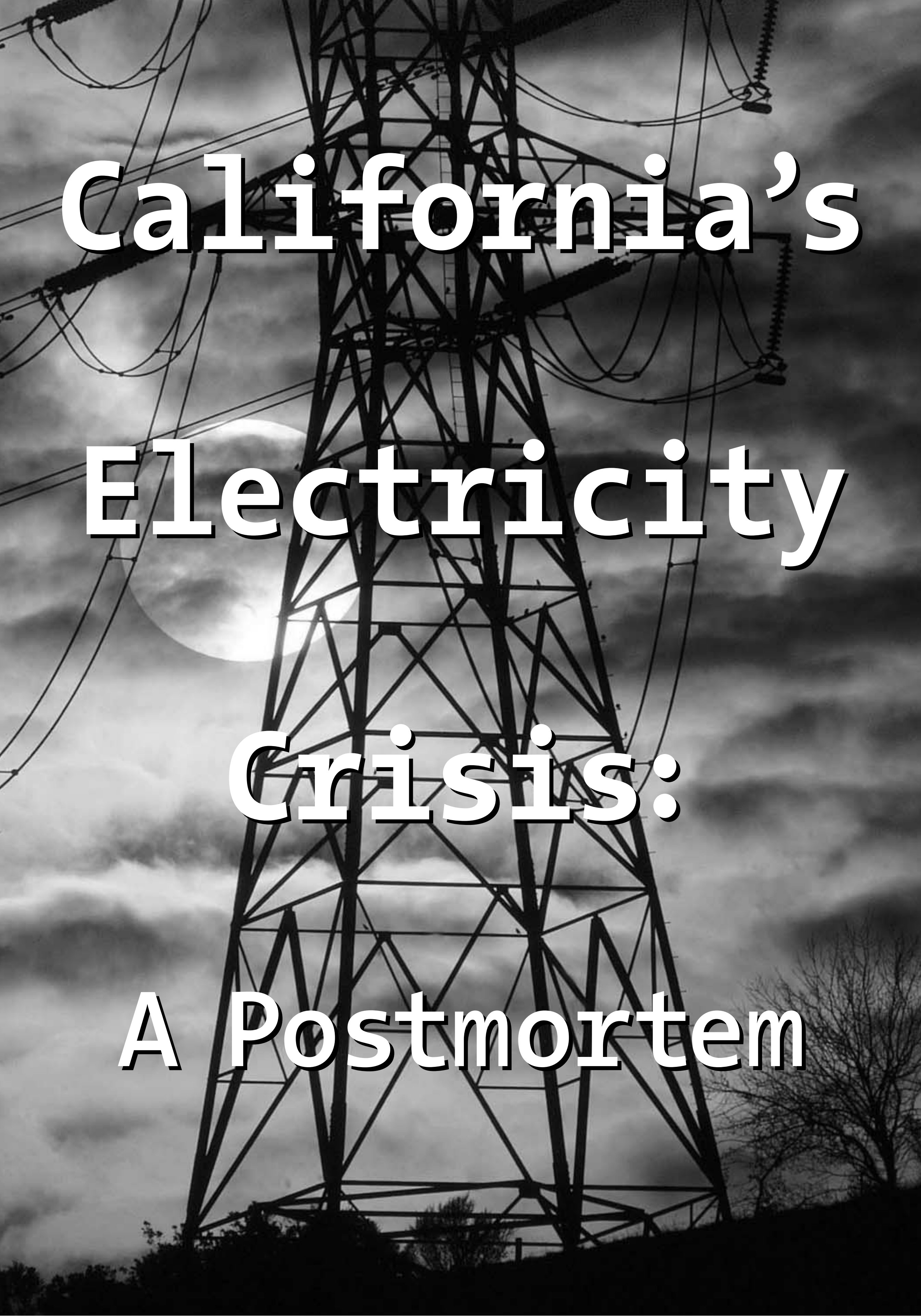
California's Electricity Crisis: A Postmortem



by Paul L. Joskow

In April 1998, California initiated an ambitious program to bring retail and wholesale competition to its electricity sector. Those pressing for the sweeping changes believed the program would lead to lower consumer prices, a host of innovative retail services, improved performance from existing generating plants and massive investment in clean new ones. Most of the rhetoric focused on lower prices and better service. Jeffrey Skilling, then president and chief operating officer of Enron, told officials that consumers would save nearly $9 billion a year with "deregulation."

Both the California Legislature and Pete Wilson, the governor at the time, embraced the initiative. California, the thinking went, would be at the vanguard of a movement to transform a tired old industry composed of imperfectly regulated monopolies into one that tapped the innovation and discipline of the free market.

The experiment now lies in ruins. Rather than becoming an example of how to transform the industry, it has become an international symbol of the dangers inherent in deregulation. The state's two largest utilities became insolvent in early 2001 and stopped paying for power. Supply interruptions soon followed, and the state had to intervene to purchase power to keep the lights on, spending $12 billion in just a few months and committing Sacramento to another $40 billion of long-term contracts with unregulated electricity suppliers. Retail consumers now pay about 40 percent more for electricity than they did before the program began.

Little of the promised clean, cheap new generating capacity was completed before mid-2001. And just as consumer prices were increased in June 2001 to help to pay for the costs of power purchased by the state, wholesale prices began to fall drastically. The state is now stuck with obligations to pay $40 billion for electricity with a likely market value of $20 billion.

Other states and other countries have initiated similar programs, often with initial stumbles. But none blundered into a mess comparable to California's. Herewith, my take on what went wrong and what can be learned from the experience.

LEFT: MICHAEL MACOR/SAN FRANCISCO CHRONICLE/CORBIS SABA; RIGHT: © SUSAN GOLDMAN/THE IMAGE WORKS

For nearly a century, California's electricity industry was organized around three private regulated companies, which owned and operated generation, transmission and distribution facilities for all consumers in their exclusive franchise areas. The Pacific Gas & Electric Company (PG&E), the Southern California Edison Company (SCE) and the San Diego Gas & Electric Company (SDG&E) account for about three-quarters of the electricity sold to retail consumers in the state. (The rest is supplied by municipal utilities, irrigation districts and public water agencies, which did not participate in deregulation.)

The three utilities' prices and service obligations were set by the California Public Utilities Commission (CPUC). While the three owned generating plants to supply most of their retail customers' needs, they did purchase significant amounts of power from utilities in other western states, as well as from Canada and Mexico. These wholesale transactions and associated transmission arrangements are regulated by the Federal Energy Regulatory Commission (FERC).

Responding to complaints from industrial customers, who paid much more for power than competitors in neighboring states, the CPUC began a review of California's electricity industry in 1993. Everything from the high costs of nuclear power to expensive long-term contracts with independent power suppliers to excess generating capacity was attributed to California's dependence on regulated, vertically integrated monopolies. Not surprisingly, there was broad agreement that something had to change. Also not surprisingly, there was no consensus about how.

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In April 1994, the CPUC proposed what was then viewed as radical reform. Production from existing generating plants and new plants would be deregulated and the power would be sold in a competitive wholesale market. Transmission, distribution and related network operating functions would continue to be regulated monopolies. However, these services would be sold separately from the power produced by competing unregulated generating plants, enabling consumers to buy "transportation" service at regulated prices while choosing their retail electric service suppliers (ESPs) in a competitive market. ESPs would acquire power in the new competitive wholesale markets, reselling it to consumers along with other services – energy management services, telephone service on power lines and the like. This vision was heavily influenced by reforms carried out in England and Wales in 1990.

The CPUC's proposal met opposition from several quarters. First, the utilities were concerned that retail competition would make it impossible for them to recover both their past investments in nuclear power plants and the costs of state-mandated contracts with cogenerators and renewable energy suppliers. Wholesale market prices were expected to be in the range of $25 to $30 per megawatt-hour, while the utilities' regulated costs of generation were about $65/Mwh. The difference between the "regulatory value" of these generation sources and their expected market value was potential "stranded cost," and the utilities argued that they were owed a means of recovering these costs. Industrial consumers naturally opposed recovery because stranded costs stood between them and much lower energy prices.

There were also heated debates about market design. The CPUC's original proposal would have created wholesale markets similar to those in England. Following the experience there, the plan would have phased in retail competition over several years, starting with the largest customers and working gradually to small businesses and households.

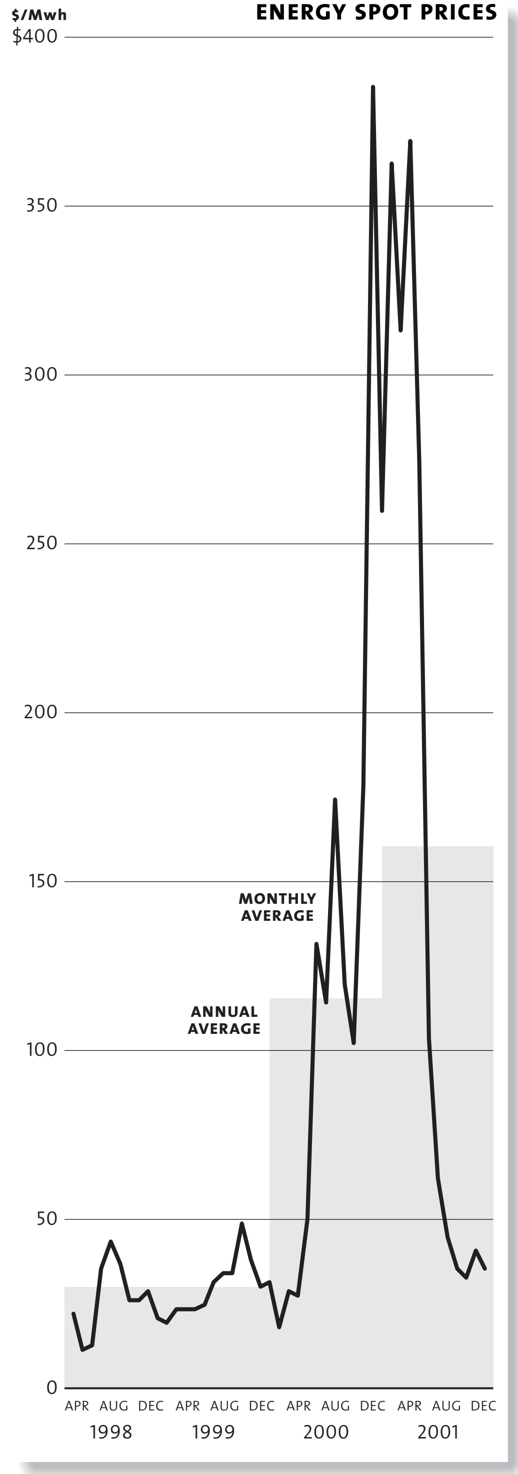
Marketers (led by Enron) and industrial consumers opposed replicating the British model, arguing that it gave too much control to a quasi-public operating authority. They wanted a decentralized market, where the role of the system operator was limited, and the opportunities for buyers and sellers to wheel and deal were maximized. Small customers supported the CPUC's wholesale market model, but opposed the phase-in of retail competition because they were concerned that it would leave small customers with a disproportionate share of stranded costs. On the other hand, they wanted the big utilities to be obligated to provide regulated "default service" as a safety net, in case competition did not work as expected.

THE RESTRUCTURING PROGRAM

The CPUC came up with a plan in early 1996 that embodied numerous compromises to accommodate the various interest groups. Later that year, the California Legislature passed a restructuring law that largely followed the plan, but included a number of refinements. The details of the restructuring program are complex; here, I will focus on aspects that played an important role in the system's later collapse.

The privately owned utilities (prophetically called IOUs – investor-owned utilities) were directed to help to create two new nonprofit transmission network and wholesale market institutions, and to work with all "stakeholders" to design the operating rules for the associated wholesale markets. The first was the California Independent System Operator (ISO), which would operate the

CALIFORNIA HOURLY WHOLESALE ENERGY SPOT PRICES



transmission networks owned by the three major utilities and would be responsible for running the energy balancing, ancillary service and congestion management markets needed to maintain reliability. The second was the California Power Exchange (PX), which would run hour-ahead and day-ahead wholesale markets for electricity. Both the ISO and the PX were nonprofit corporations with governing boards that included representatives of major interest groups.

Designing the wholesale market institutions proved extremely contentious. Interest groups presented different reform models. The CPUC was itself divided, with one group preferring a "Poolco" model similar to that introduced in England in 1990 and another preferring a "bilateral contracts" model based loosely on America's natural gas markets. Ideology and rhetoric played a bigger role in the debate than serious analysis. In the end, the design represented a series of compromises that drew on bits and pieces of alternative models for market design, congestion management, transmission pricing and new-generator interconnection rules.

The two largest IOUs were ordered to sell at least half of their coal- and gas-fired generating capacity in California and strongly encouraged to sell the rest. All three IOU's did sell all of their fossil-fueled generation in California to five new unregulated companies. However, they retained their nuclear and hydropower plants, as well as their existing long-term wholesale purchase contracts from alternative suppliers.

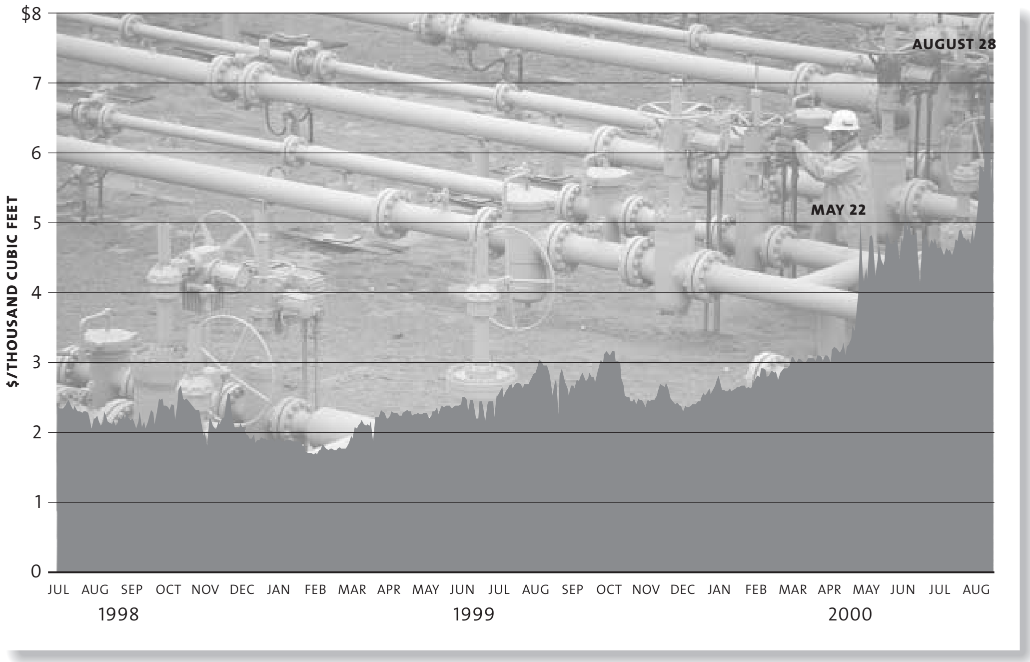
While all retail customers were given the opportunity to choose an electricity service provider (ESP), retail prices continued to be regulated ("capped") for up to four years. The rules of the regulated retail price system played an important role in the later collapse of the system. First, a fixed retail price ("retail rate freeze") was established for each utility at a level that was expected to allow the utility to recover its stranded costs in four years or less. That is, this price included a charge for generation service that was far above the anticipated wholesale market price. This was the "default service price" that retail customers would pay their local utilities if they did not choose an ESP. It was set at about 10 percent below then-prevailing regulated prices for small customers.

Second, retail customers who did choose an ESP were required to pay this fixed default service price minus the competitive spot market prices realized each hour of the day in the new wholesale markets. Thus, these customers effectively also paid their share of the utilities' stranded costs, since stranded cost is the difference between the regulated cost of generation service and the competitive market value of generation service. Utilities were supposed to recover their stranded costs by charging all customers for the difference between the generation charges reflected in the default service price and the wholesale market value of the power in the spot market.

These arrangements settled the stranded-cost problem for the utilities as long as wholesale prices remained well below the historical regulated prices. However, the approach made life difficult for ESPs, since their customers, too, were obliged to share stranded costs. By the summer of 2000, customers representing only 12 percent of demand had switched to ESPs – and most of the switching was done by large industrial customers. Thus, the utilities still had to provide for the vast bulk of the electricity needs of California's retail consumers.

What's more, the three IOUs were required to meet their service obligations by purchasing all of their customers' requirements in the

SOUTHERN CALIFORNIA NATURAL GAS PRICES, JULY 1998–AUGUST 2000



MICHAEL HART/GETTY IMAGES/FPG

day-ahead and real-time spot wholesale markets. The utilities thus sold power from their remaining generating assets (including long-term contracts) into these markets and then bought back all of the power they needed to meet their default service demand. They were effectively "short" the difference between default service demand and what they could supply from their own generating assets. Requests to hedge their short positions beginning in 1999 were either denied or so restricted by the CPUC that little hedging took place before 2001. Accordingly, their exposure to volatile spot market prices was much larger than anyone had expected.

INITIAL WHOLESALE MARKET PERFORMANCE

Problems emerged almost immediately after the new markets opened for business in April 1998. The software to manage the wholesale markets wasn't ready in time, and operations began without important functions in place. Moreover, numerous compromises in market design led to poor coordination between the power exchange and the system operator, and the limitations placed on the system operator's ability to play an active role in energy markets led to numerous problems well before the highly visible meltdown that began in May 2000. In addition, episodic price explosions and instances of anticompetitive gaming by suppliers emerged in the markets operated by the system operator during periods of very high demand during the summer of 1998, requiring regulators to step in to impose price caps and to change market rules.

In 1999, additional concerns were registered. The system operator openly worried about the slow pace of completion of new power plants, the rapid growth in demand and the resulting reduction in reserve margins. Meanwhile, spot market price volatility raised concerns about California's reliance on spot markets to meet retail demand and about potential shortages and price spikes if permitting new power plants was not speeded up. However, state regulators did nothing to speed the siting review process or to otherwise facilitate completion of new generating plants. Nor did the CPUC try to reform retail market institutions and wholesale purchasing rules as the utilities completed the divestiture of their gas-fired power plants.

design. However, all changes had to be mediated through a contentious stakeholder process that was slow and led to compromises that were far from ideal.

MAY 2000–SEPTEMBER 2000: THE MARKET MELTDOWN BEGINS

In May 2000, wholesale electricity prices began to rise above historical peak levels. Prices increased significantly in June and stayed high for the rest of the summer. The

All things considered, wholesale prices before May 2000 were perhaps 15 percent higher than they would have been in a system without the design flaws.

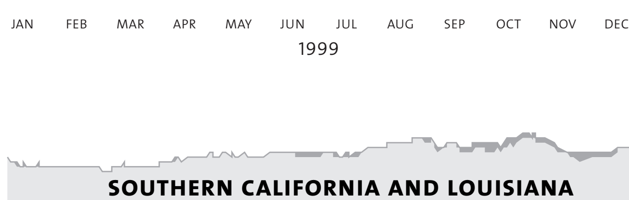
wholesale prices prevailing between June and Sept. were much higher than the fixed retail price the utilities were permitted to charge for retail service. SCE and PG&E thus began to lose a lot of money: losses mount fast when you are buying power for $120, distributing it through a high-maintenance grid and collecting just $60 from customers.

The rate freeze of the third utility, SDG&E, ended in late 1999 when it had recovered all of its stranded generation costs and, in theory, its retail customers thereafter bore the risk from changes in wholesale market conditions. SDG&E's retail prices initially fell in early 2000, reflecting the end of stranded costs charges and the low wholesale prices. However, retail prices rose sharply along with

Facing forecasts of potential shortages, the system operator did initiate a program in 1999 to bring new plants online to cover peak demand by the summer of 2000. But this program was not successful.

Despite the nascent problems, average wholesale market prices for power between April 1998 and April 2000 were reasonably close to pre-reform projections. Analysts expected that average hourly prices would start at about $25/Mwh and rise to about $30/Mwh as excess capacity was gradually dissipated. All things considered, wholesale prices before May 2000 were perhaps 15 percent higher than they would have been in a system without the design flaws noted above. Indeed, the retail rate freeze for SDG&E's customers ended in December 1999, and San Diegans received the benefits of lower wholesale prices during the first five months of 2000.

As of Jan. 2000, state officials acknowledged a variety of market design problems, but believed they could be fixed at a leisurely pace. The FERC was less sanguine and ordered changes in the wholesale market



wholesale prices during the summer of 2000. Exploding retail prices in San Diego infuriated consumers and ultimately led the California Legislature to cap the generation service component of SDG&E's default service prices at $65/Mwh with a commitment that any difference between what SDG&E paid for power and what it could charge would "eventually" be recoverable as a surcharge on retail distribution charges.

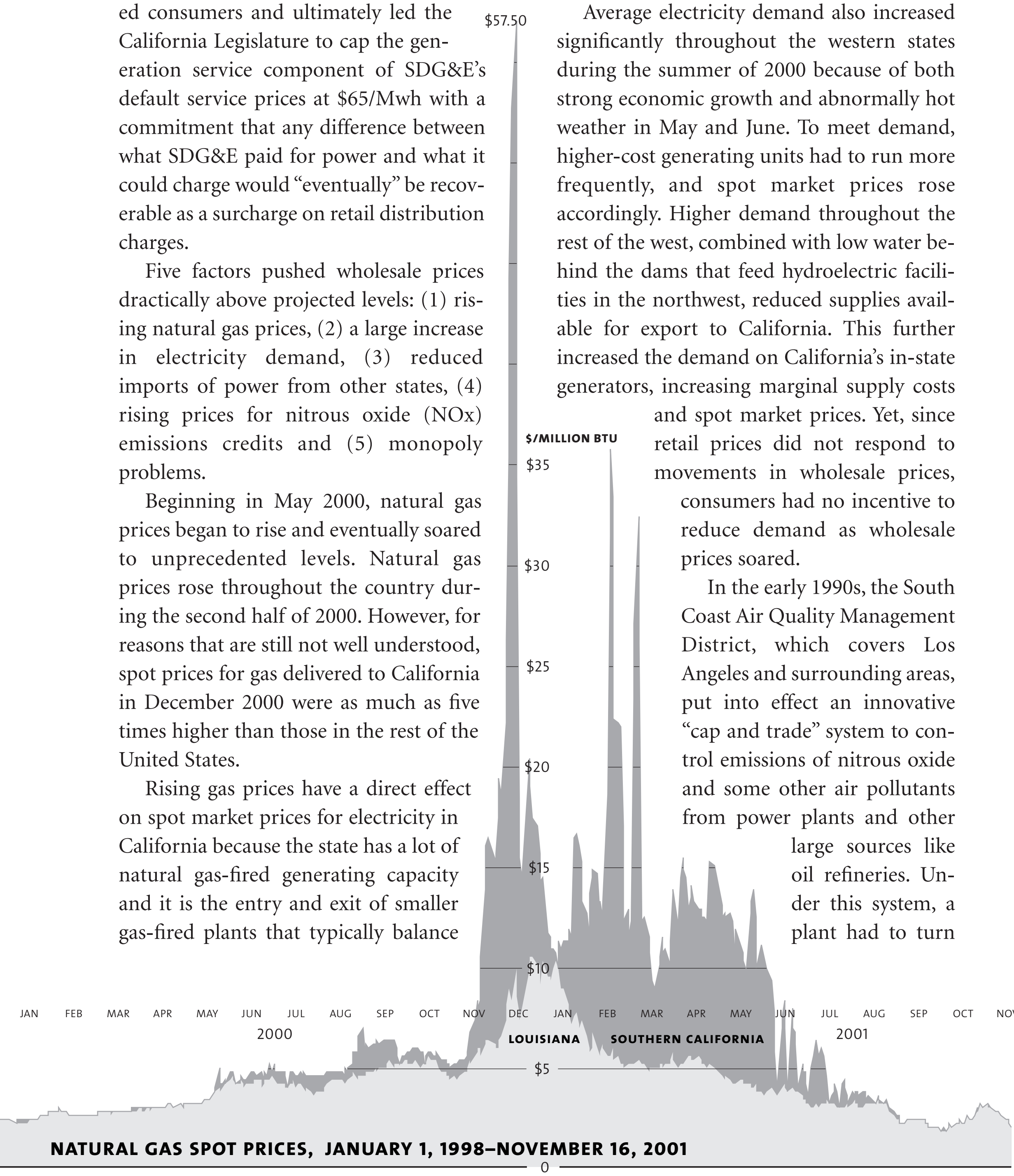
Five factors pushed wholesale prices dractically above projected levels: (1) rising natural gas prices, (2) a large increase in electricity demand, (3) reduced imports of power from other states, (4) rising prices for nitrous oxide (NOx) emissions credits and (5) monopoly problems.

Beginning in May 2000, natural gas prices began to rise and eventually soared to unprecedented levels. Natural gas prices rose throughout the country during the second half of 2000. However, for reasons that are still not well understood, spot prices for gas delivered to California in December 2000 were as much as five times higher than those in the rest of the United States.

Rising gas prices have a direct effect on spot market prices for electricity in California because the state has a lot of natural gas-fired generating capacity and it is the entry and exit of smaller gas-fired plants that typically balance supply and demand in the wholesale market during peak use.

Average electricity demand also increased significantly throughout the western states during the summer of 2000 because of both strong economic growth and abnormally hot weather in May and June. To meet demand, higher-cost generating units had to run more frequently, and spot market prices rose accordingly. Higher demand throughout the rest of the west, combined with low water behind the dams that feed hydroelectric facilities in the northwest, reduced supplies available for export to California. This further increased the demand on California's in-state generators, increasing marginal supply costs and spot market prices. Yet, since retail prices did not respond to movements in wholesale prices, consumers had no incentive to reduce demand as wholesale prices soared.

In the early 1990s, the South Coast Air Quality Management District, which covers Los Angeles and surrounding areas, put into effect an innovative "cap and trade" system to control emissions of nitrous oxide and some other air pollutants from power plants and other large sources like oil refineries. Under this system, a plant had to turn



NATURAL GAS SPOT PRICES, JANUARY 1, 1998–NOVEMBER 16, 2001

in enough permits or "credits" to cover its emissions each year. Between April and Sept. 2000, the price of pollution permits to cover NOx emissions from power plants increased nearly tenfold. This further increased the costs of meeting power demand.

Thus, even if California's wholesale market had been perfectly competitive, wholesale spot prices would have risen in the spring and summer of 2000. But there is abundant evidence that during high demand periods, California's spot electricity markets were far from competitive. Because electricity cannot be stored and short-run demand is very inelastic, even suppliers with small market shares have the incentive and ability to withhold output from the market in order to drive up prices. Several studies have demonstrated that what economists euphemistically call "strategic behavior" by suppliers led to significant increases in wholesale prices.

By Sept. 2000, utilities were paying nearly three times as much for wholesale power as they could charge at retail, and they began to confront serious cash-flow problems. SCE and PG&E pleaded with the CPUC to lift the retail rate freeze and to allow them to charge customers for the cost of purchasing wholesale power on their behalf. The CPUC refused; no retail price increases were permitted for the balance of 2000.

OCTOBER 2000–DECEMBER 2000: THE MELTDOWN CONTINUES

Government officials expected wholesale power prices to decline during the fall, winter and spring, giving them time to figure out how to respond to cascading electricity-related problems. However, while power demand fell as usual after the summer, gas prices continued to rise, electricity imports remained low, NOx credit prices remained high and, most important, unusually large amounts of generating capacity remained out of service. Wholesale prices did fall modestly in Oct. 2000, but then soared to new heights in November and December. By mid-December, the utilities were paying almost $400/Mwh for power and reselling it for $65/Mwh!

At that differential, the utilities were losing about $50 million a day. Their requests for permission to increase retail prices were either rejected or deferred by the CPUC. Similarly, repeated requests to FERC to deal with market failures were ignored until Nov. 2000. In a report and order issued on Nov. 15 (and a subsequent order issued Dec. 15), the agency concluded that the California markets were fundamentally flawed and, pursuant to its legal responsibilities under the Federal Power Act, found that wholesale prices were "unjust and unreasonable." It proposed a number of structural changes in California's markets. In mid-December FERC ordered the system operator to lift the existing wholesale price caps, which the commissioners apparently believed were contributing to shortages. But FERC's initiatives actually made things worse, and wholesale prices rose even higher.

With no retail price increases permitted by the CPUC and wholesale prices soaring to levels eight times greater than the prices that they could charge retail consumers, PG&E and SCE were quickly approaching insolvency. In mid-December, power suppliers said they would not provide further power to the market unless payments were accelerated. Accordingly, credit problems may have further reduced supplies, contributing to the continued increase of wholesale prices during Dec. 2000.

JANUARY 2001–MID-JUNE 2001: SACRAMENTO RESPONDS

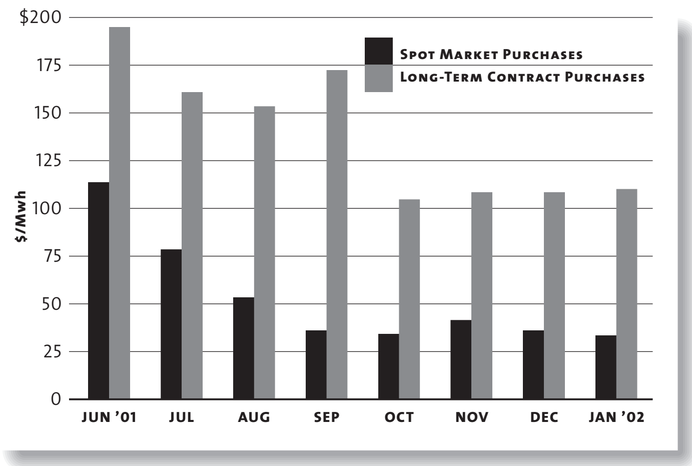
By the first week in Jan. 2001, it became clear that California regulators would not raise retail prices sufficiently to restore the utilities' credit. More power suppliers then began to refuse to sell electricity for fear of never getting paid. In mid-January, PG&E and SCE ceased making payments for power, including payments owed for supplies delivered through the power exchange in November and December 2000.

Shortages and involuntary curtailments of power to individual consumers soon followed. The PX ceased operating its day-ahead markets on Jan. 31, 2001, in response to utility credit problems. The only thing that kept the lights on in California through early 2001 were emergency orders from the U.S. Department of Energy (and subsequently from the federal courts) requiring generators to stay online.

The Bush administration, which took office on Jan. 20, 2001, indicated that it would no longer force generators to supply electricity without assurances that they would be paid. Since the utilities had no cash or credit left, the State of California, through California Department of Water Resources (CDWR), began to buy power to cover the utilities' net short positions sometime in the second half of Jan. 2001, and it continues to do so today. CDWR spent about $8 billion through June 2001.

At the direction of Gov. Gray Davis, the CDWR also began to negotiate long-term contracts (up to 20 years) with generators and marketers. The state pursued long-term contracts in order to obtain better prices than were expected to be available in the spot market, to provide incentives to generators to sell electricity, to reduce suppliers' incentives to exercise market power in the spot market, and to encourage the completion of new generating plants. The CDWR contracts appear to involve commitments of about $40 billion over the next 10 years. The governor also announced a number of measures to encourage conservation and to speed siting approvals for new generating plants.

PRICES PAID FOR POWER BY CALIFORNIA DEPARTMENT OF WATER RESOURCES, JUNE 2001–JANUARY 2002



On March 27, 2001, the CPUC announced that retail prices would be increased by about 40 percent, with rates structured to reward reductions and penalize increases in consumption. Retail consumers began to see these rises in their bills in June 2001. The increase was intended to begin to compensate the CDWR for the costs it had incurred to purchase power. It was not sufficient, however, to restore the utilities' credit, and PG&E soon sought protection in federal bankruptcy court.

One-third of the generating capacity in the ISO's areas remained out of service for most of the winter and spring of 2001, and imports remained low. As a result, supply emergencies were in effect for most of this period, despite the fact the peak winter demand was not unusually high and was far less than power typically supplied by in-state generators. Predictions made during early spring 2001 for the coming summer were bleak as well. Demand was projected to continue to grow, yet little new generating capacity was expected to come online. The system operator predicted there would be hundreds of hours of blackouts during the summer. During this period, forward prices for electricity for the summer months were as high as $700/Mwh.

In response to the growing crisis, California officials intensified conservation efforts, increased efforts to speed the completion of new plants and continued to enter into long-term contracts with electricity suppliers. The Southern California Air Quality District helped out by dropping power plants from the cap and trade program, and by replacing the NOx credit trading system with a modest penalty of $7.50 per pound for exceeding emissions limits.

With blackouts looming and forward prices for electricity in the stratosphere, California and other Western states also pressed Washington to restore caps on wholesale prices and to force generators to make all the electricity they could produce available to the market. FERC responded, albeit slowly, to the political pressure.

On April 26, it required generators to bid all available supplies that had not already been scheduled into the auction market. It also adopted bid caps for supplies when system operating reserves fell below 7 percent (Stage 1 emergency condition). On June 18, FERC modified this price mitigation plan by applying it to all hours and to all spot sales of electricity in the west. Finally, FERC instituted a proceeding to resolve claims that California had been overcharged for power in 2000 and 2001 and held out the possibility of substantial refunds.

JUNE 2001–DECEMBER 2001: WHOLESALE PRICES FALL AS RETAIL PRICES RISE

During the first week in June 2001, spot and forward wholesale prices finally began to fall. The decline continued for the rest of the summer, and by August prices returned to levels that had not been seen since mid-May 2000 and remained low for the rest of the year. Forward prices for 2002 also dropped drastically. Indeed, both spot market and forward prices have now fallen well below the prices in the long-term contracts negotiated by the state. Forward prices for 2002 average about $35/Mwh, far lower than the expected prices under the CDWR's contracts.

Why the fall? Many of the same factors that caused prices to explode during the summer of 2000 appear to have been operating in reverse during the summer of 2001.

First, weather-adjusted electricity demand started to slip in January and stayed well below 2000 levels for the rest of 2001. Since retail electricity prices did not rise significantly until June 2001, we must attribute the decline in demand, in part, to all the jawboning about conservation as well as to the formal energy conservation programs imposed by the state. However, the large price increases put into effect in June, which were structured to provide incentives for consumers to reduce demand, also induced conservation during the summer. Then, too, the recession played a role.

Second, natural gas prices declined across the country, and after early June 2001 differences in the price of gas between Southern California and the rest of the country declined drastically.

Third, easing emissions restrictions in Southern California made a difference.

Fourth, power suppliers seem to have lost the ability or the will to use strategic behavior to influence prices. It is fairly clear that FERC's price mitigation program, along with the intense scrutiny of suppliers by regulators, courts and the media, provided powerful incentives for suppliers to be on their best behavior during the summer of 2001. Large amounts of generating capacity returned to service: average daily outages fell from 10,000 megawatts in April to 4,000 in June and 3,500 in August. In early July, three new power plants began operating in California – the first new generating capacity in nearly a decade. Additional generating capacity came online later in the summer, for a total increase of about 1,800 megawatts.

KIM KULISH/CORBIS SABA

IS THE CRISIS OVER?

The expected supply shortages never emerged during the summer of 2001 and wholesale prices have fallen to near their pre-reform expected levels. New generating plants are slowly being completed and shortages are not expected for the coming year. However, the good news came at a very high cost. The state is now saddled with tens of billions of dollars in long-term contracts that are likely to carry prices well above their competitive market value. The costs of these contracts will be paid either through future electricity prices or state taxes or both. Retail prices are now much higher than they were in 1996, when restructuring began, and are likely to remain high for years. The economic consequences for consumers are just beginning to be felt.

Moreover, the future of California's electricity sector remains murky. The organized wholesale power markets have largely disintegrated. The California Power Exchange stopped operating at the end of Jan. 2001 and subsequently went bankrupt, eliminating a large, transparent day-ahead market for electricity. The two largest utilities remain insolvent. While the California Independent System Operator continues to operate real-time markets for energy, this market has also become dysfunctional as utility credit problems have led the ISO to rely increasingly on the state for supplies. The California Public Utilities Commission has now suspended the retail competition program that was the primary motivation for the restructuring initiated in the mid-1990s. A state power authority has been created with vague responsibilities to provide for new generating capacity, to subsidize renewable energy projects and to encourage conservation.

The State of California has effectively taken over many key components of the electric power industry in the state, replacing the nascent competitive power markets with state power procurement and regulated retail prices in large part determined by the state's need to recoup the cost of power purchased during the crisis. There is little doubt that

California's electricity sector is in a much worse position than it was in when the discussion of restructuring began in 1994.

LESSONS LEARNED, AND FORGOTTEN AT OUR PERIL

Start with the reality that electricity has unusual physical attributes that challenge our abilities to design a well-functioning competitive market. Thus, effective market design simply isn't possible if the objective input of experts from many disciplines, including power system engineering, economics, information technology, finance and accounting, is compromised. Design flaws weren't the primary cause of the collapse of California's competition program. However, the tone set by the interest group maneuvering in the market design process infected all aspects of California's competition program.

Electricity markets can't work well if consumers are completely insulated from changes in wholesale prices. California deregulated wholesale prices, but failed to deregulate retail prices or to allow the utilities to use forward contracts to hedge their regulated retail service obligations. Not only did this drive the utilities into insolvency, but left consumers without incentives to reduce consumption.

Spot electricity markets are inherently volatile. Spot market prices can rise to extraordinary levels and are especially susceptible to manipulation when supplies are tight. Creating a retail market framework ensuring that a large fraction of consumer demand is covered by longer term fixed-price contracts will help to avoid problems that emerged in California and better match most consumers' taste for bearing risk.

Real-time retail pricing allows commercial consumers to express their individual preferences for reliability. It also introduces demand elasticity into the spot wholesale market, which in turn dampens price volatility and helps to neutralize suppliers' market power. While many consumers will prefer to hedge volatile spot market prices with forward contracts, large price-sensitive consumers will find it advantageous to adjust their consumption to swings in hourly prices. California both refused to allow utilities to enter into forward contracts and ignored proposals for programs that would allow industrial customers to respond to wholesale price spikes by reducing consumption.

From the broad societal prospective, the benefits of electricity sector reform should come from investments in efficient power plants and innovative demand management. Speeding the ability of developers to build environmentally sound generating plants and providing good incentives to expand transmission networks are essential for good long-run market performance. California focused too much on illusive short-run gains from low-priced power available when there was excess capacity and focused too little on creating institutions to support investment in generation and transmission facilities.

Mid-course corrections have almost always been needed to mitigate problems in restructured electricity markets. If the California and federal regulators had acted in September 2000, when the current problems had became crystal-clear, the crisis would have been of far less consequence. For example, the terms and conditions of forward contracts would have been much more favorable than those negotiated by CDWR if the state had encouraged the utilities to enter into longer term contracts during the summer of 2000 when they requested this authority. Both the CPUC and FERC acted slowly and ineffectively as the crisis deepened and spent more energy pointing fingers than finding solutions.