SOUTHERN CALIFORNIA
EDISON®
An EDISON INTERNATIONAL® Company

May 20, 2003

A. Edward Scherer
Manager of
Nuclear Regulatory Affairs

U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, D. C. 20555

Subject: **Docket Nos. 50-361, 50-362, 50-528, 50-529, and 50-530**
Annual Certified Financial Statement
San Onofre Nuclear Generating Station Units 2 and 3
Palo Verde Nuclear Generating Station Units 1, 2, and 3

Gentlemen:

Southern California Edison (SCE), as agent for the owners of the San Onofre Nuclear Generating Station Units 2 and 3 and SCE's 15.8% ownership share of Palo Verde Units 1,2, and 3, submits the following documents in accordance with 10 CFR 140.21(e):

- 2003 Cash Reserve statement which is from the consolidated financial statements included in SCE's 2002 Annual Report
- SCE's Annual Report for the fiscal year ending December 31, 2002
- SCE's Annual Report to the Securities and Exchange Commission (Form 10K) for the fiscal year ending December 31, 2002

If you have any questions or require further information about these documents, please contact me or Mr. Jack Rainsberry (949/368-7420).

Sincerely,

Enclosures

cc: E. W. Merschoff, Regional Administrator, NRC Region IV
B. M. Pham, NRC Project Manager, San Onofre Units 2, and 3
C. C. Osterholtz, NRC Senior Resident Inspector, San Onofre Units 2 & 3

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SOUTHERN CALIFORNIA EDISON COMPANY

2003 Cash Reserve
(Dollars in Thousands)

Cash Reserve as of December 31, 2002	$992,000
Percentage Ownership in All Nuclear Units:	
San Onofre Nuclear Generating Station Units 2 & 3	
o Southern California Edison Company	75.05%
o San Diego Gas & Electric Company	20.00%
o City of Anaheim	3.16%
o City of Riverside	1.79%
Palo Verde Nuclear Generating Station Units 1, 2 & 3	15.80%
Annual Per Incident Contingent Liability:	
San Onofre Nuclear Generating Station Unit 2	$10,000 (1)
San Onofre Nuclear Generating Station Unit 3	$10,000 (1)
Palo Verde Nuclear Generating Station Unit 1	$1,580 (2)
Palo Verde Nuclear Generating Station Unit 2	$1,580 (2)
Palo Verde Nuclear Generating Station Unit 3	$1,580 (2)
Total	$24,740

(1) The value represents 100% of the SONGS Annual Per Incident Contingent Liability.

(2) The value represents 15.8% (SCE's share) of the Palo Verde Annual Per Incident Contingent Liability.

SOUTHERN CALIFORNIA
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2002 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 117-year-old electric utility, serves a 50,000-square-mile area of central, coastal and southern California.

Contents

Selected Financial and Operating Data: 1998 – 2002

Southern California Edison Company

Dollars in millions	2002	2001	2000	1999	1998
Income statement data:					
Operating revenue	**$ 8,706**	$ 8,126	$ 7,870	$ 7,548	$ 7,500
Operating expenses	**6,579**	3,509	10,529	6,242	6,136
Fuel and purchased power expenses	**2,259**	3,982	4,882	3,405	3,586
Income tax (benefit)	**642**	1,658	(1,022)	438	442
Provisions for regulatory adjustment clauses – net	**1,502**	(3,028)	2,301	(763)	(473)
Interest expense – net of amounts capitalized	**584**	785	572	483	485
Net income (loss)	**1,247**	2,408	(2,028)	509	515
Net income (loss) available for common stock	**1,228**	2,386	(2,050)	484	490
Ratio of earnings to fixed charges	**4.21**	6.15	*	2.94	2.95
*less than 1.00					
Balance sheet data:					
Assets	**$ 18,314**	$ 22,453	$ 15,966	$ 17,657	$ 16,947
Gross utility plant	**16,341**	15,982	15,653	14,852	14,150
Accumulated provision for depreciation and decommissioning	**8,094**	7,969	7,834	7,520	6,896
Short-term debt	**—**	2,127	1,451	796	470
Common shareholder's equity	**4,384**	3,146	780	3,133	3,335
Preferred stock:					
Not subject to mandatory redemption	**129**	129	129	129	129
Subject to mandatory redemption	**147**	151	256	256	256
Long-term debt	**4,504**	4,739	5,631	5,137	5,447
Capital structure:					
Common shareholder's equity	**47.8%**	38.5%	11.5%	36.2%	36.4%
Preferred stock:					
Not subject to mandatory redemption	**1.4%**	1.6%	1.9%	1.5%	1.4%
Subject to mandatory redemption	**1.6%**	1.9%	3.8%	2.9%	2.8%
Long-term debt	**49.2%**	58.0%	82.8%	59.4%	59.4%
Operating data:					
Peak demand in megawatts (MW)	**18,821**	17,890	19,757	19,122	19,935
Generation capacity at peak (MW)	**9,767**	9,802	9,886	10,431	10,546
Kilowatt-hour deliveries (in millions)	**79,693**	78,524	84,430	78,602	76,595
Total energy requirement (kWh) (in millions)	**71,663**	83,495	82,503	78,752	80,289
Energy mix:					
Thermal	**40.2%**	32.5%	36.0%	35.5%	38.8%
Hydro	**5.0%**	3.6%	5.4%	5.6%	7.4%
Purchased power and other sources	**54.8%**	63.9%	58.6%	58.9%	53.8%
Customers (in millions)	**4.53**	4.47	4.42	4.36	4.27
Full-time employees	**12,113**	11,663	12,593	13,040	13,177

This Management's Discussion and Analysis of Results of Operations and Financial Condition (MD&A) contains forward-looking statements. These statements are based on Southern California Edison's (SCE) knowledge of present facts, current expectations about future events and assumptions about future developments. Forward-looking statements are not guarantees of performance; they are subject to risks, uncertainties and assumptions 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, but are not limited to, risks discussed below under "Financial Condition," "Market Risk Exposures" and "Forward-Looking Information and Risk Factors."

This MD&A includes information about SCE, a regulated public utility company providing electricity to retail customers in central, coastal, and southern California.

CURRENT DEVELOPMENTS

Between May 2000 and June 2001, the cost of unregulated wholesale power in California rose above revenue collected in rates that were frozen in 1998 and SCE was not allowed by the CPUC to pass these excess costs through to its customers. As a result SCE incurred $4.7 billion (pre-tax) in write-offs related to its undercollected costs and generation-related regulatory assets through August 31, 2001. In October 2001, SCE entered into a settlement agreement with the California Public Utilities Commission (CPUC) that allowed SCE to recover $3.6 billion in past procurement-related costs through the creation of a procurement-related obligations account (PROACT) regulatory asset. The balance in this regulatory asset decreased to $574 million at year-end 2002 and SCE expects to recover the remaining balance by mid-2003.

The Utility Reform Network (TURN), a consumer advocacy group, and other parties appealed to the federal court of appeals seeking to overturn the district court judgment that approved the settlement agreement. In September 2002, an appeals court opinion affirmed the district court on all claims, with the exception of challenges founded upon California state law, which the appeals court referred to the California Supreme Court. On November 20, 2002, the California Supreme Court issued an order indicating that it would hear the case. The key issues in this matter are whether the district court judgment violated California's electric industry restructuring statute providing for a rate freeze and state laws requiring open meetings and public hearings. SCE continues to operate under the settlement agreement and to believe it is probable that SCE will ultimately recover its past procurement costs through regulatory mechanisms, including the PROACT. However, SCE cannot predict with certainty the outcome of the pending legal proceedings.

In January 2001, the state of California began purchasing power on behalf of SCE's customers because SCE's financial condition prevented it from purchasing power supplies for its customers. On January 1, 2003, SCE resumed power procurement of its residual net short position (the amount of energy needed to serve SCE's customers from sources other than its own generating plants, power purchase contracts and California Department of Water Resources (CDWR) contracts).

These and other matters are discussed in detail in "Regulatory Matters."

RESULTS OF OPERATIONS

Earnings

In 2002, SCE earned $1.2 billion compared to earnings of $2.4 billion in 2001, and a loss of $2.1 billion in 2000. SCE's 2002 earnings included a $480 million benefit related to the implementation of the California Public Utilities Commission's (CPUC) utility retained generation (URG) decision. 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. Excluding the $480 million benefit in 2002, the $2.0 billion benefit in 2001, and the $2.5 billion write-off in 2000, SCE's earnings were $748 million in 2002, $408 million in 2001 and $471 million in 2000. The $340 million increase in 2002 primarily reflects increased revenue resulting from the CPUC's 2002

decision in SCE's performance-based ratemaking (PBR) proceeding, increased earnings from SCE's larger rate base in 2002 compared to 2001, lower interest expense, PBR rewards from prior years and increased income from San Onofre Nuclear Generating Station (San Onofre) Units 2 and 3. The increase was partially offset by higher operating and maintenance expense. The $63 million decrease in 2001 was primarily due to the February 2001 fire and resulting outage at San Onofre Unit 3 and lower kilowatt-hour sales.

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 a CPUC decision in March 2001, the $4.5 billion transition revenue account undercollection as of December 31, 2000 and the coal and hydroelectric balancing account overcollections were reclassified, and the transition cost balancing account (TCBA) balance was recalculated to be a $2.9 billion undercollection. 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 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

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.

The following table sets forth the major changes in operating revenue:

In millions Year ended December 31,	2002 vs. 2001	2001 vs. 2000
Operating revenue—		
Rate changes (including refunds)	$ 565	$ 2,338
Direct access credit	(604)	273
Interruptible noncompliance penalty	(8)	117
Sales volume changes	684	(2,402)
Other (including intercompany transactions)	(57)	(70)
Total	$ 580	$ 256

Operating revenue increased in 2002 as compared to 2001 (as shown in the table above) primarily due to a 3¢-per-kWh surcharge authorized by the CPUC as of March 27, 2001. Although the surcharge was authorized as of March 27, 2001, it was not collected in rates until the CPUC determined how the rate increase would be allocated among SCE's customer classes, which occurred in May 2001. In addition, the increase in revenue resulted from an increase in sales volume primarily due to SCE providing its customers with a greater volume of energy generated from its own generating plants and power purchase contracts, rather than the CDWR purchasing power on behalf of SCE's customers. Amounts SCE bills to and collects from its customers for electric power purchased and sold by the CDWR to SCE's customers (beginning January 17, 2001) and CDWR bond-related costs (beginning November 15, 2002) are being remitted to the CDWR and are not recognized as revenue by SCE. These amounts were $1.4 billion and $2.0 billion for the years ended December 31, 2002 and 2001, respectively. The increase in operating revenue was partially offset by a decrease in revenue arising from an increase in credits given to direct

access customers in 2002, compared to 2001, due to a significant increase in the number of direct access customers.

Operating revenue increased in 2001 (as shown in the table above), primarily due to the 4¢-per-kWh (1¢ in January and 3¢ in June) surcharge effective in 2001, the effects of the reduced credits given to direct access customers in 2001 and an increase in revenue related to penalties customers incurred for not complying with their interruptible contracts. The increases were partially offset by a decrease in retail sales volume primarily attributable to CDWR purchases on behalf of SCE customers and conservation efforts, as well as a decrease in revenue related to operation and maintenance services.

From 1998 through mid-September 2001, SCE's customers were able to choose to purchase power directly from an energy service provider other than SCE (thus becoming direct access customers) or continue to have SCE purchase power on their behalf. On March 21, 2002, the CPUC issued a decision affirming that new direct access arrangements entered into by SCE's customers after September 20, 2001 were invalid. Direct access arrangements entered into prior to September 20, 2001 remain valid. Most direct access customers continue to be billed by SCE, but are given a credit for the generation costs SCE saves by not serving them. Operating revenue is reported net of this credit. See "Direct Access – Historical Procurement Charge" discussion under "Regulatory Matters—Direct Access Proceedings" below.

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, 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 could be reevaluated.

Operating Expenses

Fuel expense increased in both 2002 and 2001. The 2002 increase was primarily due to fuel related costs related to a settlement agreement entered into with Peabody Western Coal Company associated with the Mohave Generating Station (Mohave). The 2001 increase was 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 both 2002 and 2001. The 2002 decrease resulted primarily from lower expenses at SCE related to qualifying facilities (QFs), bilateral contracts and interutility contracts, as discussed below. In addition, the decrease reflects the absence of California Power Exchange (PX)/ Independent System Operator (ISO) purchased-power expense after mid-January 2001. PX/ISO purchased-power expense increased significantly between May 2000 and mid-January 2001, due to dramatic wholesale electricity price increases. In December 2000, the FERC eliminated the requirement that SCE buy and sell all power through the PX. Due to SCE's noncompliance with the PX's tariff requirement for posting collateral for all transactions, as a result of the downgrades in its credit rating, the PX suspended SCE's market trading privileges effective mid-January 2001. The 2001 decrease resulted from the absence of PX/ISO purchased-power expense after mid-January 2001, partially offset by increased expenses related to QFs, bilateral contracts and interutility contracts.

Federal law and CPUC orders required SCE to enter into contracts to purchase power from QFs at CPUC-mandated prices. These contracts expire on various dates through 2025. In 2002, purchased-power expense declined significantly, primarily due to lower payments to QFs. Generally, energy payments for gas-fired QFs are tied to spot natural gas prices. Effective May 2002, energy payments for renewable QFs were based on a fixed price of 5.37¢ per kWh. During 2002, spot natural gas prices were significantly lower than the same periods in 2001. The decrease in 2002 purchased-power expense related to bilateral contracts and interutility contracts was also due to the decrease in natural gas prices. In 2001, purchased-power expense related to QFs increased due to higher prices for natural gas. 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.

Provisions for regulatory adjustment clauses – net increased in 2002 and decreased in 2001. The 2002 increase was primarily due to the establishment of the PROACT regulatory asset in 2001, overcollections used to recover the PROACT balance and revenue collected to recover the rate reduction bond regulatory asset, partially offset by the impact of SCE's implementation of CPUC decisions related to URG and the PBR mechanism, as well as the impact of other regulatory actions. The 2001 decrease resulted from SCE recording the $3.6 billion PROACT regulatory asset in fourth quarter 2001.

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

SCE's other operation and maintenance expense increased in 2002 primarily due to the San Onofre Unit 2 refueling outage in 2002, increases in transmission and distribution maintenance and inspection activities, and cost containment efforts that took place in 2001. The increases were partially offset by lower expenses related to balancing accounts.

Depreciation, decommissioning and amortization expense increased in 2002 and decreased in 2001. The increase in 2002 was mainly due to an increase in depreciation expense associated with SCE's additions to transmission and distribution assets and an increase in SCE's nuclear decommissioning expense. A 1994 CPUC decision allowed SCE to accelerate the recovery of its nuclear-related assets while deferring the recovery of its distribution-related assets for the same amount. Beginning in January 2002, the CPUC approved the commencement of recovery of SCE's deferred distribution assets. In addition, the increases reflect amortization expense on the nuclear regulatory asset reestablished during second quarter 2002 based on the URG decision (discussed below). The decrease in 2001 was primarily due to SCE's nuclear investment amortization expense ceasing because the unamortized nuclear investment regulatory asset was included in the December 31, 2000 write-off.

Other Income and Deductions

Interest and dividend income increased for both 2002 and 2001. The 2002 increase was mainly due to the interest income earned on the PROACT balance, partially offset by lower interest income due to lower average cash balances and lower interest rates. The 2001 increase was mainly due to an overall higher cash balance, as SCE conserved cash due to its liquidity crisis.

Other nonoperating income increased in 2002 and decreased in 2001. The 2002 increase was primarily due to property condemnation settlements received, partially offset by PBR incentive awards for 1999 and 2000, which were approved by the CPUC and recorded in 2002. The decrease in 2001 primarily reflects the gains on sales of marketable securities in 2000.

Interest expense – net of amounts capitalized decreased in 2002, and increased in 2001. The 2002 decrease was mainly due to lower short-term debt balances, as well as lower interest expense related to the suspension of purchased power in 2001, partially offset by an increase in interest expense related to the senior secured credit facility issued in March 2002. The 2001 increase reflects additional long-term debt and higher short-term debt balances.

Other nonoperating deductions decreased in 2002 and 2001, primarily due to lower accruals for regulatory matters in both periods.

Income Taxes

Income taxes decreased in 2002 and increased in 2001. The 2002 decrease was primarily due to a reduction in pre-tax income. Other decreases in tax expense resulted from a favorable resolution of tax

audits and the reestablishment of tax related regulatory assets upon implementation of the URG decision. The increase in 2001 reflects $1.5 billion in income tax expense related to the PROACT regulatory asset establishment in fourth quarter 2001. Absent the $1.5 billion income tax expense in 2001, SCE's income tax expense increased due to higher pre-tax income.

SCE's federal and state statutory tax rate was 40.551% for all years presented. The lower effective tax rate of 34% realized in 2002 was primarily due to the reestablishment of tax-related regulatory assets upon implementation of the URG decision as well favorable resolution of tax audits. The 2001 effective tax rate was comparable to the composite federal and state statutory tax rate.

FINANCIAL CONDITION

Cash Flows from Operating Activities

Net cash provided by operating activities was $631 million in 2002, $3.3 billion in 2001 and $829 million in 2000. The 2002 decrease in cash provided by operating activities was mainly due to the March 2002 repayment of past-due obligations, partially offset by higher overcollections used to recover regulatory assets resulting from the CPUC-approved surcharges (1¢ per kWh in January 2001 and 3¢ per kWh in June 2001). The increase in 2001 was primarily due to 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 2001 and 3¢ per kWh in June 2001) that were billed in 2001.

Cash Flows from Financing Activities

SCE's short-term debt is normally used to finance procurement-related obligations. Long-term debt is used mainly to finance the utility's rate base. External financings are influenced by market conditions and other factors.

During the first quarter of 2002, SCE paid $531 million of matured commercial paper and remarketed $196 million of the $550 million of pollution-control bonds repurchased during December 2000 and early 2001. Also during the first quarter of 2002, SCE replaced the $1.65 billion credit facility with a $1.6 billion financing and made a payment of $50 million to retire the entire credit facility. Throughout the year, SCE paid approximately $1.2 billion of maturing long-term debt. The $1.6 billion financing included a $600 million, one-year term loan due March 3, 2003. SCE prepaid $300 million of this loan in August 2002 and prepaid the balance on February 11, 2003. See additional discussion in "Liquidity Issues."

In December 1997, $2.5 billion of rate reduction notes were issued on behalf of SCE by SCE Funding LLC, a special purpose entity. These notes were issued to finance the 10% rate reduction mandated by state law. The proceeds of the rate reduction notes were used by SCE Funding LLC to purchase from SCE an enforceable right known as transition property. Transition property is a current property right created by the electric industry restructuring legislation and a financing order of the CPUC and consists generally of the right to be paid a specified amount from nonbypassable rates charged to residential and small commercial customers. The rate reduction notes are being repaid over 10 years through these nonbypassable residential and small commercial customer rates, which constitute the transition property purchased by SCE Funding LLC. The remaining series of outstanding rate reduction notes have scheduled maturities through 2007, with interest rates ranging from 6.22% to 6.42%. The notes are collateralized by the transition property and are not collateralized by, or payable from, assets of SCE or Edison International. SCE used the proceeds from the sale of the transition property to retire debt and equity securities. Although, as required by accounting principles generally accepted in the United States, SCE Funding LLC is consolidated with SCE and the rate reduction notes are shown as long-term debt in the consolidated financial statements, SCE Funding LLC is legally separate from SCE. The assets of SCE Funding LLC are not available to creditors of SCE or Edison International and the transition property is legally not an asset of SCE or Edison International.

Cash Flows from Investing Activities

Cash flows from investing activities are affected by additions to property and plant, primarily for transmission and distribution assets, 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.

Liquidity Issues

SCE expects to meet its continuing obligations in 2003 from cash on hand, which was $1.0 billion at December 31, 2002, and operating cash flows.

Sustained high wholesale energy prices from May 2000 through June 2001 and a delay by the CPUC in passing those costs on to ratepayers resulted in significant undercollections of wholesale power costs. These undercollections, 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, beginning in January 2001, SCE suspended payments for purchased power, deferred payments on outstanding debt, and did not declare or pay dividends on any of its cumulative preferred stock or common stock.

In January 2002, the CPUC adopted a resolution implementing a settlement agreement with SCE. Based on the rights to power procurement cost recovery and revenue established by the agreement and the PROACT resolution, SCE repaid its undisputed past-due obligations and near-term debt maturities in March 2002, using cash on hand resulting from rate increases approved by the CPUC in 2001 and the proceeds of $1.6 billion in senior secured credit facilities and the remarketing of $196 million in pollution-control bonds. The $1.6 billion financing included a $600 million, one-year term loan due on March 3, 2003. SCE prepaid $300 million of this loan on August 14, 2002 and the remaining $300 million on February 11, 2003. The $1.6 billion financing also included a $300 million line of credit, which is fully drawn and expires March 2004, and a $700 million term loan with a March 2005 final maturity. Under the term loan, net cash proceeds for the issuance of capital stock or new indebtedness must be used to reduce the term loan subject to certain exceptions.

On February 24, 2003, SCE completed an exchange offer for its 8.95% variable rate notes due November 2003. A total of $966 million of these notes were exchanged for $966 million of a new series of first and refunding mortgage bonds due February 2007. As a result of the exchange offer and the $300 million payment on February 11, 2003, SCE's remaining significant debt maturities in 2003 are approximately $159 million, comprising $34 million of the 8.95% variable rate notes due November 2003 that were not exchanged and $125 million in first and refunding mortgage bonds due June 2003. In addition, approximately $250 million of rate reduction notes are due throughout 2003. These notes have a separate cost recovery mechanism approved by state legislation and CPUC decisions.

SCE currently expects to recover the PROACT balance in mid-2003. Material factors affecting the timing of recovery of the PROACT balance are discussed in "Regulatory Matters—PROACT Regulatory Asset." As of December 31, 2002, SCE's common equity to total capitalization ratio, for rate-making purposes, was approximately 62%. This is substantially greater than the CPUC-authorized level of 48%. SCE's settlement agreement with the CPUC provides that the CPUC will not impose any penalty on SCE for noncompliance with the authorized capital structure during the PROACT recovery period. SCE expects to rebalance its capital structure to CPUC-authorized levels in the future by paying dividends to its parent,

Edison International, and issuing debt as necessary. Factors that affect the amount and timing of such actions include, but are not limited to, the outcome of the pending appeal of the stipulated judgment approving SCE's settlement agreement with the CPUC (See "Regulatory Matters—CPUC Litigation Settlement Agreement), SCE's access to the capital markets, and actions by the CPUC. SCE resumed procurement of its residual net short on January 1, 2003 and as of February 28, 2003 posted $86 million in collateral to secure its obligations under power purchase contracts and to transact through the ISO for imbalance power. See "Market Risk Exposures—SCE's Market Risks" below.

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

COMMITMENTS

SCE's commitments for the years 2003 through 2007 are estimated below:

In millions	2003	2004	2005	2006	2007
Long-term debt maturities and sinking fund requirements	$ 1,671	$ 671	$ 1,142	$ 446	$ 246
Estimated noncancelable lease payments	13	11	8	6	4
Fuel supply contract payments	155	118	121	124	127
Purchased-power capacity payments	597	595	578	543	543
Preferred securities redemption requirements	9	9	9	9	9

SCE's projected construction expenditures for 2003 are $1.0 billion.

MARKET RISK EXPOSURES

SCE's primary market risks include interest rate, generating fuel commodity price and credit risks.

Interest Rate Risk

SCE is exposed to changes in interest rates primarily as a result of its borrowing and investing activities used for liquidity purposes and to fund business operations, as well as to finance capital expenditures. The nature and amount of SCE's long-term and short-term debt can be expected to vary as a result of future business requirements, market conditions and other factors. As the result of California's energy crisis, SCE has been required to pay significantly higher interest rates, which intensified its liquidity crisis during 2001 (further discussed in "Financial Condition—SCE's Liquidity Issues").

Changes in interest rates also impact SCE's authorized rate of return on common equity, which is established in SCE's annual cost of capital proceeding. See "Regulatory Matters—Cost of Capital Decision."

At December 31, 2002, 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. At December 31, 2002, the fair market value of SCE's long term debt was $4.5 billion. A 10% increase in market interest rates would have resulted in a $164 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 $190 million increase in the fair market value of SCE's long-term debt.

Commodity Price Risk

Under the CPUC settlement agreement, SCE is permitted full recovery of its past power procurement costs. Thereafter, SCE expects to recover its reasonable power procurement costs in customer rates through regulatory mechanisms established in rate-making proceedings. Assembly Bill (AB) 57, which the Governor of California signed in September 2002, provides that the CPUC shall adjust rates, or order refunds, to amortize undercollections or overcollections of power procurement costs. Until January 1,

2006, the CPUC must adjust rates if the undercollection or overcollection exceeds 5% of SCE's prior year's procurement costs, excluding revenue collected for the CDWR. As a result of these regulatory mechanisms, changes in energy prices may impact SCE's cash flows but are not expected to have an impact on earnings.

On January 1, 2003, SCE resumed procurement of its residual net short (the amount of energy needed to serve SCE's customers from sources other than its own generating plants, power purchase contracts and CDWR contracts). SCE forecasts that its average 2003 residual net short, on an energy basis, will be approximately 4% of the total energy needed to serve SCE's customers, with most of the short position occurring during off-peak hours. SCE's residual net short exposure was larger during the first quarter of 2003, because of a planned refueling outage at San Onofre Unit 3. In the second half of 2003, this exposure declines significantly as more power deliveries are scheduled to commence under existing CDWR contracts that are allocated to SCE's customers. Factors that could cause SCE's residual net short to be larger than expected include: direct access customers returning to utility service from their energy service provider; lower utility generation; lower deliveries from QFs, CDWR or interutility contracts; or higher load requirements.

To reduce SCE's residual net short exposure, SCE entered into six transition capacity contracts with terms of up to 5 years. Through fuel tolling arrangements, SCE is responsible for providing natural gas when the underlying contract facilities are called upon to provide energy. SCE has not hedged its expected natural gas use for these capacity contracts. In addition, pursuant to CPUC decisions, SCE arranges for natural gas and related services for the CDWR contracts allocated by the CPUC to SCE. Financial and legal responsibility for the allocated contracts remain with the CDWR. Neither the CDWR, nor SCE, on behalf of the CDWR, has hedged the expected natural gas requirements for the allocated contracts. To the extent the price of natural gas were to increase above the levels assumed for cost recovery purposes, state law permits the CDWR to recover its actual costs through rates established by the CPUC.

SCE has entered into power purchase contracts with gas-fired and non-gas QFs. To mitigate the volatility experienced in 2000 and 2001 associated with the gas-fired QFs, SCE entered into hedging instruments to hedge a majority of its natural gas price risk exposure for 2002 and 2003. After 2003, SCE will be subject to natural gas price risk exposures for its gas-fired QFs. A 10% increase in the projected forward curve for natural gas prices in 2004 could increase payments made to these QFs by approximately $65 million. SCE is not exposed to energy price risk associated with most of its non-gas QFs, as such contracts are based on a fixed price of 5.37¢ per kWh through May 2007. SCE expects to fully recover its QF procurement costs in customer rates through regulatory mechanisms established in rate-making proceedings.

As mentioned above, 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 non-renewable QF contracts for 2002 and 2003. See "Regulatory Matters—Hedging Cost Recovery Decision." At December 31, 2002, the fair value of the gas call option was $77 million, compared with the original book value of remaining options of $116 million. At December 31, 2002, a 10% increase in market gas prices would have resulted in a $49 million increase in the fair market value of the SCE's gas call options. A 10% decrease in market gas prices would have resulted in a $34 million decrease in the fair market value of the gas call options. Any fair value changes for gas call options are offset through a regulatory mechanism.

Credit Risk

The reduction in the credit quality of many trading parties increases SCE's credit and market risk. In the event a counterparty were to default on its obligations, SCE would be exposed to potentially higher costs for replacement power. SCE has developed standards that limit extension of unsecured credit based upon a number of objective factors. In negotiating capacity contracts, SCE also has included collateral requirements and credit enforcements to mitigate the risk of possible defaults. However, these actions may not protect SCE in the event of bankruptcy of a counterparty.

See additional discussion on these matters in "Regulatory Matters—CPUC Litigation Settlement Agreement, —Generation Procurement Proceedings and —Wholesale Electricity Markets" below.

REGULATORY MATTERS

In the mid-1990s, state lawmakers and the CPUC initiated the electric industry restructuring process. Under state law, beginning in January 1, 1998 a multi-year freeze on the rates SCE could charge its customers was implemented. In addition, a transition cost recovery mechanism was adopted to allow SCE to recover its stranded costs associated with generation-related assets. 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 were recovered. As a result of CPUC orders, SCE divested its gas-fired generation plants, representing approximately 9,500 MW of capacity. Between May 2000 and June 2001, prices charged by sellers of power escalated far beyond what SCE was allowed by the CPUC to charge its customers. As a result, SCE incurred $2.7 billion (after tax), or $4.7 billion (pre-tax), in write-offs through August 31, 2001. In January 2001, the State of California began purchasing power on behalf of SCE's customers because SCE's financial condition prevented it from purchasing power supplies for its customers. In a lawsuit filed against the CPUC in November 2000, SCE asserted claims under the federal "filed rate doctrine," for recovery of its electricity procurement related costs. See "—CPUC Litigation Settlement Agreement" for further discussion of the lawsuit.

SCE has restored substantially all of its write-offs as a result of the implementation of a settlement with the CPUC of the filed rate doctrine lawsuit in fourth quarter 2001 and the CPUC's URG decision in second quarter 2002 to return SCE's retained generation assets to cost-based ratemaking. In addition, on January 1, 2003, SCE resumed procurement of its residual net short position.

This section of the MD&A presents regulatory matters using three main subsections: generation and power procurement, transmission and distribution, and other regulatory matters.

Generation and Power Procurement

This subsection of "Regulatory Matters" discusses: the settlement agreement with the CPUC to allow recovery of undercollected power procurement costs arising from the California energy crisis in 2000 and 2001 and an intervenor's lawsuit seeking to overturn this agreement; the PROACT regulatory asset allowed in the settlement agreement; separate proceedings related to direct access, surcharge decisions, hedging cost recovery, the return of utility-retained generation assets to cost-based ratemaking, power procurement, the allocation of the CDWR contracts; and the ultimate disposition of Mohave.

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 electricity procurement costs incurred during the energy crisis in accordance with the tariffs filed with the FERC. 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 less SCE's cash and cash equivalents as of that date, 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 in rates for up to an additional two years.

- 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 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. See discussion in "Market Risk Exposures—SCE's Market Risks" and "—Hedging Cost Recovery Decision."
- 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.
- 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. See "—Wholesale Electricity Markets."

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.

TURN and other parties appealed to the federal court of appeals seeking to overturn the stipulated judgment of the district court that approved the settlement agreement. On March 4, 2002, the United States Court of Appeals for the Ninth Circuit heard argument on the appeal, and on September 23, 2002, the court issued its opinion. In the opinion, the court affirmed the district court on all claims, with the exception of the challenges founded upon California state law, which the appeals court referred to the California Supreme Court. Specifically, the appeals court affirmed the district court in the following respects: (1) the district court did not err in denying the motions to intervene brought by entities other than TURN; (2) the district court did not err in denying standing for the entities other than TURN to appeal the stipulated judgment; (3) the district court was not deprived of original jurisdiction over the lawsuit; (4) the district court did not err in declining to abstain from the case; (5) the district court did not exceed its authority by approving the stipulated judgment without TURN's consent; (6) the district court's approval of the settlement agreement did not deny TURN due process; and (7) the district court did not violate the Tenth Amendment of the United States Constitution in approving the stipulated judgment. In sum, the appeals court concluded that none of the substantive arguments based on federal statutory or constitutional law compelled reversal of the district court's approval of the stipulated judgment.

However, the appeals court stated in its opinion that there is a serious question whether the settlement agreement violated state law, both in substance and in the procedure by which the CPUC agreed to it. The appeals court added that if the settlement agreement violated state law, the CPUC lacked capacity to consent to the stipulated judgment, and the stipulated judgment would need to be vacated. The appeals court indicated that, on a substantive level, the stipulated judgment appears to violate California's electric industry restructuring statute providing for a rate freeze. The appeals court also indicated that, on a procedural level, the stipulated judgment appears to violate California laws requiring open meetings and public hearings. Because federal courts are bound by the pronouncements of the state's highest court on applicable state law, and because the federal appeals court found no controlling precedents from California courts on the issues of state law in this case, the appeals court issued a separate order certifying those issues in question form to the California Supreme Court and requested that the California Supreme Court accept certification.

The appeals court stayed further proceedings in the case pending a response from the California Supreme Court on the request for certification. The appeals court did not stay the continued operation of the settlement agreement, thus collection of past procurement costs under PROACT is continuing. On October 29, 2002, SCE filed briefs requesting that the California Supreme Court answer the appeals' court certification and requesting that the hearing of the matter be placed on the California Supreme Court's March 2003 calendar, or heard at the court's earliest convenience and requesting that the California Supreme Court reformulate one of the certified questions. On November 20, 2002, the California Supreme Court issued an order indicating that it would hear the case, and would reformulate the certified question as requested by SCE. The court ordered that all briefing be submitted by March 2003 and further stated that the case would be scheduled for expedited oral argument after briefing has been completed. SCE and the CPUC filed their respective opening briefs on the merits of the certified questions. TURN filed its answering brief, and SCE and the CPUC filed reply briefs. Various third parties, including the Governor, submitted friend-of-the-court briefs concerning the certified questions. In addition, the California Supreme Court requested that the parties provide supplemental briefing with respect to an issue related to California's open meeting laws. The parties have complied with such request. SCE continues to operate under the settlement agreement. SCE continues to believe it is probable that SCE ultimately will recover its past procurement costs through regulatory mechanisms, including the PROACT. However, SCE cannot predict with certainty the outcome of the pending legal proceedings.

PROACT Regulatory Asset

In accordance with the settlement agreement and an implementing resolution adopted by the CPUC, in the fourth quarter of 2001, SCE established the PROACT regulatory balancing account, with an initial balance of $3.6 billion reflecting the net amount of past procurement-related liabilities to be recovered by SCE. Each month, SCE applies to the PROACT the positive or negative 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 was $2.6 billion at December 31, 2001, $574 million on December 31, 2002 and $594 million on February 28, 2003. SCE previously projected that it would recover the remaining balance of the procurement-related obligations in the PROACT by the end of 2003. Based on decisions made by the CPUC at the end of 2002, SCE now believes it will recover the PROACT balance by mid-2003. There still exist potential factors that could change SCE's estimate of the timing of PROACT recovery. These factors include:

- the level of output of SCE's generating plants and contract power deliveries (for example, lower than forecasted output could slow PROACT recovery);
- authorized revenue changes for distribution, transmission, and SCE retained-generation costs (see discussion in "—2003 General Rate Case Proceeding", "—PBR Decision" and "—URG Decision");
- outcome of issues currently being addressed in the CPUC's power procurement proceedings, including further adjustments to the CPUC-authorized allocation among the California utilities of power contracted by the CDWR for 2003 and the related CDWR revenue requirement impacts;
- SCE's share of the CDWR revenue requirement (see discussion in "—CDWR Power Purchases and Revenue Requirement Proceedings");
- level of retail sales (for example, higher than forecasted sales would accelerate PROACT recovery);
- level of direct access (see "—Direct Access Proceedings" discussions below);
- direct access customers' contribution to recovery of SCE's PROACT-related costs and to the CDWR's costs (see "—Direct Access Proceedings" discussions regarding the historical procurement charge and exit fees below);

- a decision by the CPUC, which could be made under the settlement agreement, directing $150 million of surplus revenue to be used for any utility purpose (which would delay PROACT recovery); and
- potential energy supplier refunds (see discussion in "—Wholesale Electricity Markets").

The following is an update on various regulatory proceedings impacting the timing of PROACT recovery:

Direct Access Proceedings

Direct Access – Historical Procurement Charge

From 1998 through mid-September 2001, SCE's customers were able to choose to purchase power directly from an energy service provider other than SCE (thus becoming direct access customers) or continue to purchase power from SCE. (Customers who continue to purchase power from SCE are referred to as bundled service customers). On March 21, 2002, the CPUC issued a final decision affirming that new direct access arrangements entered into by SCE's customers after September 20, 2001, are invalid. This decision did not affect direct access arrangements in place before that date. Direct access customers receive a credit for the generation costs SCE saves by not serving them. Operating revenue is reported net of this credit. Because of this credit, direct access power purchases resulted in additional undercollected power procurement costs to SCE during 2000 and 2001. On July 17, 2002, the CPUC issued an interim decision to establish a nonbypassable historical procurement charge requiring direct access customers to pay $391 million of SCE's past power procurement costs and directed SCE to reduce the PROACT balance by $391 million and create a new regulatory asset for the same amount. The historical procurement charge is to be collected from direct access customers by reducing their existing generation credit by 2.7¢ per kWh (effective July 27, 2002) until the CPUC issues and implements an order to determine a surcharge for direct access customers' share of the CDWR's costs, as discussed in the paragraph below. Once that surcharge was implemented on January 1, 2003, the contribution by direct access customers to the historical procurement charge was reduced from 2.7¢ per kWh to 1¢ per kWh until the $391 million is collected, with the remainder of the 2.7¢ per kWh utilized for CDWR's costs associated with direct access customers. On October 16, 2002, SCE filed a petition with the CPUC to modify the historical procurement charge interim decision to provide that direct access customers be responsible for $497 million of SCE's past procurement costs. In subsequent testimony, SCE reduced its request to $493 million. Once the interim decision becomes permanent, SCE will evaluate whether a new regulatory asset could be created. If such a regulatory asset was created, the net effect of this action would be to accelerate PROACT recovery. Evidentiary hearings on SCE's petition to modify were held on March 4, 2003, and a decision is expected in May or June 2003.

Direct Access – Exit Fees

In addition to the historical procurement charge, the CPUC, in a November 7, 2002 decision, assigned responsibility for a portion of four other cost categories to the direct access customers. The first category consists of the CDWR's power procurement costs incurred between January 17, 2001 and September 30, 2001. The CDWR sold approximately $11 billion in bonds in fourth quarter 2002 to repay the amounts it borrowed to pay these costs. The CPUC decision stated that the direct access customers are responsible for paying a portion of the bond charge to recover the principal and financing costs associated with these bonds. The second category relates to the CDWR's power procurement costs for the last quarter of 2001 and the year 2002. The CPUC stated that direct access customers must pay a share of these costs to make bundled service customers indifferent to suspension by the CPUC of the direct access program on September 20, 2001. The third category includes the CDWR long-term contract costs for 2003 and beyond. The CPUC decision stated that a portion of these costs should be paid by direct access customers to keep bundled service customers indifferent to the later suspension of direct access on the premise that the CDWR signed some of its long-term contracts with the expectation of serving the load that switched to direct access after July 1, 2001. Finally, the last category relates to the above-market costs of SCE's URG (e.g., qualifying facilities contract costs) that pursuant to AB 1890 are to be recovered from all customers on an ongoing basis. The CPUC decision states that: (1) the bond charge is applicable to all direct access customers except those who were continuously on direct access and never

used any CDWR power (less than 1% of SCE's load); (2) the next two categories of costs are applicable to direct access customers who took bundled service at any time after February 1, 2001; and (3) the last category is applicable to all direct access customers, including continuous direct access customers. The cap on the amount of exit fees to be paid by direct access customers will be addressed in hearings scheduled to begin in early April 2003. The exact amount of exit fees to be paid by direct access customers will be determined on an annual basis after the CDWR's submission of its requested revenue requirement to the CPUC.

The impact of the November 7, 2002 decision is incorporated into SCE's current projection of the timing of PROACT recovery.

Surcharge Decisions

A March 2001 CPUC decision authorized a 3¢-per-kWh revenue surcharge and made permanent a 1¢-per-kWh temporary surcharge authorized in January 2001, with the restriction that the revenue arising from both surcharges apply only to ongoing procurement charges and future power purchases. On November 7, 2002, the CPUC issued a decision modifying the March 2001 decision to allow the surcharge revenue to be used not only for power costs but also for returning SCE to reasonable financial health. The decision stated that the extent to which the surcharge revenue could be used for future power costs or obtaining reasonable financial health would be the subject of future proceedings. The decision ordered SCE to continue tracking the surcharge revenue in balancing accounts, subject to later adjustment and possible refund. See "—Customer Rate-Reduction Plan." This decision is incorporated into SCE's current projection of the timing of PROACT recovery.

The CPUC allowed the continuation of the 0.6¢-per-kWh temporary surcharge that was scheduled to terminate in June 2002 and required SCE to track the associated revenue in a balancing account for rate-making purposes, until the CPUC determines the use of the surcharge. The continuation of the surcharge resulted in a $187 million cash increase in 2002 and is expected to result in an increase of $352 million in 2003, but has no impact on earnings. A December 17, 2002, CPUC decision authorized SCE to use the revenue associated with this surcharge to partially offset its and the CDWR's higher 2003 revenue requirement, and SCE has incorporated that assumption into its current projection of the timing of PROACT recovery. For financial reporting purposes, amounts billed in 2002 as a result of this surcharge are credited to a regulatory liability account, because the surcharge is to be used to recover costs to be incurred in the future. This account will be amortized into revenue in 2003.

Hedging Cost Recovery Decision

Pursuant to its authority mentioned in "—CPUC Litigation Settlement Agreement," SCE purchased $209 million in hedging instruments (gas call options) in late 2001 to hedge a majority of its natural gas price exposure associated with QF contracts for 2002 and 2003. A February 13, 2003 CPUC decision allows SCE to transfer the entire $209 million into the PROACT regulatory asset during first quarter 2003. SCE has incorporated this decision into its current projection of the timing of PROACT recovery.

URG Decision

On April 4, 2002, the CPUC issued a decision to return generation assets retained by SCE (utility-retained generation) to cost-of-service ratemaking until the implementation of the 2003 general rate case (GRC) proceeding described below. The URG decision:

- Allows recovery of incurred costs for all URG components other than San Onofre Units 2 and 3, subject to reasonableness review by the CPUC;
- Retains the incremental cost incentive pricing mechanism (ICIP) for San Onofre Units 2 and 3 through 2003;

- Establishes an amortization schedule for SCE's nuclear facilities that reflects their current remaining Nuclear Regulatory Commission license durations, using unamortized balances as of January 1, 2001 as a starting point;
- Establishes balancing accounts for the costs of utility generation, purchased power, and ancillary services from the ISO; and
- Continues the use of SCE's last CPUC-authorized return on common equity of 11.6% for SCE's URG rate base other than San Onofre Units 2 and 3, and keeps in place the 7.35% return on rate base for San Onofre Units 2 and 3 under the ICIP.

Based on this decision, during the second quarter of 2002, SCE reestablished for financial reporting purposes regulatory assets related to its unamortized nuclear facilities, purchased-power settlements and flow-through taxes, reduced the PROACT regulatory asset balance (by $256 million), and recorded a corresponding credit to earnings of $480 million after tax. The reduction in the PROACT balance reflects a change in SCE's unamortized nuclear facilities amortization schedule to reflect a ten-year amortization period rather than a four-year amortization period, which was used to calculate the surplus revenue contributed to the PROACT, for rate-making purposes, during the last four months of 2001.

CDWR Power Purchases and Revenue Requirement Proceedings

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 are remitted directly to the CDWR and are not recognized as revenue by SCE. In February 2001, AB 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 SCE's retail customers, and authorized the CDWR to issue bonds to finance electricity purchases. In addition, the CPUC has the responsibility to allocate the CDWR's revenue requirement among the customers of SCE, Pacific Gas and Electric (PG&E), and San Diego Gas & Electric (SDG&E).

On February 21, 2002, the CPUC allocated to SCE's customers $3.5 billion (38.2%) of the CDWR's total power procurement revenue requirement of $9 billion for the period 2001 and 2002. This resulted in an average annual CDWR revenue requirement of $1.7 billion being allocated to SCE. In its February 21, 2002 decision, the CPUC ordered that allocation of that revenue requirement to each utility be trued-up based on the CDWR's actual recorded costs for the 2001–2002 period and a specific methodology set forth in that decision.

On October 24, 2002, the CPUC issued a decision that adopts a methodology for establishing a charge to repay the CDWR's $11 billion bond issue. The bond charge is to be set by dividing the annual revenue requirement for bond-related costs by an estimate of the annual electricity consumption of bundled service customers subject to the charge. The charge will apply to electricity consumed on and after November 15, 2002 and will be set annually based on annual expected debt-related costs and projected electricity consumption. For 2003, the CPUC allocated to SCE's customers $331 million (about 44%) of the CDWR's bond charge revenue requirement of $745 million. The bond charge is set at a rate of 0.513¢ per kWh for SCE's customers. In a November 7, 2002 decision, the CPUC assigned responsibility for a portion of the bond charge to direct access customers (see "—Direct Access—Exit Fees"). This decision is incorporated into SCE's current projection of the timing of PROACT recovery.

On December 17, 2002, the CPUC adopted an allocation of the CDWR's forecast power procurement revenue requirement for 2003, based on the quantity of electricity expected to be supplied under the CDWR contracts to customers of each of the three utility companies by the CDWR. SCE's allocated share is $1.9 billion of the CDWR's total 2003 power procurement revenue requirement of $4.5 billion. In a February 13, 2003 decision on rehearing of the December 17, 2002 decision, the CPUC increased the CDWR's total revenue requirement by $29 million, restoring it to the level originally requested by the CDWR. This is an interim allocation and will be superseded by a later allocation after the CDWR submits a supplemental determination of its 2003 revenue requirement. The CPUC stated that the later allocation could result in a reduction in the CDWR's revenue requirement, with a corresponding decrease in the

CDWR's rate charged to bundled service customers. The CPUC's December 17, 2002 decision did not address issues relating to the true-up of the CDWR's 2001–2002 revenue requirement, stating that those issues will be addressed after actual data for 2002 becomes available, expected in April 2003. A true-up of the CDWR's revenue requirement, as well as the additional allocation of contracts, have not been incorporated into SCE's current projection of the timing of PROACT recovery.

Generation Procurement Proceedings

In October 2001, the CPUC issued an Order Instituting Rulemaking directing SCE and the other major California electric utilities to provide recommendations for establishing policies and mechanisms to enable the utilities to resume power procurement by January 1, 2003. Although the proceeding began before the enactment of AB 57, that statute (in its draft form, and, after enactment, in its final form) has guided the proceeding. Senate Bill (SB) 1078 has also had an impact on this proceeding, as described below.

AB 57, which provides for SCE and the other California utilities to resume procuring power for their customers, was signed into law by the Governor of California in September 2002. A second senate bill was enacted not long after AB 57 to shorten the period between the adoption of a utility's initial procurement plan and the resumption of procurement from 90 days to 60 days. Under these statutes, SCE is effectively allowed to recover procurement costs incurred in compliance with an approved procurement plan. Only limited categories of costs, including contract administration and least-cost dispatch, are subject to reasonableness reviews.

In addition, SB 1078, which was signed into law by the Governor in September 2002 and is effective January 1, 2003, provides that, commencing January 1, 2003, SCE and other California utilities shall increase their procurement of renewable resources by at least an additional 1% of their annual electricity sales per year so that 20% of the utility's annual electricity sales are procured from renewable resources by no later than December 31, 2017. Utilities are not required to enter into long-term contracts for renewable resources in excess of a market-price benchmark to be established by the CPUC pursuant to criteria set forth in the statute. Similar provisions are also found in AB 57.

The CPUC issued four major decisions in this proceeding in 2002 addressing: (1) transitional procurement contracts; (2) the allocation of contracts previously entered into by the CDWR among the three major California utilities; (3) the resumption of power procurement activities by these utilities on January 1, 2003 and adoption of a regulatory framework for such activities; and (4) SCE's short-term procurement plan for 2003.

The first decision, relating to transitional procurement contracts, was issued on August 22, 2002. It authorized the utilities to enter into capacity contracts between the effective date of the decision and January 1, 2003, referred to as the transitional procurement period. Under this decision, the CPUC would approve or disapprove the transitional contracts proposed by a utility by means of an expedited advice letter process. As a result of this process, SCE entered into six transitional capacity contracts with terms up to five years. These contracts were approved by the CPUC.

This decision also required the utilities to procure, during the transitional procurement period, at least 1% of their annual electricity sales through a competitive procurement process set aside for renewable resources. The utilities were required to solicit bids for renewable contracts with terms of five, ten and fifteen years and to enter into contracts providing for the commencement of deliveries by the end of 2003. In accordance with this CPUC directive, SCE conducted a solicitation of offers from owners of renewable resources and, based upon the results of the solicitation, provisionally entered into six contracts, subject to subsequent CPUC approval.

On December 24, 2002 and January 14, 2003, SCE filed advice letters seeking CPUC approval of these six renewable contracts. On January 30, 2003, the CPUC issued a resolution approving four of the six renewable contracts. In addition, draft resolutions have been issued disapproving the two remaining renewable contracts, with an alternative draft resolution approving one of the two remaining contracts. The CPUC is expected to rule on the remaining contracts in the second quarter of 2003.

The second decision addressed the issue of allocating among the three major California utilities the contracts previously entered into by the CDWR. In this decision, issued on September 19, 2002, the CPUC allocated the CDWR contracts on a contract-by-contract basis. Under the decision, utility responsibility for the contracts is limited to that of scheduling and dispatch. The decision significantly reduces SCE's net short and also increases the likelihood that SCE will have excess power during certain periods. Wholesale revenue from the sale of such surplus energy is to be prorated between the CDWR and SCE, pursuant to several CPUC orders. Under the decision, SCE acts as limited agent for the CDWR for contract implementation, but legal title, financial reporting and responsibility for the payment of contract-related bills remain with the CDWR. On January 17, 2003, the CDWR filed a petition to modify the September 19, 2002 decision requesting the allocation of four additional contracts that are not currently part of the CDWR's 2003 revenue requirement. The CPUC allocated one of the four contracts to SCE in a February 27, 2003 decision.

The third decision was issued on October 24, 2002. It ordered the utilities to resume procurement and adopting the regulatory framework for the utilities resuming full procurement responsibilities on January 1, 2003. The decision distinguished the utilities' responsibilities on the basis of short-term (2003) versus long-term (2004–2024) procurement. It adopted the utilities' procurement plans filed on May 1, 2002, and directed that they be modified prior to January 1, 2003 to reflect the decision, the allocation of existing CDWR contracts, and any transitional procurement done under the August 22, 2002 decision. The October 24, 2002 decision also set forth a detailed process and procedural schedule to develop long-term procurement planning that includes the filing by each utility of a long-term plan by April 1, 2003 and an evidentiary hearing in early July 2003. In addition, the decision called for each of the utilities to establish a balancing account, to be known as the energy resource recovery account, to track energy costs. These balancing accounts will be used for examining procurement rate adjustments on a semi-annual basis, as well as on a more expedited basis in the event fuel and purchased-power costs exceed a prescribed threshold. The decision also provided clarification as to certain elements of the CPUC's August 22, 2002 order regarding interim procurement of additional renewable resources and established a schedule for parties to provide comments in January 2003 on various aspects of SB 1078 implementation in anticipation of an implementation report to be submitted by the CPUC to the legislature by June 30, 2003. On November 25, 2002, SCE filed an application with the CPUC for rehearing of the October 24 decision seeking the correction of legal errors in the decision. The CPUC has not yet ruled on SCE's application for rehearing, but has indicated that it will address SCE's application and others in future decisions.

The fourth decision, issued on December 19, 2002, approved modified short-term procurement plans filed in November 2002 by SCE, PG&E, and SDG&E. It modified and clarified the cost-recovery mechanisms and standards of behavior adopted in the October 24 decision, and provided further guidance on the long-term planning process to be undertaken in the next phase of the power procurement proceeding. The CPUC found that the utilities were capable of resuming full procurement on January 1, 2003 and ordered that they take all necessary steps to do so.

Among other things, the December 19, 2002 decision determined that SCE's maximum disallowance risk exposure for procurement activities, contract administration and least-cost dispatch would be capped at twice SCE's "annual procurement administrative expenses."

On January 21, 2003, SCE filed an application for rehearing of the December 19, 2002 procurement plan decision. Issues addressed included certain standard of conduct provisions, bilateral contracting, level of customer risk tolerance, lack of an appropriate tracking mechanism for certain costs, lack of definition for least cost dispatch, and the finding that SCE was non-compliant with the August 22, 2002 decision. SCE has filed a petition for modification which addressed, among other things, the need for the cap on SCE's maximum disallowance risk exposure to be extended to cover all procurement activities.

On March 4, 2003, SCE also filed a motion for consolidated consideration of the numerous applications for rehearing and petitions for modification that have been filed, and will be filed, on the various CPUC decisions addressing the investor owned utilities management of their power supply portfolios. In the motion, SCE urged the CPUC to conduct a comprehensive review of its procurement decisions and act on the various applications for rehearing and petitions for modification in an integrated manner, avoiding the piecemeal action that failed to fully resolve the outstanding issues.

In accordance with the CPUC's October 24, 2002 decision, on February 3, 2003, SCE and the other utilities filed outlines of their long-term procurement plans. SCE proposed in its outline that the CPUC separate the proceeding so that SCE would file a separate 2004 short-term procurement plan as well as its long-term plan. The assigned administrative law judge agreed with this proposal. SCE plans to file the long-term resource plan and the 2004 short-term procurement plan on April 1, 2003 and May 1, 2003, respectively. Hearings on the short-term plan and certain key issues in the long-term plan are expected to take place in June and July 2003. The issues that will be incorporated into the long-term plan were addressed during the prehearing conference on March 7, 2003. Pursuant to a ruling of the assigned administration law judge, issues related to implementation of SB 1078 will be determined on a separate, expedited schedule. Testimony on the implementation of SB 1078 will be filed on March 27, 2003, and hearings will be held in April 2003. A preliminary decision is expected in June 2003, followed by a report by the CPUC to the Legislature on June 30, 2003.

CDWR Contracts

On December 19, 2002, the CPUC adopted an operating order under which SCE, PG&E, and SDG&E perform the operational, dispatch, and administrative functions for the CDWR's long-term power purchase contracts, beginning January 1, 2003. The operating order sets forth the terms and conditions under which the three utility companies administer the CDWR contracts and requires the utility companies to dispatch all the generating assets within their portfolios on a least-cost basis for the benefit of their ratepayers. PG&E and SDG&E filed an emergency motion in which they sought to substitute their negotiated operating agreements with the CDWR for the CPUC's operating order. The CPUC has not yet ruled on their motion and it is not clear what impact, if any, a CPUC ruling on their motion will have on SCE. On February 24, 2003, the assigned administrative law judge issued a draft decision approving the two negotiated operating agreements subject to certain additions and deletions to the terms agreed to by the parties. This draft decision is subject to comments and must be approved by the CPUC before it is final.

The CPUC also approved amendments to the servicing agreements between the utilities and the CDWR relating to transmission, distribution, billing, and collection services for the CDWR's purchased power. The servicing order issued by the CPUC identifies the formulas and mechanisms to be used by SCE to remit to the CDWR the revenue collected from SCE's customers for their use of energy from the CDWR contracts that have been allocated to SCE.

Mohave Generating Station Proceeding

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

Due to the lack of progress in negotiations with the Tribes and other parties to resolve several coal and water supply issues, SCE's application stated that it probably would not be possible for SCE to extend Mohave's operation beyond 2005. Uncertainty over a post-2005 coal and water supply has prevented SCE and the other Mohave co-owners from starting to make approximately $1.1 billion (SCE's share is $605 million) of Mohave-related investments that will be necessary if Mohave operations are to extend past 2005, including the installation of pollution control equipment that must be put in place pursuant to a 1999 Consent Decree related to air quality, if Mohave's operations are extended past 2005.

SCE's May 17, 2002, application requested either: a) pre-approval for SCE to immediately begin spending up to $58 million on Mohave pollution controls in 2003, if by year-end 2002 SCE had obtained adequate assurance that the outstanding coal and slurry-water issues would be satisfactorily resolved; or b) authority for SCE to establish certain balancing accounts and otherwise begin preparing to terminate Mohave's coal-fired operations at the end of 2005.

The CPUC issued a ruling on January 7, 2003, requesting further written testimony from SCE and initial written testimony from other parties on specified issues relating to Mohave and its coal and slurry-water

supply. The ruling states that the purpose of the CPUC proceeding is to determine whether it is in the public interest to extend Mohave operations post 2005. In its supplemental testimony submitted on January 30, 2003, SCE stated, among other things, that the currently available information is not sufficient for the CPUC to make this determination at this time. The testimony states that neither SCE nor any other party has sufficient assurance of whether and how the currently unresolved coal and water supply issues will be resolved. Unless all key issues are resolved in a timely way, Mohave will cease operation as a coal-fired plant at the end of 2005 under the terms of the consent decree and the existing coal supply agreements. In that event, there would be no need for the CPUC to make the determination it has described, since extension of the present operating period would not be an option. SCE's supplemental testimony accordingly requests that the CPUC authorize the establishment of the balancing accounts that SCE first requested in its May 17, 2002 application, in order to prepare for an orderly shutdown of Mohave by the end of 2005, but the testimony also states that even with such authorization, SCE will continue to work with the relevant stakeholders to attempt to resolve the issues surrounding Mohave's coal and slurry-water supply.

On January 14, 2003, the Natural Resources Defense Council, Black Mesa Trust and others served a notice of intent to sue the U.S. Department of the Interior and other federal government agencies and individuals, challenging the failure of the government to issue a final permit to Peabody Western Coal Company for the operation of the Black Mesa Mine. The prospective plaintiffs claim that the federal government must begin a proceeding for issuance of a final permit to Peabody rather than allow Peabody to continue long-term operation of the Black Mesa Mine on an interim basis including groundwater extraction for use in the coal slurry pipeline. The notice indicates that the prospective plaintiffs would then challenge any issuance of a permanent mining permit for the Black Mesa Mine unless, at a minimum, an alternate source of slurry water is obtained. If the prospective plaintiffs prevail in any future lawsuit, the coal supply to Mohave could be interrupted.

For additional matters related to Mohave see the "Other Developments—Navajo Nation Litigation" section.

In light of all of the issues discussed above, SCE concluded that it is probable Mohave will be shut down at the end of 2005. Because the expected undiscounted cash flows from the plant during the years 2003–2005 were less than the $88 million carrying value of the plant as of December 31, 2002, SCE incurred an impairment charge of $61 million. However, in accordance with accounting standards for rate-regulated enterprises, this incurred cost was deferred and recorded as a regulatory asset, based on SCE's expectation that any unrecovered book value at the end of 2005 would be recovered in future rates through the rate-making mechanism discussed in its May 17, 2002 application and again in its January 30, 2003 supplemental testimony.

The outcome of SCE's application is not expected to impact Mohave's operation through 2005. Consequently, this matter has no impact on the timing of PROACT recovery.

Transmission and Distribution

This subsection of "Regulatory Matters" discusses the certain key regulatory proceedings.

PBR Decision

On April 22, 2002, the CPUC issued a decision that modified the PBR mechanism in the following significant respects:

- SCE's current PBR distribution sales mechanism was converted to a revenue requirement mechanism to prevent material revenue undercollections or overcollections resulting from errors in estimates of electric sales. A balancing account has been established to record any undercollections or overcollections, effective retroactively as of June 14, 2001.
- A methodology was adopted to set SCE's distribution revenue requirement for June 14 to December 31, 2001, calendar year 2002 and calendar year 2003 until replaced by the GRC. The methodology (a) established 2000 as the base year, (b) annually adjusts SCE's distribution revenue requirement by the change in the Consumer Price Index minus a productivity factor of 1.6%, and (c) annually increases SCE's distribution revenue requirement to account for additional costs of

expanding the distribution network to connect new customers (an allowance of about $650 per customer).

- The performance benchmarks for worker safety, customer satisfaction and outage frequency have been updated effective in 2002 to reflect historical improvements in SCE's performance. These changes will reduce rewards SCE would earn compared to the previous standards.

As a result of this decision, in 2002, SCE recorded credits to earnings of approximately $26 million for revenue undercollections during the period June 14, 2001 through December 31, 2001, and credits to earnings of $73 million for the year ended December 31, 2002. All of these amounts are on an after-tax basis. This decision is incorporated into SCE's current projection of the timing of PROACT recovery.

2003 General Rate Case Proceeding

In December 2001, SCE submitted a notice of intent to file its 2003 GRC with the CPUC, requesting an increase of approximately $500 million in revenue (compared to 2000 recorded revenue) for its distribution and generation operations. On May 3, 2002, SCE filed its formal application for the 2003 GRC. After taking into account the effects of the CPUC's April 22, 2002 PBR decision, SCE requested a revenue requirement increase of $286 million. The requested revenue increase is primarily related to capital additions, updated depreciation costs and projected increases in pension and benefit expenses. In October 2002, the CPUC's Office of Ratepayer Advocates issued its testimony and recommended a $172 million decrease in SCE's base rates. Several other intervenors have also proposed further reductions to SCE's request or have made other substantive proposals regarding SCE's operations. Direct evidentiary hearings were concluded in January 2003. Rebuttal testimony has been filed and rebuttal hearings were held in late February 2003. A final decision is expected in the third quarter of 2003.

Cost of Capital Decision

On November 7, 2002, the CPUC issued a decision in SCE's cost of capital proceeding, adopting an 11.6% return on common equity for 2003 for SCE's CPUC jurisdictional assets. The 2003 cost of capital decision also established authorized costs for long-term debt and preferred stock, and established SCE's authorized rate-making capital structure for 2003 (although it does not apply during the PROACT recovery period), in addition to setting SCE's authorized return on common equity. This decision is incorporated into SCE's current projection of the timing of PROACT recovery.

Electric Line Maintenance Practices Proceeding

In August 2001, the CPUC issued an order instituting investigation (OII) regarding SCE's overhead and underground electric line maintenance practices. The OII is based on a report issued by the CPUC's Protection and Safety Consumer Services Division (CPSD), which alleges SCE had a pattern of noncompliance with the CPUC's General Orders for the maintenance of electric lines over the period 1998–2000. The OII also alleges that noncompliant conditions were "involved" in 37 accidents resulting in death, serious injury, or property damage. The CPSD identified 4,817 alleged violations of the General Orders during the three-year period. The OII placed SCE on notice that it is potentially subject to a penalty of between $500 and $20,000 for each violation or accident.

Prepared testimony was filed on this matter in April 2002 and hearings were concluded in September 2002. In opening briefs filed on October 21, 2002, the CPSD recommended SCE be assessed a penalty of $97 million, while SCE requested that the CPUC dismiss the proceeding and impose no penalties. SCE stated in its opening brief that it has acted reasonably, allocating its financial and human resources in pursuit of the optimum combination of employee and public safety, system reliability, cost-effectiveness, and technological advances. SCE also encouraged the CPUC to transfer consideration of issues related to development of standardized inspection methodologies and inspector training to an Order Instituting Rulemaking to revise these General Orders opened by the CPUC in October 2001, or to a new rulemaking proceeding. On March 14, 2003, SCE and the CPSD filed Opening Briefs in response to the assigned administrative law judge's direction to address application of the appropriate standard to govern SCE's electric line maintenance obligation. Oral arguments are scheduled for April 22, 2003. A decision is

expected in the second or third quarter of 2003. SCE is unable to predict with certainty whether this matter ultimately will result in any material financial penalties or impacts on SCE.

Wholesale Electricity Markets

On April 25, 2001, after months of 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 through September 30, 2002. On July 17, 2002, the FERC issued an order reviewing the ISO's proposals to redesign the market and implementing a market power mitigation program for the 11-state western region. The FERC declined to extend beyond September 30, 2002 all of the market mitigation measures it had previously adopted. However, effective October 1, 2002, the FERC extended a requirement, first ordered in its June 19, 2001 decision, that all western energy sellers offer for sale all operationally and contractually available energy. It also ordered a cap on bids for real-time energy and ancillary services of $250/MWh to be effective beginning October 1, 2002 and ordered various other market power mitigation measures. Implementation of the $250/MWh bid cap and other market power mitigation measures were delayed until October 31, 2002 by a FERC order issued September 26, 2002. The FERC did not set a specific expiration date for its new market mitigation plan. SCE cannot yet determine whether the new market mitigation plan adopted by the FERC will be sufficient to mitigate market price volatility in the wholesale electricity markets in which SCE will purchase its residual net short electricity requirements (i.e., the amount of energy needed to serve SCE's customers from sources other than its own generating plants, power purchase contracts and CDWR contracts).

On August 2, 2000, SDG&E filed a complaint with the FERC seeking relief from alleged energy overcharges in the PX and ISO market. SCE intervened in the proceeding on August 14, 2000. On August 23, 2000, the FERC issued an order initiating an investigation of the justness and reasonableness of rates charged by sellers in the PX and ISO markets. Those proceedings were consolidated. On July 25, 2001, the FERC issued an order that limits potential refunds from alleged overcharges by energy suppliers 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 conducted evidentiary hearings on this matter in March, August and October 2002 and issued and initial decision on December 12, 2002.

On November 20, 2002, in the consolidated proceeding, the FERC issued an order authorizing 100 days of discovery by market participants into market manipulation and abuse during the period January 1, 2000 through June 20, 2001. SCE joined with the California parties (PG&E, the California Attorney General, the Electricity Oversight Board, and the CPUC to submit briefs and evidence demonstrating that sellers and marketers violated tariffs, withheld power, and distorted and manipulated the California electricity markets.

At a FERC meeting on March 26, 2003, the FERC issued orders that initiated procedures for determining additional refunds arising from market manipulation by energy suppliers. Based on public comments at the meeting and the FERC's press releases, it appears that the FERC acknowledges that there was pervasive gaming and market manipulation of the electric and gas markets in California and on the west coast. A new FERC staff report issued on March 26, 2003 also describes many of the techniques and effects of electric and gas market manipulation. The FERC will be modifying the administrative law judge's initial decision of December 12, 2002 to reflect the fact that the gas indices used in the market manipulation formula overstated the cost of gas used to generate electricity.

SCE has not yet completed an evaluation of the FERC actions taken on March 26, 2003 and cannot determine the timing or amount of any potential refunds. Under the settlement agreement with the CPUC, any refunds will be applied to reduce the PROACT balance until the PROACT is fully recovered. After PROACT recovery is complete, 90% of any refunds will be refunded to ratepayers.

Other Regulatory Matters

This subsection of "Regulatory Matters" discusses an SCE plan to reduce customer rates after the PROACT has been fully recovered and the current status of the holding company proceeding.

Customer Rate-Reduction Plan

On January 17, 2003, SCE filed with the CPUC a detailed plan outlining how customer rates could be reduced later in 2003 when SCE expects to have completed recovery of uncollected procurement costs incurred on behalf of its customers during the California energy crisis and reflected in the PROACT. In its January 17, 2003 filing, SCE proposed that the CPUC apply rate reductions of about $1.3 billion in the same manner it applied a series of rate surcharges during the height of the energy crisis in 2001, primarily to rates paid by business and higher-use residential customers. If approved by the CPUC, after PROACT recovery is completed, bills for larger-use residential customers would decline 8%, and average rates would decline 19% for small and medium business customers and 26% for larger-use business customers. The CPUC has set a prehearing conference for March 21, 2003 and has asked for additional evidence on the effect on rates of applying the reductions on an equal cents-per-kilowatt-hour basis across all customer classes rather than as SCE has proposed. SCE cannot predict when the matter will be decided.

Holding Company Proceeding

In April 2001, the CPUC issued an OII that reopens the past CPUC decisions authorizing utilities to form holding companies and initiates an investigation into, among other things: whether the holding companies violated CPUC requirements to give first priority to the capital needs of their respective utility subsidiaries; 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. 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. The decision did not determine if any of the utility holding companies had violated this condition, reserving such a determination for a later phase of the proceedings. On February 11, 2002, SCE and Edison International filed an application before the CPUC for rehearing of the decision. On July 17, 2002, the CPUC affirmed its earlier decision on the first priority condition and also denied Edison International's request for a rehearing of the CPUC's determination that it had jurisdiction over Edison International in this proceeding. On August 21, 2002, Edison International and SCE jointly filed a petition requesting a review of the CPUC's decisions with regard to first priority considerations, and Edison International filed a petition for a review of the CPUC decision asserting jurisdiction over holding companies, both in state court as required. PG&E, SDG&E and their respective holding companies filed similar challenges, and all cases have been transferred to the First District Court of Appeals in San Francisco. The CPUC filed briefs in opposition to the writ petitions. SCE, Edison International, and the other petitioners filed reply briefs on March 6, 2003. No hearings have been scheduled. The court may rule without holding hearings. SCE cannot predict with certainty what effects this investigation or any subsequent actions by the CPUC may have on SCE.

OTHER DEVELOPMENTS

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 10 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 41 identified sites is $99 million. The sites include SCE's divested gas-fueled generation plants, for which SCE retained some liability as a result of their sale. 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 $282 million.

The CPUC allows SCE to recover environmental-cleanup costs at certain sites, representing $38 million of its recorded liability, through an incentive mechanism, which is discussed in Note 10. SCE has recorded a

regulatory asset of $70 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 2002 were $25 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.

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

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).

SCE's share of the costs of complying with the consent decree and taking other actions to continue operation of the Mohave station beyond 2005 is estimated to be approximately $605 million over the next four years. This amount is included in the $2.0 billion for SCE's projected environmental capital expenditure (discussed below). SCE has received from the State of Nevada a permit to construct the necessary controls. However, SCE has suspended its efforts to seek CPUC approval to install the Mohave controls because it has not obtained reasonable assurance of adequate coal and water supplies for operating Mohave beyond 2005. Unless adequate coal and water supplies are obtained, it will become necessary to shut down 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 $27 million as of December 31, 2002) and the related regulatory asset (approximately $61 million as of December 31, 2002), and plant closure and decommissioning-related costs are recoverable in future rates. SCE cannot predict, with certainty, what effect any future actions by the CPUC may have on this matter. See "Regulatory Matters—Mohave Generating Station Proceeding" for further discussion of the Mohave issues.

SCE's projected environmental capital expenditures are $2.0 billion for the 2003–2007 period, mainly for undergrounding certain transmission and distribution lines.

Electric and Magnetic Fields

Electric and magnetic fields (EMFs) naturally result from the generation, transmission, distribution and use of electricity. Since the 1970s, concerns have been raised about the potential health effects of EMFs. After 30 years of research, no health hazard has been established. Many of the questions about specific diseases have been successfully resolved due to an aggressive international research program. Potentially important public health questions remain about whether there is a link between EMF exposures in homes or work and some diseases, including childhood leukemia and a variety of other adult diseases (e.g., adult cancers and miscarriages), and because of these questions, some health authorities have identified magnetic field exposures as a possible human carcinogen.

In October 2002, the California Department of Health Services (CDHS) released its report evaluating the possible risks from electric and magnetic fields (CDHS Report) to the CPUC and the public. The CDHS Report's conclusions contrast with other recent reports by authoritative health agencies in that the CDHS has assigned a substantially higher probability to the possibility that there is a causal connection between

EMF exposures and a number of diseases and conditions, including childhood leukemia, adult leukemia, amyotrophic lateral sclerosis, and miscarriages.

This report concludes a program initiated by the CPUC's 1993 Interim EMF Decision. Under the policies advanced by that decision, utilities have already committed to funding research, providing education materials to employees and customers, and taking proactive steps to lower magnetic fields from new facilities.

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

Navajo Nation Litigation

Peabody Holding Company (Peabody) supplies coal from mines on Navajo Nation lands to Mohave. In June 1999, the Navajo Nation filed a complaint in federal district court against Peabody and certain of its affiliates, Salt River Project Agricultural Improvement and Power District, and SCE. The complaint asserts claims against the defendants for, among other things, violations of the federal RICO statute, interference with fiduciary duties and contractual relations, fraudulent misrepresentation by nondisclosure, and various contract-related claims. The complaint claims that the defendants' actions prevented the Navajo Nation from obtaining the full value in royalty rates for the coal. The complaint seeks damages of not less than $600 million, trebling of that amount, and punitive damages of not less than $1 billion, as well as a declaration that Peabody's lease and contract rights to mine coal on Navajo Nation lands should be terminated.

In February 2002, Peabody and SCE filed cross claims against the Navajo Nation, alleging that the Navajo Nation had breached a settlement agreement and final award between Peabody and the Navajo Nation by filing their lawsuit.

The Navajo Nation had previously filed suit in the Court of Claims against the United States Department of Interior, alleging that the Government had breached its fiduciary duty concerning contract negotiations including the Navajo Nation and the defendants. In February 2000, the Court of Claims issued a decision in the Government's favor, finding that while there had been a breach, there was no available redress from the Government. Following appeal of that decision by the Navajo Nation, an appellate court ruled that the Court of Claims did have jurisdiction to award damages and remanded the case to the Court of Claims for that purpose. On June 3, 2002, the Government's request for review of the case by the United States Supreme Court was granted. On March 4, 2003, the Supreme Court reversed the appellate court and held that the Government is not liable to the Navajo Nation as there was no breach of a fiduciary duty.

SCE cannot predict with certainty the outcome of the 1999 Navajo Nation's complaint against SCE, nor the impact on this complaint or the Supreme Court's decision on the outcome of the Navajo Nation's suit against the Government, or the impact of the complaint on the operation of Mohave beyond 2005.

Employee Compensation and Benefit Plans

SCE measures compensation expense related to stock-based compensation by the intrinsic value method. If SCE were to adopt the fair-value method of accounting and charge the cost of the stock options to expense, effective with stock options granted in 2002, SCE's earnings for the year ended December 31, 2002, would have been reduced by approximately $1 million, based on a Black-Scholes option-pricing model.

Under accounting standards for pension costs, if the accumulated benefit obligation (ABO) exceeds the market value of plan assets at the measurement date, the difference may result in a reduction to shareholder's equity through a charge to other comprehensive income. As of December 31, 2002, the $41 million in ABO for one of SCE's two pension plans, measured using a discount rate that represented the market interest rate for high quality fixed income investments, exceeded the market value of the

related pension plan assets, resulting in a $5 million (net of tax) reduction to shareholder's equity. As of December 31, 2002, the $2.1 billion in ABO of the other pension plan was approximately $140 million less than the market value of the related plan assets, resulting in no additional reduction to shareholder's equity. For this plan, a reduction of shareholder's equity may be required at the next measurement date in December 2003, depending on such factors as the discount rate, plan asset rate of return experience and contributions made by SCE in 2003. See additional discussion in "Critical Accounting Policies—Pensions."

San Onofre Inspection

SCE's San Onofre Unit 2 returned to service on July 2, 2002 after a 43-day outage for scheduled refueling and maintenance. SCE's San Onofre Unit 3 returned to service on February 17, 2003 after a 42-day outage for scheduled refueling and maintenance. During these outages, detailed inspections of the reactor vessel head nozzle penetrations were conducted. The subject of reactor vessel head nozzle penetrations has received industry attention recently due to the leakage from such nozzles at the Davis Besse nuclear plant in Ohio. The inspections conducted at San Onofre Units 2 and 3 found no indications of leakage or degradation in the reactor vessel head nozzle penetrations.

Federal Income Taxes

On August 7, 2002, Edison International received a notice from the IRS asserting deficiencies in federal corporate income taxes for Edison International's 1994 to 1996 tax years. Included in these amounts are deficiencies asserted against SCE. Substantially all of SCE's tax deficiencies are timing differences and, therefore, amounts ultimately paid, if any, would benefit it as future tax deductions. Edison International is challenging the deficiencies asserted by the IRS. SCE believes that it has meritorious legal defenses to deficiencies asserted against it and believes that the ultimate outcome of this matter will not result in a material impact on its consolidated results of operations or financial position.

Edison International is, and may in the future be, under examination by tax authorities in varying tax jurisdictions with respect to positions it takes in connection with the filing of its tax returns. Matters raised upon audit may involve substantial amounts, which, if resolved unfavorably, an event not currently anticipated, could possibly be material. However, in SCE's opinion, it is unlikely that the resolution of any such matters will have a material adverse effect upon its financial condition or results of operations.

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.

Asset Impairment

SCE evaluates long-lived assets whenever indicators of potential impairment exist. Accounting standards require that if the undiscounted expected future cash flow from a company's assets or group of assets is less than its carrying value, an asset impairment must be recognized in the financial statements. The amount of impairment is determined by the difference between the carrying amount and fair value of the asset.

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

During the fourth quarter of 2002, SCE assessed the impairment of its Mohave plant due to the probability of a plant shutdown at the end of 2005. Because the expected undiscounted cash flows from the plant during the years 2003–2005 were less than the $88 million carrying value of the plant as of December 31,

2002, SCE incurred an impairment charge of $61 million. However, in accordance with accounting principles for rate regulated companies, this incurred cost was deferred and recorded as a regulatory asset, due to the expectation that the unrecovered book value of Mohave at the time of shutdown will be recovered through the rate-making process. See "Regulatory Matters—Mohave Generating Station Proceeding" and "—Rate Regulated Enterprises."

Income Taxes

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

As part of the process of preparing its consolidated financial statements, SCE is required to estimate its income taxes in each of the jurisdictions in which it operates. This process involves estimating actual current tax expense together with assessing temporary differences resulting from differing treatment of items, such as depreciation, for tax and accounting purposes. These differences result in deferred tax assets and liabilities, which are included within SCE's consolidated balance sheet. Management continually evaluates its income tax exposures and provides for allowances and/or reserves as deemed necessary.

Pensions

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

The discount rate enables SCE to state expected future cash flows at a present value on the measurement date. At the December 31, 2002 measurement date, SCE used a discount rate of 6.5% that represented the market interest rate for high-quality fixed income investments.

To determine the expected long-term rate of return on pension plan assets, current and expected asset allocations are considered, as well as historical and expected returns on plan assets. The expected rate of return on plan assets was 8.5%. Actual return on plan assets resulted in losses in the pension trusts of $311 million in 2002. However, accounting principles provide that differences between expected and actual returns are recognized over the average future service of employees.

At December 31, 2002, SCE's pension plans included $2.6 billion in projected benefit obligation (PBO), $2.2 billion in ABO and $2.3 billion in plan assets. A 1% decrease in the discount rate would increase the PBO by $205 million, and a 1% increase would decrease the PBO by $190 million, with corresponding changes in the ABO. A 1% decrease in the expected rate of return on plan assets would decrease pension expense by $26 million.

SCE records pension expense equal to the amount funded to the trusts, as calculated using an actuarial method required for ratemaking purposes, in which the impact of market volatility on plan assets is recognized in earnings on a more gradual basis. Any difference between pension expense calculated in accordance with ratemaking methods and pension expense or income calculated in accordance with accounting standards, is accumulated in a regulatory asset or liability, and will, over time, be recovered from or returned to ratepayers. As of December 31, 2002, this cumulative difference amounted to a regulatory liability of $185 million, meaning that the ratemaking method has resulted in recognizing $185 million more in expense that the accounting method since implementation of the pension accounting standard in 1987.

Under accounting standards, if the ABO exceeds the market value of plan assets at the measurement date, the difference may result in a reduction to shareholders' equity through a charge to other comprehensive income, but would not affect current income. The reduction to other comprehensive

income would be restored through shareholders' equity in future periods to the extent the market value of trust assets exceeded the ABO.

Rate Regulated Enterprises

SCE applies accounting principles for rate-regulated enterprises to the portion of its operations, in which regulators set rates at levels intended to recover the estimated costs of providing service, plus a return on capital. Due to timing and other differences in the collection of revenue, these principles allow an incurred cost that would otherwise be charged to expense by a 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. SCE's management continually assesses whether the regulatory assets are probable of future recovery by considering factors such as the current regulatory environment, the issuance of rate orders on recovery of the specific incurred cost or a similar incurred cost to SCE or other rate-regulated entities in California, and assurances from the regulator (as well as its primary intervenor groups) that the incurred cost will be treated as an allowable cost (and not challenged) for rate-making purposes. Because current rates include the recovery of existing regulatory assets and settlement of regulatory liabilities, and rates in effect are expected to allow SCE to earn a reasonable rate of return, management believes that existing regulatory assets and liabilities are probable of recovery. This determination reflects the current political and regulatory climate in California and is subject to change in the future. If future recovery of costs ceases to be probable, all or part of the regulatory assets and liabilities would have to be written off against current period earnings. At December 31, 2002, the balance sheet included regulatory assets, less regulatory liabilities, of $4.3 billion. Management continually evaluates the anticipated recovery of regulatory assets, liabilities, and revenue subject to refund and provides for allowances and/or reserves as deemed necessary.

SCE applied judgment in the use of the above principles when: it 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, in fourth quarter 2001; it created the $3.6 billion PROACT regulatory asset, in second quarter 2002; it restored $480 million (after-tax) of generation-related regulatory assets based on the URG decision; in fourth quarter 2002, it established a $61 million regulatory asset related to the impaired Mohave plant. In all instances, SCE recorded corresponding credits to earnings upon concluding that such incurred costs were probable of recovery in the future. See further discussion in "Results of Operations—Earnings (Loss) from Continuing Operations" and "Regulatory Matters—PROACT Regulatory Asset, —URG Decision, and —Mohave Generating Station Proceeding" sections.

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. Effective April 1, 2002, SCE also adopted an authoritative accounting interpretation to this standard, which precludes fuel contracts that have variable amounts from qualifying under the normal purchases and sales exception. The adoption of this interpretation had no impact on SCE's financial statements.

Effective January 1, 2003, SCE will adopt a new accounting standard, Accounting for Asset Retirement Obligations, which requires entities to record the fair value of a liability for a legal asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the entity capitalizes the cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is increased to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss upon settlement. However, rate-regulated entities may recognize regulatory assets or liabilities as a result of timing differences between the recognition of costs as recorded in accordance with this statement and costs recovered through the ratemaking process. Regulatory assets and liabilities may be recorded when it is probable that the asset retirement costs will be recovered through the rate-making process. Upon adoption, the cumulative effect of applying this standard will be recorded as a change in accounting principle and will be presented after net income (loss) on the consolidated statements of income (loss).

SCE estimates the impact of adopting this standard will be as follows:

- SCE will adjust its nuclear decommissioning obligation to reflect the fair value of decommissioning its nuclear power facilities. SCE will also recognize asset retirement obligations associated with the decommissioning of other coal-fired generation assets.

- At December 31, 2002, the total nuclear decommissioning obligation accrued for SCE's active nuclear facilities was $2.0 billion and is included in accumulated provision for depreciation and decommissioning on the consolidated balance sheet. SCE has accrued, at December 31, 2002, $12 million to decommission certain coal-fired generation assets based on its estimate of the decommissioning obligation under the accounting principles in effect at that time. These decommissioning obligations are also included in accumulated provision for depreciation and decommissioning on the consolidated balance sheet.

- SCE estimates that it will record a $190 million decrease to its recorded nuclear and coal facility decommissioning obligations for asset retirement obligations in existence as of January 1, 2003. The estimated cumulative effect of a change in accounting principle from unrecognized accretion expense and adjustments to depreciation, decommissioning and amortization expense accrued to date is a $408 million gain (pre-tax), which will be reflected as a regulatory liability as of January 1, 2003.

FORWARD-LOOKING INFORMATION AND RISK FACTORS

In the preceding MD&A and elsewhere in this quarterly report, the words estimates, expects, anticipates, believes, predict, and other similar expressions are intended to identify forward-looking information that involves risks and uncertainties. Actual results or outcomes could differ materially from those anticipated. Risks, uncertainties and other important factors that could cause results to differ, or that otherwise could impact SCE, include, among other things:

- the outcome of the pending appeal of the stipulated judgment approving SCE's settlement agreement with the CPUC, and the effects of other legal actions, if any, attempting to undermine the provisions of the settlement agreement or otherwise adversely affecting SCE;

- changes in prices and availability of wholesale electricity, natural gas, other fuels, transmission services, and other changes in operating costs, which could affect the timing of SCE's energy procurement cost recovery or otherwise impact SCE's operations and financial results;

- the effects of declining interest rates and investment returns on employee benefit plans and nuclear decommissioning trusts;

- changing conditions in wholesale power markets, such as general credit constraints and thin trading volumes, that could make it difficult for SCE to enter into hedging agreements;

- 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;

- actions by state and federal regulatory and administrative bodies setting rates, adopting or modifying cost recovery, holding company rules, accounting and rate-setting mechanisms or otherwise changing the regulatory and business environments within which SCE does business, as well as legislative or judicial actions affecting the same matters;

- the effects of increased competition in energy-related businesses, including new market entrants and the effects of new technologies that may be developed in the future;
- threatened attempts by municipalities within SCE's service territory to form public power entities and/or acquire SCE's facilities for customers;
- new or increased environmental requirements that could require capital expenditures or otherwise affect the operations and cost of SCE, and possible increased liabilities under new or existing requirements; and
- weather conditions, natural disasters, and other unforeseen events.

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Consolidated Statements of Income (Loss)

Southern California Edison Company

In millions Year ended December 31,	2002	2001	2000
Operating revenue	**$ 8,706**	$ 8,126	$ 7,870
Fuel	**243**	212	195
Purchased power	**2,016**	3,770	4,687
Provisions for regulatory adjustment clauses – net	**1,502**	(3,028)	2,301
Other operation and maintenance	**1,926**	1,771	1,772
Depreciation, decommissioning and amortization	**780**	681	1,473
Property and other taxes	**117**	112	126
Net gain on sale of utility plant	**(5)**	(9)	(25)
Total operating expenses	**6,579**	3,509	10,529
Operating income (loss)	**2,127**	4,617	(2,659)
Interest and dividend income	**262**	215	173
Other nonoperating income	**82**	57	118
Interest expense – net of amounts capitalized	**(584)**	(785)	(572)
Other nonoperating deductions	**2**	(38)	(110)
Income (loss) before taxes	**1,889**	4,066	(3,050)
Income tax (benefit)	**642**	1,658	(1,022)
Net income (loss)	**1,247**	2,408	(2,028)
Dividends on preferred stock	**19**	22	22
Net income (loss) available for common stock	**$ 1,228**	$ 2,386	$(2,050)

Consolidated Statements of Comprehensive Income (Loss)

In millions Year ended December 31,	2002	2001	2000
Net income (loss)	**$ 1,247**	$ 2,408	$ (2,028)
Other comprehensive income, net of tax:			
Minimum pension liability adjustment	**(5)**	—	—
Unrealized gain on securities – net	**—**	—	3
Cumulative effect of change in accounting for derivatives	**—**	398	—
Unrealized gain (loss) on and amortization of cash flow hedges	**11**	(420)	—
Reclassification adjustment for loss included in net income (loss)	**—**	—	(25)
Comprehensive income (loss)	**$ 1,253**	$ 2,386	$ (2,050)

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

Consolidated Balance Sheets

In millions December 31,	2002	2001
ASSETS		
Cash and equivalents	$ 992	$ 3,414
Receivables, less allowances of $36 and $32 for uncollectible accounts at respective dates	767	1,093
Accrued unbilled revenue	437	451
Fuel inventory	12	14
Materials and supplies, at average cost	159	146
Accumulated deferred income taxes – net	42	433
Regulatory assets – net	509	83
Prepayments and other current assets	104	145
Total current assets	3,022	5,779
Nonutility property – less accumulated provision for depreciation of $29 and $17 at respective dates	154	159
Nuclear decommissioning trusts	2,210	2,275
Other investments	214	224
Total investments and other assets	2,578	2,658
Utility plant, at original cost:		
Transmission and distribution	14,202	13,568
Generation	1,457	1,729
Accumulated provision for depreciation and decommissioning	(8,094)	(7,969)
Construction work in progress	529	556
Nuclear fuel, at amortized cost	153	129
Total utility plant	8,247	8,013
Regulatory assets – net	3,838	5,528
Other deferred charges	629	475
Total deferred charges	4,467	6,003
Total assets	$ 18,314	$ 22,453

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

In millions, except share amounts December 31,	2002	2001
LIABILITIES AND SHAREHOLDER'S EQUITY		
Short-term debt	$ —	$ 2,127
Long-term debt due within one year	1,671	1,146
Preferred stock to be redeemed within one year	9	105
Accounts payable	745	3,261
Accrued taxes	699	823
Other current liabilities	1,439	1,645
Total current liabilities	4,563	9,107
Long-term debt	4,504	4,739
Accumulated deferred income taxes – net	2,658	3,365
Accumulated deferred investment tax credits	148	153
Customer advances and other deferred credits	964	739
Power-purchase contracts	309	356
Accumulated provision for pensions and benefits	356	420
Other long-term liabilities	152	148
Total deferred credits and other liabilities	4,587	5,181
Commitments and contingencies (Notes 2, 9 and 10)		
Preferred stock:		
Not subject to mandatory redemption	129	129
Subject to mandatory redemption	147	151
Total preferred stock	276	280
Common stock (434,888,104 shares outstanding at each date)	2,168	2,168
Additional paid-in capital	340	336
Accumulated other comprehensive loss	(16)	(22)
Retained earnings	1,892	664
Total common shareholder's equity	4,384	3,146
Total liabilities and shareholder's equity	$ 18,314	$ 22,453

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

Consolidated Statements of Cash Flows

In millions Year ended December 31,	2002	2001	2000
Cash flows from operating activities:			
Net income (loss)	**$ 1,247**	$ 2,408	$ (2,028)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, decommissioning and amortization	**780**	681	1,473
Other amortization	**106**	82	97
Deferred income taxes and investment tax credits	**(640)**	1,313	(928)
Regulatory assets – long-term – net	**1,860**	(3,135)	1,759
Gas call options	**14**	(91)	20
Net gain on sale of marketable securities	**—**	—	(41)
Other assets	**7**	(68)	24
Other liabilities	**132**	17	(13)
Changes in working capital:			
Receivables and accrued unbilled revenue	**338**	(243)	(282)
Regulatory assets – short-term – net	**(426)**	(278)	97
Fuel inventory, materials and supplies	**(11)**	(16)	29
Prepayments and other current assets	**41**	(21)	(14)
Accrued interest and taxes	**(191)**	365	48
Accounts payable and other current liabilities	**(2,626)**	2,251	588
Net cash provided by operating activities	**631**	3,265	829
Cash flows from financing activities:			
Long-term debt issued	**(32)**	—	1,760
Long-term debt repaid	**(1,200)**	—	(525)
Bonds remarketed (repurchased) and funds held in trust – net	**191**	(130)	(440)
Redemption of preferred securities	**(100)**	—	—
Rate reduction notes repaid	**(246)**	(246)	(246)
Nuclear fuel financing – net	**(59)**	(21)	9
Short-term debt financing – net	**(527)**	676	655
Dividends paid	**(40)**	(1)	(395)
Net cash provided (used) by financing activities	**(2,013)**	278	818
Cash flows from investing activities:			
Additions to property and plant – net	**(1,046)**	(688)	(1,096)
Net funding of nuclear decommissioning trusts	**(12)**	(36)	(69)
Proceeds from sales of marketable securities	**—**	—	41
Sales of investments in other assets	**18**	12	34
Net cash used by investing activities	**(1,040)**	(712)	(1,090)
Net increase (decrease) in cash and equivalents	**(2,422)**	2,831	557
Cash and equivalents, beginning of year	**3,414**	583	26
Cash and equivalents, end of year	**$ 992**	$ 3,414	$ 583

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

Consolidated Statements of Changes in Common Shareholder's Equity

Southern California Edison Company

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, 1999	$ 2,168	$ 335	$ 22	$ 608	$ 3,133
Net loss				(2,028)	(2,028)
Unrealized gain on securities			8		8
Tax effect			(5)		(5)
Reclassified adjustment for loss 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 and amortization of 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
Net income				1,247	1,247
Minimum pension liability adjustment			(9)		(9)
Tax effect			4		4
Amortization of loss on cash flow hedges			4		4
Tax effect			7		7
Dividends accrued on preferred stock				(19)	(19)
Capital stock expense and other		4			4
Balance at December 31, 2002	$ 2,168	$ 340	$ (16)	$ 1,892	$ 4,384

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

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

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

Note 1. Summary of Significant Accounting Policies

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.

Basis of Presentation

The consolidated financial statements include SCE and its subsidiaries. Intercompany transactions have been eliminated.

SCE's accounting policies conform to accounting principles generally accepted in the United States, including the accounting principles for rate-regulated enterprises, which reflect the rate-making policies of the California Public Utilities Commission (CPUC) and the Federal Energy Regulatory Commission (FERC). In 1997, due to changes in the rate recovery of generation-related assets, SCE began using accounting principles applicable to enterprises in general for its investment in generation facilities. In April 2002, SCE reapplied accounting principles for rate-regulated enterprises to assets that were returned to cost-based regulation under the utility-retained generation (URG) decision (see "URG Proceeding" in Note 2).

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

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

Cash Equivalents

Cash equivalents include time deposits and other investments with original maturities of three months or less. All investments are classified as available for sale. For a discussion of restricted cash, see "Restricted Cash" section.

Debt and Equity 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, except for San Onofre Nuclear Generating Station (San Onofre) Unit 1, which is recorded against the related regulatory asset. 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.

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. Effective April 1, 2002, SCE also adopted an authoritative accounting interpretation to this standard, which precludes fuel contracts that have variable amounts from qualifying under the normal purchases and sales exception. The adoption of this interpretation had no impact on SCE's financial statements.

Effective January 1, 2003, SCE will adopt a new accounting standard, Accounting for Asset Retirement Obligations, which requires entities to record the fair value of a liability for a legal asset retirement

obligation in the period in which it is incurred. When the liability is initially recorded, the entity capitalizes the cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is increased to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss upon settlement. However, rate-regulated entities may recognize regulatory assets or liabilities as a result of timing differences between the recognition of costs as recorded in accordance with this statement and costs recovered through the ratemaking process. Regulatory assets and liabilities may be recorded when it is probable that the asset retirement costs will be recovered through the rate-making process.

SCE estimates the impact of adopting this standard will be as follows:

- SCE will adjust its nuclear decommissioning obligation to reflect the fair value of decommissioning its nuclear power facilities. SCE will also recognize asset retirement obligations associated with the decommissioning of other coal-fired generation assets.

- At December 31, 2002, the total nuclear decommissioning obligation accrued for SCE's active nuclear facilities was $2.0 billion and is included in accumulated provision for depreciation and decommissioning on the consolidated balance sheet. SCE has accrued, at December 31, 2002, $12 million to decommission certain coal-fired generation assets based on its estimate of the decommissioning obligation under the accounting principles in effect at that time. These decommissioning obligations are also included in accumulated provision for depreciation and decommissioning on the consolidated balance sheet.

- SCE estimates that it will record a $190 million decrease to its recorded nuclear and coal facility decommissioning obligations for asset retirement obligations in existence as of January 1, 2003. The estimated cumulative effect of a change in accounting principle from unrecognized accretion expense and adjustments to depreciation, decommissioning and amortization expense accrued to date is a $408 million gain (pre-tax), which will be reflected as a regulatory liability as of January 1, 2003.

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 Units 2 and 3 and Palo Verde Nuclear Generating Station (Palo Verde) on an accelerated basis, as authorized by the CPUC. The accelerated recovery was to continue through December 2001, earning a 7.35% fixed rate of return on investment. San Onofre's operating costs, including nuclear fuel and nuclear fuel financing costs, and incremental capital expenditures, were recovered through an incentive pricing plan that allows SCE to receive about 4¢ per kilowatt-hour through 2003. Any differences between these costs and the incentive price would flow through to shareholders. Palo Verde's accelerated plant recovery, as well as operating costs, including nuclear fuel and nuclear fuel financing costs, and incremental capital expenditures, were subject to balancing account treatment through 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). See further discussion of the TCBA in "Regulatory Assets and Liabilities."

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 of December 31, 2000, SCE was no longer able to conclude that the unamortized nuclear investment was probable of recovery through the rate-making process. As a result, this balance was written off as a charge to earnings at that time. As a result of the CPUC's April 4, 2002 decision that returned SCE's URG assets to cost-based ratemaking, SCE reestablished for financial reporting purposes its unamortized nuclear investment and related flow-through taxes, retroactive to August 31, 2001, based on a 10-year recovery period, effective

January 1, 2001, with a corresponding credit to earnings. SCE adjusted the procurement-related obligations account (PROACT) regulatory asset balance to reflect recovery of the nuclear investment in accordance with the final URG decision.

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

Other Nonoperating Income and Deductions

Other nonoperating income and deductions are as follows:

In millions Year ended December 31,	2002	2001	2000
Gain on sale of marketable securities	$ —	$ —	$ 41
Property condemnation settlement	38	—	—
Allowance for funds used during construction	19	16	21
Other	25	41	56
Total other nonoperating income	**$ 82**	**$ 57**	**$ 118**
Provisions for regulatory issues and refunds	$ (35)	$ 7	$ 78
Other	33	31	32
Total other nonoperating deductions	**$ (2)**	**$ 38**	**$ 110**

Planned Major Maintenance

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

Purchased Power

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

In millions Year ended December 31,	2002	2001	2000
PX/ISO:			
Purchases	$ 75	$ 775	$ 8,449
Generation sales	—	324	6,120
Purchased power – PX/ISO – net	75	451	2,329
Purchased power – bilateral contracts	61	188	—
Purchased power – interutility/QF contracts	1,880	3,131	2,358
Total	**$ 2,016**	**$ 3,770**	**$ 4,687**

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

From January 17, 2001 to December 31, 2002, the California Department of Water Resources (CDWR) purchased power for delivery to SCE's customers in an amount equal to the difference between customer requirements and supplies provided through QF and bilateral contracts, and SCE's utility retained generation.

Effective January 1, 2003, SCE assumed responsibility for power requirements not met by the CDWR. Power purchased by the CDWR for delivery to SCE's customers is not considered a cost to SCE.

Regulatory Assets and Liabilities

In accordance with accounting principles for rate-regulated enterprises, SCE records regulatory assets, which represent probable future 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.

The gains resulting from the sale of 12 of SCE's generating plants during 1998 were 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 PROACT regulatory asset for previously incurred energy procurement costs, retroactive to August 31, 2001. The settlement agreement called 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 applies 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 accrues 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.

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

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

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

In millions December 31,	2002	2001
PROACT – net	$ 574	$ 2,641
Rate reduction notes – transition cost deferral	1,215	1,453
Unamortized nuclear investment – net	630	—
Unamortized coal plant investment – net	61	—
Other:		
Flow-through taxes – net	1,336	1,017
Unamortized loss on reacquired debt	237	254
Environmental remediation	70	57
Regulatory balancing accounts and other – net	224	189
Total	$ 4,347	$ 5,611

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

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

Related Party Transactions

Certain Edison Mission Energy (a wholly owned subsidiary of Edison International) subsidiaries have 49% – 50% ownership in partnerships (QFs) that sell electricity generated by their project facilities to SCE under long-term power purchase agreements with terms and pricing approved by the CPUC. SCE's purchases from these partnerships were $548 million in 2002, $983 million in 2001 and $716 million in 2000.

SCE holds $153 million in notes receivable from affiliates, due in June 2007.. The notes were issued by Edison International in second quarter 1997, and assigned to SCE in fourth quarter 1997. A $78 million note receivable from Edison Mission Energy bears interest at LIBOR plus 0.275%; and a $75 million note receivable from Edison Capital bears interest at a 30-day commercial paper rate.

Restricted Cash

SCE had restricted cash of $47 million at December 31, 2002 and $35 million at December 31, 2001, which was included in the caption "prepayments and other current assets" on the balance sheets. These restricted amounts are used exclusively to make scheduled payments on the current maturities of rate reduction notes issued on behalf of SCE by a special purpose entity.

Revenue

Operating revenue is recognized as electricity is delivered and includes amounts for services rendered but unbilled at the end of each year. Amounts charged for services rendered are based on CPUC-authorized rates. Rates include amounts for current period costs, plus the recovery of previously incurred costs (see discussions under "Regulatory Assets and Liabilities"). However, in accordance with accounting standards for rate-regulated enterprises, amounts currently authorized in rates for recovery of costs to be incurred in the future are not considered as revenue until the associated costs are incurred.

Since January 17, 2001, power purchased by the CDWR or through the ISO for SCE's customers is not considered a cost to SCE, because SCE is acting as an agent for these transactions. Further, amounts billed to ($1.4 billion in 2002 and $2.0 billion in 2001) and collected from its customers for these power purchases and CDWR bond-related costs (effective November 15, 2002 for bond-related costs) are being remitted to the CDWR and are not recognized as revenue to SCE.

Stock-Based Employee Compensation

SCE has three stock-based employee compensation plans, which are described more fully in Note 7. SCE accounts for those plans using the intrinsic value method. Upon grant, no stock-based employee compensation cost is reflected in net income, as all options granted under those plans had an exercise price equal to the market value of the underlying common stock on the date of grant. Compensation expense recorded under the stock-compensation program was $7 million in 2002, $1 million in 2001 and $4 million in 2000. The following table illustrates the effect on net income if the company had used the fair-value accounting method.

In millions Year ended December 31,	2002	2001	2000
Net income (loss) available for common stock, as reported	$ 1,228	$ 2,386	$ (2,050)
Less: Additional stock-based compensation expense using the fair-value accounting method – net of tax	(2)	3	4
Pro forma net income (loss) available for common stock	**$ 1,230**	**$ 2,383**	**$ (2,054)**

Supplemental Accumulated Other Comprehensive Income (Loss) Information

Supplemental information regarding SCE's accumulated other comprehensive income (loss) is:

In millions December 31,	2002	2001
Minimum pension liability – net[1]	$ (5)	$ —
Cumulative effect of change in accounting for derivatives	—	398
Unrealized losses on cash flow hedges – net	(11)	(420)
Accumulated other comprehensive loss	**$ (16)**	**$ (22)**

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

Unrealized gains (losses) on cash flow hedges relate to SCE's interest rate swap (the swap terminated on January 5, 2001 but the related debt matures in 2008). The unamortized loss of $11 million (as of December 31, 2002 net of tax) on the interest rate swap will be amortized over a period ending in 2008. Approximately $2 million, after tax, of the unamortized loss on this swap will be reclassified into earnings during 2003.

Supplemental Cash Flows Information

SCE supplemental cash flows information is:

In millions Year ended December 31,	2002	2001	2000
Cash payments for interest and taxes:			
Interest – net of amounts capitalized	$ 487	$ 455	$ 303
Tax payments (receipts)	1,110	(105)	306
Non-cash investing and financing activities:			
Details of senior secured credit facility transaction:			
Retirement of credit facility	$ 1,650	—	—
Cash paid on retirement of credit facility	(50)	—	—
Senior secured credit facility replacement	$ 1,600	—	—

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 $11 million in 2002, $7 million in 2001 and $11 million in 2000. AFUDC – debt was $8 million in 2002, $9 million in 2001 and $10 million in 2000.

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 4.2% for 2002, and 3.6% for 2001 and 2000.

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

Generation plant	30 years to 45 years
Distribution plant	24 years to 53 years
Transmission plant	40 years to 60 years
Other plant	5 years to 40 years

SCE's net investment in generation-related utility plant was $842 million at December 31, 2002 and $1.0 billion at December 31, 2001.

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

Note 2. Regulatory Matters

CPUC Litigation Settlement Agreement

In 2001, SCE and the CPUC entered into a settlement of SCE's lawsuit against the CPUC, which sought a ruling that SCE is entitled to full recovery of its past electricity procurement costs. A key element of the settlement agreement was the establishment of a $3.6 billion rate-recovery mechanism called the PROACT as of August 31, 2001. The Utility Reform Network (TURN), a consumer advocacy group, and other parties appealed to the federal court of appeals seeking to overturn the stipulated judgment of the district court that approved the settlement agreement. On March 4, 2002, the court of appeals heard argument on the appeal, and on September 23, 2002 the court issued its opinion. In the opinion, the court affirmed the district court on all claims, with the exception of the challenges founded upon California state law, which the appeals court referred to the California Supreme Court. Specifically, the appeals court affirmed the district court in the following respects: (1) the district court did not err in denying the motions

to intervene brought by entities other than TURN; (2) the district court did not err in denying standing for the entities other than TURN to appeal the stipulated judgment; (3) the district court was not deprived of original jurisdiction over the lawsuit; (4) the district court did not err in declining to abstain from the case; (5) the district court did not exceed its authority by approving the stipulated judgment without TURN's consent; (6) the district court's approval of the settlement agreement did not deny TURN due process; and (7) the district court did not violate the Tenth Amendment of the United States Constitution in approving the stipulated judgment. In sum, the appeals court concluded that none of the substantive arguments based on federal statutory or constitutional law compelled reversal of the district court's approval of the stipulated judgment.

However, the appeals court stated in its opinion that there is a serious question whether the settlement agreement violated state law, both in substance and in the procedure by which the CPUC agreed to it. The appeals court added that if the settlement agreement violated state law, the CPUC lacked capacity to consent to the stipulated judgment, and the stipulated judgment would need to be vacated. The appeals court indicated that, on a substantive level, the stipulated judgment appears to violate California's electric industry restructuring statute providing for a rate freeze. The appeals court also indicated that, on a procedural level, the stipulated judgment appears to violate California laws requiring open meetings and public hearings. Because federal courts are bound by the pronouncements of the state's highest court on applicable state law, and because the federal appeals court found no controlling precedents from California courts on the issues of state law in this case, the appeals court issued a separate order certifying those issues in question form to the California Supreme Court and requested that the California Supreme Court accept certification.

The California Supreme Court accepted the certification, reformulated one of the certified questions as SCE had requested, and set a briefing schedule that will be followed by oral argument. SCE and the CPUC filed their respective opening briefs on the certified questions on December 20, 2002. TURN filed its answering brief on January 24, 2003 and SCE and the CPUC filed reply briefs on February 13, 2003. Various third parties, including the Governor, submitted friend-of-the-court briefs concerning the certified questions. In addition, the California Supreme Court requested that the parties provide supplemental briefing with respect to an issue related to California's open meeting laws. The parties have complied with such request. The California Supreme Court will set a hearing date on the matter. Once the California Supreme Court rules, the matter will return to the Ninth Circuit, which in turn should be guided by the California Supreme Court's answers and interpretations of state law. In the meantime, the case is stayed in the federal appellate court. SCE continues to operate under the settlement agreement. SCE continues to believe it is probable that SCE ultimately will recover its past procurement costs through regulatory mechanisms, including the PROACT. However, SCE cannot predict with certainty the outcome of the pending legal proceedings.

Under the settlement agreement, SCE cannot pay dividends or other distributions on its common stock (all of which is held by its parent, Edison International) prior to the earlier of the date on which SCE has recovered all of its procurement-related obligations or January 1, 2005, except that 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 prior to January 1, 2005 and the CPUC will not unreasonably withhold its consent.

CDWR Power Purchases and Revenue Requirement Proceedings

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 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 SCE's retail customers and authorized the CDWR to issue bonds to finance electricity purchases. In addition, the CPUC has the responsibility to allocate the CDWR's revenue requirement among the customers of SCE, Pacific Gas and Electric (PG&E) and San Diego Gas & Electric (SDG&E).

On February 21, 2002, the CPUC allocated to SCE's customers $3.5 billion (38.2%) of the CDWR's total power procurement revenue requirement of $9 billion for 2001 and 2002. This resulted in an average

annual CDWR revenue requirement of $1.7 billion being allocated to SCE. In its February 21, 2002 decision, the CPUC ordered that allocation of that revenue requirement to each utility be trued-up based on the CDWR's actual recorded costs for the 2001–2002 period and a specific methodology set forth in that decision.

On October 24, 2002, the CPUC issued a decision which adopts a methodology for establishing a charge to repay bond-related costs resulting from the CDWR's $11 billion bond issue. The bond charge is to be set by dividing the annual revenue requirement for bond-related costs by an estimate of the annual electricity consumption of bundled service customers subject to the charge. The charge will apply to electricity consumed on and after November 15, 2002 and will be set annually based on annual expected debt-related costs and projected electricity consumption. For 2003, the CPUC allocated to SCE's customers $331 million (about 44%) of the CDWR's bond charge revenue requirement of $745 million. The bond charge is set at a rate of 0.513¢ per kWh for SCE's customers. In a November 7, 2002 decision, the CPUC assigned responsibility for a portion of the bond charge to direct access customers.

On December 17, 2002, the CPUC adopted an allocation of the CDWR's forecast power procurement revenue requirement for 2003, based on the quantity of electricity expected to be supplied under the CDWR contracts to customers of each of the three utility companies by the CDWR. SCE's allocated share is $1.9 billion of the CDWR's total 2003 power procurement revenue requirement of $4.5 billion. This is an interim allocation and will be superseded by a later allocation after the CDWR submits a supplemental determination of its 2003 revenue requirement. The CPUC stated that the later allocation could result in a reduction in the CDWR's revenue requirement, with a corresponding decrease in the CDWR's rate charged to bundled service customers. The CPUC's December 17, 2002 decision did not address issues relating to the true-up of the CDWR's 2001–2002 revenue requirement, stating that those issues will be addressed after actual data for 2002 becomes available, expected in April 2003.

Electric Line Maintenance Practices Proceeding

In August 2001, the CPUC issued an Order Instituting Investigation (OII) regarding SCE's overhead and underground electric line maintenance practices. The OII is based on a report issued by the CPUC's Protection and Safety Consumer Services Division (CPSD), which alleges SCE had a pattern of noncompliance with the CPUC's General Orders for the maintenance of electric lines over the period 1998–2000. The OII also alleges that noncompliant conditions were involved in 37 accidents resulting in death, serious injury or property damage. The CPSD identified 4,817 alleged "violations" of the General Orders during the three-year period. The OII placed SCE on notice that it is potentially subject to a penalty of between $500 and $20,000 for each violation or accident.

Prepared testimony was filed on this matter in April 2002, and hearings were concluded in September 2002. In opening briefs filed on October 21, 2002, the CPSD recommended that SCE be assessed a penalty of $97 million, while SCE requested that the CPUC dismiss the proceeding and impose no penalties. SCE stated in its opening brief that it has acted reasonably, allocating its financial and human resources in pursuit of the optimum combination of employee and public safety, system reliability, cost-effectiveness, and technological advances. SCE also encouraged the CPUC to transfer consideration of issues related to development of standardized inspection methodologies and inspector training to an Order Instituting Rulemaking to revise these General Orders opened by the CPUC in October 2001 or to a new rulemaking proceeding. On March 14, 2003, SCE and the CPSD filed opening briefs in response to the assigned administrative law judge's direction to address application of the appropriate standard to govern SCE's electric line maintenance obligation. Oral arguments are scheduled for April 22, 2003. A decision is expected in the second or third quarter of 2003. SCE is unable to predict with certainty whether this matter ultimately will result in any material financial penalties or impacts on SCE.

Generation Procurement Proceedings

In October 2001, the CPUC issued an Order Instituting Rulemaking directing SCE and the other major California electric utilities to provide recommendations for establishing policies and mechanisms to enable the utilities to resume power procurement by January 1, 2003. Although the proceeding began before the enactment of Assembly Bill 57 (AB 57), that statute (in its draft form, and, after enactment, in its final form) has guided the proceeding. Senate Bill 1078 (SB 1078) has also had an impact on this proceeding, as described below.

AB 57, which provides for SCE and the other California utilities to resume procuring power for their customers, was signed into law by the Governor of California in September 2002. A second senate bill was enacted not long after AB 57 to shorten the time period between the adoption of a utility's initial procurement plan and the resumption of procurement from 90 to 60 days. Under these statutes, SCE is effectively allowed to recover procurement costs incurred in compliance with an approved procurement plan. Only limited categories of costs, including contract administration and least-cost dispatch, are subject to reasonableness reviews.

In addition, SB 1078, which was signed into law by the Governor in September 2002 and is effective January 1, 2003 provides that, commencing January 1, 2003, SCE and other California utilities shall increase their procurement of renewable resources by at least an additional 1% of their annual electricity sales per year so that 20% of the utility's annual electricity sales are procured from renewable resources by no later than December 31, 2017. Utilities are not required to enter into long-term contracts for renewable resources in excess of a market-price benchmark to be established by the CPUC pursuant to criteria set forth in the statute. Similar provisions are also found in AB 57.

The CPUC issued four major decisions in this proceeding in 2002 addressing: (1) transitional procurement contracts; (2) the allocation of contracts previously entered into by the CDWR among the three major California utilities; (3) the resumption of power procurement activities by these utilities on January 1, 2003 and adoption of a regulatory framework for such activities; and (4) SCE's short-term procurement plan for 2003.

The first decision, relating to transitional procurement contracts, was issued on August 22, 2002. It authorized the utilities to enter into capacity contracts between the effective date of the decision and January 1, 2003 referred to as the transitional procurement period. Under this decision, the CPUC would approve or disapprove the transitional contracts proposed by a utility by means of an expedited advice letter process. As a result of this process, SCE entered into six transitional capacity contracts with terms up to five years. These contracts were approved by the CPUC.

This decision also required the utilities to procure, during the transitional procurement period, at least 1% of their annual electricity sales through a competitive procurement process set aside for renewable resources. The utilities were required to solicit bids for renewable contracts with terms of five, ten and fifteen years and to enter into contracts providing for the commencement of deliveries by the end of 2003. In accordance with this CPUC directive, SCE conducted a solicitation of offers from owners of renewable resources and, based upon the results of the solicitation, provisionally entered into six contracts, subject to subsequent CPUC approval. On December 24, 2002 and January 14, 2003, SCE filed advice letters seeking CPUC approval of these six renewable contracts. On January 30, 2003, the CPUC issued a resolution approving four of the six renewable contracts. In addition, draft resolutions have been issued disapproving the two remaining renewable contracts, with an alternative draft resolution approving one of the two remaining contracts. The CPUC is expected to rule on the remaining contracts in the second quarter of 2003.

The second decision addressed the issue of allocating among the three major California utilities the contracts previously entered into by the CDWR. In this decision, issued on September 19, 2002, the CPUC allocated the CDWR contracts on a contract-by-contract basis. Under the decision, utility responsibility for the contracts is limited to that of scheduling and dispatch. The decision significantly reduces SCE's net short and also increases the likelihood that SCE will have excess power during certain periods. Wholesale revenue from the sale of such surplus energy is to be prorated between the CDWR and SCE, pursuant to several CPUC orders. Under the decision, SCE acts as limited agent for the CDWR for contract implementation, but legal title, financial reporting and responsibility for the payment of contract-related bills remain with the CDWR. On January 17, 2003, the CDWR filed a petition to modify the September 19, 2002 decision requesting the allocation of four additional contracts which are not currently part of the CDWR's 2003 revenue requirement. The CPUC allocated one of the four contracts to SCE in a February 27, 2003 decision.

The third decision was issued on October 24, 2002. It ordered the utilities to resume procurement and adopting the regulatory framework for the utilities resuming full procurement responsibilities on January 1,

2003. The decision distinguished the utilities' responsibilities on the basis of short-term (2003) versus long-term (2004–2024) procurement. It adopted the utilities' procurement plans filed on May 1, 2002 and directed that they be modified prior to January 1, 2003 to reflect the decision, the allocation of existing CDWR contracts, and any transitional procurement done under the August 22, 2002 decision. The October 24, 2002 decision also set forth a detailed process and procedural schedule to develop long-term procurement planning that includes the filing by each utility of a long-term plan by April 1, 2003 and an evidentiary hearing in early July 2003. In addition, the decision called for each of the utilities to establish a balancing account, to be known as the energy resource recovery account, to track energy costs. These balancing accounts will be used for examining procurement rate adjustments on a semi-annual basis, as well as on a more expedited basis in the event fuel and purchased-power costs exceed a prescribed threshold. The decision also provided clarification as to certain elements of the CPUC's August 22, 2002 order regarding interim procurement of additional renewable resources and established a schedule for parties to provide comments in January 2003 on various aspects of SB 1078 implementation in anticipation of an implementation report to be submitted by the CPUC to the legislature by June 30, 2003. On November 25, 2002, SCE filed an application with the CPUC for rehearing of the October 24 decision seeking the correction of legal errors in the decision. The CPUC has not yet ruled on SCE's application for rehearing, but has indicated that it will address SCE's application and others in future decisions.

The fourth decision, issued on December 19, 2002, approved modified short-term procurement plans filed in November 2002 by SCE, PG&E, and SDG&E. It modified and clarified the cost-recovery mechanisms and standards of behavior adopted in the October 24 decision, and provided further guidance on the long-term planning process to be undertaken in the next phase of the power procurement proceeding. The CPUC found that the utilities were capable of resuming full procurement on January 1, 2003 and ordered that they take all necessary steps to do so.

Among other things, the December 19, 2002 decision determined that SCE's maximum disallowance risk exposure for procurement activities, contract administration and least-cost dispatch, would be capped at twice SCE's annual procurement administrative expenses.

On January 21, 2003, SCE filed an application for rehearing of the December 19 procurement plan decision. Issues addressed included certain standard of conduct provisions, bilateral contracting, level of customer risk tolerance, lack of an appropriate tracking mechanism for certain costs, lack of definition for least cost dispatch, and the finding that SCE was non-compliant with the August 22, 2002 decision. SCE has filed a petition for modification which addressed, among other things, the need for the cap on SCE's maximum disallowance risk exposure to be extended to cover all procurement activities.

On March 4, 2003, SCE also filed a motion for consolidated consideration of the numerous applications for rehearing and petitions for modification that have been filed, and will be filed, on the various CPUC decisions addressing the investor owned utilities management of their power supply portfolios. In the motion, SCE urged the CPUC to conduct a comprehensive review of its procurement decisions and act on the various applications for rehearing and petitions for modification in an integrated manner, avoiding the piecemeal action that failed to fully resolve the outstanding issues.

In accordance with the CPUC's October 24, 2002 decision, on February 3, 2003, SCE and the other utilities filed outlines of their long-term procurement plans. SCE proposed in its outline that the CPUC separate the proceeding so that SCE would file a separate 2004 short-term procurement plan as well as its long-term plan. The assigned administrative law judge agreed with this proposal. SCE plans to file the long-term resource plan and the 2004 short-term procurement plan on April 1, 2003 and May 1, 2003, respectively. Hearings on the short-term plan and certain key issues in the long-term plan are expected to take place in June and July 2003. The issues that will be incorporated into the long-term plan were addressed during the prehearing conference on March 7, 2003. Pursuant to a ruling of the assigned administration law judge, issues related to implementation of SB 1078 will be determined on a separate, expedited schedule. Testimony on the implementation of SB 1078 will be filed on March 27, 2003 and hearings will be held in April 2003. A preliminary decision is expected in June 2003, followed by a report by the CPUC to the legislature on June 30, 2003.

Holding Company Proceeding

In April 2001, the CPUC issued an order instituting investigation that reopens the past CPUC decisions authorizing utilities to form holding companies and initiates an investigation into, among other things: whether the holding companies violated CPUC requirements to give first priority to the capital needs of their respective utility subsidiaries; 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. 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. The decision did not determine if any of the utility holding companies had violated this condition, reserving such a determination for a later phase of the proceedings. On February 11, 2002, SCE and Edison International filed an application before the CPUC for rehearing of the decision. On July 17, 2002, the CPUC affirmed its earlier decision on the first priority condition and also denied Edison International's request for a rehearing of the CPUC's determination that it had jurisdiction over Edison International in this proceeding. On August 21, 2002, Edison International and SCE jointly filed a petition requesting a review of the CPUC's decisions with regard to first priority considerations, and Edison International filed a petition for a review of the CPUC decision asserting jurisdiction over holding companies, both in state court as required. PG&E and SDG&E and their respective holding companies filed similar challenges, and all cases have been transferred to the First District Court of Appeals in San Francisco. The CPUC filed briefs in opposition to the writ petitions. Edison International, SCE and the other petitioners filed reply briefs on March 6, 2003. No hearings have been scheduled. The court may rule without holding hearings. SCE cannot predict with certainty what effects this investigation or any subsequent actions by the CPUC may have on SCE or any of its subsidiaries.

Mohave Generating Station Proceeding

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

Due to the lack of progress in negotiations with the Tribes and other parties to resolve several coal and water supply issues, SCE's application stated that it probably would not be possible for SCE to extend Mohave's operation beyond 2005. Uncertainty over a post-2005 coal and water supply has also prevented SCE and the other Mohave co-owners from starting to make approximately $1.1 billion (SCE's share is $605 million) of Mohave-related investments that will be necessary if Mohave operations are to extend past 2005, including the installation of pollution-control equipment that must be put in place pursuant to a 1999 Consent Decree related to air quality, if Mohave's operations are extended past 2005.

SCE's May 17, 2002 application requested either: a) pre-approval for SCE to immediately begin spending up to $58 million on Mohave pollution controls in 2003, if by year-end 2002, SCE had obtained adequate assurance that the outstanding coal and slurry-water issues would be satisfactorily resolved; or b) authority for SCE to establish certain balancing accounts and otherwise begin preparing to terminate Mohave's coal-fired operations at the end of 2005.

The CPUC issued a ruling on January 7, 2003 requesting further written testimony from SCE and initial written testimony from other parties on specified issues relating to Mohave and its coal and slurry-water supply. The ruling states that the purpose of the CPUC proceeding is to determine whether it is in the public interest to extend Mohave operations post 2005. In its supplemental testimony submitted on January 30, 2003, SCE stated, among other things, that the currently available information is not sufficient for the CPUC to make this determination at this time. The testimony states that neither SCE nor any other party has sufficient assurance of whether and how the currently unresolved coal and water supply issues will be resolved. Unless all key unresolved issues are resolved in a timely way, moreover, Mohave will cease operation as a coal-fired plant at the end of 2005 under the terms of the consent decree and the existing coal supply agreements. In that event, there would be no need for the CPUC to make the determination it has described, since extension of the present operating period would not be an option. SCE's supplemental testimony accordingly requests that the CPUC authorize the establishment of the

balancing accounts that SCE first requested in its May 17, 2002 application in order to prepare for an orderly shutdown of Mohave by the end of 2005, but the testimony also states that even with such authorization, SCE will continue to work with the relevant stakeholders to attempt to resolve the issues surrounding Mohave's coal and slurry-water supply.

On January 14, 2003, the Natural Resources Defense Council, Black Mesa Trust and others served a notice of intent to sue the U.S. Department of the Interior and other federal government agencies and individuals, challenging the failure of the government to issue a final permit to Peabody Western Coal Company for the operation of the Black Mesa Mine. The prospective plaintiffs claim that the federal government must begin a proceeding for issuance of a final permit to Peabody rather than allow Peabody to continue long-term operation of the Black Mesa Mine on an interim basis including groundwater extraction for use in the coal slurry pipeline.

The notice indicates that the prospective plaintiffs would then challenge any issuance of a permanent mining permit for the Black Mesa Mine unless, at a minimum, an alternate source of slurry water is obtained. If the prospective plaintiffs prevail in any future lawsuit, the coal supply to Mohave could be interrupted.

In light of all of the issues discussed above, SCE has concluded that it is probable Mohave will be shut down at the end of 2005. Because the expected undiscounted cash flows from the plant during the years 2003–2005 were less than the $88 million carrying value of the plant as of December 31, 2002, SCE incurred an impairment charge of $61 million. However, in accordance with accounting standards for rate-regulated enterprises, this incurred cost was deferred and recorded as a regulatory asset, based on SCE's expectation that any unrecovered book value at the end of 2005 would be recovered in future rates through the rate-making mechanism discussed in its May 17, 2002 application and again in its January 30, 2003 supplemental testimony.

URG Decision

On April 4, 2002, the CPUC issued a decision to return URG assets to cost-based ratemaking through the end of 2002. After that time, SCE's URG-related revenue requirement will be determined through the 2003 general rate case proceeding. Key elements of the URG decision are: retention of the San Onofre incentive pricing mechanism through 2003; recovery of incurred costs for all URG components other than San Onofre; establishment of an amortization schedule for SCE's nuclear plants based on their remaining useful lives; and establishment of balancing accounts for utility generation, purchased power and ISO ancillary services.

Based on this decision, during second quarter 2002, SCE reestablished for financial reporting purposes regulatory assets related to its unamortized nuclear plant, purchased-power settlements and flow-through taxes, reduced the PROACT balance, and recorded a corresponding credit to earnings of $480 million after tax. The impact of the URG decision is reflected in the financial statements as a credit (decrease) to the provisions for regulatory clauses of $644 million, partially offset by an increase in deferred income tax expense of $164 million. The reduction in the PROACT balance reflects a change in the amortization schedule of SCE's unamortized nuclear facilities from the schedule required to be used to calculate the surplus revenue contributed to the PROACT, for rate-making purposes, during the last four months of 2001. Implementation of the URG decision, together with the PROACT mechanism, allowed SCE to reestablish substantially all of the regulatory assets previously written off to earnings.

Wholesale Electricity Markets

On April 25, 2001, after months of 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 through September 30, 2002. On July 17, 2002, the FERC issued an order reviewing the ISO's proposals to redesign the market and implementing a market power mitigation program for the 11-state western region. The FERC declined to extend beyond September 30, 2002 all of the market mitigation measures it had previously adopted. However, effective October 1, 2002, the FERC extended a requirement, first ordered in its June 19, 2001 decision, that all

western energy sellers offer for sale all operationally and contractually available energy. It also ordered a cap on bids for real-time energy and ancillary services of $250/MWh to be effective beginning October 1, 2002 and ordered various other market power mitigation measures. Implementation of the $250/MWh bid cap and other market power mitigation measures were delayed until October 31, 2002 by a FERC order issued September 26, 2002. The FERC did not set a specific expiration date for its new market mitigation plan. SCE cannot yet determine whether the new market mitigation plan adopted by the FERC will be sufficient to mitigate market price volatility in the wholesale electricity markets in which SCE will purchase its residual net short electricity requirements (i.e., the amount of energy needed to serve SCE's customers from sources other than its own generating plants, power purchase contracts and CDWR contracts).

On August 2, 2000, SDG&E filed a complaint with the FERC seeking relief from alleged energy overcharges in the PX and ISO market. SCE intervened in the proceeding on August 14, 2000. On August 23, 2000, the FERC issued an order initiating an investigation of the justness and reasonableness of rates charged by sellers in the PX and ISO markets. Those proceedings were consolidated. On July 25, 2001, the FERC issued an order that limits potential refunds from alleged overcharges by energy suppliers 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 conducted evidentiary hearings on this matter in March, August and October 2002 and issued and initial decision on December 12, 2002.

On November 20, 2002, in the consolidated proceeding, the FERC issued an order authorizing 100 days of discovery by market participants into market manipulation and abuse during the period January 1, 2000 through June 20, 2001. SCE joined with the California parties (PG&E, the California Attorney General, the Electricity Oversight Board, and the CPUC to submit briefs and evidence demonstrating that sellers and marketers violated tariffs, withheld power, and distorted and manipulated the California electricity markets.

At a FERC meeting on March 26, 2003, the FERC issued orders that initiated procedures for determining additional refunds arising from market manipulation by energy suppliers. Based on public comments at the meeting and the FERC's press releases, it appears that the FERC acknowledges that there was pervasive gaming and market manipulation of the electric and gas markets in California and on the west coast. A new FERC staff report issued on March 26, 2003 also describes many of the techniques and effects of electric and gas market manipulation. The FERC will be modifying the administrative law judge's initial decision of December 12, 2002 to reflect the fact that the gas indices used in the market manipulation formula overstated the cost of gas used to generate electricity.

SCE has not yet completed an evaluation of the FERC actions taken on March 26, 2003 and cannot determine the timing or amount of any potential refunds. Under the settlement agreement with the CPUC, any refunds will be applied to reduce the PROACT balance until the PROACT is fully recovered. After PROACT recovery is complete, 90% of any refunds will be refunded to ratepayers.

Note 3. 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. SCE also adopted subsequent interpretations of this standard issued in July 2001, October 2001 and December 2001. 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 unamortized loss of $11 million (as of December 31, 2002 net of tax) on the interest rate swap will be amortized over a period ending in 2008, when the related debt matures. 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 during 2002 and 2003. This amount is being recovered through the PROACT mechanism. Amounts paid to QFs for energy are based on natural gas prices. Any fair value changes for gas call options are offset through a regulatory balancing account; therefore, fair value changes do not affect earnings.

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

Fair values of financial instruments are:

In millions December 31,	2002	2001
Financial assets:		
Decommissioning trusts	**$ 2,210**	$ 2,275
Gas options	**77**	91
Financial liabilities:		
DOE decommissioning and decontamination fees	**22**	25
QF power contracts	**70**	—
Short-term debt	**—**	2,103
Long-term debt	**4,543**	4,659
Long-term debt due within one year	**1,722**	1,153
Preferred stock subject to mandatory redemption	**129**	118
Preferred stock to be redeemed within one year	**8**	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; financial models for QF power contracts; 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 4. Debt

Almost all SCE properties are subject to a trust indenture lien. SCE has pledged first and refunding mortgage bonds as security for borrowed funds obtained from pollution-control bonds issued by government agencies. SCE used these proceeds to finance construction of pollution-control facilities. Bondholders have limited discretion in redeeming certain pollution-control bonds, and SCE has

arrangements with securities dealers to remarket or purchase them if necessary. 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 remarketed $196 million of the pollution-control bonds that SCE had repurchased in late 2000.

Debt premium, discount and issuance expenses are amortized over the life of each issue. Under CPUC rate-making procedures, debt reacquisition expenses are amortized over the remaining life of the reacquired debt or, if refinanced, the life of the new debt. California law prohibits SCE from incurring or guaranteeing debt for its nonutility affiliates.

In December 1997, $2.5 billion of rate reduction notes were issued on behalf of SCE by SCE Funding LLC, a special purpose entity. These notes were issued to finance the 10% rate reduction mandated by state law. The proceeds of the rate reduction notes were used by SCE Funding LLC to purchase from SCE an enforceable right known as transition property. Transition property is a current property right created by the restructuring legislation and a financing order of the CPUC and consists generally of the right to be paid a specified amount from nonbypassable rates charged to residential and small commercial customers. The rate reduction notes are being repaid over 10 years through these nonbypassable residential and small commercial customer rates, which constitute the transition property purchased by SCE Funding LLC. The notes are collateralized by the transition property and are not collateralized by, or payable from, assets of SCE or Edison International. SCE used the proceeds from the sale of the transition property to retire debt and equity securities. Although, as required by accounting principles generally accepted in the United States, SCE Funding LLC is consolidated with SCE and the rate reduction notes are shown as long-term debt in the consolidated financial statements, SCE Funding LLC is legally separate from SCE. The assets of SCE Funding LLC are not available to creditors of SCE or Edison International and the transition property is legally not an asset of SCE or Edison International.

Long-term debt is:

In millions December 31,	2002	2001
First and refunding mortgage bonds:		
2002 – 2026 (5.625% to 7.25% and variable)	$ 2,275	$ 1,175
Rate reduction notes:		
2002 – 2007 (6.22% to 6.42%)	1,232	1,478
Pollution-control bonds:		
2005 – 2040 (5.125% to 7.2% and variable)	1,216	1,216
Bonds repurchased	(354)	(550)
Funds held by trustees	(21)	(20)
Debentures and notes:		
2001 – 2029 (5.875% to 7.625% and variable)	1,750	2,450
Subordinated debentures:		
2044 (8.375%)	100	100
Commercial paper for nuclear fuel	—	60
Long-term debt due within one year	(1,671)	(1,146)
Unamortized debt discount – net	(23)	(24)
Total	$ 4,504	$ 4,739

Long-term debt maturities and sinking-fund requirements for the next five years are: 2003 – $1.7 billion; 2004 – $671 million; 2005 – $1.1 billion; 2006 – $446 million; and 2007 – $246 million.

On February 24, 2003, SCE completed an exchange offer of the $1.0 billion of variable rate notes due November 2003. A total of $966 million of these notes were exchanged for $966 million of a new series of first and refunding mortgage bonds due February 2007. The new debt was issued with an 8% interest rate. Approximately $34 million of the exchanged variable rate notes remain outstanding and are due in November 2003.

Short-term debt is used to finance fuel inventories, balancing account undercollections and general cash requirements, including power purchase payments. At December 31, 2001, commercial paper intended to

finance nuclear fuel scheduled to be used more than one year after the balance sheet date was classified as long-term debt in connection with refinancing terms under five-year term lines of credit with commercial banks.

Short-term debt is:

In millions December 31,	2002	2001
Commercial paper	$ —	$ 531
Bank loans	—	1,650
Other	—	6
Amount reclassified as long-term debt	—	(60)
Total	$ —	$ 2,127
Weighted average interest rates	—	5.3%

As of December 31, 2002, SCE had no available short-term credit lines and had fully drawn a long-term credit line of $300 million.

Note 5. 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: 2003 – $9 million; 2004 – $9 million; 2005 – $9 million; 2006 – $9 million and 2007 – $9 million.

Cumulative preferred stocks are:

Dollars in millions, except per share amounts December 31,	December 31, 2002 Shares Outstanding	December 31, 2002 Redemption Price	2002	2001
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	—	—	—	100
7.23	807,000	100.00	81	81
Preferred stock to be redeemed within one year			(9)	(105)
Total			$ 147	$ 151

In 2002, SCE redeemed 1,000,000 shares of 6.45% Series preferred stock. There were no other redemptions, and no issuances, of preferred stock in the last three years.

The 7.23% Series preferred stock has mandatory sinking funds, requiring SCE to redeem at least 50,000 shares per year from 2002 through 2006, and 750,000 shares in 2007. However, SCE is allowed to credit previously repurchased shares against the mandatory sinking fund provisions. Since SCE had previously repurchased 193,000 shares of this series, no shares were redeemed in 2002. At December 31, 2002,

SCE had 143,000 of previously repurchased, but not retired, shares available to credit against the mandatory sinking fund provisions.

Note 6. 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's tax liability is computed as if it filed a separate return.

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 are:

In millions, December 31,	2002	2001
Deferred tax assets:		
Accrued charges	$ 416	$ 472
Investment tax credits	73	72
Property-related	178	192
Regulatory balancing accounts	5,365	1,709
Unrealized gains or losses	274	310
Other	212	244
Total	$ 6,518	$ 2,999
Deferred tax liabilities:		
Property-related	$ 2,399	$ 2,248
Capitalized software costs	204	224
Regulatory balancing accounts	6,054	2,929
Unrealized gains and losses	171	208
Other	306	322
Total	$ 9,134	$ 5,931
Accumulated deferred income taxes – net	$ 2,616	$ 2,932
Classification of accumulated deferred income taxes:		
Included in deferred credits	$ 2,658	$ 3,365
Included in current assets	42	433

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

In millions, Year ended December 31,	2002	2001	2000
Current:			
Federal	$ 990	$ 1,240	$ (104)
State	273	29	—
	1,263	269	(104)
Deferred:			
Federal	(504)	1052	(746)
State	(117)	337	(172)
	(621)	1,389	(918)
Total	$ 642	$ 1,658	$ (1,022)

The major components of deferred tax expense (benefit), which arise from tax credits and timing differences between financial and tax reporting, are:

In millions Year ended December 31,	2002	2001	2000
Deferred – federal and state:			
Accrued charges	$ 56	$ (79)	$ (133)
Investment tax credits	(6)	(6)	(41)
Property-related	74	174	(302)
Regulatory asset amortization	(99)	(138)	251
Regulatory balancing accounts	(575)	1,345	(740)
State tax privilege year	(76)	(36)	31
Unbilled revenue	—	101	20
Pension reserve	34	(4)	1
Other	(29)	32	(5)
Total	$ (621)	$ 1,389	$ (918)

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

Year ended December 31,	2002	2001	2000
Federal statutory rate	35.0%	35.0%	35.0%
Favorable resolution of audit	(1.9)	—	—
Investment tax credits	(0.3)	(0.1)	1.4
Property-related and other	(4.2)	0.1	(6.6)
State tax – net of federal deduction	5.4	5.8	3.7
Effective tax rate	34.0%	40.8%	33.5%

The composite federal and state statutory income tax rate was 40.551% for all years presented. The lower effective tax rate of 34% realized in 2002 was primarily due to reestablishing a tax-related regulatory asset due to implementation of the URG decision and recording the benefit of favorable settlement of Internal Revenue Service (IRS) audits.

As a matter of course, SCE is regularly audited by federal and state taxing authorities. For further discussion of this matter, see "Federal Income Taxes" in Note 10.

Note 7. Employee Compensation and Benefit Plans

Employee Savings Plan

SCE has a 401(k) defined-contribution savings plan designed to supplement employees' retirement income. The plan received employer contributions of $30 million in 2002, $29 million in 2001 and $29 million in 2000.

Pension Plan

SCE has defined-benefit pension plans, including executive and non-executive plans, which cover employees meeting minimum service requirements. The non-executive plan has a cash balance feature. SCE recognizes pension expense for the non-executive plan as calculated by the actuarial method used for ratemaking.

At December 31, 2002, the accumulated benefit obligation of the executive pension plan exceeded the related plan assets at the measurement date. In accordance with accounting standards, SCE recorded an additional minimum liability of $12 million, with corresponding charges of $3 million as an intangible asset and $9 million as a reduction to shareholder's equity through a charge to accumulated other comprehensive income. The charge to accumulated other comprehensive income would be restored through shareholder's equity in future periods to the extent the fair value of the plan assets exceed the accumulated benefit obligation.

The projected benefit obligation and accumulated benefit obligation for the executive pension plans were $55 million and $41 million, respectively, as of December 31, 2002, and $44 million and $32 million, respectively, as of December 31, 2001. There were no plan assets for the executive plans at December 31, 2002, or December 31, 2001. As of December 31, 2002 and 2001, the fair value of plan assets exceeded the accumulated benefit obligation for the non-executive plans.

Information on plan assets and benefit obligations is shown below:

In millions	Year ended December 31,	2002	2001
Change in projected benefit obligation			
Benefit obligation at beginning of year		$ 2,371	$ 2,247
Service cost		69	69
Interest cost		158	157
Actuarial loss		90	84
Benefits paid		(138)	(186)
Projected benefit obligation at end of year		$ 2,550	$ 2,371
Change in plan assets			
Fair value of plan assets at beginning of year		$ 2,723	$ 3,067
Actual return on plan assets		(311)	(162)
Employer contributions		7	4
Benefits paid		(138)	(186)
Fair value of plan assets at end of year		$ 2,281	$ 2,723
Funded status		$ (269)	$ 352
Unrecognized net loss (gain)		394	(222)
Unrecognized transition obligation		11	17
Unrecognized prior service cost		98	112
Recorded asset		$ 234	$ 259
Discount rate		6.5%	7.0%
Rate of compensation increase		5.0%	5.0%
Expected return on plan assets		8.5%	8.5%

Expense components are:

In millions	Year ended December 31,	2002	2001	2000
Service cost		$ 69	$ 69	$ 64
Interest cost		158	157	158
Expected return on plan assets		(224)	(251)	(266)
Special termination benefits		—	13	—
Net amortization and deferral		21	(7)	(38)
Expense under accounting standards		24	(19)	(82)
Regulatory adjustment – deferred		(18)	39	88
Total expense recognized		$ 6	$ 20	$ 6

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,	2002	2001
Change in benefit obligation		
Benefit obligation at beginning of year	$ 1,925	$ 1,762
Service cost	42	44
Interest cost	133	129
Actuarial loss	82	61
Benefits paid	(79)	(71)
Benefit obligation at end of year	$ 2,103	$ 1,925
Change in plan assets		
Fair value of plan assets at beginning of year	$ 1,139	$ 1,200
Actual return on plan assets	(148)	(92)
Employer contributions	160	102
Benefits paid	(79)	(71)
Fair value of plan assets at end of year	$ 1,072	$ 1,139
Funded status	$ (1,031)	$ (786)
Unrecognized net loss	702	390
Unrecognized transition obligation	268	295
Recorded asset (liability)	$ (61)	$ (101)
Discount rate	6.75%	7.25%
Expected return on plan assets	8.2%	8.2%

Expense components are:

In millions Year ended December 31,	2002	2001	2000
Service cost	$ 42	$ 44	$ 39
Interest cost	133	129	121
Expected return on plan assets	(93)	(98)	(106)
Special termination benefits	—	2	—
Net amortization and deferral	37	27	27
Total expense	$ 119	$ 104	$ 81

The assumed rate of future increases in the per-capita cost of health care benefits is 9.75% for 2003, 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, 2002 by $341 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, 2002 by $274 million and annual aggregate service and interest costs by $26 million.

Stock-Based Employee Compensation

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

Under the 1992, 1998 and 2000 plans, options on 6.7 million shares of Edison International common stock are currently outstanding to officers and senior managers of SCE.

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

Edison International stock options awarded prior to 2000 include a dividend equivalent feature. Dividend equivalents on stock options issued after 1993 and prior to 2000 are accrued to the extent dividends are declared on Edison International common stock and are subject to reduction unless certain performance criteria are met. Only a portion of the 1999 Edison International stock option awards include a dividend equivalent feature.

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

Unvested options of any person who has served in the past on the SCE management committee (which was dissolved in 1993) will vest and be exercisable upon a qualifying event. If a qualifying event occurs, the vested options may continue to be exercised within their original terms by the recipient or beneficiary except that in the case of termination by the company where the option holder is not eligible for retirement, vested options are forfeited unless exercised within one year of termination date. If an option holder is terminated other than by a qualifying event, options 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 pro forma disclosures in Note 1, was determined on the date of grant using the Black-Scholes option-pricing model. The following assumptions were used in determining fair value through the model:

December 31,	2002	2001	2000
Expected life	7 years – 10 years	7 years – 10 years	7 years – 10 years
Risk-free interest rate	4.7% – 6.1%	4.7% – 6.1%	4.7% – 6.0%
Expected dividend yield	1.8%	3.3%	4.5%
Expected volatility	18% – 54%	17% – 52%	17% – 46%

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

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

The weighted-average fair value of options granted during 2002 and 2001 was $7.86 per share option and $4.53 per share option, respectively. The weighted-average remaining life of options outstanding as of December 31, 2002 and December 31, 2001 was 6 years.

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 vested and were paid on March 12, 2003 in shares of Edison International common stock.

In October 2001, a stock option retention exchange offer was extended, offering holders of Edison International stock options granted in 2000 the opportunity to exchange those options for a lesser number of deferred stock units. The exchange ratio was based on the Black-Scholes value of the options and the stock price at the time the offer was extended. The exchange took place in November 2001; the options that participants elected to exchange were cancelled, and deferred stock units were issued. Approximately three options were cancelled for each deferred stock unit issued. Twenty-five percent of the deferred stock units will vest and be paid in Edison International Common Stock per year over four years, with the first vesting and payment date in November 2002. The following assumptions were used in determining fair value through the Black-Scholes option-pricing model: expected life – 8 to 9 years; risk-free interest rate – 5.10%; expected volatility – 52%.

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

Note 8. Jointly Owned Utility Projects

SCE owns interests in several generating stations and transmission systems for which each participant provides its own financing. SCE's share of expenses for each project is included in the consolidated statements of income.

The investment in each project as of December 31, 2002 is:

In millions	Investment in Facility	Accumulated Depreciation and Amortization	Ownership Interest
Transmission systems:			
Eldorado	$ 45	$ 12	60%
Pacific Intertie	246	86	50%
Generating stations:			
Four Corners Units 4 and 5 (coal)	480	374	48%
Mohave (coal)[1]	341	253	56%
Palo Verde (nuclear)[2]	1,631	1,424	16%
San Onofre (nuclear)[2]	4,305	3,859	75%
Total	$ 7,048	$ 6,008	

[1] A portion is included in regulatory assets on the balance sheet. See Note 1.
[2] Included in regulatory assets on the balance sheet.

Note 9. Commitments

Leases

SCE has operating leases, primarily for vehicles, with varying terms, provisions and expiration dates. Operating lease expense was $16 million in 2002, $19 million in 2001 and $20 million in 2000.

Estimated remaining commitments for noncancelable leases at December 31, 2002 are:

Year ended December 31,	In millions
2003	$ 13
2004	11
2005	8
2006	6
2007	4
Thereafter	9
Total	$ 51

Nuclear Decommissioning

Decommissioning is estimated to cost $2.5 billion in current-year dollars, based on site-specific studies performed in 2001 for San Onofre and Palo Verde. Changes in the estimated costs, timing of decommissioning, or the assumptions underlying these estimates could cause material revisions to the estimated total cost to decommission in the near term. SCE estimates that it will spend approximately $11.8 billion through 2060 to decommission its nuclear facilities. This estimate is based on SCE's current-dollar decommissioning costs, escalated at rates ranging from 0.9% 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 3.7% to 6.4%. If the assumed return on trust assets is not earned, it is probable that additional funds needed for decommissioning will be recoverable through rates.

Decommissioning of San Onofre Unit 1 (shut down in 1992 per CPUC agreement) started in 1999 and will continue through 2008. All of SCE's San Onofre's Unit 1 decommissioning costs will be paid from its nuclear decommissioning trust funds. The estimated remaining cost to decommission San Onofre Unit 1 is recorded as a liability ($298 million at December 31, 2002). Total expenditures for the decommissioning of San Onofre Unit 1 were $197 million through December 31, 2002.

SCE plans to decommission its active 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 as authorized by the CPUC, are recorded as a component of depreciation expense.

Decommissioning expense was $73 million in 2002, $96 million in 2001 and $106 million in 2000. The accumulated provision for decommissioning, excluding San Onofre Unit 1 and unrealized holding gains, was $1.6 billion at December 31, 2002 and $1.5 billion at December 31, 2001.

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, 2002	2001
Municipal bonds	2002 – 2039	$ 442	$ 463
Stocks	—	752	637
U.S. government issues	2002 – 2032	252	332
Short-term and other	2002 – 2003	321	334
Total		$1,767	$1,766

Trust fund earnings (based on specific identification) increase the trust fund balance and the accumulated provision for decommissioning. Net earnings (loss) were $(25) million in 2002, $13 million in 2001 and $38 million in 2000. Proceeds from sales of securities (which are reinvested) were $3.8 billion in 2002, $3.9 billion in 2001 and $4.7 billion in 2000. Approximately 91% of the cumulative 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 $134 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 $30 million). The transmission service contract requires a minimum payment of approximately $6 million a year.

Certain commitments for the years 2003 through 2007 are estimated below:

In millions	2003	2004	2005	2006	2007
Fuel supply contract payments	$ 155	$ 118	$ 121	$ 124	$ 127
Purchased-power capacity payments	597	595	578	543	543

Note 10. 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 Issue

In October 2000, a federal class action securities lawsuit was filed against SCE and Edison International. The lawsuit, as amended, involved securities fraud claims arising from alleged improper accounting for the energy-cost undercollections. The complaint was 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 was consolidated with another similar lawsuit filed on March 15, 2001. SCE and Edison International filed a motion to dismiss the lawsuits for failure to state a claim and on March 8, 2002, the district court dismissed the complaint with prejudice. The plaintiffs have dismissed their appeal and on April 26, 2002, the federal court of appeals dismissed the appeal with prejudice.

Environmental Remediation

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 remediation 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 41 identified sites is $99 million. The sites include SCE's divested gas-fueled generation plants, for which SCE retained some liability after their sale. 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 $282 million. The upper limit of this range of costs was estimated using assumptions least favorable to SCE among a range of reasonably possible outcomes.

The CPUC allows SCE to recover environmental remediation costs at certain sites, representing $38 million of its recorded liability, through an incentive mechanism (SCE may request to include additional sites). Under this mechanism, SCE will recover 90% of cleanup costs through customer rates; shareholders fund the remaining 10%, with the opportunity to recover these costs from insurance carriers and other third parties. SCE has successfully settled insurance claims with all responsible carriers. SCE expects to recover costs incurred at its remaining sites through customer rates. SCE has recorded a regulatory asset of $70 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 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 $15 million to $25 million. Recorded costs for 2002 were $25 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 for its identified sites and, based upon the CPUC's regulatory treatment of environmental remediation 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.

Federal Income Taxes

On August 7, 2002, Edison International received a notice from the IRS asserting deficiencies in federal corporate income taxes for its 1994 to 1996 tax years. Included in these amounts are deficiencies asserted against SCE. The vast majority of SCE's tax deficiencies are timing differences and, therefore, amounts ultimately paid, if any, would benefit it as future tax deductions. SCE believes that it has meritorious legal defenses to deficiencies asserted against it and believes that the ultimate outcome of this matter will not result in a material impact on its results of operations or financial position.

Navajo Nation Litigation

Peabody Holding Company (Peabody) supplies coal from mines on Navajo Nation lands to Mohave. In June 1999, the Navajo Nation filed a complaint in federal district court against Peabody and certain of its

affiliates, Salt River Project Agricultural Improvement and Power District, and SCE. The complaint asserts claims against the defendants for, among other things, violations of the federal RICO statute, interference with fiduciary duties and contractual relations, fraudulent misrepresentation by nondisclosure, and various contract-related claims. The complaint claims that the defendants' actions prevented the Navajo Nation from obtaining the full value in royalty rates for the coal. The complaint seeks damages of not less than $600 million, trebling of that amount, and punitive damages of not less than $1 billion, as well as a declaration that Peabody's lease and contract rights to mine coal on Navajo Nation lands should be terminated.

In February 2002, Peabody and SCE filed cross claims against the Navajo Nation, alleging that the Navajo Nation had breached a settlement agreement and final award between Peabody and the Navajo Nation by filing their lawsuit.

The Navajo Nation had previously filed suit in the Court of Claims against the United States Department of Interior, alleging that the Government had breached its fiduciary duty concerning contract negotiations including the Navajo Nation and the defendants. In February 2000, the Court of Claims issued a decision in the Government's favor, finding that while there had been a breach, there was no available redress from the Government. Following appeal of that decision by the Navajo Nation, an appellate court ruled that the Court of Claims did have jurisdiction to award damages and remanded the case to the Court of Claims for that purpose. On June 3, 2002, the Government's request for review of the case by the United States Supreme Court was granted. On March 4, 2003, the Supreme Court reversed the appellate court and held that the Government is not liable to the Navajo Nation as there was no breach of a fiduciary duty and that the Navajo Nation did not have a right to relief against the Government.

SCE cannot predict with certainty the outcome of the 1999 Navajo Nation's complaint against SCE, nor the impact on this complaint or the Supreme Court's decision on the outcome of the Navajo Nation's suit against the government, or the impact of the complaint on the operation of Mohave beyond 2005.

Nuclear Insurance

Federal law limits public liability claims from a nuclear incident to $9.5 billion. SCE and other owners of the San Onofre and Palo Verde nuclear generating stations have purchased the maximum private primary insurance available ($200 million at December 31, 2002 and $300 million beginning January 1, 2003). 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. The U.S. Congress has extended the expiration date of the applicable law until December 31, 2003 and is considering amendments that, among other things, are expected to extend the law beyond 2003.

Property damage insurance covers losses up to $500 million, including decontamination costs, at San Onofre and Palo Verde. Decontamination liability and property damage coverage exceeding the primary $500 million also has been purchased in amounts greater than federal requirements. Additional insurance covers part of replacement power expenses during an accident-related nuclear unit outage. A mutual insurance company owned by utilities with nuclear facilities issues these policies. If losses at any nuclear facility covered by the arrangement were to exceed the accumulated funds for these insurance programs, SCE could be assessed retrospective premium adjustments of up to $38 million per year. Insurance premiums are charged to operating expense.

Spent Nuclear Fuel

Under federal law, the U.S. Department of Energy (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 0.1¢ per kWh 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. The San Onofre Units 2 and 3 spent fuel pools currently contain San Onofre Unit 1 spent fuel in addition to spent fuel from Units 2 and 3. Current capability to store spent fuel in the Units 2 and 3 spent fuel pools is adequate through 2005. SCE plans to move the Unit 1 spent fuel to an interim spent fuel storage facility by the third quarter of 2003. The spent fuel pool storage capacity for Units 2 and 3 will then accommodate needs until 2007 for Unit 2 and 2008 for Unit 3. SCE expects to begin using an interim spent fuel storage facility for Units 2 and 3 spent fuel by early 2006. 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, expects to begin using an interim spent fuel storage facility in the first half of 2003.

Quarterly Financial Data (Unaudited)

	2002					2001				
In millions	Total	Fourth	Third	Second	First	Total	Fourth	Third	Second	First
Operating revenue	$8,706	$1,952	$2,714	$2,133	$1,907	$8,126	$2,296	$2,726	$1,592	$1,512
Operating income (loss)	2,127	264	452	1,107	304	4,617	3,956	1,294	204	(837)
Net income (loss)	1,247	157	238	700	152	2,408	2,310	657	34	(593)
Net income (loss) available for common stock	1,228	153	234	695	146	2,386	2,304	652	28	(598)
Common dividends declared	—	—	—	—	—	—	—	—	—	—

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 accountants, PricewaterhouseCoopers LLP, are engaged to audit the financial statements in accordance with auditing standards generally accepted in the United States and to express an informed opinion on the fairness, in all material respects, of 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 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 accountants (who are ultimately responsible to the board and the committee) 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.

Thomas M. Noonan
Vice President
and Controller

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

March 26, 2003

To the Board of Directors and
Shareholder of Southern California Edison Company:

In our opinion, the accompanying consolidated balance sheet and the related consolidated statements of income (loss), comprehensive income (loss), changes in common shareholder's equity, and cash flows present fairly, in all material respects, the financial position of Southern California Edison Company and its subsidiaries at December 31, 2002, and the results of their operations and their cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion. The financial statements of the Company as of December 31, 2001, and for each of the two years in the period ended December 31, 2001, were audited by other independent accountants who have ceased operations. Those independent accountants expressed an unqualified opinion on those financial statements in their report dated March 25, 2002.

PricewaterhouseCoopers LLP

Los Angeles, California
March 26, 2003

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

To 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

Los Angeles, California
March 25, 2002

John E. Bryson
Chairman of the Board,
President and Chief Executive Officer,
Edison International
Chairman of the Board,
Southern California Edison Company

Alan J. Fohrer
Chief Executive Officer
Southern California Edison Company

Bradford M. Freeman
Founding Partner,
Freeman Spogli & Co.
(private investment company),
Los Angeles, California

Joan C. Hanley
The Former General Partner and
Manager,
Miramonte Vineyards,
Rancho Palos Verdes, California

Bruce Karatz
Chairman and
Chief Executive Officer,
KB Home (homebuilding),
Los Angeles, California

Luis G. Nogales
Managing Partner,
Nogales Investors and Managing
Director, Nogales Investors LLC
(private equity investment
companies),
Los Angeles, California

Ronald L. Olson
Senior Partner,
Munger, Tolles and Olson (law firm),
Los Angeles, California

James M. Rosser
President,
California State University, Los Angeles,
Los Angeles, California

Richard T. Schlosberg, III
President and Chief Executive Officer,
The David and Lucile Packard
Foundation (private family foundation),
Los Altos, California

Robert H. Smith
Managing Director,
Smith and Crowley Inc.
(merchant banking),
Pasadena, California

Thomas C. Sutton
Chairman of the Board and
Chief Executive Officer
Pacific Life Insurance Company,
Newport Beach, California

Daniel M. Tellep
Retired Chairman of the Board,
Lockheed Martin Corporation
(aerospace),
Saratoga, California

Management Team

John E. Bryson
Chairman of the Board

Alan J. Fohrer
Chief Executive Officer

Robert G. Foster
President

Harold B. Ray
Executive Vice President,
Generation

Pamela A. Bass
Senior Vice President,
Customer Service

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

Stephen E. Pickett
Senior Vice President and
General Counsel

Richard M. Rosenblum
Senior Vice President,
Transmission and Distribution

W. James Scilacci
Senior Vice President and
Chief Financial Officer

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

Diane L. Featherstone
Vice President and General Auditor

Bruce C. Foster
Vice President, Regulatory
Operations

A. Larry Grant[1]
Vice President, Power Delivery

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

Harry B. Hutchison
Vice President, Customer Service
Operations

James A. Kelly
Vice President,
Regulatory Compliance and
Environmental Affairs

Russell W. Krieger
Vice President,
Power Production

Thomas M. Noonan
Vice President and Controller

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

Barbara J. Parsky
Vice President,
Corporate Communications

Pedro J. Pizarro
Vice President,
Strategy and Business Development

Frank J. Quevedo
Vice President, Equal Opportunity

Dale E. Shull, Jr.[2]
Vice President, Power Delivery

Anthony L. Smith
Vice President, Tax

Joseph J. Wambold
Vice President, Nuclear Generation

Beverly P. Ryder
Corporate Secretary

[1] Effective April 1, 2003
Formerly Vice President,
Engineering and Technical Services
[2] Retiring April 1, 2003

Shareholder Information

Annual Meeting of Shareholders

Thursday, May 15, 2003
10:00 a.m.
Hyatt Regency Long Beach
200 South Pine Avenue
Long Beach, California

Corporate Governance Practices

A description of SCE's corporate governance practices is available on our Web site at www.edisoninvestor.com. The Nominating/Corporate Governance Committee periodically reviews the Company's corporate governance practices and makes recommendations to the Company's Board that the practices be updated from time to time.

Stock Listing and Trading Information

SCE Preferred Stock

SCE'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% and 7.23% series of the $100 cumulative preferred stock are not listed; however, the 7.23% series are traded over-the-counter. 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., which maintains shareholder records, is the transfer agent and registrar for SCE'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, to speak with a representative (or to use the interactive voice response unit 24 hours a day, seven days a week) regarding:

- stock transfer and name-change requirements;
- address changes, including dividend 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

SOUTHERN CALIFORNIA
EDISON®

An *EDISON INTERNATIONAL®* Company

2244 Walnut Grove Avenue, Rosemead, California 91770
626.302.1212
www.edison.com

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

/X/ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2002

/ / TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _____ to _____

Commission File Number 1-2313

SOUTHERN CALIFORNIA EDISON COMPANY
(Exact name of registrant as specified in its charter)

California **(State or other jurisdiction of incorporation or organization)**	**95-1240335** **(I.R.S. Employer Identification No.)**
2244 Walnut Grove Avenue **Rosemead, California** **(Address of principal executive offices)**	**91770** **(Zip Code)**

Registrant's telephone number, including area code: (626) 302-1212

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	**Name of each exchange on which registered**
Capital Stock Cumulative Preferred 4.08% Series 4.32% Series 4.24% Series 4.78% Series	American and Pacific

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes [X] No [ ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [X]

Indicate by check mark whether the registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2). Yes [ ] No [X]

As of June 28, 2002, there were 434,888,104 shares of Common Stock outstanding, all of which are held by the registrant's parent holding company. The aggregate market value of registrant's voting and non-voting common equity held by non-affiliates was zero. As of March 26, 2003, there were 434,888,104 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the following documents listed below have been incorporated by reference into the parts of this report so indicated.

(1) Designated portions of the registrant's Annual Report to Shareholders for the year ended December 31, 2002 ..... Parts I and II

(2) Designated portions of the Joint Proxy Statement relating to registrant's 2003 Annual Meeting of Shareholders ..... Part III

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PART I

FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K contains forward-looking statements that reflect Southern California Edison Company's (SCE) current expectations and projections about future events based on SCE's knowledge of present facts and circumstances and assumptions about future events. Other information distributed by SCE that is incorporated in this report, or that refers to or incorporates this report, may also contain forward-looking statements. In this report and elsewhere, the words "expects," "believes," "anticipates," "estimates," "intends," "plans," "probable," and variations of such words and similar expressions are intended to identify forward-looking statements. Such statements necessarily involve risks and uncertainties that could cause actual results to differ materially from those anticipated. Some of the risks, uncertainties and other important factors that could cause results to differ, or that otherwise could impact SCE are listed under the heading "FORWARD-LOOKING INFORMATION AND RISK FACTORS" in the Management's Discussion and Analysis of Results of Operations and Financial Condition (MD&A) that appears in SCE's 2002 Annual Report to Shareholders and is incorporated by reference into Part II, Item 7 of this report.

Additional information about risks and uncertainties is contained throughout this report, in the MD&A, and in the Notes to Consolidated Financial Statements (Notes to Financial Statements) that appear in SCE's 2002 Annual Report to Shareholders and are incorporated by reference into Part II, Item 8 of this report. Readers are urged to read this entire report, including the information incorporated by reference, and carefully consider the risks, uncertainties and other factors that affect SCE's business. The information contained in this report is subject to change without notice, and SCE is not obligated to publicly update or revise forward-looking statements. Readers should review future reports filed by SCE with the Securities and Exchange Commission (SEC).

Item 1. Business

SCE was incorporated in 1909 under the laws of the State of California. SCE is a public utility primarily engaged in the business of supplying electric energy to a 50,000 square-mile area of central, coastal and southern California, excluding the City of Los Angeles and certain other cities. This SCE service territory includes approximately 800 cities and communities and a population of more than 12 million people. In 2002, SCE's total operating revenue was derived as follows: 33% residential customers, 45% commercial customers, 10% industrial customers, 7% public authorities, 2% agricultural and other customers, and 3% other electric revenue. At December 31, 2002, SCE had consolidated assets of $18.2 billion and total shareholder's equity of $4.4 billion. SCE had 12,113 full-time employees at year-end 2002.

Regulation

SCE's retail operations are subject to regulation by the California Public Utilities Commission (CPUC). The CPUC has the authority to regulate, among other things, retail rates, issuance of securities, and accounting practices. SCE's wholesale operations are subject to regulation by the Federal Energy Regulatory Commission (FERC). The FERC has the authority to regulate wholesale rates as well as other matters, including retail transmission service pricing, accounting practices, and licensing of hydroelectric projects.

Additional information about the regulation of SCE by the CPUC and the FERC, and about SCE's competitive environment, appears in the MD&A under "REGULATORY MATTERS," and that information is incorporated herein by reference.

SCE is subject to the jurisdiction of the United States Nuclear Regulatory Commission (NRC) with respect to its nuclear power plants. NRC regulations govern the granting of licenses for the construction and operation of nuclear power plants and subject those power plants to continuing review and regulation.

The construction, planning, and siting of SCE's power plants within California are subject to the jurisdiction of the California Energy Commission and the CPUC. SCE is subject to the rules and regulations of the California Air Resources Board, State of Nevada, and local air pollution control districts with respect to the emission of pollutants into the atmosphere; the regulatory requirements of the California State Water Resources Control Board and regional boards with respect to the discharge of pollutants into waters of the state; and the requirements of the California Department of Toxic Substances Control with respect to handling and disposal of hazardous materials and wastes. SCE is also subject to regulation by the United States Environmental Protection Agency (EPA), which administers federal statutes relating to environmental matters. Other federal, state, and local laws and regulations relating to environmental protection, land use, and water rights also affect SCE.

The California Coastal Commission issued a coastal permit for the construction of San Onofre Nuclear Generating Station (San Onofre) Units 2 and 3 in 1974. This permit, as amended, requires mitigation for impacts to fish and the San Onofre kelp bed. California Coastal Commission jurisdiction will continue for several years due to ongoing implementation and oversight of these permit mitigation conditions, consisting of restoration of wetlands and construction of an artificial reef for kelp. These mitigation measures were required to offset San Onofre's cooling water intake impacts to fish and kelp. SCE has a coastal permit to construct a temporary dry cask spent fuel storage installation for San Onofre Units 2 and 3. The California Coastal Commission also has continuing jurisdiction over coastal permits issued for the decommissioning of San Onofre Unit 1, including for the construction of a temporary dry cask spent fuel storage installation for spent fuel from that unit.

The United States Department of Energy has regulatory authority over certain aspects of SCE's operations and business relating to energy conservation, power plant fuel use and disposal, electric sales for export, public utility regulatory policy, and natural gas pricing.

In 1997, the CPUC issued a decision which established additional rules governing the relationship between California's natural gas local distribution companies, electric utilities, and certain of their affiliates. While SCE and its affiliates have been subject to affiliate transaction rules since the establishment of its holding company structure in 1988, these additional rules are more detailed and restrictive. As required by the 1997 rules and an interim CPUC resolution, SCE has filed compliance plans which set forth SCE's implementation of the additional affiliate transaction rules. The CPUC has not ruled on the sufficiency of SCE's compliance plans. In January 2001, the CPUC issued an order instituting rulemaking to commence the review of the 1997 affiliate transaction rules that the original decision requires. The CPUC proposed that some rules be considered for streamlining or other revision, while inviting interested parties to submit proposals of their own. No decision has yet been issued, and the CPUC suspended the proceeding in light of having opened the holding company proceeding, discussed next below.

In April 2001, the CPUC adopted an order instituting investigation that reopened the past CPUC decisions authorizing the utilities to form holding companies and initiated an investigation into whether

Edison International and PG&E Corporation violated CPUC requirements to give first priority to the capital needs of their respective utility subsidiaries; whether actions by Edison International and PG&E Corporation and their respective nonutility affiliates to shield, or "ring-fence," nonutility assets also violated the requirements that the holding companies 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; whether there are 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. For more information on this matter, see "REGULATORY MATTERS – Holding Company Proceeding" in the MD&A.

SCE cannot predict with certainty what effects the CPUC's investigation or any other actions by the CPUC may have on SCE.

Properties

SCE supplies electricity to its customers through extensive transmission and distribution networks. Its transmission facilities, which deliver power from generating sources to the distribution network, consist of approximately 8,144 circuit miles of 33 kilovolt (kV), 55 kV, 66 kV, 115 kV, and 161 kV lines and 3,579 circuit miles of 220 kV lines (all located in California), 1,236 circuit miles of 500 kV lines (998 miles in California, 126 miles in Nevada, and 112 miles in Arizona), and 814 substations (all in California). SCE's distribution system, which takes power from substations to the customer, includes approximately 60,662 circuit miles of overhead lines, 34,606 circuit miles of underground lines, 1.5 million poles, 563 distribution substations, 672,597 transformers, and 723,000 area and street lights, all of which are located in California.

SCE owns and operates the following generating facilities: (a) an undivided 75.05% interest (1,614 megawatts (MW)) in San Onofre Units 2 and 3, which are large pressurized water nuclear units located on the California coastline between Los Angeles and San Diego; (b) 36 hydroelectric plants (1,175 MW) located in California's Sierra Nevada, San Bernardino and San Gabriel mountain ranges, (c) a diesel-fueled generating plant (9 MW) located on Santa Catalina island off the Southern California coast, and (d) an undivided 56% interest (885 MW net) in Mohave Generating Station, which consists of two coal-fueled generating units located in Clark County, Nevada near the California border.

SCE also owns an undivided 15.8% interest (590 MW) in Palo Verde Nuclear Generating Station, which is located near Phoenix, Arizona, and an undivided 48% interest (754 MW) in Units 4 and 5 at Four Corners Generating Station, which is a coal-fueled generating plant located in the Four Corners area of New Mexico. The Palo Verde and Four Corners plants are operated by other utilities.

At year-end 2002, the SCE-owned generating capacity (summer effective rating) was divided approximately as follows: 44% nuclear, 32% coal, 23% hydroelectric, and less than 1% diesel. The capacity factors in 2002 for SCE's nuclear and coal-fired generating units were: 96% for San Onofre; 73% for Mohave; 72% for Four Corners; and 94% for Palo Verde. For SCE's hydroelectric plants, generating capacity is dependent on the amount of available water. Therefore, while SCE's hydroelectric plants operated at a 35% capacity factor in 2002 due to a below normal water year, these plants were operationally available for 93.4% of the year.

The San Onofre units, Four Corners station, certain of SCE's substations, and portions of its transmission, distribution and communication systems are located on lands of the United States or others under (with minor exceptions) licenses, permits, easements or leases, or on public streets or highways

pursuant to franchises. Certain of such documents obligate SCE, under specified circumstances and at its expense, to relocate transmission, distribution, and communication facilities located on lands owned or controlled by federal, state, or local governments.

Thirty-one of SCE's 36 hydroelectric plants (some with related reservoirs) are located in whole or in part on United States lands pursuant to 30 to 50 year FERC licenses that expire at various times between 2003 and 2029 (the remaining five plants are located entirely on private property and are not subject to FERC jurisdiction). Such licenses impose numerous restrictions and obligations on SCE, including the right of the United States to acquire projects upon payment of specified compensation. When existing licenses expire, FERC has the authority to issue new licenses to third parties that have filed competing license applications, but only if their license application is superior to SCE's and then only upon payment of specified compensation to SCE. New licenses issued to SCE are expected to contain more restrictions and obligations than the expired licenses because laws enacted since the existing licenses were issued require FERC to give environmental purposes greater consideration in the licensing process. SCE's applications for the relicensing of certain hydroelectric projects with an aggregate dependable operating capacity of 134.82 MW are pending. Annual licenses have been issued to SCE hydroelectric projects that are undergoing relicensing and whose long-term licenses have expired. Federal Power Act Section 15 requires that the annual licenses be renewed until the long-term licenses are issued or denied.

On March 22, 2002, SCE, jointly with Pacific Terminals LLC, filed an application with the CPUC requesting authorization for the sale of certain oil storage and pipeline facilities by SCE to Pacific Terminals. The facilities were formerly used by SCE to provide fuel oil to its generating stations and, more recently, to conduct an oil storage and transport business for third parties. The agreed-upon sales price is approximately $158 million, of which approximately $47 million represents the net gain on sale. The March 2002 joint application seeks final CPUC approval of the sale. In the application, SCE proposed that all of the net gain on sale should be allocated to SCE shareholders. A coalition of utility employees has opposed the sale, claiming that it could negatively impact the environment, health and safety, competition, and jobs, and that the sale is barred by a California law prohibiting the CPUC from approving any sale of utility generating facilities until 2006. The CPUC's Office of Ratepayer Advocates has opposed SCE's proposed allocation of the net gain on sale, claiming that as much as 86% of the gain should be allocated to ratepayers. Submittal of written testimony, hearings and briefings took place in the summer and fall of 2002. The CPUC has not yet ruled on the application.

Substantially all of SCE's properties are subject to the lien of a trust indenture securing First and Refunding Mortgage Bonds, of which approximately $3.7 billion in principal amount was outstanding on March 1, 2003. Such lien and SCE's title to its properties are subject to the terms of franchises, licenses, easements, leases, permits, contracts, and other instruments under which properties are held or operated, certain statutes and governmental regulations, liens for taxes and assessments, and liens of the trustees under the trust indenture. In addition, such lien and SCE's title to its properties are subject to certain other liens, prior rights and other encumbrances, none of which, with minor or insubstantial exceptions, affect SCE's right to use such properties in its business, unless the matters with respect to SCE's interest in the Four Corners plant and the related easement and lease referred to below may be so considered.

SCE's rights in the Four Corners station, which is located on land of the Navajo Nation of Indians under an easement from the United States and a lease from the Navajo Nation, may be subject to possible defects. These defects include possible conflicting grants or encumbrances not ascertainable because of the absence of, or inadequacies in, the applicable recording law and the record systems of the Bureau of Indian Affairs and the Navajo Nation, the possible inability of SCE to resort to legal process to enforce its rights against the Navajo Nation without Congressional consent, the possible impairment or termination under certain circumstances of the easement and lease by the Navajo Nation, Congress, or

the Secretary of the Interior, and the possible invalidity of the trust indenture lien against SCE's interest in the easement, lease, and improvements on the Four Corners station.

Construction Program

Cash spent by SCE for its construction expenditures totaled $1.0 billion in 2002, $688 million in 2001, and $1.1 billion in 2000. Construction expenditures for 2003 are forecasted at $1.0 billion.

Nuclear Power Matters

Nuclear Plant Reactor Vessel Heads and Steam Generators Inspections

Recent nuclear industry concern has been expressed on the subject of leakage from nuclear reactor vessel head nozzle penetrations due to leakage at the Davis-Besse nuclear plant in Ohio. Inspections of the reactor head penetrations provide early detection of the conditions that cause the Davis-Besse type leakage. During scheduled refueling and maintenance outages at San Onofre Units 2 and 3, conducted in 2002 and 2003, vessel head nozzle penetrations in both units were inspected and no indications of leakage or degradation were detected. Inspections of Palo Verde Units 1 and 2 were also performed during scheduled refueling and maintenance outages in 2002 and no indications of leakage or degradation were detected. The vessel head of Palo Verde Unit 3 will be inspected in the spring of 2003.

The San Onofre Units 2 and 3 steam generators experience tube degradation as in other nuclear power plants. This degradation eventually leads to reduced plant output and the need for steam generator replacement. To date, 9% of Unit 2's tubes and 7% of Unit 3's tubes have been removed from service.

Palo Verde Plant Steam Generator Replacements

During the fall of 2003, the steam generators are scheduled to be replaced at Palo Verde Unit 2. A decision has also been made to prepare for replacement of steam generators for Units 1 and 3. Although a final determination of when Units 1 and 3 steam generators will be replaced has not yet been made, SCE and the other participants have approved the procurement of replacement steam generators and initiation of engineering work. This action will provide Palo Verde participants an option to replace the steam generators in the 2005 to 2007 time period should they ultimately decide to do so. SCE estimates that its portion of the fabrication and installation costs and associated power upgrade modifications will be approximately $70 million over the next seven years.

Nuclear Facility Decommissioning

On June 3, 1999, the CPUC adopted a settlement agreement providing for SCE to decommission San Onofre Unit 1 using decommissioning trust funds. On February 15, 2000, the California Coastal Commission approved SCE's application for a coastal permit to demolish and remove San Onofre Unit 1 buildings and other structures and to construct a temporary dry cask spent fuel storage facility as part of the decommissioning project. On February 7, 2003, the Coastal Commission granted SCE an amendment revising this approval to allow SCE to transport the Unit 1 reactor pressure vessel by a vehicle transporter through a state park and the federal military's Camp Pendleton to a boat dock (the original permit authorized transport by rail). Several parties have indicated their intent to challenge this amendment. SCE is unable to predict with certainty the outcome of any future litigation and the potential cost of this matter. Decommissioning of Unit 1 is underway and will be completed in three phases: (1) decontamination and dismantling of all structures and some foundations, (2) spent fuel storage monitoring, and (3) fuel storage facility dismantling, removal of remaining foundations, and site

restoration. Phase one is anticipated to continue through 2008. Phase two is expected to continue until 2026. Phase three will be conducted concurrently with the San Onofre Units 2 and 3 decommissioning projects. SCE expects that its reasonable San Onofre Unit 1 decommissioning costs will be paid from its nuclear decommissioning trust funds. SCE maintains a customer-funded trust with a sufficient balance to pay for its share of the estimated cost for the remaining San Onofre Unit 1 decommissioning work. SCE plans to decommission its other nuclear generating facilities following expiration of the operating licenses as expeditiously as possible once authorized by the NRC. The operating licenses expire in 2022 for San Onofre Units 2 and 3, and in 2024, 2026 and 2027 for the Palo Verde units. SCE customers are continuing to contribute to the decommissioning trusts for San Onofre Units 2 and 3, and for the Palo Verde units. Decommissioning costs are recorded as a component of depreciation expense.

Decommissioning (including Unit 1) is estimated to cost $2.5 billion (in year 2002 dollars) based on site-specific studies performed in 1998 for the San Onofre and Palo Verde units. This estimate considers the total cost of decommissioning and dismantling the plant, including labor, material, burial, and other costs. The site-specific studies are updated approximately every three years. 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.

Decommissioning expenses were $73 million in 2002, $96 million in 2001, and $106 million in 2000. The accumulated provision for decommissioning, excluding San Onofre Unit 1 and unrealized holding gains, was $1.6 billion at December 31, 2002, and $1.5 billion at December 31, 2001. The remaining cost to decommission San Onofre Unit 1 was approximately $298 million at December 31, 2002, and was recorded as a liability. Total expenditures for decommissioning of San Onofre Unit 1 through December 31, 2002, were $196 million.

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

Nuclear Insurance

Federal law limits public liability claims from a nuclear incident to $9.5 billion. SCE and other owners of the San Onofre and Palo Verde units have purchased the maximum private primary insurance available ($200 million at December 31, 2002, and $300 million beginning January 1, 2003). The balance is covered by the industry's retrospective rating plan that uses deferred premium charges to every reactor licensee if a nuclear incident at any licensed reactor in the United States results in claims and/or costs which exceed the primary insurance at that plant site. Federal regulations require this secondary level of financial protection. The NRC 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. It would have to pay, however, no more than $20 million per incident in any one year. Such amounts include a 5% surcharge if additional funds are needed to satisfy public liability claims and are subject to adjustment for inflation. If the public liability limit above is insufficient, federal regulations may impose further revenue-raising measures to pay claims, including a possible additional assessment on all licensed reactor operators. The Federal law requiring the nuclear insurance described above for all new NRC licensed reactors was due to expire in August 2002. The United States Congress has extended the expiration date of the applicable law until December 31, 2003, and is considering amendments that, among other things, are expected to extend the law beyond 2003.

Property damage insurance covers losses up to $500 million, including decontamination costs, at the San Onofre and Palo Verde units. Decontamination liability and property damage coverage exceeding the primary $500 million has also 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 $38 million per year. Insurance premiums are charged to operating expense.

Fuel Supply and Purchased Power

SCE obtains the power needed to serve its customers from its generating facilities and from purchases from other utilities, independent power producers, qualifying facilities and the California Independent System Operator (ISO). In addition, power is provided to SCE's customers through purchases by the California Department of Water Resources ("CDWR") under contracts with third parties. See the discussion in the MD&A under "REGULATORY MATTERS" for more information about power procurement activities. Sources of power to serve SCE's customers during 2002 were as follows: 33.4% purchased power; 21.4% CDWR; and 45.3% SCE-owned generation consisting of 25.7% nuclear, 14.4% coal, and 5.2% hydro.

Natural Gas Supply

SCE's only gas requirement in 2002 was for start-up use at Mohave coal-fired generation facility where firm transportation rights of 18,000 million British thermal units (mmBtu) per day were maintained on Southwest Gas Corp.'s pipeline. SCE also maintains firm access rights onto the Southern California Gas Company system at Wheelers Ridge for 198,863 mmBtu per day as a result of a 13-year contract entered into in August 1993. In 2002, the CPUC instructed the investor-owned utilities to bid on El Paso Natural Gas (EPNG) pipeline capacity in anticipation of a gas requirement in 2003. SCE participated in the auction and was awarded 9,218 mmBtu per day for delivery commencing in November 2002. Since there was no gas requirement on the EPNG pipeline in 2002, all capacity was released by SCE back to the market at tariff rates. The CPUC is currently investigating whether the acquisition of the EPNG capacity was consistent with Commission directions.

The acquired electrical capacity secured by SCE for 2003 included contracts requiring gas to be supplied as part of the contractual obligation (tolling arrangements). In preparation, SCE entered into a number of North American Energy Standards Board agreements (master gas agreements) that define the terms and conditions of all transactions with a particular supplier prior to any financial commitment.

Nuclear Fuel Supply

SCE has contractual arrangements covering 100% of the projected nuclear fuel requirements for San Onofre Units 2 and 3 through the years indicated below:

Uranium concentrates	2008
Conversion	2008
Enrichment	2008
Fabrication	2005

Assuming normal operation and full utilization of existing on-site fuel-storage capacity, San Onofre Units 2 and 3 will maintain full-core offload reserve through 2005. The Nuclear Waste Policy Act of 1982 requires that the United States Department of Energy provide for the disposal of utility spent

nuclear fuel beginning January 31, 1998. The Department of Energy has defaulted on its obligation to begin acceptance of spent nuclear fuel from the commercial nuclear industry by that date. Additional spent fuel storage either on-site or at another location will be required to permit continued operations beyond 2005. Additional on-site spent fuel storage capacity is being developed as necessary to allow for continued operation of San Onofre Units 2 and 3.

Participants in the Palo Verde units have contractual agreements to meet a majority of the 2003–2004 nuclear fuel requirements. Negotiations are being completed with various suppliers to provide the remaining portion of the 2003–2004 requirements not currently under contract. With the execution of these contracts, all nuclear fuel requirements will be covered through 2008. Fabrication requirements are covered through 2015.

The Palo Verde plant has existing fuel storage pools and is in the process of completing construction of a new facility for on-site dry storage of spent fuel. With the existing storage pools and the addition of the new facility, spent fuel storage or disposal methods will be available for use by the Palo Verde plant to allow its continued operation through the term of the plant license.

Coal Supply

SCE purchases coal pursuant to long term contracts to provide stable and reliable fuel supplies to its two coal-fired generating stations, the Mohave and Four Corners plants. SCE entered into a coal contract, dated September 1, 1966, with BHP Navajo Coal Company, the predecessor to the current owner of the Navajo mine, to supply coal to Four Corners Units 4 and 5. The initial term of this coal supply contract for the Four Corners plant is through 2004 and includes extension options for up to 15 additional years. For discussion of the litigation affecting the coal supply contract for the Mohave plant, see "*Navajo Nation Litigation*" in Part 1, Item 3 of this report. SCE does not have reasonable assurance of an adequate coal supply for operating the Mohave plant after 2005. If reasonable assurance of an adequate coal supply is not obtained, it will become necessary to shut down the Mohave plant after December 31, 2005. For additional information, see "REGULATORY MATTERS – Mohave Generating Station Proceeding" in the MD&A.

Environmental Matters

Legislative and regulatory activities in the areas of air and water pollution, waste management, hazardous chemical use, noise abatement, land use, aesthetics, and nuclear control continue to result in the imposition of numerous restrictions on SCE's operation of existing facilities, on the timing, cost, location, design, construction, and operation by SCE of new facilities, and on the cost of mitigating the effect of past operations on the environment. These activities substantially affect future planning and will continue to require modifications of SCE's existing facilities and operating procedures. SCE is unable to predict the extent to which additional regulations may affect its operations and capital expenditure requirements.

Air Quality

The Mohave plant located in Laughlin, Nevada, and the Four Corners plant located in the Four Corners area of New Mexico are subject to various air quality regulations, including the federal Clean Air Act and similar state and local statutes.

Mohave Consent Decree. In 1998, several environmental groups filed suit against the co-owners of the Mohave plant regarding alleged violations of emissions limits. In order to resolve the lawsuit and

accelerate resolution of key environmental issues regarding the plant, the parties entered into a consent decree, which was approved by the court in December 1999. The decree also addressed concerns raised by EPA programs regarding regional haze and visibility. As to regional haze, the EPA issued final rulemaking on July 1, 1999, that did not impose any additional emissions control requirements on the Mohave plant beyond meeting the provisions of the consent decree. As to visibility, the EPA issued its final rule regarding visibility impairment at the Grand Canyon on February 8, 2002. This final rule incorporated the terms of the consent decree into the Visibility Federal Implementation Plan for the state of 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 plant beyond 2005 is estimated to be approximately $605 million over the next four years; however, SCE has suspended its efforts seeking CPUC approval for the installation of such Mohave plant controls. See "OTHER DEVELOPMENTS – *Environmental Protection*" in the MD&A for more information on these issues.

Mercury Maximum Achievable Control Technology (MACT) Determination. In December 2000, the EPA announced its intent to regulate mercury emissions and other hazardous air pollutants from coal-fired electric power plants under Section 112 of the Clean Air Act and indicated that it would propose a rule to regulate these emissions by no later than December 15, 2003. The regulations are required to become final in 2004 with controls in place by 2007. This section of the Clean Air Act provides only for technology based standards, and does not permit market trading options. Until the EPA's standards relating to emissions of mercury and other hazardous air pollutants are actually promulgated, the potential cost of these control technologies cannot be estimated, and SCE cannot determine the potential impact on the operations of its facilities.

National Ambient Air Quality Standard. A new ambient air quality standard was adopted by the EPA in July 1997 to address emissions of fine particulate matter. It is widely understood that attainment of the fine particulate matter standard may require reductions in emissions of nitrogen oxides and sulfur dioxides. This standard was challenged in the courts, and on March 26, 2002, the United States Court of Appeals for the District of Columbia Circuit upheld the EPA's revised ozone and fine particulate matter ambient air quality standards.

Because of the delays resulting from the litigation over the standard, the EPA's new schedule for implementing the 8-hour ozone and fine particulate matter standards calls for designation of attainment and nonattainment areas under the two standards in 2004. Once these designations are published, states will be required to revise their implementation plans to achieve attainment of the revised standards, and determine which plans are likely to require additional emission reductions from facilities that are significant emitters of ozone precursors and particulates. Any requirement imposed on SCE's coal-fired generating facilities to further reduce their emissions of sulfur dioxide, nitrogen oxides and fine particulates as a result of the ozone and fine particulate matter standard will not be known until the states revise their implementation plans.

New Source Review Requirements. On November 3, 1999, the United States Department of Justice filed suit against a number of electric utilities, not including SCE, for alleged violations of the Clean Air Act's "new source review" (NSR) requirements related to modifications of air emissions sources at electric generating stations. Around that same time, the EPA issued requests for information pursuant to the Clean Air Act to numerous other electric utilities seeking to determine whether these utilities also engaged in activities in violation of the NSR requirements. On June 27, 2000, the EPA issued a request for information to the Four Corners plant. On September 1, 2000, Arizona Public Service Company, the

operator of the plant, replied to the request. To date, no further action has been taken by the EPA with respect to the Four Corners plant.

Several utilities have reached formal agreements or agreements-in-principle with the United States to resolve alleged NSR violations. These settlements involved installation of additional pollution controls, supplemental environment projects, and the payment of civil penalties. The agreements provided for a phased approach to achieving required emission reductions over the next 10 to 15 years, and some called for the retirement or repowering of coal-fired generating units. The total cost of some of these settlements exceeded $1 billion; the civil penalties agreed to by these utilities range between $1 million and $10 million. Because of the uncertainty created by the Bush administration's review of the NSR regulations and NSR enforcement proceedings, some of these settlements have not been finalized. However, the Department of Justice review released in January 2002 concluded "EPA has a reasonable basis for arguing that the enforcement actions are consistent with both the Clean Air Act and the Administrative Procedure Act." No change in the Department of Justice's position regarding pending NSR legal actions has been announced as a result of EPA's proposed NSR reforms (discussed immediately below).

On December 31, 2002, the EPA finalized a rule to improve the NSR program. This rule is intended to provide additional flexibility with respect to NSR by, among other things, modifying the method by which a facility calculates the emissions' increase from a plant modification; exempting, for a period of ten years, units that have complied with NSR requirements or otherwise installed pollution control technology that is equivalent to what would have been required by NSR; and allowing a facility to make modifications without being required to comply with NSR if the facility maintained emissions below plant-wide applicability limits. Although states, industry groups and environmental organizations have filed litigation challenging various aspects of the rule, it became effective March 3, 2003. It is unknown whether any litigation may lead to changes to the requirements of the new rule.

In addition to this final rule, the EPA has proposed a rule to clarify the "routine maintenance and repair" exclusion contained in the EPA's regulations. The public comment period for this rule has been extended to May 2, 2003. A clearer definition of "routine maintenance, repair and replacement," would provide SCE greater guidance in determining what investments can be made at its existing plants to improve the safety, efficiency and reliability of its operations without triggering NSR permitting requirements.

SCE is presently unable to determine the impact of these developments relating to NSR on SCE's coal-fired generating facilities.

Greenhouse Gas Emissions Reductions. On February 14, 2002, President Bush announced objectives to slow the growth of greenhouse gas emissions by reducing the amount of greenhouse gas emissions per unit of economic output by 18% by 2012 and to provide funding for climate-change related programs. The President's proposed program does not include mandatory reductions of greenhouse gas emissions. However, various bills have been, or are expected to be, introduced in Congress to require greenhouse gas emissions reductions and to address other issues related to climate change. In addition, in February 2003, seven states gave notice of their intent to sue EPA alleging that EPA has failed to regulate carbon dioxide and other greenhouse gas emissions from power plants as required by the Clean Air Act.

SCE is presently unable to determine the impact of these developments relating to greenhouse gas emissions on SCE's coal-fired generating facilities.

Federal Legislative Initiatives. There have been a number of bills introduced in the last session of Congress and the current session of Congress that would amend the Clean Air Act to specifically target emissions of certain pollutants from electric utility generating stations. These bills would mandate reductions in emissions of nitrogen oxides, sulfur dioxide and mercury; some bills would also impose limitations on carbon dioxide emissions. The various proposals differ in many details, including the timing of any required reductions, the extent of required reductions; and the relationship of any new obligations that would be imposed by these bills with existing legal requirements. There is significant uncertainty as to whether any of the proposed legislative initiatives will pass in their current form or whether any compromise can be reached that would facilitate passage of legislation. Accordingly, SCE is not able to evaluate the potential impact of these proposals at this time.

Hazardous Waste Compliance and Remediation

Under various federal, state and local environmental laws and regulations, a current or previous owner or operator of any facility, including an electric generating facility, may be required to investigate and remediate releases or threatened releases of hazardous or toxic substances or petroleum products located at that facility, and may be held liable to a governmental entity or to third parties for property damage, personal injury and investigation and remediation costs incurred by these parties in connection with these releases or threatened releases. Many of these laws, including the Comprehensive Environmental Response, Compensation and Liability Act of 1980, commonly referred to as CERCLA, as amended by the Superfund Amendments and Reauthorization Act of 1986, impose liability without regard to whether the owner knew of or caused the presence of the hazardous substances, and courts have interpreted liability under these laws to be strict and joint and several. The cost of investigation, remediation or removal of these substances may be substantial. In addition, persons who arrange for the disposal or treatment of hazardous or toxic substances at a disposal or treatment facility may be liable for the costs of removal or remediation of a release or threatened release of hazardous or toxic substances at that disposal or treatment facility, whether or not that facility is owned or operated by that person. Some environmental laws and regulations create a lien on a contaminated site in favor of the government for damages and costs it incurs in connection with the contamination. The owner of a contaminated site and persons who arrange for the disposal of hazardous substances at that site also may be subject to common law claims by third parties based on damages and costs resulting from environmental contamination emanating from that site.

Toxic Substances Control Act. The federal Toxic Substances Control Act and accompanying regulations govern the manufacturing, processing, distribution in commerce, use, and disposal of listed compounds, such as polychlorinated biphenyls, a toxic substance used in certain electrical equipment. Current costs for remediation and disposal of this substance are immaterial.

The CPUC allows SCE to recover in retail rates paid by its customers environmental remediation costs at certain sites through an incentive mechanism. See Note 10 of the Notes to Financial Statements and the "OTHER DEVELOPMENTS – *Environmental Protection*" section in the MD&A for more information.

Water Quality

Clean Water Act. Regulations under the federal Clean Water Act require permits for the discharge of certain pollutants into United States waters and permits for the discharge of stormwater flows from certain facilities. Under this act, the EPA issues effluent limitation guidelines, pretreatment standards, and new source performance standards for the control of certain pollutants. The Clean Water Act also regulates the thermal component (heat) of effluent discharges and the location, design, and construction of cooling water intake structures at facilities such as San Onofre. Individual states may impose more

stringent effluent limitations than EPA. California has an EPA program to issue individual or group (general) permits for Clean Water Act discharges.

SCE incurs additional expenses and capital expenditures in order to comply with guidelines and standards applicable to certain of its power plants. SCE presently has discharge permits for all applicable facilities.

The U.S. EPA is scheduled to adopt new regulations governing cooling water intake structures in February 2004. The San Onofre facility would be subject to these rules. If the final rules resemble those proposed by EPA, SCE believes the new rules will not significantly impact San Onofre and that the facility will be compliant without any physical or operational modifications.

Safe Drinking Water and Toxic Enforcement Act. California's Safe Drinking Water and Toxic Enforcement Act prohibits the exposure of individuals to chemicals known to the State of California to cause cancer or reproductive harm and the discharge of such chemicals into potential sources of drinking water. As SCE's operations call for use of different products, and as additional chemicals are placed on the State's list, SCE is required to incur additional costs to review and possibly revise its operations to ensure compliance with the requirements of this law.

Item 2. Properties

The principal properties of SCE are described above under "Properties."

Item 3. Legal Proceedings

Navajo Nation Litigation

On June 18, 1999, SCE was served with a complaint filed by the Navajo Nation in the United States District Court for the District of Columbia (D.C. District Court) against Peabody Holding Company and certain of its affiliates (Peabody), Salt River Project Agricultural Improvement and Power District, and SCE. The complaint asserts claims against the defendants for, among other things, violations of the federal RICO statute, interference with fiduciary duties and contractual relations, fraudulent misrepresentation by nondisclosure, and various contract-related claims. Peabody supplies coal from mines on Navajo Nation lands to the Mohave Station. The complaint claims that the defendants' actions prevented the Navajo Nation from obtaining the full value in royalty rates for the coal. The complaint seeks damages of not less than $600 million, trebling of that amount, and punitive damages of not less than $1 billion, as well as a declaration that Peabody's lease and contract rights to mine coal on Navajo Nation lands should be terminated. SCE joined Peabody's motion to strike the Navajo Nation's complaint. In addition, SCE and the other defendants filed motions to dismiss.

On March 15, 2001, the District Court granted the Hopi Tribe's motion to intervene in the litigation. The District Court also on that date granted Salt River's motion to dismiss the Navajo Nation's complaint against it on jurisdictional grounds.

On February 21, 2002, Peabody filed a demand to arbitrate in the United States District Court in Arizona (Arizona District Court) pursuant to a provision of their agreement with the Navajo Nation. At the same time, Peabody and SCE filed cross claims against the Navajo Nation in the D.C. District Court action, alleging that the Navajo breached a settlement agreement between Peabody and the Navajo Nation by filing their lawsuit. Additionally, Peabody filed a motion to transfer the action to the Arizona District Court or to stay the D.C. District Court action pending the outcome of arbitration-related proceedings. The D.C. District Court granted SCE's and Peabody's motion for leave to file the counterclaims, but denied Peabody's motion to transfer or stay the D.C. District Court action. Peabody and SCE appealed that part of the order denying the requested stay. On January 16, 2003, the Arizona District Court ruled that it did not have jurisdiction and dismissed the Arizona District Court action.

Some of the issues included in this case were recently addressed by the United States Supreme Court. The Navajo Nation had previously filed suit in the Court of Claims against the United States Department of Interior, alleging that the Government had breached its fiduciary duty concerning the above-referenced contract negotiations. On February 4, 2000, the Court of Claims issued a decision in the Government's favor, finding that while there had been a breach, there was no available redress from the Government. In its decision, the Court indicated that it was making no statements regarding, or findings in, the above federal civil court action. The Navajo Nation filed an appeal and the Court of Appeals ruled that the Court of Claims did have jurisdiction to award damages and remanded the case for that purpose. The United States filed for a Writ of Certiorari to the United States Supreme Court which was granted. On March 4, 2003, the Supreme Court issued its majority decision reversing the decision of the Court of Appeals. The Supreme Court concluded that there was no breach of a fiduciary duty and that the Navajo Nation did not have a right to relief against the Government.

Power Exchange Performance Bond Litigation

On January 19, 2001, American Home Assurance Company (American Home) notified SCE that due to SCE's failure to comply with its payment obligations to the California Power Exchange (PX), the PX issued a demand to American Home on a $20,000,000 pool performance bond. American Home

demanded payment from SCE by January 29, 2001, of $20,000,000 under an indemnity agreement between SCE and American Home.

SCE has exercised its right under the indemnity agreement to assume the defense of American Home against claims arising from the pool performance bond. As required by the indemnity agreement, in February 2001, SCE deposited $20,200,000 in an account in trust to be available to satisfy any judgment, should there be one, against American Home as a result of SCE's alleged default. SCE has further instituted the alternative dispute resolution provisions provided for in the applicable PX tariff, which provide for negotiation followed by mediation and, if unsuccessful, arbitration.

On or about September 13, 2001, the PX submitted a demand for arbitration against American Home, asserting causes of action for breach of contract and bad faith refusal to pay. On September 25, 2001, American Home demanded that SCE indemnify and defend American Home in connection with the demand for arbitration, pursuant to the operative documents between the parties. SCE assumed the defense of the arbitration.

On March 1, 2002, SCE made payment directly to the PX on the full amount of its outstanding obligations. The PX was unwilling to provide American Home with an exoneration of the pool performance bond, and has continued to pursue the arbitration, asserting, among other things, that it is entitled to the face amount of the bond on account of PG&E's default.

On March 19, 2002, American Home initiated suit against SCE, alleging that SCE's failure to obtain an exoneration of the bond in connection with SCE's payment of its indebtedness was a material breach of the indemnity agreement. On April 30, 2002, SCE filed its answer to American Home's lawsuit denying the material allegations of the complaint and filed a cross complaint against American Home, alleging causes of action for breach of contract and bad faith, reformation of conduct, breach of fiduciary duty, and declaratory relief. Among other relief, SCE seeks the return of its previously deposited $20,200,000.

CPUC Litigation and Settlement

See the discussion, which is incorporated herein by this reference, under "REGULATORY MATTERS – CPUC Litigation Settlement Agreement" in the MD&A for a description of SCE's lawsuit against the CPUC, its settlement, and the appeal of the stipulated judgment approving the settlement.

CPUC Investigation Regarding SCE's Electric Line Maintenance Practices

On August 25, 2001, the CPUC issued an order instituting investigation (OII) regarding SCE's overhead and underground electric line maintenance practices. The OII was based on a report issued by the CPUC's Protection and Safety Consumer Services Division (CPSD), which alleged a pattern of noncompliance with the CPUC's general orders for the maintenance of electric lines over the period 1998–2000. The OII also alleged that noncompliant conditions were involved in 37 accidents resulting in death, serious injury, or property damage. The CPSD identified 4,817 alleged violations of the general orders during the three-year period; and the OII put SCE on notice that it is potentially subject to a penalty of between $500 and $20,000 for each violation or accident.

Prepared testimony was filed in this matter in April 2002, and hearings were conducted in September 2002. In its opening brief on October 21, 2002, CPSD recommended SCE be assessed a penalty of $97 million. SCE addressed in its reply brief the legal, factual, and equitable reasons why CPSD's penalty recommendation should be rejected. On December 20, 2002, SCE filed a petition seeking to set aside the CPSD's submission. On February 21, 2003, the administrative law judge (ALJ) issued a ruling setting aside

submission, directed further briefing on the application of the appropriate standard to govern SCE's electric line maintenance obligation, and scheduled closing argument for April 22, 2003. On March 14, 2003, SCE and the CPSD filed additional briefs in response to the ALJ's direction. A decision is expected in the second or third quarter of 2003. See the discussion under "REGULATORY MATTERS – Electric Line Maintenance Practices Proceeding" in the MD&A for additional information.

Item 4. Submission of Matters to a Vote of Security Holders

Inapplicable

Pursuant to Form 10-K's General Instruction (General Instruction) G(3), the following information is included as an additional item in Part I:

Executive Officers[1] of the Registrant

Executive Officer	Age at December 31, 2002	Company Position
John E. Bryson	59	Chairman of the Board
Alan J. Fohrer	52	Chief Executive Officer and Director
Robert G. Foster	55	President
Harold B. Ray	62	Executive Vice President, Generation
Pamela A. Bass	55	Senior Vice President, Customer Service
John R. Fielder	57	Senior Vice President, Regulatory Policy and Affairs
Stephen E. Pickett	52	Senior Vice President and General Counsel
Richard M. Rosenblum	52	Senior Vice President, Transmission and Distribution
W. James Scilacci	47	Senior Vice President and Chief Financial Officer
Mahvash Yazdi	51	Senior Vice President and Chief Information Officer
Bruce C. Foster	50	Vice President, Regulatory Operations
Frederick J. Grigsby, Jr.	55	Vice President, Human Resources and Labor Relations
Thomas M. Noonan	51	Vice President and Controller
Pedro J. Pizarro	37	Vice President, Strategy and Business Development

[1] The term "Executive Officers" is defined by Rule 3b-7 of the General Rules and Regulations under the Securities Exchange Act of 1934, as amended.

None of SCE's executive officers is related to each other by blood or marriage. As set forth in Article IV of SCE's Bylaws, the elected officers of SCE are chosen annually by and serve at the pleasure of SCE's Board of Directors and hold their respective offices until their resignation, removal, other disqualification from service, or until their respective successors are elected. All of the above officers have been actively engaged in the business of SCE, Edison International and/or the nonutility company affiliates of SCE for more than five years except Frederick J. Grigsby, Jr., and Pedro J. Pizarro. Those officers who have not held their present position with SCE for the past five years had the following business experience during that period:

Executive Officer	Company Position	Effective Dates
John E. Bryson	Chairman of the Board, SCE	January 2003 to present
	Chairman of the Board, President, and Chief Executive Officer, Edison International	January 2000 to present
	Chairman of the Board, Edison Capital	January 2000 to present
	Chairman of the Board, Edison Mission Energy	January 2000 to December 2002
	Chairman of the Board and Chief Executive Officer, Edison International and SCE	October 1990 to December 1999
Alan J. Fohrer	Chief Executive Officer and Director, SCE	January 2003 to present
	Chairman of the Board and Chief Executive Officer, SCE	January 2002 to December 2002
	President and Chief Executive Officer, Edison Mission Energy	January 2000 to December 2001
	Executive Vice President and Chief Financial Officer, Edison International	September 1996 to January 2000
	Chairman of the Board, Edison Enterprises	January 1998 to September 1999
	Executive Vice President and Chief Financial Officer, SCE	September 1996 to December 1999
	Vice Chairman of the Board, Edison Mission Energy	May 1993 to January 1999
Robert G. Foster	President, SCE	January 2002 to present
	Senior Vice President, External Affairs, Edison International and SCE	April 2001 to December 2001
	Senior Vice President, Public Affairs, Edison International and SCE	November 1996 to April 2001
Pamela A. Bass	Senior Vice President, Customer Service, SCE	March 1999 to present
	Vice President, Customer Solutions Business Unit, SCE	June 1996 to February 1999
John R. Fielder	Senior Vice President, Regulatory Policy and Affairs, SCE	February 1998 to present
	Vice President, Regulatory Policy and Affairs, SCE	February 1992 to February 1998

Executive Officer	Company Position	Effective Dates
Stephen E. Pickett	Senior Vice President and General Counsel, SCE Vice President and General Counsel, SCE Associate General Counsel, SCE	January 2002 to present January 2000 to December 2001 November 1993 to December 1999
Richard M. Rosenblum	Senior Vice President, Transmission and Distribution, SCE Vice President, Distribution Business Unit, SCE	February 1998 to present January 1996 to February 1998
W. James Scilacci	Senior Vice President and Chief Financial Officer, SCE Vice President and Chief Financial Officer, SCE Director, 2002 General Rate Case, SCE Director, Qualifying Facility Resources, SCE	January 2003 to present January 2000 to December 2002 August 1999 to December 1999 January 1996 to August 1999
Mahvash Yazdi	Senior Vice President and Chief Information Officer, SCE and Edison International Vice President and Chief Information Officer, SCE and Edison International	January 2000 to present May 1997 to December 1999
Frederick J. Grigsby, Jr.	Vice President, Human Resources and Labor Relations Senior Vice President, Human Resources, Fluor Corporation[(1)(2)] Vice President, Human Resources, Thermo King Corporation[(1)(3)]	July 2001 to present December 1998 to October 2000 December 1995 to November 1998
Thomas M. Noonan	Vice President and Controller, SCE and Edison International Assistant Controller, SCE and Edison International	March 1999 to present September 1993 to March 1999
Pedro J. Pizarro	Vice President, Strategy and Business Development, SCE Vice President, Technology Business Development, Edison International Director, Strategic Planning, Edison International Consultant, McKinsey & Company[(1)(4)]	July 2001 to present September 2000 to June 2001 May 1999 to September 2000 October 1993 to April 1999

(1) This entity is not a parent, subsidiary or other affiliate of SCE.

(2) The Fluor Corporation is one of the world's largest, publicly owned engineering, procurement, construction, and maintenance services organizations.

(3) Thermo King Corporation provides climate control solutions for global transportation industries.

(4) McKinsey & Company is a management consulting firm.

PART II

Item 5. Market for Registrant's Common Equity and Related Stockholder Matters

Certain information responding to Item 5 with respect to frequency and amount of cash dividends is included in SCE's Annual Report to Shareholders for the year ended December 31, 2002 (Annual Report), under Quarterly Financial Data on page 63 and is incorporated by reference pursuant to General Instruction G(2). As a result of the formation of a holding company described above in Item 1, all of the issued and outstanding common stock of SCE is owned by Edison International and there is no market for such stock.

Item 201(d) of Regulation S-K, "Securities Authorized For Issuance Under Equity Compensation Plans," is not applicable because SCE has no compensation plans under which equity securities of SCE are authorized for issuance.

Item 6. Selected Financial Data

Information responding to Item 6 is included in the Annual Report under "Selected Financial and Operating Data: 1998–2002" on page 1, and is incorporated herein by reference pursuant to General Instruction G(2).

Item 7. Management's Discussion and Analysis of Results of Operations and Financial Condition

Information responding to Item 7 is included in the Annual Report under "Management's Discussion and Analysis of Results of Operations and Financial Condition" on pages 2 through 29 and is incorporated herein by reference pursuant to General Instruction G(2).

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Information responding to Item 7A is included in the Annual Report under "Management's Discussion and Analysis of Results of Operations and Financial Condition – MARKET RISK EXPOSURES" on pages 8 through 9, and is incorporated herein by reference pursuant to General Instruction G(2).

Item 8. Financial Statements and Supplementary Data

Certain information responding to Item 8 is set forth after Item 15 in Part III. Other information responding to Item 8 is included in the Annual Report on pages 31 through 63 and is incorporated herein by reference pursuant to General Instruction G(2).

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

PART III

Item 10. Directors and Executive Officers of the Registrant

Information concerning executive officers of SCE is set forth in Part I in accordance with General Instruction G(3), pursuant to Instruction 3 to Item 401(b) of Regulation S-K. Other information responding to Item 10 will appear in SCE's definitive Joint Proxy Statement (Proxy Statement) to be filed

with the SEC in connection with SCE's Annual Shareholders' Meeting to be held on May 15, 2003, under the heading "Election of Directors, Nominees for Election" and is incorporated herein by reference pursuant to General Instruction G(3).

Item 11. Executive Compensation

Information responding to Item 11 will appear in the Proxy Statement under the headings "Director Compensation," "Executive Compensation – Summary Compensation Table," "Option/SAR Grants in 2002," "Aggregated Option/SAR Exercises in 2002 and FY-End Option/SAR Values," "Long-Term Incentive Plan Awards in Last Fiscal Year," "Pension Plan Table," "Other Retirement Benefits," "Employment Contracts and Termination of Employment Arrangements," and "Compensation and Executive Personnel Committees' Interlocks and Insider Participation," and is incorporated herein by reference pursuant to General Instruction G(3).

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information responding to Item 12 will appear in the Proxy Statement under the headings "Stock Ownership of Directors and Executive Officers" and "Stock Ownership of Certain Shareholders" and is incorporated herein by reference pursuant to General Instruction G(3).

Item 201(d) of Regulation S-K, "Securities Authorized For Issuance Under Equity Compensation Plans," is not applicable because SCE has no compensation plans under which equity securities of SCE are authorized for issuance.

Item 13. Certain Relationships and Related Transactions

Information responding to Item 13 will appear in the Proxy Statement under the headings "Certain Relationships and Transactions" and "Other Management Transactions," and is incorporated herein by reference pursuant to General Instruction G(3).

Item 14. Controls and Procedures

Under the Sarbanes-Oxley Act of 2002 and implementing rules and regulations adopted by the Securities and Exchange Commission (SEC), SCE must maintain disclosure controls and procedures. The term "disclosure controls and procedures" is defined in the SEC's regulations to mean, as applied to SCE, controls and other procedures that are designed to ensure that information required to be disclosed by SCE in reports filed with the SEC is recorded, processed, summarized, and reported within the time frames specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by SCE in its SEC reports is accumulated and communicated to Edison International's management, including its Chief Executive Officer and its Chief Financial Officer, as appropriate to allow timely decisions regarding disclosure. The SEC's regulations also require SCE to carry out evaluations, under the supervision and with the participation of SCE's management, including its Chief Executive Officer and its Chief Financial Officer, of the effectiveness of the design and operation of SCE's disclosure controls and procedures. These evaluations must be carried out within the 90-day period prior to the filing date of certain reports, including this Annual Report on Form 10-K.

The Chief Executive Officer and the Chief Financial Officer of SCE have evaluated the effectiveness of the design and operation of SCE's disclosure controls and procedures as of March 24, 2003. They have

concluded that those disclosure controls and procedures, as of the evaluation date, were effective in ensuring that information required to be disclosed by SCE in its reports filed with the SEC was (1) accumulated and communicated to SCE's management, as appropriate to allow timely decisions regarding disclosure, and (2) recorded, processed, summarized, and reported within the time frames specified in the SEC's rules and forms.

The Chief Executive Officer and the Chief Financial Officer of SCE also have concluded that there were no significant changes in SCE's internal controls or in other factors that could significantly affect those controls subsequent to the date of their evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Item 15. Exhibits, Financial Statement Schedules, and Reports on Form 8-K

(a)(1) Financial Statements

The following items contained in the Annual Report are found on pages 2 through 63, and are incorporated by reference in this report.

Management's Discussion and Analysis of Results of Operations and Financial Condition
Responsibility for Financial Reporting
Report of Independent Accountants
Report of Predecessor Independent Accountants
Consolidated Statements of Income – Years Ended December 31, 2002, 2001 and 2000
Consolidated Balance Sheets – December 31, 2002, and 2001
Consolidated Statements of Cash Flows – Years Ended December 31, 2002, 2001 and 2000
Consolidated Statements of Changes in Common Shareholders' Equity – Years Ended December 31, 2002, 2001, 2000 and 1999
Notes to Consolidated Financial Statements

(a)(2) Report of Independent Accountants and Schedules Supplementing Financial Statements

The following documents may be found in this report at the indicated page numbers:

	Page
Report of Independent Accountants on Financial Statement Schedule	22
Report of Predecessor Independent Public Accountants on Supplemental Schedules	23
Schedule II – Valuation and Qualifying Accounts for the Years Ended December 31, 2002, 2001, and 2000	24

Schedules I through V, inclusive, except those referred to above, are omitted as not required or not applicable.

(a)(3) Exhibits

See Exhibit Index beginning on page 30 of this report.

The Company will furnish a copy of any exhibit listed in the accompanying Exhibit Index upon written request and upon payment to the Company of its reasonable expenses of furnishing such exhibit, which shall be limited to photocopying charges and, if mailed to the requesting party, the cost of first-class postage.

(b) Reports on Form 8-K

November 20, 2002 Item 5: Other Events	California Public Utilities Commission Litigation Settlement Agreement
December 13, 2002 Item 5: Other Events	John E. Bryson to become Chairman of the Board

Report of Independent Accountants on
Financial Statement Schedule

To the Board of Directors and
Shareholder of Southern California Edison Company:

Our audit of the consolidated financial statements referred to in our report dated March 26, 2003 appearing in the 2002 Annual Report to Shareholders of Southern California Edison Company (which report and consolidated financial statements are incorporated by reference in this Annual Report on Form 10-K) also included an audit of the 2002 financial statement schedule information listed in Item 15(a)(2) of this Form 10-K. In our opinion, the 2002 financial statement schedule presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. The 2001 and 2000 financial statement schedule information of Southern California Edison Company was audited by other independent accountants who have ceased operations. Those independent accountants expressed an unqualified opinion on that financial statement schedule information in their report dated March 25, 2002.

PricewaterhouseCoopers LLP

Los Angeles, California
March 26, 2003

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

REPORT OF PREDECESSOR INDEPENDENT PUBLIC ACCOUNTANTS ON SUPPLEMENTAL SCHEDULES

To Southern California Edison Company:

We have audited, in accordance with auditing standards generally accepted in the United States, the consolidated financial statements included in the 2002 Annual Report to Shareholders of Southern California Edison Company incorporated by reference in this Form 10-K, and have issued our report thereon dated March 25, 2002. Our audits were made for the purpose of forming an opinion on those consolidated financial statements taken as a whole. The supplemental schedules listed in Part III of this Form 10-K are the responsibility of Southern California Edison Company's management and are presented for purposes of complying with the Securities and Exchange Commission's rules and regulations, and are not part of the consolidated financial statements. These supplemental schedules have been subjected to the auditing procedures applied in the audits of the consolidated financial statements and, in our opinion, fairly state in all material respects the financial data required to be set forth therein in relation to the consolidated financial statements taken as a whole.

ARTHUR ANDERSEN LLP

Los Angeles, California
March 25, 2002

Southern California Edison Company

SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS

For the Year Ended December 31, 2002

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
	(In thousands)				
Uncollectible Accounts:					
Customers	$ 28,300	$ 21,035	$ —	$ 19,297	$ 30,038
All other	3,656	4,308	—	1,940	6,024
Total	$ 31,956	$ 25,343	$ —	$ 21,237(a)	$ 36,062

(a) Accounts written off, net.

Southern California Edison Company

SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS

For the Year Ended December 31, 2001

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
	(In thousands)				
Group A:					
Uncollectible Accounts:					
Customers	$ 19,793	$ 28,926	$ —	$ 20,419	$ 28,300
All other	3,427	1,836	—	1,607	3,656
Total	$ 23,220	$ 30,762	$ —	$ 22,026(a)	$ 31,956
Group B:					
DOE Decontamination and Decommissioning	$ 29,920	$ —	$	$ 5,520(b)	$ 24,400
Purchased-power settlements	466,232		—	110,353(c)	355,879
Pension and benefits	296,278	195,558		72,037(d)	419,799
Maintenance Accrual Insurance, casualty and other	64,058	54,827	—	43,815(e)	75,070
Total	$ 856,488	$ 250,385	$ —	$ 231,725	$ 875,148

(a) Accounts written off, net.
(b) Represents amounts paid.
(c) Represents the amortization of the liability established for purchased-power contract settlement agreements.
(d) Includes pension payments to retired employees, amounts paid to active employees during periods of illness and the funding of certain pension benefits.
(e) Amounts charged to operations that were not covered by insurance.

Southern California Edison Company

SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS

For the Year Ended December 31, 2000

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
	(In thousands)				
Group A:					
Uncollectible accounts					
Customers	$ 21,656	$ 24,017	$ —	$ 25,880	$ 19,793
All other	3,009	1,201	—	783	3,427
Total	$ 24,665	$ 25,218	$ —	$ 26,663(a)	$ 23,220
Group B:					
DOE Decontamination and Decommissioning	$ 34,590	$ —	$ (219)(b)	$ 4,451(c)	$ 29,920
Purchased-power settlements	563,459	17,188	—	114,415(d)	466,232
Pension and benefits	232,901	44,244	24,101(e)	4,968(f)	296,278
Insurance, casualty and other	68,880	42,749	—	47,571(g)	64,058
Total	$ 899,830	$ 104,181	$ 23,882	$ 171,405	$ 856,488

(a) Accounts written off, net.
(b) Represents revision to estimate based on actual billings.
(c) Represents amounts paid.
(d) Represents the amortization of the liability established for purchased-power contract settlement agreements.
(e) Primarily represents transfers from the accrued paid absence allowance account for required additions to the comprehensive disability plan accounts.
(f) Includes pension payments to retired employees, amounts paid to active employees during periods of illness and the funding of certain pension benefits.
(g) Amounts charged to operations that were not covered by insurance.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

SOUTHERN CALIFORNIA EDISON COMPANY

By:

Kenneth S. Stewart
Assistant General Counsel

Date: March 27, 2003

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
Principal Executive Officer:		
Alan J. Fohrer*	Chief Executive Officer and Director	March 27, 2003
Principal Financial Officer:		
W. James Scilacci*	Senior Vice President and Chief Financial Officer	March 27, 2003
Controller or Principal Accounting Officer:		
Thomas M. Noonan*	Vice President and Controller	March 27, 2003
Board of Directors:		
John E. Bryson*	Director	March 27, 2003
Bradford M. Freeman*	Director	March 27, 2003
Joan C. Hanley*	Director	March 27, 2003
Bruce Karatz*	Director	March 27, 2003
Luis G. Nogales*	Director	March 27, 2003
Ronald L. Olson*	Director	March 27, 2003
James M. Rosser*	Director	March 27, 2003
Richard T. Schlosberg, III*	Director	March 27, 2003
Robert H. Smith*	Director	March 27, 2003
Thomas C. Sutton*	Director	March 27, 2003
Daniel M. Tellep*	Director	March 27, 2003

*By:

Kenneth S. Stewart
Assistant General Counsel

CERTIFICATION

I, ALAN J. FOHRER, certify that:

1. I have reviewed this annual report on Form 10-K of SCE;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 27, 2003

ALAN J. FOHRER
Chief Executive Officer

CERTIFICATION

I, W. JAMES SCILACCI, certify that:

1. I have reviewed this annual report on Form 10-K of SCE;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 27, 2003

W. JAMES SCILACCI
Senior Vice President and Chief Financial Officer

EXHIBIT INDEX

Exhibit Number	Description
3.1	Certificate of Amendment and Restated Articles of Incorporation of SCE effective June 1, 1993 (File No. 1-2313, Form 10-K for the year ended December 31, 1993)*
3.2	Certificate of Correction of Restated Articles of Incorporation of SCE dated effective August 21, 1997 (File No. 1-2313, Form 10-Q for the quarter ended September 30, 1997)*
3.3	Amended Bylaws of Southern California Edison Company as adopted by the Board of Directors on January 1, 2003
4.1	SCE First Mortgage Bond Trust Indenture, dated as of October 1, 1923 (Registration No. 2-1369)*
4.2	Supplemental Indenture, dated as of March 1, 1927 (Registration No. 2-1369)*
4.3	Third Supplemental Indenture, dated as of June 24, 1935 (Registration No. 2-1602)*
4.4	Fourth Supplemental Indenture, dated as of September 1, 1935 (Registration No. 2-4522)*
4.5	Fifth Supplemental Indenture, dated as of August 15, 1939 (Registration No. 2-4522)*
4.6	Sixth Supplemental Indenture, dated as of September 1, 1940 (Registration No. 2-4522)*
4.7	Eighth Supplemental Indenture, dated as of August 15, 1948 (Registration No. 2-7610)*
4.8	Twenty-Fourth Supplemental Indenture, dated as of February 15, 1964 (Registration No. 2-22056)*
4.9	Eighty-Eighth Supplemental Indenture, dated as of July 15 1992 (File No. 1-2313, Form 8-K dated July 22, 1992)*
4.10	Indenture dated as of January 15, 1993 (File No. 1-2313, Form 8-K dated January 28, 1993)*
4.11	Indenture dated as of May 1, 1995 (File No. 1-2313, Form 8-K dated May 24, 1995)*
4.12	Ninety-Seventh Supplemental Indenture, dated as of February 21, 2002 (File No. 1-2313, filed as Exhibit 4.12 to Form 10-K for the year ended December 31, 2001)*
4.13	Ninety-Eight Supplemental Indenture, dated February 15, 2003
10.1	1981 Deferred Compensation Agreement (File No. 1-2313, filed as Exhibit 10.2 to Form 10-K for the year ended December 31, 1981)*
10.2	1985 Deferred Compensation Agreement for Executives (File No. 1-2313, filed as Exhibit 10.3 to Form 10-K for the year ended December 31, 1985)*
10.3	1985 Deferred Compensation Agreement for Directors (File No. 1-2313, filed as Exhibit 10.4 to Form 10-K for the year ended December 31, 1985)*
10.4	Director Deferred Compensation Plan (File No. 1-9936, filed as Exhibit 10.1 to the Edison International Form 10-Q for the quarter ended June 30, 2002)*
10.4.1	Director Deferred Compensation Plan Amendment No. 1 (File No. 1-9936, filed as Exhibit 10.4.1 to the Edison International Form 10-K for the year ended December 31, 2002)*
10.5	Director Grantor Trust Agreement (File No. 1-9936, filed as Exhibit 10.10 to the Edison International Form 10-K for the year ended December 31, 1995)*
10.5.1	Director Grantor Trust Agreement Amendment 2002-1 (File No. 1-9936, filed as Exhibit 10.4 to the Edison International Form 10-Q for the quarter ended June 30, 2002)*
10.6	Executive Deferred Compensation Plan (File No. 1-9936, filed as Exhibit 10.2 to the Edison International Form 10-Q for the quarter ended March 31, 1998)*
10.6.1	Executive Deferred Compensation Plan Amendment No. 1 (File No. 1-9936, filed as Exhibit 10.6.1 to the Edison International Form 10-K for the year ended December 31, 2002)*
10.7	Executive Grantor Trust Agreement (File No. 1-9936, filed as Exhibit 10.12 to the Edison International Form 10-K for the year ended December 31, 1995)*
10.7.1	Executive Grantor Trust Agreement Amendment 2002-1 (File No. 1-9936, filed as Exhibit 10.3 to the Edison International Form 10-Q for the quarter ended June 30, 2002)*

10.8 Executive Supplemental Benefit Program (File No. 1-9936, filed as Exhibit 10.2 to the Edison International Form 10-Q for the quarter ended September 20, 1999)*

10.9 Dispute resolution amendment of 1981 Executive Deferred Compensation Plan, 1985 Executive and Director Deferred Compensation Plans and Executive Supplemental Benefit Program (File No. 1-9936, filed as Exhibit 10.21 to the Edison International Form 10-K for the year ended December 31, 1998)*

10.10 Executive Retirement Plan (File No. 1-9936, filed as Exhibit 10.1 to the Edison International Form 10-Q for the quarter ended September 30, 1999)*

10.10.1 Executive Retirement Plan Amendment 2001-1 (File No. 1-9936, filed as Exhibit 10.1 to the Edison International Form 10-Q for the quarter ended March 31, 2001)*

10.10.2 Executive Retirement Plan Amendment 2002-1 (File No. 1-9936, filed as Exhibit 10.10.2 to the Edison International Form 10-K for the year ended December 31, 2002)*

10.11 Executive Incentive Compensation Plan (File No. 1-9936, filed as Exhibit 10.12 to the Edison International Form 10-K for the year ended December 31, 1997)*

10.12 Executive Disability and Survivor Benefit Program (File No. 1-9936, filed as Exhibit 10.22 to the Edison International Form 10-K for the year ended December 31, 1994)*

10.13 Retirement Plan for Directors (File No. 1-9936, filed as Exhibit 10.2 to the Edison International Form 10-Q for the quarter ended June 30, 1998)*

10.14 Officer Long-Term Incentive Compensation Plan (File No. 1-9936, filed as Exhibit 10.3 to the Edison International Form 10-Q for the quarter ended March 31, 1998)*

10.15 Equity Compensation Plan (File No. 1-9936, filed as Exhibit 10.1 to the Edison International Form 10-Q for the quarter ended June 30, 1998)*

10.15.1 Equity Compensation Plan Amendment No. 1 (File No. 1-9936, filed as Exhibit 10.3 to the Edison International Form 10-Q for the quarter ended June 30, 2000)*

10.16 2000 Equity Plan (File No. 1-9936, filed as Exhibit 10.1 to the Edison International Form 10-Q for the quarter ended June 30, 2000)*

10.17 Forms of Agreement for long-term compensation awards under the Officer Long-Term Incentive Compensation Plan, the Equity Compensation Plan or the 2000 Equity Plan (File No. 1-9936, for 1992-1995 stock option awards filed as Exhibit 10.21.1 to the Edison International Form 10-K for the year ended December 31, 1995, for 1996 stock option awards filed as Exhibit 10.16.2 to the Edison International Form 10-K for the year ended December 31, 1996, for 1997 stock option awards filed as Exhibit 10.16.3 to the Edison International Form 10-K for the year ended December 31, 1997, for 1998 stock option awards filed as Exhibit 10.4 to the Edison International Form 10-Q for the quarter ended June 30, 1998, for 1999 stock option awards filed as Exhibit 10.1 to the Edison International Form 10-Q for the quarter ended March 31, 1999, for January 2000 stock option and performance share awards as restated filed as Exhibit 10.2 to the Edison International Form 10-Q for the quarter ended March 31, 2001, for May 2000 special stock option awards filed as Exhibit 10.2 to the Edison International Form 10-Q for the quarter ended June 30, 2000, for 2001 basic stock option and performance share awards filed as Exhibit 10.3 to the Edison International Form 10-Q for the quarter ended March 31, 2001, for 2001 special stock option awards filed as Exhibit 10.4 to the Edison International Form 10-Q for the quarter ended March 31, 2001, for 2001 retention incentives filed as Exhibit 10.5 to the Edison International Form 10-Q for the quarter ended March 31, 2001, for 2001 exchange offer deferred stock units filed as Attachment C of Exhibit (a)(1) to Schedule TO-I dated October 26, 2001, and for 2002 stock option and performance share awards filed as Exhibit 10.1 to the Edison International Form 10-Q for the quarter ended March 31, 2002)*

10.18 Director Nonqualified Stock Option Terms and Conditions under the Equity Compensation Plan (File No. 1-9936, filed as Exhibit 10.1 to the Edison International Form 10-Q for the quarter ended June 30, 2002)*

10.19	Estate and Financial Planning Program as amended April 1, 1999 (File No. 1-2313, filed as Exhibit 10.2 to Form 10-Q for the quarter ended June 30, 1999)*
10.20	Option Gain Deferral Plan as restated September 15, 2000 (File No. 1-9936, filed as Exhibit 10.25 to the Edison International Form 10-K for the year ended December 31, 2000)*
10.21	Election Terms for Warren Christopher (File No. 1-9936, filed as Exhibit 10.22 to the Edison International Form 10-K for the year ended December 31, 1997)*
10.22	Executive Severance Plan as adopted effective January 1, 2001 (File No. 1-9936, filed as Exhibit 10.34 to the Edison International Form 10-K for the year ended December 31, 2001)*
10.23	Resolution regarding the computation of disability and survivor benefits prior to age 55 for Alan J. Fohrer (File No. 1-9936, filed as Exhibit 10.2 to the Edison International Form 10-Q for the quarter ended March 31, 2000)*
10.24	Employment Letter Agreement with Mahvash Yazdi (File No. 1-9936, filed as Exhibit 10.34 to the Edison International Form 10-K for the year ended December 31, 2002)*
12.	Computation of Ratios of Earnings to Fixed Charges
13.	Annual Report to Shareholders for year ended December 31, 2002
23.	Consent of Independent Accountants – PricewaterhouseCoopers LLP
24.1	Power of Attorney
24.2	Certified copy of Resolution of Board of Directors Authorizing Signature
99	Statement Pursuant to 18 U.S.C. Section 1350

* Incorporated by reference pursuant to Rule 12b-32.