



High Risk:

The California State Auditor Has Designated Electricity Production and Delivery as a High-Risk Issue

June 2009 Report 2008-602



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June 16, 2009

2008-602

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 authorized by Chapter 251, Statutes of 2004, the Bureau of State Audits (bureau) presents its report designating the production and delivery of electricity as a high-risk issue in California. In May 2007 the bureau published its initial assessment of issues that pose a high risk to California, its citizens, and select state agencies. Our initial assessment identified five significant statewide risk areas and two specific state agencies facing challenges to their day-to-day and long-term operations. Because of the ongoing challenges the State faces to ensure a reliable supply of electricity, which is critical to our economy and daily lives, the bureau has added the production and delivery of electricity to its list of high-risk issues.

Since California's restructuring of the electricity industry in the late 1990s and the subsequent energy crisis of 2000 and 2001, the electricity sector has continued to evolve. In fact, industry observers suggest that the actions the State and other market participants have taken have decreased the risk of another energy crisis. However, these stakeholders continue to work to resolve issues and to further refine the actions taken to alleviate the earlier energy crisis. This report also identifies significant new issues and challenges in the electricity sector that the State faces, which have the potential to influence the supply of electricity, its transmission, and consumer rates. For example, we found that decisions concerning certain environmental policies may substantially reduce electricity supplies from existing power plants and restrict the construction of new power plants, most notably in Southern California. We also found that the State's ability to meet the targets it has adopted to increase the use of renewable sources of electricity is constrained by various obstacles that are preventing the construction of key infrastructure. We further found that a proposed reorganization of certain energy-related programs and functions present additional uncertainties related to the State's ability to formulate strategic energy policies. Because we have designated the production and delivery of electricity as high risk, the bureau will continue to monitor developments and challenges that affect the reliability and affordability of electricity, and may undertake future projects to further evaluate policy changes that potentially affect electricity supplies and rates in California.

Respectfully submitted,



ELAINE M. HOWLE, CPA
State Auditor

Contents

Summary	1
Introduction	5
Analysis Results	
Various Factors Contributed to the Energy Crisis of 2000 and 2001	17
Mitigating Actions Have Reduced the Likelihood of Another Energy Crisis	20
The Need to Replace or Retrofit Aging and Environmentally Harmful Power Plants May Cause Significant Reductions in Electricity Supplies	26
Large Investor-Owned Utilities Have Secured Long-Term Contracts as Water Resources' Role Phases Out, but Some Uncertainty Remains	32
Meeting California's Renewable Resource Targets Will Be Challenging	37
It Is Too Early to Tell Whether the ISO's New Market Structure Will Continue to Succeed	39
Several Entities Have Identified a Need to Reorganize the State's Energy-Related Entities	43
The Bureau Will Continue to Monitor Developments in the Electricity Sector and in Related Policies and Programs	44

Summary

Results in Brief

Because California's electricity sector faces multiple challenges and problems related to energy production and consumption, the Bureau of State Audits (bureau) has added the production and delivery of electricity to its list of issues that pose a high risk to the State of California (State) and its citizens. The reliable supply of electricity provides a critical foundation both for California's economy and its citizens' standard of living. The electricity industry is evolving to address problems highlighted by the energy crisis of 2000 and 2001 while simultaneously working to introduce mechanisms to increase competition and to support the State's overall energy targets. Since the energy crisis, the State has continued to deal with the challenges of ensuring that sufficient capacity exists to generate the volume of electricity needed, that California has the infrastructure necessary to transport the electricity to the areas that most need it, and that the appropriate regulatory agencies work collaboratively in their efforts to ensure that an energy crisis does not reoccur.

In 1996, when the State took the lead in the national move toward restructuring the electricity industry to allow for greater competition, proponents assumed that these actions would reduce California's electric rates. Despite this intent, the State experienced rolling blackouts and, in January 2001, the governor proclaimed a state of emergency. Wholesale electricity prices escalated to unprecedented levels. Because of a cap on retail prices, two of the State's three largest electricity providers—Pacific Gas and Electric Company (PG&E) and Southern California Edison—could not recoup their costs from customers and PG&E ultimately filed for bankruptcy.

By many accounts, several interconnected events during the early part of the current decade contributed to the energy crisis. For instance, the State and energy providers did not meet increased demand for electricity with investments in new generation of electricity or in upgrades to the State's system for transmitting electricity. Compounding this imbalance, a flawed market design relied too heavily on short-term markets, leaving participants overexposed to market manipulation that led to high wholesale prices. Because of the uncertainty related to the ability of the large electricity providers to secure enough energy supplies to meet their customers' needs, the State took steps to alleviate the crisis, including procuring long-term power contracts to ensure both a reliable supply of electricity and rate stability.

Review Highlights . . .

Our review of California's production and delivery of electricity revealed that since the energy crisis of 2000 and 2001, new issues and challenges could impact the supply of electricity, its transmission, and consumer rates. Some of these challenges include the following:

- » *Numerous aging and environmentally harmful power plants need to be replaced or retrofitted.*
- » *Key air and water policies could reduce the electricity supply from existing power plants and limit new plants.*
- » *As the State's remaining power contracts expire, there is uncertainty surrounding the ability of electricity providers to procure sufficient energy supplies.*
- » *Uncertainties about the introduction of a new wholesale market structure.*

Since the energy crisis of 2000 and 2001, the electricity sector has continued to evolve. In fact, industry observers suggest that the actions the State has taken have decreased the risk of another energy crisis. However, the State and other market participants continue to work to resolve issues and to further refine the actions taken to alleviate the earlier energy crisis. In addition, significant new issues and challenges in the electricity sector have the potential to influence the supply of electricity, its transmission, and consumer rates. These issues include the following:

- The State's need to replace or retrofit aging and environmentally harmful power plants.
- Ongoing decisions surrounding key air and water policies—most notably affecting Orange County and the urban portions of Los Angeles, Riverside, and San Bernardino counties—which may reduce the electricity supply from existing power plants and limit the siting, construction, and operation of new plants.
- Uncertainty surrounding the financial recovery of California's large electricity providers and their ability to procure sufficient energy supplies to meet consumers' needs as the State's power contracts expire.
- The State's targets to increase the use of electricity produced from renewable energy sources.
- Modifications to the market structure, such as the reinstatement of energy markets that failed at the height of the energy crisis; a new wholesale electricity pricing scheme; and the use of a new computer model of the electric grid that will allow, for example, better identification of transmission bottlenecks.
- A proposal currently before the Legislature to reorganize certain energy-related entities and create a new state Department of Energy.

Consequently, we believe that our list of high-risk issues should include energy concerns—and, more specifically, the areas related to supplying electricity to California's citizens. We will continue to monitor new developments and challenges that affect the industry as well as their effects on the reliability and affordability of electricity. To the extent that resources are available, the bureau may undertake future projects that could include recommendations to improve electricity-related policies and programs and how best to implement those improvements. For example, the bureau may monitor developments in a court ruling regarding a proposed policy that potentially affects electricity supplies in Southern California. The bureau may report on the status of the

State's expiring energy contracts and the ability of large electricity providers to procure sufficient energy supplies to meet consumers' needs. Also, should major developments occur, the bureau may consider deeper evaluations of the new market structure, the State's ability to meet its renewable resource targets, and, if one is created, the effectiveness of a new state Department of Energy.

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Introduction

Background

In May 2007 the Bureau of State Audits (bureau) published its initial assessment of the high-risk issues that the State of California (State) and select state agencies face. As the text box shows, our assessment, titled *High Risk: The California State Auditor's Initial Assessment of the High-Risk Issues the State and Select State Agencies Face*, identified five significant statewide risk areas and two specific state agencies facing challenges to their day-to-day and long-term operations. High-risk programs and functions include not only those particularly vulnerable to fraud, waste, abuse, and mismanagement or that present major challenges associated with their economy, efficiency, or effectiveness, but also those of particular interest to California citizens and those that have or could have significant impacts on the public's health, safety, and economic well-being.

In considering the criteria named above, we reviewed energy concerns—specifically those related to the electricity sector—to decide whether it belongs on the list of issues that are subject to the high-risk audit program authorized by California Government Code, Section 8546.5. Because the State is continuing to address the factors that contributed to the rolling blackouts earlier this decade and because it is attempting to address more current issues related to electricity generation, such as the State's need to replace older power plants and its targets to increase the use of renewable energy, we believe such an assessment is warranted. For a description of the criteria used to determine whether an issue merits a high-risk designation, see the Appendix to our May 2007 report on high-risk issues. In addition, the text box on the following page lists the bureau's most recent reports on the topic of energy.

The Electric System, Past and Present

The electric system is a network of infrastructure that allows consumers to have readily available electricity regardless of their proximity to power-generating facilities. As Figure 1 on page 7 illustrates, the generation, transmission, and distribution of electricity are interdependent industry segments that function sequentially. Generated at power plants and then transported to

Statewide Risk Areas That the Bureau of State Audits Identified in May 2007

- Emergency preparedness
- Maintaining and improving infrastructure
- Information technology
- Management of human resources
- Other post-employment benefits of retiring state employees

State Agencies That Meet the Criteria for High Risk

- Department of Corrections and Rehabilitation
- Department of Health Services*

Source: *High Risk: The California State Auditor's Initial Assessment of the High-Risk Issues the State and Select State Agencies Face*, Bureau of State Audits, May 2007, 2006-601.

* Effective July 1, 2007, the Department of Health Services was reorganized and became two departments—the Department of Health Care Services and the Department of Public Health.

Reports Issued by the Bureau of State Audits on Energy Topics

Energy Deregulation: The Benefits of Competition Were Undermined by Structural Flaws in the Market, Unsuccessful Oversight, and Uncontrollable Competitive Forces, Report 2000-134.1, March 2001

Energy Deregulation: The State's Energy Balance Remains Uncertain but Could Improve With Changes to Its Energy Programs and Generation and Transmission Siting, Report 2000-134.2, May 2001

California Energy Commission: Although External Factors Have Caused Delays in Its Approval of Sites, Its Application Process Is Reasonable, Report 2001-118, August 2001

California Energy Markets: Pressures Have Eased, but Cost Risks Remain, Report 2001-009, December 2001

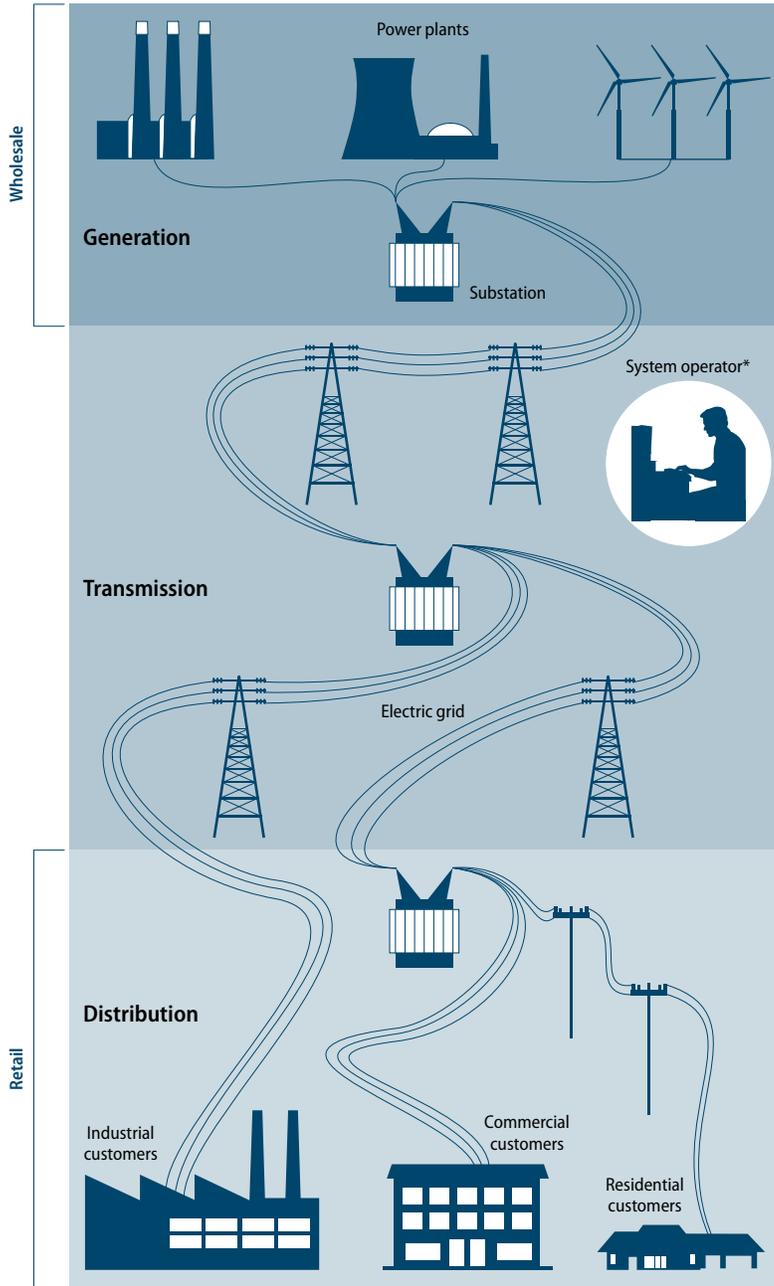
California Energy Markets: The State's Position Has Improved, Due to Efforts by the Department of Water Resources and Other Factors, but Cost Issues and Legal Challenges Continue, Report 2002-009, April 2003

Solar Energy: As the Cost of This Resource Becomes More Competitive With Other Renewable Resources, Applications to Construct New Solar Power Plants Should Increase, Report 2007-119, January 2008

consumers at their homes and businesses, electricity travels via high-voltage transmission lines and then through lower-voltage distribution lines that snake throughout communities and neighborhoods; taken together, the segments of this system are commonly referred to as the *electric grid*. Because energy providers cannot store significant amounts of electricity economically, the volume of electricity generated and supplied must almost exactly match the volume used by residents and businesses only milliseconds later. Should more or less electricity enter the grid than the amount used by customers, the grid could fail. Momentary imbalances can result in lights dimming or in brief power disruptions. However, more significant imbalances can cause cascading blackouts, such as the one that occurred in Ontario, Canada, and the Northeastern United States in August 2003. That cascading blackout left an estimated 50 million people without power, some for up to four days, and cost the economy billions of dollars. To maintain electric grid balance, system operators, which include utilities and independent entities charged with the responsibility of monitoring and managing grid operations, can increase or decrease the volume of electricity put onto the grid, and they can reroute the flows of electricity through the various transmission lines and substations that make up the grid.

Before the passage of Assembly Bill 1890 (AB 1890) in 1996, which facilitated the restructuring of California's electricity industry, three large *investor-owned utilities*—or privately held utilities—owned and controlled the electric systems that served most Californians. The utilities owned and operated the capacity to generate, transmit, and distribute electricity. They also functioned as system operators, responsible for monitoring and maintaining the fine balance between electricity supplied and consumed. Electric utilities in general were interconnected to the extent that they could buy (import) and sell (export) electricity from one another as necessary, even over state lines, to ensure that their systems were in balance. Moreover, consumers were typically limited to purchasing power from the utility designated to serve the area in which the consumer was located; thus, consumer choice on a retail level did not exist. As natural monopolies, the investor-owned utilities were subject to state and federal government regulation: The California Public Utilities Commission (CPUC) oversaw retail rates in California, while the Federal Energy Regulatory

Figure 1
Electricity Supplies Must Be in Balance With Real-Time Consumption to
Ensure the Integrity of Bulk Electric Systems and Reliable Service



Sources: Bureau of State Audits based on information from and discussion with the California Independent System Operator (ISO), and on information obtained from various Web sites, such as those maintained by the Federal Energy Regulatory Commission, the California Public Utilities Commission, and the Institute of Electrical and Electronics Engineers.

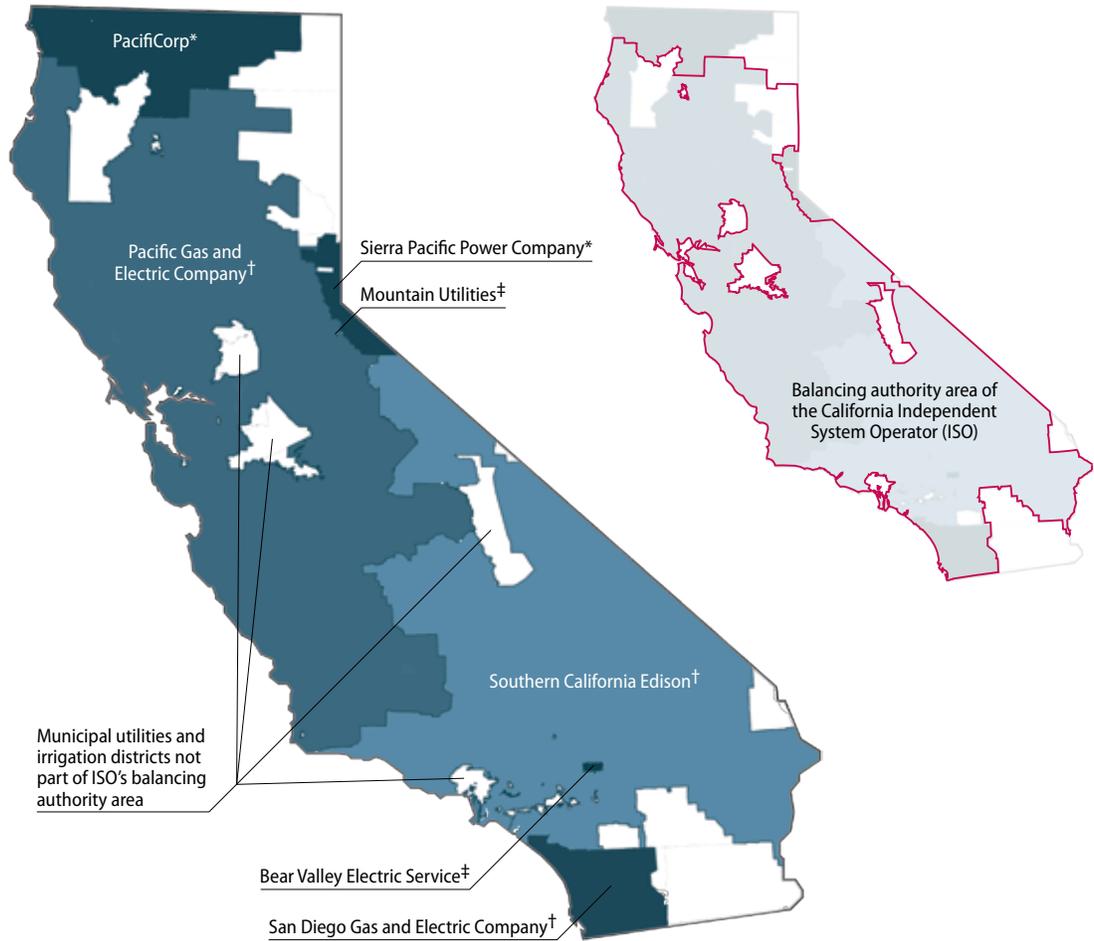
* A system operator is responsible for monitoring and ensuring equilibrium on the electric grid of electricity supplied and consumed in real time. The jurisdiction of a system operator is called its balancing authority area. The ISO manages roughly 80 percent of the State's electric grid. Other system operators include municipal utilities and water irrigation districts.

Commission (FERC) had regulatory oversight for the interstate transmission of electricity, including ensuring that wholesale rates were “just and reasonable.” The retail electricity prices set by the CPUC included the charges to cover the costs of generating the electricity as well as the costs of maintaining and operating the transmission and distribution systems. Utilities were allowed to earn a “normal rate of return” on all approved capital expenditures required to build generating facilities and on the transmission system itself.

As the next section discusses, after the passage of AB 1890 in 1996, market restructuring separated the wholesale segment of the industry (electricity generation) from the retail segment (electricity distribution). Nonetheless, the three large investor-owned utilities continue to deliver electricity to most consumers in California.

Figure 2 illustrates the areas served by the seven investor-owned utilities providing electricity retail service in California as well as those areas served by municipal utilities and rural irrigation districts. We use the term *large investor-owned utilities* to refer solely to the three largest investor-owned utilities in California—Pacific Gas and Electric Company (PG&E), Southern California Edison, and San Diego Gas & Electric Company. Serving a substantial proportion of California consumers, these providers manage sizeable operations that involve complex electricity generation, transmission, and distribution systems. According to the California Energy Commission (Energy Commission), the State’s principal energy policy and planning agency, the operating decisions made by the large investor-owned utilities have potentially significant statewide impacts. In contrast, the small investor-owned utilities—Bear Valley Electric Service and Mountain Utilities—manage less complex electric systems that may not even be connected to the grid and serve much smaller populations. Finally, as the Energy Commission explained to us, the utility commissions of other states primarily regulate the multijurisdictional investor-owned utilities—Sierra Pacific and PacifiCorp—that operate in California. The CPUC provides oversight for the fraction of the two utilities’ total costs expected to be recovered from their California customers, who receive services from these multijurisdictional utilities for various reasons, such as a significant barrier existed between the locations of these electricity consumers and the nearest California utility or the locations were too far from a California utility. In addition to electricity services provided by the investor-owned utilities, publicly owned municipal utilities (municipal utilities) and irrigation districts manage approximately 20 percent of California consumers’ electricity demand. In place of the CPUC and its regulating authority, a board of directors sets rates and enforces pertinent rules and regulations for each municipal utility and irrigation district.

Figure 2
Service Areas of California's Electric Utilities and of Its Independent System Operator



Source: California Energy Commission.

Note: Areas shown in white are served by various publicly owned utilities, including municipal utilities and irrigation districts.

* Multijurisdictional investor-owned utility.

† Large investor-owned utility.

‡ Small investor-owned utility. Bear Valley Electric Service is within ISO's balancing authority area. Mountain Utilities is not connected to the high-voltage electric grid.

The Restructuring of California's Electricity Industry

Since the late 1970s, under the direction of various federal laws and regulations, the nation has moved to open the electricity industry to competition. For example, the federal government required investor-owned utilities nationwide to purchase electricity supplies from alternative sources not generated by the utilities themselves, such as from wind and solar energy, and to partially open their

transmission systems to allow electricity to pass through to neighboring utilities' service areas. Cumulatively, such actions were intended to create an energy market that encouraged competition.

In 1992, prompted by the federal Energy Policy Act and California's high electricity rates, the CPUC began a comprehensive review of the electricity industry. This review led, in 1994, to a formal rulemaking proceeding to consider possible approaches to the restructuring of the industry. In December 1995 and January 1996, the CPUC issued decisions to guide restructuring in California. In response to concerns raised by FERC, these decisions encouraged investor-owned utilities to transfer voluntarily to unrelated parties the ownership of at least 50 percent of their generation facilities powered by fossil fuel. Additionally, the decisions required investor-owned utilities 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, or a wholesale market through which the utilities must sell any electricity generated by facilities that they still owned and must purchase all electricity required to meet their consumers' needs.

In 1996 the State then took the lead in the national move toward restructuring the electricity industry when the Legislature passed AB 1890, which codified many of the recommendations included in the earlier CPUC decisions. The legislation created two nonprofit, public-benefit corporations, the California Independent System Operator (ISO) and the Power Exchange (PX), as well as the Electricity Oversight Board¹ to oversee the PX and the ISO. The Legislature also froze the retail rates that 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 could select their electricity suppliers; they were no longer obligated to purchase their power from the utility that serviced their area. Specifically, consumers could choose *direct access*, a retail option that enabled consumers to select an electricity provider other than the one that had previously supplied their electricity. On the other hand, these consumers were not obligated to switch. It was assumed that these actions would reduce California's electric rates by at least 20 percent by April 1, 2002. Municipal utilities, rural irrigation districts, and their customers were exempt from AB 1890.

¹ The Electricity Oversight Board ceased operations on April 1, 2008. According to the Department of Finance, other entities such as the CPUC and the ISO have taken on some of the Electricity Oversight Board's responsibilities, including providing market oversight and pursuing refunds of overcharges.

The Evolution of California's Electricity Market Structure

Under the restructured market system, which began operating in March 1998, the establishment of the PX and the ISO introduced new ways by which the utilities procured and delivered electricity for consumers. The large investor-owned utilities divested or sold off power plants and turned over the operational control of transmission lines to the ISO, allowing other companies to enter the new market and competition to arise. Investor-owned utilities were required to sell and purchase all of their electricity through the PX until March 2002 or until the CPUC ruled that they had recovered certain costs, whichever occurred first.² Other entities, such as municipal utilities or rural irrigation districts, could also purchase electricity through the PX if they chose. Additionally, the ISO became the system operator responsible for monitoring and managing grid operations for the service areas of all three large investor-owned utilities. Further, because of industry restructuring, municipal utilities and rural irrigation districts had the option either to remain in control of balancing the electricity flow within their respective jurisdictions or to release that responsibility to the ISO. As Figure 2 shows, the ISO's balancing authority area currently encompasses the service areas of all three large investor-owned utilities, Bear Valley Electric Service, and smaller municipal utilities and irrigation districts.

Of the several short-term markets that the PX operated, the *day-ahead market* was the largest. In this market, buyers requested the amount of electricity that they anticipated needing for each hour of the next day and stipulated the prices that they were willing to pay. At the same time, sellers stated the amount of electricity that they could produce and the prices that they required for each of those hours. These bids established the market-clearing price at which all electricity was sold. Additionally, these market trades resulted in matched supply and demand schedules submitted to the ISO, which compared these schedules to the capabilities of the transmission system. If the ISO determined that the electricity providers had scheduled more electricity to flow across a certain transmission path than the lines could transmit—a situation known as *congestion*—the ISO rerouted the electricity through a different path, thus avoiding overloading the transmission system. In these instances, the ISO charged electricity suppliers and users congestion fees.

² In an order dated December 15, 2000, FERC eliminated the State's requirement that the investor-owned utilities use the PX to sell all of the electricity that they generated and to buy all of the electricity needed to serve their customers. In January 2001 the PX ceased operating.

The ISO was also and continues to be responsible for procuring *ancillary services* for each day. Ancillary services are purchased for several different purposes, one of which is to balance the electric system in real time. For example, although the utilities and other providers estimate 24 hours in advance the gross levels of electricity that California consumers will demand and that the electricity providers will supply, 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 electricity supplied to the system. Such transactions are called *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 that the ISO procures are electricity reserves used as a safety net in case a power generator or transmission line unexpectedly fails. These services include the capacity to produce electricity. The ISO purchases or *reserves* these ancillary services, which the ISO ranks according to the speed at which they can be made available if needed.

In the midst of the State's energy crisis, which we will discuss later in this report, the short-term markets operated by the PX closed in January 2001. Subsequently, long-term power contracts initially secured by the State in many cases, provided an increasing amount of California's electricity needs. However, the ISO continued to operate the real-time, ancillary services market to ensure the reliability of electrical services.

The Role of Regulators in the Current Market

Regulatory entities that currently play important roles in the electricity market include FERC, the CPUC, the Energy Commission, the California Air Resources Board (Air Resources Board), and the State Water Resources Control Board (Water Control Board).

The 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 that they are not unduly discriminatory or preferential. Because California's transmission system connects to systems in other states, allowing California to import and export power, FERC has some regulatory authority over the ISO. FERC reviews and approves the ISO's rates and other filings covering

topics such as the structure of its governing board, access to the interstate electric grid, or the publication of information regarding the operation of the electric grid. FERC also grants permission for Western power generators to participate in California's electricity market and to charge market-based wholesale rates for the electricity they sell. Finally, as a result of the federal Energy Policy Act of 2005, FERC established rules to prohibit electricity market manipulation and fraud.

The California Public Utilities Commission

The CPUC regulates the State's privately owned utilities, which include all investor-owned utilities. The CPUC is charged with the following:

- Under AB 1890, implementing *direct retail access*, a program that allows consumers to choose to contract directly for electricity from a power supplier rather than purchase electricity from their local utility. However, as discussed in a later section, direct access was suspended in 2001.
- Regulating retail rates charged by investor-owned utilities.
- Ensuring retail power reliability.
- Overseeing mergers of investor-owned utilities.
- Implementing consumer protection and education programs about 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 is complete.

The California Energy Commission

Established by the Legislature in 1974, the Energy Commission is the State's primary energy policy and planning agency, and it is responsible for the following:

- Forecasting future energy needs and keeping historical energy data.

- Licensing thermal power plants that are 50 megawatts or larger. This process, generally referred to as *siting*, encompasses an analysis of all aspects of a proposed project, including need, public health and environmental impacts, safety, efficiency, and reliability. Plants smaller than 50 megawatts 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 California Air Resources Board

In California, one of the principal environmental issues involved in generating and transmitting electricity relates to air quality. The Air Resources Board, established by the Legislature in 1967, 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. 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 the Air Resources Board's air quality control is *emissions credits*, which are also known as *pollution credits*. Power plant owners must obtain an annual allocation of credits per facility that allows 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 *NOx*. As the plants run, their emissions are measured and their credits are depleted. 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 all of its emissions credits, it must either purchase additional credits from another entity or restrict its electricity 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.

The State Water Resources Control Board

The Water Control Board is responsible for water allocation and water quality protection for the State. Some power plants are fueled by natural gas or nuclear reactors that use significant amounts of water to cool their systems and that discharge this water back into the environment, a practice that, among other things, kills fish and shellfish. Therefore, the Water Control Board's regulations affect the operation of these plants.

Other Entities That Contribute to California's Electric Industry

The California Independent System Operator

The ISO is responsible for managing the flow of electricity along approximately 80 percent of California's electric grid. The nonprofit public-benefit corporation began operating in March 1998, when the wholesale electricity market began functioning in California.

The Department of Water Resources

The State's Department of Water Resources (Water Resources) manages a portfolio of long-term power contracts with wholesale generators and of bond debts issued to pay for the contracts. In response to the energy crisis of 2000 and 2001, the governor and the Legislature authorized Water Resources to enter into these contracts on behalf of the large investor-owned utilities. Water Resources' authority to enter into new contracts ended in 2003.

Scope and Methodology

California Government Code, Section 8546.5, authorizes the bureau to establish an audit program for identifying state agencies that are at high risk for potential waste, fraud, abuse, and mismanagement or that have major challenges associated with their economy, efficiency, or effectiveness. The law also authorizes the bureau to audit any state agency that it identifies as being at high risk and to publish related audit reports at least once every two years. This includes challenges that cut across programs or management functions at all state agencies or multiple state agencies: we refer to these as statewide issues. The considerations the bureau uses for determining high risk are set forth in the Appendix to the inaugural high-risk list published in the bureau's report titled *High Risk: The California State Auditor's Initial Assessment of High-Risk Issues the State and Select State Agencies Face*,

Report 2006-601, May 2007. This report adds the production and delivery of electricity to the initial list of high-risk areas that the bureau identified.

Throughout this report, we cite information obtained from the Energy Commission, the CPUC, the ISO, Water Resources, and other agencies and entities. Other than confirming that the information appeared reasonable in the context of other information in our possession, we did not perform procedures to test the reliability of the data presented. Where possible, we relied on data from the Energy Commission, which is the State's primary energy policy and planning agency, to perform our analysis.

In reviewing the factors that caused the energy crisis of 2000 and 2001, the mitigating actions undertaken by the State and market participants, and the status of ongoing energy-related initiatives and programs, we interviewed various subject-matter experts working for the Energy Commission, the CPUC, the ISO, and Water Resources, and we obtained their feedback on this report. For example, we spoke to experts to verify our understanding of the factors that gave rise to the energy crisis of 2000 and 2001 and to obtain the status of long-term energy contracts managed by Water Resources. They were also helpful in identifying the major issues, critical documents, and data surrounding each of the identified risk areas.

Analysis Results

Various Factors Contributed to the Energy Crisis of 2000 and 2001

A complex combination of factors contributed to the statewide energy crisis of 2000 and 2001, and some of these factors continue to pose concerns and to contribute to the decision by the Bureau of State Audits (bureau) to identify energy—and especially the production and delivery of electricity—as a high-risk issue for the State of California (State). For example, sharp fluctuations in the price of natural gas and reduced availability of electricity imports from the Pacific Northwest contributed to California’s energy crisis. Additionally, design flaws in the energy market, such as the manipulation of wholesale prices by generators and electricity brokers, played a role in the energy crisis. The text box outlines these and other circumstances that factored into California’s difficulties involving the generation, transmission, and delivery of electricity.

The various problems that played parts in the energy crisis included an increasing demand for electricity by residents and businesses, inadequate generation of electricity within the State, and inadequate transmission capacity to transport electricity within the State. Because of population expansion and rapid economic growth, electricity demand within the State increased by more than 3 percent over the prior year in both 1999 and 2000. However, the California Energy Commission (Energy Commission) had received and approved few power plant applications in the early 1990s, apparently due in part to a combination of excess supply at the time and uncertainty on the part of the investor-owned utilities, or privately owned utilities, about the potential effects of energy market restructuring. As a result, only three generating plants larger than 50 megawatts (defined in the text box on the following page) were built in the State from 1996 to 2000, and these did not provide the additional electricity needed to meet the State’s increased demand. Delays in the siting process also postponed the opening of power plants that could have helped meet electricity needs. Limited transmission capacity in certain areas of the State, such as the San Francisco peninsula, further exacerbated the increased but unmet need for electricity. For example, due to congestion, the primary transmission connection

Factors That Contributed to California’s Energy Crisis During 2000 and 2001

General factors in higher energy prices and shortages:

- California’s electricity demand grew, but the number of new power plants and transmission lines did not keep up with that growth.
- Transmission congestion made it difficult to transport electricity to locations that needed it most.
- Below average rainfall in the Pacific Northwest decreased hydroelectric power available for import into California.
- Population growth in neighboring states increased demand for power and reduced electricity available for import into California.
- Power generators were subjected to increased costs, including the price of natural gas.

Specific problems caused by design flaws in California’s restructured market:

- Investor-owned utilities could not sign long-term power contracts that would have provided some protection against the increases in wholesale electricity prices.
- Short-term market structure, particularly the day-ahead and real-time markets, permitted the manipulation of prices by wholesale electricity generators and electricity brokers.
- The price freeze on retail prices meant investor-owned utilities could not recover higher-than-expected costs of wholesale electricity.

Sources: Bureau of State Audits’ analysis and the Public Policy Institute of California.

Megawatt:

One megawatt equals 1 million watts or 1,000 kilowatts, which is enough electricity to meet the instantaneous demand of roughly 750 homes at once. (The number of homes fluctuates because electricity demand changes based on the season, the time of day, and other factors.)

Source: California Independent System Operator's Web site.

between Northern and Southern California could not transmit the volume of electricity that Northern California needed in January 2001, and this situation contributed to the rolling blackouts that ultimately occurred.

Additionally, other dynamics outside the State's direct control further decreased the available supply of electricity and contributed to an increase in its wholesale cost. A report published by the Public Policy Institute of California³ (policy

institute) noted that dry winters in the northwestern states reduced the availability of hydroelectric power that the State could import. Further, the report concluded that neighboring states grew at rapid rates, consuming power that otherwise might have gone to California. Between 1988 and 1998, Nevada's electricity demand grew by an average of 6.2 percent annually, and Arizona's demand grew 3.7 percent annually. Moreover, the policy institute report cites additional costs to generators that contributed to a general escalation in wholesale electricity prices. These costs arose from such circumstances as unprecedented volatility and increases in the price of natural gas in California, which was used to generate 38 percent of the State's electricity in 2000, and higher costs for air pollution permits, which air quality regulators require of generators that run the higher polluting plants.

In addition to the problems previously described, California's restructuring efforts led to potentially avoidable market design flaws that contributed to record wholesale electricity prices and the energy crisis. Specifically, the initial decision by the California Public Utilities Commission (CPUC) to restrict California's investor-owned utilities from using long-term contracts—agreements that specify that a purchaser can buy a certain amount of electricity in the future at a predefined price—hindered these utilities from absorbing shocks and volatility in the wholesale price of electricity. Long-term contracts can potentially give investor-owned utilities an effective hedge against price fluctuations in short-term markets by providing price certainty in the future as well as supply availability. Various considerations caused the State to require the three large investor-owned utilities—Pacific Gas and Electric Company (PG&E), Southern California Edison, and San Diego Gas & Electric Company—to make all of their energy purchases in the short-term markets instead of through contracts. One such consideration was that this purchasing method made the utilities' transactions easier to monitor for regulators. Further, markets need sufficient participation

³ Christopher Weare, *The California Electricity Crisis: Causes and Policy Options* (Public Policy Institute of California, 2003).

to function efficiently. Forcing investor-owned utilities into the short-term markets helped ensure sufficient participation and the market's continued financial viability.

In contrast to California's focus on short-term markets for electricity, other states and countries have taken a different approach to restructuring. Energy providers in these states and countries used contracts to purchase most of the electricity used; energy providers purchased only 10 percent to 20 percent of their power in short-term markets.

Unfortunately, the structure of California's electricity markets allowed for price manipulation. Evidence suggests that wholesale electricity generators and brokers sought to increase prices further by withholding available power from the markets. For instance, an analysis by the U.S. Government Accountability Office found that California's highest electricity prices in 2000 occurred during periods of low demand; however, one would expect to see the highest prices during periods of high demand. Also, the policy institute report notes that it is debated whether generators intentionally took power plants off-line to withhold supply and drive prices up between November 2000 and May 2001—during the peak of the energy crisis. At the time, generators claimed that power plants were out of service for maintenance. Complicating its operation of the electric grid, the California Independent System Operator (ISO) had no authority to control the scheduling of power plant outages for maintenance. Conversely, in an effort to drive down wholesale prices, the three large investor-owned utilities—which before restructuring had been successful historically in forecasting consumers' demand within 2 percent to 3 percent—allegedly underscheduled the volume of electricity needed to service their customers in the day-ahead market, leaving the utilities' more exposed to higher prices in the real-time market.

Because of a freeze on retail electricity rates imposed by state law, the two largest investor-owned utilities soon could not recoup the increased costs of electricity that they were buying for their customers. As a result, PG&E and Southern California Edison began defaulting on their bills, and PG&E filed for bankruptcy in April 2001. Various credit-rating firms took note of the three large investor-owned utilities' worsening financial condition and, in January 2001, downgraded the utilities' credit ratings to junk bond status, that is, at higher risk of defaulting on debts. Such actions eliminated the ability of PG&E and Southern California Edison to enter into contracts, or indeed to purchase any electricity at all. In December 2000 the Federal Energy Regulatory Commission (FERC) negated the CPUC requirement that the three large investor-owned utilities purchase their power through the markets

Evidence suggests that wholesale electricity generators and brokers sought to increase prices further by withholding available power from the markets.

of the Power Exchange (PX), which largely ceased to operate in January 2001. (See this report's Introduction for more information about the PX and its role in the electricity markets.)

Mitigating Actions Have Reduced the Likelihood of Another Energy Crisis

In the wake of rolling blackouts and high prices, key state entities and participants in the electricity market took various actions to mitigate the electric system imbalances and the specific design problems that the restructured market revealed had contributed to the crisis. To stabilize prices and reduce exposure to the price volatility that occurred in the short-term markets, the CPUC allowed greater use of long-term contracts. In addition, the Legislature empowered the Department of Water Resources (Water Resources) to enter into long-term contracts to buy power from wholesalers on behalf of the three large investor-owned utilities, which were not in a financial position to enter into contracts. This was largely due to the retail rate freeze that was imposed by law. Additionally, regulators began ensuring that these utilities procured enough electricity to meet demand forecasts. Market participants also took actions to bring more electricity generation online in California, to improve the transmission system to reduce congestion, and to implement programs to reduce the overall demand for electricity. Market observers suggest that together these actions have expanded energy infrastructure and decreased the risk of another energy crisis.

On Behalf of Investor-Owned Utilities, Water Resources Entered Into Long-Term Electricity Contracts to Stabilize the Price of Electricity

Taking a major step to alleviate the energy crisis and to stabilize the price of electricity, the State entered into long-term contracts with companies that supply electricity, thus moving away from its directive that California's energy providers must purchase almost all electricity through the short-term markets. In doing so, the State retreated from several of the key features of the restructured market design. During the energy crisis, the CPUC granted emergency authorizations for the two largest investor-owned utilities to enter into long-term contracts. However, in January 2001, it became increasingly apparent that the investor-owned utilities would have difficulties purchasing electricity. At that time, the governor proclaimed a state of emergency. In February 2001 the governor approved legislation that authorized Water Resources to enter into long-term contracts to purchase electricity on behalf of the financially stressed investor-owned utilities. Subsequently, Water Resources entered into 57 long-term contracts in 2001 and 2002 at a total

The Legislature empowered Water Resources to enter into long-term contracts to buy power from wholesalers on behalf of the three large investor-owned utilities.

cost of approximately \$42.6 billion over 10 years. Although Water Resources' authority to enter into these long-term contracts expired in January 2003, many of these contracts remain in effect today. As this report discusses in a later section, the large investor-owned utilities currently enter into their own long-term contracts to make up the difference in the electricity provided to retail consumers under the remaining Water Resources' contracts.

According to the director of the ISO's department of market monitoring (monitoring director), the State's long-term contracts and subsequent contracts entered into by the large investor-owned utilities have provided several important market benefits, the most important of which are a reduction in the large investor-owned utilities' exposure to price volatility in the short-term markets, a decrease in the wholesale generators' incentive to manipulate prices, and an increase in investment in new power plants. The monitoring director concluded that the use of long-term contracts shifts the financial risk from the large investor-owned utilities to the suppliers and reduces the incentive for wholesale generators to withhold electricity generation. Additionally, the monitoring director explained that with long-term contracts in place, the volume of electricity sold in the short-term markets becomes so small that it is not profitable for wholesale generators to attempt to manipulate prices. Furthermore, the monitoring director noted that long-term contracts provide incentives for wholesale generators to better maintain their power plants because the generators are aiming to fulfill their contracts in the least costly manner. This improvement in maintenance may also have reduced the number of forced outages of power plants.

The use of long-term contracts shifts the financial risk from the large investor-owned utilities to suppliers and reduces the incentive for wholesale generators to withhold electricity generation.

A Cooperative Regulatory Approach Helps Ensure That Utilities Acquire Adequate Power Supplies to Meet Forecasted Demand

Further contributing to the stability of the energy market, under State law, CPUC now requires that investor-owned utilities plan and contract for sufficient power to meet forecasted peak demand plus a reserve margin, known as *resource adequacy*. According to the CPUC, it currently requires the large investor-owned utilities, among others, to demonstrate that they have contracted for power to meet their anticipated demand for electricity, plus an additional 15 percent to account for forecast error and generation outages, over yearly and monthly intervals. The ISO also indicated that if investor-owned utilities cannot demonstrate that they have enough electricity available to meet the CPUC resource adequacy requirements, the ISO can intervene and procure additional supplies to ensure that an adequate volume of electricity is flowing through the grid to maintain stability and reliability of services to consumers.

As part of the resource adequacy program, the Energy Commission's deputy director for the electricity supply analysis division explained that the Energy Commission ensures that the demand forecasts that the investor-owned utilities use for resource adequacy are consistent with the Energy Commission's forecasts. Furthermore, according to the Energy Commission, under state law it also provides oversight for resource adequacy implementation by the municipal utilities and irrigation districts. The CPUC and the Energy Commission indicated that they require the investor-owned and municipal utilities to develop and submit procurement plans, which detail how utilities expect to meet customer needs for the next 10 years. According to the CPUC, its long-term procurement plans program requires utilities to forecast future electric capacity and energy needs and develop a plan that ensures electricity needs will be met. Additionally, the CPUC indicated that the plans, which are updated every two years, include building new utility-owned power plants, entering contracts that support the building of new independently owned power plants, and entering into short-term, intermediate-term, and long-term contracts with existing power plants. According to Energy Commission staff, it takes about five years to plan and bring online new power plants or expansions of existing plants and seven years to plan and construct transmission infrastructure, demonstrating the importance of estimating demand at least 10 years ahead and then planning accordingly.

Other forecasting efforts assist in providing additional assurance that the State will have enough electricity in the future. For instance, according to the Energy Commission, the ISO prepares forecasts independently from those prepared by the Energy Commission and focuses on its balancing authority area, whereas the Energy Commission focuses on the entire state. According to Energy Commission staff, the two entities meet a couple of times a year to review each other's energy forecasts and to discuss and understand differences between the forecasts, such as disparities in economic assumptions or identified congestion constraints. To improve the accuracy of the forecasts, the Energy Commission indicated that it is working to develop a model that will incorporate into its long-term forecasting expected benefits from energy efficiency programs and contract requirements.

The Energy Commission is working towards incorporating into its long-term forecasting expected benefits from energy efficiency programs and contract requirements.

Additionally, since 2001 the Energy Commission has issued a summer electricity supply and demand outlook report that provides an assessment of the electric system's capability to meet peak electricity demand in the summer months in California and in the smaller geographic regions overseen by the ISO. According to the Energy Commission's deputy director for the electricity supply analysis division, the supply-and-demand outlook report for summer electricity is an early warning projection for the coming

summer months and merely alerts the Energy Commission to a looming planning failure; it can do little to prevent a failure. However, it can be used to make public appeals for conservation or to reschedule planned outages.

New Generation and Transmission Upgrades Improve the Flow of Electricity

Significant additions in the energy infrastructure have taken place since the energy crisis that helps to reduce the risk that another energy crisis may occur. However, as a later section explains, what was gained in electricity supplies by building new power plants during the last 10 years may be somewhat offset by the need to replace environmentally harmful and aging power plants in the near future and by the difficulties that the State faces in doing so.

During the last decade the Energy Commission has approved new power plants. According to the Energy Commission's reports on the status of energy facilities, as of May 2009, it had approved 69 power plants. These approved plants have the capacity to produce more than 25,000 total megawatts of power; however, as of May 2009, only 42 of these power plants were online. As Table 1 on the following page indicates, the facilities brought online have the capacity to produce just over 14,200 total megawatts. Although energy providers have retired some power plants, the increase in megawatts brought online has resulted in roughly 9,200 megawatts of power available to meet electricity demands. Further, according to the Energy Commission's reports on the status of energy facilities as of May 2009, power plants currently under construction will have the capacity to generate nearly 2,400 megawatts. An additional 6,600 megawatts could be generated from approved plants for which construction has not begun or is on hold due to unfavorable markets or unavailable financing. Additionally, power plants with applications pending before the Energy Commission could have the capacity to produce over 10,500 megawatts if approved and placed online.

According to the ISO's monitoring director, California has made significant strides in adding to its electrical infrastructure since the energy crisis. For example, the monitoring director explained that from the end of the energy crisis in 2001 through 2007, the ISO gained approximately 15,800 megawatts to its *balancing authority area*, or the region in which it has the authority to balance the electricity flow across transmission lines. This figure represents an increase of approximately 39 percent over the 41,000 megawatts of estimated available generation in 2000. Additionally, the monitoring director concluded that new electricity generation throughout the West provides additional opportunities for California to import

power when needed to meet peak demands. Further, in its 2008 *Annual Report on Market Issues and Performance*, the ISO projects that generation additions in Southern California will just keep pace with consumer demand and unit retirements. However, after the ISO accounts for consumer demand and unit retirement, it forecasts that Northern California will see a larger increase in new electricity generation. Thus, the supply shortages that contributed to the energy crisis in 2000 and 2001 are not as likely to reoccur.

Table 1
Maximum Generating Capacity of California Power Plants Brought Online or Retired From 1998 Through 2009
(In Megawatts)

YEAR	MEGAWATTS BROUGHT ONLINE	MEGAWATTS RETIRED*	NET CHANGE IN MEGAWATTS
1998	0	1	(1)
1999	0	56	(56)
2000	0	1	(1)
2001	1,914	39	1,875
2002	2,504	807	1,697
2003	3,893	2,122	1,771
2004	0	328	(328)
2005	2,584	1,320	1,264
2006	2,015	219	1,796
2007	177	0	177
2008	93	0	93
2009 [†]	1,050	0	1,050
Totals	14,230	4,893	9,337

Source: The California Energy Commission's (Energy Commission) energy facility status reports as of May 2009.

* According to the Energy Commission, *retired* generally refers to generation from those plants that will never come back online (that is, components of the plant have been disassembled and removed for resale or scrap).

† The data presented for calendar year 2009 represents megawatts brought online or retired through May 1, 2009.

According to the ISO, in addition to the construction of new power plants, improvements to California's key transmission lines are complete. The ISO's monitoring director noted that the capacity on frequently congested transmission lines in the ISO's balancing authority area has increased by approximately 4,600 megawatts. Notably, in 2004 and 2005, utilities completed upgrades to the main transmission lines that allow electricity to move between California's southern and northern regions—regions that experienced significant congestion during the energy crisis, thus causing blackouts.

New Programs Aim to Reduce Energy Consumption, Especially During Peak Demand

Because development of electricity-generating capacity must consider peak demand and because the addition of new system capacity is time-consuming and expensive, state entities and other participants in the electricity market are also working to implement programs, such as conservation and energy efficiency rebates, to reduce electricity usage. In particular, the Energy Commission, the ISO, and the CPUC aim to reduce usage during *peak demand periods*, or the hours when most consumers use electricity and when electricity costs are highest. To accomplish this goal, both investor-owned and municipal utilities offer *demand response programs* (demand response) that provide incentives to businesses and consumers when they reduce their consumption when asked during certain periods. Both the Energy Commission and the CPUC agree that demand response can reduce electricity use during peak periods when the least efficient generation occurs, which may thereby reduce greenhouse gas and other air emissions. Additionally, according to the CPUC, it has set timetables to introduce dynamic pricing programs that reflect high and low periods of usage for large commercial and industrial customers. In fact, according to the Energy Commission, the State has a goal of reducing peak usage by 5 percent through the use of demand response.

Even outside of peak demand periods, state agencies and market participants are working to reduce total demand through conservation and energy efficiency programs. Assembly Bill 2021 (AB 2021), Statutes of 2006, set a statewide goal of reducing total forecasted electricity consumption by 10 percent over the next decade. Under AB 2021, the Energy Commission and the CPUC are responsible for setting annual statewide efficiency targets in a public process using the most recent targets from investor-owned and publicly owned utilities. To increase energy efficiency, the Energy Commission sets building and appliance standards, and the utilities and public agencies run programs that promote energy conservation. For example, according to the CPUC, the energy efficiency programs run by the investor-owned utilities between 2006 and 2008 reduced the need for approximately 1,500 megawatts of electric-generating capacity, which is the equivalent of three large power plants, through hundreds of targeted programs aimed at encouraging consumers to invest in efficient buildings and appliances. In addition, new efficiency standards for buildings will go into effect on August 1, 2009. Finally, California's *Flex Your Power* campaign is a statewide marketing and outreach effort operating since 2001 to encourage energy

Demand response programs provide incentives to businesses and consumers when they reduce their consumption when asked during certain periods, such as during peak periods when the least efficient generation occurs.

conservation. The *Flex Your Power* Web site directs consumers to various rebate and incentive programs offered by the utilities and other organizations.

The Need to Replace or Retrofit Aging and Environmentally Harmful Power Plants May Cause Significant Reductions in Electricity Supplies

Although the State is working to increase electricity generation and transmission, aging and environmentally harmful power plants that supply a significant portion of California's electricity capacity may need to undergo expensive retrofittings of their cooling systems or shut down. At the same time, various issues may delay or prevent the construction of new power plants or updates to existing plants. The uncertainty about the power plant owners' ability or desire to replace the cooling systems at existing power plants poses a high risk to the State because loss of electricity supplies could compromise the reliability of electrical services. In particular, Southern California may bear the greatest burden because many of the aging and environmentally harmful power plants that may be forced to retrofit or close are in that region, and it lacks adequate transmission capacity to allow the import of sufficient electricity from other sources on peak demand days. Nonetheless, a recent court order required the South Coast Air Quality Management District (South Coast Air District) to halt certain activities to enable new power plant construction and upgrades in this region.

A Proposed Statewide Policy May Force Certain Power Plants to Close

Once-through cooling:

A process that uses seawater to remove waste heat produced during power generation and then discharges the heated water back into the environment. The heated water can affect the marine environment. Additionally, marine organisms may be killed or injured when they are pulled into the power plant cooling system.

Source: California Energy Commission.

The State Water Resources Control Board (Water Control Board), which is responsible for water allocation and water quality protection for the State, has proposed a statewide policy to implement the 1977 federal Clean Water Act, as amended, that controls the harmful effects of water intake structures for *once-through cooling* on marine life. The Water Control Board and the California Environmental Protection Agency (Cal/EPA) have pointed out that California power plants that use once-through cooling damage over 79 billion fish and other organisms annually.

In June 2006 the two agencies issued a scoping document that presented information on a proposed statewide policy related to complying with the federal Clean Water Act regulations. In the scoping document, the two agencies identified the 21 power plants in California that would be subject to the federal act. In a letter dated September 2006, the ISO provided comments to the Water Control Board related to the proposed statewide policy indicating that it had

reviewed the list of power plants subject to the federal Clean Water Act, and the ISO offered the following observations: “The policy will essentially require existing power plants to retrofit to a cooling tower or they will no longer have a valid water permit and be forced to retire. Either scenario has a negative impact on the amount of generation available to meet the electricity needs of California. In the case of a cooling system retrofit, the facilities will produce less electricity, be less efficient, and may have to run longer to recover the retrofit costs. Alternatively, if the power plant retired before new generation is available, it could result in adverse impacts on public health and safety and the economy due to insufficient generation to meet all the electricity needs of California.”

In March 2008 the Water Control Board and Cal/EPA issued a second scoping document that updated the 2006 document and took into consideration some federal regulatory changes to the Clean Water Act. In this version, the agencies indicated that they intended the document to give the public a preliminary proposal for a statewide policy to implement the Clean Water Act. The Energy Commission provided a summary of the Water Control Board and Cal/EPA’s proposal in its 2008 Integrated Energy Policy Report, which indicated that the proposed policy calls for the phased elimination of once-through cooling between 2015 and 2021 and that without alternative mitigation measures, accomplishing this goal will require the retrofiting, repowering, replacement, or retirement of 19 power plants, which currently represents nearly 40 percent of the State’s generating capacity.⁴ Although the Water Board and Cal/EPA indicated that these 19 power plants actually produced only 20 percent of the State’s electricity in 2005, both the ISO and the Energy Commission agree that some of these plants are essential to ensuring reliable electricity service throughout California. Figure 3 on the following page shows the locations and generating capacity of the power plants that use once-through cooling.

Finally, to further add to the concerns expressed above by the Energy Commission and the ISO, a number of energy agencies—including the Energy Commission, the CPUC, and the ISO—believe that power plant owners, concerned about the ability to recoup the substantial investments necessary to retrofit or replace their power plants, will opt to retire their existing facilities rather than to invest the funds needed to pay for the new

⁴ Two power plants have closed since the 2006 proposal identified 21 power plants.

Figure 3
Power Plants Affected by Proposals to Retire Aging and Once-Through Cooling Plants



Source: California Energy Commission.

Note: See page 26 for a definition of *once-through cooling*.

* The total megawatts for the Haynes power plant includes 560 megawatts from units that use once-through cooling, but are not aging.

† The total megawatts for the Huntington Beach power plant includes 450 megawatts from units that use once-through cooling, but are not aging.

‡ The total megawatts for the Pittsburg power plant includes 682 megawatts that are from units that are aging, but do not use once-through cooling.

§ The total megawatts for the Moss Landing power plant includes 1,080 megawatts that use once-through cooling, but are not aging.

|| Built before 1980 and larger than 10 megawatts.

technology. In a May 2008 letter to the Water Control Board, the Energy Commission reiterated that although it supports efforts to reduce the environmental impacts of once-through cooling, it is concerned that a majority of the affected plants are located in areas that would have insufficient capacity to assure reliable electric service during periods of extreme summer peak demand if any more than minimal amounts of capacity were to be retired. In the same letter, the Energy Commission also indicated its support of a statewide task force to address these reliability concerns and to prevent disruptions of the State's electrical power supply.

Since the first proposal for a statewide policy in 2006 related to the once-through cooling process, various stakeholders have studied the potential costs and timelines for retrofitting or replacing the power plants that use once-through cooling. More specifically, governmental agencies and organizations representing such stakeholders as environmental groups, power plant owners, and consumer advocacy organizations have commissioned studies to examine the financial costs and impacts of eliminating electricity supplies generated by power plants that use once-through cooling. For example, the ISO performed a study that assessed power plant owners' preliminary plans for retiring or retrofitting their affected facilities and identified the impacts these changes would have on the electric grid. Another organization representing the electric industry performed a study that examined the scientific and technical issues related to phasing out once-through cooling, including estimating the costs to retrofit the existing plants. Finally, according to the external affairs manager with the ISO, the CPUC, the Energy Commission, and the ISO are working together with the Water Control Board to develop their recommendations and a schedule as to how the Water Control Board should implement its proposed policy related to phasing out the use of once-through cooling. The external affairs manager also indicated that the Water Control Board plans to issue a revised draft policy in July 2009, which will contain as an appendix an implementation plan and a compliance schedule developed by the ISO, the Energy Commission, and the CPUC. He believes the Water Control Board expects to adopt the policy by the end of the year.

Moreover, the Energy Commission also classifies many of the power plants that rely on once-through cooling as *aging power plants*, for which, in its 2005 Integrated Energy Policy Report, the Energy Commission recommended retirement. Figure 3 shows the power plants that use the once-through cooling process; some of these are also classified as aging power plants. According to information provided by the Energy Commission and the Water Control Board, the aging power plants typically are more than 30 years old, use older less efficient technologies, have higher rates of pollution, and are expensive to operate. In its 2005 and 2007 Integrated Energy

Aging power plants typically are more than 30 years old, use older less efficient technologies, have higher rates of pollution, and are expensive to operate.

Policy Reports, the Energy Commission recommended the orderly retirement of the aging power plants throughout California, a process that raises additional concerns about the reliable, affordable delivery of electricity.

Replacing Once-Through Cooling and Aging Power Plants in Southern California Presents Additional Challenges

The Water Control Board's proposed policy to shut down or replace the once-through cooling and aging power plants will be particularly challenging for Southern California. More specifically, a number of factors, including air quality requirements and a court ruling, provide obstacles to the power plant owners that want either to retrofit or to replace the aging power plants or those that use the once-through cooling process in Southern California.

The South Coast Air District is the air pollution control agency for Orange County and the urban portions of Los Angeles, Riverside, and San Bernardino counties. As one of the smoggiest regions in the nation, this area is also subject to stringent local air quality requirements. To obtain an operating permit from the South Coast Air District, the owner of any facility that will release pollutants into the air must demonstrate that the facility has the required number of emissions credits. The purpose of an emissions credit process is to ensure that new facilities do not increase pollution levels and reduce air quality in a region. Thus, before a facility that generates air pollution begins operating, it must obtain a sufficient number of emissions credits to offset the anticipated pollution that the facility will emit.

In 1990 the South Coast Air District established a *priority reserve bank* of emissions credits that it awarded to entities that serve a public interest, such as hospitals and police facilities. In response to concerns about the need to construct new power plants in Southern California, in 2007 the South Coast Air District added power plants to the list of entities eligible to receive emissions credits from the reserve bank. However, this action was successfully challenged in California Superior Court as it relates to the sufficiency of the South Coast Air District's environmental analysis and the district's addition of power plants to its list of those eligible to receive emissions credits from its bank. Specifically, a July 2008 trial court ruling found that the California Environmental Quality Act (CEQA) analysis that the South Coast Air District prepared was inadequate for a number of reasons. According to the Energy Commission's February 2009 staff paper on this topic, the court stated that the South Coast Air District had failed to perform an adequate CEQA analysis to evaluate the potential impacts of the power plants that proposed to use priority reserve credits. The Energy Commission also stated that the court decision

indicated that a sufficient environmental document would require significant new analysis that the South Coast Air District believes it cannot reasonably provide. Moreover, according to the South Coast Air District, the court decision invalidated how the South Coast Air District accounts for the emissions credits that are available in its reserve bank. Consequently, in January 2009, the South Coast Air District issued a moratorium on permits to construct or operate power plants that require air emissions credits from the reserve bank.

In addition to the moratorium on any new projects, according to the South Coast Air District, the court's ruling could also invalidate any permits issued since the South Coast Air District added power plants to the list of entities eligible to receive emissions credits from the reserve bank. According to the Energy Commission, seven power plants are currently going through the Energy Commission's licensing process, and the South Coast Air District's problem with its reserve bank's emissions credits will affect this process. Data provided by the Energy Commission indicates that if these seven power plants are constructed, they will potentially generate more than 4,300 megawatts of electricity, offsetting some of the 7,500 megawatts of power that will be lost when the aging and once-through cooling plants close.

At this time, according to the South Coast Air District, it is issuing permits to construct new power plants only to those entities that can provide or purchase their own emissions credits because, as previously described, the South Coast Air District is unable to release any emissions credits held in its reserve bank. If investors that desire to construct power plants in this area are unable to provide their own emissions credits, their next option is to attempt to purchase them on the open market; however, according to the South Coast Air District these credits are scarce and can be very expensive. In fact, the South Coast Air District estimates the cost to purchase emissions credits for a power plant could be between \$100 million and \$200 million. According to the South Coast Air District, between 2000 and 2008, the average market price has increased by over 3,700 percent. In other words, the price has risen from an average of \$3,860 per pound per day of emissions to \$148,760 per pound per day. Further, as of March 2009, emissions credits sold for as high as \$320,000 per pound per day, an amount that is more than double the average 2008 price. If power plant operators can purchase the necessary emissions credits to bring additional power online, according to the Energy Commission, the current prices would contribute significantly to the cost of the new plant itself, which electricity providers would pass on to consumers in the form of electricity rate increases.

Early in 2009 the South Coast Air District issued a moratorium on permits to construct or operate power plants that require air emissions credits from the reserve bank as a result of a trial court ruling.

According to the Energy Commission, it might be difficult to build sufficient new transmission capacity before the 2015 proposed deadline requiring power plant owners to discontinue using the once-through cooling process.

Further contributing to the problem associated with replacing electricity supplies potentially lost in the South Coast Air District is the fact that according to the Energy Commission this region also lacks sufficient transmission capacity to allow it to import electricity from other areas; thus, unless additional high-voltage transmission lines are constructed, most of the replacement power plants must be built in the same general areas as the existing power plants. As we discuss in a later section, constructing new transmission lines is particularly challenging in part because multiple agencies may be involved in providing regulatory approval and oversight for constructing new transmission lines. Additionally, local opposition and environmental reviews can cause additional delays. The Energy Commission reported it might be difficult to build sufficient new transmission capacity before the 2015 deadline the Water Control Board recommended in its proposed policy to require power plant owners to discontinue using the once-through cooling process.

Large Investor-Owned Utilities Have Secured Long-Term Contracts as Water Resources' Role Phases Out, but Some Uncertainty Remains

Water Resources played a critical role in providing electricity during the energy crisis; however, as the contracts it entered into during that time expire, the importance of its role has been declining, and efforts are currently under way to return all responsibility for supplying electricity to the investor-owned utilities, about five years prior to the expiration of the last of Water Resources' long-term contracts. As Table 2 depicts, Water Resources is managing a portfolio worth approximately \$8.9 billion. According to data provided by Water Resources, it has 26 contracts that are still in effect. These long-term contracts are expected to supply roughly 23 percent of the large investor-owned utilities' electricity needs in 2009. Although the utilities have been able to secure sufficient supplies of electricity through their own contracts to meet the balance of their customers' demand, there is still uncertainty as to whether the utilities will continue to be in a position to secure an adequate supply. Further, efforts led by a group representing electricity suppliers and various private and public electricity consumers to again allow direct access—an option that enables customers to choose an electricity provider other than their default utility—creates additional uncertainty within the electricity market.

Overall Electricity Supplied by Water Resources Is Declining

As we discussed previously, urgency legislation passed during the energy crisis earlier in the decade allowed Water Resources to enter into long-term contracts to purchase and supply electricity on behalf of the State's large investor-owned utilities, which were not

Table 2
The Department of Water Resources' Remaining Long-Term Electricity Contracts

YEAR	LONG-TERM CONTRACT CAPACITY* (IN MEGAWATTS)	VALUE* (DOLLARS IN BILLIONS)
2009	8,900	\$3.6
2010	7,600	2.9
2011	5,500	2.0
2012 through 2015	1,500	0.4
Totals	23,500	\$8.9

Source: California Energy Resources Scheduling Division of the Department of Water Resources.

* Annual projections may vary due to contract use and other assumptions.

in a financial position to adequately secure electricity and meet the needs of their customers. The legislation granted Water Resources the authority to purchase electricity, issue bonds to pay for the electricity, and provide a mechanism for the State to collect its costs from the utilities and, ultimately, their electricity customers. To assist in stabilizing electricity prices, and to enhance the reliability of the supply, Water Resources entered into a total of 57 long-term contracts as of the end of October 2001, at a cost of \$42.6 billion.⁵ As shown in Figure 4 on the following page, the portion of power supplied by Water Resources' long-term contracts has been declining, and in 2009 these contracts will provide only 23 percent of the electricity needed under the large investor-owned utilities' projections. By 2010 Water Resources' contracts will cover only 18 percent of the utilities' projected demand, and in 2011 they will supply only 12 percent, according to Water Resources. The final contract is projected to cover less than 1 percent of the large investor-owned utilities' annual electricity needs between 2012 and 2015.

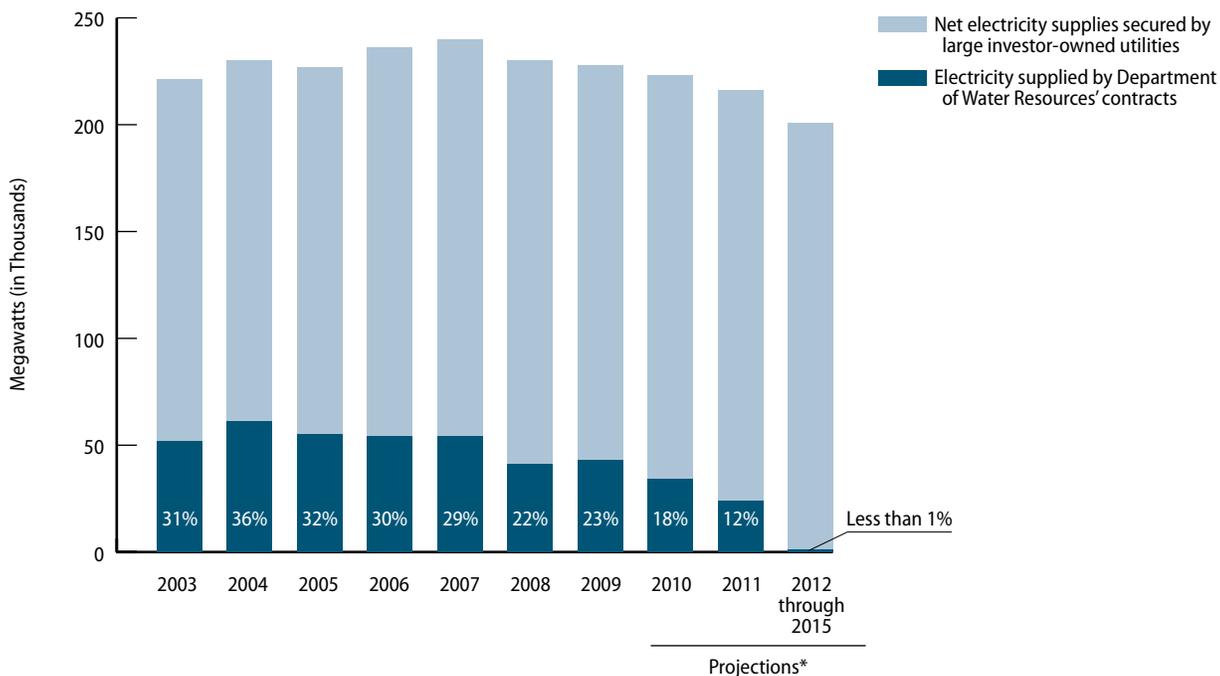
Currently, the three large investor-owned utilities are responsible for managing the balance of their electricity purchases that are not covered by the Water Resources' long-term contracts. Each utility must procure electricity to supply the balance remaining based on the utility's energy forecasts. The utilities must submit each proposed long-term electricity contract to the CPUC for review. As part of its oversight responsibilities, the CPUC determines

⁵ We obtained the number of long-term contracts and total cost from the Bureau of State Audits' report, *California Energy Markets: The State's Position Has Improved Due to Efforts by the Department of Water Resources and Other Factors, but Cost Issues and Legal Challenges Continue*, Report 2002-009, April 2003.

whether the rates under each contract are just and reasonable. As shown in Figure 4, the investor-owned utilities currently supply approximately 77 percent of the electricity their customers need.

Figure 4

Percentage of Electricity That Has Been or Will Be Supplied to Customers of Large Investor-Owned Utilities by the Department of Water Resources' Long-Term Electricity Contracts



Source: California Energy Resources Scheduling Division of the Department of Water Resources (Water Resources).

Note: Historical percentages (2003 through 2008) are approximate and are based on a Water Resources' analysis of publicly available information from large investor-owned utilities (Pacific Gas and Electric Company, Southern California Edison, and San Diego Gas & Electric Company).

* Projected percentages are based on Water Resources' October 29, 2008, final revised revenue requirement filed at the California Public Utilities Commission and November 2007 California Energy Commission projections of consumption by customers, also known by the industry as load requirements.

Financial Recovery of Large Investor-Owned Utilities Since the Energy Crisis Has Raised Concerns Over Efforts to Eliminate Water Resources' Role in Supplying Power

Although the CPUC believes customers would benefit if Water Resources were removed from its role as energy supplier, according to credit rating agencies this could have an adverse effect on the utilities' credit ratings, resulting in higher borrowing costs and ultimately affecting their overall financial stability. As Water Resources' management pointed out, some contracts specify minimum credit ratings the utilities must meet in order to assume the contracts, while others lack a clause requiring the seller to

release Water Resources from its obligations under the contract. Thus, there is some uncertainty as to whether the utilities will be able to take over the existing contracts or negotiate replacement contracts that will benefit the ratepayers.

A CPUC ruling dated November 2008 identified potential cost savings from reduced administrative costs if Water Resources were removed as a party to the contracts. Although the CPUC acknowledged that the potential savings cannot be accurately estimated, it believes that a net savings to ratepayers is a reasonable prospect, and the CPUC set January 2010 as its goal for eliminating Water Resources' role in supplying power, including its role in the remaining contracts. To accomplish this, a working group was established to develop protocols and strategies for renegotiating or replacing the contracts. According to the CPUC's ruling, each utility, along with Water Resources, will be responsible for negotiating its assigned replacement agreements; however, the CPUC will review and approve the contracts to determine that they are just and reasonable. Water Resources agrees that its role as an energy supplier should end if ratepayers' costs will not increase as a result, and it is working with the CPUC toward that goal. However, Water Resources recognizes that eliminating its contractual responsibilities by January 2010 will be a challenge.

Some long-term contracts may be more difficult to transfer to a utility or to renegotiate because they do not require the seller to release Water Resources from its obligations, and some include a requirement that the utility assuming the contract must meet minimum credit requirements. According to Water Resources' analysis of the investor-owned utilities' credit ratings as of June 2008, there is uncertainty as to whether the utilities can meet the minimum credit ratings required by some long-term contract agreements. For example, as we mentioned earlier, PG&E filed bankruptcy as a result of the energy crisis, and its credit ratings have not yet recovered to the level required in some of Water Resources' long-term contracts. According to a CPUC decision dated November 2008, PG&E's bankruptcy settlement required that until PG&E's credit rating reaches a specified level—which it has not yet attained—the CPUC cannot require that it assume any of Water Resources' long-term contracts. The CPUC decision further indicates that PG&E can waive this requirement. PG&E has stated that it is not willing to do so at this time but would reconsider this choice, depending upon the potential benefits it would receive.

Options for Modifying Existing Contracts for California's Electricity Supplies

Novation: Completely removes Water Resources from any subsequent financial or operational responsibility for the contract. The utility enters into a replacement contract with the seller and performs all of Water Resources' former responsibilities.

Assignment: Transfers Water Resources' contractual rights and responsibilities to the utility. Unlike novation, assignment leaves Water Resources liable unless there is a release of liability by the seller.

Source: Department of Water Resources' Overview of DWR Power Contracts: Background and Review of Portfolio Novation and Assignments to the California Investor-Owned Utilities, June 2, 2008.

By assuming Water Resources' long-term contracts, the utilities would be increasing their debt, which may negatively affect their financial statements. In its June 2008 presentation to CPUC, Water Resources estimated that if the utilities assumed the long-term contracts on January 1, 2009, they would increase their debt by approximately \$532 million.

Despite the potential benefits and cost savings that the State may realize if the utilities take over Water Resources' long-term contracts, the potential impact on the financial stability of the utilities remains uncertain. If the utilities' credit ratings decline, there is some risk that they may be unable to enter into additional long-term contracts or make short-term market purchases.

Efforts to Reinstate Direct Access Have Raised Additional Concerns

When it authorized Water Resources to purchase power on behalf of the utilities, the Legislature suspended direct access, a retail option that enables customers to choose another electricity provider. The legislation required that the direct access suspension remain in effect until Water Resources is no longer supplying power. Suspending direct access, according to a September 2001 decision by the CPUC, provided a stable customer base from which Water Resources could recover the costs of the power it purchased.

In December 2006 a group representing power suppliers and various private and public electricity consumers petitioned the CPUC, requesting that it lift the suspension on direct access prior to the expiration of Water Resources' contracts and arguing that they did not believe the Legislature intended for direct access to be suspended for this long. The CPUC concluded that it could not lift the suspension on direct access because Water Resources continues to supply electricity under its long-term contracts for eventual sale to retail customers. However, it decided that there was merit in considering ways to expedite the removal of Water Resources as a power supplier and, ultimately, to reinstate direct access.

There is some uncertainty as to the impact that restoring direct access would have on the large investor-owned utilities. For example, in its 2008 annual report, PG&E identified uncertainties associated with its ability to recover all its costs if its number of customers declines due to the general economic downturn and the restoration of direct access. Additionally, a January 2009 Standard and Poor's credit analysis indicated that certain policies, including the potential for the State to restore direct access, make it difficult to determine the utilities' long-term credit stability. More specifically, with respect to Southern California Edison, the credit analysis went on to explain that direct access complicates

After power suppliers and various private and public electricity consumers petitioned the CPUC in 2006, it decided that there was merit in considering ways to expedite the removal of Water Resources as a power supplier and, ultimately to reinstate direct access.

the utility's electricity procurement process, which could result in an inability for the utility to recover all of its costs. Thus, if direct access is reinstated without full consideration of the impact on the utilities, there is some risk that the utilities' financial stability could again be impaired, reducing their ability to negotiate competitive prices and purchase adequate electricity to meet the needs of their customers.

Meeting California's Renewable Resource Targets Will Be Challenging

Since the energy crisis, California has adopted targets to increase the use of renewable sources of electricity. However, the State is at risk of failing to meet these targets because various obstacles are preventing the construction of the infrastructure needed to generate and transmit electricity from such renewable sources as wind, solar, geothermal, biomass, and small hydroelectric facilities. To help increase the total production of renewable electricity statewide, the State adopted a renewables portfolio standard. Moreover, the Legislature established a target of generating 20 percent of California's total retail sales of electricity from renewable energy resources by December 31, 2010. According to the Energy Commission, in 2007 roughly 12 percent of the State's electricity was supplied by renewable sources. Additionally, the governor recently announced a more aggressive target, increasing the target to 33 percent by 2020. However, the State needs to overcome a number of barriers before it can meet either of these targets.

The Energy Commission and the CPUC are responsible for implementing the State's renewables portfolio standard. The Energy Commission has sponsored programs to encourage the development of renewable electricity production, increase consumer education, and subsidize the use of electricity generated from renewable sources through rebates. The Energy Commission also certifies and tracks facilities whose generation applies toward meeting the State's targets for producing renewable electricity. In addition to assessing the investor-owned utilities' procurement plans for meeting these targets, the CPUC determines annual procurement targets, reviews all proposed long-term contracts, and enforces compliance.

According to the Energy Commission, some of the difficulties that the State faces in meeting its renewable energy targets include those involving the siting and construction of renewable electricity generators, such as wind and solar facilities. For example, according to the federal Bureau of Land Management (BLM), large solar thermal power plants require many acres of land to gather sufficient radiant energy. The BLM anticipates that new

Some of the difficulties the State faces in meeting its renewable energy targets include siting and constructing renewable electricity generators, such as wind and solar facilities.

solar power plants may require an average of at least 500 acres to produce 100 megawatts of electricity. Additionally, the amount of sunlight reaching the earth's surface is affected by the season, time of day, climate, and air pollution. Information from the National Renewable Energy Laboratory, which is part of the U.S. Department of Energy, indicates that the Mojave Desert's potential for the siting of solar power plants is as great as or greater than that of any other region in the country. However, according to Energy Commission documents, the transmission infrastructure serving the area requires expansion. According to the CPUC, it has approved several new transmission lines to facilitate the delivery of renewable energy to consumers, and others have been proposed.

Associated with the issue of constructing renewable energy generation facilities in remote areas, as the Energy Commission points out, is the complex regulation of the construction of new transmission lines. In particular, the agencies that provide regulatory approval and oversight for constructing the lines can vary depending on where the lines are located. For example, different federal agencies have permitting oversight for long-distance transmission lines depending on what federal land the proposed facilities will be built. Additionally, the ISO must approve the interconnection of any new power-generating facilities to the electric grid within its control area. Each of these entities may apply different criteria to the process before granting their approval.

Several other barriers exist that could affect the development of renewable energy sources. For example, according to the Energy Commission, the demand for electricity can vary throughout the day as well as by season. To some extent, these variations determine the type of renewable energy sources that are most feasible. For instance, according to information from the Energy Commission, wind generation can peak at various times of the day or night, depending on the season and location. These peak times may not coincide with peak demand, which occurs in midafternoon to early evening. Solar power offers an attractive approach to help meet the demand for electricity, because its period of greatest availability roughly coincides with the timing of California's peak demand. However, according to the Energy Commission, to help ensure that the electric grid does not fail, local reliability requirements often necessitate that electricity be generated close to demand areas. As we just discussed, however, many of the renewable energy sources would likely be constructed in remote locations. Additionally, the process for approving new generation can take more than a year and, according to the Energy Commission, an influx of new and less-experienced developers who may not understand the complex project development process might contribute to the difficulty in

The difficulty in licensing new generation facilities could be due to the lengthy process for approving new generation and an influx of new and less-experienced developers that may not understand the complex project development process.

licensing new generation facilities. As a result of these and other factors, siting and constructing renewable generation can be a difficult process.

All of these barriers play a role in whether and when California can meet its renewable energy targets. In the 2008 update to the Energy Action Plan, the Energy Commission and the CPUC point out that the State will likely not achieve the target of generating 20 percent of California's total retail sales of electricity from renewable energy resources by 2010. However, state agencies that are responsible for regulating California's energy infrastructure have begun taking steps toward overcoming these barriers. For instance, in November 2008 the governor signed an executive order that established a Renewable Energy Action Team to create a one-stop process for permitting renewable energy facilities. Another example of action by state agencies is the Renewable Energy Transmission Initiative (RETI), a statewide initiative to facilitate and coordinate the planning and permitting of transmission and generation projects needed to make progress toward the State's renewable policy targets. According to the Energy Commission's Web site, the Energy Commission, the CPUC, the ISO, and three publicly owned utilities are coordinating the RETI effort. Additionally, the ISO has created an Integration of Renewable Resources Program to foster the integration of renewable resources into the electric grid. Finally, the federal American Recovery and Reinvestment Act of 2009 (Recovery Act) allocated \$275.6 million to the Energy Commission for programs related to energy efficiency and renewable energy. According to the Energy Commission's Web site, these funds will be administered under two programs: the State Energy Program (Energy Program) and the Energy Efficiency and Conservation Block Grant Program. The Energy Program provides funding for retrofits of buildings and industrial facilities to make them more energy efficient and supports renewable energy projects and other activities. The energy block grants assist local and state governments in implementing projects and programs that reduce total energy use and fossil fuel emissions, among other efforts. Additionally, the U.S. Department of Energy will provide up to \$36 billion nationwide through competitive grants funded under the Recovery Act for climate change and energy-related programs. In total, California is expected to receive an estimated \$1.3 billion in Recovery Act funds for energy-related purposes.

According to two electricity regulators, the State will likely not achieve the target of generating 20 percent of total retail sales of electricity from renewable resources by 2010.

It Is Too Early to Tell Whether the ISO's New Market Structure Will Continue to Succeed

On March 31, 2009, the ISO went live with its Market Redesign and Technology Update (MRTU). MRTU is a project that reintroduces day-ahead electricity trading and establishes a new wholesale

It took the ISO more than seven years to work out the details of the new day-ahead market redesign and gain approval to introduce the changes.

pricing scheme and a new computer model of the electric grid. The ISO expects MRTU to result in more reliable delivery of electricity, greater wholesale price transparency, and an increase in investment in electricity infrastructure.

In December 2001 FERC ordered the ISO to design a new day-ahead market, with the goals of reducing the volatility of wholesale electricity prices and relieving electricity scheduling problems. Many market participants expressed concerns with the endeavor—in fact, because of the multitude of stakeholders involved and the complexity of the system, it took the ISO more than seven years to work out the details of the market redesign and gain final FERC approval to introduce the changes. In the interim, utilities procured electricity through long-term contracts and in the ISO's real-time market. Because MRTU has been in operation only since March 31, 2009, its success is still too early to gauge, and is another reason we consider electricity to be a high-risk issue for the State.

Before the introduction of MRTU, the transmission grid managed by the ISO was divided into three zones, generally representing Northern California, Central California, and Southern California. One price for wholesale electricity was set throughout each zone for all wholesale buyers and sellers. These prices did not accurately reflect the true cost of generating and transmitting electricity to all areas within a zone. For example, the potential high costs of serving high-demand areas with insufficient transmission infrastructure were borne by all wholesale buyers in a zone. Additionally, before the introduction of MRTU, the ISO was able to identify bottlenecks between zones only in its day-ahead scheduling. As a result, transmission paths inside the three zones that were overloaded or insufficient for meeting demand were not identified until real time, resulting in increased costs to rearrange schedules in real time and creating the potential for service interruptions. According to the ISO, in 2004 the cost of managing congestion from bottlenecks was \$1 billion.

MRTU, according to the ISO, will provide it with the tools to remedy market design flaws and inadequacies, as well as provide needed software and computer upgrades. MRTU comprises three major elements: the Integrated Forward Market (forward market), Locational Marginal Pricing (locational pricing), and the Full Network Model (network model). The ISO anticipates that MRTU will produce greater efficiencies and assurances of electric grid reliability, as well as greater wholesale price transparency that can help investors estimate potential revenue and build profitable transmission lines and power plants. Moreover, because the CPUC generally requires that large investor-owned utilities

contract for 95 percent of their electricity requirements outside the short-term markets, typically no more than 5 percent of electricity needs will be procured through the ISO's markets.

In the new day-ahead market, the ISO anticipates an increase in competition among the wholesale sellers and a reduction in costs that will allow the ISO to better manage congestion along key transmission paths where demand may exceed capacity. As we discussed in the Introduction, the ISO will also procure its ancillary services, which correct supply and demand imbalances and are necessary to ensure the reliability and integrity of the electric grid, in the day-ahead market. Because transmission capacity, electricity supplies, and reserves can be procured simultaneously in the day-ahead market, the ISO also anticipates fewer ways for market participants to manipulate the market, as was possible in the sequential procurement that occurred in the pre-MRTU market.

With locational pricing, the wholesale electricity market under the control of the ISO is structured around a system of roughly 3,000 nodes, instead of the three large zones that were used previously. Nodes are part of the MRTU system model that represent local generation and transmission costs. The purpose of locational pricing is to more accurately reflect the cost of supplying specific areas with electricity. According to the ISO, locational pricing is already used by independent system operators throughout the central and eastern United States, including the New York, New England, Midwest, and PJM independent system operators. The node prices take into account the cost of generating electricity as well as transmission costs, so areas with congested transmission lines will have higher wholesale prices than areas with little demand or surplus transmission capacity. Although wholesale prices for sellers will vary among the 3,000 nodes, the ISO anticipates that retail customers will not experience the periodic spikes in the short-term markets' prices, in part because retail prices will be averaged over large geographical areas served by individual utilities, thereby smoothing any high locational wholesale prices. Also, as we mentioned earlier, purchases from the ISO markets typically represent only a small fraction of wholesale electricity procurement.

According to the ISO, locational pricing is also expected to assist in the development of new transmission and electricity generation infrastructure by revealing the true costs of supplying specific areas with electricity. For example, locational prices reveal how new power plants will affect the grid, helping investors estimate the revenue streams they can expect by siting at potential locations. In addition, differences in prices among nodes caused by congestion will more easily identify areas with congested transmission lines so that profit-minded companies and regulated utilities can build new lines to improve efficiency and reliability.

Because transmission capacity, electricity supplies, and reserves can be procured simultaneously in the day-ahead market, the ISO anticipates there will be fewer ways for market participants to manipulate the market.

The final element of MRTU is the network model, which is a computer model of the entire electric grid operated by the ISO. According to the ISO, the new network model should allow it to identify any bottlenecks that could result in transmission congestion on the network. The ISO can then act to mitigate those bottlenecks before and during real-time balancing of the system, using ancillary services, thus avoiding excessive costs and increasing reliability. With an accurate and complete model of the grid, the network model will provide information that will assist the ISO in routing electricity.

The ISO recognizes that while it believes the market design has been improved, like any market design, it may be vulnerable to manipulation by market participants. Therefore, the ISO has included programs that will monitor its markets to ensure that electricity prices remain reasonable and to keep wholesale buyers and sellers from unduly influencing the price of electricity. One mechanism checks for transmission constraints by comparing scheduled electricity bids against the ISO's demand forecasts. Additionally, the ISO monitors the grid to ensure that areas with traditionally high demand have enough electricity supply planned to meet the ISO's demand forecasts.

Although the ISO is confident that the transition to MRTU has been successful, market participants recently voiced their concerns about MRTU. Specifically, in January 2009, market participants filed comments and protests with FERC over the implementation of MRTU. These entities included the CPUC; the U.S. Department of Energy; various electricity generators; the cities of Anaheim, Pasadena, Riverside, and Santa Clara; PG&E; Southern California Edison; San Diego Gas & Electric Company; Sacramento Municipal Utility District; and the Western Area Power Administration. Some market participants gave conditional support for the March 31, 2009, implementation date, while others, including the U.S. Department of Energy, requested postponement of the launch until the ISO addressed their concerns, which ranged from the readiness of MRTU elements for implementation to concerns about how MRTU will affect pricing. Nonetheless, while recognizing that some milestones were yet to be reached, the ISO maintained that MRTU was on track for a successful implementation on March 31, 2009. FERC accepted the ISO's readiness certification for MRTU on March 13, 2009. Additionally, during the ISO's March 2009 board of governors meeting, the three large investor-owned utilities expressed their support for MRTU's start date. MRTU is currently operating in California, and as of May 18, 2009, based on seven weeks of experience, the ISO stated, "New ISO markets are generally performing well." However,

Many market participants initially voiced concerns regarding the implementation of the Market Redesign and Technology Update.

we believe it is still too early to determine whether MRTU will continue to be successful and whether the market participants' earlier concerns have been fully resolved.

Several Entities Have Identified a Need to Reorganize the State's Energy-Related Entities

The governor, members of the Legislature, and two independent entities within California have called for a reorganization of the State's numerous energy-related entities. Advocates of energy reorganization generally believe it would improve efficiency in the formulation of a more strategic energy policy and provide for better administration of certain energy programs. Because the governor, members of the Legislature, and two independent entities have identified a need for reorganization, we considered these concerns when deciding to designate electricity as a high-risk area.

The governor and certain legislators have tried more than once to reorganize and consolidate some of the State's numerous energy-related entities and create a single Department of Energy. For example, in 2005 the governor submitted to the Legislature a plan, known as the governor's reorganization plan, to reorganize the State's energy-related activities by creating a new Department of Energy. In the plan, the governor emphasized that California needs a more comprehensive approach to energy policy development to reduce the level of regulatory uncertainty in the marketplace and attract the necessary investment in new resources and energy infrastructure to meet future demand. However, the Legislature exercised its authority to reject the governor's proposal. In February 2009, Assembly Bill 1016 (AB 1016) was introduced and is currently moving through the legislative process. If adopted as introduced, AB 1016 would reorganize certain energy-related programs in a fashion substantially similar to the governor's earlier proposed reorganization plan.

Also acknowledging the need for California to consolidate energy regulatory and policy functions within one department are two independent government oversight agencies. For instance, in its review of the governor's 2005 reorganization plan, the Little Hoover Commission stated that a compelling case can be made that diffused regulatory authority contributed to the State's clumsy response to the energy crisis, and that a more centralized structure is needed to forge and execute a cohesive strategy for ensuring an adequate supply of energy. The Little Hoover Commission stated that organizational changes were necessary and that it enthusiastically supported the proposal to create a Department of Energy led by a secretary of energy. It also stressed that the need for leadership on energy was essential and could not be ignored.

The governor and certain legislators have tried more than once to reorganize and consolidate some of the State's numerous energy-related entities.

Two oversight entities have expressed concerns with the organizational structure of the State's energy entities and have proposed creating a consolidated Department of Energy.

Similarly, in its analysis of the 2006–07 Budget Bill, the Legislative Analyst's Office (legislative analyst) pointed out several problems with the organizational structure of the State's energy entities. For instance, it explained that the current structure of California's energy entities reduces accountability by spreading responsibility for policy making and regulatory decision making across multiple entities. Further, the legislative analyst recommended that the Legislature adopt the organizational structure of a consolidated department approach, stating that a more accountable and efficient organizational structure should improve the State's ability to address its considerable energy challenges in a comprehensive manner while allowing enough flexibility to adapt to new challenges as they arise. Finally, because any reorganization presents inherent risks that require mitigation, the legislative analyst identified general risks related to government restructuring, including that it is a time-consuming, tedious process that takes a lot of effort and commitment with no guarantee of success.

The Bureau Will Continue to Monitor Developments in the Electricity Sector and in Related Policies and Programs

Our assessment of current electricity issues has led the bureau to add the area of electricity production and delivery to its list of high-risk issues. The importance and pervasiveness of electricity to our economy and daily lives establishes the need for a reasonably priced and reliable supply of electricity. In the past, California sought to increase competition in the electricity industry; however, the State's experience with the energy crisis of 2000 and 2001 proved that restructuring an industry upon which so many citizens rely needs to be based on a well-planned strategy and coordination. Because electricity generation, transmission, and pricing are statewide issues, the bureau will continue to monitor new developments in the industry and in the State's energy policies, identifying any challenges and evaluating their effects on the industry's ability to provide consumers with reliable and affordable electricity. To the extent that resources are available, the bureau may undertake future projects that could include recommendations to improve electricity-related policies and programs and to implement those improvements. For example, the bureau may monitor developments in the court cases affecting the Water Control Board's proposed policy to eliminate the use of the once-through cooling process and the various energy agencies' plans to assure the replacement of electricity supplies. The bureau may also report on the status of the efforts to have the investor-owned utilities assume Water Resources' long-term energy contracts and on the success of efforts to reinstate direct access as a competitive retail option. Also, should major developments occur,

the bureau may consider deeper evaluations of MRTU, the State's ability to meet its renewable resource targets, and, if one is created, the effectiveness of a new state Department of Energy.

We prepared this report under the authority vested in the California State Auditor by Section 8546.5 of the California Government Code.

Respectfully submitted,



ELAINE M. HOWLE, CPA
State Auditor

Date: June 16, 2009

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