California State Auditor

BUREAU OF STATE AUDITS

California Energy Markets:

The State's Position Has Improved, Due to Efforts by the Department of Water Resources and Other Factors, but Cost Issues and Legal Challenges Continue

April 2003
2002-009

The first five copies of each California State Auditor report are free.
Additional copies are $3 each, payable by check or money order.
You can obtain reports by contacting the Bureau of State Audits
at the following address:

California State Auditor
Bureau of State Audits
555 Capitol Mall, Suite 300
Sacramento, California 95814
(916) 445-0255 or TDD (916) 445-0255 x 216

OR

This report is also available
on the World Wide Web
http://www.bsa.ca.gov/bsa/

The California State Auditor is pleased to announce
the availability of an online subscription service.
For information on how to subscribe, please contact
David Madrigal at (916) 445-0255, ext. 201, or
visit our Web site at www.bsa.ca.gov/bsa

Alternate format reports available upon request.

Permission is granted to reproduce reports.

CALIFORNIA STATE AUDITOR

ELAINE M. HOWLE
STATE AUDITOR

STEVEN M. HENDRICKSON
CHIEF DEPUTY STATE AUDITOR

April 2, 2003

2002-009

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 required by Assembly Bill 1 of the 2001-02 First Extraordinary Session, the Bureau of State Audits presents its second audit report concerning the Department of Water Resources' (department) management of the power-purchasing program.

This report concludes that in the aftermath of the California energy crisis of 2000 and 2001, the department has had some successes in renegotiating its power contracts to better match consumer demand, reduce contract costs, and improve the terms of the agreements. During 2002, the department was able to minimize its sales of surplus power, but it was not able to coordinate the dispatch of its power resources with those of the investor-owned utilities, an action that could have produced savings to ratepayers.

Even though the investor-owned utilities are again responsible for providing power to cover the net short, including dispatching the power from the department's contracts, the department faces continuing challenges in managing the financial and legal risks in its contract portfolio. These challenges include the department's ongoing stewardship of the Electric Power Fund, mitigation of the potential high costs of its contracts, management of its operating and service agreements with the utilities, and the administration of the bonds issued to finance the power-purchasing program. Further, many aspects of the State's power market remain unresolved including creditworthiness of the utilities, long-term governance of the utilities' power procurement practices, further development of new power supplies, and dealing with the outcomes of outstanding investigations and litigation associated with the power crisis.

Respectfully submitted,

Elaine M. Howle

ELAINE M. HOWLE
State Auditor

BUREAU OF STATE AUDITS
555 Capitol Mall, Suite 300, Sacramento, California 95814 Telephone: (916) 445-0255 Fax: (916) 327-0019 www.bsa.ca.gov/bsa

CONTENTS

SUMMARY

Audit Highlights . . .

The Department of Water Resources (department) has renegotiated 23 power contracts with 14 suppliers to improve the energy delivery, financial, and legal aspects of these contracts. In addition, the investor-owned utilities are once again responsible for purchasing the net short.

- ***The portfolio better fits California's power needs by converting nondispatchable power to dispatchable power, but much of the improved fit is due to a reduction of forecasted demand, not the renegotiated contracts.***
- ***Reported contract cost reductions were estimated at $5.5 billion on a nominal basis and based on assumptions at the time of the renegotiations.***
- ***The terms and conditions of the restructured contracts have significantly improved reliability, but the department remains restricted in its ability to assign contracts to other parties and thus remains legally and financially responsible.***

continued on next page

RESULTS IN BRIEF

Forced to act quickly to restore stability to the State's electrical power system during the California energy crisis of 2000 and 2001, the Department of Water Resources (department) entered into a number of long-term contracts for electricity, many of which later proved to be unfavorable to the State. This report follows up on a previous audit report issued in December 2001 that examined those contracts and the department's power-purchasing role and called for a strategic framework for California's electricity industry. The department has had some success in renegotiating the contracts to fit the power supply more closely to consumer demand and to improve the terms and conditions of some contracts. In addition, the responsibility for purchasing the net short (any electricity that the utilities themselves cannot supply) has reverted back to the three largest investor-owned utilities (Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric). However, significant future challenges in energy issues remain for the department, the California Public Utilities Commission, and the investor-owned utilities, particularly with respect to management of the contract portfolio.

During the height of the energy crisis, extreme shortages of electricity caused numerous warnings of blackouts and in some cases led to rolling blackouts. At the same time, electricity prices in the State rose to all-time highs, causing credit problems for the State's three largest investor-owned utilities and leading to a reluctance on the part of generators of electricity to sell power to the utilities. In response to this crisis, the governor declared a state of emergency and the Legislature gave the department the authority to purchase the net-short energy required by the three utilities. The department was given this responsibility by Assembly Bill 1 of the 2001–02 First Extraordinary Session (AB 1X). On January 1, 2003, after nearly two years of purchasing the net-short energy for the investor-owned utilities, the department's power-purchasing responsibility ended and the utilities themselves became responsible for purchasing the energy needed to cover their net-short requirements.

- *Based on March 2003 market assumptions, replacement power costs, and discounting to present value, the department consultant currently estimates ratepayer savings as $580 million.*
- *During 2002 the department was not able to coordinate its power supplies with the utilities' generating facilities so as to minimize ratepayers' costs.*

Even though the investor-owned utilities have resumed purchasing the net short, the department retains substantial responsibilities, including:

- *Stewardship of the Electric Power Fund.*
- *Vigilance to mitigate the potential high costs of its contracts.*
- *Management of operating and service agreements with the investor-owned utilities.*
- *Administration of the bonds issued to finance the power-purchasing program.*

Our December 2001 report observed that the responsibility assigned to the department by AB 1X was an immense challenge, given the crisis situation, the short time to prepare for this new role, and the department's limited power-purchasing experience and lack of infrastructure relative to the scale of this effort. Despite these impediments, the department did step in and buy the power needed to keep the lights on in California. In fulfilling its new role, the department entered into 52 long-term contracts with a face value (nominal value) of $42.9 billion to deliver power in California, and it spent approximately $10.7 billion to purchase power to meet the State's daily power needs through the first nine months of 2001. However, our report concluded that the department needed to make improvements in several areas, including improving the terms and conditions of the power contracts it had entered into, managing the future cost and legal risks of these long-term contracts, and developing the infrastructure to support its power-purchasing role. In addition, in the wake of California's failed deregulation plan, we recommended that the governor and Legislature develop a strategic framework for California's electricity industry.

Since our December 2001 report, the department has made progress in implementing our recommendations, but much remains to be done to manage the continuing financial and legal risks that face the State. The department has renegotiated the terms and conditions of 23 long-term power contracts with 14 suppliers, representing over one-half of the total value of the portfolio. These renegotiated contracts contribute to the improved fit of the portfolio to the State's forecasted demand for power by converting significant amounts of nondispatchable or must-take power—power that the department was obligated to purchase regardless of the need—to power deliveries the department can use when needed. In addition, the renegotiated portfolio increases power deliveries in Northern California in 2002 and 2003 to meet demand. Further, the department was able to shift some deliveries of power from Southern to Northern California, which reduced the amount of surplus power projected in Southern California. The department also renegotiated for more capacity tied to tolling agreements—cost-management arrangements that allow the department either to purchase the fuel needed for the power facilities under contract or to tie the fuel cost to the current cost of natural gas.

However, most of the improvement in the fit of the power supply to the demand has resulted from significant changes in the demand forecast rather than from significant improvements in the power contracts. These changes in the forecast include reductions in the demand for power from the investor-owned utilities for a variety of reasons, including the ability of certain electricity customers to buy electricity from alternate suppliers.

The contract renegotiation efforts have reduced the costs of the department's contract portfolio. The savings resulting from the renegotiated contracts can be calculated in a variety of ways, each with some merits and each with some limitations. Throughout the energy crisis, the department and the governor's office reported both the contract costs and the savings in terms of the contract payments to suppliers. Thus, they reported that the estimated reductions in contract costs from the restructuring of the contracts totaled approximately $5.5 billion, which represents approximately 13 percent of the total original contract costs of $42.9 billion. These contract cost reductions were based on information available at the time of the renegotiations and were calculated using a negotiation model that the department used when evaluating the effect of different renegotiation options on the reduction in contract costs.

While this savings estimate reasonably reflects reductions in the nominal cost of the contract portfolio to the department, an alternative analysis would estimate the savings to the utilities' customers. With consideration of the replacement power costs and using a revenue requirement model, a department consultant currently estimates that the net savings to ratepayers in nominal terms is $1.5 billion. Also, because these savings will occur over the next 20 years, the department consultant currently estimates that the net present value of the future stream of savings to ratepayers is $580 million. These March 2003 estimates of customer savings are a function of economic, market, and dispatch assumptions used by the department consultant in its modeling and would change if those assumptions changed. Also, the department indicates that its revenue requirement model is not designed to value nonprice benefits resulting from the renegotiation efforts, such as the improved availability and reliability provisions in the contracts. Further, most of these contract cost reductions will result not from reducing the price per megawatt-hour of the power purchased but rather from shortening the length of the contracts or reducing the amount of power to be delivered. However, this reduction of contract length contributed to a department objective to shorten the time that it would have financial or legal responsibility for the contracts and, in the process, permit the utilities to procure energy themselves to meet the additional uncovered net short.

According to the department, the March 2003 estimate of savings to the consumer from the renegotiated contracts as of December 31, 2002, using the revenue requirement model, was made only at our request, and the department would not otherwise have made this calculation. In addition, the amounts are from its consultant's draft report, and as of March 17, 2003, the amounts had not gone through the department's ordinary standards of review for reports of this nature. However, this is the only estimate the department provided to us of the savings to the consumer from the renegotiated portfolio as of December 31, 2002. Further, we observed that these forecasts are consistent with the forecasts prepared by the department consultant in establishing the department's revenue requirements and were also used in support of the revenue bonds that the department issued in October and November 2002.

Our review of the legal terms and conditions of the restructured contracts indicates that although the economic benefits to individual consumers are likely to be modest, the renegotiations have generally resulted in improved terms over those in the original contracts, as shown in our updated report card evaluation of certain contracts. For example, we found that the restructured contracts have much stronger guarantees that the sellers will deliver the power promised under the contracts and build the new generation facilities promised in the contracts. As a result, the renegotiated contracts better meet the reliable energy goals of AB 1X and thus better ensure the availability of electricity to satisfy consumer demand. These improvements are accomplished through stronger terms and conditions, such as termination rights for the State and penalty provisions when sellers fail to deliver energy or construct new generation facilities as promised under the contract. Changes in the type of energy products purchased under the contracts also increase the reliability of the department's long-term contract portfolio. Both the stronger terms and conditions, and the product changes are likely to provide economic benefits to ratepayers.

Another benefit from the renegotiations is that the State has entered into settlement agreements with suppliers, in some cases substantial ones. In most of these settlements, the suppliers agreed to cooperate with the attorney general's energy investigation and to make financial settlements to the State.

While the restructured contracts are better from a legal standpoint, significant risks remain for the department, particularly in the contracts that the State has not renegotiated.

An area of continuing concern is the restrictions on the department's ability to assign the contracts to other parties, particularly to the investor-owned utilities. Now that the department's power-purchasing authority under AB 1X has expired, the investor-owned utilities have resumed purchasing the net short and have also assumed the day-to-day management and operation of the contract portfolio. Nonetheless, the department remains legally and financially responsible for the contracts, until either the investor-owned utilities meet certain credit standards or suppliers decide to release the department from this obligation. As a result, the department continues to have significant ongoing legal and technical responsibilities for the management of the long-term contracts and could retain those responsibilities for the remaining life of the contracts.

In our December 2001 audit, we indicated that in future years the department would have significant amounts of surplus power that it would need to sell. In 2002 the department did sell surplus power, but these sales were not significant in proportion to the department's total purchases. Our consultant advises us that the costs reported from the department's surplus power sales do not appear unreasonable. Although the department's renegotiation efforts have reduced the potential for surplus power sales in future years, it is still likely that significant sales will occur, particularly in the years 2003 through 2005. However, because providers of the net short must ensure that they have sufficient power to meet demand, some sales of surplus power are inevitable to ensure a sufficient supply of power.

The department was not able to achieve a coordinated dispatch of power supplies between the contract portfolio and the investor-owned utilities' generating facilities so as to minimize costs to ratepayers. The electric power that the retail customers of the investor-owned utilities purchase is obtained from a variety of sources—hydroelectric dams, nuclear, and fossil fuel-fired power plants that the utilities own, as well as a variety of contracts with suppliers entered into by the department and the investor-owned utilities—each with a different cost per unit of power delivered during different times of the day and week. As such, there is an opportunity each day to optimize this mix of sources to provide power at the lowest possible cost. In our December 2001 audit, we cite a specific example in which small savings in daily power costs could result in annualized savings to the ratepayers of tens of millions of dollars. However, the department has been unable to implement a coordinated dispatch of power sources with the investor-owned utilities. It attributes this inability, to some degree, to the investor-owned utilities' failure to share with the department information about the availability of their generating facilities and the terms of their third-party contracts, as well as to fluctuations in demand forecasts by the investor-owned utilities that make minimizing purchase costs more difficult.

Finally, substantial work remains to be done by others to restore California's electric markets to full health and to manage the power portfolio assembled by the department during its two-year tenure as power buyer for the State. Issues involving the creditworthiness of the investor-owned utilities must be resolved, plans must be made for the long-term governance of the utilities' power-procurement practices, and changes are needed in the power market structure to assure that the markets are effective and well monitored. Although California's power supply situation has improved over the past two years, accounting and credit issues have affected many companies in the power supply industry, raising questions regarding the further development of new supplies. Furthermore, substantial outstanding investigations and litigation associated with the power crisis are still unresolved. As this range of issues makes clear, much remains to be done to stabilize the State's power markets.

In addition to marketwide issues, the department's ongoing stewardship of the Electric Power Fund and the contract portfolio will be an important component of the State's power supply for years to come. The contract portfolio is likely to remain under department management for much of the next decade and will require continued vigilance to mitigate the potentially high costs of those contracts. Attendant upon those responsibilities will be the need for the department to manage its operating partnerships with the utilities to schedule and deliver the power and to procure fuel. In addition, the department will continue to be responsible for managing the Electric Power Fund and for the administration of the bonds issued to finance the cost of the AB 1X power program. These remaining responsibilities carry substantial ongoing obligations to manage costs and risks and will require a sustained professional organization at the department to properly protect the State's interests.

RECOMMENDATIONS

The department's future activities can be described as falling into four broad categories, each defined by basic contractual responsibilities that it will carry into the future. Our recommendations are that the department continue to (1) meet its legal and technical responsibilities regarding the contract portfolio, (2) manage the operating agreements that set forth how the investor-owned utilities are to operate the contracts, (3) manage the servicing agreements with the investor-owned utilities under which the department collects revenues from the utilities to pay for power and debt service, and (4) service the revenue bonds that were issued to finance the power-purchasing program.

AGENCY COMMENTS

The department indicates that it appreciates our efforts along with those of our consultant in preparing this report. ■

Blank page inserted for reproduction purposes only.

INTRODUCTION

BACKGROUND

Under the terms of Assembly Bill 1 of the 2001–02 First Extraordinary Session (AB 1X), in February 2001 the Department of Water Resources (department) became responsible for buying the net-short power needs of the State's three largest investor-owned utilities (Pacific Gas & Electric [PG&E], Southern California Edison [SCE], and San Diego Gas & Electric [SDG&E]) through December 31, 2002. The net short is the difference between the power that the investor-owned utilities provide from their own supplies and the total consumer demand for power at any given time. AB 1X gave the department its new role in the midst of an unprecedented financial and reliability crisis in the State's electricity industry. During the height of the energy crisis, extreme shortages of electricity caused utilities to issue numerous warnings and in some cases led to rolling blackouts. At the same time, electricity prices in the State rose to all-time highs, causing credit problems for the State's three largest investor-owned utilities and leading to a reluctance on the part of generators of electricity to sell power to the utilities.

Key Provisions of AB 1X*

- The department is authorized to purchase the power necessary to meet the energy needs of the three largest investor-owned utilities and to sell the power to retail customers.
- The department is to build a portfolio of contracts for energy resulting in reliable service at the lowest possible price per kilowatt-hour.
- The cost of the power is to be recovered through consumers' rates.
- The department's procurement authority ends December 31, 2002, but the department can continue to manage the contracts it enters into.

* These provisions became effective on February 1, 2001.

Those primarily affected by the department's power-purchasing activities are the retail customers of the State's three largest investor-owned utilities: PG&E, SCE, and SDG&E. These utilities serve the coastal areas of the State from Eureka to the Mexican border and the majority of the State's inland areas, accounting for approximately 77 percent of the electrical power consumers in the State.

By January 1, 2003, when the department's two-year power-purchasing responsibility ended, it had expended approximately $14 billion for power bought and delivered to consumers. In addition, the department had assembled a portfolio of 52 long-term power contracts for power to be delivered over the next 20 years at an estimated cost of $42.9 billion. In buying that power and executing those contracts, the department incurred administrative and general expenses of approximately $79 million during the two-year period.

FINDINGS FROM OUR 2001 AUDIT

In compliance with the California Water Code, Section 80270, in December 2001 the Bureau of State Audits (bureau) released an audit of the department's responsibilities under AB 1X, titled *California Energy Markets: Pressures Have Eased, but Cost Risks Remain*. In it, we described the underlying problems with California's electricity supply that led to the crisis, the Legislature's response to the crisis, and how the mission of AB 1X dwarfed the department's capabilities. Our audit concluded that the department faced an immense challenge in purchasing the net-short energy of the three investor-owned utilities, but that it had successfully kept the lights on in California. Further, we found that although the crisis had eased, the department's response to the crisis had created certain financial and legal risks that would need careful management, as described in Table 1.

TABLE 1

Key Findings From Our December 2001 Audit

- The speed with which the department entered into contracts in response to the crisis precluded the planning process necessary to implement a power-purchasing program of this size. As a result, the department assembled a portfolio of power contracts, which presents significant risks that will need careful management to avoid increased costs to consumers.
- The portfolio does not contain sufficient power for peak-demand periods, thus potentially exposing consumers to high-market prices if the energy supply becomes limited during those periods.
- The majority of the contracts are not written to ensure a reliable source of power and instead convey lucrative financial terms upon the suppliers to ensure that energy is delivered. In addition, the contracts contain provisions that can increase the cost of power; thus, they need careful management to avoid additional costs to consumers.
- The department lacks the infrastructure needed to properly manage its purchases of the net short, but is taking steps to build up its capabilities.
- Many decisions need to be made about the State's future role in the power market. The department's authority to contract and purchase the net short ends after 2002, yet it or another entity will need to manage the considerable market and legal risks of the power contracts and, if the investor-owned utilities are not creditworthy, purchase the net short.
- Operational improvements are needed to strengthen the department's administration of the power-purchasing program.

We made many recommendations to the department regarding how to address these findings and how to more effectively plan and manage the economic and legal aspects of its portfolio.

In addition, we recommended that the governor and the Legislature work together to develop a strategic plan for the future role of the State in the power market. Appendix A provides a summary of the recommendations from our December 2001 audit and the actions the department has taken to implement those recommendations.

RECENT CHANGES THAT HAVE AFFECTED THE DEPARTMENT'S POWER PROGRAM

Since our December 2001 audit, several changes have occurred that affect the department's power program. One of the more significant of these is the department's effort to renegotiate long-term contracts with the intent to obtain more favorable financial and legal terms and conditions. The renegotiations were possibly easier to accomplish due to actions filed by others against suppliers claiming that they had manipulated the California energy markets to increase profits. In addition, the department was able to secure the financing to pay for its power-purchasing activities. Finally, the responsibility for purchasing power to cover the net short successfully reverted from the department back to the investor-owned utilities on January 1, 2003.

Goals and Objectives of Contract Renegotiation

- Reduce nondispatchable energy to shape supply to match energy demand.
- Shorten contract terms to avoid purchases that sellers required but that were not vital to the State.
- Reduce contract prices to just and reasonable levels and reduce overall portfolio costs.
- Reduce volumes of purchases in later years of contracts.
- Enhance the reliability of energy by improving contract terms.
- Make contracts assignable to other parties.
- Facilitate contract administration by improving the department's contractual rights.
- Target customer savings of at least 20 percent.

Sources: Navigant Consulting, Inc., *Renegotiation of Power Contracts*, October 2002, and Electric Power Group, *Contract Renegotiation Framework and Principles*, June 2002. Both are consultants for the Department of Water Resources.

The State Has Restructured Many of the Long-Term Power Contracts

Recognizing that the financial and legal terms and conditions of the long-term power contracts were not favorable to the ratepayers, the State has worked to renegotiate many of the contracts. The contracts had been criticized by many outside parties as being unfair to the State, and thus in late 2001 the State began making plans to approach sellers to renegotiate the deals. Department consultants recommended that the contracts be renegotiated to achieve certain outcomes and goals, as shown in the text box at left. Key among these goals was the need to reduce the amount of nondispatchable or must-take energy—power that the department must purchase regardless of whether it is needed to meet demand—because the portfolio that the department had assembled focused too much on round-the-clock nondispatchable energy instead of on energy that could be dispatched as needed to meet demand at times when requirements were high. To accomplish the renegotiations, the State assembled a negotiating team consisting of staff from several state entities, including the governor's office, the California Public Utilities Commission (CPUC), the attorney general's office, and the department. Several consultant and legal firms also assisted in the effort. The governor's office directed the renegotiation efforts for most of the contracts.

The first contracts were renegotiated in April 2002, and by December 2002 the State reported renegotiating or canceling 23 contracts, with a $5.5 billion reduction in contract payments. In addition, the governor's office and the department indicated that the renegotiation effort incorporated many of the recommendations from our December 2001 audit, including providing the State with stronger commitments for new power plants, more flexibility, and greater reliability in obtaining power; allowing greater freedom to tailor power supply to meet demand; and improving the department's ability to assign the contracts to the investor-owned utilities after they become creditworthy.

In some instances, the renegotiations have included settlements of claims with the attorney general. For example, two generators paid $8.5 million to the State in exchange for ending the attorney general's claims against them for improper electricity pricing practices. In addition, the State agreed to discontinue its action with the Federal Energy Regulatory Commission (FERC) seeking refunds from the two generators for the allegedly illegal electricity pricing practices in California. The department reports that the renegotiation efforts are continuing in 2003.

In Chapters 1 and 2 of this report, we evaluate the economic benefits and reduction of costs to ratepayers resulting from the contract renegotiations; in Chapter 3 we discuss the extent to which the terms and conditions of the contracts have improved.

A Variety of Factors May Have Helped Bring Generators to the Negotiating Table

As we pointed out in our December 2001 audit, most of the contracts were lucrative for the sellers, and thus there would appear to be little incentive for sellers to renegotiate the contracts. Nonetheless, in early 2002, sellers started coming to the negotiating table. In doing so, they could have been influenced by any of several events. As the negotiating team was identifying areas in which the contracts could be improved and opportunities for aggressively managing the contracts, other state agencies were pursuing relief in other forums from high prices in contracts negotiated in an electricity market that FERC has described as dysfunctional. For example, the CPUC and the California Electricity Oversight Board filed separate complaints with FERC under Section 206 of the Federal Powers Act. These complaints made several allegations, chief among them that the rates under the original contracts are not just and reasonable or consistent with the public's interest, as the Federal Powers Act requires.

In addition, some generators were and are the subject of numerous civil lawsuits alleging, for example, that they engaged in illegal practices such as unfair business practices. The attorney general is investigating whether some generators manipulated the energy market. Moreover, the California State Senate Select Committee to Investigate Price Manipulation of the Wholesale Energy Market continues to investigate the events that led to the State's energy crisis, including the possibility of market manipulation by some of the generators with which the State has long-term energy contracts, placing additional pressure on generators. Further, since mid-2001, when the contracts were signed, various economic factors, including changes in the energy market, have presented generators with new financial challenges, which may have provided additional incentive to renegotiate the contracts. The various pending investigations and lawsuits have created a climate of uncertainty, which the sellers could seek relief from, possibly through settlements with the State. Thus, the State's willingness to enter into settlement agreements with sellers that agreed to renegotiate contracts was likely a factor in getting those sellers to the table and in the ultimate renegotiation of the contracts.

Delays Have Occurred in Recovering the Billions of Dollars Lent to the Department to Finance Power Purchases

After a lengthy delay, the department's mechanism for recovering the costs of operating the power-purchasing program, known as the revenue requirement, was formally implemented in February 2002. The revenue requirement is the amount that the department determines is sufficient, along with the funds in the Electric Power Fund, to pay bond costs, to pay for power purchased, to fund necessary or desirable reserves, to repay advances from the State's General Fund for power purchases with interest, and to pay the department's administrative costs for this program. Under AB 1X, the department is to determine the revenue requirement at least annually and is to recover it through the electricity rates that the CPUC establishes.

Before it could be assured that all its costs would be included in future rates collected by the utilities, the department indicates that it was advised by its financial advisors and the credit rating agencies that in order to sell bonds, it was necessary to enter into a rate agreement with the CPUC regarding the procedures to follow to determine the charges to ratepayers. The CPUC delayed approving the rate agreement until February 2002 so that it could resolve its concerns as to whether the costs and terms in the long-term power contracts were in the best interest of the public. It also had some concerns about the lack of oversight of department costs.

With the approval of the rate agreement and the implementation of the revenue requirement, the department was able to issue bonds in October and November 2002 to finance the costs of the power-purchasing program. These bonds totaled $11.26 billion plus premium and were used to repay the approximately $6.1 billion plus interest that had been advanced from the General Fund and to pay off a short-term loan balance of $3.5 billion that was issued to help fund power purchases. These bonds will be repaid from revenues collected from ratepayers of the three investor-owned utilities, as spelled out in the rate agreement. The department had originally anticipated issuing these bonds in mid to late 2001 but had to wait until the rate agreement was in place.

Responsibility for Purchasing the Net Short Has Reverted to the Investor-Owned Utilities

On January 1, 2003, the department's responsibility for purchasing the net-short energy ended and reverted to the investor-owned utilities. Although AB 1X provided the department the authority to procure power only until December 31, 2002, several issues needed to be resolved before the investor-owned utilities could resume this role. Key among these issues was the need to provide assurances to electricity suppliers that the investor-owned utilities were creditworthy and had the financial resources to resume purchasing the net-short energy needed by their customers. By December 2000 both PG&E and SCE had become uncreditworthy and were financially unable to buy power. PG&E filed for bankruptcy protection in April 2001. Neither utility had regained creditworthy status by December 2002. Thus, to enable them to resume buying power on January 1, 2003, the California Independent System Operator (ISO), which operates the State's short-term electricity markets, required PG&E and SCE to submit security deposits to cover their purchasing activities until they regain full creditworthy status.

Another issue concerned who would manage and dispatch the energy from the department's long-term power contracts. By late December 2002, the CPUC had acted to allocate the department's contracts among the investor-owned utilities and had issued orders necessary for them to fully assume power-purchasing functions and all the operational, dispatch, and administrative functions for the allocated contracts, allowing the utilities to act as agents for the department. This was necessary because the department's contracts were written so that the department could not easily assign its rights and obligations under the contracts to the investor-owned utilities.

Once the investor-owned utilities began operating the contracts on behalf of the department, formal operating agreements were needed to ensure that the department receives the information it needs to perform its existing statutory and contractual obligations. Without such agreements, the department would be vulnerable to financial and legal risks. The operating agreements, which the CPUC is currently considering for approval, are intended to mitigate the department's risks by providing it assurances on a number of issues, including that the investor-owned utilities will dispatch energy from their generating facilities and the department's contracts in a manner that results in the least cost to ratepayers. We discuss these operating agreements in more detail in Chapter 6.

SCOPE AND METHODOLOGY

The California Water Code, Section 80270, requires the bureau to conduct two financial and performance audits of the department's implementation of the power-purchasing program: the first due by December 31, 2001, and the second due by March 31, 2003. We completed the first required audit on December 20, 2001, and this audit fulfills the requirement for the second audit report. To implement this broad mandate, our first audit focused on the critical tasks necessary to implement and manage a program to purchase a sufficient and reliable supply of electric power at the lowest possible price per kilowatt-hour. In this audit, we follow up on the department's actions with respect to the recommendations from our 2001 audit. To assist us in forming our conclusions related to the economic issues involved, we retained the services of an energy economics firm. This firm, La Capra Associates, performed various analyses that we requested.

To understand the department's progress in implementing the recommendations from our December 2001 audit, we reviewed its 60-day and six-month responses to the audit. We also interviewed key department staff, along with staff from the consulting firms assisting it in performing the duties required under AB 1X.

A major effort for the department since our last audit—and one of our key recommendations—was to restructure certain of the long-term power contracts from the original portfolio that it assembled in early to mid-2001. Thus, we focused on three aspects of how the restructuring benefited the department and ratepayers. Specifically, we looked at whether the restructuring efforts (1) improved the fit of power deliveries to consumer demand, (2) resulted in financial savings in terms of contract cost reductions and reduced costs to ratepayers, and (3) provided better legal terms and conditions for ensuring that power suppliers fulfill their contractual obligations. As we noted earlier, these benefits were among the specific goals and objectives that the State had set.

To determine whether the restructuring improved the fit of deliveries to consumer demand, we reviewed department documents and data to understand the changes to long-term contracts resulting from contract renegotiation. We also reviewed the results of the department's modeling of the California wholesale power market to obtain information regarding market prices, along with the generation and power costs associated with the contract portfolio. We did not review the terms and conditions of the individual renegotiated contracts to verify the accuracy of inputs to the department's model, but our consultant was satisfied that the department's data were reasonably accurate. Our consultant used the model results to update the capacity, cost, and product-type analysis of the contract portfolio presented in our December 2001 audit. Next our consultant compared the contract portfolio before and after renegotiations to determine whether the renegotiated portfolio of long-term contracts better met the department's future capacity and energy needs and, if so, whether the improvement was attributable to the renegotiation efforts, other factors, or a combination of the two. Finally, we analyzed whether the cost of electricity supplied by the new portfolio better tracked changes in gas costs.

In addition, our consultant analyzed the fit of the power supplies to consumer demand for 2004, using a load duration analysis. A load duration analysis is a standard tool used by energy experts to compare on an hourly basis the power deliveries by product type to forecasted demand. Our consultant used department data in this analysis to graphically display the fit of the contract portfolio to forecasted demand before and after the contract restructuring efforts. Three metrics were used in our consultant's analysis: (1) the remaining capacity need in megawatt-hours, (2) the remaining energy need in gigawatt-hours, and (3) energy surpluses from must-take contracts. In each case, the evaluation was conducted for Northern and Southern California, referred to as north of Path 15 (NP15) and south of Path 15 (SP15), as well as for the entire area served by the contract portfolio, for both peak and off-peak periods. To determine the effect of a change in forecasted demand on the fit of the contract portfolio to consumer demand, our consultant also analyzed the fit of the contract portfolio before renegotiations against forecasts of market conditions as of mid-2001 and mid-2002.

To determine whether the restructuring efforts resulted in financial savings, we reviewed the department consultant's calculations of contract cost reductions and ratepayer savings. Our analysis focused on the renegotiated contracts with the largest reported cost reductions because these contracts represent approximately 95 percent of the reported cost reductions. For these contracts, we reviewed the specific terms and conditions that were renegotiated, to determine whether the department's estimates of cost reductions were reasonable. We also sought to determine the main sources of the cost reductions—reductions in contract length, quantity of power, or price. In addition, we reviewed the department consultant's estimates of ratepayer savings. We did not conduct a comprehensive review of all the underlying assumptions used in these calculations; however, our consultant was satisfied that the calculations were reasonably prepared. Finally, we compared per-unit costs of energy in the renegotiated portfolio to the latest forecast of market prices by the department consultant to assess the degree of improvement in the renegotiated portfolio relative to current estimates of competitively priced power.

To determine whether the restructured contracts provide better legal terms and conditions for (1) ensuring that power suppliers fulfill their contractual obligations, (2) providing the department with more flexibility in managing the contracts, and (3) facilitating the transfer of the contracts to the investor-owned utilities, we first compared the terms and conditions of the renegotiated Calpeak, Calpine, GWF, High Desert, Sunrise, and Williams contracts, representing approximately 95 percent of the reported cost reductions, with those of the original contracts to identify changes in the contracts. We next requested that the department provide us with a list identifying changes in the renegotiated contracts based on the criteria we used in the contract report card presented in our December 2001 report. We then compared the changes the department identified with the changes we identified in the renegotiated contracts we reviewed to determine whether the renegotiated contracts made changes in areas we identified as weak in the December 2001 report. We then analyzed each change to determine whether it resulted in an improvement to the contract. We also reviewed each of the selected renegotiated contracts for changes to determine whether the renegotiated contract provides the department with more flexibility in managing the contract and whether it better facilitates transfer of the contract to the investor-owned utilities.

Another key recommendation from our previous audit was that the department carefully monitor levels of surplus energy from the contract portfolio to ensure that these sales are minimized so as to avoid increased costs for ratepayers. To analyze the department's efforts to control the levels of surplus energy and the resulting sales, we reviewed reports showing these sales during 2002. We also obtained information regarding market prices, the net short, and variations in the net short to better understand the context within which the sales were made. Using these data, we identified specific days to analyze to determine the degree to which sales for 2002 might be explained by sales of surplus power, changes in the investor-owned utilities' forecasts of the net short, and the use of dispatchable contracts to earn profits to offset the department's overall energy program costs. We obtained and reviewed invoices and 10-minute interval data from the ISO to evaluate the extent to which the department's power-scheduling decisions might have been influenced by the actual, real-time net short. We did not evaluate sales or imbalance data for every day during 2002. To provide context, we often have attempted to present our conclusions in annualized terms. However, in most instances such conclusions are necessarily extrapolations based on the days in our sample.

We also analyzed the department's efforts to minimize the cost to ratepayers by coordinating the dispatch of power between the contract portfolio and power sources owned by or retained by the investor-owned utilities. However, based on discussions with the department and its consultant, we determined that no progress had been made toward achieving a coordinated dispatch of power sources. Thus, we analyzed documents to develop an estimate of the potential value of a coordinated hydropower dispatch, representing only one aspect of a potentially broader coordinated dispatch effort. Because the department relies upon forecasts of power needs from the investor-owned utilities to make power-purchasing decisions, we performed analyses to determine the degree to which changes in these forecasts of the net short might be complicating the department's efforts to minimize the costs of its dispatch. We did not seek to obtain data from the investor-owned utilities to estimate the benefit of a fully coordinated dispatch because these data were unavailable to the department.

The department contracts with a private accounting firm to audit the Electric Power Fund and its water project funds. Therefore, we generally limited our financial audit to evaluating the department's efforts to segregate properly the expenditures of the power-purchasing program from the other programs it administers. We did find several immaterial errors in segregating expenditures that we brought to the attention of department management. We also reviewed administrative expenditures charged to the power-purchasing program and found no evidence of unauthorized expenditures in the sample we tested.

Because the revenue requirement receives outside scrutiny from consumer advocates and the CPUC, we did not perform a detailed review of the department's methods and analyses in determining those requirements.

Because of past problems with ensuring that individuals working in the power-purchasing program disclose potential conflicts of interest, we reviewed the department's current practice of monitoring for such conflicts. We found a few instances of contractor employees not being screened to determine if they needed to complete required disclosure forms, which we brought to the attention of department management.

Finally, we identified and explored the major continuing challenges with respect to the energy issues facing the department and the State. We examined provisions in statute, CPUC rulings, and formal operating agreements between the department and the investor-owned utilities, focusing on optimization of the combined supply portfolios of the department and the investor-owned utilities to benefit ratepayers. We also obtained the views of senior staff from the department and its consultants on important issues confronting the department and the department's plans for addressing them. Finally, we reviewed state and federal regulatory challenges affecting the contract portfolio. ■

CHAPTER 1

With Renegotiated Contracts and a Reduction in Forecasted Demand, the Contracted Electricity Portfolio Better Matches California's Needs and Better Tracks Changes in Fuel Costs

CHAPTER SUMMARY

Our December 2001 audit concluded that the contract portfolio assembled by the Department of Water Resources (department) contained significant cost risks that the department would need to manage carefully. Over the past year, a state negotiating team has reached agreement on new terms and conditions for 23 of the long-term contracts, improving the fit of the department's power supplies to California's energy and capacity needs. While the improved fit has reduced the department's exposure to cost risk, an even greater reduction in cost risk results from the forecasted reduction in the demand for power that the utilities must buy (the net short).

The renegotiated portfolio better matches California's power needs in several critical areas. The portfolio now contains significantly less nondispatchable or must-take energy—energy that must be purchased regardless of the need. The nondispatchable capacity has been replaced in large part by dispatchable contracts that allow the department to take delivery only when the power is needed. These changes will allow the department to significantly reduce its excess energy purchases, particularly in Southern California, where the capacity under contract from the fourth quarter of 2003 through the first quarter of 2005 was expected to exceed average peak demands, resulting in significant energy surpluses. The total capacity of the portfolio has also increased in some years, a change that increases the proportion of the net-short peak demand that is met by long-term contracts. This, in turn, reduces some of the ratepayers' exposure to spikes in spot market prices.

Further, contract renegotiation has increased the amount of capacity in the portfolio associated with tolling contracts, in which either the buyer supplies the fuel used to generate electricity or the cost of power is tied to the cost of natural gas. The percentage of capacity that involves tolling has increased by more than 2,000 megawatts per year above that in the original portfolio from 2003 to 2010. While this change has increased the opportunity for California consumers to benefit from lower natural gas prices in the future, it has also made consumers more susceptible to the risk of higher gas prices. During 2002 the department did reasonably well in purchasing natural gas at market prices for its tolling contracts, but in the role defined by the California Public Utilities Commission (CPUC), it faces the challenge of ensuring that the investor-owned utilities appropriately manage future gas purchases.

THE DEPARTMENT SOUGHT THROUGH CONTRACT RENEGOTIATION TO ALLEVIATE THE COST RISKS EXISTING IN THE ORIGINAL PORTFOLIO OF CONTRACTS

The department assembled the portfolio under extraordinary circumstances, entering into 40 agreements with a value of $35.9 billion in 30 days.

The department's renegotiation efforts sought to address many of the cost risks existing in the contract portfolio that it created during the energy crisis. As we noted in our December 2001 audit, the department assembled the portfolio under extraordinary circumstances and in a short time period—40 agreements with a value of $35.9 billion were entered into in 30 days—which undoubtedly complicated these efforts. Our December 2001 audit discussed the advantages and disadvantages of the department's procurement strategy and that the original contract portfolio presented the following cost risks:

- The original portfolio is priced substantially above the future market prices then projected for power purchased in the spot market. Forecasts of market prices can be expected to change over time, affecting the relative cost of these fixed-price nondispatchable energy purchases. Further, because these nondispatchable products provide a shelter against the volatility of spot market prices by locking in a fixed price for future purchases, it can be expected that such purchases will, over time, command a premium over market prices, depending on supply and demand conditions. However, our consultant believes that the premium paid in the department's contracts is greater than what these factors would suggest it should be.

- The original portfolio provides most of the net-short energy needed during most hours of the year but much less of the capacity needed during peak-demand periods. As a result, the portfolio would not cover a substantial portion of the peak demand on hot summer days, when spot market prices are likely to be at their highest.

- Most of the department's original contracts are nondispatchable, meaning that the department must take, and pay for, the power that it has contracted for. Thus, the original portfolio provides little flexibility to reduce purchases at times when lower-priced market power is available or when power supplies exceed demand. After the crisis eased, a great deal of lower-cost power did become available, but the department was unable to benefit significantly from these reduced prices.

- The original portfolio contains relatively few contracts that allow power prices to float with changes in the price of natural gas, which was projected to fall from the record high levels that existed at the time the department signed most of the contracts.

- The original portfolio provides for the delivery of more power than customers in Southern California are expected to use during the period from late 2003 through early 2005, creating the potential for substantial sales of surplus power—likely at a loss—during that period.

- Despite the legislative intent for the department to procure as much power as possible from renewable energy sources—generating sources that produce less pollution than other sources of energy—less than 2 percent of the power in the original portfolio comes from renewable sources.

Through December 2002, 23 long-term contracts with 14 suppliers were renegotiated, accounting for approximately half of the original portfolio value of $42.9 billion.

A state negotiating team began an effort to renegotiate selected long-term contracts in late 2001, with the intent of mitigating these problems. Through December 2002, the state team had renegotiated the terms and conditions of 23 long-term contracts with 14 suppliers. These 23 contracts account for approximately half of the original portfolio cost of $42.9 billion[1], and they represent 44 percent of the total capacity originally slated for delivery in 2003. This chapter addresses the extent to which the renegotiations improved the fit of the original portfolio to the State's future power needs. That is, it addresses whether the renegotiated portfolio is better able to meet the utilities' future net-short capacity and energy requirements at a lower cost and with reduced energy surpluses.

[1] In our December 2001 audit, our consultant estimated the cost of portfolio in its first 10 years to be $42.6 billion. The estimate above, $42.9 billion, based on an analysis performed by the department consultant, incorporates the full life of the portfolio of 20 years using 2001 market assumptions. Some assumptions, particularly fuel prices, may also differ.

THE DEPARTMENT WAS ABLE TO REDUCE THE AMOUNT OF NONDISPATCHABLE ENERGY IN THE PORTFOLIO AND REPLACE IT WITH DISPATCHABLE CAPACITY, BUT ROOM FOR IMPROVEMENT EXISTS

Our December 2001 audit noted that most of the contracts in the department's portfolio required sellers to deliver, and the department to take, energy at a constant rate during specified time periods. For example, most base products in the department's portfolio obligated sellers to deliver firm energy at a constant rate 24 hours a day, seven days a week, 52 weeks a year (known as 7x24 nondispatchable energy products). Similarly, most peak products committed suppliers to deliver firm energy at a constant rate during peak hours for a specified number of days per week (such as the 6x16 product, which delivers energy 16 hours a day, six days a week, 52 weeks a year). These types of products are known as nondispatchable because the buyer has no ability to change the rate at which electricity is taken in order to better match supply and demand or to take advantage of lower-cost supply alternatives.

For the period from 2002 to 2010, 71 percent of the megawatts under contract in the original power portfolio were contained in nondispatchable contracts that provide no flexibility to curtail deliveries. Given the variability of electricity supply and demand, no sizable utility system can perfectly match supply to demand on an hour-by-hour basis. However, we concluded that the original portfolio contained too much nondispatchable power and that the magnitude of the difference between the department's nondispatchable energy purchases and the net-short energy requirements during certain periods of low demand would require the sale of significant quantities of surplus energy at prices well below the full contract cost. We also noted in our December 2001 audit that the quantity of surplus energy could increase substantially because the department's net-short position is subject to significant volatility.

Energy Versus Capacity

Energy is a measure of the quantity of electricity produced or delivered over a period of time, and is often measured in kilowatt-hours, megawatt-hours, or gigawatt-hours (where one gigawatt-hour is equal to one thousand megawatt-hours or one million kilowatt-hours).

Capacity is a measure of the rate at which electric energy can be produced or delivered at any point in time, and is often measured in kilowatts or megawatts (where one megawatt is equal to one thousand kilowatts).

In order to mitigate these portfolio problems, the department sought to negotiate changes in its long-term contracts that would reduce the proportion of nondispatchable capacity in the portfolio and increase the proportion of dispatchable capacity. Purchasing dispatchable capacity allows the department to improve the fit of its power supplies to the actual demand. In contrast to nondispatchable contracts, dispatchable contracts provide the department the choice to dispatch—or use—the power under contract when needed, within specified limitations. If demand falls below supply, the department is not obligated to use or pay for the power. Dispatchable contracts also provide the department the option of purchasing the energy on the spot market, rather than dispatching it from some of its contracts, if the spot market price is less than the contract price.

With approximately 59 percent of the capacity still provided by nondispatchable contracts, the renegotiated contract portfolio continues to lack the flexibility to meet the hour-to-hour variation in the net-short energy position.

Table 2 shows that the department was indeed able to reduce the amount of nondispatchable capacity and increase the amount of dispatchable capacity, but room for improvement exists. As a result of these changes, the percentage of megawatts contained in nondispatchable contracts fell from an average of 71 percent in the original portfolio to 59 percent on average in the renegotiated portfolio for the period from 2002 through 2010. During this same period, the dispatchable capacity increased from 38 percent of the portfolio's megawatts in 2002 to 52 percent in 2010, as compared to an average of 29 percent in the original portfolio. However, with approximately 59 percent of the capacity still provided by nondispatchable contracts, the renegotiated contract portfolio continues to lack the flexibility to meet the hour-to-hour variation in the net-short energy position. As a result of this inflexibility, the potential for significant sales of surplus energy continues to exist. For the year 2004, our consultant has estimated that the surplus sales could be as much as 5,700 gigawatt-hours during peak hours, based on the department's current forecast of consumer demand.

TABLE 2

Net Change in Capacity Supplied by Long-Term Contracts After Renegotiations (in Megawatts)

	Calendar Year									
	2001	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Dispatchable	142	892	2,625	1,770	1,995	920	920	790	790	1,090
Nondispatchable	(165)	362	(818)	(1,318)	(1,468)	(705)	(690)	(1,065)	(1,065)	(3,365)
Total for all contracts	**(23)**	**1,254**	**1,807**	**452**	**527**	**215**	**230**	**(275)**	**(275)**	**(2,275)**

Source: Analysis by La Capra Associates using data provided by the Department of Water Resources.

Note: The amounts are the change in the type of capacity after renegotiations, and the total for the year is the change for the portfolio as a result of the renegotiations. Capacities are for peak periods for July and August. A more detailed table is presented on page 144.

CHANGES IN FORECASTED DEMAND FOR POWER AND CONTRACT RENEGOTIATIONS HAVE IMPROVED THE NET-SHORT CAPACITY POSITION

In our December 2001 audit we noted that the department consultant had determined the contracts in the original portfolio would cover, on average, only about half of the net-short capacity needed for the period 2002 through 2010, based on then-current forecasts of peak demand. Net-short capacity refers to the total capacity needed to cover the portion of the peak demand for electricity that the investor-owned utilities cannot produce. Because power cannot be stored in significant quantities for future use, system operators must have sufficient generating capacity operating at all times to meet consumer demand. In Table 3, the Original Portfolio section shows that even in 2004, when the capacity of the original portfolio is at its maximum, only 58 percent of the projected net-short capacity requirement is covered by the department's contracts.

Since our December 2001 audit, the department's consultant has updated its analysis of the net-short capacity to reflect the effects of contract renegotiation and new forecasts of peak demand, direct access, and conservation and load management. The net result of this analysis is summarized in the Renegotiated Portfolio section of Table 3, which shows the required net-short capacity ranging from approximately 12,200 megawatts in 2002 to 22,200 megawatts in 2010. For comparison, the Original Portfolio section of Table 3 shows that the net-short capacity for the same period ranges from approximately 17,100 megawatts to 26,700 megawatts. As a result of this reduction in the estimated net-short capacity required, the percentage of the projected peak demand covered by the department's contracts has increased considerably, especially during the period from 2002 to 2005, when the average coverage of the net short by the department's contracts has risen to 67 percent or more. The Net Change section of Table 3 shows that the factors contributing to the reduction in the net short are a reduction in the forecast peak demand for electricity, an increase in direct access by consumers, and a reduction in the amount of demand carried over by discontinued conservation and load management programs.

Elements of the Forecasted Demand for Power

- **Peak demand**—The greatest demand for power that occurs during a given time period.
- **Utility-retained generation**—The capacity available from sources that the investor-owned utilities provide.
- **Conservation and load management**—Energy conservation programs designed to reduce the demand for power.
- **Direct access**—A program that allowed consumers to choose to directly contract for power from a power supplier, rather than purchasing power from their local utilities.

TABLE 3

Forecasted Net-Short Capacity (in Megawatts)

	Calendar Year								
	2002	2003	2004	2005	2006	2007	2008	2009	2010
ORIGINAL PORTFOLIO*									
Peak Demand	**43,105**	**44,093**	**45,100**	**45,541**	**46,517**	**47,550**	**48,541**	**49,494**	**50,289**
Self-Generation	(312)	(543)	(795)	(1,059)	(1,309)	(1,545)	(1,779)	(2,014)	(2,248)
Direct Access	(355)	(382)	(395)	(403)	(1,713)	(2,708)	(2,961)	(3,154)	(3,183)
Utility-Retained Generation	(19,753)	(19,682)	(19,386)	(18,185)	(17,535)	(17,303)	(16,569)	(16,148)	(15,924)
Conservation and Load Management	(5,536)	(3,389)	(2,777)	(2,587)	(2,617)	(2,415)	(2,201)	(2,222)	(2,238)
Net Short	**17,149**	**20,097**	**21,747**	**23,307**	**23,343**	**23,579**	**25,031**	**25,956**	**26,696**
Department Contracts	(7,917)	(11,046)	(12,555)	(11,680)	(11,617)	(11,602)	(11,302)	(11,302)	(11,002)
Residual Net Short	**9,232**	**9,051**	**9,192**	**11,627**	**11,726**	**11,977**	**13,729**	**14,654**	**15,694**
Department Contracts as a Percent of Net Short	46%	55%	58%	50%	50%	49%	45%	44%	41%
RENEGOTIATED PORTFOLIO†									
Peak Demand	**37,651**	**38,351**	**39,162**	**40,028**	**40,858**	**41,641**	**42,461**	**43,262**	**44,102**
Self-Generation	(121)	(256)	(365)	(475)	(548)	(620)	(696)	(776)	(860)
Direct Access	(4,714)	(4,714)	(4,714)	(4,714)	(4,714)	(4,714)	(4,714)	(4,714)	(4,714)
Utility-Retained Generation	(20,610)	(20,772)	(19,616)	(18,782)	(18,018)	(17,636)	(17,532)	(16,660)	(16,333)
Conservation and Load Management	(55)	0	0	0	0	0	0	0	0
Net Short	**12,151**	**12,609**	**14,467**	**16,057**	**17,578**	**18,671**	**19,519**	**21,112**	**22,195**
Department Contracts	(8,407)	(11,143)	(11,332)	(10,721)	(10,446)	(9,928)	(9,628)	(9,628)	(7,328)
Residual Net Short	**3,744**	**1,466**	**3,135**	**5,336**	**7,132**	**8,743**	**9,891**	**11,484**	**14,867**
Department Contracts as a Percent of Net Short	69%	88%	78%	67%	59%	53%	49%	46%	33%
NET CHANGE	-13%	-13%	-13%	-12%	-12%	-12%	-13%	-13%	-12%
Peak Demand	**(5,454)**	**(5,742)**	**(5,938)**	**(5,513)**	**(5,659)**	**(5,909)**	**(6,080)**	**(6,232)**	**(6,187)**
Self-Generation	(191)	(287)	(430)	(584)	(761)	(925)	(1,083)	(1,238)	(1,388)
Direct Access	4,359	4,332	4,319	4,311	3,001	2,006	1,753	1,560	1,531
Utility Retained Generation	857	1,090	230	597	483	333	963	512	409
Conservation and Load Management	(5,481)	(3,389)	(2,777)	(2,587)	(2,617)	(2,415)	(2,201)	(2,222)	(2,238)
Net Short	**(4,998)**	**(7,488)**	**(7,280)**	**(7,250)**	**(5,765)**	**(4,908)**	**(5,512)**	**(4,844)**	**(4,501)**
Department Contracts	490	97	(1,223)	(959)	(1,171)	(1,674)	(1,674)	(1,674)	(3,674)
Residual Net Short	**(5,488)**	**(7,585)**	**(6,057)**	**(6,291)**	**(4,594)**	**(3,234)**	**(3,838)**	**(3,170)**	**(827)**

* Power Supply Revenue Bonds, Department of Water Resources, draft consultant report, July 2001, prepared by Navigant Consulting, Inc.

† Power Supply Revenue Bonds, Department of Water Resources, consultant report, October 2002, prepared by Navigant Consulting, Inc.

The forecast peak demand for electricity has dropped by about 13 percent from the forecast that the department consultant used to evaluate the original portfolio. The department consultant attributes this reduction to the new energy conservation programs begun in 2001, to changes made by consumers in response to higher prices for power charged by the investor-owned utilities, and to changes in power usage in response to the energy crisis.

The increase in direct access load since the previous analysis reflects the fact that customers who contracted to buy electricity from alternate suppliers on or before the date that the CPUC suspended the direct access program will continue to be eligible for such service. As we noted in our December 2001 audit, the CPUC order suspended all contracts for the direct access program that were entered into after September 20, 2001, instead of using a much earlier cut-off date, as the department consultant had expected. The effect of this order is to reduce the peak demand for power served by the contract portfolio because the order allowed more customers than expected to remain in contracts with alternate suppliers rather than receiving their power from the three investor-owned utilities.

Finally, the reduction in conservation and load management is explained by the fact that funding for all but one of these programs was discontinued in 2002. The remaining program is expected to provide a much lower reduction in energy usage during 2002. However, the conservation and load management initiatives undertaken in 2001 are expected to provide continuing load-reduction benefits. According to the department consultant, the reduction in demand resulting from continuing conservation and load management programs is included in the peak demand in the forecast for the renegotiated portfolio shown previously in Table 3.

CONTRACT RENEGOTIATION EFFORTS HAVE REDUCED THE OVERSUPPLY OF POWER IN SOUTHERN CALIFORNIA, BUT RISKS REMAIN

Although the State's renegotiation efforts have alleviated some of the oversupply problem in Southern California, a substantial surplus continues in that zone. Further, the renegotiation efforts have had minimal impact on the need for additional capacity to meet peak demand in Northern California. Our consultant used the load duration curves shown in Figure 1 on page 30 and Figure 2 on page 31 to analyze the fit of the contract portfolio before and after the contract renegotiations. A load duration curve ranks the hourly customer demands for power from greatest to least in a given period, such as a year. That is, the highest or maximum hourly demand, which occurs in only one hour of the year, is shown at approximately 0 percent on the curve. In contrast, the lowest or minimum hourly demand occurs at one hour of the year and is shown at approximately 100 percent (hour 8,760) on the curve. The highest load defines the maximum operating generating capacity needed during the year and determines the capacity requirement—the total number of megawatts the generation system must be capable of producing instantaneously to assure reliable supplies. There are very few hours in the year when generation production must be close to that level. The annual energy requirement is the sum of the hourly loads over all of the hours in the year and is expressed in terms of megawatt-hours.

In our December 2001 audit, we used a hypothetical load duration figure to illustrate that while the department had contracted for sufficient energy to cover most of the net-short energy required through 2010, it had acquired enough capacity to cover only about half of the net-short capacity it would require. We also noted that the net-short capacity needed was subject to considerable variation, to which the department would have to respond over time. This variation is the result of changes in capacity contributions from the investor-owned utilities' own generation, changes in loads with the seasons, and daily and hourly changes in loads as commercial facilities initiate and close operations and residential customers switch their home appliances on and off.

Our consultant's load duration curve analysis for this audit sought to determine (1) the remaining net-short capacity need in megawatts that is not being met by the portfolio, (2) the remaining net-short energy need in gigawatt-hours that is not being met by the portfolio, and (3) energy surpluses from nondispatchable contracts. To determine only the changes that resulted from contract renegotiations, the load duration curves for before and after contract renegotiation use a demand forecast prepared by the department consultant in mid-2002, at the time of the department's 2002 revenue requirement filing. Further, our consultant's analysis was split between the peak and off-peak hours of the day because the power needs as well

Peak Hours Versus Off-peak Hours

Peak hours—Range from 7 a.m. to 11 p.m., the time when the demand for power is greatest in the day.

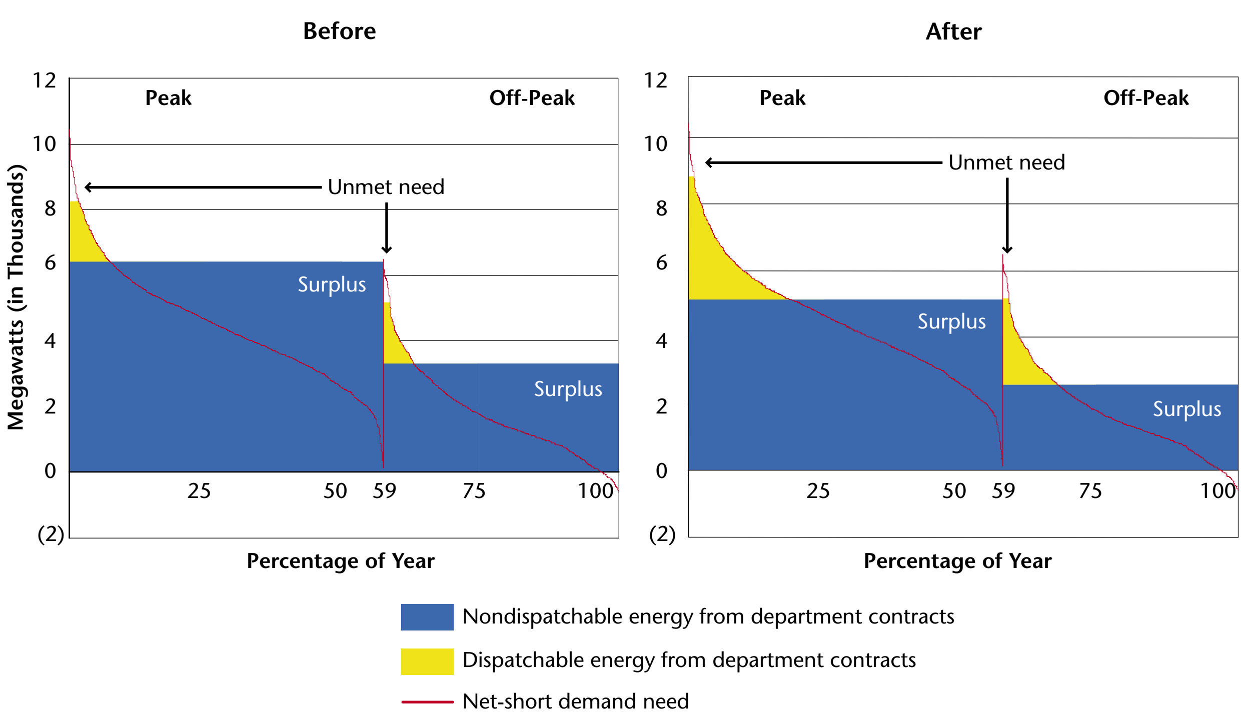
Off-peak hours—Range from 11 p.m. to 7 a.m., usually the time of least power demand.

as the energy supplies available are different during these times. The load duration curves use 2004 as a reference year because this is the year that the capacity of the department's portfolio is at its maximum and, therefore, the year with the greatest potential for energy surpluses. Figure 1 covers the zone south of Path 15 (SP15), which includes the service areas of Southern California Edison and San Diego Gas & Electric—basically Southern California. Figure 2 covers the zone north of Path 15 (NP15), which includes the Pacific Gas & Electric service area—basically Northern California. We have examined these regions separately because it is currently not possible to transmit large amounts of power between the two regions, due to limited transmission capacity.

The load duration curves use a red line to depict the consumer demand for power during various hours of the year. The shaded areas represent power deliveries from the contract portfolio—marked by type of product—with shaded areas above the line being surplus power that is not needed to meet forecasted demand.

FIGURE 1

Load Duration Curves for the SP15 Zone Before and After Contract Renegotiation for 2004



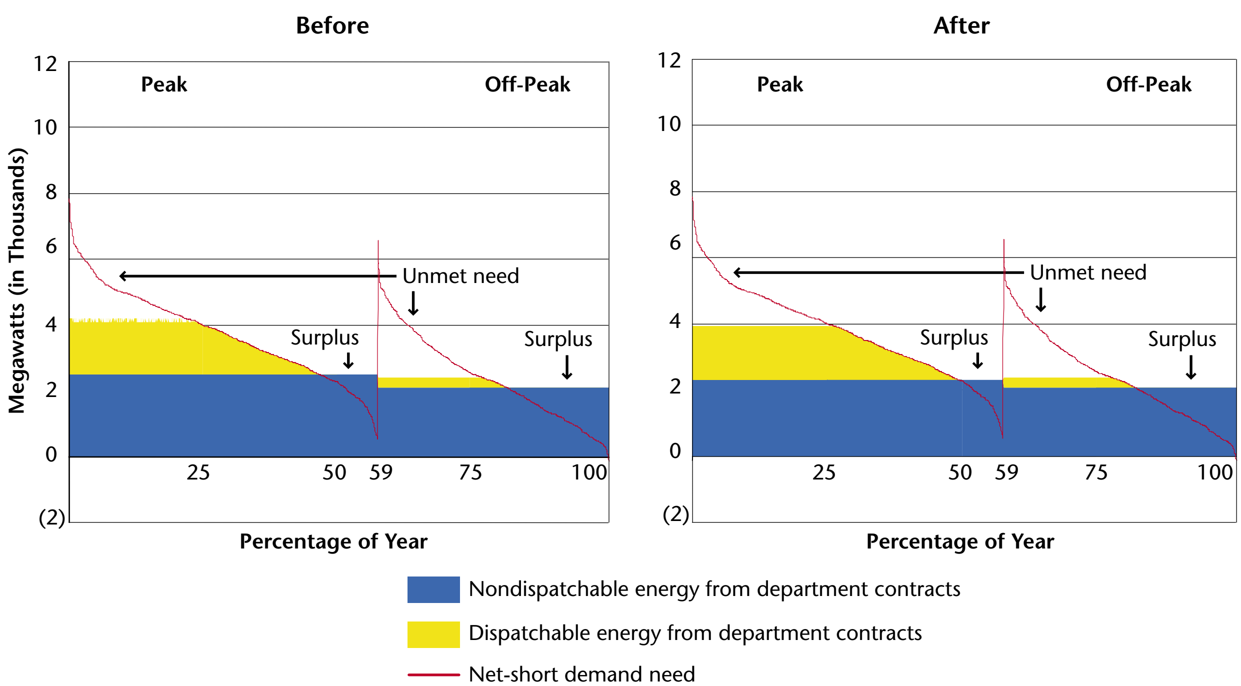
Source: Load duration analysis by La Capra Associates. To show only the change in power delivered from the contract portfolio, both curves use a September 2002 demand forecast prepared by the Department of Water Resources' consultant, Navigant Consulting, Inc.

This power would need to be disposed of, most likely at less than the contract price. White areas under the red line represent capacity that will need to be purchased to meet demand.

The Southern California load duration curves shown in Figure 1 indicate that, in that region, the department contracts will provide most of the power needed to meet the regional net short in 2004. Also, while the renegotiations have reduced the amounts of surplus energy, significant amounts remain in both peak and off-peak hours. Thus there is a need for the department, the investor-owned utilities, and the CPUC—in accordance with their respective roles—to carefully monitor surplus power sales to minimize the cost to ratepayers.

FIGURE 2

Load Duration Curves for the NP15 Zone Before and After Contract Renegotiation for 2004



Source: Load duration analysis by La Capra Associates. To show only the change in power delivered from the contract portfolio, both curves use a September 2002 demand forecast prepared by the Department of Water Resources' consultant, Navigant Consulting, Inc.

Figure 2 compares the peak and off-peak load duration curves for the NP15 zone before and after contract renegotiation. These curves depict a different energy supply situation than the one shown in Figure 1. In this region there is some surplus energy at times, but not to the extent existing in Southern California. Instead, there is a continued cost risk associated with the additional capacity needed to meet peak demand, as shown by the significant amount of white areas under the red line. During these peak demand hours, spot market prices can spike, with the resulting increased costs potentially passed on to ratepayers. The State's renegotiation efforts will have minimal impact on the power deliveries to this zone in 2004, and thus the power-procurement strategies that the investor-owned utilities use to address this peak period risk will need close attention.

THE CHANGE IN FORECAST HAD A GREATER IMPACT THAN RENEGOTIATION ON IMPROVING THE FIT OF THE CONTRACT PORTFOLIO TO CONSUMER DEMAND

Table 4 summarizes the peak-hour capacity along with the energy needs and energy surpluses displayed in the load duration curves shown previously in Figures 1 and 2. In addition, the table includes similar data for the original portfolio, but using the 2001 forecast. In order to separate the effects of contract renegotiation from the effects of the change in the demand forecast, our consultant constructed two distinct load duration curves for the before-contract-renegotiation scenario: one based on the 2001 forecast and the other based on the 2002 forecast. To obtain the changes due solely to contract renegotiation, we compared the results from the after-contract-renegotiation scenario, which are based on the 2002 forecast, with the results from the before-contract-renegotiation scenario based on the 2002 forecast. In contrast, to obtain the changes due to both contract renegotiation and the change in the demand forecast, we compared the results from the after-contract-renegotiation scenario with the results of the before-contract-renegotiation scenario based on the 2001 forecast.

The projected energy surplus in the peak hours of 2004 has fallen by about 14,600 gigawatt-hours, but only 5,300 gigawatt-hours of this reduction was due to the renegotiated contracts; the remainder was due to a reduction in forecasted demand.

These analyses reveal that the change in forecast had a greater impact on improving the fit of the portfolio than did contract renegotiation. For example, the energy surplus for both the SP15 and NP15 zones in the peak hours fell from a total of approximately 20,300 gigawatt-hours before renegotiation (shown previously as the shaded areas above the red demand line in Figures 1 and 2, and the number in the column headed 2001 Market Assumptions in Table 4) to approximately 5,700 gigawatt-hours after renegotiation, a change of about 14,600 gigawatt-hours. However, the reduction in energy surpluses due solely to contract renegotiation (shown in Table 4 as the

TABLE 4

Estimated Capacity Need and Energy Surplus in 2004 Before and After Renegotiations (Assumes no energy exchange between NP15 and SP15)

	Peak			Off-peak		
	Before		After	Before		After
Total	**2001 Market Assumptions**	**2002 Market Assumptions**	**2002 Market Assumptions**	**2001 Market Assumptions**	**2002 Market Assumptions**	**2002 Market Assumptions**
Capacity need after nondispatchable and dispatchable contracts (in megawatts)	6,795	5,841	5,564	10,716	5,368	5,386
Energy need after nondispatchable and dispatchable contracts (in gigawatt-hours)	2,873	2,003	2,354	3,295	1,965	2,012
Energy surplus from nondispatchable contracts (in gigawatt-hours)	20,316	10,985	5,726	8,465	7,903	5,641
NP15	**2001 Market Assumptions**	**2002 Market Assumptions**	**2002 Market Assumptions**	**2001 Market Assumptions**	**2002 Market Assumptions**	**2002 Market Assumptions**
Capacity need after nondispatchable and dispatchable contracts (in megawatts)	5,355	3,642	3,932	6,623	4,084	4,112
Energy need after nondispatchable and dispatchable contracts (in gigawatt-hours)	2,815	1,884	2,300	2,996	1,895	1,943
Energy surplus from nondispatchable contracts (in gigawatt-hours)	1,835	581	409	1,076	1,516	1,469
SP15	**2001 Market Assumptions**	**2002 Market Assumptions**	**2002 Market Assumptions**	**2001 Market Assumptions**	**2002 Market Assumptions**	**2002 Market Assumptions**
Capacity need after nondispatchable and dispatchable contracts (in megawatts)	1,440	2,199	1,632	4,093	1,284	1,274
Energy need after nondispatchable and dispatchable contracts (in gigawatt-hours)	58	119	54	299	70	69
Energy surplus from nondispatchable contracts (in gigawatt-hours)	18,481	10,404	5,317	7,389	6,387	4,172

Sources: Load duration analysis of 2004 by La Capra Associates using contract-modeling data prepared by the Department of Water Resources' consultant, Navigant Consulting, Inc. The 2001 Market Assumptions are based on market information from October 2001 and the 2002 Market Assumptions are based on market information from September 2002.

difference between the approximate 11,000 gigawatt-hours in the **Before** column headed 2002 Market Assumptions and the approximate 5,700 gigawatt-hours in the **After** column headed 2002 Market Assumptions) is only about 5,300 gigawatt-hours.

Contract renegotiation had very little effect on the projected 2004 energy surpluses in Northern California, assuming a scenario of no exchange between the two regions, but this should not be a concern, given that the peak and off-peak surpluses in that area are relatively small in comparison to those in Southern California. Further, if the planned upgrade of the transmission lines connecting Northern and Southern California eliminates the existing transmission constraints, our consultant indicates that the total energy surpluses could fall from about 5,700 gigawatt-hours to about 2,900 gigawatt-hours during peak hours and from 5,600 gigawatt-hours to 4,900 gigawatt-hours during off-peak hours. However, the transmission upgrade is not expected to occur until late 2004 at the earliest, and thus it will not be in place in time to alleviate the energy surplus in 2004.

Absent the replacement of more nondispatchable energy by dispatchable capacity, our consultant expects that the energy surpluses in the SP15 zone could continue for at least the next several years. In addition, absent the purchase of additional capacity, we expect that the need for additional peak-hour capacity will continue in the NP15 zone throughout the life of the contract portfolio. Thus the department, the investor-owned utilities, and the CPUC—in accordance with their respective roles—must carefully monitor the situations in each zone to try to minimize the costs passed to ratepayers.

THE ADDITION OF MORE DISPATCHABLE CONTRACTS HAS REDUCED THE POTENTIAL ENERGY SURPLUSES IN SOUTHERN CALIFORNIA AND MET SOME OF THE NEED FOR INCREASED CAPACITY AND ENERGY IN NORTHERN CALIFORNIA

In our December 2001 audit, we noted that the capacity contracted for delivery in Southern California from the fourth quarter of 2003 through the first quarter of 2005 was expected to exceed the average peak demands of consumers in that area, resulting in significant energy surpluses and potentially higher electricity rates because ratepayers will be charged for any loss on sales of surplus energy. The department consultant expects that the surplus will be either sold to out-of-state purchasers at a loss or exchanged with utilities in the Pacific Northwest, since the energy needs of the two regions complement each other. As we mentioned previously, the reason the expected mismatch of loads and supplies in Southern California is a problem is that there is insufficient transmission capacity to move surplus power into Northern California to meet the needs of that area. Table 5 shows that the need for additional power supplies in Northern California has been partially met, but only on a temporary basis, by an increase in the capacity of contracts delivering power to that area in 2002 and 2003.

TABLE 5

Net Change in Allocation of Contract Capacity Among Zones After Renegotiations (in Megawatts)

	Calendar Year					
Zone	**2001**	**2002**	**2003**	**2004**	**2005**	**2006–2010**
NP15	(215)	1,327	1,140	(115)	110	(489)
SP15	192	(73)	667	567	417	14
Total for all contracts	**(23)**	**1,254**	**1,807**	**452**	**527**	**(475)**

Source: Analysis by La Capra Associates using contract summary data from the Department of Water Resources.

Note: The amounts are the change in capacity for that zone after the renegotiations, and the total for the year is the capacity change for the portfolio as a result of the renegotiations. Capacities are for peak periods for July and August. A detailed table is presented on page 145.

Table 5 shows that in 2003 the amount of capacity in SP15 has increased by approximately 670 megawatts, falling to 420 megawatts by 2005. Since this increased capacity is from dispatchable power—as noted previously in Table 2—it will not exacerbate the energy surplus in that zone but rather should help address the remaining peak-hour need.

ALTHOUGH THE DEPARTMENT'S PORTFOLIO HAS BEEN ENHANCED BY THE ADDITION OF MORE TOLLING CONTRACTS, THE RISK OF GAS PRICE INCREASES MUST BE MANAGED

During 2001 the department signed a number of power supply agreements that incorporated tolling agreements, but our December 2001 audit concluded that it could have procured more tolling agreements to allow for better control of gas costs. A tolling agreement is a contract by which the owner of

In a tolling contract, the power buyer, such as the department, is responsible for the fuel supply and for buying the service of converting the fuel into electricity.

a generating facility is paid to "convert" a fuel supply, such as natural gas, to electricity for delivery to a power supply buyer. Tolling agreements typically specify that the generating facility owner will supply fuel, then charge the buyer for fuel costs according to some contractually determined price (these often rely on market indices). Some tolling agreements offer buyers the option of purchasing the fuel supply directly from fuel suppliers. Thus, the main difference between a tolling contract and a power-purchase contract lies in who pays for the fuel used to generate the power. In a power-purchase contract, the power supplier is responsible for the fuel supply and assumes any risk involving fuel availability and price. In a tolling contract, the power buyer, such as the department, is responsible for the fuel supply and for buying the service of converting the fuel into electricity.

In taking responsibility for the fuel supply, the buyer acquires the ability to negotiate with fuel suppliers over price and to determine the appropriate level of fuel price variability for consumers. That is, the power buyer could choose to pass all changes in fuel costs through to consumers, which would mean that power costs would increase when fuel prices increase and decrease when they fell. Alternatively, since fuel prices are among the most volatile of all commodities, the power buyer could adopt a procurement strategy that involves entering into financial contracts to better balance the potential benefits and costs of volatile fuel markets. Financial contracts, such as forwards, futures, and options contracts, transfer risk, especially price risk, to those who are able and willing to bear it. If used effectively, financial contracts can mitigate the cost risk to consumers of large price swings.

Despite the fact that most of the energy for which the department contracted is generated by natural gas-fired power plants, only between 36 percent and 45 percent of the original contract capacity for each year after 2001 contains terms that allow the price of electricity to float with changes in natural gas prices. Thus our December 2001 audit concluded that the original portfolio does not provide consumers the opportunity to benefit meaningfully from falling gas prices and that the department should have procured more tolling contracts, particularly since its consultant was projecting a reduction in natural gas prices from the record high levels of late 2000 and early 2001.

With the renegotiation of some contracts, the capacity in the portfolio associated with tolling contracts has increased considerably. As Table 6 shows, the capacity from tolling contracts has increased by more than 2,000 megawatts above that in the original portfolio for the period from 2003 to 2010. If properly managed, this increase will provide more control over fuel costs associated with the portfolio. While this change has increased the opportunity for consumers to benefit from lower natural gas prices, it also means that consumers bear the risk of higher gas prices. Indeed, given that natural gas prices have fallen well below the record levels of late 2000 and early 2001, when the contracts were first negotiated, the likelihood of future significant price reductions is smaller than the likelihood of significant price increases. In October 2002 the department consultant projected that natural gas prices will increase by approximately 50 percent by 2011. Now that the investor-owned utilities are managing the fuel costs for these contracts, the department and the CPUC—in accordance with their respective roles—will need to be vigilant to ensure that each investor-owned utility adopts a procurement strategy to minimize the risk that ratepayers will be subjected to higher electricity rates due to surges in natural gas prices.

TABLE 6

Net Change in Capacity of Tolling and Indexed Price Contracts After Renegotiations (in Megawatts)

	Calendar Year									
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Tolling and indexed price*	232	1,142	2,920	2,065	2,490	2,265	2,265	2,135	2,135	2,135
Fixed price	(255)	112	(1,113)	(1,613)	(1,963)	(2,050)	(2,035)	(2,410)	(2,410)	(4,410)
Total for all contracts	**(23)**	**1,254**	**1,807**	**452**	**527**	**215**	**230**	**(275)**	**(275)**	**(2,275)**

Source: Analysis by La Capra Associates using contract summary data from the Department of Water Resources.

Note: The amounts are the change in the capacity for that contract type after the renegotiations, and the total for the year is the capacity change for the overall portfolio as a result of the renegotiations. Capacities are for peak periods for July and August. A detailed table is presented on page 146.

* Power-purchase contracts containing an indexed variable fuel cost component or provides an opportunity for the buyer to purchase fuel.

THE DEPARTMENT HAS REASONABLY CONTROLLED ITS GAS COSTS, BUT SIGNIFICANT CONCERNS REMAIN FOR THE FUTURE

As we noted previously, certain of the department's long-term contracts have gas tolling provisions that allow it the option of purchasing natural gas directly, instead of paying a fixed price to the seller. In the latter half of 2001 and 2002, the department developed and implemented a strategy for managing gas costs under these tolling agreements. We found that the department's gas purchases and financial hedging activities under tolling agreements for which it had gas procurement rights brought its overall gas supply costs roughly into line with gas market prices during 2002. The important gas procurement issues facing the department in coming years are discussed in Chapter 6.

During the Latter Part of 2001 and 2002, the Department Developed and Implemented a Strategy to Manage the Cost of Fuel for Tolling Agreements

When the department began its role of purchasing electricity to meet the net short, it initially paid relatively little attention to managing the tolling provisions of its power-purchase contracts. In particular, during the first six months of 2001, we found no evidence that the department made gas supply purchases or implemented financial hedges to control gas supply costs under tolling agreements in which it had gas purchase rights. However, the department was obviously aware of the benefits of using tolling agreements with gas procurement rights to manage fuel costs, since it had included such tolling agreements in the contract portfolio.

Department records reflect that several months after its purchase obligations under long-term contracts had started, it began to develop a strategy for purchasing gas and managing its gas-related assets. Among the initial steps was the formation of a Fuel Management Working Group, as discussed in a June 2001 Gas Business Plan document. This plan indicates that the Fuel Management Working Group was to include department staff and outside consultants with considerable experience in the natural gas industry and specific experience in the California market. The Fuel Management Working Group was directed to perform two basic functions: (1) undertake strategic planning for the purchase of fuel supplies and (2) implement those plans. The strategic planning focused on assessing the natural gas market and developing recommendations regarding the overall gas purchase strategy, the appropriate fuel product mix, and the tools necessary to meet gas supply needs. To implement these plans, the department would sign agreements not only to purchase gas supplies but also to transport gas on interstate and local pipeline systems and to access fuel storage facilities to hold the gas until needed. Contracts in effect during 2001 offering the department a fuel purchase option included the Dynegy, GWF, Alliance, and Sunrise contracts.

Department documents suggest that it took some months for the Fuel Management Working Group to begin making gas purchase transactions. As we discuss in greater detail later, gas cost data provided by the department indicate that it did not begin to engage in third-party gas supply transactions until July 2001. Moreover, a February 2002 department memorandum introduced an approved Fuel Management Program, identified the mission and objectives of this effort as being to exercise gas purchase rights under certain tolling agreements, and designated certain individuals as members of the fuels team. The memorandum also indicates that the Fuel Management Program by then included a risk management component (that is, financial hedging) to assist in meeting established fuel cost objectives.

A potential impediment to the department's efforts to manage fuel costs was its concern that Assembly Bill 1 of the 2001–02 First Extraordinary Session (AB 1X) would not allow it to engage in price hedging activities—such as the use of gas futures and options contracts—to mitigate the risk of cost increases due to rising gas prices. However, in December 2001 the attorney general provided the department an opinion indicating that the department had the legal authority to engage in transactions to hedge gas supply prices. Subsequently, the department established an account with a brokerage firm in mid-2002 with a balance of $10 million to allow it to engage in financial hedging transactions.

In December 2001 the attorney general opined that the department had the legal authority to engage in financial hedging activities for managing gas supply prices.

An example of how the department implemented this hedging strategy was its management of gas for its Dynegy contract. Its gas procurement strategy suggested that 30 percent of anticipated baseload gas supply requirements under the contract be purchased six months in advance, another 30 percent three months in advance, 20 percent in the prior-month market, and the remaining 20 percent in the daily spot market for gas. The use of financial hedges to lock in or limit gas procurement costs was also recommended.

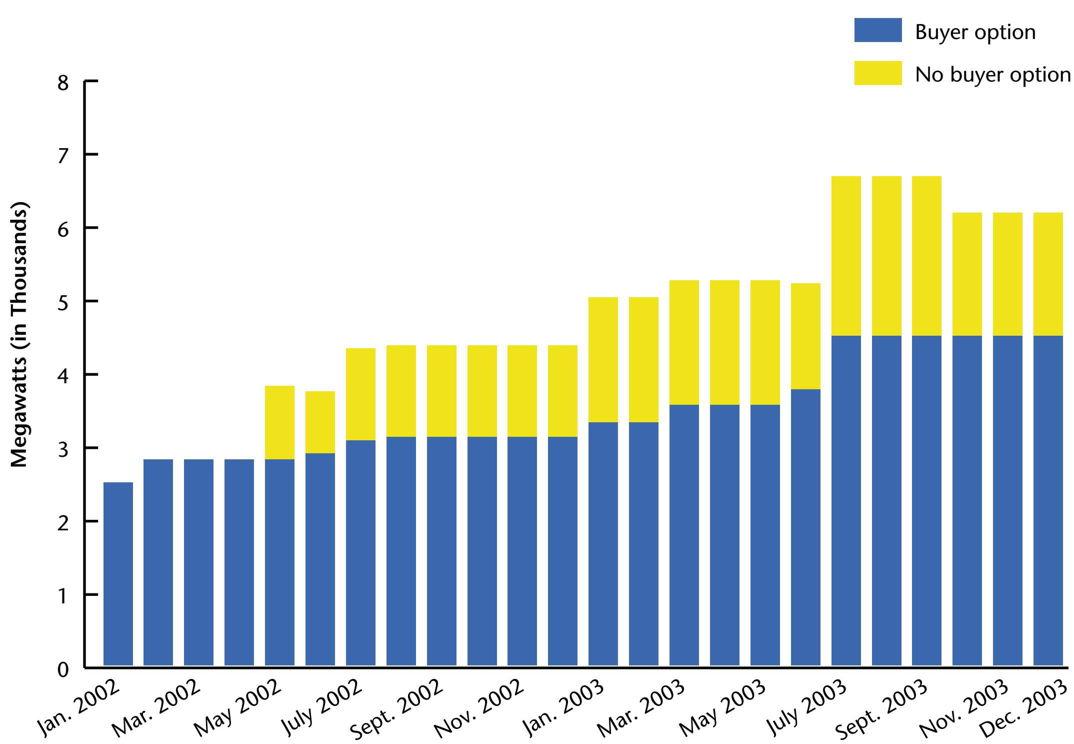
Documents submitted by the department to the CPUC in spring 2002 offer a view of fuel supply activities, describing specific objectives for the department's gas purchase program and identifying the activities of the fuels team. These activities included weekly meetings to review market conditions, discuss the ongoing gas procurement and hedging plan, review gas supplier performance, and address other related issues. A detailed list of activities also addressed the fuels team's involvement in entering into gas purchase agreements, acquiring financial hedging tools, and so on. Other department documents reveal that the department's gas procurement and gas hedging activity extended into January 2003 to ease the transition to the investor-owned utilities.

The Department's Gas Procurement and Gas Price Hedging Activity Increased During 2002

Figure 3 provides a perspective on the department's gas tolling opportunity during 2002 and its expectations for 2003. It illustrates the combined maximum capacity of the department's gas tolling agreements during peak hours for a given month, broken down into the capacity contributed by contracts with a gas purchase option and those without such an option, where the risk of changing gas prices is assigned through a formula in the contract. As shown, the number of megawatts covered under the department's tolling contracts that have a gas purchase option continued to increase during 2002. As Table 6 on page 37 indicated, contract renegotiations have increased the capacity of tolling agreements in the portfolio. By December 2002, the department had power supply contracts with seven entities that included tolling agreements with gas purchase rights, representing approximately 3,100 megawatts.

FIGURE 3

2002 and 2003 Gas Tolling Agreements With and Without Gas Purchase Option



Source: La Capra Associates' analysis of contract data from the Department of Water Resources.

During 2002 the department's gas purchase activities focused on three of its power supply contracts. The department's physical gas purchases were made largely for the Dynegy and Sunrise contracts. These gas purchases totaled just over 41 million MMBtus (million British thermal units) during the year, with a value of roughly $141 million. A gas-fired generation facility will typically require between 7.5 to 13 MMBtus of natural gas to produce one megawatt-hour of electricity, depending on its efficiency.

Beginning in July 2002, the department also engaged in financial hedging activity to manage gas costs. Department records reflect that its hedging activity included transactions related to its Dynegy contract. Calpine represented a third important contract that was a focal point of the fuels team's efforts. However, the department indicates that it did not initially make physical gas purchases for the Calpine contract during 2002 because it observed that the gas prices that Calpine charged were generally consistent with market prices. In late 2002, the department made some physical gas purchases for the Calpine contract as a result of financial incentives offered by Calpine.

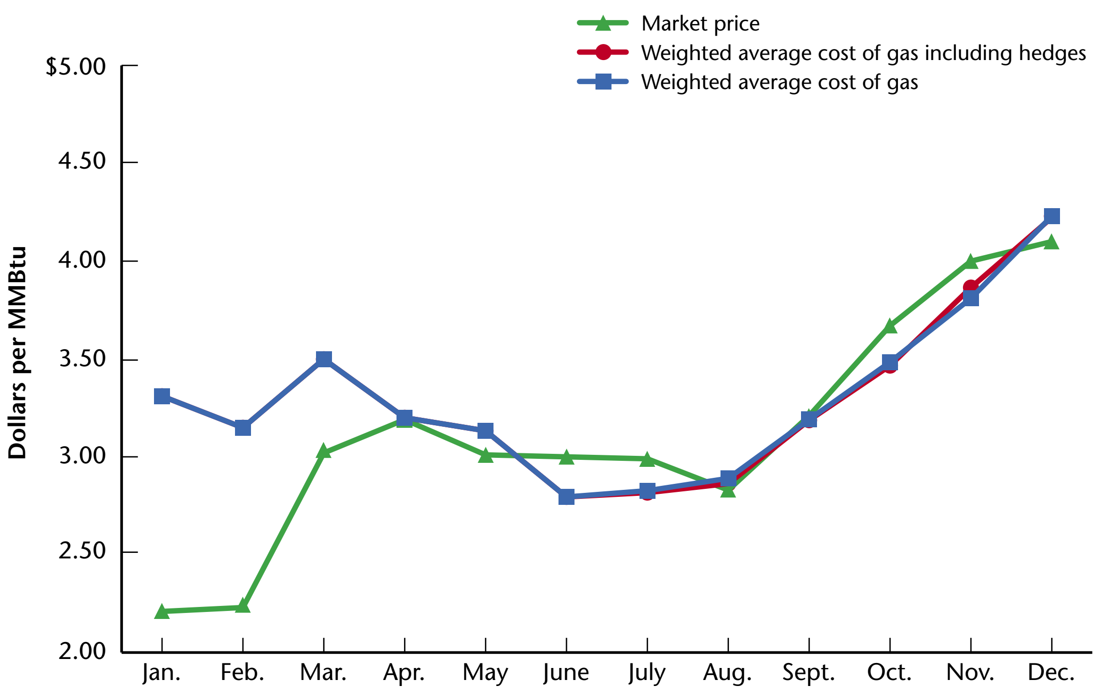
The Cost of Gas Purchased by the Department Under the Tolling Contracts Was in Line with Natural Gas Market Prices by April 2002

By April 2002 the department's gas purchase and financial hedging activities for tolling agreements with a gas purchase option resulted in gas costs that were roughly in line with market prices. The Dynegy and Calpine contracts were the most significant tolling agreements with gas purchase rights in the department's portfolio during the year. After the Calpine contract took effect in mid-2002, the department identified the combined gas needs under the two contracts as roughly 275,000 MMBtu per day.

Figure 4 on the following page presents a view of the department's gas costs, including physical purchases and financial hedging, for those two contracts. This figure contains three lines. The first line shows the department's market price index, which climbed from just under $2.25 per MMBtu in January to almost $4.25 per MMBtu by December. The second line shows the weighted average cost of gas for the Dynegy and Calpine contracts. This line reveals that weighted average gas costs were above market by as much as $1 per MMBtu during early 2002, indicating that a previous effort by Dynegy to purchase gas in advance resulted in ratepayers paying more in fuel costs than if the forward purchase had not occurred. The department indicated that this was largely the result of forward purchase commitments made during 2001, when gas price expectations were higher. By April 2002, however, the department's weighted average gas costs were very close to its market index, and they remained there through the rest of the year. The third line in Figure 4 begins in July 2002—the month when the department began its financial hedging activities—and reflects (on a monthly basis) the resulting costs and cost savings to the department.

FIGURE 4

2002 Gas Costs Versus Market Price



Sources: La Capra Associates' analysis of data provided by the Department of Water Resources. The market price line is from *Gas Daily* or Department of Water Resources' estimates.

In addition to its 2002 activities described above, the department was able to reduce gas costs during 2001 by using its right to purchase gas under the Dynegy tolling agreement. This agreement allows Dynegy to pass gas costs through to the department or, alternatively, allows the department to purchase the gas for Dynegy. After the department's fuel team was formed, it reviewed the gas costs in the invoices from Dynegy and observed that they were roughly $500,000 to $1 million per month above levels consistent with prevailing market prices. Once the department began purchasing a portion of the gas requirements for the Dynegy contract in October 2001, Dynegy's invoiced gas costs began to move closer to market prices. ■

Blank page inserted for reproduction purposes only.

CHAPTER 2

While the Renegotiation Effort Will Provide Some Savings to Ratepayers, the Department's Portfolio Still Remains Above Market Prices

CHAPTER SUMMARY

The contract renegotiation efforts have reduced the costs to the Department of Water Resources (department) of its portfolio of long-term power contracts. The savings resulting from the renegotiated contracts can be calculated in a variety of ways, each with some merits and each with some limitations. Throughout the energy crisis, the department and the governor's office reported both the contract costs and the savings in terms of the contact payments to suppliers. Thus, they reported that the reductions in contract costs from the restructuring of the contracts totaled approximately $5.5 billion, which represents approximately 13 percent of the total original contract costs of $42.9 billion. These contract cost reductions were based on information available at the time of the renegotiations and were calculated using a negotiation model that the department used when evaluating the effect of different renegotiation options on the reduction in contract costs.

While this savings estimate reasonably reflects cost reductions in the nominal value of the contract portfolio, an alternative analysis would estimate the savings to the consumer by taking into account the cost to replace the power that was eliminated through renegotiations. The department consultant performed this analysis during the renegotiations, using its negotiation model, and, at our request, in March 2003, using its revenue requirement model for estimating portfolio costs. When estimating what ratepayers may pay to replace the power that was eliminated from the contracts, the department consultant's calculations show that the net savings to ratepayers in nominal terms is currently estimated to be $1.5 billion. Also, because these savings will occur over the next 20 years, the department consultant calculates that the net present value of the future stream of savings to ratepayers is currently estimated to be $580 million. During the renegotiations, the department consultant also performed net present value analyses of the estimated contract cost reductions and ratepayer savings for individual contracts.

These March 2003 estimates of customer savings are a function of economic, market, and dispatch assumptions used by the department consultant in its modeling and would change if those assumptions were changed. Also, the department indicates that its revenue requirement model is not designed to value nonprice benefits resulting from the renegotiation efforts, such as the improved availability and reliability provisions in the contracts discussed in Chapter 3. Further, most of these contract cost reductions will result not from reducing the price per megawatt-hour of the power purchased but rather from shortening the length of the contracts or reducing the amount of power to be delivered. In other words, the contracts will continue to deliver high-cost power—power that is priced significantly above forecasted spot market prices—just less of it. However, this reduction of contract length contributed to one of the department's objectives, which was to shorten the time period for which it would have financial or legal responsibility for the contracts and, in the process, permit the utilities to procure energy themselves to meet the additional uncovered net short.

The department had not intended to estimate the savings to ratepayers that resulted from the contracts that were renegotiated through December 31, 2002. According to the department, the March 2003 estimate of savings to the consumer from the renegotiated contracts as of December 31, 2002, using the revenue requirement model, was made only at our request, and the department would not otherwise have made this calculation. In addition, the amounts are from its consultant's draft report, and as of March 17, 2003, the amounts had not gone through the department's ordinary standards of review for reports of this nature. However, this is the only estimate the department provided to us of the savings to the consumer from the renegotiated portfolio as of December 31, 2002. Further, we observed that these forecasts are consistent with the forecasts prepared by the department in establishing its revenue requirements, and its models and assumptions have been reviewed by the California Public Utilities Commission (CPUC) and many others in the development of those forecasts. These forecast methods were also used by the department consultant in the consultant's report provided in support of the revenue bonds that the department issued in October and November 2002.

BY THE END OF 2002, REPORTED COST REDUCTIONS ASSOCIATED WITH THE RESTRUCTURING OF THE 22 LONG-TERM POWER CONTRACTS TOTALED $5.5 BILLION

As we discussed in our December 2001 audit, the crisis during which the department entered into these contracts led to a power portfolio that presented significant cost risks needing careful management. After the crisis began to ease, the department in fact began to address many of these risks, implementing some of the audit recommendations. The department consultant indicates that in late 2001, a negotiating team approached various suppliers about restructuring the power contracts signed in 2001, and initially at least one supplier was responsive.

The State restructured 23 contracts with 14 of its 29 suppliers in 2002. Following the announcement of the renegotiation of the Sunrise Power contract on December 31, 2002, the total reported reductions in contract costs were estimated at approximately $5.5 billion. Table 7 provides a list of the renegotiated contracts and the resulting reductions in committed expenditures, as reported in state press releases.

TABLE 7

Reported Reduction in Contract Costs Resulting From Renegotiations (in Millions)

Contract	Contract Cost Reductions
Cabazon	$ 20
Calpine	2,990
Capitol Power	6
High Desert	560
Whitewater Hill	31
Calpeak	71
Soledad	2
GWF	215
Colton Power (formerly Alliance)	15
PG&E	3
Williams	1,400
Clearwood	28
Santa Cruz	2
Wellhead Power	8
Sunrise	121
Total	**$5,472**

Source: Press releases from the governor's office and the Department of Water Resources. Because a range of reductions were reported for Cabazon and Whitewater Hill, we used the mid-point of the reductions for this table. In December 2002, the department reported that the total contract cost reductions were $5.2 billion, but the individual amounts add to approximately $5.5 billion in the table.

The department's original contracts with the 14 suppliers previously listed in Table 7 represented a cost obligation that totaled about $24 billion over the life of the contracts—over half of the department's entire portfolio—or, in present value terms, about $14.5 billion, according to estimates made by the department during the renegotiations.

The department also renegotiated other nonprice terms and conditions that do not directly affect contract price. Many of these provide greater reliability in energy supply. For example, new provisions have been added to ensure that power plants are built according to agreed-upon schedules. The restructured contracts also provide greater flexibility in the dispatch of energy, allowing the department to call upon a particular supplier's resources within shorter time frames. While the value of such new or revised provisions is not captured in the reported $5.5 billion in estimated contract cost reductions, they clearly provide value to the State. The department indicates that the models it uses to estimate contract cost reductions do not value these nonprice changes to the renegotiated contracts. For a more detailed discussion of the significance of these nonprice terms and conditions and how they improved the energy products in the contracts, see Chapter 3. The remainder of this section focuses on the specific terms and conditions that resulted in the reported $5.5 billion contract cost reductions.

The department also renegotiated other nonprice terms and conditions that do not directly affect contract price and cannot be easily quantified in terms of savings, but they clearly provide value to the State.

The reported contract cost reductions represent reductions in the expected payments to suppliers as a result of renegotiations. As discussed in Chapter 1, many of the contract changes involved converting fixed-price, nondispatchable energy products to dispatchable products, some of which are gas tolling agreements. Therefore, estimates of future payments for these renegotiated contracts depend on fuel price expectations. Any cost reductions resulting from such changes would be determined by the difference between payments for the original nondispatchable product and payments for the new dispatchable product.

Because a dispatchable product allows the department to choose whether to take energy from the contract or instead purchase from the energy market, the payments made to a supplier of a dispatchable contract also depend on expected market prices of energy relative to contract prices. Expected future market prices, in turn, depend on a myriad of factors, principally fuel prices, future demand for electricity, and future construction of power plants and transmission lines. Therefore, in order to estimate the expected payments to suppliers—and the contract cost reductions as a result of renegotiations—the department and its consultants developed a negotiation model that allowed for the analysis of the potential savings resulting from the renegotiation of an individual contract. The department indicated that it used the negotiation model to analyze changes in an individual contract assuming that the remainder of the portfolio remained constant in order to produce results quickly to permit analysis of the different renegotiation options being considered. The department and its consultant have a revenue requirement model that they use to analyze portfolio changes, but they indicated that running and validating the results using this model can take days to weeks, and thus it could not be responsive to the fast pace needed to make decisions during the contract renegotiation process.

The reported contract cost reductions as shown in Table 7 on page 47 were largely based on the results from the negotiation model used during the contract renegotiations, which used market assumptions developed in fall 2001. However, the department indicates that market conditions have changed somewhat since the negotiations were completed in December 2002 and the results in Table 7 were derived. To reflect these changes and at our request, the department used the negotiation model to conduct a similar analysis based on assumptions representative of market conditions in the first quarter of 2003. The results of this analysis are shown in Table 8 for the three renegotiated contracts with the largest reported savings.

TABLE 8

Estimated Contract Cost Reductions of Selected Renegotiations (in Millions)

Contract	Per Original Analysis	Per March 2003 Analysis
Calpine	$2,486	$2,283
Williams	1,003	621
High Desert	1,167	1,063

Source: The Department of Water Resources' consultant, Navigant Consulting, Inc. These estimates do not match those in Table 7 due to omissions and inconsistencies in cost reductions between the reported amounts and the supporting documentation provided by Navigant Consulting.

As shown previously in Table 8, the March 2003 analysis results in smaller contract cost reduction estimates for these contracts, resulting from the changed market conditions reflected in this analysis. These March 2003 estimates of savings are based on current economic, market, and dispatch assumptions used by the department consultant.

Our consultant indicates that the March 2003 analysis includes assumptions that reflect higher demand for electricity and fewer power plants being constructed than in the original analysis. This combination of higher demand and lower supply results in higher forecasted market prices for energy. All else being equal, higher market prices will result in the department choosing to take more energy from its dispatchable products, thereby increasing payments to suppliers and lowering the cost reductions under the renegotiated, dispatchable contracts, relative to the prior analysis. Further, both the renegotiated Calpine and High Desert contracts involved gas tolling agreements. Because the 2003 analysis included a higher gas price forecast, this further increases the cost of these renegotiated contracts and lowers the cost reductions. While these estimates, reflecting more recent market conditions, were not available to the negotiators during the process of renegotiations, the negotiators were provided with cost reduction estimates based on market conditions at that time.

Cost Reductions in Contracts May Not Translate to Lower Electricity Bills, Due to the Cost of Replacement Power

The estimated contract cost reductions noted previously represent reductions in the total amount of power purchased and, as a result, reductions in payments to suppliers over the lives of the restructured contracts. However, because the restructured contracts also result in fewer power purchases compared to the original contracts, the cost of the power that will be procured to make up for this reduction in purchases (replacement power costs) must be taken into account when determining actual savings to ratepayers.

Much of the power no longer supplied as a result of contract renegotiations must be replaced to meet demand, thus the cost of the replacement power must be taken into account when determining actual savings to ratepayers.

Much of the power no longer supplied to the department as a result of contract renegotiations, while high priced, was not surplus, particularly in instances where negotiations led to reductions in contract lengths. Replacement power, presumably at more favorable market rates, will be required to supply the portion of the net short that would otherwise have been met by this contract power. While the department will not purchase that replacement power and will not incur the costs of that power, ratepayers will bear the costs that the utilities incur in their procurement of that replacement power from alternate suppliers. This additional cost to ratepayers will partially offset the savings that ratepayers will realize from the contract cost reductions. It is the net result of these effects—the amount of contract cost reductions less the amount that must be spent by the utilities to purchase replacement power—that will ultimately determine the net effect on ratepayers' bills.

The following example illustrates this point. Suppose that as part of the renegotiations, a supplier agrees to eliminate the department's obligation to purchase 100,000 megawatt-hours of power at $75 per megawatt-hour in a given time period. Suppose also that the department anticipated it will still need 60 percent of that power to meet electricity demand during that time. If the department believes the market price of power during that time will be, say, $50 per megawatt-hour, ratepayer savings associated with the elimination of these purchases will be as shown in Table 9.

TABLE 9

Hypothetical Ratepayer Savings When Replacement Power Costs Are Considered

	Original Contract	Restructured Contract
Cost of contract	$7,500,000 (100,000 megawatts at $75 per megawatt-hour)	$0
Cost of replacement power	$0	$3,000,000 (60,000 megawatts at $50 per megawatt-hour)
Total ratepayer cost	$7,500,000	$3,000,000
Ratepayer savings		**$4,500,000** ($7,500,000 - $3,000,000)

Source: La Capra Associates' analysis.

Ratepayer savings are highly dependent on projections of future market prices for power. If, for instance, the department altered its projections of future market prices from $50 per megawatt-hour to, say, $70 per megawatt-hour, ratepayer savings in the example described would be reduced from the $4.5 million shown in Table 9 to $3.3 million.

A closer look at the reduction in expenditures achieved as a result of the contract renegotiations reveals the importance of considering replacement power costs. Our analysis focused on the contract cost reductions associated with five of the renegotiated contracts—Calpine, Williams, High Desert, GWF, and Sunrise—because the renegotiations with these five suppliers account for more than 95 percent of all cost reductions resulting from the 23 restructured contracts. Cost reductions associated with these restructured contracts arise from four principal types of contract changes, which can generally be categorized as follows:

- **Changes in contract term.** In many instances, contract lengths were shortened to reduce the cost. For example, a 20-year contract with Calpine was shortened to a 10-year contract. Shortening this contract reduced the cost by effectively reducing the amount of power purchased as well as avoiding capacity charges—fixed payments for making a power facility available to provide power to the department—for the canceled part of the contract.

- **Reductions in the quantity of power purchased.** Some restructured contracts call for purchasing less power than the original contract.

- **Changes in product type.** This change often involves the conversion of a nondispatchable energy purchase to a dispatchable purchase, allowing the department to take energy only when needed. It could also mean converting a contract to a tolling agreement, allowing the buyer to manage fuel costs.

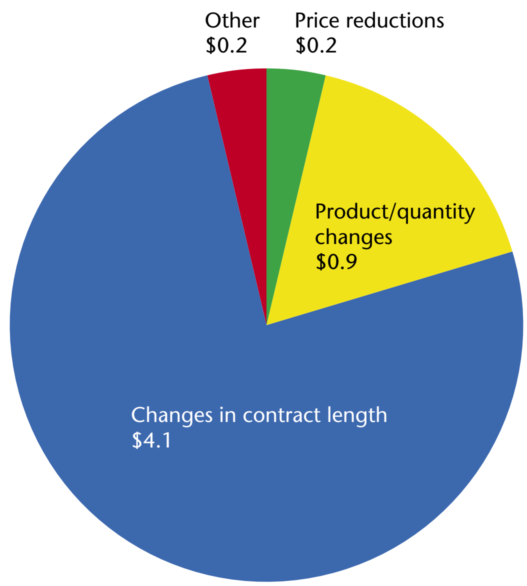
- **Reductions in price.** In some instances, the changed contract provisions reduce the price paid per megawatt-hour purchased without altering the quantity of power or type of product purchased.

Figure 5 shows the reported cost reductions from the five largest restructured contracts divided into the categories just described. The second and third categories—reductions in the quantity of power purchased and changes in product type—are combined into one in the figure.

As the figure shows, the vast majority of the reported cost reductions—approximately $4.1 billion—result from the first category, reductions in the length of the contracts. Changes in product type and quantities purchased produce $900 million in cost reductions. Another $200 million of the cost reductions comes from direct price reductions.

FIGURE 5

The Vast Majority of the Reported $5.5 Billion Contract Cost Reductions Results From Reductions in the Length of Contracts (in Billions, Nominal)



Source: La Capra Associates' analysis of the renegotiated contracts.

Note: Data shown does not sum to $5.5 billion due to rounding. "Other" refers to the cost reduction with the other nine suppliers. We did not split out these expenditures because the amounts were immaterial in comparison to the cost reductions for the five largest suppliers.

Only reductions in price have a direct effect on ratepayers' bills without requiring consideration of replacement power costs. Every dollar in reduced payments to suppliers as a result of direct price changes is a $1 less that the department pays for power and is hence a $1 reduction in ratepayers' bills. Reductions in contract quantities, while leading to large decreases in payments to suppliers, require the consideration of the need to buy replacement power to understand the net impact on ratepayer savings. The same principle also applies to reductions in the length of a contract—in both instances the quantity of power purchased is reduced, but some or all of the power must be replaced to cover the net short. However, if the cost of contract power is significantly above market prices—as in the case of the department's contracts, reducing the amount of power purchased can actually save the consumer more than a reduction in the cost per megawatt-hour purchased.

Any accurate estimate of replacement power costs must be estimated on a total portfolio basis and also consider other economic factors such as projected market prices and future demand for electricity.

Because the vast majority of the reported $5.5 billion estimate of the reduction in payments to suppliers requires consideration of replacement power costs, these costs will have a large impact on the ultimate ratepayer savings. Estimates of replacement power costs are necessarily dependent on future market prices, as illustrated by the hypothetical example in Table 9 on page 51, as well as on future demand for electricity, which will determine how much power must be replaced. Any estimate of replacement power costs will therefore involve considerable uncertainty.

Estimating replacement power costs also involves considering all of the department's energy resources to determine, at any given time, how much power the department's portfolio of contracts obligates it to take and how much power is actually needed to meet the net short. In other words, the department's replacement power costs must be estimated based on the entire portfolio. The negotiation model that the department and its consultant used to respond to the fast pace of the renegotiations could compute a rough estimate of the ratepayer savings for an individual contract, but it could not make this estimate in aggregate for the entire portfolio. That is, the negotiation model could only examine the effects of each individual contract in isolation, without considering the remainder of the portfolio. The revenue requirement model can estimate ratepayer savings for the entire portfolio, but as we noted previously, the department indicates that it needs days to weeks to produce this estimate.

The Department Consultant's Latest Estimates Show That Contract Renegotiations Are Currently Estimated to Save Ratepayers About $1.5 Billion Over the Next 20 Years, Which in Present Value Terms Is Roughly $580 Million

In 2003 the department consultant used the revenue requirement model to estimate the replacement power costs for the entire renegotiated portfolio as of December 31, 2002. The department consultant's estimate is based on market assumptions revised in the first quarter of 2003, consistent with those used to develop the contract cost reductions shown in the second column of Table 8 on page 49. The results from the revenue requirement model show that estimated total contract cost reductions are approximately $4.8 billion and that the total cost to replace power associated with the renegotiated contracts is estimated to be about $3.3 billion. Ratepayer savings—the difference between contract cost reductions and replacement power costs—are currently estimated to be about $1.5 billion.

It should be noted that the department consultant's estimates of contract cost reductions and ratepayer savings are highly dependent on expected future market conditions. The estimate of $1.5 billion in ratepayer savings reflects changes in market conditions since the department negotiated the restructured contracts, as well as the use of a sophisticated modeling tool that considers the effects on the entire portfolio of all of the renegotiations. Therefore, this estimate was unavailable to the department during the renegotiations.

The estimate of $1.5 billion in ratepayer savings will accrue over the life of the original contracts, which extends over the next 20 years. This estimate provides no indication of how quickly or slowly these savings will be passed on to ratepayers. Clearly, receiving $1.5 billion 10 years from now is much less valuable than receiving it all now. Therefore, calculating the savings in present value terms, as opposed to nominal terms, provides a more accurate indication of the true value to ratepayers. Further, when making decisions regarding power purchases, utilities generally evaluate the costs in present value terms so that alternatives covering different numbers of years can be evaluated in equal terms.

Ratepayer savings will accrue over the next 20 years, thus calculating the savings in present value terms, as opposed to nominal terms, provides a more accurate indicator of the true value of the savings to ratepayers.

The present value of a sum of money to be received in the future is the amount that would have to be invested today at a given rate of return (referred to as the discount rate) to be equivalent to a future stream of payments. For instance, given a rate of return of 9 percent, California ratepayers could invest about $660 million today and receive roughly $1.5 billion 10 years from now. This amount is considered the present value of a $1.5 billion payment in 10 years, given a discount rate of 9 percent.

Presenting both the estimated contract cost reductions and the estimated ratepayer savings in present value terms is especially important given the characteristics of many of the renegotiated contracts. In particular, the restructuring of the three contracts with the largest reported cost reductions—Calpine, Williams, and High Desert—all involved reductions in contract length as well as additional purchases in the near term, particularly in 2002 through 2003. The value of such restructuring varies significantly depending on whether it is expressed in nominal or present value terms.

The department consultant did conduct an analysis of the estimated present value of contract cost reductions and ratepayer savings as the renegotiations were occurring. Using this analysis, Table 10 on the following page shows the difference when contract cost reductions are considered on a nominal and present value basis for the Calpine contract, the restructured contract with the largest reported cost reductions. Because the vast majority of cost savings for this contract will not be realized until 2010 and beyond, they decline dramatically when considered on a present value basis. The Calpine contract cost reduction of approximately $2.5 billion drops to $1.3 billion and $820 million when expressed on a present value basis at a discount rate of 5 percent and 9 percent, respectively.

TABLE 10

Calpine Contract Changes and Their Present Value Reductions in Contract Cost (in Millions)

	Nominal	Present Value at 5 Percent	Present Value at 9 Percent
End-of-term changes			
Elimination of 7x24 nondispatchable energy in 2010 and 2011	$2,095	$1,319	$925
Elimination of 10 years (2011—2021) of dispatchable energy	800	387	225
Totals	**2,895**	**1,706**	**1,150**
Additional purchases in 2002 and 2003	(398)	(371)	(352)
All other contract changes	(11)	11	22
Net reductions in cost	**$2,486**	**$1,346**	**$820**
Percent change		**-46%**	**-67%**

Sources: La Capra Associates' analysis of data from the Department of Water Resources' consultant, Navigant Consulting, Inc. Data presented is based on the original reported contract cost reductions for this contract, as presented in the first column of Table 8 on page 49 using the negotiation model. Positive amounts represent cost reductions, while negative amounts represent cost increases.

The issue of the appropriate discount rate to use for a present value calculation is a contentious one. The higher the discount rate used, the lower the present value of a given stream of future payments. In making power-purchasing decisions, utilities often use their weighted average cost of capital. However, in determining the present value from the ratepayers' perspective, a percentage equivalent to the rate of return consumers would receive for an investment of similar risk should be used. The result represents the amount ratepayers would be required to invest today to receive a future stream of payments equivalent to the expected ratepayer savings. The department consultant used two discount rates in its analysis, 5 percent and 9 percent. The 5 percent rate was used because it represented the department's cost to borrow funds, while the 9 percent rate was an approximation of a private party's borrowing cost. However, the department consultant acknowledged that others could argue that a higher discount rate should be used. Our consultant believes that a 9 percent discount rate is consistent with the rates that public utility commissions typically use to evaluate such transactions on behalf of consumers.

Table 11 shows the distribution of the $1.5 billion estimate in ratepayer savings over time. While ratepayers will bear additional costs through 2005 as a result of the renegotiations, they will realize significant savings after this time. However, because most of the ratepayer savings in the renegotiated contracts do not accrue immediately, the present value of the savings is considerably smaller than the nominal contract cost reductions that were reported.

TABLE 11

Yearly Ratepayer Savings From Contract Renegotiations (in Millions, Nominal)

2001	$ 0
2002	-28
2003	-152
2004	-44
2005	-31
2006	81
2007	84
2008	162
2009	138
2010	396
2011	198
2012	254
2013	-10
2014	-26
2015	0
2016	80
2017	80
2018	80
2019	80
2020	80
2021	47
Total	**$1,469**

Source: The Department of Water Resources' consultant, Navigant Consulting, Inc. Positive amounts represent ratepayer savings, while negative amounts represent ratepayer costs.

For the entire portfolio, the department consultant's analysis indicates that total ratepayer savings from all renegotiated contracts are currently estimated to be about $580 million on a present value basis, as shown in Table 12. As we mentioned previously, the estimates of contract cost reductions and ratepayer savings are highly dependent on expected future market conditions. The data presented in Table 12 reflects both changes in market conditions since the department negotiated the restructured contracts and the use of the department's revenue requirement model, which is able to consider the effects on the entire total portfolio of all of the renegotiations.

The department had not intended to estimate the savings to ratepayers that resulted from the contracts that were renegotiated through December 31, 2002. According to the department, the March 2003 estimate of savings to the consumer from the renegotiated contracts as of December 31, 2002, using the revenue requirement model, was made only at our request, and the department would not otherwise have made this calculation. In addition, the amounts are from its consultant's draft report and as of March 17, 2003, the amounts had not gone through the department's ordinary standards of review for reports of this nature. However, this is the only estimate the department provided to us of the savings to the consumer from the renegotiated portfolio as of December 31, 2002. Further, the department asserts that specific information from the revenue requirement model, such as the percentage of power that was eliminated through the renegotiations but will need to be replaced and the cost reductions for each renegotiated contract, is confidential and cannot be publicly disclosed.

As shown in Table 12, while the department consultant estimates on a nominal basis that the total portfolio contract cost reductions are about $4.8 billion, after considering replacement power costs the department consultant estimates that the customer savings are about $1.5 billion. Similarly, the department consultant estimates that the net present value of the contract cost reductions, at a 9 percent discount rate, is about $2.3 billion and customer savings are about $580 million. This analysis was performed by the department consultant using the revenue requirement model in early 2003, and it therefore was not available to negotiators during the renegotiations.

TABLE 12

Estimated Ratepayer Savings From Renegotiations (in Millions)

	Nominal Value	Net Present Value at 5 Percent	Net Present Value at 9 Percent
Total original contract cost	$44,437	$36,938	$32,449
Total contract cost after renegotiations	39,614	33,770	30,141
Reduction in contract costs from renegotiations	4,823	3,168	2,308
Cost to replace power that was eliminated through renegotiations	(3,354)	(2,298)	(1,728)
Cumulative customer savings of renegotiated contracts	1,469	870	580

Source: The Department of Water Resources' consultant, Navigant Consulting, Inc. The amounts above show the effect on the total portfolio and are based on market assumptions in the first quarter of 2003. The replacement power costs assume that the purchases are made on the spot market. The $44.4 billion of original contract costs differs from the previously mentioned $42.9 billion of original contract costs on page 23 due to the change in market conditions between 2001 and 2003.

The department consultant's analyses performed with the negotiation model at the time its contracts were being restructured generally included estimates of both contract cost reductions and ratepayer savings, particularly with the larger contract renegotiations. Further, it performed these estimates on both a nominal and present value basis. Documentation provided by the department indicates that the estimates were available to the negotiators to assist them in evaluating proposals being offered by the suppliers. The documentation also shows that the department and the governor's office had both estimates of ratepayer savings available when they reported nominal contract cost reductions in press releases.

The department states that the decision to report the nominal value of the contract cost reductions was consistent with the previously reported $42.9 billion nominal cost estimate of the department's portfolio. It also states that it did not report the ratepayer savings figures because of the limitations of calculating that number. In making these decisions, however, the department did not provide ratepayers with a relevant piece of information related to the outcome of the renegotiations. Disclosing ratepayer savings—on both a nominal and present value basis—would have put the savings from individual contracts that were renegotiated into context.

The deputy director in charge of the department's power activities provided the following additional comments about using the estimated customer savings:

> "The Department and its consultants have indicated that they believe the forecasts of customer savings using a single model output for a long term (in this case, ten-year) projection of savings is a rough estimate at best and cannot be relied on to accurately predict actual customer savings in the future. Retail customer savings projections require estimating the most volatile part of the net short energy requirements—the portion of remaining energy that is still required by electric customers after accounting for the utilities' existing power supplies and the Department's contracts. Therefore, estimating both the amount and the price of the replacement energy needed to determine retail customer savings is subject to many variables that can change over a multi-year period and are not easily captured in a single energy volume and pricing model.
>
> Examples of a few of these variables include: total future electric demand, future gas prices, seasonal variations from year to year on the amount of hydroelectric energy (subject to variable regional rainfall levels), market structure at the federal or state level, and the amount of energy that direct access customers elect to purchase from suppliers other than the utilities. In addition, the Department's consultants assumed that all of the net short energy no longer met by the Department's renegotiated long-term contracts would be met by spot market purchases, a very conservative assumption. To the extent that the utilities enter into long-term contracts to acquire such replacement energy or already have replacement energy sources in their portfolios rather than make spot market purchases, the costs would differ and change customer savings. The renegotiated contract savings, which we included in press releases, are less susceptible to these variables than customer savings. Promptly following each renegotiation, the Department disclosed the entire text of the contracts on its website, so that others could calculate customer savings using their own assumptions for these variables.

> In addition, the model used by the Department's consultant does not attempt to capture all the value associated with the improvements made to the renegotiated contracts. For example, it does not ascribe differing values to differing kinds of energy products, e.g., dispatchable vs. must-take energy, even though such products have inherently different economic values. Likewise, it does not attempt to value the various non price-term contract modifications. Although these changes will convey value to ratepayers through greater reliability and other means, they are not captured in the customer savings analysis given the difficulty in quantifying the economic value. For all of these reasons, the customer savings estimate should be read only in the context of the assumptions and limitations of the model and against the backdrop of the overall improvements to the contract."

It is difficult to reconcile the department's qualification of its own customer savings estimates as "rough estimates at best and cannot be relied on to accurately predict actual customer savings" with its own development and use of these estimates. Department records confirm that its consultant used two models, one simplified (the negotiation model) and one more complex (the revenue requirement model), to derive estimates of customer savings as part of the information provided for consideration by the negotiating team as it evaluated renegotiation opportunities. Our consultant offers the following observations on the department's qualification of these forecasts:

- The department consultant responsible for preparing those forecasts specializes in such forecasts and prepares them for the department and its other clients on a regular basis.
- Forecasts of this type are commonly prepared and used in decisions on power contracts, recognizing that any forecast cannot resolve inherent uncertainties in future market conditions.
- Customer savings estimates do require complex forecasts of future market conditions. The department consultant utilizes a commonly accepted forecasting model, PROSYM, to develop the more detailed forecasts, one that the department consultant has used consistently for analyses provided in support of the department's power program over the past two years.

- These forecast methods were used by the department consultant in the consultant's report provided in support of the revenue bonds that the department issued in October and November 2002.

- These forecasts are consistent with the forecasts prepared by the department consultant in establishing the department's revenue requirements, and its models and assumptions have been reviewed by the CPUC and many others in the development of those forecasts.

- The ratepayer savings figures are the department consultant's estimates based on market conditions at a given point in time, as noted previously in this chapter.

- These forecasts do not capture the many nonprice provisions obtained in the renegotiations, as is noted in Chapter 3 and elsewhere in this audit report.

Our consultant also advises that despite the inevitable limitations inherent in such forecasts, the department's renegotiation objectives recognized the importance of customer savings. The department is to be commended for its efforts to estimate the direct customer savings at the time it renegotiated the contracts. As noted further in Chapter 6, we recommend that the department monitor market conditions on a going-forward basis, reflecting changes in market conditions as they become known, to continue to make informed decisions on contract management that can have material implications for savings to consumers.

Finally, our consultant states that it is important to remember that, going forward, the contracts remain well above the department consultant's current (albeit uncertain) estimates of future market prices. This in no way concludes that there was a better price outcome available to the negotiating team last year, nor does it say anything about the value of the other concessions gained. Consequently, we make no finding that the renegotiation efforts were flawed or were unsuccessful. Without great leverage, the renegotiations could not hope to fully reconcile the contracts to current market prices and terms, and thus, as we discuss in Chapter 6, the department must continue to look for (and make) opportunities to further improve those contracts. As a part of that effort, the department needs to do the analysis necessary to assess changing market conditions and assess the merits of any future proposals or opportunities.

MUCH OF THE DEPARTMENT'S PORTFOLIO REMAINS AT ABOVE-MARKET PRICES

Contract prices after the renegotiations remain well above the future prices projected by the department consultant, as shown in Figures 6 and 7 on the following pages. Contracts for standard nondispatchable energy products, which still make up more than 90 percent of all energy purchases in the department's portfolio, remain priced substantially above expected market prices. However, the negotiations have reduced the average prices of such products by eliminating high-priced purchases, as well as by reducing some contract prices.

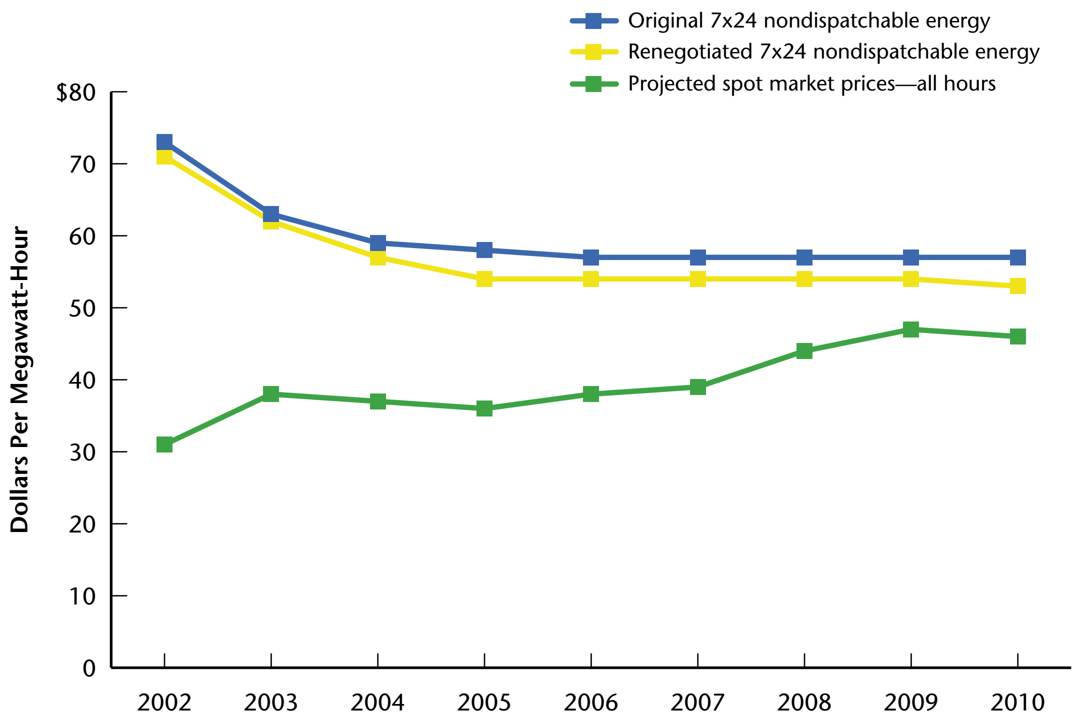
Figure 6 compares the average price of around-the-clock (7x24) nondispatchable energy before and after renegotiations with the most recent projection of future spot market prices prepared by the department consultant, reflecting market conditions in early 2003. It shows that for the period from 2002 to 2010, prices for this product declined by an average of $3 per megawatt-hour as a result of the negotiations. However these prices still average about $15 per megawatt-hour above expected market prices. Also as a result of the negotiations, obligatory purchases of energy associated with this 7x24 product were reduced by about 10 percent during this period.

Contracts for standard nondispatchable energy products remain priced substantially above expected market prices although the negotiations have reduced the average price of such products.

Due to changes in market expectations, forecasts of market prices can be expected to change over time, affecting the relative cost of these nondispatchable energy purchases to market prices. Further, because nondispatchable energy purchases provide a shelter against the volatility of spot market prices by locking in a fixed price for future purchases, it can be expected that over time such purchases will command a premium over market prices, although of varying magnitude depending on demand and supply conditions. However, our consultant believes that the current differential between nondispatchable energy purchases and expected market prices is greater than these factors would suggest it should be.

FIGURE 6

Average Price of the Department's 7x24 Nondispatchable Energy Before and After Renegotiations Compared to Projected Spot Market Prices

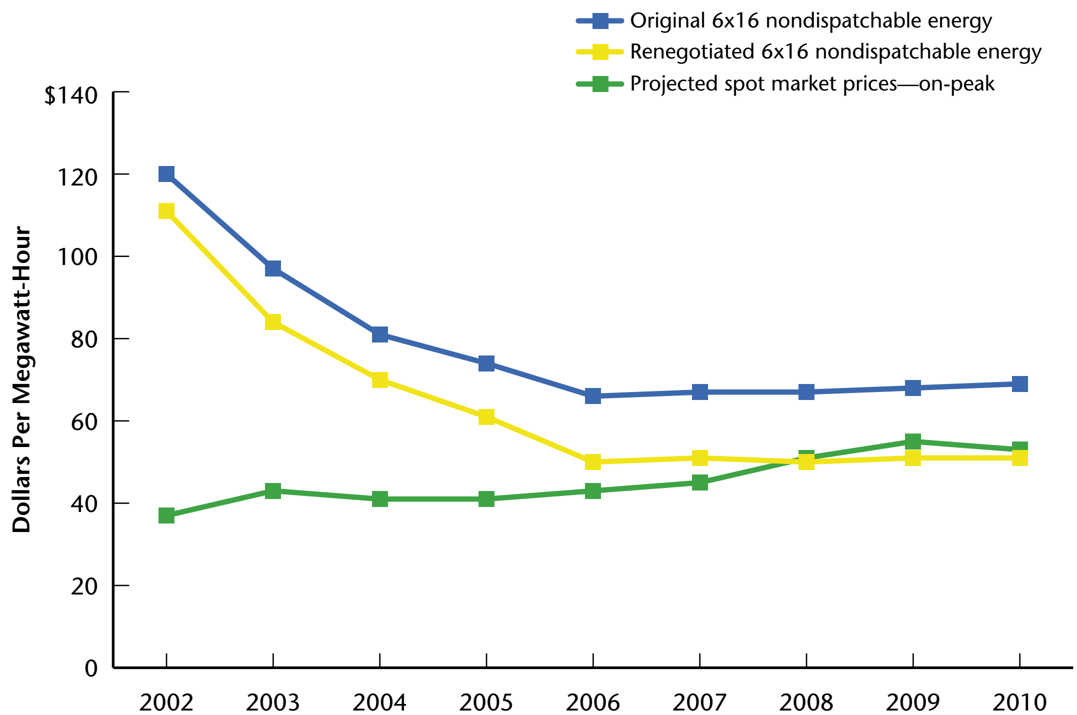


Sources: La Capra Associates' analysis of data from the Department of Water Resources' consultant, Navigant Consulting, Inc. Projected spot market prices are all-hours average prices in the Northern California zone, as forecasted by Navigant Consulting, Inc., based on a March 2003 analysis.

Figure 7 presents the same information for peak-hour (6x16) nondispatchable energy blocks and peak-hour market prices. As shown in Figure 7, after 2005 prices for the nondispatchable peak product after negotiations converge with projected peak-hour market prices. However, while the negotiations reduced prices by an average of $15 per megawatt-hour through 2010, these prices remain about $16 per megawatt-hour above projected market prices through 2005. The negotiations produced a 2 percent increase in the quantity of nondispatchable peak-hour purchases. As in the case of the 7x24 nondispatchable purchases, while forecasts of market prices will change over time and fixed-price nondispatchable purchases provide value by sheltering the department from volatile spot market prices, our consultant believes that through 2005 these contract prices remain high relative to market expectations.

FIGURE 7

Average Price of the Department's 6x16 Nondispatchable Energy Before and After Renegotiations Compared to Projected Spot Market Prices



Sources: La Capra Associates' analysis of data from the Department of Water Resources' consultant, Navigant Consulting, Inc. Projected spot market prices are the on-peak average prices in the Northern California zone, as forecasted by Navigant Consulting, Inc., based on a March 2003 analysis.

The figures show that while the average price of these products under the renegotiated portfolio has fallen, power delivered from the portfolio still remains at prices above current market projections of the department consultant. As we noted previously, much of the cost reductions were the result of shortening contract lengths, but it appears that the State has had little success in convincing suppliers to lower the prices they are charging for power. It is clear that in the future, the department, the investor-owned utilities, and the CPUC will need to continue to manage cost risks associated with the portfolio in accordance with their respective roles. Further renegotiations as the opportunities arise may be one avenue to do so. We discuss additional recommendations in Chapter 6 of this audit report. ■

Blank page inserted for reproduction purposes only.

CHAPTER 3

The Renegotiated Contracts Improve the Reliability and Flexibility of the Department's Energy Portfolio, but Challenges Remain

CHAPTER SUMMARY

Although as Chapter 2 discussed, the readily quantifiable economic benefits of the renegotiated contracts to individual consumers are likely to be modest, our review indicates that the renegotiations generally resulted in stronger guarantees that the sellers will deliver the power promised under the contracts and will build the new generation units promised in the contracts. Thus, the renegotiated contracts better meet the reliable energy goals of Assembly Bill 1 of the 2001–02 First Extraordinary Session (AB 1X) and better ensure the availability of electricity to satisfy consumer demand. These improvements are accomplished through stronger terms and conditions, such as termination rights for the State and penalty provisions when sellers fail to deliver energy or construct new generation units as promised under the contract. Although not readily quantifiable, these changes are also likely to provide economic benefits to ratepayers. In addition, changes in the type of energy products purchased under the contracts increase the reliability of the Department of Water Resources' (department) long-term contract portfolio. As noted in Chapter 1, changes in the types of energy products purchased also serve to improve the fit of the department's supply portfolio relative to its net-short obligation and have economic value, as discussed in Chapter 2.

Since our December 2001 audit, the power-purchase authority given to the department under AB 1X has ceased. Further, through a series of rulings and orders issued by the California Public Utilities Commission (CPUC), the day-to-day management and operation of the long-term energy contracts has been transferred to the investor-owned utilities. Nonetheless, the department remains legally and financially responsible under the contracts.

The renegotiated contracts all contain clauses known as novation clauses, which call for transfer of the contract to the investor-owned utilities if two key events occur. According to the department's legal counsel, sellers would only agree to the clause if it was made contingent upon the creditworthiness of the investor-owned utilities and upon the CPUC's determination that the contracts are just and reasonable. Thus the timing of the complete transfer of contract responsibility is uncertain. Moreover, the original contracts that have not been renegotiated do not have the novation language that now exists in the renegotiated contracts, making it more difficult to transfer those contracts to the investor-owned utilities. As a result, the department continues to have significant legal and technical responsibilities for the ongoing management of the long-term contracts.

OUR DECEMBER 2001 AUDIT IDENTIFIED NUMEROUS WEAKNESSES IN THE TERMS AND CONDITIONS OF THE LONG-TERM POWER-PURCHASE CONTRACTS

In our December 2001 audit, we measured the department's long-term power-purchase contracts against the stated purpose of AB 1X of ensuring a reliable source of energy at the lowest possible price. In reviewing the long-term energy contracts (contracts), we found that they lacked many of the terms and conditions we would expect to see in contracts designed to provide reliable energy to consumers. In contrast, we noted that the prices paid for energy in the contracts were likely to be well above market prices, which gave sellers an economic incentive to continue to deliver energy under the contract but did not adequately protect the State's interests. Thus, we reported that the contracts might not always ensure that power would be delivered when wanted except by conferring substantial benefits on sellers for delivery.

Our December 2001 audit evaluated the reliability and price stability of the contracts using the following factors:

- **Reliability of performance—delivery.** Does this contract have terms that ensure that the seller will deliver the energy that it agreed to provide under the contract?
- **Reliability of performance—availability.** Does this contract have terms that ensure that facilities will be available to deliver the power the seller agreed to provide under the contract?
- **Reliability of performance—building new generation.** If the contract relies on the construction of new generation units, does the contract have terms that ensure that the units will be built?
- **Price risk—uncertainty of price.** Does the contract have terms that ensure price stability?

In reaching our conclusions, we performed an in-depth analysis of five contracts (Allegheny, Calpine, Coral, Sempra, and Sunrise), as well as an in-depth analysis of certain provisions of the Williams contract. In addition, we performed a higher-level review of other contracts, which were reported on a contract "report card." We identified several key terms that we would expect to see in long-term energy contracts designed to provide reliable electricity supplies, as outlined in the text box at left.

Using these criteria, we found that the majority of the contracts we reviewed were lacking in several of these categories. In reviewing the terms and conditions, we found that the contracts, particularly the early ones, lacked provisions that would ensure reliable delivery of power. Moreover, we found that the types of energy products the department purchased also affected the reliability of the department's portfolio.

Based on these findings, we made several legal recommendations for the original contracts. We recommended that the department first conduct an in-depth assessment of legal risks associated with the contracts. We also recommended that the department develop an effective legal management strategy based on the results of that assessment, to identify the department's leverage points and the trouble spots that the department needs to guard against in the contracts. In addition, we recommended that the department develop a contract renegotiation strategy that focused on improving the reliability and overall performance of the portfolio.

In our December 2001 audit we found that the contracts were not easily assignable to investor-owned utilities.

Given the weaknesses we identified in the original contracts, in the December 2001 audit we also evaluated the contracts to determine the department's ability to renegotiate or quit the contracts. Also, because the department's power-purchasing authority under AB 1X was to end on December 31, 2002, we evaluated whether the contracts would permit an easy transition from the department to the investor-owned utilities. We found that the long-term energy contracts were not easily assignable to the investor-owned utilities, and thus we identified a need for the department to develop a strategy for its ongoing legal and technical responsibilities. We recommended that the department establish an ongoing legal services function that specializes in power contract management, negotiation, and litigation, and that the department investigate all audit and other rights available to it under its contracts to ensure that it can develop a proper performance enforcement program.

Our December 2001 audit also evaluated the contracts on the following basis:

- **Flexibility to renegotiate or quit the contract:**
  - Constraints on the department's ability not to perform.
  - The department's ability to obtain relief through governmental action.
- **The department's ability to assign or delegate the contract if the department exits the program.**

THE TERMS AND CONDITIONS OF THE RENEGOTIATED ENERGY CONTRACTS BETTER ENSURE RELIABLE SUPPLIES OF ENERGY

As we discussed in detail in the Introduction, since the December 2001 audit the department has assembled a team of legal and technical experts to examine the contracts, set goals for renegotiation, identify opportunities to enter renegotiations, and renegotiate the contracts. The team has vigorously pursued renegotiation of both the price and reliability terms of the energy contracts, as seen in Table 13 on the following page.

TABLE 13

Summary of Contracts Renegotiated in 2002

Contract	2003 Capacity* (In Megawatts)	Percent of Portfolio	Product Changes†
Cabazon	43	0.3%	None
Calpine	3,175	23.9	Fixed energy price to gas tolling on 495 megawatts for 2002 to 2009.
Capitol Power (terminated)	–	–	N/A
High Desert	1,330	10.0	Approximately 60,000 gigawatt-hours of nondispatchable energy replaced with up to 800 megawatts of dispatchable capacity through 2011.
Whitewater Hill	65	0.5	None
Calpeak	291	2.2	49 megawatts moved to NP15.
Soledad	13	0.1	N/A
GWF	340	2.6	None
Colton Power (formerly Alliance)	80	0.6	None
PG&E	66	0.5	None
Williams	1,875	14.1	Approximately 40,000 gigawatt-hours of nondispatchable energy replaced with dispatchable capacity that varies from 430 to 1,175 megawatts through 2010.
Clearwood	25	0.2	None
Santa Cruz	3	0.0	None
Wellhead Power	118	0.9	None
Sunrise	560	4.2	None
Total—Renegotiated Contracts	**7,984**	**60.0%**	
Total—Renegotiated Portfolio	**13,262**		

* July/August peak-hour capacity.

† Only addresses product changes, which includes effective replacements of product type but not straight additions, deletions, or reductions of products.

N/A = Not applicable.

For this audit, we reviewed the terms and conditions of the renegotiated contracts with 6 sellers (Calpine, GWF, High Desert, Calpeak, Williams, and Sunrise), using the same criteria we measured them against in the December 2001 audit. First, we looked at whether the renegotiated provisions meet the stated purpose of AB 1X to ensure a reliable source of energy at the lowest possible price. We also reviewed the contracts for improvements in the department's ability to transfer them to the investor-owned utilities. In Appendix C we have updated our contract report card to reflect the changes we found in the renegotiated contracts we reviewed.

Although the readily quantifiable economic benefits that the renegotiated contracts will have for individual consumers are likely to be modest, our review indicates that the renegotiations resulted in stronger guarantees that the sellers will deliver the power promised under the contracts and will build the new generation units promised in the contracts as seen on Table 14 on the following page. Thus, the renegotiated contracts better meet the reliable energy goals of AB 1X and better ensure the availability of electricity to satisfy consumer demand. Although not readily quantifiable, these changes are likely to provide some economic benefit to ratepayers. These improvements are accomplished through stronger terms and conditions, such as termination rights for the State and penalty provisions when sellers fail to deliver energy or construct new generation units as promised under the contract. In addition, changes in the type of energy products purchased under the contracts increase the reliability of the department's long-term contract portfolio. As noted in Chapter 1, changes in the types of energy products purchased also serves to improve the fit of the department's supply portfolio relative to its net-short obligations. According to our consultants, such changes have economic value that is captured as part of the $900 million estimate of contract cost reductions from combined product and quantity changes, as presented in Figure 5 on page 53.

In reviewing the renegotiated contracts, we found that they have resulted in major improvements in many of the areas we identified as weak in our December 2001 audit. The changes in the renegotiated contracts are the product of complex negotiations between the sellers and the State. As a result, the changes are not always uniform in every contract and the gains are not identical. Nonetheless, we found that they collectively contain many of the terms and conditions we would expect to see in contracts entered into with the goal of providing reliable energy to consumers, as shown in Table 14. Thus, while we found that not all contracts gained improvements in each area that we identified as weak, as a whole the new terms and conditions of each renegotiated contract make significant improvements in the reliability of the power promised under the contracts. Moreover, as seen in Table 13, several renegotiated contracts resulted in changes in the types of energy products the State is purchasing, which also increases the reliability of the overall portfolio.

TABLE 14

Changes in Contract Terms by Category

Category and Issues Graded	Total Contracts Reviewed	Total Contracts With Changes	Contracts With Terms Rated Negatively in December 2001 Audit	Number of Contracts Rated Negatively That Had Improved Terms	Percent of Problem Terms Addressed
RELIABILITY OF ELECTRICITY SUPPLY					
A. Reliability of Performance—Delivery					
Is seller's failure to deliver an event of default? (–1, 0, 1)	10	8	7	5	71%
Penalties for seller's nonperformance (–1, 0, 1)	10	9	7	6	86
Seller's contractual incentives to perform (–1, 0, 1)	10	4	3	1	33
Seller's price incentives to perform (–1, 0, 1)	10	0	0	N/A	N/A
Department's ability to manage risk of nonperformance (0, 1)	10	10	0	N/A	N/A
Seller's outs (–1, 0, 1)	10	7	8	6	75
B. Reliability of Performance—Availability					
Is seller's failure to perform an event of default? (–1, 0, 1)	10	7	7	4	57
Penalties for seller's nonperformance (–1, 0, 1)	10	10	3	3	100
Seller's contractual incentives to perform (–1, 0, 1)	10	6	2	1	50
Seller's price incentives to perform (–1, 0, 1)	10	1	0	N/A	N/A
Department's ability to manage risk of nonperformance (0, 1)	10	10	0	N/A	N/A
Seller's outs (–1, 0, 1)	10	5	6	4	67
C. Reliability of Performance—Building New Generation					
Is seller's failure to perform an event of default? (–1, 0, 1)	10	1	4	0	0
Penalties for seller's nonperformance (–1, 0, 1)	10	6	3	3	100
Seller's contractual incentives to perform (–1, 0, 1)	10	3	2	1	50
Seller's price incentives to perform (–1, 0, 1)	10	3	1	1	100

Category and Issues Graded	Total Contracts Reviewed	Total Contracts With Changes	Contracts With Terms Rated Negatively in December 2001 Audit	Number of Contracts Rated Negatively That Had Improved Terms	Percent of Problem Terms Addressed
Department's ability to manage risk of nonperformance (0, 1)	10	5	0	N/A	N/A
Seller's outs (–1, 0, 1)	10	0	4	0	0%
D. Price Risk—Uncertainty of Price					
Seller's pass-throughs (–1, 0, 1)	10	8	6	6	100
Department credits (0, 1)	10	7	0	N/A	N/A
Allocation of environmental risk (–1, 0)	10	2	3	2	67
E. Price Risk—Tolling Agreement					
Department's exposure to fuel price risk (–1, 0, 1)	10	6	0	N/A	N/A
Department's exposure to operating inefficiency risk (–1, 0, 1)	10	5	0	N/A	N/A
FLEXIBILITY TO RENEGOTIATE OR QUIT					
A. Constraints on Department's Ability Not to Perform					
Outs for department (–1, 0, 1)	10	9	6	5	83
Dispatchable versus take or pay (1, –1)	10	9	4	3	75
Limits of state's liability (–1, 0, 1)	10	0	4	0	0
B. Department's Ability to Obtain Relief Through Governmental Action					
Recoup expenditures through taxes (0,1)	10	1	0	N/A	N/A
Obtain relief from FERC (0, 1)	10	3	0	N/A	N/A
ABILITY TO ASSIGN/DELEGATE IF DEPARTMENT EXITS THE PROGRAM					
Ability to assign/delegate to government entities (–1, 0, 1)	10	0	0	N/A	N/A
Ability to assign/delegate to nongovernment entities (–1, 0, 1)	10	10	9	9	100

Source: Department of Water Resources' data reviewed by the Bureau of State Audits.

Note: In many cases, changes in contract clauses affected multiple categories. In these cases, we evaluated the effect of the change on each category. Also, this report card does not include the following renegotiated contracts because they are insignificant in value to the overall portfolio: Cabazon, Clearwood, PG&E, Santa Cruz, Soledad, Wellhead Power, and Whitewater. We reviewed a total of 16 transactions, but treated our review as a review of 10 contracts because the department treated them as such. The 10 contracts are listed on page 148.

N/A = Not applicable.

The renegotiated contracts represent more than one-half of the value of the State's long-term contract portfolio. As a result, the renegotiated contracts have improved the reliability of roughly half of the energy portfolio. Further, all of these improvements, although difficult to quantify, are likely to provide some economic benefit to ratepayers.

The Renegotiated Contracts Make the Delivery of Power More Reliable

Provisions ensuring reliable delivery were particularly important in an environment in which the State suspected generators of engaging in activities such as withholding power to drive up spot market prices.

In our December 2001 audit, we examined the contracts for provisions that would ensure that sellers deliver electricity as called for by the contracts. Our consultants advised us that provisions ensuring reliable delivery were particularly important in an environment in which the State suspected generators of engaging in activities such as withholding power to drive up spot market prices. We found that the terms and conditions of the majority of the original long-term contracts may not assure the reliable delivery of promised power. For example, we found that under most of the original contracts we reviewed, failure to deliver energy is rarely defined as an event of default that would give the department the right to terminate the contract, and the contracts also do not assess penalties on sellers for failing to deliver promised power. Thus, under these original contracts the department cannot terminate a contract or assess penalties, even if a seller repeatedly or deliberately fails to deliver power, and even at times when the State is in dire need of it. Instead, the department is limited to recovering the difference between the contract price and the price the department has to pay to replace the energy the seller failed to deliver, a remedy commonly known as cover damages. We found that cover damages are not adequate to ensure delivery of power, because they assume that an adequate supply of power will be available from which the buyer can purchase replacement power. As demonstrated by the numerous warnings of potential blackouts in 2000 and 2001, however, that may not be a valid assumption in California's energy market.

All of the renegotiated contracts have terms that better assure that power will be delivered as promised, as seen in the box on the following page. For example, the remedies available to the State under the renegotiated contracts in the event of default impose greater penalties on the seller and make it much more likely that the seller will be motivated to perform.

Reliability of Performance—Delivery

Criteria	Contracts Changed
Is the seller's failure to deliver an event of default?	8
Penalties for seller's nonperformance?	9
Seller's contractual incentives to perform?	4
Seller's price incentives to perform?	0
Department's ability to manage risk of nonperformance	10
Seller's outs	7

The renegotiated Calpine, High Desert, and Williams Product D contracts still provide cover damages for failure to deliver. However, in addition to that remedy, those contracts now call for payment adjustments for failure to deliver. Moreover, those contracts, as well as five others, now make failure to deliver power under the contract an event of default under certain circumstances. Once an event of default occurs, the State may be entitled to terminate the contract and, under some circumstances, to collect termination damages.

For example, the renegotiated GWF contract makes it an event of default for GWF to willfully fail to make power available as called for by the contract and to instead deliver the energy to a third party. If that event of default occurs, the State may terminate the contract and receive termination damages equal to the difference between what the department would have paid for the power under the contract and the cost of the replacement power.

Similarly, in the renegotiated Williams Product D contract, an event of default occurs under two circumstances: if Williams fails to deliver power during a stage emergency called by the California Independent System Operator (ISO) or if Williams has three unexcused failures to deliver. The threat of termination for failure to deliver under these circumstances gives the sellers a powerful incentive to ensure that power is delivered to the State when necessary. The Williams Product D contract is noteworthy in that it ties this threat to failures to deliver electricity when the State needs it most—that is, during the stage emergencies called by the ISO, when the State's electricity supply is tight and rolling blackouts may occur.

Ten of the renegotiated contracts also have other terms and conditions that encourage sellers to perform, such as penalties for failure to deliver. For example, several of the original contracts call for the payment of capacity payments to sellers. Long-term energy contracts often include capacity payments, which pay generators a fee for keeping specified amounts of energy capacity available to the buyer. When the buyer actually schedules energy for delivery, the buyer then pays an additional fee per megawatt-hour for the energy that is actually delivered. The capacity payment is thus simply a payment in exchange for keeping power available at certain levels. In contracts of this type, language clearly delineating the seller's responsibilities to maintain the availability of the contract supplies can help ensure reliable supplies of energy.

Several renegotiated contracts contain major revisions of contract language relating to capacity and, as a result, have strengthened the reliability of those contracts. For example, two of the renegotiated Calpine contracts (Calpine 3 and Calpine 4) require a reduction in capacity payments for failure to deliver electricity as called for by the contract. The two other Calpine contracts (Calpine 1 and Calpine 2) require a reduction in capacity payments if the rate at which Calpine delivers electricity is below 95 percent of the capacity of the generating units the contract designates to produce electricity.

Penalties for failure to deliver power during ISO stage emergencies discourage market manipulation.

Four of the renegotiated contracts call for the seller to pay the State liquidated damages for failure to deliver under certain circumstances. Liquidated damages are essentially a predetermined or agreed-upon estimate of the loss or damage that the buyer will suffer if the seller fails to deliver. For example, the renegotiated High Desert contract imposes a $7.5 million penalty for intentional withholding of power. Similarly, the GWF and Sunrise contracts require the sellers to pay the State $1.5 million in liquidated damages for willful failure to deliver during an ISO stage alert. Penalties for failure to deliver power during ISO stage emergencies provide additional incentives for sellers to deliver power when it is most needed and discourage the market manipulation that the State suspects generators engaged in during the height of the energy crisis. The High Desert contract, for example, imposes a penalty by making the seller responsible for the payment of ISO imbalance charges that result when energy is not delivered as required by the contract.

Four of the renegotiated contracts provide contractual incentives to sellers that improve the reliability of the delivery of power. For example, the Calpine 3 and Calpine 4 contracts promise capacity payment bonuses if the capacity of designated new generation units exceeds the amounts designated in the contracts.

All of the renegotiated contracts contain provisions that improve the ability of the department to manage the risk that the seller will not deliver power. For example, the Calpine 3 and Calpine 4 contracts restrict improper use of the imbalance energy market to effect delivery of power, and other contracts provide the department with access to real-time data, enabling the department to better anticipate shortfalls in supplies. The threat of penalties and termination also provides the department with better tools to ensure seller performance.

Seven renegotiated contracts include provisions that impose greater limits on excuses for seller nonperformance. The renegotiated Calpeak, Calpine, and Williams Product D contracts contain revisions to the force majeure clauses. These clauses generally excuse generators from performing under contracts if certain defined events beyond the control of the generator occur. Under those circumstances, failure to perform is not an event of default or grounds for termination, nor is the generator liable for any damages. In our December 2001 audit, we found that most force majeure clauses were broadly worded, providing the generator with a wide range of excuses for failure to deliver. In contrast, the renegotiated Calpine contract, for example, narrows the force majeure clause by excluding from that definition events relating to defined economic factors or Calpine's failure to operate generating units within prudent industry standards. Through narrowed force majeure clauses, giving sellers fewer excuses for failing to deliver electricity, the sellers have greater incentives to deliver power as called for by the contract.

By renegotiating the contracts to contain these enhanced reliability provisions, the department has increased its ability to manage the risk of nonperformance in each renegotiated contract.

The Renegotiated Contracts Better Ensure That Power Is Available When Needed

In our December 2001 audit, we also examined the original contracts for provisions that would ensure that electricity is actually available for delivery as called for by the contract. Because electricity cannot be stored, provisions ensuring that energy is available when needed, especially during peak demand periods, are essential to ensuring reliable sources of energy. We found that the original contracts generally lack provisions that ensure that the energy the department is entitled to under the contract is actually available when the State needs it. For example, the original contracts generally do not require that the generating units designated to supply power under the contract be operated and maintained within prudent industry standards. Similarly, few of the original contracts provide the department with the right to inspect and monitor generators to ensure that units are being properly maintained and available to deliver energy. We found that the right to inspect any unit having an

Provisions ensuring that energy is available when needed are essential to ensuring reliable energy supplies.

unscheduled outage, in order to confirm that the outage was due to a genuine operating failure, would be valuable if the State suspected that generators were seeking to drive up prices by inappropriately withholding generation.

Reliability of Performance—Availability

Term	Contracts Changed
Is seller's failure to perform an event of default?	7
Penalties for seller's nonperformance	10
Seller's contractual incentives to perform	6
Seller's price incentives to perform	1
Department's ability to manage risk of nonperformance	10
Seller's outs	5

All of the renegotiated contracts contain provisions that should help ensure that the energy the department is entitled to under the contract is actually available when the State needs it, as shown in the box at left.

As we discussed earlier, several contracts now reduce the capacity payments that the State would otherwise owe under a contract if the seller fails to maintain the availability of power at the levels set in the contract. Seven of the renegotiated contracts have provisions that permit the State to terminate the contract if the sellers fail to keep power available at the capacity level specified in the contract under certain circumstances. For example, the Calpine 1 and Calpine 2 contracts permit the State to terminate the contract if for two consecutive months Calpine delivers electricity to the State at a rate that is below 95 percent of the capacity levels required in the contract. The threat of termination and loss of future payments under the contract gives Calpine strong incentives to perform and thus strengthens the reliability of the energy supply under the contract.

The Williams Product D contract establishes penalties if Williams dispatches the energy capacity the State contracted for to a third party. More specifically, if Williams dispatches power to any other party or sells or commits the contract's energy capacity to another party, the State may terminate the contract and Williams must pay the State liquidated damages amounting to five times what Williams would have been paid under the contract if it had delivered the power to the State.

Three of the renegotiated contracts also have additional incentives for sellers to maintain the availability of power. For example, the Calpine 3 and Calpine 4 contracts and the Williams Product D contract provide bonuses if the actual availability of the designated generating units to produce power exceeds the minimum number of megawatts the unit is required to make available under the contract.

Changes in Energy Products Enhance the Reliability and Flexibility of the State's Energy Portfolio

The types of energy products that compose the department's energy portfolio also affect the reliability of the supply of power. Energy products often define how energy is delivered. For example, during our December 2001 audit, we found that the department's energy contracts often contain two types of energy products: unit contingent products, which excuse the seller for failing to deliver power from the specified unit due to force majeure events, and firm energy with liquidated damages (firm LD contracts), which excuse the seller for failing to deliver power in the case of force majeure events. A contract for unit contingent energy products may be less reliable than a contract for firm LD energy products because a unit contingent contract excuses the seller from delivery from the designated unit for various reasons, with no damages owed to the purchaser, while firm LD energy contracts require the seller to either deliver power from some source or pay cover damages.

Changes in energy products have improved the reliability of the supply of power. For example, the original Calpine 1 contract calls for unit contingent power, which makes Calpine's obligation to deliver power contingent on the ability of a specified generation unit to produce the power. The renegotiated contract converts it to a firm LD contract, which means Calpine must deliver the called-for energy or pay the State cover damages.

The Renegotiated Contracts Calling for New Generation Better Assure That the Generation Units Will Be Built

In our December 2001 audit, we reported that contracts calling for the construction of new generation facilities have numerous weaknesses in provisions relating to the new generation. Several of the original contracts we reviewed in that audit rely on the generator to build new generation units to provide the energy the generator agreed to provide to the State. However, our review of the original contracts revealed they lack provisions to ensure that the new generating units they call for will actually be constructed. This is particularly true of the early original contracts. For example, the original contracts lack many provisions that ensure performance, even though the State pays a premium for the construction of the new generation units in addition to the fee per megawatt-hour it will pay when the power is actually delivered. We found that the original contracts generally lack terms that (1) impose penalties on the generator for failure to complete a unit as described in the contract, (2) make failure to build the generation unit an event of default, (3) mandate construction unless the seller can demonstrate that construction was impossible, or (4) establish construction milestones that the generator must meet, along with bonuses for early completion or penalties for late completion. The absence of these provisions makes it more difficult for the State to ensure that new generating units are built and the power is actually made available and delivered.

Changes in Reliability of Performance—Building New Generation

Term	Contracts Changed
Is seller's failure to perform an event of default?	1
Penalties for seller's nonperformance	6
Seller's contractual incentives to perform	3
Seller's price incentives to perform	3
Department's ability to manage risk of nonperformance	5
Seller's outs	0

The department has renegotiated several contracts that call for the construction of new generation units, representing a total of 5,400 megawatts that have and will become available to the State over the next three years. All of these renegotiated contracts contain revised terms and have added new terms that give the State greater assurances that the sellers will actually build the new generation units the contract calls for and that the State needs to increase its overall generating capacity. The box at left summarizes these changes.

Moreover, under some renegotiated contracts, if a seller fails to build the new generation units within timelines specified in the contract, the seller must pay monetary penalties and in some circumstances run the risk that the State will exercise its right to terminate the contract for nonperformance. As a result, the renegotiated terms not only increase the reliability of the department's energy portfolio but also better ensures that new generation units will be brought on-line to meet the State's future energy needs.

The department has exercised its right to terminate a contract for nonperformance, canceling the renegotiated contract with Capitol Power because the seller failed to bring agreed-upon generation units on-line by July 15, 2002, as called for by the contract.

Three of the renegotiated contracts make payment of capacity payments contingent on the generation units achieving commercial operation or call for reductions in capacity payments if the deadline to achieve commercial operation is missed. Three of the renegotiated contracts also have new contractual incentives for the sellers to perform. For example, the Calpine 2 contract permits the State to take ownership of a project if Calpine fails to meet construction and development milestones. Although the State would essentially be required to purchase the project from Calpine at cost to exercise that right, doing so in any of the years 2003 through 2010 would allow the State to ensure that 495 megawatts per year are actually added to the department's portfolio. Moreover, the threat of a state takeover and the loss of profits from the project give Calpine a strong incentive to perform. In addition, if Calpine does not achieve commercial operation of certain units by December 31, 2003, the number of megawatts under the contract is reduced. In other words, if Calpine does not have the generators up and running by December 31, 2003, it loses its contractual right to require the State to pay for those megawatts in future years.

Six renegotiated contracts have penalties for failing to bring new generation units on-line as promised.

Six renegotiated contracts have penalties for failing to bring new generation units on-line as promised. For example, while the original High Desert contract contains relatively few terms assuring that construction will occur, the new contract has numerous incentives for High Desert to perform. The contract now makes it an event of default if High Desert fails to achieve commercial operation by October 2004. Moreover, if the State terminates the contract as a result of that default, High Desert must make a $50 million termination payment to the State. The High Desert contract will cost $2.4 billion, and thus a $50 million penalty is quite substantial when coupled with the future profits High Desert would lose upon termination of the contract.

Like the High Desert contract, the renegotiated GWF contract also improves terms relating to new construction, although the provisions are not quite as strong. The GWF contract provides penalties for each day that a project designated under the contract misses its construction deadline, and it permits the State to terminate the contract if it has not met a July 1, 2003, completion date. However, if the State exercises its right to terminate, it is not entitled to termination damages, although GWF still faces the prospect of losing future revenue under the contract, thus providing GWF an incentive to perform.

Some of the contracts also improve the ability of the department to manage the risk of the seller's not performing. For example, the Calpine 3 and Calpine 4 contracts have added language requiring Calpine to provide periodic written reports to the State regarding its progress toward achieving commercial operation of the new generation units and permits the State to inspect the units. The High Desert and GWF contracts contain similar reporting requirements and inspection rights for the State. Reports and inspection rights put the State in a position to intervene and require the seller to correct problems before they become critical, thus making the contract more reliable.

The Renegotiated Contracts Better Manage Price Risks

In reviewing the sample of the original contracts, we found that several of them leave the department vulnerable to price risks. Generally, power-purchase agreements provide that all costs up to the point of delivery are borne by the seller, and all costs after the point of delivery are borne by the buyer. But the original long-term contracts often permit sellers to shift costs to the State based on various governmental actions.

For example, the original contracts commonly require the department to pay for any new taxes that California might levy that affect the generation or delivery of power. Others require the department to reimburse the seller for any new taxes imposed by any entity, including the federal government, as well as for charges imposed by any federal agency, including the Federal Energy Regulatory Commission (FERC). Some contracts go so far as to increase the contract price for any increase in the seller's costs that results from any governmental action. Other contracts permit sellers to pass on cost increases arising from compliance with environmental regulations, such as the cost of air emissions credits. We found that these provisions create significant contract management problems for the department and risk exposing the department to future price volatility as sellers seek to pass increasing costs on to the department.

Changes in Price Risk—Uncertainty of Price

Term	Contracts Changed
Seller's pass-throughs	8
Department credits	7
Allocation of environmental risk	2

Eight of the renegotiated contracts contain terms that modify the price risks we identified in our December 2001 audit, and several make other changes that make the price more certain, as summarized in the box at left.

Eight of the renegotiated contracts modify the language permitting the seller to pass its costs through to the State. For example, the Calpine contracts have narrowed the circumstances under which Calpine may pass its costs to the State, and they entitle the State to receive the benefit of certain reductions in Calpine's costs as a result of government action. In other words, if Calpine's costs are reduced as a result of a reduction in taxes enacted by the Legislature, the State is entitled to the benefit of those reductions, provided they relate to the Calpine transaction.

The original GWF contract permits pass-throughs to the State for increased costs imposed by any local, regional, state, or federal agency, but it now limits the pass-through of costs to increases resulting from action by the federal government that is directed at electricity generation, sale, purchase, or transmission. Finally, the overly broad language in the Williams contract that we identified as particularly risky in Appendix B of our December 2001 audit is now narrowed to permit Williams to pass through only costs resulting from taxes or other impositions enacted by the California Legislature that are directed at assets or activities relating to generation, sale, ownership, or transmission of electricity. The Williams Product D contract still provides some protection for Williams from government action by now permitting Williams to terminate the agreement if the State refuses to adjust contractual payments should Williams experience adverse financial circumstances created by governmental action.

The renegotiated Williams Product D contract also provides better price risk protection for the State by permitting the State to, in effect, step into Williams' rights to electricity under a long-term energy contract that Williams has had with AES[2] since May 1998 (AES agreement). The AES agreement is a capacity sale and tolling agreement under which AES agrees to provide 3,956 megawatts of dependable capacity to Williams over a 15-year period. While the original Williams contracts seek to pass costs relating to environmental regulation, such as air emissions penalties, along to the State, the AES agreement, which the State now gets the benefit of to the same extent that Williams does, requires AES to bear the costs for complying with applicable environmental laws.

The original Williams contract does not tie the power it is supplying to the State under its agreement with AES to its contract with the State. Thus, under the original contract, the State is not able to take advantage of numerous reliable energy guarantees that Williams negotiated in the AES agreement, even though Williams is likely providing at least some of the energy to the State from supplies it is entitled to under the AES agreement. Interestingly, the Williams–AES power agreement contains many of the reliability guarantees that we expected to find when we reviewed the original contracts.

The Renegotiated Contracts Better Protect the State From Fuel Price Risks

In our December 2001 audit, we found that the terms of the tolling agreements associated with the contracts we reviewed are generally favorable to the State. As we discussed in Chapter 1,

[2] AES refers to AES Alamitos, L.L.C., AES Huntington Beach L.L.C.

Change in Price Risk—Tolling Agreements

Terms	Contracts Changed
Department's exposure to fuel price risk	6
Department's exposure to operating inefficiency risk	5

tolling agreements permit the buyers to take advantage of decreases in natural gas prices. Nonetheless, the renegotiation team sought, and in several cases achieved, improvements in the tolling agreements, as shown in the box at left.

For example, the GWF contract now requires GWF to use commercially reasonable efforts to secure the best costs and terms for gas management services and requires GWF to obtain at least two competitive bids.

THE RENEGOTIATED CONTRACTS ARE MORE FLEXIBLE AND EASIER TO TRANSFER TO INVESTOR-OWNED UTILITIES, BUT CHALLENGES REMAIN

Since our December 2001 audit, the department's power-purchase authority under AB 1X has ceased. Further, Assembly Bill 57, which became effective in September 2002, laid the groundwork for transfer of energy purchasing back to the investor-owned utilities. In response to that legislation the CPUC, through a series of rulings and orders, required the day-to-day management and operation of the long-term energy contracts to be transferred back to the investor-owned utilities. Nonetheless, the department remains legally and financially responsible under the contracts.

The renegotiated contracts call for the transfer to the investor-owned utilities when they are deemed creditworthy—making the timing of the transfer uncertain.

The renegotiated contracts call for the transfer of the contracts to the investor-owned utilities when they are deemed creditworthy and upon the CPUC's determination that the contracts are just and reasonable, thus making the timing of the transfer uncertain. Moreover, the original contracts that have not been renegotiated do not have the assignment language that now exists in the renegotiated contracts, making it more difficult to transfer those contracts to the investor-owned utilities. According to the department, seven original contracts are candidates for renegotiation while others are not, primarily because they have expired or will expire in the near future. As a result, the department continues to have significant legal and technical responsibilities for the ongoing management of the long-term contracts, as we discuss in detail in Chapter 6.

The Renegotiated Contracts Provide the Department with Greater Flexibility to Quit the Contract

As we discussed earlier, in view of the weaknesses we identified in the terms and conditions of the original contracts with respect to the reliability of power delivery, we also reviewed them for opportunities for the department to quit or renegotiate the contracts. In our December 2001 audit, we also noted that the original contracts we reviewed place various restrictions on the department's ability to petition the FERC to void its power-purchase contracts on the basis that the rates are not just and reasonable.

The new terms should provide the State with better ability to aggressively administer the contracts.

While we have reviewed the renegotiated contracts for flexibility, this report does not evaluate whether the renegotiated contracts provide further opportunities to renegotiate the contracts. We note, however, that in our December 2001 audit, we found that the limitations on the department's ability to declare events of default weaken its ability to aggressively administer the contracts, since contract management is often dependent on the rights that it has against the seller. The new terms should provide the State with better ability to aggressively administer the renegotiated contracts and ensure seller performance because the department's ability to declare events of default and to terminate contracts has improved significantly.

Further, the settlement agreements place some constraints on what the State can do with regard to claims arising from the original versions of the contracts. In the settlements, the State agrees to release the majority of its pending claims arising from the original contracts, as well as to release those claims arising from issues relating to the validity of the contracts and whether they are just and reasonable and to cease pending investigations. Although the State gave up these rights, it appears that the benefits achieved in the renegotiated contracts are worth the release of those claims.

In our December 2001 audit, we found that the original contracts give the State few excuses for failing to perform its obligations under the contract. In contrast, we found that the contracts give the sellers numerous excuses for failing to deliver, even when that failure is repeated and intentional, and that the contracts also include excuses for failure to maintain the availability of power and to construct new generation units as called for by the contracts. Ten of the renegotiated contracts lessen the constraints on the department's ability not to perform by providing the State with termination rights for certain failures to deliver or failures to construct generation units called for in the contracts. As we discussed earlier, several of the renegotiated contracts permit the State to declare an event of default for repeated or intentional failure to deliver, failure to meet availability requirements, or failure to bring new generation units on-line within the timelines established by the contracts. Thus, the renegotiated contracts now provide the State with more opportunities to walk away from unreliable generators.

Product Changes Have Enhanced the Flexibility of the Contracts

Changes in the product portfolio, as seen in Table 14 on pages 72 and 73, have also increased the State's flexibility and provided the department with new tools to manage the risks of nonperformance by the seller. The shift from nondispatchable energy products to dispatchable energy products as reflected in Table 2 on page 25, permits the department to schedule and pay for power when needed, rather than paying for contracted energy that it may not need during some periods.

The Williams renegotiation has resulted in a new fully dispatchable product giving the State greater flexibility to schedule power.

In addition to changing products, the department has successfully added products. For example, renegotiating the Williams contract has resulted in Williams Product D, a new, fully dispatchable product that includes full day-ahead, hour-ahead, and real-time energy scheduling rights for the State. The Williams renegotiation has given the State greater flexibility to schedule power when it actually needs it, even an hour ahead or on a real-time basis.

Renegotiation of the High Desert contract also resulted in a product change. Under the original contract, the State purchases unit contingent energy, meaning that High Desert is obligated to deliver only if a designated unit is available. When the unit is available, however, the State is required to accept delivery of power, whether it needs it or not. The renegotiated High Desert contract calls for dispatchable power, meaning that the energy product in the High Desert contract has been changed from one that the State was required to pay for whether it needed it or not to one that gives the State flexibility to order and pay as consumer demand requires. As shown in Table 2 on page 25, through renegotiations about 800 or more megawatts of dispatchable capacity has been added each year between 2003 through 2010. This not only results in costs savings to the State but also provides the State with a more manageable portfolio.

The Renegotiated Contracts Make Few Changes in the Department's Ability to Obtain Relief Through Government Action

In the December 2001 audit, we also looked at the department's ability to obtain relief from the contracts by taking various actions, such as renegotiation, reassignment of contract obligations, or contract termination. In that audit, we noted that the long-term contracts generally contain a clause that purports to limit the department's right to seek relief from FERC.

The renegotiated contracts have language stating that the contracts are just and reasonable under the Federal Powers Act and state law. Under the settlement agreements, the State agrees not only to dismiss its FERC claim against the seller but also to dismiss other claims and stop certain investigations of the seller by, for example, the California attorney general. Thus, in most of the renegotiated contracts, the State generally waives its rights to obtain further relief from the original contracts through governmental action. Finally, the State's willingness to enter into these settlement agreements was likely a factor in getting generators to the table and in the ultimate renegotiation of the contracts.

The Renegotiated Contracts Call for Transfer to the Investor-Owned Utilities, but the Department Faces Numerous Challenges in the Process

In the December 2001 audit, we found that while the department often has the authority to assign its rights under the contract to another government entity, assignment to a nongovernmental entity generally requires the consent of the seller. We identified this as a challenge because AB 1X ended the state's power-purchasing authority on December 31, 2002, with the goal of transferring that responsibility, as well as the operational and legal management of the long-term contracts, back to the investor-owned utilities. Obtaining the sellers' consent to assign the contracts could involve protracted negotiations, and not all sellers may agree to assignment. All of the renegotiated contracts have addressed this concern by adding a novation clause, which essentially transfers the rights, duties, and responsibilities of the contracts to the investor-owned utilities upon the occurrence of certain events.

The novation clause provides that any time after January 1, 2003, the seller, at the request of the State, must enter into a new agreement with one or more of the investor-owned utilities and that execution of the new agreement is a novation that relieves the State of any liability or obligations under the renegotiated contract. Under the novation clause there are two hurdles that must be passed before the seller is obligated to enter into the new agreement. First, the clause is triggered only if the investor-owned utility to which the contract will be assigned is creditworthy. Second, the CPUC must have issued an order finding that the new agreement is just and reasonable under Section 451 of the Public Utilities Code. According to the department's legal counsel, sellers would only agree to the novation clause if it was made contingent on occurrence of these two key events. Pacific Gas & Electric (PG&E), one of the three largest investor-owned utilities, filed for bankruptcy in April 2001, and those proceedings are likely to continue for months to come. As a result, it is unlikely that PG&E will meet the creditworthiness requirement anytime soon. Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E) experienced similar financial challenges from the energy crisis. According to the department, SDG&E is currently creditworthy, and SCE is approaching creditworthy status. Thus, it appears that the department will continue to have legal and management responsibility for all of the contracts for several years.

It appears the department will have legal and management responsibility for all of the contracts for several years.

The department was not able to assign its rights and obligations to the investor-owned utilities under any of the long-term energy contracts prior to January 1, 2003, nor do current conditions permit the department to assign any contracts now, including the renegotiated contracts. Thus, to facilitate the transition of energy purchasing back to the investor-owned utilities, the CPUC has made several orders regarding the responsibilities of the investor-owned utilities to manage the contracts after January 1, 2003. In September 2002, the CPUC issued an order allocating portions of the contracts to the investor-owned utilities. On December 19, 2002, the CPUC issued operating orders that set forth the responsibilities of the investor-owned utilities to perform functions under the allocated contracts on behalf of the department in accordance with the contracts.

As we explain in further detail in Chapter 6, the operating orders require the investor-owned utilities to act as the department's agent in managing the operational duties called for by the contracts. These orders state that the department remains legally and financially responsible under each of the contracts and will cooperate fully with the investor-owned utilities. The CPUC has regulatory authority only over the investor-owned utilities and not over the department, and thus the operating orders govern the responsibilities of only those entities. However, as long as the department remains a party to the contracts, the department clearly has significant ongoing responsibilities for the administration of the contracts as well as the revenue bonds. As we discuss more fully in Chapter 6, this responsibility presents numerous challenges and risks for the department until the contracts are transferred to the investor-owned utilities. ■

Blank page inserted for reproduction purposes only.

CHAPTER 4

Sales of Surplus Power Have Not Significantly Affected the Costs of the Power-Purchasing Program

CHAPTER SUMMARY

As the Department of Water Resources (department) progressed in supplying the net short, and market prices stabilized in the summer of 2001, the long-term implications of the contracts began to emerge. Our December 2001 audit report established that the department's long-term contracts would likely require it to purchase more power than would be needed during some hours. Those quantities would be expected to be sold as surplus and thus have the potential to affect the overall costs of the department's power program. However, the previous report did not explore the financial effects of sales of surplus power, or of sales from other sources made by the department as it sought to fulfill its responsibilities under Assembly Bill 1 of the 2001–02 First Extraordinary Session (AB 1X).

The department's sales of surplus power during 2001 and 2002 have remained small in relation to its volume of power purchases. A certain level of surplus sales is a normal result of meeting anticipated power demands using power-purchase contracts and short-term purchases in advance of the demand period, rather than relying too heavily on real-time or spot market purchases when the power is needed. This surplus power can result from more than one cause, such as unexpected changes in the weather, purchase contracts that do not fit well with the demand for power the department must fill, or fluctuations in forecasts of the net short that are provided in seven-day, day-ahead, and hour-ahead intervals by the investor-owned utilities to inform the department's traders of the expected upcoming demand for power.

Power sales during a given period do not necessarily result in significant economic losses to the department. Indeed, some sales may yield economic benefits. Sales of surplus power often can entail anticipated losses that were taken into account when making cost-effective purchase transactions. In a sense, such losses are artificial. Some sales of surplus power, however, can result in true economic losses. Our consultant advises us that the cost that has resulted from the department's sales of surplus power does not appear unreasonable.

SURPLUS POWER SALES INCREASED DURING 2002 BUT WERE NOT SIGNIFICANT COMPARED TO POWER PURCHASES

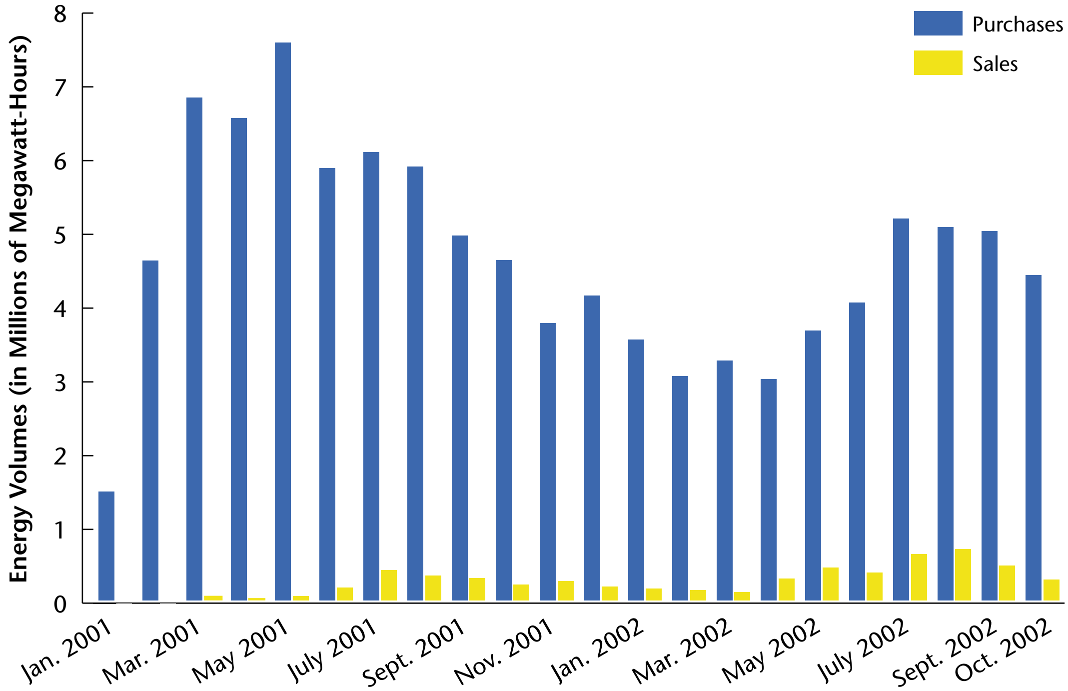
Sales of surplus power during the first three quarters of 2002 totaled only about 3 percent of the total cost of the department's energy program during that time.

The department made a considerable number of sales transactions in the forward, day-ahead, and hour-ahead markets from March 2001 through October 2002. However, from the standpoint of transaction dollars and volumes, power sales were not a large part of the department's activities. Sales revenues during the first three quarters of 2002 totaled $73 million, or only about 3 percent of the $2.6 billion total cost of the department's energy program during that time. Similarly, sales volumes during the same period totaled 3,320 gigawatt-hours, or only 9 percent of the department's total purchase volumes of roughly 36,000 gigawatt-hours. Based on our consultant's review of the department's purchase and sales data from August 2002, they concluded that most sales appear to have resulted from the shorter term buying and selling required to manage the volatile net-short requirements. From their analysis, it appears that less than 20 percent of the surplus power sold is attributable to the department's long-term contracts. Figure 8 summarizes the department's gross purchase and gross sales transaction volumes for each month during 2001 and most of 2002.

In the months immediately following its February 2001 debut as buyer of the investor-owned utilities' net short, the department's focus was on obtaining sufficient supplies to ensure the reliability of the California electrical system. Although its sales transactions were very limited during the first four months of 2001, as Figure 8 shows, sales began to climb during the summer of 2001. The department's trading manager explained that the department's scheduled purchases were typically in balance with the utilities' forecasted net-short positions. However, department records reflected a high percentage of sales made in response to requests by the California Independent System Operator (ISO) that the department step in to balance real-time consumer demands and supplies in the California power system. The department made out-of-market purchases and sales to perform this real-time balancing function, which under normal market conditions had been performed by the ISO.

FIGURE 8

Monthly Total Purchases and Sales During 2001 and 2002



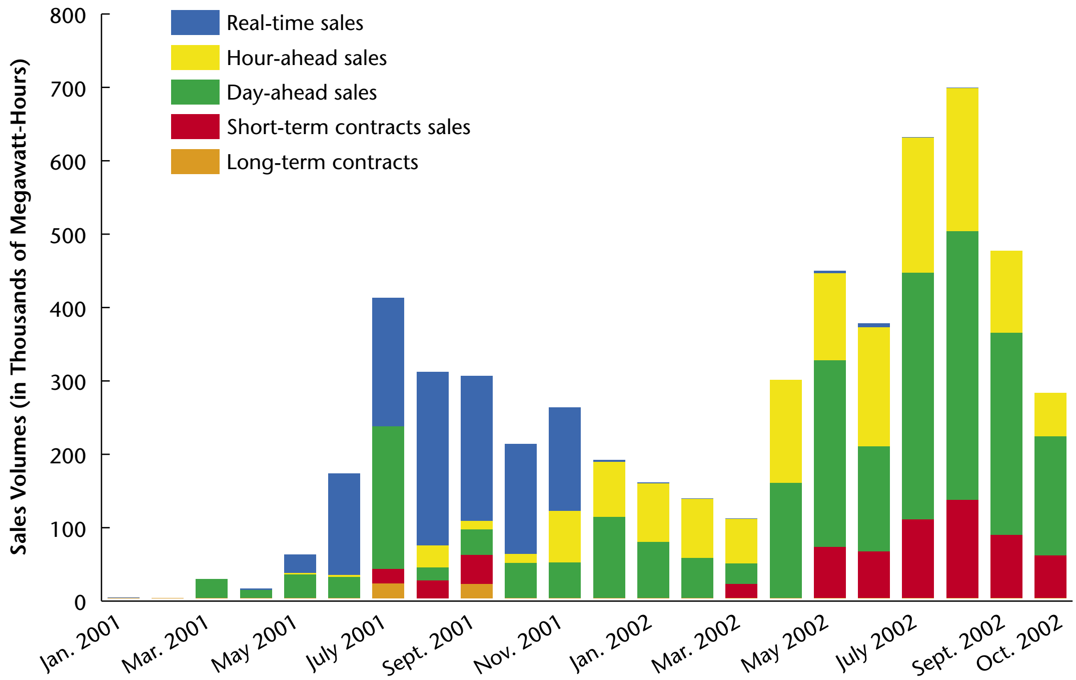
Source: La Capra Associates' analysis of data from the Department of Water Resources.

On November 20, 2001, the Federal Energy Regulatory Commission (FERC) ordered the ISO to stop relying on the department to perform the market balancing function. As a consequence, the department no longer routinely made out-of-market transactions (either sales or purchases) on behalf of the ISO. Figure 9 on the following page reflects the distinct drop in the department's sales of surplus power in the spot market after FERC's order.

Figure 9 on the following page presents basic information regarding the department's sales activity. As we just noted, the substantial real-time sales activity in the latter portion of 2001 reflects the out-of-market transactions conducted by the department on behalf of the ISO. The real-time volumes after November 2001, when FERC issued its order, reflect occasional sales by the department to the ISO. The figure also provides a view of the degree to which sales were being made through short-term contracts. These short-term contracts represent agreements the department struck in advance to sell surplus nondispatchable power over periods ranging from one day to three months. Figure 9 also shows the level of sales in the day-ahead and hour-ahead markets.

FIGURE 9

Monthly Summary of Sales by Type, 2001 Through 2002



Source: La Capra Associates' analysis of data from the Department of Water Resources.

THE REASONS FOR THE DEPARTMENT'S SURPLUS POWER SALES VARIED

The department faced a significant challenge in securing power supplies to meet the net short. Several aspects of this challenge are important relative to the level of sales transacted by the department. For example, the magnitude of the net short is substantial, comparable to or even exceeding the loads served by many utilities, and is inherently quite variable, since the electricity needs of California utility customers (like those of other electric utilities) vary significantly from day to day and month to month. Variations in the net short also occur from hour to hour within each day. As we noted in our December 2001 audit, the department's net-short responsibility included buying roughly one-third of the power requirements of the three investor-owned utilities. As such, the department was responsible for the most volatile portion of power demand.

Some level of surplus power is a normal result of a prudent strategy to deliver a low-cost reliable power supply with limited reliance on the spot market.

Some level of surplus power is a normal result of a prudent strategy of any portfolio manager seeking to deliver a low-cost, reliable power supply with limited reliance on the real-time or spot markets. Overreliance on the real-time and spot markets was a contributing factor to the power crisis in 2000 and 2001. In the post-crisis conditions, relying on California's real-time or spot markets for supplies from which to serve the net short would have brought significant risks of price volatility and (in temporary instances of tight supply) reliability. The department chose to mitigate these risks through forward, or advance, purchases of power, in the form of long- and short-term contract commitments made well in advance of delivery. Such forward purchases of power result in surplus power when significant variations in the net short inevitably occur.

The department uses forward purchases of power to mitigate price and reliability risks that can be present in the real-time or spot power markets. In the wholesale market, such forward purchases are primarily available in blocks (for example, 6x16 products that deliver power six days a week, in 16 prescribed hours a day) in which the delivery amounts by hour are fixed. The sizable daily and even hourly variations in the net short make it impossible to match such forward purchases to the net short at all times. To allow utilities to cover shortages, power suppliers may offer dispatchable products and other products (such as "super peak" power) that provide power only when needed. But such products are not always available in the market, and they typically command premium prices. Thus, supply portfolio managers often find it necessary or cost-effective to rely a great deal on nondispatchable purchases of standard 6x16 and 7x24 products to meet their needs. This may be true even when those purchases are expected to lead to surplus supplies during instances when (1) nondispatchable quantities exceed the forecasted need during particular hours or (2) the actual net short falls below forecast levels. In this context, and given the market conditions, sales of surplus power from long- and short-term contracts can be part of a cost-effective portfolio management strategy.

The department's surplus power sales volumes were sometimes affected by downward revisions in forecasts of the net short provided by the investor-owned utilities.

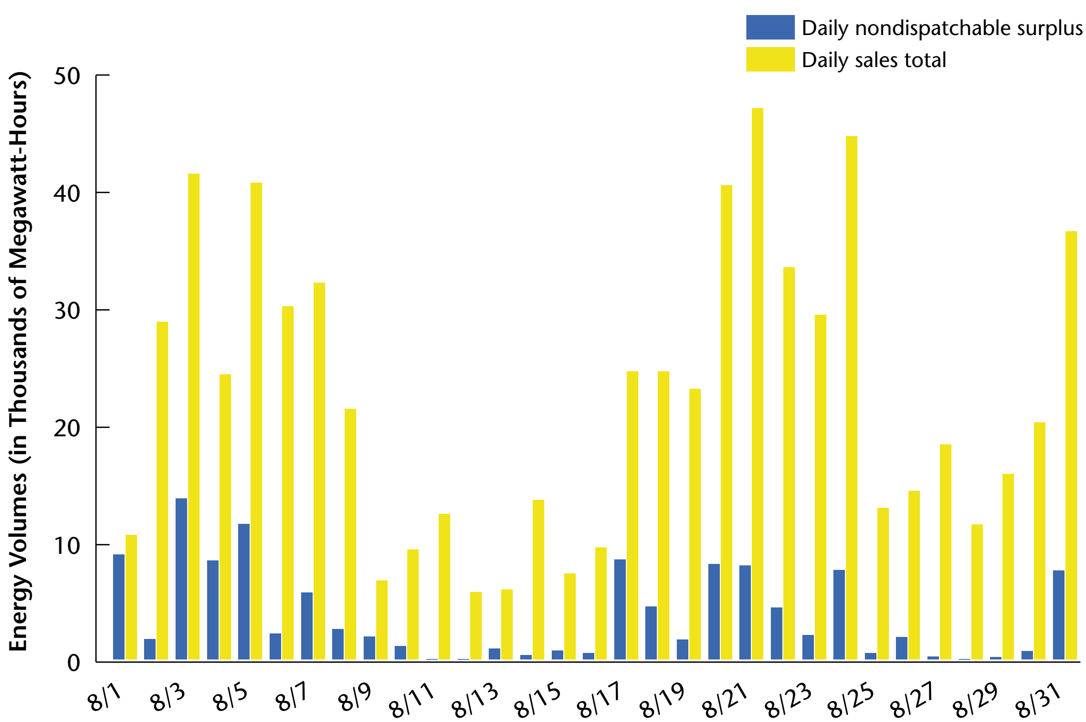
In addition, the department's surplus power sales volumes were sometimes affected by downward revisions in forecasts of the net short provided by the investor-owned utilities. Sales can occur when the department increases its advance nondispatchable commitments in response to the day-ahead forecast for a given hour, only to find that a subsequent reduction in the hour-ahead forecast has rendered those purchases surplus. We also examined whether the department had taken advantage of relatively high-market prices to sell its lower-cost contract supplies at a profit; however, we did not find any instances in which the department appeared to be using this strategy.

A Small Portion of Sales Are Attributable to Surplus Capacity From the Department's Long-Term Contracts

Our consultant estimates that sales attributable to surplus power from the department's long-term contracts represented less than 20 percent of total sales during 2002, based on an evaluation of surplus power sales in a targeted sampling of days during 2002. To arrive at this estimate, our consultant developed a calculation of the amounts by which nondispatchable volumes under the department's long-term contracts exceeded the hour-ahead net short for each day during August 2002. Figure 9 on page 94 shows that 2002 sales peaked during August. In Figure 10, we present the quantities of surplus nondispatchable power beside the total sales volumes for each day during that month. These energy surpluses occurred even during a summer month when the net short was typically quite large. However, Figure 10 reveals that the total sales each day considerably exceeded the quantities of surplus

FIGURE 10

Surplus Power From Long-Term Contracts Versus Total Sales August 2002



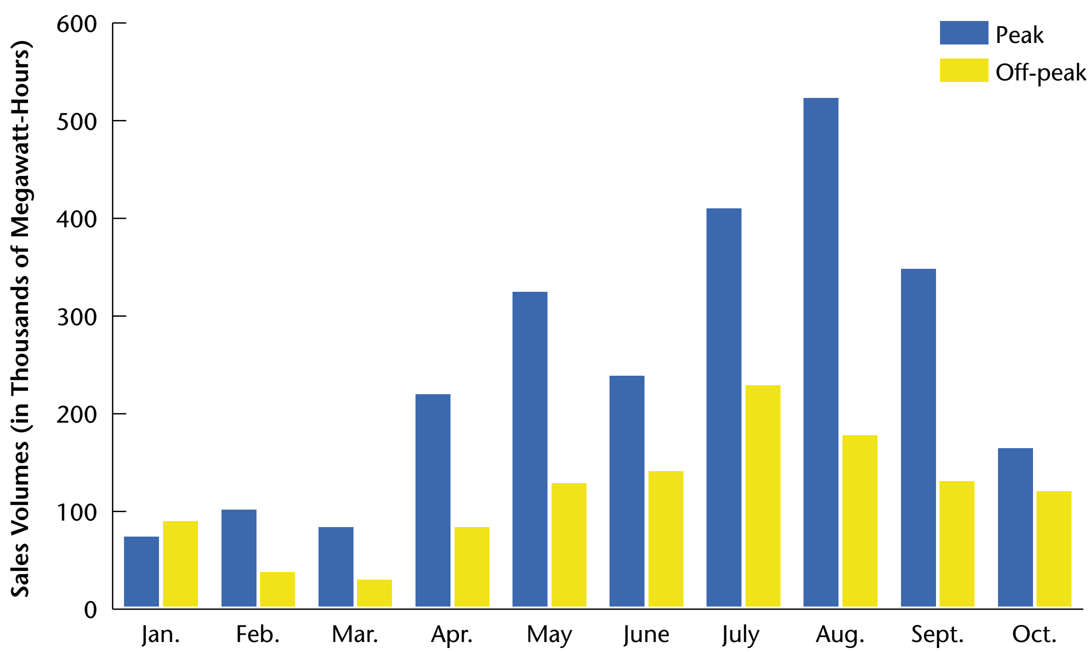
Source: La Capra Associates' analysis of data from the Department of Water Resources.

power from the long-term contracts. Thus, only a fraction of sales during August can be attributed to surplus power from the department's long-term contracts.

Figure 11 identifies sales made during peak and off-peak hours during 2002. This figure is revealing in that the large portion of sales during peak periods is consistent with a strategy of using standard 6x16 blocks of power purchased through long-term contracts to meet peak loads while anticipating some surpluses during the lower-load hours of the 16-hour block. In fact, the department discusses such a strategy in its plan to transition responsibility for procuring the net short back to the investor-owned utilities.

FIGURE 11

Sales During Daily Peak Versus Off-Peak Periods During 2002



Source: La Capra Associates' analysis of data from the Department of Water Resources.

The December 2001 audit anticipated significant levels of surplus energy as a consequence of the 7x24 and 6x16 nondispatchable volumes under the department's long-term contracts. During 2002 there were moderate increases in quantities of nondispatchable capacity from long-term contracts for 7x24 and 6x16 power products. These increases correspond to increases in the quantities of surplus power during peak periods. As nondispatchable power from the department's long-term contracts becomes an increasingly large portion of the power purchases necessary to meet the overall net-short requirements, the department's ability to respond to variations in the net short is increasingly constrained. In this light, the observation that more sales occurred during peak hours is not unexpected.

Sales of Surplus Power From Short-Term Purchases Explain a Significant Portion of the Department's Sales During 2002

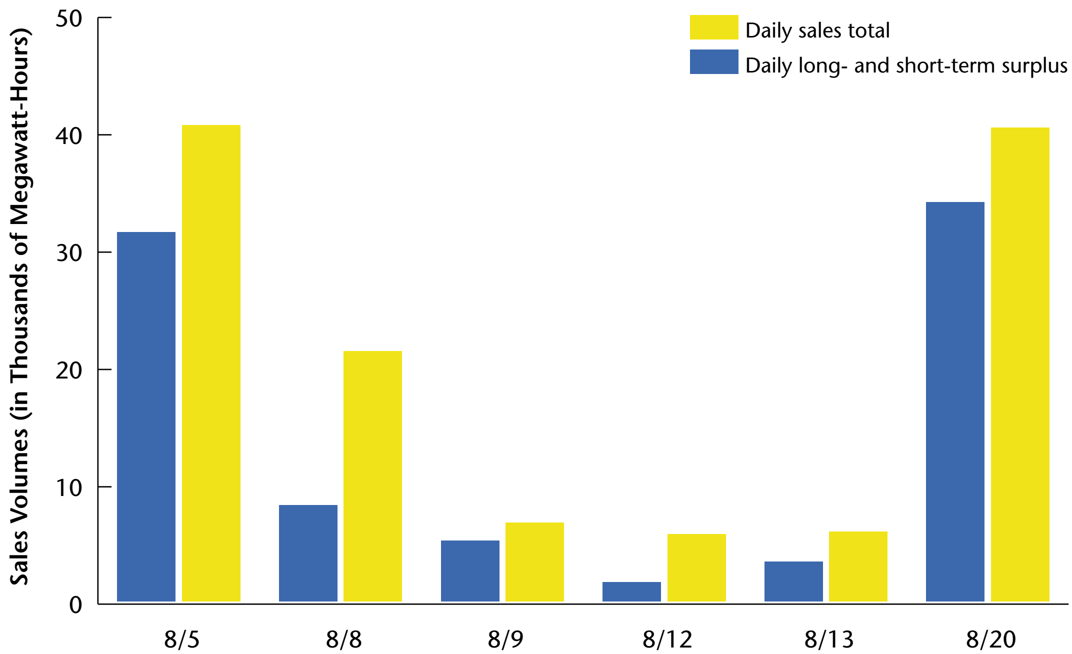
Much of the observed level of sales during 2002 appears to be a result of short-term contract purchases that the department made to cover the net short. Short-term contract purchases are advance purchases for power supplies delivered across periods ranging from one day to three months.

Figure 12 presents the results of an analysis of surplus power from the department's long- and short-term contracts relative to total sales for five select days in August 2002. Like Figure 10, it compares nondispatchable volumes to the hour-ahead net short to calculate surplus energy levels in each day. Here, however, nondispatchable volumes include those from both long- and short-term contract purchases. Using the data from Figure 12, our consultant concluded that a high percentage of the department's sales, almost 70 percent across the five days, are attributable to the combined effects of long- and short-term contract commitments. Our consultant indicates that this pattern of surplus power sales is consistent with the department's strategy of using long- and short-term contracts in an attempt to cost-effectively meet the net short and believes that a similar percentage may apply to nondispatchable sales throughout the year.

Note that the days that are the focus of Figure 12 represent days with both high- and low-level of sales, corresponding to days on which the most accurate estimates of the net short, the hour-ahead forecasts, varied from relatively low to high, as shown for the corresponding days in Figure 13 on page 100. This is important because it shows, as would be expected, that the department's surpluses from nondispatchable contracts were considerably smaller on the days when the hour-ahead forecast net-short levels were high.

FIGURE 12

Surplus Power From Long- and Short-Term Contracts Versus Total Sales for Select Days During August 2002

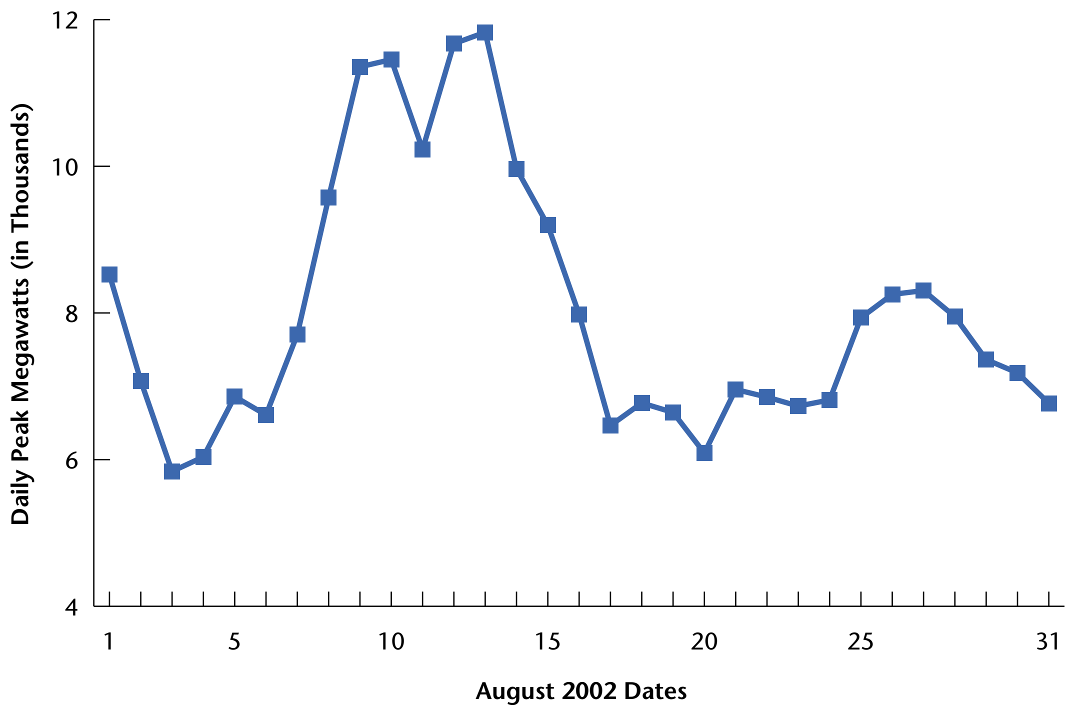


Source: La Capra Associates' analysis of data from the Department of Water Resources.

Figure 13 on the following page provides insight into the daily challenges faced by the department in attempting to use forward purchases of power to meet the net short during the month of August. It reveals the magnitude of the daily swings in the net short, as measured using the investor-owned utilities' hour-ahead forecasts. As the figure shows, on August 3 the net short peaked at below 6,000 megawatts, while several days later peak net-short levels were nearly double that level. Later in the month, the peak net-short levels dropped back to 6,000 megawatts. Under such conditions, making power purchases to ensure sufficient supplies to meet peak-load conditions without causing at least occasional surplus conditions would have been very difficult. In a market in which concerns regarding the availability of cost-effective supplies in spot markets made forward purchase commitments a necessity, it probably was impossible.

FIGURE 13

Daily Variations in the Hour-Ahead Forecast of the Net Short During August 2002

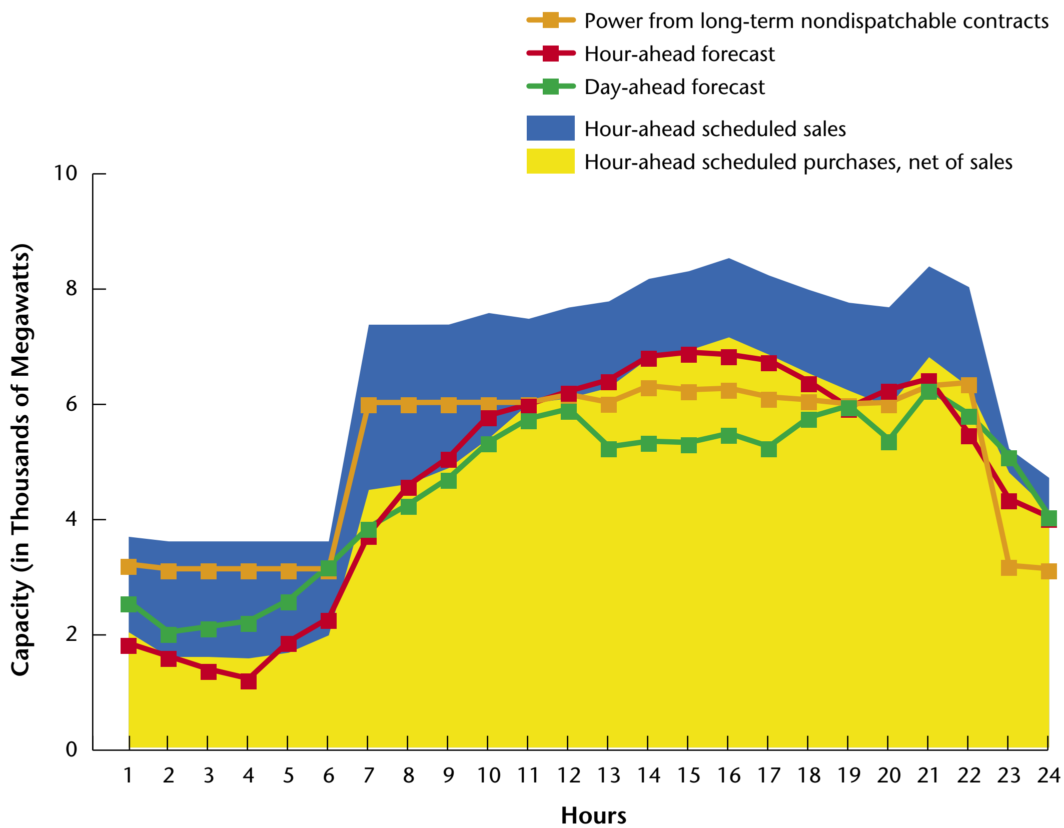


Source: La Capra Associates' analysis of data from the Department of Water Resources.

Our consultant performed a detailed analysis of power sales made on Monday, August 5, 2002. On that summer day, the investor-owned utilities' hour-ahead net-short forecast peaked at roughly 7,000 megawatts during the 16th hour, considerably below the roughly 12,000-megawatt peaks seen later in the month. Figure 14 illustrates the hour-ahead purchase and sales schedules that the department submitted to the ISO (through the investor-owned utilities) for the day, as well as the day-ahead and hour-ahead net-short forecasts that the department received from the investor-owned utilities. In the figure, the hour-ahead scheduled sales are stacked on the hour-ahead scheduled purchases, net of sales, to represent the total scheduled purchases for the day. These schedules and forecasts provide a view of the department's target at different points in time. The figure does not, however, include spot market transactions to bring scheduled purchases and sales in balance with actual demand.

FIGURE 14

The Hour-Ahead Schedule to the ISO, August 5, 2002



Source: La Capra Associates' analysis of data from the Department of Water Resources.

Note: In this figure, hour-ahead scheduled sales are stacked on hour-ahead scheduled purchases, net of sales, to produce total scheduled purchases.

Several items within Figure 14 are noteworthy. First, the figure illustrates the surplus power inherent in blocks of power purchased through the department's long-term contracts. This surplus is demonstrated where the total scheduled sales, as represented by the blue area of the figure, shown below the long-term, nondispatchable contract volumes in hours 1 through 10. Second, the department's final scheduled purchase amount, the amount of scheduled purchases, net of sales, tracks fairly closely to the hour-ahead net-short forecast provided by the investor-owned utilities. As we noted earlier, the department's staff indicated that this was their typical approach to scheduling for a given day. Third, the increase in the net-short forecast from the day-ahead to the hour-ahead forecast during the midday hours caused the department to make additional purchases for those hours. Finally, the figure shows that sales volumes for August 5 considerably exceeded the levels of surplus energy from long-term contracts. In fact, sales occurred in every hour of the day. The department's records show that, in addition to its long-term contracts, the department had made short-term contract purchases for delivery over the course of the month, averaging approximately 1,500 megawatts during peak hours, perhaps anticipating the typically higher net-short loads of the month. The data supporting the figure show that on August 5, a day in which the net short dropped below the average and was well below the peak for the month, it was necessary for the department to sell its short-term contract supply to bring its portfolio into line with the net short.

The department projects increased surplus sales as more long-term contracts take effect.

As of January 1, 2003, the investor-owned utilities resumed the responsibility for purchasing the residual net short. As part of this responsibility, they will also manage the department's long-term contracts. In a December 2002 decision, the CPUC stated that it has the exclusive authority to review the utilities' administration of the department's contracts. The CPUC also stated that it is responsible for monitoring the investor-owned utilities' sales of surplus power from the department's long-term contracts to mitigate the costs of these sales to the ratepayers. However, because it retains legal and financial responsibility for the contracts the utilities will administer, the department will retain a role in observing the activities of the utilities and working with the CPUC to ensure that the utilities comply with the CPUC's decision. The department projects increased surplus sales as more long-term contracts take effect. In Chapter 6 we discuss the department's future challenges in successfully limiting sales of surplus power.

Limited Sales Resulted From Changing the Investor-Owned Utilities' Forecasts of the Net Short and Other Factors

The department's sales volumes were sometimes affected by downward revisions in the investor-owned utilities' forecasts of the net short. However, we did not find evidence that these changing forecasts, particularly those involving downward revisions in the projected net short, affected the department's surplus power sales activity in any consistent manner. Moreover, we found no evidence that changes in the forecast led to a meaningful level of unnecessary additional purchases by the department. The investor-owned utilities routinely provided the department with forecasts of their anticipated net-short position seven days ahead of time (and for each hour of a given day), and then updated those forecasts on a day-ahead and hour-ahead basis. Documents provided by the department indicate that forecast changes frequently occurred in the transition from the day-ahead forecasts to the hour-ahead forecasts. These changes were occasionally of considerable magnitude. In Chapter 5 we explore possible reasons for variations in the net-short forecasts.

Our consultant developed an analysis of variances in the forecasts, using data from the department's review of forecast variances and by comparing the investor-owned utilities' forecasts of hourly power demand from their day-ahead forecasts to their hour-ahead forecasts for July, August, and September 2002. Our consultants' analysis revealed that for almost 80 percent of the days in those months the change between the total day-ahead and the total hour-ahead was 20 percent or less of the net short.

Our consultant then assessed the degree to which those changes in forecast were causing the department to make sales. An analysis of roughly 20 selected days in August and October reveals that there were some instances in which reductions in the forecast of the (total) net short coincided with sales in the hour-ahead markets by the department. A reasonable conclusion is that at least some sales were caused by the falling forecasts provided by the investor-owned utilities. However, sales did not always follow reductions in the forecast.

Other factors could have contributed to the observed levels of sales activity during 2002. Notable among these would be the sale of power from the department's lower-cost dispatchable contracts during periods when high prices in California's spot markets would enable the department to sell the power at a profit. Such profits could, to a degree, offset the department's overall program costs. During the course of this audit, our consultant performed a limited review of potential opportunities for the department to profitably sell power from its dispatchable contracts. We did not observe any instances in which it was clear that power sales were resulting from such a strategy.
In this context it is notable that much of the department's dispatchable contract capacity in 2002 was from peaking units with relatively high production costs. It would be cost-effective for the department to resell power from these contracts only when market prices exceed the cost of the contract energy. We did not observe any instances in which market prices may have been high enough to justify the dispatch of the department's

peak-hour contracts. Moreover, documents provided by the department show that it does not view that its mandate under AB 1X allows speculative trading.

POWER SALES CAN BE COSTLY, BUT THEY DO NOT NECESSARILY RESULT IN SIGNIFICANT ECONOMIC LOSSES

The department, like other market participants, often made short-term purchases, expecting to resell some of the power during days or hours when the net short was lower than average. However, sales of surplus power from short-term contracts (for example, monthly or quarterly forward purchase commitments made during 2002 for delivery in 2002) would not necessarily represent a significant financial loss. If market prices are relatively stable and the surplus is resold at a price that approximates the cost of the power, no material loss would be realized. This appears to have been the case during much of 2002, when market prices were much more stable than in 2001. The prices of the short-term contracts created in 2002 were not nearly as high as the contracts the department signed in early 2001.

The department suffered some losses on the sale of surplus power from long-term contracts.

Some losses were realized on the sale of surplus power from long-term contracts. However, these losses were likely smaller than they might appear. Our consultant estimated the apparent loss on sales of surplus long-term contract power in August 2002. The calculation simply contrasted the average cost of long-term contract purchases made for August supplies to the average amount received from power sales during that month, using data provided by the department. The calculation identified average purchase prices that exceeded average sales prices by $58.54 per megawatt-hour, representing an apparent loss of $6.8 million on surplus energy volumes of just over 116,000 megawatt-hours. This simplified calculation likely overstates the department's true loss from such sales, however.

To be sure, market prices have fallen greatly since the department's long-term contracts were signed in the first half of 2001. During 2002, conditions in California's electricity markets continued to improve. Average power costs were considerably lower and more stable than had been witnessed at the height of the crisis. Power prices declined through midsummer 2001 and remained relatively low through the balance of 2001 and 2002. Average power costs in 2002, as reported by the ISO and including costs in the department's power portfolio, were under $50 per megawatt-hour. Data from the Dow Jones index of daily prices indicate that power in California's markets frequently traded at below $35 per megawatt-hour. These figures are only a fraction of the $300-plus per megawatt-hour prices seen during the peak of the crisis in December 2000. As a result, the prices that the department received in 2002 for its sales were certainly lower than the price it committed to pay for the long-term contract energy. In this sense, the sale of surplus energy from the department's long-term contracts has entailed some financial loss.

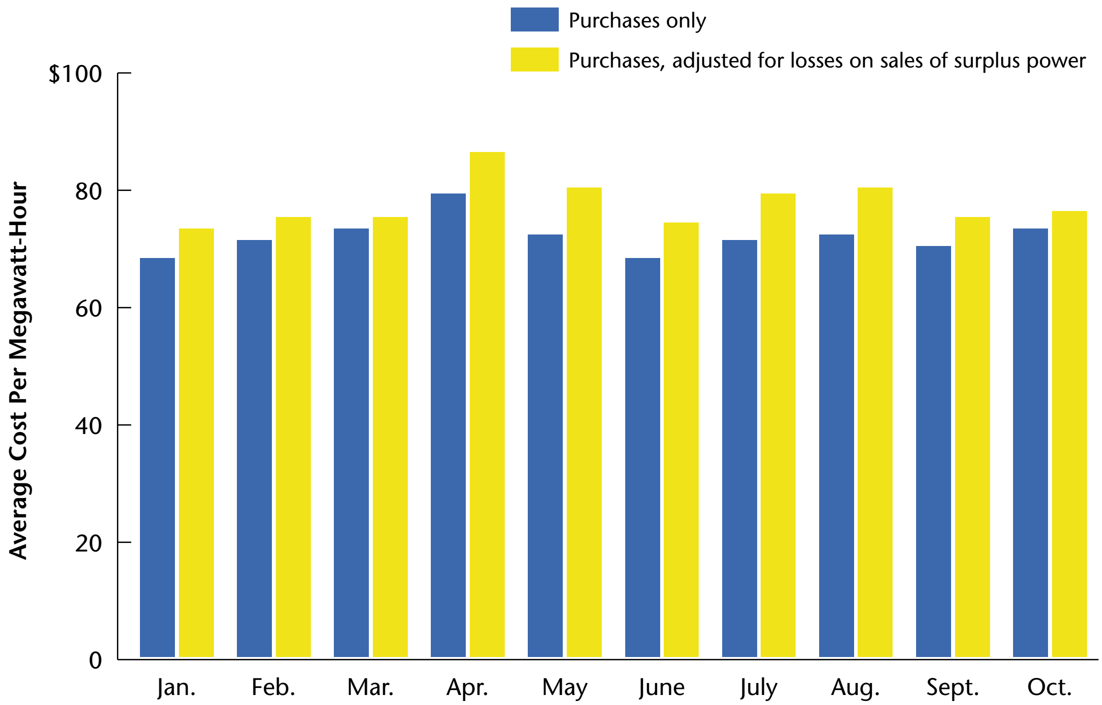
However, our consultant indicates that a proper quantification of such losses would be a complicated exercise. Assessing the economics of surplus power sales by the department would, for example, require estimating the value of power purchases relative to selling prices on an hourly basis. Also, the surplus energy that the department bought under its long-term contracts provided value in that it was at least an imperfect hedge against higher spot market prices that could have occurred (but did not). Therefore, we have not quantified the losses associated with sales of surplus long-term contract energy.

The effect of power sales over the course of 2002 was to increase the effective per-unit cost of the overall power supply portfolio by more than $6 per megawatt-hour, an amount our consultant advises does not appear unreasonable

Figure 15 on the following page provides additional insight into the effects of sales of surplus power on the department's overall supply portfolio. The "purchases only" bars represent the gross average cost of power for the department's entire portfolio of purchases during each month of 2002. Gross purchases include power that the department obtained from its long- and short-term contracts, day-ahead purchases, hour-ahead purchases, and real-time purchases. The "purchases, adjusted for losses on sales of surplus power" bars represent the net average cost of power for the department's entire portfolio; that is, they show average power costs after factoring in the economic losses that resulted from the sales of surplus power. The figure shows that the department's power sales reduced its total quantity of power somewhat more—in relative terms—than they reduced overall power costs. Thus, the effect of power sales over the course of 2002 was to increase the effective per-unit cost of the overall power supply portfolio by more than $6 per megawatt-hour. Our consultant advises us that, all else being equal, this differential in gross and net average power costs does not appear unreasonable. Moreover, had the department purchased nonstandard products that would have enabled it to meet the net short exactly in all hours of 2002 (that is, without any sales), its average power costs might have been even higher.

FIGURE 15

Average Cost of the Power Portfolio During 2002



Source: La Capra Associates' analysis of data from the Department of Water Resources.

A review of the department's sales records and ISO invoices reveals that on occasion the department made power sales in the hour-ahead markets only to have the ISO purchase power on its behalf in the spot market to meet the net short. In a limited review, we identified two days during which the department's total costs increased by roughly $60,000 and $40,000 because it sold power in the hour-ahead markets at relatively low prices, followed by real-time purchases by the ISO at a higher cost to meet the net short. During other days we reviewed, we saw no evidence of such activity. To some degree, such costs are inevitable because of the complexities of scheduling power supplies as real time approaches. For the same reason, it is difficult to estimate the extent to which such costs were, in fact, avoidable. We do not have evidence that such repurchase activity represented a fundamental problem. ■

CHAPTER 5

The Department Was Not Able to Achieve Coordinated Dispatch of Power Supplies That Could Reduce Costs

CHAPTER SUMMARY

The electric power that the retail customers of the investor-owned utilities receive is produced from a variety of sources, each with different costs per unit of power delivered during different times of the day and week. The sources include hydroelectric dams, nuclear, and fossil fuel-fired power plants owned by the investor-owned utilities, as well as a variety of contracts with suppliers entered into by the Department of Water Resources (department) and the investor-owned utilities. As such, there is an opportunity each day to provide electric power to the utilities' retail customers from a mix of sources—some controlled by the utilities and some controlled by the department—that results in the lowest possible price to ratepayers. In our December 2001 audit, we cite a specific example in which small savings in daily power costs could result in annualized savings to the ratepayers representing potentially tens of millions of dollars.

The department has achieved improvements in its portfolio of power-purchase contracts and gained experience in trading in California's wholesale power markets. While these factors enhanced its ability to implement a coordinated dispatch, the department and the investor-owned utilities did not establish the structures and mechanisms that would have enabled them to coordinate the dispatch of power to minimize costs to ratepayers in 2002. The reasons that a coordinated dispatch was not achieved are not entirely clear, but the department had two concerns in this regard: the investor-owned utilities' failure to share information about the availability of their generating facilities and the terms of their contracts with suppliers, and frequent and sometimes substantial changes in the net-short forecasts prepared by the investor-owned utilities.

THE DEPARTMENT DID NOT ACHIEVE A COORDINATED DISPATCH OF ITS POWER SUPPLIES AND UTILITY RESOURCES

The department believes that coordinating the dispatch of the department's contracts and the investor-owned utilities' generating assets during 2002 could potentially have reduced overall costs to retail customers by a substantial amount.

Although the potential existed, the department was not successful in its attempts to interact with the investor-owned utilities to coordinate all of the electric power resources available to them to ensure that they provided the lowest-cost power to the utilities' retail customers. In our December 2001 audit, we indicated that better opportunities existed for coordination between the department's supply resources and the investor-owned utilities' generating assets. The department believes that coordinating the dispatch of its contracts and the investor-owned utilities' generating assets during 2002 could potentially have reduced overall costs to retail customers by a substantial amount.

Our December 2001 audit suggested several ways in which coordinated dispatch decisions could bring savings to California's ratepayers. For example, our audit indicated that it may have been possible to reshape hourly dispatch schedules of the investor-owned utilities' hydropower facilities to minimize the cost of the department's purchases. The utilities might also have reduced the output of their thermal units occasionally when spot market prices were low and increased the output of their thermal units when spot market prices were high. Our December 2001 audit also pointed to the hydropower units as a potentially low-cost source of power for needed power reserves. It indicated that the department's staff and consultants believed that a coordinated dispatch could achieve meaningful savings, but that they were not able to reach a full understanding of the magnitude of savings that such a dispatch could attain.

During 2002 the department pursued coordination to tailor the investor-owned utilities' hydroelectric energy production to promote a least-cost dispatch of power to their retail customers, but it was not successful in its attempts to engage Southern California Edison (SCE) and Pacific Gas & Electric (PG&E) in the effort. The department suggested that the dispatch of each utility's hydropower facilities be coordinated with that of its own contracts. The goal was to enable the department to minimize its purchase of expensive, nonstandard products, such as power for "super peak" periods and power for a particular hour of the day, which were otherwise required to cover the net short as it changed from hour to hour. The department had concluded that the investor-owned utilities' hydropower facilities could be dispatched to perform this matching of loads and resources in a manner that would not alter the total output of a given hydropower facility across a given day. Preserving the total daily output was expected to ensure that the utilities' revenues would not be affected by the coordinated dispatch.

Documents provided by the department include estimates of potential savings. For example, for the single day of March 5, 2002, the department estimated that using PG&E's hydropower facilities to lessen the need for spot market purchases to meet the net short would potentially have saved $115,000. A similar estimate for SCE suggested daily savings of the same order. The department's documents did not address the degree to which the days analyzed might be representative of savings across a broader period. However, our consultant's analysis of the department's calculations suggests that, if such savings could have been replicated across even one in every four days, cumulative annual savings to ratepayers could exceed $20 million in any given year.

During 2002 the Opportunity Remained to Optimize the Overall Dispatch to Benefit Ratepayers

The opportunity to pursue savings through a coordinated dispatch remained throughout 2002. The investor-owned utilities' hydropower facilities continued to represent a flexible resource that, through coordination with the department, could have been used to reduce total power costs. A coordinated dispatch also would have brought savings by making the best use of the investor-owned utilities' and the department's power supplies relative to a given set of market prices and consumer demand levels.

The investor-owned utilities' hydropower facilities continued to represent a flexible resource that, through coordination with the department, could have been used to reduce total power costs.

As we discussed in Chapter 1, a number of the department's long-term contracts have been renegotiated to reduce the proportion of the power volume provided through nondispatchable contracts and to increase the proportion of dispatchable power. Table 2 in Chapter 1 shows that while the amount of nondispatchable power supplied by the department's long-term contracts increased somewhat during 2002 as a consequence of contract renegotiations, proportionate to the department's total contract portfolio, the share of power volumes from nondispatchable contracts shrinks while the share from dispatchable contracts grows. As a consequence, during 2002 the department was better positioned to match its contract supplies to consumer demand and to respond effectively to changing market conditions on a daily and hourly basis.

The Reasons That a Coordinated Dispatch Was Not Achieved During 2002 Are Not Entirely Clear, but the Department Identified Two Notable Concerns

The reasons that further progress was not made in coordinating the hydropower dispatch are not entirely clear. The department indicated that it received no written proposal or counterproposal from any investor-owned utility on how to improve the overall dispatch. According to the department, during 2002 the investor-owned utilities did not share sufficient details related to the availability of utility-retained generating facilities or information on the basic price and dispatchability terms of their contracts with suppliers. Without this essential information, the department could not have reliably anticipated the dispatch of the investor-owned utilities' generating sources and acted on opportunities to reduce the overall dispatch costs.

Without sufficient details of the availability of the utilities' generating facilities or price and dispatchability terms of their contracts with suppliers, the department could not have acted on opportunities to reduce the overall dispatch costs.

Coordination issues aside, the investor-owned utilities' changing forecasts of the net short likely increased the department's difficulties in optimizing its dispatch to best serve the net short. The department's documents indicate that its schedulers were quite dependent on the investor-owned utilities for accurate forecasts of the net short. The net short is important to a discussion of coordinated dispatch because it is derived as the difference between estimated total demand and the power provided from the utilities' generation and from contracts for power from the portfolios of both the department and the investor-owned utilities. Although the department and its consultants reviewed the various forecasts, they did not have access to important data and underlying assumptions regarding customer demand and power-generation capabilities. As we discussed in Chapter 4, the investor-owned utilities' net-short forecasts changed regularly and in amounts that occasionally were substantial.

The department's staff indicated that it sought to discuss the causes behind the changed net-short forecasts with utility personnel but obtained little information. The department performed an analysis of the magnitude of changes in the investor-owned utilities' day-ahead net-short forecasts relative to those provided on an hour-ahead basis. According to the department, the only documents outlining the results of its investigation into the causes of those forecast changes exist in the form of an e-mail exchange between the department's trading manager and an individual at SCE. The trading manager expressed concern with SCE's substantial changes (from 400 to 1,150 megawatts in some hours) between its day-ahead forecast and its hour-ahead forecast for Sunday, September 15, 2002, and indicated that those changes were forcing the department to purchase large amounts of power on short notice. She stated that "this typically causes prices to drive up and may cause difficulty in managing and meeting the net short requirement." The response that the trading manager received to her question as to what was causing the changes was simply, "The same things that always change (and always will): load and QFs." (Qualifying facilities (QFs) refers to suppliers of power through contracts held by the investor-owned utilities.)

The forecast changes may have reflected more than just natural supply and demand fluctuations or imprecise forecasting by the investor-owned utilities. During the course of this audit, department personnel expressed concerns about the potential for the investor-owned utilities to "game" the dispatch of power from their various sources to maximize their revenues at the expense of ratepayers. They stated that the investor-owned utilities had never provided the department with sufficient information to understand how the utilities dispatch their power resources. In a July 30, 2002, letter to the California Public Utilities Commission (CPUC) regarding the need for operating agreements between the department and the utilities, the department expressed its desire for the CPUC to order the utilities to implement an approach in serving their retail customers that utilizes all of the department's nondispatchable power and results in a least-cost dispatch of power to retail customers. This audit did not address the details of the CPUC's ratemaking practices relative to power supplies from the department and the investor-owned utilities.

As we mention in Chapter 6, part of the utilities' responsibility for purchasing the net short will be to manage the department's long-term contracts. The CPUC has stated that it has the exclusive authority to review the utilities' administration of the department's contracts, and it has also stated that it is responsible for monitoring the investor-owned utilities' sales of surplus power from the department's long-term contracts to mitigate the costs of these sales to the ratepayers. However, because it retains legal and financial responsibility for the contracts the utilities will administer, the department will retain a role in observing the activities of the utilities and working with the CPUC to ensure that the utilities comply with the CPUC's decision. In Chapter 6 we discuss the department's future challenges in working with the utilities and the CPUC to ensure least-cost dispatch of power resources to the utilities' retail customers. ■

Blank page inserted for reproduction purposes only.

CHAPTER 6

The Department Will Continue to Face Cost and Legal Challenges

CHAPTER SUMMARY

Two years ago, Assembly Bill 1 of the 2001–02 First Extraordinary Session (AB 1X) established the Department of Water Resources (department), on behalf of the State, as the sole buyer of power for the substantial unmet needs of the consumers served by Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E), the State's three largest investor-owned utilities. This responsibility came in the midst of, and was in direct response to, an unprecedented crisis that included financial insolvency of the utilities, shortages of power supplies, exorbitant prices, and what the Federal Energy Regulatory Commission (FERC) concluded was a dysfunctional power market. Today, two years later, the crisis conditions have substantially abated and the department's buying authority under AB 1X has ended. However, substantial work remains to be done by others to restore California's electric markets to full health and to manage the power portfolio assembled by the department during its two-year tenure as power buyer for the State.

Many aspects of the State's power market still require substantial action. PG&E and SCE each have important challenges left before they can become restored to full financial viability as buyers of power. The California Public Utilities Commission (CPUC) is developing rules that will govern the utilities' power-procurement practices over the longer term. The California Independent System Operator (ISO) is now engaged in a multiphased process to develop and implement a number of changes to its market structure, needed to ensure that the markets are effective and well monitored. California's power supply situation has improved over the past two years, as 8,000 megawatts of new supplies have or will soon come into operation. Accounting and credit issues have affected many companies in the power supply industry over the past year, leading to restructuring in the industry and changes in financial accounting systems and raising questions regarding the further development of new power supplies in the market. Substantial outstanding investigations and litigation associated with the power crisis remain unresolved. This range of activities makes clear that much remains to be done to stabilize the State's power markets.

The department's ongoing stewardship of the Electric Power Fund and the power contract portfolio will be an important component of the State's power supply for years to come. Financial and legal responsibility for the portfolio of power contracts is likely to remain with the department for much of the next decade and will require continued vigilance to mitigate the high costs of those contracts to the extent possible. Attendant upon those management responsibilities will be the need for the department to manage its operating partnerships with the utilities to schedule and deliver the power and to procure fuel. In addition, the department will retain continued management of the Electric Power Fund and the administration of the bonds issued to finance the cost of the AB 1X power program. These remaining responsibilities carry substantial ongoing obligations to manage costs and risks and will require a sustained professional organization at the department to properly protect the State's interests.

THE STATE HAS MUCH LEFT TO DO TO SUCCESSFULLY RESTORE THE ELECTRICITY MARKETS

While the department's role as power buyer on behalf of the State has ended, this milestone does not signal the end of the challenges facing the State in restoring the power markets. Continued diligence in many areas remains necessary to ensure that the State can avoid a return to the crisis conditions of two years ago. Many of these challenges are outside of the department's responsibilities.

Two Investor-Owned Utilities Have Not Yet Regained Creditworthiness

Only one of three investor-owned utilities meets the investment-grade rating standard of creditworthiness.

AB 1X was implemented in February 2001 to establish an entity, the department, that had the financial capability to buy power on behalf of PG&E, SCE, and SDG&E at a time when those utilities had become financially unable to do so. Today, SDG&E is the only one of these utilities that meets the investment-grade credit rating standard of creditworthiness.

As of January 1, 2003, PG&E remained in bankruptcy. The bankruptcy court has two competing plans for reorganization before it and has scheduled substantial hearings on these completing plans in February and March of 2003. It remains unclear when this bankruptcy will be resolved, what the reorganized company will be, and when a fully creditworthy utility will be established. To reestablish its ability to buy power to meet its net-short requirement, PG&E was required to post a security deposit with the ISO.

SCE began 2003 with a credit rating below investment grade. The company has been operating under a rate settlement agreement with the CPUC that provides for the repayment of debts incurred during the power crisis. SCE has projected that, under the agreement, by the end of 2003, it expects to recover all of the costs to procure power during the energy crisis that it was not previously able to charge to its customers. This agreement is now the subject of a legal challenge and is scheduled to be considered by the California Supreme Court in March 2003. Notwithstanding its below-investment-grade standing, SCE has been able to resume power-procurement responsibilities.

Despite creditworthiness issues, each utility began 2003 with sufficient ability to resume buying power supplies, aided substantially by lower market prices and reduced residual net-short requirements.

Nevertheless, each of the utilities began 2003 with sufficient ability to resume buying power supplies needed to meet its respective net-short position. This ability to resume procurement, despite the lack of full creditworthiness by PG&E and SCE, was aided by the substantially lower prices in the market and by the significant reduction in the residual net-short requirements resulting from the department's power contract portfolio.

Regulations Governing the Investor-Owned Utilities' Responsibilities for Power Procurement Are Being Developed

AB 1X provided the department with the authority to assemble a portfolio of power-supply contracts, an authority distinct from the more limited authority that the investor-owned utilities had in 2000 and that they were financially unable to perform in 2001. The Legislature and CPUC took steps in 2002 to create a statutory and regulatory framework to give the utilities the authority to secure long-term supplies and to transfer the power-procurement function to the utilities. These actions fostered the return of the power-procurement responsibility to the utilities from the department on January 1, 2003, and established a framework for long-term power-procurement planning and implementation by the utilities.

Assembly Bill 57 (AB 57), signed into law in September 2002, included statutory provisions to allocate the contracts in the department's portfolio to the utilities; to require the investor-owned utilities to optimize the utilization of the overall portfolio, including the department's contracts; and to otherwise enable the utilities to reassume the responsibility for procuring power. In addition, AB 57 established requirements for a long-term procurement planning process to be conducted by the utilities under CPUC regulation. This responsibility for portfolio planning and procurement is akin to the responsibility vested in the department by AB 1X in 2001 and 2002. Prior to AB 1X, the utilities were restricted in their procurement responsibilities to reliance on spot market transactions and limited short-term contracts.

Senate Bill 1078 (SB 1078), also enacted in September 2002, established a renewable portfolio standard requiring utilities to increase their reliance on renewable sources of power and to ultimately obtain 20 percent of the power needed for retail sales from renewable sources by December 2017. Before they can make procurements under this statute, the utilities must first regain creditworthiness by attaining an investment-grade rating.

In concert with these legislative actions, the CPUC took actions to implement the utilities' return to the procurement function. In August 2002, the CPUC authorized an accelerated power-procurement process that authorized PG&E and SCE to solicit power to be contracted in tandem with the department before the year's end. This interim procurement process was intended to further minimize the amounts of power that these utilities would need to procure on their own in 2003. The SCE did complete several capacity contracts using this process and the department indicates that it signed agreements with two suppliers for PG&E.

In September 2002, the CPUC allocated the department's contracts among the three investor-owned utilities. This allocation is displayed in Table 15. This contract allocation provided a basis from which each utility could then determine its remaining needs for power supply and develop procurement plans for January 2003 and beyond. It also established those contracts for which each utility would assume operating responsibility in 2003.

In October 2002, the CPUC issued an order directing all three investor-owned utilities to resume power-procurement responsibilities on January 1, 2003, and establishing a regulatory framework for the utilities' forthcoming procurement activities under Assembly Bill 57.

In October 2002, the CPUC issued an order directing all three investor-owned utilities to resume power-procurement responsibilities on January 1, 2003, and establishing a regulatory framework for the process of planning and implementing the utilities' forthcoming procurement activities under AB 57. In this order, the CPUC made provisions for the adoption of interim procurement plans that would serve as the basis for the start of procurement in 2003. In addition, the CPUC initiated a process for developing long-term procurement plans for each

TABLE 15

Adopted Allocation of Department Contracts

Long-Term Contract	Contract Category	Adopted Allocation
Allegheny 2 (150 MW 6x16 in NP15 for 2003)	Nondispatchable	PG&E
Calpine 1 Product 1	Nondispatchable	PG&E
Calpine 2 Product 1	Nondispatchable	PG&E
Capitol Power *	Nondispatchable	PG&E
Clearwood	Nondispatchable	PG&E
Constellation - Product 2 (400 MW 7x24 May to October 2003)	Nondispatchable	PG&E
Coral	Nondispatchable	PG&E
El Paso (50 MW 6x16 in NP15)	Nondispatchable	PG&E
Intercom	Nondispatchable	PG&E
Santa Cruz	Nondispatchable	PG&E
Soledad	Nondispatchable	PG&E
Allegheny 1 (Excluding NP15 deliveries)	Nondispatchable	SCE
Constellation (200 MW 6x16 through June 2003)	Nondispatchable	SCE
Dynegy	Nondispatchable	SCE
El Paso (50 MW 6x16 in SP15)	Nondispatchable	SCE
Morgan Stanley	Nondispatchable	SDG&E
PG&E	Nondispatchable	SCE
Primary Power	Nondispatchable	SDG&E
Sempra	Nondispatchable	SCE
Cabazon	Nondispatchable	SDG&E
Whitewater Hill	Nondispatchable	SDG&E
Williams	Nondispatchable	SDG&E
Calpine 1 - Product 2	Dispatchable	PG&E
Calpine 2 - Products 3 & 4	Dispatchable	PG&E
Calpine 3	Dispatchable	PG&E
Calpine SJ	Dispatchable	PG&E
Calpeak (3 contracts) New Site, Panoche, and Vaca-Dixon	Dispatchable	PG&E
GWF	Dispatchable	PG&E
Pacificorp	Dispatchable	PG&E
Wellhead Power (3 contracts) Fresno, Gates, and Panoche	Dispatchable	PG&E
Alliance (now Colton Power)	Dispatchable	SCE
Calpeak (3 contracts) Border, El Cajon, and Escondido	Dispatchable	SDG&E
Dynegy (1,000 MW Peak System Contingent)	Dispatchable	SCE
High Desert	Dispatchable	SCE
Sunrise	Dispatchable	SDG&E

Source: California Public Utilities Commission (CPUC) Decision 02-09-053, Table 1, September 19, 2002. The contract category reflects the category the CPUC used in its decision.

* The department later terminated the contract with the supplier.

MW = Megawatts

utility and for implementing the renewable portfolio standard in 2003. Each utility will file proposed long-term procurement plans in April 2003 for consideration in subsequent adjudicatory proceedings to be conducted by the CPUC to ensure that it complies with the framework established by AB 57, SB 1078, and the CPUC's October 2002 order. The CPUC and the California Energy Commission (energy commission) will also jointly determine procedures for implementing the renewable portfolio standard. These legislative and regulatory actions are designed to restore the utilities as effective, long-term providers of the power supplies needed for consumers in their respective service territories.

Enhancements to the Wholesale Power Market Are Not Yet Implemented

While the actions taken by the ISO and FERC have contributed to the stabilization of market conditions, substantial work remains to implement the reforms necessary to fully restructure the market.

The department's power-buying authority under AB 1X came at a time when FERC concluded the wholesale markets were dysfunctional. The ISO and FERC have taken steps toward the wholesale market reforms needed to address the dysfunctions that were at the center of the crisis two years ago. While the actions taken have contributed to the stabilization of market conditions, substantial work remains to implement the reforms necessary to fully restructure the market.

In June 2001, FERC ordered a set of price mitigation measures to be applied throughout western markets. These measures were to be in effect through September 2002 to allow time for the development of long-term structural reforms.

In April 2002, the ISO put forth a Comprehensive Market Design Proposal (redesign proposal). This proposal is a three-phased, multiyear effort to undertake a comprehensive redesign of its market systems. It includes improved methods of mitigating the potential for the exercise of market power, managing the congestion within the transmission system, and improving the structure of the spot markets and real-time operation of the market.

In July 2002, FERC authorized an extension of the price mitigation measures beyond the original September 2002 endpoint. These measures require all in-state non-hydropower generating units to bid all available capacity into the ISO's market in all hours and place a bid price cap of $250 per megawatt-hour on power for all western markets. These market protections will apply until the ISO is able to implement further market reforms and FERC concludes its investigations of market power and market manipulation in western markets.

According to the ISO, on October 30, 2002, phase 1a of the redesign proposal went into effect, including the price cap and automated mitigation procedures. These procedures apply a set of price screens to bid prices offered by generators, with automatic adjustments to the bids applied if the bids fail the price tests. These mitigation procedures will ensure that bid prices above competitive levels will not be accepted or affect market prices.

As of December 2002, the ISO's schedule for implementing the redesign proposal calls for completing the remaining phases of the proposal by the summer of 2004. The actual design and implementation schedule remain subject to further proposals and FERC approvals.

The Outlook for the Power Supply Infrastructure Is Improving

Shortages in supplies of power and limitations in transmission infrastructure contributed to the power crisis. Over the past two years, substantial progress has been made in the development of power supply and transmission infrastructure.

Over the past two years, 18 new power plants totaling 4,980 megawatts have become operational, with an additional 3,106 megawatts from seven more plants due online by August 2003.

The energy commission recently reported that the State's power supply situation has improved over the past two years and that its supply outlook is good in the near term. In California, 18 new power plants totaling 4,980 megawatts have become operational in the past two years, with an additional 3,106 megawatts from seven more plants due on-line by August 2003. These approximately 8,000 megawatts have been matched by a like amount of new capacity in other locations in the western marketplace. The energy commission's current outlook indicates that supplies are expected to be sufficient to meet summer peak requirements over the near term. The development of new supplies has been partially offset by generation retirements. The ISO reports that requirements for additional pollution controls by the end of 2003 are contributing to the closing of 948 megawatts of older peaking units.

ISO operations have shown improvement in maintaining sufficient reserves of energy to continue operations with minimal declaration of emergencies since the crisis of 2000 and 2001. The number of declared emergencies in 2002 was closer to the number in the years before the crisis, as shown in Table 16 on the following page.

TABLE 16

Declared Emergencies Over the Past Five Years

Declaration	1998	1999	2000	2001	2002*
Alert	7	2	34	180	3
Warning	8	6	85	181	4
Stage 1 Emergency	7	4	55	70	2
Stage 2 Emergency	5	1	36	65	1
Stage 3 Emergency	0	0	1	38	0

Source: California Independent System Operator 2002–03 Winter Assessment.

* January through September 5, 2002, data.

In addition to power supplies, transmission bottlenecks have been a concern. Most notably, a transmission linkage known as Path 15 has been a limiting factor in power transfers between Northern and Southern California. The ISO has observed that prior pressures on Path 15 have been reduced more recently, as significant new generation has been added in Northern California. For example, in the first nine months of 2002, 2,283 megawatts of 2,771 total new megawatts in California were located north of Path 15. Further improvement in Path 15 interconnection is planned. The Western Area Power Administration, PG&E, and Trans-Elect, Inc. recently completed a construction agreement to add a new 500-kilovolt line to this interface, increasing north-south transfer capacity by 1,500 megawatts. In February 2003, the Western Area Power Association reported that this project is planned for completion in late 2004.

The Commercial Power Industry Is Under Significant Financial Stress

The high market prices during the California power crisis created a financial crisis for power buyers, notably PG&E, SCE, the Power Exchange, and, initially, the department. Subsequent events in the markets have led to substantial financial turmoil for commercial power producers and wholesale power-trading entities, raising significant questions regarding the financial ability of the industry to proceed with needed investment.

The well-chronicled collapse of Enron in late 2001 is an example of the unprecedented reversal in financial health throughout the commercial power industry.

The well-chronicled collapse of Enron in late 2001 is an example of the unprecedented reversal in financial health throughout the commercial power industry. The troubles in this industry can be attributed to several factors. Problems with accounting practices at Enron and, to a lesser degree, throughout the industry, have caused significant restatements of earnings and modification to practices and standards. Enron and several other market participants have acknowledged participating in certain trading activities that may be found to be illegal, as well as in improper price reporting in the California market, leading to indictments and ongoing investigations of trading activities by FERC, the Securities and Exchange Commission, the Department of Justice, and the Commodity Futures Trading Commission. In addition to these legal troubles, the recent development of commercial generation projects nationally has led to surplus power supply and depressed price margins. These lower prices, combined with tighter credit requirements, have placed substantial financial pressure on all generation companies. Power-trading businesses have also substantially diminished, as several formerly major traders, such as Enron, El Paso, Aquilla, and Dynegy, have eliminated their trading functions, while others have substantially scaled back trading activities.

Surplus power supply, depressed price margins, and tighter credit requirements have led many to expect a debt crisis in the industry in the coming months.

These problems in the industry have led many to expect a debt crisis in the industry in the coming months. These financial pressures affect many participants in California's markets, as credit downgrades are now widespread and many are deferring or canceling investments to improve their financial positions. For example, AES recently announced losses of $3.5 billion for 2002 and a $400 million write-off for a partially constructed and now suspended 1,100-megawatt plant in Redlands. The California Power Authority, in its recent draft investment plan, noted that the majority of major generation participants in California stand at or near junk investment status. In this context, continued improvement in the power supply situation in California will depend upon planned improvements in accounting and business practices in the industry and resolution of the current credit crisis in the commercial power industry.

THE DEPARTMENT REMAINS THE HOLDER OF A SIGNIFICANT PORTFOLIO OF HIGH-PRICED CONTRACTS, REQUIRING ONGOING DILIGENCE IN SEEKING REFORMS AND IMPROVEMENTS TO MITIGATE THOSE COSTS

Although the department's AB 1X authority to enter into new contracts to buy power has come to an end, the substantial power contract portfolio it acquired remains. The department remains legally and financially responsible for those contracts and retains authority under AB 1X to carry out that responsibility. As we noted in Chapter 3, the renegotiated contracts now contain provisions that provide for the transfer of some contracts to the investor-owned utilities when creditworthiness standards are met and the CPUC issues an order finding the contracts just and reasonable. However, even if all of these transfers occur, approximately half of the power under contract could remain with the department for the duration of the contracts. As we noted in our December 2001 audit, the original contracts do not include strong provisions for assignment or transfer to the utilities.

The department's substantial efforts to seek opportunities to renegotiate the contracts over the past year have produced important improvements, but many of the problems still remain in the original contracts.

The department's challenges in managing this power contact portfolio are very similar to those discussed in our December 2001 audit. Despite the progress made in restructuring several of the contracts, the portfolio remains substantially more costly than projected market prices, as we noted in Chapter 2. For those contracts that have not been renegotiated, the many problematic provisions identified in the previous audit remain. The department's substantial efforts to seek opportunities to renegotiate the contracts over the past year have produced important improvements, but many of the problems still remain in the original contracts.

Despite the problematic aspects of the portfolio, the power supplies secured by these contracts remain important to the stabilization and recovery of the California power markets. The department's contracts together with the investor-owned utilities' own sources of supply secure over 90 percent of the power needed in the near term, thus reducing the volume of power that the utilities must purchase. This is particularly important for PG&E and SCE while they work toward their return to financial health.

The department's program going forward should continue to manage the contracts aggressively to develop and capture opportunities to improve the contract portfolio, in terms of both cost and reliability. Further opportunities may develop due to the current credit crisis affecting many of the suppliers in the industry. Over time, as the situation of individual suppliers or conditions in the market change, other opportunities may develop. A sustained and systematic contract management program over time is necessary, given the size of the portfolio.

THE DEPARTMENT RETAINS SIGNIFICANT ONGOING RESPONSIBILITIES UNDER AB 1X FOR MANAGING THE ELECTRIC POWER FUND

After nearly two years, the department successfully completed the sale of revenue bonds worth $11.26 billion to finance the costs it incurred in its role as buyer of power for the State during the power crisis. The proceeds from these bonds were used to repay loans from the State's General Fund of $6.1 billion plus interest and to repay interim loans of $3.5 billion from commercial sources. This financing includes a series of 31 bonds with an annual debt service of approximately $900 million. The final bond matures in May 2022, more than 20 years from the beginning of the department's power-buying responsibility.

As revenue bonds, the department's bonds are supported by the revenues received from customers of the three investor-owned utilities. Under a rate agreement with the CPUC established in February 2002 and associated servicing agreements with each of the utilities, the department receives revenues needed to cover power costs and repayment of the bonds through charges to customers of the utilities. Two charges are set annually. Bond charges are set to recover financing costs associated with the bonds, and power charges are set to recover the annual cost of power under the contracts. These revenue streams, secured by a rate agreement with the CPUC regarding the procedures to be followed to determine the amounts to charge ratepayers, ensure that there will be sufficient cash to pay bondholders and were necessary to secure more favorable ratings on the bonds to lower the overall cost of the program.

Going forward, the department will be responsible for ensuring that revenues are sufficient to cover the costs of the bonds for the life of the bonds and to cover the costs of the power purchased under the power contracts for as long as the department holds the contracts.

Going forward, the department will be responsible for ensuring that revenues are sufficient to cover the costs of the bonds for the life of the bonds and to cover the costs of the power purchased under the power contracts for as long as the department holds the contracts. Each year, the department must determine the amount of revenue it needs to collect, and it must submit that requirement to the CPUC. For 2003, the department has determined its revenue requirements to include $4.6 billion for the power it sells to the utilities' retail customers and revenues needed for debt service on bonds of nearly $1.2 billion. The department estimates its ongoing debt service to be approximately $900 million per year through 2022.

To carry out its financial responsibilities under AB 1X, the department must ensure that its available cash is sufficient to maintain its credit standing with its power suppliers and the bondholders, and it must conduct the analysis and reporting functions necessary to support that activity. The department will be required to maintain the capability to carry out this significant financial and reporting responsibility for the duration of the bonds. As described in Chapter 1, the power charges will remain significant through 2010 and will be substantially reduced thereafter. The department will have regular reporting requirements to the CPUC, bond investors, auditors, the governor, and Legislature.

The return of power-purchasing authority to the utilities carries with it a set of issues to be resolved in establishing the methods of recovering revenue from the three utilities. As we mentioned previously, in September 2002, the CPUC allocated the department's contracts among the three investor-owned utilities for the purpose of power-procurement planning. This was followed by a December 2002 interim order allocating contract costs to the three utilities. A number of issues remain to be resolved, including the equitable allocation of costs and modification of servicing agreements, which state the terms and conditions for various services, including billing and collection. These issues illustrate the nature of the ongoing role that the department will have in managing its revenue recovery process.

THE DEPARTMENT'S CONTRACT OPERATIONS ARE TRANSFERRING TO THE UTILITIES, BUT SIGNIFICANT COORDINATION AND MONITORING RESPONSIBILITIES REMAIN

On December 31, 2002, the department's AB 1X authority to enter into new contracts to buy power came to an end. Beginning January 1, 2003, that responsibility and function returned to the three investor-owned utilities. In addition, while the department remains financially and legally responsible for the contracts, the investor-owned utilities, as agents of the department, have assumed the dispatch and administrative functions related to the portfolio.

The Department's Role in the Management of Contract Operations Changes With the Transfer of Power Operations to the Utilities

In conjunction with its role as power buyer for each of the utilities in 2001 and 2002, the department also conducted scheduling and dispatch functions in coordination with the utilities. Through agreements with the CPUC and the utilities, these scheduling and operating functions for the department's contract portfolio are being transferred to the utilities, at the same time that the utilities are reassuming the scheduling and dispatch functions for meeting their overall load responsibilities.

In September 2002, a CPUC order allocated the department's contracts to the three utilities, establishing those contracts for which each utility would assume operating responsibility in 2003.

The department, the CPUC, and the utilities conducted negotiations and regulatory proceedings in 2002 to establish the regulatory and contractual framework for the transfer of operating functions to the utilities. The September 2002 CPUC order allocating the department's contracts among the three utilities established those contracts for which each utility would assume operating responsibility in 2003. Another order issued in October 2002 directed all three utilities to resume power procurement responsibilities on January 1, 2003, and made provisions for the adoption of interim procurement plans that would serve as the basis for the start of utility procurement in 2003. In December 2002, the CPUC issued an operating order that set forth the principles under which the utilities would conduct operations, including the management of the department's contracts. The operating order was adopted in lieu of formal operating agreements between the department and each of the utilities, due to the time limits imposed by the January 1, 2003, deadline for transition. The department completed operating agreements with PG&E and SDG&E prior to January 1, 2003, and the utilities filed these agreements with the CPUC for approval. The department and the utilities continue to work toward completion of formal, CPUC-approved operating agreements.

Under the operating agreements between the department and each utility, and under the operating order until agreements between the department and each utility are completed, the utilities are now serving as agents for the department regarding the day-to-day operations, including dispatch and scheduling of the department's contracts. According to the department, functions that had been conducted by it prior to January 1, 2003, that are now the responsibility of the utilities, include the following:

- Purchasing power to meet the daily net-short requirements.
- Forecasting the net-short requirements.
- Scheduling contracts for deliveries to meet the net-short requirements.
- Purchasing of natural gas associated with department contracts.
- Interacting with the ISO on scheduling and settlements.

Under the CPUC's operating order, the utilities are now serving as agents for the department regarding the day-to-day operations, including dispatch and scheduling of the department's contracts.

The operating agreements provide a contractual basis for the performance of these functions. As regulated entities, the utilities' participation in and performance under the operating agreements, along with their other functions in procuring power and providing it to their customers, is subject to regulatory oversight by the CPUC. Thus, the department's power operations role is now indirect. The department must maintain the capabilities to manage and oversee its contracts with the utilities, but it no longer requires the capacity to perform those operating functions directly.

Dispatch Optimization Remains an Important Issue for the Department and California's Ratepayers

In our December 2001 audit, and in Chapter 5 of this report, we have noted the importance of and the need for close coordination between the department and the investor-owned utilities in power procurement and dispatch operations to assure that the department's contracts and the utilities resources are coordinated to minimize costs to consumers. This issue will remain important in the years ahead and has been recognized by the Legislature, the CPUC, the department, and the utilities in structuring the transfer of operating responsibility back to the utilities.

AB 57 makes clear the Legislature's intent that ". . . each electrical corporation optimizes the value of its overall supply portfolio, including Department of Water Resources contracts and procurement . . . for the benefit of its bundled service customers." In its December 2002 order regarding the operating agreements, the CPUC espouses this same principle, stating, "Least-cost or 'economic' dispatch should be the operating rule for the utility's portfolio of resources, including the DWR [department] contracts." It has reflected that same principle in the operating protocols included in that order. The operating agreements that the department has negotiated with PG&E and SDG&E contain the following language in the operating protocols:

> "Utility agrees to use good faith efforts to dispatch Allocated Contracts and, prior to novation, Interim Contracts, based on the principle of "least cost dispatch" to retail customers, consistent with the Contract Allocation Order and other Applicable Commission Orders. Utility shall undertake these least cost dispatch functions both of the Contracts and its URG [utility-retained generation] so as to minimize the cost of service to retail customers based on circumstances known or that reasonably could have been known at the time dispatch decisions are made. DWR shall have no role in enforcement or review of Utility least cost dispatch under this Agreement and all issues of Utility compliance with least cost dispatch shall be within the sole review of the Commission."

This statutory, regulatory, and contractual construct makes clear the responsibilities of the utilities in conducting the operations in a least-cost manner. As of this writing, the role of the CPUC in overseeing the utilities' performance in that regard is being contested by the utilities, leaving unresolved the precise nature of the utilities' accountability in implementing this operating principle.

Based on our consultant's review of past coordination issues between the department and the utilities, the ratepayer savings with fully coordinated dispatch are potentially on the order of tens of millions of dollars annually.

Optimizing the dispatch across the three investor-owned utilities for the benefit of customers may remain a challenge. Consolidating resources in the hands of the utilities creates an opportunity for them to coordinate the dispatch of their own supplies and their allocated department contracts more easily than they could if (as was the case in 2002) the department contracts and the utility generation sources are each dispatched by separate entities. The CPUC recently stated that "the best way to coordinate DWR's existing contracts with utility resources is to put them all in the utilities' resource portfolios to be scheduled and dispatched in a least-cost manner." However, this allocation to the utilities does end the single, statewide dispatch that was being conducted by the department, breaking the contract portfolio into three parts. The department has worked to establish operating agreements with the utilities that would, to the extent possible, standardize operating procedures and limit the utilities' ability to manipulate the dispatch of generating facilities to maximize their own revenues while increasing department costs and, ultimately, ratepayers' bills.

Implementing least-cost dispatch is an important and difficult challenge in practice. Based on our consultant's review of past coordination issues between the department and the utilities, the potential ratepayer savings with fully coordinated dispatch are on the order of tens of millions of dollars annually. However, the dispatch operations process is complex to audit and could be very difficult to police. The situation is not unlike the challenge of monitoring wholesale power markets for inappropriate pricing practices, where the sheer volume and complexity of the relevant data can make monitoring behavior and detecting problems extremely challenging. As such, a failure to establish, prospectively, data retention requirements, data sharing protocols, monitoring mechanisms, and evaluation standards would be problematic. Ensuring that the department's future contract costs are consistent with those of a least-cost dispatch requires that the principles articulated in the operating agreements be effectively implemented in practice.

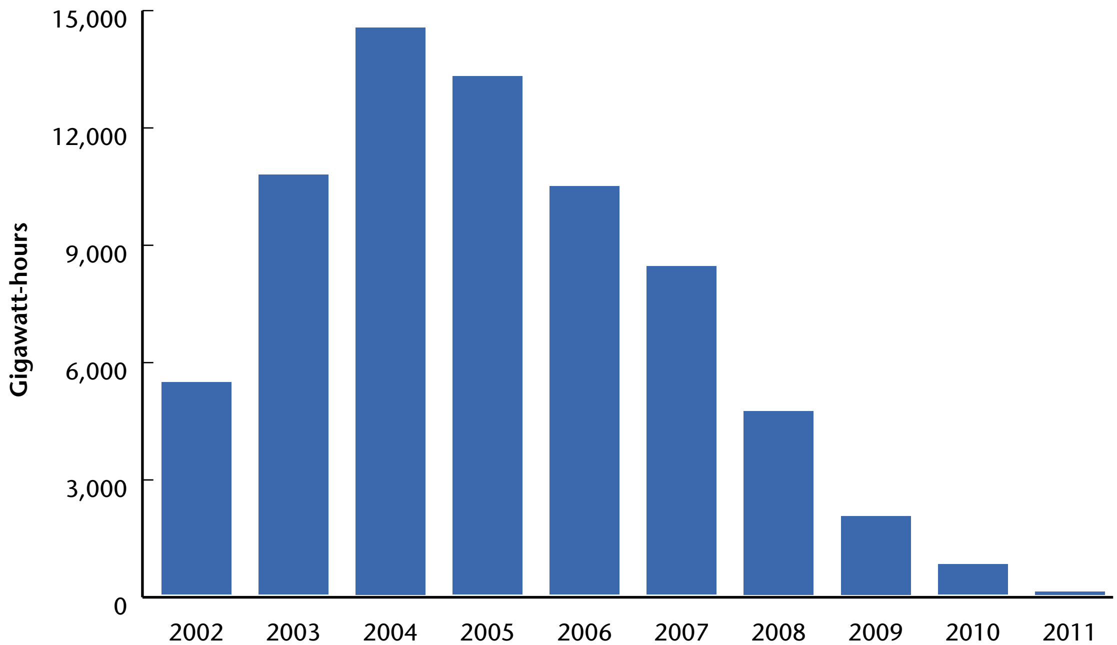
The Potential for Sales of Surplus Power Is Increasing

As shown in Figure 16, the department's projections of the future sales of surplus power indicate a substantial increase in the potential for sales over the 2002 levels described in Chapter 4. Total dispatchable and nondispatchable contract supplies in 2003 will be more than 50 percent above 2002 levels and will remain high for several more years. As the figure indicates, the department's projected sales of power from its long-term contracts is expected to peak in 2004 at well above 14,000 gigawatt-hours. While the department's forecast is derived from an analysis of the total load of the three utilities, the surplus sales potential for each of the individual utilities may be larger, as the three systems will be operated individually rather than under a single dispatch conducted by the department.

This significant potential for surplus power received considerable attention in recent CPUC proceedings. In its September 2002 order allocating the department's contracts to individual utilities, the CPUC established a proportionate sharing policy for the allocation of revenues gained or losses incurred from such sales, recognizing that there would otherwise be an incentive for the utilities to attribute a disproportionate share of the surplus sales to department contracts. This proportionate sharing principle is included in the operating order and in the operating agreements executed with PG&E and SDG&E.

FIGURE 16

Projected Off-System Sales of Excess Contract Energy



Source: Power Supply Revenue Bonds, Department of Water Resources, consultant report, October 2002, prepared by Navigant Consulting, Inc.

The operating agreements include requirements that the utilities provide monthly sales plans and provide information necessary for the department to assess the utility's activities. Due to the detailed nature of the information needed to assess the sales activity, the department will be required to maintain an active capability to monitor this activity and the impacts on its revenue.

Substantial Challenges Are Looming in Relation to Gas Procurement

The department's gas tolling agreements will be of increasing importance to the department and California ratepayers. The cost of natural gas is the single most significant component of the cost of electricity, and it is increasing in volume as the contracts operating in the department's portfolio increase in the coming years. The gas costs for the five contracts containing

The cost of natural gas is the single most significant component of the cost of electricity, and it is increasing in volume as the contracts operating in the department's portfolio increase in the coming years.

the most significant gas tolling opportunities (that is, those where the department has gas purchase rights, including Dynegy, Calpine, Sunrise, PacifiCorp, and High Desert), based on total projected gas volumes of nearly 250 million MMBtu for the year, could exceed $1 billion in 2003. As we note in Appendix B, the department's contract capacity from agreements with gas tolling in 2003 will be nearly 8,000 megawatts, almost double the 2002 levels.

The generators selling electricity to the department on fuel pass-through agreements do not appear to have strong contractual incentives to minimize their fuel costs; they will simply pass those costs on to the department in the electricity sales price. For example, in 2003 if fuel costs were to escalate by as little as 25 cents per MMBtu due to poor gas cost management practices, $62.5 million in additional costs would accrue to the department and California ratepayers over the course of the year if the CPUC failed to identify the problem during one of its reviews. The department's experience to date indicates that its active involvement, or such involvement by the utilities as its agents in 2003, will be important to ensure that gas costs are properly minimized.

Under the operating agreements with the utilities, the utilities will operate as agents for the department in administering the fuel procurement associated with the tolling agreements. The utilities will prepare annual gas supply plans, subject to department and CPUC review, and will conduct the gas procurement and risk management activities called for in these plans. Issues that will need to be resolved as the utilities assume this responsibility include the approach to hedging and the process for developing and reviewing gas supply plans. The transition has also proved challenging, as gas supply plans for the first few months of 2003 were not in place.

The generators selling electricity to the department on fuel pass-through agreements do not appear to have strong contractual incentives to minimize their fuel costs; they will pass those costs on to the department in the electricity sales price.

Credit and collateral issues will also be important. The ability to lock in low gas prices may be hampered by credit problems of the utilities and of the sellers under department contracts. For example, even after the department's retail revenue stream was established and it had achieved a payment history, its ability to make forward purchases of gas was constrained by credit limits. By contrast, Dynegy's current credit situation is more difficult. Dynegy is likely to have to pay a premium to make forward purchases, and thus the department is buying gas for that contract. If gas procurement is left to Dynegy, it can be expected to purchase the gas on the daily spot market. Similarly, credit concerns could limit the ability of the California utilities to purchase gas on a forward basis, particularly in the near term.

THE DEPARTMENT IS STILL DEVELOPING THE ABILITY TO VALIDATE REVENUE REMITTANCES FROM THE INVESTOR-OWNED UTILITIES

In our December 2001 audit, we reported that the department needed to implement a process to ensure that it receives all of the revenue it is due from the electric power it purchases for the retail customers of the investor-owned utilities. The department responded that it was developing a system to track the electric power delivered to the investor-owned utilities' retail customers and to reconcile that power to the revenues the investor-owned utilities remit to the department, to ensure that it receives all amounts it is owed. Although the department has developed a tool to estimate amounts owed to it by the investor-owned utilities, due to the many variables involved in identifying revenues owed to the department, it is still working with the utilities to develop a mutually satisfactory methodology for calculating revenue remittances on a current month basis. As a result, the department cannot yet validate that the daily and monthly remittances it receives account for all of the revenue it is due from two investor-owned utilities, and for the third utility it must wait six months for a final reconciliation of revenues based on estimated versus actual power delivered. These delayed collections can cause cash-flow problems for the department's operations by mismatching revenues and expenditures and increasing the probability that any revenues that have not been remitted will not be detected. For calendar year 2003, the department expects to collect approximately $4.6 billion for the power it sells to the investor-owned utilities' retail customers.

For calendar year 2003, the department expects to collect approximately $4.6 billion for the power it sells to the investor-owned utilities' retail customers.

According to the department, developing a process for validating the revenues remitted by the investor-owned utilities on a regular and current basis has been a challenge—complicated by the indirect relationship among department power deliveries, amounts utilities bill on behalf of the department, and the way that utilities report remittances; changes in the charges the investor-owned utilities must collect for the department; and, most recently, the investor-owned utilities' resumption of the responsibility for purchasing the net short.

To validate that it receives all of the revenues it is owed on a timely basis, the department has determined that it must reconcile the amount of power it purchases to the amount of power that the investor-owned utilities bill to their retail customers. Next, the department has determined that it needs to reconcile the amounts the investor-owned utilities bill to their retail customers for the delivered power to the amounts that the utilities remit to the department. According to the department, it is currently in the final stages of developing a methodology to validate the revenues and is working with one utility, SDG&E, to fine-tune this methodology. The purpose of this methodology is to provide a satisfactory level of comfort that the department receives the revenues it is due and that the utility does not overpay the department. Once the department has developed a satisfactory model, it plans to apply it, with variations, to the other two investor-owned utilities to ensure that remittances are received in a timely manner. This methodology will use acceptable assumptions and margins of error for estimates that are necessary due to the varied billing cycles the investor-owned utilities use in connection with electric power sales—compounded by the timing of the collections of those bills. According to the department, these factors make the absolute validation of the revenues administratively infeasible, at times requiring the department to measure the reasonableness of the remittances, using acceptable margins of error when comparing power purchased to revenues received.

Currently, the department relies on power transaction settlement information from the ISO and information provided by the investor-owned utilities to determine the amount of power delivered to the utilities' retail customers, and it performs periodic analyses in an attempt to verify that it receives all the revenue it is due. For example, during a 2002 year-end remittance validation process, the department completed a preliminary remittance analysis that revealed some discrepancies between the amount of department power delivered to the utilities' retail customers and the amount of department power for which the utilities billed their customers. These discrepancies could be the result of factors such as delays in billing department revenues, possibly due to certain customers receiving delayed utility bills or normal utility billing errors that will likely be corrected in the future. The department states that it has met with the investor-owned utilities to discuss the discrepancies and to begin quantifying the impact of certain types of billing deviations.

In addition, the validation of remittances has been complicated by associated factors, such as retroactive department power rates established by the CPUC and orders from the CPUC that require the utilities to remit revenues associated with the department's imbalance power purchases and to collect department bond charges and fees from retail customers who elect to purchase their electric power from sources other than the three investor-owned utilities affected by the power-purchasing program. These orders have created substantial changes in the amount of revenue the utilities owe the department for delivered power. For example, analyses the department conducted in September 2002 of the effect of these orders resulted in two additional remittances from the investor-owned utilities of about $198 million and $873 million.

According to the department, it will need to make extensive changes in its revenue validation processes in 2003 to accommodate changes that the CPUC has ordered to the power charge calculations.

According to the department, it will need to make extensive changes in its revenue validation processes in 2003 to accommodate changes that the CPUC has ordered in the power charge calculations. The department began collecting bond charges from utility customers in November 2002 and is currently developing processes to validate these remittances. In addition, in January 2003 the department began to receive power charges from direct access customers, and it expects to receive remittances for bond charges from direct access customers later this year. The development of new remittance validations for all of these collections is dependent on the department receiving additional information from the investor-owned utilities and on a clear interpretation by the department and the investor-owned utilities of the methods approved by the CPUC.

Finally, as of December 31, 2002, the department no longer purchases the residual net short for the investor-owned utilities. Because it is no longer a market participant, the department may not receive data directly from the ISO regarding the power used to satisfy the residual net short and delivered to utility customers. The department is currently working with the investor-owned utilities to secure the data it needs to validate power and bond charges. In the near future, this will result in additional changes in the methodology it uses to validate revenue remittances and additional challenges in reconciling the amount of power the department delivers to the utilities' retail customers to the amount of department power billed to those customers.

RECOMMENDATIONS

The department's future activities can be described as falling into four broad categories, each defined by basic contractual responsibilities that it will carry into the future. If the department is to successfully complete its remaining mission under AB 1X, it will need to do the following:

Management of Long-Term Contracts

- Monitor the performance of power suppliers relative to their contractual obligations.
- Promptly address and resolve any supplier deviations from contractual obligations.
- Persistently and aggressively manage the long-term contracts to capture opportunities to improve the overall supply portfolio.

Management of Operating Agreements With the Investor-Owned Utilities

- Recognizing the CPUC's established role in overseeing the dispatch decisions of the investor-owned utilities, the department should routinely monitor resource scheduling and other data provide by each utility to ensure that dispatch decisions are consistent with established operating protocols and its fiduciary responsibility to bondholders.
- Routinely collect and analyze data (including ISO settlement data) on power sales by the investor-owned utilities.
- Address proposed annual gas supply plans for contracts with tolling agreements. Respond to situations in which the credit standing of the investor-owned utilities may adversely affect the department's costs.
- Maintain capabilities to analyze conditions in electricity and gas markets.
- Advise the CPUC in a range of proceedings in which its regulatory oversight of the investor-owned utilities intersects with the department's responsibilities.

Management of Servicing Agreements With the Investor-Owned Utilities

- Monitor dispatch statements from the investor-owned utilities relative to their accounting statements to the department.

- Advise the CPUC in proceedings in which its regulatory oversight of the investor-owned utilities intersects with the department's responsibilities.

Servicing the Revenue Bonds

- Prepare revenue requirements filings for the CPUC. Advise the CPUC in revenue requirements proceedings (and others) in which its regulatory oversight of the investor-owned utilities intersects with the department's responsibilities under the revenue bonds.

- Act to mitigate risks that may adversely affect bondholders. Address CPUC ratemaking practices that may create incentives for the investor-owned utilities to act in a manner contrary to the interests of the department's bondholders or to its mission under AB 1X.

- Perform financial and accounting activities necessary to support the department's obligations (including fulfilling reporting requirements to bond investors, auditors, rating agencies, the governor, and the Legislature) under the revenue bonds.

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

ELAINE M. HOWLE
State Auditor

Date:	April 2, 2003
Executive Staff:	Philip J. Jelicich, CPA, Deputy State Auditor Sharon Reilly, Esq., Chief Legal Counsel
Staff:	John Baier, CPA, Project Manager Norm Calloway, CPA Michael K. Adjemian
Consultant:	La Capra Associates

APPENDIX A

A Summary of the Department's Progress Toward Implementing the December 2001 Recommendations of the Bureau of State Audits

The Bureau of State Audits (bureau) made a variety of recommendations to the Department of Water Resources (department) in its December 2001 audit titled, *California Energy Markets: Pressures Have Eased, but Cost Risks Remain* (report number 2001-109). The table in this appendix shows the bureau's recommendations and the department's progress in implementing those recommendations.

TABLE A.1

Bureau Recommendations and the Department's Actions Since the December 2001 Audit

Recommendations	Department's Actions
The power-purchasing program was conceived during an unprecedented crisis. The crisis has abated to a large degree, and the State and the department now need to reassess with a longer-term perspective the goals of this power-purchasing program and the program's implementation. At this juncture, in view of the evolving creditworthiness of the investor-owned utilities and the emerging role of the power authority, the Legislature and the governor should consider the following actions:	
• Develop a comprehensive, long-term strategic framework for the electricity industry in the State and for the department's role in that system.	• The governor and the Legislature have taken some actions on this recommendation, but have not crafted a comprehensive, long-term strategic framework for the State's electricity industry.
• Establish an appropriate statutory framework, including the possible amendment of AB 1X, to extend the department's purchasing authority in order to allow adequate time to implement the strategic framework, to afford more flexibility in the termination of the department's purchasing authority, and to assure continuity of the purchasing function and an effective transition for this function, presumably to the investor-owned utilities.	• The transition of the power-purchasing role from the department to the investor-owned utilities occurred on January 1, 2003. As discussed in Chapter 6, certain challenges continue for the department in the post-transition period.
In the context of the evolving state policy on the future of the industry and the power-purchasing program, the department should take these steps:	
• Create a strategic plan for the future of the power-purchasing program at the department, including the assessment of the transition processes needed to allow orderly transfer of functions to the ISO, the investor-owned utilities, and others, as appropriate.	• Effective January 1, 2003, the responsibility for purchasing the net short returned to the investor-owned utilities. As such, the department has a limited future role in the power market. (See Chapter 6 for a discussion of the department's forward-looking issues.)

continued on next page

Recommendations	Department's Actions
• Continue efforts to coordinate the responsibilities of the department with respect to the Power Authority to establish clearly the roles and responsibilities of each organization.	• Effective January 1, 2003, the department's authority to enter into contracts or purchase power outside its existing contracts expired. Given such a limited role, the roles and responsibilities of the Power Authority with respect to those of the department are irrelevant.
With the substantial long-term contract portfolio in hand, the department needs an aggressive cost and risk management program. Actions taken or initiatives underway include the following: • Energy Transacting and Risk Management (ETRM) System—a database system designed as a decision support and management tool to support portfolio management, risk assessment, and pricing analysis for transactions and contracts. The system is scheduled for implementation in two phases during the first two quarters of 2002, and it is designed to address market risk, financial risk, and credit risk. • Contract Management Protocol—an organizational structure and set of business processes being implemented in fall 2001 designed to conduct the contract management function related to the power-purchasing program. In doing so, the department should also take these steps:	
• Conduct within 90 days, in conjunction with the legal review noted below, an in-depth economic assessment of the contracts and the overall supply portfolio serving the investor-owned utilities' customers to ensure that the department can develop an effective overall contract management strategy. This assessment should focus on how the contracts fit into the overall portfolio and on the costs relative to current expectations of market conditions.	• In September 2002, the CPUC allocated the department's power contracts to the investor-owned utilities to facilitate the transition to the utilities of purchasing the net short. As such, the utilities will manage the department's contracts, and the associated risks, along with their power resources in providing electric power to their retail customers.
• Develop a contract renegotiation strategy, informed by the legal and economic reviews, that focuses on improving the reliability and overall performance of the portfolio.	• During 2002, the department renegotiated 23 of its larger contracts in an attempt to improve the amount and prices of the power and the terms of the contracts. We discuss the amount of power under the renegotiated contracts in Chapter 1, the costs in Chapter 2, and the terms in Chapter 3.
• Ensure that the contract management plan addresses the department's obligations under the contracts both before and after the in-service dates.	• See the previous comments.
• Consider staffing approaches, including further consultants and contractors if needed, to ensure that personnel shortages do not continue to hinder the development and implementation of these systems.	• Effective January 1, 2003, the investor-owned utilities resumed responsibility for purchasing the net short. As a result, the department indicates that it is re-aligning its organization and reducing its staff to meet its reduced responsibilities.
• Establish a planning process that more directly integrates the entire portfolio of supplies serving customers of the investor-owned utilities with the role of the department's contracts in that portfolio. As specified in AB 1X, this process should include consultation with the CPUC and with the investor-owned utilities.	• Effective January 1, 2003, the investor-owned utilities resumed the responsibility of purchasing the net short and the CPUC allocated the department's power contracts to the utilities. As a result, the utilities will be responsible for integrating the department's contracts into their portfolios and dispatching their power resources in a least-cost manner for their retail customers under the regulation of the CPUC.

Recommendations	Department's Actions
The department now holds many long-term power contracts that have many "seller-friendly" provisions that represent important legal risks to the department. Further, it is reasonable to assume that with a long-term contract portfolio of this size and complexity, the department will have some litigation with the generators concerning the interpretation of the terms and conditions of the contracts. In this context, the department should do the following:	
• Conduct in-depth assessments of legal risk and legal services requirements within 90 days to assure that the department can develop an effective legal management strategy, including an effective "swords and shields" plan.	• During 2002, the department renegotiated 23 of its contracts, which generally resulted in much stronger guarantees that sellers will deliver the power promised under the contracts and build the new generation promised in the contracts. See Chapter 3 for a full discussion of the terms of the renegotiated contracts.
• Establish an ongoing legal services function that specializes in power contract management, negotiation, and litigation to assure that the department's legal assessment and representation is on par with those of the other parties participating in the contracts. When necessary to avoid conflicts, this legal function should be separate and distinct from counsel retained to sell bonds or to provide legal advice to the State Water Project.	• To examine the contracts and set goals for renegotiation and to renegotiate the contracts, the department assembled a team comprised of the department's legal and technical consultants as well as representatives from the attorney general's office, the CPUC, and the governor's office.
• Investigate all audit and other rights available to the department under its contracts to assure that it can develop a proper performance enforcement program.	• See the previous comments.
Department actions taken or initiatives underway to improve its short-term transactions functions include the following: • Power Scheduling and Settlements System—a system designed to support the power scheduling and ISO settlement functions. Scheduled for implementation in the fourth quarter of 2001. • ETRM System—this system provides support for short-term trading and management as well as for the longer-term portfolio management discussed above. These actions are obviously important, and the department should implement them as soon as possible. In doing so, the department should take these actions:	
• Clarify and resolve settlement process problems associated with the energy and ancillary services functions that the department has been and continues to conduct on behalf of the ISO.	• In November 2001, the Federal Energy Regulatory Commission ordered the ISO to stop relying on the department to make imbalance and ancillary services transactions on behalf of the ISO.
• Conduct an assessment of the imbalance energy sales and purchase volumes to determine whether they are significantly increasing the department's net power costs. If so, the department should develop plans to mitigate those costs.	• The department's sales of surplus power have not had a significant effect on the costs of the power-purchasing program. (See Chapter 4 for a full discussion of the department's sales of surplus power.)
• Enhance the organization's skills for market analysis and contract management to properly address the implications of uncertainty on portfolio management and dispatch decisions.	• Effective January 1, 2003, the investor-owned utilities resumed responsibility for purchasing the net short. As a result, the department indicates that it is re-aligning its organization and reducing its staff to meet its reduced responsibilities.

continued on next page

Recommendations	Department's Actions
• Fully staff the power-purchasing program. Although the program's organization has come a long way, it lacks adequate staff to match the magnitude of its trading and related activities (for example, planning, settlement, and fuel management). The planning and operational duties will also increase in the coming months as a significant amount of dispatchable long-term contracts take effect.	• See the previous comments.
• Develop a transition plan for the orderly transfer of the short-term purchasing and net short management functions at the conclusion of the AB 1X purchasing authority.	• The department has worked with the investor-owned utilities and the CPUC to transfer the purchasing of the net short to the utilities, effective January 1, 2003.
• Consider staffing approaches, including further consultants and contractors if needed, to assure that personnel shortages do not continue to hinder these operations over the next year and to provide for an effective transfer of the purchasing functions at the conclusion of the AB 1X authority.	• Effective January 1, 2003, the investor-owned utilities resumed responsibility for purchasing the net short. As a result, the department indicates that it is re-aligning its organization and reducing its staff to meet its reduced responsibilities.
The department should take the following actions to improve its capabilities to effectively coordinate with the utility-retained generation to minimize the total costs of serving the customers of the investor-owned utilities:	
• Collaborate with the investor-owned utilities to share information about their respective generation sources and to organize a least-cost dispatch of those sources. The investor-owned utilities also need to commit to this effort and to plan for ongoing coordination when the investor-owned utilities reassume the net-short purchasing authority, including coordination of dispatch with the department contracts.	• Coordinated dispatch of power resources to produce a least-cost dispatch of power to retail customers is an element of the operating order the CPUC placed on the investor-owned utilities. As the State's utility regulatory agency, the CPUC will enforce its orders through annual procurement reviews of the utilities. (See Chapter 5 for a discussion of coordinated dispatch.)
• Coordinate with the investor-owned utilities to ensure that the collective supply sources operate in a manner that minimizes the total cost of providing energy and ancillary services.	• See the previous comments.
• Work with the investor-owned utilities and the CPUC to ensure that the rate incentives associated with utility-retained generation scheduling are resolved to support a least-cost dispatch.	• See the previous comments.
To improve its ability to carry out the full functions of a power-purchasing program of this scale, the department should take these actions:	
• In its future efforts to protect the interests of the power-purchasing program, the department should retain independent legal counsel to advise the department on matters pertaining to state and federal regulatory issues affecting the power-purchasing program when those interests conflict with the interests of the State Water Project.	• In light of its reduced role in the California power market, the department indicates that it is realigning its organization and staffing levels, including legal and technical consultants, to support its post-January 1, 2003, responsibilities.
• Conduct a comprehensive assessment of the department's collaboration with the attorney general, the Energy Oversight Board, the CPUC, and other state entities to assure that the interests of the power-purchasing program are distinctly and adequately represented in regulatory proceedings.	• Effective January 1, 2003, the investor-owned utilities have resumed responsibility for purchasing the net short. The department has been active in CPUC proceedings to shape its future role.
• Seek clear statutory authority to use financial instruments to manage gas and electric transaction risks.	• In December 2001, the attorney general provided the department with an opinion indicating that the department has the legal authority to engage in transactions to hedge gas supply prices.

Recommendations	Department's Actions
To improve its ability to monitor the investor-owned utilities' performance in complying with the terms of the servicing agreements, the department should do the following:	
• Amend the servicing agreements to include language that promotes accuracy in estimates of customer usage provided by the investor-owned utilities.	• Because as of January 1, 2003, the department no longer purchases the net short on behalf of the investor-owned utilities, it no longer needs estimates of customer power usage.
• Complete its efforts to ensure that it can account for all of the amounts it is owed by the investor-owned utilities, including the completion of its project to track power delivered to retail customers.	• The department is conducting an ongoing effort to identify a methodology to ensure that it receives all of the revenue it is due from the sale of the power it purchases for the retail customers of the investor-owned utilities. The task has been challenging due to changes in the rates to retail customers and also due to utilities' collections of direct access fees from retail customers and the department's revenue requirements to repay its bonds.
• Develop audit procedures to review periodically the investor-owned utilities' performance of critical elements in the servicing agreements, such as cash remittance methodologies, the allocation to customers of the investor-owned utilities of the power that the department purchases, and the cost of energy conservation programs.	• The CPUC ordered the investor-owned utilities to enter into servicing agreements with the department. As the State's utility regulatory agency, the CPUC will enforce these orders with the utilities.
• Coordinate with the investor-owned utilities to develop audit procedures designed to detect noncompliance with the critical elements of the servicing agreements. These procedures can be performed by the investor-owned utilities' certified public accountants in conjunction with annual financial audits.	• Although the department agrees that audit procedures will help it monitor the utilities' compliance with certain requirements of the servicing agreements, due to competing priorities, it has not yet developed such procedures.
• Complete its efforts to execute agreements with the three investor-owned utilities that cover power purchases designed to balance in real time the electrical power supplied to the power grid with total customer usage.	• Because effective January 1, 2003, the department no longer purchases the net short on behalf of the investor-owned utilities, it no longer needs agreements with the utilities to cover real-time purchases of power to cover the net short.
To help ensure that its contractors do not have conflicts of interest, the department should continue its efforts to review all employees and consultants twice each year and it should retain a record of its review for each review period.	
	The department implemented new procedures to ensure that all department employees and contractor employees are screened for the requirement to disclose financial interests that may represent a conflict of interest. We found that the department substantially complies with its new procedures.
The department should improve its controls designed to have all power-purchasing program costs appropriately charged to the program and supported by evidence of service.	
	Although we found immaterial errors, the department has taken adequate steps to ensure that all power-purchasing program costs are appropriately charged to the Electric Power Fund.

Blank page inserted for reproduction purposes only.

APPENDIX B

Detailed Tables to Support Summary Data Shown in Chapter 1

Tables 2, 5, and 6 in Chapter 1 display the results of our analysis of the capacity distribution in the contract portfolio before and after the State's contract restructuring activities during 2002. These three summary tables show the net change in capacity before and after the contract renegotiations, and we use them to show the improved fit of the contract portfolio to consumer demand after renegotiation. To place those summary tables in perspective, this appendix presents three detailed tables, B.1, B.2, and B.3, to show the total capacity amounts involved, measured in megawatts. The headings of each detailed table correspond to the headings of the summary table from Chapter 1 and also indicate the page number where the summary table can be found.

TABLE B.1

Change in Capacity Supplied by Long-Term Contracts*
(in Megawatts)

Capacity Type	Calendar Year 2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Original Portfolio										
Dispatchable	704	2,829	3,444	3,544	2,319	3,169	3,169	3,169	3,169	2,869
Nondispatchable	5,032	5,646	8,011	8,920	8,270	7,358	7,340	7,040	7,040	7,040
Total for all contracts	**5,736**	**8,475**	**11,455**	**12,464**	**10,589**	**10,527**	**10,509**	**10,209**	**10,209**	**9,909**
Dispatchable	12%	33%	30%	28%	22%	30%	30%	31%	31%	29%
Nondispatchable	88	67	70	72	78	70	70	69	69	71
Total for all contracts	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
Renegotiated Portfolio										
Dispatchable	846	3,721	6,069	5,314	4,314	4,089	4,089	3,959	3,959	3,959
Nondispatchable	4,867	6,008	7,193	7,602	6,802	6,653	6,650	5,975	5,975	3,675
Total for all contracts	**5,713**	**9,729**	**13,262**	**12,916**	**11,116**	**10,742**	**10,739**	**9,934**	**9,934**	**7,634**
Dispatchable	15%	38%	46%	41%	39%	38%	38%	40%	40%	52%
Nondispatchable	85	62	54	59	61	62	62	60	60	48
Total for all contracts	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
Net Change										
Dispatchable	142	892	2,625	1,770	1,995	920	920	790	790	1,090
Nondispatchable	(165)	362	(818)	(1,318)	(1,468)	(705)	(690)	(1,065)	(1,065)	(3,365)
Total for all contracts	**(23)**	**1,254**	**1,807**	**452**	**527**	**215**	**230**	**(275)**	**(275)**	**(2,275)**

Source: Analysis by La Capra Associates using contract summary data from the Department of Water Resources. Capacities are for peak periods for July and August.

* Summary table found on page 25.

TABLE B.2

Change in Allocation of Contract Capacity Among Zones* (in Megawatts)

	Calendar Year					
Zone	**2001**	**2002**	**2003**	**2004**	**2005**	**2006–2010**
Original Portfolio						
NP15	1,945	3,638	3,893	4,218	3,993	3,915
SP15	3,791	4,837	7,562	8,246	6,596	6,416
Totals	**5,736**	**8,475**	**11,455**	**12,464**	**10,589**	**10,331**
NP15	34%	43%	34%	34%	38%	38%
SP15	66	57	66	66	62	62
Total for all contracts	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
Renegotiated Portfolio						
NP15	1,730	4,965	5,033	4,103	4,103	3,426
SP15	3,983	4,764	8,229	8,813	7,013	6,430
Totals	**5,713**	**9,729**	**13,262**	**12,916**	**11,116**	**9,856**
NP15	30%	51%	38%	32%	37%	35%
SP15	70	49	62	68	63	65
Total for all contracts	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
Net Change						
NP15	(215)	1,327	1,140	(115)	110	(489)
SP15	192	(73)	667	567	417	14
Total for all contracts	**(23)**	**1,254**	**1,807**	**452**	**527**	**(475)**

Source: Analysis by La Capra Associates using contract summary data from the Department of Water Resources.

Note: Capacities are for peak periods for July and August.

* Summary table found on page 35.

TABLE B.3

Change in Capacity of Tolling and Indexed Price Contracts*
(in Megawatts)

Contract Type	Calendar Year 2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Original portfolio										
Tolling and indexed price†	3,039	3,079	4,999	5,649	3,724	4,574	4,574	4,274	4,274	3,974
Fixed prices	2,697	5,396	6,456	6,815	6,865	5,953	5,935	5,935	5,935	5,935
Total for all contracts	**5,736**	**8,475**	**11,455**	**12,464**	**10,589**	**10,527**	**10,509**	**10,209**	**10,209**	**9,909**
Tolling and indexed price	53%	36%	44%	45%	35%	43%	44%	42%	42%	40%
Fixed prices	47	64	56	55	65	57	56	58	58	60
Total for all contracts	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
Renegotiated portfolio										
Tolling and indexed price	3,271	4,221	7,919	7,714	6,214	6,839	6,839	6,409	6,409	6,109
Fixed prices	2,442	5,508	5,343	5,202	4,902	3,903	3,900	3,525	3,525	1,525
Total for all contracts	**5,713**	**9,729**	**13,262**	**12,916**	**11,116**	**10,742**	**10,739**	**9,934**	**9,934**	**7,634**
Tolling and indexed price	57%	43%	60%	60%	56%	64%	64%	65%	65%	80%
Fixed prices	43	57	40	40	44	36	36	35	35	20
Total for all contracts	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
Net change										
Tolling and indexed price	232	1,142	2,920	2,065	2,490	2,265	2,265	2,135	2,135	2,135
Fixed prices	(255)	112	(1,113)	(1,613)	(1,963)	(2,050)	(2,035)	(2,410)	(2,410)	(4,410)
Total for all contracts	**(23)**	**1,254**	**1,807**	**452**	**527**	**215**	**230**	**(275)**	**(275)**	**(2,275)**

Source: Analysis by La Capra Associates using contract summary data from the Department of Water Resources.

Note: Capacities are for peak periods for July and August.

* Summary table found on page 37.

† Power-purchase contracts containing an indexed variable fuel cost component or provides an opportunity for the buyer to purchase fuel.

APPENDIX C

Detailed Report Card of Terms Revised Through Renegotiations for Those Contracts Reviewed in Our December 2001 Audit

In Chapter 3 we discuss the progress made by the Department of Water Resources (department) in restructuring the legal terms and conditions of certain contracts in the portfolio. We also present a summary report card table (Table 14 on pages 72 and 73) that summarizes the changes in the legal terms that we identified as being necessary to protect the department's interests and to ensure that suppliers abide by the contractual agreements. In this appendix, we present the same report card table on the following pages with the changes outlined by each of the renegotiated contracts that were included in the report card analysis of our December 2001 audit. The shading in the table indicates contracts that we found to have a deficient term during our December 2001 audit, and an "X" indicates that a term was changed when the contract was renegotiated.

TABLE C.1

Detailed Report Card of Changes in Contract Terms and Conditions

Category and Issues Graded	Supplier										Total Contracts Reviewed	Total Contracts With Changes	Contracts With Terms Rated Negatively In 2001 Audit	Number of Contracts Rated Negatively That Had Improved Terms	Percent of Problem Terms Addressed
	Calpeak*	Calpine 1	Calpine 2	Calpine 3	Calpine 4	GWF	High Desert†	Sunrise	Williams A,B,C‡	Williams D					
RELIABILITY OF ELECTRICITY SUPPLY															
A. Reliability of Performance—Delivery															
Is seller's failure to deliver an event of default? (–1, 0, 1)	X	X	X	X	X	X		X		X	10	8	7	5	71%
Penalties for seller's nonperformance (–1, 0, 1)	X	X	X	X	X	X	X	X	X		10	9	7	6	86
Seller's contractual incentives to perform (–1, 0, 1)				X	X		X		X		10	4	3	1	33
Seller's price incentives to perform (–1, 0, 1)											10	0	0	N/A	N/A
Department's ability to manage risk of nonperformance (0, 1)	X	X	X	X	X	X	X	X	X	X	10	10	0	N/A	N/A
Seller's outs (–1, 0, 1)	X	X	X	X	X				X	X	10	7	8	6	75
B. Reliability of Performance—Availability															
Is seller's failure to perform an event of default? (–1, 0, 1)	X	X	X			X	X	X		X	10	7	7	4	57
Penalties for seller's nonperformance (–1, 0, 1)	X	X	X	X	X	X	X	X	X	X	10	10	3	3	100
Seller's contractual incentives to perform (–1, 0, 1)	X			X	X	X			X	X	10	6	2	1	50
Seller's price incentives to perform (–1, 0, 1)									X		10	1	0	N/A	N/A
Department's ability to manage risk of nonperformance (0, 1)	X	X	X	X	X	X	X	X	X	X	10	10	0	N/A	N/A
Seller's outs (–1, 0, 1)		X	X	X					X	X	10	5	6	4	67
C. Reliability of Performance—Building New Generation															
Is seller's failure to perform an event of default? (–1, 0, 1)						X					10	1	4	0	0
Penalties for seller's nonperformance (–1, 0, 1)	X		X	X	X	X	X				10	6	3	3	100
Seller's contractual incentives to perform (–1, 0, 1)				X	X		X				10	3	2	1	50
Seller's price incentives to perform (–1, 0, 1)				X		X		X			10	3	1	1	100
Department's ability to manage risk of nonperformance (0, 1)			X	X	X	X	X				10	5	0	N/A	N/A
Seller's outs (–1, 0, 1)											10	0	4	0	0
D. Price Risk—Uncertainty of Price															
Seller's pass-throughs (–1, 0, 1)		X	X	X	X	X	X		X	X	10	8	6	6	100
Department credits (0, 1)		X	X	X	X		X		X	X	10	7	0	N/A	N/A
Allocation of environmental risk (–1, 0)									X	X	10	2	3	2	67

Category and Issues Graded	Supplier: Calpeak*	Calpine 1	Calpine 2	Calpine 3	Calpine 4	GWF	High Desert†	Sunrise	Williams A,B,C‡	Williams D	Total Contracts Reviewed	Total Contracts With Changes	Contracts With Terms Rated Negatively in 2001 Audit	Number of Contracts Rated Negatively That Had Improved Terms	Percent of Problem Terms Addressed
E. Price Risk—Tolling Agreement															
Department's exposure to fuel price risk (–1, 0, 1)		X	X	X			X	X		X	10	6	0	N/A	N/A
Department's exposure to operating inefficiency risk (–1, 0, 1)				X	X		X	X		X	10	5	0	N/A	N/A
FLEXIBILITY TO RENEGOTIATE OR QUIT															
A. Constraints on Department's Ability Not to Perform															
Outs for department (–1, 0, 1)	X	X	X	X	X	X	X	X		X	10	9	6	5	83%
Dispatchable versus take or pay (1, –1)	X	X	X	X	X	X	X	X		X	10	9	4	3	75
Limits of state's liability (–1, 0, 1)											10	0	4	0	0
B. Department's Ability to Obtain Relief Through Governmental Action															
Recoup expenditures through taxes (0,1)										X	10	1	0	N/A	N/A
Obtain relief from FERC (0, 1)	X						X	X			10	3	0	N/A	N/A
ABILITY TO ASSIGN/DELEGATE IF DEPARTMENT EXITS THE PROGRAM															
Ability to assign/delegate to government entities (–1, 0, 1)											10	0	0	N/A	N/A
Ability to assign/delegate to nongovernment entities (–1, 0, 1)	X	X	X	X	X	X	X	X	X	X	10	10	9	9	100

Source: Department of Water Resources data reviewed by the Bureau of State Audits.

Notes: In many cases, changes in contract clauses affected multiple catagories. In these cases, we evaluated the effect of the change on each category. Also, this report card does not include the following renegotiated contracts because they are insignificant in value to the overall portfolio: Cabazon, Clearwood, PG&E, Santa Cruz, Soledad, Wellhead Power, and Whitewater.

Negative rating in our December 2001 audit (-1).

We concluded the attribute was not applicable in our December 2001 audit.

* We rated this contract as four contracts in our December 2001 audit because the department treated it as such. For this audit, we treat it as one contract to be consistent with the current treatment of the department.

† This column also addresses the Constellation contract.

‡ These three contracts were rated individually in our December 2001 audit.

N/A = Not applicable.

Blank page inserted for reproduction purposes only.

Agency's comments provided as text only.

Department of Water Resources
1416 Ninth Street, Suite 1311
Sacramento, CA 95814

To: Elaine M. Howle, State Auditor
Bureau of State Audits
555 Capitol Mall, Suite 300
Sacramento, California 95814

From: Mary D. Nichols *(Signed by: Mary D. Nichols)*
Secretary for Resources

Subject: Department of Water Resources' Response to the Bureau of State Audit's Draft Report

Enclosed is the Department of Water Resources' response to the Bureau of State Audit's draft report entitled "California Energy Markets: The State's Position Has Improved, Due to Efforts by the Department of Water Resources and Other Factors, but Cost Issues and Legal Challenges Continue, April 2003."

If your staff has any questions, please call Peter Garris, Deputy Director of the California Energy Resources Scheduling Division, Department of Water Resources at (916) 574-2733.

Enclosure

M e m o r a n d u m

Date: March 20, 2003

To: Honorable Mary D. Nichols
Secretary for Resources
The Resources Agency
1416 Ninth Street, Room 1311
Sacramento, California 95814

From: Department of Water Resources

Subject: Department of Water Resources' Response to the Bureau of State Audit's Draft Report

The Department of Water Resources has reviewed the draft report entitled : "California Energy Markets: The State's Position Has Improved, Due to Efforts by the Department of Water Resources and Other Factors, but Cost Issues and Legal Challenges Continue, April 2003". We appreciate the efforts of the Bureau of State Audits and its consultant in preparing this report.

If you have any questions, please contact me or your staff may contact Peter Garris, Deputy Director of California Energy Resources Scheduling, at (916) 574-2733.

(Signed by: Stephen W. Verigin for)

Thomas M. Hannigan
Director
(916) 653-7007

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