EDISON INTERNATIONAL

2003 ANNUAL REPORT

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THE PEOPLE OF EDISON INTERNATIONAL:

integrity

excellence

Respect

We have traveled some rough roads together in recent times. It gives me great pleasure to confirm that 2003 was a year of outstanding progress at Edison International. In talking about how far we have come, and where we are going, I want to tell you about the principal elements of that progress. I also want to give you some sense of the largest issues that lie immediately ahead.

EDISON INTERNATIONAL IN 2003 – A BRIEF OVERVIEW

This past year was remarkable from several perspectives. It marked the successful completion of the company's highest priority goal since the year 2000: to restore Southern California Edison to financial health in the aftermath of the California power crisis. It saw strong operating and financial performance at Edison Mission Energy which set the foundation for a plan to restore strength there. It prepared us to resume new investments at Edison Capital, placed on hold the last three years as we dedicated all our resources to rapid recovery of financial strength across Edison International. Finally, it was the year in which we were able to declare a shareholder dividend for the first time since the power crisis. We know how important this is to you.

During 2003, outstanding performance by Edison people across a wide range of company operations allowed us to meet or exceed nearly every important target we had set for the year. As a result, your stock value increased 85% during the 2003 calendar year.

SOUTHERN CALIFORNIA EDISON IN 2003

At Southern California Edison (SCE), strong operations and intense focus resulted in final recovery of $3.6 billion in previously unrecovered costs which we incurred to keep power flowing to our customers during the power crisis. Our legal right to that recovery was affirmed by both the California Supreme Court and by the U.S. federal courts.

This recovery of power crisis costs in turn paved the way for large rate reductions to our utility customers – in the aggregate, more than $1.6 billion in 2003. It also set the foundation for restoration of the credit strength essential for us to serve customers in the years to come. SCE's credit rating has now been restored to investment grade.

SCE's earnings from continuing operations of $872 million substantially exceeded both our internal targets and market expectations. Among many contributors to those earnings, two stand out: excellent operating results at our San Onofre Nuclear Generating Station (SONGS) and the resolution of a number of outstanding regulatory issues left undecided in prior years.

SCE leads U.S. utilities in the use of renewable energy. Last year, SCE set a new record: nearly 18% of all the kilowatt hours we provided our customers was supplied by renewable energy. Under mandates from California regulation, we have played a pioneering role in supporting the development of renewable power. At the same time, however, the state's "standard offer" contracts for these resources are much too costly. We will continue to focus on bringing these costs down, even while we continue to advocate the value of a diverse energy resource base – including renewables.

We received two notable awards in 2003. Our field employees were recognized for a second consecutive year with the Edison Electric Institute's annual "Emergency Response Award" – for preserving and restoring electric service in storm and wildfire conditions. And, for the third consecutive year, SCE was recognized as the most reliable utility in the western United States.

Finally, to our great disappointment, we learned recently that at least 12 employees from SCE's transmission and distribution organization falsified information used in customer satisfaction surveys. This was a serious breach of the company's highest value. It is essential to our business that everyone with whom we deal has confidence in our integrity. Any violation of that value will not be tolerated in our company.

EDISON MISSION ENERGY IN 2003 AND BEYOND

In 2003, the people of Edison Mission Energy (EME) managed exceptionally well the difficulties arising from the prior year's precipitous decline in U.S. wholesale power markets. As the year began, EME faced a daunting challenge: a total of $1.2 billion in EME-related debt was set to mature with no clear means for extending or refinancing that debt.

Because all EME financings are "non-recourse" to Edison International (EIX), our shareholders are positioned to benefit from up-side value at EME; but, beyond the equity previously invested, they are shielded from down-side risk. We require that EME meet its debt challenges exclusively on the strength of its own resources. And it is doing so.

EME people across each region operated our generation facilities at record levels in 2003, and significantly exceeded our annual earnings and cash flow targets. For the year, excluding impairment charges, EME produced earnings from continuing operations of $214 million – compared with the January 2003 outlook of no net income.

That performance made the critical difference for us. At the beginning of 2003, debt markets priced EME bonds as if that portion of our business would fail. Three other major U.S. independent power companies did fail altogether last year. With strong results through three quarters, we were able to put forth a comprehensive plan for going forward. By year end, the maturing EME-related debt was paid off and ongoing liquidity was enhanced through new borrowings and the strength of internal cash flows.

The EME debt restructure plan will require no new investment on the part of EIX going forward. However, in order to restore financial strength to EME as rapidly as possible, we have placed all of EME's non-U.S. generation facilities up for sale. This was a difficult decision. A talented and dedicated team of EME people developed this large and valuable diversified portfolio of power plants over the past 15 years. But we believe the sale proceeds will make a decisive difference in providing the ongoing EME with reduced debt costs and improved financial health for the future. We expect to complete the sale near the end of 2004.

Following the international asset sale, EME operations in the U.S. will focus primarily on 7,500 megawatts (MW) of low-cost, coal-fired power generation in Illinois and Pennsylvania selling into wholesale markets there, and on slightly less than 1,000 MW of natural gas-fired power generation in California selling under contract to utility buyers. In total capacity, even after the currently planned power plant sales, EME's power generation will be about one and one-half times the size of SCE's power generation. With these plants, EME will concentrate on developing a diverse portfolio of contracts for sale of our power, and on continuing to generate positive margins on high volumes of energy sold.

Some of the principal power markets served by EME in the Midwest and East currently have an oversupply of generation resources. This means that "capacity values" – as reflected in customer payments for assurance that power plants will be available when needed – are now very limited or absent in those markets. Capacity values will be restored at some point as the supply/demand balance returns. Our planning does not assume that this will happen soon; but when it does, it should further improve our results.

EDISON CAPITAL

Last year's company achievements also allow us to look forward to growing our Edison Capital business again. Edison Capital had been constrained from new investments since the power crisis in order to focus the entire company's efforts on building cash and restoring credit. Edison Capital people contributed significantly to that accelerated recovery effort, including providing $225 million in dividends to the parent company last year. Beginning this year, we are refocusing on new investments initially concentrated in two areas in which Edison Capital developed expertise in the past: renewable energy and affordable housing.

WHAT LIES AHEAD FOR SCE

In 2003, SCE regained the minimum financial health necessary to assure reasonable access to capital markets essential to the utility business. But that in itself is not sufficient to optimize our ability to serve our customers and shareholders well in the years to come.

In the next several years, California's electric system will require billions of dollars of investment in power transmission and distribution systems. A large part of the transmission and distribution in the State was built 40 or more years ago. These older systems are beginning to show their age. They need to be replaced or reconstructed on a planned basis. Compounding this need for major new capital investment is the substantial growth in new customers we are experiencing at SCE.

California will also need new power generating facilities. In February and March, SCE received final state and federal regulatory agency approvals for construction of a critically needed addition to California's power generating capacity. This new natural gas-fired 1,054-MW power plant, known as Mountainview, is being built in the heart of SCE's fastest growing customer base east of Los Angeles County. Mountainview will come on line just in time to help avoid an unacceptably large risk of summer power outages in 2006.

Even as we move forward with new power generation, SCE faces challenges with respect to its existing generation facilities which today provide both low customer costs and fuel-supply diversity. The continued availability of the SCE-operated Mohave coal-fired plant is uncertain beyond the end of next year, due primarily to issues pertaining to adequate water and coal supply. Looking further into the future, the SCE-operated SONGS will need a large investment to replace its existing steam generators, if it is to be counted on to operate beyond 2009. That plant is essential to electric system reliability and operating stability in Southern California. As yet, however, there is no agreement on the part of our co-owners in that facility on whether to make that critical investment.

Now that SCE's financial health is improving, public officials may once again be tempted to impose on us new and costly obligations. Major new contractual obligations, involving commitments of millions or even billions of dollars, would again stress the company's credit strength. Where these are not strictly necessary to serve our customers, we will vigorously oppose them. Where they are appropriate, we will seek reasonable compensation for enabling others to lean on our credit.

UNRESOLVED FUNDAMENTAL ISSUES IN CALIFORNIA

Reliable electric systems require sound, long-term planning, and major capital investments made on a timely basis. Commitment of capital, in turn, requires a durable legal and regulatory framework within which that investment can take place. In the aftermath of the power crisis, there is neither a comprehensive framework nor a consensus on what such a framework should look like.

In the last two years, the California Public Utilities Commission (CPUC) has taken significant steps toward developing an orderly plan for going forward. The CPUC has concluded that investor-owned utilities should own and operate power plants and should also contract for additional power to ensure sufficient reserves to meet customer needs. This makes sense; but critical questions remain unresolved.

The first is how new power generation will be built and financed. The CPUC correctly proposes to retain judgment to determine which plants and what mix of utility-owned and utility-contracted plants best serve customers. However, some argue that every new plant investment should be made in a statutorily prescribed auction process, the financial credit for which would be provided by long-term utility contracts. This would reduce the important role of judgment in selecting plants and would pass most market risks to utilities, with no corresponding utility benefit.

Another key issue – as yet largely unresolved – is whether utility customers will again be allowed to opt out of utility systems. That raises questions about whether investor-owned utilities will have a reasonably predictable customer base over the next decades. Utilities have traditionally invested in electric facilities and recovered reasonably incurred costs from customers through rates spread over the long lives of those assets. To the extent that there is doubt about the practical capacity of the California regulatory framework to allow utilities to plan their recovery of major commitments over as much as three decades, customer risks and costs will go up.

A high-priority task for your management team in the next year or years will be to advocate effectively to state officials the adoption of a sound, comprehensive legal and regulatory framework to ensure, at reasonable cost, California electric system reliability. Southern California Edison's future health depends on providing our customers those essential values.

IN CONCLUSION

The accomplishments of the past year are attributable in large part to the focus, talent, experience and energies of the people who make their careers with our company. They are outstanding at what they do.

Thanks are also due to our Board of Directors. I especially want to recognize two retiring directors, Joan Hanley and Dan Tellep. They have given us many years of sound guidance and counsel.

Finally, we extend our deepest thanks to you, our shareholders. Your investment in us is what makes our business possible. We are committed to seeing to it that you will be well-served by your investment in us.

Sincerely,

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

March 24, 2004

EDISON INTERNATIONAL

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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) is a holding company for EME. 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, EME, Edison Capital or MEHC mean each such company with its subsidiaries on a consolidated basis. References to Edison International (parent) or parent company mean Edison International on a stand-alone basis, not consolidated with its subsidiaries. References to SCE, EME, Edison Capital or MEHC 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 2003. Following is a company-by-company discussion of Edison International's principal operating subsidiaries (SCE, MEHC and EME, Edison Capital) and Edison International (parent). Each principal operating subsidiary's discussion includes a management overview and discussions of liquidity, market risk exposures, and other matters (as relevant to each principal operating subsidiary). 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, new accounting principles, commitments and guarantees, off-balance sheet transactions, and other developments. These sections should be read in conjunction with each subsidiary's section.

EDISON INTERNATIONAL

EDISON INTERNATIONAL: MANAGEMENT OVERVIEW

Edison International was significantly impacted by California's energy crisis, which began in late 2000, and by world-wide developments during 2001 and 2002 that adversely affected independent power producers and merchant generators. Therefore, Edison International's primary management focus in 2003 continued to be restoring the company's financial health. In this regard, three objectives were particularly critical:

- Validating and completing SCE's recovery of power procurement costs arising from the energy crisis. In July 2003, SCE completed recovery of $3.6 billion of procurement-related obligations through the regulatory account known as the Procurement-Related Obligations Account (PROACT). By late 2003, both the California Supreme Court and the United States Court of Appeals for the Ninth Circuit (Ninth Circuit) had issued decisions upholding the 2001 CPUC settlement agreement that provided for creation of the PROACT and SCE's recovery of procurement-related costs. (See "SCE: Regulatory Matters—Generation and Power Procurement—CPUC Litigation Settlement Agreement," and "—PROACT Regulatory Asset").

- Comprehensively addressing the indebtedness at EME and its subsidiaries that mature or expire in 2003 and 2004, with a focus on debt reduction. In December 2003, EME's subsidiary, Mission Energy Holding International, Inc., received funding under a three-year, $800 million secured loan which was used, together with other internally generated cash, to repay $1.2 billion of EME and Edison Mission Midwest Holdings indebtedness. See further discussion under "MEHC and EME: Liquidity—Key Financing Developments." This was the first step in a four-part restructuring plan announced in November 2003. The remaining steps are described below.

- Positioning the company to resume common stock dividends. In November 2003, Edison International paid previously deferred interest on its quarterly income debt securities, which was a precondition to declaring a common stock dividend. In December 2003, the Board of Directors of Edison International declared a 20¢ per share common stock quarterly dividend. The $65 million dividend payment was made on January 30, 2004.

In 2004, Edison International's management intends to focus on continuing the company's financial recovery and resuming investments in growth at Edison Capital. Key objectives in 2004 include:

- Completing the remaining three steps in EME's four-part restructuring plan, which consists of refinancing indebtedness associated with EME's Illinois plants, including termination of the lease at the Collins Station, selling some or all of EME's international operations and using the proceeds of asset sales to reduce EME's consolidated indebtedness. See further discussion in "MEHC and EME: Management Overview—EME's Restructuring Plan" and "MEHC and EME: Liquidity—Key Financing Developments—EME's Subsidiary Financing Plans—Agreement in Principle to Terminate the Collins Station Lease," and "—Edison Mission Midwest Holdings."

- Reducing Edison International (parent)'s debt. At December 31, 2003, Edison International (parent) had outstanding $618 million of notes due September 2004. During January and February 2004, Edison International repurchased approximately $46 million of these notes, leaving a remaining balance of $572 million of notes due in September 2004. (See "Edison International (Parent): Liquidity Issues").

- Making important investments at SCE to ensure electric reliability. SCE currently plans to invest up to $9 billion over the next five years to replace and expand distribution and transmission infrastructure and construct and replace generation assets. (See "SCE: Management Overview").

- Restarting investments at Edison Capital in affordable housing and electric infrastructure, ending a three-year investment hiatus (see "Edison Capital: Management Overview").

Edison International's recorded earnings were $821 million or $2.52 per share in 2003, compared to $1.1 billion or $3.31 per share in 2002, which included a gain of $480 million related to a regulatory decision on SCE's utility-retained generation (URG). Excluding this one-time 2002 gain, Edison International's earnings from continuing operations in 2003 increased $124 million over 2002. Major factors contributing to the increase of $124 million over the prior year included the resolution of significant regulatory proceedings at SCE, the impact of higher United States wholesale energy prices on EME, increased generation from EME's Homer City plant and the absence of write-offs incurred in 2002 at EME. These positive impacts to earnings were partially offset in 2003 by asset impairment charges at EME. Edison International's consolidated earnings for 2003 also included a gain on an SCE asset sale and related operating earnings totaling $50 million reported in discontinued operations, and charges of $9 million for the cumulative effect of a change in accounting principles at EME. For a detailed review and analysis of the consolidated results of operations and historical cash flows, see "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 California Public Utilities Commission (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 and distribution plant (or rate base). Base rates provide for recovery of operations and maintenance (O&M) 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 currently authorized by the CPUC through a General Rate Case (GRC) proceeding. 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 O&M 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 O&M costs, changes in capital-related costs and the expected number of nuclear refueling outages. 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 annual cost of capital proceedings. The rate of return is a blend of a return on equity and cost of long-term debt and preferred stock. SCE's 2003 cost of capital decision, issued on November 7, 2002, will remain in effect throughout 2004. Accordingly, SCE's CPUC-authorized rate of return of 9.75%, return on common equity of 11.6% and authorized rate-making capital structure will be maintained through 2004.

Current CPUC ratemaking also provides for performance incentives or penalties for differences between actual results and GRC-determined standards of reliability, customer satisfaction 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 is subject to refund until a FERC decision is issued. SCE currently receives approximately $260 million in annual revenue to recover the costs associated with its transmission function and to earn a reasonable return on its $1.1 billion transmission rate base.

Cost-Recovery Rates: Revenue requirements to recover SCE's costs of fuel, power procurement, demand-side management programs, nuclear decommissioning costs, and rate reduction debt requirements 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. 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 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 or cash flow.

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

SCE Issues Overview

This overview discusses key business issues facing SCE. It is not intended to be an exhaustive discussion. It includes issues that could materially affect SCE's earnings, cash flow or business risk. The overview includes a discussion of current and planned capital expenditures (including the acquisition and construction of the Mountainview project, either potential expenditures or the possibility of a shutdown at the Mohave Generating Station (Mohave), and costs of replacing the steam generators at the San Onofre Nuclear Generating Station (San Onofre)), anticipated procurement requirements (including the effects of a resource adequacy requirement, community aggregation, and related ratemaking), and the 2003 and 2006 CPUC General Rate Cases.

The issues discussed in this overview are described in more detail in the remainder of this "Southern California Edison Company" section.

SCE's utility business is experiencing significant growth in actual and planned capital expenditures. SCE plans to spend up to $1.9 billion during 2004, compared to $1.2 billion in 2003. The growth in spending will require a partial reinvestment of earnings and issuance of debt securities to maintain a balanced capital structure, as required by the CPUC. For 2005 and beyond, capital spending is anticipated to remain at levels substantially above historical levels, but somewhat below planned spending for 2004.

Each of SCE's business areas (distribution, transmission and generation) is contributing to the capital spending growth. The distribution area, which represents approximately 70% of SCE's rate base, is experiencing continued expansion of the number of customer accounts. Beginning with a base of 4.6 million active accounts, for 2004, SCE expects to add approximately 60,000 new accounts, and forecasts a similar level of activity over the next several years. SCE also forecasts that it will need to accelerate the replacement of distribution poles, transformers and other infrastructure to maintain existing levels of system reliability.

SCE forecasts that expenditures for transmission facilities will substantially increase over the balance of the decade. SCE is now planning for and beginning to construct new substations to meet customer load-growth requirements. Moreover, SCE is conducting preliminary engineering on new and existing transmission lines that would expand the capacity to bring in additional energy from the Southwest.

In 2004, generation capital expenditures will increase dramatically, driven primarily by the recently approved Mountainview project. In addition, SCE will spend in excess of $50 million at the San Onofre plant to construct facilities to protect the site against a design basis threat as determined by the Nuclear Regulatory Commission. These expenditures are in addition to ongoing capital expenditures to maintain the safety and reliability of SCE's nuclear, coal and hydroelectric facilities. Beyond 2004, SCE may replace the San Onofre steam generators in the 2009–2010 time frame. Given the lead-time requirements to fabricate the steam generators, SCE must make commitments to begin fabrication during 2004.

Recently, the CPUC ordered all load-serving entities to procure sufficient resources to meet their customers' needs. This resource adequacy requirement phases in over the 2005–2008 period and requires planning reserve margins of 15–17% of peak load. This resource adequacy requirement, combined with the anticipated closure of Mohave at the end of 2005, expected reductions in deliveries under CDWR contracts, expected expiration of contracts with some independent power producers known as qualifying facilities (QFs), and expected peak-load growth of 1.5–2.0% per year, will require SCE to either construct new generation facilities or enter into additional power-purchase contracts to provide for forecasted customer requirements. Implementation of the CPUC order will be addressed in workshops commencing in mid-March 2004.

At the same time that SCE is evaluating new generation investments and contractual obligations, SCE has raised fundamental concerns about the stability of its customer base in the CPUC's ongoing long-term procurement proceeding. The CPUC's direct access rules, the possible expansion of community choice aggregation, other forms of municipalization, and application of exit fees to departing customers all affect the ability of SCE to retain bundled service customers (customers who purchase power from SCE). It is SCE's goal to ensure that customers who depart from utility generation service pay their fair share of costs, and that costs are not unfairly shifted to remaining bundled service customers, which could have the effect of increasing SCE's rates and causing more customers to seek alternative providers.

SCE is aware that the concern for high rates was a contributing factor that led California regulators to deregulate the electric services industry in the mid-1990's. Today, SCE's system average rate is 12.3¢-per-kilowatt-hour (kWh) for bundled service customers and its average monthly bill is $79. On a cents-per-kWh basis, SCE's average rate is above the national average, but similar to the other investor-owned electric utilities in California. Therefore, SCE is focused on providing bundled service customers competitive and stable electric rates. But this focus must be balanced with the obligation to safely and reliably serve customers.

At the beginning of 2003, SCE resumed procurement of power for its bundled service customers. During 2003, much of management's attention was focused on establishing fair and reasonable rules for the procurement of power for utility customers. Additional work is needed. For 2004 and 2005, SCE forecasts that it will have a residual long position in the majority of hours. SCE's residual-net long position arises primarily because of the CPUC's allocation of CDWR contract energy. For the reasons listed above, such as customer growth and run-off of existing contracts, SCE expects to have substantially greater power procurement requirements beyond 2005. The acquisition and construction of the Mountainview project, the replacement of the San Onofre steam generators and the expansion of transmission facilities are all part of SCE's plan to meet a portion of expected customer requirements. However, even more additional resources will be needed to meet those expected requirements.

To promote and ensure recovery of both generation investments and contract costs, SCE has established a corporate priority to secure a fair and durable regulatory framework. To this end, SCE supports adoption of Assembly Bill 2006, introduced by California's Speaker of the Assembly Fabian Nunez. The bill is pending before the California State Assembly.

SCE is in the final stages of its 2003 GRC proceeding, which will set annual base rates for the years 2003–2005 years. On February 13, 2004, SCE received a proposed decision from the administrative law judge that heard the 2003 GRC. SCE is seeking a $251 million increase in its annual base rate revenue, but the proposed decision would allow only a $15 million increase. SCE is disappointed with the proposed decision and will press for reinstatement of its requested amount by the CPUC commissioners. The CPUC commissioners can accept, reject, or modify any proposed decision.

SCE is now preparing its 2006 General Rate Case. SCE's preliminary application files in August 2004, with the application scheduled to file before year-end 2004. With the expected growth in capital spending discussed above, SCE expects that it will need further increases in its revenue requirement.

SCE: LIQUIDITY ISSUES

SCE's liquidity is primarily affected by under- or over-collections of procurement-related costs as discussed in "SCE: Management Overview—Background" and access to capital markets or external financings. In the fourth quarter of 2003, Moody's Investors Service and Standard & Poor's both raised SCE's credit ratings to investment grade.

At December 31, 2003, SCE had cash and equivalents of $95 million. SCE's long-term debt, including current maturities, at December 31, 2003, was $4.5 billion. SCE has a $700 million credit facility that expires in December 2006. SCE drew $200 million on the facility on December 19, 2003. In addition, the facility supported letters of credit in the amount of $33 million at year-end 2003. At December 31, 2003, SCE had borrowing capacity under its credit facility of $467 million. SCE's 2004 cash requirements consist of:

- $125 million of 5.875% bonds due in September 2004;
- Approximately $246 million of rate reduction notes that are due at various times in 2004, but which have a separate cost recovery mechanism approved by state legislation and CPUC decisions;
- Projected capital expenditures of $1.9 billion, including the investment in the Mountainview project and related capital expenditures (see "Acquisitions and Dispositions");
- Dividend payments to SCE's parent company;
- Fuel and procurement-related costs; and
- General operating expenses.

SCE expects to meet its continuing obligations and cash outflows for 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.

SCE's capital structure is regulated by the CPUC. SCE's CPUC-authorized common equity to total capitalization ratio level is 48%. On October 16, 2003, SCE transferred, through a dividend to Edison International, $945 million of equity that exceeded the CPUC-authorized level. This dividend was a first step to rebalance SCE's capital structure in accordance with CPUC requirements. As of December 31, 2003, SCE's common equity to total capitalization ratio, for rate-making purposes, was approximately 55%.

In January 2004, SCE issued $975 million of first and refunding mortgage bonds. The issuance included $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. The proceeds were used to redeem $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 March 2004, SCE remarketed approximately $550 million of pollution-control bonds with varying maturity dates ranging from 2008 to 2040.

SCE resumed procurement of its residual-net short (the amount of energy needed to serve SCE's customers from sources other than its own generating plants, power-purchase contracts and CDWR contracts) on January 1, 2003, and as of December 31, 2003, had posted approximately $66 million ($33 million in cash and $33 million in letters of credit) as collateral to secure its obligations under power-purchase contracts and to transact through the Independent System Operator (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.

SCE's liquidity may be affected by, among other things, matters described in "SCE: Regulatory Matters—Generation and Power Procurement—CPUC Litigation Settlement Agreement," "—CDWR Power Purchases and Revenue Requirement Proceedings," and "—Generation Procurement Proceedings" sections.

SCE: MARKET RISK EXPOSURES

SCE's primary market risks include fluctuations in interest rates, generating fuel commodity prices and volume and counterparty credit. Fluctuations in interest rates can affect earnings and cash flows. However, fluctuations in fuel prices and volumes and counterparty credit losses temporarily affect cash flows, but should not affect earnings.

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 2003 and 2004), 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, 2003, 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, 2003, the fair market value of SCE's long-term debt was $4.4 billion. A 10% increase in market interest rates would have resulted in a $166 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 $183 million increase in the fair market value of SCE's long-term debt. At December 31, 2003, the fair market value of SCE's preferred stock subject to mandatory redemption was $139 million. A 10% increase in market interest rates would have resulted in a $12 million decrease in the fair market value of SCE's preferred stock subject to mandatory redemption. A 10% decrease in market interest rates would have resulted in a $14 million increase in the fair market value of SCE's preferred stock subject to mandatory redemption.

Generating Fuel Commodity Price Risk

SCE's purchased-power expense in 2003 was approximately 38% 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. Until January 1, 2006, 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. 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 procurement of its residual-net short. SCE forecasts that it will have a residual long position in the majority of hours for 2004. SCE's residual-net long position arises from an expected increase in deliveries under CDWR contracts allocated to SCE's customers. SCE has incorporated a price and volume forecast from expected sales of residual-net long power in its 2004 procurement plan filed with the CPUC, as well as in the 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 2004 and beyond, several factors could cause SCE's residual-net short to be much larger than expected, including the return of direct access customers (customers who choose to purchase power directly from an electric service provider other than SCE) to utility service, lower utility generation due to expected or unexpected outages or plant closures, lower deliveries under third-party power contracts, higher than anticipated demand for electricity, or displacement of existing generation resources with economic short-term transactions. Such an increase in procurement requirements could lead to temporary revenue undercollections if the costs to purchase the additional energy were to exceed the amount recovered in rates.

SCE anticipates it will need to purchase additional capacity and/or ancillary services to meet its peak-energy requirements in 2004 and 2005. In 2006, SCE's residual-net short exposure will increase significantly from the reduction in expected CDWR power deliveries, expiration of certain contracts with QFs, expected shutdown of Mohave, and load growth.

Pursuant to CPUC decisions, SCE, as the CDWR's limited agent, arranges for natural gas and performs related services for CDWR contracts allocated to SCE by the CPUC. Financial and legal responsibility for the allocated contracts remains with the CDWR. The CDWR, through the coordination of SCE, has hedged a portion of its expected natural gas requirements for certain contracts allocated to SCE. To the extent the price of natural gas were to increase above the levels assumed for cost recovery purposes, 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.

SCE purchases power from QFs under CPUC state-mandated contracts. Contract energy prices for most nonrenewable QFs are tied to the Southern California border price of natural gas established on a monthly basis. The CPUC has authorized SCE to hedge a majority of its natural gas price exposure associated with these QF contracts. During 2003, SCE substantially hedged the risk of increasing natural gas prices through hedging instruments purchased in late 2001 pursuant to authority granted by the CPUC. The cost of these hedging instruments was recovered through PROACT. None of these hedging instruments were outstanding as of December 31, 2003. The CPUC approved SCE's short-term resource plan, which includes hedging of natural gas price exposure for its existing QF contracts for 2004. These hedging costs are recovered through a balancing account known as Energy Resource Recovery Account (ERRA) and should have no impact on earnings. 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.

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. 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

During the California energy crisis, prices charged by sellers of wholesale power escalated far beyond what SCE was permitted by the CPUC to charge its customers. In November 2000, SCE filed a lawsuit against the CPUC in federal district court seeking a ruling that SCE is entitled to full recovery of its electricity procurement costs incurred during the energy crisis in accordance with the tariffs filed with the FERC. In October 2001, SCE and the CPUC entered into a settlement of SCE's lawsuit against the CPUC. A key element of the 2001 CPUC settlement agreement was the establishment of a $3.6 billion regulatory balancing account, called the PROACT, as of August 31, 2001. The Utility Reform Network (TURN) and other parties appealed to the Ninth Circuit seeking to overturn the stipulated judgment of the federal district court that approved the 2001 CPUC settlement agreement. On September 23, 2002, the Ninth Circuit issued its opinion affirming the federal district court on all claims, with the exception of the challenges founded upon California state law, which the Ninth Circuit referred to the California Supreme Court.

On August 21, 2003, the California Supreme Court issued its decision on the certified questions on challenges founded upon California state law, concluding that the 2001 CPUC settlement agreement did not violate California law in any of the respects raised by the Ninth Circuit. Specifically, the California Supreme Court concluded that: (1) the commissioners of the CPUC had the authority to propose the stipulated judgment under the provisions of California's restructuring statute, Assembly Bill 1890, as amended or impacted by subsequent legislation; (2) the procedures employed by the CPUC in entering the stipulated judgment did not violate California's open meeting law for public agencies; and (3) the stipulated judgment did not violate California's public utilities code by allegedly altering rates without a public hearing and issuance of findings.

On October 22, 2003, the California Supreme Court denied TURN's petition for rehearing of the decision. The matter was returned to the Ninth Circuit for final disposition, subject to any efforts by TURN to pursue further federal appeals. On December 19, 2003, the Ninth Circuit unanimously affirmed the original stipulated judgment of the federal district court, and no petition for rehearing was filed. On January 12, 2004, the Ninth Circuit issued its mandate, relinquishing jurisdiction of the case and returning jurisdiction to the federal district court. TURN and those parties whose appeals to the Ninth Circuit were consolidated with TURN's appeal currently have 90 days from December 19, 2003 in which to seek discretionary review from the United States Supreme Court. SCE continues to believe it is probable that recovery of its past procurement costs through regulatory mechanisms, including the PROACT, will not be invalidated. However, SCE cannot predict with certainty the ultimate outcome of further legal proceedings, if any.

PROACT Regulatory Asset

In accordance with the 2001 CPUC settlement agreement described above and an implementing resolution adopted by the CPUC, in the fourth quarter of 2001, SCE established the PROACT regulatory balancing account, with an initial balance of approximately $3.6 billion. The initial balance reflected the net amount of past procurement-related liabilities to be recovered by SCE. On a monthly basis, the difference between SCE's revenue from retail electric rates (including surcharges) and the costs that SCE was authorized by the CPUC to recover in retail electric rates was applied to the PROACT until SCE fully recovered the balance.

At July 31, 2003, the PROACT regulatory balancing account was overcollected by $148 million. On October 14, 2003, the CPUC approved SCE's advice filing which allowed SCE to transfer this July 31, 2003 overcollected PROACT balance and a temporary surcharge balancing account overcollection (see "—Generation and Power Procurement—Temporary Surcharges") to the ERRA (discussed below) on August 1, 2003, and to implement a $1.2 billion customer rate reduction effective August 1, 2003.

Energy Resource Recovery Account Proceedings

In an October 24, 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," 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.

SCE submitted its first ERRA forecast application in April 2003, in which it forecast procurement-related costs for the 2003 calendar year of $2.5 billion. On January 22, 2004, the CPUC issued a decision that approved SCE's forecast as submitted. The CPUC issued a proposed decision on February 24, 2004, approving SCE's 2004 forecast revenue requirement and rates for both generation and delivery services.

In October 2003, SCE submitted its first ERRA reasonableness review application, in which it requested the CPUC find its procurement-related operations during the period from September 1, 2001 through June 30, 2003 to be reasonable. Because this is the first annual review of this activity, pursuant to new California state law, the CPUC's interpretation and application of California state law is uncertain. SCE cannot predict with certainty the outcome of its application and recovery of its procurement-related operations costs.

Pursuant to the assigned commissioner's scoping memo issued on December 9, 2003, the CPUC's Office of Ratepayer Advocates (ORA) was allowed to review the accounting calculations used in the PROACT mechanism. The ORA testimony, due on March 19, 2004, will include an audit of these accounting calculations. Hearings are scheduled to be held during April 2004.

Utility-Retained Generation

As a result of an April 2002 CPUC decision, SCE's retained generation assets were returned to cost-of-service ratemaking after operating in a deregulated environment since 1998. The CPUC decision provided for the: (1) recovery of costs for all URG components other than San Onofre Units 2 and 3, subject to reasonableness review by the CPUC; (2) retention of the incremental cost incentive pricing mechanism (ICIP) for San Onofre Units 2 and 3 through 2003; (3) establishment of an amortization schedule for SCE's nuclear facilities that reflects their current remaining Nuclear Regulatory Commission license durations, using unamortized balances as of January 1, 2001 as a starting point; (4) establishment of balancing accounts for the costs of utility generation, purchased power, and ancillary services purchased from the ISO; and (5) continuation of the use of SCE's last CPUC-authorized return on common equity of 11.6% for SCE's URG rate base other than San Onofre Units 2 and 3, and the 7.35% return on rate base for San Onofre Units 2 and 3 under the ICIP. SCE will operate under the April 2002 CPUC decision until implementation of the 2003 GRC (see "—Transmission and Distribution—2003 General Rate Case Proceeding").

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. During the fourth quarter of 2002, the CDWR issued $11 billion in bonds to finance its 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). Amounts billed to and collected from SCE's customers for electric power purchased and sold by the CDWR (approximately $1.7 billion in 2003) are remitted directly to the CDWR and are not recognized as revenue by SCE.

Direct Access Proceedings

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. During that time, direct access customers received a credit for the generation costs SCE saved by not serving them, resulting in additional undercollected power procurement costs to SCE during 2000 and 2001. On March 21, 2002, the CPUC issued a decision affirming that new direct access arrangements entered into by SCE's customers after September 20, 2001 are invalid. That decision did not affect direct access arrangements in place before that date.

In May 2003, a CPUC decision allowed customers with valid direct access arrangements to switch back and forth between bundled service provided by SCE and direct access. This decision, as well as CPUC decisions or proceedings discussed below, affects 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.

The CPUC has received several petitions requesting clarification of previous decisions on whether to allow load growth on existing direct access accounts or add new accounts if necessary to accommodate direct access customers who relocate their facilities. Recently, the CPUC agreed, in response to one of these petitions, to allow direct access customers to add new accounts when relocating facilities as long as there is no increase in a customer's total eligible direct access load. SCE cannot predict how the CPUC will rule on the remaining petitions. If the CPUC allows load growth on existing direct access accounts and allows new direct access accounts to be added notwithstanding the suspension of direct access, the level of direct access load in SCE's territory could rise considerably, resulting in a shift of a greater portion of SCE's costs to bundled service customers.

The CPUC has also opened a proceeding to identify issues relating to the implementation of a 2002 California law authorizing community choice aggregation. This form of direct access 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. Hearings on this matter are scheduled to begin in May 2004. Depending on how many, if any, cities choose to participate in community choice aggregation, a large amount of load could depart from SCE's bundled service, resulting in additional shifting of cost responsibility.

The CPUC has issued decisions or has 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. The charges recovered from these customers are used to reduce SCE's rates to bundled service customers and have no impact on earnings.

Temporary Surcharges

A March 2001 CPUC decision, authorized a 3¢-per-kWh revenue surcharge to SCE's customers and made permanent a 1¢-per-kWh surcharge to SCE's customers authorized in January 2001. In addition, the CPUC authorized an additional 0.6¢-per-kWh catch-up surcharge for a twelve-month period, beginning in June 2001, to compensate SCE for a delay in collecting the 3¢-per-kWh surcharge. These surcharges were used for SCE's procurement costs.

The CPUC later allowed the continuation of the 0.6¢-per-kWh catch-up surcharge. Amounts collected between June 2002 and December 2002 were to be used to recover 2003 procurement costs. As a result, at December 31, 2002, this revenue ($187 million of surcharge revenue) was credited to a regulatory liability account until it was used to offset SCE's higher 2003 procurement revenue requirement. Between January 1, 2003 and July 31, 2003, $150 million of this regulatory liability account was amortized into revenue. The remaining balance of $37 million was transferred to the ERRA as of August 1, 2003.

The $1.2 billion customer rate reduction plan implemented by SCE eliminated all of the temporary surcharges (see "—Generation and Power Procurement—PROACT Regulatory Asset").

Generation Procurement Proceedings

SCE resumed power procurement responsibilities for its residual-net short position 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.

Short-Term Procurement Plan

In 2003, SCE operated under a CPUC-approved short-term procurement plan, which includes contracts entered into during a transitional period beginning in August 2002 for deliveries in 2003 and the allocation of CDWR contracts. In December 2003, the CPUC adopted a 2004 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.

Long-Term Resource Plan

On April 15, 2003, SCE filed its long-term resource plan with the CPUC, which includes a 20-year forecast. SCE's long-term resource plan included both a preferred plan and an interim plan (both described below). On January 22, 2004, the CPUC issued a decision which did not adopt any long-term resource plan, but adopted a framework for resource planning. Until the CPUC approves a long-term resource plan for SCE, SCE will operate under its interim resource plan.

- Preferred Resource Plan: The preferred resource plan contains long-term commitments intended to encourage investment in new generation and transmission infrastructure, increase long-term reliability and decrease price volatility. These commitments include energy efficiency and demand-response investments, additional renewable resource contracts that will meet or exceed the requirements of legislation passed in 2002, additional utility and third-party owned generation, and new major transmission projects.

- Interim Resource Plan: The interim resource plan, by contrast, relies exclusively on new short- and medium-term contracts with no long-term resource commitments (except for new renewable contracts).

In its long-term resource plan filing, SCE maintained that implementation of its preferred resource plan requires resolution of various issues including: (1) stabilizing SCE's customer base; (2) restoring SCE's investment-grade creditworthiness; (3) restructuring regulations regarding energy efficiency and demand-response programs; (4) removing barriers to transmission development; (5) modifying prior decisions, which impede long-term procurement; and (6) adopting a commercially realistic cost-recovery framework that will enable utilities to obtain financing and enable contracting for new generation.

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. This resource adequacy requirement phases in over the 2005–2008 period and requires planning reserve margins of 15–17% of peak load. The decision requires SCE to enter into forward contracts for 90% of SCE's summer peaking needs a year in advance and to file a revised long-term resource plan in 2004. The decision does not comprehensively address important issues SCE has raised about its customer base, recovery of indirect procurement costs (including debt equivalence) and other matters.

Procurement of Renewable Resources

As part of SCE's resumption of power procurement, 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. 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. As of December 31, 2003, SCE procured approximately 18% of its annual electricity from renewable resources.

SCE has received bids for renewable resource contracts in response to a solicitation it made in August 2003, and is proceeding to enter into negotiations for contracts with some bidders based upon its preliminary bid evaluation.

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.

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 the 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 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.

Negotiations are continuing among the relevant parties in an effort to resolve the coal and water supply issues, but no resolution has been reached. The Mohave co-owners, the Tribes, and the federal government have recently finalized a memorandum of understanding under which the Mohave co-owners will fund, subject to the terms and conditions of the memorandum of understanding, a $6 million study of a possible alternative groundwater source for the slurry water. The study is expected to begin in early 2004. SCE and other parties submitted further testimony and made various other filings in 2003 in SCE's application proceeding. On February 9, 2004, the CPUC held a prehearing conference to discuss whether additional testimony and hearings are needed to determine the future of the plant. The CPUC has not issued any ruling as result of the prehearing conference, but has indicated that further testimony can be expected in early to mid-2004. The outcome of the coal and water negotiations and SCE's application are not expected to impact Mohave's operation through 2005, but could have a major impact on SCE's long-term resource plan.

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

In light of all of the issues discussed above, SCE has concluded that it is probable Mohave will 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 as a regulatory asset, based on SCE's expectation that any unrecovered book value at the end of 2005 would be recovered in future rates through a balancing account mechanism presented in its May 17, 2002 application and discussed in its supplemental testimony filed in January 2003.

Transmission and Distribution

2003 General Rate Case Proceeding

On May 3, 2002, SCE filed its application for a 2003 GRC, requesting: (1) a 2003 revenue requirement of approximately $3.1 billion; (2) a 2004 revenue requirement of approximately $3.5 billion; and (3) a 2005 revenue requirement of approximately $3.7 billion. These revenue requirements were based on SCE's projected rate base amounts of $7.8 billion in 2003, $8.2 billion in 2004 and $8.5 billion in 2005. When compared to forecast revenue at currently authorized rates (approximately $2.8 billion), SCE's 2003 GRC request was an increase of $286 million, which was subsequently revised to an increase of $251 million. The requested revenue increase for 2003 was primarily related to capital additions, updated depreciation costs and projected increases in pension and benefit expenses. 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 ICIP rate-making mechanism at year-end 2003 and a forecast of increased sales. The expiration of San Onofre ICIP mechanism is expected to decrease SCE's 2004 earnings by approximately $100 million. Beginning in 2004, San Onofre Units 2 and 3 cost recovery reverts to cost-of-service ratemaking.

In a proposed decision issued on February 13, 2004, a CPUC administrative law judge recommended that the CPUC adopt only $15 million of the $251 million increase in authorized base rate revenue requirement that SCE had requested. SCE filed comments opposing parts of the proposed decision in an attempt to restore important components of the requested revenue requirement. The CPUC is scheduled to vote on the proposed decision on March 16, 2004, either modifying or accepting it. If an alternate decision is proposed, a final decision could be delayed into April 2004. If the CPUC adopts the administrative law judge's proposed decision without modification, and if SCE does not reduce its expected capital or operating expenditures accordingly, SCE estimates that on an annual basis SCE's earnings per share would be about 15¢-per-share lower and cash flow would be approximately $135 million lower than if SCE's base rate request had been granted in full. SCE cannot predict with certainty the final outcome of SCE's GRC application.

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 (the date a final CPUC decision was originally scheduled to be issued) and the date a final decision is ultimately adopted. The revenue requirement approved in the final GRC decision will be effective retroactive to May 22, 2003. Any balance in the GRC memorandum account authorized by the CPUC would be recovered in rates beginning in 2004, together with the combined revenue requirement authorized by the CPUC in the GRC decision for 2003 and 2004.

Hearings to address revenue allocation and rate design issues have been continued until after the CPUC issues a decision on SCE's revenue requirement. Due to the implementation of SCE's $1.2 billion customer rate-reduction plan, rate design changes will not be effective until August 2004, at the earliest. Until SCE's 2003 GRC is implemented, SCE's revenue requirement related to distribution operations is determined through a performance-based rate-making (PBR) mechanism.

Electric Line Maintenance Practices Proceeding

In August 2001, the CPUC issued an order instituting investigation regarding SCE's overhead and underground electric line maintenance practices. The order was based on a report issued by the CPUC's Consumer Protection and Safety Division, which alleged a pattern of noncompliance with the CPUC's general orders for the maintenance of electric lines for 1998–2000. The order also alleged that noncompliant conditions were involved in 37 accidents resulting in death, serious injury or property damage. The Consumer Protection and Safety Division identified 4,817 alleged violations of the general orders during the three-year period; and the order put SCE on notice that it could be subject to a penalty of between $500 and $20,000 for each violation or accident. In its opening brief on October 21, 2002, the Consumer Protection and Safety Division recommended that SCE be assessed a penalty of $97 million.

On June 19, 2003, a CPUC administrative law judge issued a presiding officer's decision on the Consumer Protection and Safety Division report. The decision did the following:

- Fined SCE $576,000 for 2% of the alleged violations involving death, injury or property damage, failure to identify unsafe conditions or exceeding required inspection intervals. The decision did not find that any of the alleged violations compromised the integrity or safety of SCE's electric system or were excessive compared to other utilities.

- Ordered SCE to consult with the Consumer Protection and Safety Division and refine SCE's maintenance priority system consistent with the decision.

- Adopted an interpretation that all SCE's nonconformances with the CPUC's general orders for the maintenance of electric lines are violations subject to potential penalty.

On July 21, 2003, SCE filed an appeal with the CPUC challenging, among other things, the decision's interpretation of nonconformance. The Consumer Protection and Safety Division also appealed, challenging the fact that the decision did not penalize SCE for 4,721 of the 4,817 alleged violations. A final decision is scheduled to be issued on March 16, 2004.

Transmission Rate Case

In July 2000, the FERC issued a decision in SCE's 1998 transmission rate case in which it ordered a reduction of approximately $38 million to SCE's requested annual transmission revenue requirement of $213 million. In the decision, the FERC rejected SCE's proposed method for allocating overhead costs between transmission and distribution operations, which accounted for approximately $24 million of the $38 million reduction. After the FERC decision, SCE sought recovery in distribution rates from the CPUC. In third quarter 2003, the CPUC authorized recovery of $133 million of overhead costs for the period April 1, 1998 to August 31, 2002, and SCE credited this amount to provisions for regulatory adjustment clauses – net in the consolidated statements of income. On September 22, 2003, the ORA applied for rehearing of the matter. On February 11, 2004, the CPUC denied the ORA's request and reaffirmed its decision authorizing recovery.

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)/ 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 will be refunded to customers, except for the El Paso Natural Gas Company settlement agreement discussed below.

El Paso Natural Gas Company entered into a settlement agreement with parties to a class action lawsuit (including SCE, PG&E and the State of California) settling claims stated in proceedings at the FERC and in San Diego County Superior Court that El Paso Natural Gas Company 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 San Diego County Superior Court approved the settlement on December 5, 2003. Notice of appeal of that judgment was filed by a party to the action on February 6, 2004. Accordingly, until the appeal is resolved, the judgment is not final and no refunds will be paid. Pursuant to a CPUC decision, SCE will refund to customers any amounts received under the terms of the El Paso Natural Gas Company settlement (net of legal and consulting costs) through its ERRA mechanism. In addition, amounts El Paso Natural Gas Company refunds to the CDWR will result in equivalent reductions in the CDWR's revenue requirement allocated to SCE.

On February 24, 2004, SCE and PG&E entered into a settlement agreement with The Williams Cos. and Williams Power Company, providing for approximately $140 million in refunds against some of Williams' power charges in 2000–2001. The allocation of refunds under the settlement agreement has not been determined. The settlement is subject to the approval of the FERC, the CPUC and the PG&E bankruptcy court.

Other Regulatory Matters

Catastrophic Event Memorandum Account

The catastrophic event memorandum account (CEMA) is a CPUC-authorized mechanism 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 initiated a second CEMA associated with the fires that occurred in SCE territory in October 2003. Costs tracked through the CEMA mechanism are expected to be recovered in future rates 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 ensure that all dead, dying and diseased trees and vegetation are completely cleared from their utility rights-of-way to mitigate the potential fire damage. SCE estimates that it may incur several hundred million dollars 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. In 2003, SCE removed approximately 26,000 dead or dying trees at an incremental expense of approximately $18 million which has been reflected in the CEMA as of December 31, 2003. SCE expects to submit an advice filing with the CPUC in the first quarter of 2004 to recover these costs. SCE estimates that it will spend up to $150 million on this project in 2004.

Fire-Related CEMA

During the last two weeks of October 2003, wildfires damaged SCE's electrical infrastructure, primarily in the San Bernardino Mountains of Southern California where an estimated 1,500 power poles and 220 transformers were damaged or downed. SCE notified the CPUC that it initiated a CEMA on October 21, 2003 to track the incremental costs to repair and restore its infrastructure. These costs are estimated to be approximately $30 million. The balance in this CEMA account is approximately $9 million as of December 31, 2003.

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 November 26, 2003, the Court of Appeals issued an order indicating it would hear the cases but did not decide the merits of the petitions. Oral argument was held before the Court of Appeals on March 5, 2004, and the Court of Appeals is expected to rule within 90 days.

Investigation Regarding Performance Incentives Rewards

SCE is eligible under its CPUC-approved PBR mechanism to earn rewards or penalties based on its performance in comparison to CPUC-approved standards of reliability, customer satisfaction, and employee safety. SCE received two letters over the last year from 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 is conducting an internal investigation and has determined that some wrongdoing by a number of the service planning employees has occurred. SCE has informed the CPUC of its findings to date, and will continue to inform the CPUC of developments as the investigation progresses. SCE anticipates that, after the investigation is completed, there may be CPUC proceedings to determine whether any portion of past and potential rewards for customer satisfaction should be refunded or disallowed. It also is possible that penalties could be imposed. SCE recorded aggregate customer satisfaction rewards of $28 million for the years 1998, 1999, and 2000. Potential customer satisfaction rewards aggregating $10 million for 2001 and 2002 are pending before the CPUC and have not been recognized in income by SCE. SCE also had anticipated that it could be eligible for customer satisfaction rewards of about $10 million for 2003. SCE has not yet been able to determine whether or to what extent employee misconduct has compromised the surveys that are the basis for a portion of the awards. Accordingly, SCE cannot predict with certainty the outcome of this matter. SCE plans to complete its investigation as quickly as possible and cooperate fully with the CPUC in taking appropriate remedial action.

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.

It is not yet clear what actions the CPUC will take to respond to the report of the California Department of Health Services and to the recent electric and magnetic fields reports by other health authorities such as the National Institute of Environmental Health Sciences, the World Health Organization's International Agency for Research on Cancer, and the United Kingdom's National Radiation Protection Board. Possible outcomes may include continuation of current policies or imposition of more stringent policies to implement greater reductions in electric and magnetic fields exposures. The costs of these different outcomes are unknown at this time.

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. 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.

Some of the issues included in this case were addressed by the United States Supreme Court in a separate legal proceeding filed by the Navajo Nation in the 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 filed a motion to dismiss or, in the alternative, for summary judgment in the D.C. District Court action. The motion remains pending.

The Federal Circuit Court of Appeals, acting on a suggestion on remand filed by the Navajo Nation, held in a October 24, 2003 decision that the Supreme Court's March 24, 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 Court of Appeals decision. Both petitions were denied on March 9, 2004.

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.

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 Unit 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 asked the CPUC to issue a decision by July 2005 finding that it is reasonable for SCE to replace the San Onofre Unit 2 and 3 steam generators and establishing appropriate ratemaking for the replacement costs. In its application, SCE stated that the San Onofre operating agreement requires unanimous approval of all co-owners for the costs of the steam generator replacement to be included in the capital budget for Units 2 and 3 and, therefore, SCE must have the approval of its co-owners to go forward as planned, which approval currently is lacking. Because SCE will need to enter into commitments in 2004 to obtain timely delivery of replacement steam generators, SCE also asked the CPUC to create a memorandum account by September 2004 for SCE to recover initial costs of up to $50 million if the replacement project ultimately is not approved by the CPUC or co-owner approval is not obtained. If the CPUC finds investment in the steam generators to be reasonable and cost effective and the steam generator replacement takes place, SCE's investment should be reflected in retail rates for recovery over the remaining useful life of the plants. SCE currently does not expect that it would proceed with replacement of the San Onofre Units 2 and 3 steam generators without CPUC approval of reasonable cost recovery.

Palo Verde Steam Generators

The steam generators at the Palo Verde Nuclear Generating Station (Palo Verde), in which SCE owns a 15.8% interest, have the same design and material properties as 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 Units 1 and 3 in the 2005 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 $110 million; SCE plans to seek recovery of that amount through the rate-making process.

MISSION ENERGY HOLDING COMPANY and EDISON MISSION ENERGY

MEHC AND EME: MANAGEMENT OVERVIEW

MEHC as a Holding Company

MEHC is the holding company of EME which, itself, operates 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 worldwide. MEHC has no business activities other than through its ownership interest in EME. During 2001, MEHC issued $800 million of senior secured notes and borrowed $385 million under a term loan. The senior secured notes and the term loan are secured by a first priority security interest in EME's common stock. MEHC's ability to honor its obligations under the senior secured notes and the term loan is entirely dependent upon the receipt of dividends from EME and receipt of tax-allocation payments from MEHC's parent, Edison Mission Group Inc., and ultimately Edison International (see "MEHC and EME: Liquidity—EME's Liquidity as a Holding Company—Intercompany Tax-Allocation Payments"). Dividends from EME are limited based on its earnings and cash flow, terms of restrictions contained in EME's contractual obligations (including its corporate credit facility), EME's charter documents, business and tax considerations, and restrictions imposed by applicable law. MEHC did not receive any distributions from EME during 2003.

The lenders under MEHC's $385 million term loan due in 2006 have the right to require MEHC to repurchase up to $100 million of principal amount at par on July 2, 2004 (referred to as the "Term Loan Put-Option"). In order for MEHC to have sufficient cash in the event of an exercise of a significant portion, or all, of the Term Loan Put-Option, MEHC would require additional cash from dividends from EME, or would need to either extend the effective date of the Term Loan Put-Option or extend or refinance the term loan. Dividends from EME are currently limited as described in "MEHC and EME: Liquidity—Financial Ratios—Ability of EME to Pay Dividends."

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 worldwide. 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. EME also owns a 51% interest in Contact Energy, an integrated energy company located in New Zealand. As of December 31, 2003, EME's subsidiaries and affiliates owned or leased interests in 28 projects, of which 14 are domestic and 14 (including EcoEléctrica) are international.

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 nonrecourse 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. Because of such a contractual constraint, distributions to EME from cash generated from the Illinois plants has been restricted since October 1, 2002 due to a downgrade of the credit rating of this project's debt to below investment grade. EME also is currently subject to constraints on its ability to make distributions to its parent, MEHC. For a description of the most significant contractual constraints under the projects, see "MEHC and EME: Liquidity—Dividend Restrictions in Major Financings."

EME's project portfolio may be grouped into two categories: contracted plants and merchant plants. At December 31, 2003, EME owned 25 projects that sell a majority of their power to customers under long-term sales arrangements (greater than 5 years) consisting of power-purchase agreements or hedge contracts (in the case of Contact Energy, sales are made through its retail electricity business). While these projects involve 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 three projects (the Illinois plants, the Homer City facilities and the First Hydro Power Plants) which operate in whole or in part without long-term sales arrangements (representing approximately 70% 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, the amount of capacity and energy subject to sale under these contracts has been gradually reduced in the ensuing contract years, and these contracts will expire 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. A description of these market forces and the risks associated with them is included under "MEHC and EME: Market Risk Exposures."

EME Industry Developments

Beginning in 2001, a number of significant developments adversely affected merchant generators (companies that sell a majority of their generation into wholesale energy markets), including EME. These developments included lower prices and greater volatility in wholesale energy markets both in the United States and United Kingdom, significant declines in the credit ratings of most major market participants, decreased availability of debt financing or refinancing, and a resulting decline of liquidity in the energy markets due to growing concern about the ability of counterparties to perform their obligations.

Overview of EME's 2003 Operating Performance

EME's 2003 operating performance was significantly improved over 2002. A number of important items affected this performance, including the following:

- Power prices in PJM rebounded in 2003 from their depressed prices in 2002 driven largely by higher natural gas prices in the United States as discussed further below. The 24-hour PJM market price (at the Homer City busbar) increased 37% from $25.63 per megawatt hour in 2002 to $35.08 per megawatt hour in 2003. The increase in market price substantially improved the profitability of the Homer City plant.

- Higher natural gas prices also resulted in improved profitability of EME's interest in Four Star Oil & Gas Company and the Big 4 projects.

- EME achieved an availability factor of 89% across its project portfolio and a forced outage rate of 5% compared to a benchmark (NERC-GD) availability factor of 85% and a forced outage rate of 7% for an equivalent project portfolio.

- The Paiton project debt was restructured following on the late 2002 revisions in its power-purchase contracts.

- The Sunrise project completed Phase 2 of its development ahead of schedule and, thus, was able to generate additional capacity revenue during the summer of 2003.

- Contact Energy continued to expand its retail customer base which, together with increases in retail prices and higher sales of wholesale natural gas, collectively improved the profitability of this subsidiary.

- On the negative side, EME recorded three asset impairment charges (pre-tax) during 2003:

  - $245 million related to the impairment of eight small peaking units of the Illinois plants resulting from a revised long-term outlook for capacity revenue from these units. The lower capacity revenue outlook is the result of a number of factors, including higher forecasted long-term natural gas prices and the current oversupply of generation in the Mid-America Interconnected Network (MAIN) region;

  - $53 million related to the write-down of EME's investment in the Brooklyn Navy Yard project due to its planned disposition; and

  - $6 million related to the write-down of EME's investment in the Gordonsville project, which was subsequently sold in 2003.

- Also on the negative side, the amount of capacity sold to Exelon Generation from the Illinois plants decreased significantly from 2002 as discussed further below.

In 2003, the Illinois plants had 4,739 MW of contracted capacity (to Exelon Generation) and 3,109 MW of uncontracted capacity available for sale in the merchant generation market, compared with 8,987 MW of contract capacity and 300 MW of such uncontracted capacity in 2002. The reduction in contracted generating capacity decreased revenue from Exelon Generation as a percentage of the Illinois plants' total energy and capacity revenue to 68% in 2003 from 99% in each of 2002 and 2001. The reduction in contracted capacity resulted in a decrease of capacity revenue of $222 million, partially offset by an increase of $127 million in energy revenue from sales of increased merchant generation. Prices realized from sales of merchant generation were significantly higher than energy prices payable under the power-purchase agreements with Exelon Generation. EME expects that capacity prices in the MAIN region will, in the near term, be significantly lower than those payable under the existing agreements with Exelon Generation (due to generation overcapacity conditions in the MAIN region market), but also expects that merchant energy prices will, in the near term, be higher than those currently received under the existing agreements with Exelon. See "MEHC and EME: Market Risk Exposures" for further discussion of forward market prices in the MAIN region.

A significant factor affecting merchant generators in 2003 was the substantial increase in the price of natural gas, especially when compared with the less volatile cost of other fuels, such as coal. During 2003, natural gas prices at Henry Hub (a major natural gas trading hub) averaged $5.48 per million British Thermal Units, commonly referred to as MMBtu, compared to $3.37 per MMBtu for 2002. Based upon data from NYMEX as of December 26, 2003, the calendar year 2004 forward natural gas price at

Henry Hub was $5.45 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). This increase in natural gas prices was a positive factor for low-cost merchant coal facilities (such as a majority of EME's domestic merchant plants) in markets dominated by gas-fired plants and somewhat positive for such facilities in those markets more dependent on low-cost coal and nuclear facilities. In contrast, for gas-fired merchant generators that sell their power into markets dominated by low-cost coal and nuclear power plants, the increase in natural gas prices adversely affected their results. These conditions adversely affected the Collins Station and small peaking units in Illinois as discussed above.

EME's Restructuring Plan

EME has undertaken a four-step restructuring plan with the goal of reducing consolidated indebtedness. The four-step restructuring plan includes:

1) *Repayment of the December 2003 debt maturity at Edison Mission Midwest Holdings and other near term debt maturities.*

   In December 2003, EME's subsidiary, Mission Energy Holding International, Inc., received funding under a three-year, $800 million secured loan which was used, together with other internally generated cash, to repay $1.2 billion of EME and Edison Mission Midwest Holdings indebtedness. See further discussion under "MEHC and EME: Liquidity—Key Financing Developments."

2) *Refinancing indebtedness associated with the Illinois Plants.*

   EME intends to arrange a refinancing of indebtedness associated with the Illinois plants. This consists of $693 million of debt due at Edison Mission Midwest Holdings and the planned termination of the Collins Station lease. See "MEHC and EME: Liquidity—Key Financing Developments—EME's Subsidiary Financing Plans—Agreement in Principle to Terminate the Collins Station Lease." EME expects that the refinancing of these arrangements will be completed well in advance of December 2004, but there is no assurance that this will be accomplished.

3) *Selling some or all of its international operations.*

   EME has engaged investment bankers to market for sale its international project portfolio. The marketing efforts commenced during the first quarter of 2004. Completion of the sale of some or all of EME's international project portfolio is contingent on receiving acceptable offers with respect to both price and terms and conditions.

4) *Using the proceeds of asset sales to reduce consolidated indebtedness.*

   Assuming a successful sale of its international assets and completion of the sale of identified domestic projects, EME plans to use the proceeds first to repay the $800 million term loan described above and, with any additional proceeds received, to retire other consolidated indebtedness.

Expansion of PJM in Illinois

For the Illinois plants to achieve their optimal value, it is important that efficient and fair markets exist in the Midwest region. The Illinois plants are located within the service territory of Exelon Generation's affiliate, Commonwealth Edison (ComEd), which has made a filing with the FERC to join the PJM System effective May 1, 2004. Although FERC has indicated its general approval for ComEd and American Electric Power (AEP) to join PJM if certain conditions designed to foster broad regional markets in the Midwest are met, the integration of AEP into PJM has been stalled due to the opposition of the states of Virginia and Kentucky. While EME and Midwest Generation have supported the entry of ComEd and AEP into PJM at the same time, they have nevertheless opposed ComEd's entry into PJM without AEP on numerous grounds, including the importance of the AEP system to the proper functioning of the markets administered by PJM. This issued is currently pending before FERC.

If the integration of ComEd into PJM standing alone is allowed by the FERC to proceed on May 1, 2004, the Illinois plants will become subject to PJM's market rules, including those designed to mitigate generation market power, which PJM has indicated may be applied as if the market is limited only to the generation within the ComEd footprint. (By contrast, PJM has stated to the FERC that market mitigation measures will likely not be necessary from and after the integration of AEP into PJM.) EME and Midwest Generation have strongly opposed this limited view of the market with the FERC, and the matter is pending decision in connection with the ComEd/PJM integration filing. If this opposition is unsuccessful, the price for sales of energy from such plants (during the period prior to AEP's integration) not sold pursuant to bilateral agreement could be capped at their marginal operating cost to produce such energy plus ten percent, under the proposed rules of the PJM Market Monitor.

Contracting Strategy

EME's 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 plans to implement a layered contracting strategy for forward sales from the Illinois plants and the Homer City facilities. A layered contracting strategy means that EME's marketing subsidiary, Edison Mission Marketing & Trading, plans to enter into a number of forward contracts diversified by counterparty, contract term and generation product to reduce risk and enhance the predictability of revenue. Implementation of this strategy 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.

MEHC AND EME: LIQUIDITY

At December 31, 2003, MEHC and its subsidiaries had cash and cash equivalents of $654 million. MEHC's consolidated debt at December 31, 2003 was $7.4 billion, including $693 million of debt maturing on December 15, 2004 which is owed by EME's largest subsidiary, Edison Mission Midwest Holdings. In addition, EME's subsidiaries have $6.7 billion of long-term lease obligations that are due over a period ranging up to 31 years.

The following discussion of liquidity is organized in the following sections:

- MEHC's Liquidity
- Key Financing Developments
- 2004 Capital Expenditures
- EME's Credit Ratings
- EME's Liquidity as a Holding Company
- Dividend Restrictions in Major Financings
- Financial Ratios

MEHC's Liquidity

MEHC's ability to honor its obligations under the senior secured notes and the term loan, and to pay overhead is entirely 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 "—EME's Liquidity as a Holding Company—Intercompany Tax-Allocation Payments"). Dividends from EME are limited based on its earnings and cash flow, terms of restrictions contained in EME's contractual obligations (including its corporate credit facility), EME's charter documents, business and tax considerations, and restrictions imposed by applicable law. MEHC did not receive any distributions from EME during 2003.

At December 31, 2003, MEHC had cash and cash equivalents of $150 million (excluding amounts held by EME and its subsidiaries). The lenders under MEHC's $385 million term loan due in 2006 have the right to require MEHC to repurchase up to $100 million of principal amount at par on July 2, 2004 (referred to as the "Term Loan Put-Option"). In order for MEHC to have sufficient cash in the event of an exercise of a significant portion, or all, of the Term Loan Put-Option, MEHC would require additional cash from dividends from EME, or would need to either extend the effective date of the Term Loan Put-Option or extend or refinance the term loan. The timing and amount of dividends from EME and its subsidiaries may be affected by many factors beyond MEHC's control. Dividends from EME are currently limited as described in "—Financial Ratios—Ability of EME to Pay Dividends."

Key Financing Developments

On December 11, 2003, EME's subsidiary, Mission Energy Holdings International, received funding under a three-year, $800 million secured loan from Citigroup, Credit Suisse First Boston, JPMorganChaseBank, and Lehman Brothers. Interest on this secured loan is based on LIBOR (with a LIBOR floor of 2%) plus 5%. After payment of transaction expenses, a portion of the net proceeds from this financing was used to make an equity contribution of $550 million to Edison Mission Midwest Holdings which, together with cash on hand, was used to repay Edison Mission Midwest Holdings' $781 million indebtedness due December 11, 2003. The remaining net proceeds from this financing were used to make a deposit of cash collateral of approximately $67 million under the new letter of credit facility described below and to repay approximately $160 million of indebtedness of a foreign subsidiary under the Coal and Capex facility guaranteed by EME. Mission Energy Holdings International owns substantially all of EME's international operations through its subsidiary, MEC International B.V. As security for this loan, Mission Energy Holdings International, directly, and through its subsidiaries, pledged approximately 65% of its ownership interest in MEC International B.V. See "MEHC and EME: Management Overview" for discussion of the plan to sell off some of or all of EME's international projects.

On December 11, 2003, EME's subsidiary, Midwest Generation EME, LLC, entered into a three-year, $100 million letter of credit facility with Citibank, N.A., as Issuing Bank. 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. On December 11, 2003, EME canceled $67 million of the commitment under its existing line of credit and was relieved of its reimbursement obligations with respect to the same amount of letters of credit issued thereunder. Concurrently, such letters of credit were issued under Midwest Generation EME's new letter of credit facility, and Midwest Generation EME made a deposit of cash collateral in the amount of $67 million for this purpose. The funds for this deposit were obtained as part of the financing referred to above. At December 31, 2003, $47 million of letters of credit were outstanding under Midwest Generation EME's letter of credit facility. Midwest Generation EME owns 100% of Edison Mission Midwest Holdings, which in turn owns 100% of Midwest Generation LLC.

EME's Subsidiary Financing Plans

Agreement in Principle to Terminate the Collins Station Lease

Midwest Generation operates the Collins Station under a long-term lease. See "Off-Balance Sheet Transactions—EME's Off-Balance Sheet Transactions—Sale-Leaseback Transactions" for detail of the lease of the Collins Station. Due in part to higher long-term natural gas prices and the current oversupply of generation in the MAIN region, Midwest Generation does not believe the Collins Station is economically competitive in the current marketplace. In light of this, Midwest Generation has agreed in principle with the lease equity investor to terminate the Collins Station lease. The agreement in principle sets forth specified conditions required for the termination, including Midwest Generation successfully borrowing funds to finance the repayment of Collins Station lease debt of $774 million and settlement of Midwest Generation's termination liability with the lease equity investor. There is no assurance that the agreement in principle will result in termination of the Collins Station lease. If the termination occurs, Midwest Generation will take title to the Collins Station and, subject to its contractual obligation to Exelon Generation, plans to subsequently abandon the Collins Station or sell it to a third party.

If Midwest Generation completes the lease termination and subsequently abandons the Collins Station, EME expects to record a pre-tax loss of approximately $1 billion (approximately $620 million after tax). This loss will reduce EME's net worth (using December 31, 2003) from $1.9 billion to approximately $1.3 billion. To avoid the possibility of covenant defaults which could arise from a decline in net worth, EME plans to take the following actions before or simultaneously with the Collins Station lease termination:

- replace its $145 million corporate credit facility with a new secured credit facility;
- repay the $28 million due under the Coal and Capex facility (guaranteed by EME); and
- eliminate or modify the net worth covenant in its guaranty of the Powerton-Joliet lease.

If Midwest Generation completes the termination of the Collins Station lease followed by abandonment or sale to a third party, EME anticipates that the termination payment would result in a substantial income tax deduction. Because of these arrangements, EME does not expect that termination of the Collins Station lease will have a material adverse effect on its liquidity. If the lease termination does not occur, the terms of the lease will remain in effect and Midwest Generation will seek to restructure the lease with the lease equity investor.

Edison Mission Midwest Holdings

EME's wholly owned subsidiary, Edison Mission Midwest Holdings, has $693 million of debt maturing on December 15, 2004 which will need to be repaid or refinanced. Edison Mission Midwest Holdings is currently not expected to have sufficient cash to repay the $693 million debt due in December 2004, and there is no assurance that it will be able to refinance this debt obligation on similar terms and rates as the existing debt, on commercially reasonable terms, on the terms permitted under the financing documents entered into by MEHC in July 2001, or under the guarantee entered into by Midwest Generation EME in December 2003, or at all. MEHC's independent auditors' audit opinion for the year ended December 31, 2003 contains an explanatory paragraph that indicates the consolidated financial statements are prepared on the basis that MEHC will continue as a going concern and that the uncertainty about Edison Mission Midwest Holdings' ability to repay or refinance this obligation raises substantial doubt about MEHC's ability to continue as a going concern. Accordingly, the consolidated financial statements do not include any adjustments that might result from the resolution of this uncertainty.

A failure to repay or refinance Edison Mission Midwest Holdings' $693 million of debt as required by its terms would result in an event of default under the Edison Mission Midwest Holdings financing documents. Furthermore, these events would trigger cross-defaults under agreements to which Edison Mission Midwest Holdings and Midwest Generation are parties, including the Collins, Powerton and Joliet leases. An acceleration of debt and lease payments due under these agreements could result in a substantial claim for termination value under the EME guarantee of the Powerton and Joliet leases and could result in a default under EME's financing arrangements. A default by EME on its financing arrangements or a default by one of its subsidiaries on indebtedness considered under the MEHC financing documents as having recourse to EME is likely to result in a default under the MEHC financing documents. These events could make it necessary for MEHC or EME or both to file a petition for reorganization under Chapter 11 of the United States Bankruptcy Code.

2004 Capital Expenditures

The estimated construction expenditures of EME's subsidiaries for 2004 are $78 million. These expenditures are planned to be financed by existing subsidiary credit agreements and cash generated from their operations.

EME's Credit Ratings

Overview

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

	Moody's Rating	S&P Rating
EME	B2	B
Edison Mission Midwest Holdings	Ba3	B
Edison Mission Marketing & Trading	Not Rated	B

On October 28, 2003, Standard & Poor's Ratings Service downgraded EME's senior unsecured credit rating to B from BB-. Standard & Poor's also lowered the credit ratings of EME's wholly owned indirect subsidiaries, Edison Mission Midwest Holdings (syndicated loan facility to B from BB-) and Edison Mission Marketing & Trading (corporate credit rating to B from BB-). Standard & Poor's removed the ratings from CreditWatch with negative implications on December 12, 2003, following the repayment of $781 million of debt by Edison Mission Midwest Holdings; however, the outlook remains negative. In addition, Moody's Investors Service has assigned a negative rating outlook for EME and Edison Mission Midwest Holdings.

These ratings actions did not trigger any defaults under EME's credit facilities or those of the other affected entities. See "—EME's Credit Ratings—Credit Ratings of Edison Mission Midwest Holdings" for a discussion of the impact of the ratings action on Edison Mission Midwest Holdings. 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 agreed to provide collateral in the form of cash and letters of credit for the benefit of counterparties for its price risk management and domestic trading activities related to accounts payable and unrealized losses ($65 million as of February 27, 2004). EME has also provided collateral for a portion of its United Kingdom trading activities. To this end, EME's subsidiary, Edison Mission Operation and Maintenance

Limited, has obtained a cash collateralized credit facility, under which letters of credit totaling £20 million have been issued as of February 27, 2004.

EME anticipates that sales of power from its Illinois plants, Homer City facilities and First Hydro plants in the United Kingdom may require additional credit support, depending upon market conditions and the strategies adopted for the sale of this power. Changes in forward market prices and margining requirements could further increase the need for credit support for the price risk management and trading activities related to these projects. EME currently projects the potential working capital required to support its price risk management and trading activity to be between $100 million and $200 million from time to time.

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 further. 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.

Credit Ratings of Edison Mission Midwest Holdings

As a result of Edison Mission Midwest Holdings' credit rating being below investment grade since October 2002, provisions in the agreements binding on Edison Mission Midwest Holdings and Midwest Generation have restricted the ability of Edison Mission Midwest Holdings to make distributions to its parent company, thereby eliminating distributions to EME. The provisions in the agreements binding on Edison Mission Midwest Holdings required it to deposit, on a quarterly basis, 100% of its excess cash flow as defined in the agreements into a cash flow recapture account held and maintained by the collateral agent. In accordance with these provisions, Edison Mission Midwest Holdings deposited $246 million into the cash flow recapture account in 2002 and 2003.

As a result of the October 28, 2003 Standard & Poor's downgrade of Edison Mission Midwest Holdings to B from BB-, the cash on deposit in the cash flow recapture account ($246 million) was required to be used to prepay Edison Mission Midwest Holdings' indebtedness, with the amount of such prepayment applied ratably to the $911 million and $808 million tranches thereof. Therefore, on October 29, 2003, $130 million from the cash flow recapture account was applied to the $911 million tranche, and $116 million to the $808 million tranche, thereby reducing Edison Mission Midwest Holdings' debt obligations to $781 million and $693 million, respectively. Subsequently, Edison Mission Midwest Holdings repaid the $781 million tranche in full on December 11, 2003. In the future, so long as Edison Mission Midwest Holdings' ratings remain at the current level or lower, amounts of excess cash flow deposited in the cash flow recapture account at the end of each calendar quarter will be used upon deposit to prepay amounts then outstanding under the $693 million bank facility. There was no change to the cost of borrowings for Edison Mission Midwest Holdings as a result of the downgrade.

As part of the sale-leaseback of the Powerton and Joliet power stations, Midwest Generation loaned the proceeds ($1.4 billion) to EME in exchange for promissory notes in the same aggregate amount. Debt service payments by EME on the promissory notes may be used by Midwest Generation to meet its payment obligations under these leases in whole or part. Furthermore, EME has guaranteed the lease obligations of Midwest Generation under these leases. EME's obligations under the promissory notes payable to Midwest Generation are general corporate obligations of EME and are not contingent upon receiving distributions from Edison Mission Midwest Holdings. Accordingly, EME must continue to make payments under the intercompany notes notwithstanding that Edison Mission Midwest Holdings is not permitted to make distributions to EME. If EME were not able to make the loan payments, it would result in a default under the financing documents to which Edison Mission Midwest Holdings is a party and could result in a default under EME's financing arrangements. This could have a material adverse effect on the results of operations and cash flow of MEHC and EME. See "—Dividend Restrictions in

Major Financings—Edison Mission Midwest Holdings Co. (Illinois Plants)" for a discussion of implications for the Powerton and Joliet leases.

Credit Rating of Edison Mission Marketing & Trading

Pursuant to the Homer City sale-leaseback documents, a below investment grade credit rating of Edison Mission Marketing & Trading restricts the ability of EME Homer City Generation L.P. to enter into permitted trading activities, as defined in the documents, with Edison Mission Marketing & Trading to sell forward the output of the Homer City facilities. 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, 2004. EME Homer City continues to be in compliance with the terms of the consent, although as a result of the downgrade of Edison Mission Marketing & Trading's corporate credit rating to B from BB-, the consent is now revocable. The owner participant has not indicated that it intends to revoke the consent; however, there can be no assurance that it will not do so in the future. Revocation of the consent would not affect trades between Edison Mission Marketing & Trading and EME Homer City that had been entered into while the consent was still in effect. EME is permitted to sell the output of the Homer City facilities into the spot market at any time. See "MEHC and EME: Market Risk Exposures—Commodity Price Risk—Homer City Facilities."

EME's Liquidity as a Holding Company

Overview

EME has a $145 million corporate credit facility that expires on September 17, 2004. At December 31, 2003, EME had borrowing capacity of $145 million and corporate cash and cash equivalents of $179 million. During 2003, EME's cash position increased primarily due to an increase of distributions received from its consolidated subsidiaries and initial distributions from the Sunrise project upon completion of project financing. The timing and amount of distributions from EME's subsidiaries may be affected by many factors beyond its control. See "—EME's Liquidity as a Holding Company—Historical Distributions Received by EME" and "—Dividend Restrictions in Major Financings." In addition, the right of EME to receive tax-allocation payments, and the timing and amount of tax-allocation payments received by EME are subject to factors beyond EME's control. See "—EME's Liquidity as a Holding Company—Intercompany Tax-Allocation Payments."

EME's corporate credit facility provides credit available in the form of cash advances or letters of credit. At December 31, 2003, there were no cash advances outstanding or letters of credit outstanding under the credit facility. In addition to the interest payments, EME pays a facility fee determined by its long-term credit ratings (1.00% at December 31, 2003) on the credit facility independent of the level of borrowings. Under the credit agreement governing its credit facility, EME has agreed to maintain an interest coverage ratio that is based on cash received by EME, including tax-allocation payments, cash disbursements and interest paid. At December 31, 2003, EME met this interest coverage ratio. The interest coverage ratio in the ring-fencing provisions of EME's certificate of incorporation and bylaws remains relevant for determining EME's ability to make distributions. See "—Financial Ratios—EME's Interest Coverage Ratio."

Historical Distributions Received By EME

The following table is presented as an aid in understanding the cash flow of EME 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 December 31,	**2003**	2002
Domestic Projects		
Distributions from Consolidated Operating Projects:		
EME Homer City Generation L.P. (Homer City facilities)(1)	**$ 128**	$ —
Holding companies of other consolidated operating projects	**1**	2
Distributions from Unconsolidated Operating Projects:		
Edison Mission Energy Funding Corp. (Big 4 Projects)(2)	**98**	137
Four Star Oil & Gas Company	**21**	21
Sunrise Power Company(3)	**69**	—
Holding companies for Westside projects	**25**	42
Holding companies of other unconsolidated operating projects	**7**	10
Total Distributions from Domestic Projects	**$ 349**	$ 212
International Projects (Mission Energy Holdings International)		
Distributions from Consolidated Operating Projects:		
First Hydro Holdings (First Hydro project)	**$ 18**	$ —
Loy Yang B	**39**	27
Doga	**18**	47
Contact Energy	**16**	12
Valley Power	**8**	—
Kwinana	**4**	6
Distributions from Unconsolidated Operating Projects:		
ISAB Energy	**27**	1
IVPC4 (Italian Wind project)	**10**	33
Derwent	**3**	2
Paiton(4)	**9**	—
Tri Energy	**4**	3
Holding companies of other unconsolidated operating project	**2**	8
Total Distributions from International Projects	**$ 158**	$ 139
Total Distributions	**$ 507**	$ 351

(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. The remaining $92 million EME has classified as a return of capital.

(4) Represents a return of capital received as part of completion of the restructuring of the Paiton debt obligations.

Total distributions to EME increased between 2003 and 2002 due to:

- Distributions from Homer City due to increased generation and higher energy prices. The project did not make any distributions in 2002 because of outages in the first half of 2002;
- Distribution from the First Hydro project in May 2003. The project did not make any distributions in 2002 due to restrictions under its bond indenture;
- Initial distributions from the Sunrise project upon completion of project financing; and
- Initial partner distributions from the ISAB Energy project.

Partially offset by:

- Lower distributions from the Big 4 projects (in March 2002, SCE paid the Big 4 projects their past due accounts receivable that accrued during the California energy crisis);
- Lower distributions from the Westside projects due to payments of past due accounts receivable from Pacific Gas & Electric in 2002 that accrued during the California energy crisis; and
- 2003 distributions from the Doga and Italian Wind projects represented twelve months of operating cash flow, whereas the initial distributions in 2002 included cash flow from prior years.

Intercompany Tax-Allocation Payments

MEHC 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. These arrangements depend on Edison International continuing to own, directly or indirectly, at least 80% of the voting power of the stock of MEHC and EME and at least 80% of the value of such stock. The arrangements are subject to the terms of tax-allocation and payment agreements among Edison International, MEHC, EME, and other Edison International subsidiaries. The agreements to which MEHC and EME are parties may be terminated by the immediate parent company of MEHC at any time, by notice given before the first day of the first tax year with respect to which the termination is to be effective. However, termination does not relieve any party of any obligations with respect to any tax year beginning prior to the notice. MEHC 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. The right of MEHC and EME to receive and the amount and timing of tax-allocation payments are dependent on the inclusion of MEHC and EME, respectively, in the consolidated income tax returns of Edison International and its subsidiaries, the amount of net operating losses and other tax items of MEHC, EME, its subsidiaries, and other subsidiaries of Edison International and specific procedures regarding allocation of state taxes. MEHC 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's tax losses or the tax losses of EME in the consolidated income tax returns for Edison International and its subsidiaries. MEHC received $61 million and $89 million in tax-allocation payments from Edison International during 2003 and 2002, respectively. EME received $112 million and $395 million in tax-allocation payments from Edison International during 2003 and 2002, respectively. In the future, based on the application of the factors cited above, MEHC and EME may be obligated during periods it generates taxable income to make payments under the tax-allocation agreements.

Dividend Restrictions in Major Financings

General

Each of EME's direct or indirect subsidiaries is organized as a legal entity separate and apart from EME and its other subsidiaries. Assets of EME's subsidiaries are not available to satisfy EME's obligations or the obligations of any of its other subsidiaries. However, unrestricted cash or other assets that are available for distribution may, subject to applicable law and the terms of financing arrangements of the parties, be advanced, loaned, paid as dividends or otherwise distributed or contributed to EME or to its subsidiary holding companies. EME itself has restrictions on its ability to pay dividends under its organizational documents and its corporate credit facility. See "—Financial Ratios—Ability of EME to Pay Dividends."

Set forth below is a description of covenants binding EME's principal subsidiaries that may restrict the ability of those entities to make distributions to EME directly or indirectly through the other holding companies owned by EME.

Edison Mission Midwest Holdings Co. (Illinois Plants)

Edison Mission Midwest Holdings Co. is the borrower under a $1.9 billion credit facility with a group of commercial banks. Amounts outstanding under this facility have been reduced to $693 million as of December 31, 2003. The funds borrowed under this facility were used to fund the acquisition of the Illinois plants and provide working capital to such operations. Midwest Generation, a wholly owned subsidiary of Edison Mission Midwest Holdings, owns or leases and operates the Illinois plants. As part of the original acquisition, Midwest Generation entered into a sale-leaseback transaction for the Collins Station, which Edison Mission Midwest Holdings guarantees, and then subsequently entered into sale-leaseback transactions for the Powerton Station and the Joliet Station in August 2000. In order for Edison Mission Midwest Holdings to make a distribution, Edison Mission Midwest Holdings must be in compliance with the covenants specified in these agreements, including maintaining a minimum credit rating. Because Edison Mission Midwest Holdings' credit rating is below investment grade, no distributions can currently be made by Edison Mission Midwest Holdings to its parent company, and ultimately to EME, at this time. See "—EME's Credit Ratings."

Edison Mission Midwest Holdings must maintain a debt service coverage ratio for the prior twelve-month period of at least 1.50 to 1 as long as the power-purchase agreements with Exelon Generation represent 50% or more of Edison Mission Midwest Holdings' and its subsidiaries' revenue. If the power-purchase agreements with Exelon Generation represent less than 50% of Edison Mission Midwest Holdings' and its subsidiaries' revenue, it must maintain a debt service coverage ratio of at least 1.75 to 1. In addition, Edison Mission Midwest Holdings must maintain a debt-to-capital ratio no greater than 0.60 to 1. Failure to meet the historical debt service coverage ratio and the debt-to-capital ratio are events of default under the credit agreement and Collins lease agreements, which, upon a vote by a majority of the lenders, could cause an acceleration of the due date of the obligations of Edison Mission Midwest Holdings and those associated with the Collins lease. Such an acceleration would result in an event of default under the Powerton and Joliet leases. During the 12 months ended December 31, 2003, the historical debt service coverage ratio was 2.06 to 1 and the debt-to-capital ratio was approximately 0.36 to 1.

There are no restrictions on the ability of Midwest Generation to make payments on the outstanding intercompany loans from its affiliate Edison Mission Overseas Co. (which is also a subsidiary of Edison Mission Midwest Holdings) or to make distributions directly to Edison Mission Midwest Holdings.

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 in the bullet point above) projected for each of the prospective two twelve-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.

During the 12 months ended December 31, 2003, the senior rent service coverage ratio was 4.68 to 1.

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) and bonds ($190 million), 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. During the 12 months ended December 31, 2003, the debt service coverage ratio was 2.16 to 1. 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.

Mission Energy Holdings International

Mission Energy Holdings International owns substantially all of EME's international operations through its subsidiary, MEC International B.V., as more fully described in "—Key Financing Developments."

In order to make a distribution, Mission Energy Holdings International must be in compliance with the covenants specified in the credit agreement, including the following:

- Maintenance of a specified interest coverage ratio. For more information about the interest coverage ratio, see "—Financial Ratios—Mission Energy Holdings International Interest Coverage Ratio."

- Ownership by Edison International, directly or indirectly, of at least 80% of Mission Energy Holdings International.

When measured for the twelve-month period ended December 31, 2003, Mission Energy Holdings International interest coverage ratio was 2.75 to 1.

The following subsidiaries of EME have guaranteed the obligations of Mission Energy Holdings International under its secured credit agreement:

- Midwest Generation EME – a direct subsidiary of EME and an indirect parent of Midwest Generation, the entity that owns the Illinois plants.

- Edison Mission Finance – a direct subsidiary of Edison Mission Holdings and the holder of intercompany receivables due from EME Homer City.

- Mission Del Cielo – a direct subsidiary of EME and an indirect parent of Sunrise Power Company, LLC, the entity that owns the Sunrise project.

- Viejo Energy Company, Anacapa Energy Company, Del Mar Energy Company and Silverado Energy Company – each is a direct subsidiary of EME and a general partner in a partnership that owns each of the Westside projects.

Distributions may be made by any of these entities so long as, neither a default nor event of default exists under the Mission Energy Holdings International secured credit agreement.

First Hydro Holdings

A subsidiary of First Hydro Holdings, First Hydro Finance plc, has issued £400 million of Guaranteed Secured Bonds due in 2021. In order to make a distribution, First Hydro Finance must be in compliance with the covenants specified in its bond indenture, including the following interest coverage ratio:

- As determined on June 30 and December 31 of each year, the ratio of net revenue (which is generally the consolidated profit of First Hydro Holdings and its subsidiaries before tax) to interest payable on the Guaranteed Secured Bonds for the prior twelve-month period (taken as a whole) must be greater than 1.2 to 1.

First Hydro Holdings' interest coverage ratio must also exceed a minimum default threshold included in the Guaranteed Secured Bonds. When measured for the twelve-month period ended December 31, 2003, First Hydro Holdings' interest coverage ratio was 1.6 to 1.

In March 2003, the trustee for the First Hydro bonds sent a letter to First Hydro Finance plc on behalf of a group of First Hydro bondholders, requesting First Hydro Finance to engage in a process to determine whether the termination of the pool system in the United Kingdom during 2001 (replaced with the new electricity trading arrangements, referred to as NETA) was materially prejudicial to the interests of the First Hydro bondholders. If this were the case, it could provide the First Hydro bondholders with an early redemption option. First Hydro Finance does not believe that this event was materially prejudicial to the

First Hydro bondholders and has continued to meet all of its debt service obligations and financial covenants under the bond documentation, including required interest coverage ratio. First Hydro Finance is not aware of further actions being pursued by First Hydro bondholders regarding this matter.

Financial Ratios

MEHC's Interest Coverage Ratio

The following details of MEHC's interest coverage ratio are provided as an aid to understanding the components of the computations that are 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 used 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 is comprised of interest income and expense related to its holding company activities and the consolidated financial information of EME. For a complete discussion of EME's interest coverage ratio and the components included therein, see "—Financial Ratios—EME's Interest Coverage Ratio" below. The following table sets forth MEHC's interest coverage ratio for the years ended December 31, 2003 and 2002:

In millions December 31,	**2003**	2002
Funds Flow from Operations:		
EME	**$ 699**	$ 692
Operating cash flow from unrestricted subsidiaries	**(2)**	(17)
Funds flow from operations of projects sold	**(1)**	2
MEHC	**1**	7
	$ 697	$ 684
Interest Expense:		
EME	**$ 286**	$ 293
EME – affiliate debt	**1**	2
MEHC interest expense	**160**	159
Total interest expense	**$ 447**	$ 454
Interest Coverage Ratio	**1.56**	1.51

The above interest coverage ratio was determined in accordance with the definitions set forth in the bond indenture governing MEHC's senior secured notes and the credit agreement governing the term loan. 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 1.75 to 1 for the immediately preceding four fiscal quarters prior to December 31, 2003 and 2.0 to 1 for periods thereafter.

Ability of EME to Pay Dividends

EME's organizational documents and corporate credit facility contain restrictions on its ability to declare or pay dividends or distributions. These restrictions require the unanimous approval of its Board of Directors, including at least one independent director, before it can declare or pay dividends or distributions, unless either of the following is true:

- EME then has investment grade ratings with respect to its senior unsecured long-term debt and receives rating agency confirmation that the dividend or distribution will not result in a downgrade; or

- such dividends and distributions do not exceed $32.5 million in any fiscal quarter and EME then meets an interest coverage ratio of not less than 2.2 to 1 for the immediately preceding four fiscal quarters.

EME's interest coverage ratio for the twelve months ended December 31, 2003 was 2.45 to 1. See further details of EME's interest coverage ratio below. Accordingly, EME is currently permitted to pay dividends of up to $32.5 million per quarter beginning the first quarter of 2004 under the "ring-fencing" provisions of EME's certificate of incorporation and bylaws and corporate credit facility without the approval of the independent director. EME did not pay or declare any dividends to MEHC during 2003.

EME's Interest Coverage Ratio

The following details of EME's interest coverage ratio (defined as Funds Flow from Operations divided by Interest Expense) are provided as an aid to understanding the components of the computations that are set forth in EME's organizational documents. This information is not intended to measure the financial performance of EME and, accordingly, should not be used in lieu of the financial information set forth in EME's consolidated financial statements. The terms Funds Flow from Operations, Operating Cash Flow and Interest Expense are as defined in EME's organizational documents and are not the same as would be determined in accordance with generally accepted accounting principles.

The following table sets forth the major components of the interest coverage ratio for 2003 and 2002:

In millions December 31,	2003	2002
Funds Flow from Operations:		
Operating Cash Flow(1) from Consolidated Operating Projects(2):		
Illinois plants(3)	**$ 242**	$ 294
Homer City	**153**	51
First Hydro	**(8)**	47
Other consolidated operating projects	**165**	158
Price risk management and energy trading	**11**	16
Distributions from unconsolidated Big 4 projects(4)	**98**	137
Distributions from other unconsolidated operating projects	**178**	120
Interest income	**4**	8
Operating expenses	**(144)**	(139)
Total funds flow from operations	**$ 699**	$ 692
Interest Expense:		
From obligations to unrelated third parties	**$ 172**	$ 178
From notes payable to Midwest Generation	**113**	115
Total interest expense	**$ 285**	$ 293
Interest Coverage Ratio	**2.45**	2.36

(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.

(3) Distribution to EME of funds flow from operations of the Illinois plants is currently restricted. See "—EME's Credit Ratings—Credit Ratings of Edison Mission Midwest Holdings."

(4) The Big 4 projects are comprised of investments in the Kern River project, Midway-Sunset project, Sycamore project and Watson project.

The major factors affecting funds flow from operations during 2003 as compared to 2002, were:

- lower earnings at the Illinois plants primarily due to lower capacity revenue from the reduction in megawatts contracted under the power-purchase agreements;
- repayment of $29 million debt service reserve loan at First Hydro;
- lower distributions from the Big 4 projects (in March 2002, SCE paid the Big 4 projects their past due accounts receivable that accrued during the California energy crisis);
- higher revenue at Homer City due to increased generation and higher energy prices; and
- initial partner distributions from the Sunrise and ISAB Energy projects.

Interest expense decreased by $8 million for the twelve months ended December 31, 2003, compared to the year ended December 31, 2002 due to a lower average debt balance.

The above interest coverage ratio is not determined in accordance with generally accepted accounting principles as reflected in Edison International's Consolidated Statements of Cash Flows. Accordingly, this ratio should not be considered in isolation or as a substitute for cash flows from operating activities or cash flow statement data set forth in Edison International's Consolidated Statement of Cash Flows. This ratio does not measure the liquidity or ability of EME's subsidiaries to meet their debt service obligations. Furthermore, this ratio is not necessarily comparable to other similarly titled captions of other companies due to differences in methods of calculations.

EME Recourse Debt to Recourse Capital Ratio

Under the credit agreement governing its credit facility, EME has agreed to maintain a recourse debt to recourse capital ratio as shown in the table below.

Financial Ratio	Covenant	Actual at December 31, 2003	Description
Recourse Debt to Recourse Capital Ratio	Less than or equal to 67.5%	59.8%	Ratio of (a) senior recourse debt to (b) sum of (i) adjusted shareholder's equity as defined in the credit agreement, *plus* (ii) senior recourse debt

The recourse debt to recourse capital ratio of EME at December 31, 2003 and 2002 was calculated as follows:

In millions December 31,	2003	2002
Recourse Debt(1)		
Corporate Credit Facilities	**$ —**	$ 140
Senior Notes	**1,600**	1,600
Guarantee of termination value of Powerton/Joliet operating leases	**1,470**	1,452
Coal and Capex Facility	**29**	182
Other	**—**	30
Total Recourse Debt to EME	**$ 3,099**	$ 3,404
Adjusted Shareholder's Equity(2)	**$ 2,085**	$ 2,066
Recourse Capital(3)	**$ 5,184**	$ 5,470
Recourse Debt to Recourse Capital Ratio	**59.8%**	62.2%

(1) Recourse debt means senior direct obligations of EME or obligations related to indebtedness or rental expenses of one of its subsidiaries for which EME has provided a guarantee.

(2) Adjusted shareholder's equity is defined as the sum of total shareholder's equity and equity preferred securities, less changes in accumulated other comprehensive gain or loss after December 31, 1999.

(3) Recourse capital is defined as the sum of adjusted shareholder's equity and recourse debt.

EME's indirect subsidiary, Midwest Generation, reported in its second quarter report on Form 10-Q an asset impairment charge of $475 million, after tax, related to the 2,698 MW gas-fired Collins Station. The impairment charge resulted from a write-down of the book value of capitalized assets related to the Collins Station from $858 million to an estimated fair market value of $78 million. The impairment charge by Midwest Generation is not reflected in the operating results of EME because the lease related to the Collins Station is treated in EME's financial statements as an operating lease and not as an asset and, therefore, is not subject to impairment for accounting purposes. See "—Key Financing Developments—EME's Subsidiary Financing Plans—Agreement in Principle to Terminate the Collins Station Lease" for further discussion of the plan to replace EME's corporate credit facility with a new secured credit facility.

Mission Energy Holdings International Interest Coverage Ratio

Under the credit agreement governing its term loan (see "—Dividend Restrictions in Major Financings—Mission Energy Holdings International"), Mission Energy Holdings International has agreed to a minimum interest coverage ratio of 1.30 to 1 beginning March 2004 for the trailing twelve month period.

The following table sets forth the major components of the interest coverage ratio for the twelve months ended December 31, 2003 on a pro forma basis assuming the term loan had been in existence at the beginning of 2003:

	2003		
In millions	Actual	Pro Forma Adjustment[2]	Pro Forma
Funds Flow from Operations			
Historical distributions from international projects[1]	$ 158	$ —	$ 158
Other fees and cash payments considered distributions under the term loan	20	—	20
Administrative and general expenses	(2)	—	(2)
Total Flow of Funds from Operations	$ 176	$ —	$ 176
Term Loan Interest Expense	$ 4	$ 60	$ 64
Interest Coverage Ratio			2.75

(1) See "—EME's Liquidity as a Holding Company—Historical Distributions Received By EME."

(2) The pro forma adjustment assumes the $800 million loan was outstanding at the beginning of 2003. Pro forma interest expense was calculated using the interest rate floor of 7% plus amortization of deferred financing costs.

The above details of Mission Energy Holdings International's interest coverage ratio are provided as an aid to understanding the components of the computations that are set forth in the term loan credit agreement. The terms Funds Flow from Operations and Interest Expense are as defined in the term loan and are not the same as would be determined in accordance with generally accepted accounting principles.

Summarized combined financial information (unaudited) of Mission Energy Holdings International, Inc. and its Subsidiaries and Edison Mission Project Co. is set forth below:

December 31,	**2003**	2002	2001
Revenue	**$1,526**	$1,148	$ 835
Expenses	**1,410**	1,112	2,003
Net income (loss)	**$ 116**	$ 36	$(1,168)

December 31,	**2003**	2002
Current assets	**$ 621**	$ 473
Noncurrent assets	**6,723**	5,260
Total assets	**$7,344**	$5,733
Current liabilities	**$ 580**	$ 470
Noncurrent liabilities	**4,994**	3,154
Minority interest	**746**	652
Preferred security	—	131
Equity	**1,024**	1,326
Total liabilities and equity	**$7,344**	$5,733

The majority of noncurrent liabilities are comprised of project financing arrangements that are nonrecourse to EME.

MEHC AND EME: MARKET RISK EXPOSURES

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 and fuel prices, emission allowances, transmission rights, interest rates and foreign currency exchange rates. EME manages these risks in part by using derivative financial instruments in accordance with established policies and procedures. See "MEHC and EME: Management Overview," "MEHC and EME: Liquidity—EME's Credit Ratings" and "Critical Accounting Policies" for a discussion of market developments and their impact on EME's credit and the credit of its counterparties.

Commodity Price Risk

EME's merchant power plants and energy trading activities expose EME to commodity price risks. Commodity price risks are actively monitored to ensure compliance with EME's risk management policies. Policies are in place which define risk tolerances for each EME regional business unit. Procedures exist which allow for monitoring of all commitments and positions with regular reviews by a risk management committee. In order to provide more predictable earnings and cash flow, EME may hedge a portion of the electric output of its merchant plants, the output of which is not committed to be sold under long-term contracts. When appropriate, EME manages the spread between electric prices and fuel prices, and uses forward contracts, swaps, futures, or options contracts to achieve those objectives. There is no assurance that contracts to hedge changes in market prices will be effective.

EME's revenue and results of operations of its merchant power plants will depend upon prevailing market prices for capacity, energy, ancillary services, fuel oil, coal and natural gas and associated transportation costs and emission credits 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;
- the cost 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.

EME performs a "value at risk" analysis in its daily business to 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. Despite this, there can be no assurance that all risks have been accurately identified, measured and/or mitigated.

Electric power generated at EME's domestic 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, in the case of the Homer City facilities, to the PJM and/or the New York Independent System Operator (NYISO). 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.

Illinois Plants

Energy power generated at the Illinois plants has historically been sold under three power-purchase agreements between EME's wholly owned subsidiary, Midwest Generation, and Exelon Generation Company, in which Exelon Generation purchases capacity and has the right to purchase energy generated by the Illinois plants. The power-purchase agreements, which began on December 15, 1999 and expire in December 2004, provide for capacity and energy payments. Exelon Generation is 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 capacity payments provide the Illinois plants revenue for fixed charges, and the energy payments compensate the Illinois plants for all, or a portion of, variable costs of production.

Approximately 65% of the energy and capacity sales from the Illinois plants in 2003 were to Exelon Generation under the power-purchase agreements. As a result of notices given in 2003, Midwest Generation's reliance on sales into the wholesale market will increase in 2004 from 2003. As discussed in detail below, 3,859 MW of Midwest Generation's generating capacity remains subject to power-purchase agreements with Exelon Generation in 2004. 2004 is the final contract year under these power-purchase agreements.

In June 2003, Exelon Generation exercised its option to contract 687 MW of capacity and the associated energy output (out of a possible total of 1,265 MW subject to option) during 2004 from Midwest Generation's coal-fired units in accordance with the terms of the existing power-purchase agreement related to Midwest Generation's coal-fired generation units. As a result, 578 MW of capacity at the Crawford Unit 7, Waukegan Unit 6 and Will County Unit 3 is no longer subject to the power-purchase agreement beginning January 1, 2004. For 2004, Exelon Generation will have 2,383 MW of capacity related to its coal-fired generation units under contract with Midwest Generation.

In October 2003, Exelon Generation exercised its option to retain under a power-purchase agreement for calendar year 2004 the 1,084 MW of capacity and energy from Midwest Generation's Collins Station. Exelon Generation also exercised its option to release from a related power-purchase agreement 302 MW of capacity and energy (out of a possible total of 694 MW subject to the option) from Midwest Generation's natural gas and oil-fired peaking units, thereby retaining under that contract 392 MW of the capacity and energy of such units for calendar year 2004.

The energy and capacity from any units which are not subject to one of the power-purchase agreements with Exelon Generation will be 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 a term of two years or less. Thus, EME is subject to market risks related to the price of energy and capacity described above. EME expects that capacity prices for merchant energy sales will, in the near term, be negligible in comparison to those Midwest Generation currently receives under its existing agreements with Exelon Generation (the possibility of minimal revenue is due to the current oversupply conditions in this marketplace). EME further expects that the lower revenue resulting from this difference will be offset in part by energy prices, which EME believes will, in the near term, be higher for merchant energy sales than those Midwest Generation currently receives under its existing 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.

During 2004, the primary markets available to Midwest Generation for wholesale sales of electricity from the Illinois plants are expected to be direct "wholesale customers" and broker-arranged "over-the-counter customers." The most liquid over-the-counter markets in the Midwest region are sales into the control area of Cinergy, referred to as "Into Cinergy," and, to a lesser extent, sales into the control areas of ComEd and AEP, referred to as "Into ComEd" and "Into AEP," respectively. "Into Cinergy," "Into ComEd" and "Into AEP" are bilateral markets for the sale or purchase of electrical energy for future delivery. 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.

The following table depicts the historical average market prices for energy per megawatt-hour "Into ComEd" and "Into Cinergy" for 2003. Due to geographic proximity, "Into ComEd" has been the primary market for Midwest Generation. Market prices are included for "Into Cinergy" for illustrative purposes.

	2003 Into ComEd*			**2003 Into Cinergy***		
Historical Energy Prices	On-Peak(1)	Off-Peak(1)	24-Hr	On-Peak(1)	Off-Peak(1)	24-Hr
January	$ 42.62	$ 20.77	$ 30.81	$ 44.38	$ 21.46	$ 32.00
February	54.43	23.13	37.81	58.09	24.00	39.99
March	47.96	22.35	33.92	51.68	24.34	36.69
April	39.12	15.05	26.67	41.12	15.96	28.11
May	29.59	10.80	19.57	28.89	10.68	19.18
June	30.27	8.17	19.22	28.41	8.31	18.36
July	41.63	12.81	27.07	39.15	11.72	25.29
August	48.75	13.84	29.61	48.80	13.53	29.46
September	27.44	9.85	17.67	28.07	10.36	18.23
October	24.47	12.01	18.17	24.95	13.51	19.17
November	24.78	14.32	18.51	23.66	14.61	18.23
December	34.72	12.49	22.56	34.71	14.73	23.73
Yearly Average	$ 37.15	$ 14.63	$ 25.13	$ 37.66	$ 15.27	$ 25.70

(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 both "Into ComEd" and "Into Cinergy" delivery points.

The following table sets forth the forward month-end market prices for energy per megawatt-hour for the calendar year 2004 and calendar year 2005 "strips," which are defined as energy purchases for the entire calendar year, as quoted for sales "Into ComEd" and "Into Cinergy" during 2003. These forward prices will continue to fluctuate as a result of a number of factors, including gas prices, electricity demand, which is also affected by economic growth, 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.

Forward Energy Prices	Into ComEd*					
	2004			2005		
Date	On-Peak(1)	Off-Peak(1)	24-Hr	On-Peak(1)	Off-Peak(1)	24-Hr
January 31, 2003	$45.50	$ 18.75	$30.83	$40.75	$ 19.50	$29.10
February 28, 2003	41.15	18.25	28.78	39.75	19.00	28.88
March 31, 2003	37.00	16.75	26.76	38.75	17.75	28.14
April 30, 2003	34.39	16.25	25.12	36.75	17.25	26.35
May 31, 2003	31.09	15.75	22.35	33.50	16.75	24.31
June 30, 2003	34.17	17.25	25.52	36.00	18.25	26.93
July 31, 2003	44.72	20.00	31.16	45.50	21.00	31.54
August 30, 2003	43.72	19.00	30.70	44.50	20.00	32.12
September 30, 2003	31.33	15.75	23.02	31.00	16.75	23.40
October 31, 2003	27.17	14.75	20.36	28.00	15.75	21.28
November 27, 2003	28.17	14.75	21.01	29.00	15.75	21.93
December 31, 2003	30.17	15.25	22.63	31.00	16.25	22.91

Forward Energy Prices	Into Cinergy*					
	2004			2005		
Date	On-Peak(1)	Off-Peak(1)	24-Hr	On-Peak(1)	Off-Peak(1)	24-Hr
January 31, 2003	$45.00	$ 20.00	$31.29	$41.57	$ 21.38	$30.50
February 28, 2003	41.53	19.70	29.73	40.56	20.88	30.25
March 31, 2003	38.86	18.57	28.60	38.95	19.63	29.18
April 30, 2003	36.80	18.07	27.22	36.95	19.13	27.44
May 31, 2003	32.95	17.98	24.42	34.18	18.43	25.54
June 30, 2003	36.68	18.98	27.63	37.74	19.93	28.64
July 31, 2003	46.15	21.88	32.84	47.34	22.88	33.40
August 30, 2003	45.15	20.88	32.36	46.34	21.88	33.98
September 30, 2003	33.25	17.36	24.77	33.63	18.44	25.52
October 31, 2003	29.62	17.08	22.74	30.12	17.68	23.29
November 27, 2003	30.62	17.08	23.40	31.11	17.68	23.95
December 31, 2003	32.62	17.58	25.02	33.11	18.18	24.92

(1) On-peak refers to the hours of the day between 6:00 a.m. and 10:00 p.m. Monday through Friday, excluding 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 both "Into ComEd" and "Into Cinergy" delivery points.

Midwest Generation intends to hedge a portion of its merchant portfolio risk through Edison Mission Marketing & Trading. To the extent it does not do so, the unhedged portion will be subject to the risks and benefits of spot market price movements. The extent to which Midwest Generation will hedge its market price risk through forward over-the-counter sales depends on several factors. First, Midwest Generation will evaluate over-the-counter market prices to determine whether sales at forward market prices are sufficiently attractive compared to assuming the risk associated with spot market sales. Second, Midwest Generation's ability to enter into hedging transactions will depend upon its and Edison Mission Marketing & Trading's credit capacity and upon the over-the-counter forward sales markets having sufficient liquidity to enable Midwest Generation to identify counterparties who are able and willing to enter into hedging transactions with it. Due to factors beyond Midwest Generation's control, market liquidity has decreased significantly since the beginning of 2002 and a number of formerly significant trading parties have completely withdrawn from the market or substantially reduced their trading activities, resulting in far fewer creditworthy participants in these electricity markets. See "—Credit Risk," below.

In addition to the prevailing market prices, Midwest Generation's ability to derive profits from the sale of electricity from the released units will be affected by the cost of production, including costs incurred to comply with environmental regulations. The costs of production of the released units vary and, accordingly, depending on market conditions, the amount of generation that will be sold from the released units is expected to vary from unit to unit. In this regard, Midwest Generation suspended operations of Will County Units 1 and 2 and Collins Station Units 4 and 5 at the end of 2002 pending improvement in market conditions.

Under PJM's proposed revisions to the PJM Tariff, the integration of ComEd into PJM could result in market power mitigation measures being imposed on future power sales by Midwest Generation in the NICA energy and capacity markets. In addition, power produced by Midwest Generation not under contract with Exelon Generation is sold using transmission obtained from ComEd under its open-access tariff filed with the FERC, and the application of the PJM Tariff to ComEd's transmission system could also affect the rates, terms and conditions of transmission service received by Midwest Generation. EME and Midwest Generation have contested the appropriateness of ComEd joining PJM on an "islanded" basis and the imposition of market power mitigation measures proposed by PJM for the NICA energy and capacity markets. EME is unable to predict the outcome of these efforts, the effect of integration of ComEd into PJM on an "islanded" basis, the effect of integration of AEP into PJM, or any final integration configuration for PJM on the markets into which Midwest Generation sells its power.

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.

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. 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 average market prices per megawatt-hour in PJM during the past three years:

	24-Hour PJM Historical Energy Prices*		
	2003	2002	2001
January	$ 36.56	$ 20.52	$ 36.66
February	46.13	20.62	29.53
March	46.85	24.27	35.05
April	35.35	25.68	34.58
May	32.29	21.98	28.64
June	27.26	24.98	26.61
July	36.55	30.01	30.21
August	39.27	30.40	43.99
September	28.71	29.00	22.44
October	26.96	27.64	21.95
November	29.17	25.18	19.58
December	35.89	27.33	19.66
Yearly Average	$ 35.08	$ 25.63	$ 29.07

* 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 2003 were higher than the average historical market prices during 2002, although in September and October of each year the power prices were similar. 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, 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.

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 forecasted generation 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 delivery to a collection of delivery points known as 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, has the effect of raising prices at those delivery points affected by transmission congestion. During the past 12 months, an increase in transmission congestion at delivery points east of the Homer City facilities has resulted in prices at the PJM West Hub (which includes delivery points east of the Homer City facilities) being higher than those at the Homer City busbar. Thus, while forward prices at PJM West Hub have historically been higher than the prices at the Homer City busbar by less than 5%, increased congestion during the last 12 months at delivery points east of the Homer City facilities has resulted in prices at PJM West Hub being on average 6% higher than those at the Homer City busbar.

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 fixed transmission rights in PJM, and may continue to do so in the future. A fixed transmission right provides the holder with a financial instrument 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 fixed 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 per megawatt-hour for the calendar 2004 and 2005 "strips," which are defined as energy purchases for the entire calendar year, as quoted for sales into the PJM West Hub during 2003:

	24-Hour PJM West Forward Energy Prices*	
	2004	**2005**
January 31, 2003	$ 43.03	$ 37.75
February 28, 2003	42.88	38.18
March 31, 2003	39.57	33.88
April 30, 2003	34.45	32.85
May 31, 2003	30.20	30.60
June 30, 2003	34.23	33.45
July 31, 2003	41.67	39.77
August 30, 2003	42.31	41.61
September 30, 2003	30.20	30.62
October 31, 2003	29.02	28.51
November 27, 2003	29.49	28.74
December 31, 2003	30.18	28.51

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

The ability of EME's subsidiary, EME Homer City, to make payments under the long-term lease entered into as part of the sale-leaseback transaction discussed under "Off-Balance Sheet Transactions—EME's Off-Balance Sheet Transactions—Sale-Leaseback Transactions," depends on revenue generated by the Homer City facilities, which depend in part on the market conditions for the sale of capacity and energy. These market conditions are beyond EME's control.

United Kingdom

The First Hydro plant sells electrical energy and capacity through bilateral contracts of varying terms in the England and Wales wholesale electricity market.

The electricity trading arrangements introduced in March 2001 provide, among other things, for the establishment of a range of voluntary short-term power exchanges and brokered markets operating from a year or more in advance to 1 hour prior to the delivery or receipt of power. In the final hour after the notification of all contracts, the system operator can accept bids and offers in the Balancing Mechanism to balance generation and demand and resolve any transmission constraints. There is a mandatory settlement process for recovering imbalances between contracted and metered volumes with strong incentives for being in balance, and a Balancing and Settlement Code Panel to oversee governance of the Balancing Mechanism. The system operator can also purchase system reserve and response services to maintain the quality of the electrical supply directly from generators (generally referred to as "ancillary services"). Ancillary services contracts typically run for up to a year and can consist of both fixed amounts and variable amounts represented by prices for services that are only paid for when actually called upon by the grid operator. A key feature of the trading arrangements is the requirement for firm physical delivery, which means that a generator must deliver, and a consumer must take delivery of, its net contracted positions or pay for any energy imbalance at the imbalance prices calculated by the system operator based on the prices of bids and offers accepted in the Balancing Mechanism. This provides an incentive for parties to contract in advance and for the development of forwards and futures markets. Under these arrangements, there has been an increased emphasis on credit quality, including the need for parent company guarantees or letters of credit for companies below investment grade.

The wholesale price of electricity has decreased significantly in recent years. The reduction has been driven principally by surplus generating capacity and increased competition. During 2003, prices were more volatile. There was further downward pressure on wholesale prices in the first part of the year followed by some recovery during the summer in prices and in the peak/off peak differentials for the upcoming winter period. That recovery tailed off towards the end of the year with a considerable narrowing in the peak/off peak differentials. Compliance with First Hydro's bond financing documents is subject to market conditions for electric energy and ancillary services, which are beyond First Hydro's control.

Australia

The Loy Yang B plant and the Valley Power Peaker project sell electrical energy through a centralized electricity pool, which provides for a system of generator bidding, central dispatch and a settlements system based on a clearing market for each half-hour of every day. The National Electricity Market Management Company, operator and administrator of the pool, determines a spot price each half-hour. To mitigate exposure to price volatility of the electricity traded into the pool, the Loy Yang B plant and the Valley Power Peaker project have entered into a number of financial hedges. The State Hedge agreement with the State Electricity Commission of Victoria is a long-term contractual arrangement based upon a fixed price commencing May 8, 1997 and terminating October 31, 2016. The State Government of Victoria, Australia guarantees the State Electricity Commission of Victoria's obligations under the State Hedge. From January 2003 to July 2014, approximately 77% of the Loy Yang B plant output sold is hedged under the State Hedge. From August 2014 to October 2016, approximately 56% of the Loy Yang B plant output sold is hedged under the State Hedge. Additionally, the Loy Yang B plant and the Valley Power Peaker project have entered into a number of derivative contracts to mitigate further against price volatility inherent in the electricity pool. These contracts consist of fixed forward electricity contracts and/or cap contracts that expire on various dates through December 31, 2006.

New Zealand

Contact Energy generates about 30% of New Zealand's electricity and is the largest retailer of natural gas and electricity in New Zealand. A substantial portion of Contact Energy's generation output is matched with the demand of its retail electricity customers or sold through forward contracts with other wholesale electricity counterparties. The forward contracts and/or option contracts have varying terms that expire on various dates through June 30, 2010, although the majority of the forward contracts are short term (less than two years).

The New Zealand government released a government policy statement in December 2001, which called for the industry to rationalize the three existing industry codes, form a single governance structure and address transmission investment and pricing issues. The industry was unable to agree on new rules to facilitate the government policy statement.

Subsequently, in May 2003, the New Zealand government announced that it would establish a new governance body to be known as the Electricity Commission along with a set of rules to govern the market. The Electricity Governance Regulations and Rules were finalized in 2003. The Regulations came into force on January 16, 2004, and the Rules came into force during February and March of 2004.

During the winter of 2003, wholesale electricity prices increased significantly in response to lower hydro inflows, higher demand and anticipated restrictions on the availability of thermal fuel. The New Zealand government responded by calling for nationwide energy savings in the order of 10%. Recent rains and anticipated snowmelt have largely improved the earlier conditions with wholesale electricity prices returning to more normal levels. The national energy savings program ended in July 2003.

However, there are ongoing concerns that new investment in generation has not been forthcoming and that there is a significant risk that similar events may arise in subsequent years. As a consequence the New Zealand government announced that it will take the following steps:

- the Electricity Commission will be given responsibility for managing dry year reserve, expected to be through the procurement of reserve capacity; and

- the Electricity Commission will be given additional reserve powers ranging from information disclosure to imposing hedge obligations on major users and generators.

Submissions have been made in respect of the policy, which are currently being considered by the New Zealand government. Final details of the policy were released in September 2003, and it is expected that legislation will be passed in 2004.

The New Zealand government announced in July 2003 that it would purchase a new 155 MW power plant before winter 2004 to increase electricity security. The plant is to be situated at Whirinaki, Hawkes Bay. The Electricity Commission will be required to include this plant in its portfolio of reserve energy. The Whirinaki plant will be located on a site leased to the government from Contact Energy and will also be operated under contract by Contact Energy.

Credit Risk

In conducting EME's price risk management and trading activities, EME contracts with a number of utilities, energy companies and financial institutions, collectively referred to as counterparties. Due to factors beyond EME's control, a number of formerly significant trading parties have completely withdrawn from the market or substantially reduced their trading activities since the beginning of 2002, thereby potentially increasing exposure to the remaining counterparties. The reduction in the credit quality of traditional trading parties increases EME's credit risk. In addition, the decrease in market liquidity may require EME to rely more heavily on wholesale electricity sales to wholesale customer markets which may also increase EME's credit risk. In the event a counterparty were to default on its trade obligation, EME would be exposed to the risk of possible loss associated with reselling the contracted product at a lower price if the nonperforming counterparty were unable to pay the resulting liquidated damages owed to EME. Further, EME would be exposed to the risk of nonpayment 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 by the sum of: (i) 60 days of accounts receivable, (ii) current fair value of open positions, and (iii) a credit value at risk. 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, 2003, the credit ratings of EME's counterparties were as follows:

In millions December 31,	**2003**
S&P Credit Rating	
A or higher	**$ 101**
A-	**26**
BBB+	**82**
BBB	**57**
BBB-	**14**
Below investment grade	**—**
Total	**$ 280**

Exelon Generation accounted for 22%, 40% and 42% of nonutility power generation revenue in 2003, 2002 and 2001, respectively. EME expects the percentage to be less in 2004 because a smaller number of plants will be subject to contracts with Exelon Generation. See "—Commodity Price Risk—Illinois Plants." Any failure of Exelon Generation to make payments under the power-purchase agreements could adversely affect EME's results of operations and financial condition.

EME's contracted power plants and the 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. During 2002, the counterparty to the Lakeland project power-purchase agreement filed a notice of disclaimer of its power-purchase agreement with the project, ultimately resulting in an impairment of $77 million, after tax. See "Results of Operations and Historical Cash Flow Analysis—Results of Operations—Earnings (Loss) from Discontinued Operations."

Interest Rate Risk

MEHC has mitigated the risk of interest rate fluctuations associated with the $385 million term loan due 2006 by arranging for variable rate financing with interest rate swaps. Swaps covering interest accrued from January 2, 2002 to January 2, 2003 expired on January 2, 2003. Subsequently, MEHC entered into swaps that cover interest accrued from January 2, 2003 to July 2, 2004 and April 2, 2003 to July 2, 2004. A 10% fluctuation in market interest rates at December 31, 2003 would change the fair value of MEHC's interest rate swaps by approximately $237 thousand.

The fair market value of MEHC's (stand alone) total long-term obligations was $1.2 billion at December 31, 2003, compared to the carrying value of $1.2 billion. A 10% increase in market interest rates at December 31, 2003 would result in a decrease in the fair value of total long-term obligations by approximately $34 million. A 10% decrease in market interest rates at December 31, 2003 would result in an increase in the fair value of total long-term obligations by approximately $36 million.

Interest rate changes affect the cost of capital needed to operate EME's projects and the lease costs under the Collins Station lease. EME has mitigated 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. Interest expense included $60 million, $34 million and $17 million of additional interest expense for the years 2003, 2002 and 2001, respectively, as a result of interest rate hedging mechanisms. EME has entered into several interest rate swap agreements under which the maturity date of the swaps occurs prior to the final maturity of the underlying debt. A 10% increase in market interest rates at December 31, 2003 would result in a $14 million increase in the fair value of EME's interest rate hedge agreements. A 10% decrease in market interest rates at December 31, 2003 would result in a $15 million decrease in the fair value of EME's interest rate hedge agreements. Based on the amount of variable rate long-term debt for which EME has not entered into interest rate hedge agreements and the amount of the Collins lease at December 31, 2003, a 100 basis point change in interest rates at December 31, 2003 would increase or decrease 2004 income before taxes by approximately $23 million.

EME had short-term obligations of $52 million at December 31, 2003, consisting of promissory notes related to Contact Energy. The fair values of these obligations approximated their carrying values at December 31, 2003, and would not have been materially affected by changes in market interest rates. 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 obligations (including current portion) was $7.3 billion at December 31, 2003, compared to the carrying value of $7.4 billion. A 10% increase in market interest rates at December 31, 2003 would result in a decrease in the fair value of total long-term obligations by approximately $159 million. A 10% decrease in market interest rates at December 31, 2003 would result in an increase in the fair value of total long-term obligations by approximately $172 million.

Foreign Exchange Rate Risk

Fluctuations in foreign currency exchange rates can affect, on a United States dollar equivalent basis, the amount of EME's equity contributions to, and distributions from, its international projects. At times, EME has hedged a portion of its current exposure to fluctuations in foreign exchange rates through financial derivatives, offsetting obligations denominated in foreign currencies, and indexing underlying project agreements to United States dollars or other indices reasonably expected to correlate with foreign exchange movements. In addition, EME has used statistical forecasting techniques to help assess foreign exchange risk and the probabilities of various outcomes. EME cannot provide assurances, however, that fluctuations in exchange rates will be fully offset by hedges or that currency movements and the relationship between certain macroeconomic variables will behave in a manner that is consistent with historical or forecasted relationships.

The First Hydro plant in the United Kingdom and the plants in Australia have been financed in their local currencies, pounds sterling and Australian dollars, respectively, thus hedging the majority of their acquisition costs against foreign exchange fluctuations. Furthermore, EME has evaluated the return on the remaining equity portion of these investments with regard to the likelihood of various foreign exchange scenarios. These analyses use market-derived volatilities, statistical correlations between specified variables, and long-term forecasts to predict ranges of expected returns.

During 2003, foreign currencies in Australia, New Zealand and the United Kingdom increased in value compared to the United States dollar by 34%, 25% and 11%, respectively (determined by the change in the exchange rates from December 31, 2002 to December 31, 2003). The increase in value of these currencies was the primary reason for the foreign currency translation gain of $154 million during 2003. A 10% increase in the exchange rates at December 31, 2003 would result in foreign currency translation gains of $329 million. A 10% decrease in the exchange rates at December 31, 2003 would result in foreign currency translation gains of $40 million.

Contact Energy enters into foreign currency forward exchange contracts to hedge identifiable foreign currency commitments associated with transactions in the ordinary course of business. The contracts are primarily in Australian and United States dollars with varying maturities through February 2006. At December 31, 2003, the outstanding notional amount of the contracts totaled $29 million and the fair value of the contracts totaled $(2) million. A 10% decrease in the exchange rates at December 31, 2003 would result in a $2 million increase in the fair value of the contracts.

In addition, Contact Energy enters into cross currency interest rate swap contracts in the ordinary course of business. These cross currency swap contracts involve swapping fixed and floating-rate United States and Australian dollar loans into floating-rate New Zealand dollar loans with varying maturities through April 2018.

EME will continue to monitor its foreign exchange exposure and analyze the effectiveness and efficiency of hedging strategies in the future.

Fair Value of Financial Instruments

Non-Trading Derivative Financial Instruments

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

In millions December 31,	**2003**	2002
Derivatives:		
Interest rate:		
Interest rate swap/cap agreements	**$ (34)**	$ (56)
Interest rate options	**(1)**	(2)
Commodity price:		
Electricity	**(126)**	(100)
Foreign currency forward exchange agreements	**(2)**	—
Cross currency interest rate swaps	**(91)**	(2)

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% adverse price change at December 31, 2003 is $(143) 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, 2003):

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	$ (3)	$ (4)	$ 1	$ —	$ —
Prices based on models and other valuation methods	(123)	19	8	(13)	(137)
Total	$(126)	$ 15	$ 9	$ (13)	$(137)

The fair value of the electricity rate swap agreements (included under commodity price-electricity) entered into by the Loy Yang B plant and the First Hydro plant has been estimated by discounting the future net cash flows resulting from the difference between the average aggregate contract price per MW and a forecasted market price per MW multiplied by the number of MW remaining to be sold under the contract.

Energy Trading Derivative Financial Instruments

EME's risk management and trading operations are conducted by its subsidiary, Edison Mission Marketing & Trading. As a result of a number of industry and credit-related factors, Edison Mission Marketing & Trading has minimized its price risk management and trading activities not related to EME's power plants or investments in energy projects. To the extent Edison Mission Marketing & Trading engages in trading activities, Edison Mission Marketing & Trading seeks to manage price risk and to create stability of future income by selling electricity in the forward markets and, to a lesser degree, to generate profit from price volatility of electricity and fuels by buying and selling these commodities in wholesale markets. EME generally balances forward sales and purchase contracts and manages its exposure through a value at risk analysis as described under "—Commodity Price Risk."

The fair value of the commodity financial instruments related to energy trading activities as of December 31, 2003 and December 31, 2002, are set forth below:

	December 31, 2003		December 31, 2002	
In millions	Assets	Liabilities	Assets	Liabilities
Electricity	**$104**	**$ 11**	$109	$ 15
Other	**—**	**1**	—	2
Total	**$104**	**$ 12**	$109	$ 17

The fair value of trading contracts that would be expected after a 10% adverse price change at December 31, 2003 are shown in the table below:

In millions	Fair Value	Fair Value After 10% Adverse Price Change
Electricity	$ 93	$ 94
Other	(1)	(1)
Total	$ 92	$ 93

The change in the fair value of trading contracts for the year ended December 31, 2003, was as follows:

In millions	Fair Value
Fair value of trading contracts at January 1, 2003	$ 92
Net gains from energy trading activities	40
Amount realized from energy trading activities	(40)
Fair value of trading contracts at December 31, 2003	$ 92

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 nonrecourse 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 (as of December 31, 2003):

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	$ —	$ —	$ —	$ —	$ —
Prices based on models and other valuation methods	92	(3)	5	9	81
Total	$ 92	$ (3)	$ 5	$ 9	$ 81

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 $2.6 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 $71 million invested in affordable housing projects 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 currently concerned about several matters. First, the Internal Revenue Service (IRS) is expected to challenge Edison Capital's tax position in certain types of cross-border, leveraged leases as further described in "Other Developments—Federal Income Taxes." Second, Edison Capital's investments in three aircraft leased to American Airlines may be impacted by economic conditions affecting American Airlines. Third, Edison Capital's receipt of payments under a lease of a domestic electric generation asset may be indirectly impacted by the regulatory and economic conditions affecting the utility purchasing power from that asset. The matters are discussed below.

Edison Capital is currently pursuing new electric infrastructure investments, including renewable energy, after suspending all new investments since 2001 in order to conserve cash in response to the California energy crisis. Edison Capital is also evaluating whether to pursue new affordable housing investments.

EDISON CAPITAL: LIQUIDITY

Since 2001, as a result of the California energy crisis, Edison Capital reduced debt and accumulated cash, which resulted in a significant de-leveraging of Edison Capital. In light of Edison Capital's improved liquidity, Edison Capital made a $225 million dividend payment to Edison International while maintaining a cash and cash equivalent balance of $354 million at December 31, 2003. The improvement in liquidity is primarily from Edison International's utilization of tax benefits that had been delayed in previous years because of the California energy crisis. 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. To the extent that certain funding conditions are satisfied, Edison Capital has unfunded current and long-term commitments of $68 million for energy and infrastructure investments. In 2004, Edison Capital is evaluating its capital structure, the potential for additional borrowings and potentially making dividend payments to Edison International.

At December 31, 2003, 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 and EME: Liquidity—EME's Liquidity as a Holding Company—Intercompany Tax-Allocation Payments" for additional information regarding these arrangements. Edison Capital received $141 million in tax-allocation payments from Edison International during 2003. The amount received is net of payments made to Edison International. In the future, Edison Capital may be obligated to make payments under the tax-allocation agreements. (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

Changes in interest rates can have an impact on Edison Capital's results of operations. Edison Capital is exposed to changes in interest rates primarily as a result of its borrowing and investing activities. The nature and amount of Edison Capital's long- and short-term debt can be expected to vary as a result of future business requirements and other factors.

Edison Capital believes that the fair market value of its fixed rate long-term debt is subject to interest rate risk. At December 31, 2003, a 10% increase in market interest rates would have resulted in a $6 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 a $7 million increase in the fair market value of Edison Capital's long-term debt.

Foreign Currency Exchange Risk

At December 31, 2003, Edison Capital's outstanding debt included £75 million and the cash equivalents balance included £75 million (both approximately $134 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.

Credit and Performance Risk

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

At December 31, 2003, Edison Capital has $42 million invested for an 8.5% ownership interest in a 1,500 MW gas-fired co-generation power plant leased to Midland Cogeneration Ventures. Midland Cogeneration Ventures sells electricity to Consumers Energy under a long-term power-purchase agreement. The energy and capacity prices paid to Midland Cogeneration Ventures under the power-purchase agreement are based on the avoided cost of a coal plant established by the Michigan Public Services Commission. However, the cost of gas that Midland Cogeneration Ventures must purchase to operate the plant has increased significantly in the last several years.

Consumers Energy is seeking Michigan Public Services Commission's authorization of a resource conservation plan designed to provide natural gas conservation that would revise dispatch procedures applicable to the power purchased under the power-purchase agreement. Edison Capital is currently evaluating the impact that the resource conservation plan might have on Midland Cogeneration Ventures and its ability to make lease payments to Edison Capital. At December 31, 2003, Midland Cogeneration Ventures was current on its lease payments to Edison Capital. Midland Cogeneration Ventures also had lease payment reserves of $299 million at January 31, 2004.

Edison Capital has $63 million invested in three aircraft leased to American Airlines. The independent auditors' opinion on the year-end 2002 financial statements of AMR Corporation, parent company of American Airlines, questions AMR Corporation's ability to continue as a going concern. As disclosed in AMR Corporation's Form 10-Q filing for September 30, 2003, there were some improvements made in 2003, such as concessionary agreements with unions and certain other lessors, and reporting operating income of $165 million for the third quarter of 2003. However, significant uncertainty remains and if 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 2004 is $46 million. A restructure of the lease could also result in a loss of some or all of the investment. At December 31, 2003, American Airlines was current in its lease payments to Edison Capital.

EDISON INTERNATIONAL (PARENT)

EDISON INTERNATIONAL (PARENT): LIQUIDITY ISSUES

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 is focused on reducing its parent company debt in 2004, which may further impact Edison International's liquidity.

Edison International (parent)'s 2004 cash requirements primarily consist of:

- $618 million of 6-7/8% notes due September 2004. During January and February 2004, Edison International repurchased approximately $46 million of these notes, leaving a remaining balance of $572 million of notes due in September 2004;
- Interest payments on its long-term notes payable related to the quarterly income debt securities of approximately $67 million;
- General operating expenses; and
- Dividends to common shareholders.

Edison International (parent) expects to meet its continuing obligations through cash and cash equivalents on hand and dividends from its subsidiaries. At December 31, 2003, Edison International (parent) had approximately $1.1 billion of cash and cash equivalents on hand.

Beginning in May 2001, Edison International deferred interest payments in accordance with the terms of its outstanding $825 million quarterly income debt securities, due 2029, issued to affiliates (EIX Trust I and II, which are Delaware business trusts). This interest payment deferral caused a corresponding deferral of distributions on quarterly income preferred securities issued by that affiliate. Interest payments may be deferred for up to 20 consecutive quarters. On December 2, 2003, Edison International made aggregate payments of approximately $205 million, which covered repayment of the deferred distributions, with interest, and payment of the distribution due on November 30, 2003. Edison International has resumed quarterly distributions on the quarterly income debt securities, subject to its rights to begin deferring distributions again in the future at its election. As of December 31, 2003, Edison International deconsolidated EIX Trust I and II, and as a result these securities are now included in long-term debt. See "New Accounting Principles" for further discussion.

On October 16, 2003, Edison International received cash dividends of $945 million from SCE and $225 million from Edison Capital. The receipt of dividends from SCE and Edison Capital, as well as the payment of all deferred amounts on the quarterly income debt securities allowed Edison International to declare a common dividend to its shareholders. On December 11, 2003, the Board of Directors of Edison International declared a 20¢ per share common stock dividend. The $65 million dividend payment was made on January 30, 2004.

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. SCE's 2001 CPUC settlement agreement precluded SCE from declaring or paying dividends or other distributions on its common stock (all of which is held by its parent, Edison International) prior to the date on which SCE had recovered all of its procurement-related obligations, with certain exceptions. SCE fully recovered the PROACT balance during July 2003, and paid a $945 million dividend to Edison International in October 2003 (see further discussion in "SCE: Liquidity Issues"). 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.

MEHC may not pay dividends unless it has an interest coverage ratio of at least 2.0 to 1. At December 31, 2003, its interest coverage ratio was 1.56 to 1. See "MEHC and EME: Liquidity—Financial Ratios—MEHC's Interest Coverage Ratio." MEHC did not declare or pay a dividend in 2003. MEHC's ability to pay dividends is dependent on EME's ability to pay dividends to MEHC. EME and its subsidiaries have certain dividend restrictions as discussed in the "MEHC and EME: Liquidity" section above. EME did not pay or declare a dividend to MEHC in 2003.

Edison International's investment in MEHC, through a wholly owned subsidiary, as of December 31, 2003, was $874 million. MEHC's investment in EME, as of December 31, 2003, was $1.9 billion. MEHC's and EME's independent accountants' audit opinion for the year ended December 31, 2003, contains an explanatory paragraph that indicates the consolidated financial statements have been prepared on the basis that EME will continue as a going concern and that the uncertainty about Edison Mission Midwest Holdings' ability to repay or refinance Edison Mission Midwest Holdings' $693 million of debt due in December 2004 raises substantial doubt about EME's ability to continue as a going concern. Accordingly, the consolidated financial statements do not include any adjustments that might result from the resolution of this uncertainty.

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 $300 million. In October 2003, Edison Capital paid a $225 million cash dividend to Edison International. Edison Capital currently meets the minimum net worth covenant.

EDISON INTERNATIONAL (PARENT): MARKET RISK EXPOSURES

The parent company is exposed to changes in interest rates primarily as a result of its borrowing and investing activities, the proceeds of which are 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.

At December 31, 2003, the fair market value of Edison International (parent)'s 6-7/8% notes due September 2004 was $637 million. A 10% increase/decrease in market interest rates would have resulted in a $1.1 million decrease/increase in the fair market value of the parent company's 6-7/8% notes. At December 31, 2003, the fair market value of Edison International (parent)'s long-term note payable related to the quarterly income debt securities was $830 million. A 10% increase in market interest rates would have resulted in a $68 million decrease in the fair market value of the long-term note payable related to the quarterly income debt securities. A 10% decrease in market interest rates would have resulted in a $78 million increase in the fair market value of the long-term note payable related to the quarterly income debt securities.

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.

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, new accounting principles, commitments and guarantees, 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, 2003, 2002 and 2001, and the relative contributions by its subsidiaries.

In millions, except per share amounts	Earnings (Loss)			Earnings per Share		
Year Ended December 31,	**2003**	2002	2001	**2003**	2002	2001
Earnings (Loss) from Continuing Operations:						
Core Earnings:						
SCE	**$ 872**	$ 748	$ 408	**$ 2.68**	$ 2.30	$ 1.25
EME	**28**	82	113	**0.08**	0.26	0.35
Edison Capital	**57**	33	84	**0.17**	0.10	0.26
MEHC (stand alone)	**(98)**	(94)	(49)	**(0.30)**	(0.29)	(0.15)
Edison International (parent) and other	**(80)**	(114)	(132)	**(0.24)**	(0.35)	(0.41)
Edison International Core Earnings	**779**	655	424	**2.39**	2.02	1.30
SCE implementation of URG decision	—	480	—	—	1.47	—
SCE procurement and generation-related adjustment	—	—	1,978	—	—	6.07
Edison International Consolidated Earnings from Continuing Operations	**779**	1,135	2,402	**2.39**	3.49	7.37
Earnings (Loss) from Discontinued Operations	**51**	(58)	(1,367)	**0.16**	(0.18)	(4.19)
Cumulative Effect of Accounting Change	**(9)**	—	—	**(0.03)**	—	—
Edison International Consolidated	**$ 821**	$ 1,077	$ 1,035	**$ 2.52**	$ 3.31	$ 3.18

Earnings (Loss) from Continuing Operations

Edison International's 2003 earnings from continuing operations were $779 million, or $2.39 per share, compared with earnings of $1.1 billion, or $3.49 per share, in 2002 and earnings of $2.4 billion, or $7.37 per share, in 2001.

2003 vs. 2002

SCE's earnings from continuing operations were $872 million in 2003, compared to $748 million in 2002, excluding the $480 million gain. 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 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.

EME's earnings from continuing operations in 2003 were $28 million compared to $82 million in 2002. The decrease in earnings was primarily due to the asset impairment charge of $150 million, after tax, for Midwest Generation's peaking facilities, a reduction in capacity revenue for the Illinois power plants and a $32 million, after tax, asset impairment charge related to EME's investment in the Brooklyn Navy Yard project, partially offset by higher United States wholesale energy prices, increased generation from the Homer City plant and other net charges in 2002. These net charges, after tax, include write-offs totaling $66 million related to the cancellation of turbine orders, the suspension of the Powerton SCR project, and the impairment of goodwill 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. EME's 2003 earnings included increased profitability from its interest in the Paiton project in Indonesia and its interest in the Sunrise project which commenced operation of Phase II in June 2003. These favorable items together with higher profitability from Contact Energy were partially offset by lower state tax benefits.

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 2003 loss at MEHC (stand alone) increased by $4 million due to lower interest income and higher consulting fees.

The loss for Edison International (parent) and other decreased $34 million primarily from charges in 2002 associated with businesses the company exited.

2002 vs. 2001

SCE's earnings were $748 million in 2002, excluding the $480 million benefit related to the implementation of the CPUC's URG decision, compared to earnings of $408 million in 2001 excluding an adjustment of $2.0 billion to establish the PROACT and record the recovery of SCE's past procurement-related costs. The $340 million or 83% increase in SCE's earnings primarily reflects increased revenue resulting from the CPUC's 2002 decision in SCE's PBR proceeding, increased earnings from SCE's larger rate base in 2002 compared to 2001, lower interest expense, PBR rewards from prior years and increased income from San Onofre Units 2 and 3. The increase was partially offset by higher operating and maintenance expense.

Based on the CPUC's January 23, 2003 PROACT resolution, SCE was able to conclude that $3.6 billion in regulatory assets previously written off were probable of recovery through the rate-making process as of December 31, 2001. As a result, SCE's December 31, 2001 consolidated income statement included a $3.6 billion credit to provisions for regulatory adjustment clauses and a $1.5 billion charge to income tax expense, to reflect the $2.1 billion (after tax) credit to earnings.

EME's earnings from continuing operations in 2002 were $82 million, compared to $113 million in 2001. The decrease in earnings was primarily due to lower west coast energy prices, unplanned outages at the Homer City plant, gains related to gas swaps from EME's oil and gas activities, the implementation of a new accounting standard for derivatives in 2001, and other net charges during 2002 totaling $50 million, after tax, or $0.15 per share. These net charges included a $27 million loss from a settlement agreement that terminated the obligation to build additional generation in Chicago and a $66 million write-down of assets related to the cancellation of turbine orders, the suspension of the Powerton SCR project, and an impairment of goodwill, partially offset by a gain of $43 million from the settlement of a postretirement employee benefit liability. The decrease in earnings from continuing operations was partially offset by improved operating results at EME's Illinois, Loy Yang B and ISAB plants, income from the Paiton project in Indonesia, and lower state income taxes.

Edison Capital's earnings were $33 million in 2002 compared with $84 million in 2001. The decrease in earnings was primarily the result of a write-off of an investment in aircraft leases with United Airlines totaling $34 million, after tax, or $0.11 per share. Also contributing to the decline in earnings was lower earnings attributable to a maturing investment portfolio and gains in 2001 associated with asset sales. The decline in earnings was partially offset by lower interest expense and higher tax benefits.

The loss at MEHC (stand alone) increased by $45 million reflecting the issuance of debt in mid-2001.

The loss for Edison International (parent) and other decreased $18 million primarily from lower interest expense and a tax adjustment in 2001.

Operating Revenue

SCE's retail sales represented approximately 91%, 96% and 94% of electric utility revenue in 2003, 2002, and 2001, respectively. Due to warmer weather during the summer months, electric utility revenue during the third quarter of each year is significantly higher than other quarters.

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

In millions Year ended December 31,	**2003 vs. 2002**	2002 vs. 2001
Electric utility revenue		
Rate changes (including surcharges)	**$ (677)**	$ 563
Direct access credit	**471**	(604)
Sales volume changes	**(60)**	696
Sales for resale	**394**	(11)
Other (including intercompany transactions)	**20**	(59)
Total	**$ 148**	$ 585

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 the CPUC-authorized temporary surcharge collected in 2002, used to recover costs incurred in 2003 (see "SCE: Regulatory Matters—Generation and Power Procurement—Temporary Surcharges"). 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. As a result of CDWR contracts allocated to SCE, excess energy from SCE sources may exist at certain times and is resold in the energy markets.

Electric utility revenue increased by $585 million in 2002 as compared to 2001 (as shown in the table above). The increase in electric utility revenue due to rate changes resulted from a 3¢-per-kWh surcharge authorized by the CPUC as of March 27, 2001. The decrease in electric utility revenue due to direct access credits resulted from an increase in credits given to direct access customers due to a significant increase in the number of direct access customers. The increase in electric utility revenue resulting from changes in sales volume was primarily due to SCE providing its customers with a greater volume of energy generated from its own generating plants and power-purchase contracts, rather than the CDWR purchasing power on behalf of SCE's customers.

Amounts SCE bills and collects from its customers for electric power purchased and sold by the CDWR to SCE's customers (beginning January 17, 2001), CDWR bond-related costs (beginning November 15, 2002) and direct access exit fees (beginning January 1, 2003) are remitted to the CDWR and are not recognized as revenue by SCE. These amounts were $1.7 billion, $1.4 billion, and $2.0 billion for the years ended December 31, 2003, 2002, and 2001, respectively.

Nonutility power generation revenue increased in both 2003 and 2002. The 2003 increase was primarily due to increased electric revenue from EME's Homer City facilities and Contact Energy projects, partially offset by lower capacity revenue from EME's Illinois plants due to a deduction in megawatts under contract with Exelon Generation. The increases at EME's Homer City facilities were primarily due to increased generation and higher energy prices. The increases at EME's Contact Energy projects were primarily due to higher wholesale energy prices, higher generation and an increase in the average exchange rate. The 2002 increase was primarily due to EME's consolidation of Contact Energy for a full year in 2002, compared to a partial year in 2001 (ownership interest increased to 51%, effective June 1, 2001), and increased revenue from the Illinois plants and First Hydro plant. These increases were partially offset by decreased revenue from EME's Homer City facilities.

During 2003, 2002 and 2001, 22%, 40% and 42%, respectively, of nonutility power generation revenue was derived under three power-purchase agreements between EME's wholly owned subsidiary, Midwest Generation, and Exelon Generation Company, a subsidiary of Exelon Corporation. Revenue under these agreements was $708 million in 2003 and $1.1 billion in both 2002 and 2001. Midwest Generation expects to be less dependent on Exelon Generation as a major customer during 2004 due to Exelon Generation's release of 3,262 MW of capacity from the coal units and 1,614 MW of capacity from the Collins Station. In 2004, 2,383 MW of capacity from the coal units and 1,084 MW of capacity from the Collins Station will remain subject to the power-purchase agreements. The power-purchase agreements terminate at the end of 2004. Exelon Corporation is the holding company of ComEd and PECO Energy Company, major utilities located in Illinois and Pennsylvania. If Exelon Generation were to fail, become unable to fulfill, or choose to terminate some of its obligations under these power-purchase agreements, Midwest Generation might not be able to find another customer on similar terms for the output of the Illinois plants. Any material failure by Exelon Generation to make payments to Midwest Generation under these power-purchase agreements could result in a shortfall of cash available for Midwest Generation to meet its obligations. A default by Midwest Generation in meeting its obligations could in turn have a material adverse effect on EME.

Nonutility power generation revenue during the third quarter is materially higher than revenue related to other quarters of the year because warmer weather during the summer months results in higher revenue being generated from EME's Homer City facilities and Illinois plants. By contrast, EME's First Hydro plants have higher revenue during their winter months.

Financial services and other revenue increased in 2003 and decreased in 2002. 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. In addition to the above, the 2002 decrease also reflected the impact of adopting the equity method of accounting in conformance with the infrastructure funds accounting policies.

Operating Expenses

Fuel expense increased for both 2003 and 2002. The increase in 2003 was primarily due to increased generation at EME's Homer City facilities primarily resulting from outages experienced during the first two quarters of 2002, increased fuel costs at EME's Contact Energy projects primarily due to higher gas prices and an increase in the value of the New Zealand dollar compared to the United States dollar. The increase in 2002 was primarily related to EME's consolidation of Contact Energy for a full year in 2002 as compared to a partial year in 2001, increased pumping power costs from EME's First Hydro plant, increased fuel costs from EME's Illinois plants and an increase at SCE related to a payment received under a settlement agreement with Peabody associated with Mohave. The 2002 increase was partially offset by decreased fuel costs from EME's Homer City facilities.

Purchased-power expense increased in 2003 and decreased in 2002. 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. The 2002 decrease resulted primarily from lower expenses at SCE related to power purchased from QFs, bilateral contracts and interutility contracts, mainly due to lower spot natural gas prices in 2002 as compared to 2001. In addition, the decrease reflects the absence of PX/ISO purchased-power expense after mid-January 2001.

Federal law and CPUC orders required SCE to enter into contracts to purchase power from QFs at CPUC-mandated prices. These contracts expire on various dates through 2025. Energy payments to gas-fired cogeneration 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, compared with an average of 3.1¢-per-kWh during the period of January and April 2002. During 2003, spot natural gas prices were higher compared to the same period in 2002. During 2002, spot natural gas prices were significantly lower than the same periods in 2001.

Provisions for regulatory adjustment clauses – net decreased in 2003 and increased in 2002. 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 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. The 2002 increase was primarily due to the establishment of the PROACT regulatory asset in 2001, overcollections used to recover the PROACT balance and revenue collected to recover the rate reduction bond regulatory asset, partially offset by the impact of SCE's implementation of the CPUC decision related to URG and the PBR mechanism, as well as the impact of other regulatory actions.

As a result of the URG decision received in 2002, SCE reestablished regulatory assets previously written off (approximately $1.1 billion) related to its nuclear plant investments, purchased-power settlements and flow-through taxes, and decreased the PROACT balance by $256 million, all retroactive to January 1, 2002. The impact of the URG decision is reflected in the 2002 financial statements as a credit (decrease) to the provisions for regulatory adjustment clauses of $644 million, partially offset by an increase in deferred income tax expense of $164 million, for a net credit to earnings of $480 million. As a result of the CPUC decision that modified the PBR mechanism, SCE recorded a $136 million credit (decrease) to the provisions for regulatory adjustment clauses in the second quarter of 2002, to reflect undercollections in CPUC-authorized revenue resulting from changes in retail rates.

Other operation and maintenance expense increased in both 2003 and 2002 primarily due to increases at both SCE and EME.

SCE's other operating and maintenance expense increase in 2003 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 (see "SCE: Regulatory Matters—Other Regulatory Matters—Catastrophic Event Memorandum Account"). SCE's other operation and maintenance expense increase in 2002 was primarily due to the San Onofre Unit 2 refueling outage in 2002, increases in transmission and distribution maintenance and inspection activities, and temporary cost containment efforts that took place in 2001. The 2002 increases were partially offset by lower expenses related to balancing accounts.

EME's other operation and maintenance expense increased in 2003 due to an increase in transmission costs due to higher retail sales generated by EME's Contact Energy and an increase in the value of the New Zealand dollar, compared to the United States dollar. EME's other operation and maintenance expense increased in 2002 mainly due to an increase in transmission costs, primarily due to consolidating Contact Energy, effective June 1, 2001 and an increase in operating leases due to the sale-leaseback transactions for the Homer City and Powerton-Joliet power facilities. There were no comparable lease costs for the Homer City facilities through the period ended December 2001 and the Powerton-Joliet power facilities through the period ended August 2000. See "Off-Balance Sheet Transactions—EME's Off-Balance Sheet Transactions—Sale-Leaseback Transactions," for discussion of the financial impact of sale-leaseback transactions. In addition, in 2002, EME recorded a $45 million charge related to a settlement of EME's Chicago In-City obligation. These increases were partially offset by a gain recorded 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 expense in 2003 consisted of $245 million related to the impairment of eight small peaking plants owned by EME's wholly owned subsidiary, Midwest Generation, $53 million to write-down the estimated net proceeds from the planned sale of EME's Brooklyn Navy Yard project and $6 million related to EME's write-down of its investment in the Gordonsville project due to its planned disposition (see "Acquisitions and Dispositions" for further discussion). 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 the current generation overcapacity in the MAIN region market. See "MEHC and EME: Liquidity—Financial Ratios—EME's Recourse Debt to Recourse Capital Ratio." 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 pre-tax cash flows using a 17.5% discount rate. Asset impairment expense 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 environmental improvements project at its Illinois plants.

Depreciation, decommissioning and amortization expense increased in both 2003 and 2002. 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 SCE's nuclear decommissioning expense and higher depreciation expense at EME's Contact Energy projects associated with the Taranaki Station acquisition. The 2003 increase also included additional depreciation expense resulting from the termination of EME's Midwest Generation equipment lease in August 2002, and an increase in amortization expense at Edison Capital resulting from a change from the cost method to the equity method of accounting for its fund investments in 2002. The 2003 increase was 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. The increase in 2002 was mainly due to an increase in depreciation expense associated with SCE's additions to transmission and distribution assets and an increase in SCE's nuclear decommissioning expense. A 1994 CPUC decision allowed SCE to accelerate the recovery of its nuclear-related assets while deferring the recovery of its distribution-related assets for the same amount. Beginning in January 2002, the CPUC approved the commencement of recovery of SCE's deferred distribution assets. In addition, the increases reflect amortization expense on the nuclear regulatory asset reestablished during second quarter 2002 based on the URG decision. These 2002 increases were partially offset by lower depreciation expense at EME's Homer City facilities due to the sale-leaseback transaction that took place in December 2001, as well as ceasing the amortization of goodwill in January 1, 2002.

Other Income and Deductions

Interest and dividend income decreased in 2003 and increased in 2002. The 2003 decrease was mainly due to lower interest income on the PROACT balance at SCE as well as lower interest income from lower average cash balances at SCE, compared to the same period in 2002. The 2002 increase was mainly due to the interest income earned on the PROACT balance at SCE. The 2002 increase was partially offset by lower interest income due to lower average cash balances and lower interest rates at SCE, EME and Edison Capital during 2002, as compared to 2001 and lower earnings from Edison Capital's investments.

Equity in income from partnerships and unconsolidated subsidiaries – net increased in 2003 and decreased in 2002. 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. Also contributing to the 2003 increase were increased earnings from Edison Capital's infrastructure funds. The 2002 decrease was primarily due to a decrease in EME's income from the Big 4 projects and Four Star Oil & Gas, partially offset by an increase in EME's income from the Paiton Energy and ISAB projects. EME's third quarter equity in income from its domestic energy projects is materially higher than equity in income related to other quarters for the year due to warmer weather during the summer months and because a number of EME's domestic energy projects, located on the West Coast, have power sales contracts that provide for higher payments during the summer months.

Other nonoperating income increased in 2003 and decreased in 2002. The 2003 increase was mainly due to SCE's recognition of 2000 and 2001 Palo Verde performance rewards approved by the CPUC during 2003, as well as higher gains on the sale of EME's development projects in 2003 as compared to 2002. The increase was almost entirely offset by property condemnation settlements received at SCE in 2002, with no comparable settlements received in 2003 and lower foreign exchange gains at Edison Capital in 2003, compared to 2002. The 2002 decrease was primarily due to a decrease at EME, partially offset by increases at SCE and Edison Capital. The decrease at EME was mainly due to foreign exchange losses in 2002 compared to foreign exchange gains in 2001, lower gains on the sale of EME's interest in energy projects in 2002 compared to 2001, as well as a gain on early extinguishment of debt in 2001. The 2002 increase at SCE was primarily due to property condemnation settlements received, partially offset by PBR incentive awards for 1999 and 2000, which were approved by the CPUC and recorded in 2001. The increase at Edison Capital was primarily due to higher foreign exchange gains in 2002 compared to 2001.

Interest expense – net of amounts capitalized decreased in both 2003 and 2002. The 2003 decrease was due to lower interest expense at SCE due to the accrual of interest in 2002 related to 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. The 2003 decrease was partially offset by higher interest costs at EME's Illinois plants due to a downgrade of the credit rating of Edison Mission Midwest Holdings (see "MEHC and EME: Liquidity—EME's Credit Ratings") and higher levels of borrowings at EME's Contact Energy related to the Taranaki Station acquisition. Interest expense – net in 2003 reflects a change in the classification of dividend payments on preferred securities to interest expense – net from dividends on preferred securities. 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 are not included in interest expense – net of amounts capitalized in the consolidated statements of income. The 2002 decrease is mainly due to: lower long-term debt balances at Edison Capital as compared to 2001; lower short-term debt balances at Edison International (parent) and all of the principal operating subsidiaries compared to 2001; and lower interest expense at SCE related to the suspension of payments for purchased power during 2001, which were subsequently paid in early 2002. The decrease was partially offset by: an increase in interest expense on long-term debt at SCE due to higher long-term debt balances; an increase in long-term debt interest expense at MEHC resulting from the debt financing that took place in July 2001; and the consolidation of Contact Energy at EME.

Other nonoperating deductions increased in both 2003 and 2002. The 2003 increase was primarily due to the reversal of accruals for regulatory matters in 2002, partially offset by a goodwill impairment charge associated with EME's Citizens Power acquisition resulting from adoption of an accounting standard in 2002, as well as lower foreign exchange losses at Edison Capital. 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. The 2002 increase was mainly due to the goodwill impairment charge at EME, partially offset by the reversal of accruals for regulatory matters at SCE in 2002.

Income Taxes

Income tax expense decreased in both 2003 and 2002. The 2003 and 2002 decreases were primarily due to reductions in pre-tax income. The 2003 decrease also resulted from the favorable resolution of a FERC rate case at SCE. The 2003 decrease was 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. The 2002 decrease also resulted from the reestablishment of tax-related regulatory assets upon implementation of the URG decision at SCE, a cumulative adjustment to deferred tax balances at Edison Capital to reflect changes in its effective state tax rate and favorable resolution of tax audits at SCE.

Edison International's composite federal and state statutory rate was approximately 40% for all years presented. The lower effective tax rate of 21.5% realized in 2003 was primarily due to the resolution of a FERC rate case at SCE, recording the benefit of favorable resolution of tax 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 25.6% realized in 2002 was primarily due to the reestablishment of tax-related regulatory assets upon implementation of the URG decision at SCE, a cumulative adjustment to deferred tax balances at Edison Capital to reflect changes in its effective state tax rate, the favorable resolution of tax audit issues at SCE and the benefits received from low-income housing and production credits at Edison Capital.

Earnings (Loss) from Discontinued Operations

Edison International's earnings from discontinued operations in 2003 were $51 million, including a $44 million (after-tax) gain on the sale of SCE's fuel oil pipeline business. Edison International's loss from discontinued operations in 2002 represent the one-time asset impairment charge of $77 million (after tax) resulting from EME's Lakeland project being placed into administrative receivership in the United Kingdom, offset by $22 million in 2002 operating results from the Lakeland project. See further discussion at "Discontinued Operations" and "Acquisitions and Dispositions." The 2002 loss also includes minor adjustments related to the sale of EME's Fiddler's Ferry and Ferrybridge coal stations and the sale of a majority of Edison Enterprises (a nonutility subsidiary of Edison International that formerly provided retail services) assets in 2001. The 2001 loss includes impairment charges resulting from the sale of the Fiddler's Ferry and Ferrybridge plants and the majority of Edison Enterprises' assets, as well as operating results from the discontinued entities.

Cumulative Effect of Accounting Change – net of tax

Edison International's results for 2003 include a $9 million charge at EME for the cumulative effect of an accounting change related to the new accounting standard for recording asset retirement obligations adopted by Edison International in January 2003. As SCE follows accounting principles for rate-regulated enterprises, implementation of this new standard did not affect earnings. (See "New Accounting Principles.")

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,	**2003**	2002	2001
Continuing operations	**$ 3,359**	$ 2,241	$ 3,121
Discontinued operations	**(52)**	80	(147)
	$ 3,307	$ 2,321	$ 2,974

The 2003 increase in cash provided by operating activities from continuing operations was mainly due to SCE's March 2002 repayment of past-due obligation. The change was also due to timing of cash receipts and disbursements related to working capital items at both SCE and EME. The 2002 decrease in cash provided by operating activities from continuing operations was mainly due to SCE's March 2002 repayment of past-due obligations, partially offset by higher overcollections used to recover regulatory assets resulting from the CPUC-approved surcharges (1¢-per-kWh in January 2001 and 3¢-per-kWh in June 2001) and an increase in operating cash flow from EME resulting from the timing of cash payments related to working capital items.

Cash used by operating activities from discontinued operations in 2003 primarily reflects operating activities at SCE's fuel oil pipeline business. Cash provided by operating activities from discontinued operations in 2002 primarily reflects the settlement of working capital items from EME's Fiddler's Ferry and Ferrybridge power plants and operating income from the EME's Lakeland power plant during 2002. Cash used by operating activities from discontinued operations in 2001 reflects operating losses from EME's Fiddler's Ferry and Ferrybridge power plants in 2001, as compared to operating income in 2000, and the timing of cash payments related to working capital items.

Cash Flows from Financing Activities

Net cash used by financing activities:

In millions Year ended December 31,	**2003**	2002	2001
Continuing operations	**$ (2,006)**	$ (2,582)	$ (379)
Discontinued operations	**—**	(19)	(1,178)
	$ (2,006)	$ (2,601)	$(1,557)

Cash used by financing activities from continuing operations in 2003 mainly consisted of long-term and short-term debt payments at SCE and EME.

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. EME's financing activity during 2003 includes an $800 million secured loan received by EME's subsidiary, Mission Energy Holdings International, combined with borrowings of $800 million and $275 million in borrowings by Contact Energy, EME's 51% owned subsidiary, used to finance Contact Energy's acquisition of the Taranaki Combined Cycle power station (see "Acquisitions and Dispositions" for further discussion of the acquisition). EME's financing activity in 2003 also included 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, debt service payments of $118 million related to three of EME's subsidiaries, and repayment of $31 million of debt obligations due from EME's acquisition of the Spanish Hydro project.

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. EME'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 $487 million corporate credit facility, $44 million related to debt service payments and payments of $86 million on EME's debentures and notes. Edison Capital's net payments on short-term debt were approximately $312 million.

Cash used by financing activities from continuing operations in 2001 consisted of long-term debt repayments at EME and short-term debt repayments at the parent company and at EME. The uses of cash were partially offset by the issuance of long-term debt at EME of $1.0 billion and at MEHC of $1.2 billion.

Cash used by financing activities from discontinued operations in 2002 represents repayments of long-term debt at EME's Lakeland power plant. Cash used by financing activities from discontinued operations in 2001 related to the early repayment of a term loan facility in connection with the sale of the Ferrybridge and Fiddler's Ferry power plants on December 21, 2001.

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 electric industry 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 remaining series of outstanding rate reduction notes have scheduled maturities through 2007, with interest rates ranging from 6.38% to 6.42%. 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.

Cash Flows from Investing Activities

Net cash provided (used) by investing activities:

In millions Year ended December 31,	**2003**	2002	2001
Continuing operations	**$ (1,725)**	$ (1,331)	$ (424)
Discontinued operations	**150**	2	1,125
	$ (1,575)	$ (1,329)	$ 701

Cash flows from investing activities are affected by additions to property and plant, EME's sales of assets and SCE's funding of nuclear decommissioning trusts.

Additions to SCE's property and plant during 2003 were approximately $1.2 billion, primarily for transmission and distribution assets. EME's capital additions in 2003 were $127 million primarily for new plant and equipment related to EME's Illinois plants, its Homer City facilities, and Contact Energy projects. EME's 2003 investing activity also included $275 million paid by Contact Energy for the acquisition of the Taranaki Combined Cycle power station (see "Acquisitions and Dispositions" for further discussion of the acquisition).

Additions to SCE's property and plant during 2002 were approximately $1.0 billion, primarily for transmission and distribution assets; EME's capital additions of $554 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 increases were primarily for the Valley Power Peaker project in Australia, the 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.

Cash flows from investing activities from continuing operations in 2001 included proceeds from EME's sale-leaseback transaction with respect to the Homer City facilities in December 2001 and from EME's sale of a 50% interest in the Sunrise project, as well as EME's equity contributions to meet capital calls by its QF partnerships in California.

Investing cash flows from discontinued operations in 2003 represents the proceeds received from SCE's sale of its fuel oil pipeline business. Cash flows from investing activities from discontinued operations in 2001 includes the proceeds received from EME's sale of Ferrybridge and Fiddler's Ferry power plants on December 21, 2001.

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 $2.1 billion as of December 31, 2003, based on site-specific studies performed in 2001 for San Onofre and Palo Verde. As of December 31, 2003, the decommissioning trust balance was $2.5 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.

DISCONTINUED OPERATIONS

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 2003, the results of SCE's oil storage and pipeline facilities unit have been accounted for as a discontinued operation in the consolidated financial statements.

On December 19, 2002, the lenders to EME's Lakeland project accelerated the debt owing under the bank agreement that governs the project's indebtedness, and on December 20, 2002, the Lakeland project lenders appointed an administrative receiver over the assets of Lakeland Power Ltd. The appointment of the administrative receiver results in the treatment of Lakeland power plant as an asset held for sale under an accounting standard related to the impairment or disposal of long-lived assets. Due to EME's loss of control arising from the appointment of the administrative receiver, EME no longer consolidates the activities of Lakeland Power Ltd. 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. In 2002, the results of the Lakeland project are reflected as discontinued operations in the consolidated financial statements.

On December 21, 2001, EME completed the sale of the Fiddler's Ferry and Ferrybridge coal stations located in the United Kingdom to two wholly owned subsidiaries of AEP. 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 specific 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 $1.9 billion charge includes the asset impairment charge recorded in third quarter 2001 to reduce the carrying value of the assets held for sale to reflect estimated fair value less the cost to sell and related currency adjustments. EME had acquired the plants in 1999 for approximately $2.0 billion (£1.3 billion).

In August 2001, Edison Enterprises, a wholly owned subsidiary of Edison International, sold a subsidiary principally engaged in the business of providing residential security services and residential electrical warranty repair services. In October 2001, Edison Enterprises completed the sale of substantially all of its assets of another subsidiary (engaged in the business of commercial energy management) to the subsidiary's current management. As a result, Edison International recorded a charge of $127 million (after tax) in 2001 related to the losses on these sales. The impairment charges recorded in 2001 to reduce the carrying value of these investments held for sale to reflect the estimated fair value less cost to sell are included in the $127 million charge. For all years presented, the results of the Fiddler's Ferry and Ferrybridge coal stations and Edison Enterprises subsidiaries sold during 2001 have been reflected as discontinued operations in the consolidated financial statements.

ACQUISITIONS AND DISPOSITIONS

On December 31, 2003, EME agreed to sell its 50% partnership interest in Brooklyn Navy Yard Cogeneration Partners L.P. to a third party. Completion of the sale, currently expected in the first quarter of 2004, is subject to closing conditions, including obtaining regulatory approval. Proceeds from the sale are expected to be 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.

On December 12, 2003, EME agreed to sell 100% of its stock of Edison Mission Energy Oil & Gas, which in turn holds minority interests in Four Star Oil & Gas, to Medicine Bow Energy Corporation. Following receipt of regulatory approvals and satisfaction of all other closing conditions, EME completed this sale on January 7, 2004. Proceeds from the sale were approximately $100 million. EME expects to record a pre-tax gain on the sale of approximately $47 million during the first quarter of 2004.

On November 21, 2003, Gordonsville Energy Limited Partnership, in which EME owns a 50% interest, completed the sale of the Gordonsville cogeneration facility to Virginia Electric and Power Company. Proceeds from the sale, including distribution of a debt service reserve fund, were $36 million. EME recorded an impairment charge of $6 million during the second quarter of 2003 related to the planned disposition of this investment.

On July 17, 2003, SCE signed an option agreement with Sequoia Generating LLC, a subsidiary of InterGen, to acquire Mountainview Power Company LLC, the owner of a new 1,054-megawatt, combined-cycle, natural gas-fired power plant currently being developed in Redlands, California. Mountainview Power Company LLC would sell all the output of the power plant to SCE pursuant to a 30-year tolling power-purchase agreement. The power-purchase agreement would be a cost-based contract providing for recovery of investment, fixed and variable costs, and a regulated rate of return, over the 30-year life of the contract. On December 18, 2003, the CPUC approved the Mountainview power-purchase agreement, subject to SCE receiving a FERC decision approving the agreement without any modifications that would have potential rate impacts. On February 25, 2004, the FERC granted conditional approval of the Mountainview power-purchase agreement. On March 1, 2004, a CPUC administrative law judge issued a proposed decision that would accept the conditions in the FERC approval of the power-purchase agreement. The matter is scheduled to be considered by the CPUC at its meeting on March 16, 2004. On February 28, 2004, SCE exercised its option to purchase Mountainview Power LLC. SCE currently anticipates that it will close the purchase before the end of March 2004 and recommence construction of the project immediately thereafter. SCE estimates that the project will be completed in March 2006 at a cost of approximately $600 million, excluding financing costs. SCE expects to finance the capital costs of the project with debt and equity at the utility level consistent with its authorized capital structure.

On July 10, 2003, the CPUC approved a joint application filed by SCE and Pacific Terminals LLC, requesting authorization for the sale of certain oil storage and pipeline facilities by SCE to Pacific Terminals for $158 million. The sale closed on July 31, 2003 and resulted in a $44 million after-tax gain to shareholders recorded in the third quarter of 2003.

On March 3, 2003, Contact Energy, EME's 51% owned subsidiary, completed a transaction with NGC Holdings Ltd. to acquire the Taranaki Combined Cycle power station and related interests. The Taranaki station is a 357 MW combined cycle, natural gas-fired plant located near Stratford, New Zealand. Consideration for the Taranaki station consisted of a cash payment of approximately $275 million, which was initially financed with bridge loan facilities. The bridge loan facilities were subsequently repaid with proceeds from Contact Energy's issuance of long-term United States dollar denominated notes.

CRITICAL ACCOUNTING POLICIES

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 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 the second quarter of 2003, EME assessed the impairment of its Illinois plants. EME has grouped the Illinois plants into two asset groups: coal-fired power plants and the small peaker plants. Management judgment was required to make this assessment based on the lowest level of cash flow that was viewed by management as largely independent of each other. The expected future undiscounted cash flow from EME's merchant power plants is a critical accounting estimate because: (1) estimating future prices of energy and capacity in wholesale energy markets is susceptible to significant change, and (2) the forecast is over an extended time period due to the estimated useful life (15 to 33.75 years) of power plants, and (3) the impact of an impairment on EME's consolidated financial position and results of operations would be material. The expected undiscounted future cash flow from the small peaker plants did not exceed the carrying value of that asset group. 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. The impairment charge relating 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 the current generation overcapacity in the MAIN region market. See "MEHC and EME: Market Risk Exposures—Commodity Price Risk—Illinois Plants."

In addition to the asset impairment charge related to the small peaking plants in 2003, EME's indirect subsidiary, Midwest Generation, also reported an impairment charge of $475 million, after tax, related to the 2,698 MW gas-fired Collins Station in its second quarter report on Form 10-Q. The impairment charge resulted from a write-down of the book value of the Collins Station capitalized assets from $858 million to an estimated fair market value of $78 million. The impairment charge by Midwest Generation is not reflected in the operating results of EME because the lease related to the Collins Station is treated in EME's financial statements as an operating lease and not as an asset and, therefore, is not subject to impairment for accounting purposes. See "MEHC and EME: Liquidity—Financial Ratios—EME Recourse Debt to Recourse Capital Ratio."

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 principles for rate regulated companies, this incurred cost was deferred and recorded as a regulatory asset, due to the expectation that the unrecovered book value of Mohave at the time of shutdown will be recovered through the rate-making process. See "SCE: Regulatory Matters—Generation and Power Procurement—Mohave Generating Station and Related Proceedings," and "—Rate Regulated Enterprises."

During the fourth quarter of 2002, an impairment charge of $92 million ($77 million after tax) was recorded by EME's subsidiary holding the Lakeland power plant due to the change in financial condition of TXU Europe and its subsidiaries, one of which was counterparty to a long-term power-purchase agreement (considered an indicator of impairment under the accounting standard). Management's judgment was required to determine the asset group, which was determined as the power plant and claim under the power-purchase agreement. Furthermore, a management estimate was required to determine the fair value of the asset group as the expected undiscounted future cash flow was less than the carrying value of the asset. See "Results of Operations and Historical Cash Flow Analysis—Results of Operations—Earnings (Loss) from Discontinued Operations," for further discussion.

Edison International also would record an impairment charge if a decision is made (which generally occurs when Edison International enters into an agreement to sell an asset) to dispose of an asset and the fair value is less than Edison International's book value. The accounting standards require the following criteria to be met to classify an asset held for sale:

1. management approves the action and commits to a plan to sell an asset, which is generally evidenced by the signing of an asset sales agreement or Board of Directors approval;

2. the long-lived asset (asset group) is generally deemed to be available for immediate sale and conditions for sale is subject only to the terms and conditions customary for sale of such assets;

3. management has actively engaged in a program to locate a buyer and has initiated other such actions required to complete the plan to sell the asset;

4. the sale is probable and the transfer of the asset is expected to be completed within one year;

5. the asset is being marketed at a price that is believed to be reasonable in relation to fair value; and

6. management believes that it is unlikely that significant changes to the plan that asset will be made or that the plan will be withdrawn.

EME has engaged investment bankers to market for sale its international project portfolio which commenced during the first quarter of 2004. Completion of the sale of all or part of EME's international project portfolio is contingent on receiving acceptable offers in terms of both price and terms and conditions related to risk factors. Due to the uncertainty regarding completion of the sale of all or part of the international project portfolio through the current offering process, management has concluded that it has not met all of the requirements listed above at December 31, 2003. EME's book value of its international project portfolio was approximately $2.2 billion at December 31, 2003. Edison International cannot predict with certainty whether EME will be able to sell these assets at or above book value.

During 2003, EME met the asset held for sale criteria under the accounting standards regarding its investment in the Gordonsville and Brooklyn Navy projects and recorded an impairment based on the net proceeds expected from the sale of $6 million and $53 million, respectively. Using this type of analysis, EME recorded $1.9 billion impairment of EME's Ferrybridge and Fiddler's Ferry power plants during the third quarter of 2001 and Edison Enterprises recorded $127 million impairment for the majority of its assets in 2001. See "Results of Operations and Historical Cash Flow Analysis—Results of Operations—Earnings (Loss) from Discontinued Operations," for further discussion.

EME operates several power plants under leases as described below under "—Off-Balance Sheet Financing." Under generally accepted accounting principles as currently interpreted, EME is not required to record a loss if future cash flows from use of an asset under lease are less than the expected minimum lease payments. This accounting issue has been discussed in an authoritative accounting interpretation for the recognition by a purchaser of losses on firmly committed executory contracts, without reaching a consensus. Future minimum lease payments on the Collins Station are estimated to be $1.3 billion. As a result, if the accounting guidance in this area were to change, EME could be required to record a loss on this lease, depending on an assessment of future expected cash flow at the time such guidance was changed.

Due to lower wholesale prices for energy during 2002 and 2003 (see "MEHC and EME: Market Risk Exposures—Commodity Price Risk"), EME has suspended operations of four units at the Illinois plants (Units 1 and 2 at Will County and Units 4 and 5 at the Collins Station). EME continues to record depreciation on such assets during the period that EME has suspended operations. Accounting for these units as idle facilities requires management's judgment that these units will return to service. EME has continued the maintenance of these units in order to return them to service when market conditions improve on a sustained basis and future environmental uncertainties are resolved. If market conditions do not improve on a sustained basis, environmental uncertainties are not resolved or are resolved unfavorably, or if a decision is made not to return them to service due to other factors, EME could sell or decommission one or more of these units. Such a decision could result in a loss on sale or a write-down of the carrying value of these assets.

EME evaluates goodwill whenever indicators of impairment exist, but at least annually on October 1 of each year. EME's goodwill is primarily related to the acquisitions of Contact Energy and First Hydro. EME determined through a fair value analysis conducted by third parties that the fair value of the Contact Energy and First Hydro reporting units was in excess of book value. Accordingly, no impairment of the goodwill related to these reporting units was recorded upon adoption of this standard.

Determining the fair value of the reporting unit under the goodwill and other intangible accounting standard is a critical accounting estimate because: (1) it is susceptible to change from period to period since it requires assumptions regarding future revenue and costs of operations and discount rates over an indefinite life, and (2) the impact of recognizing an impairment on EME's consolidated financial position and results of operations would be material. EME has engaged third parties to conduct appraisals of the fair value of the major reporting units with goodwill on October 1, 2003 (the annual impairment testing date). The fair value of the First Hydro and Contact Energy reporting units set forth in these appraisals exceeded the carry value.

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 net gains (losses) from price risk management and energy trading in the accompanying 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 and EME: 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

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 are subject to interpretation and audit by the IRS. As further described in "Other Developments—Federal Income Taxes," the IRS has raised issues in the 1994 to 1996 audit of Edison International's tax returns with respect to certain leveraged leases at Edison Capital and Edison Capital expects the IRS will also challenge several of its other leveraged leases in the audit of years 1997 through 1999. Edison International does not provide for federal income taxes or tax benefits on the undistributed earnings or losses of its international subsidiaries because such earnings are either reinvested indefinitely or would not be subject to additional taxes if repatriated. At December 31, 2003, EME reviewed the undistributed earnings of its international subsidiaries and concluded:

- Its international holding company, MEC B.V., had negative retained earnings under United States generally accepted accounting principles and negative accumulative earnings and profits for federal income tax purposes.
- Distributions of lower tier international subsidiaries to MEC B.V. are either not taxable or could be distributed without additional income taxes.
- MEC B.V. had outstanding indebtedness to domestic subsidiaries of EME totaling $445 million at December 31, 2003 which could be repaid without incurring additional income taxes.

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 Collins, 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. Completion of sale-leaseback transactions of these power plants is a complex matter involving management judgment to determine compliance with the provisions of the accounting standards, including the transfer of all 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." Also see "MEHC and EME: Liquidity—Key Financing Developments—EME's Subsidiary Financing Plans—Agreement in Principle to Terminate the Collins Station Lease."

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

Partnership investments, in which Edison International owns a percentage interest and does not have operational control or significant voting rights, are accounted for under the equity method as required by accounting standards. As such, the project assets and liabilities are not consolidated on the balance sheet. Rather, the financial statements reflect only the proportionate ownership share of net income or loss. See "Off-Balance Sheet Transactions."

Pensions and Postretirement Benefits Other than Pensions

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

The discount rate enables Edison International to state expected future cash flows at a present value on the measurement date. At the December 31, 2003 measurement date, Edison International used a discount rate of 6.0% for pensions and 6.25% 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 8.5% for pensions and 8.2% for PBOP. A portion of PBOP trusts asset returns are subject to taxation, so the 8.2% figure above is determined on an after-tax basis. Actual returns on the pension plan assets were 27.6%, 7.3% and 10.8% for the one-year, five-year and ten-year periods ended December 31, 2003, respectively. Actual returns on the PBOP plan assets were 26%, 2.2% and 9.1% 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, 2003, Edison International's pension plans included $3.0 billion in projected benefit obligation (PBO), $2.6 billion in accumulated benefit obligation (ABO) and $2.9 billion in plan assets. A 1% decrease in the discount rate would increase the PBO by $210 million, and a 1% increase would decrease the PBO by $195 million, with corresponding changes in the ABO. A 1% decrease in the expected rate of return on plan assets would increase pension expense by $22 million.

SCE accounts for about 92% of Edison International's total pension obligation, and 96% of its assets held in trusts, at December 31, 2003. 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, 2003, this cumulative difference amounted to a regulatory liability of $140 million, meaning that the rate-making method has resulted in recognizing $140 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.

See "Other Developments—Employee Compensation and Benefit Plans" for information related to Edison International's cash balance pension plan.

At December 31, 2003, Edison International's PBOP plans included $2.2 billion in PBO and $1.4 billion in plan assets. Total expense for these plans was $122 million for 2003. Increasing the health care cost trend rate by one percentage point would increase the accumulated obligation as of December 31, 2003 by $317 million and annual aggregate service and interest costs by $29 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated obligation as of December 31, 2003 by $257 million and annual aggregate service and interest costs by $23 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. Edison International has elected to defer accounting for the effects of the Act until the earlier of the issuance of guidance by the Financial Accounting Standards Board on how to account for the Act, or the remeasurement of plan assets and obligations subsequent to January 31, 2004. Accordingly, any measures of the accumulated postretirement benefit obligation or net periodic postretirement benefit expense above do not reflect the effects of the Act on Edison International's plans. Specific authoritative guidance on the accounting for the federal subsidy is pending and that guidance, when issued, could require Edison International to restate previously reported information.

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, 2003, the Consolidated Balance Sheets included regulatory assets, less regulatory liabilities, of $234 million. 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) created the $3.6 billion PROACT regulatory asset in the fourth quarter of 2001; (2) restored $480 million (after-tax) of generation-related regulatory assets based on the URG decision in the second quarter of 2002; and (3) 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 "Results of Operations and Historical Cash Flow Analysis—Results of Operations—Earnings (Loss) from Continuing Operations" and "SCE: Regulatory Matters—Generation and Power Procurement—PROACT Regulatory Asset," "—Utility-Retained Generation," and "—Mohave Generating Station and Related Proceedings" sections.

NEW ACCOUNTING PRINCIPLES

On January 1, 2001, Edison International adopted a new accounting standard for derivative instruments and hedging activities. An authoritative accounting interpretation issued in October 2001 precludes fuel contracts that have variable amounts from qualifying under the normal purchases and sales exception effective April 1, 2002. The adoption of this interpretation did not have a significant impact on Edison International's financial statements. Under a revised authoritative accounting interpretation issued in December 2001, EME's forward electricity contracts no longer qualify for the normal sales exception since EME has net settlement provisions with its counterparties. However, these contracts qualify as cash flow hedges. Edison International implemented the December 2001 interpretation, effective April 1, 2002.

In June 2003, clarifying guidance was issued related to derivative instruments and hedging activities. The guidance is related to pricing adjustments in contracts that qualify under the normal purchases and normal sales exception under derivative instrument accounting. This implementation guidance became effective on October 1, 2003. The guidance had no impact on Edison International's consolidated financial statements.

On January 1, 2003, Edison International adopted a new accounting standard, Accounting for Asset Retirement Obligations, which requires entities to record the fair value of a liability for a legal asset retirement obligation (ARO) in the period in which it is incurred. When the liability is initially recorded, the entity capitalizes the cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is increased to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss upon settlement. However, rate-regulated entities may recognize regulatory assets or liabilities as a result of timing differences between the recognition of costs as recorded in accordance with this standard and the recovery of costs through the rate-making process. Regulatory assets and liabilities may also be recorded when it is probable that the ARO will be recovered through the rate-making process.

Edison International's impacts of adopting this standard were:

- SCE adjusted its nuclear decommissioning obligation to reflect the fair value of decommissioning its nuclear power facilities. SCE also recognized ARO associated with the decommissioning of other coal-fired generation assets. Fair values were determined based on site-specific studies conducted by third-party contractors.

- At December 31, 2002, SCE had accrued $2.3 billion to decommission its nuclear facilities and $12 million to decommission its share of a coal-fired generating plant, under accounting principles in effect at that time. Of these amounts, $298 million to decommission its inactive nuclear facility was recorded in other long-term liabilities, and the remaining $2.0 billion was recorded as a component of the accumulated provision for depreciation and decommissioning on the consolidated balance sheets in the 2002 Annual Report.

- As of January 1, 2003, SCE reversed the $2.3 billion it had previously recorded for decommissioning, recorded the fair value of its AROs of approximately $2.02 billion in the deferred credits and other liabilities section of the balance sheet, and increased its unamortized nuclear investment by $303 million. The cumulative effect of a change in accounting principle from unrecognized accretion expense and adjustments to depreciation, decommissioning and amortization expense recorded to date was a $354 million after-tax gain, which under accounting standards for rate-regulated enterprises was deferred as a regulatory liability, partially offset by a $235 million deferred tax asset, as of January 1, 2003. Accretion expense on the ARO ($128 million) and depreciation expense on the new asset ($15 million) resulting from the application of the new standard in 2003 reduced the regulatory liability, with no impact on earnings. SCE's ARO liability account increased from $2.02 billion to $2.08 billion in 2003, with the $128 million in accretion partially offset by $68 million in expenditures related to the decommissioning of its inactive nuclear facility. As of December 31, 2003, SCE's ARO for its nuclear facilities totaled approximately $2.07 billion and its nuclear decommissioning trust assets had a fair value of $2.5 billion. If the new standard had been in place on January 1, 2002, SCE's ARO as of that date would have been $1.98 billion. If the standard had been applied retroactively for the years ended December 31, 2002 and 2001, it would not have had any effect on SCE's results of operations.

- SCE has collected in rates amounts for the future costs of removal and decommissioning of assets, and has historically recorded these amounts in accumulated provision for depreciation. However, in accordance with recent Securities and Exchange Commission accounting guidance, the amounts accrued in accumulated provision for depreciation for decommissioning and costs of removal were reclassified to regulatory liabilities as of December 31, 2002. The cost of removal amounts collected for assets not legally required to be removed remains in regulatory liabilities as of December 31, 2003. Amounts collected through rates for cost of removal of plant assets not considered to be legal obligations ($2.02 billion at December 31, 2003 and $1.92 billion at December 31, 2002) are included in regulatory liabilities.

- As of January 1, 2003, EME's ARO was approximately $17 million and EME recorded a cumulative effect adjustment that decreased net income by approximately $9 million, net of tax. If the new standard had been applied retroactively in the years ended December 31, 2002 and 2001, it would not have had a material effect on EME's results of operations.

In December 2003, the Financial Accounting Standards Board issued a revision to an accounting Interpretation (originally issued in January 2003), Consolidation of Variable Interest Entities (VIEs). The primary objective of the Interpretation is to provide guidance on the identification of, and financial reporting for, so-called "variable interest entities," where control may be achieved through means other than voting rights. Under the Interpretation, the enterprise that, using a discounted cash flow method, is expected to absorb or receive the majority of a VIE's expected losses or residual returns, or both, must consolidate the VIE. 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.

Guidance related to implementation of this Interpretation is evolving. SCE has over 240 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, and the CPUC controls the terms and pricing. Under this accounting Interpretation, SCE could be required to consolidate some or all of the entities that hold these contracts depending on (1) whether these power generators are considered to be VIEs, and (2) whether SCE is considered to be the consolidating entity. These entities are not legally obligated to provide the financial information to SCE, which would be required to determine whether SCE must consolidate these entities. SCE does not know which, if any, of these entities will provide the necessary information. SCE has no investment in, nor obligation to provide support to, these entities other than its requirement to make payment as required by the power-purchase agreements. However, if SCE is required to consolidate these entities, it may be required to recognize losses to the extent of any negative equity. These losses, if any, would not affect SCE's liquidity. EME's interests in certain power generators could also potentially be considered as variable interests. EME's maximum exposure to loss is generally limited to its investment in these entities. EME has 49%–50% ownership in four QF partnerships that have long-term power sales contracts with SCE. EME accounts for these projects using the equity method. If long-term power-purchase contracts are deemed to be variable interests, and due to the related-party nature of this transaction, it is likely that these four QFs could be consolidated by either EME or SCE.

Edison International had originally disclosed that it would adopt the Interpretation as of October 1, 2003. As a result of the December 2003 revision to the Interpretation and uncertainty surrounding its application to long-term power contracts, Edison International delayed implementation for its special purpose entities to December 31, 2003, and for all other entities until March 31, 2004, as allowed under the December revision of the Interpretation. As a result, EME's Brooklyn Navy Yard project, which is a VIE, was not consolidated as previously disclosed. On December 31, 2003, EME agreed to sell its 50% partnership interest in Brooklyn Navy Yard to a third party. Completion of the sale, expected in first quarter 2004, is subject to closing conditions, including obtaining regulatory approval. If the sale is completed prior to March 31, 2004, EME will not be required to consolidate this entity regardless of the results of the power-contract analysis described above. If the sale is not completed by this date, EME could be required to consolidate the Brooklyn Navy Yard project at March 31, 2004, if it is considered to be the consolidating entity. If required, consolidation would result in EME recording a cumulative effect, after-tax loss of approximately $44 million, primarily due to cumulative losses allocated to the other 50% partner in excess of their equity contributions. If this loss were recorded, it would be reversed in a subsequent period if the sale were completed after March 31, 2004.

Edison Capital has concluded that its investments in its affordable housing and wind projects are variable interests in VIEs. Edison Capital also has power-purchase agreements that could potentially be considered to be variable interests. At December 31, 2003, the maximum exposure to loss from Edison Capital's investments is limited to its investment balance and certain guarantees for a total of $424 million, and recapture of tax credits.

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. The bonds and securities associated with these financing entities are now included in long-term debt on Edison International's consolidated balance sheet and Edison International no longer consolidates the assets and liabilities of these special purpose entities.

Effective July 1, 2003, Edison International adopted a new accounting standard, Amendment of Statement 133 on Derivative Instruments and Hedging Activities. This statement amends and clarifies financial accounting and reporting for derivative instruments and for hedging activities under derivative instrument accounting. The amendment reflects decisions made by accounting authorities in connection with issues raised about the application of the derivative instrument accounting standard. Generally, the provisions of this new standard apply prospectively for contracts entered into or modified after June 30, 2003 and for hedging relationships designated after June 30, 2003. The adoption of this standard had no impact on Edison International's consolidated financial statements.

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 are included in interest expense – net of amounts capitalized on Edison International's consolidated statements of income. Prior period financial statements are not permitted to be restated for these changes. Therefore, upon adoption there was no cumulative impact incurred due to this accounting change.

In May 2003, the Emerging Issues Task Force (EITF) reached a consensus on Determining Whether an Arrangement Contains a Lease, which provides guidance on how to determine whether an arrangement contains a lease that is within the scope of the standard, Accounting for Leases. A lease is defined as an agreement conveying the right to use property, plant, or equipment (land and/or depreciable assets) usually for a stated period of time. The guidance issued by the EITF could affect the classification of a power sales agreement that meets specific criteria, such as a power sales agreement for substantially all of the output from a power plant to one customer. If a power sales agreement meets the guidance issued by the EITF, it would be accounted for as a lease subject to the lease accounting standard. The consensus is effective prospectively for arrangements entered into or modified after June 30, 2003. The consensus had no impact on Edison International's consolidated financial statements.

COMMITMENTS AND GUARANTEES

Edison International's commitments for the years 2004 through 2008 and thereafter are estimated below:

In millions	2004	2005	2006	2007	2008	Thereafter
Long-term debt maturities and sinking fund requirements	$ 2,003	$ 753	$ 1,805	$ 1,764	$ 1,276	$ 6,189
Fuel supply contract payments	911	814	533	377	204	1,579
Gas transportation payments	7	7	7	7	7	65
Purchased-power capacity payments	682	663	637	637	444	3,621
Unconditional purchase obligations	10	10	10	10	10	89
Estimated noncancelable lease payments	334	374	452	487	484	4,577
Preferred securities redemption requirements	9	9	173	69	54	—

Edison International's projected construction expenditures for 2004 are $2.0 billion, including the investment and projected construction expenditures for the Mountainview project (see "Acquisitions and Dispositions"). These expenditures are planned to be financed primarily through cash generated from operations and borrowings.

Fuel Supply Contracts

SCE and EME have fuel supply contracts which require payment only if the fuel is made available for purchase. Certain gas and coal fuel contracts require payment of certain fixed charges whether or not gas or coal is delivered. In addition, fuel supply contract payments include payments for nuclear fuel commitments at SCE.

Gas Transportation

At December 31, 2003, 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.

Power-Purchase Contracts

SCE has power-purchase contracts with certain QFs (cogenerators and small power producers) and other utilities. These contracts provide for capacity payments if a facility meets certain performance obligations and energy payments based on actual power supplied to SCE. 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 settlements to end its contract obligations with certain QFs. The settlements are reported as power-purchase contracts on the balance sheets. In addition, SCE entered into bilateral forward power contracts during 2003, which contain capacity payment provisions.

Unconditional Purchase Obligations

SCE has unconditional purchase obligations for part of a power plant's generating output, as well as firm transmission service from another utility. Minimum payments are based, in part, on the debt-service requirements of the provider, whether or not the plant or transmission line is operable. The purchased-power contract is expected to provide approximately 5% of current or estimated future operating capacity, and is reported as power-purchase contracts (approximately $28 million).

Leases

Edison International has operating leases for office space, vehicles, property and other equipment (with varying terms, provisions and expiration dates).

At December 31, 2003, minimum operating lease payments were primarily related to long-term leases for EME's Collins, Powerton, Joliet and Homer City power plants. In connection with the 1999 acquisition of the Illinois plants, EME assigned the right to purchase the Collins gas and oil-fired power plant to third-party lessors. The third-party lessors purchased the Collins Station for $860 million and leased the plant to EME. During 2000, EME entered into sale-leaseback transactions for equipment, primarily the Illinois peaker power units, and for two power facilities, the Powerton and Joliet coal fired stations located in Illinois, with third-party lessors. In August 2002, EME exercised its option and repurchased the Illinois peaker power units. 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. For further discussion, see "Off-Balance Sheet Transactions—EME's Off-Balance Sheet Transactions—Sale-Leaseback Transactions."

Other Commitments

As of December 31, 2003, Edison Capital had outstanding commitments of $68 million to fund energy and infrastructure investments. Prior to funding any commitments, specific contract conditions must be satisfied. At December 31, 2003, Edison Capital had deposited approximately $5 million as collateral for several letters of credit currently outstanding.

At December 31, 2003, EME had firm commitments to spend approximately $80 million on construction and other capital investments during 2004 through 2006. The construction expenditures primarily relate to the construction of a power plant in New Zealand by Contact Energy. The capital expenditures primarily relate to new plant and equipment at EME's Midwest Generation subsidiary and its Contact Energy project.

At December 31, 2003, EME's Midwest Generation was party to a long-term power-purchase contract with Calumet Energy Team LLC entered into as part of the settlement agreement with ComEd, which terminated Midwest Generation's obligation to build additional gas-fired generation in the Chicago area. The contract requires Midwest Generation to pay a monthly capacity payment and gives Midwest Generation an option to purchase energy from Calumet Energy Team LLC at prices based primarily on operations and maintenance and fuel costs.

EME Homer City entered into a Coal Cleaning Agreement with Homer City Coal Processing Corporation to operate and maintain a coal cleaning plant owned by EME Homer City. Under the terms of the agreement, EME Homer City is obligated to reimburse Homer City Coal Processing Corporation for the actual costs incurred in the operations and maintenance of the coal cleaning plant, a fixed general and administrative service fee of approximately $260 thousand per year, and an operating fee that ranges from $.20 to $.35 per ton depending on the level of tonnage. The agreement expired on August 31, 2002 and was renewed with the same terms through December 31, 2005, with a two-year extension option.

At December 31, 2003, commitments related to these two contracts discussed above are summarized as follows: 2004 – $11 million; 2005 – $10 million; 2006 – $4 million; 2007 – $4 million; and 2008 – $4 million.

Edison International's expected contributions (all by the employer) for United States pension and PBOP plans are approximately $47 million and $100 million, respectively, for the year ended December 31, 2004. These amounts are subject to change based on, among other things, the limits established for federal tax deductibility (pension plans) and the impact of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (PBOP plans).

EME's Guarantees and Indemnities

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, EME 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 obligations under these tax indemnity agreements, EME cannot determine a maximum potential liability. The indemnities would be triggered by a valid claim from the lessors. EME has not recorded a liability related to these indemnities.

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 ComEd with respect to environmental liabilities before and after the date of sale as specified in the Asset Sale Agreement dated

March 22, 1999. The indemnification claims are reduced by any insurance proceeds and tax benefits related to such claims and are subject to a requirement by ComEd to 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. The indemnification for the environmental liabilities referred to above is not limited in term and would be triggered by a valid claim from ComEd. Except as discussed below, EME has not recorded a liability related to this indemnity.

Midwest Generation entered into a supplemental agreement with ComEd 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 ComEd 50% of specific existing asbestos claims less recovery of insurance costs, and agreed to a sharing arrangement for liabilities associated with future asbestos related claims as specified in the agreement. 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 to terminate). Payments are made under this indemnity by a valid claim provided from ComEd. At December 31, 2003, Midwest Generation had $10 million recorded as a liability related to this matter and had made $1 million in payments.

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 Generation L.P. (EME Homer City) agreed to indemnify the sellers with respect to 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

In connection with the sale of assets, EME has provided indemnities to the purchasers for taxes imposed with respect to operations of the asset prior to the sale, and EME or its subsidiaries have received similar indemnities from purchasers related to taxes arising from operations after 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

Brooklyn Navy Yard is a 286 MW gas-fired cogeneration power plant in Brooklyn, New York. EME's wholly owned subsidiary owns 50% of the project. In February 1997, the construction contractor asserted general monetary claims under the turnkey agreement against Brooklyn Navy Yard Cogeneration Partners, L.P. A settlement agreement was executed on January 17, 2003, and all litigation has been dismissed. EME agreed to indemnify Brooklyn Navy Yard Cogeneration Partners, L.P. for any payments due under this settlement agreement, which are scheduled through 2006. At December 31, 2003, EME recorded a liability of $14 million related to this indemnity.

Guarantee of 50% of TM Star Fuel Supply Obligations

TM Star was formed for the limited purpose of selling natural gas to March Point Cogeneration Company, an affiliate through common ownership, under a fuel supply agreement that extends through December 31, 2011. TM Star has entered into fuel purchase contracts with unrelated third parties to meet a portion of the obligations under the fuel supply agreement. EME has guaranteed 50% of TM Star's obligation under the fuel supply agreement to March Point Cogeneration Company. Due to the nature of the obligation under this guarantee, a maximum potential liability cannot be determined. TM Star has met its obligations to March Point Cogeneration Company, and, accordingly, no claims against this guarantee have been made. TM Star was merged into March Point Cogeneration Company effective as of January 16, 2004, and this guarantee terminated by operation of law as of that date.

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, 2003, if payment were required, would be $181 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.

Bank Indemnity under a Letter of Credit Supporting ISAB Energy's Debt Service Reserve Account

EME agreed to indemnify its lenders under its credit facilities from amounts drawn on a $26 million letter of credit issued for the benefit of the lenders to ISAB Energy, a 49% unconsolidated affiliate, in lieu of ISAB Energy funding a debt service reserve account using additional equity contributions. Accordingly, a default under ISAB Energy's project debt could result in a draw under the letter of credit which, in turn, would result in a borrowing under EME's credit facilities. The letter of credit is renewed each six-month period or until ISAB Energy funds the debt service account. The indemnification is subject to the maximum amount drawn under the letter of credit. EME 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

Investments in which EME has a 50% or less ownership interest are accounted for under the equity method in accordance with current accounting standards. Under the equity method, the project assets and related liabilities are not consolidated in EME'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.

On an international basis, for purposes of risk mitigation, EME has often invested in energy projects with strategic partners where its ownership interest is 50% or less.

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, 2003, entities which EME has accounted for under the equity method had indebtedness of $6 billion, of which $3 billion is proportionate to EME's ownership interest in these projects.

Sale-Leaseback Transactions

EME has entered into sale-leaseback transactions related to the Collins, 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 (or, in the case of the Collins Station, the rights to purchase them) 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. In the case of Powerton and Joliet and Homer City, the lessor debt takes the form generally referred to as secured lease obligation bonds. In the case of Collins, the lessor debt takes the form of lessor notes as described in the footnote to the table below.

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 $81 million, $89 million and $55 million in 2003, 2002 and 2001, respectively.

The lessor equity and lessor debt associated with the sale-leaseback transactions for the Collins, 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)					
Collins	$ 860	PSEG	$ 117	$ 774	(i)
Powerton/Joliet	1,367	PSEG/	238	333.5	2009
		Citicapital		813.5	2016
Homer City	1,591	GECC	798	300	2019
				530	2026

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

(i) The owner/lessor under the Collins Station lease issued notes in the amount of the lessor debt to Midwest Funding LLC, a funding vehicle which is owned by Broad Street Contract Services, Inc. These notes mature in January 2014 and are referred to as the lessor notes. Midwest Funding LLC, in turn, entered into a commercial paper and loan facility with a group of banks pursuant to which it borrowed the funds required for its purchase of the lessor notes. These borrowings are currently scheduled to mature in December 2004 and are referred to as the lessor borrowings.

The rent under the Collins Station lease includes both a fixed component and a variable component, which is affected by movements in defined interest rate indices. If the lessor borrowings are not repaid at maturity, by a refinancing or otherwise, the interest rate on them would increase at specified increments every three months, which would be reflected in adjustments to the Collins Station lease rent payments. EME's subsidiary lessee under the Collins Station lease may request the owner/lessor to cause Midwest Funding LLC to refinance the lessor borrowings in accordance with guidelines set forth in the lease, but such refinancing is subject to the owner/lessor's approval. If the lessor borrowings are not refinanced by December 2004 because the owner/lessor's approval is not obtained or a refinancing is not commercially available, rent under the Collins Station lease in 2005 would increase by approximately $9 million for the first quarter of 2005 and increase approximately $2 million for each subsequent quarter thereafter.

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 EME'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, 2003 and 2002, prepaid rent on these leases was $214 million and $117 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 Collins, 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 and Guarantees." Also see "MEHC and EME: Liquidity—Key Financing Developments—EME's Subsidiary Financing Plans—Agreement in Principle to Terminate 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 EME'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	Amount
Years Ending December 31,	
2004	$ 2
2005	2
2006	3
2007	3
2008	4
Thereafter	1,352
Total	$1,366

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, 2003, Edison Capital had made guarantees to lenders in the amount of $5 million.

At December 31, 2003, entities that Edison Capital has accounted for under the equity method had indebtedness of $1.7 billion, of which approximately $474 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, 2003, Edison Capital had investments 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 32 identified sites at SCE (26 sites) and EME (6 sites related to Midwest Generation) is $94 million, $92 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 $238 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.

The CPUC allows SCE to recover environmental remediation costs at certain sites, representing $34 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 $71 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 2003 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 expects to have excess allowances under Phase II of the Clean Air Act (2000 and later).

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. However, SCE has suspended its efforts to seek CPUC approval to install the Mohave pollution-control equipment because it has not obtained reasonable assurance of adequate coal and water supplies for operating Mohave beyond 2005. Unless adequate coal and water supplies are obtained, it will become necessary to shut down

Mohave after December 31, 2005. 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 $24 million as of December 31, 2003) and the related regulatory asset (approximately $66 million as of December 31, 2003), 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 (EPA) has initiated investigations of numerous electric utilities seeking to determine whether these utilities engaged in activities in violation of the NSR requirements, brought enforcement actions against some of those utilities, and reached settlements with some of those utilities. 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 EPA relating to NSR compliance.

Over this same period, 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, 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 are $2.3 billion, including the $605 million for Mohave discussed above for the 2004–2008 period, mainly for undergrounding certain transmission and distribution lines at SCE and upgrading environmental controls at EME.

Employee Compensation and Benefit Plans

On July 31, 2003, a federal district court held that the formula used in a cash balance pension plan created by International Business Machine Corporation (IBM) in 1999 violated the age discrimination provisions of the Employee Retirement Income Security Act of 1974. In its decision, the federal district court set forth a standard for cash balance pension plans. This decision, however, conflicts with the decisions from two other federal district courts and with the proposed regulations for cash balance pension plans issued by the IRS in December 2002. On February 12, 2004, the same federal district court ruled that IBM must make back payments to workers covered under this plan. IBM has indicated that it will appeal both decisions to the United States Court of Appeals for the Seventh Circuit. The formula for Edison International's cash balance pension plan does not meet the standard set forth in the federal district court's July 31, 2003 decision. Edison International cannot predict with certainty the effect of the two IBM decisions on Edison International's cash balance pension plan.

Federal Income Taxes

In August 2002, Edison International received a notice from the IRS asserting deficiencies in federal corporate income taxes for its 1994 to 1996 tax years. The vast majority of the asserted tax deficiencies are timing differences and, therefore, amounts ultimately paid (exclusive of interest and penalties), if any, would benefit Edison International as future tax deductions. Edison International believes that it has meritorious legal defenses to those deficiencies and believes that the ultimate outcome of this matter will not result in a material impact on Edison International's consolidated results of operations or financial position.

Among the issues raised by the IRS in the 1994 to 1996 audit was Edison Capital's treatment of the EPZ and Dutch electric locomotive leases. Written protests were filed against these deficiency notices, as well as other alleged deficiencies, 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 Capital will contest the assessment through administrative appeals and litigation, if necessary, and believes it should prevail in an outcome that will not have a material adverse financial impact.

The IRS is examining the tax returns for Edison International, which includes Edison Capital, for years 1997 through 1999. Edison Capital expects the IRS will also challenge several of its other leveraged leases based on recent Revenue Rulings addressing a specific type of leveraged lease (termed a lease in/lease out or LILO transaction). Edison Capital believes that the position described in the Revenue Ruling is incorrectly applied to Edison Capital's transactions and that its leveraged leases are factually and legally distinguishable in material respects from that position. Edison Capital intends to defend, and litigate if necessary, against any challenges based on that position.

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The management of Edison International is responsible for the integrity and objectivity of the accompanying financial statements. 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.

Edison International and its subsidiaries maintain systems of internal control to provide reasonable, but not absolute, assurance that assets are safeguarded, transactions are executed in accordance with management's authorization and the accounting records may be relied upon for the preparation of the financial statements. There are limits inherent in all systems of internal control, the design of which involves management's judgment and the recognition that the costs of such systems should not exceed the benefits to be derived. Edison International believes its systems of internal control achieve this appropriate balance. These systems are augmented by internal audit programs through which the adequacy and effectiveness of internal controls and policies and procedures are monitored, evaluated and reported to management. Actions are taken to correct deficiencies as they are identified.

Edison International's independent auditors, PricewaterhouseCoopers LLP, are engaged to audit the financial statements in accordance with auditing standards generally accepted in the United States and to express an informed opinion on the fairness, in all material respects, of Edison International's reported results of operations, cash flows and financial position.

As a further measure to assure the ongoing objectivity 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 (who are ultimately responsible to the committee) to conduct audits of Edison International's financial statements; considers the independence of such firm and the overall adequacy of the audit scope and Edison International's systems of internal control; reviews 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.

Thomas M. Noonan
Vice President
and Controller

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

March 10, 2004

To the Board of Directors and Shareholders of Edison International:

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, 2003 and 2002, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion. The financial statements of the Company for the year ended December 31, 2001 were audited by other independent accountants who have ceased operations. Those independent accountants expressed an unqualified opinion on the financial statements and included an explanatory paragraph that described the change in manner in which the Company accounts for derivative instruments and hedging activities and the impairment of long-lived assets discussed in Note 1 to the financial statements in their report dated March 25, 2002.

As discussed in Note 1 to the consolidated financial statements, the Company 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 certain variable interest entities as of December 31, 2003.

PricewaterhouseCoopers LLP

Los Angeles, California
March 10, 2004

THE FOLLOWING REPORT IS A COPY OF A REPORT PREVIOUSLY ISSUED BY ARTHUR ANDERSEN LLP AND HAS NOT BEEN REISSUED BY ARTHUR ANDERSEN LLP

To the Shareholders and the Board of Directors, Edison International:

We have audited the accompanying consolidated balance sheets of Edison International (a California corporation) and its subsidiaries as of December 31, 2001, and 2000, and the related consolidated statements of income (loss), comprehensive income (loss), cash flows and common shareholders' equity for each of the three years in the period ended December 31, 2001. 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 in accordance with auditing standards generally accepted in the 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 includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Edison International and its subsidiaries as of December 31, 2001, and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

As explained in Note 1 to the financial statements, effective January 1, 2001, Edison International has changed its method of accounting for derivative instruments and hedging activities in accordance with SFAS 133, "Accounting for Derivative Instruments and Hedging Activities," and its method of accounting for the impairment or disposal of long-lived assets in accordance with SFAS 144, "Accounting for the Impairment or Disposal of Long-lived Assets."

Arthur Andersen LLP

Los Angeles, California
March 25, 2002

In millions, except per-share amounts Year ended December 31,	2003	2002	2001
Electric utility	$ 8,853	$ 8,705	$ 8,120
Nonutility power generation	3,181	2,750	2,594
Financial services and other	101	33	348
Total operating revenue	12,135	11,488	11,062
Fuel	1,338	1,186	1,128
Purchased power	2,786	2,016	3,770
Provisions for regulatory adjustment clauses – net	1,138	1,502	(3,028)
Other operation and maintenance	3,389	3,156	3,029
Asset impairment	304	86	—
Depreciation, decommissioning and amortization	1,184	1,030	973
Property and other taxes	210	145	114
Net gain on sale of utility plant	(5)	(5)	(6)
Total operating expenses	10,344	9,116	5,980
Operating income	1,791	2,372	5,082
Interest and dividend income	127	287	282
Equity in income from partnerships and unconsolidated subsidiaries – net	354	249	343
Other nonoperating income	91	90	108
Interest expense – net of amounts capitalized	(1,226)	(1,283)	(1,582)
Other nonoperating deductions	(84)	(74)	(70)
Dividends on preferred securities	(51)	(96)	(92)
Dividends on utility preferred stock	(10)	(19)	(22)
Income from continuing operations before tax	992	1,526	4,049
Income tax	213	391	1,647
Income from continuing operations	779	1,135	2,402
Income (loss) from discontinued operations (including gain on disposal of $44 in 2003 and loss on disposal of $1,309 in 2001) – net of tax	51	(58)	(1,367)
Income before accounting change	830	1,077	1,035
Cumulative effect of accounting change – net of tax	(9)	—	—
Net income	$ 821	$ 1,077	$ 1,035
Weighted-average shares of common stock outstanding	326	326	326
Basic earnings (loss) per share:			
Continuing operations	$ 2.39	$ 3.49	$ 7.37
Discontinued operations	0.16	(0.18)	(4.19)
Cumulative effect of accounting change	(0.03)	—	—
Total	$ 2.52	$ 3.31	$ 3.18
Weighted-average shares, including effect of dilutive securities	329	328	326
Diluted earnings (loss) per share:			
Continuing operations	$ 2.37	$ 3.46	$ 7.36
Discontinued operations	0.16	(0.18)	(4.19)
Cumulative effect of accounting change	(0.03)	—	—
Total	$ 2.50	$ 3.28	$ 3.17
Dividends declared per common share	$ 0.20	$ —	$ —

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

In millions Year ended December 31,	**2003**	2002	2001
Net income	**$ 821**	$1,077	$1,035
Other comprehensive income (expense), net of tax:			
Foreign currency translation adjustments	**154**	125	6
Minimum pension liability adjustment	**(2)**	(21)	—
Unrealized gain (loss) on investments – net	**2**	(9)	—
Unrealized gains (losses) on cash flow hedges:			
Cumulative effect of change in accounting for derivatives	**—**	6	148
Other unrealized gain (loss) on cash flow hedges – net	**50**	(20)	(359)
Reclassification adjustment for gain (loss) included in net income	**(10)**	—	16
Other comprehensive income (expense)	**194**	81	(189)
Comprehensive income	**$1,015**	$1,158	$ 846

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

Consolidated Balance Sheets

In millions December 31,	2003	2002
ASSETS		
Cash and equivalents	**$ 2,198**	$ 2,468
Restricted cash	**79**	53
Receivables, less allowances of $37 and $49 for uncollectible accounts at respective dates	**1,200**	1,111
Accrued unbilled revenue	**408**	437
Fuel inventory	**92**	124
Materials and supplies, at average cost	**252**	219
Accumulated deferred income taxes – net	**508**	527
Trading and price risk management assets	**48**	34
Regulatory assets – net	**—**	459
Prepayments	**88**	85
Other current assets	**176**	142
Total current assets	**5,049**	5,659
Nonutility property – less accumulated provision for depreciation of $1,318 and $911 at respective dates	**7,701**	6,873
Nuclear decommissioning trusts	**2,530**	2,210
Investments in partnerships and unconsolidated subsidiaries	**1,908**	2,011
Investments in leveraged leases	**2,361**	2,313
Other investments	**176**	256
Total investments and other assets	**14,676**	13,663
Utility plant, at original cost		
Transmission and distribution	**14,861**	14,202
Generation	**1,371**	1,348
Accumulated provision for depreciation	**(4,386)**	(4,057)
Construction work in progress	**600**	529
Nuclear fuel, at amortized cost	**141**	153
Total utility plant	**12,587**	12,175
Goodwill	**868**	661
Restricted cash	**339**	412
Regulatory assets – net	**510**	—
Other deferred charges	**917**	914
Total deferred charges	**2,634**	1,987
Assets of discontinued operations	**16**	123
Total assets	**$ 34,962**	$ 33,607

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

In millions, except share amounts December 31,	2003	2002
LIABILITIES AND SHAREHOLDERS' EQUITY		
Short-term debt	$ 252	$ 78
Long-term debt due within one year	2,003	2,761
Preferred stock to be redeemed within one year	9	9
Accounts payable	1,086	786
Accrued taxes	596	855
Trading and risk management liabilities	168	45
Regulatory liabilities – net	276	—
Other current liabilities	1,777	2,070
Total current liabilities	6,167	6,604
Long-term debt	11,787	11,578
Accumulated deferred income taxes – net	5,967	6,099
Accumulated deferred investment tax credits	149	167
Customer advances and other deferred credits	1,554	1,486
Power-purchase contracts	213	309
Other preferred securities subject to mandatory redemption	305	—
Accumulated provision for pensions and benefits	425	461
Asset retirement obligations	2,106	—
Regulatory liabilities – net	—	393
Other long-term liabilities	247	218
Total deferred credits and other liabilities	10,966	9,133
Liabilities of discontinued operations	13	72
Total liabilities	28,933	27,387
Commitments and contingencies (Notes 2, 9 and 10)		
Minority interest	517	425
Preferred stock of utility:		
Not subject to mandatory redemption	129	129
Subject to mandatory redemption	—	147
Company-obligated mandatorily redeemable securities of subsidiaries holding solely parent company debentures	—	951
Other preferred securities	—	131
Total preferred securities of subsidiaries	129	1,358
Common stock (325,811,206 shares outstanding at each date)	1,970	1,973
Accumulated other comprehensive loss	(53)	(247)
Retained earnings	3,466	2,711
Total common shareholders' equity	5,383	4,437
Total liabilities and shareholders' equity	$ 34,962	$ 33,607

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

Consolidated Statements of Cash Flows			Edison International
In millions Year ended December 31,	**2003**	2002	2001
Cash flows from operating activities:			
Income from continuing operations, after accounting change, net of tax	**$ 770**	$ 1,135	$ 2,402
Adjustments to reconcile to net cash provided by operating activities:			
Cumulative effect of accounting change – net of tax	**9**	—	—
Depreciation, decommissioning and amortization	**1,184**	1,030	973
Other amortization	**108**	113	92
Deferred income taxes and investment tax credits	**194**	160	1,908
Equity in income from partnerships and unconsolidated subsidiaries	**(354)**	(249)	(343)
Income from leveraged leases	**(82)**	(6)	(154)
Regulatory assets – long-term – net	**495**	1,860	(3,135)
Gas options	**75**	14	(91)
Asset impairment	**304**	86	—
Write-down of nonutility assets	**—**	—	245
Levelized rent expense	**(96)**	—	—
Other assets	**134**	3	(51)
Other liabilities	**(347)**	170	(134)
Changes in working capital:			
Receivables and accrued unbilled revenue	**(160)**	193	(47)
Regulatory assets – short-term – net	**697**	(376)	(278)
Fuel inventory, materials and supplies	**4**	(11)	(16)
Prepayments and other current assets	**86**	(17)	203
Accrued interest and taxes	**(120)**	523	(240)
Accounts payable and other current liabilities	**42**	(2,724)	1,551
Distributions and dividends from unconsolidated entities	**416**	337	236
Operating cash flows from discontinued operations	**(52)**	80	(147)
Net cash provided by operating activities	**3,307**	2,321	2,974
Cash flows from financing activities:			
Long-term debt issued	**1,058**	409	3,386
Long-term debt repaid	**(2,796)**	(1,784)	(1,761)
Bonds remarketed (repurchased) and funds held in trust – net	**—**	191	(130)
Issuance of preferred securities	**—**	—	104
Redemption of preferred securities	**(6)**	(100)	(164)
Rate reduction notes repaid	**(246)**	(246)	(246)
Nuclear fuel financing – net	**—**	(59)	(21)
Short-term debt financing – net	**26**	(956)	(1,547)
Dividends to minority shareholders	**(42)**	(37)	—
Financing cash flows from discontinued operations	**—**	(19)	(1,178)
Net cash used by financing activities	**(2,006)**	(2,601)	(1,557)
Cash flows from investing activities:			
Additions to property and plant – net	**(1,288)**	(1,590)	(933)
Purchase of power sales agreement	**—**	(80)	—
Purchase of common stock of acquired companies	**(278)**	—	—
Proceeds from sale of property	**7**	62	1,032
Proceeds from sale of interest in projects	**41**	—	—
Contributions to nuclear decommissioning trusts – net	**(86)**	(12)	(36)
Distributions from (investments in) partnerships and unconsolidated subsidiaries	**(63)**	42	(122)
Net investments in leveraged leases	**—**	—	68
Other assets	**(58)**	247	(433)
Investing cash flows from discontinued operations	**150**	2	1,125
Net cash provided (used) by investing activities	**(1,575)**	(1,329)	701
Effect of exchange rate changes on cash	**4**	23	(37)
Net increase (decrease) in cash and equivalents	**(270)**	(1,586)	2,081
Cash and equivalents, beginning of year	**2,468**	4,054	1,973
Cash and equivalents, end of year	**2,198**	2,468	4,054
Cash and equivalents – discontinued operations	**—**	—	(63)
Cash and equivalents – continuing operations	**$ 2,198**	$ 2,468	$ 3,991

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

In millions	Common Stock	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total Common Shareholders' Equity
Balance at December 31, 2000	$ 1,960	$ (139)	$ 599	$ 2,420
Net income			1,035	1,035
Foreign currency translation adjustments		(1)		(1)
Tax effect		7		7
Other unrealized loss on cash flow hedges		(296)		(296)
Tax effect		(63)		(63)
Reclassification adjustment for gain included in net income		24		24
Tax effect		(8)		(8)
Cumulative effect of change in accounting for derivatives		24		24
Tax effect		124		124
Stock option appreciation	6			6
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)
Stock option appreciation and other	7			7
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 included in net income		(9)		(9)
Tax effect		(1)		(1)
Dividends declared on common stock			(65)	(65)
Stock option appreciation and other	(3)		(1)	(4)
Balance at December 31, 2003	$ 1,970	$ (53)	$ 3,466	$ 5,383

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; Edison Mission Energy (EME), a producer of electricity engaged in the development and operation of electric power generation facilities worldwide; Edison Capital, a provider of capital and financial services; and Mission Energy Holding Company (MEHC), a holding company for EME. EME and Edison Capital have domestic and foreign projects, primarily in Europe, Asia, Australia and Africa.

EME's plants are located in different geographic areas, partially mitigating the effects of regional markets, economic downturns or unusual weather conditions. EME's domestic facilities (other than Homer City and the Illinois plants) generally sell power to a limited number of electric utilities under long-term (15 years to 30 years) contracts. A plant in Australia sells its energy and capacity production through a centralized power pool. A plant in the United Kingdom sells its energy production by entering into physical bilateral contracts with various counterparties. Other electric power generated overseas is sold under short- and long-term contracts to electricity companies, electricity buying groups or electric utilities located in the country where the power is generated. EME also conducts energy trading and price risk management activities for its generation in power markets open to competition.

Basis of Presentation

The consolidated financial statements include Edison International and its wholly owned subsidiaries. Edison International's subsidiaries consolidate their majority owned subsidiaries. In addition, Edison International's subsidiaries generally use the equity method to account for significant investments in partnerships and subsidiaries in which they own 50% or less of the significant voting rights. However, beginning October 1, 2003, Edison Capital began consolidating its Storm Lake project due to taking temporary control of the project company. Effective December 31, 2003, Edison International no longer consolidates the assets and liabilities of three special purpose entities, EIX Trusts I and II (which are Delaware business trusts), and Mission Capital, L.P. 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. Except as indicated, amounts presented in the Notes to the Consolidated Financial Statements relate to continuing operations.

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 (URG) decision.

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 and other investments with original maturities of three months or less. All investments are classified as available for sale. 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.

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 (stock-based compensation) are added to the weighted-average shares. Dilutive securities are excluded from the diluted EPS calculation during periods of 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,	**2003**	2002	2001
Basic weighted-average shares of common stock outstanding	**326**	326	326
Stock-based compensation awards exercisable	**3**	2	—
Dilutive weighted-average shares of common stock outstanding	**329**	328	326

Fuel Inventory

SCE's fuel inventory is valued under the last-in, first-out method for fuel oil, and under the first-in, first-out method for coal. EME's fuel inventory is stated at the lower of weighted-average cost or market value.

Goodwill

Goodwill represents the excess of cost incurred over the fair value of net assets acquired in a purchase transaction. Goodwill was amortized on a straight-line basis over periods ranging from 20 to 40 years. On January 1, 2002, the amortization of goodwill ceased upon adoption of a new accounting standard. As required by this new accounting standard, EME evaluates goodwill whenever indicators of impairment exist, but at least annually on October 1 of each year. EME's goodwill ($867 million at December 31, 2003 and $660 million at December 31, 2002) is primarily related to the acquisitions of Contact Energy and First Hydro. In 2003, EME determined through a fair value analysis conducted by third parties that the fair value of the Contact Energy and First Hydro reporting units was in excess of book value. Accordingly, no adjustment to impair goodwill was necessary at December 31, 2003.

New Accounting Principles

On January 1, 2001, Edison International adopted a new accounting standard for derivative instruments and hedging activities. An authoritative accounting interpretation issued in October 2001 precludes fuel contracts that have variable amounts from qualifying under the normal purchases and sales exception effective April 1, 2002. The adoption of this interpretation did not have a significant impact on Edison International's financial statements. Under a revised authoritative accounting interpretation issued in December 2001, EME's forward electricity contracts no longer qualify for the normal sales exception since EME has net settlement provisions with its counterparties. However, these contracts qualify as cash flow hedges. Edison International implemented the December 2001 interpretation, effective April 1, 2002.

In June 2003, clarifying guidance was issued related to derivative instruments and hedging activities. The guidance is related to pricing adjustments in contracts that qualify under the normal purchases and normal sales exception under derivative instrument accounting. This implementation guidance became effective on October 1, 2003. The guidance had no impact on Edison International's consolidated financial statements.

On January 1, 2003, Edison International adopted a new accounting standard, Accounting for Asset Retirement Obligations, which requires entities to record the fair value of a liability for a legal asset retirement obligation (ARO) in the period in which it is incurred. When the liability is initially recorded, the entity capitalizes the cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is increased to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss upon settlement. However, rate-regulated entities may recognize regulatory assets or liabilities as a result of timing differences between the recognition of costs as recorded in accordance with this standard and the recovery of costs through the rate-making process. Regulatory assets and liabilities may also be recorded when it is probable that the ARO will be recovered through the rate-making process.

Edison International's impacts of adopting this standard were:

- SCE adjusted its nuclear decommissioning obligation to reflect the fair value of decommissioning its nuclear power facilities. SCE also recognized AROs associated with the decommissioning of other coal-fired generation assets. Fair values were determined based on site-specific studies conducted by third-party contractors.

- At December 31, 2002, SCE had accrued \$2.3 billion to decommission its nuclear facilities and \$12 million to decommission its share of a coal-fired generating plant, under accounting principles in effect at that time. Of these amounts, \$298 million to decommission its inactive nuclear facility was recorded in other long-term liabilities, and the remaining \$2.0 billion was recorded as a component of the accumulated provision for depreciation and decommissioning on the consolidated balance sheets in the 2002 Annual Report.

- As of January 1, 2003, SCE reversed the \$2.3 billion it had previously recorded for decommissioning, recorded the fair value of its AROs of approximately \$2.02 billion in the deferred credits and other liabilities section of the balance sheet, and increased its unamortized nuclear investment by \$303 million. The cumulative effect of a change in accounting principle from unrecognized accretion expense and adjustments to depreciation, decommissioning and amortization expense recorded to date was a \$354 million after-tax gain, which under accounting standards for rate-regulated enterprises was deferred as a regulatory liability, partially offset by a \$235 million deferred tax asset, as of January 1, 2003. Accretion expense on the ARO (\$128 million) and depreciation expense on the new asset

($15 million) resulting from the application of the new standard in 2003 reduced the regulatory liability, with no impact on earnings. SCE's ARO liability account increased from $2.02 billion to $2.08 billion in 2003, with the $128 million in accretion partially offset by $68 million in expenditures related to the decommissioning of its inactive nuclear facility. As of December 31, 2003, SCE's ARO for its nuclear facilities totaled approximately $2.07 billion and its nuclear decommissioning trust assets had a fair value of $2.5 billion. If the new standard had been in place on January 1, 2002, SCE's ARO as of that date would have been $1.98 billion. If the standard had been applied retroactively for the years ended December 31, 2002 and 2001, it would not have had any effect on SCE's results of operations.

- SCE has collected in rates amounts for the future costs of removal and decommissioning of assets, and has historically recorded these amounts in accumulated provision for depreciation. However, in accordance with recent Securities and Exchange Commission accounting guidance, the amounts accrued in accumulated provision for depreciation for decommissioning and costs of removal were reclassified to regulatory liabilities as of December 31, 2002. The cost of removal amounts collected for assets not legally required to be removed remain in regulatory liabilities as of December 31, 2003. Amounts collected through rates for cost of removal of plant assets not considered to be legal obligations ($2.02 billion at December 31, 2003 and $1.92 billion at December 31, 2002) are included in regulatory liabilities.

- As of January 1, 2003, EME's ARO was approximately $17 million and EME recorded a cumulative effect adjustment that decreased net income by approximately $9 million, net of tax. If the new standard had been applied retroactively in the years ended December 31, 2002 and 2001, it would not have had a material effect on EME's results of operations.

In December 2003, the Financial Accounting Standards Board issued a revision to an accounting Interpretation (originally issued in January 2003), Consolidation of Variable Interest Entities (VIEs). The primary objective of the Interpretation is to provide guidance on the identification of, and financial reporting for, so-called "variable interest entities," where control may be achieved through means other than voting rights. Under the Interpretation, the enterprise that, using a discounted cash flow method, is expected to absorb or receive the majority of a VIE's expected losses or residual returns, or both, must consolidate the VIE. 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.

Guidance related to implementation of this Interpretation is evolving. SCE has over 240 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, and the CPUC controls the terms and pricing. Under this accounting Interpretation, SCE could be required to consolidate some or all of the entities that hold these contracts depending on (1) whether these power generators are considered to be VIEs, and (2) whether SCE is considered to be the consolidating entity. These entities are not legally obligated to provide the financial information to SCE, which would be required to determine whether SCE must consolidate these entities. SCE does not know which, if any, of these entities will provide the necessary information. SCE has no investment in, nor obligation to provide support to, these entities other than its requirement to make payment as required by the power purchase agreements. However, if SCE is required to consolidate these entities, it may be required to recognize losses to the extent of any negative equity. These losses, if any, would not affect SCE's liquidity. EME's interests in certain power generators could also potentially be considered as variable interests. EME's maximum exposure to loss is generally limited to its investment in these entities. EME has 49% to 50% ownership in four QF partnerships that have long-term power sales contracts with SCE. EME accounts for these projects using the equity method. If long-term power-purchase contracts are deemed to be variable interests, and due to the related-party nature of this transaction, it is likely that these four QFs could be consolidated by either EME or SCE.

Edison International had originally disclosed that it would adopt the Interpretation as of October 1, 2003. As a result of the December 2003 revision to the Interpretation and uncertainty surrounding its application to long-term power contracts, Edison International delayed implementation for its special purpose entities to December 31, 2003, and for all other entities until March 31, 2004, as allowed under the December revision of the Interpretation. As a result, EME's Brooklyn Navy Yard project, which is a VIE, was not consolidated as previously disclosed. On December 31, 2003, EME agreed to sell its 50% partnership interest in Brooklyn Navy Yard to a third party. Completion of the sale, expected in first quarter 2004, is subject to closing conditions, including obtaining regulatory approval. If the sale is completed prior to March 31, 2004, EME will not be required to consolidate this entity regardless of the results of the power-contract analysis described above. If the sale is not completed by this date, EME could be required to consolidate the Brooklyn Navy Yard project at March 31, 2004, if it is considered to be the consolidating entity. If required, consolidation would result in EME recording a cumulative-effect, after-tax loss of approximately $44 million, primarily due to cumulative losses allocated to the other 50% partner in excess of their equity contributions. If this loss were recorded, it would be reversed in a subsequent period if the sale were completed after March 31, 2004.

Edison Capital has concluded that its investments in its affordable housing and wind projects are variable interests in VIEs. Edison Capital also has power-purchase agreements that could potentially be considered to be variable interests. At December 31, 2003, the maximum exposure to loss from Edison Capital's investments is limited to its investment balance and certain guarantees for a total of $424 million, and recapture of tax credits.

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. The bonds and securities associated with these financing entities are now included in long-term debt on Edison International's consolidated balance sheet and Edison International no longer consolidates the assets and liabilities of these special purpose entities.

Effective July 1, 2003, Edison International adopted a new accounting standard, Amendment of Statement 133 on Derivative Instruments and Hedging Activities. This statement amends and clarifies financial accounting and reporting for derivative instruments and for hedging activities under derivative instrument accounting. The amendment reflects decisions made by accounting authorities in connection with issues raised about the application of the derivative instrument accounting standard. Generally, the provisions of this new standard apply prospectively for contracts entered into or modified after June 30, 2003 and for hedging relationships designated after June 30, 2003. The adoption of this standard had no impact on Edison International's consolidated financial statements.

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 are included in interest expense – net of amounts capitalized on Edison International's consolidated statements of income. Prior period financial statements are not permitted to be restated for these changes. Therefore, upon adoption there was no cumulative impact incurred due to this accounting change. See disclosures regarding these preferred securities in Note 4.

In May 2003, the Emerging Issues Task Force (EITF) reached a consensus on Determining Whether an Arrangement Contains a Lease, which provides guidance on how to determine whether an arrangement contains a lease that is within the scope of the standard, Accounting for Leases. A lease is defined as an agreement conveying the right to use property, plant, or equipment (land and/or depreciable assets) usually for a stated period of time. The guidance issued by the EITF could affect the classification of a power sales agreement that meets specific criteria, such as a power sales agreement for substantially all of the output from a power plant to one customer. If a power sales agreement meets the guidance issued by the EITF, it would be accounted for as a lease subject to the lease accounting standard. The consensus is effective prospectively for arrangements entered into or modified after June 30, 2003. The consensus had no impact on Edison International's consolidated financial statements.

Nuclear

SCE's nuclear plant investments are recorded as a regulatory asset on its balance sheets. This classification does not affect the rate-making treatment for these assets. SCE had been recovering its investments in San Onofre Nuclear Generating Station (San Onofre) Units 2 and 3 and Palo Verde Nuclear Generating Station (Palo Verde) on an accelerated basis, as authorized by the CPUC. The accelerated recovery was to continue through December 2001, earning a 7.35% fixed rate of return on investment. San Onofre's operating costs, including nuclear fuel and nuclear fuel financing costs, and incremental capital expenditures, were recovered through an incentive pricing plan that allows SCE to receive about 4¢ per kilowatt-hour (kWh) through 2003. Any differences between these costs and the incentive price would flow through to shareholders. Palo Verde's accelerated plant recovery, as well as operating costs, including nuclear fuel and nuclear fuel financing costs, and incremental capital expenditures, were subject to balancing account treatment through the effective date of the 2003 general rate case.

The nuclear rate-making plans were to continue for rate-making purposes at least through the 2003 general rate case effective date for Palo Verde operating costs and through 2003 for the San Onofre incentive pricing plan. However, due to the various unresolved regulatory and legislative issues as of December 31, 2000, SCE was no longer able to conclude that the unamortized nuclear investment was probable of recovery through the rate-making process. As a result, this balance was written off as a charge to earnings at that time. As a result of the CPUC's April 4, 2002 decision that returned SCE's URG assets to cost-based ratemaking, SCE reestablished for financial reporting purposes its unamortized nuclear investment and related flow-through taxes, retroactive to August 31, 2001, based on a 10-year recovery period, effective January 1, 2001, with a corresponding credit to earnings. SCE adjusted the procurement-related obligations account (PROACT) regulatory asset balance to reflect recovery of the nuclear investment in accordance with the final URG decision.

In a September 2001 decision, the CPUC granted SCE's request to continue the current rate-making treatment for Palo Verde, including the continuation of the existing nuclear unit incentive procedure with a 5¢ per kWh cap on replacement power costs, until resolution of SCE's next general rate case or further CPUC action. Palo Verde's existing nuclear unit incentive procedure calculates a reward for performance of any unit above an 80% capacity factor for a fuel cycle. The San Onofre Units 2 and 3 incentive rate-making plan continued until December 31, 2003. In its general rate case, SCE has requested to transition San Onofre Units 2 and 3 back to traditional cost-of-service ratemaking on January 1, 2004, and to return Palo Verde to traditional cost-of-service ratemaking upon the effective date of the decision on that application.

Other Nonoperating Income and Deductions

Other nonoperating income and deductions are as follows:

In millions Year ended December 31,	**2003**	2002	2001
Nonutility nonoperating income	**$ 19**	$ 15	$ 51
Utility nonoperating income	**72**	75	57
Total nonoperating income	**$ 91**	$ 90	$ 108
Nonutility nonoperating deductions	**$ 43**	$ 83	$ 32
Utility nonoperating deductions	**41**	(9)	38
Total nonoperating deductions	**$ 84**	$ 74	$ 70

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 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 4.3% for 2003, 4.2% for 2002 and 3.6% for 2001.

AFUDC – equity was $21 million in 2003, $11 million in 2002 and $7 million in 2001. AFUDC – debt was $6 million in 2003, $8 million in 2002 and $9 million in 2001.

Replaced or retired property costs are charged to the accumulated provision for depreciation. Historically, cash payments for removal costs less salvage were charged to the accumulated provision for depreciation and decommissioning and cash collections from customers for future decommissioning were credited to accumulated provision for depreciation and decommissioning. However, as a result of recent guidance from the staff of the Securities and Exchange Commission, SCE reclassified amounts related to removal costs to regulatory liabilities in its December 31, 2003 and 2002 balance sheets. See further discussion in "New Accounting Principles" and "Regulatory Assets and Liabilities."

Estimated useful lives of SCE's property, plant and equipment, 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 $867 million at December 31, 2003 and $842 million at December 31, 2002.

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, including interest incurred on borrowed funds that finance construction. Depreciation of nonutility properties is primarily computed on a straight-line basis over their estimated useful lives 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, 3.3% for 2003, 3.5% for 2002 and 4.2% for 2001.

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.

Estimated useful lives for nonutility property are as follows:

Furniture and equipment	3 years to 11 years
Building, plant and equipment	3 years to 100 years
Emission allowances	25 years to 35 years
Civil works	25 years to 100 years
Leasehold improvements	Life of lease

Purchased Power

SCE purchased power through the California Power Exchange (PX) and California Independent System Operator (ISO) from April 1998 through mid-January 2001. SCE has bilateral forward contracts with other entities and power-purchase contracts with other utilities and independent power producers classified as QFs. Purchased-power detail is provided below:

In millions Year ended December 31,	**2003**	2002	2001
PX/ISO:			
Purchases	**$ 284**	$ 75	$ 775
Generation sales	**—**	—	324
Purchased power – PX/ISO – net	**284**	75	451
Purchased power – bilateral contracts	**342**	61	188
Purchased power – interutility/QF contracts	**2,160**	1,880	3,131
Total	**$ 2,786**	$ 2,016	$ 3,770

Net PX/ISO amounts for 2002 reflect only billing adjustments. These billing adjustments are recovered through the PROACT and have no impact on earnings. Net PX/ISO amounts for 2003 include ISO imbalance purchases and billing adjustments.

From January 17, 2001 to December 31, 2002, the California Department of Water Resources (CDWR) purchased power for delivery to SCE's customers in an amount equal to the difference between customer requirements and supplies provided through QF and bilateral contracts, and SCE's utility-retained generation. Effective January 1, 2003, SCE assumed responsibility for power requirements not met by the CDWR. Power purchased by the CDWR for delivery to SCE's customers is not considered a cost to SCE.

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.

SCE assessed the probability of recovery of its generation-related regulatory assets in light of the CPUC's March 27, 2001 decisions. These decisions and other regulatory and legislative actions did not meet SCE's prior expectation that the CPUC would provide adequate cost recovery mechanisms. SCE was unable to conclude that its generation-related regulatory assets were probable of recovery through the rate-making process as of December 31, 2000. Therefore, in accordance with accounting rules, SCE recorded a $2.5 billion after-tax charge to earnings at that time, to write off various regulatory assets.

In accordance with an October 2001 settlement agreement between the CPUC and SCE, the CPUC passed a resolution on January 23, 2002 allowing SCE to establish the PROACT regulatory asset for previously incurred energy procurement costs, retroactive to August 31, 2001. SCE fully recovered the PROACT balance during July 2003 and on August 1, 2003, transferred the PROACT overcollection to a new energy resource recovery account regulatory balancing account. The new balancing account acts as a mechanism to recover SCE's fuel costs related to its generating stations, purchased-power costs related to cogeneration and renewable contracts, existing interutility and bilateral contracts that were entered into prior to January 17, 2001, and new procurement-related costs that SCE began incurring on January 1, 2003, the date on which the CPUC transferred back to SCE the responsibility for procuring energy resources for its customers.

Based on the CPUC's April 2002 decision related to SCE's URG assets, during the second quarter of 2002, SCE reestablished for financial reporting purposes regulatory assets related to its unamortized nuclear facilities, purchased-power settlements and flow-through taxes.

Due to the current status of the Mohave Generating Station (Mohave) and Related Proceedings (discussed in Note 2), SCE has concluded that it is probable Mohave will be shut down at the end of 2005 and that its book value must be reduced to fair value in accordance with an impairment-related accounting standard. Based on SCE's expectation that any unrecovered book value at the end of 2005 would be recovered in future rates through the rate-making mechanism discussed in its May 17, 2002 application and again in its January 30, 2003 supplemental testimony, and in accordance with accounting standards for rate-regulated enterprises, SCE reclassified for financial reporting purposes approximately $61 million of Mohave's $88 million book value (at December 31, 2002) to a regulatory asset as of December 31, 2002.

As part of a new accounting standard, Accounting for Asset Retirement Obligations, SCE capitalized the initial cost 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 as recorded in accordance with this standard and the recovery of the related asset retirement costs through the rate-making process. The ARO regulatory liability defers the impact on earnings of the change in accounting principle. See further discussion in "New Accounting Principles."

SCE has collected in rates amounts for the future costs of removal and decommissioning of assets, and has historically recorded these amounts in accumulated provision for depreciation. However, in accordance with recent Securities and Exchange Commission accounting guidance, the amounts accrued in accumulated provision for depreciation for 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, 2003.

Regulatory assets, less regulatory liabilities, included in the consolidated balance sheets are:

In millions December 31,	**2003**	2002
Current:		
PROACT – net	**$ —**	$ 574
Regulatory balancing accounts and other – net	**(276)**	(115)
	(276)	459
Long-term:		
Flow-through taxes – net	**974**	1,336
Rate reduction notes – transition cost deferral	**949**	1,215
Unamortized nuclear investment – net	**601**	630
Nuclear-related ARO investment – net	**288**	—
Unamortized coal plant investment – net	**66**	61
Unamortized loss on reacquired debt	**222**	237
Environmental remediation	**71**	70
ARO	**(720)**	—
Costs of removal	**(2,020)**	(4,231)
Regulatory balancing accounts and other – net	**79**	289
	510	(393)
Total	**$ 234**	$ 66

The regulatory asset related to the rate reduction notes will be recovered over the terms of those notes. The net regulatory asset related to the unamortized nuclear investment will be recovered by the end of the remaining useful lives of the nuclear assets. SCE has requested a four-year recovery period for the net regulatory asset related to its unamortized coal plant investment. CPUC approval is pending. The other regulatory assets and liabilities are being recovered through other components of electric rates.

Balancing account undercollections and overcollections accrue interest based on a three-month commercial paper rate published by the Federal Reserve. PROACT accrued interest based on the interest expense for the debt issued to finance the procurement-related obligations, net of interest income on SCE's cash balance. Income tax effects on all balancing account changes are deferred.

Related Party Transactions

Certain 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. SCE's purchases from these partnerships were $754 million in 2003, $548 million in 2002 and $983 million in 2001.

Restricted Cash

Edison International had total restricted cash of $418 million at December 31, 2003 and $465 million at December 31, 2002. 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. In 2003, the restricted amounts were also held by others for the specific use of Edison Capital for its operations. The restricted amounts included in deferred charges in both 2003 and 2002 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. 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.

Since January 17, 2001, power purchased by the CDWR or through the 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 ($1.7 billion in 2003, $1.4 billion in 2002 and $2.0 billion in 2001) 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. Some nonutility power generation revenue from power sales contracts is deferred and amortized to income over the life of the contracts. Included in this deferred revenue is the deferred gain from the termination of the Loy Yang B power sales agreement. Nonutility power generation revenue is adjusted for price differentials resulting from electricity rate swap agreements in the United States, United Kingdom and Australia.

Generally, financial services and other revenue is recorded by recognizing income from leveraged leases over the term of the lease so as to produce a constant rate of return based on the investment leased. Ordinary gains and losses from sale of assets are recognized at the time of the transaction.

Stock-Based Employee Compensation

Edison International has three stock-based employee 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 employee 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. Compensation expense recorded under the stock-compensation program was $12 million in 2003, $13 million in 2002 and $1 million in 2001. 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,	**2003**	2002	2001
Net income, as reported	**$ 821**	$ 1,077	$ 1,035
Add: stock-based compensation expense using the intrinsic value accounting method – net of tax	**7**	8	1
Less: stock-based compensation expense using the fair-value accounting method – net of tax	**9**	5	5
Pro forma net income	**$ 819**	$ 1,080	$ 1,031
Basic EPS:			
As reported	**$ 2.52**	$ 3.31	$ 3.18
Pro forma	**2.51**	3.31	3.17
Diluted EPS:			
As reported	**$ 2.50**	$ 3.28	$ 3.17
Pro forma	**2.49**	3.29	3.16

Supplemental Accumulated Other Comprehensive Loss Information

Supplemental information regarding Edison International's accumulated other comprehensive loss, including the discontinued operations of the Ferrybridge and Fiddler's Ferry power plants and Lakeland project, is:

In millions December 31,	**2003**	2002
Foreign currency translation adjustments – net	**$ 146**	$ (8)
Minimum pension liability – net(1)	**(23)**	(21)
Unrealized loss on investments – net	**(7)**	(9)
Unrealized losses on cash flow hedges – net	**(169)**	(209)
Accumulated other comprehensive loss	**$ (53)**	$ (247)

(1) The minimum pension liability is discussed in Note 7, Employee Compensation and Benefit Plans.

Unrealized losses on cash flow hedges included losses on interest rate hedges and commodity hedges. Unrealized losses on commodity hedges included those related to EME's hedge agreement with the State Electricity Commission of Victoria for electricity prices from the Loy Yang B project in Australia. This contract does not qualify under the normal sales and purchases exception because financial settlement of the contract occurs without physical delivery. These commodity hedge losses arise because current forecasts of future electricity prices in these markets are greater than contract prices. In addition to this contract, unrealized losses on cash flow hedges included those related to EME's share of interest rate swaps of its unconsolidated affiliates and the Loy Yang B project. Interest rate swaps entered into to hedge the floating interest rate risk on MEHC's $385 million term loan due 2006 qualify for treatment under the derivative accounting standard as cash flow hedges with appropriate adjustments made to other comprehensive income. Included in Edison International's accumulated other comprehensive loss at December 31, 2003, was a $156 million loss related to EME's unrealized losses on cash flow hedges. Of the $156 million loss, $77 million was related to EME's commodity hedges and $79 million was related to EME's interest rate hedges.

Unrealized losses on cash flow hedges also 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 $9 million (as of December 31, 2003, 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 2004. Additionally, SCE recorded a $1 million unrealized loss as of December 31, 2003, on an interest rate hedge that terminated on January 7, 2004.

As EME's hedged positions are realized, approximately $13 million (after tax) of the net unrealized gains on cash flow hedges at December 31, 2003 are expected to be reclassified into earnings during 2004. EME expects that when the hedged items are recognized in earnings, the net unrealized gains associated with them will be offset. The maximum period over which EME has designated a cash flow hedge, excluding those forecasted transactions related to the payment of variable interest on existing financial instruments, is 13 years. 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.

Supplemental Cash Flows Information

Edison International supplemental cash flows information is:

In millions Year ended December 31,	2003	2002	2001
Cash payments for interest and taxes:			
Interest – net of amounts capitalized	**$ 1,280**	$ 1,113	$ 1,192
Tax payments (receipts)	**230**	(301)	(70)
Non-cash investing and financing activities:			
Obligation to fund investments in partnerships and unconsolidated subsidiaries	—	—	$ 4
Obligation to fund investment in acquisition	**$ 8**	—	—
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)**	—	—
Cash paid	**500**	—	—
Short-term credit line utilized	**200**	—	—
Details of assets acquired:			
Fair value of assets acquired	**$ 336**	$ 16	$ 898
Cash paid for acquisitions	**(278)**	(16)	(97)
Liabilities assumed	**$ 58**	$ —	$ 801
Details of senior secured credit facility transaction:			
Retirement of credit facility	—	$ 1,650	—
Cash paid on retirement of credit facility	—	(50)	—
Senior secured credit facility replacement	—	$ 1,600	—

Translation of Foreign Financial Statements

Assets and liabilities of most foreign operations are translated at end of period rates of exchange and the income statements are translated at the average rates of exchange for the year. Gains or losses from translation of foreign currency financial statements are included in accumulated other comprehensive income in shareholders' equity. Gains or losses resulting from foreign currency transactions are included in other nonoperating income or deductions. Foreign currency transaction gains/(losses) were $2 million, $(8) million and $2 million for 2003, 2002 and 2001, respectively.

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. During the fourth quarter of 2002, the CDWR issued $11 billion in bonds to finance its 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). Amounts billed to and collected from SCE's customers for electric power purchased and sold by the CDWR (approximately $1.7 billion in 2003) are remitted directly to the CDWR and are not recognized as revenue by SCE.

CPUC Litigation Settlement Agreement

During the California energy crisis, prices charged by sellers of wholesale power escalated far beyond what SCE was permitted by the CPUC to charge its customers. In November 2000, SCE filed a lawsuit against the CPUC in federal district court seeking a ruling that SCE is entitled to full recovery of its electricity procurement costs incurred during the energy crisis in accordance with the tariffs filed with the FERC. In October 2001, SCE and the CPUC entered into a settlement of SCE's lawsuit against the CPUC. A key element of the 2001 CPUC settlement agreement was the establishment of a $3.6 billion regulatory balancing account, called the PROACT, as of August 31, 2001. The Utility Reform Network (TURN) and other parties appealed to the United States Court of Appeals for the Ninth Circuit (Ninth Circuit) seeking to overturn the stipulated judgment of the federal district court that approved the 2001 CPUC settlement agreement. On September 23, 2002, the Ninth Circuit issued its opinion affirming the federal district court on all claims, with the exception of the challenges founded upon California state law, which the Ninth Circuit referred to the California Supreme Court.

On August 21, 2003, the California Supreme Court issued its decision on the certified questions on challenges founded upon California state law, concluding that the 2001 CPUC settlement agreement did not violate California law in any of the respects raised by the Ninth Circuit. Specifically, the California Supreme Court concluded that: (1) the commissioners of the CPUC had the authority to propose the stipulated judgment under the provisions of California's restructuring statute, Assembly Bill 1890, as amended or impacted by subsequent legislation; (2) the procedures employed by the CPUC in entering the stipulated judgment did not violate California's open meeting law for public agencies; and (3) the stipulated judgment did not violate California's public utilities code by allegedly altering rates without a public hearing and issuance of findings.

On October 22, 2003, the California Supreme Court denied TURN's petition for rehearing of the decision. The matter was returned to the Ninth Circuit for final disposition, subject to any efforts by TURN to pursue further federal appeals. On December 19, 2003, the Ninth Circuit unanimously affirmed the original stipulated judgment of the federal district court, and no petition for rehearing was filed. On January 12, 2004, the Ninth Circuit issued its mandate, relinquishing jurisdiction of the case and returning jurisdiction to the federal district court. TURN and those parties whose appeals to the Ninth Circuit were consolidated with TURN's appeal currently have 90 days from December 19, 2003 in which to seek discretionary review from the United States Supreme Court. SCE continues to believe it is probable that recovery of its past procurement costs through regulatory mechanisms, including the PROACT, will not be invalidated. However, SCE cannot predict with certainty the ultimate outcome of further legal proceedings, if any.

Electric Line Maintenance Practices Proceeding

In August 2001, the CPUC issued an order instituting investigation regarding SCE's overhead and underground electric line maintenance practices. The order was based on a report issued by the CPUC's Consumer Protection and Safety Division, which alleged a pattern of noncompliance with the CPUC's general orders for the maintenance of electric lines for 1998–2000. The order also alleged that noncompliant conditions were involved in 37 accidents resulting in death, serious injury or property damage. The Consumer Protection and Safety Division identified 4,817 alleged violations of the general orders during the three-year period; and the order put SCE on notice that it could be subject to a penalty of between $500 and $20,000 for each violation or accident. In its opening brief on October 21, 2002, the Consumer Protection and Safety Division recommended that SCE be assessed a penalty of $97 million.

On June 19, 2003, a CPUC administrative law judge issued a presiding officer's decision on the Consumer Protection and Safety Division report. The decision did the following:

- Fined SCE $576,000 for 2% of the alleged violations involving death, injury or property damage, failure to identify unsafe conditions or exceeding required inspection intervals. The decision did not find that any of the alleged violations compromised the integrity or safety of SCE's electric system or were excessive compared to other utilities.

- Ordered SCE to consult with the Consumer Protection and Safety Division and refine SCE's maintenance priority system consistent with the decision.

- Adopted an interpretation that all of SCE's nonconformances with the CPUC's general orders for the maintenance of electric lines are violations subject to potential penalty.

On July 21, 2003, SCE filed an appeal with the CPUC challenging, among other things, the decision's interpretation of nonconformance. The Consumer Protection and Safety Division also appealed, challenging the fact that the decision did not penalize SCE for 4,721 of the 4,817 alleged violations. A final decision is scheduled to be issued on March 16, 2004.

Generation Procurement Proceedings

SCE resumed power procurement responsibilities for its residual-net short position 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.

Short-Term Procurement Plan

In 2003, SCE operated under a CPUC-approved short-term procurement plan, which includes contracts entered into during a transitional period beginning in August 2002 for deliveries in 2003 and the allocation of CDWR contracts. In December 2003, the CPUC adopted a 2004 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.

Long-Term Resource Plan

On April 15, 2003, SCE filed its long-term resource plan with the CPUC, which includes a 20-year forecast. SCE's long-term resource plan included both a preferred plan and an interim plan (both described below). On January 22, 2004, the CPUC issued a decision which did not adopt any long-term resource plan, but adopted a framework for resource planning. Until the CPUC approves a long-term resource plan for SCE, SCE will operate under its interim resource plan.

- Preferred Resource Plan: The preferred resource plan contains long-term commitments intended to encourage investment in new generation and transmission infrastructure, increase long-term reliability and decrease price volatility. These commitments include energy efficiency and demand-response investments, additional renewable resource contracts that will meet or exceed the requirements of legislation passed in 2002, additional utility and third-party owned generation, and new major transmission projects.

- Interim Resource Plan: The interim resource plan, by contrast, relies exclusively on new short- and medium-term contracts with no long-term resource commitments (except for new renewable contracts).

In its long-term resource plan filing, SCE maintained that implementation of its preferred resource plan requires resolution of various issues including: (1) stabilizing SCE's customer base; (2) restoring SCE's investment-grade creditworthiness; (3) restructuring regulations regarding energy efficiency and demand-response programs; (4) removing barriers to transmission development; (5) modifying prior decisions, which impede long-term procurement; and (6) adopting a commercially realistic cost-recovery framework that will enable utilities to obtain financing and enable contracting for new generation.

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. This resource adequacy requirement phases in over the 2005–2008 period and requires planning reserve margins of 15% to 17% of peak load. The decision requires SCE to enter into forward contracts for 90% of SCE's summer peaking needs a year in advance and to file a revised long-term resource plan in 2004. The decision does not comprehensively address important issues SCE has raised about its customer base, recovery of indirect procurement costs (including debt equivalence) and other matters.

Procurement of Renewable Resources

As part of SCE's resumption of power procurement, 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. 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. As of December 31, 2003, SCE procured approximately 18% of its annual electricity from renewable resources.

SCE has received bids for renewable resource contracts in response to a solicitation it made in August 2003, and is proceeding to enter into negotiations for contracts with some bidders based upon its preliminary bid evaluation.

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 the 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 the CDWR contracts is included within the cap.

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.

In January 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. In February 2002, SCE and Edison International filed an application before the CPUC for rehearing of the decision. In July 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. In August 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 November 26, 2003, the Court of Appeals issued an order indicating it would hear the cases but not decide the merits of the petitions. Oral argument was held before the Court of Appeals on March 5, 2004, and the Court of Appeals is expected to rule within 90 days.

Mohave Generating Station and Related Proceedings

In May 2002, SCE filed an application with the CPUC to address certain issues (mainly coal and slurry-water supply issues) facing the 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 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.

Negotiations are continuing among the relevant parties in an effort to resolve the coal and water supply issues, but no resolution has been reached. The Mohave co-owners, the Tribes and the federal government have recently finalized a memorandum of understanding under which the Mohave co-owners will fund, subject to the terms and conditions of the memorandum of understanding, a $6 million study of a possible alternative groundwater source for the slurry water. The study is expected to begin in early 2004. SCE and other parties submitted further testimony and made various other filings in 2003 in SCE's application proceeding. On February 9, 2004, the CPUC held a prehearing conference to discuss whether additional testimony and hearings are needed to determine the future of the plant. The CPUC has not issued any ruling as result of the prehearing conference, but has indicated that further testimony can be expected in early to mid-2004. The outcome of the coal and water negotiations and SCE's application are not expected to impact Mohave's operation through 2005, but could have a major impact on SCE's long-term resource plan.

For additional matters related to Mohave, see "Navajo Nation Litigation" in Note 10.

In light of all of the issues discussed above, SCE has concluded that it is probable Mohave will 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 as a regulatory asset, based on SCE's expectation that any unrecovered book value at the end of 2005 would be recovered in future rates through a balancing account mechanism presented in its May 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 PX/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 will be refunded to customers, except for the El Paso Natural Gas Company settlement agreement discussed below.

El Paso Natural Gas Company entered into a settlement agreement with parties to a class action lawsuit (including SCE, PG&E and the State of California) settling claims stated in proceedings at the FERC and in San Diego County Superior Court that El Paso Natural Gas Company 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 San Diego County Superior Court approved the settlement on December 5, 2003. Notice of appeal of that judgment was filed by a party to the action on February 6, 2004. Accordingly, until the appeal is resolved, the judgment is not final and no refunds will be paid. Pursuant to a CPUC decision, SCE will refund to customers any amounts received under the terms of the El Paso Natural Gas Company settlement (net of legal and consulting costs) through its energy resource recovery account mechanism. In addition, amounts El Paso Natural Gas Company refunds to the CDWR will result in equivalent reductions in the CDWR's revenue requirement allocated to SCE.

On February 24, 2004, SCE and PG&E entered into a settlement agreement with The Williams Cos. and Williams Power Company, providing for approximately $140 million in refunds against some of Williams' power charges in 2000–2001. The allocation of refunds under the settlement agreement has not been determined. The settlement is subject to the approval of the FERC, the CPUC and the PG&E bankruptcy court.

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 oil, gas and energy prices but prohibits the use of these instruments for speculative or trading purposes, except at EME's trading operations unit.

On January 1, 2001, Edison International adopted a new accounting standard for derivative instruments and hedging activities. Edison International has also adopted subsequent interpretations of this standard. The standard requires derivative instruments to be recognized on the 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 the hedge. For a 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. Fair value changes for EME's trading operations are reflected in earnings.

SCE recorded its interest rate swap agreement (terminated January 5, 2001) and its block forward power-purchase contracts at fair value effective January 1, 2001. The unamortized loss of $9 million (as of December 31, 2003, net of tax) on the interest rate swap will be amortized over a period ending in 2008, when the related debt matures.

In December 2003, SCE entered into an interest rate lock to hedge its exposure to changes in interest rates for $825 million of anticipated issuances of first mortgage bonds. SCE recorded a $1 million liability as of December 31, 2003, representing the fair value of the interest rate lock. The lock expired on January 7, 2004, the pricing date of $975 million of new mortgage bonds, resulting in a payment of $6 million to the counterparties due to a decline in treasury rates. This loss will be treated as a debt discount and amortized over the life of the mortgage bonds.

SCE has bilateral forward power contracts, which are considered normal purchases under accounting rules. SCE is exposed to credit loss in the event of nonperformance by the counterparties to its bilateral forward contracts, but does not expect the counterparties to fail to meet their obligations. The counterparties are required to post collateral depending on the creditworthiness of each counterparty.

In October and November 2001, SCE purchased $209 million of call options that mitigated its exposure to increases in natural gas prices during 2002 and 2003. This amount was recovered through a balancing account mechanism. Amounts paid to QFs for energy are based on natural gas prices. Any fair value changes for gas call options are offset through a regulatory balancing account; therefore, fair value changes do not affect earnings. In fourth quarter 2003, SCE purchased $4 million of call options to hedge some gas price exposure for 2004.

SCE purchases power from certain QFs in which the contract pricing is based on a natural gas index, but the power is not generated with natural gas. A portion of these contracts is not eligible for the normal purchases and sales exception under accounting rules and the fair value is recorded on the balance sheet. Any fair value changes for these QF contracts are offset through a regulatory mechanism; therefore, fair value changes do not affect earnings.

EME's primary market risk exposures arise from fluctuations in electricity and fuel prices, emission and transmission rights, interest rates and foreign currency exchange rates. EME manages these risks in part by using derivative financial instruments in accordance with established policies and procedures.

In 2001, EME recorded a $250,000 (after tax) increase to income from continuing operations, a $6 million (after tax) increase to income from discontinued operations and a $230 million (after tax) decrease to other comprehensive income as the cumulative effect of a change in accounting for derivatives. Upon implementation, EME's forward sales contracts from the Homer City facilities qualified as cash flow hedges. EME did not use the normal purchases and sales exception for these forward sales contracts due to net settlement procedures with counterparties. As a result of higher market prices for forward sales from its Homer City facilities, EME recorded a liability of $116 million at January 1, 2001, deferred tax benefits of $54 million and a decrease in other comprehensive income of $62 million. EME's hedge agreement with the State Electricity Commission of Victoria for electricity prices from its Loy Yang B project in Australia qualified as a cash flow hedge. This contract could not qualify under the normal purchases and sales exception because financial settlement of the contract occurs without physical delivery. As a result of higher market prices for forward sales from EME's Loy Yang B plant, EME recorded a liability of $227 million at January 1, 2001, deferred tax benefits of $68 million and a decrease in other comprehensive income of $159 million. The majority of EME's activities related to the fuel contracts for EME's Collins Station in Illinois did not qualify for either the normal purchases and sales exception or as cash flow hedges. EME could not conclude, based on information available at January 1, 2001, that the timing of generation from the Collins Station met the probable requirement for a specific forecasted transaction under the new accounting standard for derivatives and hedging activities. Accordingly, these contracts were recorded at fair value, with subsequent changes in fair value reflected in nonutility power generation revenue in the consolidated income statement. EME has continued to record fuel contracts for its Collins Station at fair value.

New accounting guidance effective July 1, 2001, modified the normal purchases and sales exception to include electricity contracts which include terms that require physical delivery by the seller in quantities that are expected to be sold in the normal course of business. This modification resulted in EME's Homer City forward sales contracts qualifying for the normal sales and purchases exception commencing July 1, 2001. Based on this accounting guidance, on July 1, 2001, EME eliminated the value of the Homer City forward sales contracts from its consolidated balance sheet. The cumulative effect of this change in accounting is reflected as a $16 million (after tax) decrease to other comprehensive income in 2001. Also, for the period between January 1, 2001 and June 30, 2001, EME applied the normal purchases and sales exception for long-term commodity contracts that included both selling and buying electricity by EME's First Hydro plant. However, the criteria applicable to the buyer of power under the new interpretation precluded the contracts from qualifying under the normal purchases and sales exception as of July 1, 2001, because First Hydro is not contractually obligated to maintain sufficient capacity to meet electricity needs of a customer. Accordingly, EME recorded a $15 million (after tax) increase to income from continuing operations as the cumulative effect of change in accounting for derivatives in the consolidated income statement as of July 1, 2001. All subsequent changes in the fair value of these contracts will be reflected in nonutility power generation revenue in the consolidated income statement.

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.

In June 2003, clarifying guidance was issued related to derivative instruments and hedging activities. The guidance is related to pricing adjustments in contracts that qualify under the normal purchases and normal sales exception under derivative instrument accounting. This implementation guidance became effective on October 1, 2003, but did not have any impact on Edison International's consolidated financial statements.

Under the accounting standard for derivatives and hedging activities, the portion of a cash flow hedge that does not offset the change in value of the transaction being hedged, which is referred to as the ineffective portion, is immediately recognized in earnings. EME recorded a net loss of approximately $2 million and $1 million in 2002 and 2001, respectively, representing the amount of cash flow hedges' ineffectiveness; these amounts are reflected in nonutility power generation revenue in the consolidated income statement.

Under EME's fixed to variable swap agreements, the fixed interest rate payments are at a weighted average rate of 6.39% and 6.91% at December 31, 2003 and 2002, respectively. Variable rate payments under EME's corporate agreements were based on six-month LIBOR capped at 9% at December 31, 2001. Variable rate payments pertaining to its foreign subsidiary agreements are based on an equivalent interest rate benchmark to LIBOR. The weighted average rate applicable to these agreements was 5.36% and 6.18% at December 31, 2003 and 2002, respectively. Under the variable to fixed swap agreements, EME will pay counterparties interest at a weighted average fixed rate of 6.74% and 6.96% at December 31, 2003 and 2002, respectively. Counterparties will pay EME interest at a weighted average variable rate of 5.07% and 5.10% at December 31, 2003 and 2002, respectively. The weighted average variable interest rates are based on LIBOR or equivalent interest rate benchmarks for foreign denominated interest rate swap agreements. Under EME's interest rate options, the weighted average strike interest rate is was 6.24% and 6.90% and December 31, 2003 and 2002, respectively.

In September 2000, EME acquired the trading operations of Citizens Power LLC, expanding EME's operations beyond the traditional marketing of electric power to include trading of electricity and fuels. Energy trading and price risk management activities give rise to market risk (potential loss that can be caused by a change in the market value of a particular commitment). Market risks are actively monitored to ensure compliance with EME's risk management policies. EME performs a "value at risk" analysis daily to monitor its overall market risk exposure. This analysis measures the worst expected 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 other techniques, including the use of stress testing and worst case scenario analysis, as well as stop limits and counterparty credit exposure limits.

MEHC, a wholly owned indirect subsidiary of Edison International, has two interest rate swaps to hedge floating interest rate risk on its term loan. These contracts qualify for treatment as cash flow hedges with appropriate adjustments made to other comprehensive income. During the years ended December 31, 2003 and 2002, MEHC recorded decreases to other comprehensive income of $3 million (after tax) and $5 million (after tax), respectively, resulting from unrealized holding losses on these contracts. Under the variable-to-fixed swap agreements, MEHC will pay counterparties interest at a weighted average fixed rate of 2.84% and 3.04% at December 31, 2003 and 2002, respectively; counterparties will pay interest at a weighted average variable rate based on LIBOR of 1.15% and 1.63% at December 31, 2003 and 2002, respectively.

Edison Capital had an interest rate swap and an interest rate cap in place during 2003. The purpose of the interest rate swap was to convert floating rate debt to fixed rate debt to hedge changes in interest rates. The purpose of the interest rate cap was to limit Edison Capital's exposure to an increase in interest rates. In 2003, Edison Capital made payments on its swap agreement at a weighted average rate of 6.79% and received payments at a weighted average rate of 1.17%. In 2003, Edison Capital received no payments on its cap agreement.

Notes to Consolidated Financial Statements

Fair values of financial instruments are:

In millions December 31,	2003	2002
Derivatives:		
Interest rate hedges	**$ (35)**	$ (56)
Interest rate options	**(1)**	(2)
Commodity price		
Electricity	**(126)**	(100)
Natural gas	**3**	77
Foreign currency forward exchange agreements	**(2)**	—
Cross currency interest rate swaps	**(91)**	(2)
Other:		
Decommissioning trusts	**2,530**	2,210
Long-term receivables	**6**	6
DOE decommissioning and decontamination fees	**(18)**	(22)
QF power contracts	**(32)**	(70)
Long-term debt	**(11,833)**	(9,952)
Long-term debt due within one year	**(2,029)**	(2,812)
Preferred stock to be redeemed within one year	**(9)**	(8)
Company-obligated mandatorily redeemable securities of subsidiaries	**—**	(741)
Other preferred securities subject to mandatory redemption	**(303)**	(375)
Trading Activities:		
Assets	**104**	109
Liabilities	**(12)**	(17)

The fair value of the interest rate hedges and interest rate options is based on quoted market prices.

The fair value of the commodity contracts considers quoted market prices, time value, volatility of the underlying commodities and other factors. The fair value of the electricity rate swap agreements (included under commodity price) is estimated by discounting the future cash flows on the difference between the average aggregate contract price per MW and a forecasted market price per MW, multiplied by the amount of MW sales remaining under contract. The fair value of the QF power contracts is based on financial models; the fair value of the gas call options (included under commodity price) is based on quoted market prices.

Foreign currency forward exchange agreements and cross currency interest rate swaps are based on bank quotes.

Other fair values are based on: quoted market prices for decommissioning trusts and long-term receivables; discounted future cash flows for United States Department of Energy (DOE) decommissioning and decontamination fees; and brokers' quotes for long-term debt, company-obligated mandatorily redeemable securities of subsidiaries, and preferred stock and preferred securities subject to mandatory redemption.

Quoted market prices are used to determine the fair values of trading instruments. Assets from trading and price risk management 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 trading and price risk management activities include the fair value of open financial positions related to trading activities and the present value of net amounts payable from structured transactions.

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 are now 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.

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. Bondholders have limited discretion in redeeming certain pollution-control bonds, and SCE has arrangements with securities dealers to remarket or purchase them if necessary. In December 2000 and early 2001, as a result of investors' concerns regarding SCE's liquidity difficulties and overall financial condition, SCE had to repurchase $550 million of pollution-control bonds that could not be remarketed in accordance with their terms. On March 1, 2002, SCE remarketed $196 million of the pollution-control bonds that SCE had repurchased in late 2000.

Debt premium, discount and issuance expenses are amortized 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.

MEHC used the common stock of EME as security for MEHC's corporate debt obligations. MEHC's senior secured notes and credit agreement are nonrecourse to Edison International and EME, and accordingly, Edison International and EME have no obligations under these instruments.

MEHC's consolidated debt at December 31, 2003 was $7.4 billion, including $693 million of debt maturing in December 2004 that is owed by EME's largest subsidiary, Edison Mission Midwest Holdings. Edison Mission Midwest Holdings is not expected to have sufficient cash to repay the

$693 million debt due in December 2004. Edison Mission Midwest Holdings plans to refinance the $693 million debt obligation prior to its expiration in December 2004. EME believes that Edison Mission Midwest Holdings will be able to refinance the debt maturing in December 2004 through a combination of borrowings in the bank and capital markets. Completion of this refinancing is subject to a number of uncertainties, including availability of new credit from the capital and bank markets. Accordingly, there is no assurance that Edison Mission Midwest Holdings will be able to extend or refinance this debt when it becomes due or that the terms will not be substantially different from those under the current credit facility.

On December 11, 2003, EME's subsidiary, Mission Energy Holdings International, Inc., received funding under a three-year, $800 million secured loan. Interest on this secured loan is based on LIBOR (with a LIBOR floor of 2%) plus 5%. After payment of transaction expenses, a portion of the net proceeds from this financing was used to make an equity contribution of $550 million to Edison Mission Midwest Holdings that, together with cash on hand, was used to repay Edison Mission Midwest Holdings' $781 million indebtedness due December 11, 2003. The remaining net proceeds from this financing were used to make a deposit of cash collateral of approximately $67 million under a new letter of credit facility and to repay approximately $160 million of indebtedness of a foreign subsidiary under the Coal and Capex facility guaranteed by EME. Mission Energy Holdings International owns substantially all of EME's international operations through its subsidiary, MEC International B.V.

To isolate EME from credit downgrades of Edison International and SCE and to help preserve the value of EME, EME has adopted certain provisions (ring-fencing) in the form of amendments to its articles of incorporation and bylaws. The provisions include the appointment of an independent EME director whose consent is required for EME to: consolidate or merge with any entity that does not have substantially similar provisions in its organizational documents; institute or consent to bankruptcy, insolvency or similar proceedings; or declare or pay dividends unless certain conditions exist. Such conditions are that EME has an investment grade rating and receives rating agency confirmation that the dividend will not result in a downgrade, or such dividends do not exceed $32.5 million in any quarter and EME meets an interest coverage ratio of 2.2 to 1 for the immediately preceding four quarters.

Long-term debt is:

In millions December 31,	**2003**	2002
First and refunding mortgage bonds:		
2004 – 2026 (5.875% to 8.00% and variable)	**$ 1,816**	$ 2,275
Rate reduction notes:		
2004 – 2007 (6.38% to 6.42%)	**985**	1,232
Pollution-control bonds:		
2005 – 2040 (5.125% to 7.2% and variable)	**1,216**	1,216
Bonds repurchased	**(354)**	(354)
Debentures and notes:		
2004 – 2039 (2.31% to 13.5% and variable)	**9,927**	9,922
Subordinated debentures:		
2024 – 2044 (8.375% to 9.875%)	**254**	100
Long-term debt due within one year	**(2,003)**	(2,761)
Unamortized debt discount – net	**(54)**	(52)
Total	**$ 11,787**	$ 11,578

Note: Rates and terms as of December 31, 2003.

Long-term debt maturities and sinking-fund requirements for the next five years are: 2004 – $2.0 billion; 2005 – $753 million; 2006 – $1.8 billion; 2007 – $1.7 billion; and 2008 – $1.3 billion.

Long-term debt due within one year includes $29 million and $31 million of debt related to Edison Capital's Storm Lake project that is not due until 2011 and 2017, respectively. This debt has been reclassified to long-term debt due within one year as a result of various defaults asserted by the lenders and related to the Enron bankruptcy among other things, which may give the lenders the ability to call the loans due and payable. However, the lenders are currently discussing resolution of the defaults with Storm Lake and are not actively pursuing remedies.

In January 2004, SCE issued $975 million of first and refunding mortgage bonds. The issuance included $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. The proceeds were used to redeem $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 March 2004, SCE remarketed approximately $550 million of pollution-control bonds with varying maturity dates ranging from 2008 to 2040.

During January and February 2004, Edison International repurchased approximately $46 million of its outstanding $618 million of 6-7/8% notes, leaving a remaining balance of $572 million of notes due September 2004.

Short-Term Debt

Short-term debt is used to finance fuel inventories, balancing account undercollections and general cash requirements, including power purchase payments.

Short-term debt is:

In millions December 31,	**2003**	2002
Bank loans	**$ 200**	$ —
Floating rate notes	**—**	78
Other short-term debt	**52**	—
Total	**$ 252**	$ 78
Weighted-average interest rate	**3.2%**	6.1%

Lines 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.

At December 31, 2002, Edison International's subsidiaries had short-term and long-term lines of credit totaling $787 million, with various expiration dates, and when available, could be drawn down at negotiated or bank index rates. Of the total lines of credit, $512 million were long-term. EME had total lines of credit of $487 million, with $355 million available to finance general cash requirements. SCE had a fully drawn long-term line of credit of $300 million.

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.

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 have a stated maturity of July 2029, but are redeemable at the option of Edison International, in whole or in part, beginning July 2004. The 8.6% securities have a stated maturity of October 2029, but are redeemable at the option of Edison International, in whole or in part, beginning October 2004. Both of these securities are guaranteed by Edison International. In order to reduce its cash requirements, in May 2001, the parent company deferred the interest payments in accordance with the terms of its outstanding quarterly income debt securities issued to an affiliate. This caused a corresponding deferral of distributions on quarterly income preferred securities issued by the affiliate. Interest payments may be deferred for up to 20 consecutive quarters. During the deferral period, the principal of the debt securities and each unpaid interest installment continues to accrue interest at the applicable coupon rate. All interest in arrears must be paid in full at the end of the deferral period. The parent company cannot pay dividends on or purchase its common stock while interest is being deferred. In December 2003, Edison International made aggregate payments of approximately $205 million, which covered repayment of the deferred distributions, with interest, and payment of the distribution due on November 30, 2003.

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. No securities have been redeemed as of December 31, 2003.

EME has the right from time to time to extend the interest payment period on its junior subordinated deferrable interest debentures to a period not exceeding 60 consecutive months, at the end of which all accrued and unpaid interest will be paid in full. If EME does not make interest payments on its junior subordinated debentures, it is expected that this limited partnership will not declare or pay distributions on its cumulative monthly income preferred securities. During an extension period, EME may not do any of the following:

- declare or pay any dividend on, or purchase, acquire or make a distribution or liquidation payment with respect to, any of its common or preferred stock;

- acquire for cash or other property any indebtedness of any affiliate of EME (other than affiliates of EME which meet specified requirements) for money borrowed; or

- make any loan or advance to, or guarantee or become contingently liable in respect of indebtedness of, any affiliate of EME (other than affiliates of EME which meet specified requirements).

Further, as long as any preferred securities remain outstanding, EME will not be able to declare or pay dividends on, or purchase, any of its common stock if at such time it is in default on its payment obligations under the guarantee or the subordinated indenture unless EME has given notice of the extended interest payment period described above.

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 entities are now included in long-term debt on Edison International's consolidated balance sheet. Under the prior accounting treatment, these securities would have been eliminated in consolidation and reflected as company-obligated mandatorily redeemable securities of subsidiary.

Other Preferred Securities Subject to Mandatory Redemption

SCE has 12 million authorized shares of preferred stock subject to mandatory redemption. All cumulative preferred stock is redeemable. 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: 2004 – $9 million; 2005 – $9 million; 2006 – $9 million; 2007 – $69 million; and 2008 – $54 million.

SCE's cumulative preferred stock subject to mandatory redemption is:

Dollars in millions, except per-share amounts	December 31,		**2003**	2002
	December 31, 2003			
	Shares Outstanding	Redemption Price		
$100 par value:				
6.05% Series	693,800	$ 100.00	**$ 69**	$ 75
7.23	807,000	100.00	**81**	81
Preferred stock to be redeemed within one year			**(9)**	(9)
Total			**$ 141**	$ 147

In 2001, SCE did not redeem any preferred stock. In 2002, SCE redeemed 1,000,000 shares of 6.45% Series preferred stock. In 2003, SCE redeemed 56,200 shares of 6.05% Series preferred stock. SCE did not issue any preferred stock in the last three years.

The 7.23% Series preferred stock 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 2002 or 2003. At December 31, 2003, SCE had 93,000 of previously repurchased, but not retired, shares available to credit against the mandatory sinking fund provisions.

During 2001, a subsidiary of EME issued $104 million of redeemable preferred shares (250 million shares at a price of one New Zealand dollar per share with a dividend rate of 6.03%). The shares are redeemable in July 2006 at the issuance price. At December 31, 2003, total accumulated dividends were approximately $5 million. Optional early redemption may occur if the holders pass an extraordinary resolution to redeem the shares if certain EME subsidiaries cease to be subsidiaries of EME or in the case of certain defaults of the security trust deed. The security trust deed secures a limited recourse guarantee by an EME subsidiary's payment obligations to holders of the redeemable preferred shares.

Note 5. Preferred Securities Not Subject to Mandatory Redemption

SCE's authorized shares are: $25 cumulative preferred – 24 million and preference – 50 million. All cumulative preferred stock is redeemable. When preferred shares are redeemed, the premiums paid, if any, are charged to common equity.

SCE's cumulative preferred stock not subject to mandatory redemption is:

Dollars in millions, except per-share amounts	December 31,		**2003**	2002
	December 31, 2003			
	Shares Outstanding	Redemption Price		
$25 par value:				
4.08% Series	1,000,000	$25.50	**$ 25**	$ 25
4.24	1,200,000	25.80	**30**	30
4.32	1,653,429	28.75	**41**	41
4.78	1,296,769	25.80	**33**	33
Total			**$129**	$129

Note 6. Income Taxes

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

As part of the process of preparing its consolidated financial statements, Edison International is required to estimate its income taxes in each of the jurisdictions in which it operates. This process involves estimating actual current tax exposure together with assessing temporary differences resulting from differing treatment of items, such as depreciation, for tax and accounting purposes. These differences result in deferred tax assets and liabilities, which are included within Edison International's consolidated balance sheet.

Edison International's subsidiary, EME, does not provide for federal income taxes or tax benefits on the undistributed earnings or losses of its international subsidiaries because such earnings are reinvested indefinitely or would not be subject to additional income taxes if repatriated. EME reviewed undistributed earnings of its international subsidiaries and concluded that no additional income taxes are required to be provided since (1) its international holding company had negative retained earnings and negative accumulated earnings and profits for federal income tax purposes, (2) distributions from lower tier international subsidiaries would either not be taxable or could be distributed without additional income taxes and (3) its international holding company had outstanding indebtedness to domestic subsidiaries of $445 million at December 31, 2003, which could be repaid without incurring additional income taxes.

Income tax expense includes the current tax liability from operations and the change in deferred income taxes during the year. Investment tax credits are amortized over the lives of the related properties.

The sources of income (loss) before income taxes are:

In millions Year ended December 31,	**2003**	2002	2001
Domestic	**$ 787**	$ 1,379	$ 3,962
Foreign	**205**	147	87
Total continuing operations	**992**	1,526	4,049
Discontinued operations	**84**	(74)	(2,223)
Change in accounting	**(13)**	—	—
Total	**$ 1,063**	$ 1,452	$ 1,826

The components of income tax expense (benefit) by location of taxing jurisdiction are:

In millions Year ended December 31,	**2003**	2002	2001
Current:			
Federal	**$ 194**	$ 585	$ (215)
State	**100**	111	—
Foreign	**54**	38	30
	348	734	(185)
Deferred:			
Federal	**(101)**	(312)	1,422
State	**(67)**	(43)	406
Foreign	**33**	12	4
	(135)	(343)	1,832
Total continuing operations	**213**	391	1,647
Discontinued operations	**33**	(16)	(856)
Change in accounting	**(4)**	—	—
Total	**$ 242**	$ 375	$ 791

The components of the net accumulated deferred income tax liability are:

In millions December 31,	**2003**	2002
Deferred tax assets:		
Property-related	**$ 243**	$ 178
Unrealized gains or losses	**365**	274
Investment tax credits	**68**	73
Regulatory balancing accounts	**144**	5,365
Deferred income	**177**	172
Decommissioning	**166**	—
Accrued charges	**344**	501
Loss carryforwards	**373**	448
Other	**211**	240
Subtotal	**2,091**	7,251
Valuation allowance	**(74)**	(21)
Total	**$ 2,017**	$ 7,230
Deferred tax liabilities:		
Property-related	**$ 4,337**	$ 4,424
Leveraged leases	**2,055**	2,044
Capitalized software costs	**160**	204
Regulatory balancing accounts	**360**	5,606
Unrealized gains and losses	**262**	171
Other	**302**	353
Total	**$ 7,476**	$12,802
Accumulated deferred income taxes – net	**$ 5,459**	$ 5,572
Classification of accumulated deferred income taxes:		
Included in deferred credits	**$ 5,967**	$ 6,099
Included in current assets	**$ 508**	$ 527

The federal statutory income tax rate is reconciled to the effective tax rate from continuing operations as follows:

Year ended December 31,	**2003**	2002	2001
Federal statutory rate	**35.0%**	35.0%	35.0%
Resolution of FERC rate case	**(7.6)**	—	—
Housing credits	**(2.7)**	(2.4)	(1.2)
Property-related and other	**(3.9)**	(8.3)	0.6
Favorable resolution of audit	**(3.6)**	(2.4)	—
State tax – net of federal deduction	**4.3**	3.7	6.3
Effective tax rate	**21.5%**	25.6%	40.7%

Edison International's composite federal and state statutory tax rate was approximately 40% for all years presented. The lower effective tax rate of 21.5% realized in 2003 was primarily due to the resolution of a FERC rate case at SCE, recording the benefit of favorable settlements of Internal Revenue Service (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 25.6% 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;

recording the benefit of favorable settlements of IRS audits at SCE; and the effect of lower foreign tax rates and permanent reinvestment of earnings of foreign affiliates at EME, offset by foreign losses which were not able to be utilized in the current period.

At December 31, 2003, Edison International and its subsidiaries have federal tax credits of $116 million which expire between 2018 and 2021, California net operating loss carryforwards of $1.2 billion which expire between 2009 and 2011, and California capital loss carryforwards of $88 million that expire in 2005. In addition, EME has foreign loss carryforwards, primarily Australian, of $487 million and $204 million at December 31, 2003 and 2002, respectively, with no expiration date. EME has state loss carryforwards for various states of $168 million and $230 million at December 31, 2003 and 2002, respectively, with various expiration dates.

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. Employee 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 $43 million in 2003, $42 million in 2002 and $40 million in 2001.

Pension Plan and Postretirement Benefits Other Than Pensions

Pension Plan

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. Certain foreign subsidiaries of EME also participate in their own respective defined benefit pension plans.

EME's Ferrybridge and Fiddler's Ferry employees joined a separate defined benefit pension plan during first quarter 2000. In December 2001, the Ferrybridge and Fiddler's Ferry plants were sold to two wholly owned subsidiaries of American Electric Power. American Electric Power hired EME's employees upon completion of the purchase and all of EME's former employees transferred to the new plan as of December 20, 2002. In accordance with accounting standards, Edison International recorded a curtailment gain of approximately $10 million related to the cessation of future benefits for EME's former employees in 2001. The curtailment gain reduced actuarial losses incurred during the year and, therefore, did not impact Edison International's pension expense.

At December 31, 2003 and December 31, 2002, the accumulated benefit obligations of the executive pension plans, as well as the First Hydro and Edison Mission Limited 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 $47 million for the year ended December 31, 2004. 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 for all of its plans.

Information on plan assets and benefit obligations for United States plans is shown below:

In millions Year ended December 31,	2003	2002
Change in projected benefit obligation		
Projected benefit obligation at beginning of year	**$ 2,694**	$ 2,480
Service cost	**95**	86
Interest cost	**170**	165
Amendments	**—**	3
Actuarial loss	**139**	104
Benefits paid	**(139)**	(144)
Projected benefit obligation at end of year	**$ 2,959**	$ 2,694
Accumulated benefit obligation at end of year	**$ 2,540**	$ 2,288
Change in plan assets		
Fair value of plan assets at beginning of year	**$ 2,322**	$ 2,768
Actual return on plan assets	**605**	(316)
Employer contributions	**47**	14
Benefits paid	**(139)**	(144)
Fair value of plan assets at end of year	**$ 2,835**	$ 2,322
Funded status	**$ (124)**	$ (372)
Unrecognized net loss	**144**	439
Unrecognized transition obligation	**7**	12
Unrecognized prior service cost	**86**	101
Recorded asset	**$ 113**	$ 180
Additional detail of amounts recognized in balance sheets:		
Intangible asset	**$ 4**	$ 4
Accumulated other comprehensive income	**(22)**	(19)
Pension plans with an accumulated benefit obligation in excess of plan assets:		
Projected benefit obligation	**$ 162**	$ 100
Accumulated benefit obligation	**121**	76
Fair value of plan assets	**25**	—
Weighted-average assumptions at end of year:		
Discount rate	**6.0%**	6.5%
Rate of compensation increase	**5.0%**	5.0%

Expense components for United States plans are:

In millions Year ended December 31,	**2003**	2002	2001
Service cost	**$ 95**	$ 86	$ 82
Interest cost	**170**	165	164
Expected return on plan assets	**(191)**	(228)	(255)
Special termination benefits	**3**	—	13
Net amortization and deferral	**36**	22	(6)
Expense under accounting standards	**113**	45	(2)
Regulatory adjustment – deferred	**(44)**	(18)	39
Total expense recognized	**$ 69**	$ 27	$ 37
Change in accumulated other comprehensive income	**$ (3)**	$ (19)	$ —
Weighted-average assumptions:			
Discount rate	**6.5%**	7.0%	7.25%
Rate of compensation increase	**5.0%**	5.0%	5.0%
Expected return on plan assets	**8.5%**	8.5%	8.5%

Asset allocations for United States plans are:

	Target for	December 31,	
	2004	**2003**	2002
United States equity	45%	**46%**	45%
Non-United States equity	25%	**26%**	25%
Private equity	4%	**3%**	3%
Fixed income	26%	**25%**	27%

Notes to Consolidated Financial Statements

Information on plan assets and benefit obligation for foreign plans is shown below:

In millions Year ended December 31,	2003	2002
Change in projected benefit obligation		
Benefit obligation at beginning of year	**$ 66**	$ 114
Service cost	**4**	2
Interest cost	**4**	8
Actuarial loss (gain)	**12**	(4)
Curtailment	**2**	(53)
Plan participants' contribution	**1**	1
Benefits paid	**(4)**	(2)
Projected benefit obligation at end of year	**$ 85**	$ 66
Change in plan assets		
Fair value of plan assets at beginning of year	**$ 43**	$ 110
Actual return on plan assets	**16**	(18)
Employer contributions	**8**	4
Curtailment	**—**	(51)
Benefits paid	**(4)**	(2)
Fair value of plan assets at end of year	**$ 63**	$ 43
Funded status	**$ (22)**	$ (23)
Unrecognized net loss	**20**	19
Recorded liability	**$ (2)**	$ (4)
Pension plans with an accumulated benefit obligation in excess of plan assets:		
Projected benefit obligation	**$ 73**	$ 58
Accumulated benefit obligation	**69**	52
Fair value of plan assets	**53**	37
Weighted-average assumptions at end of year:		
Discount rate	**5.50%**	5.0% to 5.50%
Rate of compensation increase	**3.80% to 4.0%**	3.5% to 4.0%

Expense components for foreign plans are:

In millions Year ended December 31,	2003	2002	2001
Service cost	**$ 4**	$ 2	$ 3
Interest cost	**4**	8	6
Expected return on plan assets	**(5)**	(10)	(7)
Curtailment/settlement	**1**	—	—
Net amortization and deferral	**—**	15	—
Total expense recognized	**$ 4**	$ 15	$ 2
Weighted-average assumptions:			
Discount rate	**5.0% to 5.5%**	4.0% to 6.0%	4.0% to 6.0%
Rate of compensation increase	**3.5% to 4.0%**	3.5% to 4.0%	3.75% to 4.5%
Expected return on plan assets	**7.5% to 8.0%**	8.0%	5.75% to 9.0%

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

On December 8, 2003, President Bush signed the Medicare Prescription Drug, Improvement and Modernization Act of 2003. The Act authorized a federal subsidy to be provided to plan sponsors for certain prescription drug benefits under Medicare. Edison International has elected to defer accounting for the effects of the Act until the earlier of the issuance of guidance by the Financial Accounting Standards Board on how to account for the Act, or the remeasurement of plan assets and obligations subsequent to January 31, 2004. Accordingly, any measures of the accumulated postretirement benefit obligation or net periodic postretirement benefit expense in the financial statements or this Note do not reflect the effects of the Act on Edison International's plans. Specific authoritative guidance on the accounting for the federal subsidy is pending and that guidance, when issued, could require Edison International to restate previously reported information.

The expected contributions (all by the employer) for the postretirement benefits other than pensions plan are approximately $100 million for the year ended December 31, 2004. This amount is subject to change based on, among other things, the Act referenced above and the impact of any benefit plan amendments.

Edison International uses a December 31 measurement date.

Notes to Consolidated Financial Statements

Information on plan assets and benefit obligations is shown below:

In millions Year ended December 31,	2003	2002
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 2,171**	$ 2,053
Service cost	**44**	49
Interest cost	**126**	141
Amendments	**(640)**	—
Actuarial loss	**588**	82
Settlement	—	(74)
Benefits paid	**(90)**	(80)
Benefit obligation at end of year	**$ 2,199**	$ 2,171
Change in plan assets		
Fair value of plan assets at beginning of year	**$ 1,072**	$ 1,139
Actual return on assets	**292**	(148)
Employer contributions	**116**	161
Benefits paid	**(90)**	(80)
Fair value of plan assets at end of year	**$ 1,390**	$ 1,072
Funded status	**$ (809)**	$ (1,099)
Unrecognized net loss	**1,047**	715
Unrecognized transition obligation	—	269
Unrecognized prior service cost	**(361)**	(2)
Recorded liability	**$ (123)**	$ (117)
Assumed health care cost trend rates:		
Rate assumed for following year	**12.0%**	9.75%
Ultimate rate	**5.0%**	5.0%
Year ultimate rate reached	**2010**	2008
Weighted-average assumptions at end of year:		
Discount rate	**6.25%**	6.75%

Expense components are:

In millions Year ended December 31,	2003	2002	2001
Service cost	**$ 44**	$ 49	$ 50
Interest cost	**126**	141	137
Expected return on plan assets	**(89)**	(93)	(98)
Special termination benefits	**1**	—	2
Settlement	—	(71)	—
Net amortization and deferral	**40**	37	27
Total expense	**$ 122**	$ 63	$ 118
Assumed health care cost trend rates:			
Current year	**9.75%**	10.5%	11.0%
Ultimate rate	**5.0%**	5.0%	5.0%
Year ultimate rate reached	**2008**	2008	2008
Weighted-average assumptions:			
Discount rate	**6.4%**	7.25%	7.5%
Expected return on plan assets	**8.2%**	8.2%	8.2%

Increasing the health care cost trend rate by one percentage point would increase the accumulated obligation as of December 31, 2003 by $317 million and annual aggregate service and interest costs by $29 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated obligation as of December 31, 2003 by $257 million and annual aggregate service and interest costs by $23 million.

Asset allocations are:

	Target for 2004	December 31, 2003	December 31, 2002
United States equity	64%	**64%**	64%
Non-United States equity	16%	**13%**	13%
Fixed income	20%	**23%**	23%

Description of Investment Strategies for United States Plans

The investment of plan assets is overseen by a fiduciary investment committee. Plan assets are invested using a combination of asset classes, and may have active and passive investment strategies within asset classes. Edison International employs multiple investment management firms. Investment managers within each asset class cover a range of investment styles and approaches. Risk is controlled through diversification among multiple asset classes, managers, styles and securities. Plan, asset class and individual manager performance is measured against targets. Edison International also monitors the stability of its investments managers' organizations.

Allowable investment types include:

United States Equity: Common and preferred stock of large, medium, and small companies which are predominantly United States-based.

Non-United States Equity: Equity securities issued by companies domiciled outside the United States and in depository receipts which represent ownership of securities of non-United States companies.

Private Equity: Limited partnerships that invest in nonpublicly traded entities.

Fixed Income: Fixed income securities issued or guaranteed by the United States government, non-United States governments, government agencies and instrumentalities, mortgage backed securities and corporate debt obligations. A small portion of the fixed income position may be held in debt securities that are below investment grade.

Permitted ranges around asset class portfolio weights are plus or minus 5%. Where approved by the fiduciary investment committee, futures contracts are used for portfolio rebalancing and to approach fully invested portfolio positions. Where authorized, a few of the plan's investment managers employ limited use of derivatives, including futures contracts, options, options on futures and interest rate swaps in place of direct investment in securities to gain efficient exposure to markets. Derivatives are not used to leverage the plans or any portfolios.

Determination of the Expected Long-Term Rate of Return on Assets for United States Plans

The overall expected long term rate of return on assets assumption is based on the target asset allocation for plan assets, capital markets return forecasts for asset classes employed, and active management excess return expectations. A portion of postretirement benefits other than pensions trust asset returns are subject to taxation, so the expected long-term rate of return for these assets is determined on an after-tax basis.

Capital Markets Return Forecasts

The estimated total return for fixed income is based on an equilibrium yield for intermediate United States government bonds plus a premium for exposure to nongovernment bonds in the broad fixed income market. The equilibrium yield is based on analysis of historic data and is consistent with experience over various economic environments. The premium of the broad market over United States government bonds is a historic average premium. The estimated rate of return for equity is estimated to be a 3% premium over the estimated total return of intermediate United States government bonds. This value is determined by combining estimates of real earnings growth, dividend yields and inflation, each of which was determined using historical analysis. The rate of return for private equity is estimated to be a 5% premium over public equity, reflecting a premium for higher volatility and illiquidity.

Active Management Excess Return Expectations

For asset classes that are actively managed, an excess return premium is added to the capital market return forecasts discussed above.

Long-Term Incentive Plans

Phantom Stock Options

Phantom stock option performance awards were granted through 1999 at EME and Edison Capital as part of the Edison International long-term incentive compensation program for senior management. In August 2000, all outstanding phantom options were exchanged for a combination of cash and stock equivalent units relating to Edison International common stock, in accordance with the EME and Edison Capital affiliate option exchange offers. Compensation expense recorded for the phantom stock options was $5 million in 2003, $3 million in 2002 and $7 million in 2001.

Stock-Based Employee Compensation

In 1998, Edison International shareholders approved the Edison International Equity Compensation Plan, replacing the long-term incentive compensation program that had been adopted by Edison International shareholders in 1992. The 1998 plan authorizes a limited annual number of Edison International common shares that may be issued in accordance with plan awards. The annual authorization is cumulative, allowing subsequent issuance of previously unutilized awards. In May 2000, the Edison International Board of Directors adopted an additional plan, the 2000 Equity Plan, under which stock options, including the special options discussed below, may be awarded.

Under the 1992, 1998 and 2000 plans, options on 14.8 million shares of Edison International common stock are currently outstanding to officers and senior managers.

Each option may be exercised to purchase one share of Edison International common stock and is exercisable at a price equivalent to the fair market value of the underlying stock at the date of grant. Options generally expire 10 years after date of grant and vest over a period of up to five years.

Edison International stock options awarded prior to 2000 include a dividend equivalent feature. Dividend equivalents on stock options issued after 1993 and prior to 2000 are accrued to the extent dividends are declared on Edison International common stock and are subject to reduction unless certain performance criteria are met. Only a portion of the 1999 Edison International stock option awards include a dividend equivalent feature. The 2003 options include a dividend equivalent feature for the first five years of the option term. Dividend equivalents accumulate without interest.

Options issued after 1997 generally have a four-year vesting period. The special options granted in 2000 vest over five years, in 25% increments beginning in May 2002. Earlier options had a three-year vesting period with one-third of the total award vesting annually. If an option holder retires, dies, is terminated by the company, or is terminated while permanently and totally disabled (qualifying event) during the vesting period, the unvested options will vest on a pro rata basis.

Unvested options of any person who has served in the past on the SCE Management Committee (which was dissolved in 1993) will vest and be exercisable upon a qualifying event. If a qualifying event occurs, the vested options may continue to be exercised within their original terms by the recipient or beneficiary except that in the case of termination by the company where the option holder is not eligible for retirement, vested options are forfeited unless exercised within one year of termination date. If an option holder is terminated other than by a qualifying event, options that had vested as of the prior anniversary date of the grant are forfeited unless exercised within 180 days of the date of termination. All unvested options are forfeited on the date of termination.

The fair value for each option granted, reflecting the basis for the pro forma disclosures in Note 1, was determined on the date of grant using the Black-Scholes option-pricing model. The following assumptions were used in determining fair value through the model:

December 31,	**2003**	2002	2001
Expected life	**10 years**	7 years – 10 years	7 years – 10 years
Risk-free interest rate	**3.8% to 4.5%**	4.7% to 6.1%	4.7% to 6.1%
Expected dividend yield	**1.8%**	1.8%	3.3%
Expected volatility	**44% to 53%**	18% to 54%	17% to 52%

The expected dividend yield above is computed using an average of the previous 12 quarters. The expected volatility above is computed on a historical 36-month basis.

The application of fair-value accounting to calculate the pro forma disclosures is not an indication of future income statement effects. The pro forma disclosures do not reflect the effect of fair-value accounting on stock-based compensation awards granted prior to 1995.

A summary of the status of Edison International's stock options is as follows:

	Share Options	Exercise Price	Weighted-Average Exercise Price	Weighted-Average Fair Value At Grant	Weighted-Average Remaining Life
Outstanding, Dec. 31, 2000	19,774,672	$14.56–$29.34	$22.24		8 years
Granted	1,001,704	$ 9.10–$15.92	$10.90	$3.88	
Expired	(74,512)	$18.75–$19.35	$18.79		
Forfeited	(11,407,835)	$ 9.15–$29.34	$20.91		
Exercised	—	—	—		
Outstanding, Dec. 31, 2001	9,294,029	$ 9.10–$29.34	$22.45		6 years
Granted	3,450,393	$ 8.90–$19.45	$18.59	$7.88	
Expired	(520,706)	$ 9.57–$29.34	$23.34		
Forfeited	(318,980)	$ 9.10–$28.13	$17.43		
Exercised	(68,444)	$ 9.15–$16.59	$12.45		
Outstanding, Dec. 31, 2002	11,836,292	$ 8.90–$29.25	$21.46		6 years
Granted	3,819,930	$11.88–$19.80	$12.38	$7.31	
Expired	(482,394)	$ 9.57–$29.25	$23.48		
Forfeited	(110,094)	$ 9.57–$18.73	$15.02		
Exercised	(260,481)	$ 9.10–$20.19	$17.67		
Outstanding, Dec. 31, 2003	14,803,253	$ 8.90–$28.94	$19.17		

The number of options exercisable and their weighted-average exercise prices at December 31, 2003, 2002 and 2001 were 7,337,939 at $23.37, 6,475,029 at $23.61 and 5,930,024 at $22.92, respectively.

Other Equity-Based Awards

For the years after 1999, a portion of the executive long-term incentives was awarded in the form of performance shares. Performance shares were awarded in January 2001, January 2002 and January 2003. The performance shares vest December 31, 2003, December 31, 2004 and December 31, 2005, respectively, and are paid out half in shares of Edison International common stock and half in cash. The number of shares that will be paid out from the 2002 and 2003 performance share awards will depend on the performance of Edison International common stock relative to the stock performance of a specific group of peer companies. The 2001 performance share values are accrued ratably over the three-year performance period. The 2002 and 2003 performance shares will be valued based on Edison International's stock performance relative to the stock performance of other such entities.

In March 2001, deferred stock units were awarded as part of a retention program. These vest and were paid on March 12, 2003 in shares of Edison International common stock.

In October 2001, a stock option retention exchange offer was extended, offering holders of Edison International stock options granted in 2000 the opportunity to exchange those options for a lesser number of deferred stock units. The exchange ratio was based on the Black-Scholes value of the options and the stock price at the time the offer was extended. The exchange took place in November 2001; the options that participants elected to exchange were cancelled, and deferred stock units were issued. Approximately three options were cancelled for each deferred stock unit issued. Twenty-five percent of the deferred stock units will vest and be paid in Edison International common stock per year over four years; the first and second vesting dates were in November 2002 and November 2003, respectively. The following assumptions were used in determining fair value through the Black-Scholes option-pricing model: expected life – 8 to 9 years; risk-free interest rate – 5.1%; expected volatility – 52%.

See Note 1 for Edison International's accounting policy and expenses related to stock-based employee 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.

The investment in each project as of December 31, 2003 is:

In millions	Investment in Facility	Accumulated Depreciation and Amortization	Ownership Interest
Transmission systems:			
Eldorado	$ 45	$ 11	60%
Pacific Intertie	257	80	50
Generating stations:			
Four Corners Units 4 and 5 (coal)	488	384	48
Mohave (coal) (1)	347	257	56
Palo Verde (nuclear)(2)	1,657	1,460	16
San Onofre (nuclear)(2)	4,297	3,923	75
Total	$7,091	$ 6,115	

(1) A portion is included in regulatory assets on the consolidated balance sheet. See Note 1.
(2) Included in regulatory assets on the consolidated balance sheet.

Note 9. Commitments

Leases

Edison International has operating leases for office space, vehicles, property and other equipment (with varying terms, provisions and expiration dates).

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 will be 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.

In connection with EME's acquisition of the Illinois plants, EME assigned the right to purchase the Collins Station in Illinois to third-party lessors. The third-party lessors purchased the Collins Station and entered into leases of the plant with EME. The base lease rent includes both a fixed and variable component; the variable component of which is impacted by movements in defined short-term interest rate indexes. See further discussion in Note 16.

Estimated remaining commitments (the majority of which are related to EME's long-term leases for the Collins, Powerton, Joliet and Homer City power plants) for noncancelable leases at December 31, 2003 are:

Year ended December 31,	In millions
2004	$ 334
2005	374
2006	452
2007	487
2008	484
Thereafter	4,577
Total	$ 6,708

Operating lease expense was $257 million in 2003, $249 million in 2002 and $182 million in 2001.

Nuclear Decommissioning

Effective January 1, 2003, SCE adopted a new accounting standard, Accounting for Asset Retirement Obligations, which requires entities to record the fair value of a liability for a legal ARO in the period in which it is incurred. At that time, SCE adjusted its nuclear decommissioning obligation, increased its unamortized nuclear investment for a new ARO asset, and recorded a regulatory liability to defer the impact on earnings of the change in accounting principle (see further details in "New Accounting Principles" in Note 1). The fair value of decommissioning SCE's nuclear power facilities is $2.1 billion as of December 31, 2003, based on site-specific studies performed in 2001 for San Onofre and Palo Verde. Changes in the estimated costs, timing of decommissioning, or the assumptions underlying these estimates could cause material revisions to the estimated total cost to decommission in the near term. SCE estimates that it will spend approximately $11.4 billion through 2049 to decommission its nuclear facilities. This estimate is based on SCE's current-dollar decommissioning cost methodology used for rate-making purposes, escalated at rates ranging from 0.9% 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 (shut down in 1992 per CPUC agreement) started in 1999 and will continue through 2008. All of SCE's San Onofre Unit 1 decommissioning costs will be paid from its nuclear decommissioning trust funds. The estimated remaining cost to decommission San Onofre Unit 1 is recorded as an ARO liability ($177 million at December 31, 2003). Total expenditures for the decommissioning of San Onofre Unit 1 were $317 million through December 31, 2003.

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, 2003.

Decommissioning expense under the rate-making method was $118 million in 2003, $73 million in 2002 and $96 million in 2001. The ARO for decommissioning SCE's active nuclear facilities was $1.9 billion at December 31, 2003 and $1.8 billion at December 31, 2002.

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,	**2003**	2002
Municipal bonds	2004 – 2041		**$ 702**	$ 486
Stock	–		**1,324**	1,085
United States government issues	2004 – 2033		**363**	264
Corporate bonds	2004 – 2038		**91**	270
Short-term	2004		**50**	105
Total			**$ 2,530**	$ 2,210

Note: Maturity dates as of December 31, 2003.

Trust fund earnings (based on specific identification) increase the trust fund balance and the ARO regulatory liability. Net earnings (loss) were $93 million in 2003, $(25) million in 2002 and $13 million in 2001. Proceeds from sales of securities (which are reinvested) were $2.2 billion in 2003, $3.8 billion in 2002 and $3.9 billion in 2001. Gross unrealized holding gains were $677 million and $443 million at December 31, 2003 and 2002, respectively. There were no unrealized holding losses for the years presented. Approximately 91% of the cumulative trust fund contributions were tax-deductible.

Other Commitments

At December 31, 2003, EME had firm commitments to spend approximately $80 million on construction and other capital investments during 2004 through 2006. The construction expenditures primarily relate to the construction of a power plant in New Zealand by Contact Energy. The capital expenditures primarily relate to new plant and equipment at EME's Midwest Generation subsidiary and its Contact Energy project.

At December 31, 2003, EME's Midwest Generation subsidiary was party to a long-term power-purchase contract. The contract requires Midwest Generation to pay a monthly capacity payment and gives Midwest Generation an option to purchase energy at prices based primarily on operations and maintenance and fuel costs.

An EME subsidiary entered into a coal cleaning agreement with an outside party to operate and maintain a coal cleaning plant owned by the EME subsidiary. Under the terms of the agreement, the subsidiary is obligated to reimburse the outside party for the actual costs incurred in the operations and maintenance of the coal cleaning plant, a fixed general and administrative service fee and an operating fee that is dependent on the level of tonnage. The agreement expires on December 31, 2005, with a two-year extension option.

At December 31, 2003, commitments related to these two contracts discussed above are summarized as follows: 2004 – $11 million; 2005 – $10 million; 2006 – $4 million; 2007 – $4 million; and 2008 – $4 million.

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

At December 31, 2003, 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.

SCE has power-purchase contracts with certain QFs (cogenerators and small power producers) and other utilities. These contracts provide for capacity payments if a facility meets certain performance obligations and energy payments based on actual power supplied to SCE. There are no requirements to make debt-service payments. In an effort to replace higher-cost contract payments with lower-cost replacement power, SCE has entered into purchased-power settlements to end its contract obligations with certain QFs. The settlements are reported as power-purchase contracts on the balance sheets.

Certain commitments for the years 2004 through 2008 are estimated below:

In millions	2004	2005	2006	2007	2008
Fuel supply contracts	$ 911	$ 814	$ 533	$ 377	$ 204
Gas transportation payments	7	7	7	7	7
Purchased-power capacity payments	682	663	637	637	444

SCE has unconditional purchase obligations for part of a power plant's generating output, as well as firm transmission service from another utility. Minimum payments are based, in part, on the debt-service requirements of the provider, whether or not the plant or transmission line is operable. SCE's minimum commitment under both contracts is approximately $139 million through 2017. The purchased-power contract is expected to provide approximately 5% of current or estimated future operating capacity, and is reported as power-purchase contracts (approximately $28 million). The transmission service contract requires a minimum payment of approximately $6 million a year.

As of December 31, 2003, Edison Capital had outstanding commitments of $68 million to fund energy and infrastructure investments. Prior to funding any commitments, specific contract conditions must be satisfied. At December 31, 2003, Edison Capital had deposited approximately $5 million as collateral for several letters of credit currently outstanding.

EME's Guarantees and Indemnities

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, EME has 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 obligations under these tax indemnity agreements, EME cannot determine a maximum potential liability. The indemnities would be triggered by a valid claim from the lessors. EME has not recorded a liability related to these indemnities.

Indemnities Provided as Part of EME's Acquisitions

In connection with the acquisition of the Illinois plants and the Homer City project, EME agreed to indemnify the sellers against damages, claims, fines, liabilities and expenses and losses arising from, among other things, environmental liabilities before and after the date of each sale as specified in the specific asset sale agreements (August 1, 1998 for Homer City and March 22, 1999 for the Illinois plants). In the case of the Illinois plants, the indemnification claims are reduced by any insurance proceeds and tax benefits related to such claims and are subject to a requirement by the seller to take all reasonable steps to mitigate losses related to any such indemnification claim. Due to the nature of the obligation under these indemnities, a maximum potential liability cannot be determined. Each of these indemnifications is not limited in term and would be triggered by a valid claim from the respective seller. Except as discussed below, EME has not recorded a liability related to these indemnities.

Midwest Generation entered into a supplemental agreement to resolve a dispute regarding interpretation of its reimbursement obligation for asbestos claims under the environmental indemnities set forth in the Illinois plants asset sale agreement. Under this supplemental agreement, Midwest Generation agreed to reimburse the seller 50% of specific existing asbestos claims, less recovery of insurance costs, and agreed to a sharing arrangement for liabilities associated with future asbestos related claims as specified in the agreement. 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 to terminate). Payments are made under this indemnity by a valid claim provided from the seller. At December 31, 2003, Midwest Generation recorded a $10 million liability related to this matter and had made $1 million in payments.

Indemnities Provided Under Asset Sale Agreements

In connection with the sale of assets, EME has provided indemnities to the purchasers for taxes imposed with respect to operations of the asset prior to the sale, and EME or its subsidiaries have received similar indemnities from purchasers related to taxes arising from operations after the sale. EME 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 50% of TM Star Fuel Supply Obligations

TM Star was formed for the limited purpose to sell natural gas to the March Point Cogeneration Company, an affiliate through common ownership, under a fuel supply agreement that extends through December 31, 2011. TM Star has entered into fuel purchase contracts with unrelated third parties to meet a portion of the obligations under the fuel supply agreement. EME has guaranteed 50% of TM Star's obligation under the fuel supply agreement to March Point Cogeneration. Due to the nature of the obligation under this guarantee, a maximum potential liability cannot be determined. TM Star has met its obligations to March Point Cogeneration, and, accordingly, no claims against this guarantee have been made. TM Star was merged into March Point Cogeneration Company effective as of January 16, 2004, and this guarantee terminated by operation of law as of that date.

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, 2003, if payment were required, would be $181 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.

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 $63 million invested in three aircraft leased to American Airlines. The independent auditors' opinion on the year-end 2002 financial statements of AMR Corporation, parent company of American Airlines, questions AMR Corporation's ability to continue as a going concern. As disclosed in AMR Corporation's Form 10Q filing for September 30, 2003, there were some improvements made in 2003, such as concessionary agreements with unions and certain other lessors, and reporting operating income of $165 million for the third quarter of 2003. However, significant uncertainty remains and if 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 2004 is $46 million. A restructure of the lease could also result in a loss of some or all of the investment. At December 31, 2003, American Airlines was current in its lease payments to Edison Capital.

Employee Compensation and Benefit Plans

On July 31, 2003, a federal district court held that the formula used in a cash balance pension plan created by International Business Machine Corporation (IBM) in 1999 violated the age discrimination provisions of the Employee Retirement Income Security Act of 1974. In its decision, the federal district court set forth a standard for cash balance pension plans. This decision, however, conflicts with the decisions from two other federal district courts and with the proposed regulations for cash balance pension plans issued by the IRS in December 2002. On February 12, 2004, the same federal district court ruled that IBM must make back payments to workers covered under this plan. IBM has indicated that it will appeal both decisions to the United States Court of Appeals for the Seventh Circuit. The formula for Edison International's cash balance pension plan does not meet the standard set forth in the federal district court's

July 31, 2003 decision. Edison International cannot predict with certainty the effect of the two IBM decisions on Edison International's cash balance pension plan.

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 32 identified sites at SCE (26 sites) and EME (6 sites related to Midwest Generation) is $94 million, $92 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 $238 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.

The CPUC allows SCE to recover environmental remediation costs at certain sites, representing $34 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 $71 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 2003 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

In August 2002, Edison International received a notice from the IRS asserting deficiencies in federal corporate income taxes for its 1994 to 1996 tax years. The vast majority of the asserted tax deficiencies are timing differences and, therefore, amounts ultimately paid (exclusive of interest and penalties), if any, would benefit Edison International as future tax deductions. Edison International believes that it has meritorious legal defenses to those deficiencies and believes that the ultimate outcome of this matter will not result in a material impact on Edison International's consolidated results of operations or financial position.

Among the issues raised by the IRS in the 1994 to 1996 audit was Edison Capital's treatment of the EPZ and Dutch electric locomotive leases. Written protests were filed against these deficiency notices, as well as other alleged deficiencies, 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 Capital will contest the assessment through administrative appeals and litigation, if necessary, and believes it should prevail in an outcome that will not have a material adverse financial impact.

The IRS is examining the tax returns for Edison International, which includes Edison Capital, for years 1997 through 1999. Edison Capital expects the IRS will also challenge several of its other leveraged leases based on recent Revenue Rulings addressing a specific type of leveraged lease (termed a lease in/lease out or LILO transaction). Edison Capital believes that the position described in the Revenue Ruling is incorrectly applied to Edison Capital's transactions and that its leveraged leases are factually and legally distinguishable in material respects from that position. Edison Capital intends to defend, and litigate if necessary, against any challenges based on that position.

Investigation Regarding Performance Incentives Rewards

SCE is eligible under its CPUC-approved performance-based rate-making (PBR) mechanism to earn rewards or penalties based on its performance in comparison to CPUC-approved standards of reliability, customer satisfaction, and employee safety. SCE received two letters over the last year from 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 is conducting an internal investigation and has determined that some wrongdoing by a number of the service planning employees has occurred. SCE has informed the CPUC of its findings to date, and will continue to inform the CPUC of developments as the investigation progresses. SCE anticipates that, after the investigation is completed, there may be CPUC proceedings to determine whether any portion of past and potential rewards for customer satisfaction should be refunded or disallowed. It also is possible that penalties could be imposed. SCE recorded aggregate customer satisfaction rewards of $28 million for the years 1998, 1999, and 2000. Potential customer satisfaction rewards aggregating $10 million for 2001 and 2002 are pending before the CPUC and have not been recognized in income by SCE. SCE also had anticipated that it could be eligible for customer satisfaction rewards of about $10 million for 2003. SCE has not yet been able to determine whether or to what extent employee misconduct has compromised the surveys that are the basis for a portion of the awards. Accordingly, SCE cannot predict with certainty the outcome of this matter. SCE plans to complete its investigation as quickly as possible and cooperate fully with the CPUC in taking appropriate remedial action.

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. 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.

Some of the issues included in this case were addressed by the United States Supreme Court in a separate legal proceeding filed by the Navajo Nation in the 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 filed a motion to dismiss or, in the alternative, for summary judgment in the D.C. District Court action. The motion remains pending.

The Federal Circuit Court of Appeals, acting on a suggestion on remand filed by the Navajo Nation, held in a October 24, 2003 decision that the Supreme Court's March 24, 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 Court of Appeals decision. Both petitions were denied on March 9, 2004.

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 $10.9 billion. SCE and other owners of the San Onofre and Palo Verde Nuclear Generating Stations 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. The United States Congress has extended the expiration date of the applicable law until December 31, 2004.

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 $38 million per year. Insurance premiums are charged to operating expense.

Spent Nuclear Fuel

Under federal law, the United States 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 has the obligation to begin acceptance of spent nuclear fuel not later than January 31, 1998. However, the DOE did not meet its obligation. 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, including 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 Federal Court of Claims seeking damages for DOE's failure to meet its obligation to begin accepting spent nuclear fuel from San Onofre.

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 1, 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 is scheduled to be completed by late 2004 and from the Unit 2 spent fuel pool to the independent spent fuel storage installation by late 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 early 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, 2003, Edison Capital had an investment of approximately $73 million in Storm Lake Power, a project developed by Enron Wind, a subsidiary of Enron Corporation. As of December 31, 2003, Storm Lake had outstanding loans of approximately $60 million. The lenders claim that Enron's bankruptcy, among other things, is an event of default under the loan agreement and as a result, the debt has been reclassified to long-term debt due within one year. However, the lenders are currently discussing resolution of the defaults with Storm Lake and are not actively pursuing remedies.

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, 2003 and 2002.

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,	**2003**	2002	2001
Income from leveraged leases	**$ 82**	$ 105	$ 154
Recomputation due to tax rate change	—	(99)	—
Tax effect of pre-tax income:			
Current	**40**	138	246
Deferred	**(71)**	(86)	(307)
Total tax (expense) benefit	**(31)**	52	(61)
Net income from leveraged leases	**$ 51**	$ 58	$ 93

The net investment in leveraged leases is:

In millions December 31,	**2003**	2002
Rentals receivable (net of principal and interest on nonrecourse debt)	**$ 3,497**	$ 3,496
Unearned income	**(1,178)**	(1,260)
Investment in leveraged leases	**2,319**	2,236
Estimated residual value	**42**	42
Deferred income taxes	**(2,055)**	(2,044)
Net investment in leveraged leases	**$ 306**	$ 234

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. The difference between the carrying value of energy projects and oil and gas investments and the underlying equity in the net assets was $264 million at December 31, 2003. The difference related to the energy projects is being amortized over the life of the energy projects; the difference related to the oil and gas investments is amortized on a unit-of-production basis over the life of the reserves for the oil and gas projects. Amortization stopped January 1, 2002 in accordance with a new accounting standard.

Summarized financial information of these investments is:

In millions Year ended December 31,	2003	2002	2001
Revenue	$ 4,068	$ 1,523	$ 3,380
Expenses	3,450	1,312	2,847
Net income	**$ 618**	$ 211	$ 533

In millions December 31,	2003	2002
Current assets	$ 1,804	$ 790
Other assets	12,056	5,564
Total assets	**$13,860**	$ 6,354
Current liabilities	$ 1,239	$ 1,205
Other liabilities	7,930	3,759
Equity	4,691	1,390
Total liabilities and equity	**$13,860**	$ 6,354

The undistributed earnings of investments accounted for by the equity method were $283 million in 2003 and $275 million in 2002.

Note 12. Business Segments

Edison International's reportable business segments include its electric utility operation segment (SCE), a nonutility power generation segment (EME) and a financial services provider segment (Edison Capital). Its segments are based on Edison International's internal organization. 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. EME is engaged in the operation of electric power generation facilities worldwide. EME also conducts energy trading and price risk management activities in markets where power generation facilities are open to competition. Edison Capital is a provider of financial services with investments worldwide.

The accounting policies of the segments are the same as those described in Note 1.

A significant source of revenue from EME's sale of energy and capacity is derived from its Midwest Generation subsidiary's sales to Exelon Generation Company under power purchase agreements terminating in December 2004. Revenue from such sales was $708 million in 2003 and $1.1 billion for each of the years 2002 and 2001. The nonutility power generation segment is responsible for the goodwill reported on the consolidated balance sheets.

Edison International's business segment information is:

In millions	Electric Utility	Nonutility Power Generation	Financial Services	Corporate & Other[1]	Edison International
2003					
Operating revenue	$ 8,853	$ 3,181	$ 88	$ 13	$ 12,135
Depreciation, decommissioning and amortization	882	290	12	—	1,184
Interest and dividend income	100	16	8	3	127
Equity in income from partnerships and unconsolidated subsidiaries – net	—	368	(14)	—	354
Interest expense – net of amounts capitalized	457	498	26	245	1,226
Income tax (benefit) – continuing operations	388	(24)	(38)	(113)	213
Income (loss) from continuing operations	872	28	57	(178)	779
Net income (loss)	922[2]	20	57	(178)	821
Total assets	18,466	12,078	3,418	1,000	34,962
Additions to and acquisition of property and plant	1,161	127	—	—	1,288
2002					
Operating revenue	$ 8,705	$ 2,750	$ 7	$ 26	$ 11,488
Depreciation, decommissioning and amortization	780	247	—	3	1,030
Interest and dividend income	262	18	(1)	8	287
Equity in income from partnerships and unconsolidated subsidiaries – net	—	283	(34)	—	249
Interest expense – net of amounts capitalized	584	452	36	211	1,283
Income tax (benefit) – continuing operations	642	38	(146)	(143)	391
Income (loss) from continuing operations	1,228	82	33	(208)	1,135
Net income (loss)	1,228[2]	25	33	(209)	1,077
Total assets	18,637	11,092	3,479	399	33,607
Additions to and acquisition of property and plant	1,046	554	1	(11)	1,590
2001					
Operating revenue	$ 8,120	$ 2,594	$ 202	$ 146	$ 11,062
Depreciation, decommissioning and amortization	681	273	17	2	973
Interest and dividend income	215	35	19	13	282
Equity in income from partnerships and unconsolidated subsidiaries – net	—	374	(31)	—	343
Interest expense – net of amounts capitalized	785	547	64	186	1,582
Income tax (benefit) – continuing operations	1,658	96	(24)	(83)	1,647
Income (loss) from continuing operations	2,386	113	84	(181)	2,402
Net income (loss)	2,386[2]	(1,121)	84	(314)	1,035
Total assets	22,453	10,730	3,736	(145)	36,774
Additions to and acquisition of property and plant	688	242	3	—	933

(1) Includes amounts from nonutility subsidiaries (including MEHC), 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 (loss) from discontinued operations of $1 million for 2003, $(57) million for 2002 and $(1.2) billion for 2001. The net loss reported for corporate and other includes loss from discontinued operations of $(1) million for 2002 and $(133) million for 2001.

Geographic Information

Electric power and steam generated domestically by EME is sold primarily under long-term contracts to electric utilities, through a centralized power pool, or under a power-purchase agreement with a term of up to five years. A project in Australia sells its energy through a centralized power pool. A project in the United Kingdom sells its energy production by entering into physical bilateral contracts with various counterparties. Other electric power generated overseas is sold under short- and long-term contracts to electricity companies, electricity buying groups or electric utilities located in the country where the power is generated.

Edison International's foreign and domestic revenue and assets information is:

In millions Year ended December 31,	**2003**	2002	2001
Revenue			
United States	**$ 10,533**	$ 10,331	$ 10,141
Foreign countries:			
United Kingdom	**371**	317	324
Australia	**234**	204	166
New Zealand	**756**	493	294
Netherlands	**5**	(24)	—
South Africa	**6**	(16)	—
Switzerland	**62**	56	—
Other	**168**	127	137
Total	**$ 12,135**	$ 11,488	$ 11,062

In millions December 31,	**2003**	2002
Assets		
United States(1)	**$ 25,602**	$ 25,743
Foreign countries:		
United Kingdom(1)	**1,630**	1,680
Australia	**1,989**	1,565
New Zealand	**2,640**	1,738
Netherlands	**562**	556
South Africa	**642**	646
Switzerland	**545**	483
Other	**1,352**	1,196
Total	**$ 34,962**	$ 33,607

(1) Includes assets of discontinued operations.

Note 13. Acquisitions and Dispositions

Acquisitions

On July 17, 2003, SCE signed an option agreement with Sequoia Generating LLC, a subsidiary of InterGen, to acquire Mountainview Power Company LLC, the owner of a new power plant currently being developed in Redlands, California. This acquisition requires regulatory approval from both the CPUC and the FERC. On December 18, 2003, the CPUC approved SCE's application proposing a power-purchase agreement between SCE and Mountainview Power Company LLC. On February 25, 2004, the FERC granted conditional approval of the power-purchase agreement. On February 28, 2004, SCE exercised its option to purchase Mountainview. The purchase is expected to close in March 2004. SCE will recommence full construction of the project once the purchase closes.

On March 3, 2003, Contact Energy, EME's 51% owned subsidiary, completed a transaction with NGC Holdings Ltd. to acquire the Taranaki combined cycle power station and related interests. Consideration for the Taranaki station consisted of a cash payment of approximately $275 million, which was initially financed with bridge loan facilities. The bridge loan facilities were subsequently repaid with proceeds from Contact Energy's issuance of long-term United States dollar denominated notes. The Taranaki station is a 357 MW combined cycle, natural gas-fired plant located near Stratford, New Zealand.

During the second quarter of 2001, EME completed the purchase of additional shares of Contact Energy Ltd. for NZ$152 million, increasing its ownership interest from 43% to 51%. EME acquired 40% of the shares of Contact Energy during 1999 and increased its share of ownership to 43% during 2000. Accordingly, EME began accounting for Contact Energy on a consolidated basis effective June 1, 2001, upon acquisition of a controlling interest. Prior to June 1, 2001, EME used the equity method of accounting for Contact Energy. To finance the purchase of the additional shares in 2001, EME obtained a NZ$135 million, 364-day bridge loan from an investment bank under a credit facility, which was syndicated by the bank. In addition to other security arrangements, a security interest over all Contact Energy shares held has been provided as collateral. From June 2001 to October 2001, EME issued through one of its subsidiaries new preferred securities. The proceeds were used to repay borrowings outstanding under a credit facility and to repay the bridge loan.

In February 2001, EME completed the acquisition of a 50% interest in CBK Power Co. Ltd. for $20 million. CBK Power has entered into a 25-year build-rehabilitate-transfer-and-operate agreement with National Power Corporation related to a hydroelectric project located in the Philippines. Financing for this $460 million project includes equity commitments of $117 million (EME's share is approximately $59 million) and debt financing, which is in place for the remainder of the cost of this project. The indebtedness incurred by CBK Power is nonrecourse to EME.

Dispositions

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

In 2003, SCE completed the sale of certain oil storage and pipeline facilities. See additional discussion in Note 15.

On December 31, 2003, EME agreed to sell its 50% partnership interest in its Brooklyn Navy Yard project to a third party. Completion of the sale, currently expected in the first quarter of 2004, is subject to closing conditions, including obtaining regulatory approval. Proceeds from the sale are expected to be 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.

On November 21, 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.

During 2001, EME completed the sales of its interests in the Nevada Sun-Peak project (50%), Saguaro project (50%) and Hopewell project (25%) for a total gain on sale of $45 million ($24 million after tax). In addition, EME entered into agreements, subject to obtaining consents from third parties and other conditions, for the sale of its interests in the Commonwealth Atlantic, Gordonsville, EcoEléctrica, Harbor and James River projects. During 2001, EME recorded asset impairment charges of $34 million related to these projects based on the expected sales proceeds.

Also, during 2001, EME sold a 50% interest in its Sunrise project to Texaco for $84 million (50% of the project costs, prior to commercial operation). In late 2000, EME had purchased from Texaco all rights, title and interest in the Sunrise project; Texaco had an option to repurchase, at cost, a 50% interest in the project.

In December 2001, EME completed the sale of the Ferrybridge and Fiddler's Ferry coal-fired power plants located in the United Kingdom. See additional discussion in Note 15.

In 2001, Edison Capital syndicated its interests in several affordable housing projects for $169 million and recorded fee and syndication income of $40 million (after tax) resulting from the syndication.

Note 14. Asset Impairments

In fourth quarter 2001, Edison International adopted early an accounting standard for the impairment or disposal of long-lived assets. Edison International evaluates the long-lived assets whenever indicators of impairment exist. This accounting standard requires 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 the impairment is determined by the difference between the carrying amount and fair value of the asset.

During 2003, EME recorded asset impairment charges of $304 million, consisting of $245 million related to eight small peaking plants in Illinois (owned by Midwest Generation) 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 resulted from a revised long-term outlook for capacity revenue from the peaking plants due to a number of factors, including higher long-term natural gas prices and a 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 value was determined based on discounting estimated future 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 environmental improvements project at the Illinois plants.

Note 15. Discontinued Operations

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.

On December 19, 2002, the lenders to EME's Lakeland project accelerated the debt owing under the bank agreement that governs the project's indebtedness, and on December 20, 2002, the Lakeland project lenders appointed an administrative receiver over the assets of Lakeland Power Ltd. The appointment of the administrative receiver results in the treatment of Lakeland power plant as an asset held for sale under an accounting standard related to the impairment or disposal of long-lived assets. Due to EME's loss of control arising from the appointment of the administrative receiver, EME no longer consolidates the activities of Lakeland Power Ltd. 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 Fiddler's Ferry and Ferrybridge 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 specific 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 $1.9 billion charge includes the asset impairment charge recorded in third quarter 2001 to reduce the carrying value of the assets held for sale to reflect estimated fair value less the cost to sell and related currency adjustments. EME had acquired the plants in 1999 for approximately $2.0 billion (£1.3 billion).

In August 2001, Edison Enterprises, a wholly owned subsidiary of Edison International, sold a subsidiary principally engaged in the business of providing residential security services and residential electrical warranty repair services. In October 2001, Edison Enterprises completed the sale of substantially all of its assets of another subsidiary (engaged in the business of commercial energy management) to the subsidiary's current management. As a result, Edison International recorded a charge of $127 million (after tax) in 2001 related to the losses on these sales. The impairment charges recorded in 2001 to reduce the carrying value of these investments held for sale to reflect the estimated fair value less cost to sell are included in the $127 million charge.

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 prior years have not been restated and are reflected as part of continuing operations.

In 2002, the results of the Lakeland project are reflected as discontinued operations in the consolidated financial statements in accordance with an accounting standard related to the impairment and disposal of long-lived assets. Due to immateriality, the results of the Lakeland project in 2001 have not been restated and are reflected as part of continuing operations.

For all years presented, the results of the Fiddler's Ferry and Ferrybridge coal stations and Edison Enterprises subsidiaries sold during 2001 have been reflected as discontinued operations in the consolidated financial statements in accordance with an accounting standard related to the impairment and disposal of long-lived assets. 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 $21 million in 2003, $74 million in 2002 and $748 million in 2001. The before-tax earnings (losses) of the discontinued operations were $84 million in 2003, $(74) million in 2002 and $(2.2) billion in 2001.

The carrying value of assets and liabilities of discontinued operations is:

In millions December 31,	**2003**	2002
Assets		
Receivables – net	**$ —**	$ 1
Other	**5**	9
Total current assets	**5**	10
Utility plant – net	**—**	5
Nonutility property – net	**—**	51
Other noncurrent assets	**11**	57
Total assets	**$ 16**	$ 123
Liabilities		
Accounts payable and accrued liabilities	**$ 3**	$ 23
Noncurrent liabilities	**10**	49
Total liabilities	**$ 13**	$ 72

Note 16. Subsequent Event

On March 10, 2004, EME's subsidiary, Midwest Generation, agreed in principle with the lease equity investor to terminate the Collins Station lease. The agreement in principle sets forth specified conditions required for the termination, including Midwest Generation successfully borrowing funds to finance the repayment of Collins Station lease debt of $774 million and settlement of Midwest Generation's termination liability with the lease equity investor. There is no assurance that the agreement in principle will result in termination of the Collins Station lease. If the termination occurs, Midwest Generation will take title to the Collins Station and, subject to its contractual obligation to Exelon Generation, plans to subsequently abandon the Collins Station or sell it to a third party.

If Midwest Generation completes the lease termination and subsequently abandons the Collins Station, EME expects to record a pre-tax loss of approximately $1 billion (approximately $620 million after tax). This loss will reduce EME's net worth (using December 31, 2003) from $1.9 billion to approximately $1.3 billion. To avoid the possibility of covenant defaults which could arise from a decline in net worth, EME plans to take the following actions before or simultaneously with the Collins Station lease termination:

- replace its $145 million corporate credit facility with a new secured credit facility;
- repay the $28 million due under the Coal and Capex facility (guaranteed by EME); and

- eliminate or modify the net worth covenant in its guaranty of the Powerton-Joliet lease.

If Midwest Generation completes the termination of the Collins Station lease followed by abandonment or sale to a third party, EME anticipates that the termination payment would result in a substantial income tax deduction. Because of these arrangements, EME does not expect that termination of the Collins Station lease will have a material adverse effect on its liquidity. If the lease termination does not occur, the terms of the lease will remain in effect and Midwest Generation will seek to restructure the lease with the lease equity investor.

In millions, except per-share amounts	2003 Total	Fourth	Third	Second	First
Operating revenue	$ 12,135	$ 2,654	$ 3,833	$ 3,125	$ 2,523
Operating income	1,791	331	925	224	311
Income from continuing operations	779	193	500	23	63
Income from discontinued operations – net	51	3	44	1	3
Cumulative effect of accounting change – net	(9)	—	—	—	(9)
Net income	821	196	544	24	57
Basic earnings (loss) per share:					
Continuing operations	2.39	0.59	1.53	0.07	0.19
Discontinued operations	0.16	0.01	0.14	—	0.01
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	2.37	0.59	1.52	0.07	0.19
Discontinued operations	0.16	0.01	0.13	—	0.01
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

In millions, except per-share amounts	2002 Total	Fourth	Third	Second	First
Operating revenue	$ 11,488	$ 2,469	$ 3,707	$ 2,824	$ 2,488
Operating income	2,372	156	703	1,204	309
Income from continuing operations	1,135	56	345	655	79
Income (loss) from discontinued operations – net	(58)	(80)	7	10	5
Net income (loss)	1,077	(24)	352	665	84
Basic earnings (loss) per share:					
Continuing operations	3.49	0.18	1.06	2.01	0.24
Discontinued operations	(0.18)	(0.25)	0.02	0.03	0.02
Total	3.31	(0.07)	1.08	2.04	0.26
Diluted earnings (loss) per share:					
Continuing operations	3.46	0.17	1.05	1.99	0.24
Discontinued operations	(0.18)	(0.24)	0.02	0.03	0.02
Total	3.28	(0.07)	1.07	2.02	0.26
Dividends declared per share	—	—	—	—	—
Common stock prices:					
High	19.60	12.25	17.24	19.60	17.56
Low	7.80	7.80	8.80	16.26	14.82
Close	11.85	11.85	10.00	17.00	16.75

Dollars in millions, except per-share amounts	2003	2002	2001	2000	1999
Edison International and Subsidiaries					
Operating revenue	**$ 12,135**	$ 11,488	$ 11,062	$ 10,424	$ 8,932
Operating expenses	**$ 10,344**	$ 9,116	$ 5,980	$ 12,499	$ 7,359
Income (loss) from continuing operations	**$ 779**	$ 1,135	$ 2,402	$ (1,939)	$ 681
Net income (loss)	**$ 821**	$ 1,077	$ 1,035	$ (1,943)	$ 623
Weighted-average shares of common stock outstanding (in millions)	**326**	326	326	333	348
Basic earnings per share:					
Continuing operations	**$ 2.39**	$ 3.49	$ 7.37	$ (5.83)	$ 1.96
Discontinued operations	**$ 0.16**	$ (0.18)	$ (4.19)	$ (0.01)	$ (0.17)
Cumulative effect of accounting change	**$ (0.03)**	$ —	$ —	$ —	$ —
Total	**$ 2.52**	$ 3.31	$ 3.18	$ (5.84)	$ 1.79
Diluted earnings per share	**$ 2.50**	$ 3.28	$ 3.17	$ (5.84)	$ 1.79
Dividends declared per share	**$ 0.20**	$ —	$ —	$ 0.84	$ 1.08
Book value per share at year-end	**$ 16.52**	$ 13.62	$ 10.04	$ 7.43	$ 15.01
Market value per share at year-end	**$ 21.93**	$ 11.85	$ 15.10	$ 15.625	$ 26.187
Rate of return on common equity	**17.1%**	27.0%	58.0%	(41.0)%	12.2%
Price/earnings ratio	**8.7**	3.6	4.7	(2.7)	14.6
Ratio of earnings to fixed charges	**1.65**	2.08	3.21	*	1.99
Assets	**$ 34,962**	$ 33,607	$ 36,774	$ 35,100	$ 36,229
Long-term debt	**$ 11,787**	$ 11,578	$ 12,674	$ 12,150	$ 13,391
Common shareholders' equity	**$ 5,383**	$ 4,437	$ 3,272	$ 2,420	$ 5,211
Preferred stock subject to mandatory redemption	**$ 141**	$ 147	$ 151	$ 256	$ 256
Company-obligated mandatorily redeemable securities of subsidiaries holding solely parent company debentures	**$ —**	$ 951	$ 949	$ 949	$ 948
Retained earnings	**$ 3,466**	$ 2,711	$ 1,634	$ 599	$ 3,079
Southern California Edison Company					
Operating revenue	**$ 8,854**	$ 8,706	$ 8,126	$ 7,870	$ 7,548
Net income (loss) available for common stock	**$ 922**	$ 1,228	$ 2,386	$ (2,050)	$ 484
Basic earnings (loss) per Edison International common share	**$ 2.83**	$ 3.77	$ 7.32	$ (6.16)	$ 1.39
Rate of return on common equity	**20.2%**	31.8%	311.0%	(67.6)%	15.2%
Peak demand in megawatts (MW)	**20,136**	18,821	17,890	19,757	19,122
Generation capacity at peak (MW)	**9,861**	9,767	9,802	9,886	10,431
Kilowatt-hour deliveries (in millions)	**93,826**	79,693	78,524	84,430	78,602
Customers (in millions)	**4.60**	4.53	4.47	4.42	4.36
Full-time employees	**12,698**	12,113	11,663	12,593	13,040
Edison Mission Energy					
Revenue	**$ 3,181**	$ 2,750	$ 2,594	$ 2,294	$ 1,083
Income from continuing operations	**$ 28**	$ 82	$ 113	$ 101	$ 109
Net income (loss)	**$ 20**	$ 25	$ (1,121)	$ 125	$ 130
Assets	**$ 12,078**	$ 11,092	$ 10,730	$ 15,017	$ 15,534
Rate of return on common equity	**1.1%**	1.5%	(46.9)%	4.3%	8.1%
Ownership in operating projects (MW)	**18,733**	18,688	19,019	22,759	22,037
Full-time employees	**2,610**	2,662	3,021	3,391	3,245
Edison Capital					
Revenue	**$ 88**	$ 7	$ 202	$ 274	$ 282
Net income	**$ 57**	$ 33	$ 84	$ 135	$ 129
Assets	**$ 3,418**	$ 3,479	$ 3,736	$ 3,713	$ 2,712
Rate of return on common equity	**7.5%**	4.2%	11.9%	22.9%	27.0%
Full-time employees	**62**	61	66	119	115

* less than 1.00

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.

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Chairman of the Board,
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Chairman of the Board,
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* Except as otherwise indicated, service includes combined Edison International and Southern California Edison Company Board memberships

** Retiring May 20, 2004

† For Southern California Edison Company, a director from 1990-1999; 2003 to present

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Preferred Securities and Preferred Stock

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