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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.

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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

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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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