

Energy Deregulation:

*The State's Energy Balance Remains
Uncertain but Could Improve With
Changes to Its Energy Programs and
Generation and Transmission Siting*



May 2001
2000-134.2

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May 21, 2001

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

Dear Governor and Legislative Leaders:

As requested by the Joint Legislative Audit Committee, the Bureau of State Audits presents its audit report concerning the operations of the State Energy Resources Conservation and Development Commission (energy commission) and the California Public Utilities Commission (CPUC) and the role each plays in the State's deregulated energy market.

This report concludes that a growing demand for electricity, the failure of true competition to develop, and a lack of new power plant construction proposals have all contributed to California's current energy crisis. It is also likely that this summer's demand will outstrip supply, and California will have to endure some level of electricity shortage during the months ahead.

To cope with the energy supply gap, the Legislature passed AB 970, aimed at bringing new supplies of electricity on-line quickly and reducing energy demand, especially during peak hours. To comply with these mandates, the energy commission and CPUC have been creating new programs and revising existing ones. However, the estimates and timing for the additional supplies or reduced demand for electricity associated with several of these programs may not materialize in time to safeguard the State from power outages this summer. Nevertheless, other efforts such as ensuring that renewable power plants stay in production and updating building and appliance efficiency standards are helping the State currently or will produce future electricity savings. Assembly Bill 970 also requires the energy commission and the CPUC to speed up power plant permitting and reduce limitations of the electrical transmission grid. However, the time it takes the energy commission to approve or reject applications to site power plants has often exceeded the 12-month limit contained in law, pushing back the dates that plants will come on-line. Further, the CPUC has not responded to the energy crisis with an expedited process to site urgently needed transmission lines and frequently takes longer than the law allows to complete environmental reviews of transmission sites.

Finally, the expectations that consumer choice would create retail competition and drive down the costs of electricity have not materialized. Energy service providers had little chance to compete in price with the investor-owned utilities because of their small customer base and inability to negotiate wholesale purchase prices that were low enough to be attractive. Now with the State acting as the main buyer of wholesale electricity and negotiating long-term contracts with energy generators, consumer choice may not have a future.

Respectfully submitted,

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SUMMARY

Audit Highlights . . .

Despite programs to add supply and reduce demand, the State's energy balance remains uncertain:

- ☑ *Even with projections to the contrary, there is little assurance that the State will meet energy supply needs this summer.*
- ☑ *The State Energy Resources Conservation and Development Commission's (energy commission) AB 970 demand reduction programs are estimated to save 281 megawatts at June 1, however, over one-half of this savings is expected to come from programs that are voluntary in nature.*
- ☑ *The California Public Utilities Commission's (CPUC) interruptible program—the State's buffer for avoiding rolling blackouts—includes many customers who were not prepared to reduce their demand for electricity. The CPUC recently changed the program, but its viability will not be known for some time.*

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RESULTS IN BRIEF

In 1996 the California Legislature passed Assembly Bill (AB) 1890, deregulating the State's electricity industry to allow energy customers to switch from one of the three investor-owned utilities to another provider. The California Public Utilities Commission (CPUC), along with the Legislature, believed deregulation would bring about free market competition and lower electricity costs for the State's residents and businesses. The failure of true competition to develop, a growing demand for electricity, and a lack of new power plant construction proposals have all contributed to California's current energy crisis. As of March 2001, the State Energy Resources Conservation and Development Commission (energy commission) projects that newly legislated programs will bridge the gap between energy supply and demand, safely carrying California through a perilous summer. However, we are concerned that demand will outstrip supply and that California will have to cope with some level of electricity shortage.

In September 2000, after a summer when the fragility of the energy supply became painfully evident as rolling blackouts hit the San Francisco Bay Area, the Legislature responded by enacting AB 970. This legislation primarily aims to bring new supplies of electricity on-line quickly and to reduce energy demand through incentives to customers who cut back their energy use, especially during peak summer hours. As summer 2001 approaches, California's citizens are concerned that the blackouts occurring on four separate days of this past January and March are only a prelude to what may happen in July and August, when demand for air-conditioning will peak. Although the energy commission estimates that California will have enough new supply and reduced demand to avoid rolling blackouts this summer, uncertainties in its projections regarding these programs leave little assurance that the State will escape further power outages. To comply with AB 970's mandates, the energy commission and the CPUC have been creating new programs and revising existing ones. Among other features, these programs aim to cut energy use in commercial and state buildings, install energy-efficient traffic lights, and install heat-reflective roof surfaces. The energy commission estimates that its new Peak Load Reduction Program

- ☑ *Changes the energy commission made to building and appliance standards will not result in energy savings this summer but will benefit the State in 2002 and beyond.*
- ☑ *Since 1996 the energy commission has approved 12 power plants, but only 4 of those within 12 months, its statutory goal.*
- ☑ *Despite adding three new processes to hasten power plant siting, only one will add a significant amount of energy to the State's supply in time for summer 2001.*
- ☑ *The CPUC does not have an expedited transmission siting process for urgent projects.*
- ☑ *Although the CPUC relies on them for approving transmission projects, the investor-owned utilities' projections of transmission demand growth may not be reliable.*

Finally, because of the State's role in purchasing electricity for the investor-owned utilities, it remains unclear whether retail competition is consistent with the State's goal of returning the utilities to a credit worthy status.

can save 281 megawatts (MW) of power by June 1, 2001, but more than half of this savings depends on building owners and operators complying with repeated requests to reduce air-conditioning and other power use during the hot summer months. Moreover, the CPUC's costly new efficiency programs, aimed at residential and small business consumers, have many unresolved problems, including a similar consumer compliance issue. Finally, the CPUC in reviewing its interruptible program (program), which for some years has had a mechanism to free up electricity during peak demand hours, has found that program participants are unprepared for frequent requests to curtail energy use. The megawatts these programs are estimated to supply or save are summarized in the Appendix.

Although the energy commission's updating of the building and appliance efficiency standards mandated by AB 970 will not lower this summer's energy demand, this effort will produce future electricity savings. The Renewable Energy Program, part of the 1996 legislation that deregulated electricity in California, is also currently helping the State through this precarious time by ensuring that renewable power plants—plants fueled by renewable sources such as the wind—stay in production and continue to provide enough electricity to power about 4.4 million homes.

In addition to mandating new efficiency programs, AB 970 requires the energy commission and the CPUC to speed up power plant permitting and to address the limitations of the electrical transmission grid. Although legally required to reject or approve power plant siting applications within 12 months of the completion of an application, the energy commission generally does not meet that time goal. By pushing back the dates that plants come on-line, these siting delays have kept badly needed megawatts from being available to relieve energy shortages. Since 1996 the energy commission has approved 12 plants for construction using its standard siting process. If the siting for these plants had taken the 12 months specified by law and assuming no changes in their construction schedules, one plant would be operating now and a second would be coming on-line this June, by which time the 2 plants would be contributing 1,059 MW of power to the State's transmission grid. Both these power plants are now estimated to be operational in July 2001.

The time it takes the energy commission to site power plants has lengthened since the early 1980s, as more private power companies that are less familiar with the application process have planned larger plants that take more time to evaluate than the previous

smaller ones. The energy commission also reports that public opposition to power plants, application project changes, and delays of other involved agencies have caused recent siting delays. Although it has made changes to speed up its siting process, the energy commission is not evaluating the results of these changes, and so it cannot be sure that the power plant siting process will be improved. Recently, the energy commission began using three new expedited siting processes of varying lengths, but it estimates only one process will add a significant amount of energy (several hundred megawatts) to the State's electricity supply in time for this summer's peak demand.

Unlike the energy commission's effort to expedite power plant siting, the CPUC has not responded to the current energy crisis with a faster process to issue transmission line permits for its more urgent projects. Not only does a congested transmission grid risk power outages under adverse conditions, but congested lines increase costs for buyers of wholesale electricity because such congestion triggers price surcharges. Although the lack of transmission lines to transfer power from the southern to the northern parts of the State caused rolling blackouts in Northern California on January 17 of this year, the CPUC has not acted to expedite transmission siting. In almost half of the transmission permits the CPUC considered after 1990, its environmental review process has taken considerably longer than prescribed timelines set up by the California Environmental Quality Act. Major causes of the CPUC's delays are the need to coordinate with the federal government on some projects, a slow process for contracting with consultants, and other involved agencies' late permitting requirements. Although one of these causes is out of its control, and even though it has tried to minimize the contracting delays, the CPUC has not addressed the delayed involvement by other agencies.

Further complicating the transmission picture, applications for transmission projects come from the State's three investor-owned utilities, which are primarily responsible for transmission planning. However, the utilities' transmission plans use varying assumptions about demand growth in their respective service areas. Not only do these three individual plans hinder comprehensive statewide planning, but the utilities may often have little economic incentive to expand transmission lines in their respective areas because the increased transmission capacity would simply allow competition by other power generators. Thus, the investor-owned utilities' projections of transmission demand growth may not be reliable.

When deregulation was implemented in March 1998, the Legislature and the CPUC had great expectations that consumer choice would create retail competition and drive down the costs of electricity. Unfortunately, the details of deregulation provided little incentive for customers of investor-owned utilities to switch providers. As a result, true competition never emerged, and Californians never received the supposed benefits of “direct access” to energy providers. The independent energy service providers (ESPs) had little chance to compete in price with the investor-owned utilities because of their small customer base and inability to negotiate low enough wholesale purchase prices. Also, the ESPs found that electricity is not a product they could endow with brand recognition. Now, with the State being the main buyer of wholesale electricity and negotiating long-term contracts with energy generators, consumer choice may not have a future—because expanding competition now could result in the State paying for unneeded power.

Even if retail competition had taken hold in California, an ideal model of free market forces may not exactly fit the electricity industry. In theory, a lack of supply drives up prices and creates an economic incentive for energy producers to build more power plants. But because the process of bringing a power plant on-line takes several years from the initial planning to the delivery of power, energy producers may not be able to respond quickly enough to market signals, resulting in boom-bust cycles as they adjust to shortages and excesses of electricity. To spare residents and businesses in California the effects of disruptive swings in the energy supply, the State may need to continue to play a part in energy planning. As the State’s primary energy policy agency, the energy commission (in the former regulated energy market) used to ensure that the investor-owned utilities did not build too many power plants. Now the energy commission may need to take on an expanded role of planning for electricity supply, ensuring that neither too many nor too few power generation plants are built.

RECOMMENDATIONS

To provide the Legislature with information it could use to measure whether and to what extent legislative action is needed to help California meet its energy supply and demand needs in the future, the energy commission should do the following:

- Consult with the California Independent System Operator and develop an annual projection of summer supply compared to peak demand that acknowledges the full range of constraints within the State’s electricity system, including transmission constraints.
- As part of its projection, provide the Legislature with a range of possible supply and demand outcomes that reflect the likelihood that the underlying assumptions will prove true.

To ensure that it achieves its goal of reducing peak demand on an ongoing basis, the energy commission should consider modifying its Peak Load Reduction Program as follows:

- As a condition of program participation, require participants in its commercial building program to meet specified compliance levels for reducing lighting and the energy used to power air-conditioning levels for a certain period of time, such as 24 months. If the compliance levels are not met, the participants should be penalized. After 24 months, the participants’ compliance could become voluntary.
- Develop a plan to actively evaluate itself and program participants in all components of the program against set milestones, such as:
 - ◆ Securing a certain number of participants by milestone dates.
 - ◆ Verifying that equipment is ordered and delivered by scheduled due dates.
 - ◆ Ensuring that projects are installed, tested, and operational according to scheduled dates.

In an effort to maximize energy conservation over the next several years, while at the same time making the best use of funds collected from the utilities’ ratepayers, the CPUC should expand conservation measures to include those types of customers that will produce the most energy savings. This may not necessarily prompt the CPUC to abandon more costly residential and small commercial programs in favor of larger commercial, industrial, or governmental projects, but it will permit the CPUC to take advantage of potentially greater energy savings at a lower cost to ratepayers.

To help the State avoid large swings in the supply of electricity relative to demand, the Legislature and the energy commission should consider augmenting the energy commission’s role in

electricity planning. For example, the energy commission's existing planning role could be expanded to include integrating supply and demand projections and using them as a basis for making decisions regarding whether to site new power plants.

In assessing the future role of retail competition, the CPUC should consider the effects of competition at the retail level to evaluate whether retail competition is viable in the current market environment, in which the State is the primary purchaser of electricity for the investor-owned utilities.

AGENCY COMMENTS

The CPUC stated that it is working on a number of efforts to improve reliability, including energy efficiency programs, transmission planning and siting, and programs that interrupt the energy used by large customers and stated that the efforts are often consistent with our recommendations. The CPUC did express concerns that emphasizing only those energy efficiency programs with the largest savings presents equity issues in allocating funds for those programs. Moreover, the CPUC offered several aspects that it believes new legislation for expedited transmission siting should include. Finally, the CPUC agreed that the actual success or failure of changes it made to its interruptible program will not be immediately known, but noted that these changes were developed by consensus reflecting many parties' input.

The energy commission noted that the State is facing significant challenges and one of the primary contributors to the crisis is electrical generators' withholding of needed power supplies. The energy commission also stated that its siting process is complex and it works to balance many issues within its timelines but acknowledged that its average permitting time has run beyond its statutory timeline. With regard to its Peak Load Reduction Program, the energy commission stressed that its demand reduction estimates were conservative and understated the energy savings that will be achieved. The energy commission disagreed with our analysis of the commercial buildings demand response program, stating that there are certain penalties in place which will substantially reduce the level of potential noncompliance. However, the energy commission did agree with our analysis of its water systems replacement program, stating that its tracking could be more systematic. ■

INTRODUCTION

THE RESTRUCTURING OF CALIFORNIA'S ELECTRICITY INDUSTRY

In 1992 California's high electricity prices and a shift in federal energy policy prompted the California Public Utilities Commission (CPUC) to begin a comprehensive review of the State's electricity industry. That review led, in 1994, to a formal rule-making hearing on approaches to deregulation, and by January 1996, the CPUC had adopted a set of policies to guide the State's major investor-owned utilities in restructuring their operations. Before deregulation, the investor-owned utilities—Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric Company (SDG&E)—had a virtual monopoly on their electricity markets. Not only did they own most of the power plants, the three investor-owned utilities also controlled the transmission and distribution of electricity to retail customers. The primary idea behind deregulation was to allow other energy producers into the market, breaking the utilities' retail monopoly with the expectation that doing so would increase competition and lower the price of electricity.

In 1996 the Legislature passed Assembly Bill (AB) 1890, which enacted many of the CPUC policies for deregulating the electricity industry in California. Under this newly restructured system, retail customers of all sizes were allowed to choose their electricity suppliers, although they could continue to maintain service with their investor-owned utilities if they desired. The Legislature also created two nonprofit public-benefit corporations, the California Power Exchange (PX) and the California Independent System Operator (ISO), designating the PX as the State's commodity market that facilitated the buying and selling of wholesale electrical power through a competitive auction.¹ The ISO gained control of the statewide transmission system and is responsible for the reliable operation of the system that supplies wholesale power to the State's investor-owned utilities. Because the State imports and exports electricity, the Federal Energy Regulatory Commission (FERC) is also central to California's deregulated energy industry. FERC oversees the rates, terms, and conditions governing the

¹ On January 31, 2001, the PX ceased trading; it filed for bankruptcy shortly thereafter.

interstate sale and transmission of wholesale power and is responsible for ensuring that wholesale electricity rates are just and reasonable.

THE STATE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION AND THE CALIFORNIA PUBLIC UTILITIES COMMISSION

Two other regulatory entities that play important roles in the deregulated energy market are the State Energy Resources Conservation and Development Commission (energy commission) and the CPUC. Created in 1974 by the Warren-Alquist State Energy Resources Conservation and Development Commission Act, the energy commission is the State's primary energy policy and planning agency, working to ensure that a dependable supply of energy exists to meet California's needs and at the same time monitoring compliance with environmental, safety, and land use goals. Comprising five commissioners appointed by the governor to staggered five-year terms, the energy commission has experienced little change in its role since the passage of AB 1890, the State's electricity deregulation law.

Among its responsibilities, the energy commission processes applications for siting new power plants; encourages measures to reduce wasteful and inefficient use of energy; and collects and analyzes information regarding alternative ways to conserve, generate, and supply energy. State law gives the energy commission broad authority to decide that a power plant is in California's best interest and to approve the plant despite opposition based on significant adverse environmental impacts, such as air pollution or water contamination. Nevertheless, in siting power plants, the energy commission takes into account the California Environmental Quality Act (CEQA), a law requiring the State to perform an environmental review of all new projects, including power plant projects, that may have a significant effect on the environment. The energy commission's siting process is not required to follow CEQA guidelines precisely, because the California Resources Agency has certified the energy commission's siting process as being essentially equal in function and purpose to CEQA. The energy commission is also responsible for the following:

- Forecasting future energy needs and keeping historical data.
- Performing independent analyses of demand growth.²
- Licensing thermal power plants³ that are 50 megawatts⁴ (MW) or larger. Thermal power plants are ones that derive electric power from a source of heat, including natural gas, oil, coal, nuclear, geothermal, and solar sources. Plants smaller than 50 MW are licensed by city and county agencies.
- Developing energy technologies and supporting renewable energy programs.
- Promoting energy efficiency through appliance and building standards.

Whereas the energy commission focuses on energy policy and planning, the CPUC regulates the investor-owned utilities in the State and ensures that California utility customers have safe, reliable utility service at reasonable rates by establishing service standards and safety rules and authorizing utility rate changes. To protect consumers, the CPUC also prosecutes unlawful utility marketing and billing activities and resolves customer complaints against utilities. Under AB 1890, the CPUC is charged with:

- Facilitating competition at the retail level.
- Regulating retail rates charged by investor-owned utilities.
- Registering alternative energy service providers.
- Implementing consumer protection provisions relating to retail electricity services.
- Implementing education programs about retail electricity services.
- Ensuring retail power reliability.

² The energy commission is no longer required to make findings regarding the conformance of individual power plants with the analysis of demand growth.

³ The State Water Resources Control Board and FERC license all hydroelectric power plants regardless of size; the CPUC also helps license hydroelectric power plants greater than 50 MW.

⁴ At any given time, one 100 MW power plant provides enough power to supply roughly 100,000 households.

The CPUC is also responsible for evaluating the economic need for additional transmission lines, for siting transmission lines, and for reviewing the reasonableness of transmission construction costs for rate-making purposes. As part of its transmission line siting process, the CPUC analyzes environmental consequences and determines whether transmission projects are justified and necessary. It also regulates investor-owned telecommunication and transportation companies. The CPUC comprises five commissioners appointed by the governor to staggered six-year terms.

CALIFORNIA'S CURRENT ENERGY CRISIS

California's ongoing energy problems converged in the summer of 2000, causing wholesale electricity prices in the spot markets—commodity markets that sell electricity—to reach very high levels. The wholesale energy prices were symptomatic of deeper problems, some of which—like the weather and recent high natural gas prices—were beyond state regulatory control. For example, abnormal weather patterns in the western region in the summer of 2000 exacerbated a long-standing energy imbalance, in which demand for electricity increased faster than the supply in California. However, the legislated terms of deregulation and the way in which it was implemented also added to California's power woes. For example, the CPUC initially required the investor-owned utilities to sell and purchase all of the electricity they needed to serve their customers on the volatile spot market. At the same time, the two largest investor-owned utilities were unable to pass on much of these higher wholesale costs to their customers because of the legislated freeze on retail rates. As a result, by December 2000, both PG&E and SCE had amassed huge debts and teetered on the verge of bankruptcy. Moreover, because of the deteriorated credit status of these two investor-owned utilities, the State had to step in as the primary purchaser of electricity for most Californians, beginning in mid-January 2001.

On four separate days in early 2001 (two days in January and two in March), severe energy shortages forced the ISO to order the major utilities to cut power to millions of citizens, using rolling blackouts to keep the State's electricity system from crashing. Recently, the CPUC approved a rate increase that—depending on the time and energy usage—could range anywhere from no increase at all up to 47 percent for residential customers of PG&E and SCE, hoping that it would allow them to repay the State for its power purchases, restore their creditworthiness, and encourage

conservation during the summer of 2001. Nevertheless, PG&E had already voluntarily filed for Chapter 11 bankruptcy protection in federal court on April 6, 2001.

Recognizing that California is facing potentially serious electricity shortages that call for immediate action, the Legislature crafted a number of bills aimed directly at quickly increasing energy supply and reducing demand. In August 2000, the Legislature passed AB 970, the California Energy Security and Reliability Act of 2000. This legislation mandates that the energy commission and the CPUC hasten to bring new power plants on-line, address limitations in the electrical transmission and distribution system, and make significant new investments in conservation. However, the primary purpose of the legislation is to reduce demand during peak hours in time for summer 2001. AB 970 requires the energy commission and the CPUC to implement demand reduction programs, including ones offering incentives to electricity customers who take specific steps to conserve and ones aimed at reducing demand for electricity during peak periods. Some features of these programs include the following:

- Installing energy-efficient traffic lights and heat-reflective roof surfaces.
- Replacing aging equipment owned by public and private water systems with more efficient models.
- Developing systems to cut the energy used by commercial and state buildings for heating, air-conditioning, and lighting.
- Installing Internet-based technology to adjust thermostats in homes and small commercial businesses.

SCOPE AND METHODOLOGY

The Joint Legislative Audit Committee requested the Bureau of State Audits to assess the structures, operations, and overall functionality of the PX and ISO and their contributions to the rising cost of wholesale electricity in California. In March 2001 we issued a report on the PX and ISO titled *Energy Deregulation: The Benefits of Competition Were Undermined by Structural Flaws in the Market, Unsuccessful Oversight, and Uncontrollable Competitive Forces*. While working on that report, however, we realized the integral roles played by the energy commission and

the CPUC in California's deregulated energy market, specifically in the siting and planning of power plants and transmission lines and in the implementation of energy conservation and demand response programs. Thus, we are issuing this second report on energy deregulation, focusing on the responsibilities of the energy commission and the CPUC in the State's energy market.

To gain an understanding of these two commissions' roles in the State's energy market, we reviewed relevant federal and state laws and regulations, including CEQA. In addition, we studied relevant sections of procedures and protocols used by the energy commission and the CPUC. We also interviewed energy commission and CPUC staff to understand how the entities operate and their respective roles in deregulation and in responding to the energy crisis. Further, we reviewed internal documentation of the two entities to understand and assess their decision-making processes.

To understand California's likely electricity supply and demand balance for summer 2001, we analyzed projections by the energy commission and ISO, and obtained the Legislative Analyst's Office evaluation of these projections. We also interviewed energy commission and CPUC staff and examined historical documentation of events that contributed to the current energy shortage.

To gain an understanding of the energy commission's various power plant siting processes and certain ongoing changes, we examined laws, regulations, and other documentation and interviewed energy commission staff. We also analyzed data related to the energy commission's 12-month siting process to determine how long the process takes and how that length has changed over time. For certain siting applications that took in excess of 12 months, we spoke with energy commission staff and examined staff analyses of siting applications, energy commission siting decisions, and other materials to determine the causes of the delay.

To understand the CPUC's transmission siting process, we examined the relevant laws, general orders, and other documentation and interviewed CPUC staff. We analyzed data related to the length of the CPUC's transmission siting process and conducted interviews and examined documents, such as environmental documents and correspondence, to determine the causes of delays in the siting process.

To determine the extent to which the energy commission and the CPUC have implemented AB 970, we reviewed program guidelines, status reports, and project contracts. We also interviewed appropriate staff and looked at independent reviews prepared by other entities critiquing these programs. Further, we evaluated the CPUC's decisions related to energy efficiency programs, drafts of proposed programs, and information submitted by the investor-owned utilities regarding their implementation of these programs.

To understand the CPUC's role in consumer choice, we examined reports, orders, and decisions made by the commissioners, interviewed staff, and assessed the effectiveness of the decisions that were made. Finally, to determine the outcome of consumer choice, we analyzed the investor-owned utilities' monthly data reports showing the number of former utility customers who had selected other energy service providers and the number of utility customers, broken down by customer classes. ■

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CHAPTER 1

Plans to Reduce Energy Demand by Summer 2001 Overestimate Potential Peak Energy Savings

CHAPTER SUMMARY

The State faces immediate electricity supply and demand concerns that first became apparent in the summer of 2000. As California's wholesale electricity prices shot up, some consumers' utility bills tripled, and two investor-owned utilities reported losses in the billions of dollars. Further, in January and March of 2001, Californians experienced four separate days of rolling blackouts, estimated to cost businesses millions of dollars.

As summer 2001 approaches, the State's citizens are asking whether there will be further outages. In order to estimate the State's supply and demand balance for summer 2001, the California Independent System Operator (ISO) and the State Energy Resources Conservation and Development Commission (energy commission) have developed projections of supply and demand. In addition, the Legislature requested that the Legislative Analyst's Office (LAO) evaluate whether the ISO's and the energy commission's projections were reasonable. Although both the ISO's and energy commission's projections indicated a potential supply shortfall in summer 2001, the energy commission identified new programs that it believes should be adequate to avoid an electricity shortage. However, certain assumptions in the projections—such as power plants not operating and consumer response to conservation programs—leave room for uncertainty regarding whether California's residents and business owners will be secure from power outages in the summer ahead.

In anticipation of these summer outages, both the energy commission and the CPUC have set up programs mandated by Assembly Bill (AB) 970, which the Legislature passed in August 2000 and became effective in September 2000, to reduce peak energy consumption and establish new levels of energy efficiency state-wide. For example, the energy commission created the Peak Load Reduction Program, which contracts with public and private entities to reduce peak demand by various means, including installing heat-reflective roof surfaces and developing systems to

cut electrical use in commercial and state buildings during peak demand periods. However, the energy commission's projection that the Peak Load Reduction Program can save 281 megawatts (MW) of power by June 2001 is unduly optimistic. Over half of this savings relies on the unlikely scenario of building operators accepting repeated requests to reduce electricity use during the hot summer months.

Established in the mid-1980s, another program to reduce peak energy use is the CPUC's interruptible program (program), which can free up more than 2,340 MW of electricity during an energy crunch. However, this program is in chaos because increased requests for those in the program to curtail their energy use have begun to meet with resistance. Customers who are inappropriate for this program, such as hospitals and nursing homes, signed up for it to save money on their electric bills, but in reality they are not prepared to endanger their patients by cutting their power. The CPUC issued revised program guidelines in April 2001, intended to stabilize the program and keep it viable for summer 2001. Although the changes appear reasonable, it is not yet known whether they will be effective.

Adding to the uncertainty of this summer's energy supply is the fact that the CPUC may not achieve the energy savings it anticipates through the programs it has developed to fulfill AB 970's mandate that it expand existing energy efficiency programs and create new ones. The three investor-owned utilities run the CPUC's energy efficiency programs. Despite indications that the investor-owned utilities may not be meeting their past program goals and that they failed to provide sufficiently detailed and effective program plans for implementing AB 970, the CPUC approved the utilities' plans in January 2001. As a result, it is unclear whether the CPUC will successfully achieve its AB 970 program goals.

RECENT PROJECTIONS THAT THE STATE CAN AVOID ROLLING BLACKOUTS IN SUMMER 2001 ARE BASED ON ASSUMPTIONS THAT MAY NOT COME TRUE

Despite projections to the contrary, there is little assurance the State will escape rolling blackouts this summer.

Despite projections to the contrary, there is little assurance that the State will meet its energy supply needs during the summer of 2001. Responding to the increased public awareness of California's energy crisis, the ISO and the energy commission released projections of the State's likely balance between electricity supply and demand for the coming summer. Seeking to determine

The ISO's and energy commission's projections are based on assumptions about power outages, customer actions, and other factors that may not come true.

how reliable the ISO's and energy commission's projections were, the Legislature requested that the LAO review the projections for reasonableness. The ISO's projection was the most pessimistic, showing a gap between supply and demand sufficient to cause rolling blackouts. Although it also indicated a potential supply shortfall in summer 2001, the energy commission identified new programs that could make up the gap. In its evaluation, the LAO modified the energy commission's projection using more pessimistic assumptions, but it still concluded that the State's energy supply should be adequate to meet peak demand, although the ISO may have to dip into its reserves to do this. The ISO's and energy commission's projections, however, are based on assumptions about power plants not operating, customer actions, and several other factors that may not prove true. Furthermore, the projections do not consider transmission limitations between certain parts of the State or expand the prediction to include more than one possible outcome. Because of these limitations, California residents and business owners may not be secure from power outages in the summer ahead.

In February 2001 the ISO and energy commission each issued projections of electricity supply and demand for summer 2001.⁵ Focusing on those areas of the State serviced by the transmission grid it operates,⁶ the ISO projected electricity shortages of about 5,300 MW during August 2001, unless new supply comes on-line beyond that already approved or new programs are implemented that reduce demand.⁷ The ISO and energy commission projected that, relative to the other summer months (May through July), the demand for electricity will be the greatest in August. As detailed in Table 1 on page 19, a significant portion of these shortages will simply reduce the ISO's required 7 percent operating reserves. However, even if all reserves are depleted, the ISO projected that the August 2001 peak demand will still exceed supply by more than 2,100 MW, enough to cause rolling blackouts.

The energy commission projected summer 2001 supply and demand for the entire state, assuming hotter weather conditions than the ISO's projection, but also making more optimistic

⁵ To be consistent in comparing the entities' projections, we used projections that the ISO and energy commission issued at about the same time. The ISO has since issued an updated projection that still projects an electricity supply shortfall in all months of summer 2001.

⁶ The ISO's control area is composed primarily of the transmission grids owned by the State's three investor-owned utilities, which cover approximately three-fourths of the State. The rest of the State, including far Northern California and the area served by the Los Angeles Department of Water and Power, among others, is not under ISO control.

⁷ The ISO also projects that blackouts will occur in June and July 2001.

assumptions than the ISO about the amount of electricity supply the State could count on from existing independent energy producers and hydroelectric facilities. Table 1 shows that the energy commission predicted a supply shortfall of only about 1,200 MW during the State's peak summer demand, which, as previously noted, is assumed to be August 2001. Because it is less than the State's operating reserve, this shortfall would not result in rolling blackouts. The energy commission went on to identify new programs to increase supply and reduce demand that could make up not only its own projected shortfall but the larger shortfall projected by the ISO as well. Assuming that these new programs are in place by their stated goal of July 1, 2001, the State would be able to avoid the late summer shortages projected by the ISO, thus potentially avoiding rolling blackouts in July and August. However, the energy commission's new programs would not be on-line in time to prevent the shortages the ISO is predicting for June 2001.

The LAO determined the energy commission's projection was optimistic and revised several estimates downward.

On March 5, 2001, the Legislature requested the LAO to determine whether the ISO's and energy commission's projections were reasonable and whether legislative action was required to meet peak electricity supply and demand needs for summer 2001. The LAO's analysis, issued on March 13, found that the energy commission's projection was too optimistic and revised downward several estimates of programs that added supply or reduced demand. Despite its revisions to the energy commission's projection, the LAO still determined that with the new programs the State would have enough supply in place on paper to meet the peak electricity demand expected in August. Thus, as detailed in Table 1, though the ISO's and energy commission's forecasts projected a supply shortfall if no action is taken, the energy commission projects that new programs will make up the shortfall.

However, both of these projections contain several aspects that may prevent them from reliably indicating the State's summer 2001 balance between electricity supply and demand. First, the energy commission's projection and the LAO's evaluation of it is based on programs whose results are difficult to predict because they have not been tried before. In fact the LAO acknowledges the difficulty in making projections about this summer by pointing out that "roughly one-quarter of potential energy supply is produced by private generators and there is no guarantee that all this amount will be sold for use within California." Moreover, the LAO noted "numerous assumptions about difficult-to-predict-factors in arriving at our 'bottom line' figures—such as the levels

TABLE 1

**ISO and the Energy Commission Projections of August 2001
Electricity Supply and Demand (in Megawatts)**

Entity	ISO*	Energy Commission†	After LAO's Adjustments‡
Existing supply, reflecting expected outages and imports	42,700	56,166	53,991
New supply already approved and expected on-line by August 2001	2,828	3,741	3,333
Projected peak demand‡	(50,825)	(61,125)	(61,125)
Projected supply shortfall	(5,297)	(1,218)	(3,801)
<i>Actions intended to alleviate the shortfall by August 2001</i>			
New supply	0	1,312	562
Demand reduction	0	6,246	4,301
Projected balance with new supply and demand programs	(5,297)	6,340	1,062
Operating reserves (7%)	3,122	3,999	3,999
Supply and demand balance without operating reserves	(2,175)	10,339	5,061

Source: ISO Estimated Resource Plan 2001, February 1, 2001; Energy Commission California Summer 2001 Forecasted Peak Demand—Resource Balance; Legislative Analyst's Office—Report to the Assembly Subcommittee on Electrical Energy Oversight, March 13, 2001.

* Projection limited to ISO control area.

† Projection includes entire state.

‡ Assumes operating reserve of approximately 7 percent.

of power outages, participation in interruptible programs, availability of out-of-state supplies, customer behavioral responses, and federal actions.”

For example, the energy commission projected a 2,000 MW reduction in demand due to a public outreach campaign for which the State may allocate up to \$20 million. The LAO's evaluation of the energy commission's projection estimated that this megawatt savings is significantly overstated and revised it down to 1,300 MW, explaining in its report that the lower figure is “consistent with the maximum savings that the ISO was able to identify during the January stage 3 alerts⁸ and rolling blackouts.” Although the lower figure is more realistic, we question whether anything short of a stage 3 alert and rolling blackouts would cause Californians to reduce demand for electricity by

⁸ A stage 3 alert occurs when the ISO's energy reserves drop below 1.5 percent.

1,300 MW. If this is the most Californians have conserved when threatened with having their power cut off entirely, it seems unlikely that a public outreach program would be able to achieve a similar level of savings prior to a stage 3 alert being declared. Although 1,300 MW may ultimately be saved, it is more likely that they will be saved after stage 3 alerts have been declared, rather than to preclude stage 3 alerts. Without operational experience with a public outreach program or the time to conduct a detailed analysis of its potential for reducing demand, the energy commission cannot be sure of the actual level of demand reduction. Later in this chapter, we conclude that several of the new demand reduction programs included in these projections may not reach their stated goals.

Second, the ISO's and energy commission's projections do not take into account transmission constraints, or areas throughout the State where the infrastructure limits the amount of power that can flow in and out.⁹ These constraints can cause blackouts in certain areas of the State even when overall generation capacity is adequate to supply the State's needs, as demonstrated by the rolling blackouts in Northern California in January 2001. These blackouts occurred because the primary transmission connection between Northern and Southern California could not physically transmit the amount of electricity the north needed, although Southern California had enough excess supply to make up Northern California's shortfall. Thus, even if the forecasts are correct in predicting an adequate supply to meet California's total demand, transmission constraints could still cause rolling blackouts in parts of the State.

The ISO's and energy commission's analyses do not provide adequate assurance that the State will meet its energy supply needs because they do not provide enough information to assess how likely their scenarios are, thus reducing their usefulness to the Legislature. Although the energy commission issued demand projections for several different weather scenarios, each with a given probability of occurring, it did not do so for supply. Each of the two projections of possible new supply additions included only one possible outcome. Although we recognize that these entities were not asked to provide more than a single supply projection, we believe that a range of supply possibilities (such as a best, worst, and average case scenario) would better serve the Legislature. From such a range, the Legislature could see how

The Legislature may be better served by future projections that reflect a best, worst, and average case scenario from which to gauge how urgent its actions are.

⁹ The ISO's subsequent projection prepared in March 2001 explicitly acknowledged the possibility that transmission constraints could cause rolling blackouts.

urgently needed and how useful its actions might be to increase California's chances of meeting its future energy supply and demand needs.

THE ENERGY COMMISSION'S PEAK LOAD REDUCTION PROGRAM MAY MISS ITS ESTIMATE OF ELECTRICITY TO BE SAVED BY JUNE

In August 2000, in response to the State's energy problems, the Legislature passed AB 970, authorizing the energy commission to use \$50 million from the State's General Fund to create programs that would reduce peak energy consumption statewide. Known as the Peak Load Reduction Program, this broad effort aims to reduce peak demand by 200 MW from June 1 through September 30 for a four-year period beginning June 1, 2001. As recently as April 23, 2001, the energy commission estimated that by June 1, 2001, its Peak Load Reduction Program would surpass its original goal, reducing demand by 281 MW and ultimately providing as much as 335 MW of peak demand reduction. However, the energy commission may be overly optimistic in its 281 MW estimate. This is because more than half of its estimated 281 MW savings are projected to come during periods of high demand from the voluntary curbing of electricity use in commercial and state government buildings located throughout California. Although state government facilities are more likely to comply for financial and political reasons, it may be unrealistic to expect operators of commercial buildings to turn up thermostats voluntarily, and the energy commission has no way of penalizing participants if they fail to comply. Unless at least 50 percent of these building operators comply, the program will not meet its original goal of saving 200 MW, let alone the energy commission's higher estimate. Also, the energy commission's efforts to monitor its water-systems equipment program, which provides grants to replace inefficient water pumps and equipment with more efficient models, may not be sufficient to ensure that each project scheduled will actually be completed by June 1, 2001, in time to provide the planned peak demand reduction for June, which represents 17 percent of its estimated peak energy savings.

Through the Peak Load Reduction Program, the energy commission has implemented six separate programs to accomplish such goals as to install energy-efficient traffic signals and heat-reflective roof surfaces, replace aging water-systems equipment with more efficient models, and develop systems to cut electricity use in

commercial and state buildings during periods of high demand. These programs and their estimated megawatt savings are summarized in the Appendix.

The Energy Commission May Not Achieve Its Estimated 281 MW Peak Demand Reduction

The energy commission may be overly optimistic in estimating its peak demand savings since over one-half of the savings will come from the voluntary actions of program participants.

One part of the Peak Load Reduction Program provides \$10 million to assist commercial building owners with the installation of computerized systems to reduce heating, ventilation, and air-conditioning and lighting levels during ISO alerts and/or peak demand periods. The energy commission will also use \$5.5 million to help certain state-owned and operated facilities develop customized peak demand reduction plans. It estimates that these programs will reduce peak demand by 186 MW of the estimated 281 MW reduction to be achieved by June 1, 2001. However, these estimates may be overly optimistic if operators of commercial and state buildings do not always reduce energy use when called on to do so. Because actual energy savings will depend on the operators' responses to potentially frequent requests to reduce electricity use, the actual megawatt savings this program will provide are uncertain. This uncertainty does not give Californians much assurance that they will be spared rolling blackouts in the coming summer months.

For the energy commission to achieve its estimated 186 MW goal, all participants in these programs will have to act as planned: During hours of high demand or when the ISO issues a signal to reduce energy usage, operators of commercial and state buildings need to adjust the buildings' lighting and air-conditioning or take other actions to reduce peak energy consumption. Although this plan sounds fairly simple, these programs have several inherent risks. First, the contractors who install the computerized systems in commercial buildings to monitor energy use are required to offer a method to override the emergency signal. State facility operators will manually execute the energy reduction tasks in response to an ISO directive or during hours of high demand. Therefore, each commercial and state building operator has a choice to comply with the directives to reduce energy consumption during peak hours. An energy commission program manager said that the override function was needed to convince

commercial building owners to participate in the program. However, unless there is substantial voluntary compliance with requests to curtail energy use, the energy commission will likely not achieve its estimated megawatt savings.

Moreover, the energy commission does not plan to penalize those building owners or managers who override the signal, increasing the likelihood of noncompliance. For example, assume that the owner or manager of a commercial building is signaled to cut lighting by 25 percent and adjust the temperature to 77 degrees twice a week for the duration of the summer. If the owner or manager is influenced more by angry tenants than by a desire to help during the State's energy crunch, and there is no incentive to comply (such as a penalty), the end result may be more frequent overrides of the building's system. With the resulting lack of energy savings during peak periods, the State faces a greater risk of rolling blackouts during peak periods.

The ability of operators to override emergency signals to curtail energy use without fear of penalty for non-compliance, increases the risk of rolling blackouts during peak periods.

Compared to the owners and managers of commercial buildings participating in the program, state building operators may have more of an incentive to comply with demand reduction directives because they are financially and politically answerable to the State's policy makers. Nevertheless, although the ISO observed a measurable reduction in demand during a test of several state agencies who participated in a similar effort in summer 2000, tenant attitudes, facility operator preferences, and human error could potentially affect the energy commission's estimated goal to reduce energy use in state buildings.

We combined the estimated megawatt savings for the commercial and state building programs and calculated a range of peak energy savings based on a possible range of building and facility operator compliance. As Table 2 demonstrates, if compliance among participants in the state and commercial building programs drops to 70 percent, the State will lose roughly 56 MW of the energy commission's estimated June 1 demand reduction. If only half of the buildings respond to the signal to reduce their energy consumption, the gap widens to 93 MW. Moreover, assuming that the full measure of demand reduction is achieved in the other program areas, such as water-systems replacement and traffic signal retrofit, compliance by 50 percent or less of the building operators will keep the State from achieving the 200 MW demand reduction—the minimum amount originally envisioned.

TABLE 2**Range of Peak Energy Savings Based on a Possible Range of Building and Facility Operator Compliance (in Megawatts)**

Percent of Commercial and State Buildings That Comply With Demand Reduction Directives	Difference in Projected Reduction	Total Program Demand Reduction*
100%	0	281
90	(18)	263
80	(37)	244
70	(56)	225
60	(74)	207
50	(93)	188
40	(111)	170
30	(130)	151

* This assumes that all other Peak Load Reduction Program areas achieve their full estimated demand reduction.

The energy commission could also do more to ensure that participants in its water-systems replacement program meet their peak energy demand goals. Through grants to entities that supply water to the public, the program subsidizes the replacement of inefficient water pumps and equipment with more efficient ones. Because this program is the energy commission's third largest effort in the Peak Load Reduction Program and represents 17 percent of the total energy savings estimated by June 1, 2001, we would have expected the energy commission to be actively evaluating itself and program participants against set milestones such as the following:

- Securing a certain number of participants by set dates that represent the megawatt reduction goal to be reached.
- Verifying that equipment is ordered and delivered by set dates.
- Ensuring that equipment is installed, operational, and tested by set dates.

However, based on our discussions with the manager of the water-systems replacement program, these types of activities have not occurred. As of April 24, 2001, the manager and his

staff had communicated with program participants on the phone, received progress reports from participants, and visited at least 2 of approximately 64 pending project sites. However, the manager indicated that because of limited resources, neither he nor his staff would visit all of the sites. Rather, the manager intends to have his staff call all of the grantees around June 1 to determine whether the equipment has been installed and is operating. Without monitoring itself and project participants against established milestones such as those listed, the energy commission reduces its chances of achieving its peak energy reduction goals for this program. Thus, the energy commission may be overly optimistic in estimating a peak demand reduction of 281 MW by June 1, 2001.

SERIOUS PROBLEMS WITH THE INTERRUPTIBLE PROGRAM MAKE ITS FUTURE UNCERTAIN

Since the mid-1980s California's investor-owned utilities have operated the interruptible program (program), which offers discounted electricity rates to customers who agree to curtail their energy use when demand is high and the reliability of the electricity system is jeopardized. The CPUC oversees the program and recently revised it in an attempt to keep it viable for summer 2001. However, the program's effectiveness is threatened by problems such as noncompliance. Because this vital program can free up about 2,340 MW of electricity during an energy pinch, without it the State faces the increased possibility of rolling blackouts during the hot summer months, adversely affecting public health and safety.

Noncompliance by program participants threatens the interruptible program, which is capable of curtailing more than 2,340 MW of electricity in an energy emergency.

The program's instances of actual energy curtailments since 1990 has been minimal. Recently, however, as demand for electricity has begun to exceed supply, curtailments have become a frequent reality. Indeed, by the end of January 2001, requests to participants to interrupt their power use had exhausted most of the program's annual ability to request electrical curtailments. Late in 2000, the CPUC began to recognize compliance problems with the program. With more curtailment requests, more participants refused to comply, making it difficult for the utilities to reduce demand when the ISO requested. Later, responding to public health and safety concerns, the CPUC temporarily suspended the provision allowing participants to opt out of the program and also suspended all penalties to participants for not curtailing their

demand when directed. Finally, in April 2001, the CPUC developed revisions to the program, meant to maintain its viability through the summer of 2001. However, it is not yet known whether the revised program will adequately fulfill its role as a buffer that can decrease or avoid the need for rolling blackouts.

The Interruptible Program Offers Participants a Discount for Curtailing Electricity Use During Shortages

This program gives participants reduced electrical rates in exchange for agreeing to curtail their use of electricity when directed, up to a certain number of hours per year. The program's annual cost, in discounts given mainly to commercial and industrial customers of the three investor-owned utilities, is more than \$220 million a year and has totaled \$2 billion since 1990, according to the CPUC. Because they use large amounts of electricity, industrial and large commercial operations are the program's targets. However, the size and provisions of the three utilities' programs differ. As Table 3 shows, SCE has the largest amount of megawatts that can be curtailed, and PG&E has the next largest amount. (Because SDG&E's program, at 40 MW, is so small in comparison, our analysis focuses mainly on the SCE and PG&E programs.) Each year, SCE and PG&E can interrupt a participating customer's electricity supply 25 and 30 times, respectively. The combined duration of these interruptions cannot exceed 100 hours per year for PG&E customers and 150 hours per year for SCE customers. When curtailments are needed, the utilities notify their customers, giving them 30 minutes to reduce their electrical use. The financial incentive for participating customers is significant—discounts of about 15 percent of their electricity cost. This discount is tied to how much energy is subject to interruption, which customers can designate up to 100 percent. If they do not reduce their energy use by the agreed-upon percentage when directed, they are penalized. The penalty is purposely set high, so that about 10 to 25 hours of noncompliance will consume a participant's program discount for the year.

Tight energy supplies in January 2001 nearly exhausted PG&E's and SCE's interruptible programs—leaving participants less willing to curtail energy use in the summer when it is most needed.

The Program Nearly Exhausted Its Yearly Capacity in One Month

By the end of January 2001, just four weeks into the new year, tight energy supplies had already caused PG&E to nearly exhaust its program, having reached its 100-hour annual limit for the majority of its program participants. Similarly, SCE had already called on its participants to curtail power use nearly half of the

TABLE 3

**Size and Provisions of the Investor-Owned
Utilities' Interruptible Program
(As of Summer 2000)**

	SCE	PG&E
Amount of curtailable peak use under contract	1,800 MW	500 MW
Contract terms per participant		
Maximum interruptions per year	25	30
Maximum hours per interruption	6	6
Total interruptible hours per year	150	100
Average discount per interruptible program participant	15%	15%

Source: CPUC Energy Division's Report on Interruptible Programs and Rotating Outages, February 8, 2001.

25 times allowable under the program. This extensive use of their allotted curtailments so early in the year means that they will be less willing to curtail energy use during the summer, when curtailment is traditionally needed most to relieve the demand for electricity. Under this scenario, rolling blackouts are more likely during the summer, causing cuts in productivity, disruptions to the economy, and potential threats to public health and safety.

Since 1999 the wholesale electricity market has become more volatile, subjecting program customers to unpredictable electricity service. In 2000 and so far in 2001, California's investor-owned utilities have dramatically increased the number of interruptions called for under the program. PG&E and SCE each requested that their participants curtail power on 20 separate occasions in 2000, with PG&E requesting curtailments eight times between June and September alone. In contrast Table 4 shows that prior to 2000 PG&E generally made curtailment requests only one to five times a year in order to maintain system reliability, and SCE's curtailments, even during the summer, were rare.

TABLE 4**Number of Curtailment Requests Spiked in 2000**

Year	PG&E	SCE
1992	1	0
1993	1	0
1994	0	0
1995	5	0
1996	4	0
1997	1	0
1998	5	4
1999	2	0
2000	20	20

Source: CPUC Energy Division's Report on Interruptible Programs and Rotating Outages, February 8, 2001.

Serious Problems Have Recently Surfaced With the Interruptible Program

The last few months have revealed the following serious problems with the program:

- Some participants have refused to curtail their electricity use at all or have not curtailed the full amount promised when requested.
- Some participants were not well suited for the program to begin with yet had designated all of their energy use as curtailable.

Because the program acts as a buffer when the State's electricity system is threatened, if the program does not deliver the energy savings it is designed to provide, the possibility of rolling blackouts increases. In January 2001 in response to risks to public health and safety, the CPUC suspended certain aspects of the program, including imposing penalties for noncompliance. Although the CPUC released a restructuring plan in early April 2001, the program's future is uncertain.

With frequent requests to curb electricity use, more participants refuse or do not fully comply when requested to reduce their energy use.

When Compliance Drops, Rolling Blackouts Are Harder to Avoid

With requests to curb their electricity use becoming more frequent, an increasing number of participants in the program are refusing to comply or are not fully complying when asked to curtail their energy use. When compliance drops, the State's buffer for avoiding rolling blackouts grows thinner. Rather than having the agreed-upon scenario in which a select few experience power curtailments, the whole state becomes subject to the health, safety, and economic effects of blackouts. When PG&E requested its program participants to curtail their electricity use eight times over the summer of 2000, participants reduced their use by an average of 490 MW, an average of 19 MW less than they had agreed to under contract. In contrast, over the same period, SCE's participants reduced their electricity use by an average of 1,213 MW, an average of 636 MW less than called for under contract. Although PG&E's compliance rate remained high at 96 percent, SCE's compliance rate was relatively low at 62 percent.

Eligibility Resulted in a False Sense of Potential Energy Curtailment

The CPUC's energy division analyzed program participation data for 2000 and concluded that SCE's relatively low compliance rate probably resulted from SCE enrolling in its program a number of customers that were unsuited for the program. Reasoning that each participant, rather than the utility, can best decide whether it can sensibly and responsibly interrupt its power upon request, the CPUC has not previously required the investor-owned utilities to screen program participants, and indeed, SCE lacked eligibility criteria for its participants. As a result, SCE enrolled customers such as hospitals, nursing homes, and prisons in the program, many of which were unwilling or unable to reduce their energy use when requested. Further, the CPUC found that several of these participants designated their entire energy use as subject to curtailment so that they could qualify for lower rates. By doing so, these participants provided a false sense of security that their energy use would be available for curtailment, when in reality it is not feasible for customers providing essential services to curtail their entire operation. The CPUC's analysis revealed that in 2000, the SCE's compliance rates were only 2 percent for participating nursing homes, 8 percent for medical offices, and 40 percent for hospitals. Overall, the CPUC concluded that participants representing more than 1,000 MW of SCE's electricity use designated

SCE participants—representing over 1,000 MW—should not have been enrolled in the program, and 60 percent failed to curtail energy use when requested to do so.

as interruptible should not have been enrolled in the program. About 60 percent of these participants, representing more than 600 MW, failed to curtail their use of electricity when requested to do so, diminishing the program's buffer against rolling blackouts. Although these customers were assessed over \$92 million in penalties, almost all of them had been enrolled in the program since 1996 and had received at least \$300 million in reduced rates between January 1, 1998, and December 31, 2000, according to the CPUC.

The CPUC Has Taken Steps to Improve the Reliability of the Program

Responding to problems the program is facing as a result of the current energy situation in the State, the CPUC has evaluated the program and acted to try to improve it. After stabilizing the program, the CPUC has restructured its features to allow inappropriate customers to exit the program, to offer more reasonable curtailment time frames, and to require the utilities to screen customers that offer services related to public health and safety. Also, the CPUC is overseeing other similar programs to increase the amount of electricity available to be cut during summer peak hours. These decisions to restructure the program and to adopt similar programs seem reasonable, but at a minimum, it will not be until the summer of 2001 or later that anyone will know for certain whether the changes to the program will enhance its role as a buffer that can deliver energy savings and decrease or avoid the need for rolling blackouts.

Seeing that customers were exiting the program, the CPUC in October 2000 temporarily suspended the SCE program's annual opt-out provisions, preventing customers from departing the program, or from reducing the amount of energy they originally agreed to curtail, until March 31, 2001. This suspension allowed the CPUC sufficient time to evaluate the program and to maintain maximum flexibility in shaping it to address reliability concerns for the summer of 2001. Then in January 2001, the CPUC waived noncompliance penalties for all customers and also waived the tracking of the hours and number of curtailments that counted toward the participants' program limits. These actions followed an energy commission recommendation, based on a threat to public health and safety, noting that multiple curtailments of electricity had caused pipeline companies to be unable to deliver petroleum products, leading to shortages of gasoline, diesel, and jet fuel at a number of California terminals and ultimately causing a sharp rise in fuel prices across the State.

Though prompted by this threat to suspend noncompliance penalties, the CPUC made it clear that it fully expected all program customers to voluntarily respond to the maximum extent feasible when called upon to reduce their energy usage and to assist in maintaining a reliable electrical system.

In April 2001 the CPUC released a decision that revised certain aspects of the program. First, the CPUC reinstated penalties for noncompliance, as well as an annual opt-out period for SCE program participants. Based on comments from program participants, the CPUC concluded that it is reasonable to allow participants to periodically reassess their ability to curtail power or the level of power they commit to curtail. Under the reinstated opt-out period, SCE participants can choose to:

The CPUC recently decided to revise various aspects of the program in an attempt to improve its viability in time for the summer of 2001.

- Opt out retroactive to November 1, 2000, if they repay the discounts received between then and the date they decide to opt out.
- Opt out at the beginning of the next billing cycle and be obligated to pay any penalties incurred for failure to curtail electricity use when requested through the time the opt out is effective.
- Opt out at an earlier date, such as a date between when the SCE notifies its customers that they have a choice and the beginning of the next billing cycle, if mutually agreeable to the participant and SCE, and pay any penalties incurred for noncompliance.

Second, the CPUC developed program limits restricting the number of curtailments and the length of time that a participant in any of the investor-owned utilities' programs can be continuously curtailed. Under the program's earlier criteria, especially in January 2001, participants were often asked to curtail their energy use almost constantly from day to day, placing unreasonable expectations on them and nearly exhausting the program's ability to reduce power demand. The CPUC is now directing the investor-owned utilities to limit program curtailment requests directed at individual participants to no more than one 6-hour event per day, four events per week, and 40 hours total per month. In contrast, the prior provisions contained no daily, weekly, or monthly limits, aiding in the rapid exhaustion of the program's ability to curtail energy use. The annual hourly limits for SDG&E will increase from 80 to 120 hours per year, whereas annual limits for SCE and PG&E will remain unchanged. As

indicated in Table 5, the revised program will help participants avoid shutting down operations continuously over a day or a week, until the program’s annual limits are achieved. The CPUC hopes that limiting program participants’ interruptions to reasonable time frames will increase their compliance and prolong the program’s viability.

TABLE 5
Revised Provisions of the CPUC’s Interruptible Program

	Prior	Revised
Interruptions per day	Unlimited	Maximum of 1 six-hour block=6 hours
Interruptions per week	Unlimited	Maximum of 4 six-hour blocks=24 hours
Hours per month	Unlimited	40 hours
Annual limit	PG&E—100 hours SCE—150 hours SDG&E—80 hours*	PG&E—100 hours SCE—150 hours SDG&E—120 hours

Source: CPUC Decision 01-04-006, April 3, 2001.

* Under the prior program, SDG&E tariffs required that participants curtail energy use whenever the ISO declared a stage 2 or stage 3 emergency even when the participants’ annual maximum hourly limits had been reached.

Third, the CPUC declared that essential customers, such as hospitals and nursing homes, may continue to participate in the program, but utilities must screen them against eligibility criteria. To qualify as essential, a customer must provide goods or services that are vital to public health, safety, and welfare. The investor-owned utilities must now discuss with each current and future customer enrolled in the program whether or not that customer is reasonably eligible to participate. The CPUC stated that a participant should demonstrate, for example, sufficient backup generation or other means to meet essential demand if electrical power is curtailed. In guiding the utilities regarding consistent criteria to use in screening for eligibility, the CPUC suggested that each utility require essential customers to provide a declaration under penalty of perjury including a statement that they will curtail a specified percentage of their energy use when called upon and can continue to meet essential needs when curtailed through back up generation or other means. To balance these customers’ participation in the program with their need to deliver essential

goods or services, the CPUC also directed the utilities to limit the amount of energy curtailment an essential participant could commit to the program to no more than 50 percent of the participant's average peak demand.

Other interruptible programs, such as the Base Interruptible Program and Voluntary Demand Response Program, may attract new customers and make more electricity use available for curtailment when needed.

Finally, the CPUC will oversee other related programs that may increase the amount of electricity available to prepare for tight supplies this summer. One of these, the Base Interruptible Program, is a version of the program, giving customers rate discounts for designating a portion of their energy use as interruptible and being subject to curtailments of up to 120 hours per year. New participants or those in the existing program who have fulfilled the annual maximum obligation under the program can participate in the Base Interruptible Program. Also, the Voluntary Demand Response Program allows customers to reduce demand voluntarily on any given day. Either the day before or the day of the needed cutback, the utilities will notify participants of requested energy reductions, and participants will receive a cash payment of 35 cents per kilowatt hour of reduction provided. The amount of program participation is currently unknown, making it difficult to estimate how much savings this program might provide. Finally, the CPUC is requiring SCE to reopen and expand its voluntary air conditioner cycling program for residential and commercial customers. As part of this program, the utility attaches radio-controlled devices to air conditioners, allowing it to lower the air conditioner's energy use during times of peak demand. PG&E and SDG&E do not currently have air conditioner cycling programs, but they are required by the CPUC to explore the most reasonable options for implementing such programs or other curtailment programs and report to the CPUC by May 1, 2001.

Giving program participants more flexible program limits should improve their overall compliance rates, resulting in increased assurance that the program can fulfill its purpose. Further, adding new programs or expanding existing ones will likely attract new customers to the programs and make more electricity use available for interruption when the need arises. Finally, instituting eligibility criteria for essential customers should help ensure that program participants understand the requirements of the program and are suited to meet them, leading to improved compliance rates. Although the changes appear reasonable, it remains uncertain whether these program revisions will adequately enhance the program's role to deliver energy savings in the summer of 2001 and act as a buffer against rolling blackouts.

THE CALIFORNIA PUBLIC UTILITIES COMMISSION'S ENERGY EFFICIENCY PROGRAMS MAY NOT ACHIEVE PLANNED PEAK ENERGY SAVINGS

Beyond the peak savings coming from the CPUC's interruptible program and the energy commission's Peak Load Reduction Program, AB 970 also charged the CPUC with the following:

- Creating a program to increase power from self-generating energy systems such as solar panels.
- Developing a new program to reduce energy consumption in residences and small commercial businesses.
- Expanding the existing energy efficiency programs that the State's investor-owned utilities administer.

However, the CPUC's plans for implementing AB 970 may not deliver the anticipated amount of peak energy savings, and some aspects of one plan duplicate others' efforts. In addition, the CPUC has yet to resolve several issues regarding its plans to expand existing energy efficiency programs. For example, the plans the utilities submitted to the CPUC for programs they administer lacked sufficient information to confirm that AB 970 goals would be met. Consequently, in all areas, the CPUC may fall short of its AB 970 energy efficiency goals.

The CPUC Is Adding New Energy Efficiency Programs and Expanding Existing Ones

As the CPUC was planning its 2001 energy efficiency program, the Legislature adopted AB 970, requiring the CPUC, within 180 days of its enactment, to develop new energy efficiency programs and expand existing ones, using funds earmarked for these purposes and collected as part of the monthly billing process from customers of the investor-owned utilities. Although the CPUC interpreted AB 970 as not setting a date when these new and expanded programs must be in place, on January 31 and March 27, 2001, the CPUC adopted plans of action. The CPUC's plans include a self-generation program to subsidize customers for installing a means to generate their own power, such as solar panels. Additionally, the plans outline a new program to automatically control heating, ventilation, and air conditioning, thereby reducing residential and commercial businesses' energy consumption. The self-generation program is intended to reduce peak demand by an increasing amount over four years. Specifically, in its first year, the self-generation program is projected to provide

savings of 90 MW. In the second year, this program's savings are anticipated to be an additional 90 MW, for a second year total of 180 MW. In the third and fourth years, the CPUC estimates that this program will save an additional 90 MW each year. Thus, the

AB 970 requires the CPUC to expand existing programs and develop new programs based on these requirements:

- Expand/accelerate residential and commercial weatherization programs.
- Expand/accelerate programs that inspect and improve heating, ventilation, and air-conditioning (HVAC) equipment in new and existing buildings.
- Expand/accelerate programs that improve energy efficiency in new buildings.
- Provide incentives to commercial buildings with the capacity to shut down or dim lighting and HVAC equipment during energy emergencies.
- Evaluate the installation of local infrastructure to link thermostats to real-time price signals.
- Provide incentives for controlling demand and enhancing self-generation systems.
- Provide incentives for the use of renewable self-generation resources.
- Reevaluate energy efficiency cost-effectiveness tests in light of increases in wholesale electricity costs.

CPUC estimates that by the fourth year, the self-generation program will reduce peak demand by 360 MW. Additionally, the demand control program is estimated to save 8 MW by 2002. The CPUC's estimate of the megawatts the self-generation and demand control programs will save are summarized in the Appendix. Finally, as directed by AB 970, the CPUC plans to expand existing energy efficiency programs by emphasizing ways to reduce peak energy demand.

Programs for Electricity Self-Generation and Demand Control Are Not Likely to Achieve Anticipated Energy Savings

In its largest new program, the CPUC dedicates \$125 million annually to its self-generation program to subsidize the purchase and installation of solar panels, fuel cells, and nondiesel internal combustion engines by electricity customers, to allow these customers to generate their own electricity rather than drawing energy from the transmission grid. However, because the CPUC's plan is unstructured, it leaves it up to customers to choose the technology they will employ and may result in the CPUC not achieving its estimated energy savings goals. In addition, the CPUC's demand control efforts,

which include a plan to adjust thermostats during times of peak electricity use, may fall short of its estimated megawatt savings goal because participants in this program can override the technology. Finally, although not intended to reduce the demand for electricity, the Web site the CPUC directed PG&E to develop duplicates existing sites and appears to be a poor use of ratepayer funds.

In its self-generation program, the CPUC's goal is to shift peak energy demand away from the power grid to new self-generation resources. However, the program the CPUC has developed allows customers their choice of the type of self-generating technology they wish to install rather than focusing on maximizing the reduction in peak demand. As a result, customers' technology choices will greatly affect the megawatt savings the CPUC will achieve. For example, if all customers decide to install nondiesel

The CPUC did not structure its program to ensure a mix of technologies are installed to reduce dependence on the energy grid while maximizing energy savings.

internal combustion engines as their means of generating power, the CPUC could expect to achieve about 100 MW of peak energy savings annually, the maximum amount offered by this technology. However, if all customers elect to install solar panels, the CPUC would achieve peak energy savings of only 22 MW annually, the maximum savings this technology offers. The CPUC did not structure its program to encourage the use of various methods of self-generation as a means of reducing dependence on the energy grid while at the same time maximizing the energy savings that the mix of technologies would yield. Therefore, although the adoption of any of these technologies will produce some energy savings, the CPUC cannot confidently predict what the program's energy savings will be. To put the possible effect of this policy decision into context, consider that if all of the program's customers opt to install solar panels, the 22 MW of energy savings they achieve will be only one-twentieth of the peak energy savings needed to avoid the rolling blackouts that occurred on March 19, 2001.

Additionally, the CPUC's new demand control programs may not achieve the peak energy savings it anticipates. By installing Internet-based technology to adjust heating, ventilation, and air-conditioning thermostats during peak energy periods, the CPUC's new residential and small commercial pilot programs are designed to reduce energy consumption by 8 MW beginning in 2002. However, like the participants in the energy commission's program to conserve energy in commercial buildings, the new residential and small commercial participants will have the ability to override the signal to adjust their thermostats, partially or wholly negating any energy savings.

Unfortunately, the override option leaves the CPUC with a wide range of possible megawatt savings during peak times of energy demand. Assuming that all residents and small commercial building operators comply with the signal when received, the CPUC could achieve the full 8 MW of estimated savings. However, some or all of these participants could reject the signal to their thermostat, reducing the savings to little or nothing.

Though Costing Much More, the Self-Generation and Demand Control Programs Will Yield Far Fewer Peak Energy Savings Than Larger Commercial and Industrial Programs

The CPUC's goal of attaining 368 MW of peak energy reduction by the end of 2004 will cost the ratepayers of the three investor-owned utilities \$551.5 million, compared to the energy

commission's Peak Load Reduction Program, with a goal of reducing peak energy by 200 MW each year over a four-year period at a total cost of \$50 million. As a result, the CPUC's demand control and self-generation programs will be nearly six times more costly per megawatt saved than the energy commission's programs.

CPUC's demand control and self-generation programs will be nearly six times more costly on a per megawatt basis than the energy commission's programs.

The CPUC explained that energy efficiency programs aimed at residential and small commercial customers are much more costly than the energy commission's large commercial and industrial energy efficiency programs because, whereas the number of residential and small commercial sites is large, they use smaller amounts of electricity, and the opportunity for energy savings is less. Even though AB 970 requires the CPUC to address these smaller energy customers, it does not preclude the CPUC from including larger industrial and commercial customers in its demand reduction programs. Therefore, we question whether the CPUC should continue to commit utility ratepayers' funds only to residential and small commercial programs when the funds collected from the utilities' larger ratepayers could achieve greater peak energy savings when applied to large commercial, industrial, and governmental sources, such as the community college system, which the CPUC's energy efficiency programs could target.

A New \$3 Million Web Site Development Program Duplicates Existing Efforts

As part of its demand control programs, the CPUC directed PG&E to develop a new Web site for its customers to obtain information about electricity. The site will, among other things, show customers how much energy they have consumed, provide information about how electricity is priced, and provide electronic links to the Web sites of retailers that offer energy-efficient appliances. The CPUC does not intend to measure any energy savings directly attributable to the Web site and has earmarked \$3 million annually for the following:

- Developing and maintaining the Web site.
- Assessing users' satisfaction with the Web site.
- Providing energy customers with incentives for viewing the Web site.

However, because the CPUC's plan for PG&E to develop this new Web site calls for it to duplicate information already residing on the respective Web sites of PG&E, private entities, and public

entities, we believe the \$3 million annual cost for the Web site is a poor use of ratepayer funds.

When we asked the CPUC staff why the CPUC had directed PG&E to develop what seemed to be a redundant Web site, they said PG&E would tailor the site to include only information relevant to PG&E customers and stated that PG&E’s existing Web site and those of other entities contain broad information that applies to many utilities and geographic areas. However, as Table 6 demonstrates, much of the Web site information is already available on PG&E’s existing Web site, as well as on the Web sites of the energy commission and the ISO.

TABLE 6

Extent of Duplication Between PG&E’s Proposed New Web Site and Existing Web Sites

Information Expected to Be on the New PG&E Customer Web Site	Other Web Sites That Already Maintain This Information
Up-to-date information about California’s electricity market structure	ISO
Information regarding how electricity is priced	PG&E
Rate tariff options for residential customers explained in simple terms	PG&E
Historical energy billing information for customers	PG&E
Energy usage and cost information for common appliances (refrigerators, ovens, etc.)	PG&E
Links to manufacturers or retailers of high-efficiency appliances tailored to the needs of the individual	PG&E
Information about low-cost efficiency options and how much energy and cost savings they could produce (geographically)	PG&E
Information about renewable self-generation options, costs, and benefits	Energy commission
Links to manufacturers or retailers of self-generation equipment	Energy commission

Unresolved Issues Exist Regarding the CPUC’s Plans to Expand Energy Efficiency Programs

Historically, the CPUC and the investor-owned utilities have worked together to implement energy efficiency programs that serve the utilities’ customers throughout the State; the investor-owned utilities act as administrators of these programs on the

CPUC's behalf. To administer the programs, the utilities use a designated portion of the funds they collect from their ratepayers, and they earn financial incentives for meeting various program milestones set by the CPUC.

It is unclear whether the CPUC will be successful in overseeing the expansion of AB 970 programs intended to increase energy conservation.

As required by AB 970, the CPUC directed the investor-owned utilities to expand their residential and commercial weatherization programs; heating, ventilation, and air-conditioner programs; and new construction programs. In a January 2001 decision, the CPUC approved the plans for the investor-owned utilities' 2001 energy efficiency programs. The CPUC took this action despite indications that the investor-owned utilities may not have met earlier program goals. Specifically, the CPUC had information indicating that the investor-owned utilities had not fully spent previous years' program funds. Moreover, as it reviewed the utilities' plans for meeting AB 970 goals, the CPUC determined that the plans lacked sufficient information to confirm that the goals would be met. As a result, it is unclear whether the CPUC will be successful in overseeing the expansion of AB 970 programs and ultimately in increasing energy conservation during the energy crunch.

In 1999 PG&E, SCE, and SDG&E jointly collected \$227 million for energy efficiency programs such as appliance rebates, energy seminars, and home energy ratings, but they spent only \$183 million on these programs. Similarly, in 2000, the utilities projected they would spend \$193 million by the end of the year, or \$65 million less than the \$258 million they collected. Assuming that expenditures are a measure of program effectiveness, the CPUC has an early indication that the investor-owned utilities are not performing adequately.

Moreover, the CPUC determined that the information the investor-owned utilities supplied related to the AB 970 programs they are administering was incomplete. According to the CPUC's January decision, it was unsuccessful in obtaining from the utilities additional clarifying program plans, budget modifications, and anticipated peak energy savings information. Nonetheless, the CPUC approved the utilities' 2001 energy efficiency programs in January of this year, even though it was still unclear as to how the investor-owned utilities would successfully increase energy conservation through the programs outlined in AB 970. In addition, because the CPUC gave the investor-owned utilities until June 2001 to report on how they would expand existing programs, it will be halfway through the 2001 program year before the CPUC will have an understanding of how or whether

the utilities are meeting the mandates of AB 970. As a result, it remains unclear whether the CPUC will be successful in its efforts to oversee the expansion of AB 970 programs and ultimately to increase energy conservation during the current energy shortage.

RECOMMENDATIONS

To provide the Legislature with information it could use to measure whether and to what extent legislative action is needed to help California meet its electricity supply and demand needs in the future, the energy commission should do the following:

- Consult with the ISO and develop an annual projection of summer supply compared to peak demand that acknowledges the full range of constraints within the State's electricity system, including transmission constraints.
- As part of its projection, provide the Legislature with a range of possible supply and demand outcomes that reflect the likelihood that the underlying assumptions will prove true.

To ensure that it achieves its peak demand reduction goal on an ongoing basis, the energy commission should consider modifying its Peak Load Reduction Program as follows:

- Eliminate the override function from the commercial building program guidelines and modify contract language so that building managers will more readily comply with directives to reduce lighting and air-conditioning levels as agreed.
- As a condition of program participation, require commercial building program participants to meet specified compliance levels for reducing lighting and energy used to power air-conditioning for a certain period of time, such as 24 months. If the compliance levels are not met, the participants should be penalized. After 24 months, the participants' compliance could become voluntary.
- Because state government facility operators will be carrying out energy reduction plans manually rather than through computerized systems, identify ways to minimize the potential for human error or misinterpretation of directives to reduce energy usage.

- Develop a plan to actively evaluate itself and program participants in all components of the program against set milestones, such as:
 - ◆ Securing a certain number of participants by milestone dates.
 - ◆ Verifying that equipment is ordered and delivered by scheduled due dates.
 - ◆ Ensuring that projects are installed, tested, and operational according to scheduled dates.

In an effort to maximize energy conservation over the next several years while at the same time making the best use of funds collected from the utilities' ratepayers, the CPUC should give priority to conservation measures for those types of customers that will produce the most energy savings. This may not necessarily prompt the CPUC to abandon more costly residential and small commercial programs in favor of larger commercial, industrial, or governmental projects, but it will permit the CPUC to take advantage of potentially greater energy savings at a lower cost to ratepayers.

Although energy conservation is essential to avoiding rolling blackouts in the summer of 2001 and beyond, the CPUC's demand control, self-generation, and energy efficiency programs may not achieve their anticipated peak energy savings for a number of reasons. Therefore, the CPUC should do the following to maximize the energy savings produced through these programs:

- Amend the new residential and small commercial pilot programs to remove the override option from the program and to require participants to reduce peak demand as and when directed.
- Remove the Web site from its portfolio of demand control programs.
- Increase its vigilance in its oversight of the investor-owned utilities' administration of energy efficiency programs. ■

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CHAPTER 2

Some Long-Term Programs Will Improve California's Balance of Energy Supply and Demand, but the State May Still Need to Help Prevent Wide Market Swings in Supply

CHAPTER SUMMARY

After the State deregulated its electricity industry, the State Energy Resources Conservation and Development Commission (energy commission) stopped basing its decisions on new power plant applications on projections of California's energy supply needs. In theory, a competitive market is supposed to adjust supply to meet demand, so that an undersupply of energy would drive up prices, creating an economic incentive for energy companies to build new power plants. However, given the reality that power plants take a long time to site and construct, this model may subject the State to boom-bust cycles—periods of excess supply followed by periods of undersupply—as the market adjusts to shortages and surpluses of electricity. To spare the residents and businesses of California from the disruptive swings of energy supply, it is reasonable for the State to augment its role in energy planning.

To encourage the production of electricity from nonpolluting, renewable resources, the Legislature directed the energy commission to develop the Renewable Energy Program (renewable program). This legislative mandate was part of Assembly Bill (AB) 1890, which deregulated California's electricity industry in 1996. The renewable program subsidizes power plants that use renewable resources, such as solar, wind, and solid waste technologies, to produce electricity. By assisting the production of energy through renewable, nonpolluting sources, the renewable program contributes to improving the State's air quality as it lessens the State's dependence on finite fuel sources used to generate electricity. Moreover, with participating power plants now having the capacity to power about 4.4 million average households, the renewable program is also benefiting California in the current power shortage. The energy commission's renewable program maximizes available funds by subsidizing owners of existing renewable-resource power plants only for electricity they produce and only when wholesale market prices do not exceed pre-set rates. In 2000 the

energy commission used unspent subsidy payments to make \$40 million in new pledges of subsidies to power producers when they bring on-line 471 megawatts (MW) of new power plant capacity from renewable resources that the energy commission estimates will occur by the end of March 2002.

In an effort aimed at alleviating the current energy shortage, the Legislature passed AB 970 in August 2000 to reduce peak energy consumption and establish new levels of energy efficiency statewide. However, the legislation's mandate to update the energy efficiency standards for buildings and appliances will not have an impact on the State's energy demand in summer 2001, although it will lessen the demand for electricity in the future. For example, the energy commission has approved new building standards to require buildings constructed after June 1, 2001, to be 12 percent more efficient. The equivalent energy savings for one year's worth of new construction using the revised building standards ranges from 162 MW to 275 MW.

THE POTENTIAL FOR WIDE SWINGS IN ELECTRICITY SUPPLY MAY REQUIRE THAT THE STATE AUGMENT ITS ROLE IN ENERGY PLANNING

Relying on the marketplace to determine when to build new power plants may not be in the State's best interests.

After the State deregulated its electricity industry, the energy commission no longer played a role in restraining the State's level of electricity supply. Instead, the State relied on the competitive market to encourage the construction of sufficient power plants to ensure an adequate supply of power. However, relying on the marketplace to determine when to increase supply may not be in the State's best interests. Because power plants take a significant amount of time to site and construct, the industry may not be able to respond quickly enough to market signals to ensure that the State is not exposed to a boom-bust cycle. To avoid these large fluctuations in electricity supply, it may be valuable for the State to augment its planning role, ensuring that California never reaches extreme levels of oversupply or undersupply.

As the State's primary energy policy and planning agency, the energy commission has traditionally had the role of ensuring that power plant construction did not outpace the State's growth in energy demand. This role made sense under regulation, where investor-owned utilities had an incentive to overbuild because they were guaranteed to recover their costs of building and operating plants, plus a set profit margin. The energy commission countered this incentive by incorporating its projection of the State's

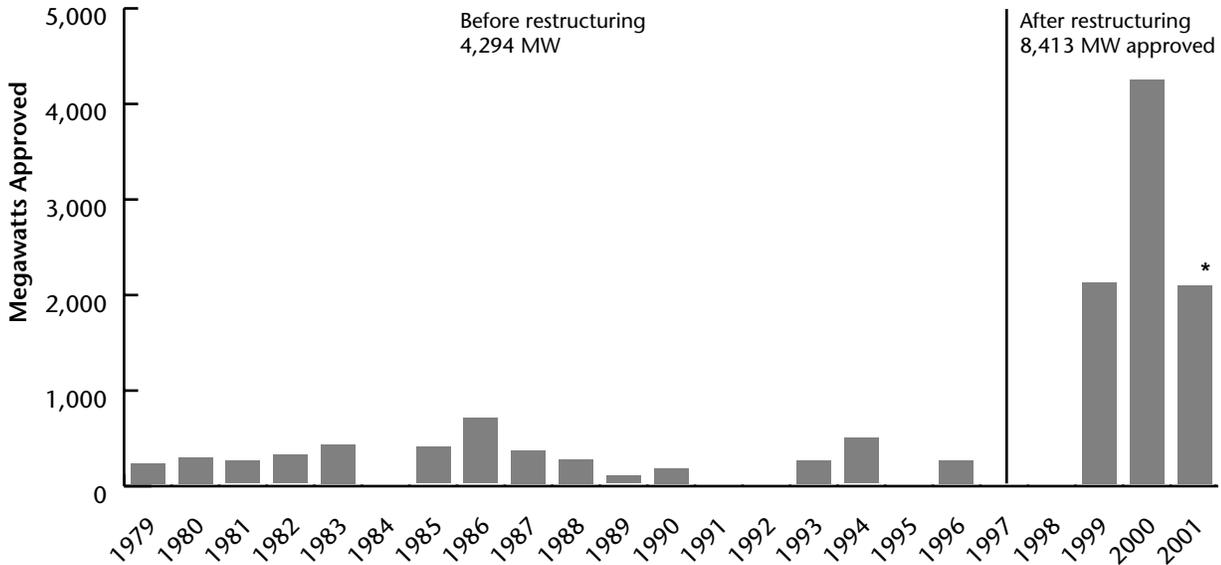
needs for new supplies of electricity into its decisions to approve or deny applications for new power plants. This process worked to provide a stable level of supply growth to match the State's projected demand growth. However, with deregulation on the horizon, the investor-owned utilities' incentives changed in the early 1990s, and their applications to build new power plants declined. Not being designed to encourage new power plant construction, the energy commission took no action to mitigate this reduction in applications. In fact, energy commission staff state that they were not concerned by the lack of new supply in the early 1990s because at that time California still had a large margin of excess supply over demand, and they expected California's new competitive market to encourage the construction of the necessary supply.

According to economic theory, in a competitive market, undersupply will drive up prices, creating an incentive for energy companies to build more plants, and oversupply will drive down prices, causing plant owners to stop building plants that might not turn a profit. In a normally competitive market, these forces will cause suppliers to adjust the supply of the product to a quantity that just prevents them from losing money, thereby driving the price to equilibrium. In such an environment, there would be no justification for the energy commission to be involved in electricity planning for supply. Indeed, legislation in 1999 reduced the energy commission's planning role by removing the requirement that the commission base power plant siting decisions on its estimate of the State's future needs for new power plants.

However, even if it functioned perfectly, the market for electricity would not quite fit the standard model of a competitive market, because electricity cannot easily be stored for later use, and building large power plants can take more than two years. Thus, even when undersupply causes prices to increase rapidly, suppliers cannot respond immediately, causing prices to remain high in the interim until new plants come on-line. In fact, the State currently appears to be in this situation because demand significantly exceeds supply. The wholesale price of electricity is high, and the energy commission has approved applications for more megawatts of supply since the restructuring legislation passed in 1996 than it did in the 20 years prior to restructuring, as shown in Figure 1. However, the long siting and construction times of large power plants prevented them from coming on-line to provide new supply by the summer of 2000, when California's supply shortage contributed to the sharp rise in wholesale prices.

FIGURE 1

Megawatts of New Supply Approved Through the Energy Commission's Standard Siting Process Since 1979



Source: Energy Commission—Siting Case History Report; Energy Facility Siting Status Report.

Note: Of the 4,294 MW approved before restructuring, 693 MW were never built. Of the 8,413 MW approved between restructuring and April 1, 2001, only 4,367 MW were under construction as of April 1.

* The amount of megawatts approved for 2001 is through April 1, 2001.

Conversely, if suppliers build an abundance of new power plants in response to the current high prices, it may cause the price of electricity to drop sharply until demand once again catches up with supply, raising prices and beginning the cycle anew. This type of boom-bust cycle could cause consumers to face alternating electricity surpluses and shortages, with the wholesale price of electricity fluctuating to match. To avoid these large fluctuations, it may be valuable for the State to have a planning role through which it attempts to prevent extreme levels of oversupply or undersupply while allowing the competitive market to operate between these extremes.

THE ENERGY COMMISSION'S RENEWABLE ENERGY PROGRAM BENEFITS THE STATE AND MAXIMIZES THE USE OF ITS FUNDS

As of March 2001 the renewable energy program had 275 plants with a capacity of 4,394 MW—enough to power nearly 4.4 million average households.

The 1996 legislation that deregulated energy also required the energy commission to preserve the State's commitment to developing diverse, environmentally sensitive electricity resources as California made the transition to a competitive electricity market. In response, the energy commission developed the renewable program, which uses funds collected from customers of the investor-owned utilities to subsidize power plants that rely on renewable resources like solar, wind, and solid waste technologies within California. These technologies significantly reduce the State's reliance on power plants fueled by finite natural resources, such as coal and natural gas that pose air quality concerns, because they use sun, wind, and solid waste to create electricity. As of March 2001 the renewable program includes 275 existing and new power plants with a capacity of 4,394 MW—enough to power approximately 4.4 million average households.

The energy commission structured the renewable program to maximize the use of its funds, subsidizing only the electricity that renewable power plants deliver to the State's power grid and subsidizing existing renewable power plants only when wholesale market prices are too low to make renewable power generation feasible. The renewable program has not had to make any subsidy payments to owners of existing power plants since August 2000. Moreover, the renewable program's flexibility has allowed the energy commission to shift these unused program funds to maximize other goals, such as encouraging the future operation of an additional 471 MW of new, renewable-resource power plant capacity, almost doubling the 552 MW of capacity the energy commission sought originally and increasing the future electricity supply within the State. Finally, by keeping existing renewable-resource facilities on-line and securing new ones, the energy commission is helping the State survive the current energy shortage.

The Renewable Program Was Mandated by AB 1890

With the passage of AB 1890 in 1996, the energy commission began developing the renewable program. The Legislature mandated that the State, with funds collected from customers of the investor-owned utilities, support the operation and development of existing and new renewable-resource technologies in California. Through subsidy payments to eligible power plant owners for

producing electricity, the renewable program supports existing and new power plants that employ renewable-resource technologies such as solar, wind, geothermal, and solid waste. Power plants are eligible for the renewable program if they meet certain criteria, including their location, date of operation, and their adherence to sales limitations and contracting restrictions.

The Renewable Program's Design Maximizes Its Funds

The renewable program's design, by maximizing the benefits of the program's funds, has contributed to the successful development of additional renewable power plants and has kept existing renewable power plants operational in the State. The following three design elements allows the energy commission to maximize the renewable program's funds by:

- Subsidizing existing and new power plant owners only for the electricity they produce.
- Limiting its payments to existing power plants to the lesser of three possible pre-set rate calculations that consider wholesale market prices, available renewable program funds, and production incentive caps.
- By using its flexibility to shift underutilized funds from one program area to another.

At the core of the renewable program is a subsidy-for-production mechanism: By subsidizing electricity production, rather than facility repair or construction, the energy commission subsidizes only the electricity that owners of existing and new renewable power plants actually deliver to the grid. Historically, the investor-owned utilities paid participants simply to be available to generate power when called upon and then also paid them for the actual energy they produced. These methods were successful in stimulating the building of renewable power plants but were not effective in keeping ratepayer costs down. Perhaps in response to this historical inefficiency, the energy commission designed the renewable program to subsidize owners of new and existing renewable-resource power plants only for producing and delivering electricity to the State's power grid.

By subsidizing owners of renewable resource power plants only for the electricity they deliver to the State's power grid, the energy commission helps maximize the program's funds.

Also, the energy commission makes subsidy payments to each owner of an existing renewable power plant based on the lowest of a three-rate calculation that considers wholesale market prices, available program funds, and production incentive caps. When

wholesale market prices are below a specified target price, the energy commission performs the three-rate calculation and pays the power plant owner the lesser amount. When wholesale market prices are above the target price, the energy commission does not make a subsidy payment to the power plant owner. For example, assume in the year 2000 the energy commission set 3.5 cents per kilowatt hour as the target price for existing wind power plants. Based on the three-rate calculation, if the wholesale market price of electricity then dipped to 2.5 cents per kilowatt hour, the energy commission would pay each wind power plant owner a subsidy in an effort to keep these power plants operating. However, if the wholesale market price rose to 5 cents per kilowatt hour, the energy commission would not subsidize the owners' electricity production. This latter scenario played out during the months that high wholesale market prices prevailed in late 2000 and early 2001; the energy commission did not make any subsidy payments to owners of existing eligible power plants from August 2000 through April 2001.

Because it has flexibility in how it uses program funds, the energy commission was able to nearly double the 552 MW of supply it originally sought to add.

Another effective element of the program's design is the energy commission's ability to shift funds from one area of the program to another as surplus funds accumulate. The energy commission significantly reduced subsidy payments to owners of existing renewable power plants during the later months of 2000, ending the calendar year with a surplus of \$41.9 million that had been budgeted for subsidies. To encourage the future operation of new renewable power plants, the energy commission shifted \$40 million of this surplus and will use it to pay future subsidies to power plant developers who, through a competitive auction, have agreed to place in operation 471 MW of new renewable capacity within the State. The energy commission will pay these new plant operators only for electricity produced and delivered to the State's power grid; the developers of the renewable power plants will bear the up-front construction or repair costs. By having the flexibility to utilize funds where they can provide the greatest benefit, the energy commission was able to nearly double the 552 MW of energy supply it originally sought to add.

The Renewable Program Is Helping the State Weather the Current Energy Crunch

The renewable program is helping to alleviate the State's current electricity supply shortage. For example, through its subsidy payments to owners of renewable power plants that were in operation before the passage of AB 1890, the energy commission

has helped these power plants compete over time with power producers that use less costly finite fuels. By subsidizing their production when necessary, the energy commission has helped keep approximately 4,276 MW of the State's existing supply of renewable-resource electricity available. In addition, through two competitive auctions, the energy commission's renewable program will have added nearly 1,000 MW of new renewable power plant energy supply to California by the end of 2003.

Past efforts of the renewable program are now expanding the State's electricity supply. In June 1998 the energy commission held a competitive auction for prospective developers of new, renewable-resource power plants. Prospective developers submitted bids with the cents-per-kilowatt-hour incentive desired over a five-year period, and the energy commission awarded future subsidy payments to each successive low-cost bidder until the available funds were allocated. As a result of the auction, the energy commission committed to subsidize about 552 MW of renewable supply once these new power plants begin producing and delivering electricity. However, three projects totaling approximately 9 MW were canceled.¹⁰ Thus, power plants delivering only 543 MW of the 552 MW awarded are or will be operational.

As shown in Table 7, 111 MW of the renewable power generation resulting from that first competitive auction are on-line and delivering electricity to the State's power grid. An additional 90 MW are expected to be on-line by July 2001, and all of the remaining plants are expected to be on-line by December 2003. Nearly all of the unfinished projects have filed the appropriate construction applications, environmental permits, and land use permits.

Although the 552 MW were expected to be operational by January 2002, because of financing difficulties and some public opposition several projects have been delayed.

Although the 552 MW awarded were initially expected to be on-line no later than January 1, 2002, several of the projects have been delayed. According to a manager of the renewable program, the current power crisis may have contributed to these delays because some developers cannot secure from the investor-owned utilities the purchase agreements needed to get the financing to build new plants. Also, some projects have faced public opposition over the environmental effects constructing these new plants might cause. It is possible that these types of difficulties may contribute to similar project delays for the 471 MW that the

¹⁰ One power plant developer encountered difficulties in obtaining a secure fuel source, another faced litigation, and the last was too small for the plant to be economical.

energy commission awarded during its most recent auction. The energy commission's on-line estimates for both auctions are summarized in the Appendix.

TABLE 7

On-Line Dates and Megawatts of Supply of New Renewable Power Plants Resulting From the Energy Commission's June 1998 Auction

	Added MW	Cumulative Total MW
Original award: 552 MW		
Power plants currently on-line	111	111
Power plants expected on-line by July 2001	90	201
Power plants expected on-line by December 2001	241	442
Power plants expected on-line by December 2003	101	543
Canceled power plants	9	552

Source: Energy Commission, Energy Technology Development Division—Renewable Energy Program.

THE ENERGY COMMISSION HAS UPDATED ITS ENERGY EFFICIENCY STANDARDS FOR BUILDINGS AND APPLIANCES

Assembly Bill 970 charged the energy commission with adopting and implementing updated building and appliance energy efficiency standards. As a result, in January 2001, the energy commission approved new building standards, which take effect June 1, 2001. The energy commission intends to finalize its new appliance standards in May 2001, to take effect in January 2002 and thereafter. Updates to the building standards include stricter window energy efficiencies, more efficient heating and air-conditioning systems, and new, nonresidential exterior building lighting standards. Electricity savings from these stricter efficiency standards for buildings and appliances will manifest primarily in 2002 and beyond. The energy commission estimates that one year's worth of new residential and nonresidential construction under the updated building standards will create energy savings in the range of about 162 MW to 275 MW statewide. Although

new construction does put an added strain on the State's power grid, these more stringent standards will improve energy efficiency and make better use of existing energy resources. Similarly, energy commission data show that one year's worth of appliance usage that meet the new standards will create energy savings of approximately 40 MW statewide. Over time, the electricity needed to operate buildings and appliances will decline as new construction, building renovations, and new appliances meet the more stringent energy efficiency standards.

Updated Building Standards Will Produce Energy Savings in the Future

Although they will not create significant energy savings in the summer of 2001, the stricter energy efficiency standards for buildings will provide energy savings in 2002 and into the future. When these standards go into effect in June 2001, energy commission staff estimate that new residential and nonresidential construction will be approximately 12 percent more energy efficient than similar buildings constructed using the earlier standards. Even though all new construction increases the strain on the State's power grid, it is unrealistic to think that no new residential or nonresidential buildings will be constructed in the State. Over time, these more stringent standards will improve energy efficiency in new and remodeled buildings, and the standards will help make better use of existing resources and slow the demand for new power plants.

Since 1978 the energy commission has typically been issuing statewide energy efficiency standards for residential and nonresidential buildings every three years (they were last updated in 1998). These standards set statewide minimum energy efficiency levels for new and remodeled residential and nonresidential buildings. For example, the building standards include wall, ceiling, and flooring insulation and window standards that will help minimize both the escape of heat in the winter and the escape of cool air in the summer. Local building officials are generally responsible for enforcing the building standards.

Through AB 970 the Legislature required the energy commission to update its building energy efficiency standards by January 4, 2001, or as soon thereafter as possible. The energy commission met this legislative mandate when it adopted updated

Although too late for the summer of 2001, stricter building energy efficiency standards will provide energy savings in 2002 and into the future.

standards on January 3, 2001. The standards require that all buildings that are constructed or remodeled after June 1, 2001, meet the new energy efficiency standards, unless specifically exempted.¹¹

Residential buildings conforming to the revised standards are expected to save from 105 MW to 205 MW of energy per year compared to buildings constructed under the old standards.

The energy commission's revisions to the 1998 standards addressed a number of areas that will significantly reduce energy demand during peak periods. For example, energy commission staff estimate that large energy savings will come in the form of stricter standards for windows, heating, and air-conditioning. In addition, they estimate that other potentially large energy savings will come from new standards for sealing air distribution ducts and lighting the exteriors of nonresidential buildings, and from the optional installation of heat-reflective cool roof technologies.

The energy commission estimates that one year's worth of new residential construction under the updated standards will save from 105 MW to 205 MW of energy when compared to one year's worth of new residential construction under the old standards. For new and remodeled nonresidential buildings, the energy commission estimates a range of roughly 57 MW to 70 MW of peak energy savings per construction year under the new standards. Although the updated standards apply to remodeled residential buildings, the energy commission has not estimated the associated megawatt savings.

New Appliance Standards Will Also Produce Future Energy Savings

Since 1978, when the first such standards were created, the energy commission has updated its appliance energy efficiency standards on an as-needed basis, with the last update occurring in 1991. However, AB 970 required the energy commission to update its appliance standards by January 4, 2001, or as soon thereafter as possible. Although the updated appliance energy efficiency standards will not create significant energy savings in the summers of 2001 or 2002, they will begin to create energy savings in 2003.

In May 2001 the energy commission plans to adopt updated appliance standards that will generally take effect in January 2002. These new standards include new and revised efficiency standards for 20 types of appliances. Overall, the commission estimates that the energy savings derived from one year's operation of these new-

¹¹ The energy commission may grant an exemption if it finds that before the adoption of a provision, substantial funds have been expended for planning, designing, architecture, or engineering of a building.

generation appliances will be about 40 MW of peak energy. Table 8 lists some examples of appliances affected by the proposed new standards and their estimated statewide energy savings.

TABLE 8
Examples of Appliances Affected by the 2001 Appliance Standards and Their Estimated Energy Savings

Appliance Type	Estimated Megawatt Savings per Appliance Type Statewide	Percent of Estimated Increase in Energy Efficiency
Commercial clothes washer	0.8 MW	62%
Commercial refrigerator—solid door	1.9	35
Commercial refrigerator—transparent door	4.1	35
Emergency exit sign	5.8	21
Torchiere lamp	5.6	60
Traffic signal	11.6	92

Source: Estimated increase in energy efficiency provided by the Energy Commission, Energy Efficiency Division, Residential Buildings and Appliances Office.

After they are adopted, these new standards should help make most of the State’s regulations consistent with federal law. However, many appliances for which California has developed proposed revised standards are more stringent than corresponding federal standards. This discrepancy creates a problem because in these instances the State’s standards would be preempted by federal law. For example, the energy commission is considering standards for air conditioners and water heaters that will save approximately 19 MW of peak energy in addition to the 40 MW projected for other appliance types affected by the new appliance standards, but parts of these standards for air conditioners and water heaters are more stringent than their federal counterparts. Therefore, even though the energy commission may approve these stricter State standards, manufacturers would not be mandated to comply with them until the State gets a waiver from the federal government exempting California from the federal

standards. According to the energy commission, if started now, this process of receiving a federal exemption will likely take until 2004 or 2006, and until then the energy commission could not require manufacturers to meet California's stricter appliance standards.

Even though the federal government generally does not allow the energy commission to mandate stricter standards without first obtaining a waiver, the State could still achieve the benefits these stricter standards offer. For example, through the use of incentive programs, such as appliance rebate programs run by the investor-owned utilities, the State could encourage demand for these more efficient appliances. Then, as older appliances of the same type are replaced with more efficient ones, the State would benefit from the immediate energy savings.

RECOMMENDATIONS

Power plants take a significant amount of time to site and construct, and energy suppliers may not be able to respond to market signals quickly enough to ensure that the State is not repeatedly exposed to periods of oversupply and undersupply. Therefore, the Legislature and the energy commission should consider augmenting the energy commission's role in electricity planning to help the State avoid large swings in the supply of electricity relative to demand. For example, the Legislature should consider expanding the energy commission's existing planning role to include integrating supply and demand projections and requiring it to use them as a basis for making decisions regarding whether to site new power plants.

While the energy commission pursues a waiver from the federal government that would allow it to require manufacturers to offer appliances that are more energy efficient in certain cases than the federal government now requires, it should coordinate with the CPUC and the investor-owned utilities to incorporate these appliances into new and existing incentive programs, such as appliance rebate programs, to create demand for these appliances so that the State could benefit from the more immediate energy savings until such time as the waiver is granted. ■

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CHAPTER 3

Efficient Planning and Permitting of New Power Plants and Transmission Lines Are Needed to Address the Energy Crisis in the Long Term

CHAPTER SUMMARY

California's power supply remains uncertain in the aftermath of a deregulation process that was supposed to create more competition, lower prices for consumers, and provide reliable electric services. Efficient planning and siting of new power plants and transmission lines is vital to the State's ability to deliver reliable power over the long term. However, the process used by the State Energy Resources Conservation and Development Commission (energy commission) to site new power plants generally takes longer than the 12-month goal set by its governing statutes. Although these delays in siting new plants did not cause California's electricity shortage, they have contributed to the lack of some new power plants coming on-line before summer 2001. The energy commission has made changes to improve its siting process, but it is not measuring the effectiveness of those changes, so it does not know whether they are making a difference. The energy commission has also started using several new, shorter siting processes, but so far they have had little effect on the State's electricity supply.

In addition to new power plants, an adequate transmission grid is important in the energy crisis. In times of high energy demand, the transmission lines are used to send large amounts of power from one part of the State to another to avoid regional power outages, thus having sufficient transmission lines is crucial. For example, because the primary transmission connection between Northern and Southern California could not transmit the amount of electricity Northern California needed, rolling blackouts occurred in January 2001. However, the State's processes for identifying and permitting transmission projects are flawed. In the first place, although the California Independent System Operator (ISO) coordinates transmission grid planning with the State's investor-owned utilities, the utilities still have the responsibility for making the demand growth projections that the ISO uses for its transmission expansion plans. These projections may be based on

conflicting assumptions that make them difficult to combine into a statewide plan. In addition, the major utility companies may have a conflict of interest between deciding to build new transmission lines and spending the money on more lucrative ventures, such as building new unregulated power plants. Also, the California Public Utilities Commission (CPUC) does not have an expedited siting process for new transmission lines that may be needed to alleviate transmission grid constraints both in the short term and in the future. Finally, because the CPUC's standard transmission siting process often takes longer than state law recommends, the State's recovery from its present energy crisis may be slowed.

THE ENERGY COMMISSION'S STANDARD SITING PROCESS HAS LENGTHENED OVER TIME BUT DID NOT CAUSE CALIFORNIA'S SUPPLY SHORTAGE

The energy commission is responsible for siting large thermal power plants in California. Although the Warren-Alquist State Energy Resources Conservation and Development Act (act) states that new power plants should be sited within 12 months, the energy commission usually does not meet this goal. In fact, the energy commission's siting process has generally grown longer over its more than 25-year history, as the characteristics of the proposed plants and the types of applicants have changed. Delays in siting new plants delay the dates those plants can come on-line and supply California with much-needed new electricity to meet demand. According to the energy commission, the primary causes of recent siting delays have been project changes made by the applicant, public opposition to power plants, and the inability of other agencies to quickly complete their reviews.

The Energy Commission's Siting Process Usually Takes Longer Than Its 12-Month Statutory Goal

Although the Legislature created the energy commission in part to reduce the time involved in approving new power plants, it is not meeting its statutory goal of ruling on most power plant applications within 12 months. Of the twelve applications it approved through its standard siting process between April 14, 1999, and April 1, 2001, only four approvals took 12 months or less. The siting process has lengthened as the types of power plant applications have changed. Over the past decade, the energy commission has received more applications from private generating companies less acquainted with the siting process, more applications for larger-capacity power plants, and

Only 4 of 12 power plant siting applications under consideration by the energy commission were approved in 12 months or less.

more applications for fossil-fueled plants than in previous years. External factors such as applicant changes to plant proposals, public opposition to applications, and the inability of other agencies to complete their reviews quickly are also delaying the siting process. Delays in siting have postponed the opening of power plants that could help California meet the current energy shortage and avoid further blackouts.

Partly to establish a faster, more coordinated power plant siting process, the act created the energy commission in 1974.¹² The act initially set up a two-part siting process that took a total of 36 months. The first part was an 18-month Notice of Intention process, during which the energy commission would decide whether an applicant's new power plant site was appropriate, considering environmental, public health and safety, economic, social, and technological factors. The second part was an 18-month Application for Certification process, during which the energy commission ensured that the proposed plant itself was designed, sited, and operated to protect the environment and assure public health and safety. In 1978 the Legislature revised the act and replaced the two-part process with a single, 12-month Application for Certification process for certain types of plants, and it later expanded this revised process to cover most types of power plants.¹³ The revised certification process, in which the energy commission examines both the proposed site and the proposed plant simultaneously, is essentially the same process now used to site new power plants.

The law requires the energy commission to issue a decision on completed applications to construct most power plants within 12 months unless the applicant agrees to a longer timeline.

Although it requires the energy commission to issue a decision on a new plant application for construction within 12 months of the date the application is complete, the act allows the energy commission and the applicant to mutually agree to a longer process when necessary. According to the deputy director of the energy commission's siting division, if there is a delay in a case, the need for an extension is usually identified by energy commission staff or another party, discussed with the applicant and the commissioners, and then decided by a written order from the commissioners based on input from the applicant and all the parties. However, these orders generally do not document the applicant's agreement with the need for an extension. Such delays have been the rule rather than the exception. For example,

¹² Before this, multiple agencies worked to site power plants; data on the overall length of these processes is not available.

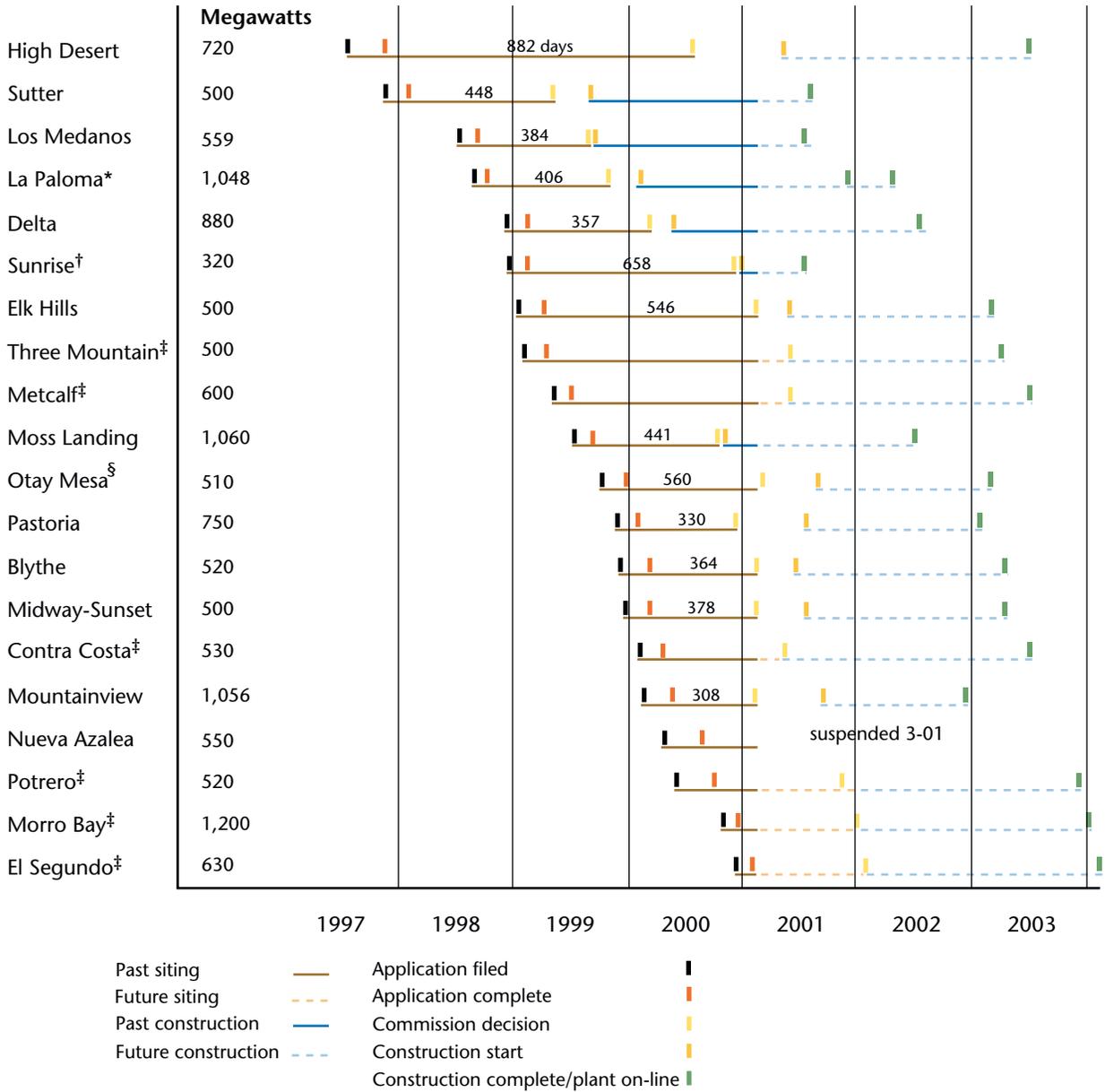
¹³ Only nuclear and coal-fired plants must still go through the Notice of Intention process. The last plant application filed using this process occurred in 1989.

between January 1997 and December 2000, the energy commission received twenty applications requiring the use of its 12-month siting process. Using the 12-month criterion, fifteen of the twenty proposed plants should have been approved or rejected on or before April 1, 2001. However, by that date, the energy commission had made decisions on only twelve of the fifteen, and only four of the twelve approved applications for construction were completed in a year or less. For the remaining eight approved applications, the length of time between completed application and construction approval averaged more than 17 months. Figure 2 shows the relevant timelines for each of the power plant applications the energy commission received for its standard siting process between January 1, 1997, and December 31, 2000. In the Appendix we summarize the energy commission's on-line dates for power plants that are under construction or currently part of its 12-month siting process.

The act also requires that the energy commission determine whether an application is complete within 45 days of the initial filing date. During that time, the energy commission may decide an application is incomplete and request whatever data it believes is missing. Once the applicant submits the additional data, the energy commission must decide within 30 days whether this additional data completes the application. This process can be repeated as many times as is necessary for the energy commission to judge the application complete, at which point the 12-month siting timeline begins. Thus, the act essentially allows the process to take as long as necessary for the applicant to provide all of the information that the energy commission requires. For the twelve applications approved by April 1, 2001, applicants and the energy commission took an average of 76 days to ensure that the applications were complete, including the time it took applicants to submit new information. Although this review period is not considered part of the overall time to site a power plant, it can delay the power plant's construction and on-line dates. Considering that the 76-day average includes occasions when the initial applications were incomplete and additional information was requested and evaluated, we believe it is reasonable.

FIGURE 2

Siting and Construction Timelines for All Plants That Applied to the Energy Commission’s 12-Month Siting Process 1997 Through 2000



Source: Energy Commission—power plant siting case data.

Note: Future dates are projected by the energy commission as of March 31, 2001, and assumes that all plants are approved and constructed.

* La Paloma consists of four turbines of approximately 250 MW each. The first turbine is projected to come on-line in December 2001, with one turbine following each month so that all are on-line by March 2002.

† The applicant filed an amendment in September 2000 changing the project from a cogeneration facility to a ‘peaker’ plant with a much shorter construction time. According to the deputy director of the energy commission’s siting division, had the applicant not amended the project, the plant would have taken two years to construct.

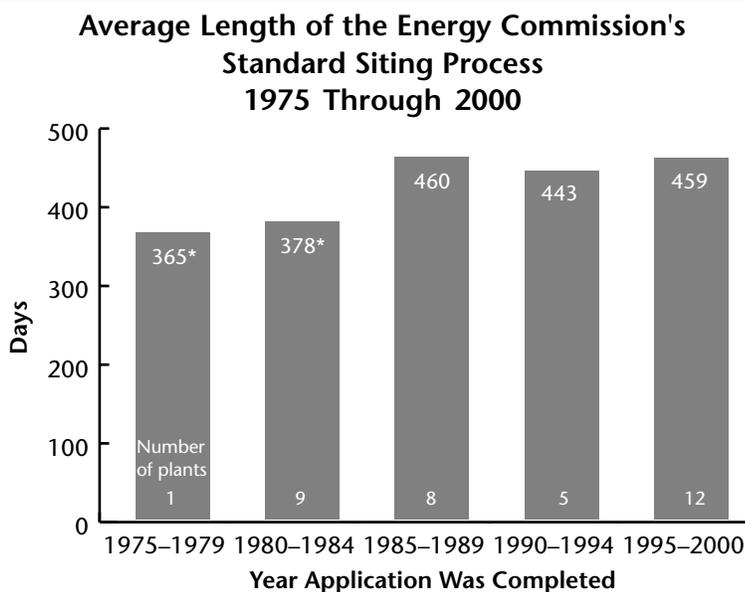
‡ These plants do not have projected construction start dates, as they have not yet been approved. Their projected construction complete dates are tentative.

§ Because this application was approved after April 1, 2001, we did not include it in our analysis of the 12 project applications that had received an energy commission decision as of that date.

The Siting Process Has Lengthened as the Types of Power Plant Applications Have Changed

The process of making decisions on the siting and building of power plants has historically been a long one, and it has lengthened over time. As Figure 3 indicates, the average length of the energy commission’s siting process for those plants that did not file a Notice of Intention increased steadily from the late 1970s to the late 1980s, after which it has remained fairly constant. The siting process lengthened as the types of applications before the energy commission changed and as the source of the applications switched from investor-owned and municipal utilities to independent generators.

FIGURE 3



Source: Energy Commission—Siting Case History Report and siting case data.

* Four additional applications completed in the late 1970s and two completed in the early 1980s filed a Notice of Intention prior to filing their Application for Certification. These plants are not reflected in this figure.

In the late 1970s and early 1980s, the investor-owned utilities and municipal utility districts, which were familiar with the energy commission’s process, proposed primarily geothermal power plants capable of generating an average of about 120 megawatts (MW) each. From the late 1980s to the present, private generating companies that have less experience with the energy commission’s siting process have generally proposed natural gas power plants averaging more than 200 MW of

generating capacity. As shown in Table 9, these factors may have contributed to the lengthening of the energy commission’s siting process. Our analysis of these factors indicates the following average effects on the siting process:

- Large plants have taken longer to site than smaller plants.
- Fossil-fueled plants have taken longer to site than solar and geothermal plants.
- Plants proposed by private generating companies have taken longer to site than plants proposed by investor-owned utilities and municipal utility districts.

TABLE 9

**Average Length of the Energy Commission’s Standard Siting Process
By Type of Plant For Years 1975 Through 2000
(in Days)**

	All Plants Between 50 MW and 200 MW	All Plants Over 200 MW	All Solar and Geothermal Plants	All Fossil- Fueled Plants	All Plants Proposed by Investor-Owned and Municipal Utilities	All Plants Proposed by Other Entities
Application completeness to approval	397	467	360	466	387	452

Other External Factors Delay the Energy Commission’s Siting Process

In addition to changes in the types of applications, other outside factors have delayed the energy commission’s siting process. Among these factors are public opposition to projects, delays by other regulatory agencies, and applicants’ changes to projects once applications are complete. These factors are at least part of the reason that one stage in the siting process has been taking about 100 days longer than the time goal set by the energy commission. Applicant changes and federal delays slowed the approval for one plant that, had it met the 12-month goal, could have been on-line and helping with the State’s energy shortage by April 2001, rather than its current projected date of July 2001. The energy commission has attempted to mitigate delays caused by other agencies by signing agreements with them stating they should complete their reviews within a specified period of time, and the Legislature has since made this a legal requirement.

To meet its 12-month siting goal, the energy commission has created a detailed internal timeline that specifies when each major step in the siting process should be completed. Table 10 shows these stages, the energy commission’s goal for completing each stage, and the average time each stage in the siting process actually took for the 12 applications approved prior to April 1, 2001. This comparison reveals that most of the delay occurs between the preliminary and final staff assessments of the application, which takes about 100 days longer than the energy commission’s goal. In contrast, the energy commission has accurately estimated the length of time needed for all of the other phases of its process.

TABLE 10

Average Length of Each Stage in the Energy Commission’s Standard Siting Process for the 12 Applications Approved Prior to April 1, 2001 (in Days)

Stage in Siting Process	Goal for Completing the Stage	Average Actual Days Required*	Days Average Exceeded Goal*
Complete application to preliminary staff assessment	165	165	0
Preliminary staff assessment to final staff assessment	35 to 55	144	89 to 109
Final staff assessment to presiding member’s proposed decision	85 to 105	93	(12) to 8
Presiding member’s proposed decision to final decision	60	43	(17)
Totals	365	459	94

* Numbers do not add up to the total because 3 of the 12 plants did not receive preliminary staff assessments, and so are not included in the first two stages.

To explain the causes of the delays between the preliminary and final staff assessment in five recent siting cases, all of which exceeded the 12-month goal for approval, siting project managers for the energy commission referred to three primary causes: changes to the project made by the applicant, public opposition to the project, and delays by other regulatory agencies involved in the energy commission’s siting process. Our review of the documentation from the individual siting applications supported these statements. For example, in one application, the applicant wanted to build a water pipeline over land owned by the U.S. Bureau of Land Management (BLM), so the U.S. Fish and Wildlife Service delayed issuing its biological opinion while it consulted with the BLM. An advocacy group also delayed the energy commission’s approval of this plant

by filing detailed opposition to several of the plant's environmental effects, demanding pollution controls not typically installed in plants of this nature. In total, this plant took 546 days from the completion of the application to the final decision, just over 6 months beyond the 12-month goal.

The same advocacy group raised similar issues that delayed another plant proposed for the same area of the State. This plant was further delayed when the applicant made multiple changes to the proposal. For example, in addition to generating electricity, the original proposal would have produced steam for use by other industries in the area. However, after the energy commission had already released its proposed decision on the project, the applicant changed the original proposal to exclude this steam generation feature, requiring energy commission staff to revise their analysis and adding 6 months to the siting process. In total, this plant's approval took 658 days. According to project managers, these types of delays are common to the energy commission's other recent siting applications.

In an effort to minimize delays caused by other review agencies, the energy commission has attempted to ensure that the other agencies conduct their permitting activities as quickly as possible. Whereas the energy commission has the primary responsibility for siting new thermal power plants, other entities—such as the California Department of Fish and Game, the Regional Water Quality Control Boards, and various local agencies—often have jurisdiction or a special interest in specific aspects of these projects. In most cases, the energy commission will not make a final decision on a project until these other agencies have completed their reviews and submitted their findings as testimony in the energy commission's hearings on the project.

According to the assistant division chief of the energy commission's siting division, in the late 1980s the energy commission began negotiating memoranda of understanding with the other involved agencies to prevent their processes from dragging out the siting process. These agreements stated that these other agencies were to complete their reviews and submit their findings to the energy commission within 180 days of the date the commission received a completed application. Upon the energy commission's recommendation, the Legislature included this 180-day comment period in legislation passed in August 2000. This restriction should improve the energy commission's chances of having the information needed from other agencies when it holds formal hearings on the siting of a

power plant. In turn, the energy commission should be better able to deliver a final decision on the plant within its 12-month timeline. Even if the energy commission does not make its decision within 12 months, this coordination among agencies at least helps ensure that projects will not require further approval after the energy commission issues its decision.

Siting Delays Did Not Cause California’s Supply Shortage but Contributed to the State’s Precarious Situation

The energy commission received few power plant applications in the early 1990s, apparently due to a combination of excess supply, uncertainty about the effect that deregulation might have, and federal regulatory decisions.

Although the energy commission generally takes longer than 12 months to render decisions on the siting of power plants, this does not appear to have been a cause of California’s electricity supply shortage. The energy commission received and approved few power plant applications in the early 1990s, apparently due to a combination of excess supply at that time and uncertainty on the part of the investor-owned utilities about the effects of deregulation, as well as a series of regulatory decisions limiting the construction of qualifying facilities—plants that produce energy through resources such as wind, solar, and natural gas. Although they are not the cause of California’s supply shortage, siting delays have prevented badly needed megawatts from coming on-line by pushing back the dates that new plants can begin construction. With the prospect of rolling blackouts looming this summer, California would be better positioned had the plants met the 12-month siting goal and were now delivering power to the State. However, some plant owners have also made business decisions to delay the start of construction on their plants, further pushing back some plants’ on-line dates.

One factor contributing to the slowdown in the growth of the State’s electricity supply was that the investor-owned utilities built fewer new power plants in the early 1990s than they had in previous years. In fact, as indicated in Figure 4 on page 68, from 1991 to 1995 the investor-owned utilities submitted only one application to the energy commission to site a new power plant through its standard siting process, whereas they submitted six such applications between 1980 and 1990. During the early 1990s, the CPUC was studying whether to deregulate the electricity market, and this appears to have been a disincentive to build more power plants. For example, if the investor-owned utilities

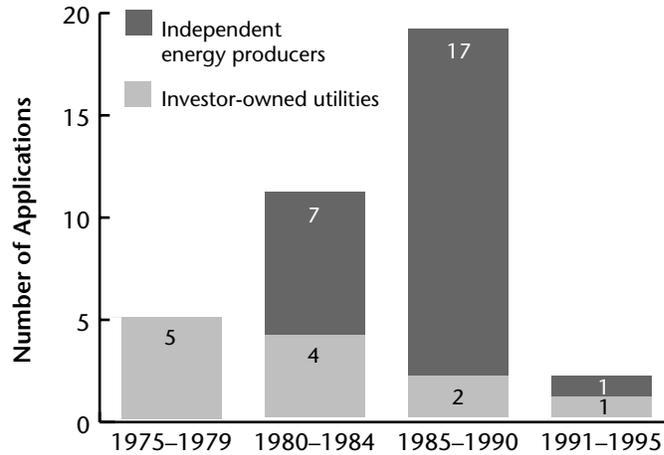
believed that after deregulation they would be required to sell their plants to other entities to facilitate competition, they might be unsure as to whether they would be able to recoup the cost of building the plants at that time. Even if they believed they would be allowed to keep their power plants, they might be unsure as to whether the wholesale price of electricity in the new deregulated market would be high enough to allow them to recoup their investment in new power plants. Therefore, uncertainty about what deregulation would require appears to have given the investor-owned utilities incentives to reduce their efforts to build new power plants.

Second, because it believed the CPUC was violating federal law in the way it was contracting with certain independent energy producers, the Federal Energy Regulatory Commission (FERC) ended the CPUC's process for determining which independent producers could build new power plants and how much the investor-owned utilities were required to pay them for their electricity. These independently owned plants, called qualifying facilities (QFs), provide about 20 percent of California's power supply and produce electricity through resources such as wind, solar, and natural gas. They were created by a 1978 federal law that required the investor-owned utilities to buy the electricity that QFs produced, after which applications for new QFs in California expanded rapidly throughout the 1980s, as shown in Figure 4. The CPUC recognized that the contracts it awarded to QFs in the 1980s gave them an incentive to overbuild, and so it created a new process in July 1989 to determine how much new supply should be added by QFs and how much the investor-owned utilities should pay them for their electricity. The CPUC and the investor-owned utilities worked together for several years to attempt to implement this process. However, the utilities complained to FERC in January 1995 that the prices set by the CPUC under the new process were higher than federal law permitted because they included a bonus based on how environmentally friendly the QFs were. FERC agreed with the utilities and issued its decision in February 1995, effectively putting an end to the process before it was ever implemented. This greatly limited the number of QFs that independent energy producers built in the State.

A FERC decision greatly limited the number of qualifying facilities built after 1995—this also contributed to the State's energy supply shortage.

FIGURE 4

**Applications Submitted Using the Energy Commission's Standard Siting Process by Investor-Owned Utilities and Independent Energy Producers
1975 Through 1995**



Source: Energy Commission—Siting Case History by Applicant Type.

The energy commission approved twelve plants through its 12-month siting process between September 1996, when AB 1890 became effective, and April 1, 2001. All of these plants are large natural gas plants proposed by private companies that will potentially sell their electricity in the wholesale market. If the siting process for these twelve plants had taken 12 months, as specified by law, two of them, representing 1,059 MW, could have been generating power by April and June 2001, assuming no change in plant construction schedules. As it now stands, neither of these plants are currently expected to be operational before July 2001. As more power plants come on-line and the State's supply margin increases over the next few years, the negative effect of delays in the energy commission's siting process will gradually decrease.

In addition to delays in the siting process, delays in starting construction are affecting the eventual opening of 5 of the 12 plants the energy commission has already approved for construction. As of April 1, 2001, 5 of the 12 power plants (totaling over 3,500 MW) are projected to begin construction four or more months after the energy commission approved them, with one 720 MW plant not scheduled to begin construction until almost a year after the energy commission approved it. The

Although already approved, five power plant developers plan to wait four or more months before beginning construction.

assistant division chief of the energy commission's siting division said that some power plant owners have made business decisions to delay construction based on their interpretation of market conditions. Nevertheless, these construction delays will contribute to the ultimate length of time it takes to bring much-needed new supplies of electricity on-line. According to the energy commission, it intends to condition all applications received after May 1, 2001, to require that construction begin within one year of the date an application is approved.

THE ENERGY COMMISSION HAS MADE CHANGES TO IMPROVE ITS SITING PROCESS BUT IS NOT EVALUATING THE EFFECTIVENESS OF THOSE CHANGES

In 1999 the Legislature mandated that the energy commission report on improvements that it could make to its siting process, and the energy commission issued its report in March 2000. As of April 1, 2001, the energy commission states that it has implemented over half of those changes. However, without a plan to measure whether these changes have been successful, the energy commission does not know whether they will improve the generation siting process as intended.

Several changes the energy commission recommended were intended to address delays encountered in its siting process, including some delays mentioned earlier in this report. For example, the energy commission recommended that its application criteria be modified to encompass the information other agencies needed for their review, thereby limiting or eliminating these agencies' requests for additional information.

As of April 1, 2001, the energy commission indicated that of the 25 report recommendations that required its action, it has fully implemented 15, has partially implemented 3, and is working on 6 others. One recommended change has been put on hold until the energy crisis is resolved. However, the energy commission has not developed methods to judge the effectiveness of its changes. For example, the energy commission changed its regulations to specify that outside parties could only request information on applications within 180 days of the date the application is complete. The energy commission found that late requests for information could delay the siting process, and it implemented this change to prevent such delays. However, the energy commission has not attempted to measure whether this

Because the energy commission is not evaluating the effectiveness of changes to its siting process, it cannot tell whether the process is improving.

new procedure has actually prevented the delays it previously identified. Thus, the energy commission cannot guarantee that this change and others it has made have actually improved the siting process as intended.

SEVERAL NEW EXPEDITED SITING PROCESSES HAVE YET TO YIELD SIGNIFICANT RESULTS

In addition to trying to improve its 12-month siting process, the energy commission recently began using three new expedited siting processes of varying lengths. Although to date none of these processes has resulted in many new plant approvals, according to the energy commission one is estimated to add several hundred megawatts to the State's electricity supply in time to meet this summer's peak demand. The energy commission's total estimated megawatts and on-line dates for plants sited under these processes are summarized in the Appendix.

The first of these new processes is a 6-month siting process intended to replace the energy commission's existing Small Power Plant Exemption (SPPE)¹⁴ for projects meeting certain criteria. The energy commission recommended this 6-month process to the Legislature, which put the new process into law with its passage of AB 970 but did not repeal the SPPE process. The energy commission recommended the change because it found that the SPPE process was not necessarily simpler or shorter for applicants than the standard 12-month process. Although the SPPE process exempted qualified applicants from its normal siting process, the energy commission found that approval took 6 to 8 months, after which applicants still needed to get permits from the relevant state and local agencies. Further, SPPE projects could be delayed for months due to inadequate applications because the process had no filing requirements. In contrast, under its new 6-month siting process, any other agencies having jurisdiction or special interest in the proposed plant must provide their comments, determinations, and opinions within 100 days of the date the energy commission judges the application complete. Also, the energy commission created stricter application criteria for this process to ensure that the plants will have minimal environmental and public health effects. Plants that meet those criteria can

¹⁴ Included in the Warren-Alquist State Energy Resources Conservation and Development Act, the Small Power Plant Exemption was intended as a means to avoid the energy commission's 12-month process for plants of 50 MW to 100 MW that the energy commission finds will have no substantial adverse environmental impact. The energy commission has granted 16 such exemptions since 1976.

receive the energy commission's approval in half the time of the standard siting process. As of April 2001 the energy commission had not completed evaluating any applications under this process, so it will not have an immediate impact on the State's current supply problem by getting more power plants on-line by summer 2001. Nevertheless, the process may provide an effective tool for approving certain plants more efficiently and may yield benefits in the long run.

The energy commission's second expedited procedure is a four-month siting process meant for so-called "peaker" plants, intended for use only during periods of peak electricity demand, to make up some of the shortfall in the State's supply. Included in AB 970, which took effect in September 2000, the four-month process was created specifically to site power plants that could be on-line by August 1, 2001. The four-month expedited process originally applied only to those companies able to file complete applications or amendments to pending applications for new plants by the end of October 2000. Although companies managed to submit applications for seven plants by the October deadline, six of the seven applications were withdrawn. According to the deputy director of the energy siting division, severe time constraints limited the applications' success. The seventh application was approved, and as of April 1, 2001, the plant was expected to be on-line by August 2001. The energy commission approved this 51 MW plant in March 2001, taking just over four months. By executive order, the governor has since extended the deadline to apply for the four-month process to December 31, 2001, with the stipulation that plants approved under the process be on-line by August 31, 2002. Energy commission staff expect to receive several applications under the new deadline and believe the four-month process will be more successful now that applicants have more time to prepare their applications.

Only one of seven applications to the 4-month siting process was approved—this 51 MW plant is expected to be on-line by August 2001.

The energy commission's third new siting process implements an emergency process written into its existing statute. By declaring a state of emergency in January 2001, the governor allowed the energy commission to use that emergency process to authorize the construction of peaker plants or renewable energy plants that can be on-line by July 31, 2001, under whatever terms it believed were necessary to protect the public interest. The energy commission has since instituted a 21-day siting process for peaker plants. As requested by the governor in a February 2001 executive order, the energy commission issued a report that month detailing 33 potential sites throughout the State that would make appropriate peaker plant locations for new plants approved under the 21-day

siting timeline. By identifying these sites in advance, the energy commission removed the need to determine on a case-by-case basis the acceptability of proposed sites, thereby reducing the time needed to approve each plant. According to the governor's Web site, this emergency process was intended to get 1,000 MW of capacity on-line by July 2001 (in addition to 1,133 MW of peaker plants the ISO had already contracted for that were also expected to be on-line by summer 2001).¹⁵

The energy commission has begun reviewing several peaker plants under the expedited process, but as of April 1 these plants were all part of the megawatts originally contracted for by the ISO.¹⁶ Although they will not meet the July 2001 goal, energy commission staff expect to receive many new applications under this process and believe they can approve applications totaling more than 1,000 MW for plants that can be on-line by September 1, 2001. However, the State's summer peak demand will likely come before September, and the energy commission concedes that no new supply will be brought on-line because of this process (except for those plants contracted for by the ISO) until August 1, 2001, with the number steadily increasing to 1,000 MW or more by the end of summer. Also, as of April 6, 2001, the new supply the ISO contracted for had increased to 1,324 MW, but the ISO predicted that only about 250 MW of this would complete the energy commission's 21-day process and be on-line by July 2001, with this number also increasing through the summer.

The energy commission's 21-day siting process is unlikely to bring a significant amount of new supply on-line until September 2001.

HAVING UTILITIES RESPONSIBLE FOR TRANSMISSION PLANNING MAY HINDER THE DEVELOPMENT OF NEW TRANSMISSION LINES

With its push to bring new power plants on-line to solve the energy supply shortage, the State also has to consider the means of delivering the electricity California needs this summer and beyond. The investor-owned utilities are primarily responsible for transmission planning, determining through their own separate analyses of demand growth what new transmission lines are

¹⁵ Recognizing the State's need for new generation by summer 2001, the ISO requested bids in August 2000 for up to 3,000 MW of new peaker plants. As of February 2001 the ISO had signed contracts for 1,133 MW. However, the ISO does not have authority to site new power plants, so the energy commission must still approve all of the ISO's contracted plants of 50 MW or more.

¹⁶ The energy commission has since received peaker plant applications that, as of April 23, 2001, it estimates will bring 207 MW on-line in August 2001.

needed and where. The ISO and CPUC coordinate, plan, and oversee the expansion of the State's transmission grid. Because the three investor-owned utilities create three individual transmission expansion plans, based on potentially varying assumptions of the future demand growth in their respective service areas, the ISO's ability to create a comprehensive statewide expansion plan may be hindered. Also, the investor-owned utilities may have incentives that conflict with their responsibility to expand the grid where necessary—in part because transmission constraints may be protecting some of the investor-owned utilities' power plants from competition. Therefore, the investor-owned utilities' demand analyses may not be the best basis for determining when and where transmission lines are needed. In relying on these analyses to determine transmission line expansion, rather than on analyses prepared independently, the ISO and CPUC lack assurance that the utilities' proposed transmission projects are optimizing the transmission grid.

Investor-Owned Utilities Have the Primary Responsibility for Planning the Transmission Grid

The transmission grid currently operated by the ISO was not originally built to function as an integrated system. Historically, each of the three investor-owned utilities, as well as the municipal utility districts throughout the State, built their own separate transmission systems to serve their individual needs. Because these entities owned most of the power plants and were the monopoly provider of electricity to customers in their area, their transmission systems were built to do little more than get the power from their generating facilities to their customers. These individual transmission systems were interconnected such that each investor-owned utility and municipal utility could import the electricity it might need under adverse conditions. However, these interconnections were not intended to allow generators from outside each area of monopoly control to regularly serve demand within that area. To ensure that their transmission systems were adequate to meet future electricity demand, the investor-owned and municipal utilities created periodic transmission expansion plans. These plans identified specific transmission projects that the various utilities determined would be necessary to meet their own analyses of projected electricity demand.

California's transmission grid was not originally designed to function as a single integrated system.

When California restructured its electricity industry, it created the ISO to control the operation of the investor-owned utilities' transmission grids and coordinate the long-term grid planning processes of the investor-owned utilities. Under the system

currently employed by the ISO, the investor-owned utilities each create a transmission expansion plan, as they did before restructuring, submitting the plans and supporting data to the ISO. The ISO analyzes the plans and identifies any additional transmission projects it determines are needed to allow for greater competition among generators or to ensure that the entire grid meets the ISO's minimum reliability criteria. However, it does not independently verify the utilities' demand growth projections, which form part of the basis for the ISO's list of needed projects. The investor-owned utilities add the additional projects the ISO has identified to their respective plans and submits individual transmission projects to the CPUC to receive environmental reviews and the final construction permits.

Although the ISO and CPUC Rely on the Investor-Owned Utilities' Projections, the Utilities May Have a Conflict of Interest in Expanding Transmission

Having created transmission expansion plans for many years, each investor-owned utility bases its demand growth projections on individual assumptions that may conflict with the others, potentially making it difficult to create a single statewide projection. In addition, the utilities may be understating their current demand growth projections. Although the law requires them to ensure that their transmission systems are adequate to serve all customers in their service area, the investor-owned utilities have economic incentives that may limit their decisions to expand their transmission systems beyond the required minimum level of service. Because both the ISO and the CPUC rely on the investor-owned utilities' demand growth data, they lack assurance that the current transmission planning process is optimizing the transmission grid. Therefore, the State may have barriers to competition among power generators and also may run a higher risk of experiencing blackouts because of transmission constraints.

Because both the ISO and CPUC rely on the investor-owned utilities' data, their current transmission planning efforts may not be optimizing the State's transmission grid.

Investor-owned utilities base their plans for transmission expansion partly upon their individual assumptions of future demand growth within their respective service areas. Even if the investor-owned utilities are making their best effort to project future demand growth, these differing assumptions may make the individual plans inconsistent with one another. For example, one investor-owned utility may assume statewide economic growth of 1 percent, while another may assume a 4 percent growth. Such

inconsistencies in the utilities' projections would make the ISO's statewide transmission plan inconsistent as well, because it is based in part on these projections.

Several areas of California's transmission grid currently do not have adequate capacity to allow free competition among generators.

In addition, the investor-owned utilities may have a disincentive to project the need for new transmission lines. Because transmission lines are not a competitive resource, FERC regulates the rates that investor-owned utilities may charge for their use, ensuring that the utilities can recover their transmission line construction and operating costs, plus a fair profit margin.¹⁷ However, each investor-owned utility is actually a subsidiary of a parent corporation that is involved in multiple energy-related activities, and transmission lines are only one of the means by which the investor-owned utilities' parent companies make a profit. Other activities, such as building unregulated power plants to compete in various energy markets, are likely to be much more lucrative. Moreover, several areas of California's transmission grid currently do not have adequate transmission capacity to allow free competition among power generators. As required by AB 970, the CPUC completed a report in February 2001 identifying constraints in the State's transmission grid. Based on ISO data, the CPUC identified eight congested transmission lines in the State that limit certain areas' access to outside sources of power. When their power plants are located in these restricted areas, the investor-owned utilities' parent companies have limited incentive to build more lines for other power generators to use to compete with them. Therefore, the utilities may have an incentive to underestimate future growth in electricity demand and to reduce the number of transmission lines they project that they need to build.

Although the ISO reviews the transmission expansion plans created by the investor-owned utilities to ensure that they meet its reliability criteria, it still relies primarily on the utilities' demand growth projections to show where future grid constraints may arise. The ISO's director of grid planning observed that since the ISO has limited ability to review the investor-owned utilities'

¹⁷ Because they are a means for conducting interstate commerce, transmission lines and the rates charged for their use are regulated by the federal government. However, the CPUC regulates the ultimate retail rates that investor-owned utilities can charge their consumers.

projections, the energy commission (which already does statewide demand growth projections) would be an appropriate independent source of this information.

In addition, the CPUC has the legal authority to determine whether transmission projects are required for “public convenience and necessity,”¹⁸ meaning that when the CPUC assesses the benefit the transmission lines provide by transmitting electricity to consumers, it considers the project’s impact on community or aesthetic values, and any significant influence on the environment. However, according to a CPUC administrative law judge, the CPUC does not independently verify the investor-owned utilities’ demand growth projections, which are the basis for hearings determining when and where a new transmission line will be needed. Rather, if it finds the testimony persuasive, the CPUC accepts the utilities’ word regarding demand growth. The administrative law judge stated that the CPUC would reject the investor-owned utility’s data only if an intervenor¹⁹ in the process submitted conflicting information and the CPUC found the intervenor’s argument more persuasive than the investor-owned utility’s.

THE CALIFORNIA PUBLIC UTILITIES COMMISSION’S TRANSMISSION SITING PROCESS IS NOT RESPONSIVE TO THE CURRENT ENERGY CRISIS

Although it is responsible for siting the electrical transmission lines that the investor-owned utilities propose,²⁰ the CPUC does not have an expedited transmission siting process that could better assist California’s recovery from the energy crisis. Moreover, in almost half of the CPUC’s siting cases using the environmental

¹⁸ Although the statute states that no investor-owned utility may build a new transmission line without the CPUC first determining that public convenience and necessity requires it, the CPUC grants a Certificate of Public Convenience and Necessity only for projects of 200 or more kilovolts. For projects between 50 and 200 kilovolts, the CPUC grants a Permit to Construct, which has somewhat less stringent application requirements but also includes an environmental review process. The CPUC does not exercise its authority over projects of 50 kilovolts or less.

¹⁹ Intervenors are individuals or organizations that request official standing in the CPUC’s hearings on a transmission siting case. Intervenors receive all documents related to the case, may submit testimony, and may make oral arguments in the hearing.

²⁰ According to the CPUC, transmission projects proposed by independent parties are under the jurisdiction of local agencies. Projects proposed by municipal utility districts are licensed by the municipal utilities themselves, as public agencies. Transmission lines required to connect most new generating plants to the existing transmission grid are licensed by the energy commission as part of its licensing of a plant, including municipal and independent plants.

review process outlined in the California Environmental Quality Act (CEQA), the CPUC significantly exceeded the 180- and 365-day goals CEQA sets for completing environmental reviews. Recent events show that a lack of adequate transmission capacity in some areas of the State can be devastating—transmission constraints have already caused rolling blackouts and have the potential to do so again in the near future. Long delays in siting added transmission could slow the State’s recovery from the current energy crisis. For example, an ISO study has found that the primary transmission connection between Northern and Southern California must be expanded to ensure delivery of electricity to Northern California from the south in adverse conditions, when rolling blackouts are a threat. The CPUC will likely have to conduct an environmental review for this expansion, and the longer this review takes, the later the expansion will occur. Major causes of delay in transmission siting cases include the need to coordinate with the federal government, contracting delays, and late involvement by other agencies. Although one of these delays is beyond the CPUC’s control, it could still improve its transmission siting process.

Almost half of the environmental reviews the CPUC has conducted on proposed transmission projects since 1990 have taken longer than CEQA recommends.

The CPUC Lacks an Expedited Siting Process, and Its Standard Siting Process Takes Longer Than the Time Goals Outlined in CEQA

The CPUC is responsible for granting certificates to the investor-owned utilities to build proposed electrical transmission lines. In spite of the likely need for near-term expansion of certain parts of the transmission grid, the CPUC does not have an expedited siting process for high-priority projects. Also, for almost half of the transmission permits requiring environmental review that the CPUC considered after 1990, it took or is taking longer than the CEQA timelines for completing those reviews. According to the ISO, at least one of these delayed permits was for a project that would reduce transmission constraints expected in the San Francisco Bay Area by summer 2001. Thus, the CPUC’s inability to meet the CEQA timelines may contribute to the State’s energy crisis.

Recent events in California indicate that certain parts of the transmission grid may need to be expanded quickly, yet the CPUC has no expedited transmission siting process for urgently needed lines. Rolling blackouts occurring in Northern California on January 17, 2001, could have been avoided if the primary transmission connection between the northern and southern parts of the state had been able to transmit more electricity. The

The CPUC does not have an expedited transmission siting process for more urgent projects.

ISO has recommended expanding this line, which will likely require an environmental review by the CPUC. The length of this review will affect how quickly the connection can be expanded. In an April 3, 2001 order, the CPUC directed PG&E to begin certain biological studies along this line that have to be completed before any construction could begin and, because of the nature of the studies, must be conducted during the spring. In its order, the CPUC stated that it took this step so that the study would not be delayed until the spring of next year because such a delay would also delay starting construction on this transmission project once the CPUC ordered such construction. However, even if the CPUC orders an expansion of this transmission line, CEQA requires that it still conduct a full environmental review once the application is filed. Unlike the energy commission, which has expedited processes for siting new power plants, the CPUC does not have any expedited siting processes for transmission projects needed to address short-term problems in the transmission grid. The CPUC's lack of an expedited process also contrasts with recent actions of the ISO, which is modifying its tariff agreement with FERC to allow the ISO to expedite its approval of new transmission projects it determines are necessary for near-term grid reliability.

Thus, the CPUC is the only one of the three entities responsible for planning or siting new electrical generation or transmission that is not implementing an expedited process to speed the expansion of California's electricity infrastructure in response to the energy crisis. When asked about the possibility of creating an expedited process, the director of the CPUC's energy division indicated that the law requires the CPUC to use the standard CEQA siting process except in an emergency. According to the energy division's director, it is the CPUC's position that although the governor declared an emergency requiring the energy commission to expedite its power plant siting process, he did not make a similar declaration relating to CPUC's transmission siting process.

The CPUC's standard transmission siting process often takes longer than state law recommends. For proposed transmission projects over 50 kilovolts²¹ that it determines are not exempt from its siting process, the CPUC must determine whether the public would benefit from the line being built and follow the CEQA guidelines to identify the environmental effects. The CEQA guidelines indicate that for projects that are likely to have a significant environmental effect that cannot be mitigated, the CPUC must complete an

²¹ Volts are a measurement of the amount of force with which electricity is pushed through a transmission line. One kilovolt (kV) is 1,000 volts.

Three of the four EIRs the CPUC began in the 1990s have taken or are taking significantly longer than 365 days.

Environmental Impact Report (EIR) within 365 days of the date the project's application is complete. For projects that will not have any significant impacts, the CPUC must complete a negative declaration, and for projects for which any potential significant impact can be avoided or mitigated, a mitigated negative declaration must be completed within 180 days of the application's completion. The CPUC hires consultants, overseen by CPUC staff, to complete these reports and declarations.

However, CEQA provides an exception to the time requirements if compelling circumstances justify additional time and the project applicant agrees—and in almost half of its environmental reviews, the CPUC has used that exception. As shown in Figure 5, almost half of the environmental reviews the CPUC has conducted for proposed transmission lines since 1990 have taken or are taking significantly longer than the prescribed CEQA timelines. Of 17 environmental reviews of transmission projects, 8 were not completed on or near the timeline set forth in CEQA. Of the 4 projects requiring EIRs:

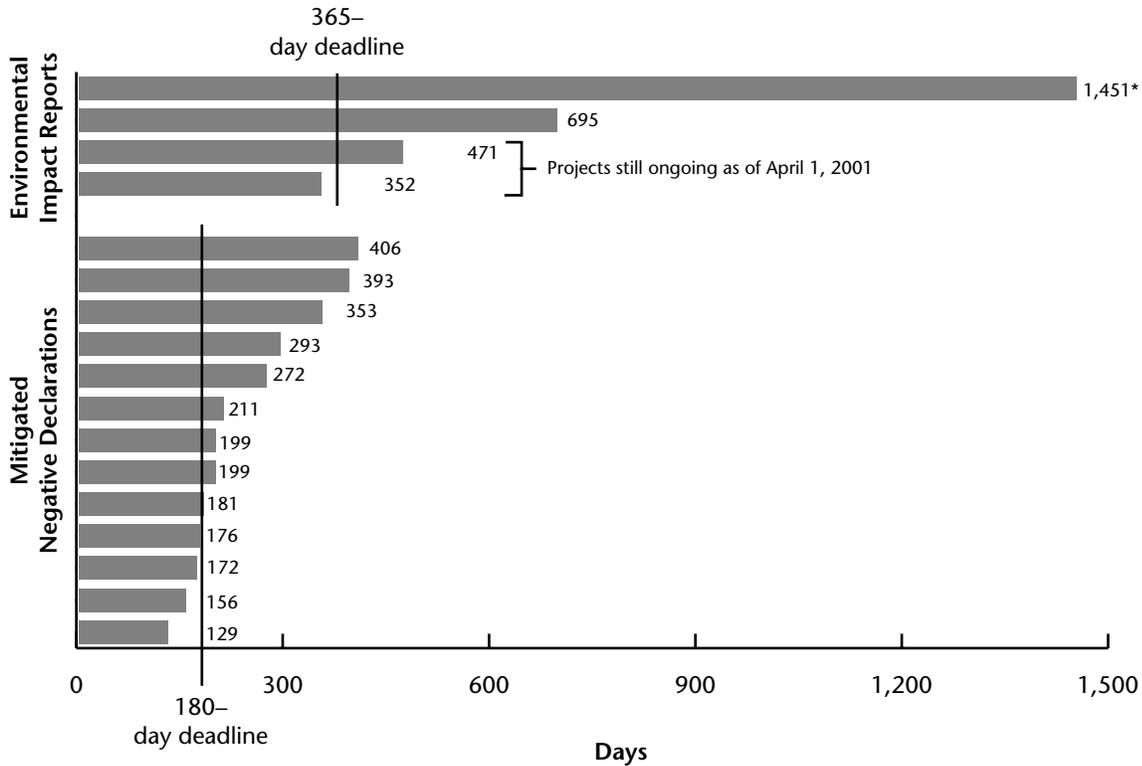
- The CPUC completed one EIR in the past decade, taking 695 days to approve it and issue a permit.
- The CPUC began a second in 1996, which was finally suspended in 2000, after about 4 years of work, when it became apparent that a permit would not be issued.
- The two other EIRs were still ongoing as of April 1, 2001; one has been under review for 16 months.

The ISO has identified at least one of these delayed projects as being needed to address transmission constraints expected in the San Francisco Bay Area by summer 2001. Although the investor-owned utility completed its application to the CPUC for a permit for this line by December 1999, the CPUC will not make a decision on whether to adopt an EIR or grant a permit before May 2001, at least 5 months beyond the one-year CEQA timeline. If approved, this project will not be operating before June 2002, according to the ISO's current projection.

The remaining 13 projects required mitigated negative declarations, and 5 of these greatly exceeded the CEQA timeline of 180 days. The average length of time from completed application to final decision for these 5 projects was 343 days, or more than 5 months beyond the CEQA deadline.

FIGURE 5

Duration of CPUC Environmental Reviews of Transmission Siting Projects Begun After 1990



Source: CPUC—Transmission project siting decisions and project-specific Web sites.

* Project suspended in October 2000.

Certain types of projects are exempted by the CPUC from detailed review, such as replacement or minor relocation of existing lines. The CPUC automatically approves these exempted projects without a CEQA review. Of the 60 transmission project applications it received between January 1, 1998, and November 2, 2000, the CPUC automatically approved 47 in this manner.

Even after the threat of blackouts has passed, congestion in the transmission grid may limit how competitive the State’s electricity market can be. For example, the ISO has identified seven transmission paths, connecting various regions of California to each other or to other states, that were so congested in 1999 and the first half of 2000 that together they cost wholesale electricity buyers an additional \$128.5 million over the wholesale price for the

power transmitted over those paths. When transmission lines are overly congested, the ISO assesses a usage charge to buyers of the electricity delivered through those lines. The higher prices paid for the wholesale electricity that arrives over congested transmission paths also signals the power generators within those affected areas to raise their prices above the levels they would ordinarily have been able to charge in a truly competitive market. The longer it takes to site and build new transmission lines to alleviate these constraints, the longer these prices will remain artificially high, and the longer the State will delay true competition.

One Cause of Transmission Siting Delays Is Beyond the CPUC's Control, but Others Could Be Addressed by Revising the Transmission Siting Process

According to CPUC siting project managers, transmission siting projects are delayed because of a slow consultant contracting process, late involvement by other agencies, and the need to coordinate with the federal government on certain projects, among other reasons. We reviewed five projects in which the environmental reviews exceeded CEQA's deadlines and confirmed the CPUC project managers' statements. For example, upon completing the draft mitigated negative declaration for one project, the CPUC received notices from two agencies indicating that the project would need to obtain additional permits beyond the one granted by the CPUC. These permitting processes were presumably still ongoing after the CPUC approved the project. Although coordination with the federal government is largely beyond its control, the CPUC has attempted to address the contracting delays. However, the CPUC has not addressed late involvement by other state agencies.

As noted earlier, the CPUC hires consultants to perform its environmental reviews, with CPUC staff overseeing the consultants' activities. The State contracting process the CPUC uses to hire contractors for many of its transmission siting projects has lengthened some siting projects by months. For example, the CPUC judged one application complete in February 1994 but was not able to sign a contract for the environmental review until May 1994. Therefore, the contractor could not begin performing the environmental review until almost three months after the CEQA timeline had begun. The CPUC indicates it addressed this type of delay by creating "on-call" contracts in 1995, through which it annually preselects contractors to perform environmental reviews during the following year. Thus, when an investor-owned utility tells the CPUC that it is preparing a new transmission

application that will require an environmental review, the CPUC can simply amend the contract with the preselected contractor to reflect the details of the siting case, with the contractor ideally being ready to begin work by the time the application is filed. CPUC staff indicate that this process has allowed them to assign work to contractors relatively quickly.

The Department of General Services (DGS) indicated to the CPUC in 1999 that its contracting rules did not allow the CPUC to use on-call contracts. However, the CPUC and DGS reached an agreement in August 2000 allowing the CPUC to continue to use on-call contracts on an interim basis while it updated its contracting rules. A representative of the CPUC's legal division anticipates that these revisions will be completed by July 2001.

As with the energy commission's siting process, several other agencies are involved in granting permits for transmission projects reviewed by the CPUC. Although the CPUC encourages these other agencies to conduct their reviews concurrently to the extent possible, it does not actively coordinate the activities of these other agencies to the extent that the energy commission does in its siting process. In fact, while the Warren-Alquist Act requires other agencies to complete their reviews before the energy commission issues its permit for a power plant, CEQA requires other agencies to use the CPUC's completed environmental document to decide whether to grant their own permits for a transmission project. Therefore, transmission projects may still need several permits after they have completed the CPUC's process, adding to the time needed to site the proposed transmission line. For example, in August 1999, the CPUC completed a draft mitigated negative declaration and subsequently received a comment letter from a regional water quality control board stating that the project may need two separate permits that together could take up to 180 days to grant from the date the board received completed applications for these permits. Similarly, the California Department of Transportation submitted a comment letter indicating that the same project may need a permit from the Federal Aviation Administration because it is close to an airport. Although the CPUC approved the project in January 2000, these additional permitting processes were presumably still ongoing after that point.

If the CPUC coordinated the activities of the other agencies involved in permitting transmission projects, as the energy commission does for siting power plants—requiring other agencies to complete their reviews within 180 days of the date the

Transmission projects may still require additional permits after the CPUC has completed its review, adding to the overall time it takes to site proposed transmission lines.

CPUC received a completed application—it could greatly speed the transmission siting process. According to the director of the energy division, even though the CPUC is supportive of such a change, it may be difficult to convince the other agencies it works with in siting transmission lines that such a change will benefit all the concerned parties.

The CPUC must also work together with the federal government on transmission siting projects in which the federal government has a specific interest. For example, on a project that began in 1996 and was suspended in October 2000, the CPUC and the federal government worked together to produce an environmental impact document because the proposed transmission project crossed land owned by several federal agencies. The CPUC and the federal government disagreed on one aspect of the project, which delayed the process, and the federal government was slow in completing part of its environmental assessment. After ultimately concluding that it could not reasonably perform a study the federal government required, the applicant suspended the application process and decided to meet its electricity needs in the area by attempting to build a power plant. Given that the applicant's disagreement was with the federal government, it does not appear that the CPUC could have prevented this outcome.

RECOMMENDATIONS

To assess the impact of recent changes to its process for siting power plants, the energy commission should establish an evaluation plan.

So that the State has an independent projection of demand growth on which to base transmission expansions, the energy commission should make regional demand growth projections for the ISO and the CPUC to use in their transmission planning and siting processes.

The Legislature should create an expedited electricity transmission siting process for projects that are needed for short-term transmission system reliability.

The Legislature should institute a coordinated electricity transmission siting process as it relates to other agencies similar to the coordinated power plant siting process used at the energy commission. ■

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CHAPTER 4

Numerous Factors Limited the Success of Consumer Choice

CHAPTER SUMMARY

On March 31, 1998, California implemented the deregulation of its electricity industry, shifting from the prior monopolistic structure to one in which energy customers could choose to stay with the investor-owned utilities or purchase their electricity from another provider. The California Public Utilities Commission (CPUC) and the Legislature had high expectations that consumer choice would increase competition and lead to lower electricity prices. However, Californians never fully realized these benefits of consumer choice because certain features of deregulation and its implementation kept consumer choice from flourishing. Moreover, if true retail competition among energy service providers (ESPs) and the investor-owned utilities had materialized, it might have helped to mitigate the skyrocketing of wholesale electricity prices, which began in the summer of 2000.

Part of the implementation strategy in deregulating the electricity industry that took place on March 31, 1998, initially required the investor-owned utilities to buy energy at spot market prices (prices charged in a commodity market that sells electricity) in the California Power Exchange (PX). The utilities in turn passed these spot prices on to their customers as the power generation portion of their rates (excluding fixed transmission and distribution rates). With a very small customer base, ESPs had difficulty negotiating purchase prices for wholesale electricity that were lower than those the power generators could afford to charge the investor-owned utilities in the spot market. As long as the ESPs had to try to beat spot market prices for their wholesale electricity purchases, they found it nearly impossible to offer their customers any substantial savings. With few customers seeking their services, California's new ESPs have struggled to remain competitive. Now, the future of consumer choice is in doubt because the State has become the main purchaser of wholesale electricity for the investor-owned utilities, negotiating long-term contracts with energy generators. The goals of consumer choice may conflict

with the State’s goal of returning the investor-owned utilities to creditworthy status—because expanding competition at this point might find the State paying for unneeded power.

CONSUMER CHOICE WAS SUPPOSED TO INCREASE RETAIL COMPETITION AND LOWER ELECTRICAL RATES

In passing Assembly Bill (AB) 1890, which deregulated California’s electricity markets, the Legislature expected that increased competition would lower energy prices for the residents and businesses of California. The CPUC informed the public about the new choices in electricity providers through a program of public information and expected that giving customers a choice would create competition. This concept of consumer choice, called “direct access,” allowed customers of Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E) to purchase their power from other sources if they chose to. The more than 70 percent of California consumers who were buying electricity from the investor-owned utilities were eligible to make such a switch to an ESP. Through some of the CPUC’s policies, enacted in AB 1890, the CPUC and the Legislature designed the electricity industry restructuring with the expectation that competitive forces—including customers being free to search for electricity providers other than their traditional investor-owned utility—would result in lower electricity rates. Competition was also expected to encourage innovation, efficiency, and better service from all market participants.

The electricity industry restructuring was designed around competition—more than 70 percent of California’s consumers could now choose where to purchase their power.

Deregulation statutes required the CPUC, in conjunction with the investor-owned utilities, to give customers the information necessary to make appropriate electricity service choices. To this end, the CPUC devised and implemented a consumer education program, spending upward of \$90 million by May 1998 to inform customers of the changes that deregulation had brought. The CPUC was careful not to advocate any particular provider but simply to emphasize that consumers now had a choice of electricity companies. The education program also informed the public about their rights as electricity customers. The CPUC used a call center, written materials, and television and radio advertisements to disperse its messages to utility customers.

In promoting competition in the new retail market, the director of the CPUC’s energy division indicated that the CPUC took a ‘hands off’ approach, believing that giving consumers a choice of ESPs would in itself create competition at the retail level, without

the need for regulatory or government intervention. Moreover, the director of the energy division stated that the CPUC saw its role as ensuring that the investor-owned utilities competed fairly and that it resolved any consumer complaints concerning either the utilities or ESPs.

NEW ENERGY SERVICE PROVIDERS FACED MANY CHALLENGES TO REMAIN COMPETITIVE

Competition—the focal point of deregulation—never fully materialized. Consumer choice was stunted from the beginning by the following factors that effectively undermined retail competition and gave the utilities a distinct advantage over newcomers:

- Because their customer base was so small, ESPs were unable to negotiate lower prices from electricity generators than the investor-owned utilities paid the power generators in the newly created wholesale spot market.
- A lack of product differentiation made it difficult for ESPs to establish a niche in the new marketplace.
- Residential customers had virtually no incentive to switch electricity providers, making it difficult for new providers to attract customers.

As a result of these factors, the number of customers currently using alternative energy providers remains quite small and the absence of retail competition has effectively removed what may have served as a brake on skyrocketing wholesale electricity prices.

Being Unable to Compete With Spot Market Prices, the Energy Service Providers Had Limited Opportunity to Profit in the Retail Market

Because they lacked the customer base to negotiate a competitive price for wholesale purchases of electricity, the ESPs were largely unable to offer lower retail prices and still make a profit. Yet the ESPs were supposed to provide competition to the investor-owned utilities under deregulation. As a result, retail competition and its associated benefits never fully materialized.

As part of deregulation, AB 1890 created the PX,²² an open spot market where electricity was generally bought and sold no more than a day before it was needed. The State's investor-owned utilities were initially required by the CPUC to sell and purchase all of their power through the PX on behalf of their customers. The utilities then passed on the wholesale spot price of the electricity they purchased—up to the limit provided in their respective frozen rate structures—in the power generation portion of the retail bills they sent to their customers. Although the power transmission and distribution parts of the retail bills were fixed, the wholesale spot price of electricity tended to fluctuate.

To compete with the investor-owned utilities, ESPs had to offer lower retail prices for electricity, which turned out to be very difficult.

ESPs, along with other wholesale energy buyers and sellers under deregulation, could participate in the PX spot market, buy wholesale electricity through other markets, or contract directly with a power generator for the energy they needed. However, when billing their customers, ESPs were required by AB 1890 to levy certain charges, such as transmission and distribution charges equal to those charged by the investor-owned utilities. Thus, the amount charged for the electricity used, called the generation charge, was the only part of the retail rate charge the ESPs could compete on. To effectively compete with the investor-owned utilities, the ESPs had to offer lower overall retail prices for electricity, which turned out to be very difficult.

For example, to negotiate lower contract prices than the wholesale spot price offered in the PX or other spot markets, an ESP would have to buy in quantities larger than the amounts purchased by the investor-owned utilities through the PX. Otherwise, the ESP's purchase would not be economically worthwhile for the power generator. Yet none of the ESPs had enough customers whose aggregate demand for electricity rivaled even the smallest investor-owned utility. The other choices that ESPs had to secure wholesale power—other spot markets or the PX spot market—would allow them only to match the prices the investor-owned utilities were charging their customers, the ESPs would be unable to better those prices and certainly would not be able to earn a profit. Again, the ESPs were unable to gain any competitive pricing advantage. Because the ESPs were not able to compete in price with the investor-owned utilities, their rates presented little or no economic incentive for customers to switch away from the investor-owned utilities.

²² On January 31, 2001, the PX ceased trading; it filed for bankruptcy shortly thereafter.

Energy Service Providers Faced Other Challenges in Trying to Compete

Although competitive pricing was their major concern, the ESPs had other challenges in trying to compete in the new deregulated structure. Because electricity is the same regardless of who provides it, the ESPs were unable to distinguish what they were selling from what the investor-owned utilities sold. Also, the legislation establishing deregulation had no built-in mechanism for moving customers from the utilities to ESPs. Finally, their long-term relationship with their utility companies had given customers a level of comfort that made them unmotivated to switch providers. These challenges contributed to the failure of competition to lower retail energy prices in California's deregulated market.

One underlying factor that enables true competition was missing—product differentiation. According to the CPUC's energy division director, the one form of product differentiation that did occur was from providers of renewable energy, who provided “clean” electricity, made from nonpolluting sources like wind, water, sun, and geothermal. These ESPs were able to differentiate their product from that of the utilities based on their sources of energy and were thus able to carve out a niche market for themselves, although some charged higher prices than the utilities. However, unable to highlight a product difference, most ESPs could not give the utilities' customers a compelling incentive to switch providers.

Unable to differentiate their product from that of the investor-owned utilities, most ESPs could not give customers a compelling incentive to switch.

A lack of legislated incentives for customers to switch electricity providers further compounded the challenges facing the ESPs. The new electricity industry offered no compelling reason why customers should transfer service from their long-time utility and enlist with a new provider about whom they knew little or nothing. Moreover, deregulation did not require the investor-owned utilities to turn over any of their customers to the new providers; rather, it simply allowed customers of the investor-owned utilities to choose an alternate energy supplier. In contrast, Pennsylvania, where retail competition under deregulation has been more successful than in California, required most of its utilities to surrender some of their customers, in some cases auctioning off customers to the retailer that could promise them the most savings. Close to 1 million customers throughout Pennsylvania have switched from utilities to other energy suppliers, compared to a peak of 223,400 California customers using ESPs in March 2000 (only about 2.2 percent of the 10.1 million customers served by the three investor-owned utilities at that time). The

Legislature's and the CPUC's omission of any incentive or reason for customers to change electricity providers likely failed to motivate customers to switch to a new energy company.

Yet another barrier to the ESPs' success in marketing their services was consumers' loyalty to their long-term providers. The three investor-owned utilities had been serving customers in their respective service areas for many years, so that without a good reason, most customers were not inclined to make a change just because they now could. According to the director of CPUC's energy division, this "customer culture" is ingrained in most people, so many customers appeared to be uninterested or apathetic toward the new industry that existed. It was plainly not worth the time to these customers to research other companies, compare prices, and exert the necessary effort to make the change. The energy division director confirmed that most customers perceived no incentive strong enough for them to initiate a change in providers.

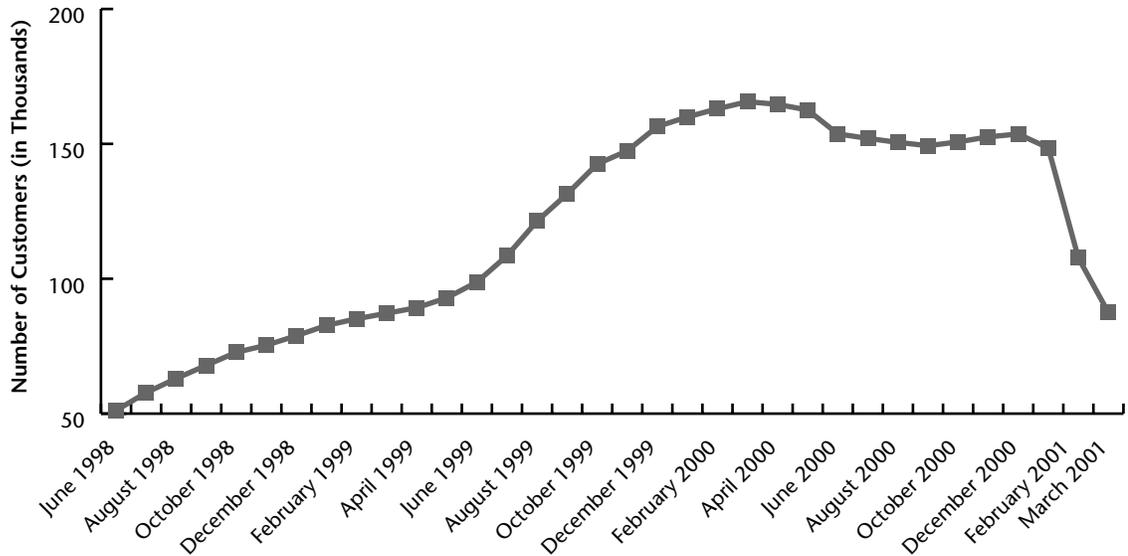
After An Initial Increase in Customers Changing Energy Providers, the Numbers Began to Decline

At the outset of deregulation, customers choosing new ESPs increased at a steady rate, although the number switching was immaterial compared to the total number of customers eligible. As of the end of June 1998, roughly 51,000 residential customers had chosen a new ESP, just over one-half of 1 percent of the almost 8.7 million residential customers of the investor-owned utilities at that time. As illustrated in Figure 6, the number of residential customers switching to a new ESP slowly but steadily increased until the spring of 2000. By the end of March 2000, the number of residential customers who had switched providers had tripled, reaching a peak of approximately 165,600, or 1.9 percent of the investor-owned utilities' residential customers. However, according to the CPUC's energy division director, many ESPs have since gradually lost customers. This is likely due to the volatility in the wholesale electricity market. If customers of an ESP did not contract for a fixed electricity rate, they are forced to pay the prevailing wholesale market rate, which reached unprecedented levels in the summer of 2000. As a result, many customers may have chosen to switch back to their investor-owned utility, where they are protected from volatile spot-market prices by the retail rate freeze. This effect of the volatile electricity market is evidenced by the total number of residential customers served by

The number of residential customers choosing an ESP peaked in March 2000 at 165,600 but has steadily declined since that time.

FIGURE 6

**Number of Residential Customers Choosing Alternative Energy Service Providers
June 1998 Through March 2001**



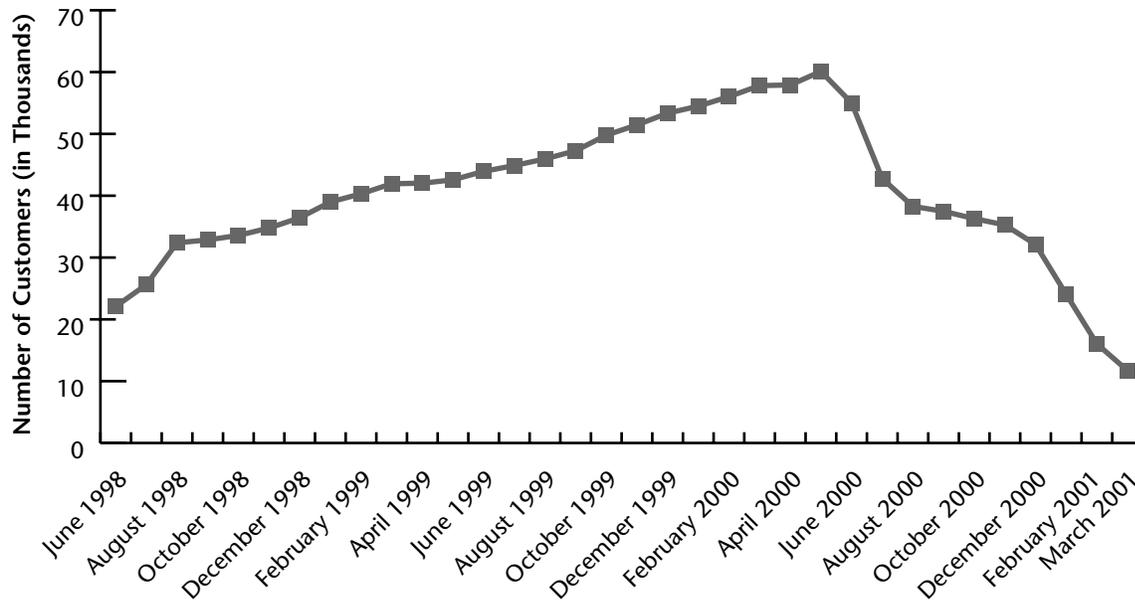
Source: CPUC Energy Division—Monthly Direct Access Implementation Activities Reports from June 30, 1998, through March 31, 2001.

the ESPs as of March 2001—roughly 87,500 residential customers received their electricity service from providers other than the investor-owned utilities, a 47 percent drop from the high of only one year earlier.

In percentage terms, nonresidential customers were initially more inclined than residential customers to change energy providers. Between June 1998 and March 2000, the percentage of nonresidential customers using an ESP almost tripled, from roughly 1.7 percent to 4.5 percent, or 58,000 out of a base of 1.3 million customers. In contrast, residential customers who switched to an ESP never exceeded 1.9 percent of the residential customer base. However, Figure 7 indicates that since May 2000 the number of nonresidential ESP customers has steadily declined. In fact, by March 2001, ESPs were serving only about half the number of nonresidential customers they had served in June 1998, at the beginning of deregulation. As the number of ESPs and their customer bases continue to shrink, retail competition is fading.

FIGURE 7

**Number of Nonresidential Customers Choosing Alternative Energy Service Providers
June 1998 Through March 2001**



Source: CPUC Energy Division—Monthly Direct Access Implementation Activities Reports from June 30, 1998, through March 31, 2001.

THE FUTURE OF CONSUMER CHOICE IS UNCLEAR

As California's electricity crisis chiefly focuses on soaring wholesale electricity prices, both the CPUC's energy division director and staff from the Office of Rate Payer Advocates—an independent body within the CPUC charged with representing the interests of all public utility customers—agree that if competition among retailers had flourished, producing the expected number of ESPs with their respective customer bases, the resulting competition may have helped hold wholesale prices in check. From an economic standpoint, the existence of many more direct access customers would have reduced the number of customers served by the investor-owned utilities, thereby lowering the utilities' aggregate electrical demand. This lowered demand might in turn have relieved pressure on the spot market and reduced the wholesale prices of electricity the investor-owned utilities were forced to pay. Increased competition might also have enhanced the ESPs'

viability, forcing the utilities to purchase power in a manner that smoothed out costs and avoided wide fluctuations in order to retain their respective market shares. The utilities might then have been more aggressive in hedging risk by entering into more fixed-rate contracts for future electricity purchases, thereby reducing their customers' exposure to wholesale price variations.

In any event, the decreasing number of ESPs and customers served by them casts considerable doubt on the future of consumer choice. Perhaps more importantly, however, because the State of California is currently the primary purchaser of wholesale electricity for the investor-owned utilities, it is now unclear whether the objective of consumer choice—increased competition—is consistent with the State's aim of returning the utilities to creditworthy status. In the past few months, the State has negotiated and continues to negotiate long-term contracts with energy generators—authority for which was specifically granted under ABX1 1—to supply enough electricity at the lowest possible prices to meet the hourly demand beyond what the investor-owned utilities are capable of generating themselves or are guaranteed to receive through contracts. Even though these long-term State contracts are still being written and we have not reviewed them, we understand that they can cover any time period, and some have been reported to extend out 20 years.

Presumably, the amount of electricity purchased through these long-term contracts is reflective of the current aggregate customer base of the investor-owned utilities. Therefore, if the price freeze were to be removed and competition were to expand at the retail level and other energy suppliers not burdened by long-term commitments could offer lower prices, large numbers of utility customers might decide to switch suppliers. In such a case, depending on the terms of the contracts, the State may be paying for power that it was required to buy but for which there were no customers. ABX1 1 may mitigate such a situation since it authorizes the CPUC to determine if or when it should suspend the right of utility customers to acquire electricity services from other providers. According to a manager in the CPUC's energy division, the CPUC has not yet made this determination; thus, customers still have the right to switch their electricity service from an investor-owned utility to an ESP. Uncertainties such as these will undoubtedly continue until the future role of consumer choice in today's fluid market environment becomes clear.

RECOMMENDATION

In assessing the future role of customer choice, the CPUC should consider the effects of competition at the retail level to evaluate whether it is viable in the current market environment, where the State is the primary purchaser of electricity for the investor-owned utilities.

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

Respectfully submitted,



ELAINE M. HOWLE
State Auditor

Date: May 21, 2001

Staff: Doug Cordiner, Audit Principal
Sharon L. Smagala, CPA
Robert Hughes
Joel Riphagen
Ryan Storm

APPENDIX

Projected Demand Reductions and Supply Additions for Summer 2001 and Beyond

The State Energy Resources Conservation and Development Commission (energy commission) and California Public Utilities Commission (CPUC) have developed, expanded, and implemented various programs targeted at reducing the State's energy demand, some in time for summer 2001. In this Appendix we summarize the energy commission's and CPUC's various program efforts, their projected megawatt savings, and the challenges these two commissions face in meeting their program goals.

In addition to working to reduce demand, the energy commission is actively siting power plants through a variety of processes including its standard 12-month process and several expedited processes, two of which were implemented specifically to address the State's immediate supply needs. Similar to its demand reduction programs, in this Appendix we sum up the total megawatts of new supply the energy commission has approved or is in the process of approving and categorize these megawatts by the date the energy commission projects them to come on-line through 2004. Our summary also includes 'peaker' plants the California Independent System Operator (ISO) has contracted for, but that may not all come under the energy commission's jurisdiction.

Finally, our summary of new supply includes the energy commission's Renewable Energy Program, through which it subsidizes renewable energy power plants within California that rely on such sources as solar, wind, and solid waste technologies to produce electricity. This program stemmed from the 1996 legislation that deregulated California's electricity industry and as of March 2001, 275 new and existing plants providing 4,394 MW of electricity—enough to power approximately 4.4 million average households—were participating in the program.

TABLE 11

**Energy Commission and CPUC Demand Reduction Programs
Estimated in Megawatts as of April 1, 2001**

	Megawatts saved by			Subtotals	After August 1	During			Totals
	June 1	July 1	August 1			2002	2003	2004	
Energy Commission									
AB 970 Programs									
Commercial building demand response	107	28		135					135
State buildings demand response	79		1	80					80
Water-systems equipment replacement	48	1		49					49
Heat reflective roof surfaces	6	7	10	23					23
Innovative products	39	2	1	42					42
Energy efficient traffic signal retrofit	2	1	3	6					6
Subtotals	281	39	15	335	-	-	-	-	335
CPUC									
AB 970 Programs									
Self-generation resources			45*	45	45*	90	90	90	360
Residential and small commercial building air-conditioning, heating, and ventilation cycling				-		8			8
Subtotals	-	-	45	45	45	98	90	90	368
Totals	281	39	60	380	45	98	90	90	703

Note: Data reflects the first point in time that the incremental megawatts estimated are available to meet peak demand.

* This program is new and the CPUC expects to achieve 90 MW of participation in its first year. We assumed, based on the newness of the program, that only half of the megawatts would be available for summer.

ENERGY COMMISSION ESTIMATED DEMAND REDUCTION

AB 970 Programs

These programs are collectively called the Peak Load Reduction Program and are intended to reduce peak energy demand during the high-demand months starting on June 1 and running through September 30, beginning in June 2001 and repeating in each of the three subsequent years. The energy commission, through contracts and grants is assisting program participants to do such things as develop systems to cut commercial and state

buildings' electricity use during periods of high demand, replace aging water-systems equipment with more efficient models, and install heat-reflective roof surfaces and energy efficient traffic signals.

Although the energy commission estimates that it will achieve 281 MW of demand reduction by June 1, 2001, and ultimately save 335 MW, these estimates appear too high for the following reasons:

- Even though the commercial building heating and air conditioning responsiveness program is computer based, participants can override directives to reduce energy use by adjusting heating and air conditioning levels. The override feature makes commercial building owners' and managers' participation voluntary and the energy commission has no penalties in place for noncompliance. In addition, operators may be less willing to comply with directives to reduce energy use as they receive more and more such requests. Thus, any savings derived from this effort will depend on the operators' responses to potentially frequent requests to reduce electricity use.
- State facility operators are preparing plans on how to respond to directives to reduce energy use. When directed, personnel will implement these plans manually by taking such steps as adjusting heating and air conditioning levels and turning off lights and other non-essential equipment. In summer 2000, the ISO observed a measurable reduction in demand during a test of several state agencies that participated in a similar effort. However, despite that test and the fact that state facility operators have more of an incentive to comply with demand reduction directives because they are answerable to state policy makers, the manual nature of this program makes its level of demand reduction subject to human error and building operator preference.
- The energy commission has engaged in limited monitoring and has not thus far evaluated the level of participation in the water-systems equipment replacement program against set milestones such as equipment order and delivery dates and project installation and test dates. Without performing such activities, the energy commission reduces its chances of achieving its peak energy reduction goals; the third largest in its Peak Load Reduction Program.

Commercial and Residential Building Standards and Appliance Standards

The energy commission updated its building standards in January 2001 and plans to complete its update of appliance standards in May 2001. These standards dictate the energy efficiency levels to be met in constructing buildings and for certain new appliance use in the State and will go into effect beginning June 2001 and thereafter. Because any new building construction and increased appliance use puts an added strain on the State's power grid and because these standards are designed simply to slow the demand for electricity rather than reduce existing levels, these programs are not reflected in Table 11.

Nonetheless, once they go into effect, the energy commission estimates that buildings constructed using these revised standards will be 12 percent more efficient; the peak energy demand associated with one year's worth of construction will be 162 MW to 275 MW less than buildings constructed using the previous standards. Similarly, appliances that meet the revised energy standards and that are placed in use over one year's time will require 40 MW less peak energy. The energy savings provided by both of these standards will most likely occur in 2002 and into the future.

CPUC ESTIMATED DEMAND REDUCTION

AB 970 Programs

The CPUC is implementing AB 970 to reduce peak energy demand in several ways. The self-generation program is designed to shift peak energy demand away from the power grid and toward new technologies that participants install such as solar panels, fuel cells, and certain nondiesel engines. The CPUC estimates that the amount of peak energy savings from this program will grow over four years culminating in 360 MW of savings in its last year. However, because the CPUC's plans for the self-generation program are unstructured and allow participants to choose their own form of technology from certain approved technology types, energy savings ultimately derived from this program will depend upon the mix of technologies participants choose to install. For example, the energy savings could range from 22 MW to 100 MW per year depending upon whether participants were to choose all solar or all engine-driven technologies.

The CPUC's second program, demand control, is meant to affect heating, ventilation, and air-conditioning thermostats in residential and small commercial buildings using Internet-based technology. However, these participants will have the ability to override the signal to adjust their thermostats, therefore, any energy savings may be partially or wholly negated.

Interruptible Program

This program gives participants reduced electric rates in exchange for agreeing to curtail their electrical use if called upon for no more than a certain number of hours per year. As of summer 2000, the three investor-owned utilities had about 2,340 MW of curtailable power under contract. However, after repeated calls to curtail their power, participants began dropping out of the program or simply stopped complying with curtailment requests. Moreover, because of tight energy supplies in January 2001, frequent calls for curtailment over one month's time have nearly exhausted the yearly requirement for participants of two of the investor-owned utilities' programs. Because of the uncertainty surrounding compliance levels and the small amount of program capacity remaining, Table 11 does not reflect the megawatts of curtailable demand this program may provide in 2001. Furthermore, we do not show the curtailable megawatts in subsequent years either because the program has recently undergone significant change and information regarding future participation was unavailable.

In April 2001 the CPUC released a decision containing program revisions meant to maintain the program's viability through summer 2001. The revisions the CPUC made included providing choices for opting out of the program or changing the amount of energy to be curtailed, setting new restrictions on the number and length of power interruptions, and better defining participant eligibility criteria. Although the changes the CPUC made appear reasonable, until participants are called upon under the new requirements it will not be certain whether these program revisions will adequately enhance the program's role in curtailing energy demand and acting as a buffer against rolling blackouts.

Also, in its April 2001 decision the CPUC approved several additional curtailment-type programs. Among these programs are the:

- Base Interruptible Program another version of the interruptible program, gives customers rate discounts for agreeing to curtail their power use up to 120 hours per year. Participants may be

new or customers who have already fulfilled their contractual obligations under the original interruptible program.

- Voluntary Demand Response Program, which allows customers to voluntarily reduce demand on any given day once they are notified by a utility. The participants will receive a cash payment of 35 cents per kilowatt hour of reduction provided.

In its decision, the CPUC did not estimate the megawatt curtailment these programs would produce; therefore, these new programs are not reflected in Table 11. And because of their relative newness, their effectiveness in reducing peak demand will not be known until this summer.

ENERGY COMMISSION ESTIMATED SUPPLY ADDITIONS

Power Plant Siting Processes

It is well known that the supply of electricity within California is insufficient to meet the State's current demand. Efficient siting of new power plants is vital to the State's ability to deliver reliable power over the long-term. According to the energy commission's April 2001 estimates for power plants it has either already approved for construction or is still in the process of reviewing more than 2,000 MW of additional electrical capacity to meet the State's energy needs by the end of August. When added to the 261 MW of new supply that the energy commission is projecting will be provided by new power plants as a result of its Renewable Energy Program and those peaker plants the ISO has contracted for, the total new capacity estimated to be available by the end of August rises to just under 3,000 MW. However, the energy commission's estimates for the delivery of much of this supply is contingent on power plant construction schedules over which it has no control. What follows is a description of the various processes the energy commission is using to add to the State's energy supply and the challenges it faces.

- Notwithstanding construction delays, beginning in July 2001, the State will begin to benefit from the electricity generated by the numerous power plants currently approved for construction under the energy commission's 12-month process. As shown in Table 12, between now and 2004, 8,413 MW are scheduled to be brought on-line, with the largest number of megawatts scheduled to come on-line during 2002.

- The energy commission's 12-month siting process, the process under which many power plants are sited, is averaging longer than the 12-month goal contained in statute. The energy commission took an average of 17 months to approve eight of twelve power plant applications it reviewed between January 1, 1997, and December 31, 2000. Although the delays in siting new plants did not cause California's electricity shortage, they have contributed to the lack of some new power plants coming on-line before the summer months of 2001. Because the process of approving or rejecting applications to site power plants often takes over a year, those power plants comprising 5,070 MW that are under review but not yet approved may slip beyond the energy commission's current projected 2003 and 2004 dates for when the plants will come on-line.

Moreover, the energy commission has recently started using three expedited siting processes of varying lengths, but they will have little effect on the State's summer 2001 electricity supply.

- As reflected in Table 12, the 6-month siting process is not estimated to yield any megawatts until 2003. Assuming the energy commission approves all the applications to site power plants that it has received within its 6-month timeline and construction schedules for these plants do not slip, the State will have an additional 820 MW of electrical supply by the end of 2004.
- The 4-month siting process mandated by AB 970 was initially created specifically to site 'peaker' power plants that could be on-line by August 1, 2001. The energy commission received seven applications under this process but six were withdrawn. The siting process on the remaining plant is complete and as of April 2001 it was estimated to provide 51 MW of new electrical supply by August 2001. The governor extended the deadline to apply using this process until December 31, 2001, for plants that can be on-line by August 31, 2002, but as of April 1, 2001, the energy commission had not received any additional applications for its review under this process.
- As of April 23, 2001 the energy commission was estimating that its 21-day emergency siting process for peaker power plants would bring 207 MW of new supply on-line in August 2001. However, the megawatts added by this process

are falling short of the original intent which, according to the governor's Web site, was to bring 1,000 MW of capacity on-line by July 2001.

In August 2000 the ISO solicited bids for peaker power plants hoping to secure 3,000 MW of power for summer 2001. As of April 6, 2001 it has only been able to contract for 1,325 MW—less than half the original goal. Moreover, the ISO estimates only 250 MW will be available in July 2001. The energy commission as well as other local agencies are responsible for reviewing these applications (the energy commission will review applications for peaker plants of 50 MW or larger). The ISO's estimates assume that the energy commission and other reviewing agencies can review and approve the ISO's contracted sites promptly, and that the developers of these plants can bring them on-line by the dates scheduled.

Table 12 also reflects two other processes through which the energy commission is reviewing applications for additional short-term and longer-term electrical supply that include:

- The Small Power Plant Exemption (SPPE) process—the energy commission uses this process to site plants between 50 MW and 100 MW that meet certain other requirements. According to the energy commission, siting under the SPPE can take 6 to 8 months not including the time other state and local agencies may need to provide relevant approvals. Thus, the 99 MW projected to come on-line in 2003 assumes that no delays occur in the energy commission's siting process, other agencies' approval processes, or in the plant's construction schedule.
- Repowering Project process—this process is for existing power plants that are not currently operating which, with relatively minor refurbishing, can be reactivated and brought back on-line. The energy commission, in response to the State's energy crisis, is attempting to review applications to repower plants within 60 days. On February 7, 2001 the energy commission began reviewing a repower application for a 450 MW plant; but as of April 2001 its review was still not complete. Assuming that the energy commission completes its review soon and the power plant owner completes any necessary refurbishment, this plant is expected to be on-line in July 2001.

AB 1890 Renewable Energy Program

The 1996 legislation that deregulated the State's electricity industry also required the energy commission to preserve the State's commitment to developing diverse, environmentally sensitive electricity resources as California made the transition to a competitive electricity market. In response, the energy commission developed the Renewable Energy Program, which uses funds collected from customers of the investor-owned utilities to subsidize power plants within California that rely on renewable resources such as solar, wind, and solid waste. In June 1998 and again in December 2000, the energy commission held auctions and agreed to subsidize developers once they put into production power plants totaling 552 MW (9 MW from the first auction was subsequently canceled leaving 543 MW) and 471 MW respectively. Although the energy commission expects the first 139 MW of renewable energy from these two auctions to be on-line by June 1, 2001, its estimate reflects that the majority of new supply coming from renewable power plants will not be available until late 2001 and 2002.

Originally, the energy commission expected that all of the 543 MW in its first auction would be on-line by January 1, 2002, however, several of the projects have been delayed. According to the energy commission, reasons for the delays include:

- Developers being unable to secure purchase agreements from the investor-owned utilities in order to obtain construction financing.
- Public opposition over the environmental effects constructing these new plants might cause.

It is possible that these types of difficulties may contribute to similar project delays for the 471 MW the energy commission secured during its most recent auction, which is all anticipated to be on-line by 2002.

Agency's comments provided as text only.

California Energy Commission
Steve Larson, Executive Director
1516 Ninth Street
Sacramento, California 95814-5512

May 14, 2001

Ms. Elaine M. Howle*
State Auditor
California State Auditor
555 Capitol Mall, Suite 300
Sacramento, CA 95814

Dear Ms. Howle:

Thank you for the opportunity to comment on your recent audit report addressing California's energy programs and siting processes. We greatly appreciate the professionalism of your audit team. California is facing significant challenges. As a result, the Governor, Legislature and State agencies are working to increase electricity generation and reduce peak use. We have the following comments on your review of these efforts.

Power Plant Licensing

Although they had a relatively short amount of time to investigate a very complex topic, the audit team developed an understanding of many aspects of electricity restructuring in California and the Energy Commission's power plant licensing program. We would like to express our compliments to the audit team for their openness, objectivity, and professional manner of dealing with these issues.

"Results in Brief"

*Page 3, Paragraph 1, Sentence 3 ***- As the report indicates, during the 1990s, few power plants were proposed in California and the rest of the nation. This was primarily because of uncertainty regarding restructuring. We would like to note that one of the primary contributions to California's energy crisis is the withholding of critical power supplies by the electrical generators. Current "forced" outages are two to four times higher than have been historically experienced. Needed electricity from generation facilities currently on the ground within California is not available resulting not only in higher electricity prices that benefit the owners of those same generation facilities but the prospect of rolling blackouts.

Page 3, Paragraph 1 and 2 - The Energy Commission's evaluation of supply and demand this summer reflected expected historical outage rates. Given the amount of existing generation capacity in-state, the number of new facilities that are expected to come on-line, and other programs such as conservation and efficiency grants/loans, from a numerical perspective there is sufficient generating capacity to meet peak demand this summer. However, for economic and perhaps other reasons, not all of this generation capacity may be available to

*California State Auditor's comments appear on page 111.

**The page numbers refer to an earlier draft report.

California consumers. The higher-than-expected "forced" outage rates demonstrate that generation capacity is in place but not always available.

Page 4 and 5 - The Energy Commission's licensing process is expected by law to meet several objectives. On occasion, attaining some objectives - ensuring legally sustainable decisions, ensuring adequate public participation, accommodating project changes requested by the applicant, ensuring coordination of all agencies, or making the findings required by an override - may result in extending the schedule of a project. The Energy Commission works to balance consideration of all issues and protect the interests of all parties in each case within the identified timeframe.

Page 5, Paragraph 1, Last Sentence - To update the progress on bringing additional generation on-line for the Summer of 2001, as of May 11, 2001, the Energy Commission has approved six projects using the Emergency Siting process for a total of 450 megawatts (MW). All of these projects are in construction. Four more projects are currently in review under that process for 420 MW and eight more are preparing applications for an additional 600 MW of capacity. The other two processes referred to in the report are currently expected to allow in excess of 1,000 MW of additional generation to come on-line by next summer.

"Introduction"

Page 12, Paragraph 1, Sentence 1 - We recommend noting that the Governor's declaration of an energy emergency allowed the Energy Commission to use its emergency permitting authority to permit projects that are exempt from CEQA.

"Chapter 1"

Pages 19 - 21 - As discussed in our comments in the section entitled, "Results in Brief," the amount of installed generation that is off-line because of "forced" outages greatly exceeds historical levels. In its estimates, the Energy Commission did not anticipate that level of existing generation would be unavailable in its evaluation of supply and demand.

"Chapter 3"

Pages 47 and 48 - As mentioned in our comments above, the Energy Commission seeks to accomplish multiple objectives in the licensing process as defined by the Warren-Alquist Act, California Environmental Quality Act, and other statutes. In addition to issuing decisions within the established time-frame, these objectives include:

- producing legally sustainable decisions
- basing decisions on an objective evaluation of the facts and consideration of all information
- appropriately balancing competing interests and needs
- integrating the comments and recommendation of all applicable local, State and federal agencies
- ensuring public participation throughout the decision-making process
- protecting public health, safety, and environmental quality
- being fair and consistent for all projects
- providing regulatory certainty

Based on the unique circumstances of each project, achieving all of these objectives may require an extension of the 12-month timing objective. Information on the unique aspects of each project are available.

As of May 11, 2001, the Energy Commission has now approved 14 major power plants (plants over 300 MW) since 1996. The most recent project was permitted in about 90 days under the Governor's Executive Orders. If this project were included, the average time for permitting those plants would be a few days less than one year. Without this project, the average permitting time is about 15 months. One project, High Desert, took two years and five months because of significant changes in the project description and issues in the case which were subsequently challenged unsuccessfully in court.

Page 62, Paragraph 1, First Sentence - As an update to the information in the report, the seventh application was approved by the Energy Commission in March 2001, but is not expected to go to construction due to lease and contract difficulties between the applicant and the City and County of San Francisco.

In addition to these projects, AB 970 allowed the project under review to be modified from a combined cycle to a simple cycle configuration and approved by the Energy Commission in four months. The applicant of the Sunrise project made this modification. The change was approved by the Energy Commission in less than four months and the project will bring 320 MW on-line this summer.

Peak Load Reduction Programs

The title of Chapter 1, "Plans to Reduce Energy Demand by Summer 2001 Overestimate Potential Peak Energy Savings," may lead readers to a different conclusion than can be drawn from the analysis in the report. The analysis concludes that the savings "may not come true" and that projections are "difficult to predict because they haven't been tried before." The Energy Commission

agrees that the peak load savings are difficult to accurately forecast. As a result, the Energy Commission has used conservative estimates of the savings. The evidence of the savings to date should reassure the Legislature that the Energy Commission's estimates understate the energy savings that will be achieved.

For example, on page 23 the report states that "it seems unlikely that a public outreach program" will be able to save the 2,000 MW the Energy Commission forecasts. The report reaches this conclusion based on the ISO experience of 1,300 MW of demand reduction occurred during January Stage 3 alerts and rolling blackouts. The 1,300 MW represents the firm electricity load that was shed by the ISO to ensure system reliability. It does not estimate the amount of demand reduction Californians have taken in reaction to the energy crisis and higher prices.

①

To estimate actual demand reduction, the Energy Commission conducted an analysis comparing the Year 2000 demand to 2001. The analysis shows demand is significantly lower this year than last year. This demand reduction of over 2,500 megawatts has occurred without the proposed new media campaigns, peak load reduction program, much higher electricity prices or the Governor's 20/20 program. If Californians conserve only at the same rate this summer as they have in March and April (9 percent), the reduction will be 4,500 megawatts. While it is uncertain how much peak reduction will occur this summer, the 2,000 megawatts estimate seems conservative.

Demand Responsive HVAC

The report suggests that the Energy Commission may be overestimating the demand reduction from the Demand Responsive HVAC program. The Report's reasoning is that the program participants voluntarily choose to react to a signal from the ISO or during high demand periods. The report states that: "it may be unrealistic to think that commercial buildings will voluntarily turn up thermostats."

The Energy Commission chose a voluntary curtailment program that provides customers with information on market conditions and the available payment for performance because they are much more likely to deliver MW savings. Mandatory programs in the past have triggered customer resentment and dramatically reduced the potential number of customers willing to participate. One example is the extreme dropout rate currently being experienced in the SCE interruptible curtailable program.

②

The report correctly observes that the Energy Commission will not penalize participants if they override a load curtailment signal but omits the vital fact that participants will be penalized for

failure to respond to the signal and reduce peak load. For example, in the ISO Demand Reduction program there is a significant cash penalty for failure to provide the contracted for load reductions. In addition, the Energy Commission's installation contractors have strong financial incentives to ensure that participating customers respond to these signals. This is because up to 40 percent of each contractor's total contract payments will be withheld if these customers do not provide the contracted for system wide load reductions as measured in the pilot test. Thus, if the participants fail to comply with load reduction signals this summer, **there will be a significant penalty to them and the installation contractors. This fact will substantially reduce the amount of potential of non-compliance.**

3

Water/Wastewater Program

The report looked at the Water/Wastewater Program and observed that they would have expected the Energy Commission to be actively evaluating itself and program participants against set milestones such as:

1. Setting a goal of securing a certain number of participants by set dates that represent the MW reduction to be reached and tracking progress toward the goal.
2. Verifying that equipment is ordered and delivered by set dates.
3. Ensuring that projects are installed, completed and tested by set dates.

The Energy Commission is tracking the commitments by set dates and is presenting that data on a frequent basis. However, the report accurately observes that the program managers' tracking of equipment and installations could be more systematic. The report observed that the Water/Wastewater Program Manager said, that because of limited resources, the evaluation against the milestones suggested above did not occur.

The Energy Commission established the Water/Wastewater program to encourage a wide variety of projects on a first-come first-served basis and was not organized as suggested in the report. It could have been operated in the suggested manner and future programs will consider doing so. However, the Energy Commission has recently received \$367 million of new peak load reduction programs but has not yet received any new staff to implement the programs. Given current resource constraints, there are no plans to visit every site. Verification will rely on telephone calls around June 1 to determine if the equipment had been installed. In addition, the Energy Commission requires monthly progress reports on the status of the projects.

Ms. Elaine M. Howle
May 14, 2001
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The Report's suggestion to track items 2 and 3 is an excellent recommendation and represents a more intensive and formal effort to evaluate progress against milestones. The Energy Commission shall consider developing procedures to obtain more detailed milestone information such as described above if resources permit.

Sincerely,

(Signed by: Steve Larson)

STEVE LARSON
Executive Director

COMMENTS

California State Auditor's Comments on the Response From the State Energy Resources Conservation and Development Commission

To provide clarity and perspective, we are commenting on the State Energy Resources Conservation and Development Commission's (energy commission) response to our audit report. The number corresponds to the number we have placed in the response.

- ① The energy commission is incorrect. According to the Legislative Analyst's Office, the 1,300 megawatts represents the average reduction in demand for energy that the California Independent System Operator (ISO) observed during stage 3 alerts and black-outs in January 2001; it does not represent actions taken by the ISO to curtail energy use to ensure system reliability.
- ② The energy commission's reference to both the ISO's demand reduction program and its own program confuses the issue. The energy commission suggests that there is a penalty for failure to respond to the signal to reduce peak demand in the ISO program. However, there is no requirement that participants of the energy commission's peak demand reduction program for commercial buildings also participate in the ISO demand reduction program. Moreover, as the energy commission does not track the number of its participants that may also be participating in the ISO's demand reduction program, it does not know the number that would be penalized by the ISO should they override demand reduction signals.
- ③ The energy commission missed the point. As we indicate on page 22 of the report, our concern is that program participants will not voluntarily comply to reach peak demand reduction goals; we do not discuss the contractors the energy commission uses for its program.

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Agency's comments provided as text only.

Public Utilities Commission
State of California
Loretta Lynch, President
505 Van Ness Avenue
San Francisco, California 94102

May 11, 2001

Elaine M. Howle*
State Auditor
555 Capitol Mall
Suite 300
Sacramento, CA 95814

Dear Ms. Howle,

Thank you for giving the CPUC this opportunity to comment on the State Auditor's Draft report on the state's oversight of California's energy markets. Our state's energy crisis evolves from a mistaken view that unregulated electricity markets could provide the state with lower cost, reliable and environmentally sound power supplies without the active oversight of state agencies. Consistent with that view, the previous administration pared back the state's regulatory infrastructure in ways that have hampered the state's response to the current crisis.

As addressed below the current Commission has embarked on a number of efforts to revitalize the state's energy efficiency programs, transmission planning and siting efforts, and programs that interrupt large customers to improve reliability. In each case, we are improving the regulatory process and programs, often in ways that are consistent with the report's recommendations.

Energy Efficiency Programs

The investor-owned utilities do not have a stellar record in managing energy efficiency programs to optimize use of ratepayer funds. The fundamental problem is that the utilities are in the business of providing energy, and they profit from increased sales of electricity and natural gas. Even though the Commission has historically instituted programs to offset the incentives that utilities have to sell more product, it is clear that other entities may make better administrators of these programs due to the inherently conflicted nature of the utility. For that reason, the Commission has initiated programs whereby non-utility organizations may administer various energy efficiency programs.

*California State Auditor's comments appear on page 117.

However, in the current crisis, the Commission had little choice but to rely on existing utility programs, which are already up and running. Given the need for immediate results, the Commission could not rely on new, unproven administration of all programs. The Commission is exploring the use of non-utility administration for future programs.

In approving the utility programs for 2001, the Commission gave the utilities' considerable flexibility to allocate funds to maximize energy savings. The Commission did not want to constrain the utilities' ability to redeploy program funds as need to respond to consumer demand for the programs.

- ① Finally, the auditor's recommendation that the Commission maximize energy savings by prioritizing measures for customers that produce the most energy savings raises equity concerns. At present, the Commission requires the utilities to allocate funds collected from each customer class (e.g. residential, commercial, and industrial) back to that customer class. If the Commission implements the auditor's recommendation, residential ratepayers will be required to subsidize energy efficiency programs for large commercial and industrial customers. In addition, SB X1 5
- ② specifically directed that funds be allocated to low-income customers to allow such customers to participate. The audit reports conclusions to emphasize only the programs with the largest savings would negate this effort to more equitably allocate funds, and include all customers in the program efforts.

AB970 Demand Response Programs

The Commission's AB970 programs were developed to minimize overlap with the California Energy Commission's programs and to maximize customer participation in the program. Consistent with the statutory mandates of AB970 regarding the specific types of programs and policy objectives, the Commission developed a tiered approach, allocating the funds among renewable, clean fossil generation, and traditional fossil generation.

- ③ The audit report recommends that the Commission eliminate funding for the \$3 million for a new utility administered website. However, in allocating \$3 million for a statewide website, the Commission intended to make it easier for utility customers to find information in one location, rather than having to go to various different utility and agency sites to find the information.

Transmission Siting

The state needs the CPUC to be the primary agency responsible for transmission planning and siting. Transmission provides major public benefits and will require major investments funded ultimately by the people of California. AB 1890 established a reliability-centered planning process at the Independent System Operator, independent from the Commission's broader review of applications for Certificates of Public Convenience and Necessity (CPCNs).

The ISO's process concentrates on technical studies aimed at satisfying reliability criteria, without consideration of environmental and siting impacts, or the extent to which lines will reduce electricity acquisition costs or produce other economic benefits. Because the Commission's CPCN process also considers public comments, environmental studies, and economic scenarios, the Commission may pick a very different set of transmission alternatives. This process is obviously prone to duplication and cannot respond ideally when needs are urgent, as in the current crisis.

Unlike the ISO, which is governed by a board of directors who are legally bound to protect the interests of that agency, the Commission is a public body fully accountable to the legislature and the governor, with the experience and the legal authority to conduct environmental reviews. PUC already regulates and is familiar with the IOUs who own the bulk of the state's transmission network, and is best situated to compare the costs and benefits of new transmission and the effect on rates consumers will pay. Finally, the CPUC already regulates the distribution network and can assure that the system as a whole is developed in a coordinated fashion.

Legislation is needed to authorize the Commission expedite the siting of transmission lines.

The auditor's report noted that the CEC's expedited siting process has proven to be effective, and that the CPUC often runs into delays in siting transmission projects because of sluggish responses by other agencies involved in the CEQA process. The commission recommends that the expediting legislation include the following components:

- The authority to impose deadlines on studies by other state agencies,
- The ability to override local authorities (and possibly other state agencies) where necessary to establish needed transmission facilities, and
- Authority to resolve environmental issues, independent of current CEQA requirements where necessary.

Interruptible programs

The concerns expressed by the State Auditor in this section mirror similar concerns of the Commission that prompted it to institute a rulemaking to comprehensively review the interruptible programs of each utility (R.00-10-002 issued in October 2000). A significant portion of the findings and analysis contained in the Auditor's Report are based on the results of the Commission's Energy Division's own report (February 2001) on the operation of these programs. As a result of this report, the Commission (through D.01-04-006) significantly revised the existing interruptible programs, as well as developing new programs. The Auditor's report concludes "the changes appear reasonable" but cautions that their actual success will not be known "until the Summer of 2001 or later." While it is true that the actual success or failure will not be immediately

known, it should be noted that the changes were largely developed based upon a consensus proposal that reflected the input of a large number of parties.

We will continue to work with the California Legislature and the State Auditor to resolve the crisis that has threatened the health and welfare of the state's economy and every one of its citizens. Thank you for your consideration.

Sincerely,

(Signed by: Robert Kinosian)

Loretta M. Lynch
President

COMMENTS

California State Auditor's Comments on the Response From the California Public Utilities Commission

To provide clarity and perspective, we are commenting on the California Public Utilities Commission's (CPUC) response to our audit report. The number corresponds to the number we have placed in the response.

- ① As we state on page 41 of the report, we are not recommending that residential ratepayers subsidize efficiency programs aimed at large commercial and industrial customers. Rather, we recommend that the CPUC look for opportunities that will produce the greatest energy savings. In doing so, the CPUC need not use funds collected from residential and small commercial classes, it can use the funds the utilities already collect from their large commercial and industrial ratepayers.
- ② The CPUC is misleading in bringing up a discussion of SB X1 5 at this point. SB X1 5 is a new program, which specifically directs that money provided from the State's General Fund be used for energy efficiency programs that benefit low-income households, among others. Thus, it has no bearing on the use of ratepayer funds for energy efficiency and conservation programs, which are the energy efficiency programs discussed in the report.
- ③ As stated on pages 37 and 38 of our report, we believe the \$3 million annual cost for the Web site the CPUC directed PG&E to create is a poor use of ratepayer funds. Much of the information that will be found on the proposed Web site duplicates information already residing on either PG&E's existing Web site or the sites of other public and private entities. It seems reasonable that the information the CPUC wants made available to the public via PG&E's Web site could be accessed through links from PG&E's existing Web site to other Web sites at significantly less cost to ratepayers.

cc: Members of the Legislature
Office of the Lieutenant Governor
Milton Marks Commission on California State
Government Organization and Economy
Department of Finance
Attorney General
State Controller
State Treasurer
Legislative Analyst
Senate Office of Research
California Research Bureau
Capitol Press