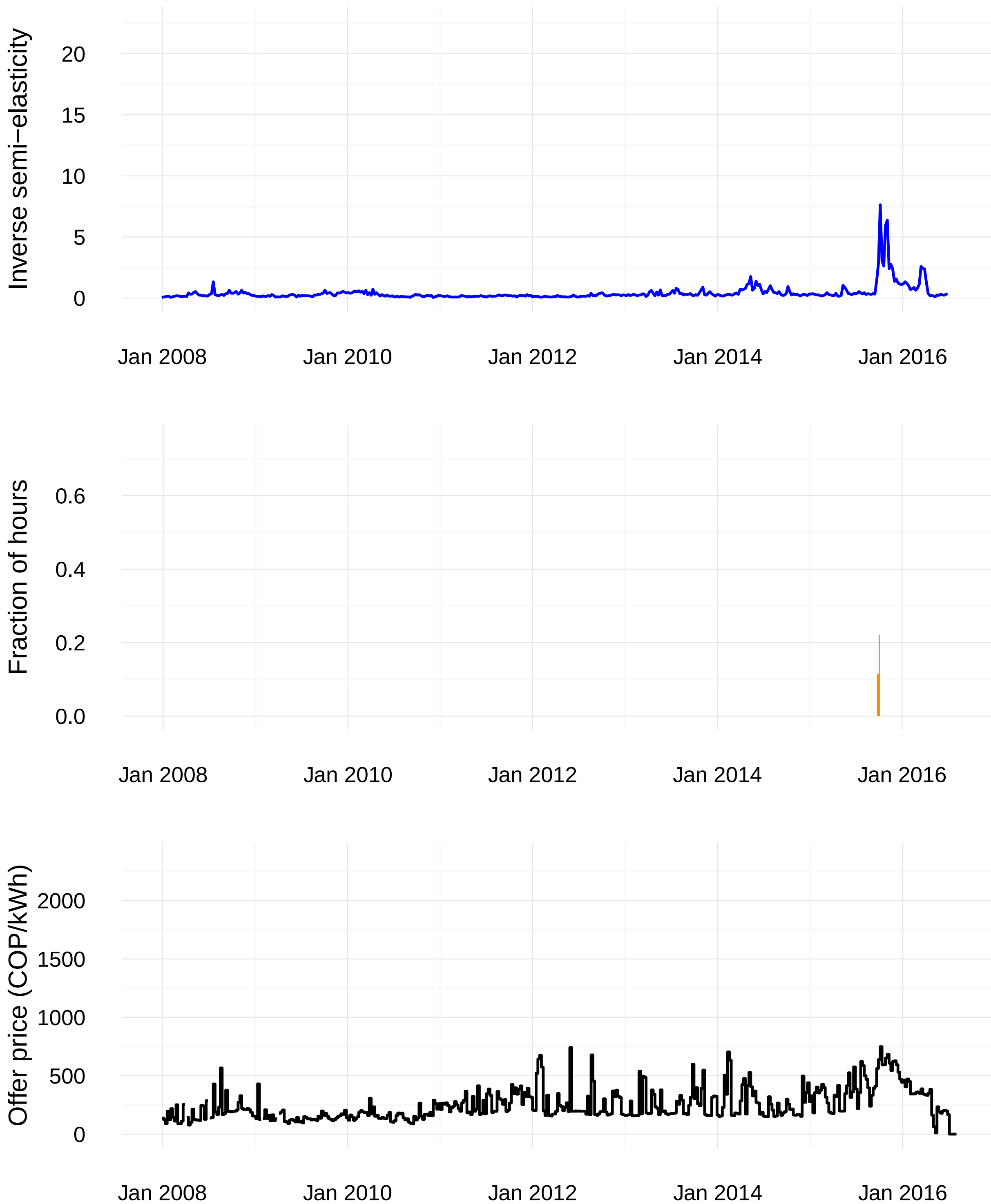
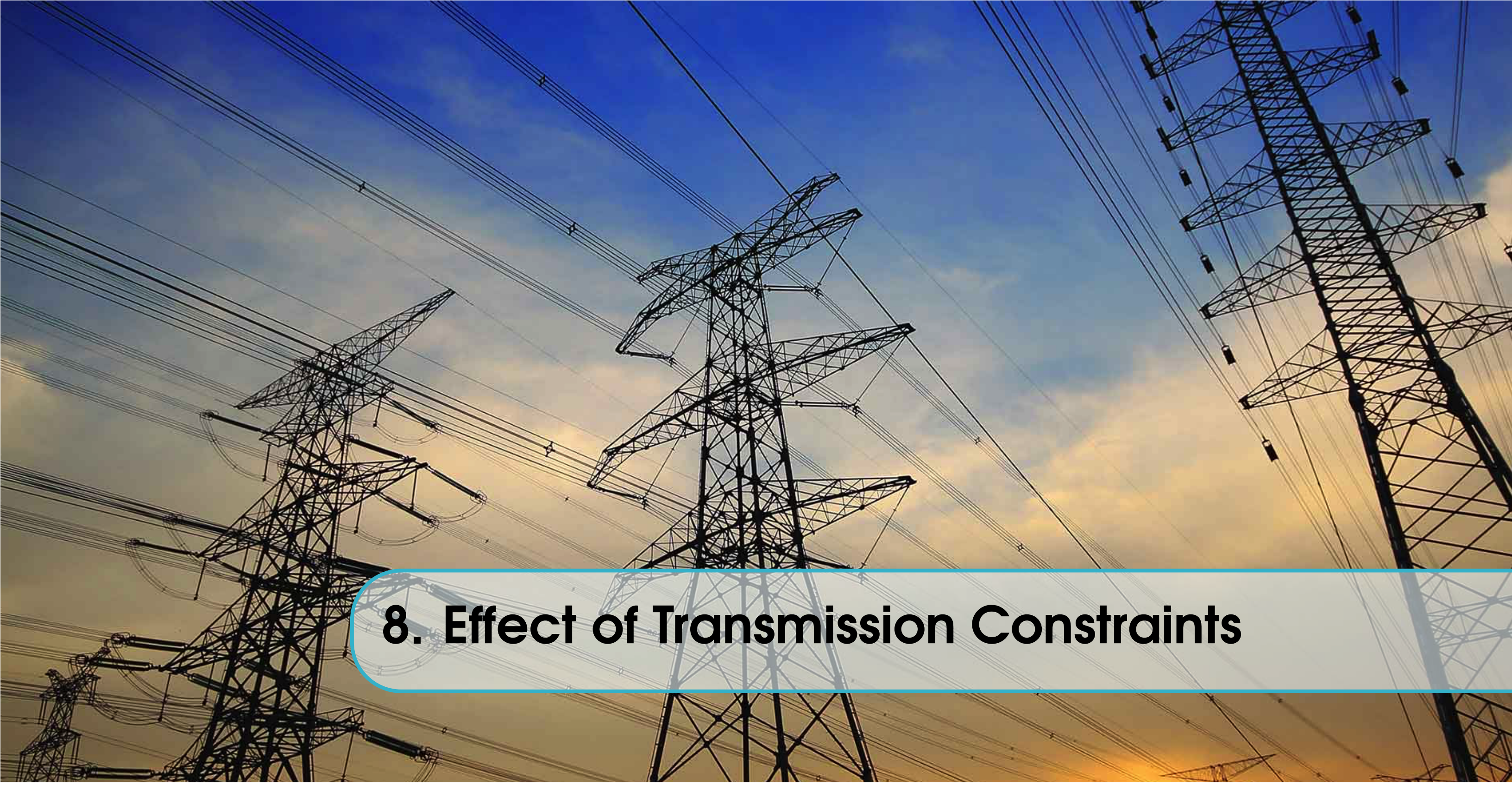



Figure 7.24: Offer prices and market power measures—Gecelca



# 8. Effect of Transmission Constraints

This chapter characterizes the impact of transmission constraints on the operation of the Colombian market. We summarize the behavior of the volume of positive and negative reconciliations by generation technology as a share of total generation by that technology and the value of positive and negative reconciliation payments in Colombian Pesos and as a share of total energy production valued at the Bolsa price. We find that both positive and negative reconciliations for hydroelectric units are a fairly constant fraction of total hydroelectric generation over our sample period, with much more negative reconciliation than positive reconciliations. The share of negative reconciliation for thermal generation units is a fairly constant over our sample period, but the share of positive reconciliation fluctuates wildly. However, during both El Niño Events this share falls, particularly during the 2015-2016 event. For the positive and negative reconciliation payments, the level tends to rise with the level of the Bolsa price, but remains steady as a share of total Bolsa market revenues over our sample period, even during the two El Niño Events.

Figure 8.1 plots the monthly quantities of positive and negative reconciliations for hydroelectric units as a share of total hydroelectric generation from 2008 to 2016. These percentages are remarkably stable over time and appear largely invariant to hydrological conditions. The negative reconciliations shares are significantly larger than positive reconciliations shares throughout the sample period. The largest shares of negative reconciliations during our sample period occur during the 2009-2010 El Niño Event period.

Figure 8.2 plots the monthly quantities of positive and negative reconciliations for thermal units as a share of total thermal generation from 2008 to 2016. The most noticeable feature of this graph is the tremendous variability in the share of positive reconciliations over the sample period. The lowest shares of positive reconciliations occurs during the 2015-2016 El Niño Event period. This is not surprising given that thermal units are paid their variable cost for positive reconciliations and the Bolsa price was above the Scarcity Price during this time period. Clearly, virtually all thermal suppliers would prefer to receive the very high Bolsa prices rather than their variable cost during this time period. Consistent with the logic that thermal generation units typically receive positive reconciliations and hydroelectric units negative reconciliations, the negative reconciliation shares are extremely small for thermal units throughout the sample period.

Figure 8.3 plots the monthly payments for both positive and negative reconciliations in Colombian Pesos. These payments have remained relatively constant from 2008 to 2015, but increased significantly in late 2015 with the rapid increase in Bolsa prices. Figure 8.4 shows that both positive and negative reconciliation payments are a significant fraction of total Bolsa market revenues. They average close to 20 percent of total Bolsa market revenues, but in some months are above 40 percent of Bolsa market revenues for both positive and negative reconciliations. The magnitude of these reconciliations and the size of these payments suggests that significant operating cost savings could be achieved by implementing a more efficient congestion management mechanism in Colombia. In Chapter 10 we suggest such an approach.

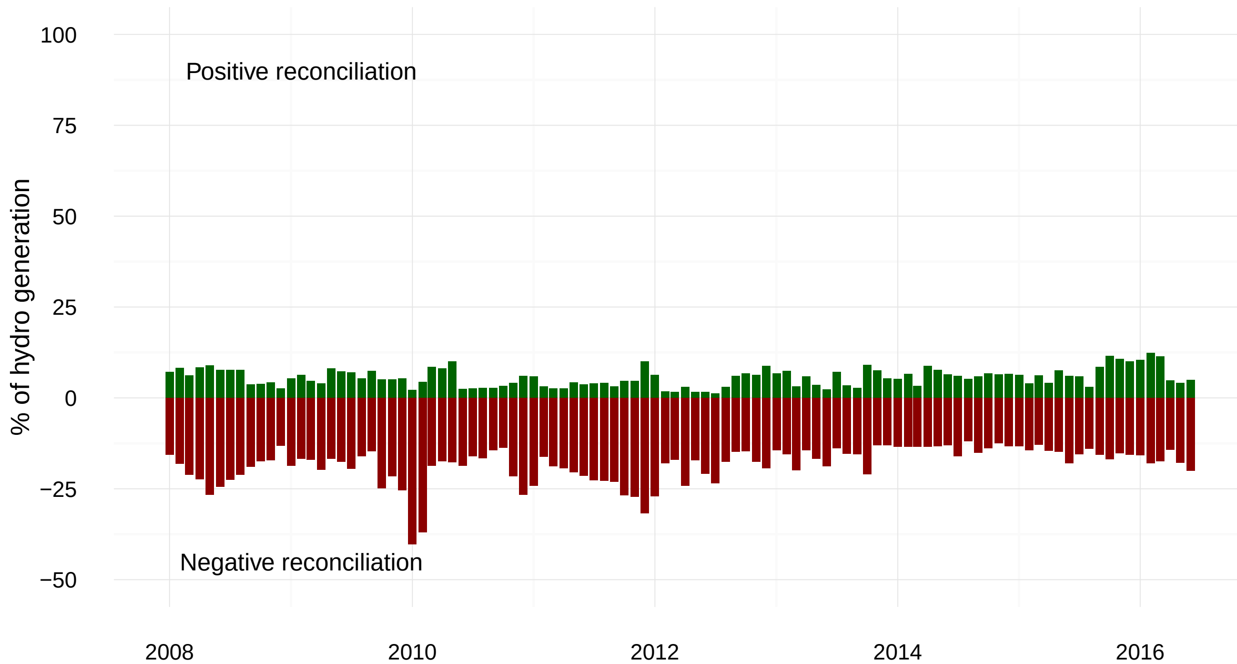



Figure 8.1: Positive and negative reconciliations in kWh for hydro generators, as a proportion of monthly hydro generation, 2008–2016

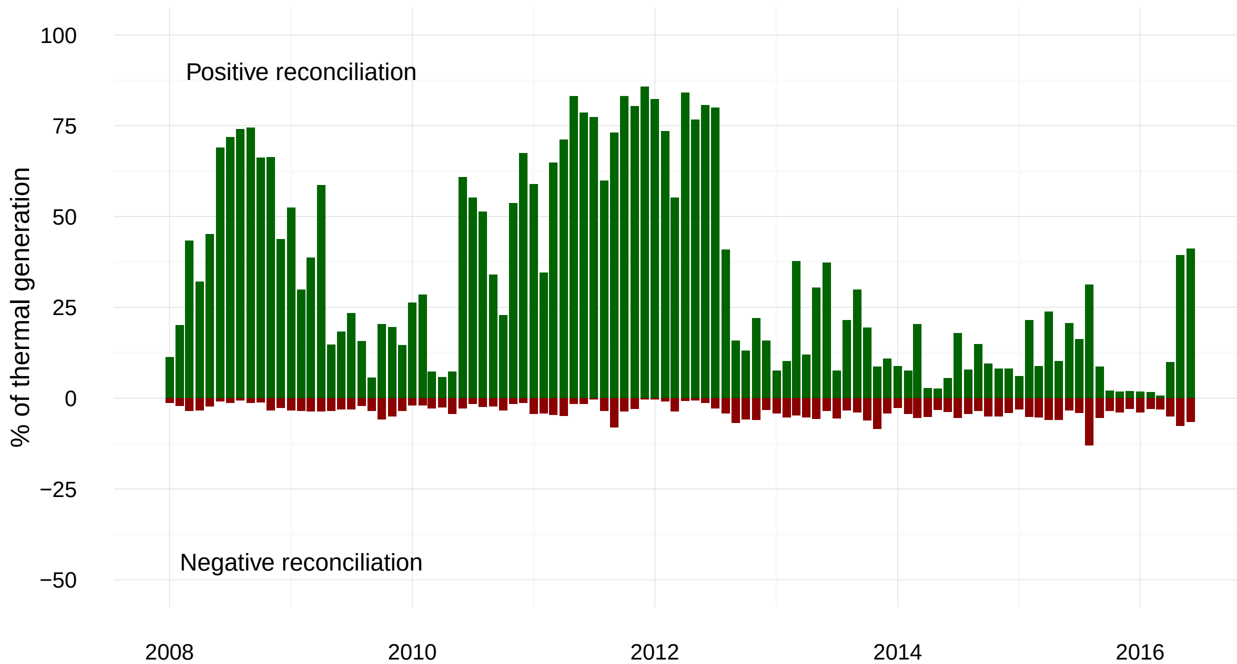



Figure 8.2: Positive and negative reconciliations in kWh for thermal generators, as a proportion of monthly thermal generation, 2008–2016

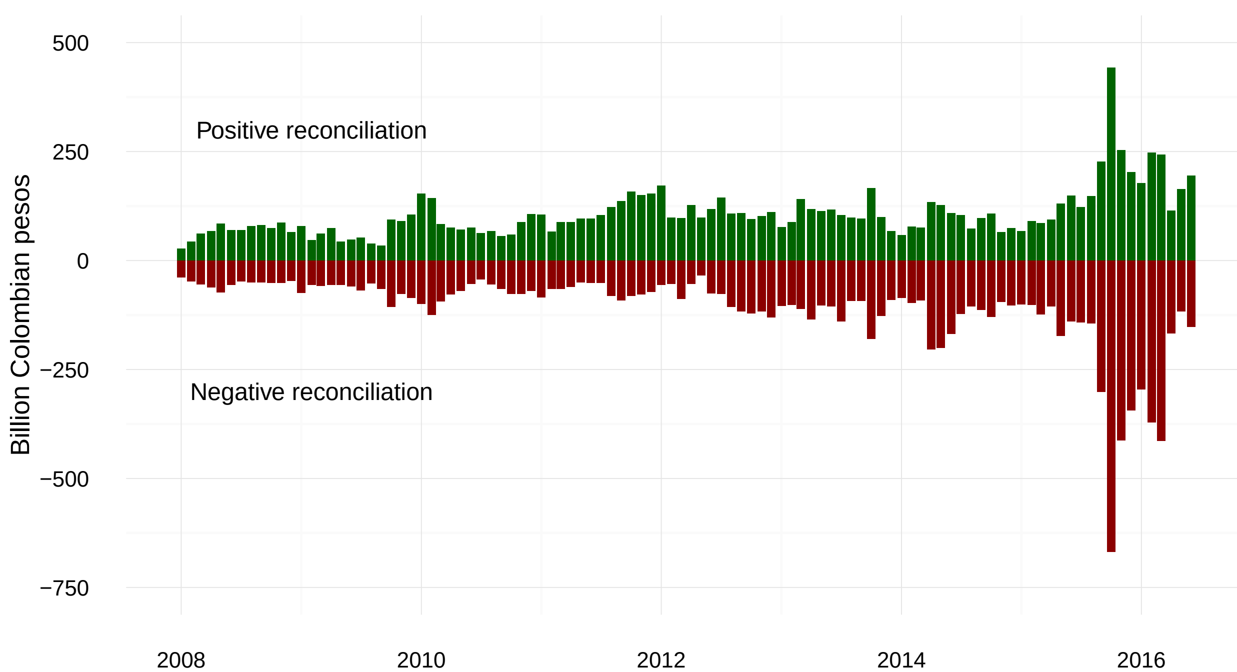



Figure 8.3: Aggregate positive and negative reconciliation payments in pesos, 2008–2016

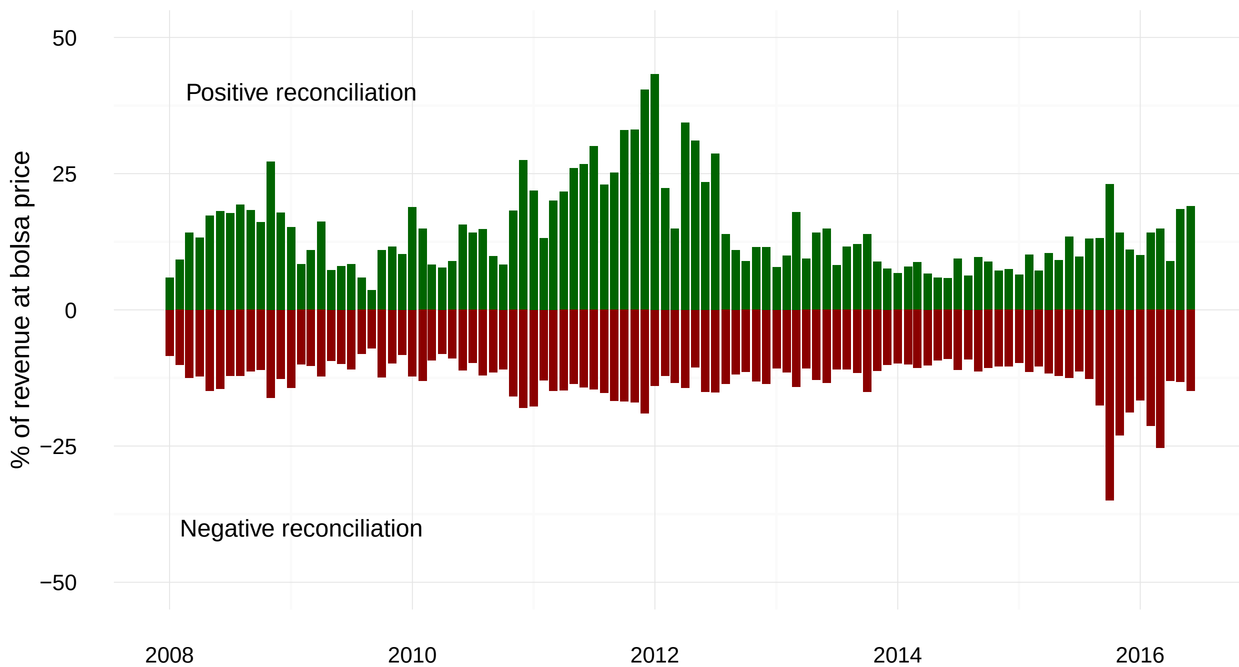
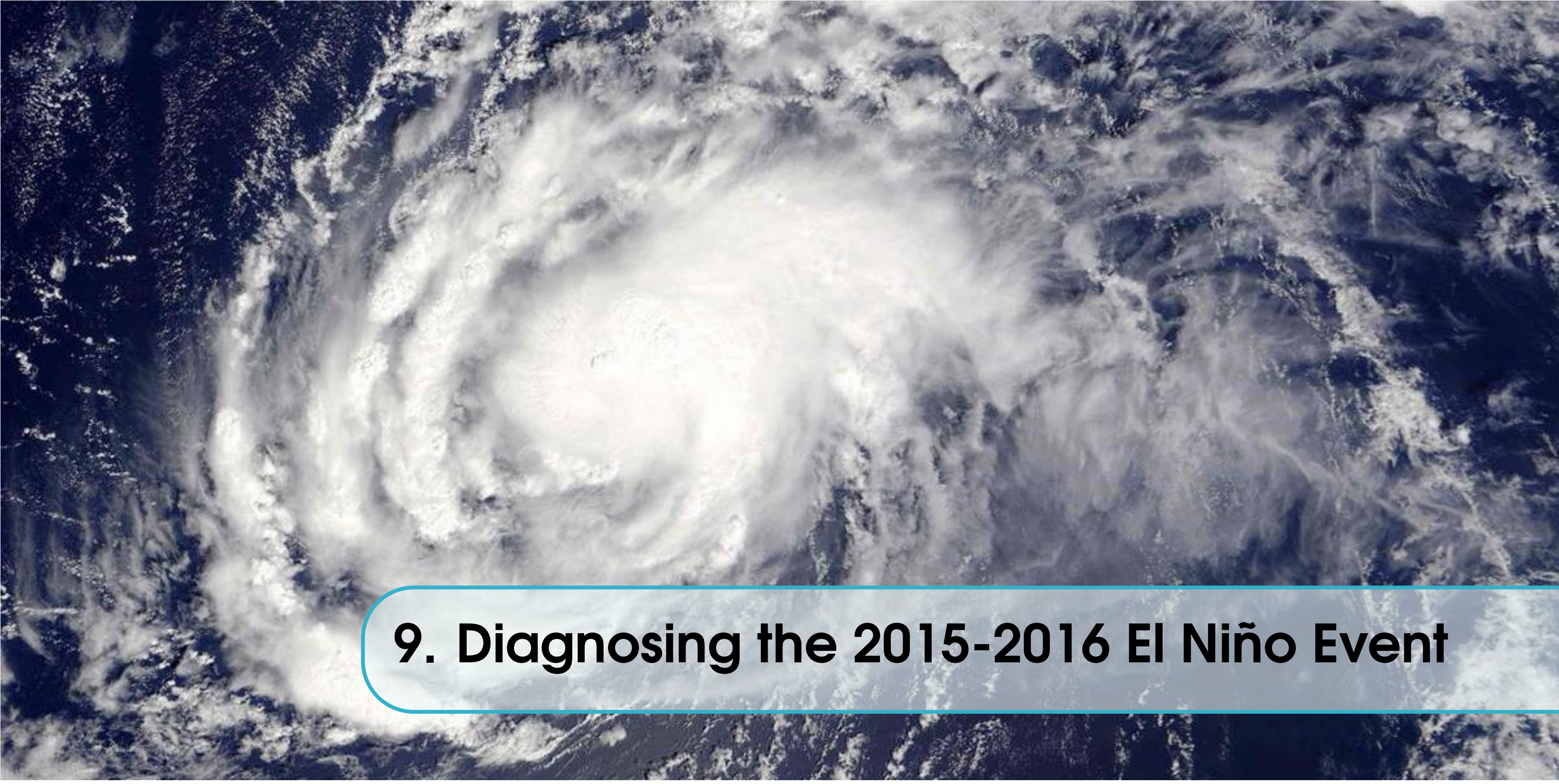



Figure 8.4: Aggregate positive and negative reconciliations in pesos, as a share of energy market revenue calculated at bolsa price, 2008–2016



# 9. Diagnosing the 2015-2016 El Niño Event

This chapter uses the results of the previous chapters to diagnose the causes of the recent El Niño Event. An important consideration in this discussion is the extent to which the Reliability Payment Mechanism (RPM) contributed to the likelihood and severity of extreme market outcomes during this El Niño Event. Because this is the second El Niño Event that has occurred under RPM, and its impact on market outcomes was substantially more severe, both in terms of the impact on Bolsa prices and average revenues paid to the generation sector, these facts call into the question the effectiveness of the RPM at ensuring a reliable supply of electricity at a reasonable price during El Niño Events.

Based on the analysis of the previous chapters, we conclude that the RPM mechanism is a significant factor contributing to both the duration and severity of the extreme market outcomes that occurred during the most recent El Niño Event. This conclusion is based on the following factors. First, the RPM mechanism is complex and opaque, which unnecessarily increases the uncertainty faced by market participants, particularly during the low water conditions. Second, the RPM requires the regulator to set number of parameters that are difficult, if not impossible, to "correctly" set to achieve to its goals. The RPM implies an "unreasonable" level of contract enforcement and sophistication in risk management on the part of suppliers. Finally, the RPM has not been particularly effective at one of its primary goals: Getting new generation units built and built on time if they are ever built. For these reasons, we believe that significant revisions to the mechanism are in order.

We then ask the question of whether there are modifications of the RPM mechanism that can allow it to achieve the goal of limiting the duration and magnitude of extreme market outcomes during El Niño Events. Based on our analysis, we conclude that the basic structure of this mechanism makes it unnecessarily challenging for suppliers to find it expected profit-maximizing to manage El Niño Events in a cost-effective manner, particularly given the current mix of generation capacity in Colombia. We then propose an alternative reliability mechanism for managing El Niño Events in Chapter 10 that we show addresses these shortcomings of the RPM and that is tailored to the mix of generation technologies that exist in Colombia.

## 9.1 Initial Conditions at Start of El Niño Event

The increasing share of hydroelectric generation capacity in Colombia from 2010 to 2016 in the face of growing electricity demand argues in favor of an increasingly conservative use of the available water. There is clearly less margin for error in surviving low water conditions in a hydroelectric-dominated system with a small share of thermal generation. Moreover, as shown in Chapter 3, the hydroelectric generation capacity added since 2011 has less storage capacity per MW of installed capacity than the existing hydroelectric units. As discussed in Chapters 2 and 5, a major factor in the severity of the most recent El Niño event was the persistent low water conditions in 2013, 2014, and the first three quarters of 2015 and the relatively small increase in the thermal generation capacity utilization rate during this time period. As shown in Chapter 5, the utilization rate of thermal capacity during 2013, 2014, and first three quarters of 2015 left many of the hydroelectric units with low water levels at the start of the El Niño period at the end of the third quarter of 2015. In fact, as shown in Chapter 6, the two largest generation units owners in Colombia—EPM and Emgesa—were offering in their thermal and hydroelectric units during this time period in a manner consistent with a desire to avoid operating their thermal units in favor of their hydroelectric units.

Given the levels of forward contracts for energy during this time period shown in Chapter 6 and the fact that scarcity conditions had yet to occur, this offer behavior may have been unilaterally profit-maximizing. As shown in Chapter 2, starting in 2013, Colombian Peso Bolsa prices rose to levels similar those that existed during the 2009-2010 El Niño Event. At these prices, neither EPM nor Emgesa would like to be short relative to their forward contract position—that is, have a value of $Q(Ideal)$ less than $Q(Contract)$. This would require them to purchase the difference between $Q(Contract)$ and $Q(Ideal)$ at the high short-term price in order to meet their forward market obligations. Moreover, producing more electricity from hydroelectric generation units is certainly cheaper than producing it from thermal units that require purchasing the necessary input fossil fuel to produce electricity.

As shown in Chapter 6, Isagen was the only one of the three largest generation capacity owners that was persistently submitting offers on its thermal below the offers for its hydro units throughout 2013 and 2014. Without the output from these thermal units, Isagen would have often been short (or even shorter) relative to its forward market position and had to purchase the difference (or a larger difference) between $Q(Contract)$ and $Q(Ideal)$ at the higher Bolsa price in order to meet its forward energy obligations.

As shown in Chapter 6, throughout 2013, Bolsa prices did not rise above the Scarcity Price and only during a small fraction of hours during the first quarter of 2014 did they rise above the Scarcity Price. Consequently, the RPM was largely irrelevant to the behavior of firms during this time period. As shown in Chapter 4, most large generation unit owners made very small payments of the positive difference between the Bolsa Price and the Scarcity Price times the difference between their Firm Energy Value and Ideal Generation from mid-2012 through the third quarter of 2015. Suppliers did face the prospect of making significant Net Firm Energy Refund payments in the future if a sustained period of prices in excess of the Scarcity Price occurred. However, if the previous 2009-2010 El Niño Event was any guide, the frequency of Bolsa prices in excess of the Scarcity Price if an El Niño Event occurred was very low. Against the backdrop of the previous El Niño Event, a strategy of protecting against significant payments for energy shortfalls relative for Net Forward Contract Quantities during 2013, 2014, and the first three quarters of 2015 by running their hydroelectric units in preference to their thermal units appears to be a rational strategy. This strategy earned these suppliers higher profits during this time period because supplying energy from their hydroelectric units did not require expenditures on input fossil fuels that would be required if their thermal units had operated.

## 9.2 Post September 22, 2015 Market Participant Behavior

As shown in Chapter 6, following the market notice issued by XM on September 22, 2015, close to 100 percent of the hours had Bolsa prices in excess of the Scarcity Price. As noted in Chapter 6, this immediately makes the Firm Energy value of a supplier relevant to its offer behavior. Specifically, suppliers with $Q(Ideal) > Q(Firm)$ make more money from a higher Bolsa price regardless of the value of $Q(contract)$ and suppliers with $Q(Ideal) < Q(Firm)$ make larger Firm Energy Refunds for a higher Bolsa price regardless of the value of $Q(contract)$. However, whether a supplier is in either of these regimes depends on their offer curves and the offer curves of all other suppliers. As noted in Chapter 6, during this time period several of the large suppliers had a significant fraction of days when $Q(Ideal) > Q(Firm)$, so these suppliers had a unilateral incentive to take actions to raise the Bolsa price. In addition, there are also many days during this time period when $Q(Ideal) > Q(Contract)$ for several of the large suppliers, which implies that they had a unilateral incentive to raise prices up to at least the Scarcity Price.

As discussed in Chapter 7, the interaction between the RPM and a supplier's forward contracts for energy can create a perverse set of incentives for a generation unit owner with a significant ability to exercise unilateral market power. As shown in Chapter 6, if $Q(Contract) > Q(Ideal) > Q(Firm)$, then the supplier will use its ability to exercise unilateral market power to increase the Bolsa price if it is above the Scarcity Price, but the supplier will use its ability to exercise unilateral market power to lower the Bolsa price if it is below the Scarcity Price. As noted earlier, because the price level depends on the offer curve of all suppliers and the level of demand, during an El Niño Event, this set of incentives is likely to lead to extreme market outcomes. Similar logic applies to the case that $Q(Firm) > Q(Ideal) > Q(Contract)$. In this case, a supplier with the ability to exercise unilateral market power will use it to drive the Bolsa price up if it is below the Scarcity Price and drive the Bolsa Price down if it is above the Scarcity Price. Again, this set of circumstances is likely to lead to extreme market outcomes during El Niño Event conditions.

As shown in Chapter 7, all of the large generation unit owners in Colombia had a substantial ability to exercise unilateral market power during the time period from September 23, 2015 through April 2016, it is not surprising that market outcomes during this time period resulted in extremely high Bolsa prices and a significant risk of energy shortfalls. As shown in Chapter 7, the six large suppliers all had a substantial ability to exercise unilateral market during this time period. The results in Chapter 7 also demonstrate that each of the three largest suppliers were pivotal a significant fraction of hours during the El Niño period, indicating that they had the ability to raise the Bolsa price in excess of any value of the Scarcity Price through their unilateral actions if they were only willing to have their Ideal Generation equal to their pivotal quantity of energy.

Just at the time that the market designer would like suppliers to find it profit-maximizing to manage low water conditions prudently, the incentives created by the RPM interacting with forward contract obligations of the large suppliers made it profit-maximizing for those suppliers with the ability to exercise unilateral market power to take actions to raise Bolsa prices. For these reasons and those discussed above, the RPM mechanism in its current form appears to be counterproductive to its intended goal during the most recent El Niño event.

## 9.3 Can the RPM Be Salvaged?

This section addresses the question of whether the RPM can be salvaged. Specifically, are there modifications of the mechanism that could increase the likelihood that it achieves its desired goals? We are skeptical that this is possible given the basic structure of the RPM for the following reason. First, the RPM is extremely complex and often opaque in terms of the incentives it creates for market participant behavior, particularly during low water conditions. Second, it requires setting a number of parameters that are difficult, if not impossible, to set "correctly". Third, the RPM involves an "unreasonable" level of contract enforcement that does not exist in other forward markets. It also requires an "unreasonable" degree of sophistication in El Niño Event risk management by suppliers. Its generally poor performance at achieving its other goal of attracting sufficient new generation capacity to meet a growing electricity demand further increases our skepticism that it can be salvaged. Finally, there is a readily available alternative approach that builds on several features of the RPM that can be easily implemented.

The firm energy value of a generation unit is an administratively determined construct. Qualitatively, the Firm Energy of a generation unit is designed to be the amount of energy the unit can produce during most extreme system conditions. Once the administratively determined Firm Energy Values have been set for each generation unit, another administrative process determines how the hourly value of the Firm Energy Value of each generation unit is determined. CREG Resolution Number 071 of 2006, a 70-page document, describes this process, as well as other aspects of how the RPM functions. In addition, the actual hourly values of the Firm Energy for each generation unit are kept confidential so market participants do not know the hourly values of Firm Energy for their competitors. This is different from the case of the hourly values of the Forward Contract Quantity for each firm. These are available to all market participants from the XM website. This lack of transparency about how the RPM mechanism impacts the behavior of market participants does not increase the likelihood of stable and predictable market outcomes, because in the absence of information, market participants will make forecasts and these forecasts are likely to be wrong. These forecast errors are likely to lead to decisions that destabilize rather than stabilize the market. These destabilizing actions are likely to have the most adverse consequences during El Niño Events.

Three parameters of the RPM that significantly impact the behavior of suppliers are largely impossible to set correctly. The first is the Firm Energy of a generation facility. Although it is possible to use historical data to compute the minimum amount of energy that a hydroelectric facility produced during low water conditions, this magnitude is unlikely to be the maximum amount the generation facility can produce in a future low water period. There are many impossible-to-predict factors that determine how much energy a hydroelectric generation facility could produce during a future low water period. However, if not for the fact that the RPM imposes penalties on generation owners for low water levels related to this Firm Energy Value, small market inefficiencies would be introduced by using the lowest historical water conditions to set the value of Firm Energy for hydroelectric generation units.

Under the current RPM rules, once the value of Firm Energy is set, suppliers are penalized for letting their water levels fall below the level that the regulator determines is necessary to supply that amount of Firm Energy for three consecutive days during a scarcity period. This penalty scheme assumes something that is unverifiable: that the minimum water level set by the regulatory process is the lowest possible water level that should ever occur for this generation unit. As noted above, it is difficult know in advance precisely how low the water level in a hydroelectric generation unit can go and still safely provide electricity. This value depends on a number of factors that are not known until low water conditions actually occur. Consequently, a superior strategy would be to provide discretion to the owner and operator of the generation unit as to how low the water level is allowed to go. Any regulatory-process-determined level is most likely wrong and likely be excessively conservative, because the regulator would not like to be implicated in causing a hydroelectric generation unit to be unable to produce electricity. Consequently, both the process of the setting the value of Firm Energy and the accompanying penalties for water levels below the NEP are likely to reduce the ability of the hydroelectric suppliers to manage El Niño Events in the most cost-effective manner.

The second parameter that is impossible to set correctly is the value of the Scarcity Price. The standard argument is that it should be set above the variable cost of the highest cost unit on the system. The major challenge is that this variable cost can change for many reasons. This is taken into account in RPM by the fact that the fuel cost component of the estimated scarcity price is indexed to a fossil fuel price. However, as a number of market participants argued, this price index did not reflect their cost of obtaining fuel during the most recent El Niño Event. This is the fundamentally unsolvable problem. It is impossible for the regulator to verify whether a supplier's claimed variable cost of production is in fact its least-cost mode of production. Virtually all disputes in regulatory price-setting processes can be traced to this asymmetric information problem between the firm and the regulator. Economists prefer market mechanisms to explicit price regulation because of this problem. Running a market for a product eliminates the need for the regulator to make this determination, because if the market for the product is competitive and there are no entry barriers, then suppliers that can produce the product at the lowest cost will supply it and the price they charge will equal the minimum cost of supplying the last unit produced.

In contrast, the Scarcity Price is set through an regulatory process that necessarily does not know the least-cost way to supply the necessary input fossil fuel or produce electricity. The regulator only has estimates of the cost of supplying the input fossil fuel and electricity based on public information, not the minimum cost of supplying electricity. Because it is impossible to predict future input fossil fuel costs, and what input fossil fuels will be used to produce electricity in the future, and what it will cost to deliver them to each generation unit in Colombia, it is impossible to set the correct Scarcity Price. It will sometimes turn out to be too high relative to the highest cost supplier's variable cost and other times too low.

An alternative view of the scarcity price is that any value, as long as it is known and predictable, is sufficient. Suppliers know that the RPM requires them to pay $\max(0, P(Bolsa) - P(Scarcity)) \times (Q(Firm) - Q(Ideal))$ and receive only $P(Scarcity)$ for $Q(Ideal)$ during scarcity conditions for whatever value of $P(Scarcity)$ the regulator sets. The important feature is then the transparency and predictability of the Scarcity Price, not whether it achieves the goal of being equal to the variable cost of the highest variable cost unit on the system. This approach makes the most sense for a hydroelectric energy-dominated system with a final demand that can reduce its consumption at a Bolsa price above the highest variable cost unit on the system. In this case, the opportunity cost of water could rise above the variable cost of the highest cost thermal generation unit on the system. This alternative view of the Scarcity Price does not mean that it is possible to set the "correct" value of the Scarcity Price, only that the regulatory process must set a stable, predictable, and enforceable Scarcity Price. In particular, the regulator must enforce the fact that suppliers of Firm Energy are liable for $\max(0, P(Bolsa) - P(Scarcity)) \times (Q(Firm) - Q(Ideal))$ and receiving only $P(Scarcity)$ for $Q(Ideal)$ during scarcity conditions for all states of the world for its chosen value of $P(Scarcity)$. No claims are made that the value of $P(Scarcity)$ satisfies any economic efficiency properties.

If one is willing to set the Scarcity Price in this manner, there is still the problem of the perverse incentives for supplier behavior discussed in Chapter 6 for suppliers with a significant ability to exercise unilateral market power. These incentives make the value of the Scarcity Price a focal point for the value of the Bolsa price simply because, as discussed in Chapter 6, there is such a drastic change in supplier incentives between Bolsa prices above and Bolsa prices below the Scarcity Price. However, any mechanism for setting the value of the Scarcity Price can create circumstances for suppliers to "claim" to lose money from supplying electricity during scarcity conditions because the Scarcity Price is lower than their unit's variable cost of production. These claims are virtually impossible to verify, so that the regulator must focus on ensuring the transparency of the RPM and the process used to set the Scarcity Price and on enforcing the terms of this contract for all states of nature. If the supplier agrees to supply Firm Energy at this Scarcity Price, then they must manage the risk that the Scarcity Price could be below their variable cost of production, particularly during El Niño Events when the price of purchasing a significant amount of fuel on the short-term market is likely to be very high.

The final parameter that is impossible to set is the aggregate amount of firm energy to purchase. The regulator must determine the amount of Firm Energy to purchase at each auction to achieve a reliable supply of electricity at a reasonable price during El Niño Events. It is virtually impossible to determine precisely the minimum amount of total Firm Energy needed to achieve this goal. Once again this is the rationale for setting up a competitive market for a product. For any product, the amount of productive capacity needed to meet demand at least cost is generally unknown. By running a market and ensuring that it is competitive, the market designer is able to learn this by observing the amount of productive capacity that gets built. However, under the RPM, the regulatory process sets the total system-wide Firm Energy that must be purchased by electricity retailers. This process is unlikely to find the economically efficient level of Firm Energy, but a level of the Firm Energy that the regulatory process determines will lead to a reliable supply of reasonably-priced electricity during low water conditions. However, for the reasons discussed above, making this determination in advance is extremely challenging and likely to be biased in favor of purchasing too much total system-wide Firm Energy. This bias in favor of purchasing too much Firm Energy is likely to be even greater given the historical fact discussed below that a significant fraction of the proposed new generation capacity purchased in Firm Energy auctions was never actually built, or if it was built it came online late.

Perhaps that most challenging aspect of the design of RPM to overcome is the "unreasonable" degree of contract enforcement. The example of the "bankruptcy" of the Termocandelaria generation unit is an example of this problem. Under the RPM mechanism a generation unit owner can receive many years of the Firm Energy payments and never supply electricity or produce at an extremely low capacity factor. This is particularly true for a thermal generation unit which has significant fuel costs and start-up costs. When it comes time to produce a significantly larger amount of electricity during low water conditions, the unit owner may instead decide to walk away from its obligation to pay $\max(0, P(Bolsa) - P(Scarcity)) \times (Q(Firm) - Q(Ideal))$ and sell $Q(Ideal)$ at $P(Scarcity)$, and instead take the accumulated reliability payments that it has received for many years and allow the generation unit to go "bankrupt" rather than fulfill its energy supply obligations under the RPM. The RPM contract is clearly not self-enforcing in the sense that a supplier of Firm Energy always finds it expected profit-maximizing to fulfill its contractual obligations. The incentive to default of the RPM contract is particularly great during El Niño Events when the supplier's cost of compliance with the RPM rapidly increases because it must purchase a much greater quantity of variable inputs such as fuel and labor to operate the unit more intensively. Precisely when the RPM is the most vulnerable to breach is also precisely when the supplier is most needed to fulfill its contractual obligations under the RPM.

For this reason, we believe that it is highly unlikely that any counterparty would sign an RPM contract without the regulatory process requiring it, unless the accumulated reliability payments are kept in a separate account that the counterparty to the contract can access at any time if the supplier decides not to supply energy or make the Net Firm Energy Refunds to the counterparty under the terms of the RPM. Self-enforcing contracts typically require that each counterparty to the contract always be in a position such that the expected profits from continuing to honor the contract exceeds the expected profits from walking away from the contract. As the Termocandelaria generation unit experience demonstrates, the RPM mechanism can create circumstances where the supplier would prefer to walk away from the contract rather than continue with it, and these circumstances are likely to be when the market most needs Firm Energy suppliers to fulfill their contractual obligations. This problem is exacerbated by the potential for the Scarcity Price to be less than the supplier's variable cost of production, which is an unavoidable problem for virtually any approach to setting the Scarcity Price.

The final "unreasonable" level of contract enforcement required by the RPM is the requirement that fossil fuel suppliers that sell firm energy have sufficient fuel sources under contract to meet their firm energy sales. As the experience of both the current El Niño Event, and to a lesser extent, the 2009-2010 Event demonstrates, this provision is virtually impossible to enforce. This RPM provision could require that the necessary input fossil fuel be stored on site at the generation facility location, but this would significantly raise the expense to thermal generation units supplying Firm Energy. Moreover, in most normal water years, this fossil fuel energy would not be used because of the availability of hydroelectric energy. Managing both the price and volume risk associated with procuring sufficient input fossil fuel for the unit to operate during an El Niño Event is an extremely challenging risk management task given the current state of fossil fuel markets in

Colombia.

The completion of Colombia's Liquified Natural Gas (LNG) import facility should go a long way to improving access to sufficient natural gas at relatively short notice when an El Niño Event occurs. Opening of this LNG facility presents an ideal opportunity to reform the natural gas industry in Colombia to increase pipeline capacity throughout the country, set more transparent cost-based tariffs for natural gas transportation, free up natural gas prices to encourage domestic production, and allow greater competition from international firms in natural gas exploration and development in Colombia and domestic wholesale natural gas sales. Even under these conditions it would still be extremely challenging for the regulator to enforce the provision of the RPM that the thermal generation unit owner has sufficient input fossil fuel to supply its Firm Energy commitment. However, these reforms should increase the liquidity of the forward markets for natural gas and electricity so that suppliers would be able to find lower cost hedges for these risks.

Evidence for the difficulty that the RPM has had in getting new generation units built and built on time if they are eventually built can be obtained from comparing the list of new plants that were awarded Firm Energy in the first three Firm Energy auctions to the actual pattern of generation unit completions and start dates (Table 9.1). This suggests that the RPM does not always deliver new generation capacity or new capacity on time even if a Firm Energy sale has occurred. The construction of several plants has been delayed, perhaps indefinitely (Termocol, Miel II and Porce IV). Other plants that did eventually open did so long after the start date of their Firm Energy allocation. For example, Gecelca 3 was supposed to start operating in December 2012, but only started generating in September 2015.[1] Similarly, Gecelca 3.2 was supposed to start operating in December 2015, but is still under construction. The hydroelectric plant El Quimbo started operating in November 2015, nearly one year late.

Figure 9.1 summarizes the allocations of Firm Energy from the first three auctions (the colored bars). The black line shows the availability of Firm Energy from the plants that were awarded Firm Energy in these auctions. (Because the availability of hydroelectric plants may greatly exceed their Firm Energy allocation, the line shows the minimum of availability offers and the Firm Energy allocation). The graph shows a very large gap between the Firm Energy awarded in the auctions for the first three quarters of 2015 and the observed availability of the new plants that received Firm Energy allocations. Consequently, it is not unreasonable to believe that the 2015-2016 El Niño event would have been significantly less severe if all of these plants had started operating on time.

One suggestion for changing the design of the RPM is raise the Scarcity Price and remove the Net Energy Refund Mechanism and replace it with a must-offer obligation for generation unit owners. This approach has been used in a number eastern United States capacity markets. Suppliers receive a capacity payment in exchange for agreeing to offer in the full capacity of their generation unit at a price below some offer price cap. In the case of Colombia, this could be the Scarcity Price. This modification of the RPM is unlikely to ensure a more reliable supply of energy at a reasonable price during El Niño Events. The must-offer requirement only requires suppliers to submit offer prices at or below the higher Scarcity Price. As shown in Chapter 7, during the 2015-2016 El Niño Event the six largest suppliers each had a substantial ability to exercise unilateral market power and used it to raise the Bolsa price. Consequently, the must-offer obligation would do little prevent Bolsa prices at or near the Scarcity Price during El Niño Events. Finally, the must-offer obligation only requires suppliers to offer their available capacity into the short-term market. If a hydroelectric unit owner does not have energy, it cannot offer any energy into the short-term market, even if there is a must-offer obligation. Similar logic applies to thermal units. The supplier only has to offer the unit into the market if it is available. Unfortunately, it is difficult, if not impossible, to verify if a unit is truly able to operate. For this

[1] See `http://www.semana.com/nacion/articulo/gecelca-obras-retrasadas-la-costa-caribe-sin-energia/434389-3`

Table 9.1: Allocation from firm energy auction and observed entry date

| Plant | Auction[1] | OEF (MWh/day) | Start date | End date | Entry date |
|---|---|---|---|---|---|
| Amoyá | OEF 1 | 587 | 2012-12-01 | 2032-11-30 | 2013-05-24 |
| Gecelca 3 | OEF 1 | 3,060 | 2012-12-01 | 2032-11-30 | 2015-09-17 |
| Termocol | OEF 1 | 4,596 | 2012-12-01 | 2032-11-30 | Not completed |
| | | | | | |
| Cucuana | GPPS 1 | 136 | 2014-12-01 | 2034-11-30 | 2015-07-29 |
| El Quimbo | GPPS 1 | 1,096 | 2014-12-01 | 2015-11-30 | 2015-11-16 |
| | | 2,329 | 2015-12-01 | 2034-11-30 | |
| Miel II | GPPS 1 | 500 | 2014-12-01 | 2015-11-30 | Not completed |
| | | 505 | 2015-12-01 | 2034-11-30 | |
| Porce IV[2] | GPPS 1 | 878 | 2015-12-01 | 2016-11-30 | Not completed |
| Sogamoso[2] | GPPS 1 | 1,096 | 2014-12-01 | 2015-11-30 | 2014-12-01 |
| | | 2,192 | 2015-12-01 | 2016-11-30 | |
| | | | | | |
| Ambeima | OEF 2 | 205 | 2015-12-01 | 2035-11-30 | Not completed |
| Carlos Lleras Restrepo | OEF 2 | 548 | 2015-12-01 | 2035-11-30 | 2015-11-22 |
| Gecelca 3.2 | OEF 2 | 5,400 | 2015-12-01 | 2035-11-30 | Not completed |
| San Miguel | OEF 2 | 336 | 2015-12-01 | 2035-11-30 | 2015-12-23 |
| Tasajero II | OEF 2 | 3,648 | 2015-12-01 | 2035-11-30 | 2015-11-30 |

[1] “OEF 1” is the first firm energy auction, held on May 6, 2008. “GPPS 1” is the first auction for plants with long planning periods, held on June 13, 2008. “OEF 2” is the second firm energy auction, held on December 27-28, 2011.

[2] These resources were allocated firm energy through 2034-11-30. However, only the firm energy quantities through the end of 2016 are shown in the table.

reason, most must-offer obligations impose penalties on suppliers for failing to offer their capacity into the market. However, setting the level of these penalties and determining precisely when they should be imposed can be an extremely challenging task for the regulator. Consequently, this modification of the RPM alone is unlikely to improve its performance and may even lead to even more extreme market outcomes during El Niño Events.

All of the above challenges with improving the RPM mechanism are largely unsolvable through modification of this mechanism. In the following Chapter, we suggest an alternative approach to achieving the goal of reliable supply of electricity at a reasonable price during El Niño Events that builds on features of this mechanism.

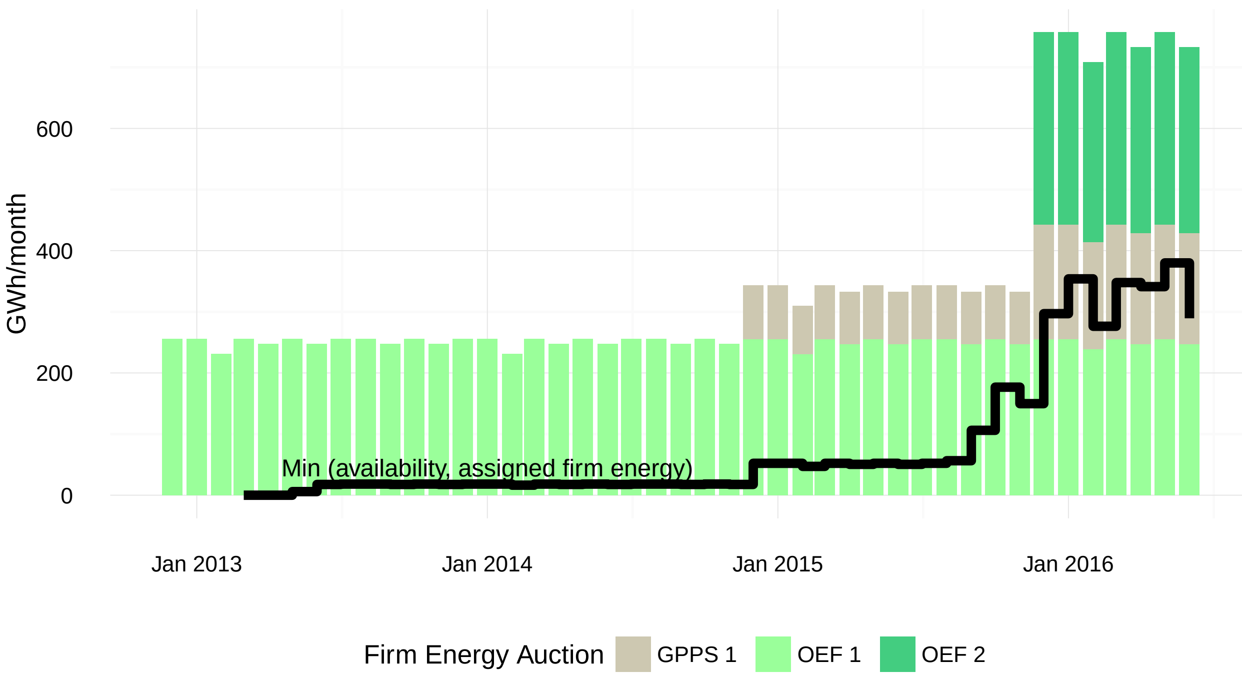



Figure 9.1: Auction allocation of firm energy to new projects and realized availability


# 10. Alternative to Managing El Niño Events

This chapter proposes an alternative approach to ensuring a reliable supply of energy at a reasonable price during El Niño Events using a generation unit's assigned Firm Energy value from the RPM. The idea of this approach is to require purchases of standardized forward contracts for energy by all loads in Colombia at various horizons to delivery. These contracts must be sold by existing or proposed new generation unit owners. The amount of these standardized contract that each supplier can sell is determined by the Firm Energy Value of each the generation units that it owns or proposes to construct. The reliability mechanism provides a consistent signal to both thermal and hydroelectric generation unit owners to manage low water conditions in a least cost manner. Suppliers are free to engage in cross-hedging arrangements to re-insure their hydrological, input fossil fuel availability, and outage risks within and across technologies using bilateral contracts. The focus of this reliability mechanism is to develop a liquid forward market for energy at long horizons to delivery (greater than two years in advance) to achieve both long-term generation adequacy and ensure that when real-time system operation arrives, the forward market positions of suppliers are closely aligned with their production of electricity under a least-cost dispatch.

We suggest other modifications to the Colombian market design that are likely to improve the efficiency and increase the effectiveness of this proposed reliability mechanism. Our primary recommendation is to implement a multi-settlement locational marginal pricing (LMP) wholesale market with day-ahead forward market and a real-time imbalance market along with a local market power mitigation mechanism. This will eliminate the need for both the positive and negative reconciliation process and as well as the need to operate a separate market for operating reserves. Both the day-ahead and real-time market would have a market for operating reserves integrated into the LMP market. As discussed below, our proposed reliability mechanism can be easily modified to work with this market design. As part of these changes, we recommend increasing the number of price offers each supplier is allow to submit for its generation units to at least 5 price steps per unit. We also recommend allowing purely financial firms—those that do not own generation units—to participate in both the wholesale and retail electrcity markets.

## 10.1 An Alternative Approach to Managing El Niño Events

Fixed-price forward contracts are the standard approach used to ensure a real-time supply and demand balance in markets for products with high fixed costs of production. The prospect of a high real-time price for the product provides incentives for customers to hedge this real-time price risk through a fixed-price forward contract. A supplier benefits from signing such a contract because it has greater quantity and revenue certainty as result. The airline industry is familiar example of this phenomenon. There is a substantial fixed cost associated with operating a flight between a given origin and destination pair. Regardless of how many passengers board the flight, the airplane, pilot and co-pilot, flight attendants and fuel must be paid for. Moreover, there are a finite number of seats on the flight, so passengers wanting to travel face the risk that if they show up at the airport one hour before the flight and attempt to purchase a ticket, they may find that it is sold out or tickets are extremely expensive because of the high real-time demand for seats. Customers hedge this short-term price risk by purchasing their tickets in advance, which is a fixed-price, fixed-quantity (one seat) forward contract for travel on the flight. These forward market purchases allow the airline to better plan the types of aircraft and flight staff it will use to serve each route and how much fuel is needed for each flight.

Similar arguments apply to wholesale electricity markets to the extent that the regulator allows short-term prices to rise to very high levels. The potential for very high short-term prices provides strong incentives for electricity retailers and large customers to purchase their electricity through fixed-price forward contracts, rather than face the risk of these extreme short-term prices. Purchasing these fixed-price and fixed-quantity forward contracts far enough in advance of delivery for new entrants to compete to provide this energy ensures that retailers will receive a competitive forward market price for their purchase. These forward market purchases far in advance of delivery also ensure that the seller of the contract has sufficient time to construct the new generation capacity needed to meet the demand purchased through fixed-price forward contracts. Consequently, in the same sense that fixed-price forward contracts for air travel allow an airline to better match airplanes and flight staff to routes, fixed-price forward contracts for electricity allow electricity suppliers to match the mix of generation capacity to the demand that has purchased fixed-price forward contracts for energy.

Key to the success of a strategy for obtaining sufficient generation capacity to meet future demand without regulatory intervention is the threat of very high short-term prices which provide the incentive for load-serving entities to sign fixed-price forward contracts for their expected future demands far enough in advance of delivery to allow new entrants to compete with existing suppliers in the provision of these forward contracts for energy. Allowing short-term prices to rise to the level necessary to achieve sufficient hedging of short-term price risk far enough in advance of delivery to obtain competitive prices for these contracts requires a liquid forward market for energy and the political will to allow prices to rise to the level needed to clear the market under all possible system conditions. Neither of these circumstances exist in virtually all wholesale electricity markets around the world. The political process in virtually all countries finds it extremely challenging to pre-commit to allowing wholesale electricity prices to rise whatever level is necessary to clear the market for as long as necessary. In the case of the hydroelectric-dominated market, the period of time needed to clear the market for the available energy can be an entire El Niño Event period, which can impose significant economic hardship on citizens of the country. For this reason, virtually all countries have a regulator-managed reliability mechanism to achieve long-term resource adequacy. The RPM is one such approach, but as discussed in the previous chapter, we believe that it has not been effective at achieving either long-term resource adequacy or in achieving a reliable supply of energy at a reasonable price during El Niño Events.

Our proposed reliability mechanism limits the amount of regulatory intervention necessary to ensure long-term resource adequacy and a reliable supply of electricity at a reasonable price during El Niño Events.

Rather than designating a required amount of Firm Energy that each retailer must purchase, this reliability mechanism mandates fixed price forward contract purchases by all electricity consumers at various horizons to delivery. This mechanism would require all electricity retailers and free consumers to purchase a standardized fixed price forward contract for energy equal to various fractions of their expected demand at various horizons to delivery. For example, a retailer and free consumers could be required to purchase 95 percent of its actual annual demand in a fixed price forward contract one year in advance of delivery, 90 percent of its actual annual demand two-years in advance of delivery, 85 percent of its annual actual demand three years in advance of delivery, and 80 percent four years in advance of delivery, and all of these contracts clear against the hourly short-term price during the delivery period. Retailers would be subject to financial penalties for under-procurement of forward contracts relative to their actual demand. Our reading of the Law 143 of 1994 is that the Colombian energy regulator (CREG) has the flexibility to set the technical criteria for "free" (or unregulated) users to obtain electric service. Our understanding is that CREG is just not allowed to set the price that the unregulated users pay for this service. Consequently, because CREG currently requires unregulated users to pay for their share of the Firm Energy payments as part of the current RPM, we do not believe it is inconsistent with Law 143 of 1994 for CREG to require free consumers to sign the required quantities of standardized forward contracts at the required horizons to delivery as part of the requirement for receiving electricity service under a new reliability mechanism.

For example, if the retailer's realized demand is 100 gigawatt-hours (GWh) and it purchased 96 GWh in the standardized forward contract one year in advance, 89 GWh two years in advance, 86 GWh three years in advance, and 81 GWh four years in advance, the retailer would only be subject to penalties for under-procurement two years in advance of delivery. These forward market energy purchases would provide retailers and free consumers with wholesale price certainty for the vast majority of their electricity demand. To the extent the regulator feels that these mandated contracting levels are insufficient to ensure a reliable supply of electricity at a reasonable price, higher levels of contract coverage can be mandated, say 98 percent one year in advance, 93 percent two years in advance, 90 percent three years in advance, and 85 percent four years in advance.

It is important to emphasize that mandating these contracting levels is unlikely to impose a financial hardship on retailers that lose customers to competing retailers. If a retailer purchased more fixed-price forward contract coverage than it ultimately needs because it lost customers to a competitor, it can sell this obligation in the secondary market. Unless the market demand for energy in the future is unexpectedly low, this retailer is just as likely to make a profit on this sale as it is to make a loss, because one of the retailers that gained customers is going to need a standardized forward contract to meet its regulatory requirements for coverage of its final demand. Only in the very unlikely case that the aggregate amount of forward contracts purchased is greater than the realized final demand for the system, will there be a potential for stranded forward contracts held by retailers that lose customers.

As discussed in Chapter 6, fixed-price forward contract obligations also significantly limit the incentive of suppliers to exercise unilateral market power in the short-term market. The closer a supplier's fixed price forward contract quantity is to its actual output level, the less incentive the supplier has to exercise unilateral market power. Recall 6.2 excluding the RPM payment:

$$\begin{aligned}\pi_{hk}(P_h(Bolsa)) &= (Q_{hk}(Ideal) - Q_{kh}(Contract)) * P_h(Bolsa) \\ &\quad + P_{hk}(Contract)Q_{kh}(Contract) - C_k(Q_{hk}(Ideal)). \quad (10.1)\end{aligned}$$

If $Q(Contract) = Q(Ideal)$ then this equation becomes:

$$\pi_{hk}(P_h(Bolsa)) = P_{hk}(Contract)Q_{kh}(Contract) - C_k(Q_{hk}(Ideal)), \quad (10.2)$$

which does not depend on the value of the Bolsa price. This means that the supplier has no incentive to exercise unilateral market power in the Bolsa market. In this case, the supplier would find it expected profit-maximizing to produce the $Q(Ideal) = Q(Contract)$ in a least-cost manner.

Clearly, the challenge of our proposed reliability mechanism is to obtain a value for $Q(Contract)$ equal to the system-wide least cost value of $Q(Ideal)$ for each supplier for all hours of the year, particularly during the El Niño Events. This is where some of the features of the existing RPM are useful. Each hydroelectric generation unit owner would only be able to sell up to its Firm Energy Value in the standardized forward contract and each thermal generation unit owner would be required to sell at least its Firm Energy Value and no more than the nameplate capacity of the generation unit in a standardized forward contract. The next section provides more detail on how these requirements would be enforced.

This rule on standardized forward contract sales ensures that during El Niño Events periods the values of $Q(Contract)$ for the hydroelectric generation units and thermal generation units are consistent with all of these unit owners producing the maximum amount of energy they are able to produce. During El Niño Events the hydroelectric generation unit owners have a strong financial incentive to produce at least $Q(Contract)(\leq Q(Firm))$ or they face the prospect of purchasing energy from the short-term market at a high price to meet their forward contract obligations. The same incentive applies to the thermal generation unit owner. It would want to produce at least $Q(Contract)(\geq Q(Firm))$ or face the prospect of purchasing energy from the short-term market at a high price to replace any energy shortfall relative to $Q(Contract)$.

During the remaining water conditions, a different dynamic would operate to ensure a reliable supply of energy at a reasonable price. During normal water conditions, it is least cost on a system-wide basis for thermal suppliers to produce significantly less electricity than $Q(Contract)(\geq Q(Firm))$. Under these circumstances the Bolsa price is likely to be significantly less than the contract price at which the thermal supplier sold electricity in the standardized forward contract market. Taking the case that the thermal generation unit owner produces no electricity during normal water conditions, its per-hour variable profits become:

$$\pi_{hk}(p_{hk}(Bolsa)) \ = \ (P_{hk}(Contract) - P_{hK}(Bolsa))Q_{kh}(Contract). \quad (10.3)$$

This equation implies that the thermal supplier earns revenues by purchasing power from the short-term market at $P(Bolsa)$ and selling it at $P(Contract)$.

However, the thermal supplier always has the option to produce electricity if it believes the Bolsa price is above $P(Contract)$. Specifically, if during any hour the supplier believes it would earn a higher profit from producing the electricity from its own generation units instead of purchasing it from the short-term market, that option exists. Consequently, thermal suppliers are expected to submit an offer to supply energy in the short-term market at their variable cost as a way to ensure that it is always making the efficient "make versus buy" decision in meeting its fixed-price forward contract obligations. The ability of the hydroelectric suppliers to raise short-term prices during normal water conditions would be limited by these offers submitted by thermal generation unit owners. Under these water conditions, even though the hydroelectric suppliers are producing substantially in excess of their $Q(Contract)(\leq Q(Firm))$ level, they have limited ability to raise Bolsa prices because of the offers submitted by the thermal suppliers attempting to ensure that they make the economically efficient "make versus buy" decision to meet their forward contract obligations.

Our reliability mechanism is ideally suited to deal with managing water early in periods suspected to turn into El Niño Events. If thermal suppliers are submitting offers at their variable cost into the short-term market to ensure that they make the efficient "make versus buy" decision for procuring the energy needed to met their standardized forward contract obligations, when hydroelectric suppliers begin to raise their offer prices to conserve water, thermal generation units will operate more frequently and intensively. This outcome occurs because the higher hydro unit offer prices will be displaced by the variable cost offers of more thermal generation units. Consequently, the standardized forward contract quantity limitations of hydro and thermal unit owners in our reliability mechanism will cause water to be conserved during these periods suspected of turning in El Niño Events.

The next aspect of this reliability mechanism to be specified is the form of the standardized forward contract. The most straightforward approach would be to make the contracts system-load-weighted. The hourly values of $Q_{hk}(Contract)$ would be computed as follows. Let $QD_{hd}$ equal the system demand in hour h of day d. Define

$$w_{hd} = \frac{QD_{hd}}{\sum_{d=1}^{D}\sum_{h=1}^{24} QD_{hd}}$$

Suppose that the standardized forward contracts are for an entire quarter, so that $D$ is the number of days in that quarter. Suppose that supplier $k$ sells $Q_k(Contract)$ MWh of energy for the quarter. The hourly value of the contract for both the buyer and seller of the contract is $Q_{hdk} = w_{hd} \times Q_k(Contract)$. Specifically, the quarterly total amount of energy sold is allocated to hours in the quarter according to the actual load shape during that quarter. Figure 10.1 plots the average daily load shape for 2008 and 2015. The values of the $w_{hd}$ would be higher during the hours of the day when the value of system load is higher, which would make $Q_{hdk}$ higher during those hours. Alternatively, the market operator could specify values of the $w_{hd}$ in advance based on historical values. The basic idea of this approach is to adjust the hourly values of the total amount of energy sold in a quarter to match the hourly load shape to limit the deviations between $Q(Contract)$ and the efficient level of $Q(Ideal)$ on an hourly basis for each supplier.

This standardized product could be offered by Derivex or some other entity, but the important aspect of this mechanism is that all retailers and free consumers are required to purchase at least the mandated percent of their realized load at various horizons to delivery or face financial penalties. This will create the demand for these standardized forward contracts. Generation unit owners will be limited in their ability to sell these contracts by their Firm Energy Values. Prices paid for these contracts will be determined through market mechanisms. Suppliers and loads are free to re-trade these obligations. The only requirement is that once a retailer makes its forward contracting compliance filing with the regulator and XM, it is no longer allowed to sell the contracts it has used for compliance. These must be held to the clearing date of the contract. For the regulated retail customers, the purchase prices of these forward contracts can also be used to set the wholesale price implicit in the regulated retail price over the time horizon that the forward contract clears. Specifically, the average price paid for standardized contracts that deliver during a given quarter by an electricity retailer can be used to set the average wholesale price of power during that quarter implicit in the quarterly regulated retail price. Consequently, one benefit of this reliability mechanism is that it provides a transparent market price to set the wholesale price component of a retailer's regulated retail price.

A final point to emphasize about this reliability mechanism is that there is no prohibition on generation unit owners or retailers engaging in other hedging arrangements outside of this mechanism. Specifically, a generation unit owner could enter into a bilateral contract for energy with another generation unit owner or a retailer. Because it mandates purchases of standardized contracts out to four years into the future, this reliability mechanism should stimulate the development of an active forward market for individually designed products to hedge the residual risks that suppliers, retailers and free consumers face that cannot be hedged with the standardized forward contract at these time horizons to delivery. This mechanism is designed to ensure reasonable market prices and the maximum supply of energy during El Niño Events.

If there is a desire to base this reliability mechanism on standardized forward contracts that clear the same volume of energy each hour during the term of the contract, instead of load-shape-weighted contracts, there would be an even greater need to develop a market for bilateral forward contracts to hedge the residual revenue risk between selling $Q_{hk}(Ideal)$ in Bolsa market and $Q_{hk}(Contract)$ in the standardized forward market for each supplier.

### 10.1.1 Advantages of Proposed Approach for Enhancing Long-Term Resource Adequacy

This mechanism has a number of advantages relative to the current RPM approach. First, it relies on only one of the difficult-to-set parameters of the RPM: the Firm Energy Value. Second, it does not rely on an "unreasonable" level of contract enforcement. There is no up-front payment that can accumulate that requires refunds at a later date. Derivex or XM can operate the standardized forward contract and manage the risk of financial default of all buyers and sellers of the contracts through its existing margin requirements process in a manner consistent with how any standardized forward market operates. The market operator can tailor the margin requirement process to the financial health of individual market participants, if necessary. If a supplier has sold energy forward at a substantially lower price than the Bolsa price that it is likely to clear against, the market operator can require this market participant to post additional funds to ensure that the supplier will follow through with its forward market commitment. Derivex already has established a clearinghouse function, so it should be able to efficiently manage this process to ensure all market participants comply with the terms of standardized forward contracts.

It is not unusual for standardized forward markets for energy to have outstanding volume trading at horizons to delivery up to four years in the future. The New York Mercantile Exchange (NYMEX) offers standardized forward contracts that clear up to 10 years in the future for natural gas and oil. There is typically significant outstanding volume in these contracts at delivery horizons at least four years into the future. Over the past 10 years, oil and natural gas markets have shown significant price volatility yet these standardized futures markets have continued to operate. Based on this evidence it appears feasible to manage the margin requirements on standardized electricity contracts in Colombia with delivery horizons up to four years in the future.

Our proposed reliability mechanism does not require hydroelectric suppliers to maintain minimum water levels. Nor does it require thermal suppliers to maintain contracts for the fossil fuel needed to provide their Firm Energy. However, as noted above, this mechanism subjects thermal suppliers that do not produce at least the contracted quantity of energy with the risk of purchasing this energy at an extremely high price in the short-term market. The same risk applies to hydroelectric generation units owners if they are unable to produce at least their contracted level of energy. However, it should stimulate the market to re-insure these risks between market participants to ensure that energy purchased by retailers and free consumers in standardized forward contracts is supplied at least cost.

This mechanism focuses on ensuring that there is adequate energy available to meet system demand at a reasonable price during El Niño Events and competition between thermal and hydroelectric suppliers to maintain reasonable prices during other water conditions. In particular, it encourages water conservation during periods suspected to transition into El Niño Events. Based on historical market outcomes during all other water conditions, competition between thermal and hydroelectric suppliers appears to be sufficient to discipline prices. This mechanism is likely to make this competition even more vigorous because the thermal suppliers that do not submit offers to supply energy in the short-term market at their variable cost face the risk that the hydroelectric suppliers raise the Bolsa price above the variable cost of the thermal supplier and so the thermal supplier earns lower profits because it must purchase energy from the short-term market at this higher price to meet its forward contract obligation. Finally, this mechanism eliminates the dramatic changes in the incentives for the offer behavior of suppliers with a significant ability to exercise unilateral market based on the value of an administratively set scarcity price shown in Chapter 6. This mechanism does not have a Scarcity Price, so all of the problems associated with setting its value are eliminated.

We now discuss why we believe this mechanism will achieve long-term resource adequacy in a more cost-effective manner than the current RPM mechanism. Before each compliance period for the standardized-forward-contract reliability mechanism the following sequence of events would occur. Each retailer and free consumer would show the regulator the quantity of contracts that it has purchased at various horizons to delivery. Specifically, each retailer would show the total energy purchased in each quarterly standardized forward contract for each quarter over the next four years. This showing would be validated by Derivex or whatever entity operates the standardized forward market. These contracts would then be placed in that retailer's compliance account and held until the clearing date. The retailer would not be allowed to sell these contracts.

On the supply side of the market, all generation unit owners can only sell a quantity of energy in a standardized forward contract in any future delivery quarter over the next four years that is in the range of their allowable energy contract quantities for that quarter. The allowable range of contract quantities for a supplier is based on our earlier requirements that all hydroelectric units sell no more than the unit's Firm Energy Value in a forward contract and thermal generation owners sell at least their Firm Energy Value and no more than the capacity of their unit in a forward contract. Summing over all of the units that a supplier owns gives the allowable range of forward contract quantities that a supplier can sell in any delivery quarter. As part of the reliability mechanism, the regulator assigns to each actual or proposed new generation unit a Firm Energy Value and the time interval over which this Firm Energy Value is valid. For existing units this Firm Energy Value would be valid for each future quarter until the unit retires. For new units, this Firm Energy Value would only be valid from the proposed initial operating date of the new generation unit until the unit retires.

For example, suppose that the suppliers owns hydroelectricity units with a quarterly Firm Energy Value equal to 40 GWh and thermal units with a quarterly Firm Energy Value of 50 GWh and maximum capacity energy equal to 55 GWH. In this case, the supplier is allowed to sell between 90 GWh and 95 GWh in the standardized forward contracts for energy during that quarter. Based on the existing and proposed capacity a supplier has and the operating date and retirement dates of these units, the quarterly allowable forward contract quantities can be constructed for each supplier for the next four years.

If the regulator is concerned that adequate new generation capacity is being built to meet future demand, milestones could be set for completing the proposed generation project that is the basis for a forward contract energy sale. For example, if energy was sold four years in advance based on proposed generation unit, then construction of the new unit must begin within a pre-specified number of months after the signing date of the contract, or the contracted quantity of energy would be automatically liquidated. This means the supplier would have to buy back the energy that it sold based on the Firm Energy Value of the proposed unit. Other completion milestones would also have to be met at future dates to ensure the unit will be ready to provide energy on its original initial operating date and if any of these milestone were not met, the contract would be liquidated. On this point, it is important to emphasize that in order for a supplier to liquidate contracted energy, the supplier must find a willing seller of the energy that it previously sold in a standardized forward contract. Because the retailers and free consumers that purchased these contracts must use them to meet their compliance obligations, buying back this energy is likely to require the supplier to pay an extremely high price, which provides the supplier with a strong incentive to deliver the Firm Energy sold from a proposed generation unit. Because of these incentives, our proposed mechanism is unlikely to leave nearly as many, if any, proposed projects sold as standardized-contract energy to be canceled or completed far behind schedule. This mechanism provides a straightforward procedure for penalizing sellers of standardized-contract energy from proposed generation units that fail to deliver the energy that the retailer or free consumer purchased.

This mechanism is likely to stimulate cross-hedging between suppliers of standardized-contract energy from proposed generation units. For example, if a firm sells energy from a proposed unit it may work an agreement with another project owner to purchase this energy at an agreed upon price in the event that this generation unit is not built. This agreement provides insurance against seller of standardized-contract energy having to buy back this standardized-contract energy at very high price.

### 10.1.2 Fostering Liquidity in the Forward Market for Energy at Long Delivery Horizons

In closing this discussion, it is important to emphasize that one goal of this mechanism is to develop a liquid forward market at long enough delivery horizons to ensure protection against El Niño Events at a reasonable price to Colombian consumers. Signing a fixed-price forward contract for energy or capacity a day, month, or even a year ahead of delivery limits the number of suppliers and modes of supply that are able to provide this energy. For example, a contract negotiated one day in advance limits the sources of supply to existing generation unit owners able to produce energy the following day. Even a year in advance limits the sources that can compete with existing generation unit owners, because it takes longer than eighteen months to site and build a substantial new generation unit in virtually all wholesale electricity markets. To obtain the most competitive prices, at a minimum, the vast majority of the fixed-price forward contracts should be negotiated far enough in advance of delivery to allow new entrants to compete with existing suppliers. This is why the mechanism mandates forward contract purchases by retailers and free consumers at up to 4 year horizons in advance of delivery, or even longer if this is determined to be necessary by the regulator.

Focusing the long-term resource adequacy process on the construction of generation units as the current RPM mechanism does also misses the important point that there is an increasing number of ways for markets to achieve long-term resource adequacy besides building generation units. For example, by the appropriate choice of the mix of generation units, the same pattern of hourly demands throughout the year can be met with less total generation capacity that can also cost electricity consumers less. Distributed generation, storage investments, and active demand-side participation in the wholesale market can also allow the same number of customers to be served with less grid-connected generation capacity.

One question often asked about an approach that focuses on the development of an active forward market for energy is whether sufficient generation resources will be built to meet demand if consumers only purchase standardized forward contracts that clear against the short-term price. On this point, it is important to bear in mind the incentives faced by a seller of the forward financial contract once this contract has been sold. The supplier has an obligation to ensure that the forward contract quantity of energy can be purchased in the short-term market at the lowest possible short-term price. The seller of the contract bears all of the risk associated with higher short-term prices. In order to prudently hedge this risk, the seller has a very strong incentive to ensure that sufficient energy is available from its generation units or generation units owned by other market participants to set the lowest possible price in the short-term market for the quantity of energy it sold in the fixed-price forward contract.

This logic implies that if a supplier signs a forward contract guaranteeing the price for 500 MWh of energy for 24 hours a day and 7 days per week, it will construct or contract for more than 500 MW of generation capacity to hedge this short-term price risk. Building only a 500 MW facility to hedge this risk would be extremely imprudent and expose the supplier to significant risk, because if this 500 MW facility is unavailable to provide electricity, the supplier must purchase the energy from the short-term market at the price that prevails at the time. Moreover, if this generation unit is unavailable, then the short-term price is likely to be extremely high.

A final issue concerns how to transition from the RPM mechanism to the standardized forward contracts mechanism. The most straightforward approach would be to assign all generation units standardized forward contracts equal to their Firm Energy Value for the term of the unit's RPM Firm Energy contract. The contract price would be set equal to an average per MWh Bolsa market revenue plus total Firm Energy Revenue (payments less refunds) over a number of years that is sufficient to account for the relative frequency that normal water years versus El Niño Events years occur. This price could then be adjusted up or down by the regulator on a case-by-case basis to ensure no suppliers are harmed or excessively benefited by this transition.

## 10.2 Matching the Market Mechanism to Actual System Operation

The increasing incidence of transmission congestion discussed in Chapter 8 and the high cost of Automatic Generation Control (AGC) can be addressed by explicitly recognizing the configuration of the transmission network and other operating constraints in the operation of the short-term market. An important lesson from electricity market design processes around the world is the extent to which the market mechanism used to dispatch and operate generation units is consistent with how the grid is actually operated. In the early stages of electricity supply industry reform processes, many regions attempted to operate wholesale markets that used simplified versions of the transmission network. These markets often assumed infinite transmission capacity between locations in the transmission grid or only recognized transmission constraints across large geographic regions. These simplifications of the transmission network configuration and other relevant operating constraints created many opportunities for market participants to take advantage of the fact that in real-time the actual configuration transmission network and other real-time operating constraints would need to be respected.

Setting a single market-clearing price for an hour for an entire country as is the case for Colombia can result in generation units that do not win in the auction that must operate and generation units that win in the auction that cannot operate. This outcome occurs because of the location of demand and available generation units within the region and the configuration of the transmission network prevents some of these low-offer-price units from producing electricity and requires some of the high-offer-price units to supply electricity. In Colombia, the former “constrained on” units provide positive reconciliations and the latter “constrained off” units provide negative reconciliations.

This outcome creates a market design challenge because how generation units are compensated for being constrained on or constrained off impacts the offer prices they submit into wholesale energy market. For example, if generation units are paid their offer price for electricity when they are constrained-on and the unit’s owner knows that it will be constrained-on, a profit-maximizing unit owner will submit an offer price far in excess of the variable cost of operating the unit and raise the total cost of electricity supplied to final consumers. A similar set of circumstances can arise for constrained off generation units. For example, in Colombia constrained-on hydroelectric units are paid the Bolsa price whereas constrained-on thermal units are paid their variable cost. This creates an incentive for hydro units that know they are required to operate to submit high offer prices, because they know this raises the price they will receive for their electricity if they receive positive reconciliation payments. On the other hand, thermal unit owners that know they are required to operate have a strong incentive to offer in at their variable costs because this at least gives them a chance of receiving a Bolsa price in excess of their variable cost. The low incidence of positive reconciliations for thermal units during the most recent El Niño Event suggests thermal suppliers accounted for this fact in making their offers. Because generation unit owners receive no compensation for providing negative reconciliations, units that know they will be unable to operate because of transmission constraints have an incentive to submit high offer prices if they have other generation units that they expect to supply energy because this action can raise the price the generation units that operate are paid for their energy.

### 10.2.1 Locational Marginal Pricing (LMP)

The incentives for supplier behavior caused by the positive and negative reconciliation process in Colombia are caused by the difference between the market model used to set dispatch levels and market prices and the actual operation of the generation units needed to serve demand. The single price Colombia market model assumes enough transmission capacity so that transmission congestion never occurs. The reality of operating the Colombian transmission network must take into account transmission constraints. Multi-settlement wholesale electricity markets that use locational marginal pricing (LMP), also referred to as nodal pricing, avoid these constrained on and constrained off problems, because all relevant transmission and other relevant operating constraints are respected in the process of determining dispatch levels and prices in the wholesale market.

Generation unit owners and load serving entities submit their location-specific willingness-to-supply energy and willingness-to-purchase energy to the wholesale market operator, but prices and dispatch levels for generation units at each location in the transmission network are determined by minimizing the as-offered costs of meeting demand at all locations in the transmission network subject to all network operating constraints. No generation unit will be accepted to supply energy if doing so would violate a transmission or other operating constraint. This process sets potentially different prices at all locations in the transmission network, depending on the configuration of the transmission network and geographic location of demand and available generation units. Because the configuration of the transmission network and the location of generation units and demands is taken into account in operating the market, only generation units that can actually operate will be accepted to serve demand and they will be paid a higher price or lower price than the average LMP, depending on whether the generation unit is in a generation-deficient or generation-rich region of the transmission network. The nodal price at each location is the increase in the minimized value of the as-offered costs objective function as a result of a one unit increase in the amount of energy withdrawn at that location in the transmission network. Bohn, Caramanis, and Schweppe (1984) provide an accessible discussion of the properties of this market mechanism.

Another strength of the LMP market design is the fact that other constraints that the system operator takes into account in operating the transmission network can also be accounted for in setting locational prices and dispatch levels. For example, suppose that reliability studies have shown that a minimum amount of energy must be produced by a group of generation units located in a small region of the grid. This operating constraint can be built into the LMP market mechanism and reflected in the resulting LMPs. An additional advantage of an LMP market for Colombia is that the procurement of ancillary services such as AGC can be co-optimized with the procurement of energy. Suppliers would submit separate offers for energy and each ancillary service and the LMP algorithm would solve for the minimum as-offered cost of simultaneously meeting all energy and ancillary services demands subject to transmission constraints and all other relevant operating constraints. This process would simultaneously set internally consistent locational marginal prices for energy and all ancillary services.

### 10.2.2 Multi-Settlement Markets

Multi-settlement nodal-pricing markets have been adopted by all US jurisdictions with a formal short-term wholesale electricity market. A multi-settlement market has a day-ahead forward market that is run in advance of real-time system operation. This market sets firm financial schedules for all generation units and loads for all 24 hours of the following day. Suppliers submit generation unit-level willingness-to-supply curves for each hour of the following day and electricity retailers submit demand curves for each hour of the following day. The system operator then minimizes the as-offered cost to meet these demands for all 24 hours of the following day subject to the anticipated configuration of the transmission network and other relevant operating constraints during all 24 hours of the following day. This gives rise to LMPs and firm financial commitments to buy and sell electricity each hour of the following day for all generation unit and load locations.

These day-ahead commitments do not require a generation unit to supply the amount sold in the day-ahead market or a load to consume the amount purchased in the day-ahead market. The only requirement is that any shortfall in a day-ahead commitment to supply energy much be purchased from the real-time market at that same location. Any production greater than the day-ahead commitment is sold at the real-time price at that same location. For loads, the same logic applies. Additional consumption beyond the load's day-ahead purchase is paid for at the real-time price at that location and the surplus of a day-ahead purchase beyond actual consumption is sold at the real-time price at that location. This process of a market setting day-ahead firm financial commitments and a real-time market for imbalances relative to these day-ahead schedules is what is meant by a multi-settlement market.

In all US multi-settlement markets, real-time LMPs are determined from the real-time offer curves from all available generation units and dispatchable loads by minimizing the as-offered cost to meet real-time demand at all locations in the control area taking into account the current configuration of the transmission network and other relevant operating constraints. This process gives rise to LMPs at all locations in the transmission network and actual hourly operating levels for all generation units. Real-time imbalances relative to day-ahead schedules are cleared at these real-time prices.

For example, suppose that a generation unit owner sells 50 MWh in the day-ahead market at $60/MWh. It receives a guaranteed $3,000 in revenues from this sale. However, if the generation unit owner fails to inject 50 MWh of energy into the grid during that hour of the following day, it must purchase the energy it fails to inject at the real-time price at that location. Suppose that the real-time price at that location is $70/MWh and generator only injects 40 MWh of energy during the hour in question. In this case, the unit owner must purchase the 10 MWh shortfall at $70/MWh. Consequently, the net revenues the generation unit owner earns from selling 50 MWh in the day-ahead market and only injecting 40 MWh is $2,300, the $3,000 of revenues earned in the day-ahead market less the $700 paid for the 10 MWh real-time deviation from the unit's day-ahead schedule.

If a generation unit produces more output than its day-ahead schedule, then this incremental output is sold in the real-time market. For example, if the unit produced 55 MWh, then the additional 5 MWh beyond the unit owner's day-ahead schedule is sold at the real-time price. By the same logic a load-serving entity that buys 100 MWh in the day-ahead market but only withdraws 90 MWh in real-time, sells the 10 MWh not consumed at the real-time price. Alternatively, if the load-serving entity consumes 110 MWh, then the additional 10 MWh not purchased in the day-ahead market must be purchased at the real-time price.

A multi-settlement LMP market can allow suppliers in Colombia far greater flexibility in scheduling their generation units in a physically feasible manner throughout the day than the existing single-settlement market because transmission constraints and all other relevant operating constraints are taken into account in solving for day-ahead schedules for all 24 hours of the following day. All US LMP markets allow each generation unit to submit a start-up cost offer and multiple price steps and quantity steps each hour of the day, rather than the current market design in Colombia of a single price step for the entire day and single quantity step for each hour of the day. Expanding this to at least 5 price steps per day per generation unit and at least 5 quantity steps per hour would provide sufficient flexibility to generation unit owners to achieve the least cost pattern of operation throughout the day in the day-ahead market. Even under the existing single settlement market design in Colombia it is difficult to see how one price step per unit per day and one quantity step per unit each hour is allowing suppliers sufficient flexibility to achieve their least cost pattern of production throughout the day.

All US markets started the electricity restructuring process with significantly less extensive transmission networks relative to their counterparts in other industrialized countries, and initially all of them attempted to operate a wholesale market that did not fully account for the configuration of the transmission network and all relevant operating constraints in the market mechanism. All of them eventually switched to a LMP market design. By this same logic, a multi-settlement nodal-pricing market is well-suited to Colombia because it explicitly accounts for the configuration of the actual transmission network in setting both day-ahead energy schedules and prices and real-time output levels and prices. This market design eliminates the need for the positive and negative reconciliation process that can increase the total cost of wholesale electricity to final consumers because of differences between the prices and schedules that the market mechanism sets and how the actual electricity network operates.

Wolak (2011) quantifies the magnitude of the economic benefits associated with the transition to nodal pricing from a zonal-pricing market such as one that currently exists in Colombia. On April 1, 2009 the California market transitioned to a multi-settlement nodal pricing market design from a multi-settlement zonal- pricing market. Wolak (2011) compares the hourly conditional means of the total amount of input fossil fuel energy in BTUs, the total hourly variable cost of production from fossil fuel units, and the total hourly number of starts from fossil fuel units before versus after the implementation of nodal pricing, controlling non-parametrically for the total of hourly output of the fossil fuel units in California and the daily prices of the major input fossil fuels. Total hourly BTUs of fossil fuel energy consumed to produce electricity is 2.5 percent lower, the total hourly variable cost of production for fossil fuels units is 2.1 percent lower, and the total number of hourly starts is 0.17 higher after the implementation of nodal pricing. This 2.1 percent cost reduction implies a roughly $105 million reduction in the total annual variable costs of producing fossil fuel energy in California associated with the introduction of nodal pricing. The economic benefits to Colombia are likely to be even greater due to the fact that it currently operating a single-pricing-zone market rather than a multiple-pricing-zone market as was the case in California.

One complaint often leveled against LMP markets is that they increase the likelihood of political backlash from consumers because prices paid for wholesale electricity can differ significantly across locations within the same geographic region. For example, customers in urban areas that primarily import electricity over congested transmission lines will pay more than customers located in generation-rich rural regions that export electricity to these regions. Because more customers live in the urban areas than in the rural regions charging final consumers a retail price that recovers the LMP at their location may be politically challenging for the regulator to implement.

Many regions with LMP pricing have overcome this potential problem by charging all customers in a given state or utility service territory a weighted average of the LMPs in the region. In the above example, this implies charging the urban and rural customers the weighted average of the LMPs in urban and rural areas, where the weight assigned to each price is the share of system load that is withdrawn at that location. Under this scheme, generation units continue to be paid the LMP at their location, but all loads pay a geographically aggregated hourly-price. This approach to pricing captures the reliability and operating efficiency benefits of an LMP market while addressing the equity concerns regulators often face with charging customers at different locations prices that reflect the configuration of the transmission network. Colombia could implement an LMP market with this approach to pricing electricity to final consumers. Our recommended reliability mechanism would then be modified to clear all standardized forward contracts against this hourly load-weighted average of the LMPs across load withdrawal points in Colombia.

A final source of benefits from adopting a multi-settlement LMP market is that Colombia could allow purely financial participants to enter the market and compete with existing retailers that have generation affiliates. As shown in Wolak (2016), the introduction of a standardized forward market in Singapore led to the entry of purely financial electricity retailers than led to significantly lower retail prices as well as lower wholesale prices. There is no reason that such an outcome could not occur if Colombia allowed the entry of purely financial participants in its wholesale and retail markets. Our recommended reliability mechanism would facilitate their entry and the associated financial benefits to Colombian consumers.

### 10.2.3 Managing and Mitigating System-wide and Local Market Power

The configuration of the transmission network, the level and location of demand, as well as the level of output of other generation units can endow certain generation units with a significant ability to exercise unilateral market power in a wholesale market. A prime example of this phenomenon is the constrained-on generation problem described earlier. The owner of a constrained-on generation unit knows that regardless of the unit's offer price, it must be accepted to supply energy. Without a local market power mitigation mechanism, there is no limit to what offer price that supplier could submit and be accepted to provide energy. The positive and negative reconciliation process in Colombia serves this role under the current market design. If Colombia transitions to a multi-settlement LMP market, it still needs a local market power mitigation mechanism.

Offer-based LMP markets require a local market power mitigation (LMPM) mechanism to limit the offers a supplier submits when it faces insufficient competition to serve a local energy need because of the combination of the configuration of the transmission network and concentration of ownership of generation units. A LMPM mechanism is a pre-specified administrative procedure (written into the market rules) that determines: (1) when a supplier has local market power worthy of mitigation, (2) what the mitigated supplier will be paid, and (3) how the amount the supplier is paid will impact the payments received by other market participants. Without a prospective local market power mitigation mechanism, system conditions are likely to arise in all wholesale markets when almost any supplier can exercise substantial unilateral market power. There are a number of LMPM mechanisms that exist in the US. None are perfect, but all are adequate to the task and have their advantages and disadvantages. If Colombia does move forward with an LMP market, this should be accompanied with an explicit LMPM that meets the three requirements discussed above, or it could simply adopt one of the existing mechanisms from the US.

## 10.3 Summary of Recommendations

We present comprehensive empirical evidence that the current RPM mechanism was a significant contributing factor to the extreme market outcomes during the current El Niño Event. We do not believe it can be modified to overcome many of the factors which led to these adverse market outcomes. For this reason, we propose an alternative approach specifically designed to ensure a reliable supply of energy and a reasonable price during El Niño Events.

In terms of longer-term changes to the Colombian electricity supply industry, we recommend the adoption of a multi-settlement locational marginal pricing market with a co-optimized energy and ancillary service auction and a fully-integrated local market power mitigation mechanism. We recommend increasing the number of price steps each generation unit is allowed to offer each hour. We also recommend allowing purely financial participants into the wholesale and retail electricity markets. Finally, we support reforming the natural gas industry in Colombia to create a more vibrant wholesale market to supply natural gas to the electricity sector.

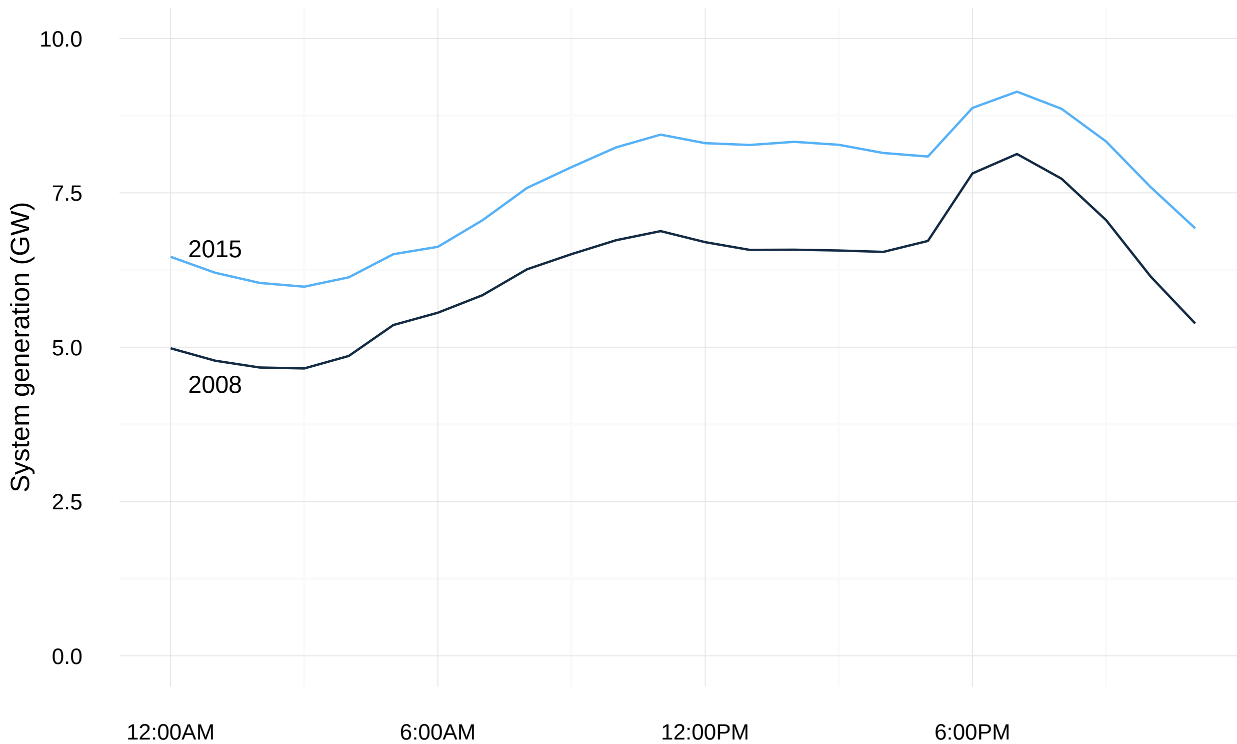
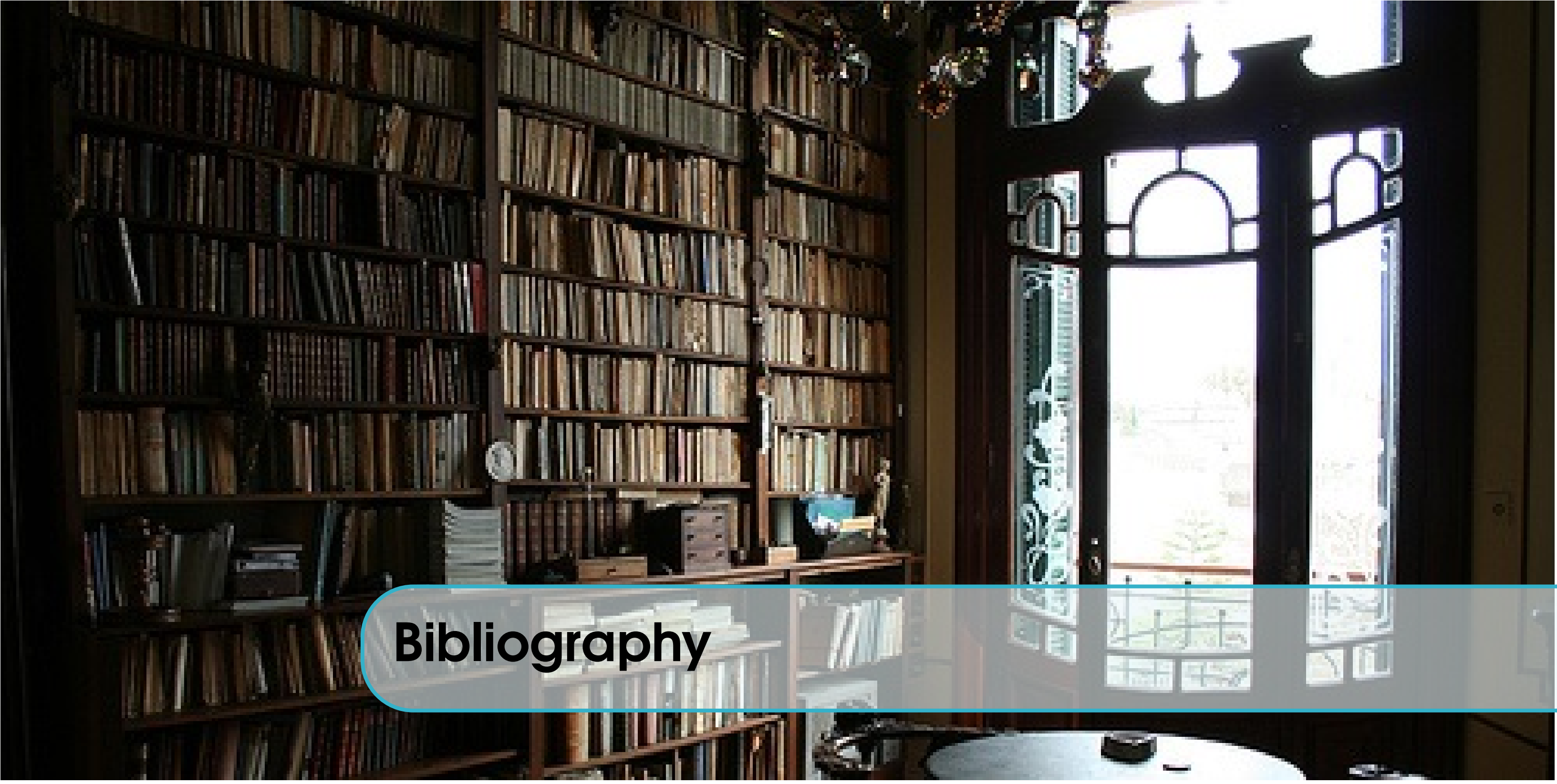



Figure 10.1: Profile of mean hourly generation for 2008 and 2015



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