4

THROUGH CRISIS

By December 2000 and January 2001, there was no question that California was in the midst of a crisis. Yet even then, statewide policy actions were available to avoid the long-term consequences of that crisis, although perhaps it was too late to avoid the short-term consequences. However, the failure of leadership persisted. And the crisis deepened.

This chapter examines the growth and subsequent remission of California's energy crisis and the evolution of state and federal policy during that crisis.

THE NATURE OF THE CRISIS

The California "energy crisis," like the challenge, can be seen as two crises—a western electricity crisis and a financial crisis of the investor-owned utilities that turned into a state budgetary crisis. Once the challenge reached crisis proportions, these two crises exacerbated one another. Conceptually, the two crises were separable from one another. There could have been a western electricity crisis that did not lead to a financial crisis,[1] and there could have

[1]In fact, in the Pacific Northwest, as well as the remainder of the eleven western states, there was the same electricity crisis, but it did not turn into a financial crisis primarily because the utilities did not face the same risky posture as the California investor-owned utilities. Most of the utilities in the West were protected through long-term contracts for most of their electricity aquisitions.

been a financial crisis without an electricity crisis. However, these two crises fed on one another during late 2000 and early 2001, spiraling California deeper into the dual crises.

The electricity crisis grew directly from the electricity challenge that was facing the western states because the basic problem—the increase in demand for electricity coupled with the decreases in electricity supply—was managed poorly by the State of California. The financial crisis started primarily as a crisis for the investor-owned electric utilities and turned into a crisis for the State budget. That the financial challenge turned into a financial crisis was the direct result of State regulatory, administrative, and legislative action or, more precisely, inaction.

Not only did the electricity crisis lead to the financial crisis but also the financial crisis made the electricity crisis substantially worse. Since the investor-owned utilities did not receive adequate revenue to pay their suppliers, the utilities began delaying their payments, promising to pay later, which created significant uncertainty among suppliers, who could not be sure they would ever be paid. The uncertainty of future payments would lead a rational supplier to increase the price at which it was offering to sell the supplies into the California market, therefore increasing the wholesale prices further. In addition, because the investor-owned utilities were delaying their payments to suppliers, some suppliers were not financially able to continue generating electricity. For the smaller companies, cash flow problems could be severe. In particular, many QFs were owned by relatively small companies that were not able to continue generating electricity without being paid. Therefore, some of these generators went off-line and stopped delivering electricity, thus further reducing electricity supply and exacerbating the electricity crisis, which in turn made the financial crisis worse.

In what follows, these two crises are discussed separately, even though they were tightly interrelated. Some policies are integrated into discussion of the crises; however, some crosscutting policy issues are discussed in separate sections.

THE ELECTRICITY CRISIS

By December 2000, the challenge had grown into a crisis, with even greater increases in the wholesale electricity prices and frequent energy emergencies. The crisis remained severe all winter.

Not until late spring 2001 did the electricity crisis start to disappear, with wholesale prices falling, electricity consumption declining, and the frequency of energy emergencies falling. During the peak of the crisis, the standard belief was that summer 2001 would be even worse than December and January had been, since summer is California's period of peak electricity use. However, by summer 2001, the energy crisis had mostly subsided. By that time, new generating plants, whose applications for certification were filed in 1997 or 1998 (see Table 3.3), were first coming on-line, and electricity demand had declined relative to 2000. Wholesale prices had declined sharply from their peaks, and the energy crisis had all but disappeared. By fall 2001, wholesale prices had declined to typical historical levels and energy emergencies had disappeared entirely. The crisis had passed.

The California energy crisis was a short-term event—of only seven months' duration—though intensely painful. Large amounts of the new generation capacity, mostly initiated in the first few years after AB 1890 was passed, are projected to come on-line during the next few years. Thus, it is unlikely that the electricity crisis will return soon, if at all, unless California policies chill the investment climate enough that many plants currently planned or under construction are canceled.

Wholesale Prices

Monthly average data for electricity sales on the day-ahead PX market through December 2000 are shown in Figure 4.1 with data shown separately for Southern California (SP15) and Northern California (NP15).[2] The average spot wholesale price of electricity reached a short-term peak in August 2000, declining during the next two months as the days grew cooler and the demand for electricity decreased. However, even the $100/MWh price in October was several times higher than normal. November and December showed new increases in the electricity prices. In December, the average PX price for electricity in Northern California slightly exceeded $300/MWh, while in Southern California that price was roughly $225/MWh. Daily peaks were much higher than either of these figures in December for both Northern and Southern California, where

[2]Comparable data for subsequent months are not available because the PX was shut down in January. The PX ultimately declared bankruptcy in March 2001.

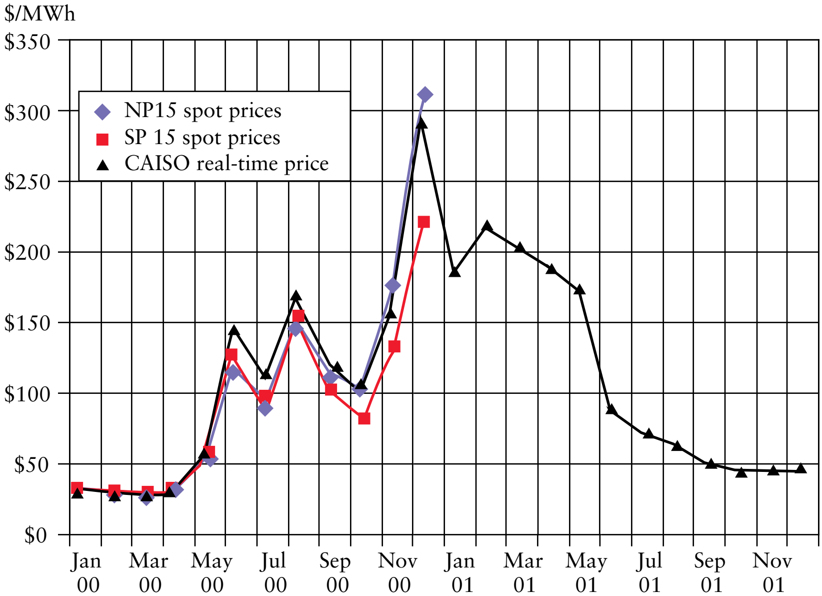

FIGURE 4.1: Spot Wholesale Prices, California PX (Day-Ahead), CAISO Real-Time

the maximum December price on the PX was slightly above $1,000/MWh. The *minimum* price of electricity sold on the PX for any one hour throughout the month of December in Northern California was $132/MWh!

The longer series in Figure 4.1, the "CAISO real-time price," is the weighted average of prices paid for all wholesale real-time purchases of electricity scheduled through the CAISO. This includes electricity sold under the price cap (whenever a price cap existed), electricity transactions based on bids accepted over the price cap, and out-of-market purchases scheduled in real time.[3]

These two price series differ in that the "CAISO real-time price" includes out-of-market purchases, which come from entities that are not in the CAISO control area, such as out-of-state generators or municipal utilities, for example, the LADWP. These out-of-market

[3]Source: Data from a sequence of CAISO monthly memos entitled "Market Analysis Report for . . . ." The most recent available is "Market Analysis Report for December 2001," a memo from Anjali Sheffrin, Director of Market Analysis, CAISO, to ISO Board of Governors. www.caiso.com/docs/09003a6080/12/50/09003a6080125047.PDF.

purchases never went through the PX but were negotiated in real time. Whenever the price caps were in effect, the out-of-market purchases generally carried a higher price than those purchases transacted on the PX. Thus, the exclusion of these observations generally biases the PX prices downward, as can be seen in Figure 4.1.

To the extent data are available, prices were similar among the western markets most of the time, with the exception of two weeks in December 2000 (the week of December 11 and the week of December 18). During those weeks, the maximum prices during the peak period were \$5,000/MWh at Mid-Columbia and \$4,000/MWh at the California-Oregon Border, while the maximum prices recorded on the PX were \$1,400 and \$950. Figure 4.2 shows the same type of data that were displayed in Figure 3.12, the average of the high and low prices during peak periods on a week-by-week basis for the various market centers, although for a longer time period. Data are shown from April 1, 2000, to October 1, 2001. The top pane of the chart shows the full range of prices; the bottom pane is truncated at \$500/MWh.

As Figure 4.1 illustrates, the wholesale price paid for electricity reached the maximum monthly average in December 2000, stayed high through May 2001, and has been falling ever since.

The sharp decrease in wholesale electricity prices had not generally been anticipated much in advance of the actual reductions. Expectations of future prices can be measured by observation of the futures prices prevailing at different times. Figure 4.3 shows the published futures prices for electricity averaged over the two markets centers, Palo Verde and the COB, relevant for imports and exports of California electricity. This figure shows that on May 4, the futures price for electricity to be delivered in August was \$550/MWh. Prices were near \$400/MWh for delivery in June, July, and September. However, by June 8, the August futures price had declined to \$240/MWh and prices for adjacent months had gone down to below \$200/MWh. By July 16, all futures prices had declined to below \$100/MWh.

These figures reflect very sharp changes in beliefs, occurring between early May and early June, about the prices electricity would command in wholesale markets. In addition, the beliefs seem to have continued to evolve downward through July and into August, consistent with the actual reductions in prices.

One can use either the time that wholesale prices sharply decreased or the time that beliefs about future prices sharply decreased in order

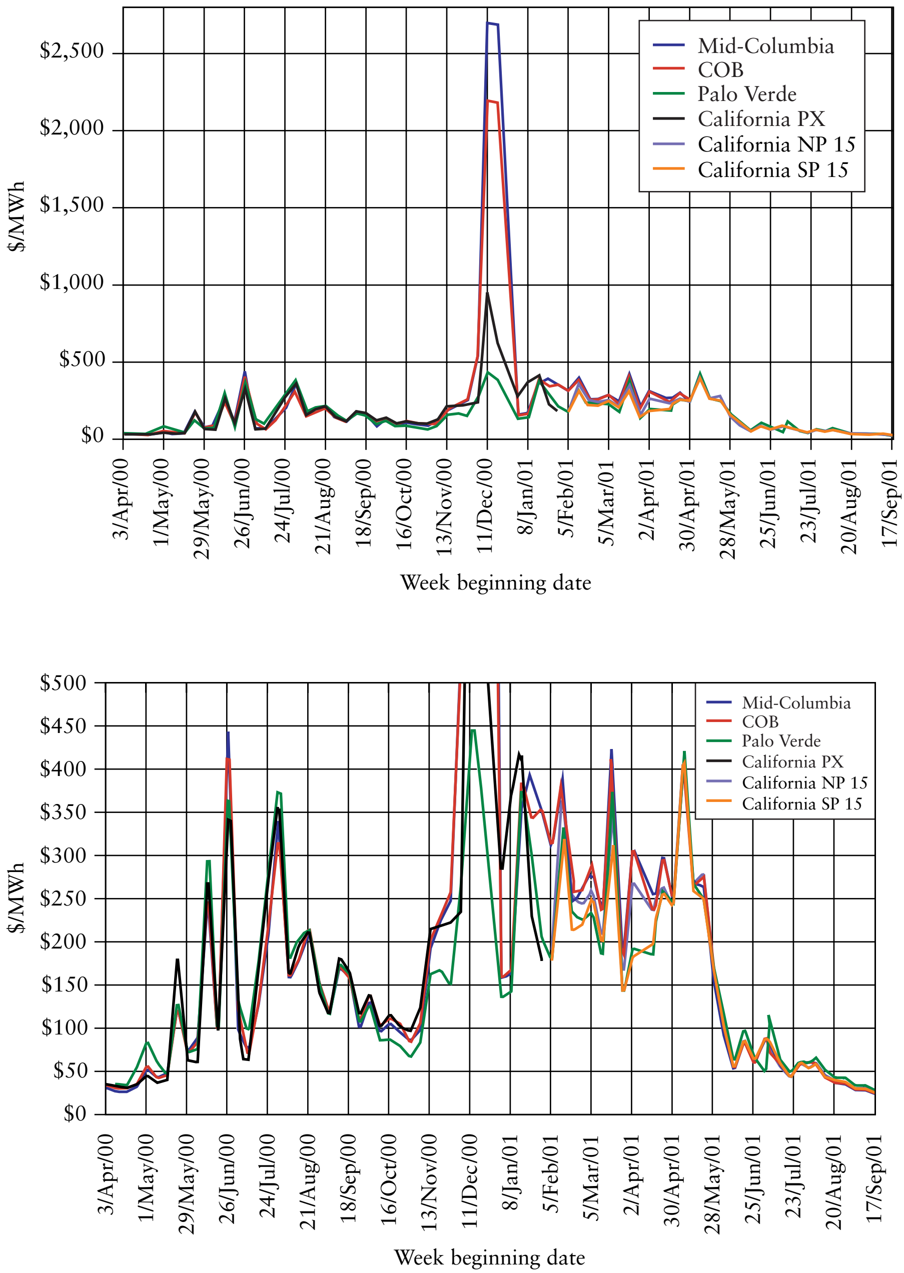

FIGURE 4.2: Spot Power Prices: Average of High and Low Peak Prices, Various Western Markets

SOURCE: *Western Price Survey*, www.newsdata.com

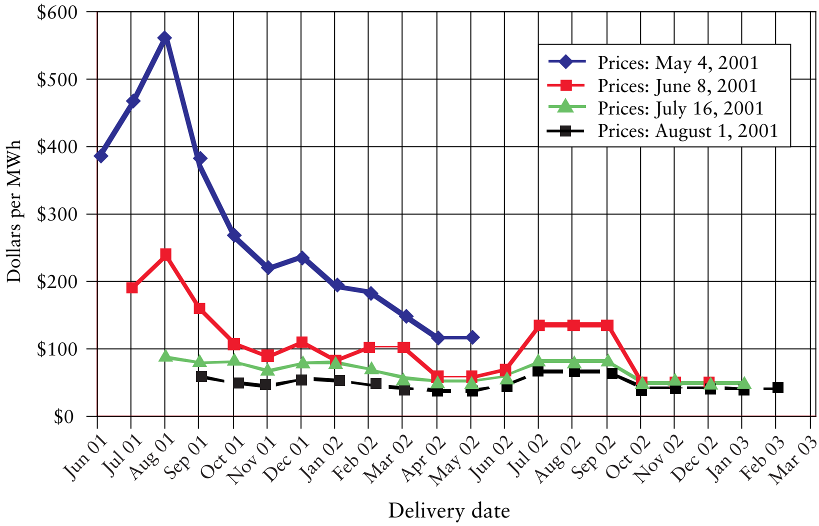

FIGURE 4.3: California Electricity Futures Prices at Several Different Times

to define the end of the California electricity crisis. Using those criteria, the crisis can be seen as beginning in late November 2000 and ending in June 2001, a seven-month event: short, but painful.

ELECTRICITY SUPPLY AND DEMAND

The basic economic forces underlying the price increases and their subsequent declines throughout the West were the same forces of electricity demand (particularly peak demand), available generating capacity, electricity-generation costs, and possible market power described in the previous chapter. None of the difficulties had been overcome by the end of the challenge period and some became worse as a result of the California financial crisis. This section describes only those factors that changed in important ways from the challenge period and during the crisis.

Electricity Imports and Exports

What at first might have seemed surprising was that prices were so high in winter, since demand for electricity in California typically peaks in summer and declines in the winter. However, Pacific Northwest utilities peak in the winter and decline in the summer.

During the winter, when California typically needs less electricity and the Pacific Northwest needs more, California exports electricity to the Pacific Northwest.

During 2000, the low rainfall in the Pacific Northwest reduced the availability of water for hydropower generation and that reduction continued to reduce the available generation of electricity in the Pacific Northwest. Thus, the demands for exports of electricity from California during winter 2001 increased.

In terms of Figure 3.15, California's demand for electricity is reduced during the winter—the demand curve shifts leftward—but the import supply curve is also reduced and also shifts leftward.

Natural Gas Prices

Contributing to the increase in electricity prices during the crisis were even more dramatic increases in the natural gas price than had occurred earlier in 2000. In December, the California natural gas price jumped to above \$50 per million Btu, a factor of ten higher than it had been. Although this price peak lasted for only two weeks, the spot natural gas prices in California remained above \$10 per million Btu until June 2001 (see Figure 4.4). These high prices did not result from limitations in the availability of natural gas at the wellhead or at market centers. Prices of natural gas at Henry Hub, Louisiana, the major market center, remained below \$10 per million Btu, whereas the California price exceeded \$50. Rather the price spike resulted directly from the large demand for natural gas to fuel electric generators during the winter, when the demand for natural gas naturally peaks, coupled by limitations in the pipeline capacity to transport natural gas within the state[4] and the absence of natural gas held in storage from previous months.

The sharp increase in natural gas prices, coming just when investor-owned utilities were not paying generators for electricity they sold, provided strong incentives for generators either to stop producing electricity or to bid very high prices to sell the electricity they did generate. Thus, these natural gas prices probably con-

[4]The CPUC, SCE, and PG&E brought suit in the FERC against El Paso Corp., a Texas pipeline company, charging that it had withheld capacity so as to cause a gas shortage that would increase prices. In October 2001, the chief administrative law judge of the FERC ruled in favor of El Paso, concluding that the California parties failed to prove the contention that El Paso had withheld capacity.

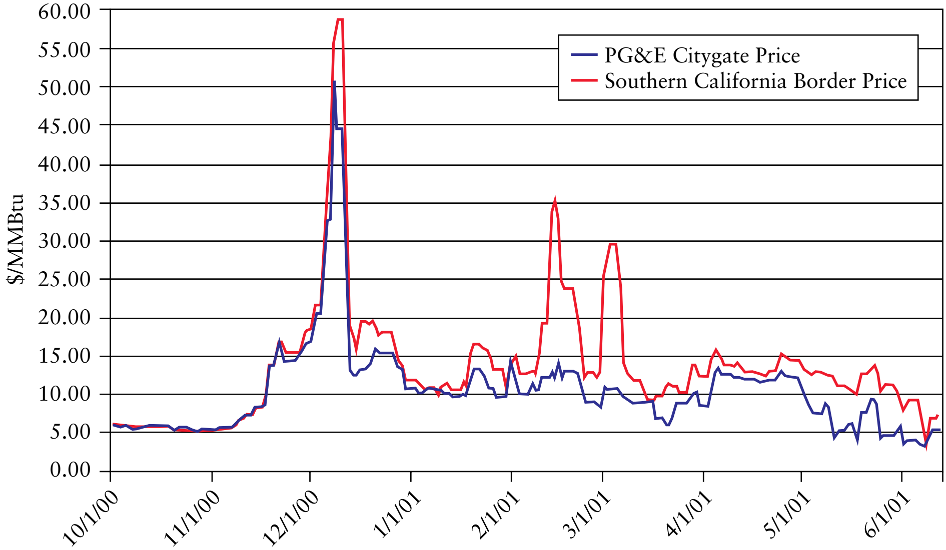

FIGURE 4.4: Natural Gas Spot Market Prices: PG&E Citygate and Southern California Border

SOURCE: Enerfax.com

tributed substantially to the wholesale electricity price increases during the crisis, particularly to the December electricity price spikes.

Risk Created by the Financial Crisis

Because of the financial crisis, which will be discussed in a subsequent section of this chapter, the utilities began delaying their payments to electricity generators, promising to pay later. However, it was becoming clear that unless the state took appropriate policy measures, the utilities were unlikely to become capable of paying for the electricity in a timely manner, if at all, creating significant uncertainty among suppliers. And most suppliers would be able to sell their electricity out-of-state or to the municipal utilities in California if they were not compelled to sell to California's investor-owned utilities.

Uncertainty of future payments would lead a rational supplier to increase the price at which it was offering to sell supplies into the California market, thereby increasing the wholesale prices further. For example, if a supplier believed that there was only a 70 percent probability of receiving $100/MWh for electricity and 30 percent probability of never being paid at all, then the sale of that electricity would be worth no more than $70/MWh to the supplier. If the cost to that supplier of generating the electricity were $77/MWh, that supplier would not be willing to sell the electricity for a promised price of $100/MWh. A bid of $110/MWh[5] would represent a bid at exactly the expected value of the cost of generating the electricity. The uncertainty of payment alone would have had the direct effect of increasing the bid prices and thus the market-clearing prices in the wholesale market.

This increase in bids to account for market risk would appear exactly as if the generator were trying to exercise market power to increase the wholesale price of electricity. Determining whether such bidding was based on an attempt to exercise market power or a competitive response to the financial risk is very difficult, since it depends on the generator's assessment of the probability it would be paid.

This phenomenon was particularly obvious in the November 2000 through January 2001 period, when the utilities were not paying for the electricity they were receiving and their credit ratings were declining sharply. In January, however, the State of California stepped in as the creditworthy buyer, seemingly guaranteeing the payment for all electricity purchased on behalf of the utilities. Instead, California refused, despite repeated FERC orders, to pay its own spot market wholesale power bills. Until November 2001, the DWR did not even allow itself to be billed by CAISO for its purchases. The investor-owned utilities still have not paid for wholesale electricity purchased before January 2000. During 2001, continuing nonpayment caused some suppliers to drop off-line, and continuing risk of nonpayment caused others to include a credit premium in their bids. The FERC subsequently approved a 10 percent credit premium to compensate for continuing financial risks for sales to California. Thus, even though the State had seemed to guarantee payment for all electricity, the state-created financial crisis continued through 2001 to reduce supplies and to place upward pressures on wholesale prices. A subsequent section, "Policies Impacting Risk to Electricity Suppliers," further discusses this continued risk.

[5] $110/MWh multiplied by 0.7 equals $77/MWh.

Possible Exercise of Market Power

As will be discussed in a later section, in mid-January 2001 the governor ordered the DWR to start purchasing wholesale electricity on behalf of the electric utilities, since they were no longer considered creditworthy buyers. Other than electricity self-generated or purchased through preexisting contracts, the investor-owned utilities no longer acquired electricity other than through the DWR. This change fundamentally altered the market structure in California, shifting market power toward the State. Instead of several competing buyers of electricity buying on an organized market, for all practical purposes, the DWR became the dominant buyer of electricity in California. The DWR was able to choose how much of the electricity it should purchase ahead of time and how much it should acquire on the real-time CAISO market; thus, if DWR chose, it could acquire almost all its electricity through bilateral contracts outside the CAISO.

As the dominant buyer, the DWR was not able to change the total electricity consumption or the timing of that consumption, which were passively determined by the load. Nevertheless, the DWR could negotiate short-, medium-, and long-term contracts with the various sellers. The DWR was not required to pay the same price to each seller or to disclose the prices it paid for any particular transactions:[6] it had the ability to price-discriminate for purchases other than those on the real-time market.

Figure 4.5, based on data released by the DWR, illustrates both the large numbers of entities from which the DWR was buying electricity and the wide range of prices it was paying. Each bar on the chart represents a private sector or public sector entity selling electricity to the DWR during the first six months of 2001. Blue bars represent public entities: Powerex (a subsidiary of BC Hydro), LADWP, DWR, BPA, SMUD, and the City of Burbank. Red bars represent private entities: Mirant, Dynergy, Williams, AES, and Duke Energy. Sellers are shown in order of their total electricity sales to the DWR, with those selling the most electricity furthest to the left. The height of the bars shows the cumulative fraction of electricity purchased, that is, the fraction of purchases represented

[6]Data on purchase prices ultimately had to be released, but the releases came long enough after the time of transactions that the information would have little or no value to the generators trying to defend against discriminatory pricing by the state.

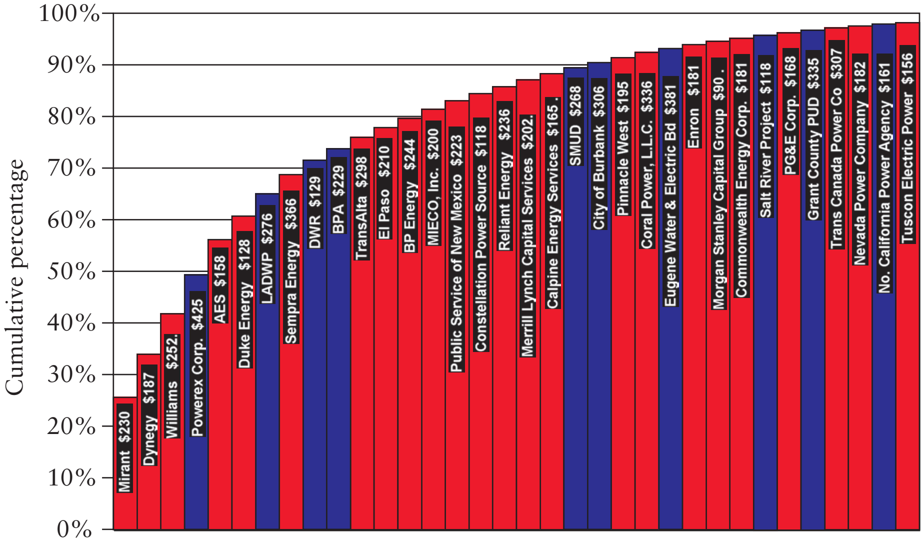

FIGURE 4.5: DWR Electricity Purchases, January through June 2001

by that seller and all larger sellers. Mirant supplied 26 percent of the DWR purchases. Dynergy supplied 8 percent; thus the cumulative supply for dynergy and Mirant is 34 percent. Williams sold another 8 percent, and thus the cumulative percentage is shown as 42 percent. The graph shows that four sellers accounted for almost 50 percent of the purchases by the DWR, eleven sellers accounted for 75 percent, and twenty-one sellers together accounted for 90 percent. Thus the market structure was one in which a single dominant buyer, the DWR, was purchasing electricity from very many competing sellers.

The average prices of electricity sold to the DWR are shown above the names of the sellers. Figure 4.5 shows that the prices negotiated by the DWR varied widely across the sellers. Of the four largest sellers, the DWR paid Mirant an average price of $230/MWh, Dynergy an average price of $187/MWh, Williams $252/MWh, and Powerex $425/MWh. The highest price in the group was more than twice the lowest. Among the sellers accounting for 90 percent of the transactions, the DWR paid prices ranging from $128/MWh (Duke Energy) to $425/MWh (Powerex Corporation), a difference of greater than three-to-one. Monthly data show the same pattern of price discrimination by the DWR among the sellers for each of the six months.

A skillful, price-discriminating dominant buyer purchasing from a group of competing sellers should always be able to reduce the total acquisition cost, even without reducing the total amount of electricity purchased, although it could not reduce the acquisition price below the prices at which the generators could sell electricity out of state, where there were competing buyers.

The DWR's ability to price-discriminate in its purchases reduced the incentives, if they existed, for sellers to attempt to exercise market power in the ways described in previous sections. For with the DWR as the dominant buyer, if a firm offered a small portion of its output at a high price and the rest at a low price, the DWR could simply choose to buy the low-price portions at the bid price, reject the high-price offer, and purchase that quantity from another supplier instead. Although a seller would have incentives to increase the price at which it offered the bulk of its product, as would be the case in an as-bid auction, the seller's lack of information about the cutoff price created incentives against price increases. If it suspected that a seller was trying to manipulate market prices, the DWR could purchase from other sellers, even those offering electricity at higher prices, to discipline sellers it suspected were attempting to manipulate market prices. This possibility of strategic purchasing by the DWR implied that as of late January, any generator market power could be exercised only (1) for sales through the CAISO real-time market and ancillary services markets or (2) through actual reductions of generation, say by taking plants off-line. Even if the DWR chose not to operate in a proactive manner to exercise its new market power, at the minimum the DWR had the power to block any maneuvers by suppliers attempting to manipulate markets.

Thus, to the extent that suppliers were exercising market power, that market power disappeared during the last half of January 2001, to be replaced by DWR market power as the dominant buyer. Therefore, if market power was an important force for increasing prices during the challenge period and into December and early January, it is unlikely to have been an important force for keeping prices high in February through May.

Generators Off-Line

A fundamental driving force for the supply reductions, and hence the wholesale price increases, during winter 2001 was the reduction in availability of electricity generated in California. Large numbers of generators went off-line during late fall 2000 and winter 2001. Historically, between 1,000 and 6,000 MW average daily generating capacity would normally be off-line in a month. However in the period between October 2000 and May 2001, a monthly average of 12,000 MW generating capacity was off-line, reaching a peak of 15,000 MW in April 2001. Figure 4.6 shows these data.

This large amount of off-line generating capacity resulted from a combination of causes, but the greatest fraction of generators was reportedly off-line for repairs or maintenance. However, whether the maintenance and repairs were forced upon the generators, were part of a competitive cost-minimizing solution, or were designed to increase wholesale prices has not been fully resolved. This empirical matter probably cannot be resolved without careful in-depth assessment of facts that currently are not publicly available.

It is reasonable to believe that all or most of the generators were shut down for legitimate maintenance and repair needs. Many of the gas-fired units were old and had deteriorated with age. California had just gone through a summer in which generators were being operated more intensively than they had been in many years, and many had been cycled on and off, adding to the stress on

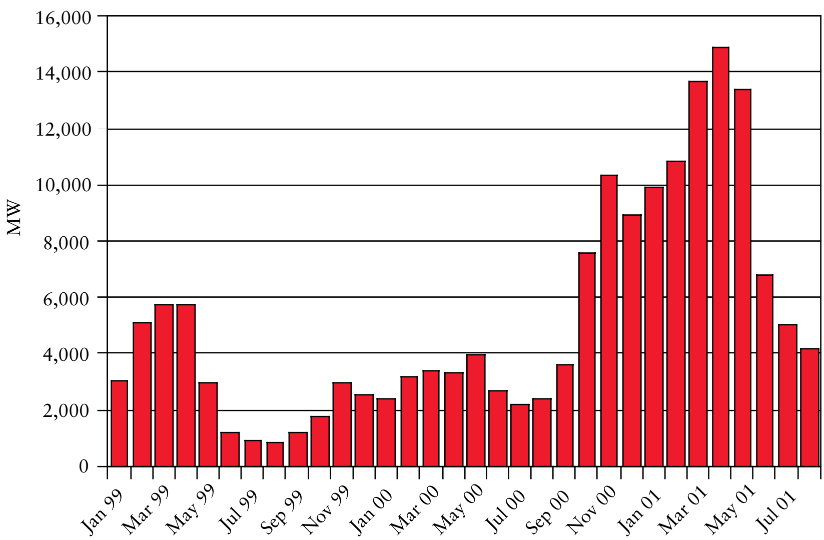

FIGURE 4.6: Average Generating Capacity Off-Line

SOURCE: California Energy Commission

these old plants. The firms operating the generators have asserted that a larger than average need for repairs resulted from running the plants at full capacity for the entire summer and that plants had been forced off-line for needed repairs. One such outage has been very well documented: an accident at SCE's San Onofre nuclear power plant in February 2001 took over 1,000 MW off-line for several months. Since SCE was a buyer of electricity, it had an intense incentive to bring that plant back to operation as soon as possible.

It is also reasonable to believe that shutting down some plants was largely a matter of choice, not of necessity. Whether some old plants can still be run while in need of repairs is a matter of engineering and operational judgment. There were economic incentives to shut down some of the plants. Firms that owned a portfolio of generators had an incentive to withhold one of their plants from generating electricity in order to increase the wholesale price of electricity sold by the remaining plants. Such an opportunity to exercise market power would be a financial motivation to take one plant off-line for repairs, even though the plant could have continued to operate if the owner had so chosen.

In response to the concern that the large number of plants off-line could have been the result of deliberate withholding, the FERC initiated an investigation. In February 2001, the FERC issued a report on the causes of the outages with the following conclusion, based on its field and office observations:

> *The telephone audits and the on-site inspections disclosed that the outages occurred at generating plants that were 30 to 40 years old. These generating facilities were operated at a significantly higher rate in 2000 than in previous years. Most of the generating facilities were out-of-service because of tube leaks and casing problems, turbine seal leaks and turbine blade wear, valve failure, pump, and pump motor failures.*
>
> *Staff did not discover any evidence suggesting that the audited companies were scheduling maintenance or incurring outages in an effort to influence prices. Rather, the companies appeared to have taken whatever steps were necessary to bring the generating facilities back on-line as soon as possible by accelerating maintenance and incurring additional expenses. Also, the outages did*

> *not necessarily correlate to the movement of prices on a given day.*[7]

Other observers argue that these telephone audits could not have detected plants that were shut down for manipulating market prices. In addition, even field audits may not detect actions to slow down repairs. The GAO reviewed the FERC analysis and concluded:

> *FERC's study was not thorough enough to support its overall conclusion that audited generators were not physically withholding electricity supply to influence prices. FERC's study was largely focussed on determining whether or not the outages that occurred were caused by actual physical problems—such as leaks in cooling tubes—requiring maintenance or repairs. However, it is practically impossible to accurately determine whether such outages are orchestrated or not because plants frequently run with physical problems and the timing of repairs and maintenance is often a judgment call on the part of plant owners or operators.*[8]

Neither the FERC study nor the GAO was able to assess quantitatively and definitively the genesis of the plant outages. The FERC "did not discover any evidence" of strategic manipulation of outages but did not claim to have proved there were no strategic manipulations. The GAO concluded that "FERC's study was not thorough enough" but did not claim to have evidence that there was strategic manipulation. Absent litigation, with discovery of internal documents and testimony under oath—and possibly even with a litigation—it is unlikely that we will ever know definitively whether these outages were uncontrollable or whether they resulted from strategic manipulation.

A smaller but significant number of the off-line plants—perhaps up to 3,000 MW—were not the old gas-fired units but rather

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[7]FERC, "Report on Plant Outages in the State of California." Prepared by Office of the General Counsel, Market Oversight & Enforcement, Office of Markets, Tariffs and Rates Division of Energy Markets, February 1, 2001.

[8]USGAO, "Energy Markets: Results of Studies Assessing High Electricity Prices in California" (June 2001). USGAO, "Energy Markets: Results of FERC Outage Study and Other Market Power Studies," Statement of Jim Wells, Director Natural Resources and Environment (Thursday, August 2, 2001).

were the QFs whose operators were not being paid for the electricity they were selling the investor-owned utilities.[9] Thus, some portion of the reductions in capacity, but far from a majority, was the direct result of the uncertainty imposed on the QFs and the reduction in their cash flow, which was a direct result of the financial crisis.

Figure 4.6 shows that May 2001 was the last month for which such a large amount of generating capacity was off-line: in May almost 14,000 MW were off-line, whereas in June that figure dropped to 7,000 MW. The 7,000 MW increase in available supply of electricity was a very important component to loosening the market and driving wholesale prices down toward more normal levels in June.

The reasons for the sudden change in available supply are not altogether clear. As discussed in the subsequent section on FERC rulemaking, the FERC May and June Orders included "must offer" provisions. These Orders may have had a significant impact. In addition, by June, QFs were being paid for the electricity they sold and had, for the most part, come back on-line. Natural gas prices had dropped substantially and the costs of running the less efficient units had decreased substantially, thus making it more attractive for them to be kept operational.

New Generation Capacity

During the challenge period small amounts of new generation capacity became available. In May through July 2000, approximately 1,000 MW of new generation capacity had come on-line in Colorado, Nevada, and New Mexico. A 250 MW cogeneration plant went on-line in British Columbia at the beginning of October 2000.

However, during the last half of the crisis, new generation capacity was rapidly becoming operational throughout the West, including California. A very small amount became operational in March 2001, but starting in late April, new plants came on-line at the rate of around 1,000 MW per month for the next six

[9]On March 20, 2001, the *Los Angeles Times* reported, in a story entitled "Small Power Firms' Cutbacks Contribute to Blackouts": "Monday, about 3,000 megawatts of qualified-facilities generation went offline because the companies that operate the power plants can no longer afford to buy natural gas used to fuel the plants due to the utilities' failure to pay money owed to the companies, said Jim Detmer, vice president of operations for the state's Independent System Operator."

months. By June 1, 2001, almost 2,000 MW had become operational; by August 1, over 5,000 MW had become operational; and by October 1, almost 7,000 MW were on-line. Figure 4.7 shows the cumulative new generation coming on-line after August 2000, with data from ten western states plus British Columbia.[10] Additional capacity was completed in the Mexican portions of WSCC, but these data are not included in that figure.

Figure 4.7 shows that about 800 MW of new capacity came on-line in British Columbia and Arizona around the beginning of May 2001 and that over 1,000 more went on-line by June 1. The additions were primarily in Arizona, but smaller amounts also went on-line in Colorado and Wyoming. These increases in new generation capacity combined with the June reductions in the number of plants off-line placed significant downward pressure on spot wholesale prices, which declined sharply around June 1.

In California, as of the beginning of the crisis, no new generation capacity had yet come on-line, although much was in the construction pipeline. Not until late June and July 2001, *after* the sharp decline in wholesale prices, did any new generation capacity become operational. These new plants, Sunrise Power, Sutter Power, and the

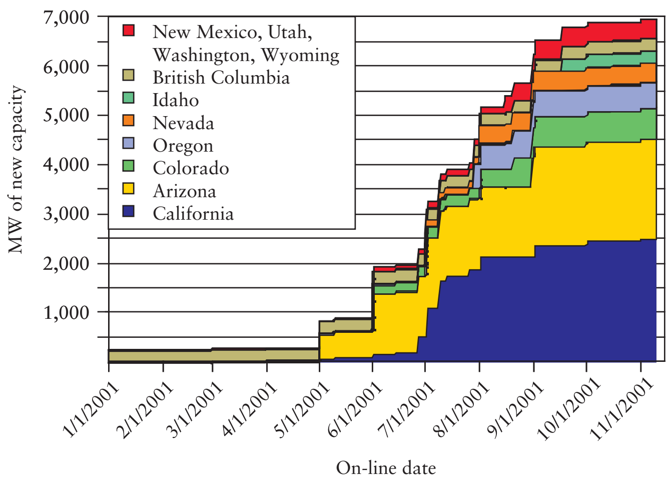

FIGURE 4.7: New Electric Generation Capacity On-Line in WSCC (excluding Mexico)

[10]These data were compiled from many different publicly available sources, including the California Energy Commission for plants in California.

Los Medanos Energy Center, contributing 1,400 MW of capacity, had been initiated between December 1997 and December 1998, shortly after the restructuring legislation. However, they were completed slightly too late to have had any impact on electricity prices until after the crisis had ended.

Figure 4.7 shows that as of November 2001, of the new capacity in the West, 36 percent was in California, which is comparable to California's 40 percent of the electricity consumption. And California's new capacity came on-line after the first new capacity in Arizona and British Columbia. These data thus do not support a claim that California State governmental actions successfully brought a disproportionate number of plants on-line nor that the State's actions were particularly successful in speeding up the construction process for those plants already under construction.

The new generation capacity under construction in California and the rest of the West can be expected to insure against a near-term repeat of the electricity crisis. Figure 4.8 provides estimates, published by the California Energy Commission, of the new California-only generation capacity projected to come on-line before the end of 2004. These data are based on electricity-generating plants currently under construction. Figure 4.8 shows the capacity additions both from large plants (greater than 300 MW) and from

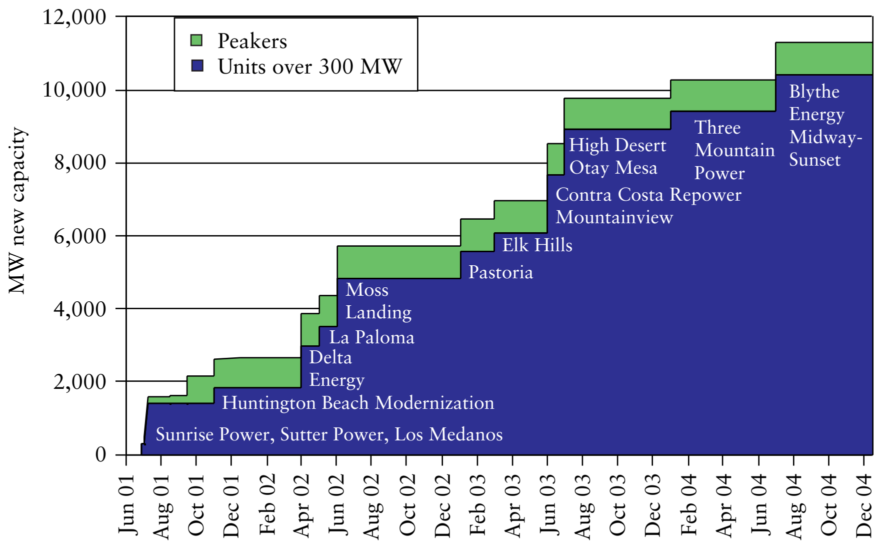

FIGURE 4.8: Expected New Generating Capacity in California from Plants under Construction

peaking units currently under construction.[11] Figure 4.8 shows that by the beginning of summer 2002 there can be expected to be roughly 4,000 MW of new capacity on-line and almost 6,000 MW by the end of summer 2002.

Energy Conservation

Electricity demand, measured both in terms of peak demands and total megawatt hours, declined from 2000 to 2001. During spring and summer 2001, these significant reductions in the consumption of electricity and the peak demands for electricity started becoming apparent, thereby taking pressure off the tight electricity market. The reductions continued at least through the end of 2001.

Figure 4.9 shows the reduction in average electricity consumption and in peak demand based on California Energy Commission data.[12] The bars show the peak demand reductions on a month-by-month basis from 2000 to 2001; the lines show the reductions in average electricity use. The monthly peak electricity demand was reduced, on average, by 1,900 MW (4.4 percent), and the monthly average use was reduced by 1,200 MW (4.3 percent). Although this demand reduction was substantially smaller than variations in the capacity of plants off-line, it was comparable in magnitude to the new generation capacity on-line by the end of the period. Demand reductions, which generally can occur more rapidly than new construction, have been important in putting downward pressure on wholesale prices.

Some of the month-to-month variability was the result of differences in weather conditions between 2000 and 2001. The California Energy Commission has estimated that weather-adjusted peak demand, averaged over the months from January through November, declined by 7.4 percent and that the weather-adjusted average electricity consumption declined by 5.2 percent, figures somewhat larger than the unadjusted changes.

In addition, there were reductions in electricity use throughout the West. In the Pacific Northwest, in particular, there were significant numbers of industrial shutdowns, including in the aluminum industry, which together reduced the demand for electricity in the West.

[11]Because the construction time for peaking units is so short, there may be more peaking units on-line during this time horizon, if needed, based on plants for whom no application has yet been filed.

[12]Data are published by the California Energy Commission on its web page.

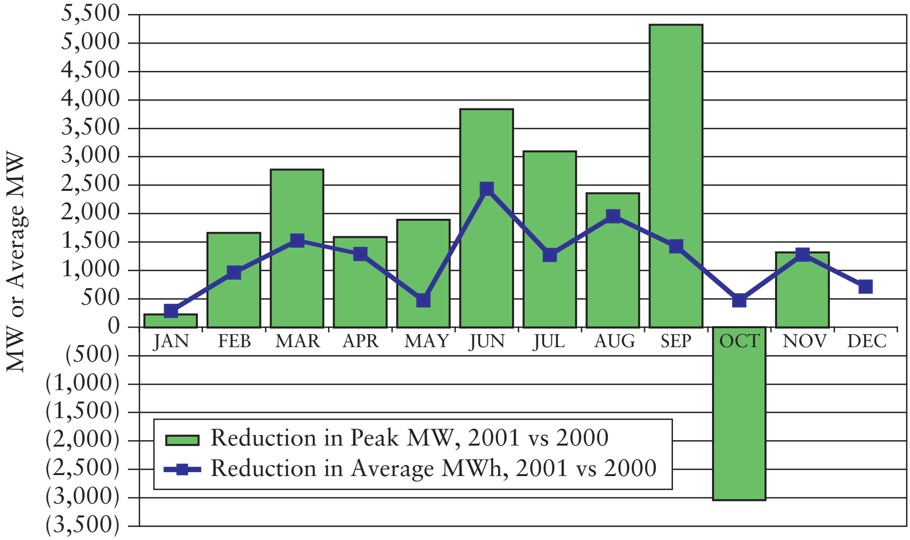

FIGURE 4.9: Reductions in Electricity Use, 2001 versus 2000, MW Peak and Average MW

SOURCE: California Energy Commission

These demand reductions stem from a combination of factors—expectations of increased electricity prices, high retail natural gas prices,[13] the energy demand management programs, energy efficiency and conservation programs, publicity about electricity problems, and the decline in the California economy. Subsequent empirical work will be needed to assess the quantitative significance of these various factors.

Some of the demand reductions can be expected to be transient; for example, the significantly reduced lighting levels in large stores

[13]Many customers, particularly in Northern California, received one single bill for natural gas and electricity purchases. When the natural gas prices increased, newspapers carried stories about consumers whose energy bills had increased and who were finding ways of reducing their electricity consumption in response. Although a reduction in electricity use in response to an increase in the natural gas price is not what economists normally predict, it seemed to be occurring in California. Perhaps subsequent empirical work will be able to examine whether this phenomenon in fact occurred in significant amounts. But the requisite empirical work has not yet been completed, or at least not yet been published.

or parking lots in shopping centers or the changes in temperature settings of air conditioners. In addition, the demand reductions associated with the decline in the California economy will be reversed as the economy recovers and again starts to grow.

However, many of the demand reductions will be permanent.[14] The reduction in public sector use through the substitution of light-emitting diodes in traffic lights rather than conventional lightbulbs will not be reversed. Buildings have been reroofed with light-colored materials, thereby reflecting radiant energy rather than absorbing it, reducing the air-conditioning load. Consumers and firms that have substituted compact fluorescent lights for conventional incandescent lights are unlikely to go back. The utilities are again promoting energy efficiency programs, and these, too, can be expected to result in permanent reductions in electricity use.

California could still face electricity problems in the winter of 2002 if many generating plants again go off-line, or if a cold winter leads to large demand in the Pacific Northwest.[15] As time goes on, however, the probability of continuing problems declines. With the large amount of new capacity scheduled to come on-line within the next several years and continuing demand reductions, supplies of electricity are likely to remain adequate, unless California policies chill the investment climate enough that many plants currently planned or under construction are canceled.

Energy Emergencies and Rolling Blackouts

The electricity crisis was marked by energy emergencies and fear of rolling blackouts. Crises resulted from supply and demand imbalances: electricity supply was not sufficient to satisfy all electricity demand and keep a safe margin of operational reserves. Blackouts occurred when supply was so small that groups of customers had to be "blacked out" to avoid instability in the grid. Although blackouts came to symbolize the electricity crisis, energy emergencies were the norm during the crisis and blackouts were the exception.

[14]These reductions will be permanent, relative to the level of economic activity and to the population. But a growing population and growing economy will increase the overall level of electricity use even with these permanent reductions.

[15]Particularly in Washington, electricity is used for space heating in many homes. Cold weather can greatly increase the space-heating loads.

Figure 4.10 diagrams the various stages of energy emergencies and the demand responses, alerts, and warnings issued by the CAISO at the various stages of energy emergencies. Blackouts occur only when the CAISO has declared that a Stage 3 emergency exists, that is, when operating reserves decline below 1.5 percent. During some Stage 3 emergencies, rolling blackouts, although threatened, are not ultimately required.

As Figure 4.10 indicates, in anticipation that Stage 3 emergencies might occur, several options would be taken in turn. First, during a Stage 1 emergency, when operating reserves were projected to fall below 7 percent, public alerts were issued with calls for people to reduce their use of electricity during the energy emergency, particularly during peak times. Commercial establishments would be encouraged to reduce "unnecessary" lighting and to curtail use of air conditioning or other heavy uses of electricity.

During a Stage 2 emergency, when operating reserves were projected to fall below 5 percent, more severe measures were taken. Utilities had contracts with large users, particularly large

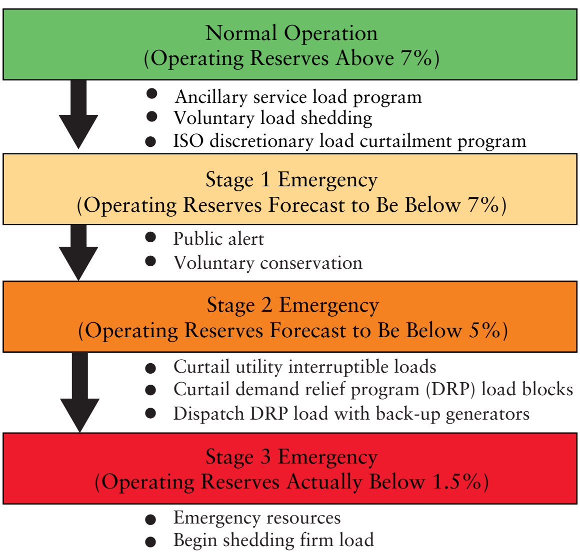

FIGURE 4.10: Electricity System Emergency Levels

SOURCE: *CAISO 2001 Summer Assessment,* March 22, 2001, California Independent System Operator industrial users,[16] to reduce use of electricity significantly during Stage 2 emergencies. The loads for these large users could be interrupted during energy emergencies, although such contracts included a provision limiting the number of such required interruptions. Since these users had each voluntarily agreed to such contracts, this load shedding would be concentrated on firms whose operations would not be severely damaged by an interruption of electricity service. In addition, the CAISO established a demand relief program (DRP) under which energy aggregators agreed to reduce their aggregate demand when so ordered by CAISO. Under this program, load aggregators develop and market programs to those end-use customers willing to reduce electricity use in response to a CAISO curtailment order, which could be issued during a Stage 2 emergency, up to a limited number of curtailment hours in each month for a given participant.

These curtailments sometimes were not sufficient to avoid moving to a Stage 3 emergency, during which the CAISO called on emergency generating resources and ordered utilities to begin shedding firm load; that is, it ordered blackouts. In rolling blackouts, shortages were allocated to the utilities. The utilities had been required to identify electricity "blocks," or areas that could be blacked out simultaneously. During the emergency, utilities were required to shut down all electricity in those blocks for a limited time, typically one to two hours. If the shortage continued, other blocks would be blacked out in sufficient quantities to ensure that the entire grid did not crash.

Alternatively, the CAISO could have been willing to pay higher prices to obtain additional supplies, either from the generators participating in the California market or from out-of-market purchases. While the price caps were in effect, this option had been foreclosed. Upon the lifting of the price caps, however, such high-price purchases were possible, to a limited extent.

The separation of the PX and the CAISO, and the resulting restrictions embedded in the CAISO tariff, made this process of ac-

[16]Other large users could have such interruptible service. For example, the Claremont Colleges had interruptible electricity contracts and experienced such contractual blackouts.

quiring electricity to avoid Stage 3 energy emergencies far more difficult than it needed to be. As discussed above, when the PX and CAISO were established, the PX was given responsibility for all trading on the day-ahead and the day-of markets. The CAISO was not allowed to buy or sell on those markets; that is, the CAISO was restricted to real-time purchases and sales of electricity. "Real-time" has been interpreted as during the hour that the electricity is needed. Thus, because of the early decisions to separate the PX and the CAISO, the CAISO tariff precludes it from acquiring electricity to meet emergency conditions earlier than during the hour that electricity is needed.

This restriction was in effect even when CAISO personnel were confident ahead of time that the electricity would be needed. Moreover, as discussed at another point, the utilities were typically greatly underscheduling their loads, sometimes by as much as 35 percent. All underscheduled loads had to be covered by CAISO purchases with purchases occurring *during the hour that the electricity was needed,* thereby making the process far more hurried than it needed to be.

Organizations other than the CAISO could make contractual commitments to purchase electricity well in advance of the time it would be used. Thus, when electricity supplies were short throughout the western states, the CAISO, because of limitations in its tariff, would be the last entity to be able to acquire supplies to avoid energy emergencies. That restriction thus increased the likelihood that the blackouts would be concentrated in California.

Figure 4.11 plots the energy emergencies declared by CAISO during the challenge and the crisis periods. Data are presented on a daily basis; each major division on the horizontal axis represents two weeks. Stage 1, 2, and 3 emergencies are indicated by the 1, 2, and 3 on the vertical axis. Rolling blackouts are shown as one level higher.

The first energy emergency was declared on June 14. This one-day Stage 1 emergency resulted from the heat wave hitting California and surrounding states while supplies were tight. During mid-July through August, Stage 1 and Stage 2 emergencies, including multiday emergencies, became common. Mid-September saw a brief return of energy emergencies. With the cooler autumn weather, there were no more energy emergencies until November.

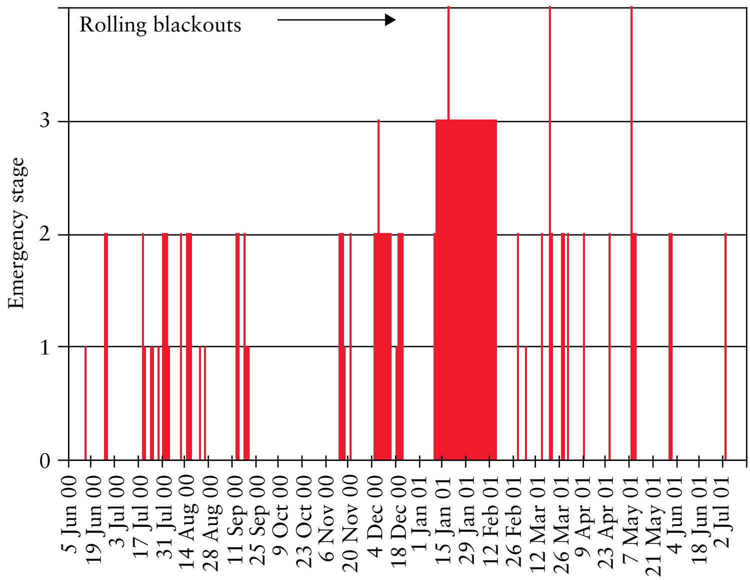

FIGURE 4.11: Energy Emergencies and Blackouts in California

Stage 2 energy emergencies returned in mid-November. However, in December and January energy emergencies became the norm. December 4 began an eleven-day period of Stage 2 emergencies, during which the CAISO first declared a Stage 3 emergency. The emergencies seemed to take a break for the holidays at the end of the year—a time of generally reduced commercial activities. After the first week of January, the CAISO declared energy emergencies for thirty-two consecutive days. The first rolling blackouts occurred January 17 and 18.

Once the coldest part of the winter had passed and the heating loads in the Pacific Northwest had subsided, energy emergencies became less common. Stage 2 emergencies, however, continued to recur, including two episodes of rolling blackouts, each two days long.

Although everyone in California was asked to conserve energy during each energy emergency, none of the demand reductions was mandatory unless a Stage 2 or Stage 3 emergency was called. During a Stage 2 emergency, conservation or load shedding was mandatory, but only for those organizations that had entered contracts allowing for such mandatory load shedding. Only when Stage 3 emergencies were severe enough to require rolling blackouts did the shedding of loads extend to individuals or organizations that had not agreed to allow such curtailments.

Blackouts came to symbolize the electricity crisis in California. Nevertheless, although blackouts were the symbol, and the threat of blackouts was frequent, actual blackouts were very rare. The CAISO ordered blackouts in fact on only six separate days, as shown in Figure 4.11 and in Table 4.1. Moreover, blackouts were called for only a small fraction of the load at any time, as shown in Table 4.1. The most severe was on January 18, in which 1,000 MW of load was curtailed, accounting for 3.2 percent of the peak demand that day. Other rolling blackouts ranged from 300 MW to 500 MW, or 0.9 to 1.7 percent of the peak load.

Perhaps blackouts came to symbolize the electricity crisis in California because, for several months, the threat of blackouts was always real. Initially almost everyone was vulnerable to such interruptions, with the exception of hospitals and other emergency locations. Blackouts hitting industrial plants on only short notice could and did lead to very high costs. Blackouts covering areas of street lighting and traffic lights raised the risk of traffic accidents. The fear of blackouts was expressed frequently in newspaper stories, editorial cartoons, and letters to editors. Thus, although there were many instances of very large costs incurred, particularly by industrial facilities, the fear of blackouts may have generally been greater than the direct consequences of the blackouts themselves.

The last rolling blackout was ordered on May 8; the last energy emergency was declared on July 3 during a heat wave. Since that day, the CAISO has not declared any energy emergency.

TABLE 4.1
Rolling Blackouts in California

Date (All 2001)	*Curtailment Ordered (MW)*	*% of Peak*
January 17	500	1.6
January 18	1,000	3.2
March 19	500	1.7
March 20	500	1.7
May 7	300	0.9
May 8	400	1.1

THE FINANCIAL CRISIS

As of December 2000, the financial challenge had become a crisis that ultimately resulted in PG&E declaring bankruptcy and SCE teetering on the brink of bankruptcy for a month. Once the financial limits of the utilities had been reached, this crisis moved to a hemorrhaging state budget. At this time, the state budgetary issues have yet to be fully resolved.

That the financial challenge turned into a financial crisis was the direct result of state regulatory, administrative, and legislative action. The state could have averted the financial crisis during the challenge period if it had stopped forcing investor-owned utilities to deeply subsidize electricity use by their customers.[17]

Had the state relaxed its price controls, the utilities would not have faced a financial crisis and the state budget would have retained a sizable surplus. Consumers and businesses would have faced higher electricity prices but not of crisis proportions. Thus, the financial crisis was caused simply by the unwillingness of the state regulatory authorities, under the leadership of the governor, to allow retail electricity prices to rise sufficiently to cover the cost of acquiring that electricity, or even most of the cost.

The significance of the regulatory controls is apparent from a comparison of the impacts on the investor-owned utilities with the impacts on the municipal and investor-owned utilities throughout the other ten western states and on the municipal utilities in California. During both the challenge period and the crisis, the increases in spot wholesale prices were very similar throughout the eleven western states. Therefore, other than electricity purchased under long- or medium-term contracts, wholesale electricity prices increased by roughly the same amount for investor-owned and municipal utilities throughout the entire eleven-state region.

Yet only California, and only the investor-owned utilities of California, faced a fundamental financial crisis. Some investor-owned utilities in other states and some municipal utilities in California faced difficult financial problems, but none was brought to the brink of bankruptcy, as were the investor-owned utilities in California.

[17]As noted previously, California municipal utilities were not so required and were free to increase their prices based on decisions by their governing boards.

There are two fundamental differences between California's investor-owned utilities and all the other entities. All the other entities acquired the vast bulk of their electricity through either their own generation or a mix of medium- and long-term contracts, and faced regulatory bodies that could have increased the retail prices if needed to keep them creditworthy, although in many cases these bodies did not increase retail price by as much as wholesale price increased. Only the California investor-owned utilities faced the western electricity crisis with a requirement to purchase most of their electricity on spot markets and with a regulatory body that refused to raise retail electricity rates until it was too late. Therefore, only the California investor-owned utilities faced the devastating financial crisis.

The financial crisis did not end even when all financial assets of the utilities were depleted. The state took over from the investor-owned utilities the obligation to purchase sufficient electricity to satisfy electricity demand. As a result, over the course of roughly six months, this decision decimated the State budgetary surplus. In essence, the State of California had put itself in the place of the investor-owned utilities as the only entity facing the western electricity crisis without long-term contracts to purchase electricity and with price controls limiting the price at which the electricity was sold to its customers. Thus, the State of California started facing the same financial crisis that the CPUC and Governor Davis had imposed on the investor-owned utilities. However, as will be discussed at a later point, the CPUC had the power to raise retail electricity rates and the state had the power to enter medium- and long-term contracts to purchase electricity. When needed to reduce the impact on the California State Treasury during the crisis, the CPUC and the state ultimately took the actions they had precluded the utilities from taking.

The Financial Crisis and the Utilities

Until January 2001, no retail rate increase was forthcoming and the investor-owned utilities remained trapped between soaring wholesale prices and the retail price controls rigidly enforced by the CPUC and strongly endorsed by the governor.

A loud and clear warning came from the financial community on December 20, 2000, when Standard & Poor's warned that utilities would not be able to finance wholesale power purchases without clear and definitive action from California's regulators to ensure that costs could be repaid. Citing the likelihood of default, Standard & Poor's asserted that unless such clear and definitive actions were taken within twenty-four to forty-eight hours, there would be a downgrade of credit ratings of the utilities to "deeply speculative" levels.

In a classic "too little, too late" move, on January 3 the CPUC proposed, and on January 4 agreed, to allow SCE and PG&E to raise rates by a mere 1 cent/KWh ($10/MWh). The increase was too small by a factor of at least 3 to begin to compensate for average wholesale cost increases of over $100/MWh. Moreover, the CPUC made it clear that the rate increase would be a *temporary* surcharge, to be in effect for ninety days and subject to refund. The CPUC promised to investigate the rate issue further during the ninety-day period, stating, "we do not yet have the facts to evaluate the utilities' claims of their dire circumstances." By that decision, the CPUC clearly signaled that they were willing to drive the utilities to bankruptcy.

The governor only grudgingly accepted any price increase at all, stating in a press release: "If I had my way there would be no rate increase to consumers. But given the colossal failure of California's deregulation scheme, the PUC's decision was unfortunately necessary."

However, four days later, Governor Davis did offer the investor-owned utilities some hope. In his "State of the State" address on January 8, 2001, he stated unequivocally:

> *To utilities and the financial community, let me say this: I reject the irresponsible notion that we can afford to allow our major utilities to go bankrupt. Our fate is tied to their fate. Bankruptcy would mean that millions of Californians would be subject to electricity blackouts. Public safety would be jeopardized. Businesses would close. Jobs would be lost. Investment would flee the state. And our economy would suffer a devastating blow.*

Yet even with those dramatic, although overstated, comments, the governor remained opposed to the single most important action that he could take to solve the financial crisis—a meaningful retail price increase consistent with the cost increases the utilities were facing. And, as it turned out, Governor Davis did nothing to back up his words with actions.

To keep buying electricity, both PG&E and SCE used their available cash and credit to pay for the massive financial shortfalls. However, the rate of net outflow was staggering. For example, the costs that PG&E faced exceeded their revenues by roughly $1 billion per month. By PG&E estimates, the cumulative shortfall was $3.4 billion by October 2000, $4.5 billion by November, and $6.7 billion by year-end 2000. By the end of the first quarter of 2001, the cumulative shortfall amounted to about $9 billion. Similarly, SCE, by the end of the process, had incurred liabilities and indebtedness from procuring electricity, totaling approximately $6 billion. Any company, including PG&E and SCE, faces limits on its financial reserves and its borrowing capacity. By January, SCE had reached those limits. PG&E reached its limits in a similar timeframe.

On January 16, SCE formally notified the U.S. Securities and Exchange Commission (SEC) that it had suspended payment of some power purchase and debt obligations. Its public filing stated that the utility's cash reserves of approximately $1.2 billion as of January 15 would be exhausted by February 2 if it met all its financial obligations. This default meant that debtors would be entitled to exercise legal remedies to collect. Standard & Poor's and Moody's Investors Service subsequently downgraded SCE's bonds to below investment grade. No longer would SCE be treated as a creditworthy buyer of electricity.

On January 19, Standard & Poor's downgraded the ratings on PG&E's bonds to below investment grade, reflecting PG&E's defaults on January 17. Therefore, PG&E would no longer be treated as a creditworthy buyer. On February 1, 2001, PG&E announced that it could not make full payment to the CAISO and QFs for November CAISO energy purchases and December QF electricity deliveries. Of the somewhat more than $1 billion due, it would make partial payments of $161 million.

Before that time, the utilities had been able to purchase electricity even though they were delaying payment for it, because they were creditworthy. Some QFs with contracts to sell electricity to the utilities had attempted to break the contracts, citing that the utilities were not paying for the electricity, but the attempts usually had been rebuffed in court. As long as a utility was deemed creditworthy, suppliers were obligated to continue supplying electricity.

Once a utility was not creditworthy, however, sellers had a legal right to abrogate their electricity sales contracts with that utility. Moreover, there was strong motivation for these suppliers to break the contracts, because the spot prices of electricity at that time had so far exceeded the fixed prices in the long-term contracts and the seller could no longer be assured it would be paid. The motivation coupled with the legal right to break the contracts made it clear that all the contracts were vulnerable.

The FERC chair, apparently anguished by the growing disaster, clearly communicated to the policymakers of California on January 18:

> *This year, energy is costlier in most regions of the country, but in California a cavalcade of misjudgments and bad luck have caused a genuine economic and social crisis. The situation has deteriorated further since early January. Negotiations over long term contracts have reached impasse, notwithstanding many hours of tough talk in Washington and the herculean (but ultimately inadequate) efforts of state legislators to buttress sagging utility creditworthiness and to find a sustainable retail rate compromise. California's reserves have evaporated this winter as recurrent plant outages continue and weather forced valuable units off line. Yesterday, the ISO had no choice but to order rolling blackouts in northern and central California in order to prevent a system collapse. So, to the financial crisis, we now add a serious threat to human welfare. With consumer rates frozen below cost (and below 1996 levels), with generators wary of making sales to entities probably unable to pay for power generated at unseasonably (and even historically) high cost, and with no plan to amortize existing utility arrearage, Southern California Edison and Pacific Gas & Electric stand at the brink of insolvency. For following the state's restructuring law, they may go bankrupt. Moreover, with only minimal forward contracting and utilities still subjected to high PX spot market prices for their "net short" position, the Commission's plan to diminish and discipline the spot market remains unrealized. Amidst a severe power shortage, conspiracy theories, resistance to more realistic rates, and calls for palliative price caps continue to obscure the issues and delay solutions.*
>
> *Perhaps bankruptcy can be averted. . . .*

Urgency is a must. I am persuaded that California's utilities can still be withdrawn from the brink. But their descent into Chapter 11 does not materially alter the need to act to devise a coordinated plan of action. We have reached this stage of growing crisis through a series of acts of short-term thinking and now the desperation is palpable. We cannot, however, keep moving from one failure to the next, with no agreed-upon objectives. The Governor's stated plans are unrealistic and ours cannot be fully implemented without his help. Time to put down the guns.[18]

By mid-January the governor had delivered reassuring words for public consumption but had taken no action to support those words; the CPUC had granted merely a temporary rate increase that was far too small; the legislature had taken no meaningful actions to solve the financial crisis; wholesale prices remained well above the retail prices; utilities were rapidly running out of financial assets and borrowing capacity; utility bond ratings had been downgraded to junk bond levels; and electricity suppliers arguably were no longer legally required to sell electricity to the two utilities. The plight of the utilities was desperate and the governor's "irresponsible notion" was promising to become a reality.

Then, and only then, was the governor forced to begin to address the financial crisis, since absence of action could have resulted in large regions of the state without electricity, a condition that surely would have destroyed the governor's chances for reelection. Several options remained at that time.

First, the state could stand by and allow the utilities to file for bankruptcy protection. The implications of this alternative were not completely known but various scenarios could be envisioned. Bankruptcy would put the future of the utilities under the control of a federal judge who would have very strong powers. The judge could not force suppliers to continue selling electricity to the utilities unless the utilities could ensure that those new obligations would be paid. Alternatively, the judge could order the generating assets to be sold to the highest bidders. However, if market power was being exercised, it was likely that the highest bidder would be the one most

[18]FERC Chairman Hoecker, "Addendum to remarks of January 4, 2001" (January 18, 2001).
http://www.ferc.gov/electric/bulkpower/Furtherconcurrence_Jan_18.PDF.

able to increase the value of the generating asset through the exercise of market power. One way or the other, a bankruptcy judge would be expected to ensure that the utility's selling price for electricity would be no less than its purchase price. Therefore, the judge would have the power to require that the retail prices of electricity be raised to cover the ongoing costs of purchasing electricity.

Alternatively, the judge could allow the utilities to stop supplying electricity to those customers whose prices were below costs for new purchases. However, it would have been highly unlikely for any judge to take such a harsh action; it would have such devastating consequences for all of California. Thus, absent reduction in the wholesale price of electricity, it was reasonable to expect that retail customers would face greatly increased electricity prices one way or the other, if the governor simply allowed the utilities to go bankrupt.

The second option would have been to allow what so many people had been urging: to increase the retail price of electricity for both consumers and businesses. The CPUC could have entered such an order. However, based on CPUC normal procedures, that would have been a slow process. Moreover, the CPUC had just affirmed that they were not willing to provide a rate increase of more than \$10/MWh. Thus, by the time the growing crisis forced the governor into action, it was too late to depend entirely upon the CPUC, at least for the short-term solution.

However, the governor of California does have almost unlimited powers conferred by the State Government Code, including the ability to suspend both statutes and regulations. Explicitly included in the code are almost unlimited powers to deal with sudden and severe shortages of electrical energy. Governor Davis could have used this emergency power unilaterally, without approval by the legislature, to suspend retail price controls and unilaterally increase electricity prices. Then, while retail price controls were suspended, the governor could have worked with the legislature to modify the law and with the CPUC to set the basis for the appropriate retail price increases. The personal risk to the governor would have been that voters, knowing that he had raised electricity rates contrary to his previous public statements, might not support his reelection. He chose not to take that course of action.

Instead, on January 17, immediately after the credit rating downgrade implied that the utilities were no longer creditworthy buyers, Governor Davis chose to use his emergency powers another way. He issued a Proclamation that a "state of emergency" existed within California, allowing him to take unilateral action. Governor Davis ordered the DWR to assume responsibility for procurement of wholesale electricity for customers of California's three major IOUs and to start purchasing electricity on behalf of the electric utilities. Subsequent legislation[19] extended and broadened the authority available to the governor once he had declared the state of emergency.

Under the governor's plan, the state would purchase the electricity on behalf of the utilities' customers and the utilities would sell the electricity on behalf of the state and reimburse the DWR based on the retail rates at which the electricity was sold. Essentially, the DWR would sell the electricity it purchased to the utilities, charging a price equivalent to the utilities' retail prices. This plan allowed the state to avoid the consequences of power suppliers refusing to sell electricity to the California utilities.

In addition, the DWR would ask the CPUC to increase retail rates to allow the utilities to begin fully reimbursing the DWR for its electricity purchase costs. Apparently, the governor saw rate increases as acceptable if implemented on behalf of the State Treasury.

Adding injury to insult, on January 19 the CPUC confirmed that, no matter how much the utilities were paying to buy electricity in the wholesale market relative to the regulated selling price of electricity, and no matter whether they were creditworthy, they were obligated to continue buying sufficient electricity to fully serve all their customers. The temporary restraining order issued by the CPUC stated in part:

> *In this interim decision, we are issuing a temporary restraining order (TRO) preventing Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (Edison) from refusing to provide adequate service to all of their customers. . . . We affirm that regulated California utilities must serve their customers. This requirement, known as the "obligation to serve," is mandated by state law.*

[19]On January 19, 2001, he signed SB 7, which directed DWR to procure electricity for the next twelve days and appropriated initial funds for this purpose. On February 1, 2001, the Legislature enacted AB 1X, which, among other provisions, authorized the DWR to continue purchasing electricity through December 31, 2002.

> *A bankruptcy filing or the threat of insolvency has no bearing on this aspect of state law. Even utilities that file for reorganization must serve their customers.*[20]

On January 23, the U.S. Department of Energy extended for two weeks an emergency federal order directing electricity producers to sell to SCE and PG&E, even though they were not creditworthy. In doing so, however, Energy Secretary Spencer Abraham warned that there would probably be no further extensions.

State Payments to Buy Electricity

Under Governor Davis's order that the DWR purchase electricity on behalf of the utilities, the retail prices would remain low and the high cost of wholesale power purchases would be borne initially by the State Treasury. The state would issue long-term revenue bonds to reimburse the State Treasury. Repayment of interest and principal of these bonds would be a surcharge on retail electricity prices and thus ultimately the ratepayers would pay all of these costs. Although meant as a temporary measure until the utilities again became creditworthy purchasers, this was the first of several steps taken by the government to interject the state squarely into the middle of the electricity system.

Once the state became the primary buyer of electricity, there were no longer any transactions on the PX, and that institution had no way of raising money to pay its costs. The process of dismantling the PX began. The PX ultimately declared bankruptcy in March, thus eliminating one of the two market institutions established by AB 1890.

Governor Davis continued to assert that increases in the retail electricity price to meet the cost of electricity would not be in the interests of the consumers of electricity. However, his assertions failed to acknowledge that the people of California would in fact pay the entire wholesale price of the electricity even though the retail prices would be kept low during the crisis. The high wholesale price of electricity represented the cost to the State of California, whatever the retail price. The entire cost would be paid by a combination of consumers, businesses, and taxpayers in California. The price of retail electricity determined *which* of

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[20]The entire text is available at http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/4653.htm.

these entities would be paying what fractions of the total cost, not whether the cost would be paid. Low prices to consumers would save those consumers money as purchasers of electricity but cost the taxpayers of the state the same amount saved by consumers. Low retail prices of electricity to businesses would save those businesses money in their role as buyers of electricity but cost the taxpayers of the state the same amount saved by the businesses. If the state issued bonds to pay the costs, as had been announced by Governor Davis, then future ratepayers would be responsible for paying the entire cost of current electricity purchases. None of that difference would be paid by the electric utilities, because they had no financial assets left. Therefore, at best, low retail pricing was a zero-sum game among businesses, residential consumers, and taxpayers, many of whom, of course, were the same people.

However, the failure to raise retail prices did more than simply move the burden of payments from Californians as buyers of electricity to Californians as taxpayers or from current ratepayers to future ratepayers. The low prices eliminated the natural market incentives to respond to those high prices by reducing electricity use, which would have lowered the wholesale price and therefore reduced the cost to California. So more than simply reallocating the high wholesale cost, the failure to raise retail prices greatly increased that cost. After all, why would corporations and individuals choose to go through the cost and difficulties of reducing their use of electricity to save costs for the state if people other than the firm or consumer reducing the use would capture much of the savings?

As of the beginning of 2001, it was generally projected that California would have an $8 billion budgetary surplus during the year. This projected surplus was largely the result of a healthy California economy; however, Governor Davis's commitment for the state to become the wholesale purchaser of electricity changed that.

Once the state took over the purchasing of electricity on behalf of the utilities, purchase costs remained as high, just less visible. Rather than a transparent market—the PX—that was observable by the public, either directly through the web site or indirectly through newspaper reports, the purchases by the DWR were hidden from public view. However periodically, information would be issued about the purchase costs, often as press releases from the governor's office and later from the DWR.

Table 4.2 shows monthly data of DWR electricity purchases, including the price per MWh of electricity purchased under contracts,

TABLE 4.2

State Costs for Electricity Purchases

	Spot Cost ($/MWh)	*Contract Cost ($/MWh)*	*Average Cost ($/MWh)*	*Fraction Spot*	*Fraction Contract*	*Total MWh (in thousands)*	*Total Cost ($ Millions)*
Jan. 17–31	321	368	332	77%	23%	1,654	549
February	308	279	304	86%	14%	4,743	1,442
March	271	239	261	69%	31%	6,903	1,801
April	331	207	269	50%	50%	6,913	1,860
May	271	216	243	49%	51%	8,222	1,999
June	113	194	168	32%	68%	6,201	1,041
July	78	160	146	17%	83%	6,212	909
August	53	153	131	22%	78%	6,228	815
September	36	172	134	28%	72%	5,069	679
October	34	104	89	21%	79%	4,658	415
November	41	109	94	21%	79%	3,768	355
December	36	107	88	27%	73%	4,256	373
January	33	110	92	23%	77%	3,396	313
Total						68,223	12.5 Billion

the price per MWh of electricity purchased on spot markets, the fractions purchased on spot markets versus under contract, and the overall costs during the month of January 2001 through January 2002.[21]

These data show that beginning in June 2001, spot prices of electricity dropped sharply from the high levels during the peak of the crisis. By January 2002 spot prices had declined to \$33/MWh. However, the DWR cost for electricity purchased under contract remained above \$100/MWh for each month, including both medium- and long-term contracts the state had negotiated while spot prices were high. However, from early 2001 through autumn, the fraction of electricity purchased under spot prices dropped sharply. Because spot purchases had been reduced to about one quarter of state acquisitions by the end of 2001, the state was not able to reduce its average acquisition cost by nearly as great a percentage as the spot price had dropped.

In the first quarter of 2001, DWR electricity purchases cost \$3.8 billion. At the then current retail price of electricity, these purchases would have returned about \$1.0 billion to the state, thus depleting the State budget by \$2.8 billion during this quarter alone.[22]

Amid warnings by the State Treasurer that the state intervention to purchase electricity was decimating the budget, at the end of March the CPUC agreed to do what it had been unwilling to do previously—to raise the average retail electricity price another 3 cents/KWh, or \$30/MWh, although the increase was not implemented until May (see discussion in the next section).

In the second quarter of 2001, DWR electricity purchases increased to \$4.9 billion. Although the wholesale spot and contract prices had declined from the first quarter, the total megawatts of

[21]Data for price per MWh of electricity purchased on spot markets, overall purchases, purchases on spot markets versus under contract, and the overall costs are taken from DWR data. Average cost per MWh for electricity purchased under contract is backed out of these data. Data source: http://www.owe.water.ca.gov/newsreleases/2002/energy/02-02jan-cost.html.

[22]The estimates of State revenues are given as the revenue ultimately recovered by the state for selling the electricity. There was a lag from selling the electricity to the time that the payments for the electricity were delivered to the state. This and subsequent State revenue estimates do not account for this lag and thus the estimates do not describe the month-by-month cash flows.

electricity purchased by the state increased, resulting in the increased total purchase costs. The sale of this electricity by the state would have returned roughly $1.8 billion.[23] Thus, the State budget was depleted by another $3.1 billion in the second quarter, bringing the cumulative state deficit to about $5.9 billion.

During the third quarter the state budgetary hemorrhaging had greatly subsided. Retail prices of electricity had been increased and therefore the state was able to recover more revenue for each MWh of electricity it acquired on behalf of the investor-owned utilities. In addition, spot wholesale electricity prices had declined sharply so that by the beginning of the third quarter, the spot price had fallen below the retail electricity price. However, the state was purchasing over 70 percent of its electricity on medium-term contracts, which had been negotiated earlier and included prices well above the spot prices for electricity. Therefore, the average acquisition price of electricity purchased by the state remained above the retail price. During that quarter, the state paid a total of $2.4 billion and was entitled to recover about $1.8 billion, leading to an additional budgetary deficit that in the third quarter had declined to about $0.6 billion.

By October, the average price of electricity purchased by the state on spot markets had declined to $34/MWh and the average purchase price had declined to $89/MWh (the average cost of electricity purchased under contracts was $104/MWh). The retail price remained at about $105/MWh for sales by the state. Thus, for the first month since the state began buying electricity, it was able to sell the electricity it acquired at prices high enough to reduce the overall deficit by roughly $0.1 billion. The electricity-purchase-induced hemorrhaging of the State budget had ended.

The governor's plan had been simply to borrow the money from the State Treasury to cover the cumulative deficit and pay the treasury back through issuance of DWR revenue bonds. Although the necessary amount of revenue bonds has grown over time, most recently the state has been attempting to sell $12.5 billion worth of revenue bonds to cover the costs of purchasing electricity. The longer-term consequences of this bond sale will be discussed in the next chapter.

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[23]This assumes an average selling price of $75/MWh for April and May and $105/MWh for June.

The Financial Crisis of the Utilities: The Saga Continues

In the months after the state had started purchasing electricity on behalf of the investor-owned utilities, the governor and the legislature began addressing the financial plight of the utilities. Initially, rather than accepting a rate increase to allow the utilities to work their way back to solvency, the governor started a process of negotiating with the utilities, offering to purchase the electricity transmission facilities, some generating facilities, and other assets. The colorful phrase characterizing the process was "I give you a dollar, you give me a hot dog."[24] The State Legislature and the governor took the view that for the utilities to get financial relief from the controls imposed by the state, they would be required to sell significant proportions of their physical assets to California.[25]

By late March and early April there had been little real progress in the negotiations. However, with much fanfare, Governor Davis announced he would deliver a live address to Californians on the electricity crisis. At that time the CPUC had proposed retail electric rate increases that could at least stabilize both the utility financial conditions and the State budget, but that would not repair either. It seemed an appropriate time for the governor to lend his support to that plan. In addition, many expected to hear positive progress on his negotiations with the utilities. However, he instead proposed an alternative and significantly lower set of rate increases. On his negotiations with the utilities and on his rate increase he stated: "Unlike the PUC, my plan includes funds to restore the utilities to financial stability—if they agree to three main conditions: They must provide low-cost regulated power to the state for ten years, agree to sell us their transmission system, and dismiss their lawsuits seeking to double your electricity rates."

After PG&E executives listened to Gray Davis's live address, the next day, April 6, PG&E declared bankruptcy. Their filing for reorganization under Chapter 11 of the U.S. Bankruptcy Code cited "unreimbursed energy costs which are now increasing by more than $300 million per month, continuing CPUC decisions that economically disadvantage the company, and the now unmistakable fact that negotiations with Governor Gray Davis and

[24]The characterization originated with Senate leader, John Burton.

[25]This requirement was part of the policy framework developed by the Governor in January. See section on state policy.

his representatives are going nowhere."[26] Gray Davis had finally pushed the largest utility over the brink.

Later that day Governor Davis met with John Bryson, CEO of Southern California Edison (SCE), announcing, "We are determined to work out the few remaining issues that we have between us. . . . But I am hopeful we will have a satisfactory result for the people of this state within the next few days, proving that negotiation, not bankruptcy, is the appropriate path." The SCE did not file for bankruptcy protection but continued the negotiations with the governor and the State Legislature.

The governor's "next few days" became the next six months. By September, the issues with the SCE had not been resolved, and Governor Davis called for a special session of the legislature to examine a possible bailout plan for the SCE. The financial crisis for the SCE was finally resolved on October 2, 2001, through negotiations between the SCE and the CPUC, before the special session was to begin.

In this settlement, the SCE agreed to release the PUC from all claims under its Filed Rate Doctrine lawsuit and agreed to withhold payment of dividends to its stockholders for at least three years. By the time of the agreement, wholesale electricity prices had declined to precrisis levels and the second round of retail rate increases had been implemented, so that retail prices were by then well above wholesale prices. Under the agreement, the CPUC agreed to keep SCE retail rates at the elevated levels for several years, providing the SCE with sufficient cash flow that it should be able to pay its debts. Thus, the agreement ensures that the people of Southern California will pay high electricity bills over the course of years. The CPUC expressed confidence that the agreement would restore the SCE to creditworthiness so it could, at some time, begin purchasing electricity for its customers. However, many creditors, including many electricity generators and traders, have not yet been paid, and the settlement terms are still purported to give the CPUC significant control over which wholesale electricity purchase bills will ever be paid. The settlement did not reach any resolution on the filed rate doctrine. The SCE withdrew the claim and the CPUC made no concessions about its own or State regulatory authority over the SCE. However, the SCE was able to keep all its physical assets, including its transmission and generation facilities.

[26]PG&E News Release, April 6, 2001.

Governor Davis rescinded his request for a special session of the legislature, officially signaling the end of SCE's crisis, stating, "Their settlement has protected the public interest and will allow the state's second-largest utility to return to financial health."

The terms of the settlement suggest that, had the CPUC been willing to raise rates in autumn of 2000 to the same extent they were raised in spring 2001, the entire financial crisis could have been avoided.

PG&E remains in bankruptcy court. On September 20, 2001, it filed a proposed reorganization plan, which promised to pay all creditors in full. The plan would separate PG&E into four separate companies, completing the vertical disintegration. One company would own and operate the retail electric distribution functions and operate as a regulated utility local distribution company,[27] selling most of its assets, including its electric generation and transmission assets, to the other three companies. These companies would operate as deregulated entities, each owned by its parent, PG&E Corporation. Proceeds from the sale of assets would allow PG&E to pay all creditors. Under this plan, the state would have very few options to control retail prices well below wholesale costs since the retail entity would own none of the generation and transmission assets. The plan would allow PG&E to escape much of the state's regulation of its activities and avoid legal restrictions imposed by the CPUC or the State Legislature. Governor Davis, the CPUC, and several consumer groups opposed this change, citing the possibility that retail price increases could occur under this plan.

On February 7, 2002, the federal bankruptcy judge (Judge Dennis Montali) refused to approve PG&E's reorganization plan and rejected PG&E's argument that U.S. bankruptcy law must supersede state law. The judge's ruling allowed PG&E to attempt to establish "with particularity" specific state laws and regulations that should be preempted by federal bankruptcy law. Nevertheless, he made it clear that PG&E must establish that the preemption is based on conflicts with particular provisions of federal bankruptcy law, not simply a general preemption.

On February 13, 2002, the CPUC submitted an alternate reorganization plan that would keep almost all PG&E activities under control of State regulators. The CPUC-proposed plan has many

[27]The natural gas components would be divided in a similar way, with natural gas transmission going to the unregulated entity and the retail natural gas functions staying with the regulated utility.

similarities to the one negotiated between the SCE and the CPUC. Similar to the SCE situation, retail electricity rates significantly exceed costs of acquiring electricity (for quantification, see Figure 4.12 in a subsequent section of this chapter), now that wholesale prices have dropped. Thus, PG&E is now accumulating revenues well in excess of its costs. The CPUC proposal would keep PG&E retail rates at the elevated levels for at least several years, providing PG&E with sufficient cash flow that it should be able to pay its debts over the next few years. The PG&E would not pay any dividends to its stockholders from 2001 through 2003. The PG&E proposal, if accepted, would assure that the people of Northern California, like those of Southern California, would pay high electricity bills over the course of years. The CPUC expressed confidence its proposal would restore PG&E to creditworthiness so it could begin purchasing electricity for its customers by January 2003.

The judge has not ruled on the CPUC proposal and PG&E has not yet filed a response to the judicial decision. However, it appears that the end of the PG&E crisis could be in sight, even though complete resolution may not come quickly. Nevertheless, until a full settlement is reached, PG&E is precluded from paying most of its debts, including the money it owes for purchasing wholesale electricity in the pre-January 2001 time. Thus, more than a year after PG&E purchased the electricity, many generators and electricity traders still have not been paid.

STATE AND FEDERAL POLICY RESPONSES

The time of crisis, even more than the challenge period, was a time for strong, wise political leadership. Faced with the reality of the crisis at its peak, the California governor and the legislature made energy one of the highest priorities for communication and for policy development. However, as in the challenge period, much of the policy action seemed primarily intent on casting blame outside of California, hiding the short-term problems and shifting the consequences to the future, even at the cost of greatly increasing the overall difficulties for California.

The policies favored by the California political leadership emphasized direct government intervention in the market place, reliance on retail and wholesale price controls, and strong regulatory intervention. The CPUC, now with different leadership than when AB 1890 had been passed, stopped trying to improve markets, strongly enforced retail price controls (which the state could control), and lobbied for wholesale price controls (which the state could not control). The California governor intensified his public relations campaign of blaming California's electricity problems on the federal government, federal regulators, electricity generators, and "deregulation," without mentioning his own policy inaction. He continued his lead role in militating for strong price control regimes at both the retail level and the wholesale level. The legislature failed to modify the most damaging problems of the system but did take leadership in encouraging energy conservation and energy efficiency measures. When the governor and legislature were forced to respond to the financial crisis, their response relied on direct governmental wholesale purchases of electricity and negotiations to acquire assets of the utilities, therefore moving the state toward public power and direct state participation in electricity markets.

At the same time, federal action through the FERC, though slow, sometimes misdirected, and inconsistent over time, seemed designed to address the underlying flaws in the market design and implementation, to avoid simple ineffective palliatives, and to strengthen the role of markets. Like the CPUC of the early through mid-1990s, the FERC operated as a regulatory agency trying to move away from direct control of market transactions and market pricing. The FERC policy actions, overall, had the hope of providing longer-term solutions to California's energy crisis by attempting to identify, analyze, and correct fundamental problems.

The ideological conflict was painful between state leadership, which continued to favor dominantly public sector roles, and the FERC, which continued to favor dominantly private sector roles. The state and the FERC each had jurisdiction over important parts of the restructured system, so neither could fully impose its views on the other, and each needed actions of the other to be fully effective. The fundamental ideological differences were never fully resolved and continue to this date.

Actions by the State Executive Branch and Legislative Branch

Public Relations and Rhetoric

First, starting during the challenge period and extending through the crisis, Governor Davis waged a public relations campaign in which he sought to assign blame for California's electricity problems to many organizations outside of his own office. Perhaps his most frequent target was the electricity generators and marketers. In speech after speech and press release after press release, Governor Davis made it clear that he believed the generators were engaging in wrongful and possibly criminal activities. Words and phrases such as "profiteering," "plunder," "unconscionable," "price gouging," "exorbitant profits," "market marauders," "pirate generators," "privateers," "obscene profits," and "outrageous wholesale prices" peppered his formal statements.

Governor Davis often associated these words with phrases such as "out-of-state generators," which, like so much of his rhetoric, was a distortion of reality: electricity sales by in-state entities were at negotiated market prices, just as were spot market sales by out-of-state sellers (as would typically be the case in any markets). In fact, the two largest municipal utilities in California, the LADWP and the SMUD, were selling electricity at negotiated prices[28] just like every other seller. Yet it seemed politically expedient for the governor to shift all blame to entities outside California, completely distorting reality.[29]

[28]The DWR data for the first half of 2001, presented previously in Figure 4.5, show that the DWR paid California sellers, including California municipal utilities, higher prices than it paid the out-of-state suppliers Governor Davis had so often accused of price gouging. The DWR paid an average of $276/MWh to the LADWP, $268/MWh to the SMUD, and $305/MWh to the City of Burbank. It paid San Diego-based Sempra Energy an average price of $366/MWh. Among the ten largest out-of-state sellers to the DWR, only two (both Canadian entities) were able to negotiate prices higher than SMUD: private sector TransAlta ($298/MWh) and public sector Powerex Corporation ($425/MWh). The DWR paid an average of $236/MWh to the ten largest out-of-state suppliers, less than to any of the in-state sellers (with the exception of DWR purchases from itself).

[29]As of January 8, 2002, Governor Davis had shifted his rhetoric to focus attention on California municipal utilities. In his 2002 State of the State address he asserted: "Merchant generators, even some of our own municipal utilities—were gouging us unconscionably." Shortly thereafter, Governor Davis launched a daily series of political advertisements implying that Richard Riordan, former mayor of Los Angeles and a contender for the Republican gubernatorial nomination for California governor, was responsible for the LADWP charging prices "twice as high" as the prices charged by other sellers of electricity. The pure political motivation for Governor Davis's changing rhetoric and his distortion of reality had become painfully apparent.

The rhetoric included the governor's well-publicized announcements that the State of California was initiating a criminal investigation into the actions by the generators and marketers. However, to this date, the state has not announced that it has ever uncovered such illegal activities, suggesting that the criminal investigation never uncovered any illegal activities since, given the governor's pattern of public rhetoric, he would have broadly publicized any evidence of wrongdoing that the state found.

Federal organizations, particularly the FERC, were also subject to his biting attacks. A particularly vicious Gray Davis attack was prompted by the FERC's decisive steps to deny California's various attempts to extend state-managed price controls. In a communication for public consumption, he stated:

> *The Federal Energy Regulatory Commission has abdicated its responsibility to the people in the West. Their responsibility is to ensure just and reasonable rates. Instead, they have chosen to ensure unconscionable profits for the pirate generators and power brokers who are gouging California consumers and businesses. . . .*
>
> *This is an inexplicable decision by armchair Washington bureaucrats fixated on economic ideology that has no practical application to the dysfunctional energy market in California and the West. Instead of acting in the best interests of consumers and businesses, the FERC commissioners have acted as pawns of generators and power sellers whose only interest is to plunder our economy. . . .*
>
> *The public health and safety of California's citizens and the economy of the State cannot be subject to the blackmail of a few greedy privateers working in concert with a handful of Washington bureaucrats.*[30]

Governor Davis became fond of labeling electricity deregulation as the villain, rather than his own leadership, or lack of leadership, in managing the challenge and crisis. He referred to FERC actions as a "reckless deregulation experiment" that would make "guinea pigs of California consumers" and described California's problems as the "ravages of a dysfunctional marketplace." Governor Davis's language was colorful but did not serve the interests of the people

[30]Press release issued by Governor Davis on December 15, 2000.

of the State of California. The colorful language served only his personal political interests.

Regrettably, Governor Davis made threats that the assets of the generators would be subject to eminent domain procedures. Such threats, far from solving any of the real problems of the state, tend to chill the desire of other firms to invest in new generation in California and thus were counterproductive to electricity system solutions.

The low point of the rhetoric from the California Executive Branch came when California's chief law enforcement officer, Attorney General Bill Lockyer, managed to utter one of the most offensive statements imaginable from a person charged with the integrity of the criminal justice system in California. Lockyer stated in a *Wall Street Journal* interview (May 2001) that he hoped to imprison—and more than simply imprison—Kenneth Lay, the chairman of Houston-based Enron Corp, a person who was not charged with any crime in California, much less convicted: "I would love to personally escort (Enron Chairman Kenneth) Lay to an 8-by-10 cell that he could share with a tattooed dude who says, 'Hi, my name is Spike, honey.'"

The State Framework for Policy

In addition to the rhetoric that emanated from the Executive Branch of the California government, there did emerge an overall framework for policy making. Unlike Governor Davis's policy framework from the challenge period, this framework, developed in combination with the leaders of California's legislature, recognized both the electricity crisis and the financial crisis. In addition, unlike the governor's price control policy framework from the challenge period, it recognized the importance of electricity supply and demand to the electricity problems. Announced on January 26, 2001, as a "rough consensus reached with bipartisan leadership of California's Senate and Assembly," the policy framework was stated as:

1. Aggressively promote energy efficiency, conservation, and demand reduction among consumers, businesses and public entities.
2. Increase the supply of electrical generation in California through continuing efforts to streamline permitting and construction of new plants, while protecting the environment, and remove obstacles to the development of distributed generation.

3. Authorize the state to purchase the "net short" electricity needed to serve investor-owned utility customers. The "net short" is the power needed beyond that generated by the utilities themselves or available to them from "qualifying facilities" (QFs) and other long-term contracts. It is anticipated that most of this power will be purchased through long-term contracts with power suppliers.
4. Provide that the state will sell power directly to ratepayers with the investor-owned utilities collecting and remitting a dedicated portion of rate revenues to the state.
5. Reduce the price of power delivered by QFs to the utilities by changing the contracts between the utilities and QFs through action by the PUC and/or the legislature to a reduced rate agreed to by the QFs.
6. Provide ratepayers with an asset of value such as stock warrants as equity participation in the financial recovery of the utilities. This equity participation will be used either to help retire bonds or otherwise provide tangible benefits to consumers.
7. Continue negotiations with the investor-owned utilities and others on a plan to deal with the unrecovered costs that threaten the economic viability of the utilities while protecting the ratepayers.
8. Resolve outstanding regulatory and legal actions initiated by the utilities to recover all their undercollections.
9. A public authority that could ensure adequate power supply and adequate transmission capacity.[31]

This overall framework included five major points—numbers 3, 4, 6, 7, and 9—that, as implemented or negotiated by the state, would increase the public sector's direct participation in the energy markets as a buyer or seller of electricity. One major point—number 1—would involve increases in direct governmental regulation in energy markets. Point number 5 would require the state to use its regulatory or legislative power to alter the long-standing contracts QFs had with utilities. One point—number 8—would involve resolving the legal challenges brought by the utilities challenging the right of California to maintain retail price controls. Only point number 2 would involve increasing the ability of markets to work effectively.

[31]This can be accessed through http://www.governor.ca.gov/state/govsite/gov_homepage.jsp. Once on the govenor's homepage, click on "Press Room," then on "Press Releases," and finally on "January 2001."

Elements missing from the framework were significant. There was no part of the framework designed to move the state away from the price controls imposed on investor-owned utilities, only a point to resolve the challenges to the price controls. There was no part of the framework proposing to allow the utilities to participate in a much broader range of contracts to buy electricity. Nothing in the framework addressed the dangers of energy emergencies, including blackouts. There were no points about working constructively with federal agencies to improve the operations of electricity markets.

Moreover, the subsequent policy actions taken or attempted by the state were roughly, although not completely, consistent with this policy framework. And similarly, the omissions in the policy framework remained omissions in state policy implementation. Some policies have already been discussed; some will be discussed in what follows.

Governor Davis called two concurrent extraordinary sessions of the legislature, the first on January 3, 2001, and the second on May 17 at the expiration of the first session. The work of these special sessions proceeded in parallel to the work during the (simultaneous) regular sessions but served to focus legislative policy attention on the electricity and financial crises.

Policies Impacting Energy Demand

The most beneficial of its policy actions in terms of loosening the supply/demand balance were designed to reduce electricity demand in both the short run and the long run. Although only the short-run programs would reduce the severity of the energy crisis, the long-run programs could help ensure there would not be a repeat of the crisis.

One of the most publicized was the "20/20 plan," which encouraged all residential and small commercial purchasers of electricity to reduce their use of electricity by 20 percent from the previous year. Those who did so would be rewarded not only with the reduction in the electricity bill based on less usage but also would enjoy a 20 percent reduction in their overall electricity bill. The 20/20 plan accomplished two objectives. It was effective in dramatizing a goal for reducing electricity consumption and making it clear that the goal was achievable. In addition, the plan had embedded in it a significant financial incentive that essentially increased the marginal price of electricity to consumers without increasing the average price.[32]

The state, with help from the Advertising Council, launched the "Flex Your Power" campaign featuring the image of a light switch and a finger turning off the switch, which further sensitized people to the public value of reducing electricity use.

The governor issued an Executive Order requiring retail business to reduce substantially "unnecessary outdoor lighting wattage" during nonbusiness hours.[33] Failure to do so would subject the commercial establishments to fines. Police were authorized to search out those companies using too much electricity and cite them. Whether this had any real effect or simply served to dramatize the goal of reducing electricity use was unclear.

The AB 1890 had included a component of the retail electricity price to pay for public benefit programs, including $228 million a year to pay for energy efficiency, conservation activities, and other demand-side management programs. However, the particular expenditures of these funds, earmarked for these specific purposes, needed state approval, which was forthcoming during the crisis. These funds paid for costs incurred by utilities in promoting energy efficiency improvements throughout California's economy. Perhaps the most successful was the subsidy offered for the sales of compact fluorescent lights at high-volume discount retail stores, such as Costco. The PG&E alone reported around 3.5 million sales of compact fluorescent lights under its 2001 incentive programs.[34] This initiative reduced electricity usage very quickly and can be expected to have a continuing impact on consumption.

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[32]The incentive was a discontinuous one. There was a benefit for meeting or exceeding the goal, no benefit for almost meeting the goal, and no further benefit for exceeding the goal. Thus this plan increased the marginal cost only for reductions of 20 percent, not for increases.

[33]Executive Order D-19-01, February 1, 2001.

[34]A typical compact fluorescent light (CFL) uses about 20 watts to produce the same light as a 75-watt incandescent bulb. Thus, a CFL substituted for an incandescent light reduces electricity consumption by 55 watts during times either light would be on. If 50 percent of the PGE-subsidized CFLs were lighted at a given time, that would reduce electricity use by about 100 MW (0.5×3.5 million $\times$ 55 watts = 96 MW), roughly equivalent to the maximum output of two typically sized peaker generating plants.

In January 2001 the California Building Standards Commission adopted comprehensive emergency modifications to California's statewide building efficiency standards (effective in July 2001), giving California the toughest building efficiency standards for new construction in the nation. Among other features, the standards require more efficient air conditioning and heating ducts in new homes and impose standards on new windows designed to reduce solar radiative heat transfer. These modifications had no effect on the immediate crisis but can be expected to have a longer-term impact on electricity demand.

The legislature passed two major bills to reduce electricity use during the time of the crisis: SB 5X and AB 29X. The latter allocated $35 million to acquire and install real-time meters for industrial customers using more than 200 KW of power, many of which have been installed. However, to this date, the CPUC has yet to approve a tariff that would allow electricity to be sold at real-time prices, and thus this investment had no beneficial effect during the energy crisis.

The AB 29X also allocated $20 million to distribute compact fluorescent lights through the California Conservation Corps. SB 5X allocated about $430 million in general fund revenues to emergency energy efficiency incentives and $220 million in funds to reduce electricity prices for low-income households. The latter could be expected to increase slightly the usage of electricity while easing the financial impact of high electricity prices on low-income families.

Policies Impacting Electricity-Generation Capacity

In February 2001, Governor Davis signed six Executive Orders to expedite the review and permitting process of power-generating facilities in California. One order allowed small peaking plants to be quickly approved and constructed and was limited to those that could be completed before September 2001. The other orders envisioned a four-month and a six-month licensing process, where the time period was based on expectations of permitting time after all data to the California Energy Commission were deemed to be adequate, a process that itself could take months. The four-month licensing process was limited to simple cycle, thermal power plants, which had to be able to be on-line by December 31, 2002, and would be required to convert from a simple cycle mode to combined cycle mode or cogeneration within three years. The orders do have the longer-run potential of increasing the supply responsiveness by reducing the time for new plants to be approved and ultimately come on-line.

The governor negotiated with those companies that were in the process of constructing new generating plants in order to provide them with an incentive to come on-line earlier than they otherwise would have. The financial incentive offered for coming on-line early may have moved the on-line date for plants by a small amount but did not result in any plants coming on-line during the crisis. These incentives were politically valuable, however, since press releases from Governor Davis continued to suggest that his actions were responsible for construction of those plants, even though they had already been under construction when he took office.

Policies Impacting Risk to Electricity Suppliers

Throughout 2001, state actions continued to create financial risk for sellers of electricity and thereby reduced the supply of electricity from generating units within California. Those risks also discouraged those generating electricity outside California from selling into the California market. Such California electricity supply reductions could be expected to raise the wholesale price of California electricity. Financial risks stemmed from four classes of California actions (or inactions) continuing through much of 2001: change of the CAISO board composition, failure of the DWR to pay for spot electricity purchases through the CAISO, CPUC refusal to allow investor-owned utilities to pay challenge-period bills, and California's continued demands that the FERC order large refunds.

First, by the end of January 2001, Governor Davis had replaced the CAISO stakeholder board with a new five-person board, three of whom were closely associated with the Davis administration.[35] Control of the CAISO board had moved to the state. Once the PX stopped operating, the DWR was purchasing all its spot market electricity through the CAISO. Thus, the State of California had become the largest market participant and had gained control of the CAISO. The harsh rhetoric by Governor Davis castigating the

[35]Governor Davis appointed Maria Contreras-Sweet (California Secretary of Business, Transportation, and Housing), Tal Finney (Director of Policy, Governor's Office), Mike Florio (Attorney, The Utility Reform Network), Carl Guardino (President and CEO, Silicon Valley Manufacturing Group), Michael Kahn (Attorney; Chairman of Energy Oversight Board). Maria Contreras-Sweet left the board after the September 11 terrorist attack.

electricity generators and marketers was continuing. Thus, it was reasonable for all generators and marketers to believe that CAISO would not treat them fairly but rather would act to favor the State of California and electricity buyers whenever possible. This rational belief could be expected to increase significantly the perceived risks facing generators and marketers.

Second, from January through November 2001, the DWR purchased about $1 billion worth of spot market electricity through the CAISO. During this time, however, the DWR did not pay any of its obligations for purchasing electricity through the CAISO, and since the CAISO had no resources of its own to pay for purchases, as of November, the CAISO had not paid the generators. Nor could the generators be sure that either the DWR or CAISO would ever pay them.

It appeared that the CAISO had established policies that encouraged the DWR not to pay, or at least did not discourage its nonpayment. The CAISO had argued in a sequence of FERC filings that sellers were required to supply electricity for the CAISO's real-time markets whether they were paid or not. The DWR and CAISO argued to the FERC that the DWR might not be required to pay for all electricity it purchased on behalf of the investor-owned utilities. Until November, the CAISO and the DWR had not even reached a satisfactory agreement on how the CAISO would bill the DWR, and thus the CAISO never even billed the DWR for its electricity purchases until that month.

The FERC repeatedly ordered the CAISO to enforce its tariff provisions, requiring all buyers of electricity to be creditworthy. Finally, on November 7, 2001, the FERC found the CAISO in violation of its tariff and ordered that it pay all overdue amounts within three months:

> *We have repeatedly directed the ISO to enforce its creditworthy standards under the Tariff. . . . Although DWR represents that it is the guarantor of transactions for the non-creditworthy UDCs [utility distribution companies] DWR has yet to pay for these net short positions. . . . Moreover, a creditworthy party pays its bills when they are due.*[36]

[36]FERC, "Order Granting Motion Concerning Creditworthiness Requirement and Rejecting Amendment No. 40" (November 7, 2001). Available at http://www.ferc.gov/electric/bulkpower/er01-889-008-11-7-01.PDF.

Only after the FERC had issued the November 7 Order did the CAISO begin to bill the DWR for the power it had been purchasing since January. Until that time, the failure of the DWR to pay for its purchases created significant risk for the generators and traders that were selling to CAISO.

The FERC has quantified the risk to sellers resulting from DWR and the CAISO business practices. On June 19, 2001, the FERC issued an order outlining the methodology for calculating any noncompetitive overcharges in sales through the PX and CAISO. The FERC determined that a competitive price estimate could include a 10 percent "creditworthiness adder" for transactions after January 5, 2001, reflecting increased credit risks in California. As late as December 19, 2001, the FERC ruled that this 10 percent creditworthiness adder was still justified.

> *In the June 19 Order, the Commission instituted the 10 percent adder to recognize both the larger risk of nonpayment in California when compared with that in the larger West-Wide market, and the longer payment lag in the ISO spot markets when compared with that in the Western bilateral spot markets. The Commission also pointed out that questionable business practices have sent negative signals to future suppliers, credit rating agencies, and investors. . . . However, despite our repeated instructions to the ISO to ensure that there is a creditworthy party backing up each and every transaction, we have continued to receive complaints that suppliers are not being paid. Under these circumstances, we continue to believe that the circumstances that justified institution of a creditworthiness adder have not abated. Until the risk of nonpayment by purchasers in California has been relieved, the adder is still justified.*[37]

Third, the state has taken actions to block the investor-owned utilities from paying their pre-January 2001 wholesale electricity acquisition bills. The PG&E's bankruptcy and the SCE's extended presettlement negotiations with CPUC have ensured that the two investor-owned utilities have not paid the generators and traders for their pre-January 2001 electricity purchases (see discussion in

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[37]FERC, "Order on Clarification and Rehearing" (December 19, 2001). http://www.ferc.gov/electric/bulkpower/el00-95-001-12-19-01.PDF.

the section, "The Financial Crisis of the Utilities: The Saga Continues"). The CPUC proposal for the PG&E restructuring would significantly delay PG&E payments to the generators even after PG&E emerges from bankruptcy. Although the SCE now has large cash balances, the CPUC is still not approving complete payments of SCE debts for purchases from the generators. The total unpaid amount is greater than $10 billion. California seems to link blocking of payments to California's inflated $8.9 billion estimate of the refunds due from generators. This payment delay creates not only risks of nonpayment but also cash-flow problems for the relatively small electricity generators. Some implications of this refusal have already been discussed in the section entitled "Generators Off-Line."

Fourth, the state has continued to press the FERC for aggressively large refunds, asserting that the generators had overcharged California and continued to overcharge. The FERC initiated settlement hearings to reach an agreement on the appropriate amount of the refunds. However, attempts by FERC Chief Administrative Law Judge Curtis L. Wagner, Jr., to bring the parties to a settlement were blocked by California's unwillingness to budge in its refund demands. On July 12, 2001, Judge Wagner issued a report and recommendation in which he made it clear that California's claims were far too large:

> *That very large refunds are due is clear. . . . While the amount of such refunds is not $8.9 billion as claimed by the State of California, they do amount to hundreds of millions of dollars, probably more than a billion dollars in an aggregate sum.*
>
> *The State of California has publicly made it clear that the refund amount claimed by the State of California is $8.9 billion. It has not moved from that position and Governor Davis makes it publicly clear that it will not. . . . However, it is the opinion of the Chief Judge that the amount claimed by the State of California has not and cannot be substantiated.*[38]

Because California was never able to reach an agreement with any other parties, the actual amount of refunds will be settled by

[38] FERC, "Report and Recommendation of Chief Judge and Certification of Record" (July 12, 2001).

evidentiary hearing unless the parties are able to come to agreement beforehand. The schedule contemplates a sequence of hearings scheduled for March through July 2002. Absent settlement, the refund amounts will not be determined until after all hearings have been completed. The uncertainty about the outcomes of these hearings further increases the risk for market participants.

Policies Related to Energy Emergency Responses

The state took no leadership in mitigating energy emergencies until after the last of the blackouts had occurred, when the rules for managing blackouts were modified to reduce costs if blackouts were to continue. For example, large industrial users were allowed to enter contractual relationships in which they agreed, when requested during energy emergencies, to reduce their use of electricity by 20 percent from then current levels. In exchange, they were assured that they would be spared from rolling blackouts. However, as more and more electricity users became exempt from blackouts, the more those blackouts would be concentrated on the remaining users. By late spring 2001, an estimated 50 percent of electricity use had been exempted from blackouts, and therefore the remaining nonexempt users faced a doubled risk of being blacked out themselves. This plan had another drawback. For many companies, the easiest way of ensuring they could reduce demand by 20 percent on short notice was to keep demand at least 20 percent above their minimum needs for electricity. Thus, there was an incentive for companies to avoid reducing demand by as much as they might otherwise in order to assure their ability to cut back from then current levels when needed.[39] Although this system did enhance the demand reductions during emergencies, it probably increased the use of electricity in nonemergency times and thereby increased the probability of energy emergencies.

In addition, in a change from the practice during the early blackouts, when the area being blacked out was given only a very short warning, a plan was developed to provide more advance warnings about forthcoming blackouts. This change was intended to allow emergency personnel to be positioned more effectively

[39]This incentive comes about because the cutback was to be measured from consumption levels in the few weeks before the companies were called on to cut back. If the cutback was measured from consumption levels at some base time, say at the time the rule was passed, then there would not have been this perverse incentive.

during rolling blackouts and to allow companies to make some plans to cope with anticipated blackouts. However, no blackouts occurred after the decision was made to provide the warnings and thus it is unclear how well the system would have worked.

These actions were potentially useful for the most part but, other than the energy conservation and efficiency programs, did nothing fundamental to help solve the energy crisis.

Retail Electricity Pricing

Most needed to address the energy crisis (and the financial crisis) was for retail electricity prices to adjust to the changing wholesale prices. Increases in retail prices would have more sharply reduced electricity demand and therefore would have reduced wholesale prices. Nevertheless, that was the action most strongly opposed by the governor. Instead, even during the crisis period, the pervasive message from the governor and the other state institutions was their demands for expanding wholesale electricity price controls as a companion to continued retail price controls.

However, after many months of refusing to approve retail electricity price increases, the CPUC accepted the idea that it could keep the retail base prices of electricity and could add "surcharges" on to the retail rates to start bringing retail rates up toward the wholesale prices. On January 4, 2000, the CPUC took the first small step, approving a 1-cent/KWh, ninety-day surcharge on customer bills (equivalent to $10/MWh), an amount far smaller than desirable for encouraging the needed electricity demand reductions, but a step. This surcharge would increase residential rates about 9 percent, small business customers 7 percent, medium commercial customers 12 percent, and large commercial and industrial customers 15 percent.

Using conventional estimates of the elasticity of demand[40] for electricity, the average retail price increase of 10 percent could be expected to motivate a roughly 1–2 percent reduction in demand over a short run, starting almost immediately. Although this demand reduction was smaller than desirable

[40]The elasticity of demand is defined as the percentage reduction in demand motivated by a 1 percent increase in price. Here, and for other numerical examples, a short-run elasticity of demand for electricity will be approximated as 0.1–0.2. Long-run elasticities have typically been estimated to be as large as 1.0 and possibly larger.

with the very tight market, even the 1–2 percent reduction in demand could have some impacts on the wholesale price. Using the previous assumption that a 1 percent change in supply or demand leads to a 10 percent change in wholesale price, such demand reduction could motivate a 10–20 percent reduction in wholesale price. On the other hand, if a 1 percent change in supply or demand leads to a 2 percent change in wholesale price, such demand reduction could motivate only a 2–4 percent reduction in wholesale price. Thus, although this surcharge was far too small to solve the financial crisis facing the utilities, it contributed somewhat to the demand reductions that were observed during that time.

Perhaps more importantly, the principle had been established that retail price increases could be a viable response to the energy crisis.

Governor Davis seemed well aware that allowing retail prices to increase sufficiently would have been fundamental to addressing the energy problems. However, he still refused to allow that step. In one well-publicized February press conference, he stated: "Believe me, if I wanted to raise rates I could have solved this problem in 20 minutes. But I am not going to ask the ratepayers to accept a disproportionate burden."[41] And he did not raise the rates. At least not until the state was threatened with budgetary chaos.

By early March, with the California DWR purchasing the electricity, the economic realities of the high wholesale price and low retail price were now falling most sharply on the state, not on the utilities. The State budget had been decimated. Political leaders began seeing the wisdom of increasing retail electricity prices to compensate the State Treasury for the costs of its wholesale electricity purchases. Even Governor Davis grudgingly accepted retail price increases. On March 27, 2001, the CPUC voted to increase retail electricity rates by 3 cents/KWh for SCE and PG&E customers and to make permanent the 1 cent/KWh temporary surcharge. It was estimated at the time of its passage that this increase would be sufficient to allow revenues collected from the

[41]Transcript of press conference, Governor Gray Davis, February 16, 2001. By the time he had made this statement, Governor Davis had already developed the plan for selling state revenue bonds to pay for state purchases of electricity and for requiring ratepayers to pay all of the interest and principal of these bonds. Under this plan, the ratepayers would be forced to accept the entire burden, completely contrary to the public statement he was making.

sale of electricity to cover the cost of DWR purchases of wholesale electricity but would do little or nothing to bring the utilities back to financial health.

Even then, Governor Davis worked to reduce the rate increase. During a live address to the people of California on April 5, Gray Davis proposed an alternative to the CPUC increase: an average increase of 2.4 cents/KWh for PG&E residential customers, 2.2 cents/KWh for SCE residential customers, and between 2.6 and 3.0 cents/KWh for commercial/industrial customers.

Although the CPUC announced that the increase would be effective immediately, the promised tiered-rate proposal had yet to be designed. It was widely reported in the media that, although the actual charges might not appear on consumer bills right away, the customer billings would be implemented retroactively to the end of March. Thus, even before the price increase was implemented, the belief by individuals and companies that there would be a hefty price increase probably motivated a significant reduction in electricity consumption.

On May 15, the CPUC adopted the specific rate structure, which would appear on June bills. The two retail rates together increased retail rates by roughly 30–35 percent. Using the same estimates of elasticity of demand, these price increases could be expected to motivate short-run demand reductions of 3–7 percent, reductions large enough to affect significantly the tight electricity markets.

As implemented, the rates adopted by the CPUC are highly tiered, with households that use low amounts of energy paying prices slightly lower than the cost of delivery services plus acquisition cost of electricity and those using larger amounts paying almost twice the cost of that electricity for additional units purchased. Figure 4.12 illustrates the rate structure for PG&E in December 2001.[42] The red line shows the marginal price of electricity at various levels of monthly electricity consumption, ranging from zero electricity use through 2,000 KWh per month. For reference, the average use of electricity per residential customer in California (548 KWh) is noted.

For those who use less than 130 percent of the "baseline" quantities per month (the winter baseline for the San Francisco Bay Area

[42] These particular data are for a home in the San Francisco Bay Area not using electricity as its primary source of space heating and are included in bills PG&E sends to its residential customers.

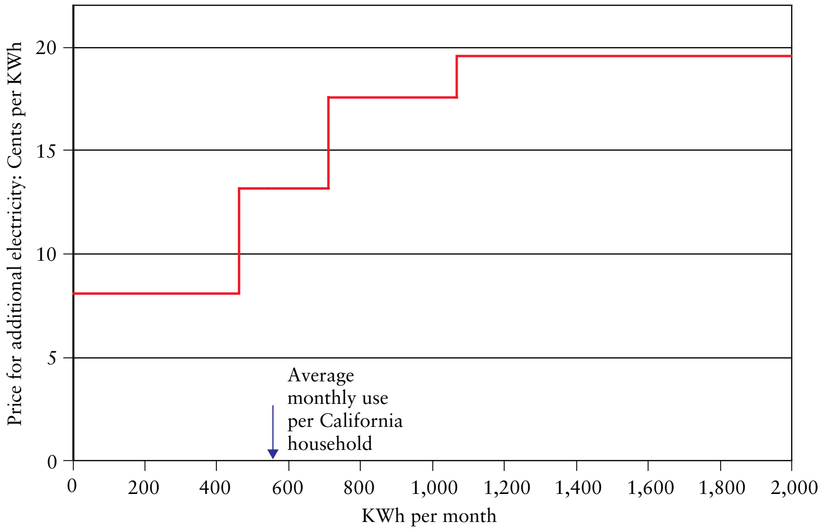

FIGURE 4.12: Electricity Prices for PG&E Residential Customers (San Francisco Bay Area), December 2001

is 356.5 KWh), the customer pays 8.0 cents/KWh; for those that use more than 300 percent of the baseline, the marginal price rises to 19.5 cents/KWh.

These figures can be compared with the pre-restructuring price of about 9 cents/KWh, the current spot cost of wholesale electricity plus service fees (transmission, distribution, and public purpose programs), totaling about 6 cents/KWh, or the cost of the DWR electricity purchases plus service fees, totaling about 13 cents/KWh. By any of these measures of cost, this rate structure greatly overcharges those residential customers who use a large amount of electricity relative to the baseline. The retail price for the greatest users of electricity (more than 300 percent of the baseline) is over twice as high as the 9 cents/KWh average price of retail electricity prior to restructuring. Thus, even though the electricity crisis is over, those customers who use over 300 percent of the baseline quantities of electricity pay twice the rate they faced before the crisis.

FERC RULE MAKING

Early in the challenge period, the FERC started to carefully examine problems of wholesale electricity markets throughout the United States. On July 26, 2000, the FERC ordered its staff "to conduct an investigation of electric bulk power markets so that it can determine whether markets are working efficiently and, if not, the causes of the problems." The commission asked its staff to "investigate the markets, including volatile price fluctuations, and report their findings by November 1, 2000." After San Diego Gas and Electric filed a complaint with the FERC in August 2000, the commission directed staff to accelerate its analysis in California and the western region of the United States.

Federal policy implemented through the FERC was necessarily more limited than state policy could be, since the FERC did not have jurisdiction over any retail market operations, electricity consumers, plant siting, or utility electricity purchases. It did have primary authority over wholesale markets, although it had allowed California institutions to take the lead in designing the wholesale markets within the state. Those wholesale markets commanded most of the FERC attention.

In November 2000, the FERC released the staff report and simultaneously issued a Market Order proposing remedies for California wholesale electric markets. Through that November Order proposing remedies and the subsequent December Order directing those remedies to be implemented, the FERC had started the process of taking control of market design from California institutions and providing that leadership itself. Governor Davis and other California political leaders strongly resisted that shift in control. The painful process of wresting control over wholesale markets from California officials while California leaders fought to retain control continued throughout the entire crisis.

For the most part, the FERC was pursuing a market approach, attempting to repair defects in the California wholesale markets rather than controlling prices. However, as an organization that operated for the most part as a judicial body, with operational procedures comparable to those in litigations, FERC decision making, with one exception, was typically slow and laborious. Moreover, FERC decision making depended not only on judicial rules but also on the beliefs of FERC commissioners. The change in the composition and leadership of the FERC during the process itself implied that FERC decisions were not necessarily consistent over time. Ultimately, the FERC implemented temporary wholesale price controls, primarily in the form of bid caps, initially throughout California and then throughout the western region, as the crisis was nearing its end.

November 1 and December 15, 2000, Orders

On November 1, 2000, the FERC issued a Market Order that proposed a set of remedies for California's wholesale electricity markets. The remedies were, for the most part, to take effect at the end of 2000. The Order provided a three-week period during which anyone could comment on the various proposals. The FERC followed, on December 15, with an Order directing the remedies. Except for the more extensive discussion, the December 15 Order was very consistent with the November 1 Order.

In these orders, the FERC reiterated its earlier conclusion that the wholesale prices were not "just and reasonable" and stated the two issues fundamental to the problem:

> *The existing market structure and market rules, in conjunction with an imbalance of supply and demand in California, have caused and, until remedied, will continue to have the potential to cause, unjust and unreasonable rates for short-term energy during certain time periods.*[43]

The FERC went on to propose measures designed to repair the defects in the wholesale markets and, while the defects were being repaired, to keep prices lower than they would otherwise be. The FERC had started the process of removing from California formal leadership in wholesale electricity market design. A first goal was to reduce the overreliance in California on the spot markets for wholesale electricity.

The FERC eliminated the requirement that the investor-owned utilities buy and sell all power on the PX or CAISO. This change, in principle, permitted utilities to participate in bilateral markets and forward markets, not simply in spot markets. It allowed them to use the electricity they had generated without selling the electricity and buying it back. This was an important long-term change, but given the precarious financial situation of the utilities by that time, its short-term impact was probably limited to allowing the utilities direct use of the electricity they generated.

However, for this Order to have any significance, it was necessary for the CPUC to eliminate the requirements it had set on the utilities. The FERC noted that without CPUC cooperation, this portion of the Order would be ineffectual:

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[43]Language from the November 1 Order.

> *We cannot emphasize enough that the California Commission must act decisively and immediately to eliminate the requirement for the IOUs to buy the balance of their load from the PX. This is the most serious flaw in the market design created by AB1890 and the California Commission's implementing Orders. . . . In addition it is crucial that the California Commission move quickly to provide the IOUs with approval of their forward purchases. The specter of after-the-fact disallowance for transactions other than PX purchases has certainly chilled the decision making process and continues to subject California's ratepayers to the volatility of spot prices.*[44]

In addition, the FERC imposed strong incentives on utilities and generators to complete almost all scheduling of load and generation with the CAISO ahead of time, rather than in real-time transactions. These incentives were designed to move electricity transactions away from the real-time market. The FERC required all California market participants to preschedule all resources and loads with the CAISO and imposed a large penalty on all real-time energy transactions greater than 5 percent of the prescheduled amount.

The CAISO's Replacement Reserve capacity market rules were modified so that a supplier bidding into this market would receive only the energy payment if it were called on to deliver energy, not the capacity payment in addition. These modifications could be expected to make market scheduling more rational, the acquisition process more deliberate, energy emergencies less frequent, and ancillary market manipulation more difficult.

In addition to reducing the reliance on spot markets, these Orders rejected a central component of the governor's policy framework from the challenge period. The FERC Orders decisively rejected the proposal that the PX be given authority to implement wholesale price caps and denied the request that the CAISO continue its authority to manage price caps. However, in order to keep continuity, the FERC ordered that the CAISO implement a $250 price cap on its purchases, without modifying the $100 price cap it had imposed for replacement reserves, until the end of December. Thus, the CAISO was precluded from further

[44]FERC, "Order Directing Remedies for California Wholesale Electric Markets" (December 15, 2000).

changing these price caps during that period without the express permission of the FERC; after the end of December, the state would no longer have the authority to manage or modify any wholesale price controls.

The FERC substituted its own price mitigation measures to begin at the end of December, ordering that all single-price auctions run by the CAISO or the PX be temporarily modified to a hybrid system, often described as a "soft price cap." Under this system, a single market-clearing price would be used if it were no greater than $150/MWh. However, if the market did not clear at $150/MWh or below, any accepted bid above $150/MWh would be paid the bid price, which would not be used to set the market-clearing price. Typically, suppliers bidding less than $150/MWh would be paid an amount at or near $150/MWh, and those bidding above would be paid their actual bid.

This rule changed optimal bidding strategies for those times participants expected that the market would not clear at a price at or below $150/MWh. Under these changed rules, it was no longer optimal for independent firms to bid at their marginal cost but rather to guess the cut-off price and to bid a little below that price, as in any as-bid auction system. Thus such a soft price cap system leads to a lower total cost of purchases for a fixed set of bids but motivates firms to increase their bid prices. Thus, it is dubious whether the partial move to an as-bid system would in fact have led to expenditure reductions. It could have increased total costs.

In addition, the PX and CAISO were required to report confidentially to the FERC all bids in excess of $150, and each seller was required to file bid price, electricity quantity, and marginal generation cost of each such transaction. The expressed intent was for the FERC to monitor the market and to observe attempts to exercise market power. Those bidding above $150/MWh would be asked to justify their bids, and lack of justification could result in the supplier being forced to refund the higher price.

Such a requirement for bid justification could provide strong motivation for limiting bids if generators believed that price bids above costs would be detected and that the refunds would include a penalty in addition to the difference between price and marginal cost. However, if generators believed that bids well above costs were unlikely to be detected and that, if detected, the only penalty would be a requirement to refund the difference, then this requirement would prove ineffective.

In addition to changes in the market rules, the FERC required changes in the governance of the PX and CAISO, rejecting stakeholder boards and requiring that the boards of the PX and CAISO be replaced with independent nonstakeholder boards. The FERC promised to give further guidance on the selection of these boards.

The state seemed to agree with the last of the requirements, subsequently passing its own legislation that would eliminate the stakeholder boards. However, in another test of state versus federal authority, the governor pointed out to the FERC that he had the power to make appointments within the State of California. The California legislation made it explicit that the governor would appoint the CAISO Board of Governors,[45] which he subsequently did, apparently without consulting the FERC about its composition.

The Board of Governors consisted of Maria Contreras-Sweet (California Secretary of Business, Transportation, and Housing), Tal Finney (Director of Policy, Governor's Office), Mike Florio (Attorney, The Utility Reform Network), Carl Guardino (President and CEO, Silicon Valley Manufacturing Group), and Michael Kahn (Attorney; Chairman of Energy Oversight Board). Although unquestionably each board member was highly talented, the board composition led immediately to the appearance, if not the reality, that the CAISO—the California *Independent* System Operator—would no longer be independent.

The FERC had ordered that CAISO be governed by an "independent non-stakeholder board." A California state agency was the largest buyer of electricity in the state and thus the state was clearly a market stakeholder. Two members of the new CAISO Board of Governors were members of the Davis Administration. One was chair of Governor Davis's Energy Oversight Board. Thus a voting majority of the board was clearly associated with the State government, in particular, with the Davis administration. It would be difficult to characterize this as an "independent nonstakeholder board."

[45]This legislation is AB 5X by Assembly member Fred Keeley (D-Boulder Creek). It replaces the existing governing board of the Independent System Operator (ISO), composed of twenty-six so-called "stakeholders," with a governing board composed of five members appointed by the governor. Board members were required to be independent of any ISO market participant but could be members of the State Admininstration.

However, other than the last issue of who had the authority to appoint the members to the PX and the CAISO boards, these Orders very clearly wrested control from the state and moved it to the federal level. However, with members of the PX and CAISO boards appointed by the governor, and with board members having authority to implement the FERC rules, this structure promised to prolong the jurisdictional conflict.

CAISO Tariff Amendment No. 33

Shortly before CAISO's authority to maintain price caps had expired, it requested that the FERC allow a change of its purchase rules (Tariff Amendment No. 33, issued December 8, 2000). In what may have been its only very fast response on an important policy issue, FERC agreed immediately. The CAISO replaced the cap on imbalance energy bids with a soft price cap system, with the interim break point set at $250/MWh (rather than the $150 in the November 1 Order). Under this interim procedure, the CAISO stopped rejecting bids priced above the then current $250/MWh price cap and began evaluating those bids in merit order, from low price to high price. Bids in excess of the $250 break point would not set the market-clearing price for imbalance energy, but rather would be paid as bid.

The CAISO's reason for this change underscored the difficulties of the price cap system under which California had been operating.[46] The CAISO noted that it had been forced to declare Stage 2 emergencies for the previous four days, and saw no immediate relief. The change was designed to allow the CAISO to compete for more needed electricity. Terry Winter, chief executive officer of the CAISO, explained, "I couldn't keep the system working if we didn't get relief."[47] It is very likely that the new plan did make more electricity available and reduced the severity of energy emergencies. It is also likely that the plan allowed wholesale prices to increase in California by essentially eliminating the price cap in the real-time market several weeks before FERC's order would have done so.

These were intended as interim plans, to remain in effect while the FERC led the process of developing more comprehensive price mitigation plans and systematically improving market operations.

[46]FERC Docket No. ER01-607-000, "Order Accepting Tariff Amendment on an Emergency Basis" (December 8, 2000).

[47]Nancy Vogel, *Los Angeles Times*, Nov. 7, 2000.

However, the FERC Orders did not stop the drumbeat of demands from the governor and the CPUC that more rigid price controls be imposed on the wholesale markets. The pressure operated through press releases and press conferences, communication by members of the California delegation in the U.S. Congress, and direct appeal to other decision makers in Washington. Finally, on April 26, the FERC did issue an Order that accepted wholesale price controls, or in FERC vocabulary, "price mitigation."

April 26, 2001, FERC Price Mitigation Order

This Order established a prospective "mitigation and monitoring" plan for the California wholesale electric markets, scheduled to become effective May 29, 2001. The plan included several central elements that the FERC described as intended to strike a balance between market-determined prices and controlled prices.[48]

The plan included provisions designed to control the number of generating plants that would be off-line at any time (see Figure 4.6), since by then the problem of plants off-line was well recognized. It required that all planned outages by units with Participating Generator Agreements[49] (PGAs) with the CAISO be coordinated with and approved by the CAISO, presumably making it easier to ensure that any outages of generating units were for legitimate reasons, not simply to increase market prices. Perhaps more importantly, it would allow the CAISO to develop a central body of information that would give early warning of tight markets.

The price mitigation plan moved a step back from the hybrid auctions of the November 1 and December 15 Orders and toward restoring single-price auctions. Rather than keeping the soft cap, which was set at a fixed, somewhat arbitrary level, all price caps would be removed. Replacing the soft caps would be "bid caps," limitations on the prices that given generation units could bid. Each generation unit would be required to bid a price no higher than an

[48]See www.rtowest.org/Doc/FERCOrder_April262001_EL00-95-012_CalISOMktMitigation.PDF.

[49]A Participating Generator Agreement is a legal agreement between a generator and the CAISO that establishes "the terms and conditions on which the ISO and the Participating Generator will discharge their respective duties and responsibilities under the ISO Tariff." The agreement allows the Participating Generator to schedule energy and submit bids to the CAISO through a Scheduling Coordinator.

administratively determined estimate of the marginal cost of operating that plant. The estimated marginal cost would be based on the unit's heat rate and emissions rate, the price of natural gas and emissions credits, and a $2/MWh fee for operation and maintenance costs. These bids, limited by bid caps, would be processed in a single-price auction to give the market-clearing price, a price each generator would receive if its bid were below that level.

There was an opportunity for an exception to the bid caps. If a firm could establish that its cost was in fact above the calculated bid cap, that firm could submit a higher bid; however, that bid would not be used to determine the market-clearing prices. In addition, these firms would be required to justify their costs or pay refunds. Similarly, resources located outside California could bid, but their bids would not be used in setting the market-clearing price during mitigated periods.

The bid caps would not always be imposed. Rather they would be imposed whenever any energy emergency had been declared. No caps would be imposed in the absence of an energy emergency, following the theory that competitive forces would be sufficient in those times.

However, this structure left open the possibility that the bid caps would limit prices during an emergency at levels lower than the market-clearing prices in nonemergency situations. Whether this would occur, however, depended on whether the competitive forces would be sufficient during nonemergency times.

In addition to the bid cap requirement was a rule designed to stop generators from exercising market power by simply not bidding at all, rather than just bidding a high price. The plan imposed a "must offer" requirement, stating that all sellers with PGAs offer all their available power to the ISO in real time if it is available and not already scheduled to run, which would apply to all sellers with PGAs, as well as nonpublic utility generators located in California that use any CAISO facilities. The requirement would not be imposed on hydroelectric plants.

The Order prohibited other bidding practices if they were seen as potentially allowing anticompetitive market manipulation, such as bids that vary with the output of a unit in a manner not related to the known cost characteristics of the unit, thus excluding the types of bids—described in a previous chapter—in which the last MW of electricity is bid at a very high price relative to most of the electricity from the same unit. Similarly, a single unit in a portfolio could not be bid at a very high level compared to the remainder of the portfolio unless there was a clear performance or input cost basis. Bids that appear to change only as electricity demand goes up, independent of the operations of the generating unit, would be outlawed.

Finally, the Order made it clear that demand response should be part of the market response. Load-serving entities were required to establish demand response mechanisms in which they identified the price at which load should be curtailed.

This mitigation plan was conditioned on the CAISO and the three investor-owned utilities filing a proposal for a Regional Transmission Organization (RTO) by June 1, 2001. This requirement was meant to develop regional responses to regional problems; however, the plan was California-specific in all other respects.

FERC June 19 Order Broadening the Scope of Price Mitigation

Ultimately, after comments were received, a more comprehensive plan was adopted on June 19, extending the price control regime to all of the western states and to all times, including times when there was no energy emergency. The Order primarily extended the scope of the April 6 Order. It was scheduled to remain in effect until September 30, 2002.

As opposed to the April 6 Order, the June 19 Order set rules to be implemented in a common manner[50] across all of the markets in the western region. As in the April 6 Order, whenever there is an energy emergency, it forces the generators to offer bids at some estimated marginal cost.[51] In addition, however, in nonemergency times the mitigation order sets price controls based on the market-clearing price in the last Stage 1 emergency. Moreover, it further attempts to eliminate California's reliance on spot markets.

In addition to the bid cap system of the April 6 Order, the June 19 Order imposes price caps on bilateral sales. These bilateral trans-

[50]A 10 percent price premium was allowed for sales to California to compensate for California-specific risk. Whether this premium is larger than needed to compensate for risk or is too small has been debated intensively. See an earlier section of this chapter on the "creditworthiness adder."

[51]FERC, "Order on Rehearing of Monitoring and Mitigation Plan for the California Wholesale Electric Markets, Establishing West-Wide Mitigation, and Establishing Settlement Conference" (June 19, 2001).

actions would be based on whatever prices are negotiated between the buyer and the seller, but the market-clearing price in the single-price auction would set an upper limit on the allowable prices for these transactions.

Different bid caps were applied to generators and marketers. During energy emergencies, the bid by a generator could be no higher than an administratively derived estimate of marginal cost of electricity from that generator. The estimate would be equal to the marginal cost of the gas used (with that gas purchased at that moment on a spot market for gas) plus variable operations and maintenance costs.

The costs of emissions credits or other emissions costs and start-up fuel costs would not be included in setting the market-clearing price. Rather these costs would be directly billed to the CAISO. Such a system would no longer ensure that the lowest-cost units would have their bids accepted. In particular, emissions and start-up costs would not count in determining which plants would be dispatched. Unfortunately, this would create a bias toward selecting the plants with weaker environmental performance if their costs otherwise were low.

In addition, generators would be given an opportunity to justify costs higher than the administratively determined bid caps, but these higher costs would not be used in setting the market-clearing price.

Marketers, as opposed to generators, would not be allowed to bid higher than the market-clearing price. That is, they would act as price takers.

Simple price caps would be imposed for spot market sales in times other than energy emergencies. The price for spot market sales could be no greater than 85 percent of the highest CAISO hourly market-clearing price established while the last Stage 1 emergency (not Stage 2 or 3) was in effect. When the next Stage 1 emergency is declared, the new price cap, which could be higher or lower than the one that had been set before, would be set for the subsequent time.

This FERC Order currently sets all price mitigation rules throughout the western region. As such, it sharply changes the California system from one that used blunt price caps in California markets, which were viewed in isolation from the rest of the interconnected region, to one that uses caps on bids tailored to generation costs and that fully reflects the interconnected nature of the western region. Moreover, its lifetime is limited to one additional year.

Some Impacts of the Current FERC Price Mitigation Rules

It is difficult to access definitively the impacts of the FERC April 26 and June 19 Orders. Just before they came into effect, wholesale prices fell to below the maximum prices allowed under these mitigation rules and soon fell to well below the maximum prices. Although it is conceivable that FERC price control rules caused a sharp decline in prices, price controls typically do not cause prices to fall well below the controlled levels. Therefore, it is unlikely that either the bid caps or the nonemergency price caps can account for the observed reduction in prices.

However, it is possible that the rule prohibiting anticompetitive bidding practices changed the pricing dynamics in the market, though the impact of this rule could not be assessed without careful evaluation of the confidential CAISO data on the nature of bids before and after this change. These confidential data, if ever made available to researchers, might provide some information about the significance of that rule.

The price mitigation rules do have one troubling feature. The non–energy emergency price caps for the entire West are fundamentally controlled by a California organization, the CAISO. This price cap is set equal to 85 percent of the highest CAISO hourly market-clearing price established when the last Stage 1 emergency was in effect, but only if that emergency was in effect for a full hour. However, the CAISO itself declares energy emergencies and in some circumstances can control whether or not the Stage 1 emergency lasts for more than one full hour, and thus can decide whether or not to reset the price cap. Though there has been no evidence that this power has been misused, the potential is troubling.

CALIFORNIA POLICY DURING THE CRISIS: A CRITIQUE

The sad history of a challenge that grew into a full-blown crisis need not have occurred. At every step of the way, there were alternatives that the state could have taken to address the financial crisis, the electricity crisis, or both. However, the steps would have taken leadership at the gubernatorial level.

The first alternative that could have been taken, but was not, would have been to allow the utilities in spring 2000 to start purchasing electricity on medium- or long-term contracts. This action could have been taken by the CPUC, since by that time, the purpose being served by the restrictions was no longer valid. Presumably, the governor, having appointed the president of the CPUC, could have worked with her to accomplish that action if he had chosen. Alternatively, if the CPUC had been unwilling to cooperate with the governor (an unlikely possibility), he could have taken action by exercising his broad emergency powers. Neither the governor nor the CPUC ever took this first crucial step.

This single step would have had a large direct impact on avoiding both the financial crisis and the electricity crisis, since the financial crisis was exacerbating the electricity crisis. If the utilities had entered into long-term contracts for a large share of their electricity supplies, they could have remained financially viable throughout the time, and if they had remained financially viable, the generators of electricity could have remained confident of being paid for electricity sold. Without uncertainty about whether they would be paid, their bid prices would have been lower and suppliers would not have been forced to shut down plants because they could not pay for generating electricity. Although wholesale prices would have risen, it is very doubtful that they would have risen to such high levels had there not been the financial crisis.

With the failure to authorize long- or medium-term contracts, the governor and the CPUC kept the investor-owned utilities facing a high risk. Ironically, this solution, initially denied to the utilities, was an action taken by the state at the height of the crisis. Thus rather than the utilities entering into long-term contracts at relatively low prices, the state entered into long-term contracts later, at much higher prices.

Second, the political leadership failed to allow the retail price to move with the wholesale price. This failure was fundamental to the financial crisis and, as discussed above, was a fundamental reason the energy crisis remained as severe as it did.

Although the leadership failure must rest squarely with the governor, the overall failure was fundamentally bipartisan. Neither the Republicans nor the Democrats in the California Legislature were as a whole demanding increases in the retail prices. Some isolated exceptions were pointing out the importance of retail price increases.[52] Nevertheless, legislators of both parties, fearing adverse voter reaction to any dramatic increases in retail prices, acquiesced

[52]For example, early in the crisis, Representative Joseph Simitian, a Democrat, was calling for retail rate increases, at least in the marginal prices of electricity.

to the governor's position, seen by Democratic legislative leaders as the "bookends" of Governor Davis's policies. At least a high cost to the state was less visible to voters than would be the high cost of increased utility bills if retail prices had been allowed to increase. In addition, if the state were able to issue bonds to cover the cumulative state shortfalls, the high cost would be seen by ratepayers over the long, distant future and would not be as obvious during the next election. The political calculus seemed very strong and neither party took leadership by fighting to bring about retail price increases until the State budget had been decimated.

Given that the actions actually undertaken by the governor were primarily politically expedient actions and those that he avoided were more difficult, politically riskier actions, the question arises whether the governor understood the seriousness of the problem that California was facing. If there was any doubt that Governor Davis was aware the state faced a serious challenge, the report[53] he received on August 2, 2000, from two of his key energy appointees—Michael Kahn, Chairman of the EOB, and Loretta Lynch, President of the CPUC—confirms that he had been fully informed early in the challenge period and that he had been advised by people whom he trusted that strong actions were needed. With this advice, he soon afterwards developed a policy framework relying exclusively on price controls. He sent letters to the CPUC, the PX, the CAISO, and the EOB strongly urging them to take actions following the strategy he had developed.[54] In addition, Governor Davis did his part to communicate his perspectives on the energy situation externally, as was discussed in a previous section. Thus, it is clear that Governor Davis was very personally involved from the early days of the challenge period, that he felt comfortable exerting his power as governor to direct these California agencies, and that it was he determining the central policy choices taken by the California government.

Throughout the entire emergence, growth, peaking, and remission of the California electricity crisis there was a frequent stream of advice to the state from the FERC in the form of responses to California requests, orders initiated by FERC in response to complaints filed by participants in the California markets, FERC stud-

[53]Report discussed more fully in previous section "State Policy Responses during the Challenge Period."

[54]More complete discussion appears in previous section "State Policy Responses during the Challenge Period."

ies and other reports, and direct communication by FERC members and staff with Governor Davis and other California state or private agencies. This advice made it clear that the FERC was willing to work in a cooperative manner with the State of California, but that California had much to do in order to correct its internal policies. Although much of this advice may not have been welcome by Governor Davis, the information was brought forcefully to his attention.

In addition, advice to Governor Davis was not limited to advice from Washington but was forcefully communicated both personally and publicly. One of the more public communications was issued in late January 2001 by an ad-hoc group of energy and public policy experts[55] convened through University of California, Berkeley. This group, including university faculty, former public officials, and energy consultants, issued a call to action entitled "Manifesto on the California Electricity Crisis," outlining a set of

[55]Signed by: Sanford Berg (Director, Public Utility Research Center, University of Florida); Tom Campbell (Professor, Stanford Law School); John Chandley (Principal, Law & Economics Consulting Group); Carl Danner (Former Chief of Staff to the President of the CPUC); Harold Demsetz (Professor Emeritus, Economics, UCLA); Roger Farmer (Professor, Economics, UCLA); Lee Friedman (Professor of Public Policy, U.C. Berkeley); Richard Gilbert (Professor, Economics, U.C. Berkeley); William Hogan (Professor, John F. Kennedy School of Government, Harvard University); Paul Joskow (Professor, Economics and Management, Director, MIT Center for Energy and Environmental Policy Research); Paul Kleindorfer (Professor of Operations & Information Management, Professor of Public Policy & Management, The Wharton School, University of Pennsylvania); Amartya Lahiri (Assistant Professor, Economics, UCLA); Robert Lawrence (Professor, John F. Kennedy School of Government, Harvard University); Tracy Lewis (Professor, Economics, University of Florida); Chris Marnay (Staff Scientist, Lawrence Berkeley Nat'l Laboratory); Daniel McFadden (Nobel Laureate, Professor of Economics, U.C. Berkeley); Phil McLeod (Principal, Law & Economics Consulting Group); Robert Michaels (Professor of Economics, California State University, Fullerton); Lee Ohanian (Associate Professor of Economics, UCLA); Shmuel Oren (Professor of Industrial Engineering and Operations Research, U.C. Berkeley); Joseph Ostroy (Professor of Economics, UCLA); Larry Ruff (Consultant); Richard Rumelt (Professor of Business and Society, UCLA); Pablo Spiller (Professor of Business, U.C. Berkeley); Robert Solow (Nobel Laureate, Professor of Economics, MIT); James Sweeney (Professor of Management Science and Engineering, Stanford University); David Teece (Professor, Director, Institute of Management, Innovation & Organization, Haas School of Business, U.C. Berkeley); Phillip Verleger (PK Verleger LLC); Mitch Wilk (Former President and Commissioner CPUC); Oliver Williamson (Professor, Haas School of Business, U.C. Berkeley); Janet Yellen (Professor, Haas School of Business, U.C. Berkeley).

public policy solutions designed to help California solve the energy crisis.[56]

The Manifesto made it clear that the financial crisis:

> *must be dealt with immediately before it gets further out of hand. If the creditworthiness of the investor-owned utilities can be restored, California can both solve the immediate supply shortage problems resulting from credit risks and then look to proper long-term solutions to its electricity problems.*

The Manifesto urged four key elements to these long-term solutions:

> *freedom to engage in long-term contracts, retail price flexibility, competition at both the wholesale and retail levels, and more effective cooperation between federal and state regulators to fix a variety of market imperfections and resulting market performance problems.*

The Manifesto stressed the importance of avoiding actions that would make matters worse:

> *In particular, a State takeover of the business would make matters worse, as would turning the State into a permanent electricity purchasing authority. It would also be unfortunate if the State were itself to commit to long-term contracts for a large portion of California's electricity needs. The State's credentials as an astute player in the electricity market aren't impressive, and there is no reason to expect major improvement in the future. Accordingly, emergency state contracts should be avoided if at all possible. Nor would the State buying up existing generation assets add to supply. In the end, new power plants are needed, and the State should focus on creating a supportive environment for necessary new private investment. State ownership is not a solution at all—merely a guarantee that the taxpayers will be saddled with additional obligations for decades to come.*

[56]The complete document is available at http://www.haas.berkeley.edu/news/california_electricity_crisis.html.

The advice from within California was clear, forceful, and well publicized. It could not have been missed. Unfortunately, Governor Davis chose to reject this advice, as he continued to reject the advice of federal authorities, doing almost exactly the opposite on every count. California continues to suffer the consequences of his decision making.