3

THE CHALLENGE

The year after AB 1890 was passed, a group of consumer advocates, led by Harvey Rosenfield, started the process of legally challenging the restructuring legislation. This group began collecting signatures to qualify what became Proposition 9, voted on in the 1998 statewide California ballot. Proposition 9 would have turned back the restructuring and reinforced a system of tightly regulated electricity transactions. It was not until the defeat of Proposition 9 in November 1998 that it was ensured AB 1890 would be allowed to operate.

Until its defeat, Proposition 9 created much uncertainty and reduced the incentives for private companies to invest in new electricity-generating facilities. By creating significant delays in the capital investment associated with investing in new generating plants, Proposition 9 increased the risks that were inherent in this newly restructured system.

Until early 2000, the new system seemed to be operating as intended in terms of the publicly visible goals. Wholesale prices remained below historical average costs and the utilities gained profits that they could apply to cover the stranded costs. By 1999, SDG&E had earned sufficient profits to cover all of its stranded costs and would no longer be subject to the retail price caps.

The divestiture of generating assets owned by the utilities was proceeding surprisingly well. Many old generating plants had

been sold at prices that far exceeded the expected prices. These sales moved the electric utilities closer to the time when they would be able to leave the price control regime.

However, the high sales prices should have raised questions in the CPUC. It can be presumed that those plant buyers were not being irrational and that they believed future electricity wholesale prices would rise. These high selling prices thus should have suggested to CPUC members that there was a significant risk that future wholesale prices would increase dramatically. High prices also could have implied the need for long-term contracts or other methods for the utilities to protect themselves and the ratepayers from such risks.

Although the overall supply/demand balance had not yet improved in California or the western region, improvements were under way. In California, applications to construct many new electricity-generating units had been filed and approved; construction had begun for many thousands of MW of new capacity. Demand for electricity continued to grow but was growing at a relatively slow pace. Looking ahead, it was reasonable to project that the new electricity-generating plants would be on-line before growing demand surpassed the available supply of electricity.

One disappointment with operation of the new system seemed to be the lack of a competitive retail market for electricity. Several companies entered the market to sell consumers green electricity, advertised to be generated entirely by renewable sources; however, this component of the market was small. Other companies that tried to enter the market complained that the tightly regulated system gave them no opportunity to compete successfully.

Less publicly visible, however, were the operations of the PX and the CAISO. The market structure continued to prove unwieldy and the CAISO submitted to the FERC a sequence of proposed amendments to its tariff. After twenty-four amendments were filed, the FERC finally summarized its perceptions: "The problem facing the [California] ISO is that the existing congestion management approach is fundamentally flawed and needs to be overhauled or replaced."[1] This started a process of rethinking the market design that was never completed, since the events beginning in spring

[1]Federal Energy Regulatory Commission, "Order Accepting for Filing in Part and Rejecting in Part Proposed Tariff Amendment and Directing Reevaluation of Approach to Addressing Intrazonal Congestion," Docket ER00-555-000, 90 FERC 61, 000 (Washington, D.C., January 7, 2000), p. 9.

2000 overtook the process.[2] There were clearly continued problems with the market design and its detailed implementation. Personnel within the PX, CAISO, and FERC, as well as analysts studying electricity markets, were working to improve it.

By spring 2000, warning signs about the supply and demand imbalance throughout the western region had become obvious. Wholesale prices spiked upward in May 2000 and then again in June. There was insufficient electricity available in San Francisco on one day, causing a blackout. Lawsuits were filed to identify and hold accountable any companies responsible for the rapid price increases. The challenge had become apparent not just to technical specialists but also to the public and political leaders of the state.

In what follows, we analyze the changing circumstances that turned the risky situation into a challenge for the State of California. The challenge to California initially arose from changes in the supply and demand patterns throughout the western portion of the United States coupled with characteristics of electricity markets, which inherently made electricity wholesale prices highly volatile. Particular characteristics of California's restructuring combined with these additional changes to create the "perfect storm." This was the challenge that California faced in the year 2000.

THE NATURE OF THE CHALLENGE

The challenge grew in terms of two types of problems: (1) an electricity challenge associated with very tight wholesale markets for electricity in the West and California's management of its electricity markets, and (2) a financial crisis of California's investor-owned utilities associated with the State's regulatory control of these utilities.

The electricity challenge was primarily part of the challenge facing the western states as of mid-2000. Demands for electricity throughout the West had grown over the years, but supply had not. New generation capacity in California was under construction, but construction had not been completed. There were no direct

[2]For more discussion of the problems with the market system appearing before spring 2000, see William W. Hogan, "Electricity Market Restructuring: Reforms of Reforms" (Harvard University, May 25, 2001). Available at http://ksghome.harvard.edu/~.whogan.cbg.Ksg/.

incentives for consumers in California to reduce their demands for electricity because the State rigidly maintained retail price controls. Short-term supply reductions led to very tight markets and wholesale spot prices increased sharply in California and throughout the West.

The financial challenge was one facing the investor-owned electric utilities. As wholesale markets grew tighter, the investor-owned utilities, forced to rely to an inappropriately large extent on spot prices, faced the prospect of sharply escalating costs of acquiring electricity on wholesale markets. Yet the retail price controls, were they to be continued, would preclude the utilities from passing any of those costs on to their customers: the investor-owned utilities would be required to deeply subsidize electricity use by their customers.[3] The difference between acquisition cost and retail selling price was threatening to become great enough to deplete all their financial assets, absent relaxation of retail price controls. During this challenge period, two things were needed to avert a crisis: the retail price controls needed to be relaxed and the utilities needed to move away from spot wholesale markets and toward medium-term and long-term electricity supply contracts.

In what follows, these two challenges are discussed separately, with the electricity market challenge presented first.

ELECTRICITY SUPPLY AND DEMAND PATTERNS

Regional Market Linkage

Contrary to many popular discussions, supply and demand conditions in California's electricity system are tightly linked to conditions throughout the western region of the United States; California's system is not isolated from electricity markets in the rest of the West. High-voltage transmission lines, across which electricity can be transmitted, connect adjacent states and adjacent regions within a state. Through this transmission system, the eleven western states, plus the Canadian provinces of British Columbia and Alberta, are electrically linked to one another. In principle, electricity generation in any part of the western region—more precisely, the Western Systems Coordinating

[3]The California municipal utilities were not so required and were free to increase their prices, based on decisions by their governing boards.

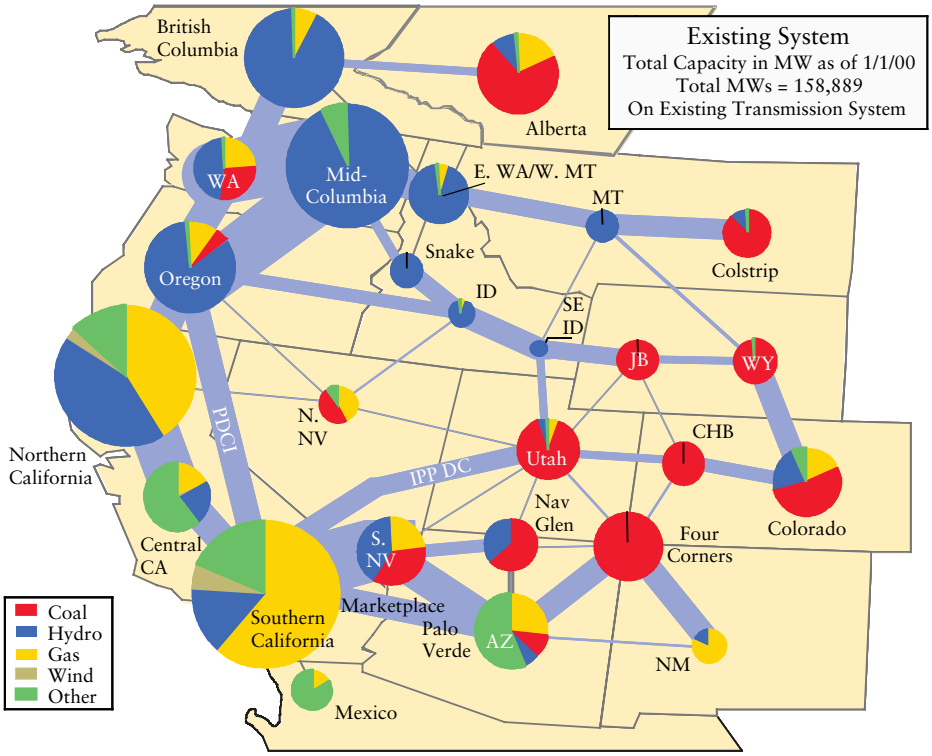

FIGURE 3.1: Installed Capacity by Generation Type in the Western Grid, as of January 2000

SOURCE: Western Governors' Association

Council[4] (WSCC)—could be used to satisfy electricity loads in any other part of the western region, subject to transmission constraints.

Figure 3.1, created by the Western Governors' Association,[5] gives an indication of the transmission capacity between the various states and portions of states. The widths of the blue lines connecting the circles are proportional to the relative transmission capacities.

[4]Eleven states are interconnected as part of the Western Systems Coordinating Council (WSCC) area: Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming. WSCC also includes the provinces of Alberta, British Columbia, the northern portion of Baja California, Mexico, and portions of several other states.

[5]Western Governors' Association, "Conceptual Plans for Electricity Transmission in the West," August 2001.

Figure 3.1 shows that there is much transmission capacity between California and the Pacific Northwest and between California, Nevada, and Arizona. Thus, these parts of the western region are linked particularly closely and the greatest flows of electricity occur among these areas. California represents 42 percent of the generation and 51 percent of the consumption in this tightly linked portion of WSCC.

Given the possibility of transmitting electricity among states and given that federal regulations allowed open access to the transmission network,[6] utilities in the West had traded with one another either directly or through marketers well before California restructured its electricity markets. Significant quantities of electricity generated in one state have been routinely bought, sold, and transmitted between states. This was not the product of California's restructuring, which did allow the possibility of increased trade and increased electricity flow between states.

Thus, for the most part, in practice, electricity generation in any part of the West could be used to serve the electrical loads in any other part of the West, including California, subject to transmission constraints, which at some times could limit the amount of trade. Similarly, electricity loads in any part of the West could reduce the amount of electricity available to serve loads in any other part of the West, including California.

Since utilities and marketers can freely trade across state boundaries (subject to transmission constraints), spot prices tend to equate between any two adjacent regions whenever the transmission interconnections between the regions have excess capacity.[7] Any price difference would be an opportunity for traders to arbitrage the differences, buying in the low price area and selling in the high price area, thus eliminating price differences.

Because of the relative ease of electricity trade and the tendency toward price equality among the western states, changing supply and demand conditions anywhere in the interconnected western region have similar impacts on spot market prices throughout the entire region. A tight market in the Pacific Northwest can easily translate into a tight market in California, and vice versa. A tight market any place

[6]Particularly important were EPACT and FERC Order 888. See Chapter 2.

[7]Whenever the interconnections reach capacity, price differences can persist, just as there are price differences between the western region and the Midwest.

will typically lead to high spot wholesale prices everywhere in the West.

Although spot wholesale prices across the region tend to equalize quickly, long-term contractual arrangements reduce the amount available for sale on the spot markets at any moment of time. In most of the states other than California, the vast majority of electricity is generated by the utilities themselves or is contractually committed to the various publicly or privately owned utilities. Under such contracts, generators have committed to provide fixed quantities of electricity to particular utilities, or they have dedicated all electricity from particular generating plants to those utilities. Electricity so committed under firm contracts is generally not available for sale on the spot markets.

Spot market prices respond to the demand and supply for electricity transacted on the spot markets, not necessarily to the overall demand and supply in the region. In the short run, electricity loads and electricity supplies committed under long-term contracts are removed from transactions on the spot market, leaving a smaller spot market supply and an equivalently smaller spot market demand.

Residual quantities are not removed, however. Utilities operating under long-term wholesale contracts but with projected loads exceeding their committed generation are free to compete to purchase electricity on the spot market. Similarly, generators with supplies greater than their long-term contractual sales are free to offer to sell the surplus on the spot markets. Thus, supply and demand variations within the region translate directly into equivalent volume supply and demand variations in the spot markets.

Because long-term contracts reduce the total volumes available for transactions on the spot markets, a given magnitude of supply or demand variation represents a much larger percentage variation than would be the case absent the long-term contracts. This in turn implies that spot market prices are far more volatile than they would otherwise be. A given magnitude of supply reduction or demand increase leads to a much greater price increase on the spot markets than would be the case if there were no long-term contracts. Similarly, the large number of long-term contracts implies that supply increases or demand decreases have disproportionate impacts on spot market price reductions.

Thus, in the mixed system characterizing the West—most electricity sold on long-term contracts and a smaller amount sold on spot markets—spot market prices tend to vary sharply, whereas

existing long- and medium-term contracts continue to operate at the contractually agreed prices.[8]

In the longer term (say, over a course of weeks or months), spot market conditions do influence the supplies and loads committed under long-term contracts. Buyers of electricity under long-term contracts may be able to reduce their use and sell the saved quantities into the spot markets when spot prices are significantly higher than long-term contractual prices. Alternatively, sellers and buyers may renegotiate long- and medium-term contracts to allow both to benefit from the opportunity to respond to high spot prices. The adjustment process under such long-term or medium-term contracts, however, is much slower than the adjustment in the spot markets.

Thus, in the mixed market system with most electricity sold on long-term contracts and a smaller amount sold on spot markets, those participants with long-term contracts are buffered from the changing market conditions. Because they are buffered, they need not respond as quickly or as greatly as those facing the more volatile spot markets. The diminished responses from those with long- and medium-term contracts have direct implications for the dynamics of the spot market. They imply that a greater response is called for from those participating primarily in spot markets and that spot market prices will be more volatile than would otherwise be the case.

Given the regionally linked electricity system and the mixed market system of term contracts and spot markets, supply and demand changes occurring either inside or outside of California could translate into very tight supply and demand conditions throughout the West, including slow supply and demand adjustment throughout the region and rapid and profound changes in wholesale spot market prices.

California's investor-owned utilities, after divesting most of their own generating capacity, and facing prohibitions against buffering themselves with long-term contracts, were forced to acquire much of their electricity on the very volatile spot markets.

[8]New long- and medium-term contracts, however, may reflect the volatility in the spot markets, since those contractual terms reflect the expectations of the buyers and sellers about the future expected spot market prices. In addition, if contract prices diverge greatly from current market prices for long periods, contracts can be renegotiated so as to benefit both contracting parties.

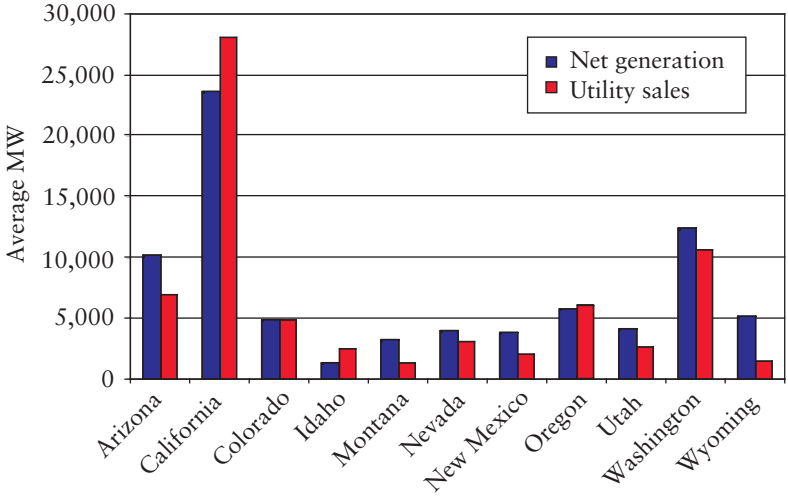

FIGURE 3.2: Net Generation and Utility Sales, WSCC States, 2000

Thus, as a result of California's restructuring, California investor-owned utilities were cast unenviably as buyers participating primarily in spot markets, while most utilities throughout the West and most municipal utilities in California were well buffered by a mix of long- and medium-term contracts. The fury of the perfect storm would be concentrated on the California investor-owned utilities, amplified by the buffering the other utilities were enjoying.

WESTERN REGIONAL SUPPLY AND DEMAND BALANCES

Figure 3.2, using data from the U.S. Department of Energy, Energy Information Administration, shows yearly average rate of net generation[9] and the yearly average rate of utility sales in the eleven western states that are interconnected as part of WSCC for the year 2000. California's retail sales of electricity account for 40 percent of the total retail sales in these eleven states; California generation accounts for 30 percent of the total. Thus, although California is the largest single state, neither its generation nor its consumption represents a majority in the West.

The total electricity use in a state must be the sum of net generation plus net imports from other states, minus transmission and

[9]Net generation is generation net of the electricity used in the generating plant itself. Net generation is measured at the generating plant. Line losses and other distribution losses must be subtracted from net generation in order to determine the amount of electricity available for utility sales.

other losses. Therefore, whenever electricity sales in a state exceed net generation less losses, the difference is made up through electricity imports from other states or other countries (Canada and Mexico).

In a typical year, California generates 75 percent of its electricity in state, importing 25 percent from the Pacific Northwest and the U.S. Southwest. These are not simply one-way flows of electricity into California. In the summer, California imports much electricity from the Pacific Northwest. In the winter, California exports electricity to the Pacific Northwest. Figure 3.2 shows that California and Idaho are the only states that must import large portions of their electricity. Most of the other western states are nearly balanced or are net exporters of electricity.

In addition to information about transmission capacities, Figure 3.1 provides data on the primary sources of electricity generation in each state. The circles on the chart show the summer-installed generating capacity, by generation type, for each state or portion of a state. The sizes of the circles are proportional to the summer-installed capacities as of January 2000. Figure 3.1 shows that the primary energy source for electricity generation varies significantly across the western region. The Pacific Northwest relies primarily on hydropower, with some natural gas and coal. The mountain states, except Colorado, rely primarily on coal as an energy source for electricity generation. Colorado uses coal, hydropower, and natural gas. California relies on a diverse mix of energy sources, including natural gas and hydropower.

Although Figure 3.1 shows generation capacity in 2000, an analogous diagram for 1990 would look virtually the same. There had been very little growth in generating capacity throughout the western region in the decade prior to 2000.[10] However, there had been continuing growth in electricity use throughout the region. Thus, the amount of reserve capacity throughout the western region had been declining steadily for at least a decade before 2000. Tight supply and demand conditions had started to characterize most of the western region.

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[10]A complete discussion of the long-term trends in California and the West appear in Jolanka V. Fisher and Timothy P. Duane, "Trends in Electricity Consumption, Peak Demand, and Generating Capacity in California and the Western Grid, 1977–2000" (Working paper from the University of California Energy Institute Program on Workable Energy Regulation [POWER], September 2001).

Throughout the region, most of the municipal utilities and investor-owned utilities had adjusted to this market tightening by ensuring their own supplies of electricity, either through their own generating units or through a combination of medium- and long-term contracts to purchase electricity. California investor-owned utilities had not been allowed to do so.

The generation capacity shown in Figure 3.1 could vary significantly with changes in the local conditions. In particular, the hydroelectric capacity represents the capacity of generators. But if the amount of available water were insufficient, some of that generated capacity must remain unused. Thus, low rainfall conditions in Northern California and in the Pacific Northwest can, and did, reduce the amount of hydropower that could be generated in those locations.

In addition, the electricity demand was notoriously time-dependent. A hot summer could greatly increase the demand for electricity in California or Arizona because of the large air conditioning loads; a cold winter could greatly increase the demand for electricity in the Pacific Northwest because of the large electric-resistance space-heating loads.

In spring 2000, then, California was part of a region that was tightly interconnected electrically. With California's particular regulatory environment, the dynamics of wholesale electricity market adjustments were skewed against California's investor-owned utilities. Most electricity either outside California or sold to California's municipal utilities was committed to long-term contracts. Most electricity purchased by California's investor-owned utilities was transacted on spot markets with supplies that could shrink rapidly in response to changing conditions either inside or outside of California. The markets for electricity had gradually become tighter and tighter throughout the region. Moreover, in spring 2000, rapidly changing conditions external and internal to California created for California the perfect storm.

The following sections focus more sharply on California and its changing supply and demand conditions, which can help explain why California was not prepared to weather the storm.

California Electricity Use

California has been a relatively low user of electricity when measured on a per capita basis. The industrial structure, although intensely dependent on electricity, particularly for the high-tech

industries, is not a heavy electricity consumer relative to industry in other states. The state is blessed with a temperate climate, and thus air conditioning loads are relatively low. High prices for electricity, coupled with aggressive energy demand management programs, have kept consumption relatively low. California has had a long tradition of efficiency incentives and services that have helped to reduce California's electricity intensity in recent decades.

Table 3.1, using 1999 data from the U. S. Department of Energy,[11] shows that the residential electricity consumption per customer was 37 percent below the U.S. average during that year. Thus, the challenge California was facing did not stem from California being a particularly large user of electricity on a per capita basis. Conversely, that California had a lower per capita use of electricity than most states did not allow California to avoid the challenge.

During the period from 1997 through 2000, the consumption of electricity in California continued to grow slowly as it had for the previous ten years. The California economy was remaining healthy and population was continuing to grow steadily. Per capita electricity use grew modestly during that time. Figure 3.3 shows the net result. From 1990 to 2000, use of electricity increased from a 26,000 MW average consumption rate to one just above 30,000 MW, a growth of 16 percent over ten years, or 1.4 percent per year. Growth in energy consumption, however, was somewhat faster during the

TABLE 3.1
California versus All U.S. Residential Electricity Use per Residential Customer

	California	*All U.S.*	*California Relative to U.S.*
Monthly Average Residential Consumption (MWh)	0.548 MWh	0.866 MWh	37% below National Average
Average Residential Consumption Rate (MW)	0.75 MW	1.19 MW	
Retail Average Revenues ($/MWh)	$107/MW	$82/MW	9th Highest

[11]Data in table are from http://www.eia.doe.gov/cneaf/electricity/esr/esrt14p4.html. Data are based on the number of customers in the residential sector. This figure corresponds closely to the number of households.

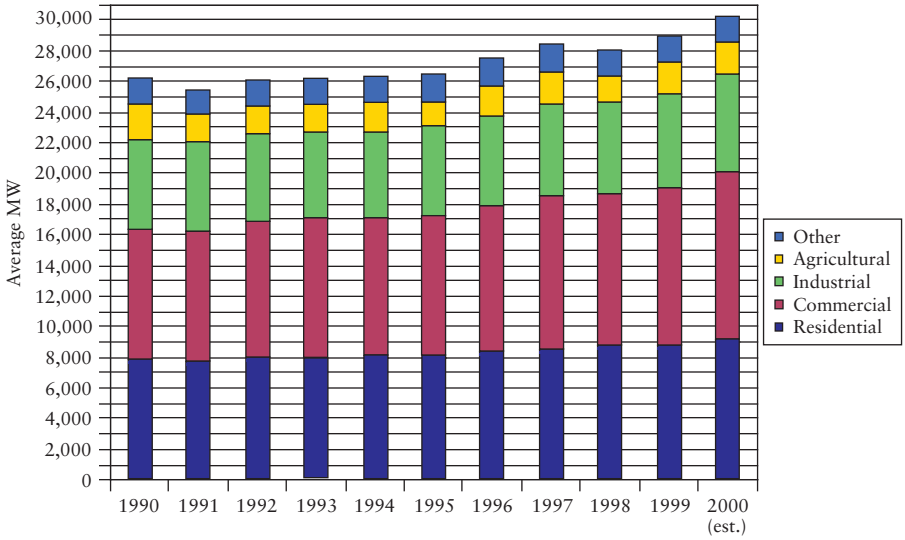

FIGURE 3.3: California Energy Consumption Growth

SOURCE: California Energy Commission

1997–2000 period, increasing by almost 2,000 MW during the three years, or an average growth rate of 2.3 percent per year average. From 1999 to 2000, average consumption increased slightly more than 1,000 MW, almost 4 percent. Peak loads were growing at roughly the same rates.

Thus, although peak loads and total electricity consumption grew, growth was relatively slow. Taken alone, neither the absolute magnitude of electricity use nor the growth rate would have been likely to create a particularly significant challenge.

Some have argued that electricity demand in California has grown much more rapidly than expected, even if not particularly rapidly on an absolute scale. Although it is difficult to document the wide range of growth expectations, it is possible to compare actual growth to California's official forecasts of growth in electricity consumption and growth in peak loads.

Table 3.2 shows these forecasts of growth and actual growth over the five-year interval from 1995 to 2000, based on two California Energy Commission reports: the 1996 *Electricity Report* and the 1998 *Baseline Energy Outlook*. Since measured peak demand can be influenced strongly by curtailments, peak demand growth is shown first ignoring the curtailments and then adjusted for curtailments. Adjusting for curtailments, peak demand grew

13.4 percent from 1995 to 2000, in contrast to the 10.4 percent growth forecast in the California Energy Commission's 1996 *Electricity Report*.[12] Total consumption grew 14.5 percent from 1995 to 2000, in contrast to the 11.6 percent and 11.7 percent total growth in consumption forecast in the 1996 *Electricity Report* and the 1998 *Baseline Energy Outlook,* respectively.

Table 3.2 thus shows that electricity consumption and peak demand did grow somewhat faster than forecast by the California Energy Commission. Growth, measured by peak demand or by total electricity consumption, however, was no more than three percentage points greater than those forecasts. Therefore, the "electricity demand grew surprisingly fast" explanation can account for only a part of the tight market conditions.

TABLE 3.2
Official California Forecasts of Electricity Demand and Consumption Growth versus Actual Growth

		Actual or Forecast Five-Year Growth	*Underestimate of Five-Year Growth*
Five-Year Growth in Peak Electricity Demand	Actual Growth Ignoring Voluntary Curtailments	9.2%	
	Actual Growth Adjusted for Voluntary Curtailments	13.4%	
	1996 *Electricity Report*	10.4%	3.0%
Five-Year Growth in Electricity Consumption	Actual Growth	14.5%	
	1996 *Electricity Report*	11.7%	2.8%
	1998 *Baseline Energy Outlook*	11.6%	2.9%

[12]The growth forecasts are based on noncoincident peaks since no forecast was available for coincident peaks. The actual peak growth is based on coincident peaks. The year 2000 coincident peak demand in the CAISO control area was 43,784 MW, but there were 1,710 MW of voluntary curtailments that day. No adjustment for curtailments was made for total electricity consumption since voluntary curtailments had a much greater percentage impact on peak demand than on total consumption during the year.

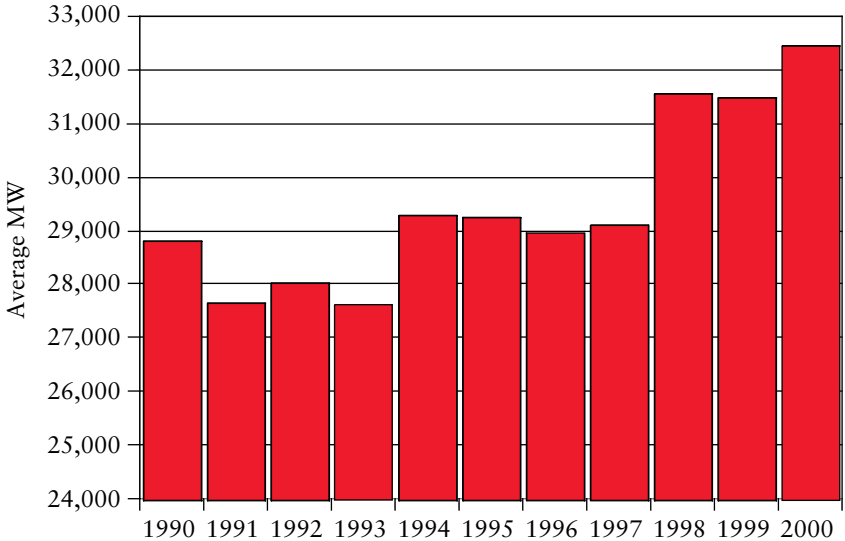

FIGURE 3.4: Electricity Generation Supporting California's Electricity Use

CALIFORNIA ELECTRICITY GENERATION AND IMPORTS

Total generation[13] required to support electricity consumption is shown in Figure 3.4, in which the vertical axis has a suppressed zero and which shows data for only the 1990 through 2000 period.[14] Note that total generation is slightly larger than use since there are losses in the transmission and distribution system.

From 1997 to 1998, total generation required to support California loads increased by 2,500 MW average and increased again by 1,000 MW in 2000. From 1990 to 2000, total generation required increased 12.6 percent over ten years, or 1.2 percent per year. Growth, however, was somewhat faster during the 1997 through 2000 period, increasing by 3.7 percent per year average. Measured in terms of electricity generation required to support California's electric loads, the growth rate was slightly faster than that measured by

[13]Data in this graph and the following graphs of California energy generation have been obtained from the California Energy Commission web site: http://www.energy.ca.gov/electricity/electricity_generation.html.

[14]Note that the consumption data and the generation data for 1997 seem inconsistent, with consumption shown as only 500 MW larger than generation in this year, in contrast to each other year. This is most likely an error in California Energy Commission data.

California data on electricity consumption. But under either measurement, growth was not particularly fast, and that growth alone would not have created a particularly significant challenge.

California had two generic sources of electricity to support the slowly growing electrical loads: electricity generated in California plus the net[15] imports of electricity into California. The two added together must be equal to the total use of electricity (consumption plus losses). Thus, if one of these two sources were to decline, the other had to increase more rapidly to satisfy the slow growth in use.

With tightening of electricity markets in the West, the amount of electricity available for sale on spot markets was shrinking, with that shrinkage occurring primarily outside of California. This resulted directly in an increase in the exports of electricity from California and a decrease in the imports of electricity into California: thus net imports into California declined.

Since 1990, imports had been averaging just above 5,000 MW, with, on average, equal quantities from the Pacific Northwest and the Pacific Southwest. In 2000, however, imports from the Pacific Northwest dropped with the extraordinarily low rainfall, following years of particularly high hydroelectric supply. Imports from the Pacific Southwest dropped sharply. The overall impact was a reduction in net imports to California of 2,200 MW (see Figure 3.5).

This measured reduction in net imports to California from surrounding regions underestimates the significance to the California energy crisis of the changes in the supply and demand balance in the remainder of the WSCC.[16] In response to the tight market conditions, spot market prices of electricity in these regions increased sharply during 2000. Increases in electricity prices reduced demand in these

[15]The net imports are the difference between imports into California and exports from California.

[16]This was pointed out by Jolanka V. Fisher and Timothy P. Duane (Fisher and Duane, "Trends in Electricity Consumption"), who reach similar conclusions: "Neither increases in California's annual consumption (or peak demand) nor decreases in California's historical share of WSCC-wide generating capacity is therefore at the heart of the state's supply and demand relationship from 1977 to 1998. Instead, the tightening of supplies throughout the WSCC during this period primarily reflects increases in consumption and peak demand in other states and a region-wide decline in new capacity additions relative to those increases in consumption. Above-average hydropower production (especially in the Pacific Northwest) from 1996 to 1999 masked this shift, then hydropower availability decreased significantly in 2000 (combined with significant increases in consumption in California and throughout the WSCC) to reveal apparent shortages."

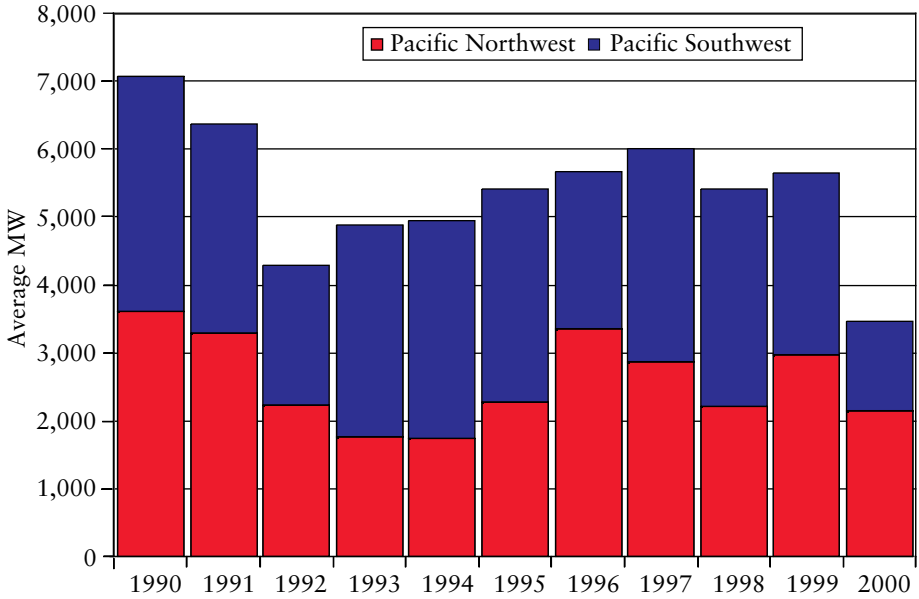

FIGURE 3.5: Electricity Imports into California

regions and increased supply, making more electricity available for export to California. The data in Figure 3.5 reflect the *equilibrium* quantities of net imports from these regions once the market prices adjusted to the supply/demand conditions. The measured level of net imports into California during 2000 therefore overestimates the net imports that would have been available absent the sharp increases in spot market prices. The drop in measured imports underestimates the impact of changing import availability in reducing the supply function in 2000 for electricity in California.

The combination of the increase in California consumption and the reduction in available net imports implied that more electricity was needed from domestic sources. Figure 3.6 below shows that the total production of electricity from California sources[17] grew sharply since the electricity restructuring, with increases from 1997 to 1998 of 3,000 MW and from 1999 to 2000 of 3,100 MW, an increase of 12 percent in that year.

[17]In this and the following figures, coal-fired units are included as California generation even though they are located outside of California. This coal-fired generation capacity is owned or controlled by California utilities.

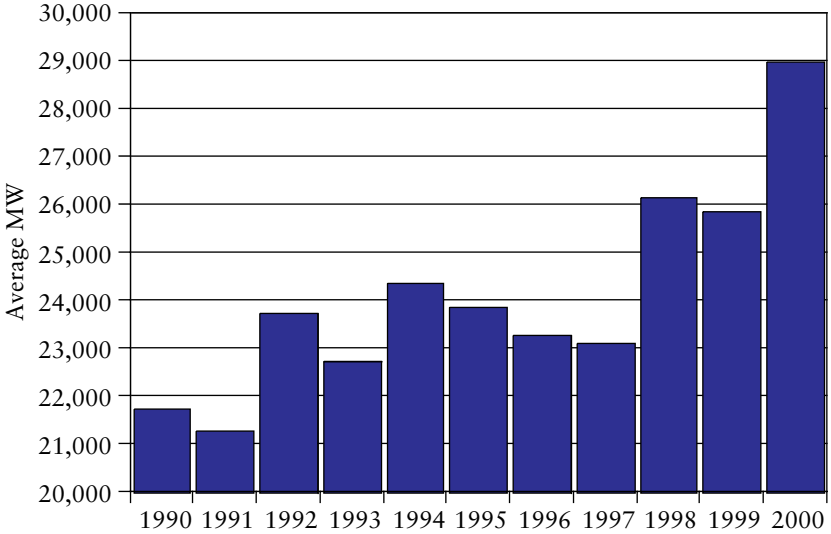

FIGURE 3.6: In-State Electricity Generation

The pressure on California's electricity supply was even greater than suggested by those figures since, other than the natural gas- and oil-fired units, virtually all of the generating sources run at full available capacity.[18] Almost all of the oil-fired facilities have long ago been converted to natural gas, and thus virtually all of the generating facilities were capacity-limited, with the exception of natural gas-fired units. Figure 3.7 shows the production over time from these various sources, except for natural gas.

Hydroelectric power does vary from year to year, but variation is controlled by rainfall. Thus the hydropower output averaged over the year cannot adjust significantly to economic conditions.

The remaining supply of electricity came from natural gas–fired units. Figure 3.8 shows this total generation from gas-fired units over the last decade and that from 1999 to 2000, generation from these units increased 26 percent, reaching an all-time maximum production rate. During the decade from 1990 through 2000, however, 1,500 MW of gas-fired generation was retired. Thus, more gas-fired electricity generation was needed even though there were fewer gas-fired generating units left to generate that electricity.

[18]Available capacity for wind machines and solar generators is considerably less than nameplate capacity.

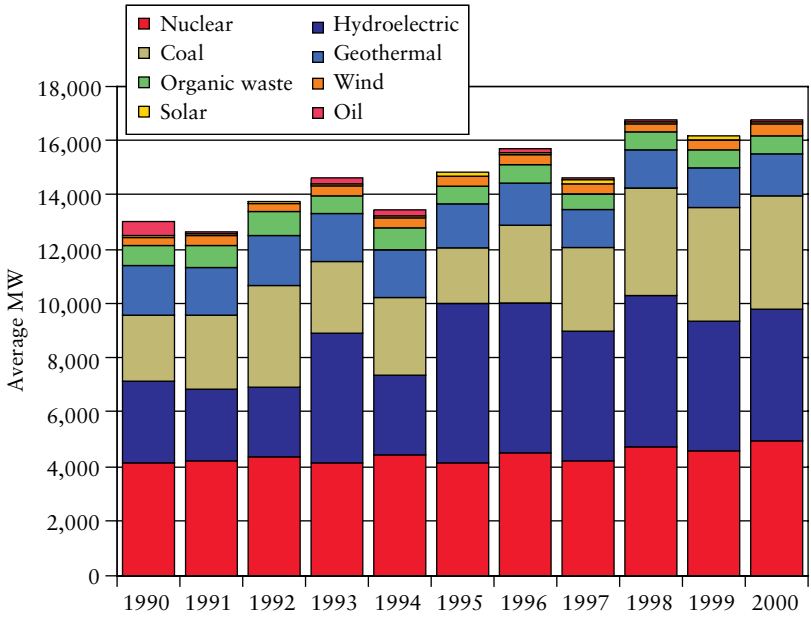

FIGURE 3.7: Sources of California Electricity Generation, Other Than Natural Gas

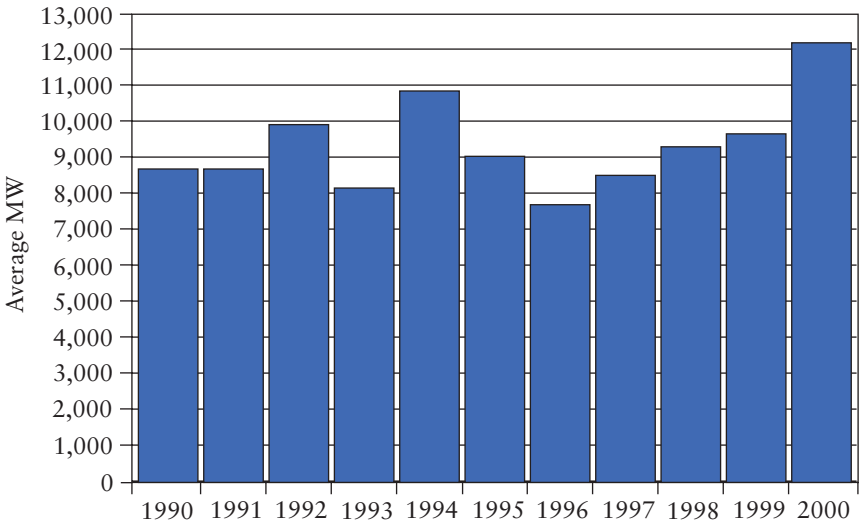

FIGURE 3.8: Gas-Fired Electricity Generation in California

This sudden increase in the generation from gas-fired units, coupled with the retirement of some existing units, could normally be expected to greatly increase the marginal cost of generating from the operating units and thus, under the market system, to increase the price of all wholesale electricity. Absent new construction, such a change would require the oldest and least efficient plants to be brought into service. Moreover, this change could be expected to increase the demand for natural gas in the state, thereby increasing its price and further increasing the marginal cost of generating electricity and thus further increasing the wholesale price. Each of these impacts, which would normally be expected, in fact occurred, as will be discussed later.

Investment in New Generating Units in California

One of the reasons for the restructuring of the electricity system was that market forces were expected to call forth new supplies of electricity in California if needed; however, new supplies could be brought forth only if there were sufficient capacity to generate the electricity. For the private market to create additional generating capacity takes time, and the California process is particularly lengthy.

The sponsor of a new plant with more than 50 MW of nameplate capacity must bring an application to the California Energy Commission, proposing new plant construction. The California Energy Commission conducts an extensive review process, involving both in-house review and public hearing, often taking two or more years.[19] Once the plans for the plant are approved, construction can start. Other than for simple cycle peaker plants, construction can take one to two years.

Once the construction is complete, the plant is tested, first off-line and then in a low level of power output, before it is finally certified for operation. Until the last step is completed, the plant cannot supply electricity. The entire process from application to on-line status typically takes three to four years for large plants but can be reduced to less than one year for peaker plants.[20]

[19]In February 2001, Governor Gray Davis signed six Executive Orders to expedite the review and permitting of power-generating facilities in California.

[20]Peakers are simple, relatively low efficiency plants that generally are used only at times of peak need. Often these are simple cycle plants.

Thus, the issue of whether the restructuring was leading to greater supplies of electricity generated in California[21] was dependent on whether there was a significant change in the applications for new plants, their approvals, and the numbers subsequently under construction. It was unrealistic to expect that new capacity resulting from the restructuring would be on-line by summer 2000.

The following graph (Figure 3.9) provides the estimates of new applications, approvals, cancellations, construction, and subsequent operation of new generating plants in California, including the period before the restructuring, through 1996, and the period after restructuring, 1997 through 2001. Data are based on the year the application for certification was filed. The total height of each bar in the graph shows the number of applications made during a year. Data include utility-owned generation and QFs, including cogeneration plants and renewable energy.[22] Currently operational plants of capacity smaller than 50 MW are shown separately from plants with capacity of 50 MW or greater.

Figure 3.9 shows that in the 1980s annual applications to build new California electricity-generating capacity averaged about 1,000 MW per year. The majority of these were plants with capacity below 50 MW, which are not subject to California Energy Commission approval. But between 1990 and 1996, annual applications for certification averaged about 250 MW per year,[23] while annual retirements of generating capacity averaged about 450 MW per year,[24] decreasing generating capacity within California during those seven years by about 1,400 MW. Electricity use during that time continued to grow in California, as in the rest of the West. As opposed to the 1980s, when capacity was increasing by more than electricity use, California

[21]Electricity destined for the California market did not have to be generated in California. Merchant plants could be built just north of the California-Oregon border or just east of the California-Nevada or California-Arizona border without facing the slow approval processes in California. The following discussion, however, limits itself to generation plants in California.

[22]Application dates of plants of 50 MW capacity or greater are available from the California Energy Commission. For smaller plants data are available for the years the plants went on-line. In constructing this graph it was assumed that the smaller plants had a planning start date, equivalent to an application date, two years before they went on-line, except for the 2001 applications that were completed that year.

[23]New capacity growth was similarly very slow throughout WSCC.

[24]Source: California Energy Commission. www.energy.ca.gov/electricity/inactive_plants.html.

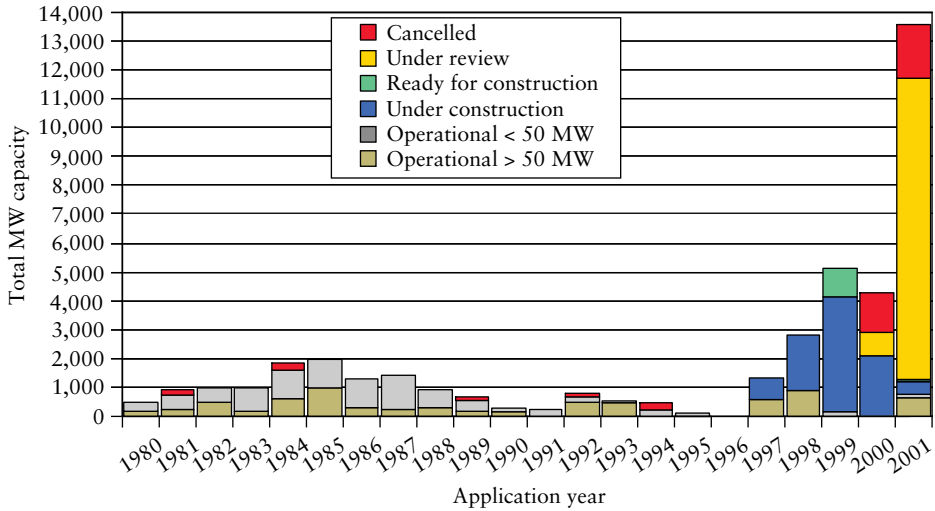

FIGURE 3.9: Current Status of New Generating Plants, Applications Since 1980

was increasing its need for electricity generation while decreasing the capabilities to provide that electricity.

Figure 3.10 shows in more detail the composition of the new generation capacity in California coming on-line since 1978 (as opposed to Figure 3.9, which shows applications). The blue component of the bars shows the plants with nameplate capacity of

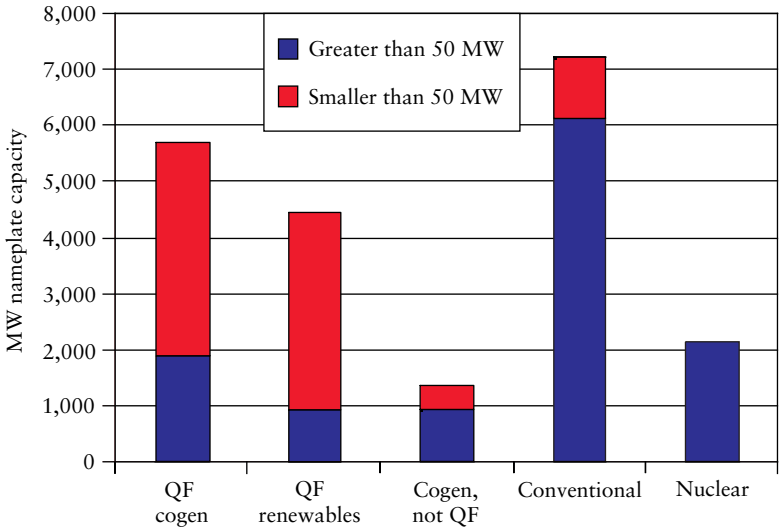

FIGURE 3.10: New Plant Construction Since 1978

50 MW or greater; the red component of the bars shows plants with nameplate capacity smaller than 50 MW.

Figure 3.10 shows that the largest single source of new nameplate capacity was conventional generation, including both base-load facilities and peakers. About one-half of the total new nameplate capacity was QFs, either cogeneration or renewables.[25] The majority of the QF capacity was from small units (nameplate capacity smaller than 50 MW) and thus much of this capacity is often not highlighted in many public information sources.[26]

The restructuring marked a sharp turnaround in applications. In the years 1997 through 2000, applications averaged about 3,300 MW per year. All applications in the years 1997 and 1998 resulted in plants that are now either operational or under construction. Of the 1999 applications, all those approved are now either under construction or about to begin construction. One 1999 project, the Metcalf energy center in San Jose, has only recently been approved and is under construction.[27] The applications remained high in the year 2000 and jumped sharply in 2001, largely in response to the very high electricity prices. Therefore, in terms of the goal of calling forth increased supply, restructuring has been a complete success.

As of the end of the year 2000, none of this new supply was yet operational and, as of mid-2001, only 1,400 MW of this new capacity was on-line. Of the three plants now operational, one, a peaking plant with nameplate capacity of 320 MW, first went on-line in late June 2001, and two combined cycle plants with total nameplate capacity of 1,100 MW went on-line in early July 2001. In addition, 500 MW of peaker capacity, applications for which were filed in March 2001 or later, went on-line during summer or fall 2001. Table 3.3 provides basic data on those post-restructuring plants currently on-line, and Table 3.4 provides similar data for

[25]Delivered electricity from many renewables, particularly wind and solar, are significantly smaller than suggested by the nameplate capacity.

[26]For example, the California Energy Commission shows a graph that looks somewhat like Figure 3.9 on its web site, but with far less new capacity constructed in the 1980s. The difference is that the California Energy Commission graph excludes all nuclear power plants and small QFs.

[27]The approval was blocked for around two years by objections raised by Cisco Systems. Environmental groups, including the Sierra Club and the American Lung Association, endorsed this plant.

TABLE 3.3

Electricity-Generating Plants Going On-Line after Restructuring

Project	*Applicant/ Host*	*Size (megawatts)*	*Project Type*	*Location*	*AFC Filing Date [1]*	*Date Deemed Data Adequate[2]*	*Date Approved*	*Construction Start Date*	*Date On-Line*
Sunrise Power	Texaco Global Gas & Power	320 MW	Simple Cycle	Fellows, Kern County (Peaker)	Dec. 21, 1998	Feb. 1999	12/6/00	Dec. 2000	Jun. 27, 2001
Sutter Power	Calpine	540 MW	Combined Cycle	Yuba City area, Sutter County	Dec. 15, 1997	Jan. 1998	4/14/99	Jul. 1999	Jul. 2, 2001
Los Medanos Energy Center	Calpine	555 MW	Combined Cycle	Pittsburg, Contra Costa County	Jun. 15, 1998	Jul. 1998	8/17/99	Sept. 17, 1999	Jul. 9, 2001
Calpeak Border	Calpine	49.5 MW	Simple Cycle	Otay Mesa, San Diego County	Jun. 16, 2001	Jun. 18, 2001	7/11/01		Oct. 27, 2001
Calpeak Escondido	Calpine	49.5 MW	Simple Cycle	Escondido, San Diego County	May 8, 2001	May 16, 2001	6/6/01		Sept. 30, 2001

Alliance Century	Alliance Colton LLC	40 MW	Simple Cycle	Colton, San Bernardino County	Mar. 23, 2001	Apr. 5, 2001	4/25/01	Sept. 11, 2001
Alliance Drews	Alliance Colton LLC	40 MW	Simple Cycle	Colton, San Bernardino County	Mar. 23, 2001	Apr. 5, 2001	4/25/01	Aug.16, 2001
Hanford Energy Park Peaker	GWF Power Systems	95 MW	Simple Cycle	Hanford, Kings County	Apr. 5, 2001	Apr. 11, 2001	5/10/01	Sept. 3, 2001
Indigo Units 1, 2, and 3	Wildflower Energy LLP	135 MW	Simple Cycle	Palm Springs, Riverside County	Mar. 7, 2001	Mar. 16, 2001	4/4/01	Jul. 26, 2001 Unit 3, 9/1/01
Larkspur	Wildflower Energy LLP	90 MW	Simple Cycle	San Diego, San Diego County	Mar. 7, 2001	Mar. 16, 2001	4/4/01	Jul. 13, 2001

SOURCE: California Energy Commission; web site: www.energy.ca.gov/sitingcases/approved.html
(1) Applicant's filing date of Application for Certification (AFC).
(2) Formal process begins following Executive Director recommendation and Commission acceptance of Data Adequacy of the AFC.

TABLE 3.4

Electricity-Generating Plants, Greater Than 300 MW, Approved after Restructuring, Not Yet On-Line

Project	*Applicant/ Host*	*Size*	*Project Type*	*Location*	*AFC Filing Date [1]*	*Date Deemed Data Adequate[2]*	*Date Approved*	*Construction Start Date % Completed*	*Estimated On-Line*
Blythe Energy	Wisvest	520 MW	Combined Cycle	Blythe, Riverside County	Dec. 9, 1999	Mar. 2000	3/21/01	Apr. 27, 2001, 10% complete	Jul. 2004
Contra Costa Repower	Southern Energy	530 MW	Combined Cycle	Antioch, Contra Costa County	Jan. 31, 2000	May 2000	5/30/01	Aug. 1, 2001, 1% complete	Jun. 2003
Delta Energy Center	Calpine and Bechtel	880 MW	Combined Cycle	Pittsburg, Contra Costa County	Dec. 18, 1998	Feb. 1999	2/9/00	Apr. 2000, 58% complete	Apr. 2002
Elk Hills	Sempra/ OXY	500 MW	Combined Cycle	Elk Hills, Kern County	Feb. 24, 1999	Jun. 1999	12/6/00	May 7, 2001, 8% complete	Mar. 2003 (simple cycle 3/2002)
High Desert	Inland Group and Constellation Energy	720 MW	Combined Cycle	Victorville, San Bernardino County	Jun. 30, 1997	Dec. 1997	5/3/00	May 1, 2001, 11% complete	Jul. 2003
Huntington Beach Modernization	AES	450 MW	Combined Cycle	Huntington Beach, Orange County	Dec. 1, 2000	Feb. 7, 2001	5/10/01	May 1, 2001, 95% complete	Nov. 2001

La Paloma	PG&E National Energy Group	1,048 MW	Combined Cycle	McKittrick area, Kern County	Aug. 12, 1998	Aug. 1998	10/6/99	Jan. 2000, 70% complete	4/02 turbine #1, 5/02 #2, #3, 6/02 #4
Metcalf Energy Center	Calpine and Bechtel	600 MW	Combined Cycle	San Jose, Santa Clara County	Apr. 30, 1999	Jun. 1999	9/24/01		
(Western) Midway-Sunset	ARCO Western Energy Company	500 MW	Combined Cycle	McKittrick, Kern County	Dec. 22, 1999	Mar. 2000	3/21/01	Mar. 2002	Jul. 2004
Moss Landing	Duke Energy	1,060 MW	Combined Cycle	Moss Landing, Monterey County	May 7, 1999	Aug. 1999	10/25/00	Nov. 2000, 40% complete	Jun. 2002
Mountain-view	Thermo Ecotek	1,056 MW	Combined Cycle	San Bernardino County	Feb. 1, 2000	May 2000	3/21/01	Aug. 21, 2001, 1% complete	Jun. 2003

TABLE 3.4 *(continued)*

Project	*Applicant/ Host*	*Size*	*Project Type*	*Location*	*AFC Filing Date [1]*	*Date Deemed Data Adequate[2]*	*Date Approved*	*Construction Estimated Start Date % Completed*	*On-Line*
Otay Mesa	Otay Mesa Generating Company, LLC (Calpine Corporation)	510 MW	Combined Cycle	Otay Mesa area, San Diego County	Aug. 2, 1999	Oct. 1999	4/18/01	Aug. 24, 2001, 0% complete	Jul. 2003
Pastoria	Enron	750 MW	Combined Cycle	Tejon Ranch, Kern County	Nov. 30, 1999	Jan. 2000	12/20/00	Jun. 1, 2001, 1% complete	Jan. 2003
Three Mountain Power	Ogden Pacific Power	500 MW	Combined Cycle	Burney, Shasta County	Mar. 3, 1999	Jun. 1999	5/16/01	Sept. 2001, 0% complete	Jan. 2004

SOURCE: California Energy Commission; web site: www.energy.ca.gov/sitingcases/approved.html

those plants (300 MW or greater) that have been approved, but are not yet on-line.

Supply and Demand Summary

As of May 2000, much new electricity generation capacity was under construction; however, approval of new plants remained slow and had been delayed by the abortive Proposition 9 campaign. Electricity use—both average and peak load—continued to grow. The entire western region was facing very tight electricity supplies. Electricity imports into California were reduced because of the needs in neighboring states. The amount of reserve generation capacity was shrinking rapidly. California's electricity system was facing a very severe challenge stemming from regional changes, not simply California changes.

WHOLESALE PRICE INCREASES

The growing challenge showed up temporarily in increased regional spot prices in May but had become readily apparent in June 2000, when wholesale electricity prices in all of the regional markets, including the California PX, reached[28] peaks above $400/MWh. In July, peak prices soared even higher on all of the western markets, with all markets showing highest prices in excess of $500/MWh during one week.

Figure 3.11 shows price ranges, estimated in *Western Price Survey,* on a weekly basis from April 1, 2000, through September 30, 2000. Data are present for three market centers—the California-Oregon Border[29] (COB), receipt points along the Columbia River (Mid-C), and the Palo Verde nuclear power plant switchyard, Arizona—and for exchanges on the PX. For each market, Figure 3.11 shows the lowest and highest prices estimated in *Western Price Survey* for each week.

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[28]The Energy NewsData publication *Clearing Up* reported on June 16, 2000: "Markets throughout the region were drawn into price spikes. Power prices at Palo Verde/Four Corners and Mid-Columbia/COB moved upward in huge increments all week, with almost no overlap from day to day. At the peak of trading on Wednesday Palo Verde peak power was fetching 450 to 500 mills/KWh. COB and Mid-C had been over 400 mills/KWh."

[29]COB is located at the interconnection point at the California/Oregon border of the Pacific Northwest/Pacific Southwest AC Intertie. *Western Price Survey* is published by Energy NewsData Corporation of Seattle, Washington, www.newsdata.com.

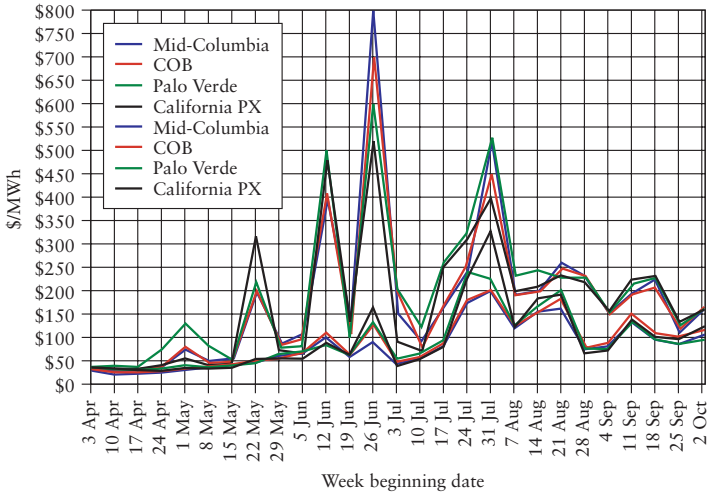

FIGURE 3.11: Spot Wholesale Prices, Western Electricity Markets through September 2000, Minimum and Maximum Prices

Figure 3.12 shows the off-peak and peak electricity spot prices at the same four locations as in Figure 3.11. Here the data are the average of the highest and the lowest peak prices estimated during the various weeks, as well as the average of the highest and the lowest off-peak prices. The tight markets in the West led to

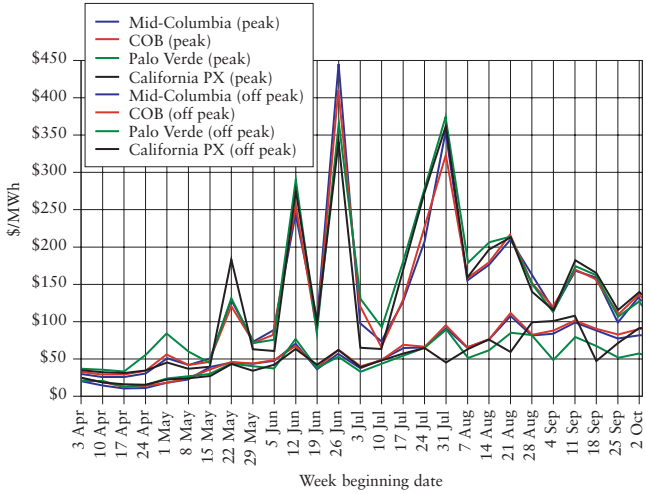

FIGURE 3.12: Peak and Off-Peak Spot Wholesale Prices, Western Electricity Markets through September 2000, Average of Minimum and Maximum Prices

large percentage increases in not only the peak period wholesale prices but also the off-peak wholesale electricity prices.

Although those not carefully watching the electricity system might not have noticed the changes in supply and demand conditions described above, the dramatic changes in the wholesale price made the challenge obvious. Moreover, by that time, SDG&E had gone past the price control period and its retail prices increased correspondingly. Newspapers throughout the state covered the story. The first lawsuit was filed. The public had become aware that something dramatic was happening to the electricity system. There was a severe challenge to be overcome. Nevertheless, reasonable solutions were available and, at that point, the crisis could have been averted.

WHY DID WHOLESALE PRICES INCREASE SO MUCH?

The question of why wholesale prices increased so much in California and throughout the West is a subject of debate and of litigation. Some of the issues are inherent in the changes in supply and demand; others resulted from the restructured system; still others stemmed from the actions taken by various participants in the system, including manipulation of market rules.

Most fundamentally, the growth in demand with no growth in generation capacity led to a very tight market for electricity throughout the West. Peak loads and the system resources to meet these loads were almost equal to one another, so that there was very little unused generation capacity. In addition, the nature of the supply functions and the demand functions in this market implied that small variations in supply or demand for electricity could lead to disproportionately large variations in price. This characteristic—small quantity changes leading to very large price changes—is to be expected in wholesale electricity markets, absent sharp changes in their structure. California's retail price control made the matter worse. In addition, there was probably an increase in the degree to which merchant generators were able to exercise market power to raise wholesale prices. These issues will be discussed in the following sections.

Short-Run Supply Functions for Electricity

On the supply side of the market, the essential feature is capacity limitation of generating facilities. Each generator is constrained by its physical capacity to produce electricity. The operator can choose to produce below capacity or to pursue maintenance and

repair policies that influence the fraction of time that the plant operates, but cannot generate electricity from a plant at rates beyond its capacity. In California, many plants are quite similar to one another so that many would have similar marginal costs if they were operating significantly below capacity. For these reasons, the short-run supply curve for the system took on a "hockey stick" shape. For a wide range of system-wide outputs, the supply price increased gradually with increases in generation. However, as the system neared full capacity, larger fractions of the generating units operated at full capacity and more of the inefficient high-cost units were brought into service. At some point, even these very inefficient plants would be operating at full capacity. This physical capacity constraint leads to the hockey stick shape of the supply curve.[30]

Figure 3.13 illustrates this short-run supply function using data from the PX during July 1999. Each dot represents an observation

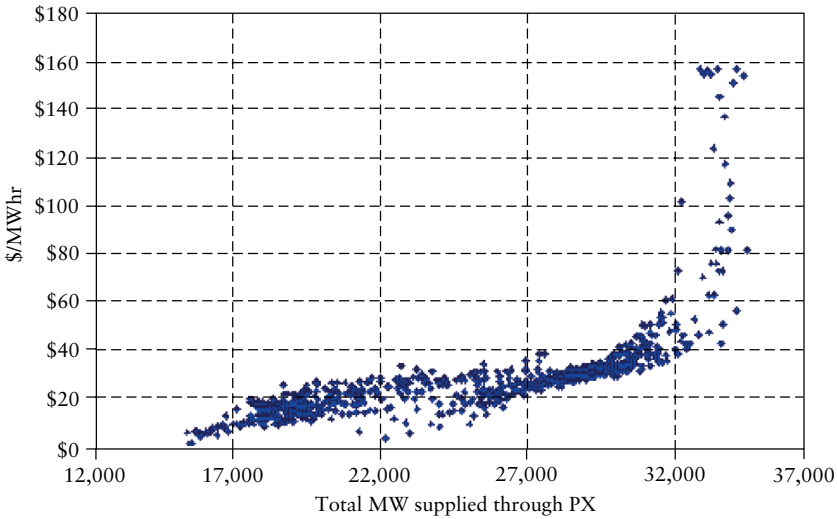

FIGURE 3.13: Price versus Quantity for California PX, July 1999
SOURCE: California Energy Commission, www.energy.ca.gov/electricity/wepr

[30]Whether this curve is both a supply curve and a marginal cost curve depends on whether the generators at the margin were bidding their units at their marginal cost. If so, then this is both a marginal cost curve and a supply curve. If not, it is still a supply curve.

of an hourly price and quantity supplied during the month of July. The horizontal axis represents the MW of electricity committed through the PX for given hours during the month. As such, it includes both electricity generated in California and that imported to California. It excludes electricity purchased by municipal utilities under medium-term and long-term contracts, since that electricity was not exchanged on the PX. The vertical axis represents the market-clearing price for electricity for those hours. Under the assumption that the power exchange was operating as intended, the vertical axis is approximately equal to the highest marginal cost of generating facilities, given the total quantity sold.

The particular points were determined by market equilibria on different days of the month and during different times of the day. During the middle of the day, particularly on weekdays, the demand for electricity was high; during the night demand was low. A process through which the demand function has moved and the supply function has remained approximately stationary has generated these points. Thus, the set of dots traces out a short-run supply curve for electricity. If the sellers were bidding their particular quantities at their marginal costs, then this set of dots also traces out a marginal cost curve.

The hockey stick character of the short-run supply function is obvious. For quantities between 20,000 and 30,000 MW the price varied generally between $10 and $30 per MWh. However, for quantities around 34,000 MW the locus of points became nearly vertical.

This hockey stick shape of the short-run supply function is the result of the physical capacity limitations in the generating system, as discussed above, which would be inherent in this system regardless of the restructuring.

Contractual commitments throughout the rest of the West played a significant role in the shape of the short-run supply functions in California. Given the contractual commitments, available imports into California responded very little in the short run to changing prices in California. Had they been more responsive, the total quantity of electricity made available in California would not have had such a vertical section of the supply curve, since imports into California would have increased in response to price increases.

In the longer run—say over the course of several months—imports to California would be more responsive to the average price

expected during a day.[31] Over this period, demand could adjust and contracts could be renegotiated. For example, in Washington, aluminum plants and other intense users of electricity shut down and eliminated their use of electricity altogether in response to the electricity price increases. A significant share of that electricity would then be available for exportation to California. Therefore, the medium-term supply curve can be expected to be somewhat less steeply sloped than the one in Figure 3.13.

The isolated nature of the west coast electricity market also played a role. Because there are only very limited interconnections between the western region of the United States and the rest of the nation, price differentials between the Pacific Coast and the Midwest could persist indefinitely without electricity being transmitted from the Midwest to the west coast. Thus, even in the long run, given that regional isolation, changing imports from the rest of the country would play little or no role in influencing the shape of the supply curve for electricity into California.

In what follows, I will abstractly represent the short-run supply curve by a line that generally has a shape as shown in Figure 3.13 but that has quantities more responsive to price. However, the electricity generated in California and the imports to California will be separated in order to clarify the analysis.

Short-Run Demand Functions for Electricity

The use of electricity declines in response to increases in the retail electricity price even over a period of months, although over a many-month period the demand declines by a far smaller percentage than the retail price increases. Using conventional estimates of the elasticity of demand[32] for electricity—the percentage reduction in demand motivated by a 1 percent increase in price—each average retail price increase of 10 percent could be expected to motivate a roughly 1–3 percent reduction in demand over the short run, perhaps over several months.

[31]This implies that analyses of the California electricity markets that use data on the intra-day adjustment of imports into California in order to estimate the slope of the import supply curve will systematically underestimate the impact of prices on supply to California.

[32]Here, and for other numerical examples, a short-run elasticity of demand for electricity will be approximated as 0.1–0.3. Long-run elasticities have typically been estimated to be as large as 1.0.

Therefore, to motivate a 4 percent reduction in demand, an amount that would roughly compensate for the demand increase from 1999 to 2000, would require a 13–40 percent increase in retail price. The average retail price of electricity[33] was about 12 cents/KWh (equivalent to $120/MWh) and the retail price would need to rise by between 1.6 cents/KWh and 4.8 cents/KWh to motivate that demand reduction, which would correspond to an increase of $16/MWh to $48/MWh.[34]

However, because of the retail price control in California, the increase in wholesale price did not lead to any increase in the retail price for most California customers. Therefore, when the wholesale market price increased, the average consumer of electricity in California did not face a direct economic motivation to reduce demand. In addition, the investor-owned utilities did not have the legal option to reduce their wholesale purchases[35] but were required to acquire as much electricity as their customers used. With this economic isolation between the wholesale price and the retail price, demand for electricity at the wholesale level in California was made very unresponsive to the wholesale price.

There were demand responses for customers of the municipal utilities in California or for industrial customers purchasing directly from generators or marketers. Most other utilities had sufficient medium-term and long-term contracts so that retail rate increases were not required, at least not immediately. Therefore, these demand responses were muted or eliminated. In fact, almost all utilities sell electricity at prices corresponding to the average cost of acquiring that electricity and acquire their electricity dominantly under long-term contracts. Therefore, the average cost— and thus the retail price—changes by far less than the spot wholesale price. Thus, even without retail price caps, spot wholesale price changes translate to far smaller changes in retail prices for most utilities.

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[33]This is actually the bundled price of electricity and electricity delivery services. The conventional estimates of demand elasticity were based on this bundled combination.

[34]This amount is roughly the price increase that was allowed by the CPUC in January and March 2001, an average price increase of 4 cents/KWh.

[35]Utilities could choose to reduce their purchases through the PX by underscheduling the amount of electricity that they would need to satisfy their customers. If they underscheduled on the PX, they would be required to purchase additional electricity on the CAISO imbalance market. One way or the other, the utility had to acquire all electricity its customers used.

Some large industrial customers and state agencies, such as the California Department of Water Resources, had contracts to buy electricity at prices responsive to wholesale prices. And some had contracts to purchase a fixed quantity of electricity at a negotiated price. If this quantity could be resold, that user had an incentive to reduce electricity use when prices increased. In addition, some consumers chose to reduce electricity use because they understood that there was an "energy crisis" and they chose to help the state by reducing demand.

The net result is that short-run demand functions for electricity, when measured at the wholesale level of the market, tend to be almost vertical. That is, very large increases in wholesale spot prices lead to only small reductions in demand. Thus, I show demand functions as steeply sloping, only somewhat responsive to prices.

There were demand responses in other states for those utilities whose retail rates increased. Some companies—for example, those making aluminum in the Pacific Northwest—shut down all production, therefore completely eliminating their need for electricity; however, those responses would be reflected in the availability of net import supply of electricity to California. These demand (and supply) responses in other states would have the effect of making the supply curve for electricity more responsive to price than illustrated in Figure 3.13.

Impacts of Supply and Demand Changes on Wholesale Prices

Figure 3.14 illustrates what the combined impact of increased California electricity demand and reduced supply of electricity imports would be on the spot wholesale price of electricity if the wholesale price increase had been allowed to translate to retail prices in California. The horizontal axis on this graph represents sales of electricity on the wholesale market for California use; the vertical axis represents the spot wholesale price of that electricity.

The upward-sloping hockey-stick-shaped lines together represent the supply function. The green line (the left-most of the three) represents the supply function for electricity generated in California. The two blue lines (the right-most lines) add the supply of electricity imports into California to the supply of electricity generated in California. The dashed blue line represents the 1999 situation with normal import availability; the solid blue

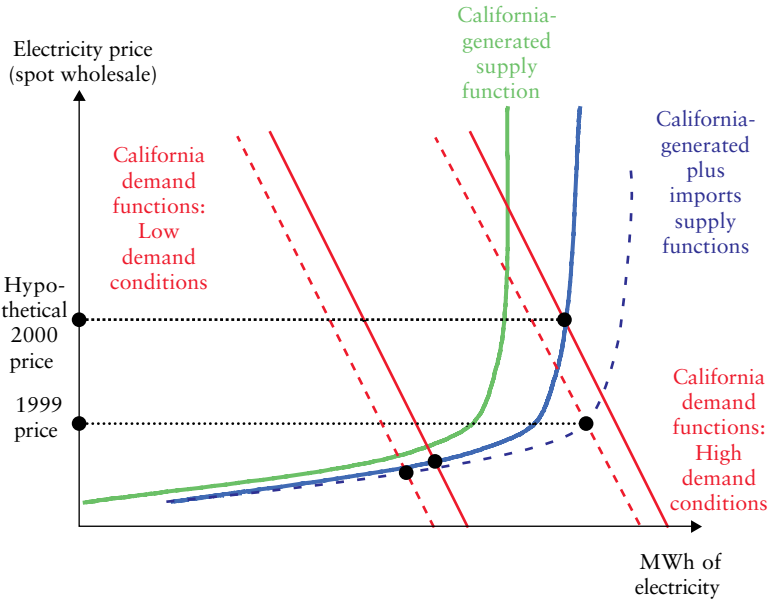

FIGURE 3.14: Market Equilibria without Retail Price Control

line represents the 2000 situation with sharply reduced import availability.

There are four downward-sloping lines representing different California electricity demand functions, under the assumption that the increases in the average wholesale prices facing California investor-owned utilities were passed on to retail customers.[36] The right-most two represent the demand conditions in the years 1999 and 2000, with the dashed line representing 1999 and the solid line representing 2000. The left-most two represent low demand conditions and will be discussed at a later point.

Black dots are drawn at the 1999 and 2000 points of intersection between the California demand functions and the electricity supply functions (California-generated plus imports to California). Broken lines show the spot prices that would occur in the two years, under the counter-factual assumption that wholesale prices of electricity were passed on to retail customers. In response to increased retail prices, California consumers would find ways of reducing electricity use: turning off lights, unplugging spare

[36]If the entire spot market price increase were passed on to the retail customers, the demand functions would be less steep than shown here: there would be greater demand reductions in response to the price increases.

refrigerators, turning off air conditioners, or adjusting the thermostat. Even with the demand response plus the supply response to higher prices, the spot wholesale electricity price would have increased significantly, as shown in this graph.

Similarly, Figure 3.15 illustrates the impact of changed demand and supply on the wholesale price of electricity, given the reality of the retail price caps in California. The only difference between this graph and the graph of Figure 3.14 is that the demand functions are much steeper in Figure 3.15; price increases lead to much smaller reductions in demand. The demand functions are much steeper because California's retail price cap did not allow wholesale prices of electricity to be passed on to retail customers. Therefore there was not a direct economic incentive for California consumers to find ways of reducing electricity use.

Figure 3.15 shows that absent the demand response, the spot wholesale electricity price increased dramatically. Spot wholesale price increases were limited somewhat by the increased supply of California-generated electricity as prices increased and by the increase in imports to California in response to the price jumps (in-

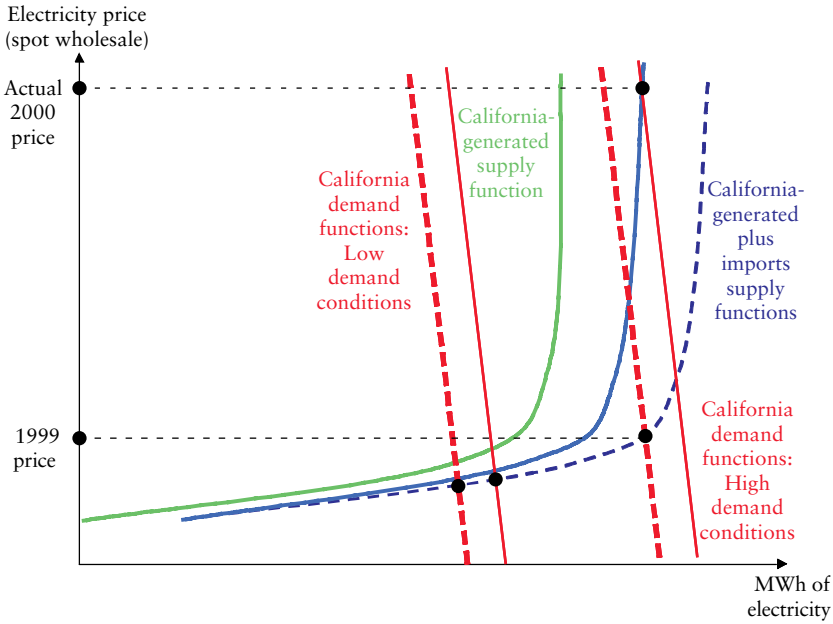

FIGURE 3.15: Market Equilibria with Retail Price Control

creases relative to the downward shift in supply resulting from the reduced rainfall in the Pacific Northwest and the increased use in the Pacific Southwest). But absent demand reduction by consumers, spot wholesale prices jumped much more than they would have, had retail prices been allowed to increase along with the wholesale electricity prices.

In both of these graphs, in addition to the 1999 and 2000 demand functions, are two other, lower quantity demand functions. These left two demand functions represent the operation of the system during those times when there was sufficient excess capacity in the system. Modest increases in the demand function coupled with the decrease in import supply would lead to only small changes in price (the vertical positions of the two dots are very similar to one another). The response of electricity supply to prices, when there is adequate capacity, would serve to limit greatly the increases in wholesale prices resulting from demand increases, even if demand is very unresponsive to prices.

A comparison of Figure 3.14 to Figure 3.15 suggests that, had retail prices been allowed to move with wholesale prices in California, there still would have been a challenge and there still would have been wholesale price increases. However, because consumers would observe these price increases and be motivated to reduce demand, the wholesale price increases would have been much smaller than they in fact were. Thus California alone, with no changes in regulation from the neighboring states, could have sharply reduced the wholesale price increases that each of the states faced. But California political leaders chose not to take this action.

Figure 3.15 gives a primary explanation of why wholesale prices jumped greatly once the system neared capacity after having remained relatively stable for several years when there was adequate capacity.[37]

These figures also suggest that wholesale price volatility should not be viewed as an anomaly of the California situation but rather as inherent in electricity markets, as long as both the supply functions and the demand functions are very steep at the point of their intersection. The California price caps simply made a difficult situation much worse.

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[37]See EMF Report 17, "Prices and Emissions in a Restructured Electricity Industry" (Energy Modeling Forum, Stanford University, May 2001) for a model-based analysis of the sensitivity of electricity prices to economic growth rates. This phenomenon is illustrated quantitatively by that study.

Increases in Electricity Generation Costs: Natural Gas Prices

Increasing demand for natural gas, coupled with limitations on pipeline capacity into California and within California, led to increases in the natural gas price, increasing electricity generation costs. Figure 3.16 (data provided by Enerfax.com, publisher of *Enerfax Daily,* "North America's Free Natural Gas and Power Prices and News Information Source," www.enerfax.com) below shows increases in the California natural gas spot prices from April 1998 through October 2000. Note that in this period price more than doubled from $2.50 per million Btu to $6.00 per million Btu.

It is possible to estimate the impact of this natural gas price increase on the costs of operating a typical new combined-cycle plant or an inefficient unit.

Heat rates of a new combined-cycle power plant may be as low as 6.8 million Btu per MWh. For such a new combined-cycle power plant, when natural gas was selling for $2.50 per million Btu, the cost for natural gas alone would be roughly $17/MWh. When the natural gas price increased to $6 per million Btu, this cost of natural gas alone would increase to $41, a jump of $24/MWh, and the marginal cost of electricity generation would increase by $24/MWh. If these plants were at the high cost end of

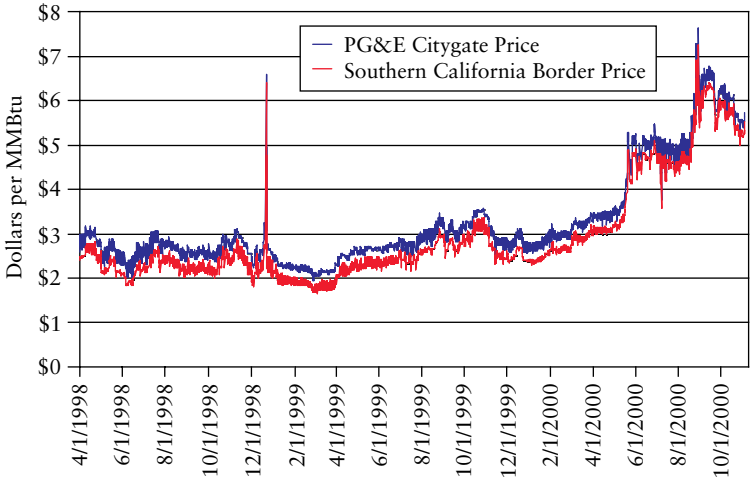

FIGURE 3.16: Natural Gas Spot Prices in California: PG&E Citygate and Southern California Border

SOURCE: Enerfax.com

the merit order and thus determining the wholesale price, absent demand adjustment, wholesale price of electricity would increase by $24/MWh. In terms of Figure 3.15, the supply curve for California-generated electricity would shift upward by $24/MWh; the import supply component of the total supply function would not adjust; thus, the total supply function would shift upward by somewhat less than $24/MWh. With price controls in place, there would be only a small further adjustment of demand and the wholesale price of electricity could increase by almost $24/MWh.

The cost increase would be greater, however, for older, less efficient plants. Older plants may have twice the heat rate as the newer plants. For example, the SCE Highgrove 1 and 2 plants have heat rates estimated to be about 13.4 million Btu per MWh.[38] For these older plants, the marginal cost of the natural gas alone would be roughly $34/MWh when gas was selling for $2.50 per million Btu. However, when the natural gas price increased to $6, this marginal cost would increase to roughly $80/MWh, a jump of $46/MWh. In terms of Figure 3.15, the high-price portions of the nearly vertical section of the supply curve for California-generated electricity would shift upward by $46/MWh; the total supply function would shift upward by somewhat less than $46/MWh.

In times of excess capacity, the older inefficient plant would be rarely, if ever, used, but as total generation increased, the old inefficient plants became the source of the additional generation. Thus, the old inefficient plants, rather than the newer power plants, became the highest-cost units used and their operating costs determined the marginal cost of electricity generation. Therefore, two factors worked together to increase wholesale prices: the marginal electricity-generating units used to set the wholesale price shifted from efficient plants to old inefficient plants and the natural gas price used by these plants increased. These two factors together implied that the natural gas costs of the marginal electricity-generating unit increased from $17/MWh to $80/MWh, an increase of $63/MWh, which directly increased the wholesale price of electricity. In terms of Figure 3.15, this change represents a combination of the movement upward along the total supply function and a shift upward of that function together leading to the price change.

[38]Data estimated from Joel B. Klein, "The Use of Heat Rates in Production Cost Modeling and Market Modeling" (April 17, 1998, California Energy Commission).

In addition, as the system reaches full capacity and the use of natural gas increases, the quantity of natural gas needed exceeds the quantity purchased under long-term contracts. Therefore, the additional natural gas is purchased on the spot market. Thus, although long-term contract prices for natural gas may have influenced pricing behavior when the system was well below full capacity, at full capacity the spot market price of natural gas determines the marginal cost of electricity generation.

The simultaneous shift to use of the inefficient plants, the shift from contract natural gas to spot natural gas markets, and the overall increase in the natural gas price could account for a large share of the increase in the wholesale price of electricity occurring in this period. It should be recognized that these shifts did not *cause* the wholesale electricity price increase but rather were a response to the changing supply and demand conditions that were the primary cause of the wholesale price increases.

It should be noted that, because most of the electricity generated from gas-fired units is based on combined-cycle units, the average cost of electricity generation increased by far less than did the marginal cost. This increase in the natural gas price, therefore, led to increases in the profits of most electricity generators running gas-fired plants. If there had been long-term contracts in place, even contracts indexed for the price of natural gas, the cost that the utilities would have paid to acquire their electricity would have increased by far less than it actually did.

Increases in Electricity Generation Costs: RECLAIM Credits and Annual Emissions Constraints

A change in the price of an additional input was significant. In 1993 the South Coast Air Quality Management District instituted the REgional Clean Air Incentives Market (RECLAIM) to meet the target of NOx and SOx emissions. The RECLAIM program, a market-based approach to regulation, required emitters of NOx and SOx to acquire enough RECLAIM Trading Credit permits to match their actual emissions each year. Through 1998, there was an excess supply of permits in the market, primarily because the number of allocated permits exceeded the normal emissions levels. However, the number of allowed permits was decreasing sharply, and during 1999 the number of allocated permits had diminished to be equal to the total emissions. Through compliance year 1999, the price of NOx trading credits ranged from $1,500

to $3,000 per ton. For compliance year 2000, although permits had been selling for approximately $4,300 per ton in 1999, the prices for the first ten months of the year 2000 increased to an average of about $45,000 per ton.[39]

The significance of this price increase for electricity is related to the emissions characteristics of electricity-generating plants. A typical base-load gas-fired generating unit releases about 0.1 pounds of NOx per MWh of electricity generated. At a price of $2,000 per ton, or $1.00 per pound, the price of RECLAIM credits would add an insignificant amount (10 cents per MWh) to the marginal cost of such units. When the price soared to $45,000 per ton, or $22.50 per pound, this added about $2.25/MWh for a typical base-load gas-fired generating unit, an increase that still was small in comparison to the wholesale price increase. In terms of Figure 3.15, some of the flat, lower portions of the supply curve for California-generated electricity would shift upward by about $2.25/MWh, but this, itself, would have no impact on the high price equilibrium.

Old gas-fired turbines, however, may emit up to four pounds of NOx per MWh. For such units, the price of $2,000 per ton would add to the marginal cost of electricity generation about $4/MWh, still small but significant. However, when the price soared to $45,000 per ton, for the old turbine releasing four pounds of NOx per MWh of electricity generated, this increased the marginal cost by $90/MWh.

During times of energy emergencies, when all available generating units were operating, old gas-fired turbines, many of which were very inefficient, would set the marginal cost of generating electricity in California. For these plants, the incremental cost of natural gas could have been $80/MWh and the incremental cost of RECLAIM credits could have been $90/MWh. Adding these two costs together, in terms of Figure 3.15, the very highest-price portions of the nearly vertical section of the supply curve for California-generated electricity would shift upward by $170/MWh, resulting in much greater increases in wholesale prices for the very limited times in which the system was operating at that point.

Here too, it should be recognized that these shifts did not *cause* the wholesale electricity price increase but rather were a response to the changing supply and demand conditions that were

[39] "White Paper on Stabilization of NOx RTC Prices," South Coast Air Quality Management District, web site: http://www.aqmd.gov/hb/010123a.html.

the primary cause of the wholesale price increases. The significance of the increase in RECLAIM costs is that the uppermost part of the vertical section of the California electricity supply function was made more nearly vertical by the tight limitations on the RECLAIM market.

In addition, many plants, both inside and outside the South Coast Air Quality Management District, had annual emissions limits—in particular, annual NOx emissions limits. Absent retrofits to install new pollution control equipment, annual emissions limits translate directly to limits on the total MWh of electricity that can be generated from an individual unit in a given year.

Violation of those emissions limits was punishable by large fines and therefore, to avoid fines, generators had an incentive to reduce their electricity generation from those units. In one well-publicized case, the South Coast Air Quality Management District brought legal action against AES Corporation for exceeding its annual allowable emissions by about 600 tons. In December 2000, the District and AES reached a settlement in which AES agreed to pay a $17 million penalty, equivalent to about $28,000 per ton of NOx *in addition to* purchasing emissions credits to make up for the excess emissions, installing state-of-the-art air pollution controls on three of its power plants, and deducting the year 2000 excess emissions from its future year allocations. (Ironically, although AES was fined because it produced more electricity in 2000 than allowable within its annual emissions limits, California officials have accused AES of withholding generation in 2000—that is, of producing too little electricity.)

A power plant facing an annual emissions limit, and therefore able to generate only a limited number of annual MWh, incurs an opportunity cost in addition to the marginal cost of electricity generation. The opportunity cost exists because generating an additional MWh of electricity at one time eliminates the opportunity for the plant to generate an additional MWh of electricity at some other time. The cost to the plant owner of that eliminated opportunity—the "opportunity cost" of generation—is measured by the additional profit that could be earned at that other time from generating an additional MWh. More precisely, the "other time" must be where the firm expects not to operate at capacity and therefore when it could generate and sell another MWh. The opportunity cost is equal to the maximum additional profit that could be earned at such a time.

A profit-maximizing generator would not be willing to sell electricity unless the price it expected to receive were at least as great as its marginal cost *plus* opportunity cost. A firm bidding competitively thus would not offer a bid equal to its marginal cost but rather would offer one equal to its marginal cost *plus* opportunity cost. Therefore, annual emissions limits lead competitively bidding generators to increase bid prices above marginal cost and further reduce electricity generation. Bidding to sell electricity at a price equal to marginal cost *plus* opportunity cost is thus *not* an indicator that the firm is gaming the market or exercising market power but rather that the firm is bidding competitively, recognizing its annual emissions limits.

Possible Exercise of Market Power by Generators

A second possible explanation for the rapid increase in wholesale price is the exercise of market power by electricity generators selling into California markets. This explanation continues to have great political appeal, partly because, if true, it can be asserted that the challenge was not caused by flaws of the restructured system but rather by actions of corporations supplying electricity to California.

As discussed in Chapter 2, the theory underlying the operation of the California PX was that each generator of electricity would bid in its available supplies at its marginal cost. The quantities would be ranked in merit order from lowest cost to highest cost until sufficient quantities were available. The market-clearing price would be set equal to the marginal cost of the highest-cost unit needed to satisfy the demand for electricity on the wholesale market. Each supply that was bid into the market at a marginal cost below the market-clearing price would be able to sell its electricity at the market-clearing price. Any quantity bid at a higher marginal cost would not be sold. In this way, in theory, a price would be set for each hour such that all the electricity-generating units with marginal costs lower than that price would be called on to supply electricity and all the units with marginal costs higher than that price would not be called on.

That theory was based firmly on a belief that the price bids of the generators would always be equal to their marginal cost of generating electricity, which was itself dependent on an assumption that each generating unit was being bid independently of every other unit. However, for generators owning multiple units, it could be expected that the bidding would be coordinated

among the various generating units;[40] the units would not be bidding independently of one another.

A company that owned several generators could choose to bid at prices higher than its marginal cost for some of its generating units (or to refrain from bidding at all). For those units whose bid was below the market-clearing price, such a bidding strategy would be irrelevant, since the payment would be based on the final market-clearing price. However, if a unit increased its bid sufficiently so that the bid became higher than the market-clearing price, the result would be the same as if that firm withheld from bidding entirely. The relevant portion of the supply curve—that below the new market-clearing price—would be moved to the left and the market-clearing price would be driven upward. As long as that firm had additional units that bid below the market-clearing price, it could make additional profits from those units.

In terms of Figure 3.15, the impact of such bidding would be to shift the California-generated and the total supply function toward the left, thereby increasing the equilibrium wholesale price. When the system was near full capacity, this reduction in supply would have increased the market-clearing price substantially. The firm could then make additional profits from the rest of its generating units, which would draw the higher price, but would have to trade those additional profits against the lost profits from the unit that increased its bid.

The success of these strategies was made more likely by the California retail price control and the resulting very steep demand curve, as can be seen by comparing the price responses to the fixed supply shift illustrated in Figures 3.14 and 3.15. Since in market clearing, as suggested by Figure 3.15, there would be little reduction in the observed generation of electricity, and since there would be an incentive for many of the generators to follow similar strategies, there might be little changes in the mix of electricity ultimately generated by the various companies. Thus, aggregate quantity data might not readily show the impacts of the strategy.

The incentive for firms to increase their bids in this way was intensified by the operations of the CAISO, whose mission was to

[40]Under the U.S. antitrust laws, companies are not prohibited from coordinating their price bids internally, that is, within one company. However, any coordination of price bids between two or more companies would generally be illegal under the Sherman Antitrust Act.

ensure that there would always be sufficient electricity available to avoid blackouts. In order to do this, the CAISO stood ready to purchase electricity on the imbalance market at any price up to some price cap, which varied over time (see the section "Wholesale Price Control Regimes"). Since this quantity to be purchased did not vary significantly with the prices of the electricity offered for sale at that time, the very short-run demand curve was very steep.

Generators understood this willingness, which would have provided a significant incentive for generators to alter their bidding into the PX. In particular, firms increasing their bids on electricity that they offered for sale could be expected to trade the possibility of increased profits against the risk that they would bid too high and not be able to sell their electricity at all. However, on most days the CAISO needed to acquire additional quantities of electricity on the real-time imbalance market the next day. Thus, firms that bid too much might not sell any electricity on the PX but could sell it the next day on the real-time market. Moreover, because there was an incentive for utilities to acquire significant quantities of electricity from CAISO real-time purchases,[41] the suppliers could have reasonable confidence there would be a demand for their electricity. Therefore, the dual market reduced the risk facing firms that were tempted to increase their bid prices greatly on the PX.

In addition, any incentive to withhold supplies to increase the price would be made stronger by the lack of long-term contracts for the utilities to buy electricity.[42] If a generator had a long-term fixed-price contract to sell its electricity, then even under the incentives described above, that generator would have no incentive to withhold its generation. Withholding would increase the market-clearing price, but that firm would reap no benefits from the increased price, given the fixed-price contractual sales of electricity. However, the deliberate public policy decision to discourage such long-term contracts ensured

[41]As will be discussed at a later point, the CAISO price caps provided an incentive for utilities to underschedule their electricity needs on the PX. Therefore they had to acquire significant quantities on the imbalance market.

[42]Some of the generators did have long-term contracts with marketers, not utilities. Such contracts would have reduced incentives to reduce electricity supply but would not have reduced the incentives on the marketers to exercise market power in ways described above.

that there would be strong incentives to withhold supply to drive prices upward.

Whether exercise of market power was important to the price jumps early in 2000 or whether the fundamental issue was the basic problems of supply and demand growth is still subject to disagreement.[43] Nevertheless, several issues do seem clear.

First, the restructured system included short-run incentives for firms operating fully within the regulations promulgated by the CPUC to submit bids above their marginal cost when the entire system was near capacity. When the system is near capacity, the hockey stick character of the supply function, in particular the nearly vertical section of the supply function, is relevant. In that situation, small changes in electricity supply could lead to large changes in price, or equivalently, large changes in price could be associated with only small changes in quantity supplied. Under those circumstances there is an incentive for firms to submit bids significantly in excess of their marginal cost if they believe those price bids can influence the revenues they receive for the electricity they sell.[44] However, the amount above marginal cost these firms could be expected to bid depends on several factors that have not been adequately quantified: the short-run and medium-run responsiveness to wholesale prices of electricity imports into California, the beliefs of generators about impacts of current price increases on future electricity demand reductions and consequently future profit reductions, the perceived risk of FERC-imposed

[43]For a more complete theoretical and empirical examination of the exercise of market power through September 1999, see Severin Borenstein, James Bushnell, and Frank Wolak,"Diagnosing Market Power in California's Deregulated Wholesale Electricity Market," University of California Energy Institute (August 2000). For analyses of market power during the summer of 2000, see P. Joskow and E. Kahn, "A Quantitative Analysis of Pricing Behavior in California's Wholesale Electricity Market During Summer 2000" (NBER Working Paper 8157, March 2001); Scott Harvey and William Hogan, "On the Exercise of Market Power Through Strategic Withholding in California" (April 2001), available at http://ksghome. harvard. edu/~.whogan.cbg.Ksg/; Paul Joskow and Edward Kahn, "Identifying the Exercise of Market Power: Refining the Estimates" (July 5, 2001), available at http://econ-www.mit.edu/faculty/pjoskow/papers.htm.

[44]Note that when the system is well below full capacity, there is some incentive for firms with multiple units to bid above the marginal cost, although the incentive is small and the optimal bid exceeds the marginal costs by only a small amount. This is because in that circumstance large reductions in supply result in only small price increases.

penalties for firms found to be bidding significantly above costs, and the supply and demand responses of the municipal utilities.

Second, pricing goods for sale anywhere in the economy exactly at marginal cost is probably the exception, not the rule. The issue is the degree of divergence between price and marginal cost. Non-marginal-cost pricing should not be a surprise.

Third, the requirement imposed on the utilities that they buy and sell all of their electricity on the PX or the CAISO precluded them from purchasing electricity through bilateral contracts or on other markets. To the extent that the state-chartered markets—the PX and the CAISO—had flawed rules that encouraged the exercise of market power, the ability to exit these markets would have been valuable to the utilities; however, the California rules prohibited that exit, giving the PX and CAISO monopoly positions.

There was a clear challenge to the state to the extent that firms were withholding supplies entirely or bidding well above their marginal costs. Market rules did provide opportunities for firms to increase their bids above their costs of operations perfectly legally. California public officials, however, were expressing outrage that the firms might have responded to incentives created by public policy. The challenge then, to the extent market power was a fundamental problem, was to change the behavior of the firms without changing the market rules, or to change the market rules. As will be discussed below, the state actions focused on trying to change the behavior of firms or to strengthen the price controls that had been imposed on the markets. The federal actions focused more on modifying the market structures.

CALIFORNIA-CONTROLLED WHOLESALE PRICE CONTROLS

As the challenge became more severe, California officials began calling on the FERC to limit the increases in wholesale electricity prices in California through the imposition of wholesale price controls. However, price caps had been features of the California wholesale market from soon after the approval of the restructuring plans, and the management of those price caps was in the hands of California organizations.

In March 1998, the CAISO observed large increases in prices for some ancillary services and proposed price caps in the ancillary services markets and the imbalance market as the solution. In July

1998, the FERC responded, authorizing the CAISO to reject any bids to provide ancillary services whenever the CAISO believed those bids were higher than appropriate. The FERC explained that, because the CAISO had a responsibility as procurer of ancillary services, it had the discretion to reject bids that were too high.[45] With this decision, the FERC gave the State of California discretionary power over the price caps applicable to the CAISO.

Subsequently, the FERC authorized the CAISO to treat the real-time imbalance market similarly, allowing the CAISO to adopt price caps for its purchases in the imbalance (real-time) energy market. The FERC allowed the CAISO to set the purchase price at whatever level it deemed necessary and appropriate, thereby ceding a significant price control authority to a state institution. The FERC granted this authority until November 1999; however, the FERC offered the CAISO the opportunity to ask to extend the duration of its authority if the CAISO determined that there remained serious problems in the design of the markets.

The CAISO set an initial price cap of $250/MWh for its purchases in both the imbalance market and the ancillary services markets. In September 1999, the CAISO proposed to extend the price cap authority for one year, until November 2000. That same month the CAISO raised the price cap from $250 to $750/MWh, but indicated that it might lower the caps to $500 in June 2000 or to some unspecified amount if it determined that the markets were not workably competitive. The FERC accepted these proposals. In July 2000, the CAISO did lower the price cap to $500/MWh and in August 2000 further reduced the purchase price cap to $250/MWh. The CAISO applied the same price cap for ancillary services and for real-time electricity purchases.

Although the FERC authorized these price caps for the CAISO, the FERC never authorized formal price caps for sales on the PX. Nevertheless, as discussed in Chapter 2, because buyers could choose to purchase from either the PX or the CAISO, the CAISO price caps translated into price caps for the wholesale price in each of the markets.

Thus the price caps for the CAISO markets created incentives for sales and purchase transactions to be moved to the imbalance

[45]Subsequently the FERC ruled that the CAISO's maximum purchase price authority was acceptable because the CAISO did not have the authority to require sellers to bid into its markets and thus could not dictate the prices of those sellers.

market (or ancillary services markets), greatly increasing the transactions in the real-time market. However, the imbalance market had never been designed for large-volume transactions. Since these transactions were conducted in real time, there could never be an assurance that sufficient electricity would be available for the expected consumption. Therefore, the price-cap-induced movement of transactions from the day-ahead and day-of markets to the real-time imbalance market significantly increased the likelihood that there would be insufficient electricity to satisfy customer needs and therefore significantly increased the probability of blackouts, which fortunately did not occur during the period of growing challenge.

This incentive to move transactions to the CAISO imbalance market was so strong that by November the PX data no longer gave any indication of a conventional supply curve for electricity. Figure 3.17 shows the prices versus the quantities of electricity sold on the PX for November 2000, using the same data measured in the same way as Figure 3.13. Figure 3.17 is based on observations of prices and quantities of electricity transacted on the PX in November 2000, whereas Figure 3.13 provides information for July 1999.

The wide spread of prices for any given quantity primarily resulted from transactions moving away from the PX and toward

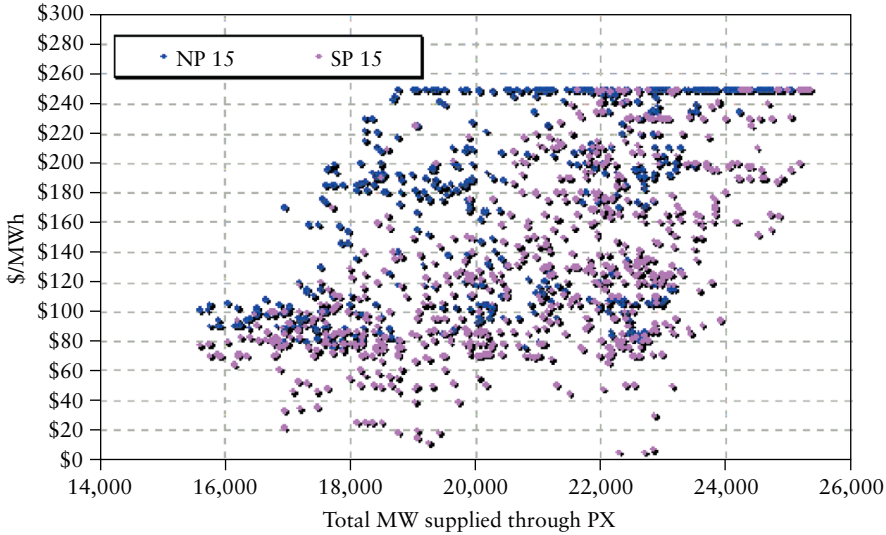

FIGURE 3.17: Price versus Quantity for California PX, November 2000

SOURCE: California Energy Commission, www.energy.ca.gov/electricity/wepr

the CAISO imbalance market. By November 2000, as much as 30 percent of the electricity (10,000 MW) was sometimes bought and sold on the imbalance market, not going through the PX at all. In Figure 3.13, the supply curve became almost vertical for total transactions of about 34,000 MW through the PX. Because so much electricity was being transacted directly on the imbalance market, the maximum quantities being bought and sold on the PX during November never exceeded 26,000 MW, even though the peak load most weekdays was between 32,000 MW and 34,000 MW.

Figure 3.17 also shows the direct result on the PX prices of the CAISO price caps, with all PX prices remaining at or below $250/MWh.

In addition, price controls themselves created incentives for California suppliers to sell their electricity out of state whenever the out-of-state prices exceeded the California price caps. For example, in the final week of June 2000 the Bonneville Power Administration and utilities and the Pacific Northwest outbid California for electricity, reportedly paying as much as $1400/MWh.

Single-state price caps in a regionally interconnected market proved, not surprisingly, to be a recipe for creating shortages. Fortunately, however, the shortages were relatively mild during the period of growing challenge and did not escalate to blackouts.

Governor Gray Davis seemed to understand these facts but placed blame on the generators, not on the state market structure. Looking back on the period of growing crisis, Governor Davis, in his January 2001 State of the State speech, asserted:

> *On many days, 10 to 12 percent of the electricity generated in California leaves our state in search of even more exorbitant prices elsewhere. On some occasions, the merchant generators have brought the State to the very brink of blackouts by refusing to sell us back our own power because they could find higher prices elsewhere.*

Although the governor was aware that price caps in California were creating problems, he continued to advocate even greater price control authority.

Given that price caps on the CAISO imbalance market, absent explicit price caps on the PX, were creating more difficulties than would coordinated CAISO price caps, there were at least two possible policy directions: eliminate the price caps on the imbalance mar-

ket or increase the scope of price controls, imposing price controls on the PX as well.

California political leaders chose the latter strategy. In August 2000, after being encouraged by Governor Davis, the PX proposed to the FERC that it be allowed to change from implicit price caps to explicit price caps. It proposed to impose maximum prices on demand and supply bids for the day-ahead and the day-of markets to be equal to $350/MWh, a figure calculated as the sum of the $250 price cap on CAISO purchases of imbalance energy plus a $100/MWh estimate of the cost the CAISO at that time was paying for replacement reserves.[46]

Soon thereafter, in September 2000, also after urging by Governor Davis, the CAISO proposed to the FERC that it be allowed to further extend the termination date of CAISO purchase price cap authority beyond November 2000. In October, the three investor-owned utilities and The Utility Reform Network (TURN) filed a request to the FERC that would impose a price cap of $100/MWh for all electricity sales. The CPUC filed a motion requesting the $100/MWh price cap but with a set of defined exceptions.

California's electricity organizations were lining up behind price controls rather than correcting the fundamental flaws in its markets, a pattern that would continue beyond the challenge period and into the crisis period. As will be discussed in the following section, this strategy of continued pressure on the FERC for wholesale price controls was consistent with Gray Davis's challenge period policy framework.

In November 2000, the FERC took decisive steps to remove price cap authority from California organizations, denying the PX

[46]Price caps on the ancillary services markets, combined with the price caps on the imbalance market, could impose an effective limit on PX prices. Under CAISO procedures, offering electricity as replacement reserves could be a particularly profitable strategy whenever the generators believed the total supplies of electricity would not be adequate to meet the demands without drawing on the replacement reserves. A supplier could offer its capacity into the replacement reserves market and would receive $100/MWh of capacity each hour. If that electricity were sold, the supplier would receive an additional payment of $250/MWh, for a total payment of $350/MWh. If the probability of selling electricity were high, then that strategy would be as profitable as selling the same electricity on the PX for almost $350/MWh. In this case, the market-clearing price on the PX would be almost $350. The PX proposal was designed to set an explicit price cap equal to this implicit cap.

request for its price control authority and announcing that it was removing the CAISO price cap authority in sixty days. In the interim, it removed the authority from the CAISO to modify the price caps, freezing the CAISO price cap at the then current level of $250 for sixty days, until the price cap authority would disappear. The era of California-managed wholesale price controls was about to end.

In place of California-managed wholesale price controls, the FERC ordered that at the end of the sixty days the CAISO and PX auctions be changed to a "soft price cap" system that would limit market-clearing prices to $150/MWh but would allow market participants to submit bids over $150/MWh with appropriate cost verification. Such bids above $150/MWh could be paid "as bid," but they would not set the market-clearing price.

But before the end of the sixty days, the CAISO markets were on the edge of collapse. The CAISO was forced to declare Stage 2 emergencies for four days in a row and saw no end to the shortage. Blackouts were imminent. The electricity challenge was turning into a full-blown crisis. On December 8, 2000, Terry Winter, chief executive officer of the CAISO, asked the FERC to allow the CAISO to replace its $250/MWh price cap with a soft price cap system similar to the one scheduled for the end of the sixty days but with the interim break point set at $250/MWh. The FERC agreed immediately and California could then purchase electricity to avoid blackouts. Predictably, Governor Davis and the California legislature vilified Mr. Winter for that action, but his actions probably saved California from wide-scale blackouts during December. These FERC-controlled changes in price caps are discussed more fully in the following chapter.

THE FINANCIAL CHALLENGE

The high wholesale prices, the lack of long-term contracts, the divestiture of utility generation assets, and the retail price controls together created a tremendous financial challenge for the utilities, one that urgently needed to be addressed during the challenge period. In early 2000 the utilities had seen that there would be pressures on supply and demand for electricity and knew they faced a fundamental challenge, a challenge they could not surmount absent action by the governor, legislature, or the CPUC.

By the time the challenge became apparent, they had divested about 60 percent of their generating assets. Divestiture itself

would not have been particularly harmful if the utilities had replaced these generating assets with long-term contracts to acquire the electricity, perhaps at prices indexed to natural gas prices.[47] But they had not been allowed to do so.

As of mid-2000, the utilities could have reduced, but not eliminated, the risk of wholesale price increases if they had been able to enter long-term contracts to purchase electricity at fixed prices. In early spring, these contracts were being offered to the utilities. For example, in June and July several of the larger generators were offering to sell significant amounts of capacity with opening offer prices of about $50/MWh.[48] Prices were likely to have been lower than $50/MWh earlier in 2000. Both PG&E and SCE made requests of the CPUC and appealed to Governor Davis to allow them to enter such contracts. The initial response was quite negative.

On June 22, 2000, the CPUC decided, in a narrowly split vote, to allow the utilities to buy power outside the CAISO and the PX markets. However, the California Legislature subsequently overrode the decision, requesting that the CPUC demonstrate that allowing utilities to purchase energy from outside of the CAISO and the PX was in the public interest, a demonstration that the CPUC never provided. Thus the utilities were forced to continue purchasing and selling all electricity on these two markets.

However, in August, once prices had jumped sharply, the CPUC did file an order allowing the utilities to enter limited numbers of bilateral contracts. Even then, any purchases other than from the PX would either need preapproval or face an after-the-fact reasonableness review, whereas all purchases from the PX were considered per se reasonable. And without clear guidelines about the CPUC vision of reasonableness, utilities faced the prospect of being severely penalized if, retrospectively, their long-term contracting decisions turned out to be economically unattractive, but they could not expect to be rewarded if, retrospectively, their decisions turned out to be economically attractive. Throughout the challenge period—in fact, throughout the electricity crisis—the CPUC never adopted any guidelines and did not preapprove any contracts. These strong asymmetric

[47]In fact many municipal utilities had no generating assets at all. But they maintained portfolios of medium-term and long-term contracts under which they acquired electricity.

[48]Private communication from Robert Weisenmiller, based on his polling of many of the larger generators.

economic incentives gave the investor-owned utilities a significant incentive to rely on the PX and not enter into longer-term forward contracts to buy electricity. Thus, even this limited concession did not reasonably encourage long-term contracts.

This failure to encourage long-term contracts and the resultant overreliance on spot markets helped establish the financial challenge. The overreliance on spot markets ensured that when wholesale prices began to soar, the utilities would pay these high prices for almost half of the electricity they would need to serve their loads. This lack of reasonable risk management options was central to the financial challenge.

By fall 2000, the challenge was hitting the electric utilities with a tremendous force.[49] The restructured system left them selling electricity to their customers at an average price of about $65/MWh for the electricity (plus another $60/MWh for transmission, distribution, and other delivery services), yet the wholesale price of electricity ranged from $150/MWh to $1000/MWh for half of the electricity they were selling (see Figure 3.11). Almost one-half of the remainder from the QFs was already being purchased at high prices. Generation from their own hydroelectric assets and nuclear power plants accounted for only 30 percent of their electricity, thanks to the divestiture.

The accumulations into the transition accounts to pay for stranded costs quickly reversed, with large *negative* competition transition charges. Thus, the more electricity they sold, the more money they lost. But, unlike most other businesses, they were not allowed to tell their customers that, because the cost of the product was too high, they would not supply it. Not only were the utilities subsidizing all industrial, commercial, and residential customers, they were forced to continue doing so.

The utilities could readily project forward to the time when all of their financial assets would be spent and their credit would be gone. The option of medium- and long-term contracts was no longer helpful because the pricing being offered for medium- and long-term contracts had risen along with the spot wholesale prices.

During the challenge period the political institutions—the governor, the legislature, and the CPUC—needed to allow the wholesale price increases to be translated into retail prices. Without

[49]An excellent timeline of these events, compiled by Southern California Edison, appears on the web: www.sce.com/SC3/005_regul_info/005g_market/005g2_chronology.shtml.

reductions of the wholesale prices or corresponding increases of the retail prices, the utilities could project their own insolvency.

Once the financial imbalance became obvious, each of the utilities requested increases in retail rates to cover the average cost of the electricity they were selling. Even though there were price controls on the electricity sales, these price controls had been established to allow the utilities to accumulate sufficient revenues to pay for the stranded costs. Thus, it was perfectly logical that if the pricing structure were no longer serving the goal for which it was established—enabling the utilities to accumulate financial assets to pay for the stranded costs—it should not have been continued, especially since it was operating in exactly the opposite direction, reducing the financial assets available to pay for stranded costs.

The requests for retail price increases (often referred to as "rate relief") were made primarily to the CPUC and secondarily to Governor Davis. Through the challenge period, absolutely no rate relief was made available to the utilities. In fact, SDG&E, the only one of the three major investor-owned utilities that under AB 1890 would no longer be subject to retail price controls, remained free of the controls only for a limited time. The California Legislature voted to reimpose those controls.

With the political institutions—the CPUC, the governor, and the legislature—turning their backs on the legitimate requests of the utilities, PG&E and SCE sued the CPUC in Federal District Court. The utilities relied on the federal "filed rate doctrine," which requires states to pass the costs of electricity purchased subject to federal tariffs on to utility customers. The utilities interpreted federal tariffs to include FERC-approved tariffs.

In addition, utilities argued, "the CPUC's rulings also are unlawful in that they violate the Commerce, Takings, and Due Processes Clauses of the Constitution."

> *In particular, the Takings Clause requires the State to set retail rates that are not confiscatory. Rates are confiscatory if they fail to provide the utility a reasonable opportunity to recover its prudent costs of service and a fair rate of return commensurate with the risks undertaken. Confiscatory rates unlawfully interfere with reasonable investment-backed expectations.*[50]

[50]Both quotations from *Southern California Edison Company v. Loretta M. Lynch et al.,* Complaint for Injunctive and Declaratory Relief, November 13, 2000.

However, legal proceedings seldom proceed quickly, and this was no exception. The lawsuit remained in progress through the challenge period and the crisis, until SCE finally settled its suit in October 2001. The PG&E case is still proceeding in U.S. District Court.[51]

Although the challenge facing the investor-owned utilities could have been solved by early action from the governor, the CPUC, or the legislature, by the end of the November 2000 none of the appropriate policy responses had been forthcoming. Thus, by the end of the challenge period, they were facing a near-certain financial crisis, absent an abrupt state policy shift.

STATE POLICY RESPONSES DURING THE CHALLENGE PERIOD

On June 15, 2000, soon after the June price spikes, Governor Davis requested that Michael Kahn, Chairman of the Electricity Oversight Board, and Loretta Lynch, President of the CPUC, examine the causes of the blackout that had occurred in the San Francisco Bay Area and the associated wholesale price increases. Ms. Lynch and Mr. Kahn duly responded to Governor Davis's request and issued a report, which they forwarded to Governor Davis and posted on the CPUC web site.[52] The cover letter of the report, dated August 2, 2000, began:

> *Dear Governor Davis:*
> *In response to your letter of June 15th, included as Attachment 1, the attached report analyzes the electricity conditions facing California, including the Bay Area black-outs of June 14th and the circumstances giving rise to forced outages and related pricing problems. Your*

[51]On May 2, 2001, U.S. District Judge Ronald Lew dismissed as premature the PG&E lawsuit that sought to overrule decisions by the CPUC that PG&E was not entitled to recover money it had spent to buy electricity for its customers during the crisis. The judge ruled that the CPUC orders were not yet final, but were only interim orders. Judge Lew stated that PG&E could refile its suit when the CPUC orders were finalized. PG&E has done so.

[52]*California's Electricity Options And Challenges: Report To Governor Gray Davis.* The report is available on-line through the California Public Utilities Commission: http://www.cpuc.ca.gov/published/report/Table%20of%20Contents.htm.

> *concerns have proved well-founded in light of recent retail price escalations in San Diego and the state-wide wholesale price upsurges. The Bay Area outages and the San Diego price increases are only the first manifestations of problems in our electricity system.*

The first paragraph of the executive summary of the report stated:

> *California is experiencing major problems with electricity supply and pricing caused by policies and procedures adopted over the past ten years. This summer, California has seen both electricity price volatility—exemplified by huge increases in wholesale electric prices and increases in retail prices in San Diego—and supply and delivery system instability—culminating in unprecedented black-outs in the Bay Area. These serious, but thus far isolated, examples represent a precursor of what lies ahead for California's economy over the next 30 months. California's reliability deficits and retail price volatility may not improve in that time without a mid-course correction.*

Thus, very early in the process, Governor Davis was aware that there were important challenges facing California. Moreover, two of his appointees gave him broad advice and a set of specific recommendations designed to address the problems they had identified. But even after that report, California policy responses during the period of growing electricity challenges were surprisingly limited, relying almost entirely on efforts to establish or strengthen price controls at both the retail and wholesale levels.

One policy framework, articulated by Governor Davis, provided the guidance for California's response to the challenge. Price controls at both the wholesale and the retail level seemed to be the one and only goal of the State's policy framework during the challenge period. The State could enforce and expand retail price controls, which they did very aggressively, though they could not unilaterally impose wholesale price controls since the federal government, and particularly the FERC, had the primary jurisdiction over wholesale markets. Thus, Governor Davis orchestrated a broad campaign to urge the FERC to maintain and expand wholesale price controls.

Governor Davis articulated his overall strategy in a series of letters dated July 27, 2000, and summarized that strategy in a press release issued that day. Portions of that press release follow:[53]

SACRAMENTO—Governor Gray Davis today called on federal and state regulators to take swift action to extend the caps on wholesale electric rates in California and provide San Diego ratepayers with millions of dollars in refunds. . . .

In letters to two state regulatory agencies and two California-based panels charged with overseeing California's power market, Governor Davis called for a coordinated state effort to urge federal regulators to take strong measures to reduce power rates in both the short- and long-term.

The legislation signed into law in 1996 by Governor Pete Wilson to deregulate California's investor-owned electric utilities left state agencies and the Governor with limited options to regulate prices, Governor Davis noted. However, today's initiatives are designed to maximize the leverage of California's regulatory agencies with the Federal Energy Regulatory Commission. . . .

In letters released today, Governor Davis:

- *Called on the California Independent Systems Operator . . . to immediately apply to FERC for extension of its authority to establish price caps for wholesale power. . . . Governor Davis also requested the ISO to reduce the "wholesale price cap to the lowest reasonable level". . .*
- *Urged the California Public Utilities Commission (PUC) . . . to "take all actions necessary to assure that electricity supplies are adequate and that prices paid by California consumers are just and reasonable." He called on the Commission to file a petition with federal regulators next week to support extending wholesale price caps. He also urged the PUC to ask FERC to declare that no competitive market for energy currently exists in California—action that would support wholesale price caps.*

[53]This and other press releases can be reached through Governor Davis's home page: http://www. governor.ca.gov/state/govsite/gov_homepage.jsp.

- *Requested the Electricity Oversight Board . . . to take three actions at its August 1, 2000 meeting. They include: urging the ISO to petition FERC for continued authority to impose wholesale price caps; establish price caps at the lowest reasonable level; and file a petition with FERC requesting a finding that no competitive market exists in California. . . .*
- *Called on the California Power Exchange . . . to apply for caps on the price bid for wholesale electricity in the day-ahead and day-of "spot markets" that it operates. . . .*

In a separate letter to the PUC President Loretta Lynch, Governor Davis requested the PUC at its August 3, 2000 meeting to authorize the return of $100 million in refunds from the California Power Exchange to San Diego Gas & Electric ratepayers.

As discussed above, the PX and the CAISO both complied with the governor's request, submitting requests to the FERC to establish or extend their price control authority.

In addition, although the California Legislature took only very limited actions, they were consistent with the governor's overall strategy. Several bills were introduced, but never passed, to urge the FERC to impose price controls on the wholesale market. Assembly Joint Resolution No. 77, a joint resolution of the California Senate and Assembly, did gather sufficient votes to pass. It reiterated the wholesale price control strategy, resolving:

That the Electricity Oversight Board, working with the Public Utilities Commission, shall petition FERC to modify the Independent System Operator (ISO) tariffs to require that the prices in the energy and ancillary services markets are just and reasonable whether they result from the operation of these markets or other mechanisms.

It further resolved:

The Electricity Oversight Board shall direct the Independent System Operator to show cause why the price caps in the ancillary services and real-time energy markets should not be lowered to $100 per megawatt-hour immediately and continue until at least March 31, 2001.

In September, the California Legislature reestablished retail price controls in San Diego. Assembly Bill 265, authored by Assemblywoman Susan Davis (D–San Diego) and Senator Deirdre Alpert (D–Coronado), imposed retail price controls on electricity for consumers and small businesses in San Diego at $65/MWh (6.5 cents/KWh). The price control regime, slated to continue through December 2003, was made retroactive from June 1, 2000. This reduction of electricity prices could be expected to increase electricity demand and to exacerbate the electricity problems.

Gray Davis's policy framework, focusing entirely on price control, thus was fundamental to almost all the steps the State took during the challenge period. The State continued to force the investor-owned utilities to rely on wholesale spot markets, and thus the utilities were not able to begin to manage the wholesale price risks they faced. In addition to the reestablishment of retail price controls in San Diego, such controls were not relaxed for PG&E and SCE. No significant steps were taken to guard against the possibility of energy emergencies.

Only very limited positive steps were taken within California to go beyond Governor Davis's policy framework, namely, those taken to increase electricity supplies and decrease electricity demands. Governor Davis signed an executive order that directed "all California agencies involved in building new energy facilities to streamline the review process for siting new power plants without compromising environmental laws or public health and safety protections." The order required that "all state agencies involved in permitting new facilities must submit their review and findings within 100 days of receiving a completed application." That order could be expected to speed new construction but would have no impact on electricity supply during the challenge period or during the crisis. In September, Senate Bill 1388, authored by Senator Steve Peace (D–San Diego), was passed, speeding the approval process for new power plants.

State-owned buildings were directed to reduce their use of electricity, but only during serious energy emergencies.[54] Senate Bill 1194, authored by Senator Byron Sher (D–Palo Alto), and AB 995,

[54]The order was applicable only to Stage 2 and Stage 3 emergencies. See Chapter 4 for a discussion of these emergencies.

authored by Assemblyman Rod Wright (D–South Central Los Angeles), were signed into law. These extended in time the existing AB 1890 requirement of a separate electricity rate component, collected as a bypassable charge, to fund energy efficiency and conservation activities, public interest research and development, and development of renewable resources technology.

In short, other than imposing or urging others to impose electricity price controls, the State governmental bodies took remarkably few significant policy steps to avert the coming electricity crisis. Moreover, the State took no positive steps to avert the coming financial crisis, but rather, by reimposing price controls in San Diego, threatened to exacerbate the problems.

IN SUMMARY

Between 1997 and the autumn of 2000, the risk embedded in the restructured system, although perhaps not apparent to all participants in that system, had become a reality. California consumption of electricity grew slightly faster than historically, available imports in California dropped sharply as markets became much tighter throughout the West, new California generation capacity was being constructed but was not yet operational, virtually all California electricity generation units other than natural gas–fired were at full capacity, and as a result, production in California from existing gas-fired units increased sharply. The increase in use of gas-fired units implied not only that the efficient ones were on-line, but that the old inefficient plants were brought on-line as well. The inefficient ones used more natural gas and emitted more NOx and SOx than the newer, more efficient units, thereby increasing the marginal cost of generating electricity. The increase in the use of natural gas pushed up its price. The RECLAIM market experienced a massive jump in the price of emissions credits as the available supply of credits decreased. These factors together would contribute to the challenge.

During the summer and fall of 2000, the severe challenge demanded leadership and wisdom from California's political leaders. Mastering the challenge would not be easy after wholesale electricity prices had jumped during the summer of 2000. By that time, all meaningful solutions were likely to involve short-term economic sacrifices by many, including the

voters in California. Yet, as of the summer of 2000, there were important policy actions still possible that would have avoided a California electricity crisis and a financial crisis. However, California's political leaders never rose to the challenge. This failure of political leadership turned the challenge into a crisis.