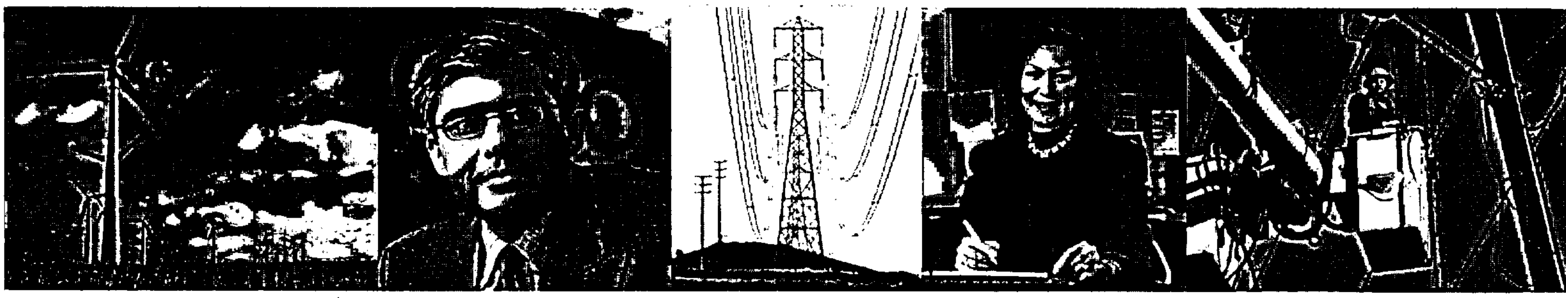
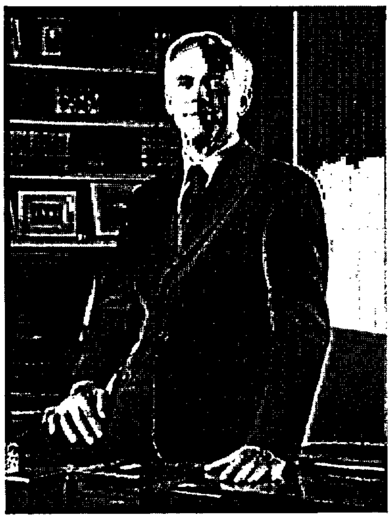
EDISON INTERNATIONAL 2004 Annual Report



Edison International: Building the Future

Dear Fellow Shareholders:



It is with pride and satisfaction that I report to you another year of strong performance by Edison International. The total return on your investment in us during 2004 was 51 percent. This spring, the value of your shares rose to an all-time high.

In recent years the Edison International story has been one of rebuilding, as we survived first the California power crisis and then the collapse of the U.S. wholesale power market. Initially, our increased value was largely attributable to the success of our recovery efforts. In 2004, we turned an important corner as further value increases were driven principally by the favorable post-recovery longer-term outlook.

On behalf of all the employees of Edison International, I thank you and all the other shareholders who remained confident in us through the uncertain times. It gives us great pleasure to reward your confidence.

Last fall, our senior management team and I presented to investors and our employees a forward-looking, multi-year strategic plan called *Building the Future*. Its rationale is simple but powerful: We intend to capture the above-average growth inherent in our existing operations. We like the opportunities squarely in front of us.

Edison International has one unifying focus – providing the electrical energy that enhances people's lives. We generate it from diverse fuels, including natural gas, coal, nuclear, hydroelectric and renewables. We transmit it over long distances. We buy and sell it wholesale. And we distribute it to retail customers who are its end users.

In Southern California Edison (SCE), we have a strong utility serving a dynamic region where both average energy usage per customer and the population are growing. Serving our customers by making the large capital investments needed for our utility electric system should also result

in substantial growth in the utility's earnings base over the next five years.

Our independent power and infrastructure finance businesses make up almost one-third of our assets. They are well positioned to compete in wholesale power markets and in the development of renewable energy. Our independent power business includes a large base of low-cost coal generation plants which provide good margins today and offer substantial additional upside potential.

If we execute our plan well in these business lines and continue to secure sound regulation in California, we should be able to produce healthy earnings and dividend growth through the next five years.

Investments to Serve Our Utility Customers

In Southern California, two factors have converged to create a need for substantially increased investment in our utility wires business. First, our customer base and per capita usage are growing, requiring extensive construction and expansion. Second, much of the electrical system was built in the decades following World War II. Those decades-old elements of that infrastructure are aging and should be systematically replaced and modernized.

Investments in our utility wires business, excluding generation, make up $9 billion of the $11 billion in capital spending projected in our *Building the Future* strategic plan. This represents a near doubling of our wires business investments over the previous six years. We are also stepping up investments in utility power generation. As a result, in 2004 alone, we increased our total utility capital expenditures by about 70 percent over the previous year.

Significantly, the California Public Utilities Commission (CPUC) last year endorsed our plan for increased infrastructure investment and provided rate support for these investments through the end of 2005. This was a critically important step forward.

Successful International Asset Sale

In the fall of 2003, following a sharp downward revision in the overall credit ratings of companies within the independent power industry, we decided that the sale of our large, valuable portfolio of international power plants would likely strengthen our independent power business.

The sales are now substantially complete – only one plant remains to be sold – and have brought in approximately $2.4 billion after taxes and costs. The completion of these sales, along with cash from operations and plant

decommissioning, allowed us in the last year to pay off $1.4 billion in debt within our independent power business line and to increase cash on its books to slightly in excess of $2 billion.

Today, our independent power business owns approximately 7,700 megawatts of low-cost coal plants in Illinois and Pennsylvania and slightly more than 1,000 megawatts of natural gas plants operating predominantly in California. Although challenges lie ahead, this business offers shareholders both current value and substantial potential for the future.

Other Highlights

New Renewable Energy Investments. We began making investments in renewable energy projects in the mid-1990s, but had to put that initiative on hold during the power crisis. In 2004 we started again within Edison Capital to grow that business. If conditions remain favorable, we propose to make investments in excess of $1 billion in renewable energy over the next five years.

New Generation for California. Early in 2004, federal and state utility regulators approved SCE's proposal for the construction of Mountainview, a large natural gas generating facility. It is scheduled to be complete in time to provide additional capacity for the summer of 2006, when supplies are forecast to be tight.

Award-winning Conservation Programs. During the past three years, Southern California Edison has conserved more energy through its energy-efficiency programs than any utility in the U.S. Our programs have helped customers reduce their energy use by more than one billion kilowatt-hours during that time, or enough power to supply 140,000 average homes for one year.

Customer Refunds. We are continuing to work with California and federal officials to seek refunds from suppliers who overcharged our customers during the power crisis. Through early 2005, we have reached settlements with five suppliers totaling more than $400 million, most of which goes to our customers.

Strong Financial Results

When we serve our customers well, our shareholders benefit. In 2004 our earnings were $2.81 per share, an increase of 12 percent over the previous year. Our common stock value increased 46 percent. We also paid off all the outstanding debt – approximately $1.5 billion – at the Edison International parent level. Edison International and Southern California Edison are now both rated investment grade by Moody's and Standard and Poor's, reducing our borrowing costs. Finally, at the end of

2004 we were able to increase our dividend by 25%, to an annualized rate of $1.00 per share.

Key SCE Generation Issues

Two issues I mentioned in last year's letter deserve brief updates. SCE's Mohave and San Onofre generating plants provide cost-effective sources of power and fuel diversity in a state heavily reliant on natural gas for its power generation. However, continued operation of the Mohave plant beyond 2005 is in question. We are working diligently to resolve difficult outstanding issues of coal and water supply in an effort to extend that plant's operating life. At our San Onofre nuclear plant, four steam generators must be replaced at an estimated total cost of $680 million to permit continued safe and reliable operation. We filed for advance authorization from the CPUC early last year, and expect a decision in 2005.

A Significant Disappointment

During 2004, we discovered serious problems with data SCE had submitted to the CPUC to support potential incentive awards for customer satisfaction and safety. We advised the CPUC of these issues, conducted a thorough investigation and submitted the results to the commission. In addition to firm disciplinary action for those who violated company policy, we launched a strengthened ethics and compliance program, including a new officer-level position, to enforce rigorously our century-old commitment to both service and integrity.

Building the Future

Our principal objectives for the next years are established. Our challenge is to meet the targets established in our *Building the Future* strategic plan. Four initiatives will be particularly important in the coming year:

First, our efforts to reduce costs and improve efficiency will continue. In our non-utility operations, that means further debt reduction, as well as reductions in general and administrative expenses. At SCE, our infrastructure improvement plan will require a level of skilled field work that surpasses anything in our history. We recently launched a multi-year productivity effort to drive more work through our system while keeping costs down. This will be a major emphasis.

Second, we will seek continuing regulatory support for our electric infrastructure improvement plan, in the form of three-year forward rate recovery that builds on the rate-making precedent set by the CPUC last year. The only good thing that may have come from the power crisis was the consensus it created about the importance of maintaining a reliable electric system. California's recent experience has been a harsh teacher.

Third, we will solidify our independent power business, expand our renewable energy investments, and carefully evaluate our prospects for growth in this sector. One opportunity that may present itself is in California, where it is likely that a significant portion of much-needed new generation will be developed through competitive processes.

Finally, although East Coast and Midwest power markets served by our fleet of low-cost coal plants remain oversupplied with generation, we make solid margins because wholesale power prices are often set by more expensive natural gas plants. When economic growth restores a better balance of supply and demand in these markets, our plants should also earn capacity values – the price paid to generators for on-call access to their supply. We are focused on optimizing these values as we operate and sell the output of these plants.

Concluding Thoughts

I have had the privilege of serving in senior roles at Edison International for more than 20 years, and I still marvel at the inventiveness and drive of our employees when conditions are at their worst.

During the 2004 holiday season, a series of storms moved across Southern California, causing widespread damage to our utility electric system and disrupting service to hundreds of thousands of customers. As they have done countless times before, our employees answered the call, found means to overcome large unexpected obstacles, and sacrificed their own holiday celebrations to restore reliable power delivery.

I believe this same spirit sustained our company these last few years during back-to-back crises as serious as any in our 118-year history. When other companies might have failed, the men and women of Edison International rose to the occasion and helped engineer a remarkable turnaround.

We still face worthy challenges but, once again, we are on a path to sustainable growth. We have a solid five-year strategic plan and a balanced business mix, with talented people and deep, well-tested experience in both regulated and competitive markets. We are positioned well to take advantage of the large opportunities that lie ahead.

Sincerely,

John E. Bryson
Chairman of the Board,
President and Chief Executive Officer

March 21, 2005

Edison International

[illegible] Edison International, through its subsidiaries, is a generator and distributor of electric power and an investor in infrastructure and energy assets, including renewable energy. Headquartered in Rosemead, California, Edison International is the parent company of Southern California Edison – a regulated electric utility – and two nonutility businesses: Edison Capital and Mission Energy Holding Company, the parent of Edison Mission Energy.

[illegible]

- Hold integrity as our paramount value
- Commit to excellence
- Respect each other and the people with whom we deal

These personal values we hold and the customer value we deliver are essential to create shareholder value.

[illegible]

INTRODUCTION

This Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) contains forward-looking statements. These statements are based on Edison International's knowledge of present facts, current expectations about future events and assumptions about future developments. Forward-looking statements are not guarantees of performance; they are subject to risks and uncertainties that could cause actual future outcomes and results of operations to be materially different from those set forth in this discussion. Important factors that could cause actual results to differ are discussed throughout this MD&A.

Edison International is engaged in the business of holding, for investment, the common stock of its subsidiaries. Edison International's principal operating subsidiaries are Southern California Edison Company (SCE), Edison Mission Energy (EME) and Edison Capital. Mission Energy Holding Company (MEHC) (parent), a subsidiary of Edison International, is the holding company for its wholly owned subsidiary EME. Since the second quarter of 2004, MEHC (parent) and EME are presented as one business segment on a consolidated basis due primarily to the elimination of EME's so-called "ring fencing" provisions in EME's certificate of incorporation and bylaws discussed below under "MEHC: Liquidity—MEHC (parent)'s Liquidity." SCE comprises the largest portion of the assets and revenue of Edison International. In this MD&A, except when stated to the contrary, references to each of Edison International, SCE, MEHC, EME or Edison Capital mean each such company with its subsidiaries on a consolidated basis. References to Edison International (parent) or parent company and MEHC (parent) mean Edison International or MEHC on a stand-alone basis, not consolidated with its subsidiaries. References to SCE, EME or Edison Capital followed by "(stand alone)" mean each such company alone, not consolidated with its subsidiaries.

This MD&A is presented in 13 major sections. The MD&A begins with an Edison International management overview and a brief review of the company's consolidated earnings for 2004. Following is a company-by-company discussion of Edison International's principal business segments (SCE, MEHC, and Edison Capital) and Edison International (parent). Each principal business segment's discussion includes a management overview and discussions of liquidity, market risk exposures, and other matters (as relevant to each principal business segment). The remaining sections discuss Edison International on a consolidated basis, including results of operations and historical cash flow analysis, discontinued operations, acquisitions and dispositions, critical accounting policies and estimates, new accounting principles, commitments, guarantees and indemnities, off-balance sheet transactions, and other developments. These sections should be read in conjunction with the continuing operations discussion of each principal business segment's section.

EDISON INTERNATIONAL

EDISON INTERNATIONAL: MANAGEMENT OVERVIEW

In 2004, Edison International's primary management focus was to continue restoring the company's financial health from the impacts of the California energy crisis and world-wide developments that adversely affected independent power producers and merchant generators. In this regard, critical objectives met in 2004 included:

- Completing EME's restructuring plan, which consisted of the substantial completion of the sale of EME's international assets and the refinancing of indebtedness associated with EME's Illinois plants, including the termination of the lease at the Collins Station. The proceeds from the asset sales were used to repay certain indebtedness, with the remaining proceeds retained to meet future debt obligations, support working capital requirements and for other EME corporate purposes. See further discussion in "MEHC: Management Overview—EME Restructuring Activities" and "MEHC: Liquidity—Key Financing Developments," and "—Termination of the Collins Station Lease."

- Finalizing the 2003 General Rate Case (GRC), in which the California Public Utilities Commission (CPUC) approved nearly all of SCE's request to support its multi-billion dollar infrastructure replacement program for the 2003 through 2005 period to improve electric reliability. The CPUC decision provided cost recovery for SCE's forecasted increase in capital investments in 2004 and 2005. See "SCE: Regulatory Matters—Transmission and Distribution—2003 General Rate Case Proceeding."

- Eliminating all of Edison International (parent)'s debt. See "Edison International (Parent): Liquidity."

- Restarting investments at Edison Capital, ending a three-year investment hiatus. See "Edison Capital: Management Overview."

In 2005, Edison International's strategic plan sets forth a balanced approach for growth, dividends, and balance sheet strength. Principal objectives in 2005 include:

- Continuing to be effective in advocating sound, stable and consistent regulatory decisions, including successful resolution of SCE's 2006 GRC where SCE is requesting an increase in its revenue requirements to support the expected growth in capital and operating expenditures. Currently, SCE plans to invest approximately $9.4 billion over the next five years to replace and expand its distribution and transmission infrastructure and construct and replace generation assets.

- Effectively managing enterprise risks by controlling costs, by securing reasonable long-term procurement rules and fair cost allocation rules, and by avoiding uneconomic cost shifting from direct access customers.

- Effectively operating EME's plants, reducing volatility by entering into forward contracts through EME's marketing and trading subsidiary to reduce market risk and enhance the predictability of revenue, and reducing EME's leverage by repaying debt at maturity and repurchasing existing debt where early retirement is considered beneficial.

- Sustaining the tax treatment of lease transactions at Edison Capital against the current Internal Revenue Service (IRS) challenge (see "Other Developments—Federal Income Taxes"), as well as resuming investment in new electric infrastructure, including renewable energy.

Edison International's primary management focus in 2005 will include substantially strengthening ethics and compliance programs at all of the Edison International companies. Integrity is Edison International's paramount value and the management of Edison International intends to devote the appropriate focus and address employee accountability to uphold this core value. In addition, Edison International management will focus on developing the talent critical to achieve its strategic plan objectives, including enhancing leadership capabilities, rotations within and across the companies and organizational and process changes.

Edison International's recorded earnings were $916 million or $2.81 per share in 2004, compared to $821 million or $2.52 per share in 2003. Increased earnings primarily reflect net benefits from the sale of MEHC's international projects and the resolution of several regulatory and prior years' tax issues at SCE that more than offset the net effect of MEHC's asset impairments and lease termination costs and lower operating earnings at both SCE and MEHC. The decrease in operating earnings reflects the expiration of SCE's performance-incentive mechanisms for San Onofre, the absence of earnings from MEHC's interest in the Four Star Oil & Gas Company, net of the gain, which was sold in the first quarter of 2004, lower earnings at MEHC's Homer City facilities, and a charge for an indemnity related to asbestos claims at MEHC's Illinois plants. The decrease in operating earnings was partially offset by higher revenue net of operating expenses at SCE and improved operating performance at MEHC's international projects (including depreciation expense) and MEHC's Illinois plants. For a detailed review and analysis of the consolidated results of operations and historical cash flows, see the "Results of Operations and Historical Cash Flow Analysis" section.

SOUTHERN CALIFORNIA EDISON COMPANY

SCE: MANAGEMENT OVERVIEW

Background

SCE is an investor-owned utility company providing electricity to retail customers in central, coastal and southern California. SCE is regulated by the CPUC and the Federal Energy Regulatory Commission (FERC). SCE bills its customers for the sale of electricity at rates authorized by these two commissions. These rates are categorized into two groups: base rates and cost-recovery rates.

Base Rates: Revenue arising from base rates is designed to provide SCE a reasonable opportunity to recover its costs and earn an authorized return on the net book value of SCE's investment in generation, transmission and distribution plant (or rate base). Base rates provide for recovery of operations and maintenance costs, capital-related carrying costs (depreciation, taxes and interest) and a return or profit, on a forecast basis. Base rates related to SCE's generation and distribution functions are authorized by the CPUC through a GRC. In a GRC proceeding, SCE files an application with the CPUC to update its authorized annual revenue requirement. After a review process and hearings, the CPUC sets an annual revenue requirement by multiplying an authorized rate of return, determined in annual cost of capital proceedings (as discussed below), by rate base, then adding to this amount the adopted operation and maintenance costs and capital-related carrying costs. Adjustments to the revenue requirement for the remaining years of a typical three-year GRC cycle are requested from the CPUC based on criteria established in a GRC proceeding for escalation in operation and maintenance costs, changes in capital-related costs and the expected number of nuclear refueling outages. See "SCE: Regulatory Matters—Transmission and Distribution—2003 General Rate Case Proceeding" for SCE's current annual revenue requirement. Variations in generation and distribution revenue arising from the difference between forecast and actual electricity sales are recorded in balancing accounts for future recovery or refund, and do not impact SCE's operating profit, while differences between forecast and actual costs, other than cost-recovery costs (see below), do impact profitability.

SCE's capital structure, including the authorized rate of return, is regulated by the CPUC and is determined in an annual cost of capital proceeding. The rate of return is a weighted average of the return on common equity and cost of long-term debt and preferred stock.

Current CPUC ratemaking also provides for performance incentives or penalties for differences between actual results and GRC-determined standards of reliability and employee safety.

Base rate revenue related to SCE's transmission function is authorized by the FERC in periodic proceedings that are similar to the CPUC's GRC proceeding, except that requested rate changes are generally implemented when the application is filed, and revenue collected prior to a final FERC decision is subject to refund. SCE's current authorized annual revenue requirement of approximately $260 million recovers the costs associated with its transmission function and earns a reasonable return on its $1.1 billion transmission rate base.

Cost-Recovery Rates: Revenue requirements to recover SCE's costs of fuel, purchased power, demand-side management programs, nuclear decommissioning costs, rate reduction debt requirements, and public purpose programs are authorized in various CPUC proceedings on a cost-recovery basis, with no markup for return or profit. Approximately 50% of SCE's annual revenue relates to the recovery of these costs. Although the CPUC authorizes balancing account mechanisms to refund or recover any differences between estimated and actual costs in these categories in future proceedings, under- or over-collections in these balancing accounts can build rapidly due to fluctuating prices (particularly in power procurement) and can greatly impact cash flows. Rates are adjusted, as necessary, to recover or refund any under- or

over-collections. The majority of costs eligible for recovery are subject to CPUC reasonableness reviews, and thus could negatively impact earnings and cash flows if found to be unreasonable and disallowed.

As described below under "SCE: Regulatory Matters—Generation and Power Procurement—CDWR Power Purchases and Revenue Requirement Proceedings," the California Department of Water Resources (CDWR) began purchasing power on behalf of utility customers in 2001, during the California energy crisis. In addition to billing its customers for SCE's power procurement activities, SCE also bills and collects from its customers for power purchased and sold by the CDWR, CDWR bond-related charges and direct access exit fees. These amounts are remitted to the CDWR as they are collected and are not recognized as revenue by SCE. As a result, these transactions should have no impact on SCE's earnings.

For a discussion of important issues related to the rate-making process, see the "SCE: Regulatory Matters" section.

SCE 2004 Issues – Overview

In 2004, SCE's primary management focus was on numerous business issues that could have materially affected SCE's earnings, cash flow, or business risk. The following is a brief review of SCE's performance on its 2004 key business issues.

- In July 2004, the CPUC issued a final decision in SCE's 2003 GRC, authorizing an annual increase of $73 million in base rates and providing for base rate adjustments in 2004 and 2005. The CPUC's decision is retroactive to May 22, 2003. In the decision, the CPUC approved nearly all of SCE's requested capital spending. Moreover, the CPUC adopted a mechanism to adjust base rates based on SCE's forecast of capital expenditures and operating and maintenance escalation for 2004 and 2005.

- All of SCE's major business functions (distribution, transmission and generation) had significant demands for capital investment. During 2004, SCE's new account additions totaled 68,400. In 2004, SCE spent approximately $2.0 billion in capital expenditures, including $285 million related to the acquisition of the Mountainview project. At year-end 2004, SCE's rate base was $9.4 billion. With the 2003 GRC decision, SCE substantially increased the replacement of distribution poles, transformers and other infrastructure during 2004. This is part of a long-term effort known as the Infrastructure Replacement Program, which is designed to step up the level of infrastructure replacement to maintain existing levels of system reliability. A significant portion of SCE's existing distribution infrastructure was installed during the post-World War II population boom.

- During 2004, SCE took major steps in implementation of its transmission expansion plans to meet customer load-growth requirements, including:

    - Completed the reconstruction of the Sylmar Converter Station. This $120 million project (SCE's share is $60 million), allows 3,100 megawatt (MW) of power to flow to southern California;

    - Obtained regulatory approval to spend $125 million to upgrade SCE's Devers/Palo Verde 1 transmission line. This project will add 505 MW by 2006;

    - Filed an application with the California Independent System Operator (ISO) for approval to construct the $680 million Devers/Palo Verde 2 transmission line. This application was approved on February 24, 2005. If approved by other regulatory agencies, the line would add 1,200 MW of power to southern California by 2009;

- Filed an application with the CPUC to construct the $224 million Antelope Area Transmission project. This project will expand SCE's transmission system, allowing additional suppliers of wind energy from the Tehachapi wind region (near Mohave, California).

- Generation capital spending increased dramatically in 2004. SCE made significant progress in the construction of the 1,054 MW Mountainview project. At year-end 2004, the project was about 50% completed and was on schedule to complete construction by the end of the first quarter 2006. At SCE's San Onofre Nuclear Generating Station (San Onofre) site, security upgrades driven by the Nuclear Regulatory Commission required $54 million of capital spending, slightly above what had been budgeted for 2004. Also during 2004, San Onofre Unit 3 experienced an extended outage due to the replacement of the pressurizer heater sleeves as a result of degradation. This outage reduced the 2004 capacity factor of Unit 3 to 74%.

- In February 2004, SCE filed an application with the CPUC to replace the San Onofre steam generators and to adopt the estimated reasonable replacement cost of $510 million (SCE's share). In September 2004, SCE signed a contract for the fabrication of new steam generators. See "SCE: Regulatory Matters—Generation and Power Procurement—San Onofre Nuclear Generating Station."

- During 2004, SCE and its co-owners of the Mohave Generating Station (Mohave), a 1,580 MW coal-fired plant (SCE has a 56% ownership), continued negotiations to find a reasonable path to continue Mohave operations beyond 2005. Under the terms of a consent decree, the Mohave owners must install certain pollution-control equipment in order to operate beyond 2005. Before the investment can be evaluated by the co-owners, future coal and water supply issues must be resolved. See "SCE: Regulatory Matters—Generation and Power Procurement—Mohave Generating Station and Related Proceedings."

- SCE has numerous concerns associated with providing power for its bundled service customers. As discussed in the "—Background" section, SCE recovers only reasonable costs associated with procuring power for its customers, with no markup or profit. Because of the substantial costs associated with power procurement, SCE spends considerable management focus to ensure that both customer and shareholder risks are reasonably protected. During 2004, SCE supported Assembly Bill 2006, which would have created a fairer and more durable regulatory framework associated with generation investments and purchased-power costs. Although the bill was passed by the State Legislature, it was vetoed by the Governor of California. However, in the CPUC's decisions affecting power procurement, meaningful progress was made towards a fairer regulatory framework supporting power procurement. In particular, the CPUC:

  - recognized the financial implications of debt equivalence (the fixed financial obligations resulting from long-term power-purchase contracts) when evaluating competitive bids on power-purchase contracts, and also provided a mechanism to begin mitigating its impact;

  - extended the power procurement trigger mechanism, allowing for adjustment in procurement rates should currently authorized rates cause revenue to exceed or under run actual costs by 5% of SCE prior year's procurement costs (see "SCE: Market Risk Exposures—Commodity Price Risk"); and

  - provided stranded cost recovery for long-term power procurement arrangements.

- SCE has identified that resource adequacy requirements, anticipated closure of Mohave at the end of 2005, reduction in deliveries of CDWR allocated-contract power, expiration of qualifying facilities (QF) contracts, and peak-load growth of 1.5% to 2% per year would require SCE to seek substantial amounts of incremental capacity. During 2004, SCE conducted a number of competitive solicitations

to meet its resource requirements, as specified by regulatory rules. Based on the results of SCE's 2004 solicitations, SCE expects to meet its 2005 requirements and has significantly reduced its estimate of the amount of resources needed to meet the requirements for 2006 and 2007. SCE also is seeking additional suppliers of renewable power to attain CPUC-mandated levels. At year-end 2004, SCE obtained approximately 18% of its power supplies from renewable resources. SCE must achieve 20% by 2010, or could be subject to penalties.

- During 2004, SCE remained concerned about high customer rates, which were a contributing factor that led to the deregulation of the electric services industry during the mid-1990s. At the beginning of 2004, SCE's system average rate for bundled service customers was 12.5¢-per-kilowatt-hour (kWh). As of December 31 2004, that rate was 12.2¢-per-kWh. On April 14, 2005, SCE expects to implement new rates that will result in a system average of 13.0¢-per-kWh. The expected rate increase is due to higher gas prices and increased power purchases resulting from resource adequacy requirements and a reduction in CDWR power deliveries. On a cents-per-kWh basis, SCE's average rate is above the national average, but similar to other investor-owned electric utilities in California.

- During 2004, a new issue emerged that affected SCE's performance. SCE found that a number of employees had falsified customer data which was reported to the CPUC in support of certain performance incentive rewards. Upon further investigation, SCE also discovered that it had not appropriately collected or maintained data on employee safety which is also tied to a CPUC performance incentive reward. SCE reported its findings to the CPUC, terminated and disciplined certain employees, and committed to the CPUC to either refund or not seek any performance incentives in the affected areas. SCE recorded a $29 million pre-tax earnings charge in 2004 to account for the anticipated refund of the previously received performance incentive rewards. SCE is committed to implementing programs that greatly strengthen the ethics and compliance programs and culture at SCE.

SCE 2005 Issues – Overview

This overview discusses key business issues facing SCE in 2005. It is not intended to be an exhaustive discussion, but a summary of current or developing corporate issues. It includes items that could materially affect SCE's earnings, cash flow, or business risk. The issues discussed in this overview are described in more detail in the remainder of this "Southern California Edison Company" section.

In October 2004, Edison International adopted a comprehensive multi-year strategic plan. For the remaining years, 2005–2009, the plan provides for SCE to incur $9.4 billion in capital expenditures which would increase SCE's rate base from $9.4 billion at year-end 2004 to $14.2 billion by year-end 2009. To achieve this projected growth, SCE must have all regulatory approvals to spend the forecasted capital, and the people, processes, and systems to implement the authorized capital expenditures. Pursuant to the plan, SCE expects to spend $1.6 billion on capital projects in 2005 and expects to have a rate base of $10.2 billion at year-end 2005. Through the 2003 GRC decision, ratemaking for SCE's 2005 capital expenditures already is in place. Significant investments in 2005 are expected to include:

- $200 million related to transmission projects.

- $1.1 billion related to distribution projects.

- $300 million related to generation projects, including the completion of the construction of the Mountainview project.

In order to achieve this growth for 2005 and beyond, SCE needs to make meaningful progress on several transmission projects including:

- Devers/Palo Verde 1 transmission line upgrades.
- Rancho Vista Substation, Devers/Palo Verde 2 transmission line, and Antelope Transmission project, all of which were approved by the ISO in 2005. The CPUC approval process must now be initiated.

2005 is an important year for several generation projects. The Mountainview project will be substantially completed in 2005, with an anticipated in-service date during the first quarter of 2006. During 2005, the CPUC is expected to render a final decision on SCE's San Onofre steam generator replacement application. In addition, future ownership of San Onofre is affected by co-owners opting out of steam generator investments. This could result in SCE assuming a greater financial responsibility for steam generator replacement and increased ownership interest. See "SCE: Regulatory Matters—Generation and Power Procurement—San Onofre Nuclear Generating Station." The future of Mohave still remains uncertain. SCE will continue to seek a solution permitting extension of Mohave's operation beyond 2005 on commercially reasonable terms, or provide for its permanent shutdown. A commitment to extend Mohave's operation and the possible $1.1 billion capital expenditures (SCE's share is $605 million), is not included in SCE's capital forecast. See "SCE: Regulatory Matters—Generation and Power Procurement—Mohave Generating Station and Related Proceedings."

In December 2004, SCE filed an application with the CPUC for its 2006 GRC. The application requests the CPUC to increase base rates by $370 million, primarily for capital-related expenditures to accommodate customer and load growth and substantially higher operation and maintenance expenditures particularly in SCE's transmission and distribution business unit. The application also seeks base rate increases for 2007 and 2008, permitting escalation for operating expenditures and planned capital expenditures. If the schedule is maintained, a final decision is expected at year-end 2005. See "SCE: Regulatory Matters—Transmission and Distribution—2006 General Rate Case Proceeding." Adoption of the capital forecast incorporated in SCE's 2006 GRC is essential to meeting the targets incorporated in SCE's strategic plan.

In 2004, SCE commenced a broad initiative to redesign key work processes associated with capital expenditures within the transmission and distribution business unit. The initiative, known as business process integration, is designed to modify existing work processes which focus on individual business units and replace them with integrated work processes spanning the entire utility. This initiative should produce efficiency of business systems, reduction of capital requirements and streamlined business processes. SCE has incorporated expected savings from business process integration in its 2006 GRC forecast.

In 2005, SCE will continue to focus on meeting the CPUC's new minimum planning reserve margin of 15–17% above its average-year peak load. In January 2004, the CPUC adopted this minimum planning reserve margin for all load-serving entities, including SCE, which supplies power to about 85% of the retail load served by its transmission and distribution system. In October 2004, the CPUC accelerated the effective date for the minimum planning reserve margin from 2008 to 2006. SCE has met the minimum planning reserve margin for 2005. However, as power-purchase contracts expire, generating plants retire, and load grows, SCE anticipates the need to sign additional power-purchase contracts in the years ahead to meet the minimum planning reserve requirement beyond 2005. The ISO, CPUC and the California Energy Commission have identified SCE's service territory as an area in which new generation will soon be needed. SCE will continue to advocate to State officials the need for a market and regulatory framework that will support developers' efforts to obtain financing for new generation projects. Over time, a robust resource adequacy framework implemented through stable capacity markets may achieve this goal; in the interim, developers may not be able to obtain financing without long-term contracts with creditworthy load-serving entities. Long-term contracts with new generators are likely to be more costly than short-term contracts with existing generators. However, load-serving entities are not in a position to sign these more costly, long-term contracts for new generation in an environment in which their retail customers can elect another service provider. SCE will continue working with State officials to find

transitional and long-term solutions to this fundamental problem that treat all load-serving entities equitably and are workable even if the State expands competitive retail markets.

SCE: LIQUIDITY

SCE's liquidity is primarily affected by under- or over-collections of procurement-related costs, collateral and mark-to-market requirements associated with power-purchase contracts, and access to capital markets or external financings. At December 31, 2004, SCE's credit and long-term senior secured issuer ratings from Standard & Poor's and Moody's Investors Service were BBB and A3, respectively. On February 16, 2005, Standard & Poor's raised SCE senior secured credit rating to BBB+ from BBB. On September 17, 2004, Moody's Investors Service assigned SCE a short-term credit rating of P2 in connection with SCE's launch of a new $700 million commercial paper program. Standard and Poor's had previously issued SCE a short-term credit rating of A2. As of December 31, 2004, SCE had $88 million in commercial paper outstanding.

As of December 31, 2004, SCE had cash and equivalents of $122 million ($90 million relates to cash held by SCE's consolidated Variable Interest Entities (VIEs)). As of December 31, 2004, long-term debt, including current maturities of long-term debt, was $5.5 billion. As of December 31, 2004, SCE posted approximately $75 million ($65 million in cash and $10 million in letters of credit) as collateral to secure its obligations under power-purchase contracts and to transact through the ISO for imbalance energy. SCE's collateral requirements can vary depending upon the level of unsecured credit extended by counterparties, the ISO's credit requirements, changes in market prices relative to contractual commitments, and other factors. At December 31, 2004, SCE had a $700 million senior secured credit facility with an expiration date of December 2006. The credit facility was not utilized, except for $98 million supporting the commercial paper outstanding and the letters of credit as mentioned above. Subsequently, in February 2005, the $700 million credit facility was replaced with a $1.25 billion senior secured 5-year revolving credit facility. As of February 28, 2005, SCE's new credit facility supported $306 million of commercial paper outstanding and $10 million in letters of credit, leaving $934 million available under its credit facility.

SCE's 2005 estimated cash outflows consist of:

- Approximately $246 million of rate reduction notes that are due at various times in 2005, but which have a separate cost recovery mechanism approved by state legislation and CPUC decisions;
- Projected capital expenditures primarily to replace and expand distribution and transmission infrastructure and construct and replace generation assets;
- Dividend payments to SCE's parent company;
- Fuel and procurement-related costs; and
- General operating expenses.

SCE expects to meet its continuing obligations, including cash outflows for power-procurement undercollections (if incurred), through cash and equivalents on hand, operating cash flows and short-term borrowings, when necessary. Projected capital expenditures are expected to be financed through cash flows and the issuance of long-term debt and preferred stock.

In December 1997, $2.5 billion of rate reduction notes were issued on behalf of SCE by SCE Funding LLC, a special purpose entity. These notes were issued to finance the 10% rate reduction mandated by state law. The proceeds of the rate reduction notes were used by SCE Funding LLC to purchase from SCE an enforceable right known as transition property. Transition property is a current property right

created by the restructuring legislation and a financing order of the CPUC and consists generally of the right to be paid a specified amount from nonbypassable rates charged to residential and small commercial customers. The rate reduction notes are being repaid over 10 years through these nonbypassable residential and small commercial customer rates, which constitute the transition property purchased by SCE Funding LLC. The notes are collateralized by the transition property and are not collateralized by, or payable from, assets of SCE or Edison International. SCE used the proceeds from the sale of the transition property to retire debt and equity securities. Although, as required by accounting principles generally accepted in the United States, SCE Funding LLC is consolidated with SCE and the rate reduction notes are shown as long-term debt in the consolidated financial statements, SCE Funding LLC is legally separate from SCE. The assets of SCE Funding LLC are not available to creditors of SCE or Edison International and the transition property is legally not an asset of SCE or Edison International.

SCE is experiencing significant growth in actual and planned capital expenditures to replace and expand its distribution and transmission infrastructure and construct and replace generation assets. In 2004, SCE spent $2.0 billion, including the acquisition and construction of the Mountainview project. SCE expects its capital expenditures to be $1.6 billion, $1.8 billion and $1.9 billion in 2005, 2006 and 2007, respectively. In the 2003 GRC the CPUC approved nearly all of SCE's requested capital spending for the 2003 through 2005 period. SCE is seeking regulatory approval, in its 2006 GRC, to continue its infrastructure program for the 2006 through 2009 period.

The CPUC regulates SCE's capital structure and limits the dividends it may pay Edison International (see "Edison International (Parent): Liquidity" for further discussion). In SCE's most recent cost of capital proceeding, the CPUC set an authorized capital structure for SCE which included a common equity component of 48%. SCE determines compliance with this capital structure based on a 13-month weighted-average calculation. At December 31, 2004, SCE's 13-month weighted-average common equity component of total capitalization was 50.5%. At December 31, 2004, SCE had the capacity to pay $222 million in additional dividends based on the 13-month weighted-average method. Based on recorded December 31, 2004 balances, SCE's common equity to total capitalization ratio, for rate-making purposes, was 50.4%. SCE had the capacity to pay $213 million of additional dividends to Edison International based on December 31, 2004 recorded balances. The CPUC has authorized SCE to increase the amount of preferred stock in its authorized capital structure from 5% to 9% of total capitalization. Correspondingly, SCE will use the proceeds to fund capital expenditures. The exact amount and timing of such issuances is dependent upon many factors, including market conditions.

In January 2005, SCE issued $650 million of first and refunding mortgage bonds. The issuance included $400 million of 5% bonds due in 2016 and $250 million of 5.55% bonds due in 2036. The proceeds were used to redeem the remaining $50,000 of 8% first and refunding mortgage bonds due February 2007 (Series 2003A) and $650 million of the $966 million 8% first and refunding mortgage bonds due February 2007 (Series 2003B).

SCE has debt covenants that require certain interest coverage, interest and preferred dividend coverage, and debt to total capitalization ratios to be met. At December 31, 2004, SCE was in compliance with these debt covenants.

SCE's liquidity may be affected by, among other things, matters described in "SCE: Regulatory Matters."

SCE: MARKET RISK EXPOSURES

SCE's primary market risks include fluctuations in interest rates, commodity prices and volume, and counterparty credit. Fluctuations in interest rates can affect earnings and cash flows. However, fluctuations in commodity prices and volumes and counterparty credit losses temporarily affect cash flows, but should not affect earnings due to recovery through regulatory mechanisms. SCE uses

derivative financial instruments to manage its market risks, but prohibits the use of these instruments for speculative purposes.

Interest Rate Risk

SCE is exposed to changes in interest rates primarily as a result of its borrowing and investing activities used for liquidity purposes and to fund business operations, as well as to finance capital expenditures. The nature and amount of SCE's long-term and short-term debt can be expected to vary as a result of future business requirements, market conditions and other factors. In addition, SCE's authorized return on common equity (11.6% for 2004 and 11.4% for 2005), which is established in SCE's annual cost of capital proceeding, is set on the basis of forecasts of interest rates and other factors.

At December 31, 2004, SCE did not believe that its short-term debt and current portion of long-term debt and preferred stock was subject to interest rate risk, due to the fair market value being approximately equal to the carrying value.

At December 31, 2004, the fair market value of SCE's long-term debt was $5.6 billion. A 10% increase in market interest rates would have resulted in a $186 million decrease in the fair market value of SCE's long-term debt. A 10% decrease in market interest rates would have resulted in a $206 million increase in the fair market value of SCE's long-term debt. At December 31, 2004, the fair market value of SCE's preferred stock subject to mandatory redemption was $140 million. A 10% increase and decrease in market interest rates would have resulted in a $2 million decrease and increase, respectively, in the fair market value of SCE's preferred stock subject to mandatory redemption.

Commodity Price Risk

In 2004, SCE's purchased-power expense was approximately 36% of SCE's total operating expenses. SCE recovers its reasonable power procurement costs through regulatory mechanisms established by the CPUC. The California Public Utilities Code provides that the CPUC shall adjust rates, or order refunds, to amortize undercollections or overcollections of power procurement costs. Under a trigger mechanism, the CPUC must adjust rates if the undercollection or overcollection exceeds 5% of SCE's prior year's procurement costs, excluding revenue collected for the CDWR. The CPUC issued a decision on December 16, 2004, that keeps the trigger mechanism in effect during the term of long-term contracts, or 10 years, whichever is longer. As a result of these regulatory mechanisms, changes in energy prices may impact SCE's cash flows but should have no impact on earnings.

On January 1, 2003, SCE resumed power procurement responsibilities for its customers. SCE forecasts that it will have a net-long position (generation supply exceeds expected load requirements) in the majority of hours during 2005. SCE's net-long position arises primarily from "must-take" deliveries under CDWR contracts allocated to SCE's customers. SCE has incorporated a 2005 price and volume forecast from expected sales of net-long power in its 2005 revenue forecast used for setting rates. If actual prices or volumes vary from forecast, SCE's cash flow would be temporarily impacted, but should not affect earnings. For 2006, SCE forecasts that it will have a net-short position (expected load requirements exceed generation supply) at certain times. SCE's forecast net-short position increases from year-to-year, assuming no new generation supply is added, as existing contracts expire, SCE generating plants retire, and load grows. However, the CPUC has set resource adequacy requirements which require SCE to acquire and demonstrate enough generating capacity in its portfolio for a planning reserve margin of 15–17% above its peak load as forecast for an average year (see "SCE: Regulatory Matters—Generation and Power Procurement—Generation Procurement Proceedings"). Accordingly, SCE anticipates continued generation contracting over time to maintain the minimum reserve margin. The establishment of a sufficient planning reserve margin mitigates, to some extent, several conditions that could increase SCE's net-short position, including lower utility generation due to expected or unexpected outages or plant closures, lower deliveries under third-party power contracts, or higher than anticipated

demand for electricity. However, SCE's planning reserve margin may not be sufficient to supply the needs of all returning direct access customers (customers who choose to purchase power directly from an electric service provider other than SCE but then decide to return to utility service). Increased procurement costs resulting from the return of direct access customers could lead to temporary undercollections and the need to increase rates.

SCE anticipates purchasing additional capacity and/or ancillary services to meet its peak-energy requirements in 2005 and beyond if its net-short position is significantly higher than SCE's current forecast. As of December 31, 2004, SCE entered into power tolling arrangement and forward physical contracts to mitigate its exposure to energy prices in the spot market. The fair market value of the power tolling arrangements as of December 31, 2004, was a liability of $6 million. A 10% increase in energy prices would have resulted in a $49 million increase in the fair market value. A 10% decrease in energy prices would have resulted in a $37 million decrease in the fair market value. The fair market value of the forward physical contracts as of December 31, 2004, was an asset of $8 million. A 10% increase in energy prices would have resulted in a $1 million increase in the fair market value. A 10% decrease in energy prices would have resulted in a $2 million decrease in the fair market value.

SCE is also exposed to increases in natural gas prices related to its QF contracts, fuel tolling arrangements, and owned gas-fired generation, including the Mountainview project (expected to be on-line in 2006). SCE purchases power from QFs under CPUC -mandated contracts. Contract energy prices for most nonrenewable QFs are based in large part on the monthly southern California border price of natural gas. In addition to the QF contracts, SCE has power contracts in which SCE has agreed to provide the natural gas needed for generation under those power contracts, which are known as fuel tolling arrangements. SCE has an active gas fuel hedging program in place to minimize ratepayer exposure to spot market price spikes. However, movements in gas prices over time will impact SCE's gas costs and the cost of QF power which is related to natural gas prices.

As of December 31, 2004, SCE entered into gas forward transactions including options, swaps and futures, and fixed price contracts to mitigate its exposure related to the QF contracts and fuel tolling arrangements. The fair market value of the forward transactions as of December 31, 2004, was a liability of $11 million. A 10% increase in gas prices would have resulted in a $21 million increase in the fair market value. A 10% decrease in gas prices would have resulted in a $21 million decrease in the fair market value. SCE cannot predict with certainty whether in the future it will be able to hedge customer risk for other commodities on favorable terms or that the cost of such hedges will be fully recovered in rates.

SCE's gas expenses and gas hedging costs, as well as its purchased-power costs, are recovered through a balancing account known as the Energy Resource Recovery Account (ERRA). To the extent SCE conducts its power and gas procurement activities in accordance with its CPUC-authorized procurement plan, California statute (Assembly Bill 57) establishes that SCE is entitled to full cost recovery. Certain SCE activities, such as contract administration, SCE's duties as CDWR's limited agent for allocated CDWR contracts, and portfolio dispatch, are reviewed annually by the CPUC for reasonableness. The CPUC has currently established a maximum disallowance cap of $37 million for these activities.

Pursuant to CPUC decisions, SCE, as the CDWR's limited agent, performs certain services for CDWR contracts allocated to SCE by the CPUC, including arranging for natural gas supply. Financial and legal responsibility for the allocated contracts remains with the CDWR. The CDWR, through coordination with SCE, has hedged a portion of its expected natural gas requirements for the gas tolling contracts allocated to SCE. Increases in gas prices over time, however, will increase the CDWR's gas costs. California state law permits the CDWR to recover its actual costs through rates established by the CPUC. This would affect rates charged to SCE's customers, but would not affect SCE's earnings or cash flows.

Quoted market prices, if available, are used for determining the fair value of contracts, as discussed above. If quoted market prices are not available, internally maintained standardized or industry accepted models are used to determine the fair value. The models are updated with spot prices, forward prices, volatilities and interest rates from regularly published and widely distributed independent sources.

Credit Risk

Credit risk arises primarily due to the chance that a counterparty under various purchase and sale contracts will not perform as agreed or pay SCE for energy products delivered. SCE uses a variety of strategies to mitigate its exposure to credit risk. SCE's risk management committee regularly reviews procurement credit exposure and approves credit limits for transacting with counterparties. Some counterparties are required to post collateral depending on the creditworthiness of the counterparty and the risk associated with the transaction. SCE follows the credit limits established in its CPUC-approved procurement plan, and accordingly believes that any losses which may occur should be fully recoverable from customers, and therefore should not affect earnings.

SCE: REGULATORY MATTERS

This section of the MD&A describes SCE's regulatory matters in three main subsections:

- generation and power procurement;
- transmission and distribution; and
- other regulatory matters.

Generation and Power Procurement

CPUC Litigation Settlement Agreement

In October 2001, SCE and the CPUC entered into a settlement of SCE's lawsuit against the CPUC which sought full recovery of its electricity procurement costs incurred during the energy crisis. A key element of the 2001 CPUC settlement agreement was the establishment of a $3.6 billion regulatory balancing account, called the Procurement-Related Obligations Account (PROACT), as of August 31, 2001 (which was fully recovered by August 2003).

Energy Resource Recovery Account Proceedings

In an October 2002 decision, the CPUC established the ERRA as the rate-making mechanism to track and recover SCE's: (1) fuel costs related to its generating stations; (2) purchased-power costs related to cogeneration and renewable contracts; (3) purchased-power costs related to existing interutility and bilateral contracts that were entered into before January 17, 2001; and (4) new procurement-related costs incurred on or after January 1, 2003 (the date on which the CPUC transferred back to SCE the responsibility for procuring energy resources for its customers). As described in "SCE: Management Overview—Background," SCE recovers these costs on a cost-recovery basis, with no markup for return or profit. SCE files annual forecasts of the above-described costs that it expects to incur during the following year. As these costs are subsequently incurred, they will be tracked and recovered through the ERRA, but are subject to a reasonableness review in a separate annual ERRA application. If the ERRA overcollection or undercollection exceeds 5% of SCE's prior year's procurement costs, SCE can request an emergency rate adjustment in addition to the annual forecast and reasonableness ERRA applications.

2004 ERRA Forecast

SCE submitted an ERRA forecast application on October 3, 2003, in which it forecast a procurement-related revenue requirement for the 2004 calendar year of $2.3 billion. The CPUC issued a decision on April 22, 2004, approving SCE's 2004 forecast revenue requirement and rates for both generation and distribution services.

ERRA Reasonableness Review for the Period September 1, 2001 through June 30, 2003

On October 3, 2003, SCE submitted its first ERRA reasonableness review application requesting that the CPUC find its procurement-related operations during the period from September 1, 2001 through June 30, 2003 to be reasonable. The CPUC's Office of Ratepayer Advocates (ORA) was allowed to review the accounting calculations used in the PROACT mechanism. The ORA recommended disallowances that totaled approximately $14 million of costs recovered through the PROACT mechanism during the period from September 1, 2001 through June 30, 2003. In April 2004, SCE reached an agreement with the ORA (subject to CPUC approval) to reduce the PROACT disallowances to approximately $4 million. On January 27, 2005, the CPUC issued a decision approving the agreement. The $4 million, which is mainly comprised of ISO grid management charges and employee-related retraining costs, will be refunded to ratepayers through a credit to the ERRA.

The January 27, 2005 CPUC decision also provides that SCE's administration of its procurement contracts will be subject to reasonableness review under the "reasonable manager" standard. However, the CPUC decision provides that the review of SCE's daily dispatch of its generation resources will be subject to a compliance review, not a reasonableness review, and will only include a review of spot market transactions in the day-ahead, hour-ahead and real-time markets. The decision found that SCE's daily dispatch decisions during the record period complied with the CPUC's standard, and that its administration of its contracts was reasonable in all respects. It authorized recovery of amounts paid to Peabody Coal Company for costs associated with the Mohave mine closing as well as transmission costs related to serving municipal utilities, and also resolved outstanding issues from 2000 and 2001 related to CDWR costs. As a result of this decision, SCE recorded a pre-tax net regulatory gain of $118 million in 2004.

ERRA Reasonableness Review for the Period July 1, 2003 through December 31, 2003

On April 1, 2004, SCE submitted its second ERRA reasonableness review application requesting that the CPUC find its procurement-related operations during the period from July 1, 2003 through December 31, 2003, to be reasonable. In addition, SCE requested recovery of a $10 million reward for Palo Verde Nuclear Generating Station (Palo Verde) Unit 3 efficient operation and $5 million in electric energy transaction administration costs.

On January 17, 2005, the CPUC issued a decision finding that SCE's administration of its power purchase agreements and its daily decisions dispatching its procurement resources were reasonable and prudent. The decision also found that the revenue and expenses recorded in SCE's ERRA account during the record period were reasonable and prudent, and approved SCE's requested recovery of the items discussed above.

2005 ERRA Forecast

SCE submitted an ERRA forecast application on August 2, 2004, in which it forecasted a procurement-related revenue requirement for the 2005 calendar year of $3.0 billion, an increase of $733 million over 2004. The forecast increase is primarily due to a reduction in expected power purchases by the CDWR. On February 2, 2005, the CPUC issued a proposed decision adopting SCE's requested revenue requirement for the 2005 calendar year. A final decision is expected in March 2005.

CDWR Power Purchases and Revenue Requirement Proceedings

In accordance with an emergency order by the Governor of California, the CDWR began making emergency power purchases for SCE's customers on January 17, 2001. In February 2001, a California law was enacted which authorized the CDWR to: (1) enter into contracts to purchase electric power and sell power at cost directly to SCE's retail customers; and (2) issue bonds to finance those electricity purchases. The CDWR's total statewide power charge and bond charge revenue requirements are allocated by the CPUC among the customers of SCE, Pacific Gas and Electric (PG&E) and San Diego Gas & Electric (SDG&E) (collectively, the investor-owned utilities). Amounts billed to SCE's customers for electric power purchased and sold by the CDWR (approximately $2.5 billion in 2004) are remitted directly to the CDWR and are not recognized as revenue by SCE and therefore have no impact on SCE's earnings.

In December 2004, the CPUC issued its decision on how the CDWR's power charge revenue requirement for 2004 through 2013, when the last CDWR contract expires, will be allocated among the investor-owned utilities. The CPUC rejected a settlement agreement among PG&E, the Utility Reform Network (TURN), and SCE and which the ORA supported. However, the CPUC's final decision adopts key attributes of that settlement agreement. It adopts a cost-follows-contract allocation to each of the investor-owned utilities of the unavoidable portion of costs incurred under CDWR contracts. A previous CPUC decision allocated the avoidable portion of the costs on a cost-follows-contract basis. Allocating the avoidable and unavoidable portions on a cost-follows-contract basis provides the investor-owned utilities the appropriate incentives to operate and administer the contracts that have been allocated to them. In addition, in order to fairly allocate the total burden of the CDWR contracts among the investor-owned utilities, the decision adjusts the cost-follows-contract allocation of the total costs (avoidable and unavoidable) such that the above-market cost burden associated with the contracts is allocated as follows: 44.8% to PG&E's customers, 45.3% to SCE's customers, and 9.9% to SDG&E's customers. The CPUC's December 2004 decision is based on the above market cost analysis that SCE presented in its initial testimony in December 2003.

In response to an application filed by SDG&E, the CPUC issued an order granting limited rehearing of the December 2004 decision. The rehearing permits parties to present alternative methodologies and updated data for the calculation of above market costs associated with the CDWR contracts. A schedule has not been adopted for the rehearing, but it is expected to take place in the second quarter of 2005. SDG&E has also filed a petition for modification of the decision urging the CPUC to replace the adopted methodology with a methodology that would retain the cost-follows-contract allocation of the avoidable costs, but would allocate the unavoidable costs associated with the contracts: 42.2% to PG&E's customers, 47.5% to SCE's customers, and 10.3% to SDG&E's customers. Such an allocation would decrease the total costs allocated to SDG&E's customers and increase the total costs allocated to SCE's customers. The CPUC is expected to act on the petition in March 2005.

Direct Access and Community Choice Aggregation

From 1998 through mid-September 2001, SCE's customers were able to choose to purchase power directly from an electric service provider other than SCE (thus becoming direct access customers) or continue to purchase power from SCE. In September 2001, the CPUC suspended the right of retail end-use customers to acquire direct access service until the CDWR no longer procures power for retail end-user customers. In addition, a 2002 California law authorized community choice aggregation which is a form of direct access that allows local governments to combine the loads of its residents, businesses, and municipal facilities in a community-wide electricity buyers program and to create an entity called a community choice aggregator.

As a result of these customer options, the CPUC issued decisions or opened proceedings to establish various charges (exit fees) for customers who (1) switch to another electric service provider, (2) switch to a municipal utility; or (3) install onsite generation facilities or arrange to purchase power from another entity that installs such facilities. Separately, the CPUC opened a proceeding to identify issues relating to the implementation of community choice aggregation and adopted a similar exit fee approach for customers who switch to community choice aggregation service. The charges recovered from these customers are used to reduce SCE's rates to bundled service customers and have no impact on earnings. These decisions and proceedings affect SCE's ability to predict the size of its customer base, the amount of bundled service load for which it must procure or generate electricity, its net-short position, and its ability to plan for resource requirements.

Generation Procurement Proceedings

SCE resumed power procurement responsibilities for its net-short position (expected load requirements exceed generation supply) on January 1, 2003, pursuant to CPUC orders and California statutes passed in 2002. The current regulatory and statutory framework requires SCE to assume limited responsibilities for CDWR contracts allocated by the CPUC, and provide full power procurement responsibilities on the basis of annual short-term procurement plans, long-term resource plans and increased procurement of renewable resources. Currently, the CPUC and the California Energy Commission are working together to set rules for various aspects of generation procurement which are described below.

Procurement Plan

Resource Planning Component of the Procurement Plan

On April 1, 2004, the CPUC instituted a resource planning proceeding that, among other things, will coordinate consideration of long-term resource plans. On July 9, 2004, SCE filed testimony on its long-term procurement plan, which includes a substantial commitment to cost-effective energy efficiency and an advanced load-control program. A CPUC decision approving SCE's long-term procurement plan was issued in December 2004. The decision required all long-term procurement to be conducted through all-source solicitations; allowed the consideration of debt equivalence in the bid evaluation process; and required the use of a greenhouse gas adder as a bid evaluation component. The decision also extended the utilities' authority to procure longer-term products and lifted the affiliate ban on long-term power products. SCE's next long-term procurement plan will be filed in 2006.

Assembly Bill 57 Component of the Procurement Plan

In December 2003, the CPUC adopted a 2004 short-term procurement plan for SCE which established a target level for spot market purchases equal to 5% of monthly need, and allowed SCE to enter into contracts of up to five years. Currently, SCE is operating under this approved short-term procurement plan. To the extent SCE procures power in accordance with the plan, SCE receives full-cost recovery of its procurement transactions pursuant to Assembly Bill 57. Accordingly, the plan is referred to as the Assembly Bill 57 component of the procurement plant.

Each quarter, SCE is required to file a report with the CPUC demonstrating that SCE's procurement-related transactions associated with serving the demands of its bundled electricity customers were in conformance with SCE's adopted short-term procurement plan. SCE has submitted seven quarterly compliance filings covering the period from January 1, 2003 through September 30, 2004, including its third quarter 2004 compliance filing on November 1, 2004. To date, however, the CPUC has only issued one resolution approving SCE's first compliance report for the period January 1, 2003 to March 31, 2003. While SCE believes that all of its procurement transactions were in compliance with its adopted short-term procurement plan, SCE cannot predict with certainty whether or not the CPUC will agree with SCE's interpretation regarding some elements.

Resource Adequacy Requirements

Under the framework adopted in the CPUC's January 22, 2004 decision, all load-serving entities in California have an obligation to procure sufficient resources to meet their customers' needs. On October 28, 2004, the CPUC issued a decision clarifying the January 2004 decision. The October 2004 decision requires load-serving entities to ensure that adequate resources have been contracted to meet that entity's peak forecasted energy resource demand and an additional planning reserve margin of 15-17% of that peak load by June 1, 2006. Currently, the decision requires SCE to demonstrate that it has contracted 90% of its May–September 2006 resource adequacy requirement by September 30, 2005. As the May-September period approaches, SCE will be required to fill out the remaining 10% of its resource adequacy requirement one month in advance of expected need. The October 28, 2004 decision also clarified that although the first compliance filing will only cover May–September 2006, the 15–17% planning reserve margin is a year-round requirement. In its October 2004 decision, the CPUC also decided that long-term CDWR contracts allocated to the investor-owned utilities during the 2001 energy crisis are to be fully counted for resource adequacy purposes, and that deliverability standards developed during subsequent phases will be applied to such contracts. These deliverability standards, as well as a wide range of other issues, including scheduling and load forecasting, will be addressed in a separate phase of the proceeding which is expected to be completed by mid-2005. SCE expects to meet its resource adequacy requirements by the deadlines set forth in the decision.

Avoided Cost Proceeding

SCE purchases electric energy and capacity from various QFs pursuant to contracts that provide for payment at avoided cost, as determined by the CPUC. On April 22, 2004, the CPUC opened a rulemaking to develop, review and update methodologies for determining avoided costs, including the methodologies SCE uses to pay its QFs. Among other things, the rulemaking is to consider modifications to the current methodology for short-run avoided cost energy pricing and the current as-available capacity pricing. The rulemaking also proposes to develop a long-run avoided cost pricing methodology for QFs. Hearings are scheduled for May 2005. Although the rulemaking may affect the amounts paid to QFs and customer rates, changes to pricing methodology should not affect SCE's earnings as such costs are recovered from ratepayers, subject to reasonableness review.

Extension of QF Contracts and New QF Contracts

SCE has 270 power-purchase contracts with QFs, a number of which will expire in the next five years. On September 30, 2004, the CPUC issued a ruling requesting proposals and comments on the development of a long-term policy for expiring QF contracts and new QFs. SCE filed its response to the ruling on November 10, 2004, in which it proposed to purchase electricity from QFs by (1) allowing QFs to compete in SCE's competitive solicitations; (2) conducting bilateral negotiations for new contracts or contract extensions with QFs; or (3) offering an energy-only contract at market-based avoided cost prices. Hearings are scheduled for May 2005.

Procurement of Renewable Resources

As part of SCE's resumption of power procurement, and in accordance with a California statute passed in 2002, SCE is required to increase its procurement of renewable resources by at least 1% of its annual electricity sales per year so that 20% of its annual electricity sales are procured from renewable resources by no later than December 31, 2017. At year-end 2004, SCE obtained approximately 18% of its power supplies from renewable resources. In June 2003, the CPUC issued a decision adopting preliminary rules and guidance on renewable procurement-related issues, including penalties for noncompliance with renewable procurement targets. In June 2004, the CPUC issued two decisions adopting additional rules on renewable procurement: a decision adopting standard contract terms and conditions and a decision

adopting a market-price methodology. In July 2004, the CPUC issued a decision adopting criteria for the selection of least-cost and best-fit renewable resources. In December 2004, an assigned commissioner's ruling and scoping memo was issued establishing a schedule for addressing various renewable procurement-related issues that were not resolved by prior rulings and decision and directing the utilities to file renewable procurement plans addressing their 2005 renewable procurement goals and a plan for renewable procurement over the period 2005–2014. SCE's 2005 renewable procurement plan was filed on March 7, 2005.

SCE received bids for renewable resource contracts in response to a solicitation it made in August 2003 and conducted negotiations with bidders regarding potential procurement contracts. On March 8, 2005, SCE filed an advice letter with the CPUC requesting approval of 6 renewable contracts. SCE expects a CPUC decision on its advice letter by the second quarter of 2005. The procedures for measuring renewable procurement are still being developed by the CPUC. Based upon the current regulatory framework, SCE anticipates that it will comply, even without new renewable procurement contracts, with renewable procurement mandates through at least 2005. Beyond 2005, SCE will either need to sign new contracts and/or extend existing renewable QF contracts.

CDWR Contract Allocation and Operating Order

The CDWR power-purchase contracts entered into as a result of the California energy crisis have been allocated on a contract-by-contract basis among SCE, PG&E and SDG&E, in accordance with a 2002 CPUC decision. SCE only assumes scheduling and dispatch responsibilities and acts only as a limited agent for the CDWR for contract implementation. Legal title, financial reporting and responsibility for the payment of contract-related bills remain with the CDWR. The allocation of CDWR contracts to SCE significantly reduces SCE's residual-net short and also increases the likelihood that SCE will have excess power during certain periods. SCE has incorporated CDWR contracts allocated to it in its procurement plans. Wholesale revenue from the sale of excess power, if any, is prorated between the CDWR and SCE.

SCE's maximum annual disallowance risk exposure for contract administration, including administration of allocated CDWR contracts and least cost dispatch of CDWR contract resources, is $37 million. In addition, gas procurement, including hedging transactions, associated with CDWR contracts is included within the cap.

On January 28, 2005, the CPUC opened a new phase of its procurement proceeding to consider the reallocation of certain CDWR contracts. Evidentiary hearings may be held later this year.

Mohave Generating Station and Related Proceedings

On May 17, 2002, SCE filed an application with the CPUC to address certain issues (mainly coal and slurry-water supply issues) facing any future extended operation of Mohave, which is partly owned by SCE. Mohave obtains all of its coal supply from the Black Mesa Mine in northeast Arizona, located on lands of the Navajo Nation and Hopi Tribe (the Tribes). This coal is delivered from the mine to Mohave by means of a coal slurry pipeline, which requires water from wells located on lands belonging to the Tribes in the mine vicinity.

Due to the lack of progress in negotiations with the Tribes and other parties to resolve several coal and water supply issues, SCE's application stated that SCE would probably be unable to extend Mohave's operation beyond 2005. The uncertainty over a post-2005 coal and water supply has prevented SCE and other Mohave co-owners from making approximately $1.1 billion in Mohave-related investments (SCE's share is $605 million), including the installation of enhanced pollution-control equipment that must be put in place in order for Mohave to continue to operate beyond 2005, pursuant to a 1999 consent decree concerning air quality.

On December 2, 2004 the CPUC issued a final decision on the application. Principally, the decision: (1) directs SCE to continue the ongoing negotiations and other efforts toward resolving the post-2005 coal and water supply issues; (2) directs SCE to conduct a study of potential generation resources that might serve as alternatives or complements to Mohave including solar generation and coal gasification; (3) provides an opportunity for SCE to recover in future rates certain Mohave-related costs that SCE has already incurred or is expected to incur by 2006, including certain preliminary engineering costs, water study costs and the costs of the study of potential Mohave alternatives; and (4) authorizes SCE to establish a rate-making account to track certain worker protection-related costs that might be incurred in 2005 in preparation for a temporary or permanent Mohave shutdown after 2005.

In parallel with the CPUC proceeding, negotiations have continued among the relevant parties in an effort to resolve the coal and water supply issues. Since November 2004, the parties have engaged in negotiations facilitated by a professional mediator, but no final resolution has been reached. In addition, agencies of the federal government are now conducting both a hydro-geological study and an environmental review regarding a possible alternative groundwater source for the slurry water; these studies, projected to cost approximately $6 million, are being funded by SCE and the other Mohave co-owners subject to the terms and conditions of a 2004 memorandum of understanding among the Mohave co-owners, the Tribes and the federal government.

The outcome of the coal and water negotiations and SCE's application are not expected to impact Mohave's operation through 2005, but the presence or absence of Mohave as an available resource beyond 2005 will impact SCE's long-term resource plan. The outcome of this matter is not expected to have a material impact on earnings.

For additional matters related to Mohave, see "SCE: Other Developments—Navajo Nation Litigation."

In light of the issues discussed above, in 2002 SCE concluded that it was probable Mohave would be shut down at the end of 2005. Because the expected undiscounted cash flows from the plant during the years 2003–2005 were less than the $88 million carrying value of the plant as of December 31, 2002, SCE incurred an impairment charge of $61 million in 2002. However, in accordance with accounting standards for rate-regulated enterprises, this incurred cost was deferred and recorded in regulatory assets as a long-term receivable to be collected from customer revenue. This treatment was based on SCE's expectation that any unrecovered book value at the end of 2005 would be recovered in future rates (together with a reasonable return) through a balancing account mechanism, as presented in its May 17, 2002 application and discussed in its supplemental testimony filed in January 2003.

San Onofre Nuclear Generating Station

San Onofre Steam Generators

Like other nuclear power plants with steam generators of the same design and material properties, San Onofre Units 2 and 3 have experienced degradation in their steam generators. Based on industry experience and analysis of recent inspection data, SCE has determined that the existing San Onofre Units 2 and 3 steam generators may not enable continued reliable operation of the units beyond their scheduled refueling outages in 2009–2010. SCE currently estimates that the cost of replacing the steam generators would be about $680 million, of which SCE's 75% share would be about $510 million. On February 27, 2004, SCE filed an application with the CPUC seeking a decision that it is reasonable for SCE to replace the San Onofre Units 2 and 3 steam generators and establishing appropriate ratemaking for recovery in rates of the reasonable cost of the replacement project. In June 2004, the CPUC established a schedule providing for a final CPUC decision in September 2005. Evidentiary hearings were held between January 31, 2005, and February 11, 2005.

The ORA has proposed that the CPUC disallow recovery of between 28.75% and 32.5% of the costs of steam generator replacement project costs or, in the alternative, require SCE to bear an equivalent percentage of the assumed replacement power costs if the steam generator replacement does not go forward and, as a result, San Onofre Units 2 and 3 experience reduced or suspended periods of operation in the future. ORA contends that SCE should incur one of these alternative consequences due to its alleged imprudence in failing to pursue claims against the manufacturer of the steam generators or its successors and/or in providing a broader release to the manufacturer than was allegedly appropriate. Assuming currently estimated project costs, including construction financing costs, a 32.5% proposed disallowance could be about $260 million. SCE is vigorously opposing ORA's proposed disallowance as unwarranted and confiscatory. TURN has also recommended that the CPUC find SCE's failure to pursue claims against the steam generator manufacturer and providing a broader release to the manufacturer than was allegedly appropriate to be unreasonable. However, TURN has not recommended that the CPUC adopt a specific disallowance amount. A CPUC decision on the proposed disallowance is expected at the same time as the CPUC's decision on SCE's application for steam generator replacement.

On September 30, 2004, SCE entered into a contract for steam generator fabrication. By the time of the CPUC's scheduled decision in September 2005, SCE anticipates that it will have incurred approximately $50 million in steam generator fabrication and associated project costs. SCE will seek recovery of these costs in the event that the CPUC does not authorize SCE to go forward with steam generator replacement. If the CPUC authorizes SCE to go forward with steam generator replacement, SCE will recover all of these costs that are reasonably incurred as part of the steam generator replacement capital costs.

Under the San Onofre operating agreement among the co-owners, a co-owner may elect to reduce its ownership share in lieu of paying its share of the cost of repairing an "operating impairment," as such term is defined in the San Onofre operating agreement. SCE has declared an "operating impairment" in connection with the need for steam generator replacement. SDG&E and the City of Anaheim have elected to reduce their respective 20% and 3.16% ownership shares rather than participate in the steam generator replacement project. The other co-owner, the City of Riverside (which owns 1.79% of the units), has elected to participate in the project. If steam generator replacement proceeds, SDG&E's and the City of Anaheim's ownership shares of San Onofre Units 2 and 3 will, upon completion of the project, be reduced in accordance with the formula set forth in the operating agreement. Under the formula, the City of Anaheim's share of San Onofre Units 2 and 3 will be reduced to zero percent. SDG&E disputed the proper application of the formula. As a result, the matter was subject to arbitration. The arbitrator's decision was issued on February 18, 2005. Assuming the cost of steam generator replacement is not significantly lower than currently estimated, under the arbitrator's decision, SDG&E's ownership share would also be reduced to zero percent under the arbitrator's decision. Under the terms of the operating agreement, the decision of the arbitrator is subject to approval by the CPUC. The transfer of all or any portion of SDG&E's and the City of Anaheim's respective ownership share as a result of their election not to participate in steam generator replacement will require Nuclear Regulatory Commission approval. The transfer of all or any portion of SDG&E's ownership share to SCE will also require CPUC approval.

San Onofre Reactor Vessel Heads

During the ongoing San Onofre Unit 3 refueling outage in the fourth quarter of 2004, SCE conducted a planned inspection of the Unit 3 reactor vessel head and found indications of degradation. Although the indications were far below the level at which leakage would occur, SCE repaired these indications using readily available tooling and a Nuclear Regulatory Commission-approved repair technique. While this was San Onofre's first experience of this kind of degradation to the reactor vessel head, the detection and repair of similar degradation is now common in the industry. SCE plans to replace the Unit 2 and 3 reactor vessel heads during the planned refueling outages in 2009–2010.

San Onofre Pressurizer Heater Sleeve Replacement

San Onofre Units 2 and 3 each include a pressurizer tank that contains 30 heater penetrations fabricated from the same material used in the steam generator tubes. These penetrations, also known as sleeves, are 13-inch long sections of pipe welded into the bottom of the pressurizer. During the recent Unit 3 outage, SCE performed inspections of two sleeves and found evidence of degradation. Degradation of the pressurizer sleeves has been a concern in the nuclear industry for some time, and SCE had been planning to replace all of the sleeves in both units during their next scheduled refueling outages in 2005 and 2006, respectively. With the discovery of sleeve degradation, SCE decided to move the planned replacement of 29 of the 30 Unit 3's sleeves forward from 2006 into the 2004 outage. This extra work extended the outage from 55 days to 92 days. This outage reduced the 2004 capacity factor of Unit 3 to 74%. The CPUC will review the reasonableness of outage-related capital costs and replacement power costs in future rate-making proceedings. SCE believes the costs are reasonable, recovery of the costs should be authorized, and the acceleration of the needed repairs should not impact earnings.

Palo Verde Steam Generators

The steam generators at the Palo Verde, in which SCE owns a 15.8% interest, have material properties that are similar to the San Onofre units. During 2003, the Palo Verde Unit 2 steam generators were replaced. In addition, the Palo Verde owners have approved the manufacture of two additional sets of steam generators for installation in Units 1 and 3. The Palo Verde owners expect that these steam generators will be installed in Unit 1 in 2005 and in Unit 3 in the 2007 to 2008 time frame. SCE's share of the costs of manufacturing and installing all the replacement steam generators at Palo Verde is estimated to be about $115 million; SCE expects to recover these costs through the rate-making process.

Inspections of Palo Verde Units 1, 2 and 3 reactor vessel heads were performed during scheduled refueling and maintenance outages in 2003 and 2004 and no indications of leakage or degradation were found.

Transmission and Distribution

2003 General Rate Case Proceeding

On May 3, 2002, SCE filed its application for a 2003 GRC, requesting an increase of $286 million in SCE's base rate revenue requirement, which was subsequently revised to an increase of $251 million. The application also proposed an estimated base rate revenue decrease of $78 million in 2004, and a subsequent increase of $116 million in 2005. The forecast reduction in 2004 was largely attributable to the expiration of the San Onofre incremental cost incentive pricing (ICIP) rate-making mechanism at year-end 2003 and a forecast of increased sales.

The CPUC issued a final decision on SCE's 2003 GRC application on July 8, 2004, authorizing an annual increase of approximately $73 million in base rates, retroactive to May 22, 2003 (the date a final CPUC decision was originally scheduled to be issued). The decision also authorized a base rate revenue decrease of $49 million in 2004, and a subsequent increase of $84 million in 2005. During the second quarter of 2004, SCE recorded a pre-tax net regulatory gain of $180 million as a result of the implementation of the 2003 GRC decision, primarily relating to the recognition of revenue from the rate recovery of pension contributions during the time period that the pension plan was fully funded, the resolution of the allocation of costs between transmission and distribution for 1998 through 2000, partially offset by the deferral of revenue previously collected during the ICIP mechanism for dry cask storage. The gain was included in the caption "provisions for regulatory adjustment clauses— net" on the income statement.

Because processing of the GRC took longer than initially scheduled, in May 2003, the CPUC approved SCE's request to establish a memorandum account to track the revenue requirement increase during the period between May 22, 2003 and the date a final decision was adopted. In July 2004, SCE submitted an advice filing to record the amount in this memorandum account and recorded an approximate $55 million pre-tax gain in the third quarter of 2004 included in the caption "electric utility revenue" on the income statement. In addition, during the third quarter of 2004 SCE recorded approximately $48 million in pre-tax gains related to the 1997–1998 generation-related capital additions ($31 million, which is included in the caption "provisions for regulatory adjustment clauses—net" on the income statement) and the related rate recovery ($17 million, which is included in the caption "electric utility revenue" on the income statement).

The amount recorded in the GRC memorandum account is being recovered in rates together with the 2004 revenue requirement authorized by the CPUC in the GRC decision. The GRC rate increase was combined with other rate changes from pending rate proceedings and became effective August 5, 2004.

2006 General Rate Case Proceeding

On December 21, 2004, SCE filed its application for a 2006 GRC, requesting an increase of $370 million in SCE's 2006 base rate revenue requirement, primarily for capital-related expenditures to accommodate customer and load growth and substantially higher operation and maintenance expenditures particularly in SCE's transmission and distribution business unit. SCE also requested that the CPUC authorize continuation of SCE's existing post-test year rate-making mechanism, which would result in base rate revenue increases of $159 million and $122 million in 2007 and 2008, respectively. If the CPUC approves these requested increases and allocates them to ratepayer groups on a system average percentage change basis, the total increase over current base rates is estimated to be 10%. A decision on SCE's 2006 GRC is expected in December 2005.

2005 Cost of Capital

SCE's annual cost of capital applications with the CPUC are required to be filed in May of each year, with decisions rendered in such proceedings becoming effective January 1 of the following year. On May 10, 2004, SCE filed an application requesting the CPUC to maintain for 2005 the currently authorized 11.60% return on common equity for SCE's CPUC-jurisdictional assets. SCE also requested a change in its authorized capital structure to offset the effects of debt equivalence of power-purchase agreements and revised SCE's projected costs of long-term debt and preferred stock. SCE's overall request projected a decrease in revenue requirements of approximately $28 million.

On December 16, 2004, the CPUC issued a final decision granting an 11.4% return on common equity and debt equivalent recognition through a higher preferred equity capitalization ratio. The decision resulted in a $47 million decrease in revenue requirements due to lower interest costs and the reduced return on equity and an overall rate of return of 9.07% on CPUC-jurisdictional assets.

Transmission Proceeding

In August and November 2002, the FERC issued opinions affirming a September 1999 administrative law judge decision to disallow, among other things, recovery by SCE and the other California public utilities of costs reflected in network transmission rates associated with ancillary services and losses incurred by the utilities in administering existing wholesale transmission contracts after implementation of the restructured California electric industry. SCE has incurred approximately $80 million of these unrecovered costs since 1998. After the three California utilities appealed the decisions to the United States Court of Appeals for the D.C. Circuit, the FERC filed a motion with the D.C. Circuit Court seeking voluntary remand to permit issuance of a further order. On February 12, 2004, the D.C. Circuit Court granted the FERC's motion and remanded the record back to the FERC for further consideration. On

May 6, 2004, the FERC issued its order reaffirming its earlier decisions. SCE and the other two California utilities are pursuing the appeal before the D.C. Circuit Court, and filed their opening briefs with the D.C. Circuit Court on October 12, 2004. Oral argument is set for May 9, 2005.

Wholesale Electricity and Natural Gas Markets

In 2000, the FERC initiated an investigation into the justness and reasonableness of rates charged by sellers of electricity in the California Power Exchange (PX) and ISO markets. On March 26, 2003, the FERC staff issued a report concluding that there had been pervasive gaming and market manipulation of both the electric and natural gas markets in California and on the West Coast during 2000–2001 and describing many of the techniques and effects of that market manipulation. SCE is participating in several related proceedings seeking recovery of refunds from sellers of electricity and natural gas who manipulated the electric and natural gas markets. Under the 2001 CPUC settlement agreement, mentioned in "—Generation and Power Procurement—CPUC Litigation Settlement Agreement," 90% of any refunds actually realized by SCE net of costs will be refunded to customers, except for the El Paso Natural Gas Company settlement agreement discussed below.

El Paso Natural Gas Company (El Paso) entered into a settlement agreement with a number of parties (including SCE, PG&E, the State of California and various consumer class action representatives) settling various claims stated in proceedings at the FERC and in San Diego County Superior Court that El Paso had manipulated interstate capacity and engaged in other anticompetitive behavior in the natural gas markets in order to unlawfully raise gas prices at the California border in 2000–2001. The United States District Court has issued an order approving the stipulated judgment and the settlement agreement has become effective. Pursuant to a CPUC decision, SCE will refund to customers amounts received under the terms of the El Paso settlement (net of legal and consulting costs) through its ERRA mechanism. In June 2004, SCE received its first settlement payment of $76 million. Approximately $66 million of this amount was credited to purchased-power expense, and will be refunded to SCE's ratepayers through the ERRA over the next 12 months, and the remaining $10 million was used to offset SCE's incurred legal costs. Additional settlement payments totaling approximately $127 million are due from El Paso over a 20-year period. As a result, SCE recorded a receivable and corresponding regulatory liability of $65 million in 2004 for the discounted present value of the future payments (discounted at an annual rate of 7.86%). Amounts El Paso refunds to the CDWR will result in reductions in the CDWR's revenue requirement allocated to SCE in proportion to SCE's share of the CDWR's power charge revenue requirement.

On July 2, 2004, the FERC approved a settlement agreement between SCE, SDG&E and PG&E and The Williams Cos. and Williams Power Company, providing for approximately $140 million in refunds and other payments to the settling purchasers and others against some of Williams' power charges in 2000–2001. In August 2004, SCE received its $37 million share of the refunds and other payments under the Williams settlement.

On April 26, 2004, SCE, PG&E, SDG&E and several California state governmental entities agreed to settlement terms with West Coast Power, LLC and its owners, Dynegy Inc. and NRG Energy, Inc. (collectively, Dynegy). The settlement terms provide for refunds and other payments totaling $285 million, with a proposed allocation to SCE of approximately $42 million. The Dynegy settlement terms were approved by the FERC on October 25, 2004 and SCE received its $42 million share of the settlement proceeds in November 2004.

On July 12, 2004, SCE, PG&E, SDG&E and several governmental entities agreed to settlement terms with Duke Energy Corporation and a number of its affiliates (collectively Duke). The settlement terms agreed to with the Duke parties provide for refunds and other payments totaling in excess of $200 million, with a proposed allocation to SCE of approximately $45 million. The Duke settlement was approved by

the FERC on December 7, 2004 and SCE received its $45 million share of the settlement proceeds in January 2005.

On January 14, 2005, SCE, PG&E, SDG&E and several governmental entities agreed to settlement terms with Mirant Corporation and a number of its affiliates (collectively Mirant), all of whom are debtors in a Chapter 11 bankruptcy proceeding pending in Texas. Among other things, the settlement terms provide for expected cash and equivalent refunds totaling $320 million, of which SCE's allocated share is approximately $68 million. The settlement also provides for an allowed, unsecured claim totaling $175 million in the bankruptcy of one of the Mirant parties, with SCE being allocated approximately $33 million of the unsecured claim. The actual value of the unsecured claim will be determined as part of the resolution of the Mirant parties' bankruptcies. The Mirant settlement was submitted to the FERC for its approval on January 31, 2005 and was submitted to the Mirant bankruptcy court for its approval on February 23, 2005.

On November 19, 2004, the CPUC issued a resolution authorizing SCE to establish an Energy Settlement Memorandum Account (ESMA) for the purpose of recording the foregoing settlement proceeds from energy providers and allocating them in accordance with the terms of the CPUC litigation settlement agreement. The resolution accordingly provides a mechanism whereby portions of the settlement proceeds recorded in the ESMA will be allocated to recovery of SCE's litigation costs and expenses in the FERC refund proceedings described above and as a shareholder incentive pursuant to the CPUC litigation settlement agreement. Remaining amounts for each settlement are to be refunded to ratepayers through the ERRA mechanism. In 2004, SCE recorded in the caption "Other nonoperating income" on the income statement a total of $12 million as shareholder incentives related to refunds received in 2004.

Other Regulatory Matters

Catastrophic Event Memorandum Account

The catastrophic event memorandum account (CEMA) is a CPUC-authorized mechanism established in 1991 that allows SCE to immediately start the tracking of all of its incremental costs associated with declared disasters or emergencies and to subsequently receive rate recovery of its reasonably incurred costs upon CPUC approval. Incremental costs associated with restoring utility service; repairing, replacing or restoring damaged utility facilities; and complying with governmental agency orders are tracked in the CEMA. SCE currently has a CEMA for the bark beetle emergency and a CEMA associated with the fires that occurred in SCE territory in October 2003. Costs tracked through the CEMA mechanism may be recovered in future rates after SCE's filing of a request with the CPUC, a showing of their reasonableness and approval by the CPUC with no impact on earnings. However, cash flow will be impacted due to the timing difference between expenditures and rate recovery.

Bark Beetle CEMA

On March 7, 2003, the Governor of California issued a proclamation declaring a state of emergency in Riverside, San Bernardino and San Diego counties where an infestation of bark beetles has created the potential for catastrophic forest fires. The proclamation requested that the CPUC direct utilities with transmission lines in these three counties to assist local jurisdictions in responding to this emergency by ensuring that all dead, dying and diseased trees and vegetation are completely cleared from their utility rights-of-way to mitigate the risk of fire. SCE's role in this effort is to support the State of California, federal and local agencies by hiring contractors who are capable of removing these trees and vegetation in a vast area for the purpose of protecting against potential damage that may occur from fires and the collapse or falling of these tress into SCE's electrical lines and facilities. SCE estimates that it may incur over $100 million in incremental expenses over the next several years to remove over 350,000 of these trees. This cost estimate is subject to significant change, depending on a number of evolving circumstances, including, but not limited to the spread of the bark beetle infestation, the speed at which

trees can be removed, and tree disposal costs. As of December 31, 2004, the bark beetle CEMA had a balance of $131 million. On September 23, 2004, the CPUC issued a resolution on SCE's advice filing granting recovery of the majority of the $18 million bark beetle related costs recorded in 2003. The CPUC disallowed approximately $500,000 in recorded costs based on the assertion that such costs were already recovered in rates under SCE's routine line-clearing program. The CPUC also modified its original authorization and now requires future bark beetle CEMA filings to be applications instead of advice letters. SCE estimates that it will spend approximately $40 million on this project in 2005 and approximately $45 million in both 2006 and 2007. SCE will submit an application to recover the 2004 costs in 2005.

Fire-Related CEMA

In October and November of 2003, wildfires damaged SCE's electrical infrastructure, primarily in the San Bernardino Mountains of southern California where an estimated 2,085 power poles 2,059 services, 371 transformers, 557,033 of overhead conductors and 25,822 feet of underground cable were replaced or repaired. SCE notified the CPUC that it initiated a CEMA on October 21, 2003 to track the incremental costs to repair and restore its infrastructure. As of December 31, 2004, the fire-related CEMA had a balance of $12 million. The total costs associated with the fire-related CEMA, as of December 31, 2005, are expected to be $16 million. SCE filed an application with the CPUC on December 2, 2004 to seek recovery of its fire-related costs over a one-year period commencing January 1, 2006. In addition, SCE is requesting that the CPUC find reasonable $28 million of incremental capital expenditures, which would be recovered in rates over the useful life of the particular asset.

Holding Company Proceeding

In April 2001, the CPUC issued an order instituting investigation that reopened the past CPUC decisions authorizing utilities to form holding companies and initiated an investigation into, among other things: (1) whether the holding companies violated CPUC requirements to give first priority to the capital needs of their respective utility subsidiaries; (2) any additional suspected violations of laws or CPUC rules and decisions; and (3) whether additional rules, conditions, or other changes to the holding company decisions are necessary.

On January 9, 2002, the CPUC issued an interim decision interpreting the CPUC requirement that the holding companies give first priority to the capital needs of their respective utility subsidiaries. The decision stated that, at least under certain circumstances, holding companies are required to infuse all types of capital into their respective utility subsidiaries when necessary to fulfill the utility's obligation to serve its customers. The decision did not determine whether any of the utility holding companies had violated this requirement, reserving such a determination for a later phase of the proceedings. On February 11, 2002, SCE and Edison International filed an application before the CPUC for rehearing of the decision. On July 17, 2002, the CPUC affirmed its earlier decision on the first priority requirement and also denied Edison International's request for a rehearing of the CPUC's determination that it had jurisdiction over Edison International in this proceeding. On August 21, 2002, Edison International and SCE jointly filed a petition in California state court requesting a review of the CPUC's decisions with regard to first priority requirements, and Edison International filed a petition for a review of the CPUC decision asserting jurisdiction over holding companies. PG&E and SDG&E and their respective holding companies filed similar challenges, and all cases have been transferred to the First District Court of Appeals in San Francisco.

On May 21, 2004, the Court of Appeal issued its decision in the two consolidated cases, and denied the utilities' and their holding companies' challenges to both CPUC decisions. The Court of Appeal held that the CPUC has limited jurisdiction to enforce in a CPUC proceeding the conditions agreed to by holding companies incident to their being granted authority to assume ownership of a CPUC-regulated utility. The Court of Appeal held that the CPUC's decision interpreting the first priority requirement was not

reviewable because the CPUC had not made any ruling that any holding company had violated the first priority requirement. However, the Court of Appeal suggested that if the CPUC or any other authority were to rule that a utility or holding company violated the first priority requirement, the utility or holding company would be permitted to challenge both the finding of violation and the underlying interpretation of the first priority requirement itself. On June 30, 2004, Edison International and the other utility holding companies filed with the California Supreme Court a petition for review of the Court of Appeal decision as to jurisdiction over holding companies, but they and the utilities did not file a challenge to the decision as to the first priority issue. On September 1, 2004, the California Supreme Court denied the petition for review. The Court of Appeal's decision, as to jurisdiction, is now final.

The original order instituting the investigation into whether the utilities and their holding companies have complied with CPUC decisions and applicable statutes remains in effect. However, on February 11, 2005, an administrative law judge ruling was issued which provides that any party to the proceedings that believes the proceedings should remain open has 30 days to file comments listing matters that remain to be decided and explaining why they must be resolved at the CPUC rather than in another forum. The CPUC indicated that if comments are not received in the 30 day time period, a decision closing the proceeding will be prepared for CPUC consideration and no further comment will be allowed. At this time, SCE is not aware whether or not comments have been received or whether the CPUC has taken further action.

Investigation Regarding Performance Incentives Rewards

SCE is eligible under its CPUC-approved performance-based ratemaking (PBR) mechanism to earn rewards or penalties based on its performance in comparison to CPUC-approved standards of customer satisfaction, employee injury and illness reporting, and system reliability.

SCE has been conducting investigations into its performance under these PBR mechanisms and has reported to the CPUC certain findings of misconduct and misreporting as further discussed below. As a result of the reported events, the CPUC could institute its own proceedings to determine whether and in what amounts to order refunds or disallowances of past and potential PBR rewards for customer satisfaction, injury and illness reporting, and system reliability portions of PBR. The CPUC also may consider whether to impose additional penalties on SCE. SCE cannot predict with certainty the outcome of these matters or estimate the potential amount of refunds, disallowances, and penalties that may be required.

Customer Satisfaction

SCE received two letters in 2003 from one or more anonymous employees alleging that personnel in the service planning group of SCE's transmission and distribution business unit altered or omitted data in attempts to influence the outcome of customer satisfaction surveys conducted by an independent survey organization. The results of these surveys are used, along with other factors, to determine the amounts of any incentive rewards or penalties to SCE under the PBR provisions for customer satisfaction. SCE recorded aggregate customer satisfaction rewards of $28 million for the years 1998, 1999 and 2000. Potential customer satisfaction rewards aggregating $10 million for the years 2001 and 2002 are pending before the CPUC and have not been recognized in income by SCE. SCE also anticipated that it could be eligible for customer satisfaction rewards of about $10 million for 2003.

SCE has been conducting an internal investigation and keeping the CPUC informed of its progress. On June 25, 2004, SCE submitted to the CPUC a PBR customer satisfaction investigation report, which concluded that employees in the design organization of the transmission and distribution business unit deliberately altered customer contact information in order to affect the results of customer satisfaction surveys. At least 36 design organization personnel engaged in deliberate misconduct including alteration of customer information before the data were transmitted to the independent survey company. Because of

the apparent scope of the misconduct, SCE proposed to refund to ratepayers $7 million of the PBR rewards previously received and forego an additional $5 million of the PBR rewards pending that are both attributable to the design organization's portion of the customer satisfaction rewards for the entire PBR period (1997–2003). In addition, during its investigation, SCE determined that it could not confirm the integrity of the method used for obtaining customer satisfaction survey data for meter reading. Thus, SCE also proposed to refund all of the approximately $2 million of customer satisfaction rewards associated with meter reading. As a result of these findings, SCE accrued a $9 million charge in the caption "Other nonoperating deductions" on the income statement in 2004 for the potential refunds of rewards that have been received.

SCE has taken remedial action as to the customer satisfaction survey misconduct by severing the employment of several supervisory personnel, updating system process and related documentation for survey reporting, and implementing additional supervisory controls over data collection and processing. Performance incentive rewards for customer satisfaction expired in 2003 pursuant to the 2003 GRC.

The CPUC has not yet opened a formal investigation into this matter. However, it has submitted several data requests to SCE and has requested an opportunity to interview a number of SCE employees in the design organization. SCE has responded to these requests and the CPUC has conducted interviews of approximately 20 employees who were disciplined for misconduct.

Employee Injury and Illness Reporting

In light of the problems uncovered with the customer satisfaction surveys, SCE is conducting an investigation into the accuracy of SCE's employee injury and illness reporting. The yearly results of employee injury and illness reporting to the CPUC are used to determine the amount of the incentive reward or penalty to SCE under the PBR mechanism. Since the inception of PBR in 1997, SCE has received $20 million in employee safety incentives for 1997 through 2000 and, based on SCE's records, may be entitled to an additional $15 million for 2001 through 2003.

On October 21, 2004, SCE reported to the CPUC and other appropriate regulatory agencies certain findings concerning SCE's performance under the PBR incentive mechanism for injury and illness reporting. Under the PBR mechanism, rewards and/or penalties for the years 1997 through 2003 were based upon a total incident rate, which included two equally weighted measures: Occupational Safety and Health Administration (OSHA) recordable incidents and first aid incidents. The major issue disclosed in the investigative findings to the CPUC was that SCE failed to implement an effective recordkeeping system sufficient to capture all required data for first aid incidents. SCE's investigation also found reporting inaccuracies for OSHA recordable incidents, but the impact of these inaccuracies did not have a material effect on the PBR mechanism.

As a result of these findings, SCE proposed to the CPUC that it not collect any reward under the mechanism for any year before 2005, and it return to ratepayers the $20 million it has already received. Therefore, SCE accrued a $20 million charge in the caption "Other nonoperating deductions" on the income statement in 2004 for the potential refund of these rewards. SCE has also proposed to withdraw the pending rewards for the 2001–2003 time frames.

SCE is taking other remedial action to address the issues identified, including revising its organizational structure and overall program for environmental, health and safety compliance. Additional actions, including disciplinary action against specific employees identified as having committed wrongdoing, may result once the investigation is completed. SCE submitted a report on the results of its investigation to the CPUC on December 3, 2004. As with the customer satisfaction matter, the CPUC has not yet opened a formal investigation into this matter. However, SCE anticipates that the CPUC will be submitting data requests and seeking additional information in the near future.

System Reliability

In light of the problems uncovered with the PBR mechanisms discussed above, SCE is conducting an investigation into the third PBR metric, system reliability. Since the inception of PBR payments in 1997, SCE has received $8 million in rewards and has applied for an additional $5 million reward based on frequency of outage data for 2001. For 2002, SCE's data indicates that it earned no reward and incurred no penalty. Based on the application of the PBR mechanism, as adopted, SCE's data would result in penalties of $5 million and $1 million for 2003 and 2004, respectively. These penalties have not yet been assessed. As a result of SCE's data and calculations, SCE has accrued a $6 million charge in the caption "Other nonoperating deductions" on the income statement in 2004.

On February 28, 2005, SCE provided its final investigatory report to the CPUC concluding that the reliability reporting system is working as intended.

SCE: OTHER DEVELOPMENTS

Electric and Magnetic Fields

Electric and magnetic fields naturally result from the generation, transmission, distribution and use of electricity. Since the 1970s, concerns have been raised about the potential health effects of electric and magnetic fields. After 30 years of research, a health hazard has not been established to exist. Potentially important public health questions remain about whether there is a link between electric and magnetic fields exposures in homes or work and some diseases, and because of these questions, some health authorities have identified electric and magnetic fields exposures as a possible human carcinogen.

In October 2002, the California Department of Health Services released to the CPUC and the public its report evaluating the possible risks from electric and magnetic fields. The conclusions in the report of the California Department of Health Services contrast with other recent reports by authoritative health agencies in that the California Department of Health Services has assigned a substantially higher probability to the possibility that there is a causal connection between electric and magnetic fields exposures and a number of diseases and conditions, including childhood leukemia, adult leukemia, amyotrophic lateral sclerosis, and miscarriages.

On August 19, 2004, the CPUC issued an order instituting a rulemaking to update the CPUC's policies and procedures related to electromagnetic fields emanating from regulated utility facilities. SCE and other interested parties submitted comments to clarify the issues to be addressed in the proceeding in December 2004 and January 2005. It is anticipated that the CPUC will schedule a prehearing conference in the near future. SCE cannot predict with certainty the outcome of this proceeding.

Navajo Nation Litigation

In June 1999, the Navajo Nation filed a complaint in the United States District Court for the District of Columbia (D.C. District Court) against Peabody Holding Company (Peabody) and certain of its affiliates, Salt River Project Agricultural Improvement and Power District, and SCE arising out of the coal supply agreement for Mohave. The complaint asserts claims for, among other things, violations of the federal Racketeer Influenced and Corrupt Organizations statute, interference with fiduciary duties and contractual relations, fraudulent misrepresentation by nondisclosure, and various contract-related claims. The complaint claims that the defendants' actions prevented the Navajo Nation from obtaining the full value in royalty rates for the coal supplied to Mohave. The complaint seeks damages of not less than $600 million, trebling of that amount, and punitive damages of not less than $1 billion, as well as a declaration that Peabody's lease and contract rights to mine coal on Navajo Nation lands should be terminated. SCE joined Peabody's motion to strike the Navajo Nation's complaint. In addition, SCE and other defendants filed motions to dismiss. The D.C. District Court denied these motions for dismissal,

except for Salt River Project Agricultural Improvement and Power District's motion for its separate dismissal from the lawsuit.

Certain issues related to this case were addressed by the United States Supreme Court in a separate legal proceeding filed by the Navajo Nation in the United States Court of Federal Claims against the United States Department of Interior. In that action, the Navajo Nation claimed that the Government breached its fiduciary duty concerning negotiations relating to the coal lease involved in the Navajo Nation's lawsuit against SCE and Peabody. On March 4, 2003, the Supreme Court concluded, by majority decision, that there was no breach of a fiduciary duty and that the Navajo Nation did not have a right to relief against the Government. Based on the Supreme Court's analysis, on April 28, 2003, SCE and Peabody filed motions to dismiss or, in the alternative, for summary judgment in the D.C. District Court action. On April 13, 2004, the D.C. District Court denied SCE's and Peabody's April 2003 motions to dismiss or, in the alternative, for summary judgment. The D.C. District Court subsequently issued a scheduling order that imposed a December 31, 2004 discovery cut-off. Pursuant to a joint request of the parties, the D.C. District Court granted a 120-day stay of the action to allow the parties to attempt to resolve, through facilitated negotiations, all issues associated with Mohave. Negotiations are ongoing and the stay has been continued until further order of the court.

The United States Court of Appeals for the D.C. Circuit, acting on a suggestion on remand filed by the Navajo Nation, held in an October 24, 2003 decision that the Supreme Court's March 4, 2003 decision was focused on three specific statutes or regulations and therefore did not address the question of whether a network of other statutes, treaties and regulations imposed judicially enforceable fiduciary duties on the United States during the time period in question. The Government and the Navajo Nation both filed petitions for rehearing of the October 24, 2003 D.C. Circuit Court decision. Both petitions were denied on March 9, 2004. On March 16, 2004, the D.C. Circuit Court issued an order remanding the case against the Government to the Court of Federal Claims, which conducted a status conference on May 18, 2004. As a result of the status conference discussion, the Navajo Nation and the Government are in the process of briefing the remaining issues following remand. Peabody's motion to intervene as a party in the remanded Court of Federal Claims case was denied.

SCE cannot predict with certainty the outcome of the 1999 Navajo Nation's complaint against SCE, the impact of the Supreme Court's decision in the Navajo Nation's suit against the Government on this complaint, or the impact of the complaint on the operation of Mohave beyond 2005.

MISSION ENERGY HOLDING COMPANY

MEHC: MANAGEMENT OVERVIEW

MEHC as a Holding Company

MEHC has a 100% ownership interest in EME, which itself operates through its subsidiaries and affiliates. EME continues to operate predominantly in one line of business, electric power generation with all of its continuing operations located in the United States. MEHC (parent) has no business activities other than through its ownership interest in EME.

EME Introduction

EME is a holding company which operates primarily through its subsidiaries and affiliates which are engaged in the business of owning or leasing, operating and selling energy and capacity from electric power generation facilities. EME's subsidiaries or affiliates have typically been formed to own all of or an interest in one or more power plants and ancillary facilities, with each plant or group of related plants being individually referred to by EME as a project. As of December 31, 2004, EME's subsidiaries and affiliates owned or leased interests in 18 power plants.

EME has financed the development and construction or acquisition of its projects by contributions of equity from EME and the incurrence of so-called project financed debt obligations by the subsidiaries and affiliates owning the operating facilities. These project level debt obligations are generally structured as non-recourse to EME, with several exceptions, including EME's guarantee of the Powerton and Joliet leases as part of a refinancing of indebtedness incurred by its project subsidiary to purchase the Illinois plants. As a result, these project level debt obligations have structural priority with respect to revenue, cash flows and assets of the project companies over debt obligations incurred by EME itself. In this regard, EME has, itself, borrowed funds to make the equity contributions required of it for its projects and for general corporate purposes. Since EME does not, itself, directly own any revenue producing generation facilities, it depends for the most part on cash distributions from its projects to meet its debt service obligations, to pay for general and administrative expenses and to pay dividends to its parent, MEHC. Distributions to EME from projects are generally only available after all current debt service obligations at the project level have been paid and are further restricted by contractual restrictions on distributions included in the documentation evidencing the project level debt obligations.

EME Restructuring Activities

During 2004, EME completed the restructuring of indebtedness related to the Illinois plants and completed the sale of most of its international operations. These transactions were undertaken as part of a restructuring plan that was announced in late 2003.

Refinancing of Indebtedness Associated with the Illinois Plants

In April 2004, Midwest Generation, LLC (Midwest Generation) completed a private offering of $1 billion aggregate principal amount of its 8.75% second priority senior secured notes due 2034. Concurrently with the issuance of the notes, Midwest Generation borrowed $700 million under a new first priority senior secured term loan facility. Midwest Generation also entered into a new five-year $200 million working capital facility that replaced a prior facility. Midwest Generation used the proceeds of the notes issuance and the term loan to refinance $693 million of indebtedness (plus accrued interest and fees) owed by its direct parent, Edison Mission Midwest Holdings Co., which had been guaranteed by Midwest Generation and was due in December 2004, and to make the termination payment under the Collins Station lease described below.

Also in April 2004, Midwest Generation terminated the Collins Station lease through a negotiated transaction with the lease equity investor. Midwest Generation made a lease termination payment of approximately $960 million. This amount represented the $774 million of lease debt outstanding, plus accrued interest, and the amount owed to the lease equity investor for early termination of the lease. Midwest Generation received title to the Collins Station as part of the transaction. EME recorded a pre-tax loss of approximately $956 million (approximately $587 million after tax) due to termination of the lease and the planned decommissioning of the asset. Following the termination of the Collins Station lease, Midwest Generation permanently ceased operations at the Collins Station and decommissioned the plant.

Disposition of International Operations

EME's international operations, except the Doga project, are accounted for as discontinued operations in accordance with an accounting standard for accounting for the impairment or disposal of long-lived assets, and, accordingly, all prior periods have been restated to reclassify the results of operations and assets and liabilities as discontinued operations. The financial statements and the discussion set forth herein have been adjusted to this format of reporting.

EME has now completed the sale of most of its international operations through the following transactions:

- In September 2004, EME sold its 51.2% interest in Contact Energy Limited (Contact Energy) to Origin Energy New Zealand Limited. Consideration from the sale of Mission Energy Universal Holdings was NZ$1,101.4 million (approximately US$739 million) in cash and NZ$535 million (approximately US$359 million) of assumed debt. (See "Results of Operations and Historical Cash Flow Analysis—Results of Operations—Income from Discontinued Operations," and "Discontinued Operations.")

- In December 2004, EME sold ten projects representing most of its remaining international power generation portfolio owned by a wholly owned Dutch subsidiary, MEC International B.V., to a consortium comprised of International Power plc (70%) and Mitsui & Co., Ltd. (30%), referred to as IPM. Consideration from the sale of its Dutch holding company and related assets was $2.0 billion. (See "Results of Operations and Historical Cash Flow Analysis—Results of Operations—Income from Discontinued Operations," and "Discontinued Operations.")

- In January 2005, EME sold its 50% equity interest in the Caliraya-Botocan-Kalayaan (CBK) project to CBK Projects B.V., the purchasing entity designated by its partner for $104 million.

- In February 2005, EME sold its 25% equity interest in the Tri Energy project to IPM for approximately $20 million.

In connection with the above transactions, together with cash in hand, EME:

- Repaid $800 million of indebtedness arranged in December 2003 to provide interim financing until asset sales were completed.

- Made distributions to MEHC (in January 2005) totaling $360 million which were subsequently used primarily to repay the remaining $285 million portion of the term loan.

- Repaid EME's junior subordinated debentures (in January 2005) and consequently repaid the monthly income preferred securities (MIPS) of $150 million.

A substantial portion of the proceeds derived from the above transactions has been retained by EME to meet future debt obligations, support working capital requirements and for other corporate purposes discussed further below. At February 28, 2005, EME had corporate cash and cash equivalents of $1.8 billion. While EME will continue to seek to sell its ownership interest in the Doga project, there is no assurance that such efforts will result in a sale.

EME Domestic Operations

EME's domestic project portfolio may be grouped into two categories: contracted plants and merchant plants. At December 31, 2004, EME owned interests in 11 contracted power plants that sell a majority of their power to customers under long-term sales arrangements (greater than five years) consisting of power purchase agreements or hedge contracts. While operating these projects involves a number of risks, their long-term sales arrangements generally provide a stable and predictable revenue stream which results in reasonably predictable cash distributions to EME.

EME owns seven merchant power plants (the Illinois plants and the Homer City facilities) which operate in whole or in part without long-term sales arrangements. EME's merchant plants represent approximately 88% of EME's project portfolio based on capacity. Although the generation of the Illinois plants was at the time of their acquisition in late 1999 subject to sale under contracts with Exelon Generation Company LLC (Exelon Generation), all of these contracts had expired at the end of 2004. Output from merchant plants (as well as excess output from contracted plants) which is not committed to be sold under long-term sales arrangements is subject, in terms of price and volume, to market forces which determine the actual amount and price of power sold from these power plants.

Beginning in 2003, a significant factor affecting merchant generators was the substantial increase in the price of natural gas, especially when compared to the less volatile cost of coal. For the years 2003 and 2004, natural gas prices at Henry Hub (a major natural gas trading hub) averaged $5.48 and $5.91, respectively, per million British thermal units, commonly referred to as MMBtu, compared to $3.37 per MMBtu for 2002. Based upon data from the New York Mercantile Exchange (NYMEX) as of December 28, 2004, the calendar year 2005 forward natural gas price at Henry Hub was $6.34 per MMBtu. Increases in natural gas prices during 2003 resulted in higher wholesale electricity prices (since natural gas is the primary fuel for many generating plants). The increase in natural gas prices was a positive factor for low-cost merchant coal facilities in markets dominated by gas-fired plants and somewhat positive for coal facilities in those markets more dependent on low-cost coal and nuclear facilities. These conditions adversely affected certain of the Illinois plants, specifically the Collins Station and small peaking units. A description of these market forces and the risks associated with them is included under "MEHC: Market Risk Exposures."

Expansion of PJM in Illinois

The Illinois plants are located within the service territory of Exelon Generation's affiliate, Commonwealth Edison Company (Commonwealth Edison), which on April 27, 2004 was granted approval by the FERC to join PJM Interconnection, LLC (PJM) effective May 1, 2004. On October 1, 2004, American Electric Power (AEP) was also integrated into PJM. As a result, as of October 1, 2004, Midwest Generation has direct access to a fully interconnected market that covers twelve states and the District of Columbia, and serves a peak load of over 107,000 MW over 49,300 miles of transmission lines. For further discussion, see "MEHC: Other Development—Regulatory Matters."

Management Focus

Management's focus in 2005 is on the following key items:

- *Transition to Primarily Domestic Operations* — With the sale of EME's international operations, management intends to complete a review of its organization and operations and ensure that resources are effectively and efficiently aligned with business requirements.

- *Asset Optimization* — With the Illinois plants and the Homer City facilities being the largest portion of EME's domestic operations, efforts will continue from 2004 to ensure that gross margin from these plants is optimized.

- *Risk Management* — EME's management goal is to reduce the volatility of its earnings and cash flow and, thus, improve the predictability of operating results. To do this, EME's management is evaluating strategies for a combination of short-term sales, longer-term bilateral contracts, and potential participation in utility auctions for basic generation services (sometimes called "BGS Auctions"). Implementation of these strategies would be undertaken through EME's marketing and trading subsidiary by entering into forward contracts to reduce market risk and enhance the predictability of revenue from the Illinois plants and the Homer City facilities. Implementation of these strategies is dependent on a number of factors, such as a reduction in the current oversupply of generation, the rate of demand growth, and agreement between counterparties of reasonable credit support undertakings.

- *Liability Management* — EME's management intends to focus on reducing EME's leverage by repaying debt at maturity and repurchasing existing debt where early retirement is considered beneficial, thereby increasing financial flexibility for future growth.

- *New Investments* — With the greater financial stability resulting from the sale of EME's international operations, EME's management intends to evaluate and make new investments where appropriate.

Dispositions of Investments in Other Energy Plants

On January 7, 2004, EME completed the sale of 100% of its stock of Edison Mission Energy Oil & Gas, which in turn held minority interests in Four Star Oil & Gas, to Medicine Bow Energy Corporation. Proceeds from the sale were approximately $100 million. EME recorded a pre-tax gain on the sale of approximately $47 million during the first quarter of 2004.

On March 31, 2004, EME completed the sale of 100% of its stock of Mission Energy New York, Inc., which in turn owned a 50% partnership interest in Brooklyn Navy Yard Cogeneration Partners L.P., to a third party for a sales price of approximately $42 million. EME recorded an impairment charge of $53 million during the fourth quarter of 2003 related to the planned disposition of this investment and a pre-tax loss of approximately $4 million during the first quarter of 2004 due to changes in the terms of the sale.

MEHC: LIQUIDITY

Introduction

MEHC's liquidity discussion is organized in the following sections:

- MEHC (parent)'s Liquidity
- EME's Liquidity
- Key Financing Developments

- Termination of the Collins Station Lease
- 2005 Capital Expenditures
- EME's Credit Ratings
- EME's Liquidity as a Holding Company
- Dividend Restrictions in Major Financings
- MEHC's Interest Coverage Ratio

MEHC (parent)'s Liquidity

MEHC (parent)'s ability to honor its obligations under the senior secured notes and to pay overhead is substantially dependent upon the receipt of dividends from EME and receipt of tax-allocation payments from MEHC's parent, Edison Mission Group, and ultimately Edison International. See "MEHC: Liquidity—EME's Liquidity as a Holding Company—Intercompany Tax-Allocation Agreement." Dividends from EME are limited based on its earnings and cash flow, terms of restrictions contained in EME's corporate credit facility, business and tax considerations and restrictions imposed by applicable law.

At December 31, 2004, MEHC (parent) had cash and cash equivalents of $2 million (excluding amounts held by EME and its subsidiaries). During 2001, MEHC issued $800 million of 13.50% senior secured notes due 2008 and borrowed $385 million under a term loan. Since the beginning of 2004, MEHC (parent)'s principal source of liquidity has been cash dividends from EME.

On April 5, 2004, the lenders under MEHC (parent)'s $385 million term loan exercised their right to require MEHC (parent) to repurchase $100 million of the principal amount at par on July 2, 2004 (referred to as the "Term Loan Put-Option"). The $100 million of principal, plus interest, was repaid on July 2, 2004. The remaining $285 million of principal, plus interest, was paid on January 3, 2005.

The senior secured notes are secured by a first priority security interest in EME's common stock. Any foreclosure on the pledge of EME's common stock by the holders of the senior secured notes would result in a change in control of EME. EME has not guaranteed the senior secured notes which are non-recourse to EME. The MEHC financing documents contain restrictions on EME's ability and the ability of EME's subsidiaries to enter into specified transactions or engage in specified business activities and require, in some instances, that EME obtains the approval of the MEHC's Board of Directors. EME's certificate of incorporation binds it to the restrictions in MEHC's financing documents by restricting EME's ability to enter into specified transactions or engage in specified business activities, other than as permitted in MEHC's financing documents, without shareholder approval.

Dividends to MEHC (parent)

In 2004, EME made dividend payments of $74 million to MEHC. These payments were used together with cash on hand to meet the Term Loan Put-Option payment discussed above. In January 2005, EME made total dividend payments of $360 million to MEHC. A portion of these payments was used to repay the remaining $285 million of the term loan plus interest discussed above.

EME amended its certificate of incorporation and bylaws in May 2004 to eliminate the so-called "ring-fencing" provisions that were implemented in early 2001 during the California energy crisis, which had included restrictions on dividends.

Dividend Restriction in EME's Corporate Credit Agreement

On April 27, 2004, EME replaced its $145 million corporate credit agreement with a new $98 million secured corporate credit agreement. As of December 31, 2004, EME had no borrowings outstanding

under this credit agreement. EME would not be able to make a distribution if an event of default were to occur and be continuing after giving effect to the distribution.

EME's Liquidity

At December 31, 2004, EME and its subsidiaries had cash and cash equivalents of $2.3 billion, including $2.0 billion received from the sale of its international assets to IPM in December 2004, and EME had available the full amount of borrowing capacity under a $98 million corporate credit facility. EME's consolidated debt at December 31, 2004 was $3.7 billion. In addition, EME's subsidiaries had $5.0 billion of long-term lease obligations that are due over periods ranging up to 30 years.

Key Financing Developments

EME Financing Developments

On October 5, 2004, EME's subsidiary, Mission Energy Holdings International, Inc., repaid $600 million of the $800 million secured loan with the majority of the proceeds received from the sale of Contact Energy and cash on hand. In December 2004, EME completed the repayment of the remaining $200 million secured loan at Mission Energy Holdings International, Inc. Accordingly, this credit agreement has been terminated.

On April 27, 2004, EME replaced its $145 million corporate credit facility with a new $98 million secured corporate credit facility. This credit facility matures on April 27, 2007. Loans made under this credit facility bear interest at LIBOR plus 3.50% per annum. As security for its obligations under this credit facility, EME pledged its ownership interests in the holding companies through which it owns its interests in the Illinois plants, the Homer City facilities, the Westside projects, and the Sunrise project. EME also granted a security interest in an account into which all distributions received by it from the Big 4 projects will be deposited. EME is free to use these distributions unless and until an event of default occurs under its corporate credit facility.

Midwest Generation Financing Developments

On April 27, 2004, Midwest Generation completed a private offering of $1 billion aggregate principal amount of its 8.75% second priority senior secured notes due 2034. Holders of the notes may require Midwest Generation to repurchase, or Midwest Generation may elect to repay, the notes on May 1, 2014 and on each one-year anniversary thereafter at 100% of their principal amount, plus accrued and unpaid interest. Concurrent with the issuance of the notes, Midwest Generation borrowed $700 million under a new first priority senior secured term loan facility. The term loan has a final maturity of April 27, 2011 and bears interest at LIBOR plus 3.25% per annum. Midwest Generation has agreed to repay $1,750,000 of the term loan on each quarterly payment date. Midwest Generation also entered into a new five-year $200 million working capital facility that replaced a prior facility. The new working capital facility also provides for the issuance of letters of credit. As of December 31, 2004, Midwest Generation had no borrowings outstanding under the working capital facility and had reimbursement obligations under a letter of credit for approximately $3 million that expires in 2005. Midwest Generation used the proceeds of the notes issuance and the term loan to refinance $693 million of indebtedness (plus accrued interest and fees) owed by its direct parent, Edison Mission Midwest Holdings Co., which had been guaranteed by Midwest Generation and was due in December 2004, and to make the termination payment under the Collins Station lease in the amount of approximately $960 million.

Midwest Generation is permitted to use the new working capital facility and cash on hand to provide credit support (either through loans or letters of credit) for forward contracts with third-party counterparties entered into by Edison Mission Marketing & Trading on its behalf for capacity and energy generated from the Illinois plants. Utilization of this credit facility in support of such forward contracts

provides additional liquidity support for implementation of EME's contracting strategy for the Illinois plants.

The term loan and working capital facility share a first priority lien and the senior secured notes have a second priority lien in a collateral package which consists of, among other things, substantially all the coal-fired generating plants owned by Midwest Generation and the assets relating to those plants, as well as the equity interests of Midwest Generation and its parent company and the intercompany notes entered into by EME and Midwest Generation in connection with the Powerton-Joliet sale-leaseback transaction.

Termination of the Collins Station Lease

On April 27, 2004, Midwest Generation terminated the Collins Station lease through a negotiated transaction with the lease equity investor. Midwest Generation made a lease termination payment of approximately $960 million. This amount represented the $774 million of lease debt outstanding, plus accrued interest, and the amount owed to the lease equity investor for early termination of the lease. Midwest Generation received title to the Collins Station as part of the transaction. EME recorded a pre-tax loss of approximately $951 million (approximately $585 million after tax) due to termination of the lease and the planned decommissioning of the asset.

Following the termination of the Collins Station lease, Midwest Generation announced plans on May 28, 2004 to permanently cease operations at the Collins Station by December 31, 2004 and decommission the plant. By the fourth quarter of 2004, the Collins Station was decommissioned and all units were permanently retired from service, disconnected from the grid, and rendered inoperable, with all operating permits surrendered.

2005 Capital Expenditures

The estimated capital and construction expenditures of EME's subsidiaries are $78 million, $20 million and $24 million for 2005, 2006 and 2007, respectively. Non-environmental expenditures relate to upgrades to dust collection/mitigation systems, coal handling system and component replacement projects. These expenditures are planned to be financed by existing subsidiary credit agreements and cash generated from their operations. Included in the estimated expenditures are environmental expenditures of $28 million for 2005 and $1 million for 2006. In late 2004, Midwest Generation returned Will County Units 1 and 2 to service. As part of returning these units to service, Midwest Generation expects to install environmental improvements of approximately $10 million in 2005. In addition, Homer City plans to spend approximately $18 million in 2005 related to environmental projects such as selective catalytic reduction system improvements on all three units and ash removal improvements on two of the units.

EME's Credit Ratings

Overview

Credit ratings for EME and its subsidiaries, Midwest Generation, LLC and Edison Mission Marketing & Trading, are as follows:

	Moody's Rating	S&P Rating
EME	B1	B
Midwest Generation, LLC:		
First priority senior secured rating	Ba3	B+
Second priority senior secured rating	B1	B-
Edison Mission Marketing & Trading	Not Rated	B

On August 6, 2004, Moody's raised EME's credit rating to B1 from B2. EME cannot provide assurance that its current credit ratings or the credit ratings of its subsidiaries will remain in effect for any given period of time or that one or more of these ratings will not be lowered. EME notes that these credit ratings are not recommendations to buy, sell or hold its securities and may be revised at any time by a rating agency.

EME does not have any "rating triggers" contained in subsidiary financings that would result in EME being required to make equity contributions or provide additional financial support to its subsidiaries.

The credit ratings of EME are below investment grade and, accordingly, EME has historically provided collateral in the form of cash and letters of credit for the benefit of counterparties for its price risk management and trading activities related to accounts payable and unrealized losses. As a result of Midwest Generation's new working capital facility, Midwest Generation now provides credit support for forward contracts entered into by Edison Mission Marketing & Trading related to the Illinois plants.

Edison Mission Marketing & Trading has provided credit for the benefit of counterparties in the form of cash and letters of credit ($79 million as of December 31, 2004) for EME's price risk management and domestic trading activities (including Midwest Generation and Homer City) related to accounts payable and unrealized losses.

EME expects to have higher merchant generation in 2005 than in previous years, as a result of the expiration in 2004 of the power purchase agreements between Midwest Generation and Exelon Generation. The increased merchant generation will increase the potential for margin and collateral requirements. Changes in forward market prices and the strategies adopted for merchant generation could further increase the need for credit support for price risk management activities related to EME's projects. Using common industry analytics, EME estimates that total margin and collateral requirements to support price risk management could increase to approximately $400 million in 2005 if 50% of merchant generation from the Illinois plants and Homer City facilities is sold forward for one year and power prices subsequently increased. Midwest Generation is expected to have cash on hand and a $200 million working capital facility that can be used to provide credit support for forward contracts entered into on behalf of the Illinois plants. In addition, EME is expected to have cash on hand and a $98 million working capital facility that can be used to provide credit support for its subsidiaries. See "MEHC: Liquidity—EME's Liquidity" for further discussion.

Credit Rating of Edison Mission Marketing & Trading

The Homer City sale-leaseback documents restrict EME Homer City Generation L.P.'s (EME Homer City's) ability to enter into trading activities, as defined in the documents, with Edison Mission Marketing & Trading to sell forward the output of the Homer City facilities if Edison Mission Marketing & Trading does not have an investment grade credit rating from Standard & Poor's or Moody's or, in the absence of those ratings, if it is not rated as investment grade pursuant to EME's internal credit scoring procedures. These documents include a requirement that the counterparty to such transactions, and EME Homer City, if acting as seller to an unaffiliated third party, be investment grade. EME currently sells all of the output from the Homer City facilities through Edison Mission Marketing & Trading, which has a below investment grade credit rating, and EME Homer City is not rated. Therefore, in order for EME to continue to sell forward the output of the Homer City facilities, either: (1) EME must obtain consent from the sale-leaseback owner participant to permit EME Homer City to sell directly into the market or through Edison Mission Marketing & Trading; or (2) Edison Mission Marketing & Trading must provide assurances of performance consistent with the requirements of the sale-leaseback documents. EME has obtained a consent from the sale-leaseback owner participant that will allow EME Homer City to enter into such sales, under specified conditions, through December 31, 2006. EME Homer City continues to be in compliance with the terms of the consent; however, the consent is revocable by the sale-leaseback owner participant at any time. The sale-leaseback owner participant has not indicated that

it intends to revoke the consent; however, there can be no assurance that it will not do so in the future. Revocation of the consent would not affect trades between Edison Mission Marketing & Trading and EME Homer City that had been entered into while the consent was still in effect. EME is permitted to sell the output of the Homer City facilities into the spot market at any time. See "MEHC: Market Risk Exposures—Commodity Price Risk— Energy Price Risk Affecting Sales from the Homer City Facilities."

EME's Liquidity as a Holding Company

Overview

At December 31, 2004, EME had corporate cash and cash equivalents of $1.9 billion to meet liquidity needs. See "MEHC: Liquidity—EME's Liquidity." EME had no borrowings outstanding or letters of credit outstanding on the $98 million secured line of credit at December 31, 2004. During 2004, EME's cash position increased primarily due to proceeds received from the sale of most of its international assets and an increase of distributions received from its consolidated subsidiaries. Cash distributions from EME's subsidiaries and partnership investments, and unused capacity under its corporate credit facility represent EME's major sources of liquidity to meet its cash requirements. The timing and amount of distributions from EME's subsidiaries may be affected by many factors beyond its control. See "MEHC: Liquidity—Dividend Restrictions in Major Financings."

EME's secured corporate credit facility provides credit available in the form of cash advances or letters of credit. In addition to the interest payments, EME pays a commitment fee of 0.50% on the unutilized portion of the facility. EME has agreed to maintain a minimum interest coverage ratio and a minimum recourse debt to recourse capital ratio (as such ratios are defined in the credit agreement). At December 31, 2004, EME met both these ratio tests.

As security for its obligations under its new corporate credit facility, EME pledged its ownership interests in the holding companies through which it owns its interests in the Illinois plants, the Homer City facilities, the Westside projects and the Sunrise project. EME also granted a security interest in an account into which all distributions received by it from the Big 4 projects will be deposited. EME is free to use these distributions unless and until an event of default occurs under its corporate credit facility.

At December 31, 2004, EME also had available $87 million under Midwest Generation EME, LLC's $100 million letter of credit facility with Citibank, N.A., as Issuing Bank, that expires in December 2006. Under the terms of this letter of credit facility, Midwest Generation EME is required to deposit cash in a bank account in order to cash collateralize any letters of credit that may be outstanding under it. The bank account is pledged to the Issuing Bank. Midwest Generation EME owns 100% of Edison Mission Midwest Holdings, which in turn owns 100% of Midwest Generation, LLC.

Historical Domestic Distributions Received By EME

The following table is presented as an aid in understanding the cash flow of EME's domestic operations and its various subsidiary holding companies which depend on distributions from subsidiaries and affiliates to fund general and administrative costs and debt service costs of recourse debt.

In millions	Years Ended December 31, 2004	2003	2002
Distributions from Consolidated Operating Projects:			
EME Homer City Generation L.P. (Homer City facilities)	$ 61	$ 128 (1)	$ —
Edison Mission Midwest Holdings (Illinois plants)	88	—	—
Holding companies of other consolidated operating projects	1	1	2
Distributions from Unconsolidated Operating Projects:			
Edison Mission Energy Funding Corp. (Big 4 Projects)(2)	108	98	137
Four Star Oil & Gas Company	—	21	21
Sunrise Power Company	19	69 (3)	—
Holding companies for Westside projects	18	25	42
Holding companies of other unconsolidated operating projects	3	7	10
Total Distributions	**$ 298**	$ 349	$ 212

(1) Excludes $34 million distributed by EME Homer City from additional cash on hand due to accelerated payments received from Edison Mission Marketing & Trading.

(2) The Big 4 projects are comprised of investments in the Kern River project, Midway-Sunset project, Sycamore project and Watson project. Distributions do not include either capital contributions made during the California energy crisis or the subsequent return of such capital. Distributions reflect the amount received by EME after debt service payments by Edison Mission Energy Funding Corp.

(3) Includes $59 million of the $151 million proceeds from the Sunrise project financing. EME has classified the remaining $92 million as a return of capital.

Intercompany Tax-Allocation Agreement

MEHC (parent) and EME are included in the consolidated federal and combined state income tax returns of Edison International and are eligible to participate in tax-allocation payments with other subsidiaries of Edison International. MEHC (parent) became a party to the tax-allocation agreement with Edison Mission Group on July 2, 2001, when it became part of the Edison International consolidated filing group. EME and MEHC have historically received tax-allocation payments related to domestic net operating losses incurred by EME and MEHC (parent). The right of MEHC (parent) and EME to receive and the amount and timing of tax-allocation payments is dependent on the inclusion of MEHC (parent) and EME, respectively, in the consolidated income tax returns of Edison International and its subsidiaries and other factors, including the consolidated taxable income of Edison International and its subsidiaries, the amount of net operating losses and other tax items of MEHC (parent), EME, its subsidiaries, and other subsidiaries of Edison International and specific procedures regarding allocation of state taxes.
MEHC (parent) and EME receive tax-allocation payments for tax losses when and to the extent that the consolidated Edison International group generates sufficient taxable income in order to be able to utilize MEHC (parent)'s tax losses or the tax losses of EME in the consolidated income tax returns for Edison International and its subsidiaries. Based on the application of the factors cited above, MEHC (parent) and EME may be obligated during periods they generate taxable income to make payments under the tax-allocation agreements.

Dividend Restrictions in Major Financings

General

Each of EME's direct or indirect subsidiaries is organized as a legal entity separate and apart from EME and its other subsidiaries. Assets of EME's subsidiaries are not available to satisfy EME's obligations or the obligations of any of its other subsidiaries. However, unrestricted cash or other assets that are available for distribution may, subject to applicable law and the terms of financing arrangements of the

parties, be advanced, loaned, paid as dividends or otherwise distributed or contributed to EME or to its subsidiary holding companies.

Key Ratios of EME's Principal Subsidiaries Affecting Dividends

Set forth below are key ratios of EME's principal subsidiaries for the twelve months ended December 31, 2004:

Subsidiary	Financial Ratio	Covenant	Actual
Midwest Generation, LLC (Illinois plants)	Interest Coverage Ratio	Greater than or equal to 1.25 to 1	2.28 to 1(1)
Midwest Generation, LLC (Illinois plants)	Secured Leverage Ratio	Less than or equal to 8.75 to 1	6.00 to 1
EME Homer City Generation L.P. (Homer City facilities)	Senior Rent Service Coverage Ratio	Greater than 1.7 to 1	2.33 to 1
Edison Mission Energy Funding Corp. (Big 4 Projects)	Debt Service Coverage Ratio	Greater than or equal to 1.25 to 1	2.63 to 1

(1) Interest coverage ratio was computed on a pro forma basis assuming the credit facility had been in existence for a 12-month period.

Midwest Generation Financing Restrictions on Distributions

Midwest Generation is bound by the covenants in its credit agreement and indenture as well as certain covenants under the Powerton-Joliet lease documents with respect to Midwest Generation making payments under the leases. These covenants include restrictions on the ability to, among other things, incur debt, create liens on its property, merge or consolidate, sell assets, make investments, engage in transactions with affiliates, make distributions, make capital expenditures, enter into agreements restricting its ability to make distributions, engage in other lines of business or engage in transactions for any speculative purpose. In addition, the credit agreement contains financial covenants binding on Midwest Generation.

Covenants in Credit Agreement

In order for Midwest Generation to make a distribution, its credit agreement requires that it be in compliance with the covenants specified under its credit agreement, including maintaining the following two financial performance requirements:

- At the end of each fiscal quarter, Midwest Generation's consolidated interest coverage ratio for the immediately preceding four consecutive fiscal quarters must be at least 1.25 to 1. The consolidated interest coverage ratio is defined as the ratio of consolidated net income (plus or minus specified amounts as set forth in the credit agreement), to consolidated interest expense (as more specifically defined in the credit agreement).

- Midwest Generation's secured leverage ratio for the 12-month period ended on the last day of the immediately preceding fiscal quarter may be no greater than 8.75 to 1. The secured leverage ratio is defined as the ratio of the aggregate principal amount of Midwest Generation secured debt plus all

indebtedness of a subsidiary of Midwest Generation, to the aggregate amount of consolidated net income (plus or minus specified amounts as set forth in the credit agreement).

In addition, Midwest Generation's distributions are limited in amount. The aggregate amount of distributions made by Midwest Generation since April 27, 2004 may not exceed the sum of (1) 75% of excess cash flow (as defined in the credit agreement) generated since that date, plus (2) up to 100% of the amount of equity contributions or subordinated loans made by EME or a subsidiary of EME to Midwest Generation after April 27, 2004, but in this latter case only to the extent excess cash flow not used for a dividend under (1) is available for such payments. With the remaining excess cash flow, Midwest Generation must offer to prepay the term loan to the lenders. Each of the lenders may, at its option, decline such prepayment with respect to its pro rata share of the term loan. If Midwest Generation is rated investment grade, the aggregate amount of distributions made by Midwest Generation may equal but not exceed 100% of excess cash flow generated since becoming investment grade plus 75% of excess cash flow generated during the period between April 27, 2004 and the date immediately prior to becoming investment grade.

In October 2004, Midwest Generation made a distribution of $88 million and as required under its credit agreement, Midwest Generation offered to prepay $29 million of its term loan, of which $5 million was accepted by certain lenders and repaid in October 2004. Midwest Generation subsequently made a voluntary prepayment, as provided under the credit agreement, of $24 million in December 2004.

In January 2005, Midwest Generation made a distribution of $62 million and, as required under its credit agreement, Midwest Generation offered to prepay $20 million of the term loan, of which $5 million was accepted by certain lenders and repaid on January 24, 2005. Midwest Generation subsequently made a voluntary prepayment, as provided under the credit agreement, of $15 million on January 28, 2005.

Covenants in Indenture

Midwest Generation's indenture contains restrictions on its ability to make a distribution substantially similar to those in the credit agreement. Failure to achieve the conditions required for distributions will not result in a default under the indenture, nor does the indenture contain any other financial performance requirements.

EME Homer City Generation L.P. (Homer City facilities)

EME Homer City Generation L.P. completed a sale-leaseback of the Homer City facilities in December 2001. In order to make a distribution, EME Homer City must be in compliance with the covenants specified in the lease agreements, including the following financial performance requirements measured on the date of distribution:

- At the end of each quarter, the senior rent service coverage ratio for the prior twelve-month period (taken as a whole) must be greater than 1.7 to 1. The senior rent service coverage ratio is defined as all income and receipts of EME Homer City less amounts paid for operating expenses, required capital expenditures, taxes and financing fees divided by the aggregate amount of the debt portion of the rent, plus fees, expenses and indemnities due and payable with respect to the lessor's debt service reserve letter of credit.

At the end of each quarter, the equity and debt portions of rent then due and payable must have been paid. The senior rent service coverage ratio (discussed above) projected for each of the prospective two 12-month periods must be greater than 1.7 to 1. No more than two rent default events may have occurred, whether or not cured. A rent default event is defined as the failure to pay the equity portion of the rent within five business days of when it is due.

Edison Mission Energy Funding Corp. (Big 4 Projects)

EME's subsidiaries, which EME refers to in this context as the guarantors, that hold EME's interests in the Big 4 projects completed a $450 million secured financing in December 1996. Edison Mission Energy Funding Corp., a special purpose Delaware corporation, issued notes ($260 million which was paid in September 2003) and bonds ($190 million of which $139 million was the remaining balance at December 31, 2004), the net proceeds of which were lent to the guarantors in exchange for a note. The guarantors have pledged their cash proceeds from the Big 4 projects to Edison Mission Energy Funding as collateral for the note. All distributions receivable by the guarantors from the Big 4 projects are deposited into trust accounts from which debt service payments are made on the obligations of Edison Mission Energy Funding and from which distributions may be made to EME if the guarantors and Edison Mission Energy Funding are in compliance with the terms of the covenants in their financing documents, including the following requirements measured on the date of distribution:

- The debt service coverage ratio for the preceding four fiscal quarters is at least 1.25 to 1.
- The debt service coverage ratio projected for the succeeding four fiscal quarters is at least 1.25 to 1.

The debt service coverage ratio is determined primarily based upon the amount of distributions received by the guarantors from the Big 4 projects during the relevant quarter divided by the debt service (principal and interest) on Edison Mission Energy Funding's notes and bonds paid or due in the relevant quarter. Although the credit ratings of Edison Mission Energy Funding's notes and bonds are below investment grade, this has no effect on the ability of the guarantors to make distributions to EME.

EME Secured Credit Agreement Restrictions on Distributions from Subsidiaries

EME's secured credit agreement contains covenants that restrict its ability, and the ability of several of its subsidiaries, to make distributions. This restriction binds the subsidiaries through which EME owns the Westside projects, the Sunrise project, the Illinois plants, the Homer City facilities and the Big 4 projects. These subsidiaries would not be able to make a distribution to EME if an event of default were to occur and be continuing under EME's secured credit agreement after giving effect to the distribution.

In addition, EME granted a security interest in an account into which all distributions received by it from the Big 4 projects will be deposited. EME is free to use these distributions unless and until an event of default occurs under the credit agreement.

As of December 31, 2004, EME had no borrowings outstanding under this credit agreement.

MEHC's Interest Coverage Ratio

The following details with respect to MEHC's interest coverage ratio are provided as an aid to understanding the computations set forth in the indenture governing MEHC's senior secured notes. This information is not intended to measure the financial performance of MEHC and, accordingly, should not be read in lieu of the financial information set forth in MEHC's consolidated financial statements. The terms Funds Flow from Operations, Operating Cash Flow and Interest Expense are as defined in the indenture and are not the same as would be determined in accordance with generally accepted accounting principles.

MEHC's interest coverage ratio equals Funds Flow from Operations divided by Interest Expense and is comprised of interest income and expense related to its holding company activities and the consolidated financial information of EME. The following table sets forth MEHC's interest coverage ratio for the years ended December 31, 2004 and 2003:

In millions	December 31, 2004	December 31, 2003
Funds Flow from Operations:		
Operating Cash Flow[1] from Consolidated Operating Projects[2]:		
Illinois plants	$ 214	$ 242
Homer City	95	153
First Hydro	48	(8)
Other consolidated operating projects	128	165
Price risk management and energy trading	1	11
Distributions from unconsolidated Big 4 projects	108	98
Distributions from other unconsolidated operating projects	131	178
Interest income	8	4
Operating expenses	(167)	(144)
Total EME funds flow from operations	$ 566	$ 699
Operating cash flow from unrestricted subsidiaries	1	(2)
Funds flow from operations of projects sold	(195)	(1)
MEHC (parent)	(2)	1
Total funds flow from operations	$ 370	$ 697
Interest Expense:		
EME	$ 265	$ 286
EME – affiliate debt	1	1
MEHC (parent) interest expense	158	160
Interest savings on projects sold	(110)	—
Total interest expense	$ 314	$ 447
Interest Coverage Ratio	1.18	1.56

(1) Operating cash flow is defined as revenue less operating expenses, foreign taxes paid and project debt service. Operating cash flow does not include capital expenditures or the difference between cash payments under EME's long-term leases and lease expenses recorded in EME's income statement. EME expects its cash payments under its long-term power plant leases to be higher than its lease expense through 2014.

(2) Consolidated operating projects are entities of which EME owns more than a 50% interest and, thus, include the operating results and cash flows in its consolidated financial statements. Unconsolidated operating projects are entities of which EME owns 50% or less and which EME accounts for on the equity method or EME is not the primary beneficiary under a new accounting interpretation for variable interest entities.

The above interest coverage ratio was determined in accordance with the definitions set forth in the bond indenture governing MEHC's senior secured notes. The interest coverage ratio prohibits MEHC, EME and its subsidiaries from incurring additional indebtedness, except as specified in the indenture and the financing documents, unless MEHC's interest coverage ratio exceeds 2.0 to 1 for the immediately preceding four fiscal quarters.

MEHC: MARKET RISK EXPOSURES

Introduction

EME's primary market risk exposures are associated with the sale of electricity from and the procurement of fuel for its uncontracted generating plants. These market risks arise from fluctuations in electricity, capacity and fuel prices, emission allowances, transmission rights, and interest rates. EME manages these risks in part by using derivative financial instruments in accordance with established policies and procedures. See "MEHC: Management Overview," "Critical Accounting Policies and Estimates," and

"MEHC: Liquidity—EME's Credit Ratings" for a discussion of market developments and their impact on EME's credit and the credit of its counterparties.

This section discusses these market risk exposures under the following headings:

- Commodity Price Risk
- Credit Risk
- Interest Rate Risk
- Fair Value of Financial Instruments

Commodity Price Risk

General Overview

EME's revenue and results of operations of its merchant power plants depend upon prevailing market prices for capacity, energy, ancillary services, emission allowances or credits, fuel oil, coal, natural gas and associated transportation costs in the market areas where EME's merchant plants are located. Among the factors that influence the price of power in these markets are:

- prevailing market prices for fuel oil, coal and natural gas and associated transportation costs;

- the extent of additional supplies of capacity, energy and ancillary services from current competitors or new market entrants, including the development of new generation facilities;

- transmission congestion in and to each market area;

- the market structure rules to be established for each market area and regulatory developments affecting the market areas;

- the cost and availability of emission credits or allowances;

- the availability, reliability and operation of nuclear generating plants, where applicable, and the extended operation of nuclear generating plants beyond their presently expected dates of decommissioning;

- weather conditions prevailing in surrounding areas from time to time; and

- the rate of electricity usage as a result of factors such as regional economic conditions and the implementation of conservation programs.

A discussion of commodity price risk for the Illinois plants and Homer City facilities is set forth below.

Energy Price Risk – Introduction

Electric power generated at EME's merchant plants is generally sold under bilateral arrangements with utilities and power marketers under short-term transactions with terms of two years or less or to the PJM and/or the New York Independent System Operator (NYISO) markets. As discussed further below, beginning in 2003, EME has been selling a significant portion of the power generated from its Illinois plants into wholesale power markets, including PJM since May 1, 2004.

EME's merchant operations expose it to commodity price risk, which represents the potential loss that can be caused by a change in the market value of a particular commodity. Commodity price risks are actively monitored by a risk management committee to ensure compliance with EME's risk management policies.

Policies are in place which define risk tolerance, and procedures exist which allow for monitoring of all commitments and positions with regular reviews by EME's risk management committee. Despite this, there can be no assurance that all risks have been accurately identified, measured and/or mitigated.

EME performs a "value at risk" analysis in its daily business to identify, measure, monitor and control its overall market risk exposure in respect of its Illinois plants, its Homer City facilities, and its trading positions. The use of value at risk allows management to aggregate overall commodity risk, compare risk on a consistent basis and identify the risk factors. Value at risk measures the possible loss over a given time interval, under normal market conditions, at a given confidence level. Given the inherent limitations of value at risk and relying on a single risk measurement tool, EME supplements this approach with the use of stress testing and worst-case scenario analysis for key risk factors, as well as stop loss limits and counterparty credit exposure limits.

Energy Price Risk Affecting Sales from the Illinois Plants

Status of the Exelon Generation Power Purchase Agreements

Energy generated at the Illinois plants was historically sold under three power purchase agreements between Midwest Generation and Exelon Generation, under which Exelon Generation was obligated to make capacity payments for the plants under contract and energy payments for the energy produced by these plants and taken by Exelon Generation. The power purchase agreements began on December 15, 1999. The power purchase agreement for the Collins Station was terminated effective September 30, 2004; the other two contracts (for coal-fired generation and peaking units) expired on December 31, 2004. The capacity payments provided the units under contract with revenue for fixed charges, and the energy payments compensated those units for all, or a portion of, variable costs of production.

Approximately 53% of the energy and capacity sales from the Illinois plants in 2004 were to Exelon Generation under the power purchase agreements.

Merchant Sales

Beginning in 2005, all the energy and capacity from the Illinois plants are sold under terms, including price and quantity, negotiated by Edison Mission Marketing & Trading with customers through a combination of bilateral agreements, forward energy sales and spot market sales. These arrangements generally have terms of two years or less. Thus, EME is subject to the market risks related to the price of energy and capacity from the Illinois plants. Capacity prices for merchant energy sales are, and are expected in the near term to remain, substantially lower than those Midwest Generation historically received under the 1999 power purchase agreements with Exelon Generation. EME expects that lower revenue resulting from lower capacity prices will be offset in part by energy prices, which EME believes will, in the near term, be higher for merchant energy sales than those historically received under the Exelon Generation power purchase agreements, as indicated below in the table of forward-looking prices. EME intends to manage this price risk, in part, by accessing both the wholesale customer and over-the-counter markets described below, as well as using derivative financial instruments in accordance with established policies and procedures. Edison Mission Marketing & Trading may also, from time to time, participate in auctions for "full requirement service" in various states for the procurement of power for electric utilities' bundled customers, in which Edison Mission Marketing & Trading would contract for the sale of power to end users over delivery periods defined in each auction. For instance, Edison Mission Marketing & Trading participated in the New Jersey Basic Generation Auction of February 2005 and was the winning bidder on some sales to large industrial customers for a one-year term.

Prior to May 1, 2004, the primary markets available to Midwest Generation for wholesale sales of electricity from the Illinois plants were direct "wholesale customers" and broker arranged "over-the-counter customers." The most liquid over-the-counter markets in the Midwest region have historically

been for sales into the control area of Cinergy and, to a lesser extent, for sales into the control areas of Commonwealth Edison and American Electric Power, referred to as "Into ComEd" and "Into AEP," respectively. "Into ComEd" and "Into AEP" are bilateral markets for the sale or purchase of electrical energy for future delivery. Due to geographic proximity, "Into ComEd" was the primary market for Midwest Generation.

The following table depicts the historical average market prices for energy per megawatt-hour "Into ComEd" for the first four months of 2004.

	Into ComEd*		
Historical Energy Prices	On-Peak[1]	Off-Peak[1]	24-Hr
January	$ 43.30	$ 15.18	$ 27.88
February	43.05	18.85	29.98
March	40.38	21.15	30.66
April	39.50	16.76	27.88
Four-Month Average	$ 41.56	$ 17.99	$ 29.10

(1) On-peak refers to the hours of the day between 6:00 a.m. and 10:00 p.m. Monday through Friday, excluding North American Electric Reliability Council (NERC) holidays. All other hours of the week are referred to as off-peak.

* Source: Energy prices were determined by obtaining broker quotes and other public price sources, for "Into ComEd" delivery points.

Following the transfer of control of the control area systems of Commonwealth Edison and AEP to PJM, on May 1, 2004 and October 1, 2004, respectively, sales of electricity from the Illinois plants now include bilateral and spot sales into PJM, with spot sales being based on locational marginal pricing. These sales into the expanded PJM, the primary market currently available to Midwest Generation, replaced sales previously made as bilateral sales and spot sales "Into ComEd" and "Into AEP." See "MEHC: Other Development—Regulatory Matters" for a more detailed discussion of recent developments regarding Commonwealth Edison's joining PJM and "—Energy Price Risk Affecting Sales from the Homer City Facilities" below for a discussion of locational marginal pricing.

The following table depicts the historical average market prices for energy per megawatt-hour at the Northern Illinois Hub since it became a part of PJM's service territory on May 1, 2004.

	24-Hour Historical Northern Illinois Hub Energy Prices*
May	$ 34.05
June	28.58
July	30.92
August	26.31
September	27.98
October	30.93
November	29.15
December	29.90
Eight-Month Average	$ 29.73

* Energy prices calculated at the Northern Illinois Hub delivery point using hourly real-time prices as published by PJM. There is no comparison for the same months in 2003.

Forward market prices at the Northern Illinois Hub fluctuate as a result of a number of factors, including natural gas prices, transmission congestion, changes in market rules, electricity demand which is affected by weather and economic growth, plant outages in the region, and the amount of existing and planned power plant capacity. The actual spot prices for electricity delivered by the Illinois plants into these markets may vary materially from the forward market prices set forth in the table below.

The following table sets forth the forward month-end market prices for energy per megawatt-hour for the calendar year 2005 and calendar year 2006 "strips," which are defined as energy purchases for the entire calendar year, as quoted for sales into the Northern Illinois Hub during 2004:

	24-Hour Northern Illinois Hub Forward Energy Prices*	
	2005	2006
January 31, 2004	$ 26.15	$ 26.22
February 29, 2004	29.45	30.72
March 31, 2004	31.45	32.35
April 30, 2004	31.13	31.41
May 31, 2004	34.64	34.55
June 30, 2004	33.09	32.32
July 31, 2004	33.07	32.33
August 31, 2004	31.34	30.80
September 30, 2004	32.82	32.85
October 31, 2004	36.60	36.95
November 30, 2004	34.47	34.19
December 31, 2004	33.05	33.44

* Energy prices were determined by obtaining broker quotes and other public sources for the Northern Illinois Hub delivery point.

Midwest Generation intends to hedge a portion of its merchant portfolio risk through Edison Mission Marketing & Trading. The following table summarizes Midwest Generation's hedge position (primarily based on prices at the Northern Illinois Hub) at December 31, 2004:

	2005	2006
Megawatt hours	12,234,078	619,150
Average price/MWh[1]	$ 39.44	$ 32.30

(1) The above hedge positions include forward contracts for the sale of power during different periods of the year and the day. Market prices tend to be higher during on-peak periods during the day and during summer months, although there is significant variability of power prices during different periods of time. Accordingly, the above hedge position at December 31, 2004 is not directly comparable to the 24-hour Northern Illinois Hub prices set forth above.

To the extent Midwest Generation does not hedge its merchant portfolio, the unhedged portion will be subject to the risks and benefits of spot market price movements. The extent to which Midwest Generation will hedge its market price risk through forward over-the-counter sales depends on several factors. First, Midwest Generation will evaluate over-the-counter market prices to determine whether sales at forward market prices are sufficiently attractive compared to assuming the risk associated with spot market sales. Second, Midwest Generation's ability to enter into hedging transactions will depend upon its and Edison Mission Marketing & Trading's credit capacity and upon the over-the-counter forward sales markets having sufficient liquidity to enable Midwest Generation to identify counterparties

who are able and willing to enter into hedging transactions. Midwest Generation is permitted to use its new working capital facility and cash on hand to provide credit support for forward contracts entered into by Edison Mission Marketing & Trading for capacity and energy generation by Midwest Generation under an energy services agreement between the two companies. Utilization of this credit facility in support of such forward contracts is expected to provide additional liquidity support for implementation of Midwest Generation's contracting strategy for the Illinois plants. See "MEHC: Market Risk Exposures—Credit Risk," below.

In addition to the prevailing market prices, Midwest Generation's ability to derive profits from the sale of electricity will be affected by the cost of production, including costs incurred to comply with environmental regulations. The costs of production of the units vary and, accordingly, depending on market conditions, the amount of generation that will be sold from the units is expected to vary from unit to unit.

Effective May 1, 2004, the control area system of Commonwealth Edison was placed under the control of PJM. Furthermore, the transmission system of AEP was integrated into PJM on October 1, 2004, which linked eastern PJM and the Northern Illinois control areas of the PJM system and improved access from the Illinois plants into the broader PJM market. Under the PJM tariff, Midwest Generation is no longer required to arrange and pay separately for transmission when making sales to wholesale buyers located within the PJM system. Under another order of the FERC effective December 1, 2004, Midwest Generation may make sales to customers located in the MISO without incurring the "through-and-out rate" that was previously imposed on transactions between those two regional transmission organizations. Transition mechanisms intended to compensate transmission owners for loss of these "through-and-out" revenue do not apply to Midwest Generation under the current PJM tariff, but the costs and other issues regarding these transition mechanisms have been controversial and may become the subject of hearings at the FERC. The ultimate outcome of any such proceedings cannot be predicted.

In addition to the price risks described previously, Midwest Generation's ability to transmit energy to counterparty delivery points to consummate spot sales and hedging transactions may also be affected by transmission service limitations and constraints and new standard market design proposals proposed by and currently pending before the FERC. Although the FERC and the relevant industry participants are working to minimize such issues, Midwest Generation cannot determine how quickly or how effectively such issues will be resolved.

EME is continuing to monitor the activities at the FERC related to the expansion of PJM and to advocate regulatory positions that promote efficient and fair markets in which the Illinois plants compete.

Energy Price Risk Affecting Sales from the Homer City Facilities

Electric power generated at the Homer City facilities is sold under bilateral arrangements with domestic utilities and power marketers pursuant to transactions with terms of two years or less, or to the PJM or the NYISO markets. These pools have short-term markets, which establish an hourly clearing price. The Homer City facilities are situated in the PJM control area and are physically connected to high-voltage transmission lines serving both the PJM and NYISO markets.

The following table depicts the historical average market prices for energy per megawatt-hour in PJM during the past three years:

	24-Hour PJM Historical Energy Prices*		
	2004	2003	2002
January	$ 51.12	$ 36.56	$ 20.52
February	47.19	46.13	20.62
March	39.54	46.85	24.27
April	43.01	35.35	25.68
May	44.68	32.29	21.98
June	36.72	27.26	24.98
July	40.09	36.55	30.01
August	34.76	39.27	30.40
September	40.62	28.71	29.00
October	37.37	26.96	27.64
November	35.79	29.17	25.18
December	38.59	35.89	27.33
Yearly Average	$ 40.79	$ 35.08	$ 25.63

* Energy prices were calculated at the Homer City busbar (delivery point) using historical hourly real-time prices provided on the PJM-ISO web-site.

As shown on the above table, the average historical market prices at the Homer City busbar (delivery point) during 2004 were higher than the average historical market prices during 2003. Forward market prices in PJM fluctuate as a result of a number of factors, including natural gas prices, transmission congestion, changes in market rules, electricity demand which is affected by weather and economic growth, plant outages in the region, and the amount of existing and planned power plant capacity. The actual spot prices for electricity delivered into these markets may vary materially from the forward market prices set forth in the table below.

Sales made in the real-time or day-ahead market receive the actual spot prices at the Homer City busbar. In order to mitigate price risk from changes in spot prices at the Homer City busbar, EME may enter into forward contracts with counterparties for energy to be delivered in future periods. Currently, there is not a liquid market for entering into forward contracts at the Homer City busbar. A liquid market does exist for a delivery point known as the PJM West Hub, which EME's price risk management activities use to enter into forward contracts. EME's revenue with respect to such forward contracts include:

- sales of actual generation in the amounts covered by such forward contracts with reference to PJM spot prices at the Homer City busbar, plus,

- sales to third parties under such forward contracts at designated delivery points (generally the PJM West Hub) less the cost of purchasing power at spot prices at the same designated delivery points to fulfill obligations under such forward contracts.

Under the PJM market design, locational marginal pricing (sometimes referred to as LMP), which establishes hourly prices at specific locations throughout PJM by considering factors including generator bids, load requirements, transmission congestion and losses, can cause the price of a specific delivery point to be raised or lowered relative to other locations depending on how the point is impacted by transmission constraints. During the past 12 months, transmission congestion in PJM has resulted in prices at the PJM West Hub (the primary trading hub in PJM) being higher than those at Homer City by an average of 4%.

By entering into forward contracts using the PJM West Hub as the delivery point, EME is exposed to "basis risk," which occurs when forward contracts are executed on a different basis (in this case PJM West Hub) than the actual point of delivery (Homer City busbar). In order to mitigate basis risk resulting from forward contracts using PJM West Hub as the delivery point, EME has participated in purchasing financial transmission rights in PJM, and may continue to do so in the future. A financial transmission right is a financial instrument that entitles the holder thereof to receive actual spot prices at one point of delivery and pay prices at another point of delivery that are pegged to prices at the first point of delivery, plus or minus a fixed amount. Accordingly, EME's price risk management activities include using financial transmission rights alone or in combination with forward contracts to manage the risks associated with changes in prices within the PJM market.

The following table sets forth the forward month-end market prices for energy per megawatt-hour for the calendar 2005 and 2006 "strips," which are defined as energy purchases for the entire calendar year, as quoted for sales into the PJM West Hub during 2004:

	24-Hour PJM West Hub Forward Energy Prices*	
	2005	2006
January 31, 2004	$ 36.65	$ 37.01
February 29, 2004	38.53	36.07
March 31, 2004	40.79	39.62
April 30, 2004	41.65	40.97
May 31, 2004	44.43	42.43
June 30, 2004	44.40	42.31
July 31, 2004	44.76	42.99
August 31, 2004	44.23	43.19
September 30, 2004	46.19	44.81
October 31, 2004	49.35	47.13
November 30, 2004	46.68	44.88
December 31, 2004	44.41	44.41

* Energy prices were determined by obtaining broker quotes and other public sources for the PJM West Hub delivery point. Forward prices at PJM West Hub are generally higher than the prices at the Homer City busbar.

The following table summarizes Homer City's hedge position at December 31, 2004:

	2005
Megawatt hours	9,288,000
Average price/MWh(1)	$ 44.96

(1) The above hedge positions include forward contracts for the sale of power during different periods of the year and the day. Market prices tend to be higher during on-peak periods during the day and during summer months, although there is significant variability of power prices during different periods of time. Accordingly, the above hedge position at December 31, 2004 is not directly comparable to the 24-hour PJM West Hub prices set forth above.

The average price/MWh for Homer City's hedge position is based on PJM West Hub. Energy prices at the PJM West Hub have averaged 4% higher than energy prices at the Homer City busbar during the past twelve months. A discussion of the basis risk between PJM West Hub and Homer City is set forth above.

Coal Price Risk

The Illinois plants use 16 million to 20 million tons of coal annually, primarily obtained from the Southern Powder River Basin of Wyoming. In addition, the Homer City facilities use approximately 5 million tons of coal annually, obtained from mines located near the facilities in Pennsylvania. Coal purchases are made under a variety of supply agreements ranging from one year to five years in length. The following table summarizes the percent of expected coal requirements by year that are under contract at December 31, 2004.

	2005	2006	2007	2008	2009
Percent of coal requirements under contract	92%	64%	39%	14%	2%

EME is subject to price risk for purchases of coal that are not under contract. Prices of Northeast coal have risen considerably in 2004. The price of Northern Appalachian coal with 13,000 British thermal units (Btu) content for delivery in calendar year 2005 has risen from $35.10 per ton to $57.88 per ton between January 2004 and December 2004. This 65% increase in price has been largely attributed to greater demand from domestic power producers and increased international shipments partly driven by a decline in the value of the U.S. dollar. The prices of the Powder River Basin coal have been largely static. The price of Powder River Basin coal with 8,800 Btu content for calendar year 2005 delivery has fluctuated between $6.06 per ton and $7.83 per ton during the course of the year, with the price of $6.32 per ton at December 30, 2004. See "Commitments, Guarantees and Indemnities—Fuel Supply Contracts" for more information regarding fuel supply interruptions and the dispute with two suppliers.

For forecasted 2005 coal purchases in which EME has not entered into contracts, EME expects that a 10% change in the market price of coal at December 31, 2004 would increase or decrease pre-tax income in 2005 by approximately $2 million.

Emission Allowances Price Risk

Under the federal Acid Rain Program (which requires electric generating stations to hold sulfur dioxide allowances) and Illinois and Pennsylvania regulations implementing the federal NOx SIP Call requirement, EME purchases (or sells) emission allowances based on the amounts required for actual generation in excess of (or less than) the amounts allocated under these programs. As part of the acquisition of the Illinois plants and the Homer City facilities, EME obtained the rights to the emission allowances that have been or are allocated to these plants. The net cost of sulfur dioxide (SO2) and nitrogen oxide (NOx) emission allowances purchased during 2004 to meet the regulatory requirements was $17 million.

The price of emission allowances, particularly SO2 allowances issued through the U.S. EPA Acid Rain Program, also increased substantially in 2004. The average cost of SO2 allowances increased from $170 per ton during 2003 to $436 per ton in 2004. The market for SO2 allowances also experienced increased volatility in 2004, with prices ranging from $220 to $740 per ton (in contrast to a range of $100 to $220 per ton between 1998 and 2003). These developments have been attributed to reduced numbers of both allowance sellers and prior vintage allowances.

EME expects that a 10% change in the price of SO2 emission allowances at December 31, 2004 would increase or decrease pre-tax income in 2005 by approximately $5 million.

Credit Risk

In conducting EME's price risk management and trading activities, EME contracts with a number of utilities, energy companies, financial institutions, and other companies, collectively referred to as counterparties. In the event a counterparty were to default on its trade obligation, EME would be exposed

to the risk of possible loss associated with re-contracting the product at a price different from the original contracted price if the non-performing counterparty were unable to pay the resulting liquidated damages owed to EME. Further, EME would be exposed to the risk of non-payment of accounts receivable accrued for products delivered prior to the time such counterparty defaulted.

To manage credit risk, EME looks at the risk of a potential default by counterparties. Credit risk is measured by the loss that would be incurred if counterparties failed to perform pursuant to the terms of their contractual obligations. EME measures, monitors and mitigates, to the extent possible, credit risk. To mitigate counterparty risk, master netting agreements are used whenever possible and counterparties may be required to pledge collateral when deemed necessary. EME also takes other appropriate steps to limit or lower credit exposure. Processes have also been established to determine and monitor the creditworthiness of counterparties. EME manages the credit risk on the portfolio based on credit ratings using published ratings of counterparties and other publicly disclosed information, such as financial statements, regulatory filings, and press releases, to guide it in the process of setting credit levels, risk limits and contractual arrangements including master netting agreements. A risk management committee regularly reviews the credit quality of EME's counterparties. Despite this, there can be no assurance that these efforts will be wholly successful in mitigating credit risk or that collateral pledged will be adequate.

EME measures credit risk exposure from counterparties of its merchant energy activities as either: (1) the sum of 60 days of accounts receivable, current fair value of open positions, and a credit value at risk, or (2) the sum of delivered and unpaid accounts receivable and the current fair value of open positions. EME's subsidiaries enter into master agreements and other arrangements in conducting price risk management and trading activities which typically provide for a right of setoff in the event of bankruptcy or default by the counterparty. Accordingly, EME's credit risk exposure from counterparties is based on net exposure under these agreements. At December 31, 2004, the amount of exposure, broken down by the credit ratings of EME's counterparties was as follows:

In millions	December 31, 2004
S&P Credit Rating	
A or higher	$ 37
A-	11
BBB+	70
BBB	16
BBB-	4
Below investment grade	2
Total	$ 140

EME's plants owned by unconsolidated affiliates in which EME owns an interest sell power under long-term power purchase agreements. Generally, each plant sells its output to one counterparty. Accordingly, a default by a counterparty under a long-term power purchase agreement, including a default as a result of a bankruptcy, would likely have a material adverse affect on the operations of such power plant.

For the year ended December 31, 2004, approximately 15% of EME's consolidated operating revenue generated at the Homer City facilities and Illinois plants was from sales to BP Energy Company, a third-party customer. An investment grade affiliate of BP Energy has guaranteed payment of amounts due under the related contracts.

Interest Rate Risk

The fair market value of MEHC (parent)'s total long-term debt was $1.3 billion at December 31, 2004, compared to the carrying value of $1.1 billion. A 10% increase in market interest rates at December 31, 2004 would result in a decrease in the fair value of total long-term debt by approximately $16 million.

A 10% decrease in market interest rates at December 31, 2004 would result in an increase in the fair value of total long-term debt by approximately $16 million.

Interest rate changes affect the cost of capital needed to operate EME's projects. EME mitigates the risk of interest rate fluctuations by arranging for fixed rate financing or variable rate financing with interest rate swaps, interest rate options or other hedging mechanisms for a number of its project financings. Based on the amount of variable rate long-term debt for which EME has not entered into interest rate hedge agreements at December 31, 2004, a 100-basis-point change in interest rates at December 31, 2004 would increase or decrease 2005 income before taxes by approximately $7 million. The fair market values of long-term fixed interest rate obligations are subject to interest rate risk. The fair market value of MEHC's total long-term debt (including current portion) was $5.5 billion at December 31, 2004, compared to the carrying value of $4.8 billion. A 10% increase in market interest rate at December 31, 2004 would result in a decrease in the fair value of total long-term debt by approximately $162 million. A 10% decrease in market interest rates at December 31, 2004 would result in an increase in the fair value of total long-term debt by approximately $180 million.

Fair Value of Financial Instruments

Non-Trading Derivative Financial Instruments

The following table summarizes the fair values for outstanding derivative financial instruments used in EME's continuing operations for purposes other than trading by risk category and instrument type:

In millions	December 31, 2004	December 31, 2003
Commodity price:		
Electricity	$ 10	$ (7)
Interest rate:		
Interest rate swaps	$ —	$ (5)

In assessing the fair value of EME's non-trading derivative financial instruments, EME uses a variety of methods and assumptions based on the market conditions and associated risks existing at each balance sheet date. The fair value of commodity price contracts takes into account quoted market prices, time value of money, volatility of the underlying commodities and other factors. The fair value of outstanding derivative commodity price contracts that would be expected after a 10% decrease in the market price at December 31, 2004 is $94 million. The following table summarizes the maturities, the valuation method and the related fair value of EME's commodity price risk management assets and liabilities as of December 31, 2004:

In millions	Total Fair Value	Maturity Less than 1 year	Maturity 1 to 3 years	Maturity 4 to 5 years	Maturity Greater than 5 years
Prices actively quoted	$ 10	$ 11	$ (1)	$ —	$ —

Energy Trading Derivative Financial Instruments

EME's risk management and trading operations are conducted by its subsidiary, Edison Mission Marketing & Trading. As a result of a number of industry and credit-related factors, Edison Mission Marketing & Trading has minimized its price risk management and trading activities not related to EME's power plants or investments in energy projects. To the extent Edison Mission Marketing & Trading engages in trading activities, Edison Mission Marketing & Trading seeks to manage price risk and to create stability of future income by selling electricity in the forward markets and, to a lesser degree, to

generate profit from price volatility of electricity and fuels by buying and selling these commodities in wholesale markets. EME generally balances forward sales and purchase contracts and manages its exposure through a value at risk analysis as described under "MEHC: Market Risk Exposures—Commodity Price Risk."

The fair value of the commodity financial instruments related to energy trading activities as of December 31, 2004 and December 31, 2003, are set forth below:

	December 31, 2004		December 31, 2003	
In millions	Assets	Liabilities	Assets	Liabilities
Electricity	$ 125	$ 36	$ 104	$ 11
Other	—	—	—	1
Total	$ 125	$ 36	$ 104	$ 12

The fair value of trading contracts that would be expected after a 10% decrease in the market price at December 31, 2004 is shown in the table below:

In millions	Fair Value	Fair Value After 10% Price Decrease
Electricity	$ 89	$ 91
Other	—	—
Total	$ 89	$ 91

The change in the fair value of trading contracts for the year ended December 31, 2004, was as follows:

In millions	
Fair value of trading contracts at January 1, 2004	$ 92
Net gains (losses) from energy trading activities	(36)
Amount realized from energy trading activities	33
Fair value of trading contracts at December 31, 2004	$ 89

Quoted market prices are used to determine the fair value of the financial instruments related to energy trading activities, except for the power sales agreement with an unaffiliated electric utility that EME's subsidiary purchased and restructured and a long-term power supply agreement with another unaffiliated party. EME's subsidiary recorded these agreements at fair value based upon a discounting of future electricity prices derived from a proprietary model using a discount rate equal to the cost of borrowing the non-recourse debt incurred to finance the purchase of the power supply agreement. The following table summarizes the maturities, the valuation method and the related fair value of energy trading assets and liabilities:

In millions As of December 31, 2004	Total Fair Value	Maturity Less than 1 year	Maturity 1 to 3 years	Maturity 4 to 5 years	Maturity Greater than 5 years
Prices actively quoted	$ (2)	$ (2)	$ —	$ —	$ —
Prices based on models and other valuation methods	91	(2)	7	12	74
Total	$ 89	$ (4)	$ 7	$ 12	$ 74

MEHC: OTHER DEVELOPMENT

Regulatory Matters

Prior to May 1, 2004, the primary markets available to Midwest Generation for wholesale sales of electricity from the Illinois plants were direct "wholesale customers" and broker-arranged "over-the-counter customers." Wholesale customer transactions are bilateral sales to regional buyers, including investor-owned utilities, municipal utilities, rural electric cooperatives and retail energy suppliers. Wholesale customer transactions include real-time, daily and longer term structured sales; they are not arranged through brokers and may be tailored to meet the specific requirements of wholesale electricity consumers. Over-the-counter markets are generally accessed through third-party brokers and electronic exchanges, and include forward sales of electricity. The most liquid over-the-counter markets in the Midwest region have historically been sales into the control area of Cinergy, referred to as "Into Cinergy," and, to a lesser extent, sales into the control areas of Commonwealth Edison and American Electric Power, referred to as "Into ComEd" and "Into AEP," respectively. "Into ComEd" and "Into AEP" were bilateral markets for the sale or purchase of electrical energy for future delivery. Due to geographic proximity, "Into ComEd" was the primary market for Midwest Generation.

On May 1, 2004 and October 1, 2004, respectively, operational control of the control area systems of Commonwealth Edison and AEP was transferred to PJM, which is now the primary market available to Midwest Generation. This transfer resulted in the conversion of the "Into ComEd" and "Into AEP" trading hubs to locational marginal pricing, which has further facilitated transparency of prices and provided liquidity to support risk management strategies. Performance of transactions in these markets is subject to contracts that generally provide for liquidated damages supported by a variety of credit requirements, which may include independent credit assessment, parent company guarantees, letters of credit and cash margining arrangements. However, liquidity in all of these markets has been adversely affected by the financial problems of trading and marketing entities.

Following the transfer of control of the control area systems of Commonwealth Edison and AEP to PJM, sales of electricity from the Illinois plants now include bilateral and spot sales into PJM, with spot sales being based on locational marginal pricing. These sales into the expanded PJM replaced sales previously made as bilateral sales and spot sales "Into ComEd" and "Into AEP." The Northern Illinois Hub is the primary trading hub for Midwest Generation produced power due to geographic proximity and high pricing correlation to the plant's output locations.

The Midwest Independent Transmission System Operator, an RTO authorized pursuant to a FERC order, commonly referred to as the MISO, which will control the former control areas of Alliant Energy Corporation (Wisconsin Power and Light Co. and Interstate Power and Light Co.), Aquila, Inc., Ameren Corporation, Cinergy Corp., Kentucky Utilities Company, LG&E Energy LLC, Vectren Corporation and Xcel Energy, Inc., among others, is scheduled to begin operation of its locational marginal pricing market on April 1, 2005. It is anticipated that the opening of the MISO market will provide increased liquidity in the Midwest electricity markets. "Into Cinergy" will become a locational marginal pricing location in the MISO at that time.

Historically, sales of power produced by Midwest Generation required using transmission that had to be obtained from Commonwealth Edison. An independent system operator did not yet oversee operations of the Commonwealth Edison control area; however, effective May 1, 2004 such operations were placed under the control of PJM. Furthermore, the transmission system of AEP was integrated into PJM on October 1, 2004, which linked the Northern Illinois and eastern portions of the PJM system and permitted the Illinois plants to be dispatched into the broader PJM market. In addition, a number of other utilities in the region participate in the MISO where a bilateral market with a single rate for transmission within the RTO already exists. The regional market is further supported by open access transmission under various utility company transmission tariffs that are not within the MISO. The open access transmission tariffs of the MISO and others in the region allow Midwest Generation to utilize their transmission and distribution systems to sell power at wholesale on a non-discriminatory basis relative to the system's owners. Such tariffs are vital to allow Midwest Generation to compete in the deregulated electricity markets because they provide a uniform set of prices and standards of transmission service that have been approved by regulatory agencies and are publicly available.

On November 18, 2004, the FERC issued an order eliminating regional through and out transmission rates in the region encompassed by PJM (as recently expanded) and the MISO. The effect of this order was to eliminate so-called rate pancaking between PJM and the MISO. Rate pancaking occurs when energy must move through multiple, separately priced transmission systems to travel from its point of production to its point of delivery, and each transmission owner along the line charges separately for the use of its system. At the same time, the FERC also imposed a transitional revenue recovery mechanism which has created controversy and some continuing uncertainty as to the impact of such mechanism on transactions in the region. The mechanism required the filing of tariffs by PJM and the MISO imposing a "Seams Elimination Cost Adjustment" (SECA) to be in effect until May 1, 2006, to compensate the "new PJM companies" — AEP, Commonwealth Edison and Dayton Power & Light, among others—for lost revenue attributable to such elimination. On November 30, 2004, the FERC clarified that SECAs can be recovered for lost revenue associated with elimination on intra-RTO pancaking.

The response to the November 18 and November 30 orders from the parties liable for the SECAs has been strongly negative, and a rehearing has been sought by a broad range of interests that are opposed to the imposition of SECAs. Although both PJM and the MISO have made tariff filings with the FERC that purport to comply with such order and eliminate through and out transmission rates as of December 1, 2004, numerous protests to such filings have been made, challenging SECAs on legal and equitable grounds and demanding evidentiary hearings by the FERC. In its tariff filing, PJM imposes SECAs only on load-serving entities, and not on other transmission customers such as Midwest Generation, but the MISO tariff provision imposes SECAs on all such customers. That provision does not directly affect Midwest Generation because it is not a transmission customer of the MISO; however, the issue of which entities should bear SECAs is one of the many points that have been raised in the protests described above and have become the subject of hearings ordered by the FERC.

Pending further orders of the FERC and/or the outcome of the hearings described above, under the provisions of the PJM tariff as filed, Midwest Generation is currently not subject to SECAs with respect to its sales of power within PJM. It is not possible, however, to predict the outcome of the hearings or to rule out the possibility that Midwest Generation could be ordered in the future to pay SECAs with respect to sales within PJM after December 1, 2004.

See "MEHC: Market Risk Exposures" for a discussion of the risks related to EME's Midwest Generation's sale of electricity and transmission service.

EDISON CAPITAL

EDISON CAPITAL: MANAGEMENT OVERVIEW

Edison Capital is a global provider of capital and financial services in energy, affordable housing, and infrastructure projects focusing primarily on investments related to the production and delivery of electricity.

Edison Capital has $2.7 billion invested worldwide in energy and infrastructure projects, including electric generation, transmission and distribution, transportation and telecommunications. These investments are in the form of long-term domestic and cross-border leveraged leases, partnership interests in international infrastructure funds, and domestic companies that operate renewable energy projects including wind power. The leveraged lease investments depend upon the operation of the asset, the lessee's performance of its contract obligations, enforcement of remedies and the sufficiency of collateral in the event of default, and realization of tax benefits. The infrastructure fund investments depend upon the sale on favorable terms of the project assets held by the funds. The domestic wind power investments depend upon wind resources, the operation of the assets, the sale of electricity under long-term power-purchase agreements and realization of energy production tax credits and other tax benefits.

Edison Capital also has $70 million invested in affordable housing projects, including $27 million invested in 2004, located throughout the United States. The investments are usually in the form of majority interests in limited partnerships or limited liability companies of which a significant portion has been sold to other parties. The affordable housing investments depend primarily upon realization of low-income housing tax credits.

A significant portion of revenue is derived from lease income. A major component of earnings includes the realization of low-income housing and energy production tax credits and gains or losses realized on sale of project assets by the infrastructure funds. Sources of cash result from lease payments, distributions from sale of project assets by the infrastructure funds and Edison International's ability to utilize tax benefits and credits from Edison Capital's investments.

Edison Capital management is primarily focused on the following matters for 2005:

- Sustaining the tax treatment of lease transactions against the current IRS challenge as further described in "Other Developments—Federal Income Taxes."

- Resuming investment in new electric infrastructure, including renewable energy.

- Managing the impact of economic conditions affecting American Airlines on Edison Capital's investment in three aircraft leased to American Airlines.

- Monitoring the indirect impact of regulatory and economic conditions affecting Edison Capital lease counterparties.

EDISON CAPITAL: LIQUIDITY

Edison Capital invested $14 million in new renewable investments in 2004 and continued to build its pipeline for additional renewable investments. As of February 28, 2005, Edison Capital had unfunded commitments of $81 million, and had signed binding term sheets, subject to closing, for $96 million of additional renewable energy. Edison Capital's pursuit of new renewable energy investments depends upon economic and regulatory conditions and continuation of government policies supporting renewable energy.

During 2004, Edison Capital repurchased seven previously syndicated affordable housing investments for approximately $27 million. Edison Capital will continue to evaluate the potential for re-investment opportunities within its current affordable housing portfolio.

In 2004, Edison Capital made a $75 million dividend payment to Edison International and had unrestricted cash and cash equivalents of $180 million as of December 31, 2004. Edison Capital expects to meet its operating cash needs through cash on hand, tax-allocation payments from the parent company and expected cash flow from operating activities.

At December 31, 2004, Edison Capital's long-term debt had credit ratings of Ba1 and BB+ from Moody's and Standard & Poor's, respectively.

Edison Capital's Intercompany Tax-Allocation Payments

Edison Capital is included in the consolidated federal and combined state income tax returns of Edison International and is eligible to participate in tax-allocation payments with Edison International and other subsidiaries of Edison International. See "MEHC: Liquidity—EME's Liquidity as a Holding Company—Intercompany Tax-Allocation Agreement" for additional information regarding these arrangements. Edison Capital made $8 million in tax-allocation payments to Edison International during 2004. The amount paid is net of payments received from Edison International. (See "Other Developments—Federal Income Taxes" for further discussion of tax-related issues regarding Edison Capital's leveraged leases).

EDISON CAPITAL: MARKET RISK EXPOSURES

Edison Capital is exposed to interest rate risk, foreign currency exchange rate risk and credit and performance risk that could adversely affect its results of operations or financial position.

Interest Rate Risk

The fair market value of Edison Capital's total long-term debt was $353 million at December 31, 2004, compared to a carrying value of $340 million. A 10% increase in market interest rates would have resulted in a $7 million decrease in the fair market value of Edison Capital's long-term debt. A 10% decrease in market interest rates would have resulted in an $8 million increase in the fair market value of Edison Capital's long-term debt.

Foreign Currency Exchange Risk

At December 31, 2004, Edison Capital's outstanding debt included £75 million and the cash equivalents balance included £75 million (both approximately $144 million) which result in self hedging of the outstanding balances with differences in interest rates and payment dates subject to foreign currency exchange fluctuations. A decrease in the cash equivalents balance noted above will increase the risk associated with foreign currency exchange fluctuations. In early 2005, Edison Capital repatriated the £75 million cash equivalents and executed a cross-currency swap agreement to hedge all future cash flows associated with the £75 million of outstanding debt. The hedge eliminated the need to maintain a portion of Edison Capital's cash balances in British pounds. This swap also eliminates the impact of any future dollar to British pound exchange rate fluctuations on Edison Capital's results of operations.

Credit and Performance Risk

Edison Capital's investments may be affected by the financial condition of other parties, the performance of the asset, economic conditions and other business and legal factors. Edison Capital generally does not

control operations or management of the projects in which it invests and must rely on the skill, experience and performance of third party project operators or managers. These third parties may experience financial difficulties or otherwise become unable or unwilling to perform their obligations. Edison Capital's investments generally depend upon the operating results of a project with a single asset. These results may be affected by general market conditions, equipment or process failures, disruptions in important fuel supplies or prices, or another party's failure to perform material contract obligations, and regulatory actions affecting utilities purchasing power from the leased assets. Edison Capital has taken steps to mitigate these risks in the structure of each project through contract requirements, warranties, insurance, collateral rights and default remedies, but such measures may not be adequate to assure full performance. In the event of default, lenders with a security interest in the asset may exercise remedies that could lead to a loss of some or all of Edison Capital's investment in that asset.

Edison Capital has a gross investment, before deferred taxes, of $61 million in three aircraft leased to American Airlines. American Airlines has reported very large operating and net losses due to reduced pricing power, increases in capacity in excess of demand, deeply discounted fare sales and significant increases in fuel prices. In the event American Airlines defaults in making its lease payments, the lenders with a security interest in the aircraft or leases may exercise remedies that could lead to a loss of some or all of Edison Capital's investment in the aircraft plus any accrued interest. The total maximum loss exposure to Edison Capital in 2005 is $45 million. A restructure of the lease could also result in a loss of some or all of the investment. At December 31, 2004, American Airlines was current in its lease payments to Edison Capital.

EDISON CAPITAL: OTHER DEVELOPMENT

Federal Income Taxes

Edison International received Revenue Agent Reports from the IRS in August 2002 and in January 2005 asserting deficiencies in federal corporate income taxes with respect to audits of its 1994 to 1996 and 1997 to 1999 tax years, respectively. Among the issues raised were items related to Edison Capital. See "Other Developments—Federal Income Taxes" for further discussion of these matters.

EDISON INTERNATIONAL (PARENT)

EDISON INTERNATIONAL (PARENT): LIQUIDITY

The parent company's liquidity and its ability to pay interest, debt principal, operating expenses and dividends to common shareholders are affected by dividends from subsidiaries, tax-allocation payments under its tax-allocation agreements with its subsidiaries, and access to capital markets or external financings. Edison International was focused on reducing its parent company debt in 2004, and as of December 31, 2004, had no debt outstanding.

Edison International (parent)'s 2005 cash requirements primarily consist of:

- Dividends to common shareholders. Edison International's management has increased its annual dividend from $0.80 per share in 2004 to $1.00 per share in 2005. On February 17, 2005, the Board of Directors of Edison International declared a $0.25 per share common stock dividend payable on April 30, 2005; and

- General and administrative expenses.

Edison International (parent) expects to meet its continuing obligations through cash and cash equivalents on hand, short-term borrowings, when necessary, and dividends from its subsidiaries. At December 31, 2004, Edison International (parent) had approximately $106 million of cash and cash equivalents on hand. In February 2005, Edison International (parent) entered into a $750 million senior unsecured 5-year revolving credit facility and as of February 28, 2005, had the entire amount available under its credit facility. The ability of subsidiaries to make dividend payments to Edison International is dependent on various factors as described below.

The CPUC regulates SCE's capital structure by requiring that SCE maintain prescribed percentages of common equity, preferred stock and long-term debt in the utility's capital structure. SCE may not make any distributions to Edison International that would reduce the common equity component of SCE's capital structure below the prescribed level. The CPUC also requires that SCE establish its dividend policy as though it were a comparable stand-alone utility company and give first priority to the capital requirements of the utility as necessary to meet its obligation to serve its customers. Other factors at SCE that affect the amount and timing of dividend payments by SCE to Edison International include, among other things, SCE's cash requirements, SCE's access to capital markets, and actions by the CPUC. SCE paid cash dividends of $300 million, $145 million, $150 million, and $155 million to Edison International in March 2004, May 2004, September 2004, and December 2004, respectively.

MEHC may not pay dividends unless it has an interest coverage ratio of at least 2.0 to 1. At December 31, 2004, its interest coverage ratio was 1.18 to 1. See "MEHC: Liquidity—MEHC's Interest Coverage Ratio." In addition, MEHC's certificate of incorporation and senior secured note indenture, contain restrictions on MEHC's ability to declare or pay dividends or distributions (other than dividends payable solely in MEHC's common stock). These restrictions require the unanimous approval of MEHC's Board of Directors, including its independent director, before it can declare or pay dividends or distributions, as long as any indebtedness is outstanding under the indenture. MEHC did not declare or pay a dividend in 2004 to Edison International. MEHC's ability to pay dividends is dependent on EME's ability to pay dividends to MEHC (parent). EME and its subsidiaries have certain dividend restrictions as discussed in the "MEHC: Liquidity—Dividend Restrictions in Major Financings" section.

Edison Capital's ability to make dividend payments is currently restricted by debt covenants, which require Edison Capital, through a wholly owned subsidiary, to maintain a specified minimum net worth of $200 million. Edison Capital met this minimum net worth as of December 31, 2004. Edison Capital declared and paid a $75 million dividend to Edison International in December 2004.

EDISON INTERNATIONAL (PARENT): MARKET RISK EXPOSURES

Although Edison International (parent) had no debt outstanding as of December 31, 2004, the parent company may be exposed to changes in interest rates which may result from future borrowing and investing activities, the proceeds of which may be used for general corporate purposes, including investments in nonutility businesses. The nature and amount of the parent company's long-term and short-term debt can be expected to vary as a result of future business requirements, market conditions and other factors.

EDISON INTERNATIONAL (PARENT): OTHER DEVELOPMENTS

Holding Company Proceeding

Edison International is a party to a CPUC holding company proceeding. See "SCE: Regulatory Matters—Other Regulatory Matters—Holding Company Proceeding" for a discussion of this matter.

Federal Income Taxes

Edison International received Revenue Agent Reports from the IRS in August 2002 and in January 2005 asserting deficiencies in federal corporate income taxes with respect to audits of its 1994 to 1996 and 1997 to 1999 tax years, respectively. See "Other Developments—Federal Income Taxes" for further discussion of these matters.

EDISON INTERNATIONAL (CONSOLIDATED)

The following sections of the MD&A are on a consolidated basis. The section begins with a discussion of Edison International's consolidated results of operations and historical cash flow analysis. This is followed by discussions of discontinued operations, acquisitions and dispositions, critical accounting policies and estimates, new accounting principles, commitments, guarantees and indemnities, off-balance sheet transactions and other developments.

RESULTS OF OPERATIONS AND HISTORICAL CASH FLOW ANALYSIS

The following subsections of "Results of Operations and Historical Cash Flow Analysis" provide a discussion on the changes in various line items presented on the Consolidated Statements of Income as well as a discussion of the changes on the Consolidated Statements of Cash Flows.

Results of Operations

The table below presents Edison International's earnings and earnings per share for the years ended December 31, 2004, 2003 and 2002, and the relative contributions by its subsidiaries.

In millions, except per share amounts	Earnings (Loss)			Earnings per Share		
Year Ended December 31,	**2004**	2003	2002	**2004**	2003	2002
Earnings (Loss) from Continuing Operations:						
SCE	**$ 915**	$ 872	$ 1,228	**$ 2.81**	$ 2.68	$ 3.77
MEHC	**(666)**	(194)	(90)	**(2.05)**	(0.60)	(0.28)
Edison Capital	**60**	57	33	**0.18**	0.17	0.10
Edison International (parent) and other	**(83)**	(80)	(116)	**(0.25)**	(0.24)	(0.35)
Edison International Consolidated Earnings from Continuing Operations	**226**	655	1,055	**0.69**	2.01	3.24
Earnings (Loss) from Discontinued Operations	**690**	175	22	**2.12**	0.54	0.07
Cumulative Effect of Accounting Change	**—**	(9)	—	**—**	(0.03)	—
Edison International Consolidated	**$ 916**	$ 821	$ 1,077	**$ 2.81**	$ 2.52	$ 3.31

Earnings (Loss) from Continuing Operations

Edison International's 2004 earnings from continuing operations were $226 million, or $0.69 per share, compared with earnings of $655 million, or $2.01 per share, in 2003 and earnings of $1.1 billion, or $3.24 per share, in 2002.

2004 vs. 2003

SCE's earnings from continuing operations for the year ending December 31, 2004 increased by $43 million, compared to the same period last year mainly due to the resolution of regulatory proceedings and prior year tax issues which increased earnings by $86 million over 2003. The 2004 proceedings included the 2003 GRC that was resolved in July 2004 and the 2003 ERRA proceeding addressing power procurement reasonableness that was resolved in the fourth quarter of 2004. Also, in the fourth quarter of 2004, SCE favorably resolved prior year tax issues. Excluding these items, earnings decreased $43 million, primarily from the expiration at year-end 2003 of the ICIP mechanism at San Onofre partially offset by the increase in revenue authorized by the 2003 GRC decision. Post-test-year revenue increases for 2004 and 2005, to compensate for customer growth and increased capital expenditures were authorized in the 2003 GRC decision.

MEHC had a loss from continuing operations of $666 million during 2004 compared to a loss of $194 million during 2003. MEHC's 2004 loss from continuing operations increased by $472 million

from 2003 primarily due to $608 million of charges for both terminating EME's Collins lease and impairment of EME's Illinois small-peaking plants during 2004. This decrease in earnings was partially offset by $186 million of impairment charges in 2003 primarily related to EME's Illinois small-peaking plants and EME's investment in the Brooklyn Navy Yard project. MEHC's 2004 results were favorably impacted by a gain on the sale of EME's interest in Four Star Oil & Gas which mostly offset the earnings recorded from the project during 2003. During the fourth quarter of 2004, MEHC's subsidiary, Midwest Generation, recorded a charge of $34 million related to a contract indemnity for asbestos claims from activities at EME's Illinois plants prior to their acquisition in 1999. In addition, the earnings from EME's Homer City facilities were lower in 2004 from 2003 due to unplanned outages and higher fuel costs related to emission allowances. The earnings from EME's Illinois plants, excluding the above asbestos charge, improved in 2004 over 2003 from higher generation and energy prices, which more than offset the lower capacity revenues under the power purchase agreement with Exelon.

Edison Capital's earnings for the year ended December 31, 2004 were $60 million, compared with $57 million in 2003. This increase is primarily due to higher income from Edison Capital's global infrastructure investment funds. The increase was partially offset by Edison Capital's maturing lease and housing portfolios which produce lower income.

The loss for Edison International (parent) and other increased $3 million over last year with the write-off of unamortized debt costs from the early payment of the Edison International quarterly income debt securities and other expenses being virtually offset by lower net interest expense.

2003 vs. 2002

SCE's earnings from continuing operations were $872 million in 2003, compared to $748 million in 2002, excluding a $480 million gain related to a regulatory decision on SCE's utility-retained generation. The $124 million increase results from the net effect of the resolution of several regulatory proceedings in 2002 and 2003. The 2003 proceedings include the CPUC decision on the allocation of certain costs between state and federal regulatory jurisdictions, tax impacts from the FERC rate case, and the final disposition of the PROACT which had been created to record the recovery of SCE's procurement-related obligations. The positive effects of these factors on 2003 earnings were partially offset by the implementation in 2002 of the CPUC's utility-retained generation (URG) decision and PBR rewards received in 2002. SCE's results also included higher depreciation expense and lower net interest income, partially offset by higher FERC and PBR revenue.

MEHC's loss from continuing operations in 2003 was $194 million compared to $90 million in 2002. The increased loss was primarily due to the asset impairment charge of $150 million, after tax, for Midwest Generation's small peaking facilities, a $36 million, after tax, asset impairment charge related to EME's investment in the Brooklyn Navy Yard and Gordonsville projects, a reduction in capacity revenue for the Illinois power plants, and lower interest income and higher consulting fees at MEHC (parent). The 2003 increased loss was partially offset by higher revenue from EME's Homer City facilities due to higher energy prices, improved profitability of EME's interest in Four Star Oil & Gas due to higher natural gas prices, the start of operations at Phase 2 of EME's Sunrise project in June 2003 and other net charges in 2002. These 2002 net charges, after tax, include write-offs totaling $52 million related to the cancellation of turbine orders and the suspension of the Powerton selective catalytic reduction system project and a $27 million loss from a settlement agreement that terminated the obligation to build additional generation in Chicago; partially offset by a gain of $43 million from the settlement of a postretirement employee benefit liability.

Earnings from continuing operations for Edison Capital were $57 million in 2003 compared with $33 million in 2002. The increase in earnings was primarily the result of the write-off in 2002 of an investment in aircraft leases with United Airlines totaling $34 million, after-tax, partially offset by a maturing investment portfolio which produces lower income.

The loss for Edison International (parent) and other decreased $36 million primarily from charges in 2002 associated with businesses the company exited.

Operating Revenue

SCE's retail sales represented over approximately 85% of electric utility revenue. Due to warmer weather during the summer months, electric utility revenue during the third quarter of each year is generally significantly higher than other quarters.

The following table sets forth the major changes in electric utility revenue:

In millions Year ended December 31,	**2004 vs. 2003**	2003 vs. 2002
Electric utility revenue		
Rate changes (including surcharges)	**$ (707)**	$ (677)
Direct access credit	**—**	471
Sales volume changes	**(159)**	(60)
Sales for resale	**164**	394
SCE's variable interest entities	**285**	—
Other (including intercompany transactions)	**12**	20
Total	**$ (405)**	$ 148

Total electric utility revenue decreased by $405 million in 2004 (as shown in the table above). The reduction in electric utility revenue due to rate changes resulted from the implementation of a CPUC-approved customer rate reduction plan effective August 1, 2003 and the recognition of revenue in 2003 from a CPUC-authorized surcharge collected in 2002 used to recover costs incurred in 2003. There was no surcharge revenue recognized in 2004. The electric utility revenue reduction related to rate changes also reflects an increase in distribution rates and a further decrease in generation rates, effective in August 2004, resulting from the implementation of the 2003 GRC, and an allocation adjustment for the CDWR energy purchases recorded in 2003. The decrease in electric revenue resulting from sales volume changes was mainly due to the CDWR providing a greater amount of energy to SCE's customers in 2004, as compared to 2003 (see discussion below), partially offset by an increase in kWh sold. Sales for resale increased due to a greater amount of excess energy in 2004, as compared to 2003. As a result of the CDWR contracts allocated to SCE, excess energy from SCE sources may exist at certain times, which then is resold in the energy markets. SCE's variable interest entities revenue represents the recognition of revenue resulting from the consolidation of SCE's variable interest entities on March 31, 2004 (see "Critical Accounting Policies and Estimates" and "New Accounting Principles").

Total electric utility revenue increased by $148 million in 2003 (as shown in the table above). The reduction in electric utility revenue due to rate changes resulted from the implementation of a CPUC-approved customer rate-reduction plan effective August 1, 2003, partially offset by the recognition of revenue from a CPUC-authorized temporary surcharge collected between June and December 2002, used to recover costs incurred in 2003. The increase in electric utility revenue due to direct access credits resulted from a net 1¢-per-kWh decrease in credits given to direct access customers. The reduction in electric revenue resulting from changes in sales volume was mainly due to an increase in the amount allocated to the CDWR for bond and direct access exit fees (see discussion below), partially offset by an increase in kWh sold due to warmer weather in 2003 as compared to 2002. Sales for resale revenue increased due to a greater amount of excess energy at SCE in 2003 as compared to 2002.

Amounts SCE bills and collects from its customers for electric power purchased and sold by the CDWR to SCE's customers (beginning January 17, 2001), CDWR bond-related costs (beginning November 15, 2002) and direct access exit fees (beginning January 1, 2003) are remitted to the CDWR and are not

recognized as revenue by SCE. These amounts were $2.5 billion, $1.7 billion, and $1.4 billion for the years ended December 31, 2004, 2003, and 2002, respectively.

Nonutility power generation revenue decreased in 2004 and increased in 2003. The 2004 decrease was mainly due to the deconsolidation of EME's Doga project at March 31, 2004, in accordance with accounting standards (see "New Accounting Principles"). Revenue from EME's Doga project was $29 million (representing the first quarter of 2004) in 2004, $124 million in 2003, and $111 million in 2002. The decrease was also due to a $39 million decrease resulting from lower net gains from EME's price risk management and energy trading activities. The 2004 decrease was partially offset by higher energy revenue of $98 million at EME's Illinois plants resulting from increased merchant generation at higher merchant energy prices which offset the lower capacity payments of $91 million received at EME's Illinois plants under the power purchase agreements with Exelon Generation. The 2003 increase was primarily due to increased energy revenue from EME's Homer City facilities and EME's Illinois plants, partially offset by lower capacity revenue from EME's Illinois plants due to a deduction in megawatts under contract with Exelon Generation. The energy revenue increase at EME's Homer City facilities was primarily due to increased generation and higher energy prices. The increase in energy revenue at EME's Illinois plants was due to the shift to merchant generation.

Nonutility power generation revenue is materially higher in the third quarter than revenue related to other quarters of the year. Due to higher electric demand resulting from warmer weather during the summer months, nonutility power generation revenue generated from EME's Homer City facilities and the Illinois plants are generally higher during the third quarter of each year.

Financial services and other revenue increased in both 2004 and 2003. The 2004 increase was primarily due to the recognition of $12 million in revenue resulting from the consolidation of Edison Capital's variable interest entities (see "New Accounting Principles") and the consolidation of a project at Edison Capital in the fourth quarter of 2003 resulting from a change in control. The 2003 increase was primarily due to Edison Capital's recording of the cumulative impact of a change in its effective state tax rate on leveraged leases in 2002 (that was substantially offset by tax benefits), partially offset by Edison Capital's maturing lease portfolio, the termination of a major contract at a nonutility subsidiary providing operation and maintenance services and no nonutility real estate sales in 2003, as compared to 2002, for another subsidiary.

Operating Expenses

Fuel Expense

In millions Year ended December 31,	**2004**	2003	2002
SCE	**$ 810**	$ 235	$ 243
MEHC	**619**	670	611
Edison International Consolidated	**$ 1,429**	$ 905	$ 854

SCE's fuel expense increased in 2004 primarily due to the consolidation of SCE's variable interest entities resulting in the recognition of fuel expense of $578 million (see "New Accounting Principles").

MEHC's fuel expense decreased in 2004 primarily due to the deconsolidation of EME's Doga project, resulting in a decrease of $67 million. The decrease was partially offset by higher cost of emission allowances at EME's Homer City facilities. The 2003 increase was primarily due to increased generation at EME's Homer City facilities primarily resulting from outages experienced during the first two quarters of 2002.

Purchased-Power Expense

Purchased-power expense decreased $454 million in 2004 and increased $770 million in 2003. The 2004 decrease was mainly due to the consolidation of SCE's variable interest entities which resulted in a $669 million reduction in purchased-power expense (see "New Accounting Principles") and the receipt of approximately $190 million in settlement agreement payments between SCE and sellers of electricity and natural gas. See "SCE: Regulatory Matters—Transmission and Distribution—Wholesale Electricity and Natural Gas Markets" for a discussion of the settlements reached. The decrease was partially offset by higher expenses of approximately $150 million related to power purchased by SCE from QFs, as discussed below, higher expenses of approximately $100 million resulting from an increase in the number of gas bilateral contracts in 2004, as compared to 2003, and higher expenses of approximately $130 million related to ISO purchases. The 2003 increase was mainly due to higher expenses resulting from SCE's resumption of power procurement on January 1, 2003. The higher expenses resulted from an increase in the number of bilateral contracts entered into during 2003 and an increase in energy purchased in 2003. The increase also includes higher expenses related to power purchased by SCE from QFs, mainly due to higher spot natural gas prices in 2003 as compared to 2002.

Federal law and CPUC orders required SCE to enter into contracts to purchase power from QFs at CPUC-mandated prices. Energy payments to gas-fired QFs are generally tied to spot natural gas prices. Effective May 2002, energy payments for most renewable QFs were converted to a fixed price of 5.37¢-per-kWh. Average spot natural gas prices were higher during 2004 as compared to 2003, and were higher during 2003, as compared to 2002.

Provisions for Regulatory Adjustment Clauses – Net

Provisions for regulatory adjustment clauses – net decreased $1.3 billion in 2004 and $364 million in 2003. The 2004 decrease was mainly due to the collection of the PROACT balance in 2003 and the implementation of the CPUC-authorized rate-reduction plan in the summer of 2003, resulting in decreases of approximately $700 million. The decrease also reflects a net effect of approximately $335 million of regulatory adjustments, related to the implementation of SCE's 2003 GRC decision (see "SCE: Regulatory Matters—Transmission and Distribution—2003 General Rate Case Proceeding") and ERRA-related adjustments resulting from a CPUC decision received in January 2005 (see "SCE: Regulatory Matters—Generation and Power Procurement—Energy Resource Recovery Account Proceedings"), and the deferral of costs for future recovery in the amount of approximately $100 million associated with the bark beetle infestation (see "SCE: Regulatory Matters—Other Regulatory Matters—Catastrophic Event Memorandum Account"). The decrease was partially offset by approximately $190 million in settlement agreement payments received and refunded to ratepayers and shareholder incentives (see "SCE: Regulatory Matters—Transmission and Distribution—Wholesale Electricity and Natural Gas Markets"), the favorable resolution of certain regulatory cases recorded in the third quarter of 2003 (as discussed below), and an allocation adjustment of approximately $110 million for CDWR energy purchases recorded in 2003. The 2003 decrease was mainly due to lower overcollections used to recover SCE's PROACT balance, the implementation of the CPUC-authorized customer rate-reduction plan, a net increase in energy procurement costs and favorable resolution of several regulatory proceedings. The 2003 proceedings include the CPUC decision on the allocation of certain costs between state and federal regulatory jurisdictions and the final disposition of the PROACT. The 2003 decrease was partially offset by the implementation of the CPUC decision related to URG and the PBR mechanism, as well as the impact of other regulatory actions recorded in 2002.

As a result of the URG decision received in 2002, SCE reestablished regulatory assets previously written off (approximately $1.1 billion) related to its nuclear plant investments, purchased-power settlements and flow-through taxes, and decreased the PROACT balance by $256 million, all retroactive to January 1, 2002. The impact of the URG decision is reflected in the 2002 financial statements as a credit (decrease) to the provisions for regulatory adjustment clauses of $644 million, partially offset by an increase in deferred

income tax expense of $164 million, for a net credit to earnings of $480 million. As a result of the CPUC decision that modified the PBR mechanism, SCE recorded a $136 million credit (decrease) to the provisions for regulatory adjustment clauses in the second quarter of 2002, to reflect undercollections in CPUC-authorized revenue resulting from changes in retail rates.

Other Operation and Maintenance Expense

In millions Year ended December 31,	**2004**	2003	2002
SCE	**$ 2,457**	$ 2,072	$ 1,935
MEHC	**819**	783	762
Other	**66**	55	115
Edison International Consolidated	**$ 3,342**	$ 2,910	$ 2,812

SCE's other operating and maintenance expense increased in 2004 and 2003. The 2004 increase was mainly due to approximately $130 million of costs incurred in 2004 related to the removal of trees and vegetation associated with the bark beetle infestation (see "SCE: Regulatory Matters—Other Regulatory Matters—Catastrophic Event Memorandum Account"), higher operation and maintenance costs of approximately $60 million related to the San Onofre refueling outages in 2004, operating and maintenance expense of $66 million related to the consolidation of SCE's variable interest entities, higher operation and maintenance costs related to a scheduled major overhaul at SCE's Four Corners coal facility and additional costs for 2003 incentive compensation due to upward revisions in the computation in 2004. These increases were partially offset by a decrease in postretirement benefits other than pensions, including the effects of adopting the Medicare Prescription Drug, Improvement and Modernization Act of 2003 in the third quarter of 2004 (see "New Accounting Principles" for further discussion) and lower worker's compensation claims in 2004. The 2003 increase was mainly due to higher health-care costs, higher spending on certain CPUC-authorized programs, higher transmission access charges and costs incurred in 2003 related to the removal of dead, dying and diseased trees and vegetation associated with the bark beetle infestation.

MEHC's other operation and maintenance expense increased in 2004 and 2003. The 2004 increase was mainly due to a $56 million charge at EME's Illinois plants related to an estimate of possible future payments under a contract indemnity agreement related to asbestos claims with respect to activities at EME's Illinois plants prior to their acquisition in 1999. For further discussion see "Commitments, Guarantees and Indemnities—Guarantees and Indemnities—Indemnities Provided as Part of the Acquisition of the Illinois Plants." The increase was partially offset by lower plant operating lease costs due to the termination of EME's Collins Station lease in April 2004. In 2002, EME recorded a $45 million charge related to a settlement of EME's Chicago In-City obligation and a $71 million gain related to the termination of postretirement benefits, as discussed below.

The settlement of postretirement employee benefit liability in 2002 relates to a retirement health care and other benefits plan for union-represented employees at the Illinois plants that expired on June 15, 2002. In October 2002, Midwest Generation reached an agreement with its union-represented employees on new benefits plans, which extend from January 1, 2003 through June 15, 2006. Midwest Generation continued to provide benefits at the same level as those in the expired agreement until December 31, 2002. The accounting for postretirement benefits liabilities has been determined on the basis of a substantive plan under an accounting standard for postretirement benefits other than pensions. A substantive plan means that Midwest Generation assumed, for accounting purposes, it would provide for postretirement health care benefits to union-represented employees following conclusion of negotiations to replace the current benefits agreement, even though Midwest Generation had no legal obligation to do so. Under the new agreement, postretirement health care benefits will not be provided. Accordingly, Midwest Generation treated this as a plan termination in accordance with this accounting standard and recorded a pre-tax gain of $71 million during the fourth quarter of 2002.

Asset Impairment and Loss on Lease Termination

Asset impairment and loss on lease termination in 2004 consist of a $961 million loss recorded in 2004 related to the termination of EME's Collins Station lease and the return of ownership of the Collins Station to EME, and the impairment of plant assets and related inventory reserves (see "MEHC: Liquidity—Termination of the Collins Station Lease" for further discussion) and a $29 million charge related to the impairment of six of EME's eight small peaking units in Illinois. Asset impairment and loss on lease termination in 2003 consisted of $245 million related to the impairment of all eight small peaking plants owned by EME's subsidiary, Midwest Generation, and $59 million loss related to the write-down of EME's investment in the Brooklyn Navy Yard and Gordonsville projects. The impairment charge related to the peaking plants resulted from a revised long-term outlook for capacity revenue from the peaking plants. The lower capacity revenue outlook is the result of a number of factors, including higher long-term natural gas prices and generation overcapacity. Asset impairment and loss on lease termination in 2002 consisted of $61 million related to the write-off of capitalized costs associated with EME's termination of equipment purchase contracts and $25 million related to the write-off of capitalized costs associated with EME's suspension of its Powerton Station selective catalytic reduction major capital improvement project at its Illinois plants.

Depreciation, Decommissioning and Amortization Expense

In millions Year ended December 31,	**2004**	2003	2002
SCE	**$ 860**	$ 882	$ 780
MEHC	**143**	154	145
Other	**19**	11	3
Edison International Consolidated	**$ 1,022**	$ 1,047	$ 928

SCE's depreciation, decommissioning and amortization expense decreased in 2004 and increased in 2003. The 2004 decrease was mainly due to a change in the Palo Verde and San Onofre rate-making mechanisms in 2003 and 2004, partially offset by an increase in SCE's depreciation associated with additions to transmission and distribution assets, the consolidation of SCE's variable interest entities, and an increase in nuclear decommissioning expense. The 2003 increase was mainly due to an increase in depreciation expense associated with SCE's additions to transmission and distribution assets, an increase in nuclear decommissioning expense, partially offset by a change in the amortization period for SCE's San Onofre recorded in the third quarter of 2002 based on the implementation of a CPUC decision.

Other Income and Deductions

Interest and Dividend Income

In millions Year ended December 31,	**2004**	2003	2002
SCE	**$ 15**	$ 96	$ 254
Other	**31**	22	25
Edison International Consolidated	**$ 46**	$ 118	$ 279

SCE's interest and dividend income decreased in both 2004 and 2003, mainly due to the absence of interest income on the PROACT balance. At July 31, 2003, the PROACT balance was overcollected and was transferred to the ERRA on August 1, 2003. The 2003 decrease was also due to lower interest income from lower average cash balances, compared to the same period in 2002.

Equity in Income from Partnerships and Unconsolidated Subsidiaries – Net

Equity in income from partnerships and unconsolidated subsidiaries – net decreased $165 million in 2004 and increased $68 million in 2003. The 2004 decrease was due to the effects of accounting for variable interest entities consolidated upon adoption of a new accounting pronouncement in second quarter 2004, resulting in a decrease of $139 million. As a result, SCE now consolidates projects previously treated under the equity method by EME. The 2004 decrease also resulted from the sale of EME's ownership interest in Four Star Oil & Gas on January 7, 2004. Equity in income from EME's Four Star Oil & Gas in 2003 and 2002 were $43 million and $20 million, respectively, compared to no earnings in 2004. In addition, the 2004 decrease resulted from the early termination of notes related to 8.6% and 7.875% cumulative quarterly income preferred securities issued through affiliates (EIX Trust I and II) resulting in the write-off of approximately $20 million in associated unamortized debt expenses. The 2004 decrease was partially offset by an increase of approximately $26 million primarily in earnings from Edison Capital's global infrastructure funds. The 2003 increase was primarily due to an increase in EME's income from the Big 4 projects, Four Star Oil & Gas and the Sunrise project mainly due to higher energy prices and increased earnings from Edison Capital's global infrastructure funds.

Other Nonoperating Income

In millions	Year ended December 31,	2004	2003	2002
SCE		**$ 84**	$ 72	$ 75
MEHC		**51**	3	—
Other		**—**	11	10
Edison International Consolidated		**$ 135**	$ 86	$ 85

MEHC's other nonoperating income increased in 2004 relates to a pre-tax gain of $47 million on the sale of EME's interest in Four Star Oil & Gas on January 7, 2004 (see "Acquisitions and Dispositions").

Interest Expense – Net of Amounts Capitalized

In millions	Year ended December 31,	2004	2003	2002
SCE		**$ (409)**	$ (457)	$ (584)
MEHC		**(449)**	(451)	(453)
Other		**(127)**	(112)	(89)
Edison International Consolidated		**$ (985)**	$ (1,020)	$(1,126)

In 2003 dividend payments on certain preferred securities were reclassified to interest expense. Effective July 1, 2003, dividend payments on preferred securities subject to mandatory redemption are included as interest expense based on the adoption of a new accounting standard. The new standard did not allow for prior period restatements, therefore dividends on preferred securities subject to mandatory redemption for the first six months of 2003 and 2002 are not included in interest expense – net of amounts capitalized in the consolidated statements of income.

In addition to the discussion above, SCE's interest expense – net of amounts capitalized decreased in both 2004 and 2003. The 2004 decrease was mainly due to lower interest expense on long-term debt resulting from the redemption of high interest rate debt by issuing new debt with lower interest rates. The 2003 decrease was due to higher interest expense in 2002 resulting from the 2001 and early 2002 suspension of payments for purchased power (these suspended payments were paid in March 2002), as well as lower interest expense on SCE's long-term debt resulting from the early retirement of debt.

Other Nonoperating Deductions

In millions Year ended December 31,	2004	2003	2002
SCE	**$ (69)**	$ (23)	$ 18
Other	**(11)**	(9)	(50)
Edison International Consolidated	**$ (80)**	$ (32)	$ (32)

SCE's other nonoperating deductions increased in 2004 and 2003. The 2004 increase was mainly due to a $29 million pre-tax charge for the anticipated refund of the previously received performance incentive rewards as well as the accrual of $6 million in system reliability penalties (see "SCE: Regulatory Matters—Other Regulatory Matters—Investigation Regarding Performance Incentive Rewards"). The 2003 increase was due to the resolution of regulatory matters accrued for in 2002.

Other nonoperating income in 2002 for other subsidiaries mainly represents a goodwill impairment charge associated with EME's Citizens Power acquisition resulting from adoption of an accounting standard in 2002. The adoption of the standard was not material to Edison International; therefore the impact was recorded in other nonoperating deductions, rather than as a cumulative effect of a change in accounting principle and foreign exchange losses at Edison Capital.

Minority Interest

Minority interest represents the effects of the adoption of a new accounting pronouncement in second quarter 2004 related to SCE's variable interest entities (see "Critical Accounting Policies and Estimates" and "New Accounting Principles").

Income Taxes

In millions Year ended December 31,	2004	2003	2002
SCE	**$ 438**	$ 388	$ 642
MEHC	**(462)**	(174)	(90)
Edison Capital	**(13)**	(38)	(146)
Edison International (parent) and other	**(55)**	(52)	(76)
Edison International Consolidated	**$ (92)**	$ 124	$ 330

Income tax expense decreased in both 2004 and 2003. The 2004 and 2003 decreases were primarily due to reductions in pre-tax income. The 2004 decrease also resulted from adjustments to accrued tax liabilities to reflect the receipt of an IRS audit report and progress achieved in settlement negotiations for issues relating to prior year tax liabilities at SCE, partially offset by the favorable resolution of FERC rate case recorded by SCE in 2003. The 2003 decrease also resulted from the favorable resolution of a FERC rate case at SCE, partially offset by the reestablishment of tax-related regulatory assets upon implementation of the URG decision at SCE and the cumulative adjustment to deferred tax balances at Edison Capital to reflect changes in its effective state tax rate, both recorded in 2002.

Edison International's composite federal and state statutory rate was approximately 40% for all years presented. The effective tax benefit rate of 68.7% realized in 2004 was primarily due to adjustments to tax liabilities relating to prior years at SCE and the benefits received from low income housing and production tax credits at Edison Capital, partially offset by property-related flow-through items and property-related adjustments at SCE. The lower effective tax rate of 16.0% realized in 2003 was primarily due to the resolution of a FERC rate case and recording the benefit of settlements of IRS audit issues at SCE and the benefits received from low-income housing and production tax credits at Edison Capital. The lower effective tax rate of 23.7% realized in 2002 was primarily due to the reestablishment

of tax-related regulatory assets upon implementation of the URG decision at SCE, a cumulative adjustment to deferred tax balances at Edison Capital to reflect changes in its effective state tax rate, the benefit of favorable settlements of IRS audits at SCE and the benefits received from low-income housing and production credits at Edison Capital.

Income from Discontinued Operations

Income from discontinued operations for the year ended December 31, 2003 included a gain on sale and operating results totaling $50 million from SCE's pipeline business which was sold in the third quarter of 2003 and income from discontinued operations of $690 million in 2004 compared to $124 million in 2003 at MEHC. MEHC's 2004 results of discontinued operations include gains of $533 million related to both the sale of its interests in Contact Energy and the sale of the Dutch holding company. In 2004, MEHC completed the sale of 11 of its 14 international projects. Two of the three remaining projects were sold in early 2005 and one project has not been sold at this time.

Excluding the gain, MEHC's earnings from discontinued operations were $157 million during 2004 compared to $124 million in 2003. The increase in earnings is due to improved performance at First Hydro, EcoEléctrica and Loy Yang B offset by interest costs related to the $800 million bridge loan completed in December 2003.

Cumulative Effect of Accounting Change – Net of Tax

Edison International's results for 2003 include a charge at EME for the cumulative effect of an accounting change related to the accounting standard for recording asset retirement obligations. Because SCE follows accounting principles for rate-regulated enterprises and receives recovery of these costs through rates, implementation of this new standard did not affect earnings.

Historical Cash Flow Analysis

The "Historical Cash Flow Analysis" section of this MD&A discusses consolidated cash flows from operating, financing and investing activities.

Cash Flows from Operating Activities

Net cash provided by operating activities:

In millions	Year ended December 31,	**2004**	2003	2002
Continuing operations		**$ 1,600**	$ 3,061	$ 2,011

The 2004 decrease in cash provided by operating activities from continuing operations was mainly due to SCE's implementation of a CPUC-approved customer rate reduction plan effective August 1, 2003 and EME's 2004 lease termination payment of $960 million related to its Collins Station lease. The 2003 increase in cash provided by operating activities from continuing operations was mainly due to SCE's March 2002 repayment of past-due obligations. The change during both periods was also due to timing of cash receipts and disbursements related to working capital items at both SCE and EME.

Cash Flows from Financing Activities

Net cash used by financing activities:

In millions Year ended December 31,	2004	2003	2002
Continuing operations	**$ (1,258)**	$ (2,113)	$ (2,487)

Cash used by financing activities from continuing operations mainly consisted of long-term and short-term debt payments at SCE and EME.

In 2004, Edison International (parent) repaid its $618 million 6-7/8% notes due September 2004 and $825 million of notes related to 8.6% and 7.875% cumulative quarterly income preferred securities issued through affiliates (EIX Trust I and II). SCE financing activities in 2004 include the issuance of $300 million of 5% bonds due in 2014, $525 million of 6% bonds due in 2034 and $150 million of floating rate bonds due in 2006 all issued during the first quarter of 2004. The proceeds from these issuances were used to call at par $300 million of 7.25% first and refunding mortgage bonds due March 2026, $225 million of 7.125% first and refunding mortgage bonds due July 2025, $200 million of 6.9% first and refunding mortgage bonds due October 2018, and $100 million of junior subordinated deferrable interest debentures due June 2044. In addition, during the first quarter of 2004, SCE paid the $200 million outstanding balance of its credit facility, as well as remarketed approximately $550 million of pollution-control bonds with varying maturity dates ranging from 2008 to 2040. Approximately $354 million of these pollution-control bonds had been held by SCE since 2001 and the remaining $196 million were purchased and reoffered in 2004. In March 2004, SCE issued $300 million of 4.65% first and refunding mortgage bonds due in 2015 and $350 million of 5.75% first and refunding mortgage bonds due in 2035. A portion of the proceeds from the March 2004 first and refunding mortgage bond issuances were used to fund the acquisition and construction of the Mountainview project. During the third quarter, SCE paid $125 million of 5.875% bonds due in September 2004. During the fourth quarter, SCE issued $150 million of floating rate first and refunding mortgage bonds due in 2007. MEHC's financing activities included the $1 billion secured notes and $700 million term loan facility received by Midwest Generation in April 2004, the repayment of the $800 million secured loan at EME's subsidiary, Mission Energy Holdings International, Inc., $693 million related to Edison Mission Midwest Holdings' credit facility, $28 million related to the EME's Coal and Capex facility in April 2004, and $100 million related to MEHC's $385 million term loan in July 2004. Edison Capital's financing activities included net payments of $119 million on long-term debt. Financing activities in 2004 also included dividend payments of $261 million paid by Edison International to its shareholders.

During the first quarter of 2003, Edison International (parent) repurchased approximately $132 million of the outstanding $750 million of its 6-7/8% notes due September 2004. No repurchases were made during the remainder of 2003. SCE's financing activities during 2003 included an exchange offer of $966 million of 8.95% variable rate notes due November 2003 for $966 million of new series first and refunding mortgage bonds due February 2007. In addition, during 2003, SCE repaid $125 million of its 6.25% bonds, the outstanding balance of $300 million of a $600 million one-year term loan due March 3, 2003, $300 million on its revolving line of credit, and $700 million of a term loan due March 2005. The $700 million term loan was retired with a cash payment of $500 million and $200 million drawn on a $700 million credit facility that expires in 2006. MEHC's financing activity during 2003 includes an $800 million secured loan received by EME's subsidiary, Mission Energy Holdings International, Inc., debt service payments of $911 million related to Tranche A and $116 million related to Tranche B of Edison Mission Energy Holdings' credit facility, repayment of $167 million on the Coal and Capex facility guaranteed by EME, and debt service payments of $118 million related to three of EME's subsidiaries.

During the first quarter of 2002, SCE paid $531 million of matured commercial paper and remarketed $196 million of the $550 million of pollution-control bonds repurchased during December 2000 and early 2001. Also during the first quarter of 2002, SCE replaced the $1.65 billion credit facility with a $1.6 billion financing and made a payment of $50 million to retire the entire credit facility. Throughout the year, SCE paid approximately $1.2 billion of maturing long-term debt. The $1.6 billion financing included a $600 million, one-year term loan due March 3, 2003. SCE prepaid $300 million of this loan in August 2002. MEHC's debt payments in 2002 consisted of payment of $100 million of senior notes that matured in 2002, net payments of $80 million on EME's corporate credit facility, $44 million related to debt service payments, payments of $86 million on EME's debentures and notes and net payments of $30 million in connection with a swap agreement. In addition, a wholly owned subsidiary of EME borrowed $84 million under a note purchase agreement. Edison Capital's net payments on short-term debt were approximately $312 million.

Cash Flows from Investing Activities

Net cash provided (used) by investing activities:

In millions	Year ended December 31,	2004	2003	2002
Continuing operations		**$ 640**	$ (1,173)	$ (1,225)

Cash flows from investing activities are affected by capital expenditures, EME's sales of assets and SCE's funding of nuclear decommissioning trusts.

Investing activities in 2004 reflect $1.7 billion in capital expenditures at SCE, primarily for transmission and distribution assets, including approximately $70 million for nuclear fuel acquisitions, and $55 million in capital expenditures at EME. In addition, investing activities include $285 million of acquisition costs related to the Mountainview project at SCE, $118 million in proceeds received in 2004 at EME from the sale of 100% of EME's stock of Edison Mission Energy Oil & Gas and the sale of EME's 50% partnership interest in the Brooklyn Navy Yard project, and $2.7 billion in proceeds received in 2004 at EME from the sale of its international projects.

SCE's capital expenditures during 2003 were approximately $1.2 billion, primarily for transmission and distribution assets. EME's capital expenditures in 2003 were $81 million primarily for new plant and equipment related to EME's Illinois plants and its Homer City facilities.

SCE's capital expenditures during 2002 were approximately $1.0 billion, primarily for transmission and distribution assets; EME's capital expenditures of $497 million included a $300 million payment for the Illinois peaker power units that were subject to a lease (see "Off-Balance Sheet Transactions—EME's Off-Balance Sheet Transactions"). The remaining capital expenditures were primarily for EME's Illinois plants, the Homer City facilities and payments related to three turbines. These increases were partially offset by proceeds from the sale of various EME projects.

Nuclear decommissioning costs are recovered in utility rates. These costs are expected to be funded from independent decommissioning trusts that receive SCE contributions of approximately $32 million per year. The fair value of decommissioning SCE's nuclear power facilities is $2.2 billion as of December 31, 2004, based on site-specific studies performed in 2001 for San Onofre and Palo Verde. As of December 31, 2004, the decommissioning trust balance was $2.7 billion. The CPUC has set certain restrictions related to the investments of these trusts. Contributions to the decommissioning trusts are reviewed every three years by the CPUC. The contributions are determined from an analysis of estimated decommissioning costs, the current value of trust assets and long-term forecasts of cost escalation and after-tax return on trust investments. Favorable or unfavorable investment performance in a period will not change the amount of contributions for that period. However, trust performance for the three years

leading up to a CPUC review proceeding will provide input into future contributions. SCE's costs to decommission San Onofre Unit 1 are paid from the nuclear decommissioning trust funds. These withdrawals from the decommissioning trusts are netted with the contributions to the trust funds in the Consolidated Statements of Cash Flows.

Net Change in Cash of Discontinued Operations

Net change in cash of discontinued operations for 2004 was $(519) million which primarily related to the reduction in working capital resulting from the sale of substantially all of EME's international projects described under "Discontinued Operations." The gross proceeds from EME's sale of its international projects is reflected as cash flow from investing activities in the Consolidated Statement of Cash Flows, whereby the cash from discontinued operations acquired by the purchasing entity (approximately $145 million) and income taxes resulting from the sale of the projects (approximately $400 million) are reflected as a decrease in cash of discontinued operations.

DISCONTINUED OPERATIONS

On February 3, 2005, EME sold its 25% equity interest in the Tri Energy project for approximately $20 million.

On January 10, 2005, EME completed the sale of its 50% equity interest in the Caliraya-Botocan-Kalayaan (CBK) project pursuant to a purchase agreement, dated November 5, 2004, by and between EME and Corporacion IMPSA S.A. Proceeds from the sale were approximately $104 million.

On December 16, 2004, EME completed the sale of the stock and related assets of MEC International B.V. (MECIBV) to a consortium comprised of International Power plc (70%) and Mitsui & Co., Ltd. (30%), referred to as IPM, pursuant to a purchase agreement dated July 29, 2004. The purchase agreement was entered into following a competitive bidding process. The sale of MEC International B.V. included the sale of EME's interests in ten electric power generating projects or companies located in Europe, Asia, Australia, and Puerto Rico. Consideration from the sale of MECIBV and related assets was $2.0 billion.

On September 30, 2004, EME completed the sale of its 51% interest in Contact Energy to Origin Energy New Zealand Limited pursuant to a purchase agreement dated July 20, 2004. The purchase agreement was entered into following a competitive bidding process. Consideration for the sale was NZ$1.6 billion (approximately $1.1 billion) which includes NZ$535 million of debt assumed by the purchaser.

On July 10, 2003, the CPUC approved SCE's sale of certain oil storage and pipeline facilities to Pacific Terminals LLC for $158 million. In third quarter 2003, SCE recorded a $44 million after-tax gain to shareholders.

In 2001, EME ceased consolidating the activities of Lakeland Power Ltd. when an administrative receiver was appointed following a default by Norweb Energi Ltd., the counterparty to a long-term power sales agreement. In 2003, a third party completed the purchase of the Lakeland power plant from the administrative receiver for £24 million. The proceeds from the sale and existing cash were used to fund partial repayment of the outstanding debt owed to secured creditors of the project. Lakeland Power Ltd.'s administrative receiver has filed a claim against Norweb Energi Ltd. for termination of the power purchase agreement. Norweb Energi Ltd. is a subsidiary of TXU (UK) Holdings Limited (TXU UK) and is an indirect subsidiary of TXU Europe Group plc (TXU Europe). On November 19, 2002, TXU UK and TXU Europe, together with a related entity, TXU Europe Energy Trading Limited (TXU Energy), entered into formal administration proceedings in the United Kingdom (similar to bankruptcy proceedings in the United States). To the extent that Lakeland Power receives payment under its claim, such amounts will first be used to repay amounts due to creditors. In October 2004, EME purchased the debt owed

them by Lakeland Power from Lakeland's secured creditors for approximately £6 million. The purchase of the outstanding bank debt was completed to maximize EME's recovery from the proceeds ultimately received from the claim against Norweb Energi. Based on the settlement of claims currently being discussed as part of the TXU Europe administration proceeding, the secured debt of Lakeland Power is expected to be repaid in full. In addition, depending on the outcome of the TXU Europe administration proceedings, EME may receive additional cash from the settlement of the claims. The loss from operations of Lakeland in 2002 includes an impairment charge of $92 million ($77 million after tax) and a provision for bad debts of $1 million (after tax) arising from the write-down of the Lakeland power plant and related claims under the power sales agreement (an asset group according to an impairment standard) to their fair market value. The fair value of the asset group was determined based on discounted cash flows and estimated recovery under related claims under the power sales agreement.

On December 21, 2001, EME completed the sale of the Ferrybridge and Fiddler's Ferry coal stations located in the United Kingdom to two wholly owned subsidiaries of American Electric Power. The net proceeds from the sale (£643 million) were used to repay borrowings outstanding under the existing debt facility related to the acquisition of the plants. In addition, the buyers acquired other assets and assumed specified liabilities associated with the plants. EME recorded a charge of $1.9 billion ($1.1 billion after tax) related to the loss on sale. The loss from operations of Ferrybridge and Fiddler's Ferry in 2002 includes a $7 million loss on settlement of the pension plan related to previous employees of the Ferrybridge and Fiddler's Ferry project, partially offset from an insurance recovery from claims filed prior to the sale of the power plants. The loss on settlement of the pension plan arose from the election by former employees in March 2002 to transfer to AEP's new pension plan and the subsequent transfer of pension assets and liabilities in December 2002 in accordance with the terms of the sale agreement.

For all years presented, the results of EME's international projects discussed above have been accounted for as discontinued operations in the consolidated financial statements in accordance with an accounting standard related to the impairment and disposal of long-lived assets.

Additionally, in 2003 the results of SCE's oil storage and pipeline facilities unit have been accounted for as a discontinued operation in accordance with an accounting standard related to the impairment and disposal of long-lived assets. Due to immateriality, the results of this unit for 2002 have not been restated and are reflected as part of continuing operations.

Unless otherwise discussed above, the consolidated financial statements have been restated to conform to the discontinued operations presentation for all years presented.

Revenue from discontinued operations was $1.3 billion in 2004, $1.5 billion in 2003 and $1.2 billion in 2002. The before-tax earnings of the discontinued operations were $737 million in 2004, $296 million in 2003 and $66 million in 2002. The before-tax earnings of discontinued operations in 2004 included a $532 million gain on sale related to EME's international power generation portfolio.

ACQUISITIONS AND DISPOSITIONS

Acquisition

On March 12, 2004, SCE acquired Mountainview Power Company LLC, which owns a power plant under construction in Redlands, California. SCE recommenced full construction of the approximately $600 million project, which is expected to be completed in early 2006.

Dispositions

See "Discontinued Operations" for a discussion of dispositions accounted for as discontinued operations.

On March 31, 2004, EME completed the sale of its 50% partnership interest in Brooklyn Navy Yard Cogeneration Partners L.P. for a sales price of approximately $42 million. EME recorded an impairment charge of $53 million during the fourth quarter of 2003 related to the planned disposition of this investment and a pre-tax loss of approximately $4 million during the first quarter of 2004 due to changes in the terms of the sale.

On January 7, 2004, EME completed the sale of 100% of its stock of Edison Mission Energy Oil & Gas, which in turn held minority interests in Four Star Oil & Gas. Proceeds from the sale were approximately $100 million. EME recorded a pre-tax gain on the sale of approximately $47 million during the first quarter of 2004.

In fourth quarter 2003, Gordonsville Energy Limited Partnership, in which EME owns a 50% interest, completed the sale of the Gordonsville cogeneration facility. Proceeds from the sale, including distribution of a debt service reserve fund, were $36 million. In second quarter 2003, EME recorded an impairment charge of $6 million related to the planned disposition of this investment.

During 2002, EME completed the sales of its 50% interests in the Commonwealth Atlantic and James River projects and its 30% interest in the Harbor project. Proceeds received from the sales were $44 million. During 2001, EME had previously recorded asset impairment charges of $32 million related to these projects based on the expected sales proceeds. No gain or loss was recorded from the sale of EME's interests in these projects during 2002.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The accounting policies described below are viewed by management as critical because their application is the most relevant and material to Edison International's results of operations and financial position and these policies require the use of material judgments and estimates.

Asset Dispositions and Related Matters

During 2004, EME completed the sale of the majority of its international operations and recorded a gain on sale. Computing the after-tax gain on sale involved a number of critical accounting estimates requiring management's judgment, including determining the fair value of contract indemnities and income taxes under new regulations as described below:

- The asset sale agreements contain indemnities from EME to the purchasers, including indemnification for pre-closing environmental liabilities and for pre-closing foreign taxes imposed with respect to operations of assets prior to the sale. EME also provided an indemnity to IPM for matters arising out of the exercise by one of its project partners of a purported right of first refusal. Under accounting standards, EME recorded the fair value of the contract indemnities as a liability.

- Prior to the completion of the sale of the international projects, EME paid a dividend from its Dutch holding company. On October 22, 2004, The American Jobs Creation Act of 2004 was enacted which, among other things, included a provision to exclude from federal income taxes 85% of dividends repatriated from foreign subsidiaries for permitted purposes. While announced by the IRS, its detailed guidance on how these provisions will be interpreted has not yet been issued.

At December 31, 2004, EME recorded a liability of $158 million related to the above matters which was included in determining the gain on sale of the international projects.

In addition to the foreign items related to asset sales, Midwest Generation has agreed to reimburse Commonwealth Edison and Exelon Generation for 50% of specific existing asbestos claims and expenses less recovery of insurance costs, and agreed to a sharing arrangement for liabilities and expenses associated with future asbestos-related claims as specified in a supplemental agreement (see "Commitments, Guarantees and Indemnities—Guarantees and Indemnities"). Midwest Generation engaged an independent actuary with extensive experience in performing asbestos studies to estimate future losses based on the claims experience and other information available. In calculating future losses, the actuary made various assumptions, including, but not limited to, the settlement of future claims under the supplemental agreement with Commonwealth Edison as described above, the distribution of exposure sites, and that the filing date of asbestos claims will not be after 2045. At December 31, 2004, Midwest Generation had $69 million recorded as a liability related this contract indemnity.

Asset Impairment

Edison International evaluates long-lived assets whenever indicators of potential impairment exist. Accounting standards require that if the undiscounted expected future cash flow from a company's assets or group of assets (without interest charges) is less than its carrying value, an asset impairment must be recognized in the financial statements. The amount of impairment is determined by the difference between the carrying amount and fair value of the asset.

The assessment of impairment is a critical accounting estimate because significant management judgment is required to determine: (1) if an indicator of impairment has occurred, (2) how assets should be grouped, (3) the forecast of undiscounted expected future cash flow over the asset's estimated useful life to determine if an impairment exists, and (4) if an impairment exists, the fair value of the asset or asset group. Factors Edison International considers important, which could trigger an impairment, include operating losses from a project, projected future operating losses, the financial condition of counterparties, or significant negative industry or economic trends.

During 2004 and 2003, EME recorded impairment charges of $35 million and $304 million, respectively, related to specific assets included in continuing operations. See "Results of Operations and Historical Cash Flow Analysis—Results of Operations."

During the fourth quarter of 2002, SCE assessed the impairment of Mohave due to the probability of a plant shutdown at the end of 2005. Because the expected undiscounted cash flows from the plant during the years 2003–2005 were less than the $88 million carrying value of the plant as of December 31, 2002, SCE incurred an impairment charge of $61 million. However, in accordance with accounting standards for rate-regulated enterprises, this incurred cost was deferred and recorded in regulatory assets as a long-term receivable to be collected from customer revenue. This treatment was based on SCE's expectation that any unrecovered book value at the end of 2005 would be recovered in future rates (together with a reasonable return) through a balancing account mechanism. See "SCE: Regulatory Matters—Generation and Power Procurement—Mohave Generating Station and Related Proceedings," and "—Rate Regulated Enterprises."

Derivative Financial Instruments and Hedging Activities

Edison International follows the accounting standard for derivative instruments and hedging activities, which requires derivative financial instruments to be recorded at their fair value unless an exception applies. The accounting standard also requires that changes in a derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. For derivatives that qualify for hedge accounting, depending on the nature of the hedge, changes in fair value are either offset by changes in the fair value of the hedged assets, liabilities or firm commitments through earnings, or recognized in other comprehensive income until the hedged item is recognized in earnings. The ineffective portion of a derivative's change in fair value is immediately recognized in earnings.

EME uses derivative financial instruments for price risk management activities and trading purposes. Derivative financial instruments are mainly utilized to manage exposure from changes in electricity and fuel prices, interest rates and fluctuations in foreign currency exchange rates.

Management's judgment is required to determine if a transaction meets the definition of a derivative and whether the normal sales and purchases exception applies or whether individual transactions qualify for hedge accounting treatment. The majority of EME's power sales and fuel supply agreements related to its generation activities either: (1) do not meet the definition of a derivative as they are not readily convertible to cash, or (2) qualify as normal purchases and sales and are, therefore, recorded on an accrual basis.

Derivative financial instruments used at EME for trading purposes includes forwards, futures, options, swaps and other financial instruments with third parties. EME records at fair value derivative financial instruments used for trading. The majority of EME's derivative financial instruments with a short-term duration (less than one year) are valued using quoted market prices. In the absence of quoted market prices, derivative financial instruments are valued at fair value, considering time value of money, volatility of the underlying commodity, and other factors as determined by EME. Resulting gains and losses are recognized in nonutility power generation in Edison International's consolidated income statements in the period of change. Assets from price risk management and energy trading activities include the fair value of open financial positions related to derivative financial instruments recorded at fair value, including cash flow hedges, that are in-the-money and the present value of net amounts receivable from structured transactions. Liabilities from price risk management and energy trading activities include the fair value of open financial positions related to derivative financial instruments, including cash flow hedges, that are out-of-the-money and the present value of net amounts payable from structured transactions.

Determining the fair value of derivatives under this accounting standard is a critical accounting estimate because the fair value of a derivative is susceptible to significant change resulting from a number of factors, including volatility of energy prices, credits risks, market liquidity and discount rates. See "MEHC: Market Risk Exposures," and "SCE: Market Risk Exposures" for a description of risk management activities and sensitivities to change in market prices.

EME enters into master agreements and other arrangements in conducting price risk management and trading activities with a right of setoff in the event of bankruptcy or default by the counterparty. Such transactions are reported net in the balance sheet in accordance with an authoritative interpretation for offsetting amounts related to certain contracts.

Income Taxes

Edison International's eligible subsidiaries are included in Edison International's consolidated federal income tax and combined state franchise tax returns. Edison International has tax-allocation and payment agreements with certain of its subsidiaries. For subsidiaries other than SCE, the right of a participating subsidiary to receive or make a payment and the amount and timing of tax-allocation payments are dependent on the inclusion of the subsidiary in the consolidated income tax returns of Edison International and other factors including the consolidated taxable income of Edison International and its includible subsidiaries, the amount of taxable income or net operating losses and other tax items of the participating subsidiary, as well as the other subsidiaries of Edison International. There are specific procedures regarding allocations of state taxes. Each subsidiary is eligible to receive tax-allocation payments for its tax losses or credits only at such time as Edison International and its subsidiaries generate sufficient taxable income to be able to utilize the participating subsidiary's losses in the consolidated tax return of Edison International. Under an income tax-allocation agreement approved by the CPUC, SCE's tax liability is computed as if it filed a separate return.

The accounting standard for income taxes requires the asset and liability approach for financial accounting and reporting for deferred income taxes. Edison International uses the asset and liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences.

As part of the process of preparing its consolidated financial statements, Edison International is required to estimate its income taxes in each of the jurisdictions in which it operates. This process involves estimating actual current tax expense together with assessing temporary differences resulting from differing treatment of items, such as depreciation, for tax and accounting purposes. These differences result in deferred tax assets and liabilities, which are included within Edison International's consolidated balance sheet. Edison International takes certain tax positions it believes are applied in accordance with tax laws. The application of these positions is subject to interpretation and audit by the IRS. As further described in "Other Developments—Federal Income Taxes," the IRS has raised issues in the audit of Edison International's tax returns with respect to certain leveraged leases at Edison Capital.

Management continually evaluates its income tax exposures and provides for allowances and/or reserves as deemed necessary.

Off-Balance Sheet Financing

EME has entered into sale-leaseback transactions related to the Powerton and Joliet plants in Illinois and the Homer City facilities in Pennsylvania. (See "Off-Balance Sheet Transactions—EME's Off-Balance Sheet Transactions—Sale-Leaseback Transactions.") Each of these transactions was completed and accounted for by EME as an operating lease in its consolidated financial statements in accordance with the accounting standard for sale-leaseback transactions involving real estate, which requires, among other things, that all of the risk and rewards of ownership of assets be transferred to a new owner without continuing involvement in the assets by the former owner other than as normal for a lessee. The sale-leaseback transactions of these power plants were complex matters that involved management judgment to determine compliance with accounting standards, including the transfer of all of the risk and rewards of ownership of the power plants to the new owner without EME's continuing involvement other than as normal for a lessee. These transactions were entered into to provide a source of capital either to fund the original acquisition of the assets or to repay indebtedness previously incurred for the acquisition. Each of these leases uses special purpose entities.

Based on existing accounting guidance, EME does not record these lease obligations in its consolidated balance sheet. If these transactions were required to be consolidated as a result of future changes in accounting guidance, it would: (1) increase property, plant and equipment and long-term obligations in the consolidated financial position, and (2) impact the pattern of expense recognition related to these obligations as EME would likely change from its current straight-line recognition of rental expense to an annual recognition of the straight-line depreciation on the leased assets as well as the interest component of the financings which is weighted more heavily toward the early years of the obligations. The difference in expense recognition would not affect EME's cash flows under these transactions. See "Off-Balance Sheet Transactions."

Edison Capital has entered into lease transactions, as lessor, related to various power generation, electric transmission and distribution, transportation and telecommunications assets. All of the debt under Edison Capital's leveraged leases is nonrecourse and is not recorded on Edison International's balance sheet in accordance with the applicable accounting standards.

Partnership investments, in which Edison International owns a percentage interest and does not have operational control or significant voting rights, are accounted for under the equity method as required by accounting standards. As such, the project assets and liabilities are not consolidated on the balance sheet.

Rather, the financial statements reflect only the proportionate ownership share of net income or loss. See "Off-Balance Sheet Transactions."

Pensions and Postretirement Benefits Other than Pensions

Pension and other postretirement obligations and the related effects on results of operations are calculated using actuarial models. Two critical assumptions, discount rate and expected return on assets, are important elements of plan expense and liability measurement. Additionally, health care cost trend rates are critical assumptions for postretirement heath care plans. These critical assumptions are evaluated at least annually. Other assumptions, such as retirement, mortality and turnover, are evaluated periodically and updated to reflect actual experience.

The discount rate enables Edison International to state expected future cash flows at a present value on the measurement date. At the December 31, 2004 measurement date, Edison International used a discount rate of 5.5% for pensions and 5.75% for postretirement benefits other than pensions (PBOP) that represented the market interest rate for high-quality fixed income investments.

To determine the expected long-term rate of return on pension plan assets, current and expected asset allocations are considered, as well as historical and expected returns on plan assets. The expected rate of return on plan assets was 7.5% for pensions and 7.1% for PBOP. A portion of PBOP trusts asset returns are subject to taxation, so the 7.1% figure above is determined on an after-tax basis. Actual time-weighted, annualized returns on the pension plan assets were 12.2%, 5.0% and 11.9% for the one-year, five-year and ten-year periods ended December 31, 2004, respectively. Actual time-weighted, annualized returns on the PBOP plan assets were 11.4%, 1.2% and 10.1% over these same periods. Accounting principles provide that differences between expected and actual returns are recognized over the average future service of employees.

At December 31, 2004, Edison International's pension plans had a $3.2 billion projected benefit obligation (PBO), a $2.8 billion accumulated benefit obligation (ABO) and $3.1 billion in plan assets. A 1% decrease in the discount rate would increase the PBO by $246 million, and a 1% increase would decrease the PBO by $266 million, with corresponding changes in the ABO. A 1% decrease in the expected rate of return on plan assets would increase pension expense by $28 million.

SCE accounts for about 94% of Edison International's total pension obligation, and 97% of its assets held in trusts, at December 31, 2004. SCE records pension expense equal to the amount funded to the trusts, as calculated using an actuarial method required for rate-making purposes, in which the impact of market volatility on plan assets is recognized in earnings on a more gradual basis. Any difference between pension expense calculated in accordance with rate-making methods and pension expense or income calculated in accordance with accounting standards is accumulated in a regulatory asset or liability, and will, over time, be recovered from or returned to customers. As of December 31, 2004, this cumulative difference amounted to a regulatory liability of $114 million, meaning that the rate-making method has resulted in recognizing $114 million more in expense than the accounting method since implementation of the pension accounting standard in 1987.

Under accounting standards, if the ABO exceeds the market value of plan assets at the measurement date, the difference may result in a reduction to shareholders' equity through a charge to other comprehensive income, but would not affect current net income. The reduction to other comprehensive income would be restored through shareholders' equity in future periods to the extent the market value of trust assets exceeded the ABO. This assessment is performed annually.

At December 31, 2004, Edison International's PBOP plans had a $2.2 billion PBO and $1.5 billion in plan assets. Total expense for these plans was $91 million for 2004. Increasing the health care cost trend rate by one percentage point would increase the accumulated obligation as of December 31, 2004 by

$318 million and annual aggregate service and interest costs by $28 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated obligation as of December 31, 2004 by $259 million and annual aggregate service and interest costs by $22 million.

On December 8, 2003, President Bush signed the Medicare Prescription Drug, Improvement and Modernization Act of 2003. The Act authorized a federal subsidy to be provided to plan sponsors for certain prescription drug benefits under Medicare. In May 2004, the Financial Accounting Standards Board (FASB) issued accounting guidance related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003. Edison International adopted this guidance effective July 1, 2004, which resulted in a decrease of $120 million to Edison International's accumulated benefit obligation for postretirement benefits other than pensions. Edison International's 2004 expense decreased approximately $9 million as a result of the subsidy. According to proposed federal regulations, Edison International's retiree health care plans provide prescription drug benefits that are deemed to be actuarially equivalent to Medicare benefits. Accordingly, Edison International recognized the subsidy in the measurement of its accumulated obligation and recorded an actuarial gain.

Rate Regulated Enterprises

SCE applies accounting principles for rate-regulated enterprises to the portion of its operations, in which regulators set rates at levels intended to recover the estimated costs of providing service, plus a return on capital. Due to timing and other differences in the collection of revenue, these principles allow an incurred cost that would otherwise be charged to expense by a nonregulated entity to be capitalized as a regulatory asset if it is probable that the cost is recoverable through future rates and conversely allow creation of a regulatory liability for probable future costs collected through rates in advance. SCE's management continually assesses whether the regulatory assets are probable of future recovery by considering factors such as the current regulatory environment, the issuance of rate orders on recovery of the specific incurred cost or a similar incurred cost to SCE or other rate-regulated entities in California, and assurances from the regulator (as well as its primary intervenor groups) that the incurred cost will be treated as an allowable cost (and not challenged) for rate-making purposes. Because current rates include the recovery of existing regulatory assets and settlement of regulatory liabilities, and rates in effect are expected to allow SCE to earn a reasonable rate of return, management believes that existing regulatory assets and liabilities are probable of recovery. This determination reflects the current political and regulatory climate in California and is subject to change in the future. If future recovery of costs ceases to be probable, all or part of the regulatory assets and liabilities would have to be written off against current period earnings. At December 31, 2004, the Consolidated Balance Sheets included regulatory assets of $3.8 billion and regulatory liabilities of $3.8 billion. Management continually evaluates the anticipated recovery of regulatory assets, liabilities, and revenue subject to refund and provides for allowances and/or reserves as deemed necessary.

SCE applied judgment in the use of the above principles when it: (1) restored $480 million (after-tax) of generation-related regulatory assets based on the URG decision in the second quarter of 2002; and (2) established a $61 million regulatory asset related to the impaired Mohave in the fourth quarter of 2002. In all instances, SCE recorded corresponding credits to earnings upon concluding that such incurred costs were probable of recovery in the future. See further discussion in "SCE: Regulatory Matters—Generation and Power Procurement—Mohave Generating Station and Related Proceedings" section.

NEW ACCOUNTING PRINCIPLES

A new accounting standard requires companies to use the fair value accounting method for stock-based compensation. Edison International currently uses the intrinsic value accounting method for stock-based compensation. Edison International will adopt the new method effective July 1, 2005. The difference in

expense, net of tax, between the two methods is $6 million. Edison International is reviewing the new standard and has not yet selected a transition method for adoption of the new standard.

In December 2004, the FASB issued guidance (Staff Position 109-1) on accounting for a tax deduction resulting from the American Jobs Creation Act of 2004. The primary objective of this Position is to provide guidance on accounting for the provision within the American Jobs Creation Act of 2004 that provides a tax deduction on qualified production activities. Under this Position, recognition of the tax deduction on qualified production activities, which include the production of electricity, is reported in the year it is earned. This FASB Staff Position had no material impact on Edison International's financial statements. Edison International is evaluating the effect that the manufacturer's deduction will have in subsequent years.

In March 2004, the FASB issued new guidance on participating securities and the two-class method under the applicable accounting standard for calculating EPS. The new guidance, which was effective in second quarter 2004, requires the use of the two-class method of computing EPS for companies with participating securities (including vested dividend equivalents on stock options). The two-class method is an earnings allocations formula that determines EPS for each class of common stock and participating security. Edison International has participating securities, but determined that the effect on 2004, 2003 and 2002 EPS in immaterial. Edison International is reviewing the potential effect of this guidance on 2005 EPS.

In December 2003, the FASB issued a revision to an accounting Interpretation (originally issued in January 2003), Consolidation of VIEs. The primary objective of the Interpretation is to provide guidance on the identification of, and financial reporting for, VIEs, where control may be achieved through means other than voting rights. Under the Interpretation, the enterprise that is expected to absorb or receive the majority of a VIE's expected losses or residual returns, or both, must consolidate the VIE, unless specific exceptions apply. This Interpretation is effective for special purpose entities, as defined by accounting principles generally accepted in the United States, as of December 31, 2003, and all other entities as of March 31, 2004. Edison International implemented the Interpretation for its special purpose entities as of December 31, 2003. As a result, Edison International deconsolidated three special purpose entities: EIX Trusts I and II; and EME's Mission Capital, L.P. These special purpose entities function as financing entities. In late 2004 and early 2005, the bonds and securities associated with these financings entities were paid off.

SCE has 270 long-term power-purchase contracts with independent power producers that own QFs. SCE was required under federal law to sign such contracts, which typically require SCE to purchase 100% of the power produced by these facilities under terms and pricing controlled by the CPUC. SCE conducted a review of its QF contracts and determined that SCE has variable interests in 12 contracts with gas-fired cogeneration plants that are potential VIEs and that contain variable pricing provisions based on the prices of natural gas and for which SCE does not have sufficient information to determine if the projects qualify for a scope exception. SCE requested from the entities that hold these contracts the financial information necessary to determine whether SCE must consolidate these projects. All 12 entities declined to provide SCE with the necessary financial information. However, four of the 12 contracts are with entities 49%–50% owned by EME. Although the four related-party entities have declined to provide their financial information to SCE, Edison International has access to such information and has provided combined financial statements to SCE. SCE has determined that it must consolidate the four power projects partially owned by EME based on a qualitative analysis of the facts and circumstances of the entities, including the related-party nature of the transaction. SCE will continue to attempt to obtain information for the other eight projects in order to determine whether they should be consolidated by SCE.

The remaining 258 contracts will not be consolidated by SCE under the new accounting standard since SCE lacks a variable interest in these contracts or the contracts are with governmental agencies, which are generally excluded from the standard.

Edison International analyzes its potential variable interests by calculating operating cash flows. A fixed-price contract to purchase electricity from a power plant does not transfer sufficient risk to the purchaser to be considered a variable interest. A contract with a non-natural-gas-fired plant that is based on the price of natural gas is also not a variable interest. SCE has other power contracts with non-QF generators. SCE has determined that these contracts are not significant variable interests.

On March 31, 2004, SCE consolidated four power projects partially owned by EME, EME deconsolidated two power projects, and Edison Capital consolidated two affordable housing partnerships and three wind projects. Edison International recorded a cumulative effect adjustment that decreased net income by less than $1 million, net of tax, due to negative equity at one of Edison Capital's newly consolidated entities.

COMMITMENTS, GUARANTEES AND INDEMNITIES

Edison International's commitments for the years 2005 through 2009 and thereafter are estimated below:

In millions	2005	2006	2007	2008	2009	Thereafter
Long-term debt maturities and sinking fund requirements(1)	$ 1,486	$ 1,693	$ 2,061	$ 1,820	$ 1,240	$ 8,688
Fuel supply contract payments	499	256	198	113	68	480
Gas and coal transportation payments	210	168	102	44	8	68
Purchased-power capacity payments	898	725	648	421	394	3,059
Unconditional purchase obligations	5	5	5	5	6	43
Estimated noncancelable lease payments	366	400	362	360	353	3,309
Preferred stock redemption requirements	9	9	74	56	—	—
Employee benefit plans contributions(2)	113	130	131	—	—	—

(1) Amount includes scheduled principal payments for debt outstanding as of December 31, 2004, assuming long-term debt is held to maturity, except for EME's Midwest Generation senior secured notes which is assumed to be held until 2014, and related forecast interest payments over the applicable period of the debt.

(2) Amount includes estimated contributions to the pension plans and postretirement benefits other than pensions. The estimated contributions beyond 2007 are not available.

Fuel Supply Contracts

SCE and EME have fuel supply contracts which require payment only if the fuel is made available for purchase. SCE has a coal fuel contract that requires payment of certain fixed charges whether or not coal is delivered.

During 2004, EME Homer City experienced interruptions of supply under two agreements. On December 21, 2004, EME Homer City was given written notice of an event of force majeure at one mine, which is a source of coal under both of the agreements. The claimed force majeure event is the result of alleged geologic conditions that, in the suppliers' opinion, prevent the delivery of coal under the agreements. These two agreements together provide for the delivery to EME Homer City of 1,290,000 tons of coal in 2005.

The suppliers also seek to terminate one of the agreements, which was scheduled to run through December 2007, under a provision that allows either party to the agreement to terminate if an event of force majeure lasts 30 days or more. The suppliers allege that the geologic problems encountered at the mine prevent mining and will continue beyond a 30-day period. The parties' second agreement with a term through December 2006 does not contain a similar termination provision, and the suppliers have requested contract modifications to the term, quantity, quality and price provisions of the agreement.

EME Homer City disputes the force majeure claim as it relates to both agreements and has filed suit. EME Homer City's complaint seeks equitable relief by way of an order requiring the defendant to fulfill their contracted obligations and such other monetary relief as is just and proper.

Gas and Coal Transportation

At December 31, 2004, EME had a contractual commitment to transport natural gas. EME is committed to pay minimum fees under this agreement, which has a term of 15 years.

At December 31, 2004, EME had contractual commitments to transport coal. The contracts range from three years to seven years. EME is committed to pay minimum fees under these agreements.

Power-Purchase Contracts

SCE has power-purchase contracts with certain QFs (cogenerators and small power producers) and other power producers. These contracts provide for capacity payments if a facility meets certain performance obligations and energy payments based on actual power supplied to SCE (the energy payments are not included in the table above). There are no requirements to make debt-service payments. In an effort to replace higher-cost contract payments with lower-cost replacement power, SCE has entered into purchased-power settlements to end its contract obligations with certain QFs. The settlements are reported as power-purchase contracts on the balance sheets.

Unconditional Purchase Obligations

SCE has an unconditional purchase obligation for firm transmission service from another utility. Minimum payments are based, in part, on the debt-service requirements of the provider, whether or not the transmission line is operable.

Leases

Edison International has operating leases for office space, vehicles, property and other equipment (with varying terms, provisions and expiration dates). Additionally, in accordance with an accounting standard, certain power contracts in which SCE takes virtually all of the power from specific power plants are classified as operating leases.

At December 31, 2004, minimum operating lease payments were primarily related to long-term leases for the Powerton, Joliet and Homer City power plants. During 2000, EME entered into sale-leaseback transactions for two power facilities, the Powerton and Joliet coal-fired stations located in Illinois, with third-party lessors. During the fourth quarter of 2001, EME entered into a sale-leaseback transaction for the Homer City coal-fired facilities located in Pennsylvania, with third-party lessors. Total minimum lease payments during the next five years are $293 million in 2005, $337 million in 2006, $336 million in 2007, $337 million in 2008, $336 million in 2009, and the minimum lease payments due after 2009 are $3.2 billion. For further discussion, see "Off-Balance Sheet Transactions—EME's Off-Balance Sheet Transactions— Sale-Leaseback Transactions."

Other Commitments

As of December 31, 2004, Edison Capital had outstanding commitments of $81 million to fund energy and infrastructure investments and had signed binding term sheets, subject to closing, for $85 million of additional renewable energy investments. Prior to funding any commitments, specific contract conditions must be satisfied. At December 31, 2004, Edison Capital had deposited approximately $5 million as collateral for several letters of credit currently outstanding.

At December 31, 2004, EME had firm commitments to spend approximately $25 million on capital expenditures in 2005, primarily for component replacement projects.

Guarantees and Indemnities

Edison International's subsidiaries have various financial and performance guarantees and indemnifications which are issued in the normal course of business. As discussed below, these contracts include performance guarantees, guarantees of debt and indemnifications.

Tax Indemnity Agreements

In connection with the sale-leaseback transactions that EME has entered into related to the Collins Station and the Powerton and Joliet Stations in Illinois and the Homer City facilities in Pennsylvania, EME or one of its subsidiaries entered into tax indemnity agreements. Under these tax indemnity agreements, these entities agreed to indemnify the lessors in the sale-leaseback transactions for specified adverse tax consequences that could result in certain situations set forth in each tax indemnity agreement, including specified defaults under the respective leases. The potential indemnity obligations under these tax indemnity agreements could be significant. Due to the nature of these potential obligations, EME cannot determine a maximum potential liability which would be triggered by a valid claim from the lessors. EME has not recorded a liability related to these indemnities. In connection with the termination of the lease for the Collins Station (Refer to "MEHC: Liquidity—Termination of the Collins Station Lease" for further information), Midwest Generation will continue to have obligations under the tax indemnity agreement with the former lease equity investor.

Indemnities Provided as Part of EME's Acquisition of the Illinois Plants

In connection with the acquisition of the Illinois plants, EME agreed to indemnify Commonwealth Edison with respect to specified environmental liabilities before and after December 15, 1999, the date of sale. The indemnification claims are reduced by any insurance proceeds and tax benefits related to such claims and are subject to a requirement that Commonwealth Edison take all reasonable steps to mitigate losses related to any such indemnification claim. Due to the nature of the obligation under this indemnity, a maximum potential liability cannot be determined. This indemnification for environmental liabilities is not limited in term and would be triggered by a valid claim from Commonwealth Edison. Except as discussed below, EME has not recorded a liability related to this indemnity.

Midwest Generation entered into a supplemental agreement with Commonwealth Edison and Exelon Generation on February 20, 2003 to resolve a dispute regarding interpretation of its reimbursement obligation for asbestos claims under the environmental indemnities set forth in the Asset Sale Agreement. Under this supplemental agreement, Midwest Generation agreed to reimburse Commonwealth Edison and Exelon Generation for 50% of specific existing asbestos claims and expenses less recovery of insurance costs, and agreed to a sharing arrangement for liabilities and expenses associated with future asbestos-related claims as specified in the agreement. As a general matter, Commonwealth Edison and Midwest Generation apportion responsibility for future asbestos-related claims based upon the number of exposure sites that are Commonwealth Edison locations or Midwest Generation locations. The obligations under this agreement are not subject to a maximum liability. The supplemental agreement has a five-year term with an automatic renewal provision (subject to the right of either party to terminate). Payments are made under this indemnity upon tender by Commonwealth Edison of appropriate proof of liability for an asbestos-related settlement, judgment, verdict, or expense. There were between 130 and 170 cases for which Midwest Generation was potentially liable and that had not been settled and dismissed by the end of 2004. At December 31, 2004, Midwest Generation had $9 million recorded as a liability for asserted claims related to this matter and had made $5 million in payments through December 31, 2004.

In view of its experience since 2003, Midwest Generation engaged an independent actuary in the fourth quarter of 2004 to determine if a reasonable estimate of future losses could be made based on claims and other available information. After review, the actuary determined that an estimate could be prepared, and, accordingly, Midwest Generation engaged the actuary to complete an estimate of future losses. Based on the actuary's analysis, Midwest Generation recorded an undiscounted $56 million pre-tax charge for its indemnity for future asbestos claims through 2045. In calculating future losses, the actuary made various assumptions, including but not limited to, the settlement of future claims under the supplemental agreement with Commonwealth Edison as described above, the distribution of exposure sites, and that no asbestos claims will be filed after 2045.

The $56 million pre-tax charge was recorded as part of plant operations on Edison International's consolidated income statement and reduced net income by $34 million. Midwest Generation anticipates obtaining periodic updates of the estimate of future losses. On a quarterly basis, Midwest Generation will monitor actual experience against the number of forecasted claims to be received and expected claim payments. Adjustments to the estimate will be recorded quarterly, if necessary.

The amounts recorded by Midwest Generation for the asbestos-related liability were based upon known facts at the time the report was prepared. Projecting future events, such as the number of new claims to be filed each year, the average cost of disposing of claims, as well as the numerous uncertainties surrounding asbestos litigation in the United States, could cause the actual costs to be higher or lower than projected.

Indemnity Provided as Part of the Acquisition of the Homer City Facilities

In connection with the acquisition of the Homer City facilities, EME Homer City agreed to indemnify the sellers with respect to specific environmental liabilities before and after the date of sale as specified in the Asset Purchase Agreement dated August 1, 1998. EME guaranteed the obligations of EME Homer City. Due to the nature of the obligation under this indemnity provision, it is not subject to a maximum potential liability and does not have an expiration date. Payments would be triggered under this indemnity by a claim from the sellers. EME has not recorded a liability related to this indemnity.

Indemnities Provided Under Asset Sale Agreements

The asset sale agreements for the sale of EME's international assets contain indemnities from EME to the purchasers, including indemnification for taxes imposed with respect to operations of the assets prior to the sale and for pre-closing environmental liabilities. EME also provided an indemnity to IPM for matters arising out of the exercise by one of its project partners of a purported right of first refusal. Not all indemnities under the asset sale agreements have specific expiration dates. Payments would be triggered under these indemnities by valid claims from the sellers or purchasers, as the case may be. At December 31, 2004, EME had recorded a liability of $158 million related to these matters.

In connection with the sale of various domestic assets, EME has from time to time provided indemnities to the purchasers for taxes imposed with respect to operations of the asset prior to the sale. EME has also provided indemnities to purchasers for items specified in each agreement (for example, specific pre-existing litigation matters and/or environmental conditions). Due to the nature of the obligations under these indemnity agreements, a maximum potential liability cannot be determined. Not all indemnities under the asset sale agreements have specific expiration dates. Payments would be triggered under these indemnities by valid claims from the sellers or purchasers, as the case may be. EME has not recorded a liability related to these indemnities.

Guarantee of Brooklyn Navy Yard Contractor Settlement Payments

On March 31, 2004, EME completed the sale of 100% of the stock of Mission Energy New York, Inc., which holds a 50% partnership interest in Brooklyn Navy Yard Cogeneration Partners, L.P. (referred to as

Brooklyn Navy Yard), to BNY Power Partners LLC. Brooklyn Navy Yard owns a 286 MW gas-fired cogeneration power plant in Brooklyn, New York. In February 1997, the construction contractor asserted general monetary claims under the turnkey agreement against Brooklyn Navy Yard. A settlement agreement was executed on January 17, 2003, and all litigation has been dismissed. EME agreed to indemnify Brooklyn Navy Yard and, in connection with the sale of EME's interest in Brooklyn Navy Yard, BNY Power Partners for any payments due under this settlement agreement, which are scheduled through 2006. At December 31, 2004, EME had recorded a liability of $11 million related to this indemnity.

Capacity Indemnification Agreements

EME has guaranteed, jointly and severally with Texaco Inc., the obligations of March Point Cogeneration Company under its project power sales agreements to repay capacity payments to the project's power purchaser in the event that the power sales agreements terminate, March Point Cogeneration Company abandons the project, or the project fails to return to normal operations within a reasonable time after a complete or partial shutdown, during the term of the power contracts. In addition, subsidiaries of EME have guaranteed the obligations of Kern River Cogeneration Company and Sycamore Cogeneration Company under their project power sales agreements to repay capacity payments to the projects' power purchaser in the event that the projects unilaterally terminate their performance or reduce their electric power producing capability during the term of the power contracts. The obligations under the indemnification agreements as of December 31, 2004, if payment were required, would be $153 million. EME has no reason to believe that any of these projects will either cease operations or reduce its electric power producing capability during the term of its power contract. EME has not recorded a liability related to this indemnity.

Indemnity Provided as Part of the Acquisition of Mountainview

In connection with the acquisition of Mountainview, SCE agreed to indemnify the seller with respect to specific environmental claims related to SCE's previously owned San Bernardino Generating Station, divested by SCE in 1998 and reacquired as part of the Mountainview acquisition. The generating station has not operated since early 2001, and SCE retained certain responsibilities with respect to environmental claims as part of the original divestiture of the station. The aggregate liability for either party to the purchase agreement for damages and other amounts is a maximum of $60 million. This indemnification for environmental liabilities expires on or before March 12, 2033. SCE has not recorded a liability related to this indemnity.

OFF-BALANCE SHEET TRANSACTIONS

This section of the MD&A discusses off-balance sheet transactions at EME and Edison Capital. SCE does not have any off-balance sheet transactions. Included are discussions of investments accounted for under the equity method for both subsidiaries, as well as sale-leaseback transactions at EME, EME's obligations to one of its subsidiaries, and leveraged leases at Edison Capital.

EME's Off-Balance Sheet Transactions

EME has off-balance sheet transactions in two principal areas: investments in projects accounted for under the equity method and operating leases resulting from sale-leaseback transactions.

Investments Accounted for under the Equity Method

EME has a number of investments in power projects that are accounted for under the equity method. Under the equity method, the project assets and related liabilities are not consolidated in Edison International's consolidated balance sheet. Rather, EME's financial statements reflect its investment in

each entity and it records only its proportionate ownership share of net income or loss. These investments are of three principal categories.

Historically, EME has invested in QFs, those which produce electrical energy and steam, or other forms of energy, and which meet the requirements set forth in the Public Utility Regulatory Policies Act. These regulations limit EME's ownership interest in QFs to no more than 50% due to EME's affiliation with SCE, a public utility. For this reason, EME owns a number of domestic energy projects through partnerships in which it has a 50% or less ownership interest.

Entities formed to own these projects are generally structured with a management committee or board of directors in which EME exercises significant influence but cannot exercise unilateral control over the operating, funding or construction activities of the project entity. EME's energy projects have generally secured long-term debt to finance the assets constructed and/or acquired by them. These financings generally are secured by a pledge of the assets of the project entity, but do not provide for any recourse to EME. Accordingly, a default on a long-term financing of a project could result in foreclosure on the assets of the project entity resulting in a loss of some or all of EME's project investment, but would generally not require EME to contribute additional capital. At December 31, 2004, entities which EME has accounted for under the equity method had indebtedness of $681 million, of which $303 million is proportionate to EME's ownership interest in these projects.

Sale-Leaseback Transactions

EME has entered into sale-leaseback transactions related to the Powerton and Joliet plants in Illinois and the Homer City facilities in Pennsylvania. Each of these transactions was completed and accounted for according to an accounting standard, which requires, among other things, that all of the risk and rewards of ownership of assets be transferred to a new owner without continuing involvement in the assets by the former owner other than as normal for a lessee. These transactions were entered into to provide a source of capital either to fund the original acquisition of the assets or to repay indebtedness previously incurred for the acquisition. In each of these transactions, the assets were sold to and then leased from owner/lessors owned by independent equity investors. In addition to the equity invested in them, these owner/lessors incurred or assumed long-term debt, referred to as lessor debt, to finance the purchase of the assets. Also, the lessor debt takes the form generally referred to as secured lease obligation bonds.

EME's subsidiaries account for these leases as financings in their separate financial statements due to specific guarantees provided by EME or another one its subsidiaries as part of the sale-leaseback transactions. These guarantees do not preclude EME from recording these transactions as operating leases in its consolidated financial statements, but constitute continuing involvement under the accounting standard that precludes EME's subsidiaries from utilizing this accounting treatment in their separate subsidiary financial statements. Instead, each subsidiary continues to record the power plants as assets in a similar manner to a capital lease and records the obligations under the leases as lease financings. EME's subsidiaries, therefore, record depreciation expense from the power plants and interest expense from the lease financing in lieu of an operating lease expense which EME uses in preparing its consolidated financial statements. The treatment of these leases as an operating lease in its consolidated financial statements in lieu of a lease financing, which is recorded by EME's subsidiaries, results in an increase in consolidated net income by $73 million, $81 million and $89 million in 2004, 2003 and 2002, respectively.

The lessor equity and lessor debt associated with the sale-leaseback transactions for the Powerton, Joliet and Homer City assets are summarized in the following table:

In millions	Acquisition Price	Equity Investor	Equity Investment in Owner/Lessor	Amount of Lessor Debt	Maturity Date of Lessor Debt
Power Station(s)					
Powerton/Joliet	$ 1,367	PSEG/	$ 238	$ 333.5	2009
		Citicapital		813.5	2016
Homer City	1,591	GECC	798	300	2019
				530	2026

PSEG – PSEG Resources, Inc.
GECC – General Electric Capital Corporation

The operating lease payments to be made by each of EME's subsidiary lessees are structured to service the lessor debt and provide a return to the owner/lessor's equity investors. Neither the value of the leased assets nor the lessor debt is reflected in Edison International's consolidated balance sheet. In accordance with generally accepted accounting principles, EME records rent expense on a levelized basis over the terms of the respective leases. To the extent that EME's cash rent payments exceed the amount levelized over the term of each lease, EME records prepaid rent. At December 31, 2004 and 2003, prepaid rent on these leases was $277 million and $214 million, respectively. To the extent that EME's cash rent payments are less than the amount levelized, EME reduces the amount of prepaid rent.

In the event of a default under the leases, each lessor can exercise all of its rights under the applicable lease, including repossessing the power plant and seeking monetary damages. Each lease sets forth a termination value payable upon termination for default and in certain other circumstances, which generally declines over time and in the case of default may be reduced by the proceeds arising from the sale of the repossessed power plant. A default under the terms of the Powerton and Joliet or Homer City leases could result in a loss of EME's ability to use such power plant and would trigger obligations under EME's guarantee of the Powerton and Joliet leases. These events could have a material adverse effect on EME's results of operations and financial position.

EME's minimum lease obligations under its power related leases are set forth under "Commitments, Guarantees and Indemnities." Also see "MEHC: Liquidity—Termination of the Collins Station Lease."

EME's Obligations to Midwest Generation, LLC

The proceeds, in the aggregate amount of approximately $1.4 billion, received by Midwest Generation from the sale of the Powerton and Joliet plants, described above under Sale-Leaseback Transactions, were loaned to EME. EME used the proceeds from this loan to repay corporate indebtedness. Although interest and principal payments made by EME to Midwest Generation under this intercompany loan assist in the payment of the lease rental payments owing by Midwest Generation, the intercompany obligation does not appear on Edison International's consolidated balance sheet. This obligation was disclosed to the credit rating agencies at the time of the transaction and has been included by them in assessing EME's credit ratings. The following table summarizes principal payments due under this intercompany loan:

In millions	Years Ending December 31,	Principal Amount	Interest Amount	Total
2005		$ 2	$ 113	$ 115
2006		3	113	116
2007		3	113	116
2008		4	112	116
2009		4	112	116
Thereafter		1,348	740	2,088
Total		$1,364	$1,303	$2,667

EME funds the interest and principal payments due under this intercompany loan from distributions from EME's subsidiaries, including Midwest Generation, cash on hand, and amounts available under corporate lines of credit. A default by EME in the payment of this intercompany loan could result in a shortfall of cash available for Midwest Generation to meet its lease and debt obligations. A default by Midwest Generation in meeting its obligations could in turn have a material adverse effect on EME.

Edison Capital's Off-Balance Sheet Transactions

Edison Capital has entered into off-balance sheet transactions for investments in projects, which, in accordance with generally accepted accounting principles, do not appear on Edison International's balance sheet.

Investments Accounted for under the Equity Method

Partnership investments, in which Edison Capital does not have operational control or significant voting rights, are accounted for under the equity method as required by accounting standards. As such, the project assets and liabilities are not consolidated on the balance sheet; rather, the financial statements reflect the carrying amount of the investment and the proportionate ownership share of net income or loss.

Edison Capital has invested in affordable housing projects utilizing partnership or limited liability companies in which Edison Capital is a limited partner or limited liability member. In these entities, Edison Capital usually owns a 99% interest. With a few exceptions, an unrelated general partner or managing member exercises operating control; voting rights of Edison Capital are limited by agreement to certain significant organizational matters. Edison Capital has subsequently sold a majority of these interests to unrelated third party investors through syndication partnerships in which Edison Capital has retained an interest, with one exception, of less than 20%. The debt of those partnerships and limited liability companies is secured by real property and is nonrecourse to Edison Capital, except in limited cases where Edison Capital has guaranteed the debt. At December 31, 2004, Edison Capital had made guarantees to lenders in the amount of $3 million.

Edison Capital has also invested in three limited partnership funds which make investments in infrastructure and infrastructure-related projects. Those funds follow special investment company accounting which requires the fund to account for its investments at fair value. Although Edison Capital would not follow special investment company accounting if it held the funds' investment directly, Edison Capital records its proportionate share of the funds' results as required by the equity method.

At December 31, 2004, entities that Edison Capital has accounted for under the equity method had indebtedness of approximately $1.7 billion, of which approximately $581 million is proportionate to Edison Capital's ownership interest in these projects. Substantially all of this debt is nonrecourse to Edison Capital.

Leveraged Leases

Edison Capital is the lessor in various power generation, electric transmission and distribution, transportation and telecommunications leases. The debt in these leveraged leases is nonrecourse to Edison Capital and is not recorded on Edison International's balance sheet in accordance with the applicable accounting standards.

At December 31, 2004, Edison Capital had gross investments, before deferred taxes, of $2.4 billion in its leveraged leases, with nonrecourse debt in the amount of $5 billion.

OTHER DEVELOPMENTS

Environmental Matters

Edison International is subject to numerous environmental laws and regulations, which require it to incur substantial costs to operate existing facilities, construct and operate new facilities, and mitigate or remove the effect of past operations on the environment.

Edison International believes that it is in substantial compliance with environmental regulatory requirements; however, possible future developments, such as the enactment of more stringent environmental laws and regulations, could affect the costs and the manner in which business is conducted and could cause substantial additional capital expenditures. There is no assurance that additional costs would be recovered from customers or that Edison International's financial position and results of operations would not be materially affected.

Environmental Remediation

Edison International records its environmental remediation liabilities when site assessments and/or remedial actions are probable and a range of reasonably likely cleanup costs can be estimated. Edison International reviews its sites and measures the liability quarterly, by assessing a range of reasonably likely costs for each identified site using currently available information, including existing technology, presently enacted laws and regulations, experience gained at similar sites, and the probable level of involvement and financial condition of other potentially responsible parties. These estimates include costs for site investigations, remediation, operations and maintenance, monitoring and site closure. Unless there is a probable amount, Edison International records the lower end of this reasonably likely range of costs (classified as other long-term liabilities) at undiscounted amounts.

Edison International's recorded estimated minimum liability to remediate its 31 identified sites at SCE (24 sites) and EME (7 sites related to Midwest Generation) is $84 million, $82 million of which is related to SCE. In third quarter 2003, SCE sold certain oil storage and pipeline facilities. This sale caused a reduction in Edison International's recorded estimated minimum environmental liability. Edison International's other subsidiaries have no identified remediation sites. The ultimate costs to clean up Edison International's identified sites may vary from its recorded liability due to numerous uncertainties inherent in the estimation process, such as: the extent and nature of contamination; the scarcity of reliable data for identified sites; the varying costs of alternative cleanup methods; developments resulting from investigatory studies; the possibility of identifying additional sites; and the time periods over which site remediation is expected to occur. Edison International believes that, due to these uncertainties, it is reasonably possible that cleanup costs could exceed its recorded liability by up to $123 million, all of which is related to SCE. The upper limit of this range of costs was estimated using assumptions least favorable to Edison International among a range of reasonably possible outcomes. In addition to its identified sites (sites in which the upper end of the range of costs is at least $1 million), SCE also had 30 immaterial sites whose total liability ranges from $4 million (the recorded minimum liability) to $9 million.

The CPUC allows SCE to recover environmental remediation costs at certain sites, representing $27 million of its recorded liability, through an incentive mechanism (SCE may request to include additional sites). Under this mechanism, SCE will recover 90% of cleanup costs through customer rates; shareholders fund the remaining 10%, with the opportunity to recover these costs from insurance carriers and other third parties. SCE has successfully settled insurance claims with all responsible carriers. SCE expects to recover costs incurred at its remaining sites through customer rates. SCE has recorded a regulatory asset of $55 million for its estimated minimum environmental-cleanup costs expected to be recovered through customer rates.

Edison International's identified sites include several sites for which there is a lack of currently available information, including the nature and magnitude of contamination, and the extent, if any, that Edison International may be held responsible for contributing to any costs incurred for remediating these sites. Thus, no reasonable estimate of cleanup costs can be made for these sites.

Edison International expects to clean up its identified sites over a period of up to 30 years. Remediation costs in each of the next several years are expected to range from $13 million to $25 million. Recorded costs for 2004 were $14 million.

Based on currently available information, Edison International believes it is unlikely that it will incur amounts in excess of the upper limit of the estimated range for its identified sites and, based upon the CPUC's regulatory treatment of environmental remediation costs incurred at SCE, Edison International believes that costs ultimately recorded will not materially affect its results of operations or financial position. There can be no assurance, however, that future developments, including additional information about existing sites or the identification of new sites, will not require material revisions to such estimates.

Clean Air Act

The Clean Air Act requires power producers to have emissions allowances to emit sulfur dioxide. Power companies receive emissions allowances from the federal government and may bank or sell excess allowances. SCE has had and expects to continue to have excess allowances under Phase II of the Clean Air Act.

In 1999, SCE and other co-owners of Mohave entered into a consent decree to resolve a federal court lawsuit that had been filed alleging violations of various emissions limits. This decree, approved by a federal court in December 1999, required certain modifications to the plant in order for it to continue to operate beyond 2005 to comply with the Clean Air Act.

SCE's share of the costs of complying with the consent decree and taking other actions to continue operation of Mohave beyond 2005 is estimated to be approximately $605 million. SCE has received from the State of Nevada a permit to install the necessary pollution-control equipment. If the station is shut down at that time, the shutdown is not expected to have a material adverse impact on SCE's financial position or results of operations, assuming the remaining book value of the station (approximately $8 million as of December 31, 2004) and the related regulatory asset (approximately $78 million as of December 31, 2004), and plant closure and decommissioning-related costs are recoverable in future rates. SCE cannot predict with certainty what effect any future actions by the CPUC may have on this matter. See "SCE: Regulatory Matters—Generation and Power Procurement—Mohave Generating Station and Related Proceedings" for further discussion of the Mohave issues.

Edison International's facilities in the United States are subject to the Clean Air Act's new source review (NSR) requirements related to modifications of air emissions sources at electric generating stations. Over the past five years, the United States Environmental Protection Agency (U.S. EPA) has initiated investigations of numerous electric utilities seeking to determine whether these utilities engaged in

activities in violation of the NSR requirements, brought enforcement actions against some of those utilities, and reached settlements with some of those utilities. The U.S. EPA has made information requests concerning electric generating stations in which SCE and EME hold ownership interests, including SCE's Four Corners station and EME's Midwest Generation and Homer City stations. Other than these requests for information, no enforcement-related proceedings have been initiated against any Edison International facilities by the U.S. EPA relating to NSR compliance.

Over this same period, the U.S. EPA has proposed several regulatory changes to NSR requirements that would clarify and provide greater guidance to the utility industry as to what activities can be undertaken without triggering the NSR requirements. Several of these regulatory changes have been challenged in the courts. As a result of these developments, the U.S. EPA's enforcement policy on alleged NSR violations is currently uncertain.

These developments will continue to be monitored by Edison International, SCE, and EME, to assess what implications, if any, they will have on the operation of domestic power plants owned or operated by SCE, EME, or their subsidiaries, or the impact on Edison International's results of operations or financial position.

Edison International's projected environmental capital expenditures over the next three years are: 2005 – $435 million; 2006 – $445 million; and 2007 – $530 million. The projected environmental capital expenditures are mainly for undergrounding certain transmission and distribution lines at SCE and upgrading environmental controls at EME.

Federal Income Taxes

Edison International has reached a tentative settlement with the IRS on tax issues and pending affirmative claims relating to its 1991 to 1993 tax years currently under appeal. This settlement, which should be finalized in 2005, is expected to result in a net earnings benefit for Edison International of approximately $70 million, most of which relates to SCE.

Edison International received Revenue Agent Reports from the IRS in August 2002 and in January 2005 asserting deficiencies in federal corporate income taxes with respect to audits of its 1994 to 1996 and 1997 to 1999 tax years, respectively. Many of the asserted tax deficiencies are timing differences and, therefore, amounts ultimately paid (exclusive of interest and penalties), if any, would be deductible on future tax returns of Edison International.

As part of a nationwide challenge of certain types of lease transactions, the IRS has raised issues about the deferral of income taxes in audits of the 1994 to 1996 and 1997 to 1999 tax years associated with Edison Capital's cross-border leases. The IRS is challenging Edison Capital's foreign power plant and electric locomotive sale/leaseback transactions (termed a sale-in/lease-out or SILO transaction). The estimated federal and state taxes deferred from these leases was $44 million in the 1994 to 1996 and 1997 to 1999 audit periods and $32 million in subsequent years through 2004.

The IRS is also challenging Edison Capital's foreign power plant and electric transmission system lease/leaseback transactions (termed a lease-in, lease-out or LILO transaction). The estimated federal and state income taxes deferred from these leases was $558 million in the 1997 to 1999 audit period and $565 million in subsequent years through 2004. The IRS has also proposed interest and penalties in its challenge to each SILO and LILO transaction.

Edison International believes it properly reported these transactions based on applicable statutes, regulations and case law in effect at the time the transactions were entered into. Written protests were filed to appeal the 1994 to 1996 audit adjustments asserting that the IRS's position misstates material facts, misapplies the law and is incorrect. This matter is now being considered by the Administrative

Appeals branch of the IRS. Edison International will also file written protests to appeal the issues raised in the 1997 to 1999 audit. Edison International intends to contest these proposed deficiencies through administrative appeals and litigation, if necessary.

Edison Capital also entered into a lease/service contract transaction in 1999 involving a foreign telecommunication system (termed a "Service Contract"). The IRS did not assert an adjustment for this lease in the 1997 to 1999 audit cycle but is expected to challenge this lease in subsequent audit cycles similar to positions asserted against the SILOs discussed above. The estimated federal and state taxes deferred from this lease are $221 million through 2004.

If Edison International is not successful in its defense of the tax treatment for the SILOs, LILOs and the Service Contract, the payment of taxes, exclusive of any interest or penalties, would not affect results of operations under current accounting standards, although it could have a significant impact on cash flow. However, the FASB is currently considering changes to the accounting for leases. If the proposed accounting changes are adopted and Edison International's tax treatment for the SILOs, LILOs and Service Contract is significantly altered as a result of IRS challenges, there could be a material effect on reported earnings by requiring Edison International to reverse earnings previously recognized as a current period adjustment and to report these earnings over the remaining life of the leases. At this time, Edison International is unable to predict the impact of the ultimate resolution of these matters.

The IRS Revenue Agent Report for the 1997 to 1999 audit also asserted deficiencies with respect to a transaction entered into by an SCE subsidiary which may be considered substantially similar to a listed transaction described by the IRS as a contingent liability company. While Edison International intends to defend its tax return position with respect to this transaction, the tax benefits relating to the capital loss deductions will not be claimed for financial accounting and reporting purposes until and unless these tax losses are sustained.

In April 2004, Edison International filed California Franchise Tax amended returns for tax years 1997 through 2002 to abate the possible imposition of new California penalty provisions on transactions that may be considered as listed or substantially similar to listed transactions described in an IRS notice that was published in 2001. These transactions include certain Edison Capital leveraged lease transactions and the SCE subsidiary contingent liability company transaction described above. Edison International filed these amended returns under protest retaining its appeal rights.

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The management of Edison International is responsible for the integrity and objectivity of the accompanying financial statements and related information. The statements have been prepared in accordance with accounting principles generally accepted in the United States and are based, in part, on management estimates and judgment. Management believes that the financial statements fairly reflect Edison International's financial position and results of operations.

As a further measure to assure the ongoing objectivity and integrity of financial information, the Audit Committee of the Board of Directors, which is composed of outside directors, meets periodically, both jointly and separately, with management, the independent auditors and internal auditors, who have unrestricted access to the committee. The Committee annually appoints a firm of independent auditors to conduct an audit of Edison International's financial statements and internal control over financial reporting; reviews accounting, internal control, auditing and financial reporting issues; and is advised of management's actions regarding financial reporting and internal control matters.

Edison International and its subsidiaries maintain high standards in selecting, training and developing personnel to assure that its operations are conducted in conformity with applicable laws and are committed to maintaining the highest standards of personal and corporate conduct. Management maintains programs to encourage and assess compliance with these standards.

Edison International's independent registered public accounting firm, PricewaterhouseCoopers LLP, are engaged to audit the financial statements included in this Annual Report in accordance with the standards of the Public Company Accounting Oversight Board (United States) and to express an opinion on whether those consolidated financial statements fairly present, in all material respects, Edison International's results of operations, cash flows and financial position.

Management's Report on Internal Control over Financial Reporting

Edison International's management is responsible for establishing and maintaining adequate internal control over financial reporting (as that term is defined in Rule 13a-15(f) under the Exchange Act). Under the supervision and with the participation of its Chief Executive Officer and Chief Financial Officer, Edison International's management conducted an evaluation of the effectiveness of internal control over financial reporting based on the framework set forth in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on its evaluation under the COSO framework, Edison International's management concluded that internal control over financial reporting was effective as of December 31, 2004. Management's assessment of the effectiveness of Edison International's internal control over financial reporting as of December 31, 2004 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report on the financial statements in Edison International's 2004 Annual Report to shareholders, which is incorporated herein by this reference.

Disclosure Controls and Procedures

The certifications of the Chief Executive Officer and Chief Financial Officer that are required by Section 302 of the Sarbanes-Oxley Act of 2002 are included as exhibits to Edison International's annual report on Form 10-K. In addition, in 2004, Edison International's Chief Executive Officer provided to the New York Stock Exchange (NYSE) the Annual CEO Certification regarding Edison International's compliance with the NYSE's corporate governance standards.

To the Board of Directors and Shareholders of Edison International

We have completed an integrated audit of Edison International's 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2004 and audits of its 2003 and 2002 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, cash flows and changes in common shareholders' equity present fairly, in all material respects, the financial position of Edison International and its subsidiaries at December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of Edison International's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the consolidated financial statements, Edison International changed the manner in which it accounts for asset retirement costs as of January 1, 2003, financial instruments with characteristics of both debt and equity as of July 1, 2003, and variable interest entities as of December 31, 2003 and March 31, 2004.

Internal control over financial reporting

Also, in our opinion, management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that Edison International maintained effective internal control over financial reporting as of December 31, 2004 based on criteria established in "Internal Control – Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, Edison International maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on criteria established in "Internal Control – Integrated Framework" issued by the COSO. Edison International's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of Edison International's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

Los Angeles, California
March 15, 2005

In millions, except per-share amounts Year ended December 31,	2004	2003	2002
Electric utility	$ 8,448	$ 8,853	$ 8,705
Nonutility power generation	1,639	1,778	1,713
Financial services and other	112	101	33
Total operating revenue	10,199	10,732	10,451
Fuel	1,429	905	854
Purchased power	2,332	2,786	2,016
Provisions for regulatory adjustment clauses – net	(201)	1,138	1,502
Other operation and maintenance	3,342	2,910	2,812
Asset impairment and loss on lease termination	989	304	86
Depreciation, decommissioning and amortization	1,022	1,047	928
Property and other taxes	186	192	132
Net gain on sale of utility plant	—	(5)	(5)
Total operating expenses	9,099	9,277	8,325
Operating income	1,100	1,455	2,126
Interest and dividend income	46	118	279
Equity in income from partnerships and unconsolidated subsidiaries – net	66	231	163
Other nonoperating income	135	86	85
Interest expense – net of amounts capitalized	(985)	(1,020)	(1,126)
Other nonoperating deductions	(80)	(32)	(32)
Dividends on preferred securities subject to mandatory redemption	—	(52)	(102)
Income from continuing operations before tax and minority interest	282	786	1,393
Income tax (benefit)	(92)	124	330
Dividends on utility preferred stock not subject to mandatory redemption	6	5	6
Minority interest	142	2	2
Income from continuing operations	226	655	1,055
Income from discontinued operations (including gain on disposal of $533 in 2004 and $44 in 2003) – net of tax	690	175	22
Income before accounting change	916	830	1,077
Cumulative effect of accounting change – net of tax	—	(9)	—
Net income	$ 916	$ 821	$ 1,077
Weighted-average shares of common stock outstanding	326	326	326
Basic earnings (loss) per share:			
Continuing operations	$ 0.69	$ 2.01	$ 3.24
Discontinued operations	2.12	0.54	0.07
Cumulative effect of accounting change	—	(0.03)	—
Total	$ 2.81	$ 2.52	$ 3.31
Weighted-average shares, including effect of dilutive securities	331	329	328
Diluted earnings (loss) per share:			
Continuing operations	$ 0.68	$ 1.99	$ 3.22
Discontinued operations	2.09	0.54	0.06
Cumulative effect of accounting change	—	(0.03)	—
Total	$ 2.77	$ 2.50	$ 3.28
Dividends declared per common share	$ 0.85	$ 0.20	$ —

The accompanying notes are an integral part of these financial statements.

In millions Year ended December 31,	2004	2003	2002
Net income	$ 916	$ 821	$1,077
Other comprehensive income (loss), net of tax:			
Foreign currency translation adjustments	(18)	154	125
Reclassification adjustment for sale of investment in a foreign subsidiary	(127)	—	—
Minimum pension liability adjustment	7	(2)	(21)
Unrealized gain (loss) on investments – net	7	2	(9)
Unrealized gains (losses) on cash flow hedges:			
Cumulative effect of change in accounting for derivatives	—	—	6
Other unrealized gain (loss) on cash flow hedges – net	92	50	(20)
Reclassification adjustment for gain (loss) included in net income	88	(10)	—
Other comprehensive income	49	194	81
Comprehensive income	$ 965	$1,015	$1,158

The accompanying notes are an integral part of these financial statements.

Consolidated Balance Sheets

In millions December 31,	2004	2003
ASSETS		
Cash and equivalents	$ 2,688	$ 1,988
Restricted cash	73	79
Receivables, less allowances of $31 and $31 for uncollectible accounts at respective dates	846	846
Accrued unbilled revenue	320	273
Fuel inventory	73	92
Materials and supplies	231	213
Accumulated deferred income taxes – net	288	563
Trading and price risk management assets	41	22
Regulatory assets	553	299
Other current assets	336	175
Total current assets	5,449	4,550
Nonutility property – less accumulated provision for depreciation of $1,311 and $619 at respective dates	3,922	3,288
Nuclear decommissioning trusts	2,757	2,530
Investments in partnerships and unconsolidated subsidiaries	608	828
Investments in leveraged leases	2,424	2,361
Other investments	197	173
Total investments and other assets	9,908	9,180
Utility plant, at original cost:		
Transmission and distribution	15,685	14,861
Generation	1,356	1,388
Accumulated provision for depreciation	(4,506)	(4,386)
Construction work in progress	789	601
Nuclear fuel, at amortized cost	151	141
Total utility plant	13,475	12,605
Restricted cash	155	206
Regulatory assets	3,285	3,725
Other deferred charges	875	753
Total deferred charges	4,315	4,684
Assets of discontinued operations	122	7,248
Total assets	$ 33,269	$ 38,267

The accompanying notes are an integral part of these financial statements.

In millions, except share amounts December 31,	2004	2003
LIABILITIES AND SHAREHOLDERS' EQUITY		
Short-term debt	$ 88	$ 201
Long-term debt due within one year	809	1,932
Preferred stock to be redeemed within one year	9	9
Accounts payable	749	548
Accrued taxes	226	495
Accrued interest	233	236
Customer deposits	168	152
Book overdrafts	232	189
Trading and risk management liabilities	31	36
Regulatory liabilities	490	659
Other current liabilities	1,002	1,261
Total current liabilities	4,037	5,718
Long-term debt	9,678	9,220
Accumulated deferred income taxes – net	5,233	5,334
Accumulated deferred investment tax credits	138	149
Customer advances and other deferred credits	1,109	903
Power-purchase contracts	130	213
Preferred stock subject to mandatory redemption	139	141
Accumulated provision for pensions and benefits	523	425
Asset retirement obligations	2,188	2,089
Regulatory liabilities	3,356	3,234
Other long-term liabilities	232	247
Total deferred credits and other liabilities	13,048	12,735
Liabilities of discontinued operations	15	4,565
Total liabilities	26,778	32,238
Commitments and contingencies (Notes 2, 9 and 10)		
Minority interest	313	517
Preferred stock of utility not subject to mandatory redemption	129	129
Common stock (325,811,206 shares outstanding at each date)	1,975	1,970
Accumulated other comprehensive loss	(4)	(53)
Retained earnings	4,078	3,466
Total common shareholders' equity	6,049	5,383
Total liabilities and shareholders' equity	$ 33,269	$ 38,267

The accompanying notes are an integral part of these financial statements.

Consolidated Statements of Cash Flows **Edison International**

In millions Year ended December 31,	2004	2003	2002
Cash flows from operating activities:			
Income from continuing operations, after accounting change, net of tax	$ 226	$ 646	$ 1,055
Adjustments to reconcile to net cash provided by operating activities:			
Cumulative effect of accounting change – net of tax	—	9	—
Depreciation, decommissioning and amortization	1,022	1,047	928
Other amortization	98	108	113
Minority interest	142	2	2
Deferred income taxes and investment tax credits	557	106	136
Equity in income from partnerships and unconsolidated subsidiaries	(67)	(231)	(163)
Income from leveraged leases	(81)	(82)	(6)
Regulatory assets – long-term	442	535	(6,738)
Regulatory liabilities – long-term	(69)	(48)	8,589
Asset impairment	35	304	86
Levelized rent expense	(59)	(96)	(97)
Other assets	(68)	133	191
Other liabilities	66	(333)	168
Receivables and accrued unbilled revenue	47	(33)	360
Inventory, prepayments and other current assets	(27)	159	(125)
Regulatory assets – short-term	(254)	13,268	(1,252)
Regulatory liabilities – short-term	(169)	(12,486)	876
Accrued interest and taxes	(273)	(211)	520
Accounts payable and other current liabilities	(52)	(111)	(2,939)
Distributions from unconsolidated entities	84	375	307
Net cash provided by operating activities	1,600	3,061	2,011
Cash flows from financing activities:			
Long-term debt issued and issuance costs	3,508	766	113
Long-term debt repaid	(4,331)	(2,656)	(1,510)
Bonds remarketed – net	350	—	191
Redemption of preferred securities	(2)	(6)	(100)
Rate reduction notes repaid	(246)	(246)	(246)
Change in book overdrafts	43	65	77
Nuclear fuel financing – net	—	—	(59)
Short-term debt financing – net	(112)	(17)	(943)
Shares purchased for stock-based compensation	(109)	(24)	(7)
Proceeds from stock option exercises	48	5	—
Dividends to minority shareholders	(146)	—	(3)
Dividends paid	(261)	—	—
Net cash used by financing activities	(1,258)	(2,113)	(2,487)
Cash flows from investing activities:			
Capital expenditures	(1,733)	(1,234)	(1,508)
Acquisition costs related to nonutility generation plant	(285)	—	—
Purchase of power sales agreement	—	—	(80)
Purchase of common stock of acquired companies	—	(3)	—
Proceeds from sale of property and interest in projects	118	43	57
Proceeds from sale of discontinued operations	2,740	146	—
Contributions to and earnings from nuclear decommissioning trusts – net	(109)	(86)	(12)
Distributions from (investments in) partnerships and unconsolidated subsidiaries	(4)	(34)	41
Purchase of short-term investments – net	(120)	(20)	—
Sales of investments in other assets	33	15	277
Net cash provided (used) by investing activities	640	(1,173)	(1,225)
Effect of consolidation of variable interest entities on cash	79	—	—
Effect of deconsolidation of variable interest entities on cash	(32)	—	—
Net changes in cash of discontinued operations	(519)	(77)	100
Effect of exchange rate changes on cash	—	13	15
Net increase (decrease) in cash and equivalents	510	(289)	(1,586)
Cash and equivalents, beginning of year	2,179	2,468	4,054
Cash and equivalents, end of year	2,689	2,179	2,468
Cash and equivalents – discontinued operations	(1)	(191)	(182)
Cash and equivalents – continuing operations	$ 2,688	$1,988	$ 2,286

The accompanying notes are an integral part of these financial statements.

In millions	Common Stock	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total Common Shareholders' Equity
Balance at December 31, 2001	$ 1,966	$ (328)	$ 1,634	$ 3,272
Net income			1,077	1,077
Foreign currency translation adjustments		128		128
Tax effect		(3)		(3)
Minimum pension liability adjustment		(29)		(29)
Tax effect		8		8
Unrealized loss on investment		(14)		(14)
Tax effect		5		5
Other unrealized loss on cash flow hedges		(22)		(22)
Tax effect		2		2
Cumulative effect of change in accounting for derivatives		12		12
Tax effect		(6)		(6)
Shares purchased for stock-based compensation	(6)		(1)	(7)
Non-cash stock-based compensation	13			13
Capital stock expense and other			1	1
Balance at December 31, 2002	$ 1,973	$ (247)	$ 2,711	$ 4,437
Net income			821	821
Foreign currency translation adjustments		159		159
Tax effect		(5)		(5)
Minimum pension liability adjustment		(3)		(3)
Tax effect		1		1
Unrealized gain on investment		3		3
Tax effect		(1)		(1)
Other unrealized gain on cash flow hedges		54		54
Tax effect		(4)		(4)
Reclassification adjustment for loss on derivatives included in net income		(9)		(9)
Tax effect		(1)		(1)
Common stock dividend declared			(65)	(65)
Shares purchased for stock-based compensation	(18)		(6)	(24)
Proceeds from stock option exercises			5	5
Non-cash stock-based compensation	14			14
Capital stock expense and other	1			1
Balance at December 31, 2003	$ 1,970	$ (53)	$ 3,466	$ 5,383

The accompanying notes are an integral part of these financial statements.

In millions	Common Stock	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total Common Shareholders' Equity
Balance at December 31, 2003	$ 1,970	$ (53)	$ 3,466	$ 5,383
Net income			916	916
Foreign currency translation adjustments		(14)		(14)
Tax effect		(4)		(4)
Reclassification adjustment for sale of investment in foreign subsidiary		(127)		(127)
Minimum pension liability adjustment		6		6
Tax effect		1		1
Unrealized gain on investment		11		11
Tax effect		(4)		(4)
Other unrealized gain on cash flow hedges		98		98
Tax effect		(6)		(6)
Reclassification adjustment for loss on derivatives included in net income		152		152
Tax effect		(64)		(64)
Common stock dividend declared			(277)	(277)
Shares purchased for stock-based compensation	(34)		(75)	(109)
Proceeds from stock option exercises			48	48
Non-cash stock-based compensation	39			39
Balance at December 31, 2004	$ 1,975	$ (4)	$ 4,078	$ 6,049

Authorized common stock is 800 million shares with no par value.

The accompanying notes are an integral part of these financial statements.

Significant accounting policies are discussed in Note 1, unless discussed in the respective Notes for specific topics.

Note 1. Summary of Significant Accounting Policies

Edison International's principal wholly owned subsidiaries include: Southern California Edison Company (SCE), a rate-regulated electric utility that supplies electric energy to a 50,000 square-mile area of central, coastal and southern California; Mission Energy Holding Company (MEHC), a holding company for Edison Mission Energy (EME), which is engaged in the business of owning or leasing, operating and selling energy and capacity from electric power generation facilities; and Edison Capital, a provider of capital and financial services. EME has domestic projects and one foreign project in Turkey; Edison Capital has domestic projects and foreign projects, primarily in Europe, Australia and Africa.

Basis of Presentation

The consolidated financial statements include Edison International and its wholly owned subsidiaries. Edison International's subsidiaries consolidate their subsidiaries in which they have a controlling interest and variable interest entities (VIEs) in which they are the primary beneficiary. In addition, Edison International's subsidiaries generally use the equity method to account for significant investments in (1) partnerships and subsidiaries in which they own a significant or less than controlling interest and (2) VIEs in which they are not the primary beneficiary. See further discussion in "New Accounting Principles." Intercompany transactions have been eliminated, except EME's profits from energy sales to SCE, which are allowed in utility rates.

SCE's accounting policies conform to accounting principles generally accepted in the United States, including the accounting principles for rate-regulated enterprises, which reflect the rate-making policies of the California Public Utilities Commission (CPUC) and the Federal Energy Regulatory Commission (FERC). In 1997, due to changes in the rate recovery of generation-related assets, SCE began using accounting principles applicable to enterprises in general for its investment in generation facilities. In April 2002, SCE reapplied accounting principles for rate-regulated enterprises to assets that were returned to cost-based regulation under the utility-retained generation decision.

Effective second quarter 2004, EME amended its certificate of incorporation and bylaws to eliminate the so-called ring fencing provisions that were implemented in early 2001 during the California energy crisis. The ring fencing provisions were implemented to protect EME's credit rating from the negative events then affecting Edison International and SCE. Despite the ring-fencing provisions, EME's Standard & Poor's credit rating fell to "B" and therefore, EME's management believed that these provisions, which included dividend restrictions and a requirement to maintain an independent director, were no longer necessary. Due to the removal of these ring fencing provisions, Edison International includes MEHC (parent only), which holds debt of $800 million (after repaying the remaining $285 million of a term loan on January 3, 2005) and has no business activities other than through its ownership interest in EME, in its nonutility power generation business segment. As a result, the nonutility power generation business segment is comprised of MEHC (parent only) and EME.

Effective third quarter 2004, Edison International's consolidated financial statements for all years presented reflect the reclassification of the results of EME's international power generation portfolio that was sold or held for sale as discontinued operations in accordance with an accounting standard related to the impairment and disposal of long-lived assets. See further discussion in Note 15. Except as indicated, amounts presented in the Notes to the Consolidated Financial Statements relate to continuing operations.

Certain prior-year amounts were reclassified to conform to the December 31, 2004 financial statement presentation.

Financial statements prepared in compliance with accounting principles generally accepted in the United States require management to make estimates and assumptions that affect the amounts reported in the financial statements and Notes. Actual results could differ from those estimates. Certain significant estimates related to electric utility regulatory matters, financial instruments, income taxes, pensions and postretirement benefits other than pensions, decommissioning and contingencies are further discussed in Notes 2, 3, 6, 7, 9 and 10 to the Consolidated Financial Statements, respectively.

Cash Equivalents

Cash equivalents include time deposits ($203 million at December 31, 2004 and $33 million at December 31, 2003) and other investments ($2.2 billion at December 31, 2004 and $1.8 billion at December 31, 2003) with original maturities of three months or less. Additionally, at December 31, 2004, the four projects that SCE is consolidating under the new accounting interpretation for VIEs had $90 million in cash and equivalents. For a discussion of restricted cash, see "Restricted Cash."

Debt and Equity Investments

Net unrealized gains (losses) on equity investments are recorded as a separate component of shareholders' equity under the caption "Accumulated other comprehensive income." Unrealized gains and losses on decommissioning trust funds increase or decrease the related regulatory asset or liability. All investments are classified as available-for-sale.

Dividend Restriction

The CPUC regulates SCE's capital structure and limits the dividends it may pay Edison International. SCE's authorized capital structure includes a common equity component of 48%. SCE determines compliance with this capital structure based on a 13-month weighted-average calculation. At December 31, 2004, SCE's 13-month weighted-average common equity component of total capitalization was 50.5%. At December 31, 2004, SCE had the capacity to pay $222 million in additional dividends based on the 13-month weighted-average method. Based on recorded December 31, 2004 balances, SCE's common equity to total capitalization ratio was 50.4% for rate-making purposes. SCE had the capacity to pay $213 million of additional dividends to Edison International based on December 31, 2004 recorded balances.

Earnings (Loss) Per Share (EPS)

Basic EPS is computed by dividing net income (loss) by the weighted-average number of common shares outstanding. In arriving at net income (loss), dividends on preferred securities and preferred stock have been deducted. For the diluted EPS calculation, dilutive securities (employee stock options) are added to the weighted-average shares. Dilutive securities are excluded from the diluted EPS calculation for items with a net loss due to their antidilutive effect.

The following table presents the effect of dilutive securities on the number of weighted-average shares of common stock outstanding:

In millions Year ended December 31,	**2004**	2003	2002
Weighted-average shares of common stock outstanding	**326**	326	326
Stock-based compensation awards exercisable	**5**	3	2
Weighted-average shares including effect of dilutive securities	**331**	329	328

Inventory

Inventory is stated at the lower of cost or market, cost being determined by the first-in, first-out method for SCE's fuel, the weighted-average cost method for EME's fuel, and the average cost method for materials and supplies.

New Accounting Principles

A new accounting standard requires companies to use the fair value accounting method for stock-based compensation. Edison International currently uses the intrinsic value accounting method for stock-based compensation. Edison International will adopt the new method effective July 1, 2005. The difference in expense between the two methods is shown in Note 1 under "Stock-Based Compensation." Edison International is reviewing the new standard and has not yet selected a transition method for adoption of the new standard.

In December 2004, the Financial Accounting Standards Board (FASB) issued guidance (Staff Position 109-1) on accounting for a tax deduction resulting from the American Jobs Creation Act of 2004. The primary objective of this Position is to provide guidance on accounting for the provision within the American Jobs Creation Act of 2004 that provides a tax deduction on qualified production activities. Under this Position, recognition of the tax deduction on qualified production activities, which include the production of electricity, is reported in the year it is earned. This FASB Staff Position had no material impact on Edison International's financial statements. Edison International is evaluating the effect that the manufacturer's deduction will have in subsequent years.

In March 2004, the FASB issued new guidance on participating securities and the two-class method under the applicable accounting standard for calculating EPS. The new guidance, which was effective in second quarter 2004, requires the use of the two-class method of computing EPS for companies with participating securities (including vested dividend equivalents on stock options). The two-class method is an earnings allocations formula that determines EPS for each class of common stock and participating security. Edison International has participating securities, but determined that the effect on 2004, 2003 and 2002 EPS in immaterial. Edison International is reviewing the potential effect of this guidance on 2005 EPS.

In December 2003, the FASB issued a revision to an accounting Interpretation (originally issued in January 2003), Consolidation of VIEs. The primary objective of the Interpretation is to provide guidance on the identification of, and financial reporting for, VIEs, where control may be achieved through means other than voting rights. Under the Interpretation, the enterprise that is expected to absorb or receive the majority of a VIE's expected losses or residual returns, or both, must consolidate the VIE, unless specific exceptions apply. This Interpretation was effective for special purpose entities, as defined by accounting principles generally accepted in the United States, as of December 31, 2003, and all other entities as of March 31, 2004. Edison International implemented the Interpretation for its special purpose entities as of December 31, 2003. As a result, Edison International deconsolidated three special purpose entities: EIX Trusts I and II; and EME's Mission Capital, L.P. These special purpose entities function as financing entities. In late 2004 and early 2005, the bonds and securities associated with these financings entities were paid off. See further discussion in "Company-Obligated Manditorily Redeemable Securities of Subsidiary" in Note 4.

SCE has 270 long-term power-purchase contracts with independent power producers that own qualifying facilities (QFs). SCE was required under federal law to sign such contracts, which typically require SCE to purchase 100% of the power produced by these facilities under terms and pricing controlled by the CPUC. SCE conducted a review of its QF contracts and determined that SCE has variable interests in 12 contracts with gas-fired cogeneration plants that are potential VIEs and that contain variable pricing provisions based on the prices of natural gas and for which SCE does not have sufficient information to determine if the projects qualify for a scope exception. SCE requested from the entities that hold these

contracts the financial information necessary to determine whether SCE must consolidate these projects. All 12 entities declined to provide SCE with the necessary financial information. However, four of the 12 contracts are with entities 49%–50% owned by EME. Although the four related-party entities have declined to provide their financial information to SCE, Edison International has access to such information and has provided combined financial statements to SCE. SCE has determined that it must consolidate the four power projects partially owned by EME based on a qualitative analysis of the facts and circumstances of the entities, including the related-party nature of the transaction. SCE will continue to attempt to obtain information for the other eight projects in order to determine whether they should be consolidated by SCE.

The remaining 258 contracts will not be consolidated by SCE under the new accounting standard since SCE lacks a variable interest in these contracts or the contracts are with governmental agencies, which are generally excluded from the standard.

Edison International analyzes its potential variable interests by calculating operating cash flows. A fixed-price contract to purchase electricity from a power plant does not transfer sufficient risk to the purchaser to be considered a variable interest. A contract with a non-natural-gas-fired plant that is based on the price of natural gas is also not a variable interest. SCE has other power contracts with non-QF generators. SCE has determined that these contracts are not significant variable interests.

On March 31, 2004, SCE consolidated four power projects partially owned by EME, EME deconsolidated two power projects, and Edison Capital consolidated two affordable housing partnerships and three wind projects. Edison International recorded a cumulative effect adjustment that decreased net income by less than $1 million, net of tax, due to negative equity at one of Edison Capital's newly consolidated entities.

See "Variable Interest Entities" for further information.

Effective July 1, 2003, Edison International adopted a new accounting standard, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity, which required issuers to classify certain freestanding financial instruments as liabilities. These freestanding liabilities include mandatorily redeemable financial instruments, obligations to repurchase the issuer's equity shares by transferring assets and certain obligations to issue a variable number of shares. Effective July 1, 2003, Edison International reclassified its company-obligated mandatorily redeemable securities, its other mandatorily redeemable preferred securities and SCE's preferred stock subject to mandatory redemption to the liabilities section of its consolidated balance sheet. These items were previously classified between liabilities and equity. In addition, effective July 1, 2003, dividend payments on these instruments were included in interest expense – net of amounts capitalized on Edison International's consolidated statements of income. Prior period financial statements were not permitted to be restated for these changes. Therefore, upon adoption there was no cumulative impact incurred due to this accounting change.

Nuclear

Effective January 1, 2004, San Onofre Nuclear Generating Station (San Onofre) Units 2 and 3 returned to traditional cost-of-service ratemaking. The July 8, 2004 CPUC decision on SCE's 2003 general rate case returned Palo Verde Nuclear Generating Station (Palo Verde) to traditional cost-of-service ratemaking retroactive to May 22, 2003 (the date a final CPUC decision was originally scheduled to be issued). As authorized by the CPUC, SCE had been recovering its investments in San Onofre and Palo Verde on an accelerated basis; these units also had incentive rate-making plans.

SCE's nuclear plant investments made prior to the return to cost-of-service ratemaking are recorded as regulatory assets on its balance sheets. Since the return to cost-of-service ratemaking, capital additions are recorded in utility plant. These classifications do not affect the rate-making treatment for these assets.

Other Nonoperating Income and Deductions

Other nonoperating income and deductions are as follows:

In millions Year ended December 31,	2004	2003	2002
Nonutility nonoperating income	$ 51	$ 14	$ 10
Utility nonoperating income	84	72	75
Total nonoperating income	**$ 135**	$ 86	$ 85
Nonutility nonoperating deductions	$ 11	$ 9	$ 50
Utility nonoperating deductions	69	23	(18)
Total nonoperating deductions	**$ 80**	$ 32	$ 32

Planned Major Maintenance

Certain plant facilities require major maintenance on a periodic basis. All such costs are expensed as incurred.

Property and Plant

Utility plant additions, including replacements and betterments, are capitalized. Such costs include direct material and labor, construction overhead, a portion of administrative and general costs capitalized at a rate authorized by the CPUC, and an allowance for funds used during construction (AFUDC). AFUDC represents the estimated cost of debt and equity funds that finance utility-plant construction. AFUDC is capitalized during plant construction and reported in current earnings in other nonoperating income. AFUDC is recovered in rates through depreciation expense over the useful life of the related asset. Depreciation of utility plant is computed on a straight-line, remaining-life basis.

Depreciation expense stated as a percent of average original cost of depreciable utility plant was 3.9% for 2004, 4.3% for 2003 and 4.2% for 2002.

AFUDC – equity was $23 million in 2004, $21 million in 2003 and $11 million in 2002. AFUDC – debt was $12 million in 2004, $6 million in 2003 and $8 million in 2002.

Replaced or retired property costs are charged to the accumulated provision for depreciation. Cash payments for removal costs less salvage reduce the liability for asset retirement obligations.

Estimated useful lives of SCE's utility plant, as authorized by the CPUC, are as follows:

Generation plant	38 years to 81 years
Distribution plant	24 years to 53 years
Transmission plant	40 years to 60 years
Other plant	5 years to 40 years

SCE's net investment in generation-related utility plant was $920 million at December 31, 2004 and $867 million at December 31, 2003.

Nuclear fuel is recorded as utility plant in accordance with CPUC rate-making procedures.

Nonutility property, including leasehold improvements and construction in progress, is capitalized at cost. Interest incurred on borrowed funds that finance construction and project development costs are also

capitalized. Capitalized interest was $9 million in 2004, $7 million in 2003 and $5 million in 2002. SCE's Mountainview power plant is included in nonutility property in accordance with the rate-making treatment. Depreciation and amortization is primarily computed on a straight-line basis over the estimated useful lives of nonutility properties and over the lease term for leasehold improvements.

Depreciation expense stated as a percent of average original cost of depreciable nonutility property was, on a composite basis, 4.1% for 2004, 4.2% for 2003 and 4.6% for 2002.

Emission allowances were acquired by EME as part of its Illinois plants and Homer City facilities acquisitions. Although these emission allowances are freely transferable, EME intends to use substantially all the emission allowances in the normal course of its business to generate electricity. Accordingly, Edison International has classified emission allowances expected to be used by EME to generate power as part of nonutility property. These acquired emission allowances will be amortized over the estimated lives of the plants on a straight-line basis.

Nonutility property included in the consolidated balance sheets is comprised of:

In millions December 31,	2004	2003
Furniture and equipment	**$ 117**	$ 108
Building, plant and equipment	**3,154**	2,326
Land	**74**	68
Emission allowances	**1,305**	1,305
Leasehold improvements	**81**	64
Construction in progress	**502**	36
	5,233	3,907
Less accumulated provision for depreciation	**1,311**	619
Nonutility property – net	**$ 3,922**	$ 3,288

Estimated useful lives for nonutility property are as follows:

Furniture and equipment	3 years to 10 years
Building, plant and equipment	3 years to 40 years
Emission allowances	25 years to 35 years
Leasehold improvements	Life of lease

As a result of an accounting standard adopted in 2003, Edison International recorded the fair value of its liability for legal asset retirement obligations (ARO), which was primarily related to the decommissioning of SCE's nuclear power facilities. In addition, SCE capitalized the initial costs of the ARO into a nuclear-related ARO regulatory asset, and also recorded an ARO regulatory liability as a result of timing differences between the recognition of costs recorded in accordance with the standard and the recovery of the related asset retirement costs through the rate-making process. SCE has collected in rates amounts for the future costs of removal of its nuclear assets, and has placed those amounts in independent trusts. Prior to this standard, SCE had recorded these amounts in accumulated provision for depreciation and decommissioning.

A reconciliation of the changes in the ARO liability is as follows:

In millions	
Initial ARO liability as of January 1, 2003	$ —
Adoption of new standard	2,028
Accretion expense	129
Liabilities settled	(68)
ARO liability as of December 31, 2003	2,089
Accretion expense	132
Liabilities settled	(33)
ARO liability as of December 31, 2004	$ 2,188
Fair value of nuclear decommissioning trusts	$ 2,757

Due to adoption of the new accounting standard related to AROs in 2003, Edison International recorded a cumulative effect adjustment that decreased net income by approximately $9 million, net of tax. The cumulative effect adjustment was the result of EME's adoption of the new standard. SCE follows accounting principles for rate-regulated enterprises and receives recovery of these costs through rates; therefore, implementation of this new standard at SCE did not affect Edison International's earnings.

Purchased Power

From January 17, 2001 to December 31, 2002, the California Department of Water Resources (CDWR) purchased power on behalf of SCE's customers for SCE's residual net short power position (the amount of energy needed to serve SCE's customers in excess of SCE's own generation and purchased power contracts). Additionally, the CDWR signed long-term contracts which provide power for SCE's customers. Effective January 1, 2003, SCE resumed power procurement responsibilities for its residual net short position. SCE acts as a billing agent for the CDWR power, and any power purchased by the CDWR for delivery to SCE's customers is not considered a cost to SCE.

Receivables

SCE records an allowance for uncollectible accounts, as determined by the average percentage of revenue not collected in prior accounting periods. SCE assesses its customers a late fee of 0.9% per month, beginning 19 days after the bill is prepared. Inactive accounts are written off after 180 days.

Regulatory Assets and Liabilities

In accordance with accounting principles for rate-regulated enterprises, SCE records regulatory assets, which represent probable future recovery of certain costs from customers through the rate-making process, and regulatory liabilities, which represent probable future credits to customers through the rate-making process.

Included in these regulatory assets and liabilities are SCE's regulatory balancing accounts. Sales balancing accounts accumulate differences between recorded revenue and revenue SCE is authorized to collect through rates. Cost balancing accounts accumulate differences between recorded costs and costs SCE is authorized to recover through rates. Undercollections are recorded as regulatory balancing account assets. Overcollections are recorded as regulatory balancing account liabilities. SCE's regulatory balancing accounts accumulate balances until they are refunded to or received from SCE's customers through authorized rate adjustments. Primarily all of SCE's balancing accounts can be classified as one of the following types: generation-revenue related, distribution-revenue related,

generation-cost related, distribution-cost related, transmission-cost related or public purpose and other cost related.

Balancing account undercollections and overcollections accrue interest based on a three-month commercial paper rate published by the Federal Reserve. Income tax effects on all balancing account changes are deferred.

Regulatory Assets

Regulatory assets included in the consolidated balance sheets are:

In millions December 31,	2004	2003
Current		
Regulatory balancing accounts	**$ 371**	$ 140
Direct access procurement charges	**109**	90
Purchased-power settlements	**62**	57
Other	**11**	12
	553	299
Long-term		
Flow-through taxes – net	**1,018**	974
Rate reduction notes – transition cost deferral	**739**	985
Unamortized nuclear investment – net	**526**	583
Nuclear-related ARO investment – net	**272**	288
Unamortized coal plant investment – net	**78**	66
Unamortized loss on reacquired debt	**250**	222
Direct access procurement charges	**141**	250
Environmental remediation	**55**	71
Purchased-power settlements	**91**	153
Other	**115**	133
	3,285	3,725
Total Regulatory Assets	**$ 3,838**	$ 4,024

SCE's regulatory assets related to direct access procurement charges are for amounts direct access customers owe bundled service customers for the period May 1, 2000 through August 31, 2001, and are offset by corresponding regulatory liabilities to the bundled service customers. These amounts will be collected by mid-2007. SCE's regulatory assets related to purchased-power settlements will be recovered through 2008. Based on current regulatory ratemaking and income tax laws, SCE expects to recover its net regulatory assets related to flow-through taxes over the life of the assets that give rise to the accumulated deferred income taxes. SCE's regulatory asset related to the rate reduction bonds is amortized simultaneously with the amortization of the rate reduction bonds liability, and is expected to be recovered by the end of 2007. SCE's nuclear-related regulatory assets are expected to be recovered by the end of the remaining useful lives of the nuclear facilities. SCE has requested a four-year recovery period for the net regulatory asset related to its unamortized coal plant investment. CPUC approval is pending. SCE's regulatory asset related to its unamortized loss on reacquired debt will be recovered over the remaining original amortization period of the reacquired debt over periods ranging from one year to 31 years. SCE's regulatory asset related to environmental remediation represents the portion of SCE's environmental liability recognized at the end of the period in excess of the amount that has been recovered through rates charged to customers. This amount will be recovered in future rates as expenditures are made.

SCE earns a return on three of the regulatory assets listed above: unamortized nuclear investment – net, unamortized coal plant investment – net and unamortized loss on reacquired debt.

Regulatory Liabilities

Regulatory liabilities included in the consolidated balance sheets are:

In millions December 31,	2004	2003
Current		
Regulatory balancing accounts	$ 357	$ 549
Direct access procurement charges	109	90
Other	24	20
	490	659
Long-term		
ARO	819	720
Costs of removal	2,112	2,020
Direct access procurement charges	141	250
Employee benefits plans	200	207
Other	84	37
	3,356	3,234
Total Regulatory Liabilities	$ 3,846	$ 3,893

SCE's regulatory liability related to the ARO represents timing differences between the recognition of nuclear decommissioning obligations in accordance with generally accepted accounting principles and the amounts recognized for rate-making purposes. SCE's regulatory liabilities related to costs of removal represent revenue collected for asset removal costs that SCE expects to incur in the future. Historically, these removal costs have been recorded in accumulated depreciation; however, in accordance with recent Securities and Exchange Commission accounting guidance, the amounts accrued in provision for depreciation for decommissioning and costs of removal were reclassified to regulatory liabilities as of December 31, 2002. SCE's regulatory liabilities related to direct access procurement charges are a liability to its bundled service customers and are offset by regulatory assets from direct access customers. SCE's regulatory liabilities related to employee benefit plan expenses represent pension and postretirement benefits other than pensions costs recovered through rates charged to customers in excess of the amounts recognized as expense. These balances will either be returned to ratepayers in some future rate-making proceeding, or be charged against expense to the extent that future expenses exceed amounts recoverable through the rate-making process.

Related Party Transactions

Four EME subsidiaries have 49% to 50% ownership in partnerships (QFs) that sell electricity generated by their project facilities to SCE under long-term power purchase agreements with terms and pricing approved by the CPUC. Beginning March 31, 2004, SCE consolidates these projects (see "Variable Interest Entities").

An indirect wholly owned affiliate of EME has entered into operation and maintenance agreements with partnerships in which EME has a 50% or less ownership interest. EME recorded revenue under these agreements of $24 million, $24 million and $22 million in 2004, 2003 and 2002, respectively. EME's accounts receivable with this affiliate totaled $6 million at December 31, 2004 and 2003.

Restricted Cash

Edison International had total restricted cash of $228 million at December 31, 2004 and $285 million at December 31, 2003. The restricted amounts included in current assets are primarily used to make scheduled payments on the current maturities of rate reduction notes issued on behalf of SCE by a special purpose entity, as well as to serve as collateral at Edison Capital for outstanding letters of credit. The restricted amounts included in deferred charges are primarily to pay amounts for debt payments at MEHC and EME and letter of credit expenses at EME.

Revenue

Electric utility revenue is recognized as electricity is delivered and includes amounts for services rendered but unbilled at the end of each year. Amounts charged for services rendered are based on CPUC-authorized rates and FERC-approved rates. Revenue related to SCE's transmission function is authorized by the FERC in periodic proceedings that are similar to the CPUC's proceedings, except that requested rate changes are generally implemented when the application is filed, and revenue collected prior to a final FERC decision is subject to refund. Rates include amounts for current period costs, plus the recovery of certain previously incurred costs. However, in accordance with accounting standards for rate-regulated enterprises, amounts currently authorized in rates for recovery of costs to be incurred in the future are not considered as revenue until the associated costs are incurred. Instead, these amounts are recorded as deferred revenue. For costs recovered through CPUC-authorized general rate case rates, costs incurred in excess of revenue billed are deferred in a balancing account, and recovered in future rates.

Since January 17, 2001, power purchased by the CDWR or through the California Independent System Operator (ISO) for SCE's customers is not considered a cost to SCE, because SCE is acting as an agent for these transactions. Further, amounts billed to ($2.5 billion in 2004, $1.7 billion in 2003 and $1.4 billion in 2002) and collected from SCE's customers for these power purchases, CDWR bond-related costs (effective November 15, 2002) and direct access exit fees (effective January 1, 2003) are being remitted to the CDWR and are not recognized as revenue to SCE.

Generally, nonutility power generation revenue is recorded as electricity is generated or services are provided. In addition, in accordance with accounting rules for derivatives, nonutility power generation revenue includes amounts related to EME's cost of purchased power netted against related third party sales in markets that use locational marginal pricing, financial swaps and option transactions that are settled net, and the resulting net gains and losses.

Financial services and other revenue is generally derived from two sources; leveraged leases and renewable energy. Revenue from leveraged leases is recorded by recognizing income over the term of the lease so as to produce a constant rate of return based on the investment leased. Revenue from renewable energy is earned under long-term power sales contracts. The amounts recognized are the lesser of amounts billable under the contract or the amount determined by the kilowatt-hours (kWhs) made available during the period multiplied by the estimated average revenue per kWh over the term of the contract.

Ordinary gains and losses from sale of assets are recognized at the time of the transaction.

Stock-Based Compensation

Edison International has stock-based compensation plans, which are described more fully in Note 7. Edison International accounts for those plans using the intrinsic value method. Upon grant, no stock-based compensation cost is reflected in net income, as all options granted under those plans had an exercise price equal to the market value of the underlying common stock on the date of grant. The following table illustrates the effect on net income and EPS if Edison International had used the fair-value accounting method.

In millions Year ended December 31,	2004	2003	2002
Net income, as reported	**$ 916**	$ 821	$ 1,077
Add: stock-based compensation expense using the intrinsic value accounting method – net of tax	**51**	7	8
Less: stock-based compensation expense using the fair-value accounting method – net of tax	**57**	9	5
Pro forma net income	**$ 910**	$ 819	$ 1,080
Basic EPS:			
As reported	**$ 2.81**	$ 2.52	$ 3.31
Pro forma	**2.79**	2.51	3.31
Diluted EPS:			
As reported	**$ 2.77**	$ 2.50	$ 3.28
Pro forma	**2.75**	2.49	3.29

Supplemental Accumulated Other Comprehensive Loss Information

Supplemental information regarding Edison International's accumulated other comprehensive loss, including discontinued operations, is:

In millions December 31,	2004	2003
Foreign currency translation adjustments – net	**$ —**	$ 146
Minimum pension liability – net	**(15)**	(23)
Unrealized loss on investments – net	**—**	(7)
Unrealized gains (losses) on cash flow hedges – net	**11**	(169)
Accumulated other comprehensive loss	**$ (4)**	$ (53)

The minimum pension liability is discussed in Note 7, Compensation and Benefit Plans.

Included in Edison International's accumulated other comprehensive loss at December 31, 2004, was an $18 million gain related to EME's unrealized gains on cash flow hedges and a $7 million loss related to SCE's interest rate swap (see discussion below). Of the $18 million gain, a gain of $26 million was related to EME's commodity hedges and an $8 million loss was related to EME's interest rate hedges. Unrealized gains (losses) pertained to both continuing and discontinued operations as follows:

Continuing operations – Unrealized gains on commodity hedges for continuing operations included those primarily related to EME's Homer City and Midwest Generation forward electricity contracts that did not meet the normal sales and purchases exception under the derivative accounting standard. These gains arise because current forecasts of future electricity prices in these markets are greater than contract prices. Unrealized gains on commodity hedges also included those related to EME's share of fuel contracts at its March Point cogeneration facility.

Unrealized losses on cash flow hedges for continuing operations included those related to SCE's interest rate swap (the swap terminated on January 5, 2001, but the related debt matures in 2008). The unamortized loss of $7 million (as of December 31, 2004, net of tax) on the interest rate swap will be amortized over a period ending in 2008. Approximately $2 million, after tax, of the unamortized loss on this swap will be reclassified into earnings during 2005.

As EME's hedged positions for continuing operations are realized, approximately $11 million (after tax) of the net unrealized gains on cash flow hedges at December 31, 2004 are expected to be reclassified into earnings during 2005. EME expects that reclassification of net unrealized gains will offset energy revenue recognized at market prices. Actual amounts ultimately reclassified into earnings over the next 12 months could vary materially from this estimated amount as a result of changes in market conditions. The maximum period over which an EME cash flow hedge is designated is through December 31, 2006.

Discontinued operations – Unrealized losses on interest rate hedges pertained to discontinued operations only and were primarily related to EME's share of interest rate swaps of its Caliraya-Botocan-Kalayaan (CBK) project.

The unrealized losses for discontinued operations were reclassified into earnings upon the completion of the sale of EME's CBK project in January 2005.

Supplemental Cash Flows Information

Edison International supplemental cash flows information is:

In millions Year ended December 31,	2004	2003	2002
Cash payments for interest and taxes:			
Interest – net of amounts capitalized	**$ 878**	$ 1,280	$ 1,113
Tax payments (receipts)	**(33)**	230	(301)
Non-cash investing and financing activities:			
Details of consolidation of variable interest entities:			
Assets	**$ 625**	—	—
Liabilities	**(704)**	—	—
Details of deconsolidation of variable interest entities:			
Assets	**$ (133)**	—	—
Liabilities	**165**	—	—
Obligation to fund investment in acquisition	—	$ 8	—
Reoffering of pollution-control bonds	**$ 196**	—	—
Dividends declared but not paid	**$ 81**	65	—
Details of pollution-control bond redemption:			
Release of funds held in trust	**$ 20**	—	—
Pollution-control bonds redeemed	**(20)**	—	—
Details of long-term debt exchange offer:			
Variable rate notes redeemed	—	$ (966)	—
First and refunding mortgage bonds issued	—	966	—
Details of debt exchange:			
Retirement of senior secured credit facility	—	$ (700)	—
Short-term credit facility utilized	—	200	—
Cash paid	—	$ (500)	—
Details of senior secured credit facility transaction:			
Retirement of credit facility	—	—	$ (1,650)
Senior secured credit facility replacement	—	—	1,600
Cash paid on retirement of credit facility	—	—	$ (50)

Variable Interest Entities

Entities Consolidated Upon Implementation of New Accounting Standard

SCE has variable interests in contracts with certain QFs that contain variable contract pricing provisions based on the price of natural gas. Further, four of these contracts are with entities that are partnerships owned in part by a related party, EME. These four contracts have 20-year terms. The QFs sell electricity to SCE and steam to nonrelated parties. Under a new accounting standard, Edison International and SCE consolidated these four projects effective March 31, 2004. Prior periods have not been restated. The

book value of the projects' plant assets at December 31, 2004 is $377 million ($896 million at original cost less $519 million in accumulated depreciation) and is recorded in nonutility property.

Project	Capacity	Termination Date	EME Ownership
Kern River	300 MW	August 2005	50%
Midway-Sunset	225 MW	May 2009	50%
Sycamore	300 MW	December 2007	50%
Watson	385 MW	December 2007	49%

SCE has no investment in, nor obligation to provide support to, these entities other than its requirement to make contract payments. Any liabilities of these projects are nonrecourse to SCE.

The variable interest entities' operating costs, instead of purchased power expense, are shown in Edison International's income statements effective April 1, 2004. Further, Edison International's electric utility revenue now includes revenue from the sale of steam by these four projects.

Edison Capital has investments in affordable housing and wind projects that are variable interests. Effective March 31, 2004, Edison Capital consolidated two affordable housing partnerships and three wind projects. These projects are funded with nonrecourse debt totaling $33 million at December 31, 2004. Properties serving as collateral for these loans had a carrying value of $48 million and are classified as nonutility property on the December 31, 2004 balance sheet. The creditors to these projects do not have recourse to the general credit of Edison Capital.

Entities Deconsolidated Upon Implementation of New Accounting Standard

EME deconsolidated the Doga and Kwinana projects effective March 31, 2004. The Kwinana project was sold on December 16, 2004, as part of EME's sale of its international operations and, accordingly, is included in discontinued operations.

Significant Variable Interests in Entities Not Consolidated

EME has a significant variable interest in the Sunrise project, which is a gas-fired facility located in California. As of December 31, 2004, EME had a 50% ownership interest in the project and its investment was $97 million. EME's maximum exposure to loss is generally limited to its investment in this entity.

Edison Capital's maximum exposure to loss from affordable housing investments in this category is generally limited to its net investment balance of $70 million and recapture of tax credits.

Entities with Unavailable Financial Information

SCE has eight nonrelated-party contracts with certain QFs that contain variable pricing provisions based on the price of natural gas and are potential VIEs. SCE might be considered to be the consolidating entity under the new accounting standard. However, these entities are not legally obligated to provide the financial information to SCE that is necessary to determine whether SCE must consolidate these entities. These eight entities have declined to provide SCE with the necessary financial information. SCE will continue to attempt to obtain information for these projects in order to determine whether they should be consolidated by SCE. The aggregate capacity dedicated to SCE for these projects is 267 MW. SCE paid $166 million in 2004 to these projects. These amounts are recoverable in utility customer rates. SCE has no exposure to loss as a result of its involvement with these projects.

Note 2. Regulatory Matters

CDWR Power Purchases and Revenue Requirement Proceedings

In accordance with an emergency order by the Governor of California, the CDWR began making emergency power purchases for SCE's customers on January 17, 2001. In February 2001, a California law was enacted which authorized the CDWR to: (1) enter into contracts to purchase electric power and sell power at cost directly to SCE's retail customers; and (2) issue bonds to finance those electricity purchases. The CDWR's total statewide power charge and bond charge revenue requirements are allocated by the CPUC among the customers of SCE, Pacific Gas and Electric (PG&E) and San Diego Gas & Electric (SDG&E) (collectively, the investor-owned utilities). Amounts billed to SCE's customers for electric power purchased and sold by the CDWR (approximately $2.5 billion in 2004) are remitted directly to the CDWR and are not recognized as revenue by SCE and therefore have no impact on SCE's earnings.

In December 2004, the CPUC issued its decision on how the CDWR's power charge revenue requirement for 2004 through 2013, when the last CDWR contract expires, will be allocated among the investor-owned utilities. The CPUC rejected a settlement agreement among PG&E, the Utility Reform Network (TURN), and SCE and which the ORA supported. However, the CPUC's final decision adopts key attributes of that settlement agreement. It adopts a cost-follows-contract allocation to each of the investor-owned utilities of the unavoidable portion of costs incurred under CDWR contracts. A previous CPUC decision allocated the avoidable portion of the costs on a cost-follows-contract basis. Allocating the avoidable and unavoidable portions on a cost-follows-contract basis provides the investor-owned utilities the appropriate incentives to operate and administer the contracts that have been allocated to them. In addition, in order to fairly allocate the total burden of the CDWR contracts among the investor-owned utilities, the decision adjusts the cost-follows-contract allocation of the total costs (avoidable and unavoidable) such that the above-market cost burden associated with the contracts is allocated as follows: 44.8% to PG&E's customers, 45.3% to SCE's customers, and 9.9% to SDG&E's customers. The CPUC's December 2004 decision is based on the above market cost analysis that SCE presented in its initial testimony in December 2003.

In response to an application filed by SDG&E, the CPUC issued an order granting limited rehearing of the December 2004 decision. The rehearing permits parties to present alternative methodologies and updated data for the calculation of above market costs associated with the CDWR contracts. A schedule has not been adopted for the rehearing, but it is expected to take place in the second quarter of 2005. SDG&E has also filed a petition for modification of the decision urging the CPUC to replace the adopted methodology with a methodology that would retain the cost-follows-contract allocation of the avoidable costs, but would allocate the unavoidable costs associated with the contracts: 42.2% to PG&E's customers, 47.5% to SCE's customers, and 10.3% to SDG&E's customers. Such an allocation would decrease the total costs allocated to SDG&E's customers and increase the total costs allocated to SCE's customers. The CPUC is expected to act on the petition in March 2005.

CPUC Litigation Settlement Agreement

In October 2001, SCE and the CPUC entered into a settlement of SCE's lawsuit against the CPUC which sought full recovery of its electricity procurement costs incurred during the energy crisis. A key element of the 2001 CPUC settlement agreement was the establishment of a regulatory balancing account, called the Procurement-Related Obligations Account (PROACT), which was fully recovered by August 2003.

Energy Resource Recovery Account Proceedings

In an October 2002 decision, the CPUC established the ERRA as the rate-making mechanism to track and recover SCE's: (1) fuel costs related to its generating stations; (2) purchased-power costs related to

cogeneration and renewable contracts; (3) purchased-power costs related to existing interutility and bilateral contracts that were entered into before January 17, 2001; and (4) new procurement-related costs incurred on or after January 1, 2003 (the date on which the CPUC transferred back to SCE the responsibility for procuring energy resources for its customers). SCE recovers these costs on a cost-recovery basis, with no markup for return or profit. SCE files annual forecasts of the above-described costs that it expects to incur during the following year. As these costs are subsequently incurred, they will be tracked and recovered through the ERRA, but are subject to a reasonableness review in a separate annual ERRA application. If the ERRA overcollection or undercollection exceeds 5% of SCE's prior year's procurement costs, SCE can request an emergency rate adjustment in addition to the annual forecast and reasonableness ERRA applications.

ERRA Reasonableness Review for the Period September 1, 2001 through June 30, 2003

On October 3, 2003, SCE submitted its first ERRA reasonableness review application requesting that the CPUC find its procurement-related operations during the period from September 1, 2001 through June 30, 2003 to be reasonable. The CPUC's Office of Ratepayer Advocates (ORA) was allowed to review the accounting calculations used in the PROACT mechanism. The ORA recommended disallowances that totaled approximately $14 million of costs recovered through the PROACT mechanism during the period from September 1, 2001 through June 30, 2003. In April 2004, SCE reached an agreement with the ORA (subject to CPUC approval) to reduce the PROACT disallowances to approximately $4 million. On January 27, 2005, the CPUC issued a decision approving the agreement. The $4 million, which is mainly comprised of ISO grid management charges and employee-related retraining costs, will be refunded to ratepayers through a credit to the ERRA.

The January 27, 2005 CPUC decision also provides that SCE's administration of its procurement contracts will be subject to reasonableness review under the "reasonable manager" standard. However, the CPUC decision provides that the review of SCE's daily dispatch of its generation resources will be subject to a compliance review, not a reasonableness review, and will only include a review of spot market transactions in the day-ahead, hour-ahead and real-time markets. The decision found that SCE's daily dispatch decisions during the record period complied with the CPUC's standard, and that its administration of its contracts was reasonable in all respects. It authorized recovery of amounts paid to Peabody Coal Company for costs associated with the Mohave mine closing as well as transmission costs related to serving municipal utilities, and also resolved outstanding issues from 2000 and 2001 related to CDWR costs. As a result of this decision, SCE recorded a pre-tax net regulatory gain of $118 million in 2004.

ERRA Reasonableness Review for the Period July 1, 2003 through December 31, 2003

On April 1, 2004, SCE submitted its second ERRA reasonableness review application requesting that the CPUC find its procurement-related operations during the period from July 1, 2003 through December 31, 2003, to be reasonable. In addition, SCE requested recovery of a $10 million reward for Palo Verde Unit 3 efficient operation and $5 million in electric energy transaction administration costs.

On January 17, 2005, the CPUC issued a decision finding that SCE's administration of its power purchase agreements and its daily decisions dispatching its procurement resources were reasonable and prudent. The decision also found that the revenue and expenses recorded in SCE's ERRA account during the record period were reasonable and prudent, and approved SCE's requested recovery of the items discussed above.

Generation Procurement Proceedings

SCE resumed power procurement responsibilities for its net-short position (expected load requirements exceed generation supply) on January 1, 2003, pursuant to CPUC orders and California statutes passed in

2002. The current regulatory and statutory framework requires SCE to assume limited responsibilities for CDWR contracts allocated by the CPUC, and provide full power procurement responsibilities on the basis of annual short-term procurement plans, long-term resource plans and increased procurement of renewable resources. Currently, the CPUC and the California Energy Commission (CEC) are working together to set rules for various aspects of generation procurement which are described below.

Procurement Plan

Resource Planning Component of the Procurement Plan

On April 1, 2004, the CPUC instituted a resource planning proceeding that, among other things, will coordinate consideration of long-term resource plans. On July 9, 2004, SCE filed testimony on its long-term procurement plan, which includes a substantial commitment to cost-effective energy efficiency and an advanced load-control program. A CPUC decision approving SCE's long-term procurement plan was issued in December 2004. The decision required all long-term procurement to be conducted through all-source solicitations; allowed the consideration of debt equivalence in the bid evaluation process; and required the use of a greenhouse gas adder as a bid evaluation component. The decision also extended the utilities' authority to procure longer-term products and lifted the affiliate ban on long-term power products. SCE's next long-term procurement plan will be filed in 2006.

Assembly Bill 57 Component of the Procurement Plan

In December 2003, the CPUC adopted a 2004 short-term procurement plan for SCE which established a target level for spot market purchases equal to 5% of monthly need, and allowed SCE to enter into contracts of up to five years. Currently, SCE is operating under this approved short-term procurement plan. To the extent SCE procures power in accordance with the plan, SCE receives full-cost recovery of its procurement transactions pursuant to Assembly Bill 57. Accordingly, the plan is referred to as the Assembly Bill 57 component of the procurement plant.

Each quarter, SCE is required to file a report with the CPUC demonstrating that SCE's procurement-related transactions associated with serving the demands of its bundled electricity customers were in conformance with SCE's adopted short-term procurement plan. SCE has submitted seven quarterly compliance filings covering the period from January 1, 2003 through September 30, 2004, including its third quarter 2004 compliance filing on November 1, 2004. To date, however, the CPUC has only issued one resolution approving SCE's first compliance report for the period January 1, 2003 to March 31, 2003. While SCE believes that all of its procurement transactions were in compliance with its adopted short-term procurement plan, SCE cannot predict with certainty whether or not the CPUC will agree with SCE's interpretation regarding some elements.

Resource Adequacy Requirements

Under the framework adopted in the CPUC's January 22, 2004 decision, all load-serving entities in California have an obligation to procure sufficient resources to meet their customers' needs. On October 28, 2004, the CPUC issued a decision clarifying the January 2004 decision. The October 2004 decision requires load-serving entities to ensure that adequate resources have been contracted to meet that entity's peak forecasted energy resource demand and an additional planning reserve margin of 15-17% of that peak load by June 1, 2006. Currently, the decision requires SCE to demonstrate that it has contracted 90% of its May–September 2006 resource adequacy requirement by September 30, 2005. As the May-September period approaches, SCE will be required to fill out the remaining 10% of its resource adequacy requirement one month in advance of expected need. The October 28, 2004 decision also clarified that although the first compliance filing will only cover May–September 2006, the 15–17% planning reserve margin is a year-round requirement. In its October 2004 decision, the CPUC also decided that long-term CDWR contracts allocated to the investor-owned utilities during the 2001 energy

crisis are to be fully counted for resource adequacy purposes, and that deliverability standards developed during subsequent phases will be applied to such contracts. These deliverability standards, as well as a wide range of other issues, including scheduling and load forecasting, will be addressed in a separate phase of the proceeding which is expected to be completed by mid-2005. SCE expects to meet its resource adequacy requirements by the deadlines set forth in the decision.

Avoided Cost Proceeding

SCE purchases electric energy and capacity from various QFs pursuant to contracts that provide for payment at avoided cost, as determined by the CPUC. On April 22, 2004, the CPUC opened a rulemaking to develop, review and update methodologies for determining avoided costs, including the methodologies SCE uses to pay its QFs. Among other things, the rulemaking is to consider modifications to the current methodology for short-run avoided cost energy pricing and the current as-available capacity pricing. The rulemaking also proposes to develop a long-run avoided cost pricing methodology for QFs. Hearings are scheduled for May 2005. Although the rulemaking may affect the amounts paid to QFs and customer rates, changes to pricing methodology should not affect SCE's earnings as such costs are recovered from ratepayers, subject to reasonableness review.

Extension of QF Contracts and New QF Contracts

SCE has 270 power-purchase contracts with QFs, a number of which will expire in the next five years. On September 30, 2004, the CPUC issued a ruling requesting proposals and comments on the development of a long-term policy for expiring QF contracts and new QFs. SCE filed its response to the ruling on November 10, 2004, in which it proposed to purchase electricity from QFs by (1) allowing QFs to compete in SCE's competitive solicitations; (2) conducting bilateral negotiations for new contracts or contract extensions with QFs; or (3) offering an energy-only contract at market-based avoided cost prices. Hearings are scheduled for May 2005.

Procurement of Renewable Resources

As part of SCE's resumption of power procurement, and in accordance with a California statute passed in 2002, SCE is required to increase its procurement of renewable resources by at least 1% of its annual electricity sales per year so that 20% of its annual electricity sales are procured from renewable resources by no later than December 31, 2017. At year-end 2004, SCE obtained approximately 18% of its power supplies from renewable resources. In June 2003, the CPUC issued a decision adopting preliminary rules and guidance on renewable procurement-related issues, including penalties for noncompliance with renewable procurement targets. In June 2004, the CPUC issued two decisions adopting additional rules on renewable procurement: a decision adopting standard contract terms and conditions and a decision adopting a market-price methodology. In July 2004, the CPUC issued a decision adopting criteria for the selection of least-cost and best-fit renewable resources. In December 2004, an assigned commissioner's ruling and scoping memo was issued establishing a schedule for addressing various renewable procurement-related issues that were not resolved by prior rulings and decision and directing the utilities to file renewable procurement plans addressing their 2005 renewable procurement goals and a plan for renewable procurement over the period 2005-2014. SCE's 2005 renewable procurement plan was filed on March 7, 2005.

SCE received bids for renewable resource contracts in response to a solicitation it made in August 2003 and conducted negotiations with bidders regarding potential procurement contracts. On March 8, 2005, SCE filed an advice letter with the CPUC requesting approval of 6 renewable contracts. SCE expects a CPUC decision on its advice letter by the second quarter of 2005. The procedures for measuring renewable procurement are still being developed by the CPUC. Based upon the current regulatory framework, SCE anticipates that it will comply, even without new renewable procurement contracts, with

renewable procurement mandates through at least 2005. Beyond 2005, SCE will either need to sign new contracts and/or extend existing renewable QF contracts.

CDWR Contract Allocation and Operating Order

The CDWR power-purchase contracts entered into as a result of the California energy crisis have been allocated on a contract-by-contract basis among SCE, PG&E and SDG&E, in accordance with a 2002 CPUC decision. SCE only assumes scheduling and dispatch responsibilities and acts only as a limited agent for the CDWR for contract implementation. Legal title, financial reporting and responsibility for the payment of contract-related bills remain with the CDWR. The allocation of CDWR contracts to SCE significantly reduces SCE's residual-net short and also increases the likelihood that SCE will have excess power during certain periods. SCE has incorporated CDWR contracts allocated to it in its procurement plans. Wholesale revenue from the sale of excess power, if any, is prorated between the CDWR and SCE.

SCE's maximum annual disallowance risk exposure for contract administration, including administration of allocated CDWR contracts and least cost dispatch of CDWR contract resources, is $37 million. In addition, gas procurement, including hedging transactions, associated with CDWR contracts is included within the cap.

On January 28, 2005, the CPUC opened a new phase of its procurement proceeding to consider the reallocation of certain CDWR contracts. Evidentiary hearings may be held later this year.

Holding Company Proceeding

In April 2001, the CPUC issued an order instituting investigation that reopened the past CPUC decisions authorizing utilities to form holding companies and initiated an investigation into, among other things: (1) whether the holding companies violated CPUC requirements to give first priority to the capital needs of their respective utility subsidiaries; (2) any additional suspected violations of laws or CPUC rules and decisions; and (3) whether additional rules, conditions, or other changes to the holding company decisions are necessary.

On January 9, 2002, the CPUC issued an interim decision interpreting the CPUC requirement that the holding companies give first priority to the capital needs of their respective utility subsidiaries. The decision stated that, at least under certain circumstances, holding companies are required to infuse all types of capital into their respective utility subsidiaries when necessary to fulfill the utility's obligation to serve its customers. The decision did not determine whether any of the utility holding companies had violated this requirement, reserving such a determination for a later phase of the proceedings. On February 11, 2002, SCE and Edison International filed an application before the CPUC for rehearing of the decision. On July 17, 2002, the CPUC affirmed its earlier decision on the first priority requirement and also denied Edison International's request for a rehearing of the CPUC's determination that it had jurisdiction over Edison International in this proceeding. On August 21, 2002, Edison International and SCE jointly filed a petition in California state court requesting a review of the CPUC's decisions with regard to first priority requirements, and Edison International filed a petition for a review of the CPUC decision asserting jurisdiction over holding companies. PG&E and SDG&E and their respective holding companies filed similar challenges, and all cases have been transferred to the First District Court of Appeals in San Francisco.

On May 21, 2004, the Court of Appeal issued its decision in the two consolidated cases, and denied the utilities' and their holding companies' challenges to both CPUC decisions. The Court of Appeal held that the CPUC has limited jurisdiction to enforce in a CPUC proceeding the conditions agreed to by holding companies incident to their being granted authority to assume ownership of a CPUC-regulated utility. The Court of Appeal held that the CPUC's decision interpreting the first priority requirement was not reviewable because the CPUC had not made any ruling that any holding company had violated the first

priority requirement. However, the Court of Appeal suggested that if the CPUC or any other authority were to rule that a utility or holding company violated the first priority requirement, the utility or holding company would be permitted to challenge both the finding of violation and the underlying interpretation of the first priority requirement itself. On June 30, 2004, Edison International and the other utility holding companies filed with the California Supreme Court a petition for review of the Court of Appeal decision as to jurisdiction over holding companies, but they and the utilities did not file a challenge to the decision as to the first priority issue. On September 1, 2004, the California Supreme Court denied the petition for review. The Court of Appeal's decision, as to jurisdiction, is now final.

The original order instituting the investigation into whether the utilities and their holding companies have complied with CPUC decisions and applicable statutes remains in effect. However, on February 11, 2005, an administrative law judge ruling was issued which provides that any party to the proceedings that believes the proceedings should remain open has 30 days to file comments listing matters that remain to be decided and explaining why they must be resolved at the CPUC rather than in another forum. The CPUC indicated that if comments are not received in the 30 day time period, a decision closing the proceeding will be prepared for CPUC consideration and no further comment will be allowed. At this time, SCE is not aware whether or not comments have been received or whether the CPUC has taken further action.

Mohave Generating Station and Related Proceedings

On May 17, 2002, SCE filed an application with the CPUC to address certain issues (mainly coal and slurry-water supply issues) facing any future extended operation of Mohave, which is partly owned by SCE. Mohave obtains all of its coal supply from the Black Mesa Mine in northeast Arizona, located on lands of the Navajo Nation and Hopi Tribe (the Tribes). This coal is delivered from the mine to Mohave by means of a coal slurry pipeline, which requires water from wells located on lands belonging to the Tribes in the mine vicinity.

Due to the lack of progress in negotiations with the Tribes and other parties to resolve several coal and water supply issues, SCE's application stated that SCE would probably be unable to extend Mohave's operation beyond 2005. The uncertainty over a post-2005 coal and water supply has prevented SCE and other Mohave co-owners from making approximately $1.1 billion in Mohave-related investments (SCE's share is $605 million), including the installation of enhanced pollution-control equipment that must be put in place in order for Mohave to continue to operate beyond 2005, pursuant to a 1999 consent decree concerning air quality.

On December 2, 2004 the CPUC issued a final decision on the application. Principally, the decision: (1) directs SCE to continue the ongoing negotiations and other efforts toward resolving the post-2005 coal and water supply issues; (2) directs SCE to conduct a study of potential generation resources that might serve as alternatives or complements to Mohave including solar generation and coal gasification; (3) provides an opportunity for SCE to recover in future rates certain Mohave-related costs that SCE has already incurred or is expected to incur by 2006, including certain preliminary engineering costs, water study costs and the costs of the study of potential Mohave alternatives; and (4) authorizes SCE to establish a rate-making account to track certain worker protection-related costs that might be incurred in 2005 in preparation for a temporary or permanent Mohave shutdown after 2005.

In parallel with the CPUC proceeding, negotiations have continued among the relevant parties in an effort to resolve the coal and water supply issues. Since November 2004, the parties have engaged in negotiations facilitated by a professional mediator, but no final resolution has been reached. In addition, agencies of the federal government are now conducting both a hydro-geological study and an environmental review regarding a possible alternative groundwater source for the slurry water; these studies, projected to cost approximately $6 million, are being funded by SCE and the other Mohave

co-owners subject to the terms and conditions of a 2004 memorandum of understanding among the Mohave co-owners, the Tribes and the federal government.

The outcome of the coal and water negotiations and SCE's application are not expected to impact Mohave's operation through 2005, but the presence or absence of Mohave as an available resource beyond 2005 will impact SCE's long-term resource plan. The outcome of this matter is not expected to have a material impact on earnings.

For additional matters related to Mohave, see "Navajo Nation Litigation" in Note 10.

In light of the issues discussed above, in 2002 SCE concluded that it was probable Mohave would be shut down at the end of 2005. Because the expected undiscounted cash flows from the plant during the years 2003–2005 were less than the $88 million carrying value of the plant as of December 31, 2002, SCE incurred an impairment charge of $61 million in 2002. However, in accordance with accounting standards for rate-regulated enterprises, this incurred cost was deferred and recorded in regulatory assets as a long-term receivable to be collected from customer revenue. This treatment was based on SCE's expectation that any unrecovered book value at the end of 2005 would be recovered in future rates (together with a reasonable return) through a balancing account mechanism, as presented in its May 17, 2002 application and discussed in its supplemental testimony filed in January 2003.

Wholesale Electricity and Natural Gas Markets

In 2000, the FERC initiated an investigation into the justness and reasonableness of rates charged by sellers of electricity in the California Power Exchange (PX) and ISO markets. On March 26, 2003, the FERC staff issued a report concluding that there had been pervasive gaming and market manipulation of both the electric and natural gas markets in California and on the West Coast during 2000–2001 and describing many of the techniques and effects of that market manipulation. SCE is participating in several related proceedings seeking recovery of refunds from sellers of electricity and natural gas who manipulated the electric and natural gas markets. Under the 2001 CPUC settlement agreement, mentioned in "CPUC Litigation Settlement Agreement," 90% of any refunds actually realized by SCE net of costs will be refunded to customers, except for the El Paso Natural Gas Company settlement agreement discussed below.

El Paso Natural Gas Company (El Paso) entered into a settlement agreement with a number of parties (including SCE, PG&E, the State of California and various consumer class action representatives) settling various claims stated in proceedings at the FERC and in San Diego County Superior Court that El Paso had manipulated interstate capacity and engaged in other anticompetitive behavior in the natural gas markets in order to unlawfully raise gas prices at the California border in 2000–2001. The United States District Court has issued an order approving the stipulated judgment and the settlement agreement has become effective. Pursuant to a CPUC decision, SCE will refund to customers amounts received under the terms of the El Paso settlement (net of legal and consulting costs) through its ERRA mechanism. In June 2004, SCE received its first settlement payment of $76 million. Approximately $66 million of this amount was credited to purchased-power expense, and will be refunded to SCE's ratepayers through the ERRA over the next 12 months, and the remaining $10 million was used to offset SCE's incurred legal costs. Additional settlement payments totaling approximately $127 million are due from El Paso over a 20-year period. As a result, SCE recorded a receivable and corresponding regulatory liability of $65 million in 2004 for the discounted present value of the future payments (discounted at an annual rate of 7.86%). Amounts El Paso refunds to the CDWR will result in reductions in the CDWR's revenue requirement allocated to SCE in proportion to SCE's share of the CDWR's power charge revenue requirement.

On July 2, 2004, the FERC approved a settlement agreement between SCE, SDG&E and PG&E and The Williams Cos. and Williams Power Company, providing for approximately $140 million in refunds

and other payments to the settling purchasers and others against some of Williams' power charges in 2000–2001. In August 2004, SCE received its $37 million share of the refunds and other payments under the Williams settlement.

On April 26, 2004, SCE, PG&E, SDG&E and several California state governmental entities agreed to settlement terms with West Coast Power, LLC and its owners, Dynegy Inc. and NRG Energy, Inc. (collectively, Dynegy). The settlement terms provide for refunds and other payments totaling $285 million, with a proposed allocation to SCE of approximately $42 million. The Dynegy settlement terms were approved by the FERC on October 25, 2004 and SCE received its $42 million share of the settlement proceeds in November 2004.

On July 12, 2004, SCE, PG&E, SDG&E and several governmental entities agreed to settlement terms with Duke Energy Corporation and a number of its affiliates (collectively Duke). The settlement terms agreed to with the Duke parties provide for refunds and other payments totaling in excess of $200 million, with a proposed allocation to SCE of approximately $45 million. The Duke settlement was approved by the FERC on December 7, 2004 and SCE received its $45 million share of the settlement proceeds in January 2005.

On January 14, 2005, SCE, PG&E, SDG&E and several governmental entities agreed to settlement terms with Mirant Corporation and a number of its affiliates (collectively Mirant), all of whom are debtors in a Chapter 11 bankruptcy proceeding pending in Texas. Among other things, the settlement terms provide for expected cash and equivalent refunds totaling $320 million, of which SCE's allocated share is approximately $68 million. The settlement also provides for an allowed, unsecured claim totaling $175 million in the bankruptcy of one of the Mirant parties, with SCE being allocated approximately $33 million of the unsecured claim. The actual value of the unsecured claim will be determined as part of the resolution of the Mirant parties' bankruptcies. The Mirant settlement was submitted to the FERC for its approval on January 31, 2005 and was submitted to the Mirant bankruptcy court for its approval on February 23, 2005.

On November 19, 2004, the CPUC issued a resolution authorizing SCE to establish an Energy Settlement Memorandum Account (ESMA) for the purpose of recording the foregoing settlement proceeds from energy providers and allocating them in accordance with the terms of the CPUC litigation settlement agreement. The resolution accordingly provides a mechanism whereby portions of the settlement proceeds recorded in the ESMA will be allocated to recovery of SCE's litigation costs and expenses in the FERC refund proceedings described above and as a shareholder incentive pursuant to the CPUC litigation settlement agreement. Remaining amounts for each settlement are to be refunded to ratepayers through the ERRA mechanism. In 2004, SCE recorded in the caption "Other nonoperating income" on the income statement a total of $12 million as shareholder incentives related to refunds received in 2004.

Note 3. Derivative Instruments and Hedging Activities

Edison International's risk management policy allows the use of derivative financial instruments to manage financial exposure on its investments and fluctuations in interest rates, foreign currency exchange rates, emission and transmission rights, and commodity prices but prohibits the use of these instruments for speculative purposes, except at EME's trading operations unit. Edison International manages these risks in part by entering into interest rate swap, cap and lock agreements, and forward commodity transactions, including options, swaps and futures.

Edison International is exposed to credit loss in the event of nonperformance by counterparties. Counterparties are required to post collateral for certain transactions depending on the creditworthiness of each counterparty and the risk associated with the transaction. Edison International does not expect the counterparties to fail to meet their obligations.

Edison International records its derivative instruments on its balance sheet at fair value unless they meet the definition of a normal purchase or sale. The normal purchases and sales exception requires, among other things, physical delivery in quantities expected to be used or sold over a reasonable period in the normal course of business. Gains or losses from changes in the fair value of a recognized asset or liability or a firm commitment are reflected in earnings for the ineffective portion of a designated hedge. For a designated hedge of the cash flows of a forecasted transaction or a foreign currency exposure, the effective portion of the gain or loss is initially recorded as a separate component of shareholders' equity under the caption "accumulated other comprehensive income," and subsequently reclassified into earnings when the forecasted transaction affects earnings. The ineffective portion of the hedge is reflected in earnings immediately. Hedge accounting requires Edison International to formally document, designate, and assess the effectiveness of hedge transactions.

On April 1, 2002, EME implemented a revised interpretation (issued in December 2001) that resulted in EME's forward electricity contracts no longer qualifying for the normal purchases and sales exception since EME has net settlement agreements with its counterparties. Under this exception, EME records revenue on an accrual basis. Subsequent to implementation of this interpretation, EME accounted for these contracts as cash flow hedges. Under a cash flow hedge, EME records the fair value of the forward sales agreements on its balance sheet and records the effective portion of the cash flow hedge as part of other comprehensive income. The ineffective portion of EME's cash flow hedges is recorded directly in its income statement. Upon implementation, EME recorded assets at fair value of $12 million, deferred taxes of $6 million and a $6 million increase to other comprehensive income as the cumulative effect of adoption of this interpretation.

EME recorded net gains (losses) of approximately $(13) million, $11 million and $(2) million in 2004, 2003 and 2002, respectively, representing the amount of cash flow hedges' ineffectiveness for continuing operations; these amounts are reflected in nonutility power generation revenue in the consolidated income statement. Fair value changes for EME's trading operations are reflected in earnings. SCE's transactions are pre-approved by the CPUC or executed in compliance with CPUC-approved procurement plans. Hedge accounting is not used for these transactions. Any fair value changes for these QF contracts are offset through a regulatory mechanism; therefore, fair value changes do not affect earnings.

Included in Edison International's other financial instruments are certain QF contracts from which SCE purchases power under contract pricing that is based on a natural gas index, but the power is not generated with natural gas. The portion of these contracts that is not eligible for the normal purchases and sales exception under accounting rules is recorded on the balance sheet at fair value.

EME's risk management and trading operations are conducted by a subsidiary. As a result of a number of industry and credit-related factors, the subsidiary has minimized its price risk management and trading activities not related to EME's power plants or investments in energy projects. To the extent it engages in trading activities, EME's trading subsidiary seeks to manage price risk and to create stability of future income by selling electricity in the forward markets and, to a lesser degree, to generate profit from price volatility of electricity and fuels by buying and selling these commodities in wholesale markets. EME generally balances forward sales and purchase contracts and manages its exposure through a value at risk analysis. Assets from price risk management and energy trading activities include the fair value of open financial positions related to trading activities and the present value of net amounts receivable from structures transactions. Liabilities from price risk management and energy trading activities include the fair value of open financial positions related to trading activities and the present value of net amounts payable from structured transactions.

The carrying amounts and fair values of financial instruments are:

	December 31,			
	2004		2003	
In millions	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Derivatives:				
Interest rate hedges	$ 3	$ 3	$ (6)	$ (6)
Commodity price assets	24	24	3	3
Commodity price liabilities	(12)	(12)	(7)	(7)
Other:				
Decommissioning trusts	2,757	2,757	2,530	2,530
DOE decommissioning and decontamination fees	(13)	(13)	(19)	(18)
QF power contracts	(12)	(12)	(32)	(32)
Long-term debt	(9,678)	(10,718)	(9,220)	(9,520)
Long-term debt due within one year	(809)	(815)	(1,932)	(1,958)
Preferred stock to be redeemed within one year	(9)	(9)	(9)	(9)
Preferred stock subject to mandatory redemption	(139)	(140)	(141)	(139)
Trading Activities:				
Assets	125	125	104	104
Liabilities	(36)	(36)	(12)	(12)

Fair values are based on: brokers' quotes for interest rate hedges, long-term debt and preferred stock; financial models for commodity price derivatives and QF power contracts; quoted market prices for decommissioning trusts; and discounted future cash flows for United States Department of Energy (DOE) decommissioning and decontamination fees.

Quoted market prices are used to determine the fair value of the financial instruments related to energy trading activities, except for the power sales agreement with an unaffiliated electric utility that EME's subsidiary purchased and restructured and a long-term power supply agreement with another unaffiliated party. EME's subsidiary recorded these agreements at fair value based upon a discounting of future electricity prices derived from a proprietary model using a discount rate equal to the cost of borrowing the non-recourse debt incurred to finance the purchase of the power supply agreement.

Due to their short maturities, amounts reported for cash equivalents approximate fair value.

Note 4. Liabilities and Lines of Credit

Long-Term Debt

In fourth quarter 2003, Edison International adopted a new accounting interpretation regarding VIEs which required Edison International to deconsolidate three special purpose entities, EIX Trusts I and II, and Mission Capital, L.P. As a result of these deconsolidations, the bonds and securities associated with these financing entities were included in long-term debt on Edison International's consolidated balance sheet. Under prior accounting treatment, these bonds and securities would have been eliminated in consolidation and the bonds and securities held by the special purpose entities would have been included in company-obligated mandatorily redeemable securities of subsidiary on the consolidated balance sheet. In late 2004 and early 2005, the bonds and securities associated with these financing entities were paid off.

Almost all SCE properties are subject to a trust indenture lien. SCE has pledged first and refunding mortgage bonds as security for borrowed funds obtained from pollution-control bonds issued by government agencies. SCE used these proceeds to finance construction of pollution-control facilities. SCE had debt covenants that require certain interest coverage, interest and preferred dividend coverage,

and debt to total capitalization ratios to be met. At December 31, 2004, SCE was in compliance with these covenants.

MEHC used the common stock of EME as security for MEHC's corporate debt obligations. MEHC's senior secured notes and the term loan are nonrecourse to Edison International and EME, and accordingly, Edison International and EME have no obligations under these instruments. MEHC's senior secured notes and the term loan contain restrictions on MEHC paying dividends unless it has an interest coverage ratio of at least 2.0 to 1.0 as defined in the respective agreements. At December 31, 2004 MEHC's interest coverage ratio was 1.18 to 1.0.

Debt premium, discount and issuance expenses are deferred and amortized through interest expense over the life of each issue. Under CPUC rate-making procedures, debt reacquisition expenses are amortized over the remaining life of the reacquired debt or, if refinanced, the life of the new debt. California law prohibits SCE from incurring or guaranteeing debt for its nonutility affiliates.

In December 1997, $2.5 billion of rate reduction notes were issued on behalf of SCE by SCE Funding LLC, a special purpose entity. These notes were issued to finance the 10% rate reduction mandated by state law. The proceeds of the rate reduction notes were used by SCE Funding LLC to purchase from SCE an enforceable right known as transition property. Transition property is a current property right created by the restructuring legislation and a financing order of the CPUC and consists generally of the right to be paid a specified amount from nonbypassable rates charged to residential and small commercial customers. The rate reduction notes are being repaid over 10 years through these nonbypassable residential and small commercial customer rates, which constitute the transition property purchased by SCE Funding LLC. The notes are collateralized by the transition property and are not collateralized by, or payable from, assets of SCE or Edison International. SCE used the proceeds from the sale of the transition property to retire debt and equity securities. Although, as required by accounting principles generally accepted in the United States, SCE Funding LLC is consolidated with SCE and the rate reduction notes are shown as long-term debt in the consolidated financial statements, SCE Funding LLC is legally separate from SCE. The assets of SCE Funding LLC are not available to creditors of SCE or Edison International and the transition property is legally not an asset of SCE or Edison International.

Long-term debt is:

In millions December 31,	2004	2003
First and refunding mortgage bonds:		
2007 – 2035 (4.65% to 8.00% and variable)	**$ 2,741**	$ 1,816
Rate reduction notes:		
2005 – 2007 (6.38% to 6.42%)	**739**	985
Pollution-control bonds:		
2006 – 2031 (2% to 7.2%)	**1,196**	1,216
Bonds repurchased	**—**	(354)
Debentures and notes:		
2005 – 2053 (non-interest bearing to 13.5% and variable)	**5,690**	7,289
Subordinated debentures:		
2024 – 2025 (8.5% to 9.875%)	**154**	254
Long-term debt due within one year	**(809)**	(1,932)
Unamortized debt discount – net	**(33)**	(54)
Total	**$ 9,678**	$ 9,220

Note: Rates and terms as of December 31, 2004.

Long-term debt maturities and sinking-fund requirements for the next five years are: 2005 – $809 million; 2006 – $1.1 billion; 2007 – $1.5 billion; 2008 – $1.2 billion; and 2009 – $832 million.

Long-term debt due within one year includes $25 million and $15 million of debt related to Edison Capital's Storm Lake project that is not due until 2011 and 2017, respectively. This debt has been classified as long-term debt due within one year as a result of an agreement with the lenders to reduce the project loan balances subject to recovering damages in Enron's bankruptcy.

On January 3, 2005, MEHC repaid the remaining $285 million of its term loan.

In January 2005, SCE issued $650 million of first and refunding mortgage bonds. The issuance included $400 million of 5% bonds due in 2016 and $250 million of 5.55% bonds due in 2036. The proceeds were used to redeem $650 million of 8% first and refunding mortgage bonds due February 2007.

Short-Term Debt

Short-term debt is used to finance fuel inventories, balancing account undercollections and general cash requirements, including power purchase payments. Edison International's outstanding amount and weighted-average interest rate, respectively, for short-term debt was $88 million at 2.48% for December 31, 2004 and $200 million at 2.83% for December 31, 2003.

Lines of Credit

At December 31, 2004, Edison International's subsidiaries had lines of credit totaling $1.1 billion, with various expiration dates, and when available, can be drawn down at negotiated or bank index rates. EME had total lines of credit of $398 million, with $382 available to finance general cash requirements. SCE had drawn $98 million on a $700 million line of credit.

At December 31, 2003, Edison International's subsidiaries had lines of credit totaling $845 million, with various expiration dates, and when available, can be drawn down at negotiated or bank index rates. EME had total lines of credit of $145 million, with all of it available to finance general cash requirements. SCE had drawn $200 million on a $700 million line of credit.

Preferred Securities Subject to Mandatory Redemption

In compliance with a new accounting standard, effective July 1, 2003, Edison International reclassified its company-obligated mandatorily redeemable securities, its other mandatorily redeemable preferred securities and SCE's preferred stock subject to mandatory redemption to the liabilities section of its consolidated balance sheet. These items were previously classified between liabilities and equity. In addition, dividend payments on these preferred securities subject to mandatory redemption are included as interest expense effective July 1, 2003.

Company-Obligated Mandatorily Redeemable Securities of Subsidiary

In 1999, Edison International (the parent company) issued, through affiliates (EIX Trusts I and II), $500 million of 7.875% cumulative quarterly income preferred securities and $325 million of 8.6% cumulative quarterly income preferred securities, at a price of $25 per security. The 7.875% securities had a stated maturity of July 2029, but were redeemable at the option of Edison International, in whole or in part, beginning July 2004. The 8.6% securities had a stated maturity of October 2029, but were redeemable at the option of Edison International, in whole or in part, beginning October 2004. Both of these securities were guaranteed by Edison International. In late 2004, Edison International redeemed all of the securities issued by EIX Trusts I and II.

In November 1994, EME issued, through a limited partnership (Mission Capital, L.P.), 3.5 million shares of 9.875% cumulative monthly income preferred securities, at a price of $25 per security and invested the proceeds in 9.875% junior subordinated deferrable interest debentures due 2024. These securities are

redeemable at the option of the partnership (EME is the sole general partner), in whole or in part, with mandatory redemption in 2024 at a redemption price of $25 per security plus accrued and unpaid distributions. In August 1995, EME also issued, through a limited partnership, 2.5 million shares of 8.5% cumulative monthly income preferred securities, at a price of $25 per security and invested the proceeds in 8.5% junior subordinated deferrable interest debentures due 2025. These securities are redeemable at the option of the partnership, in whole or in part, with mandatory redemption in 2025 at a redemption price of $25 per security plus accrued and unpaid distributions. EME issued a guarantee in favor of its preferred securities holders, which ensures the payments of distributions declared on the preferred securities, payments upon liquidation of the limited partnership and payments on redemption for securities called for redemption by the limited partnership. On January 25, 2005, all 6 million shares of these securities were redeemed for a purchase price of 100% of the principal amount, plus accrued interest through January 25, 2005, for a total of $150 million. These junior subordinated debentures are included in long-term debt on Edison International's consolidated balance sheet at both December 31, 2004 and 2003 due to deconsolidation of Mission Capital L.P. in compliance with an accounting interpretation regarding VIEs. In January 2005, EME repaid $154 million of these junior subordinated debentures.

Preferred Stock Subject to Mandatory Redemption

SCE has 12 million authorized shares of preferred stock subject to mandatory redemption. Shares of SCE's preferred stock have liquidation and dividend preferences over shares of SCE's common stock. Mandatorily redeemable preferred stock is subject to sinking-fund provisions. When preferred shares are redeemed, the premiums paid, if any, are charged to expense.

SCE's preferred stock redemption requirements for the next five years are: 2005 – $9 million; 2006 – $9 million; 2007 – $74 million; 2008 – $56 million; and 2009 – none.

SCE's cumulative preferred stock subject to mandatory redemption is:

Dollars in millions, except per-share amounts	December 31,		**2004**	2003
	December 31, 2004			
	Shares Outstanding	Redemption Price		
$100 par value:				
6.05% Series	673,800	$ 100.00	**$ 67**	$ 69
7.23	807,000	100.00	**81**	81
Preferred stock to be redeemed within one year			**(9)**	(9)
Total			**$ 139**	$ 141

The 6.05% Series preferred stock has mandatory sinking funds, requiring SCE to redeem at least 37,500 shares per year from 2003 through 2007, and 562,500 shares in 2008. SCE is allowed to credit previously repurchased shares against the mandatory sinking fund provisions. In 2004, SCE redeemed 20,000 shares of 6.05% Series preferred stock. In 2003, SCE redeemed 56,200 shares of 6.05% Series preferred stock. At December 31, 2004, SCE had 1,200 of previously repurchased, but not retired, shares available to credit against the mandatory sinking fund provisions.

The 7.23% Series preferred stock also has mandatory sinking funds, requiring SCE to redeem at least 50,000 shares per year from 2002 through 2006, and 750,000 shares in 2007. However, SCE is allowed to credit previously repurchased shares against the mandatory sinking fund provisions. Since SCE had previously repurchased 193,000 shares of this series, no shares were redeemed in the last three years. At

December 31, 2004, SCE had 43,000 of previously repurchased, but not retired, shares available to credit against the mandatory sinking fund provisions.

In 2002, SCE redeemed 1,000,000 shares of 6.45% Series preferred stock. SCE did not issue any preferred stock in the last three years.

Note 5. Preferred Stock of Utility Not Subject to Mandatory Redemption

SCE's authorized shares are: $25 cumulative preferred – 24 million and preference – 50 million. Shares of SCE's preferred stock have liquidation and dividend preferences over shares of SCE's common stock. All cumulative preferred stock is redeemable. When preferred shares are redeemed, the premiums paid, if any, are charged to common equity. No preferred stock not subject to mandatory redemption was issued or redeemed in the last three years.

SCE's cumulative preferred stock not subject to mandatory redemption is:

Dollars in millions, except per-share amounts	December 31,		**2004**	2003
	December 31, 2004			
	Shares Outstanding	Redemption Price		
$25 par value:				
4.08% Series	1,000,000	$25.50	**$ 25**	$ 25
4.24	1,200,000	25.80	**30**	30
4.32	1,653,429	28.75	**41**	41
4.78	1,296,769	25.80	**33**	33
Total			**$129**	$129

Note 6. Income Taxes

Edison International's eligible subsidiaries are included in Edison International's consolidated federal income tax and combined state franchise tax returns. Edison International has tax-allocation and payment agreements with certain of its subsidiaries. For subsidiaries other than SCE, the right of a participating subsidiary to receive or make a payment and the amount and timing of tax-allocation payments are dependent on the inclusion of the subsidiary in the consolidated income tax returns of Edison International and other factors including the consolidated taxable income of Edison International and its includible subsidiaries, the amount of taxable income or net operating losses and other tax items of the participating subsidiary, as well as the other subsidiaries of Edison International. There are specific procedures regarding allocations of state taxes. Each subsidiary is eligible to receive tax-allocation payments for its tax losses or credits only at such time as Edison International and its subsidiaries generate sufficient taxable income to be able to utilize the participating subsidiary's losses in the consolidated tax return of Edison International. Under an income tax-allocation agreement approved by the CPUC, SCE's tax liability is computed as if it filed a separate return.

As part of the process of preparing its consolidated financial statements, Edison International is required to estimate its income taxes in each of the jurisdictions in which it operates. This process involves estimating actual current tax exposure together with assessing temporary differences resulting from differing treatment of items, such as depreciation, for tax and accounting purposes. These differences result in deferred tax assets and liabilities, which are included within Edison International's consolidated balance sheet.

Income tax expense includes the current tax liability from operations and the change in deferred income taxes during the year. Investment tax credits are deferred and amortized over the lives of the related properties.

The sources of income (loss) before income taxes are:

In millions Year ended December 31,	2004	2003	2002
Domestic	$ 128	$ 767	$ 1,368
Foreign	6	12	17
Total continuing operations	134	779	1,385
Discontinued operations	737	298	66
Accounting change	—	(13)	—
Total	$ 871	$ 1,064	$ 1,451

The components of income tax expense (benefit) by location of taxing jurisdiction are:

In millions Year ended December 31,	2004	2003	2002
Current:			
Federal	$ (560)	$ 186	$ 578
State	(36)	100	109
Foreign	—	6	10
	(596)	292	697
Deferred:			
Federal	458	(103)	(322)
State	46	(67)	(43)
Foreign	—	2	(2)
	504	(168)	(367)
Total continuing operations	(92)	124	330
Discontinued operations	47	123	44
Accounting change	—	(4)	—
Total	$ (45)	$ 243	$ 374

The components of the net accumulated deferred income tax liability are:

In millions December 31,	2004	2003
Deferred tax assets:		
Property-related	$ 196	$ 243
Unrealized gains or losses	392	365
Investment tax credits	64	69
Regulatory balancing accounts	321	204
Deferred income	3	40
Decommissioning	84	105
Accrued charges	278	344
Loss and credit carryforwards	217	223
Other	270	217
Subtotal	1,825	1,810
Valuation allowance	3	11
Total	$ 1,822	$ 1,799
Deferred tax liabilities:		
Property-related	$ 3,161	$ 3,430
Leveraged leases	2,142	2,056
Capitalized software costs	164	160
Regulatory balancing accounts	710	360
Unrealized gains and losses	298	262
Other	292	302
Total	$ 6,767	$ 6,570
Accumulated deferred income taxes – net	$ 4,945	$ 4,771
Classification of accumulated deferred income taxes:		
Included in deferred credits	$ 5,233	$ 5,334
Included in current assets	$ 288	$ 563

The federal statutory income tax rate is reconciled to the effective tax rate from continuing operations as follows:

Year ended December 31,	2004	2003	2002
Federal statutory rate	35.0%	35.0%	35.0%
Tax audit adjustments	(73.9)	(4.5)	(2.6)
Resolution of FERC rate case	—	(9.6)	—
Housing and production credits	(22.9)	(4.3)	(3.2)
Property-related	10.4	1.1	(2.8)
Amortization of ITC credits	(6.7)	(1.0)	(0.4)
State tax – net of federal deduction	3.0	5.3	3.8
ESOP dividend payment	(6.2)	—	—
Transition costs	—	—	(6.2)
Other	(7.4)	(6.0)	0.1
Effective tax rate	(68.7)%	16.0%	23.7%

Edison International's composite federal and state statutory tax rate was approximately 40% for all years presented. The effective tax benefit rate of 68.7% realized in 2004 was primarily due to adjustments to tax liabilities relating to prior years at SCE and the benefits received from low income housing and production tax credits at Edison Capital, partially offset by property-related flow-through items and property-related adjustments at SCE. The lower effective tax rate of 16.0% realized in 2003 was

primarily due to the resolution of a FERC rate case at SCE, recording the benefit of favorable settlements of IRS audit issues at SCE and the benefits received from low income housing and production tax credits at Edison Capital. The lower effective tax rate of 23.7% realized in 2002 was primarily due to: reestablishing a tax related regulatory asset at SCE due to implementation of the CPUC's URG decision; a favorable adjustment to Edison Capital's cumulative deferred taxes for changes in its effective state tax rate; the benefits received from low income housing and production tax credits at Edison Capital; and recording the benefit of favorable settlements of IRS audits at SCE.

At December 31, 2004, Edison International and its subsidiaries have federal tax credits of $161 million which expire between 2020 and 2023 and California net operating loss carryforwards of $848 million which expire in 2013. In addition, EME has state loss carryforwards for various states of $45 million and $189 million at December 31, 2004 and 2003, respectively, with expiration dates beginning in 2006, and state capital loss carryforwards of $33 million at December 31, 2003.

As a matter of course, Edison International is regularly audited by federal, state and foreign taxing authorities. For further discussion of this matter, see "Federal Income Taxes" in Note 10.

Note 7. Compensation and Benefit Plans

Employee Savings Plan

Edison International has a 401(k) defined contribution savings plan designed to supplement employees' retirement income. The plan received employer contributions of $50 million in 2004, $43 million in 2003 and $42 million in 2002.

Pension Plans and Postretirement Benefits Other Than Pensions

Pension Plans

Defined benefit pension plans (some with cash balance features) cover United States employees meeting minimum service and other requirements. SCE recognizes pension expense for its nonexecutive plan as calculated by the actuarial method used for ratemaking.

At December 31, 2004 and December 31, 2003, the accumulated benefit obligations of the executive pension plans exceeded the related plan assets at the measurement dates. In accordance with accounting standards, Edison International's balance sheets include an additional minimum liability, with corresponding charges to intangible assets and shareholders' equity (through a charge to accumulated other comprehensive income). The charge to accumulated other comprehensive income would be restored through shareholders' equity in future periods to the extent the fair value of the plan assets exceed the accumulated benefit obligation.

The expected contributions (all by the employer) for United States plans are approximately $53 million for the year ended December 31, 2005. This amount is subject to change based on, among other things, the limits established for federal tax deductibility. Edison International's expenses for its foreign plans are included in discontinued operations.

Edison International uses a December 31 measurement date for all of its plans. The fair value of the plan assets is determined by market value.

Information on plan assets and benefit obligations for United States plans is shown below:

In millions Year ended December 31,	2004	2003
Change in projected benefit obligation		
Projected benefit obligation at beginning of year	$ 2,959	$ 2,694
Service cost	103	95
Interest cost	171	170
Amendments	22	—
Actuarial loss	125	139
Benefits paid	(149)	(139)
Projected benefit obligation at end of year	$ 3,231	$ 2,959
Accumulated benefit obligation at end of year	$ 2,790	$ 2,540
Change in plan assets		
Fair value of plan assets at beginning of year	$ 2,835	$ 2,322
Actual return on plan assets	323	605
Employer contributions	53	47
Benefits paid	(149)	(139)
Fair value of plan assets at end of year	$ 3,062	$ 2,835
Funded status	$ (169)	$ (124)
Unrecognized net loss	148	144
Unrecognized transition obligation	1	7
Unrecognized prior service cost	93	86
Recorded asset	$ 73	$ 113
Additional detail of amounts recognized in balance sheets:		
Intangible asset	$ 4	$ 4
Accumulated other comprehensive income	(28)	(22)
Pension plans with an accumulated benefit obligation in excess of plan assets:		
Projected benefit obligation	$ 211	$ 162
Accumulated benefit obligation	164	121
Fair value of plan assets	45	25
Weighted-average assumptions at end of year:		
Discount rate	5.5%	6.0%
Rate of compensation increase	5.0%	5.0%

Expense components for United States plans are:

In millions Year ended December 31,	2004	2003	2002
Service cost	$ 103	$ 95	$ 86
Interest cost	171	170	165
Expected return on plan assets	(206)	(191)	(228)
Special termination benefits	—	3	—
Net amortization and deferral	25	36	22
Expense under accounting standards	93	113	45
Regulatory adjustment – deferred	(26)	(44)	(18)
Total expense recognized	$ 67	$ 69	$ 27
Change in accumulated other comprehensive income	$ (6)	$ (3)	$ (19)
Weighted-average assumptions:			
Discount rate	6.0%	6.5%	7.0%
Rate of compensation increase	5.0%	5.0%	5.0%
Expected return on plan assets	7.5%	8.5%	8.5%

The following benefit payments, which reflect expected future service, are expected to be paid:

In millions Year ended December 31,	
2005	$ 213
2006	225
2007	240
2008	255
2009	267
2010–2014	1,506
Total	$ 2,706

Asset allocations for United States plans are:

	Target for 2005	December 31, 2004	December 31, 2003
United States equity	45%	47%	46%
Non-United States equity	25%	25%	26%
Private equity	4%	2%	3%
Fixed income	26%	26%	25%

Postretirement Benefits Other Than Pensions

Most United States nonunion employees retiring at or after age 55 with at least 10 years of service are eligible for postretirement health and dental care, life insurance and other benefits. Eligibility depends on a number of factors, including the employee's hire date.

The settlement of postretirement employee benefits liability, shown in the table below, relates to a retirement health care and other benefits plan for represented employees at the Midwest Generation unit (EME's subsidiary that is operating the Illinois plants) that expired on June 15, 2002. In October 2002, Midwest Generation reached an agreement with its union-represented employees on new benefits plans, for the period of January 1, 2003 through June 15, 2006. Midwest Generation continued to provide

benefits at the same level as those in the expired agreement until December 31, 2002. The accounting for postretirement benefits liabilities has been determined on the basis of a substantive plan under applicable accounting rules. A substantive plan means that Midwest Generation assumed, for accounting purposes, that it would provide postretirement health care benefits to union-represented employees following conclusion of negotiations to replace the current benefits agreement, even though Midwest Generation had no legal obligation to do so. Under the new agreement, postretirement health care benefits will not be provided. Accordingly, Midwest Generation treated this as a plan termination and recorded a pre-tax gain of $71 million during fourth quarter 2002.

On December 8, 2003, President Bush signed the Medicare Prescription Drug, Improvement and Modernization Act of 2003. The Act authorized a federal subsidy to be provided to plan sponsors for certain prescription drug benefits under Medicare. Edison International adopted a new accounting pronouncement for the effects of the Act, effective July 1, 2004, which reduced Edison International's accumulated benefits obligation by $120 million upon adoption. Edison International's 2004 expense decreased by approximately $9 million as a result of the subsidy.

The expected contributions (all by the employer) to the postretirement benefits other than pensions trust are $77 million for the year ended December 31, 2005. This amount is subject to change based on, among other things, the limits established for federal tax deductibility.

Edison International uses a December 31 measurement date. The fair value of plan assets is determined by market value.

Information on plan assets and benefit obligations is shown below:

In millions Year ended December 31,	2004	2003
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 2,199**	$ 2,171
Service cost	**42**	44
Interest cost	**126**	126
Amendments	**30**	(640)
Actuarial loss (gain)	**(90)**	588
Benefits paid	**(95)**	(90)
Benefit obligation at end of year	**$ 2,212**	$ 2,199
Change in plan assets		
Fair value of plan assets at beginning of year	**$ 1,390**	$ 1,072
Actual return on assets	**144**	292
Employer contributions	**26**	116
Benefits paid	**(95)**	(90)
Fair value of plan assets at end of year	**$ 1,465**	$ 1,390
Funded status	**$ (747)**	$ (809)
Unrecognized net loss	**858**	1,047
Unrecognized prior service cost	**(299)**	(361)
Recorded liability	**$ (188)**	$ (123)
Assumed health care cost trend rates:		
Rate assumed for following year	**10.0%**	12.0%
Ultimate rate	**5.0%**	5.0%
Year ultimate rate reached	**2010**	2010
Weighted-average assumptions at end of year:		
Discount rate	**5.75%**	6.25%

Expense components are:

In millions Year ended December 31,	2004	2003	2002
Service cost	$ 42	$ 44	$ 49
Interest cost	126	126	141
Expected return on plan assets	(96)	(89)	(93)
Special termination benefits	—	1	—
Settlement	—	—	(71)
Amortization of unrecognized prior service costs	(31)	(21)	—
Amortization of unrecognized loss	50	52	10
Amortization of unrecognized transition obligation	—	9	27
Total expense	$ 91	$ 122	$ 63
Assumed health care cost trend rates:			
Current year	12.0%	9.75%	10.5%
Ultimate rate	5.0%	5.0%	5.0%
Year ultimate rate reached	2010	2008	2008
Weighted-average assumptions:			
Discount rate	6.25%	6.4%	7.5%
Expected return on plan assets	7.1%	8.2%	8.2%

Increasing the health care cost trend rate by one percentage point would increase the accumulated obligation as of December 31, 2004 by $318 million and annual aggregate service and interest costs by $28 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated obligation as of December 31, 2004 by $259 million and annual aggregate service and interest costs by $22 million.

The following benefit payments are expected to be paid:

In millions Year ended December 31,	
2005	$ 107
2006	106
2007	112
2008	112
2009	119
2010–2014	682
Total	$ 1,238

Asset allocations are:

	Target for 2005	December 31, 2004	December 31, 2003
United States equity	64%	64%	64%
Non-United States equity	16%	14%	13%
Fixed income	20%	22%	23%

Description of Pension and Postretirement Benefits Other Than Pensions Investment Strategies

The investment of plan assets is overseen by a fiduciary investment committee. Plan assets are invested using a combination of asset classes, and may have active and passive investment strategies within asset classes. Edison International employs multiple investment management firms. Investment managers

within each asset class cover a range of investment styles and approaches. Risk is controlled through diversification among multiple asset classes, managers, styles and securities. Plan, asset class and individual manager performance is measured against targets. Edison International also monitors the stability of its investments managers' organizations.

Allowable investment types include:

United States Equity: Common and preferred stock of large, medium, and small companies which are predominantly United States-based.

Non-United States Equity: Equity securities issued by companies domiciled outside the United States and in depository receipts which represent ownership of securities of non-United States companies.

Private Equity: Limited partnerships that invest in nonpublicly traded entities.

Fixed Income: Fixed income securities issued or guaranteed by the United States government, non-United States governments, government agencies and instrumentalities, mortgage backed securities and corporate debt obligations. A small portion of the fixed income position may be held in debt securities that are below investment grade.

Permitted ranges around asset class portfolio weights are plus or minus 5%. Where approved by the fiduciary investment committee, futures contracts are used for portfolio rebalancing and to approach fully invested portfolio positions. Where authorized, a few of the plan's investment managers employ limited use of derivatives, including futures contracts, options, options on futures and interest rate swaps in place of direct investment in securities to gain efficient exposure to markets. Derivatives are not used to leverage the plans or any portfolios.

Determination of the Expected Long-Term Rate of Return on Assets for United States Plans

The overall expected long term rate of return on assets assumption is based on the target asset allocation for plan assets, capital markets return forecasts for asset classes employed, and active management excess return expectations. A portion of postretirement benefits other than pensions trust asset returns are subject to taxation, so the expected long-term rate of return for these assets is determined on an after-tax basis.

Capital Markets Return Forecasts

The estimated total return for fixed income is based on an equilibrium yield for intermediate United States government bonds plus a premium for exposure to nongovernment bonds in the broad fixed income market. The equilibrium yield is based on analysis of historic data and is consistent with experience over various economic environments. The premium of the broad market over United States government bonds is a historic average premium. The estimated rate of return for equity is estimated to be a 3% premium over the estimated total return of intermediate United States government bonds. This value is determined by combining estimates of real earnings growth, dividend yields and inflation, each of which was determined using historical analysis. The rate of return for private equity is estimated to be a 5% premium over public equity, reflecting a premium for higher volatility and illiquidity.

Active Management Excess Return Expectations

For asset classes that are actively managed, an excess return premium is added to the capital market return forecasts discussed above.

Stock-Based Compensation

Under various plans, Edison International may grant stock options at exercise prices equal to the market price at the grant date and other awards based on its common stock to directors and certain employees. Options generally expire 10 years after the grant date and vest over a period of up to five years, with expense accruing evenly over the vesting period. Edison International has approximately 14 million shares remaining for future issuance under equity compensation plans.

Most Edison International stock options issued prior to 2000 accrue dividend equivalents, subject to certain performance criteria. The 2003 and 2004 options accrue dividend equivalents for the first five years of the option term. Unless deferred, dividend equivalents accumulate without interest.

The fair value for each option granted, reflecting the basis for the pro forma disclosures in Note 1, was determined as of the grant date using the Black-Scholes option-pricing model. The following assumptions were used in determining fair value through the model:

December 31,	**2004**	2003	2002
Expected years until exercise	**9 to 10**	10	7 to 10
Risk-free interest rate	**4.0% to 4.3%**	3.8% to 4.5%	4.7% to 6.1%
Expected dividend yield	**2.7% to 3.7%**	1.8%	1.8%
Expected volatility	**19% to 22%**	44% to 53%	18% to 54%

A summary of the status of Edison International stock options is as follows:

		Weighted-Average	
	Share Options	Exercise Price	Fair Value at Grant
Outstanding, Dec. 31, 2001	9,294,029	$22.45	
Granted	3,450,393	$18.59	$7.88
Expired	(520,706)	$23.34	
Forfeited	(318,980)	$17.43	
Exercised	(68,444)	$12.45	
Outstanding, Dec. 31, 2002	11,836,292	$21.46	
Granted	3,819,930	$12.38	$7.31
Expired	(482,394)	$23.48	
Forfeited	(110,094)	$15.02	
Exercised	(260,481)	$17.67	
Outstanding, Dec. 31, 2003	14,803,253	$19.17	
Granted	4,550,344	$21.97	$6.60
Expired	(6,194)	$18.10	
Forfeited	(218,695)	$17.63	
Exercised	(2,766,788)	$17.25	
Outstanding, Dec. 31, 2004	16,361,920	$20.30	

A summary of stock options outstanding at December 31, 2004 is as follows:

	Outstanding			Exercisable	
Range of Exercise Prices	Number of Options	Weighted Average Remaining Years of Contractual Life	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
$ 8.90–$12.99	3,682,806	8	$12.13	912,920	$11.95
$13.00–$18.99	3,285,758	6	$18.25	1,733,865	$18.00
$19.00–$29.09	9,393,356	6	$24.21	4,933,251	$26.28
Total	16,361,920	7	$20.30	7,580,036	$22.66

The number of options exercisable and their weighted-average exercise prices at December 31, 2003 and 2002 were 7,337,939 at $23.37 and 6,475,029 at $23.61, respectively.

Performance shares were awarded to executives in January 2002, January 2003 and January 2004 and vest at the end of December 2004, 2005 and 2006, respectively. The number of common shares paid out from the performance share awards depends on the performance of Edison International common stock relative to the stock performance of a specified group of companies. Performance share values are accrued ratably over the vesting period based on the value of the underlying Edison International common stock. The number of performance shares granted and their weighted-average grant-date fair value for 2004, 2003 and 2002 were 344,244 at $21.93, 570,313 at $12.32, and 434,698 at $15.21, respectively.

In November 2001, deferred stock units were issued in exchange for stock options granted in 2000. The deferred stock units vest at a rate of 25% per year over four years.

See Note 1 for Edison International's accounting policy and expenses related to stock-based compensation.

Note 8. Jointly Owned Utility Projects

SCE owns interests in several generating stations and transmission systems for which each participant provides its own financing. SCE's share of expenses for each project is included in the consolidated statements of income.

SCE's investment in each project as of December 31, 2004 is:

In millions	Investment in Facility	Accumulated Depreciation and Amortization	Ownership Interest
Transmission systems:			
Eldorado	$ 48	$ 16	60%
Pacific Intertie	305	80	50
Generating stations:			
Four Corners Units 4 and 5 (coal)	497	395	48
Mohave (coal)	347	262	56
Palo Verde (nuclear)	1,679	1,459	16
San Onofre (nuclear)	4,420	3,943	75
Total	$7,296	$ 6,155	

A portion of Mohave, San Onofre and Palo Verde is included in regulatory assets on the balance sheet. See Notes 1 and 2.

Note 9. Commitments

Leases

Edison International has operating leases for office space, vehicles, property and other equipment (with varying terms, provisions and expiration dates). Additionally, in accordance with an accounting standard, certain power contracts in which SCE takes virtually all of the power from specific power plants are classified as operating leases.

During 2001, EME entered into a sale-leaseback of its Homer City facilities to third-party lessors for an aggregate purchase price of $1.6 billion, consisting of $782 million in cash and assumption of debt (with a fair value of $809 million).

During 2000, EME entered into a sale-leaseback transaction for power facilities, located in Illinois, with third party lessors for an aggregate purchase price of $1.4 billion.

The lease costs for the power facilities are levelized over the terms of the power facilities' respective leases. The gain on the sale of the facilities, power plant and equipment has been deferred and is being amortized over the terms of the respective leases.

Estimated remaining commitments (the majority of which are related to EME's long-term leases for the Powerton, Joliet and Homer City power plants) for noncancelable leases at December 31, 2004 are:

In millions	Year ended December 31,
2005	$ 366
2006	400
2007	362
2008	360
2009	353
Thereafter	3,309
Total	$ 5,150

Operating lease expense was $228 million in 2004, $257 million in 2003 and $251 million in 2002.

Nuclear Decommissioning

As a result of an accounting standard adopted in 2003, SCE recorded the fair value of its liability for legal asset retirement obligations (ARO), primarily related to the decommissioning of its nuclear power facilities. At that time, SCE adjusted its nuclear decommissioning obligation, capitalized the initial costs of the ARO into a nuclear-related ARO regulatory asset, and also recorded an ARO regulatory liability as a result of timing differences between the recognition of costs recorded in accordance with the standard and the recovery of the related asset retirement costs through the rate-making process. SCE has collected in rates amounts for the future costs of removal of its nuclear assets, and has placed those amounts in independent trusts. The fair value of decommissioning SCE's nuclear power facilities is $2.2 billion as of December 31, 2004, based on site-specific studies performed in 2001 for San Onofre and Palo Verde. Changes in the estimated costs, timing of decommissioning, or the assumptions underlying these estimates could cause material revisions to the estimated total cost to decommission in the near term. SCE estimates that it will spend approximately $11.4 billion through 2049 to decommission its nuclear facilities. This estimate is based on SCE's current-dollar decommissioning cost methodology used for

rate-making purposes, escalated at rates ranging from 1.1% to 10.0% (depending on the cost element) annually. These costs are expected to be funded from independent decommissioning trusts, which effective October 2003 receive contributions of approximately $32 million per year. SCE estimates annual after-tax earnings on the decommissioning funds of 3.7% to 6.5%. If the assumed return on trust assets is not earned, it is probable that additional funds needed for decommissioning will be recoverable through rates.

Decommissioning of San Onofre Unit 1 is underway and will be completed in three phases: (1) decontamination and dismantling of all structures and some foundations; (2) spent fuel storage monitoring; and (3) fuel storage facility dismantling, removal of remaining foundations, and site restoration. Phase one is anticipated to continue through 2008. Phase two is expected to continue until 2026. Phase three will be conducted concurrently with the San Onofre Units 2 and 3 decommissioning projects. On February 3, 2004, SCE announced that it has discontinued plans to ship the San Onofre Unit 1 reactor pressure vessel to a disposal site until such time as appropriate arrangements are made for its permanent disposal. It will continue to be stored at its current location at San Onofre Unit 1, where it poses no risk to the public or the environment. This action results in placing the disposal of the reactor pressure vessel in Phase three of the San Onofre Unit 1 decommissioning project.

All of SCE's San Onofre Unit 1 decommissioning costs will be paid from its nuclear decommissioning trust funds, subject to CPUC review. The estimated remaining cost to decommission San Onofre Unit 1 is recorded as an ARO liability ($154 million at December 31, 2004). Total expenditures for the decommissioning of San Onofre Unit 1 were $360 million through December 31, 2004.

SCE plans to decommission its nuclear generating facilities by a prompt removal method authorized by the Nuclear Regulatory Commission. Decommissioning is expected to begin after the plants' operating licenses expire. The operating licenses expire in 2022 for San Onofre Units 2 and 3, and in 2024, 2026 and 2027 for the Palo Verde units. Decommissioning costs, which are recovered through nonbypassable customer rates over the term of each nuclear facility's operating license, are recorded as a component of depreciation expense, with a corresponding credit to the ARO regulatory liability. The earnings impact of amortization of the ARO asset included within the unamortized nuclear investment and accretion of the ARO liability, both created under this new standard, are deferred as increases to the ARO regulatory liability account, with no impact on earnings.

SCE has collected in rates amounts for the future costs of removal of its nuclear assets, and has historically recorded these amounts in accumulated provision for depreciation and decommissioning. However, in accordance with recent Securities and Exchange Commission accounting guidance, the amounts accrued in accumulated provision for depreciation and decommissioning for nuclear decommissioning and costs of removal were reclassified to regulatory liabilities as of December 31, 2002. Upon implementation of the new accounting standard for AROs, SCE reversed the decommissioning amounts collected for assets legally required to be removed and recorded the fair value of this ARO (included in the deferred credits and other liabilities section of the consolidated balance sheet). The cost of removal amounts collected for assets not legally required to be removed remain in regulatory liabilities as of December 31, 2004.

Decommissioning expense under the rate-making method was $125 million in 2004, $118 million in 2003 and $73 million in 2002. The ARO for decommissioning SCE's active nuclear facilities was $2.0 billion at December 31, 2004 and $1.9 billion at December 31, 2003.

Decommissioning funds collected in rates are placed in independent trusts, which, together with accumulated earnings, will be utilized solely for decommissioning.

Trust investments (at fair value) include:

In millions	Maturity Dates	December 31,	2004	2003
Municipal bonds	2005 – 2042		$ 784	$ 702
Stock	–		1,403	1,324
United States government issues	2005 – 2033		485	363
Corporate bonds	2005 – 2037		41	91
Short-term	2005		44	50
Total			$ 2,757	$ 2,530

Note: Maturity dates as of December 31, 2004.

Trust fund earnings (based on specific identification) increase the trust fund balance and the ARO regulatory liability. Net earnings (loss) were $91 million in 2004, $93 million in 2003 and $(25) million in 2002. Proceeds from sales of securities (which are reinvested) were $2.5 billion in 2004, $2.2 billion in 2003 and $3.8 billion in 2002. Net unrealized holding gains were $796 million and $677 million at December 31, 2004 and 2003, respectively. Approximately 91% of the cumulative trust fund contributions were tax-deductible.

Other Commitments

At December 31, 2004, EME had firm commitments to spend approximately $25 million on capital expenditures in 2005, primarily for component replacement projects.

SCE and EME have fuel supply contracts which require payment only if the fuel is made available for purchase. SCE has a coal fuel contract that requires payment of certain fixed charges whether or not coal is delivered.

During 2004, EME Homer City experienced interruptions of supply under two agreements. On December 21, 2004, EME Homer City was given written notice of an event of force majeure at one mine, which is a source of coal under both of the agreements. The claimed force majeure event is the result of alleged geologic conditions that, in the suppliers' opinion, prevent the delivery of coal under the agreements. These two agreements together provide for the delivery to EME Homer City of 1,290,000 tons of coal in 2005. The suppliers also seek to terminate one of the agreements, which was scheduled to run through December 2007, under a provision that allows either party to the agreement to terminate if an event of force majeure lasts 30 days or more. The suppliers allege that the geologic problems encountered at the mine prevent mining and will continue beyond a 30-day period. The parties' second agreement with a term through December 2006 does not contain a similar termination provision, and the suppliers have requested contract modifications to the term, quantity, quality and price provisions of the agreement. EME Homer City disputes the force majeure claim as it relates to both agreements and has filed suit. EME Homer City's complaint seeks equitable relief by way of an order requiring the defendant to fulfill their contracted obligations and such other monetary relief as is just and proper.

At December 31, 2004, EME had a contractual commitment to transport natural gas. EME is committed to pay minimum fees under this agreement, which has a term of 15 years.

At December 31, 2004, EME had contractual commitments to transport coal. The contracts range from three years to seven years. EME is committed to pay minimum fees under these agreements.

SCE has power-purchase contracts with certain QFs (cogenerators and small power producers) and other power producers. These contracts provide for capacity payments if a facility meets certain performance obligations and energy payments based on actual power supplied to SCE (the energy payments are not included in the table below). There are no requirements to make debt-service payments. In an effort to

replace higher-cost contract payments with lower-cost replacement power, SCE has entered into purchased-power settlements to end its contract obligations with certain QFs. The settlements are reported as power purchase contracts on the balance sheets.

Certain commitments for the years 2005 through 2009 are estimated below:

In millions	2005	2006	2007	2008	2009
Fuel supply	$ 499	$ 256	$ 198	$ 113	$ 68
Gas and coal transportation payments	210	168	102	44	8
Purchased power	898	725	648	421	394

SCE has an unconditional purchase obligation for firm transmission service from another utility. Minimum payments are based, in part, on the debt-service requirements of the provider, whether or not the transmission line is operable. The contract requires minimum payments of $69 million through 2016 (approximately $6 million per year).

As of December 31, 2004, Edison Capital had outstanding commitments of $81 million to fund energy and infrastructure investments and had signed binding term sheets, subject to closing, for $85 million of additional renewable energy investments. Prior to funding any commitments, specific contract conditions must be satisfied. At December 31, 2004, Edison Capital had deposited approximately $5 million as collateral for several letters of credit currently outstanding.

Guarantees and Indemnities

Edison International's subsidiaries have various financial and performance guarantees and indemnifications which are issued in the normal course of business. As discussed below, these contracts included performance guarantees, guarantees of debt and indemnifications.

Tax Indemnity Agreements

In connection with the sale-leaseback transactions that EME has entered into related to the Collins Station, Powerton and Joliet plants in Illinois and the Homer City facilities in Pennsylvania, EME or one of its subsidiaries has entered into tax indemnity agreements. Under these tax indemnity agreements, these entities agreed to indemnify the lessors in the sale-leaseback transactions for specified adverse tax consequences that could result in certain situations set forth in each tax indemnity agreement, including specified defaults under the respective leases. The potential indemnity obligations under these tax indemnity agreements could be significant. Due to the nature of these potential obligations under these tax indemnity agreements, EME cannot determine a maximum potential liability which would be triggered by a valid claim from the lessors. EME has not recorded a liability related to these indemnities. In connection with the termination of the lease for the Collins Station (see Note 14), Midwest Generation will continue to have obligations under the tax indemnity agreement with the former lease equity investor.

Indemnities Provided as Part of EME's Acquisition of the Illinois Plants

In connection with the acquisition of the Illinois plants, EME agreed to indemnify Commonwealth Edison with respect to specified environmental liabilities before and after December 15, 1999, the date of sale. The indemnification claims are reduced by any insurance proceeds and tax benefits related to such claims and are subject to a requirement that Commonwealth Edison takes all reasonable steps to mitigate losses related to any such indemnification claim. Due to the nature of the obligation under this indemnity, a maximum potential liability cannot be determined. This indemnification for environmental liabilities is not limited in term and would be triggered by a valid claim from Commonwealth Edison. Except as discussed below, EME has not recorded a liability related to this indemnity.

Midwest Generation entered into a supplemental agreement with Commonwealth Edison and Exelon Generation on February 20, 2003 to resolve a dispute regarding interpretation of its reimbursement obligation for asbestos claims under the environmental indemnities set forth in the asset sale agreement. Under this supplemental agreement, Midwest Generation agreed to reimburse Commonwealth Edison and Exelon Generation for 50% of specific existing asbestos claims and expenses, less recovery of insurance costs, and agreed to a sharing arrangement for liabilities and expenses associated with future asbestos-related claims as specified in the agreement. As a general matter, Commonwealth Edison and Midwest Generation apportion responsibility for future asbestos-related claims based upon the number of exposure sites that are Commonwealth Edison locations or Midwest Generation locations. The obligations under this agreement are not subject to a maximum liability. The supplemental agreement has a five-year term with an automatic renewal provision (subject to the right of either party to terminate). Payments are made under this indemnity upon tender by Commonwealth Edison of appropriate proof of liability for an asbestos-related settlement, judgment, verdict, or expense. There were between 130 and 170 cases for which Midwest Generation was potentially liable and that had not been settled and dismissed by the end of 2004. At December 31, 2004, Midwest Generation had $9 million recorded as a liability for asserted claims related to this matter and had made $5 million in payments through December 31, 2004.

In view of its experience since 2003, Midwest Generation engaged an independent actuary in the fourth quarter of 2004 to determine if a reasonable estimate of future losses could be made based on is claims and other available information. After review, the actuary determined that an estimate could be prepared and, accordingly, Midwest Generation engaged the actuary to complete an estimate of future losses. Based on the actuary's analysis, Midwest Generation recorded an undiscounted $56 million pre-tax charge for its indemnity for future asbestos claims through 2045. In calculating future losses, the actuary made various assumptions, including but not limited to, the settlement of future claims under the supplemental agreement with Commonwealth Edison as described above, the distribution of exposure sites, and that no asbestos claims will be filed after 2045.

The $56 million pre-tax charge was recorded as part of other operation and maintenance expense on Edison International's consolidated income statement and reduced net income by $34 million. Midwest Generation anticipates obtaining periodic updates of the estimate of future losses. On a quarterly basis, Midwest Generation will monitor actual experience against the number of forecasted claims to be received and expected claim payments. Adjustments to the estimate will be recorded quarterly, if necessary.

The amounts recorded by Midwest Generation for the asbestos-related liability were based upon known facts at the time the report was prepared. Projecting future events, such as the number of new claims to be filed each year, the average cost of disposing of claims, as well as the numerous uncertainties surrounding asbestos litigation in the United States, could cause the actual costs to be higher or lower than projected.

Indemnity Provided as Part of EME's Acquisition of the Homer City Facilities

In connection with the acquisition of the Homer City facilities, EME Homer City Generation L.P. (EME Homer City) agreed to indemnify the sellers with respect to specific environmental liabilities before and after the date of sale as specified in the asset purchase agreement dated August 1, 1998. EME guaranteed the obligations of EME Homer City. Due to the nature of the obligation under this indemnity provision, it is not subject to a maximum potential liability and does not have an expiration date. Payments would be triggered under this indemnity by a claim from the sellers. EME has not recorded a liability related to this indemnity.

Indemnities Provided Under Asset Sale Agreements

The asset sale agreements for the sale of EME's international assets contain indemnities from EME to the purchasers, including indemnification for taxes imposed with respect to operations of the assets prior to the sale and for pre-closing environmental liabilities. EME also provided an indemnity to IPM for matters arising out of the exercise by one of its project partners of a purported right of first refusal. Not all indemnities under the asset sale agreements have specific expiration dates. Payments would be triggered under these indemnities by valid claims from the sellers or purchasers, as the case may be. At December 31, 2004, EME had recorded a liability of $87 million related to these matters.

In connection with the sale of various domestic assets, EME has from time to time provided indemnities to the purchasers for taxes imposed with respect to operations of the asset prior to the sale. EME has also provided indemnities to purchasers for items specified in each agreement (for example, specific pre-existing litigation matters and/or environmental conditions). Due to the nature of the obligations under these indemnity agreements, a maximum potential liability cannot be determined. Not all indemnities under the asset sale agreements have specific expiration dates. Payments would be triggered under these indemnities by valid claims from the sellers or purchasers, as the case may be. EME has not recorded a liability related to these indemnities.

Guarantee of Brooklyn Navy Yard Contractor Settlement Payments

On March 31, 2004, EME completed the sale of its 50% partnership interest in Brooklyn Navy Yard Cogeneration Partners, L.P. (referred to as Brooklyn Navy Yard), to BNY Power Partners LLC. Brooklyn Navy Yard owns a 286 MW gas-fired cogeneration power plant in Brooklyn, New York. In February 1997, the construction contractor asserted general monetary claims under the turnkey agreement against Brooklyn Navy Yard. A settlement agreement was executed on January 17, 2003, and all litigation has been dismissed. EME agreed to indemnify Brooklyn Navy Yard and, in connection with the sale of EME's interest in Brooklyn Navy Yard, BNY Power Partners for any payments due under this settlement agreement, which are scheduled through 2006. At December 31, 2004, EME had recorded an $11 million liability related to this indemnity.

Capacity Indemnification Agreements

EME has guaranteed, jointly and severally with Texaco Inc., the obligations of March Point Cogeneration Company under its project power sales agreements to repay capacity payments to the project's power purchaser in the event that the power sales agreements terminate, March Point Cogeneration Company abandons the project, or the project fails to return to normal operations within a reasonable time after a complete or partial shutdown, during the term of the power contracts. In addition, subsidiaries of EME have guaranteed the obligations of Kern River Cogeneration Company and Sycamore Cogeneration Company under their project power sales agreements to repay capacity payments to the projects' power purchaser in the event that the projects unilaterally terminate their performance or reduce their electric power producing capability during the term of the power contracts. The obligations under the indemnification agreements as of December 31, 2004, if payment were required, would be $153 million. EME has no reason to believe that any of these projects will either cease operations or reduce its electric power producing capability during the term of its power contract. EME has not recorded a liability related to this indemnity.

Indemnity Provided as Part of the Acquisition of Mountainview

In connection with the acquisition of Mountainview, SCE agreed to indemnify the seller with respect to specific environmental claims related to SCE's previously owned San Bernardino Generating Station, divested by SCE in 1998 and reacquired as part of the Mountainview acquisition. The generating station has not operated since early 2001, and SCE retained certain responsibilities with respect to environmental

claims as part of the original divestiture of the station. The aggregate liability for either party to the purchase agreement for damages and other amounts is a maximum of $60 million. This indemnification for environmental liabilities expires on or before March 12, 2033. SCE has not recorded a liability related to this indemnity.

Note 10. Contingencies

In addition to the matters disclosed in these Notes, Edison International is involved in other legal, tax and regulatory proceedings before various courts and governmental agencies regarding matters arising in the ordinary course of business. Edison International believes the outcome of these other proceedings will not materially affect its results of operations or liquidity.

Aircraft Leases

Edison Capital has invested in three aircraft leased to American Airlines. American has reported very large operating and net losses due to reduced pricing power, increases in capacity in excess of demand, deeply discounted fare sales and significant increases in fuel prices. In the event American Airlines defaults in making its lease payments, the lenders with a security interest in the aircraft or leases may exercise remedies that could lead to a loss of some or all of Edison Capital's investment in the aircraft plus any accrued interest. The total maximum loss exposure to Edison Capital in 2005 is $45 million. A restructure of the lease could also result in a loss of some or all of the investment. At December 31, 2004, American Airlines was current in its lease payments to Edison Capital.

Environmental Remediation

Edison International is subject to numerous environmental laws and regulations, which require it to incur substantial costs to operate existing facilities, construct and operate new facilities, and mitigate or remove the effect of past operations on the environment.

Edison International believes that it is in substantial compliance with environmental regulatory requirements; however, possible future developments, such as the enactment of more stringent environmental laws and regulations, could affect the costs and the manner in which business is conducted and could cause substantial additional capital expenditures. There is no assurance that additional costs would be recovered from customers or that Edison International's financial position and results of operations would not be materially affected.

Edison International records its environmental remediation liabilities when site assessments and/or remedial actions are probable and a range of reasonably likely cleanup costs can be estimated. Edison International reviews its sites and measures the liability quarterly, by assessing a range of reasonably likely costs for each identified site using currently available information, including existing technology, presently enacted laws and regulations, experience gained at similar sites, and the probable level of involvement and financial condition of other potentially responsible parties. These estimates include costs for site investigations, remediation, operations and maintenance, monitoring and site closure. Unless there is a probable amount, Edison International records the lower end of this reasonably likely range of costs (classified as other long-term liabilities) at undiscounted amounts.

Edison International's recorded estimated minimum liability to remediate its 31 identified sites at SCE (24 sites) and EME (7 sites related to Midwest Generation) is $84 million, $82 million of which is related to SCE. In third quarter 2003, SCE sold certain oil storage and pipeline facilities. This sale caused a reduction in Edison International's recorded estimated minimum environmental liability. Edison International's other subsidiaries have no identified remediation sites. The ultimate costs to clean up Edison International's identified sites may vary from its recorded liability due to numerous uncertainties inherent in the estimation process, such as: the extent and nature of contamination; the scarcity of reliable

data for identified sites; the varying costs of alternative cleanup methods; developments resulting from investigatory studies; the possibility of identifying additional sites; and the time periods over which site remediation is expected to occur. Edison International believes that, due to these uncertainties, it is reasonably possible that cleanup costs could exceed its recorded liability by up to $123 million, all of which is related to SCE. The upper limit of this range of costs was estimated using assumptions least favorable to Edison International among a range of reasonably possible outcomes. In addition to its identified sites (sites in which the upper end of the range of costs is at least $1 million), SCE also had 30 immaterial sites whose total liability ranges from $4 million (the recorded minimum liability) to $9 million.

The CPUC allows SCE to recover environmental remediation costs at certain sites, representing $27 million of its recorded liability, through an incentive mechanism (SCE may request to include additional sites). Under this mechanism, SCE will recover 90% of cleanup costs through customer rates; shareholders fund the remaining 10%, with the opportunity to recover these costs from insurance carriers and other third parties. SCE has successfully settled insurance claims with all responsible carriers. SCE expects to recover costs incurred at its remaining sites through customer rates. SCE has recorded a regulatory asset of $55 million for its estimated minimum environmental-cleanup costs expected to be recovered through customer rates.

Edison International's identified sites include several sites for which there is a lack of currently available information, including the nature and magnitude of contamination, and the extent, if any, that Edison International may be held responsible for contributing to any costs incurred for remediating these sites. Thus, no reasonable estimate of cleanup costs can be made for these sites.

Edison International expects to clean up its identified sites over a period of up to 30 years. Remediation costs in each of the next several years are expected to range from $13 million to $25 million. Recorded costs for 2004 were $14 million.

Based on currently available information, Edison International believes it is unlikely that it will incur amounts in excess of the upper limit of the estimated range for its identified sites and, based upon the CPUC's regulatory treatment of environmental remediation costs incurred at SCE, Edison International believes that costs ultimately recorded will not materially affect its results of operations or financial position. There can be no assurance, however, that future developments, including additional information about existing sites or the identification of new sites, will not require material revisions to such estimates.

Federal Income Taxes

Edison International has reached a tentative settlement with the IRS on tax issues and pending affirmative claims relating to its 1991 to 1993 tax years currently under appeal. This settlement, which should be finalized in 2005, is expected to result in a net earnings benefit for Edison International of approximately $70 million, most of which relates to SCE.

Edison International received Revenue Agent Reports from the IRS in August 2002 and in January 2005 asserting deficiencies in federal corporate income taxes with respect to audits of its 1994 to 1996 and 1997 to 1999 tax years, respectively. Many of the asserted tax deficiencies are timing differences and, therefore, amounts ultimately paid (exclusive of interest and penalties), if any, would be deductible on future tax returns of Edison International.

As part of a nationwide challenge of certain types of lease transactions, the IRS has raised these issues about the deferral of income taxes in audits of the 1994 to 1996 and 1997 to 1999 tax years associated with Edison Capital's cross-border leases. The IRS is challenging Edison Capital's foreign power plant and electric locomotive sale/leaseback transactions (termed a sale-in/lease-out or SILO transaction).

The estimated federal and state taxes deferred from these leases was $44 million in the 1994 to 1996 and 1997 to 1999 audit periods and $32 million in subsequent years through 2004.

The IRS is also challenging Edison Capital's foreign power plant and electric transmission system lease/leaseback transactions (termed a lease-in, lease-out or LILO transaction). The estimated federal and state income taxes deferred from these leases was $558 million in the 1997 to 1999 audit period and $565 million in subsequent years through 2004. The IRS has also proposed interest and penalties in its challenge to each SILO and LILO transaction.

Edison International believes it properly reported these transactions based on applicable statutes, regulations and case law in effect at the time the transactions were entered into. Written protests were filed to appeal the 1994 to 1996 audit adjustments asserting that the IRS's position misstates material facts, misapplies the law and is incorrect. This matter is now being considered by the Administrative Appeals branch of the IRS. Edison International will also file written protests to appeal the issues raised in the 1997 to 1999 audit. Edison International intends to contest these proposed deficiencies through administrative appeals and litigation, if necessary.

Edison Capital also entered into a lease/service contract transaction in 1999 involving a foreign telecommunication system (termed a Service Contract). The IRS did not assert an adjustment for this lease in the 1997 to 1999 audit cycle but is expected to challenge this lease in subsequent audit cycles similar to positions asserted against the SILOs discussed above. The estimated federal and state taxes deferred from this lease are $221 million through 2004.

If Edison International is not successful in its defense of the tax treatment for the SILOs, LILOs and the Service Contract, the payment of taxes, exclusive of any interest or penalties, would not affect results of operations under current accounting standards, although it could have a significant impact on cash flow. However, the FASB is currently considering changes to the accounting for leases. If the proposed accounting changes are adopted and Edison International's tax treatment for the SILOs, LILOs and Service contract is significantly altered as a result of IRS challenges, there could be a material effect on reported earnings by requiring Edison International to reverse earnings previously recognized as a current period adjustment and to report these earnings over the remaining life of the leases. At this time, Edison International is unable to predict the impact of the ultimate resolution of these matters.

The IRS Revenue Agent Report for the 1997 to 1999 audit also asserted deficiencies with respect to a transaction entered into by an SCE subsidiary which may be considered substantially similar to a listed transaction described by the IRS as a contingent liability company. While Edison International intends to defend its tax return position with respect to this transaction, the tax benefits relating to the capital loss deductions will not be claimed for financial accounting and reporting purposes until and unless these tax losses are sustained.

In April 2004, Edison International filed California Franchise Tax amended returns for tax years 1997 through 2002 to abate the possible imposition of new California penalty provisions on transactions that may be considered as listed or substantially similar to listed transactions described in an IRS notice that was published in 2001. These transactions include certain Edison Capital leveraged lease transactions and the SCE subsidiary contingent liability company transaction described above. Edison International filed these amended returns under protest retaining its appeal rights.

Investigations Regarding Performance Incentives Rewards

SCE is eligible under its CPUC-approved performance-based ratemaking (PBR) mechanism to earn rewards or penalties based on its performance in comparison to CPUC-approved standards of customer satisfaction, employee injury and illness reporting, and system reliability.

SCE has been conducting investigations into its performance under these PBR mechanisms and has reported to the CPUC certain findings of misconduct and misreporting as further discussed below. As a result of the reported events, the CPUC could institute its own proceedings to determine whether and in what amounts to order refunds or disallowances of past and potential PBR rewards for customer satisfaction, injury and illness reporting, and system reliability portions of PBR. The CPUC also may consider whether to impose additional penalties on SCE. SCE cannot predict with certainty the outcome of these matters or estimate the potential amount of refunds, disallowances, and penalties that may be required.

Customer Satisfaction

SCE received two letters in 2003 from one or more anonymous employees alleging that personnel in the service planning group of SCE's transmission and distribution business unit altered or omitted data in attempts to influence the outcome of customer satisfaction surveys conducted by an independent survey organization. The results of these surveys are used, along with other factors, to determine the amounts of any incentive rewards or penalties to SCE under the PBR provisions for customer satisfaction. SCE recorded aggregate customer satisfaction rewards of $28 million for the years 1998, 1999 and 2000. Potential customer satisfaction rewards aggregating $10 million for the years 2001 and 2002 are pending before the CPUC and have not been recognized in income by SCE. SCE also anticipated that it could be eligible for customer satisfaction rewards of about $10 million for 2003.

SCE has been conducting an internal investigation and keeping the CPUC informed of its progress. On June 25, 2004, SCE submitted to the CPUC a PBR customer satisfaction investigation report, which concluded that employees in the design organization of the transmission and distribution business unit deliberately altered customer contact information in order to affect the results of customer satisfaction surveys. At least 36 design organization personnel engaged in deliberate misconduct including alteration of customer information before the data were transmitted to the independent survey company. Because of the apparent scope of the misconduct, SCE proposed to refund to ratepayers $7 million of the PBR rewards previously received and forego an additional $5 million of the PBR rewards pending that are both attributable to the design organization's portion of the customer satisfaction rewards for the entire PBR period (1997–2003). In addition, during its investigation, SCE determined that it could not confirm the integrity of the method used for obtaining customer satisfaction survey data for meter reading. Thus, SCE also proposed to refund all of the approximately $2 million of customer satisfaction rewards associated with meter reading. As a result of these findings, SCE accrued a $9 million charge in the caption "Other nonoperating deductions" on the income statement in 2004 for the potential refunds of rewards that have been received.

SCE has taken remedial action as to the customer satisfaction survey misconduct by severing the employment of several supervisory personnel, updating system process and related documentation for survey reporting, and implementing additional supervisory controls over data collection and processing. Performance incentive rewards for customer satisfaction expired in 2003 pursuant to the 2003 general rate case.

The CPUC has not yet opened a formal investigation into this matter. However, it has submitted several data requests to SCE and has requested an opportunity to interview a number of SCE employees in the design organization. SCE has responded to these requests and the CPUC has conducted interviews of approximately 20 employees who were disciplined for misconduct.

Employee Injury and Illness Reporting

In light of the problems uncovered with the customer satisfaction surveys, SCE is conducting an investigation into the accuracy of SCE's employee injury and illness reporting. The yearly results of employee injury and illness reporting to the CPUC are used to determine the amount of the incentive

reward or penalty to SCE under the PBR mechanism. Since the inception of PBR in 1997, SCE has received $20 million in employee safety incentives for 1997 through 2000 and, based on SCE's records, may be entitled to an additional $15 million for 2001 through 2003.

On October 21, 2004, SCE reported to the CPUC and other appropriate regulatory agencies certain findings concerning SCE's performance under the PBR incentive mechanism for injury and illness reporting. Under the PBR mechanism, rewards and/or penalties for the years 1997 through 2003 were based upon a total incident rate, which included two equally weighted measures: Occupational Safety and Health Administration (OSHA) recordable incidents and first aid incidents. The major issue disclosed in the investigative findings to the CPUC was that SCE failed to implement an effective recordkeeping system sufficient to capture all required data for first aid incidents. SCE's investigation also found reporting inaccuracies for OSHA recordable incidents, but the impact of these inaccuracies did not have a material effect on the PBR mechanism.

As a result of these findings, SCE proposed to the CPUC that it not collect any reward under the mechanism for any year before 2005, and it return to ratepayers the $20 million it has already received. Therefore, SCE accrued a $20 million charge in the caption "Other nonoperating deductions" on the income statement in 2004 for the potential refund of these rewards. SCE has also proposed to withdraw the pending rewards for the 2001–2003 time frames.

SCE is taking other remedial action to address the issues identified, including revising its organizational structure and overall program for environmental, health and safety compliance. Additional actions, including disciplinary action against specific employees identified as having committed wrongdoing, may result once the investigation is completed. SCE submitted a report on the results of its investigation to the CPUC on December 3, 2004. As with the customer satisfaction matter, the CPUC has not yet opened a formal investigation into this matter. However, SCE anticipates that the CPUC will be submitting data requests and seeking additional information in the near future.

System Reliability

In light of the problems uncovered with the PBR mechanisms discussed above, SCE is conducting an investigation into the third PBR metric, system reliability. Since the inception of PBR payments in 1997, SCE has received $8 million in rewards and has applied for an additional $5 million reward based on frequency of outage data for 2001. For 2002, SCE's data indicates that it earned no reward and incurred no penalty. Based on the application of the PBR mechanism, as adopted, SCE's data would result in penalties of $5 million and $1 million for 2003 and 2004, respectively. These penalties have not yet been assessed. As a result of SCE's data and calculations, SCE has accrued a $6 million charge in the caption "Other nonoperating deductions" on the income statement in 2004.

On February 28, 2005, SCE provided its final investigatory report to the CPUC concluding that the reliability reporting system is working as intended.

Navajo Nation Litigation

In June 1999, the Navajo Nation filed a complaint in the United States District Court for the District of Columbia (D.C. District Court) against Peabody Holding Company (Peabody) and certain of its affiliates, Salt River Project Agricultural Improvement and Power District, and SCE arising out of the coal supply agreement for Mohave. The complaint asserts claims for, among other things, violations of the federal Racketeer Influenced and Corrupt Organizations statute, interference with fiduciary duties and contractual relations, fraudulent misrepresentation by nondisclosure, and various contract-related claims. The complaint claims that the defendants' actions prevented the Navajo Nation from obtaining the full value in royalty rates for the coal supplied to Mohave. The complaint seeks damages of not less than $600 million, trebling of that amount, and punitive damages of not less than $1 billion, as well as a

declaration that Peabody's lease and contract rights to mine coal on Navajo Nation lands should be terminated. SCE joined Peabody's motion to strike the Navajo Nation's complaint. In addition, SCE and other defendants filed motions to dismiss. The D.C. District Court denied these motions for dismissal, except for Salt River Project Agricultural Improvement and Power District's motion for its separate dismissal from the lawsuit.

Certain issues related to this case were addressed by the United States Supreme Court in a separate legal proceeding filed by the Navajo Nation in the United States Court of Federal Claims against the United States Department of Interior. In that action, the Navajo Nation claimed that the Government breached its fiduciary duty concerning negotiations relating to the coal lease involved in the Navajo Nation's lawsuit against SCE and Peabody. On March 4, 2003, the Supreme Court concluded, by majority decision, that there was no breach of a fiduciary duty and that the Navajo Nation did not have a right to relief against the Government. Based on the Supreme Court's analysis, on April 28, 2003, SCE and Peabody filed motions to dismiss or, in the alternative, for summary judgment in the D.C. District Court action. On April 13, 2004, the D.C. District Court denied SCE's and Peabody's April 2003 motions to dismiss or, in the alternative, for summary judgment. The D.C. District Court subsequently issued a scheduling order that imposed a December 31, 2004 discovery cut-off. Pursuant to a joint request of the parties, the D.C. District Court granted a 120-day stay of the action to allow the parties to attempt to resolve, through facilitated negotiations, all issues associated with Mohave. Negotiations are ongoing and the stay has been continued until further order of the court.

The United States Court of Appeals for the D.C. Circuit, acting on a suggestion on remand filed by the Navajo Nation, held in an October 24, 2003 decision that the Supreme Court's March 4, 2003 decision was focused on three specific statutes or regulations and therefore did not address the question of whether a network of other statutes, treaties and regulations imposed judicially enforceable fiduciary duties on the United States during the time period in question. The Government and the Navajo Nation both filed petitions for rehearing of the October 24, 2003 D.C. Circuit Court decision. Both petitions were denied on March 9, 2004. On March 16, 2004, the D.C. Circuit Court issued an order remanding the case against the Government to the Court of Federal Claims, which conducted a status conference on May 18, 2004. As a result of the status conference discussion, the Navajo Nation and the Government are in the process of briefing the remaining issues following remand. Peabody's motion to intervene as a party in the remanded Court of Federal Claims case was denied.

SCE cannot predict with certainty the outcome of the 1999 Navajo Nation's complaint against SCE, the impact of the Supreme Court's decision in the Navajo Nation's suit against the Government on this complaint, or the impact of the complaint on the operation of Mohave beyond 2005.

Nuclear Insurance

Federal law limits public liability claims from a nuclear incident to $10.8 billion. SCE and other owners of San Onofre and Palo Verde have purchased the maximum private primary insurance available ($300 million). The balance is covered by the industry's retrospective rating plan that uses deferred premium charges to every reactor licensee if a nuclear incident at any licensed reactor in the United States results in claims and/or costs which exceed the primary insurance at that plant site. Federal regulations require this secondary level of financial protection. The Nuclear Regulatory Commission exempted San Onofre Unit 1 from this secondary level, effective June 1994. The maximum deferred premium for each nuclear incident is $101 million per reactor, but not more than $10 million per reactor may be charged in any one year for each incident. Based on its ownership interests, SCE could be required to pay a maximum of $199 million per nuclear incident. However, it would have to pay no more than $20 million per incident in any one year. Such amounts include a 5% surcharge if additional funds are needed to satisfy public liability claims and are subject to adjustment for inflation. If the public liability limit above is insufficient, federal regulations may impose further revenue-raising measures to pay claims, including a

possible additional assessment on all licensed reactor operators. All licensed operating plants including San Onofre and Palo Verde are grandfathered under the applicable law.

Property damage insurance covers losses up to $500 million, including decontamination costs, at San Onofre and Palo Verde. Decontamination liability and property damage coverage exceeding the primary $500 million also has been purchased in amounts greater than federal requirements. Additional insurance covers part of replacement power expenses during an accident-related nuclear unit outage. A mutual insurance company owned by utilities with nuclear facilities issues these policies. If losses at any nuclear facility covered by the arrangement were to exceed the accumulated funds for these insurance programs, SCE could be assessed retrospective premium adjustments of up to $44 million per year. Insurance premiums are charged to operating expense.

Spent Nuclear Fuel

Under federal law, the United States Department of Energy (DOE) is responsible for the selection and construction of a facility for the permanent disposal of spent nuclear fuel and high-level radioactive waste. The DOE did not meet its obligation to begin acceptance of spent nuclear fuel not later than January 31, 1998. It is not certain when the DOE will begin accepting spent nuclear fuel from San Onofre or other nuclear power plants. Extended delays by the DOE have led to the construction of costly alternatives and associated siting and environmental issues. SCE has paid the DOE the required one-time fee applicable to nuclear generation at San Onofre through April 6, 1983 (approximately $24 million, plus interest). SCE is also paying the required quarterly fee equal to 0.1¢-per-kWh of nuclear-generated electricity sold after April 6, 1983. On January 29, 2004, SCE, as operating agent, filed a complaint against the DOE in the United States Court of Federal Claims seeking damages for DOE's failure to meet its obligation to begin accepting spent nuclear fuel from San Onofre. The case if currently stayed pending development in other spent nuclear fuel cases also before the United States Court of Federal Claims.

SCE has primary responsibility for the interim storage of spent nuclear fuel generated at San Onofre. Spent nuclear fuel is stored in the San Onofre Units 2 and 3 spent fuel pools and the San Onofre independent spent fuel storage installation. Movement of Unit 1 spent fuel from the Unit 3 spent fuel pool to the independent spent fuel storage installation was completed in late 2003. Movement of Unit 1 spent fuel from the Unit 1 spent fuel pool to the independent spent fuel storage installation was completed in late 2004. Movement of Unit 1 spent fuel from the Unit 2 spent fuel pool to the independent spent fuel pool storage installation is scheduled to be completed by summer 2005. With these moves, there will be sufficient space in the Unit 2 and 3 spent fuel pools to meet plant requirements through mid-2007 and mid-2008, respectively. In order to maintain a full core off-load capability, SCE is planning to begin moving Unit 2 and 3 spent fuel into the independent spent fuel storage installation by late 2006.

In order to increase on-site storage capacity and maintain core off-load capability, Palo Verde has constructed a dry cask storage facility. Arizona Public Service, as operating agent, plans to continually load casks on a schedule to maintain full core off-load capability for all three units.

Storm Lake

As of December 31, 2004, Edison Capital had an investment of approximately $59 million in Storm Lake Power, a project developed by Enron Wind, a subsidiary of Enron Corporation.

Storm Lake and Edison Capital's claims for damages in Enron's bankruptcy of approximately $60 million were included in Enron's plan of reorganization which was confirmed on July 15, 2004. The plan provides for distributions to be made as soon as practicable.

Note 11. Investments in Leveraged Leases, Partnerships and Unconsolidated Subsidiaries

Leveraged Leases

Edison Capital is the lessor in various power generation, electric transmission and distribution, transportation and telecommunication leases with terms of 24 to 38 years. Each of Edison Capital's leveraged lease transactions was completed and accounted for in accordance with lease accounting standards. All operating, maintenance, insurance and decommissioning costs are the responsibility of the lessees. The acquisition cost of these facilities was $6.9 billion at both December 31, 2004 and 2003.

The equity investment in these facilities is generally 20% of the cost to acquire the facilities. The balance of the acquisition costs was funded by nonrecourse debt secured by first liens on the leased property. The lenders do not have recourse to Edison Capital in the event of loan default.

The net income from leveraged leases is:

In millions Year ended December 31,	2004	2003	2002
Income from leveraged leases	$ 81	$ 82	$ 105
Recomputation due to tax rate change	—	—	(99)
Tax effect of pre-tax income:			
Current	35	40	138
Deferred	(64)	(71)	(86)
Total tax (expense) benefit	(29)	(31)	52
Net income from leveraged leases	$ 52	$ 51	$ 58

The net investment in leveraged leases is:

In millions December 31,	2004	2003
Rentals receivable (net of principal and interest on nonrecourse debt)	$ 3,479	$ 3,497
Unearned income	(1,097)	(1,178)
Investment in leveraged leases	2,382	2,319
Estimated residual value	42	42
Deferred income taxes	(2,132)	(2,055)
Net investment in leveraged leases	$ 292	$ 306

Partnerships and Unconsolidated Subsidiaries

Edison International and its nonutility subsidiaries have equity interests primarily in energy projects, oil and gas and real estate investment partnerships. For 2003 and 2002, the summarized financial information included Four Star Oil & Gas Company, Gordonsville Energy and Brooklyn Navy Yard. On January 7, 2004, EME sold 100% of its stock of Edison Mission Energy Oil & Gas, which in turn held minority interests in Four Star Oil & Gas. On November 21, 2003, EME sold its interest in Gordonsville Energy and on March 31, 2004, EME sold its interest in Brooklyn Navy Yard. Therefore, Gordonsville and Four Star Oil & Gas are not included in the balances for 2004. Brooklyn Navy Yard's first quarter 2004 results are included in the summarized financial information for 2004. The summarized financial information for 2003 and 2002 also included four power projects (Kern River, Midway-Sunset, Sycamore and Watson) partially owned by EME. In compliance with a new accounting standard, on March 31, 2004, SCE began consolidating these projects; therefore, they are not included in the balances for 2004. See "New Accounting Principles" in Note 1 for further details.

The difference between the carrying value of energy projects and oil and gas investments and the underlying equity in the net assets was $2 million at December 31, 2004. The difference is being amortized over the life of the energy projects.

Summarized financial information of these investments is:

In millions Year ended December 31,	2004	2003	2002
Revenue	$ 719	$ 2,399	$ 1,666
Expenses	698	2,062	1,365
Income before accounting change	21	337	301
Cumulative effect of accounting change – net of tax	—	(7)	—
Net income	$ 21	$ 330	$ 301

In millions December 31,	2004	2003
Current assets	$ 485	$ 863
Other assets	4,462	6,535
Total assets	$ 4,947	$ 7,398
Current liabilities	$ 234	$ 564
Other liabilities	2,277	3,245
Equity	2,436	3,589
Total liabilities and equity	$ 4,947	$ 7,398

The undistributed earnings of investments accounted for by the equity method were $75 million in 2004 and $157 million in 2003.

Note 12. Business Segments

Edison International's reportable business segments include its electric utility operation segment (SCE), a nonutility power generation segment (MEHC – parent only which holds debt and has no business activities other than through its ownership interest in EME and EME), and a financial services provider segment (Edison Capital). They are separate business units and are managed separately. Edison International evaluates performance based on net income.

SCE is a rate-regulated electric utility that supplies electric energy to a 50,000 square-mile area of central, coastal and Southern California. SCE also produces electricity. MEHC, through its ownership of EME and its subsidiaries, is engaged in the business of owning or leasing, operating and selling energy and capacity from electric power generation facilities. Through EME, MEHC also conducts price risk management and energy trading activities in power markets open to competition. Edison Capital is a provider of financial services with investments worldwide.

The significant accounting policies of the segments are the same as those described in Note 1.

In previous years, a significant source of revenue from EME's sale of energy and capacity was derived from its Midwest Generation subsidiary's sales to Exelon Generation Company under power purchase agreements which terminated in December 2004. Revenue from such sales was $586 million in 2004, $708 million in 2003 and $1.1 billion in 2002.

For the year ended December 31, 2004, approximately $241 million of EME's nonutility power generation revenue was from sales to BP Energy Company, a third-party customer. An investment grade affiliate of BP Energy has guaranteed payment of amounts due under the related contracts.

Edison International's business segment information (including the elimination of intercompany transactions) is:

In millions	Electric Utility	Nonutility Power Generation	Financial Services	Corporate & Other[1]	Edison International
2004					
Operating revenue	$ 8,448	$ 1,639	$ 102	$ 10	$ 10,199
Depreciation, decommissioning and amortization	860	143	20	(1)	1,022
Interest and dividend income	15	8	10	13	46
Equity in income from partnerships and unconsolidated subsidiaries – net	—	76	12	(22)	66
Interest expense – net of amounts capitalized	409	451	32	93	985
Income tax (benefit) – continuing operations	438	(462)	(13)	(55)	(92)
Income (loss) from continuing operations	915	(666)	60	(83)	226
Net income (loss)	915[2]	24	60	(83)	916
Total assets	23,290	6,683	3,537	(241)	33,269
Capital expenditures	1,678	55	—	—	1,733
2003					
Operating revenue	$ 8,853	$ 1,778	$ 88	$ 13	$ 10,732
Depreciation, decommissioning and amortization	881	154	12	—	1,047
Interest and dividend income	100	10	8	—	118
Equity in income from partnerships and unconsolidated subsidiaries – net	—	245	(14)	—	231
Interest expense – net of amounts capitalized	457	453	26	84	1,020
Income tax (benefit) – continuing operations	388	(174)	(38)	(52)	124
Income (loss) from continuing operations	872	(194)	57	(80)	655
Net income (loss)	922[2]	(79)	57	(79)	821
Total assets	21,771	12,251	3,418	827	38,267
Capital expenditures	1,153	81	—	—	1,234
2002					
Operating revenue	$ 8,705	$ 1,713	$ 7	$ 26	$ 10,451
Depreciation, decommissioning and amortization	780	145	—	3	928
Interest and dividend income	262	24	(1)	(6)	279
Equity in income from partnerships and unconsolidated subsidiaries – net	—	197	(34)	—	163
Interest expense – net of amounts capitalized	584	454	36	52	1,126
Income tax (benefit) – continuing operations	642	(82)	(146)	(84)	330
Income (loss) from continuing operations	1,228	(90)	33	(116)	1,055
Net income (loss)	1,228[2]	(68)	33	(116)	1,077
Total assets	36,058	11,366	3,479	125	51,028
Capital expenditures	1,037	497	1	(27)	1,508

In accordance with an accounting standard related to operating segments, prior periods have been restated to conform to Edison International's business segment definition.

(1) Includes amounts from nonutility subsidiaries, as well as Edison International (parent) not significant as a reportable segment.

(2) Net income available for common stock.

The net income reported for electric utility includes earnings from discontinued operations of $50 million for 2003. The net income (loss) reported for nonutility power generation includes earnings from discontinued operations of $690 million for 2004, $124 million for 2003 and $22 million for 2002. The net loss reported for corporate and other includes loss from discontinued operations of $(1) million for 2002.

Geographic Information

Edison International's foreign and domestic revenue and assets information is:

In millions	Year ended December 31,	2004	2003	2002
Revenue				
United States		**$ 10,096**	$ 10,533	$ 10,331
International		**103**	199	120
Total		**$ 10,199**	$ 10,732	$ 10,451

In millions	December 31,	2004	2003
Assets			
United States		**$ 30,838**	$ 28,596
International		**2,309**	2,423
Assets of discontinued operations		**122**	7,248
Total		**$ 33,269**	$ 38,267

Note 13. Acquisition and Dispositions

Acquisition

On March 12, 2004, SCE acquired Mountainview Power Company LLC, which owns a power plant under construction in Redlands, California. SCE recommenced full construction of the approximately $600 million project, which is expected to be completed in early 2006.

Dispositions

On March 31, 2004, EME completed the sale of its 50% partnership interest in Brooklyn Navy Yard Cogeneration Partners L.P. for a sales price of approximately $42 million. EME recorded an impairment charge of $53 million during the fourth quarter of 2003 related to the planned disposition of this investment and a pre-tax loss of approximately $4 million during the first quarter of 2004 due to changes in the terms of the sale.

On January 7, 2004, EME completed the sale of 100% of its stock of Edison Mission Energy Oil & Gas, which in turn held minority interests in Four Star Oil & Gas. Proceeds from the sale were approximately $100 million. EME recorded a pre-tax gain on the sale of approximately $47 million during the first quarter of 2004.

In fourth quarter 2003, Gordonsville Energy Limited Partnership, in which EME owns a 50% interest, completed the sale of the Gordonsville cogeneration facility. Proceeds from the sale, including distribution of a debt service reserve fund, were $36 million. In second quarter 2003, EME recorded an impairment charge of $6 million related to the planned disposition of this investment.

During 2002, EME completed the sales of its 50% interests in the Commonwealth Atlantic and James River projects and its 30% interest in the Harbor project. Proceeds received from the sales were $44 million.

During 2001, EME had previously recorded asset impairment charges of $32 million related to these projects based on the expected sales proceeds. No gain or loss was recorded from the sale of EME's interests in these projects during 2002.

Note 14. Asset Impairments and Loss on Lease Termination

During 2004, EME recorded asset impairment and loss on lease termination charges of $989 million. On April 27, 2004, EME's subsidiary, Midwest Generation LLC, terminated the Collins Station lease through a negotiated transaction with the lease equity investor. Midwest Generation made a lease termination payment of approximately $960 million. This amount represented the $774 million of lease debt outstanding, plus accrued interest, and the amount owed to the lease equity investor for early termination of the lease. Midwest Generation received title to the Collins Station as part of the transaction. EME recorded a pre-tax loss of approximately $956 million (approximately $587 million after tax) due to termination of the lease and the planned decommissioning of the asset, and disposition of excess inventory.

Following the termination of the Collins Station lease, Midwest Generation announced plans on May 28, 2004 to permanently cease operations at the Collins Station by December 31, 2004 and decommission the plant. By the fourth quarter of 2004, the Collins Station was decommissioned and all units were permanently retired from service, disconnected from the grid, and rendered inoperable, with all operating permits surrendered. In September 2004, EME recorded a pre-tax impairment charge of $5 million resulting from the termination of the power purchase agreement effective September 30, 2004 for the two units at the Collins Station that remained under contract. In addition, EME recognized a $4 million pre-tax charge for exit costs recorded as part of other operation and maintenance expense on Edison International's consolidated income statement related to reducing the workforce in Illinois during the fourth quarter of 2004.

In September 2004, EME completed an analysis of future competitiveness in the expanded PJM Interconnection, LLC marketplace of its eight remaining small peaking units in Illinois. Based on this analysis and regulatory approval, planning efforts are in progress to decommission six of the eight small peaking units. As a result of the decision to decommission the units, projected future cash flows associated with the Illinois peaking units were less than the book value of the units resulting in an impairment under an accounting standard for the impairment or disposal of long-lived assets. During the third quarter of 2004, EME recorded a pre-tax impairment charge of $29 million (approximately $18 million after tax). At September 30, 2004, the fair value of the small peaking plants was approximately $4 million.

During 2003, EME recorded asset impairment charges of $304 million, consisting of $245 million related to eight small peaking plants owned by Midwest Generation in Illinois and $53 million and $6 million to write-down the estimated net proceeds from the planned sale of its interests in the Brooklyn Navy Yard and Gordonsville projects, respectively (see Note 13). The impairment charge related to the peaking plants in Illinois resulted from a revised long-term outlook for capacity revenue from the peaking plants. The lower capacity revenue outlook is the result of a number of factors, including higher long-term natural gas prices and current generation overcapacity. The book value of these assets was written down from $286 million to an estimated fair market value of $41 million. The estimated fair market value was determined based on discounting estimated future pretax cash flows using a 17.5% discount rate.

During 2002, EME recorded asset impairment charges of $86 million, consisting of $61 million related to the write-off of capitalized costs associated with the termination of equipment purchase contracts with Siemens Westinghouse and $25 million related to the write-off of capitalized costs associated with the suspension of the Powerton Station selective catalytic reduction major capital improvement project at the Illinois plants.

Note 15. Discontinued Operations

On February 3, 2005, EME sold its 25% equity interest in the Tri Energy project for approximately $20 million.

On January 10, 2005, EME completed the sale of its 50% equity interest in the Caliraya-Botocan-Kalayaan (CBK) project pursuant to a purchase agreement, dated November 5, 2004, by and between EME and Corporacion IMPSA S.A. Proceeds from the sale were approximately $104 million.

On December 16, 2004, EME completed the sale of the stock and related assets of MEC International B.V. (MECIBV) to a consortium comprised of International Power plc (70%) and Mitsui & Co., Ltd. (30%), referred to as IPM, pursuant to a purchase agreement dated July 29, 2004. The purchase agreement was entered into following a competitive bidding process. The sale of MEC International B.V. included the sale of EME's interests in ten electric power generating projects or companies located in Europe, Asia, Australia, and Puerto Rico. Consideration from the sale of MECIBV and related assets was $2.0 billion.

On September 30, 2004, EME completed the sale of its 51% interest in Contact Energy to Origin Energy New Zealand Limited pursuant to a purchase agreement dated July 20, 2004. The purchase agreement was entered into following a competitive bidding process. Consideration for the sale was NZ$1.6 billion (approximately $1.1 billion) which includes NZ$535 million of debt assumed by the purchaser.

On July 10, 2003, the CPUC approved SCE's sale of certain oil storage and pipeline facilities to Pacific Terminals LLC for $158 million. In third quarter 2003, SCE recorded a $44 million after-tax gain to shareholders.

In 2001, EME ceased consolidating the activities of Lakeland Power Ltd. when an administrative receiver was appointed following a default by Norweb Energi Ltd., the counterparty to a long-term power sales agreement. In 2003, a third party completed the purchase of the Lakeland power plant from the administrative receiver for £24 million. The proceeds from the sale and existing cash were used to fund partial repayment of the outstanding debt owed to secured creditors of the project. Lakeland Power Ltd.'s administrative receiver has filed a claim against Norweb Energi Ltd. for termination of the power purchase agreement. Norweb Energi Ltd. is a subsidiary of TXU (UK) Holdings Limited (TXU UK) and is an indirect subsidiary of TXU Europe Group plc (TXU Europe). On November 19, 2002, TXU UK and TXU Europe, together with a related entity, TXU Europe Energy Trading Limited (TXU Energy), entered into formal administration proceedings in the United Kingdom (similar to bankruptcy proceedings in the United States). To the extent that Lakeland Power receives payment under its claim, such amounts will first be used to repay amounts due to creditors. In October 2004, EME purchased the debt owed them by Lakeland Power from Lakeland's secured creditors for approximately £6 million. The purchase of the outstanding bank debt was completed to maximize EME's recovery from the proceeds ultimately received from the claim against Norweb Energi. Based on the settlement of claims currently being discussed as part of the TXU Europe administration proceeding, the secured debt of Lakeland Power is expected to be repaid in full. In addition, depending on the outcome of the TXU Europe administration proceedings, EME may receive additional cash from the settlement of the claims. The loss from operations of Lakeland in 2002 includes an impairment charge of $92 million ($77 million after tax) and a provision for bad debts of $1 million (after tax) arising from the write-down of the Lakeland power plant and related claims under the power sales agreement (an asset group according to an impairment standard) to their fair market value. The fair value of the asset group was determined based on discounted cash flows and estimated recovery under related claims under the power sales agreement.

On December 21, 2001, EME completed the sale of the Ferrybridge and Fiddler's Ferry coal stations located in the United Kingdom to two wholly owned subsidiaries of American Electric Power. The net proceeds from the sale (£643 million) were used to repay borrowings outstanding under the existing debt

facility related to the acquisition of the plants. In addition, the buyers acquired other assets and assumed specified liabilities associated with the plants. EME recorded a charge of $1.9 billion ($1.1 billion after tax) related to the loss on sale. The loss from operations of Ferrybridge and Fiddler's Ferry in 2002 includes a $7 million loss on settlement of the pension plan related to previous employees of the Ferrybridge and Fiddler's Ferry project, partially offset from an insurance recovery from claims filed prior to the sale of the power plants. The loss on settlement of the pension plan arose from the election by former employees in March 2002 to transfer to AEP's new pension plan and the subsequent transfer of pension assets and liabilities in December 2002 in accordance with the terms of the sale agreement.

For all years presented, the results of EME's international projects discussed above have been accounted for as discontinued operations in the consolidated financial statements in accordance with an accounting standard related to the impairment and disposal of long-lived assets.

Additionally, in 2003 the results of SCE's oil storage and pipeline facilities unit have been accounted for as a discontinued operation in accordance with an accounting standard related to the impairment and disposal of long-lived assets. Due to immateriality, the results of this unit for 2002 have not been restated and are reflected as part of continuing operations.

Unless otherwise discussed above, the consolidated financial statements have been restated to conform to the discontinued operations presentation for all years presented.

Revenue from discontinued operations was $1.3 billion in 2004, $1.5 billion in 2003 and $1.2 billion in 2002. The before-tax earnings of the discontinued operations were $737 million in 2004, $296 million in 2003 and $66 million in 2002. The before-tax earnings of discontinued operations in 2004 included a $532 million gain on sale related to EME's international power generation portfolio.

The carrying value of assets and liabilities recorded as discontinued operations and assets held for sale is:

In millions December 31,	2004	2003
Assets		
Cash and equivalents	$ 2	$ 191
Receivables – net	—	204
Other current assets	2	182
Total current assets	4	577
Investments in partnerships and unconsolidated subsidiaries	107	1,080
Nonutility property – net	—	4,413
Goodwill	—	865
Other deferred charges	11	313
Total assets of discontinued operations	$ 122	$ 7,248
Liabilities		
Accounts payable and accrued liabilities	$ 2	$ 269
Long-term debt due within one year	—	70
Other current liabilities	—	184
Total current liabilities	2	523
Long-term debt	—	2,566
Accumulated deferred income taxes and investment tax credits – net	—	638
Customer advances and other deferred credits	4	488
Other long-term liabilities	9	350
Total liabilities of discontinued operations	$ 15	$ 4,565

Assets and liabilities of most of EME's foreign operations were translated at end of period rates of exchange, and the income statements were translated at the monthly average rates of exchange. Gains or losses from translation of foreign currency financial statements are included in comprehensive income in shareholders' equity.

In millions, except per-share amounts	Total	Fourth	2004 Third	Second	First
Operating revenue	$ 10,199	$ 2,327	$ 3,188	$ 2,565	$ 2,116
Operating income	1,100	451	788	(381)	239
Income from continuing operations	226	259	314	(400)	52
Income from discontinued operations – net	690	120	498	26	46
Cumulative effect of accounting change – net	—	—	—	—	(1)
Net income	916	379	813	(374)	97
Basic earnings (loss) per share:					
Continuing operations	0.69	0.79	0.96	(1.23)	0.16
Discontinued operations	2.12	0.37	1.53	0.08	0.14
Total	2.81	1.16	2.49	(1.15)	0.30
Diluted earnings (loss) per share:					
Continuing operations	0.68	0.78	0.95	(1.21)	0.16
Discontinued operations	2.09	0.36	1.51	0.08	0.14
Total	2.77	1.14	2.46	(1.13)	0.30
Dividends declared per share	0.85	0.25	0.20	0.20	0.20
Common stock prices:					
High	32.52	32.52	27.49	25.82	24.35
Low	21.24	26.39	25.14	21.77	21.24
Close	32.03	32.03	27.39	25.57	24.29

In millions, except per-share amounts	Total	Fourth	2003 Third	Second	First
Operating revenue	$ 10,732	$ 2,241	$ 3,452	$ 2,798	$ 2,242
Operating income	1,455	206	834	158	257
Income from continuing operations	655	134	461	19	41
Income from discontinued operations – net	175	63	83	5	25
Cumulative effect of accounting change – net	(9)	—	—	—	(9)
Net income	821	197	544	24	57
Basic earnings (loss) per share:					
Continuing operations	2.01	0.41	1.42	0.06	0.12
Discontinued operations	0.54	0.19	0.25	0.01	0.08
Cumulative effect of accounting change	(0.03)	—	—	—	(0.03)
Total	2.52	0.60	1.67	0.07	0.17
Diluted earnings (loss) per share:					
Continuing operations	1.99	0.41	1.40	0.06	0.12
Discontinued operations	0.54	0.19	0.25	0.01	0.08
Cumulative effect of accounting change	(0.03)	—	—	—	(0.03)
Total	2.50	0.60	1.65	0.07	0.17
Dividends declared per share	0.20	0.20	—	—	—
Common stock prices:					
High	22.07	22.07	19.65	17.12	14.00
Low	10.57	19.10	15.81	13.30	10.57
Close	21.93	21.93	19.10	16.43	13.69

The amounts reported above are different from those previously reported because of the reclassification of the results of EME's international power generation portfolio as discontinued operations in accordance with an accounting standard related to impairment and disposal of long-lived assets. In addition, as a result of rounding, the total of the four quarters does not always equal the amount for the year.

Selected Financial and Operating Data: 2000 – 2004					Edison International
Dollars in millions, except per-share amounts	2004	2003	2002	2001	2000
Edison International and Subsidiaries					
Operating revenue	$ 10,199	$ 10,732	$ 10,451	$ 10,345	$ 9,887
Operating expenses	$ 9,099	$ 9,277	$ 8,325	$ 5,417	$ 12,202
Income (loss) from continuing operations	$ 226	$ 655	$ 1,055	$ 2,381	$ (1,981)
Net income (loss)	$ 916	$ 821	$ 1,077	$ 1,035	$ (1,943)
Weighted-average shares of common stock outstanding (in millions)	326	326	326	326	333
Basic earnings per share:					
Continuing operations	$ 0.69	$ 2.01	$ 3.24	$ 7.31	$ (5.96)
Discontinued operations	$ 2.12	$ 0.54	$ 0.07	$ (4.13)	$ 0.12
Cumulative effect of accounting change	$ —	$ (0.03)	$ —	$ —	$ —
Total	$ 2.81	$ 2.52	$ 3.31	$ 3.18	$ (5.84)
Diluted earnings per share	$ 2.77	$ 2.50	$ 3.28	$ 3.17	$ (5.84)
Dividends declared per share	$ 0.85	$ 0.20	$ —	$ —	$ 0.84
Book value per share at year-end	$ 18.56	$ 16.52	$ 13.62	$ 10.04	$ 7.43
Market value per share at year-end	$ 32.03	$ 21.93	$ 11.85	$ 15.10	$ 15.625
Rate of return on common equity	17.1%	17.1%	27.0%	58.0%	(41.0)%
Price/earnings ratio	11.4	8.7	3.6	4.7	(2.7)
Ratio of earnings to fixed charges	1.26	1.58	1.93	3.28	*
Assets	$ 33,269	$ 38,267	$ 51,028	$ 36,774	$ 35,100
Long-term debt	$ 9,678	$ 9,220	$ 9,728	$ 10,965	$ 10,732
Common shareholders' equity	$ 6,049	$ 5,383	$ 4,437	$ 3,272	$ 2,420
Preferred stock subject to mandatory redemption	$ 139	$ 141	$ 147	$ 151	$ 256
Company-obligated mandatorily redeemable securities of subsidiaries holding solely parent company debentures	$ —	$ —	$ 951	$ 949	$ 949
Retained earnings	$ 4,078	$ 3,466	$ 2,711	$ 1,634	$ 599
Southern California Edison Company					
Operating revenue	$ 8,448	$ 8,854	$ 8,706	$ 8,126	$ 7,870
Net income (loss) available for common stock	$ 915	$ 922	$ 1,228	$ 2,386	$ (2,050)
Basic earnings (loss) per Edison International common share	$ 2.81	$ 2.83	$ 3.77	$ 7.32	$ (6.16)
Rate of return on common equity	21.0%	20.2%	31.8%	311.0%	(67.6)%
Peak demand in megawatts (MW)	20,762	20,136	18,821	17,890	19,757
Generation capacity at peak (MW)	10,207	9,861	9,767	9,802	9,886
Kilowatt-hour deliveries (in millions)	97,273	92,763	79,693	78,524	84,430
Customers (in millions)	4.67	4.60	4.53	4.47	4.42
Full-time employees	13,454	12,698	12,113	11,663	12,593
Mission Energy Holding Company					
Revenue	$ 1,639	$ 1,778	$ 1,713	$ 1,771	$ 1,653
Income (loss) from continuing operations	$ (666)	$ (194)	$ (90)	$ 28	$ 46
Net income (loss)	$ 24	$ (79)	$ (68)	$ (1,170)	$ 125
Assets	$ 6,888	$ 12,259	$ 11,367	$ 11,108	$ 15,017
Rate of return on common equity	3.4%	(10.6)%	(9.2)%	(59.9)%	4.2%
Ownership in operating projects (MW)	8,834	18,733	18,688	19,019	22,759
Full-time employees	1,768	2,610	2,662	3,021	3,391
Edison Capital					
Revenue	$ 102	$ 88	$ 7	$ 202	$ 274
Net income	$ 60	$ 57	$ 33	$ 84	$ 135
Assets	$ 3,537	$ 3,418	$ 3,479	$ 3,736	$ 3,713
Rate of return on common equity	9.3%	7.5%	4.2%	11.9%	22.9%
Full-time employees	51	62	61	66	119

* less than 1.00

During 2004, EME sold 11 international projects. During 2003, SCE sold certain oil storage and pipeline facilities. During 2002, EME recorded an impairment charge related to its Lakeland plant and during 2001, EME sold its generating plants located in the United Kingdom and Edison Enterprises sold the majority of its assets. Amounts presented in this table have been restated to reflect continuing operations unless stated otherwise. See Note 15, Discontinued Operations, for further discussion. Information related to 2001 and 2000 was derived from information audited by other independent accountants who have ceased operations. Information disclosed in 2000 for MEHC represents EME information only since MEHC was not formed until July 2001.

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Board of Directors*

John E. Bryson [3]
Chairman of the Board,
President and
Chief Executive Officer,
Edison International;
Chairman of the Board, Southern California Edison Company;
Chairman of the Board, Edison Capital
A director since 1990†

France A. Córdova [2,4]
Chancellor,
University of California, Riverside
Riverside, California
A director since 2004

Bradford M. Freeman [1,4,5]
Founding Partner,
Freeman Spogli & Co.
(private investment company)
Los Angeles, California
A director since 2002

Bruce Karatz [2,3,5]
Chairman and Chief Executive Officer,
KB Home (homebuilding)
Los Angeles, California
A director since 2002

Luis G. Nogales [1,2,4]
Managing Partner,
Nogales Investors, and
Managing Director,
Nogales Investors, LLC
(private equity investment companies)
Los Angeles, California
A director since 1993

Ronald L. Olson [3,4]
Senior Partner,
Munger, Tolles and Olson (law firm)
Los Angeles, California
A director since 1995

James M. Rosser [3,4]
President,
California State University, Los Angeles
Los Angeles, California
A director since 1985

Richard T. Schlosberg, III [1,2,5]
Retired President and
Chief Executive Officer,
The David and Lucile Packard Foundation (private family foundation)
San Antonio, Texas
A director since 2002

Robert H. Smith [1,2,5]
Robert H. Smith Investments and Consulting
(banking and financial-related consulting services)
Pasadena, California
A director since 1987

Thomas C. Sutton [1,2,3]
Chairman of the Board and
Chief Executive Officer,
Pacific Life Insurance Company
Newport Beach, California
A director since 1995

1 Audit Committee
2 Compensation and Executive Personnel Committee
3 Executive Committee
4 Finance Committee
5 Nominating/Corporate Governance Committee

* Except as otherwise indicated, service includes combined Edison International and Southern California Edison Company Board memberships.

† For Southern California Edison Company, a director from 1990-1999; 2003 to present

Management Team

Edison International

John E. Bryson
Chairman of the Board, President and Chief Executive Officer

Bryant C. Danner [6]
Executive Vice President and General Counsel

Thomas R. McDaniel
Executive Vice President,
Chief Financial Officer and Treasurer

Mahvash Yazdi
Senior Vice President,
Business Integration, and
Chief Information Officer

Diane L. Featherstone
Vice President and
General Auditor

Polly L. Gault
Vice President, Public Affairs,
Washington, D.C.

Frederick J. Grigsby, Jr.
Vice President,
Human Resources and Labor Relations

Ronald L. Litzinger
Vice President,
Strategic Planning

Jo Ann Newton
Vice President,
Investor Relations

Thomas M. Noonan
Vice President and
Controller

Barbara J. Parsky
Vice President,
Corporate Communications

Beverly P. Ryder
Vice President,
Community Involvement, and
Corporate Secretary

Anthony L. Smith
Vice President,
Tax

Kenneth S. Stewart
Vice President and
Chief Ethics and Compliance Officer

Southern California Edison Company

John E. Bryson
Chairman of the Board

Alan J. Fohrer
Chief Executive Officer

Robert G. Foster
President

Harold B. Ray
Executive Vice President,
Generation

Pamela A. Bass
Senior Vice President,
Customer Service

John R. Fielder
Senior Vice President,
Regulatory Policy and Affairs

Stephen E. Pickett
Senior Vice President and
General Counsel

Richard M. Rosenblum
Senior Vice President,
Transmission and Distribution

Mahvash Yazdi
Senior Vice President,
Business Integration, and
Chief Information Officer

Robert C. Boada
Vice President and
Treasurer

William L. Bryan
Vice President,
Major Customer Division

Jodi M. Collins
Vice President,
Information Technology

Diane L. Featherstone
Vice President and
General Auditor

Bruce C. Foster
Vice President,
Regulatory Operations

Polly L. Gault
Vice President, Public Affairs,
Washington, D.C.

Frederick J. Grigsby, Jr.
Vice President,
Human Resources and Labor Relations

Harry B. Hutchison
Vice President,
Customer Service Operations

Walter J. Johnston
Vice President,
Power Delivery

Brian Katz
Vice President,
Nuclear Oversight and
Regulatory Affairs

James A. Kelly
Vice President,
Engineering and Technical Services

Russ W. Krieger
Vice President,
Power Production

Thomas M. Noonan
Vice President,
Chief Financial Officer, and
Controller

Dwight E. Nunn
Vice President,
Nuclear Engineering and
Technical Services

Barbara J. Parsky
Vice President,
Corporate Communications

Pedro J. Pizarro
Vice President,
Power Procurement, and
General Manager,
Edison Carrier Solutions

Frank J. Quevedo
Vice President,
Equal Opportunity

Barbara A. Reeves
Vice President,
Shared Services

Anthony L. Smith
Vice President,
Tax

Kenneth S. Stewart
Vice President and
Chief Ethics and Compliance Officer

Raymond W. Waldo
Vice President,
Nuclear Generation

Beverly P. Ryder
Corporate Secretary

Edison Mission Energy

Theodore F. Craver, Jr.
Chairman of the Board, President and
Chief Executive Officer

Georgia R. Nelson [7]
Senior Vice President,
General Manager, and
President, Midwest Generation

W. James Scilacci
Senior Vice President and
Chief Financial Officer

Raymond W. Vickers
Senior Vice President and
General Counsel

Edison Capital

John E. Bryson
Chairman of the Board

Theodore F. Craver, Jr.
Chief Executive Officer

Ashraf T. Dajani [8]
President and
Chief Operating Officer

Larry C. Mount
Senior Vice President,
General Counsel and Secretary

W. James Scilacci
Senior Vice President and
Chief Financial Officer

6 Retiring June 30, 2005
7 Resigning June 1, 2005
8 Retiring June 1, 2005

Shareholder Information

The annual meeting of shareholders will be held on Thursday, May 19, 2005, at 10:00 a.m., Pacific Time, at the Pacific Palms Conference Resort; One Industry Hills Parkway, City of Industry, California 91744.

A description of Edison International's corporate governance practices is available on our Web site at *www.edisoninvestor.com*. The Edison International Board Nominating/Corporate Governance Committee periodically reviews the Company's corporate governance practices and makes recommendations to the Company's Board that the practices be updated from time to time.

The New York Stock Exchange uses the ticker symbol EIX; daily newspapers list the stock as EdisonInt.

Southern California Edison Company's 4.08%, 4.24%, 4.32% and 4.78% Series of $25 par value cumulative preferred stock are listed on the American Stock Exchange under the ticker symbol SCE. Previous day's closing prices, when stock was traded, are listed in the daily newspapers in the American Stock Exchange composite table. The 6.05% and 7.23%[1] Series of the $100 par value cumulative preferred stock are not listed and are traded over-the-counter.

Wells Fargo Bank, N.A., which maintains shareholder records, is the transfer agent and registrar for Edison International's common stock and Southern California Edison Company's preferred stock. Shareholders may call Wells Fargo Shareowner Services, (800) 347-8625, between 7 a.m. and 7 p.m. (Central Time), Monday through Friday, to speak with a representative (or to use the interactive voice response unit 24 hours a day, seven days a week) regarding:

- stock transfer and name-change requirements;
- address changes, including dividend payment addresses;
- electronic deposit of dividends;
- taxpayer identification number submissions or changes;
- duplicate 1099 and W-9 forms;
- notices of, and replacement of, lost or destroyed stock certificates and dividend checks;
- Edison International's Dividend Reinvestment and Direct Stock Purchase Plan, including enrollments, purchases, withdrawals, terminations, transfers, sales, duplicate statements, and direct debit of optional cash for dividend reinvestment; and
- requests for access to online account information.

Inquiries may also be directed to:

Wells Fargo Bank, N.A.
Shareowner Services Department
161 North Concord Exchange Street
South St. Paul, MN 55075-1139

(651) 450-4033

stocktransfer@wellsfargo.com

www.edisoninvestor.com

www.shareowneronline.com

A prospectus and enrollment forms for Edison International's common stock Dividend Reinvestment and Direct Stock Purchase Plan are available from Wells Fargo Shareowner Services upon request.

(1) The 7.23% Series will be redeemed on April 26, 2005.

EDISON
INTERNATIONAL®

2244 Walnut Grove Avenue
Rosemead, California 91770
www.edison.com

Salt River Project
2004 ANNUAL REPORT

Prepare > Deliver > Serve >

Contents

SRP: Power and Water to the Valley

SRP provides electricity to more than 2 million people in a 2,900-square-mile area in the thriving metropolitan Phoenix area known as the "Valley."

SRP also is the Valley's largest water supplier for a service area that spans 375 square miles. In addition, SRP manages the 13,000-square-mile watershed that supplies a majority of the Valley's surface water.

Population growth in the areas served by SRP is robust: Phoenix is the sixth-largest city in the nation, with an annual increase last year of 3.8 percent – three times the national average. The Valley is home to three of the country's fastest-growing large cities – Chandler, Gilbert and Peoria.

With this growth comes many challenges and demands upon SRP to continue as a stable and responsive provider of electricity and water. SRP prepares for the future every day, performing critical functions to deliver reliable power and water, and serving communities in many other ways.

Founded in 1903, SRP is an integrated electric utility, providing generation, transmission and distribution services. It also is the third-largest public power utility in the United States. The Water Users' Association normally delivers more than 1 million acre-feet of water a year.

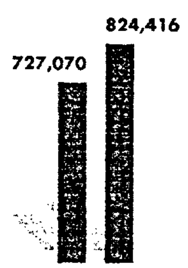
SRP's mission reflects today's challenges: "The mission of Salt River Project is to deliver ever-improving contributions to the people we serve through the provision of low-cost, reliable water and power, and community programs, to ensure the vitality of the Salt River Valley."

Electric Retail Revenues

($million)

Retail revenues were up nearly 10 percent in FY04 from FY03.

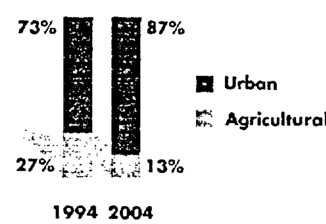
Electric Retail Customers



SRP retail customer growth is up about 13.5 percent over five years.

Urban Land Growth

(% of the total acres)



Commercial and residential development continues its rapid conversion of land within the SRP water service area.

By any measure, the past year was a success for SRP and the communities we serve.

This accomplishment is especially notable considering the greater Phoenix area's population growth. During the year, Phoenix edged closer to the No. 5 position on the list of the nation's largest cities, and our customer base experienced record growth. In the past five years, we have added nearly 100,000 customers – a 13.5 percent increase. The local economy is now in a period of consistent growth. Housing affordability and favorable interest rates, for example, pushed housing permits up more than 30 percent this spring from the previous year – more than double the national average.

Competitive commercial and industrial real estate costs, and a lower cost of living than most large regions, are other notable features of the Valley. In May 2004, Arizona's economy added a net of 3,000 jobs, a pace that promises to gather speed as the economy accelerates.

For the year, SRP's total combined revenues topped $2 billion, with combined net revenues at $112 million. Although some continued difficulties in the local manufacturing sector affected SRP's retail sales, an again-favorable wholesale energy market and weather conditions bolstered total revenues. The year's results help to ensure stable, competitive pricing for our customers and provide resources for our capital projects to support our overall strategic growth plan. Our solid financial performance also allowed us to continue to hold bond ratings of AA and Aa2 from Standard & Poor's and Moody's, a significant accomplishment in today's environment.

The prolonged drought plaguing Arizona brings into perspective the foresight of those who, more than 100 years ago, planned the dams and reservoirs of our water system. This foresight has allowed us to efficiently manage water supplies for the Valley in times of drought as well as in times of plenty. Long-range planning, investment in water supply alternatives, and a gradual increase in water conservation technology and education has allowed us to weather this drought well.

Nonetheless, the future of water in the desert presents its own challenges. As the Valley's primary water steward, we will continue to stay ahead of the curve in our efforts to manage surface and groundwater supplies for the cities, agriculture and other water systems we serve. Water-acquisition activities – through trades, transfers and purchases – will be examined closely, while we continue to protect the water rights of our shareholders.

Our employee volunteer organization is recognized nationally as a model of innovation and effectiveness. In addition to giving time to charitable groups, SRP employees last year contributed more than $1 million to non-profit organizations. SRP is proud to support Arizona's non-profit community, including civic, arts and culture, education, environmental and human service initiatives. Combined with employee contributions, funding to non-profit organizations topped $3 million last year.

At SRP, we know we must always prepare for the future to ensure we deliver the best value to our electric customers, water shareholders, and communities. We look forward to the new year with enthusiasm and continued commitment.

William P. Schrader

William P. Schrader
President

John M. Williams Jr.

John M. Williams Jr.
Vice President

The past year has provided SRP the opportunity to focus on fundamental utility issues, and we have done so with substantial success. From the drought in the Southwest to generating-resource issues, from critical information system needs to pricing, SRP has implemented solutions with favorable results. Residential growth continues at a record pace, while the commercial economy recovers. Progress continues in enhancing efficiency in Western wholesale markets, though retail competition has ceased in Arizona, for now.

With respect to drought, we have learned through 1,000-year-plus tree-ring research that longer dry periods have occurred in the Southwest than previously believed. Therefore, we continue to prepare for prolonged drought, including commissioning further tree-ring research and reduced water allocations. Our reservoirs remain at comfortable levels, thanks to availability of supplemental water from the Colorado River, supplied by the Central Arizona Project. The Colorado River watershed also is in drought, however, so our ability to continue to rely on this supply is in doubt.

SRP has completed construction of new combined-cycle capacity at Kyrene Generating Station, and by 2005, will have done the same at Santan Generating Station. This incremental capacity, importantly, is located in our load center, decreasing transmission risk and improving reliability. In addition, we acquired a recently constructed combined-cycle plant. We had been buying the output of this facility, but its purchase secures use of the resource for the long-term.

During this past year, we focused on resolving infrastructure issues related to increasing reliance on natural gas to fuel power plants. The Federal Energy Regulatory Commission's (FERC) reallocation of capacity on the pipeline that delivers natural gas to our power plants is generally acceptable. We are seeking to develop alternative pipeline and storage options to further secure supply.

Maintaining and adding to our diversified generation, we entered into long-term arrangements for development of new coal-fired generation. SRP signed a long-term purchase agreement from the new third unit at the Springerville station in eastern Arizona and secured rights to construct the fourth unit at that station. These are substantial additions to our "base load" generation and will satisfy the need for this type of generation for many years.

We prepared much of the year to replace our outdated customer information system, in place since the 1970s. The new system, PHOENIX, is up and running, and will allow us to provide new services as we continue to offer outstanding customer service.

SRP's Board, in a pricing process at the end of the fiscal year, reinforced our commitment to renewables by adopting Sustainable Portfolio Principles that combine renewable energy resources with energy conservation programs. Concurrent with the pricing process and in anticipation of the end of "stranded cost" amortization on June 1, 2004, SRP's Board approved an increase in energy prices equal to the decrease in stranded cost amortization. Therefore, while customer bills did not increase, SRP's bottom line will improve as the amortization of these costs end.

The wholesale electric market continues to function, although Congress has yet to agree on comprehensive national energy legislation. FERC now seems to recognize there are regional differences, making different market designs more equitable. Productive efforts continue as we develop a wholesale market acceptable to FERC.

Retail competition experienced a substantial setback when a state appellate court invalidated the Corporation Commission's rules for competition. The ruling currently is on review before the Arizona Supreme Court. Our service territory, while open for competition, has no retail marketers.

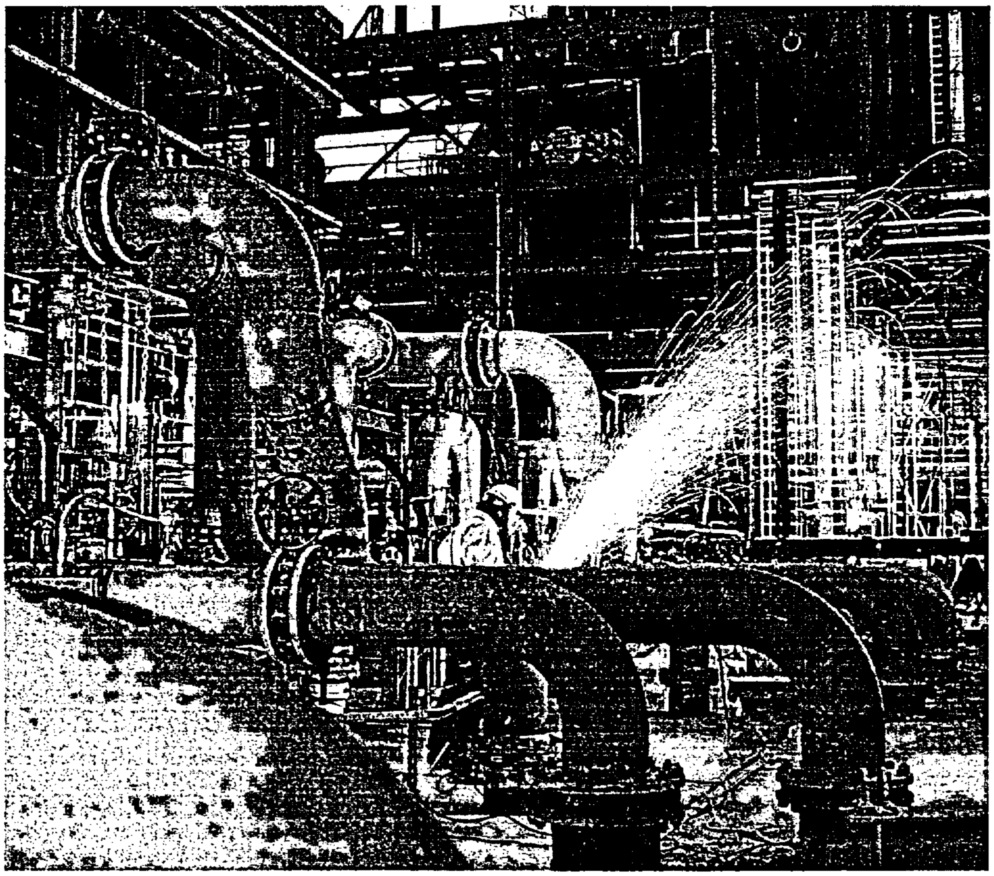
Public power critics have been less vocal this past year as the electric utility industry in many parts of the country, still recovering from the California experience of several years ago, reverts to the vertically integrated utility model and regulation re-emerges.

Strengths of SRP are the men and women who make up our workforce and perform exemplary service for SRP and our communities. We are proud of their contributions. And, we owe appreciation as well to the wisdom and judgment of our elected officials, whose insight and dedication contribute significantly to SRP's success.

Richard H. Silverman

Richard H. Silverman
General Manager

We prepare for the needs of our power customers



Ted Loukota, SRP Operations and Maintenance Specialist, at the Santan Expansion Project

Providing energy that is reliable and affordable – with innovation and superior service – makes SRP a consistent electric industry leader.

With sound risk management and effective planning, SRP continues to achieve excellence in producing energy for a thriving central Arizona marketplace.

Rebounding from an economic slump that affected most of the nation, the greater Phoenix area demands increasing amounts of electricity for new homes, businesses and industries.

Reliable power with real value is a key component of the area's infrastructure that makes it so attractive as a place to live, work and play.

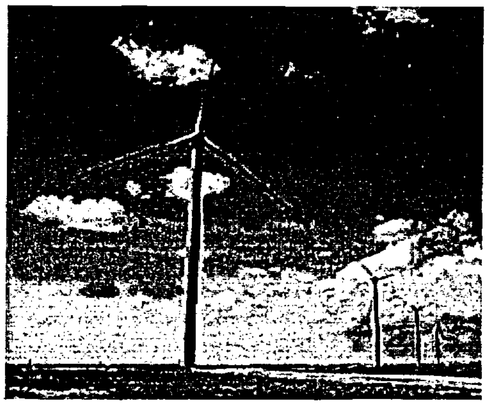
We know what it takes to support a region that outpaces the national average for economic and population growth. In the energy business, planning looks out several years, which is necessary to prepare for future resource needs in generation, transmission and distribution. Investing in the future is a daily occurrence.

New plant serves growth

The Southeast Valley community of Gilbert again topped the list this year of the fastest-growing large cities in the United States. And it is in Gilbert that SRP is building a natural-gas-fired power plant to serve that community and rapidly growing neighboring cities as well.

Chandler, which borders Gilbert on the west, also is among the nation's fastest-growing communities, and it too will benefit from SRP's Santan Expansion Project.

Construction activity on the project reached its peak this spring, with testing beginning on plant equipment in preparation for commercial operation in summer 2005. The plant will offer increased reliability and peaking-capacity for SRP customers in this growing area of the Valley. The project includes $20 million in community and site improvements, and $30 million in environmental controls.



Wind power joins SRP green efforts

SRP maintains a strong commitment to environmental stewardship, this year adding wind power to our "green energy" resources. A five-year contract for 50 MW of wind-produced energy and associated renewable-energy credits with Public Service Company of New Mexico provides enough power to serve several thousand homes.

The power is produced at the New Mexico Wind Energy Center about 170 miles southeast of Albuquerque. With this addition, SRP's total renewable capacity now is 80 MW and includes electricity generated from geothermal, low-head hydro, solar and landfill gas sources.

The number of wind farms in the U.S. has increased substantially in the past few years, generating an estimated 5,000 MW – enough to power up to 750,000 homes. SRP will continue to evaluate other renewable energy resource opportunities in Arizona and the Southwest.

This year, SRP's generating resources, including owned and purchased power, total 7,035 megawatts (MW). Our build-and-purchase activities of the past few years position us well to meet expected retail growth and to maintain adequate reserves through this decade.

As a plant owner and operator, SRP is able to control costs and maximize value to our retail customers. By 2005, we will have completed two new urban generating facilities in five years, representing 800 MW in new SRP resources. Both plants will serve the Valley, and in particular the southeastern-most reaches of our service area where two of the nation's fastest-growing cities are located. The first facility became operational in 2002; commercial operation of the second project begins in summer 2005. SRP is sole owner and operator of both facilities.

We also assumed ownership and operation of the natural-gas-fired Desert Basin Generating Station in the community of Casa Grande south of Phoenix, which adds in excess of 550 MW to our capacity. Favorable market conditions allowed SRP to finance a purchase of the plant, rather than obtaining output through a purchase-power contract.

In addition, SRP has procured 100 MW from a coal-fired facility under construction in eastern Arizona, the Springerville Generating Station. This resource will be available in 2006. We also acquired a development option for another unit at the facility, providing SRP with substantial flexibility in fuel diversity.

A diversified and balanced fuel mix with adequate and reliable supplies becomes increasingly important as demand grows. Our customers receive important economic and reliability benefits from a mix of power plants that use coal, natural gas, hydro, nuclear and renewable energy. Essentially all of our coal and nuclear fuel is purchased through long-term contracts; coal-fired plants produce about 60 percent of SRP's power. Our coal supplies were augmented last year with a new long-term agreement from mines in Wyoming and Montana for use at our Coronado Generating Station. This new supply proved more economically feasible than developing the planned Fence Lake Coal Mine in New Mexico.

Natural gas plays an important role at SRP's peak-demand plants in the Valley. Nationally, the demand for natural gas continues to grow while the addition of new supplies has been limited. From a procurement perspective, SRP is working to manage volatility in natural gas prices, as well as establishing adequate delivery options, including pursuing local gas storage possibilities to ensure that peak generation requirements are met. Local gas storage will help SRP on days when fuel demands are high due to climate conditions.

Transmission development continues across SRP's service area, improving our import levels and load-serving capabilities. Most recently, SRP gained regulatory approval for the first section of a 500 kilovolt (kV) transmission line project that will reach from the area of Palo Verde Nuclear Generating Station in the far West Valley to the Southeast Valley. The 50-mile section will consist of two 500 kV lines, with the

first line scheduled to be in operation in 2006. Siting for the remainder of the project continues, with an expected completion date of 2011. Partners in the project include SRP as project manager, Arizona Public Service Co., Tucson Electric Power Co. and the Santa Cruz Water and Power Districts Association.

This is the first major project sited and permitted as a direct result of the Central Arizona Transmission System Study (CATS), a three-phase effort that takes a collaborative, regional approach to transmission development. The study, conducted by several of the state's electric utilities, generators and regulators, addresses the increasing energy demands created by rapid business and residential growth in the central Arizona and Tucson areas during the past decade. The major conclusion: transmission in central Arizona requires significant expansion.

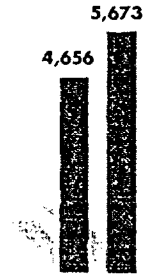
SRP's capital plan for distribution projects focuses on customer growth and maintenance, all in the interest of providing low-cost, reliable energy. Electrical system expansion will require upgrades to the distribution system including 38 substation transformers planned through 2010, many located in the remote reaches of our service area. A major underground cable-replacement effort continues: over the past nine years, SRP has replaced nearly 9 million feet of primary distribution cable, and will continue with nearly 1 million feet this year. That will bring new cable replacement to about 25 percent of SRP's 40 million feet existing.

Other upgrades include an ongoing effort to replace aging 69 kV system wood poles with steel poles where appropriate, to improve reliability and public safety especially during the high winds associated with the Valley's summer monsoon season.

While disruptions in service are inevitable in the distribution segment of the business, especially weather-related interruptions, SRP consistently ranks favorably among utilities in terms of outage times and occurrences. For example, most SRP customers averaged 1.3 interruptions a year, with a typical duration of 44 minutes. According to the most recent Large City Reliability Survey, customers in other metropolitan areas often endured more outages of longer durations.

Energy efficiency for our customers makes good sense. We provide a range of products and services designed to help customers save money and control their energy use. For example, this past year two of our school

SRP System Peak
(MW)



Peak demand on the SRP electric system has jumped 22 percent in five years.

Putting power in the hands of our electric customers pays off

Prepaying for electricity is an idea whose time has come. With an in-home display and a smart card, SRP's M-Power Program® makes electricity tangible to customers. In fact, 95 percent of our prepay customers tell us that they have gained control of their electricity costs; they also cut their electric use by an average of 10 percent compared with conventional payment programs.

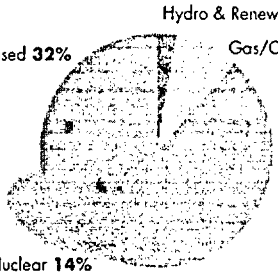
SRP M-Power is the largest prepay plan in North America, with 33,500 customers and growing. This year, we signed an agreement with a metering company in the United Kingdom to develop new equipment for the program.

Our goal is to add 10,000 participants per year, a pace that will allow us to provide the best service and value. We include the M-Power program in our Sustainable Energy Portfolio to underscore its advantages in energy conservation.

district customers saved a combined $1 million through energy-efficiency efforts implemented with our guidance and assistance.

As a summer-peaking utility, SRP for many years has made efforts to balance the summer-winter load relationships through seasonal price differentials. This means prices rise in the summer and drop in the winter. Consequently, we encourage customers to sign up for SRP's Time-of-Use Price Plans, which reward off-peak power use with financial incentives. About 20 percent of our residential and 7 percent of our commercial customers participate, saving as much as 10 percent off their annual electric bills.

SRP Generation Resources FY04*



**Total does not equal 100% due to rounding*

Another customer-friendly offering is SRP's Earthwise Energy Program™, in which participants pay a small premium on their monthly electric bill to support the continued development of clean energy technologies. We added 1,300 new participants this past year, bringing participation to 4,500 SRP electric customers, both commercial and residential.

SRP electric customers enjoy exceptional value for their energy dollar. Even with an estimated 1.5 percent overall price increase to be effective November 2004, SRP's retail electric prices across all customer classes remain among the lowest in the Southwest.

Nicole Knox, SRP Commercial Customer Service Representative

Customers tell us they like our service—again and again

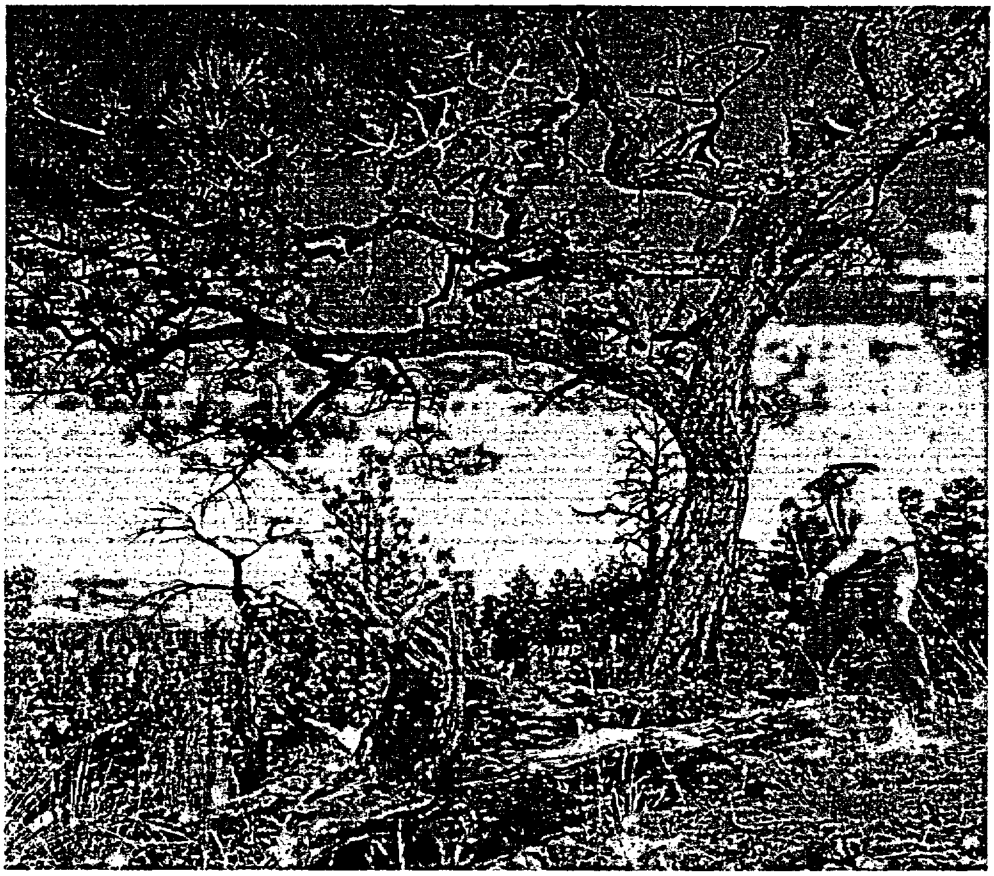
SRP's success in providing high-value customer service and reliable, low-cost power was recognized again this year by J.D. Power and Associates.*

Our business customers rated us No. 1 in customer satisfaction among the largest electricity providers in the United States. The 2004 Electric Utility Business Customer Satisfaction Study by J.D. Power and Associates placed SRP first in business customer satisfaction in the West. Also, for the past three years, SRP scored highest in customer satisfaction for residential electric service among electricity providers in the western U.S.

Our customer service efforts aim to make it easy and convenient to do business with us while providing value through reduced costs and increased efficiency.

**J.D. Power and Associates is a global marketing information services firm operating in key business sectors including market research, forecasting, consulting, training and customer satisfaction.*

We deliver a secure water supply



Dave Meko, Research Specialist Principal, UofA Laboratory of Tree-Ring Research

Trees "talk" of the past

Trees have a story to tell about drought, and tree-ring research allows us to listen.

The University of Arizona's Laboratory of Tree-Ring Research is using an SRP grant to analyze tree rings in the Salt, Verde and Upper Colorado river basins to provide a historic look at the duration and frequency of droughts in the SRP and Colorado watersheds.

By looking back 1,000 years, tree-ring research may help SRP determine how the available water supplies have varied over time, as well as how to devise a management tool to aid water supply decision-making. SRP will share the research findings with the Arizona Department of Water Resources, the Central Arizona Project, the U.S. Bureau of Reclamation and Valley cities.

Responsible management of the Valley's water resources marks SRP's past, present and future.

Our water stewardship is the one constant that has protected the Valley's ability to grow and prosper for more than 100 years. As the Valley's largest water supplier, SRP manages and delivers water to cities, agricultural users and urban irrigators. Several reservoirs and a watershed that spans 13,000 square miles typically supply the bulk of SRP's total deliveries to the greater Phoenix area.

Today, with drought as the key issue for the Valley's water situation, surface water levels are low in SRP reservoirs. Nine years of drought on the watershed of the Salt and Verde rivers has taken a toll on surface water supplies.

It is important to note that the Valley's water supplies for the near future are adequate. However, the drought has sharpened concern for ensuring a supply for the future. Buffeting this concern is the understanding that droughts are a normal desert occurrence, and the knowledge that a few years of above-average

precipitation could fix the problem.

Unfortunately, it is impossible to accurately predict how long this drought will last. So the question becomes, are we doing what needs to be done to endure the drought and address the implications it could have for the future? For SRP's part, the answer is a resounding "Yes."

SRP has developed a water storage, management and delivery system that has allowed us to support metropolitan Phoenix through many unusual years – both very dry and very wet. We play a role in the management and/or use of the three primary water sources available: surface water, groundwater, and Central Arizona Project (CAP) water from the Colorado River.

Typically, SRP surface water provides more than two-thirds of our water deliveries; this year it was less than 40 percent. About 34 percent of deliveries came from increased groundwater pumping. CAP water this year continued as a critical supplement, accounting for about 32 percent of SRP's total water deliveries. It was the sixth consecutive year that SRP utilized this supplemental supply. Excess CAP water also is being stored underground *(See article below)*.

In addition, to preserve existing surface supplies, SRP maintained a reduced water allocation to shareholders of 2.0 acre-feet/per acre annually for the second consecutive year. This means that all of our water recipients – cities, agriculture and urban irrigators – are receiving one-third less water from SRP. The immediate impact has been minimal, however. Supplies remain sufficient for most Valley communities, and shareholders can acquire supplemental water where needed from other sources.

The same cannot be said for much of rural Arizona, however, where the drought is having its most severe impact. In some areas on the watershed, expanding populations and limited potable water resources are creating divergent claims to the same resources already held by SRP shareholders, which include metropolitan Phoenix-area municipalities. We monitor activities in the watershed to protect our shareholders' water rights, and we continue to contest unauthorized activities that affect our supply. The fact is, every acre-foot diverted without rights from the watershed is an acre-foot lost to the Valley.

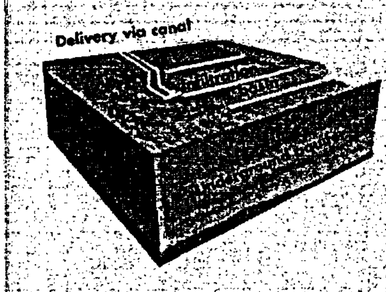
Cooperative efforts also are underway between the private and public sectors to assist rural areas with current and future water issues. SRP is offering technical assistance and helping these areas with water transfer and exchange possibilities. Also, a governor-appointed task

Rim lake could join SRP water system

In another effort to maintain ample water for the Valley, SRP is negotiating to acquire the Blue Ridge Reservoir from the Phelps Dodge Corporation under the terms of a 1962 agreement. The reservoir is about 125 miles north of Phoenix on the Coconino National Forest in an area known as the Mogollon Rim, and has the infrastructure to transfer water into the Verde River basin. The Verde River is a major supply of surface water to the Valley.

The purchase would include the reservoir, a dam, and related facilities such as land, a pumping station, and a small hydroelectric plant. The canyon-bound public lake has a capacity of 15,000 acre-feet, and the area is popular for fishing, boating and hiking. With the acquisition of Blue Ridge, SRP would then manage the water supply of seven reservoirs for the Valley.

Saving water for the future with underground recharge



Schematic of underground water storage

Innovative solutions to water management in Arizona include underground recharge projects. This year SRP began its second major project of this type to help secure future water supplies.

These direct-surface recharge efforts deliver water into infiltration basins, where it seeps into the underground aquifer. This serves to store excess surface water supplies for the future while recharging depleted underground aquifers, which have been affected by the drought due to increased groundwater pumping.

Over the past five years, SRP has stored nearly 400,000 acre-feet of surface water – enough to serve up to a half-million people for a full year – at the Granite Reef Underground Storage Project, a recharge project in the East Valley. This year's new project, located in the rapidly growing West Valley, will have an annual recharge capacity of 75,000 acre-feet. Expected to be in operation by mid-2005, the new project is the cooperative effort of SRP and three Valley cities.

force of state agencies and legislative leaders is developing a statewide drought plan, focusing first on the hard-hit rural areas. SRP has loaned a water resource engineer for one year to help with the plan, which will identify vulnerabilities and suggest ways to reduce impacts and assist stakeholders. A first draft of the plan is expected in the fall of 2004.

All three state universities are involved in drought studies. This year, SRP extended its financial support to Northern Arizona University for a water supply-and-demand study of the watersheds of northern and central Arizona. We also provided a research grant to the University of Arizona's Laboratory of Tree-Ring Research, the world's largest dendrochronology lab.

A significant milestone in our responsibility to safeguard water rights was achieved this past year when SRP's Governing Board, the Gila River Indian Community, and about 30 other interested parties reached an agreement to settle the Gila Community's water rights claims. The settlement, which took nearly 15 years to negotiate, creates the terms to resolve the largest Indian water rights claims in Arizona.

In addition, the second phase of water rights settlement for the Zuni Heaven Reservation was completed. Federal approval paves the way for the next and last phase of the settlement, which clarifies SRP's ability to continue to operate wells to serve the Coronado Generating Station near St. Johns, Ariz.

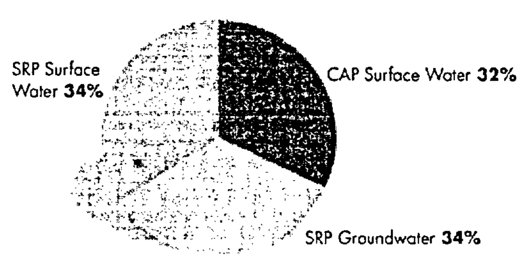
With each and every settlement that is made, Arizona's water future becomes more certain.

And, as Arizona develops a "culture of conservation," SRP has formulated a strategy to encourage the wise use of water resources. Our strategy has three main objectives:

- Conduct effective consumer outreach communications to build awareness and commitment
- Enhance relationships with cities and other water planning agencies by partnering in conservation efforts and programs
- Encourage the use of products and programs that promote a public conservation ethic and wise-water stewardship.

SRP's Blueprint for Water Management: Your Role in the Valley's Water Future explains the need for sound planning strategies and the public's role in making a difference. To learn more about The Blueprint, visit our Web site, **www.srpnet.com/blueprint.**

SRP Water Deliveries*



**Water data is for calendar year 2003*

We serve our communities

Grants support learning

Life Sciences teacher Susan Holt at Supai Middle School in Scottsdale seized the opportunity to apply for a Learning Grant by SRP. This spring, her school received nearly $5,000 for much-needed laboratory equipment and supplies to support the study of molecular biology and genetic technology.

Learning Grants by SRP support schools in Arizona through programs or projects that seek to improve student proficiency in math, science and technology.

From left, Life Sciences teacher Susan Holt, students Adrian Lopez, Nina Porter and Sierra Orozco

Serving our communities is a main tenet of SRP's mission statement. In fact, we have been an active supporter of our local communities – and Arizona – for more than 100 years. During that time, we have dedicated substantial resources to provide for the people who live, work and play here.

Today, when we ask our electric customers and water shareholders where we should focus our support, they tell us "youth education." We continue to increase our emphasis on education efforts for children in grades K-12. Our focus is threefold: classroom opportunities for students, teacher development and enrichment, and leadership activities in educational organizations.

This past year, we reached more than 200,000 children across Arizona with hands-on help and financial grants to broaden their school experiences. SRP extended nearly $750,000 in educational support through grants and gifts.

We have developed many opportunities with new programs and ideas that are meaningful and fun for schoolchildren. For example, the Learning Grants by SRP Program this year offers students and teachers funding support for in-school projects and equipment.

Among these was a grant to a Glendale elementary school to develop "math packs" that can be used at home to help young students learn basic addition, subtraction, multiplication and division.

We also continued a special employee-grant program that began during our centennial year in 2003. The SRP Employee Community Service Grant program allows employee volunteers to go beyond the usual time and energy they donate by addressing a specific need in the community. SRP provides the funding, and employees enlist the help of co-workers who volunteer their time to complete the projects. For example, one grant this year will be used to build back-to-work facilities for a men's homeless shelter in Mesa.

SRP's Arizona Heritage Project, also launched during our centennial year, is a unique opportunity for high school students across the state to explore the cultural threads of their communities with the help of local libraries and museums. SRP is proud to partner with the American Folklife Center at the Library of Congress, where the students' final projects will be archived for future generations.

We also recognized the outstanding academic achievements of three Arizona high schools where students demonstrated excellence through their participation in state academic competitions. The SRP Academic Marathon winners – two schools in Mesa and one in Tucson – received grants for math, science and technology improvements and for teacher participation and enrichment.

Our community outreach efforts extend to non-profit organizations in the arts, environment, and social service. For example, we offered funding to Chicanos Por La Causa for their annual fundraising event, and helped to bring a special exhibit of bronze works by Edgar Degas to the Phoenix Art Museum for the enjoyment of our communities.

All told, during the year $3.4 million was provided to non-profit programs in the communities we serve – $2.3 million in SRP funding and $1.1 million from employee donations. Contributions last year supported more than 300 non-profit organizations in Arizona.

Courtney Rickard, left, SRP employee Mellissa Gauman, center, and Reilly Gauman

Water safety saves lives

At SRP, we put our energy into saving young lives. Always committed to community safety, SRP takes a very active role in water safety education programs. Drowning is the number one cause of death for children in Arizona under age 5.

SRP, in community partnerships and through its own outreach efforts, promotes public awareness of the need for water safety and CPR, for children, parents and caregivers. Through SRP Safety Connection™, we provide a comprehensive water safety program that offers public education through events, communications and other opportunities. One of these is Target Zero, whose sponsors include SRP, local firefighter organizations and *The Arizona Republic*.

SRP VOLUNTEERS Margaret Burt, left, David Daer and Sharon Rawls

SRP VOLUNTEERS reach out to organizations across Arizona

The cornerstone of SRP's culture of community service is our employee volunteer program. To this point: SRP employees and their friends and family members collectively contributed 700,000 volunteer hours last year.

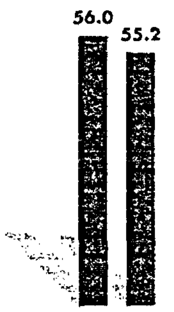
Through corporate-sponsored SRP VOLUNTEERS and their own efforts, our employees are dedicated to helping communities grow and prosper. From building houses to repairing agency facilities, supporting youth sports and staffing charitable events, SRP employees have developed an outstanding reputation in Arizona for their generous and capable volunteer efforts.

Some of the non-profit groups that realized SRP VOLUNTEERS support this past year were the Phoenix Zoo, Make A Difference, Andre House, and the Scottsdale Cultural Council, to name just a few.

Remarkably, more than 85 percent of SRP employees are involved in their communities in some way, often providing service that community-based organizations otherwise would not be able to afford.

This section explains the general financial condition and results of operations for SRP for fiscal year 2004. SRP includes the Salt River Project Agricultural Improvement and Power District (the "District"), its subsidiaries, and the Salt River Valley Water Users' Association. The results of these entities are combined for financial reporting purposes.

Debt Ratio
(percent)



Although SRP's level of long-term debt increased slightly as a result of financing the purchase of the Desert Basin generating facility, SRP's debt ratio showed a slight improvement this past year due to strong net revenues increasing SRP's equity.

Overview of Business

The District owns and operates an electric system which generates, transmits and distributes electricity to residential, commercial, industrial and agricultural power users in a 2,900-square-mile service territory spanning portions of Maricopa, Gila and Pinal counties, as well as mining loads in an adjacent 2,400-square-mile area in Gila and Pinal counties.

The District remains a vertically integrated organization. It is developing additional generation, transmission and distribution resources to keep pace with retail load growth. To meet resource needs, the District pursues building new generation, short- and long-term purchases of existing generation resources, and refinements to its conservation programs.

For example, during the past fiscal year the District completed negotiations for 100 megawatts (MW) of output from the Unit Three expansion of the Springerville Generating Station in Springerville, Ariz. Additionally, the District obtained the rights to build a 400 MW coal-fired unit (Unit Four) in the future on the same site. This development is subject to numerous conditions and no assurance can be given that such conditions will be satisfied.

SRP manages a system of dams and reservoirs, and has responsibility for the construction, maintenance and operation of a supply system to deliver water for irrigation and municipal treatment purposes. It provides the water supply for an area of approximately 248,200 acres located within the major portions of the cities of Phoenix, Avondale, Glendale, Mesa, Tempe, Chandler, Gilbert, Peoria, Scottsdale and Tolleson.

The District's subsidiaries include New West Energy Corp., which supports the District's energy services activities in Arizona; Papago Park Center, Inc., which manages a mixed-use commercial development known as Papago Park Center on land owned by the District adjacent to its administrative offices; and SRP Captive Risk Solutions, Ltd., which is a domestic captive insurer incorporated in January 2004 to access property/boiler and machinery insurance coverage under the Federal Terrorism Risk Insurance Act of 2002 for certified acts of terrorism.

Results of Operations

SRP's combined net revenues for the fiscal year ended April 30, 2004, were $112.2 million compared to $46.7 million for the previous year. Operating revenues were $2.1 billion for FY04, compared to $1.9 billion for FY03. The increased revenue this past year principally was due to continued growth in the greater Phoenix metropolitan area, weather conditions and the fuel and purchase power adjustment mechanism.

Specifically for SRP:

• Total customers increased 3.5 percent from the previous year with 91 percent of the increase occurring in the residential class of customers.

• With this year's warmer summer months and cooler winter months, degree hours were 9.2 percent more than in the previous year. Degree hours are the sum of degrees outside the comfort range of 65 to 75 degrees (above or below that range) for each hour.

• The fuel and purchase power adjustment mechanism contributed $48.4 million more in revenues than the prior year.

Operating expenses were $1.9 billion for the year, compared to $1.7 billion for FY03. Some of the major variances from last year were:

• Operations expenses increased due to internal technology services projects, and increased costs of employee benefits.

• Maintenance costs increased 29.5 percent due to the completion of several maintenance projects postponed during FY03. Additionally, significant turbine repairs were necessary at both the Agua Fria and Desert Basin generating stations during FY04.

• Fuel expense also increased due to higher natural gas prices than in the prior year.

In water operations, delivery revenues were $11.8 million compared to $12.4 million the previous year, due to continuing drought conditions.

Accounting Issues

The District adopted Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143), on May 1, 2003. SFAS No. 143 requires the recognition and measurement of liabilities for legal obligations associated with the retirement of tangible long-lived assets. Under the standard, these liabilities are recognized at fair value as incurred and capitalized as part of the cost of the related tangible long-lived assets. Accretion of the liabilities, due to the passage of time, is an operating expense and the capitalized cost is depreciated over the useful life of the long-lived asset. Retirement obligations associated with long-lived assets included within the scope of SFAS No. 143 are those for which a legal obligation exists under enacted laws, statutes, and written or oral contracts, including obligations arising under the doctrine of promissory estoppel. For a detailed explanation of the effects of SFAS No. 143 on the District's financial results and other recently issued accounting standards, see Note 2 in the accompanying Notes to the Combined Financial Statements.

Energy Risk Management Program

The District's mission to serve its retail customers is the cornerstone of its risk management approach. The District builds or acquires resources to serve retail customers – not the wholesale

Net Financing Costs
($thousands)

A decrease in SRP's net financing costs in FY04 is attributed primarily to reduced interest expenses on bonds and other obligations.

market. However, as a summer-peaking utility, there are times when the District's resources and/or reserves are in excess of its retail load, thus giving rise to some wholesale activity. The District has an Energy Risk Management Program to limit exposure to risks inherent in normal retail and wholesale energy business operations by measuring and minimizing exposure to market risks, credit risks and operating risks. To meet the goals of the Energy Risk Management Program, the District uses various physical and financial instruments, including forward contracts, futures, swaps and options. Certain of these transactions are accounted for under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." For a detailed explanation of the effects of SFAS No. 133 on the District's financial results, see Note 3 in the accompanying Notes to the Combined Financial Statements.

The Energy Risk Management Program is managed according to a policy approved by the District's Board of Directors (Board), and is overseen by a "Risk Oversight Committee." The policy covers areas such as strategies, specific price and control risk issues, and the credit policy that the District applies to its wholesale counter parties. The Risk Oversight Committee is composed of senior executives. The District maintains an "Energy Risk Management Department," separate from the energy marketing area, that regularly reports to the Risk Oversight Committee. In addition, the District has established a credit reserve for its activity in wholesale markets. The District believes that its existing risk management structure is appropriate and that any exposures are adequately covered by existing reserves.

Electric Pricing

The District has a diversified customer base, with no single retail customer providing more than 1.4 percent of its operating revenues. The District has implemented projects and programs geared towards enhancing customer loyalty by offering a range of pricing and service options. Moreover, the District is one of the low-price leaders in the Southwest.

The District is a summer-peaking utility and for many years has made an effort to balance the summer-winter load relationships through seasonal price differentials. In addition, the District prices on a time-of-day basis for large commercial and industrial, and certain residential and small commercial users.

On Oct. 6, 2003, the District's Board approved a change to the fuel and purchase power adjustment mechanism effective Nov. 1, 2003. The adjustment charge, a direct pass-through of expenses, resulted in an average annual increase in retail customer bills of 3.6 percent.

On April 26, 2004, SRP's Board approved a 1.5 percent increase in retail electric prices effective Nov. 1, 2004. This is the first general increase in prices in more than 10 years.

Capital

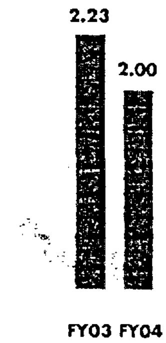
The Capital Improvement Program is driven by the need to expand the generation, transmission and distribution systems of the District to meet growing customer electricity needs and to maintain a satisfactory level of service reliability. Of the total Capital Improvement Program, 29 percent of the funds are directed to generation projects. These include: the potential construction of Unit Four at the Springerville Generating Station; improvements required for continued operation at Mohave Generating Station in southern Nevada; the expansion of the Santan Generating Station in the southeast portion of the District's service territory; and, the replacement of steam generators at the Palo Verde Nuclear Generating Station. Another 33 percent of the funds are for expansion of the electrical distribution system to meet new growth and to replace aging underground cable. The addition of new 69 kilovolt transmission facilities and the construction of a new high-voltage transmission line account for an additional 7 percent of the funds. The plan also allocates funding for uncertain future projects at various generating stations.

The District pays a portion of the cost for its Capital Improvement Program from internally generated funds and a portion from the proceeds of Revenue Bonds.

Desert Basin Generating Station

In fiscal year 2001, the District entered into a 10-year contract with Reliant Energy Desert Basin, LLC (Reliant) for the long-term exclusive purchase of power produced at Desert Basin Generating Station south of Phoenix. The amount of capacity available to the District was in excess of 500 MW annually. In October 2003, the District acquired a 100 percent interest in the generating station from Reliant for $282.5 million and assumed operations, thereby terminating the long-term purchase power agreement with Reliant. The purchase was financed through the Desert Basin Lease-Purchase Agreement, via a transfer of the assets to the Desert Basin Independent Trust, and the issuance of Certificates of Participation. For further explanation of the Desert Basin Lease-Purchase Agreement, see Note (5) Long-term Debt and Note (9) Capital Lease in the accompanying Notes to the Combined Financial Statements.

Debt Service Coverage Ratio



SRP's debt service coverage ratio dipped slightly as a result of larger debt principal payments in FY04 than in FY03. These larger payments were due to intentionally accelerating the retirement of generation- and transmission-related debt as part of SRP's recent recapitalization plan effort.

COMBINED BALANCE SHEETS

As of April 30, 2004 and 2003 (Thousands)

Assets	2004	2003
UTILITY PLANT		
Plant in service –		
Electric	$ 7,284,080	$ 6,927,360
Irrigation	252,595	242,156
Common	417,006	403,752
Total plant in service	7,953,681	7,573,268
Less – Accumulated depreciation on plant in service	(3,721,311)	(3,536,026)
	4,232,370	4,037,242
Plant held for future use	14,341	20,399
Construction work in progress	739,295	556,217
Nuclear fuel, net	40,503	41,692
	5,026,509	4,655,550
OTHER PROPERTY AND INVESTMENTS		
Non-utility property and other investments	131,507	96,556
Segregated funds, net of current portion	437,919	516,205
	569,426	612,761
CURRENT ASSETS		
Cash and cash equivalents	280,962	397,641
Temporary investments	60,750	57,925
Current portion of segregated funds	96,756	137,767
Receivables, net of allowance for doubtful accounts	177,664	168,970
Fuel stocks	33,257	35,281
Materials and supplies	72,875	65,087
Other current assets	62,166	39,530
	784,430	902,201
DEFERRED CHARGES AND OTHER ASSETS	332,577	466,873
	$ 6,712,942	$ 6,637,385

The accompanying notes are an integral part of these combined financial statements.

As of April 30, 2004 and 2003 (Thousands)

Capitalization and Liabilities	2004	2003
LONG-TERM DEBT	$ 2,933,338	$ 2,809,581
ACCUMULATED NET REVENUES AND OTHER COMPREHENSIVE INCOME	2,381,390	2,203,928
TOTAL CAPITALIZATION	5,314,728	5,013,509
CURRENT LIABILITIES		
Current portion of long-term debt	170,029	260,428
Accounts payable	126,651	142,621
Accrued taxes and tax equivalents	67,177	64,174
Accrued interest	45,796	54,398
Customers' deposits	49,659	40,157
Other current liabilities	151,999	147,741
	611,311	709,519
DEFERRED CREDITS AND OTHER NON-CURRENT LIABILITIES	786,903	914,357
COMMITMENTS AND CONTINGENCIES (Notes 5, 7, 8, 9, 10, 11 and 12)		
	$ 6,712,942	$ 6,637,385

The accompanying notes are an integral part of these combined financial statements.

COMBINED STATEMENTS OF NET REVENUES & COMPREHENSIVE INCOME (LOSS)

For the years ended April 30, 2004 and 2003 (Thousands)

	2004	2003
OPERATING REVENUES	$ 2,077,314	$ 1,893,549
OPERATING EXPENSES		
Power purchased	310,019	293,641
Fuel used in electric generation	406,034	395,683
Other operating expenses	436,541	362,123
Maintenance	196,588	151,834
Depreciation and amortization	417,522	435,815
Taxes and tax equivalents	100,693	90,388
Total operating expenses	1,867,397	1,729,484
Net operating revenues	209,917	164,065
OTHER INCOME (EXPENSES)		
Interest income	23,573	29,192
Other income (expenses), net	5,042	(1,725)
Total other income (expenses), net	28,615	27,467
Net revenues before financing costs	238,532	191,532
FINANCING COSTS		
Interest on bonds	131,264	139,844
Capitalized interest	(23,327)	(16,770)
Amortization of bond discount/premium and issuance expenses	(9,386)	(6,511)
Interest on other obligations	17,054	21,572
Net financing costs	115,605	138,135
NET REVENUES BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	122,927	53,397
CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	(10,707)	(6,728)
NET REVENUES	112,220	46,669
OTHER COMPREHENSIVE INCOME (LOSS)	65,242	(144,831)
COMPREHENSIVE INCOME (LOSS)	$ 177,462	$ (98,162)

The accompanying notes are an integral part of these combined financial statements.

For the years ended April 30, 2004 and 2003 (Thousands)

	2004	2003
CASH FLOWS FROM OPERATING ACTIVITIES		
Net revenues	$ 112,220	$ 46,669
Adjustments to reconcile net revenues to net cash provided by operating activities:		
Depreciation and amortization	417,522	435,815
Post-retirement benefits expense	43,800	36,900
Amortization of provision for loss on long-term contracts	(13,281)	(13,281)
Amortization of net bond discount/premium and issuance expenses	(9,386)	(6,511)
Amortization of spent nuclear fuel storage	1,641	1,562
Decommissioning accretion	10,761	–
Cumulative effect of change in accounting principle	10,707	6,728
Other, net	–	233
Decrease (increase) in –		
Fuel stocks and materials & supplies	(5,764)	5,307
Receivables, including unbilled revenues, net	(8,694)	(28,127)
Other assets	(35,483)	(37,267)
Increase (decrease) in –		
Accounts payable	(15,970)	20,894
Accrued taxes and tax equivalents	3,003	6,353
Accrued interest	(8,602)	13,417
Other liabilities, net	111,929	10,568
Net cash provided by operating activities	614,403	499,260
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to utility plant, net	(628,158)	(512,887)
Purchases of securities	(213,586)	(135,773)
Sales and maturities of securities	174,851	282,311
Net cash used for investing activities	(666,893)	(366,349)
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from issuance of revenue bonds	122,110	876,450
Proceeds from Desert Basin finance lease	282,680	–
Retirement of commercial paper	–	(150,000)
Repayment of long-term debt, including refundings	(356,224)	(843,490)
Payment of capital lease obligation	(251,365)	(25,334)
Increase in segregated funds	138,610	(187,419)
Net cash used for refinancing activities	(64,189)	(329,793)
NET DECREASE IN CASH AND CASH EQUIVALENTS	(116,679)	(196,882)
BALANCE AT BEGINNING OF YEAR IN CASH AND CASH EQUIVALENTS	397,641	594,523
BALANCE AT END OF YEAR IN CASH AND CASH EQUIVALENTS	$ 280,962	$ 397,641
SUPPLEMENTAL INFORMATION		
Cash Paid for Interest (Net of capitalized interest)	$ 133,593	$ 131,229
Non-cash Financing Activities		
Loss on defeasance	$ (3,990)	$ 45,289

The accompanying notes are an integral part of these combined financial statements.

(1) Basis of Presentation:

The Company – The Salt River Project Agricultural Improvement and Power District (the District) is an agricultural improvement district organized in 1937 under the laws of the State of Arizona. It operates the Salt River Project (the Project), a federal reclamation project, under contracts with the Salt River Valley Water Users' Association (the Association), by which it has assumed the obligations of the Association to the United States of America for the care, operation and maintenance of the Project. The District owns and operates an electric system that generates, purchases, transmits and distributes electric power and energy, and provides electric service to residential, commercial, industrial and agricultural power users in a 2,900 square mile service territory in parts of Maricopa, Gila and Pinal Counties, plus mine loads in an adjacent 2,400 square mile area in Gila and Pinal Counties. The Association, incorporated under the laws of the Territory of Arizona in 1903, operates an irrigation system as the agent of the District.

In 1997, the District established a wholly-owned, taxable subsidiary, New West Energy Corporation (New West Energy), to market, at retail, energy available to the District that was surplus to the needs of its retail customers, and energy that might have been rendered surplus in Arizona by retail competition in the supply of generation. However, as a result of several factors including the turmoil in the California energy market, New West Energy has discontinued marketing excess energy, although it may resume this activity in the future. New West Energy now primarily supports the District's energy services activities in Arizona.

Possession and Use of Utility Plant – The United States of America retains a paramount right or claim in the Project that arises from the original construction and operation of certain of the Project's electric and water facilities as a federal reclamation project. Rights to the possession and use of, and to all revenues produced by, these facilities are evidenced by contractual arrangements with the United States of America.

Principles of Combination – The accompanying combined financial statements reflect the combined accounts of the Association and the District (together referred to as SRP). The District's financial statements are consolidated with its three wholly-owned taxable subsidiaries, New West Energy, SRP Captive Risk Solutions, Limited (CRS) and Papago Park Center, Inc. (PPC). PPC is a real estate management company. CRS is a domestic captive insurer incorporated in January 2004 to access property/boiler and machinery insurance coverage under the Federal Terrorism Risk Insurance Act of 2002 for certified acts of terrorism. All material inter-company transactions and balances have been eliminated.

Regulation and Pricing Policies – Under Arizona law, the District's publicly elected Board of Directors (the Board) has the authority to establish electric prices. The District is required to follow certain public notice and special Board meeting procedures before implementing any changes in the standard electric price plans.

(2) Significant Accounting Policies:

Basis of Accounting – The accompanying combined financial statements are presented in conformity with accounting principles generally accepted in the United States of America (GAAP) and reflect the pricing policies of the Board. The District's "regulated" operations apply Statement of Financial Accounting Standards No. 71, *"Accounting for the Effects of Certain Types of Regulation"* (SFAS No. 71), while "non-regulated" operations follow GAAP for enterprises in general. Classification of regulated and non-regulated operations is determined in accordance with applicable GAAP accounting guidelines.

By virtue of SRP operating a federal reclamation project under contract, with the federal government's pre-emptive rights, asset ownership and certain approval rights, SRP is considered for financial reporting purposes to follow accounting standards as set forth by the Federal Accounting Standards Advisory Board (FASAB). Entities reporting in accordance with the standards issued by the Financial Accounting Standards Board (FASB) prior to October 19, 1999 (the date the American Institute of Certified Public Accountants (AICPA) designated the FASAB as the accounting standard setting body for entities under the Federal government) are permitted to continue to report in accordance with those standards. Consequently, SRP's financial statements are reported in accordance with FASB standards.

The preparation of financial statements in compliance with GAAP requires management to make estimates and assumptions that affect the reported amounts in the financial statements and disclosures of contingencies. Actual results could differ from the estimates.

Utility Plant – Utility plant is stated at the historical cost of construction, less any impairment losses. Capitalized construction costs include labor, materials, services purchased under contract, and allocations of indirect charges for engineering, supervision, transportation and administrative expenses and capitalized interest or an allowance for funds used during construction (AFUDC). AFUDC is the estimated cost of funds used to finance plant additions and is recovered in prices through depreciation expense over the useful life of the related asset. The cost of property that is replaced, removed or abandoned, together with removal costs, less salvage, is charged to accumulated depreciation.

Composite rates of 4.56% and 4.70% were used in fiscal years 2004 and 2003 to calculate interest on funds used to finance construction work in progress, resulting in $23.3 million and $16.8 million of interest capitalized, respectively.

Depreciation expense is computed on the straight-line basis over the estimated useful lives of the various classes of plant assets. The following table reflects the District's average depreciation rates on the average cost of depreciable assets, for the fiscal years ended April 30:

	2004	**2003**
Average electric depreciation rate	3.57%	3.99%
Average irrigation depreciation rate	2.61%	2.68%
Average common depreciation rate	4.38%	5.18%

Bond Expense – Bond discount/premium and issuance expenses are amortized using the effective interest method over the terms of the related bond issues.

Allowance for Doubtful Accounts – The District has provided for an allowance for doubtful accounts of $17.9 million and $64.4 million as of April 30, 2004 and 2003, respectively.

In April 2004, Pacific Gas and Electric Company (PG&E) emerged from Bankruptcy Chapter 11. PG&E repaid the District $40.0 million it owed for pre-bankruptcy accounts receivable. In prior periods, the District had reserved all but $4.0 million of amounts due from PG&E. Upon repayment, the District recorded a $36.0 million reduction of operating expense.

Nuclear Fuel – The District amortizes the cost of nuclear fuel using the units of production method. The nuclear fuel amortization and the disposal expense are components of fuel expense. Accumulated amortization of nuclear fuel at April 30, 2004 and 2003 was $354.8 million and $337.3 million, respectively.

Asset Retirement Obligation – The District adopted Statement of Financial Accounting Standards No. 143, *"Accounting for Asset Retirement Obligations,"* (SFAS No. 143), on May 1, 2003. SFAS No. 143 requires the recognition and measurement of liabilities for legal obligations associated with the retirement of tangible long-lived assets. Under the standard, these liabilities are recognized at fair value as incurred and capitalized as part of the cost of the related tangible long-lived assets. Accretion of the liabilities, due to the passage of time, is an operating expense and the capitalized cost is depreciated over the useful life of the long-lived asset. Retirement obligations associated with long-lived assets included within the scope of SFAS No. 143 are those for which a legal obligation exists under enacted laws, statutes, and written or oral contracts, including obligations arising under the doctrine of promissory estoppel.

The District has identified retirement obligations for the Palo Verde Nuclear Generating Station (PVNGS), Navajo Generating Station (NGS), Four Corners Generating Station and certain other assets. On May 1, 2003, the District recorded a liability of $173.7 million for asset retirement obligations, including the accretion impacts, a $63.3 million increase in the carrying amount of the associated assets, a net decrease of $99.7 million in accumulated decommissioning liability related to the reversal of the previously recorded accumulated decommissioning and a charge to earnings as a cumulative effect of $10.7 million.

Amounts recorded under SFAS No. 143 are subject to various assumptions and determinations, such as determining whether an obligation exists to remove assets, estimating the fair value of the costs of removal, estimating when final removal will occur, and determining the credit-adjusted risk-free interest rates to be utilized on discounting future liabilities. Changes that may arise over time with regard to these assumptions and determinations will change amounts recorded in the future as expense for asset retirement obligations.

A summary of the asset retirement obligation activity of the District for the year ended April 30, 2004, is included below (in millions):

Balance, May 1, 2003	$ 173.7
Newly incurred liabilities	2.5
Accretion Expense	10.7
Balance, April 30, 2004	$ 186.9

In accordance with regulations of the Nuclear Regulatory Commission, the District maintains a trust for the decommissioning of PVNGS. Decommissioning funds of $137.1 million and $114.5 million, stated at market value, as of April 30, 2004 and 2003, respectively, are held in the trust and are classified as segregated funds in the accompanying Combined Balance Sheets. Unrealized gains on decommissioning fund assets of $30.2 million and $17.0 million at April 30, 2004 and 2003, respectively, are included in deferred credits and other non-current liabilities in the accompanying Combined Balance Sheets.

Accounting for Energy Risk Management Activities – The District has an energy risk management program to limit exposure to risks inherent in normal energy business operations. The goal of the energy risk management program is to measure and minimize exposure to market risks, credit risks and operational risks. Specific goals of the energy risk management program include reducing the impact of market fluctuations on energy commodity prices associated with customer energy requirements, excess generation and fuel expenses, in addition to meeting customer pricing needs, and maximizing the value of physical generating assets. The District employs established policies and procedures to meet the goals of the energy risk management program using various physical and financial instruments, including forward contracts, futures, swaps and options. Certain of these transactions are accounted for under Statement of Financial Accounting Standards No. 133, *"Accounting for Derivative Instruments and Hedging Activities,"* as amended (SFAS No. 133). Under SFAS No. 133, derivatives are recorded in the balance sheet as either an asset or liability measured at their fair value. The standard also requires changes in the fair value of the derivative be recognized each period in current earnings or other comprehensive income depending on the purpose for using the derivative and/or its qualification, designation and effectiveness as a hedging transaction. Many of the District's contractual agreements qualify for the normal purchases and sales exception allowed under SFAS No. 133 and are not recorded at market value. For further explanation of the effects of SFAS No. 133 on the District's financial results, see Note (3) Accounting for Derivative Instruments and Hedging Activities.

Concentrations of Credit Risk – The use of contractual arrangements to manage the risks associated with changes in energy commodity prices creates credit risk exposure resulting from the possibility of nonperformance by counterparties pursuant to the terms of their contractual obligations. In addition, volatile energy prices can create significant credit exposure from energy market receivables. The District has a credit policy for wholesale counterparties, and continuously monitors credit exposures, routinely assesses the financial strength of its counterparties, minimizes credit risk by dealing primarily with creditworthy counterparties, entering into standardized agreements which allow netting of exposures to and from a single counterparty and by requiring letters of credit, parent guarantees or other collateral when it does not consider the financial strength of a counterparty sufficient.

Income Taxes – The District is exempt from federal and Arizona state income taxes. Accordingly, no provision for income taxes has been recorded for the District in the accompanying combined financial statements.

The District has three wholly-owned taxable subsidiaries; New West Energy, CRS and PPC. The tax effect of these subsidiaries' operations on the combined financial statements is immaterial.

Cash Equivalents – The District treats short-term temporary cash investments with original maturities of three months or less as cash equivalents.

Revenue Recognition – The District recognizes revenue when billed and accrues estimated revenue for electricity delivered to customers that has not yet been billed.

Materials and Supplies, and Fuel Stocks – Materials and supplies are stated at lower of market or average cost. Fuel stocks are stated at lower of market or weighted average cost.

Reclassifications – For comparative purposes, certain prior year amounts have been reclassified to conform with the current year presentation. The reclassifications had no impact on net revenues or cash flows.

Recently Issued Accounting Standards – FASB has issued the following Statement of Financial Accounting Standards (SFAS), Staff Positions (FSP), and Interpretations (FIN) that may have financial impacts on the District:

SFAS No. 132 (R), *"Employers' Disclosures about Pensions and Other Postretirement Benefits"* (SFAS No. 132 (R)), was issued in December of 2003 and replaces SFAS No. 132, *"Employers' Disclosures about Pensions and Other Postretirement Benefits"* (SFAS No. 132). This statement revises employers' disclosures about pension plans and other postretirement benefit plans. The disclosures required beyond those in the original SFAS No. 132 include additional information regarding plan assets, the accumulated benefit obligations, projected benefit payments, estimated expected contributions, assumptions used in the calculations and the measurement date of the plans. It does not change the measurement or recognition of those plans. This statement is effective for financial statements with fiscal years ending after December 15, 2003 and interim periods beginning after December 15, 2003. The disclosure regarding estimated future benefit payments will be effective for fiscal years ending after June 15, 2004. The District has adopted the revised standard. See Note (7) Employee Benefit Plans and Incentive Programs.

FIN No. 46, *"Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin No. 51"* (FIN No. 46), provides guidance on the identification and consolidation of entities for which control is achieved through means other than voting rights (variable interest entities). FIN No. 46 also requires additional disclosure describing transactions with variable interest entities in which consolidation is not required. In December 2003, the FASB revised FIN No. 46 (FIN No. 46R) to defer the implementation date for pre-existing variable interest entities (VIEs) that are special purpose entities (SPEs) until the end of the first interim or annual period ending after December 31, 2003. For VIEs that are not SPEs, companies must apply FIN No. 46R no later than the end of the first reporting period ending after March 15, 2004. SRP adopted FIN No. 46R as required. The adoption did not have a material impact on the accompanying combined financial statements. See also Notes (5) and (9) regarding the lease purchase of the Desert Basin Generating Station (Desert Basin).

FSP 106-1 and FSP 106-2, *"Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003,"* were released in January and May 2004, respectively. The Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Act) was signed into law in December 2003 and establishes a prescription drug benefit, as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a prescription drug benefit that is at least actuarially equivalent to Medicare's prescription drug coverage.
FSP 106-2 provides guidance on the accounting for the effects of the Medicare Act for employers that sponsor postretirement health care plans that provide prescription drug benefits and requires those employers to provide certain disclosures regarding the effect of the federal subsidy provided by the Medicare Act. Under FSP 106-1, the District elected to defer accounting for the effects of the Medicare Act. This deferral remains in effect until the appropriate effective date of FSP 106-2. For entities that elected deferral and for which the impact is significant, the FSP is effective for the first interim or annual period beginning after June 15, 2004. For entities that will not recognize a significant impact, delayed recognition of the effects of the Medicare Act until the next regularly scheduled measurement date following the issuance of FSP 106-2 is allowed. The District is still evaluating the impact of the Medicare Act. Accordingly, the accompanying combined financial statements do not reflect the effects that may result from the Medicare Act.

(3) Accounting for Derivative Instruments and Hedging Activities:

The District follows SFAS No. 133, as amended, which requires that entities recognize all derivatives as either assets or liabilities in the balance sheet and measure those instruments at fair value. Changes in the fair value of derivative financial instruments are either recognized periodically in net revenues or accumulated net revenues (as a component of other comprehensive income), depending on whether or not the derivative meets specific hedge accounting criteria. The criteria include a requirement for hedge effectiveness, which is measured based on the relative changes in fair value between the derivative contract and the hedged item over time. Changes in the fair value resulting from ineffectiveness are recognized immediately in net revenues.

The District enters into contracts for electricity, natural gas and other energy commodities to meet the expected needs of its retail customers. The District sells excess capacity during periods when it is not needed to meet retail requirements. The District's energy risk management program uses various physical and financial contracts to hedge exposures to fluctuating commodity prices. The District examines contracts at inception to determine the appropriate accounting treatment. If a contract does not meet the derivative criteria, or if it qualifies for the SFAS No. 133 normal purchases and sales scope exception, the District accounts for the contract using settlement accounting (costs and revenues are recorded when physical delivery occurs). Contracts that qualify as a derivative but do not meet the SFAS No. 133 normal purchases and sales scope exception are further examined by the District to determine if they qualify for hedge accounting. If a contract does not meet the hedging criteria in SFAS No. 133, the District recognizes the changes in the fair value of the derivative instrument in net revenues each period (mark to market). If the contract does qualify for hedge accounting, changes in the fair value are recorded in accumulated net revenues and other comprehensive income (as a component of other comprehensive income).

The District formally documents all relationships between hedging instruments and hedged items, as well as its risk-management objective and strategy for undertaking various hedge transactions. This process includes linking all derivatives to the forecasted transactions. The District also formally assesses (both at the hedge's inception and on an ongoing basis) whether the derivatives used in hedging transactions have been highly effective in offsetting changes in cash flow of hedged items and whether those derivatives may be expected to remain highly effective in future periods. When it is determined that a derivative is not (or has ceased to be) highly effective as a hedge, the District discontinues hedge accounting prospectively, as discussed below.

The District discontinues hedge accounting when: (1) it determines that the derivative is no longer effective in offsetting changes in cash flows of a hedged item; (2) the derivative expires or is sold, terminated or exercised; (3) it is no longer probable that the forecasted transaction will occur; or (4) management determines that designating the derivative as a hedging instrument is no longer appropriate.

When the District discontinues hedge accounting because it is no longer probable that the forecasted transaction will occur in the originally expected period, the gain or loss on the derivative is reclassified into net revenues. If the derivative remains outstanding, the District will carry the derivative at its fair value in the Combined Balance Sheets, recognizing changes in the fair value in current-period net revenues.

In December 2001, the Derivatives Implementation Group issued revised guidance on the accounting for electricity contracts with option characteristics and the accounting for contracts that combine a forward contract and a purchased option contract. The effective date for the revised guidance for the District was May 1, 2002. As a result of this new guidance the District recognized $16.6 million of derivative assets and $23.3 million of derivative liabilities in the Combined Balance Sheets as of May 1, 2002. Also as of May 1, 2002, the District recorded a $6.7 million loss in combined net revenues as a cumulative effect of change in accounting principle.

As of April 30, 2004 and 2003, the valuation of the District's energy risk management contracts resulted in an increase in electric revenues of $7.3 million and $12.7 million, respectively, and a decrease in fuel expenses of $21.5 million and $7.8 million, respectively. The impact to combined net revenues for fiscal years 2004 and 2003 was an unrealized gain of $28.8 million and $20.5 million, respectively. Accumulated net revenues and other comprehensive income (as a

component of other comprehensive income), were unchanged as of April 30, 2004 and increased by $0.1 million as of April 30, 2003 due to unrealized cash flow hedge gains. The following table summarizes the District's derivative-related assets and liabilities at April 30 (in thousands):

	2004	2003
Other Current Assets	$ 40,195	$ 29,794
Deferred Charges and Other Assets	41,020	27,586
Other Current Liabilities	(37,783)	(31,274)
Deferred Credits and Other Non-Current Liabilities	(29,758)	(47,279)
Net Asset (Liability)	$ 13,674	$ (21,173)

The District adopted Emerging Issues Task Force (EITF) 03-11, *"Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not 'Held for Trading Purposes' As Defined in EITF Issue No. 02-3,"* which provides guidance on reporting realized gains and losses on a gross or net basis. The task force determined that the final reporting "is a matter of judgment that depends on the relevant facts and circumstances." The electric industry engages in an activity called "book-out," under which some energy purchases are netted against sales, and power does not actually flow in settlement of the contract. As a result of adopting this EITF, the District nets the impacts of these financial settled contracts, which reduced revenues and purchase power expense by $91.2 million and $100.4 million for fiscal years 2004 and 2003, respectively, but which did not impact net revenues or cash flows.

SFAS No. 149, *"Amendment of Statement 133 on Derivative Instruments and Hedging Activities"* (SFAS No. 149), amends and clarifies accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts (collectively referred to as derivatives) and for hedging activities under SFAS No. 133. The provisions of SFAS No. 149 relating to SFAS No. 133 Implementation Issues are applied in accordance with their respective effective dates. In general, other provisions are applied prospectively to contracts entered into or modified after June 30, 2003. The District has implemented this standard; however, it did not have a material impact on its financial statements.

In November 2003, the FASB revised its derivative guidance on Issue No. C15, *"Normal Purchases and Normal Sales Exception for Option-Type Contracts and Forward Contracts in Electricity."* The new guidance, which is effective for the District on May 1, 2004, affects the criteria for the normal purchases and sales exception for purchase power and sales agreements. The District does not expect this change to materially impact its financial statements.

(4) Accumulated Net Revenues And Other Comprehensive Income:

The following table summarizes accumulated net revenues and other comprehensive income (in thousands):

	Accumulated Net Revenues	Accumulated Other Comprehensive Income (Loss)	Accumulated Net Revenues And Other Comprehensive Income
BALANCE, April 30, 2002	$ 2,265,587	$ 36,503	$ 2,302,090
Net revenues	46,669	–	46,669
Minimum pension liability	–	(127,900)	(127,900)
Unrealized gain on derivative instruments	–	87	87
Reclassification of realized loss to income	–	134	134
Net unrealized loss on available-for-sale securities	–	(17,152)	(17,152)
BALANCE, April 30, 2003	$ 2,312,256	$ (108,328)	$ 2,203,928
Net revenues	112,220	–	112,220
Minimum pension liability	–	48,500	48,500
Reclassification of realized loss to income	–	(2,477)	(2,477)
Net unrealized gain on available-for-sale securities	–	19,219	19,219
BALANCE, April 30, 2004	$ 2,424,476	$ (43,086)	$ 2,381,390

The majority of net unrealized gain (loss) on available-for-sale securities originates from segregated fund investments. Net unrealized gain (loss) on available-for-sale securities consists of gross unrealized gain (loss) on equity funds of $20.4 million and $(20.0) million, and gross unrealized gain (loss) on debt funds of $(1.2) million and $2.8 million, at April 30, 2004 and 2003, respectively.

(5) Long-Term Debt:

Long-term debt consists of the following at April 30 (in thousands):

	Interest Rate	2004	2003
Revenue bonds (mature through 2032)	3.0 – 6.5%	$ 2,375,549	$ 2,648,084
Unamortized bond discount/premium		49,648	46,925
Total revenue bonds outstanding		2,425,197	2,695,009
Finance Lease (FL)	2.0 – 5.3%	282,680	-
Unamortized FL discount/premium		20,490	-
Commercial paper	0.9 – 1.1%	375,000	375,000
Total long-term debt		3,103,367	3,070,009
Less-current portion		(170,029)	(260,428)
Total long-term debt, net of current portion		$ 2,933,338	$ 2,809,581

The annual maturities of long-term debt (excluding commercial paper and unamortized bond discount/premium) as of April 30, 2004, due in fiscal years ending April 30, are as follows (in thousands):

	Revenue Bonds	Finance Lease
2005	$ 171,733	$ -
2006	274,793	16,300
2007	115,056	16,015
2008	134,892	17,780
2009	153,455	16,790
Thereafter	1,525,620	215,795
	$ 2,375,549	$ 282,680

Revenue Bonds – Revenue bonds are secured by a pledge of, and a lien on, the revenues of the electric system, after deducting operating expenses, as defined in the bond resolution. Under the terms of the amended and restated bond resolution, effective in January 2003, the District is no longer required to make monthly deposits to an externally trusteed debt service fund for the payment of future principal and interest. However, the District is continuing to make debt service deposits to a non-trusteed segregated fund. Included in segregated funds in the accompanying Combined Balance Sheets is $164.5 million and $210.7 million of debt service related funds as of April 30, 2004 and 2003, respectively.

The District has $57.4 million of mini-revenue bonds outstanding which are redeemable at the option of the bondholder under certain circumstances. Based on historical redemptions made on these bonds, management believes there are sufficient funds available to cover potential redemptions in any year.

The debt service coverage ratio, as defined in the bond resolution, is used by bond rating agencies to help evaluate the financial viability of the District. For the years ended April 30, 2004 and 2003, the debt service coverage ratio was 2.00 and 2.23, respectively.

Interest and the amortization of the bond discount, premium and issue expense on the various issues results in an effective rate of 5.01% over the remaining term of the bonds.

The District has authorization to issue additional Electric System Revenue Bonds totaling $1.18 billion principal amount and Electric System Refunding Revenue Bonds totaling $2.94 billion principal amount, net of amounts issued in fiscal year 2004.

In January 2004, the District issued $122.1 million of Electric System Refunding Revenue Bonds. The net proceeds from these bonds were used to defease outstanding revenue bonds with an aggregate par amount of $134.9 million. The defeasance is expected to reduce total debt payments over the life of the bonds by $23.7 million and is expected to result in present value savings of approximately $15.9 million. This transaction resulted in a net loss for accounting purposes of $4.0 million, which was deferred and will be amortized over the life of the bonds to be refunded.

Finance Lease – In December 2003, the District entered into a lease-purchase agreement (Desert Basin Lease-Purchase Agreement) with Desert Basin Independent Trust (DBIT) to finance the acquisition of Desert Basin located in Central Arizona. In a concurrent transaction, $282.7 million in fixed-rate Certificates of Participation (COPs) were issued pursuant to a Trust Indenture, between Wilmington Trust Company, as trustee, and DBIT, to fund the acquisition of Desert Basin and other electric system assets of the District. Investors in the COPs obtained an interest in the lease payments made by the District to DBIT under the Desert Basin Lease-Purchase Agreement. Due to the nature of the Desert Basin Lease-Purchase Agreement, the District has recorded a lease-finance liability to DBIT with the same terms as the COPs.

In connection with the issuance of the COPs, the District entered into an interest rate swap transaction with Morgan Stanley Capital Services. This transaction consisted of a 6-year, $75 million fixed-to-floating swap (annual $25 million notional maturities expiring on December 1, 2007 through 2009, respectively) versus the Bond Market Association (BMA) Municipal Index. The fixed-receiver rate on the swap is 3.001%. Through the swap, the District was able to create synthetic variable rate debt and take advantage of the relationship between intermediate-term, tax-exempt borrowing costs and BMA-based,

fixed-receiver swap rates. In addition, the swap to variable rate also enables the District to increase its short-term, variable rate debt portfolio. The interest rate swap is accounted for as a derivative and qualifies for hedge accounting. For further explanation of the effects of SFAS No. 133 on the District's financial results see Note (3) Accounting for Derivative Instruments and Hedging Activities.

Commercial Paper – The District has $375.0 million of outstanding tax-exempt Series B Commercial Paper. The Series B issue has an average weighted interest rate to the District of 0.97%.

The commercial paper matures not more than 270 days from the date of issuance and is an unsecured obligation of the District. The District has the ability to refinance the outstanding commercial paper on a long-term basis in connection with its revolving line of credit that supports the commercial paper and is available through April 10, 2006. As such, the District has classified the commercial paper as long-term debt in the Combined Balance Sheets as of April 30, 2004.

While the revolving credit agreement contains covenants that could prohibit borrowing under certain conditions, management believes financing would be available. The District has never borrowed under the agreement and management does not expect to do so in the future. Alternative sources of funds to support the commercial paper program include existing funds on hand or the issuance of alternative debt, such as revenue bonds.

Line-of-Credit Agreements – The District has a $375.0 million revolving line-of-credit agreement that supports the $375.0 million tax-exempt Series B Commercial Paper Program. The agreement has various covenants, with which the District was in compliance at April 30, 2004.

(6) Fair Value of Financial Instruments:

The following methods and assumptions were used to estimate the fair value of each class of financial instruments identified in the following items in the accompanying Combined Balance Sheets.

Investments in Marketable Securities – The District invests in U.S. government obligations, certificates of deposit and other marketable investments. Such investments are classified as other investments, segregated funds, cash and cash equivalents or temporary investments in the accompanying Combined Balance Sheets depending on the purpose and duration of the investment. The fair value of marketable securities with original maturities greater than one year is based on published market data. The carrying amount of marketable securities with original maturities of one year or less approximates their fair value because of their short-term maturities.

Long-Term Debt – The fair value of the District's revenue bonds, including the current portion, was estimated by using pricing scales from independent sources. The carrying amount of commercial paper approximates the fair value because of its short-term maturity.

Other Current Assets and Liabilities – The carrying amounts of receivables, accounts payable, customers' deposits and other current liabilities in the accompanying Combined Balance Sheets approximate fair value because of their short-term maturities.

The estimated carrying amounts and fair values of the District's financial instruments, at April 30, are as follows (in thousands):

	2004		2003	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Investments in marketable securities:				
Other investments	$ 50,910	$ 50,787	$ 15,000	$ 15,032
Segregated funds	535,944	537,344	653,968	657,488
Temporary investments	60,750	60,750	57,925	58,013
Long-term debt	$ 3,103,367	$ 3,151,902	$ 3,070,009	$ 3,230,661

Accounting for Debt and Equity Securities – The District's investments in debt securities are reported at amortized cost if the intent is to hold the security to maturity. At April 30, 2004, the District's investments in debt securities have maturity dates ranging from May 14, 2004, to February 28, 2012. Other debt and equity securities are reported at market, with unrealized gains or losses included as a separate component of Accumulated Net Revenues and Other Comprehensive Income. The District's investments in debt and equity securities are included in temporary investments, segregated funds and non-utility property and other investments in the accompanying Combined Balance Sheets.

(7) Employee Benefit Plans and Incentive Programs:

Defined Benefit Pension Plan and Other Post-Retirement Benefits – SRP's Employees' Retirement Plan (the Plan) covers substantially all employees. The Plan is funded entirely from SRP contributions and the income earned on invested Plan assets. The District made a contribution of $10.0 million in fiscal year 2004. No contributions were required in fiscal year 2003.

SRP provides a non-contributory defined benefit medical plan for retired employees and their eligible dependents (contributory for employees hired January 1, 2000 or later) and a non-contributory defined benefit life insurance plan for retired employees. Employees are eligible for coverage if they retire at age 65 or older with at least five years of vested service under the Plan (ten years for those hired January 1, 2000 or later), or any time after attainment of age 55 with a minimum of ten years of vested service under the Plan (20 years for those hired January 1, 2000 or later). The funding policy is discretionary and is based on actuarial determinations. The unrecognized transition obligation is being amortized over 20 years, beginning in 1994.

The following tables outline changes in benefit obligations, plan assets, the funded status of the plans and amounts included in the combined financial statements as of April 30, based on January 31 valuation dates (in thousands):

	Pension Benefits		Post-Retirement Benefits	
	2004	2003	2004	2003
Change in benefits obligation:				
Benefit obligation at beginning of year	$ 779,000	$ 644,700	$ 312,000	$ 279,900
Service cost	22,600	18,200	8,500	7,200
Interest cost	51,600	45,700	22,900	19,900
Amendments	–	17,800	–	(14,900)
Actuarial loss	68,600	83,600	59,700	30,600
Benefits paid	(32,800)	(31,000)	(10,400)	(10,700)
Benefit obligations at end of year	$ 889,000	$ 779,000	$ 392,700	$ 312,000
Change in plan assets:				
Fair value of plan assets at beginning of year	$ 545,600	$ 639,600	$ –	$ –
Actual return on plan assets	157,200	(63,000)	–	–
Employer contributions	–	–	10,500	10,700
Benefits paid	(32,800)	(31,000)	(10,500)	(10,700)
Fair value of plan assets at end of year	$ 670,000	$ 545,600	$ –	$ –

	Pension Benefits		Post-Retirement Benefits	
	2004	2003	2004	2003
Funded status	$ (219,000)	$ (233,400)	$ (392,700)	$ (312,000)
Unrecognized transition obligation	–	–	37,000	41,100
Unrecognized net actuarial loss	214,800	245,600	162,000	110,400
Unrecognized prior service cost	22,800	25,400	600	600
Post January 31 contributions	10,000	–	2,900	2,700
Net asset (liability) recognized	$ 28,600	$ 37,600	$ (190,200)	$ (157,200)
Amounts recognized in Combined Balance Sheets:				
Prepaid benefit cost	$ 28,600	$ 37,600	$ –	$ –
Accrued benefit liability	–	–	(190,200)	(157,200)
Additional minimum liability	(102,200)	(153,300)	–	–
Intangible asset	22,800	25,400	–	–
Accumulated other comprehensive income	79,400	127,900	–	–
Net amount recognized	$ 28,600	$ 37,600	$ (190,200)	$ (157,200)

The following table outlines the projected benefit obligation and accumulated benefit obligation in excess of plan assets as of April 30, based on January 31 valuation dates (in thousands):

	2004	2003
Projected benefit obligation	$ 889,000	$ 779,000
Accumulated benefit obligation	753,600	661,200
Fair value of Plan assets	670,000	545,600

The District internally funds its other post-retirement benefits obligation. At April 30, 2004 and 2003, $196.1 million and $152.3 million of segregated funds, respectively, were designated for this purpose.

The weighted average assumptions used to calculate actuarial present values of benefit obligations at April 30 were as follows:

	Pension Benefits		Post-Retirement Benefits	
	2004	2003	2004	2003
Discount rate	6.25%	6.75%	6.25%	6.75%
Rate of compensation increase	4.0%	4.0%	4.0%	4.0%

The weighted average assumptions used to calculate net periodic benefit costs were as follows:

	Pension Benefits		Post-Retirement Benefits	
	2004	2003	2004	2003
Discount rate	6.75%	7.25%	6.75%	7.25%
Expected return on Plan assets	8.25%	8.75%	N/A	N/A
Rate of compensation increase	4.0%	4.0%	4.0%	4.0%

For employees who retire at age 65 or younger, for measurement purposes, a 9.0% annual increase before attainment of age 65 and 11.0% annual increase on and after attainment of age 65 in per capita costs of health care benefits were assumed during 2004; these rates were assumed to decrease uniformly until equaling 5.0% in all future years.

Components of net periodic benefit (gain) costs for the years ended April 30, are as follows (in thousands):

	Pension Benefits		Post-Retirement Benefits	
	2004	2003	2004	2003
Service cost	$ 22,500	$ 18,200	$ 8,500	$ 7,200
Interest cost	51,600	45,800	22,900	19,900
Expected return on Plan assets	(57,700)	(62,000)	–	–
Amortization of transition obligation	–	–	4,100	5,600
Recognized net actuarial loss	–	–	8,300	4,200
Amortization of prior service cost	2,700	1,100	–	–
Net periodic benefit (gain) cost	$ 19,100	$ 3,100	$ 43,800	$ 36,900

Assumed health care cost trend rates have a significant effect on the amounts reported for health care plans. A one-percentage-point change in the assumed health care cost trend rates would have the following effect (in thousands):

	One-Percentage-Point Increase	One-Percentage-Point Decrease
Effect on total service cost and interest cost components	$ 5,000	$ (4,400)
Effect on post-retirement benefit obligation	$ 58,500	$ (51,500)

Plan Assets – The Board has established an investment policy for Plan assets and has delegated oversight of such assets to a compensation committee (the Committee). The investment policy sets forth the objective of providing for future pension benefits by targeting returns consistent with a stated tolerance of risk. The investment policy is based on analysis of the characteristics of the Plan sponsors, actuarial factors, current Plan condition, liquidity needs, and legal requirements. The primary investment strategies are diversification of assets, stated asset allocation targets and ranges, and external management of Plan assets. The Committee determines the overall target asset allocation ratio for the Plan and defines the target asset allocation ratio deemed most appropriate for the needs of the Plan and the risk tolerance of the District.

The Plan's weighted-average asset allocations at April 30, based on January 31 valuations, are as follows:

	Target Allocations	2004	2003
Equity Securities	65.0%	67.2%	60.3%
Debt Securities	25.0%	22.8%	27.6%
Real Estate	10.0%	10.0%	12.1%
Total	100.0%	100.0%	100.0%

The investment policy allows for a tolerance range of plus or minus 5% from the stated target asset allocation.

Long-Term Rate of Return – The expected return on Plan assets is based on a review of the Plan asset allocations and consultations with a third-party investment consultant and the Plan actuary, considering market and economic indicators, historical market returns, correlations and volatility, and recent professional or academic research. As history has demonstrated, markets may decline and increase dramatically; however, the expected rate of return on the Plan assets is reasonable given its asset allocation in relation to historical and expected future performance.

Employer Contributions – The District expects to contribute $38.4 million to the Plan over the next valuation period.

Defined Contribution Plan – SRP's Employees' 401(k) Plan (the 401(k) Plan) covers substantially all employees. The 401(k) Plan receives employee pre-tax and post-tax contributions and partial employer matching contributions. Employer matching contributions to the 401(k) Plan were $9.1 million and $8.4 million during fiscal years 2004 and 2003, respectively.

Employee Incentive Compensation Program – SRP has an incentive compensation program covering substantially all regular employees. The incentive compensation amount is based on achievement of pre-established targets. An accrual of $24.7 million and $8.3 million for fiscal years ended April 30, 2004 and 2003, respectively is included in other current liabilities in the accompanying Combined Balance Sheets. This liability is stated net of receivables from participants in jointly-owned electric plants of $2.4 million and $0.9 million at April 30, 2004 and 2003, respectively.

(8) Interests In Jointly-Owned Electric Utility Plants:

The District has entered into various agreements with other electric utilities for the joint ownership of electric generating and transmission facilities. Each participating owner in these facilities must provide for the cost of its ownership share. The District's share of expenses of the jointly-owned plants is included in operating expenses in the accompanying Combined Statements of Net Revenues.

The following table reflects the District's ownership interest in jointly-owned electric utility plants as of April 30, 2004 (in thousands):

Generating Station	Ownership Share	Plant In Service	Accumulated Depreciation	Construction Work In Progress
Four Corners (NM) (Units 4 & 5)	10.00%	$ 102,735	$ 91,944	$ 5,926
Mohave (NV) (Units 1 & 2)	20.00%	131,900	112,215	4,577
Navajo (AZ) (Units 1, 2 & 3)	21.70%	345,710	237,710	6,692
Hayden (CO) (Unit 2)	50.00%	113,178	72,794	2,143
Craig (CO) (Units 1 & 2)	29.00%	243,104	163,165	35,401
PVNGS (AZ) (Units 1, 2 & 3)	17.49%	1,233,595	829,621	23,999
		$ 2,170,222	$ 1,507,449	$ 78,738

(9) Capital Lease:

In fiscal year 2001, the District entered into a ten-year contract with Reliant Energy Desert Basin, LLC (Reliant) for the long-term exclusive purchase of power and energy produced at Desert Basin. The amount of capacity available to the District was approximately 588 megawatts annually. The payments included costs for both capacity and operation and maintenance of the facility. Upon inception of the contract, the present value of the fixed payment attributable to capacity costs met the requirement for accounting for this contract as a capital lease. For the fiscal year ended April 30, 2003 the utility plant under the capital lease was $246.8 million, net of accumulated amortization of $45.3 million, and the capital lease obligation was $251.4 million.

In October 2003, the District acquired a 100% interest in Desert Basin from Reliant for $282.5 million and assumed operations, thereby terminating the long-term purchase power agreement with Reliant and the capital lease asset and obligation. The purchase was financed through the Desert Basin Lease-Purchase Agreement, via a transfer of the assets to DBIT, and the issuance of COPs. For further explanation of the Desert Basin Lease-Purchase Agreement see Note (5) Long-term Debt. The District will continue to operate Desert Basin at its own risk through the term of the lease-purchase agreement and upon transfer of ownership to the District at the end of the lease term. Continuing involvement in Desert Basin precluded the use of sale-leaseback accounting. GAAP requires the District to report the proceeds under the Desert Basin Lease-Purchase Agreement as a liability, continue to report the facility as a utility plant asset, and continue to depreciate the property. The sales proceeds have been recorded as a liability of $282.7 million and are included in long-term debt in the accompanying Combined Balance Sheets as of April 30, 2004.

(10) Regulatory Issues:

Fundamental Changes in the Electric Utility Industry – The District historically operated in a highly regulated environment in which it had an obligation to deliver electric service to customers within its service area. In 1998, the Arizona Electric Power Competition Act (the Act) authorized competition in the retail sales of electric generation, recovery of stranded costs and competition in billing, metering and meter reading.

The Act allows a temporary surcharge on electric distribution service prices to pay for all or a portion of unmitigated stranded costs of electric generation service incurred as a direct result of the onset of competition. Such costs must have been incurred to serve customers in Arizona before December 26, 1996. This surcharge may not continue past December 31, 2004, and must not cause prices to exceed the prices in effect on December 30, 1998. Effective June 1, 2004, the District ceased collection of this surcharge.

In 1999, the Arizona Corporation Commission (the Commission), which regulates public service corporations, approved final rules for retail electric competition. The Commission subsequently entered into agreements with each of its regulated utilities, establishing terms and conditions precedent to a framework for stranded cost recovery and unbundled tariffs. Beginning January 1, 2001, all customers were given the right to select an alternative generation provider. In 2002, due to California's unsuccessful experience with competition and other market developments, the Commission began a review of its existing competition rules to provide additional safeguards for consumers and to identify key issues that impede competition and areas that could be improved. This review is ongoing.

In May 2002, the Arizona Legislature established a committee to examine the status of deregulation and determine whether the Act should be modified. The committee met during 2002 and issued a final report on June 12, 2003, with its recommendation to continue to study the Act. The committee was reappointed in November 2003 to continue its evaluation of retail competition and possible changes to the Act.

In January 2004, the Arizona Court of Appeals found numerous provisions of the Commission's retail electric competition rules to be invalid. Specifically, the Court concluded that the Certificates of Convenience and Necessity awarded by the Commission to fifteen competitive electric service providers were invalid due to the Commission's failure to determine the fair value of the utility's Arizona property in setting rates. Other rules affected included the requirement to create an independent

scheduling administrator and billing and collection practices. One of the plaintiffs in the action, Trico Electric Cooperative, Inc., filed a petition for review with the Arizona Supreme Court and the matter is pending.

No retail competition exists today in Arizona.

The Federal Energy Regulatory Commission (FERC) regulates the electric utility industry under the authority of various statutes. FERC issued rules in 1996 mandating, among other things, open nondiscriminatory access to transmission lines. The rules require comparable transmission service in order to use the transmission systems of utilities under FERC jurisdiction (jurisdictional utilities). The District has filed a comparable open access transmission tariff to ensure reciprocal access, pursuant to rules FERC developed for non-jurisdictional utilities like the District. Also, FERC has issued procedures for jurisdictional utilities that own, control or operate electric transmission facilities to use for interconnecting generating facilities capable of producing more than 20 megawatts of power. The District jointly owns with jurisdictional utilities certain transmission facilities, which arguably would be subject to FERC's rules.

In December 1999, FERC issued its Order No. 2000 requiring all jurisdictional public utilities that own, operate or control interstate transmission to attempt to develop proposals for regional transmission organizations (RTO). The District is participating in the development of an RTO for the Southwest.

The Changing Regulatory Environment – The District has fully opened its service area to competition in generation and billing, metering and meter reading. The District's electric distribution area remains regulated by its Board and the District will not provide distribution services in the distribution areas of other utilities.

The District's price plans have been unbundled since 1999. The Board approved a 1.5% overall price increase for the District, to become effective on November 1, 2004. Certain changes to the various components of the existing price plans will take effect on June 1 but will not have any impact on the overall price levels. Among other things, the Board approved a new Fuel and Purchase Power Adjustment Mechanism that permits the District to implement automatic changes in this mechanism on a seasonal basis subject to a 2-mill deadband and implemented a Transmission Cost Adjustment Factor. The Fuel and Purchase Power Adjustment Mechanism provides for a true-up between related costs and expenses every six months and provides for the prospective collection of amounts for fuel and purchase power costs above predetermined levels. The Transmission Cost Adjustment Factor provides for a collection of new costs resulting from the establishment of regional or other entities to oversee transmission operations, regional planning and wholesale markets for electricity or the establishment of new operating rules for wholesale markets. The District prices its electric generation based upon market and cost of service factors.

Since December 31, 1998, the District has been recovering stranded costs through a competitive transition charge (CTC) paid by all distribution customers. In fiscal year 2001 management determined, based upon projections using current economic conditions that the full CTC of $795.0 million might not be collected. Management, therefore, reduced the amount of the CTC asset and took a charge to depreciation and amortization expense of $85.0 million as of April 30, 2001. Further, as part of the November 2001 price plans review, the District reviewed the level of its CTC associated with stranded cost recovery and elected to retain the CTC at its current level until June 1, 2004. The remaining $10.6 million, recorded as a current asset as of April 30, 2004, was fully collected in May 2004. Effective June 2004, the District stopped collecting the CTC.

Through a surcharge to the District's transmission and distribution customers, the District recovers the costs of programs benefiting the general public, such as discounted rates for the elderly or impoverished, efficiency programs, demand-side management measures, renewable energy programs, economic development, research and development and nuclear decommissioning, including the cost of spent fuel storage. In its recent pricing approval, the Board approved additional funding for renewable energy programs, energy efficiency and energy conservation. These surcharges continue to be separately identified and included in the District's price plans for the regulated portion of its operations.

Regulatory Accounting – The District accounts for the financial effects of the regulated portion of its operations in accordance with the provisions of SFAS No. 71, which requires cost-based, rate-regulated utilities to reflect the impacts of regulatory decisions in their financial statements.

As a result of the Board actions in August 1998 to open the District's service area to competition in generation, the District discontinued the application of SFAS No. 71 to its electric generation operations in fiscal year 1999. From that time forward, the provisions of SFAS No. 101, *"Regulated Enterprises: Accounting for the Discontinuation of Application of FASB Statement No. 71,"* have been applied to the portion of its business no longer meeting the provisions of SFAS No. 71.

In fiscal year 1999, the District evaluated the carrying amounts of its generation operations in relation to future cash flows, expected to be generated from their use in a competitive environment, and determined that $850.2 million of these assets were impaired. Impairment of $631.8 million was attributable to generation operations, and $163.7 million was attributable to long-term energy contracts. Of the total impairment, a maximum of $795.0 million could be recovered through the CTC, and such amount was recorded as a regulatory asset (CTC regulatory asset). The CTC regulatory asset was recovered through the competitive transition charge over the period beginning December 31, 1998, and continuing through May 31, 2004. Since December 31, 1998, the District has amortized or charged $784.9 million of the CTC asset to depreciation and amortization expense and recovered $758.3 million through CTC revenue.

Regulatory assets for spent nuclear fuel storage are amortized over the life of the nuclear plant. Bond defeasance regulatory assets are amortized over different periods, beginning in fiscal year 1997 and ending in fiscal year 2031. Regulatory assets are included in deferred charges and other assets on the accompanying Combined Balance Sheets.

Mohave Generating Station – The District and the other Participants in the Mohave Generating Station ("Mohave") entered into a settlement with the Sierra Club that requires the installation of certain pollution abatement equipment by the end of 2005 if the plant will continue to be operated as a coal-fired electric generating facility. (See Note (12) Contingencies, for additional information on air quality issues.) In addition, the initial term of the agreement to supply coal to Mohave will expire at the end of 2005 and the Hopi Tribe has demanded that the pumping of water for the slurry pipeline serving Mohave cease by the end of 2005. The Mohave Participants have refused to commit to install pollution abatement equipment without reasonable assurance that water will be available to enable the delivery of coal to the plant. Due to the lead-time required to place orders and complete installation of the pollution abatement equipment, it is likely that the plant will cease operations at the end of 2005 for some extended period of time. The federal government and other interested parties have executed a memorandum of understanding that will provide funding by the Mohave Participants toward a feasibility study and environmental report for an alternative water supply. The District has included approximately $113.0 million in its Capital Improvement Program to cover the costs of such equipment or alternate resources, if necessary.

Although the Mohave Participants and the Tribe are trying to reach a settlement, it is not certain if, and when, a resolution will be reached. The District has already replaced a portion of the energy and is considering several options for replacing the balance of the capacity in the event of a prolonged shutdown.

If the negotiations are not successful and the Mohave Participants are unable to secure the extension of the life of Mohave, the Board has authorized the recovery of the balance of the District's investment in Mohave in its revenue requirements over the remainder of the scheduled useful life of the plant. Consequently, it was determined that the plant's carrying value would not be realized through future revenues and a write-down of its carrying value of $66.2 million was recorded in fiscal year ended April 30, 2003, and an additional $6.6 million of impairment was recorded in fiscal year ended April 30, 2004. In accordance with accounting standards for rate-regulated enterprises (SFAS No. 71), a regulatory asset was established for $72.8 million, based on the District's expectation that any unrecovered book value at the end of 2005 would be recovered in future rates.

Deferred charges and other assets consist primarily of the following at April 30 (in thousands):

	2004	2003
CTC regulatory asset	$ –	$ 137,764
Bond defeasance regulatory asset	98,278	114,291
Mohave Generating Station regulatory asset	72,836	66,231
Spent nuclear fuel storage regulatory asset	22,830	22,418
Prepaid pension benefits	28,600	37,600
Derivatives market valuation	41,020	27,586
Pension intangible asset	22,800	25,400
Other	46,213	35,583
	$ 332,577	$ 466,873

If events were to occur making full recovery of these regulatory assets no longer probable, the District would be required to write off the remaining balance of such assets as a one-time charge to net revenues.

Deferred credits and other non-current liabilities consist primarily of the following at April 30 (in thousands):

	2004	2003
Asset retirement obligation	$ 186,921	$ –
Capital lease obligation	–	224,500
Accrued post-retirement benefit liability	190,200	157,200
Additional pension minimum liability	102,200	153,300
Accrued decommissioning costs	30,232	116,725
Provision for contract losses	92,900	106,180
Derivatives market valuation	29,758	47,279
Accrued spent nuclear fuel storage	25,328	25,966
Accrued environmental issues	80,348	48,656
Other	49,016	34,551
	$ 786,903	$ 914,357

(11) Commitments:

Subsidiary Guarantees – The District acts as guarantor for New West Energy's contractual obligations as necessary to satisfy performance security requirements under agreements with utility distribution companies, brokers and counterparties for financial hedge transactions and power purchasers and sellers. No payments were made under these guarantees during fiscal years 2004 and 2003. Existing guarantees were terminated May 31, 2003, and New West Energy has not entered into any agreements since then.

Improvement Program – The Improvement Program represents the District's six-year plan for major construction projects and capital expenditures for existing generation, transmission, distribution and irrigation assets. For the 2005-2010 period,

the District estimates capital expenditures of approximately $3.3 billion. Major construction projects include expansion of generation at the Santan Generating Station, possible construction of an additional unit at Springerville Generating Station and other key strategic distribution and transmission projects.

Long-Term Power Contracts – The District entered into three contracts, collectively, with the United States Bureau of Reclamation (United States), the Western Area Power Administration and the Central Arizona Water Conservation District (CAWCD) for the long-term sale, through September 2011, of power and energy associated with the United States' entitlement to NGS. The amount of energy available to the District varies annually and is expected to decline over the life of the contracts. The District pays a fixed amount under the contracts, pays the cost of NGS generation and other related costs and supplies energy at cost to CAWCD for Central Arizona Project facilities. The fixed portion of the District's payment obligations under the three contracts totals $47.0 million annually through fiscal year 2009, and $113.5 million thereafter. Of the total obligation, $25.2 million annually through fiscal year 2009 and $60.9 million thereafter are unconditionally payable regardless of the availability of power. Payments under these contracts totaled $65.3 million and $99.4 million in fiscal years 2004 and 2003, respectively.

The District entered into two other long-term power purchase agreements to obtain a portion of its projected load requirements through 2011. Minimum payments under these contracts are $41.1 million annually through fiscal year 2009 and $73.2 million thereafter. Total payments under these two contracts, including the minimum payments, were $66.1 million and $61.9 million in fiscal years 2004 and 2003, respectively. In conjunction with the impairment analysis performed on generation-related operations, the District has recorded provisions for losses on these contracts. The provisions recorded in August 1998, of $163.7 million, are being amortized over the life of the contracts, commencing January 1, 1999. Amortization of $13.3 million has been reflected as a reduction in purchased power expense in fiscal years 2004 and 2003. The remaining liability at April 30, 2004 of $92.9 million is included in deferred credits and other non-current liabilities in the Combined Balance Sheets.

Fuel Supply – At April 30, 2004, minimum payments under long-term coal supply contract commitments are estimated to be $224.7 million in fiscal year 2005, $215.4 million in fiscal year 2006, $187.2 million in fiscal year 2007, $138.0 million in fiscal year 2008, $62.5 million in fiscal year 2009, and $663.6 million thereafter.

(12) Contingencies:

Nuclear Insurance – Under existing law, public liability claims arising from a single nuclear incident are limited to $10.8 billion. PVNGS Participants insure for this potential liability through commercial insurance carriers to the maximum amount available ($300.0 million) with the balance covered by an industry-wide retrospective assessment program as required by the Price-Anderson Act. If losses at any nuclear power plant exceed available commercial insurance, the District could be assessed retrospective premium adjustments. The maximum assessment per reactor per nuclear incident under the retrospective program is $100.6 million including a 5% surcharge, applicable in certain circumstances, but not more than $10.0 million per reactor may be charged in any one year for each incident.

Based on the District's ownership share of PVNGS, the maximum potential assessment would be $52.8 million, including the 5% surcharge, but would be limited to $5.2 million per incident in any one year.

Spent Nuclear Fuel – Under the Nuclear Waste Policy Act of 1982, the District pays 1/10 of one cent per kWh on its share of net energy generation at PVNGS to the U. S. Department of Energy (DOE). The DOE was responsible for the selection and development of repositories for permanent storage and disposal of spent nuclear fuel not later than December 31, 1998. Because of the significant delays in the DOE's schedule, it cannot be determined when the DOE will accept waste from PVNGS or from the other owners of spent nuclear fuel. It is unlikely, due to PVNGS' position in DOE's queue for receiving spent fuel, that Arizona Public Service Company (APS), the operating agent of PVNGS, will be able to initiate shipments to DOE during the licensed life of PVNGS. Accordingly, APS has constructed an on-site dry cask storage facility to receive and store PVNGS spent fuel that is sufficient to provide storage for all three units for a 40-year operating life. The facility stored its first cask in March 2003.

The District's share of on-site interim storage at PVNGS is estimated to be $29.9 million for costs to store spent nuclear fuel from inception of the plant through fiscal year-end 2004, and $1.8 million per year going forward. These costs have been included in the District's regulated operations price plans for transmission and distribution.

Navajo Nation Lawsuit – In June 1999, the Navajo Nation filed a lawsuit in the United States District Court in Washington D.C., alleging that the coal supplier for the Navajo and Mohave Generating Stations (Peabody Coal Company), Southern California Edison Company, the District, and other defendants, had induced the United States to breach its fiduciary duty to the Navajo Nation and had violated federal racketeering statutes. The lawsuit arises out of negotiations that culminated in 1987 with amendments to the coal royalty and lease agreements for mining coal for the Navajo and Mohave Generating Stations. The suit alleges $600.0 million in damages and seeks treble damages along with punitive damages of not less than $1.0 billion. In March 2001, the Hopi Tribe intervened in the suit. However, the claims of both the Navajo Nation and the Hopi Tribe have been dismissed in their entirety with respect to the District. The Navajo Nation and the Hopi Tribe may appeal the dismissals.

Previously, the Navajo Nation had filed a lawsuit against the United States Government based on similar allegations. The lawsuit had been dismissed, but on appeal, it was reinstated and the Court of Appeals, in August 2001, held that the United States had breached its fiduciary duty to the Navajo Nation, and that a claim for damages was within the jurisdiction of the Court of Federal Claims. Subsequently, the United States Supreme Court, in March 2003, reversed the decision of the Court of Appeals and remanded the case to the Court of Appeals for further proceedings consistent with its opinion. In October 2003, the Court of Appeals remanded the case to the Court of Federal Claims and ordered that court to determine if the Navajo Nation had waived any claims with respect to statutes and regulations other than those the Court of Appeals concluded were at issue before the Supreme Court. If the Court of Federal Claims determines that there was not a waiver, it will determine if such other statutes and regulations impose enforceable fiduciary duties upon the United States in connection with Peabody's leases and, if so, whether the United States breached such duties.

Peabody claims it is entitled to reimbursement under the coal supply agreements for its costs associated with both lawsuits as well as for additional costs if the coal royalty rate under the coal leases were retroactively raised above the current rate. The Mohave Participants and NGS Participants dispute Peabody's attempt to recover its legal costs under the coal supply agreements and the issue is the subject of ongoing arbitration and litigation. The District is unable to predict the likely outcome of these matters at this time but does not believe that these disputes will have material adverse effects on its operations or financial condition.

Environmental – SRP is subject to numerous legislative, administrative and regulatory requirements relative to air quality, water quality, hazardous waste disposal and other environmental matters. SRP conducts ongoing environmental reviews of its properties for compliance and to identify those properties it believes may require remediation. Such requirements have resulted, and will continue to result, in increased costs associated with the operation of existing properties.

In September of 2003, the District received notice from the U.S. Environmental Protection Agency (EPA) that it is potentially liable under the Comprehensive Environmental Response, Compensation and Liability Act as an owner and operator of a facility (the 16th St. facility) within the Motorola 52nd Street Superfund Site. The District is potentially liable for past costs incurred and for future work to be conducted within the Superfund Site. Investigation and evaluation of this potential liability are in the preliminary stages and the District is unable at this time to predict the outcome, but believes that it has adequate reserves for this potential liability.

Several species of birds listed as "endangered" or "threatened" under the Endangered Species Act ("ESA") have been discovered in and around Roosevelt and Horseshoe Dams. To obtain an Incidental Take Permit (ITP), the District entered into formal consultation with the United States Fish and Wildlife Service (USFWS), and developed a Habitat Conservation Plan (Plan), which allows full operation of Roosevelt Dam and reservoir, provided the District mitigates for the "taking" of species by the establishment of other habitat for the birds in other areas. The District has reserved funds, which it believes will be sufficient to implement the Plan. The District is currently engaged in similar consultations with the USFWS towards the

objective of obtaining an ITP for operation of Horseshoe and Bartlett Dams on the Verde River.

Indemnifications – From time to time the District enters into agreements that provide indemnifications relating to liabilities arising from or related to those agreements. Generally, a maximum obligation is not explicitly stated in the indemnifications and, therefore, the overall maximum amount of the obligations under such indemnifications cannot be reasonably estimated. Based on historical experience and evaluation of the specific indemnities, the District does not believe that any material loss related to such indemnifications is likely and, therefore, no related liability has been recorded.

Air Quality – The federal Clean Air Act as amended, among other things, requires reductions in sulfur dioxide and nitrogen oxide emissions from electric generating stations and regulates emissions of hazardous air pollutants by generating stations.

In December 1999, the participants in Mohave Generating Station settled a lawsuit alleging numerous and continuing violations of opacity and sulfur dioxide standards. Under the terms of the settlement, the participants must install by January 1, 2006, a sulfur dioxide scrubber and other pollution control equipment. Major plant modifications, including emissions controls, are required for continued operation as a coal-fired plant. Capital costs are estimated at $710.4 million, of which the District's share would be $142.1 million. These costs are included in capital contingencies portion of the 2004-2009 Improvement Program. However, as discussed in Note (10) Regulatory Issues, the uncertainty in post-2005 coal and water supply have caused the Mohave Participants to be unwilling to make the necessary investments at this time.

Congress is considering new legislation, including amendments to the Clean Air Act (CAA), which could affect the cost of generating and purchasing power. While it is too early to determine whether the legislation will be enacted, and in what form, or what their effect will be, the changes may materially impact the cost of power generated at affected generating units.

On December 15, 2003, the EPA issued draft regulations for the control of mercury emissions from coal and oil-fired utility boilers. The EPA will receive public comments on the draft regulations and then finalize the regulations by March 2005, with an expected compliance date of December 2008. The District is evaluating the impacts of the draft regulations, which could range from no change to the installation of new emission controls.

President Bush has proposed a Clear Skies Initiative (CSI) that would achieve dramatic reduction of sulfur dioxide, oxides of nitrogen and mercury emissions in a coordinated and phased manner. The administration expects that the CSI would provide the electric power generating industry with regulatory certainty while maintaining fuel supply diversity. A number of other bills are also under consideration in Congress and call for significant reductions in sulfur dioxide, nitrogen and mercury as well as carbon dioxide. The CAA contains several provisions that are directed at emissions of sulfur dioxide, nitrogen and mercury. The District is planning on future emission reductions at its coal-fired power plants as a result of these legislative and regulatory initiatives. The specific level of reduction and compliance cost will not be known until new legislation is passed or the EPA and the states finalize regulatory programs under the CAA.

Coal Mine Reclamation – In management's opinion, there are sufficient accruals in the accompanying combined financial statements for the District's obligation to reimburse certain coal providers for amounts due for certain coal reclamation costs. However, the District is contesting certain other coal mine reclamation costs. Neither the District's responsibility or the ultimate amount of liability, if any, can be determined at this time. Management does not believe that the outcome of these matters will have a material adverse effect on the District's financial position or results of operations.

Gas Supply – Effective September 1, 2003, FERC converted the full requirement contracts of the District and other entities in Arizona with El Paso Natural Gas Company for the transportation of natural gas to contract demand status with monthly limits for natural gas transportation service. A number of entities, including the Commission and the District, have challenged the orders in the U.S. Court of Appeals for the D.C. Circuit. The District has prepared a gas transportation plan that should provide the District with sufficient gas to meet its retail electric demands. As part of the gas transportation plan, the District is considering alternatives, including gas storage and taking gas transportation service from firms that have proposed new pipelines into or through Arizona, in order to mitigate the impact of an adverse outcome.

Voluntary Contributions in Lieu of Taxes – The Arizona Department of Revenue (ADOR) challenged the District's exclusion of contributions in aid of construction (CIAC) in calculating the total value of District property for purposes of computing "in lieu" property taxes paid by the District. While the District obtained a favorable ruling from the Arizona State Board of Equalization, the Arizona Tax Court subsequently rendered a favorable decision to the ADOR on appeal. The District intends to appeal the decision to the Court of Appeals and cannot predict the outcome at this time. If the District is unsuccessful in such appeal, it would be liable for approximately $8.9 million in additional assessments for fiscal years 2003 and 2004, in the aggregate, plus interest. Going forward, the District would stand to incur approximately $7.3 million in additional assessments each year. The District believes it has adequate reserves for this potential liability.

California Energy Market Issues – A number of lawsuits have been filed concerning aspects of the California energy market. In addition, the State of California and federal authorities are conducting investigations and other proceedings concerning various aspects of the energy market. Some of the proceedings involve potential refunds. Several of these investigations focus on the involvement of Enron in allegedly manipulating the market.

Because the District bought and sold power into the California energy market, the District has been drawn into many of the proceedings. However, the District was a net buyer in the California market during the time periods being scrutinized, and believes it is entitled to refunds if any are ordered.

Indian Matters – From time to time, SRP is involved in litigation and disputes with various Indian tribes on issues concerning regulatory jurisdiction, royalty payments, taxes and water rights, among others (see Navajo Nation Lawsuit and Air Quality above). Resolution of these matters may result in increased operating expenses.

Other Litigation – In the normal course of business, SRP is exposed to various litigations or is a defendant in various litigation matters. In management's opinion, the ultimate resolution of these matters will not have a material adverse effect on SRP's financial position or results of operations.

Self-Insurance – The District maintains various self-insurance retentions for certain casualty and property exposures. In addition, the District has insurance coverage for amounts in excess of its self-insurance retention levels. The District provides reserves based on management's best estimate of claims, including incurred but not reported claims. In management's opinion, the reserves established for these claims are adequate and any changes will not have a material adverse effect on the District's financial position or results of operations.

REPORT OF INDEPENDENT AUDITORS

To the Board of Directors of
Salt River Project Agricultural Improvement
and Power District, and
the Board of Governors of
Salt River Valley Water Users' Association

In our opinion, the accompanying combined balance sheets and the related combined statements of net revenues and comprehensive income (loss) and of cash flows present fairly, in all material respects, the financial position of Salt River Project Agricultural Improvement and Power District and its subsidiaries and Salt River Valley Water Users' Association (collectively, the Company) at April 30, 2004 and April 30, 2003, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 2 to the combined financial statements, the Company changed its method of accounting for asset retirement obligations, as of May 1, 2003.

As discussed in Note 3 to the combined financial statements, the Company changed its method of accounting for realized gains and losses on physically settled derivative contracts not held for trading purposes, as of May 1, 2003.

As discussed in Note 2 to the combined financial statements, the Company changed its method of accounting for consolidation of variable interest entities, as of January 1, 2004.

PricewaterhouseCoopers, LLP
Los Angeles, California
June 15, 2004

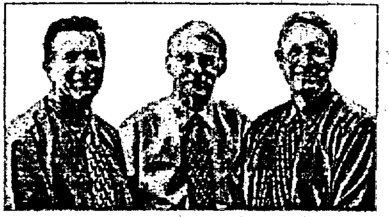
SRP COUNCILS
Association & District

District/Division 1

(left to right)
Robert L. Cook
Kevin J. Johnson
John R. Starr

District/Division 2

(left to right)
Wayne A. Hart
Vice Chairman
John A. Vanderwey
Paul E. Rovey

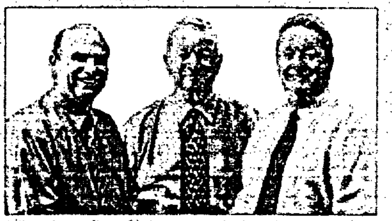


District/Division 3

(left to right)
John E. Anderson
Mario J. Herrera
Robert T. Van Hofwegen

District/Division 4

(left to right)
Lloyd E. Banning
Charles D. Coppinger
Leslie C. Williams



District/Division 5

(left to right)
Ramon P. Trujillo
Wayne A. Weiler
Stephen H. Williams

District/Division 6

(left to right)
Ben A. Butler
Robert W. Warren
Jacqueline L. Diller Miller

District/Division 7

(left to right)
Mark A. Lewis
Ann M. Burton
Harmen Tjaarda Jr.

District/Division 8

(left to right)
Deborah S. Hendrickson
John R. Hoopes
Chairman
Mark L. Farmer

District/Division 9

(left to right)
Edward E. Johnson
Arthur L. Freeman
W. Curtis Dana

District/Division 10

(left to right)
Orland R. Hatch
William P. Schrader Jr.
Mark V. Pace

SRP Two-Year Financial & Operational Review

Financial Data ($000)	2004	2003
Total operating revenues	$2,077,314	$1,893,549
Electric revenues	2,065,496	1,881,123
Water & irrigation revenues	11,818	12,426
Total operating expenses	1,867,397	1,729,484
Total other income, net	28,615	27,467
Net financing costs	116,605	138,135
Net revenues for the year	112,220	46,669
Taxes and tax equivalents	100,693	90,388
Utility plant, gross	8,747,820	8,191,576
Long-term debt	2,933,338	2,809,581
Electric revenue contributions to support water operations	62,925	44,222

Selected Data*		
Debt service coverage ratio	2.00	2.23
Total electric sales (million kWh)	33,806	35,166
Peak-SRP retail customers (kW)	5,673,000	5,296,000
Water deliveries (acre-feet)		848,791
Runoff (acre-feet)		778,786
Employees at year-end	4,267	4,231
Electric customers at year-end	824,416	796,171

**Water data is by calendar year, all other data is by fiscal year ending April 30.*

Corporate Officers

President	William P. Schrader
Vice President	John M. Williams Jr.
Secretary	Terrill A. Lonon
Treasurer	Steven J. Hulet

Executive Management

General Manager	Richard H. Silverman
Associate General Managers	David G. Areghini, *Power, Construction & Engineering Services*
	Mark B. Bonsall, *Commerical & Customer Services*
	D. Michael Rappoport, *Public & Communications Services*
	John F. Sullivan, *Water Group*
	L.J. U'Ren, *Operations, Information & Human Resources Services*
Corporate Counsel	Jane D. Alfano
Manager	Richard M. Hayslip, *Environmental, Land, Risk Management & Telecom*

Financial Inquiries

Dean Yee, Manager, SRP Financial Services
(602) 236-5231

Energy Services
Department of Water and Power
City of Los Angeles

Report and Financial Statements and
Required Supplementary Information

June 30, 2004

Los Angeles Department of Water and Power
Energy Services
Financial Statements and Required Supplementary Information – June 30, 2004
Table of Contents

Los Angeles Department of Water and Power
Energy Services

Management's Discussion and Analysis
(Unaudited)

June 30, 2004

The following discussion and analysis of the financial performance of the City of Los Angeles' (the City) Department of Water and Power's (the Department), Power System Fund (Energy Services), provides an overview of the financial activities for the fiscal year ended June 30, 2004. Descriptions and other details pertaining to Energy Services are included in the notes to the financial statements. This discussion and analysis should be read in conjunction with the Energy Services' financial statements, which begin on page 20.

Background and Creation of the Department

The Department is the largest municipal utility in the United States and is a separate proprietary agency of the City, controlling its own funds with full responsibility for meeting the electric and water requirements of its service area. The Department provides electric and water service almost entirely within the boundaries of the City, which encompasses some 465 square miles, to a population of approximately 3.9 million people. Certain factors, which affect the electric industry, generally apply to the Department's operation of Energy Services.

The Department was established under the City Charter adopted in January 1925 as amended effective July 2000. It had its beginning, however, in the early 1900's. The first Board of Water and Power Commissioners was established in 1902. The responsibilities for the provision of water as well as electricity were given to a new Los Angeles Department of Public Service organized in 1911. The Department of Public Service was superceded in 1925 when a new Charter was adopted creating the Department. Subsequently the Water Works and Electric Works came to be known as the Water System (Water Services) and the Power System (Energy Services). The operations and finances of Energy Services are separate from those of Water Services.

Charter Provisions

Governance

Pursuant to the Charter of the City (the Charter), the five-member Board of Water and Power Commissioners (the Board) is the governing body of the Department and the General Manager administers the affairs and operations of the Department. The Board is granted the possession, management and control of Energy Services. Board Commissioners are appointed for a term of five years by the mayor and confirmed by the City Council (the Council).

The provisions of the Charter relating to the Department are found in Article VI. Among other things, Article VI provides that all Energy Services revenue collected by the Department shall be deposited in the Power Revenue Fund, that the Board shall control the money in the Power Revenue Fund, and makes provisions for the issuance of Department bonds, notes and other evidences of indebtedness payable out of the Power Revenue Fund.

Section 245 of the Charter provides that any action of the Board shall become final at the expiration of the next five meeting days of the Council, during which time the Council may bring the matter for review, or veto such action. If the Council votes to bring the matter for review, it has 21 days to conduct its review, otherwise the Board's action on the matter is final.

Rates

Pursuant to the Charter, the Board, subject to the approval of the Council by ordinance, fixes the rates for electric service provided by Energy Services. The Charter provides that such rates shall be fixed by the Board from time to time as necessary. The Charter also provides that such rates shall, except as authorized by the Charter, be of uniform operation for customers of similar circumstances throughout the City, as near as may be, and shall be fair and reasonable, taking into consideration, among other things, the nature of the uses, the quantity supplied, and the value of the service, and the financial impact on Energy Services resulting from such service.

A rate freeze for all Department electric customers was instituted effective April 1, 1998, which froze electric rates at the level in effect as of October 1997. This rate freeze remained in effect during fiscal year 2004.

Transfers to the Reserve Fund of the City of Los Angeles

Under the provisions of the City Charter, Energy Services transfers funds at its discretion to the reserve fund of the City. Pursuant to covenants contained in the bond indentures, the transfers may not be in excess of the increase in fund net assets before transfers to the reserve fund of the City, of the prior fiscal year. Such payments are not in lieu of taxes and are recorded as a reduction of fund net assets in accordance with governmental accounting standards. Energy Services made a transfer of 7% of its fiscal 2003 operating revenues, plus an additional $60 million transfer, totaling $210 million to the reserve fund of the City in fiscal 2004. Energy Services expects to transfer 7% of its fiscal 2004 operating revenues, or approximately $160 million, to the reserve fund of the City in fiscal 2005.

Competitive Abilities

In 1996, certain amendments to the Charter were approved to enable the Department to compete more effectively in a deregulated electric market. These amendments are part of the amended Charter and include:

- Greater flexibility in debt structuring;
- The express authority to sell energy and related products and services outside the City;
- The ability to enter into contracts with retail customers for terms of up to ten years;
- The ability to invest cash held in the Power Revenue Fund in any investment authorized for City funds; and
- The authority to finance the energy efficiency investments of the Department's retail customers.

Critical Accounting Policies

Method of Accounting

The accounting records of Energy Services are maintained in accordance with accounting principles generally accepted in the United States of America. As a government-owned utility, in prior years the Department applied all statements issued by the Governmental Accounting Standards Board (GASB) and all statements and interpretations issued by the Financial Accounting Standards Board (FASB), which are not in conflict with statements issued by the GASB. In fiscal year 2003, the Department changed its election under the guidance in GASB Statement No. 20, "*Accounting and Financial Reporting for Proprietary Funds and Other Governmental Entities that Use Proprietary Fund Accounting*" (GASBS No. 20), to follow GASB statements and only FASB statements and interpretations issued on or before November 30, 1989. The Department is required to retroactively apply this change by restating prior years presented. The Department continued to apply the provisions of Statement of Financial Accounting Standards (SFAS) No. 106, "*Employers' Accounting for Postretirement Benefits Other Than Pensions,*" until the prescriptive guidance under governmental standards was issued. GASBS No. 45 was issued in 2004 and the Department early adopted the standard in fiscal year 2004 in accordance with the transition guidance to be in full compliance with GASBS No. 20. See Note 2 of the financial statements.

SFAS No. 71

Energy Services' rates are determined by the Board and are subject to review and approval by the Council. As a regulated enterprise, the Department's financial statements are prepared in accordance with SFAS No. 71, "*Accounting for the Effects of Certain Types of Regulation,*" which requires that the effects of the ratemaking process be recorded in the financial statements. Such effects primarily concern the time at which various items enter into the determination of changes in fund net assets in order to follow the principle of matching costs and revenues.

Revenue Recognition

Energy Services' rates are established by a rate ordinance, which is approved by the City Council. Energy Services recognizes energy costs in the period incurred and accrues for estimated energy sold but not yet billed. The Department's current rates include amounts designated for the pre-collection of out-of-market future purchased power costs. These amounts are included in deferred credits. At the discretion of the Department and approval by the Board, these amounts will be recognized in future periods pending further rate treatment. At June 30, 2004 and 2003, \$540.1 million and \$479.7 million, respectively, of pre-collected purchased power costs have been deferred.

Adoption of GASBS No. 45

Effective fiscal year 2004, the Department early adopted GASB Statement No. 45 "*Accounting and Financial Reporting by Employers for Postemployment Benefits Other Than Pensions*" (GASBS No. 45), and discontinued following FASB Statement No. 106 "*Employers' Accounting for Postretirement Benefits Other Than Pensions*" (SFAS No. 106). The adoption of GASBS No. 45 had a significant effect on the results of fiscal year 2003-04, but had no impact on the healthcare benefits provided to active and retired employees, and had no impact on the amount or the value of the funds established to meet this obligation. See Note 2 to the financial statements for further information and a description of the impact of the change on the financial statements.

In the July 1, 2003 actuarial valuation, the entry age normal cost method was used. The actuarial assumptions include a 6.50 percent discount rate which represents the expected long term return on plan assets, an annual health care cost trend rate of 16 percent initially, reduced by decrements to an ultimate rate of 5.75 percent after seven years. Both rates include a 3.5 percent inflation assumption. The actuarial value of assets was determined using techniques that spread the unfunded actuarial accrued liability being amortized as a level percentage of projected payroll over a 30 year period.

Allowances and Reserves

The Department establishes reserves and allowances for accounts receivable balances where the collection of the full receivable is uncertain. In fiscal year 2004, Energy Services increased the allowance for doubtful accounts due to certain accounts requiring above normal collection efforts.

California Receivables

The Department's policy is to reserve for known contingencies that are probable and can be estimated. The Department has recorded receivables due from two California agencies totaling $166 million as of June 30, 2004. Energy Services has also recorded a $50 million reserve against this receivable, representing management's estimate of the most probable potential refunds that may be ordered by the FERC. The FERC has questioned whether amounts charged for energy during 2000 and 2001 represent unlawful profits that should be subject to refund. It is management's belief that the entire receivable represents a valid claim and should be paid with interest by the parties owing the Department, primarily the California Power Exchange (the CPX) and the California Independent Systems Operator. In January 2001, the CPX filed for bankruptcy and management has not yet determined how and when receivables will be paid from that organization. Two utilities that had significant amounts due to these agencies, Southern California Edison Company and Pacific Gas & Electric have paid all amounts due from them to the CPX, however the amounts remain in an escrow account pending the resolution of disbursement of the funds and any offsets for the wind-up costs of the PX and allocation of any shortfalls in the CPX clearing account and interest accounts. The City Attorney continues to represent the interests of the Department in closing out this issue.

Litigation

It is the Department's policy to review the status and amount of lawsuits filed against the Department and to accrue for any probable costs based on the opinion of the City Attorney. If the City Attorney identifies a potential exposure range, with no amount within that range being more probable than the other amounts, the Department will accrue for the lowest amount within the range of potential exposure.

Using This Financial Report

This financial annual report consists of the financial statements and reflects the self-supporting activities of Energy Services that are funded primarily through the sale of energy, transmission and distribution services to the public it serves.

Balance Sheets, Statements of Revenue, Expenses and Changes in Fund Net Assets, and Statements of Cash Flows

The financial statements provide an indication of Energy Services' financial health. The Balance Sheets include all of Energy Services' assets and liabilities, using the accrual basis of accounting, as well as an indication about which assets can be utilized for general purposes, and which assets are restricted as a result of bond covenants and other commitments. The Statements of Revenue, Expenses, and Changes in Fund Net Assets report all of the revenues and expenses during the time periods indicated. The Statements of Cash Flows report the cash provided and used by operating activities, as well as other cash sources such as investment income and cash payments for bond principal and capital additions and betterments.

The following table summarizes the financial condition and changes to fund net assets and cash flows of Energy Services as of and for the fiscal years ending June 30, 2004 and 2003 (amounts in millions):

Table 1 - Summary of financial condition and changes in fund net assets

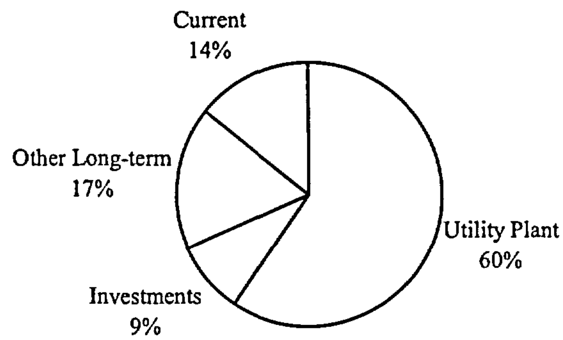
	June 30, 2004	June 30, 2003
Assets		
Utility plant, net	$ 5,165	$ 4,964
Investments	780	1,004
Other long-term assets	1,519	1,412
Current assets	1,241	1,096
	$ 8,705	$ 8,476
Liabilities and Fund Net Assets		
Long-term debt	$ 3,357	$ 3,232
Other long-term liabilities	571	722
Current liabilities	726	829
	4,654	4,783
Fund net assets:		
Invested in capital assets, net of related debt	1,664	1,568
Restricted	1,059	1,188
Unrestricted	1,328	937
Total fund net assets	4,051	3,693
	$ 8,705	$ 8,476
Revenue, Expenses, and Changes in Fund Net Assets		
Operating revenues	$ 2,288	$ 2,146
Operating expenses	(2,035)	(1,924)
Operating income	253	222
Investment income	92	132
Other income and expenses, net	17	12
Debt expenses	(134)	(139)
Contributions in aid of construction	39	26
Transfer to the reserve fund of the City of Los Angeles	(210)	(185)
Extraordinary loss on extinguishment of debt	(6)	-
Increase in fund net assets	51	68
Beginning balance of fund net assets	3,693	3,625
Adjustment due to change in accounting principle from SFAS No. 106 to GASBS No. 45	307	-
Ending balance of fund net assets	$ 4,051	$ 3,693
Cash Flows		
Cash flows from operating activities	$ 505	$ 793
Cash flows from noncapital financing activities	(185)	(188)
Cash flows from capital and related financing activities	(486)	(813)
Cash flows from investing activities	270	205
Change in cash increase (decrease)	$ 104	$ (3)

Assets

Utility Plant

Utility plant is the first category of assets shown on the balance sheet. The utility industry is unique in this regard as most other industries list their long-term assets such as plant and equipment after current assets on the balance sheet. This difference is due to the capital-intensive nature of the utility industry with the most significant portion of that capital being invested in utility plant. As depicted in the chart below, utility plant, net of accumulated depreciation, makes up 60% of the total assets of Energy Services as of June 30, 2004.

Chart 1 - Total Assets by Type



During fiscal year 2004, Energy Services capitalized $642 million of additions to utility plant in service. Of the $642 million, $378 million, or 59% related to generation plant assets. The majority of these additions were incurred as part of Energy Services' Integrated Resource Plan. Furthermore, Energy Services had capital improvements to its transmission and distribution utility plant assets to maintain and support normal load growth of the distribution and transmission systems.

Construction work in progress decreased by $110.6 million from fiscal year 2003 primarily as a result of ongoing local generation projects under the Integrated Resource Plan being placed in commercial service.

Energy Services has budgeted approximately $643 million of capital expenditures for fiscal year 2005.

During the fourth quarter of fiscal year 2004, Energy Services adopted a depreciation study covering utility plant assets. The study was completed by an independent third party and recommended changing the useful life estimates on certain assets. The adoption of the study resulted in reducing depreciation expense by $11 million for the fourth quarter of 2004.

The Department's strategy is to have generating utility plant assets that can produce energy from a variety of fuel types. This is referred to as a hedged power supply. This is important in that if the costs related to a particular fuel type rise substantially in a short period of time, the Department can utilize its mix of generation assets to meet customer demand and to minimize increases in fuel expense. The Department has implemented a $2 billion, ten-year plan to upgrade its local power plants and to implement a program that includes demand side management, alternative energy sources and distributed generation. Through June 30, 2004, the Department has incurred $1.2 billion related to such upgrades.

The table below summarizes the generating resources available to the Department as of June 30, 2004. These resources include those owned by the Department (either solely or jointly with other utilities) as well as resources available through long-term purchase agreements. Generating station capacity is measured in megawatts.

Table 2 - Generation resources

Resource Type	Number of Units		Maximum Capacity (MWs)	Dependable Capacity
Oil and gas	20		3,195	3,157
Coal	7		1,837	1,788
Nuclear	3		373	367
Hydro	30	*	1,948	1,832
	60		7,353	7,144

* Hoover Plant Station is counted as one unit.

Due From Water Services

As of June 30, 2004, Energy Services was owed $20 million from Water Services, as compared to a payable to Water Services of $67 million as of June 30, 2003. Amounts owed between the two funds are generally settled within one month.

Investments

The Department sets aside funds to be used in future years for specified purposes. At June 30, 2004, a total of $780 million in restricted and other investments was held by Energy Services, consisting primarily of U.S. government securities, bonds and repurchase agreements and other investments such as commercial paper and negotiable certificates of deposit. These investments are set aside for the following purposes:

- Refunding debt: the escrow investments are held to call specified revenue bonds at scheduled maturity dates. As of June 30, 2004 the balance of the escrow investment was $0.

- Debt reduction: the debt reduction trust funds were established during fiscal year 1997 to provide for the payment of principal and interest on long-term debt obligations and purchased power obligations arising from the Department's participation in the Intermountain Power Agency (IPA) and the Southern California Public Power Authority (SCPPA). Energy Services has $664 million in the debt reduction trust fund as of June 30, 2004.

- Nuclear decommissioning: nuclear decommissioning trust funds will be used to pay the Department's share of decommissioning the Palo Verde Nuclear Generating Station at the end of its useful life. Energy Services has $91 million in the decommissioning trust funds as of June 30, 2004.

- Postretirement benefits: the postretirement health care benefit fund was established to provide for the payment of the Department's postretirement health care benefits. The adoption of GASBS No. 45 did not impact the amount or value of this fund. As of June 30, 2004 Energy Services had $198 million in the postretirement fund. This fund is not included as a restricted investment, but instead netted against Energy Services post retirement liability under appropriate accounting guidance.

- Natural gas trust fund: the natural gas trust fund was established to serve as depository for funds transferred from the Power Revenue Fund to pay for costs, expenses, and post margin or collateral in connection with financial transactions for natural gas. These transactions are entered into to stabilize the natural gas portion of the Department's fuel costs. As of June 30, 2004 Energy Services had $25 million in the natural gas trust fund.

- Other: other investments consist of funds held by SCPPA on behalf of the Department and by the Department for payment of future SCPPA obligations. Certain of these investments are currently being used by the Department to provide for the payment of principal and interest on long-term debt obligations and purchased power obligations arising from the Department's participation in SCPPA. As of June 30, 2004, Energy Services had $35 thousand in other investments.

The Department has a securities lending program which allows it to lend up to 20% of its investments held in the debt reduction trust funds, decommissioning trust funds, and plan assets held in the postretirement benefits fund for securities, cash collateral or letters of credit equal to 102% of the market value of the loaned securities and interest, if any. The lending agent provides indemnification for borrower default. There were no violations of legal or contractual provisions and no borrower or lending agent default losses during fiscal years 2004 and 2003.

In addition, Energy Services participates in the City's securities lending program and is allocated its share of the collateral received and the related liability, as well as earnings from the program. As of June 30, 2004 and 2003, the amount of collateral and liability pertaining to both securities lending programs combined were $226 million and $243 million, respectively.

Management believes that participation in these securities lending programs increases interest earnings and results in minimal credit risk exposure to the Department because the amounts owed to the borrowers exceed the amounts that have been loaned.

Other Long-term Assets

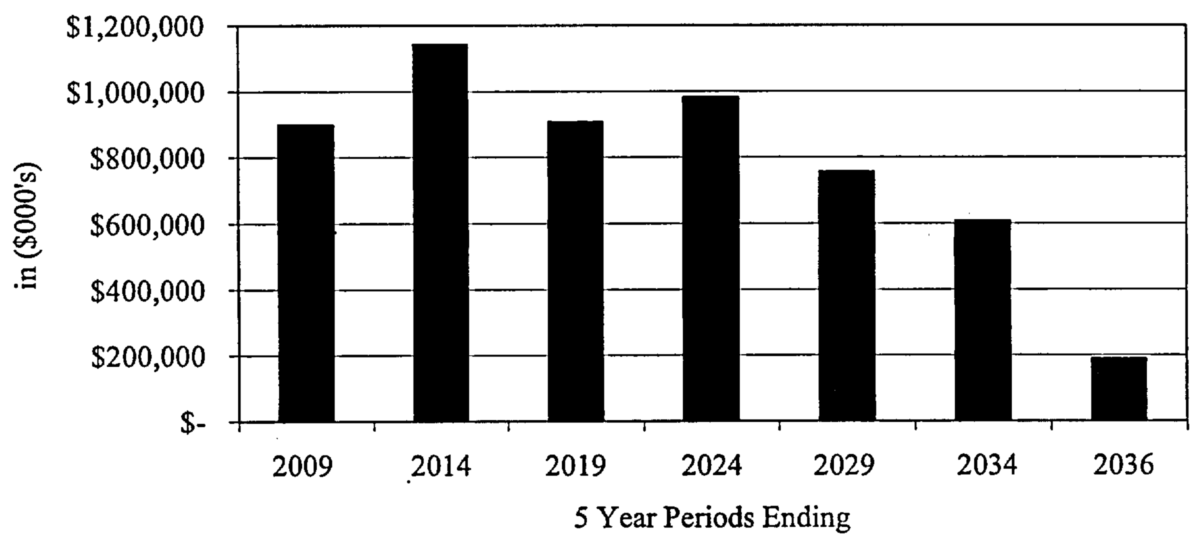
A significant portion of other long-term assets is Energy Services' long-term notes receivable. Prior to fiscal year 2002, the Department transferred $1.3 billion to IPA in exchange for long-term notes receivable. The funds transferred were obtained from the debt reduction trust fund and through the issuance of variable rate bonds. IPA used the proceeds to defease bonds with a face value of $1.4 billion. By establishing these long term notes, the Department's purchased power costs will be lower in future periods due to lower debt service requirements. See Note 6 of the financial statements for further information on purchased power costs.

Liabilities and Fund Net Assets

Long-term debt

As of June 30, 2004, Energy Services' total long-term debt balance was $3.5 billion. The increase of $108 million from the prior year mainly resulted from the issuance of $200 million of new money bonds to fund capital expenditures, less $36 million of scheduled maturities. Furthermore, Energy Services issued $956 million in revenue bonds and used $93 million in cash to refund $1.06 billion of revenue bonds outstanding. Energy Services also issued an additional $10 million in Mini-Bonds to employees and retirees. Outstanding principal, plus scheduled interest as of June 30, 2004, is scheduled to mature as shown in the chart below:

Chart 2: Debt Service Requirements



As of June 30, 2004, $432 million principal amount of long-term debt is considered defeased and remains outstanding. This debt, together with trust funds set aside for its full repayment at scheduled maturity dates, has been derecognized and is not reflected on the balance sheet.

In September 2004, Standard & Poor's and Fitch affirmed Energy Services' bond rating of AA- due to Energy Services' strong financial position, debt reduction program, hedged power supply, experienced management team, and favorable customer/revenue mix.

Other long-term liabilities

Other long term liabilities decreased $150 million in fiscal year 2004. The decrease is due to the change in the postretirement liability of $231 million offset by an increase of $74 million in deferred credits and a $6 million increase in accrued workers' compensation claims.

Current liabilities

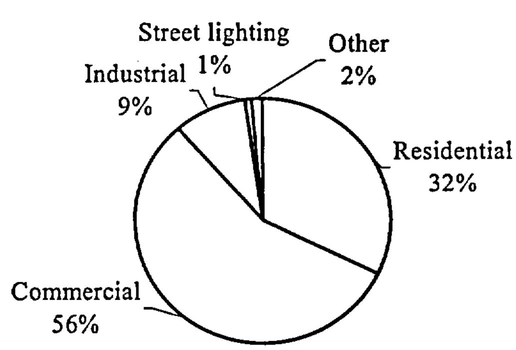
Current liabilities decreased $103 million during fiscal year 2004. The decrease is primarily due to Energy Services' repayment of the $67 million due to Water Services as of June 2003, a reduction of $50 million in accounts payable and other accrued expenses, and an $18 million decrease in other short term payables, offset by an increase in the payables to the City of Los Angeles $31 million.

Changes in Fund Net Assets

Revenues

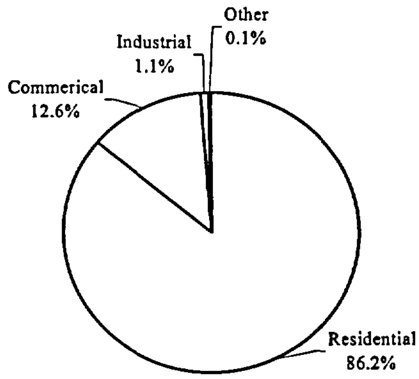
The operating revenues of Energy Services are generated from wholesale and retail customers. There are four major customer categories of retail revenue. These categories include residential, commercial, industrial, and other, which includes public street lighting. Chart 3 summarizes the percentage contribution of retail revenues from each customer segment in fiscal year 2004.

Chart 3: Revenues



While commercial customers consume the most electricity, residential customers represent the largest customer class. As of June 30, 2004, Energy Services had approximately 1.4 million customers. As shown in Chart 4, 1.2 million, or 86% of total customers were in the residential customer class.

Chart 4: Number of Customers



Fiscal year 2004

Wholesale and retail revenues in all customer classes increased from fiscal year 2003 due to an increase in consumption. The increase is mostly due to increased consumption in the months of April and May 2004 due to warmer than expected weather.

Fiscal year 2003

While retail revenues increased from fiscal year 2002, overall operating revenues decreased from fiscal year 2002 levels due to a reduction in wholesale business. Wholesale prices declined from an average of $68 per MWH in fiscal year 2002 to an average of $44 per MWH in fiscal year 2003 for the Department. The decline in market pricing resulted in a reduction of market opportunities for the Department's excess generation.

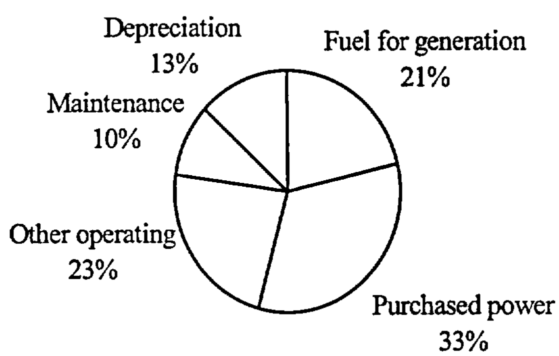
Operating Expenses

Fuel for generation and purchased power are two of the largest expenses that Energy Services incurs each fiscal year. Fuel for generation expense includes the cost of fuel that is used to generate energy. The majority of fuel costs include the cost of natural gas, coal, and nuclear fuel.

Purchased power expense includes the cost of buying power on the open market and paying the current portion of Energy Services' purchase power contracts. Under these purchase power contracts, the Department has an entitlement to the energy that is produced at various generating stations, and an entitlement to the use of various transmission facilities. Most of these contracts require the Department to pay for these services regardless of whether the energy or transmission is used. These types of contracts are referred to as "take-or-pay" contracts.

Depreciation expense is computed using the straight-line method based on service lives for all projects completed after July 1, 1973, and for all office and shop structures, related furniture and equipment, and transportation and construction equipment. Depreciation for facilities completed prior to July 1, 1973 is computed using the 5% sinking fund method based on estimated service lives. The Department uses the composite method of depreciation and therefore groups assets into composite groups for purposes of calculating depreciation expense. Estimated service lives range from 5 to 75 years. Amortization expense for computer software is computed using the straight-line method over 5 years. The chart below summarizes Energy Services' operating expenses during fiscal year 2004:

Chart 5: Operating Expenses



Fiscal year 2004

Fiscal year 2004 operating expenses were $111 million higher as compared to the prior year. Fuel for generation expense had the largest increase of $160 million due to increased natural gas costs. These costs were offset by lower purchased power costs, and lower health care costs that needed to be distributed due to an accounting change.

Depreciation expense decreased slightly during fiscal year 2004 as compared to fiscal year 2003, mainly due to the implementation of the 2003 Depreciation Study. The depreciation study was adopted in the fourth quarter of 2004 and resulted in an $11 million reduction to deprecation expense. The decrease was offset by additional depreciation in the current year as a result of additions to utility plant.

Furthermore, Energy Services recognized a $13 million impairment charge during fiscal year 2004 relating to the expected closure of the Mohave Generating Station and discontinued use of a procurement software program. See Note 14 of the financial statements for further discussion.

Fiscal year 2003

Fiscal year 2003 operating expenses were $45 million higher as compared to the prior year. Maintenance and other operating expenses had the largest increase of $77 million due to increased labor and employee benefit costs, in addition to continued increases in security costs. The largest increases incurred by Energy Services were in distribution plant maintenance, production operating expense and customer accounting expenses.

Depreciation expense decreased during fiscal year 2003 as compared to fiscal year 2002, mainly due to a change in estimated service lives of certain utility plant assets and the cessation of depreciation of two major facilities as they reached the end of their useful lives for accounting purposes. This change in estimate resulted in a reduction to Energy Services' depreciation expense by a total of $54 million. The decrease was offset by additional depreciation in the current year as a result of additions to utility plant.

Furthermore, Energy Services recognized an $8 million impairment charge during fiscal year 2003 relating to the sale of one of its administrative facilities. The Department further reduced the sales price of the facilities as a result of mold that was discovered in the facility. See Note 14 of the financial statements for further discussion.

Non-Operating Revenue and Expenses

Fiscal year 2004

The major non-operating activities of Energy Services for fiscal year 2004 included the transfer of $210 million to the City's General Fund, interest income earned on investments of $92 million, and $134 million in debt expenses. Interest on investments followed the general trend in interest rates and decreased from an average yield of 2.84% in fiscal year 2003 to 2.33% in fiscal year 2004. Interest on debt declined due to lower rates on variable rate debt and the effects of the debt restructuring program which lowered average interest rates on fixed rate debt. Interest income declined from fiscal year 2003 to 2004 due to a reduction in investments of $175 million.

Fiscal year 2003

The major non-operating activities of Energy Services for fiscal year 2003 included the transfer of $185 million to the City's General Fund, interest income earned on investments of $132 million, and $139 million in debt expenses. Interest on investments followed the general trend in interest rates and declined from an average yield of 3.44% in fiscal year 2002 to 2.84% in fiscal year 2003. Interest on debt declined due to lower rates on variable rate debt and the effects of the debt restructuring program which lowered average interest rates on fixed rate debt.

Changes in Operating, Investing and Financing Activities

Operating activities

Cash from operating activities was $288 million lower in fiscal year 2004 due to increased payments to suppliers of $241 million, increased in cash payments to other agencies for fees collected of $32 million and increased cash payments of $109 million for interfund services offset by increased cash from retail sales of $111 million.

Noncapital financing activities

The noncapital financing activities for Energy Services for fiscal year 2004 included the transfer to the City of Los Angeles of $179 million, and interest paid on noncapital revenue bonds of $5 million.

Capital and related financing activities

The capital and related financing activities for fiscal year 2004 were $327 million less than the capital and related financing activities of fiscal year 2003. The main decreases were lower net additions to utility plant of $125 million, $28 million of lower interest payments, and $114 million of bond proceeds in excess of principal payments and maturities. Below is a summary of the Department's debt management program and purpose.

Debt Management Program

The debt restructuring element of the Debt Management Program includes the issuance of refunding bonds to achieve debt service savings and to accelerate the maturity of certain bonds while maintaining an appropriate overall annual debt service schedule for all of the Department's obligations in connection with Energy Services. As of June 30, 2004 the Department completed its refunding program, including the issuance of several series of refunding bonds payable from the Power Revenue Fund under a Master Bond Resolution adopted by the Board on February 6, 2001. Pursuant to this refunding program, the Department issued $3.1 billion principal amount of refunding bonds to redeem, defease or purchase $2.5 billion principal amount of Department revenue bonds payable from the Power Revenue Fund and $0.6 billion principal amount of Intermountain Power Agency (IPA) bonds. As of August 2003, Energy Services had completed its refunding program.

In addition, Energy Services has $664 million on deposit in trust funds restricted for the use of debt reduction as of June 30, 2004. The Debt Management Program is intended to bring Energy Services' cost structure to a competitive level.

Investing activities

Investing activities during fiscal year 2004 provided an additional $65 million of cash as compared to fiscal year 2003. The increase was due mostly to higher investment maturities than amounts reinvested in securities. Below is a summary of the Department's investment policy and controls.

Investment Policy and Controls

The Department's cash, other than cash in certain trust funds, is deposited with the City Treasurer, who invests the funds in securities under the City Treasurer's pooled investment program, for the purpose of maximizing interest earnings. Under the program, available funds of the City and its independent operating departments are invested on a combined basis. The primary responsibilities of the City Treasurer are to protect the principal and asset holdings of the City's portfolio and to ensure adequate liquidity to provide for the prompt and efficient handling of City disbursements. The City Treasurer invests these funds in compliance with the applicable California Government Code and the City's Investment Policy. Generally, investments are limited to government securities with credit ratings of AAA and are of varying maturities, which can range from less than 90 days to in excess of two years.

Risk Factors

Energy Services' primary business is to provide its retail customers with reliable electricity service. Energy Services manages its overall cost of providing service by monitoring wholesale markets and purchasing electricity for customers when the market price is below the marginal cost of producing energy from Department resources. Energy Services sells its surplus generation to the market when the cost of excess resources is below the market price. The transactions are executed with external parties, primarily other utility companies and broker dealers which we refer to as counterparties.

The Department manages its counterparty risk by evaluating each of the entities that it transacts with and limiting its transaction volume based on an assessment of the entity's financial strength. In addition, the Department enters into master netting agreements with other Western System Coordinating Council participants.

Energy Services is subject to market risk in that the wholesale market price of energy impacts its cost of energy purchases in addition to its ability to market surplus power. The Department manages that risk by devoting its owned and contract resources to service retail customers. Only surplus resources are made available to wholesale markets. During fiscal 2004, the Department's peak load was 5,410 MWs. Net dependable capacity from owned and contract resources totaled 7,144 MWs.

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Report of Independent Auditors

To the Board of Water and Power Commissioners
Department of Water and Power
City of Los Angeles

In our opinion, the accompanying balance sheets and the related statements of revenue, expenses and changes in fund net assets and of cash flows present fairly, in all material respects, the financial position of the Power System (Energy Services) of the Department of Water and Power of the City of Los Angeles at June 30, 2004 and 2003, and the changes in its financial position and cash flows for each of the three years in the period ended June 30, 2004 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Department's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Notes 2 and 12 to the financial statements, effective July 1, 2003, Energy Services adopted Governmental Accounting Standards Board (GASB) Statement No. 45, "Accounting and Financial Reporting by Employers for Postemployment Benefits Other Than Pensions" and discontinued applying Financial Accounting Standards Board Statement No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions," in accounting for its healthcare costs.

As discussed in Notes 2 and 14 to the financial statements, effective July 1, 2003, Energy Services adopted GASB Statement No. 42, "Accounting and Financial Reporting for Impairment of Capital Assets and for Insurance Recoveries."

The management's discussion and analysis included on pages 1 through 18 and the information on the postretirement benefits other than pension plans on page 70 are not a required part of the basic financial statements but are supplementary information required by the Governmental Accounting Standards Board. We have applied certain limited procedures, which consisted primarily of inquiries of management regarding the methods of measurement and presentation of the required supplementary information. However, we did not audit the information and express no opinion on it.

PricewaterhouseCoopers LLP

February 7, 2005

Los Angeles Department of Water and Power
Energy Services Balance Sheets
(Amounts in thousands)

	June 30, 2004	June 30, 2003
Assets		
Non-Current Assets		
Utility Plant		
Generation	$ 2,989,566	$ 2,622,137
Transmission	855,561	829,457
Distribution	3,999,153	3,893,836
General	942,117	915,054
	8,786,397	8,260,484
Accumulated depreciation	4,286,243	4,073,466
	4,500,154	4,187,018
Construction work in progress	652,375	763,000
Nuclear fuel, at amortized cost	12,553	13,431
	5,165,082	4,963,449
Restricted and other investments	780,575	1,004,372
Long-term California wholesale energy receivable, net	116,486	128,715
Long-term notes and other receivables	1,121,096	1,164,457
Net pension asset	122,271	119,198
Net postretirement asset	159,183	-
	1,519,036	1,412,370
Current Assets		
Cash and cash equivalents - unrestricted	188,350	126,072
Cash and cash equivalents - restricted	162,762	120,742
Cash collateral received from securities lending transactions	225,995	243,361
Customer and other accounts receivable, net of $28,585 and $11,000 allowance for losses, respectively	232,308	216,535
Current portion of long-term notes receivable	55,076	63,827
Due from Water Services	20,007	-
Accrued unbilled revenue	130,527	118,853
Materials and fuel	108,716	111,236
Prepayments and other current assets	117,033	95,635
	1,240,774	1,096,261
	$ 8,705,467	$ 8,476,452

The accompanying notes are an integral part of these financial statements.

Los Angeles Department of Water and Power
Energy Services Balance Sheets
(Amounts in thousands)

Fund Net Assets and Liabilities	June 30, 2004	June 30, 2003
Fund Net Assets		
Invested in capital assets, net of related debt	$ 1,663,861	$ 1,568,405
Restricted fund net assets	1,058,674	1,188,192
Unrestricted fund net assets	1,328,398	936,465
	4,050,933	3,693,062
Long term debt	3,356,548	3,232,088
Other Non-Current Liabilities		
Deferred credits	540,143	466,167
Accrued postretirement liability, net	-	230,693
Accrued workers' compensation claims	31,352	25,163
Commitments and contingencies (Notes 6 and 15)	-	-
	571,495	722,023
Current Liabilities		
Current portion of long-term debt	146,838	163,180
Accounts payable and accrued expenses	165,384	212,161
Payable to the reserve fund of the City of Los Angeles	60,000	29,000
Accrued interest	63,005	49,723
Accrued employee expenses	65,269	64,407
Due to Water Services	-	67,447
Obligation under securities lending transactions	225,995	243,361
	726,491	829,279
	$ 8,705,467	$ 8,476,452

The accompanying notes are an integral part of these financial statements.

Los Angeles Department of Water and Power
Energy Services Statements of Revenue, Expenses, and Changes in Fund Net Assets
(Amounts in thousands)

	Year Ended June 30,		
	2004	2003	2002
			(Restated)
Operating Revenues			
Residential	$ 717,912	$ 643,641	$ 632,113
Commercial and industrial	1,460,814	1,403,422	1,377,135
Sales for resale	73,959	64,097	191,073
Other	49,682	47,544	46,316
Uncollectible accounts	(14,271)	(12,791)	(11,573)
	2,288,096	2,145,913	2,235,064
Operating Expenses			
Fuel for generation	434,122	273,905	280,851
Purchased power	662,070	697,824	688,790
Maintenance and other operating expenses	661,404	675,181	598,391
Depreciation and amortization	264,126	268,612	302,887
Loss on asset impairment and abandoned projects	13,634	8,330	-
	2,035,356	1,923,852	1,870,919
Operating Income	252,740	222,061	364,145
Other Income and Expense			
Investment income	91,849	132,431	130,079
Gain on sale of utility plant asset	-	-	67,615
Other non-operating income	21,066	17,013	20,934
	112,915	149,444	218,628
Other non-operating expenses	3,967	4,807	19,724
	108,948	144,637	198,904
Debt Expenses			
Interest on debt	135,793	141,238	154,600
Allowance for funds used during construction	(1,903)	(1,799)	(1,393)
	133,890	139,439	153,207
Contributions in aid of construction	38,514	25,818	22,014
Change in fund net assets before transfers			
to the reserve fund of the City of Los Angeles	266,312	253,077	431,856
Transfers to the reserve fund of the City of Los Angeles	(210,214)	(185,358)	(179,153)
Extraordinary loss on extinguishment of debt	(5,624)	-	-
Increase in fund net assets	50,474	67,719	252,703
Fund net assets			
Beginning of period	3,693,062	3,625,343	3,372,640
Adjustment due to change in accounting principle			
from SFAS No. 106 to GASBS No. 45 (See Note 2)	307,397	-	-
End of period	$ 4,050,933	$ 3,693,062	$ 3,625,343

The accompanying notes are an integral part of these financial statements.

Los Angeles Department of Water and Power
Energy Services Statements of Cash Flows
(Amounts in thousands)

	Year Ended June 30,		
	2004	2003	2002
Cash Flows from Operating Activities:			(Restated)
Cash Receipts			
Cash receipts from retail customers	$ 2,306,676	$ 2,195,695	$ 2,088,916
Cash receipts from retail customers for other agency services	289,096	269,158	273,361
Cash receipts from wholesale customers	96,988	112,613	266,489
Cash receipts from interfund services provided	286,023	283,803	256,774
Cash Disbursements			
Cash payments to employees	(388,834)	(368,289)	(328,508)
Cash payments to suppliers	(1,374,458)	(1,133,505)	(1,241,118)
Cash payments for interfund services used	(396,332)	(287,448)	(254,213)
Cash payments to other agencies for fees collected	(302,871)	(271,246)	(276,419)
Other operating cash payments	(11,101)	(8,196)	(349)
	505,187	792,585	784,933
Cash Flows from Noncapital Financing Activities:			
Payments to the reserve fund of the City of Los Angeles	(179,214)	(181,358)	(154,153)
Cash received for state grant	-	-	8,000
Cash disbursed for state grant expenses	-	-	(14,753)
Interest paid on noncapital revenue bonds	(5,402)	(6,862)	(9,829)
	(184,616)	(188,220)	(170,735)
Cash Flows from Capital and Related Financing Activities:			
Additions to plant and equipment, net	(547,527)	(672,865)	(523,445)
Proceeds from sale of utility plant asset	-	-	95,000
Contributions in aid of construction	45,477	26,025	11,060
Purchases of escrow investments	-	(34,408)	-
Proceeds from escrow investment maturities	34,262	28,593	250,315
Principal payments and maturities on long-term debt, net	(1,125,282)	(419,320)	(392,699)
Issuance of bonds and revenue certificates, net	1,222,461	402,385	112,837
Debt interest payments	(115,458)	(143,462)	(136,517)
	(486,067)	(813,052)	(583,449)
Cash Flows from Investing Activities:			
Purchases of investment securities	(4,026,043)	(4,637,343)	(3,197,807)
Proceeds from sales and maturities of investment securit	4,129,278	4,636,609	2,857,321
Proceeds from notes receivables	64,453	70,322	36,002
Investment income	102,106	135,690	131,372
	269,794	205,278	(173,112)
Cash and Cash Equivalents:			
Net increase (decrease)	104,298	(3,409)	(142,363)
Cash and cash equivalents July 1 (including $120,742, $83,463, and $174,002 reported in restricted accounts, respectively)	246,814	250,223	392,586
Cash and cash equivalents June 30 (including $162,762, $120,742, and $83,463 reported in restricted accounts, respectively)	$ 351,112	$ 246,814	$ 250,223

The accompanying notes are an integral part of these financial statements.

Los Angeles Department of Water and Power
Energy Services Statements of Cash Flows, continued
(Amounts in thousands)

	Year Ended June 30,		
	2004	2003	2002 (Restated)
Reconciliation of operating income to net cash provided by operating activities			
Operating income	$ 252,740	$ 222,061	$ 364,145
Adjustments to reconcile operating income to net cash provided by operating activities			
Depreciation and amortization	264,126	268,612	302,887
Provision for losses on customer and other accounts receivable	14,271	12,791	11,573
Loss on asset impairment and abandoned projects	13,634	8,330	
Changes in assets and liabilities:			
Customer and other accounts receivable	(20,445)	43,697	32,373
Accrued unbilled revenue	(11,674)	1,175	4,449
Materials and fuel	2,521	(3,646)	(2,610)
Net pension asset	(3,073)	6,457	(13,393)
Accounts payable and accrued expenses	(46,777)	63,439	(35,235)
Deferred credits	73,975	44,335	70,938
Due (from) to Water Services	(68,588)	61,423	(1,316)
Accrued postretirement asset / liability	38,065	49,863	41,055
Workers' compensation liability and other	(3,588)	14,048	10,067
Cash provided by operating activities	$ 505,187	$ 792,585	$ 784,933

The accompanying notes are an integral part of these financial statements.

NOTE 1: Summary of Significant Accounting Policies

The Department of Water and Power of the City of Los Angeles (the Department) exists as a separate proprietary agency of the City of Los Angeles (the City) under and by virtue of the City Charter enacted in 1925 and as revised effective July 2000. The Department's Power System (Energy Services) is responsible for the generation, transmission, and distribution of electric power for sale in the City.

Method of accounting

The accounting records of Energy Services are maintained in accordance with accounting principles generally accepted in the United States of America. As a government-owned utility, in prior years the Department applied all statements issued by the Governmental Accounting Standards Board (GASB) and all statements and interpretations issued by the Financial Accounting Standards Board (FASB), which are not in conflict with statements issued by the GASB. In fiscal year 2003 the Department changed its election under the guidance in GASB Statement No. 20, "*Accounting and Financial Reporting for Proprietary Funds and Other Governmental Entities that Use Proprietary Fund Accounting*" (GASBS No. 20), to follow all GASB statements and only FASB statements and interpretations issued on or before November 30, 1989. Fiscal year 2002 was restated. See Note 2. The Department continued to follow Statement of Financial Accounting Standards (SFAS) No. 106 for postretirement benefits until the beginning of fiscal year 2004 when the Department early adopted GASBS No. 45 for postretirement benefits. See Note 2.

The Department's rates are determined by the Board of Water and Power Commissioners (the Board) and are subject to review and approval by the City Council. As a regulated enterprise, the Department utilizes SFAS No. 71, "*Accounting for the Effects of Certain Types of Regulation,*" which requires that the effects of the ratemaking process be recorded in the financial statements. Such effects primarily concern the time at which various items enter into the determination of changes in fund net assets. Accordingly, Energy Services records various regulatory assets and liabilities to reflect the Board's actions. Management believes that Energy Services meets the criteria for continued application of SFAS No. 71, but will continue to evaluate its applicability based on changes in the regulatory and competitive environment (see Note 3).

Use of estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

NOTE 1: (continued)

Utility plant

The costs of additions to utility plant and replacements of retired units of property are capitalized. Costs include labor, materials, an allowance for funds used during construction (AFUDC), and allocated indirect charges such as engineering, supervision, transportation and construction equipment, retirement plan contributions, health care costs, and certain administrative and general expenses. The costs of maintenance, repairs and minor replacements are charged to the appropriate operations and maintenance expense accounts. The original cost of property retired, net of removal and salvage costs, is charged to accumulated depreciation.

During fiscal year 2004, Energy Services reversed previously capitalized postretirement health care costs of $70 million from utility plant assets, net. These costs were capitalized as construction charges under SFAS No. 106 as a component of labor expenses. As a result of the adoption of GASBS 45, these costs were eliminated. See Note 2 for the effect in the change in accounting from SFAS No. 106 to GASBS 45.

Impairment of long-lived assets

Effective fiscal year 2004, the Department adopted GASBS No. 42 "*Accounting and financial Reporting for Impairment of Capital Assets and for Insurance Recoveries*", (GASBS 42). Governments are required to evaluate prominent events or changes in circumstances affecting capital assets to determine whether impairment of a capital asset has occurred. A capital asset is considered impaired when its service utility has declined significantly and unexpectedly. Under GASBS 42, impaired capital assets that will no longer be used by the government should be reported at the lower of carrying value or fair value. Impairment losses on capital assets that will continue to be used by the government should be measured using the method that best reflects the diminished service utility of the capital asset. (See Notes 2 and 14.)

Depreciation and amortization

Depreciation expense is computed using the straight-line method based on service lives for all projects completed after July 1, 1973, and for all office and shop structures, related furniture and equipment, and transportation and construction equipment. Depreciation for facilities completed prior to July 1, 1973 is computed using the 5% sinking fund method based on estimated service lives. The Department uses the composite method of depreciation and therefore groups assets into composite groups for purposes of calculating depreciation expense. Estimated service lives range from 5 to 75 years. Amortization expense for computer software is computed using the straight-line method over 5 years. Depreciation and amortization expense as a percentage of average depreciable utility plant in service was 3.2%, 3.4% and 4.0% for fiscal years 2004, 2003 and 2002, respectively.

NOTE 1: (continued)

During fiscal year 2004, the Department hired an independent third party to complete a depreciation study on Energy Services utility plant assets. The study recommended lengthening the lives of certain utility plant assets and shortening others. The results of the study were adopted in the fourth quarter of 2004 and resulted in an $11 million decrease to depreciation expense as compared to the depreciation expense that would have been recorded under the previous rates.

During fiscal year 2003, Energy Services ceased depreciating two of its major facilities as they reached the end of their useful lives for accounting purposes.

Nuclear decommissioning

The Department owns a 5.7% direct ownership interest in the Palo Verde Nuclear Generating Station (PVNGS). In addition, through its participation in the Southern California Public Power Authority (SCPPA), the Department is party to a contract for an additional 3.95% of the output of PVNGS. Nuclear decommissioning costs associated with the Department's output entitlement are included in purchased power expense (see Note 6).

Decommissioning of PVNGS is expected to commence subsequent to the year 2024. The total cost to decommission the Department's direct ownership interest in PVNGS is estimated to be $112 million in 2001 dollars. This estimate is based on an updated site-specific study prepared by an independent consultant in 2001. As of June 30, 2004 and 2003, the Department has recorded $110.9 million and $110.2 million, respectively, to accumulated depreciation to provide for the decommissioning liability.

Prior to December 1999, the Department contributed $70.2 million to external trusts established in accordance with the PVNGS participation agreement and Nuclear Regulatory Commission requirements. During fiscal year 2000, the Department suspended contributing additional amounts to the trust funds, as management believes that contributions made, combined with reinvested earnings, will be sufficient to fully fund the Department's share of decommissioning costs. The Department will continue to reinvest its investment income into the decommissioning trusts. The Department reinvested $0.7 million and $4.7 million of investment income in fiscal years 2004 and 2003, respectively. Decommissioning funds, which are included in restricted investments, totaled $91.3 and $90.6 million as of June 30, 2004 and 2003 (at fair value), respectively. The Department's current accounting policy recognizes any realized and unrealized investment earnings from nuclear decommissioning trust funds as a component of accumulated depreciation.

NOTE 1: (continued)

Nuclear fuel

Nuclear fuel is amortized and charged to fuel for generation on the basis of actual thermal energy produced relative to total thermal energy expected to be produced over the life of the fuel. Under the provisions of the Nuclear Waste Policy Act of 1982, the federal government assesses each utility with nuclear operations, including the Department, $1 per megawatt hour of nuclear generation. The Department includes this charge as a current year expense in fuel for generation. See Note 15 for discussion of spent nuclear fuel disposal.

Cash and cash equivalents

As provided for by the California Government Code, the Department's cash is deposited with the City Treasurer in the City's general investment pool for the purpose of maximizing interest earnings through pooled investment activities. Cash and cash equivalents in the City's general investment pool are reported at fair value and changes in unrealized gains and losses are recorded in the statements of revenue, expenses, and changes in fund net assets. Interest earned on such pooled investments is allocated to the participating funds based on each fund's average daily cash balance during the allocation period. The City Treasurer invests available funds of the City and its independent operating departments on a combined basis. The Department classifies all cash and cash equivalents that are restricted either by creditors, the Board, or by law, as restricted cash and cash equivalents on the balance sheet. The Department considers its portion of pooled investments with an original maturity of three months or less to be cash equivalents.

At June 30, 2004 and 2003 restricted cash and cash equivalents include the following (amounts in thousands):

	June 30,	
	2004	2003
Bond redemption and interest funds	$ 114,983	$ 86,162
Construction funds	2,164	222
Self insurance fund	42,475	32,475
Other	3,140	1,883
	$ 162,762	$ 120,742

Materials and fuel

Materials and supplies are recorded at average cost. Fuel is recorded at lower of cost or market, on an average cost basis.

NOTE 1: (continued)

Restricted and other investments

Restricted and other investments include primarily commercial paper, United States government and governmental agency securities, and corporate bonds. Investments are reported at fair value and changes in unrealized gains and losses are recorded in the statement of revenue, expenses and changes in fund net assets. Gains and losses realized on the sale of investments are generally determined using the specific identification method. The stated fair value of investments is generally based on published market prices or quotations from major investment dealers.

Accrued employee expenses

Accrued employee expenses include accrued payroll and an estimated liability for vacation leave, sick leave and compensatory time, which is accrued when employees earn the rights to the benefits.

Debt expenses

Debt premium, discount and issue expenses are deferred and amortized to debt expense using the effective interest method over the lives of the related debt issues. Gains and losses on refundings related to bonds redeemed by proceeds from the issuance of new bonds are amortized to debt expense using the effective interest method over the shorter of the life of the new bonds or the remaining term of the bonds refunded. Gains and losses on bond defeasances financed with cash are reported as an extraordinary gain or loss on extinguishment of debt in the statements of revenue, expenses and changes in fund net assets.

Gas and electricity option and swap agreements

Gas and electricity option and location swap agreements were previously reported at fair value on the balance sheet. With the change in election under GASBS No. 20, the Department now accounts for these contracts on a settlement basis (see Note 2). The Department does not enter into gas and option agreements for trading purposes. The Department is exposed to risk of nonperformance if the counterparties default or if the swap agreements are terminated (see Note 9).

Accrued workers' compensation claims

Liabilities for unpaid workers' compensation claims are recorded at their present value when they are probable of occurrence and the amount can be reasonably estimated. The liability is actuarially determined, based on an estimate of the present value of the claims outstanding and an amount for claim-events incurred but not reported based upon the Department's loss experience, less the amount of claims and settlements paid to date. The discount rate used to calculate this liability at its present value was 4% at June 30, 2004, which approximates the Department's long term investment yield.

NOTE 1: (continued)

Overall indicated reserves for workers' compensation claims, for both Water and Energy Services, undiscounted, have increased from $45.5 million as of June 30, 2003, to $56.0 million as of June 30, 2004. This increase is mainly attributable to increased medical inflation (particularly in the area of prescription drugs), significant increases in benefit levels implemented in California in the past few years, increased payroll levels of the Department contributing to higher indemnity losses, and increasing claim frequencies experienced by the Department in the past few years. As the claims typically take longer than 1 year to settle and close out, the entire discounted liability is shown as long term on the balance sheets as of June 30, 2004 and 2003. Energy Services' portion of the discounted reserves as of June 30, 2004 and 2003 is $31.4 million and $25.2 million, respectively.

Customer deposits

Customer deposits represent deposits collected from customers upon opening of new accounts. These deposits are obtained when the customer does not have a previously established credit history with the Department. Original deposits plus interest is paid to the customer once a satisfactory payment history is maintained, generally after one to three years.

Water Services is responsible for collection, maintenance and refunding of these deposits for all Department customers, including those of Energy Services. As such, Water Services' balance sheets include a deposit liability of $49.9 million and $42.3 million as of June 30, 2004 and 2003, respectively, for all customer deposits collected. In the event that Water Services defaults on refunds of such deposits, Energy Services would be required to pay amounts owing to its customers.

Revenues

Energy Services' rates are established by a rate ordinance, which is approved by the City Council. Energy Services sells energy to other City departments at rates provided in the ordinance. Energy Services recognizes energy costs in the period incurred and accrues for estimated energy sold but not yet billed. The Department's current rates include amounts designated for the pre-collection of out-of-market future purchase power costs. These amounts are included in deferred credits. At the discretion of the Department and approval by the Board, these amounts will be recognized in future periods. At June 30, 2004 and 2003, $540.1 million and $479.7 million, respectively, of pre-collected purchased power costs have been deferred pending future rate treatment.

NOTE 1: (continued)

Non-operating revenues

Contributions in aid of construction and other grants received by the Department for constructing utility plant and other activities are recognized as non-operating revenues when all applicable eligibility requirements, including time requirements, are met.

Allowance for funds used during construction

Allowance for funds used during construction represents the cost of borrowed funds used for the construction of utility plant. Capitalized AFUDC is included as part of the cost of utility plant and as a reduction of debt expenses. The average AFUDC rate was 4.9%, 4.2% and 5.4% for each of fiscal years 2004, 2003, and 2002 respectively.

Reclassifications

Certain financial statement items for prior years have been reclassified to conform to the current year presentation.

Recent Accounting Pronouncements

In March 2003, the GASB issued GASBS No. 40, "*Deposit and Risk Investment Disclosures an amendment of GASB Statement No. 3.*" GASBS 40 requires specific disclosures if applicable for credit risk, concentration of credit risk, interest rate risk, and foreign currency risk. It also modifies GASB Statement No. 3, "*Deposits with Financial Institutions, Investments (including Repurchase Agreements), and Reverse Purchase Agreements,*" in part to limit the required disclosure of custodial credit risk to one category of deposits and investments. This Statement is effective for the Department beginning in fiscal year 2005. The Department does not expect that there will be a material impact to the financial statement disclosures as a result of adopting this Statement.

NOTE 2: Accounting Changes

GASB Statement No. 45

On July 1, 2003, the Department early adopted GASB Statement No. 45 "*Accounting and Financial Reporting by Employers for Postemployment Benefits Other Than Pensions*" (GASBS No. 45), and discontinued following Financial Accounting Standards Board Statement No. 106 "*Employers' Accounting for Postretirement Benefits Other Than Pensions*" (SFAS No. 106). The Department does not administer its plan for postretirement benefits other than pensions (health care benefits) as a trust or equivalent arrangement. Therefore, it does not prepare financial statements for the plan. See Note 12 for a description of the plan.

The following amounts were recorded on Energy Services books as of June 30, 2003 as accrued postretirement liability under SFAS No. 106 (dollar amounts in thousands):

	June 30, 2003
Postretirement liability	$ (361,940)
Postretirement fund assets	131,247
Net postretirement liability	$ (230,693)

Prior to July 1, 2003, the Department was applying SFAS No. 106 in accounting for postretirement costs. The postretirement obligation at June 30, 2003 amounted to $362 million. The adoption of GASBS No. 45 allows the Department to set the beginning postretirement obligation to zero and reverse the previously reported obligation. To reverse Energy Services' postretirement liability, management reviewed the charges for health care costs created by SFAS No. 106 and reversed the costs as of July 1, 2003. Costs were reversed from previous capitalized labor charges included in utility plant and other operating expenses recorded in prior fiscal years.

The change from SFAS No. 106 to GASBS No. 45 had no change to the health plan benefits to active or retired employees. The change also did not affect the assets designated for postretirement benefits. The change from SFAS No. 106 to GASBS No. 45 changed the postretirement liability as of July 1, 2003 the annual required funding contribution for subsequent fiscal years, and the actuarial accrued liability calculations. See Note 12.

NOTE 2: (continued)

As a result of the adoption of GASBS No. 45, the following adjustment were recorded to Energy Services' balance sheet as of July 1, 2003 (dollar amounts in thousands):

Balance Sheet Item	Reported as of June 2003	Adjustments	Adjusted Balance
Generation assets	$2,622,137	($4,109)	$2,618,028
Transmission assets	829,457	(7,761)	821,696
Distribution assets	3,893,836	(64,375)	3,829,461
General assets	915,054	(8,675)	906,379
Accumulated depreciation	(4,073,466)	14,880	(4,058,586)
Prepayments and other current assets	95,635	(3,370)	92,265
Due to Water Services	(67,447)	18,867	(48,580)
Accrued postretirement liability/asset	(230,693)	361,940	131,247
Fund net assets	(3,693,062)	(307,397)	(4,000,459)

With the adoption of GASBS No. 45 the Department's postretirement liability for both Energy Services and Water Services combined decreased from $119.7 million in fiscal year 2003 under SFAS No. 106 to $107 million in fiscal year 2004 under GASBS No. 45. The difference is due to a change in the discount rate from 5.75% to 6.50%, a change in the actuarial cost method from the Projected Unit Credit Cost Method to the Entry Age Normal Method, and a change in the amortization period for prior service costs from 20 to 30 years. See Note 12 for the required information under GASBS No. 45.

Of the $107 million postretirement liability recorded under GASBS No. 45, $70.9 million was allocated to Energy Services. Energy Services paid $32.4 million for retiree premiums during fiscal year 2004 leaving $38.5 million as a liability on Energy Services books as of June 30, 2004. In addition, the Department made additional contributions to the postretirement funds. As a result, the net postretirement asset on Energy Services as of June 30, 2004 is as follows (dollar amounts in thousands):

	June 30, 2004
Postretirement liability	$ (38,487)
Postretirement trust fund assets	197,670
Net postretirement asset	$ 159,183

NOTE 2: (continued)

GASB Statement No. 42

In November 2003, the GASB issued GASBS No. 42 "*Accounting and Financial Reporting for Impairment of Capital Assets and for Insurance Recoveries.*" This Statement established accounting and financial reporting standards for impairment of capital assets. A capital asset is considered impaired when its service utility has declined significantly and unexpectedly. This Statement also clarified and established accounting requirements for insurance recoveries. Under the standard, impaired capital assets that will no longer be used by the government should be reported at the lower of carrying value or fair value. Impairment losses on capital assets that will continue to be used by the government should be measured using the method that best reflects the diminished service utility of the capital asset.

The Department early adopted GASBS No. 42 and calculated the impairment to its Mohave Generating Station and a procurement system. No retroactive restatement was required. See Note 14 for a discussion on the impairment.

GASB Statement No. 39

In fiscal year 2004, the Department adopted GASBS No. 39 "*Determining Whether Certain Organizations Are Component Units.*" This Statement amends GASB Statement No. 14, "*The Financial Reporting Entity,*" to provide additional guidance to determine whether certain organizations for which the primary government is not financially accountable should be reported as component units, based on the nature and significance of their relationship with the primary government. Generally, it requires reporting, as a component unit, an organization that raises and holds economic resources for the direct benefit of a governmental unit. The Department is a component unit of the City of Los Angeles, and will continue to be included as part of the City's consolidated annual financial report. As part of the adoption of GASBS No. 39, the Department reviewed its relationships between Energy Services and the Intermountain Power Agency, and the Southern California Public Power Authority. Neither of these relationships met the component unit requirements of GASBS No. 39. As a result, there was no impact to the Department's financial statements as a result of adopting this Statement.

NOTE 2: (continued)

Change in election under GASB Statement No. 20

In fiscal year 2003, the Department changed its election under the guidance in GASB Statement No. 20, "*Accounting and Financial Reporting for Proprietary Funds and Other Governmental Entities that Use Proprietary Fund Accounting*" (GASBS No. 20), to follow GASB statements and only FASB statements and interpretations issued on or before November 30, 1989. The Department is required to retroactively apply this change by restating prior years presented. Management believes that this change in election represents a change to a preferable method of accounting.

The impact on Energy Services' financial statements as a result of this change was the discontinuation of the application of Financial Accounting Standard No. 133, "*Accounting for Derivative Instruments and Hedging Activities*" (SFAS No. 133). The Department adopted SFAS No. 133 in fiscal year 2001 and consequently began reporting its derivative instruments at fair value. With the change in election under GASBS No. 20, Energy Services is no longer required to report its derivative instruments at fair value, however it must now provide certain disclosures related to derivative instruments as required by GASB Technical Bulletin No. 2003-1, "*Disclosure Requirements for Derivatives Not Reported at Fair Value on the Statement of Net Assets*," (see Note 9). In addition, the Department continued to apply the provisions of SFAS No. 106, "*Employers' Accounting for Postretirement Benefits Other Than Pensions*," until the prescriptive guidance under governmental standards was issued. GASB Statement No. 45 was issued in 2004 and the Department early adopted the standard on July 1, 2003 in accordance with the transition guidance to be in full compliance with GASBS No. 20.

NOTE 2: (continued)

Energy Services restated its prior year financial statements to retroactively apply this change in election and recorded the following amounts (amounts in thousands):

		As Previously Reported		Adjustments		As Restated
				June 30, 2002		
Balance Sheets:						
Prepayments and other current assets	$	85,540	$	(5,538)	$	80,002
Unrestricted fund net assets	$	1,399,479	$	(5,538)	$	1,393,941
Total fund net assets	$	3,630,881	$	(5,538)	$	3,625,343
Statements of Revenue, Expenses and Changes in Fund Net Assets				Year ended June 30, 2002		
Sales for resale	$	189,690	$	1,383	$	191,073
Fuel for generation	$	280,474	$	377	$	280,851
Purchased power expense	$	683,572	$	5,218	$	688,790
Increase in fund net assets	$	256,915	$	(4,212)	$	252,703
Statements of Revenue, Expenses and Changes in Fund Net Assets				Year ended June 30, 2001		
Sales for resale	$	998,551	$	(54,707)	$	943,844
Purchased power expense	$	899,082	$	(5,218)	$	893,864
Cummulative effect of change in accounting principle	$	48,163	$	(48,163)	$	-
Increase in fund net assets	$	315,143	$	(1,326)	$	313,817

NOTE 3: Regulatory Matters

Effective April 1, 1998, customers of California's investor-owned utilities (IOU) became eligible for direct access. The introduction of direct access resulted in significant structural changes to the electric power industry, including plant divestitures and management of IOU transmission assets through the California Independent System Operator (CISO). In 2001, legislation was enacted to suspend direct access to retail customers in California. No definitive plan for allowing direct access to customers in the Department's service area has been adopted; however, if the Department implements direct access in the future, it is likely that its generation business will no longer qualify for accounting under SFAS No. 71. SFAS No. 71 requires that the effects of the ratemaking process be recorded in the financial statements.

As a government-owned utility, the Department was not compelled to participate in direct access or to divest its generation assets. Management continues to evaluate the Department's alternatives in response to deregulation, the introduction of direct access and participation in the CISO. In addition, management has implemented debt and cost reduction programs and restructured certain purchase power commitments in response to the changes in the electric utility market. Furthermore, in August 2000, the City Council approved a $1.7 billion, ten-year plan to upgrade the Department's local power plants and to implement a program that includes demand side management, alternative energy sources and distributed generation. This plan has been amended to allow for a total budget of $2.0 billion. Through June 30, 2004, the Department has incurred $1.2 billion related to such upgrades.

Federal Energy Regulatory Commission Price Mitigation Plan

In June 2001, the Federal Energy Regulatory Commission (FERC) issued a price mitigation plan on spot market sales in the Western Electric Coordinating Council (WECC). The plan imposes price limits on the sale of electricity in WECC based on a calculation that estimates the cost of production of the least efficient gas-fired generation plant in California and a fixed factor to account for other variable costs. Energy Services' purchases and sales of electricity occur entirely within the WECC and as such are subject to these measures. These measures have in part, contributed to stabilizing the market and resulting in overall lower wholesale prices.

NOTE 3: (continued)

California Receivables and FERC refund hearings

During fiscal year 2001, the Department made sales to two California agencies that were formed by Assembly Bill 1890 to facilitate the purchase and sale of energy and ancillary services in the State of California. Through June 30, 2004, these agencies, the CISO and the California Power Exchange (CPX), have made minimal payments since April 2001 on amounts outstanding to counterparties, including Energy Services, for certain energy purchases in fiscal years 2000 and 2001. The CPX filed for protection under Chapter 11 of the Federal Bankruptcy Statute in January of 2001. Two utilities with significant amounts due to these agencies, Southern California Edison Company and Pacific Gas & Electric, have previously stated in public disclosure documents that they may not be able to pay for all the power they consumed in 2001. Both Pacific Gas & Electric and Southern California Edison Company have paid all amounts due by it to the CPX, however the amounts remain in an escrow account pending the resolution of disbursement of the funds.

As of June 30, 2004 a total of $166.5 million was due to Energy Services from the CISO and the CPX. The FERC has questioned whether amounts charged for energy sold to the CISO and the CPX during 2000 and 2001 represent "unlawful profits" that should be subject to refund. The FERC has considered various options for determination of a refund amount but has not issued definitive guidance on what represents unlawful profits for sales during the period. If the FERC issues an order requiring a refund under defined conditions, the Department may be liable to refund a portion of amounts recorded as sales. However, it has not been established that the FERC has any jurisdiction over municipal utilities, including the Department.

Energy Services has recorded a $50.0 million reserve as of June 30, 2004 against the $166.5 million receivable, for potential refunds pertaining to its wholesale sales during 2000 and 2001. Management believes that this is the most probable amount that will be paid by the Department and is based on the most recent formula disclosed by FERC. Energy Services estimated this amount to be $40.0 million in the prior year based on the best information available at the time and therefore recorded a reserve of $40.0 million as of June 30, 2003. While management has recorded its estimate of the most probable amounts that will be paid, management does believe that it is entitled to all amounts due from sales to counterparties in California, including those named above. Furthermore, management believes that interest may be due to it on those amounts but any potential receivable is not estimable at this time. In addition, management does not believe that Energy Services' exposure to any additional losses with respect to these receivable balances is currently estimable. If final settlement of these receivables results in an amount less than the recorded balance, net of the $50.0 million reserve recorded, the Department will be required to record a loss in the statement of revenue, expenses and changes in fund net assets.

NOTE 3: (continued)

Public benefits

In accordance with Assembly Bill 1890, as amended by Assembly Bill 995 and pursuant to direction from the Board, a percentage of the Department's retail revenue is designated for use for qualifying public benefits programs. Qualifying programs include cost-effective demand side management services to promote energy-efficiency and energy conservation, new investment in renewable energy resources and technologies, development and demonstration programs to advance science and technology, and services provided for low-income electricity customers. In accordance with current legislation and the Department's plans, the program is currently expected to cease January 1, 2012.

The Department defers public benefits revenue from customers in excess of costs incurred under qualifying programs and defers qualifying expenses in excess of collections pursuant to approval received from the Board. During fiscal year 2003, Energy Services changed its public benefits deferral estimate. The change in estimate was the result of an updated interpretation of Assembly Bill 1890. As a result, the Department recorded an increase in its public benefits deferred credit balance of $27 million. During fiscal years 2004, 2003, and 2002, the Department spent $64.2 million, $74.9 million, and $65.8 million, respectively, on public benefits programs. These programs include investments in electric buses and vehicles, photovoltaics, or solar power and other alternative energy sources, and support for low-income and life support customers. As of June 30, 2004 and 2003, the Department has recorded a deferred debit in the amounts of $9.7 million and $11.7 million, respectively, due to public benefit expenses incurred in excess of revenues. The regulatory asset will be recovered when the corresponding revenue is earned.

Accounting for the State Energy Efficiency Grant

During fiscal year 2001, the Department was awarded a $16 million grant by the State of California for the purpose of reducing energy demand during the summer months. The Department received $8 million in fiscal year 2001 and the remaining $8 million in fiscal year 2002. Grant money received was initially recorded as a deferred credit on the balance sheet. As funds were disbursed on qualifying energy efficiency programs, Energy Services recognized the grant funds received as non-operating revenues, and recognized the expenditures as non-operating expenses. During fiscal years 2002 and 2001, the Department recognized $15 million and $1 million, respectively, of these grant funds as non-operating income. The entire grant was disbursed as of June 2002.

NOTE 4: Utility Plant

Energy Services had the following activity in utility plant during fiscal year 2004 (amounts in thousands):

	Balance June 30, 2003	Adjustment due to GASBS 45 Adoption	Adjusted Beginning Balance	Additions	Retirements and Disposals	Transfers	Balance June 30, 2004
Nondepreciable utility plant							
Land and land rights	$ 156,725	$ -	$ 156,725	$ 1,087	$ (24)	$ -	$ 157,788
Construction work in prog	763,000	-	763,000	433,200		(543,825)	652,375
Nuclear fuel**	13,431	-	13,431	5,709	(6,587)	-	12,553
Total nondepreciable utility plan	933,156	-	933,156	439,996	(6,611)	(543,825)	822,716
Depreciable utility plant							
Generation	2,613,144	(4,109)	2,609,035	21,777	(6,292)	356,048	2,980,568
Transmission	749,750	(7,761)	741,989	2,880	(88)	31,074	775,855
Distribution	3,842,174	(64,375)	3,777,799	58,069	(5,106)	115,670	3,946,432
General	898,691	(8,675)	890,016	9,749	(15,044)	41,033	925,754
Total depreciable utility plant	8,103,759	(84,920)	8,018,839	92,475	(26,530)	543,825	8,628,609
Less accumulated depreciation*	(4,073,466)	14,880	(4,058,586)	(254,187)	26,530	-	(4,286,243)
Total utility plant, net	$ 4,963,449	$ (70,040)	$ 4,893,409	$ 278,284	$ (6,611)	$ -	$ 5,165,082

* *Additions to accumulated depreciation include capitalized depreciation of $24.9 million.*

** *Nuclear fuel disposals represent amortization.*

NOTE 5: Jointly-Owned Utility Plant

Energy Services has direct interests in several electric generating stations and transmission systems, which are jointly-owned with other utilities. As of June 30, 2004 utility plant includes the following amounts related to Energy Services' ownership interest in each jointly-owned utility plant (amounts in thousands, except as indicated):

	Ownership Interest	Share of Capacity (MW)	Utility Plant in Service: Cost	Utility Plant in Service: Accumulated Depreciation
Palo Verde Nuclear Generating Station	5.7%	217	$ 529,063	$ 256,458
Navajo Generating Station	21.2%	477	210,467	216,120
Mohave Generating Station	10.0%	158	68,163	67,459
Pacific Intertie DC Transmission Line	40.0%	1240	195,712	56,047
Other transmission systems		Various	76,336	37,827
			$ 1,079,741	$ 633,911

NOTE 5: (continued)

Energy Services will incur certain minimum operating costs related to the jointly-owned facilities, regardless of the amount or its ability to take delivery of its share of energy generated. Energy Services' proportionate share of the operating costs of the joint plants is included in the corresponding categories of operating expenses.

On November 27, 2001, the Los Angeles City Council approved the sale of fifty percent of the Department's twenty percent ownership interest in the Mohave Generating Station to the Salt River Project Agricultural Improvement and Power District (SRP). SRP took the place of the original purchaser, AES Corporation, under the terms of the Mohave Project Plant Site Conveyance and Co-Tenancy Agreement. SRP paid $95 million in cash for the 10% interest. The sale resulted in the recognition of a gain of $67.6 million, which is included in other income and expense on the statements of revenue, expenses, and changes in fund net assets in fiscal year 2002.

NOTE 6: Purchase Power Commitments

The Department has entered into a number of energy and transmission service contracts, which involve substantial commitments as follows (amounts in thousands, except as indicated):

			Department's Interest in Agency's Share		
	Agency	Agency Share	Interest	Capacity MW	Outstanding Principal
Intermountain Power Project	IPA	100.0%	66.8%	1,068	$ 1,650,634
Palo Verde Nuclear Generating Station	SCPPA	5.9%	67.0%	151	$ 477,218
Mead-Adelanto Project	SCPPA	67.9%	35.7%	291	$ 81,826
Mead-Phoenix Project	SCPPA	17.8% - 22.4%	24.8%	148	$ 17,881
Southern Transmission System	SCPPA	100.0%	59.5%	1,142	$ 570,109

IPA: The Intermountain Power Agency is an agency of the State of Utah established to own, acquire, construct, operate, maintain, and repair the Intermountain Power Project (IPP). Energy Services serves as the Project Manager and Operating Agent of IPP.

SCPPA: The Southern California Public Power Authority, a California Joint Powers Agency. Note: SCPPA's interest in the Mead-Phoenix Project includes three components.

NOTE 6: (continued)

The above agreements require Energy Services to make certain minimum payments, which are based primarily upon debt service requirements. In addition to average annual fixed charges of approximately $258 million during each of the next five years, the Department is required to pay for operating and maintenance costs related to actual deliveries of energy under these agreements (averaging approximately $239 million annually during each of the next five years). The Department made total payments under these agreements of approximately $551 million, $546 million, and $514 million in fiscal years 2004, 2003, and 2002, respectively. These agreements are scheduled to expire from 2027 to 2030.

Energy Services earned fees under the IPP Project Manager and Operating agreements totaling $18.2 million, $15.8 million, and $14.7 million in fiscal years 2004, 2003, and 2002, respectively.

Long-term notes receivable

Under the terms of its purchase power agreement with IPA, the Department is charged for its output entitlements based on its share of IPA's costs, including debt service. During fiscal year 2000, the Department restructured a portion of this obligation by transferring $1.12 billion to IPA in exchange for long-term notes receivable. The funds transferred were obtained from the debt reduction trust funds and through the issuance of new variable rate debentures (see Notes 7 and 10). IPA used the proceeds from these transactions to defease and to tender for bonds with par values of approximately $615 million and $611 million, respectively.

On September 7, 2000, the Department transferred $187 million to IPA in exchange for additional long-term notes receivable. IPA used the proceeds to defease bonds with a face value of $198 million.

The IPA notes are subordinate to all of IPA's publicly held debt obligations. The Department's future payments to IPA will be partially offset by interest payments and principal maturities from the subordinated notes receivable. The net IPA notes receivable balance totaled $1.17 billion and $1.23 billion as of June 30, 2004 and 2003, respectively.

Energy entitlement

The Department has a contract through 2017 with the U.S. Department of Energy for the purchase of available energy generated at the Hoover Power Plant. The Department's share of capacity at Hoover is approximately 500 megawatts. The cost of power purchased under this contract was $12 million, $12 million, and $11 million in each of fiscal years 2004, 2003 and 2002 respectively.

NOTE 7: Restricted and Other Investments

A summary of Energy Services' restricted and other investments is as follows (amounts in thousands):

	June 30, 2004	June 30, 2003
Restricted and other investments:		
Escrow investments	$ -	$ 34,262
Debt reduction trust funds	664,019	836,427
Nuclear decommissioning trust funds	91,338	90,576
Natural gas trust fund	25,183	-
Other investments	35	43,107
Total Restricted and other investments	$ 780,575	$ 1,004,372
Other:		
Cash collateral received from securities lending transactions (see Note 8)	$ 225,995	$ 243,361
Postretirement health care benefit fund	197,670	131,247
Total	$ 1,204,240	$ 1,378,980

All restricted and other investments are held in trust accounts to be used for a designated purpose as follows:

Escrow investments

Escrow investments are held to call specified revenue bonds at scheduled maturity dates.

Debt reduction trust funds

The debt reduction trust funds were established during fiscal year 1997 to provide for the payment of principal and interest on long-term debt obligations and purchased power obligations arising from the Department's participation in the Intermountain Power Project and the Southern California Public Power Authority (SCPPA) (see Note 6). The Department has transferred funds from purchased power pre-collections into these trust funds. Funds from operations may also be transferred by management as funds become available.

Nuclear decommissioning trust funds

Nuclear decommissioning trust funds will be used to pay the Department's share of decommissioning the Palo Verde Nuclear Generating Station at the end of its useful life (see Note 1).

NOTE 7: (continued)

Natural gas trust fund

The natural gas trust fund was established to serve as depository for funds transferred from the Power Revenue Fund to pay for costs, and to post margin or collateral in connection with contracts for the purchase and delivery of financial transactions for natural gas. These transactions are entered into to stabilize the natural gas portion of the Department's fuel for generation costs.

Postretirement health care benefit fund

The postretirement health care benefit fund was established to provide for the payment of the Department's postretirement health care benefits. Accrued postretirement liabilities are recorded net of the fund assets (see Note 12). The adoption of GASBS No. 45 had no impact on the amount or fair value of the funds.

Other investments

Other investments consist of funds held by SCPPA on behalf of the Department. Certain of these investments are currently being used by the Department to provide for the payment of principal and interest on long-term debt obligations and purchased power obligations arising from the Department's participation in SCPPA. However, there are no restrictions imposed on the Department regarding the use of these investments.

Restricted and other investments held by the Department are categorized separately below to give an indication of the level of custodial credit risk assumed by the Department. Specifically, identifiable investments are classified as to credit risk by three categories and summarized below as follows: Category 1 includes investments that are insured or registered or for which securities are held by the Department or its agent in the Department's name; Category 2 includes uninsured and unregistered investments for which the securities are held by the counterparty's trust department or agent in the Department's name; and Category 3 includes uninsured and unregistered investments for which the securities are held by the counterparty or by its trust department or agent, but not in the Department's name.

NOTE 7: (continued)

At June 30, 2004, Energy Services' restricted and other investments are categorized as follows (amounts in thousands):

Type of Investments	Category 1	Category 2	Category 3	Total
Investments - categorized				
U.S. government securities	$ 548,826	$ -	$ -	$ 548,826
Bonds	177,439	-	-	177,439
Commercial paper	33,348	-	-	33,348
Repurchase agreements	-	182,692	-	182,692
Negotiable certificates of deposits	14,365	-	-	14,365
Total categorized restricted and other investments	$ 773,978	$ 182,692	$ -	956,670
Investments - not categorized				
Investments held by broker-dealers:				
U.S. government securities				179,017
Mutual funds				25,250
General pooled securities lending cash collateral				43,303
Total				$ 1,204,240

At June 30, 2003, Energy Services' restricted and other investments are categorized as follows (amounts in thousands):

Type of Investments	Category 1	Category 2	Category 3	Total
Investments - categorized				
U.S. government securities	$ 510,281	$ -	$ -	$ 510,281
Bonds	162,375	-	-	162,375
Commercial paper	216,534	-	-	216,534
Repurchase agreements	-	218,666	-	218,666
Negotiable certificates of deposits	33,312	-	-	33,312
Total categorized restricted and other investments	$ 922,502	$ 218,666	$ -	1,141,168
Investments - not categorized				
Investments held by broker-dealers:				
U.S. government securities				212,855
Mutual funds				262
General pooled securities lending cash collateral				24,695
Total				$ 1,378,980

Repurchase agreements relate to the Department's securities lending program (see Note 8).

NOTE 8: Securities Lending Transactions

In December 1999, the Department initiated a securities lending program managed by its custodial bank to increase interest income. The bank lends up to 20% of the investments held in the debt reduction trust funds, decommissioning trust funds, and plan assets held in the postretirement benefits trust fund for securities, cash collateral or letters of credit equal to 102% of the market value of the loaned securities and interest, if any. The Department can sell collateral securities only in the event of borrower default. Both the investments purchased with the collateral received and the related liability to repay the collateral are reported on the balance sheets. A summary of Energy Services' securities lending transactions as of June 30, 2004 and 2003 is as follows (amounts in thousands):

	June 30, 2004		June 30, 2003	
Securities lent for cash collateral	Fair value of underlying securities	Collateral value	Fair value of underlying securities	Collateral value
US Government and agency securities	$ 179,017	$ 182,692	$ 213,199	$ 218,667

Cash collateral received is reinvested by the lending agent in open repurchase agreements. As such, the maturities of reinvested cash collateral always match the maturities of the underlying securities lent. The lending agent provides indemnification for borrower default. There were no violations of legal or contractual provisions and no borrower or lending agent default losses during fiscal years 2004 and 2003.

General Investment Pool Program

The Department also participates in the City's securities lending program through the pooled investment fund. The City's program has substantially the same terms as the Department's direct securities lending program. The Department recognizes its proportionate share of the cash collateral received for securities loaned and the related obligation for the general investment pool. As of June 30, 2004 and 2003, Energy Services' attributed share of cash collateral and the related obligation from the City's program was $43.3 million and $24.7 million, respectively.

Management believes that participation in these securities lending programs increases interest earnings and results in minimal credit risk exposure to the Department because the amounts owed to the borrowers exceed the amounts that have been loaned.

NOTE 9: Derivative Instruments

As a result of the Department's change in election under GASBS No. 20 (see Note 2), Energy Services no longer records its derivative instruments at fair value on the balance sheets, but instead discloses the derivatives in the financial statement footnotes and records the impact upon settlement of the derivatives. Energy Services has three main types of derivative instruments as of June 30, 2004: electricity swaps, gas forward contracts, and financial natural gas hedges. As of June 30, 2004 and 2003, the fair value of these outstanding derivative instruments were $24.8 million and $0.3 million, respectively.

Objective of electricity swap, and options

In order to obtain the highest market value on energy that is sold into the wholesale market, the Department monitors the sales price of energy which varies based on which hub the energy is to be delivered. There are three primary hubs within the Department's transmission region: Palo Verde, California-Oregon Border and Mead. The Department enters into various locational swap transactions with other electric utilities in order to effectively utilize its transmission capacity and to achieve the most economical exchange of energy purchased and sold.

A call option is the right, but not the obligation, to buy energy at a fixed price on or before a specific date. Because the Department has excess electric generation available at certain times during the year, it sells call options for a premium to other utilities. If the buyer calls the option, the Department is obligated to sell the energy for a specified dollar amount and deliver it to a specific delivery point. If the buyer does not call the option, the Department has no obligation to deliver energy, but does retain the premium paid. Premiums received are deferred and amortized to income over the period the option is outstanding and are recorded as part of Sales for Resale revenue. As of June 30, 2004 and 2003, Energy Services has recorded $0 and $1.3 million, respectively, of deferred option revenue relating to options entered into prior to the fiscal year end.

Objective of gas forward contracts

The Department enters into gas forward contracts in order to supply its gas requirements to produce electricity to serve its customers.

Objective of financial natural gas hedges

The Department enters into natural gas hedging contracts in order to stabilize the cost of gas needed to produce electricity to serve its customers.

NOTE 9: (continued)

Certain of the derivatives described above qualify as an exception provided under GTB 2003-1 for activities that are considered normal purchases and normal sales. These transactions are excluded from the scope of GTB 2003-1.

As of June 30, 2004, Energy Services had the following derivatives, which were not recorded at fair value on its balance sheet:

Derivative Description	Total Contract Quantities	Contract Price Range $ per Unit	First Effective Date	Last Termination Date	Fair Value ($000's)	Cash received at derivative inception ($000's)
Electricity swaps						
Puchases	44,048 MW	52.00 - 69.77	6/1/04	9/30/04	(220)	$ -
Sales	44,048 MW	54.00 - 71.48	6/1/04	9/30/04	300	-
Gas contract *	26,307,310 MMBtu	5.0725 - 6.073	3/15/91	3/15/06	(2,268)	-
Financial Natural Gas Hedges**	39,707,000 MMBtu	3.82 - 5.65	8/1/03	6/30/06	27,023	-

* *The gas contract quantities represent the contract maximum of 50,000 MMBtu per day. Contract prices are based in part on Gas Price Indices, Including Henry Hub and Kern River Prices.*

** *Financial hedges were variable to fixed rate swaps that serve to lock in a fixed cost of natural gas.*

Fair value

All fair values were estimated using forward market prices available from broker quotes or exchange prices in the case of the gas contract.

NOTE 9: (continued)

Credit Risk

Energy Services is exposed to credit risk related to nonperformance by its wholesale counterparties under the terms of contractual agreements. In order to limit the risk of counterparty default, the Department has implemented a Wholesale Marketing Counterparty Evaluation Policy (the Policy). The Policy includes provisions to limit risk including: the assignment of internal credit ratings to all Department counterparties based on counterparty and/or debt ratings; the requirement for credit enhancements (including irrevocable letters of credit, escrow trust accounts and parent company guarantees) for counterparties that do not meet an acceptable level of risk; and the use of standardized agreements which allow for the netting of positive and negative exposures associated with a single counterparty. As discussed in Note 3, during fiscal year 2001, Energy Services experienced nonperformance and material counterparty default with the CISO and the CPX. Energy Services does not anticipate nonperformance by any other of its counterparties and has no reserves related to nonperformance at June 30, 2004 and 2003, respectively. Apart from the events discussed in Note 3, Energy Services did not experience any material counterparty default during fiscal years 2004, 2003 or 2002.

Termination Risk

Energy Services or its counterparties may terminate the contractual agreements if the other party fails to perform under the terms of the contract.

NOTE 10: Long-term Debt

Long-term debt outstanding as of June 30, 2004 consists of revenue bonds and refunding revenue bonds due serially in varying annual amounts as follows (amounts in thousands):

Bond Issues	Date of Issue	Effective Interest Rate	Fiscal Year of Last Scheduled Maturity	Principal Outstanding
Issue of 2001, Series A1	03/20/01	4.931%	2025	$ 1,105,550
Issue of 2001, Series A2	11/06/01	5.109%	2022	109,095
Issue of 2001, Series A3	04/01/01	5.095%	2025	116,295
Issue of 2001, Series B	06/05/01	Variable	2035	620,600
Issue of 2001, Series C1	11/15/01	4.744%	2017	5,545
Issue of 2002, Series A	08/22/02	Variable	2036	388,500
Issue of 2002, Series C2	11/22/02	4.375%	2018	13,744
Issue of 2003, Series A1	07/31/03	3.410%	2017	440,110
Issue of 2003, Series A2	08/19/03	4.662%	2032	515,830
Issue of 2003, Series B	08/28/03	5.013%	2036	200,000
Issue of 2004, Series C3	04/07/04	4.298%	2020	12,467
	Total principal amount			3,527,736
	Unamortized debt-related costs (including net loss on refundings)			(24,350)
	Debt due within one year (including current portion of variable rate debt)			(146,838)
				$ 3,356,548

Revenue bonds generally are callable ten years after issuance. The Department has agreed to certain covenants with respect to bonded indebtedness. Significant covenants include the requirement that Energy Services' net income, as defined, will be sufficient to pay certain amounts of future annual bond interest and of future annual aggregate bond interest and principal maturities. Revenue bonds and refunding bonds are collateralized by the future revenues of Energy Services.

NOTE 10: (continued)

Long term debt activity

Energy Services had the following activity in long-term debt for the twelve months ended June 30, 2004 (amounts in thousands):

	Balance at June 30, 2003	Additions	Reductions	Balance at June 30, 2004	Current Portion
Long term debt	$ 3,232,088	$ 1,250,000	$ (1,125,540)	$ 3,356,548	$ 146,838

New issuances

Fiscal Year 2004

In July 2003, Energy Services issued $956 million of Power System Revenue Bonds. The bonds were issued for the purpose of refunding portions of the Refunding Issue of 1993, the Second Issue of 1993 and the Issue of 2000. The net proceeds along with $93 million in cash were used to defease bonds with a par value of $1.06 billion. The defeasance is expected to reduce total debt payments over the life of the new issues by $186 million and is expected to result in present value savings of approximately $71 million. This transaction resulted in a net loss for accounting purposes of $59.1 million, of which $53.5 million was deferred and is being amortized over the shorter of the life of the bonds retired or the life of the new bonds and $5.6 million which was recognized in fiscal year 2004 as an extraordinary loss.

In August 2003, Energy Services issued $200 million of Power System Revenue Bonds. The net proceeds were deposited into the construction fund to be used for distribution system capital improvements. Also, in April 2004, the Department issued $10 million of Energy Services fixed rate bonds as part of the Mini-Bond Program for employees and retirees. The net proceeds were deposited into the construction fund to be used for distribution system capital improvements.

Furthermore, in September 2004, Energy Services issued $200 million of Power System Revenue Commercial Paper Notes. The commercial paper notes were issued for the purpose of electric system capital improvements.

NOTE 10: (continued)

Fiscal Year 2003

In August 2002, the Department issued $388.5 million of Energy Services variable rate bonds for the purpose of defeasing outstanding commercial paper. The net proceeds from the issuance were deposited into a trust and were used to secure the new bonds until September 2002 at which time the commercial paper was paid. The purpose of the defeasance was to bring the variable rate debt under Energy Services' new Master Bond Resolution. The defeasance is not expected to reduce total debt payments over the life of the new issues nor to result in present value savings.

In November 2002, the Department issued $14 million of Energy Services fixed rate bonds as part of the Mini-Bond Program for employees and retirees. Energy Services' Mini-Bond Program allows for a maximum total issuance of $50 million. The net proceeds were deposited into the construction fund to be used for distribution system capital improvements.

Fiscal Year 2002

In June 2001, the Department issued $621 million of Energy Services variable rate bonds for the purpose of defeasing the Second Issue of 2000 bonds in August 2001. The net proceeds from the issuance were deposited into a trust and were used to secure the new bonds until August 2001 at which time the Second Issue of 2000 bonds were defeased. The purpose of the defeasance was to bring the variable rate bonds under Energy Services' new Master Bond Resolution. The defeasance is not expected to reduce total debt payments over the life of the new issues nor to result in present value savings. This transaction resulted in a net gain for accounting purposes of $2 million, which was deferred and is being amortized through 2010.

In November 2001, the Department issued $109 million of Energy Services fixed rate bonds. The net proceeds were used to defease bonds with a par value of $107 million. The defeasance is expected to reduce total debt payments over the life of the new issues by $21 million and is expected to result in present value savings of approximately $8 million. This transaction resulted in a net loss for accounting purposes of $5 million, which was deferred and is being amortized through 2021.

In November 2001, the Department issued $7 million of Energy Services fixed rate bonds as part of the Mini-Bond Program for employees and retirees. The net proceeds were deposited into the construction fund to be used for distribution system capital improvements.

Outstanding debt defeased

As discussed above, Energy Services defeased certain revenue bonds in prior years by placing cash or the proceeds of new revenue bonds in irrevocable trusts to provide for all future debt service payments on the old bonds. Accordingly, the trust account assets and the liability for the defeased bonds are not included in Energy Services' financial statements.

NOTE 10: (continued)

At June 30, 2004, the following revenue bonds outstanding are considered defeased (amounts in thousands):

Bond Issues	Principal Outstanding
Third Issue of 1991	$ 970
Issue of 1992	1,865
Second Issue of 1993	116,100
Refunding Issue of 1994	55,755
Issue of 1994	6,400
Issue of 2000	251,145
	$ 432,235

Variable rate bonds

The variable rate bonds currently bear interest at daily and weekly rates (ranging from 1.06% to 1.13% as of June 30, 2004). The Department can elect to change the interest rate period of the bonds, with certain limitations. The bondholders have the right to tender the bonds to the tender agent on any business day with seven days prior notice. The Department has entered into Standby Agreements with a syndicate of commercial banks in initial amounts of $620.6 million and $388.5 million to provide liquidity for these bonds. The extended Standby Agreements expire on February 8, 2007 for the $620.6 million issue and on August 26, 2005 for the $388.5 million issue.

Bonds purchased under the agreements will bear interest that is payable quarterly at the greater of the Federal Funds Rate plus 0.50% or the bank's announced base rate, as defined. The unpaid principal of bonds purchased is payable in ten equal semi-annual installments, commencing after the termination of the agreement. At its discretion, the Department has the ability to convert the outstanding bonds to fixed rate obligations, which cannot be tendered by the bondholders. These bonds have been classified as long term on the balance sheets as the liquidity facilities give the Department the ability to refinance on a long term basis and the Department intends to either renew the facility or exercise its right to tender the debt as a long term financing. That portion which would be due in the next fiscal year in the event that the outstanding variable rate bonds were tendered and purchased by the commercial banks under the Standby Agreements, has been included in the current portion of long term debt and was $100.9 million as of June 30, 2004 and 2003.

NOTE 10: (continued)

Escrow investments

In July 2000, the Department deposited $32 million into a trust established for the purpose of making future debt service payments on specified revenue bonds with a par value of $35 million. The final maturity of the related revenue bonds is 2031. The escrow balance was $34.3 million (stated at fair value as of June 30, 2003). Interest expense from the related bonds and interest income earned on the related escrow investments are included in investment income.

In 2003, the Department restructured the escrow to allow for the bonds to be called at their earliest call date. On September 1, 2003, the bonds were called. This transaction resulted in a net loss for accounting purposes of $1.7 million, which was recognized in fiscal year 2004 as part of debt expenses.

Scheduled principal maturities and interest

Scheduled annual principal maturities and interest are as follows (amounts in thousands):

	Principal	Interest and Amortization
Fiscal years ending June 30,		
2005	$ 45,928	$ 133,183
2006	55,961	130,630
2007	67,985	128,010
2008	41,908	126,445
2009	43,525	124,835
2010 - 2014	593,344	548,827
2015 - 2019	501,869	405,281
2020 - 2024	741,132	239,763
2025 - 2029	667,325	88,718
2030 - 2034	581,345	26,387
2035 - 2036	187,414	758
Total Requirements	$ 3,527,736	$ 1,952,837

The scheduled maturities for the fiscal year ending June 30, 2005 exclude $100.9 million in variable rate bonds classified as short term for reporting purposes as described above. Interest and amortization includes interest requirements for variable rate debt, using the average variable debt interest rate in effect at June 30, 2004 of 1.07%.

NOTE 10: (continued)

Fair value

The fair value of long-term debt is $3.0 billion and $3.2 billion at June 30, 2004 and 2003, respectively. Management has estimated fair value based on the present value of interest and principal payments on the long-term debt and refunding bonds, discounted using current interest rates obtainable by the Department for debt of similar quality and maturities.

Energy Services is in compliance with all debt covenants. The most restrictive covenant is the additional bonds test. It requires that the adjusted net income for the applicable calculation period (12 months) shall amount to at least 1.25 times the maximum annual adjusted debt service on all parity obligations. As of June 30, 2004, the net debt service coverage ratio is 2.48.

NOTE 11: Retirement, Disability and Death Benefit Insurance Plan

The Department has a funded contributory retirement, disability and death benefit insurance plan covering substantially all of its employees. The Water and Power Employees' Retirement, Disability and Death Benefit Insurance Plan (the Plan) operates as a single-employer benefit plan to provide pension benefits to eligible Department employees and to provide disability and death benefits from the respective insurance funds. Plan benefits are generally based on years of service, age at retirement and the employee's highest 12 consecutive months of salary before retirement. Active participants who joined the Plan on or after June 1, 1984 are required to contribute 6% of their annual covered payroll. Participants who joined the Plan prior to June 1, 1984 contribute an amount based upon an entry-age percentage rate. The Department contributes $1.10 for each $1.00 contributed by participants plus an actuarially determined annual required contribution as determined by the Plan's independent actuary. The contributions are allocated between Energy Services and Water Services based on the current year labor costs.

The Retirement Board of Administration (the Retirement Board) is the administrator of the Plan. The Plan is subject to provisions of the Charter of the City of Los Angeles and the regulations and instructions of the Board of Water and Power Commissioners (the Board of Commissioners). The Plan is an independent pension trust fund of the Department.

Plan amendments must be approved by both the Retirement Board and the Board of Commissioners. The Plan issues separately available financial statements on an annual basis.

NOTE 11: (continued)

The annual pension cost (APC) and net pension obligation (NPO) for the Department's plan consists of the following (amounts in thousands):

	Year Ended June 30, 2004	Year Ended June 30, 2003
Annual required contribution	$ 44,614	$ 41,417
Interest on net pension asset	(13,558)	(14,107)
Adjustment to annual required contribution	20,203	21,021
APC (including $16.1 million and $14.1 million of amounts capitalized in fiscal 2003 and 2002, respectively)	51,259	48,331
Department contributions	(55,694)	(40,577)
Change in NPO	(4,435)	7,754
NPO (asset) at beginning of year	(177,749)	(185,503)
NPO (asset) at end of year	$ (182,184)	$ (177,749)

Energy Services' allocated share of APC and NPO consists of the following (amounts in thousands):

	Year Ended June 30, 2004	Year Ended June 30, 2003
Annual required contribution	$ 29,445	$ 31,560
Interest on net pension asset	(8,948)	(10,750)
Adjustment to annual required contribution	13,334	16,017
APC (including $9.1 million and $9.1 million of amounts capitalized in fiscal 2004 and 2003, respectively)	33,831	36,827
Department contributions	(36,904)	(30,370)
Change in NPO	(3,073)	6,457
NPO (asset) at beginning of year	(119,198)	(125,655)
NPO (asset) at end of year	$ (122,271)	$ (119,198)

NOTE 11: (continued)

Annual required contributions are determined through actuarial valuations using the entry age normal actuarial cost method. The actuarial value of assets in excess of the Department's actuarial accrued liability (AAL) was being amortized by level contribution offsets over the period ending June 30, 2004. As a result of an April 2000 amendment to the Plan, the amortization period was changed to rolling fifteen-year periods effective July 1, 2000.

In accordance with actuarial valuations, the Department's required contribution rates are as follows:

Actuarial Valuation Date June 30	Normal Cost	Surplus Amortization	Contribution Rate
2004	10.83%	2.10%	13.45%
2003	10.89%	-2.76%	8.45%
2002	10.97%	-2.64%	8.66%

The significant actuarial assumptions include an investment rate of return of 8%, projected inflation-adjusted salary increases of 5.5%, and postretirement benefit increases of 3%. The actuarial value of assets is determined using techniques that smooth the effects of short-term volatility in the market value of investments over a four-year period. Plan assets consist primarily of corporate and government bonds, common stocks, mortgage-backed securities and short-term investments.

NOTE 11: (continued)

Trend information for fiscal years 2004, 2003 and 2002 for Energy Services is as follows (amounts in thousands):

Year ended June 30,	NPO (asset)	Percentage of APC Contributed	APC
2004	$ (122,271)	109%	$ 33,831
2003	$ (119,198)	84%	$ 36,827
2002	$ (125,655)	400%	$ 4,986

The following schedule provides information about the Department's overall progress made in accumulating sufficient assets to pay benefits when due, prior to allocations to Water Services and Energy Services (amounts in thousands):

Actuarial Valuation Date June 30,	Actuarial Value of Assets	AAL	Actuarial Assets over/(under) AAL	Funded Ratio	Covered Payroll	(Underfunding) Overfunding as a % of Covered Payroll
2004	$ 6,251,421	$ 6,421,814	$ (170,393)	97%	$ 581,039	-29%
2003	$ 6,128,376	$ 6,042,087	$ 86,289	101%	$ 527,787	16%
2002	$ 5,790,263	$ 5,714,525	$ 75,738	101%	$ 430,398	18%

Disability and death benefits

Energy Services' allocated share of disability and death benefit plan costs and administrative expenses totaled $8 million, $11 million, and $10 million for each of the fiscal years 2004, 2003, and 2002, respectively.

NOTE 12: Postretirement Health Care Plan

Effective July 1, 2003, the Department adopted GASBS 45 "*Accounting and Financial Reporting by Employers for Postemployment Benefits Other Than Pensions*" (GASBS 45), and discontinued following Financial Accounting Standards Board Statement No. 106 "*Employers' Accounting for Postretirement Benefits Other Than Pensions*" (SFAS 106). See Note 2.

The adoption of GASBS 45 did not affect the benefits provided by the health plan, the amount of the postretirement trust fund assets, or the fair value of assets. The adoption of GASBS 45 changed the accounting for the health care costs, the actuarial cost method, and the assumptions required by the independent third party actuary to value the Department's obligation related to postretirement health care coverage.

Plan Description

The Department provides certain health care benefits to active and retired employees and their dependents. The health care plan is administered by the Department. The Retirement Board and the Board of Water and Power Commissioners have the authority to approve provisions and obligations. Eligibility for benefits for retired employees is dependent on a combination of age and service of the participants pursuant to a predetermined formula. Any changes to these provisions must be approved by the Boards. The total number of active and retired Department participants entitled to receive benefits was approximately 16,760 at June 30, 2004.

The health plan is a single employer plan that is not administered as a trust or equivalent arrangement and therefore, does not have separate financial statements.

Funding Policy

The Department pays a monthly maximum subsidy of health plan premiums. Participants choosing plans with a cost in excess of the subsidy are required to pay the difference. No funding policy has been established for the future benefits to be provided under this plan. However, in fiscal year 2004, the Department made an employer contribution of $100 million (Energy Services portion, $66 million) in addition to the $49 million it paid for current retiree premiums (Energy Services portion, $32 million).

NOTE 12: (continued)

Annual OPEB Cost and Net OPEB Obligation

The annual other postretirement benefit (OPEB) cost (expense) is calculated based on the annual required contribution of the employer (ARC), an amount actuarially determined in accordance with the parameters of GASBS 45. The ARC represents a level of funding that, if paid on an ongoing basis, is projected to cover normal cost under each year and amortize any unfunded actuarial liabilities (or funding excess) over a period not to exceed thirty years. The following table shows the components of the Department's and the share of Energy Services in annual OPEB cost for the year, the amount actually contributed to the plan, and changes in the net postretirement liability/asset (dollar amount in thousands):

	Department	Energy Services Share
Annual required contribution	$ 107,435	$ 70,907
Contributions made	(149,794)	(98,843)
Increase in net post retirement asset	(42,359)	(27,936)
Net postretirement asset- beginning of year	(184,725)	(131,247)
Net postretirement asset - end of year	$ (227,084)	$ (159,183)

The reconciliation of the beginning net postretirement asset is as follows (dollar amount in thousands):

	Department	Energy Services Share
Net postretirement liability - beginning of year as previously reported	$ 329,879	$ 230,693
Adjustment due to change in accounting to GASBS 45 (see Note 2)	(514,604)	(361,940)
Net postretirement asset - as adjusted	$ (184,725)	$ (131,247)

The Department's and Energy Services share in the annual OPEB cost, the percentage of annual OPEB cost contributed to the plan, and the net retirement obligation for fiscal year 2004 were as follows (dollar amount in thousands):

NOTE 12: (continued)

	Department	Energy Services Share
Annual OPEB cost	$ 107,435	$ 70,907
Percentage of annual OPEB cost contributed	139%	139%
Net postretirement asset	$ 227,084	$ 159,183

Funded Status and Funding Progress

As of July 1, 2003, the plan was 11 percent funded. The actuarial accrued liability for benefits was $1.7 billion and the actuarial value of assets was $186.9 million, resulting in an unfunded actuarial accrued liability (UAAL) of $1.5 billion. The covered payroll (annual payroll of active employees covered by the plan) was $571 million, and the ratio of the UAAL to the covered payroll was 270 percent.

Actuarial valuations of an ongoing plan involve estimates of the value of reported amounts and assumptions about the probability of occurrence of events far into the future. Examples include assumptions about future employment, mortality, and the health care cost trend. Amounts determined regarding the funded status of the plan and the annual required contributions of the Department are subject to continual revision as actual results are compared with past expectations and new estimates are made for the future. The schedule of funding progress, presents information about whether the actuarial value of plan assets is increasing or decreasing over time relative to the actuarial accrued liabilities for benefits.

Actuarial Methods and Assumptions

Projections of benefits for financial reporting purposes are based on the substantive plan (the plan understood by the Department and the plan members) and include the types of benefits provided at the time of each valuation and the historical pattern of sharing of benefit costs between the Department and the plan members to that point. The actuarial methods and assumptions used include techniques that are designed to reduce the effects of short-term volatility in actuarial accrued liabilities and the actuarial value of assets, consistent with the long-term perspective of the calculations.

NOTE 12: (continued)

In the July 1, 2003 actuarial valuation, the entry age normal cost method was used. The actuarial assumptions include 6.50 percent discount rate which represents the expected long term return on plan assets, an annual health care cost trend rate of 16 percent initially, reduced by decrements to an ultimate rate of 5.75 percent after seven years. Both rates include a 3.5 percent inflation assumption. The actuarial value of assets was determined using techniques that spread UAAL being amortized as a level percentage of projected payroll over a 30 year period.

New legislation

In December 2003, the President signed into law the Medicare Prescription Drug, Improvement and Modernization Act of 2003 effective in 2006. Two important aspects of the law may affect the employer's financial statements before 2006. First, the opportunity for retirees to obtain prescription drug benefits under new Medicare Part D will tend to shift benefits and related costs out of employer plans. Second, employers that provide prescription drug benefits that are at least as valuable as (actuarially equivalent) those under Medicare Part D will be entitled to annual subsidy from Medicare equal to 28% of prescription drug costs between $250 and $5,000 for each Medicare-eligible retiree who does not join part D. The Department has not yet determined the financial statement impact of adopting the new law.

NOTE 12: (continued)

For fiscal year 2003 the Department followed SFAS 106. The applicable disclosures for fiscal year 2003 are provided below:

The Department provides certain health care benefits to active and retired employees and their dependents. The health plan is administered by the Department, and the Retirement Board and the Board of Water and Power Commissioners have the authority to approve provisions and obligations. Eligibility for benefits is dependent on a combination of age and service of the participants pursuant to a predetermined formula. Any changes to these provisions must be approved by the Board. The Department pays a maximum subsidy of health plan premiums. Participants choosing plans with a cost in excess of the subsidy are required to pay the difference. The total number of active and retired Department participants entitled to receive benefits was approximately 14,200 at June 30, 2003.

The allocated cost to Energy Services of providing such benefits amounted to $134 million, and $109 million for fiscal years 2003 and 2002, respectively. Of these costs, $33 million and $26 million were capitalized and the remainder was charged to expense for fiscal years 2003 and 2002, respectively.

Postretirement benefits

The Department accounts for postretirement benefits in accordance with SFAS No. 106, "*Employers' Accounting for Postretirement Benefits Other Than Pensions*", which requires that the cost of postretirement benefits be recognized as expense over employees' service periods.

NOTE 12: (continued)

Energy Services' allocated share of postretirement benefit costs is summarized as follows (amounts in thousands):

	Year ended June 30, 2003	2002
Service cost	$ 13,281	$ 10,829
Interest cost	43,958	37,549
Expected return on plan assets	(2,645)	(2,614)
Amortization of transition obligation	9,979	9,994
Amortization of prior service costs	9,231	5,081
Amortization of actuarial losses	5,073	5,400
	$ 78,877	$ 66,239

The funded status and the accrued benefit cost related to postretirement benefits for the Department, prior to allocations to Water Services and Energy Services, are summarized as follows (amounts in thousands):

	June 30, 2003
Change in benefit obligation:	
Benefit obligation at beginning of year	$ 941,626
Service cost	20,154
Interest cost	66,704
Actuarial losses	846,000
Benefits paid	(43,132)
Benefit obligation at end of year	1,831,352
Change in fair value of plan assets:	
Fair value of plan assets at beginning of year	81,493
Department contribution	96,000
Actual return on plan assets	7,232
Fair value of plan assets at end of year	184,725
Funded status	1,646,627
Unrecognized net loss	1,124,256
Unrecognized transition obligation	152,721
Unrecognized prior service cost	39,771
Accrued benefit cost	$ 329,879
Energy Services' allocated share of accrued postretirement liability	$ (230,693)

NOTE 12: (continued)

Weighted average actuarial assumptions used in determining postretirement benefit costs are as follows:

	June 30, 2003	June 30, 2002
Discount rate	5.75%	7.25%
Expected return on plan assets	6.25%	6.50%

Plan assets consist primarily of commercial paper, United States government and governmental agency securities, and corporate bonds. In addition to having set up a trust fund, the Department currently pays benefits on a "pay as you go" basis. No funding policy has been established for the future benefit to be provided under this plan, however in fiscal year 2003, the Department made an employer contribution of $96 million.

For measurement purposes, a 10.0% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2003; the rate was assumed to decrease gradually to 5.5% in 2012 and remain at that level thereafter. For the dental plan, an 8.0% annual rate of increase in the per capita cost was assumed for 2003; the rate was assumed to decrease gradually to 5.5% in 2008 and remain at that level thereafter. The effect of a 1% change in these assumed health care cost trend rates would increase or decrease the Department's total benefit obligation by approximately $387 or $298 million, respectively. In addition, such a 1% change would increase or decrease the aggregate service and interest cost components of net periodic benefit cost by approximately $13 million or $10 million, respectively.

During fiscal year 2000, the Department began contributing toward dental coverage for retirees enrolled in a Department-sponsored plan. This amendment resulted in a $46 million increase in the Department's accumulated postretirement benefit obligation at June 30, 2000. Energy Services' allocated $35 million share of this increase is being amortized through 2008, the remaining average service period. This change also resulted in an $12 million increase in postretirement benefit costs for fiscal years 2003 and 2002 of which $8 million, was allocated to Energy Services.

NOTE 13: Shared Operating Expenses

Energy Services shares certain administrative functions with the Department's Water Services. Generally, the costs of these functions are allocated on the basis of the benefits provided. Operating expenses shared with Water Services were $642 million, $603 million and $514 million for fiscal years 2004, 2003 and 2002, respectively, of which $408 million, $384 million and $328 million were allocated to Energy Services, respectively.

NOTE 14: Loss on Asset Impairment and Abandoned Project

During fiscal year 2004, the Department recorded a loss on the Mohave Generating Station (Mohave) totaling $8.1 million. The loss was recorded using the service units approach under GASBS 42. Department management believes Mohave will close in December 2005 due to environmental, water, and coal issues. As of June 2004, management did not have a plan to remedy the issues to keep Mohave operating after December 2005.

During fiscal year 2004, the Department discontinued using a procurement system. Energy Services' portion of the loss related to this system totaled $5.5 million.

During fiscal year 2001, management approved the sale of one of its administrative facilities and Energy Services reported its portion of the loss on asset impairment of $28 million. The completion of the sale was expected to occur within 12 to 24 months for a total original purchase price of $50 million, which was below the total asset carrying value. During fiscal year 2002, management became aware that the facility had mold in the structure. Management and the purchaser of the facility each conducted a study to determine an estimated cost for mold cleanup. As of June 30, 2002, no estimate was available to record a clean-up liability, however, as of June 30, 2003, management approved the sale of this administrative building for a reduced price of $37 million, which is pending Board approval. This reduction in price caused Energy Services to recognize an additional loss of $8.3 million as of June 30, 2003. There were no further updates to the sale during fiscal year 2004.

NOTE 15: Commitments and Contingencies

Transfers to the reserve fund of the City of Los Angeles

Under the provisions of the City Charter, Energy Services transfers funds at its discretion to the reserve fund of the City. Pursuant to covenants contained in the bond indentures, the transfers may not be in excess of the increase in fund net assets before transfers to the reserve fund of the City, of the prior fiscal year. Such payments are not in lieu of taxes and are recorded as a non-operating expense in the statement of revenue, expenses, and changes in fund net assets.

The Department authorized total transfers of $210.2 million, $185.4 million, and $179.2 million in fiscal years 2004, 2003, and 2002, respectively, from Energy Services to the reserve fund of the City. In 2002, 2003, and 2004, the Department authorized additional transfers of $25.0 million, $29.0 million, and $60.0 million respectively, which was accrued as a liability as of fiscal year end. The $25.0 million accrued as of June 30, 2002 was paid in fiscal year 2003. The $29.0 million accrued as of June 30, 2003 was paid in July 2003, and the $60.0 million accrued as of June 30, 2004 was paid in fiscal year 2005.

NOTE 15: (continued)

Palo Verde Nuclear Generating Station (PVNGS) matters

As a joint project participant in PVNGS, the Department has certain commitments with respect to nuclear spent fuel and waste disposal. Under the Nuclear Policy Act, the Department of Energy (the DOE) was to develop the facilities necessary for the storage and disposal of spent fuel and to have the first such facility in operation by 1998; however, the DOE has announced that such a repository cannot be completed before 2010. There is ongoing litigation with respect to the DOE's ability to accept spent nuclear fuel; however, no permanent resolution has been reached.

In July 2002, a measure was signed into law designating the Yucca Mountain in the State of Nevada, as the nation's high-level nuclear waste repository. This means the DOE can now file a construction and operation plan for Yucca Mountain with the Nuclear Regulatory Commission (the NRC). The DOE expects that the Yucca Mountain site would be open by 2010, a date which many believe is highly optimistic. The State of Nevada and its congressional delegation have vowed to prevent the launch of the project through the NRC process or through legal challenges.

Disagreement over funding of the repository is ongoing. The Administration and Congressional leaders continue to push for full and adequate funding in order for the DOE to meet the application deadline of 2004. The Nevada delegation has been working diligently to try to delay the DOE's work on the license application for the Yucca site in hopes of halting the transfer of nuclear waste to the Nevada facility.

Capacity in existing fuel storage pools at PVNGS was exhausted in 2003. A Dry Cask Storage Facility (also called the Independent Spent Fuel Storage Facility) was built and completed in 2003 at a total cost of $33.9 million (about $3.3 million for the Department). In addition to the facility, the costs also account for heavy lift equipment inside the units and at the yard, railroad track, tractors, transporter, transport canister, and surveillance equipment. The facility has the capacity to store all the spent fuel generated by the plant until 2026, the end of its lifetime. To date, five casks, each containing 24 fuel assemblies, from Unit 2 were placed in the Storage Facility. Moving of the spent fuel from Unit 1 to the Storage Facility is in progress. The current plan calls for the removal of between 240 and 288 fuel assemblies from the units to the Storage Facility every year. The costs incurred in the procurement, packing, preparation and transportation of the casks are included as part of the fuel expenses, and would cost approximately $12 million a year (about $1.2 million for the Department). If the permanent repository in Yucca Mountain is opened as scheduled in 2010, the spent fuel from PVNGS will be shipped to the repository starting in 2031. The Department accrues for current nuclear fuel storage costs as a component of fuel expense as the fuel is burned. The Department's share of spent nuclear fuel costs related to its indirect interest in PVNGS is included in purchased power expense.

NOTE 15: (continued)

The Price-Anderson Act (the Act) requires that all utilities with nuclear generating facilities share in payment for claims resulting from a nuclear incident. The Act limits liability from third-party claims to over $9.5 billion per incident. Participants in PVNGS currently insure potential claims and liability through commercial insurance with a $300 million limit; the remainder of the potential liability is covered by the industry-wide retrospective assessment program provided under the Act. This program limits assessments to a maximum of $100.6 million for each licensee for each nuclear incident occurring at any nuclear reactor in the United States; payments under the program are limited to $10 million per incident, per year. Based on the Department's 5.7% direct interest and its 3.95% indirect investment interest through SCPPA, the Department would be responsible for a maximum assessment of $9 million per incident, limited to payments of $1 million per incident annually.

Environmental matters

Numerous environmental laws and regulations affect Energy Services' facilities and operations. The Department monitors its compliance with laws and regulations and reviews its remediation obligations on an ongoing basis.

The Department's generating station facilities are subject to the Regional Clean Air Incentives Market (RECLAIM) nitrogen oxide (NOx) emission reduction program adopted by the South Coast Air Quality Management District (SCAQMD). In accordance with this program, SCAQMD established annual NOx allocations for NOx RECLAIM facilities based on historical emissions and type of emission sources operated. These allocations are in the form of RECLAIM trading emission credits (RTCs). Facilities that exceed their allocations may buy RTCs from other companies that have emissions below their allocations. The Department has a program of installing emission controls and purchasing RTCs, as necessary, to meet its emission requirements.

In May 2001, SCAQMD adopted amendments to RECLAIM with the intent of lowering and stabilizing RTC prices. One key element of the amendments is that existing power plants were bifurcated from the rest of the RECLAIM market until 2004 and were required to install Best Available Retrofit Control Technology (BARCT). As required under SCAQMD rules, the Department met the BARCT compliance date of January 1, 2003. In January 2005, SCAQMD extended the date from the fall of 2004 until January 1, 2007 when power producers could reenter the RECLAIM market. However, as a result of the installation of NOx control equipment and the repowering of existing units, the Department has sufficient RTCs to meet its native load requirements for normal operations. Overall NOx emissions will be reduced by over 65 percent from 1999 levels.

NOTE 15: (continued)

Litigation

The State and a number of local government agencies that are electric customers of the Department claim that the Department has violated the State's False Claim Act by charging such governmental customers the standard rates applicable to both public and private customers in their respective customer rate categories. The plaintiffs allege that such rates include a capital facilities charge in violation of the State's statute. The plaintiffs are seeking unspecified amounts for treble damages, civil penalties, and injunctive relief. The Department intends to vigorously defend the claim.

A number of claims and suits are also pending against the Department for alleged damages to persons and property and for other alleged liabilities arising out of its operations. In the opinion of management, any ultimate liability, which may arise from these actions, are not expected to materially impact Energy Services' financial position, results of operations or cash flows as of June 30, 2004.

Risk management

Energy Services is subject to certain business risks common to the utility industry. The majority of these risks are mitigated by external insurance coverage obtained by Energy Services. For other significant business risks, however, Energy Services has elected to self-insure. Management believes that exposure to loss arising out of self-insured business risks will not materially impact Energy Services' financial position, results of operations or cash flows as of June 30, 2004.

Credit risk

Financial instruments, which potentially expose the Department to concentrations of credit risk, consist primarily of retail and wholesale receivables. The Department's retail customer base is concentrated among commercial, industrial, residential and governmental customers located within the City. Although the Department is directly affected by the City's economy, management does not believe significant credit risk exists at June 30, 2004, except as provided in the allowance for losses. The Department manages its credit exposure by requiring credit enhancements from certain customers and through procedures designed to identify and monitor credit risk.

Schedule of Funding Progress for the Los Angeles Department of Water and Power Postretirement Health Care Plan

(dollar amounts in thousands.)

Actuarial Valuation Date	Actuarial Value of Assets (a)	Actuarial Accrued Liability (b)	Unfunded AAL (b-a)	Funded Ratio (a/b)	Covered Payroll (c)	UAAL as a Percenatge of Covered Payroll ((b-a)/c)
July 1, 2003	$ 186,904	$ 1,729,706	$ 1,542,802	11%	$ 571,725	270%

For fiscal year 2004 Energy Services was allocated 66 percent of the post retirement obligation, and held $131.2 million of the $186.9 million of fund assets. Actuarial valuations are performed at the beginning of the fiscal year.

Water Services
Department of Water and Power
City of Los Angeles

Report and Financial Statements and
Required Supplementary Information

June 30, 2004

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Los Angeles Department of Water and Power
Water Services

Management's Discussion and Analysis
(Unaudited)

June 30, 2004

The following discussion and analysis of the financial performance of the City of Los Angeles' (the City) Department of Water and Power's (the Department), Water System Fund (Water Services), provides an overview of the financial activities for the fiscal year ended June 30, 2004. Descriptions and other details pertaining to Water Services are included in the notes to the financial statements. This discussion and analysis should be read in conjunction with the Water Services' financial statements, which begin on page 19.

Background and Creation of the Department

The Department is the largest municipal utility in the United States and is a separate proprietary agency of the City, controlling its own funds with full responsibility for meeting the electric and water requirements of its service area. The Department provides electric and water service almost entirely within the boundaries of the City, which encompasses some 465 square miles, to a population of approximately 3.9 million people. Certain factors, which affect the water industry, generally apply to the Department's operation of Water Services.

The Department was established under the City Charter adopted in January 1925 as amended effective July 2000. It had its beginning, however, in the early 1900's. The first Board of Water and Power Commissioners was established in 1902. The responsibilities for the provision of water as well as electricity were given to a new Los Angeles Department of Public Service organized in 1911. The Department of Public Service was superceded in 1925 when a new Charter was adopted creating the Department. Subsequently the Water Works and Electric Works came to be known as the Water System (Water Services) and the Power System (Energy Services). The operations and finances of Water Services are separate from those of Energy Services.

Charter Provisions

Governance

Pursuant to the Charter of the City (the Charter), the five-member Board of Water and Power Commissioners (the Board) is the governing body of the Department and the General Manager administers the affairs and operations of the Department. The Board is granted the possession, management, and control of Water Services. Board Commissioners are appointed for a term of five years by the mayor and confirmed by the City Council (the Council).

The provisions of the Charter relating to the Department are found in Article VI. Among other things, Article VI provides that all Water Services revenue collected by the Department shall be deposited in the Water Revenue Fund, that the Board shall control the money in the Water Revenue Fund, and makes provisions for the issuance of Department bonds, notes and other evidences of indebtedness payable out of the Water Revenue Fund.

Section 245 of the Charter provides that actions of the Board shall become final at the expiration of the next five meeting days of the Council, during which time the Council may bring the matter for review, or veto such action. If the Council votes to bring the matter for review, it has 21 days to conduct its review, otherwise the Board's action on the matter is final.

Rates

Pursuant to the Charter, the Board, subject to the approval of the Council by ordinance, fixes the rates for water service provided by Water Services. The Charter provides that such rates shall be fixed by the Board from time to time as necessary. The Charter also provides that such rates shall, except as authorized by the Charter, be of uniform operation for customers of similar circumstances throughout the City, as near as may be, and shall be fair and reasonable, taking into consideration, among other things, the nature of the uses, the quantity supplied, and the value of the service, and the financial impact on Water Services resulting from such service.

Transfers to the Reserve Fund of the City of Los Angeles

Under the provisions of the Charter, Water Services transfers funds at its discretion to the reserve fund of the City. Pursuant to covenants contained in the bond indentures, the transfers may not be in excess of the increase in fund net assets before transfers to the reserve fund of the City, of the prior fiscal year. Such payments are not in lieu of taxes and are recorded as a reduction of fund net assets in accordance with governmental accounting standards. Water Services made a transfer of 5% of its fiscal 2003 operating revenues, totaling $28 million, to the reserve fund of the City in fiscal 2004. Water Services expects to transfer 5% of its fiscal 2004 operating revenues, or approximately $30 million, to the reserve fund of the City in fiscal 2005.

Critical Accounting Policies

Method of Accounting

The accounting records of Water Services are maintained in accordance with accounting principles generally accepted in the United States of America. As a government-owned utility, in prior years the Department applied all statements issued by the Governmental Accounting Standards Board (GASB) and all statements and interpretations issued by the Financial Accounting Standards Board (FASB), which are not in conflict with statements issued by the GASB. In fiscal year 2003, the Department changed its election under the guidance in GASB Statement No. 20, *"Accounting and Financial Reporting for Proprietary Funds and Other Governmental Entities that Use Proprietary Fund Accounting*" (GASBS No. 20), to follow GASB statements and only FASB statements and interpretations issued on or before November 30, 1989. While the Department is required to retroactively apply this change by restating prior years presented, the change did not have any impact on prior years' financial statements. Therefore, prior periods were not restated. The Department continued to apply the provisions of Statement of Financial Accounting Standards (SFAS) No. 106, "*Employers' Accounting for Postretirement Benefits Other Than Pensions*," until the prescriptive guidance under governmental standards was issued. GASBS No. 45 was issued in 2004 and the Department early adopted the standard in fiscal year 2004 in accordance with the transition guidance to be in full compliance with GASBS No. 20. See Note 2 to the financial statements.

SFAS No. 71

Water Services' rates are determined by the Board and are subject to review and approval by the Council. As a regulated enterprise, the Department's financial statements are prepared in accordance with SFAS No. 71, "*Accounting for the Effects of Certain Types of Regulation,*" which requires that the effects of the ratemaking process be recorded in the financial statements. Such effects primarily concern the time at which various items enter into the determination of changes in fund net assets, in order to follow the principle of matching costs and revenues.

Revenue Recognition

Water Services sells water to retail customers at rates provided in the ordinance. Water Services recognizes water costs in the period incurred and accrues for estimated water sold but not yet billed.

Adoption of GASBS No. 45

Effective fiscal year 2004, the Department early adopted Governmental Accounting Standard No. 45 "*Accounting and Financial Reporting by Employers for Postemployment Benefits Other Than Pensions*" (GASBS No. 45), and discontinued following Financial Accounting Board Statement No. 106 "*Employers' Accounting for Postretirement Benefits Other Than Pensions*" (SFAS No. 106). The adoption of GASBS No. 45 had a significant effect on the results of fiscal year ended June 30, 2004, but had no impact on the healthcare benefits provided to active and retired employees, and had no impact on the amount or the value of the funds established to meet this obligation. See Note 2 to the financial statements for further information and a description of the impact of the change on the financial statements.

In the July 1, 2003 actuarial valuation, the entry age normal cost method was used. The actuarial assumptions include a 6.5 percent discount rate which represents the expected long term return on plan assets, an annual health care cost trend rate of 16 percent initially, reduced by decrements to an ultimate rate of 5.75 percent after seven years. Both rates include a 3.5 percent inflation assumption. The actuarial value of assets was determined using techniques that spread the unfunded actuarial accrued liability being amortized as a level percentage of projected payroll over a 30 year period.

Allowances and Reserves

The Department establishes reserves and allowances for accounts receivable balances where the collection of the full receivable is uncertain.

Litigation

It is the Department's policy to review the status and amount of lawsuits filed against the Department and to accrue for any probable costs based on the opinion of the City Attorney. If the City Attorney identifies a potential exposure range, with no amount within that range being more probable than the other amounts, the Department will accrue for the lowest amount within the range of potential exposure.

Using This Financial Report

This financial annual report consists of the financial statements and reflects the self-supporting activities of Water Services that are funded primarily through the sale of water to the public it serves.

Balance Sheets, Statements of Revenue, Expenses and Changes in Fund Net Assets, and Statements of Cash Flows

The financial statements provide an indication of Water Services' financial health. The Balance Sheets include all of Water Services' assets and liabilities, using the accrual basis of accounting, as well as an indication about which assets can be utilized for general purposes, and which assets are restricted as a result of bond covenants and other commitments. The Statements of Revenue, Expenses, and Changes in Fund Net Assets report all of the revenues and expenses during the time periods indicated. The Statements of Cash Flows report the cash provided and used by operating activities, as well as other cash sources such as investment income and cash payments for bond principal and capital additions and betterments.

The following table summarizes the financial condition and changes to fund net assets of Water Services as of and for the fiscal years ended June 30, 2004 and 2003 (amounts in millions):

Table 1 - Summary of financial condition and changes in fund net assets

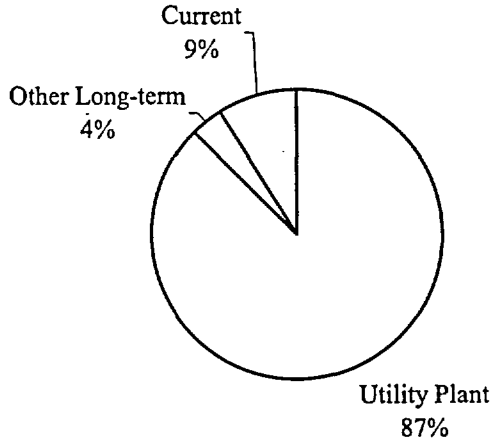
	June 30, 2004	June 30, 2003
Assets		
Utility plant, net	$ 2,993	$ 2,849
Restricted investments	-	4
Other long-term assets	128	58
Current assets	304	539
	$ 3,425	$ 3,450
Liabilities and Fund Net Assets		
Long-term debt	$ 1,212	$ 1,297
Other long-term liabilities	15	110
Current liabilities	302	251
	1,529	1,658
Fund net assets:		
Invested in capital assets, net of related debt	1,729	1,689
Restricted fund net assets	107	108
Unrestricted fund net assets	60	(5)
	1,896	1,792
	$ 3,425	$ 3,450
Revenue, Expenses, and Changes in Fund Net Assets		
Operating revenues	$ 596	$ 553
Operating expenses	(518)	(506)
Operating income	78	47
Investment income	1	11
Other income and expenses, net	(1)	3
Debt expense	(50)	(43)
Contributions in aid of construction	21	14
Transfer to the reserve fund of the City of Los Angeles	(28)	(28)
Extraordinary loss on extinguishment of debt	(3)	-
Increase in fund net assets	18	4
Beginning balance of fund net assets	1,792	1,788
Adjustment due to change in accounting principle from SFAS No. 106 to GASBS No. 45	86	-
Ending balance of fund net assets	$ 1,896	$ 1,792
Cash Flows		
Cash flows from operating activities	$ 283	$ 113
Cash flows from noncapital financing activities	(28)	(28)
Cash flows from capital and related financing activities	(389)	34
Cash flows from investing activities	(26)	(21)
Change in cash increase (decrease)	$ (160)	$ 98

Assets

Utility Plant

Utility plant is the first category of assets shown on the balance sheet. The utility industry is unique in this regard as most other industries list their long-term assets such as plant and equipment after current assets on the balance sheet. This difference is due to the capital-intensive nature of the utility industry with the most significant portion of that capital being invested in utility plant. As depicted in the chart below, utility plant, net of accumulated depreciation, makes up 87% of the total assets of Water Services as of June 30, 2004.

Chart 1 - Total Assets by Type



During fiscal year 2004, Water Services capitalized $207 million of additions to utility plant in service. Of the $207 million, $141 million, or 68% related to distribution utility plant assets, and $21 million was added to purification assets. Additions to distribution utility plant assets comprised the completion of various major reservoir and trunk line projects. Additions to purification assets include water quality lab additions and improvements. The remaining $45 million of additions were incurred for normal capital activities to maintain and support general plant, pumping and purification systems.

Water Services has budgeted approximately $427 million of capital expenditures for fiscal year 2005.

During the fourth quarter of fiscal year 2004, Water Services adopted a depreciation study covering utility plant assets. The study was completed by an independent third party and recommended changing the useful life estimates on certain assets. The adoption of the study resulted in reducing depreciation expense by $6 million for the fourth quarter of 2004.

Water Services utility plant assets fall into five major categories: source of water supply, pumping, purification, distribution, and general. Each category of assets is important to providing water services and has a specific purpose. Source of water supply assets are the assets that the Department has constructed and/or purchased to help ensure an adequate supply of water. The Department has four major sources of water. These include:

- Los Angeles Aqueduct and Second Los Angeles Aqueduct supply imported water from the Owens Valley and the Mono Basin;
- Local groundwater supply (with pumping rights in the San Fernando, Sylmar, Central and West Coast Basins);
- Purchased supply from Metropolitan Water District;
- Recycled water.

All sources of water, except for recycled water, are supplied for potable use; that is, the water from these sources is of drinkable quality. Table 2 below shows the percentage of potable water delivered from the major sources.

Table 2 - Sources of Potable Water Supplied During Fiscal Year 2004

Source	Millions of Gallons	Percent
Aqueduct	73,448	33%
Wells	30,719	14%
Purchases	119,845	53%
	224,012	100%

Water storage during low demand, cold, or wet periods is essential for conservation, to supply the extra water needed during warm weather or emergency situations.

The Water System's 101 tanks and reservoirs, ranging in size from 10 thousand to 60 billion gallons, have a current capacity of approximately 339,261 acre-feet, or 110.54 billion gallons. Eight aqueduct reservoirs provide 92% of the Water System's storage capacity; major and minor distribution reservoirs provide the remaining 8%.

Under-recovered costs

Under-recovered costs are a current asset on Water Services' balance sheet. Under-recovered costs are the costs that Water Services has incurred for water supply and other designated costs in excess of amounts billed to the customer. Expenses that are recovered through this rate include purchased water expense, water quality expense, reclaimed water expense, demand-side management expense (or conservation expense), water or system security expense, and certain operation and maintenance costs.

Under-recovered costs increased by $10.3 million from June 30, 2003 to June 30, 2004, due to new costs such as security and certain operation and maintenance costs being included as specific recoverable costs recovered through the water rate adjustment factors. These costs are expected to be recovered through future billings.

Investments

The Department sets aside funds to be used in future years for specified purposes. Restricted investments in general consist of U.S. government securities. At June 30, 2004, Water Services share of the Department's postretirement health care benefit fund, established to provide for the payment of the Department's postretirement health care benefits, totaled $88 million. The adoption of GASBS No. 45 did not impact the amount or value of this fund. The fund is not included as a restricted investment, but instead netted against Water Services postretirement liability under appropriate accounting guidance.

The Department has a securities lending program which, for Water Services, allows it to lend up to 20% of its investments held in the postretirement benefits trust fund for securities, cash collateral or letters of credit equal to 102% of the market value of the loaned securities and interest, if any. The lending agent provides indemnification for borrower default. There were no violations of legal or contractual provisions and no borrower or lending agent default losses during fiscal years 2004 and 2003.

In addition, Water Services participates in the City's securities lending program to enhance its earnings on investments, and is allocated its share of the collateral received and the related liability, as well as earnings from the program. As of June 30, 2004 and 2003, the amount of collateral and liability pertaining to both securities lending programs combined was $23 million and $40 million, respectively. Management believes that participation in these securities lending programs results in minimal credit risk exposure to the Department because the amounts owed to the borrowers exceed the value of the securities that are on loan.

Current Assets

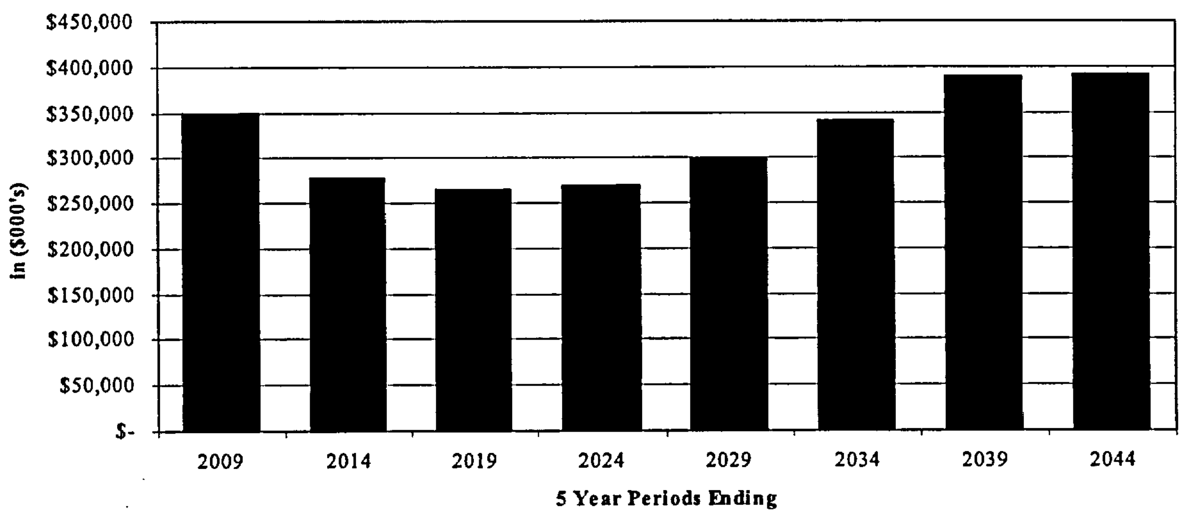
Current Assets decreased $234 million in fiscal year 2004. The causes for the decrease were primarily due to $178 million of restricted cash in construction funds being used during 2004 and the repayment of the receivable from Energy Services of $67 million.

Liabilities and Fund Net Assets

Long term debt

As of June 30, 2004, Water Services' total long-term debt balance was $1.3 billion. The balance decreased by $74 million over the prior year, reflecting primarily the issuance of $164 million in revenue bonds and deploying $70 million of cash during the year to refund $236 million of revenue bonds, and maturities of $15 million. An additional $4.5 million in State Revolving Fund (SRF) Drinking Water loan proceeds were received from the State that offset net amortization of losses on refundings, debt discounts and premiums of $4.5 million. Outstanding principal, plus scheduled interest and amortization as of June 30, 2004, is scheduled to mature as shown in the chart below:

Chart 2: Debt Service Requirements



As of June 30, 2004, $427 million principal amount of long-term debt is considered defeased and remains outstanding. This debt, together with trust funds set aside for its full repayment at scheduled maturity dates, has been derecognized and is not reflected on the balance sheet.

In July 2004, Standard & Poor's and Fitch affirmed Water Services' bond rating of AA and AA+, respectively.

Due to Energy Services

As of June 30, 2004, Water Services owed $20 million to Energy Services, a decrease of $87 million over June 30, 2003. Amounts owed between the two funds are generally settled within one month.

Other long-term liabilities

Other long-term liabilities decreased $95 million in fiscal year 2004. The decrease is due to the change in the postretirement liability of $99 million offset by an increase of $4 million in accrued workers' compensation claims.

Current liabilities

Current liabilities increased by $51 million in fiscal year 2004. The primary causes for the increase were due to an increase of $20 million due to Energy Services, and an additional $31 million increase in other accounts payable and accrued expenses.

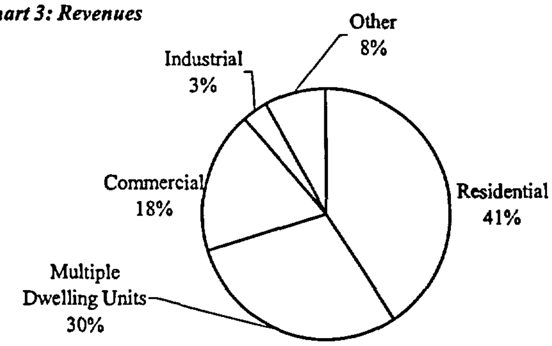
Changes in Fund Net Assets

Revenues

The operating revenues of Water Services are generated from selling water to its customers. The current water rate has two components, a base rate, and an adjustable rate, which is referred to as a pass through rate. The pass through rate is in place to recover the cost of specific expenses. These specific expenses include purchased water, water quality, reclaimed water, demand-side management (or conservation expense), and water security. As a result of the inclusion of a pass through rate in water rates, revenue can increase or decrease from one year to the next based on Water Services incurring greater or smaller expenses in these categories.

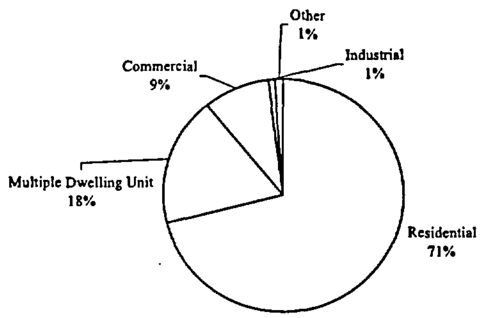
Water Services has five major customer categories. These categories include residential, multiple dwelling units, commercial, industrial, and other. Chart 3 summarizes the percentage contribution of revenues from each customer category during fiscal year 2004:

Chart 3: Revenues



Residential customers provide 41% of Water Services' revenue representing the largest class of customers. As of June 30, 2004, Water Services had approximately 662 thousand customers. As shown in Chart 4, 471 thousand, or 71% of total customers, were in the residential customer class as of June 30, 2004.

Chart 4: Number of Customers



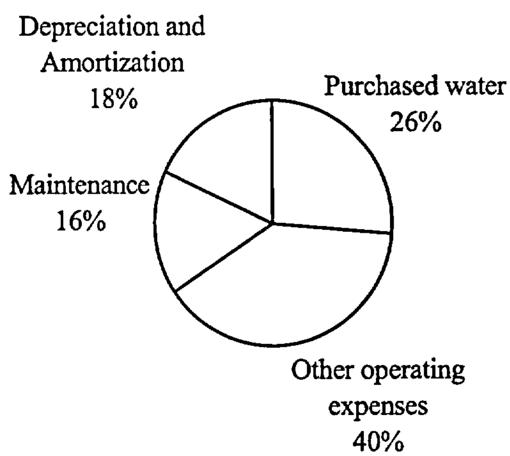
During fiscal year 2004, operating revenues increased by $43 million, or 8% from fiscal year 2003 revenues. The increase was due to an increase in consumption of 5%, an increase in recoverable purchased water costs, and an increase in other operating revenues.

During fiscal year 2003, operating revenues increased by $3 million, or 0.5% from fiscal year 2002 revenues due to an increase in pass-through recoverable costs. Due to additional qualifying pass-through recoverable costs, the average rate was higher in fiscal year 2003. The additional revenue from pass-through rates was partially offset by a minor decrease in consumption for all customer classes due to cooler and wetter weather.

Operating Expenses

Purchased water expense is the single largest expense that Water Services incurs each fiscal year. Purchased water expense represents the cost of buying water, primarily from the Metropolitan Water District (MWD). For fiscal year 2004, 53% of the potable water supplied to Water Services' customers was purchased water. Chart 5 summarizes Water Services' operating expenses for fiscal year 2004:

Chart 5: Operating Expenses



<u>*Fiscal year 2004*</u>

Fiscal year 2004 operating expenses were $12 million higher as compared to the prior year. This increase was mostly due to an increase in other operating and maintenance expenses of $17 million, and an increase of $1 million for depreciation expense offset by a $6 million decrease in purchased water costs.

Other operating and maintenance expenses increased primarily as a result of continued increases in environmental costs associated with ongoing operations and maintenance phases of Owens Valley remediation.

Purchased water costs have decreased $6 million over fiscal year 2003. Water Services purchased 1,452 million fewer gallons of water during 2004.

The increase in depreciation and amortization expense is associated with utility plant additions offset by the results of a depreciation study the Department completed in the fourth quarter of fiscal year 2004 which reduced fourth quarter depreciation by $6 million.

In addition, Water Services recognized a $3 million loss on asset impairment related to a procurement system.

Fiscal year 2003

Fiscal year 2003 operating expenses were $56 million higher as compared to the prior year. This increase was due to an increase in purchased water costs of $6 million, an increase in other operating and maintenance expenses of $46 million, and an increase of $4 million in depreciation and amortization expense.

Other operating and maintenance expenses increased primarily as a result of continued increases in environmental costs associated with ongoing operations and maintenance phases of Owens Valley remediation, increased retirement, death and disability expenses and health care costs as a result of higher benefit and medical costs.

Purchased water costs have increased $6 million over fiscal year 2002. In fiscal year 2002, Water Services received a revenue rebate credit from MWD of approximately $6 million. The Department did not receive such a credit in fiscal year 2003 and otherwise experienced similar expense levels due to higher quantities purchased offset by lower average unit prices.

The increase in depreciation and amortization expense is associated with utility plant additions. Furthermore, Water Services recognized a $3 million impairment charge during fiscal year 2003 relating to the sale of one of its administrative facilities. The Department entered into a sale transaction for the facility and reduced the sale price as a result of mold that was discovered in the facility. See Note 10 of the financial statements for further discussion.

Non-Operating Revenue and Expenses

Fiscal year 2004

The major non-operating activities of Water Services for fiscal year 2004 include the transfer of $28 million to the reserve fund of the City of Los Angeles; $50 million in debt expenses, net of allowance for funds used during construction, and earned contributions in aid of construction of $21 million.

Interest on investments for Water Services followed the general trend in interest rates and remained relatively unchanged from an average yield of 3.77% in fiscal year 2003 to 3.42% in fiscal year 2004. Interest income decreased $10 million in fiscal year 2004 as compared to fiscal year 2003 due to a reduction of $176 million in cash available for investment.

Contribution in aid of construction revenue increased by $7 million mostly due to a grant of $6 million received from MWD.

Fiscal year 2003

The major non-operating activities of Water Services for fiscal year 2003 include the transfer of $28 million to the reserve fund of the City of Los Angeles; interest income earned on cash and investments of $11 million, $43 million in debt expenses, net of allowance for funds used during construction, and earned contributions in aid of construction of $14 million. Interest on investments followed the general trend in interest rates and declined from an average yield of 4.28% in fiscal year 2002 to 3.77% in fiscal year 2003. Interest on debt service increased due to additional debt of $300 million being issued during fiscal 2003.

Changes in Operating, Investing and Financing Activities

Operating activities

Cash from operating activities was $170 million higher in fiscal year 2004 due to increased receipts from retail customers of $18 million and increased receipts of $110 million for interfund services and decrease in payments to suppliers of $63 million.

Noncapital financing activities

The noncapital financing activities for Water Services for fiscal year 2004 was the payment of the transfer to the City of Los Angeles for $28 million.

Capital and related financing activities

The capital and related financing activities for fiscal year 2004 provided $423 million fewer dollars than the capital and related financing activities of fiscal year 2003. The reduction of cash inflows was mostly due to a $325 million reduction of new bond proceeds, an increase of $35 million in refunded bond payments, a $21 million increase in interest payments, a $13 million increase in principal payments on long term debt, and a $39 million increase in cash used for utility plant additions. These reductions of cash were offset by a $5 million increase in contributions in aid of construction revenue, and a $4 million loan from the State. Below is a summary of the Department's debt management program and purpose.

Debt Management Program

The debt restructuring element of the Debt Management Program includes the issuance of refunding bonds to achieve debt service savings and to accelerate the maturity of certain bonds while maintaining an appropriate overall annual debt service schedule for all of the Department's obligations in connection with the Water System. The Department has completed the major portion of its refunding program, including the issuance of several series of refunding bonds payable from the Water Revenue Fund under a Master Bond Resolution adopted by the Board on February 6, 2001. Management completed its refunding program during fiscal year 2004.

Investing activities

Investing activities during fiscal year 2004 remained relatively unchanged from 2003. Below is the Department's investment policy and controls.

Investment Policy and Controls

The Department's cash, other than cash in certain trust funds, is deposited with the City Treasurer, who invests the funds in securities under the City Treasurer's pooled investment program, for the purpose of maximizing interest earnings. Under the program, available funds of the City and its independent operating departments are invested on a combined basis. The primary responsibilities of the City Treasurer are to protect the principal and asset holdings of the City's portfolio and to ensure adequate liquidity to provide for the prompt and efficient handling of City disbursements. The City Treasurer invests these funds in compliance with the applicable California Government Code and the City's Investment Policy. Generally, investments are limited to government securities with credit ratings of AAA and are of varying maturities which can range from less than 90 days to in excess of two years.

Risk Factors

Water Services' primary business is to provide its customers with safe and reliable water service. Water Services manages its overall cost of providing service by monitoring its water supply and demand data. In addition, Water Services purchases water for customers when the Department's supply is maximized.

The Department has traditionally acquired the majority of its water from the Los Angeles Aqueduct, the Second Los Angeles Aqueduct, local wells, and purchases from MWD. The Department believes that proper management of these sources, coupled with water recycling and conservation programs will provide adequate water supplies to meet the needs of the City for the foreseeable future. Rules and regulations surrounding water quality and the environment continue to become more stringent. As such, the Department continually monitors its compliance requirements. Water Services may incur additional capital expenditures in order to meet the rules and regulations. Requirements currently in place that affect Water Services include the Surface Water Treatment Rule and environmental remediation relating to Owens Valley. Based on current significant requirements in effect, Water Services expects that it will incur a total of approximately $954 million to meet these requirements through 2007.

With respect to water supply, the Department is working at protecting the reliability of existing supplies and sources. It is the Department's intent to ensure the reliability of imported water. The Department has adopted a goal of meeting as much of the additional water demands arising from growth over the next 20 years through water conservation and reclamation programs as possible. Any additional supply will be obtained through purchases from MWD. However, the Department cannot guarantee that these programs or other measures will provide the additional supply requirements of the City.

PRICEWATERHOUSECOOPERS

Report of Independent Auditors

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To the Board of Water and Power Commissioners
Department of Water and Power
City of Los Angeles

In our opinion, the accompanying balance sheets and the related statements of revenue, expenses and changes in fund net assets and of cash flows present fairly, in all material respects, the financial position of the Water System (Water Services) of the Department of Water and Power of the City of Los Angeles at June 30, 2004 and 2003, and the changes in its financial position and cash flows for each of the three years in the period ended June 30, 2004 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Department's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Notes 2 and 8 to the financial statements, effective July 1, 2003, Water Services adopted Governmental Accounting Standards Board (GASB) Statement No. 45, "Accounting and Financial Reporting by Employers for Postemployment Benefits Other Than Pensions" and discontinued applying Financial Accounting Standards Board Statement No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions," in accounting for its healthcare costs.

As discussed in Notes 2 and 10 to the financial statements, effective July 1, 2003, Water Services adopted GASB Statement 42, "Accounting and Financial Reporting for Impairment of Capital Assets and for Insurance Recoveries."

The management's discussion and analysis included on pages 1 through 17 and the information on the postretirement benefits other than pension plans on page 58 are not a required part of the basic financial statements but are supplementary information required by the Governmental Accounting Standards Board. We have applied certain limited procedures, which consisted primarily of inquiries of management regarding the methods of measurement and presentation of the required supplementary information. However, we did not audit the information and express no opinion on it.

PricewaterhouseCoopers LLP

February 7, 2005

Los Angeles Department of Water and Power
Water Services Balance Sheets
(Amounts in thousands)

	June 30, 2004	June 30, 2003
Assets		
Non-Current Assets		
Utility Plant		
Source of water supply	$ 592,654	$ 584,317
Pumping	193,810	190,074
Purification	258,515	239,979
Distribution	2,712,827	2,612,116
General	364,067	345,655
	4,121,873	3,972,141
Accumulated depreciation	1,460,835	1,385,526
	2,661,038	2,586,615
Construction work in progress	331,983	262,252
	2,993,021	2,848,867
Restricted investments	-	4,613
Net pension asset	59,913	58,552
Net postretirement asset, net	67,901	-
	127,814	63,165
Current Assets		
Cash and cash equivalents - unrestricted	60,890	45,078
Cash and cash equivalents - restricted	55,651	231,767
Cash collateral received from securities lending transactions	23,382	40,071
Customer and other accounts receivable, net of $3,500 allowance for losses	50,270	62,467
Underrecovered costs	33,448	23,075
Due from Energy Services	-	67,447
Accrued unbilled revenue	47,853	44,214
Materials and supplies	16,339	15,027
Prepayments and other current assets	16,584	9,482
	304,417	538,628
	$ 3,425,252	$ 3,450,660

The accompanying notes are an integral part of these financial statements

Los Angeles Department of Water and Power
Water Services Balance Sheets
(Amounts in thousands)

	June 30, 2004	June 30, 2003
Fund Net Assets and Liabilities		
Fund Net Assets		
Invested in capital assets, net of related debt	$ 1,728,947	$ 1,688,726
Restricted fund net assets	107,097	108,089
Unrestricted fund net assets (deficit)	60,693	(4,708)
	1,896,737	1,792,107
Long term debt	1,212,113	1,297,190
Other Non-Current Liabilities		
Accrued postretirement liability, net	-	99,186
Accrued workers' compensation claims	14,603	10,969
Commitments and contingencies (Note 11)	-	-
	14,603	110,155
Current Liabilities		
Current portion of long-term debt	58,891	47,632
Accounts payable and accrued expenses	95,543	67,960
Accrued interest	19,862	20,214
Accrued employee expenses	34,210	33,010
Obligation under securities lending transactions	23,382	40,071
Due to Energy Services	20,007	-
Customer deposits	49,904	42,321
	301,799	251,208
	$ 3,425,252	$ 3,450,660

The accompanying notes are an integral part of these financial statements.

Los Angeles Department of Water and Power
Water Services Statements of Revenue, Expenses, and Changes in Fund Net Assets
(Amounts in thousands)

	Year Ended June 30,		
	2004	2003	2002
Operating Revenues			
Residential	$ 243,257	$ 227,265	$ 225,611
Multiple dwelling units	176,598	169,760	169,279
Commercial and industrial	128,601	129,111	125,716
Other	50,796	32,689	35,343
Uncollectible accounts	(2,951)	(5,848)	(5,480)
	596,301	552,977	550,469
Operating Expenses			
Purchased water	135,165	141,389	135,049
Maintenance and other operating expenses	286,469	269,510	223,341
Depreciation and amortization	93,029	91,520	87,493
Loss on asset impairment and abandoned projects	3,474	3,402	15,550
	518,137	505,821	461,433
Operating Income	78,164	47,156	89,036
Other Income and Expense			
Investment income	1,204	11,490	9,075
Gain on sale of land	21	2,270	4,896
Other non-operating income	3,978	5,156	5,918
	5,203	18,916	19,889
Other non-operating expenses	5,218	4,618	4,709
	(15)	14,298	15,180
Debt Expenses			
Interest on debt	51,449	46,464	40,223
Allowance for funds used during construction	(1,607)	(2,987)	(3,409)
	49,842	43,477	36,814
Contributions in aid of construction	20,696	14,044	16,757
Change in fund net assets before transfers to the reserve fund of the City of Los Angeles and extraordinary item	49,003	32,021	84,159
Transfers to the reserve fund of the City of Los Angeles	(27,649)	(27,523)	(27,247)
Increase in fund net assets before extraordinary item	21,354	4,498	56,912
Extraordinary loss on extinguishment of debt	(2,744)	-	-
Increase in fund net assets	18,610	4,498	56,912
Fund net assets			
Beginning of period	1,792,107	1,787,609	1,730,697
Adjustment due to change in accounting principle from SFAS No. 106 to GASBS No. 45 (see Note 2)	86,020	-	-
End of period	$ 1,896,737	$ 1,792,107	$ 1,787,609

The accompanying notes are an integral part of these financial statements.

Los Angeles Department of Water and Power
Water Services Statements of Cash Flows
(Amounts in thousands)

	Year Ended June 30,		
	2004	2003	2002
Cash Flows from Operating Activities:			
Cash Receipts			
Cash receipts from customers	$ 611,693	$ 593,625	$ 599,034
Cash receipts from customers for other agency services	368,712	360,886	360,216
Cash receipts from interfund services provided	345,427	235,412	238,918
Other operating cash receipts	2,438	-	6,761
Cash Disbursements			
Cash payments to employees	(205,469)	(179,611)	(176,869)
Cash payments to suppliers	(236,162)	(298,676)	(229,037)
Cash payments for interfund services used	(232,905)	(238,347)	(201,228)
Cash payments to other agencies for fees collected	(370,820)	(359,274)	(355,254)
Other operating cash payments	-	(1,175)	-
	282,914	112,840	242,541
Cash Flows from Noncapital Financing Activities:			
Payments to the reserve fund of the City of Los Angeles	(27,649)	(27,523)	(27,247)
Cash Flows from Capital and Related Financing Activities:			
Additions to plant and equipment, net	(285,703)	(245,944)	(339,833)
Contributions in aid of construction	22,174	16,936	24,043
Proceeds from escrow investment maturities	4,613	3,085	96,648
Principal payments and maturities on long-term debt, net	(15,381)	(2,565)	(10,185)
Issuance of bonds, net	164,343	489,773	3,004
Payment for refunded revenue bonds	(232,128)	(197,310)	(94,800)
Proceeds from California Department of Water Resources loan	4,499	-	13,253
Debt interest payments	(51,487)	(30,049)	(48,670)
	(389,070)	33,926	(356,540)
Cash Flows from Investing Activities:			
Purchases of investment securities	(176,106)	(32,640)	-
Sale of investment securities	140,723	-	
Investment income	8,884	11,582	19,503
	(26,499)	(21,058)	19,503
Cash and Cash Equivalents:			
Net (decrease) increase	(160,304)	98,185	(121,743)
Cash and cash equivalents July 1 (including $231,767, $75,355, and 274,000 reported in restricted accounts, respectively	276,845	178,660	300,403
Cash and cash equivalents June 30 (including $55,651, $231,767, and $75,355 reported in restricted accounts, respectively	$ 116,541	$ 276,845	$ 178,660

The accompanying notes are an integral part of these financial statements.

Los Angeles Department of Water and Power
Water Services Statements of Cash Flows, continued
(Amounts in thousands)

	Year Ended June 30, 2004	2003	2002
Reconciliation of operating income to net cash provided by operating activities			
Operating income	$ 78,164	$ 47,156	$ 89,036
Adjustments to reconcile operating income to net cash provided by operating activities			
Depreciation and amortization	93,029	91,520	87,493
Provision for losses on customer and other accounts receivable	2,951	5,848	5,480
Loss on asset impairment and abandoned projects	3,474	3,402	15,550
Changes in assets and liabilities:			
Customer and other accounts receivable	3,604	5,264	(10,331)
Accrued unbilled revenues	(3,639)	-	-
Due from Energy Services	68,587	(61,423)	1,316
Materials and supplies	(1,312)	2,725	(81)
Net pension asset	(1,361)	1,296	(7,026)
Accounts payable and accrued expenses	27,583	(18,386)	9,836
Accrued employee expenses	4,834	7,009	2,145
Under/Overrecovered costs	(11,497)	1,094	(4,682)
Accrued postretirement liability	19,577	26,435	22,501
Workers' compensation liability and other	(1,080)	900	31,304
Cash provided by operating and other activities	$ 282,914	$ 112,840	$ 242,541

The accompanying notes are an integral part of these financial statements.

NOTE 1: Summary of Significant Accounting Policies

The Department of Water and Power of the City of Los Angeles (the Department) exists as a separate proprietary agency of the City of Los Angeles (the City) under and by virtue of the City Charter enacted in 1925 and as revised effective July 2000. The Department's Water System (Water Services) is responsible for the procurement, quality, and distribution of water for sale in the City.

Method of accounting

The accounting records of Water Services are maintained in accordance with accounting principles generally accepted in the United States of America. As a government-owned utility, in prior years, the Department applied all statements issued by the Governmental Accounting Standards Board (GASB) and all statements and interpretations issued by the Financial Accounting Standards Board (FASB), which are not in conflict with statements issued by the GASB. In fiscal year 2003, the Department changed its election under the guidance in GASB Statement No. 20, "*Accounting and Financial Reporting for Proprietary Funds and Other Governmental Entities that Use Proprietary Fund Accounting*" (GASBS No. 20), to follow GASB statements and only FASB statements and interpretations issued on or before November 30, 1989. See Note 2. The Department continued to follow Statement of Financial Accounting Standards (SFAS) No. 106 "*Employers' Accounting for Postretirement Benefits Other Than Pensions*" for postretirement benefits until the beginning of fiscal year 2004 when the Department early adopted GASBS No. 45 for postretirement benefits. See Notes 2 and 8.

The Department's rates are determined by the Board of Water and Power Commissioners (the Board) and are subject to review and approval by the City Council. As a regulated enterprise, the Department utilizes SFAS No. 71, "*Accounting for the Effects of Certain Types of Regulation,*" which requires that the effects of the ratemaking process be recorded in the financial statements. Such effects primarily concern the time at which various items enter into the determination of changes in fund net assets. Accordingly, Water Services records various regulatory assets and liabilities to reflect the Board's actions. Management believes that Water Services meets the criteria for continued application of SFAS No. 71, but will continue to evaluate its applicability based on changes in the regulatory and competitive environment.

Use of estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

NOTE 1: (continued)

Utility plant

The costs of additions to utility plant and replacements of retired units of property are capitalized. Costs include labor, materials, an allowance for funds used during construction (AFUDC), and allocated indirect charges such as engineering, supervision, transportation and construction equipment, retirement plan contributions, health care costs, and certain administrative and general expenses. The costs of maintenance, repairs and minor replacements are charged to the appropriate operations and maintenance expense accounts. The original cost of property retired, net of removal and salvage costs, is charged to accumulated depreciation.

During fiscal year 2004, Water Services reversed previously capitalized postretirement health care costs of $46.7 million from utility plant assets, net. These costs were capitalized as construction costs under SFAS No. 106 as a component of labor expenses. As a result of the adoption of GASBS No. 45, these costs were eliminated. See Note 2 for the effect in the change in accounting from SFAS No. 106 to GASBS No. 45.

Impairment of long-lived assets

Effective fiscal year 2004, the Department adopted GASBS No. 42 "*Accounting and financial Reporting for Impairment of Capital Assets and for Insurance Recoveries*", (GASBS No. 42). Governments are required to evaluate prominent events or changes in circumstances affecting capital assets to determine whether impairment of a capital asset has occurred. A capital asset is considered impaired when its service utility has declined significantly and unexpectedly. Under GASBS No. 42, impaired capital assets that will no longer be used by the government should be reported at the lower of carrying value or fair value. Impairment losses on capital assets that will continue to be used by the government should be measured using the method that best reflects the diminished service utility of the capital asset. (See Notes 2 and 10.)

Depreciation and amortization

Depreciation expense is computed using the straight-line method based on service lives. The Department uses the composite method of depreciation and therefore groups assets into composite groups for purposes of calculating depreciation expense. Estimated service lives range from 5 to 70 years. Amortization expense for computer software is computed using the straight-line method over 5 years. Depreciation and amortization expense as a percentage of average depreciable utility plant in service was 2.3%, 2.6%, and 2.6% for each of the fiscal years ended 2004, 2003, and 2002, respectively.

NOTE 1: (continued)

During fiscal year 2004, the Department hired an independent third party to complete a depreciation study on Water Services utility plant assets. The study recommended lengthening the lives of some utility plant assets and shortening others. The results of the study were adopted in the fourth quarter of 2004 and resulted in a $5.6 million decrease to depreciation expense as compared to the depreciation expense that would have been recorded under the old rates.

Cash and cash equivalents

As provided for by the California Government Code, the Department's cash is deposited with the City Treasurer in the City's general investment pool for the purpose of maximizing interest earnings through pooled investment activities. Cash and cash equivalents in the City's general investment pool are reported at fair value and changes in unrealized gains and losses are recorded in the statements of revenue, expenses, and changes in fund net assets. Interest earned on such pooled investments is allocated to the participating funds based on each fund's average daily cash balance during the allocation period. The City Treasurer invests available funds of the City and its independent operating departments on a combined basis. The Department classifies all cash and cash equivalents that are restricted either by creditors, the Board, or by law, as restricted cash and cash equivalents on the balance sheet. The Department considers its portion of pooled investments with an original maturity of three months or less to be cash equivalents.

At June 30, 2004 and 2003, restricted cash and cash equivalents includes the following (amounts in thousands):

	June 30,	
	2004	2003
Bond redemption and interest funds	$ 37,556	$ 36,921
Construction funds	6,930	184,681
Self insurance fund	11,165	10,165
	$ 55,651	$ 231,767

Materials and supplies

Materials and supplies are recorded at average cost.

NOTE 1: (continued)

Restricted investments

Water Services' restricted investments consist of escrow investments held to pay interest on previously issued refunding revenue bonds. Such investments include U.S. government and governmental agency securities. Investments are reported at fair value and changes in unrealized gains and losses are recorded in the statement of revenue, expenses, and changes in fund net assets. Gains and losses realized on the sale of investments are generally determined using the specific identification method. The stated fair value of investments is generally based on published market prices or quotations from major investment dealers.

Accrued employee expenses

Accrued employee expenses includes accrued payroll and an estimated liability for vacation leave, sick leave and compensatory time, which is accrued when employees earn the rights to the benefits.

Debt expenses

Debt premium, discount, and issue expenses are deferred and amortized to debt expense using the effective interest method over the lives of the related debt issues. Gains and losses on refundings related to bonds redeemed by proceeds from the issuance of new bonds are amortized to debt expense using the effective interest method over the shorter of the life of the new bonds or the remaining term of the bonds refunded. Gains and losses on bond defeasances financed with cash are reported as an extraordinary gain or loss on extinguishment of debt in the statements of revenue, expenses, and changes in fund net assets.

Accrued workers' compensation claims

Liabilities for unpaid workers' compensation claims are recorded at their net present value when they are probable of occurrence and the amount can be reasonably estimated. The liability is actuarially determined, based on an estimate of the present value of the claims outstanding and an amount for claim-events incurred but not reported based upon the Department's loss experience, less the amount of claims and settlements paid to date. The discount rate used to calculate this liability at its present value was 4% at June 30, 2004, which approximates the Department's long term investment yield.

NOTE 1: (continued)

Overall indicated reserves for workers' compensation claims, for both Water and Energy Services, undiscounted, have increased from \$45.5 million as of June 30, 2003, to \$56.0 million as of June 30, 2004. This increase is mainly attributable to increased medical inflation (particularly in the area of prescription drugs), significant increases in benefit levels implemented in California in the past few years, increased payroll levels of the Department contributing to higher indemnity losses, and increasing claim frequencies experienced by the Department in the past few years. As the claims typically take longer than 1 year to settle and close out, the entire discounted liability is shown as long term on the balance sheets as of June 30, 2004 and 2003. Water Services' portion of the discounted reserves as of June 30, 2004 and 2003 are \$14.6 million and \$11.0 million, respectively.

Customer deposits

Customer deposits represent deposits collected from customers upon opening of new accounts. These deposits are obtained when the customer does not have a previously established credit history with the Department. Original deposits plus interest is paid to the customer once a satisfactory payment history is maintained, generally after one to three years.

Water Services is responsible for collection, maintenance and refunding of these deposits for all Department customers, including those of Energy Services. As such, Water Services' balance sheets include a deposit liability of \$49.9 million and \$42.3 million as of June 30, 2004 and 2003, respectively, for all customer deposits collected. In the event that Water Services defaults on refunds of such deposits, Energy Services would be required to pay amounts owing to its customers.

Revenues

Water Services' rates are established by a rate ordinance, which is approved by the City Council. Water Services sells water to other City departments at rates provided in the ordinance. Water Services recognizes water costs in the period incurred and accrues for estimated water sold but not yet billed.

Revenues consist of billings to customers for water consumption at rates specified in the water rate ordinance. These rates include a cost adjustment factor that provides Water Services with full recovery of purchased water costs. Water Services is also authorized to collect approved demand-side management, water reclamation, a portion of the operation and maintenance costs related to the pumping of in-City groundwater, water quality improvement expenditures, and water security costs. Management estimates these costs to establish the cost recovery component of customer billings and any difference between billed and actual costs is adjusted in subsequent billings. This difference is reflected as under- or over-recovered costs on the balance sheet. During fiscal year 2004 and 2003, Water Services incurred expenditures of \$23 million and \$24 million, respectively, in excess of these limits, which is being funded through funds received from the issuance of debt.

NOTE 1: (continued)

Current Rate Ordinance

A conservation-based water rate ordinance has been in effect since February 16, 1993 with periodic amendments approved by the City Council. The last amendment was approved in May 2004 and was effective June 20, 2004. The ordinance incorporates marginal cost pricing through a two-tiered rate structure. The upper block rate is established at the estimated marginal cost for water. The lower block price is established to generate the revenue required for efficient operations. As a result of concerns expressed about the rate structure's impact on larger volume single-family residential customers, the first tier allowances were revised effective June 1, 1995. The revisions established five lot size categories and three temperature zones (as the basis for the first tier usage blocks for each category). Extra units (one unit equals 100 cubic feet or 748 gallons) at the first tier rate are available based on household sizes. The rates also reflect equity considerations for water-intensive businesses, large turf customers, and other customers having high seasonal variation in their water usage. Fixed monthly service availability charges apply only to private fire service. The rate revisions effective June 20, 2004 established a water security adjustment factor, amended the water procurement factor to include operation and maintenance costs for in-City groundwater and booster pumping, increased the cap on the recovery of combined expenditures for demand-side management, water reclamation, water quality improvement, and water security.

The Water System's rate ordinance contains a water procurement adjustment factor, a water quality adjustment factor, and a water security adjustment factor. The water procurement adjustment factor under which the cost of purchased water, including water purchased from the Metropolitan Water District (MWD), demand-side management programs, reclaimed water projects, and a percentage of the operation and maintenance costs required to operate the in-City groundwater and booster pumping are recovered by direct adjustments to customers' bills. The water quality improvement adjustment factor recovers expenditures to upgrade and equalize water quality throughout the City and to construct facilities to meet State and federal water quality standards, including the payment of debt service on bonds issued for such purposes. The water security adjustment factor was added as part of the last ordinance amendment. The water security adjustment factor recovers expenditures to secure and protect the water supply, storage, conveyance infrastructure and related facilities. The ordinance currently limits to $0.50 per billing unit the recovery of combined expenditures for demand-side management, water reclamation, water quality improvement, and water security.

NOTE 1: (continued)

The Water System's rate ordinance also contains a revenue adjustment mechanism in the form of a surcharge that is designed to assure a minimum level of base rate revenue each fiscal year. The annual revenue target for years since June 30, 2002 was $294 million. This amount is adjusted annually for increases in interest expense and shall not exceed $325 million per fiscal year; provided however, the annual revenue target limit of $325 million shall be increased in proportion to any increases in the commodity charge. The revenue adjustment factor becomes effective upon a determination by the Board that the surcharge is needed. The rate ordinance limits the surcharge to $0.18 per billing unit, unless a higher amount is approved by the Board and the City Council.

Non-operating revenues

Contributions in aid of construction and other grants received by the Department for constructing utility plant and other activities are recognized as non-operating revenues when all applicable eligibility requirements, including time requirements, are met.

Allowance for funds used during construction

Allowance for funds used during construction represents the cost of borrowed funds used for the construction of utility plant. Capitalized AFUDC is included as part of the cost of utility plant and as a reduction of debt expenses. The average AFUDC rate used by Water Services was 3.8%, 4.6%, and 5.8% for each of fiscal years 2004, 2003 and 2002.

Reclassifications

Certain financial statement items for prior years have been reclassified to conform to the current year presentation.

Recent Accounting Pronouncements

In March 2003, the GASB issued GASBS No. 40, "*Deposit and Risk Investment Disclosures an amendment of GASB Statement No. 3.*" GASBS No. 40 requires specific disclosures if applicable for credit risk, concentration of credit risk, interest rate risk, and foreign currency risk. It also modifies GASBS No. 3, "*Deposits with Financial Institutions, Investments (including Repurchase Agreements), and Reverse Purchase Agreements,*" in part to limit the required disclosure of custodial credit risk to one category of deposits and investments. This Statement is effective for the Department beginning in fiscal year 2005. The Department does not expect that there will be a material impact to the financial statement disclosures as a result of adopting this Statement.

NOTE 2: Accounting Changes

GASB Statement No. 45

On July 1, 2003, the Department early adopted GASB Statement No. 45 "*Accounting and Financial Reporting by Employers for Postemployment Benefits Other Than Pensions*" (GASBS No. 45), and discontinued following Financial Accounting Standards Board Statement No. 106 "*Employers' Accounting for Postretirement Benefits Other Than Pensions*" (SFAS No. 106). The Department does not administer its plan for postretirement benefits other than pensions (health care benefits) as a trust or equivalent arrangement. Therefore, it does not prepare financial statements for the plan. See Note 8 for a description of the plan.

The following amount was recorded on Water Services books as of June 30, 2003 as the net postretirement liability under SFAS No. 106 (amounts in thousands):

	June 30, 2003
Postretirement liability	$ (152,664)
Postretirement fund assets	53,478
Net postretirement liability	$ (99,186)

Prior to July 1, 2003, the Department was applying SFAS No. 106 in accounting for postretirement costs. The postretirement obligation as at June 30, 2003 amounted to $153 million. The adoption of GASBS No. 45 allows the Department to set the beginning postretirement obligation to zero and reverse the previously reported obligation. To reverse Water Services' postretirement liability, management reviewed the charges for health care costs created by SFAS No. 106 and reversed the costs as of July 1, 2003. Costs were reversed from previous capitalized labor charges included in utility plant and other operating expenses recorded in prior fiscal years.

The change from SFAS No. 106 to GASBS No. 45 had no change to the health plan benefits to active or retired employees. The change also did not affect the assets designated for postretirement benefits. The change from SFAS No. 106 to GASBS No. 45 changed the postretirement liability as of July 1, 2003, the annual required funding contribution for subsequent fiscal years, and the actuarial accrued liability calculations. See Note 8.

As a result of the adoption of GASBS No. 45, the following adjustments were recorded to Water Services' balance sheet as of July 1, 2003 (amounts in thousands):

NOTE 2: (continued)

Balance Sheet Item	Reported as of June 30, 2003	Adjustments	Adjusted Balance
Source of supply assets	$584,317	($7,531)	$576,786
Pumping assets	190,074	(1,121)	188,953
Purification assets	239,979	(3,365)	236,614
Distribution assets	2,612,116	(38,135)	2,573,981
General assets	345,655	(2,565)	343,090
Accumulated depreciation	(1,385,526)	6,063	(1,379,463)
Due from Energy Services	(67,447)	(18,867)	(86,314)
Underrecovered costs	23,075	(1,123)	21,952
Accrued postretirement (liability)/asset	(99,186)	152,664	53,478
Fund net assets	(1,792,107)	(86,020)	(1,878,127)

With the adoption of GASBS No. 45 the Department's postretirement liability decreased from $119.7 million in fiscal year 2003 under SFAS No. 106 to $107 million in fiscal year 2004 under GASBS No. 45. The difference is due to a change in the discount rate from 5.75% to 6.50%, a change in the funding method from the Projected Unit Credit Cost Method to the Entry Age Normal Method, and a change in the amortization period for prior service costs from 20 to 30 years. See Note 8 for the required information under GASBS No. 45.

Of the $107 million postretirement liability recorded under GASBS No. 45, $36.5 million was allocated to Water Services. Water Services paid $16.5 million for retiree premiums during fiscal year 2004 leaving $20.0 million as a liability on Water Services books as of June 30, 2004. In addition, the Department made additional contributions to the postretirement funds. As a result, the net postretirement asset on Water Services books as of June 30, 2004 is as follows (dollar amounts in thousands):

	June 30, 2004
Postretirement liability	$ (19,992)
Postretirement fund assets	87,893
Net postretirement asset	$ 67,901

NOTE 2: (continued)

GASB Statement No. 42

In November 2003, the GASB issued GASBS No. 42 "*Accounting and Financial Reporting for Impairment of Capital Assets and for Insurance Recoveries.*" This Statement established accounting and financial reporting standards for impairment of capital assets. A capital asset is considered impaired when its service utility has declined significantly and unexpectedly. This Statement also clarified and established accounting requirements for insurance recoveries. Under the standard, impaired capital assets that will no longer be used by the government should be reported at the lower of carrying value or fair value. Impairment losses on capital assets that will continue to be used by the government should be measured using the method that best reflects the diminished service utility of the capital asset.

The Department early adopted GASBS No. 42 and calculated the impairment to its procurement system. No retroactive restatement was required. See Note 10 for a discussion on the impairment.

GASB Statement No. 39

In fiscal year 2004, the Department adopted GASBS No. 39 "*Determining Whether Certain Organizations Are Component Units.*" This Statement amends GASB Statement No. 14, "*The Financial Reporting Entity,*" to provide additional guidance to determine whether certain organizations for which the primary government is not financially accountable should be reported as component units, based on the nature and significance of their relationship with the primary government. Generally, it requires reporting, as a component unit, an organization that raises and holds economic resources for the direct benefit of a governmental unit. The Department is a component unit of the City of Los Angeles, and will continue to be included as part of the City's consolidated annual financial report. This Statement was effective for the Department beginning in fiscal year 2004. There was no impact to the Department's financial statements as a result of adopting this Statement.

NOTE 2: (continued)

Change in election under GASB Statement No. 20

In fiscal year 2003, the Department changed its election under the guidance in GASB Statement No. 20, "*Accounting and Financial Reporting for Proprietary Funds and Other Governmental Entities that Use Proprietary Fund Accounting*" (GASBS No. 20), to follow GASB statements and only FASB statements and interpretations issued on or before November 30, 1989. While the Department is required to retroactively apply this change by restating prior years presented, the change did not have any impact on prior years' financial statements. Therefore, prior periods were not restated. Management believes that this change in election represents a change to a preferable method of accounting.

The Department continued to apply the provisions of SFAS No. 106, "*Employers' Accounting for Postretirement Benefits Other Than Pensions,*" until the prescriptive guidance under governmental standards was issued. GASBS No. 45 was issued in 2004 and the Department early adopted the standard in accordance with the transition guidance to be in full compliance with GASBS No. 20.

NOTE 3: Utility Plant

Water Services had the following activity in utility plant during fiscal year 2004 (amounts in thousands):

	Balance June 30, 2003	GASBS 45 Adjustment	Adjusted Beginning Balance July 1, 2003	Additions	Retirements and Disposals	Transfers	Balance June 30, 2004
Nondepreciable utility plant							
Land and land rights	$ 92,381	$ -	$ 92,381	$ 7,279	$ -	$ -	$ 99,660
Construction work in progress	262,252	-	262,252	198,179	-	(128,448)	331,983
Total nondepreciable utility plant	354,633	-	354,633	205,458	-	(128,448)	431,643
Depreciable utility plant							
Source of water supply	511,307	(7,531)	503,776	4,879	-	4,636	513,291
Pumping	187,975	(1,121)	186,854	1,971	(14)	2,900	191,711
Purification	239,970	(3,365)	236,605	5,052	(81)	15,973	257,549
Distribution	2,597,695	(38,135)	2,559,560	49,787	(1,977)	91,034	2,698,404
General	342,813	(2,565)	340,248	16,377	(9,272)	13,905	361,258
Total depreciable utility plant	3,879,760	(52,717)	3,827,043	78,066	(11,344)	128,448	4,022,213
Less accumulated depreciation*	(1,385,526)	6,063	(1,379,463)	(92,716)	11,344	-	(1,460,835)
Total utility plant, net	$ 2,848,867	$ (46,654)	$ 2,802,213	$ 190,808	$ -	$ -	$ 2,993,021

* *Additions to accumulated depreciation include capitalized depreciation of $8.7 million.*

NOTE 4: Restricted Investments

A summary of Water Services' restricted investments is as follows (amounts in thousands):

	June 30, 2004	June 30, 2003
Restricted Investments:		
Escrow investments	$ -	$ 4,613
Other:		
Cash collateral received from securities lending transactions (see Note 5)	$ 23,382	$ 40,071
Postretirement health care benefit fund	87,893	53,478
Total	$ 111,275	$ 98,162

All restricted and other investments are held in trust accounts to be used for a designated purpose as follows:

Escrow investments

Escrow investments are held to pay interest on previously issued refunding revenue bonds.

Postretirement health care benefit fund

The postretirement health care benefit fund was established to provide for the payment of the Department's postretirement health care benefits. Accrued postretirement liabilities are recorded net of the fund (see Note 8). The adoption of GASBS No. 45 had no impact on the amount or fair value of the postretirement health care benefit fund.

Restricted and other investments held by the Department are categorized separately below to give an indication of the level of custodial credit risk assumed by the Department. Specifically, identifiable investments are classified as to credit risk by three categories and summarized below as follows: Category 1 includes investments that are insured or registered or for which securities are held by the Department or its agent in the Department's name; Category 2 includes uninsured and unregistered investments for which the securities are held by the counterparty's trust department or agent in the Department's name; and Category 3 includes uninsured and unregistered investments for which the securities are held by the counterparty or by its trust department or agent, but not in the Department's name.

NOTE 4: (continued)

At June 30, 2004, Water Services' restricted and other investments are categorized as follows (amounts in thousands):

Type of Investments	Category 1	Category 2	Category 3	Total
Investments - categorized				
U.S. government securities	$ 55,816	$ -	$ -	$ 55,816
Bonds	14,841	-	-	14,841
Commercial paper	7,277	-	-	7,277
Repurchase Agreements	-	10,156	-	10,156
Total categorized restricted and other investments	$ 77,934	$ 10,156	$ -	88,090
Investments - not categorized				
Investments held by broker-dealers:				
U.S. government securities				9,959
General pooled securities lending cash collateral				13,226
Total				$ 111,275

At June 30, 2003, Water Services' restricted and other investments were categorized as follows (amounts in thousands):

Type of Investments	1	2	3	Total
Investments - categorized				
U.S. government securities	$ 50,223	$ -	$ -	$ 50,223
Bonds	7,815	-	-	7,815
Commercial paper	20	-	-	20
Total categorized restricted and other investments	$ 58,058	$ -	$ -	58,058
Investments - not categorized				
Investments held by broker-dealers:				
Mutual funds				33
General pooled securities lending cash collateral				40,071
Total				$ 98,162

Repurchase agreements relate to the Department's securities lending program (see Note 5). Because Water Services did not have any of its securities lent under its own program at June 30, 2003, there are no repurchase agreements at that date.

NOTE 5: Securities Lending Transactions

In December 1999, the Department initiated a securities lending program managed by its custodial bank. The bank lends up to 20% of the investments held in Water Services' plan assets held in the postretirement benefits trust fund for securities, cash collateral or letters of credit equal to 102% of the market value of the loaned securities and interest, if any. The Department can sell collateral securities only in the event of borrower default. Both the investments purchased with the collateral received and the related liability to repay the collateral are reported on the balance sheets. A summary of Water Services' securities lending transactions as of June 30, 2004 and 2003 is as follows (amounts in thousands):

	June 30, 2004		June 30, 2003	
Securities lent for cash collateral	Fair value of underlying securities	Collateral value	Fair value of underlying securities	Collateral value
U.S. government and agency securities	$ 9,959	$ 10,156	$ -	$ -

The lending agent provides indemnification for borrower default. There were no violations of legal or contractual provisions and no borrower or lending agent default losses during fiscal years 2004 and 2003.

General Investment Pool Program

The Department also participates in the City's securities lending program through the pooled investment fund. The City's program has substantially the same terms as the Department's direct securities lending program. The Department recognizes its proportionate share of the cash collateral received for securities loaned and the related obligation for the general investment pool. As of June 30, 2004 and 2003, Water Services' attributed share of cash collateral and the related obligation from the City's program was $13 million and $40 million, respectively.

Management participates in the securities lending programs to maximize earnings from investments, and believes that participation in these securities lending programs results in minimal credit risk exposure to the Department because the amounts owed to the borrowers exceed the amounts that are on loan.

NOTE 6: Long-term Debt

Long-term debt outstanding as of June 30, 2004 consists of revenue bonds and refunding revenue bonds due serially in varying annual amounts, and other long-term debt, as follows (amounts in thousands):

Bond Issues	Date of Issue	Effective Interest Rate	Fiscal Year of Last Scheduled Maturity	Principal Outstanding
Revenue Bonds				
Issue of 2001, Series A	02/01/01	5.202%	2042	$ 308,925
Issue of 2001, Series B	02/28/01	Variable	2036	325,000
Issue of 2001, Series C	11/15/01	4.788%	2017	3,909
Issue of 2003, Series A	01/07/03	5.084%	2044	300,000
Issue of 2003, Series B	03/06/03	4.014%	2031	189,910
Issue of 2004, Series A	04/06/04	2.500%	2008	50,000
Issue of 2004, Series B	04/06/04	Variable	2026	114,420
	Total principal amount			1,292,164
	Unamortized debt-related costs (including net loss on refundings)			(38,209)
	Debt due within one year (including current portion of variable rate debt)			(58,364)
				1,195,591
Other Long-term Debt				
Loan payable to California Department of Water Resources (CDWR)	12/27/2001	2.320%	2022	17,049
	Current portion of loan from CDWR			(527)
				16,522
				$ 1,212,113

Revenue bonds generally are callable ten years after issuance. The Department has agreed to certain covenants with respect to bonded indebtedness. Significant covenants include the requirement that Water Services' net income, as defined, will be sufficient to pay certain amounts of future annual bond interest and of future annual aggregate bond interest and principal maturities. Revenue bonds and refunding bonds are collateralized by the future revenues of Water Services.

NOTE 6: (continued)

Long term debt activity

Water Services had the following activity in long-term debt during fiscal year 2004 (amounts in thousands):

	Balance at June 30, 2003	Additions	Reductions	Balance at June 30, 2004	Current Portion
Long term debt, including - loan from CDWR	$ 1,297,190	178,343	(263,420)	$ 1,212,113	$ 58,891

New issuances

Fiscal Year 2004

In April 2004, Water Services issued $164 million of Water System Revenue Bonds. The bonds were issued for the purpose of refunding portions of the Refunding Issue of 1998. The net proceeds along with $70 million in cash were used to defease bonds with a par value of $236 million. This transaction resulted in a net loss for accounting purposes of $9 million, of which $6 million was deferred and is being amortized the shorter of the life of the bonds retired or the life of the new bonds and $3 million which was recognized in fiscal year 2004 as an extraordinary loss.

In September 2003, Water Services received the remaining $4 million from the California Department of Water Resources (CDWR) under its loan agreement. The loan agreement allows for a total maximum loan of $17 million, at a fixed interest rate of 2.32%. In December 2001, the Department received $13 million under the agreement. The proceeds are being used to fund water quality capital improvements. Water Services began making principal payments under this arrangement in fiscal year 2004.

Furthermore, in July 2004, Water Services issued $200 million of Water System Revenue Bonds. The bonds were issued for the purpose of water system capital improvements.

NOTE 6: (continued)

Fiscal Year 2003

In January 2003, the Department issued $300 million of Water Services fixed rate bonds. The net proceeds were deposited into the construction fund to be used for water system capital improvements. In March 2003, the Department issued $202 million of Water Services fixed rate bonds to refund the Water Works Refunding Revenue Bonds, Issue of 1993 and Second Issue of 1993. Based on interest cost of 4.0% for the fixed rate bonds, the refunding is expected to decrease total debt payments over the life of the new issues by approximately $15 million and is expected to result in present value savings of approximately $10 million. These transactions resulted in a net loss for accounting purposes of $15 million which was deferred and will be amortized through 2030.

Outstanding debt defeased

As discussed above, Water Services defeased certain revenue bonds in prior years by placing cash or the proceeds of new revenue bonds in irrevocable trusts to provide for all future debt service payments on the old bonds. Accordingly, the trust account assets and the liability for the defeased bonds are not included in Water Services' financial statements. At June 30, 2004, the following revenue bonds outstanding are considered defeased (amounts in thousands):

Issue of 1994	$ 47,700
Issue of 1995	43,850
Issue of 1998 R	235,730
Issue of 1999	100,000
	$ 427,280

Variable rate bonds

The variable rate bonds currently bear interest at daily and weekly rates (ranging from 1.00% to 1.34% as of June 30, 2004). The Department can elect to change the interest rate period of the bonds, with certain limitations. The bondholders have the right to tender the bonds to the tender agent on any business day with seven days prior notice. The Department has entered into Standby Agreements with a syndicate of commercial banks in an initial amount of $325 million to provide liquidity for these bonds. The initial and extended Standby Agreements expire in March 2007 and November 2004.

NOTE 6: (continued)

Bonds purchased under the agreements will bear interest that is payable quarterly at the greater of the Federal Funds Rate plus 0.50% or the bank's announced base rate, as defined. The unpaid principal of bonds purchased is payable in ten equal semi-annual installments, commencing after the termination of the agreement. At its discretion, the Department has the ability to convert the outstanding bonds to fixed rate obligations, which cannot be tendered by the bondholders. These bonds have been classified as long term on the balance sheets as the liquidity facilities give the Department the ability to refinance on a long term basis and the Department intends to either renew the facilities or exercise its right to tender the debt as a long term financing. That portion which would be due in the next fiscal year in the event that the outstanding variable rate bonds were tendered and purchased by the commercial banks under the Standby Agreements, has been included in the current portion of long term debt and was \$43.9 million and \$32.5 million as of June 30, 2004 and 2003, respectively.

Advance refunding bonds

In fiscal year 2004 Water Services defeased the 1998 Water Refunding Bonds and removed the irrevocable escrow trusts off of the balance sheet. The remaining bonds are scheduled to be called in fiscal year 2005.

Scheduled principal maturities and interest

Scheduled annual principal maturities and interest are as follows (amounts in thousands):

	Principal	Interest and Amortization
Fiscal years ending June 30,		
2005	\$ 15,145	\$ 47,533
2006	23,410	46,504
2007	34,130	45,218
2008	36,255	43,643
2009	13,693	43,068
2010 - 2014	72,068	205,307
2015 - 2019	76,939	188,962
2020 - 2024	93,463	176,511
2025 - 2029	132,545	165,046
2030 - 2034	187,360	152,378
2035 - 2039	270,630	118,632
2040 - 2044	353,575	37,734
Total Requirements	\$ 1,309,213	\$ 1,270,536

NOTE 6: (continued)

The scheduled maturities for the fiscal year ending June 30, 2004 exclude $43.9 million in variable rate bonds classified as short term for reporting purposes as described above. Interest and amortization includes interest requirements for variable rate debt, using the average variable debt interest rate in effect at June 30, 2004, of 1.15%.

Fair value

The fair value of long-term debt is $1.1 billion and $1.3 billion at June 30, 2004 and 2003, respectively. Management has estimated fair value based on the present value of interest and principal payments on the long-term debt and refunding bonds, discounted using current interest rates obtainable by the Department for debt of similar quality and maturities.

Water Services is in compliance with all debt covenants. The most restrictive covenant is the additional bonds test. It requires that the adjusted net income for the applicable calculation period (12 months) shall amount to at least 1.25 times the maximum annual adjusted debt service on all parity obligations. As of June 30, 2004, the net debt service coverage ratio is 1.94.

NOTE 7: Retirement, Disability, and Death Benefit Insurance Plan

The Department has a funded contributory retirement, disability, and death benefit insurance plan covering substantially all of its employees. The Water and Power Employees' Retirement, Disability and Death Benefit Insurance Plan (the Plan) operates as a single-employer benefit plan to provide pension benefits to eligible Department employees and to provide disability and death benefits from the respective insurance funds. Plan benefits are generally based on years of service, age at retirement and the employee's highest 12 consecutive months of salary before retirement. Active participants who joined the plan on or after June 1, 1984 are required to contribute 6% of their annual covered payroll. Participants who joined the plan prior to June 1, 1984 contribute an amount based upon an entry-age percentage rate. The Department contributes $1.10 for each $1.00 contributed by participants plus an actuarially determined annual required contribution as determined by the Plan's independent actuary. The contributions are allocated between Water Services and Energy Services based on the current year labor costs.

The Retirement Board of Administration (the Retirement Board) is the administrator of the Plan. The Plan is subject to provisions of the Charter of the City of Los Angeles and the regulations and instructions of the Board of Water and Power Commissioners (the Board of Commissioners). The Plan is an independent pension trust fund of the Department.

Plan amendments must be approved by both the Retirement Board and the Board of Commissioners. The Plan issues separately available financial statements on an annual basis.

NOTE 7: (continued)

The annual pension cost (APC) and net pension obligation (NPO) for the Department's plan consists of the following (amounts in thousands):

	Year Ended June 30, 2004	Year Ended June 30, 2003
Annual required contribution	$ 44,614	$ 41,417
Interest on net pension asset	(13,558)	(14,107)
Adjustment to annual required contribution	20,203	21,021
APC (including $16.1 million and $14.1 million of amounts capitalized in fiscal 2004 and 2003, respectively)	51,259	48,331
Department contributions	(55,694)	(40,577)
Change in NPO	(4,435)	7,754
NPO (asset) at beginning of year	(177,749)	(185,503)
NPO (asset) at end of year	$ (182,184)	$ (177,749)

Water Services' allocated share of annual pension cost (APC) and net pension obligation (NPO) consists of the following (amounts in thousands):

	Year Ended June 30, 2004	Year Ended June 30, 2003
Annual required contribution	$ 15,169	$ 9,857
Interest on net pension asset	(4,610)	(3,357)
Adjustment to annual required contribution	6,869	5,003
APC (including $7.1 million and $5 million of amounts capitalized in fiscal 2004 and 2003, respectively)	17,428	11,503
Department contributions	(18,789)	(10,207)
Change in NPO	(1,361)	1,296
NPO (asset) at beginning of year	(58,552)	(59,848)
NPO (asset) at end of year	$ (59,913)	$ (58,552)

Annual required contributions are determined through actuarial valuations using the entry age normal actuarial cost method. The actuarial value of assets in excess of the Department's actuarial accrued liability (AAL) was being amortized by level contribution offsets over the period ending June 30, 2003. As a result of an April 2000 amendment to the Plan, the amortization period was changed to rolling fifteen-year periods effective July 1, 2000.

NOTE 7: (continued)

In accordance with actuarial valuations, the Department's required contribution rates are as follows:

Actuarial Valuation Date June 30	Normal Cost	Surplus Amortization	Required Contribution Rate
2004	10.83%	2.10%	13.45%
2003	10.89%	-2.76%	8.45%
2002	10.97%	-2.64%	8.66%

The significant actuarial assumptions include an investment rate of return of 8%, projected inflation-adjusted salary increases of 5.5%, and postretirement benefit increases of 3%. The actuarial value of assets is determined using techniques that smooth the effects of short-term volatility in the market value of investments over a four-year period. Plan assets consist primarily of corporate and government bonds, common stocks, mortgage-backed securities and short-term investments.

Trend information for fiscal years 2004, 2003, and 2002 for Water Services is as follows (amounts in thousands):

Year ended June 30,	NPO (asset)	Percentage of APC Contributed	APC
2004	$ (59,913)	108%	$ 17,428
2003	$ (58,552)	84%	$ 11,503
2002	$ (59,848)	400%	$ 1,844

The following schedule provides information about the Department's overall progress made in accumulating sufficient assets to pay benefits when due, prior to allocations to Water Services and Energy Services (amounts in thousands):

Actuarial Valuation Date June 30,	Actuarial Value of Assets	AAL	Actuarial Assets over/(under) AAL	Funded Ratio	Covered Payroll	Overfunding as a % of Covered Payroll
2004	$ 6,251,421	$ 6,421,814	$ (170,393)	97%	$ 581,039	-29%
2003	$ 6,128,376	$ 6,042,087	$ 86,289	101%	$ 527,787	16%
2002	$ 5,790,263	$ 5,714,525	$ 75,738	101%	$ 430,398	18%

NOTE 7: (continued)

Disability and death benefits

Water Services' allocated share of disability and death benefit plan costs and administrative expenses totaled $4, million, $4 million, and $3 million for each of the fiscal years 2004, 2003, and 2002, respectively.

NOTE 8: Postretirement Health Care Plan

Effective July 1, 2003, the Department adopted GASBS No. 45 "*Accounting and Financial Reporting by Employers for Postemployment Benefits Other Than Pensions*" (GASBS No. 45), and discontinued following Financial Accounting Standards Board Statement No. 106 "*Employers' Accounting for Postretirement Benefits Other Than Pensions*" (SFAS No. 106). See Note 2.

The adoption of GASBS No. 45 did not affect the benefits provided by the health plan, the amount of the postretirement fund assets, or the fair value of assets. The adoption of GASBS No. 45 changed the accounting for the health care costs, the actuarial cost method, and the assumptions required by the independent third party actuary to value the Department's obligation related to postretirement health care coverage.

Plan Description

The Department provides certain health care benefits to active and retired employees and their dependents. The health care plan is administered by the Department. The Retirement Board and the Board of Water and Power Commissioners have the authority to approve provisions and obligations. Eligibility for benefits for retired employees is dependent on a combination of age and service of the participants pursuant to a predetermined formula. Any changes to these provisions must be approved by the Boards. The total number of active and retired Department participants entitled to receive benefits was approximately 16,760 at June 30, 2004.

The health plan is a single employer plan that is not administered as a trust or equivalent arrangement and therefore, does not have separate financial statements.

Funding Policy

The Department pays a monthly maximum subsidy of health plan premiums. Participants choosing plans with a cost in excess of the subsidy are required to pay the difference. No funding policy has been established for the future benefits to be provided under this plan. However, in fiscal year 2004, the Department made an employer contribution of $100 million (Water Services portion, $34 million) in addition to the $49 million it paid for current retiree premiums (Water Services portion, $16.5 million).

NOTE 8: (continued)

Annual OPEB Cost and Net OPEB Obligation

The annual other postretirement benefit (OPEB) cost (expense) is calculated based on the annual required contribution of the employer (ARC), an amount actuarially determined in accordance with the parameters of GASBS No. 45. The ARC represents a level of funding that, if paid on an ongoing basis, is projected to cover normal cost under each year and amortize any unfunded actuarial liabilities (or funding excess) over a period not to exceed thirty years. The following table shows the components of the Department's and the share of Water Services in annual OPEB cost for the year, the amount actually contributed to the plan, and changes in the net postretirement liability/asset liability/asset (dollar amount in thousands):

	Department	Water Services Share
Annual required contribution	$ 107,435	$ 36,528
Contributions made	(149,794)	(50,951)
Increase in net postretirement asset	(42,359)	(14,423)
Net postretirement asset - beginning of year	(184,725)	(53,478)
Net postretirement asset - end of year	$ (227,084)	$ (67,901)

The reconciliation of the beginning net postretirement asset is as follows (dollar amount in thousands):

	Department	Water Services Share
Net postretirement liability - beginning of year as previously reported	$ 329,879	$ 99,186
Adjustment due to change in accounting to GASBS No. 45 (see Note 2)	(514,604)	(152,664)
Net postretirement asset - as adjusted	$ (184,725)	$ (53,478)

The Department's and Water Services share in the annual OPEB cost, the percentage of annual OPEB cost contributed to the plan, and the net postretirement obligation for fiscal year 2004 were as follows (dollar amount in thousands):

NOTE 8: (continued)

	Department	Water Services Share
Annual OPEB cost	$ 107,435	$ 36,528
Percentage of annual OPEB cost contributed	139%	139%
Net postretirement asset	$ 227,084	$ 67,901

Funded Status and Funding Progress

As of July 1, 2003, the plan was 11 percent funded. The actuarial accrued liability for benefits was $1.7 billion and the actuarial value of assets was $186.9 million, resulting in an unfunded actuarial accrued liability (UAAL) of $1.5 billion. The covered payroll (annual payroll of active employees covered by the plan) was $571 million, and the ratio of the UAAL to the covered payroll was 270 percent.

Actuarial valuations of an ongoing plan involve estimates of the value of reported amounts and assumptions about the probability of occurrence of events far into the future. Examples include assumptions about future employment, mortality, and the health care cost trend. Amounts determined regarding the funded status of the plan and the annual required contributions of the Department are subject to continual revision as actual results are compared with past expectations and new estimates are made for the future. The schedule of funding progress, presents information about whether the actuarial value of plan assets is increasing or decreasing over time relative to the actuarial accrued liabilities for benefits.

Actuarial Methods and Assumptions

Projections of benefits for financial reporting purposes are based on the substantive plan (the plan understood by the Department and the plan members) and include the types of benefits provided at the time of each valuation and the historical pattern of sharing of benefit costs between the Department and the plan members to that point. The actuarial methods and assumptions used include techniques that are designed to reduce the effects of short-term volatility in actuarial accrued liabilities and the actuarial value of assets, consistent with the long-term perspective of the calculations.

NOTE 8: (continued)

In the July 1, 2003 actuarial valuation, the entry age normal cost method was used. The actuarial assumptions include a 6.5 percent discount rate which represents the expected long term return on plan assets, an annual health care cost trend rate of 16 percent initially, reduced by decrements to an ultimate rate of 5.75 percent after seven years. Both rates include a 3.5 percent inflation assumption. The actuarial value of assets was determined using techniques that spread UAAL being amortized as a level percentage of projected payroll over a 30 year period.

New legislation

In December 2003, the President signed into law the Medicare Prescription Drug, Improvement and Modernization Act of 2003 effective in 2006. Two important aspects of the law may affect the employer's financial statements before 2006. First, the opportunity for retirees to obtain prescription drug benefits under new Medicare Part D will tend to shift benefits and related costs out of employer plans. Second, employers that provide prescription drug benefits that are at least as valuable as (actuarially equivalent) those under Medicare Part D will be entitled to annual subsidy from Medicare equal to 28% of prescription drug costs between $250 and $5,000 for each Medicare-eligible retiree who does not join part D. The Department has not yet determined the financial statement impact of adopting the new law.

NOTE 8 (continued)

For fiscal year 2003, the Department followed SFAS No. 106. The applicable disclosures for fiscal year 2003 are provided below:

The Department provides certain health care benefits to active and retired employees and their dependents. The health plan is administered by the Department, and the Retirement Board and the Board of Water and Power Commissioners have the authority to approve provisions and obligations. Eligibility for benefits is dependent on a combination of age and service of the participants pursuant to a predetermined formula. Any changes to these provisions must be approved by the Board. The Department pays a maximum subsidy of health plan premiums. Participants choosing plans with a cost in excess of the subsidy are required to pay the difference. The total number of active and retired Department participants entitled to receive benefits was approximately 14,200 at June 30, 2003.

The allocated cost to Water Services of providing such benefits amounted to $42 million and $39 million for fiscal years 2003 and 2002, respectively. Of these costs, $17 million and $17 million were capitalized and the remainder was charged to expense for fiscal years 2003 and 2002, respectively.

Postretirement benefits

The Department accounts for postretirement benefits in accordance with SFAS No. 106, "*Employers' Accounting for Postretirement Benefits Other Than Pensions*", which requires that the cost of postretirement benefits be recognized as expense over employees' service periods.

Water Services' allocated share of postretirement benefit costs is summarized as follows (amounts in thousands):

	Year ended June 30,	
	2003	2002
Service cost	$ 6,873	$ 5,578
Interest cost	22,746	19,344
Expected return on plan assets	(1,369)	(1,347)
Amortization of transition obligation	5,163	5,148
Amortization of prior service costs	4,777	2,617
Amortization of actuarial losses	2,625	2,782
	$ 40,815	$ 34,122

NOTE 8: (continued)

The funded status and the accrued benefit cost related to postretirement benefits for the Department, prior to allocations to Water Services and Energy Services, are summarized as follows (amounts in thousands):

	June 30, 2003
Change in benefit obligation:	
Benefit obligation at beginning of year	$ 941,626
Service cost	20,154
Interest cost	66,704
Actuarial losses	846,000
Benefits paid	(43,132)
Benefit obligation at end of year	1,831,352
Change in fair value of plan assets:	
Fair value of plan assets at beginning of year	81,493
Department contribution	96,000
Actual return on plan assets	7,232
Fair value of plan assets at end of year	184,725
Funded status	1,646,627
Unrecognized net loss	1,124,256
Unrecognized transition obligation	152,721
Unrecognized prior service cost	39,771
Accrued benefit cost	$ 329,879
Water Services' allocated share of accrued postretirement liability	$ (99,186)

Weighted average actuarial assumptions used in determining postretirement benefit costs are as follows:

	June 30, 2003	June 30, 2002
Discount rate	5.75%	7.25%
Expected return on plan assets	6.25%	6.50%

NOTE 8: (continued)

Plan assets consist primarily of commercial paper, United States Government and governmental agency securities, and corporate bonds. In addition to having set up a fund, the Department currently pays benefits on a "pay as you go" basis. No funding policy has been established for the future benefit to be provided under this plan, however in fiscal year 2003, the Department made an employer contribution of $96 million.

For measurement purposes, a 10.0% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2003; the rate was assumed to decrease gradually to 5.5% in 2012 and remain at that level thereafter. For the dental plan, an 8.0% annual rate of increase in the per capita cost was assumed for 2003; the rate was assumed to decrease gradually to 5.5% in 2008 and remain at that level thereafter. The effect of a 1% change in these assumed health care cost trend rates would increase or decrease the Department's total benefit obligation by approximately $387 or $298 million, respectively. In addition, such a 1% change would increase or decrease the aggregate service and interest cost components of net periodic benefit cost by approximately $13 million or $10 million, respectively.

During fiscal year 2000, the Department began contributing toward dental coverage for retirees enrolled in a Department-sponsored plan. This amendment resulted in a $46 million increase in the Department's accumulated postretirement benefit obligation at June 30, 2000. Water Services' allocated $11 million share of this increase is being amortized through 2008, the remaining average service period. This change also resulted in a $12 million increase in postretirement benefit costs for fiscal years 2003 and 2002, of which $4 million in each of these years, was allocated to Water Services.

NOTE 9: Shared Operating Expenses

Water Services shares certain administrative functions with the Department's Energy Services. Generally, the costs of these functions are allocated on the basis of the benefits provided. Operating expenses shared with Energy Services were $642 million, $603 million, and $514 million for fiscal years 2004, 2003, and 2002, respectively, of which $234 million, $219 million, and $186 million were allocated to Water Services.

NOTE 10: Loss on Asset Impairment and Abandoned Projects

During fiscal year 2004, management discontinued using a procurement system and wrote off $3.5 million, which was Water Services' portion of the net book value.

During fiscal year 2001, management approved the sale of one of its administrative facilities and Water Services reported its portion of the loss on asset impairment of $12 million. The completion of the sale was expected to occur within 12 to 24 months for a total original purchase price of $50 million, which was below the total asset carrying value. During fiscal year 2002, management became aware that the facility has mold in the structure. Management and the purchaser of the facility each conducted a study to determine an estimated cost for mold cleanup. As of June 30, 2002, no estimate was available to record a clean-up liability, however, as of June 30, 2003, management approved the sale of this administrative building for a reduced price of $37 million, which is pending Board approval. This reduction in price caused Water Services to recognize an additional loss of $3.4 million as of June 30, 2003. There were no changes to the sale of this building during fiscal year 2004.

During fiscal year 2002, management formally abandoned certain water projects and reported a loss on abandonment totaling approximately $16 million in the statement of revenue, expenses, and changes in fund net assets. Projects abandoned included design work related to a well field and a filter plant, and small construction projects that will not be completed.

NOTE 11: Commitments and Contingencies

Transfers to the reserve fund of the City of Los Angeles

Under the provisions of the City Charter, Water Services transfers funds at its discretion to the reserve fund of the City. Pursuant to covenants contained in the bond indentures, the transfers may not be in excess of the increase in fund net assets before transfers to the reserve fund of the City, of the prior fiscal year. Such payments are not in lieu of taxes and are recorded as a non-operating expense in the statement of revenue, expenses, and changes in fund net assets.

The Department authorized total transfers of $27.6 million, $27.5 million, and $27.2 million in fiscal years 2004, 2003, and 2002, respectively, from Water Services to the reserve fund of the City.

NOTE 11: (continued)

Operating lease

Water Services utilizes an advanced wastewater treatment facility owned and operated by a separate department of the City. The use of this facility is accounted for as an operating lease. Estimated expenditures for fiscal year 2005 are approximately $2 million to operate and maintain this asset. There are no minimum rental payments that the Department has to make. However, the Department is obligated to reimburse the other City department for that department's operating and maintenance costs to operate the facility, estimated to be about $2 million per year, for a term of 25 years. Water Services will also pay additional monies to the other City department, if revenues generated by Water Services exceed the costs of operation and maintenance as defined by the agreement. Water Services does not expect to pay such additional amounts as it does not expect that a net operating profit will be achieved based on current demand for recycled water.

Surface Water Treatment Rule

The State of California Surface Water Treatment Rule (SWTR) imposes increased filtration requirements at any open distribution reservoirs exposed to surface water runoff. The Department has had four major reservoirs in its system subject to the SWTR: Upper and Lower Hollywood, Lower Stone Canyon, and Encino. To comply with the SWTR, the Department has designed projects to remove these reservoirs from regular service through construction of larger pipelines and alternate covered storage facilities. These changes will improve water quality while maintaining flexibility in the water system.

The Hollywood Water Quality Improvement Project was completed in July 2002. Upper and Lower Hollywood Reservoirs were removed from service and functionally replaced by two 30 million gallon tanks and additional pipelines. Construction began on the Encino project in December 2002 and on the Stone Canyon Water Quality Improvement Project in December 2003. As of June 30, 2004, the cost of SWTR compliance related to engineering studies and construction activities at the four reservoirs and for the addition of key pipelines in the San Fernando Valley totaled $378 million and are expected to reach $632 million at completion in 2008.

NOTE 11: (continued)

Owens Valley

During 1997, the Great Basin Unified Air Pollution Control District (the District) adopted an initial State Implementation Plan, as amended, and an implementing order requiring the Department to initiate pollution control measures to control particulate matters emitting from the Owens Dry Lake bed. The Department disputed the remediation measures imposed by the original order; however, in July of 1998 the City and the District entered in an historic Memorandum of Agreement (MOA) to mitigate the dust problem. The MOA delineated the dust producing areas on the lakebed that needed to be controlled, specified what measures must be used to control the dust, and specified a timetable for implementation of the control measures. The MOA called for phased implementation to permit the effectiveness of the control measures to be evaluated and modifications to be made as the control measures were being installed.

The MOA was incorporated into a formal air quality State Implementation Plan (SIP) by the District. This SIP was approved by the United States Environmental Protection Agency on October 4, 1999. The District revised and adopted the SIP in November 2003. The revised SIP defines the additional boundaries and areas required to be controlled on the lakebed. The Department was allowed to examine the District's methodology to determine the additional areas to be controlled. As a result of those efforts the District ordered in the revised SIP 29.8 square miles that will be required to be controlled. That amount includes the areas the City agreed to and completed. The revised SIP demonstrates that upon completion of the City's work, emissions from Owens Lake bed will have been reduced so that the Owens Valley Planning Area will attain and maintain the federal Clean Air Act ambient air quality standards for particulate matter. The federal Clean Air Act requires that Owen Lake meet ambient air quality standards by the end of 2006.

NOTE 11: (continued)

The MOA specified that the City must choose from among 3 control measures the District has certified as Best Available Control Measures for Owens Lake. The three measures are Shallow Flooding, Managed Vegetation, and Gravel. To date, the City has completed construction on and is operating approximately 19.5 square miles of dust control measures. Therefore, the city is nearly two-thirds complete with its obligation. The first phase of dust control implementation, completed December 2001, consists of 13.5 square miles of Shallow Flooding. Shallow Flooding involves flooding the area to be controlled until it is either inundated with a few inches of water or the soil becomes thoroughly saturated to the surface with water. The second phase of dust control implementation, completed in July 2002, consists of about four square miles of Managed Vegetation. Managed Vegetation involves growing native vegetative cover that will hold the shifting and emissive lakebed in place, locking up the dust. The third phase of dust control implementation, completed in March 2003, consists of one and a third square miles of additional Shallow Flooding. Planning and design are currently underway for the additional areas specified in District's revised SIP. An additional two construction phases will be executed to meet these requirements.

As of June 30, 2004, the Department has incurred capital costs of approximately $270 million associated with the Owens Lake Dust Mitigation Program. Based on the 2003 SIP, management estimates that the total capital related costs of implementing the pollution control measures through 2006 will be approximately $415 million.

Litigation

A number of claims and suits are pending against the Department for alleged damages to persons and property and for other alleged liabilities arising out of its operations. In the opinion of management, any ultimate liability, which may arise from these actions, are not expected to materially impact Water Services' financial position, changes in fund net assets, or cash flows as of June 30, 2004.

Risk management

Water Services is subject to certain business risks common to the utility industry. The majority of these risks are mitigated by external insurance coverage obtained by Water Services. For other significant business risks, however, Water Services has elected to self-insure. Management believes that exposure to loss arising out of self-insured business risks will not materially impact Water Services' financial position, changes in fund net assets, or cash flows as of June 30, 2004.

NOTE 11: (continued)

Credit risk

Financial instruments, which potentially expose the Department to concentrations of credit risk, consist primarily of retail receivables. The Department's retail customer base is concentrated among commercial, industrial, residential and governmental customers located within the City. Although the Department is directly affected by the City's economy, management does not believe significant credit risk exists at June 30, 2004, except as provided in the allowance for losses. The Department manages its credit exposure by requiring credit enhancements from certain customers and through procedures designed to identify and monitor credit risk.

Schedule of Funding Progress for the Los Angeles Department of Water and Power Postretirement Health Care Plan

(dollar amounts in thousands.)

Actuarial Valuation Date	Actuarial Value of Assets (a)	Actuarial Accrued Liability (b)	Unfunded AAL (b-a)	Funded Ratio (a/b)	Covered Payroll (c)	UAAL as a Percenatge of Covered Payroll ((b-a/c)
July 1, 2003	$ 186,904	$ 1,729,706	$ 1,542,802	11%	$ 571,725	270%

For fiscal year 2004 Water Services was allocated 34 percent of the postretirement obligation, and held $53.5 million of the $186.9 million of fund assets. Actuarial valuations are performed at the beginning of the fiscal year.