

The California Electricity Market: An Assessment of the First Year of Operations (Panel on Evolution of Electricity Market Structures)

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April 1, 1999 marked the completion of one full year of operation of the California Independent System Operator (ISO) and Power Exchange (PX). The market design in California incorporated many new features. A year's experience with the market affords an opportunity to assess how well some of these features worked and to review some of the changes being made in the market.

Some of the key aspects in the Cal ISO and PX design were the principle of self-commitment by generators, the use of competitive auctions for ancillary services, a congestion management approach that applied the power balance constraint on each participant's portfolio, the use of Reliability Must Run (RMR) contracts, a stakeholder governing board, a multi-settlements design with financially binding day-ahead, hour-ahead and real-time markets. We will examine some of these areas.

The PX markets

The Cal ISO does not operate a day-ahead market. Instead, the operation of the day-ahead market is left to competing Scheduling Coordinators. The PX is the largest Scheduling Coordinator and operates a day-ahead and hour-ahead market. The day-ahead market of the PX uses simple price/quantity bids and offers and ignores all operational constraints, which are left as the responsibility of the bidders. On the whole, the PX auction appears to be working quite well. During the first year, the PX day-ahead market accounted for approximately 80 percent of the total volume in the market. The daily volume in the PX averaged 517,842 MWh at an average price of \$24.44/MWh. Since the PX auction seems to be working well, plans to introduce iterative bidding have been put on hold indefinitely. This decision was based on market simulations involving PX participants in November 1998. The primary concerns were strategic behavior during the iterations and the additional time required in an already complex and lengthy bidding and scheduling process.

The PX hour-ahead market suffered from a problem of poor liquidity and was modified to a day-of market. The day-of market is similar to the hour-ahead market except that auctions are conducted thrice daily instead of every hour. This change resulted in improving the liquidity in the market.

Demand Side Bidding

Electric utility restructuring in California like most other states involves a transition period during which utility rates remain frozen and during which the utilities are able to recover their stranded costs via a competition transition charge (CTC). The rate freezes and rate reductions insulate end use customers from the spikes and volatility in market prices. Thus, there has been little experience with true demand side bidding that involves physical curtailments and inter-temporal shifts in electricity consumption. However, demand side bidding has been used as a mechanism to check market power by moving demand between the day-ahead, hour-ahead and real-time markets. In California, the transition period can last as long as four years from the April 1, 1998 start-date or until the CTC has been fully collected whichever occurs first. At least one utility in the state expects to fully collect its CTC in 1999. This should accelerate the transition to a post rate freeze environment in San Diego Gas and Electric's service territory which could witness greater incentives for demand side participation in the electricity market.

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Ancillary Services

The California ISO was the first attempt in establishing competitive auctions for ancillary services. Some problems that were predicted prior to the start-up of the ISO did occur as envisioned. Others were unforeseen. Foremost among the problems that were predicted was the effect of selective application of price caps on utility owned generators. The net effect of this was a shortfall in supply. This problem was exacerbated with the FERC pronouncement that no price caps were applicable on one particular ancillary service, i.e., replacement reserves. On July 9, 1998 the prices in this market were as high as \$9999/MW. This was followed by the imposition of price caps of 500 \$/MW subsequently reduced to 250 \$/MW. The problem of selective application of price caps was finally eliminated on Nov 3, 1998. The most severe shortfalls of ancillary services occurred in the regulation/AGC market. In the period May 21, 1998 through Nov 3, 1998, the ISO instituted an additional side payment for regulation bidders known as REPA (regulation energy payment adder). Shortfalls in ancillary services were also made up by Reliability Must Run (RMR) generation.

Much attention was given to the bid format and bid evaluation criteria for the reserves auction during the design of the ISO. However, the interaction between the different reserve auctions was not considered to be a serious problem. The AS auction is really a sequence of four different auctions. The sequence begins with regulation, followed by spinning reserves, non-spinning reserves and replacement reserves respectively. This particular sequence was chosen to reflect a monotonically decreasing product quality, i.e., a unit selling regulation can also offer the same capacity as spinning reserves in case it is not selected in the regulation auction and so on. Two different problems emerged in this sequential process. The first was the seemingly irrational decision by some bidders to not roll over their bids from the earlier auction to the subsequent auctions in case they did not win in the earlier auctions. The consequence of this behavior was that unused bids from earlier auctions could not be used in later auctions even if they were less expensive. A second problem was that prices in the auctions could often be paradoxical, i.e., the auctions for lower quality products could often clear at higher prices than those for higher quality products. The ISO intends to fix both problems by the introduction of a so-called "rational buyer" protocol for procuring ancillary services. By means of this protocol, the ISO will be able to substitute the purchase of a lower quality product by that of a higher quality product if it lowers overall costs. Critics of the ISO argue that this is a complex fix to a transitional problem involving irrational bidding. They also argue that the alignment of prices with the quality of products may come at the price of increased volatility in quantities procured for each service.

Another serious problem in the ancillary services market was the allocation of costs based on scheduled demand. This created a perverse incentive for under-scheduling load in the forward markets in order to avoid ancillary services charges. This problem is likely to be fixed with the shift to cost allocation based on metered demand. The ISO's ancillary services costs have been roughly 15-20 percent of the energy costs as reflected by the PX day-ahead market.

Other changes being implemented are an automation of dispatch instructions to resources. The reliance on voice communications can introduce delays that have a detrimental effect on the market prices. The ISO attempted to reduce these delays by increasing its dispatch interval from 5 minutes to 10 minutes. However, this step alone has proved insufficient to resolve the problem.

Regulation of ISO Costs

During the early restructuring debate, analogies between ISOs and air traffic controllers were common. Given that backdrop, considering that the ISO's corollary to the FAA's overriding objective of air safety is reliability, it should hardly come as a surprise that ISOs seem to view the maintenance of reliable grid operation as their main, if not only, charter. This is achieved by extreme operational conservatism and higher costs. A classic example of sacrificing efficiency on the altar of reliability is the rise in uplift costs in the United Kingdom after the grid operator commenced operation. These uplift costs approximately doubled in the first four years of the gridco's operation. These costs were brought under control by linking the profits of the grid operator to the management of the uplift costs. Although the UK experience was sufficient to guarantee the abandonment of uplifts in favor of some form of locational pricing for handling congestion, a larger problem in ISO development was introduced by the very nature of non-profit ISOs, like the Cal ISO. By making the ISOs non-profit, cost-pass-through entities, it is difficult to adopt incentive-based solutions such as those used in the U.K. Indeed, a non-profit ISO has even less incentive than a utility, which may have its authorized rate of return at risk. This culture, that costs are a straight pass through to users, coupled with its overarching emphasis on reliability, has resulted in the Cal ISO's very high costs. This is one reason that for-profit Transco are being viewed as a better alternative to a non-profit ISO. However, the Transco model still remains suspect as it may, depending on its management and ownership structures, result in little change from existing arrangements.

Market participants incur a large number of ISO-related costs. These include Grid Management Charges (ISO overhead—computer systems, personnel costs, etc.), unaccounted for energy (UFE), and neutrality charges. Charges related to markets operated by the ISO include ancillary services charges, congestion charges and imbalance charges in the real time market.

The costs incurred in the name of reliability are significant. These costs are driven up by excessive use of Reliability Must Run (RMR) generation and bypass of market protocols (Out-of-Market Dispatch).

It is tempting to view California's RMRs as a substitute for Installed Capacity (ICAP), but that would be incorrect. While ICAP is motivated by generation adequacy arguments that have nothing to do with transmission, RMR generation is motivated by transmission reliability. Specifically, RMR generation refers to generation resources that need to be operated for local reliability purposes in the transmission grid, such as for voltage support and intra-zonal congestion. The payments made by the ISO under the RMR contract can be higher than the market-clearing price of energy. This difference is made up by the transmission owner in whose service territory the RMR generator is located, who then incorporates these costs into its transmission access charges. The rationale for this allocation of RMR costs is that the RMRs are necessitated by insufficient investment in transmission. Thus high RMR costs are supposed to provide incentives for the grid owners to make the necessary upgrades. The Cal ISO however, has been using RMR generation to provide ancillary services. Such use of RMR generation to make up shortfalls of ancillary services could result in RMR costs being an inaccurate indicator of the need for grid investment and result in an artificial inflation of transmission access charges. As an example, a large Northern California utility had to make up approximately \$150 million for RMR payments incurred by the California ISO in the three quarters of its operation in 1998. This figure is approximately one-half of the utility's annual transmission revenue requirement.

Out-of-market dispatch refers to dispatch actions taken by the ISO that are not reflected in the ISO's real-time market prices. Instead the cost of out-of-market dispatch is recovered through a separate neutrality charge. At the Cal ISO these dispatch actions are taken by dispatchers who procure energy to make up for imbalances by telephoning selected resources or control area operators that choose not to submit any bids into the ISO's markets. These calls result in bilateral trades negotiated by the ISO in a manner that bypasses and undermines the ISO's real-time market. The very premise of a real time market is to reflect physical imbalances in the market price for energy. Out-of-market dispatch can make the market price a poor or meaningless indicator of physical imbalances, e.g., the market price may be low even if there is excess demand in the system. In 1998 the Cal ISO used out of market dispatch on a number of occasions. The neutrality charge, which is where the costs of out-of-market dispatch are reflected, varied from a low of \$0.04/MWh in April to between \$2.18-\$3.24/MWh in the summer peak months of July-October.

Another cost incorporated into the neutrality charge is the so-called unaccounted for energy charges (UFE)². UFE charges include errors from the mis-reporting of meter data by Scheduling Coordinators. (UFE has other components as well as misreported meter data, such as load profile errors, theft and errors in estimated losses.) The Cal ISO has the attractive feature that each retail marketer through its Scheduling Coordinator is responsible for forwarding its own meter/profile data to the ISO (unlike PJM where meter/profile data are the responsibility of the utilities). While this may resolve the transparency problem, it does permit unscrupulous marketers to shift costs to those who play by the rules. Although ISOs have set up market surveillance committees with FERC's blessing (and created new research opportunities for economists and academics), little emphasis seems to be placed on auditing meter data submission or otherwise imposing the discipline necessary to reduce UFE.

Finally, the Cal ISO also has high administrative costs. All these costs are passed on to ISO users including ESPs—in a low margin business, this can mean the difference between profit and loss. The Grid Management Charge for the Cal ISO is 0.78 \$/MWh. This is in contrast to \$ 0.29/MWh for PJM.

ISO Governance

The Cal ISO governing board has 25 voting seats occupied by representatives from every conceivable stakeholder group. However, the class directly exposed to ISO costs (scheduling coordinators, i.e., non-utility "private buyers and sellers") holds only two of 25 seats, and only one these two is a load serving entity (LSE). Although, a board that allows for stakeholder representation has advantages, it may also have some disadvantages. The ISO governing board can often become a forum for public policy debates, rather than being limited to ISO management and operational issues.

The ISO has effected significant changes to both electric system operation and allocation of costs since its start up. While some of these changes are at the direction of the Governing Board, the ISO staff has had a strong influence on the Board. In some cases, the role of the ISO staff in policymaking is essential. However, carried too far, this can present a challenge to the principle that the management of the ISO should be in the hands of its users.

² UFE arises when the power inputs (i.e., generation) into the grid do not add up to the power outputs (i.e., loads plus estimated losses).