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* SOUTHERN CALIFORNIA
EDISON® CO. *

An *EDISON INTERNATIONAL*® Company

2001 Annual Report

Southern California Edison Company (SCE) is one of the nation's largest investor-owned electric utilities. Headquartered in Rosemead, California, SCE is a subsidiary of Edison International.

SCE, a 116-year-old electric utility, serves a 50,000-square-mile area of central, coastal and southern California.

Contents

Selected Financial and Operating Data: 1997 – 2001

Southern California Edison Company

Dollars in millions	2001	2000	1999	1998	1997
Income statement data:					
Operating revenue	$ 8,126	$ 7,870	$ 7,548	$ 7,500	$ 7,953
Operating expenses	3,509	10,529	6,242	6,136	6,311
Fuel and purchased power expenses	3,982	4,882	3,405	3,586	3,735
Income tax (benefit)	1,658	(1,022)	438	442	520
Provisions for regulatory adjustment clauses – net	(3,028)	2,301	(763)	(473)	(411)
Interest expense – net of amounts capitalized	785	572	483	485	444
Net income (loss)	2,408	(2,028)	509	515	606
Net income (loss) available for common stock	2,386	(2,050)	484	490	576
Ratio of earnings to fixed charges	6.15	(4.28)	2.94	2.95	3.49
Balance sheet data:					
Assets	$ 22,453	$ 15,966	$ 17,657	$ 16,947	$ 18,059
Gross utility plant	15,982	15,653	14,852	14,150	21,483
Accumulated provision for depreciation and decommissioning	7,969	7,834	7,520	6,896	10,544
Short-term debt	2,127	1,451	796	470	322
Common shareholder's equity	3,146	780	3,133	3,335	3,958
Preferred stock:					
Not subject to mandatory redemption	129	129	129	129	184
Subject to mandatory redemption	151	256	256	256	275
Long-term debt	4,739	5,631	5,137	5,447	6,145
Capital structure:					
Common shareholder's equity	38.5%	11.5%	36.2%	36.4%	37.5%
Preferred stock:					
Not subject to mandatory redemption	1.6%	1.9%	1.5%	1.4%	1.7%
Subject to mandatory redemption	1.9%	3.8%	2.9%	2.8%	2.6%
Long-term debt	58.0%	82.8%	59.4%	59.4%	58.2%
Operating data:					
Peak demand in megawatts (MW)	17,890	19,757	19,122	19,935	19,118
Generation capacity at peak (MW)	9,802	9,886	10,431	10,546	21,511
Kilowatt-hour deliveries (in millions)	78,524	84,430	78,602	76,595	77,234
Total energy requirement (kWh) (in millions)	83,496	82,503	78,752	80,289	86,849
Energy mix:					
Thermal	32.5%	36.0%	35.5%	38.8%	44.6%
Hydro	3.6%	5.4%	5.6%	7.4%	6.5%
Purchased power and other sources	63.9%	58.6%	58.9%	53.8%	48.9%
Customers (in millions)	4.47	4.42	4.36	4.27	4.25
Full-time employees	11,663	12,593	13,040	13,177	12,642

The following discussion contains forward-looking statements. These statements are based on Southern California Edison's (SCE) current expectations about future events, based on knowledge of present facts and assumptions about future developments. These forward-looking statements are subject to risks and uncertainties that could cause actual future activities and results of operations to be materially different from those set forth in this discussion. Important factors that could cause actual results to differ include risks discussed in the Market Risk Exposures and Forward-Looking Statements sections.

Until early 2002, SCE faced a crisis resulting from deregulation of the generation side of the electric utility industry through legislation enacted by the California Legislature and decisions issued by the California Public Utilities Commission (CPUC). Under the legislation and CPUC decisions, prices for wholesale purchases of electricity from power suppliers are set by markets while the retail prices paid by utility customers for electricity delivered to them remained frozen at June 1996 levels except for the 10% residential rate reduction starting in 1998 and the 4¢-per-kWh surcharge effective in 2001. See further discussion of the CPUC rate increases in Rate Stabilization Proceedings. Beginning in May 2000, SCE's costs to obtain power (at wholesale electricity prices) for resale to its customers substantially exceeded revenue from frozen rates. The shortfall was accumulated in the transition revenue account (TRA), a CPUC-authorized regulatory asset. As a result of a March 27, 2001, CPUC decision, the TRA balance was transferred retroactively to the transition cost balancing account (TCBA). The TCBA was a regulatory balancing account that tracked the recovery of generation-related transition costs, including stranded investments. SCE has borrowed significant amounts of money to finance its electricity purchases. Uncertainty regarding SCE's ability to recover funds spent to purchase power created a severe liquidity crisis at SCE. However, based on the settlement agreement with the CPUC (discussed below) permitting full recovery of past power procurement costs, SCE was able to arrange new financing and together with cash on hand, was able to repay its undisputed past-due obligations in March 2002.

In October 2001, a federal district court in California entered a stipulated judgment approving an agreement between the CPUC and SCE to settle a lawsuit. On January 23, 2002, the CPUC adopted a resolution approving the establishment of the procurement-related obligations account (PROACT). See discussion below. SCE believes that the settlement agreement will enable SCE to recover its previously undercollected power procurement costs. In compliance with the terms of the settlement agreement and the CPUC resolution, in the fourth quarter of 2001, SCE established a $3.6 billion regulatory asset for these previously incurred procurement costs, called the PROACT. A corresponding credit to earnings was recorded, in connection with this regulatory asset, in the amount of $3.6 billion ($2.1 billion after tax).

On September 1, 2001, SCE began applying to the PROACT the difference between SCE's revenue from retail electric rates and the costs that SCE is authorized by the CPUC to recover in retail electric rates. The settlement also calls for the end of the TCBA mechanism as of August 31, 2001, and continuation of the rate freeze until the earlier of December 31, 2003, or the date that SCE recovers the PROACT balance. If SCE has not recovered the entire PROACT balance by the end of 2003, the remaining balance will be amortized in retail rates for up to an additional two years. For further details on the settlement with the CPUC and the CPUC resolution, see CPUC Litigation Settlement Agreement and PROACT Regulatory Asset discussions.

Accounting principles generally accepted in the United States permit SCE to defer costs and record regulatory assets if those costs are determined to be probable of recovery in future rates. SCE assessed the probability of recovery of the undercollected costs that were previously recorded in the TCBA in light of the CPUC's March 27, 2001, and April 3, 2001, decisions, including the retroactive transfer of balances from SCE's TRA to its TCBA and related changes that are discussed in more detail in Rate Stabilization Proceedings. These decisions and other regulatory and legislative actions did not meet SCE's prior expectation that the CPUC would provide adequate cost recovery mechanisms. As a result, SCE's financial results for the year ended December 31, 2000, included an after-tax charge of approximately $2.5 billion ($4.2 billion pre-tax), reflecting a write-off of the TCBA and net regulatory assets to be recovered through the TCBA mechanism, as of December 31, 2000. Transition costs in excess of transition revenue were also incurred during 2001, resulting in additional net charges against earnings of $328 million ($552 million pre-tax) through August 31, 2001 (the effective date of the PROACT mechanism).

The following pages include a discussion of the history of the TRA and TCBA and related circumstances, the significantly negative effect on the financial condition of SCE of undercollections recorded in the TRA and TCBA, the current status of the undercollections, the impact of the CPUC's March 27, 2001, decisions and related matters, and the implementation of the CPUC settlement agreement and the PROACT mechanism, and SCE's March 2002 financing.

Results of Operations

Earnings

In 2001, SCE earned $2.4 billion, compared with a loss of $2.1 billion in 2000 and earnings of $484 million in 1999. SCE's 2001 earnings included a $2.1 billion (after tax) benefit resulting from the reestablishment of procurement-related regulatory assets and liabilities as a result of the PROACT resolution and recovery of $178 million (after tax) of previously written off generation-related regulatory assets, partially offset by $328 million (after tax) of net undercollected transition costs incurred between January and August 2001. SCE's loss in 2000 included a $2.5 billion (after tax) write-off of regulatory assets and liabilities as of December 31, 2000. SCE's 1999 earnings included a $15 million one-time tax benefit due to an Internal Revenue Service ruling. Excluding the $2.0 billion net benefit in 2001, the $2.5 billion (after tax) write-off in 2000 and the $15 million benefit in 1999, SCE's earnings were $408 million in 2001, $471 million in 2000 and $469 million in 1999. The $63 million decrease in 2001 was primarily due to the February 2001 fire and resulting outage at San Onofre Nuclear Generation Station Unit 3 and lower kilowatt-hour sales. In 2000, superior operating performance at San Onofre and higher kilowatt-hour sales were almost completely offset by adjustments to reflect potential regulatory refunds and lower gains from sales of equity investments.

Accounting principles generally accepted in the United States require SCE at each financial statement date to assess the probability of recovering its regulatory assets through a regulatory process. Based on the rules arising from the CPUC's March 27, 2001, rate stabilization decision, the $4.5 billion TRA undercollection as of December 31, 2000, and the coal and hydroelectric balancing account overcollections were reclassified, and the TCBA balance was recalculated to be a $2.9 billion undercollection (see further discussion of the CPUC rate increase in the Rate Stabilization Proceeding section and the components of the TCBA undercollection in the Status of Transition and Power-Procurement Cost Recovery section of Regulatory Environment). As a result, SCE was unable to conclude that, under applicable accounting principles, the $2.9 billion TCBA undercollection (as recalculated above) and $1.3 billion (book value) of other net regulatory assets that were to be recovered through the TCBA mechanism by the end of the rate freeze, were probable of recovery through the rate-making process as of December 31, 2000. As a result, SCE's December 31, 2000, income statement included a $4.0 billion charge to provisions for regulatory adjustment clauses and a $1.5 billion net reduction in income tax expense, to reflect the $2.5 billion (after tax) write-off.

Based on the rules arising from the CPUC's January 23, 2002, 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.

Operating Revenue

From 1998 through mid-September 2001, SCE's customers were able to choose to purchase power directly from an energy service provider (thus becoming direct access customers) or continue to have SCE purchase power on their behalf. Most direct access customers continued to be billed by SCE, but were given a credit for the generation purchased from the energy service provider. Operating revenue is reported net of this credit. On September 20, 2001, the CPUC suspended the ability of retail customers to select alternative providers of electricity until the California Department of Water Resources (CDWR) stops buying power for retail customers, pending further review by the CPUC. On March 21, 2002, the

CPUC issued a final decision affirming September 20, 2001, as the date when direct access was suspended in the state.

During 2000, as a result of the power shortage in California, SCE's customers on interruptible rate programs (which provide for lower generation rates with a provision that service can be interrupted if needed, with penalties for noncompliance) were asked to curtail their electricity usage at various times. As a result of noncompliance with SCE's requests, those customers were assessed significant penalties. On January 26, 2001, the CPUC waived the penalties assessed to noncompliant customers after October 1, 2000, until the interruptible programs can be reevaluated.

Operating revenue increased in 2001 (as shown in the table below), primarily due to the effects of the reduced credits given to direct access customers in 2001 and the 4¢-per-kWh (1¢ in January and 3¢ in June) surcharge effective in 2001. The increases were partially offset by: a decrease in retail sales volume primarily attributable to conservation efforts; a decrease in revenue related to penalties customers incurred for not complying with their interruptible contracts; a decrease in revenue related to operation and maintenance services; and a decrease in revenue related to electric power provided to SCE customers by the CDWR or Independent System Operator (ISO). Amounts SCE bills to and collects from its customers for electric power purchased and sold by the CDWR or through the ISO on behalf of SCE's customers (beginning January 17, 2001) are being remitted to the CDWR and are not recognized as revenue by SCE. In 2001, this amount was $2.0 billion. See CDWR Power Purchases discussion.

Operating revenue increased in 2000 (as shown in the table below), primarily due to: warmer weather in the second and third quarters of 2000 as compared to the same periods in 1999; increased resale sales; and an increase in revenue related to penalties customers incurred for not complying with their interruptible contracts.

The changes in operating revenue resulted from:

In millions Year ended December 31,	2001	2000	1999
Operating revenue –			
Rate changes (including refunds)	$ 422	$ 120	$ (75)
Direct access credit	566	(434)	(213)
Interruptible noncompliance penalty	(117)	102	6
Sales volume changes	(544)	520	195
Other	(71)	14	136
Total	$ 256	$ 322	$ 49

More than 94% of operating revenue was from retail sales. Retail rates are regulated by the CPUC and wholesale rates are regulated by the Federal Energy Regulatory Commission (FERC).

Due to warmer weather during the summer months, operating revenue during the third quarter of each year is significantly higher than other quarters.

Operating Expenses

Fuel expense increased in 2001 and decreased in 2000. The increase in 2001 and the decrease in 2000 were both due to fuel-related refunds resulting from a settlement with another utility that SCE recorded in the second and third quarters of 2000.

Purchased-power expense decreased in 2001 and increased in 2000. The 2001 decrease resulted from the absence of California Power Exchange (PX)/ISO purchased-power expense after mid-January 2001, partially offset by increased expenses related to qualifying facilities (QFs), bilateral contracts and interutility contracts. See Purchased Power table in Note 1 to the Consolidated Financial Statements and discussion in CDWR Power Purchases. PX/ISO purchased-power expense increased significantly between May 2000 and mid-

January 2001, due to a number of factors, including increased demand for electricity in California, dramatic price increases for natural gas (a key input of electricity production), and problems in the structure and conduct of the PX and ISO markets. In December 2000, the FERC eliminated the requirement that SCE buy and sell all power through the PX and ISO. Due to SCE's noncompliance with the PX's tariff requirement for posting collateral for all transactions in the day-ahead and day-of markets as a result of the downgrade in its credit rating, the PX suspended SCE's market trading privileges effective mid-January 2001.

Prior to April 1998, federal law and CPUC orders required SCE to enter into contracts to purchase power from QFs at CPUC-mandated prices even though energy and capacity prices under many of these contracts are generally higher than other sources. These contracts expire on various dates through 2025. See further discussion regarding new QF agreements in Litigation. Purchased-power expense related to QFs increased due to the short-run avoided cost factor (which is based on the price of natural gas) of the QF contracts causing a significant increase in the payments to QFs. In early 2001, structural problems in the market caused abnormally high gas prices. The increase related to bilateral contracts was the result of SCE not having these contracts in 2000. The increase related to interutility contracts was volume-driven.

SCE has contracts with certain QFs in which Edison Mission Energy (a wholly owned subsidiary of Edison International) has 49% – 50% interests. The terms and pricing of these contracts are approved by the CPUC. SCE's power purchases from these facilities were $983 million in 2001, $716 million in 2000 and $513 million in 1999.

Provisions for regulatory adjustment clauses decreased for 2001 and increased for 2000. The 2001 decrease resulted from SCE recording the $3.6 billion PROACT regulatory asset in fourth quarter 2001. The increase in 2000 was mainly due to SCE's write-off as of December 31, 2000, of $4.2 billion in regulatory assets and liabilities as a result of the California energy crisis. Adjustments to reflect potential regulatory refunds related to the outcome of the CPUC's reevaluation of the operation of the interruptible rate programs also contributed to the increase in 2000.

Other operation and maintenance expense decreased in 2000. The decrease was primarily due to a $120 million decrease in mandated transmission service (known as reliability must-run services) expense and a $19 million decrease in operating expenses at San Onofre. The decrease at San Onofre in 2000 was primarily due to scheduled refueling outages for both units in the first half of 1999. San Onofre had only one refueling outage in 2000.

Depreciation, decommissioning and amortization expense decreased in 2001, mainly due to SCE's nuclear investment amortization expense ceasing since the unamortized nuclear investment regulatory asset was included in the December 31, 2000, write-off.

Net gain on sale of utility plant in 2000 resulted from the sale of additional property related to four of the generating stations SCE sold in 1998. The gains were returned to the ratepayers through the TCBA mechanism.

Other Income and Deductions

Interest and dividend income increased in both 2001 and 2000. The increase in 2001 was mainly due to an overall higher cash balance, as SCE conserved cash due to its liquidity crisis. The increase in 2000 was mostly due to increases in interest earned on higher balancing account undercollections.

Other nonoperating income decreased in both 2001 and 2000. The decrease in 2001 primarily reflects the gains on sales of marketable securities in 2000. The decrease in 2000 was primarily due to larger gains on sales of marketable securities in 1999.

Interest expense – net of amounts capitalized increased in both 2001 and 2000. The increase in 2001 reflects additional long-term debt and higher short-term debt balances. The increase in 2000 was mostly due to higher overall short-term debt balances necessary to meet general cash requirements (especially PX and ISO payments) and higher interest expense related to balancing account overcollections.

Other nonoperating deductions decreased in 2001 primarily due to lower accruals for regulatory matters in 2001.

Income Taxes

Income taxes increased in 2001 and decreased in 2000. The increase in 2001 reflects $1.5 billion in income tax expense related to the PROACT regulatory asset establishment in fourth quarter 2001. The decrease in 2000 was primarily due to the $1.5 billion income tax benefit related to the write-off as of December 31, 2000, of regulatory assets and liabilities in the amount of $2.5 billion (after tax). Absent the impact of the PROACT regulatory asset in 2001 and the write-off in 2000, SCE's income tax expense increased in both 2001 and 2000 due to higher pre-tax income in both years.

Financial Condition

SCE's liquidity is affected primarily by regulation affecting its ability to recover the cost of power purchases, debt maturities, access to capital markets, credit ratings, dividend payments and capital expenditures. Capital resources include cash from operations and external financings.

Liquidity Issues

Sustained higher wholesale energy prices that began in May 2000 persisted through June 2001. This resulted in undercollections in the TRA and TCBA. Undercollections, coupled with SCE's anticipated near-term capital requirements (detailed in Projected Commitments) and the adverse reaction of the credit markets to continued regulatory uncertainty regarding SCE's ability to recover its current and future power procurement costs, materially and adversely affected SCE's liquidity throughout 2001. As a result of its liquidity concerns, SCE took steps to conserve cash to continue to provide service to its customers. As a part of this process, beginning in January 2001, SCE suspended payments owed to the ISO, the PX and QFs, deferred payments of certain obligations for principal and interest on outstanding debt and did not declare dividends on any of its cumulative preferred stock. As applicable, unpaid obligations continued to accrue interest. As of March 31, 2001, SCE resumed payment of interest on its debt obligations. However, since June 30, 2001, SCE deferred the interest payments on its quarterly income debt securities (subordinated debentures), as allowed by the terms of the securities. All interest in arrears must be paid at the end of the deferral period. As long as accumulated dividends on SCE's preferred stock remain unpaid, SCE could not pay dividends on its common stock. Common stock dividends are additionally restricted as detailed in the CPUC Litigation Settlement discussion.

Based on the rights to cost recovery and revenue established by the settlement agreement with the CPUC and CPUC implementing orders, including the PROACT resolution, SCE repaid its undisputed past-due obligations on March 1, 2002, with lump-sum payments to creditors from the proceeds of $1.6 billion in senior secured credit facilities, the remarketing of $196 million in pollution-control bonds which were repurchased in late 2000, and existing cash on hand. The $1.6 billion senior secured credit facilities consist of a $300 million, two-year revolving credit loan, a $600 million, one-year loan and a $700 million, three-year loan.

The proceeds from the senior secured credit facilities and pollution-control bond remarketing were used, along with SCE's available cash, to repay $3.2 billion in past-due obligations and $1.65 billion in near-term debt maturities. The past-due obligations consisted of: (1) $875 million to the PX; (2) $99 million to the ISO; (3) $1.1 billion to QFs; (4) $193 million in PX energy credits for energy service providers; (5) $531 million of matured commercial paper; (6) $400 million of principal on its 5-7/8% and 6-1/2% senior unsecured notes which were issued prior to the energy crisis; and (7) $23 million in preferred dividends in arrears. The near-term debt maturities consisted of credit facilities whose maturity dates were extended several times and were scheduled to mature in March and May 2002. In addition, SCE entered into an agreement with the CDWR to pay for prior deliveries of energy in installments of $100 million on April 1, 2002, $150 million on June 3, 2002, and the balance on July 1, 2002. After making the above-described payments, SCE has no material undisputed obligations that are past due or in default.

SCE expects to meet its continuing obligations from remaining cash on hand and future operating cash flows.

For additional discussion on the impact of California's energy crisis on SCE's liquidity, see Cash Flows from Financing Activities. For a discussion on the settlement agreement with the CPUC and the PROACT resolution to resolve SCE's crisis, see CPUC Litigation Settlement Agreement and PROACT Regulatory Asset sections.

Cash Flows from Operating Activities

Net cash provided by operating activities was $3.3 billion in 2001, $829 million in 2000 and $1.5 billion in 1999. The increase in 2001 was primarily due to SCE suspending payments for purchased power and other obligations beginning in January 2001. Cash provided by operating activities also reflects the CPUC-approved surcharges (1¢ per kWh in January and 3¢ per kWh in June) that were billed in 2001. The decrease in 2000 was the result of extremely high prices SCE paid for energy and ancillary services procured through the PX and ISO.

Cash Flows from Financing Activities

At December 31, 2001, SCE had drawn on its entire credit lines of $1.65 billion. These unsecured lines of credit have various expiration dates and, when available, could be drawn down at negotiated or bank index rates. On March 1, 2002, SCE's credit lines ($1.65 billion) were repaid using proceeds from the March 1, 2002, financing. See additional discussion in Liquidity Issues.

Short-term debt is used to finance balancing account undercollections, fuel inventories and general cash requirements, including purchased-power payments. Long-term debt is used mainly to finance capital expenditures. External financings are influenced by market conditions and other factors. Because of the $2.5 billion charge to earnings as of December 31, 2000, SCE does not currently meet the interest coverage ratio that is required for SCE to issue additional preferred stock.

As a result of investors' concerns regarding the California energy crisis and its impact on SCE's liquidity and overall financial condition, during December 2000 and early 2001, SCE had to repurchase $550 million of pollution-control bonds that could not be remarketed in accordance with their terms. SCE remarketed $196 million of these bonds in March 2002 (see additional discussion in Liquidity Issues). The remaining amount of these bonds may be remarketed in the future. In addition, SCE remains unable to sell its commercial paper and other short-term financial instruments.

Although Fitch IBCA, Standard & Poor's and Moody's Investors Service raised their credit ratings significantly for SCE in March 2002, the new ratings are still below investment grade. The new ratings reflect the ongoing financial recovery of SCE that began in October 2001 with SCE's settlement agreement with the CPUC and has continued with the CPUC's January 2002 PROACT resolution and the repayment of SCE's past-due obligations. SCE lost its investment-grade ratings in January 2001.

California law prohibits SCE from incurring or guaranteeing debt for its nonutility affiliates. Additionally, the CPUC regulates SCE's capital structure, thereby limiting the dividends it may pay Edison International.

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 non-bypassable rates charged to residential and small commercial customers. The rate reduction notes are being repaid over 10 years through these non-bypassable 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 beginning in 2002 and ending in 2007, with interest rates ranging from 6.22% to 6.42%. The notes are secured by the transition property and are not secured 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. Due to its credit rating downgrade in late 2000, in January 2001, SCE began remitting its customer collections related to the rate-reduction notes on a daily basis.

Cash Flows from Investing Activities

Cash flows from investing activities are affected by additions to property and plant and funding of nuclear decommissioning trusts. Decommissioning costs are recovered in utility rates. These costs are expected to be funded from independent decommissioning trusts that receive SCE contributions of approximately $25 million per year. In 1995, the CPUC determined the restrictions related to the investments of these trusts. They are: not more than 50% of the fair market value of the qualified trusts may be invested in equity securities; not more than 20% of the fair market value of the trusts may be invested in international equity securities; up to 100% of the fair market values of the trusts may be invested in investment grade fixed-income securities including, but not limited to, government, agency, municipal, corporate, mortgage-backed, asset-backed, non-dollar, and cash equivalent securities; and derivatives of all descriptions are prohibited. 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.

Projected Commitments

SCE's projected construction expenditures for 2002 are $921 million.

Long-term debt maturities and sinking fund requirements for the next five years are: 2002 – $1.1 billion; 2003 – $1.4 billion; 2004 – $371 million; 2005 – $246 million; and 2006 – $446 million.

Fuel supply contract payments for the next five years are: 2002 – $168 million; 2003 – $108 million; 2004 – $103 million; 2005 – $106 million; and 2006 – $109 million.

Purchased-power capacity payments for the next five years are: 2002 – $629 million; 2003 – $629 million; 2004 – $626 million; 2005 – $624 million; and 2006 – $572 million.

Preferred stock redemption requirements for the next five years are: 2002 – $105 million; 2003 – $9 million; 2004 – $9 million; 2005 – $9 million; and 2006 – $9 million.

Market Risk Exposures

SCE's primary market risk exposures include commodity price risk and interest rate risk that could adversely affect results of operations or financial position. Commodity price risk arises from fluctuations in the market price of an energy commodity, such as electricity, natural gas, or coal. Interest rate risk arises from fluctuations in interest rates. Additionally, natural gas is a key input for the prices specified in approximately half of SCE's QF (including non-gas QF) contracts. Virtually all of SCE's exposure to changes in the spot market price for natural gas through 2003 is hedged through financial derivatives or fixed-price contracts. SCE's risk management policy allows the use of derivative financial instruments to manage its financial exposures, but prohibits the use of these instruments for speculative or trading purposes.

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. As a result of California's energy crisis, SCE has been exposed to significantly higher interest rates, which intensified its liquidity crisis during 2001 (further discussed in the Liquidity Issues section of Financial Condition).

At December 31, 2001, SCE did not believe that its short-term debt was subject to interest rate risk, due to the fair market value being approximately equal to its carrying value. SCE did believe that the fair market value of its fixed-rate long-term debt was subject to interest rate risk. At December 31, 2001, a 10% increase in market interest rates would have resulted in a $128 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 $141 million increase in the fair market value of SCE's long-term debt.

Since April 1998, the price SCE paid to acquire power on behalf of customers was allowed to float, in accordance with the 1996 electric utility restructuring law. Until May 2000, retail rates were sufficient to cover the cost of power and other SCE costs. However, between May 2000 and June 2001, market power prices escalated, creating a substantial gap between costs and retail rates. In response to the dramatically higher prices, the ISO and the FERC have placed certain caps on the price of power (see further discussion in Wholesale Electricity Markets).

Under the terms of the CPUC settlement agreement, SCE purchased $209 million in hedging instruments (gas call options) in October and November 2001 to hedge a majority of its natural gas price exposure associated with QF contracts for 2002 and 2003. Although these gas call options are reflected in the income statement, any fair value changes of the gas call options are offset through a regulatory balancing account; therefore, fair value changes do not affect earnings. At December 31, 2001, a 10% increase in market gas prices would have resulted in a $32 million increase in the fair market value of SCE's gas call options. A 10% decrease in market gas prices would have resulted in a $27 million decrease in the fair market value of the gas call options.

In accordance with an accounting standard for derivatives, on January 1, 2001, SCE recorded its block-forward contracts at fair value on the balance sheet. Because SCE suspended payments for purchased power on January 16, 2001, the PX sought to liquidate SCE's remaining block-forward contracts. Before the PX could do so, on February 2, 2001, the state seized the contracts. On September 20, 2001, a federal appeals court ruled that the governor of California acted illegally when he seized the power contracts held by SCE. In conjunction with its settlement agreement with the CPUC (discussed in CPUC Litigation Settlement Agreement), SCE has agreed to release any claim for compensation against the state for these contracts. However, if the PX prevails in its claims against the state, SCE may receive some refunds. Due to its speculative grade credit ratings, SCE has been unable to purchase additional bilateral forward contracts, and some of the existing contracts were terminated by the counterparties.

Regulatory Environment

SCE operates in a highly regulated environment and has an exclusive franchise within its service territory. SCE has an obligation to deliver electric service to its customers and regulatory authorities have an obligation to provide just and reasonable rates. In the mid-1990s, state lawmakers and the CPUC initiated the electric industry restructuring process. SCE was directed by the CPUC to divest the bulk of its gas-fired generation portfolio. Today, independent power companies own the divested generating plants. The electric industry restructuring plan also instituted a multi-year freeze on the rates that SCE could charge its customers and transition cost recovery mechanisms (as described in Status of Transition and Power-Procurement Cost Recovery) designed to allow SCE to recover its stranded costs associated with generation-related assets. California's electric industry restructuring statute included provisions to finance a portion of the stranded costs that residential and small commercial customers would have paid between

1998 and 2001, which allowed SCE to reduce rates by at least 10% to these customers, effective January 1, 1998. These frozen rates (except for the surcharge effective in 2001) were to remain in effect until the earlier of March 31, 2002, or the date when the CPUC-authorized costs for utility-owned generation assets and obligations are recovered. However, between May 2000 and June 2001, the prices charged by sellers of power escalated far beyond what SCE could charge its customers. As a result, SCE incurred $2.7 billion (after tax), or $4.7 billion (pre-tax), in write-offs as of December 31, 2000, and net undercollected transition costs through August 31, 2001. As indicated below, implementation of the CPUC settlement agreement and CPUC approval of SCE's Utility-Retained Generation (URG) application is expected to allow SCE to recover substantially all of the $4.7 billion.

Generation and Power Procurement

During the rate freeze, recovery of generation-related transition costs was tracked through the TCBA mechanism. Revenue from generation-related operations was determined through the market and transition cost recovery mechanisms, which included the nuclear rate-making agreements. During fourth quarter 2001, the TCBA mechanism was terminated retroactive to September 1, 2001, and a $3.6 billion PROACT regulatory asset was created in accordance with the October 2001 settlement agreement with the CPUC and the PROACT resolution adopted in January 2002. In accordance with a state law passed in January 2001, SCE will continue to own its remaining generation assets, which will be subject to cost-based ratemaking, through 2006 (see further discussion in URG Proceeding).

Through December 31, 2000, SCE had been recovering its investment in its nuclear facilities on an accelerated basis (over four years) in exchange for a lower authorized rate of return on investment. SCE's nuclear assets were earning an annual rate of return on investment of 7.35%. However, due to the various unresolved regulatory and legislative issues (as discussed in Status of Transition and Power-Procurement Cost Recovery), as of December 31, 2000, SCE was no longer able to conclude that the $610 million balance of unamortized nuclear investment regulatory assets 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 (see further discussion in Earnings). Should the URG application be approved, SCE expects to reestablish for financial reporting purposes its unamortized nuclear investment and related flow-through taxes retroactive to August 31, 2001, with recovery based on a 10-year period, effective January 1, 2001, with a corresponding credit to earnings, and adjust the PROACT regulatory asset balance as necessary to reflect recovery of the nuclear investment in accordance with the final URG decision.

The San Onofre incentive-pricing plan authorizes a fixed rate of approximately 4¢ per kWh generated for operating costs including incremental capital costs, nuclear fuel and nuclear fuel financing costs. The San Onofre incentive-pricing plan started in April 1996 and ends in December 2003. The Palo Verde Nuclear Generating Station's operating costs, including incremental capital costs, and nuclear fuel and nuclear fuel financing costs, were subject to balancing account treatment. The Palo Verde plan started in January 1997 and was to end in December 2001. The benefits of operation of the San Onofre units and the Palo Verde units were required to be shared equally with ratepayers beginning in 2004 and 2002, respectively. In a June 2001 decision, the CPUC granted SCE's request to eliminate the San Onofre post-2003 sharing mechanism based on compliance with a state law enacted in early 2001. In a September 2001 decision, the CPUC granted SCE's request to eliminate the Palo Verde post-2001 sharing mechanism and to continue the current rate-making treatment for Palo Verde, including the continuation of the existing nuclear 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. Beginning January 1, 1998, both the San Onofre and Palo Verde rate-making plans became part of the TCBA mechanism. These rate-making plans and the TCBA mechanism were to continue for rate-making purposes at least through the end of the rate freeze period. However, in its URG application, SCE proposed to move the recovery of nuclear costs to another balancing account mechanism. See discussion in URG Proceeding for the proposed and alternate decisions' impact on the incentive-pricing plans.

<u>CPUC Litigation Settlement Agreement</u>

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 past electricity procurement costs in accordance with the tariffs filed with the FERC. By agreement of the parties, a stay of the lawsuit was issued in April 2001 while SCE sought implementation of legislative, regulatory and executive actions to resolve the California energy crisis and SCE's related financial and liquidity problems. In October 2001, the federal district court entered a stipulated judgment approving an agreement between the CPUC and SCE to settle the pending lawsuit. On January 23, 2002, the CPUC adopted a resolution implementing the settlement agreement. See discussion below in PROACT Regulatory Asset.

Key elements of the settlement agreement include the following items:

- Establishment of the PROACT, as of September 1, 2001, with an opening balance equal to the amount of SCE's procurement-related liabilities as of August 31, 2001 (approximately $6.4 billion), less SCE's cash and cash equivalents as of that date (approximately $2.5 billion), and less $300 million.

- Beginning on September 1, 2001, SCE will apply to the PROACT, on a monthly basis, the difference between SCE's revenue from retail electric rates (including surcharges) and the costs that SCE is authorized by the CPUC to recover in retail electric rates. Unrecovered obligations in the PROACT will accrue interest from September 1, 2001.

- Maintain current rates (including surcharges) in effect until December 31, 2003, subject to certain adjustments, or, if earlier, until the date that SCE recovers the entire PROACT balance. If SCE has not recovered the entire balance by December 31, 2003, the unrecovered balance will be amortized for up to an additional two years. The parties project that existing retail electric rates, including surcharges and as adjusted to reflect certain costs, will likely result in SCE recovering substantially all of its unrecovered procurement-related obligations prior to the end of 2003.

- If the CPUC concludes that it is desirable to authorize a securitized financing of SCE's procurement-related obligations, the parties will work together to achieve the securitization. Proceeds of any securitization will be credited to the PROACT when they are actually received.

- During the period that SCE is recovering its previously incurred procurement-related obligations, no penalty will be imposed by the CPUC on SCE for any noncompliance with CPUC-mandated capital structure requirements.

- SCE can incur up to $250 million of recoverable costs to acquire financial instruments and engage in other transactions intended to hedge fuel cost risks associated with SCE's retained generation assets and power purchase contracts with QFs and other utilities. As of December 31, 2001, SCE had purchased $209 million in hedging instruments. See discussion in Market Risk Exposures.

- SCE will not declare or pay dividends or other distributions on its common stock (all of which is held by its parent) prior to the earlier of the date SCE has recovered all of its procurement-related obligations in the PROACT or January 1, 2005. However, if SCE has not recovered all of its procurement-related obligations by December 31, 2003, SCE may apply to the CPUC for consent to resume common stock dividends, and the CPUC will not unreasonably withhold its consent.

- To ensure the ability of SCE to continue to provide adequate service, SCE may make capital expenditures above the level contained in current rates, up to $900 million per year, which will be treated as recoverable costs.

- Subject to certain qualifications, SCE will cooperate with the CPUC and the California Attorney General to pursue and resolve SCE's claims and rights against sellers of energy and related services, SCE's defenses to claims arising from any failure to make payments to the PX or ISO, and similar claims by the State of California or its agencies against the same adverse parties. During the recovery period discussed above, refunds obtained by SCE related to its procurement-related liabilities will be applied to the balance in the PROACT.

The settlement agreement states that one of its purposes is to restore the investment grade creditworthiness of SCE as rapidly as reasonably practicable so that it will be able to provide reliable electrical service as a state-regulated entity as it has in the past. SCE cannot provide assurance that it will regain investment grade credit ratings by any particular date.

On November 28, 2001, a federal court of appeals denied a California consumer group's request for a long-term stay of the settlement. The group had alleged that it was denied due process and that the CPUC had no authority to agree with SCE to violate the statutory rate freeze. In its ruling, the federal court of appeals also granted SCE's request for an expedited hearing of an appeal of the settlement filed by the consumer group. On March 4, 2002, the court of appeals heard argument on the appeal and the matter is now under submission. A decision could be issued anytime during the next several months. SCE cannot predict the outcome of the appeal or the impact that any outcome would have upon the stipulated judgment or the settlement, at this time. Possible outcomes include affirmance, a return to the district court or reversal of the stipulated judgment. SCE cannot predict whether or how a ruling on the stipulated judgment could also affect the settlement agreement.

PROACT Regulatory Asset

According to the terms of the settlement agreement and the CPUC resolution, in the fourth quarter of 2001, SCE established (retroactive to August 31, 2001) a $3.6 billion PROACT regulatory asset for its previously incurred procurement costs.

The beginning balance of the PROACT, as verified by the CPUC, was calculated as follows:

In millions	
Past-due bills:	
PX or ISO	$ 924
QFs	1,219
PX energy credits	236
Imbalance energy (CDWR)	383
Ancillary services for resale cities	30
Total past-due bills	2,792
Procurement-related debt (including accrued interest):	
Credit facilities	1,298
Bilateral credit facilities	415
Defaulted commercial paper	563
Floating rate notes due May 2002	313
Variable rate notes due November 2003	1,043
Total procurement-related debt	3,632
Total procurement-related liabilities	6,424
Less: Cash and cash equivalents on hand	(2,547)
Less: Amount stipulated in agreement	(300)
Net PROACT balance as of August 31, 2001	$ 3,577

For a comparison between the PROACT balance as of August 31, 2001, and the TCBA balance as of that date, see discussion in Status of Transition and Power-Procurement Cost Recovery.

CDWR Power Purchases

In accordance with an emergency order signed by the governor, the CDWR began making emergency power purchases for SCE's customers on January 17, 2001. Amounts SCE bills to and collects from its customers for electric power purchased and sold by the CDWR and through the ISO are remitted directly to the CDWR and are not recognized as revenue by SCE. In February 2001, Assembly Bill 1 (First Extraordinary Session, AB 1X) was enacted into law. AB 1X authorized the CDWR to enter into contracts to purchase electric power and sell power at cost directly to retail customers being served by SCE, and authorized the CDWR to issue bonds to finance electricity purchases.

On March 27, 2001, the CPUC issued an interim order requiring SCE to pay the CDWR a per-kWh price equal to the applicable generation-related retail rate per kWh for electricity (based on rates in effect on January 5, 2001), for each kWh the CDWR sells to SCE's customers. The CPUC determined that the generation-related retail rate should be equal to the total bundled electric rate (including the 1¢-per-kWh surcharge adopted by the CPUC on January 4, 2001) less certain nongeneration-related rates or charges. For the period January 19 through January 31, 2001, the CPUC ordered SCE to pay the CDWR at a rate of 6.277¢ per kWh for power delivered to SCE's customers. The CPUC determined that the applicable rate component is 7.277¢ per kWh (which increased to 10.277¢ per kWh for electricity delivered after March 27, 2001, due to the 3¢-surcharge discussed in Rate Stabilization Proceedings), for electricity delivered by the CDWR to SCE's retail customers after February 1, 2001, until more specific rates are calculated. The CPUC ordered SCE to pay the CDWR within 45 days after the CDWR supplies power to retail customers, subject to penalties for each day the payment is late.

On February 21, 2002, the CPUC issued a decision implementing a CDWR revenue requirement of $9.0 billion to pay its bonds' costs and energy procurement costs for the period January 17, 2001, through December 31, 2002. The decision states that SCE's allocated share of this revenue requirement would be approximately $3.6 billion, and changes SCE's payment to 9.744¢ per kWh for all bills rendered on or after March 15, 2002. The decision requires SCE to pay the CDWR in equal monthly installments over a six-month period the difference in rates between January 17, 2001, and March 15, 2002. SCE estimates that this amount could be approximately $41 million.

On February 28, 2002, SCE and the CDWR executed an agreement that resolves outstanding issues relating to the payment for electric power purchased for SCE's customers through the ISO real-time market (known as imbalance energy). Under this agreement, SCE will pay the CDWR for imbalance energy previously delivered in three installments ($100 million on April 1, 2002; $150 million on June 3, 2002; and the balance on July 1, 2002).

Status of Transition and Power-Procurement Cost Recovery

SCE's transition costs to be recovered through the TCBA mechanism included power purchases from QF contracts (which are the direct result of prior legislative and regulatory mandates), recovery of certain generating assets and other costs incurred to provide service to customers. Other costs included the recovery of income tax benefits previously flowed through to customers, postretirement benefit transition costs and accelerated recovery of investment in nuclear generating units. Recovery of costs related to power-purchase QF contracts was permitted through the terms of each contract. Legislation and regulatory decisions issued prior to the beginning of the rate freeze called for most of the remaining transition costs to be recovered through the end of the four-year transition period (not later than March 31, 2002). Because regulatory and legislative actions that make such recovery probable were not taken in a timely manner during the energy crisis, as of December 31, 2000, SCE was unable to conclude that the net regulatory assets related to purchased-power settlements, the unamortized loss on SCE's generating plant sales in 1998, and various other generation regulatory assets were probable of recovery through the rate-making process. As a result, these balances were written off as a charge to earnings at that time (see further discussion in Earnings).

There were three sources of revenue available to SCE for transition cost recovery through the TCBA mechanism: revenue from the sale or valuation of generation assets in excess of book values, net market revenue from the sale of SCE-controlled generation into the ISO and PX markets and competition transition charge (CTC) revenue. Revenue from the first two sources has not been available since January 2001. Net proceeds of the 1998 plant sales were used to reduce transition costs, which otherwise had been expected to be collected through the TCBA mechanism. However, state legislation enacted in January 2001 prohibits the sale of SCE's remaining generation assets until 2006. SCE stopped selling power from its generation into the ISO and PX markets in January 2001, after SCE's credit ratings were downgraded and the PX suspended SCE's trading privileges (see discussion in Generation and Power Procurement).

CTC revenue was determined residually (i.e., CTC revenue was the residual amount remaining from monthly gross customer revenue under the rate freeze after subtracting the revenue requirements for transmission, distribution, nuclear decommissioning and public benefit programs, and ISO payments and power purchases from the PX and ISO). The CTC applied to all customers who were using or began using utility services on or after the CPUC's 1995 restructuring decision date. Residual CTC revenue was calculated through the TRA mechanism. In accordance with the March 27, 2001, rate stabilization decision, both positive and negative residual CTC revenue was transferred from the TRA to the TCBA on a monthly basis, retroactive to January 1, 1998 (see further discussion in Rate Stabilization Proceedings). A previous decision had called only for a transfer of positive residual CTC revenue (TRA overcollections) to the TCBA and there had not been any positive residual CTC revenue between May 2000 and June 2001.

Because the regulatory and legislative actions that made such recovery probable were not taken, SCE was unable to conclude as of December 31, 2000, that the recalculated TCBA net undercollection was probable of recovery through the rate-making process. As a result, the $2.9 billion TCBA net undercollection was written off as a charge to earnings as of that date (see further discussion in Earnings), and an additional $552 million (pre-tax) of net undercollected transition costs was charged to earnings between January 1, 2001, and August 31, 2001. Although the TCBA was written off, SCE continued to calculate the account for rate-making purposes, and the account reflected a $4.2 billion undercollection as of August 31, 2001, the effective date of the beginning of the PROACT mechanism and the end of the TCBA mechanism. If the TCBA would have been adjusted for the impact of SCE's treatment of the nuclear facilities as proposed in the URG proceeding, the TCBA balance as of August 31, 2001, would have reflected an undercollection of $3.626 billion, substantially equal to the $3.577 billion undercollection in the PROACT regulatory asset.

For more details on the matters discussed above, see discussions in Rate Stabilization Proceedings, URG Proceeding and PROACT Regulatory Asset.

Litigation

In October 2000, a federal class action securities lawsuit was filed against SCE and Edison International. As amended in December 2000 and March 2001, the lawsuit involves securities fraud claims arising from alleged improper accounting for the TRA undercollections. The second amended complaint is supposedly filed on behalf of a class of persons who purchased Edison International common stock between July 21, 2000, and April 17, 2001. This lawsuit has been consolidated with another similar lawsuit filed on March 15, 2001. A consolidated class action complaint was filed on August 3, 2001. On September 17, 2001, SCE and Edison International filed a motion to dismiss for failure to state a claim. On March 8, 2002, the district court issued an order dismissing the complaint with prejudice. The plaintiffs could appeal this ruling to the court of appeals.

In addition to the lawsuits filed against Edison International and SCE discussed above, SCE has been a defendant in a number of legal actions brought by various QFs arising out of SCE's suspension of payments for electricity delivered by the QFs during the period November 1, 2000, through March 26, 2001. The QF claims were eventually largely subsumed within agreements with the litigating QFs providing for a provisional settlement of the parties' disputes. On March 1, 2002, SCE paid the amounts due under settlement agreements with these QFs, which triggered the releases and other provisions of the settlements. As a result, the litigation with those QFs to whom payment in full has been made under the parties' settlement agreements should be dismissed during 2002. However, SCE's March 1, 2002, payments excluded several QFs or did not result in immediate releases under the settlement agreements based on unique disputes or other unique circumstances, including the status of regulatory approval.

Rate Stabilization Proceedings

In January 2000, SCE filed an application with the CPUC proposing rates that would go into effect when the four-year rate freeze was to end on March 31, 2002, or earlier, depending on the pace of transition cost recovery. In December 2000, SCE filed an amended rate stabilization plan application, stating that the statutory rate freeze had ended in accordance with California law, and requesting the CPUC to approve an immediate 30% increase to be effective, subject to refund, January 4, 2001.

In January 2001, independent auditors hired by the CPUC issued a report on the financial condition and solvency of SCE and its affiliates. The report confirmed what SCE had previously disclosed to the CPUC in public filings about SCE's financial condition. The audit report covered, among other things, cash needs, credit relationships, accounting mechanisms to track stranded cost recovery, the flow of funds between SCE and Edison International, and earnings of SCE's California affiliates. In April 2001, the CPUC adopted an order instituting investigation that reopens the past CPUC decision authorizing the utilities to form holding companies and initiates an investigation into: whether the holding companies violated CPUC requirements to give first priority to the capital needs of their respective utility subsidiaries; whether ring-fencing actions by Edison International and PG&E Corporation and their respective nonutility affiliates also violated the requirements to give priority to the capital needs of their utility subsidiaries; whether the payment of dividends by the utilities violated requirements that the utilities maintain dividend policies as though they were comparable stand-alone utility companies; any additional suspected violations of laws or CPUC rules and decisions; and whether additional rules, conditions, or other changes to the holding company decisions are necessary. The CPUC ordered testimony and briefing on these matters, which SCE filed in May and June 2001. On January 9, 2002, the CPUC issued an interim decision on the first priority condition. The decision stated that, at least under certain circumstances, the condition includes the requirement that holding companies infuse all types of capital into their respective utility subsidiaries when necessary to fulfill the utility's obligation to serve. On February 11, 2002, SCE filed an application for rehearing of the decision stating that the decision is an unlawful and erroneous attempt to rewrite the first priority condition rather than interpret it and that the decision would result in higher rates for SCE's customers. SCE cannot predict what effects this investigation or any subsequent actions by the CPUC may have on SCE.

In March 2001, the CPUC ordered a rate increase in the form of a 3¢-per-kWh surcharge applied only to going-forward electric power procurement costs and affirmed that a 1¢ interim surcharge granted in January 2001 is permanent. The 3¢ surcharge is to be added to the rate paid to the CDWR (see CDWR Power Purchases). Although the 3¢-increase was authorized as of March 27, 2001, the surcharge was not collected in rates until the CPUC established a rate design in early June 2001. To compensate for the two-month delay in collecting the 3¢ surcharge, the CPUC authorized an additional ½¢ surcharge for a 12-month period beginning in June 2001.

<u>URG Proceeding</u>

In June 2001, SCE filed a comprehensive proposal for new cost-of-service ratemaking for utility retained generation through the end of 2002. After that time, SCE's URG-related revenue requirement will be determined by the general rate case. The URG proposal calls for balancing accounts for SCE-owned generation, QF and interutility contracts, procurement costs and ISO charges based on either actual or CPUC-authorized revenue requirements. Under the proposal, the four new balancing accounts would be effective January 1, 2001, for capital-related costs, and February 1, 2001, for non-capital-related costs. In addition, SCE's unamortized nuclear investment would be amortized and recovered in rates over a 10-year period, effective January 1, 2001. Should this application be approved as filed, SCE expects to reestablish for financial reporting purposes its unamortized nuclear investment and regulatory assets related to purchased-power settlements and flow-through taxes, with a corresponding credit to earnings, and adjust the PROACT regulatory asset balance in accordance with the final URG decision.

On January 18, 2002, a CPUC administrative law judge issued a proposed decision and a CPUC commissioner issued an alternate proposed decision. Both the proposed and alternate proposed decisions adopt most of the elements of SCE's application, but propose eliminating an incentive-pricing plan for San Onofre, effective January 1, 2002, and replacing it with balancing account treatment for San Onofre's operating costs, subject to a later reasonableness review. On February 7, 2002, another CPUC commissioner issued an alternate proposed decision recommending continuing the incentive-pricing plan for San Onofre Units 2 and 3 through December 31, 2003, as originally provided in CPUC decisions adopted in early 1996. A final decision is expected in second quarter 2002.

Generation Procurement Proceeding

In October 2001, the CPUC issued an order instituting rulemaking (OIR) to establish policies and cost recovery mechanisms for generation procurement. The OIR directed SCE and the other major California electric utilities to provide recommendations for establishing these policies and mechanisms to enable the utilities to resume their power procurement responsibilities in 2003. In comments filed with the CPUC on November 26, 2001, SCE recommended that the CPUC issue a procurement framework decision in February 2002, and direct the utilities to submit their specific procurement plan proposals and related framework compliance proposals in March 2002. SCE also proposed that a final decision be issued in October 2002 adopting utility-specific procurement plans. The CPUC has not yet acted on SCE's recommendations, but is expected in second quarter 2002 to issue a scoping memo setting forth issues to be addressed in this proceeding.

Accounting for Generation-Related Assets and Power Procurement Costs

In 1997, SCE discontinued application of accounting principles for rate-regulated enterprises for its generation assets. At that time, SCE did not write off any of its generation-related assets, including related regulatory assets, because the electric utility industry restructuring plan made probable their recovery through a non-bypassable charge to distribution customers.

During the second quarter of 1998, in accordance with asset impairment accounting standards, SCE reduced its remaining nuclear plant investment by $2.6 billion (as of June 30, 1998) and recorded a regulatory asset on its balance sheet for the same amount. For this impairment assessment, the fair value of the investment was calculated by discounting expected future net cash flows. This reclassification had no effect on SCE's results of operations.

As of December 31, 2000, SCE assessed the probability of recovery of its generation-related assets and power procurement costs in light of the CPUC's March 27, 2001, and April 3, 2001, decisions, and could not conclude that its $2.9 billion TCBA undercollection (as redefined in the March 27 decisions) and $1.3 billion (book value) of its net generation-related regulatory assets to be amortized into the TCBA, were probable of recovery through the rate-making process. As a result, accounting principles generally accepted in the United States required that the balances in the accounts be written off as a charge to earnings. In addition to the $4.2 billion pre-tax write-off, SCE incurred approximately $552 million (pre-tax) in net undercollected transition costs through August 31, 2001 (see Earnings).

In accordance with the CPUC settlement agreement and the PROACT resolution, in fourth quarter 2001, SCE established a $3.6 billion regulatory asset for previously incurred power procurement costs, called the PROACT, retroactive to August 31, 2001. See further discussion in PROACT Regulatory Asset. CPUC approval of the URG application, as filed (see URG Proceeding), together with implementation of the PROACT mechanism is expected to allow SCE to recover substantially all of the $4.7 billion in write-offs as of December 31, 2000, and net undercollected transition costs incurred through August 31, 2001.

If the CPUC approves SCE's URG application, as filed, SCE expects to reapply accounting principles for rate-regulated enterprises for its generation assets. These assets will then be subject to traditional cost-of-service regulation.

Distribution

Revenue related to distribution operations is determined through a performance-based rate-making (PBR) mechanism and the distribution assets have the opportunity to earn a CPUC-authorized 9.49% return on investment. Key elements of the distribution PBR include: distribution rates indexed for inflation based on the Consumer Price Index less a productivity factor; adjustments for cost changes that are not within SCE's control; a cost-of-capital trigger mechanism based on changes in a utility bond index; standards for customer satisfaction; service reliability and safety; and a net revenue-sharing mechanism that determines how customers and shareholders will share gains and losses from distribution operations. The distribution PBR was to have ended in December 2001, but in June 2001 the CPUC extended the mechanism until SCE's next general rate case, which will be effective in 2003. A CPUC proposed decision on the PBR mechanism for 2002 was issued in January 2002. The proposed decision authorized SCE to use a formula to determine its distribution revenue requirement for the last half of 2001 and 2002, and a revenue balancing account to ensure that variations in sales do not result in under or overcollections. A final decision is expected in second quarter 2002. At this time, SCE cannot predict the effect of the final decision on its results of operations.

In December 2001, SCE filed its 2003 general rate case with the CPUC, requesting an increase of approximately $500 million in revenue (compared to 2000 recorded revenue) for its distribution and generation operations. Hearings are expected to begin in July 2002, with a final decision expected in second quarter 2003.

Transmission

Transmission revenue is determined through FERC-authorized rates and is subject to refund.

Wholesale Electricity Markets

In October 2000, SCE filed a joint petition urging the FERC to immediately find the California wholesale electricity market to be not workably competitive, immediately impose a cap on the price for energy and ancillary services, and institute further expedited proceedings regarding the market failure, mitigation of market power, structural solutions and responsibility for refunds. In December 2000, the FERC took limited action and failed to impose a price cap. SCE filed an emergency petition in the federal court of appeals challenging the FERC order and requesting the FERC to immediately establish cost-based wholesale rates. The court denied SCE's petition in January 2001.

In its December 2000 order, the FERC established an underscheduling penalty effective January 1, 2001, applicable to scheduling coordinators that do not schedule sufficient resources to supply 95% of their respective loads. In December 2001, the FERC eliminated the underscheduling penalty retroactive to January 1, 2001.

On April 25, 2001, after months of extremely high power prices, the FERC issued an order providing for energy price controls during ISO Stage 1 or greater power emergencies (7% or less in reserve power). The order establishes an hourly clearing price based on the costs of the least efficient generating unit during the period. Effective June 20, 2001, the FERC expanded the April 25, 2001, order to include non-emergency periods and price mitigation in the 11-state western region. The latest order is in effect until September 30, 2002.

After unsuccessful settlement negotiations among utilities, power sellers and state representatives, on July 25, 2001, the FERC issued an order that limits potential refunds from alleged overcharges to the ISO and PX spot markets during the period from October 2, 2000, through June 20, 2001, and adopted a refund methodology based on daily spot market gas prices. An administrative law judge will conduct evidentiary hearings on this matter. SCE cannot predict the amount of any potential refunds. Under the settlement of litigation with the CPUC, refunds will be applied to the balance in the PROACT.

Environmental Protection

SCE 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.

As further discussed in Note 12 to the Consolidated Financial Statements, SCE records its environmental liabilities when site assessments and/or remedial actions are probable and a range of reasonably likely cleanup costs can be estimated. SCE's recorded estimated minimum liability to remediate its 42 identified sites is $111 million. SCE believes that, due to uncertainties inherent in the estimation process, it is reasonably possible that cleanup costs could exceed its recorded liability by up to $279 million. In 1998, SCE sold all of its gas-fueled power plants but has retained some liability associated with the divested properties.

The CPUC allows SCE to recover environmental-cleanup costs at certain sites, representing $50 million of its recorded liability, through an incentive mechanism, which is discussed in Note 12. SCE has recorded a regulatory asset of $76 million for its estimated minimum environmental-cleanup costs expected to be recovered through customer rates.

SCE's identified sites include several sites for which there is a lack of currently available information. As a result, no reasonable estimate of cleanup costs can be made for these sites. SCE 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 $10 million to $25 million. Recorded costs for the year ended December 31, 2001, were $18 million.

Based on currently available information, SCE believes it is unlikely that it will incur amounts in excess of the upper limit of the estimated range and, based upon the CPUC's regulatory treatment of environmental-cleanup costs, SCE 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.

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). A study was undertaken to determine the specific impact of air contaminant emissions from the Mohave Generating Station on visibility in Grand Canyon National Park. The final report on this study, which was issued in March 1999, found negligible correlation between measured Mohave station tracer concentrations and visibility impairment. The absence of any obvious relationship cannot rule out Mohave station contributions to haze in Grand Canyon National Park, but strongly suggests that other sources were primarily responsible for the haze. In June 1999, the Environmental Protection Agency (EPA) issued an advanced notice of proposed rulemaking regarding assessment of visibility impairment at the Grand Canyon. The EPA issued its final rule on February 8, 2002, which incorporates the terms of the consent decree into the visibility provisions of its Federal Implementation Plan for Nevada, making the terms of the consent decree federally enforceable.

SCE's share of the costs of complying with the consent decree and taking other actions to continue operation of the Mohave station is estimated to be approximately $560 million over the next four years. However, SCE has suspended its efforts to seek approval to install the Mohave controls because it has not obtained reasonable assurance of an adequate coal supply for operating Mohave beyond 2005. If an adequate coal supply is not obtained, it will become necessary to shut down the Mohave station 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 $88 million as of December 31, 2001), and plant closure and decommissioning-related costs are recoverable in future rates. SCE cannot predict what effect any future actions by the CPUC may have on this matter.

SCE's projected environmental capital expenditures are $1.3 billion for the 2002–2006 period, mainly for undergrounding certain transmission and distribution lines.

San Onofre Nuclear Generating Station

In February 2001, SCE's San Onofre Unit 3 experienced a fire due to an electrical fault in the non-nuclear portion of the plant. The turbine rotors, bearings and other components of the turbine generator system were damaged extensively. In June 2001, Unit 3 returned to service. Under the currently effective San Onofre rate-recovery plan (discussed in the Generation and Power Procurement section of Regulatory Environment), SCE's lost revenue was approximately $98 million as a result of the fire and related outage.

The San Onofre Units 2 and 3 steam generators' design allows for the removal of up to 10% of the tubes before the rated capacity of the unit must be reduced. Increased tube degradation was found during routine inspections in 1997. To date, 8% of Unit 2's tubes and 6% of Unit 3's tubes have been removed from service. A decreasing (favorable) trend in degradation has been observed in more recent inspections.

Critical Accounting Policies

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

SCE applies accounting principles for rate-regulated enterprises to the portion of its operations, where 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 a cost that would otherwise be charged to expense by a non-regulated 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. See further discussion of regulatory assets and liabilities in Note 1 to the Consolidated Financial Statements.

SCE applied judgment in the use of the above principles when it concluded, as of December 31, 2000, that $4.2 billion of generation-related regulatory assets and liabilities were no longer probable of recovery, and wrote off these assets as a charge to earnings, and again in fourth quarter 2001 when it created the $3.6 billion PROACT regulatory asset with a corresponding credit to earnings upon receiving regulatory assurance of collection of these costs. See further discussion in Earnings section.

New Accounting Standards

On January 1, 2001, SCE adopted a new accounting standard for derivative instruments and hedging activities. The standard requires derivatives to be recognized on the balance sheet at fair value, unless they meet the definition of a normal purchase or sale. 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, the effective portion of the gain or loss is initially recorded as a separate component of shareholder's 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. SCE does not anticipate any earnings impact from any derivatives, since it expects that any market price changes will be recovered in rates. In October 2001, additional implementation guidance, which will be effective April 1, 2002, was issued. SCE is still evaluating the impact of this new implementation guidance.

In July and August 2001, three new accounting standards were issued: Business Combinations; Goodwill and Other Intangibles; and Accounting for Asset Retirement Obligations.

The new Business Combinations standard eliminates the pooling-of-interests method, effective June 30, 2001. After that, all business combinations will be recorded under the purchase method (i.e., record purchase based upon value exchanged and record goodwill for excess of costs over the net assets acquired).

The new Goodwill and Other Intangibles standard requires that companies cease amortizing goodwill, effective January 1, 2002. Goodwill initially recognized after June 30, 2001, will not be amortized. Goodwill on the balance sheet at June 30, 2001, was amortized until December 31, 2001. Under the new standard, goodwill will be tested for impairment using a fair-value approach when events or circumstances occur indicating that impairment might exist. Also, a benchmark assessment for goodwill is required within six months of the date of adoption of the standard.

The Accounting for Asset Retirement Obligations standard requires entities to record the fair value of a liability for a legal asset retirement obligation 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. The standard is effective for SCE beginning on January 1, 2003.

SCE is studying the impact of the new Asset Retirement Obligations standard and is unable to predict at this time the effect on its financial statements. SCE does not anticipate any material impact on its results of operations or financial position from the other two new accounting standards.

In October 2001, a new accounting standard was issued related to accounting for the impairment or disposal of long-lived assets. Although the standard supersedes a prior accounting standard related to the impairment of long-lived assets, it retains the fundamental provisions of the impairment standard regarding recognition/measurement of impairment of long-lived assets to be held and used and measurement of long-lived assets to be disposed of by sale. Under the new accounting standard, asset write-downs from discontinuing a business segment will be treated the same as other assets held for sale. The new standard also broadens the financial statement presentation of discontinued operations to include the disposal of an asset group (rather than a segment of a business). The standard (effective on January 1, 2002) was adopted early, in fourth quarter 2001. The adoption of this standard had no effect on SCE's financial statements.

Forward-looking Information

In the preceding Management's Discussion and Analysis of Results of Operations and Financial Condition and elsewhere in this annual report, the words estimates, expects, anticipates, believes, and other similar expressions are intended to identify forward-looking information that involves risks and uncertainties. Actual results or outcomes could differ materially as a result of important factors that may be outside SCE's control, including among other things: the outcome of the pending appeals of the stipulated judgment approving the settlement agreement with the CPUC, and the effects of other legal actions or ballot initiatives, if any, attempting to undermine the provisions of the settlement agreement or otherwise adversely affecting SCE; changes in prices of wholesale electricity and natural gas or in SCE's operating costs, which could cause SCE's cost recovery to be less than anticipated; the actions of securities rating agencies, including the determination of whether or when to make changes in SCE's credit ratings, the ability of SCE to regain investment grade ratings, and the impact of current or lowered ratings and other financial market conditions on the ability of SCE to obtain needed financing on reasonable terms; further actions by state and federal regulatory bodies setting rates, adopting or modifying cost recovery, accounting or rate-setting mechanisms and implementing the restructuring of the electric utility industry, as well as legislative or judicial actions affecting the same matters; the effects of increased competition in energy-related businesses, including the market entrants and the effects of new technologies that may be developed in the future; new or increased environmental liabilities; and weather conditions, natural disasters, and other unforeseen events.

In millions Year ended December 31,	2001	2000	1999
Operating revenue	$ 8,126	$ 7,870	$ 7,548
Fuel	212	195	215
Purchased power	3,770	4,687	3,190
Provisions for regulatory adjustment clauses – net	(3,028)	2,301	(763)
Other operation and maintenance	1,771	1,772	1,933
Depreciation, decommissioning and amortization	681	1,473	1,548
Property and other taxes	112	126	122
Net gain on sale of utility plant	(9)	(25)	(3)
Total operating expenses	3,509	10,529	6,242
Operating income (loss)	4,617	(2,659)	1,306
Interest and dividend income	215	173	69
Other nonoperating income	57	118	162
Interest expense – net of amounts capitalized	(785)	(572)	(483)
Other nonoperating deductions	(38)	(110)	(107)
Income (loss) before taxes	4,066	(3,050)	947
Income tax (benefit)	1,658	(1,022)	438
Net income (loss)	2,408	(2,028)	509
Dividends on preferred stock	22	22	25
Net income (loss) available for common stock	$ 2,386	$ (2,050)	$ 484

Consolidated Statements of Comprehensive Income (Loss)

In millions Year ended December 31,	2001	2000	1999
Net income (loss)	$ 2,408	$ (2,028)	$ 509
Other comprehensive income, net of tax:			
Unrealized gain on securities – net	—	3	28
Cumulative effect of change in accounting for derivatives	398	—	—
Unrealized loss on cash flow hedges	(420)	—	—
Reclassification adjustment for loss included in net income (loss)	—	(25)	(45)
Comprehensive income (loss)	$ 2,386	$ (2,050)	$ 492

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

Consolidated Balance Sheets

In millions December 31,	2001	2000
ASSETS		
Cash and equivalents	$ 3,414	$ 583
Receivables, less allowances of $32 and $23 for uncollectible accounts at respective dates	1,093	919
Accrued unbilled revenue	451	377
Fuel inventory	14	12
Materials and supplies, at average cost	146	132
Accumulated deferred income taxes – net	433	545
Regulatory assets – net	83	—
Prepayments and other current assets	145	124
Total current assets	5,779	2,692
Nonutility property – less accumulated provision for depreciation of $17 and $11 at respective dates	159	102
Nuclear decommissioning trusts	2,275	2,505
Other investments	224	90
Total investments and other assets	2,658	2,697
Utility plant, at original cost:		
Transmission and distribution	13,568	13,129
Generation	1,729	1,745
Accumulated provision for depreciation and decommissioning	(7,969)	(7,834)
Construction work in progress	556	636
Nuclear fuel, at amortized cost	129	143
Total utility plant	8,013	7,819
Regulatory assets – net	5,528	2,390
Other deferred charges	475	368
Total deferred charges	6,003	2,758
Total assets	$ 22,453	$ 15,966

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

In millions, except share amounts December 31,	2001	2000
LIABILITIES AND SHAREHOLDER'S EQUITY		
Short-term debt	$ 2,127	$ 1,451
Long-term debt due within one year	1,146	646
Preferred stock to be redeemed within one year	105	—
Accounts payable	3,261	1,055
Accrued taxes	823	536
Regulatory liabilities – net	—	195
Other current liabilities	1,645	1,502
Total current liabilities	9,107	5,385
Long-term debt	4,739	5,631
Accumulated deferred income taxes – net	3,365	2,009
Accumulated deferred investment tax credits	153	164
Customer advances and other deferred credits	739	722
Power-purchase contracts	356	467
Accumulated provision for pensions and benefits	420	296
Other long-term liabilities	148	127
Total deferred credits and other liabilities	5,181	3,785
Commitments and contingencies (Notes 3, 11 and 12)		
Preferred stock:		
Not subject to mandatory redemption	129	129
Subject to mandatory redemption	151	256
Total preferred stock	280	385
Common stock (434,888,104 shares outstanding at each date)	2,168	2,168
Additional paid-in capital	336	334
Accumulated other comprehensive income (loss)	(22)	—
Retained earnings (deficit)	664	(1,722)
Total common shareholder's equity	3,146	780
Total liabilities and shareholder's equity	$ 22,453	$ 15,966

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

Consolidated Statements of Cash Flows

In millions Year ended December 31,	2001	2000	1999
Cash flows from operating activities:			
Net income (loss)	$ 2,408	$ (2,028)	$ 509
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, decommissioning and amortization	681	1,473	1,548
Other amortization	82	97	95
Deferred income taxes and investment tax credits	1,313	(928)	178
Regulatory assets – long-term – net	(3,135)	1,759	(1,354)
Gas call options	(91)	20	11
Net gain on sale of marketable securities	—	(41)	(77)
Other assets	(68)	24	(73)
Other liabilities	17	(13)	17
Changes in working capital:			
Receivables and accrued unbilled revenue	(243)	(282)	99
Regulatory liabilities – short-term – net	(278)	97	363
Fuel inventory, materials and supplies	(16)	29	(5)
Prepayments and other current assets	(21)	(14)	(19)
Accrued interest and taxes	365	48	(186)
Accounts payable and other current liabilities	2,251	588	352
Net cash provided by operating activities	3,265	829	1,458
Cash flows from financing activities:			
Long-term debt issued	—	1,760	491
Long-term debt repaid	—	(525)	(363)
Bonds repurchased and funds held in trust	(130)	(440)	—
Rate reduction notes repaid	(246)	(246)	(246)
Nuclear fuel financing – net	(21)	9	(37)
Short-term debt financing – net	676	655	326
Dividends paid	(1)	(395)	(686)
Net cash provided (used) by financing activities	278	818	(515)
Cash flows from investing activities:			
Additions to property and plant	(688)	(1,096)	(986)
Funding of nuclear decommissioning trusts	(36)	(69)	(116)
Proceeds from sales of marketable securities	—	41	84
Sales of investments in other assets	12	34	19
Net cash used by investing activities	(712)	(1,090)	(999)
Net increase (decrease) in cash and equivalents	2,831	557	(56)
Cash and equivalents, beginning of year	583	26	82
Cash and equivalents, end of year	$ 3,414	$ 583	$ 26
Cash payments for interest and taxes:			
Interest – net of amounts capitalized	$ 455	$ 303	$ 287
Tax payments (receipts)	(105)	306	433

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

In millions	Common Stock	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings (Deficit)	Total Common Shareholder's Equity
Balance at December 31, 1998	$ 2,168	$ 334	$ 39	$ 794	$ 3,335
Net income				509	509
Unrealized gain on securities			46		46
Tax effect			(18)		(18)
Reclassified adjustment for gain included in net income			(77)		(77)
Tax effect			32		32
Dividends declared on common stock				(666)	(666)
Dividends declared on preferred stock				(25)	(25)
Stock option appreciation				(3)	(3)
Capital stock expense and other		1		(1)	—
Balance at December 31, 1999	$ 2,168	$ 335	$ 22	$ 608	$ 3,133
Net income (loss)				(2,028)	(2,028)
Unrealized gain on securities			8		8
Tax effect			(5)		(5)
Reclassified adjustment for gain included in net income			(41)		(41)
Tax effect			16		16
Dividends declared on common stock				(279)	(279)
Dividends declared on preferred stock				(22)	(22)
Stock option appreciation				(1)	(1)
Capital stock expense and other		(1)			(1)
Balance at December 31, 2000	$ 2,168	$ 334	$ —	$ (1,722)	$ 780
Net income				2,408	2,408
Cumulative effect of change in accounting for derivatives			398		398
Unrealized loss on cash flow hedges			(420)		(420)
Dividends accrued on preferred stock				(22)	(22)
Capital stock expense and other		2			2
Balance at December 31, 2001	$ 2,168	$ 336	$ (22)	$ 664	$ 3,146

Authorized common stock is 560 million shares with no par value.

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

Note 1. Summary of Significant Accounting Policies

Nature of Operations

Southern California Edison Company (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 operates in a highly regulated environment and has an exclusive franchise within its service territory. SCE has an obligation to deliver electric service to its customers and regulatory authorities have an obligation to provide just and reasonable rates. In the mid-1990s, state lawmakers and the California Public Utilities Commission (CPUC) initiated an electric industry restructuring process. SCE, as directed by the CPUC, sold its gas-fired generating stations. See Note 3 for a further discussion of regulatory changes in the electric utility industry.

Basis of Presentation

The consolidated financial statements include SCE and its subsidiaries. Intercompany transactions have been eliminated. Certain prior-year amounts were reclassified to conform to the December 31, 2001, financial statement presentation.

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 CPUC and the Federal Energy Regulatory Commission (FERC). Since 1997, as a result of industry restructuring legislation enacted by the State of California and related changes in the rate recovery of generation-related assets, SCE has used accounting principles applicable to enterprises in general for its investment in generation facilities.

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 disclosure of contingencies. Actual results could differ from those estimates. Certain significant estimates related to regulatory matters, financial instruments, decommissioning and contingencies are further discussed in Notes 3, 4, 11 and 12 to the Consolidated Financial Statements, respectively.

SCE's outstanding common stock is owned entirely by its parent company, Edison International.

Revenue

Operating revenue includes amounts for services rendered but unbilled at the end of each year. Since January 17, 2001, power purchased by the California Department of Water Resources (CDWR) or through the Independent System Operator (ISO) for SCE's customers is not considered a cost to SCE, since SCE is acting as an agent for these transactions. Further, amounts billed to ($2.0 billion in 2001) and collected from its customers for these power purchases are being remitted to the CDWR and are not recognized as revenue to SCE. See further discussion in Note 3.

Related Party Transactions

Certain Edison Mission Energy (a wholly owned subsidiary of Edison International) subsidiaries have 49% - 50% ownership in partnerships (qualifying facilities (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 $983 million in 2001, $716 million in 2000 and $513 million in 1999.

Purchased Power

SCE purchased power through the California Power Exchange (PX) from April 1998 through mid-January 2001. SCE has bilateral forward contracts with other entities (as discussed in Note 4) 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,	2001	2000	1999
PX/ISO:			
Purchases	$ 775	$ 8,449	$ 2,490
Generation sales	324	6,120	1,719
Purchased power – PX/ISO – net	451	2,329	771
Purchased power – bilateral contracts	188	—	—
Purchased power – interutility/QF contracts	3,131	2,358	2,419
Total	$ 3,770	$ 4,687	$ 3,190

Since January 17, 2001, all other power is purchased by the CDWR for delivery to SCE's customers and is not considered a cost to SCE.

Planned Major Maintenance

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

Other Nonoperating Income and Deductions

Other nonoperating income and deductions was comprised of:

In millions Year ended December 31,	2001	2000	1999
Gain on sale of marketable securities	$ —	$ 41	$ 77
AFUDC	16	21	24
Other	41	56	61
Total other nonoperating income	$ 57	$ 118	$ 162
Provisions for regulatory issues and refunds	$ 7	$ 78	$ 79
Other	31	32	28
Total other nonoperating deductions	$ 38	$ 110	$ 107

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.

Fuel Inventory

Fuel inventory is valued under the last-in, first-out method for fuel oil and under the first-in, first-out method for coal.

Investments

Net unrealized gains (losses) on equity investments are recorded as a separate component of shareholder's equity under the caption "Accumulated other comprehensive income." Unrealized gains and losses on decommissioning trust funds are recorded in the accumulated provision for decommissioning. All investments are classified as available-for-sale.

Utility 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.

AFUDC – equity was $7 million in 2001, $11 million in 2000 and $13 million in 1999. AFUDC – debt was $9 million in 2001, $10 million in 2000 and $11 million in 1999.

Replaced or retired property and removal costs less salvage are charged to the accumulated provision for depreciation. Depreciation expense stated as a percent of average original cost of depreciable utility plant was 3.6% for 2001, 2000 and 1999.

SCE's net investment in generation-related utility plant was $1.0 billion at both December 31, 2001, and December 31, 2000.

Nuclear

During the second quarter of 1998, SCE reduced its remaining nuclear plant investment by $2.6 billion (book value as of June 30, 1998) and recorded a regulatory asset on its balance sheet for the same amount in accordance with asset impairment accounting standards. For this impairment assessment, the fair value of the investment was calculated by discounting expected future net cash flows. The reclassification had no effect on SCE's 1998 results of operations.

SCE had been recovering its investments in San Onofre Nuclear Generating Station Units 2 and 3 and Palo Verde Nuclear Generating Station 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 through 2003. Any differences between these costs and the incentive price would flow through to the 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 December 31, 2001. The San Onofre and Palo Verde rate recovery plans and the Palo Verde balancing account were part of the transition cost balancing account (TCBA).

The nuclear rate-making plans and the TCBA mechanism were to continue for rate-making purposes at least through 2001 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 discussed in Note 3), 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. Should SCE's utility-retained generation (URG) application be approved, SCE would reestablish 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, and adjust the PROACT regulatory asset balance to reflect recovery of the nuclear investment in accordance with the final URG decision.

The benefits of operation of the Palo Verde and San Onofre units were required to be shared equally with ratepayers beginning in 2002 and 2004, respectively. In a June 2001 decision, the CPUC granted SCE's request to eliminate the San Onofre post-2003 benefit sharing mechanism. The CPUC based its action on compliance with a new state law. In a September 2001 decision, the CPUC granted SCE's request to eliminate the Palo Verde post-2001 benefit sharing mechanism and 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. See discussion in Note 3 for the proposed and alternate decisions' impact on the incentive pricing plans.

Regulatory Assets and Liabilities

In accordance with accounting principles for rate-regulated enterprises, SCE records regulatory assets, which represent probable future revenue associated with certain costs that will be recovered from customers through the rate-making process, and regulatory liabilities, which represent probable future reductions in revenue associated with amounts that are to be credited to customers through the rate-making process.

The TCBA was established for the recovery of generation-related transition costs during the four-year rate freeze period. The transition revenue account (TRA) was a CPUC-authorized regulatory asset account in which SCE recorded the difference between revenue received from customers through frozen rates and the costs of providing service to customers, including power procurement costs. SCE's discontinuance of accounting principles for rate-regulated enterprises applicable to its generation assets did not result in a write-off of its generation-related regulatory assets at that time since the CPUC had approved recovery of these assets through the TCBA mechanism.

The gains resulting from the sale of 12 of SCE's generating plants during 1998 have been credited to the TCBA. The coal and hydroelectric generation balancing accounts tracked the differences between market revenue from coal and hydroelectric generation and the plants' operating costs after April 1, 1998.

On March 27, 2001, the CPUC issued a decision stating, among other things, that the rate freeze had not ended, and the TCBA mechanism was to remain in place. However, the decision required SCE to recalculate the TCBA retroactive to January 1, 1998, the beginning of the rate freeze period. The new calculation required the coal and hydroelectric balancing account overcollections (which amounted to $1.5 billion as of December 31, 2000) to be transferred monthly to the TRA, rather than annually to the TCBA (as previously required). In addition, it required the TRA to be transferred to the TCBA on a monthly basis. Previous rules had called only for overcollections to be transferred to the TCBA monthly, while undercollections were to remain in the TRA until they were recovered from future overcollections or the end of the rate freeze, whichever came first.

There are many factors that affect SCE's ability to recover its regulatory assets. SCE assessed the probability of recovery of its generation-related regulatory assets in light of the CPUC's March 27, 2001, decisions, including the retroactive transfer of balances from SCE's TRA to the TCBA and related changes. 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 the TCBA and other regulatory assets.

In addition to the TCBA, generation-related regulatory assets totaling $1.3 billion (including the unamortized nuclear investment, flow-through taxes, unamortized loss on sale of plant, purchased-power settlements and other regulatory assets) were written off as of December 31, 2000.

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 procurement-related obligations account (PROACT) regulatory asset for previously incurred energy procurement costs, retroactive to August 31, 2001. The settlement agreement calls for the end of the TCBA mechanism as of August 31, 2001, and continuation of the rate freeze (including surcharges) until the earlier of December 31, 2003, or the date SCE recovers its previously incurred (undercollected) power procurement costs. During a period beginning on September 1, 2001, and ending on the earlier of the date that SCE has recovered all of its procurement-related obligations recorded in the PROACT or December 31, 2005, SCE will apply to the

PROACT the difference between SCE's revenue from retail electric rates (including surcharges) and the costs that SCE is authorized by the CPUC to recover in retail electric rates. The balance in the PROACT will accrue interest. If SCE has not recovered the entire balance by December 31, 2003, the unrecovered balance will be amortized for up to an additional two years.

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

In millions December 31,	2001	2000
PROACT	$ 2,641	$ —
Rate reduction notes – transition cost deferral	1,453	1,090
Other:		
Flow-through taxes	1,017	874
Unamortized loss on reacquired debt	254	273
Environmental remediation	57	52
Regulatory balancing accounts and other	189	(94)
Total	$ 5,611	$ 2,195

The regulatory asset related to the rate reduction notes will be recovered over the terms of those notes. 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. Income tax effects on all balancing account changes are deferred.

New Accounting Standards

On January 1, 2001, SCE adopted a new accounting standard for derivative instruments and hedging activities. Adoption of this standard had no material impact on SCE's financial statements. 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. SCE is still evaluating the impact of this new interpretation.

In July and August 2001, three new accounting standards were issued: Business Combinations; Goodwill and Other Intangibles; and Accounting for Asset Retirement Obligations.

The new Business Combinations standard eliminates the pooling-of-interests method, effective June 30, 2001. After that, all business combinations will be recorded under the purchase method (record goodwill for excess of costs over the net assets acquired).

The new Goodwill and Other Intangibles standard requires that companies cease amortizing goodwill, effective January 1, 2002. Goodwill initially recognized after June 30, 2001, was not amortized. Goodwill on the balance sheet at June 30, 2001, was amortized until December 31, 2001. Under the new standard, goodwill will be tested for impairment using a fair-value approach when events or circumstances occur indicating that impairment might exist. Also, a benchmark assessment for goodwill is required within six months of the date of adoption of the standard.

The Accounting for Asset Retirement Obligations standard requires entities to record the fair value of a liability for a legal asset retirement obligation 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. The standard is effective for SCE on January 1, 2003.

SCE is studying the impact of the new Asset Retirement Obligations standard, and is unable to predict at this time the effect on its financial statements. SCE does not anticipate any material impact on its results of operations or financial position from the Business Combinations and Goodwill and Other Intangibles accounting standards.

In October 2001, a new accounting standard was issued related to accounting for the impairment or disposal of long-lived assets. Although the standard supersedes a prior accounting standard related to the impairment of long-lived assets, it retains the fundamental provisions of the impairment standard regarding recognition/measurement of impairment of long-lived assets to be held and used and measurement of long-lived assets to be disposed of by sale. Under the new accounting standard, asset write-downs from discontinuing a business segment will be treated the same as other assets held for sale. The new standard also broadens the financial statement presentation of discontinued operations to include the disposal of an asset group (rather than a segment of a business). The standard (effective on January 1, 2002) was adopted early, in fourth quarter 2001. The adoption of this new standard had no effect on SCE's financial statements.

Note 2. Liquidity Issues

SCE's liquidity is affected primarily by regulation affecting its ability to recover the cost of power purchases, debt maturities, access to capital markets, credit ratings, dividend payments and capital expenditures. Capital resources include cash from operations and external financings.

Undercollections in the TRA and TCBA mechanisms, coupled with SCE's anticipated near-term capital requirements and the adverse reaction of the credit markets to continued regulatory uncertainty regarding SCE's ability to recover its current and future power procurement costs, materially and adversely affected SCE's liquidity throughout 2001. As a result of its liquidity concerns, SCE took steps to conserve cash to continue to provide service to its customers. As a part of this process, beginning in January 2001, SCE suspended payments owed to the ISO, the PX and QFs, deferred payments of certain obligations for principal and interest on outstanding debt and did not declare dividends on any of its cumulative preferred stock. As applicable, unpaid obligations continued to accrue interest. As of March 31, 2001, SCE resumed payment of interest on its debt obligations. However, since June 30, 2001, SCE deferred the interest payments on its quarterly income debt securities (subordinated debentures), as allowed by the terms of the securities. See Note 5. As long as accumulated dividends on SCE's preferred stock remained unpaid, SCE could not pay any dividends on its common stock. Common stock dividends are additionally restricted as detailed in Note 3.

Based on the rights to cost recovery and revenue established by the settlement agreement with the CPUC and CPUC implementing orders, including the PROACT resolution, SCE repaid its undisputed past-due obligations on March 1, 2002, with lump-sum payments to creditors from the proceeds of $1.6 billion in senior secured credit facilities, the remarketing of $196 million in pollution control bonds which were repurchased in late 2000, and existing cash on hand. The $1.6 billion senior secured credit facilities consist of a $300 million, two-year revolving credit loan, a $600 million, one-year loan and a $700 million, three-year loan. See Note 5.

The proceeds from the senior secured credit facilities and pollution control bond remarketing were used along with SCE's available cash to repay $3.2 billion in past-due obligations and $1.65 billion in near-term debt maturities. The past-due obligations consisted of: (1) $875 million to the PX; (2) $99 million to the ISO; (3) $1.1 billion to QFs; (4) $193 million in PX energy credits for energy service providers; (5) $531 million of matured commercial paper; (6) $400 million of principal on its 5-7/8% and 6-1/2% senior unsecured notes which were issued prior to the energy crisis; and (7) $23 million in preferred dividends in arrears. After making these payments, SCE has no material undisputed obligations that are past due or in default. The near-term debt maturities consisted of credit facilities whose maturity dates were extended several times and were scheduled to mature in March and May 2002. In addition, SCE has entered into an agreement with the CDWR to pay for prior deliveries of energy in installments of $100 million on April 1, 2002, $150 million on June 3, 2002, and the balance on July 1, 2002.

SCE's Board of Directors has not declared quarterly common stock dividends to SCE's parent, Edison International, since September 2000. Payment of dividends on SCE's common stock is restricted by the settlement agreement between the CPUC and SCE as detailed in Note 3.

Note 3. Regulatory Matters

CPUC Litigation Settlement Agreement

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 past electricity procurement costs in accordance with the tariffs filed with the FERC. By agreement of the parties, a stay of the lawsuit was issued in April 2001 while SCE sought implementation of legislative, regulatory and executive actions to resolve the California energy crisis and SCE's related financial and liquidity problems. In October 2001, the court entered a stipulated judgment approving an agreement between the CPUC and SCE to settle the pending lawsuit. On January 23, 2002, the CPUC adopted a resolution implementing the settlement agreement.

Key elements of the settlement agreement include the following items:

- Establishment of the PROACT as of September 1, 2001, with an opening balance equal to the amount of SCE's procurement-related liabilities as of August 31, 2001 (approximately $6.4 billion), less SCE's cash and cash equivalents as of that date (approximately $2.5 billion), and less $300 million.

- Beginning September 1, 2001, SCE will apply to the PROACT, on a monthly basis, the difference between SCE's revenue from retail electric rates (including surcharges) and the costs that SCE is authorized by the CPUC to recover in retail electric rates. Unrecovered obligations in the PROACT will accrue interest from September 1, 2001.

- Maintain current rates (including surcharges) in effect until December 31, 2003, subject to certain adjustments or, if earlier, until the date that SCE recovers the entire PROACT balance. If SCE has not recovered the entire balance by December 31, 2003, the unrecovered balance will be amortized for up to an additional two years. The parties project that existing retail electric rates, including surcharges and as adjusted to reflect certain costs, will likely result in SCE recovering substantially all of its unrecovered procurement-related obligations prior to the end of 2003.

- If the CPUC concludes that it is desirable to authorize a securitized financing of SCE's procurement-related obligations, the parties will work together to achieve the securitization. Proceeds of any securitization will be credited to the PROACT when they are actually received.

- During the period that SCE is recovering its previously incurred procurement-related obligations, no penalty will be imposed by the CPUC on SCE for any noncompliance with CPUC-mandated capital structure requirements.

- SCE can incur up to $250 million of recoverable costs to acquire financial instruments and engage in other transactions intended to hedge fuel cost risks associated with SCE's retained generation assets and power purchase contracts with QFs and other utilities. As of December 31, 2001, SCE had purchased $209 million in hedging instruments.

- SCE will not declare or pay dividends or other distributions on its common stock (all of which is held by its parent) prior to the earlier of the date SCE has recovered all of its procurement-related obligations in the PROACT or January 1, 2005. However, if SCE has not recovered all of its procurement-related obligations by December 31, 2003, SCE may apply to the CPUC for consent to resume common stock dividends, and the CPUC will not unreasonably withhold its consent.

- To ensure the ability of SCE to continue to provide adequate service, SCE may make capital expenditures above the level contained in current rates, up to $900 million per year, which will be treated as recoverable costs.

- Subject to certain qualifications, SCE will cooperate with the CPUC and the California Attorney General to pursue and resolve SCE's claims and rights against sellers of energy and related services, SCE's defenses to claims arising from any failure to make payments to the PX or ISO, and similar claims by the State of California or its agencies against the same adverse parties. During the recovery period discussed above, refunds obtained by SCE related to its procurement-related liabilities will be applied to the balance in the PROACT.

The settlement agreement states that one of its purposes is to restore the investment grade creditworthiness of SCE as rapidly as reasonably practicable so that it will be able to provide reliable electrical service as a state-regulated entity as it has in the past. SCE cannot provide assurance that it will regain investment grade credit ratings by any particular date.

On November 28, 2001, a federal court of appeals denied a California consumer group's request for a long-term stay of the settlement. The group had alleged that it was denied due process and that the CPUC had no authority to agree with SCE to violate the statutory rate freeze. In its ruling, the federal court of appeals also granted SCE's request for an expedited hearing of the appeal of the settlement filed by the consumer group. On March 4, 2002, the court of appeals heard argument on the appeal and the matter is now under submission. A decision could be issued anytime during the next several months. SCE cannot predict the outcome of the appeal or the impact that any outcome would have upon the stipulated judgment or settlement. Possible outcomes include affirmance, a return to the district court or reversal of the stipulated judgment. SCE cannot predict whether or how a ruling on the stipulated judgment could also affect the settlement agreement.

CDWR Power Purchases

In accordance with an emergency order signed by the governor, the CDWR began making emergency power purchases for SCE's customers on January 17, 2001. Amounts SCE bills to and collects from its customers for electric power purchased and sold by the CDWR and through the ISO are remitted directly to the CDWR and are not recognized as revenue by SCE. In February 2001, Assembly Bill 1 (First Extraordinary Session, AB 1X) was enacted into law. AB 1X authorized the CDWR to enter into contracts to purchase electric power and sell power at cost directly to retail customers being served by SCE, and authorized the CDWR to issue bonds to finance electricity purchases.

On March 27, 2001, the CPUC issued an interim order requiring SCE to pay the CDWR a per-kWh price equal to the applicable generation-related retail rate per kWh for electricity (based on rates in effect on January 5, 2001), for each kWh the CDWR sells to SCE's customers. The CPUC determined that the generation-related retail rate should be equal to the total bundled electric rate (including the 1¢ per kWh surcharge adopted by the CPUC on January 4, 2001) less certain nongeneration-related rates or charges. For the period January 19 through January 31, 2001, the CPUC ordered SCE to pay the CDWR at a rate of 6.277¢ per kWh for power delivered to SCE's customers. The CPUC determined that the applicable rate component is 7.277¢ per kWh (which increased to 10.277¢ per kWh for electricity delivered after March 27, 2001, due to the 3¢ surcharge discussed in Rate Stabilization Proceedings), for electricity delivered by the CDWR to SCE's retail customers after February 1, 2001, until more specific rates are calculated. The CPUC ordered SCE to pay the CDWR within 45 days after the CDWR supplies power to retail customers, subject to penalties for each day the payment is late.

On February 21, 2002, the CPUC issued a decision implementing a CDWR revenue requirement of $9.0 billion to pay its bonds' costs and energy procurement costs for the period January 17, 2001, through December 31, 2002. The decision states that SCE's allocated share of this revenue requirement would be approximately $3.6 billion, and changes SCE's payment to 9.744¢ per kWh for all bills rendered on or after March 15, 2002. The decision requires SCE to pay the CDWR in equal monthly installments over a six-month period the difference in rates between January 17, 2001, and March 15, 2002. SCE estimates that this amount is approximately $41 million.

On February 28, 2002, SCE and the CDWR executed an agreement that resolves outstanding issues relating to the payment for electric power purchased for SCE's customers through the ISO real-time market (known as imbalance energy). Under this agreement, SCE will pay the CDWR for imbalance energy previously delivered in three installments ($100 million on April 1, 2002; $150 million on June 3, 2002; and the balance on July 1, 2002).

Rate Stabilization Proceedings

In January 2000, SCE filed an application with the CPUC proposing rates that would go into effect when the four-year rate freeze was to end on March 31, 2002, or earlier, depending on the pace of transition cost recovery. In December 2000, SCE filed an amended rate stabilization plan application, stating that the statutory rate freeze had ended in accordance with California law, and requesting the CPUC to approve an immediate 30% increase to be effective, subject to refund, January 4, 2001.

In January 2001, independent auditors hired by the CPUC issued a report on the financial condition and solvency of SCE and its affiliates. The report confirmed what SCE had previously disclosed to the CPUC in public filings about SCE's financial condition. The audit report covered, among other things, cash needs, credit relationships, accounting mechanisms to track stranded cost recovery, the flow of funds between SCE and Edison International, and earnings of SCE's California affiliates. In April 2001, the CPUC adopted an order instituting investigation that reopens the past CPUC decision authorizing the utilities to form holding companies and initiates an investigation into: whether the holding companies violated CPUC requirements to give first priority to the capital needs of their respective utility subsidiaries; whether ring-fencing actions by Edison International and PG&E Corporation and their respective nonutility affiliates also violated the requirements to give first priority to the capital needs of their utility subsidiaries; whether the payment of dividends by the utilities violated requirements that the utilities maintain dividend policies as though they were comparable stand-alone utility companies; any additional suspected violations of laws or CPUC rules and decisions; and whether additional rules, conditions, or other changes to the holding company decisions are necessary. The CPUC ordered testimony and briefing on these matters, which SCE filed in May and June 2001. On January 9, 2002, the CPUC issued an interim decision on the first priority condition. The decision stated that, at least under certain circumstances, the condition includes the requirement that holding companies infuse all types of capital into their respective utility subsidiaries when necessary to fulfill the utility's obligation to serve. On February 11, 2002, SCE filed an application for rehearing of the decision stating that the decision is an unlawful and erroneous attempt to rewrite the first priority condition rather than interpret it and that the decision could result in higher rates for SCE's customers. Neither Edison International nor SCE can predict what effects this investigation or any subsequent actions by the CPUC may have on either one of them.

In March 2001, the CPUC ordered a rate increase in the form of a 3¢ per kWh surcharge applied only to going-forward electric power procurement costs, effective immediately, and affirmed that a 1¢ interim surcharge granted in January 2001 is permanent. The 3¢ surcharge is to be added to the rate paid to the CDWR. Although the 3¢ increase was authorized as of March 27, 2001, the surcharge was not collected in rates until the CPUC established a rate design in early June 2001. To compensate for the two-month delay in collecting the 3¢ surcharge, the CPUC authorized an additional ½¢ surcharge for a 12-month period beginning in June 2001.

Utility-Retained Generation Proceeding

In June 2001, SCE filed a comprehensive proposal for new cost-of-service ratemaking for utility retained generation through the end of 2002. After that time, SCE's URG-related revenue requirement will be determined in the general rate case. The URG proposal calls for balancing accounts for SCE-owned generation, QF and interutility contracts, procurement costs and ISO charges based on either actual or CPUC-authorized revenue requirements. Under the proposal, the four new balancing accounts would be effective January 1, 2001, for capital-related costs, and February 1, 2001, for non-capital-related costs. In addition, SCE's unamortized nuclear investment would be amortized and recovered in rates over a 10-year period, effective January 1, 2001. Should this application be approved as filed, SCE expects to reestablish for financial reporting purposes its unamortized nuclear investment and regulatory assets related to purchased-power settlements and flow-through taxes, with a corresponding credit to earnings, and adjust the PROACT regulatory asset balance in accordance with the final URG decision.

On January 18, 2002, a CPUC administrative law judge issued a proposed decision and a CPUC commissioner issued an alternate proposed decision. Both the proposed and alternate proposed decisions adopt most of the elements of SCE's application, but propose eliminating an incentive pricing plan for San Onofre, effective January 1, 2002, and replacing it with balancing account treatment for San Onofre's operating costs, subject to a later reasonableness review. On February 7, 2002, another CPUC commissioner issued an alternate proposed decision recommending continuing the incentive pricing plan for San Onofre Units 2 and 3 through December 31, 2003, as originally provided in CPUC decisions adopted in early 1996. A final decision is expected in second quarter 2002.

Wholesale Electricity Markets

In October 2000, SCE filed a joint petition urging the FERC to immediately find the California wholesale electricity market to be not workably competitive, immediately impose a cap on the price for energy and ancillary services, and institute further expedited proceedings regarding the market failure, mitigation of market power, structural solutions and responsibility for refunds. In December 2000, the FERC took limited action and failed to impose a price cap. SCE filed an emergency petition in the federal court of appeals challenging the FERC order and requesting the FERC to immediately establish cost-based wholesale rates. The court denied SCE's petition in January 2001.

In its December 2000 order, the FERC established an "underscheduling" penalty effective January 1, 2001, applicable to scheduling coordinators that do not schedule sufficient resources to supply 95% of their respective loads. In December 2001, the FERC eliminated the underscheduling penalty retroactive to January 1, 2001.

On April 25, 2001, after months of extremely high power prices, the FERC issued an order providing for energy price controls during ISO Stage 1 or greater power emergencies (7% or less in reserve power). The order establishes an hourly clearing price based on the costs of the least efficient generating unit during the period. Effective June 20, 2001, the FERC expanded the April 25, 2001, order to include non-emergency periods and price mitigation in the 11-state western region. The latest order is in effect until September 30, 2002.

After unsuccessful settlement negotiations among utilities, power sellers and state representatives, on July 25, 2001, the FERC issued an order that limits potential refunds from alleged overcharges to the ISO and PX spot markets during the period from October 2, 2000, through June 20, 2001, and adopted a refund methodology based on daily spot market gas prices. An administrative law judge will conduct evidentiary hearings on this matter. SCE cannot predict the amount of any potential refunds. Under the settlement of litigation with the CPUC, refunds will be applied to the balance in the PROACT.

Note 4. Derivative Instruments and Hedging Activities

SCE's risk management policy allows the use of derivative financial instruments to manage financial exposure on its investments, fluctuations in interest rates and energy prices, but prohibits the use of these instruments for speculative or trading purposes.

On January 1, 2001, SCE adopted a new accounting standard for derivative instruments and hedging activities. 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, the effective portion of the gain or loss is initially recorded as a separate component of shareholder's 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.

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 realized loss of $26 million on the interest rate swap will be amortized over a period ending in 2008. Due to downgrades in SCE's credit ratings and SCE's failure to pay its obligations to the PX, the PX suspended SCE's market trading privileges and sought to liquidate SCE's remaining block forward contracts. Before the PX could do so, on February 2, 2001, the state seized the contracts. On September 30, 2001, a federal appeals court ruled that the governor of California acted illegally when he seized the contracts held by SCE. In conjunction with its settlement agreement with the CPUC, SCE has agreed to release any claim for compensation against the state for these contracts. However, if the PX prevails in its claims against the state, SCE may receive some refunds.

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 mitigate its exposure to increases in natural gas prices. Amounts paid to QFs for energy are based on natural gas prices. The options cover various periods from 2002 through 2003, averaging 11 million MMBtus per month. Any fair value changes for gas call options are offset through a regulatory balancing account; therefore, fair value changes do not affect earnings.

Fair values of financial instruments were:

In millions	December 31,	2001	2000
Financial assets:			
Decommissioning trusts		$ 2,275	$ 2,505
Gas options		91	—
Financial liabilities:			
DOE decommissioning and decontamination fees		25	31
Interest rate swap		—	21
Short-term debt		2,103	1,339
Long-term debt		4,659	5,178
Preferred stock subject to mandatory redemption		118	157
Preferred stock to be redeemed within one year		102	—

The fair value of financial assets is based on quoted market prices.

Financial liabilities' fair values are based on: discounted future cash flows for U.S. Department of Energy (DOE) decommissioning and decontamination fees; quoted market prices for the interest rate swap; and brokers' quotes for short-term debt, long-term debt and preferred stock. Due to their short maturities, amounts reported for cash equivalents approximate fair value.

Note 5. Long-Term Debt

California law prohibits SCE from incurring or guaranteeing debt for its nonutility affiliates.

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 uses 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. 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 in December 2000 and early 2001 that could not be remarketed in accordance with their terms. On March 1, 2002, SCE sold approximately $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.

Commercial paper intended to be refinanced for a period exceeding one year, for which SCE has the ability to refinance, and used to finance nuclear fuel scheduled to be used more than one year after the balance sheet date is classified as long-term debt.

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 non-bypassable rates charged to residential and small commercial customers. The rate reduction notes are being repaid over 10 years through these non-bypassable residential and small commercial customer rates which constitute the transition property purchased by SCE Funding LLC. The notes are secured by the transition property and are not secured 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. Due to SCE's credit downgrade, in January 2001, SCE began remitting its customer collections related to the rate-reduction notes on a daily basis.

Long-term debt consisted of:

In millions December 31,	2001	2000
First and refunding mortgage bonds:		
2002 – 2026 (5.625% to 7.25%)	$ 1,175	$ 1,175
Rate reduction notes:		
2002 – 2007 (6.22% to 6.42%)	1,478	1,724
Pollution-control bonds:		
2008 – 2040 (5.125% to 7.2% and variable)	1,216	1,216
Bonds repurchased	(550)	(420)
Funds held by trustees	(20)	(20)
Debentures and notes:		
2001 – 2029 (5.875% to 7.625% and variable)	2,450	2,450
Subordinated debentures:		
2044 (8.375%)	100	100
Commercial paper for nuclear fuel	60	79
Long-term debt due within one year	(1,146)	(646)
Unamortized debt discount – net	(24)	(27)
Total	$ 4,739	$ 5,631

Long-term debt maturities and sinking-fund requirements for the next five years are: 2002 – $1.1 billion; 2003 – $1.4 billion; 2004 – $371 million; 2005 – $246 million; and 2006 – $446 million.

As a result of its liquidity concerns, SCE took steps to conserve cash to continue to provide service to its customers. As a part of this process, SCE suspended payments of certain obligations, including $400 million of maturing principal on its 5-7/8% and 6-1/2% senior unsecured notes. From June 30, 2001, SCE deferred the interest payments on its quarterly income debt securities (subordinated debentures), as allowed by the terms of the securities. All interest in arrears will be paid on April 1, 2002.

On March 1, 2002, SCE closed on $1.6 billion in syndicated senior secured credit facilities providing for $600 million of one-year term loans, $700 million of three-year term loans, and $300 million of two-year revolving credit loans. The interest rate for the revolving credit loans and the one-year loan is a eurodollar rate plus 2.5% or a bank prime or equivalent rate plus 1.5%, at SCE's election. The interest rate for the three-year loans is a eurodollar rate plus 3% or a bank prime or equivalent rate plus a margin of 2%, at SCE's election. The credit facilities are secured by three newly issued series of SCE first mortgage bonds. The proceeds of the loans, along with available cash, were used to repay all of SCE's past due obligations and near-term maturities, which include the senior notes.

Note 6. Short-Term Debt

Short-term debt is used to finance fuel inventories, balancing account undercollections and general cash requirements, including power purchase payments. Commercial paper intended to finance nuclear fuel scheduled to be used more than one year after the balance sheet date is classified as long-term debt in connection with refinancing terms under five-year term lines of credit with commercial banks.

Short-term debt consisted of:

In millions December 31,	2001	2000
Commercial paper	$ 531	$ 700
Bank loans	1,650	835
Other	6	—
Amount reclassified as long-term debt	(60)	(79)
Unamortized discount	—	(5)
Total	$ 2,127	$ 1,451
Weighted average interest rates	5.3%	6.9%

As of January 2001, SCE had borrowed the entire $1.65 billion in funds available under its credit lines. The proceeds were used in part to repurchase pollution control bonds; the balance was retained as a liquidity reserve. SCE conserved cash by deferring payment of $531 million of matured commercial paper.

SCE repaid its credit line borrowings and commercial paper using proceeds from its March 1, 2002, financings. See further discussion in Note 2.

Note 7. Preferred Stock

Authorized shares of preferred and preference stocks are: $25 cumulative preferred – 24 million; $100 cumulative preferred – 12 million; and preference – 50 million. All cumulative preferred stocks are redeemable. Mandatorily redeemable preferred stocks are subject to sinking-fund provisions. When preferred shares are redeemed, the premiums paid are charged to common equity.

Preferred stock redemption requirements for the next five years are: 2002 – $105 million; 2003 – $9 million; 2004 – $9 million; 2005 – $9 million; and 2006 – $9 million.

Cumulative preferred stocks consisted of:

Dollars in millions, except per share amounts	December 31, 2001 Shares Outstanding	December 31, 2001 Redemption Price	2001	2000
Not subject to mandatory redemption:				
$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
Subject to mandatory redemption:				
$100 par value:				
6.05% Series	750,000	$ 100.00	$ 75	$ 75
6.45	1,000,000	100.00	100	100
7.23	807,000	100.00	81	81
Preferred stock to be redeemed within one year			(105)	—
Total			$ 151	$ 256

SCE did not issue or redeem any preferred stock in the last three years.

In 2001, SCE's Board did not declare the regular quarterly dividends for any of SCE's cumulative preferred stock. As of February 28, 2002, SCE's preferred stock dividends in arrears were $23 million. On March 11, 2002, SCE repaid its past due preferred stock dividends.

Note 8. Income Taxes

SCE and its subsidiaries are included in Edison International's consolidated federal income tax and combined state franchise tax returns. Under an income tax allocation agreement approved by the CPUC, SCE calculates its tax liability on a stand-alone basis.

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 components of the net accumulated deferred income tax liability were:

In millions December 31,	2001	2000
Deferred tax assets:		
Decommissioning	$ 99	$ 98
Accrued charges	472	379
Investment tax credits	72	81
Property-related	192	277
Regulatory balancing accounts	1,709	1,763
Unbilled revenue	(10)	101
Unrealized gains or losses	310	420
Other	145	56
Total	$ 2,989	$ 3,175
Deferred tax liabilities:		
Property-related	$ 2,248	$ 2,184
Capitalized software costs	224	264
Regulatory balancing accounts	2,929	1,632
Unrealized gains and losses	208	317
Other	312	242
Total	$ 5,921	$ 4,639
Accumulated deferred income taxes – net	$ 2,932	$ 1,464
Classification of accumulated deferred income taxes:		
Included in deferred credits	$ 3,365	$ 2,009
Included in current assets	433	545

The current and deferred components of income tax expense (benefit) were:

In millions Year ended December 31,	2001	2000	1999
Current:			
Federal	$ 240	$ (104)	$ 299
State	29	—	79
	269	(104)	378
Deferred – federal and state:			
Accrued charges	(79)	(133)	(76)
Investment and energy tax credits – net	(6)	(41)	(45)
Property-related	174	(302)	(194)
Regulatory asset amortization	(138)	251	7
Regulatory balancing accounts	1,345	(740)	371
State tax – privilege year	(36)	31	7
Unbilled revenue	101	20	(5)
Other	28	(4)	(5)
	1,389	(918)	60
Total	$ 1,658	$ (1,022)	$ 438

The composite federal and state statutory income tax rate was 40.551% for all years presented.

The federal statutory income tax rate is reconciled to the effective tax rate below:

Year ended December 31,	2001	2000	1999
Federal statutory rate	35.0%	35.0%	35.0%
Capitalized software	—	—	(2.4)
Investment and energy tax credits	(0.1)	1.4	(4.4)
Property-related and other	0.1	(6.6)	9.3
State tax – net of federal deduction	5.8	3.7	8.5
Effective tax rate	40.8%	33.5%	46.0%

Note 9. Employee Compensation and Benefit Plans

Employee Savings Plan

SCE has a 401(k) defined-contribution savings plan designed to supplement employees' retirement income. The plan received employer contributions of $29 million in 2001, $29 million in 2000 and $25 million in 1999.

Pension Plan

SCE has a noncontributory, defined-benefit pension plan that covers employees meeting minimum service requirements. SCE recognizes pension expense as calculated by the actuarial method used for ratemaking. In April 1999, SCE adopted a cash balance feature for its pension plan.

Information on plan assets and benefit obligations is shown below:

In millions Year ended December 31,	2001	2000
Change in benefit obligation		
Benefit obligation at beginning of year	$ 2,200	$ 2,075
Service cost	67	63
Interest cost	154	155
Actuarial loss (gain)	88	90
Benefits paid	(182)	(183)
Benefit obligation at end of year	$ 2,327	$ 2,200
Change in plan assets		
Fair value of plan assets at beginning of year	$ 3,067	$ 3,078
Actual return on plan assets	(162)	143
Employer contributions	—	29
Benefits paid	(182)	(183)
Fair value of plan assets at end of year	$ 2,723	$ 3,067
Funded status	$ 396	$ 867
Unrecognized net loss (gain)	(234)	(745)
Unrecognized transition obligation	17	22
Unrecognized prior service cost	109	118
Recorded asset	$ 288	$ 262
Discount rate	7.0%	7.25%
Rate of compensation increase	5.0%	5.0%
Expected return on plan assets	8.5%	8.5%

Expense components were:

In millions Year ended December 31,	2001	2000	1999
Service cost	$ 67	$ 63	$ 66
Interest cost	154	155	146
Expected return on plan assets	(251)	(266)	(188)
Special termination benefits	13	—	—
Net amortization and deferral	(9)	(40)	12
Expense under accounting standards	(26)	(88)	36
Regulatory adjustment – deferred	39	88	14
Total expense recognized	$ 13	$ —	$ 50

Postretirement Benefits Other Than Pensions

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.

Information on plan assets and benefit obligations is shown below:

In millions Year ended December 31,	2001	2000
Change in benefit obligation		
Benefit obligation at beginning of year	$ 1,762	$ 1,462
Service cost	44	39
Interest cost	129	121
Actuarial loss (gain)	61	202
Benefits paid	(71)	(62)
Benefit obligation at end of year	$ 1,925	$ 1,762
Change in plan assets		
Fair value of plan assets at beginning of year	$ 1,200	$ 1,283
Actual return on plan assets	(92)	(40)
Employer contributions	102	19
Benefits paid	(71)	(62)
Fair value of plan assets at end of year	$ 1,139	$ 1,200
Funded status	$ (786)	$ (562)
Unrecognized net loss (gain)	390	141
Unrecognized transition obligation	295	323
Recorded asset (liability)	$ (101)	$ (98)
Discount rate	7.25%	7.5%
Expected return on plan assets	8.2%	8.2%

Expense components were:

In millions Year ended December 31,	2001	2000	1999
Service cost	$ 44	$ 39	$ 46
Interest cost	129	121	109
Expected return on plan assets	(98)	(106)	(79)
Special termination benefits	2	—	—
Net amortization and deferral	27	27	27
Total expense	$ 104	$ 81	$ 103

The assumed rate of future increases in the per-capita cost of health care benefits is 10.5% for 2002, gradually decreasing to 5.0% for 2008 and beyond. Increasing the health care cost trend rate by one percentage point would increase the accumulated obligation as of December 31, 2001, by $300 million and annual aggregate service and interest costs by $33 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated obligation as of December 31, 2001, by $243 million and annual aggregate service and interest costs by $26 million.

Stock Options and Other Equity-Based Awards

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 award of Edison International common shares and options on shares. 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 the special options discussed below were awarded.

Under the 1992, 1998 and 2000 plans, options on 4.9 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 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 1999 Edison International stock option awards include a dividend equivalent feature.

Options issued after 1997 generally have a four-year vesting period. The special options granted in 2000 vest over five years, but vesting does not begin until 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 which 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 above pro forma disclosures, 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,	2001	2000
Expected life	7 years – 10 years	7 years – 10 years
Risk-free interest rate	4.7% – 6.1%	4.7% – 6.0%
Expected volatility	17% – 52%	17% – 46%

The application of fair-value accounting to calculate the pro forma disclosures above 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.

The weighted-average fair value of options granted during 2001 and 2000 was $4.53 per share option and $5.50 per share option, respectively. The weighted-average remaining life of options outstanding as of December 31, 2001, and December 31, 2000, was 6 years and 7 years, respectively.

For the years after 1999, a portion of the executive long-term incentives was awarded in the form of performance shares. The 2000 performance shares were restructured as retention incentives in December 2000, which pay as a combination of Edison International common stock and cash if the executive remains employed at the end of the performance period. The performance period ended December 31, 2001, for half of the award, and ends on December 31, 2002, for the remainder. Additional performance shares were awarded in January 2001 and January 2002. The 2001 performance shares vest December 31, 2003, half in shares of Edison International common stock and half in cash. The 2002 performance shares vest December 31, 2004, also half in shares of common stock and half in cash. The number of shares that will be paid out from the 2002 performance share awards will depend on the performance of Edison International common stock relative to the stock performance of a specified group of peer companies.

The 2000 and 2001 performance shares and deferred stock unit values are accrued ratably over a three-year performance period. The 2002 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 will be paid between March 12, 2002, and March 12, 2003, depending on performance. The deferred stock units are payable on the vesting date 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. The deferred stock units will vest 25% per year over four years, with the first vesting date in November 2002. The following assumptions were used in determining fair value through the Black-Scholes option-pricing model: expected life: 8 – 9 years; risk-free interest rate: 5.10%; expected volatility: 52%.

SCE measures compensation expense related to stock-based compensation by the intrinsic value method. Compensation expense recorded under the stock-compensation program was $1 million in 2001, $4 million in 2000 and $5 million in 1999.

Stock-based compensation expense under the fair-value method of accounting would have resulted in pro forma net income (loss) available for common stock of $2.383 billion for 2001, $(2.054) billion for 2000 and $484 million for 1999.

Note 10. 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, 2001, was:

In millions	Investment in Facility	Accumulated Depreciation and Amortization	Ownership Interest
Transmission systems:			
Eldorado	$ 41	$ 11	60%
Pacific Intertie	240	84	50
Generating stations:			
Four Corners Units 4 and 5 (coal)	469	365	48
Mohave (coal)	334	246	56
Palo Verde (nuclear)(1)	1,653	1,648	16
San Onofre (nuclear)(1)	4,305	4,283	75
Total	$ 7,042	$ 6,637	

(1) Regulatory assets, which were written off as a charge to earnings as of December 31, 2000, as discussed in Note 1.

Note 11. Commitments

Leases

SCE has operating leases, primarily for vehicles, with varying terms, provisions and expiration dates. Operating lease expense was $19 million in 2001, $20 million in 2000 and $17 million in 1999.

Estimated remaining commitments for noncancelable leases at December 31, 2001, were:

Year ended December 31,	In millions
2002	$ 14
2003	13
2004	11
2005	8
2006	6
Thereafter	13
Total	$ 65

Nuclear Decommissioning

Decommissioning is estimated to cost $2.1 billion in current-year dollars, based on site-specific studies performed in 1998 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 $8.6 billion through 2060 to decommission its nuclear facilities. This estimate is based on SCE's current dollar decommissioning costs, escalated at rates ranging from 0.3% to 10.0% (depending on the cost element) annually. These costs are expected to be funded from independent decommissioning trusts, which effective June 1999 receive contributions of approximately $25 million per year. SCE estimates annual after-tax earnings on the decommissioning funds of 3.9% to 4.9%.

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 2026 and 2028 for the Palo Verde units. Decommissioning costs, which are recovered through non-bypassable customer rates over the term of each nuclear facility's operating license, are recorded as a component of depreciation expense.

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's Unit 1 decommissioning costs will be paid from its nuclear decommissioning trust funds.

Decommissioning expense was $96 million in 2001, $106 million in 2000 and $124 million in 1999. The accumulated provision for decommissioning, excluding San Onofre Unit 1 and unrealized holding gains, was $1.5 billion at December 31, 2001, and $1.4 billion at December 31, 2000. The estimated cost to decommission San Onofre Unit 1 is recorded as a liability.

Decommissioning funds collected in rates are placed in independent trusts, which, together with accumulated earnings, will be utilized solely for decommissioning.

Trust investments (cost basis) include:

In millions	Maturity Dates	December 31,	2001	2000
Municipal bonds	2001 – 2034		$ 463	$ 548
Stocks	–		637	531
U.S. government issues	2001 – 2029		332	421
Short-term and other	2001		334	220
Total			$ 1,766	$ 1,720

Trust fund earnings (based on specific identification) increase the trust fund balance and the accumulated provision for decommissioning. Net earnings were $13 million in 2001, $38 million in 2000 and $58 million in 1999. Proceeds from sales of securities (which are reinvested) were $3.9 billion in 2001, $4.7 billion in 2000 and $2.6 billion in 1999. Approximately 91% of the trust fund contributions were tax-deductible.

Other Commitments

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

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.

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 $158 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 $31 million). The transmission service contract requires a minimum payment of approximately $6 million a year.

Certain commitments for the years 2002 through 2006 are estimated below:

In millions	2002	2003	2004	2005	2006
Fuel supply contract payments	$ 168	$ 108	$ 103	$ 106	$ 109
Purchased-power capacity payments	629	629	626	624	572

Note 12. Contingencies

In addition to the matters disclosed in these notes, SCE is involved in other legal, tax and regulatory proceedings before various courts and governmental agencies regarding matters arising in the ordinary course of business. SCE believes the outcome of these other proceedings will not materially affect its results of operations or liquidity.

Energy Crisis Issues

In October 2000, a federal class action securities lawsuit was filed against SCE and Edison International. As amended in December 2000 and March 2001, the lawsuit involves securities fraud claims arising from alleged improper accounting for the TRA undercollections. The second amended complaint is supposedly filed on behalf of a class of persons who purchased Edison International common stock between July 21, 2000, and April 17, 2001. This lawsuit has been consolidated with another similar lawsuit filed on March 15, 2001. A consolidated class action complaint was filed on August 3, 2001. On September 17, 2001, SCE and Edison International filed a motion to dismiss for failure to state a claim. On March 8, 2002, the district court issued an order dismissing the complaint with prejudice. The plaintiffs could appeal this ruling to the court of appeals.

SCE has been a defendant in a number of legal actions brought by various QFs arising out of SCE's suspension of payments for electricity delivered by the QFs during the period November 1, 2000, through March 26, 2001. The QF claims were eventually largely subsumed within agreements with the litigating QFs providing for a provisional settlement of the parties' disputes. On March 1, 2002, SCE paid the amounts due under settlement agreements with these QFs, which triggered the releases and other provisions of the settlements. As a result, the litigation with those QFs to whom payment in full has been made under the parties' settlement agreements should be dismissed during 2002. However, SCE's March 1, 2002, payments excluded several QFs or did not result in immediate releases under the settlement agreements based on unique disputes or other unique circumstances, including the status of regulatory approval.

Environmental Protection

SCE 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.

SCE records its environmental liabilities when site assessments and/or remedial actions are probable and a range of reasonably likely cleanup costs can be estimated. SCE 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, SCE records the lower end of this reasonably likely range of costs (classified as other long-term liabilities) at undiscounted amounts.

SCE's recorded estimated minimum liability to remediate its 42 identified sites is $111 million. The ultimate costs to clean up SCE'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. SCE believes that, due to these uncertainties, it is reasonably possible that cleanup costs could exceed its recorded liability by up to $279 million. The upper limit of this range of costs was estimated using assumptions least favorable to SCE among a range of reasonably possible outcomes. SCE has sold all of its gas-fueled generation plants and has retained some liability associated with the divested properties.

The CPUC allows SCE to recover environmental-cleanup costs at certain sites, representing $50 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. Costs incurred at SCE's remaining sites are expected to be recovered through customer rates. SCE has recorded a regulatory asset of $76 million for its estimated minimum environmental-cleanup costs expected to be recovered through customer rates.

SCE'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 SCE may be held responsible for contributing to any costs incurred for remediating these sites. Thus, no reasonable estimate of cleanup costs can now be made for these sites.

SCE 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 $10 million to $25 million. Recorded costs for 2001 were $18 million.

Based on currently available information, SCE believes it is unlikely that it will incur amounts in excess of the upper limit of the estimated range and, based upon the CPUC's regulatory treatment of environmental-cleanup costs, SCE 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.

Nuclear Insurance

Federal law limits public liability claims from a nuclear incident to $9.5 billion. SCE and other owners of San Onofre and Palo Verde have purchased the maximum private primary insurance available ($200 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 U.S. 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 $88 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 $175 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.

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. These policies are issued by a mutual insurance company owned by utilities with nuclear facilities. 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 $35 million per year. Insurance premiums are charged to operating expense.

Spent Nuclear Fuel

Under federal law, the DOE is responsible for the selection and development of a facility for disposal of spent nuclear fuel and high-level radioactive waste. Such a facility was to be in operation by January 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 from other nuclear power plants. Extended delays by the DOE could lead to consideration of costly alternatives involving 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 one mill per kilowatt-hour of nuclear-generated electricity sold after April 6, 1983.

SCE, as operating agent, has primary responsibility for the interim storage of its spent nuclear fuel at San Onofre. Current capability to store spent fuel is estimated to be adequate through 2005. SCE plans to spend approximately $34 million for the initial interim spent fuel storage at San Onofre Units 2 and 3 through 2008.

Palo Verde on-site spent fuel storage capacity will accommodate needs until 2003 for Unit 2, and until 2004 for Units 1 and 3. Arizona Public Service Company, operating agent for Palo Verde, is constructing an interim fuel storage facility that is expected to be completed in 2002.

Quarterly Financial Data

	2001					2000				
In millions	Total	Fourth	Third	Second	First	Total	Fourth	Third	Second	First
Operating revenue	$8,126	$2,296	$2,726	$1,592	$1,512	$7,870	$1,755	$2,432	$1,853	$1,830
Operating income (loss)	4,617	3,956	1,294	204	(837)	(2,659)	(3,840)	447	385	349
Net income (loss)	2,408	2,310	657	34	(593)	(2,028)	(2,485)	177	161	119
Net income (loss) available for common stock	2,386	2,304	652	28	(598)	(2,050)	(2,491)	172	156	113
Common dividends declared	—	—	—	—	—	279	—	92	91	96

The management of Southern California Edison Company (SCE) 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.

SCE maintains 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. SCE 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.

SCE's independent public accountants, Arthur Andersen 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 SCE'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 public accountants and internal auditors, who have unrestricted access to the committee. The committee recommends annually to the board of directors the appointment of a firm of independent public accountants to conduct audits of SCE's financial statements; considers the independence of such firm and the overall adequacy of the audit scope and SCE's systems of internal control; reviews financial reporting issues; and is advised of management's actions regarding financial reporting and internal control matters.

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

Thos M. Noonan

Thomas M. Noonan
Vice President
and Controller

Alan J. Fohrer
Chairman of the Board
and Chief Executive Officer

March 25, 2002

To Southern California Edison Company:

We have audited the accompanying consolidated balance sheets of Southern California Edison Company (SCE, 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 changes in common shareholder's equity for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of SCE'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 SCE 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.

Arthur Andersen LLP

ARTHUR ANDERSEN LLP

Los Angeles, California
March 25, 2002

Management Team

Alan J. Fohrer
Chairman of the Board and
Chief Executive Officer

Robert G. Foster
President

Harold B. Ray
Executive Vice President,
Generation Business Unit

Pamela A. Bass
Senior Vice President,
Customer Service Business Unit

John R. Fielder
Senior Vice President,
Regulatory Policy and Affairs

Stephen E. Pickett
Senior Vice President and
General Counsel

Richard M. Rosenblum
Senior Vice President,
Transmission and Distribution
Business Unit

Mahvash Yazdi
Senior Vice President and
Chief Information Officer

Emiko Banfield
Vice President, Shared Services

Robert C. Boada
Vice President and Treasurer

Clarence Brown
Vice President,
Corporate Communications

Bruce C. Foster
Vice President, San Francisco
Regulatory Operations

A. L. Grant
Vice President, Engineering and
Technical Services

Frederick J. Grigsby, Jr.
Vice President, Human Resources
and Labor Relations

Lawrence D. Hamlin
Vice President, Power Production

Harry B. Hutchison
Vice President, Mass Customers

James A. Kelly
Vice President,
Regulatory Compliance

Russell W. Krieger
Vice President,
Nuclear Generation

Thomas M. Noonan
Vice President and Controller

Dwight E. Nunn
Vice President, Nuclear Engineering
and Technical Services

Pedro J. Pizarro
Vice President,
Business Development

Frank J. Quevedo
Vice President, Equal Opportunity

W. James Scilacci
Vice President and
Chief Financial Officer

Dale E. Shull, Jr.
Vice President, Power Delivery

Anthony L. Smith
Vice President, Tax

Joseph J. Wambold
Vice President, Nuclear Business
and Support Services

Beverly P. Ryder
Secretary

Shareholder Information

Annual Meeting of Shareholders

Tuesday, May 14, 2002
10:00 a.m.
DoubleTree Hotel Ontario
222 N. Vineyard Avenue
Ontario, California 91764

Stock Listing and Trading Information

SCE Preferred Stock

SCE's preferred stocks are listed on the American and Pacific stock exchanges under the ticker symbol SCE. Previous day's closing prices, when traded, are listed in the daily newspapers in the American Stock Exchange composite table. The 6.05%, 6.45% and 7.23% series are not listed.

Where to Buy and Sell Stock

The listed preferred stocks may be purchased through any brokerage firm. Firms handling unlisted series can be located through your broker.

Transfer Agent and Registrar

Wells Fargo Bank Minnesota, N.A. maintains shareholder records and is the transfer agent and registrar for SCE preferred stock. Shareholders may call Wells Fargo Shareowner Services, (800) 347-8625, between 7:00 a.m. and 7:00 p.m. (Central Time), Monday through Friday, regarding:

- stock transfer and name-change requirements;
- address changes, including dividend addresses;
- electronic deposit of dividends;
- taxpayer identification number submission or changes;
- duplicate 1099 forms and W-9 forms;
- notices of, and replacement of, lost or destroyed stock certificates and dividend checks; and
- requests for access to online account information.

The address of Wells Fargo Shareowner Services is:

161 North Concord Exchange Street
South St. Paul, MN 55075-1139
FAX: (651) 450-4033
E-mail: stocktransfer@wellsfargo.com

SCE Web Address:
www.edisoninvestor.com

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2001 Annual Report

Edison International

Edison International is an electric power generator, distributor and structured finance provider. Headquartered in Rosemead, California, Edison International is the parent company of Southern California Edison—a regulated electric utility—and three nonutility businesses: Edison Mission Energy, Edison Capital and Edison O&M Services.

Edison International's operating companies have offices throughout California, and in Boston, Chicago, Washington, D.C., Australia, Indonesia, Italy, the Philippines, Singapore, Spain, Turkey and the United Kingdom.

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Dear Fellow Shareholders,

As you know, last year California experienced an unprecedented energy crisis. That crisis created turmoil in the energy markets. Our company faced the greatest challenge in its hundred-year history.

These events tested the determination of the women and men of Edison International. Our people had to persevere through many months of intense disappointments and work effectively under pressure. Throughout, they remained committed to finding a solution that would restore the company's full capacity to serve our customers and provide value to you, our shareholders.

I am pleased to report that perseverance was rewarded. The key event was a litigation settlement agreement reached with the California Public Utilities Commission (CPUC) in October. As a result of that, Southern California Edison (SCE) is now on the path to recovery. Many important challenges lie ahead for the entire company, but we are committed to continuing the progress in rebuilding financial health. We are also committed to restoring our long-standing practice of making reliable dividend payments to you. The goal is to begin dividend payments by the end of next year.

In early March of this year, we achieved a major milestone in the recovery effort: we paid off the past-due debt incurred by SCE in buying power to keep our customers' lights on while the crisis raged. On the strength of a greatly improved cash position, strong cash flow, and the cost recovery settlement reached with the CPUC, we were able to arrange $1.6 billion of financing and pay off $3.2 billion in past due obligations. That was a major step toward regaining financial stability.

We never want to go through another year like the last one, but there is strength in being severely tested and meeting that test. Our ability to build the company's value and to pay shareholder dividends is dependent on working successfully through additional challenges. As demonstrated in crisis, however, our team has the determination, drive and creativity to succeed.

The Power Crisis: Effects on SCE

Southern California Edison began 2001 deeply in debt for wholesale power purchases. In November 2000, SCE had filed a federal lawsuit against the CPUC seeking prompt recovery of those costs. In mid-January 2001, our banks lost faith in the regulatory cost-recovery process and declined to lend further to SCE. To conserve the cash necessary to operate its utility system, the company was forced to suspend payments on prior obligations to lenders and wholesale power suppliers. With that, the State of California had to take over responsibility for buying power for SCE's customers.

Throughout the crisis, SCE was committed to staying out of bankruptcy, paying off our creditors and doing our part to restore the reliability and predictability of California's energy market. Although we were confident of our legal position in the federal lawsuit, pursuing full litigation over determined opposition would likely have taken years to resolve. So we continued to work hard to achieve an earlier resolution.

In early April 2001, California's largest utility, Pacific Gas and Electric, gave up on its out-of-court resolution effort and filed for bankruptcy. Shortly thereafter, we were able to work out a Memorandum of Understanding (MOU) with the Governor. That MOU, however, required implementing legislation to be effective. The Legislature was called upon to pass judgment on a major, complex commercial agreement, and was required to do so at a time of extraordinarily intense public and media focus on the crisis at the national, state and local levels. Scores of proposed resolutions were put forth. In the end, after nearly five months of developing proposed bills and holding hearings, the Legislature recessed without reaching agreement.

At that point in mid-September, prospects for a near-term resolution looked dim. The Governor persisted, calling another special session of the state Legislature. We then made one additional effort to work out a resolution with the CPUC. This time, after two weeks of intense negotiations, a settlement of the federal lawsuit, filed nearly a year earlier, was finally achieved. The settlement agreement provides a path for SCE to recover its power purchase costs and was approved by U.S. District Judge Ronald S. W. Lew on October 5.

Although the settlement allows recovery of previously unreimbursed costs, I want to underscore that much remains to be done to restore fully SCE's financial health and its full capacity to act as a provider of essential California infrastructure. As I write this letter, the CPUC has before it a number of key proposed decisions, the outcome of which will deeply affect SCE's ability to regain full investment-grade creditworthiness. At the same time, a consumer group, TURN, has appealed to the U.S. Court of Appeals the decision of Judge Lew approving SCE's settlement with the CPUC. That settlement, which the CPUC has continued to support steadfastly, is critical to SCE's recovery.

We have, throughout the crisis, regarded it as a primary obligation to pay the people and businesses to whom we owed money. For many months, they refrained from forcing us into bankruptcy. In fact, we may have set a corporate record for the duration of creditor forbearance. Whether or not that is truly a record, we are grateful to our creditors for finding our recovery efforts credible and giving us the time to get the job done.

The Power Crisis: Effects Across Edison International

The adverse impacts of the power crisis were not limited to Southern California Edison. Throughout last year, lenders—most of them already at risk with large prior commitments to SCE—sought to reduce their overall exposure to Edison International. Since SCE could not pay down debts, most lenders focused their risk-mitigation efforts on our need to refinance maturing debt at our other companies. This required repeated restructuring of debt at our holding company and at Edison Mission Energy (EME) and Edison Capital, and the cost of rolling over the debt was high.

Among all our subsidiaries, only EME retained its investment-grade credit rating. That was achieved through divesting power projects, adopting governance protections for EME creditors, and forgoing new growth initiatives. The most important of those steps was the sale of the Fiddler's Ferry and Ferrybridge (FFF) power plants in the United Kingdom, which we purchased in 1999. The loss was large, but the sale was essential.

Edison Capital was also adversely impacted by the energy crisis. Without access to capital and following a sharp drop in its credit rating, the team at Edison Capital had to change course to create liquidity. They responded quickly. The employee base was halved, operating costs were significantly reduced, and $600 million was raised through asset sales.

Finally, we found it necessary to wind up Edison Enterprises. Its principal business line was our Edison Security business, which would have required greater scale to achieve success and was hurt by the reputation impacts associated with SCE's financial weakness. The net after-tax losses associated with the FFF and Edison Security sales totaled $1.4 billion.

Other 2001 Achievements

Notwithstanding the stress of the power crisis, the people of Edison International last year not only achieved a sound path to resolve SCE's dire position, but they also met other important goals. Several of those accomplishments deserve special recognition.

During the summer of 2000, when it became apparent that California desperately needed additional power supply, I challenged our people to find a way to help fill that need. EME scoured the state, located a partially permitted but abandoned project, negotiated to buy both the project rights and turbines for it, and set out to meet a near impossible deadline. In the end, EME beat the deadline by 45 days, bringing online in June of last summer California's first new generating station in 13 years. This was an extraordinary achievement. The 320-MW Sunrise Plant, located in central California, moved from groundbreaking to ribbon cutting in a record six months, and EME committed Sunrise's electrical output to serve Californians under cost-based pricing for the next 10 years.

In Asia, after persevering through the backdrop of a severe five-year economic slump in Indonesia, the EME Asia team, along with our project partners, secured a binding agreement on terms for a renewed long-term power sales contract between our Paiton generating station and the Indonesian national utility. This important step was achieved with the support of the Indonesian government. Detailed agreements remain to be worked out during 2002.

In Illinois, the more than 1,000 represented employees who operate seven power plants owned by EME's Midwest Generation subsidiary went on strike on June 28, 2001. Throughout the summer, our management team ran the plants, setting new records for plant performance and meeting all-time high electricity demand. In October, a collective bargaining agreement that provides needed flexibility for the company and fair compensation to represented employees was finally reached. The strike came at the worst possible time for our customers in Illinois and for our company, but the management team handled it with true excellence.

Throughout the energy crisis, our SCE employees remained intent on providing excellent service to our utility customers. One key metric is exemplary; in fact, I find it amazing. We ask customers who have any form of transaction with SCE to evaluate our service. Last year, even as the crisis raged, our customer service evaluations were the second highest we have had since the customer feedback program began in 1992. That score qualifies the company for a service incentive award of $8 million from the CPUC. Also in 2001, SCE earned the highest CPUC award for reliability ($5 million) and again earned the highest award for safety ($5 million).

Edison International Year 2001 Earnings

Solvency—not earning power—was, by necessity, our primary focus in the past year. Core Edison International earnings were down by 26% from the prior year, and down at each of our companies except EME, whose earnings were up by 17%. Significant factors in SCE's reduced core earnings were a fire-caused outage at San Onofre Unit 3 and the financial impact of the power crisis.

Taking into account nonrecurring items, including the restoration to the SCE balance sheet of regulatory assets previously written off and the losses associated with asset sales at EME and Edison Enterprises, Edison International's year 2001 recorded earnings were approximately $1 billion. These results are discussed in greater detail in the "Management's Discussion and Analysis of Results of Operation and Financial Condition" section of the Annual Report.

Electricity Industry Turmoil

Last year was a time of turmoil and change, not only at Edison International, but also across much of the electricity industry. In addition to the California power crisis, three other major events will have enduring effects.

September 11 and Electric System Security

The tragic events of September 11 and their aftermath have raised concerns about the potential for terrorist acts on our electric systems. Even though in the past we have had strong security systems and processes, in response to September 11, we further tightened security at all major Edison facilities and generating stations—especially at our San Onofre Nuclear Generating Station in California.

I also want to note that the September 11 tragedy touched us in a personal way, with the loss of 22-year-old Lisa Frost, the daughter of SCE transmission system operator Tom Frost. Lisa, who perished on hijacked United Flight 175, was an exemplary student and person who, in her time with us, had made the world a little better. With the Frost family, we mourn her loss.

Enron

Another event that will likely have enduring effects on our industry was the collapse and bankruptcy of the Enron Corp. In recent years, Enron has been perhaps the most influential private party affecting public decision making in the electricity business across the nation. At this time, we do not know what impact, if any, Enron may have had in influencing prices in wholesale power markets last year in California and the West. What is certain, however, is that Enron's business practices will, and should be, investigated with intensity. We hope that the result is improved business policy and regulation, with respect to both accounting practices and fair, open electricity markets.

Independent Power Production

Finally, an extraordinary decline in market valuations for independent power companies that began late in 2001 and has continued into this year is deeply affecting the industry. Share prices for the publicly owned segment of the industry peaked in October 2001 and have declined by more than 50% to the present.

This decline has some immediate impacts on us. Lenders and credit-rating agencies are applying more stringent criteria to their judgments about independent power projects. Since last September, six publicly traded independent power producers in the U.S. have been downgraded or put on "credit watch" by the credit-rating agencies. The tightening of credit standards has reduced the number of parties with whom EME can contract. In general, with the Enron collapse and lower credit ratings in the industry, the sector is in a period of stress and change.

Edison International Outlook: 2002 and 2003

We have had the view that our company will be best served by building both a strong utility business and a strong independent power generation business. We have also had the view that our customers and shareholders will benefit from longer-term and stable arrangements for power supply. The events of the past year have strengthened our conviction in these respects.

The major focus for us in the next two years will be to restore our company's overall financial health and flexibility. That should enable us to reduce rates for SCE customers and resume paying dividends to you. It will also facilitate taking the State of California out of the power-buying business–a vital step for the state's taxpayers and our customers. With financial health, SCE will be able to implement the necessary capital investments and system enhancements to continue to provide superior service and transmission and distribution reliability. In our nonutility businesses, growth will be constrained as we give priority to strengthening credit, building liquidity, reducing volatility associated with sales into short-term power markets, entering into longer-term power purchase agreements, and ensuring that our costs are low and competitive.

Finally, and at all times, we will seek to live up to high business and personal values of integrity and high-quality service.

Board and Management Changes

Our long-time director, Dr. Edward Zapanta, passed away—far too young—in February of this year. At our annual meeting in May, Warren Christopher, Carl Huntsinger and Charles Miller will retire. All four of these men provided wise counsel, consistent support and sound judgment. We will greatly miss their service to us.

At the end of 2001, we announced new leadership at SCE and EME. After more than six years in senior leadership roles at SCE, including the past two years as Chairman, President and CEO, Stephen E. Frank retired. Steve's stewardship, particularly during the crisis, made a significant and enduring contribution to our company.

Succeeding Steve at SCE are Alan J. Fohrer, as Chairman and CEO, and Robert G. Foster, as President. Al comes to this role after serving as President and CEO of Edison Mission Energy for the past two years, and in engineering and financial capacities for nearly 30 years with Edison International and SCE. Bob has led our external affairs for Edison International and SCE during his 17 years with the company. Succeeding Al as President and CEO of EME is William J. Heller, who previously served as Division President of EME Europe, and before that, as head of strategic and corporate planning for Edison International. Finally, we made Theodore F. Craver Executive Vice President of Edison International. Ted also serves as our Chief Financial Officer. These men bring experience, dedication, sound judgment and high personal standards to the leadership of our company. I am proud to work with them.

Thank you for the trust that you, by your investments, have put in us. We will work hard to reward that trust.

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

March 28, 2002

The following discussion contains forward-looking statements. These statements are based on Edison International's current expectations about future events, based on knowledge of present facts and assumptions about future developments. These forward-looking statements are subject to risks and uncertainties that could cause actual future activities and results of operations to be materially different from those set forth in this discussion. Important factors that could cause actual results to differ include risks discussed in the Market Risk Exposures and Forward-Looking Statements sections.

Until early 2002, Southern California Edison Company (SCE) faced a crisis resulting from deregulation of the generation side of the electric utility industry through legislation enacted by the California Legislature and decisions issued by the California Public Utilities Commission (CPUC). Under the legislation and CPUC decisions, prices for wholesale purchases of electricity from power suppliers are set by markets while the retail prices paid by utility customers for electricity delivered to them remained frozen at June 1996 levels except for the 10% residential rate reduction starting in 1998 and the 4¢-per-kWh surcharge effective in 2001. See further discussion of the CPUC rate increases in Rate Stabilization Proceedings. Beginning in May 2000, SCE's costs to obtain power (at wholesale electricity prices) for resale to its customers substantially exceeded revenue from frozen rates. The shortfall was accumulated in the transition revenue account (TRA), a CPUC-authorized regulatory asset. As a result of a March 27, 2001, CPUC decision, the TRA balance was transferred retroactively to the transition cost balancing account (TCBA). The TCBA was a regulatory balancing account that tracked the recovery of generation-related transition costs, including stranded investments. SCE borrowed significant amounts of money to finance its electricity purchases. Uncertainty regarding SCE's ability to recover funds spent to purchase power created a severe liquidity crisis at SCE. However, based on the settlement agreement with the CPUC (discussed below) permitting full recovery of past procurement costs, SCE was able to arrange new financing and together with cash on hand, was able to repay its undisputed past-due obligations in March 2002.

In October 2001, a federal district court in California entered a stipulated judgment approving an agreement between the CPUC and SCE to settle a lawsuit. On January 23, 2002, the CPUC adopted a resolution approving the establishment of the procurement-related obligations account (PROACT). See discussion below. SCE believes that the settlement agreement will enable SCE to recover its previously undercollected power procurement costs. In compliance with the terms of the settlement agreement and the CPUC resolution, in the fourth quarter of 2001 SCE established a $3.6 billion regulatory asset for these previously incurred procurement costs, called the PROACT. A corresponding credit to earnings was recorded, in connection with this regulatory asset, in the amount of $3.6 billion ($2.1 billion after tax).

On September 1, 2001, SCE began applying to the PROACT the difference between SCE's revenue from retail electric rates and the costs that SCE is authorized by the CPUC to recover in retail electric rates. The settlement calls for the end of the TCBA mechanism as of August 31, 2001, and continuation of the rate freeze until the earlier of December 31, 2003, or the date that SCE recovers the PROACT balance. If SCE has not recovered the entire PROACT balance by the end of 2003, the remaining balance will be amortized in retail rates for up to an additional two years. For further details on the settlement with the CPUC and the CPUC resolution, see CPUC Litigation Settlement Agreement and PROACT Regulatory Asset discussions.

Accounting principles generally accepted in the United States permit SCE to defer costs and record regulatory assets if those costs are determined to be probable of recovery in future rates. SCE assessed the probability of recovery of the undercollected costs that were previously recorded in the TCBA in light of the CPUC's March 27, 2001, and April 3, 2001, decisions, including the retroactive transfer of balances from SCE's TRA to its TCBA and related changes that are discussed in more detail in Rate Stabilization Proceedings. These decisions and other regulatory and legislative actions did not meet SCE's prior expectation that the CPUC would provide adequate cost recovery mechanisms. As a result, SCE's financial results for the year ended December 31, 2000, included an after-tax charge of approximately $2.5 billion ($4.2 billion pre-tax), reflecting a write-off of the TCBA and net regulatory assets to be recovered through the TCBA mechanism, as of December 31, 2000. Transition costs in excess of transition revenue were also incurred during 2001, resulting in additional net charges against earnings of $328 million ($552 million pre-tax) through August 31, 2001 (the effective date of the PROACT mechanism).

The following pages include a discussion of the history of the TRA and TCBA and related circumstances, the significantly negative effect on the financial condition of SCE of undercollections recorded in the TRA and TCBA, the current status of the undercollections, the impact of the CPUC's March 27, 2001, decisions and related matters, and the implementation of the CPUC settlement agreement and the PROACT mechanism, and SCE's March 2002 financing.

Results of Operations

Edison International's 2001 basic earnings per share were $3.18 compared with a loss of $5.84 in 2000 and earnings of $1.79 in 1999. See table below.

Earnings (Loss) Per Share Year ended December 31,	2001	2000	1999
Earnings (Loss) from Continuing Operations:			
Core Earnings:			
SCE	$ 1.25	$ 1.42	$1.39
Edison Mission Energy (EME)	.35	.30	.32
Edison Capital	.26	.41	.37
Mission Energy Holding (parent only)	(.15)	—	—
Edison International (parent only)	(.41)	(.38)	(.12)
Edison International Core Earnings	1.30	1.75	1.96
SCE procurement and generation-related adjustments	6.07	(7.58)	—
Edison International Consolidated Earnings (Loss) from Continuing Operations	7.37	(5.83)	1.96
Earnings (Loss) from Discontinued Operations:			
EME's Ferrybridge and Fiddler's Ferry plants	(3.78)	.08	.05
Edison Enterprises' companies	(.41)	(.09)	(.22)
Edison International Consolidated Loss from Discontinued Operations	(4.19)	(.01)	(.17)
Total Edison International Consolidated Earnings (Loss) Per Share	$ 3.18	$(5.84)	$1.79

Earnings (Loss) from Continuing Operations

Edison International's 2001 basic earnings per share from continuing operations were $7.37, compared with a loss of $5.83 in 2000 and earnings of $1.96 in 1999.

2001 vs. 2000

SCE's 2001 earnings of $7.32 included a $6.07 per share net benefit to reflect the impact of the three procurement and generation-related adjustments: $2.1 billion (after tax) reestablishment of procurement-related regulatory assets and liabilities as a result of the PROACT resolution, the recovery of $178 million (after tax) of previously written off generation-related regulatory assets, both of which are partially offset by $328 million (after tax) of net undercollected transition costs incurred between January and August 2001. SCE's $6.16 per share loss in 2000 included a $7.58 per share ($2.5 billion after tax) write-off of regulatory assets and liabilities as of December 31, 2000. Excluding the $6.07 per share net benefit in 2001 and the $7.58 per share write-off in 2000, SCE's 2001 earnings were $1.25 compared to $1.42 in 2000. The 17¢ decrease was primarily due to the February 2001 fire and resulting outage at San Onofre Nuclear Generating Station Unit 3 and lower kilowatt-hour sales, partially offset by the impact of fewer average common shares outstanding.

Accounting principles generally accepted in the United States require SCE at each financial statement date to assess the probability of recovering its regulatory assets through a regulatory process. Based on the rules arising from the CPUC's March 27, 2001, rate stabilization decision, the $4.5 billion TRA undercollection as of December 31, 2000, and the coal and hydroelectric balancing account overcollections were reclassified, and the TCBA balance was recalculated to be a $2.9 billion undercollection (see further discussion of the CPUC rate increase in the Rate Stabilization Proceeding section and the components of the TCBA undercollection in the Status of Transition and Power-Procurement Cost Recovery section of SCE's Regulatory Environment). As a result, SCE was unable to conclude that, under applicable accounting principles, the $2.9 billion TCBA undercollection (as recalculated above) and $1.3 billion (book value) of other net regulatory assets that were to be recovered through the TCBA mechanism by the end of the rate freeze, were probable of recovery through the rate-making process as of December 31, 2000. As a result, SCE's December 31, 2000, income statement included a $4.0 billion charge to provisions for regulatory adjustment clauses and a $1.5 billion net reduction in income tax expense, to reflect the $2.5 billion (after tax) write-off.

Based on the rules arising from the CPUC's January 23, 2002, 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 2001 earnings from continuing operations of 35¢ per share increased 5¢ over 2000. The increase in 2001 reflects higher energy prices for EME's U.S. projects and increased earnings from oil and gas activities, partially offset by lower energy prices and capacity payments in the United Kingdom, the non-recurring affiliate stock option plan expense adjustment in 2000, and the partial termination of a lease for turbines.

Edison Capital's 2001 earnings of 26¢ decreased 15¢ from 2000. The decrease in 2001 was primarily due to both the contractual run-off of (i.e., as the average age of leases in the portfolio increases, earnings decline) and fewer assets in Edison Capital's lease portfolio. These decreases were partially offset by a net gain on asset sales and income from the syndication of affordable housing projects, as well as lower operating expenses.

Mission Energy Holding Company (parent only), which was formed in 2001, showed a loss of 15¢ in 2001, due to the issuance of new debt during the third quarter of 2001.

Edison International (parent company) incurred a loss of 41¢ in 2001, compared to a 38¢ loss in 2000. The increased loss in 2001 was mostly due to a prior-year tax adjustment.

2000 vs. 1999

Excluding the $7.58 per share ($2.5 billion after tax) write-off in 2000, SCE's 2000 earnings were $1.42 compared to $1.39 in 1999. The 3¢ per share net increase was mainly due to a 7¢ per share increase which reflected fewer common shares outstanding as a result of Edison International's share repurchase program referenced below and discussed in Financial Condition, partially offset by a 4¢ per share tax benefit due to a one-time adjustment that resulted from an Internal Revenue Service ruling in 1999.

EME's 2000 earnings of 30¢ per share decreased from 32¢ in 1999. The decrease in 2000 was mainly due to higher interest costs and the absence of non-recurring income tax benefits recognized in 1999, partially offset by a full year of operating results from the Illinois plants and a non-recurring affiliate stock option plan expense adjustment.

Edison Capital's 2000 earnings of 41¢ increased 4¢ over 1999. The increase was primarily due to increased earnings from new investments in infrastructure and leveraged leases, partially offset by declining revenue from existing leveraged leases.

Edison International (parent company) showed a loss of 38¢ in 2000, compared to a loss of 12¢ in 1999, mostly the result of higher interest expense.

Excluding the write-off, the reduced number of outstanding shares (due to a repurchase program discussed in Financial Condition) benefited Edison International's earnings per share by 8¢ in 2000.

Operating Revenue

From 1998 through mid-September 2001, SCE's customers were able to choose to purchase power directly from an energy service provider (thus becoming direct access customers) or continue to have SCE purchase power on their behalf. Most direct access customers continued to be billed by SCE, but were given a credit for the generation purchased from the energy service provider. Electric utility revenue is reported net of this credit. On September 20, 2001, the CPUC suspended the ability of retail customers to select alternative providers of electricity until the California Department of Water Resources (CDWR) stops buying power for retail customers, pending further review by the CPUC. On March 21, 2002, the CPUC issued a final decision affirming September 20, 2001, as the date when direct access was suspended in the state.

During 2000, as a result of the power shortage in California, SCE's customers on interruptible rate programs (which provide for lower generation rates with a provision that service can be interrupted if needed, with penalties for noncompliance) were asked to curtail their electricity usage at various times. As a result of noncompliance with SCE's requests, those customers were assessed significant penalties. On January 26, 2001, the CPUC waived the penalties assessed to noncompliant customers after October 1, 2000, until the interruptible programs can be reevaluated.

Electric utility revenue increased in 2001 (as shown in the table below), primarily due to the effects of the reduced credits given to direct access customers in 2001 and the 4¢-per-kWh (1¢ in January and 3¢ in June) surcharge effective in 2001. The increases were partially offset by: a decrease in retail sales volume primarily attributable to conservation efforts; a decrease in revenue related to penalties customers incurred for not complying with their interruptible contracts; a decrease in revenue related to operation and maintenance services; and a decrease in revenue related to electric power provided to SCE customers by the CDWR or Independent System Operator (ISO). Amounts SCE bills to and collects from its customers for electric power purchased and sold by the CDWR or through the ISO on behalf of SCE's customers (beginning January 17, 2001) are being remitted to the CDWR and are not recognized as revenue by SCE. In 2001, this amount was $2.0 billion. See CDWR Power Purchases discussion.

Electric utility revenue increased in 2000 (as shown in the table below), primarily due to: warmer weather in the second and third quarters of 2000 as compared to the same periods in 1999; increased resale sales; and an increase in revenue related to penalties customers incurred for not complying with their interruptible contracts.

The changes in electric utility revenue resulted from:

In millions Year ended December 31,	2001	2000	1999
Electric utility revenue —			
Rate changes (including refunds)	$ 422	$ 120	$ (75)
Direct access credit	566	(434)	(213)
Interruptible noncompliance penalty	(117)	102	6
Sales volume changes	(544)	520	195
Other (including intercompany transactions)	(77)	14	136
Total	$ 250	$ 322	$ 49

More than 94% of electric utility revenue was from retail sales. Retail rates are regulated by the CPUC and wholesale rates are regulated by the Federal Energy Regulatory Commission (FERC).

Due to warmer weather during the summer months, electric utility revenue during the third quarter of each year is significantly higher than other quarters.

Nonutility power generation revenue increased in both 2001 and 2000. The 2001 increase was primarily due to increases at EME related to consolidation of Contact Energy effective June 1, 2001, as a result of increasing ownership to majority control (51%) (see discussion in Acquisitions and Dispositions section), higher energy prices from generation sold by its Homer City plant, higher income from its investment in cogeneration projects and increased income from its oil and gas activities. The oil and gas activities increase resulted primarily from realized and unrealized gains for a gas swap purchased to hedge a portion of EME's gas price risk related to its oil and gas investments. These increases were partially offset by a decrease at EME's First Hydro plant due to lower energy and capacity prices in the U.K. and a reduction in trading activities in 2001 due to volatility of power prices in the west coast trading markets and reduced trading activity in 2001. The 2000 increase was mainly due to revenue increases related to EME's Illinois, Homer City and Doga plants. It is not certain that market conditions or risks related to EME's business will change to allow EME to conduct trading and price risk management activities in a manner favorable to EME.

Due to warmer weather during the summer months, EME's nonutility power generation revenue related to its Homer City plant and the Illinois plants is usually higher during the third quarter of each year. Higher summer pricing for EME's energy projects located on the western coast of the United States generally causes materially higher third quarter nonutility power generation revenue than other quarters of the year. EME's First Hydro plant is expected to contribute more to nonutility power generation revenue during the winter months. Electric power at the Illinois Plants is sold under agreements with Exelon Generation Company (ExGen). EME's revenue related to these agreements was $1.1 billion in both 2001 and 2000, representing 36% and 42%, respectively, of nonutility power generation revenue. See additional discussion related to these agreements in the EME Issues section of Market Risk Exposures.

Financial services and other revenue increased in 2001 and decreased in 2000. The increase in 2001 was primarily due to a subsidiary's sale of nonutility real estate and another subsidiary providing operation and maintenance services, primarily to power generators. Beginning in January 2001, a nonutility subsidiary began providing operation and maintenance services to independent power companies, some of which now own the generation stations SCE sold in 1998. From 1998 through December 2000, SCE provided these services for its previously owned generating stations. These 2001 increases were partially offset by a decrease in Edison Capital's revenue due to the contractual run-off from leveraged lease transactions. The decrease in 2000 was mainly due to lower revenue at Edison Capital on existing leveraged leases, partially offset by higher revenue from affordable housing syndications.

Operating Expenses

Fuel expense increased for both 2001 and 2000. The increase in 2001 was mainly due to EME's consolidation of Contact Energy due to increasing ownership to majority control (51%) and higher fuel costs at the First Hydro and Doga projects, partially offset by a decrease at EME's Illinois plants. The increase in 2000 was primarily due to increased expenses at EME reflecting a full year of operations at its Illinois plants. At SCE, a fuel-related refund resulting from a settlement with another utility recorded in the second and third quarters of 2000 caused lower fuel expense in 2000.

Purchased-power expense decreased in 2001 and increased in 2000. The 2001 decrease resulted from the absence of California Power Exchange (PX)/ISO purchased-power expense after mid-January 2001, partially offset by increased expenses related to qualifying facilities (QFs), bilateral contracts and interutility contracts. See Purchased Power table in Note 1 to the Consolidated Financial Statements and discussion in CDWR Power Purchases. PX/ISO purchased-power expense increased significantly between May 2000 and mid-January 2001, due to a number of factors, including increased demand for electricity in California, dramatic price increases for natural gas (a key input of electricity production), and problems in the structure and conduct of the PX and ISO markets. In December 2000, the FERC eliminated the requirement that SCE buy and sell all power through the PX and ISO. Due to SCE's noncompliance with the PX's tariff requirement for posting collateral for all transactions in the day-ahead and day-of markets as a result of the downgrade in its credit rating, the PX suspended SCE's market trading privileges effective mid-January 2001.

Prior to April 1998, federal law and CPUC orders required SCE to enter into contracts to purchase power from QFs at CPUC-mandated prices even though energy and capacity prices under many of these contracts are generally higher than other sources. These contracts expire on various dates through 2025. See further discussion regarding new QF agreements in Litigation. Purchased-power expense related to QFs increased due to the short-run avoided cost factor (which is based on the price of natural gas) of the QF contracts causing a significant increase in the payments to QFs. In early 2001, structural problems in the market caused abnormally high gas prices. The increase related to bilateral contracts was the result of SCE not having these contracts in 2000. The increase related to interutility contracts was volume-driven.

SCE has contracts with certain QFs in which EME has 49%-50% interests. The terms and pricing of these contracts are approved by the CPUC. SCE's power purchases from these facilities were $983 million in 2001, $716 million in 2000 and $513 million in 1999.

Provisions for regulatory adjustment clauses decreased for 2001 and increased for 2000. The 2001 decrease resulted from SCE recording the $3.6 billion PROACT regulatory asset in fourth quarter 2001. The increase in 2000 was mainly due to SCE's write-off as of December 31, 2000, of $4.2 billion in regulatory assets and liabilities as a result of the California energy crisis. Adjustments to reflect potential regulatory refunds related to the outcome of the CPUC's reevaluation of the operation of the interruptible rate programs also contributed to the increase in 2000.

Other operation and maintenance expense increased for both 2001 and 2000. The 2001 increase primarily resulted from increased plant operating expenses at EME's Illinois plants as a result of a sale-leaseback transaction, consolidation of Contact Energy due to EME's increased ownership, as well as increased expenses at a nonutility subsidiary related to the sale of real estate. The increase in 2000 primarily reflects a full year of operating expenses at EME's plants acquired in 1999. This increase was partially offset by a $26 million decrease at Edison Capital, associated with the syndication of affordable housing investments in 2000; a $60 million decrease at EME in 2000, related to accrued compensation expense reflecting a lower valuation of the exchange offer for the affiliate stock option plan that was terminated in 1999; and decreases at SCE in 2000, related to lower expenses for mandated transmission service (known as reliability must-run services); and lower operating expenses at San Onofre. Mandated transmission service expense decreased $120 million in 2000 compared to 1999. A $19 million decrease at San Onofre in 2000 was primarily due to scheduled refueling outages at both units in the first half of 1999. San Onofre had only one refueling outage in 2000.

Depreciation, decommissioning and amortization expense decreased in 2001 and increased in 2000. The decrease in 2001 was primarily due to SCE's nuclear investment amortization expense ceasing since the unamortized nuclear investment regulatory asset was included in the December 31, 2000, write-off. The increase in 2000 is mainly due to EME's 1999 acquisitions of the Illinois and Homer City plants.

Net gain on sale of utility plant in 2000 resulted from the sale of additional property related to four of the generating stations SCE sold in 1998. The gains were returned to ratepayers through the TCBA mechanism.

Other Income and Deductions

Interest and dividend income increased in both 2001 and 2000. The increase in 2001 was mainly due to an overall higher cash balance, as SCE conserved cash due to its liquidity crisis, as well as an increase at Mission Energy Holding Company due to interest earned on funds placed into an escrow account from the sale of senior secured notes and a term loan. The increase in 2000 was primarily due to increases in interest earned on higher balancing account undercollections at SCE and an increase at EME related to higher cash balances.

Other nonoperating income decreased in both 2001 and 2000. The decrease in 2001 was primarily due to SCE's gains on sales of marketable securities in 2000. The decrease in 2001 also reflects the gain on sale of marketable securities by Edison International's insurance subsidiary in 2000. These 2001 decreases were partially offset by an increase at EME resulting from gains on sales of interests in energy projects in 2001. The decrease in 2000 was primarily due to larger gains on sales of marketable securities at SCE in 1999, partially offset by the gain on sale of marketable securities by Edison International's insurance subsidiary in 2000.

Interest expense — net of amounts capitalized increased in both 2001 and 2000. The increase in 2001 reflects additional long-term debt at SCE and issuance of new debt at Mission Energy Holding (parent only), and higher short-term debt balances at both SCE and its parent company. See further discussion of Mission Energy Holding's debt issuance in Mission Energy Holding Company's Liquidity Issues. The increase in 2000 reflects additional long-term subsidiary debt at EME to finance its acquisition of the Homer City and Illinois plants. Increased long-term debt at the parent company and at Edison Capital also contributed to the increased expense in 2000. Increased interest expense resulting from higher overall short-term debt balances at both SCE and its parent company, and short-term debt utilized to fund a portion of EME's 1999 acquisitions of the Illinois and Homer City plants also contributed to the increase in 2000. Another contributing factor to the increase in 2000 was interest expense from balancing account overcollections at SCE.

Other nonoperating deductions decreased in both 2001 and 2000. The decrease in 2001 was mainly due to lower accruals at SCE for regulatory matters in 2001, partially offset by EME's minority interest expense arising from consolidation of Contact Energy effective June 1, 2001, as a result of increasing ownership to majority control (51%) and impairment charges by EME in connection with the planned sale of projects and partial termination of a turbine lease. The decrease in 2000 was mainly due to a write-off of start-up costs at EME (in accordance with the implementation of a new accounting rule in first quarter 1999), as well as a decrease at Edison Capital related to syndications of affordable housing projects.

Dividends on preferred securities increased in 2000. The increase in 2000 resulted from the issuance of quarterly income securities by the parent company in July and October 1999.

Income Taxes

Income taxes from continuing operations increased in 2001 and decreased in 2000. The increase in 2001 reflects $1.5 billion in income tax expense related to the $3.6 billion (before tax) PROACT regulatory asset establishment in fourth quarter 2001. Absent the $1.5 billion income tax expense in 2001, Edison International's income taxes increased due to higher pre-tax income. The decrease in 2000 was primarily due to the $1.5 billion income tax benefit related to SCE's write-off as of December 31, 2000, of regulatory assets and liabilities in the amount of $2.5 billion (after tax). Absent SCE's write-off, Edison International's income tax expense increased in 2000, mainly due to higher pre-tax income, as well as income tax benefits EME and SCE recorded in 1999.

Earnings (Loss) from Discontinued Operations

Edison International's discontinued operations incurred losses of $4.19 per share ($1.4 billion after tax) in 2001, 1¢ ($4 million after tax) in 2000, and 17¢ ($58 million after tax) in 1999. EME recorded a loss from discontinued operations of $3.78 in 2001, compared with earnings of 8¢ in 2000 and earnings of 5¢ in 1999. EME's discontinued operations relate to the sale of the Ferrybridge and Fiddler's Ferry coal stations located in the U.K. Edison Enterprises recorded losses from discontinued operations of 41¢ in 2001, compared to 9¢ in 2000 and 22¢ in 1999. Edison Enterprises' discontinued operations relate to the sale of the majority of its assets. See additional discussion in Discontinued Operations.

Financial Condition

Edison International's liquidity is affected primarily by debt maturities, access to capital markets, dividend payments, capital expenditures, asset sales, investments in partnerships and unconsolidated subsidiaries, credit ratings and utility regulation affecting SCE's ability to recover the cost of power purchases. Capital resources include cash from operations, asset sales and external financings.

Beginning in 1995, Edison International's Board of Directors authorized the expenditure of up to $2.8 billion for the repurchase of outstanding shares of common stock. Edison International repurchased more than 21 million shares (approximately $400 million) of its common stock during the first six months of 2000. These were the first repurchases since 1999. Between January 1, 1995, and June 30, 2000, Edison International repurchased $2.8 billion (approximately 122 million shares) of its outstanding shares of common stock funded by dividends from its subsidiaries (primarily from SCE).

SCE's Liquidity Issues

Sustained higher wholesale energy prices that began in May 2000 persisted through June 2001. This resulted in undercollections in the TRA and TCBA. Undercollections, coupled with SCE's anticipated near-term capital requirements (detailed in Projected Commitments) and the adverse reaction of the credit markets to continued regulatory uncertainty regarding SCE's ability to recover its current and future power procurement costs, materially and adversely affected SCE's liquidity throughout 2001. As a result of its liquidity concerns, SCE took steps to conserve cash to continue to provide service to its customers. As a part of this process, beginning in January 2001, SCE suspended payments owed to the ISO, the PX and QFs, deferred payments of certain obligations for principal and interest on outstanding debt and did not declare dividends on any of its cumulative preferred stock. As applicable, unpaid obligations continued to accrue interest. As of March 31, 2001, SCE resumed payment of interest on its debt obligations. However, since June 30, 2001, SCE deferred the interest payments on its quarterly income debt securities (subordinated debentures), as allowed by the terms of the securities. All interest in arrears must be paid at the end of the deferral period. As long as accumulated dividends on SCE's preferred stock remain unpaid, SCE could not pay dividends on its common stock. Common stock dividends are additionally restricted as detailed in the CPUC Litigation Settlement discussion.

Based on the rights to cost recovery and revenue established by the settlement agreement with the CPUC and CPUC implementing orders, including the PROACT resolution, SCE repaid its undisputed past-due obligations on March 1, 2002, with lump-sum payments to creditors from the proceeds of $1.6 billion in senior secured credit facilities, the remarketing of $196 million in pollution-control bonds which were repurchased in late 2000, and existing cash on hand. The $1.6 billion senior secured credit facilities consist of a $300 million, two-year revolving credit loan, a $600 million, one-year loan and a $700 million, three-year loan.

The proceeds from the senior secured credit facilities and pollution-control bond remarketing were used along with SCE's available cash to repay $3.2 billion in past-due obligations and $1.65 billion in near-term debt maturities. The past-due obligations consisted of: (1) $875 million to the PX; (2) $99 million to the ISO; (3) $1.1 billion to QFs; (4) $193 million in PX energy credits for energy service providers; (5) $531 million of matured commercial paper; (6) $400 million of principal on its 5⅞% and 6½% senior unsecured notes which were issued prior to the energy crisis; and (7) $23 million in preferred dividends in arrears. The near-term debt maturities consisted of credit facilities whose maturity dates were extended several times and were scheduled to mature in March and May 2002. In addition, SCE entered into an agreement with the CDWR to pay for prior deliveries of energy in installments of $100 million on April 1, 2002, $150 million on June 3, 2002, and the balance on July 1, 2002. After making the above-described payments, SCE has no material undisputed obligations that are past due or in default.

SCE expects to meet its continuing obligations from remaining cash on hand and future operating cash flows.

For additional discussion on the impact of California's energy crisis on SCE's liquidity, see Cash Flows from Financing Activities. For a discussion on the settlement agreement with the CPUC and the PROACT resolution to resolve SCE's crisis, see CPUC Litigation Settlement Agreement and PROACT Regulatory Asset sections.

EME's Liquidity Issues

At December 31, 2001, EME had a $750 million corporate credit facility. The credit facility included a one-year, $538 million component that expires on September 17, 2002, and a three-year, $212 million component that expires on September 17, 2004. As of December 31, 2001, EME had borrowed or issued letters of credit aggregating $196 million under the new facility and had an unused capacity of approximately $554 million. EME plans to utilize its corporate credit facilities to fund corporate expenses, including interest, during 2002 depending on the timing and amount of distributions from its subsidiaries. EME expects 2002 cash flow will include approximately $206 million in distributions from its investments in partnerships that received payment of past-due accounts receivable from SCE in March 2002. In 2002, EME expects to receive tax sharing payments equal to its outstanding receivable from Edison International ($224 million). In addition, EME plans to extend the one-year component under its corporate facility or enter into a similar facility with other financial institutions by September 2002.

EME's certificate of incorporation and bylaws include provisions requiring 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 for payments of dividends are: EME has 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 1.0 for the immediately preceding four quarters.

EME's corporate facilities include financial covenants relating to minimum net worth, recourse debt as a percent of capital, and cash flow to interest expense. At December 31, 2001, EME met the above financial covenants. EME has $2.1 billion in recourse debt, and an additional $4 billion of debt that is non-recourse to EME, but is recourse to EME's subsidiaries. Recourse debt is 64% of recourse capital (a ratio of 67.5% or less is required). The actual interest coverage ratio of 1.64 to 1.0 during 2001 (a ratio of at least 1.5 to 1.0 is required) was adversely affected by the operating results of the Ferrybridge and Fiddler's Ferry projects in the U.K. The interest coverage ratio, excluding the activities of Ferrybridge and Fiddler's Ferry, was 1.98 to 1.0. Compliance with these covenants is subject to future financial performance of EME, including items that are beyond EME's control. See EME Issues section of Market Risk Exposures.

To isolate EME from the severe credit downgrades suffered by SCE, Edison Capital and the parent company, and to help preserve the value of EME, EME has adopted certain amendments to its articles of incorporation and bylaws. Recently, certain rating agencies have indicated they are reviewing the criteria for assessing credit risk for merchant energy companies. Although EME cannot predict whether this criteria will have an adverse impact on its credit ratings, a downgrade of EME's credit ratings below investment grade would require EME to, among other things, provide additional collateral in the form of letters of credit or cash for the benefit of the counterparties to EME's trading activities, and to support its $45 million equity contribution obligation in CBK and could limit the ability of the Illinois plants to use excess cash flow to make distributions. In addition, a below investment grade credit rating could increase EME's cost of capital, increase its credit support obligations, affect the ability to raise additional capital, adversely affect its trading operations, have an adverse impact on its subsidiaries, and affect its ability to pay dividends to Mission Energy Holding which if extended beyond July 1, 2003, would adversely affect Mission Energy Holding's ability to meet its debt obligations.

In connection with the original acquisition of the Ferrybridge and Fiddler's Ferry coal-fired electric generating plants, an EME subsidiary entered into a coal and capital expenditures credit facility. Under this credit facility, at December 31, 2001, £68 million (approximately $99 million) was outstanding for coal purchases and £105 million (approximately $153 million) was outstanding to fund capital expenditures. EME has guaranteed the obligations of its subsidiary under this agreement, including any letters of credit issued to Edison First Power, a subsidiary of EME, under this facility, including any letters of credit issued to the project. Following the completion of the sale of the power plants, the facility agreement was cancelled, but EME still owed £173 million (approximately $252 million) as of December 31, 2001. Obligations under this facility are due in 2004. EME plans to repay this credit facility from settlement of the remaining assets and liabilities of its discontinued operations (estimated at £55 million, or approximately $80 million, at December 31, 2001) and cash flows generated from its foreign subsidiaries prior to the facility's maturity in 2004. After December 31, 2001, EME made total payments of £35 million from a partial settlement of assets and liabilities of discontinued operations reducing its obligation to £138 million (approximately $194 million) at February 28, 2002.

The ability of EME's subsidiary to make interest payments on the bond financing of First Hydro is dependent on revenue generated by the First Hydro plant, which depends on market conditions for the sale of energy and ancillary services. These market conditions are beyond EME's control. The financial covenants included in the First Hydro bonds require EME's subsidiary to maintain a minimum interest coverage ratio of 1.05 to 1.0 for each trailing twelve-month period as of June 30 and December 31 of each year. EME's subsidiary was in compliance with this ratio for the twelve months ended December 31, 2001. Compliance with this ratio depends on market conditions for the sale of energy and ancillary services. EME's subsidiary may be unable to meet this ratio at June 30, 2002, if market conditions continue to be unfavorable.

Edison Capital's Liquidity Issues

As of December 31, 2001, Edison Capital had fully drawn on its $150 million bank facility, which matures on June 30, 2002. Edison Capital historically received cash from Edison International for the federal and state tax benefits and incentives flowing from Edison Capital's investments that are actually utilized on the Edison International consolidated tax return. However, Edison International is not currently fully utilizing these tax benefits and incentives and Edison Capital is not currently receiving full cash benefits for them. Without such cash, Edison Capital must meet its current obligations out of existing unrestricted cash ($73 million at February 28, 2002) and/or by liquidating some of its investments. Any failure by Edison Capital to meet its obligations as they become due could be expected to have a material adverse effect on Edison Capital's financial position and ability to conduct future operations. Under the current circumstances, Edison Capital is not pursuing any new investment opportunities.

Mission Energy Holding Company's Liquidity Issues

On July 2, 2001, Mission Energy Holding Company, a wholly owned indirect subsidiary of the parent company, issued $800 million of 13.50% senior secured notes due 2008 and borrowed $385 million under a senior secured term loan due 2006. Both the senior secured notes and the term loan are non-recourse to the parent company and EME, and are secured by the common stock of EME and interest reserve accounts covering the interest payable on those obligations for the first two years. Proceeds of the notes and term loan were used by the parent company to repay the entire outstanding principal amount of $618 million of its existing bank credit facility, plus interest of approximately $6 million, as well as a portion of the $250 million of senior unsecured notes maturing July 18, 2001. The credit facility was originally due on May 14, 2001, but the bank lenders had agreed to extend the maturity date to June 30, 2001, and to forbear exercising remedies under the credit facility due to cross-defaults by SCE. The bank credit facility has not been renewed.

The ability of Mission Energy Holding to pay its obligations after the two-year interest reserve period, expiring on July 1, 2003, is substantially dependent upon the receipt of dividends from EME and tax sharing payments from the parent company. Dividends from EME may be limited based on earnings and cash flow, business and tax considerations, terms of restrictions contained in contractual obligations, charter documents, and restrictions imposed by law (as further discussed in EME's Liquidity Issues). If Mission Energy Holding were to default on its debt obligations, it could lead to foreclosure on its ownership interest in the capital stock of EME.

Mission Energy Holding's certificate of incorporation includes provisions that require the unanimous approval of Mission Energy Holding's Board of Directors, including at least one independent director, before Mission Energy Holding can take certain actions. Such actions include: consolidate or merge with or into any other entity; transfer all or substantially all of its assets and properties to any other entity; institute or consent to bankruptcy, insolvency or similar proceedings or actions; declare or pay dividends or distributions other than dividends permitted under the terms of the indenture for its senior secured notes; or liquidate or otherwise shut down.

Edison International's Liquidity Issues

The parent company's liquidity and its ability to pay dividends is dependent upon dividends from subsidiaries and various cash flows related to income taxes. As discussed in SCE's Regulatory Environment, SCE may not pay dividends on its common stock until the PROACT balance is fully recovered. Currently, Mission Energy Holding has no restrictions on paying dividends to the parent company, but is not doing so. After July 1, 2003, Mission Energy Holding may not pay dividends to the parent company unless it has an interest coverage ratio of 2.0 to 1.0. Mission Energy Holding's ability to pay dividends is dependent on EME's ability to pay dividends to Mission Energy Holding. EME has certain dividend restrictions as discussed above. At December 31, 2001, the parent company had $31 million of cash on hand. Parent company cash obligations for 2002 are primarily for $52 million of interest on its $750 million notes due 2004, a $250 million note to SCE due December 24, 2002, and operating expenses of approximately $25 million. Edison International does not expect to pay dividends to common shareholders at least until SCE recovers the PROACT balance.

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 that 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 will continue 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.

The parent company expects to continue to pay all other obligations, as they are due.

Cash Flows from Operating Activities

Net cash provided (used) by operating activities:

In millions	Year ended December 31,	2001	2000	1999
Continuing operations		$3,121	$1,385	$2,236
Discontinued operations		(147)	19	(199)
		$2,974	$1,404	$2,037

The increase in cash provided by continuing operations in 2001 was primarily due to SCE suspending payments for purchased power and other obligations beginning in January 2001. Cash provided by continuing operations also reflects the CPUC-approved surcharges (1¢ per kWh in January and 3¢ per kWh) that SCE billed in 2001, offset by lower operating cash flow from EME from timing of cash receipts and payables related to working capital items. The decrease in cash provided by continuing operations in 2000 was mainly due to the extremely high prices SCE paid for energy and ancillary services procured through the PX and ISO.

Cash used by operating activities from discontinued operations in 2001 reflects operating losses from the Ferrybridge and Fiddler's Ferry power plants in 2001 as compared to operating income in 2000, and the timing of cash payments related to working capital items. Cash provided by operating activities from discontinued operations in 2000 compared to cash used by operating activities from discontinued operations in 1999 resulted from lower operating losses at Edison Enterprises in 2000.

Cash Flows from Financing Activities

Net cash provided (used) by financing activities:

In millions	Year ended December 31,	2001	2000	1999
Continuing operations		$ (379)	$535	$6,680
Discontinued operations		(1,178)	223	1,241
		$(1,557)	$758	$7,921

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. These uses of cash were partially offset by the issuance of long-term debt at EME of $1 billion and at Mission Energy Holding of $1.2 billion (see additional discussion in Mission Energy Holding's Liquidity Issues). Cash provided by financing activities from continuing operations in 2000 consisted of additional long-term debt issuances at the parent company, SCE and EME, partially offset by the repayment of long-term debt at both SCE and EME and the repurchase of pollution-control bonds at SCE (see additional discussion below). Cash provided by financing activities from continuing operations in 1999 consisted of additional long-term and short-term debt issuances for EME acquisitions, as well as the additional issuance of preferred securities at EME.

Cash used by financing activities from discontinued operations in 2001 related to the early repayment of the term loan facility in connection with the sale of the Ferrybridge and Fiddler's Ferry power plants on December 21, 2001. Cash provided by financing activities from discontinued operations in 1999 resulted from the financing related to the acquisition of the Ferrybridge and Fiddler's Ferry power plants.

At December 31, 2001, Edison International's subsidiaries had $556 million of borrowing capacity available under lines of credit totaling $2.6 billion. SCE and Edison Capital have drawn on their entire lines of credit. EME had total lines of credit of $750 million, with $554 million available to finance general cash requirements. These unsecured lines of credit have various expiration dates and, when available, could be drawn down at negotiated or bank index rates. Edison Capital has successfully negotiated a 365-day extension to its credit facility for $150 million, which is now due on June 30, 2002. On March 1, 2002, SCE's credit lines ($1.65 billion) were repaid using proceeds from the March 1, 2002, financing. See additional discussion in SCE's Liquidity Issues.

The parent company's short-term and long-term debt is used for general corporate purposes, including investments in nonutility business activities. EME uses its short-term and long-term debt to finance acquisitions and development, as well as for general corporate purposes. Edison Capital's short-term and long-term debt is used for general corporate purposes, as well as investments. SCE's short-term debt is used to finance balancing account undercollections, fuel inventories and general cash requirements, including purchased-power payments. Long-term debt is used mainly to finance capital expenditures. External financings are influenced by market conditions and other factors. Because of the $2.5 billion charge to earnings as of December 31, 2000, SCE does not currently meet the interest coverage ratio that is required for SCE to issue additional preferred stock.

As a result of investors' concerns regarding the California energy crisis and its impact on SCE's liquidity and overall financial condition, during December 2000 and early 2001 SCE had to repurchase $550 million of pollution-control bonds that could not be remarketed in accordance with their terms. SCE remarketed $196 million of these bonds in March 2002 (see additional discussion in SCE's Liquidity Issues). The remaining amount of these bonds may be remarketed in the future. In addition, SCE and Edison Capital remain unable to sell their commercial paper and other short-term financial instruments..

Although Fitch IBCA, Standard & Poor's and Moody's Investors Service raised their credit ratings significantly for both Edison International and SCE in March 2002, the new ratings are still below investment grade. The new ratings reflect the ongoing financial recovery of SCE that began in October

2001 with SCE's settlement agreement with the CPUC and has continued with the CPUC's January 2002 PROACT resolution and the repayment of SCE's past due obligations. Edison International and SCE lost their investment-grade ratings in January 2001.

California law prohibits SCE from incurring or guaranteeing debt for its nonutility affiliates. Additionally, the CPUC regulates SCE's capital structure, thereby limiting the dividends it may pay Edison International.

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 non-bypassable rates charged to residential and small commercial customers. The rate reduction notes are being repaid over 10 years through these non-bypassable 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 beginning in 2002 and ending in 2007, with interest rates ranging from 6.22% to 6.42%. The notes are secured by the transition property and are not secured 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. Due to its credit rating downgrade in late 2000, in January 2001, SCE began remitting its customer collections related to the rate-reduction notes on a daily basis.

EME has entered into a support agreement that commits it to contribute up to $300 million in equity to its trading operation unit. EME has firm commitments related to the Italian wind projects for asset purchases of $6 million, as well as $139 million related to the CBK and Sunrise projects. EME also has contingent obligations to make additional contributions of $45 million, primarily for equity support guarantees related to the ISAB project in Italy and the Paiton project in Indonesia. EME has capital commitments of $77 million for environmental improvements at certain projects and an obligation to build 500 MW of electric generating units in Illinois. The majority of the commitments discussed above are for the 2002-2003 period.

In June 2000, EME entered into a long-term transportation contract with Kern River Gas Transmission Company related to the expansion of the Midway-Sunset project, a 225-MW power plant in California, in which its wholly owned subsidiary owns a 50% interest. Under the terms of the contract, EME has contractual commitments of $116 million to transport natural gas beginning the later of May 1, 2003, or the first day that expansion capacity is available for transportation services. EME is committed to pay minimum fees under this agreement, which has a term of 15 years.

As a result of the California power crisis, SCE and Pacific Gas & Electric (PG&E) failed to make certain payments during the fourth quarter of 2000 and the first quarter of 2001 to QFs owned by partnerships in which EME has an interest. On April 6, 2001, PG&E filed for Chapter 11 bankruptcy protection. PG&E has paid these partnerships for power delivered after the bankruptcy filing. At the bankruptcy filing date, EME's share of the outstanding accounts receivable from these partnerships was $23 million. Effective July 31, 2001, the partnerships entered into amended power purchase agreements that were approved by both the bankruptcy court and the CPUC. PG&E is making payments for current deliveries of power and past-due receivables on an agreed schedule, which absent further defaults, should bring past-due amounts current during the first quarter of 2003. At December 31, 2001, EME's share of accounts receivable due from SCE for these partnerships was $217 million. SCE paid these past-due receivables on March 1, 2002.

Edison Capital has firm commitments of $57 million to fund affordable housing, and energy and infrastructure investments through 2003. At December 31, 2001, as a result of Edison Capital's financial condition, it had deposited approximately $7 million as collateral for several letters of credit currently outstanding.

Cash Flows from Investing Activities

Net cash provided (used) by investing activities:

In millions	Year ended December 31,	2001	2000	1999
Continuing operations		$ (424)	$(576)	$ (8,333)
Discontinued operations		1,125	(89)	(1,698)
		$ 701	$(665)	$(10,031)

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

Cash provided (used) by the nonutility subsidiaries' investing activities of continuing operations was $(522) million in 2001, $483 million in 2000 and $(7.3) billion in 1999.

Cash flows from investing activities of 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. In 2001, EME also acquired 50% interest in the CBK project and purchased additional shares in Contact Energy (see additional discussion in Acquisitions and Dispositions). In 2000, cash flows from investing activities included proceeds from EME's sale-leaseback transactions with third parties and EME's purchase of notes issued by one of the third-party lessors. In 1999, cash flows from investing activities included EME's 1999 acquisitions of the Homer City plant and the Illinois plants, as well as the purchase of a 40% ownership interest in Contact Energy.

In 2001, cash provided by investing activities from discontinued operations was primarily due to the net proceeds of £643 million (approximately $945 million) received from the sale of the Ferrybridge and Fiddler's Ferry power plants on December 21, 2001. In 1999, cash used by investing activities from discontinued operations was primarily due to the purchase of the Ferrybridge and Fiddler's Ferry power plants.

Decommissioning costs are recovered in utility rates. These costs are expected to be funded from independent decommissioning trusts that receive SCE contributions of approximately $25 million per year. In 1995, the CPUC determined the restrictions related to the investments of these trusts. They are: not more than 50% of the fair market value of the qualified trusts may be invested in equity securities; not more than 20% of the fair market value of the trusts may be invested in international equity securities; up to 100% of the fair market values of the trusts may be invested in investment grade fixed-income securities including, but not limited to, government, agency, municipal, corporate, mortgage-backed, asset-backed, non-dollar, and cash equivalent securities; and derivatives of all descriptions are prohibited. 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.

Projected Commitments

Edison International's projected construction expenditures for 2002 are $947 million.

Long-term debt maturities and sinking fund requirements for the next five years are: 2002 — $1.5 billion; 2003 — $2.4 billion; 2004 — $2.5 billion; 2005 — $607 million; and 2006 — $882 million.

Fuel supply contract payments for the next five years are: 2002 — $810 million; 2003 — $575 million; 2004 — $552 million; 2005 — $536 million; and 2006 — $523 million.

Purchased-power capacity payments for the next five years are: 2002 — $629 million; 2003 — $629 million; 2004 — $626 million; 2005 — $624 million; and 2006 — $572 million.

Estimated noncancelable lease payments for the next five years are: 2002 — $388 million; 2003 — $386 million; 2004 — $373 million; 2005 — $427 million; and 2006 — $518 million.

Preferred securities redemption requirements for the next five years are: 2002 — $105 million; 2003 — $9 million; 2004 — $9 million; 2005 — $9 million; and 2006 — $113 million.

Market Risk Exposures

Edison International's primary market risk exposures include commodity price risk, interest rate risk and foreign currency exchange risk that could adversely affect results of operations or financial position. Commodity price risk arises from fluctuations in the market price of an energy commodity, such as electricity, natural gas, oil or coal. Interest rate risk arises from fluctuations in interest rates and foreign currency exchange risk arises from fluctuations in exchange rates. Edison International's risk management policy allows the use of derivative financial instruments to manage its financial exposures, but prohibits the use of these instruments for speculative or trading purposes, except at EME's trading operations unit.

SCE Issues

Changes in interest rates and in energy prices can have a significant impact on SCE's results of operations. Additionally, natural gas is a key input for the prices specified in approximately half of SCE's QF (including non-gas QF) contracts. Virtually all of SCE's exposure to changes in the spot market price for natural gas through 2003 is hedged through financial derivatives or fixed-price contracts.

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. As the result of California's energy crisis, SCE has been exposed to significantly higher interest rates, which intensified its liquidity crisis during 2001 (further discussed in SCE's Liquidity Issues).

At December 31, 2001, SCE did not believe that its short-term debt was subject to interest rate risk, due to the fair market value being approximately equal to the carrying value. SCE did believe that the fair market value of its fixed-rate long-term debt was subject to interest rate risk. At December 31, 2001, a 10% increase in market interest rates would have resulted in a $128 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 $141 million increase in the fair market value of SCE's long-term debt.

Since April 1998, the price SCE paid to acquire power on behalf of customers was allowed to float, in accordance with the 1996 electric utility restructuring law. Until May 2000, retail rates were sufficient to cover the cost of power and other SCE costs. However, between May 2000 and June 2001, market power prices escalated, creating a substantial gap between costs and retail rates. In response to the dramatically higher prices, the ISO and the FERC have placed certain caps on the price of power (see further discussion in Wholesale Electricity Markets).

Under the terms of the CPUC settlement agreement, SCE purchased $209 million in hedging instruments (gas call options) in October and November 2001 to hedge a majority of SCE's natural gas price exposure associated with QF contracts for 2002 and 2003. Although these gas call options are reflected in the income statement, any fair value changes of SCE's gas call options are offset through a regulatory balancing account; therefore, fair value changes do not affect earnings. At December 31, 2001, a 10% increase in market gas prices would have resulted in a $32 million increase in the fair market value of SCE's gas call options. A 10% decrease in market gas prices would have resulted in a $27 million decrease in the fair market value of the gas call options.

In accordance with an accounting standard for derivatives, on January 1, 2001, SCE recorded its block-forward contracts at fair value on the balance sheet. Because SCE suspended payments for purchased power on January 16, 2001, the PX sought to liquidate SCE's remaining block-forward contracts. Before the PX could do so, on February 2, 2001, the state seized the contracts. On September 20, 2001, a federal appeals court ruled that the governor of California acted illegally when he seized the power contracts held by SCE. In conjunction with its settlement agreement with the CPUC (discussed in CPUC Litigation Settlement Agreement), SCE has agreed to release any claim for compensation against the state for these contracts. However, if the PX prevails in its claims against the state, SCE may receive some refunds. Due to its speculative grade credit ratings, SCE has been unable to purchase additional bilateral forward contracts, and some of the existing contracts were terminated by the counterparties.

EME Issues

Fluctuations in interest rates, electricity and fuel prices and foreign currency exchange rates can have a significant impact on EME's results of operations.

Changes in interest rates affect the cost of capital needed to finance the construction and operation of EME's projects. EME does not believe that its short-term debt is subject to interest rate risk, due to the fair market value being approximately equal to the carrying value. However, EME's long-term debt with fixed interest rates is subject to interest rate risk. At December 31, 2001, a 10% increase in market interest rates would have resulted in an approximately $150 million decrease in the fair value of EME's long-term debt. A 10% decrease in market interest rates would have resulted in an approximately $156 million increase in the fair value of EME's long-term debt.

EME has mitigated a portion of the risk of interest rate fluctuations by arranging for fixed rate or variable rate financing with interest rate swaps, interest rate options or other hedging mechanisms for a number of its project financings. Several of EME's interest rate swap agreements mature prior to their underlying debt. At December 31, 2001, a 10% fluctuation in market interest rates would have changed the fair value of EME's interest rate hedge agreements by $11 million.

EME hedges a portion of the electric output of its merchant plants in order to lock in desirable outcomes. EME also manages the margin between electricity prices and fuel prices when deemed appropriate. EME uses forwards, swaps, futures and option contracts to achieve these objectives.

Electric power generated at the Homer City plant is sold under bilateral arrangements with domestic utilities and power marketers under short-term contracts (two years or less) or to the Pennsylvania-New Jersey-Maryland Power Pool (PJM) or the New York Independent System Operator (NYISO). These pools have short-term markets, which establish an hourly clearing price. The Homer City plant is located in the PJM control area and is physically connected to high-voltage transmission lines serving both the PJM and NYISO markets. The Homer City plant can also transmit power to the mid-western United States.

Electric power generated at the Illinois plants is sold under three power purchase agreements with ExGen. The agreements, which began in December 1999, and have a term of up to five years, provide for capacity and energy payments. ExGen will be obligated to make a capacity payment for the units under contract and an energy payment for the electricity produced by these units and taken by ExGen. The capacity payments provide the Illinois plants revenue for fixed charges, and the energy payments compensate the Illinois plants for variable costs of production. Virtually all of the energy and capacity sales in 2001 from the Illinois plants were made to ExGen under the power purchase agreements, and a significant portion is likely to be sold to ExGen during 2002. In each of 2003 and 2004, ExGen is committed to purchase 1,696 MW of capacity from specific coal units, but has the option to terminate all or any remaining coal units and all of the natural gas and oil-fired units with prior notice as specified under each agreement. The energy and capacity from any units, which do not remain subject to one of the power purchase agreements with ExGen will be sold under terms, including price and quantity, to be negotiated with customers or into the so-called spot market. Thus, to the extent that ExGen does not purchase EME's power for 2003 or 2004, EME will be subject to the market risks related to the price of energy and capacity described above. Market prices for energy and capacity are currently below the prices set forth in the power purchase agreements with ExGen. Due to the volatility of market prices for energy and capacity during the past several years, EME cannot predict whether or not ExGen will elect to terminate any of the units currently subject to the power purchase agreements for which termination is permitted and, if they do, whether sales of energy and capacity to other customers and the market will be at prices sufficient to generate cash flow necessary to meet the obligations of EME's subsidiary. As of December 31, 2001, EME had not entered into forward energy sales contracts for the Illinois plants other than those with ExGen.

EME's trading and price risk management activities give rise to market risk, which represents the 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 the risk management policies of EME, which limit its total net exposure. 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.

At December 31, 2001, a 10% fluctuation in natural gas and electricity forward prices would have changed the fair market value of energy contracts utilized by EME's domestic trading unit in energy trading and price risk management activities by $11 million.

Since 1989, EME's projects in the U.K. sold their electric energy and capacity through a centralized electricity pool, which establishes a half-hourly clearing price, or pool price, for electric energy. On March 27, 2001, this system was replaced with a bilateral physical trading system, referred to as the new electricity trading arrangements. In connection with the new electricity trading arrangements, the First Hydro plant entered into forward contracts with varying terms that expire on various dates through October 2003. In addition, two long-term contracts with a three-year termination provision entered into in March 1999 by the First Hydro plant to buy and sell electricity were amended as forward contracts.

The new electricity trading arrangements provide for, among other things, the establishment of a range of voluntary short-term power exchanges and brokered markets operating from a year or more in advance to 3½ hours before a trading period of ½ hour; a balancing mechanism to enable the system operator to balance generation and demand and resolve any transmission constraints; 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. Physical bilateral contracts have replaced the prior financial contracts for differences, but have a similar commercial function. However, it remains difficult to evaluate the future impact of the new electricity trading arrangements. A key feature of the new arrangements is to require firm physical delivery; violators pay for any energy imbalance at highly volatile imbalance prices calculated by the market operator. A consequence of this should be to increase greatly the motivation of parties to contract in advance and develop forwards and futures markets of greater liquidity than at present. In addition, another consequence of the market change is that counterparties may start requiring additional credit support, including parent company guarantees or letters of credit.

The legislation introducing the new trading arrangements sets a principal objective for the Gas and Electric Market Authority to "protect the interests of consumers...where appropriate by promoting competition..." This objective represents a shift in emphasis toward consumer interest. However, this is qualified by the recognition that license holders should be able to finance their activities. The Utilities Act of 2000 also contains new powers for the Secretary of State to issue guidance to the Gas and Electric Market Authority on social and environmental matters, changes to the procedures for modifying licenses, and a new power for the Gas and Electric Market Authority to impose financial penalties on companies for breach of license conditions. EME is monitoring the operation of these new provisions.

During 2001, EME's operating income from the First Hydro plant decreased $106 million from the prior year primarily due to lower energy and capacity prices resulting from the new electricity trading arrangements. In addition, First Hydro's operating results have been adversely affected by lower volatility of energy prices during daytime periods when First Hydro is particularly well positioned to provide power.

The Loy Yang B project in Australia sells its electric 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 operator and administrator of the pool determine a system marginal price each half-hour. To mitigate the exposure to price volatility of the electricity traded in the pool, Loy Yang B has entered into a number of financial hedges. The state hedge with the State Electricity Commission of Victoria is a long-term contractual arrangement based upon a fixed price commencing May 1997 and terminating in October 2016. The state government guarantees the State Electricity Commission of Victoria's obligations under the state hedge. From January 2001 to July 2014, approximately 77% of the plant output sold is hedged under the state hedge. From August 2014 to October 2016, approximately 56% of the plant output sold will be hedged under the state hedge. Additionally, the Loy Yang B plant has entered into a number of derivative contracts to further mitigate against price volatility inherent in the electricity pool. These contracts consist of fixed forward electricity contracts that expire on various dates through December 31, 2004, and a five-year cap contract expiring December 31, 2006.

A substantial portion of Contact Energy's generation output is hedged by sales to retail electricity customers and forward contracts with other wholesale electricity counterparties. Contact Energy has entered into forward contracts and option contracts of varying terms that expire on various dates through September 30, 2002, and January 31, 2004, respectively. The New Zealand government commissioned an inquiry into the electricity industry in February 2000. Following the inquiry report the New Zealand government released a policy statement, which called for the industry to rationalize the three existing industry codes, form a single governance structure and address transmission pricing methodology. An essential theme throughout the policy statement was the desire that the industry retain a private multilateral self-governing structure. During 2001, an amendment to the Electricity Act of 1992 described the form that regulation would take if the industry does not heed the government's call. Progress on the single governance code is well underway. The new code is likely to be introduced in July 2002.

At December 31, 2001, a 10% increase in pool prices would have resulted in a $91 million decrease in the fair value of electricity rate swap agreements in Australia. A 10% decrease in pool prices would have resulted in a $91 million increase in the fair value of electricity rate swap agreements in Australia.

At December 31, 2001, a 10% fluctuation in electricity prices would have changed the fair value of forward contracts by $500,000.

At December 31, 2001, a 10% increase in electricity prices would have resulted in a $500,000 decrease in the fair market value of EME's option contracts. A 10% decrease in electricity prices would have resulted in a $300,000 increase in the fair market value of option contracts.

Fluctuations in foreign currency exchange rates can affect 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 U.S. dollars or other indices reasonably expected to correlate with foreign exchange movements. Statistical forecasting techniques are used to help assess foreign exchange risk and the probabilities of various outcomes. There can be no assurance, however, that fluctuations in exchange rates will be fully offset by hedges or that currency movements and the relationship between economic variables will behave in a manner that is consistent with historical or forecasted relationships.

Foreign currencies in Australia, New Zealand, and the U.K. decreased in value compared to the U.S. dollar by 8%, 6% and 3%, respectively (determined by the change in the exchange rates from December 31, 2000, to December 31, 2001). The decrease in value of these currencies was the primary reason for EME's foreign currency translation loss of $51 million during 2001. At December 31, 2001, a 10% change in the exchange rate would have resulted in foreign currency translation gains or losses of $74 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 U.S. dollars with varying maturities through September 2002. At December 31, 2001, the outstanding notional amount of the contracts totaled $17 million and the fair value of the contracts totaled $(158,000). During the period of June 1, 2001, to December 31, 2001, Contact Energy recognized a foreign exchange gain of $1 million related to the contracts that matured during the same period. At December 31, 2001, a 10% fluctuation in exchange rates would change the fair value of the contracts by approximately $2 million.

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-rate U.S. and Australian dollar loans into floating-rate New Zealand dollar loans with varying maturities through April 2018. At December 31, 2001, EME had cross-currency swap contracts in place with an approximate net-hedged value of $28 million.

EME entered into a foreign currency forward exchange contract for a portion of the purchase price related to the potential acquisition of the remaining 49% of Contact Energy for NZ$479 million (approximately $200 million). At December 31, 2001, the fair value of the contract totaled $400,000. Following EME's unsuccessful bid for the remaining shares of Contact Energy (see additional discussion in Acquisitions and Dispositions), EME closed the contract and recognized a foreign exchange gain of $700,000.

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

Edison Capital Issues

Changes in interest rates and fluctuations in foreign currency exchange 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.

At December 31, 2001, Edison Capital did not believe that its short-term debt was subject to interest rate risk, due to the fair market value being approximately equal to the carrying value. Edison Capital did believe that the fair market value of its fixed rate long-term debt was subject to interest rate risk. At December 31, 2001, a 10% increase in market interest rates would have resulted in a $16 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 $15 million increase in the fair market value of Edison Capital's long-term debt.

Edison Capital has entered into interest rate swap agreements to reduce actual or expected exposure to interest rate fluctuations. In 2001, Edison Capital's earnings were reduced by $4 million, reflecting the fair value change of an interest rate swap that does not qualify for hedge accounting. At December 31, 2001, a 10% fluctuation in market interest rates would have changed the fair value of Edison Capital's swap agreements by approximately $3 million.

At December 31, Edison Capital's outstanding debt included £150 million (approximately $212 million) that is subject to foreign currency exchange fluctuations. In March 2002, Edison Capital converted £75 million (approximately $107 million) of this amount to U.S. dollar denominated debt, mitigating the future impact of foreign currency fluctuations.

Mission Energy Holding (parent only) Issues

Changes in interest rates can have an impact on Mission Energy Holding's results of operations. Mission Energy Holding is exposed to changes in interest rates primarily as a result of its borrowing activities.

At December 31, 2001, Mission Energy Holding believed that the fair market value of its fixed rate long-term debt was subject to interest rate risk. At December 31, 2001, a 10% increase in market interest rates would have resulted in a $41 million decrease in the fair market value of Mission Energy Holding's (parent only) long-term debt. A 10% decrease in market interest rates would have resulted in a $44 million increase in the fair market value of Mission Energy Holding's (parent only) long-term debt.

Mission Energy Holding mitigated the risk of interest rate fluctuations associated with its $385 million term loan due 2006 by arranging for variable rate financing with two interest rate swaps. The swaps cover interest accrued from January 2, 2002, to January 2, 2003. At December 31, 2001, a 10% fluctuation in the market interest rates would have changed the fair value of the interest rate swaps by approximately $900,000.

Edison International Issues

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, 2001, the parent company believed that the fair market value of its fixed rate long-term debt was subject to interest rate risk. At December 31, 2001, a 10% increase in market interest rates would have resulted in a $14 million decrease in the fair market value of the parent company's long-term debt. A 10% decrease in market interest rates would have resulted in a $15 million increase in the fair market value of the parent company's long-term debt.

Off-Balance Sheet Transactions

EME

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 as required by accounting standards. Under the equity method, the project assets and related liabilities are not consolidated in Edison International's balance sheet. Rather, Edison International's financial statements reflect the investment in these entities and proportionate ownership share of net income or loss. These investments are of two principal categories: power projects classified as qualifying facilities, in which EME's ownership interest is limited to no more than 50% due to its affiliation with SCE; and on an international basis, energy projects with strategic partners, in which EME's 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 generally obtain 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, 2001, entities that EME has accounted for under the equity method had indebtedness of $6.1 billion, of which $2.6 billion is proportionate to EME's ownership interest in these projects.

EME also owns a minority interest in two oil and gas companies with the majority ownership held by a major oil company.

Sale-Leaseback Transactions

EME has entered into sale-leaseback transactions related to certain power facilities located in Illinois and its 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 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 this purpose. In each of these transactions, the assets or 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 to finance the purchase of the assets. The equity investment by the owner/lessors for these sale-leaseback transactions total $1.2 billion and the lessor debt was $2.8 billion (maturity dates 2004-2026). The fair value of the leased assets was $3.8 billion. In accordance with lease accounting standards, EME accounts for these leases as operating leases in its consolidated financial statements. Due to specific guarantees provided by EME as part of the transactions, EME subsidiaries account for these leases as financings in their separate financial statements, and accordingly record the power plants as assets and the obligations under the leases as financings (i.e., depreciation and interest expense are recorded). The treatment of these leases as an operating lease versus a lease financing on a consolidated basis resulted in an increase in EME's consolidated net income of $55 million in 2001 and $40 million in 2000.

The operating lease payments 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 and are recorded on a levelized basis over the term of the lease. Neither the value of the leased assets nor the lessor debt is reflected in Edison International's consolidated balance sheet. At December 31, 2001, prepaid rent on these leases was $20 million, which represents cash payments in excess of levelized rent expense.

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 leases could result in a loss of EME's ability to use the power plant and could have a material adverse effect on EME's results of operations and financial position.

EME has also entered into a sale-leaseback of equipment with a third party lessor, consisting primarily of Illinois peaker power units for $300 million. Under the terms of this five-year lease, an EME subsidiary operates and sells the output of these units, and has the option to repurchase the units from their current owner/lessor at the end of the lease term for the fixed price of $300 million. Should this option not be exercised, the current owner/lessor can require EME, as their agent, to sell the units and, if sold, they would no longer be available to EME. The lease payments are structured to pay the cost of the lease debt plus a return to the owner/lessor on the equity invested in it. EME has guaranteed the monthly payments by its subsidiary lessee under the lease and agreed to pay the owner/lessor a deficiency payment if EME does not exercise its purchase option and the proceeds from the sale of the equipment on its behalf is less than $300 million; provided, however, in no event can the deficiency payment exceed $255 million. In order to finance its purchase of the equipment from EME, the current owner/lessor obtained an equity investment of $9 million, and an additional $291 million through its issuance of senior notes of $255 million and subordinated notes of $36 million. As part of the transaction, EME purchased $255 million of senior notes from the owner/lessor. Thus, if EME were to exercise its option to repurchase the equipment at the end of the lease term, EME would effectively need $45 million to fund this purchase as a result of holding the senior notes. By entering into the sale-leaseback of this equipment, EME obtained $45 million of additional capital. As a result of the transaction, EME's annual depreciation expense is reduced by approximately $15 million ($9 million after tax) during the term of the lease.

EME's Obligations to Midwest Generation LLC

Proceeds received by Midwest Generation, a wholly owned subsidiary of EME, from the sale of the two Illinois plants in the aggregate amount of approximately $1.4 billion were loaned to EME. EME used the proceeds from these loans to repay corporate indebtedness. Although interest and principal payments made by EME to Midwest Generation under these intercompany loans assist in the payment of the lease rental payments owed by Midwest Generation, the intercompany obligations do not appear in Edison International's consolidated balance sheet. These obligations are included, however, by the credit rating agencies in assessing EME's corporate credit ratings.

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

Master Turbine Lease

In December 2000, EME entered into lease agreements involving the construction of four new projects, utilizing nine turbines. Under the terms of one of the agreements, an independent third party, as owner of the projects, is responsible for development and construction costs using these turbines. Upon completion of construction of each project, EME has agreed to provide a guarantee of each of the project's residual value. EME will lease the projects from the lessor at the end of the lease term. EME is required to deposit treasury notes equal to 103% of the construction costs as collateral for the lessor. The lease agreements provide a purchase option, based on the lease balance, exercisable through the term of the lease, which ends in 2010. These leases were structured to be off-balance sheet in accordance with an accounting interpretation related to leasing transactions, which requires meeting a minimum 3% independent equity at risk requirement.

Due to unfavorable market conditions, EME terminated its obligations on three of the four projects, for which it planned to use six turbines. EME exercised an option to acquire the assets of these projects, (the purchase rights for the related turbines) for a price of approximately $25 million. As a result, EME recorded a loss of $25 million in 2001. In connection with the termination, EME obtained a release of the notes held as collateral for these projects. Also, EME acquired the purchase orders for the six turbines and may continue to make progress payments and take delivery should market conditions improve. No progress payments are due until 2003, however, and EME has the right to terminate these orders prior to the end of 2002 with no additional payment obligations.

In March 2002, EME exercised its right to purchase the remaining three turbines under the lease for $61 million, effectively terminating any remaining obligations under this arrangement. EME plans to use these turbines for a new gas-fired project, and accordingly, EME plans to capitalize the amount paid on the balance sheet. EME's remaining purchase obligations for these turbines are $53 million.

Edison Capital

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 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 the carrying amount of the investment and the proportionate ownership share of net income or loss.

Edison Capital has invested in affordable housing projects under a partnership structure or limited liability company in which Edison Capital is a limited partner or limited liability member. In these entities, Edison Capital usually owns a 99% interest. Edison Capital has subsequently sold a majority of these interests in syndications to unrelated third party investors in which Edison Capital has retained an interest of less than 20%. An unrelated general partner or managing member exercises operating control; voting rights of Edison Capital are limited by agreement to certain high level matters. The debt of those partnerships and limited liability companies is secured by real property and is non-recourse to Edison Capital and its participants, except in limited cases where Edison Capital has guaranteed the debt. At December 31, 2001, Edison Capital had made guarantees to lenders in the amount of $2 million.

Beginning in 1999, Edison Capital invested in four wind partnerships, the largest project being managed and operated by Enron Wind, a subsidiary of Enron Corporation (see further discussion below). As of December 31, 2001, Edison Capital owns 75% ownership interest in three of the projects and owns 99% interest in the fourth project. In each of these projects, once Edison Capital receives its target return specified in each partnership agreement, Edison Capital's percentage interest drops below 50% for that project.

The partnerships formed to own these projects are generally structured with a management committee or board of directors in which Edison Capital exercises significant influence but cannot exercise unilateral control over the operating, funding or construction activities of the project entity. The partnerships have generally obtained long-term debt to finance the assets constructed and/or acquired by them. These financings generally are secured by a pledge of the assets and the equity is subordinated. There is no recourse to Edison Capital beyond the investment made in the projects, except for a debt service reserve guarantee of approximately $8 million. 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 Edison Capital's project investment, but Edison Capital is not required to contribute additional capital.

At December 31, 2001, entities that Edison Capital has accounted for under the equity method had indebtedness of $1.8 billion, of which approximately $630 million is proportionate to Edison Capital's ownership interest in these projects.

Edison Capital has an investment of approximately $85 million in Storm Lake Power, the wind partnership mentioned above that is being operated by Enron Wind, a subsidiary of Enron Corporation. The lenders have sent a notice to Storm Lake claiming that Enron's bankruptcy is an event of default under the loan agreement. The lenders have not indicated what actions, if any, they may take in response to Enron Wind's more recent bankruptcy. In the event of default, the lenders may exercise certain remedies, including acceleration of the loan balance, and/or repossession and foreclosure of the project, which could result in the loss of some or all of Edison Capital's investment in Storm Lake. Edison Capital expects Storm Lake to demonstrate that Enron's bankruptcy does not impair its ability to meet its loan obligations. Edison Capital also expects that Storm Lake will vigorously oppose any attempt by the lenders to exercise remedies that could result in Edison Capital's loss of investment. Edison Capital is unable to predict what effect these proceedings, if any, will have on its investment in this project.

Leveraged Leases

Edison Capital, through subsidiaries and trusts, has entered into lease transactions, as lessor, related to various energy, power, infrastructure and equipment leases. Each of these transactions was completed and accounted for in accordance with an accounting standard applicable when all debt is non-recourse to the lessor. All of the debt under Edison Capital's leveraged leases is non-recourse and is not recorded on Edison International's balance sheet. In the event of default, Edison Capital would not be required to satisfy the lessee's debt.

At December 31, 2001, Edison Capital had investments of $2.4 billion in leveraged lease transactions with third party lessees. Third party debt is $5.0 billion and is non-recourse to Edison Capital.

Paiton Project

A wholly owned subsidiary of EME (Paiton Energy) owns a 40% interest and has a $492 million investment (at December 31, 2001) in the Paiton project, a 1,230-MW coal-fired power plant in Indonesia. Under the terms of a long-term power purchase agreement between Paiton Energy and the state-owned electric utility company, the state-owned electric utility company is required to pay for capacity and fixed operating costs once each unit and the plant achieve commercial operation.

The state-owned electric utility company and Paiton Energy signed a binding term sheet on December 14, 2001, setting forth the commercial terms under which Paiton Energy is to be paid for capacity and energy charges, as well as a monthly settlement payment covering past amounts owed by the state-owned electric utility company as well as settlement of other claims. Paiton Energy and the state-owned electric utility company are continuing negotiations on an amendment to the power purchase agreement that will include the agreed commercial terms in the binding term sheet, with the aim of concluding those negotiations by March 31, 2002. The binding term sheet serves as the basis under which the state-owned electric utility company will pay Paiton Energy beginning January 1, 2002. The binding term sheet will expire on March 31, 2002, unless extended by mutual agreement. The state-owned electric utility company has made all payments to Paiton Energy as required under the agreements covering 2001, which are superseded by the binding term sheet. Paiton Energy is continuing to generate electricity to meet the power demand in the region and believes that the state-owned electric utility company will continue to agree to make payments for electricity under the binding term sheet while negotiations on the amendment to the power purchase agreement continue. Although completion of negotiations may be delayed beyond March 31, 2002, Paiton Energy continues to believe that negotiations on the long-term restructuring of the revenue schedule will be successful.

Under the binding term sheet, past-due accounts receivable due under the original power purchase agreement will be compensated through a monthly settlement payment of $4 million for 30 years. Prior to the expiration of the binding term sheet on March 31, 2002, the state-owned electric utility company and Paiton Energy may, on or before March 15, 2002, agree in writing to extend the expiration date for the binding term sheet, provided that both parties are working in good faith to complete the power purchase agreement amendment and the related conditions precedent to such agreement and the state-owned electric utility company is continuing to pay all amounts due under the binding term sheet. If the power purchase agreement amendment is not completed within reasonable time frames acceptable to Paiton Energy, the parties will be entitled to revert back to the terms and conditions of the original power purchase agreement in order to pursue arbitration in the international courts.

Any material modifications of the power purchase agreement resulting from the continuing negotiation of a new long-term revenue schedule could require a renegotiation of the Paiton project's debt agreements. The impact of any such renegotiations with the state-owned electric utility company, the Indonesian government or the project's creditors on EME's expected return on its investment in Paiton Energy is uncertain at this time; however, EME believes that it will ultimately recover its investment in the project.

Discontinued Operations

On December 21, 2001, EME completed the sale of the Ferrybridge and Fiddler's Ferry coal stations located in the U.K. for an aggregate sale price of £643 million (approximately $945 million). Included in the loss from discontinued operations in 2001 is a loss on sale of $1.9 billion ($1.15 billion after tax). Net proceeds from the sale were used to repay borrowings outstanding under the existing debt facility related to the acquisition of the power plants. In addition to the charge discussed above, the early repayment of the project's existing debt facility of £682 million (approximately $1.0 billion) at December 21, 2001, resulted in a loss of $28 million (after tax) attributable to the write-off of unamortized debt issuance costs.

During second quarter 2001, Edison Enterprises, a wholly owned subsidiary of Edison International, decided to sell most of its assets. In August 2001, it sold a subsidiary principally engaged in the business of providing residential security services and residential electrical warranty repair services. On October 18, 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. Included in the loss from discontinued operations in 2001 is a loss on sale of $127 million (after tax) related to these transactions.

The results of the coal stations and Edison Enterprises' subsidiaries sold during 2001 have been reflected as discontinued operations in the consolidated financial statements, in accordance with a recently issued and adopted accounting standard related to the impairment and disposal of long-lived assets. The consolidated financial statements have been restated to conform to the discontinued operations presentation for all years presented. The pre-tax losses of the discontinued operations were $2.2 billion in 2001, $34 million in 2000 and $111 million in 1999.

Acquisitions and Dispositions

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 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. In December 2001, the buyer terminated the sale agreement related to the EcoEléctrica project. Subsequent to December 31, 2001, EME completed the sales of its 50% interests in the Commonwealth Atlantic and James River projects and its 30% interest in the Harbor project for $48 million. The buyer terminated the sale agreement related to the Gordonsville project in February 2002. On March 8, 2002, EME filed a complaint against the proposed buyer of the EcoEléctrica project and two of its affiliates, alleging that the buyer wrongfully terminated the sale agreement for the purchase of the project. EME is currently offering for sale its interest in the Brooklyn Navy Yard, Gordonsville and EcoEléctrica projects.

Also during 2001, EME completed the sale of a 50% interest in the Sunrise project. Proceeds from the sale were $84 million.

During the second quarter of 2001, EME completed the purchase of additional shares of Contact Energy Ltd. for approximately NZ$152 million (approximately $63 million). EME now has a controlling 51% ownership interest in Contact Energy. In October 2001, EME announced its intention to acquire the remaining 49% of Contact Energy. The offer commenced on November 6, 2001, and was extended until February 3, 2002. On February 4, 2002, EME announced that it did not receive the necessary level of acceptance required to complete the transaction, and therefore, EME currently plans to continue with its current 51% ownership interest.

During first quarter 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 728 MW hydroelectric project located in the Philippines. Financing for this $460 million project comprises equity commitments of $111 million (EME's share is $55 million) and debt financing which is in place for the remainder of the cost for this project.

EME Sale-Leaseback Transaction

On December 7, 2001, EME completed 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 (fair value of $809 million). Under the terms of the 33.67-year leases, EME is obligated to make semi-annual lease payments on each April 1 and October 1, which began on December 7, 2001. Minimum lease payments during the next five years are: $175 million in 2002; $174 million in 2003; $142 million in 2004; $152 million in 2005; and $152 million in 2006. These amounts are included in the amounts disclosed in Projected Commitments. At December 31, 2001, the total remaining lease payments were $3.4 billion. The lease costs will be levelized over the terms of the leases. The gain on the sale of the facilities has been deferred and is being amortized over the terms of the leases.

SCE's Regulatory Environment

SCE operates in a highly regulated environment and has an exclusive franchise within its service territory. SCE has an obligation to deliver electric service to its customers and regulatory authorities have an obligation to provide just and reasonable rates. In the mid-1990s, state lawmakers and the CPUC initiated the electric industry restructuring process. SCE was directed by the CPUC to divest the bulk of its gas-fired generation portfolio. Today, independent power companies own the divested generating plants. The electric industry restructuring plan also instituted a multi-year freeze on the rates that SCE could charge its customers and transition cost recovery mechanisms (as described in Status of Transition and Power-Procurement Cost Recovery) designed to allow SCE to recover its stranded costs associated with generation-related assets. California's electric industry restructuring statute included provisions to finance a portion of the stranded costs that residential and small commercial customers would have paid between 1998 and 2001, which allowed SCE to reduce rates by at least 10% to these customers, effective January 1, 1998. These frozen rates (except for the surcharge effective in 2001) were to remain in effect until the earlier of March 31, 2002, or the date when the CPUC-authorized costs for utility-owned generation assets and obligations are recovered. However, between May 2000 and June 2001, the prices charged by sellers of power escalated far beyond what SCE could charge its customers. As a result, SCE incurred $2.7 billion (after tax), or $4.7 billion (pre-tax), in write-offs as of December 31, 2000, and net undercollected transition costs through August 31, 2001. As indicated below, implementation of the CPUC settlement agreement and CPUC approval of SCE's Utility-Retained Generation (URG) application is expected to allow SCE to recover substantially all of the $4.7 billion.

Generation and Power Procurement

During the rate freeze, recovery of generation-related transition costs was tracked through the TCBA mechanism. Revenue from generation-related operations was determined through the market and transition cost recovery mechanisms, which included the nuclear rate-making agreements. During fourth quarter 2001, the TCBA mechanism was terminated retroactive to September 1, 2001, and a $3.6 billion PROACT regulatory asset was created in accordance with the October 2001 settlement agreement with the CPUC and the PROACT resolution adopted in January 2002. In accordance with a state law passed in January 2001, SCE will continue to own its remaining generation assets, which will be subject to cost-based ratemaking, through 2006 (see further discussion in URG Proceeding).

Through December 31, 2000, SCE had been recovering its investment in its nuclear facilities on an accelerated basis (over four years) in exchange for a lower authorized rate of return on investment.

SCE's nuclear assets were earning an annual rate of return on investment of 7.35%. However, due to the various unresolved regulatory and legislative issues (as discussed in Status of Transition and Power-Procurement Cost Recovery), as of December 31, 2000, SCE was no longer able to conclude that the $610 million balance of unamortized nuclear investment regulatory assets 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 (see further discussion in Earnings (Loss) from Continuing Operations). Should the URG application be approved, SCE expects to reestablish for financial reporting purposes its unamortized nuclear investment and related flow-through taxes retroactive to August 31, 2001, with recovery based on a 10-year period, effective January 1, 2001, with a corresponding credit to earnings, and adjust the PROACT regulatory asset balance as necessary to reflect recovery of the nuclear investment in accordance with the final URG decision.

The San Onofre incentive-pricing plan authorizes a fixed rate of approximately 4¢ per kWh generated for operating costs including incremental capital costs, nuclear fuel and nuclear fuel financing costs. The San Onofre incentive-pricing plan started in April 1996 and ends in December 2003. The Palo Verde Nuclear Generating Station's operating costs, including incremental capital costs, and nuclear fuel and nuclear fuel financing costs, were subject to balancing account treatment. The Palo Verde plan started in January 1997 and was to end in December 2001. The benefits of operation of the San Onofre units and the Palo Verde units were required to be shared equally with ratepayers beginning in 2004 and 2002, respectively. In a June 2001 decision, the CPUC granted SCE's request to eliminate the San Onofre post-2003 sharing mechanism based on compliance with a state law enacted in early 2001. In a September 2001 decision, the CPUC granted SCE's request to eliminate the Palo Verde post-2001 sharing mechanism and to continue the current rate-making treatment for Palo Verde, including the continuation of the existing nuclear 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. Beginning January 1, 1998, both the San Onofre and Palo Verde rate-making plans became part of the TCBA mechanism. These rate-making plans and the TCBA mechanism were to continue for rate-making purposes at least through the end of the rate freeze period. However, in its URG application, SCE proposed to move the recovery of nuclear costs to another balancing account mechanism. See discussion in URG Proceeding for the proposed and alternate decisions' impact on the incentive-pricing plans.

CPUC Litigation Settlement Agreement

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 past electricity procurement costs in accordance with the tariffs filed with the FERC. By agreement of the parties, a stay of the lawsuit was issued in April 2001 while SCE sought implementation of legislative, regulatory and executive actions to resolve the California energy crisis and SCE's related financial and liquidity problems. In October 2001, the federal district court entered a stipulated judgment approving an agreement between the CPUC and SCE to settle the pending lawsuit. On January 23, 2002, the CPUC adopted a resolution implementing the settlement agreement. See discussion below in PROACT Regulatory Asset.

Key elements of the settlement agreement include the following items:

- Establishment of the PROACT, as of September 1, 2001, with an opening balance equal to the amount of SCE's procurement-related liabilities as of August 31, 2001 (approximately $6.4 billion), less SCE's cash and cash equivalents as of that date (approximately $2.5 billion), and less $300 million.

- Beginning on September 1, 2001, SCE will apply to the PROACT, on a monthly basis, the difference between SCE's revenue from retail electric rates (including surcharges) and the costs that SCE is authorized by the CPUC to recover in retail electric rates. Unrecovered obligations in the PROACT will accrue interest from September 1, 2001.

- Maintain current rates (including surcharges) in effect until December 31, 2003, subject to certain adjustments, or, if earlier, until the date that SCE recovers the entire PROACT balance. If SCE has not recovered the entire balance by December 31, 2003, the unrecovered balance will be amortized for up to an additional two years. The parties project that existing retail electric rates, including surcharges and as adjusted to reflect certain costs, will likely result in SCE recovering substantially all of its unrecovered procurement-related obligations prior to the end of 2003.

- If the CPUC concludes that it is desirable to authorize a securitized financing of SCE's procurement-related obligations, the parties will work together to achieve the securitization. Proceeds of any securitization will be credited to the PROACT when they are actually received.

- During the period that SCE is recovering its previously incurred procurement-related obligations, no penalty will be imposed by the CPUC on SCE for any noncompliance with CPUC-mandated capital structure requirements.

- SCE can incur up to $250 million of recoverable costs to acquire financial instruments and engage in other transactions intended to hedge fuel cost risks associated with SCE's retained generation assets and power purchase contracts with QFs and other utilities. As of December 31, 2001, SCE had purchased $209 million in hedging instruments. See discussion in the SCE Issues section of Market Risk Exposures.

- SCE will not declare or pay dividends or other distributions on its common stock (all of which is held by its parent) prior to the earlier of the date SCE has recovered all of its procurement-related obligations in the PROACT or January 1, 2005. However, if SCE has not recovered all of its procurement-related obligations by December 31, 2003, SCE may apply to the CPUC for consent to resume common stock dividends, and the CPUC will not unreasonably withhold its consent.

- To ensure the ability of SCE to continue to provide adequate service, SCE may make capital expenditures above the level contained in current rates, up to $900 million per year, which will be treated as recoverable costs.

- Subject to certain qualifications, SCE will cooperate with the CPUC and the California Attorney General to pursue and resolve SCE's claims and rights against sellers of energy and related services, SCE's defenses to claims arising from any failure to make payments to the PX or ISO, and similar claims by the State of California or its agencies against the same adverse parties. During the recovery period discussed above, refunds obtained by SCE related to its procurement-related liabilities will be applied to the balance in the PROACT.

The settlement agreement states that one of its purposes is to restore the investment grade creditworthiness of SCE as rapidly as reasonably practicable so that it will be able to provide reliable electrical service as a state-regulated entity as it has in the past. SCE cannot provide assurance that it will regain investment grade credit ratings by any particular date.

On November 28, 2001, a federal court of appeals denied a California consumer group's request for a long-term stay of the settlement. The group had alleged that it was denied due process and that the CPUC had no authority to agree with SCE to violate the statutory rate freeze. In its ruling, the federal court of appeals also granted SCE's request for an expedited hearing of an appeal of the settlement filed by the consumer group. On March 4, 2002, the court of appeals heard argument on the appeal and the matter is now under submission. A decision could be issued anytime during the next several months. SCE cannot predict the outcome of the appeal or the impact that any outcome would have upon the stipulated judgment or the settlement, at this time. Possible outcomes include affirmance, a return to the district court or reversal of the stipulated judgment. SCE cannot predict whether or how a ruling on the stipulated judgment could also affect the settlement agreement.

PROACT Regulatory Asset

According to the terms of the settlement agreement and the CPUC resolution, in the fourth quarter of 2001 SCE established (retroactive to August 31, 2001) a $3.6 billion PROACT regulatory asset for its previously incurred procurement costs.

The beginning balance of the PROACT, as verified by the CPUC, was calculated as follows:

In millions	
Past-due bills:	
PX or ISO	$ 924
QFs	1,219
PX energy credits	236
Imbalance energy (CDWR)	383
Ancillary services for resale cities	30
Total past-due bills	2,792
Procurement-related debt (including accrued interest):	
Credit facilities	1,298
Bilateral credit facilities	415
Defaulted commercial paper	563
Floating rate notes due May 2002	313
Variable rate notes due November 2003	1,043
Total procurement-related debt	3,632
Total procurement-related liabilities	6,424
Less: Cash and cash equivalents on hand	(2,547)
Less: Amount stipulated in agreement	(300)
Net PROACT balance as of August 31, 2001	$ 3,577

For a comparison between the PROACT balance as of August 31, 2001, and the TCBA balance as of that date, see discussion in *Status of Transition and Power-Procurement Cost Recovery*.

CDWR Power Purchases

In accordance with an emergency order signed by the governor, the CDWR began making emergency power purchases for SCE's customers on January 17, 2001. Amounts SCE bills to and collects from its customers for electric power purchased and sold by the CDWR and through the ISO are remitted directly to the CDWR and are not recognized as revenue by SCE. In February 2001, Assembly Bill 1 (First Extraordinary Session, AB 1X) was enacted into law. AB 1X authorized the CDWR to enter into contracts to purchase electric power and sell power at cost directly to retail customers being served by SCE, and authorized the CDWR to issue bonds to finance electricity purchases.

On March 27, 2001, the CPUC issued an interim order requiring SCE to pay the CDWR a per-kWh price equal to the applicable generation-related retail rate per kWh for electricity (based on rates in effect on January 5, 2001), for each kWh the CDWR sells to SCE's customers. The CPUC determined that the generation-related retail rate should be equal to the total bundled electric rate (including the 1¢-per-kWh surcharge adopted by the CPUC on January 4, 2001) less certain nongeneration-related rates or charges. For the period January 19 through January 31, 2001, the CPUC ordered SCE to pay the CDWR at a rate of 6.277¢ per kWh for power delivered to SCE's customers. The CPUC determined that the applicable rate component is 7.277¢ per kWh (which increased to 10.277¢ per kWh for electricity delivered after March 27, 2001, due to the 3¢-surcharge discussed in Rate Stabilization Proceedings), for electricity delivered by the CDWR to SCE's retail customers after February 1, 2001, until more specific rates are calculated. The CPUC ordered SCE to pay the CDWR within 45 days after the CDWR supplies power to retail customers, subject to penalties for each day the payment is late.

On February 21, 2002, the CPUC issued a decision implementing a CDWR revenue requirement of $9.0 billion to pay its bonds' costs and energy procurement costs for the period January 17, 2001, through December 31, 2002. The decision states that SCE's allocated share of this revenue requirement would be approximately $3.6 billion, and changes SCE's payment from to 9.744¢ per kWh for all bills rendered on or after March 15, 2002. The decision requires SCE to pay the CDWR in equal monthly installments over a six-month period the difference in rates between January 17, 2001, and March 15, 2002. SCE estimates that this amount is approximately $41 million.

On February 28, 2002, SCE and the CDWR executed an agreement that resolves outstanding issues relating to the payment for electric power purchased for SCE's customers through the ISO real-time market (known as imbalance energy). Under the agreement, SCE will pay the CDWR for imbalance energy previously delivered in three installments ($100 million on April 1, 2002, $150 million on June 3, 2002, and the balance on July 1, 2002).

Status of Transition and Power-Procurement Cost Recovery

SCE's transition costs to be recovered through the TCBA mechanism included power purchases from QF contracts (which are the direct result of prior legislative and regulatory mandates), recovery of certain generating assets and other costs incurred to provide service to customers. Other costs included the recovery of income tax benefits previously flowed through to customers, postretirement benefit transition costs and accelerated recovery of investment in nuclear generating units. Recovery of costs related to power-purchase QF contracts was permitted through the terms of each contract. Legislation and regulatory decisions issued prior to the beginning of the rate freeze called for most of the remaining transition costs to be recovered through the end of the four-year transition period (not later than March 31, 2002). Because regulatory and legislative actions that make such recovery probable were not taken in a timely manner during the energy crisis, as of December 31, 2000, SCE was unable to conclude that the net regulatory assets related to purchased-power settlements, the unamortized loss on SCE's generating plant sales in 1998, and various other generation regulatory assets were probable of recovery through the rate-making process. As a result, these balances were written off as a charge to earnings at that time (see further discussion in Earnings (Loss) from Continuing Operations).

There were three sources of revenue available to SCE for transition cost recovery through the TCBA mechanism: revenue from the sale or valuation of generation assets in excess of book values, net market revenue from the sale of SCE-controlled generation into the ISO and PX markets and competition transition charge (CTC) revenue. Revenue from the first two sources has not been available since January 2001. Net proceeds of the 1998 plant sales were used to reduce transition costs, which otherwise had been expected to be collected through the TCBA mechanism. However, state legislation enacted in January 2001 prohibits the sale of SCE's remaining generation assets until 2006. SCE stopped selling power from its generation into the ISO and PX markets in January 2001, after SCE's credit ratings were downgraded and the PX suspended SCE's trading privileges (see discussion in Generation and Power Procurement).

CTC revenue was determined residually (i.e., CTC revenue was the residual amount remaining from monthly gross customer revenue under the rate freeze after subtracting the revenue requirements for transmission, distribution, nuclear decommissioning and public benefit programs, and ISO payments and power purchases from the PX and ISO). The CTC applied to all customers who were using or began using utility services on or after the CPUC's 1995 restructuring decision date. Residual CTC revenue was calculated through the TRA mechanism. In accordance with the March 27, 2001, rate stabilization decision, both positive and negative residual CTC revenue was transferred from the TRA to the TCBA on a monthly basis, retroactive to January 1, 1998 (see further discussion in Rate Stabilization Proceedings). A previous decision had called only for a transfer of positive residual CTC revenue (TRA overcollections) to the TCBA and there had not been any positive residual CTC revenue between May 2000 and June 2001.

Because the regulatory and legislative actions that made such recovery probable were not taken, SCE was unable to conclude as of December 31, 2000, that the recalculated TCBA net undercollection was probable of recovery through the rate-making process. As a result, the $2.9 billion TCBA net undercollection was written off as a charge to earnings as of that date (see further discussion in Earnings (Loss) from Continuing Operations), and an additional $552 million (pre-tax) of net undercollected transition costs was charged to earnings between January 1, 2001, and August 31, 2001. Although the TCBA was written off, SCE continued to calculate the account for rate-making purposes, and the account reflected a $4.2 billion undercollection as of August 31, 2001, the effective date of the beginning of the PROACT mechanism and the end of the TCBA mechanism. If the TCBA would have been adjusted for the impact of SCE's treatment of the nuclear facilities as proposed in the URG proceeding, the TCBA balance as of August 31, 2001, would have reflected an undercollection of $3.626 billion, substantially equal to the $3.577 billion undercollection in the PROACT regulatory asset.

For more details on the matters discussed above, see discussions in Rate Stabilization Proceedings, URG Proceeding and PROACT Regulatory Asset.

Litigation

In October 2000, a federal class action securities lawsuit was filed against SCE and Edison International. As amended in December 2000 and March 2001, the lawsuit involves securities fraud claims arising from alleged improper accounting for the TRA undercollections. The second amended complaint is supposedly filed on behalf of a class of persons who purchased Edison International common stock between July 21, 2000, and April 17, 2001. This lawsuit has been consolidated with another similar lawsuit filed on March 15, 2001. A consolidated class action complaint was filed on August 3, 2001. On September 17, 2001, SCE and Edison International filed a motion to dismiss for failure to state a claim. On March 8, 2002, the district court issued an order dismissing the complaint with prejudice. The plaintiffs could appeal this ruling to the court of appeals.

In addition to the lawsuits filed against Edison International and SCE discussed above, SCE has been a defendant in a number of legal actions brought by various QFs arising out of SCE's suspension of payments for electricity delivered by the QFs during the period November 1, 2000, through March 26, 2001. The QF claims were eventually largely subsumed within agreements with the litigating QFs providing for a provisional settlement of the parties' disputes. On March 1, 2002, SCE paid the amounts due under settlement agreements with these QFs, which triggered the releases and other provisions of the settlements. As a result, the litigation with those QFs to whom payment in full has been made under the parties' settlement agreements should be dismissed during 2002. However, SCE's March 1, 2002, payments excluded several QFs or did not result in immediate releases under the settlement agreements based on unique disputes or other unique circumstances, including the status of regulatory approval.

Rate Stabilization Proceedings

In January 2000, SCE filed an application with the CPUC proposing rates that would go into effect when the four-year rate freeze was to end on March 31, 2002, or earlier, depending on the pace of transition cost recovery. In December 2000, SCE filed an amended rate stabilization plan application, stating that the statutory rate freeze had ended in accordance with California law, and requesting the CPUC to approve an immediate 30% increase to be effective, subject to refund, January 4, 2001.

In January 2001, independent auditors hired by the CPUC issued a report on the financial condition and solvency of SCE and its affiliates. The report confirmed what SCE had previously disclosed to the CPUC in public filings about SCE's financial condition. The audit report covered, among other things, cash needs, credit relationships, accounting mechanisms to track stranded cost recovery, the flow of funds between SCE and Edison International, and earnings of SCE's California affiliates. In April 2001, the CPUC adopted an order instituting investigation that reopens the past CPUC decision authorizing the utilities to form holding companies and initiates an investigation into: whether the holding companies violated CPUC requirements to give first priority to the capital needs of their respective utility subsidiaries; whether ring-fencing actions by Edison International and PG&E Corporation and their respective nonutility affiliates also violated the requirements to give priority to the capital needs of their utility subsidiaries;

whether the payment of dividends by the utilities violated requirements that the utilities maintain dividend policies as though they were comparable stand-alone utility companies; any additional suspected violations of laws or CPUC rules and decisions; and whether additional rules, conditions, or other changes to the holding company decisions are necessary. The CPUC ordered testimony and briefing on these matters, which SCE filed in May and June 2001. On January 9, 2002, the CPUC issued an interim decision on the first priority condition. The decision stated that, at least under certain circumstances, the condition includes the requirement that holding companies infuse all types of capital into their respective utility subsidiaries when necessary to fulfill the utility's obligation to serve. On February 11, 2002, SCE filed an application for rehearing of the decision stating that the decision is an unlawful and erroneous attempt to rewrite the first priority condition rather than interpret it and that the decision would result in higher rates for SCE's customers. Neither Edison International nor SCE can predict what effects this investigation or any subsequent actions by the CPUC may have on either of them.

In March 2001, the CPUC ordered a rate increase in the form of a 3¢-per-kWh surcharge applied only to going-forward electric power procurement costs and affirmed that a 1¢ interim surcharge granted in January 2001 is permanent. The 3¢ surcharge is to be added to the rate paid to the CDWR (see CDWR Power Purchases). Although the 3¢-increase was authorized as of March 27, 2001, the surcharge was not collected in rates until the CPUC established a rate design in early June 2001. To compensate for the two-month delay in collecting the 3¢ surcharge, the CPUC authorized an additional ½¢ surcharge for a 12-month period beginning in June 2001.

URG Proceeding

In June 2001, SCE filed a comprehensive proposal for new cost-of-service ratemaking for utility retained generation through the end of 2002. After that time, SCE's URG-related revenue requirement will be determined by the general rate case. The URG proposal calls for balancing accounts for SCE-owned generation, QF and interutility contracts, procurement costs and ISO charges based on either actual or CPUC-authorized revenue requirements. Under the proposal, the four new balancing accounts would be effective January 1, 2001, for capital-related costs, and February 1, 2001, for non-capital-related costs. In addition, SCE's unamortized nuclear investment would be amortized and recovered in rates over a 10-year period, effective January 1, 2001. Should this application be approved as filed, SCE expects to reestablish for financial reporting purposes its unamortized nuclear investment and regulatory assets related to purchased-power settlements and flow-through taxes, with a corresponding credit to earnings, and adjust the PROACT regulatory asset balance in accordance with the final URG decision.

On January 18, 2002, a CPUC administrative law judge issued a proposed decision and a CPUC commissioner issued an alternate proposed decision. Both the proposed and alternate proposed decisions adopt most of the elements of SCE's application, but propose eliminating an incentive-pricing plan for San Onofre, effective January 1, 2002, and replacing it with balancing account treatment for San Onofre's operating costs, subject to a later reasonableness review. On February 7, 2002, another CPUC commissioner issued an alternate proposed decision recommending continuing the incentive-pricing plan for San Onofre Units 2 and 3 through December 31, 2003, as originally provided in CPUC decisions adopted in early 1996. A final decision is expected in second quarter 2002.

Generation Procurement Proceeding

In October 2001, the CPUC issued an order instituting rulemaking (OIR) to establish policies and cost recovery mechanisms for generation procurement. The OIR directed SCE and the other major California electric utilities to provide recommendations for establishing these policies and mechanisms to enable the utilities to resume their power procurement responsibilities in 2003. In comments filed with the CPUC on November 26, 2001, SCE recommended that the CPUC issue a procurement framework decision in February 2002, and direct the utilities to submit their specific procurement plan proposals and related framework compliance proposals in March 2002. SCE also proposed that a final decision be issued in October 2002 adopting utility-specific procurement plans. The CPUC has not yet acted on SCE's recommendations, but is expected in second quarter 2002 to issue a scoping memo setting forth issues to be addressed in this proceeding.

Accounting for Generation-Related Assets and Power Procurement Costs

In 1997, SCE discontinued application of accounting principles for rate-regulated enterprises for its generation assets. At that time, SCE did not write off any of its generation-related assets, including related regulatory assets, because the electric utility industry restructuring plan made probable their recovery through a nonbypassable charge to distribution customers.

During the second quarter of 1998, in accordance with asset impairment accounting standards, SCE reduced its remaining nuclear plant investment by $2.6 billion (as of June 30, 1998) and recorded a regulatory asset on its balance sheet for the same amount. For this impairment assessment, the fair value of the investment was calculated by discounting expected future net cash flows. This reclassification had no effect on SCE's results of operations.

As of December 31, 2000, SCE assessed the probability of recovery of its generation-related assets and power procurement costs in light of the CPUC's March 27, 2001, and April 3, 2001, decisions, and could not conclude that its $2.9 billion TCBA undercollection (as redefined in the March 27 decisions) and $1.3 billion (book value) of its net generation-related regulatory assets to be amortized into the TCBA, were probable of recovery through the rate-making process. As a result, accounting principles generally accepted in the United States required that the balances in the accounts be written off as a charge to earnings. In addition to the $4.2 billion pre-tax write-off, SCE incurred approximately $552 million (pre-tax) in net undercollected transition costs through August 31, 2001 (see Earnings (Loss) from Continuing Operations).

In accordance with the CPUC settlement agreement and the PROACT resolution, in fourth quarter 2001, SCE established a $3.6 billion regulatory asset for previously incurred power procurement costs, to be called the PROACT, retroactive to August 31, 2001. See further discussion in PROACT Regulatory Asset. CPUC approval of the URG application, as filed (see URG Proceeding), together with implementation of the PROACT mechanism is expected to allow SCE to recover substantially all of the $4.7 billion in write-offs as of December 31, 2000, and net undercollected transition costs incurred through August 31, 2001.

If the CPUC approves SCE's URG application, as filed, SCE expects to reapply accounting principles for rate-regulated enterprises for its generation assets. These assets will then be subject to traditional cost-of-service regulation.

Distribution

Revenue related to distribution operations is determined through a performance-based rate-making (PBR) mechanism and the distribution assets have the opportunity to earn a CPUC-authorized 9.49% return on investment. Key elements of the distribution PBR include: distribution rates indexed for inflation based on the Consumer Price Index less a productivity factor; adjustments for cost changes that are not within SCE's control; a cost-of-capital trigger mechanism based on changes in a utility bond index; standards for customer satisfaction; service reliability and safety; and a net revenue-sharing mechanism that determines how customers and shareholders will share gains and losses from distribution operations. The distribution PBR was to have ended in December 2001, but in June 2001 the CPUC extended the mechanism until SCE's next general rate case, which will be effective in 2003. A CPUC proposed decision on the PBR mechanism for 2002 was issued in January 2002. The proposed decision authorized SCE to use a formula to determine its distribution revenue requirement for the last half of 2001 and 2002, and a revenue balancing account to ensure that variations in sales do not result in under or overcollections. A final decision is expected in second quarter 2002. At this time, SCE cannot predict the effect of the final decision on its results of operations.

In December 2001, SCE filed its 2003 general rate case with the CPUC, requesting an increase of approximately $500 million in revenue (compared to 2000 recorded revenue) for its distribution and generation operations. Hearings are expected to begin in July 2002, with a final decision expected in second quarter 2003.

Transmission

Transmission revenue is determined through FERC-authorized rates and is subject to refund.

Wholesale Electricity Markets

In October 2000, SCE filed a joint petition urging the FERC to immediately find the California wholesale electricity market to be not workably competitive, immediately impose a cap on the price for energy and ancillary services, and institute further expedited proceedings regarding the market failure, mitigation of market power, structural solutions and responsibility for refunds. In December 2000, the FERC took limited action and failed to impose a price cap. SCE filed an emergency petition in the federal court of appeals challenging the FERC order and requesting the FERC to immediately establish cost-based wholesale rates. The court denied SCE's petition in January 2001.

In its December 2000 order, the FERC established an underscheduling penalty effective January 1, 2001, applicable to scheduling coordinators that do not schedule sufficient resources to supply 95% of their respective loads. In December 2001, the FERC eliminated the underscheduling penalty retroactive to January 1, 2001.

On April 25, 2001, after months of extremely high power prices, the FERC issued an order providing for energy price controls during ISO Stage 1 or greater power emergencies (7% or less in reserve power). The order establishes an hourly clearing price based on the costs of the least efficient generating unit during the period. Effective June 20, 2001, the FERC expanded the April 25, 2001, order to include non-emergency periods and price mitigation in the 11-state western region. The latest order is in effect until September 30, 2002.

After unsuccessful settlement negotiations among utilities, power sellers and state representatives, on July 25, 2001, the FERC issued an order that limits potential refunds from alleged overcharges to the ISO and PX spot markets during the period from October 2, 2000, through June 20, 2001, and adopted a refund methodology based on daily spot market gas prices. An administrative law judge will conduct evidentiary hearings on this matter. SCE cannot predict the amount of any potential refunds. Under the settlement of litigation with the CPUC, refunds will be applied to the balance in the PROACT.

Environmental Protection

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, primarily at EME. There is no assurance that EME would be able to recover increased costs from its customers or that its financial position and results of operations would not be materially affected.

As further discussed in Note 12 to the Consolidated Financial Statements, Edison International records its environmental liabilities when site assessments and/or remedial actions are probable and a range of reasonably likely cleanup costs can be estimated. Edison International's recorded estimated minimum liability to remediate its 42 identified sites is $111 million. Edison International believes that, due to uncertainties inherent in the estimation process, it is reasonably possible that cleanup costs could exceed its recorded liability by up to $279 million. In 1998, SCE sold all of its gas-fueled power plants but has retained some liability associated with the divested properties.

The CPUC allows SCE to recover environmental-cleanup costs at certain sites, representing $50 million of its recorded liability, through an incentive mechanism, which is discussed in Note 12. SCE has recorded a regulatory asset of $76 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. As a result, 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 $10 million to $25 million. Recorded costs for the year ended December 31, 2001, were $18 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 and, based upon the CPUC's regulatory treatment of environmental-cleanup costs, 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.

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). A study was undertaken to determine the specific impact of air contaminant emissions from the Mohave Generating Station on visibility in Grand Canyon National Park. The final report on this study, which was issued in March 1999, found negligible correlation between measured Mohave station tracer concentrations and visibility impairment. The absence of any obvious relationship cannot rule out Mohave station contributions to haze in Grand Canyon National Park, but strongly suggests that other sources were primarily responsible for the haze. In June 1999, the Environmental Protection Agency (EPA) issued an advanced notice of proposed rulemaking regarding assessment of visibility impairment at the Grand Canyon. The EPA issued its final rule on February 8, 2002, which incorporates the terms of the consent decree into the visibility provisions of its Federal Implementation Plan for Nevada, making the terms of the consent decree federally enforceable.

SCE's share of the costs of complying with the consent decree and taking other actions to continue operation of the Mohave station is estimated to be approximately $560 million over the next four years. However, SCE has suspended its efforts to seek approval to install the Mohave controls because it has not obtained reasonable assurance of an adequate coal supply for operating Mohave beyond 2005. If an adequate coal supply is not obtained, it will become necessary to shut down the Mohave station 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 $88 million as of December 31, 2001), and plant closure and decommissioning-related costs are recoverable in future rates. SCE cannot predict what effect any future actions by the CPUC may have on this matter.

EME expects that compliance with the Clean Air Act will result in increased capital expenditures and operating expenses. EME anticipates upgrades to environmental controls at the Illinois plants to be about $368 million for the period 2002-2005. This amount is included in the $1.7 billion for Edison International's projected environmental capital expenditures (discussed below). In addition, EME has entered into a coal cleaning agreement related to its Homer City plant, which includes a fixed fee and variable component, based on tons of coal processed.

Edison International's projected environmental capital expenditures are $1.7 billion for the 2002-2006 period, mainly for undergrounding certain transmission and distribution lines at SCE and upgrading environmental controls at EME.

San Onofre Nuclear Generating Station

In February 2001, SCE's San Onofre Unit 3 experienced a fire due to an electrical fault in the non-nuclear portion of the plant. The turbine rotors, bearings and other components of the turbine generator system were damaged extensively. In June 2001, Unit 3 returned to service. Under the currently effective San Onofre recovery plan (discussed in the Generation and Power Procurement section of SCE's Regulatory Environment), SCE's lost revenue was approximately $98 million as a result of the fire and related outage.

The San Onofre Units 2 and 3 steam generators' design allows for the removal of up to 10% of the tubes before the rated capacity of the unit must be reduced. Increased tube degradation was found during routine inspections in 1997. To date, 8% of Unit 2's tubes and 6% of Unit 3's tubes have been removed from service. A decreasing (favorable) trend in degradation has been observed in more recent inspections.

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.

Edison International early adopted a new accounting standard in fourth quarter 2001 related to impairment or disposal of long-lived assets, which applied to the 2001 sales of EME's Ferrybridge and Fiddler's Ferry projects and the majority of the Edison Enterprises' businesses. Although the standard supersedes a prior accounting standard related to the impairment of long-lived assets, it retains the fundamental provisions for recognition and measurement of impairment of long-lived assets to be held and used and to be disposed of. The new standard also broadens the financial statement presentation of discontinued operations to include the disposal of an asset group (rather than a segment of a business).

SCE applies accounting principles for rate-regulated enterprises to the portion of its operations, where 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 a cost that would otherwise be charged to expense by a non-regulated 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. See further discussion of regulatory assets and liabilities in Note 1 to the Consolidated Financial Statements.

SCE applied judgment in the use of the above principles when it concluded, as of December 31, 2000, that $4.2 billion of generation-related regulatory assets and liabilities were no longer probable of recovery, and wrote off these assets as a charge to earnings, and again in fourth quarter 2001 when it created the $3.6 billion PROACT regulatory asset with a corresponding credit to earnings upon receiving regulatory assurance of collection of these costs. See further discussion in Earnings (Loss) from Continuing Operations section.

EME derives a substantial portion of its revenue from sales of physical power in the wholesale electricity market, as well as from energy marketing and risk management activities. With respect to physical power sales, EME considers revenue earned upon output, delivery or satisfaction of specific targets, all as specified by contractual terms. Revenue under long-term power sales arrangements is recognized on an accrual basis. For EME's long-term power contracts that provide for higher pricing in the early years of the contract, revenue is deferred and recognized on a levelized basis in accordance with relevant accounting guidance.

Effective January 1, 2001, Edison International adopted a new accounting standard for derivative instruments and hedging activities. The standard requires derivatives to be recognized on the balance sheet at fair value, unless they meet a normal purchase and sales exception. Management's judgment is required to determine whether the normal sales and purchases exception apply, whether individual transactions qualify and are designated by management as a cash flow hedge, or if transactions meet the definition of a derivative. The majority of EME's power sales and fuel supply agreements related to its generation activities qualify as normal purchases and sales under this accounting standard or do not meet the definition of a derivative as they are not readily convertible to cash and are, therefore, recorded on an accrual basis. At December 31, 2001, certain interest rate swap agreements and EME's electricity rate swap agreement at Loy Yang B qualify and have been designated by management as cash flow hedges. As such, these derivatives are recorded at fair value on the balance sheet and changes in fair value are recorded in the equity section of the balance sheet until the forecasted transaction occurs. The ineffective portion of the gain or loss is reflected in earnings immediately.

EME has entered into sale-leaseback transactions related to certain power facilities located in Illinois and its Homer City facilities in Pennsylvania. Each of these transactions was completed and accounted for by EME as an operating lease in EME's consolidated financial statements in accordance with 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 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 this purpose. EME has also entered into a sale-leaseback of equipment, consisting primarily of Illinois peaker power units. Each of these leases uses special purpose entities. See Off-Balance Sheet Transactions.

Edison Capital, through special purpose trusts, derives a substantial portion of its revenue from rental income on lease transactions. The trust, as owner /participant is the lessor on various leases related to various energy, power, infrastructure and equipment leases. See Note 11 to the Consolidated Financial Statements for more information. Each of these leveraged lease transactions was completed and accounted for in accordance with an accounting standard on lease transactions. Since the debt under Edison Capital's leveraged leases is non-recourse, the debt is not required to be recorded on Edison International's balance sheet. In the event of default, Edison Capital would not be required to satisfy the lessee's debt.

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.

Accounting Changes

On January 1, 2001, Edison International adopted a new accounting standard for derivative instruments and hedging activities. The standard requires derivatives to be recognized on the balance sheet at fair value, unless they meet the definition of a normal purchase or sale. 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 does not anticipate any earnings impact from any derivatives, since it expects that any market price changes will be recovered in rates. As a result of the adoption of the new standard, Edison International expects that earnings from EME and Edison Capital will be more volatile than earnings reported under the prior accounting policy. Edison International's 2001 earnings from continuing operations included $21 million related to the cumulative effect on prior years from the adoption of the new standard and related to the cumulative effect of a change in accounting for derivatives (based on additional authoritative guidance). In October 2001, additional implementation guidance, which will be effective April 1, 2002, was issued. SCE and EME are evaluating the impact of this new implementation guidance.

In July and August 2001, three new accounting standards were issued: Business Combinations; Goodwill and Other Intangibles; and Accounting for Asset Retirement Obligations.

The new Business Combinations standard eliminates the pooling-of-interests method, effective June 30, 2001. After that, all business combinations will be recorded under the purchase method (i.e., record purchase based upon value exchanged and record goodwill for excess of costs over the net assets acquired).

The new Goodwill and Other Intangibles standard requires that companies cease amortizing goodwill, effective January 1, 2002. Goodwill initially recognized after June 30, 2001, will not be amortized. Goodwill on the balance sheet at June 30, 2001, was amortized until December 31, 2001. Under the new standard, goodwill will be tested for impairment using a fair-value approach when events or circumstances occur indicating that impairment might exist. Also, a benchmark assessment for goodwill is required within six months of the date of adoption of the standard.

The Accounting for Asset Retirement Obligations standard requires entities to record the fair value of a liability for a legal asset retirement obligation 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. The standard is effective for Edison International beginning on January 1, 2003.

Edison International is studying the impact of the new Asset Retirement Obligations and Goodwill and Other Intangibles standards, and is unable to predict at this time the impact on its financial statements. Edison International does not anticipate any material impact on its results of operations or financial position from the Business Combinations standard.

In October 2001, a new accounting standard was issued related to accounting for the impairment or disposal of long-lived assets. Although the standard supersedes a prior accounting standard related to the impairment of long-lived assets, it retains the fundamental provisions of the impairment standard regarding recognition/measurement of impairment of long-lived assets to be held and used and measurement of long-lived assets to be disposed of by sale. Under the new accounting standard, asset write-downs from discontinuing a business segment will be treated the same as other assets held for sale. The new standard also broadens the financial statement presentation of discontinued operations to include the disposal of an asset group (rather than a segment of a business). The standard (effective on January 1, 2002) was adopted early, in fourth quarter 2001. See Discontinued Operations section for financial statement impact.

Effective January 1, 2000, EME changed its accounting method for major maintenance to record such expenses as incurred. Previously, EME recorded major maintenance costs on an accrue-in-advance method. EME voluntarily made the change in accounting due to guidance provided by the Securities and Exchange Commission. The cumulative effect of the change in accounting method was an $18 million after-tax benefit ($22 million after-tax was related to continuing operations).

Forward-Looking Information

In the preceding Management's Discussion and Analysis of Results of Operations and Financial Condition and elsewhere in this annual report, the words estimates, expects, anticipates, believes, and other similar expressions are intended to identify forward-looking information that involves risks and uncertainties. Actual results or outcomes could differ materially as a result of important factors that may be outside Edison International's control, including among other things: the outcome of the pending appeals of the stipulated judgment approving SCE's settlement agreement with the CPUC, and the effects of other legal actions or ballot initiatives, if any, attempting to undermine the provisions of the settlement agreement or otherwise adversely affecting SCE; changes in prices of wholesale electricity and natural gas or in operating costs, which could cause SCE's cost recovery to be less than anticipated and/or EME's revenue and earnings to be adversely affected; the actions of securities rating agencies, including the determination of whether or when to make changes in SCE's credit ratings, the ability of Edison

International, SCE and Edison Capital to regain, and EME to retain, investment grade ratings, and the impact of current or lowered ratings and other financial market conditions on the ability of the respective companies to obtain needed financing on reasonable terms; further actions by state and federal regulatory bodies setting rates, adopting or modifying cost recovery, accounting or rate-setting mechanisms and implementing the restructuring of the electric utility industry, as well as legislative or judicial actions affecting the same matters; the effects of increased competition in energy-related businesses, including the market entrants and the effects of new technologies that may be developed in the future; political and business risks of doing business in foreign countries, including uncertainties associated with currency exchange rates, currency repatriation, expropriation, political instability, privatization and other issues; power plant construction and operation risks, including construction delays, equipment failures, and labor issues; the operation of some of EME's power plants without long-term power purchase agreements, and other plants with agreements with a single customer, which may adversely affect EME's ability to sell the plants' output at profitable terms; new or increased environmental liabilities; and weather conditions, natural disasters, and other unforeseen events.

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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 public accountants, Arthur Andersen 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 public accountants and internal auditors, who have unrestricted access to the committee. The committee recommends annually to the board of directors the appointment of a firm of independent public accountants 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 their 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.

Thos M. Noonan

Thomas M. Noonan
Vice President
and Controller

John E. Bryson

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

March 25, 2002

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 changes in 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

ARTHUR ANDERSEN LLP

Los Angeles, California
March 25, 2002

Consolidated Statements of Income (Loss)

Edison International

In millions, except per share amounts Year ended December 31,	2001	2000	1999
Electric utility	$ 8,120	$ 7,870	$7,548
Nonutility power generation	2,968	2,561	1,327
Financial services and other	348	260	301
Total operating revenue	11,436	10,691	9,176
Fuel	1,128	1,004	546
Purchased power	3,770	4,687	3,190
Provisions for regulatory adjustment clauses — net	(3,028)	2,301	(763)
Other operation and maintenance	3,029	2,619	2,551
Depreciation, decommissioning and amortization	973	1,784	1,714
Property and other taxes	114	129	124
Net gain on sale of utility plant	(6)	(25)	(3)
Total operating expenses	5,980	12,499	7,359
Operating income (loss)	5,456	(1,808)	1,817
Interest and dividend income	282	209	92
Other nonoperating income	108	162	195
Interest expense — net of amounts capitalized	(1,582)	(1,257)	(841)
Other nonoperating deductions	(101)	(142)	(165)
Dividends on preferred securities	(92)	(100)	(44)
Dividends on utility preferred stock	(22)	(22)	(25)
Income (loss) from continuing operations before taxes	4,049	(2,958)	1,029
Income tax (benefit)	1,647	(1,019)	348
Income (loss) from continuing operations	2,402	(1,939)	681
Loss from discontinued operations (including loss on disposal of $1,309, net of tax)	(2,223)	(34)	(111)
Income tax (benefit) on discontinued operations	(856)	(30)	(53)
Net income (loss)	$ 1,035	$ (1,943)	$ 623
Weighted-average shares of common stock outstanding	326	333	348
Basic earnings (loss) per share:			
Continuing operations	$ 7.37	$ (5.83)	$ 1.96
Discontinued operations	(4.19)	(0.01)	(0.17)
Total	$ 3.18	$ (5.84)	$ 1.79
Weighted-average shares, including effect of dilutive securities	326	333	349
Diluted earnings (loss) per share:			
Continuing operations	$ 7.36	$ (5.83)	$ 1.96
Discontinued operations	(4.19)	(0.01)	(0.17)
Total	$ 3.17	$ (5.84)	$ 1.79
Dividends declared per common share	$ —	$ 0.84	$ 1.08

Consolidated Statements of Comprehensive Income (Loss)

In millions

Year ended December 31,	2001	2000	1999
Net income (loss)	$ 1,035	$ (1,943)	$ 623
Other comprehensive income, net of tax:			
Cumulative translation adjustments — net	6	(150)	(19)
Unrealized gain (loss) on securities — net	—	(7)	23
Cumulative effect of change in accounting for derivatives	148	—	—
Unrealized loss on cash flow hedges	(359)	—	—
Reclassification adjustment for gain (loss) included in net income (loss)	16	(24)	(46)
Comprehensive income (loss)	$ 846	$ (2,124)	$ 581

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

In millions December 31,	2001	2000
ASSETS		
Cash and equivalents	$ 3,991	$ 1,604
Receivables, less allowances of $41 and $25 for uncollectible accounts at respective dates	1,259	978
Accrued unbilled revenue	451	377
Fuel inventory	124	68
Materials and supplies, at average cost	203	188
Accumulated deferred income taxes — net	1,092	1,339
Trading and price risk management assets	65	252
Regulatory assets — net	83	—
Prepayments and other current assets	232	159
Total current assets	7,500	4,965
Nonutility property — less accumulated provision for depreciation of $706 and $602 at respective dates	6,414	7,298
Nuclear decommissioning trusts	2,275	2,505
Investments in partnerships and unconsolidated subsidiaries	2,253	2,700
Investments in leveraged leases	2,386	2,346
Other investments	226	92
Total investments and other assets	13,554	14,941
Utility plant, at original cost		
Transmission and distribution	13,568	13,129
Generation	1,729	1,745
Accumulated provision for depreciation and decommissioning	(7,969)	(7,834)
Construction work in progress	556	636
Nuclear fuel, at amortized cost	129	143
Total utility plant	8,013	7,819
Goodwill	633	291
Regulatory assets — net	5,528	2,390
Other deferred charges	1,341	803
Total deferred charges	7,502	3,484
Assets of discontinued operations	205	3,891
Total assets	$36,774	$35,100

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

Consolidated Balance Sheets

In millions, except share amounts December 31,	2001	2000
LIABILITIES AND SHAREHOLDERS' EQUITY		
Short-term debt	$ 2,445	$ 3,891
Long-term debt due within one year	1,499	929
Preferred stock to be redeemed within one year	105	—
Accounts payable	3,414	1,199
Accrued taxes	183	566
Regulatory liabilities — net	—	195
Trading and price risk management liabilities	24	282
Other current liabilities	2,187	2,121
Total current liabilities	9,857	9,183
Long-term debt	12,674	12,150
Accumulated deferred income taxes — net	6,367	4,537
Accumulated deferred investment tax credits	172	183
Customer advances and other deferred credits	1,675	1,598
Power-purchase contracts	356	467
Accumulated provision for pensions and benefits	505	432
Other long-term liabilities	147	127
Total deferred credits and other liabilities	9,222	7,344
Liabilities of discontinued operations	71	2,474
Commitments and contingencies (Notes 3, 11 and 12)		
Minority interest	345	19
Preferred stock of utility:		
Not subject to mandatory redemption	129	129
Subject to mandatory redemption	151	256
Company-obligated mandatorily redeemable securities of subsidiaries holding solely parent company debentures	949	949
Other preferred securities	104	176
Total preferred securities of subsidiaries	1,333	1,510
Common stock (325,811,206 shares outstanding at each date)	1,966	1,960
Accumulated other comprehensive income (loss)	(328)	(139)
Retained earnings	1,634	599
Total common shareholders' equity	3,272	2,420
Total liabilities and shareholders' equity	$36,774	$35,100

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

Consolidated Statements of Cash Flows			Edison International
In millions Year ended December 31,	2001	2000	1999
Cash flows from operating activities:			
Net income (loss) from continuing operations	$ 2,402	$(1,939)	$ 681
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, decommissioning and amortization	973	1,784	1,714
Other amortization	92	168	112
Deferred income taxes and investment tax credits	1,908	(1,080)	536
Equity in income from partnerships and unconsolidated subsidiaries	(374)	(267)	(244)
Income from leveraged leases	(154)	(192)	(214)
Regulatory assets — long-term — net	(3,135)	1,759	(1,354)
Write-down of nonutility assets	245	—	—
Gas call options	(91)	20	11
Net gain on sale of marketable securities	—	(57)	(77)
Other assets	(20)	40	(69)
Other liabilities	(134)	(107)	117
Changes in working capital:			
Receivables and accrued unbilled revenue	(47)	(159)	34
Regulatory liabilities — short-term — net	(278)	97	363
Fuel inventory, materials and supplies	(16)	30	(5)
Prepayments and other current assets	203	79	(28)
Accrued interest and taxes	(240)	185	(196)
Accounts payable and other current liabilities	1,551	797	642
Distributions and dividends from unconsolidated entities	236	227	213
Operating cash flows from discontinued operations	(147)	19	(199)
Net cash provided by operating activities	2,974	1,404	2,037
Cash flows from financing activities:			
Long-term debt issued	3,386	5,293	5,395
Long-term debt repaid	(1,761)	(4,495)	(1,022)
Bonds repurchased and funds held in trust	(130)	(440)	—
Preferred securities issued	104	—	1,124
Preferred securities redeemed	(164)	(125)	—
Common stock repurchased	—	(386)	(92)
Rate reduction notes repaid	(246)	(246)	(246)
Nuclear fuel financing — net	(21)	9	(37)
Short-term debt financing — net	(1,547)	1,296	1,931
Dividends paid	—	(371)	(373)
Financing cash flows from discontinued operations	(1,178)	223	1,241
Net cash provided (used) by financing activities	(1,557)	758	7,921
Cash flows from investing activities:			
Additions to property and plant	(933)	(1,426)	(1,188)
Purchase of nonutility generation plant	—	(47)	(5,889)
Proceeds from sale of nonutility property	1,032	1,727	115
Funding of nuclear decommissioning trusts	(36)	(69)	(116)
Investments in partnerships and unconsolidated subsidiaries	(122)	(289)	(853)
Proceeds from sales of marketable securities	—	58	84
Investments in leveraged leases	68	(255)	(99)
Investments in other assets	(433)	(275)	(387)
Investing cash flows from discontinued operations	1,125	(89)	(1,698)
Net cash provided (used) by investing activities	701	(665)	(10,031)
Effect of exchange rate changes on cash	(37)	(32)	(3)
Net increase (decrease) in cash and equivalents	2,081	1,465	(76)
Cash and equivalents, beginning of year	1,973	508	584
Cash and equivalents, end of year	4,054	1,973	508
Cash and equivalents — discontinued operations	(63)	(369)	(133)
Cash and equivalents — continuing operations	$ 3,991	$ 1,604	$ 375

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

Consolidated Statements of Changes in Common Shareholders' Equity

In millions, except share amounts	Common Stock	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total Common Shareholders' Equity
Balance at December 31, 1998	$2,109	$ 84	$ 2,906	$ 5,099
Net income			623	623
Stock repurchase and retirement (3,350,500 shares)	(20)		(72)	(92)
Dividends declared on common stock			(375)	(375)
Unrealized gain on securities		39		39
Tax effect		(16)		(16)
Reclassified adjustment for gain included in net income		(77)		(77)
Tax effect		31		31
Cumulative translation adjustment		(21)		(21)
Tax effect		2		2
Capital stock expense	1			1
Stock option appreciation			(3)	(3)
Balance at December 31, 1999	$2,090	$ 42	$ 3,079	$ 5,211
Net income (loss)			(1,943)	(1,943)
Stock repurchase and retirement (21,402,700 shares)	(130)		(257)	(387)
Dividends declared on common stock			(277)	(277)
Unrealized gain on securities		(11)		(11)
Tax effect		4		4
Reclassified adjustment for gain included in net income		(41)		(41)
Tax effect		17		17
Cumulative translation adjustment		(148)		(148)
Tax effect		(2)		(2)
Stock option appreciation			(3)	(3)
Balance at December 31, 2000	$1,960	$(139)	$ 599	$ 2,420
Net income			1,035	1,035
Cumulative translation adjustment		(1)		(1)
Tax effect		7		7
Unrealized loss on cash flow hedges		(296)		(296)
Tax effect		(63)		(63)
Reclassified 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 and other	6			6
Balance at December 31, 2001	$1,966	$(328)	$ 1,634	$ 3,272

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

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

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Note 1. Summary of Significant Accounting Policies

Nature of Operations

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; and Edison Capital, a provider of capital and financial services. 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 either 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 in power markets open to competition.

SCE operates in a highly regulated environment and has an exclusive franchise within its service territory. SCE has an obligation to deliver electric service to its customers and regulatory authorities have an obligation to provide just and reasonable rates. In the mid-1990s, state lawmakers and the California Public Utilities Commission (CPUC) initiated an electric industry restructuring process. SCE, as directed by the CPUC, sold its gas-fired generating stations. See Note 3 for a further discussion of regulatory changes in the electric utility industry.

Basis of Presentation

The consolidated financial statements include Edison International and its wholly owned subsidiaries. Edison International's subsidiaries 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. Intercompany transactions have been eliminated, except EME's profits from energy sales to SCE, which are allowed in utility rates. Certain prior-year amounts were reclassified to conform to the December 31, 2001, financial statement presentation. 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 CPUC and the Federal Energy Regulatory Commission (FERC). Since 1997, as a result of industry restructuring legislation enacted by the State of California and related changes in the rate-recovery of generation-related assets, SCE has used accounting principles applicable to enterprises in general for its investment in generation facilities.

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 disclosure of contingencies. Actual results could differ from those estimates. Certain significant estimates related to electric utility regulatory matters, financial instruments, decommissioning and contingencies are further discussed in Notes 3, 4, 11 and 12 to the Consolidated Financial Statements, respectively.

Revenue

Electric utility revenue includes amounts for services rendered but unbilled at the end of each year. Since January 17, 2001, power purchased by the California Department of Water Resources (CDWR) or through the Independent System Operator (ISO) for SCE's customers is not considered a cost to SCE, since SCE is acting as an agent for these transactions. Further, amounts billed to ($2.0 billion in 2001) and collected from its customers for these power purchases are being remitted to the CDWR and are not recognized as revenue by SCE. See further discussion in Note 3.

Some nonutility power generation revenue from power sales contracts is deferred and amortized to income over the life of the contracts. Revenue is adjusted for price differentials resulting from electricity rate swap agreements in the United States, United Kingdom and Australia.

Related Party Transactions

Certain EME subsidiaries have 49%-50% ownership in partnerships (qualifying facilities (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 $983 million in 2001, $716 million in 2000 and $513 million in 1999.

Purchased Power

SCE purchased power through the California Power Exchange (PX) from April 1998 through mid-January 2001. SCE has bilateral forward contracts with other entities (as discussed in Note 4) 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,	2001	2000	1999
PX/ISO:			
Purchases	$ 775	$8,449	$2,490
Generation sales	324	6,120	1,719
Purchased power — PX/ISO — net	451	2,329	771
Purchased power — bilateral contracts	188	—	—
Purchased power — interutility/QF contracts	3,131	2,358	2,419
Total	$3,770	$4,687	$3,190

Since January 17, 2001, all other power is purchased by the CDWR for delivery to SCE's customers and is not considered a cost to SCE.

Planned Major Maintenance

Certain plant facilities require major maintenance on a periodic basis. All such costs are expensed as incurred. Prior to January 1, 2000, EME recorded major maintenance costs on an accrue-in-advance method. EME changed its accounting method for major maintenance to record such expenses as incurred in accordance with guidance provided by the Securities and Exchange Commission. The cumulative effect of the change in accounting method was a $22 million (after-tax) increase to income from continuing operations in 2000.

Other Nonoperating Income and Deductions

Other nonoperating income and deductions was comprised of:

In millions Year ended December 31,	2001	2000	1999
Nonutility nonoperating income	$ 51	$ 44	$ 33
Utility nonoperating income	57	118	162
Total nonoperating income	$108	$162	$195
Nonutility nonoperating deductions	$ 63	$ 32	$ 58
Utility nonoperating deductions	38	110	107
Total nonoperating deductions	$101	$142	$165

Earnings (Loss) Per Share (EPS)

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

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 comprehensive income in shareholders' equity. Gains or losses resulting from foreign currency transactions are included in other nonoperating income or deductions.

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.

Fuel Inventory

SCE's 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.

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 are recorded in the accumulated provision for decommissioning. All investments are classified as available-for-sale.

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.

AFUDC — equity was $7 million in 2001, $11 million in 2000 and $13 million in 1999. AFUDC — debt was $9 million in 2001, $10 million in 2000 and $11 million in 1999.

Replaced or retired property and removal costs less salvage are charged to the accumulated provision for depreciation. Depreciation expense stated as a percent of average original cost of depreciable utility plant was 3.6% for 2001, 2000 and 1999.

SCE's net investment in generation-related utility plant was $1.0 billion at both December 31, 2001, and December 31, 2000.

Nonutility property, including leasehold improvements, 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, 4.2% for 2001, 2.9% for 2000 and 2.2% for 1999.

Goodwill

Goodwill represents the excess of cost incurred over the fair value of net assets acquired in a purchase transaction. Goodwill was being 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. See New Accounting Standards for a further discussion.

Nuclear

During the second quarter of 1998, SCE reduced its remaining nuclear plant investment by $2.6 billion (book value as of June 30, 1998) and recorded a regulatory asset on its balance sheet for the same amount in accordance with asset impairment accounting standards. For this impairment assessment, the fair value of the investment was calculated by discounting expected future net cash flows. The reclassification had no effect on SCE's 1998 results of operations.

SCE had been recovering its investments in San Onofre Nuclear Generating Station Units 2 and 3 and Palo Verde Nuclear Generating Station 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 through 2003. Any differences between these costs and the incentive price would flow through to the 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 December 31, 2001. The San Onofre and Palo Verde rate recovery plans and the Palo Verde balancing account were part of the transition cost balancing account (TCBA).

The nuclear rate-making plans and the TCBA mechanism were to continue for rate-making purposes at least through 2001 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 discussed in Note 3), 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. Should SCE's utility-retained generation (URG) application be approved, SCE would reestablish 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, and adjust the PROACT regulatory asset balance to reflect recovery of the nuclear investment in accordance with the final URG decision.

The benefits of operation of the Palo Verde and San Onofre units were required to be shared equally with ratepayers beginning in 2002 and 2004, respectively. In a June 2001 decision, the CPUC granted SCE's request to eliminate the San Onofre post-2003 benefit sharing mechanism. The CPUC based its action on compliance with a new state law. In a September 2001 decision, the CPUC granted SCE's request to eliminate the Palo Verde post-2001 benefit sharing mechanism and 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. See discussion in Note 3 for the proposed and alternate decisions' impact on the incentive pricing plans.

Regulatory Assets and Liabilities

In accordance with accounting principles for rate-regulated enterprises, SCE records regulatory assets, which represent probable future revenue associated with certain costs that will be recovered from customers through the rate-making process, and regulatory liabilities, which represent probable future reductions in revenue associated with amounts that are to be credited to customers through the rate-making process.

The TCBA was established for the recovery of generation-related transition costs during the four-year rate freeze period. The transition revenue account (TRA) was a CPUC-authorized regulatory asset account in which SCE recorded the difference between revenue received from customers through frozen rates and the costs of providing service to customers, including power procurement costs. SCE's discontinuance of accounting principles for rate-regulated enterprises applicable to its generation assets did not result in a write-off of its generation-related regulatory assets at that time since the CPUC had approved recovery of these assets through the TCBA mechanism.

The gains resulting from the sale of 12 of SCE's generating plants during 1998 have been credited to the TCBA. The coal and hydroelectric generation balancing accounts tracked the differences between market revenue from coal and hydroelectric generation and the plants' operating costs after April 1, 1998.

On March 27, 2001, the CPUC issued a decision stating, among other things, that the rate freeze had not ended, and the TCBA mechanism was to remain in place. However, the decision required SCE to recalculate the TCBA retroactive to January 1, 1998, the beginning of the rate freeze period. The new calculation required the coal and hydroelectric balancing account overcollections (which amounted to $1.5 billion as of December 31, 2000) to be transferred monthly to the TRA, rather than annually to the TCBA (as previously required). In addition, it required the TRA to be transferred to the TCBA on a monthly basis. Previous rules had called only for overcollections to be transferred to the TCBA monthly, while undercollections were to remain in the TRA until they were recovered from future overcollections or the end of the rate freeze, whichever came first.

There are many factors that affect SCE's ability to recover its regulatory assets. SCE assessed the probability of recovery of its generation-related regulatory assets in light of the CPUC's March 27, 2001, decisions, including the retroactive transfer of balances from SCE's TRA to the TCBA and related changes. 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 the TCBA and other regulatory assets.

In addition to the TCBA, generation-related regulatory assets totaling $1.3 billion (including the unamortized nuclear investment, flow-through taxes, unamortized loss on sale of plant, purchased-power settlements and other regulatory assets) were written off as of December 31, 2000.

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 procurement-related obligations account (PROACT) regulatory asset for previously incurred energy procurement costs, retroactive to August 31, 2001. The settlement agreement calls for the end of the TCBA mechanism as of August 31, 2001, and continuation of the rate freeze (including surcharges) until the earlier of December 31, 2003, or the date SCE recovers its previously incurred (undercollected) power procurement costs. During a period beginning on September 1, 2001, and ending on the earlier of the date that SCE has recovered all of its procurement-related obligations recorded in the PROACT or December 31, 2005, SCE will apply to the PROACT the difference between SCE's revenue from retail electric rates (including surcharges) and the costs that SCE is authorized by the CPUC to recover in retail electric rates. The balance in the PROACT will accrue interest. If SCE has not recovered the entire balance by December 31, 2003, the unrecovered balance will be amortized for up to an additional two years.

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

In millions December 31,	2001	2000
PROACT	$2,641	$ —
Rate reduction notes — transition cost deferral	1,453	1,090
Other:		
Flow-through taxes	1,017	874
Unamortized loss on reacquired debt	254	273
Environmental remediation	57	52
Regulatory balancing accounts and other	189	(94)
Total	$5,611	$2,195

The regulatory asset related to the rate reduction notes will be recovered over the terms of those notes. The other regulatory assets and liabilities are being recovered through other components of electric rates.

Balancing account undercollections and overcollections accrue interest. Income tax effects on all balancing account changes are deferred.

Supplemental Cash Flows Information

Edison International supplemental cash flows information was:

In millions Year ended December 31,	2001	2000	1999
Cash payments for interest and taxes:			
Interest — net of amounts capitalized	$ 1,192	$1,128	$689
Tax payments (receipts)	(70)	3	27
Non-cash investing and financing activities:			
Obligation to fund investments in partnerships and unconsolidated subsidiaries	4	42	278
Liabilities assumed (of companies acquired)	801	397	539

New Accounting Standards

On January 1, 2001, Edison International adopted a new accounting standard for derivative instruments and hedging activities. Currently, Edison International is using the normal purchases and sales exception (see Note 4) for some of its fuel supply agreements. However, an authoritative accounting interpretation issued in October 2001 precludes contracts that have variable amounts from qualifying under the normal purchases and sales exception. EME and SCE are evaluating the impact of this new interpretation, which will be effective April 1, 2002.

In July and August 2001, three new accounting standards were issued: Business Combinations; Goodwill and Other Intangibles; and Accounting for Asset Retirement Obligations.

The new Business Combinations standard eliminates the pooling-of-interests method, effective June 30, 2001. After that, all business combinations will be recorded under the purchase method (record purchase based upon value exchanged and record goodwill for excess of costs over the net assets acquired).

The new Goodwill and Other Intangibles standard requires that companies cease amortizing goodwill, effective January 1, 2002. Goodwill initially recognized after June 30, 2001, was not amortized. Goodwill on the balance sheet at June 30, 2001, was amortized until December 31, 2001. Under the new standard, goodwill will be tested for impairment using a fair-value approach when events or circumstances occur indicating that impairment might exist. Also, a benchmark assessment for goodwill is required within six months of the date of adoption of the standard.

The Accounting for Asset Retirement Obligations standard requires entities to record the fair value of a liability for a legal asset retirement obligation 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. The standard is effective for Edison International on January 1, 2003.

Edison International is studying the impact of the new Asset Retirement Obligations and Goodwill and Other Intangibles standards, and is unable to predict at this time the impact on its financial statements. Edison International does not anticipate any material impact on its results of operations or financial position from the Business Combinations standard.

In October 2001, a new accounting standard was issued related to accounting for the impairment or disposal of long-lived assets. Although the standard supersedes a prior accounting standard related to the impairment of long-lived assets, it retains the fundamental provisions of the impairment standard regarding recognition/measurement of impairment of long-lived assets to be held and used and measurement of long-lived assets to be disposed of by sale. Under the new accounting standard, asset write-downs from discontinuing a business segment will be treated the same as other assets held for sale. The new standard also broadens the financial statement presentation of discontinued operations to include the disposal of an asset group (rather than a segment of a business). The standard (effective on January 1, 2002) was adopted early, in fourth quarter 2001. See Note 16 for further discussion.

Note 2. Liquidity Issues

Edison International's liquidity is affected primarily by debt maturities, access to capital markets, dividend payments, capital expenditures, asset sales, investments in partnerships and unconsolidated subsidiaries, credit ratings and utility regulation affecting SCE's ability to recover the cost of power purchases. Capital resources include cash from operations, asset sales and external financings.

Undercollections in the TRA and TCBA mechanisms, coupled with SCE's anticipated near-term capital requirements and the adverse reaction of the credit markets to continued regulatory uncertainty regarding SCE's ability to recover its current and future power procurement costs, materially and adversely affected SCE's liquidity throughout 2001. As a result of its liquidity concerns, SCE took steps to conserve cash to continue to provide service to its customers. As a part of this process, beginning in January 2001, SCE suspended payments owed to the ISO, the PX and QFs, deferred payments of certain obligations for principal and interest on outstanding debt and did not declare dividends on any of its cumulative preferred stock. As applicable, unpaid obligations continued to accrue interest. As of March 31, 2001, SCE resumed payment of interest on its debt obligations. However, since June 30, 2001, SCE deferred the interest payments on its quarterly income debt securities (subordinated debentures), as allowed by the terms of the securities. See Note 5. As long as accumulated dividends on SCE's preferred stock remained unpaid, SCE could not pay any dividends on its common stock. Common stock dividends are additionally restricted as detailed in Note 3.

Based on the rights to cost recovery and revenue established by the settlement agreement with the CPUC and CPUC implementing orders, including the PROACT resolution, SCE repaid its undisputed past-due obligations on March 1, 2002, with lump-sum payments to creditors from the proceeds of $1.6 billion in senior secured credit facilities, the remarketing of $196 million in pollution control bonds which were repurchased in late 2000, and existing cash on hand. The $1.6 billion senior secured credit facilities consist of a $300 million, two-year revolving credit loan, a $600 million, one-year loan and a $700 million, three-year loan. See Note 5.

The proceeds from the senior secured credit facilities and pollution control bond remarketing were used along with SCE's available cash to repay $3.2 billion in past-due obligations and $1.65 billion in near-term debt maturities. The past-due obligations consisted of: (1) $875 million to the PX; (2) $99 million to the

ISO; (3) $1.1 billion to QFs; (4) $193 million in PX energy credits for energy service providers; (5) $531 million of matured commercial paper; (6) $400 million of principal on its 5⅞% and 6½% senior unsecured notes which were issued prior to the energy crisis; and (7) $23 million in preferred dividends in arrears. The near-term debt maturities consisted of credit facilities whose maturity dates were extended several times and were scheduled to mature in March and May 2002. In addition, SCE has entered into an agreement with the CDWR to pay for prior deliveries of energy in installments of $100 million on April 1, 2002, $150 million on June 3, 2002, and the balance on July 1, 2002. in energy payments. After making the above-described payments, SCE has no material undisputed obligations that are past due or in default.

SCE's Board of Directors has not declared quarterly common stock dividends to SCE's parent, Edison International, since September 2000. Edison International's Board of Directors also has not declared a common stock dividend to Edison International's shareholders. Payment of dividends on SCE's common stock is restricted by the settlement agreement between the CPUC and SCE as detailed in Note 3.

Note 3. Electric Utility Regulatory Matters

CPUC Litigation Settlement Agreement

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 past electricity procurement costs in accordance with the tariffs filed with the FERC. By agreement of the parties, a stay of the lawsuit was issued in April 2001 while SCE sought implementation of legislative, regulatory and executive actions to resolve the California energy crisis and SCE's related financial and liquidity problems. In October 2001, the court entered a stipulated judgment approving an agreement between the CPUC and SCE to settle the pending lawsuit. On January 23, 2002, the CPUC adopted a resolution implementing the settlement agreement.

Key elements of the settlement agreement include the following items:

- Establishment of the PROACT as of September 1, 2001, with an opening balance equal to the amount of SCE's procurement-related liabilities as of August 31, 2001 (approximately $6.4 billion), less SCE's cash and cash equivalents as of that date (approximately $2.5 billion), and less $300 million.

- Beginning September 1, 2001, SCE will apply to the PROACT, on a monthly basis, the difference between SCE's revenue from retail electric rates (including surcharges) and the costs that SCE is authorized by the CPUC to recover in retail electric rates. Unrecovered obligations in the PROACT will accrue interest from September 1, 2001.

- Maintain current rates (including surcharges) in effect until December 31, 2003, subject to certain adjustments, or, if earlier, until the date that SCE recovers the entire PROACT balance. If SCE has not recovered the entire balance by December 31, 2003, the unrecovered balance will be amortized for up to an additional two years. The parties project that existing retail electric rates, including surcharges and as adjusted to reflect certain costs, will likely result in SCE recovering substantially all of its unrecovered procurement-related obligations prior to the end of 2003.

- If the CPUC concludes that it is desirable to authorize a securitized financing of SCE's procurement-related obligations, the parties will work together to achieve the securitization. Proceeds of any securitization will be credited to the PROACT when they are actually received.

- During the period that SCE is recovering its previously incurred procurement-related obligations, no penalty will be imposed by the CPUC on SCE for any noncompliance with CPUC-mandated capital structure requirements.

- SCE can incur up to $250 million of recoverable costs to acquire financial instruments and engage in other transactions intended to hedge fuel cost risks associated with SCE's retained generation assets and power purchase contracts with QFs and other utilities. As of December 31, 2001, SCE had purchased $209 million in hedging instruments.

- SCE will not declare or pay dividends or other distributions on its common stock (all of which is held by its parent) prior to the earlier of the date SCE has recovered all of its procurement-related obligations in the PROACT or January 1, 2005. However, if SCE has not recovered all of its procurement-related obligations by December 31, 2003, SCE may apply to the CPUC for consent to resume common stock dividends, and the CPUC will not unreasonably withhold its consent.

- To ensure the ability of SCE to continue to provide adequate service, SCE may make capital expenditures above the level contained in current rates, up to $900 million per year, which will be treated as recoverable costs.

- Subject to certain qualifications, SCE will cooperate with the CPUC and the California Attorney General to pursue and resolve SCE's claims and rights against sellers of energy and related services, SCE's defenses to claims arising from any failure to make payments to the PX or ISO, and similar claims by the State of California or its agencies against the same adverse parties. During the recovery period discussed above, refunds obtained by SCE related to its procurement-related liabilities will be applied to the balance in the PROACT.

The settlement agreement states that one of its purposes is to restore the investment grade creditworthiness of SCE as rapidly as reasonably practicable so that it will be able to provide reliable electrical service as a state-regulated entity as it has in the past. SCE cannot provide assurance that it will regain investment grade credit ratings by any particular date.

On November 28, 2001, a federal court of appeals denied a California consumer group's request for a long-term stay of the settlement. The group had alleged that it was denied due process and that the CPUC had no authority to agree with SCE to violate the statutory rate freeze. In its ruling, the federal court of appeals also granted SCE's request for an expedited hearing of an appeal of the settlement filed by the consumer group. On March 4, 2002, the court of appeals heard argument on the appeal and the matter is now under submission. A decision could be issued anytime during the next several months. SCE cannot predict the outcome of the appeal or the impact that any outcome would have upon the stipulated judgment or settlement. Possible outcomes include affirmance, a return to the district court or reversal of the stipulated judgment. SCE cannot predict whether or how a ruling on the stipulated judgment could also affect the settlement agreement.

CDWR Power Purchases

In accordance with an emergency order signed by the governor, the CDWR began making emergency power purchases for SCE's customers on January 17, 2001. Amounts SCE bills to and collects from its customers for electric power purchased and sold by the CDWR and through the ISO are remitted directly to the CDWR and are not recognized as revenue by SCE. In February 2001, Assembly Bill 1 (First Extraordinary Session, AB 1X) was enacted into law. AB 1X authorized the CDWR to enter into contracts to purchase electric power and sell power at cost directly to retail customers being served by SCE, and authorized the CDWR to issue bonds to finance electricity purchases.

On March 27, 2001, the CPUC issued an interim order requiring SCE to pay the CDWR a per-kWh price equal to the applicable generation-related retail rate per kWh for electricity (based on rates in effect on January 5, 2001), for each kWh the CDWR sells to SCE's customers. The CPUC determined that the generation-related retail rate should be equal to the total bundled electric rate (including the 1¢ per kWh surcharge adopted by the CPUC on January 4, 2001) less certain nongeneration-related rates or charges.

For the period January 19 through January 31, 2001, the CPUC ordered SCE to pay the CDWR at a rate of 6.277¢ per kWh for power delivered to SCE's customers. The CPUC determined that the applicable rate component is 7.277¢ per kWh (which increased to 10.277¢ per kWh for electricity delivered after March 27, 2001, due to the 3¢ surcharge discussed in Rate Stabilization Proceedings), for electricity delivered by the CDWR to SCE's retail customers after February 1, 2001, until more specific rates are calculated. The CPUC ordered SCE to pay the CDWR within 45 days after the CDWR supplies power to retail customers, subject to penalties for each day the payment is late.

On February 21, 2002, the CPUC issued a decision implementing a CDWR revenue requirement of $9.0 billion to pay its bonds' costs and energy procurement costs for the period January 17, 2001, through December 31, 2002. The decision states that SCE's allocated share of this revenue requirement would be approximately $3.6 billion, and changes SCE's payment to 9.744¢ per kWh for all bills rendered on or after March 15, 2002. The decision requires SCE to pay the CDWR in equal monthly installments over a six-month period the difference in rates between January 17, 2001, and March 15, 2002. SCE estimates that this amount is approximately $41 million.

On February 28, 2002, SCE and the CDWR executed an agreement that resolves outstanding issues relating to the payment for electric power purchased for SCE's customers through the ISO real-time market (known as imbalance energy). Under this agreement, SCE will pay the CDWR for imbalance energy previously delivered in three installments ($100 million on April 1, 2002; $150 million on June 3, 2002; and the balance on July 1, 2002).

Rate Stabilization Proceedings

In January 2000, SCE filed an application with the CPUC proposing rates that would go into effect when the four-year rate freeze was to end on March 31, 2002, or earlier, depending on the pace of transition cost recovery. In December 2000, SCE filed an amended rate stabilization plan application, stating that the statutory rate freeze had ended in accordance with California law, and requesting the CPUC to approve an immediate 30% increase to be effective, subject to refund, January 4, 2001.

In January 2001, independent auditors hired by the CPUC issued a report on the financial condition and solvency of SCE and its affiliates. The report confirmed what SCE had previously disclosed to the CPUC in public filings about SCE's financial condition. The audit report covered, among other things, cash needs, credit relationships, accounting mechanisms to track stranded cost recovery, the flow of funds between SCE and Edison International, and earnings of SCE's California affiliates. In April 2001, the CPUC adopted an order instituting investigation that reopens the past CPUC decision authorizing the utilities to form holding companies and initiates an investigation into: whether the holding companies violated CPUC requirements to give first priority to the capital needs of their respective utility subsidiaries; whether ring-fencing actions by Edison International and PG&E Corporation and their respective nonutility affiliates also violated the requirements to give first priority to the capital needs of their utility subsidiaries; whether the payment of dividends by the utilities violated requirements that the utilities maintain dividend policies as though they were comparable stand-alone utility companies; any additional suspected violations of laws or CPUC rules and decisions; and whether additional rules, conditions, or other changes to the holding company decisions are necessary. The CPUC ordered testimony and briefing on these matters, which SCE filed in May and June 2001. On January 9, 2002, the CPUC issued an interim decision on the first priority condition. The decision stated that, at least under certain circumstances, the condition includes the requirement that holding companies infuse all types of capital into their respective utility subsidiaries when necessary to fulfill the utility's obligation to serve. On February 11, 2002, SCE filed an application for rehearing of the decision stating that the decision is an unlawful and erroneous attempt to rewrite the first priority condition rather than interpret it and that the decision could result in higher rates for SCE's customers. Neither Edison International nor SCE can predict what effects this investigation or any subsequent actions by the CPUC may have on either one of them.

In March 2001, the CPUC ordered a rate increase in the form of a 3¢ per kWh surcharge applied only to going-forward electric power procurement costs, effective immediately, and affirmed that a 1¢ interim surcharge granted in January 2001 is permanent. The 3¢ surcharge is to be added to the rate paid to the CDWR. Although the 3¢ increase was authorized as of March 27, 2001, the surcharge was not collected in rates until the CPUC established a rate design in early June 2001. To compensate for the two-month delay in collecting the 3¢ surcharge, the CPUC authorized an additional ½¢ surcharge for a 12-month period beginning in June 2001.

Utility-Retained Generation Proceeding

In June 2001, SCE filed a comprehensive proposal for new cost-of-service ratemaking for utility retained generation through the end of 2002. After that time, SCE's URG-related revenue requirement will be determined in the general rate case. The URG proposal calls for balancing accounts for SCE-owned generation, QF and interutility contracts, procurement costs and ISO charges based on either actual or CPUC-authorized revenue requirements. Under the proposal, the four new balancing accounts would be effective on January 1, 2001, for capital-related costs, and February 1, 2001, for non-capital-related costs. In addition, SCE's unamortized nuclear investment would be amortized and recovered in rates over a 10-year period, effective January 1, 2001. Should this application be approved as filed, SCE expects to reestablish for financial reporting purposes its unamortized nuclear investment and regulatory assets related to purchased-power settlements and flow-through taxes, with a corresponding credit to earnings and adjust the PROACT regulatory asset balance in accordance with the final URG decision.

On January 18, 2002, a CPUC administrative law judge issued a proposed decision and a CPUC commissioner issued an alternate proposed decision. Both the proposed and alternate proposed decisions adopt most of the elements of SCE's application, but propose eliminating incremental cost incentive pricing for San Onofre, effective January 1, 2002, and replacing it with balancing account treatment for San Onofre's operating costs, subject to a later reasonableness review. On February 7, 2002, another CPUC commissioner issued an alternate proposed decision recommending continuing the incentive pricing plan for San Onofre Units 2 and 3 through December 31, 2003, as originally provided in CPUC decisions adopted in early 1996. A final decision is expected in second quarter 2002.

Wholesale Electricity Markets

In October 2000, SCE filed a joint petition urging the FERC to immediately find the California wholesale electricity market to be not workably competitive, immediately impose a cap on the price for energy and ancillary services, and institute further expedited proceedings regarding the market failure, mitigation of market power, structural solutions and responsibility for refunds. In December 2000, the FERC took limited action and failed to impose a price cap. SCE filed an emergency petition in the federal court of appeals challenging the FERC order and requesting the FERC to immediately establish cost-based wholesale rates. The court denied SCE's petition in January 2001.

In its December 2000 order, the FERC established an "underscheduling" penalty effective January 1, 2001, applicable to scheduling coordinators that do not schedule sufficient resources to supply 95% of their respective loads. In December 2001, the FERC eliminated the underscheduling penalty retroactive to January 1, 2001.

On April 25, 2001, after months of extremely high power prices, the FERC issued an order providing for energy price controls during ISO Stage 1 or greater power emergencies (7% or less in reserve power). The order establishes an hourly clearing price based on the costs of the least efficient generating unit during the period. Effective June 20, 2001, the FERC expanded the April 25, 2001, order to include non-emergency periods and price mitigation in the 11-state western region. The latest order is in effect until September 30, 2002.

After unsuccessful settlement negotiations among utilities, power sellers and state representatives, on July 25, 2001, the FERC issued an order that limits potential refunds from alleged overcharges to the ISO and PX spot markets during the period from October 2, 2000, through June 20, 2001, and adopted a refund methodology based on daily spot market gas prices. An administrative law judge will conduct evidentiary hearings on this matter. SCE cannot predict the amount of any potential refunds. Under the settlement of litigation with the CPUC, refunds will be applied to the balance in the PROACT.

Note 4. 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 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 (acquired in 2000).

On January 1, 2001, Edison International adopted a new accounting standard for derivative instruments and hedging activities. 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 realized loss of $26 million on the interest rate swap will be amortized over a period ending in 2008. Due to downgrades in SCE's credit ratings and SCE's failure to pay its obligations to the PX, the PX suspended SCE's market trading privileges and sought to liquidate SCE's remaining block forward contracts. Before the PX could do so, on February 2, 2001, the state seized the contracts. On September 30, 2001, a federal appeals court ruled that the Governor of California acted illegally when he seized the contracts held by SCE. In conjunction with its settlement agreement with the CPUC, SCE has agreed to release any claim for compensation against the state for these contracts. However, if the PX prevails in its claims against the state, SCE may receive some refunds.

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 mitigate its exposure to increases in natural gas prices. Amounts paid to QFs for energy are based on natural gas prices. The options cover various periods from 2002 through 2003. Any fair value changes for gas call options are offset through a regulatory balancing account; therefore, fair value changes do not affect earnings.

EME's primary risk exposures arise from changes in electricity and fuel prices, interest rates and fluctuations in foreign currency exchange rates. These risks are managed, in part, by using derivative financial instruments in accordance with established policies and procedures.

The majority of EME's physical long-term power and fuel contracts, and the similar business activities of EME's affiliates, either do not meet the definition of a derivative or qualify under the normal purchases and sales exception. The majority of EME's remaining risk management activities, including forward sales contracts from the Homer City plant, are classified as cash flow hedges. EME's hedge agreement with the State Electricity Commission of Victoria for electricity prices from the Loy Yang B plant in Australia qualifies 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. Some of EME's derivatives did not qualify for either the normal purchases and sales exception or as cash flow hedges. These derivatives are recorded at fair value with subsequent changes in fair value recorded in the income statement. The majority of EME's risk management activities related to the fuel contracts from the Collins Station in Illinois do not qualify for either the normal purchases and sales exception or as cash flow hedges. In this situation, EME could not conclude that the timing of generation from these power plants met the probable requirement for a specific forecasted transaction under the new accounting standard.

As a result of the adoption of the new standard, Edison International expects its quarterly earnings from its EME subsidiary will be more volatile than earnings reported under the prior accounting policy. On January 1, 2001, EME recorded a $250,000 (after tax) increase to income from continuing operations and a $6 million (after tax) increase to income from discontinued operations as a cumulative change in the accounting for derivatives. In addition, EME recorded a $230 million (after tax) unrealized holding loss upon adoption as a change in accounting principle reflected in accumulated other comprehensive income in the consolidated balance sheet. In 2001, EME recorded a $61 million (after tax) increase to other comprehensive income primarily resulting from unrealized holding gains on forward sales contracts from its Homer City plant through June 30, 2001, and a net loss of $1 million representing the amount of cash flow hedges' ineffectiveness, which is reflected in nonutility power generation revenue in the consolidated income statement.

From January 1, 2001, through June 30, 2001, EME's forward sales contracts from the Homer City plant did not qualify for the normal purchases and sales exception due to net settlement provisions with the counterparties. New accounting guidance effective July 1, 2001, modified the normal purchases and sales exception to include electricity contracts if it is probable that they will result in physical delivery, notwithstanding any net settlement provisions. Accordingly, EME applied the normal purchases and sales exception for its Homer City forward sales contracts effective July 1, 2001. As a result, EME eliminated the value of its Homer City forward sales contracts from its consolidated balance sheet effective July 1, 2001. The cumulative effect of this change in accounting is reflected as a $16 million (after tax) decrease to other comprehensive income.

EME had previously applied the normal purchases and sales exception for long-term commodity contracts entered into by its First Hydro plant to buy and sell electricity for the period between January 1, 2001, through June 30, 2001. However, the criteria applicable to the buyer of power outlined in the accounting guidance precluded the contracts from qualifying under the normal purchases and sales exception as of July 1, 2001. 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.

The unrealized losses on cash flow hedges at December 31, 2001, included EME's losses on interest rate swaps and the hedge agreement with the State Electricity Commission of Victoria for electricity prices from the Loy Yang B plant in Australia. The Loy Yang B contract also could not qualify under the normal purchases and sales exception because financial settlement of the contract occurs without physical delivery. EME's accumulated other comprehensive loss at December 31, 2001, related to unrealized losses on cash flow hedges resulting from the Loy Yang B contract was $95 million. The unrealized losses resulted from current forecasts of future electricity prices in these markets greater than EME's contract prices. Assuming the long-term contract with the State Electricity Commission of Victoria continues to qualify as a cash flow hedge, future changes in the forecast of market prices for contract volumes included in this agreement will increase or decrease EME's other comprehensive income without significantly affecting EME's net income.

Under EME's fixed to variable swap agreements, the fixed interest rate payments are at a weighted average rate of 5.972% and 5.65% at December 31, 2001 and 2000, respectively. Variable rate payments under EME's corporate agreements are based on six-month LIBOR capped at 9%; 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 2.803% and 5.605% at December 31, 2001 and 2000, respectively. Under the variable to fixed swap agreements, EME will pay counterparties interest at a weighted average fixed rate of 7.118% and 7.59% at December 31, 2001 and 2000, respectively. Counterparties will pay EME interest at a weighted average variable rate of 4.762% and 6.43% at December 31, 2001 and 2000, 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 6.76%.

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.

Mission Energy Holding Company, 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 year ended December 31, 2001, Mission Energy Holding Company recorded a decrease to other comprehensive income of nearly $1 million (after tax) resulting from unrealized holding losses on these contracts. Under the variable to fixed swap agreements, Mission Energy Holding Company will pay counterparties interest at a weighted average fixed rate of 2.763% at December 31, 2001; counterparties will pay interest at a weighted average variable rate based on LIBOR of 1.981% at December 31, 2001.

Edison Capital has interest rate swaps to reduce the potential impact of changes in interest rates. On January 1, 2001, Edison Capital recorded its interest rate swap agreements. In 2001, Edison Capital's earnings were reduced by $4 million, reflecting the fair value change of an interest rate swap that does not qualify for hedge accounting. This swap was terminated in February 2002. In 2001, Edison Capital made payments on its swap agreements at a weighted average rate of 5.993% and received payments at a weighted average rate of 4.351%. In 2000, Edison Capital made payments on its swap agreements at a weighted average rate of 6.156% and received payments at a weighted average rate of 6.719%.

Fair values of financial instruments were:

In millions December 31,	2001	2000
Derivatives:		
Interest rate swap/cap agreements	$ (40)	$ (65)
Interest rate options	(1)	—
Commodity price:		
Forwards	64	(108)
Futures	(8)	(11)
Options	91	2
Swaps	(138)	16
Foreign currency forward exchange agreements	(1)	—
Cross currency interest rate swaps	28	—
Other:		
Decommissioning trusts	2,275	2,505
Long-term receivables	265	268
DOE decommissioning and decontamination fees	(25)	(31)
Long-term debt	(12,686)	(11,197)
Utility preferred stock subject to mandatory redemption	(118)	(157)
Utility preferred stock to be redeemed within one year	(102)	—
Other preferred securities subject to mandatory redemption	(258)	(327)
Short-term debt	(2,421)	(3,670)
Trading activities:		
Assets	5	306
Liabilities	(3)	(290)

The fair value of the interest rate hedges 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 swaps is based on financial models; the fair value of the gas call options 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 U.S. Department of Energy (DOE) decommissioning and decontamination fees; and brokers' quotes for short-term debt, long-term debt and preferred stock and preferred securities.

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 5. Long-Term Debt

California law prohibits SCE from incurring or guaranteeing debt for its nonutility affiliates.

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 uses 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. 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 in December 2000 and early 2001 that could not be remarketed in accordance with their terms. On March 1, 2002, SCE sold approximately $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.

Commercial paper intended to be refinanced for a period exceeding one year and used to finance nuclear fuel scheduled for use more than one year after the balance sheet date is classified as long-term debt.

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 non-bypassable residential and small commercial customer rates which constitute the transition property purchased by SCE Funding LLC. The notes are secured by the transition property and are not secured 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. Due to SCE's credit downgrade, in January 2001, SCE began remitting its customer collections related to the rate-reduction notes on a daily basis.

Long-term debt consisted of:

In millions December 31,	2001	2000
First and refunding mortgage bonds:		
2002-2026 (5.625% to 7.25%)	$ 1,175	$ 1,175
Rate reduction notes:		
2002-2007 (6.22% to 6.42%)	1,478	1,724
Pollution-control bonds:		
2008-2040 (5.125% to 7.2% and variable)	1,216	1,216
Bonds repurchased	(550)	(420)
Funds held by trustees	(20)	(20)
Debentures and notes:		
2001-2029 (5.875% to 13.5% and variable)	10,774	9,263
Subordinated debentures:		
2044 (8.375%)	100	100
Commercial paper for nuclear fuel	60	79
Capital lease obligation	1	1
Long-term debt due within one year	(1,499)	(929)
Unamortized debt discount — net	(61)	(39)
Total	$12,674	$12,150

Long-term debt maturities and sinking-fund requirements for the next five years are: 2002 — $1.5 billion; 2003 — $2.4 billion; 2004 — $2.5 billion; 2005 — $607 million; and 2006 — $882 million.

As a result of its liquidity concerns, SCE took steps to conserve cash to continue to provide service to its customers. As a part of this process, SCE had suspended payments of certain obligations, including $400 million of maturing principal on its 5⅞% and 6½% senior unsecured notes. From June 30, 2001, SCE deferred the interest payments on its quarterly income debt securities (subordinated debentures), as allowed by the terms of the securities. All interest in arrears will be paid on April 1, 2002.

On March 1, 2002, SCE closed on $1.6 billion in syndicated senior secured credit facilities providing for $600 million of one-year term loans, $700 million of three-year term loans and $300 million of two-year revolving credit loans. The interest rate for the revolving credit loans and the one-year loan is a eurodollar rate plus 2.5% or a bank prime or equivalent rate plus 1.5%, at SCE's election. The interest rate for the three-year loans is a eurodollar rate plus 3% or a bank prime or equivalent rate plus a margin of 2%, at SCE's election. The credit facilities are secured by three newly issued series of SCE first mortgage bonds. The proceeds of the loans, along with available cash, were used to repay all of SCE's past due obligations and near-term maturities, which include the senior notes.

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: 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.

In July 2001, Mission Energy Holding Company, which was formed in 2001, issued $800 million of 13.50% senior secured notes due 2008 and borrowed $385 million under a senior secured term loan due 2006. Both the senior secured notes and the term loan are non-recourse to Edison International and EME and are secured by the common stock of EME and interest reserve accounts covering the interest payable on those obligations for the first two years. Proceeds of the notes and term loan were used by the parent company to repay the entire outstanding principal amount of $618 million of its existing bank credit facility, plus interest of approximately $6 million, as well as a portion of the $250 million of senior unsecured notes maturing July 18, 2001. The credit facility was originally due on May 14, 2001, but the bank lenders had agreed to extend the maturity date to June 30, 2001, and to forbear exercising remedies under the credit facility due to cross-defaults by SCE. The bank credit facility has not been renewed.

Note 6. Short-Term Debt

Short-term debt is used to finance fuel inventories, balancing account undercollections and general cash requirements, including power purchase payments. Commercial paper intended to finance nuclear fuel scheduled to be used more than one year after the balance sheet date is classified as long-term debt in connection with refinancing terms under five-year term lines of credit with commercial banks.

Short-term debt consisted of:

In millions December 31,	2001	2000
Commercial paper	$ 531	$1,586
Bank loans	1,650	1,326
Floating rate notes	—	600
Amount reclassified as long-term	(60)	(79)
Unamortized discount	—	(14)
Other short-term debt	324	472
Total	$2,445	$3,891
Weighted-average interest rate	5.4%	7.2%

At December 31, 2001, Edison International's subsidiaries had lines of credit totaling $2.6 billion, with various expiration dates, and when available, can be drawn down at negotiated or bank index rates. Edison Capital's $300 million bank facility originally matured on June 30, 2001, but was extended until July 31, 2001. In July 2001, $150 million was extended until June 30, 2002; the remaining $150 million was paid off. EME had total lines of credit of $750 million, with $554 million available to finance general cash requirements.

As of January 2001, SCE had borrowed the entire $1.65 billion in funds available under its credit lines. The proceeds were used in part to repurchase pollution control bonds; the balance was retained as a liquidity reserve. SCE conserved cash by deferring payment of $531 million of matured commercial paper. Edison International has made and expects to continue to make all payments on its securities and other obligations as they become due.

SCE repaid its credit line borrowings and commercial paper using proceeds from the March 1, 2002, SCE financings. See further discussion in Note 2.

Note 7. Preferred Securities

Preferred Stock of Utility

SCE's authorized shares of preferred and preference stocks are: $25 cumulative preferred — 24 million; $100 cumulative preferred — 12 million; and preference — 50 million. All cumulative preferred stocks are redeemable. Mandatorily redeemable preferred stocks are subject to sinking-fund provisions. When preferred shares are redeemed, the premiums paid are charged to common equity.

Preferred stock redemption requirements for the next five years are: 2002 — $105 million; 2003 — $9 million; 2004 — $9 million; 2005 —$9 million; and 2006— $9 million.

SCE's cumulative preferred stocks consisted of:

Dollars in millions, except per share amounts	December 31, 2001 Shares Outstanding	December 31, 2001 Redemption Price	2001	2000
Not subject to mandatory redemption:				
$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
Subject to mandatory redemption:				
$100 par value:				
6.05% Series	750,000	$100.00	$ 75	$ 75
6.45	1,000,000	100.00	100	100
7.23	807,000	100.00	81	81
Preferred stock to be redeemed within one year			(105)	—
Total			$ 151	$256

SCE did not issue or redeem any preferred stock in the last three years.

In 2001, SCE's Board did not declare the regular quarterly dividends for any of SCE's cumulative preferred stock. As of February 28, 2002, SCE's preferred stock dividends in arrears were $23 million. On March 11, 2002, SCE repaid its past due preferred stock dividends.

Company-Obligated Mandatorily Redeemable Securities of Subsidiary

EME issued, through a limited partnership, 3.5 million of 9.875% cumulative monthly income preferred securities in 1994, at a price of $25 per security. These securities are redeemable at the option of the partnership, in whole or in part, beginning November 1999 with mandatory redemption in 2024 at a redemption price of $25 per security plus accrued and unpaid distributions. EME also issued, through the limited partnership, 2.5 million of 8.5% cumulative monthly income preferred securities, at a price of $25 per security in 1995. These securities are redeemable at the option of the partnership, in whole or in part, beginning August 2000 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. 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 an extended interest payment period as provided in the indenture.

In 1999, Edison International (the parent company) issued, through affiliates, $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 will continue 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. The parent company expects to continue to pay all other obligations as they are due.

Other Preferred Securities

In December 2000, EME's Series A and Series B shares were redeemed at their liquidation preference of $100,000 per share, plus an additional premium of $3,785 per share and all unpaid dividends. These shares (600 Series A and 600 Series B, with a dividend rate of 5.74%) were issued during 1999, through an indirect affiliate of EME. These securities were redeemable, in whole or in part, at the option of EME's affiliate, beginning May 2004, at $100,000 per share, plus accrued and unpaid dividends.

In 1999, EME issued through an indirect, wholly-owned affiliate $84 million of Class A redeemable preferred shares (16,000 shares priced at 10,000 New Zealand dollars per share with dividend rates between 6.19% and 6.86%). These shares were redeemable at their issuance price in June 2003.

In 1999, EME issued through an indirect affiliate $125 million of retail redeemable preference shares (240 million shares priced at one New Zealand dollar per share with dividend rates between 5.0% and 6.37%). The shares were redeemable at their issuance price, according to the following schedule: June 2001 (64 million shares); June 2002 (43 million shares); and June 2003 (133 million shares).

On July 2, 2001, EME redeemed the Class A redeemable preferred shares at 10,000 New Zealand dollars per share and the retail redeemable preferred shares at one New Zealand dollar per share.

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 issuance price. Optional early redemption may occur if the holders pass an extraordinary resolution to redeem the shares if the subsidiary ceases to be an EME subsidiary, or in the case of certain defaults of the security trust deed.

Note 8. Income Taxes

Edison International's subsidiaries are included in Edison International's consolidated federal income tax and combined state franchise tax returns. Under income tax allocation agreements, each subsidiary calculates its own tax liability.

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 components of the net accumulated deferred income tax liability were:

In millions December 31,	2001	2000
Deferred tax assets:		
Property-related	$ 192	$ 277
Unrealized gains or losses	310	420
Investment tax credits	72	81
Regulatory balancing accounts	1,709	1,763
Decommissioning	99	98
Unbilled revenue	(10)	101
Deferred income	179	183
Accrued charges	490	540
Loss carryforwards	727	902
Other	255	129
Total	$4,023	$4,494
Deferred tax liabilities:		
Property-related	$3,643	$3,454
Leveraged leases	1,972	1,665
Capitalized software costs	224	264
Regulatory balancing accounts	2,929	1,632
Decommissioning	28	28
Unrealized gains and losses	208	317
Other	294	332
Total	$9,298	$7,692
Accumulated deferred income taxes — net	$5,275	$3,198
Classification of accumulated deferred income taxes:		
Included in deferred credits	$6,367	$4,537
Included in current assets	$1,092	1,339

The current and deferred components of income tax expense (benefit) were:

In millions Year ended December 31,	2001	2000	1999
Current:			
Federal	$ (215)	$ (61)	$ (82)
State	—	—	9
Foreign	30	70	(31)
	(185)	9	(104)
Deferred — federal and state:			
Accrued charges	(79)	(98)	(128)
Depreciation and basis differences	165	(5)	(59)
Investment and energy tax credits — net	(6)	(41)	(46)
Leveraged leases	320	387	315
Loss carryforwards	36	(812)	—
Regulatory balancing accounts	1,345	(740)	371
CTC amortization	(138)	251	7
Price risk management	39	(38)	—
State tax — privilege year	(41)	30	4
Unbilled revenue	101	20	(5)
Other	90	18	(7)
	1,832	(1,028)	452
Total	$1,647	$(1,019)	$ 348

The composite federal and state statutory income tax rate was 40.551% for all years presented.

The federal statutory income tax rate is reconciled to the effective tax rate below:

Year ended December 31,	2001	2000	1999
Federal statutory rate	35.0%	35.0%	35.0%
Foreign earnings reinvestment	(0.3)	0.4	(3.9)
Housing credits	(1.2)	2.1	(6.2)
Capital loss utilization	—	—	(4.2)
Capitalized software	—	0.4	(2.2)
Property-related and other	1.1	(7.9)	9.5
Investment and energy tax credits	(0.2)	1.4	(4.1)
State tax — net of federal deduction	6.3	3.0	9.9
Effective tax rate	40.7%	34.4%	33.8%

Note 9. 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 $40 million in 2001, $41 million in 2000 and $31 million in 1999.

Pension Plan and Postretirement Benefits Other Than Pensions

Edison International has a noncontributory, defined-benefit pension plan that covers employees meeting minimum service requirements. Edison International's utility operations recognize pension expense as calculated by the actuarial method used for ratemaking. In April 1999, Edison International adopted a cash balance feature for its pension plan.

Most United States 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.

Information on plan assets and benefit obligations is shown below:

In millions Year ended December 31,	Pension Benefits 2001	Pension Benefits 2000	Other Postretirement Benefits 2001	Other Postretirement Benefits 2000
Change in benefit obligation				
Benefit obligation at beginning of year	$2,261	$ 2,121	$ 1,890	$1,547
Service cost	78	74	50	45
Interest cost	159	159	137	129
Actuarial loss (gain)	87	92	47	231
Benefits paid	(185)	(185)	(71)	(62)
Benefit obligation at end of year	$2,400	$ 2,261	$ 2,053	$1,890
Change in plan assets				
Fair value of plan assets at beginning of year	$3,109	$ 3,112	1,200	$1,283
Actual return on plan assets	(165)	143	(92)	(41)
Employer contributions	9	39	102	20
Benefits paid	(185)	(185)	(71)	(62)
Fair value of plan assets at end of year	$2,768	$ 3,109	$ 1,139	$1,200
Funded status	$ 368	$ 848	$ (914)	$ (690)
Unrecognized net loss (gain)	(225)	(741)	407	160
Unrecognized transition obligation	17	23	296	323
Unrecognized prior service cost	107	115	(3)	(3)
Recorded asset (liability)	$ 267	$ 245	$ (214)	$ (210)
Discount rate	7.0%	7.25%	7.25%	7.5%
Rate of compensation increase	5.0%	5.0%	—	—
Expected return on plan assets	8.5%	8.5%	8.2%	8.2%

Expense components were:

In millions Year ended December 31,	Pension Benefits 2001	Pension Benefits 2000	Pension Benefits 1999	Other Postretirement Benefits 2001	Other Postretirement Benefits 2000	Other Postretirement Benefits 1999
Service cost	$ 78	$ 74	$ 70	$ 50	$ 45	$ 49
Interest cost	159	159	149	137	129	111
Expected return on plan assets	(255)	(270)	(190)	(98)	(106)	(80)
Special termination benefits	13	—	—	2	—	—
Net amortization and deferral	(9)	(40)	12	27	27	27
Expense under accounting standards	(14)	(77)	41	118	95	107
Regulatory adjustment — deferred	39	88	14	—	—	—
Total expense recognized	$ 25	$ 11	$ 55	$118	$ 95	$107

The assumed rate of future increases in the per-capita cost of health care benefits is 10.5% for 2002, gradually decreasing to 5.0% for 2008 and beyond. Increasing the health care cost trend rate by one percentage point would increase the accumulated obligation as of December 31, 2001, by $331 million and annual aggregate service and interest costs by $36 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated obligation as of December 31, 2001, by $267 million and annual aggregate service and interest costs by $28 million.

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 $7 million in 2001, $13 million in 2000 and $157 million in 1999.

Stock Options

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 award of Edison International common shares and options on shares. 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 the special options discussed below were awarded.

Under the 1992, 1998 and 2000 plans, options on 9.3 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 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 1999 Edison International stock option awards include a dividend equivalent feature.

Options issued after 1997 generally have a four-year vesting period. The special options granted in 2000 vest over five years, but vesting does not begin until 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 which 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 above pro forma disclosures, 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,	2001	2000
Expected life	7 years-10 years	7 years-10 years
Risk-free interest rate	4.7%-6.1%	4.7%-6.0%
Expected volatility	17%-52%	17%-46%

The application of fair-value accounting to calculate the pro forma disclosures above 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:

			Weighted-Average		
	Share Options	Exercise Price	Exercise Price	Fair Value At Grant	Remaining Life
Outstanding, Dec. 31, 1998	5,431,268	$14.56-$29.34	$21.52		7 years
Granted	3,045,949	$24.81-$28.13	$28.10	$6.45	
Expired	—	—	—		
Forfeited	(6,805)	$28.13-$28.80	$28.65		
Exercised	(368,264)	$14.56-$25.75	$18.72		
Outstanding, Dec. 31, 1999	8,102,148	$14.56-$29.34	$24.04		7 years
Granted	13,373,680	$15.88-$28.13	$21.02	$5.63	
Expired	—	—	—		
Forfeited	(1,183,760)	$15.94-$28.94	$23.19		
Exercised	(517,396)	$14.56-$28.13	$19.35		
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

The number of options exercisable and their weighted-average exercise prices at December 31, 2001, 2000 and 1999 were 5,930,024 at $22.92, 6,782,209 at $23.27 and 5,018,556 at $21.63, respectively.

Other Equity-Based Awards

For years after 1999, a portion of the executive long-term incentives was awarded in the form of performance shares. The 2000 performance shares were restructured as retention incentives in December 2000, which pay as a combination of Edison International common stock and cash if the executive remains employed at the end of the performance period. The performance period ended December 31, 2001, for half the award, and ends on December 31, 2002, for the remainder. Additional performance shares were awarded in January 2001 and January 2002. The 2001 performance shares vest December 31, 2003, half in shares of Edison International common stock and half in cash. The 2002 performance shares vest December 31, 2004, also half in shares of common stock and half in cash. The number of shares that will be paid out from the 2002 performance share awards will depend on the performance of Edison International common stock relative to the stock performance of a specified group of peer companies.

The 2000 and 2001 performance shares and deferred stock unit values are accrued ratably over a three-year performance period. The 2002 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 will be paid between March 12, 2002, and March 12, 2003, depending on performance. The deferred stock units are payable on the vesting date 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. The deferred stock units will vest 25% per year over four years, with the first vesting date in November 2002. The following assumptions were used in determining fair value through the Black-Scholes option-pricing model: expected life: 8-9 years; risk-free interest rate: 5.10%; expected volatility: 52%.

Edison International measures compensation expense related to stock-based compensation by the intrinsic value method. Compensation expense recorded under the stock-compensation program was $1 million in 2001, $5 million in 2000 and $5 million in 1999.

Stock-based compensation expense under the fair-value method of accounting would have resulted in pro forma earnings (loss) of $1.031 billion for 2001, $(1.954) billion for 2000 and $621 million for 1999, and in pro forma basic earnings (loss) per share of $3.17 for 2001, $(5.87) for 2000 $1.79 for 1999.

Note 10. 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, 2001, was:

In millions	Investment in Facility	Accumulated Depreciation and Amortization	Ownership Interest
Transmission systems:			
Eldorado	$ 41	$ 11	60%
Pacific Intertie	240	84	50
Generating stations:			
Four Corners Units 4 and 5 (coal)	469	365	48
Mohave (coal)	334	246	56
Palo Verde (nuclear)(1)	1,653	1,648	16
San Onofre (nuclear)(1)	4,305	4,283	75
Total	$7,042	$6,637	

(1) Regulatory assets, which were written off as a charge to earnings as of December 31, 2000, as discussed in Note 1.

Note 11. 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 fair value of $809 million).

During 2000, EME entered into a sale-leaseback of certain equipment, primarily Illinois peaker power units, with a third party lessor for $300 million. In connection with the sale-leaseback, EME purchased $255 million of notes issued by the lessor which accrue interest at a variable rate depending on EME's credit rating. The notes are due and payable in 2005. Also 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.

Estimated remaining commitments for noncancelable leases at December 31, 2001, were:

Year ended December 31,	In millions
2002	$388
2003	386
2004	373
2005	427
2006	518
Thereafter	5,814
Total	$7,906

Operating lease expense was $182 million in 2001, $142 million in 2000 and $27 million in 1999.

Leveraged Leases

Edison Capital is the lessor in several leveraged-lease agreements with terms of 23 to 37 years. All operating, maintenance, insurance and decommissioning costs are the responsibility of the lessees. The total cost of these facilities was $7.0 billion and $7.5 billion at December 31, 2001, and 2000, respectively.

The equity investment in these facilities is generally 20% of the cost to acquire the facilities. The remainder is 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 investment in leveraged leases consisted of:

In millions December 31,	2001	2000
Rentals receivable (net of principal and interest on nonrecourse debt)	$ 3,555	$ 3,827
Unearned income	(1,258)	(1,531)
Investment in leveraged leases	2,297	2,296
Estimated residual value	57	57
Deferred income taxes	(1,972)	(1,665)
Net investment in leveraged leases	$ 382	$ 688

Nuclear Decommissioning

Decommissioning is estimated to cost $2.1 billion in current-year dollars, based on site-specific studies performed in 1998 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 $8.6 billion through 2060 to decommission its nuclear facilities. This estimate is based on SCE's current dollar decommissioning costs, escalated at rates ranging from 0.3% to 10.0% (depending on the cost element) annually. These costs are expected to be funded from independent decommissioning trusts, which effective June 1999 receive contributions of approximately $25 million per year. SCE estimates annual after-tax earnings on the decommissioning funds of 3.9% to 4.9%.

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 2026 and 2028 for the Palo Verde units. Decommissioning costs, which are recovered through non-bypassable customer rates over the term of each nuclear facility's operating license, are recorded as a component of depreciation expense.

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's Unit 1 decommissioning costs will be paid from its nuclear decommissioning trust funds.

Decommissioning expense was $96 million in 2001, $106 million in 2000 and $124 million in 1999. The accumulated provision for decommissioning, excluding San Onofre Unit 1 and unrealized holding gains, was $1.5 billion at December 31, 2001, and $1.4 billion at December 31, 2000. The estimated cost to decommission San Onofre Unit 1 is recorded as a liability.

Decommissioning funds collected in rates are placed in independent trusts, which, together with accumulated earnings, will be utilized solely for decommissioning.

Trust investments (cost basis) include:

In millions	Maturity Dates	December 31,	2001	2000
Municipal bonds	2001-2034		$ 463	$ 548
Stocks	—		637	531
U.S. government issues	2001-2029		332	421
Short-term and other	2001		334	220
Total			$1,766	$1,720

Trust fund earnings (based on specific identification) increase the trust fund balance and the accumulated provision for decommissioning. Net earnings were $13 million in 2001, $38 million in 2000 and $58 million in 1999. Proceeds from sales of securities (which are reinvested) were $3.9 billion in 2001, $4.7 billion in 2000 and $2.6 billion in 1999. Approximately 91% of the trust fund contributions were tax-deductible.

Other Commitments

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

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.

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 $158 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 $31 million). The transmission service contract requires a minimum payment of approximately $6 million a year.

Certain commitments for the years 2002 through 2006 are estimated below:

In millions	2002	2003	2004	2005	2006
Fuel supply contract payments	$810	$575	$552	$536	$523
Purchased-power capacity payments	629	629	626	624	572

EME has entered into a support agreement that commits it to contribute up to $300 million in equity to its trading unit. EME has firm commitments related to the Italian Wind projects for asset purchases of $6 million and equity and other contributions to its projects of $139 million, primarily for the CBK and Sunrise projects. EME also has contingent obligations to make additional contributions of $45 million, primarily for equity support guarantees related to the Paiton project in Indonesia and ISAB project in Italy. EME has capital commitments of $77 million for environmental improvements at certain projects and an obligation to build 500 MW of electricity generating units in Illinois.

Some EME subsidiaries have entered into indemnification agreements, under which the subsidiaries have agreed to repay capacity payments to the projects' power purchasers if the projects unilaterally terminate their performance or reduce their electric power producing capability during the term of the power contracts. Obligations under these indemnification agreements as of December 31, 2001, if payment were required, would be $234 million. EME does not expect these projects to terminate their performance or reduce their electric power producing capability during the term of the power contracts.

In June 2000, EME entered into a long-term transportation contract with Kern River Gas Transmission Company related to the expansion of the Midway-Sunset project, a 225-MW power plant in California, in which its wholly owned subsidiary owns a 50% interest. Under the terms of the contract, EME has contractual commitments of $116 million to transport natural gas beginning the later of May 1, 2003, or the first day that expansion capacity is available for transportation services. EME is committed to pay minimum fees under this agreement, which has a term of 15 years.

Edison Capital has commitments of $57 million to fund affordable housing, and energy and infrastructure investments through 2003. At December 31, 2001, as a result of Edison Capital's financial condition, it has deposited approximately $7 million as collateral for several letters of credit currently outstanding.

Some of the QFs owed by SCE, in which EME has interests, sought to minimize their exposure by reducing deliveries under power purchase agreements during the period in which SCE failed to make payments. Although four of these partnerships filed lawsuits against SCE, they have now entered into agreements with SCE. As a result of the deferral of payments to these QFs, the partnerships in which EME has interests have called on the partners to provide additional capital to fund operating costs of the power plants. During 2001, EME subsidiaries have made equity contributions of approximately $134 million to meet capital calls by partnerships. EME subsidiaries and the other partners may be required to make additional capital contributions to the partnerships. On March 1, 2002, SCE made payments of its past due power purchase obligations to the QFs.

Note 12. 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.

Energy Crisis Issues

In October 2000, a federal class action securities lawsuit was filed against SCE and Edison International. As amended in December 2000 and March 2001, the lawsuit involves securities fraud claims arising from alleged improper accounting for the TRA undercollections. The second amended complaint is supposedly filed on behalf of a class of persons who purchased Edison International common stock between July 21, 2000, and April 17, 2001. This lawsuit has been consolidated with another similar lawsuit filed on March 15, 2001. A consolidated class action complaint was filed on August 3, 2001. On September 17, 2001, SCE and Edison International filed a motion to dismiss for failure to state a claim. On March 8, 2002, the district court issued an order dismissing the complaint with prejudice. The plaintiffs could appeal this ruling to the court of appeals.

SCE has been a defendant in a number of legal actions brought by various QFs arising out of SCE's suspension of payments for electricity delivered by the QFs during the period November 1, 2000, through March 26, 2001. The QF claims were eventually largely subsumed within agreements with the litigating QFs providing for a provisional settlement of the parties' disputes. On March 1, 2002, SCE paid the amounts due under settlement agreements with these QFs, which triggered the releases and other provisions of the settlements. As a result, the litigation with those QFs to whom payment in full has been made under the parties' settlement agreements should be dismissed during 2002. However, SCE's March 1, 2002, payments excluded several QFs or did not result in immediate releases under the settlement agreements based on unique disputes or other unique circumstances, including the status of regulatory approval.

Environmental Protection

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, primarily at EME. There is no assurance that EME would be able to recover increased costs from its customers or that its financial position and results of operations would not be materially affected.

Edison International records its environmental 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 42 identified sites is $111 million. 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 $279 million. The upper limit of this range of costs was estimated using assumptions least favorable to Edison International among a range of reasonably possible outcomes. SCE has sold all of its gas-fueled generation plants and has retained some liability associated with the divested properties.

The CPUC allows SCE to recover environmental-cleanup costs at certain sites, representing $50 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. Costs incurred at SCE's remaining sites are expected to be recovered through customer rates. SCE has recorded a regulatory asset of $76 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 now 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 $10 million to $25 million. Recorded costs for 2001 were $18 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 and, based upon the CPUC's regulatory treatment of environmental-cleanup costs, 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.

Nuclear Insurance

Federal law limits public liability claims from a nuclear incident to $9.5 billion. SCE and other owners of San Onofre and Palo Verde have purchased the maximum private primary insurance available ($200 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 U.S. 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 $88 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 $175 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.

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. These policies are issued primarily by mutual insurance companies owned by utilities with nuclear facilities. 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 $35 million per year. Insurance premiums are charged to operating expense.

Paiton Project

A wholly owned subsidiary of EME (Paiton Energy) owns a 40% interest and has a $492 million investment (at December 31, 2001) in the Paiton project, a 1,230-MW coal-fired power plant in Indonesia.

Under the terms of a long-term power purchase agreement between the state-owned electricity company and Paiton Energy, the state-owned electricity company is required to pay for capacity and fixed operating costs once each unit and the plant achieve commercial operation.

Paiton Energy and the state-owned electricity company signed a binding term sheet on December 14, 2001, setting forth the commercial terms under which Paiton Energy is to be paid for capacity and energy charges, as well as a monthly settlement payment covering amounts owed by the state-owned electricity company as well as settlement of other claims. Paiton Energy and the state-owned electricity company are continuing negotiations on an amendment to the power purchase agreement that will include the agreed commercial terms in the binding term sheet, with the aim of concluding those negotiations by March 31, 2002. The binding term sheet serves as the basis under which the state-owned electricity company will pay Paiton Energy beginning January 1, 2002. The binding term sheet will expire on March 31, 2002, unless extended by mutual agreement. The state-owned electricity company has made all payments to Paiton Energy as required under the agreements covering 2001, which are superseded by the binding term sheet. Paiton Energy is continuing to generate electricity to meet the power demand in the region and believes that the state-owned electricity company will continue to agree to make payments for electricity under the binding term sheet while negotiations on the amendment to the power purchase agreement continue. Although completion of negotiations may be delayed beyond March 31, 2002, Paiton Energy continues to believe that negotiations on the long-term restructuring of the revenue schedule will be successful.

Under the binding term sheet, past due accounts receivable due under the original power purchase agreement will be compensated through a monthly settlement payment of $4 million for 30 years. Prior to the expiration of the binding term sheet on March 31, 2002, the state-owned electricity company and Paiton Energy may, agree in writing to extend the expiration date for the binding term sheet, provided that both parties are working in good faith to complete the power purchase agreement amendment and the related conditions precedent to such agreement and the state-owned electricity company is continuing to pay all amounts due under the binding term sheet. If the power purchase agreement amendment is not completed within reasonable time frames acceptable to Paiton Energy, the parties will be entitled to revert to the terms and conditions of the original power purchase agreement in order to pursue arbitration in the international courts.

Any material modifications of the power purchase agreement resulting from the continuing negotiation of a new long-term revenue schedule could require a renegotiation of the Paiton project's debt agreements. The impact of any such renegotiations with the state-owned electricity company, the Indonesian government or the project's creditors on EME's expected return on its investment in the Paiton project is uncertain at this time; however, EME believes that it will ultimately recover its investment in the project.

Spent Nuclear Fuel

Under federal law, the DOE is responsible for the selection and development of a facility for disposal of spent nuclear fuel and high-level radioactive waste. Such a facility was to be in operation by January 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 from other nuclear power plants. Extended delays by the DOE could lead to consideration of costly alternatives involving 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 one mill per kilowatt-hour of nuclear-generated electricity sold after April 6, 1983.

SCE, as operating agent, has primary responsibility for the interim storage of its spent nuclear fuel at San Onofre. Current capability to store spent fuel is estimated to be adequate through 2005. SCE plans to spend approximately $34 million for the initial interim spent fuel storage at San Onofre Units 2 and 3 through 2008.

Palo Verde on-site spent fuel storage capacity will accommodate needs until 2003 for Unit 2, and until 2004 for Units 1 and 3. Arizona Public Service Company, operating agent for Palo Verde, is constructing an interim fuel storage facility that is expected to be completed in 2002.

Storm Lake Power

As of December 31, 2001, Edison Capital has an investment of approximately $85 million in Storm Lake Power, a project developed by Enron Wind, a subsidiary of Enron Corporation. Storm Lake has outstanding loans of approximately $76 million. Enron and its subsidiary provided certain guarantees related to the amount of power that would be generated from Storm Lake. The lenders have sent a notice to Storm Lake claiming that Enron's bankruptcy is an event of default under the loan agreement. The lenders have not indicated what actions, if any, they may take in response to Enron Wind's recent bankruptcy. In the event of default, the lenders may exercise certain remedies, including acceleration of the loan balance, repossession and foreclosure of the project, which could result in the loss of some or all of Edison Capital's investment in Storm Lake. Edison Capital expects Storm Lake to demonstrate that Enron's bankruptcy does not impair its ability to meet its loan obligations. Edison Capital also expects that Storm Lake will vigorously oppose any attempt by the lenders to exercise remedies that could result in Edison Capital's loss of its investment.

Note 13. Investments in Partnerships and Unconsolidated Subsidiaries

Edison International's nonutility subsidiaries have equity interests 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 $266 million at December 31, 2001. The difference related to the energy projects is being amortized over the life of the projects; the difference related to the oil and gas investments is amortized on a unit of production basis over the life of the reserves. Amortization will cease January 1, 2002, in accordance with a new accounting standard.

Summarized financial information of these investments was:

In millions	Year ended December 31,	2001	2000	1999
Revenue		$ 3,380	$ 3,013	$2,338
Expenses		2,847	2,464	1,872
Net income		$ 533	$ 549	$ 466

In millions	December 31,	2001	2000
Current assets		$ 2,274	$ 2,007
Other assets		10,059	9,782
Total assets		$12,333	$11,789
Current liabilities		$ 1,971	$ 1,255
Other liabilities		7,435	7,554
Equity		2,927	2,980
Total liabilities and equity		$12,333	$11,789

The undistributed earnings of investments accounted for by the equity method were $331 million in 2001 and $271 million in 2000.

Note 14. Business Segments

Edison International's reportable business segments include its electric utility operation segment (SCE), a nonutility power generation segment (EME) and a capital and 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 segment 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 development and 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 capital and 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 sales to Exelon Generation Company under power purchase agreements terminating in December 2004. Revenue from such sales was $1.1 billion in both 2001 and 2000.

Edison International's business segment information was:

In millions	Electric Utility	Nonutility Power Generation	Capital & Financial Services	Corporate & Other[1]	Edison International
2001					
Operating revenue	$ 8,126	$ 2,968[2]	$ 202	$ 140	$11,436
Depreciation, decommissioning and amortization	681	273	17	2	973
Interest and dividend income	215	35	19	13	282
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[3]	(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
2000					
Operating revenue	$ 7,870	$ 2,561[2]	$ 274	$ (14)	$10,691
Depreciation, decommissioning and amortization	1,473	282	28	1	1,784
Interest and dividend income	173	31	10	(5)	209
Interest expense — net of amounts capitalized	572	558	57	70	1,257
Income tax (benefit) — continuing operations	(1,022)	81	(10)	(68)	(1,019)
Income (loss) from continuing operations	(2,050)	101	135	(125)	(1,939)
Net income (loss)	(2,050)[3]	125	135	(153)	(1,943)
Total assets	15,966	15,017	3,713	404	35,100
Additions to and acquisition of property and plant	1,096	331	1	45	1,473
1999					
Operating revenue	$ 7,548	$ 1,327[2]	$ 282	$ 19	$ 9,176
Depreciation, decommissioning and amortization	1,548	144	22	—	1,714
Interest and dividend income	69	44	4	(25)	92
Interest expense — net	483	308	41	9	841
Income tax (benefit) — continuing operations	438	(38)	(25)	(27)	348
Income (loss) from continuing operations	484	109	129	(41)	681
Net income	484[3]	130	129	(120)	623
Total assets	17,657	15,534	2,712	326	36,229
Additions to and acquisition of property and plant	986	6,215	—	(124)[4]	7,077

(1) Includes amounts from nonutility subsidiaries not significant as a reportable segment and intercompany eliminations.

(2) Includes equity in income from investments of $374 million in 2001, $267 million in 2000 and $244 million in 1999.

(3) Net income (loss) available for common stock.

(4) Includes liabilities assumed and deferred credits of projects acquired in 1999.

The net income (loss) reported for nonutility power generation includes income (loss) from discontinued operations of $(1.2) billion for 2001, $24 million for 2000 and $21 million for 1999. The net loss reported for corporate and other includes income (loss) from discontinued operations of $(133) million for 2001, $(28) million for 2000 and $(79) million for 1999.

Geographic Information

Electric power and steam generated domestically by EME is primarily sold 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 either electricity companies, electricity buying groups or electric utilities located in the country where the power is generated. Prior to December 15, 2000, all electric power generated by SCE was sold through the PX and ISO, as mandated by the CPUC.

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

In millions	Year ended December 31,	2001	2000	1999
Revenue				
United States		$10,492	$ 9,929	$ 8,451
Foreign countries:				
United Kingdom		327	447	432
Australia		160	178	209
Other		457	137	84
Total		$11,436	$10,691	$ 9,176

In millions	December 31,	2001	2000
Assets			
United States[1]		$31,532	$26,930
Foreign countries:			
United Kingdom[1]		1,675	5,212
Australia		1,152	1,217
New Zealand		1,331	686
Other		1,084	1,055
Total		$36,774	$35,100

(1) Includes assets of discontinued operations.

Note 15. Acquisitions and Dispositions

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 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. Subsequent to December 31, 2001, EME completed the sales of its 50% interests in the Commonwealth Atlantic and James River projects and its 30% interest in the Harbor project for $48 million. The sale agreements for EME's interests in the EcoEléctrica and Gordonsville projects were terminated by the buyers. EME is currently offering for sale its interest in the Brooklyn Navy Yard, EcoEléctrica and Gordonsville projects.

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.

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 $111 million (EME's share is $55 million). Equity is to be contributed through December 2003 upon full draw down of the debt facility, currently scheduled for late 2002. The equity commitment could be accelerated if EME's credit rating falls below investment grade. EME was notified that the project construction payment schedule required an adjustment in order to meet its obligations. EME has contributed $10 million of its equity commitment in December 2001. Debt financing has been arranged for the remainder of the cost for this project.

In September 2000, EME acquired the trading operations of Citizens Power LLC and a minority interest in certain structured transaction investments. The purchase price of $45 million (funded from existing cash) was based on the sum of the fair market value of the trading portfolio and the structured transaction investments, plus $25 million.

In March 2000, EME completed its acquisition of Edison Mission Wind Power Italy B.V., formerly known as Italian Vento Power Corp. Energy 5 B.V. Edison Mission Wind owns a 50% interest in a series of wind-generated power projects in operation or under development in Italy. When all of the projects under development are completed, currently scheduled for 2002, the total capacity of these projects will be 283 MW. The purchase price of the acquisition was $44 million with equity contribution obligations of up to $16 million, depending on the number of projects that are ultimately developed. As of December 31, 2001, the entire equity contribution has been funded.

In 1999, EME paid approximately $1.8 billion for Homer City Electric Generating Station. The purchase was partially financed by $1.5 billion of new loans, combined with corporate revolver borrowings and existing cash.

In December 1999, EME through its wholly owned subsidiary, Midwest Generation LLC, completed the acquisition of Commonwealth Edison's fossil-fueled generating plants in Illinois. The $4.9 billion transaction was funded primarily with a combination of debt secured by a pledge of the stock of certain subsidiaries, EME corporate debt, equity contributions from Edison International and amounts paid by third party lessors in connection with a lease transaction.

The above acquisitions were accounted for utilizing the purchase method. Edison International's consolidated income statements reflect the operations of Sunrise, Citizens Power LLC, Italian Wind, Homer City, and the Illinois Plants, as of the date of their respective acquisitions. Effective June 1, 2001, Contact Energy is accounted for on a consolidated basis.

Note 16. Discontinued Operations

On December 21, 2001, EME completed the sale of 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 ($1.15 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).

During second quarter 2001, Edison Enterprises, a wholly owned subsidiary of Edison International, decided to sell the majority of its assets. On August 1, 2001, Edison International completed the sale of one subsidiary (principally engaged in the business of providing residential security services and residential electrical warranty repair services) to ADT Security Services, Inc., a unit of Tyco International Ltd. On October 18, 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 loss on sale. 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.

The results of the coal stations and Edison Enterprises subsidiaries sold during 2001 have been reflected as discontinued operations in the consolidated financial statements, in accordance with the early adoption of a recently issued accounting standard related to the impairment and disposal of long-lived assets. The consolidated financial statements have been reclassified to conform to the discontinued operations presentation for all years presented. Revenue from discontinued operations was $748 million in 2001, $1.0 billion in 2000, and $520 million in 1999. The pre-tax losses of the discontinued operations were $2.2 billion in 2001, $34 million in 2000 and $111 million in 1999.

The carrying value of assets and liabilities of discontinued operations were:

In millions December 31,	2001	2000
Assets		
Cash and equivalents	$ 63	$ 369
Receivables — net	1	121
Other	90	200
Total current assets	154	690
Nonutility property — net	—	2,786
Other noncurrent assets	51	415
Total assets	$205	$3,891
Liabilities		
Accounts payable and accrued liabilities	$ 59	$ 214
Current maturities of long-term obligations	—	1,331
Short-term debt and other	5	72
Total current liabilities	64	1,617
Noncurrent liabilities	7	857
Total liabilities	$ 71	$2,474

In millions, except per share amounts	2001 Total	Fourth	Third	Second	First
Operating revenue	$11,436	$ 2,912	$ 3,882	$ 2,446	$ 2,196
Operating income	5,456	3,940	1,774	454	(712)
Income (loss) from continuing operations	2,402	2,172	801	59	(630)
Income (loss) from discontinued operations — net	(1,367)	(5)	(1,214)	(161)	13
Net income (loss)	1,035	2,167	(413)	(102)	(617)
Basic earnings (loss) per share:					
Continuing operations	7.37	6.66	2.46	0.18	(1.93)
Discontinued operations	(4.19)	(0.01)	(3.73)	(0.49)	0.04
Total	3.18	6.65	(1.27)	(0.31)	(1.89)
Diluted earnings (loss) per share:					
Continuing operations	7.36	6.66	2.46	0.18	(1.93)
Discontinued operations	(4.19)	(0.01)	(3.73)	(0.49)	0.04
Total	3.17	6.65	(1.27)	(0.31)	(1.89)
Dividends declared per share	—	—	—	—	—
Common stock prices:					
High	16.12	16.12	15.08	12.98	15.8125
Low	6.25	13.80	10.46	7.51	6.25
Close	15.10	15.10	13.16	11.15	12.64

In millions, except per share amounts	2000 Total	Fourth	Third	Second	First
Operating revenue	$10,691	$ 2,323	$ 3,434	$ 2,528	$ 2,406
Operating income (loss)	(1,808)	(3,808)	971	560	469
Income (loss) from continuing operations	(1,939)	(2,558)	381	156	82
Income (loss) from discontinued operations — net	(4)	8	(21)	(19)	28
Net income (loss)	(1,943)	(2,550)	360	137	110
Basic earnings (loss) per share:					
Continuing operations	(5.83)	(7.86)	1.17	0.47	0.24
Discontinued operations	(0.01)	0.03	(0.06)	(0.06)	0.08
Total	(5.84)	(7.83)	1.11	0.41	0.32
Diluted earnings (loss) per share:					
Continuing operations	(5.83)	(7.86)	1.16	0.47	0.24
Discontinued operations	(0.01)	0.03	(0.06)	(0.06)	0.08
Total	(5.84)	(7.83)	1.10	0.41	0.32
Dividends declared per share	0.84	—	0.28	0.28	0.28
Common stock prices:					
High	30.00	24.437	26.625	21.937	30.00
Low	14.125	14.125	19.00	16.312	15.25
Close	15.625	15.625	19.328	20.50	16.562

The sales of generating plants and other assets during 2001 is reported as discontinued operations in accordance with an accounting standard issued in October 2001. Edison International adopted the standard in fourth quarter 2001; prior periods have been restated to reflect continuing operations, unless noted otherwise.

Dollars in millions, except per-share amounts	2001	2000	1999	1998	1997
Edison International and Subsidiaries					
Operating revenue	$11,436	$10,691	$ 9,176	$ 8,860	$ 9,235
Operating expenses	$ 5,980	$12,499	$ 7,359	$ 7,076	$ 7,200
Income (loss) from continuing operations	$ 2,402	$ (1,939)	$ 681	$ 668	$ 700
Net income (loss)	$ 1,035	$ (1,943)	$ 623	$ 668	$ 700
Weighted-average shares of common stock outstanding (in millions)	326	333	348	359	400
Basic earnings per share:					
Continuing operations	$ 7.37	$ (5.83)	$ 1.96	$ 1.86	$ 1.75
Discontinued operations	$ (4.19)	$ (0.01)	$ (0.17)	—	—
Total	$ 3.18	$ (5.84)	$ 1.79	$ 1.86	$ 1.75
Diluted earnings per share	$ 3.17	$ (5.84)	$ 1.79	$ 1.84	$ 1.73
Dividends declared per share	—	$ 0.84	$ 1.08	$ 1.04	$ 1.00
Book value per share at year-end	$ 10.04	$ 7.43	$ 15.01	$ 14.55	$ 14.71
Market value per share at year-end	$ 15.10	$15.625	$26.187	$27.875	$27.187
Rate of return on common equity	58.0%	(41.0)%	12.2%	12.8%	11.7%
Price/earnings ratio	4.7	(2.7)	14.6	15.0	15.5
Ratio of earnings to fixed charges	3.21	(1.01)	1.99	2.33	2.41
Assets	$36,774	$35,100	$36,229	$24,698	$25,101
Long-term debt	$12,674	$12,150	$13,391	$ 8,008	$ 8,871
Common shareholders' equity	$ 3,272	$ 2,420	$ 5,211	$ 5,099	$ 5,527
Preferred stock subject to mandatory redemption	$ 256	$ 256	$ 256	$ 256	$ 275
Company-obligated mandatorily redeemable securities of subsidiaries holding solely parent company debentures	$ 949	$ 949	$ 948	$ 150	$ 150
Retained earnings	$ 1,634	$ 599	$ 3,079	$ 2,906	$ 3,176
Southern California Edison Company					
Operating revenue	$ 8,126	$ 7,870	$ 7,548	$ 7,500	$ 7,953
Net income (loss) available for common stock	$ 2,386	$ (2,050)	$ 484	$ 490	$ 576
Basic earnings (loss) per Edison International common share	$ 7.32	$ (6.16)	$ 1.39	$ 1.37	$ 1.44
Rate of return on common equity	311.0%	(67.6)%	15.2%	13.3%	11.6%
Peak demand in megawatts (MW)	17,890	19,757	19,122	19,935	19,118
Generation capacity at peak (MW)	9,802	9,886	10,431	10,546	21,511
Kilowatt-hour deliveries (in millions)	78,524	84,430	78,602	76,595	77,234
Customers (in millions)	4.47	4.42	4.36	4.27	4.25
Full-time employees	11,663	12,593	13,040	13,177	12,642
Edison Mission Energy					
Revenue	$ 2,968	$ 2,561	$ 1,327	$ 894	$ 975
Income from continuing operations	$ 113	$ 101	$ 109	$ 132	$ 128
Net income (loss)	$ (1,121)	$ 125	$ 130	$ 132	$ 115
Assets	$10,730	$15,017	$15,534	$ 5,158	$ 4,985
Rate of return on common equity	(46.9)%	4.3%	8.1%	14.8%	12.2%
Ownership in operating projects (MW)	19,019	22,759	22,037	5,153	5,180
Full-time employees	3,021	3,391	3,245	1,180	1,140
Edison Capital					
Revenue	$ 202	$ 274	$ 282	$ 235	$ 138
Net income	$ 84	$ 135	$ 129	$ 105	$ 61
Assets	$ 3,736	$ 3,713	$ 2,712	$ 2,276	$ 1,783
Rate of return on common equity	11.9%	22.9%	27.0%	30.2%	23.2%
Full-time employees	66	119	115	85	85

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 16, Discontinued Operations for further discussion.

John E. Bryson 1**
Chairman of the Board,
President and Chief Executive Officer,
Edison International
A director since 1990

Warren Christopher 1,4***
Senior Partner,
O'Melveny & Myers (law firm),
Los Angeles, California
A director since 1971†

Joan C. Hanley 2,4
The Former General Partner and Manager,
Miramonte Vineyards,
Rancho Palos Verdes, California
A director since 1980

Carl F. Huntsinger 1,4,5***
General Partner,
DAE Limited Partnership, Ltd.
(agricultural management),
Ojai, California
A director since 1983

Charles D. Miller 3,4,5***
Retired Chairman of the Board,
Avery Dennison Corporation
(manufacturer of self-adhesive products),
Pasadena, California
A director since 1987

Luis G. Nogales 2,3
Managing Partner,
Nogales Investors
(a private equity investment company),
Los Angeles, California
A director since 1993

Ronald L. Olson 1,2,4
Senior Partner,
Munger, Tolles and Olson
(law firm),
Los Angeles, California
A director since 1995

James M. Rosser 1,2,3
President, California State University, Los Angeles,
Los Angeles, California
A director since 1985

Robert H. Smith 3,5
Managing Director,
Smith and Crowley, Inc.
(merchant banking),
Pasadena, California
A director since 1987

Thomas C. Sutton 2,3,5
Chairman of the Board and Chief Executive Officer,
Pacific Life Insurance Company,
Newport Beach, California
A director since 1995

Daniel M. Tellep 2,5
Retired Chairman of the Board,
Lockheed Martin Corporation
(aerospace),
Saratoga, California
A director since 1992

1 Executive Committee
2 Finance Committee
3 Compensation and Executive Personnel Committee
4 Nominating Committee
5 Audit Committee

* Service includes combined Edison International and Southern California Edison Company Board memberships
** Edison International Board and Executive Committee only
*** Retiring May 14, 2002

† 8/19/71 to 1/20/77
6/18/81 to 1/19/93
5/15/97 to present

EDISON INTERNATIONAL

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

Theodore F. Craver, Jr.
Executive Vice President,
Chief Financial Officer and
Treasurer

Bryant C. Danner
Executive Vice President
and General Counsel

Mahvash Yazdi
Senior Vice President and
Chief Information Officer

Jo Ann Goddard
Vice President, Investor
Relations

Thomas M. Noonan
Vice President and Controller

Beverly P. Ryder
Vice President,
Community Involvement,
and Secretary

Anthony L. Smith
Vice President, Tax

SOUTHERN CALIFORNIA EDISON COMPANY

Alan J. Fohrer
Chairman of the Board and
Chief Executive Officer

Robert G. Foster
President

Harold B. Ray
Executive Vice President,
Generation Business Unit

Pamela A. Bass
Senior Vice President,
Customer Service Business Unit

John R. Fielder
Senior Vice President,
Regulatory Policy and Affairs

Stephen E. Pickett
Senior Vice President and
General Counsel

Richard M. Rosenblum
Senior Vice President,
Transmission and Distribution
Business Unit

Mahvash Yazdi
Senior Vice President and
Chief Information Officer

Emiko Banfield
Vice President, Shared Services

Robert C. Boada
Vice President and Treasurer

Clarence Brown
Vice President,
Corporate Communications

Bruce C. Foster
Vice President,
San Francisco Regulatory
Operations

A.L. Grant
Vice President, Engineering
and Technical Services

Frederick J. Grigsby, Jr.
Vice President, Human
Resources and Labor Relations

Lawrence D. Hamlin
Vice President, Power
Production

Harry B. Hutchison
Vice President, Customer
Service Operations

James A. Kelly
Vice President, Regulatory
Compliance

Russell W. Krieger
Vice President, Nuclear
Generation

Thomas M. Noonan
Vice President and Controller

Dwight E. Nunn
Vice President, Nuclear
Engineering and
Technical Services

Pedro J. Pizarro
Vice President, Business
Development

Frank J. Quevedo
Vice President, Equal
Opportunity

W. James Scilacci
Vice President and
Chief Financial Officer

Dale E. Shull, Jr.
Vice President, Power Delivery

Anthony L. Smith
Vice President, Tax

Joseph J. Wambold
Vice President, Nuclear Business
and
Support Services

Beverly P. Ryder
Secretary

EDISON MISSION ENERGY

John E. Bryson
Chairman of the Board

William J. Heller
President and
Chief Executive Officer

Robert M. Edgell
Executive Vice President and
President, Asia Pacific

Ronald L. Litzinger
Senior Vice President and
Chief Technical Officer

Georgia R. Nelson
Senior Vice President and
General Manager, Americas;
President, Midwest Generation

Kevin M. Smith
Senior Vice President,
Chief Financial Officer and
Treasurer

Raymond W. Vickers
Senior Vice President and
General Counsel

Paul D. Jacob
Vice President,
Marketing and Trading, Americas

S. Daniel Melita
Vice President and
General Manager, Europe

EDISON CAPITAL

John E. Bryson
Chairman of the Board

Thomas R. McDaniel
President and
Chief Executive Officer

Ashraf T. Dajani
Senior Vice President
Global Infrastructure

Larry C. Mount
Senior Vice President,
General Counsel and Secretary

Philip Dandridge
Vice President and
Chief Financial Officer

Deborah A. Ranier
Vice President,
Human Resources

EDISON O&M SERVICES

Theodore F. Craver, Jr.
Chairman of the Board

Wesley C. Moody
President and
Chief Executive Officer

Annual Meeting

The annual meeting of shareholders will be held on Tuesday, May 14, 2002, at 10:00 a.m., at the Double Tree Hotel, 222 North Vineyard Avenue, Ontario, California.

Stock Listing and Trading Information

Edison International Common Stock

The New York and Pacific stock exchanges use the ticker symbol EIX; daily newspapers list the stock as EdisonInt.

Preferred Securities and Preferred Stock

Edison International's preferred securities are listed on the New York Stock Exchange under the ticker symbols EIX prA for 7.875% QUIPS Series A and EIX prB for the 8.60% Series B. Previous day's closing prices, when traded, are listed in the daily newspapers in the New York Stock Exchange composite table. Southern California Edison Company's listed preferred stocks are listed on the American and Pacific stock exchanges under the ticker symbol SCE. Previous day's closing prices, when traded, are listed in the daily newspapers in the American Stock Exchange composite table. The 6.05%, 6.45% and 7.23% series of the $100 cumulative preferred stock are not listed; however, the 6.45% and 7.23% series are traded over-the-counter. The preferred securities of Mission Capital, an affiliate of Edison Mission Energy, are listed on the New York Stock Exchange under the ticker symbol MEPrA for the 9.875% series and MEPrB for the 8.50% series.

Transfer Agent and Registrar

Wells Fargo Bank Minnesota, N.A., maintains shareholder records and is the transfer agent and registrar for Edison International common stock and Southern California Edison Company's preferred stocks. Shareholders may call Wells Fargo Shareowner Services, (800) 347-8625, between 7 a.m. and 7 p.m. (Central Time), Monday through Friday, regarding:

- stock transfer and name-change requirements;
- address changes, including dividend addresses;
- electronic deposit of dividends;
- taxpayer identification number submission or changes;
- duplicate 1099 and W-9 forms;
- notices of, and replacement of, lost or destroyed stock certificates and dividend checks;
- direct debit of optional cash for dividend reinvestment;
- Edison International's Dividend Reinvestment and Stock Purchase Plan, including enrollments, withdrawals, terminations, transfers, sales, duplicate statements; and
- requests for access to online account information.

Inquiries may also be directed to:

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

Fax
(651) 450-4033

Email
stocktransfer@wellsfargo.com

Web Address
www.edisoninvestor.com

On line account information:
www.shareowneronline.com

Dividend Reinvestment and Electronic Transfer

A prospectus and enrollment forms for Edison International's Common Stock Dividend Reinvestment and Stock Purchase Plan are available from Wells Fargo Shareholder Services upon request.

EDISON INTERNATIONAL®

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