

California State Auditor

B U R E A U O F S T A T E A U D I T S

Energy Deregulation:

*The Benefits of Competition Were
Undermined by Structural Flaws in the
Market, Unsuccessful Oversight, and
Uncontrollable Competitive Forces*



March 2001
2000-134.1R

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March 22, 2001

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The Governor of California
President pro Tempore of the Senate
Speaker of the Assembly
State Capitol
Sacramento, California 95814

Dear Governor and Legislative Leaders:

As requested by the Joint Legislative Audit Committee, the Bureau of State Audits presents its audit report concerning the operations of the California Independent System Operator (ISO) and its relationship with the Power Exchange (PX).

This report concludes that the failure of deregulation is not the result of any single cause, but rather of a complex combination of factors. Foremost among these are certain fundamental flaws in the structure of the power market. For instance, the requirement that the investor-owned utilities sell all the power they generated themselves and purchase all their electricity through sequential short-term markets operated by the ISO and PX. This requirement established a structure that allowed—even encouraged—strategic bidding through the underscheduling of the demand and supply of power on the part of both buyers and sellers in an effort to manipulate wholesale prices to their advantage. Strategic bidding is one factor that significantly contributed to high wholesale energy prices in the year 2000.

In addition, misjudgments on the part of regulators about the effectiveness of their corrective actions also contributed to the current crisis. Starting in 1998, market monitoring groups within the ISO and PX warned the Federal Energy Regulatory Commission (FERC) and the California Public Utilities Commission (CPUC) of potential problems with the market structure. Although hindsight has shown the accuracy of these predictions, neither FERC nor the CPUC fully or successfully addressed these concerns at the time.

Finally, in analyzing the factors contributing to the energy crisis, it is important to note that some were beyond any regulator or agency's control. Competitive market forces, such as the demand for electrical power that far outstripped the growth in supply, recent unusual weather patterns, the steep increase in the cost of natural gas, and costly air quality emissions requirements were all beyond the control of California regulators or the ISO and PX. Yet, all of these factors exerted considerable influence over wholesale market prices in the year 2000.

Respectfully submitted,

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SUMMARY

Audit Highlights . . .

Deregulation of California's electricity market has failed, not as the result of any single cause, but, rather of a complex combination of factors, including:

- ☑ *Fundamental flaws in the power markets that arose both because of the terms of the legislation mandating deregulation and because of the way various entities chose to implement that legislation.*
- ☑ *Deficiencies in the rules governing the power markets that were created, such as the requirement that investor-owned utilities sell all of the power they generated themselves and purchase all of their electricity through sequential short-term markets.*
- ☑ *The existence of sequential short-term markets that have encouraged some market participants to engage in strategic bidding, which has contributed to higher wholesale prices.*
- ☑ *Limitations placed by the regulators on the authority of the utilities*

continued on next page . . .

RESULTS IN BRIEF

When California took the national lead in the move toward electricity deregulation with the passage of AB 1890 in 1996, proponents promised lower retail prices and expanded power services. At that time, few could have imagined that less than five years later, consumers would face rolling blackouts and that two of the State's three investor-owned utilities would teeter on the edge of bankruptcy. Because the credit ratings of these utilities are so poor, the Legislature has been forced to authorize the State to purchase electricity in their place.

The fact that deregulation has failed to work is the result not of any single cause, but rather of a complex combination of factors. Foremost among these are certain fundamental flaws in the structure of the power market that arose both because of the terms of legislation mandating deregulation and because of the way various entities chose to implement that legislation. For instance, the California Public Utilities Commission (CPUC) mandated that the investor-owned utilities sell all the power they generated themselves and purchase all of their electricity through sequential short-term markets operated by the Power Exchange (PX) and the Independent System Operator (ISO). This requirement established a structure that allowed—even encouraged—both buyers and sellers to use strategic bidding through the underscheduling of the demand for and supply of power in an effort to manipulate wholesale prices to their advantage.

Underscheduling involves deliberately underestimating the amount of power that will be needed or available the next day. Strategic bidding was one factor that significantly contributed to high wholesale energy prices, and the accompanying underscheduling has frequently pushed the ISO to operate in a crisis mode to secure enough electricity to avoid blackouts. Additionally, the CPUC initially limited the investor-owned utilities' use of long-term contracts. Such contracts might have neutralized some of the effects of the jumps in wholesale prices that began during the summer of 2000. These prices currently remain at unprecedented levels. However, after the CPUC authorized the increased use of this type of contract in March 2000,

to buy power from generators pursuant to long-term agreements, and the hesitation of the utilities to more fully use their authority to enter long-term agreements, thereby missing opportunities to neutralize the effects of the jumps in wholesale prices during the summer of 2000.

- Misjudgments on the part of regulators as to the efficacy of their corrective actions, including decisions made by the Federal Energy Regulatory Commission and the California Public Utilities Commission.*
 - Forces outside the control of any regulator or agency, such as last year's unusual weather patterns and the steep increases in the cost of natural gas.*
-

investor-owned utilities still chose not to use them as a hedge against summer price spikes to the extent they could have. This turned out to be an expensive choice. For example, to the extent that the investor-owned utilities did use long-term contracts, they saved roughly \$706 million from May through September 2000 according to the PX.

In addition to these flaws in the structure of the market, misjudgments on the part of regulators as to the effectiveness of their corrective actions also contributed to the current crisis. Starting in 1998, market-monitoring groups within the ISO and PX warned the Federal Energy Regulatory Commission (FERC) and the CPUC of potential problems with the market structure and rules. Although hindsight has shown the accuracy of these predictions, neither FERC nor the CPUC fully or successfully addressed these concerns at the time. When FERC did act in response to the escalating energy crisis, it focused only on modifying the market design rather than on investigating and imposing sanctions against possible abusers of market power, believing that because California's markets are still developing, altering the market rules was the best way to correct design and implementation flaws and to deal with scarce supply.

When analyzing the factors contributing to the energy crisis, it is important to note that some were outside the scope of any regulator or agency. Certain market forces, such as recent unusual weather patterns and the steep increases in the cost of natural gas, were beyond the control of California regulators or the PX and ISO, yet both of these factors have exerted considerable influence over wholesale market prices. Over the past year, a number of such forces exacerbated the State's electricity situation, including a growth in demand for electrical power that far outstripped the growth in supply and the increased costs for meeting air quality emissions requirements. Moreover, few new plants have been built in the western region in general in the last decade, despite the fact that growth in population and industry has increased the demand for electricity throughout the region.

Several recent events have further changed the already fluid nature of the current deregulated electricity market in California. Effective December 15, 2000, FERC terminated the authority of investor-owned utilities to sell generation they owned or controlled through contract into the PX market. As part of the same December order, FERC also terminated the PX's wholesale tariffs that enabled it to operate as a mandatory exchange that the

investor-owned utilities must trade in. These two actions caused the PX market to suspend all wholesale energy trading as of January 31, 2001. Finally, because the worsening financial condition of the investor-owned utilities had eroded their credit with power generators, beginning in January 2001 the State stepped in to purchase electricity on their behalf.

RECOMMENDATIONS

Eliminate the Opportunity for Strategic Bidding

Market participants were using the sequential structure of the PX and ISO electricity markets to strategically bid through underscheduling in the PX market, effectively driving large amounts of energy sales and purchases into the ISO's markets. To reduce market participants' opportunity for strategic bidding through underscheduling, the ISO should do the following:

- Eliminate its real-time markets and execute forward contracts with generators to provide imbalance energy and reserves for reliability services.
- Cease to purchase ancillary services in the spot market and instead meet its forecasted purchases of ancillary services through sealed bids.
- Purchase any short-term ancillary services needed at individually determined prices.
- Consider the option of contracting for generation capacity.

Avoid Using a Single State Wholesale Price Cap

Because in some peak demand hours the ISO price cap becomes the targeted bid price for both buyers and sellers in the PX and sellers can bid into the ISO's market through out-of-market transactions, which are not subject to the price cap, it is unclear whether the price cap is effective, and it may result in higher energy prices. Therefore, if the ISO is unsuccessful in limiting its spot market purchases to very small amounts, the use of price caps should be confined to times when markets are found to be noncompetitive and supply is being withheld to force prices higher.

Give the ISO Additional Authority for Scheduling Power Plant Maintenance

In an effort to avoid the problems encountered in California during the winter of 2000, when scheduled plant outages coincided with high demand and unscheduled outages to cause severe shortages of electricity, the ISO should coordinate with power generators over the next two to three years, or until a competitive market is established, in scheduling plant maintenance outages. This may not necessarily require that the ISO determine outage schedules, but it will at a minimum require generator participation in scheduling known outages well in advance and in keeping to the established schedule.

Limit the Amount of Market Data Published on Web Sites

Although data have been published only after the fact, when coupled with the published ISO data and PX pricing models, these data allowed market participants to begin to develop their own models and bidding strategies and to check their bidding strategy assumptions and adjust them where necessary. Although recent events have caused the PX to cease trading, the ISO continues to publish a considerable amount of data from its markets. Therefore, it should do the following:

- Avoid making available to the public any new oversight and market-monitoring models it develops.
- Delay making public for at least one year data concerning bidding and the winning bids. This is especially critical for information concerning long-term contracts the ISO may be a party to.

AGENCY COMMENTS

The ISO stated that it agreed with the basic conclusions of the report, particularly with the major causes of California's high wholesale electricity prices during the year 2000. The ISO also agreed with the fundamental objectives of the recommendations but disagreed with some of the more detailed aspects of particular recommendations or believed additional detail and analysis would be needed to determine the advisability of the recommendations.

The PX expressed its appreciation at being able to review the draft audit report but chose not to respond. ■

INTRODUCTION

BACKGROUND

On June 14, 2000, Pacific Gas and Electric Company (PG&E) interrupted service to almost 100,000 of its customers in the San Francisco Bay Area for the first time in its history. As the temperature that afternoon reached an unseasonably high 103 degrees, over three hours of rolling blackouts shut down air conditioners and industrial production. This event prompted the governor to ask the California Public Utilities Commission (CPUC) and the Electricity Oversight Board (EOB) to investigate the cause of the blackouts, citing the electric system's central role in ensuring "the health and safety of every Californian as well as California's continued economic growth." The joint report by the CPUC and EOB concluded that high demand and short supply in the San Francisco Bay Area, further constrained by power transmission limitations combined with system stability problems, led to the blackouts. Moreover, the report stated that the conditions seen in the San Francisco Bay Area and elsewhere in the State were "only the first manifestations of problems in our electricity system."

Indeed, California's electricity problems were just beginning. Throughout the summer of 2000, wholesale electricity spot prices at the California Power Exchange (PX), at that time the market through which the State's three investor-owned utilities were required to purchase and sell their power, reached very high levels. This had different effects in different areas of the State. Because by early 2000 San Diego Gas & Electric Company (SDG&E) had met certain cost recovery terms under the State's 1996 electricity restructuring statute, AB 1890, it was allowed to pass on to its customers the high wholesale electricity prices it was paying at the PX. This caused electricity rates in the area to more than double over summer 1999 prices and sparked extensive media coverage, as well as calls for legislative action. In response, the Legislature and the governor took steps to temporarily freeze the electricity rates paid by SDG&E consumers at rates below the true wholesale cost of electricity but above those paid before the year 2000.

The State's electricity restructuring law prohibited California's other two major investor-owned utility companies from passing their wholesale electricity prices directly on to consumers because, unlike SDG&E, PG&E and Southern California Edison (SCE) had not yet met certain conditions of the restructuring statute and were therefore still subject to a retail price freeze. As a result, PG&E and SCE reported losing billions of dollars over the summer of 2000. As electricity prices continued to rise in the months that followed, these losses grew, bringing the two utilities to the brink of bankruptcy by the end of the year. Moreover, because the credit status of these two investor-owned utilities inhibited their entering into contracts with generators, the State has had to buy power to meet a portion of these utilities' daily needs since mid-January 2001. Appendix A further outlines legislation that has been introduced or that has passed and been signed by the governor in an effort to correct the State's electricity problems.

GENERAL SYSTEM DEFICIENCIES

Although experts have cited many possible causes for the State's current power crisis, they generally agree on certain underlying problems with the electric system. These problems are not the focus of this report; nonetheless, addressing them is critical to ensuring long-term electric reliability and price stability in California.

- **Rapidly expanding demand.** Due to population expansion and rapid economic growth, electricity demand within the State has increased by more than 3 percent in each of the past two years.
- **Inadequate supply.** Although supply has expanded in the State, it has not kept pace with demand. Data from the California Energy Commission indicate that only three generating plants larger than 50 megawatts (MW) were built in the State from 1996 to 2000: one 240 MW plant in 1996 and two plants (123 MW and 158 MW) in 1997, for a total of 521 MW of new generation.
- **Inadequate transmission.** Certain areas of the State, such as the San Francisco peninsula, have limited transmission capacity. Thus, when demand for electricity reaches a certain level, the infrastructure in these areas limits the amount of power they receive, which may lead to blackouts.

THE RESTRUCTURING OF CALIFORNIA'S ELECTRICITY INDUSTRY

National Steps Toward Restructuring

Prior to the restructuring of the electricity industry, California's investor-owned utilities both generated and delivered the majority of the power used in the State. These utilities, like utilities in other states, were vertically integrated monopolies, meaning that they owned and operated their own power generation, transmission, and distribution facilities and were solely responsible for providing electric service to a defined portion of the State. The investor-owned utilities were interconnected to the extent that they could buy and sell electricity from one another as needed, but consumers within the utilities' defined service area were typically limited to purchasing power from the investor-owned utility where the consumer was located. As monopolies, the investor-owned utilities were subject to state and federal government regulation: The CPUC oversaw retail rates in California, while the Federal Energy Regulatory Commission (FERC) ensured that wholesale rates for electricity nationwide were "just and reasonable."

From the late 1970s through 1996, Congress passed a series of laws and FERC issued orders that moved the nation toward opening up the supply of electricity to competition. In 1978, Congress passed the Public Utilities Regulatory Policies Act requiring investor-owned utilities throughout the country to:

- Purchase electricity from "qualifying facilities" that produce power from alternative sources, such as wind and solid waste.
- Partially open their transmission systems to qualifying facilities so that electricity could be transferred to neighboring utilities' service areas.

In 1992, the Energy Policy Act broadened FERC's authority to order investor-owned utilities to make their systems available to transfer electricity produced by qualifying facilities.

In April 1996, FERC further encouraged electricity restructuring by issuing Order No. 888, which required investor-owned utilities to:

- File “open access transmission tariffs” that contained minimum terms and conditions of nondiscriminatory transmission access.
- Separate or “functionally unbundle” their generation and transmission so that transmission fees would be apparent to the ratepayer.
- Consider creating an “independent system operator” to operate transmission systems in place of the investor-owned utilities, thereby ensuring nondiscriminatory transmission access.

All of these actions were intended to create an environment that encouraged competition from generation facilities that were not traditional transmission and distribution facilities.

California’s Deregulation Process

In 1992, prompted by the Energy Policy Act and California’s high electricity rates, the CPUC began a comprehensive review of the electricity industry that led, in 1994, to a formal rulemaking proceeding to consider possible approaches to deregulation. By December 1995 and January 1996, the CPUC had adopted a set of policies to guide the utilities in restructuring their operations. Under these policies, in response to concerns raised by FERC, investor-owned utilities were encouraged to voluntarily transfer ownership of at least 50 percent of their fossil generation facilities to unrelated parties and required to transfer control, but not ownership, of their transmission facilities to an independent system operator. The CPUC also called for the creation of a power exchange, through which the utilities would be required to sell any electricity generated by facilities they still owned and to purchase all electricity required to meet demand.

In response to these new policies, the Legislature in 1996 passed AB 1890, codifying many of the CPUC’s recommendations. The legislation created two nonprofit, public-benefit corporations, the California Independent System Operator (ISO) and the PX, as well as the EOB to oversee the PX and ISO. The Legislature

also froze the retail rates a utility could charge its consumers until March 31, 2002, or earlier if the utility had fully recovered certain costs.

Under the restructured electricity scheme, retail consumers were allowed to choose their electricity suppliers; they were no longer obligated to purchase their power from the utility that serviced their area. However, these consumers were not obligated to switch. It was assumed that the result of all these actions would be an overall reduction in California's electric rates of at least 20 percent as of April 1, 2002. Municipal utilities, rural irrigation districts, and their customers were exempt from AB 1890.

Market Structure: The Roles of the PX and ISO

Under the deregulated market system, which began operating in March 1998, utilities and other large electricity purchasers—for example, large industrial consumers and companies providing competing retail service—acquired the energy they needed through the wholesale electricity market. Non-utilities could purchase this electricity through the PX or through bilateral contract agreements directly with the electricity generators. The State's investor-owned utilities were required to sell and purchase all of their power through the PX until March 2002 or until the CPUC ruled that they had recovered certain costs, whichever occurred first.¹

Of the several markets run by the PX, the day-ahead market was the largest. In this market, buyers requested the amount of electricity they anticipated needing for each hour of the next day and stipulated the prices they were willing to pay. At the same time, sellers stated the amount of energy they could produce and the prices they required for each of those hours. Once the PX had received all of the demand and supply bids, it matched them. The highest-priced supply bid necessary for meeting demand during any given hour would set the single market-clearing price to be paid by all buyers to all sellers for energy purchased for that hour. Beginning in June 1999, the PX also offered a block-forward market, in which market participants could make longer-term deals for electricity at set prices. The CPUC had to approve the amount of energy that investor-owned utilities wished to purchase using this arrangement.

¹ In its December 15, 2000, order, the FERC eliminated the State's requirement that the investor-owned utilities sell all of their generation into, and buy all their generation from, the PX.

Once the PX had matched blocks of supply and demand in one of its markets, it submitted a schedule of this information to the ISO. In this respect, the PX served as a scheduling coordinator. In addition to the PX, more than 40 other scheduling coordinators throughout the State serve entities that are not required to or choose not to buy or sell electricity through the PX. Each scheduling coordinator submits matched supply and demand schedules to the ISO for the entities it serves. Once the ISO received all of the schedules for the next day, it compared these to the capabilities of the transmission system. If it determined that more electricity had been scheduled to flow across a given line than that line could transmit—a situation known as “congestion”—it rerouted the energy through a different path, thus avoiding overloading the transmission system.

The ISO was also and continues to be responsible for procuring ancillary services for each day. Ancillary services consist of energy used for several different purposes, one of which is to balance the system in real time. For example, although the gross levels of energy that will be demanded and supplied are estimated 24 hours in advance, in real time demand can exceed supply to some degree and vice versa. The ISO monitors the real-time system functions and balances them by ordering increases or decreases in the amount of energy supplied into the system. These transactions are known as “imbalance energy” purchases. If the ISO lets the differences between supply and demand become too great, the whole electric grid is at risk of crashing.

The other ancillary services the ISO procures are reserves used as a safety net in case a power generator unexpectedly breaks down or is otherwise not available to produce electricity. These services include the capacity to produce electricity. The ISO purchases or “reserves” these types of services. Ancillary services are ranked based on how quickly they can be made available if needed.

The ISO conducts several market auctions to meet its needs. Generators that want to provide ancillary services to the ISO submit bids for these services, and the ISO selects a certain amount of each type of service based on price. Oftentimes the ISO has a price cap in place, a maximum amount it will pay for its ancillary services. If the ISO cannot procure enough ancillary services within its price cap, it can make “out-of-market” purchases, typically from other states or municipal utility districts that are not subject to the requirements of AB 1890. The ISO’s

out-of-market purchases are not subject to any price cap it may have in place. Thus, the ISO can pay any amount to procure out-of-market ancillary services.

When the ISO anticipates or realizes that the reserves portion of its ancillary services will not meet its forecasted needs, it begins issuing alerts, warnings, and then staged emergencies. An alert is issued 24 hours in advance of the operating day and signifies that reserves will fall below 7 percent. In an alert, power generators are asked to increase their power bids into the market. The ISO issues a warning when forecasted reserves for the current day fall below 7 percent. At this point the ISO begins directly buying reserves. During the operating day, when actual reserves fall below a certain level, first 7 percent, then 5 percent, and then 1.5 percent, the ISO issues a stage 1, 2, or 3 emergency, respectively. In a stage 1 emergency, the ISO makes public appeals and takes other measures to increase the power supply and decrease demand. At stage 2, power to certain customers who have agreed to have their power interrupted in exchange for reduced electricity rates is curtailed. Finally, in a stage 3 emergency, the ISO orders the investor-owned utilities to begin curtailing power to most of their customers, using rolling blackouts to keep the entire electricity system from crashing.

THE ROLE OF REGULATORS IN A DEREGULATED MARKET

Other regulatory entities that play important roles in the deregulated energy market include FERC, the CPUC, the California Energy Commission (CEC), and the California Air Resources Board (ARB).

Federal Energy Regulatory Commission

FERC is the principal federal agency that, under the Federal Power Act, oversees the rates, terms, and conditions governing the interstate sales and transmission of wholesale power. In addition, it is FERC's responsibility to assure that wholesale rates are just and reasonable and not unduly discriminatory or preferential. Because California's transmission system connects to other states, allowing California to import and export power, FERC has some regulatory authority over the ISO. As such, FERC reviews and approves the ISO's tariffs and other filings covering

topics such as access to the interstate power grid, the structure of its governing board, or the publication of information regarding the operation of the electricity grid. FERC also grants permission for western power generators to participate in California's power market and charge market-based wholesale rates for the power they sell.

California Public Utilities Commission

The CPUC regulates privately owned utilities in the State. Under AB 1890, the CPUC is charged with:

- Implementing direct retail access.
- Regulating retail rates charged by investor-owned utilities.
- Ensuring retail power reliability.
- Overseeing mergers of investor-owned utilities.
- Implementing consumer protection and education programs regarding retail electricity services.
- Monitoring the market behavior of investor-owned utilities and contracts between these utilities and qualified generators.

The CPUC is also responsible for evaluating the economic need for additional transmission capacity and for reviewing the reasonableness of construction costs for ratemaking purposes once transmission construction has been completed.

California Energy Commission

The CEC, the State's primary energy policy and planning agency, is responsible for the following:

- Forecasting future energy needs and keeping historical energy data.
- Licensing thermal power plants that are 50 MW or larger. Plants smaller than 50 MW are licensed by city- and county-based agencies.
- Promoting energy efficiency through appliance and building standards.

- Developing energy technologies and supporting renewable energy.
- Overseeing programs that fund energy research.

The CEC's responsibilities changed little, if at all, as a result of AB 1890, the State's electricity deregulation law.

California Air Resources Board

In California, the principal environmental issues involved in generating and transmitting electricity relate to air quality. The ARB is responsible for developing the State's air pollution standards and for overseeing the operation of its 35 local air quality districts that implement state and federal clean air standards. It is the districts' duty to advise the ARB on whether proposed power generation or transmission will comply with the air quality standards. Local areas that exceed federal and state standards for any of a number of identified pollutants are designated as "non-attainment" areas and are subject to more stringent regulations.

One element of air quality control is pollution credits. Power plants are issued an annual allocation of pollution credits that allow for a certain level of emissions; although power plants emit many pollutants, the most significant are nitric oxides and nitrogen dioxides collectively referred to as NO_x. As the plants run, their emissions are measured and their credits are used up at a preset ratio. However, all local air quality districts must adopt pollution credit banking programs that allow power plants and other entities to trade credits at market prices. Therefore, once a power plant uses its pollution credits up, it must either purchase additional credits from another entity or restrict its energy production. By allowing cleaner entities to trade their credits with those whose emissions exceed set standards, pollution levels overall are controlled, and no one industry is excessively penalized for its emissions levels.

SCOPE AND METHODOLOGY

The Joint Legislative Audit Committee (audit committee) requested the Bureau of State Audits to assess the PX's and ISO's structure, operations, and overall functionality and the extent to which the activities of the two contributed to the rising cost of wholesale electricity in California.

To assist us in evaluating the operations of and relationship between the PX and ISO, we engaged the services of three consulting firms specializing in energy economics and utility practices: TXP, Inc.; Pacific Economics Group; and J. A. Wright and Associates, Inc. In order to evaluate the PX and ISO in accordance with the audit committee's request, the consultants:

- Studied relevant sections of the PX and ISO tariffs and protocols.
- Reviewed internal PX and ISO documentation to understand the decision-making processes used by the two entities and assess them for effectiveness.
- Interviewed PX and ISO staff to understand how the entities operate, how they interact with each other, and how they have responded to the energy crisis.
- Studied reports and presentations of the PX Market Monitoring Committee and Compliance Unit, the ISO Market Surveillance Committee, and Department of Market Analysis and interviewed their respective members to identify the timing and content of the concerns raised by these monitoring groups.
- Examined reports, orders, and decisions made by the FERC and the CPUC addressing certain concerns raised by the monitoring groups, and assessed the effectiveness of the two regulators' actions in response to those concerns.
- Analyzed the statistical and econometric models used by the monitoring groups of the PX and ISO.

In May 2001, we will issue a second report that focuses on the roles that the CPUC and the CEC played in deregulation. ■

CHAPTER 1

The Fundamental Structure of the Market Is Flawed

CHAPTER SUMMARY

In recent months, the State has experienced record price levels for wholesale electricity that have led two of the State's three investor-owned utilities to the brink of bankruptcy. These high prices and the ensuing power crisis can be attributed, at least in part, to structural flaws in California's deregulated electrical markets. Caused by the enacting legislation as well as by the design and implementation of the deregulation model, these fundamental flaws include the following:

- The creation of multiple sequential markets that encourage strategic bidding.
- The requirement that investor-owned utilities buy and sell electricity in the short-term Power Exchange (PX) market.
- The limited nature of the long-term electricity contracts initially approved by the California Public Utilities Commission (CPUC).
- The Independent System Operator's (ISO) ability to purchase electricity for prices above market caps when its needs are not met through market auctions.
- The freeze placed on retail electricity rates.
- The ISO's inability to control the scheduling of electrical plant outages.

By initially requiring California's three investor-owned utilities, Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E), to buy all of the power their customers demanded and sell all the electricity they generated through the PX and ISO until March 31, 2002,² the State established a competitive, yet overly regulated, spot market for virtually all electric transactions—a commodity market within which electricity could be bought only within 24 hours of when it was needed. In effect, the original design

² The Federal Energy Regulatory Commission eliminated the buy/sell requirement in its final order dated December 15, 2000.

eschewed long-term transactions and created multiple markets that were segregated both physically and by their timing. This market structure created the possibility for strategic bidding—buyers and/or sellers underscheduled their next day’s electricity demand or supply in an attempt to reduce or increase the PX’s single market-clearing price—while regulators initially limited the use of long-term contracts that might have neutralized some of the effects of price jumps. In other words, the market structure encouraged price volatility while regulation limited the sorts of contracts that might have served as a safety net.

THE MULTIPLE SEQUENTIAL MARKETS OPERATED BY THE PX AND ISO RESULTED IN STRATEGIC BIDDING

Assembly Bill 1890, the legislation requiring the deregulation of California’s electrical market, included provisions for creating two nonprofit institutions: the PX, intended to provide an open, competitive commodity market for buying and selling wholesale electricity, and the ISO, intended to centrally manage and control the State’s transmission grid. However, the relationship between the ISO and PX was over-designed. Rather than creating one market or entity through which the purchasing and selling of wholesale electricity took place, the two organizations were structured to operate several markets in sequence, as described in the Introduction.

Market participants soon recognized the potential for strategic bidding and adopted various tactics to manipulate wholesale electricity prices. Both buyers and sellers appear to have bid strategically. The market participants’ strategic bidding had the result of driving energy sales and purchases out of the PX’s primary market and into the ISO’s secondary market, which was originally designed to accommodate only 3 percent to 5 percent of the State’s electricity needs. The use of the ISO as a primary market is one factor that contributed significantly to the current high energy prices and crisis operations.

The Relationship Between the PX and ISO Markets Encouraged Underscheduling

The PX’s market design could be described as a single-price auction because one market-clearing price was paid for all of the volume sold in the PX market each hour. (See Appendix B for a further discussion of single-price auctions.) Under the terms of deregulation, the PX’s “day-ahead” market was designed to be

Market participants soon recognized the potential for strategic bidding and adopted various tactics to manipulate wholesale prices.

the State's primary market for wholesale electricity. As the name implies, the PX day-ahead market allowed market participants (both buyers and sellers) to buy and sell energy 24 hours in advance of when it was needed. Market participants estimated their needed demand or available supply and then used these estimates to provide the PX with bid schedules listing the quantity of electricity they wanted to buy or sell at different market prices for each hour of the following day. Sellers submitted schedules of asking prices for various volumes each hour, and buyers submitted schedules indicating how much they would purchase and how much they were willing to pay in each hour.

The ISO's energy imbalance market was expected to accommodate at most 3 percent to 5 percent of the State's wholesale electricity needs.

After these schedules had been submitted, the PX separately ranked the various supply and demand schedules for each hour. The price of the highest supply bid necessary to satisfy the total quantity of electricity demanded within each hour became the market-clearing price. All buyers paid and all sellers received this single market-clearing price for all of the wholesale electricity transacted in the PX market in that hour. It was also possible to buy and sell electricity in real time on the day of the purchase through the ISO. However, the ISO's real-time markets were designed to be secondary to the PX's for the following reasons:

- All sales in these markets are made on the day on which the electricity is actually needed to achieve a balance between actual demand and actual supply.
- The ISO's markets were designed solely for reliability purposes and were expected to accommodate at most 3 percent to 5 percent of the State's wholesale electricity needs.

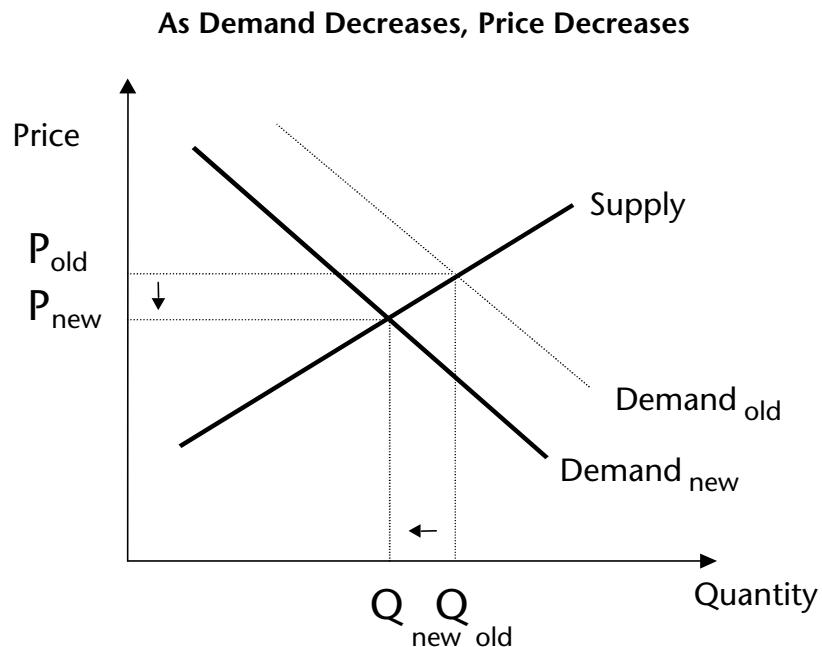
The ISO's energy imbalance market was created for the procurement of energy necessary to provide real-time reliability. For example, if the actual demand for electricity exceeds the actual supply, the ISO is required to purchase additional electricity to balance the system. This market was expected to account for a very small percentage of power purchases and sales in the market.

Overall, the California electricity wholesale marketplace was structured with the expectation that most electricity (usually measured in megawatt hours, or MWh, with 1 MWh equal to 1,000 kilowatt hours—roughly the amount of electricity it would take to power two average households for a month) would be bought and sold each hour, one day in advance, through the PX's market. For two years, the PX and ISO markets operated more or less as designed, and wholesale prices were less than

retail prices. However, during the past year, the relationship between the PX's day-ahead market and the ISO's real-time market changed drastically. This unanticipated shift began with some decidedly noncompetitive market behavior by both buyers and sellers.

In California's unique market, two buyers—PG&E and SCE—purchase nearly 90 percent of the energy traded in the wholesale market. The CPUC required these two buyers to purchase and sell all of their energy in the PX market at single market-clearing prices, as discussed earlier. However, because the ISO's real-time day-of market followed the PX's day-ahead market, buyers knew they had a second opportunity to purchase energy to cover their demand. According to the laws of supply and demand illustrated in Figure 1, if demand decreases in a market, such as the PX's day-ahead market, prices should decline. Using this logic, buyers had an incentive to underschedule their next day's electricity demand in an attempt to reduce the PX's single market-clearing price. If buyers could reduce demand in the PX's day-ahead market, the single market price for that hour should be lower and buyers would pay less for all energy purchased from the PX during that hour. Buyers could thus reduce their overall energy costs even if they had to make up their remaining demand requirements by buying the remaining portion of their energy needs in the ISO's real-time market at potentially higher prices.

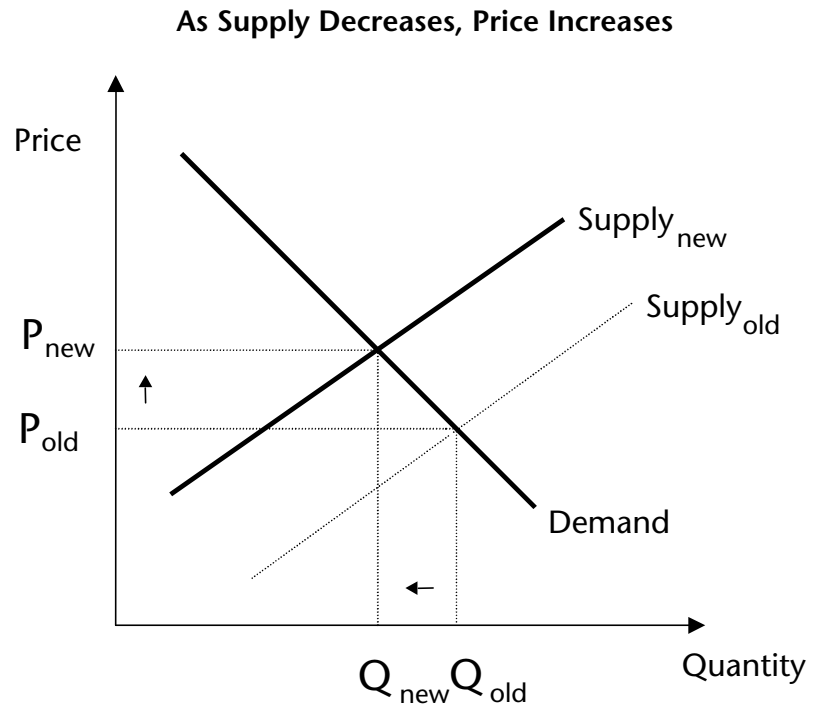
FIGURE 1



Sellers could employ a similar bidding strategy, hoping for the reverse effect. If sellers could reduce the amount of energy available in the PX's day-ahead market, supply would decrease, potentially increasing the market-clearing price. Thus, although sellers would sell less energy in the PX market, they would be paid a higher price for that energy than they might otherwise have received. Sellers could then try to sell any remaining generation they had in the ISO's secondary real-time market, perhaps at a lower price.

Therefore, the structure of the PX and ISO markets provided an opportunity for both buyers and sellers to attempt to manipulate the weighted average prices in these two markets. Figure 2 demonstrates why sellers would want to underschedule supply in the PX's day-ahead market. In theory, such conflicting buyer and seller behavior could be offsetting. However, this offset did not happen, and the shift to the ISO's real-time market caused sharp price increases.

FIGURE 2



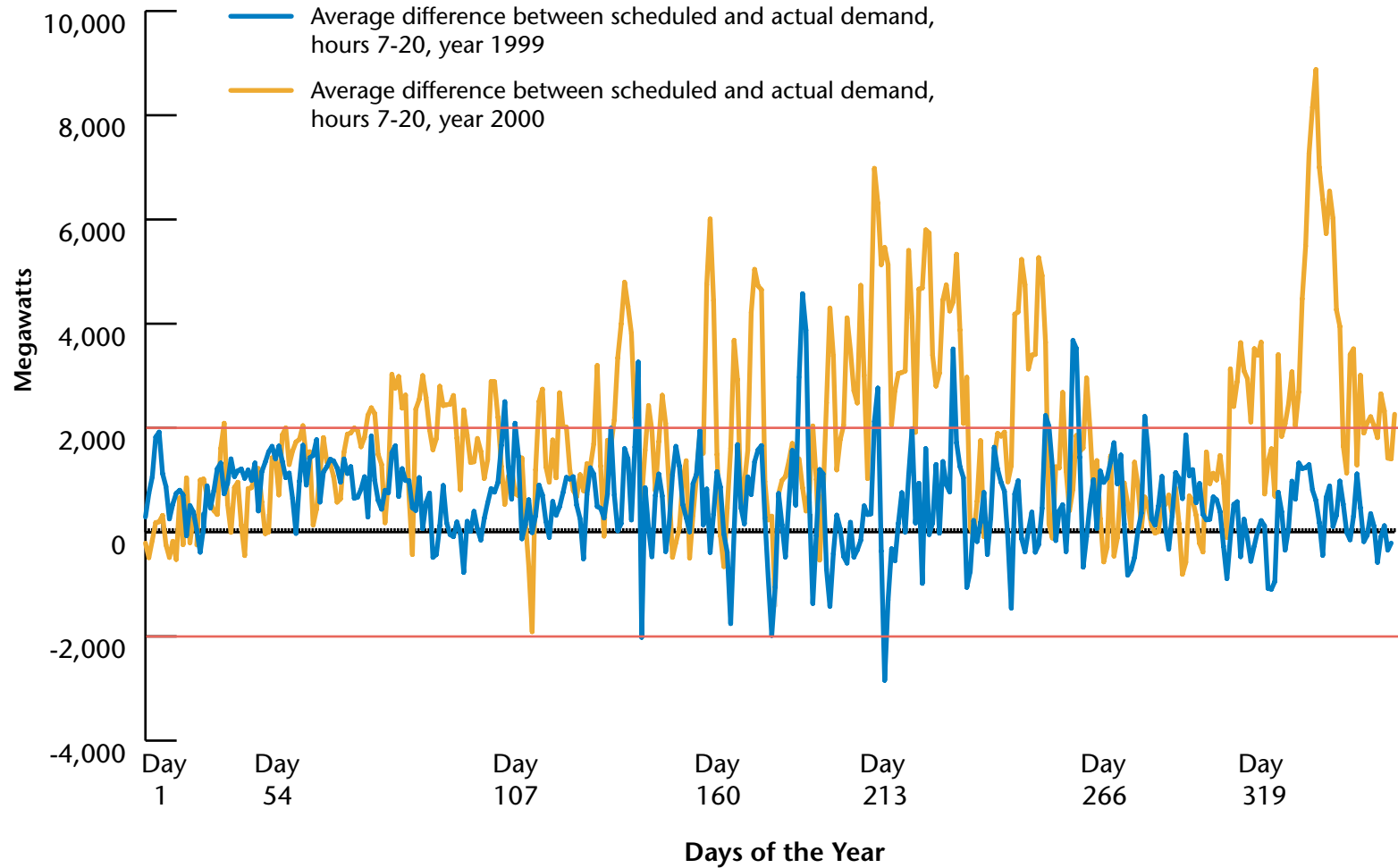
Data Suggests That Both Buyers and Sellers Used Underscheduling to Bid Strategically

Strategic bidding is often evidenced by market participants underscheduling their supply of and demand for electricity in one market to affect the weighted average price across the PX and ISO's markets. California's sequential market design offered market participants a prime opportunity to engage in this type of behavior. Although unforeseen increases in demand—caused, for example, by hotter weather than anticipated—could also cause scheduled demand to be less than actual demand, that does not appear to be the only factor that caused the shift between the PX and ISO markets in California. Bidding data from the last year suggests that both sellers and buyers utilized underscheduling in an attempt to manipulate electricity prices for their respective advantages.

The investor-owned utilities have historically been able to forecast the next day's electricity demand within at least 2 percent to 3 percent of actual demand—that is, within 500 to 1,000 MW each day—depending upon the time of year. Figure 3, which compares scheduled demand to actual demand for 1999 and 2000 during hours of high demand, demonstrates that underscheduling in 2000 significantly exceeded underscheduling in 1999. In 1999, the investor-owned utilities underscheduled by more than 2,000 MW a day about a dozen times; in 2000, this number was exceeded hundreds of times. Underscheduling reached its most extreme level during the last 40 days of 2000. This suggests that strategic bidding increasingly played a major role in shifting purchases to the ISO's real-time market. Since the ISO often pays any price necessary to maintain system balance and reliability, this shift to the ISO's market increased wholesale price levels in California in 2000.

FIGURE 3

**Comparison of Scheduled Versus Actual Demand in High Demand Hours
(1999 and 2000)**

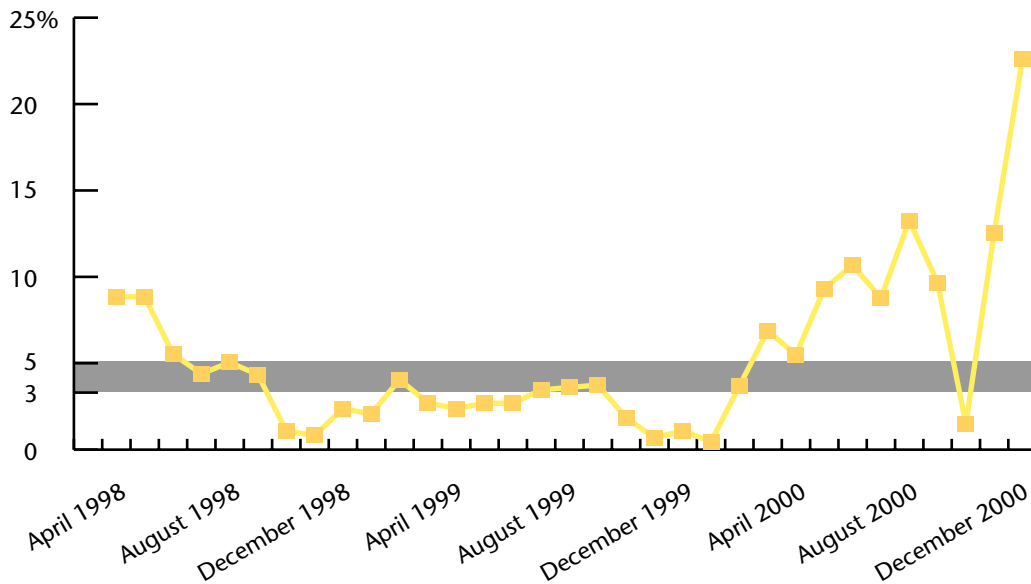


Source: University of California Energy Institute.

The total amount of energy purchased through the ISO’s real-time market further supports the conclusion that market participants were deliberately underscheduling their PX bids. As shown in Figure 4, the ISO’s real-time market has, on average, purchased 5 percent to 20 percent or more of the energy sold in the State since March 2000—up to four times more than what it was expected to purchase (3 percent to 5 percent) under the initial market design.

FIGURE 4

**Percent of Total Energy Sales Purchased by the ISO
April 1998 Through December 2000**



Source: California ISO.

These bidding strategies shifted the buying and selling activities that would normally occur in the PX’s primary day-ahead market to the ISO’s secondary, real-time market. As the choice of market shifted, the ISO was forced to conduct auctions and emergency purchases at levels neither anticipated nor built into the initial market design. This strained the ISO’s ability to find the increased supply demanded, triggered stage 2 and 3 power emergencies, and often forced the ISO to make out-of-market purchases at exorbitant prices to guarantee system reliability. Buyers were required to take the out-of-market energy purchased by the ISO, regardless of the price. Sellers, particularly out-of-market sellers, knew that the ISO was in a “must buy”

circumstance whenever a stage 2 or 3 emergency was declared. Therefore, through strategic bidding, sellers were able to set higher prices in both the PX and ISO markets during tight supply situations or emergencies.

THE TERMS OF DEREGULATION AND THE SUBSEQUENT CPUC-IMPOSED REQUIREMENTS LIMITED THE ABILITY OF INVESTOR-OWNED UTILITIES TO IMPLEMENT LONG-TERM CONTRACTS

Long-term contracts for electricity potentially provide investor-owned utilities an effective hedge against price volatility and sharp future increases in short-term and spot energy prices.

Regulating what was intended to be a competitive market is, to some degree, illogical. Yet the CPUC, Federal Energy Regulatory Commission (FERC), and the ISO all exert a considerable amount of regulation on this market. One of the most problematic forms of this over-regulation was the requirement that virtually all investor-owned wholesale electricity be bought and sold in short-term commodity or spot markets. Moreover, once forward contracts, long-term contracts, and other financial hedging instruments became available through the PX market, they were initially restricted by the CPUC. Forward and long-term bilateral contracts for electricity are contracts that specify that a purchaser can buy a certain amount of electricity at a predefined price over some future period of time. These types of contracts potentially provide investor-owned utilities with a highly effective hedge against volatile changes and sharp future increases in short-term and spot energy prices. Such contracts can provide both the buyer and the seller with future price certainty, as well as supply availability.

California's Model for Deregulation Differs Significantly From the Models Used by Other States

There were three primary reasons why the State mandated short-term energy trading. First, when the State introduced competition, there was significant excess supply, which kept short-term wholesale energy prices low. Second, investor-owned utilities owned most of the generation (approximately 70 percent in 1996), and by requiring the three investor-owned utilities to bid all of their generation into the PX's short-term markets and to make all of their energy purchases within these markets, regulators made these transactions easier to monitor. This requirement also allowed the CPUC to calculate how much each investor-owned utility had recovered of their investment in certain generation assets as allowed by AB 1890 at any point in time. Third, markets need liquidity, or sufficient participation, to function efficiently.

Forcing investor-owned utilities into the PX helped ensure sufficient market participation and the market's continued financial viability.

As Table 1 shows, in other states and countries, restructured competitive electric markets were introduced under nearly the opposite conditions, with almost all power sold under long-term or forward contracts and very little sold in the short-term commodity or spot market. Buyers in these other deregulated energy markets use short-term commodity and spot markets for a very limited amount of their electricity needs.

TABLE 1

**The Use of Market Hedges Compared to the Spot Market
in Other Deregulated Electric Markets**

	Percent of Market Hedged (long-term forward contracts or self-owned generation)	Percent of Unhedged Spot Market
Pennsylvania, New Jersey, Maryland (PJM)	85-90%	10-15%
New England	80	20
Australia	90	10
Norway	85-90	10-15
Sweden	85-90	10-15

Source: California ISO.

**The Investor-Owned Utilities Did Not Fully Utilize
Forward Contracts**

The State's view of long-term contracts began to change in March 1999, when the PX asked FERC to approve a new product called a "block-forward market service." FERC approved the PX request on May 26, 1999. The PX described this new product as a way to improve California's overall electricity market efficiency by offering long-term trading instruments to help participants hedge short-term price risk. The product offered buyers the advance purchase of power in 16-hour blocks, from 6 a.m. to 10 p.m., for each day of the month except Sundays and holidays, with the energy to be delivered from one to six months following the month of order. On February 24, 2000,

FERC conditionally approved the PX's request to expand forward contract products to cover peak hours, when energy demand is highest.

These actions prompted the two largest investor-owned utilities to seek the CPUC's authority to buy future energy in the PX block-forward market. In July 1999, the CPUC granted that authority, with certain limitations designed to prevent the utilities from speculating: The amount of power the two utilities could buy through the forward market was limited to no more than one-third of their respective historical minimum hourly demand by month, and the utilities had to take delivery of these purchases no later than October 2000.

In two separate actions during the year 2000, the CPUC authorized PG&E and SCE to enter into long-term agreements to purchase wholesale electricity.

These original restrictions were loosened in March 2000, when the CPUC authorized requests by the two larger investor-owned utilities to increase their ability to forward contract through the PX up to the amount of their respective "net short position"³— with the stipulation that, under certain circumstances, the CPUC reserved the right to conduct future reasonableness reviews, with the wholesale rates paid under contract subject to refund. Reserving the right to conduct future reasonableness reviews put forward contracts at risk for later disallowance by the CPUC. This would increase an investor-owned utility's reluctance to enter into such contracts because the costs of the contracts might later be disallowed and therefore not be recaptured.

Then, in August 2000, the CPUC granted emergency authorization for the two largest investor-owned utilities to enter into bilateral contracts that would end by December 31, 2005. These contracts could not exceed the purchasing limits for forward contracts already approved. The CPUC also continued to reserve the right to conduct future reasonableness reviews of the terms and conditions of these bilateral contracts, with the wholesale rates paid subject to review and refund.

Despite these options for long-term contracts, the investor-owned utilities were still far too dependent on spot market sales during the summer of 2000. Even after the CPUC's action in March 2000 increased the amount that the two largest investor-owned utilities could purchase through forward contracts to an upper limit of 3,000 MW for one and 5,200 MW for the other

³ The net short position is the amount of ratepayer demand that a utility's own supply (total customer demand less generation owned and under contract) falls short for any given hour.

Even though PG&E and SCE only made limited use of their ability to enter long-term agreements, the PX reported that between May and September 2000, these agreements saved the utilities \$706 million.

(their respective hourly net short positions), market data show that the utilities underused this option. According to data from FERC and the ISO, SCE used about 80 percent of its forward contracting authority of 2,200 MW in June 2000 and about 58 percent to 67 percent of its 5,200 MW limit for the months of July through August 2000. The other large utility, PG&E, used approximately 37 percent of its 3,000 MW limit in June 2000 and roughly 60 percent of its limit in both July and August 2000. The smallest investor-owned utility, SDG&E, did not participate in the PX forward contract market during this period. Yet even with this limited use of their forward contracting capability, the PX has reported that the investor-owned utilities participating in the PX forward contract market saved a total of \$706 million from May through September 2000.⁴

The investor-owned utilities' own caution appears to have prevented them from hedging their exposure to short-term price increases by purchasing additional forward contracts. Their decision not to fully participate in the forward contract market may also have been influenced by the CPUC's refusal to waive its right to review these forward contracts for reasonableness under certain circumstances in a future proceeding. In other words, if future wholesale market prices dropped below the rate for which the utility had contracted, CPUC reserved the right to require that utility to refund the difference in price to its customers. This requirement meant that the utilities were taking a significant risk in entering into contracts—a risk that they could not share with their customers.

The Debt Incurred by the Investor-Owned Utilities Has Inhibited Their Ability to Purchase Electricity

As conditions in the power market worsened between June and December 2000, the question of whether the reluctance to enter into forward contracts was based on the investor-owned utilities' business judgment or on a perception that regulation was still too restrictive proved to be moot. Beginning with the wholesale price spikes early in the summer of 2000, PG&E and SCE regularly bought power at exorbitant spot prices that they were unable to pass onto their retail customers because of the retail price freeze. As a result, these utilities quickly incurred huge

⁴ The PX reported that only 5,400 of a possible 10,000 PX forward contracts were used by the investor-owned utilities between July and September 2000. "Price Movements in California Power Exchange Markets, May–September 2000," PX Compliance Unit, November 1, 2000, pp. 79, 80.

amounts of debt for the wholesale electricity they bought from power generators. Various credit rating firms took note of the utilities' worsening financial condition and, in January 2001, downgraded their credit to junk bond status. This eliminated their ability to enter into long-term contracts or, indeed, to purchase any electricity at all.

In an attempt to correct for volatile wholesale spot prices and provide long-term customer protection, FERC issued a final order in December 2000 removing the requirement that investor-owned utilities buy and sell all electricity through the PX, thus creating the possibility for unlimited bilateral and forward contracts. However, this action came too late. The combination of the utilities' impending insolvency and FERC's decision to allow contracting outside the PX effectively eliminated the PX as California's primary wholesale spot market for electricity, leaving the State without a primary market because the investor-owned utilities no longer were required to buy or sell in the PX's market. Because the credit status of the two investor-owned utilities inhibited their entering into contracts with generators, the State has had to buy the power needed to meet these utilities' daily net short positions since mid-January 2001.

The Imposition of Price Caps May Have Contributed to Escalating Prices

As we discussed previously, the over-regulation of a supposedly competitive market is at least partly to blame for the recent energy crisis. The wholesale price caps imposed by both the ISO and FERC are another symptom of this over-regulation. Some have argued that these caps have succeeded in containing prices; others believe that they have failed. Regardless, the imposition of price caps had at least two undeniable results. First, placing a price cap on the ISO's real-time energy market in effect placed somewhat of a bidding floor on PX day-ahead prices when demand was low, that is, when there was sufficient surplus energy for suppliers to assume that PX day-ahead market sales would supply most of the demand. Under these circumstances, sellers had nothing to gain from withholding generation from the PX day-ahead market (which is not subject to the price cap). Instead, the seller would bid some of its available supply into the PX's day-ahead market, using the ISO's price cap as the price offered. If the seller's strategy was successful, the single market-clearing price in the PX day-ahead market for that particular

Some have argued that wholesale price caps have succeeded in containing prices; others believe that price caps have failed.

hour would equal the ISO price cap. Thus, in times of sufficient supply, the ISO price cap could set the single market-clearing price in the PX.

The second result of the ISO's price cap is that in times of high demand, the price cap might have caused some sellers to bid into the ISO market through out-of-market transactions, which are not subject to the price cap.⁵ For example, assume that a \$250 per MWh price cap is in effect at the ISO. A generator could sell directly to a municipal utility for \$300 per MWh. Because the municipal utility is not a market participant and thus is not subject to the ISO price cap, it could then sell this same power to the ISO for \$325 per MWh. During times of high demand or when sellers strategically bid into the system, the price cap might actually have motivated sellers (including out-of-market) to sell into the ISO's real-time marketplace.

Regional Purchases Are Not Covered by the State's Price Caps

As large as California's markets are, they are interdependent with municipal-owned utilities in the State and with other utilities in the region represented by the Western Systems Coordinating Council (WSCC).⁶ Therefore, the marketplace for power sales extends well beyond California. To ensure reliability, the ISO must sometimes purchase power from sellers throughout the western region, rather than restricting its purchases to sellers covered by the State's price caps. This means that the ISO will, and does, make out-of-market purchases, often paying considerably higher prices than it would through its normal markets.⁷ The map in Figure 5 shows the different states that comprise the western region as well as the other regions within the contiguous United States.

As large as California electricity markets are, they are interdependent with other utilities in the region. Therefore, the marketplace for power sales extends well beyond California.

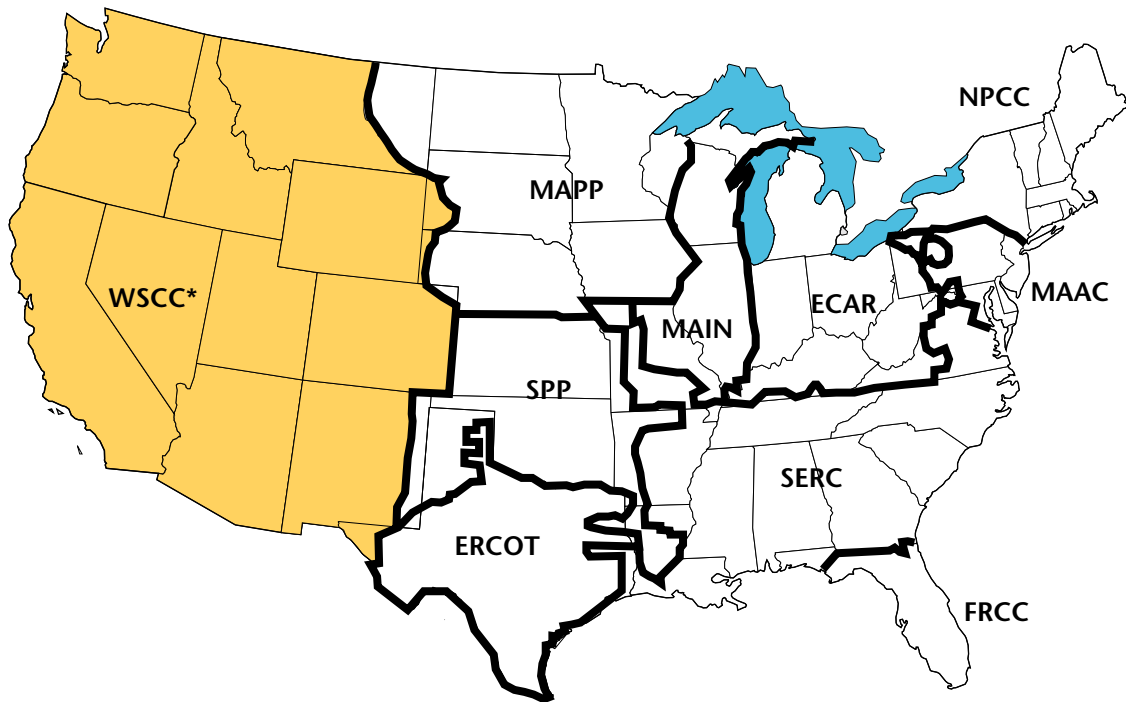
⁵ Analysis of the impact of ISO price caps on out-of-market sales initially indicated that these sales were generally below the ISO real-time energy price cap, leading some to conclude that the cap had some intrinsic effect. However, this changed in December 2000 when ISO out-of-market purchases significantly exceeded the price cap.

⁶ The WSCC oversees the western grid, which includes all or parts of 14 western states, 2 Canadian provinces, and a small portion of Mexico. The WSCC develops operating reliability criteria and policies that its voluntary members agree to follow. The WSCC, in turn, is part of the North American Electric Reliability Council, which was formed in 1968 to promote the reliability of North America's electricity supply.

⁷ Out-of-market purchases are purchases made from generators or marketers that do not directly participate in the ISO or PX markets.

FIGURE 5

North American Electric Reliability Council Regions for the Contiguous United States



* The WSCC also includes the provinces of Alberta and British Columbia, Canada, and a small portion of Baja California Norté, Mexico.

The regional nature of the energy marketplace introduces a series of problems. In this tight market, generation owners that might otherwise participate in the PX and ISO markets can instead choose to sell to California municipal utilities and out-of-state investor-owned utilities at prices that exceed the ISO’s price cap. As the ISO-regulated cap fell this past year, the level of such out-of-market sales increased significantly, as shown in Table 2.

TABLE 2

**Volume of Megawatts Purchased Out-of-Market
June Through December 2000**

	June	July	August	September	October	November	December
Average hourly out-of-market MWs purchased (hours 12-19 only)	26,880	79,205	46,872	45,150	40,796	208,950	487,382

Source: California ISO.

In turn, the same non-market participants (that is, California municipal utilities and out-of-state utilities) that purchase electricity directly from generators can then sell the electricity to the ISO at prices at or above the cap. Table 3 indicates that the average price paid by the ISO for out-of-market purchases remained at or very near the ISO price cap for most of the latter half of 2000, and in December greatly exceeded it.⁸ Finally, rather than buying directly from generators, market participants other than the investor-owned utilities can purchase from the PX day-ahead market and resell the same electricity in the ISO market and avoid the price cap. In fact, a successful strategy for avoiding ISO price caps would be for market participants to sell electricity purchased in the PX day-ahead market to exempt utilities (either within the State or outside California's borders) that would, in parallel, sell electricity back to the ISO at prices above its price cap. All parties to this transaction could gain from any such roundabout sales to the ISO.

TABLE 3

**Out-of-Market Purchase Prices Compared to the ISO Price Cap
June Through December 2000**

	June	July	August	September	October	November	December
ISO price cap \$/MWh	\$750	\$500	\$250	\$250	\$250	\$250	\$250
Average out-of-market purchase price in \$/MWh	680	500	252	250	193	245	382

Source: California ISO.

Price Caps Appear to Have Influenced Bidding in the PX Market

Although it is difficult to prove that ISO price caps encouraged strategic bidding behavior, the evidence that ISO price caps can influence PX day-ahead markets became more compelling in the summer of 2000. Aggregate PX bid data for the past two summers indicate that the supply offered in the PX market was lower in

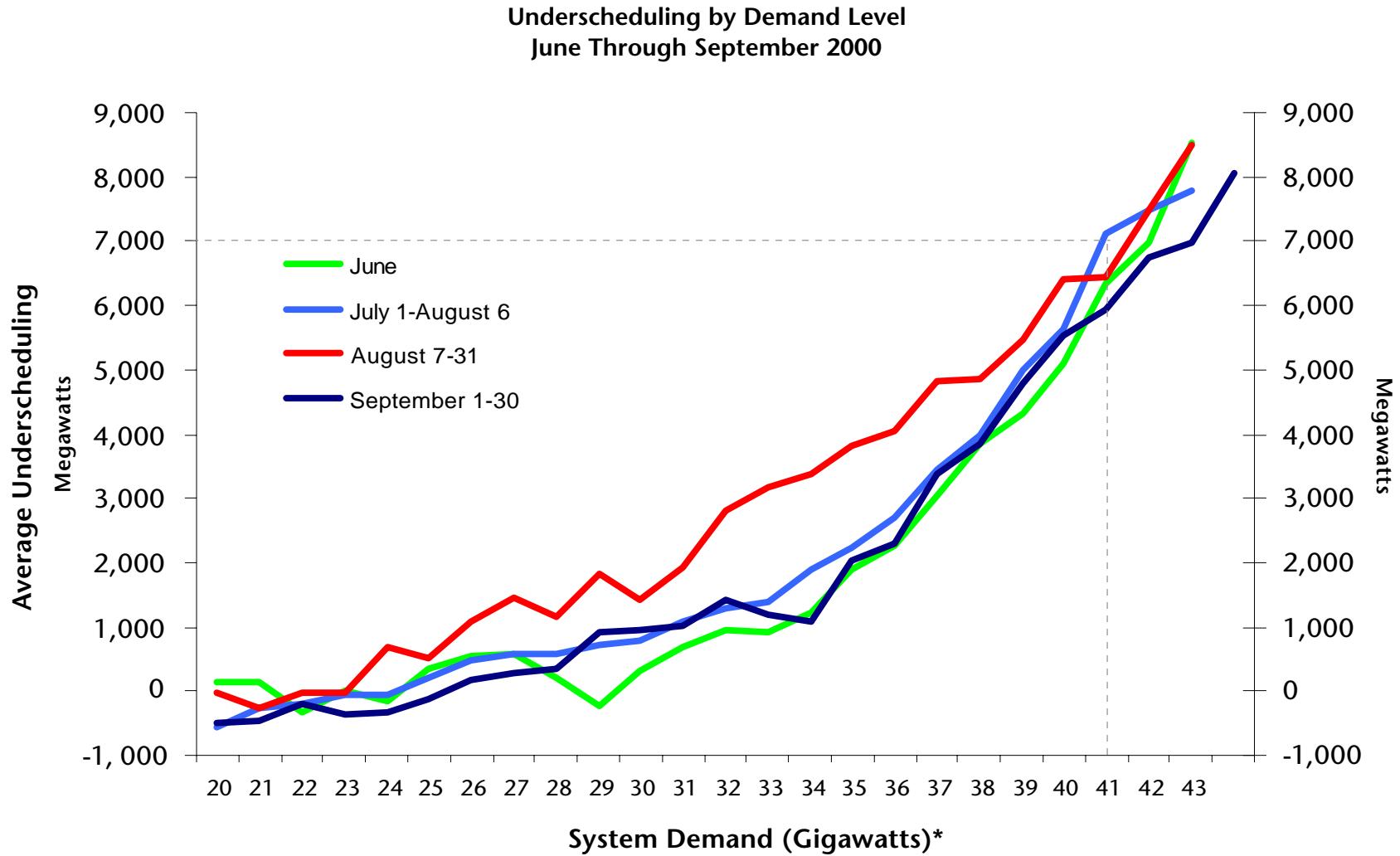
⁸ A review of ISO out-of-market sales through January 2001 indicated that these purchases continued to exceed the \$150 soft price cap.

quantity and higher in price in the summer of 2000 (with an ISO price cap of first \$750 per MWh and then \$500 per MWh in effect for most of the summer) than in the summer of 1999 (with a price cap of \$250 per MWh). This bidding pattern, particularly in times of high inelastic demand, supports the proposition that suppliers in the summer of 2000 were withholding generation from the PX day-ahead market in an attempt to sell into the ISO real-time market. Withholding bids from the PX day-ahead market in 2000 meant the possibility, particularly during hours of peak demand, of sellers selling into the ISO real-time market and receiving prices of \$500 to \$750 per MWh, whereas in 1999, under the same conditions, the price would have been capped at \$250 per MWh.

Withholding generation from the PX day-ahead market could mean that generators forced the ISO to purchase more real-time energy this year than last, under the same demand conditions. In fact, Figure 6 shows that, as the estimated demand for electricity increased from June through September 2000, the volume of demand that was underscheduled in the PX increased as well. For example, the figure shows that from June through September 2000, whenever the State's projected demand rose above 41,000 MW, more than 7,000 MW (at least 17 percent) of that demand was underscheduled in the PX and had to be met in the ISO real-time market.

Although it appears that the ISO price caps influenced bidding behavior, the most pertinent question is whether they actually led to lower prices. The data from the recent energy crisis at first seem to indicate that the answer is yes. For example, in July 2000, when the ISO price cap was \$500 per MWh, and in August and September when the ISO price cap was \$250 per MWh, the hourly caps were reached several hundred times. This lends credence to the belief that the cap restrained ISO real-time energy prices during the energy crisis.

FIGURE 6



Source: California ISO.

* One gigawatt equals 1,000 megawatts.

However, to fully understand the influence of the ISO price cap, one must consider whether it has had an observable effect on PX day-ahead prices and out-of-market ISO purchases. To answer this question, consider the fact that in 1998 and 1999, the PX day-ahead price never reached the level of the ISO real-time price cap, which fluctuated between \$125 per MWh and \$750 per MWh. Table 4 shows that this changed dramatically in the latter half of 2000, when the ISO price cap was reached numerous times. This suggests that although the price cap may have restrained real-time prices in the ISO's markets, it may also have raised the prices in the PX day-ahead market and contributed to a bidding strategy on the part of sellers.

TABLE 4

**Frequency With Which PX Prices Reached the ISO Price Cap
June Through December 2000**

ISO Real-Time Price Cap	Number of Hours the ISO Price Cap Was Reached in the PX Day-Ahead Market*	Dates the Price Cap Was Reached in the PX Day-Ahead Market†
\$750 MWh	16	6/28/00
500 MWh	43	7/17/00 to 8/6/00
250 MWh	842†	8/7/00 to 12/31/00

* Actual observations of the number of hours the PX day-ahead unconstrained market-clearing price was within \$2 of the ISO price cap.

† On 12/9/00 the \$250 price cap began to be exceeded.

Although not reflected in the table, market data also show that May 2000, when the PX price first hit the ISO's price cap, is quite probably when bidders began to fully understand and use the ISO market and its price cap as a strategic bidding "tool" to set a floor price in the PX day-ahead market. The effects of this strategy were not completely felt until December 2000. What Table 4 does not show is that 425, or 51 percent of the 842 hours shown for the period beginning August 7, the PX day-ahead price exceeded the ISO price cap, with all 425 of those hours occurring between December 9 and December 31, 2000. This means that during those hours, wholesale energy in the PX sold for more than the ISO's \$250 per MWh price cap. Therefore, when it needed energy, the ISO was forced to make out-of-market purchases at an uncapped price because sellers had already sold their available energy in the PX market for more than the ISO's cap and would most likely be unwilling to sell

power directly to the ISO for a lesser amount. Thus, the seemingly positive benefits of price caps are mitigated, if not entirely reversed, when wholesale energy prices in the PX market exceed the ISO price cap, because the ISO is forced to make energy purchases at higher, uncapped prices from out-of-state utilities, California municipal utilities, and other entities that are exempt from the ISO's price caps.

Experts Disagree About the Necessity of Price Caps

The ISO Market Surveillance Committee (ISO surveillance committee), the ISO Department of Market Analysis, and the PX Compliance Unit have all concluded that it is necessary to continue price caps. The ISO surveillance committee calls for caps reluctantly, referring to them as a “damage control” mechanism. Their primary reason for continuing caps is the lack of a competitive market, which requires:

The ISO's surveillance committee called for price caps reluctantly, referring to them as a “damage control” mechanism.

- Price-responsive demand, in which retail consumers receive price signals in the form of changes in wholesale electricity prices, causing them to alter their demand.
- An active and liquid long-term futures market with options that allow buyers to protect themselves against the risk of volatile wholesale prices.
- An adequate supply, so that sellers cannot sustain market power or charge higher prices because of scarcity.
- An adequate transmission infrastructure, so as not to restrict the supply of electricity to certain areas.
- No undue barriers to entry for supply or transmission, so that it is relatively easy for new competitors to enter the market when prices seem high relative to entry costs.

There are also legitimate arguments against imposing low price caps or, indeed, against having any price caps at all. These arguments include the following:

- Lower price caps provide less incentive to build new generation facilities.
- Caps will lead to in-state generators selling outside of California when the “outside” prices exceed the price cap. These outside participants may then resell the electricity back into the State for prices above the cap.

- Caps remove the incentives for retail consumers to respond to wholesale prices.
- Caps remove the incentive to schedule demand in the day-ahead market because prices are capped in the ISO real-time market. As such, caps can discourage investor-owned utilities and other market participants from using day-ahead and forward markets.

FERC's current solution to this situation is a \$150 per MWh soft price cap, which allows generators to be paid for bids above \$150 made in either the PX day-ahead market or the ISO real-time market. However, the generators must later justify their bids to FERC, and bids over \$150 will not set the PX or ISO market-clearing price. This soft price cap seems problematic in part because of the administrative difficulties involved in justifying bids and in part because it implicitly allows market-based pricing without a cap once sellers decipher how to justify costs above the cap. In addition, the low amount of the soft price cap fails to address the larger regional issues, since California's natural gas prices at the border this winter have easily surpassed the soft price cap equivalent. This means that high natural gas prices could cause a generating plant's fuel costs alone to exceed FERC's soft price cap. The cost of natural gas and its effect on wholesale electricity costs are discussed more fully in Chapter 3.

The Price Freeze on Retail Rates Has Constrained the Competitive Market

The conservation seen during the recent energy crisis has been based largely upon public appeals to avoid blackouts, not a reaction to higher wholesale market prices.

As the State pressed ahead with wholesale competition in the power market, its freeze on retail electric rates effectively delayed retail competition. Although customer choice is available to consumers of the three participating investor-owned utilities, there is little incentive for retail customers to choose a different energy service provider because current rates are frozen. In addition to virtually ensuring that no new utility service providers will enter retail competition, the rate freeze has also reduced the market incentives to both conserve and implement new technologies, such as distributed generation.⁹

⁹ Distributed generation consists of generating units of very small size that can include generators small enough to power a single home or a group of commercial buildings. Unlike large, central generation stations, this type of generating unit can be installed very quickly and close to where the energy is needed.

Even though wholesale prices increased dramatically between May and December 2000, consumers other than customers of SDG&E received no price signal causing them to reduce usage because of their frozen rates. Consequently, most consumers received no real-time price signal that might create an incentive to conserve or shift demand to less costly time periods. The conservation seen during the energy crisis has been based largely upon public appeals to avoid blackouts, not a reaction to higher wholesale market prices.

The ISO Lacks Authority to Effectively Schedule Outages

A final weakness in the structure of the State's power market involves the ISO's lack of authority over generator behavior with respect to scheduled plant outages for maintenance. In light of the evidence that the market is not yet workably competitive, it is unreasonable to grant generators full autonomy concerning the scheduling of plant outages. In fact, when the ISO was being formed, it argued that it needed to control scheduled plant maintenance outages in order to be able to effectively balance the system's reliability. The plant owners, however, contended that they were the ones who best knew their plants' requirements and demanded that they be allowed to maintain control over scheduled plant outages. Ultimately, the plant owners prevailed.

As a result, the ISO has virtually no control over scheduled outages other than Reliability Must Run (RMR) contracts with certain generating units.¹⁰ The ISO's lack of authority contributed to the problems this winter, as scheduled plant outages coincided with high demand, decreasing supplies, and unscheduled outages due to problems with equipment. If the ISO had some control over the scheduled outages, as do the independent system operators for PJM, New York, and New England, it could have coordinated the outages more effectively to help alleviate the problems with shortages in supply.

¹⁰ An RMR contract is made with a specific generator to ensure that certain power plants remain in operation. Frequently, these power plants serve areas where limited transmission lines restrict the amount of power that can be imported into the area.

RECOMMENDATIONS

Eliminate the Opportunity for Strategic Bidding

Market participants used the sequential structure of the PX's and the ISO's electricity markets to minimize or maximize the price of wholesale electricity by strategic bidding through underscheduling their supply and demand in the PX market. As a result, large amounts of energy sales and purchases were driven from the PX's primary market into the ISO's secondary markets, causing higher energy prices and crisis operations. To reduce market participants' opportunity for strategic bidding through underscheduling, the ISO should do the following:

- Cease conducting real-time markets. To fulfill its real-time energy needs, the ISO should undertake to execute forward contracts with generators to provide imbalance energy and reserves for reliability services.
- Consider penalizing scheduling coordinators who submit schedules that do not reflect real-time demand and supply conditions. Penalties would be shared amongst buyers and sellers.

The ISO should cease purchasing ancillary services in the spot market. Instead, the ISO should:

- Make purchases through sealed bids for most of its forecasted ancillary services requirements and significantly reduce its use of spot markets to purchase energy.
- Purchase any short-term ancillary services requirements at individually determined prices, as opposed to paying one price for all such purchases at any point in time. The ISO might accomplish this by using a spot market system and simply paying the next available bid above the market-clearing price without raising the market-clearing price or paying any individual seller more than its specific bid price.
- Consider the option of contracting for generation capacity. If contracted supply exceeds demand, the ISO should be allowed to sell unneeded capacity at cost plus an administrative fee to others through the PX or similar markets.

Avoid Using a Single State Wholesale Price Cap

Both the ISO and FERC have used price caps in an effort to control the prices paid in the California market, with mixed success. First, even when demand in the PX was low, the ISO price cap became the minimum bid in some peak demand hours. Additionally, in times of high demand, it is unclear whether any price cap is effective, simply because sellers can bid into the ISO's market through out-of-market transactions, which are not subject to the price cap. The result is higher energy prices, despite the effort to control them. Thus, if the ISO is unsuccessful in limiting spot market purchases to very small amounts, price caps should be used only if markets are found to be noncompetitive and supply is being withheld to force prices higher. Without such a finding, regulators should let the markets work to increase supply.

The ISO Should Have Additional Authority for Scheduling Power Plant Maintenance

The problems encountered in California during the winter of 2000, when scheduled plant outages coincided with high demand and unscheduled plant outages, triggering stage 2 and 3 emergencies because of scarce supplies, underscores the need for more effective scheduling of plant outages. Therefore, the ISO should coordinate with power generators in scheduling outages for plant maintenance over the next two to three years, or until a competitive market is established. This may not necessarily require that the ISO determine outage schedules, but it will, at a minimum, require generator participation in scheduling known outages well in advance and in keeping to the schedule established. ■

CHAPTER 2

Market Monitoring Identified Problems That Regulators Were Unsuccessful in Correcting

CHAPTER SUMMARY

In the State's wholesale electricity marketplace, market monitoring and oversight are closely interconnected. In order for the market to function efficiently, market-monitoring groups must quickly and accurately identify potential concerns, and those responsible for market oversight must respond effectively when informed of these problems. Beginning in August 1998, market-monitoring groups within the Independent System Operator (ISO) and the Power Exchange (PX) identified a number of fundamental flaws in California's power market structure, many of which are discussed at length in Chapter 1. These monitoring groups warned the California Public Utilities Commission (CPUC) and the Federal Energy Regulatory Commission (FERC) of potential problems caused by underscheduling, increased demand and the mandated use of short-term markets. The escalation of electricity prices that began last summer might have been significantly mitigated had the CPUC and FERC been more successful in fully addressing and correcting the problems. When the power crisis forced FERC to take action in December 2000, it focused on modifying the market rather than further investigating and imposing sanctions against possible abusers of market power.

Although the market-monitoring groups accurately anticipated problems in the electricity market, we did identify one possible concern: The market data and analysis the PX and ISO publish on the Internet may have contributed to the use of strategic bidding through underscheduling, as discussed in Chapter 1.

ISO AND PX MARKET-MONITORING GROUPS ANTICIPATED CURRENT PROBLEMS

Market-monitoring groups within the ISO and PX began to identify problems in the electricity market structure as early as the fall of 1998. The problems identified primarily required

regulatory and/or legislative action to be corrected. As required by their tariffs and protocols, these groups reported their concerns first to their senior management and governing boards, and then if warranted, to officials at FERC and the CPUC. Had the problems reported to regulators been fully addressed when initially identified, the current power crisis might have been mitigated. However, the CPUC and FERC were not successful in fully addressing and correcting the problems, and as a result, the problems escalated and eventually contributed significantly to the State's electricity crisis.

ISO and PX Monitoring Groups Were Responsible for Assessing Potential Problems in the Market

As described in Chapter 1, AB 1890 created two nonprofit institutions through which wholesale energy could be traded: the PX,¹¹ which was responsible for operating a series of markets through which energy could be purchased or sold the day before it was needed, and the ISO, which was and continues to be responsible for overseeing the State's transmission grid and, when necessary, for purchasing additional energy for reliable grid operation. Each of these organizations operates under the auspices of the Electricity Oversight Board (EOB), and each was given tariff and protocol authorization by FERC to develop formal market-monitoring capabilities. The FERC, among other things, regulates interstate energy transactions and plays an oversight role because the ISO and PX each facilitate wholesale electricity transactions that may cross state lines, which is considered interstate commerce.

The structures the ISO and PX established for monitoring their respective markets were similar. The PX hired a relatively small staff, called the Compliance Unit, to issue periodic reports (both monthly and quarterly) on PX market activity. It also assembled a group of outside academic experts as its Market Monitoring Committee, intended to provide an independent assessment of issues and trends that would affect the market. In addition to its quarterly meetings, the Market Monitoring Committee was required to submit an annual report concerning market issues to FERC. The ISO designed its Department of Market Analysis (market analysis group) to perform functions parallel to those of the Compliance Unit and created the Market Surveillance Committee (ISO surveillance committee) to provide independent reporting on market issues and trends.

Both the ISO and PX established special market-monitoring units in addition to committees of outside experts to provide an independent assessment of issues that would affect the market.

¹¹ As a result of a December 2000 FERC order, the PX suspended trading on January 31, 2001.

The tariffs and protocols that enabled each organization to monitor its particular market were similar as well. As an example, the ISO charged its market analysis group with the following duties:

- Observing the ISO's markets and developing indicators of market performance by studying market prices, bids, and overall competitiveness.
- Reviewing and identifying deliberate or inadvertent violations of market rules.
- Ensuring that the ISO's market rules promote efficient market operations.
- Determining the existence of anticompetitive behavior and notifying the appropriate regulators.

In addition, under their tariffs and protocols, the market monitors were responsible for reporting "undue concentrations of market power in generation or other structural flaws" to their chief executive officer, their external monitoring committee, or their governing board. "After due internal consultation," the tariffs state, the market monitors, when instructed, should "also provide such information or evidence to the appropriate regulatory and antitrust enforcement agency or agencies . . . (and) shall provide such other evidence, views, analyses or testimony as may be appropriate or required and as it is reasonably capable of providing to assist the investigations of such agencies." Thus, the market monitors were directed to report concerns first to senior management or the board, and then to external agencies, if necessary.

ISO and PX Monitoring Groups Identified and Reported Market Structural Flaws

Beginning as early as August 1998, both the ISO and PX monitoring groups identified anomalous market behavior and structural design flaws that hindsight has shown contributed to the recent spikes in wholesale electricity prices. Table 5 outlines a number of the issues the ISO and PX market-monitoring groups identified in their various reports. For example, between March and October of 1999, the ISO's surveillance committee issued reports outlining what it believed to be key market concerns. Prominent among these concerns were underscheduling in the PX day-ahead market, the fact that retail consumers could not modify

As early as August 1998 both the ISO and PX monitoring groups identified anomalous market behavior and structural design flaws.

their demand for energy in response to wholesale prices (demand elasticity), and the investor-owned utilities' overreliance on spot market energy purchases. Similarly, in March 1999, the PX concluded in a report to FERC that during periods of very high demand, a small number of power generators had the ability to determine the price for wholesale electricity.¹² By identifying and reporting these concerns, the monitoring groups raised red flags that should have indicated the increased potential for a significant disruption in the market.

FERC and the CPUC Only Partially Addressed the Concerns the ISO and PX Identified

In order to improve their market operations, the ISO and PX monitoring groups took certain actions to address problems over which they had direct control. For example, the ISO modified the order in which it purchased ancillary services by substituting, when possible, a higher-quality service for a lower-quality, more costly service. However, the primary causes of the summer price spikes, aside from changes in competitive market forces, involved the fundamental structure of the market, as discussed in Chapter 1. These problems required regulatory and/or legislative action to be corrected.

As we noted earlier, the market-monitoring groups were responsible for reporting market concerns to senior management or to their board and then to external agencies as required. As Table 5 indicates, the PX and the ISO monitoring groups appear to have followed this protocol to the best of their abilities. For example, between August 1998 and March 2000, both the ISO surveillance committee and the market analysis group contacted FERC and the CPUC on several occasions regarding the flaws they perceived in the structure of the market. In some of these instances, FERC and/or the CPUC responded by making changes in market requirements. However, for the most part, FERC and the CPUC were not successful in fully addressing and correcting the problems. As a result, many of the potential concerns identified by the monitoring groups contributed to what later became a power crisis.

Many of the potential concerns identified by the monitoring groups contributed to what later became a power crisis.

¹² "Second Report on Market Issues in the California PX Energy Markets," PX Market Monitoring Committee, March 9, 1999.

TABLE 5

Potential Concerns Identified by the Market-Monitoring Groups

Month Reported	Monitoring Group	Nature of Potential Market Concern	Regulatory Authority to Whom Concern Was Reported
August 1998	ISO surveillance committee PX market-monitoring committee	ISO is facing higher-than-anticipated demand for ancillary services.	CPUC FERC
March 1999	ISO surveillance committee ISO market analysis group PX market-monitoring committee	Generators are underscheduling supply in the PX day-ahead market. Investor-owned utilities may be underscheduling demand in the PX day-ahead market. The sequential structure of the PX and ISO markets has a strong effect on prices in the PX markets. Generators can set prices during periods of high demand.	CPUC FERC
June 1999	ISO surveillance committee	The investor-owned utilities needed more authority to enter into forward contracts. Consumers cannot respond to fluctuations in the wholesale price of electricity.	CPUC
July 1999	PX market compliance unit	Consumers cannot respond to fluctuations in the wholesale price of electricity.	FERC
October 1999	ISO surveillance committee	Generators can set prices during periods of high demand. Investor-owned utilities are prohibited from contracting outside of the PX day-ahead market.	FERC
March 2000	ISO surveillance committee ISO market analysis group	The size of the forward contracts available to the investor-owned utilities is too limited and restricts their ability to guard against price fluctuations.	CPUC FERC

Although FERC and the CPUC made changes to the market requirements, they were not successful in fully addressing and correcting concerns raised by market-monitoring groups.

The requirement that all trading initially occur in the short-term market without the option of entering into forward contracts is perhaps the most compelling example of this. According to interviews with the director of the ISO market analysis group and the chair of the ISO surveillance committee, they approached the CPUC as early as July 1999—almost one full year before the price spikes in May 2000—to discuss market design flaws in general and to implore that restrictions on forward contracting be eased in particular. As we discussed in Chapter 1, forward contracting is one way the investor-owned utilities could protect themselves against unanticipated wholesale price fluctuations by securing energy at a predetermined price for a specified period of time.

Although the CPUC in July 1999 issued a decision allowing at least two of the investor-owned utilities to buy energy through forward contracts, it required that the utilities make these purchases only through the PX, and it limited the amount of energy that could be purchased under forward contracts. In making this decision, the CPUC stated that it was limiting the amount and duration of the power that could be secured using forward contracts because it was concerned that the investor-owned utilities would use forward contracts to do speculative trading in the PX market. Apparently, the CPUC's July 1999 decision did not go far enough in providing the investor-owned utilities with the price protection they sought, because it had to act again in March 2000 to increase the amount of electricity the utilities could purchase in the forward market. Nonetheless, possibly due to the threat of reasonableness reviews, the investor-owned utilities did not avail themselves fully of their ability to obtain forward contracts. Moreover, the CPUC had to act again in August 2000 to grant the larger investor-owned utilities the flexibility to enter into bilateral contracts. By that time, severe wholesale price spikes were already affecting the marketplace.

Similarly, some of FERC's actions failed to fully address and correct problems identified by the PX and ISO monitoring groups. For example, in November 2000, FERC acknowledged that a change it had approved in May 1999 to the ISO's procedures for procuring replacement reserves proved ineffective at reducing the amount of energy underscheduled in the PX markets. As a result, this problem escalated and eventually contributed significantly to the State's electricity problems, as we discussed in Chapter 1.

FERC LIMITED ITS REACTION TO SUMMER 2000 ENERGY PRICES TO MODIFYING THE MARKET DESIGN

On August 23, 2000, after California's wholesale electricity markets experienced huge price increases, FERC commissioned an investigation by its staff into the conditions affecting California's power markets. The results of this staff investigation prompted FERC to issue a preliminary order in November 2000 and a final order in December 2000 that outlined the changes it believed were necessary to restore order to the State's wholesale electricity markets. Despite evidence suggesting that sellers during the past summer had the potential to exercise market power—defined by FERC as the ability of an entity to influence market outcomes for a sustained period—that may have contributed to higher wholesale electricity prices, FERC concluded that the evidence analyzed during its investigation was inconclusive in determining whether individual sellers exercised actual market power. FERC stated that further study of high bids made by individual firms or information concerning periods when generators were not running would be needed to substantiate any charges of market power abuse. However, FERC never conducted such a study. Instead, it argued that because California's markets are still developing, altering the market rules is the best way to correct design and implementation flaws and to deal with scarce supply. Even though FERC stated previously that it believed that summer 2000 wholesale electricity prices were unjust and unreasonable, FERC informed the Western Governors Association in late December 2000 that it would not pursue individual power generator repayments to those who purchased wholesale power because tracing the transactions would be a time-consuming, if not impossible, task.

Despite evidence suggesting that sellers had the potential to exercise market power, FERC stated that further study would be needed to substantiate charges of market abuse, but did not follow through with such a study.

Stating in its preliminary order that “the deregulatory approach adopted by California not only failed to address many of the existing problems which were plaguing the State, but in many ways it exacerbated and magnified those problems,” FERC concluded that “the electric market structure and market rules for wholesale sales of electric energy in California are seriously flawed.” In an attempt to rectify these problems, FERC, among other things, mandated in its December 15, 2000, order the following:

- The elimination of the requirement that the investor-owned utilities buy and sell all electricity through the PX short-term markets.

- The restructuring of the governing board of the ISO to remove stakeholders and replace them with members that are independent of market participants.
- The imposition by the ISO of penalties when 95 percent of an entity's demand is not scheduled a day ahead.

Although these changes do represent a step in the right direction, they do not fully address the flaws in the market structure. In fact, some of FERC's modifications may introduce new problems to the power market.

FERC Did Not Investigate Market Power Abuse Despite Empirical Evidence That Prices Significantly Exceeded Production Costs

In its November report, FERC acknowledged that the ISO surveillance committee employed a specific technique for analyzing the abuse of market power and that its findings suggested that market power was exercised in June 2000.

The [surveillance committee] estimated a significant degree of market power being exercised in California markets for the period October 1, 1999, to June 30, 2000 For the last month of the sample, June 2000, they estimated that prices were 64.6 percent higher than they would have been under competitive conditions. The highest previous monthly market power index was in June 1998, when prices were estimated to be 39.9 percent higher than they would have been under competitive conditions. These [findings] certainly suggest that market power was exercised in June by the standard of short run marginal costs.

In November 2000, FERC acknowledged that the ISO surveillance committee's findings suggest that market power was exercised in June 2000.

Yet, despite its apparent agreement with the ISO surveillance committee's analysis, FERC chose not to pursue a further investigation of potential market power abuse in order to mete out potential sanctions. In explaining its decision, FERC noted the difficulty in separating higher prices due to the payment of scarcity premiums from the exercise of market power, as well as the difficulty of proving market abuse by individual firms. FERC argued that a power plant owner could exercise market power either by submitting bids in significant excess of its opportunity cost in order to raise the market-clearing price or by physically withholding power from the market in order to decrease the

available supply, and that determining either type of market power abuse is problematic. Because power plant owners have many markets to choose from in California, assessing true opportunity cost—the difference between the revenue gained and the revenue forfeited by rejecting alternative courses of action—is difficult, and during periods of high demand, it is hard to differentiate physical withholding from real unit outages. Thus, what appears to be the exercise of market power may be a power plant owner responding to price signals or operational considerations.

Moreover, as a developing market, California’s problems may have been exacerbated by market design and implementation flaws. For this reason, FERC stated, the best solution for the State was to change the market rules.

FERC stated that as a developing market, California’s problems may have been exacerbated by market design and implementation flaws. For this reason, FERC believed the best solution was to change market rules.

Significant market power abuses that violate market rules need to be dealt with directly, but market power in a newly developing market may be magnified by flaws in market rules. The best approach in these cases may be to change the rules in order to mitigate the impact of market power exercise. Mitigation in the form of rule changes may be appropriate even in the absence of findings of market power exercise by specific sellers or buyers, if there are clear incentives for its exercise, and there are potentially large impacts that cannot be adequately separated from the effects of scarcity.

According to FERC, during periods of scarce supply, the price naturally increases. However, during those same periods, the ability and incentive to exercise market power also increases. Thus, it is difficult to separate scarcity from market power. Under these circumstances, FERC argued, it makes more sense to alter the rules than to try to determine whether market power was being exercised.

FERC Argued That the Reasonableness of Rates Cannot Be Determined From Isolated Time Periods

FERC’s preliminary order, issued in November 2000, stated that “while the record did not support findings of specific exercises of market power in these spot markets, and while we were not able to reach definite conclusions about the actions of individual sellers, there was clear evidence that the California market structure and rules provide the opportunity for sellers to exercise market

FERC concluded that California's electricity rates during the summer of 2000 were unjust and unreasonable under the Federal Power Act.

power when supply is tight and can result in unjust and unreasonable rates under the [Federal Power Act].” In response to this statement, various generators contacted FERC to challenge these findings or demand clarification. In its final order, FERC concluded that California’s electricity rates during the summer of 2000 were unjust and unreasonable under the Federal Power Act. However, responding to the comments of one generator, Dynegy, FERC also found that when analyzing rates for reasonableness it could not look at an isolated time period but must look instead at a representative time period.

In response to Dynegy, we agree that in analyzing the reasonableness of rates in a particular market we cannot look at prices based on an isolated time period, but rather must look at a representative time period. We further agree that we need to distinguish scarcity rents from exercises of market power; however, we disagree that, absent exercise of market power, prices are necessarily just and reasonable. Our analysis must be, as discussed above, based on a determination of whether the rate falls within a zone of reasonableness.

Even with its finding that the rates were not just and reasonable, because of the complexity of the task, FERC informed the Western Governors Association in late December 2000 that it would not trace the dollars related to the transactions that occurred in the summer of 2000. At the meeting, the former chair of FERC stated, “Because any attempt to trace all of these dollars would be a time-consuming, if not impossible, exercise, the [FERC] has focused its efforts in western markets on operating procedures and fixing structural flaws in the underlying market design.” Moreover, as FERC outlined in its December 2000 order, it decided to limit the time it would use to analyze future transactions for assessing any potential refunds.

We clarify that, unless the [FERC] issues some form of notification to a seller that its transaction is still under review, refund potential on a particular transaction will close 60 days after the initial report¹³ is filed with the [FERC]. The institution of a 60-day period for the review of the transactions will provide sellers with the certainty they request and allows a reasonable period for analysis by staff.

¹³ The initial report refers to FERC’s requirement that generators that are paid more than \$150 per megawatt hour in the PX or ISO markets, report to FERC information on their costs of production.

FERC Found That Channeling Power Through Out-of-State Markets Into the ISO Is Not Necessarily Against Market Rules

As we discussed in Chapter 1, the ISO can purchase power when necessary from out-of-state sellers for prices above the ISO price cap. This creates the potential for in-state generators to channel power through an out-of-state distributor that can in turn sell the power back to the ISO for higher prices. Despite the fact that this practice in effect circumvents the ISO price caps, FERC concluded in its December 2000 order that it becomes a problem if it is done to drive up prices. Because there are no specific administrative rules requiring sellers to participate in the PX market, such maneuvers are not improper. According to FERC:

In one sense, this is not [improper] since there are no administrative rules on the amount of capacity (electricity) that must be provided to meet [demand] as there are in the eastern ISOs. [Buyers] are required to bid into the PX, but there is no capacity (seller) penalty imposed if corresponding supply does not bid into the PX.

According to the FERC order, “These exporting practices are permitted under the rules and are not necessarily a market power problem. It may simply be the normal working of a market where sellers are maximizing profits in a competitive market, where sellers or buyers see an opportunity at one time, take an option, and exercise it at a later date.” However, FERC does state that:

It becomes a problem if it is associated with a pattern of withholding resources from the market in order to drive up prices. For example, if a large seller outside California were able to influence the price of power in the West by acquiring power from California, withholding power from the market at a critical time, and [then] selling the power back to California. As such, it is part of the overall issue of market power and scarcity in the West . . .

According to FERC, there are no administrative rules on the amount of electricity that sellers must provide in the PX market to meet demand.

FERC's Elimination of the Requirement That the Investor-Owned Utilities Purchase Energy Through the PX May Introduce New Problems

FERC's most significant market modification in its December 2000 order was the elimination of the PX buy/sell requirement for investor-owned utilities. As we discussed in Chapter 1, the original terms of deregulation required that these utilities make all of their energy purchases and sales in the PX's short-term markets. FERC eliminated this restriction, enabling the investor-owned utilities both to enter into new bilateral or long-term contracts to meet demand and to use the 25,000 megawatts (MW) of generation they had not divested to serve their own customers. Under FERC's order, the CPUC was responsible for approving the prices and terms of these new contracts. FERC also adopted, for one year, a benchmark price of \$74 per megawatt hour (MWh) that it will use to monitor whether rates for five-year wholesale supply contracts for electricity (forward contracts) are just and reasonable. However, FERC acknowledged that the benchmark is intended to provide guidance to market participants and that the CPUC still has the ultimate authority for approving the prices and terms of contracts involving investor-owned utilities.

The ISO surveillance committee correctly predicted that eliminating the buy/sell arrangement coupled with the \$150 "soft price cap" would result in the PX losing significant volumes of trading.

In response to the December order, the ISO surveillance committee commented that FERC's modifications might lead to more forward contracting, but at the expense of the ISO's ability to monitor the markets because the terms of bilateral transactions would not be reported. The ISO surveillance committee also had concerns that the elimination of the buy/sell arrangement, coupled with FERC's \$150 per MWh "soft price cap," would result in the PX losing significant volumes of trading, since sellers could avoid the cap by signing bilateral contracts, selling through other scheduling coordinators, or selling outside California.¹⁴ The ISO surveillance committee recommended that the investor-owned utilities be given greater freedom to enter into a variety of forward contracts, but that they still be required to schedule the forward contracts through the PX. It also recommended that the CPUC remove the retail rate freeze, thus introducing retail competition into the marketplace. The ISO surveillance committee's reasoning was that under retail competition, investor-owned utilities would have an effective incentive to acquire electricity as cheaply as possible.

¹⁴ Note that the latter action may simply mean that the same power is resold back into California via an out-of-state market transaction. It is unclear how the tracking of such costs would be monitored and deemed excessive even should they exceed FERC's soft cap.

In fact, the past few months have shown that the ISO surveillance committee was accurate in anticipating the effect that eliminating the buy/sell requirement would have on the PX. Shortly after the adoption of FERC's December order, the PX suspended all wholesale energy trading. As a result, it has been unable to recover enough revenues to stay in business and has announced that it is going to shut down its operations; it has already begun to make layoffs.

Regarding the imposition of FERC's \$74 per MWh benchmark price, the fact that FERC found it necessary to mandate a benchmark suggests that it believes the market is not truly competitive and that sellers might have some ability to exercise market power. Moreover, if sellers are unwilling to contract with the investor-owned utilities at this benchmark price, the utilities may be driven to make more purchases through the ISO real-time market, where they are likely to pay \$150 per MWh—the soft price cap—or more.

FERC Imposed Penalties on Buyers That Underscheduled But Did Not Impose Penalties on Sellers

FERC's December order required investor-owned utilities to schedule 95 percent of their demand through forward contracts or the day-ahead market. If the utilities failed to schedule more than 5 percent of the energy required for any hour, FERC authorized the ISO to impose a monetary penalty equal to two times the ISO's real-time cost of energy, not to exceed \$100 per MWh, with the penalty revenues to be disbursed among those market participants that accurately scheduled 95 percent or more of their demand for electricity in forward contracts or in the PX day-ahead market. FERC's objective in directing the ISO to assess this penalty, combined with its elimination of the mandatory buy/sell requirement, was to eliminate the chronic underscheduling of demand that forced the ISO to purchase significant levels of power in real time at unreasonably high prices during the last half of 2000.

FERC's objective in directing the ISO to assess penalties against buyers was to eliminate chronic underscheduling of demand.

The ISO surveillance committee expressed concern with this proposal because it does not mandate that suppliers enter into forward contracts, nor does it penalize suppliers who underschedule. The likely result is that sellers will in effect incorporate the possible price of penalties into their selling prices, reflecting the fact that buyers are willing to pay more to be fully scheduled to avoid an underscheduling penalty in the

ISO real-time market. For a more complete list of the changes that FERC and others have recommended for California's energy market, see Appendix C.

Data Published on the PX and ISO Web Sites May Adversely Affect Competitive Markets

Within the California market, specific bidding data are confidential; nevertheless, the ISO and, when it was operating, the PX, periodically, have published market-clearing price and quantity data on their respective Web sites. The PX also published its market models and gave market participants access to data that would enable them to formulate their own econometric models, such as data on market prices and volume. The argument in favor of publishing the models and detailed market information is that it helps competitive markets function more effectively, as understanding the workings of these markets is key for new and existing market participants to compete. However, by making some of the data publicly available, or not further delaying the release of certain data, the PX and ISO have facilitated the market participants' ability to bid strategically. As we discussed in Chapter 1, strategic bidding has contributed to high wholesale energy prices in the PX and ISO markets and perpetuated crisis operations for the ISO.

By making bidding data publicly available, the PX and ISO have facilitated the market participants' ability to bid strategically.

RECOMMENDATIONS

Limit the Amount of Market Data Published on Web Sites

Some argue that it was necessary for the ISO and the PX to publish as much data on price and volumes as possible so as to encourage new entry into the market. Although the data have been published only after the fact, when coupled with the published PX pricing model, this has meant that predicting market-clearing prices became increasingly easy. Even using stale data, market participants could begin to develop their own models and bidding strategies, and to check their bidding strategy assumptions and adjust them where necessary. With respect to the PX, this point is moot, because recent events have caused the PX to cease trading in its markets. The ISO, however, should:

- Avoid making available to the public any new oversight and market-monitoring models developed.
- Delay making public for at least one year, data for bidding and winning bids. This is especially critical for information concerning long-term contracts the ISO might enter into to meet its ancillary services needs. ■

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CHAPTER 3

Uncontrollable Shifts in Competitive Market Forces Affected Wholesale Energy Prices

CHAPTER SUMMARY

At the time California switched to a competitive wholesale power market, the State was emerging from a recession and had more generating capacity than it needed. In other words, the supply of electricity in California exceeded demand, and it was nearly inevitable that the creation of the Power Exchange (PX) and Independent System Operator (ISO) markets would lead to a reduction in wholesale prices. However, the competitive market forces that resulted in lower wholesale prices in 1998 shifted significantly during 2000. The following forces outside the control of the ISO and PX contributed to the recent sharp increases in the State's electricity prices:

- Growth in California and the western region's electric demand was not matched by increases in supply.
- Unusual climatic conditions in California and the entire West contributed to increased electric demand while also inhibiting the generation of hydroelectric power.
- An unexpected and dramatic rise in natural gas prices significantly increased the cost of producing electricity through gas-fired power plants.
- A high demand for power resulted in increased costs for meeting the State's air quality emissions limits.

It is important to note that although these market forces played a role in the rising wholesale electricity prices during the summer of 2000, they do not explain the entire increase. As we discussed in Chapters 1 and 2, the effect of these market forces was exacerbated by a flawed market structure and problems with market rules.

GROWTH IN DEMAND AND LIMITED INCREASES IN SUPPLY INFLUENCED ENERGY PRICES

When the California Legislature voted to deregulate the State's wholesale electricity markets in 1996, the State and the whole western region had excess generating capacity that kept California's wholesale electricity prices relatively low. However, between 1996 and 2000, demand for electricity in both California and the rest of the western region grew at unanticipated rates. During this period, generators chose not to site and build sufficient new power generation to keep pace with demand within the State. In addition, atypical weather patterns across the West during the year 2000 affected supplies of electricity while heightening demand. As a result, the excess energy available when deregulation took effect in 1998 had all but disappeared by the summer of 2000. The increased demand and decreased supply contributed to California's unprecedented wholesale electricity prices.

Regional Increases in Demand Were Not Matched by Additions to Supply

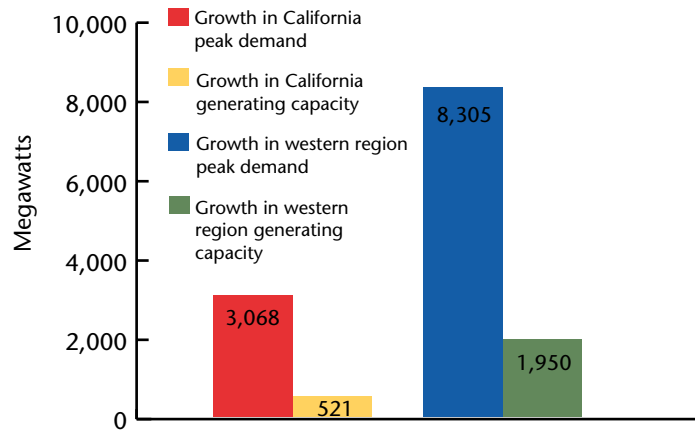
The western states' supply of and demand for electricity are interdependent. Power often flows back and forth between the states in the winter and summer months when certain states are warm and others are cold. For example, during the summer months, the Northwest typically sends power to the Southwest, and in the winter months, the reverse is generally true. This coordination of the supply of and demand for electricity optimizes each state's electrical generation year round, reducing the overall need to build power plants in the western region.

In 1996, when California's Legislature voted to deregulate the State's wholesale electricity markets, the whole western region had approximately 20 percent excess generating capacity. Because of the energy interdependence of these states, the excess capacity helped serve the electricity needs of California and the other western states. However, between 1996 and 2000, demand for electricity in both California and the rest of the western region grew at unanticipated rates. Regionwide, total power consumed rose 8.3 percent, while consumption in California climbed 9.2 percent during the same period. As Figure 7 demonstrates, neither California nor the region as a whole added capacity at a pace that matched demand growth.

Between 1996 and 2000, the western region's demand for electricity grew at unanticipated rates. Neither California nor the region added enough capacity to keep pace with demand.

FIGURE 7

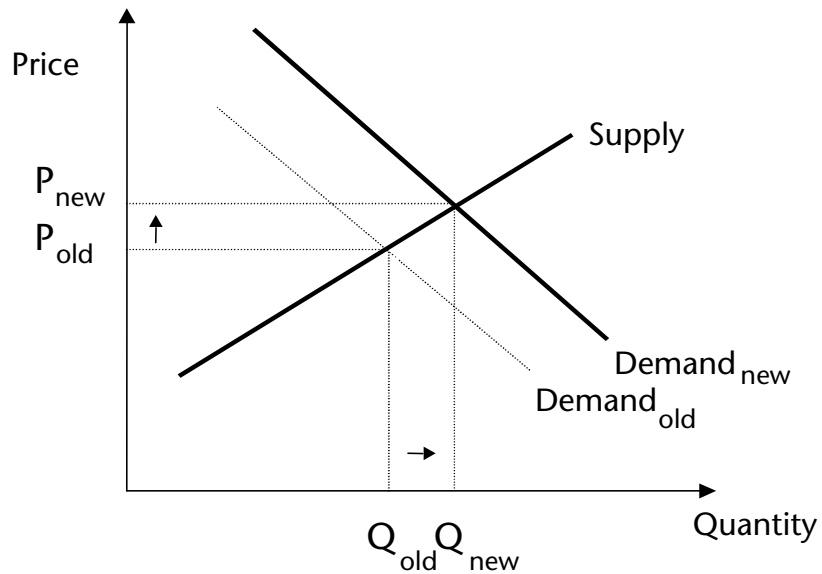
Comparison of Growth in Peak Demand Versus Growth in Generating Capacity—1996-2000



In competitive markets, the selling price of a commodity is determined by a combination of three basic factors: the cost of producing that commodity, the quantity of the commodity available on the market, and the level of buyer demand for the commodity. When any of these three factors shift—for instance, if supply increases or demand changes—the price of the commodity is directly affected. The recent popularity of a certain computer game is a good example of prices rising when demand increases and supply does not. As parents (and their children) demanded this game as a holiday gift, the price increased because there were not enough of the computer games to satisfy all of the buyers. Figure 8 illustrates this example. In commodity markets, shifts in both demand and supply are often commonplace. This means that competitive prices and quantities can be quite variable, particularly with a commodity such as electricity that cannot be readily stored.

FIGURE 8

As Demand Increases, Price Increases



The recent increases in demand for electricity can be partially explained by the western region's expanding economy. Between 1996 and 1999, regional personal income grew at more than 6 percent per year. In 2000, the western states enjoyed an 8.9 percent increase in personal income; California's personal income growth rate was slightly higher, at 9.3 percent. Additional personal income is tightly linked to an increased demand for goods and services, and electricity is a major factor in producing those goods and services. Therefore, as the West's economy grew, so did its demand for electricity.

Related to the West's healthy economy is population growth. Over the four years from 1996 through 2000, the western region collectively grew at a compound annual rate of 2 percent, compared to the nationwide pace of 1.5 percent. The population within California grew by more than 400,000 each year from 1996 through 1999, equating to a growth rate of over 4 percent. Moreover, between 1999 and 2000 alone, the State's population increased by roughly 725,000. Population growth leads to rising electricity demand, simply because more people and households require more electrical service.

Although California and the region experienced additional demand for electricity, no significant centralized generation was added to the State between 1996 and 2000. Data from the

California Energy Commission indicate that only three generating plants larger than 50 megawatts (MW) were built during this time; one 240 MW plant in 1996 and two plants (123 MW and 158 MW) in 1997, for a total of 521 MW of new generation.¹⁵ According to a report by the Federal Energy Regulatory Commission (FERC), the region as a whole reflected a similar failure to construct new power sources during the period. As was shown previously in Figure 7, additions to the electricity supply were less than sufficient to meet the increase in demand in California and the western region. The failure to close this gap to keep pace with rising demand is one of the factors leading to California's unprecedented wholesale electricity prices beginning in the summer of 2000.

Unusual Weather Patterns Upset Regional Demand and Generation Trends

As we mentioned previously, power typically flows between the states of the western region during the winter and summer months when certain states are warm and others are cold. Although weather cannot be predicted with certainty, wet years in the Northwest have often been associated with warm conditions in the Southwest, and conversely, dry years in the Northwest have been generally linked with cooler temperatures in the Southwest. The utilities located in the various western states depend on these past weather patterns to coordinate their plans to meet the region's supply and demand needs for electricity in any given year.

Past weather patterns did not hold true in 2000; low amounts of precipitation in the Northwest combined with extremely hot temperatures in the Southwest. This meant that 15 percent to 20 percent of the electricity California needed for the summer was not available.

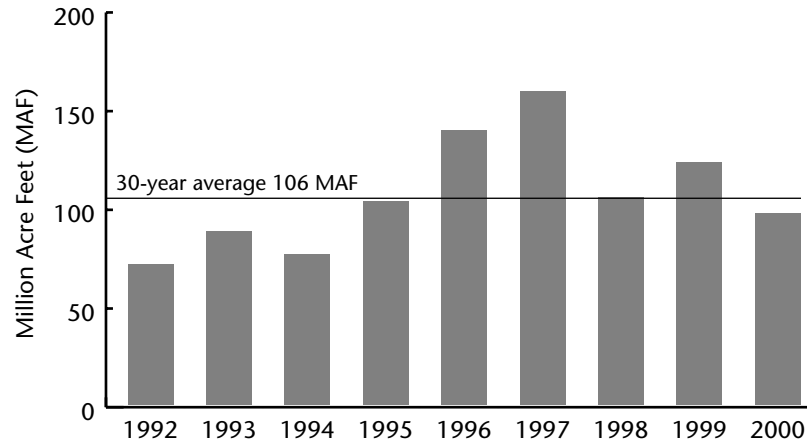
However, these weather patterns did not hold true in 2000, when low amounts of precipitation in the Northwest combined with extremely hot temperatures in the Southwest. As Figure 9 shows, the water runoff for the Northwest in the first seven months of 2000 was below the 30-year average; it was also less than any year since 1995. Because the rain and snow normally fuels the Northwest's hydroelectric generators, thereby producing electricity to help cool the Southwest, the shortfall in precipitation meant that 8,000 to 12,000 MW of electricity were not available to be sent to the Southwest in 2000. As much of the energy California uses in the summer is produced by hydroelectric generators located in the Northwest, this meant that 15 percent to 20 percent of the electricity California needed for the summer was not available from traditional out-of-state sources. The lower Northwest hydroelectric capability was thus a factor

¹⁵ A 100 MW plant will provide enough electricity to power 100,000 households.

contributing to the increased prices that began in May and June of 2000 and that have continued through the summer and the rest of the year.

FIGURE 9

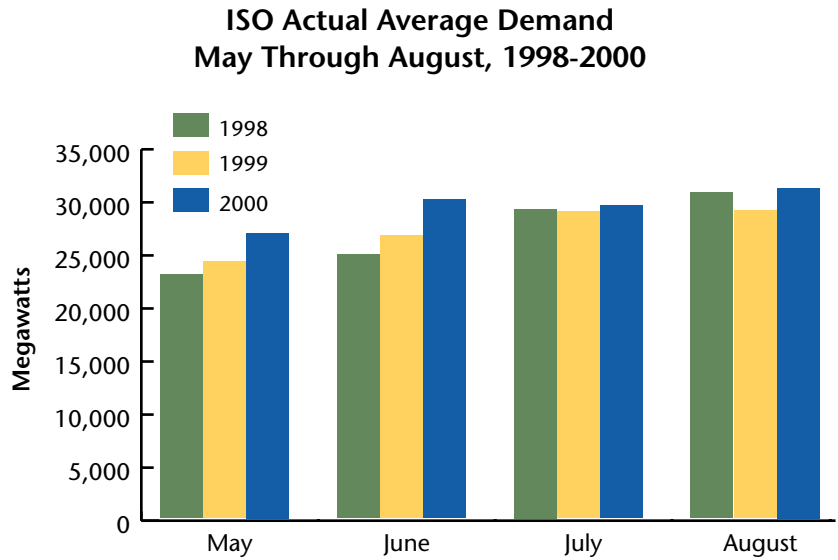
**January to July Volumes of Run-Off in the Northwest
1992 Through 2000**



Source: FERC staff report dated November 1, 2000, and PX Compliance Unit.

The earlier-than-normal hot weather and the overall higher temperatures experienced throughout the western region last summer compounded the problem of decreased hydroelectric capability in the Northwest. According to FERC, May and June 2000 ranked among the 15 hottest May/June periods in the western region in the last 100 years. This was true for California as well. As shown in Figure 10, the average demand for electricity in California in May and June 2000 was significantly higher than during the previous two years.

FIGURE 10



Source: FERC staff report dated November 1, 2000.

These high temperatures and the subsequent increased demand for energy continued throughout the summer. For example, California's average temperatures for May and June 2000 were the hottest on record in over 80 years, July was the hottest in over 20 years, and August was the hottest in more than 60 years. In other parts of the western region, such as the Southwest, the four months from May through August were ranked among the hottest in more than 80 years. This coupling of hot weather with the Northwest's low water runoff conditions contributed to higher wholesale electricity prices in California. Low water conditions curtailed the Northwest's generating capacity and, because of the weather, the energy that was produced in the Northwest was needed to serve local demand and therefore was not available for import into California.

RISING NATURAL GAS PRICES INCREASED THE COST OF GENERATING ELECTRICITY

The price of fossil fuels, in particular natural gas, is a fundamental determinant of the price of electricity. Between January and December 2000, the cost of natural gas delivered to California's electric generators more than doubled. Because 52.3 percent of the State's power is produced using natural gas, this caused a sharp increase in the operating costs of these gas-fired generating

plants that is reflected in their wholesale prices for the sale of electricity. Moreover, the rising prices for natural gas have also had an effect on the overall wholesale price of electricity. Because of the single market-clearing price used in the State's electricity market, the price of all electricity traded during certain hours is often set by natural gas-powered generators. Thus, the increase in the cost of gas-generated power has in turn caused an increase in the price of electricity generated through other methods. Like the changes in supply and demand and the unpredictability of the weather, the price of natural gas is a competitive market force, a force that affects the price of electricity but is beyond the control of either the PX or ISO.

The more than doubling of the price of natural gas in California during 2000 had a profound impact on the wholesale price of electricity.

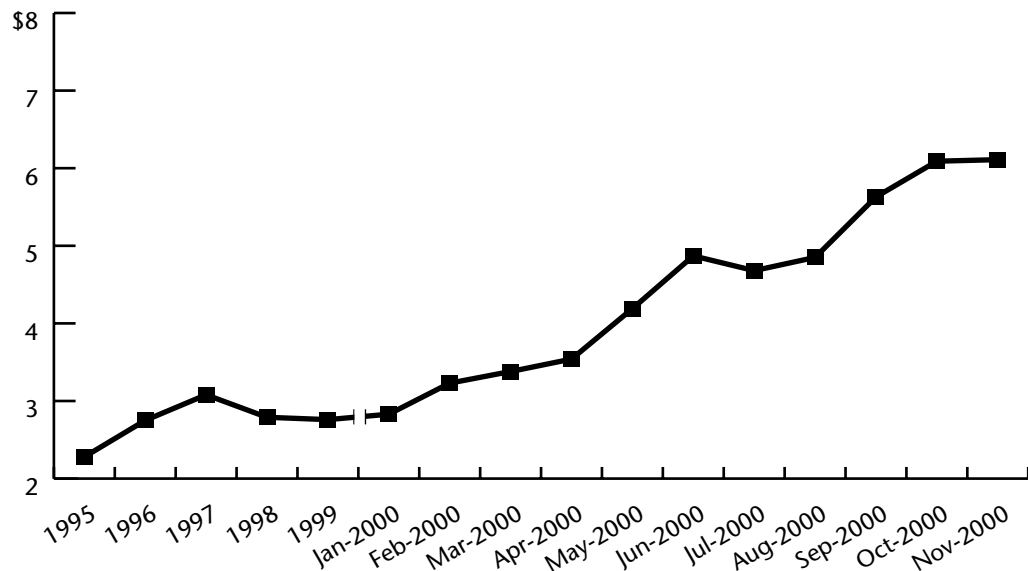
Throughout the State, there are approximately 1,000 power plants. If all were running at the same time and essentially at capacity, California is capable of producing approximately 53,200 MW of electric power. Of the total number of power plants within the State, approximately 325 are run principally on natural gas; these plants constitute 52.3 percent, or 27,829 MW, of the State's total generating capacity. Power plants that run on natural gas provide several advantages over those that use other fuel sources. First, natural gas plants typically emit fewer pollutants than plants that run on coal or diesel fuel, making them attractive in meeting California's environmental requirements. Additionally, gas-fired plants can be constructed in a variety of sizes and are thus more flexible in terms of size and operation than coal and nuclear plants. Moreover, in recent years, the cost of natural gas was low, which made gas-fired plants a relatively inexpensive source of electric power.

However, during 2000, the cost of natural gas hit historic highs in California. Natural gas can generally be purchased in one of two ways: under delivery contract or on the spot market. Buying commodities under contract reduces the purchaser's exposure to unexpected price fluctuations and may reduce the overall cost of the commodity because the purchaser is promising to buy a certain amount at a certain price. Without a delivery contract, electricity generators buy their natural gas supplies on the spot market, where the price is subject to greater fluctuation and includes a convenience and availability surcharge.

Nationwide, natural gas prices were about \$2.50 per thousand cubic feet (Mcf) in 1999. The cost of natural gas delivered to electricity generators in California was comparable. However, between January and December 2000, the cost of natural gas delivered to California electricity generators doubled to about \$6 per Mcf as shown in Figure 11. Until June 2000, prices on the natural gas spot market were just slightly above delivery contract prices, but by December, spot market prices were roughly four times higher (see Figure 12). According to the Energy Information Administration, the rise in natural gas prices in both markets was driven by the inability of natural gas production to keep pace with the rapid growth in demand. Demand for natural gas is a result of overall economic growth and the shift toward natural gas as both a direct energy source and a means to fuel electricity production.

FIGURE 11

**Cost of Natural Gas Delivered to California Electricity Generators (\$/Mcf)*
1995 Through November 2000**

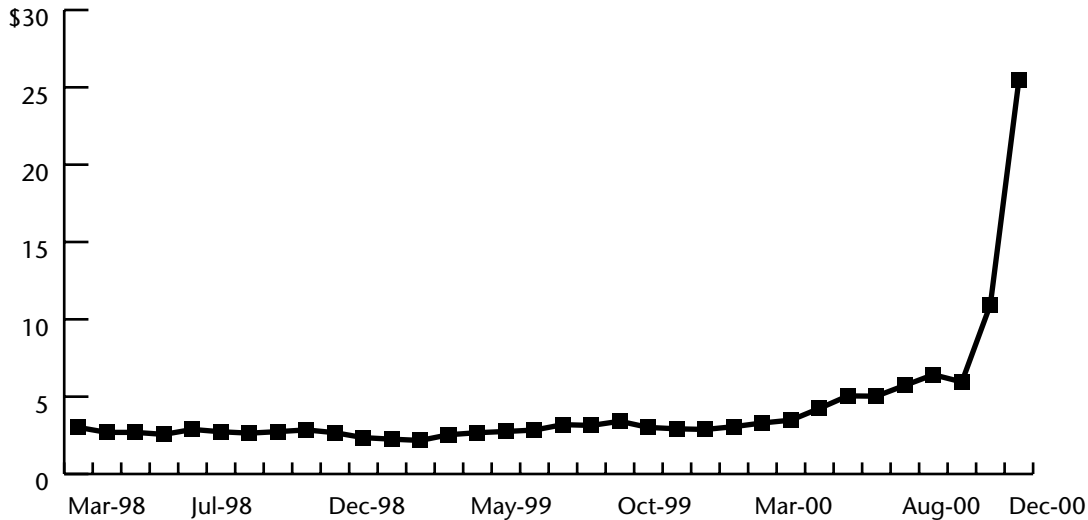


Source: Energy Information Administration (EIA) for data through August 2000.
September through November data estimated based on EIA data.

* Dollars per thousand cubic feet.

FIGURE 12

**Spot Price of Natural Gas* (\$/Mcf)[†]
March 1998 Through December 2000**



Source: California ISO.

* The spot price noted represents spot prices at California's main natural gas delivery point—the SoCal Border.

[†] Dollars per thousand cubic feet.

The sharp rise in natural gas prices has had a considerable impact on California's wholesale electricity prices. For example, assume that a typical gas-fired power plant consumes approximately 10 million British thermal units (10 MMBtu) of natural gas to produce one megawatt hour (MWh) of electricity and the wholesale spot price for one MWh of electricity was \$20. If the price of natural gas rises from \$2 per MMBtu to \$4 per MMBtu, the fuel cost increases from \$20 per MWh to \$40 per MWh. The actual increase in natural gas prices in California has caused electricity production costs in these gas-fired plants at least to double.

Because of the way the power market is structured, at times this increase has been reflected in the wholesale cost of all electricity sold through the PX. As the State's primary wholesale market for electricity, the PX was run as a single-price auction. This meant that bids to buy electricity during a given hour and bids to sell electricity during that same hour were ranked and the point where the two intersected was the price that all buyers paid and all sellers received for that hour. (See Appendix B for a further discussion of single-price auctions.) Many of the State's gas-fired power plants are used specifically to meet peak electricity demand

and are more costly to run because they are operationally less efficient than those plants designed to meet the ever-present minimum demand for electricity. Thus, at times of high demand, such as summer in warm-weather areas and winter in colder areas, peak-demand plants were bid into the PX wholesale electricity market at prices reflecting their higher operating costs. As we noted earlier, in the single-price auction, the intersection of supply and demand sets the price for all electricity sold during a particular hour. Thus, when hourly demand was high, it was the higher cost of peak-demand units run on natural gas that set the price in the PX single-price auction.

CALIFORNIA'S AIR QUALITY RESTRICTIONS HAVE CONTRIBUTED TO THE COST AND SHORTAGE OF ELECTRICITY

The increased cost of the credits that allow power plants to emit pollutants into the atmosphere, also contributed to increases in the price of wholesale electricity.

Power plants must adhere to air quality standards set by the State's Air Resources Board, which is responsible for developing the State's air pollution standards and overseeing the operation of numerous air quality districts that implement state and federal clean air standards. Annually, power plants are allocated "pollution credits" or reclaim credits allowing that plant to emit a certain amount of pollutants the most significant of which are nitric oxide and nitrogen dioxide, commonly referred to as NO_x. Typically, one NO_x reclaim credit is equal to one pound of emissions, and a reasonably efficient natural gas-powered plant emits one to two pounds of NO_x per MWh.

Once a plant exceeds its allocation of reclaim credits, the plant operator faces the choice of obtaining additional credits from other plants that will not use up their yearly allotment or shutting the plant down. The cost of these NO_x reclaim credits was another competitive market force affecting the cost of wholesale electricity this summer and through the end of the year. At the start of 2000, a NO_x reclaim credit traded for \$1. By May the price was up to \$5, and by December NO_x reclaim credits were selling for \$46 as shown in Table 6. Comparatively, the 1999 average trading cost of a NO_x reclaim credit was \$6.94.

Because the prices of NO_x reclaim credits jumped so significantly, plants that had exceeded their pollution credits faced increased production costs or, if they chose not to purchase additional credits, had to curtail power generation. Either choice affected the wholesale price for electricity. For example, if a power plant was emitting two pounds of NO_x per MWh produced and the

operator chose to purchase NOx reclaim credits in August 2000, the cost of these credits would have added \$60 (2 x \$30) to the cost of producing each MWh. Thus, a MWh that cost \$35 to produce in January would have cost \$95 to produce in August, based on the increased cost for NOx credits and assuming all other factors remained equal.

TABLE 6

**Estimated Average Monthly Price of NO_x Reclaim Credits
May Through December 2000**

	May	June	July	August	September	October	November	December
Price of NO _x reclaim credits	\$5	\$10	\$20	\$30	\$45	\$47	\$47	\$46

Source: FERC staff report dated November 1, 2000, and California ISO.

On the other hand, if operators chose to curtail power production rather than pay high prices for reclaim credits, the supply of electricity available on the market was diminished. During 2000, there are indications that a number of gas-fired power plants had to curtail their output because they had exhausted their available NOx reclaim credits. At times of diminished supply, if demand does not change or increases, the laws of economics dictate that the price of electricity goes up. Therefore, whether plants chose to purchase high-cost reclaim credits or to curtail production, the decision resulted in higher wholesale prices for electricity.

We conducted this review under the authority vested in the California State Auditor by Section 8543 et seq. of the California Government Code and according to generally accepted government auditing standards. We limited our review to those areas specified in the audit scope section of this report.

Respectfully submitted,

A handwritten signature in black ink that reads "Elaine M. Howle". The signature is written in a cursive, flowing style.

ELAINE M. HOWLE
State Auditor

Date: March 22, 2001

Staff: Doug Cordiner, Audit Principal
Sharon L. Smagala, CPA
Sharon Reilly, Esq.
Rob Hughes
Joel Riphagen
Mandi R. Steele
Ryan Storm

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APPENDIX A

Legislation and Executive Orders Addressing the Energy Crisis

Appendix A contains the following information on actions taken by the Legislature and the governor to address the energy crisis:

- Legislation enacted from the 2001-02 First Extraordinary Session of the Legislature. Each of these bills was enacted as an urgency statute.
- Executive Orders issued by the governor as of March 13, 2001.
- Legislation pending in the 2001-02 Regular Session and the 2001-02 First Extraordinary Session of the Legislature as of March 8, 2001. This exhibit is intended to provide an overview of the wide range of issues covered by the pending legislation and is not intended to be an exhaustive description of the subject matter of each bill. Bills that address multiple issues may be listed in more than one category.

Except in the case of urgency legislation or a tax levy, bills enacted at the Regular Session will take effect on January 1, 2002, and bills enacted at the First Extraordinary Session will take effect on the 91st day after adjournment of the extraordinary session. Urgency statutes and statutes providing for tax levies take effect immediately upon enactment. The vote requirement for passage of the bills is generally a majority vote of the membership of each house of the Legislature, with urgency measures or bills making an appropriation from the General Fund requiring a vote of not less than two-thirds of the membership of each house of the Legislature.

TABLE 7

Chaptered Legislation*

Bill Number [†]	Author(s)	General Description/Purpose	Status of Bill
AB 1X	Keeley	<p>Authorizes the Department of Water Resources (department) to enter into contracts for the purchase of power under terms, conditions, and rates the department deems appropriate, taking into consideration certain factors.</p> <p>Terminates the department’s authority to enter into those contracts on January 1, 2003.</p> <p>Authorizes the department to sell the power it acquires to retail end-use customers and to local publicly owned electric utilities for prices not to exceed the department’s purchase cost and requires that all money collected from that sale be deposited into the department’s Electric Power Fund (fund).</p> <p>Authorizes the department to issue bonds with the approval of the Director of Finance and the State Treasurer. Those bonds would not be backed by the full faith and credit or taxing power of the State.</p> <p>Appropriates \$495,755,000 to the fund for the purposes of the bill.</p> <p>Requires the California Public Utilities Commission (CPUC) to calculate the California Procurement Adjustment and to determine the amount of the adjustment that pertains to the power sold by the department. This amount is payable to the department for deposit in the fund upon receipt by the electrical corporation of revenues from retail customers.</p> <p>Requires the department to make quarterly and annual reports to the governor and Legislature with regard to its activities and expenditures authorized under the bill.</p> <p>Requires the Bureau of State Audits to audit and report on the department’s implementation of the bill on or before March 31, 2003.</p> <p>Exempts an aggregator or supplier of electric power for small commercial and residential customers from verification requirements when a customer calls directly to change service providers.</p> <p>Authorizes the department to hire employees at salaries exceeding Department of Personnel Administration standards and to contract with public agencies or private companies to carry out the bill’s provisions.</p>	Chapter 4, Statutes of 2001
AB 5X	Keeley	<p>Requires the existing Independent System Operator’s (ISO) governing board to be replaced by a five-member independent governing board appointed by the governor within 90 days of the bill’s effective date.</p> <p>Requires Electricity Oversight Board approval for the ISO to enter into a multistate entity or a regional organization.</p> <p>Requires the ISO to make available and update daily, a list of all power plants within the State that are nonoperational due to a planned or unplanned outage.</p>	Chapter 1, Statutes of 2001
AB 6X	Dutra	<p>Requires the CPUC to regulate electricity generation facilities owned by any public utility prior to January 1, 1997, until their disposition has been reviewed and approved by the CPUC.</p> <p>Prohibits the disposal of electricity generation facilities owned by a public utility to be disposed of prior to January 1, 2006.</p>	Chapter 2, Statutes of 2001
SB 7X	Burton	<p>Authorizes the department to purchase electric power from any party and to make that power available at cost to the ISO, public utility electrical corporations, or retail customers for not more than 12 days from the bill’s effective date. That authority lapsed on February 2, 2001.</p> <p>Transfers \$400 million from the General Fund to the department’s fund for the purpose of implementing the bill.</p>	Chapter 3, Statutes of 2001

* Each chaptered bill took effect immediately as urgency legislation.

† An “X” following the bill number indicates a bill introduced in the 2001-02 First Extraordinary Session.

TABLE 8

Executive Orders

Executive Order Number	Date Signed by Governor	General Description/Purpose
D-18-01	2/1/01	Orders the Department of Consumer Affairs to conduct a media awareness campaign to inform the public of the importance of, and methods to, conserve energy.
D-19-01	2/1/01	<p>Orders all California retail establishments to substantially reduce maximum outdoor lighting capability during nonbusiness hours except as necessary to the health and safety of the public, employees, or property.</p> <p>Requires the Office of Emergency Services (OES), in consultation with the commissioner of the California Highway Patrol and the sheriffs of certain counties, to develop plans for the voluntary implementation of the order as soon as practicable and the mandatory implementation by March 15, 2001.</p> <p>Requires the Technology, Trade and Commerce Agency, with assistance as necessary from OES and the State and Consumer Services Agency, to notify the public, retail establishments, and local officials of the order.</p> <p>Requires the Technology, Trade and Commerce Agency, and the State and the Consumer Services Agency, to submit a report recommending additional steps by commercial establishments to conserve energy.</p>
D-20-01	1/31/01	Orders the state seizure of forward contracts for the delivery of electricity by Southern California Edison to the Power Exchange (PX).
D-21-01	1/31/01	Orders the state seizure of forward contracts for the delivery of electricity by Pacific Gas and Electric to the PX.
D-22-01	2/8/01	<p>Orders that all existing power plants that increase their output above authorized levels by less than 50 megawatts between June 1, 2001, and October 1, 2001, not be subject to the California Energy Resources Conservation and Development Commission’s (Energy Commission) jurisdiction for that period of time.</p> <p>Requires the Energy Commission to expedite the processing of applications for certification for existing thermal power plants that require retooling and a current license to operate.</p> <p>Requires all local, regional, and state agencies involved in the licensing of proposed power plants to work with the Energy Commission, within its timeline, to review all such applications for certification.</p> <p>Requires the State Water Resources Control Board to ensure that power plants are not kept from operating as a result of thermal limits in waste discharge requirements.</p> <p>Requires the Department of Water Resources (department) to contract for power from power plants using renewable and other resources that do not have a market for their power.</p> <p>This order expires on December 31, 2001.</p>
D-23-01	2/8/01	<p>Orders the Independent System Operator (ISO) to:</p> <ol style="list-style-type: none"> 1. Require generators to submit planned outage schedules. 2. Prepare a quarterly coordinated outage plan. 3. Identify maintenance criteria to be met by generation facilities. 4. Maintain and provide the Electricity Oversight Board (EOB) with daily records of any unplanned generation facility outages. 5. Conduct independent audits of generation facilities that have fallen below performance benchmarks established by the ISO. 6. Consider seeking the authority under state law or federal regulation to impose fines on those generators whose facilities have fallen below the performance benchmarks.

Executive Order Number	Date Signed by Governor	General Description/Purpose
D-24-01	2/8/01	<p>Requires the EOB and the ISO to review the ISO Tariffs and Protocols to identify any necessary revisions to increase the ISO's ability to ensure adequate energy availability during peak demand periods.</p> <p>Requires the ISO board to make the necessary filings with the Federal Energy Regulatory Commission to implement any revisions to the Tariffs and Protocols.</p> <p>Requires the California Public Utilities Commission (CPUC) to ensure that the power plants still owned by regulated utilities are operated in a manner that assures the availability and reliability of the electric supply.</p> <p>Requires the EOB to propose emergency legislation to expand its authority to issue audits of generators that do not meet benchmarks for availability and performance, and issue fines against those plants, after a hearing.</p>
D-25-01	2/8/01	<p>Orders the local air pollution control and air quality management districts to modify emissions limits in air quality permits that restrict the hours of operation for power plants under contract with the department. Directs these districts to require a mitigation fee for all applicable emissions in excess of the original limits. The Air Resources Board (ARB) is required to ensure all modifications to permits are made in a timely manner.</p> <p>Requires the ARB to establish an emissions reduction credit bank through which power plants with emissions in excess of the established limits can be offset by emission reduction credits from other sources allowing the power plants to expand capacity for the summer. These offsetting credits will be provided at up to the market rate, unless the facility is under contract with the department in which case the credits will be provided at up to a 50 percent reduction in price. Requires the proceeds from the sale of credits to go to fund emission reduction programs in the air districts where the new or expanded facilities are located.</p> <p>Orders the Energy Commission to expedite the review and approval of post-certification amendments regarding thermal power plants by suspending the requirements that normally control the review and approval process of such amendments.</p> <p>Requires the Energy Commission to establish specific performance milestones for the initiation of construction within one year of certification of the project and for the construction itself. Failure to meet these milestones will result in a forfeiture of the certification.</p> <p>This order expires on December 31, 2001.</p>
D-26-01	2/8/01	<p>Authorizes state and local agencies to use a shortened seven-day review of environmental documents prepared under the California Environmental Quality Act for all power plants not subject to the jurisdiction of the Energy Commission and that can be online by the summer of 2001.</p> <p>Requires the Energy Commission to expedite its licensing process by:</p> <ol style="list-style-type: none"> 1. Expediting applications for peaking or renewable power plants, including those with a current contract with the ISO, that can be online by July 2001. 2. Suspending restrictions that would otherwise delay the licensing of proposed simple cycle thermal power plants that can be online by August 31, 2002. 3. Exempting applicants from securing emission offset credits at the time of applying for certification. 4. Conducting a study identifying potential peaking power plant sites and reporting to the governor by February 21, 2001. <p>Requires the CPUC to ensure that the investor-owned utilities complete transmission interconnection studies within seven days of receipt of a completed application.</p> <p>This order expires on December 31, 2001.</p>

Executive Order Number	Date Signed by Governor	General Description/Purpose
D-27-01	2/8/01	Orders the Department of Parks and Recreation to make its remaining appropriated funds available at the direction of the governor to the Energy Commission for the purpose of providing incentives to new power plants brought online before July 1, 2001.
D-28-01	3/7/01	<p data-bbox="589 422 1479 499">Grants the Energy Commission and other reviewing agencies the authority to modify their procedural requirements for the review of the programs covered by Executive Orders D-22-01, D-24-01, D-25-01, and D-26-01.</p> <p data-bbox="589 520 1479 598">Requires the Energy Commission to expedite certification applications for the construction and operation of peaking or renewable power plants by September 30, 2001, including those with a current contract with the ISO.</p> <p data-bbox="589 619 1479 716">Extends the provisions of Executive Order D-24-01 requiring modification of emissions limits in air quality permits that restrict hours of operation to include any power-generating facility, including those that are not currently operating. No permit modification may be valid for more than three years from the date of this order.</p> <p data-bbox="589 737 987 758">This order expires on December 31, 2001.</p>
D-30-01	3/13/01	<p data-bbox="589 791 1450 848">Orders a rate reduction program giving customers who reduce consumption by 20 percent between the months of June and September 2001 a rebate on their electricity bills.</p> <p data-bbox="589 869 1344 915">Finances program through a reduction in payments made to the department by utility companies.</p> <p data-bbox="589 936 987 955">This order expires on December 31, 2001.</p>

TABLE 9

Pending Legislation

Subject/Description	Bill Number*	Author†
Alternative Energy		
Numerous bills have been introduced to encourage the use of alternative and renewable energy, such as solar power, qualifying facilities, cogeneration, biomass to energy, microgeneration, wind facilities, and onsite generation. The subject matters include:	AB 10X	Goldberg
	AB 33X	Robert Pacheco
	AB 37X	Frommer
	AB 48X	Migden
<i>Programs to convert agricultural biomass to energy.</i>	AB 38X	Jackson
<i>Tax exemptions for purchase of alternative energy generation.</i>	AB 53X	Reyes
<i>Tax credits for use of alternative energy.</i>	AB 58X	Cox
<i>Standby charge waivers for installation of alternative energy generation.</i>	AB 64X	Strom-Martin
<i>Loans to local public utilities for alternative energy.</i>	AB 75X	Calderon
<i>Funding for research and financing for renewable energy.</i>	AB 79X	Nakano
	AB 83X	Keeley
<i>Clean distributed energy resources.</i>	AB 86X	B. Campbell
	AB 93X	B. Campbell
<i>Loan guarantees for joint powers agreements between public power entities, independent generators, and utilities to develop new and renewable energy.</i>	AB 94X	B. Campbell
	AB 95X	B. Campbell
	AB 98X	Calderon
<i>Solar energy in local building standards.</i>	AB 99X	Pavley
<i>Grants to public school facilities for use of emerging technology.</i>	AB 103X	Keeley
	AB 108X	Simitian
<i>Expediting California Environmental Quality Act (CEQA) process for new clean energy plants.</i>	SB 1X	Soto
	SB 6X	Burton
<i>Customer credits for use of renewables.</i>	SB 9X	Morrow
<i>Loan guarantees for businesses for renewable energy systems purchases.</i>	SB 15X	Alarcon
<i>On-site generation for state buildings.</i>	SB 17X	Brulte
	SB 29X	Soto
<i>Energy independence for community colleges.</i>	SB 47X	Battin
<i>Net energy metering contracts for use of alternative energy.</i>	SB 54X	Haynes
	SB 64X	Costa
<i>Local funding for energy efficient technology.</i>	AB 497	Robert Pacheco
	AB 802	Dickerson
	AB 1264	B. Campbell
	AB 1319	Cox
	SB 365	McPherson
	SB 625	Costa
Conservation Efforts		
Numerous bills have been introduced to encourage conservation efforts by private citizens, businesses, and state and local governmental agencies. The subject matters include:	AB 10X	Goldberg
	AB 15X	Rod Pacheco
	AB 29X	Kehoe
<i>Meters to measure electricity usage.</i>	AB 31X	Wright
<i>Three-tier rate structure for residential customers—lowest rate for lowest use.</i>	AB 32X	Nation
<i>Baseline quantities of gas and electricity needed to supply average residential energy needs.</i>	AB 40X	Steinberg
	AB 41X	Lowenthal
	AB 42X	Cedillo

* An "X" following the bill number indicates a bill introduced in the 2001-02 First Extraordinary Session.

† For bills with multiple authors or co-authors, this matrix lists the first named author.

Subject/Description	Bill Number*	Author†
<i>Grants for energy efficient appliances, building construction, and retrofits.</i>	AB 43X	Kehoe
<i>Energy conservation project loans for shopping malls.</i>	AB 44X	Cohn
	AB 56X	Leslie
<i>Assistance to low-income households for energy efficiency measures.</i>	AB 64X	Costa
<i>Funding to school districts, cities, and counties for energy conservation and efficiency efforts.</i>	AB 66X	Correa
	AB 67X	McLeod
<i>Tax credits for natural gas and electricity conservation and for purchase of energy reducing devices.</i>	AB 84X	B. Campbell
	AB 90X	B. Campbell
<i>State agency conservation, including decisions that may affect peak demand and shutdowns during electricity emergencies.</i>	AB 109X	Simitian
	SB 2X	Alarcon
<i>Peak-load and demand reduction programs.</i>	AB 102X	Wayne
	SB 5X	Sher
<i>Energy efficient standards for public buildings.</i>	SB 6X	Burton
<i>Building standards to increase efficiency and to decrease peak-load wastefulness.</i>	SB 21X	Machado
	SB 28X	Sher
<i>Taxing local utility users on per unit basis.</i>	SB 31X	Bowen
	SB 37X	Brulte
<i>Requiring investor-owned utilities (IOUs) to give rebates for reduced energy consumption.</i>	SB 41X	Speier
	SB 42X	Speier
<i>Energy efficient technologies rebates.</i>	SB 46X	Soto
<i>Financing authority to promote conservation and renewable energy.</i>	SB 51X	Polanco
	SB 52X	Chesbro
	SB 53X	Margett
	SB 62X	Poochigian
	SB 63X	Perata
	SCA 1X	Poochigian
	AB 1	Aanestad
	AB 549	Longville
	AB 1268	B. Campbell
	SB 497	Sher
	SB 705	Margett
	SB 1085	Bowen
Environmental Issues		
Several bills have been introduced to address the environmental issues that arise with regard to electrical energy generation, such as air emission standards, the permitting process, and CEQA. The subject matters include:	AB 20X	Zettel
	AB 28X	Daucher
	AB 31X	Wright
<i>Expediting retrofit of electrical generators while protecting and improving air quality (including clean or green plants).</i>	AB 34X	La Suer
	AB 36X	Wright
<i>Environmental guidelines for distributed energy installation.</i>	AB 55X	Rod Pacheco
	AB 59X	Robert Pacheco
<i>Expediting and streamlining environmental decisions on permits for power plants.</i>	AB 65X	Wyman
	AB 76X	Leslie
<i>Tax credits for reductions in air emissions.</i>	AB 92X	B. Campbell
<i>Exemptions for back-up generators used during power emergencies or peak demand periods.</i>	AB 94X	B. Campbell
	AB 97X	Canciamilla
<i>Exemptions and priorities for ultraclean thermal plants.</i>	AB 100X	Mountjoy
	AB 106X	Frommer
<i>Expediting permits to repower or retrofit existing plants.</i>	SB 21X	Machado
<i>CEQA exemptions for retrofits of existing power plants, the Path "15" transmission path and for a specified hydroelectric power plant.</i>	SB 28X	Sher
	SB 34X	Knight
<i>Retrofit of existing energy generating facilities.</i>	SB 35X	Morrow
	SB 38X	Oller

Subject/Description	Bill Number*	Author†
<i>Air emission credits.</i>	SB 50X	Polanco
<i>Air quality standards for distributed energy.</i>	SB 55X	McClintock
	SB 57X	Battin
	SB 58X	Battin
	AB 69	Wright
	AB 94	Daucher
	AB 569	La Suer
	AB 621	Corbett
	AB 1577	Zettel
	SB 863	Knight
	SB 1110	Battin
Forward/Bilateral Contracts		
Several bills have been introduced to address the use of forward or bilateral contracts by IOUs to purchase electricity and ensure long-term electricity price stability. The subject matters includes:	AB 2X	Pescetti
	SB 48X	Morrow
	AB 57	Wright
<i>Requiring the CPUC or Energy Commission to permit and deem reasonable forward contracts and prohibiting a later just and reasonableness review of the contracts.</i>	AB 1577	Zettel
	SB 997	Morrow
	SB 1012	Battin
<i>Requiring the CPUC to preapprove forward contracts.</i>		
<i>Requiring IOUs to maintain portfolios of forward contracts for not less than 50 percent nor more than 95 percent of electricity needs.</i>		
Hydroelectric Power		
Several bills have been introduced to address the use of hydroelectric power. The subject matters includes:	AB 76X	Leslie
	AB 110X	Kelley
<i>CEQA exemptions for a specified hydroelectric project.</i>	SB 12X	Johannessen
<i>General obligation bonds to finance Auburn Dam power generation.</i>	SB 45X	Oller
<i>Use of water storage facilities that generate hydroelectric power.</i>	SB 102	Johannessen
	SB 1008	Perata
<i>Use of reclaimed groundwater to generate electricity.</i>		
<i>Formation of joint powers authority for hydroelectric generation.</i>		
Investor-Owned Utility Assistance		
Several bills have been introduced to address the problems the IOUs are facing as a result of soaring electricity costs, including proposed modifications to AB 1X, which has been enacted and authorizes the Department of Water Resources (DWR) to enter long-term contracts for the purchase of electricity. The subject matters include:	AB 18X	Hertzberg
	AB 25X	Florez
	AB 27X	Koretz
	AB 18X	Hertzberg
	AB 35X	Bates
<i>Assessments on the real property of IOUs that the state purchases power for.</i>	AB 63X	Florez
<i>DWR's purchase and sale of electricity.</i>	AB 107X	Florez
<i>DWR's undercollection in the sale of electricity.</i>	AB 60X	Hertzberg
<i>State purchase of transmission lines from IOUs.</i>	SB 13X	Polanco
	SB 14X	Alarcon
<i>IOUs' recovery of uneconomic costs and undercollected amounts.</i>	SB 18X	Escutia
<i>Providing stability to prices.</i>	SB 27X	Bowen
	SB 33X	Burton
<i>IOU rate freeze.</i>	AB 30	Pescetti

Subject/Description	Bill Number*	Author†
<i>Financing for electricity overpayment debts of IOUs.</i>	AB 868	Bates
	AB 1124	Koretz
ISO, PX, EOB		
Several bills have been introduced that pertain to the structure and duties of the Independent System Operator (ISO), the Power Exchange (PX), and the Electricity Oversight Board (EOB). The subject matters include:	AB 8X	Migden
	AB 22X	Koretz
	AB 48X	Migden
<i>Merging the functions of the ISO and PX purchase of electricity from non-PX markets.</i>	SB 26X	Bowen
	SB 31X	Bowen
<i>Reconfiguring the ISO board.</i>	SB 50X	Polanco
	AB 58	Keeley
<i>Monitoring of power plant maintenance schedules by ISO and reports to EOB.</i>	SB 36	Burton
<i>Notice of rolling blackouts by ISO.</i>	SB 38	Bowen
<i>Priority for ultraclean power plants during transmission system overload.</i>	SB 47	Bowen
<i>Exercise of market power.</i>	SB 570	Morrow
Municipal Utilities/Local Issues		
Numerous bills have been introduced to address a wide variety of issues that arise for local government and municipal utilities. The subject matters includes:	AB 9X	Richman
	AB 23X	Canciamilla
<i>Incentives for counties and cities to site power plants within their boundaries such as exemptions from rolling blackouts, use of property tax revenues generated by the power plants, and right of first refusal to electricity.</i>	AB 37X	Frommer
	AB 47X	Wiggins
	AB 48X	Migden
<i>Identification of potential sites for power plants and transmission lines.</i>	AB 49X	B. Campbell
	AB 54X	Wright
<i>Local building standards requiring use of alternative energy or efficient designs.</i>	AB 61X	Alquist
	AB 62X	Cohn
<i>Eminent domain for power purposes.</i>	AB 68X	Firebaugh
<i>Encouraging use of distributed energy to serve local electric loads.</i>	AB 69X	La Suer
<i>Community aggregators and aggregating municipal utilities for electricity purchases.</i>	AB 91X	B. Campbell
	AB 93X	B. Campbell
<i>Joint power agreements for electricity distribution and transmission assets conservation efforts.</i>	AB 101X	Lowenthal
	AB 112X	Wyland
	SB 8X	Alarcon
<i>County approval of natural gas drilling applications.</i>	SB 9X	Morrow
<i>Rate caps on local publicly owned utility sale of surplus electricity.</i>	SB 10X	Morrow
<i>San Diego Gas & Electric Company users—rate ceilings and recovery of undercollected amounts.</i>	SB 11X	Morrow
	SB 22X	Chesbro
<i>Electricity purchases from the Los Angeles Department of Water and Power by local government.</i>	SB 23X	Soto
	SB 28X	Sher
<i>Energy conservation grants.</i>	SB 30X	Bulte
	SB 32X	Alpert
<i>Natural gas in Long Beach tidelands.</i>	SB 35X	Morrow
	SB 36X	Polanco
<i>Special districts formed to furnish electricity or gas services.</i>	SB 42X	Speier
	SB 43X	Alpert
	SB 54X	Haynes
	AB 226	B. Campbell
	AB 1042	Richman
	AB 1085	Calderon
	AB 1133	La Suer

Subject/Description	Bill Number*	Author†
	AB 1443	Alquist
	SB 60	Morrow
	SB 62	Morrow
	SB 203	Morrow
	SB 500	Torlakson
	SB 654	Haynes
	SB 1076	Soto
	SB 1126	Alarcon
Natural Gas Issues		
Several bills have been introduced that address natural gas supply and cost issues. The subject matters include:	AB 11X	Rod Pacheco
	AB 15X	Rod Pacheco
<i>Issuing revenue bonds to finance the construction and operation of natural gas pipelines.</i>	AB 57X	Dutra
	AB 73X	Canciamilla
<i>Feasibility of direct state purchase of natural gas.</i>	AB 78X	Canciamilla
	AB 89X	B. Campbell
<i>Natural gas surcharges.</i>	AB 91X	B. Campbell
<i>Natural gas conservation.</i>	AB 101X	Lowenthal
<i>Increasing natural gas supply or ensuring adequate supply in-state.</i>	AB 105X	Cogdill
<i>Natural gas infrastructure: pipelines, transportation, or storage.</i>	AB 114X	Cardoza
	AB 116X	Pescetti
<i>Expediting county approval of natural gas drilling applications.</i>	AB 117X	Pescetti
<i>Priority treatment during natural gas curtailments for firms manufacturing, transporting, or storing critical fuels.</i>	SB 6X	Burton
	SB 12X	Johannessen
<i>Irrigation district purchase of natural gas.</i>	SB 44X	Alarcon
	SB 102	Johannessen
<i>Natural gas in Long Beach tidelands.</i>		
Power Plant Maintenance		
Several bills have been introduced to address the electricity shortfalls that arise when power plants are shut down for scheduled or unscheduled maintenance. The subject matter of those bills includes:	AB 8X	Migden
	AB 16X	Oropeza
	AB 48X	Migden
<i>Requiring the ISO to prepare coordinated outage plans each year and to report to the EOB.</i>	AB 70X	La Suer
	AB 570	La Suer
<i>Requiring EOB approval of maintenance protocols.</i>		
<i>Limiting scheduled maintenance shutdowns to one power plant at a time or during off-peak periods, and limiting unscheduled maintenance.</i>		
<i>Requiring the ISO to report to the Legislature on coordinating maintenance.</i>		
Power Plant Construction/Siting		
Numerous bills have been introduced to address the shortage of electricity generators that exist in the State and propose solutions that range from expediting the review of plans for the construction and operation of power plants to providing incentives to local government to authorize construction in their boundaries. The subject matters include:	AB 9X	Richman
	AB 10X	Goldberg
	AB 20X	Zettel
	AB 23X	Canciamilla
<i>Identifying regions in the State with the greatest supply and demand imbalance.</i>	AB 34X	La Suer
	AB 36X	Wright
	AB 39X	Cardoza
<i>Identifying barriers to the full use of existing power plants.</i>	AB 49X	B. Campbell
<i>Identifying counties with the highest populations and demand.</i>	AB 60X	Hertzberg

Subject/Description	Bill Number*	Author†
<i>Low interest loans for repowering of existing facilities or new peak demand facilities</i>	AB 62X	Cohn
	AB 68X	Firebaugh
<i>Conditioning siting of power plant on applicant offering to sell electricity in the State.</i>	AB 71X	La Suer
	AB 72X	La Suer
<i>Expediting review, permitting, construction, and operation of power plants.</i>	AB 81X	Zettel
	AB 87X	B. Campbell
<i>Leasing or using state land for the siting and operation of power plants.</i>	AB 88X	B. Campbell
<i>Expediting the environmental review of power plants.</i>	AB 94X	B. Campbell
<i>Incentives for local governments to construct power plants within their boundaries.</i>	AB 106X	Frommer
	SB 6X	Burton
	SB 28X	Sher
<i>Financing for constructing, acquiring, and operating electricity generating facilities.</i>	SB 30X	Brulte
	SB 34X	Knight
<i>Expedited review of existing or new power plants on active or closed military bases.</i>	SB 40X	Speier
	SB 50X	Polanco
<i>Expediting repowering of existing facilities.</i>	SB 56X	Battin
<i>Expedited conversion of existing power plants to larger facility.</i>	SB 58X	Battin
	SB 59X	Battin
<i>Exempting power plant siting on specified Tribal land from siting requirements.</i>	AB 69	Wright
	AB 226	B. Campbell
<i>Additional transmission lines.</i>	AB 569	La Suer
	AB 578	La Suer
	AB 1042	Richman
	AB 1138	La Suer
	AB 1577	Zettel
	SB 863	Knight
	SB 1110	Battin
Rising Energy Costs		
Numerous bills have been introduced to address the soaring costs of electricity. The subject matters include:	AB 3X	Wright
	AB 7X	Wright
<i>Assistance to public schools and postsecondary institutions to pay unexpected energy costs.</i>	AB 13X	Firebaugh
	AB 26X	Leach
<i>Capping rates on agriculture related usage.</i>	AB 67X	McLeod
	AB 74X	Shelley
<i>Improvements to the California Alternate Rate for Energy (CARE) program and other assistance for persons with low-incomes and for seniors.</i>	AB 80X	Reyes
	AB 104X	Cardoza
<i>Reimbursements to consumers for high retail rates.</i>	AB 113X	Wyland
<i>Extending rate reductions for residential and small commercial customers.</i>	SB 2X	Alarcon
	SB 10X	Morrow
<i>Wholesale electricity stability.</i>	SB 11X	Morrow
<i>San Diego Gas & Electric customers.</i>	SB 20X	Soto
	SB 32X	Alpert
	SB 43X	Alpert
	AB 30	Pescetti
	AB 836	Wyland
	SB 60	Morrow
	SB 431	Monteith
	SB 1116	Alarcon

Subject/Description	Bill Number*	Author†
Rolling Blackouts/Interruptions in Services	AB 12X	Rod Pacheco
Numerous bills have been introduced addressing interruption in services, including bills to provide exemptions from interruptions for users with special needs. The subject matters include:	AB 14X	Havice
	AB 17X	Leonard
<i>Limits on interruptions in power supplies to schools, colleges, and universities; essential medical services; fire protection and law enforcement; perishable food handlers; manufacturers or transporters of critical fuels; and electricity users within a certain radius of a power plant.</i>	AB 21X	J. Campbell
	AB 22X	Koretz
<i>Notice of impending service interruptions.</i>	AB 23X	Canciamilla
	AB 24X	Daucher
<i>Opting out of or amending interruptible services contracts; waiving penalties paid for noncompliance with those contracts.</i>	AB 30X	Cardoza
	AB 31X	Wright
<i>Assistance to school districts and community college districts for additional expenses incurred in not complying with interruptible services contracts.</i>	AB 46X	Calderon
	AB 50X	Bates
<i>State building shutdowns during electricity emergencies.</i>	AB 51X	Daucher
	AB 52X	J. Campbell
<i>Funding installation and use of backup generation.</i>	AB 57X	Dutra
	AB 77X	Robert Pacheco
<i>Curtailment of seasonal users.</i>	AB 109X	Simitian
	AB 111X	Florez
<i>Looting during blackouts.</i>	SB 3X	Soto
	SB 4X	Soto
<i>Expanding and encouraging interruptible services programs.</i>	SB 19X	Haynes
	SB 21X	Machado
	SB 24X	Knight
	SB 25X	Knight
	SB 39X	Speier
	SB 60X	Perata
	SB 61X	Morrow
	AB 57	Dutra
	SB 500	Torlakson
	SB 570	Morrow
	SB 645	Perata
	SB 820	Costa
	SB 1032	Costa
	SB 1055	Morrow
	SB 1075	Soto

Subject/Description	Bill Number*	Author†
Tax Incentives		
Numerous bills have been introduced proposing various tax incentives designed to encourage efforts to ease the energy crisis. The subject matters includes:	AB 4X	Daucher
	AB 10X	Goldberg
<i>Sales and use tax exemptions for alternative energy generation purchases and the use of diesel fuel for farming activities.</i>	AB 11X	Rod Pacheco
	AB 15X	Rod Pacheco
<i>Tax credits for the purchase and installation of solar energy systems, on-site generators generally, on-site generators for dairy farms, excessive energy costs, emission reduction credits, conservation efforts, electric power generation placed in service of or offered to the State, alternative energy generation, investment in electric power generation, and power generators installed under qualified interruptible service contracts.</i>	AB 19X	Briggs
	AB 27X	Koretz
	AB 45X	Kelley
	AB 51X	Daucher
	AB 58X	Cox
	AB 79X	Nakano
<i>Exemption from property taxes for conservation improvements to real property.</i>	AB 84X	B. Campbell
	AB 85X	B. Campbell
<i>Repeal of the surcharges on natural gas and electricity consumption.</i>	AB 86X	B. Campbell
	AB 96X	B. Campbell
	AB 102X	Wayne
	AB 115X	Harman
	SB 1X	Soto
	SB 16X	Soto
	SB 17X	Brulte
	SB 49X	Morrow
	SCA 1X	Poochigian
	AB 94	Daucher
	AB 240	Runner
	AB 1124	Koretz
	AB 1169	B. Campbell
	AB 1264	B. Campbell
	AB 1276	B. Campbell
	AB 1319	Cox
	SB 365	McPherson

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APPENDIX B

Single Price Auctions

Auctions are useful in circumstances in which goods do not have fixed or determined market values—in other words, when a seller is unsure of the price he or she could receive. The form an auction takes can vary, depending on the type of good being auctioned and the nature of the demand for that good. Some auctions are open and others involve sealed bids. In some auctions the price ascends, and in others the price drops at regular intervals. Generally, experts agree that there are four major one-sided auction formats, but variations on these formats abound.

Although not classified as one of the major four auction types, the double auction has been the principal trading format in U.S. financial institutions for more than a hundred years. In this type of auction, both sellers and buyers submit bids that are then ranked highest to lowest to generate supply-and-demand profiles. From the profiles, the maximum quantity exchanged can be determined by matching selling offers (starting with the lowest price and moving up) with demand bids (starting with the highest price and moving down). This format allows buyers to make offers and allows sellers to instantly accept those offers. The double auction is essentially the format used in California's energy market, with the added factor that all successful bidders are paid the last, or highest, price accepted for a given hour. It is because of this added factor that California's auction format is called a single-price auction.

Other deregulated electricity markets, such as the spot market in New England, employ a similar auction format. Whether such a system is economically efficient is debatable. One argument against the single-price auction is based on market conditions. The argument suggests that in times of scarcity, particularly in an energy marketplace where short-term demand is inelastic, necessity can sometimes force the Independent System Operator (ISO) to accept all bids, including out-of-market bids. In these circumstances, the single-price auction becomes meaningless because sellers will receive whatever prices they ask. In fact, the availability of public market data, combined with the ISO's declarations of emergencies, in effect signal sellers that they can bid high prices and still be assured that their offers will be

accepted. In other words, the auctioneer, in this case the ISO, has signaled sellers in advance that whatever they wish to sell will be purchased, and it will be purchased at the highest bid offered (subject to any price cap).¹⁶

Critics of the single-price auction have suggested an iterative bidding process as an improvement to the current, single round, single-price auction. In an iterative bidding process, an auction is conducted over several iterations. This would allow participants in the Power Exchange (PX) day-ahead market to change their bids in response to prices revealed in earlier rounds of the auction. The major potential benefit would be that information obtained over several iterations would allow sellers to continue to reduce their bids right up to the point of recovering their marginal costs. Theoretically, this would be the minimum market price. However, at the end of the iterative bidding process, energy would still be sold at a single clearing price.

However, proponents of the single-price auction claim that conducting such an iterative process is not feasible within the current time constraints of the PX and ISO markets. They also argue that this process would significantly increase the current auction transaction costs and might allow even more strategic bidding by sellers. The PX studied the costs and benefits associated with switching to an iterative bidding process in November 1998 and concluded that the costs of such a bidding system would outweigh any benefits.

Another popular proposal has been to change the current single-price auction to an “as bid” market. Unlike the current single-price auction, in which all bidders are paid the last, and highest, bid accepted in each hour, the “as bid” auction pays successful sellers only what they bid. Unfortunately, an “as bid” system will not produce any lasting benefits in a sales market as brief as the day-ahead energy market that the PX used, because both buyers and sellers would soon be able to see the prices that other participants have paid and received. Thus, one can expect that over the course of a short time (several days at most), successive

¹⁶ One way to circumvent this potential problem would be for the ISO to conduct more of its business in futures, bilateral, and sealed bid markets.

rounds of bidding will result in the entire marketplace converging on a single, market-clearing, price.¹⁷ That single price would be the same price as would be found in the single-price auction. The PX also commissioned a blue ribbon panel to examine whether an “as bid” market would be preferable to the current single-price auction. In its report issued January 23, 2001, the panel concluded that any expectation that purchasers of power would benefit from lower wholesale prices under such a shift is mistaken.

If the California market aggressively pursues forward contracting, this will, in effect, move the market away from the single-price auction and toward an “as bid” format, at least for those sales contracted outside the PX and ISO market auctions. In these circumstances, the “as bid” format may prove more beneficial because the terms and prices of such contracts typically would not be made public. Without such knowledge, other market participants could not “home in” on the negotiated price and make it the single price for contracts with similar terms.

¹⁷ The reason the price converges is as follows: If seller A sees that seller B has received a higher price, seller A will raise its price in the next round. Similarly, if buyer A sees that buyer B has received a lower price, buyer B will lower its bid in the next round. A good description of this convergence process is found in *Electric Utility Restructuring: A Guide to the Competitive Era*, by Peter Fox-Penner (Vienna, VA: Public Utility Reports, Inc., 1997), pp. 181–184.

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APPENDIX C

Recommendations Made by Others

The elevated prices experienced in California's deregulated energy marketplace have attracted significant attention and study. As we discussed in Chapter 2, the Federal Energy Regulatory Commission (FERC) reviewed the California wholesale power market and issued an order on December 15, 2000, prescribing several modifications to the power market's structure. During the course of the FERC proceeding, many other parties provided both recommendations and comments. This appendix summarizes those recommendations.

WITH CERTAIN EXCEPTIONS, INDUSTRY OBSERVERS GENERALLY AGREE ON THE CAUSES OF THE CURRENT CRISIS

Table 10 provides an overview of the problems that industry regulators and market monitors identified as contributing to the escalating prices within California's electric marketplace. The far right column categorizes each problem as follows:

1. Fundamental market structure problems and the exercise of market power.
2. Operational problems.
3. Competitive market forces.

TABLE 10

Identified Causes of the California Energy Crisis

Problem	ISO*	ISO-MSC†	PX‡	CPUC§	FERC**	Type of Problem
Limited hydro capability due to weather	●		●		●	3
Inadequate generation supply	●	●	●	●	●	3
Limited demand responsiveness to price	●	●	●	●	●	1
High natural gas prices	●	●	●	●	●	3
Growth in demand	●	●	●	●	●	3
Inadequate transmission infrastructure	●		●	●	●	3
Inadequate forward contracting	●	●	●		●	1,2
Underscheduling of generation in the PX day-ahead market	●	●	●		●	1,2
Opportunity to exercise market power through:						
—out-of-market purchases	●	●			●	1,2
—limited number of generators	●	●				1,3
—restraints on forward contracting	●	●	●		●	1,2
—withholding of generation in one market to raise that market price		●	●	●	●	1,2
—local market power caused by restricted transmission capacity	●	●				1,3
—generator withholding caused by ISO's out-of-market payment schedule		●				1
—generators failing to respond to ISO orders to dispatch energy	●	●				1
Increased unplanned plant outages	●	●		●	●	3
Underscheduling of demand in PX day-ahead market	●	●	●		●	1,2
Higher emission costs		●	●		●	3
Transmission congestion	●	●			●	3
Lack of sufficient data to detect market manipulation by out-of-state suppliers		●		●		1,2
ISO board too large with members having conflict of interests				●	●	1
PX board too large with members having conflict of interests				●		1

* "Market Analysis Report," ISO market analysis group presentation, October 13, 2000; "Report on California Energy Market Issues and Performance: May-June, 2000," ISO market analysis group report, August 10, 2000; various ISO market analysis group monthly market surveillance reports; ISO comprehensive market redesign memorandum to the ISO Board of Governors, October 19, 2000.

† "Report on Redesign of Markets for Ancillary Services and Real-Time Energy," ISO Market Surveillance Committee reports dated March 25, 1999, and October 18, 1999.

‡ "Price Movements in California Electricity Markets," presentation by the PX Compliance Unit to the Electricity Oversight Board, August 31, 2000; "Congestion Impacts," presentation by the PX Compliance Unit to the Marketing Monitoring Committee, August 9, 2000; "An Analysis of the Market Monitoring Committee of the California Power Exchange on the FERC Order of November 1, 2000", summary.

§ "California's Electricity Options and Challenges," report to Governor Gray Davis from Michael Kahn, Chairman, Electricity Oversight Board, and Loretta Lynch, President, California Public Utilities Commission, August 2, 2000.

** "Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities," Part 1, FERC staff report, November 1, 2000.

Some of the problems in Table 10 are categorized as both structural and operational in nature. This is due to the fact that in some instances the market design can foster or allow strategic bidding, which is legal and often economically advantageous to market participants, or the exercise of market power, which is not legal. Unfortunately, it is often difficult to determine the difference between the two types of behavior.

It is important to recognize the differences among these three categories of problems because each category can call for a different type of response. For example, competitive market forces, such as high natural gas prices, may not respond to regulatory reforms. On the other hand, market structure problems invariably require modification of market design, and operational problems may require new rules or broader policy measures. Problems related to competitive market forces, such as inadequate supply, generally require solutions that may take years to implement fully, while problems related to market structure and operations can often be addressed in a shorter time frame by changing marketplace rules.

As Table 10 shows, industry regulators and market monitors generally agree on the ways in which competitive market forces have contributed to the power crisis. On the other hand, FERC has not identified as problems several of the structural factors that the Independent System Operator (ISO) Department of Market Analysis and ISO Market Surveillance Committee believe created opportunities for sellers to exercise market power. In addition, while FERC sees the ISO Board of Governors as too large, the ISO has not identified this as a problem.

AUTHORITIES DISAGREE ON WHETHER THE MARKET NEEDS MORE OR LESS REGULATION

Table 11 lists the recommendations most frequently cited for fixing the problems associated with the State's current energy crisis.

TABLE 11

Proposed Solutions for the California Electricity Market*

Recommended Changes to Current Operations	Who Made the Recommendation					
	ISO [†]	ISO-MSC [‡]	PX [§]	FERC ^{**}	CPUC ^{††}	IOUs ^{§§}
Market Structure and Market Power Problems						
Eliminate the mandatory PX buy/sell requirement				●		
Adopt a benchmark price for wholesale bilateral contracts	●			●		
Schedule a large percentage of demand prior to real-time	●		●	●	●	
Impose penalties for underscheduling demand by more than 5 percent	●			●		
Adopt a \$150 soft price cap in the ISO and PX short-term markets				●		
Require an independent and smaller ISO governing board				●		
Adopt a \$100 price cap with exceptions	●					
Adopt price caps for different levels of demand	●					
Adopt a \$100 price cap with no exceptions						●
Require in-state generators to report their operating costs						●
Assign out-of-market costs that exceed price caps to out-of-market bidders	●	●	●			
Impose penalties on generators that deviate from ISO instructions to dispatch energy in real time	●	●	●			
Eliminate restrictions on investor-owned utilities' forward contracts		●				
Freeze rates for San Diego Gas & Electric		●			●	
Alter the recovery mechanism for investor-owned utilities' stranded assets		●				
Adopt rules that promote a more competitive retail marketplace (favored approach) or abandon retail competition for all but the largest customers		●				
Competitive Market Problems						
Update procedures for connecting new generation to the grid	●	●		●		
Offer state incentives for new generation	●					
Require long-term proactive ISO grid-planning	●					
Streamline siting procedures for generation and transmission	●	●	●		●	
Incent retail customers to modify their demand in response to wholesale electricity prices	●		●		●	
ISO to obtain new peaking capacity for summer 2001	●					

* A discussion of the efficacy of each of the proposed changes noted in this table is beyond the scope of this review.

† ISO comprehensive market redesign memorandum to the ISO Board of Governors, October 19, 2000, and ISO Market Stabilization Plan, October 20, 2000.

‡ "An Analysis of the June 2000 Price Spikes in the California ISO's Energy and Ancillary Services Markets," ISO Market Surveillance Committee report, September 6, 2000.

§ "Price Movements in California Electricity Markets," presentation by the PX Compliance Unit to the Electricity Oversight Board, August 31, 2000; "An Analysis of the Market Monitoring Committee of the California Power Exchange on the FERC Order of November 1, 2000," summary.

** FERC Order Directing Remedies for California Wholesale Electric Markets, 93 FERC ¶61,294, issued December 15, 2000.

†† "California's Electricity Options and Challenges," report to Governor Gray Davis from Michael Kahn, Chairman, Electricity Oversight Board, and Loretta Lynch, President, California Public Utilities Commission, August 2000.

§§ FERC Preliminary Order Proposing Remedies for California's Wholesale Electric Market, issued November 1, 2000.

Agency's comments provided as text only.

ISO Response to State Auditor Report

The ISO agrees with the basic conclusions of the Auditor's report, particularly with respect to the major causes of the high prices experienced over the last year discussed in the report. The ISO further agrees with the fundamental objective of the recommendations in the report. However, the ISO disagrees with some of the more detailed aspects of some of these recommendations, or, in some cases, feels that additional explanation, detail and analysis would be needed to determine the advisability of these recommendations.

First, it should be noted that in the first two months of this year, California's wholesale electricity markets have undergone colossal changes including the elimination of the PX, the near financial collapse of California's two largest utilities, and the State of California's entry as a dominant short and long-term energy buyer. All of these changes have forced a reexamination of California's wholesale electricity markets and the ISO's role and function in these markets going forward. The ISO along with many other interested parties, including the Electric Oversight Board and various other State entities, are closely involved in this process. In recent weeks there have been proposals for dramatic changes in California's current market design, including a proposal from the ISO to develop a day-ahead unit commitment energy market to replace the loss of the PX Day-ahead market. In addition, the issue of whether the ISO is an appropriate entity to be entering into long-term energy and capacity contracts is also under question.

Given this uncertainty about California's future market structure and the future role and responsibilities of the ISO, it is difficult to provide comments to recommendations that are based on a past market structure that has dramatically changed in recent months and will likely undergo further significant changes in the coming months. That said, to the extent they remain applicable, the ISO will consider the report's recommendations in the context of some of the more comprehensive market design changes currently under consideration.

Recommendation 1: Eliminate Opportunities for Strategic Bidding through Underscheduling

To eliminate opportunities for strategic bidding and under-scheduling, the report recommends that the ISO:

- a) Eliminate its real time market and fulfill its real-time energy needs by executing forward contracts with generators to provide real-time imbalance energy and reserves.
- b) Consider penalizing scheduling coordinators who fail to submit balanced schedules.

c) Eliminate its Day-ahead and Hour-ahead ancillary service markets and instead meet its forecasted ancillary service requirements through “secret bids.”

d) Pay “as bid” for any short-term ancillary service requirements.

e) Consider taking long-term physical supply positions. If supply exceeds demand, sell back unneeded capacity.

The ISO believes that none of these options necessarily address the source of the problem. Market power causes lots of outcomes that are then blamed on market design elements. For instance, all load can self provide ancillary services and self balance real time energy. To the extent they use ISO, there is a value. The market provides an option that no one else can fill. Again, after removing restrictions on long-term contracting and after solving the credit crisis, load should be able to choose whether to use the real time market to balance their need. They will only use it when it is cheaper.

The ISO agrees that the sequential nature of the respective energy markets run by the Power Exchange (day-ahead and hour-ahead) and the ISO (real-time) have led to strategic bidding by both buyers and sellers and that this behavior has had the effect of shifting significant energy volumes to the ISO real-time market. The ISO also agrees that the significant volumes showing up in its real-time energy market have both jeopardized the reliable operation of the grid and led to higher energy prices. This “under-scheduling” problem was identified in the ISO’s first year of operation (e.g. Annual Report on Market Issues and Performance, ISO Department of Market Analysis, June 1999). More recently, both the ISO Department of Market Analysis (DMA) and the ISO Market Surveillance Committee (MSC) recognized this problem as one of the contributing factors to the price spikes of May-June 2000 (Report on California Energy Market Issues and Performance: May-June, 2000, ISO Department of Market Analysis, August 10, 2000), and proposed remedies for increasing forward scheduling.

An immediate measure proposed by the MSC was to change the payment for the Replacement Reserve to the generators, and to implement a real-time trading charge for both load and generation. Both of these recommendations would essentially make transacting in real-time less attractive to both buyers and sellers and thus provide incentives for greater forward scheduling. Other measures proposed by the MSC and the ISO included forward contracting quantity thresholds as a pre-requisite for market-based rate authority.

The FERC Order of December 15, 2000 included the recommended change in the payment for Replacement Reserve, but limited the real-time trading charge to the load only (penalty of \$100/MWh or twice the real-time MCP, whichever is lower, to the unscheduled load beyond 5% of the load serving entity’s actual load).

Unfortunately, because conditions in the market rapidly deteriorated shortly after the FERC's December 15th Order, there was no opportunity for these changes to have an effect. In fact, given the utilities current financial condition, the ISO recently filed comments with FERC in support of a request filed with FERC by SCE and PG&E to suspend the under-scheduling penalty.

Similar to the intended design of the ISO real-time market, the basic premise of the ISO ancillary service market design was that the Scheduling Coordinators would self provide their share of ancillary services through forward bilateral arrangements, and that the ISO would function as the provider of last resort for ancillary services. Thus, the original market design was based on the premise that Scheduling Coordinators would self-provide and schedule most of their energy and ancillary service requirements and that the ISO markets would essentially serve as residual markets for triuing up imbalances. Unfortunately, because the utilities were limited to buying their energy and ancillary services from the PX and ISO and the PX did not have a market that enabled the utilities to bilaterally purchase ancillary services until last summer, the ISO ended up as the main market for ancillary services.

Recommendation 2: Avoid using Single State Wholesale Price Cap

The Auditor's reports recommends that "the use of price caps should be confined to times when market are found to be non-competitive and supply is being withheld to force prices higher."

The ISO has previously considered the type of trigger mechanisms suggested in the Auditor's report, both for local and system-wide market power mitigation. Similar mechanisms are being worked out by the NYISO. The basic idea of such a mechanism (referred to generally as a "circuit breaker") is to pre-define metrics (such a Residual Supply Index, number of out-of-merit order suppliers providing the required service, etc.) separately for local and global market conditions. When such metrics violate pre-defined thresholds, mitigated bid caps are triggered for the local or system-wide suppliers.

At present, the ISO feels the default of any such trigger mechanism would need to be set "ON" (practically ON all the time) since markets are non-competitive. As more supply is attracted into the market (e.g., new in-state generation, or a large volume of forward contracts), the mechanisms may be treated as "normally OFF", and turned ON only when pre-defined conditions occur. The CAISO would have to develop the specifics of the metrics and the relevant thresholds. However, in light of recent market experience, the ISO is at this time cautious about the ability to design any such trigger mechanism and the potential "unintended consequences" of such an approach.

In addition, the ISO would note that if the fundamental premise of this approach is true (i.e. that a trigger can be designed that accurately differentiates between competitive and non-competitive conditions), then the difference between having such a trigger and having a permanent market power mitigation option in effect is minimal, since under competitive conditions we would expect a well designed trigger to be “non-binding” on market outcomes. At the same time, if the trigger mechanism is too “loosely” designed in order to avoid the risk of constraining the market under competitive conditions, it may allow significant market power to be exercised when market are not competitive.

The rationale provided in support of this recommendation is that (1) price caps may not be entirely effective in controlling prices under periods of high demand and market power, and (2) price caps may actually raise prices. As stated in the Auditor’s report:

“First, even when demand in the PX is low, the ISO price cap has become the minimum bid in some peak demand hours. Additionally, in times of high demand, it is unclear whether any price cap is effective because sellers can sell to the ISO through out-of-market transactions that are not subject to the price cap. Thus, the result is higher energy prices, despite the effort to control them.”

While the ISO agrees that price caps are a very imperfect tool for controlling price caps, the ISO does believe that the “single state” price caps in effect until January 2001 have had the effect of limiting prices – rather than exacerbating price spikes or being completely ineffective as some have suggested. Similarly, the ISO does not believe that these “single state” priced caps have actually raised overall market prices creating a “floor” in the PX Day ahead market under conditions of tight supply or any other way. While the price cap may indeed create a “floor” for bids in the PX under tight supply conditions from the perspective of suppliers, it also creates a “ceiling” on purchases in both the PX and real time market from the perspective of buyers. To the extent that the ISO’s real time price cap may tend to creates a “floor” in the PX Day ahead market for some sellers under conditions of tight supply, a lower price cap lowers this floor and thereby lowers the PX price. Thus, there is not reason to believe the ISO’s real time price cap raised prices in the PX Day Ahead market or overall wholesale costs in general, not is there any empirical evidence to this effect.

In addition, the ISO believes it is important to note that Table 1.3* of the Auditor’s report shows that from June through November 2000 sellers could not simply circumvent the “single state” price cap in effect during these months by selling power out-of-market at prices higher than the price cap. As shown in Table 1.3, the average price of out-of-market purchases by the ISO during these months was lower than or just slightly above the price cap. As reported in DMA’s November report to the ISO Board, prices paid for out-of-market purchases rarely exceeded the price cap during the

* This table number refers to an earlier draft of the report.

summer and fall months of 2000, with less than 1% of out-of-market purchases from May through October exceeding the price cap. Since out-of-market purchases did not receive the replacement reserve capacity payment, the total effective price of this energy was lower than the total price of real time energy purchased through the ISO's Replacement Reserve market. Thus, during this period, a strategy of withholding any firm power for sales out-of-market would have provided lower overall revenues for the supplier than a strategy of providing both capacity and real time energy through the ISO's Replacement Reserve market.

As shown in Table 1.3 of the Auditor's report, the average cost of out-of-market purchases did exceed the \$250 price cap by a significant amount during December. However, it is important to note that this can be attributed to the fundamental economics of the sharp increase in spot market gas prices during this time. As spot market gas prices rose significantly above \$25/mmbtu in December, the variable operating costs of units needing to purchase gas on the spot market started to exceed the \$250 price cap. Thus, the ISO feels the events of December merely highlight the limitation of any price cap set at an absolute level, which may become inappropriate due to extraordinary market conditions such as the tenfold increase in spot market gas prices from about \$5 to \$50 from November to December 2000. In other words, while a price cap will never work if it is below cost, there is no evidence that a price cap invites bidding at cap (when it is above system marginal cost).

Recommendation 3: The ISO Should Have Additional Authority for Scheduling Power Plant Maintenance

The ISO agrees that it needs greater authority for scheduling power plant outages. However, it does not agree that this authority will be unnecessary in another 2-3 years or until a competitive market is established. Outage coordination should not be abandoned when the market becomes more competitive but it may become highly simplified. The ISO's criterion in coordinating outages is to ensure that outage schedules are planned so as not to threaten system reliability. With adequate resources in a competitive market environment, this objective would probably be met with the ISO accepting all preferred outage schedules with minimal or no change.

The ISO is also considering using the coordinated outage schedule along with allowances for forced outages compatible with performance benchmarks to establish reference availability levels to determine and penalize strategic physical withholding.

Recommendation 4: Limit data published on websites.

Recommendation 5a: Remove the models used by market monitoring units from the public domain and not make available to the public any new oversight and market monitoring models.

The Auditor's report and staff indicate that this recommendation pertains only to the PX and not the ISO. Nevertheless, the ISO agrees with the basic principle underlying this recommendation. The ISO recognizes that many parties have a high degree of interest in public reports and analysis that may be prepared by the ISO, but believes that much of the analysis performed as part of market monitoring must remain confidential, or, at a minimum be restricted to appropriate regulatory entities.

Recommendation 5b: Don't make data on bidding and winning bids public. This is especially critical for long-term contracts, which should be kept in strictest confidence.

The ISO agrees that individual bid data should not be published to the extent that they may invite tacit collusion. That is why the existing ISO policy, approved by FERC, is to publish such data with a 6-month delay, keeping the bidder and resource identity anonymous. Though the report recommends that such data be released subject to a 1-year lag, FERC has established 6-months as an appropriate lag.

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