Price Spike Tsunami: How Market Power

Last year saw no shift in fundamentals. Then why was the ISO so willing to be deceived?

By Robert McCullough

LAST SUMMER, ON MAY 22, THE POWER market across the Western United States and Canada saw a one-time shift in market economics roughly equivalent to the removal of 8,000 megawatts of generation that cannot easily be explained by changes in the fundamentals of electricity markets. Hydroelectric streamflow was about average on the West Coast. Loads were somewhat higher, but California peaks actually registered lower than those in 1998 and 1999. Why this shift in wholesale prices by a factor of five?

Investigations are underway at the federal and state levels, but one thing already is clear: A large amount of the blame can be laid at the feet of the California Independent System Operator. The ISO's complex and secretive operations have provided a petri dish for collusive behavior.

This shift had an enormous impact on prices throughout the region. Statistical estimates through July 31 indicate that higher prices cost consumers at least 9.48 cents per kilowatt-hour during on-peak periods, and 3.3 cents per kilowatt-hour at off-peak times. Given these extraordinary events, many are asking a simple but confounding question: *Did this aberration in electricity prices arise from any fundamental shift in market conditions?*

After May 22, a number of explanations were put forward to explain why prices had increased so markedly. Favorite explanations argued that the price spike was due to shifts in natural gas prices, the runoff on the Columbia River, and increases in loads.

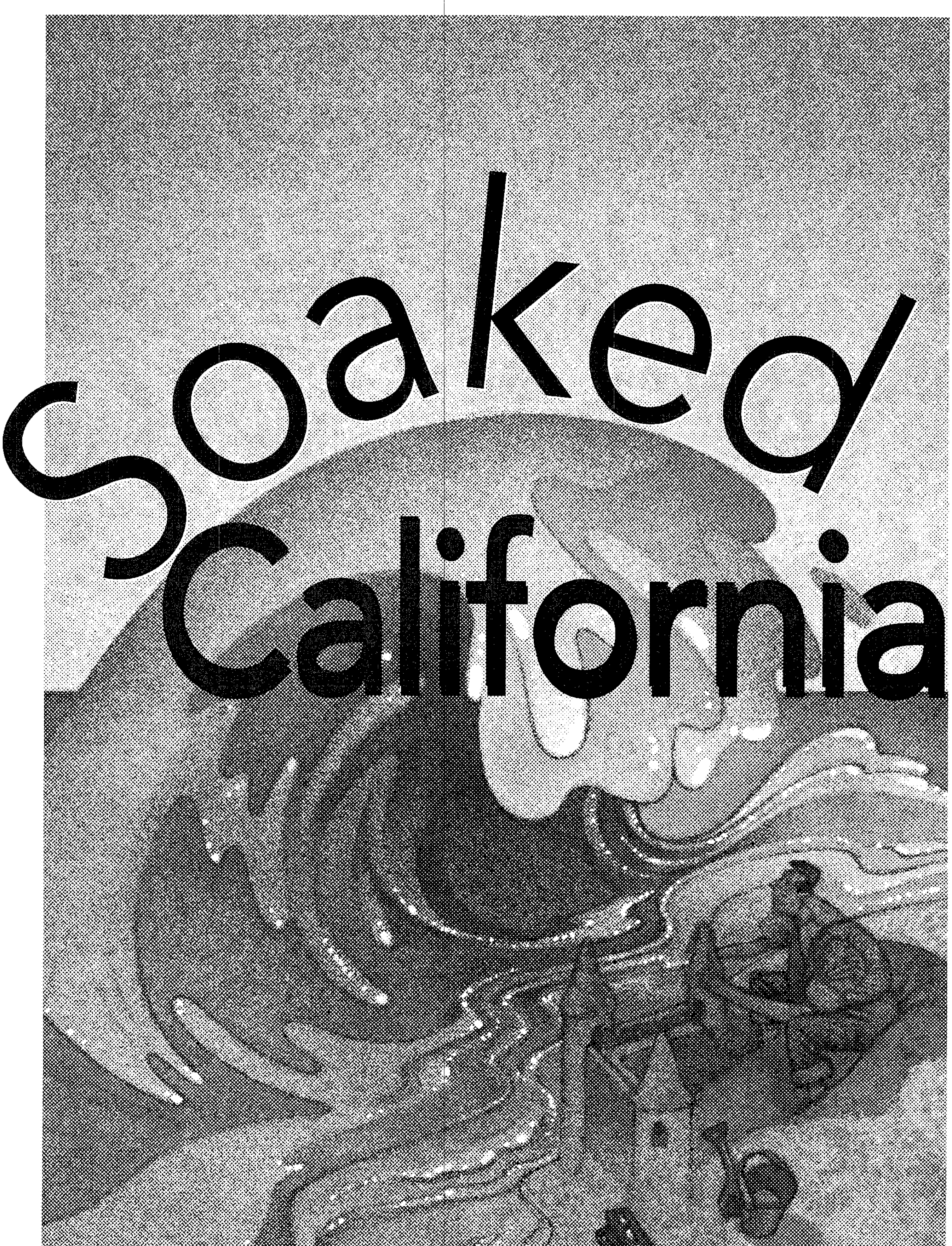
Yet almost all explanations for the price spike based on supply and demand concerns turn out to be exaggerated. Hydro conditions were average in 2000, peak loads (only ISO peak loads are currently available) were lower in 2000 than in 1999 and 1998. Gas prices were higher—considerably so—but that would explain only a portion of the price changes. Overall capacity margins appeared sufficient to meet loads across the region.

In fact, one can readily see how ordinary the summer was—in terms of load, fuel prices, and hydro generation—by a casual look at the *de facto* competitive bulk power market that has been operating in the Pacific Northwest for the last 20-odd years.

All in All, An Ordinary Year

Twenty years of competitive markets?

Yes, in a very real sense, organized competitive bulk power markets got their start on the West Coast some 20 years ago, in 1980,


Soaked
California

with the passage of the Pacific Northwest Regional Power Act. That date marks a watershed in Western power markets—when the Bonneville Power Administration turned away from its historical practice of simply allocating its hydroelectric surplus, and began an active marketing program to implement the new law.

Just as we see today, California and the Pacific Northwest soon began fighting over the appropriate price for this marketed hydro surplus. This conflict was resolved only when the Federal Energy Regulatory Commission approved the Western States Power Pool as an experiment in 1987, and later granted its final OK in 1991. These actions effectively recognized the status quo as it had existed since 1980—an unregulated bulk power market where prices largely were governed by the cost of the highest-cost, currently operating thermal unit. And this bulk power market has remained stable ever since, throughout droughts, earthquakes, and wide variations in the balance between resource and load. *(See Figure 1, Pacific Northwest—A 20-Year Snapshot.)*

Consider the following table. It shows prices at the Mid-Columbia hub since 1980. The following table shows average Columbia River inflows, natural gas prices, and Mid-C hub prices:

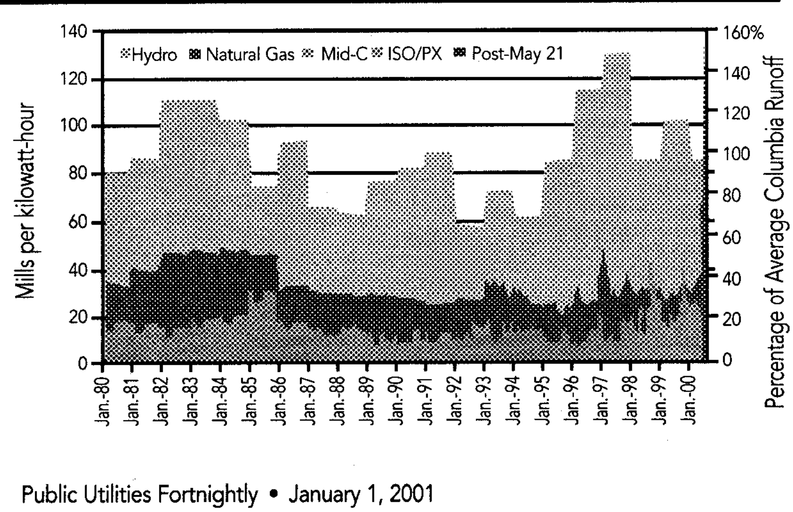
Table 1: Market Fundamentals—Pacific Northwest

20 years of stability ends in May 2000.

	Mid-C Hub Price (Cents per Kilowatt-hour)	Columbia River Inflows (Percentage Of Historical Average)	Natural Gas Price (Dollars Per mmbtu)
Jan 1980 to March 1998	1.525	99%	$3.38
April 1998 to April 2000	2.478	107%	$3.04
May 2000 to August 2000	11.630	98%	$4.55

Figure 1: Pacific Northwest—A 20-Year Snapshot

Energy prices and hydro conditions since 1980.



The significance of this table is that summer peaks in 2000 were not surprisingly high. Summer peaks were lower than the previous two years. Average energy use was higher than in 1999, but approximately equivalent to 1998.

Of course, we will not have precise data on hourly loads for the entire Western Systems Coordinating Council (WSCC) until summer 2001. However, as of late November, data was available for hourly loads for the ISO through the summer, as well as monthly energy loads for the entire WSCC through July. And retail load data was available by state for the United States and by province for Canada through July 2000.

According to this data, actual WSCC loads were higher during the summer of 1998 and winter 1999/2000 than the loads through July 2000. *(See Figure 2, WSCC—Electric Sales.)* Regional loads in May were lower than loads during a number of previous months, and roughly equivalent to the loads in May 1999.

In other words, in spite of many, many authoritative reports to the contrary, California ISO peak in summer 2000 was significantly lower than the peak in 1999. *(See Figure 3, California ISO—Peak and Average Loads.)* The 1998 California ISO peak also was higher than the peak load for summer 2000.[1]

But what about hydroelectric generation? Was 2000 a typical water year?

The major hydroelectric resource on the West Coast is the Columbia River. The Columbia is unusual among major hydroelectric resources, both for the uncertainty of its annual flows and the highly restricted amount of storage available. Columbia inflows were only average in 2000, although May hydroelectric generation was 120 percent of the May average from 1986 through 1999. In fact, all summer generation was slightly above the average for the past 14 years.

There has been substantial publicity concerning the "low" flows on the Columbia, but the actual data is very different. Columbia flows peak in the late spring as the snow melts along the Canadian Rockies. The pattern of flows in 2000 was unusual—June was lower than expected—but overall total hydroelectric generation was better than average. *(See again, Figure 1.)*

Data on hydroelectric generation is currently available through August for the Columbia River and Canada. California hydroelectric generation has been simulated statistically to provide a forecast for total August generation.

Overall, the current year is not unusual in terms of loads, hydroelectric generation, or the load/resource balance. The WSCC's assumption of "business as usual" is very reasonable in terms of the summer's operations. ISO peak loads were lower than in the previous two years, overall loads increased, and hydroelectric generation was a bit above average. Simply put, summer 2000 saw no major shift in market fundamentals.

Reliability to Blame?

From the beginning of the summer, some have doubted the accuracy of the ISO's reliability calculations. One way to check the ISO's work is to study reports from the Western Systems Coordinating Council.[2] The WSCC evaluates the state of the load resource balance in our area in a number of different documents. The two most widely known documents are the "Load and Resources Report" and the "Summer Adequacy Report." The "2000 Summer Adequacy Report" was published on May 25, 2000.

"The 2000 Summer Adequacy Report" indicated that there were sufficient resources on both a regional level and within California. *(See Figure 4, WSCC Reserve Estimates.)* The chart summarizes the reserve margin, by month, for the WSCC, California, and the ISO.[3]

The WSCC estimates for California and the ISO implied a satisfactory margin of loads over resources for this summer—a margin above 15 percent. The WSCC estimates depended on a low level of imports—2,000 MW over the summer months.[4]

Notwithstanding the foregoing, from June 23rd through the end of the summer, the ISO declared 38 separate emergencies. In each case, the ISO announced that its reserves had fallen below the appropriate trigger level. Each emergency was characterized by high prices as the ISO entered the larger WSCC bulk power market for "out of market" purchases to meet its system peaks in real time.

The contradiction between the ISO and the WSCC estimates has been difficult for the industry to resolve. As a matter of industry tradition, reliability issues are not matters that are subject to deception—declaring a false emergency is the equivalent of "crying wolf." At the same time, the ISO's frequent emergencies did not reflect the experience of the summer at any other utility in the region. (The only echo of the ISO's continuing difficulties that occurred elsewhere on the West Coast was a single day—Aug. 22, 2000—when the Bonneville Power Administration advised the national Marine Fisheries Service that low flows might threaten its environmental obligations. BPA officials later noted that they

Figure 2: WSCC Electric Sales
February 1995 to July 2000

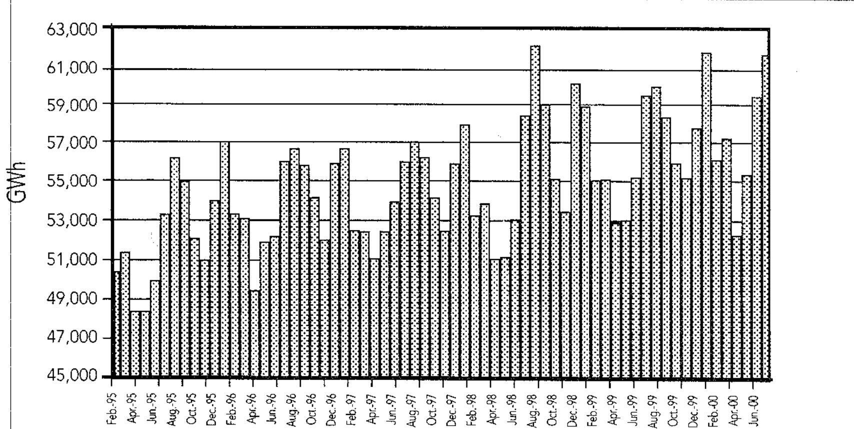


Figure 3: California ISO Loads
Last year's summer average was not excessive.

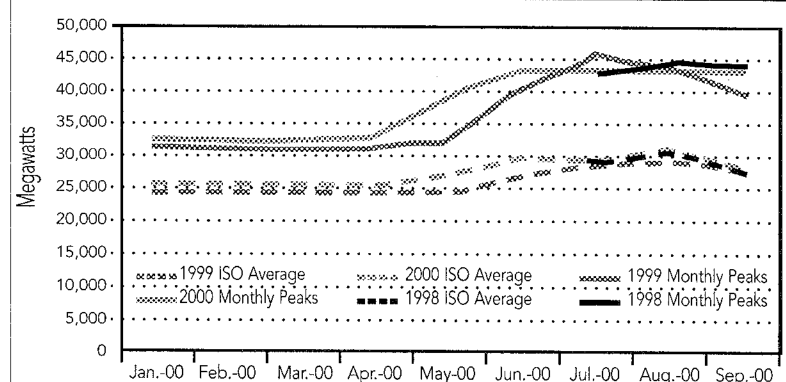
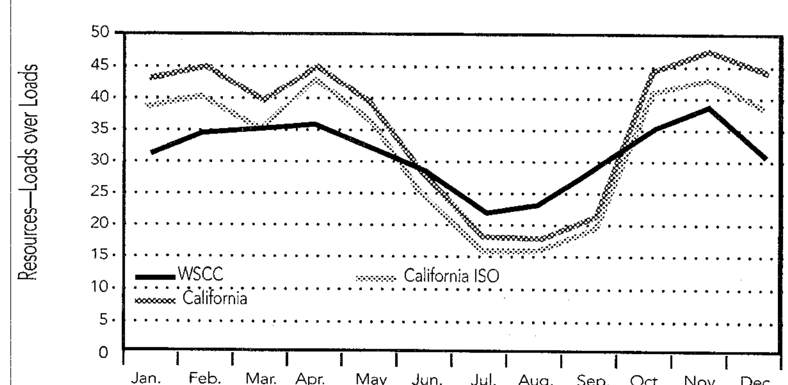


Figure 4: WSCC Reserve Estimates
Then why so many ISO emergencies?



were amazed at the quantity of offers they received the next day from potential suppliers.)

Nevertheless, despite this puzzling difference between estimates, the explanation turns out to be relatively straightforward.

Every other utility in the region makes its reliability arrangements on a reasonable prospective planning horizon. As a matter of industry practice, each utility owns or has contracted for sufficient capacity to meet summer and winter peaks—even after forced outages.[5] The ISO, on the other hand, depends on day-ahead offers of capacity to meet summer peaks. Simply put, the ISO declared each emergency when the offers of capacity were insufficient to meet its reliability criteria. It is, of course, significant that, without exception, next day real-time sellers were available to avert the ISO's emergency, but at murderous market-clearing prices. The mystery is why the ISO allowed itself to be so repeatedly deceived. This fact alone may explain why the FERC insisted in its Nov. 1 order[6] on eliminating the generators' representatives from the ISO board.

As of the end of November, there was enough data to update the WSCC's estimate of the ISO's reserve margin for actual loads and imports,[7] though at our firm, we were not yet able to update the WSCC analysis to include forced outages. However, plant outages were mentioned in the FERC's Nov. 1 staff report, which put them in the 8 percent range.[8] That would leave a reserve margin above 10 percent across all the hours during which the ISO declared emergencies.

In other words, the ISO appears to have "derated" the reserve capacity in the portion of California under its control in order to maintain consistency with its computer forecasting methodology. Our analysis shows that on average, before forced outages, the actual ISO reserve margin averaged over 20 percent during the periods last summer in which it declared emergencies.

In fact, inconsistencies between fundamentals and its offer-based methodology shows up throughout the data. For example, the generation of plants within the ISO's service territory during emergencies is very odd. *(See Figure 5, ISO Emergency—26 June 2000.)* The chart shows the capacity utilization of generating units in WSCC during the June 26 emergency. It provides data from both the WSCC's EHV database with the EPA's Acid Rain database, showing a fairly high correlation.

Overall, the situation is this: It appears that the ISO has a very poor methodology for evaluating its reliability situation. Underscheduling and market maneuvers such as scheduling power out of state can drive the ISO into declaring an emergency. The economic incentives designed into the system reward market participants for encouraging the ISO's perceptions of shortage.

The Shortage That Wasn't

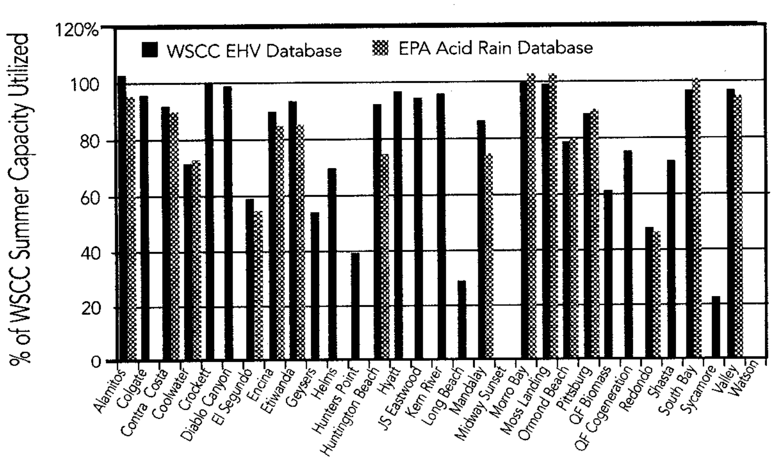
The basic mechanics of California power markets resemble a Ouija board—a small number of players maneuvering prices in a fashion difficult even for close observers to understand.

The first stage of the process begins with the filing of supply curves with the California Power Exchange by each potential supplier. The supply curve describes the quantities offered for sale at each price. Any party can file a supply curve, although the sheer complexity of the process has posed a barrier for many less-sophisticated utilities and generators. The supply curves are then aggregated into a single PX supply curve.

Under Assembly Bill 1890, the state's electric restructuring legislation, the loads of the three utilities automatically are included as the demand curve. The intersection of the supply and demand curves sets the market clearing price, and identifies which resources will operate the following day.

The supply curves are secret, but the aggregated supply curves are available from the PX on a three-month lag. As of the late-November writing of this article, aggregated supply curves

Figure 5: ISO Emergency—26 June 2000
Why was so much capacity offline?



were available only through the end of July. The vast amount of data makes it difficult to gather an understanding of the market—even for the participants. The PX data assembled since the start of the ISO occupies over 500 megabytes on a standard IBM personal computer. As always with ISO and PX data, no effort has been made to make analysis by outside parties easy or fruitful.

Nevertheless, the results of the PX comparison between the demand curve and the supply curve provide the template for operations by the ISO (though transactions actually become final at this stage).

The ISO takes the commodity results from the PX and adjusts the results to reflect transmission. It also purchases reserves under a number of schedules from the operators in the area. If underscheduling has been present, supply and demand will not match, and the ISO will use its reserves to bring the two into balance. If the reserves are insufficient, it will resort to "out of market" purchases—purchases from the market to avert an operating emergency.

The supply curves (i.e., the day-ahead offers to the PX) are not related to actual operating costs. Potential suppliers can file whatever prices and quantities they choose. In practice, the aggregated supply curves show a number of curious features. They have tended to shift upwards during high price periods—apparently reflecting the suppliers' assumption that their bids will be accepted in spite of a sharp increase in price.

Describing and working with this complex data is not easy. One method of analysis involves calculating the average weighted price from the supply curve offered for a given period—the price times the supplies offered at each price. This analysis indicates the "height" of the curve and allows us to measure how it has shifted over time. *(See Figure 6, California PX—Supply Price Curves.)*

During ISO emergencies, the supply curve shifts upward dramatically. Logically, that could only occur if the market participants could operate cooperatively. If they could not rely on competitors joining them in an increase in the supply curve, they would be better off to maintain their current supply curve and take advantage of the activities of the other players.

Figure 6 is worrisome to an economist, since it indicates that the supply curve was considerably higher throughout the summer than we would expect from the underlying production relationship (the expected power price based on natural gas.) It is even more worrisome because there are dramatic divergences from even the high historical relationship between the California PX's average supply curve price and

Figure 6: California PX—Supply Price Curves
Offer prices jumped during ISO emergencies.

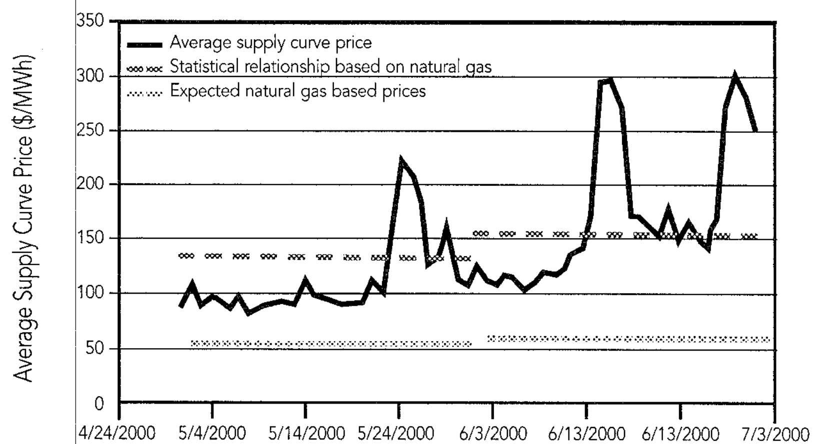
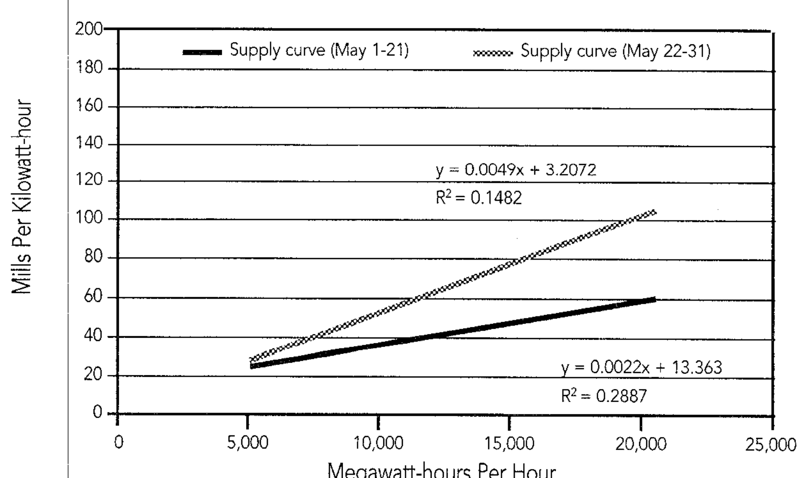


Figure 7: Supply Price Curves—COB Prices Plotted vs. ISO Generation
A paradigm shift on May 22, 2000.



the historical estimate of the relationship between gas (the red line) and the PX supply curve. There is no clear operating reason for the supply curve to surge upwards—natural gas prices did not double during these periods, nor are there other clear reasons.[9]

A competitor with excess capacity could have swept the market by simply running its unit full out. As we will see below, many California units did not operate at full capacity during these periods. It is highly unusual for a market participant to forego maximizing its profit during these periods unless some other strategy is being exercised.

Plant operations also tend to support the hypothesis that generation in California is characterized by strong market power. Two sources provide detailed data on plant operations—the Acid Rain database from the Environmental Protection Agency and the Extra-High Voltage (EHV) database from the WSCC.

We know from the prices experienced this past summer that May 22 was a major watershed. Consider two simple supply curves from actual generation data as supplied by the ISO. *(See Figure 7, Supply Price Curves—COB Prices Plotted vs. ISO Generation.)* On the vertical axis are the prices at the California Oregon border actually experienced in the real market. On the horizontal axis is the actual production from the plants provided by the ISO to the EHV database. The figure shows two distinct price curves derived from data points, using the regression equations shown on the figure. (Individual data points are omitted here for clarity).

As can be seen from the figure, between May 1 and May 22 an additional offer of 1 mill ($0.001) per kilowatt-hour ($1.00 per megawatt-hour) would have been enough to call forth a 500-MW increase in generation for the ISO-dispatched plants in the ISO database. After May 21, however, the same increase in price brought forward only 200 MW in new generation.

In the jargon of an economist, the supply curve for early May shifted upwards and to the left on May 22. Since this comparison is conducted within a single month, it effectively avoids questions of hydroelectric supply and gas price. The bottom line is that this massive shift has no explanation from market forces.

At our firm we have conducted a number of case studies of dispatch of generating plants operating within and without California during this period. The simplest analysis often is the best: Did these plants run the way we would have expected given prices and costs? We have

Figure 8: Market Power Premium—On Peak

9.48 cents per kilowatt-hour.

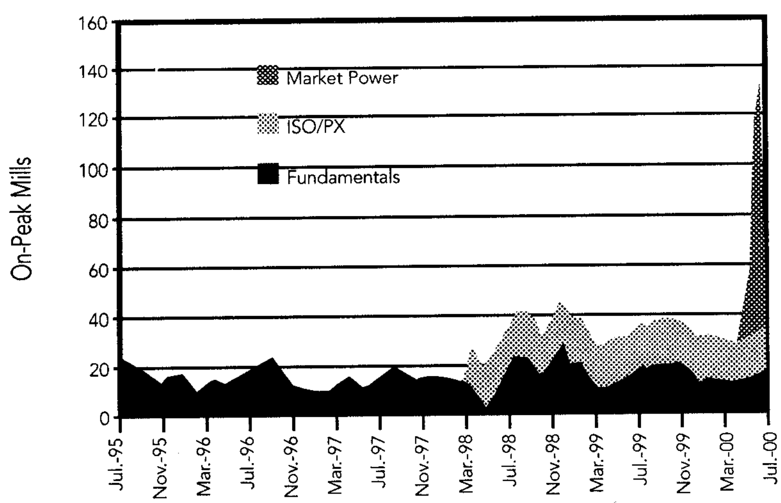
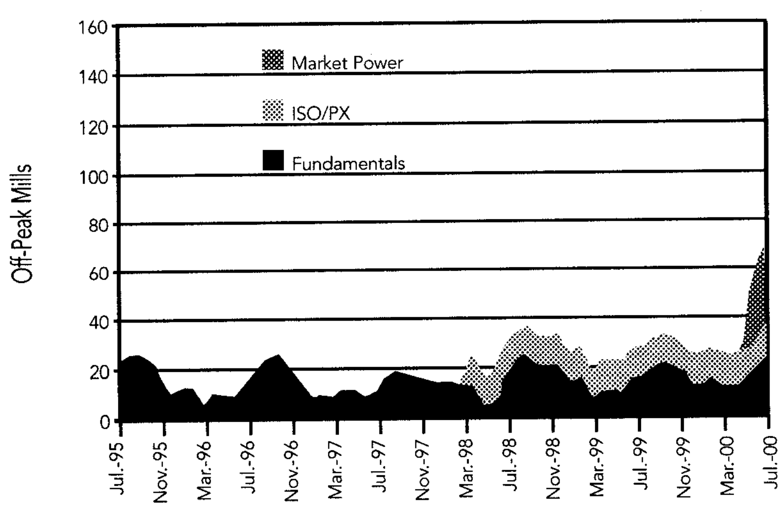


Figure 9: Market Power Premium—Off Peak

3.3 cents per kilowatt-hour.



efficiency and fuel cost estimates from a number of sources. Efficiency data can be taken from the California Energy Commission, the FERC, and the Environmental Protection Agency.

We calculated the cost of generation by taking the heat rate (the number of units of natural gas required to generate a kilowatt-hour of electricity) and added two mills for variable O&M. We conducted a variety of sensitivity studies to see if the results would change markedly if we added additional charges for losses and transmission, but given the very high prices experienced this summer, these charges were not significant. Natural gas prices are taken from the EIA's *Electric Power Monthly* publication.

The detailed analysis indicates a broad pattern of undergeneration at California thermal units. Our approach was to assume full generation when it would have been profitable for the plant to generate. During periods when the plant would not have been profitable, we have assumed zero generation.

As a general rule, the California plants in our case studies have been characterized by surprisingly low levels of generation given the prices this summer. For example, the Pittsburg unit from the San Francisco area indicates a generation level only 46.7 percent of the level of generation that we would expected for June 2000, based on data from the Environmental Protection Agency and the WSCC EHV database. Although the ISO generally has been quiet on the issues raised by this research, the ISO did criticize the EPA data as being of very poor quality.

The economic losses borne by these generators over prolonged periods of undergeneration are enormous, so enormous that the generators could have doubled their profits if they had followed traditional price signals. We do not have detailed information on possible forced outages or environmental constraints on most plants, although when the California Public Utilities Commission conducted its review of utility generating plants set to be sold, it did not find any significant environmental operating constraints for plants outside of the L.A. basin.

We do know that plant operations in the Los Angeles area were significantly affected by air emissions. The South Coast Air Quality Management District operates a market in emissions, and the cost of these emissions would affect dispatch decisions. However, that is only one of the 36 such districts in California and the only district where such auctions take place.

Clearly, given the significant deviations from traditional dispatch, forced outages or environmental constraints should have shown up either in the press or in the industry literature. With the exception of the Los Angeles area, that was not the case.

Comparable generating units outside of California do not show this behavior. We have conducted a comparable study on thermal generation outside of California. Although plant operations vary slightly from the predictions of the economic dispatch, the deviations average out to the 5 percent range.

The bottom line is straightforward—the California market was characterized by large, enduring deviations from traditional utility practice. Generators did not generate. Peakers did not peak. Emergencies appeared to lack solid justification. All of the evidence is consistent with a major, sustained exercise of market power.

Solving the Mystery: Means, Motive, Opportunity

The events this summer in the California market have all of the ingredients of a classical murder mystery: means, motive, and opportunity. While many of the questions will await detailed discovery
for final answers, the implications are quite clear.

THE MEANS. The California PX and ISO represent a strictly mechanical system that is easy for suppliers to reverse-engineer. Specific actions initiate automatic actions from the ISO and PX computer programs. The PX process has now been dismantled by the FERC, but it represented a simple target for market power.

The PX does not check for the reasonableness of the supply curves submitted by the market participants. PX and ISO market surveillance groups have been restricted to their own operations. ISO and PX data is not even routinely exchanged between the two agencies. The complexity of the process makes effective auditing virtually impossible.
The sale of thermal generating projects to a small number of owners makes market power easy to procure and easy to apply. During high load periods, the major players in California dominate the ISO's calculations.

The methodology of collusion is uncomplicated. Market players can experiment with their filings at the PX and ISO. The results in the market are available for inspection the following day. When the ISO forecasts a system peak, it is easy for bidders to adjust their behavior to decrease supply. If competitors do not join in the process, their decisions are evident in the EHV real-time data.

MOTIVE. This speaks for itself. The ability to sell into the PX and the ISO during high-priced periods is massively more profitable than business as usual. Traditional industry practice would assume that a margin of 10 mills over generation cost (1 cent per kilowatt-hour) would be more than sufficient to creative incentives for new generation projects. Since May 22, the margin has averaged five times that level.

OPPORTUNITY. The traditional problem in the exercise of market power is not the means nor the motive. The California ISO and PX may have made the means easier, but any sufficiently concentrated market can find the means to exercise market power. The major hurdle is the enforcement of non-competitive outcomes.

For 30 years the Organization of Petroleum Exporting Countries has attempted to exercise market power. Its track record is very poor. The problem is not the willingness of OPEC members to abide by production limits. The problem is the enforcement.

Most cartels cannot measure the degree to which the different market players are observing the output restrictions. The ISO's decision to collect and distribute the hourly operating data for its suppliers eliminated this challenge. Suppliers in the ISO service territory knew exactly the production levels of their competitors at any time.

The ISO's decision was all the more puzzling because the distribution of this data explicitly violated its own restrictive policies on the dissemination of market information.

Measuring the Damage

The increase in bulk power prices caused by the exercise of market power is the change not explainable by changes in natural gas prices, hydroelectric generation, and the load/resource balance. To isolate and identify that change, we have assembled a statistical model that includes these components. We have also included a "dummy" variable to represent market power, starting in the last week of May.

The results of our model indicate a very high cost associated with market power, which can be measured in terms of cents per kilowatt-hour, with a plus/minus figure showing the expected range of statistical variation, at a confidence level of 99 percent.

Table 2: Market Power Penalty

Increase in power costs for customers and usage classes.

Market	Penalty (¢/kWh)	Statistical Range
On Peak (all customers)	9.48	+/- 1.38¢
Off Peak (all customers)	3.30	+/- 1.92¢
Industrial Flat Load	7.94	+/- 1.92¢
Residential (mainly peak use)	8.71	

The surcharges shown here come on top of prior surcharges identified with increased costs in bulk power markets of 1.67 cents per kilowatt-hour and 1.17 cents per kilowatt-hour, brought about in April 1998 by the creation of the ISO and PX, respectively. These costs reflect the elimination of California's traditional advantages in import markets and the inefficiencies caused by ISO operational rules. Figures 8 and 9 illustrate the overall impact of market power through June.

Can This Market Be Saved?

On Nov. 1, FERC proposed a handful of reforms[10] for the California market, and though it was expected that the commission would revisit and fine-tune its proposed remedies, we can be relatively certain of some of the changes that the FERC has in mind, and can begin to sort out what those changes might mean for California markets.

The most significant of these reforms (and the most likely to be retained in any subsequent modified or final order) was the elimination of the restriction on California's three, major investor-owned electric utilities (IOUs) from purchasing energy outside of the Power Exchange. Freeing the IOUs from this constraint should strongly reduce the means for market manipulation. Unfortunately, however, market power can also be exercised within the complex rules of the ISO.

Of course, it is true that the FERC also encouraged the ISO to revisit its reliability approach. And the ISO's recent decision to stop disseminating the EHV data will also make collusion more difficult. But problems still remain.

The ISO still reserves the right to intervene massively in California markets with little external review. As a market player, the ISO has proved unsophisticated and gullible. FERC's replacement of the ISO board with non-market participants is unlikely to change the fundamental flaws in the organization's charter. Overall, the ISO's role as a primary energy provider during periods of undergeneration, and the corresponding tendency of the ISO to declare system emergencies during these periods, means that a substantial portion of last summer's problem remains to be solved.

The most important modification yet to be required is a careful review of the ISO's emergency purchasing powers. We expect that the ISO eventually will "buy forward," as is the practice with other utilities.

And a second modification should be imposed as well: Reduce the concentration of ownership of generation in the state of California. While the high degree of concentration is not sufficient to cause the problem in and of itself, it makes market abuse far easier than it should be.

The primary lesson from this summer's experience in California is that the desire to "improve" upon the market has many risks. The Rube Goldberg design of AB 1890 has brought market power and inefficiency to a market that would have operated far more smoothly without the supervision of the

California PX and ISO. It is easy now to predict that the summer of 2000 will dramatically reduce the roles of these two state agencies in the bulk power markets of the WSCC. If there is only one moral to take from this, it should be that state and federal legislators should avoid "deregulatory" solutions that involve extensive intervention into competitive markets. Ⓕ

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1 The hourly load data set from the University of California Energy Institute identifies the 1998 peak load as 44,759 MW, the 1999 peak as 45,574 MW, and the summer 2000 peak as 43,509 MW.

2 The WSCC is the regional reliability council that operates under the auspices of the North American Electric Reliability Council (NERC). NERC was founded in the mid-'60s in response to the "great blackout" in New York and New England. It functions as an association of the United States and Canadian entities that trade, generate, and regulate electricity. In actual practice, reliability issues are delegated to a series of local reliability councils.

3 The ISO operates within California but runs a control area smaller than the state as a whole, in that the ISO area excludes areas served by utilities that are not ISO members, such as the Los Angeles Department of Water and Power, the Sacramento Municipal Utility District, and various other municipal utilities and irrigation districts.

4 WSCC estimates are "worst case." Imports to California would be far lower if the Pacific Northwest had experienced "critical water"—the worst inflows in our historical record. As noted above, the Columbia River inflows were average, so the energy available for export to California was significantly higher than the WSCC's assumptions.

5 Industry jargon uses the phrase "forced outage" to describe the breakdown of equipment. "Planned outage" means that the plant is unavailable due to maintenance.

6 *Order Proposing Remedies for California Wholesale Electric Markets, Docket Nos. EL00-95-000, et al., Nov. 1, 2000, 93 FERC ¶61,121.*

7 A utility's reserve margin is the percentage of resources available after loads have been met. The traditional rule of thumb for the industry is that reserves should be at least 5 percent of load plus the single-largest resource in the utility's portfolio. In the case of the ISO, a reserve margin in the 7 percent to 8 percent range would be regarded as a logical minimum.

8 "Factoring in the actual planned and unplanned outages that occurred in the California market (see Figures 2-12), and holding the other assumptions equal, the reserve margins in the California subregion dropped from 26.3 to 17.5 percent for June, from 17.7 to 10.2 percent for July and from 17.4 to 8.98 percent for August." *Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities, page 5-4.*

9 The cost of emission credits has been cited as a possible explanation, but the market for emission credits is limited to the L.A. basin.

10 In its Nov. 1 order the FERC proposed to (1) allow purchasing outside the PX, (2) impose a "soft" price cap of $150 per megawatt-hour, (3) set penalties for scheduling load through real-time markets, (4) ask the ISO to rethink its reliability standards, and (5) replace the largely ceremonial boards of directors at the PX and ISO.

Secrecy at the ISO

In Section 20.3 of its tariff provisions, and in the "Information Availability Policy of October 22, 1998," the California Independent System Operator has adopted a fairly stringent secrecy policy. Simply stated, the ISO does not distribute individual bid or operating data.

Supplying Data. In the ISO's letter withdrawing from participation in the private "EHV Database" operated by the Western Systems Coordinating Council (WSCC), the ISO stated that it was willing to provide generation and line loading hourly data, but only if the WSCC would sign an "ISO Confidentiality and Use Agreement."

A Curious Reluctance. This policy appears curious, as EHV thermal plant data already is publicly available (though on a delayed basis) from the U.S. Environmental Protection Agency, under the EPA's Acid Rain program. This reluctance appears even stranger given the fact that the ISO previously had been distributing real-time operating and line loading data directly to the California market participants through the WSCC EHV real-time website.

Suspicions Raised. The erratic implementation of the ISO's secrecy policy (especially in its unwillingness to provide some of the same data to the California Public Utilities Commission*) raises the suspicion that the ISO has been attempting to avoid regulatory and operating review and to protect itself from criticism of its reliability calculations and operating decisions.

Ignored Requests. Interestingly, some requests submitted to the ISO by our firm for non-commercially sensitive information have been ignored for months, in spite of the explicit rule (5.2 of the ISO Information Availability Policy) that sets a 10-day response time and frequent telephone calls and personal requests. —R.M.

**See FERC Docket No. EL00-95-000, Calif. PUC motion filed Nov. 6, 2000, where the PUC states, "The WSCC turned down requests by the state of Oregon for access to the EHV database, despite providing access to market participants. It is appalling both that regulators lack access to such data, and that market participants have access to such data."*