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CrossMark

Capacity Payments in a Cost-Based Wholesale Electricity Market: The Case of Chile

A comparison of the generator revenue and market efficiency implications of an energy and capacity payment market relative to an energy-only market for the cost-based Chilean electricity supply industry finds that, while monthly revenue volatility for generation units is significantly higher for the energy-only market, this is almost entirely explained by an increase in short-term energy price volatility. This increased short-term price volatility provides incentives for market participant behavior that enhances market efficiency and system reliability.

Alexander Galetovic, Cristián M. Muñoz and Frank A. Wolak

I. Introduction

Restructuring of electricity supply industries around the world has led to an ongoing debate over which market design is more likely to yield market outcomes that benefit electricity consumers and maintain the long-term financial viability of the industry. One important dimension of this debate is the need for a capacity payment mechanism that establishes a per megawatt (MW) payment to generation unit owners in addition to the income from the energy and ancillary services markets.

A number of countries and regions have opted for a capacity payment mechanism with capped prices in the short-term energy

  http://dx.doi.org/10.1016/j.tej.2015.10.011

market, whereas restructured industries in other parts of the world, such as Australia, New Zealand, and Singapore, do not have a capacity payment mechanism and instead rely on periods of high short-term energy prices to provide the appropriate signals for suppliers and retailers to sign the long-term contracts necessary to finance new investments and hedge short-term price risk. The regional electricity markets in the United States with capacity payment mechanisms operate bid-based short-term energy markets, whereas the dominant paradigm in Latin America is a cost-based short-term market with a capacity payment mechanism. A number of countries in Latin America with significant hydroelectric energy shares employ this market design, most of them following the Chilean model developed in the 1980s. Brazil is one such market, and so are Argentina, Peru, Bolivia, Panama, and El Salvador (recently transformed to a cost-based market). Mexico and Ecuador have recently proposed cost-based markets for their restructured short-term wholesale electricity markets.

There has been considerable debate over the relative merits of the energy/capacity market design and the energy-only market design, but surprisingly little systematic study of this issue.[1] We compare the performance of these two approaches within the context of a cost-based market—specifically, the Chilean wholesale electricity market. Simulating market outcomes under each market design for the same set of system conditions is relatively straightforward under a cost-based format because generation unit owner offer curves are computed by the system operator using the technical characteristics of individual generation units, information on current reservoir levels, the distribution of future reservoir levels, and the evolution of future system demand. We do not have to model how generation units would change their energy offer curves under a capped short-term energy market with a capacity payment mechanism versus an energy-only market with scarcity pricing.

There has been considerable debate over the relative merits of the energy/capacity market design and the energy-only market design, but surprisingly little systematic study of this issue.

We simulate the actual operation of the Chilean Central Interconnected System (SIC) between 1989 and 2008 (19 hydrological years[2]) for each market design. We first compute the discounted present value of expected energy and capacity payment revenues for each generation unit and the system as a whole. We then eliminate the capacity payment and increase the energy cost-of-shortage parameter used in the cost-based dispatch process until the discounted present value of expected revenues from energy sales only equals the value from the energy/capacity market design.

Under the current market design the allocation of capacity payments across different technologies is relatively constant and represents roughly 19 percent of a generation unit's total annual revenue. Under the energy-only market design, the average market-clearing energy price increases from \$62/MWh to \$75/MWh (a 21 percent increase), and the energy cost-of-shortage parameter increases from \$493/MWh to \$2,350/MWh, roughly a fivefold increase.[3]

With no capacity payment the revenue volatility of each unit increases dramatically. However, this increase is almost entirely explained by greater wholesale price volatility. For all technologies, the standard deviation of the average monthly output of the generation unit under the energy-only market is not appreciably different from that under the current energy/capacity market. Because monthly generation unit level output levels are no less predictable under the energy-only market design, the primary revenue risk that must be managed is wholesale price risk. This risk can be easily hedged

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using a fixed-price, fixed-quantity of energy forward contract, where suppliers can lock in a fixed price for their expected pattern of output over the term of the contract. This is actually the case in Chile, where all energy is sold through long-term supply contracts (energy users cannot buy energy in the wholesale market).

This hedging arrangement provides a stable revenue stream for the generation unit owner for the vast majority of its actual output. When we implement a simple, yet realistic, forward energy contracting strategy under each market design, this virtually eliminates the difference in revenue volatility between the two market designs.

The energy-only market design has number of market efficiency benefits relative to the current energy/capacity market design. Besides providing incentives for generation unit owners and retailers to sign fixed-price forward contracts, the risk of high-priced periods provides generation unit owners with a strong financial incentive to keep their units in top working order. An outage during a high-priced period can be extremely expensive for the generation unit owner either in terms of foregone revenues or expensive short-term market purchases to meet their forward energy market obligations. High-priced periods also provide strong incentives for final consumers to reduce their demand and shift it to the low-priced periods.

Consequently, the combination of an energy-only market with high levels of fixed-price forward contracting for the generation unit owner's expected output can improve wholesale market efficiency because of the high-powered incentives it provides for suppliers and final consumers to take actions to benefit system reliability and limit the level and volatility in short-term prices. There is a large literature that discusses the comparative performance of energy/capacity and energy-only markets.[4] It is generally agreed that administratively set prices for capacity may be either too low (leading to underinvestment) or too high (leading to overcapacity).[5] Similarly, administratively set quantities may be either excessive or insufficient.[6]

When we implement a simple, yet realistic, forward energy contracting strategy under each market design, this virtually eliminates the difference in revenue volatility between the two market designs.

Despite of the shortcomings of capacity payments, many think that energy-only markets are more volatile and riskier and fail to adequately compensate investments. Joskow (2008) describes the problem as follows.[7] In the typical system there are only a few hours each year when capacity is fully utilized. Thus, a significant amount of generating capacity on an efficient system is ''in the money'' to generate electricity for only a small fraction of the hours, when these generators must earn all of the net revenues required to cover their fixed costs. Infra-marginal generators also earn a significant fraction of their net revenues during these hours. If prices during those critical hours are too low because of price caps, there will be underinvestment in all generating capacity, too many hours when capacity is fully utilized, and too much non-price rationing.[8]

In this article we do not model capacity investment decisions. Instead, we show that if the cost-of-shortage parameter (which is representative of consumers' willingness to pay not to be curtailed) is set higher than the current value used by the system operator in Chile, one can do away with a capacity payment and provide generation unit owners with the same amount of revenues as they get under the current regime. Moreover, a larger share of this revenue goes to the thermal units that operate infrequently—these units are ''in the money'' with a higher frequency because reservoir water is used more conservatively.

We also find that this higher cost-of-shortage parameter does not significantly alter expected monthly dispatch levels of all the

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units. It only slightly substitutes coal and other fossil fuel generation for reservoir water units. Consequently, most of the revenue volatility arises from the wholesale price of energy. This revenue volatility can be easily hedged by generation unit owners and retailers through fixed-price forward contracts for energy.[9] Indeed, with high levels of fixed-price forward contracting for energy, revenue volatility is almost eliminated under both market designs.

Last, we show that grid reliability is likely to increase in an energy-only system. One reason is that a higher cost of unserved energy fosters a more prudent use of reservoir water. Another reason (which is not modeled here) is that more volatile short-term prices provide incentives to reduce demand in those periods and for generation units to make themselves available to the system operator when they are needed most.

II. The Chilean Electricity Market

A. A brief description of SIC

The Central Interconnection System (SIC by its Spanish acronym) serves about 93 percent of Chile's population and contains 71.8 percent of its total nameplate installed capacity. In 2008, its fuel mix was 55.1 percent hydroelectricity, 27.3 percent natural gas, 9.7 percent coal, 7.4 percent diesel, and 0.4 percent served by other fuel sources.[10] Water availability varies from year to year. In a typical year, hydroelectric generation supplies around 58 percent of total energy. However, in a dry year, hydro units generate a little more than 27 percent of the SIC's energy.[11]

B. Wholesale and forward contract market overview

The Chilean electricity market was restructured during the 1980s.[12] The core of the generation unit dispatch and pricing mechanism is the so-called spot market.[13] The Economic Load Dispatch Center (CDEC by its Spanish acronym) determines the variable cost of running each unit considering its technical characteristics (e.g. heat rate) and fuel cost, which are declared by the owner of the unit. It then centrally dispatches generation units in merit order to minimize the expected discounted present value of the total operating cost, (including the cost of a shortage period) needed to meet system load.[14] The system price, which CDEC calculates every hour, equals the variable cost of the most expensive unit dispatched to meet system load. The system price is capped by a cost-of-shortage parameter set by the National Energy Regulatory Commission (NEC) at US$493/MWh. This cost-of-shortage parameter is the assumed per-megawatt cost of a 10 percent, one-month, energy supply restriction.[15]

In Chile, generators sell their electricity to regulated retailers and large industrial customers through long-term, fixed-price forward contracts.[16] Because dispatch is based on CDEC's estimate of the variable cost of each generation unit and its estimate of the opportunity cost of water, whether a generation unit operates during the hour does not depend on its fixed-price forward contract obligations. For this reason, each hour any given generator is either a net supplier to the system or a net buyer of energy from the short-term market. Net buyers pay net suppliers the system price for the energy they purchase.

A direct implication of these fixed-price forward contracts is that a generator's hourly revenue depends not only on the short-term price but, crucially, on its net buying or selling position in the wholesale market. To see this, let E be the energy generated by the unit during a given hour, E_{contract} the generator's forward contract quantity for that hour, p_{sys} the system price and p_{contract} the contract price. Then total revenues during that hour are:

$$R = p_{\text{contract}} \cdot E_{\text{contract}} + p_{\text{sys}} \cdot (E - E_{\text{contract}})$$

Note that the size of the generator's exposure to the short-term system price depends on its net sales (or purchases) in this market, $E - E_{\text{contract}}$.

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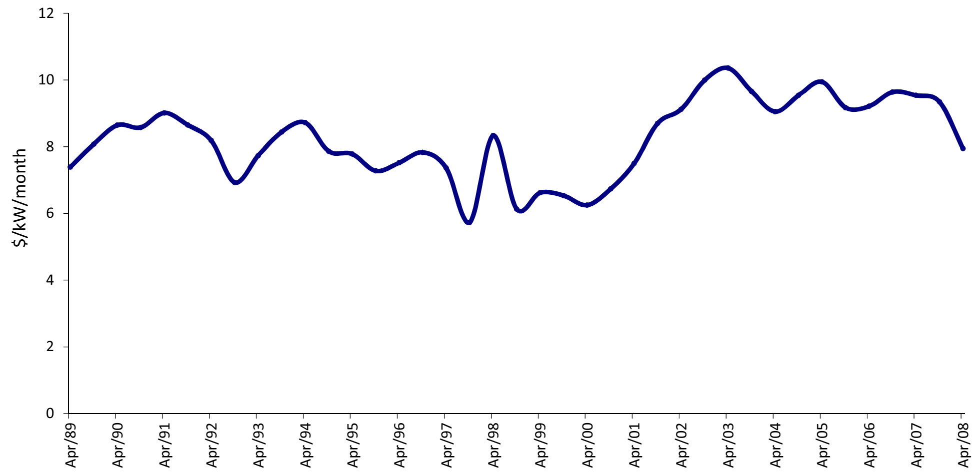

Figure 1: Capacity Price at Quillota Node (in April 2008 US$)

C. The wholesale capacity market

Generators in Chile are also paid for capacity they make available to the short-term market. The capacity price equals the cost of building and operating a diesel-fired generation unit that runs during the system peak periods (see Appendix I.A for details on how this capacity payment is determined and how a generation unit's firm capacity is determined). As can be seen in **Figure 1**, between 1989 and 2007 the capacity price varied between $US 6 and $US 10/kW/month.

As shown in **Figure 2**, nominal capacity—the sum of installed nameplate capacity—follows peak load growth between 1989 and 2007, but with a 30 percent to 40 percent reserve margin. Nominal capacity exceeds peak load by such a large margin because thermal generation capacity provides energy and operating reserves during dry years when not all hydro capacity is available to provide energy. Nevertheless, total capacity purchased each year in the wholesale market at the capacity price equals the peak demand of SIC, hence some nominal capacity does not receive a capacity payment. Instead, the nominal capacity of each plant is adjusted downward so that the sum of the firm capacity sold by generation units equals the system's peak load (see Appendix I.B). The adjustment applied to nominal capacity varies with the technology. The firm capacity of a thermal unit depends on its average available capacity since it began operating. The firm capacity of a run-of-river or reservoir hydro is based on the amount of water available to

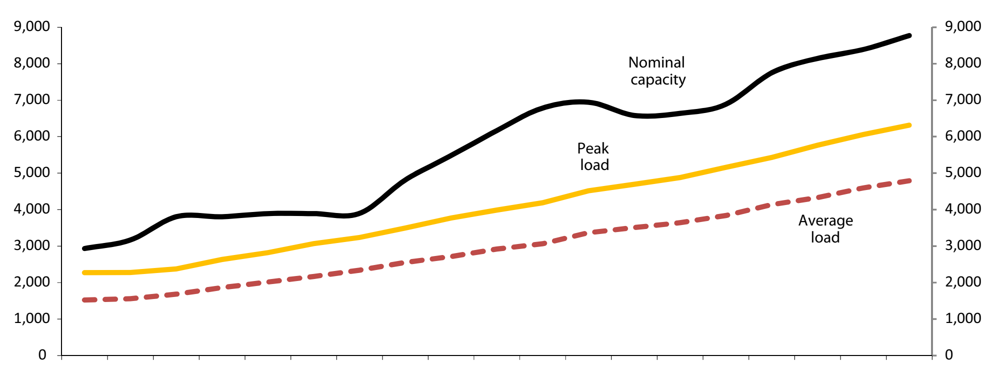

Figure 2: Nominal Capacity, Peak Load and Average Load, 1989–2007, in MW

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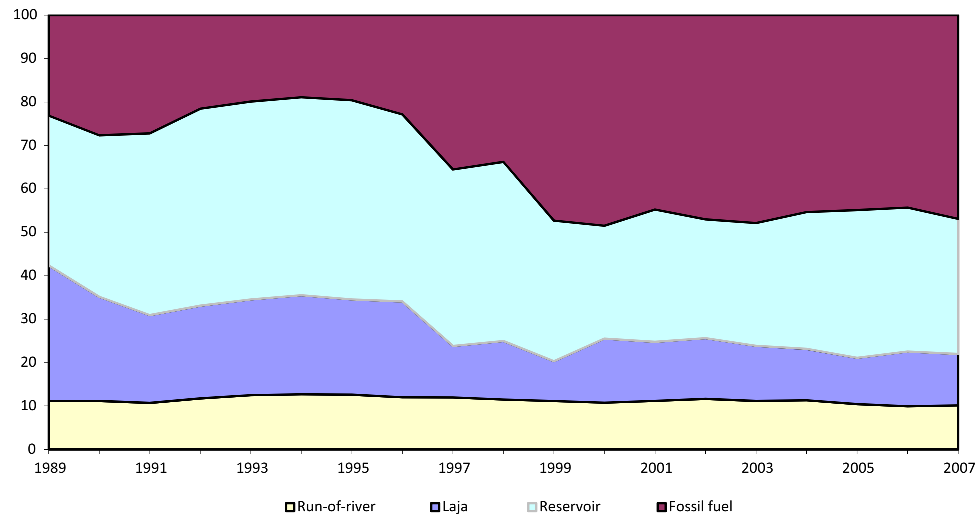

Figure 3: Capacity Payment Shares by Technology Between 1989 and 2007

produce electricity during a dry year.

Figure 3 shows the capacity payment revenue shares of generation technologies over time. The four technologies are: (1) run-of-river hydro, (2) the Lake Laja reservoir (the largest hydroelectric reservoir in Chile), (3) other reservoir hydro units, and (4) thermal generation units. In the late 1990s, capacity payments shifted towards fossil fuel generation, mainly because of natural gas imports from Argentina and large investments in combined-cycle gas turbine plants.

III. Methodology

A. Overview

We simulate the operation of Chile's SIC for April through March hydrological years between April 1989 and March 2008 for the current energy/capacity market design and for an energy-only market design. We use the OMSIC model, which was used by the CDEC to operate the SIC up to 2005.[17]

OMSIC is a stochastic dynamic programming model that optimizes the use of the water in the Lake Laja reservoir.[18] When full, it holds enough water to generate about 7,000 GWh, roughly one-seventh of the SIC's annual energy demand. Because the maximum amount of energy units that run with water from the Lake Laja can produce in a year is 2,500 GWh, water stored in Lake Laja is typically used to produce electricity for several years.

At each point in time, the model's state variable is the current level of the Lake Laja reservoir. The model trades off the benefit of using water today and displacing thermal generation, against the cost of not having water in the future and being forced to use more expensive thermal generation or ration electricity and incur the $/MWh cost-of-shortage times the MWh of unserved energy.

Each simulation of the model yields the amount of Lake Laja water used during each month and the shadow price of the remaining water. This shadow price is the system short-term price. Under normal conditions, the system price is equal to the operating cost of the most expensive thermal unit dispatched. If the model optimally predicts a shortage, the opportunity cost of water equals the cost-of-shortage parameter.

OMSIC is a stochastic model because each month's hydrology is a random variable. The probability distribution of water inflows is modeled with 61 years of monthly hydrologies (i.e., there are 61 January hydrologies, 61 February hydrologies, and a total of 61 $\times$ 12 monthly hydrologies). During each year of the simulation each of the 61 hydrologies is sampled with same probability.

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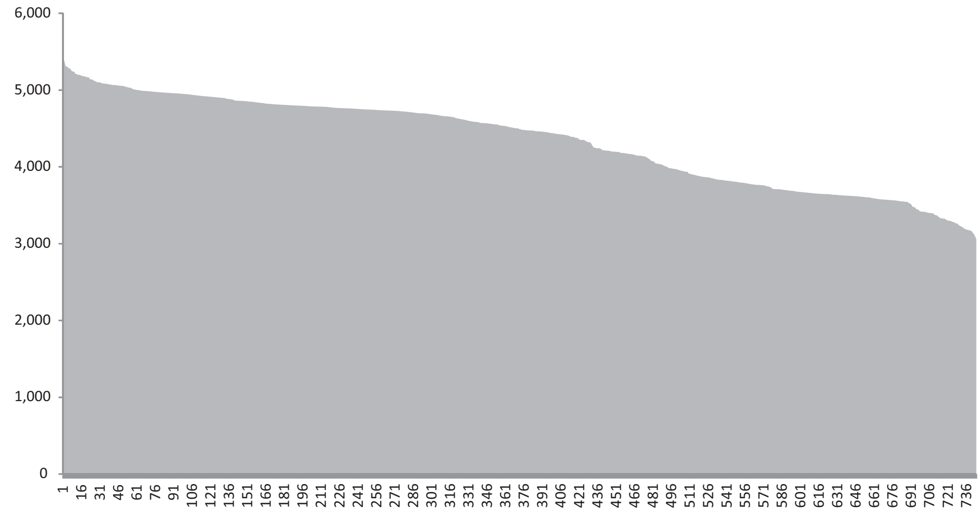

Figure 4: SIC Load Duration Curve for July 2005 in MWh

Between 1989–90 and 2007–08 we run the model with the generation units that were actually in the system at each point in time. Beyond 2007–08, we use the entry sequence that NEC projected in April 2008.[19] **Figure 4** shows a typical SIC monthly load duration curve.

B. Simulations

Because Lake Laja has multiyear storage capacity, the current year operation of the industry depends on the initial level of Lake Laja (the model's state variable) and on the complete sequence of future demands, unit availability, and hydrologies.

Therefore, to simulate the operation of a given year, say 1989–90, we proceed as follows. First we sample 5,000, 12 years of monthly hydrology sequences beginning in April 1989. Next, for each of the 5,000 sequences, OMSIC computes the expected cost-minimizing monthly operation of generation units in the SIC during the 12-year period. Last, we keep the 5.000 simulated monthly pattern of operation of generation units in the SIC during the initial year, 1989–90, and then discard the rest. We then repeat the same procedure for each of the 19 hydrological years between 1989–90 and 2007–08. As a result, we have 5,000 sequences of monthly generation unit-level production decisions for each of the 19 years. (The process of computing the simulations is described in detail in Appendix II.)

To compare the current capacity/energy market with an energy-only market, we rerun these same simulations with one change. We increase the cost-of-shortage parameter so that the energy-only market yields the same discounted present value of expected energy revenues for April 1989 to March 2008 as under the current energy/capacity market design.

IV. Results

A. Energy/capacity market vs. energy-only market

Table 1 shows that for the current market design, average annual capacity payments are 17 percent of annual average revenues. Despite of the fact that both market designs have the same expected discounted present value of revenues, the standard deviation of the annual revenues increases dramatically from 4 percent of the mean of expected annual revenues for the energy/capacity market design to 15 percent of the mean of expected annual revenues for the energy-only market design. The average market price increases from \$62/MWh to \$75/MWh, a 21 percent increase. The cost-of-shortage parameter increases from \$493/MWh under the current energy/capacity market to \$2,350/MWh under the energy-only market. The

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Table 1: Average Revenues, System Prices and Shortage Frequency 1989–2008.

	With Capacity Payment	Energy Only
Annual energy (million US$)	1,841	2,180
Annual capacity (million US$)	368	N/A
Total revenues (million US$)	2,209	2,180
Std. deviation (million US$)	87.4	320.2
System price ($/MWh)	61.6	75.3
Std. deviation (US$/MWh)	62.1	185.4
Cost-of-shortage (US$/MWh)	493.0	2,350
Shortage frequency	0.017%	0.015%
With Fixed Price Forward Contracts for Energy		
Annual revenues (million US$)	1,958	1,950
Standard deviation (million US$)	3.2	13.9

frequency of energy shortages is slightly lower under an energy-only market.

To understand the impact of the higher cost-of-shortage parameter on market prices, Figure 5 compares monthly average energy prices in the current energy/capacity market (black line) and in the energy-only market (light line) with the higher cost-of-shortage parameter. The figure shows that average energy prices are higher and more volatile under the energy-only market. This occurs because the cost-of-shortage parameter is higher and thermal units run more often. Figure 6 shows monthly energy shortage frequencies—the fraction of simulations such that there is an energy shortage larger than 1 percent of system load. Again, the current energy/capacity market is the black line, and the light line is the energy-only market. The figure shows that shortage frequencies are slightly smaller in the energy-only market. This outcome occurs because the higher cost-of-shortage parameter implies that reservoir water is used less frequently and thermal plants run more often, which leads to smaller shortage frequencies. Note that for both market designs, we compute shortage frequencies assuming the same set of generation units at each point in time. In future work, we plan to make generation unit entry decisions endogenous, which in turn will impact shortage frequencies.

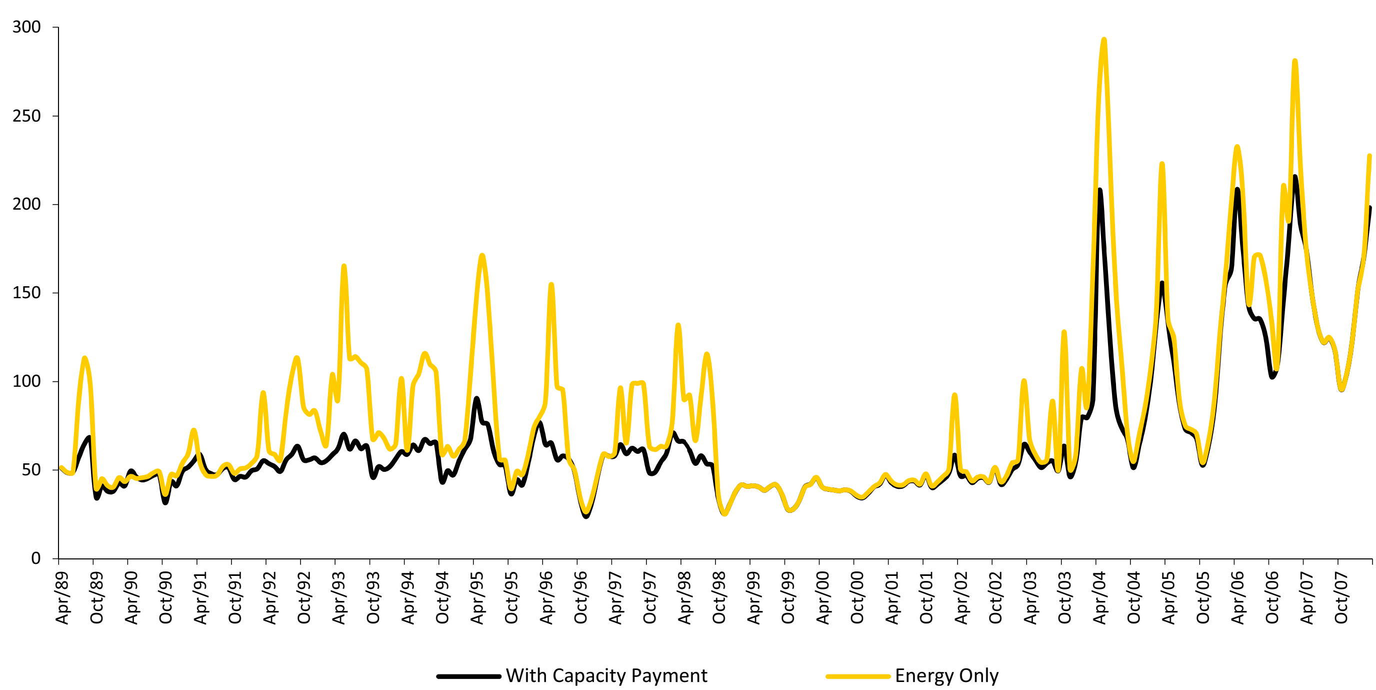

Figure 5: Monthly Average System Prices, April 1989 through March 2008, in US$/MWh

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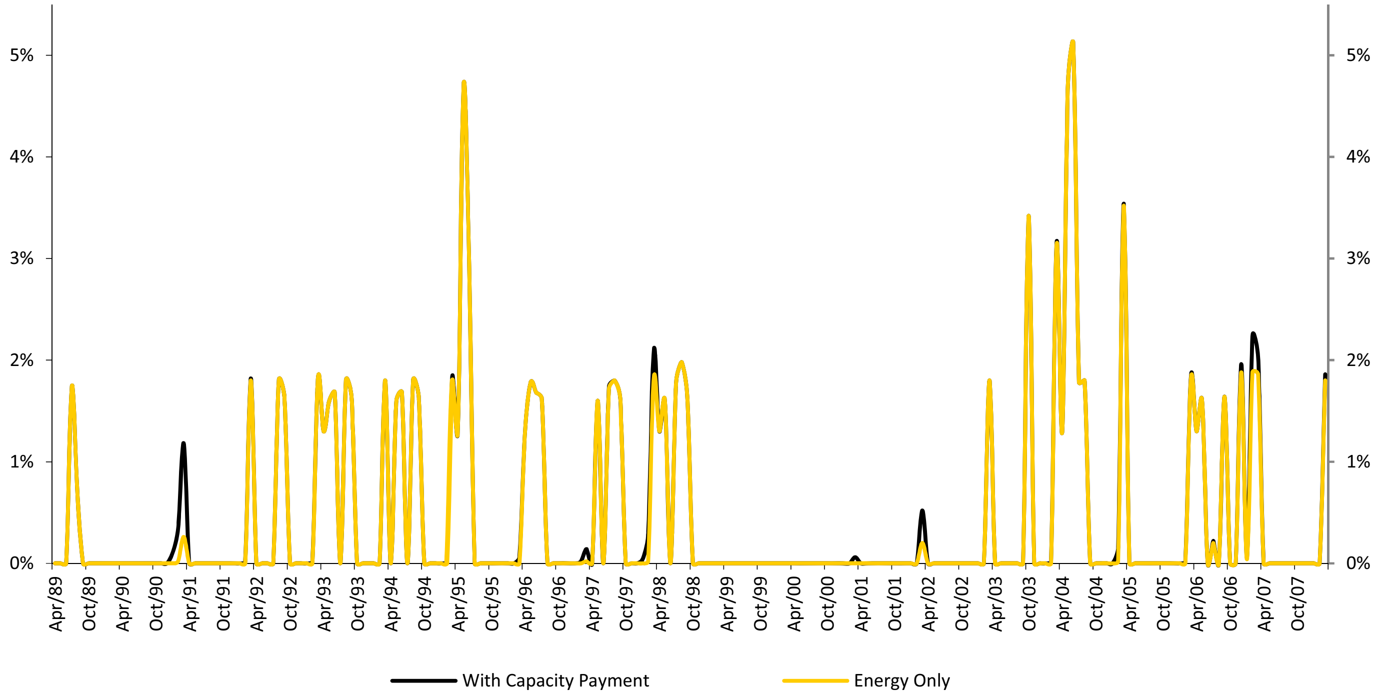

Figure 6: Monthly Deficit Frequency, April 1989 through March 2008

B. Explaining the increase in revenue volatility

We now explore the factors underlying the difference in revenue volatility in Table 1 between the current energy/capacity market and the energy-only market. **Figure 7** presents monthly mean generation by technology for the two market designs. **Figure 8** presents the monthly standard deviation of energy production by technology for the two market

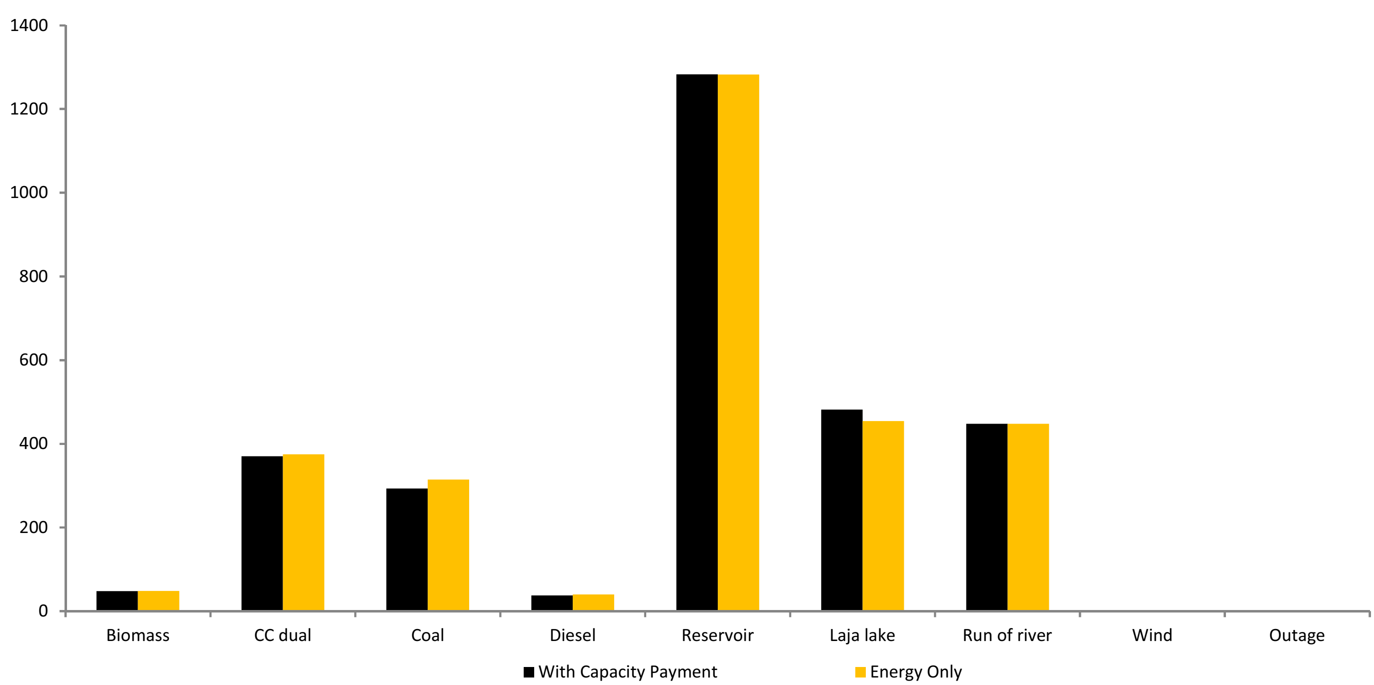

Figure 7: Mean of Monthly Generation by Technology, in GWh

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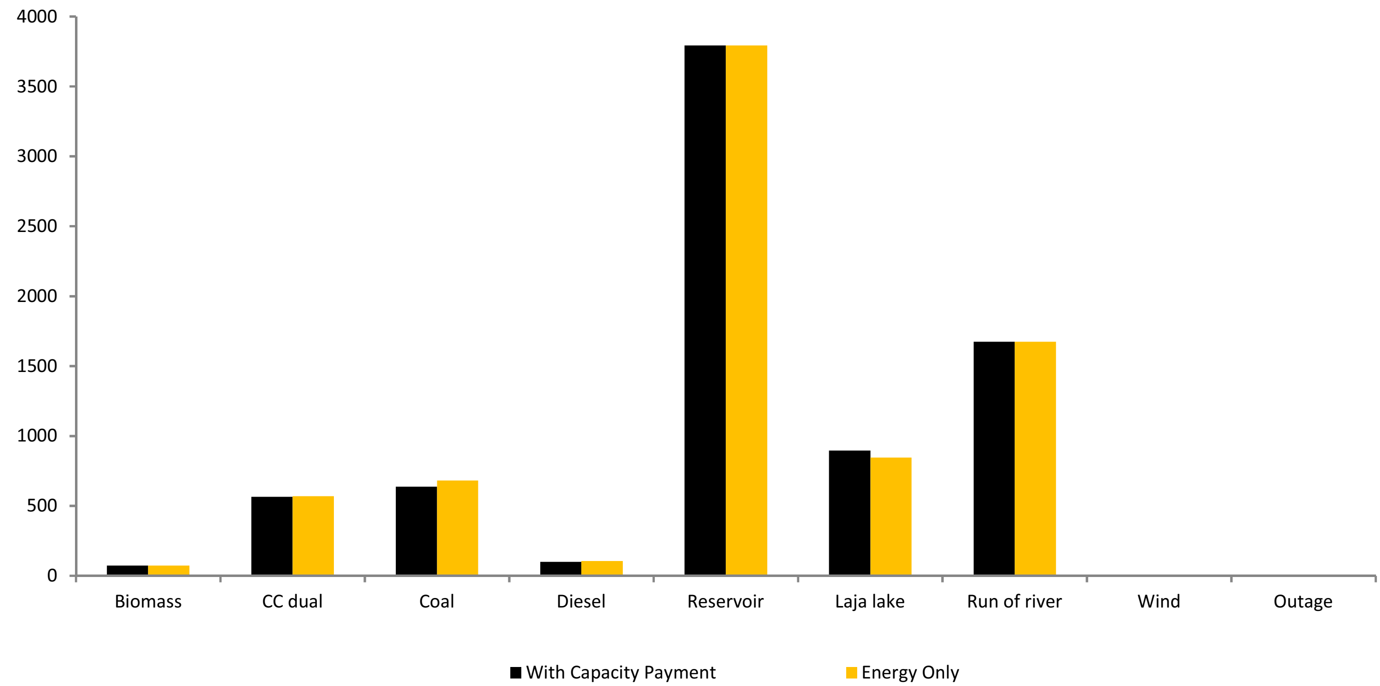

Figure 8: Standard Deviation of Monthly Generation by Technology, in GWh.

designs. There is very little difference in mean generation by technology and the standard deviation of generation by technology between the current energy/capacity market and energy-only market. Consistent with the higher cost-of-shortage parameter, under the energy-only market thermal generation units (natural-gas-fired and coal-fired) have slightly higher mean generation levels and a slightly higher standard deviation of generation under the energy-only market design.

The energy-only market design makes slightly less intensive use of the Lake Laja reservoir and in a less irregular manner. The standard deviation of monthly output of the Lake Laja units is slightly lower under the energy-only market design. Based on the results in these two figures, a case can even be made that the higher cost-of-shortage under the energy-only market design increases system reliability in Chile.

Figure 9 plots the mean monthly prices under the two market designs. Particularly during the winter months, mean prices for the energy-only market are significantly higher than those for the current energy/capacity market. **Figure 10** plots the standard deviation of monthly prices for the two market designs. For all months of the year, the standard deviation of the market price is almost three to four times higher for the energy-only market. As shown in Table 1, the standard deviation of the energy price across the 19 years and 5,000 simulations is 62.1 for the energy/capacity market and 185.4 for energy-only market. These results, together with those in Figures 7–10 demonstrate that virtually all of the revenue volatility in the energy-only market is due to price volatility.

C. Revenue volatility and forward fixed-price contracts

As shown in Table 1, although mean annual revenues across the 19 scenarios are essentially the same for the current energy/capacity market and the energy-only market, the standard deviation of annual revenues in the energy-only market is almost four times the corresponding value for the current energy/capacity market.

This difference in revenue volatility is due for the most part to the fact that we have not accounted for the impact of fixed-price forward contracts for

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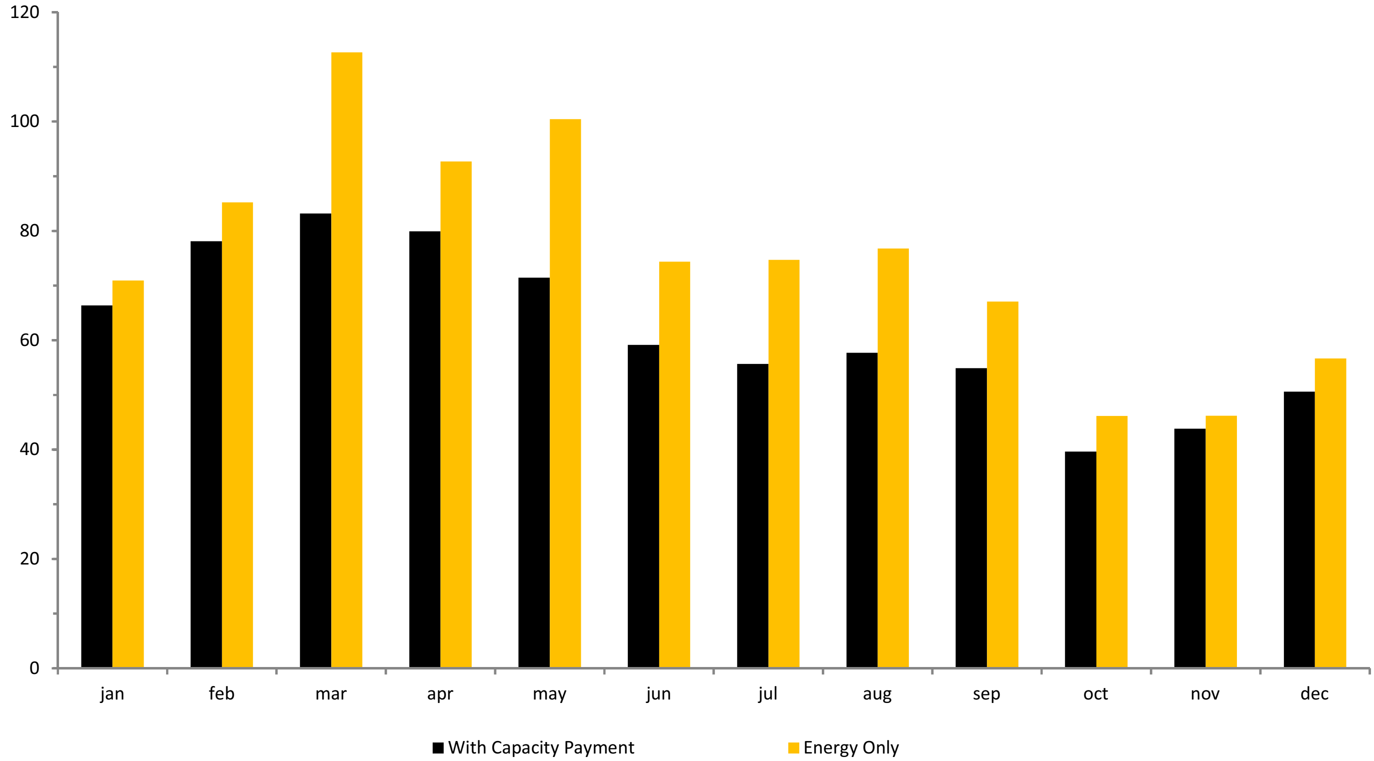

Figure 9: Mean Monthly System Prices in $US per MWh, 1989–2008.

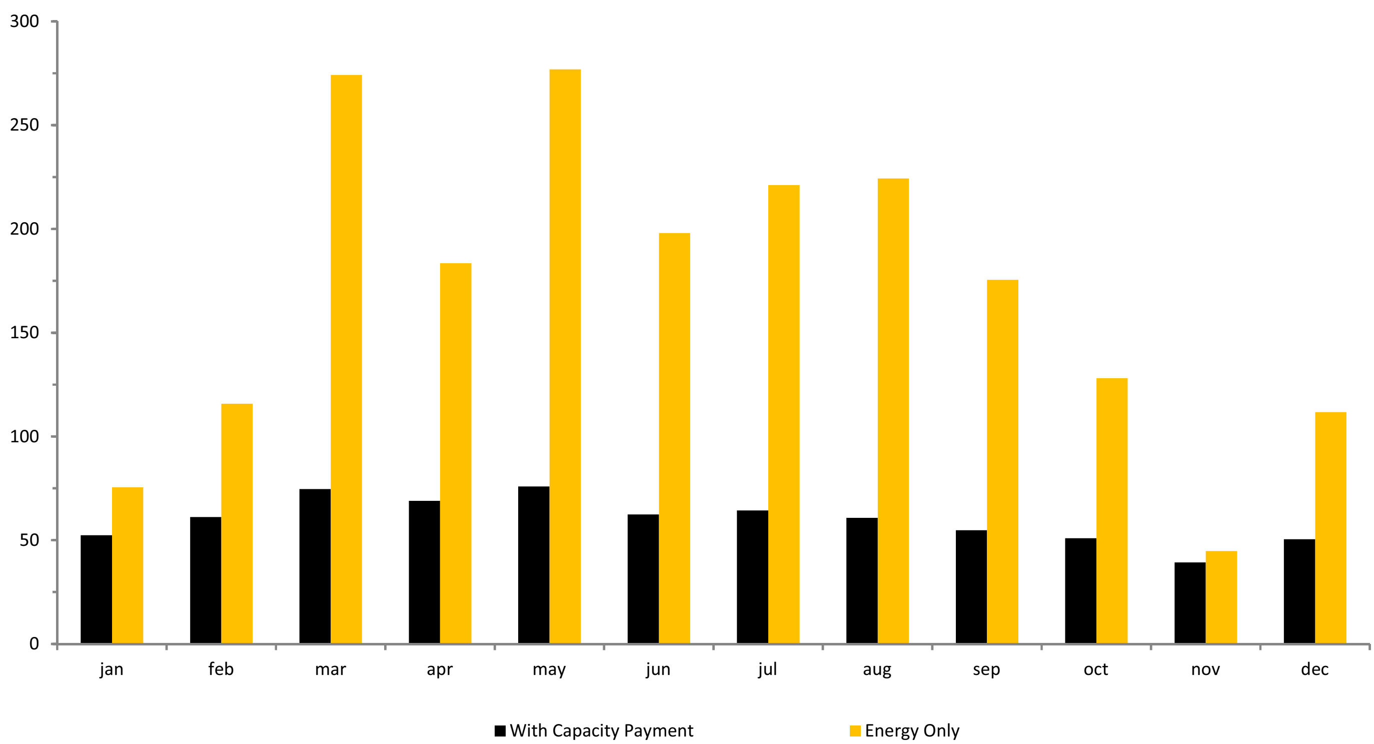

Figure 10: Standard Deviation of Monthly Prices in $US per MWh, 1989–2008

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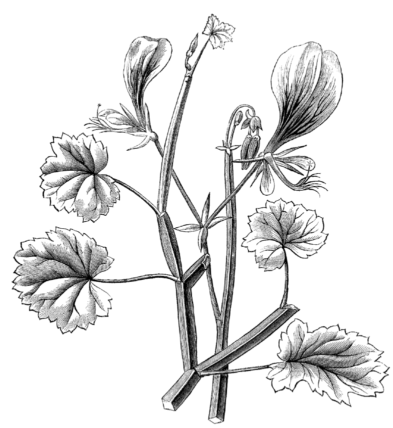
energy on the volatility of generation unit owner revenues under either market design. In all actual wholesale electricity markets, generation unit owners earn the vast majority of their revenues from selling virtually all of the energy they produce in fixed-price forward contracts. In Chile, retailers and large consumers purchase 100 percent of their demand in fixed-price forward contracts. Consequently, it is unrealistic to take the standard deviation in annual revenues figures in the top part of Table 1 as representative of what would actually occur under either market design.

Figures 7 and 8 demonstrate that both the mean and standard deviation of monthly output by generation technology are very similar under the two market designs. Consequently, depending on the pattern of the fixed-price forward contracts that generation unit owners sign, the revenue risk that results from this price volatility can be almost entirely eliminated. To see this, consider the following expression for a generation unit owners hourly revenues as a function of the system short-term price p_{sys} shown earlier:

$$R(p_{sys}) = p_{contract} \cdot E_{contract} + p_{sys}(E - E_{contract})$$

This expression implies that the generator's revenue from the short-term market in any hour is equal to zero if the amount of energy the firm sells in the short-term market (E) is equal to its fixed-price forward contract sales during that hour ($E_{contract}$). Consequently, because virtually all of the increased revenue risk faced by generation unit owners in the energy-only market is due to increased price volatility, revenue volatility under both market designs can be reduced to extremely low levels by limiting the deviations between E and $E_{contract}$.



To demonstrate how a simple 100 percent fixed-price forward contracting strategy significantly reduces revenue risk, we compute the sample average of the output of each generation unit during each month of the 19 years of market outcomes for each market design. We assume that the generation unit owners in the aggregate have signed a fixed-price forward contracts for that quantity of energy for each month at a forward contract price equal to the average short-term price given in Table 1 for that market design. In terms of the above notation, $E_{contract}$ is the mean across the 5,000 simulations of the values of E for that month during the 19 years and $p_{contract}$ is the sample mean across all years and months of the short-term price for that market design.

The bottom part of Table 1 computes the mean and standard deviation of annual revenue under both market designs assuming this 100 percent fixed-price forward contracting strategy. Once again mean annual expected revenues are approximately equal across the two market designs. But under both market designs, this forward contract strategy exposes only a small amount of energy to the short-term market price. The difference between the standard deviation of annual revenues across the two market designs is significantly smaller than in the first half of Table 1. For the case of the current energy/capacity market design, this forward contracting strategy reduces the standard deviation in annual revenues to less than 0.2 percent of the mean of annual expected revenues. For the energy-only market, this forward contracting strategy reduces the standard deviation to 0.7 percent of the mean of expected annual revenues. This result demonstrates that if the energy-only market design was actually implemented with this simple 100 percent contracting strategy, there would only be a small increase in annual revenue volatility to generation unit owners.

Consequently, concerns that an energy-only cost-based market significantly increases revenue

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volatility to generation unit owners seem unfounded once the presence of fixed-price forward contracts for energy is accounted for. This short-term price volatility also has a number of market efficiency enhancing benefits. First, it provides strong incentives for generation unit owners to maintain their generation units in top working order because if their unit fails during a period of high prices, they will have to purchase energy at a very high price to cover their fixed-price forward market obligations. The hourly revenue equation shown above, can be re-written as:

$$R(p_{\text{sys}}) = p_{\text{sys}} \cdot E + (p_{\text{contract}} - p_{\text{sys}})E_{\text{contract}}.$$

This equation implies that although the generation unit owner will earn p_{sys} for energy, E, it produces, it will have to make payments to the counterparty to the forward contracts sold equal to the difference between the high short-term price, p_{sys}, and the forward contract price, p_{contract}, times the quantity of forward contracts sold.

A second source of market efficiency benefits from the energy-only market is that these volatile short-term prices provide strong economic signals to loads to reduce their consumption during high-priced periods and increase their consumption during low-priced periods. Finally, this price volatility can provide a stronger economic case for storage and other fast-ramping technologies necessary to integrate an increasing share of intermittent renewables into an electricity supply industry's energy mix.

One concern about energy-only markets is that they may not sufficiently compensate the peaking units that run infrequently. Figure 11 investigates this claim by plotting the mean annual revenues by technology for each market design. This figure finds that relative to the existing energy/capacity market, the energy-only market provides higher annual expected revenues to peaking diesel units, combined cycle natural gas units, and coal units, precisely the units that may run infrequently except during low-hydro conditions. Consequently, at least for cost-based markets with a significant hydroelectric share such as the Chilean market, converting to an energy-only market with a higher cost-of-shortage parameter

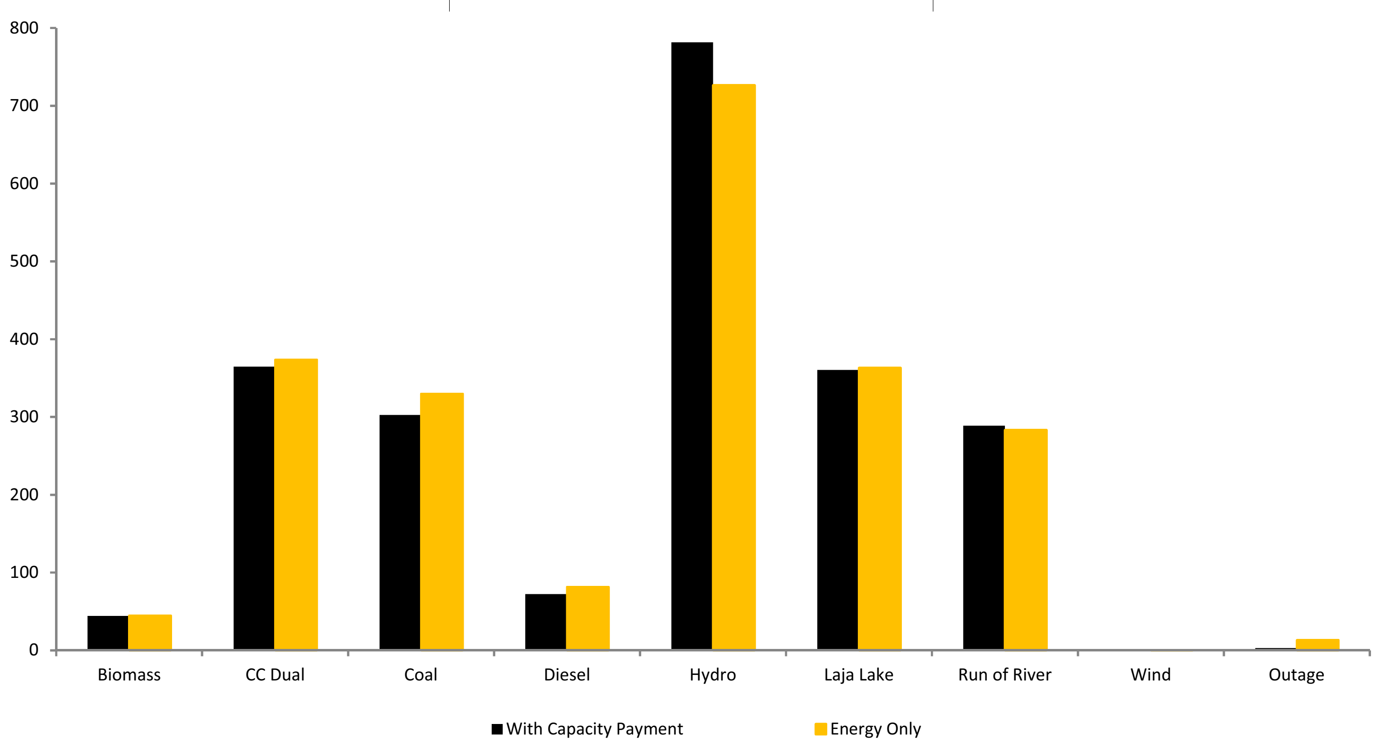

Figure 11: Mean Annual Revenues by Technology by Market Design Type (in US$ million)

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appears to compensate thermal units more than the existing energy/capacity market design, and most handsomely during precisely during the times (low water conditions) they are needed most to maintain system reliability.

Taken together these results suggest than an energy-only market has the potential to improve system reliability and benefit consumers with lower average electricity bills relative to a the current energy/capacity market design.

D. Implications of results for bid-based markets in the United States

Although cost-based markets are the dominant paradigm in Latin America, bid-based energy markets are the standard in the United States and other industrialized countries. Consequently, it is important to explore the implications of our analysis for the choice between a bid-based energy market with a capacity payment mechanism and a bid-based energy-only market. The change in supplier offer behavior between a capacity/energy market and an energy-only market is the major factor that could produce a different conclusion about the relative merits of these two market designs. Specifically, if suppliers submit significantly different offer curves under the energy-only market design relative to the energy/capacity market design, this could yield substantially higher prices and a less efficient dispatch of generation resources.

There are a several ex ante safeguards that should virtually eliminate the likelihood of this outcome. First and foremost is adequate levels of fixed-price forward contract coverage of final retail demand, with the majority of these contracts negotiated far

enough in advance of delivery that new entrants can compete to supply this energy. As discussed in Wolak (2000), suppliers with fixed-price forward contract obligations equal to their anticipated real-time production find it expected profit-maximizing to submit offer curves very close to their marginal cost curve. With this level of fixed-price forward contracting for energy by suppliers under both the energy/capacity market design and energy-only market design, suppliers can be expected to submit offer curves very close to their marginal cost curve, and our conclusions are likely to hold for bid-based energy markets.

Another safeguard that is likely to reinforce our conclusion is active participation of final consumers in the short-term wholesale market. Wolak (2013) outlines a general approach that fits with the existing federal/state regulatory paradigm in the United States that balances the need to protect consumers from bill volatility yet still provides efficient economic incentives for them to shift demand from high-priced periods to low-priced periods. Suppliers facing a final demand that is responsive to hourly wholesale prices are less likely to submit offer curves that deviate significantly from their marginal cost curves, which increases the likelihood that our conclusion about the relative performance of energy-only markets will hold for bid-based markets.

Finally, ex ante regulatory clarity in terms of what actions by market participants constitute illegal market manipulation or other violations of market rules that may be privately profitable for the market participant, but significantly degrade system reliability, is an important factor in ensuring that offer curves do not change significantly across the two market designs. With these safeguards in place, we believe that for the same amount and mix of generation capacity, short-term market efficiency will be enhanced by transitioning from an energy/capacity market to energy-only market design for bid-based short-term energy markets.

  http://dx.doi.org/10.1016/j.tej.2015.10.011

Appendix A.

I. Allocation of Capacity Payments

A. The regulated capacity price

The capacity price equals the cost of investing in a diesel-fired turbine that runs during the system peak periods. This cost equals the sum of I_{turbine}, the cost of the turbine, and I_{line}, the cost of the transmission line needed to connect it to the grid. Both are converted to a yearly equivalent figure assuming an 18-year recovery period, a system reserve margin ρ and a 10 percent real discount rate.[20] Thus

$$p_{\text{cap}} = (1+\rho)\frac{1}{R}(I_{\text{turbine}} + I_{\text{line}})$$

with $R \equiv \left[\int_0^{18} e^{-0.1\cdot r} dt\right]^{-1}$. This price is fixed in US dollars, converted to nominal Chilean Pesos and indexed to inflation.

B. Calculation of the Capacity Payment

Call $\overline{D}$ the system's peak load, which the regulator measures as the average of the 52 highest hourly loads between May and September, the winter season. Furthermore, let k^i_{nom} be the nominal capacity of unit i and

$$K_{\text{nom}} \equiv \sum_i k^i_{\text{nom}}$$

the system's nominal capacity.

Each year the capacity payment mechanism remunerates only $\overline{D}$ MW. Thus, total system-wide capacity revenue equals

$$\Pi = p_{\text{cap}} \cdot \overline{D}$$

Because $K_{\text{nom}} > \overline{D}$, the regulator adjusts nominal capacity to prorate Π. This is done in two steps. First, unit i's nominal capacity k^i_{nom} is adjusted to reflect the incremental power it can produce during the system's peak hour with probability of at least 0.99. This adjusted quantity is called a unit's *preliminary firm capacity*. The firm capacity of a thermal unit depends on its average available capacity since it entered the system. The firm capacity of a run-of-river or reservoir hydro unit is calculated with rainfall during a dry year.

Call unit i's preliminary firm capacity k^i_{prel}, with

$$K_{\text{prel}} \equiv \sum_i k^i_{\text{prel}}$$

the system's preliminary firm capacity. Now in general $K_{\text{prel}} > \overline{D}$. Thus, the regulator calculates a factor

$$\beta \equiv \frac{\overline{D}}{K_{\text{prel}}}$$

Then the *firm capacity* of unit i is defined as $k^i_{\text{firm}} = \beta k^i_{\text{prel}}$. A unit's capacity payment is equal to p_{cap} times k^i_{firm}.

II. Simulations

A. Demand and generation units

Total energy demand during each month of the simulation is divided into five demand blocks which approximate the system's actual monthly load curve. Thus, let $b = 1, 2, \ldots, 5$ denote each demand block, y denote the hydrological year and $t = 1, 2, \ldots, 12$ denote the month of the year. Then $E(b, t, y)$ is the amount of energy consumed during block b in month t of hydrological year y. For the hydrological years 1989–90 to 2007–08 we use actual energy demand. Beyond 2007–08 we use the load projections made by NEC in April 2008. We index units present during part or all of the optimization period with $i = 1, 2, \ldots, m$. Let $E^i(b, t, y)$ equal the amount of energy produced by unit i during block b of month t of year y.

B. Outputs

For each simulation $j = 1, 2, \ldots, 5{,}000$, and each demand block b of month t of the initial year y we obtain: (i) the system price, $p_{\text{sys}}(b, t, y\,; j)$; (ii) the generation of unit i, $E^i(b, t, y\,; j)$; (iii) the energy revenue of unit i, $p_{\text{sys}}(b, t, y) \cdot E^i(b, t, y\,; j)$; (iv) the energy shortfall, $E^s(b, t, y\,; j)$. Expressions (i)–(iv) can be used to compute aggregate quantities and statistics.

C. Revenues

Note that the vector $[E^i(b,t,y;j)]_{i=1}^m$ and $E^s(b, t, y\,; j)$ satisfy

$$\sum_{i=1}^{m} E^i(b,t,y;j) + E^s(b,t,y;j) \equiv E \times (b,t,y;j)$$

Therefore, total energy revenues in year y in simulation j are

$$\mathrm{RE}(y;j) \equiv \sum_{t=1}^{12}\sum_{b=1}^{5} p_{\text{sys}}(b,t,y;j) \cdot E \times (b,t,y;j)$$

and expected energy revenues in

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year y is

$$\overline{\mathrm{RE}}(y) = \frac{1}{5,000}\sum_{j=1}^{5,000}\mathrm{RE}_i(y;j)$$

Capacity revenues do not depend on the hydrology. To estimate them we calculated firm capacity of each unit, k^i_{firm}, for each year y between 1989–90 and 2007–08 for each unit i and valued each MW of firm capacity at the relevant capacity price for that year. Capacity revenues for unit i in year y are equal to

$$p_{\mathrm{cap}}\cdot k^i_{\mathrm{firm}}(y)$$

and total capacity revenues during year y are

$$\mathrm{RC}(y) = p_{\mathrm{cap}}\cdot\sum_{i=1}^{m}k^i_{\mathrm{firm}}(y) = p_{\mathrm{cap}}\cdot\overline{D}(y).$$

It follows that expected total revenues in year y are

$$\overline{\mathrm{RE}}(y) + \mathrm{RC}(y)$$

D. Equivalent energy-only market outcomes

To compare the current combined capacity and energy market with an energy-only market, we rerun the simulations. We increase the cost-of-shortage parameter so that the energy-only market generates the same discounted present value of expected energy revenues as under the current energy/capacity market design.

Let $\overline{\mathrm{RE}}(y;\mathrm{cs})$ be expected total energy revenues in year y for cost-of-shortage parameter, cs. Given that cs = US $ 493 in the energy/capacity market, we find $\widehat{\mathrm{cs}}$ such that

$$\sum_{y=1}^{19}\frac{\overline{\mathrm{RE}}(y;\mathrm{US\$493}) + \mathrm{RC}(y)}{(1+r)^y} = \sum_{y=1}^{19}\frac{\overline{\mathrm{RE}}(y;\widehat{\mathrm{cs}})}{(1+r)^y}$$

■

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Endnotes:

1. Recent discussions about market design and the impact of capacity payments have been had in California (California Public Utilities Commission, 2007), Colombia (Wolak, 2005) and England (Lane, 2012).

2. The hydrological year begins in April and ends the following March, when the runoff season ends.

3. All values are in April 2008 U.S. dollars.

4. For a brief, but complete summary of the discussion, see (Roques et al., 2005). For a theoretical equilibrium analysis with endogenous investment see (Tishler et al., 2008).

5. For example, in the capacity auctions run in Britain in 2014, National Grid set the target volume to procure at the intersection of the demand schedule with the cost of new entry (CONE), and estimated the equilibrium price at £49/kW-year, whereas the auction cleared at £(2012) 19.40/kW-year, less than 40 percent of the predicted value. See Newbery (2015).

6. For proposals on how to design capacity payments see Batelle and Pérez Arriaga (2008), Finon and Pignon (2008), Finon et al. (2008), Hobbs et al. (2005) and de Vries and Heijnen (2008).

7. See also Neuhoff and de Vries (2004), Roques (2008), Roques et al. (2005) and Söder (2010).

8. Intermittent renewables create new challenges. See Traber and Kemfert (2011) and Wolak (2013).

9. Neuhoff and de Vries (2004) point out how long-term contracts reduce revenue risk.

10. For a detailed description of the Chilean system see Moya (2002).

11. 1998–99 is the driest year on record. Very dry years are 1996–97, 1988–89, 1989–90 and 1990–91. Years with abundant precipitation are 1992–93, 1993–94 and 1997–98.

12. See Arellano (2008), Bernstein (1988), Galetovic and Muñoz (2011), and Rudnick (1994).

13. Descriptions of the Chilean price system are in Galetovic and Muñoz (2011) and Galetovic et al. (2004).

14. See Appendix B in Galetovic and Muñoz (2009) for more information about the cost-based power plant dispatch in Chile.

15. Note that the cost-of-shortage parameter, calculated every four years by a consultant hired by NEC, estimates the cost of a protracted energy shortage that forces every user to reduce her energy consumption in the same proportion during one or more months, a situation that can arise during a very dry winter with little rainfall; see Serra and Fierro (1997).

16. Most contracts last between 10 and 20 years.

17. In 2005 OMSIC was replaced by a new stochastic dynamic programming model that follows the same logic, and models reservoirs in more detail, but is unlikely to yields quantitatively different results from what we report here.

18. See Appendix B in Galetovic and Muñoz (2009) for a description of OMSIC.

19. We need to simulate after 2007–08 because each year's optimal operation of the Laja reservoir depends on the entire sequence of future hydrologies, demands, and unit availabilities.

20. In 1989 the reserve margin was set at 10 percent, but it was increased to 15 percent in 1990; reduced to 6.27 percent in October 1997; and increased yet again to 11.76 percent in October 2001.

 1040-6190/ http://dx.doi.org/10.1016/j.tej.2015.10.011