Market power and incentive-based capacity payment mechanisms*

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Abstract

Capacity markets provide guaranteed payments to electricity generation unit owners for having the "firm capacity" to produce electricity. Historically, these markets are plagued by the weak incentives they provide for plants to be available during high-demand hours. The reliability payment mechanism in the Colombian electricity market provides market-based incentives for plants to produce during periods of system scarcity. This market has served as a model for the design of capacity markets in a number of jurisdictions in North America and Europe. We demonstrate severe shortcomings of this mechanism. By adjusting their price and quantity offers, generators with the ability to exercise unilateral market power can choose whether or not a scarcity condition exists. We find that this mechanism can make it privately profitable for a firms to withhold output and create a scarcity condition. We illustrate this problem using hourly data from the first ten years of operation of the reliability payment mechanism in Colombia. The mechanism not only fails to minimize the cost of meeting electricity demand but also creates perverse incentives for electricity generators that could reduce the reliability of electricity supply. We quantify the cost of the perverse incentives caused by this capacity payment mechanism by computing a counterfactual dynamic oligopoly equilibrium for the 2015–16 El Niño event in Colombia.

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1 Introduction

In restructured electricity markets, capacity payment mechanisms provide a fixed payment to generation unit owners for the ability of these units to produce energy, even if these units do not produce any energy. The original motivation for these mechanisms was to provide an additional revenue stream for infrequently-used plants that might not cover their fixed costs from energy sales alone. The expansion of intermittent renewable generation has both aggravated this revenue adequacy problem and increased the need to keep backup generation available. While traditional capacity markets have provided additional revenue to generation unit owners, their design suffers from the relatively weak incentives they provide for plants to be available during critical system conditions (Bushnell et al., 2017).

As a result, many electricity markets are changing the design of their capacity mechanisms to provide stronger incentives for generators to be available during periods of system scarcity. These market-based incentives typically take the form of reliability option contracts that provide a implicit financial penalty to generation units that do not produce sufficient energy during critical conditions. The strike price for such options is set based on the marginal cost of the highest-cost generation technology in the system. When the wholesale market price exceeds the strike price, generation firms that do not produce the "firm capacity" from their generation units that was sold in the capacity market must refund the difference between the market and strike prices for their generation shortfall. Generation firms that produce more than their "firm capacity" receive the market price (which exceeds the strike price) for their additional output.

In this paper, we demonstrate a potentially severe flaw in capacity mechanisms based on reliability option contracts. Generation firms with market power may have the ability to choose whether or not the scarcity condition is triggered and the option is exercised. Even if the short-term wholesale market typically yields competitive market outcomes, it is during peak demand conditions—when the generation capacity is most required—that market power problems are greatest. The incentive for generators to trigger scarcity conditions depends on the relative magnitudes of their "firm capacity" quantities and their forward contract quantities. In some circumstances, we show that the reliability option mechanism increases market prices and the average cost of thermal generation relative to a counterfactual with no capacity payment mechanism at all.

We demonstrate the empirical importance of this problem using ten years of data from the reliability payment mechanism in the Colombian wholesale electricity market. The Colombian experience is highly relevant for the design of reliability options in other markets. Having started in December 2006, it is the oldest and longest-running incentive-based capacity market in the world. Recent and proposed reforms in other markets, including the Peak Energy Refund payment system, the new Pay-for-Performance rules in the New England ISO, the capacity payment mechanism in the Irish electricity market, and the proposed capacity payment mechanism in the Italian electricity market are based at least in part on the Colombian model (Mastropietro et al., 2018). Furthermore, the Colombian electricity market is heavily dependent on hydroelectric generation and suffers from periodic shortfalls in hydro inflows. It is during these low-water periods, when generation capacity requirements are greatest, that generation firms have the ability and incentive to manipulate the reliability option mechanism. Such problems will potentially occur in other markets with a high share of intermittent renewable generation.

We use hourly information provided by the Colombian market operator XM for the period December 2006 to June 2016. This hourly information includes the price and quantity offers for each generation unit, the system demand, the dispatched and actual generation output of each unit, the market price, the capacity contract quantities and prices, and the forward contract positions of each firm. We supplement the hourly data with information on hydrological inflows and storage levels, as well as information on fossil fuel usage and prices.

We first show that firms have the ability to choose whether or not a scarcity condition exists (that is, whether the reliability option is exercised). We calculate the hour-by-hour inverse residual demand curve faced by each firm in the market. When this lies entirely above or below the scarcity price, the scarcity condition will or will not be triggered, regardless of the generation output of the firm. However, when the inverse residual demand curve crosses the scarcity price at a quantity between the firm's minimum and maximum generation output, the firm's choice of generation quantity will determine the existence of a scarcity condition. The largest generation firm in the Colombian market, EPM, has the choice to trigger a scarcity condition in 9.9% of the hours in our sample.

We then calculate the profitability of triggering the scarcity condition by computing the maximum net revenue for the firm each hour under both scarcity and non-scarcity conditions. These revenues are a function of the inverse residual demand, the scarcity price, the capacity contract quantity, and the net forward contract position of the supplier. This calculation provides an accurate prediction of whether or not the scarcity condition is triggered. For EPM, the scarcity condition occurs in 99% of the hours in which it would maximize profits to do so, and it does not occur in 90% of the hours for which it would not be profit-maximizing to do so. Similar results hold for the other two large generation firms in the Colombian market.

Our analysis of plant-level bid data provides further evidence that generators are responding to the incentives created by the reliability option mechanism. During the hours when it is profit-maximizing to avoid triggering the scarcity condition, the distribution of bid prices shows a high degree of bunching immediately below the scarcity price. Conversely, in the hours when it would be optimal to trigger the scarcity condition, the distribution of bid prices lies above the scarcity price.

The observed pattern of bidding behavior had real-world effects on the reliability of the Colombian wholesale market. By keeping the bid prices of the hydro units low to avoid triggering the scarcity condition, more expensive thermal units were underutilized even when drought conditions were imminent. As discussed in McRae and Wolak (2016), the reduced level of storage in hydro reservoirs almost led to electricity rationing in early 2016.

We compare the reliability option mechanism to a counterfactual market structure without the mechanism for the May 1, 2015 to April 30, 2016 period using a dynamic oligopoly model of the three largest hydroelectric generation unit owners in Colombia, accounting for for the intertemporal constraint on firm-level generation determined by total hydro inflows, as in Bushnell (2003). Our counterfactual market structure that eliminates the reliability option, yet retains each supplier's fixed-price forward contract obligations for energy for actual water conditions, 10% lower and 20% lower water conditions for the year, yields significantly lower average wholesale prices and lower average costs for thermal energy produced relative to the reliability option mechanism combined with the energy market.

Our paper contributes to the existing theoretical literature on strategic behavior under capacity payment mechanisms. Fabra (2018) develops a simple analytical framework that incorporates both generation investment and short-run pricing decisions. She studies the cases of reliability options and their potential to mitigate market power, but acknowledges the crucial role for regulators in setting the scarcity price. Her framework does not incorporate the interaction between forward contracts and reliability options. Léautier (2016) also develops an analytical model to compare reliability options with physical capacity certificates and develops conditions under which these are equivalent. Most closely related to our paper, Ritz and Teirila (2019) construct a computational model of the Irish electricity market to study the potential exercise of market power under a system of reliability options. They model the capacity market, generator entry and exit, and the short-run wholesale market. Although the capacity market leads to new generation entry, the exercise of market power by the large incumbent generator in Ireland could increase electricity procurement costs by 40 to 100 percent relative to a competitive counterfactual.

In contrast to these existing papers, the focus of our analysis is on the interaction of reliability options and forward contracts in the short-run wholesale market. We study this issue in a dynamic oligopoly setting where strategic hydroelectric generators exercise market power by shifting their allocation of water. We abstract from the issues of the competitiveness of the capacity market auction and the level of investment in new generation.

In addition to our theoretical contribution, this paper is one of the first empirical studies of how strategic behavior in a wholesale electricity market is affected by a capacity payment mechanism. This is an urgent issue to study as more and more countries adopt an electricity market design that includes some type of capacity payment. An increasing share of final expenditure on electricity is being channeled to generators through these mechanisms instead of through direct purchases of electricity. As we show in our analysis, the reliability option design is not a panacea for market power issues and may even increase the cost for consumers of market power.

Our results are directly relevant for the many wholesale electricity markets that are planning or implementing an incentive-based capacity remuneration mechanism. Reliability options may have unexpected consequences when generators with the ability to exercise unilateral market power can endogenously choose whether or not the option is exercised. The potential reduction in system reliability is particularly troublesome given that electricity consumers are paying the generation firms for these options.

We suggest an alternative approach to long-term resource adequacy that provides strong incentives for the least-cost supply of the energy necessary to serve demand in the future. This mechanism involves a standardized market for fixed-price forward contracts. Retailers must purchased regulator-determined fractions of their realized energy demand from this market at various horizons to delivery. For example, 100% of their annual demand one-year in advance of delivery, 97% two-years in advance, and 95% three years in advance. These forward purchases will provide suppliers with the revenue streams necessary to build the generation capacity necessary serve demand in the future.

The remainder of the paper is organized as follows. Section 2 provides details on the structure of the Colombian electricity market. Section 3 uses a simple theoretical model to show the potential distortions that arise from the reliability payment mechanism. Section 4 presents a series of descriptive and analytical results for the performance of the reliability payment mechanism. Section 7 discusses the results and described our alternative energy contracting-based approach for ensuring long-term resource adequacy.

2 Institutional setting

Restructuring of the electricity industry in Colombia began in 1994. This process was motivated by a period of electricity rationing between March 1992 and March 1993, the result of an El Niño event that reduced inflows into hydro reservoirs.[1] The government lacked the financial capacity to invest in new thermal plants that could act as a backup for hydro generators in dry years (Dyner et al., 2006). After the reforms, there was considerable private investment in thermal capacity during the late 1990s.

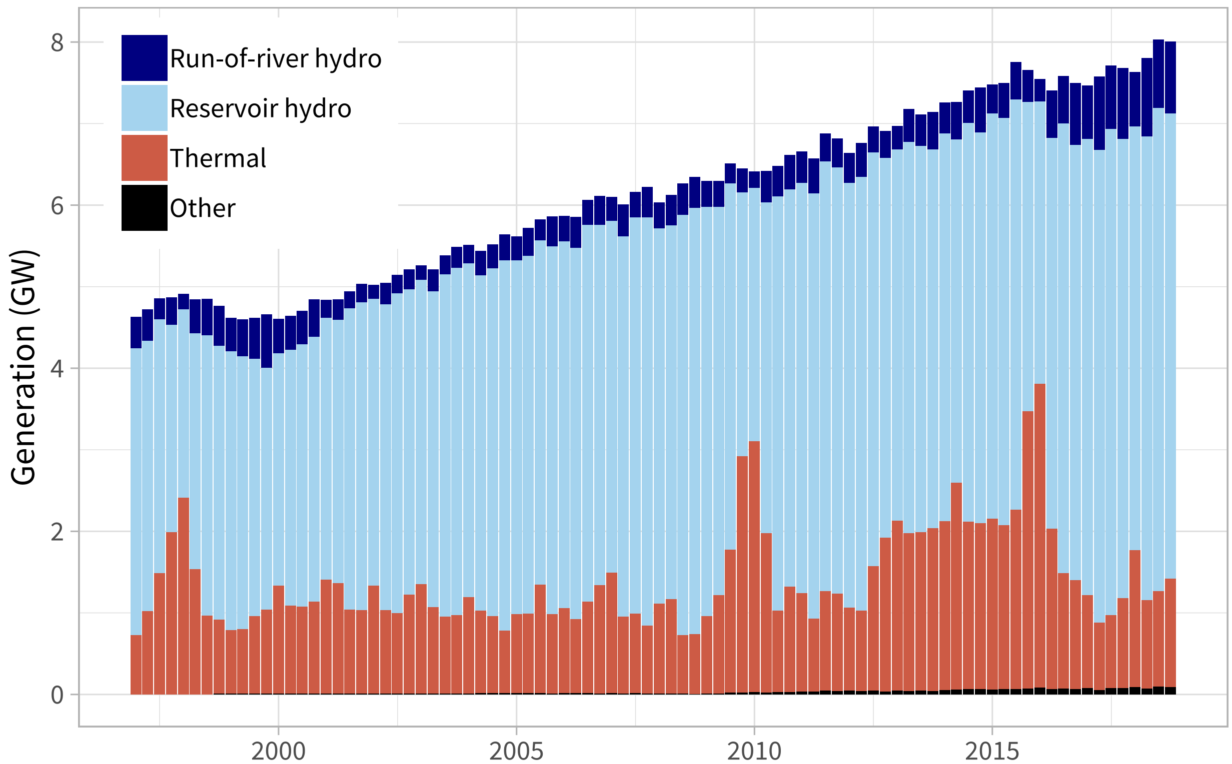
Electricity generation in Colombia remains predominantly hydroelectric. Total generation increased from 4.7 gigawatts (GW) in 2000 to 7.9 GW in 2015, an average annual growth rate of 2.9 percent. Between 2000 and 2009, most of this growth in electricity demand was met by increases in hydro generation (Figure 1). Thermal generation played a larger role between 2012 and 2016, including the 2015–16 period that we study in this paper. More recently, hydro generation has regained its share of total generation. Despite the fall to 72 percent between 2012 and 2015, the share of hydro in 2018 was 82 percent of total generation.

The most striking pattern of the composition of electricity generation in Colombia is the periodic reduction in hydroelectric energy associated with the climatic phenomenon known as *El Niño*. This event is characterized by an increase in water temperatures in the central Pacific Ocean. One effect of this for Colombia is a reduction in rainfall (and hence inflows into hydro reservoirs) in some of the major hydro-producing regions of the country. This reduction in inflows associated with El Niño occurred in 2009–10 and again in 2015–16. As seen on Figure 1, these periods were associated with a large drop in hydroelectric generation and a large increase in thermal generation.

The market design in Colombia is different from that used in any other Latin American market (Rudnick and Montero, 2002). It is based around a central pool in which prices are determined by daily price and quantity bids that generators submit to the system operator. Each generation unit may submit a single price for its output for the entire day. The

[1] Fetzer et al. (2014) use satellite night lights to study the geographical variation in rationing during the 1992–93 blackouts. They show that the electricity shortages led to a short-term increase in fertility and a permanent increase in the number of children.

Figure 1: Quarterly electricity generation in GW, by type of generator, 1997–2018



Notes: Calculation based on plant-level hourly generation data from XM Compañía de Expertos en Mercados (2019b).

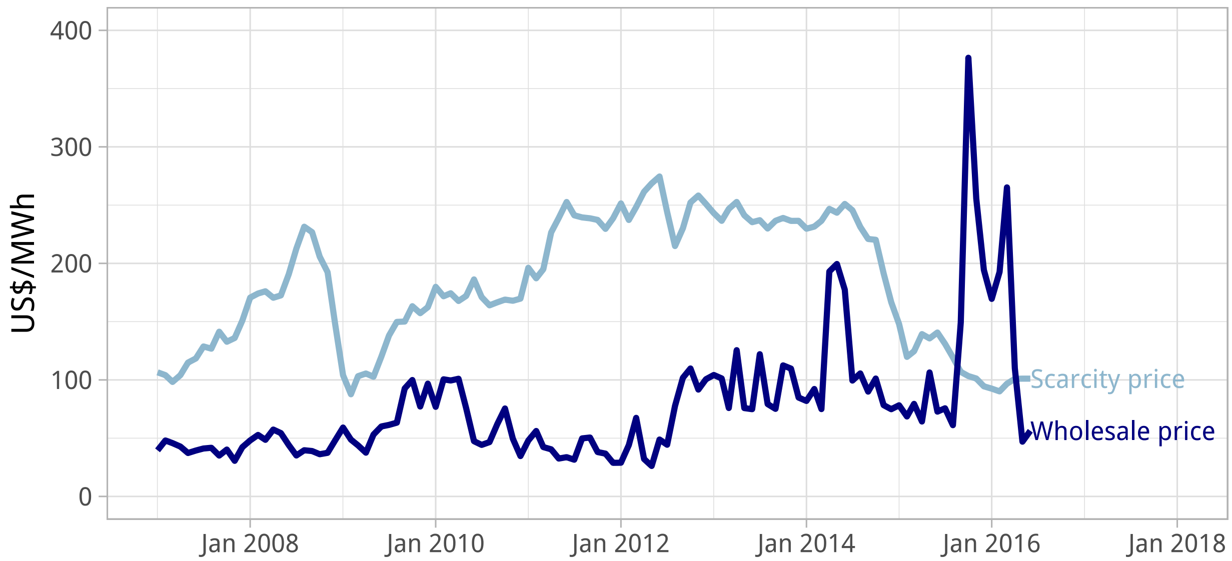
quantity made available from each generation unit is allowed to vary by hour. Beginning in 2009, generators were allowed to submit the startup costs associated with each unit, and the dispatch algorithm used by the system operator ensured that plants were only turned on if they would recover these costs.[2] By contrast to the Colombian market design, the other electricity markets in the region use a cost-based dispatch, in which the "bid price" of each unit is set based on a regulatory cost formula.[3]

The market also includes a system of capacity payments that are made to generators even when they are not producing electricity. The amount of the capacity payment (in $ per MW) is determined by auctions for long-term investment in new generation capacity, first

[2]Riascos et al. (2016) study the effect of including startup costs in the generation bids in the Colombian market. They find that it led to a reduction in production costs but this was not passed through to lower wholesale prices. Reguant (2014) studies the use of these complex bids in the Spanish wholesale electricity market.

[3]Galetovic et al. (2015) describe this mechanism for the case of Chile.

Figure 2: Wholesale market prices and scarcity prices, 2007–2016



Notes: The figure shows the monthly mean wholesale market price and the monthly scarcity price, for each month from 2007 to June 2016. For those hours in which the market price exceeds the scarcity price, generation firms are required to produce at least their firm energy quantity. This condition occurred in almost every hour between October 2015 and March 2016.

held in May 2008 and December 2011.[4] Both existing and new generation plants receive the payments for their assigned capacity, known as the firm energy obligation. During periods when the wholesale price exceeds a regulated "scarcity price", the generators who received these payments are required to pay the difference between the wholesale price and the scarcity price, multiplied by their firm energy quantity. This creates a financial incentive for the generators to make at least their firm energy capacity available during periods of system scarcity, in order to meet this financial obligation. In effect, the price that generators receive for providing their firm energy capacity is capped at the scarcity price, although they still receive the wholesale price for any generation in excess of their firm energy. The scarcity price is recalculated each month based on changes in the price of an international fuel oil benchmark.

For nearly all hours during the first nine years of operation of the reliability payment mechanism, the market price was below the scarcity price, meaning that the scarcity condition was not triggered (Figure 2). This changed during the El Niño event at the end of 2015 and start of 2016. For a six-month period, the market price exceeded the scarcity

[4]Harbord and Pagnozzi (2012) review the design, outcome and performance of these auctions.

price. Generation firms that did not produce their firm energy quantity were required to refund the shortfall, multiplied by the difference between the market and scarcity prices.

The three largest firms in the Colombian market are Empresas Públicas de Medellín (EPM), Emgesa, and Isagen, with a combined generation capacity of 60 percent of the total. These firms are predominantly hydroelectric, although each has a small proportion of thermal generation. Three smaller firms also own significant amounts of hydroelectric generation capacity: Celsia, AES Chivor, and Urrá. Ownership of thermal generation capacity is less concentrated, and there are several small firms that own or operate a single thermal plant.

3 Illustrative model

In this section we provide a simple model to illustrate the interaction of the reliability payment mechanism with the forward contract for energy market and the incentives for generation firm behavior it creates.

Market power is the ability to profitably raise and maintain prices at higher than competitive levels—what they would be if every firm submitted its marginal cost curve as its offer curve. We measure the market power of an electricity supplier by calculating its residual demand curve, the market demand less the quantity supplied by the firm's competitors at each possible market price. At any price, the residual demand curve shows the maximum quantity demanded from the firm based on the market demand and the amount that competing firms will supply at that price.

It is important to emphasize that a generation unit owner does not know the precise form of the residual demand curve it will face when it submits it bids into the short-term market because all firms submit their bids at the same time. In addition, the realized demand is unknown at the time supplier submit their offers. The market operator then aggregates these bids and crosses them with the realized demand to compute the market-clearing price paid to all generation units each hour of the day. Firms in Colombia are able to observe the bids submitted by their competitors and water levels of hydroelectric resources with a two-week delay, which helps them to predict the residual demand curve they will face.

When the firm chooses the offer curve to submit to the market operator, it is effectively choosing the point along its realized residual demand curve that it will operate. By definition, the firm will produce the generation quantity and receive the wholesale price that are set by the price and quantity pair where its offer curve crosses its realized residual demand curve. As discussed in Wolak (2000) and Wolak (2002) the firm chooses the bid price and quantity increment combinations that make up its aggregate willingness-to-supply curve given the distribution of possible residual demand curves that it faces to maximize its expected profits given the variable cost of operating its generation units.

In most electricity markets, including the Colombian wholesale market, the offer curves submitted by generators are step functions. Each step is a price and quantity pair representing the additional generation quantity that the firm is willing to supply at that price. Because the offer curves are step functions, so to are the residual demand curves. However, for analytical simplicity, we assume that residual demands are linear functions for our illustrative model. In our empirical analysis, we utilize the step function residual demand curves.

Suppose a generator faces a downward-sloping inverse residual demand curve:

$$P(Q) = 200 - 20Q \tag{1}$$

The variable Q in this expression is the generation quantity of the firm and $P(Q)$ is the corresponding market price. This inverse residual demand curve is shown in the top graph of Figure 3. For our simplified model, we assume that the firm is able to choose any price and quantity pair along this curve and the that generation unit owner has sufficient generation capacity to operate at any point on the curve.

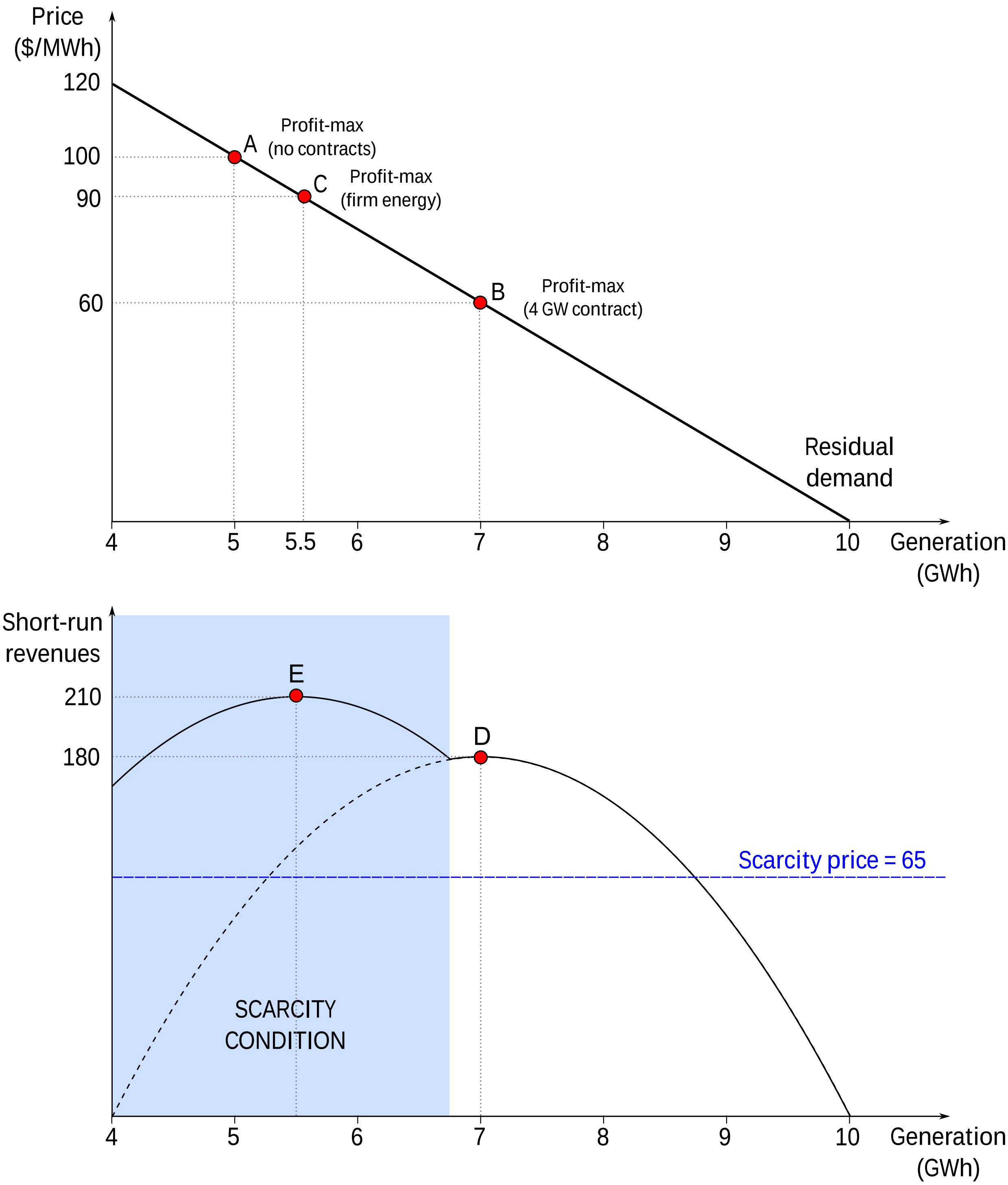
Assume the marginal cost for the generator is zero. In the absence of any forward contracts, the generator will act as a monopolist off its residual demand curve and equate marginal revenue to marginal cost. In this case, $MR = 200 - 40Q$, implying the firm will maximize profits by choosing $Q = 5$ GWh. The market price corresponding to this generation quantity is \$100/MWh. This price and quantity pair is point A in Figure 3.

Fixed-price forward contracts reduce the incentive for electricity generators to restrict their output and increase the market price. Suppose the generator in the example has signed $Q_c = 4$ GWh of forward contracts at a price P_c. With these forward contracts in place, the profit for the firm is now:

$$\mathsf{P} = P_c Q_c + P(Q)(Q - Q_c) - c(Q) \tag{2}$$

In this expression, $c(Q)$ is the cost of producing the generation quantity Q. Note that P_c and Q_c are predetermined at the time the firm is chooses its generation offer. Focusing on

Figure 3: Illustrative example of the effect for generator incentives of forward contracts and the reliability payment mechanism



the middle term (representing the short-run revenues or costs for the firm in the wholesale market), assuming costs are still zero, and substituting the inverse residual demand from Equation (1), gives the following expression for short-run revenues:

$$\begin{aligned} \mathsf{P}^{SR} &= (200 - 20Q)(Q - 4) \\ &= -20Q^2 + 280Q - 800 \end{aligned} \tag{3}$$

The dashed line in the bottom graph of Figure 3 shows this expression for short-run revenues as a function of generation quantity Q.

The generation firm will choose the quantity that maximizes profits: $Q = 7$ GWh. This is point D on the graph of short-run revenues (bottom of Figure 3) and the point B on the residual demand (top of Figure 3). Note that with the forward contracts in place, the firm has less **incentive** to withhold generation to push up the wholesale market price, even though it still has the **ability** to produce at point A on the residual demand curve.

Now suppose we consider the introduction of the reliability payment mechanism to this setting where generation firms have existing forward contracts. The generation firm has a firm energy contract with quantity Q_f and the firm energy payment P_f. There is an administratively-set scarcity price P_s. When the market price $P(Q)$ exceeds P_s, the generator is required to produce Q_f. If it produces less than Q_f, it will pay back the difference between $P(Q)$ and P_s for any shortfall between Q_f and its actual output level.

For the numerical example, assume the firm energy quantity $Q_f = 1$ GW and the scarcity price is $P_s =$\$65/MWh. Note from Figure 3 that the generator controls whether or not the market is in the scarcity condition. If the generation unit owner restricts its output below 5.75 GWh, the market-clearing price from its inverse residual demand curve will exceed \$65/MWh, triggering the scarcity condition.

Suppose the firm chooses to produce more than 5.75 GWh. The profit function will be the same as before, with the addition of the firm energy payment:

$$\mathsf{P} = P_f Q_f + P_c Q_c + P(Q)(Q - Q_c) - c(Q) \tag{4}$$

Because the short-run revenues are identical to Equation (3), point D in Figure 3 will again be locally profit-maximizing, for the case when generation exceeds 5.75 GWh.

Alternatively, suppose the firm produces less than 5.75 GWh and triggers the scarcity condition. The profit function will now be:

$$\Pi = P_f Q_f + P_c Q_c + P_s(Q - Q_c) + (P(Q) - P_s)(Q - Q_f) - c(Q) \tag{5}$$

The price that the firm will pay (or receive) in the wholesale market for generating less (or more) than the forward contract quantity Q_c is capped at the scarcity price P_s. If the firm produces more than its firm energy quantity Q_f, it receives $P(Q)$ for the additional energy it produces beyond Q_f. Conversely, if the firm produces less than its firm energy quantity, it pays the difference between $P(Q)$ and P_s for the generation shortfall. This mechanism is designed to provide incentives for the generator to produce at least its firm energy quantity during scarcity conditions.

Substituting the above parameter assumptions into Equation (5) gives the following expression for short-run revenues in the wholesale market, for the case when the scarcity condition is triggered (that is, when generation is less than 5.75 GWh):

$$\Pi^{SR} = 65(Q - 4) + (200 - 20Q - 65)(Q - 1) \tag{6}$$

$$= -20Q^2 + 220Q - 405 \tag{7}$$

This expression is shown as the solid line in the bottom graph of Figure 3. It is maximized at $Q = 5.5$ GWh, or point E in the figure.

Under the reliability payment mechanism, generators with the ability to exercise unilateral market power can choose whether or not the scarcity condition exists by their output choice. For the example, this decision is a choice between point D (profit-maximizing point with no scarcity condition) and point E (profit-maximizing point with scarcity condition). Profits are higher at E ($210,000) than at D ($180,000). Therefore the profit-maximizing firm will choose to restrict its generation to 5.5 GWh, increasing the market price to $90/MWh, and triggering the scarcity condition.

This is a striking result. The reliability payment mechanism provides an additional revenue stream $P_f Q_f$ to the generator, funded by a charge on electricity consumers. The implicit promise of the mechanism is that it will provide incentives for the generator to make its capacity available during periods when it is most required. Instead, for this example, the generator has an incentive to withhold generation relative to what it would have produced in the absence of the reliability payment mechanism.

The reliability payment mechanism may provide an incentive to withhold generation whenever the firm energy quantity Q_f is less than the forward contract quantity Q_c. This is because the Q_c becomes irrelevant for production decisions when the scarcity condition is triggered. As a result, forward contracts lose their moderating role on the incentives for firms to exercise market power. The following sections will show that this is not just a theoretical possibility. For some generation firms in the Colombian market, particularly those that own a substantial amount hydroelectric generation capacity, it is common for Q_f to lie below Q_c.

4 Empirical analysis

In this section we analyze the bidding and operating behavior of the generators in the Colombian wholesale electricity market to demonstrate the real-world relevance of the stylized model in Section 3.

The data for our analysis was provided by the Colombian market operator XM. We use hourly information on the operation of the market for the period January 2008 to June 2016. This hourly information includes the price and quantity offers for each generation unit, the system demand, the dispatched and actual generation output of each unit, and the market price. We supplement the hourly data with information on hydrological inflows and storage levels, as well as information on fossil fuel usage and prices.

4.1 Large generators have the ability to create scarcity condition

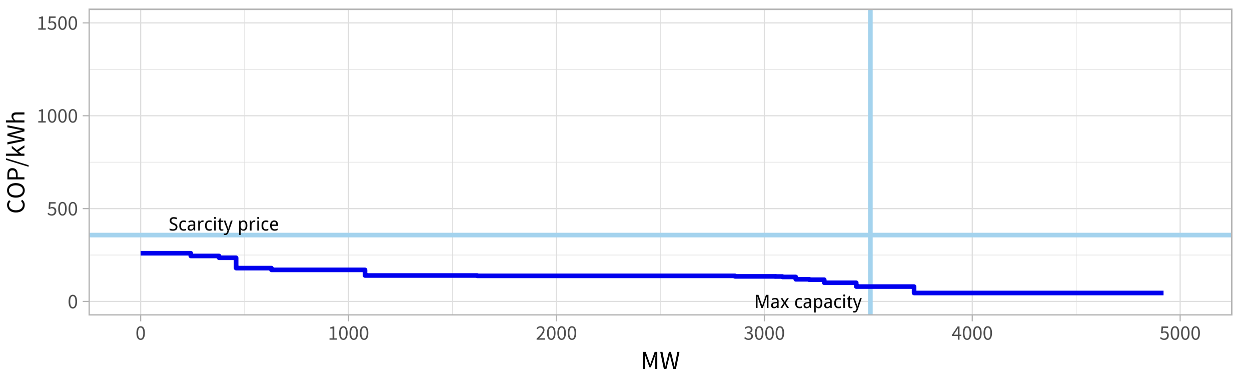
In some hours, the largest generators in the Colombian electricity market have the ability to unilaterally determine whether or not a scarcity condition exists. The realized residual demand of a generator—that is, the realized market demand less the aggregate willingness-to-supply curve of competing generators—describes the possible combinations of market price and generation quantity pairs that the firm can choose. Under the assumption that the generation unit owner observes the residual demand curve it will face, it can pick any price and quantity combination along this residual demand curve, up to its generation capacity limit, by submitting an offer curve that crosses the residual demand curve at the desired point.[5]

There are three possible configurations for the residual demand curve (Figure 4). The

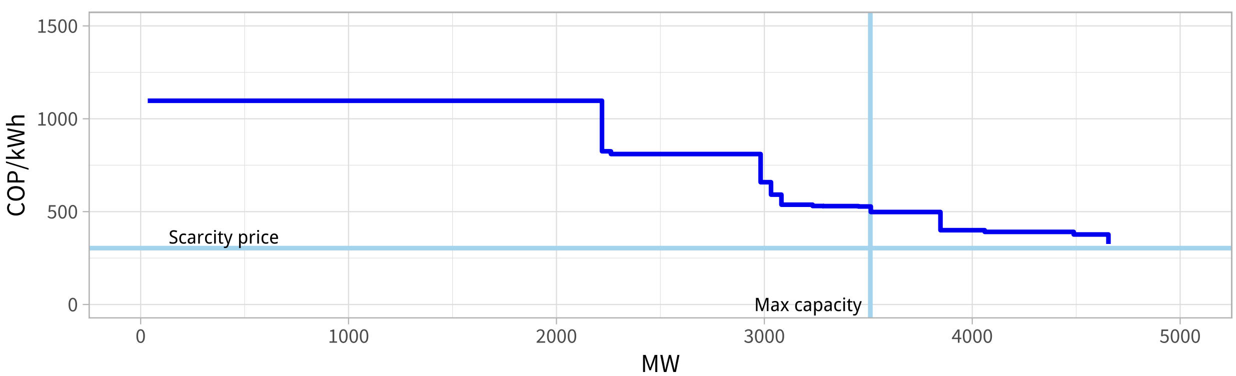
[5] As noted earlier, because the offers of other suppliers and the realized value of system demand is unknown at the time the unit owner submits it offer curve, the supplier still faces the risk that its offer curve does not intersect the realized residual demand curve at the *ex post* profit-maximizing price and quantity pair.

Figure 4: In certain system conditions, generation firms have the ability to choose whether or not the scarcity condition occurs

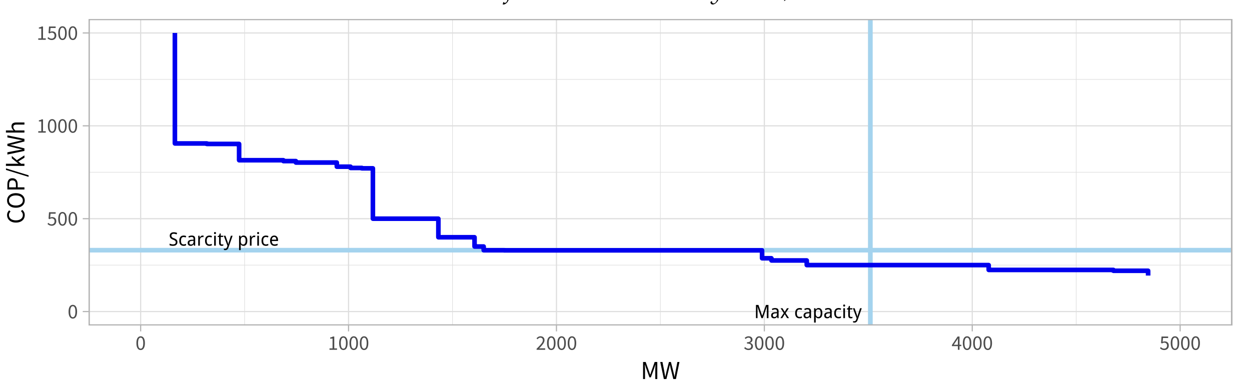
Case 1: Generation firm does not have ability to induce scarcity condition
Residual demand for EPM on 25 July 2015, at 6:00 PM.



Case 2: Scarcity condition will occur regardless of the generation quantity
Residual demand for EPM on 25 November 2015, at 6:00 PM.



Case 3: Generation firm can choose whether or not the scarcity condition occurs
Residual demand for EPM on 25 May 2015, at 6:00 PM.



first case is when the firm's inverse residual demand curve lies below the scarcity price for all feasible generation quantities. The maximum generation quantity is determined by the nameplate capacity of the generation units. The minimum generation quantity may be greater than zero for hydroelectric generators if there are environmental regulations on downstream water flows. With the inverse residual demand curve lying below the scarcity price, for any choice of generation quantity, there will not be a scarcity condition.

The second case is when the inverse residual demand curve lies above the scarcity price over the entire range of feasible generation quantities. In that case, the scarcity condition will occur regardless of the generation quantity of the firm.

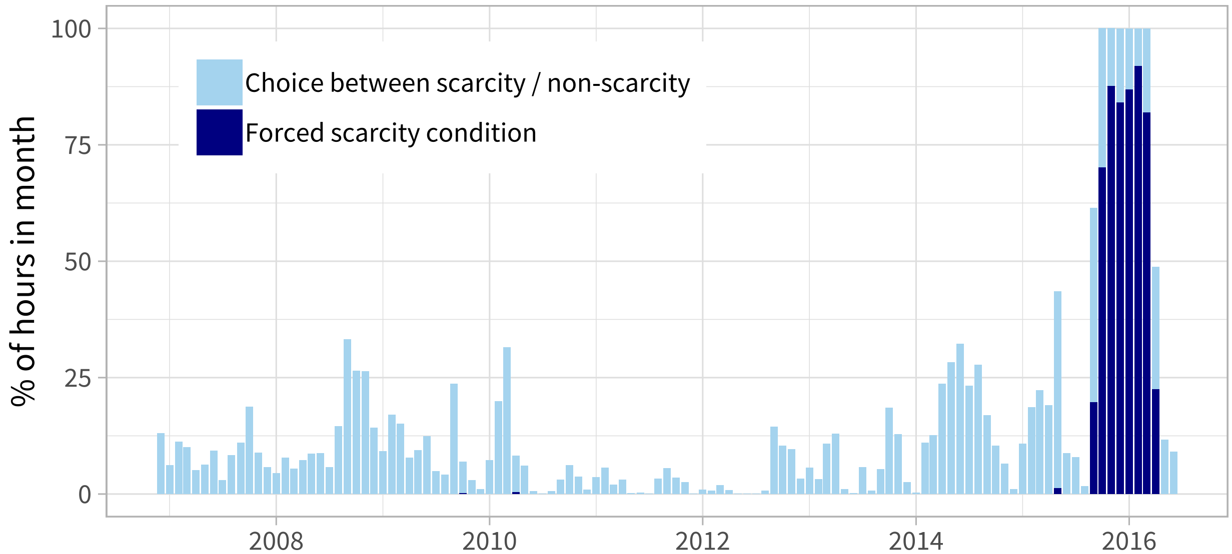
The final case is the one in which the inverse residual demand curve crosses the scarcity price at a quantity that lies within the range of feasible generation quantities. In that case, if the generator chooses a quantity that is less than the crossing point, then the scarcity condition will occur. If the generator chooses a quantity that is more than the crossing point, then there will not be a scarcity condition. For this case, because it is feasible to generate quantities that are either greater than or less than the crossing point, then the generator has the ability to choose whether or not the scarcity condition occurs. Because the residual demand curve a supplier faces is unknown at the time it submits its offer curve, there is not guarantee that its desire to create or avoid a scarcity condition will be successful.

Changes over time in the residual demand and scarcity price mean that the ability of a generator to determine the scarcity condition will vary across days and hours (Figure 4). At 6:00 PM on July 25, 2015, EPM did not have the ability to induce the scarcity condition, for any choice of quantity. At 6:00 PM on November 25, 2015, the scarcity condition would occur for any choice of generation by EPM. Finally, at 6:00 PM on May 25, 2015, EPM could have induced a scarcity condition by producing less than 1600 MW or could have avoided a scarcity condition by producing more than that quantity.

Throughout most of the sample period, EPM had the ability to induce the scarcity condition during at least a few hours of each month (Figure 5). For most of the six month period at the end of 2015 and beginning of 2016, the scarcity condition would have occurred regardless of the price and quantity bids by EPM. However, even in this extreme period, EPM had the ability to determine the scarcity outcome in a small proportion of the hours each month.

Over the entire sample period, EPM had the ability to choose between scarcity and non-scarcity conditions in 9.9 percent of hours (top block of Table 1). In 4.8 percent of

Figure 5: Proportion of hours each month in which EPM could choose to induce scarcity condition



Notes: The graph classifies the residual demand of EPM for each hour of the sample period. Light bars show the hours where the residual demand crossed the scarcity price within the range of feasible generation quantities for EPM. Dark bars show the hours where the residual demand lay above the scarcity price. For the excluded hours, the residual demand lay below the scarcity price.

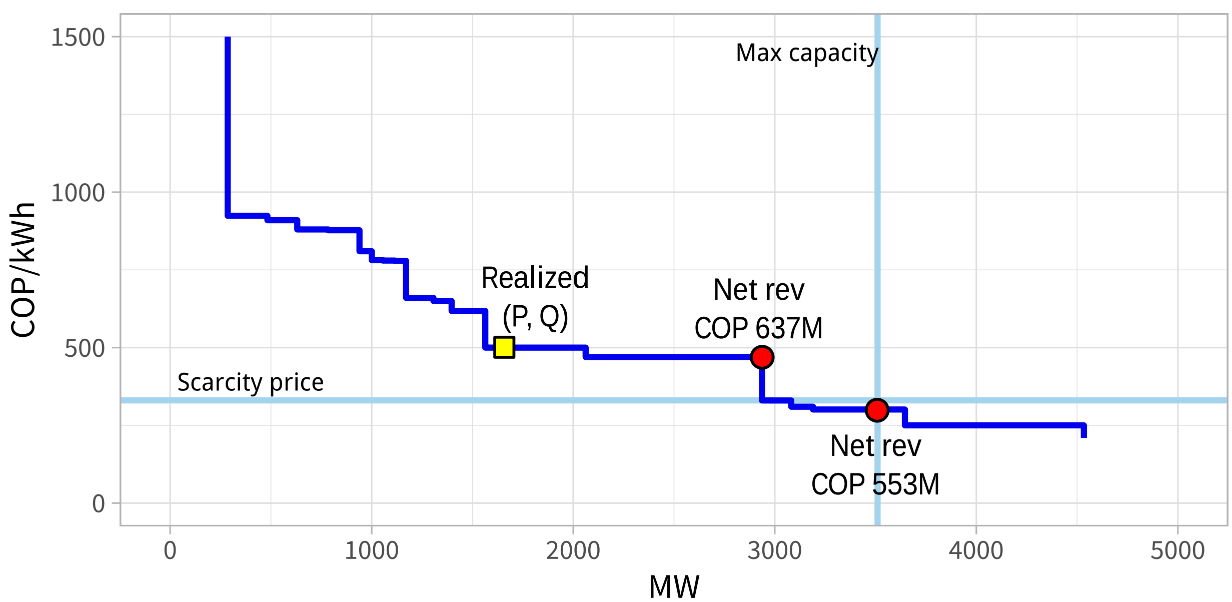
hours, all during 2015 and 2016, the scarcity condition was forced to occur for any choice of bids for EPM. The other two large generation firms also had a substantial ability to cause scarcity conditions, though in a smaller share of hours than EPM. Emgesa could induce the scarcity condition in 8.0 percent of hours and Isagen could do the same in 3.8 percent of hours. The smaller generation firms in the Colombian market had very limited ability to cause scarcity conditions.

4.2 Generation firms respond to incentive to induce the scarcity condition

Although the largest three generation firms frequently had the ability to create a scarcity condition, they will not always have the incentive to do so. Equation (4) gives the short-run profits for the firm in the absence of the scarcity condition. Equation (5) gives the short-run profits once the scarcity condition has been triggered. When a profit-maximizing firm has the ability to create the scarcity condition, it will only do so if the profits under the scarcity condition are greater than profits without the scarcity condition.

We empirically analyze the choices made by the largest generation firms during the hours in which they had the ability to create a scarcity condition. For these hours, we calculate the highest possible profit that they could achieve each hour under the scarcity condition. We used a grid search along the residual demand curve between the minimum generation quantity and the critical quantity between the scarcity and non-scarcity regions (Figure 6). At each possible quantity, we calculated the short-run profits from Equation (5), assuming a zero cost for generation. We also ignored revenue from forward contract sales and firm energy payments, because these were the same for scarcity and non-scarcity conditions. For the residual demand curve shown in the figure, the highest hourly profit that could be achieved in the scarcity region was 637 million pesos, at a generation quantity of 2900 MWh.

Figure 6: Profit incentive for choosing between scarcity and non-scarcity condition



Notes: The figure shows the residual demand faced by EPM on 15 May 2015, at 8:00 AM, plus the profit-maximizing points along the residual demand under scarcity conditions (above the scarcity price) and non-scarcity conditions. Net revenue would be higher for EPM under the scarcity condition. The realized price in this hour was above the scarcity price.

We then carried out the same procedure to calculate the highest possible profit that could be achieved each hour without the scarcity condition. For that case, we used a grid search along the residual demand curve between the critical quantity and the maximum generation quantity, calculating the short-run profits at each possible quantity from Equation (4). For the example hour in the figure, the highest possible profits in the non-scarcity region were 553 million pesos, for a generation quantity of 3,500 MW.

Table 1: Ability and incentive to choose between scarcity and non-scarcity conditions, for the three strategic firms

	Emgesa	EPM	Isagen
Non-scarcity hours	66,425	71,673	76,223
Forced scarcity hours	4,772	3,995	4,577
Scarcity/non-scarcity choice hours	6,227	8,332	3,200
Total hours	77,424	84,000	84,000
Hours when scarcity condition was profitable	103	411	174
% of which were scarcity	94.17	99.03	97.13
% of which were non-scarcity	5.83	0.97	2.87
Hours when avoiding scarcity was profitable	6,124	7,921	3,026
% of which were scarcity	4.67	9.73	13.19
% of which were non-scarcity	95.33	90.27	86.81

Notes: The top section of the table shows the classification of hourly residual demand into the three categories shown in Figure 4, for the three strategic firms. The bottom section of the table focuses on the hours in which the firm had the ability to choose between scarcity and non-scarcity, and classifies these hours based on the optimal choice (as in Figure 6. For each choice, the percentage of hours in the two categories are shown.

Profit-maximizing firms are assumed to make a choice between the scarcity and non-scarcity regions, picking the alternative that gives the highest profit. In Figure 6, the hourly profit for EPM in the scarcity region (637 million pesos) exceeded the hourly profit in the non-scarcity region (553 million pesos), making it optimal for EPM to create a scarcity condition that hour. Indeed, the scarcity condition did occur in this hour, suggesting the EPM had responded as expected to the incentives provided by the scarcity payment mechanism.

We repeat this calculation for each firm and each hour in which they have a choice between the scarcity and non-scarcity condition. Most of the time, profits would be higher if the scarcity condition were avoided. For EPM, in only 411 out of the 8,332 hours in which it had a choice (4.9 percent), profits would be higher if the scarcity condition occurred (second block of Table 1). In 99 percent of these hours, the scarcity condition did occur. This result confirms that EPM almost always created a scarcity condition when it had the ability and incentive to do so.

For the other 7,921 hours (95.1 percent) in which EPM had a choice, profits would be higher if the scarcity condition were avoided. In 90 percent of these hours, the scarcity condition did **not** occur. That is, in most of the hours in which EPM had the ability but not the incentive to create a scarcity condition, EPM ensured that the scarcity condition did not occur. These two sets of results are remarkable because, as noted earlier, EPM did not know the exact residual demand curve it would face during each of these hours. Nevertheless, it was able make the *ex post* profit-maximizing choice between inducing scarcity conditions or avoiding scarcity conditions with at least 90 percent accuracy.

The results are similar for the other two large generation firms, Emgesa and Isagen. There were 103 hours in which Emgesa had the ability and incentive to create a scarcity condition, and in 94 percent of these hours the scarcity condition occurred. For Isagen, there were 174 hours when it had the ability and incentive to create a scarcity condition, and this occurred in 97 percent of these hours. Conversely, there were 6,124 hours in which Emgesa had the ability but not the incentive to create a scarcity condition, and the scarcity condition was avoided in 95 percent of these. For Isagen, the scarcity condition did not occur in 87 percent of the hours in which it had the ability but not the incentive to induce scarcity.

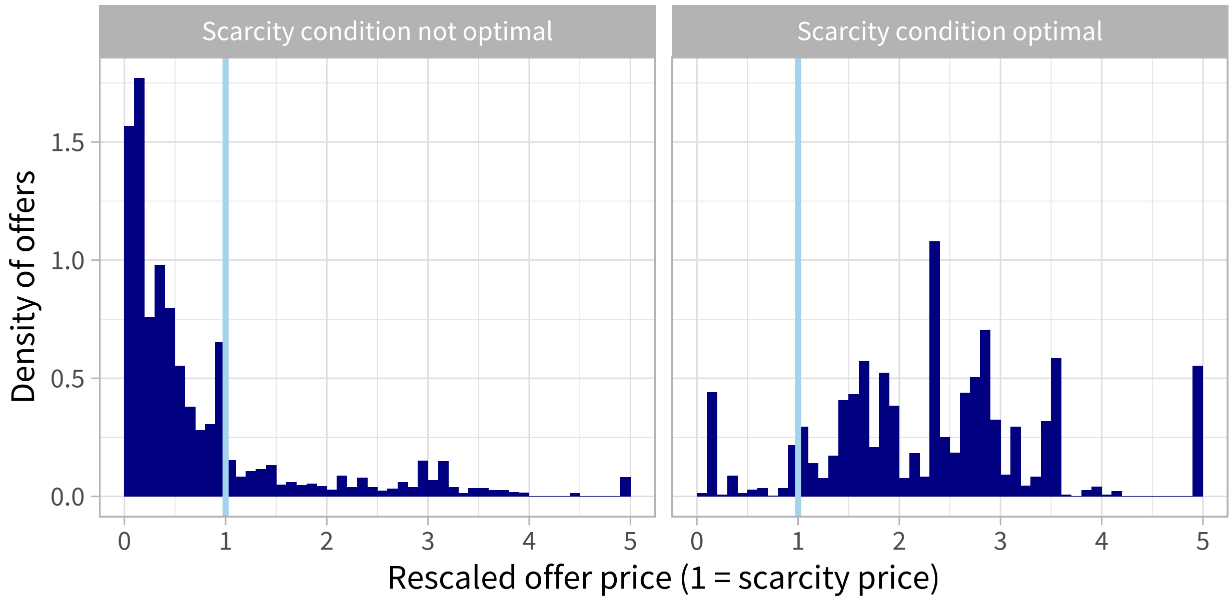
Overall, these results provide strong evidence that the major generation firms recognize the incentives created by the scarcity mechanism and respond to these incentives in their bidding behavior. Most of the time, profits would be lower under the scarcity condition, and in these hours the firms bid in a manner to avoid crossing the scarcity threshold. In a small number of hours, profits would be higher under the scarcity condition, and these cases the firms bid in a manner that attempts to create scarcity.

4.3 Bidding behavior reflects the incentives of the scarcity mechanism

In the previous subsection, we showed that the market outcomes—whether or not the scarcity condition occurred—were strongly associated with the profit-maximizing incentives for the generation firms. In this section we show direct evidence of the firms' responses to these incentives in their bidding behavior.

For each firm, we focus again on the hours in which it had the ability to choose whether or not the scarcity condition occurred. We then compare the distributions of generation bid prices for the hours when the firm did and did not have the incentive to induce scarcity, as defined above. To be able to compare the bids across different months of the sample with different scarcity prices, we scale all of the price bids by the scarcity price. That is, a price of 1 would be a price bid that exactly equals the scarcity price in effect at the time of the bid. A scaled price greater than 1 would be a bid above the scarcity price, potentially

Figure 7: Generation price offers for EPM respond to incentives to induce or avoid scarcity condition



inducing the scarcity condition. A scaled price less than 1 corresponds to a bid below the scarcity price.

For the 7,921 hours in which EPM had the incentive to avoid creating a scarcity condition, there is a high degree of bunching of bids just below the scarcity price (Figure 7). This distribution of bids is consistent with EPM recognizing its incentive to avoid scarcity and submitting generation bids that would do so. Conversely, for the 411 hours in which EPM had the incentive to create a scarcity condition, nearly all of its bids were above the scarcity price.

5 Counterfactual market outcomes

In this section, we present results from a dynamic Cournot oligopoly model of quantity-setting behavior by strategic electricity generators facing a competitive fringe. The model is similar to the model of the Western United States electricity market in Bushnell (2003). We calibrate this model to the annual May to April of the following year hydroelectric cycle in Colombia and present results for the most recent El Niño event in 2015 and 2016. We assume there are three strategic firms: EPM, Emgesa, and Isagen. The remaining generators behave competitively. The dynamic aspect of the model arises from the constraint on total water availability over the annual cycle. This introduces a shadow price for water each hour of the year into the model, with firms choosing their optimal generation from each generation unit they own each hour of the year.

We present model results for two main cases. The first approximates the reality of Colombian electricity market with the interaction between forward contract and firm energy incentives discussed in Section 4. The second case presents a counterfactual without the incentives created by the firm energy mechanism, holding fixed the existing forward contract obligations. By comparing the results from these two cases, we can describe the potential distortions that arise from the firm energy mechanism. We show how the magnitude of these distortions vary based on water availability. In particular, it is during dry years with scarce water that the firm energy incentives cause the greatest shift away from prudent reservoir management.

5.1 Model structure

We develop a stylized model of the Colombian wholesale electricity market. There are T periods and S strategic firms. The strategic firms have both hydro and thermal generation assets. In addition, there is an aggregated price-taking fringe firm that also has both hydro and thermal generation. All firms face a constraint on their aggregate hydro production across the T periods and each firm i chooses its optimal hydro allocation in period t, q^h_{it}.

The market price, p_t, depends on total generation in period t. The inverse demand is assumed to be linear and is given by Equation (8). Here Q_t is the aggregate generation in period t, summing across the strategic and fringe firms. The demand parameters a_t and b_t may vary each period.

$$p(Q_t) = (a_t/b_t) - Q_t/b_t \tag{8}$$

Profits for the strategic firms depend on their hourly forward contract position, q^c_{it}, and their firm energy allocation, q^f_{it}. Both forward contracts and firm energy are assumed to be predetermined outside the model. The scarcity price, p^s_t, is also determined exogenously outside the model.

Following Equation (4), in the periods when p_t is less than p^s_t, the profit for strategic firm i is given by:

$$\mathsf{P}(q_{it}) = P^f_{it}q^f_{it} + P^c_{it}q^c_{it} + p(Q_t)(q_{it} - q^c_{it}) - c(q_{it}) \tag{9}$$

The first-order condition for profit-maximization during non-scarcity periods is given by Equation (10):

$$\mathsf{P}'(q_{it}) = p'(Q_t)(q_{it} - q^c_{it}) + p(Q_t) - c'(q_{it}) \tag{10}$$

The alternative is that the price p_t is greater than p^s_t. In these scarcity periods, the profit for the strategic firm i is:

$$\mathsf{P}(q_{it}) = P^f_t q^f_{it} + P^c_{it} q^c_{it} + p^s_t(q_{it} - q^c_{it}) + (p(Q_t) - p^s_t)(q_{it} - q^f_{it}) - c(q_{it}) \tag{11}$$

Based on this equation, the first-order condition for profit maximization during scarcity periods is given by Equation (12). This expression depends only on the firm energy quantity q^f_{it} and not on the forward contract quantity q^c_{it}.

$$\mathsf{P}'(q_{it}) = p'(Q_t)(q_{it} - q^f_{it}) + p(Q_t) - c'(q_{it}) \tag{12}$$

For computational purposes we smooth the transition between the first-order conditions in Equations 10 and 12 at the threshold p^s_t. Equation (13) defines the marginal revenue of firm i in period t.

$$MR(q_{it}) = p'(Q_t)\{q_{it} - q^c_{it} + 0.5(1 + \tanh(p(Q_t) - p^s_t))(q^c_{it} - q^f_{it})\} + p(Q_t) \tag{13}$$

The hyperbolic tangent function is 1 for large positive arguments and -1 for large negative arguments. The formulation in Equation (13) switches the contract quantity in the first-order condition from the forward contract quantity to the firm energy quantity when the price $p(Q_t)$ exceeds the scarcity price p^s_t.

For strategic hydro generator i, the hydro generation in period t, q^h_{it}, satisfies Equation (14), where the marginal revenue is given by Equation (13).

$$MR(q_{it}) - \mathsf{l}_i - \overline{\mathsf{f}}_{it} + \underline{\mathsf{f}}_{it} = 0 \tag{14}$$

The total generation by firm i in period t, q_{it}, is the sum of hydro generation q^h_{it} and the generation from each of its thermal generation plants, q^o_{ikt}. The Lagrange multiplier on the water constraint faced by firm i is l_i. The total hydro generation over the T period must be no greater than the amount of water available for the firm, W_i. As shown by the complementarity condition in Equation (15), l_i is 0 if the water constraint does not bind, and strictly positive otherwise.

$$\sum_t q^h_{it} \leq W_i \perp \lambda \geq 0 \tag{15}$$

The other Lagrange multipliers in Equation (14) are from the constraints on the minimum and maximum hydro output each period for generator i. If hydro output is exactly equal to the minimum generation then $\underline{\phi}_{it}$ will be strictly positive, otherwise it will be zero. If hydro output is exactly equal to the maximum generation then $\overline{\phi}_{it}$ will be strictly positive, otherwise it will be zero.

For the strategic thermal generator i, thermal generation from plant k in period t, q^o_{ikt}, will satisfy Equation (16).

$$MR(q_{it}) - MC(q^o_{ikt}) - \overline{\gamma}_{ikt} + \underline{\gamma}_{ikt} = 0 \tag{16}$$

Marginal cost of plant k is assumed to be a non-decreasing linear function of output q^o_{ikt}. As in the case of hydro generation, $\overline{\gamma}_{ikt}$ and $\underline{\gamma}_{ikt}$ are multipliers on the maximum and minimum output constraints for the plant.

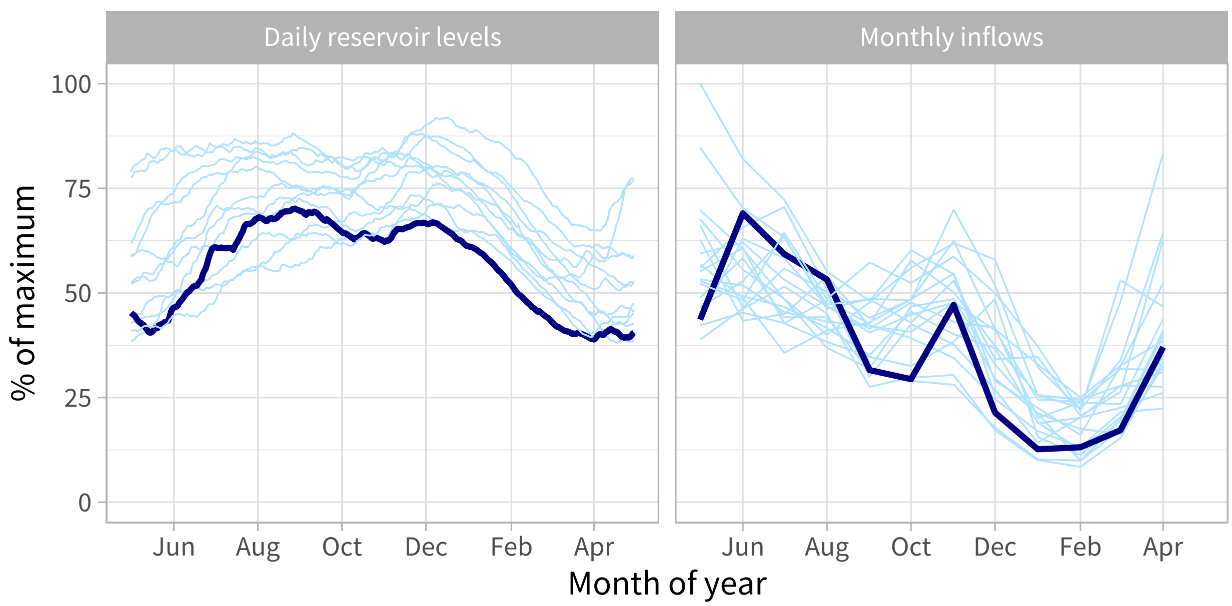
Hydro and thermal generation by the competitive fringe has exactly the same structure as Equations (14) and (16), except that the marginal revenue term $MR(q_{it})$ is replaced by the market price $p(q_{it})$. In particular, the price-taking fringe hydro generator still faces a constraint on total water availability and allocates the scarce water across the T periods. However, instead of equalizing marginal revenue across periods, the competitive firm allocates water to equalize price across periods, subject to constraints on its maximum and minimum generation each period. Similarly, the competitive thermal producer will choose its level of production to equate price with marginal cost, again subject to constraints on its hourly minimum and maximum generation.

The above conditions define a nonlinear complementarity problem, with the nonlinearity introduced by the transition between q^c_{it} and q^f_{it} in Equation (13). The solution to the problem will be an equilibrium of the dynamic oligopoly problem of strategic producers facing a competitive fringe, subject to firm-level constraints on hydro availability. We formulate this problem in the AMPL modelling language (Kernighan et al., 1993) and solve it using the PATH solver (Dirkse and Ferris, 1995).

5.2 Calibration

We calibrate the model to a hydrological year from May 1, 2015 to April 30, 2016. The choice of period was based on the observed pattern of hydrological conditions in Colombia (Figure 8). In a typical year, the lowest levels in the hydro reservoirs occur in April. Inflows are greatest between April and August. Reservoirs are usually at their highest levels in September or December. Finally, inflows are lowest between January and March, leading to a rapid run-down in storage levels during that period. For hydro generators, the choice to use water or to store it between May and August, when rainfall is plentiful, will affect the quantity that they can generate between December and March.

Figure 8: Historical reservoir levels and hydro inflows, 2006–2017



Notes: Each line represents one year. The bold lines highlight data for 2015–16. Inflows are defined as the change in reservoir level, plus generation and spill over the period. Monthly inflows are shown as the percentage of the maximum observed monthly inflow in the data. Reservoir levels are shown as the percentage of the reservoir capacity. Data on reservoir levels and spill is from XM Compañía de Expertos en Mercados (2019a).

We use data on the hourly generation from each plant in the Colombian market, including small facilities that do not participate in the market dispatch. For hydro generation, we separate reservoir and run-of-river plants. In Colombia, there are 23 hydro reservoirs that supply water to 21 plants. We aggregate the run-of-river generation to the firm level and treat the hourly generation as fixed at its observed value. We also include the output from wind and cogeneration facilities in this non-dispatched aggregate.

The choice to model the hydro reservoirs as a firm-level aggregate is appropriate in Colombia because there are few hydro chains that operate along a single river. For markets such as Brazil that have rivers with multiple hydro facilities, the output of one plant will be the input for another plant. This creates strategic interdependencies in the production decisions that might complicate aggregation (Moita, 2008; Moita and Monte, 2017).

We have the nameplate capacity for each of the reservoir hydro plants which we aggregate to give the maximum hourly output by firm. For minimum output, there are a small number of plants that have permission from the regulator to submit minimum output levels as part of their price and quantity bids.[6] In practice, the observed minimum hydro output in the data exceeds the minimum output in the bids. For example, this may be because of ancillary services provided by the large hydro generation plants. For each month, we use the minimum aggregated output in that month as our estimate of the minimum hourly output by firm.

For each of the hydro reservoirs, we have daily data on the storage levels, maximum usable storage, inflows, and spilled water (XM Compañía de Expertos en Mercados, 2019a). These variables are reported in both cubic meters and in kilowatt-hour equivalents. Because of the complexity involved in the conversion of water volumes to energy equivalents, there are often substantial discrepancies in the hydro balance identities. We avoid this problem by imputing the daily reservoir inflows from the change in storage levels, plus the daily generation and the reported spill. For each firm, we sum the reservoir inflows over the year for each of the plants, to obtain a single number for the hydro energy available for the year. In the model, the firm reallocates this energy across the hours in the year, subject to the constraints on the minimum and maximum hourly generation.

For thermal generation, we have daily data on the fuel consumption of each plant and unit in MMBTU (XM Compañía de Expertos en Mercados, 2019b). We combine the fuel data with unit-level generation to calculate an implied average heat rate for each unit and year. For costs, we obtained confidential daily plant-level data on the energy and transportation components of the fuel cost, in pesos per MMBTU. Combining the fuel prices with the heat rates provides the marginal fuel cost in pesos per kWh.

We obtained the other costs for thermal generators from the daily system information reports (XM Compañía de Expertos en Mercados, 2016). We use the regulated values from

[6]This is required because, unlike most wholesale electricity markets, firms in Colombia submit single price and quantity bids in the day-ahead market. Quantities may vary each hour but the bid price is the same for all hours of the day.

these reports for thermal operating and maintenance costs, separately for plants using coal, natural gas, and other fuels. In addition, we include the taxes and other charges paid by generators. These include charges for ancillary services, a tax to support grid expansion to unconnected regions, a tax for funding environmental regulators, and a charge to fund the capacity payments. The capacity charge is about US$16/MWh. We add the fuel cost, operating and maintenance costs, and the taxes and charges, to calculate the daily marginal cost for each thermal generating unit. For the counterfactual scenarios without the capacity payment mechanism, we exclude the capacity payment charge from the thermal marginal cost.

We use the nameplate capacity as the maximum potential generation from each unit and assume that the minimum generation from each unit is zero. In our model, we do not consider possible restrictions on fuel availability. We also do not model the ramping up and down of thermal generators would introduce dynamic constraints on the feasible program of hourly generation (Wolak, 2007; Cullen, 2011).

The three strategic firms own between one and three thermal plants. We model generation output from each of these plants individually. For the plants with multiple units, we rank the units in order of increasing marginal costs. The minimum marginal cost is the marginal cost of the lowest-cost unit. The slope of the marginal cost curve for each plant is taken from a straight line between the minimum and maximum marginal cost units, for generation quantities between zero and the maximum generation capacity of the plant.

We aggregate the thermal generation plants owned by the competitive fringe producers. For each month, we rank the plants and units in order of increasing marginal cost, allowing for changes in capacity and marginal cost from month to month. We then approximate the thermal marginal cost curve using a piecewise-linear function with three segments and two breakpoints (Muggeo et al., 2008). Maximum generation output is set to the total nameplate capacity of the plants.

The quantity of electricity demanded is set to the hourly aggregate generation. For each month, we rank the hours by the level of demand, and split the data into twelve evenly-sized bins based on percentiles of hourly demand. In the model, each bin represents between 56 and 62 hours of real-world generation. For each hour, we calibrate a linear inverse demand function. Following Bushnell (2003), we keep the slope of the inverse demand equal across all hours, with the slope calibrated to give a price elasticity of demand of -0.10 for the highest-demand hour. Given this assumption on the slope, the intercept of the inverse demand is calibrated in each binned hour to match the mean generation and

Table 2: Summary of generation data for 2015–16 hydrological year

	Generation (GW)			Storage (TWh)	
Firm	Min	Mean	Max	Min	Max
Reservoir hydro					
Emgesa	0.75	1.33	2.01	2.87	5.71
EPM	0.12	1.11	1.89	2.66	3.84
Isagen	0.31	0.98	1.84	0.30	1.20
Others (fringe)	0.13	0.80	1.47	0.02	1.08
Run-of-river hydro					
Emgesa	0.00	0.05	0.19		
EPM	0.08	0.13	0.23		
Isagen	0.02	0.05	0.08		
Others (fringe)	0.30	0.43	0.59		
Thermal					
Emgesa	0.07	0.21	0.33		
EPM	0.07	0.26	0.41		
Isagen	0.16	0.23	0.27		
Others (fringe)	1.08	2.02	2.71		
Total generation	5.53	7.61	9.61		

Notes: Summary statistics are based on the aggregation of generation data to the 144 representative hours used in the model (twelve hours for each of twelve months). Run-of-river hydro includes a small amount of non-dispatchable wind and cogeneration.

mean price for that hour.

For the strategic producers, we use hourly data on the net forward contract position and their firm energy obligation. Unlike in most other wholesale electricity markets, the quantity of forward contract obligations in publicly available, by firm and hour (XM Compañía de Expertos en Mercados, 2019c). The annual firm energy obligation for each plant is also publicly available. We use confidential data from the market operator with the calculation of the hourly firm energy obligation by firm.[7] We calculate the mean contract position and firm energy obligation for each of the binned hours in our sample. Finally, we use data from the market operator with the monthly scarcity price.

[7]There is a small secondary market that allows generators to trade their firm energy obligations. This means that the hourly shares of firm energy obligations may differ slightly from the annual share.

Table 2 provides a summary of actual generation data for 2015–16, aggregated to the 144 representative periods used in the model calibration. Most of the generation output of the three strategic firms is from reservoir hydro, supporting the modelling decision to focus on the water allocation problem. The maximum observed hydro generation from each of the three firms is about 2 GW, compared to the maximum system generation of 9.6 GW. For thermal generation, the three major hydro producers have limited thermal capacity, relative to their hydro capacity and to the total thermal capacity in the system. Ownership of the remaining thermal generation is divided among multiple small firms, several of whom own just one generation plant.

5.3 Results

We show results of two scenarios for the 2015–16 hydrological year (May 2015 to April 2016). First, we use the existing firm energy obligations and forward contract obligations for each of the strategic generators. We show the results for the equilibrium of the dynamic game, given these obligations and the exogenous path of the scarcity price during 2015–16. Second, we solve a counterfactual scenario with no firm energy and with only the forward contract obligations.

The crucial determinant of the results is the quantity of hydro inflows during the year. These determine how much water the strategic firms have available to allocate across the months of the year. The water availability determines whether the scarcity price will be binding. To illustrate the effects of the hydro inflows, we consider counterfactual scenarios with higher inflows (an increase of 10 percent or 20 percent compared to 2015–16 levels) and with lower inflows (a decrease of 10 percent or 20 percent). For these inflow scenarios, we hold everything else in the model constant: firm energy and contract obligations, thermal costs, electricity demand, and the scarcity price.

Table 3 shows the base case results for the 2015 inflows, comparing the scenario with both firm energy and forward contracts to a counterfactual scenario with only forward contracts. Subsequent sections of the table show this comparison for the cases with higher and lower hydro inflows. For each case, we show the maximum price, mean price, and the share of hours for which the price exceeds the scarcity price. To illustrate the changes in hydrological risk, we report the maximum level of the reservoirs of the strategic firms during the year. We also report the hydro generation of the strategic firms during the months with the highest rainfall, between May and August. These two measures capture the extent to which strategic firms are conserving water during the wet season. Finally, we

Table 3: Summary results from dynamic oligopoly model to show effect of firm energy incentives on wholesale market indicators

	Price (US$/MWh)			Storage	Hydro	Thermal
	Max	Mean	% > P_s	Max %	Wet TWh	Av. Cost
Base case: 2015 water						
Firm energy + contracts	123.70	109.31	71.33	82.16	9.49	61.75
Forward contracts only	111.77	91.94	2.12	82.18	9.45	61.17
High water (+20%)						
Firm energy + contracts	105.45	88.33	0.71	88.43	11.57	48.84
Forward contracts only	91.57	74.27	0.00	88.54	11.55	49.70
High water (+10%)						
Firm energy + contracts	114.96	96.74	1.41	85.37	10.50	55.10
Forward contracts only	101.16	82.60	0.00	85.11	10.54	55.88
Low water (-10%)						
Firm energy + contracts	127.10	114.28	74.86	76.15	8.84	67.73
Forward contracts only	120.85	100.69	54.10	77.94	8.56	66.58
Low water (-20%)						
Firm energy + contracts	137.55	125.18	77.62	71.06	8.09	72.98
Forward contracts only	130.39	112.48	70.74	73.10	7.77	72.75

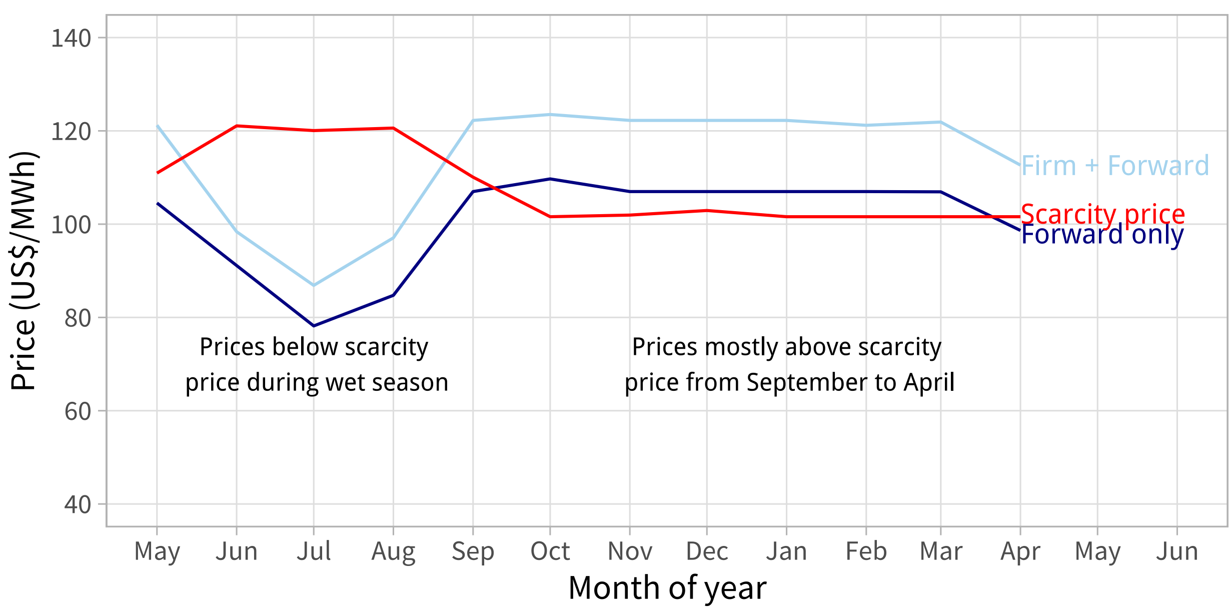
Notes: Each line represents a summary of the results from a separate case. For the "firm energy and contracts" cases, firm energy obligations and net forward contracts positions for the three strategic firms are set to their observed levels for 2015–16. For the "forward contracts only" cases, firm energy is ignored and the forward contract position is set to its 2015–16 levels. The bottom four groups show to changes to the 2015–16 inflows, either higher or lower, keeping everything else the same.

report the average cost of thermal generation for all plants over the year, in US$/MWh.

In all water scenarios, both the maximum and mean market prices are considerably lower without the firm energy mechanism. Most of the difference in price is caused by the exclusion of the firm energy charge from the marginal costs of thermal generators. Figure 9 illustrates the change in prices for the low water scenario. With only forward contracts, the price would be consistently lower throughout the year, and there would be fewer periods in which it exceeds the scarcity price (54 percent of hours compared to 75 percent of hours with the firm energy mechanism in place). If we isolate the effect of the change in strategic behavior, holding the thermal marginal costs fixed, we observe a small increase in the mean price (less than US$1/MWh) for the case without firm energy. With only forward contracts, strategic firms will generate less during the wet season, leading to higher prices between June and August. Averaged over the year, these higher prices dominate the effect of slightly lower prices for the rest of the year.

For hydro storage, the maximum reservoir level in the hydrological cycle is lower with firm energy, for the base case and for the low water cases. With a 10 percent reduction in hydro inflows, the maximum storage level would be 76 percent with firm energy and 78 percent without firm energy. The reason for the lower storage levels is apparent from the hydro generation totals for the period from May through August. With firm energy, hydro generation is higher and total thermal generation is lower. For example, in the scenario with 10 percent less water, strategic hydro generation is 8.84 TWh between May and August with firm energy and 8.56 TWh with only forward contracts.

Figure 9: Comparison of monthly mean prices between counterfactual scenarios for the low water case (10% below 2015 water levels)

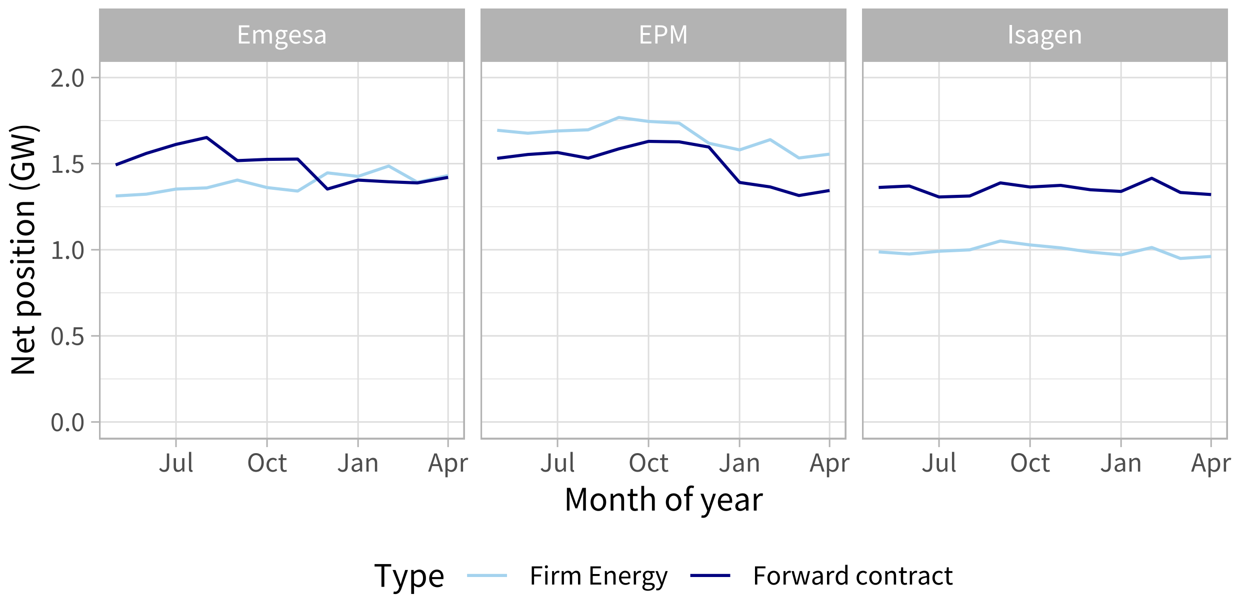


Notes: The two price lines show the mean monthly prices output from our model for the two cases, with and without the firm energy incentives. The third line on the graph shows data for the monthly scarcity price. Scarcity periods occur when the market price exceeds the scarcity price.

In the firm energy scenario, higher hydro generation implies lower thermal generation during the wet season. Because the total amount of water available is assumed to be fixed across the year, thermal generation will therefore be higher during the dry season. With a convex marginal cost curve for thermal plants, the total annual cost of thermal generation will be higher with firm energy. For the scenario with 10 percent less water, the average annual cost of thermal generation is $67.73 per MWh with firm energy and $66.58 per MWh without firm energy (final column of Table 3). In our model, the effect of reallocating thermal generation between periods is partially offset by the lower price and higher quantity demanded, given our assumption that demand is not perfectly inelastic.

The incentives for each of the strategic firms in the two cases differ based on the relative magnitude of their firm energy and forward contract obligations. Figure 10 shows data for the monthly mean firm energy and forward contract positions for the strategic firms for 2015–16. We treat these quantities as fixed parameters in the modelling analysis. Figure 11 shows the monthly reservoir hydro generation for the three firms in the two model scenarios.

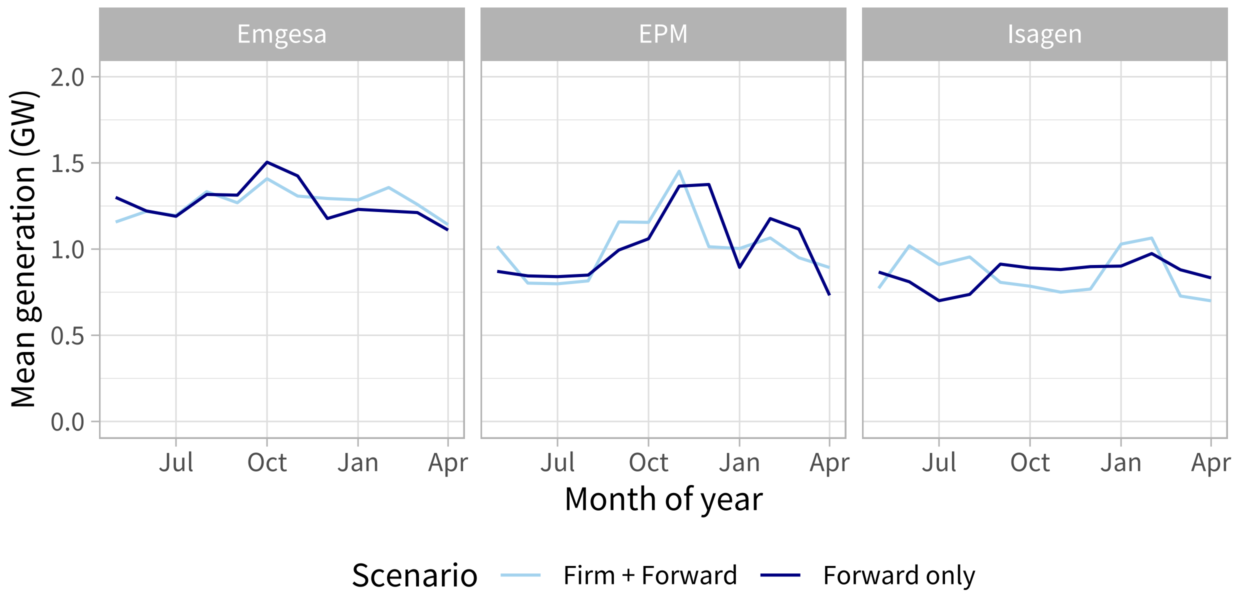
Figure 10: Comparison of monthly mean firm energy and forward contract obligations



Notes: Each graph shows data for the monthly mean net forward contract position and the monthly mean firm energy obligation, for the three strategic firms. Hourly contract data is from XM Compañía de Expertos en Mercados (2019c). XM also provided data on firm energy obligations.

For Isagen, its forward contract obligations are greater than its firm energy quantities for all months of the year. In the scenario with firm energy and forward contracts, it is the firm energy obligation that bind during scarcity periods. This obligation is lower than the forward contract quantities that binds for the scenario without firm energy. This implies that in the firm energy scenario, Isagen has a greater incentive to exercise market power during the scarcity months than in the counterfactual world without firm energy.

Figure 11: Comparison of hydro generation output for strategic firms between counterfactual scenarios for the low water case (10% below 2015 water levels)



Notes: Each graph shows the mean monthly hydro generation output from our model for the two cases, with and without the firm energy incentives.

The optimal generation output for Isagen reflects its response to these incentives (Figure 11). With firm energy, Isagen exercises market power by reallocating its water out of the scarcity period, lowering generation and increasing prices.

For EPM, the contract positions are reversed. For all months of the year, it has a forward contract obligation that is less than its firm energy quantities. In the firm energy scenario, EPM has less incentive to exercise market power during scarcity periods. The optimal response would be to allocate more water for generation during the scarcity periods, compared to the counterfactual without firm energy. Again, the modelled hydro generation for EPM matches this prediction. With firm energy, EPM would reallocate water from the non-scarcity to the scarcity period, increasing its generation and lowering prices.

The net position of the third strategic firm, Emgesa, is more balanced than for Isagen or EPM. The forward contract obligation is greater for the first part of the year and then slightly lower than the firm energy obligation for the second part of the year. The similarity between the firm energy and forward contract obligations suggests that there will be less difference in the optimal generation path between the firm energy and forward contract scenarios. This prediction matches the model results, which show similar time paths of generation output in the two scenarios.

The reallocation of water created by the firm energy mechanism, illustrated in Figure 11, only occurs during low water years. If hydro inflows are sufficiently low, then during some hours of the year the market price will exceed the scarcity price. This leads to the distortion in production incentives described above. However, if hydro inflows are high, then the value of water and the market price will be low. Few hours will be scarcity hours. In that case, there is no change in strategic incentives.

We solved the model for counterfactual cases with higher inflows than the actual inflows for 2015–16, holding all other parameters fixed (Table 3). With a 20 percent increase in inflows, less than 1 percent of hours would be scarcity hours. For this scenario, we should see little difference between the firm energy and forward contract cases. The model results confirm that maximum storage levels, mean prices, and hydro generation during the wet season are almost identical for the two cases.

We emphasize that the distortion in hydro generation during low water years is not a quirk of our model or calibration exercise. It is created by a central feature of the firm energy mechanism. By design, the firm energy allocations for large hydro generators are conservative. Market regulators calculate the allocations from worst-case scenarios based on historical inflow data. Risk-neutral generators might reasonably take on forward contract obligations exceeding their firm energy allocation. In aggregate, this is what we see in the data: the three largest generation firms have more forward contract than firm energy obligations.

The observed reallocation of water across the year follows from the relative magnitude of the firm energy and forward contract quantities. When inflows are low—and when the scarcity price is sufficiently low compared to the marginal costs of thermal generation—then there will be scarcity hours during the year. During these hours, the constraint on the exercise of market power provided by the forward contract obligation is replaced by the laxer constraint from the firm energy obligation. In aggregate, the strategic producers will have a greater incentive to exercise market power during scarcity hours than they would have had during the same hours in the absence of the firm energy mechanism. This incentive leads to the reallocation of water away from the scarcity hours.

A claimed feature of the firm energy mechanism is that it protects electricity consumers against the exercise of market power by large generation firms (Cramton and Stoft, 2008). The scarcity price caps the electricity price paid by retailers, passed on to electricity consumers through their regulated tariffs. The high market prices during scarcity prices only change the transfers between generation firms based on whether they have a short or long firm energy position.

However, for hydro-dominated systems, it is a dangerous misconception that the only costs of market power are higher prices that create transfers from consumers to producers. Hydro generators exercise market power by reallocating their scarce water. The firm energy mechanism provides an incentive to shift water in the opposite direction to what we might expect under prudent reservoir management: using more water during the wet season and storing less water for the dry season. As shown in Table 3, this leads to productive inefficiency from an increase in generation by the most expensive and most polluting thermal generation during the dry season.[8] For consumers, this reallocation also reduces reservoir levels at the start of the dry season and increases the risk of catastrophic system blackouts if there are lower-than-expected inflows or unanticipated generation unit failures.

As in any modelling exercise, our dynamic model of strategic behavior in the Colombian electricity market contains several simplifications of reality. The most important assumption is that of perfect information. We assume reservoir owners know the total amount of water they have available and the residual demand they will face. This implies that at the start of the year they can choose their optimal allocation of water in each hour of the year. In reality, there is uncertainty about future inflows, demand, and supply from other firms. In our model context, firms might face uncertainty when they are making their generation decisions in May about whether a scarcity period will occur in October.

Nonetheless, the low hydro inflows that occurred between December 2015 and March 2016 could have been anticipated at the start of our model in May 2015. The consensus forecast in May 2015 attached a higher than 80 percent probability to an El Niño event occurring in December 2015 (International Research Institute for Climate and Society, 2015). Hydro inflows after that date, between June and August 2015, were among the highest of the previous decade (Figure 8). Given the information on the high probability of low inflows eight months later, prudent reservoir managers had an opportunity to store more water earlier in the year to reduce the risk of a future shortfall.

A second simplification in our model is the assumption of a perfectly competitive thermal fringe with a generation capacity set to nameplate capacity and constant marginal cost. In reality, Colombia has a small and illiquid market for generation fuel, especially

[8] Total thermal generation costs would be lower for the year from running more low-cost generation throughout the year, saving more water and avoiding the need to run the most expensive plants later. Asker et al. (2017) provide a related example of inefficiency costs from production misallocation in a dynamic oligopoly context, for the case of the world oil market.

natural gas. This creates an upward-sloping and potentially vertical short-run supply curve for fuel inputs. Regulators are concerned about shortfalls in thermal fuel availability during periods with low hydro generation.

6 Alternative Approach to Long-Resource Adequacy

Virtually all jurisdictions with formal wholesale electricity markets have regulatory mandates aimed at maintaining an adequate long-term supply of energy at a reasonable price. Mandating participation in a standardized futures market for energy that clears against the hourly short-term price at long enough horizons to delivery to allow new entrants to compete to supply these contracts can be used as an alternative mechanism for ensuring long-term resource adequacy.

There is increasing dissatisfaction in the United States with the capacity-based long-term resource adequacy processes. This is particularly the case for regions with significant renewable energy goals. The firm capacity of a generation unit is typically defined as the amount of energy that the generation unit can produce under extreme system conditions, which makes defining the firm capacity of intermittent renewable generation units difficult, if not impossible. In addition, capacity-based resource adequacy processes procure firm capacity up to a pre-specified multiple of the peak demand, typically around 1.15, which limits wholesale price volatility and the incentive for investments in storage and active participation of final consumers in the wholesale market.

An energy-based long-term resource adequacy process has the potential to reduce the total amount of generation capacity required to serve the annual demand for energy, which can allow consumers to pay lower average wholesale prices, despite an increase in wholesale price volatility. Consumers can be protected from a significant fraction of this wholesale price volatility through the purchases of long-term contracts for energy. A liquid market for standardized forward contracts provides a mechanism for providing the necessary hedges against wholesale price volatility, as well as a mechanism for ensuring long-term resource adequacy if these mandated contract purchases are made far enough in advance of delivery to allow new entry to occur.

The wholesale market regulator could mandate that all load-serving entities in the region purchase and hold until delivery fixed-price forward contracts purchased from this standardized market equal to a pre-specified fraction of their final demand. For example, the mandate could be that all retailers purchase 97 percent of their realized final demand 1 year in advance, 95 percent 2 years in advance, and 92 percent 3 years in advance. Retailers that fail to meet this obligation would be subject to a significant per MWh penalty for every MWh their actual retail demand exceeds this forward market obligation.

These purchase mandates should be a sufficiently large fraction of the retailer's demand and continue far enough into the future to give the regulator sufficient confidence that energy adequacy will ultimately be achieved in the delivery year. To the extent the regulator is concerned that adequate generation capacity and other resources will be available to meet demand in the future, the regulator can increase the number of years in the future that the mandate to purchase exists from 3 years to, say, 5 years, and increase the percentage of demand that must be purchased in futures contracts in each year in the future, for example 97.5 per cent 1 year in advance, 95 percent 2 years in advance, 92.5 percent 3 years in advance, and 90 percent 4 years in advance.

The hourly quantities for these forward contracts can be tailored to the system load shape, rather than deliver the same quantity of energy each hour of the delivery period. This will allow retailers to bear less residual wholesale price risk in meeting their fixed-price retail load obligations. Assume that w_h is the share total energy delivered to the system during of hour h of the delivery period of the contract. If the total amount of energy purchased under the contract is QF, then the delivery quantity during hour h of the delivery period is $w_h \times QF$.

The requirement that all retailers purchase these standardized forward contracts is straightforward for the regulator to monitor. The requirement that these contracts are purchased and held to delivery by retailers ensures there are sufficient revenue streams for wholesale energy far enough into the future for the regulator to be confident that demand will be met in the future. This revenue stream provides consumers with wholesale price certainty for virtually all of their final demand far in advance of delivery to obtain a competitive price and provides a revenue stream to generation unit owners far enough in advance of delivery to allow them to bring on line sufficient resources to meet demand. Finally, the regulatory mandate that all retailers purchase these contracts, ensures liquidity in the futures market at the mandated horizons to delivery.

The mandate to purchase and hold these contracts to "delivery" does not rule out market participants entering into other bilateral hedging arrangements. For example, a renewable resource owner might enter into a cap contract with a thermal resource owner where the thermal resource owner provides price spike insurance for a fixed quantity of energy each hour in exchange for an up-front payment. For example, a 50

MW solar resource might purchase insurance against prices above \$100/MWh during the night-time hours of the day for the capacity of this resource, to hedge the risk of a price spike when its unit is unable to operate. In this case the solar resource would pay an up-front fee to the seller of the contract in exchange for the payment stream $max(0, P(spot) - \$100/MWh) * 50MW$ from the seller of the contract during each night-time hour during the contract period.[9]

Using a standardized futures markets for energy as the basis for a long-term resource adequacy process has the following advantages. First, it is technology and capacity neutral. There is no need for the regulator to determine the firm capacity of a generation unit or set an overall capacity requirement. It leaves decisions about what is the least-cost mix of generation capacity, demand response, and storage needed to meet the demand for energy in the future to market participants, which are likely to be the entities best able to make these decisions. Second, it allows wholesale prices to reflect scarcity conditions that can make storage investments and active demand-side participation economic. This will increase the capacity factor of existing generation units, which allows the same annual demand to be met with less generation capacity, thereby reducing annual average wholesale prices.

The prices of these futures contracts can also be used to set the wholesale price component of the regulated retail price. For example, if the regulator would like to set the wholesale component of the regulated retail price for the coming year, it can use the weighted average futures price for contracts delivering in the following four quarters. Because the retailer has purchased these futures contracts to meet its requlatory mandate, the regulator knows that the retailer can at least supply energy at a retail price that includes this wholesale price. In this way, the regulator is able to set the regulated retail price for a vertically integrated electricity retailer. It simply uses the average futures prices for the relevant delivery horizon as the wholesale energy price component of the retail price.

It is important to emphasize that mandating purchases of these contracts by retailers is unlikely to create a stranded asset problem for retailers that lose load to other retailers. That retailer still owns a potentially valuable asset, which is the ability to purchase energy during the delivery period of the contract at the initial price paid for the futures contract. This retailer can sell this contract at the prevailing price for deliveries in the future and will be as likely to make money as lose money on this transaction if the futures contract was initially purchased at an efficient price in a liquid forward market such as one proposed

[9]The function $max(a, b)$ produces the maximum of the two arguments a and b.

by this mechanism. Only in the extremely unlikely instance that system-wide demand falls substantially is there likely to be a stranded contract problem under this mechanism. However, this would also be the same set of circumstances under which there would be stranded capacity payments in the forward capacity market regime that currently exists in the eastern US markets.

A final very favourable property of this mechanism is that it is ideally suited to an electricity supply industry with a significant share of intermittent renewable generation capacity where the firm capacity construct makes very little sense. The firm capacity of a generation unit is the amount of energy that can be produced from a generation unit under extreme system conditions. For a thermal resource, this is a relatively well-defined concept. It is typically equal to the capacity of the unit times its availability factor. However, the amount of energy a wind unit can produce on an extremely hot high-demand day with no wind is clearly zero, and the amount of energy a solar unit can produce at dusk on an extremely hot high-demand day is close to zero. Consequently, determining the firm energy of these resources is more of a political decision than a technical engineering decision. Consequently, paying for firm capacity from these units when they are very likely not to be available during stressed system conditions is costly for consumers because they are paying for something they are not getting (firm capacity from the intermittent units) and paying for more firm capacity from dispatchable units to replace the firm capacity they are not getting from the intermittent units.

The regulator-mandated standardized market for long-term contracts approach to long-term resource adequacy avoids this issue by focusing on ensuring there is sufficient energy to meet demand in the future. As discussed in chapter 10 of McRae and Wolak (2016), this mechanism creates incentives for intermittent renewable resources to re-insure their forward energy sales with dispatchable thermal resources so that their forward commitment for energy in the future will be met.

7 Discussion

One rationale for the new capacity payment mechanism set up in 2006 was to provide financial support for new and existing thermal generators, in order to keep them available as backup for El Niño years. However, as illustrated by the market outcomes during the 2015–16 El Niño event, the mechanism has not been completely successful at achieving this goal (McRae and Wolak, 2016). Several new thermal generation plants that were assigned firm energy in the auctions were never built or were completed far behind schedule. Some existing thermal plants failed to procure sufficient fuel in order to operate at capacity during the scarcity period. In one case, a thermal plant walked away from its firm energy obligations and refused to produce electricity, in spite of having received the firm energy payment during the previous nine years. For hydroelectric generations, the mechanism placed regulatory restrictions on the management of reservoirs, which limited the ability of these firms to optimally manage their water resources.

A second rationale for the capacity payment mechanism was to limit the incentive of generation firms to exercise market power during scarcity periods. The firm energy obligation had a similar effect to a forward contract: during scarcity conditions, generation firms receive the fixed scarcity price for output up to their firm energy obligation. Output in excess of the firm energy obligation received the wholesale market price. However, unlike an ordinary forward contract, generation firms have control over the occurrence of a scarcity condition, because their market power gives them the ability to set the wholesale price (recall that scarcity conditions are defined as the wholesale price exceeding the regulated scarcity price). Furthermore, during scarcity conditions, the settlement price for existing forward contracts held by generation firms is capped at the scarcity price. This means that for wholesale market prices above the scarcity price, the forward contract quantity no longer reduces the incentive of firms to increase the market price. As a result, the capacity mechanism creates a complex set of incentives for firms to exercise market power by either increasing or reducing the market price, depending on whether the firms are short or long relative to both their firm energy obligation and their forward contract position.

The capacity mechanism did limit the extent to which final end users were affected by the exercise of market power during the 2015–16 El Niño event. The maximum price that unregulated customers had to pay for electricity was capped at the scarcity price. However, the high wholesale market prices still had important financial implications for generation firms. The generators with a long position relative to their firm energy obligations earned high profits during this period, at the expense of those generators with a short position relative to their firm energy obligations. In addition, the lack of price signals to electricity users created additional inefficiencies in the market. Consumers had no reason to adjust their consumption in response to the scarcity conditions.[10]

[10]In early 2016, the government introduced an ad hoc rebate system to provide an incentive for regulated users to reduce their electricity consumption.

Because it “solves” the incentive problem, market designers regard the reliability payment mechanism as a best-practice model for capacity markets. However, our analysis demonstrates that the mechanism not only fails to minimize the cost of meeting electricity demand but also creates perverse incentives for electricity generators that reduce the reliability of electricity supply. This result is of broad interest, especially because several wholesale electricity markets are considering the adoption of the Colombian capacity market model.

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