



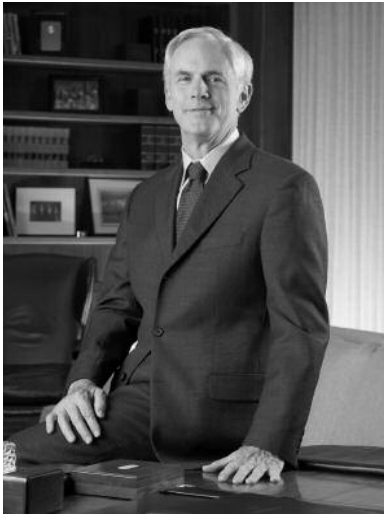
EDISON INTERNATIONAL 2004 Annual Report



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.

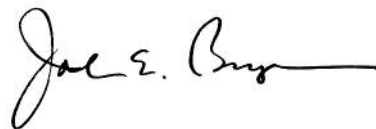
During the 2004 holiday season, a series of storms moved across Southern California, causing widespread damage to our utility electric system and disrupting service to hundreds of thousands of customers. As they have

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,

A handwritten signature in black ink, reading "John E. Bryson". The signature is fluid and cursive, with a long horizontal line extending from the end.

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

March 21, 2005

Edison International

Edison International: 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.

The People of Edison International:

- 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.

Table of Contents

1	Management's Discussion and Analysis of Financial Condition and Results of Operations
97	Management's Responsibility for Financial Reporting
97	Management's Report on Internal Control over Financial Reporting
97	Disclosure Controls and Procedures
98	Report of Independent Registered Public Accounting Firm
100	Consolidated Statements of Income
101	Consolidated Statements of Comprehensive Income
102	Consolidated Balance Sheets
104	Consolidated Statements of Cash Flows
105	Consolidated Statements of Changes in Common Shareholders' Equity
107	Notes to Consolidated Financial Statements
166	Quarterly Financial Data
167	Selected Financial and Operating Data: 2000 – 2004
169	Board of Directors and Management Team
IBC	Shareholder Information

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.

	<u>Page</u>
Edison International: Management Overview	2
Southern California Edison Company	4
Mission Energy Holding Company	30
Edison Capital	58
Edison International (Parent)	61
Results of Operations and Historical Cash Flow Analysis	63
Discontinued Operations	75
Acquisitions and Dispositions	76
Critical Accounting Policies and Estimates	77
New Accounting Principles	82
Commitments, Guarantees and Indemnities	84
Off-Balance Sheet Transactions	88
Other Developments	92

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;

Management's Discussion and Analysis of Financial Condition and Results of Operations

- 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:

Management's Discussion and Analysis of Financial Condition and Results of Operations

- 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

Management's Discussion and Analysis of Financial Condition and Results of Operations

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

Management's Discussion and Analysis of Financial Condition and Results of Operations

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.

Management's Discussion and Analysis of Financial Condition and Results of Operations

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.

Management's Discussion and Analysis of Financial Condition and Results of Operations

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 plan.

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

Management's Discussion and Analysis of Financial Condition and Results of Operations

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.

Management's Discussion and Analysis of Financial Condition and Results of Operations

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.

Management's Discussion and Analysis of Financial Condition and Results of Operations

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

Management's Discussion and Analysis of Financial Condition and Results of Operations

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 trees 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

Management's Discussion and Analysis of Financial Condition and Results of Operations

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.

Management's Discussion and Analysis of Financial Condition and Results of Operations

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

Management's Discussion and Analysis of Financial Condition and Results of Operations

- 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

Management's Discussion and Analysis of Financial Condition and Results of Operations

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

Management's Discussion and Analysis of Financial Condition and Results of Operations

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

Management's Discussion and Analysis of Financial Condition and Results of Operations

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

Management's Discussion and Analysis of Financial Condition and Results of Operations

"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

Management's Discussion and Analysis of Financial Condition and Results of Operations

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.

Historical Energy Prices	Into ComEd*		
	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

Management's Discussion and Analysis of Financial Condition and Results of Operations

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%.

Management's Discussion and Analysis of Financial Condition and Results of Operations

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

Management's Discussion and Analysis of Financial Condition and Results of Operations

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

Management's Discussion and Analysis of Financial Condition and Results of Operations

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:

In millions	December 31, 2004		December 31, 2003	
	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

Management's Discussion and Analysis of Financial Condition and Results of Operations

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

Management's Discussion and Analysis of Financial Condition and Results of Operations

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

Management's Discussion and Analysis of Financial Condition and Results of Operations

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 ERRAs-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

Management's Discussion and Analysis of Financial Condition and Results of Operations

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.

Management's Discussion and Analysis of Financial Condition and Results of Operations

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

Management's Discussion and Analysis of Financial Condition and Results of Operations

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.

Management's Discussion and Analysis of Financial Condition and Results of Operations

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

Management's Discussion and Analysis of Financial Condition and Results of Operations

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.

Management's Discussion and Analysis of Financial Condition and Results of Operations

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.

Management's Discussion and Analysis of Financial Condition and Results of Operations

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 health 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

Management's Discussion and Analysis of Financial Condition and Results of Operations

\$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 is 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.

Management's Discussion and Analysis of Financial Condition and Results of Operations

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.

Management's Discussion and Analysis of Financial Condition and Results of Operations

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

Management's Discussion and Analysis of Financial Condition and Results of Operations

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.

Management's Discussion and Analysis of Financial Condition and Results of Operations

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/ Citicapital	\$ 238	\$ 333.5 813.5	2009 2016
Homer City	1,591	GECC	798	300 530	2019 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

Management's Discussion and Analysis of Financial Condition and Results of Operations

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.

[THIS PAGE LEFT INTENTIONALLY BLANK]

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

Consolidated Statements of Income
Edison International

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.

Consolidated Statements of Comprehensive Income**Edison International**

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
Bank 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.

Consolidated Statements of Changes in Common Shareholders' Equity
Edison International

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.

Consolidated Statements of Changes in Common Shareholders' Equity
Edison International

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.

Notes to Consolidated 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.

Notes to Consolidated Financial Statements

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 is 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 Mandatorily 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

Notes to Consolidated Financial Statements

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

Notes to Consolidated Financial Statements

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,

Notes to Consolidated Financial Statements

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
<u>Current</u>			
Regulatory balancing accounts		\$ 371	\$ 140
Direct access procurement charges		109	90
Purchased-power settlements		62	57
Other		11	12
		553	299
<u>Long-term</u>			
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
<u>Current</u>			
Regulatory balancing accounts		\$ 357	\$ 549
Direct access procurement charges		109	90
Other		24	20
		490	659
<u>Long-term</u>			
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.

Notes to Consolidated Financial Statements

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.

Notes to Consolidated Financial Statements

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

Notes to Consolidated Financial Statements

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 ERRRA 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

Notes to Consolidated Financial Statements

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 plan.

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

Notes to Consolidated Financial Statements

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

Notes to Consolidated Financial Statements

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

Notes to Consolidated Financial Statements

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 structured 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.

Notes to Consolidated Financial Statements

The carrying amounts and fair values of financial instruments are:

In millions	December 31,			
	2004		2003	
	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.

Notes to Consolidated Financial Statements

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	Redemption		
	Outstanding	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

Notes to Consolidated Financial Statements

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	Redemption		
	Outstanding	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

Notes to Consolidated Financial Statements

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.

Notes to Consolidated Financial Statements

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	December 31,	
	2005	2004	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

Notes to Consolidated Financial Statements

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	December 31,	
	2005	2004	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

Notes to Consolidated Financial Statements

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:

	Share Options	Weighted-Average	
		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	

Notes to Consolidated Financial Statements

A summary of stock options outstanding at December 31, 2004 is as follows:

Range of Exercise Prices	Number of Options	Outstanding		Exercisable	
		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

Notes to Consolidated Financial Statements

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

Notes to Consolidated Financial Statements

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 its 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.

Notes to Consolidated Financial Statements

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

Notes to Consolidated Financial Statements

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.

Notes to Consolidated Financial Statements

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

Notes to Consolidated Financial Statements

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 is 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.

Notes to Consolidated Financial Statements

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.

Notes to Consolidated Financial Statements

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.

Notes to Consolidated Financial Statements

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

Notes to Consolidated Financial Statements

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.

Quarterly Financial Data (Unaudited)**Edison International**

In millions, except per-share amounts	2004				
	Total	Fourth	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	2003				
	Total	Fourth	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.

This page left intentionally blank.

Board of Directors*

John E. Bryson³
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. Danner⁶
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

Annual Meeting

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.

Corporate Governance Practices

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.

Stock Listing and Trading Information

Edison International Common Stock
The New York Stock Exchange uses the ticker symbol EIX; daily newspapers list the stock as EdisonInt.

Preferred Stock

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.

Transfer Agent and Registrar

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:

Mail

Wells Fargo Bank, N.A.
Shareowner Services Department
161 North Concord Exchange Street
South St. Paul, MN 55075-1139

Fax

(651) 450-4033

Email

stocktransfer@wellsfargo.com

Web Address

www.edisoninvestor.com

Online account information:

www.shareowneronline.com

Dividend Reinvestment and Direct Stock Purchase Plan

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.



2244 Walnut Grove Avenue
Rosemead, California 91770
www.edison.com