Simulation of the Colombian Firm Energy Market[1]

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1 Summary

We present a simulation analysis of the proposed Colombian firm energy market. The main purpose of the simulation is to assess the risk to suppliers of participation in the market. We also are able to consider variations in the market design, and assess the impact of alternative auction parameters.

Three simulation models are developed and analyzed. The first model (Model 1) uses historical price data from October 1995 through May 2006 to assess the performance risk of hypothetical thermal and hydro generating units. The second model (Model 2) uses historical price and operating data to assess performance risk of the actual generating units in Colombia over the same period. This analysis allows us to assess company risk. The third model (Model 3) differs from the other models in that it explicitly models the firm energy auction and investments going forward. Thus, the model is able to assess how the distribution of firm energy purchases differs from the firm energy target, and how this distribution depends on the firm energy demand curve. Model 3 also studies the investment decisions of suppliers, the impact of lumpy investments, and the impact of a higher scarcity price.

1.1 Model 1: Simulated units facing historical prices

An important output of Model 1 is the distribution of net firm energy payments for the hypothetical hydro and thermal units. A resource selling firm energy is selling a hedge for energy

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[1] This paper is an expansion of the paper we did in August with the same title. The main addition is the presentation of Model 3, the full simulation of the firm energy market going forward. This work was funded by XM Compañía de Expertos en Mercado S.A. E.S.P. (XM). We thank the XM staff and the commissioners and staff of Colombia's Comisión de Regulación de Energía y Gas (CREG) for many helpful comments.

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for prices above the scarcity price—whenever the spot energy price is above the scarcity price, the resource has an obligation to supply energy. The obligation is equivalent to a forward sale of energy at the scarcity price. Resources that over perform relative to the obligation are rewarded with the spot energy price for all extra output beyond their obligation; resources that under perform are penalized by effectively having to purchase the difference between the obligation and their output at the spot energy price. For taking on this obligation, resources receive a firm energy payment, which we assume here is equal to $12.85/MWh in January 2006 US dollars.[3] The net firm energy payment is the firm energy payment of $12.85 plus the reward for over performance, or minus the penalty for under performance.

Our sample period includes one major dry period, which began August 1997 and ended April 1998. The dry period is characterized by frequent scarcity hours—hours in which the energy spot price is above the scarcity price of the hedge. There is a second, shorter period of high prices when the market first began, 20 November to 30 December 1995.

In addition to the net firm energy payment, we calculate the Peak Energy Rent (PER). PER is the financial cost of the hedge—the difference between the spot price and the scarcity price for the obligation quantity in each scarcity hour. This cost is about 30 percent of the total firm energy payment.

Model 1 determines the mean and standard deviation of the net firm energy payment for hypothetical generating units. We model performance risk for thermal units by assuming that the unit randomly fails and requires time to repair. Both the time until failure and the time to repair are exponentially distributed. The initial proposal for the market defined a unit's obligation as its proportionate share of load in the hour. Thus, a unit selling 1% of the actual firm energy demanded has a 1% obligation in every scarcity hour.

For our hypothetical thermal resource, we find that its net firm energy payment is roughly constant across all years. There is some variation in the net payment during the dry periods, but the variation is small relative to the mean. The variation is larger for resources with long repair times, since it is more likely that these units will either be running or not for extended periods. This increases risk. A second result is that the thermal units tend to under perform during dry periods. This is because they tend to produce at a constant rate, which results in a tendency to over perform during low-load hours and under perform during high-load hours. Since prices tend to be higher in high-load hours, this results in a slight penalty during the dry period.

To better match a thermal unit's output with its obligation, we consider a variation in which thermal resources have a constant obligation during scarcity hours and the hydro obligation follows the residual demand after subtracting the thermal obligation. We find that this variation does slightly increase a thermal resource's mean return during dry periods, but it has almost no impact on risk. Nonetheless, the variation is desirable, since it improves the performance of the spot market in dry periods. A supplier has little incentive to exercise market power, since the supplier enters the spot market with a nearly balanced position.

Performance risk of a hydro unit in Model 1 is modeled as a random draw of firm energy during dry periods. The hydro unit sells its expected firm energy during a dry period, but its actual firm energy may be more or less than is sold. Not surprisingly, the variation in the hydro

[3] In the actual market, the firm energy payment is determined in a competitive auction. In Models 1 and 2, we do not model the auction, and so assume a particular firm energy payment. All amounts are in January 2006 US dollars.

unit's net firm energy payment is directly related to this variation in its actual firm energy. Another result is that a hydro unit tends to over perform during dry periods. This is because the hydro unit has limited water and it rationally uses this water in the highest-priced hours. As a result, the hydro unit tends to over perform during high-priced hours and under-perform during low-priced hours, and thus, it receives a reward on average.

1.2 Model 2: Actual units facing historical prices and output decisions

One limitation of Model 1 for evaluating risk is that it ignores the reality that suppliers typically own a portfolio of plants. Indeed suppliers often invest in portfolios of plants in part to reduce risk. In Model 2, we calculate the net firm energy payment for each existing generator, assuming the firm energy market was in place since October 1995. We use the unit's actual output in each hour. Each unit sells the quantity of firm energy specified in the preliminary firm energy numbers. For hydro units we calculate the net firm energy payment for both the reference quantity and the maximum quantity. The net firm energy payment includes all profits for prices above the scarcity price.

As was the case with our hypothetical units in Model 1, hydro units tend to over perform during dry periods and thermal units tend to under perform. However, because of the tendency for companies to hold diversified plant portfolios, the net firm energy payment is nearly constant across years for most companies.

Model 2 demonstrates how the hedge reduces supplier risk. Suppliers forfeit peak energy rents during dry periods for a higher constant payment that is received in all years. This stabilizes profits across wet and dry periods, and thereby reduces risk. Suppliers face some performance risk, but this risk is reduced when the supplier owns a diversified portfolio of generating units, as is common.

1.3 Model 3: Full simulation of investment decisions going forward

Model 3 models the firm energy market going forward and thus the investment decisions of companies. There are two main inputs of Model 3. One is the set of existing resources and their preliminary firm energy numbers as updated in CREG resolution 071. The second is the hydrology output data for each of the hydro resources. We use each of the 100 ten-year series to simulate hydro output over 1000 years. We simulate the firm energy market over 1000 years (actually 50 twenty-year simulations) with benchmark parameter values. This analysis supports the risk analysis of Models 1 and 2. In addition, we are able to 1) determine how the distribution of firm energy purchases differs from the firm energy target, 2) determine the impact of lumpy investments, and 3) determine the impact of a higher scarcity price. We then consider two alternatives to the benchmark scenario. In the first alternative we double the slope of the firm energy demand curve. In the second alternative we double the price elasticity of demand during scarcity periods.

There are a few differences between the model and the adopted resolution 071. We list them below, together with the likely impact of the difference.

Obligation. Our model assumes the "thermal constant obligation," which means during scarcity a thermal resource has an obligation equal to its long-run availability and hydro resources have an obligation equal to the residual demand after subtracting the thermal obligation. The adopted resolution assumes that the obligation follows dispatch for a quantity over the day consistent with the unit's firm energy sale. Given the bidding behavior in the simulation, units are dispatched consistent with the thermal constant obligation; thus, the difference has little or no impact on the calculations.

Firm energy price in years of surplus. Our model assumes that the firm energy price in surplus years is read from the firm energy demand curve, which results in a drop of the firm energy price. In the adopted resolution, the firm energy price in surplus years is set equal to the price from the last successful auction. Load purchases the target quantity and the payment is allocated pro-rata among suppliers. The resolution reduces variation in the firm energy price; thus, it likely reduces risk in the firm energy payment.

Length of commitment period for new entry. Our model assumes a ten-year commitment period for new entry; whereas, the adopted resolution has a commitment period of up to twenty years for new entry. Such a change would have a negligible impact on the simulation. The twenty-year commitment period further reduces variation in the firm energy payment for a new entrant.

None of these differences between the model and the resolution alter the main findings of Model 3. These findings are as follows.

- Lumpy investment means that few new units are added each year. Indeed, in 27% of the years no new entry occurs. (This is an overestimate to the extent that the size of winning projects reflect the actual need in the year.) In these years, the firm energy price is set by the firm energy demand curve, typically at a price that is significantly less than the prior-year price. As a result, the firm energy price fluctuates more than is desirable. As mentioned, the adopted resolution 071 addresses this problem. In a year of surplus, the firm energy price is set to the firm energy price from the last successful auction.
- Lumpy investments cause a negative bias in profits, which bidders would need to take into account. Part of the bias is due to the low firm energy prices in surplus years—a bias which is eliminated in the adopted resolution. However, part of the bias will remain—the reduced energy rents as a result of surplus.
- The mandatory hedge is remarkably successful in reducing risk. In the benchmark case, the hedge reduces aggregate profit risk by a factor of 7. More importantly, the hedge reduces company risk by a factor of 4.5 in the benchmark case. Even when we assume a high level of demand response so that prices remain low during scarcity periods and there is less profit risk to start with, the hedge reduces company risk by 55%.
- A higher scarcity price increases risk. Increasing the scarcity price shifts the profit distribution toward the no hedge case (a scarcity price of infinity). This results in a large increase in energy rent risk and a small decrease in hedge payment risk. The overall impact is a large increase in profit risk.

Taken together, the simulation results demonstrate the risk reducing benefits of the firm energy market. Provided there is competitive new entry in response to load growth, the firm energy market should work well at coordinating investment in new supply, while minimizing supplier and consumer risks.

2 Introduction

This paper presents a simulation analysis of the Colombia firm energy market. We assume that readers are familiar with the essential elements of the proposed firm energy market. As we write this, some details of the market are still under development. Our analysis is based on the description of the market presented in Peter Cramton and Steven Stoft, "Colombian Firm Energy Market," White Paper, August 2006.

The simulation analysis seeks to address several questions. For example,

1. What is the supplier risk associated with performance incentives?
2. What is the distribution of acquired firm energy relative to target firm energy in the auctions?
3. What demand curve parameters target firm energy more accurately?

The simulation model also allows us to consider variations in the market design. For example, in the proposal, the hourly obligation of both thermal and hydro resources follow load in the same way. We also consider a variation in which the obligation of the thermal resources is constant in all but the lowest-load hours, and the obligation of the hydro resources follows the residual demand after subtracting out the thermal obligation. This variation may reduce risk overall, since the thermal and hydro obligations more closely match the capability of each resource. This variation is especially relevant with respect to the question on supplier risk.

Our analysis includes three different simulation models.

1. **Unit simulation.** Simulation of a hypothetical thermal unit and a hypothetical hydro unit based on historical data. In this simulation, we assume that load's purchase of firm energy in each year exactly equals yearly demand. We focus on the question of supplier risk.
2. **Historical estimation.** Estimation of the net firm energy payment to all units based on the historical price, operation, and firm energy capability of the unit. Again we assume load's purchase of firm energy in each year exactly equals yearly demand. The focus again is on supplier risk.
3. **Market simulation.** A simulation of the market going forward. Here we assume that the purchase of firm energy is determined by market forces facing the demand curve in the proposal. Supplier's expectations about future prices are roughly consistent with what occurs, which is called "rational expectations" in economics.

Models 1 and 2 are intended to shed some light on the risk a supplier faces in the firm energy payment, as a result of performance incentives. For a thermal unit, this risk comes from random outages. For a hydro unit, the risk comes from variability in the amount of firm energy that the resource has in a particular dry period. Model 3 is intended to address longer-term issues, such as how the shape of the firm energy demand curve used in the auction impacts variation in the purchase of firm energy relative to the target.

There are many questions outside the scope of this study. For example, we cannot assess the impact of the market on reliability. The firm-energy auction is designed to purchase a target level of firm energy and to see that it is dispatched efficiently; it is not intended to *determine* the firm energy target. This choice of course impacts reliability. We take the firm energy target as given.

3 Model 1: Simulation of hypothetical units with historical prices

We begin with a simple simulation of a hypothetical thermal unit and a hypothetical hydro unit facing the history of prices from October 1995 through May 2006. The purpose is to assess supply risk from performance incentives. We model thermal and hydro units separately, since they face quite different performance risks. For thermal, the problem typically is random breakdowns, whereas for hydro units the problem is lack of water during a dry period. We assume that load's purchase of firm energy exactly matches actual load.

For both units, we calculate the firm energy payment net of performance incentives. Since the hypothetical units break-down or run out of water randomly, we simulate 1000 independent units of each type. This gives us a distribution of net firm energy payments from which we can calculate the mean, standard deviation, and other statistics both monthly and annually. All values are in January 2006 US$ per MWh of firm energy.

Since in this section we are not modeling the auction itself, we simply assume an auction price equal to $12.85/MWh of firm energy.

The sale of firm energy by a supplier includes a hedge for energy at a scarcity price. The scarcity price is a heat rate times a gas index plus other (non-fuel) variable costs. For other variable costs we use $15.20/MWh. The gas index is the New York Harbor residual fuel oil index, averaged over the prior month, and the heat rate is 12.482 MBTU/MWh.

The quantity of the hedge varies by hour in our base case. In particular, the quantity follows hourly load. Each unit has an obligation in any hour that corresponds to its share of the firm energy sold. Thus, a unit that has sold 1% of all firm energy sold has an obligation equal to 1% of the actual load in each hour. Of course, no unit will exactly meet its obligation in every scarcity hour—an hour in which the spot price exceeds the scarcity price. When the unit over-performs it is paid the spot energy price for every MWh of extra energy it delivers; when it under-performs it purchases at the spot energy price the extra energy needed to cover its obligation. Thus, in every hour in which the spot price is above the scarcity price there is either a reward or penalty based on the extent of over or under performance and the level of the spot price and the scarcity price.

The *net firm energy payment* is defined as the firm energy payment of $12.85 plus the reward for over-performing minus the penalty for under-performing. We calculate the net firm energy payment on a monthly and annual basis. We also calculate the Peak Energy Rent (PER) on a monthly and annual basis. PER is the financial cost of the hedge—the difference between the spot price and the scarcity price for the obligation quantity in each scarcity hour.

The base case described above is called the *load-following* case. We also consider a variation, called the *thermal-constant* case, in which the obligation for a thermal unit is equal to its average availability, unless load is so low that it is necessary for the thermal unit to follow load in the lowest-load hours. The hydro units in this case follow the residual demand, which is the hourly load less the obligation of the thermal units.

The motivation for this variation is that the obligation more closely matches expected performance and hence reduces risk. The simulation determines the amount of this risk reduction. During a scarcity hour, all thermal units will want to be running regardless of load. Thermal units have limited *capacity* not limited *firm energy*. A thermal unit would never want to miss a scarcity hour. In contrast, hydro units have limited firm energy. This implies a significant opportunity cost of running, which may well be above the scarcity price during a dry period. During a scarcity hour, the spot price is high because the opportunity cost of the marginal hydro unit is high. The *thermal constant* rule reflects the fact that thermal units want to run at full capacity during all scarcity hours. During scarcity hours, efficient dispatch will involve using the capacity of the thermal units first, and then the hydro capacity.

We should emphasize that the *load following* rule does not in any way distort the actual dispatch, absent market power. Either rule leads to efficient dispatch. In both cases, the supplier desires to sell as much energy as it can whenever the spot price is above it marginal cost (including opportunity cost) and not to sell when price is lower. This is exactly the efficient incentive it would face without its obligation. Like any standard hedge, this one does not distort behavior. The different rules do, however, impact the expected net payment as well as its standard deviation for both the hydro and thermal resources. Determining these differences is one of the purposes of our first simulation. In addition, the different rules impact incentives to exercise market power.

3.1 Modeling thermal units

Thermal units on occasion break down and require repair. We assume long-run availability of either 95% or 70%, a constant repair probability per unit time ("exponential time to repair"), and a constant probability of outage.[4] The mean time to repair is assumed to be either 10 hours or 40 hours. A thermal unit sells its long-run availability as firm energy (e.g., 95% of a 1 GW unit = 950 MW). We assume load purchases the actual annual energy demand as firm energy (the sum of load over all hours in year). We calculate average load/hr by dividing by the number of hours (getting something like 5541 MW in 2005). A supplier's share for a unit with 950 MW average availability is 950/5541 = 17.1%. This is used to determine its obligation in each scarcity hour. The performance reward/penalty is added to this amount.

The "exponential" model of failure and repair, assumes that failure (or repair) is just as likely right after a repair (or failure) as at any subsequent time. This is the most standard model of reliability and has substantial empirical support. If f is the mean time to failure and r is the mean time to repair, then $p = f/(f + r)$ is the long-run availability of the unit. We use this relationship to determine mean time to fail from our assumptions on p and r. For example, p = 95% and r = 40 hours, the mean time to failure, f, equals r p/(1– p), or 760 hours. As the repair time increases, autocorrelation in availability increases; that is, a resource that is available in hour h is more likely to be available in hour h+1, and a resource that is unavailable in hour h is more likely to be unavailable in hour h+1. The motivation for this analysis is that real thermal generators not only fail, but also have significant repair times.

The final parameter of the model is the marginal cost of the thermal resource. In this model we are focusing on prices above the scarcity price, and so we assume the unit's marginal cost is equal to the scarcity price.

[4] For example, if the probability of repair is 1% in each hour that the unit is still broken, then the probability that the unit has not yet been repaired after N hours is exp(– 0.01 × N) and the mean time to repair is 100 hours. Breakdowns are assumed to follow a similar pattern, but with much lower probability.

The simulation works as follows. We specify all the parameters: the marginal cost, the long-run availability *p*, and mean time to repair *r*. We then start in hour 1, randomly making the generator available with probability *p*. For a generator that is available in hour 1, we determine the hour of its next failure, which is exponentially distributed with mean *f*. Suppose it is available for A hours. Then from hour 1 to hour A, the resource is available. We then determine how long it takes to repair, which is exponentially distributed with mean r. Suppose it takes U hours to repair. Then from hour A+1 to hour A+1+U, the resource is unavailable. We continue this process until availability is determined for all hours from October 1995 through May 2006. An analogous procedure is followed when the resource starts in the unavailable state. From this hourly availability time series, we calculate the monthly net firm energy payment, for every month and year in our time period. This gives us one data point for each month and year. We repeat the above procedure 1,000 times to give us the probability distribution of net firm energy payments for the hypothetical generating resource in each month and year. We calculate the mean, median, and standard deviation of this probability distribution for each month and each year in the time period. Throughout, years are December – November, except for the first year (October – November 1995) and the last year (December – May 2006).

What is of particular interest is the risk—the variation of the payment away from the mean. The standard deviation is the most common measure of risk. For random variables that are approximately normally distributed, there is about a two-thirds chance that the realization of the random variable will fall within one standard deviation of the mean, and the probability is greater than 95% that the realization will fall within two standard deviation of the mean.

It is helpful first to look at the historical data. Table 1 displays the number of scarcity hours in each year, together with the mean and standard deviation of the spot energy price during the year's scarcity hours. Scarcity hours are frequent during the dry periods, but extremely rare at other times. Prices are both high and variable during scarcity hours.

Table 1. Scarcity Hours by Year

Energy Year	Number of Scarcity Hours	Spot Price During Scarcity Hours (Jan. 2006 US$ per MWh) Mean	Standard Deviation
1995 (Oct-Nov)	223	76.86	27.81
1996	533	116.75	51.45
1997	2371	110.66	42.45
1998	3296	93.74	31.01
1999	0		
2000	0		
2001	0		
2002	17	63.92	2.93
2003	0		
2004	2	85.18	0.67
2005	0		
2006 (Dec-May)	0		

Note: A scarcity hour is any hour in which spot price exceeds strike price.

Table 2 shows the number of scarcity hours by month and year. Here we can see how frequent scarcity hours are during dry periods. From December 1997 through March 1998, almost every hour was a scarcity hour (a 28-day month has 672 hours, a 31-day month has 744 hours).

Table 2. Scarcity Hours by Month and Year

400-599 scarcity hours
600 or more scarcity hours

Energy Year	December	January	February	March	April	May	June	July	August	September	October	November	Total
1995	-	-	-	-	-	-	-	-	-	-	1	222	223
1996	467	57	1									8	533
1997				5		62	60	74	153	663	703	651	2,371
1998	724	744	672	744	412								3,296
1999													0
2000													0
2001													0
2002			16	1									17
2003													0
2004										1	1		2
2005													0
2006							-	-	-	-	-	-	-
Total	1,191	801	689	750	412	62	60	74	153	664	705	881	6,442

Table 3 shows thermal resources' share of load by month. Not surprisingly thermal's share of load is largest during the dry periods, and especially toward the end of the dry periods. However, even during the long and severe dry period of 1997-1998, hydro resources still provided the majority of energy. Thermal's share only rarely exceeds one-third of load.

Table 3. Thermal Resources Percent of Load by Month and Year

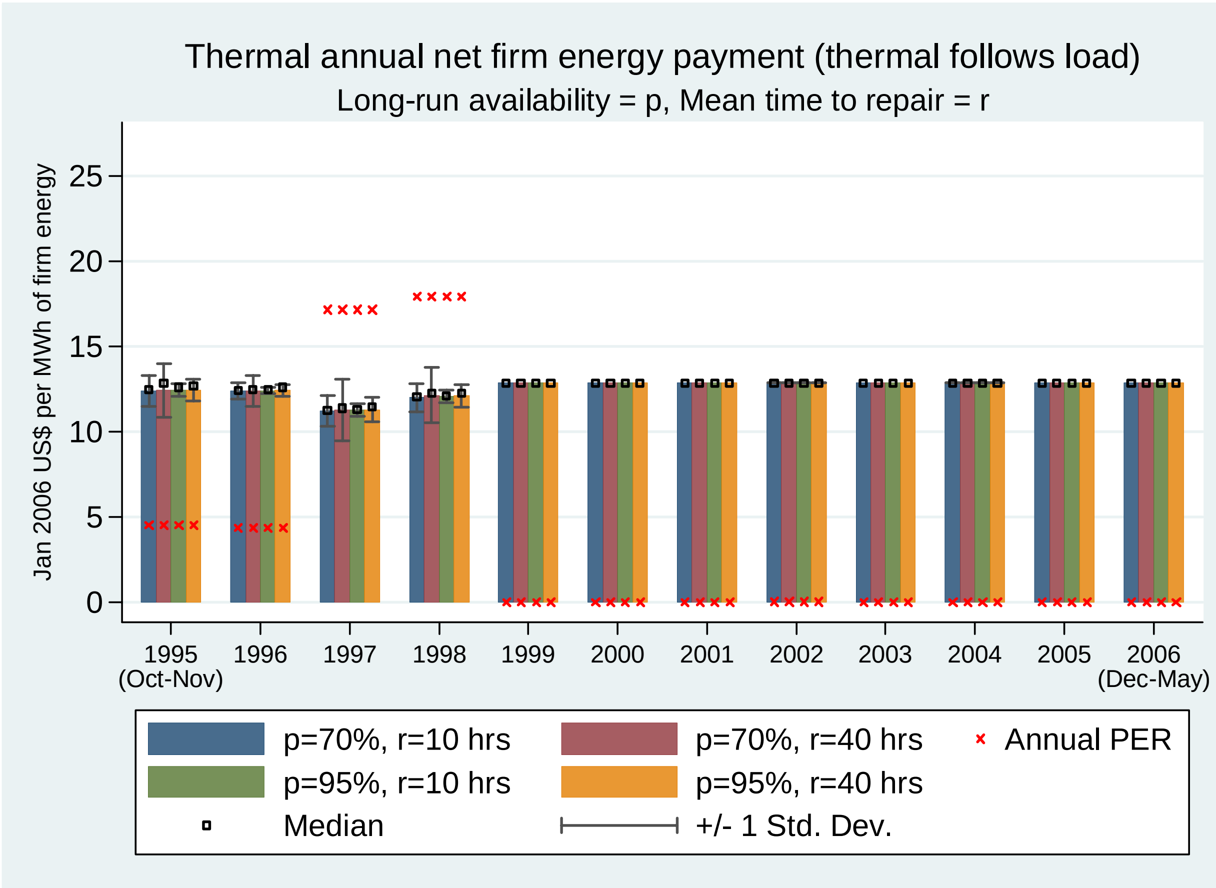
400-599 scarcity hours
600 or more scarcity hours

Energy Year	December	January	February	March	April	May	June	July	August	September	October	November	Average
1995	-	-	-	-	-	-	-	-	-	-	15.4	14.7	15.0
1996	19.8	22.0	14.3	11.9	10.5	10.7	9.6	8.6	11.5	14.7	13.8	13.2	13.4
1997	14.0	10.8	12.6	14.0	14.9	17.3	16.0	17.8	20.2	26.7	28.8	31.8	18.7
1998	28.8	35.7	36.1	35.2	37.3	20.6	16.1	12.3	11.2	12.4	17.1	18.8	23.5
1999	17.9	18.9	17.5	16.1	17.6	18.4	16.7	19.3	18.9	26.1	20.0	23.4	19.2
2000	29.3	28.3	31.1	30.4	28.3	22.8	22.7	18.8	25.0	28.8	29.2	26.0	26.7
2001	19.2	25.9	29.9	31.1	32.5	29.3	26.0	21.7	21.2	21.9	19.9	24.5	25.3
2002	19.3	24.6	31.0	25.0	25.2	19.7	18.0	17.1	21.4	21.6	24.0	21.1	22.3
2003	27.6	25.6	24.7	27.2	23.8	21.6	17.7	14.3	18.3	21.8	19.2	16.8	21.6
2004	18.2	18.9	22.0	24.6	21.2	16.4	20.5	15.7	16.0	19.9	15.5	10.6	18.3
2005	16.7	18.1	18.1	17.8	21.1	15.2	17.0	20.1	24.2	26.6	16.6	15.1	18.9
2006	21.0	15.9	16.1	23.3	17.9	17.6	-	-	-	-	-	-	18.6
Average	21.1	22.2	23.0	23.3	22.8	19.1	18.0	16.6	18.8	22.1	19.9	19.6	20.5

The simulation results for Model 1 are summarized in the following figures.

Figure 1 displays the annual net firm energy payment for hypothetical thermal units with four different characteristics: the blue and red bars are for relatively unreliable thermal units (70% availability); green and mustard bars are for reliable thermal units (95% availability). In each case, the bar represents the mean net payment over the 1000 simulations. The median is the black square, and the grey interval displays plus and minus one standard deviation around the mean. Several points are worth noting.

Figure 1



1. The mean net firm energy payment does not depend on the unit's anticipated availability. This is because we have assumed that each unit sells firm energy equal to its long-run availability. Hence, the 70% unit sells 70% as much firm energy as a perfectly reliable unit; it is paid at the same rate per MWh of firm energy, and so it receives 70% of the net firm energy payment—just as it should. Of course payments do depend on actual availability relative to anticipated availability.

2. The mean net firm energy payment does not depend on the mean time to repair the unit. However, the standard deviation of the net payment does increase with the mean time to repair. Holding long-run availability constant, longer repair times mean longer run times. Because high-price hours are clustered, if a unit is out for a long time at once, it is more likely to miss a whole cluster of high-price hours or none at all. This increases the standard deviation, and therefore, the payment risk.

3. The standard deviation, and hence risk, in the net payment is higher for less reliable units. This should be quite intuitive, since as the availability approaches 100%, the standard deviation goes to zero.

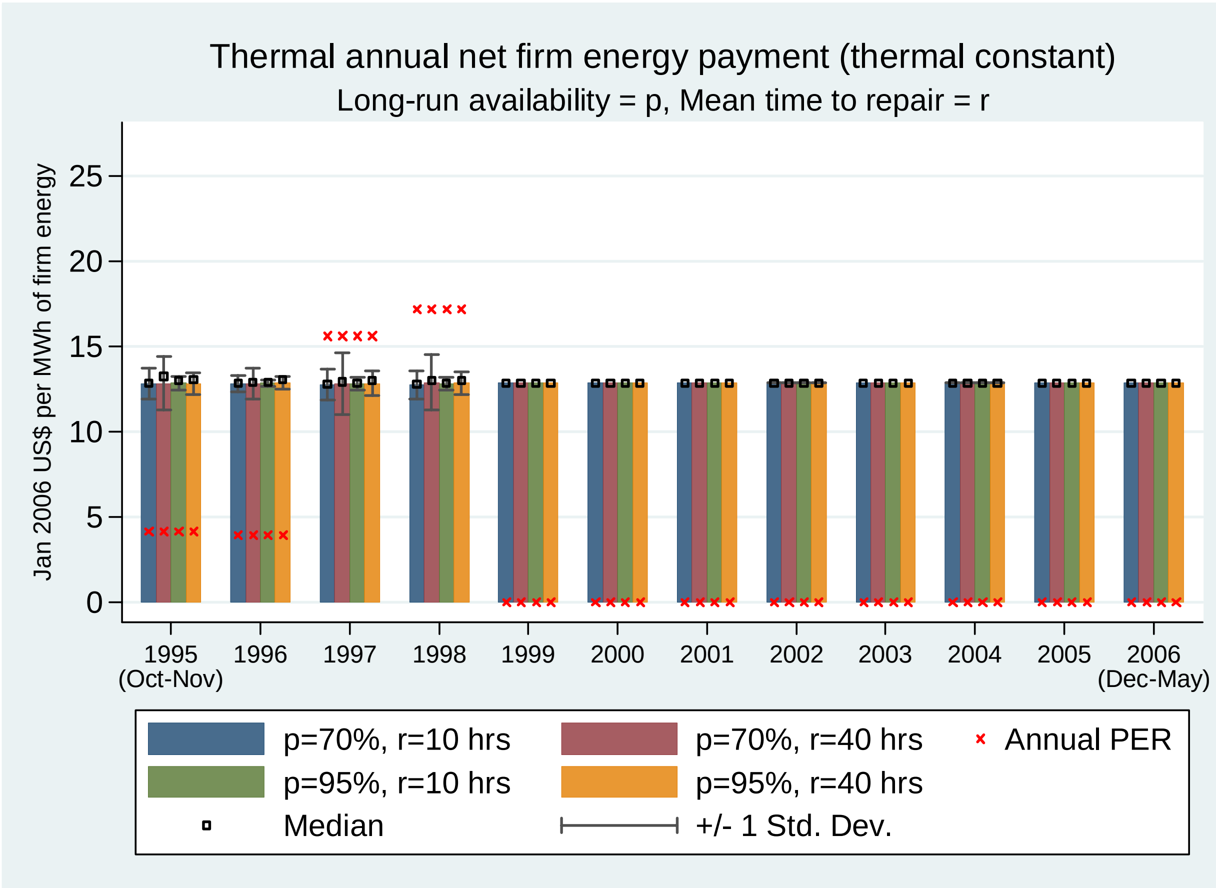
4. The net payment is constant at $12.85 in all the years 1999 to 2006. This is because there were almost no scarcity hours during these years. This history is typical of Colombia. The vast majority of years have plenty of energy and low electricity prices.

5. Dry periods are unusual. Over this history, there was one major dry period from 27 August 1997 to 20 April 1998. There was a second, shorter period from 20 November 1995 to 30 December 1995 with high prices. This is the reason we only see significant Peak Energy Rents (the bright red x) during the 1995, 1996, 1997, and 1998 energy years. PER was especially high in 1997 and 1998 as a result of the long dry period. The situation became increasingly severe in the latter stage of the dry period (1998), which is why PER is highest in this energy year. PER does not vary with the unit's characteristics; it only depends on the unit's obligation, the number of scarcity hours, and the spread between the spot price and the scarcity price in each of those scarcity hours.
6. Even in the two years, 1997 and 1998, covering the extended dry period, the standard deviation of the net payment is small relative to the mean. The risk is greatest for an unreliable unit with long repair times, but for reliable units the risk is tiny even for units with long repair times.
7. Even in dry years, the mean net payment is close to $12.85. In 1997 and 1998, the two years covering the extended dry period, the net payment is about 7% lower: roughly $11.87 in 1997 and $12.08 in 1998. Because of the load-following obligation, the supplier has a larger obligation in high-load hours than in low-load hours. Although it can fulfill its obligation on average, during some high-load hours its obligation exceeds its capacity. This is made up for by lower load hours in which its capacity exceeds it obligation. However higher-load hours tend to be higher-priced hours, so it loses more when it falls short, than it gains when it provides extra. Thus, thermal units tends to have a net penalty in years with many scarcity hours.

This last point motivates consideration of the variation, *thermal constant*, discussed above, in which the thermal obligation is constant at its long-run availability, unless load is so low that this obligation would exceed load.

Figure 2 presents the net firm energy payments under the *thermal-constant* variation. The figure looks remarkably similar to Figure 1. The only difference is that the mean payments have increased in 1997 and 1998, by an amount roughly equal to the mean net penalty in these two years under the *load-following* rule. This is just as expected, since under the *thermal-constant* variation, the thermal units no longer have a net penalty on average during years with lots of scarcity hours.

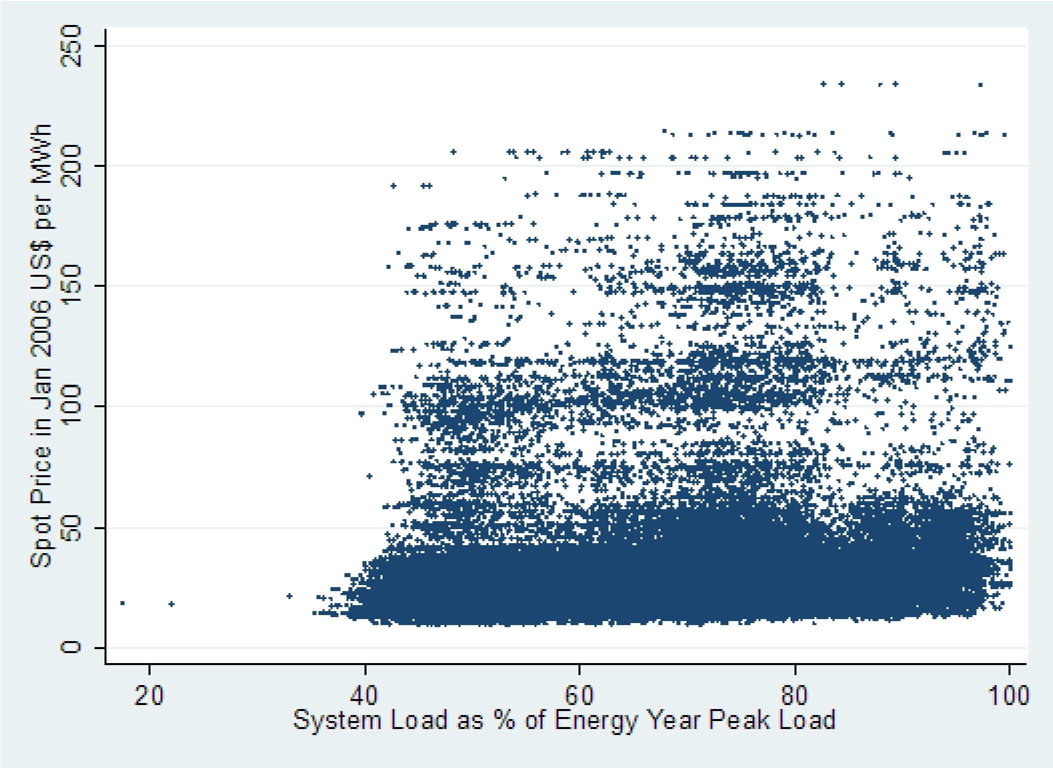
Figure 2



Notice that although the thermal-constant approach succeeded in eliminating the mean net penalties in these difficult years, the variation has almost no impact on risk. The standard deviations of the net payments are nearly unchanged across the two approaches.

One explanation for why differences are small between the two approaches is the fact that there is little correlation between the spot price and load (normalized as the percent of the annual peak load). This correlation is only 0.18, which is so small it is difficult to detect any correlation in the scatter plot of price and load shown in Figure 3. It must, however, be remembered that in the future this correlation could either increase because the spot price will be freer to respond to load or decrease because hydro units will perform more efficiently, absent an incentive to exercise market power.

Figure 3



3.2 Modeling hydro units

Next we turn to a hypothetical hydro unit. With thermal units, it was clear what the main source of risk was: outages. For a hydro unit, it is less clear how best to model hydro risk with respect to the hedge. There are at least three potential sources of risk.

The first is that the unit has an outage during a dry period. We view this risk as extremely minor because hydro units tend to be reliable, and more importantly having an outage results in little loss, because the unit can be fixed and its output can be shifted to other high-priced hours. No firm energy is actually lost. For this reason, we ignore this potential risk.[5]

The second source of risk is that the unit may have less firm energy than it sold, and so it must buy additional energy in the spot market. There are two possible explanations for the shortage and each has different implications.

First, the shortage of firm energy may be system wide, because it is drier than the dry period used in certifying firm energy. This would be a large source of risk if the firm energy certifications were biased upward. However, if the worst-case benchmark establishing the certification benchmark really is a worst-case, then this should not be a problem. Only in the most exceptional circumstances would hydro units in aggregate have less firm energy than was sold.

[5] One concern is that a landslide may disrupt the hydro unit for an extended period of time and may result in a loss of water. Of course, these events are presumably much more likely in wet periods than dry periods, unless the landslide is the result of an earthquake, but a major earthquake would be a good example of a force majeure event where the obligation would be relaxed.

Second, the shortage of firm energy may be regional, because the rainfall that has come has missed this unit's reservoir. The distribution of rainfall across the mountains of Colombia may vary in the North-South dimension from year to year. For example, if the rainfall fell further south in a particular year, then presumably the reservoirs in the South would have more water and the reservoirs in the North would have less water. Thus, the Southern units would over-perform and the Northern units would under-perform relative to the firm energy obligation.

We represent both sources of shortage risk as follows. We assume 1 MW hydro unit's firm energy capability in any dry period is normally distributed with mean p and standard deviation sd. Let p = .3 or .5 and sd = .1 or .15. Thus, we consider four different cases as before. In each dry period, the unit gets a new independent draw from the normal distribution to determine its quantity of firm energy. For the hydro simulations, there were two dry periods—the short period from 11/20/95 – 12/30/95 and the long period from 8/27/97 – 4/20/98.

We assume the unit sells firm energy based on its mean capability, since it does not observe its actual capability until several years after the auction.

Finally, we assume that the hydro unit manages its output to supply in the highest-priced hours of each day. This makes sense, since the hydro unit submits a daily bid and then is dispatched in each of the hours where the price is above its bid. Hence, the hypothetical hydro unit with firm energy of x% of its capacity, provides x% of load in each day, but it puts that x% in the highest priced hours for the day. Consider an example in which the unit has a firm energy factor of 20%. Thus, over the 24 hours, it can generate $24 \times .2 = 4.8$ MW. We sort the hours in order of price from highest to lowest and dispatch the unit to supply in the five highest priced hours as follows:

Hour	5pm	4pm	6pm	3pm	7pm	Total
Energy price	$175	$160	$145	$140	$134	
Energy from unit	1	1	1	1	0.8	4.8

Figure 4

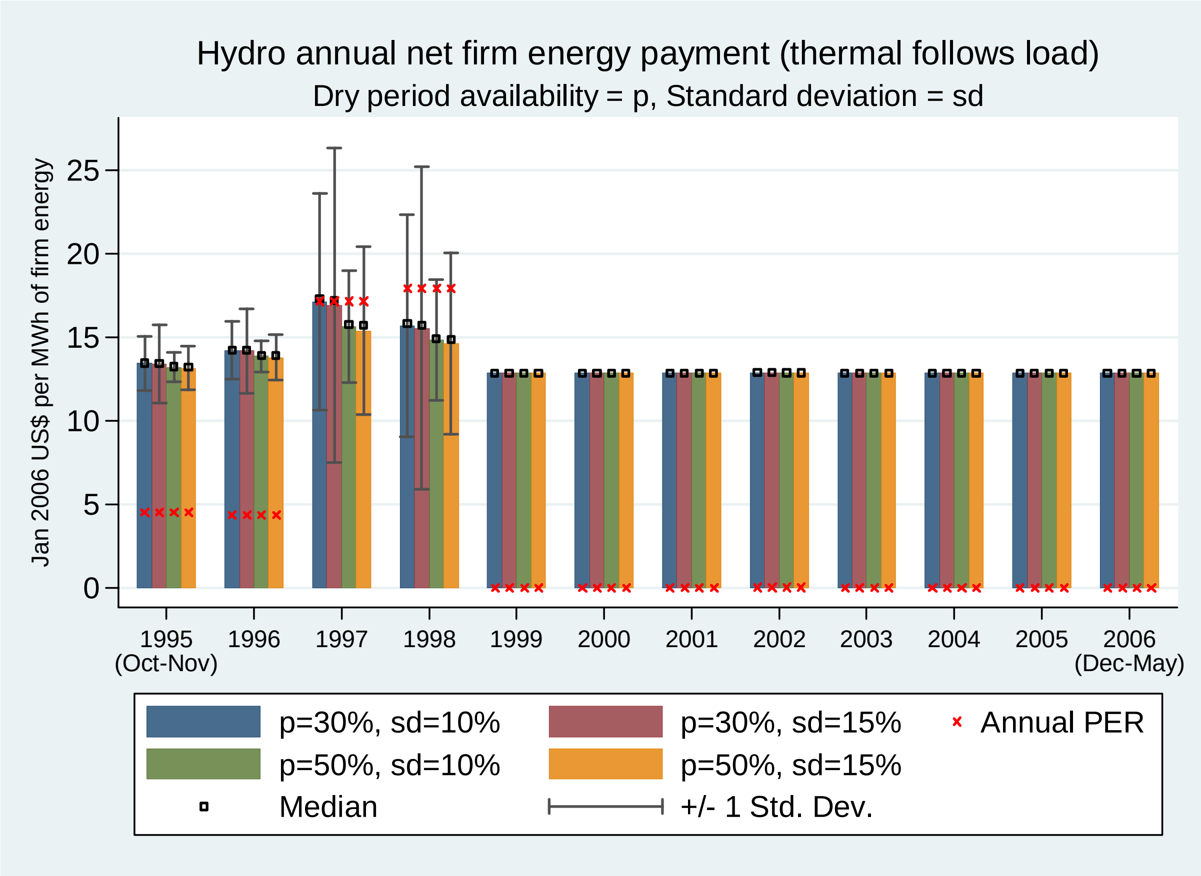


Figure 4 displays the hydro unit's net firm energy payment for the case where the obligation follows load. During the vast majority of years, the firm energy payment is constant. There are no scarcity hours and no risk associated with prices above the scarcity price. In contrast, during the dry periods, especially 1997-1998, the mean net firm energy payment increases, but has significant variation due to the large standard deviation in the unit's actual firm energy. Of course, risk is greatest when the standard deviation of firm energy is larger.

Figure 5

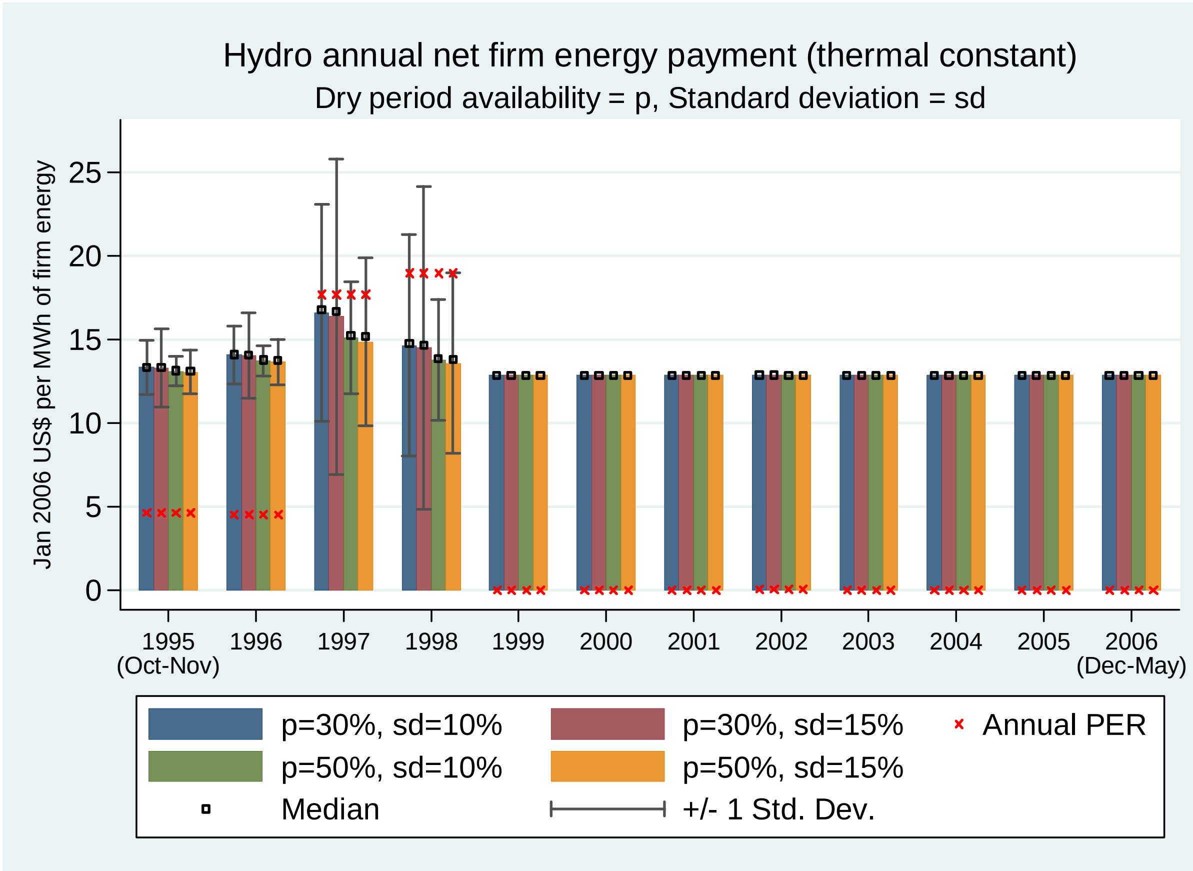
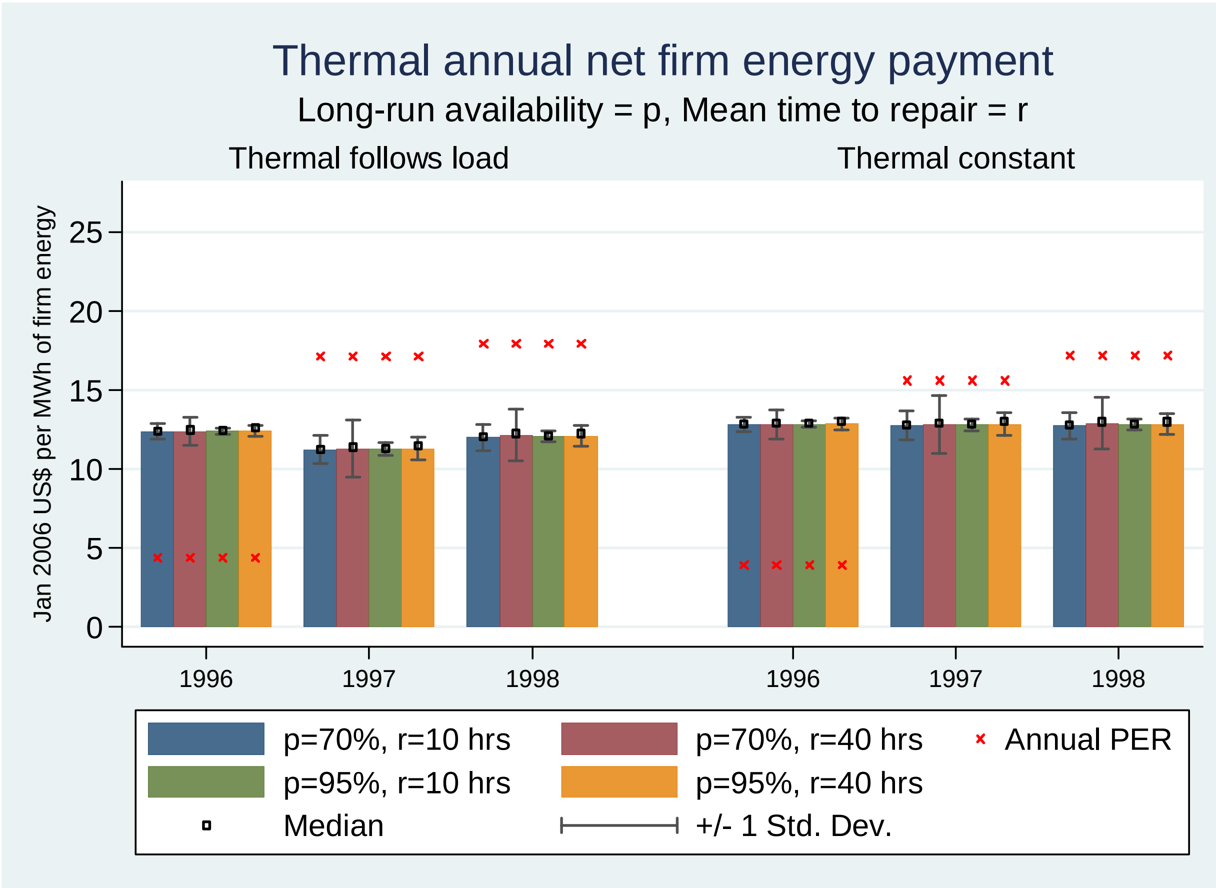


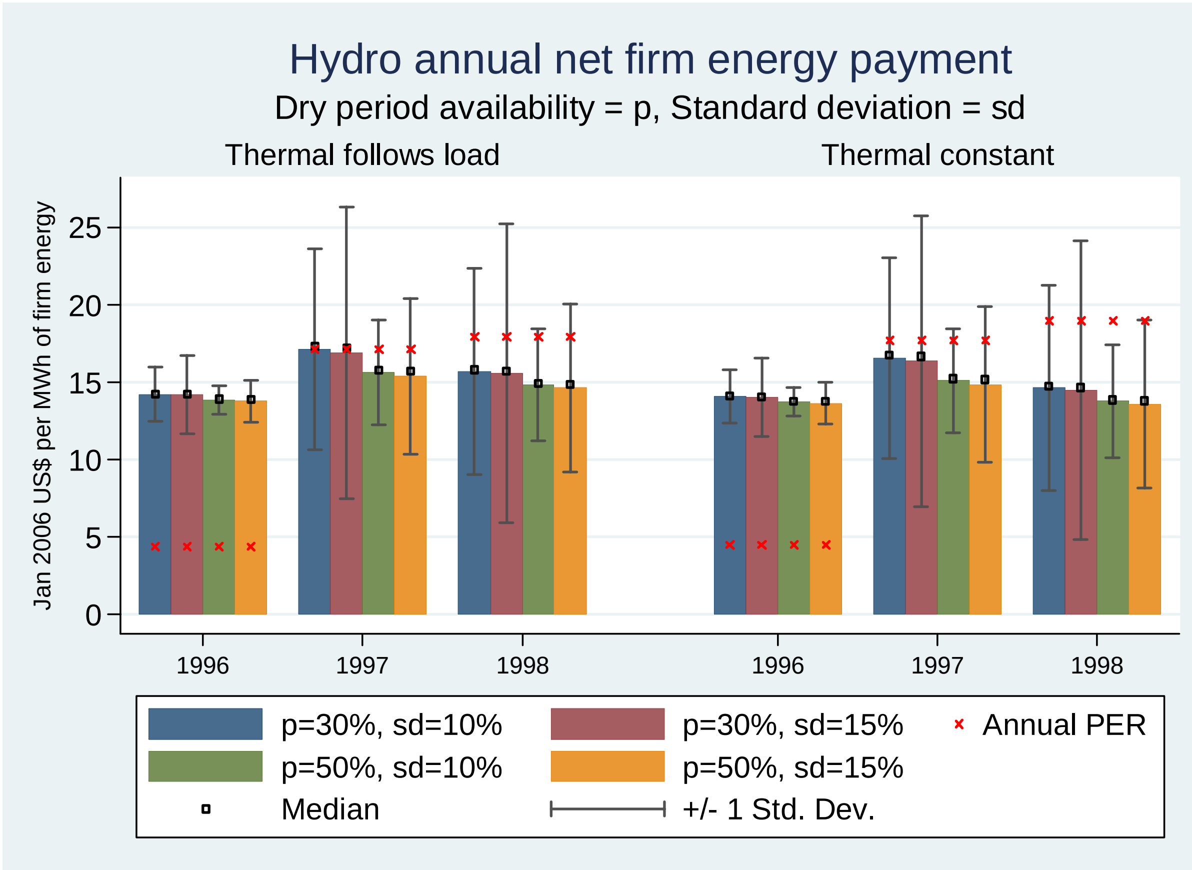
Figure 5 shows the net firm energy payment of are hypothetical hydro unit for the case in which the thermal resources have a nearly constant obligation, and the hydro resources follow load for the residual demand. Interestingly, this change has almost no impact on either risk or the size of the payments on an annual basis.

Figure 6



To better see the risk in the proposal and in the variation, Figure 6 displays the net firm energy payment for a thermal resource under each of the cases for the three years with dry periods. In all years without dry periods, the net firm energy payment is constant and has no risk. The figure confirms that there is almost no difference in risk between the two cases. Indeed, the risk to the thermal unit is slight in both cases. The reason is that the mean repair time is short relative to the length of the dry periods. Risk does increase with the mean time to repair, but does not appear to depend on whether thermal follows load or has a constant obligation during scarcity hours. The thermal unit is slightly worse off when it is asked to follow load, but the impact is not large.

Figure 7



We get a similar result for the hydro unit, as shown in Figure 7. Risk is unchanged across the two alternatives. The hydro resource is slightly better off when the thermal resources follow load, but the impact is minor.

Given that risk is unchanged across the two approaches, and mean payments are only slightly changed, we believe it is best to continue with the original proposal in which all resources follow load in the same way.

4 Model 2: Historical estimation of net firm energy payment

We now consider a model even more closely tied to historical data. In particular, we look at the individual unit data, and ask the question: “What would net firm energy payments be if the firm energy market was in operation through our entire sample period (beginning in 1995)?” An important assumption in this analysis is that the firm energy market would not influence prices or the operation of the generating units. In Model 2, we directly calculate for each unit the net firm-energy payment based on historical price, operation, and firm energy capability. Since risk is evaluated at a company level, rather than at the unit level, we aggregate the data by company.

Table 4. Hydro and Thermal Capacity, Availability, and Firm Energy by Company[1]

	Hydro Resources						Thermal Resources				All Resources			
Company	Capacity July 2006 (MWh)	Reference Firm Energy Aug 2006 (MWh)	Maximum Firm Energy Aug 2006 (MWh)	Availability in Scarcity Hours	Reference Firm Energy/ Capacity (MWh)	Maximum Firm Energy/ Capacity (MWh)	Capacity July 2006 (MWh)	Firm Energy Aug 2006 (MWh)	Availability in Scarcity Hours	Firm Energy/ Capacity (MWh)	Capacity July 2006 (MWh)	Reference Firm Energy (MWh)	Maximum Firm Energy (MWh)	Maximum Firm Energy Share
EEPPM	2,106	664	808	52.8%	31.5%	38.3%	455	452	75.5%	99.4%	2,561	1,116	1,260	19.2%
EMGESA	2,400	820	1,004	36.4%	34.2%	41.8%	358	223	73.7%	62.2%	2,758	1,043	1,227	18.7%
TEBSA							1,179	1,018	77.3%	86.4%	1,179	1,018	1,018	15.5%
ISAGEN	1,826	536	625	37.6%	29.4%	34.2%	285	271	86.0%	95.0%	2,111	807	896	13.6%
Flores							447	411	58.2%	91.9%	447	411	411	6.3%
Termocandelaria							314	294	0.0%	93.8%	314	294	294	4.5%
GENSA							314	277	77.7%	88.2%	314	277	277	4.2%
TERMOEMCALI							233	213	20.2%	91.2%	233	213	213	3.2%
TERMOVALLE							205	199	31.3%	97.0%	205	199	199	3.0%
Termotasajero							155	149	82.8%	96.1%	155	149	149	2.3%
MERILÉCTRICA							169	146	53.5%	86.2%	169	146	146	2.2%
AES CHIVOR	1,000	138	161	27.7%	13.8%	16.1%					1,000	138	161	2.5%
EPSA[2]	863	107	141	21.3%	12.4%	16.3%					863	107	141	2.1%
PROELECTRICA							90	88	80.3%	98.0%	90	88	88	1.3%
Termoyopal							49	39	46.3%	79.7%	49	39	39	0.6%
Urrá	335	27	35	39.8%	8.1%	10.5%					335	27	35	0.5%
ESSA[3]	23	2	2		6.9%	6.9%	14	13	57.5%	94.9%	37	15	15	0.2%
Total	8,552	2,294	2,776	38.2%	26.8%	32.5%	4,267	3,793	63.3%	88.9%	12,820	6,087	6,568	100.0%

Notes:

[1]The listed capacities and firm energies for each company may include units that were not used in the availability calculation because not all units were present in the generation output data. Companies are not included in this table if none of their units were present in the generation output data. Units are assigned to their current company.

[2]EPSA availability and capacity includes the one CHIDRAL unit because EPSA's ALTO ANCHICAYA unit is combined with CHIDRAL's BAJO ANCHICAYA unit in the output data.

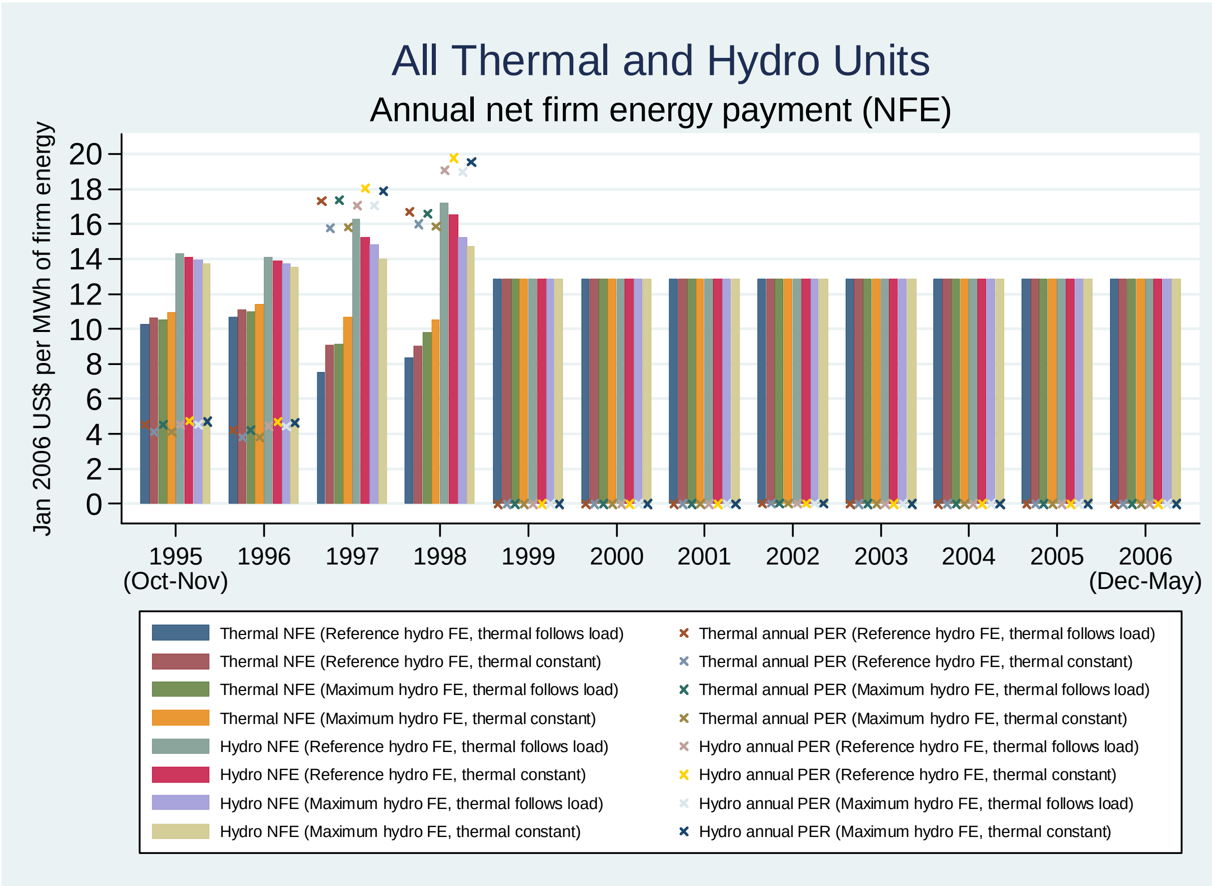
[3]ESSA's two units that were present in the generation output data were retired in 2004 and 2005. The capacity listed represents units that were not in the generation output data.

Table 4 shows the capacity, availability, and firm energy for each company in our generation output data. The firm energy numbers are the preliminary firm energy numbers, as determined by XM in August 2006 based on CREG resolution 043. There are actually two firm energy numbers for hydro resources. One is the *reference quantity*, which is based on a 98% chance that the actual quantity of firm energy for the resource will exceed what is needed. The other is the *maximum quantity*, which is based on a 95% chance that the actual quantity of firm energy for the resource will exceed the obligation. The companies are sorted in descending order based on total firm energy, using the reference quantity. In aggregate, hydro resources over performed—availability of 38.2% exceeds firm energy/capacity—and thermal resources under performed—availability of 63.3% is below firm energy/capacity.

A critical element in the net firm energy payment calculation is the quantity of firm energy sold by the resource. In all the calculations that follow, we assume a load-following obligation for all resources. We also assume that the quantity of firm energy sold by the resource is equal to its firm-energy certification. For hydro resources we consider both the reference and maximum firm-energy quantities.

As in Model 1, we assume a firm energy payment of $12.85/MWh. The calculation is done each hour for each unit, and then aggregated up to either a monthly or an annual result. The company calculation is based on the company’s entire portfolio of units, both thermal and hydro.

Figure 8

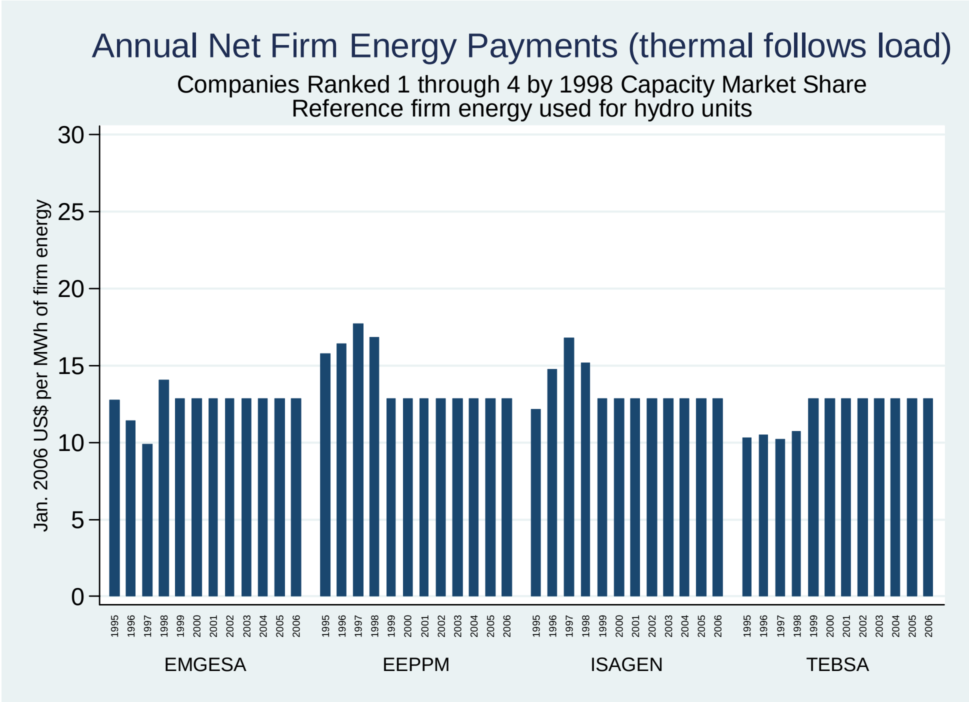


We begin by calculating the net firm energy payment for each unit and then aggregating the units by type, either thermal or hydro. Figure 8 shows how hydro resources do better than thermal resources during the dry periods. There are two reasons for this. First and most important, the hydro resources over performed on average in dry periods; whereas, the thermal resources under performed. Second, hydro resources get an additional premium because of their greater ability to follow load. This premium is largest when the thermal obligation follows load, rather than is constant. Nonetheless, the net firm energy payments for thermal units are not too far below the payment obtained in wet periods, especially in the thermal constant case.

One problem with Model 1 is that it focused on a single resource. This tends to overstate risk, since most companies operate a portfolio of generating units, and indeed the portfolio is selected with risk in mind. A major benefit of Model 2 is that it enables us to look at generator risk from a company perspective.

We calculate the net firm energy payments for each company and for each year. The net firm energy payment includes all cash flows from the firm energy payment as well as for performance above or below the company’s obligation during scarcity hours (hours in which the spot price is above the scarcity price). Calculations are done both for thermal follows load and thermal constant. In addition, both the reference and maximum hydro sales of firm energy are considered.

Figure 9



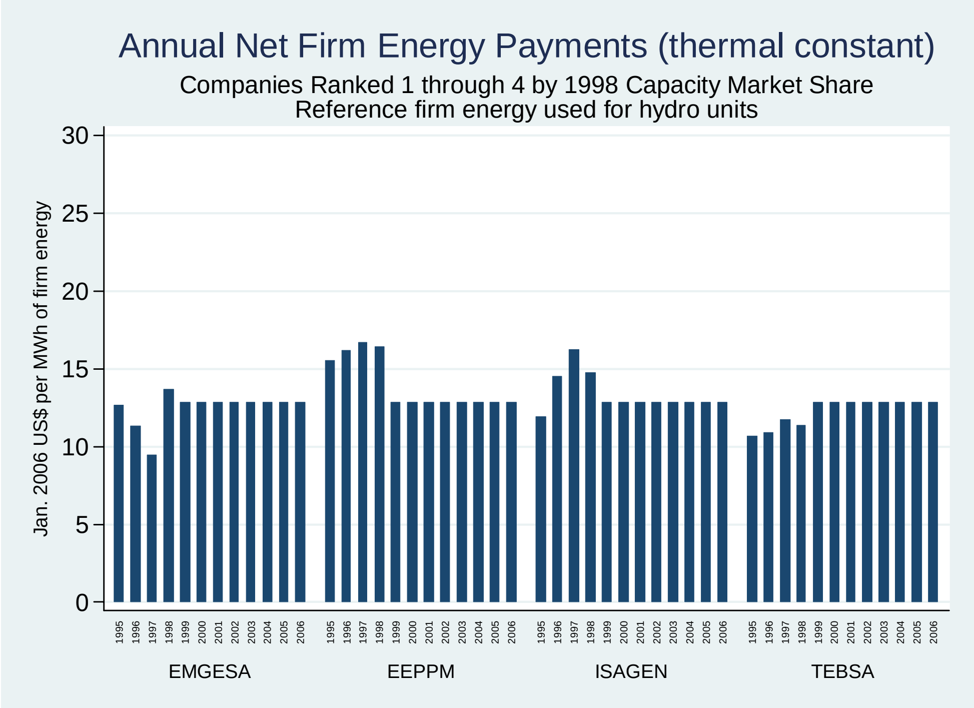
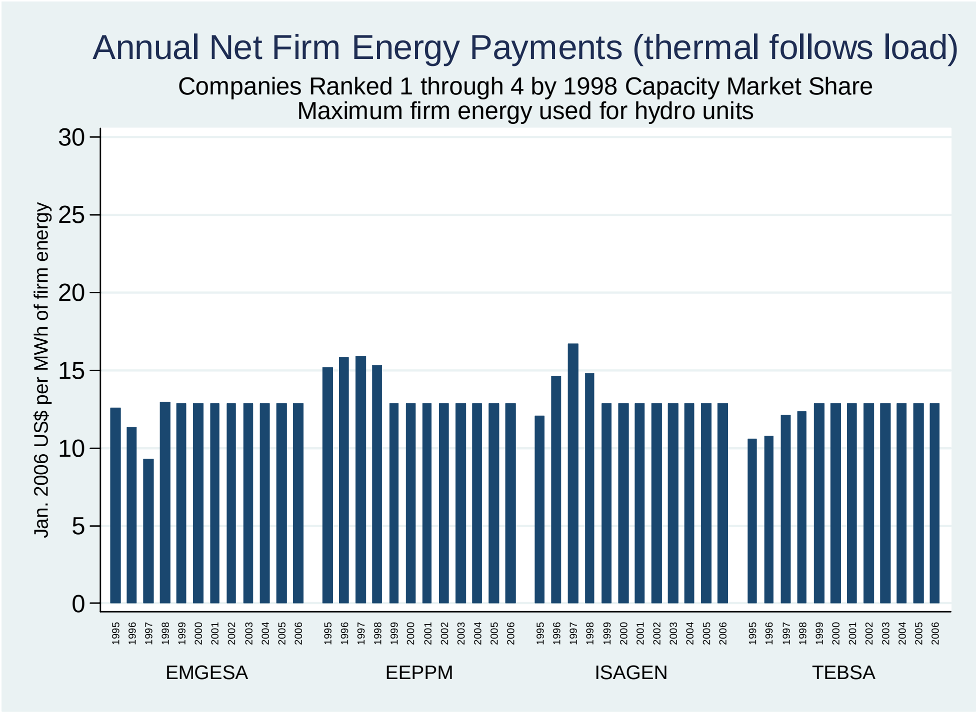


Figure 9 shows the net firm energy payment for the four-largest companies in Colombia, assuming that hydro units sell the reference level of firm energy. Most importantly, notice that the net firm energy payment is roughly constant. The payment does fall somewhat during the dry periods for EMGESA and TEBSA, under performers in 1997-1998, and rise during the dry periods for EEPPM and ISAGEN, over performers in 1997-1998.

Figure 10



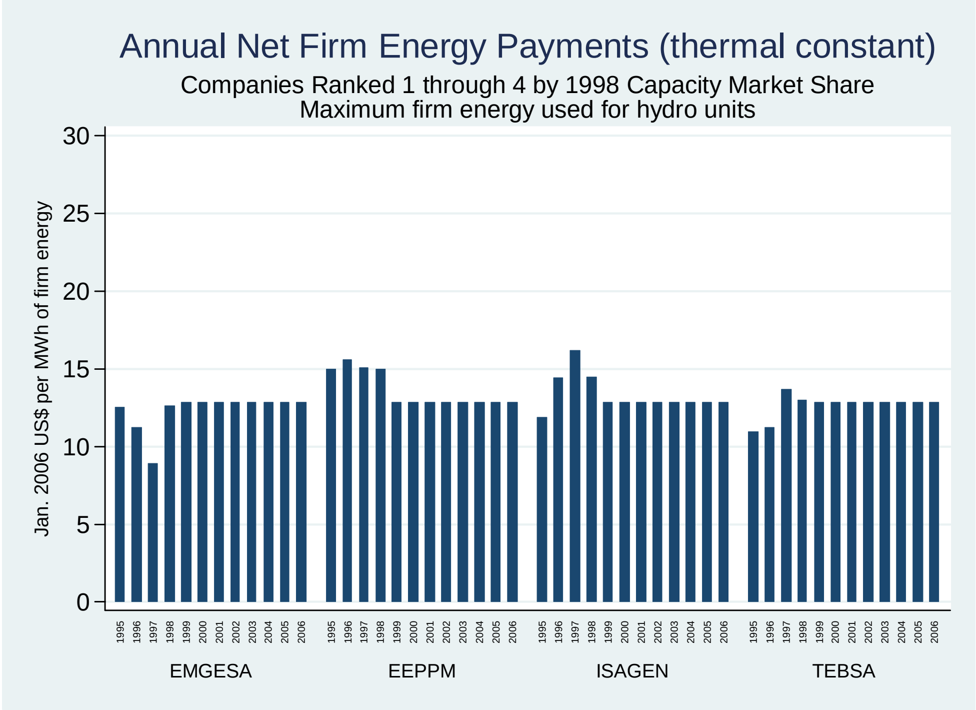
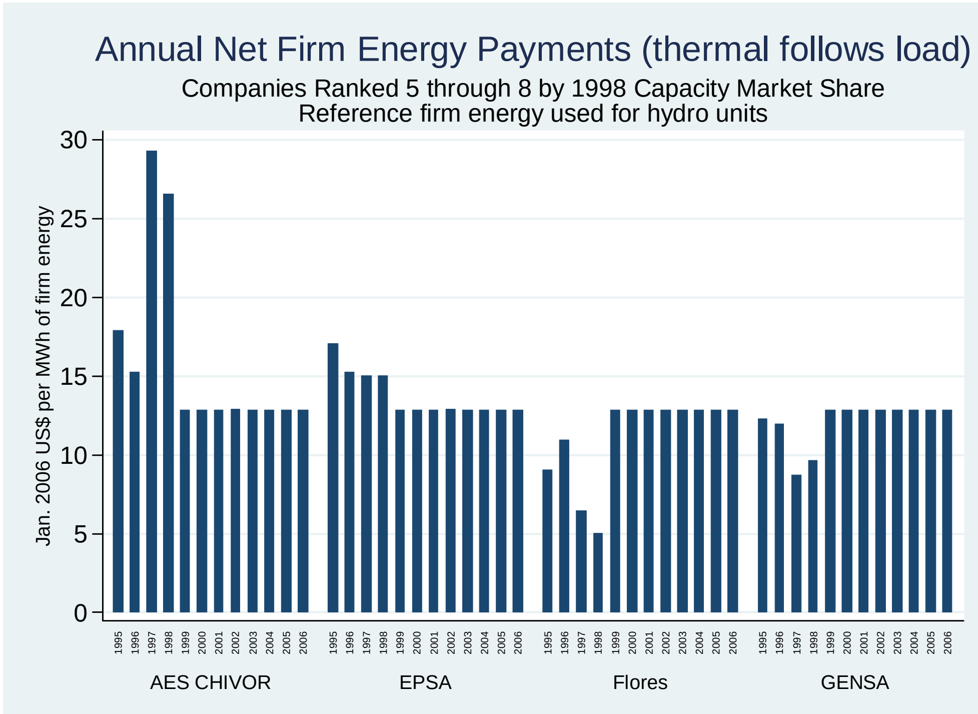


Figure 10 presents the same calculation, but this time assuming that hydro units sell at their maximum firm energy level. The results do not change substantially.

Figure 11



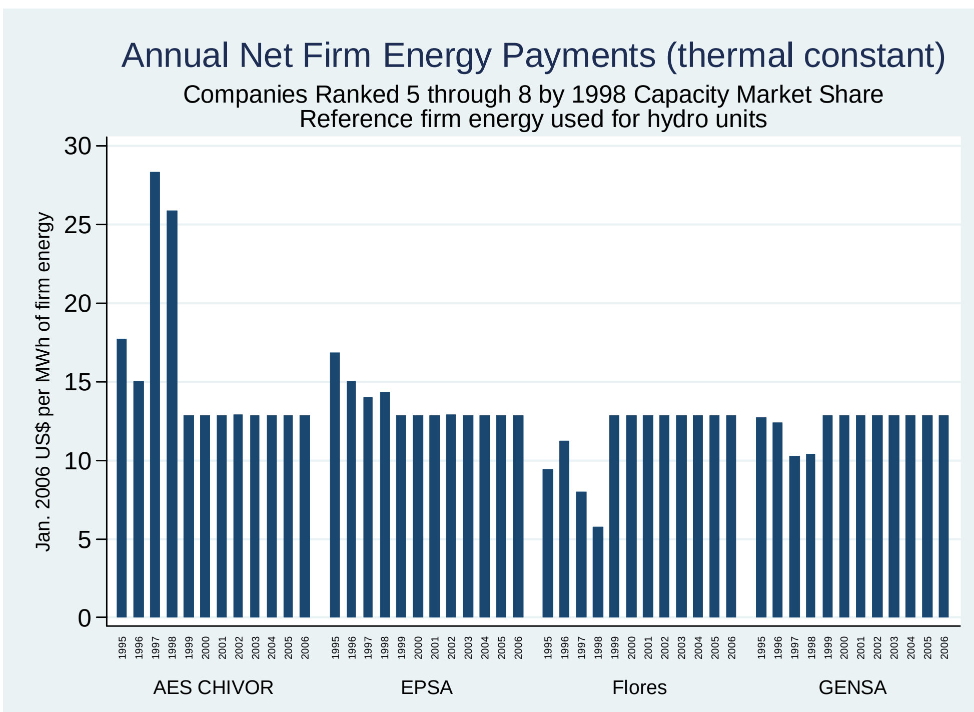


Figure 11 shows the net firm energy payment for the next four-largest companies in Colombia, assuming that hydro units sell the reference level of firm energy. For these four companies there is a bit more variability. In particular, AES CHIVOR is a significant over performer in 1997-1998, generating twice its reference firm energy, and Flores is a significant under performer, generating only 63% of its obligation.

Figure 12

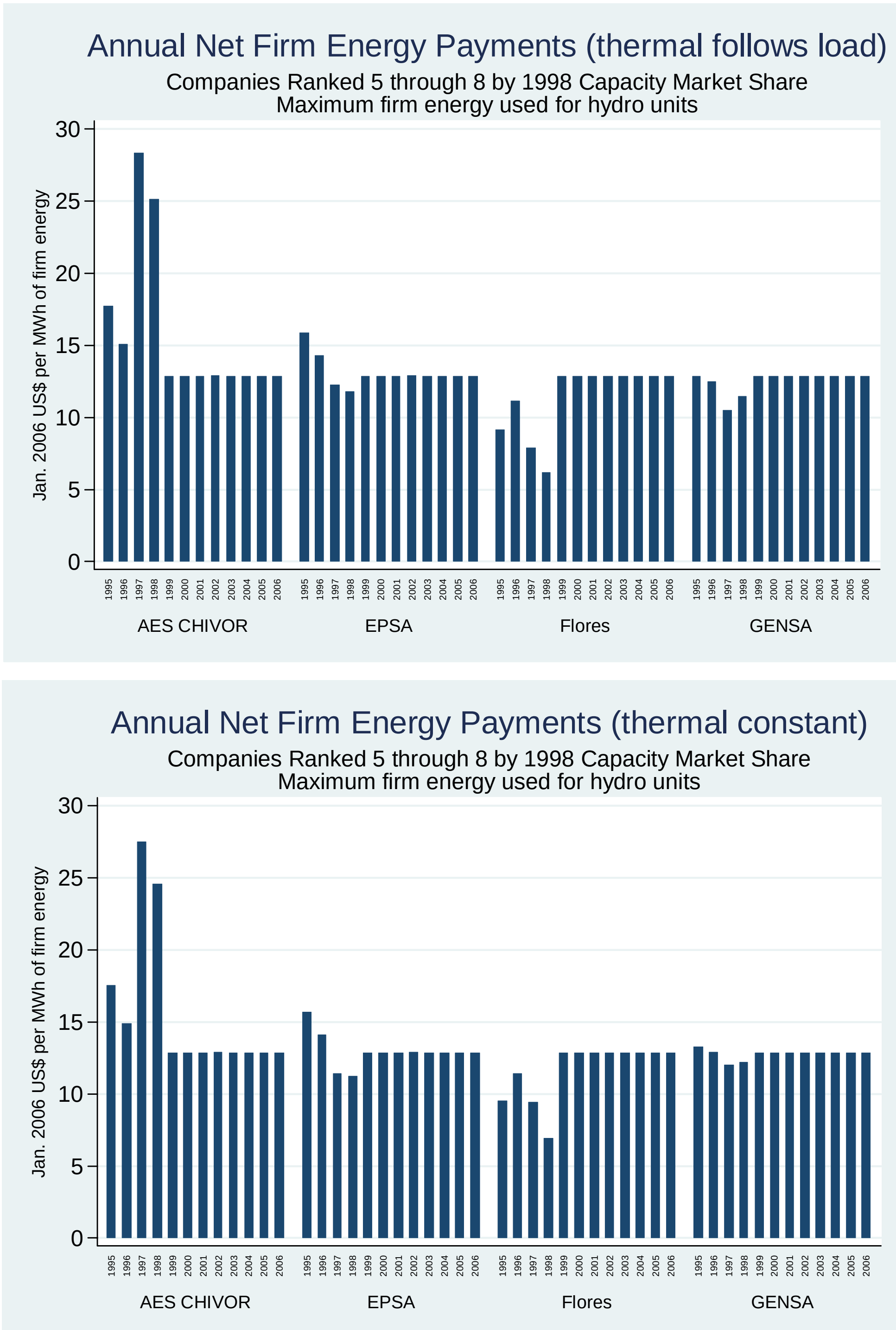


Figure 12 presents the same calculation, but this time assuming that hydro units sell at their maximum firm energy level. This reduces AES Chivor's over performance in 1997-1998 somewhat. Otherwise, the results are the same.

5 Model 3: Simulation of the market going forward

Model 3 is designed to simulate the firm energy market, its stream of investments in new capacity, and the risks to investors. The model allows us to estimate the impact of variations in the auction design. Models 1 and 2 did a good job of assessing risk to investors, but the models were closely tied to historical prices (Models 1 and 2) and historical units and output decisions (Model 2). Moreover, the annual auction and supplier investment decisions was not modeled, so questions specific to the annual auction and investments over time could not be addressed.

Model 3, by explicitly modeling the annual auction and investments, is able to consider other questions. For example, we can look at the distribution of acquired firm energy relative to the target firm energy. Also, we can consider variations in the proposal. For example, the proposal has a parameter of 4%, which determines the slope of the demand curve around the firm energy target. We can evaluate the impact of setting this demand curve parameter to 2%, rather than 4%; that is, a case where the demand curve around the firm energy target is twice as steep as in the original proposal. Finally, we can explore the impact of demand response on the market outcomes.

Model 3 does not attempt to model every aspect of the Colombia electricity system, nor every aspect of the firm energy market. Simplification is essential to any modeling exercise and this is no exception. What we have done is identified the critical elements to model explicitly. Other elements are handled with simplifying assumptions. As an example, in Model 3 we do not explicitly model the outages of thermal resources; rather, we assume an availability in each hour consistent with the long-run availability of the thermal resources. The analysis from Models 1 and 2 demonstrated that the risk for thermal units as a result of outages is small when performance is measured over one or more years. Thus, explicit modeling of outages of each unit would greatly add to the complexity of the calculations, but not have any significant impact on results. In contrast, the explicit modeling of the energy output of hydro resources is absolutely essential.

5.1 Description of the simulation

The basic features of the model are as follows.

Stationarity

For simplicity, the model has a stationary structure. For example, we assume a random exponential growth in load with a mean of 3% per year. In order to keep the market functioning for decades in a way that is similar to how it will function at the start, we scale project sizes to keep them the same size relative to total load today. Thus, after 20 years of growth, averaging 3% per year, projects are assumed to be about 75% larger than they are today. Doing this simplifies the modeling and makes the results more relevant. In particular, it maintains the importance of lumpy projects regardless of the length of the simulation.

All monetary values are in real US dollars. One must be careful in interpreting results. In some cases, the specific numbers are less meaningful than other statistics about the numbers. For example, the particular firm energy price is largely a function of the cost parameters, such as the fixed costs of each plant type. The parameters have been chosen so that the long-run equilibrium is close to the existing mix of plant types. However, one can easily increase the firm energy clearing price by a constant simply by raising the fixed cost of each plant type by the same amount. What is much more relevant is the change in the numbers, both over time, and across scenarios.

Duration

A key input to the simulation is the 1000 years (100 ten-year series) of hydro energy output as simulated by XM. We make use of all of this data in each scenario by conducting 50 20-year simulations. This is useful for looking at the behavior from the initial state, as it converges to the long-run equilibrium. By doing 50 simulations in each case, we are able to see the distribution of market outcomes.

Energy price and demand

The scarcity price is set at P_S = \$100/MWh. We are not modeling changes in fuel costs, so the scarcity price is fixed throughout the simulation.

Load in each hour is modeled from the most recent five years of load data. For prices less than the scarcity price, demand is vertical (completely inelastic). For prices greater than the scarcity price, demand has constant elasticity of –.05. This means that a 20% increase in price is needed to produce a 1% decline in quantity demanded. Such hours will be considered scarcity hours. This elasticity produces a downward sloping demand for energy, which allows us to match supply and demand during dry periods. Price rather than rationing is used to balance the market.

Specifically, the demand in any particular hour is determined as follows. Let the last five years (May 2001 to Apr 2006) be sample years (a sample year is a year of hourly loads); we remove 29 February 2004, so all years have 365 days. We then scale the data in each energy year so that that total energy over the year is the same as in the last year (May 2005 to Apr 2006). For each year of the simulation, we pick a sample year randomly. Load in hour h is equal to load in hour h of the sample year scaled for growth. The growth G in each year is normally distributed with mean 3% and standard deviation of 1%. That is,

scale factor in year T = scale factor in year T–1 times (1 + G).

Growth may be negative, although this is unlikely.

All simulations assume as an initial condition that in year 0, the firm energy target is equal to the firm energy resources—that is, we start in a condition of neither surplus nor shortage. The auctions for future years only need to accommodate the load growth.

Resources

The model includes three types of investments: hydro (H), baseload (B), and peakers (P). Peakers and baseload are characterized by a fixed cost, a variable cost, a capacity, and a long-run availability; whereas hydro is characterized by a fixed cost, a capacity, and a quantity of firm energy. The characteristics of new units are based on the characteristics of existing units.

There are 59 existing generators in the simulation: 26 hydro, 17 baseload, and 16 peaker units. Peakers are defined as gas-fired units with heat rates of 9 and higher. All other thermal resources are baseload units. New units of each type are drawn from these existing units. For baseload and peaker units, only the capacity is inherited from the existing unit. For hydro units, the firm energy is inherited as well as the simulated hydro energy for the 1000 years. The existing resources are shown in Table 5 and summarized in Table 6.

Table 5. Existing resources included in Model 3

Unit type (1)	Unit name	Actual owner (July 2006)	Owner when reassigned to a top 10 company for Model 3 simulations (2)	Firm Energy (Maximum for Hydro; Full Contract for Thermal) in MWh	Unit capacity (July 2006) in MW		Fuel	Heat rate (MBTU/ MWh)	
Peaker	FLORES 3	Flores	Flores	153.9	175	(6)	gas	9.6	
Peaker	CANDELARIA2	Termocandelaria	Termocandelaria	148.2	157	(4)	gas	9.7	
Peaker	CANDELARIA1	Termocandelaria	Termocandelaria	146.2	157	(4)	gas	9.5	
Peaker	MERILECTRICA	MERILÉCTRICA	ISAGEN	145.7	169		gas	9.6	
Peaker	GUAJIRA 1	TEBSA	TEBSA	130.3	151	(7)	gas	9.8	
Peaker	GUAJIRA 2	TEBSA	TEBSA	129.5	151	(7)	gas	9.7	
Peaker	FLORES 2	Flores	Flores	107.3	112	(6)	gas	10.2	
Peaker	CARTAGENA 2	EMGESA	EMGESA	54.4	54	(5)	gas	9.9	(11)
Peaker	CARTAGENA 3	EMGESA	EMGESA	53.9	70	(5)	gas	9.9	
Peaker	BARRANQUILL3	TEBSA	TEBSA	53.0	64	(3)	gas	9.7	
Peaker	CARTAGENA 1	EMGESA	EMGESA	51.1	64	(5)	gas	9.9	(11)
Peaker	BARRANQUILL4	TEBSA	TEBSA	43.0	63	(3)	gas	11.0	
Peaker	TERMODORADA1	CHEC	Flores	37.1	51		gas	9.7	
Peaker	TERMO YOPAL2	Termoyopal	TERMOEMCALI	27.1	30		gas	12.7	
Peaker	PALENQUE 3	ESSA	ISAGEN	13.3	14		gas	14.3	
Peaker	TERMO YOPAL1	Termoyopal	TERMOVALLE	12.4	19		gas	13.0	
Baseload	TEBSAB	TEBSA	TEBSA	662.5	750		gas	7.3	
Baseload	TERMOSIERRA	EEPPM	EEPPM	452.0	455		gas	6.4	
Baseload	TERMOCENTRO	ISAGEN	ISAGEN	270.6	285		gas	7.1	
Baseload	EMCALI	TERMOEMCALI	TERMOEMCALI	212.6	233		gas	6.8	
Baseload	TERMOVALLE 2	TERMOVALLE	TERMOVALLE	198.9	205		gas	6.6	
Baseload	FLORES 1	Flores	Flores	149.5	160	(6)	gas	7.2	
Baseload	TASAJERO 1	Termotasajero	TEBSA	148.9	155		coal	9.5	
Baseload	PAIPA 4	GENSA	GENSA	139.1	150	(8)	coal	9.3	
Baseload	ZIPAEMG4	EMGESA	EMGESA	63.9	64	(10)	coal	9.0	
Baseload	ZIPAEMG5	EMGESA	EMGESA	62.8	64	(10)	coal	8.7	
Baseload	ZIPAEMG3	EMGESA	EMGESA	62.8	63	(10)	coal	9.6	
Baseload	PAIPA 2	GENSA	GENSA	59.1	68	(8)	coal	12.2	
Baseload	PAIPA 3	GENSA	GENSA	56.2	68	(8)	coal	12.3	
Baseload	PROELECTRIC2	PROELECTRICA	GENSA	44.3	45	(9)	gas	8.2	(12)
Baseload	PROELECTRIC1	PROELECTRICA	Termocandelaria	43.9	45	(9)	gas	8.2	(12)
Baseload	ZIPAEMG2	EMGESA	EMGESA	33.3	34	(10)	coal	12.8	
Baseload	PAIPA 1	GENSA	GENSA	22.7	28	(8)	coal	13.5	
Hydro	GUAVIO	EMGESA	EMGESA	525.5	1150				
Hydro	SAN CARLOS	ISAGEN	ISAGEN	475.7	1240				
Hydro	CHIVOR	AES CHIVOR	AES CHIVOR	329.3	1000				
Hydro	PAGUA	EMGESA	EMGESA	307.7	600				
Hydro	GUATRON	EEPPM	EEPPM	260.1	512				
Hydro	GUATAPE	EEPPM	EEPPM	219.2	560				
Hydro	BETANIA	EMGESA	EMGESA	157.7	540				
Hydro	PORCE II	EEPPM	EEPPM	153.4	405				
Hydro	PLAYAS	EEPPM	EEPPM	135.6	201				
Hydro	LA TASAJERA	EEPPM	EEPPM	121.6	306				
Hydro	MIEL I	ISAGEN	ISAGEN	115.3	396				
Hydro	URRA	Urrá	EEPPM	84.2	335				
Hydro	ALTOANCHICAY	EPSA	EMGESA	73.6	365				
Hydro	JAGUAS	ISAGEN	ISAGEN	47.1	170				
Hydro	SALVAJINA	EPSA	EEPPM	28.7	285				
Hydro	SANFRANCISCO	CHEC	EMGESA	23.0	135				
Hydro	FLORIDA	CEDELCA	EMGESA	18.3	20				
Hydro	ESMERALDA	CHEC	EMGESA	17.1	30				
Hydro	INSULA	CHEC	EMGESA	16.9	19				
Hydro	BAJOANCHICAY	EPSA	Flores	16.4	74				
Hydro	CALIMA	EPSA	Flores	11.3	132				
Hydro	RIOMAYO	CEDENAR	EMGESA	9.5	21				
Hydro	PRADO	ELECTROLIMA	EEPPM	6.5	45				
Hydro	PRADO4	ELECTROLIMA	EEPPM	4.3	5				
Hydro	CALDERAS	ISAGEN	ISAGEN	3.8	20				
Hydro	RIOGRANDE 1	EEPPM	EEPPM	0.4	25				

Notes:
(1) We classify a unit as a peaker if it is a gas-fired unit with a heat rate of at least 9.5 MBTU/MWh. We classify all other thermal units as baseload units.
(2) We estimate the Top 10 companies as ranked by maximum firm energy, and then reassigned each unit owned by a non-top 10 company to a top-10 company. We keep each top-10 company's share of the total firm energy for the top 10 companies roughly the same as it was before reassigning the units.
(3) - (10) The July 2006 capacity data contained aggregate data for these units. We estimated the unit-specific capacities using their pro rata shares of capacity as of December 2005. Using this method, the capacities of ZIPAEMG3, ZIPAEMG4, and CARTAGENA 2 were slightly greater than their firm energies (less than 2 MW). Therefore, we set the capacities of those units equal to their firm energies.
(11) The heat rates for Cartagena 1 and Cartagena 2 were not available. We assume they are equal to the heat rate reported for Cartagena 3.
(12) One heat rate was reported for PROELECTRICA. We assume the heat rate applies to both the PROELECTRIC1 and PROELECTRIC2 units.

Table 6. Summary of existing resources by type

Unit type	Number	Firm energy (MWh)	Capacity (MW)
Peaker	16	1,306	1,502
Baseload	17	2,683	2,871
Hydro	26	3,162	8,591
Total	59	7,152	12,964

Firm energy is stated in average hourly terms; that is, annual firm energy / 8760.

New unit characteristics are determined as follows. First consider peakers. We randomly order the vector of peaker capacities, doing this many times to construct a list of peaker capacities for each of the 50 twenty-year simulations. Peaker capacities are then drawn in sequence from this list. With this approach since we have 16 existing peakers, each peaker size is selected once after 16 peaker entries in any given simulation, twice after 32 peaker entries, and so on. Capacities are scaled up for growth, as described below. The same approach is used for baseload and hydro entry. However, for hydro entry, the firm energy and the energy series are inherited from the existing plant characteristics. Hydro energy and firm energy is scaled up for growth as well.

The characteristics of each unit of a particular type are as follows:

Ai = long-run availability of type i resource; A_H = 100%; A_B = 93%; A_P = 87%
Baseload and peaker availabilities are based on average availability of each resource type. For simplicity, rather than simulate thermal outages, as we did in Model 1, here we will use average availabilities. This simplification has little impact on risk, as was demonstrated in the Model 1 analysis.

C_i = capacity of type i resource (MW); based on existing units as described above.

FE_i = firm energy of type i resource (MWh); FE_H = Table 5; $FE_B = A_B C_B$; $FE_P = A_P C_P$
For hydro units we use the "maximum" firm energy (not "reference"). We do this because we believe that most participants will find it profitable to sell the maximum firm energy.

VC_i = variable cost of type i resource ($/MWh); VC_H = $0; VC_B = $50; VC_P = $80

FC_i = fixed cost of type i resource ($/MWh of FE); FC_H = $90.60; FC_B = $8; FC_P = $3.90
The fixed costs were chosen so that the long-run equilibrium mix of plants is close to the existing mix of plants.

Supply and price determination in the spot energy market

The spot energy market assumes each unit bids its marginal cost, including its opportunity cost in the case of hydro. The first step is to determine the opportunity cost of hydro which is done by constructing the monthly supply as a function of hydro's opportunity cost, MC_H.

Define:

L = hourly load

MC_i = marginal cost of type i resource ($/MWh); $MC_B = VC_B$; $MC_P = VC_P$

E_i = maximum energy the resources of type i can supply in the month

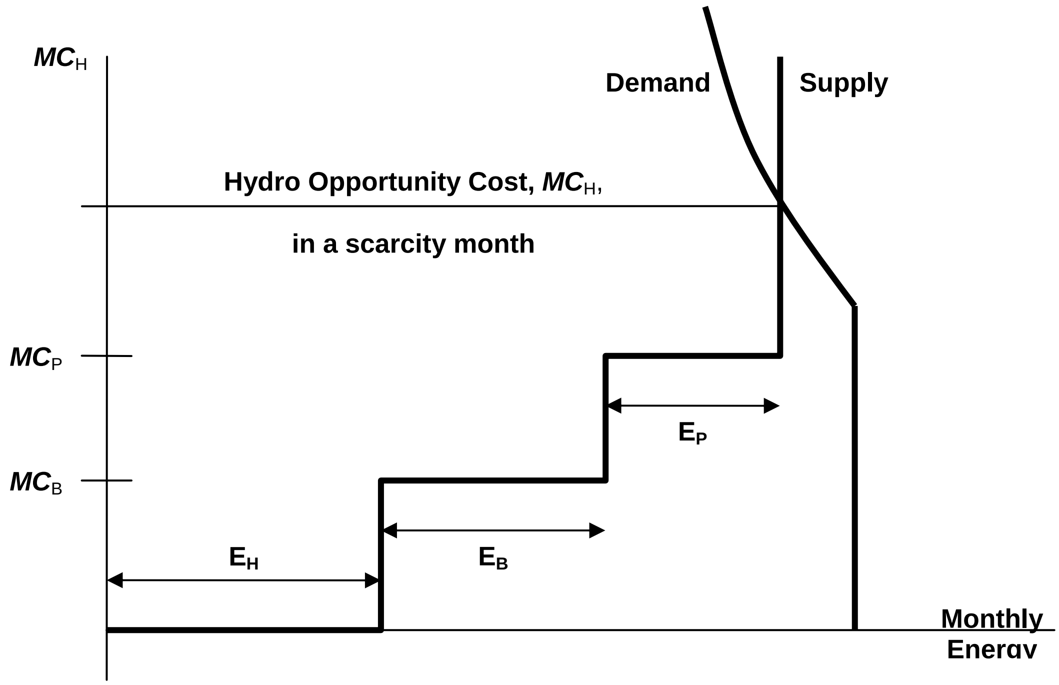
E_H is given from the hydro series for each hydro unit, and then summed over units.

E_B is the baseload energy available to the extent that baseload available capacity does not exceed load. E_B = the hourly sum of min(A_B C_B, L).

E_P is the peak energy available to the extent that baseload plus peakload available capacity does not exceed load. E_P = the hourly sum of min(A_P C_P, L – A_B C_B).

These definitions allow us to draw a supply curve as shown in Figure 13.

Figure 13. Monthly determination of the hydro opportunity cost



Intersecting the supply and demand curves determines the hydro opportunity cost for a given month. Because the demand curve is vertical at D, MC_H will equal \$0, MC_B, MC_P, or something greater. These four cases can be described using the following definitions:

e_i = energy output over the month for units of type i

p = spot price

D = monthly energy demand before demand response.

$D(MC_H)$ = demand as a function of the hydro opportunity cost.

$D(MC_H) = D$ if $MC_H \le P_S$.

$D(MC_H) = D\times(MC_H / P_S)^{\beta}$, where $\beta = -.05$ = elasticity, if $MC_H > P_S$.

There are four cases that determine prices and output for the entire month.

Case 1 (MC_H = \$0):	p = 0 in all hours.	$e_H = D$, $e_B = e_P = 0$.
Case 2 ($MC_H = MC_B$):	p = MC_B in all hours.	$e_H = E_H$, $e_B = D - e_H$, $e_P = 0$.
Case 3 ($MC_H = MC_P$):	p = MC_B or MC_P.	$e_H = E_H$, $e_B = E_B$, $e_P = D - e_H - e_B$.
Case 4 ($MC_H > MC_P$):	p = MC_B or MC_P or MC_H.	$e_H = E_H$, $e_B = E_B$, $e_P = E_P$.

Note that hourly calculations determine how much baseload energy is sold at MC_B, MC_P and MC_H. Similar calculations are used for peaker energy output at MC_P and MC_H. Hydro supplies the residual that is not supplied by baseload and peakers.

In Case 1, hydro supplies all the hourly load.

In Case 2, baseload provides a constant amount in each hour (the constant amount is calculated from the fact that hydro supplies E_H over the month), except when this amount would be greater than load for that hour (in which case baseload supplies all the load in the hour, and the constant baseload hourly output is recalculated for remaining hours). Hydro supplies the residual, which equals E_H over the month.

In Case 3, baseload supplies its long-run availability in each hour or 100% of load, whichever is less. Peaker provides a constant amount in each hour (the constant amount is calculated from baseload's hourly output and the fact that hydro supplies E_H over the month), except when this amount would be greater than load for that hour (in which case peakers supply the residual load after baseload's output in the hour, and the constant peaker hourly output is recalculated for remaining hours). Hydro supplies residual hourly load, which totals E_H.

In Case 4, baseload is dispatched first in each hour up to its long-run availability. Peaker is dispatched second in each hour up to its long-run availability. Hydro provides a constant amount in each hour (the constant amount is calculated from the hourly output of baseload and peaker, and the fact that hydro supplies E_H over the month), except when this amount would be greater than load for that hour (in which case hydro supplies the residual load after the output of baseload and peaker in the hour, and the constant hydro hourly output is recalculated for the remaining hours). This results in load being reduced in those hours with dispatched hydro, consistent with the demand response at prices above the scarcity price.

Obligation

Each unit sells its firm energy in the annual firm energy auction. New units select a 10-year commitment period. Existing units have a one-year commitment. The obligation is the thermal-constant case. Each thermal resource has an obligation equal to the unit's firm energy (capacity times long-run availability), provided these obligations sum to less than load in the hour; otherwise, the obligation is reduced proportionately to match load. Hydro resources follow the residual demand, which is the actual demand less the thermal obligation. Obligations are adjusted on a monthly basis based on the deviation between the quantity of firm energy purchased and the actual load. That is, if only 98% of actual load was purchased, then obligations are reduced by 2% in each hour.

Bidding in the firm energy market

Bids in the auction are assumed to be competitive, which means they should be just high enough that the investor expects to break even including a normal return on equity. We assume that the fixed cost per MWh of firm energy includes the cost of equity. A competitive bid then is such that the investment has an expected profit of zero. The bid depends on the fraction of firm energy coming from each of the three resource types.

F_i = fraction of firm energy from resource type i. $F_P + F_H + F_B = 1$, so F_H and F_B determine F_P and therefore the entire mix of resources.

$b_i(F_H, F_B)$ = competitive bid of type i resource given the hydro and baseload shares of firm energy.

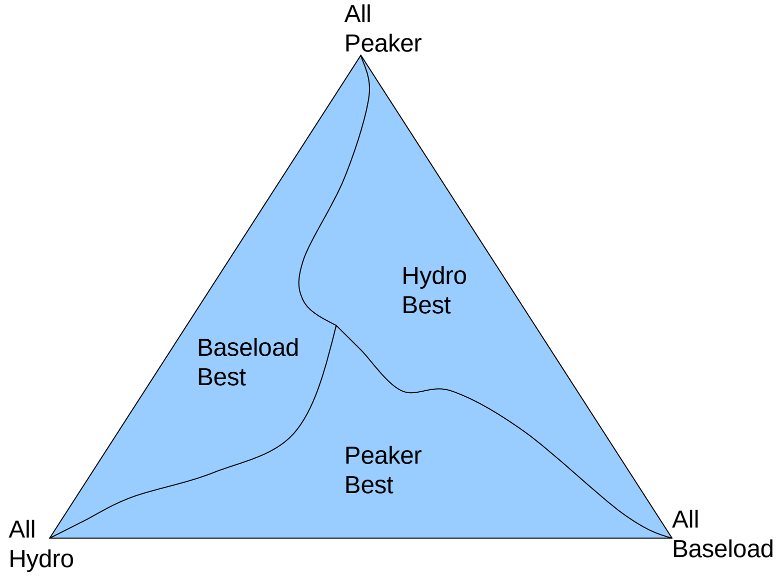
In the long-run equilibrium, the shares of each resource are such that the optimal bids of all types are the same; that is, F_H and F_B are such that $b_H(F_H, F_B) = b_B(F_H, F_B) = b_P(F_H, F_B)$. Because of lumpy investment, we are actually never at the long-run equilibrium.

We begin by calculating the competitive bid for each resource type as a function of the mix of resources. This is the firm energy price, which would result in zero expected profits given the mix of resources. To calculate $b_H(F_H, F_B)$, $b_B(F_H, F_B)$, $b_P(F_H, F_B)$, we just run the simulation for 1000 years. Effectively there are three units: F_H of hydro, F_B of baseload, and F_P of peaker. Units are never added or subtracted. The energy of the hydro "unit" is just aggregating all the existing hydro units and normalizing so there is F_H of maximum firm energy.

We compute $b_H(F_H, F_B)$, $b_B(F_H, F_B)$, $b_P(F_H, F_B)$ for each combination of F_H between 28% and 55% at 1% increments and each F_B between 27% and 60% at 1% increments, while constraining F_P to never exceed 25% or be less than 10%.

Once we compute the matrix of bids, then a scenario involves running 50 twenty-year simulations, adding the most profitable units as needed until supply exceeds demand. We match bids from the bid matrix to each year in each simulation by rounding the F_H and F_B in that year to the nearest 1%. When multiple units are required in a year, we may add some of each. Units are added sequentially, always adding the type that is most profitable, given shares (F_H, F_B). For example, suppose we are close to the long run equilibrium, so that all three are nearly equal in profitability, but that hydro is the most profitable. We add a hydro unit. But now with more hydro, baseload is best. We add a baseload unit. But with more baseload, peaker now is most profitable. We add a peaker, which gives us enough firm energy to reach the target. Thus, in this example, we add one unit of each. This sequential approach actually does a better job of approximating a descending clock auction in which the bidders observe the quantity of each resource type as the auction progresses.

Key to the analysis is identifying the regions where a particular type of resource is best; that is, most profitable among the three types of resources. For example, the regions may look something like shown below.



Market clearing

As mentioned, we add the most-profitable unit in sequence until we get to the point where FE supply > FE demand. This last unit is accepted or not, based on the "minimize total cost in the first commitment year" rule. This means we compare:

Quantity with the unit times Price with the unit, and

Quantity without the unit times Price without the unit, where

Price with the unit is the unit's competitive bid price, and Price without the unit is read from the firm energy demand curve evaluated at the quantity without the unit (this is a higher price, since supply < demand without the unit).

We accept the last unit if it has a lower total cost.

Model outputs

So that we can examine company risk, each new project is assigned to one of 10 companies. We take the top-10 existing companies in terms of maximum firm energy, and scale these up so the total market share is 100%. This results in the following target market shares.

Target Market Shares for Ten Companies

1	2	3	4	5	6	7	8	9	10
22.2%	21.1%	15.8%	14.2%	6.4%	5.1%	4.6%	4.3%	3.3%	3.1%

When a new project is added, it is added to the company that is most under its target market shares. The existing units that are not currently owned by one of the top-10 companies are assigned to a top-10 company to approximate the target market shares.

For each simulation year, we compute the components of profit on a unit basis. We also compute company profits. The model outputs are all collected from the 50 twenty-year simulations. In each hour each unit sells a quantity of energy, Q, at the spot price, p. Also, in each hour, each unit has an obligation Q_{OB} defined above. For any scarcity hour the hedge payment is $HP = (Q - Q_{OB}) \times (p - P_S)$, and the energy rent is, $ER = \max(0, Q \times (\min(p, P_S) -$

VC)) where, P_S is the scarcity price and VC is the unit's variable cost which is determined only by its type and is constant throughout the simulation. For comparison with the no-hedge world we also need energy rents including PER (the energy rents above the scarcity price). These are given by $ER^+ = \max(0, Q \times (p - VC))$.

Given these values we compute profits as described above. The various components of profit are also tracked.

Profit = FE payment + Hedge payments + Energy rents – Fixed costs

This allows risks to be compared between the three components.

Scenarios

We analyze the three scenarios shown in Table 7. The first is the benchmark scenario. The second doubles the slope of the firm energy demand curve. The third doubles the price elasticity of demand. In the high demand response case, a 10% increase in price causes a 1% drop in demand; in the benchmark, a 20% increase in prices causes a 1% drop in demand. In the steep FE demand curve case, the price moves from 2 CONE to 1/2 CONE as the firm energy quantity moves from 2% under target to 2% over target; in the benchmark, the same price movement requires deviations from the target of ±4%.

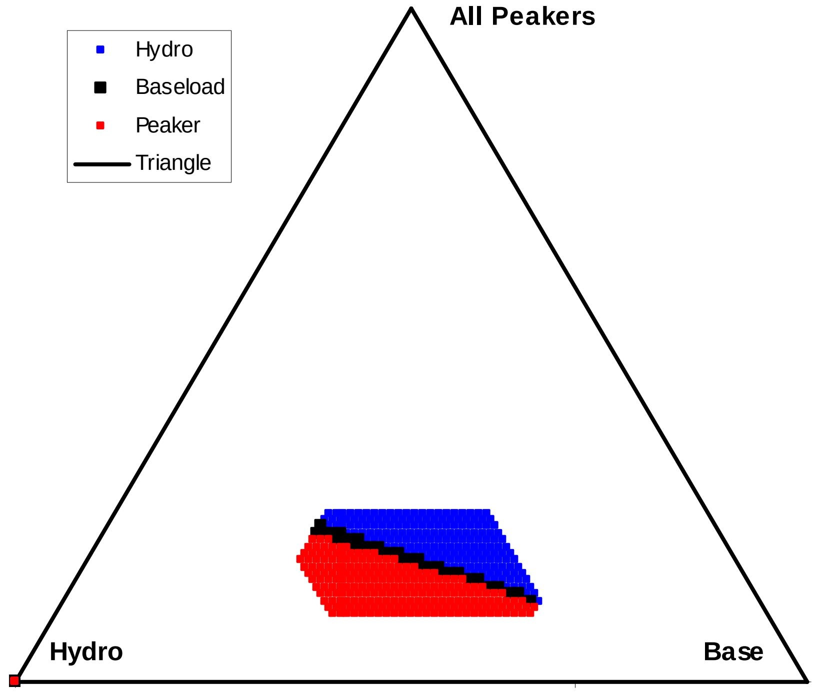
Table 7. Scenarios considered

	Scenario	Price elasticity of demand	Firm energy demand curve parameter
1	Benchmark	-0.05	4%
2	Steep FE demand curve	-0.05	2%
3	High demand response	-0.1	4%

5.2 Simulation results

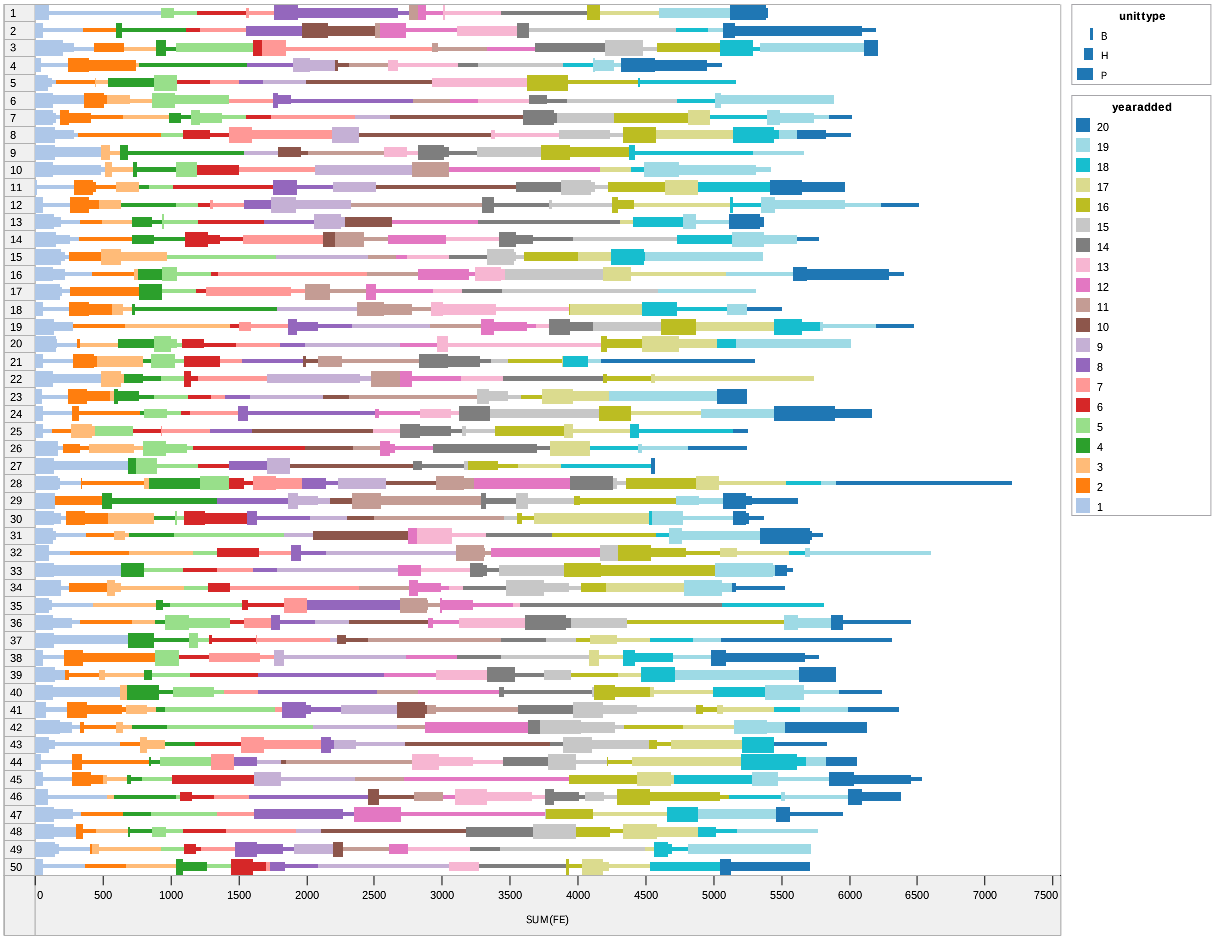
We now present the results from the three scenarios. Since our focus is on long-run investment decisions, we only display yearly results. Hourly, daily, or even monthly variations are of little concern for a company deciding on investments that span multiple decades.

Figure 14. Most profitable unit type given resource mix



The first step is to construct the bid matrix, which gives the competitive bids for each unit type given the unit mix. The competitive bids are essentially the same across all three scenarios. The reason is that energy rents dominate the profit calculation, and energy rents are the same in all scenarios. Figure 14 shows the most profitable unit type given the resource mix. Only relevant points in the resource mix triangle are calculated; that is, mixes near the current mix and long-run equilibrium mix. When the hydro share is large, peakers are best; when the peaker share is large, hydro is best; when the peaker-hydro shares are near equilibrium, baseload is best.

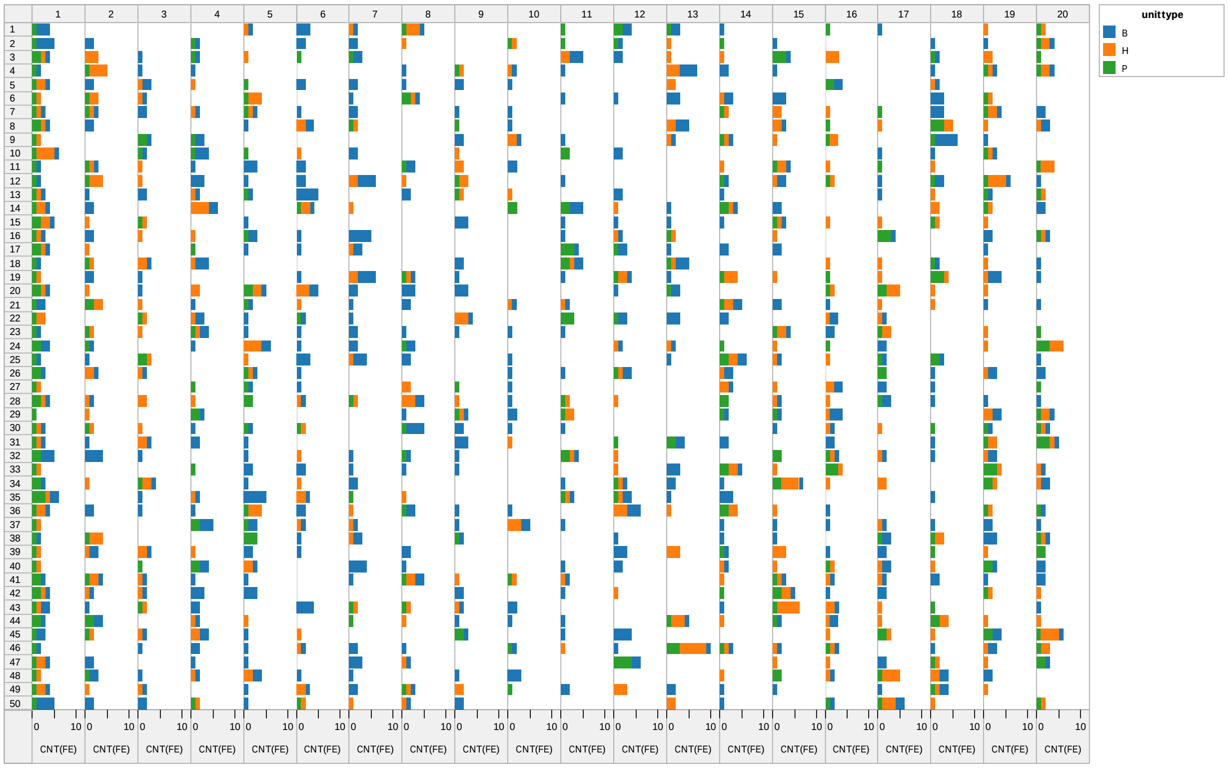
Figure 15. New entry by year and unit type (benchmark)



Sum of FE for each sim for Benchmark. Color shows details about yearadded. Size shows details about unittype. The view is filtered on yearadded and unittype. The yearadded filter excludes 0. The unittype filter keeps B, H and P.

Figure 15 shows the entry of units over the twenty years in each of the 50 benchmark simulations (covering 1000 years). The length of the bar indicates the unit's firm energy; the width of the bar indicates the unit type (peaker, fat; hydro medium; baseload, thin). For example, in year 1 (light blue) of the first simulation, one small peaker was added and three baseload. The final baseload unit was quite large, resulting in a large excess supply of 10%. As a result of this large excess supply, there is no entry until year 5, when one hydro unit and one baseload unit are added. Such a large excess supply is unusual. The implication is one or more years of no entry in which the firm energy price is determined from the firm energy demand curve.

Figure 16. Number of new entries by year and unit type (benchmark)



Count of FE for each sim broken down by yearadded for Benchmark. Color shows details about unittype. The view is filtered on yearadded and unittype. The yearadded filter excludes 0. The unittype filter keeps B, H and P.

Figure 16 shows the number of units of each type that are added in each year. On average there are 1.6 entries per year. A histogram of the number of entries per year is shown below.

Histogram of entries per year						
0	1	2	3	4	5	6
27%	29%	21%	12%	7%	3%	2%

In over one-half of the years (56%) there is either one entry or no entry. Roughly one-quarter of the time, no entry will be needed and the firm energy price will be set by the demand curve. This is likely an overstatement, since we have assumed that new project size is random and grows with load. In practice, in years in which only a small amount of additional entry is needed, it is more likely that a smaller project that better fits the need will win the auction.

Table 8. Firm energy and output shares by unit type

	Scenario:	Benchmark				Steep FE demand curve				High demand response			
Variable	Obs	Mean	Std. Dev.	Min	Max	Mean	Std. Dev.	Min	Max	Mean	Std. Dev.	Min	Max
Firm energy shares													
Baseload	1000	44%	5%	32%	58%	43%	5%	31%	53%	44%	5%	32%	58%
Hydro	1000	39%	3%	30%	48%	39%	3%	32%	49%	39%	3%	30%	48%
Peaker	1000	17%	2%	13%	21%	17%	2%	14%	21%	17%	2%	13%	21%
Output shares													
Baseload	1000	34%	7%	11%	51%	34%	7%	11%	51%	34%	7%	11%	51%
Hydro	1000	65%	7%	47%	89%	65%	7%	47%	89%	65%	7%	47%	89%
Peaker	1000	1%	1%	0%	9%	1%	1%	0%	9%	1%	1%	0%	9%

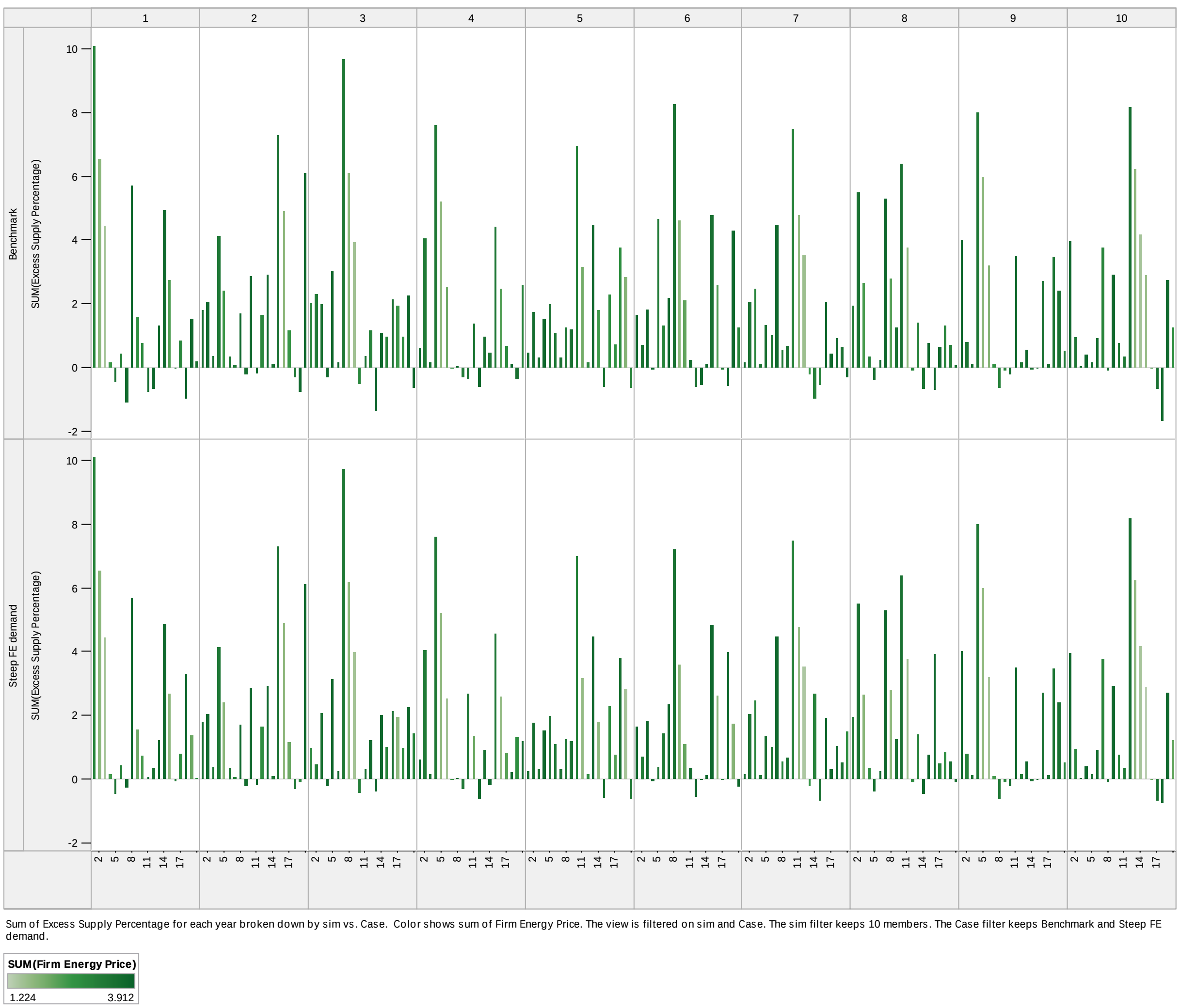
Table 8 shows statistics on the firm energy shares and the energy output shares for each scenario. The level of demand response does not impact these shares. The steeper firm energy demand curve changes the shares only slightly. The steeper demand curve alters some of the decisions on whether to accept the last unit; buying less than the target becomes more expensive, so there is a greater tendency to purchase a bit extra.

Table 9. Energy price, scarcity, and firm energy supply

	Scenario	FE demand parameter	Demand elasticity	Mean energy price in all hours	Mean scarcity hours per year	Mean energy price in scarcity hours	Mean firm energy target	Mean firm energy supply
1	Benchmark	4%	-0.05	57.04	80.5	423.76	9,868	10,027
2	Steep FE demand curve	2%	-0.05	56.76	69.8	449.32	9,868	10,046
3	High demand response	4%	-0.1	54.79	80.5	179.60	9,868	10,027

Table 9 shows the mean values of a number of variables for the three simulations. The energy price is lowest in the high demand response case. The steep demand curve has a slightly lower mean energy price as a result of the tendency to buy a bit more firm energy with the steeper curve. Scarcity hours are rare—only about 80 hours per year in the benchmark case. Doubling the demand elasticity more than halves the energy price during scarcity hours.

Figure 17. Excess supply and firm energy price in first 10 simulations



Sum of Excess Supply Percentage for each year broken down by sim vs. Case. Color shows sum of Firm Energy Price. The view is filtered on sim and Case. The sim filter keeps 10 members. The Case filter keeps Benchmark and Steep FE demand.

Figure 7 shows the excess supply of firm energy acquired in the auction for the first 10 twenty-year simulations. Darker bars indicate a higher firm energy price in the year. The excess supply does not depend on the demand elasticity, so only the two scenarios are shown. Surplus is much more common than shortage, given the minimize total cost rule. Buying less than the target results in a high firm energy price. This is especially true with a steep firm energy demand curve, which is why shortages are fewer and smaller in this case. Excess supply is never more than 10%. A large excess supply results in one or more years of surplus. In these surplus years, the firm energy price falls. This is a main source of variation in the firm energy price.

Figure 18. Scarcity hours and scarcity price

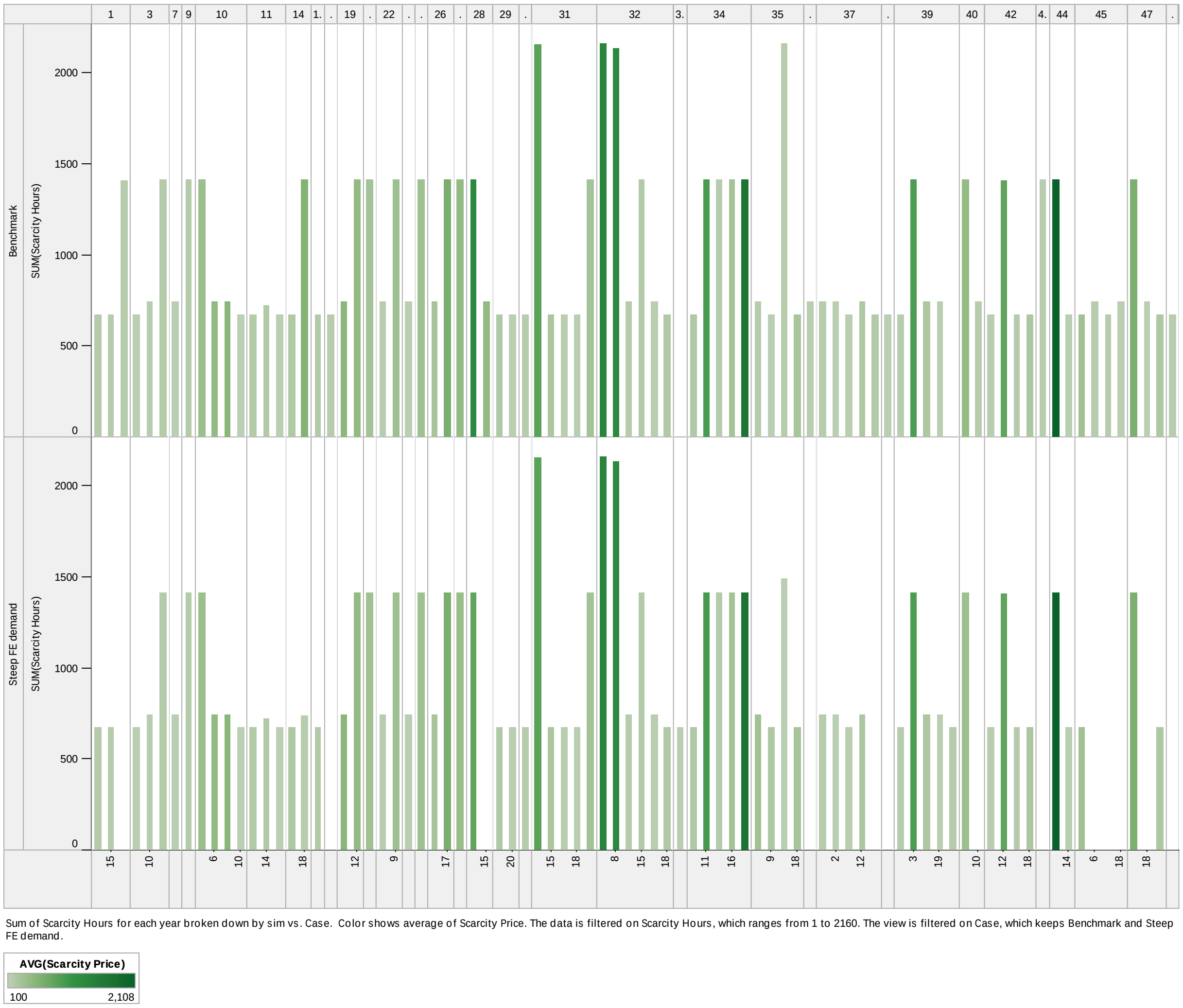


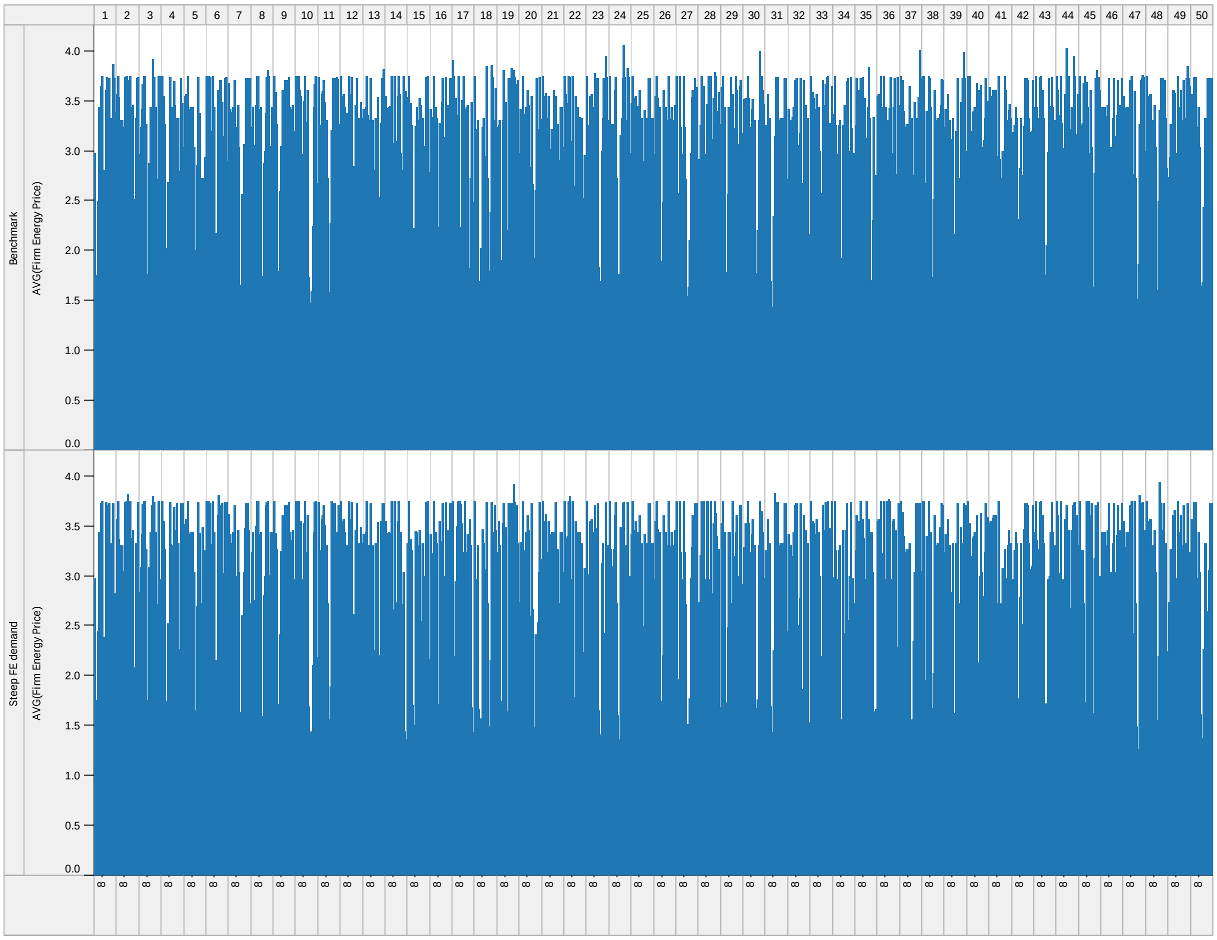
Figure 18 shows the number of scarcity hours in each year of each simulation; darker bars indicate a higher average energy price in the scarcity hours. Since hydro tends to smooth the energy price over each hour of the month, the number of scarcity hours in a year tends to be some multiple of the number of hours in a month (about 720); that is, we tend to have "scarcity months." Each year tends to have either 0, 1, 2, 3 scarcity months as shown in the histogram below.

Histogram of scarcity months

0	1	2	3
91.8%	5.4%	2.4%	0.4%

The vast majority of years have (92%) have no scarcity months. Over 1000 years, only 4 had 3 scarcity months. There are only a few years where the energy price is exceptionally high. In these dry periods, demand response would likely be much larger than assumed, resulting in more reasonable prices.

Figure 19. Firm energy price

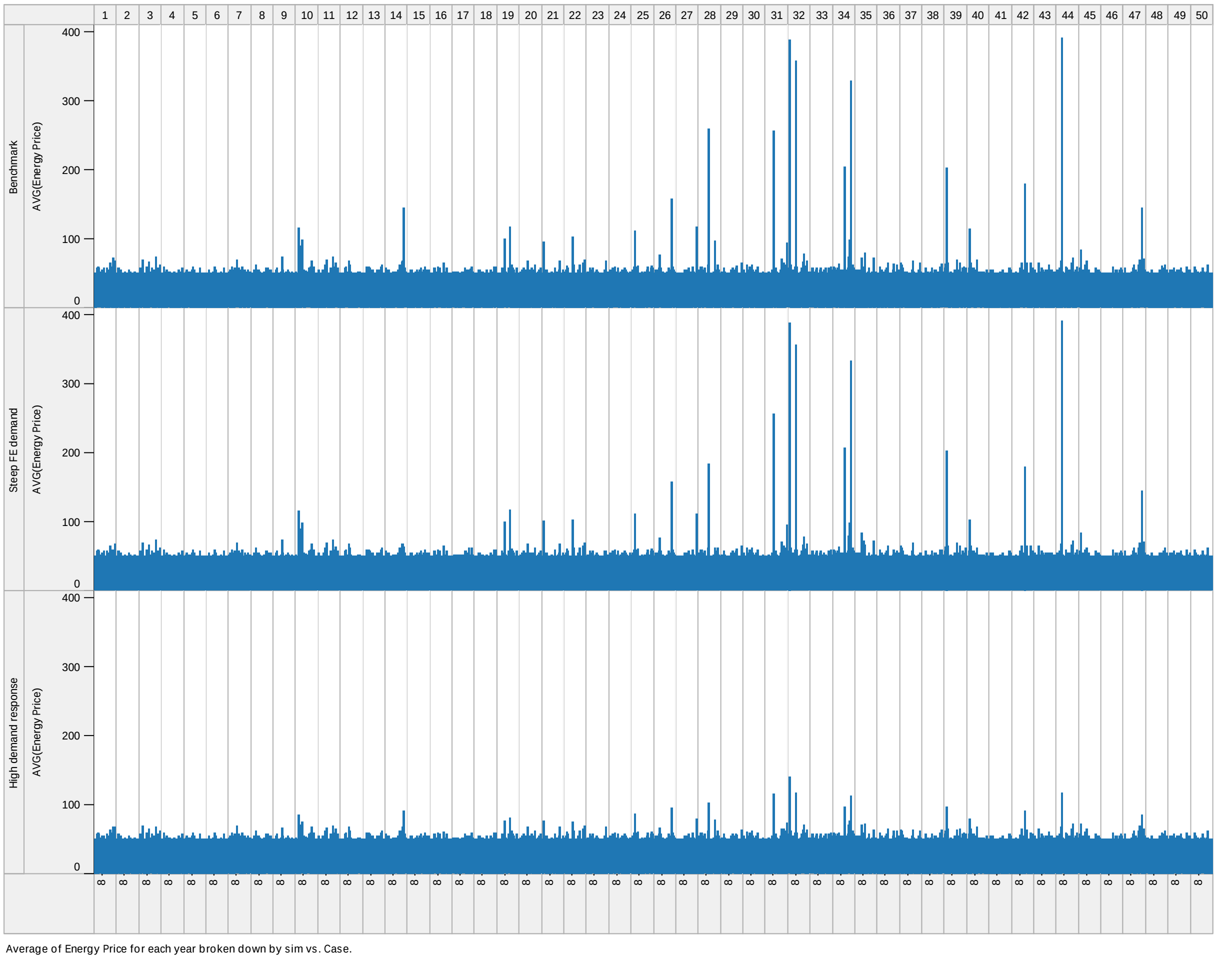


Average of Firm Energy Price for each year broken down by sim vs. Case. The view is filtered on Case, which keeps Benchmark and Steep FE demand.

Figure 19 shows the firm energy price in every year and simulation. The main source of variation is the drops that occur when there are multiple years of surplus as a result of a large new entry. The steepness of the firm energy demand curve does not have much of an impact; the reason is that the big drops are bumping into the floor at 1/2 CONE in both cases. The steeper slope results in only a 5% lower price overall.

The adopted resolution eliminates this variation in the firm energy price in surplus years, since it sets the firm energy price equal to the price from the last successful auction. Load purchases the target quantity and the payment is allocated pro-rata among suppliers. The resolution reduces variation in the firm energy price, and thus, likely reduces risk in the firm energy payment.

Figure 20. Energy price (annual mean)



The average energy price is close to the baseload marginal cost in most years. The price jumps substantially higher in a very few of the 1000 years. Notice how sensitive the spikes are to the demand response.

Figure 21. Annual profit per MWh of firm energy

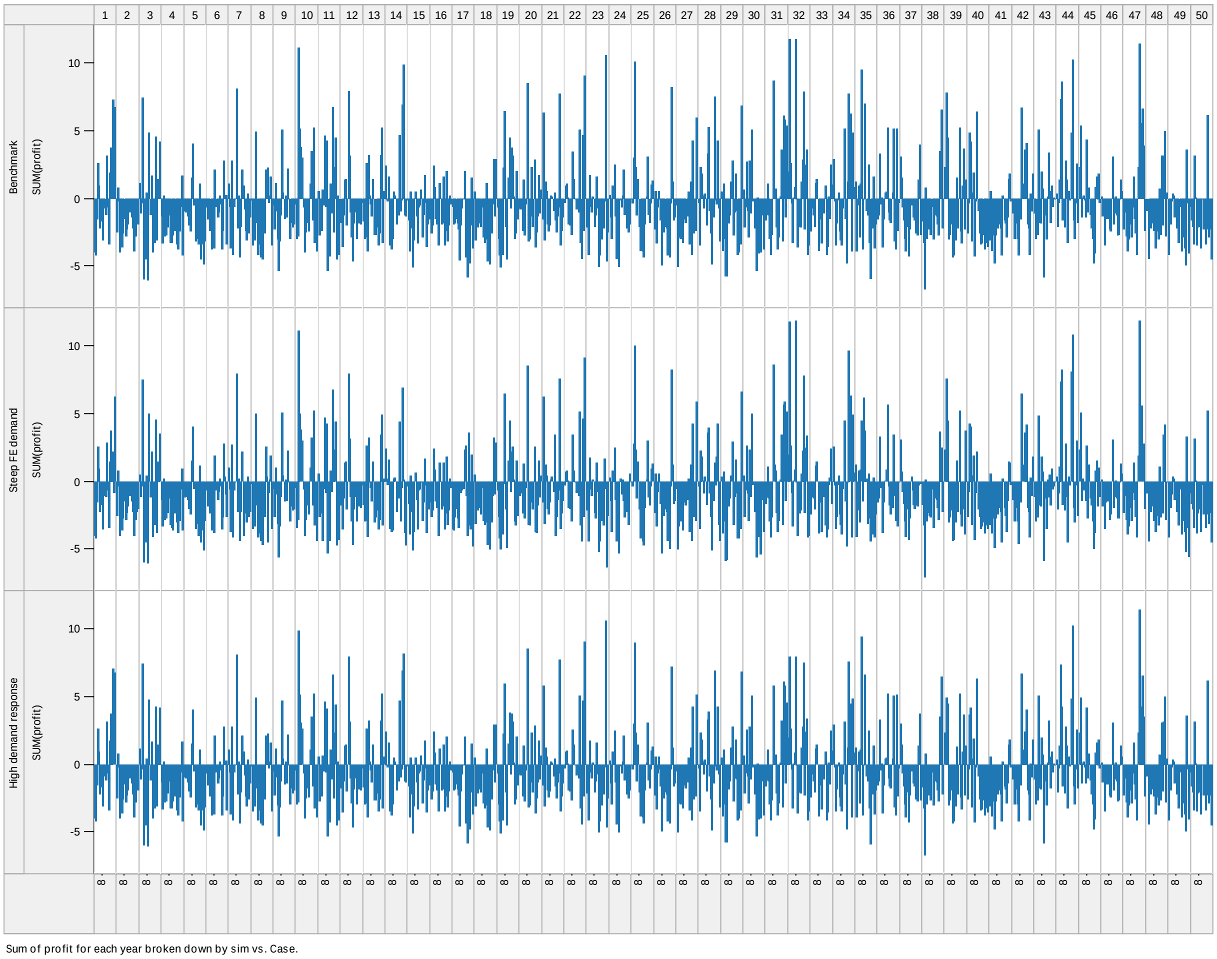


Figure 21 displays the aggregate profits for every year and simulation. The variation in profits is largely attributable to the variation in energy rents. This also explains why the variation in profits is about the same in all scenarios. The variation comes from the variation in hydro output, which is roughly the same in all alternatives. Of course, long-term energy contracts would reduce this yearly-variation in profits, but not eliminate it. We are assuming no energy contracts in our analysis.

Table 10. Aggregate annual profits per MWh of firm energy

			With hedge			No hedge	With hedge	No hedge	With hedge	No hedge
FE demand parameter	Demand elasticity	Stat	Firm energy payment	Hedge payment	Energy rent	Energy rent + peak energy rent	Profits before FC	Profits before FC	Profits after FC	Profits after FC
4%	-0.05	Mean	3.26	0.07	35.75	38.41	39.07	38.41	-0.72	-1.39
4%	-0.05	Std. Dev.	0.44	0.39	3.84	20.71	4.06	20.71	2.91	20.49
4%	-0.05	Min	1.66	0.00	25.63	25.63	29.30	25.63	-6.73	-9.68
4%	-0.05	Median	3.36	0.00	35.59	35.67	38.77	35.67	-1.34	-4.61
4%	-0.05	Max	3.94	5.33	48.24	320.22	53.73	320.22	11.81	278.21
2%	-0.05	Mean	3.15	0.06	35.75	38.24	38.97	38.24	-0.92	-1.64
2%	-0.05	Std. Dev.	0.54	0.38	3.79	20.12	4.02	20.12	2.83	19.93
2%	-0.05	Min	1.66	0.00	27.48	27.48	30.10	27.48	-7.13	-9.69
2%	-0.05	Median	3.32	0.00	35.53	35.59	38.65	35.59	-1.44	-4.68
2%	-0.05	Max	3.84	5.33	48.24	320.22	53.73	320.22	11.87	278.21
4%	-0.1	Mean	3.26	0.02	35.75	36.42	39.03	36.42	-0.77	-3.38
4%	-0.1	Std. Dev.	0.44	0.10	3.84	6.19	3.98	6.19	2.80	5.53
4%	-0.1	Min	1.66	0.00	25.63	25.63	29.30	25.63	-6.73	-9.68
4%	-0.1	Median	3.36	0.00	35.59	35.67	38.77	35.67	-1.34	-4.61
4%	-0.1	Max	3.94	1.01	48.24	99.72	52.51	99.72	11.42	59.16

Table 10 shows statistics of the components of aggregate profit per MWh of firm energy for each scenario. The three components of profits are the first energy payment, the hedge payment (reflecting rewards for overperformance and penalties for underperformance), and the energy rent. These are given in the "With hedge" columns, which is the proposed market with the hedge at the scarcity price. Summing these three columns gives the profits before fixed costs under the proposal (i.e., with hedge). For comparison, the next column gives the energy rent plus the peak energy rent (profits from prices above the scarcity price), which would be relevant in a world without the mandatory hedge. The last two columns gives the profits after fixed costs, both under the proposal (with hedge) and in an energy-only world without the hedge and capacity payment.

There are several things to note.

- As mentioned earlier, the mean of the firm energy payment is not especially relevant, since it is easily increased by adding a constant to the assumed fixed cost of each resource.
- The firm energy payment is nearly the same as the firm energy price, but it reflects the fact that the new entrants are locking in the price for ten years, whereas existing suppliers are receiving the annual price.
- The aggregate hedge payment is always nonnegative. One might think that the aggregate hedge payment should be zero in every year: since the load is always satisfied, the rewards for overperformance should balance the penalties for underperformance. This is nearly the case. The reason there is a positive hedge payment in some years is that a resource's obligation is capped in any given month by the amount of firm energy that the resource has sold. This cap limits the obligation for certain high-performing hydro resources, and thus makes the aggregate obligation less than the aggregate energy, resulting in a positive hedge payment.
- The mean profits after fixed cost are slightly negative in all scenarios. One might expect the mean profits to be zero, since the bids were chosen so the firm makes zero profits in the long run. There are two reasons profits have a negative bias: 1) In the simulation to determine bids, lumpiness was not considered; it was assumed that the firm energy target was purchased each year. In fact, when there is a surplus energy rents are less and the firm energy price in the next year may be substantially less if the surplus is more than a year's growth. 2)

The bids assume that the shares stay fixed forever. In fact, the shares drift around and tend to spend more time at levels that are less attractive than more attractive to the winning bidder. This subtle bias has to do with the fact that the clearing price is based on the lowest of the three bids. Real bidders would take these biases into account, adding them to their bids so that zero profits are attained.

- Most interesting is the standard deviation in aggregate profits, which is a good measure of aggregate risk. In all scenarios, the standard deviation is less than $3. In contrast, in a world without the mandatory hedge, the standard deviation of profits would be an order of magnitude higher in the benchmark case, and double in the case with high demand response. This highlights the advantage of the market in reducing risk. Interestingly, the standard deviation of profits is even less than the standard deviation in energy rents. It is clear that the main source of risk is variation in energy rents from year to year. This risk can be mitigated somewhat through long-term energy contracts.
- The steep firm energy demand curve changes little from the benchmark. Profits are slightly reduced, probably because the steeper demand curve makes the lumpiness bias a bit worse, since large lumps are more frequently accepted, even if only a small fraction of the lump is needed.
- The high demand response results in essentially no change under the proposal. This is because the mandatory hedge makes the suppliers immune to large changes in prices above the scarcity price. These prices are important for performance incentives, but they do not have an aggregate impact on suppliers. This is an important virtue of the market: profits and risks do not depend critically on demand's response to high prices. In contrast, in the no-hedge world, profits and especially risks are heavily dependent on demand elasticity.

Figure 22. Annual profit by unit type (Benchmark, 20 simulations)

Sum of profit for each year broken down by sim vs. unittype for Benchmark. The view is filtered on sim, which keeps 20 members.

Figure 22 shows how profit varies by unit type. Only the first 20 simulations of the benchmark are shown here. In terms of risk, peakers are the least risky, hydro is second, and baseload is the most risky. Energy rents for baseload units are highly variable in the simulation, since the baseload units are often on the margin and so earn zero energy rents, or large when peaker or hydro is on the margin. Peakers earn little energy rents; almost all of a peaker’s revenue is coming from the firm energy payment.

Table 11. Annual profits per MWh of firm energy by unit type

				With hedge			No hedge	With hedge	No hedge	With hedge	No hedge
FE demand parameter	Demand elasticity	Unit type	Stat	Firm energy payment	Hedge payment	Energy rent	Energy rent + peak energy rent	Profits before FC	Profits before FC	Profits after FC	Profits after FC
4%	-0.05	Baseload	Mean	3.27	0.00	4.06	7.04	7.33	7.04	-0.67	-0.96
4%	-0.05	Baseload	Std. Dev.	0.39	0.00	4.73	24.73	4.76	24.73	4.76	24.73
4%	-0.05	Baseload	Min	1.84	0.00	0.00	0.00	1.87	0.00	-6.13	-8.00
4%	-0.05	Baseload	Median	3.36	0.00	2.55	2.55	5.95	2.55	-2.05	-5.45
4%	-0.05	Baseload	Max	3.92	0.00	24.90	340.27	28.18	340.27	20.18	332.27
4%	-0.05	Hydro	Mean	3.26	0.17	86.29	88.48	89.72	88.48	-0.88	-2.12
4%	-0.05	Hydro	Std. Dev.	0.49	0.99	3.02	15.13	3.20	15.13	3.20	15.13
4%	-0.05	Hydro	Min	1.49	0.00	74.09	74.09	77.47	74.09	-13.13	-16.51
4%	-0.05	Hydro	Median	3.39	0.00	86.17	86.42	89.55	86.42	-1.05	-4.18
4%	-0.05	Hydro	Max	3.99	12.76	99.34	297.53	102.68	297.53	12.08	206.93
4%	-0.05	Peaker	Mean	3.23	0.00	0.18	3.16	3.42	3.16	-0.48	-0.74
4%	-0.05	Peaker	Std. Dev.	0.48	0.00	0.67	23.04	0.85	23.04	0.85	23.04
4%	-0.05	Peaker	Min	1.60	0.00	0.00	0.00	1.60	0.00	-2.30	-3.90
4%	-0.05	Peaker	Median	3.35	0.00	0.00	0.00	3.40	0.00	-0.50	-3.90
4%	-0.05	Peaker	Max	4.01	0.00	4.93	327.86	8.50	327.86	4.60	323.96
2%	-0.05	Baseload	Mean	3.17	0.00	3.98	6.76	7.15	6.76	-0.85	-1.24
2%	-0.05	Baseload	Std. Dev.	0.48	0.00	4.65	24.07	4.66	24.07	4.66	24.07
2%	-0.05	Baseload	Min	1.84	0.00	0.00	0.00	1.86	0.00	-6.14	-8.00
2%	-0.05	Baseload	Median	3.33	0.00	2.55	2.55	5.91	2.55	-2.09	-5.45
2%	-0.05	Baseload	Max	3.83	0.00	24.90	340.27	28.18	340.27	20.18	332.27
2%	-0.05	Hydro	Mean	3.14	0.15	86.18	88.21	89.48	88.21	-1.12	-2.39
2%	-0.05	Hydro	Std. Dev.	0.60	0.96	2.99	14.66	3.18	14.66	3.18	14.66
2%	-0.05	Hydro	Min	1.38	0.00	74.11	74.11	77.49	74.11	-13.11	-16.49
2%	-0.05	Hydro	Median	3.34	0.00	86.07	86.32	89.33	86.32	-1.27	-4.28
2%	-0.05	Hydro	Max	3.92	12.73	99.34	297.53	103.13	297.53	12.53	206.93
2%	-0.05	Peaker	Mean	3.11	0.00	0.16	2.94	3.27	2.94	-0.63	-0.96
2%	-0.05	Peaker	Std. Dev.	0.59	0.00	0.63	22.44	0.86	22.44	0.86	22.44
2%	-0.05	Peaker	Min	1.45	0.00	0.00	0.00	1.45	0.00	-2.45	-3.90
2%	-0.05	Peaker	Median	3.32	0.00	0.00	0.00	3.35	0.00	-0.55	-3.90
2%	-0.05	Peaker	Max	3.93	0.00	4.93	327.86	8.58	327.86	4.68	323.96
4%	-0.1	Baseload	Mean	3.27	0.00	4.06	4.79	7.33	4.79	-0.67	-3.21
4%	-0.1	Baseload	Std. Dev.	0.39	0.00	4.73	7.86	4.76	7.86	4.76	7.86
4%	-0.1	Baseload	Min	1.84	0.00	0.00	0.00	1.87	0.00	-6.13	-8.00
4%	-0.1	Baseload	Median	3.36	0.00	2.55	2.55	5.95	2.55	-2.05	-5.45
4%	-0.1	Baseload	Max	3.92	0.00	24.90	89.99	28.18	89.99	20.18	81.99
4%	-0.1	Hydro	Mean	3.26	0.05	86.29	86.86	89.60	86.86	-1.00	-3.74
4%	-0.1	Hydro	Std. Dev.	0.49	0.24	3.02	4.22	3.11	4.22	3.11	4.22
4%	-0.1	Hydro	Min	1.49	0.00	74.09	74.09	77.47	74.09	-13.13	-16.51
4%	-0.1	Hydro	Median	3.39	0.00	86.17	86.38	89.46	86.38	-1.14	-4.22
4%	-0.1	Hydro	Max	3.99	2.62	99.34	123.04	102.68	123.04	12.08	32.44
4%	-0.1	Peaker	Mean	3.23	0.00	0.18	0.92	3.42	0.92	-0.48	-2.98
4%	-0.1	Peaker	Std. Dev.	0.48	0.00	0.67	5.11	0.85	5.11	0.85	5.11
4%	-0.1	Peaker	Min	1.60	0.00	0.00	0.00	1.60	0.00	-2.30	-3.90
4%	-0.1	Peaker	Median	3.35	0.00	0.00	0.00	3.40	0.00	-0.50	-3.90
4%	-0.1	Peaker	Max	4.01	0.00	4.93	70.02	8.50	70.02	4.60	66.12

Table 11 shows the components of profit per MWh of firm energy by unit type. Notice that the aggregate hedge payments for baseload and peaker are zero. This is because of our decision not to model outages of thermal units explicitly. Hence, there is no under or over performance. However, if we did model outages explicitly aggregate hedge payments would be nearly zero.

Comparing the different unit types, we see that the negative bias in profits from lumpiness and competitive forces is greatest for hydro (-.88) and weakest for peaker (-.48). The reason is that hydro units are more dependent on energy rents for profits and therefore are more vulnerable to large lumps, which create surpluses and thus lower energy rents.

Figure 23. Annual profit by company (benchmark, 20 simulations)

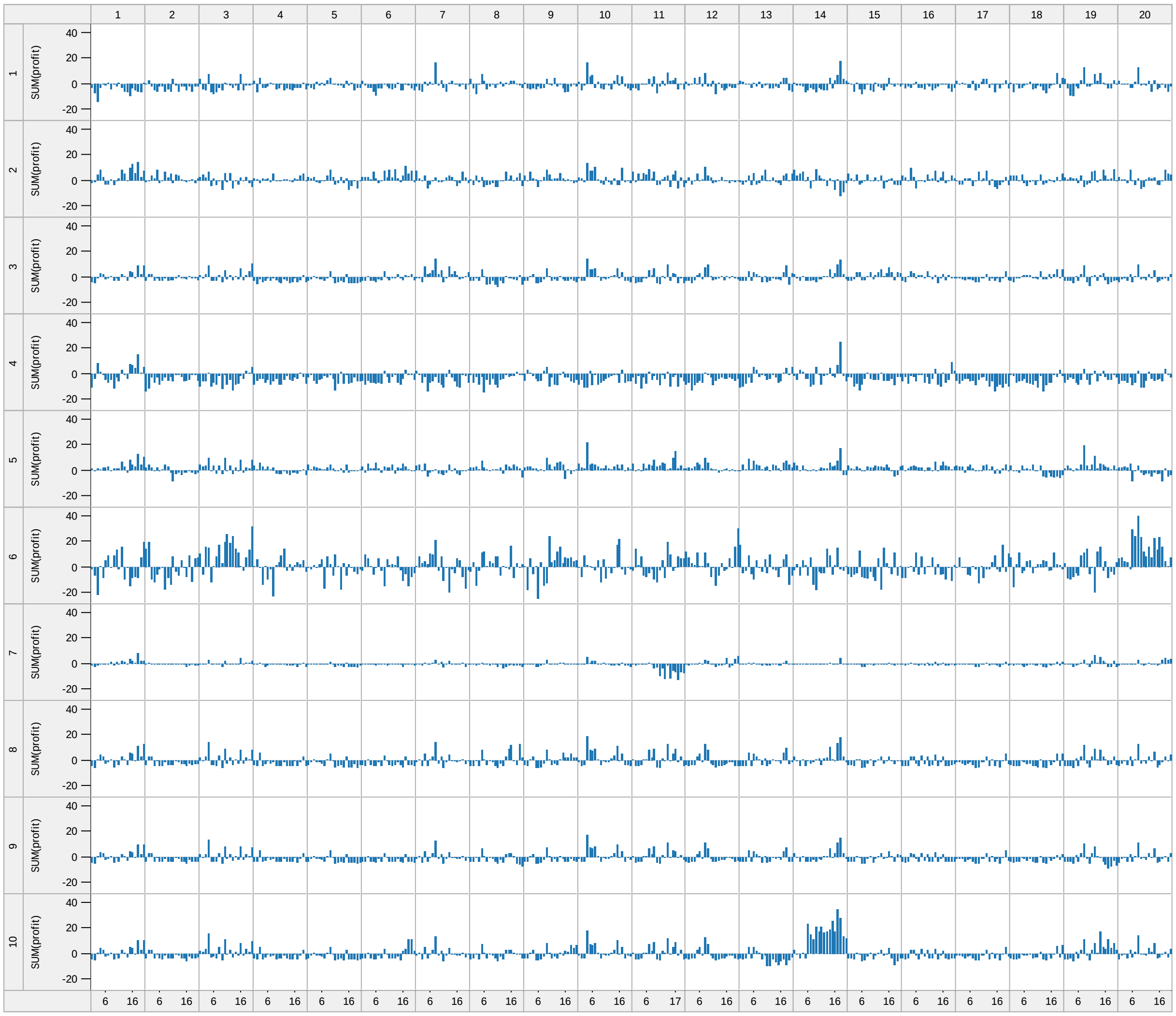


Figure 23 shows the annual profits per MWh of firm energy by company for the first 20 simulations (400 years). The profits in any year are dependent on the mix of resources that the company holds and the amount of hydro output that the firm has especially in dry periods. This is seen looking at the company with the greatest risk (company 6, based on AES Chivor) and the least risk (company 7, based on Termocandelaria). Company 6 starts with a single plant, a large hydro unit. Company 7 starts with two medium-size peakers and a tiny baseload unit.

Table 12. Annual profits per MWh of firm energy by company (benchmark)

				With hedge			No hedge	With hedge	No hedge	With hedge	No hedge
FE demand parameter	Demand elasticity	Owner Market Share Rank	Stat	Firm energy payment	Hedge payment	Energy rent	Energy rent + peak energy rent	Profits before FC	Profits before FC	Profits after FC	Profits after FC
4%	-0.05	1	Mean	3.27	0.45	49.09	51.87	52.81	51.87	-0.91	-1.84
4%	-0.05	1	Std. Dev.	0.42	4.66	9.79	24.19	11.38	24.19	6.80	22.30
4%	-0.05	1	Min	1.58	-9.04	27.02	27.02	30.39	27.02	-14.73	-16.32
4%	-0.05	1	Median	3.37	0.00	49.07	49.51	52.46	49.51	-1.94	-5.13
4%	-0.05	1	Max	3.95	81.48	76.54	375.39	153.82	375.39	89.99	322.78
4%	-0.05	2	Mean	3.28	-0.04	53.04	55.48	56.28	55.48	0.71	-0.09
4%	-0.05	2	Std. Dev.	0.43	1.93	11.04	20.57	11.28	20.57	4.68	17.97
4%	-0.05	2	Min	1.54	-34.76	27.79	27.79	15.59	27.79	-35.14	-13.05
4%	-0.05	2	Median	3.38	0.00	52.91	53.66	56.32	53.66	0.35	-2.71
4%	-0.05	2	Max	4.02	14.99	83.52	285.94	86.14	285.94	22.68	228.42
4%	-0.05	3	Mean	3.25	-0.03	9.27	12.15	12.49	12.15	-0.62	-0.95
4%	-0.05	3	Std. Dev.	0.46	0.98	9.02	24.77	9.05	24.77	3.94	23.53
4%	-0.05	3	Min	1.49	-20.05	0.00	0.00	1.61	0.00	-16.51	-14.93
4%	-0.05	3	Median	3.36	0.00	6.70	6.81	9.79	6.81	-1.33	-4.66
4%	-0.05	3	Max	4.01	12.37	40.83	336.69	44.38	336.69	26.12	329.87
4%	-0.05	4	Mean	3.25	-0.09	42.42	44.84	45.59	44.84	-4.42	-5.17
4%	-0.05	4	Std. Dev.	0.47	1.87	9.60	20.08	9.81	20.08	4.89	17.96
4%	-0.05	4	Min	1.49	-32.82	18.36	18.36	16.45	18.36	-37.68	-18.53
4%	-0.05	4	Median	3.37	0.00	42.69	43.26	45.98	43.26	-4.69	-7.59
4%	-0.05	4	Max	3.99	17.89	69.63	293.15	90.52	293.15	25.13	236.27
4%	-0.05	5	Mean	3.23	0.17	11.66	14.73	15.06	14.73	2.28	1.95
4%	-0.05	5	Std. Dev.	0.49	1.32	7.93	24.86	8.19	24.86	4.07	24.14
4%	-0.05	5	Min	1.44	-0.37	2.15	2.15	5.27	2.15	-8.68	-12.28
4%	-0.05	5	Median	3.34	0.00	9.21	9.23	12.49	9.23	1.79	-1.49
4%	-0.05	5	Max	3.97	28.07	49.02	337.65	52.32	337.65	41.51	327.41
4%	-0.05	6	Mean	3.24	-0.55	73.27	74.98	75.96	74.98	0.35	-0.63
4%	-0.05	6	Std. Dev.	0.47	5.76	16.14	20.46	17.29	20.46	11.26	15.85
4%	-0.05	6	Min	1.50	-108.03	27.71	27.71	-33.71	27.71	-110.64	-27.59
4%	-0.05	6	Median	3.35	0.00	73.65	74.36	76.33	74.36	0.05	-2.84
4%	-0.05	6	Max	3.99	33.60	119.51	279.32	133.44	279.32	42.84	202.39
4%	-0.05	7	Mean	3.23	0.08	4.31	7.29	7.62	7.29	-0.56	-0.89
4%	-0.05	7	Std. Dev.	0.52	1.44	9.76	25.37	10.19	25.37	3.09	23.18
4%	-0.05	7	Min	1.44	-2.65	0.00	0.00	1.51	0.00	-17.47	-21.08
4%	-0.05	7	Median	3.37	0.00	0.63	0.63	4.03	0.63	-0.79	-4.10
4%	-0.05	7	Max	4.05	42.09	64.91	329.47	92.66	329.47	43.12	325.04
4%	-0.05	8	Mean	3.22	0.00	6.02	8.96	9.23	8.96	-0.40	-0.67
4%	-0.05	8	Std. Dev.	0.53	0.20	9.10	25.70	9.14	25.70	5.06	24.46
4%	-0.05	8	Min	1.44	-4.65	0.00	0.00	1.51	0.00	-6.49	-9.83
4%	-0.05	8	Median	3.36	0.00	3.55	3.55	6.42	3.55	-1.81	-5.45
4%	-0.05	8	Max	4.05	3.22	62.26	340.27	67.42	340.27	35.76	332.27
4%	-0.05	9	Mean	3.21	-0.01	5.61	8.56	8.81	8.56	-0.52	-0.76
4%	-0.05	9	Std. Dev.	0.55	0.27	9.02	25.40	9.06	25.40	5.13	24.38
4%	-0.05	9	Min	1.44	-8.37	0.00	0.00	1.50	0.00	-9.77	-13.51
4%	-0.05	9	Median	3.34	0.00	2.26	2.26	5.99	2.26	-1.83	-5.28
4%	-0.05	9	Max	4.05	0.95	63.86	338.87	67.23	338.87	41.86	331.33
4%	-0.05	10	Mean	3.23	0.07	7.63	10.64	10.93	10.64	0.05	-0.24
4%	-0.05	10	Std. Dev.	0.53	1.92	11.29	26.95	11.70	26.95	6.94	25.39
4%	-0.05	10	Min	1.44	-0.59	0.00	0.00	1.50	0.00	-17.93	-20.87
4%	-0.05	10	Median	3.36	0.00	4.57	4.57	7.53	4.57	-1.82	-5.36
4%	-0.05	10	Max	4.05	60.36	76.55	339.54	106.03	339.54	79.28	331.78

Table 12 shows the components of profits per MWh of firm energy by company in the benchmark scenario. Naturally, some firms make greater profits than others. The variation stems primarily from the variation in the quantity and timing of hydro output. Those companies that happen to have relatively greater hydro output when the energy price is higher do better, because they are able to capture higher energy rents and have a positive hedge payment.

The standard deviation of profits after fixed costs (with hedge) is an important statistic. Notice that it is under $7 for all companies, except company 6 ($11.26), which is an outlier. In all cases, the primary source of variation is the energy rent. Again, this variation can be mitigated with energy contracts, but significant variation will remain as a result of hydro output variance.

Table 13. Annual profits per MWh of firm energy by company (steep FE demand curve)

				With hedge			No hedge	With hedge	No hedge	With hedge	No hedge
FE demand parameter	Demand elasticity	Owner Market Share Rank	Stat	Firm energy payment	Hedge payment	Energy rent	Energy rent + peak energy rent	Profits before FC	Profits before FC	Profits after FC	Profits after FC
2%	-0.05	1	Mean	3.17	0.43	49.58	52.19	53.18	52.19	-1.19	-2.19
2%	-0.05	1	Std. Dev.	0.52	4.65	9.95	23.80	11.50	23.80	6.77	21.84
2%	-0.05	1	Min	1.46	-6.49	27.43	27.43	29.65	27.43	-15.12	-18.62
2%	-0.05	1	Median	3.33	0.00	49.81	50.21	52.80	50.21	-2.12	-5.20
2%	-0.05	1	Max	3.89	81.27	76.54	375.39	153.61	375.39	89.78	322.78
2%	-0.05	2	Mean	3.17	-0.03	52.80	55.08	55.95	55.08	0.52	-0.34
2%	-0.05	2	Std. Dev.	0.53	1.92	10.82	20.05	11.09	20.05	4.61	17.47
2%	-0.05	2	Min	1.29	-34.67	27.79	27.79	15.73	27.79	-34.98	-12.75
2%	-0.05	2	Median	3.34	0.00	52.65	53.24	55.97	53.24	0.21	-2.86
2%	-0.05	2	Max	3.83	14.99	83.40	285.94	85.64	285.94	22.62	228.42
2%	-0.05	3	Mean	3.14	-0.02	9.33	12.04	12.45	12.04	-0.63	-1.04
2%	-0.05	3	Std. Dev.	0.56	0.98	9.26	24.23	9.31	24.23	3.93	22.93
2%	-0.05	3	Min	1.46	-20.00	0.00	0.00	1.57	0.00	-16.51	-13.67
2%	-0.05	3	Median	3.31	0.00	6.31	6.34	9.30	6.34	-1.36	-4.64
2%	-0.05	3	Max	3.82	12.65	45.39	336.69	48.19	336.69	26.40	329.87
2%	-0.05	4	Mean	3.14	-0.11	42.16	44.40	45.19	44.40	-4.71	-5.51
2%	-0.05	4	Std. Dev.	0.57	1.77	8.96	19.14	9.09	19.14	4.74	17.33
2%	-0.05	4	Min	1.47	-32.75	17.93	17.93	16.57	17.93	-37.98	-18.53
2%	-0.05	4	Median	3.33	0.00	42.49	42.83	45.52	42.83	-4.85	-7.80
2%	-0.05	4	Max	3.89	8.62	71.24	292.53	74.67	292.53	12.27	235.65
2%	-0.05	5	Mean	3.12	0.16	12.08	14.95	15.36	14.95	2.15	1.74
2%	-0.05	5	Std. Dev.	0.60	1.31	8.33	24.39	8.61	24.39	4.07	23.45
2%	-0.05	5	Min	1.22	-0.37	2.15	2.15	5.25	2.15	-8.68	-12.28
2%	-0.05	5	Median	3.31	0.00	9.21	9.22	12.38	9.22	1.61	-1.51
2%	-0.05	5	Max	3.86	28.01	49.02	337.65	52.23	337.65	41.51	327.41
2%	-0.05	6	Mean	3.12	-0.52	73.48	75.06	76.08	75.06	0.04	-0.97
2%	-0.05	6	Std. Dev.	0.57	5.59	16.21	20.30	17.30	20.30	11.20	15.66
2%	-0.05	6	Min	1.26	-107.75	29.57	29.57	-33.43	29.57	-110.36	-27.59
2%	-0.05	6	Median	3.30	0.00	74.05	74.48	76.86	74.48	-0.40	-3.05
2%	-0.05	6	Max	3.91	33.55	123.47	278.91	133.33	278.91	43.67	201.98
2%	-0.05	7	Mean	3.11	0.04	4.10	6.87	7.25	6.87	-0.66	-1.03
2%	-0.05	7	Std. Dev.	0.63	0.53	9.37	24.39	9.53	24.39	3.03	22.57
2%	-0.05	7	Min	1.22	-2.72	0.00	0.00	1.36	0.00	-17.30	-20.90
2%	-0.05	7	Median	3.32	0.00	0.63	0.63	3.92	0.63	-0.85	-4.11
2%	-0.05	7	Max	3.93	12.85	63.69	329.47	67.33	329.47	18.62	325.04
2%	-0.05	8	Mean	3.10	0.00	6.24	8.99	9.33	8.99	-0.59	-0.94
2%	-0.05	8	Std. Dev.	0.64	0.21	9.33	25.11	9.38	25.11	4.93	23.78
2%	-0.05	8	Min	1.22	-4.85	0.00	0.00	1.36	0.00	-8.53	-11.88
2%	-0.05	8	Median	3.32	0.00	3.32	3.33	6.29	3.33	-1.84	-5.45
2%	-0.05	8	Max	3.93	3.21	65.38	340.27	68.84	340.27	35.54	332.27
2%	-0.05	9	Mean	3.09	-0.01	5.21	7.98	8.30	7.98	-0.86	-1.18
2%	-0.05	9	Std. Dev.	0.66	0.28	8.28	24.55	8.33	24.55	4.30	23.58
2%	-0.05	9	Min	1.22	-8.52	0.00	0.00	1.36	0.00	-12.12	-15.46
2%	-0.05	9	Median	3.32	0.00	2.26	2.26	5.86	2.26	-1.87	-5.28
2%	-0.05	9	Max	3.93	1.05	60.79	338.87	64.53	338.87	18.38	331.33
2%	-0.05	10	Mean	3.10	0.07	7.47	10.29	10.64	10.29	-0.13	-0.49
2%	-0.05	10	Std. Dev.	0.64	1.95	11.30	26.39	11.69	26.39	7.09	24.82
2%	-0.05	10	Min	1.22	-1.64	0.00	0.00	1.36	0.00	-18.32	-20.69
2%	-0.05	10	Median	3.32	0.00	4.56	4.56	7.12	4.56	-1.91	-5.36
2%	-0.05	10	Max	3.93	61.46	76.55	339.54	107.11	339.54	80.37	331.78

Table 13 shows profits by company with the steep firm energy demand curve. The results are nearly the same, company-by-company, as the benchmark.

Table 14. Annual profits per MWh of firm energy by company (high demand response)

				With hedge			No hedge	With hedge	No hedge	With hedge	No hedge
FE demand parameter	Demand elasticity	Owner Market Share Rank	Stat	Firm energy payment	Hedge payment	Energy rent	Energy rent + peak energy rent	Profits before FC	Profits before FC	Profits after FC	Profits after FC
4%	-0.1	1	Mean	3.27	0.11	49.09	49.78	52.47	49.78	-1.25	-3.93
4%	-0.1	1	Std. Dev.	0.42	0.94	9.79	11.23	10.05	11.23	4.33	6.63
4%	-0.1	1	Min	1.58	-1.17	27.02	27.02	30.39	27.02	-14.73	-16.32
4%	-0.1	1	Median	3.37	0.00	49.07	49.38	52.44	49.38	-1.93	-5.14
4%	-0.1	1	Max	3.95	16.51	76.54	130.05	88.85	130.05	25.02	66.22
4%	-0.1	2	Mean	3.28	0.00	53.04	53.67	56.32	53.67	0.75	-1.91
4%	-0.1	2	Std. Dev.	0.43	0.41	11.04	11.63	11.09	11.63	4.16	5.56
4%	-0.1	2	Min	1.54	-5.64	27.79	27.79	30.75	27.79	-9.46	-13.05
4%	-0.1	2	Median	3.38	0.00	52.91	53.33	56.22	53.33	0.35	-2.83
4%	-0.1	2	Max	4.02	3.79	83.52	96.27	86.14	96.27	15.97	49.61
4%	-0.1	3	Mean	3.25	-0.01	9.27	9.98	12.51	9.98	-0.60	-3.13
4%	-0.1	3	Std. Dev.	0.46	0.21	9.02	10.61	9.06	10.61	3.78	6.83
4%	-0.1	3	Min	1.49	-3.81	0.00	0.00	1.61	0.00	-11.42	-14.93
4%	-0.1	3	Median	3.36	0.00	6.70	6.77	9.81	6.77	-1.32	-4.66
4%	-0.1	3	Max	4.01	2.62	40.83	84.22	44.38	84.22	15.91	77.40
4%	-0.1	4	Mean	3.25	-0.02	42.42	43.04	45.66	43.04	-4.34	-6.97
4%	-0.1	4	Std. Dev.	0.47	0.43	9.60	10.42	9.65	10.42	4.42	5.87
4%	-0.1	4	Min	1.49	-5.83	18.36	18.36	22.08	18.36	-16.22	-18.53
4%	-0.1	4	Median	3.37	0.00	42.69	43.06	46.06	43.06	-4.66	-7.63
4%	-0.1	4	Max	3.99	4.74	69.63	102.82	77.37	102.82	14.03	45.94
4%	-0.1	5	Mean	3.23	0.05	11.66	12.42	14.94	12.42	2.16	-0.36
4%	-0.1	5	Std. Dev.	0.49	0.32	7.93	9.56	8.00	9.56	3.59	6.63
4%	-0.1	5	Min	1.44	-0.13	2.15	2.15	5.27	2.15	-8.68	-12.28
4%	-0.1	5	Median	3.34	0.00	9.21	9.22	12.49	9.22	1.79	-1.49
4%	-0.1	5	Max	3.97	4.93	49.02	81.10	52.32	81.10	20.71	70.86
4%	-0.1	6	Mean	3.24	-0.12	73.27	73.73	76.39	73.73	0.78	-1.88
4%	-0.1	6	Std. Dev.	0.47	1.34	16.14	16.50	16.29	16.50	9.66	10.12
4%	-0.1	6	Min	1.50	-22.49	27.71	27.71	31.35	27.71	-25.55	-27.59
4%	-0.1	6	Median	3.35	0.00	73.65	74.10	76.67	74.10	0.17	-2.94
4%	-0.1	6	Max	3.99	10.93	119.51	134.85	123.15	134.85	40.23	57.93
4%	-0.1	7	Mean	3.23	0.02	4.31	5.05	7.56	5.05	-0.62	-3.13
4%	-0.1	7	Std. Dev.	0.52	0.29	9.76	11.20	9.88	11.20	2.71	5.84
4%	-0.1	7	Min	1.44	-0.97	0.00	0.00	1.51	0.00	-17.47	-21.08
4%	-0.1	7	Median	3.37	0.00	0.63	0.63	4.03	0.63	-0.79	-4.11
4%	-0.1	7	Max	4.05	7.51	64.91	83.51	68.59	83.51	19.24	68.18
4%	-0.1	8	Mean	3.22	0.00	6.02	6.74	9.24	6.74	-0.40	-2.89
4%	-0.1	8	Std. Dev.	0.53	0.08	9.10	11.05	9.14	11.05	5.06	7.98
4%	-0.1	8	Min	1.44	-1.71	0.00	0.00	1.51	0.00	-6.49	-9.83
4%	-0.1	8	Median	3.36	0.00	3.55	3.55	6.42	3.55	-1.81	-5.45
4%	-0.1	8	Max	4.05	1.36	62.26	89.99	65.71	89.99	33.90	81.99
4%	-0.1	9	Mean	3.21	0.00	5.61	6.34	8.82	6.34	-0.51	-2.99
4%	-0.1	9	Std. Dev.	0.55	0.05	9.02	10.80	9.07	10.80	5.13	7.90
4%	-0.1	9	Min	1.44	-1.47	0.00	0.00	1.50	0.00	-9.77	-13.51
4%	-0.1	9	Median	3.34	0.00	2.26	2.26	5.99	2.26	-1.82	-5.28
4%	-0.1	9	Max	4.05	0.36	63.86	87.73	67.23	87.73	41.68	80.20
4%	-0.1	10	Mean	3.23	0.01	7.63	8.37	10.87	8.37	0.00	-2.50
4%	-0.1	10	Std. Dev.	0.53	0.34	11.29	12.86	11.38	12.86	6.52	8.99
4%	-0.1	10	Min	1.44	-0.29	0.00	0.00	1.50	0.00	-17.63	-20.97
4%	-0.1	10	Median	3.36	0.00	4.57	4.57	7.53	4.57	-1.82	-5.36
4%	-0.1	10	Max	4.05	10.37	76.55	91.53	80.02	91.53	42.41	81.06

Table 14 shows the profits by company in the high demand response case. Here the standard deviation of profits is reduced from the benchmark case, as a result of reduced variation in the hedge payments. This benefit of greater demand response is not seen in the aggregate, because the aggregate hedge payment is nearly zero in each year. Greater demand response has a dramatic effect of reducing peak energy rents. As a result, companies face reduced performance risk from the mandatory hedge. Sensitivity of profit risk to demand elasticity is much reduced from the world without a hedge.

6 Conclusion

The simulation models presented here demonstrate the risk-reducing benefits of the proposed firm energy market. In the market, suppliers sell a hedge against high prices to load. The hedge reduces risk for both load and suppliers. Suppliers receive a higher firm energy payment for offering the hedge, and offering the hedge is not risky because the supplier has the physical generating assets to satisfy its obligation.

In Models 1 and 2, we considered a variation of the original proposal, in which the obligation for thermal resources is effectively constant during scarcity hours. In this case, hydro is asked to do all the load following. We thought that this variation might further reduce performance risk, since it results in obligations that are more consistent with the physical dispatch of the system. Our analysis, however, showed that this was not the case. Risk was unchanged. However, the variation does have substantial merit in that it improves the performance of the energy spot market in dry periods by assuring that suppliers enter the spot market with a more balanced position. For this reason, we adopt the thermal-constant obligation in Model 3.

A major advantage of the proposed firm energy market is that once load is hedged from high prices during dry periods, the energy market can rely more on market forces and less on rationing during dry periods—spot prices can be allowed to increase to reflect the true opportunity cost of hydro resources. This will of course increase supplier risk relative to the analysis in Models 1 and 2. However, an important countervailing force that will reduce supplier risk is that—faced with strong performance incentives—suppliers will operate plants and make investments, so as to limit the downside risk. Thus, it is difficult to predict whether supplier risk going forward will increase or decrease relative to the analysis of Models 1 and 2 presented here.

Model 3, by analyzing investment incentives explicitly over 50 twenty-year simulations, was able to provide several additional insights, as well as further support the results from Models 1 and 2.

Model 3 helps illuminate the issues of lumpy investments. If new plant sizes are similar to the historical plant sizes, few new units will be added in each year. Indeed, in about one-quarter of the years no new entry will occur. In these years, the simulation set the firm energy price from the firm energy demand curve, typically at a price significantly less than the prior-year price. As a result, the firm energy price fluctuates more than is desirable. The adopted resolution addresses this problem by setting the price in surplus years equal to the price in the last successful auction.

Most importantly, the mandatory hedge was shown to be remarkably successful in reducing risk. The hedge reduced company risk by a factor of 4.5 in the benchmark case. From this, we can see that a higher scarcity price would increase risk. Increasing the scarcity price shifts the profit distribution toward the no hedge case—a scarcity price of infinity. This results in a large increase in energy rent risk and a small decrease in hedge payment risk. The overall impact is a large increase in profit risk.

One important assumption of Model 3 is competitive entry. If instead there are substantial barriers to entry, then the market can be expected to perform less well. In particular, firm energy prices would rise above competitive levels. For the market to work well, it will be important for regulators to reduce entry barriers to the extent possible.