CAUSES AND LESSONS OF THE CALIFORNIA ELECTRICITY CRISIS

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PREFACE

This Congressional Budget Office (CBO) paper looks at California's attempt to restructure its electric utility industry and at the crisis in the state's electricity market that began in 2000. The paper focuses on the various conditions in western states that put stress on California's energy market. It also examines some of the elements of the state's restructuring plan that turned that stress into a crisis.

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SUMMARY

The 1996 law that restructured California's electricity industry was intended to be the first step toward lower electricity prices for 70 percent of the state's population. Few observers foresaw the situation that would exist in California by the summer of 2001. Just five years after restructuring became law, the state's electricity market was commonly described as being in crisis. The goals of restructuring—lower prices for residential customers and more competitive prices for industrial customers—seemed farther away than ever.

This paper addresses four questions:

- What happened in California's electricity market from the mid-1990s through the middle of 2001?
- What role did the state's restructuring plan play in those events?
- How did California respond to its market problems?
- What can other governments learn from California's experience?

Developments in the Electricity Market

California began the formal process of restructuring its electricity market in 1994 (see Box 1 for a chronology of that restructuring). In doing so, the state was building on federal actions dating back to the late 1970s that were intended to increase competition in electricity markets throughout the nation. By 1996, a restructuring plan was enacted to change the sources and pricing of electricity for customers of three large investor-owned utilities: Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric. Together, those utilities served almost three-quarters of the state's electricity users. (The rest were served mainly by publicly owned, or municipal, utilities, which were not covered by the plan.) California's restructuring plan was based on the assumption that greater competition among independent power generators would cause wholesale prices for electricity to fall. That assumption seemed reasonable in part because in the mid-1990s, generating capacity in the western states exceeded the demand for electricity by roughly 20 percent.

By the summer of 2000, however, demand for electricity had outpaced the generating capacity available to supply the market. The reasons for that change included increases in the demand for electricity throughout the region (because of economic growth and weather) as well as losses of hydropower capacity and other conditions that limited power supplies. In that setting, the restructured wholesale market pushed electricity prices to unanticipated levels.

BOX 1.
A CHRONOLOGY OF ELECTRICITY RESTRUCTURING IN CALIFORNIA

1994: The California Public Utility Commission (PUC) begins a formal rulemaking procedure to consider approaches to restructuring the state's electricity market. That action builds on changes in federal law and regulation that began with the Public Utilities Regulatory Policy Act of 1978 and continued with the Energy Policy Act of 1992.

1996: California law AB 1890 codifies various regulatory changes and initiatives by the PUC. Those changes include requiring the state's three major investor-owned utilities—Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E)—to sell half of their fossil-fuel capacity (they eventually sold all of it); transferring control of electricity transmission to a newly created nonprofit corporation, the California Independent System Operator (CAISO); creating another nonprofit corporation, the California Power Exchange (PX), to run wholesale auctions of electricity; and freezing retail electricity prices until 2002 (or such time as the utilities recover certain costs). The California state auditor reports that the western states as a whole have excess generating capacity of roughly 20 percent.

1998: The California PX begins operating at the end of March. Between August 1998 and March 1999, market-monitoring, surveillance, and market-analysis groups of the PX and CAISO issue reports expressing concern about the functioning of California's wholesale electricity market.

June 1999: The CAISO's Surveillance Committee recommends that investor-owned utilities be granted more authority to enter into long-term contracts.

July 1999: SDG&E recovers its stranded costs (the decline in the value of certain assets, such as generating facilities and long-term contracts with other suppliers, because of restructuring). As a result, it is allowed to charge its customers market prices for electricity.

2000: Growth of income in California and neighboring states—which affects the demand for electricity—accelerates. In California, total personal income, which had grown steadily since the restructuring debate began, jumps by about 9 percent from its level in 1999.

April 2000: The price that California's electricity generators pay for natural gas begins to climb from about $3.50 per thousand cubic feet (reaching more than $6 by November).

May 2000: The summer cooling season begins. May and June 2000 rank among the 15 hottest May-June periods of the past 100 years.

June 2000: Rising wholesale prices for electricity consistently exceed the frozen retail price. As a result, PG&E and SCE must sell purchased power at a loss. Customers of SDG&E, by contrast, pay the market price, which is three times higher than it was the previous summer. On June 14, PG&E interrupts service for the first time in its history, which affects 100,000 customers in San Francisco.

August 2000: The estimated annual prices that generators pay for pollution credits—which reflect the costs of producing electricity from fossil-fuel plants—rise to $30 per credit (from $10 in June). They reach $45 per credit by December.

BOX 1.
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September 2000: California enacts a law rolling back and freezing retail rates for SDG&E customers at the 1996 level.

October 2000: The PUC permits Southern California Edison to increase its short-term borrowing authority from $700 million to $2 billion to pay for power in the wholesale market.

November 2000: PG&E and SCE file for rate increases to cover power costs they could not collect from consumers. The Federal Energy Regulatory Commission (FERC) releases a report describing how market design and flawed regulatory policies in California have contributed to high prices.

December 2000: The CAISO declares many Stage 3 emergencies, warning of the prospect of blackouts as electricity reserves (the amount by which available generating capacity exceeds demand) fall below 1.5 percent during periods of peak demand. The U.S. Department of Energy orders electricity generators outside California to sell to the state's wholesale market. FERC imposes "soft" price controls (limits that may be exceeded in emergency circumstances) and directs California's investor-owned utilities to negotiate long-term supply contracts and reduce their reliance on the wholesale market.

January 2001: The PUC approves retail rate hikes for PG&E and SCE. The CAISO orders rolling blackouts on several occasions. Emergency orders by the governor direct the state's Department of Water Resources to buy power in response to the deteriorating financial condition of the three large investor-owned utilities. The PX suspends operations.

February 2001: The state negotiates and signs long-term agreements to buy power. It begins implementing a strategy intended to restore the financial health of the utilities, which includes having the state purchase major transmission lines.

March 2001: Rolling blackouts occur statewide. FERC directs 13 power suppliers to refund $69 million that it says they overcharged utilities in January. The PUC approves immediate increases in retail rates.

April 2001: PG&E declares Chapter 11 bankruptcy. Standard & Poor's downgrades California's bond rating (from AA to A-plus) because of the state's additional borrowing to address its electricity problems.

May 2001: California authorizes a $13 billion bond issue to finance its purchases of electricity. The North American Electric Reliability Council warns that the state could face 260 hours of rolling blackouts during the summer.

June 2001: FERC announces a price-mitigation plan for all of the western states, with wholesale prices to be capped at a level reflecting the highest cost of generating electricity in California.

July 2001: Moderate temperatures help keep the demand for electricity lower than during the previous summer. Even though water levels in the streams used to generate hydropower are low, declining demand for electricity and falling natural gas prices combine to push wholesale electricity prices to the lowest level since the spring of 2000. Prices in the spot market fall far below the level that the state is paying for electricity under its long-term contracts.

As the three large investor-owned utilities faced spiraling financial difficulties, and disruptions in electricity supplies appeared possible, some observers began to question whether the old regime (power monopolies overseen by state regulators) did a better job of meeting the demand for electricity than the new ideal (many independent producers interacting with consumers in a deregulated market). Observers pointed out that the parts of the California market outside the restructuring plan (mainly in the Los Angeles and Sacramento areas) faced fewer problems than the rest of California, as did the other western states. By mid-2001—in the wake of one bankrupt utility, even higher wholesale prices, and rolling black-outs—skeptics blamed deregulation for putting California in a perilous position.

The Role of Restructuring

Much of the blame for California's electricity crisis attaches to the state's restructuring plan—but not to its objective, electricity deregulation. The state's plan gained political support on the basis of what turned out to be faulty assumptions. It then played a role in turning market stresses—high demand for electricity and limited production capacity—in the summer of 2000 and beyond into a full-blown crisis, in which California's major utilities could not buy enough power to supply their customers. But deregulation itself did not fail; rather, it was never achieved.

The restructuring plan did not remove sufficient barriers on both the supply and demand sides of the market to allow competition to work—in part because it was not designed to. Neither the state legislature and Public Utility Commission (PUC), which framed the plan, nor the Federal Energy Regulatory Commission, which approved it, envisioned the immediate or full deregulation of the electricity market covered by the plan. Instead, retail prices were to be frozen during an interim period. After that, the PUC would continue to oversee how much the utilities could charge their retail customers for generating or distributing electricity.

In addition, the market outside the restructuring plan mostly remains regulated. The California PUC has no authority over municipal utilities in the state, utilities in neighboring states, federal power agencies, or interstate transmission companies. All of those entities are still subject to local and federal controls. The continuing regulation of utilities in other parts of California and in neighboring states contributed indirectly to California's supply problems by limiting how much power those utilities were able or willing to sell outside their traditional service areas.

Even without restructuring, California's electric utilities would have faced a difficult challenge in meeting the demand for power and holding down prices in 2000. But at several key points during the unfolding crisis, features of the restructuring plan limited the responsiveness of the supply and demand sides of the electricity market.

Consequently, wholesale electricity prices were higher than they probably would have been in either a traditionally regulated market or a more fully deregulated market.

On the supply side, the plan's freeze on retail prices left the three big utilities in a financial shambles when wholesale prices in the spot market—where those utilities were acquiring nearly half of their power—rose above the freeze level. The plan made the utilities particularly dependent on that market in two ways: it encouraged them to sell their fossil-fuel generating capacity, and it discouraged them from signing new long-term supply contracts that could have protected them from adverse movements in prices.

Faced with a universal-service requirement (they could not unilaterally drop customers) and with a negative cash flow on nearly half of their sales, the utilities saw their losses mount. Lenders downgraded their creditworthiness, thus raising their costs for new borrowing. Moreover, independent power generators were able to push up wholesale prices further and even withdrew supplies when it looked as though the utilities might not be able to pay for their purchases. That happened in part because elements of the plan’s auction system for the spot market appear to have created strong incentives for suppliers to bid strategically in a way that raised wholesale prices. Some generators may also have withheld supplies at certain times to boost prices even more.

On the demand side, two problems coincided. Extreme weather and strong economic growth put stress on the market by increasing the use of power. At the same time, the freeze on retail prices magnified the impact of that stress on wholesale prices by eliminating incentives for consumers to conserve power. Even a small drop in electricity use—like the decline that occurred in San Diego when the price freeze there was temporarily lifted—would have been enough to let the state avoid some of the disruptions it has faced.

The State’s Response

The developments in California’s electricity market and the failure of the state’s restructuring plan provoked a political crisis. At the direction of the governor, the state began taking steps in January 2001 to help secure future electricity supplies and stabilize wholesale prices. The state has assumed a new role in purchasing wholesale power on behalf of private utilities. It is also moving toward establishing a state-owned utility that, in addition to buying power, would own an extensive transmission grid and build new generating plants. Moreover, the state has abandoned the retail price freeze, raising rates to ensure that consumers help cover its costs of buying power.

In addition, the state has negotiated long-term contracts, lasting up to 20 years, with electricity suppliers. The potential cost of that intervention became apparent in the summer of 2001 when electricity prices in the spot market dropped in response to mild weather and lower demand, falling below the price the state was paying under its long-term contracts. If that situation persists, Californians could be committed to paying high electricity prices for many years to come—the prospect that led to restructuring in the first place.

Lessons for the Future

Market restructuring and concerns about electricity prices and supplies are still important issues in many parts of the country. This past summer, the California market returned to a semblance of normalcy because of slower economic growth, moderation in the extreme weather conditions that had boosted demand for electricity, and a decline in the high prices for natural gas that had inflated the cost of generating power. But the electricity market in the western United States is likely to remain vulnerable to new stresses (for example, water levels in streams used to generate hydropower remain low). Some observers have warned that the problems in California might appear in other states.

California responded to its immediate concerns about the availability of electricity and the volatility of prices by directly intervening in the market—a response that could prove costly to electricity consumers and taxpayers. Long-term solutions to California's electricity problems will most likely require three changes: removing barriers to the addition of generating capacity, eliminating bottlenecks in the electricity transmission system, and removing regulatory restrictions on the sale of power throughout the broad western market. Those actions would help make the supply of electricity more responsive to changes in prices. On the demand side, the prospects for successful restructuring would also improve if consumers faced the full costs of electricity and were better able to adjust their use of power in response to changing prices.

WHAT HAPPENED IN CALIFORNIA'S ELECTRICITY MARKET?

California's decision to restructure its electricity market came in response to changing federal regulation of such markets beginning in the 1970s and to criticism of the state's market in the early 1990s. Consensus developed about two issues: first, that regulated producers and markets delivered electricity at too high a price, and second, that the future prospects for business investment in California were being hurt because the state's electricity prices were higher than those in other western states.

Electricity prices were high in California partly because the regulated market, by assuring producers of a high rate of return on their investments, provided incentives to build too much generating capacity. Policymakers, however, considered such excess capacity a saving grace of the system when California's restructuring plan took effect. Capacity in excess of demand was a key to ensuring that wholesale prices would fall with competition.

The plan required the state's three large investor-owned utilities—Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric—to sell part of their generating capacity. It also discouraged them from entering into long-term supply contracts with independent power producers. As a result, the utilities had to rely on the newly created spot wholesale market for about half of the electricity that their customers demanded.[1] (For more details about how the electricity market in California operates, see Figure 1.)

California's restructured electricity market functioned adequately at first, although hot, dry weather throughout the West in 1998 put pressure on the system (by increasing the demand for air conditioning and reducing the stream flows necessary for generating hydroelectric power).[2] By 2000, however, it was clear that capacity no longer comfortably exceeded demand. Since 1996, when the restructuring plan was enacted, generating capacity in California and the West had changed little, although the size of the population and the economy—which affect the demand for power—continued to increase. During the summer of 2000, the previous margin of electricity reserves was eroded by further increases in demand for electricity (because of economic and weather conditions) as well as by losses of hydropower capacity and other supply circumstances. In response, electricity prices rose to unheard-of levels. By 2001, utilities were facing bankruptcy, wholesale prices were continuing to rise, and customers were experiencing rolling blackouts. Skeptics about

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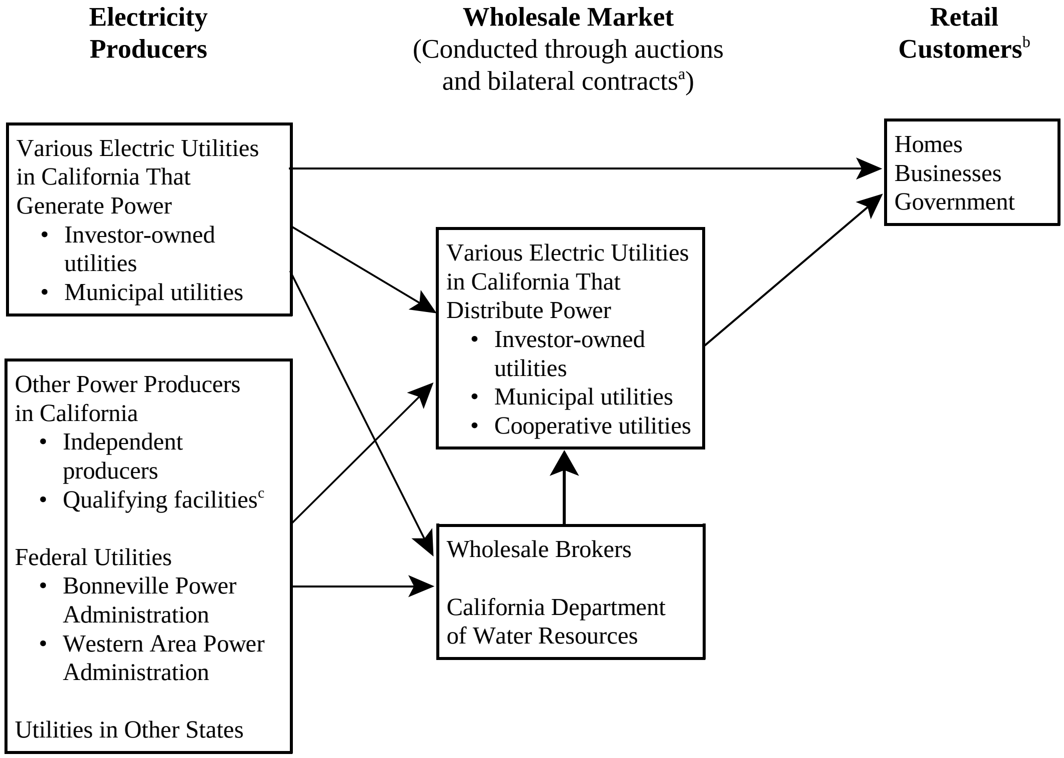
1. In spot markets, transactions are made for immediate delivery (unlike futures markets, where transactions are made for delivery from one month to one year in the future).

2. For a discussion of early pressures on the electricity market, see California State Auditor, *Energy Deregulation: The Benefits of Competition Were Undermined by Structural Flaws in the Markets, Unsuccessful Oversight, and Uncontrollable Competitive Forces* (Sacramento: California State Auditor, March 2001).

FIGURE 1. WHO SELLS TO WHOM IN CALIFORNIA'S ELECTRICITY MARKET



SOURCE: Congressional Budget Office.

a. The California Independent System Operator conducts wholesale auctions of electricity. In addition, the California Power Exchange conducted such auctions until it was shut down in January 2001.

b. California's restructuring plan allowed customers to buy electricity directly from independent producers and brokers, but virtually all customers stayed with their traditional utility supplier as long as the freeze on prices remained in effect.

c. Producers who use renewable energy sources or cogeneration (waste heat from industrial processes) to make electricity.

the restructuring plan blamed it for placing California in a perilous position and for pushing up the cost of electricity in other western states as well.

Before Restructuring

California's electricity market is part of a larger, interconnected electricity grid called the Western Interconnect. The Interconnect comprises 11 western states (as well as parts of western Canada and northern Mexico) that effectively constitute one large market for electricity. What happens to supply or demand in one part of the region will influence prices in the other parts. For example, changes in the capacity to generate hydroelectric power—the cheapest source of electricity—in Washington

State can affect the supply of electricity available to all power-importing states in the Interconnect.

California is a net importer of power from its neighbors. In 1996, the state's utilities sold about 20 percent more electricity to their customers than was generated by local plants.[3] Typically, however, the state's utilities and independent power producers also sell to other states, and in certain seasons, the net flow of power is out of California.

For years, electricity prices were much higher in California than in neighboring states. In 1996, the average price to California households and businesses was 9.5 cents per kilowatt hour (kWh)—75 percent more than the average price in the 10 other western states.[4] A big part of that difference resulted from the greater availability of cheap hydropower in other parts of the West. California's policymakers could not alter the allocation of western hydropower, which depends on nature (the location of rivers) and federal policy (regional preferences in the sale of federal hydropower). But they could address two other factors that caused high prices: the structure of California's market (regulated monopolies) and state policies to support alternative energy. The fact that the state's utilities were facing increasing market pressure from independent power producers gave policymakers an extra impetus to do something about high prices.

<u>Inefficiencies of Regulated Monopolies</u>. Before restructuring, California's electricity was supplied by a mixture of large private utilities (owned by investors) and municipal power companies (owned by cities and counties). About 70 percent of Californians were customers of the state's three large investor-owned utilities.

To varying degrees, those utilities were vertically integrated, meaning that they were involved in all phases of their industry, controlling much of the generation, transmission, and distribution of electricity in their respective service areas.[5] They also functioned as regulated monopolies, meaning that each was the only utility that could operate in its service area, though with certain restrictions. The state's Public Utility Commission (PUC) approved the retail prices that those private utilities could charge for electricity and oversaw the reliability of their service. The Federal Energy Regu-

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3. Energy Information Administration, *Electric Power Annual 1996*, vol. 1, DOE/EIA-0348(96)/1 (August 1997), Tables 9 and 23, and *Electric Power Annual 1996*, vol. 2, DOE/EIA-0348(96)/2 (February 1998), Table 63.

4. Energy Information Administration, *Electric Power Annual 1996*, vol. 2, Table 6.

5. Transmission is the movement of power over high-voltage lines from generators to local utilities. Local distribution systems then carry that power over low-voltage lines to households and businesses. Before restructuring, San Diego Gas and Electric had the lowest level of vertical integration of the three large utilities. It purchased about half of the power that it sold (rather than generating that power itself).

latory Commission (FERC) was responsible for approving the wholesale prices that electricity producers could charge utilities for power and the rates that utilities could charge for the use of their transmission lines.

Under traditional regulation, the private utilities were allowed to charge prices that recovered their costs of production and gave investors a large enough return to attract ample capital for the utilities. Economists have long pointed out that such regulation encouraged utilities to overinvest in electricity-generating capacity because the cost of additional capacity could be more than covered by higher electricity prices. Indeed, in the mid-1990s, California's private utilities had much more generating capacity than they needed to supply their customers.

<u>The Cost of Supporting Renewable Energy and Cogeneration</u>. Another factor that contributed to high electricity prices in California before restructuring was federal and state policies that ordered utilities to buy electricity generated from alternative energy sources. The federal Public Utilities Regulatory Policy Act of 1978 required utilities to purchase all of the power generated by smaller producers known as qualifying facilities. Those producers generate electricity from renewable sources of energy (such as wind power) or as a by-product of manufacturing (a process called cogeneration). The 1978 law let the individual states set the prices that the utilities would pay for power generated from those sources.

Initially, California's PUC decided that the price for power from qualifying facilities should reflect the cost of the most expensive source of electricity—nuclear power. That decision was a boon to renewable-energy producers and cogenerators in the state, who could produce electricity much more cheaply than that. In 1995 (the last year for which data are available), California utilities paid an average of 12.3 cents per kWh for electricity from qualifying facilities, compared with only 4.2 cents per kWh for power from other sources.[6] As a result, electricity from qualifying facilities grew from less than 1 percent of the state's total generation in 1980 to about 20 percent in 1996.[7] That increasing reliance on alternative energy sources pushed up the average cost of power for utilities. But because regulators allowed the utilities to pass along the full cost of that power, their customers ended up bearing the brunt of the higher costs.

<u>Competition from Independent Power Producers</u>. California's large private utilities had little incentive to try to reduce their high costs so long as their customers (both retail customers and the municipal and cooperative utilities that purchased wholesale

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6. Energy Information Administration, *Renewable Energy 1998: Issues and Trends*, DOE/EIA-0628(98) (March 1999), Table 9.

7. Energy Information Administration, *Renewable Energy 2000: Issues and Trends,* DOE/EIA-0628(2000) (February 2001), Table 6.

power from them) had little ability to choose other suppliers. Much of the momentum to restructure California's electricity market resulted from federal policies that supported the emergence of an independent power industry and gave the utilities' wholesale customers greater flexibility to shop for lower-cost supplies. Retail customers in the industrial sector also put pressure on the utilities because they had increasing incentives to switch to natural gas (and generate their own electricity) or relocate to regions with lower electricity prices.

One of the most important changes in federal policy was the Energy Policy Act of 1992, which encouraged the entry of new independent producers into electricity markets around the nation. Those independent firms increasingly sold power directly to municipal and cooperative utilities and worked with large industrial customers to develop cogeneration capabilities, which permitted those customers to supply part of their own power needs and sell excess power to the utilities. (Independent producers —many of which generate electricity from natural gas—and small producers that use renewable energy or cogeneration are known collectively as nonutilities; they are not generally subject to price regulations or universal-service requirements.) The 1992 federal law also provided incentives for utilities to spin off affiliated but unregulated independent power businesses. In addition, it gave independent producers open access to the utilities' transmission systems.

Before independents entered the market, California utilities had not faced competition. The utilities' high costs of generating power, as well as the costs of their long-term contracts with qualifying facilities, could be passed on to customers without financial harm to themselves. As competition spread, however, those generating plants and contracts increasingly became liabilities for the utilities; they eventually became known as stranded costs.[8] The utilities could not recoup those costs in a competitive market, where prices were expected to fall, unless regulators took some action, such as setting a floor for retail prices. Most of the potential stranded costs of California utilities resulted from long-term supply contracts. Any loss of wholesale customers or large retail customers to independent producers raised the prospect that the utilities' remaining customers would face even higher prices.[9]

8. For a discussion of stranded costs, see Congressional Budget Office, *Electric Utilities: Deregulation and Stranded Costs*, CBO Paper (October 1998).

9. Growing competition also threatened the utilities' ability to continue supporting state programs to promote energy conservation and renewable energy without raising prices for their remaining customers. Those programs include demand-side management (such as paying consumers to invest in efficient appliances), public benefit funds (which charge retail customers extra to pay for subsidies to renewable-energy producers), and renewable portfolio standards (which require utilities to supply a minimum percentage of their power from renewable sources).

The Restructuring Plan of 1996

Beginning in 1994, the California Public Utility Commission proposed a number of regulatory changes to the electricity market. Those changes—together with public law AB 1890, enacted in 1996—define the major elements of California's restructuring plan.

- The three large investor-owned utilities were required to divest themselves of at least half of their fossil-fuel-powered generating plants. (Fossil fuel includes natural gas, coal, and oil, but in California most of the fossil-fuel plants burn natural gas.)

- A nonprofit corporation, the Power Exchange (PX), was created to run wholesale electricity auctions, where the utilities were required to buy all of their power that was not coming from their own plants or from preexisting contracts (primarily with qualifying facilities). That requirement effectively precluded the utilities from entering into long-term contracts with independent power producers because, until 1999, the PX did not sell such contracts.

- The utilities were also required to transfer control (though not ownership) of their transmission networks to another nonprofit corporation, the California Independent System Operator (CAISO).

- The restructuring plan froze retail prices for electricity until 2002 (or such time as the utilities recovered certain stranded costs).

- Finally, consumers were given a choice of continuing to buy power from their traditional utility or purchasing it from other suppliers—with the new supplier delivering power over the utility's distribution system and consumers being billed separately for power and distribution services. (Although many people believed that consumer choice was among the plan's most significant features, few customers actually switched suppliers while prices remained frozen.)

Sale of Generating Capacity. To promote wholesale competition among power generators, the plan required the state's three large private utilities to sell half of their fossil-fuel-powered generating capacity.[10] In the end, the utilities sold all of that capacity, although they kept virtually all of their hydropower and nuclear assets. The utilities also retained their long-term supply contracts with qualifying facilities,

10. Energy Information Administration, *Electric Sales and Revenue 1999*, DOE/EIA-0540(99) (October 2000), Table 17.

although the plan gave them the resources to renegotiate the onerous pricing provisions of those contracts.

By September 2000, the effects of the required divestiture of generating assets were clearly visible. Power plants owned by the utilities provided just 28 percent of the electricity in the state's restructured power market, down from 40 percent the previous year. Meanwhile, the share from nonutilities in the state (independent power generators, including qualifying facilities) reached 58 percent, up from 40 percent in 1999.[11]

With that shift, the nonutilities assumed a more important role in determining prices in the new market. Under the plan's rules for wholesale auctions, wholesale electricity prices in the restructured market (like prices in other competitive markets) would be determined by the marginal cost—that is, the cost of the last and most expensive unit produced. Since divestiture, the utilities have generated their own electricity only from hydropower and nuclear power facilities. They usually operate those facilities to meet their base load requirements (the base level of their customers' demand for power, not counting daily and seasonal peaks in use) because of those facilities' low variable costs. The nonutilities, by contrast, generate most of their power from natural-gas-fired plants. Those plants also supply power for base load requirements, but they are especially important in meeting the increased requirements of peak periods. Thus, the contribution from gas-fired plants is critical in extreme market conditions such as those of 2000 and 2001, when demand rose to record levels and the utilities' supply from hydropower dropped. In those circumstances, the market price of electricity depends directly on the level of natural gas prices and the efficiency of operating gas-fired plants.

The Power Exchange. Most of the wholesale exchange of electricity between independent producers and the investor-owned utilities took place in a new market, under the aegis of the PX. Those utilities were required to buy power in that market. From 1998 until its termination in January 2001, the PX ran several different auctions, matching supply and demand and setting prices. Sellers submitted bids in the form of a supply schedule (how much they would supply at various prices), and buyers submitted bids in the form of a demand schedule (how much they would buy at various prices).

Initially, the PX conducted auctions only for power to be dispatched in each hour of the next day (the day-ahead market). Later, it added a block-forward market,

11. Data from the Energy Information Administration on existing capacity and planned additions to capacity for electric utilities and nonutilities are available at www.eia.doe.gov. In both 1999 and 2000, the rest of the market's electricity came from power generators in other states, including federally owned sources (such as the Bonneville Power Administration), and from municipal utilities in California. Much of that additional supply was generated from hydropower.

which allowed bids for blocks of hours for each day of the month, for one to six months in the future. In both types of auctions, the lowest-bid supplies were awarded first, but the price paid for all supplies was based on the last and most expensive unit of power sold (the marginal cost of supply in the market at that time).

The PX was shut down in January 2001 after its two largest customers, Pacific Gas and Electric and Southern California Edison, defaulted on payments for power they had purchased through the PX. At that time, sellers stopped offering electricity in PX auctions for fear of not being paid, and the exchange suspended participation by the two utilities. Much of the business formerly conducted through the PX moved to the CAISO or was replaced by direct contracts with the state government.

The California Independent System Operator. The plan's other new institution, the CAISO, took over the task of coordinating supply and demand in the state's electricity transmission system—a job that had formerly been done by the private utilities that owned the transmission lines. Electricity transmission requires the continuous balance of power supply with consumer use (or load): too much or not enough power at any moment can crash the entire system. The vertically integrated utilities that owned the lines had managed that balancing task. But with open access to transmission lines, there was concern that the utilities would give preference in scheduling to power from their own generators. A primary goal for the CAISO was to ensure nondiscriminatory access.

Besides scheduling power supplies from various sources for the next day (consistent with projections of next-day demand), the CAISO is responsible for acquiring access to additional supplies to meet unanticipated surges in demand or losses of generation. To that end, the CAISO operates a real-time market—an auction for acquiring power supplies in the next hour, separate from the auctions formerly run by the PX. (That real-time auction enables the CAISO to buy what the restructuring plan expected would be the small amounts of power necessary to balance the system.) To ensure adequate reserves and avoid the need for last-minute purchases, the CAISO conducts another auction for the provision of standby capacity. It can also forgo its auctions altogether by contracting with suppliers bilaterally in so-called out-of-market purchases. The CAISO then bills the utilities that distribute the electricity for its purchases on their behalf.

As carried out by the Public Utility Commission, the restructuring plan limited the ability of utilities to make long-term deals with independent power producers (other than qualifying facilities) by requiring them to buy all of the power they needed but did not generate themselves in the PX and CAISO markets. The restriction on long-term contracting effectively prohibited the utilities from participating in futures markets for electricity. That restriction, which was formulated as part of the 1996 plan, was eased somewhat in later actions. In 1999, the PX added the block-forward market to let utilities buy hourly blocks of power one to six months in advance. And in 2000, the PUC eased the limits on bilateral long-term contracts and futures trading.

One reason that California's restructuring plan restricted long-term contracts was to help ensure a competitive wholesale market by forcing a large share of power sales into the new PX and CAISO auctions. The plan's framers feared that if such contract arrangements were allowed, they would let the utilities maintain some degree of vertical control over independent producers and effectively thwart the goal of divestiture.

<u>Retail Price Freeze</u>. The plan mandated a reduction and freeze in the retail price of electricity. That provision had two goals. One was to allay consumers' fears that restructuring would force them to pay higher prices. The other was to assure the utilities that retail prices would not drop too much relative to wholesale prices, so they would be able to pay off their stranded costs. Accordingly, prices were supposed to be frozen at a level 10 percent below the 1996 level. The freeze was to last until 2002 or until the utilities had paid off their stranded costs—whichever came first.

As it turned out, however, the reduction in prices for consumers was close to zero because the state effectively loaned the utilities the present value of the 10 percent reduction for their immediate use in paying off stranded costs and then required them to repay that loan from a surcharge on customers' bills.[12] The remaining funds to repay stranded costs were to come from the utilities' sales of fossil-fuel-powered generating plants and from the difference between the retail price and the wholesale price that would be set in the new competitive marketplace.

<u>Consumer Choice</u>. Finally, to help ensure that electricity users would ultimately see the benefits of lower wholesale prices, consumers were immediately given the option to purchase their power directly from a retailing generator (or reselling middleman) of their choosing or to continue buying it from the utility that distributes the power.[13] Framers of the plan expected that when the plan was fully implemented (by 2002 at the latest), the retail price of electricity would reflect the wholesale price—what it cost for whichever producer customers had selected as their power source to generate

12. To make it easier for utilities to renegotiate contracts with qualifying facilities, the restructuring plan gave utilities the right to receive a stream of income from ratepayers—paid as a special surcharge on customers' power bills. In a process known as securitization, the utilities turned that right over to a state infrastructure bank in exchange for a cash payment. The state infrastructure bank then issued bonds that are backed by that stream of income. Unlike the case with debt that the utilities could issue themselves, income from those bonds is exempt from state taxes.

13. Following the lead of deregulation in natural gas and telephone service, the owners of the distribution network (which still held a monopoly) were allowed to charge a distribution fee for delivering power to those customers. The fee could include charges for other services and for state programs.

electricity. However, very few customers exercised their option to sign up with new suppliers until California directed the utilities to raise retail prices in March 2001.

Market Developments from 1996 Through 2001

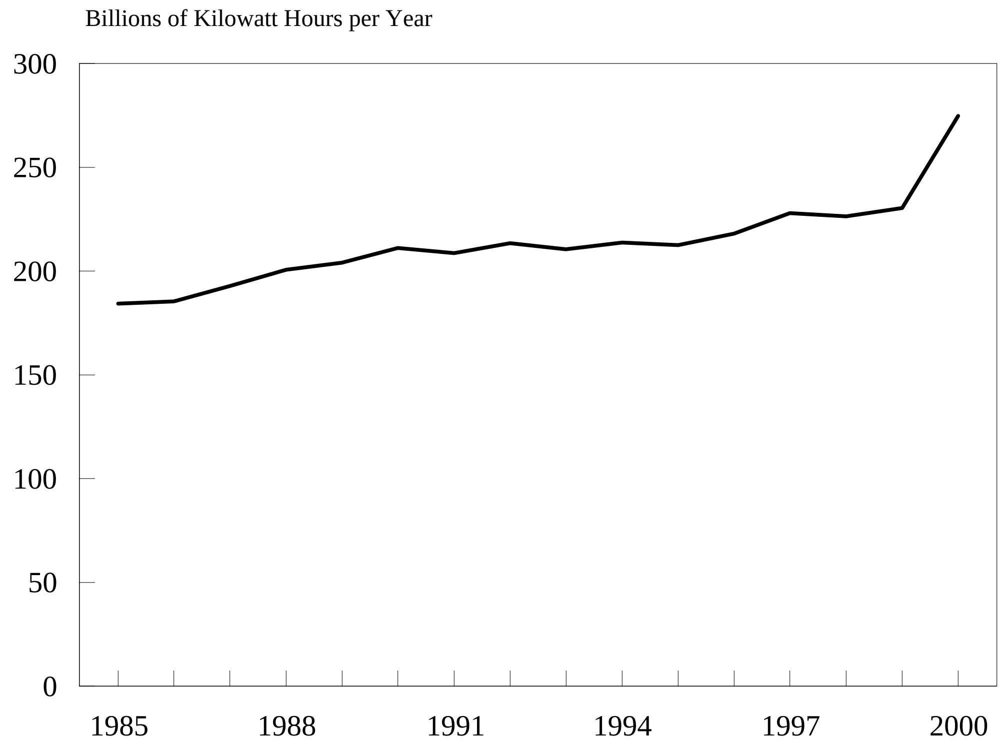
California's electricity crisis was precipitated by a convergence of long-term trends and special circumstances that created a scarcity of power and put upward pressure on electricity prices, not just in California but throughout the West. Several events are especially important to understanding the stress on electricity markets in the region. Strong economic growth in California and extreme weather throughout the West in the summer of 2000 pushed the demand for electricity to record levels. The excess generating capacity of the early 1990s had almost disappeared by that time, especially for peaking capacity (the generating capacity needed to meet the demand for electricity when it is highest). The amount of water flow in streams used to generate hydropower fell in 2000 from the high levels of 1999. And natural gas prices increased sharply, making it difficult to use gas to meet the increased demand for electricity or to replace hydropower without raising prices. In those tight market conditions, some characteristics of California's restructuring plan caused wholesale prices to rise well above what they might have been under the old regulated system or under a better restructuring plan.

Growth in Demand for Power Because of Economic Expansion. Increases in electricity consumption track increases in real (inflation-adjusted) personal income. In California, real personal income grew at an annual rate of 3.2 percent from 1994 through 1998, with a corresponding increase in electricity consumption of 1.5 percent a year.[14] In 2000, however, personal income in California grew by 9.3 percent, which contributed to a surge in demand for electricity (see Figure 2). That unexpected jump in demand put substantial upward pressure on prices.

Under normal circumstances, neighboring states in the Western Interconnect might have responded by selling more power to California utilities, which might have lessened the effect of strong demand on electricity prices. But their capacity to sell to California was strained as well. Those states had to accommodate their own growth in electricity consumption. For example, between 1994 and 1998, Arizona's electricity use grew by 3.8 percent a year, and Nevada's grew by 6.5 percent a year, rates much higher than the 1.5 percent annual growth that California experienced during those years.

14. See Bureau of Economic Analysis, "Regional Accounts Data," available at www.bea.doc.gov/bea/regional/data.htm. Real annual growth in 2000 was estimated by the Congressional Budget Office using BEA data for income and deflators for gross state product.

FIGURE 2. ELECTRICITY CONSUMPTION IN CALIFORNIA, 1985-2000



SOURCE: Congressional Budget Office based on data from Energy Information Administration, *Electric Power Annual*, vol. 1, DOE/EIA-0348/1 (various issues), Table A21.

Extreme Temperatures in Western States. Electricity consumption is also highly dependent on local weather conditions, which affect the demand for cooling in the summer and heating in the winter. For example, the California Energy Commission estimates that if summer temperatures are 5 degrees Fahrenheit higher than normal, California's electricity demand rises by 8.5 percent.[15] In a broad region such as that covered by the Western Interconnect, usually when one area is having extreme weather, such as sustained high temperatures, other areas will be experiencing moderate weather. As a result, regional demand for electricity tends to be more stable than local demand. Across the far western states, utilities have traditionally counted on a pattern of peak demand during the winter in the north (Oregon and Washington) and peak demand during the summer in the south (California, Arizona, and Nevada).

When unusually high or low temperatures occur throughout a broad area, however, demand for electricity in the region can rise significantly. In the summer of

15. California Energy Commission, *High Temperatures & Electricity Demand—An Assessment of Supply Adequacy in California: Trends & Outlook* (Sacramento: California Energy Commission, July 1999).

1998, such a coincidence of high temperatures occurred in California and the Southwest. As a result, California several times declared Stage 2 alerts, which authorized the disruption of interruptible service (service for those customers who pay less in exchange for being cut off in times of shortage). Those weather conditions represented the most extreme coincidence of regional temperatures since 1985 and were thought to be an isolated occurrence. But in the summer of 2000, they happened again, as temperatures stayed high for several periods all across California, Arizona, and New Mexico. Demand for electricity in California was 14 percent greater that summer than in the summer of 1999. Moreover, California's neighbors (which otherwise could have sent excess supply to the state) were experiencing high demand, too.

Weather conditions also had a constricting effect on the supply of power. The far northwestern states experienced earlier-than-normal winter temperatures in the fall of 2000, so little transition existed between summer and winter demand peaks for the entire western region. Because of that short transition, independent producers that had run aging gas-fueled generators at high capacity through the summer were not able to service those units fully during the normal autumn downtime. The result was added maintenance problems with natural gas facilities during the winter months.

<u>Problems with Generating Capacity</u>. The large, unexpected increase in electricity demand in 2000 came at an especially bad time, for two reasons. First, construction of generating capacity in the West had not kept pace with the long-term growth of demand. And second, unusually high levels of existing capacity in California—at times, nearly 10 percent of the state's generating capacity—were idle for maintenance and other reasons.

Between 1995 and 1999, generating capacity in the West remained essentially the same. Data from the Energy Information Administration on capacity at the region's electric utilities and nonutilities present a combined picture of the stagnation in capacity in the West (see Table 1).

When the restructuring debate began in California, the state had a large and costly reserve of generating capacity. But the state's early concern that high capacity led to high year-round prices, plus local opposition to new generating plants and an uncertain investment climate, contributed to a halt in construction of new facilities. (Uncertainty about market restructuring was probably not a major cause of that halt, since a similar lack of investment activity existed in surrounding states that did not restructure.) As California's reserve margin for electricity generation diminished in the late 1990s, it became more and more costly to boost local production to meet short-term increases in demand.

Besides limited capacity, the poor physical condition of existing generators heightened the western states' vulnerability to a severe market disruption in the face of higher demand in 2000. The California Energy Commission reported that in 1999,

TABLE 1. ELECTRICITY-GENERATING CAPACITY IN THE WESTERN STATES, 1995–1999 (In megawatts)

	1995	1996	1997	1998	1999
Electric Utilities (WSCC)	129,751	131,292	129,232	116,159	107,832
Nonutilities (Mountain and Pacific)	16,617	17,408	16,985	29,672	40,096
Total	146,368	148,700	146,217	145,831	147,928

SOURCE: Energy Information Administration, *Electric Power Annual 1999*, vol. 2, DOE/EIA-0348(99)/2 (October 2000), Tables 34 and 53.

NOTE: WSCC is the Western Systems Coordinating Council region (excluding Canada and Mexico) of the North American Electric Reliability Council. Nonutilities are independent electricity producers as well as some small producers (known as qualifying facilities) that use renewable energy sources or cogeneration to produce electricity. Mountain and Pacific are regions of the Census Bureau; figures for those regions include small amounts of generating capacity in Hawaii and Alaska.

about 60 percent of the state's oil- and gas-fired generating units—capacity that was critical for meeting peak-period demand—were at least 30 years old.[16] In part because of the maintenance demands of older equipment, a larger-than-usual share of the existing capacity in California was idle at the outset of the summer 2000 crisis.[17] Planned outages in April 2000 idled about 8,800 megawatts of capacity—nearly a fifth of the state's total. All but about 1,000 megawatts of that capacity came back on line in the next few months, but unplanned outages grew over the summer, reaching about 3,400 megawatts by August. During the subsequent winter crisis, unplanned outages in the state hovered around 4,000 megawatts, or about 10 percent of total generating capacity.[18]

The consequences of strong growth in demand, little growth in capacity, and idled generators show up in data on peak reserve margins. Traditionally, utilities have tried to maintain a large enough reserve of untapped capacity to meet peak-period

16. Ibid.

17. Federal Energy Regulatory Commission, *Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities*, Part I (November 1, 2000), Figure 2-12.

18. Federal Energy Regulatory Commission, *Report on Plant Outages in the State of California* (February 1, 2001), Figure 2.

demand (both seasonal and daily peaks).[19] With growing demand and idled capacity, peak reserve margins in California and the western region were already at historical lows before the summer of 2000.[20] In 1997 (the last year reported), the reserve margin in California and southern Nevada was only 7.8 percent, down from 14.3 percent in 1995 (just before California's restructuring plan was enacted). Those estimates are based on regional demand levels that do not assume a coincidence of extreme weather across states, such as occurred in 1998 and again in the summer of 2000.[21] As a result, they probably overestimate the actual ability of the western power market to meet demand in such circumstances. Since then, reserve margins have continued to shrink.

<u>Problems with Hydropower Supplies and Natural Gas Prices</u>. Electricity supplies in the West in the summer of 2000 were constrained and increasingly expensive because of several interrelated factors involving the supply of hydropower and the price of natural gas. Stream flows returned to normal levels in the western coastal states (from the high levels of 1999) and dropped below normal levels in the mountain states, reducing the region's capacity to generate electricity from hydropower. (In effect, the West had benefited from conditions that were especially favorable to hydropower in 1999, which had masked the problems of California's restructuring plan.) That reduction in hydropower forced the region to rely on more costly sources of electricity, particularly natural-gas-powered facilities owned by independent generators. At the same time, natural gas prices across the country began to climb toward record levels.

In 1999, the California Energy Commission estimated that the western states had just enough reserve generating capacity to accommodate another summer like that of 1998. In other words, regional demand could be met by fully utilizing all available capacity, assuming that stream levels across the West were, on average, at normal levels. That estimate also assumed that utilities would need to restrict sales to some customers with interruptible service, as they had in 1998. But in 2000, electricity generation from hydropower was lower across the western states than it had been in 1998, so noninterruptible service was threatened, too. In California, net generation from hydropower in 2000 dropped 13 percent from the above-normal level

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19. Reserve requirements are set by the North American Electric Reliability Council. Membership in the council is voluntary.

20. California Energy Commission, *High Temperatures & Electricity Demand*, Table III-1.

21. Energy Information Administration, *Electric Power Monthly*, DOE/EIA-0226 (various issues), Tables 45 and 47. Although the North American Electric Reliability Council, which includes California utilities, does not require members to maintain a reserve margin (which includes allowances for scheduled maintenance and forced outages), it does require an operating margin of 5 percent to 7 percent, which could translate into a 15 percent reserve margin.

TABLE 2. NET ELECTRICITY GENERATION FROM HYDROPOWER AND NATURAL GAS IN 11 WESTERN STATES, FIRST NINE MONTHS OF 1999 AND 2000 (In millions of kilowatt hours)

	Hydropower		Natural Gas	
	1999	2000	1999	2000
Electric Utilities	154,020	126,955	29,846	35,995
Nonutilities	3,130	5,231	69,365	102,510
Total	157,150	132,186	99,211	138,505

SOURCE: Energy Information Administration, *Electric Power Monthly*, DOE/EIA-0226(2001/01) (January 2001), Tables 10 and 65.

NOTE: Nonutilities are independent electricity producers as well as some small producers (known as qualifying facilities) that use renewable energy sources or cogeneration to produce electricity.

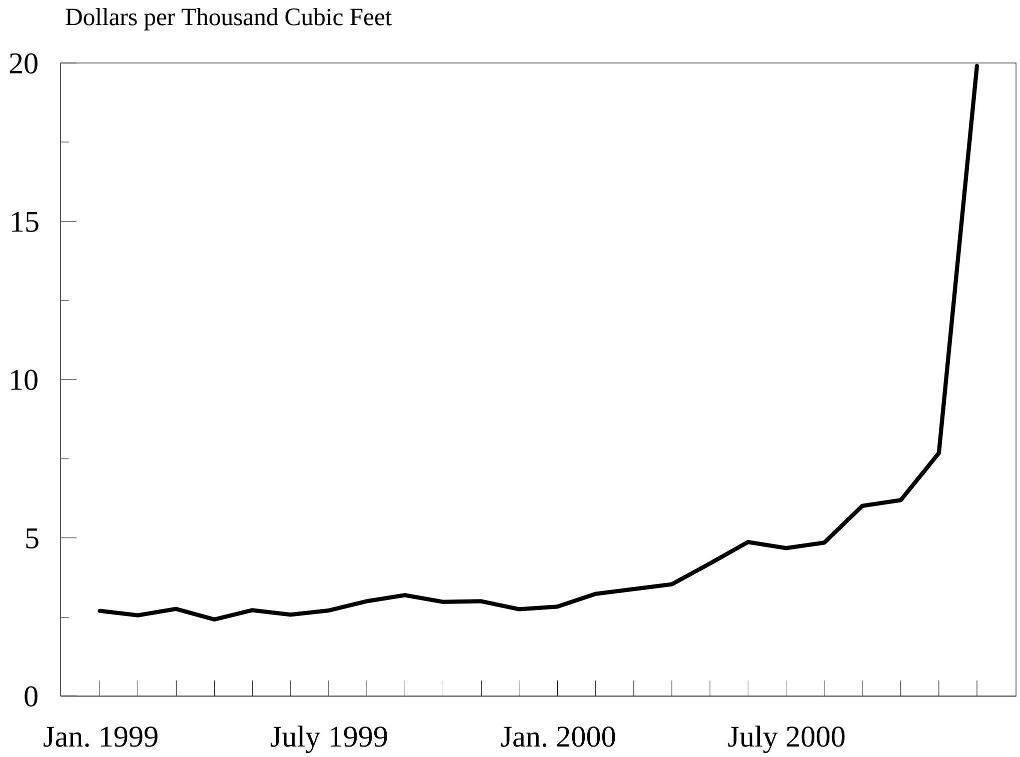
of 1999.[22] For the other western states, total hydropower production fell by 18 percent in 2000. In particular, Washington, Oregon, and Idaho—which the previous year had depended on hydropower for about 85 percent of their electricity generation (and had sent much of that power to California)—had to replace that low-cost energy with electricity from more expensive sources.

That loss of supply from inside and outside California put further upward pressure on electricity prices in the state and the region. As the demand for electricity increased relative to the supply in the summer of 2000, the western market turned increasingly to producers with natural-gas-fired generating plants (see Table 2). At the same time, the high cost of producing electricity from natural gas became greater still. The prices that electricity producers paid for natural gas had remained fairly stable—in the range of $2 to $3 per thousand cubic feet (mcf)—since the wholesale gas market was deregulated in 1986. Starting in April 2000, however, those prices rose significantly above $3 per mcf, reaching $4.90 per mcf by August (see Figure 3).[23]

22. Data for 1999 and the first 10 months of 2000 come from Energy Information Administration, *Electric Power Monthly*, DOE/EIA-0226(2001/01) (January 2001), Table 11.

23. An increase of $1 per thousand cubic feet in the price of natural gas translates into an increase of $20 per megawatt hour in the cost of producing electricity; see Federal Energy Regulatory Commission, "Notice of Proxy Price for February Wholesale Transactions in the California Wholesale Electric Market," Docket No. EL00-95-018, available at www.ferc.gov/electric/bulkpower/feb_proxy.PDF.

FIGURE 3. PRICES THAT CALIFORNIA UTILITIES PAID FOR NATURAL GAS, JANUARY 1999 THROUGH DECEMBER 2000



SOURCE: Congressional Budget Office based on data from Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130 (various issues), Table 24.

The increase in natural gas prices was itself related to developments in the electricity market. Natural gas exploration and development lagged in the past decade because of relatively low prices for oil and gas, which meant that there was little excess capacity to absorb the increase in demand for gas in 2000 that resulted from the demand for electricity. Thus, that higher electricity demand most likely played a role in raising natural gas prices. Support for that view comes from the fact that prices paid for natural gas at the wellhead did not start increasing until June 2000, whereas prices for gas delivered to utilities were already rising two months earlier. Some observers contend that gas marketers actively restrained the supply of natural gas to California in order to push up prices. Evidence for such actions is not apparent, however—the average monthly prices that local distribution companies in the state paid for gas in the past year were not significantly out of line with prices in high-cost cities in the Northeast and the South.[24]

24. Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130(2001/06) (June 2001), Table 20.

Another factor that made supplying electricity from natural gas even more costly was the environmental controls that California adopted to carry out the federal Clean Air Act and its amendments. In particular, electricity producers and other industries in California that burn fossil fuels are required to hold credits for the right to emit nitrogen oxides (NO_x), a by-product of fossil-fuel combustion.[25] Buying NO_x credits represents a cost to producers who exceed the legal standard for NO_x emissions, generally reflecting their avoided cost of acquiring cleaner fuels or investing in technology to reduce emissions. The increased use of natural gas in mid-2000 meant that more credits had to be purchased. As a result, the price of the credits leaped from \$4,000 per ton of emissions to more than \$45,000 per ton during that year. For a natural-gas-fired turbine that emits two pounds of NO_x for each megawatt hour (mWh) of electricity it generates, credit prices at that level add about \$45 per mWh to the cost of electricity.[26]

<u>Cumulative Effects</u>. By early 2001, California's restructuring plan was seen by virtually all observers as a failure. The rolling blackouts that occurred during the first few months of the year provided dramatic evidence of that failure—as did the soaring wholesale prices for electricity and the worsening financial condition of the large utilities that were subject to the plan. The prices that utilities paid for power to supply both the southern and northern California markets had generally been below \$40 per mWh in the spring of 1998. Two years later those prices started rising dramatically, reaching a monthly average of more than \$250 per mWh by the end of 2000 (see Figure 4). Although a precise total is difficult to determine, the press frequently reported that between the onset of the crisis and the first quarter of 2001, the three utilities lost a total of \$12 billion to \$14 billion. In April, Pacific Gas and Electric declared bankruptcy, claiming debts of \$8.9 billion.

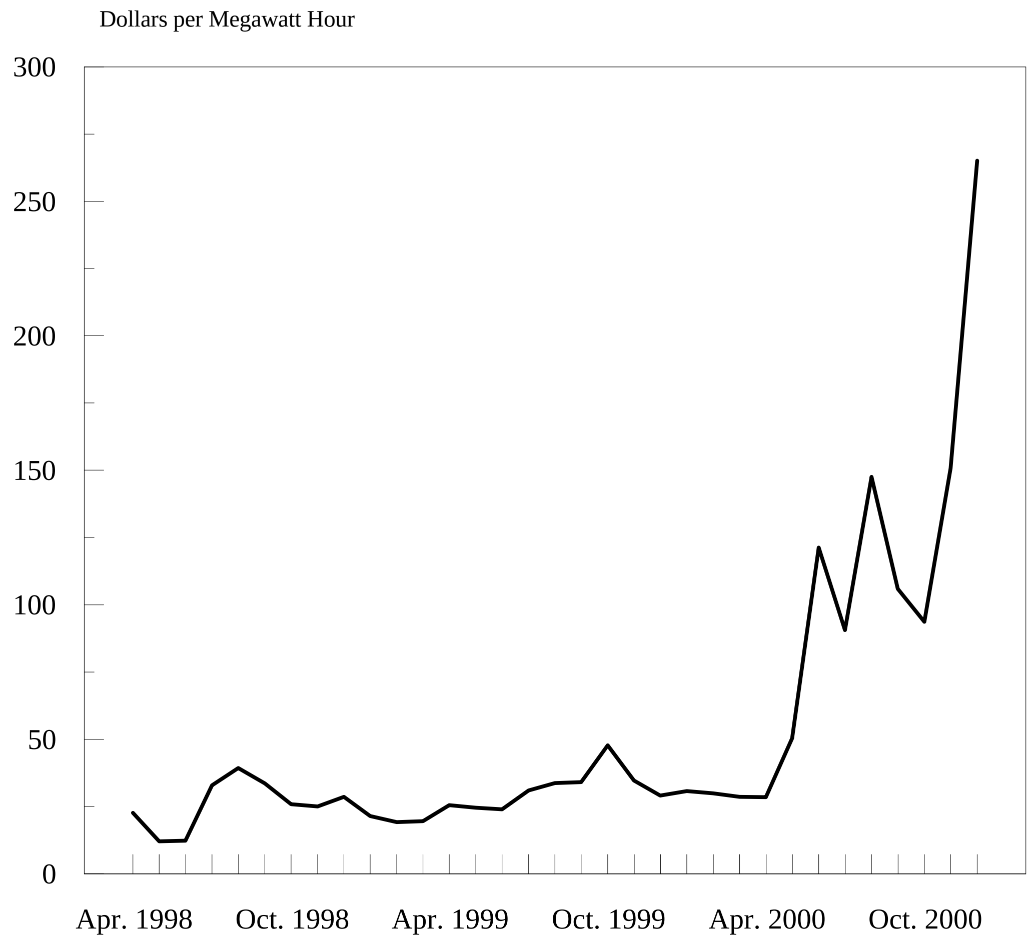
WHAT ROLE DID THE RESTRUCTURING PLAN PLAY?

When California’s plan was enacted, the expectation of falling or (at worst) stable wholesale prices was the political glue that held together the conflicting interests who formulated and agreed to the plan. However, aspects of that plan—combined with

25. The goal of the NO_x credit program is to minimize the total cost of attaining a national standard for NO_x emissions. It requires the operator of a fossil-fuel-fired plant that emits NO_x in excess of the standard to purchase credits from other operators that generate extra credits by emitting NO_x in an amount below the standard. For more information about the NO_x program, see Congressional Budget Office, *Federalism and Environmental Protection: Case Studies for Drinking Water and Ground-Level Ozone* (November 1997), and *Factors Affecting the Relative Success of EPA’s NO_x Cap-and-Trade Program*, CBO Paper (June 1998).

26. Federal Energy Regulatory Commission, *Staff Report to the Federal Energy Regulatory Commission on Western Markets*, Part I.

FIGURE 4. AVERAGE PRICES THAT UTILITIES PAID FOR ELECTRICITY IN THE CALIFORNIA POWER EXCHANGE'S DAY-AHEAD AUCTIONS, APRIL 1998 THROUGH DECEMBER 2000



SOURCE: Congressional Budget Office based on data for the northern and southern regions from the California Energy Commission (available at www.energy.ca.gov/electricity/wepr/monthly_day_ahead_prices.html).

limits on electricity supplies within the state and the rest of the West that were beyond the reach of the plan—amplified upward pressures on wholesale prices.

Analysts point to three features of the restructuring plan that go a long way in explaining how the stresses of extreme market conditions in the summer of 2000 pushed California's utilities into debt and led to supply disruptions in the state. Those features are the freeze on retail prices, the restriction on long-term contracts, and the design of the PX and CAISO markets. The first two features created a financial disaster for the investor-owned utilities when wholesale electricity prices began to rise. The third feature exacerbated those financial problems by letting independent producers avoid limits on wholesale prices and, perhaps, by enabling them to exercise their market power to raise prices even further. However, the restructuring plan did not and could not alter all of the western power market, much of which remained regulated by other states and the federal government.

The Price Freeze

Initially, the freeze on the price that retail customers could be charged for electricity acted as a price floor. The idea was that if wholesale prices fell (which they were expected to do), retail prices would not fall along with them. That would help maintain the utilities' cash flows, although it would also keep consumers from enjoying the benefits of competition at the wholesale level. In the summer of 2000, however, wholesale prices rose above the fixed retail price for a sustained period. When that happened, the freeze acted as a price ceiling: utilities could not pass on their rising costs to consumers.[27]

Not allowing retail prices to change with conditions in the wholesale market had three important effects. First, and critically, when wholesale prices rose, net cash flows for the investor-owned utilities fell, which made it impossible for them to continue distributing electricity profitably. Instead, they had to sell at a loss. Even though the utilities are required to meet all of their customers' needs for power, their financial difficulties have forced them to curtail service on several occasions (through brownouts and blackouts).[28] Second, the price freeze probably discouraged new retail sellers from entering the market. Third, the freeze diminished whatever incentive retail customers would otherwise have had to reduce their electricity use. Such a reduction could have helped dampen some of the upward pressure on wholesale prices.

Financial Problems for Utilities. The price freeze affected the wholesale market for electricity in ways that hurt the investor-owned utilities. As the financial condition of those utilities deteriorated (from having to operate at a loss), some producers demanded higher prices to sell power to the utilities to compensate for the risk that they would not get paid. Those fears proved to be realistic; the utilities stopped payments to the CAISO and to small independent generators or cogenerators of electricity. Some generators, such as those producing electricity from hydroelectric facilities, reportedly refused to sell to California utilities at any price until credit concerns could

27. As noted earlier, the freeze was intended to last until the three large investor-owned utilities recovered their stranded costs or until 2002 (whichever came first). In the summer of 2000, the freeze still applied to customers of two utilities, Pacific Gas and Electric and Southern California Edison. The freeze for customers of San Diego Gas and Electric had been lifted on July 1, 1999 (although it was reimposed later).

28. Brownouts involve decreasing the level of power supplied to customers (reducing the voltage); blackouts involve turning off power completely.

be resolved.[29] (Their reluctance was part of what prompted the state to assume responsibility for purchasing power on its own.) In addition, the large California utilities operate distribution systems for natural gas, and the severe fall in their electricity earnings jeopardized their ability to buy natural gas for resale to independent power generators.[30]

Fewer Retail Sellers. More subtly, the price freeze probably also discouraged some generators and marketers of electricity from selling power directly to retail customers in California. If the price faced by consumers who stayed with their traditional utility had tracked the wholesale price of power (even with various surcharges) rather than being frozen, the resulting variation in prices would have left room for retailers to offer fixed-price contracts to attract risk-averse consumers. Those alternative retailers would have been free to sign long-term contracts with suppliers or engage in other hedging activities to minimize the risk they faced in offering fixed prices to their customers—activities that the restructuring plan did not allow California's private utilities to pursue.

Little Incentive for Conservation. The retail price freeze also diminished the incentives for consumers to conserve electricity. The ability of consumers to greatly reduce electricity use on short notice is small relative to their total consumption. But relative to the size of the power disruptions that California has experienced so far, the ability to conserve could be significant. Reserve margins of less than 1.5 percent will trigger rolling blackouts; in the blackouts of March 2001, about 5 percent of California's households and businesses experienced a loss of service, which lasted for less than two hours. Even a very small percentage reduction in consumption could have helped avert such interruptions of service.

In San Diego, where retail customers briefly faced market prices in the summer of 2000, evidence suggests that higher prices caused a decline in power use. A doubling of retail prices led to a drop in demand of between 2.2 percent and 7.6 percent, depending on the hour of the day.[31] By September 2000, legislators had

29. The U.S. Secretary of Energy (first William Richardson and then Spencer Abraham) has required generators to sell to the California market. The Secretary derives the authority to do that from section 202(c) of the Federal Power Act. If California utilities are ultimately unable to pay for electricity that the federal government requires generators to sell to them, it is unclear who will be responsible for those losses.

30. The U.S. Secretary of Energy has required natural gas suppliers to deliver to Pacific Gas and Electric. The Secretary derives the authority to do that from section 302 of the Natural Gas Policy Act and section 101(c) of the Defense Production Act.

31. James Bushnell and Erin Mansur, *The Impact of Retail Rate Deregulation on Electricity Consumption in San Diego*, Working Paper PWP-082 (Berkeley, Calif.: University of California Energy Institute, Program on Workable Energy Regulation, April 2001), available at www.ucei.berkeley.edu/ucei/PDF/pwp082.pdf.

responded to public pressure by reducing and refreezing retail prices in San Diego, so customers there had no further incentive to curb their demand for electricity. Indeed, the opposite may have occurred, since consumers increased their use when prices dropped.

Although consumers' ability to reduce power consumption in response to higher prices is limited in the short term, it increases in the longer term. When they are faced with the full cost of electricity, residential customers have an incentive to buy energy-saving appliances, add insulation to their homes, or switch from electric to gas-fired appliances. Industrial customers can not only purchase energy-efficient equipment but also add their own power-generating facilities or even cogeneration facilities that harness waste heat from their industrial processes.

A price freeze that keeps consumers' costs low retards such reductions in the demand for electricity. By protecting consumers from price volatility, a freeze can also dampen their incentive to invest in the ability to alter electricity purchases on short notice—such as by owning auxiliary petroleum- or gas-fired generators—or even to sign up for interruptible service with their utility. The absence of a consumer response to price changes places a greater burden on suppliers to adjust to shifting market conditions.

The Restrictions on Long-Term Contracts

California's Public Utility Commission generally interpreted the restructuring plan as incompatible with allowing the utilities to contract for long-term power supplies outside the PX (until its termination) and the CAISO. That restriction applied to two types of long-term arrangements: contracts that the utilities made in the futures market and contracts in which the independent producers that had purchased the utilities' generating assets agreed to supply the utilities with a certain amount of electricity in the future.[32]

The PUC's opposition to long-term contracts was consistent with the plan's emphasis on creating a competitive wholesale market and giving that market a big role in determining the wholesale price of electricity. Indeed, in California, the spot market ended up supplying about half of the utilities' demand for power, on average, compared with only about 10 percent to 20 percent in other restructured service

32. The PX requested and was granted authority by the Federal Energy Regulatory Commission in several instances to offer forward contracts, including contracts for the block-forward market. Later, the PUC permitted the investor-owned utilities to participate in those new PX markets, although it limited the amount of power they could buy for future delivery. The PUC also reserved the right to review contracted prices for future reasonableness, so those new contracts did not effectively help the utilities guarantee a price for future delivery.

areas, such as Pennsylvania, New Jersey, Maryland, and the New England states.[33] California's reliance on spot-market purchases was even greater during periods of peak demand. But the utilities could not defend themselves against increases in wholesale prices by using their traditional recourse to self-supply or other risk-management strategies. The rationale for discouraging long-term contracting, like that for the retail price freeze, rested in large part on the assumption that available generating capacity would remain large enough to keep wholesale prices low.

Historically, California's big private utilities had not faced significant risk of adverse price movements caused by changes in supply or demand. In collaboration with the PUC, the utilities maintained a high margin of reserve capacity, which was included in their rate base and thus paid for by customers. (A high reserve margin contributes to reliability of service for consumers by making disruptions of service less likely in the event that generating units are unexpectedly idled or load increases.) Under the restructuring plan, by contrast, the new reliance on spot-market purchases and the retail price freeze made the utilities subject for the first time to the risk of financial loss if wholesale prices rose. Their ability to limit that type of risk was sharply curtailed by the plan's restrictions on the use of long-term supply contracts and futures markets and by the requirement that they sell much of their power-generating capacity.

It is not clear that the utilities recognized their new exposure to market risks or that they would have acted to reduce that exposure if they had been allowed to do so. Some accounts suggest that initially, the utilities did not want to sign long-term, fixed-price contracts because long-term prices were generally higher than the spot prices they were paying in the PX and CAISO auctions and they were trying to maximize cash flow to recover their stranded costs.

Had the utilities been able to enter into long-term contracts that guaranteed their future cost or supply of electricity, such arrangements would have helped diminish the shortage of power-generating capacity—and thus reduced the upward pressures on prices. Such long-term guarantees would have encouraged independent generators to build new capacity and would have improved the utilities' financial position, so generators might not have charged higher prices as compensation for the risk of nonpayment by the utilities.

Because the investor-owned utilities were not able to protect themselves from the risk of adverse movements in wholesale prices and because retail prices were frozen, consumers were exposed to the risk of losing service. Furthermore, the plan's heavy reliance on the spot market to meet peak-period demand potentially gave independent generators a great deal of power over that market.

33. California State Auditor, *Energy Deregulation*, p. 24.

Flawed Auction Markets, Price Caps, and Market Power

The spot market for electricity created by California's restructuring plan comprised the PX and CAISO auctions, the rules governing those auctions, and oversight by the FERC. Prices in spot markets for electricity can change quickly and dramatically because both the short-term demand for electricity and (without a large reserve margin) the short-term supply are not very responsive to changes in price. In other words, in a tight market, only a very large price increase can produce the combined responses in demand and supply that are necessary to avoid a supply shortage.

As with many features of California's plan, the spot market might have worked better if a sufficient reserve of peaking capacity had existed, as was assumed when the plan took effect. Not only did the potential for large price increases grow as the reserve margin disappeared, but some analysts believe that features of the market's design contributed to even larger price increases. Those analysts point to the design of the PX and CAISO auctions, the price caps established for the CAISO market, and the withholding of supplies during certain periods.[34]

The design of the auction systems may have given individual sellers an opportunity to engage in strategic bidding to secure higher prices.[35] Sellers in the PX auctions submitted bids in the form of a supply schedule; the markets' operators then scheduled power generation by those individual sellers, from the lowest-cost to the highest, until all of the demand to be met by the auction had been satisfied. In the CAISO auctions, sellers submit single-price bids, subject to a price cap that may be lifted during emergencies. In both markets, the price paid to all successful bidders reflects the cost of the last and most expensive increment of supply from the highest bidder. Some analysts believe that the PX system gave sellers an incentive to submit supply schedules with relatively low prices (reflecting actual costs) for most of their sales and very high prices (exceeding costs) for the last units of power offered. The idea was that sellers expected sometimes to be awarded that top price for all of their sales but never risked not selling the bulk of their power.

The CAISO established price caps to eliminate the temporary spikes in prices that can occur during periods of peak demand. Those caps may have served as a focal point when sellers set the top price in their supply bids. That is, the existence of caps

34. For a discussion of competition in the California market, see Severin Borenstein, James Bushnell, and Frank Wolak, *Diagnosing Market Power in California's Restructured Wholesale Electricity Market*, Working Paper No. 7868 (Cambridge, Mass.: National Bureau of Economic Research, September 2000).

35. For a discussion of how the auctions and price caps operate, see California State Auditor, *Energy Deregulation*.

in the CAISO market may have encouraged bidding in the CAISO and PX markets at higher prices.[36]

The caps probably did not achieve their goal of effectively restraining prices. The CAISO had discretion to lift its caps altogether if it believed that a supply shortage was imminent. If sellers withheld supply in the day-ahead market—so that it looked to the CAISO as though a real-time shortfall was imminent—the CAISO was more likely to lift its caps. Indeed, independent power producers reportedly avoided the caps by selling some power to municipal utilities in California and to utilities outside the state for resale to the CAISO, since out-of-market sales by those utilities to the CAISO were never subject to caps.

It is also possible that individual sellers tacitly colluded to withhold supplies in order to push prices above competitive levels. Taking advantage of the designs of the auction system and price caps (to bid prices that exceeded costs) would enable those suppliers to realize above-market prices and profits from withholding supplies. However, evidence about how much, if any, capacity was withheld for competitive rather than legitimate operational reasons is unclear. Academic and legal debate continues over the extent to which the price increases of the past year resulted from exercises of market power by electricity generators. Discussions about whether specific laws have been broken focus on the Federal Power Act and its requirement that wholesale electricity rates be "just and reasonable," as well as on general antitrust statutes that prohibit price fixing.

Regulated Power Markets in California and the Rest of the West

Another way in which California's restructuring plan helped turn the market stresses of mid-2000 into a crisis was by not adequately taking into account how dependent the state's large investor-owned utilities were on other utilities, both inside and outside California. The legislation that authorized the plan did not require all utilities in the state to participate in the new market, and California law of course did not govern other states' utilities or federal power agencies. The three private utilities covered by the plan buy only a small part of their electricity from those sources; but at the critical margin, constraints on the flow of power into the new wholesale market probably influenced the source and cost of the last kilowatt hour of power, which determined the price for all of the electricity sold in the market.

36. From the buyers' perspective, the price cap in the CAISO auction would have represented the maximum price they would want to pay in the PX auction. If the PX price ever exceeded the CAISO price, buyers would reduce their demand bids in the PX auction and allow the CAISO to make purchases on their behalf.

Specifically, the restructuring plan did not include 38 municipal and cooperative utilities (most notably the Los Angeles and Sacramento municipal utility districts). It also did not cover three small investor-owned utilities in the state. Together, those excluded utilities account for about 30 percent of direct retail sales of electricity in California. The state's municipal utilities did not want to join the restructured electricity market for at least two reasons. First, they did not have the same high exposure to stranded costs that the private utilities did, and hence, they did not need the state's plan to recover those costs. Second, they receive a federal tax preference that could have been jeopardized if they had sold too much power, under the plan, to other utilities (see Box 2).

Other constraints on the flow of power to the wholesale market include various types of regulations, such as the regional-preference and average-cost-pricing rules of the utilities outside the restructuring plan and regulations that impede the regional transmission of electricity.

Regional-Preference Rules. Power from utilities outside California has not been completely free to flow in response to price signals in the state's wholesale market. Those utilities (like municipally owned and cooperative producers within the state) are required to meet the power demands of their service areas before exporting power to other markets, even if wholesale prices are higher elsewhere. Similar regional-preference rules make it difficult for more power to flow to California from the federally owned Bonneville Power Administration and Western Area Power Administration. Those agencies supply about 10 percent of the California market, on average—mainly through sales to municipal and cooperative utilities. But most of their relatively inexpensive hydropower goes to municipal utilities, cooperatives, and industrial customers in the northwestern states.[37]

The regional-preference rules of local utilities and federal power agencies have the effect of impeding energy flows across the western states largely because the customers of that power do not have full rights to its use. In particular, they do not have the right to resell the power on their own or to receive compensation if the utility sells it elsewhere. That restriction has weakened somewhat in the past year, with

37. The Bonneville Power Administration (BPA) may sell excess power at higher rates outside the region and does sell some power to California's municipal utilities. The Western Area Power Administration (WAPA) sells to municipal utilities and cooperatives throughout the West at prices established under terms similar to those for the BPA. The subsidies implicit in federal rate-setting and the reliance on hydropower cause federal rates to be much lower than prices from nonfederal producers. Although the BPA and WAPA are not free to sell to investor-owned utilities in California, both agencies engage in power swaps with those utilities, dispatching federal power today to be repaid with California utility power at a later date.

BOX 2.
MUNICIPAL UTILITIES AND THE FEDERAL TAX EXEMPTION
FOR STATE AND LOCAL BONDS

Many local governments operate electric utilities, generally known as municipal utilities (or munis). The munis engage primarily in retail distribution, buying power from others and selling it to homes and businesses in their service areas. But some munis, including the Sacramento Municipal Utility District (SMUD) and the Los Angeles Water and Power District (LAWPD), also generate their own power.

The munis, like other state and local government entities, commonly issue bonds to pay for construction. The interest on such bonds is generally exempt from federal taxation. As a consequence, bondholders are willing to accept a reduced interest rate, and the munis can borrow at favorable rates. Federal policy favors the munis in other ways, too: by exempting their income from federal taxation and by giving them preferential access to low-cost federal power.

Federal restrictions on the use of the munis' borrowed funds have made California's munis reluctant to sell power to the state's investor-owned utilities for fear of losing the tax exemption on their bonds. The federal government limits the use of tax-exempt bonds in financing public facilities in order to prevent state and local officials from using the proceeds to make favorable loans to private businesses. Section 141 of the Internal Revenue Code generally allows no more than 10 percent of bond proceeds to be used by a private business if that business is receiving favorable electricity rates or is outside a muni's traditional service area. That private-use restriction applies over the life of a bond issue, and violation can result in the interest income becoming taxable retroactively.

Participation by munis in a restructured electricity market could violate the private-use rule and trigger taxation of interest payments on their bonds.[1] One example relates to munis' power sales. Selling power to utilities outside a muni's service area, if that power was generated by or transmitted over facilities financed with tax-exempt bonds that have not been paid off, could violate section 141. A second example relates to power distribution for others. Allowing investor-owned utilities to use a muni's distribution facilities that were financed with tax-exempt bonds that are still outstanding could also violate section 141. In 1999, the SMUD and LAWPD made about 15 percent of their power sales to other utilities. However, that electricity was generated at debt-free facilities (no longer subject to the private-use rule), was sold in short-term spot markets consistent with Internal Revenue Service regulations, or fit under the allowable limits on private use.

1. See Dennis Zimmerman, *Electricity Restructuring and Tax-Exempt Bonds: Economic Analysis of Legislative Proposals*, Report RL30411 (Congressional Research Service, January 20, 2000).

some suppliers offering to pay large customers not to take power (as part of their programs for demand-side management) and others granting sale rights.[38]

Average-Cost Pricing. A common feature of power regulation in the United States is that a regulated provider of electricity sets a price that reflects its average costs. All of the utilities outside California's restructured market generally adhere to that pricing rule. However, average-cost pricing reduces incentives for the customers of those utilities to limit their consumption when power costs rise. Such conservation would help free up supplies that could be sold on the wholesale market.

Although some of those utilities have been forced to buy increasingly expensive power in the wholesale market to compensate for high demand and lost hydropower capacity, price increases to their local customers have been held down by the continuing low costs of the power they generate themselves or buy from the federal government. As with regional preferences, the problem here lies not just with average-cost pricing but with the rights to the power: customers would have full incentives to conserve in the face of rising spot prices if they could resell that power in the wholesale market.

Transmission Bottlenecks. Other types of regulation, related to the construction of transmission lines and the pricing of transmission services, also impede the flow of electricity from regions where it can be produced at the lowest cost to regions where consumers value it the most. Individual transmission systems are generally part of broad power grids that connect many states. For that reason, transmission services and rates are regulated by the federal government. (Only in Texas, where transmission is entirely within the state, is there no federal role.) Decisions about the construction and siting of transmission lines, however, are primarily a local affair. With the growth of nonutility suppliers and wholesale competition, power is moving across transmission lines in directions and volumes that the utilities that designed the systems did not envision. Those new flows have created bottlenecks in the delivery of power.

The building of new transmission capacity to remove bottlenecks is limited by two factors: the extent of local control over construction decisions and the way in which transmission services are priced. Requests for permission to build transmission lines must come from local utilities, which are state-franchised monopolies, and must be approved by local regulators. Investments that create opportunities for outside utilities or independent power producers to compete in a local market or that appear

38. A notable example is Kaiser Aluminum, which buys electricity from the Bonneville Power Administration. Kaiser chose to shut down its aluminum operations until the fall of 2001 (when its current contract with BPA expires) in order to resell its cheap BPA power to California. The BPA is acting as Kaiser's marketing agent, selling most of the power at full market prices minus a small marketing fee. Kaiser employees continue to be paid during the shutdown.

primarily to benefit other communities may be suspect. The siting of transmission lines is also dependent on local approval and environmental considerations.

The regulation of prices for transmission services may also mute economic signals about when and where to add new capacity. Most transmission lines in the United States are owned by private utilities or the federal government. The principal regulatory agency for private lines is the FERC, which sets prices for transmission on the basis of a utility's average systemwide cost of building and operating transmission lines, a fair market return on the utility's investment, and its current operating costs. The federal power agencies (such as the Bonneville Power Administration) are largely self-regulating. They set their own systemwide transmission rates on the basis of historical capital costs and current operating costs. The average-cost-pricing rules used by the FERC and the federal agencies do not provide incentives to add capacity to congested parts of the transmission grid.

CALIFORNIA'S RESPONSE: A NEW ROLE FOR STATE GOVERNMENT

A broad goal of restructuring in California was to secure the benefits of competition for electricity consumers in two ways: by breaking up the vertically integrated, state-regulated monopolies to create more wholesale suppliers, and by giving retail customers the chance to choose their power producer. However, the state's response to the crisis and its efforts to secure adequate electricity supplies and control volatile wholesale prices are leaving California with a new market structure.

The new market differs from the old regulated-monopoly system, from the interim restructuring plan, and from the competitive ideal that the state was working toward. Beginning in January 2001, the governor, the California legislature, and the Public Utility Commission acted to give the state a long-term role in buying wholesale power on behalf of private utilities. Lawmakers are also moving toward establishing a new state-owned utility that would not only buy power but also own and operate the transmission systems of the state's private utilities and build and operate new generating plants. The state has effectively abandoned the freeze on retail electricity prices, raising rates to help cover its costs of buying power.

The New Purchasing Agency

The California agency now charged with purchasing electricity is the Department of Water Resources (DWR). That department has become one of the largest buyers of electricity in the country. It has reportedly signed contracts that cover 90 percent of the wholesale purchasing requirements of the state's three large investor-owned utilities—or about one-third of California's total power use. In addition, a new agency, the California Consumer Power and Conservation Authority, will acquire generating capacity to supplement the state's supplies and sell the power it generates to the DWR. A new state bureaucracy will also be needed to manage much of California's transmission grid if the state is successful in taking over the transmission lines of the three large utilities.

California is planning the largest state or local bond issue in history—as high as $13.4 billion—in the fall of 2001 to finance its purchases of electricity and natural gas in 2001 and its acquisition of private transmission assets. Revenue from the sale of those bonds may also be used to help shore up the financial position of the private utilities. In the first seven months of 2001, the DWR spent about $9.5 billion from its general fund and from short-term borrowing to buy electricity and natural gas (recouping only about $1.5 billion from reselling that power to utilities). The agency made those purchases in the spot market for immediate delivery as well as in the markets for short- and long-term delivery, with signed contracts valued at over $45 billion. The contracts guarantee delivery for various periods, some as long as 20 years.

With the emergence of the DWR, the role of the state's private utilities and the PUC (which regulates those utilities) is diminishing. And with one large buyer replacing three utilities in the state's wholesale market, competition will most likely diminish as well. Those utilities may keep their nuclear and hydropower generating plants and their long-term supply contracts with qualifying facilities, but otherwise they will have a small presence in the wholesale market. Instead, the utilities will act as distributors of power purchased by the state, charging retail customers for the full cost of those purchases.

The future position of the state's independent power producers may also be in question. Not only are they facing fewer buyers, but their biggest customer, the state, may have the authority to seize their assets if it believes they are charging too much for electricity or restricting supplies. The California Senate passed a resolution in July 2001 indicating that it would support the governor in such a seizure.

In August, the PUC effectively yielded authority to the DWR to set retail electricity rates without public review in order to ensure sufficient revenues to cover its bond issue. (Both organizations are subject to direction from the governor's office, which appoints members to the PUC and selects managers of the DWR.) The PUC had already approved rate hikes in January and March to help cover the state's costs. In future, the state will direct the large private utilities to set rates that will repay expenses incurred in 2001 and cover the state's current costs of buying power. The state plans to secure its upcoming bond issue with those power revenues. The PUC will continue to oversee the part of the retail rate that covers the utilities' cost of generating electricity, having power purchased on their behalf, and distributing power. It is not clear which organization—the PUC, DWR, or a new agency—would decide what rates are necessary to finance operations of a future state-owned transmission grid.

Implications of the State's New Role

California's actions represent a blunt solution to the problems of insecure supply and volatile prices—a solution that ultimately may present the state with many of the same problems that restructuring was intended to solve. The goal of securing the benefits of competition appears to be farther away than ever. For example, tension exists between the state's need to raise rates to pay for the debt it incurred during the crisis and the right of ratepayers in a competitive market to contract with other power providers. In fact, since the rate hike of March 2001, some industrial customers have begun exercising their option to choose other suppliers. As a result, the state wants to rescind that option for all customers. The situation is similar to the one that prevailed before the crisis, when utilities with stranded costs opposed a rapid switch to a competitive system because it would leave them unable to recover those costs from ratepayers.

Two other factors that could make it harder to achieve the goal of competitive prices are the lack of transparency of state actions and the possibility of government subsidies to the state electricity business. In general, the state will not be subject to oversight in its rate setting. Electricity rates are supposed to cover financing costs, current power costs, and administrative costs. Because the state is actively concerned about security of supply, it may be putting too much emphasis on costly long-term contracts—much as the private utilities relied too heavily on risky spot-market purchases. Already, in July 2001, as demand and wholesale prices dropped with moderate weather in the West, the average cost of the state's power purchases ($133 per mWh) rose above the average price in the spot market ($82 per mWh).[39] Those and any future losses on power purchases will be passed on to consumers. Moreover, it is not clear what "administrative costs" of the state will find their way into retail electricity prices. With no oversight, California has already demonstrated its reluctance to publish information about the contracts it has signed or its costs of purchasing power and has released that information only under court order.

If the state cannot recover all of its electricity-related costs through retail prices, California taxpayers will have to make up the difference. In short, the state may be at risk of creating a major government-subsidized industry—an industry that private suppliers could be at a disadvantage in competing against.

39. California Department of Water Resources, "July Energy Costs Down Significantly" (press release, Sacramento, July 16, 2001), available at www.owe.water.ca.gov/newsreleases/2001/7-16-01energycosts.html.

LESSONS FOR FUTURE RESTRUCTURING EFFORTS

California's problems have occurred at a time when many other states are restructuring, or are debating the merits of restructuring, their electricity markets. The experience of California suggests several lessons for those states about both the supply and demand sides of electricity markets. In particular, if markets rather than regulation are to determine the price of power, prices must be allowed to respond when unanticipated disturbances occur—such as last year's very hot summer in the West. The supply and demand sides of the market together must be sufficiently robust to dampen such swings.

Supply-Side Lessons

The lessons for the supply side of the market are twofold. First, restructuring is more likely to succeed when more of the power in a market is free to respond to price signals. As California attempted to restructure, regulatory constraints limited the flow of power to the state's wholesale market from municipal utilities in California, from utilities in other states, and from federal power agencies. Second, utilities should be free to manage the risks of adverse price movements in that competitive environment by entering into long-term contracts. One lesson not to take from the California experience relates to the size of the reserve margin: building enough generating capacity to meet the demand for electricity under any scenario may not be cost-effective.

If restructuring is to allow supply to be more responsive to prices by moving power within the market, it must also address regulatory barriers to the construction and operation of transmission systems. A restructured market that works well will probably feature an immediate increase in the demand for transmission services, as communities increasingly acquire power from new sources in new locations not envisioned by the original designers of the transmission grid.[40] The regionwide costs of supplying electricity can drop if low-cost generators from some states in the region are able to provide more power than before. Moreover, the responsiveness of regionwide supply can improve if additional suppliers from part of the region are able to put more power into the grid to offset disruptions in supply locally or unexpected surges in demand elsewhere in the region. To realize those gains, however, consumers must be willing to accept a trade-off: the lower prices that result from access to out-of-state power supplies will sometimes rise when their state sends supplies to other parts of the region.

40. Any increase in the distance that power is transmitted will result in some additional transmission losses (about 9 percent of the electricity that leaves power plants is lost to heat transfer, which results from resistance in the power lines).

Making sure that transmission capacity does not limit the responsiveness of supply may require changing how transmission services are regulated and priced (to create appropriate incentives for new construction) and how new lines are approved. For example, some analysts have called for charging different, market-sensitive rates for transmission in different parts of the overall system—a practice known as node pricing—to provide greater incentives for construction to remove bottlenecks. The FERC believes that creating regional transmission organizations to operate large sections of the grid could help, too.[41]

Restructuring is also more likely to be successful if utilities are allowed to use standard risk-management tools. Letting utilities both enter into long-term contracts with suppliers at fixed prices and hedge through the futures market would help protect them from the financial difficulties that have plagued California's power distributors. It would also enable the utilities to offer greater price certainty to their customers (in place of a freeze on retail rates). That price certainty is important not just because it protects against high prices but because it creates a better climate for producers, distributors, and consumers.

Having a large reserve of generating capacity could ease the transition from a regulated to a competitive market structure. Indeed, if California had implemented its plan in the early 1990s, when the state's utilities still possessed more capacity than they needed, the market could have better handled the stresses that arose in the summer of 2000. That improved response could in turn have masked some of the faults of the restructuring plan.

Creating such a reserve as a matter of policy, however, is an expensive way to ensure price stability. One of the reasons that the state moved to a competitive market structure was to help reduce electricity prices by lowering the costs of the utilities' reserve capacity. In a competitive market, producers' investment in reserve capacity should be consistent with the amount of price stability (or, equivalently, supply security) that consumers are willing to pay for in the form of long-term supply contracts.

Demand-Side Lessons

California's freeze on retail rates inhibited the response of electricity users to the state's supply problems. Thus, it proved to be a major factor in the ensuing crisis. A simple lesson of that experience is that consumers need to face the real cost of electricity. Exposing consumers to price changes will induce them to increase their use of power when prices fall and curtail it when prices rise. When prices do not

41. See Federal Energy Regulatory Commission, "Regional Transmission Organization," Order No. 2000, *Federal Register*, vol. 65 (January 6, 2000), p. 809.

change along with costs, and when the amount of power demanded cannot respond to prices in that way, a greater adjustment must be made on the supply side of the market.

Price signals should encourage consumers not only to buy more or less power now but also to invest in the ability to adjust their future power use. Some of the same demand responsiveness that results from having consumers pay market prices may also be achieved if utilities either compensate customers for reducing their use or allow customers to resell power to others (in which case, a third party is paying them to reduce their use).

An important distinction exists between long- and short-term capabilities for lowering power use. In California, consumers have already responded over the years to high electricity prices by, among other things, adding thermal insulation to buildings, purchasing efficient appliances, and switching to natural gas. Those are long-term investments. Indeed, the state ranks among the lowest nationally in per capita use of electricity by households. However, electricity consumers—particularly households—have acquired few devices that would let them reduce electricity use on short notice, such as real-time meters (which would tell them when prices were changing), backup power supplies, or dual-fuel capabilities. One reason is that consumers do not usually face real-time prices (in particular, the full cost of generating electricity during peak-use times). Another reason is that although electricity prices in California have been high overall, they have historically been stable.

Some analysts believe that the supply adjustments and resulting price increases in California would have been much smaller if various techniques to manage demand had been in wide use before restructuring.[42] For example, several approaches can make real-time pricing easier, such as technologies that monitor electricity use and prices, and contracting arrangements with electricity suppliers that permit the customer (or a designated agent) to interrupt service when the price rises. In many cases, large industrial customers already have the capacity to monitor and adjust their demand in the face of rising prices and, in fact, do so. Successful restructuring may necessitate that residential and commercial customers acquire many of the same demand-management capabilities that industrial consumers have.

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42. See Stephen J. Rassenti, Vernon L. Smith, and Bart J. Wilson, *Demand-Side Bidding Will Control Market Power, and Decrease the Level and Volatility of Prices* (Tucson: Economic Science Laboratory, University of Arizona, February 2001); Severin Borenstein, *The Trouble with Electricity Markets (and Some Solutions)*, Working Paper PWP-081 (Berkeley, Calif.: University of California Energy Institute, Program on Workable Energy Regulation, January 2001), available at www.ucei.berkeley.edu/ucei/PDF/pwp081.pdf; and Paul Joskow, "Deregulation and Regulatory Reform in the U.S. Electric Power Sector" (paper prepared for the Brookings-AEI Conference on Deregulation in Network Industries, December 10, 1999, revised February 17, 2000), available at http://econ-www.mit.edu/faculty/pjoskow/files/BrookingsV2.pdf.

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