Reprinted from
PUBLIC UTILITIES FORTNIGHTLY
Vienna, VA

Electric Competition, One Year Later:

Winners and Losers In California

The state foots the bill, while northern neighbors profit from a managed power market.

By Robert McCullough

CALIFORNIA'S ELECTRIC RESTRUCTURING PLAN, launched on April 1, 1998, marks one of the most ambitious attempts in U.S. history to place the state in a social engineering role. Not only was the scale of the project daunting, with implementation cost estimates running as high as $1.2 billion, but the plan places California government in control of the most minute components of the electric system.

How has the experiment gone? Most participants on the retail side agree that restructuring California-style has had little impact as yet on final consumers. The complex mechanics and high entry fees simply have made large-scale customer participation impossible. Even the largest industrial customers have seen few benefits.[1]

Instead, the most far-reaching impacts have occurred at the wholesale end of the market. This finding is surprising, moreover, because the mechanism described in the program's enabling legislation, Assembly Bill 1890, was not designed to intervene in wholesale markets.

Granted, this analysis is preliminary at best; we can call on only eight months of experience with the new institutions, including only about five or six months of hard information, since data from the U.S. Energy Information Administration is usually lagged three months or more.

Nevertheless, the preliminary indications appear quite clear. California's intervention in wholesale markets, with its complex administered Power Exchange (PX) and

The most far-reaching impacts have occurred at the wholesale end, where California has lost in three ways.

The PX apparently has eliminated the oligopsonistic [few buyers] advantage for California IOUs.

Independent System Operator (ISO), has raised both prices and volatility across the West Coast. This experience suggests a series of questions for the state, the region and the nation as a whole:

- **California.** Are total costs in California going up or down since the implementation of AB 1890?
- **WSCC.** In the larger regional sphere, encompassing the Western Systems Coordinating Council, are markets more efficient economically? Have changes brought prices closer to pure economic levels unaffected by market imperfections and monopoly power? Have the economic benefits of better (more efficient) prices been offset by higher market volatility?
- **Society.** Finally, is the nation better off for these innovations?

My sense of the preliminary data is that the West Coast is a better, more economically efficient market since implementation of AB 1890. The cost of increased volatility has not offset the economic advantages of more competitive markets. One major reason that the balance remains positive is that implementation costs have been borne largely by Californians.

California proper, however, is another situation entirely. The state has lost in three ways since AB 1890. Overall terms of trade have moved against California, imposing much higher prices for imports but leaving export prices largely unchanged. Second, the additional volatility is a cost that Californians face without the advantage of lower wholesale prices. Third, as mentioned, California has sole responsibility for implementation costs.

Fundamentals: West Coast Trading

Market players on the West Coast long have recognized a seasonal framework to transactions along the Pacific Ocean. Loads in California and the desert southwest are highest in the summer, reflecting cooling loads. Loads north of California are highest in the winter where electric resistance heating is common. In addition, supply is dominated by the runoff from the Columbia River, where melting snow fuels a huge expansion in hydroelectric generation in the late spring and early summer.

We have almost 20 years of data on wholesale prices in the WSCC. Although price reporting has improved immeasurably since 1995, this large market operated on an open competitive basis throughout the 1980s, and monthly data for specific utilities is available.

The major players in the West Coast markets have been the three large California utilities—San Diego Gas & Electric Co., Southern California Edison and Pacific Gas & Electric—and the Bonneville Power Administration to the north. Other key players are Portland General Electric and Pacific Power & Light, partial owners of the intertie south to California, and the Public Generating Pool, the owners of much of the hydroelectric generation along the Columbia River.

The price of electricity at the California-Oregon-Border (COB) node is a continuing issue among market participants on both sides of the intertie. For most of the 1980s, the major investor-owned utilities (IOUs) in California asked the Federal Energy Regulatory Commission to cap prices on imports to California, arguing that it was "dump hydro" and was selling far above its 2.5-mill cost ($2.50/megawatt-hour). Pacific Northwest actors accused Californians of monopolizing the purchase of electricity on the southern end of the intertie.

Not only did the FERC frown on the price-cap arguments, but other, smaller California utilities launched a long, controversial attempt, known as the "E Quad 7" case, to access Northwest supplies through the FERC. Ultimately, they built their own transmission line north to participate in the market. Bonneville faced years of similar pressure to allow its customers access to the southern marketplace, culminating in several litigious "Intertie Access Policies" in the later 1980s.

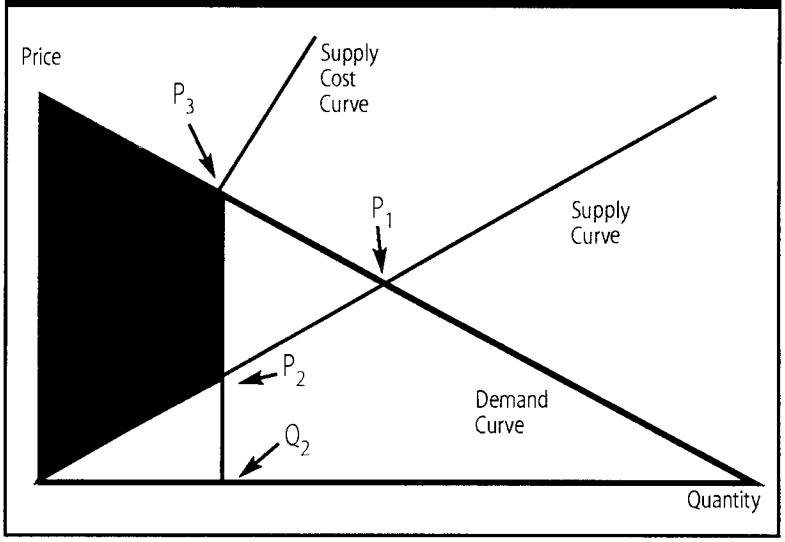
The basic problem is that the concentration of market

power in the South gave the big California utilities the upper hand in the spring and summer, when flows south dominate the market; many Pacific Northwest sellers would meet few California buyers. The resulting situation was like the reverse of buying a car in a small town with only one dealership: The Small-town buyers usually pay list price.

In power markets, with many sellers to the North and few buyers to the South, "oligopsony" would be the best label. Oligopsonistic markets are those in which the buyers have market power and can control prices and quantities by adjusting their offers. Traditional economic theory describes this market structure with the diagram in figure 1.

Figure 1: Oligopsonistic Market Power

Few buyers but many sellers.



Buyers with substantial market power will avoid paying the price indicated by the intersection of the supply and demand curves (P_1). Instead, the oligopsonistic buyer will deduce the relationship between increased purchases and the increased prices, and by reducing purchases (Q_2), can force down prices (P_2). In this way, the division of value between the consumer and the buyer can be adjusted to favor the buyer—even though the total value available to society diminishes.

Consumer value is the area bounded by the oligopsonistic price below, the quantity purchased and the demand curve above. This calculation reflects that the first unit of electricity purchased is worth a great deal. The net benefit to the buyer is the difference between the point of the demand curve (P_3) and the price paid (P_2). The immediately preceding kilowatt-hour is worth a little more. The polygon shows the economic value of the area below the demand curve and the price paid to the supplier.

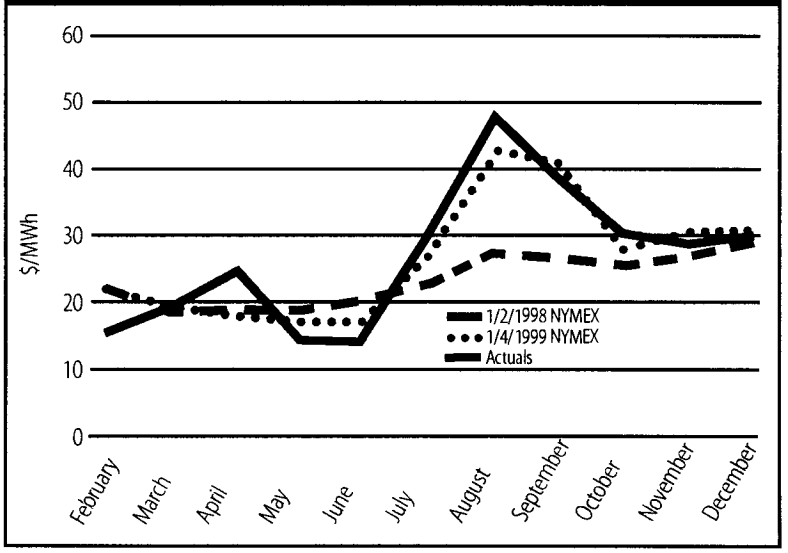
Pacific Northwest utilities noticed that California's purchases fell below their estimates based on a careful analysis of California's needs. Prices in the market also tended to be less than the avoided costs reported to the FERC by the Californians.

Early Results: 1998 Prices

Pacific Northwest expectations for California prices under AB 1890 were mixed. Some, including the author, felt that the market concentration under AB 1890 would not change and the results would mirror experience. Others, including forecasters at Bonneville Power, predicted that the power exchange would eliminate California's market power and raise prices to competitive levels.

The 1998 results support the opinion that the power exchange has eliminated California's oligopsonistic advantage.

Figure 2: On-Peak Prices at COB Higher NYMEX in January 1999 shows California buyers losing clout.



California consumers are completely insulated from PX volatility. Not so for out-of-state players—one reason why competition for retail loads in California is grinding to a halt.

At the beginning of 1998, the New York Mercantile Exchange futures at the COB reflected traditional wisdom concerning the California market. In figure 2, the lower blue line reflects the best information we had concerning summer prices in the California market. The price is substantially below our true estimates of California marginal cost during the period, reflecting traders' beliefs that California would retain its dominant market position. The yellow line shows actual on-peak prices during 1998.[2]

The red line shows the NYMEX for the same trading day in 1999. NYMEX now believes that last year's prices are a good forecast for the future. This chart indicates that NYMEX, like many of the rest of us, was surprised by the prices in the summer months when California's loads increased dramatically. Prices during the rest of the year have not changed markedly. This result makes sense, as California's power requirements tend to drive the market in the summer. We would expect different fundamentals for the winter months, when Pacific Northwestern loads peak, and the spring, when the market is dominated by hydroelectric generation.

The timing for NYMEX is very important. Pacific Northwest prices are largely determined by flows on the Columbia River. Information on the river becomes available in January and improves as time passes.[3]

The price information is not sufficient in itself to signal a change in the terms of trade between California and the rest of the region. Although the "terrible twins" of administered pricing in California have put a brave face on their failings, the PX and ISO prices often cannot be explained by traditional market forces.

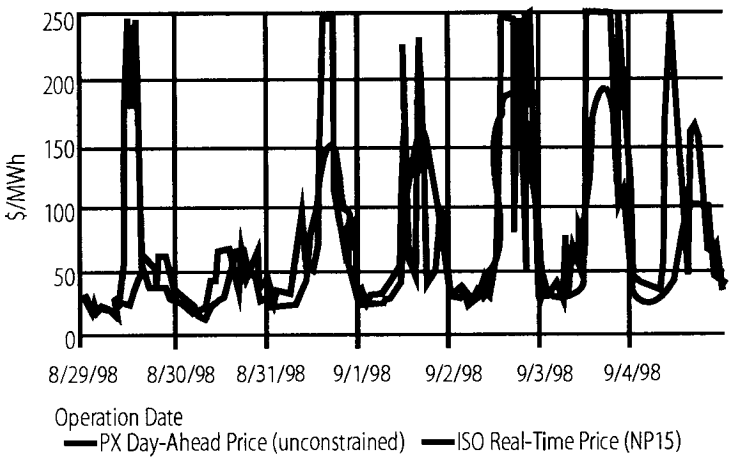
In September, for example, the ISO experienced a series of crisis purchases even though overall supplies were sufficient and no extraordinary events took place. Figure 3 describes the system in the first week of September.

The ISO real-time price often reached the ISO price cap of 250 mills per kilowatt-hour ($250/MWh). In effect, the ISO set spot prices to 250 mills for much of the first week of September.

That week represented a problem at the PX and the ISO. Explanations differ, but the result was that the ISO launched into emergency purchases for a substantial portion of the week. Clearly, a problem exists in the

Figure 3: Energy Prices: PX Day-Ahead vs. ISO Hourly Ex-Post Imbalance

ISO emergency purchases set market cap.

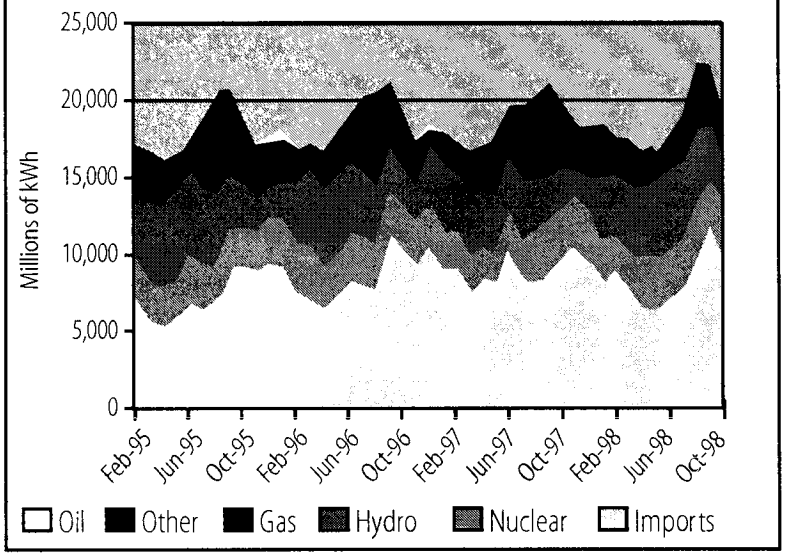


scheme that administers market prices in California, and the price spikes did not reflect a fundamental change in market economics.[4]

If the predictions of classical economics are correct, we also should have seen a change in quantities. An oligopsony reduces the quantity purchased in order to keep the price paid low. When market power is eliminated, both price and quantity return to competitive levels. Recent data from the Energy Information Administration supports this view. The EIA publishes *Electric Power Monthly*, which contains monthly generation and consumption data by state. The data for California for the last three years shows that California imported more last summer than it did in previous years, even though flows on the Columbia River were significantly less than average (*see figure 4*).

Figure 4: Supply Sources In California

Imports up, despite less hydro in Pacific Northwest.



The last comparable year to 1998 was 1995, when river flows on the Columbia were 98 percent of average. Imports into California were approximately 10 percent higher in 1998.

Implications: Market Power and Volatility

The economic changes since April 1 show ramifications from one end of the region to the other. Since major industrial rates largely are indexed to spot markets outside of California, the change in pricing has raised prices to major industries throughout the West. Puget Sound Energy's price indices are now under review at the Washington Utilities and Transportation Commission, in part

Administered vs. Market Prices

What do the PX and ISO do?

Some confusion exists as to whether California's Power Exchange and Independent System Operator report market prices or actually set market clearing prices. Are they serving as reporters or acting as price regulators?

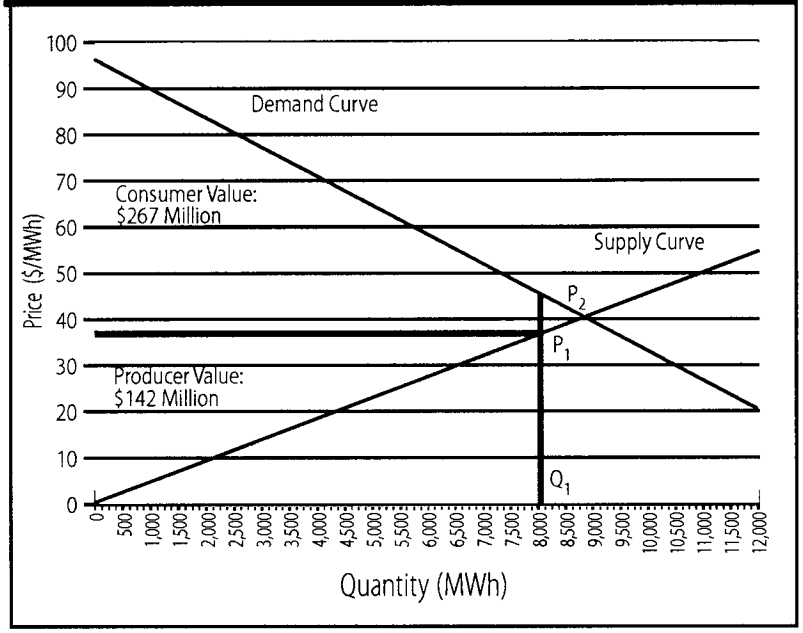
The California experiment *administers* prices according to the theories prevailing at the ISO and the PX. The September price excursions amply demonstrate this fact. Changes in ISO and PX rules—not the market themselves—continually change ISO and PX prices.

Most markets avoid administered prices. The major world commodity markets like the London Metal Exchange and the Chicago Board of Trade provide little theoretical framework around the price-setting process. In Chicago, for example, brokers actually shout back and forth in pits to buy and sell commodities.

As a general rule, administered prices are easier to manipulate and tend to show greater volatility. As one market participant recently put it, "Traders are smarter than bureaucrats."

The ISO and the PX are the most expensive administered markets in history, so we will see in the near future whether "traders are smarter than many, many, many bureaucrats."

Figure 5: Oligopsonistic Market Power in California Value is shifting to producers.



because of the surprisingly high spot prices of last summer.

Since most of the price changes occurred in the warm months when California loads increase dramatically, the following analysis is limited to July, August and September. We would expect to see the effect of the PX in other months as well, but we simply do not have sufficient information yet.

It is possible to provide a simple analysis of the costs and benefits of the terms of trade shift by using the information reviewed above and applying it to the oligopsonistic model. If the shift in market structure increased imports by 10 percent and prices by 4 mills[5], the consumer (California) and producer (Pacific Northwest) surplus is a simple arithmetic calculation.

In figure 5 it is assumed that supply and demand are straight lines. The oligopsonistic customer value is the polygon whose floor is the oligopsonistic price (P_1) with a right wall along the oligopsonistic quantity purchased (Q_1) and then the diagonal formed by the demand curve. The supplier value is the triangle formed by the oligopsonistic price and the supply curve.

Shifting to a competitive price (P_2) changes the size of the two areas. With straight-line supply and demand curves, the consumer's value is the area of the triangle formed by the competitive price bounded by the demand curve above. The supplier value is the triangle formed by the competitive price and the supply curve below.

After oligopsonistic power is lost, the distribution of surplus shifts toward producers:

	Before	After
California	$267 million	$238 million
Northwest	$142 million	$176 million
Total	**$410 million**	**$415 million**

This simple analysis indicates that the implementation of the PX and ISO has transferred approximately $100 million per year ($34 million during three summer months) from California to its suppliers.

Society as a whole has benefitted by $5 million during the three summer months—a relatively small $15 million dollars a year.

This analysis tends to understate the scale of the shift in market structure. The real world abhors straight lines. Only lecturers in economics ever see supply and demand curves this simple and easily estimated. Second, these calculations reflect a variety of dynamic factors not captured easily in a simple monthly diagram.

The estimation of the true oligopsonistic effect requires a far more detailed analysis. We have undertaken such an analysis using the limited data available, and our results indicate that the shift is on the order of twice the estimates given above. The detailed analysis is a hostage to detailed statistical data. Such data only now is becoming available, and it will be at least another six months before a full year of information exists.

A clear secondary impact of the PX/ISO system has been increased volatility of West Coast spot prices. Volatility from May 22, 1995 though March 31, 1998 was 39 percent. Volatility since that date has been 44 percent.

Valuation of volatility is always very subjective. Few ultimate consumers view electric price risk as a primary busi-

ness issue, mainly because this risk is highly independent of their other business risks. Instead they diversify their electric price risk over a portfolio of raw materials purchases. Traders cannot afford to be so confident, however. A highly profitable business is the packaging of spot supplies into long-term offers. A change in volatility does have an immediate impact on the prices that traders can offer.

Industrials in the Pacific Northwest have seen an increase in long-term offers as traders increase their required margins to offset the increased price volatility. This is a market phenomena since different traders have different appetites for risk. Traders communicate their risk perceptions in the markets by making bids and seeing whether their bids are successful.

Our most recent purchases for large industrial clients have seen a small increase in one-year prices that can be ascribed to the effect of risk itself. Our estimate of the impact is only one half of a mill across an industrial market of some 6,000 megawatts—a nominal $26 million per year. It isn't clear how much of the volatility is borne by California. Since rates for California end-users are a combination of the PX price and stranded costs that offset directly the volatility in the PX figure, end-users are insulated completely from PX volatility. Out-of-state suppliers to California end-users are not, of course, and this is one of several reasons why competition for retail loads in California is gradually grinding to a halt.

Who's Winning After All?

The answer—preliminary as it may be—is that California's out-of-state suppliers may be ahead. They are receiving better prices since they can participate in the PX and ISO on equal terms with California players. A conservative estimate is that California has transferred approximately $100 million in additional revenues to out-of-state suppliers. Our best detailed guess is that the losses are at least twice that. Savings of this magnitude are more than sufficient to reimburse outside suppliers for purchasing firm supplies in a more risky market.

California does not fare so well. Changing the terms of trade costs California $100 million to $200 million per year—and Californians have to bear the costs of additional volatility to some degree.

Overall, the experiment may cost society more in additional volatility than it gained in the more efficient market for power between California and its out-of-state suppliers, but it is far too early to reach such a pessimistic conclusion.

In the meantime, the AB 1890 experiment proves the old adage: "Beware getting what you wish for." California's experience has not brought the state much more than a concession in the long debate with its neighbors over the price of imported energy. F

Our best guess is that PX/ISO trading costs California $100 to 200 million a year.

Robert McCullough is the managing partner of McCullough Research, a firm specializing in bulk power and restructuring policy issues in the United States and Canada. He also is an adjunct professor of economics at Portland State University.

1 My firm's experience on the retail side of the California experiment strongly supports this view. Buyers, even the largest and most attractive, receive fewer and fewer offers when they approach the market. One of our clients, one of the largest California industrials, recently was approached by its supplier with an offer to pay off the discount if they would release the supplier from the California market. See also, "California's Electricity Market: Are Customers Necessary?" by Robert McCullough, *Public Utilities Fortnightly*, July 15, 1998, p. 36.

2 *Energy Market Report's* On-Peak Index at COB, average highs and lows by day.

3 The early forecasts are released during the first week of January; in 1998 they were 20 percent below average. The comparable forecast for 1999 is 10 percent above average flows.

4 One ISO representative caused a hearty round of laughter at a recent energy symposium by noting that the ISO specifically chose to avoid a general blackout during September. Famous economist Thorsten Veblen once remarked wryly that "theories are constraining on the underlying facts." Turning out the lights to validate the ISO's computer programs would have made the ISO's programs very expensive, indeed.

5 Our firm's preliminary statistical results indicate that California's experiment has raised spot prices by 9.26 mills on-peak and 4.82 mills off-peak. This estimate takes into consideration the real world where the demand and supply for electricity are not straight lines. Precise estimates of the terms of trade losses require actual dispatch curves for both regions and reflect a variety of additional issues: hydro-electric availability, fuel cost expectations and operational limitations.