

# The Role of the ISO in U.S. Electricity Markets: A Review of Restructuring in California and PJM

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*Electricity Journal*, April 1999, 71-81

Several regions of the U.S. have sought to restructure the electric power industry by separating the potentially competitive generation sector from the natural monopoly functions of electricity transmission and distribution. Under this restructuring scheme, a central authority, which we will refer to as the independent system operator (ISO), is given control over both the transmission system and the spot market for electricity. The ISO's role in managing the spot market is relatively uncontroversial. This is because the spot market takes place in real time and requires continuous physical adjustments to electricity supply and demand subject to complex constraints, such as the need to maintain voltage and frequency within tight bands.

Although the ISO's role in managing the spot market is generally accepted, its role in scheduling and pricing generators prior to actual dispatch was hotly debated during the development of California's market and remains a contentious issue.<sup>1</sup> Like other restructured electricity markets, the California market requires generators to be scheduled for operation on a day-ahead basis and allows for adjustments in these day-ahead schedules up to an hour ahead of actual dispatch. However, the California ISO has a minimal role in this scheduling process; almost all scheduling is carried out by a number of competing scheduling coordinators, referred to as SCs. In contrast, the ISO in the Pennsylvania New Jersey Maryland market (PJM) schedules all generators that do not elect to schedule themselves. This paper discusses the California and PJM approaches to shed light on the controversy over the ISO's role in pre-dispatch phases of the market. Section I describes the California market while Section II briefly reviews PJM. Section III outlines the costs and benefits associated with limiting the ISO's role in the scheduling phases of the market. Section IV summarizes recent experience in California and PJM and offers conclusions.

## I. California

### A. Overview

California's electricity market consists of: (1) a number of competing forward markets for energy, (2) day-ahead and hour-ahead markets for transmission and for ancillary services, and (3) a real-time energy spot market. Scheduling coordinators (SCs) run the forward energy markets. The ISO manages the spot market. It is also currently responsible for conducting the transmission and ancillary services markets.<sup>2</sup>

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<sup>1</sup> These scheduling phases are needed because many generation facilities require substantial notice in order to operate efficiently.

<sup>2</sup> By the second quarter of 1999, SCs may be allowed to trade firm physical rights to the transmission system (FTRs), as well as ancillary services. The term ancillary services generally refers to power system services other than the provision of real power. As discussed further in the text, California procures four ancillary services on a day-ahead and hour-ahead basis. It also obtains two additional services through contracting on a longer term basis.

Currently, California has about thirty SCs. Most of these SCs establish day-ahead schedules and prices through bilateral contracting. One SC, the Automated Power Exchange, runs a continuous market. Another SC, the Power Exchange (PX), was established as California's "official" energy market. The PX runs auctions that establish energy prices and schedules on both a day-ahead and an hour-ahead basis. It currently handles most of the trading in the California market. However, part of the reason for the PX's dominance may be the fact that all California utilities are required to bid their generation and loads into the PX for the first five years of the California market.

California established an official energy exchange to provide all traders with access to an energy market with relatively low transactions costs as an alternative to private market makers. Since PX prices are posted, they can make the market more transparent to regulators and they can be used to facilitate negotiation of bilateral contracts for sharing price risk. In contrast, bilateral markets tend to produce unique prices for every transaction, and hence do not provide an effective reference point for contracting purposes. Although an auction may be more transparent, bilateral markets are often better able to tailor contracts to individual customer needs. Most SCs that conduct bilateral trades also trade with either the PX or the Automated Power Exchange or both.<sup>3</sup>

## ***B. Market Sequence and Settlement Systems***

The PX energy market and the ISO markets for transmission and ancillary services are conducted in a sequence. First, the PX conducts the day-ahead market for energy, which is followed by ISO markets for transmission and ancillary services. Second, the PX conducts a market for energy one hour in advance of the actual dispatch hour, which is followed by the ISO's hour-ahead markets for transmission and ancillary services. Finally, in real time, the ISO conducts the energy spot market. Our discussion focuses on the day-ahead markets and the real-time market because the hour-ahead markets are essentially a repetition of the day-ahead markets.

California uses a multisettlement system, which means that the prices and quantities established in market phases prior to dispatch represent binding forward contracts for the purchase and sale of electricity.<sup>4</sup> Under this system, day-ahead PX transactions are settled at the day-ahead PX energy price and hour-ahead PX transactions are settled at the hour-ahead PX energy price. Similarly, transmission prices established in the day-ahead market apply to flows scheduled in the PX's day-ahead market while hour-ahead transmission prices apply only to flows scheduled in the PX's hour-ahead market. Finally, any difference between scheduled flows and actual flows in the real-time market are settled at the ISO-determined spot energy price. Because the prices established in the scheduling phases of the market are binding in a multisettlement system, these scheduling phases are also referred to as forward markets.<sup>5</sup>

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<sup>3</sup> PX prices are also used to determine electricity consumers' contribution towards the state's competitive transition charge (CTC) In California, the price for electricity is capped at a particular amount (say 9cents per kilowatt hour). Some fixed amount of that price (say five cents) is allocated to distribution costs and the remainder is allocated to the price of power and the CTC charge. If the PX power price is 2 cents in a particular hour then the customer will contribute 2 cents towards the CTC for that hour. If the per-kilowatt PX power price is 4 cents in a particular hour then the customer will contribute nothing towards the CTC in that particular hour.

<sup>4</sup> In a multisettlement system, predispatch phases of the market can be referred to as forward markets.

<sup>5</sup> The discussion above is most applicable to energy and transmission prices charged to PX participants. Other SCs can establish energy prices on a continuous basis; their prices may or may not be binding at the time the transaction is made and they may or may not pass on the ISO's transmission charge to their customers.

Unlike a multi-settlement system, a single settlement system settles all transactions at the spot market price; scheduling phases are used only for scheduling, not price-setting. Cramton and Wilson (1998) argue that a multisettlement system is better than a single settlement system because it ensures that bids submitted in the scheduling phases of the market are serious. Multisettlement systems also reduce risk for participants by providing market participants with some price certainty prior to actual dispatch.<sup>6</sup>

### ***C. The PX's Day-Ahead Market for Energy***

The PX day-ahead market is an auction that begins at 7 am on the day before the energy market is conducted in real-time. In this auction, PX participants bid for the right to buy and sell energy in each hour of the next day's energy market. At this time, bidders need only submit so-called portfolio bids, which report how much power they want to buy and sell but not the specific units that will provide the energy and the specific loads that will be using the energy. Using these portfolio bids, the PX establishes supply and demand curves for energy in each hour. The intersection of the supply and demand curves dictates the market clearing prices for energy in each hour. The PX does not address transmission constraints; the ISO resolves transmission congestion after the PX's energy market closes.<sup>7</sup>

Bidders that win in the energy auction submit their preferred schedules to the PX in place of their initial portfolio bids. These preferred schedules specify hourly injections and withdrawals into and out of the grid by location that sum to the amount of energy that was won through the auction. The PX allows SCs to delay submitting their preferred schedules in order to provide bidders with additional operating flexibility and to determine which resources or loads will be involved if only part of their bids are accepted.

The PX totals its participants' schedules to obtain a balanced schedule, that is, a schedule in which supply is equal to demand in each hour. The PX and the other SCs each submit their own balanced schedules to the ISO for use in the day-ahead transmission market. Along with their balanced schedules, the SCs can submit: (1) schedule adjustment bids, which the ISO uses to manage transmission congestion, (2) supplemental energy bids, which the ISO can draw upon in real-time markets to help maintain system security; and (3) ancillary service bids, which provide resources needed for conducting the real-time energy market.

### ***D. The Day-Ahead Market for Transmission***

In restructured electricity systems like California and PJM, load in an area where transmission constraints limit imports will typically pay more for electricity than load in areas where transmission is not constrained. Similarly, plants situated in the constrained area will tend to receive a higher price for their power than plants situated in the unconstrained areas. In contrast, electricity markets with uniform pricing schemes like the U.K charge the same energy price to users at all locations and recover the cost of relieving transmission constraints through a uniform uplift charge that all loads pay on a proportionate basis. There is a growing consensus that locationally differentiated delivered energy prices work better

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<sup>6</sup> See P. Cramton and R. Wilson, "A Review of ISO New England's Proposed Market Rules," Report to ISO New England, September 1998. Note that the choice of settlement system is logically separable from the decision of how much control to give the ISO over the scheduling phases of the electricity market.

<sup>7</sup> However, other SCs can and do continue to trade energy after the ISO's transmission market opens.

than uniform delivered energy prices because they reduce market participants' incentives to game the system. This section describes how transmission prices are determined in California.

The ISO conducts the day-ahead market for transmission rights at 10 am each day, after the PX's day-ahead energy market closes. First, the ISO determines whether the SCs' combined schedules produce transmission congestion *between* California's predefined congestion zones. A congestion zone is defined as an area within which congestion is expected to occur infrequently. Congestion that occurs at zonal boundaries is referred to as interzonal congestion while congestion within zones, which is expected to be less frequent and/or less costly, is referred to as intrazonal congestion. Currently, California is divided into two internal congestion zones, one covering the northern portion of the state and one covering the southern portion. These zones are separated by transmission Path 15.<sup>8</sup> In addition, there are several external congestion zones, one associated with each major tie point at the California border.

If the SCs' combined schedules do not produce congestion, the ISO accepts the SCs' preferred schedules and interzonal transportation costs are zero. On the other hand, if these combined schedules give rise to congestion, the ISO will price the right to move power across a congested path using schedule adjustment bids submitted by the SCs.<sup>9</sup> Schedule adjustment bids tell the ISO the energy price at which a generator would prefer not to run (or, alternatively, the energy price at which a load would prefer to be curtailed). For example, say that one scheduling coordinator, SC1, submits a schedule adjustment bid of \$10/MWh for one of its generators. This bid tells the ISO that SC1 would prefer not to run its generator if the market price for power is less than \$10/MWh. SC1 would be willing to submit this adjustment bid if its generator's operating cost were \$10/MWh. Then, if the market price for electricity were \$8/MWh, then SC1 would avoid the \$10/MWh cost of running its generator and pay only \$8/MWh to serve its load, a savings of \$2/MWh.

## 1. Using Schedule Adjustment Bids to Price and Allocate Transmission Capacity

To see how these schedule adjustment bids can be used to price transmission, consider a simple radial model of the transmission system. Say that there are three SCs (SC1, SC2, and SC3) and two zones (Zone1 and Zone2) that are connected by an 1100 MW tie line. Each of the three SCs has one relatively low cost 500 MW generator in Zone1, one higher cost 500 MW generator in Zone2, and 500 MW of load in Zone2. In the absence of congestion, each SC would prefer to serve its load in Zone2 with a low cost generator located in Zone 1. To make this example more concrete, assume further that SC1 has a generator that can run for \$10/MWh in Zone1 and a generator that can run for \$15/MWh in Zone2. If SC1 submits a \$10/MWh adjustment bid for its generator in Zone1, and a \$15/MWh adjustment bid for its generator in Zone2, this pair of adjustment bids will enable the ISO to infer that SC1's value for transporting power from Zone1 to Zone2 is \$5/MWh.

SC2 and SC3 will also submit adjustment bids that reflect the operating costs of their generators and the ISO will use each SC's pair of adjustment bids to determine the value that particular SC places on the right to transport power from

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<sup>8</sup> Based on historical congestion patterns four zones were established within California: a Northern zone, a Southern zone, a zone near Humboldt, and a zone near San Francisco. However, stakeholders in California determined it would be unjust at this time for load in Humboldt and San Francisco to pay the costs associated with their local transmission constraints. These two zones have been subsumed within the Northern zone for interzonal congestion purposes.

<sup>9</sup> These adjustment bids are also referred to as increments (incs) and decrements (decs). An inc reflects the payment that an SC would be willing to accept for providing the ISO with one additional MW of a resource, while a dec reflects the payment that an SC would be willing to make to the ISO for the right to reduce an offered resource by one MW.

Zone1 to Zone2. Say that these adjustment bid pairs indicate that SC2 values this right at \$4/MWh and that SC3 values this right at \$3/MWh. The ISO will stack these valuations in merit order and use this ordering to allocate the rights to its 1100 MW tie line between Zone1 and Zone2. Under this rule, SC1 and SC2 will each ship 500 MW of power to Zone2. On the other hand, SC3 will ship only 100 MW of power to Zone2 and serve its remaining 400 MW of load with its Zone2 generator. The market clearing price for transmission capacity is \$3/MWh. This price, which is determined by the valuation of the marginal user, SC3, is paid by all SCs using the transmission line. If the transmission system were a network rather than a simple radial model, optimization software would be needed to value rights to ship power on each path and to allocate these rights optimally.<sup>10</sup>

This example captures an important feature of the California transmission management system—each pair of schedule adjustment bids used to alleviate transmission congestion must come from the same SC. Supporters of this rule argue that it is necessary to realize the longer term benefits of vigorous competition among the SCs energy markets. However, the rule has been criticized on the grounds that it can lead to transmission prices that are greater or lower than the efficient level. This is because the ISO cannot pair the schedule adjustment bids from two different SCs. To remedy this problem, California allows SCs to trade adjustment bids among themselves.<sup>11</sup>

## 2. Interactions Between the ISO and the SCs

After using the adjustment bid pairs offered by each SCs to allocate and price transmission, the ISO provides the SCs with revisions to their preferred schedules, as well as the interzonal transmission charge. The SCs are allowed to respond to the revised schedules and interzonal transmission charges by changing their preferred schedules. The ISO will then use the SCs' revised schedules to determine the final day-ahead schedules and interzonal transmission charges. The purpose of this iterative process is to provide SCs with information on transmission prices so that they can adjust their use of the grid before the final day-ahead schedules are accepted; SCs can use this information to find a better solution by adjusting their own portfolios and by trading with one another. The ISO bills the final interzonal transmission charge to all SCs that have scheduled interzonal power flows in the day-ahead market.

The ISO then resolves congestion within each of California's two internal zones. In resolving this intrazonal congestion, the ISO can use individual (rather than paired) adjustment bids from the SCs. This is because California stakeholders recognized that it would be infeasible to manage intrazonal congestion using only SCs' paired adjustment and that the extent and frequency of intrazonal congestion would be low enough to make such "fine tuning" by the ISO within a zone is acceptable. Unlike the interzonal congestion charge, the net cost of intrazonal congestion is simply rolled into an uplift charge that is allocated to all users within the zone based on their share of load.

### ***E. The Day-Ahead Market for Ancillary Services***

After managing congestion and allocating transmission, the ISO also conducts a day-ahead market for four ancillary services, regulation, spinning reserves, non-spinning reserves, and replacement reserves. The ISO procures regulation

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<sup>10</sup> As will be discussed further below, the ISO's optimization algorithm for pricing and allocating transmission rights has been criticized for being non-transparent.

<sup>11</sup> For a detailed discussion of potential inefficiencies arising from this rule, see L. Kirsch, "ISO Economics: How California Flubbed in on Transmission Pricing" *Public Utilities Fortnightly*, October 15, 1998.

services from generators that are equipped to respond to its automatic generation control (AGC) signals. These signals direct generators to increase or reduce generation on a minute-to-minute basis so that system frequency is maintained within a range dictated by reliability considerations. The three types of reserves differ by the amount of time that the generator has before it must begin supplying power to the grid and whether or not the facility must be consuming resources while waiting in reserve. Spinning reserves must be on-line and synchronized with the system so that they can begin producing power as soon as they are called upon. Non-spinning reserves are offline but must be fully available within ten minutes. Replacement reserve is capacity that can be delivered as energy within one hour.<sup>12</sup>

Suppliers submit bids for these four markets with their day ahead energy schedules, offering both a capacity and an energy bid. Winning bidders are chosen solely on the basis of their capacity bids; the energy bids are used to determine whether the plant will be run in the real-time spot market. The ISO resolves the four ancillary service markets in sequence, procuring regulation first and replacement reserves last. Any bid that is not accepted in the first market is automatically assumed to be a bid in the next market, and so on. Thus, while suppliers must decide upfront how they want to allocate their generation between the energy market and the ancillary services market, they do not need to decide in advance which ancillary service they would like to offer. Currently the ISO verifies that the results of the ancillary services auctions do not impose additional transmission constraints. There may be a further integration of ancillary services auctions and transmission auctions in the future. Ancillary services costs will be allocated pro-rata based on an SC's load and resource mix.<sup>13</sup>

### ***F. The Real-Time Energy Market***

The ISO conducts the energy spot market in real time, balancing supply and demand while maintaining voltage and frequency within tight bands. Its resources consist of participants' supplemental energy bids submitted prior to the operating hour, as well as the generation capacity of winning bidders from the four ancillary service markets. If real-time demand exceeds scheduled supply, the ISO dispatches these resources in merit order and the spot price is the price of the most expensive energy bid called on in the merit order. If real time supply exceeds demand, the ISO uses market participants' adjustment bids to increase demand or reduce supply. In this case, the spot price is determined by the least profitable adjustment bid accepted. The energy spot price is computed every ten minutes. All adjustments ordered by the ISO in real time are settled at the spot price in force when the instruction was given to the generator. Similarly, any market participant that overdelivers (underdelivers) energy, relative to scheduled amounts, is paid (must pay) the spot price for that energy.

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<sup>12</sup> The ISO is also responsible for procuring voltage and reactive power (VAR support) and black start capability, through a longer term contracting process. VAR support is the injection or absorption of reactive power from generators to maintain transmission system voltages within required ranges. Reactive power is energy required to maintain polarity in transmission and distribution lines. Black start capability is needed when outages occur. Generators that provide this service must be able to go from a shut down condition to an operating condition without the assistance of the grid and then energize the grid to help start other units.

<sup>13</sup> The ISO's systems were designed to allocate costs based on forward schedules, but this resulted in an incentive for SCs to underschedule their loads, causing additional operational problems and cost shifting. Allocations will be made based on actual measured load by the first quarter of 1999.

## II. PJM

### A. Day Ahead Scheduling

Like California, PJM has a day-ahead phase for scheduling injections into and withdrawals from the grid.<sup>14</sup> However, the ISO's role in day-ahead scheduling is much greater than it is in California. On a day-ahead basis, PJM participants can either: (1) submit bids to the ISO and be centrally dispatched or (2) opt out of centralized dispatch by submitting bilateral schedules, an option referred to as self-scheduling. If a supplier chooses to bid, it must specify the prices at which it would be willing to operate and the ranges of output over which these prices would apply. If a market participant chooses to self-schedule, it must indicate the amounts of energy it will inject into and withdraw from each location in each hour of the following day. The ISO then develops a day-ahead forecast of total PJM load, while recognizing that a portion of the load will be served by self-scheduled transactions, based on the load forecasts. The total PJM load forecast is based on the load forecasts of all wholesale buyers with access to PJM.

The ISO uses the supply bids to determine the merit order that will minimize the cost of meeting forecasted load that is not to be supplied with self-scheduled resources in each hour of the next day. The ISO determines this merit order using a complex linear program, which ensures that the final dispatch is consistent with all self-scheduled transactions, as well as transmission and reliability constraints. This program also generates nodal spot prices, which reflect the cost of injecting an additional MW of power at each node on the grid. These prices, which are referred to as locational marginal prices (LMPs), effectively incorporate both the "pure" cost of energy and the cost of delivering that energy to each node.<sup>15</sup> Like the transmission pricing scheme in California system, PJM's LMPs are designed to ensure that market participants in different locations face the costs (or benefits) that their supply and demand decisions impose on (or provide to) the grid.

Currently, PJM is using a single settlement system, which means that the day-ahead phase is used only to schedule suppliers and bilateral transactions for the next day's dispatch. Under this system, the day-ahead LMPs are suppressed and all settlements are based on real time energy (spot market) prices. The only financial commitment arising from PJM's day-ahead scheduling process is the ISO's obligation to pay each pool-scheduled generator its bid costs for the day to the extent that these costs are not recovered in the hourly energy prices.

However, when PJM moves to a multisettlement system in 2000, the day-ahead schedules and the prices associated with them will be binding, just as they are in California. This move to a multisettlement system will have the added benefit of increasing the scope for demand-side bidding in PJM. Although PJM has always allowed demand-side bidding, it is currently impracticable because pre-dispatch phases of the market are used only for scheduling. As a result, demanders cannot specify in advance the price points at which they would be willing to be curtailed. Instead, loads can only request to be curtailed in real time and real-time curtailment is currently technically infeasible for the majority of loads

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<sup>14</sup> PJM also permits adjustments to schedules up to one half-hour ahead of actual dispatch.

<sup>15</sup> LMPs are equal to the value of the Lagrange multipliers on the energy balance constraint in the least cost dispatch problem.

## ***B. The Real-Time Energy Market***

In the real-time spot market, the ISO continuously optimizes its economic dispatch to meet demand while respecting reliability constraints. It also runs a program every five minutes to compute an LMP for each node on the grid. All generators that inject power into the same location receive the same LMP (i.e., the locational price where power is injected into the system) per MWh provided. Similarly, all grid users at the same location pay the same LMP (i.e. the locational price where power is withdrawn from the system) per MWh consumed. The difference between LMPs at any two nodes on the system is the charge for transporting electricity from one node to the other. Because LMPs are typically lower at points of injection than they are at points of withdrawal, the cost of transporting electricity to a particular withdrawal point is typically positive.

A PJM participant that submits a balanced schedule of injections and withdrawals to the ISO would be similar to an SC in the California system. To the extent that such an entity adheres to its balanced schedule in real time, it would pay only the cost of transportation between its injection and withdrawal points (i.e., the difference between the LMPs at points of injection and the LMPs at points of withdrawal.) However, any imbalances between the entity's scheduled supplies and loads would face the same LMPs that would apply to centrally dispatched transactions.<sup>16</sup> Hence, self-scheduled generators that inject excess energy into the grid would be paid the LMP at the injection point while self-scheduled load withdrawing "excess" energy from the grid would pay the LMP at the point where energy is withdrawn.

The PJM ISO procures essentially the same ancillary services as the California ISO. However, it procures these services on an administrative basis, allocating costs in proportion to use of grid. All purchasers in PJM pay a charge covering the cost of these ancillary services, as well as control area operations, and marginal line losses. Line losses will eventually be incorporated into the LMP.

## **III. Trade-offs Associated with Limitations on the ISO's Role**

It is easiest to understand the effects of limiting the ISO's role in the scheduling process by first considering the polar case of a "pure" pool. In such a pool, market participants are not permitted to submit bilateral schedules. Instead, the ISO accepts bids and cost information from generators on a day-ahead basis. These data are used as inputs into a complex optimal dispatch program, which produces day-ahead schedules and prices. We will assume that the pool uses a locational pricing scheme. We will also assume that this pool uses a multi-settlement system so that day-ahead locational prices apply to flows scheduled in the day-ahead market. In real time, the ISO reruns its optimization program to dispatch plants at least cost and to generate real-time location-based prices. The latter prices are used to price power flows that deviate from those scheduled in the day-ahead market. Below, we discuss both the criticisms of this approach and its potential advantages.

### ***A. Criticisms of the Pure Pooling Approach***

One of the main criticisms of the pure pool described above is that it provides no role for competing forward energy markets. These competing markets are likely to be desirable for at least two reasons. First, forward energy markets can

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<sup>16</sup> Of course, PJM participants that elect to self-schedule are not required to submit balanced schedules to the ISO, as they must in California. Generators can simply schedule to run without having to arrange for offsetting load.

be organized in many ways and competition among these alternatives can help settle the question of which market structures work best. Second, parallel forward markets can exert competitive discipline on the ISO (or the PX in California), strengthening the “official” market’s incentives to respond to customer needs, innovate, and control costs.

Both California and PJM allow for competition in the forward energy market although the form of competition differs in each case.<sup>17</sup> As discussed above, the California ISO’s role in the forward energy market is minimal. Instead, California has thirty plus SCs (including the PX) that conduct energy markets; their energy prices are expected to equilibrate because the SCs can trade with one another to erase persistent price differentials. All of the SCs have equal access to the transmission and ancillary services markets, which are currently run by the ISO.

In contrast, PJM market participants can choose to be scheduled by the ISO or they can submit their own dispatch schedules. The ISO then takes submitted schedules as given when it runs its optimization program to schedule the remaining generators. All flows scheduled in the day-ahead market are priced at the LMPs generated in the PJM ISO’s day-ahead optimization.<sup>18</sup> The PJM ISO is a competitor in the forward market and is subject to competitive discipline from bilateral trades. However, it is also a monopolist in the grid management function and the compatibility of its two roles has been the subject of extensive debate. In California, for example, the ISO was separated from the PX at least partly to prevent the ISO from using its enormous powers to bias the market in favor of its energy trading operation. Of course, the California system may sacrifice some of the efficiencies that can be realized by greater integration of the transmission and energy markets. These potential efficiencies are discussed further in Section B, below.

A second criticism of the pure pooling approach is based on informational concerns. It has been argued that bidders cannot capture the factors that they consider relevant to their scheduling decisions in the price/quantity bids and cost data that they must submit to the ISO for use in its scheduling program.<sup>19</sup> According to this argument, the factors that affect these decisions are numerous, complex, and constantly changing. Hence, allowing market participants to make their own scheduling decisions may lead to better outcomes than those produced by an optimal scheduling program.

A third, closely related problem is that market participants may treat the pool’s centralized optimization program as a device whose outputs can be manipulated by the inputs they provide in the form of purported cost functions, availabilities etc. For example, Wolak and Patrick (1996) argue that power companies have manipulated U.K. electricity prices by declaring outages among their relatively low cost units during periods of tight supply. This strategy increases the price paid for the duopolists’ inframarginal generation. It also inflates the capacity payments the duopolists receive, since these payments are inversely related to available capacity. This result is supported by Wolfram (1997), who finds that when the two largest British generation companies, Power Gen and National Power, expect to serve a large proportion of load, they

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<sup>17</sup> For the purposes of this discussion, we will assume that PJM has switched to a multi-settlement system

<sup>18</sup> As discussed above, an entity that submits a balanced schedule of injections and withdrawals to the ISO would be similar to an SC in the California system. However, the ISO does not track the extent to which entities participate in PJM in an SC-like fashion.

<sup>19</sup> For a discussion of this problem from the point of view of utilities evaluating bids for independent generation facilities, see L. Cameron “Limiting Buyer Discretion: Effects of Performance and Price in Long-Term Power Contracts,” forthcoming in the *American Economic Review*.

increase their bids. Although the potential for gaming exists in many markets, the fact that the pure pool approach mandates participation in a single, fallible market is likely to make matters worse.<sup>20</sup>

### ***B. Potential Advantages of a Pure Pool***

It has been argued that a pure pool may be able to realize greater productive efficiency and lower transactions costs than a sequence of decentralized markets for these services. This is because the ISO in a pure pool uses a complex linear program that simultaneously allocates and prices energy, transmission, and ancillary services. In contrast, more decentralized market designs, like California's, separate energy trading from the much more complex function of transmission management and clear these two markets in sequence. PJM has features of both a California-type system and a pure pool; the PJM ISO competes with bilateral schedules in the day-ahead market but its program for scheduling and pricing energy flows takes all aspects of the system into account simultaneously. Of course, PJM's optimization would be subject to more constraints than the optimization routine used to schedule and price in a pure pool. This is because the PJM ISO must take bilateral schedules as given when conducting its optimization.

Although this argument has been widely used, the question of whether a pure pool can in fact achieve maximum productive efficiency depends on a number of factors. First, pool participants must be able to express their scheduling considerations through their bids and they must not be able to game the system by manipulating their bids. Second, a sequential market structure has the potential to be as efficient as a simultaneous market, if participants in each market can form accurate expectations about the prices that will prevail in subsequent markets. According to Wilson (1998), daily repetition of power markets and market features designed to allow arbitrage across markets will aid in the formation of accurate expectations so crucial to a sequential market design.<sup>21</sup> Our review of the California market touched on several features designed to increase opportunities for arbitrage. These features include: (1) providing SCs with an opportunity to adjust their day-ahead schedules in response to the transmission prices computed by the ISO, and (2) repeating the day-ahead market on an hour-ahead basis so that traders have an opportunity to exploit price disparities.

In PJM, energy, transmission and ancillary services markets are integrated, just as they are in a pure pool. However, as pointed out above, PJM provides participants with the option of submitting their own schedules, which are taken as given when the ISO performs its day-ahead optimization. Because the ISO cannot optimize over these schedules, the system's potential to maximize productive efficiency may not be as great as that in a pure pool. However, this potential reduction in productive efficiency may be more than offset by the competitive discipline that bilateral transactions can exert on the ISO.<sup>22</sup>

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<sup>20</sup> See F. Wolak and R. Patrick, "The Impact of Market Rules and Market Structure on the Price Determination Process in the England and Wales Electricity Market," Working Paper, Stanford University, 1996 and C. Wolfram, "Strategic Bidding in a Multi-Unit Auction: An Empirical Analysis of Bids to Supply Electricity in England and Wales," Working Paper, Harvard University (1996).

<sup>21</sup> See R. Wilson, "Efficiency Considerations in Designing Electricity Markets," Report to the Competition Bureau of Industry Canada, March 31, 1998.

<sup>22</sup> An additional difference between PJM and California is the type of locational pricing employed; California uses a simplified zonal system while PJM uses a nodal system, which has the potential to produce a different energy price at each injection point on the system. The debate on nodal versus zonal pricing is beyond the scope of this paper and has been explored in depth elsewhere; see for example, S. Stoft, "Transmission Pricing Zones: Simple or Complex?" *The Electricity Journal* January/February 1997 and the references cited therein.

## IV. Conclusions

Recent experience has shown that both the PJM and California approaches towards organizing the electricity market can work.<sup>23</sup> PJM's LMP system became operational in April 1998. Its LMPs seem to be working as intended and energy prices are within reasonable range. The most important changes on the horizon include a switch from a single settlement system to a multi-settlement system and the introduction of market based procurement for some ancillary services.

In California, there is a great deal of competition among SCs, with some conducting mostly wholesale trades, several serving direct end-use customers, and a few offering exchanges to buy and sell energy. There is also some consensus that the PX has been working well, despite its separation from the ISO. Since the PX began operation on April 1, 1998, its energy prices have remained within a reasonable range, hitting \$250/MWh price caps during high demand summer months and other peak periods on an ongoing basis. There has been some concern about market power at the peaks and the need for more demand-side bidding. However, some stakeholders argue that prices need to go above the current caps to entice demand-side infrastructure improvements such as metering and automated controls that would allow for more significant demand side bidding.

The main area of concern in California has been the ancillary services market. Here the consensus seems to be that the ISO is ensuring reliability but that ancillary services markets are not workably competitive. When cost-based caps on bids in the ancillary service markets were removed in July 1998, prices for ancillary services capacity became very volatile, rising up to \$9999/MW. As a result, the ISO reimposed price caps of \$250/MW and \$250/MWh in July 1998. Wolak, Nordhaus and Shapiro (1998) have identified a number of problems in California's ancillary service markets, including the fact that ISO demand for ancillary services does not depend on ancillary service prices and that the ISO has limited ability to substitute among ancillary services and energy, a limitation that providers of ancillary services can and do exploit.

Several important changes are planned for the California market in 1999. First, SCs will be allowed to self-provide ancillary services rather than obtaining these services solely from the ISO. It is hoped that this modification will mitigate any demand-side problems arising from the ISO's inflexible procurement procedures. In addition, the California market may soon be auctioning fixed transmission rights (FTRs). These FTRs will provide their owners with the right to transport a given amount of power between zones for a fixed amount of time, such as a year. With the advent of FTRs, market participants will no longer need to purchase transmission rights in the ISO's day-ahead and hour-ahead transmission markets. Instead, they will be able to purchase FTRs and then trade these rights among themselves as required. These two modifications in the California system represent further steps towards decentralization and their effects on the market outcomes will be monitored with great interest.

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<sup>23</sup> Bill Hogan has written several articles reviewing market experience in PJM in this *Journal*. For useful discussions of market performance in California, see F. Wolak, R. Nordhaus, and C. Shapiro, "Preliminary Report on the Operation of the Ancillary Services Markets of the California Independent System Operator," August 19, 1998; R. Bohn, A. Klevorick, C. Stalon, "Report on Market Issues in the California Power Exchange Energy Markets," August 17, 1998; and P. Joskow, "Comments on the Report on Market Issues in the California Power Exchange (PX) and the Preliminary Report on Market Operations of the Ancillary Services Markets of the California Independent System Operator (ISO)," September 1, 1998.