Southern California Edison Company

2000 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 115-year-old electric utility, serves 4.3 million customers and more than 11 million people within a 50,000-square-mile area of central, coastal and Southern California.

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Selected Financial and Operating Data: 1996-2000

Southern California Edison Company

Dollars in millions	**2000**	1999	1998	1997	1996
Income statement data:					
Operating revenue	**$ 7,870**	$ 7,548	$ 7,500	$ 7,953	$ 7,583
Operating expenses	**9,522**	6,693	6,582	6,893	6,450
Fuel and purchased power expenses	**4,882**	3,405	3,586	3,735	3,336
Income tax from operations	**(1,007)**	451	446	582	578
Allowance for funds used during construction	**21**	24	20	17	25
Interest expense — net of amounts capitalized	**572**	483	485	444	453
Net income (loss)	**(2,028)**	509	515	606	655
Net income (loss) available for common stock	**(2,050)**	484	490	576	621
Ratio of earnings to fixed charges	**(4.28)**	2.94	2.95	3.49	3.54
Balance sheet data:					
Assets	**$15,966**	$17,657	$16,947	$18,059	$17,737
Gross utility plant	**15,653**	14,852	14,150	21,483	21,134
Accumulated provision for depreciation and decommissioning	**7,834**	7,520	6,896	10,544	9,431
Common shareholder's equity	**780**	3,133	3,335	3,958	5,045
Preferred stock:					
Not subject to mandatory redemption	**129**	129	129	184	284
Subject to mandatory redemption	**256**	256	256	275	275
Long-term debt	**5,631**	5,137	5,447	6,145	4,779
Capital structure:					
Common shareholder's equity	**11.5%**	36.2%	36.4%	37.5%	48.6%
Preferred stock:					
Not subject to mandatory redemption	**1.9%**	1.5%	1.4%	1.7%	2.7%
Subject to mandatory redemption	**3.8%**	2.9%	2.8%	2.6%	2.7%
Long-term debt	**82.8%**	59.4%	59.4%	58.2%	46.0%
Operating data:					
Peak demand in megawatts (MW)	**19,757**	19,122	19,935	19,118	18,207
Generation capacity at peak (MW)	**10,191**	10,474	10,546	21,511	21,602
Kilowatt-hour sales (in millions)	**83,436**	78,602	76,595	77,234	75,572
Total energy requirement (kWh) (in millions)	**82,503**	78,752	80,289	86,849	84,236
Energy mix:					
Thermal	**36.0%**	35.5%	38.8%	44.6%	47.6%
Hydro	**5.4%**	5.6%	7.4%	6.5%	6.9%
Purchased power and other sources	**58.6%**	58.9%	53.8%	48.9%	45.5%
Customers (in millions)	**4.29**	4.36	4.27	4.25	4.22
Full-time employees	**12,593**	13,040	13,177	12,642	12,057

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

California's investor-owned electric utilities, including Southern California Edison Company (SCE), are currently facing a crisis resulting from deregulation of the generation side of the electric industry through legislation enacted by the California Legislature and decisions issued by the California Public Utilities Commission (CPUC). Under the legislation and CPUC decisions, prices for wholesale purchases of electricity from power suppliers are set by markets while the retail prices paid by utility customers for electricity delivered to them remain frozen at June 1996 levels. Since May 2000, SCE's costs to obtain power (at wholesale electricity prices) for resale to its customers substantially exceeded revenue from frozen rates. The shortfall has been accumulated in the transition revenue account (TRA), a CPUC-authorized regulatory asset. SCE has borrowed significant amounts of money to finance its electricity purchases, creating a severe financial drain on SCE.

On April 9, 2001, SCE and the California Department of Water Resources (CDWR) executed a memorandum of understanding (MOU) which sets forth a comprehensive plan calling for legislation, regulatory action and definitive agreements to resolve important aspects of the energy crisis, and which is expected to help restore SCE's creditworthiness and liquidity. The Governor of the State of California and his representatives participated in the negotiation of the MOU, and the Governor endorsed implementation of all the elements of the MOU. The MOU is discussed in detail in the Memorandum of Understanding with the CDWR section. SCE and the CDWR committed in the MOU to proceed in good faith to sponsor and support the required legislation and to negotiate in good faith the necessary definitive agreements. If required legislation is not adopted and definitive agreements executed by August 15, 2001, or if the CPUC does not adopt required implementing decisions by June 8, 2001, the MOU may be terminated by SCE or the CDWR. SCE cannot provide assurance that all the required legislation will be enacted, regulatory actions taken and definitive agreements executed before the applicable deadlines.

Accounting standards generally accepted in the United States permit SCE to defer costs as regulatory assets if those costs are determined to be probable of recovery in future rates. If SCE determines that regulatory assets, such as the TRA and the transition cost balancing account (TCBA), are no longer probable of recovery through future rates, they must be written off. The TCBA is a regulatory balancing account that tracks the recovery of generation-related transition costs, including stranded investments. SCE must assess the probability of recovery of the undercollected costs that are now recorded in the TCBA in light of the CPUC's March 27, 2001, and April 3, 2001, decisions, including the retroactive transfer of balances from SCE's TRA to its TCBA and related changes that are discussed in more detail in Rate Stabilization Proceeding. These decisions and other regulatory and legislative actions did not meet SCE's prior expectation that the CPUC would provide adequate cost recovery mechanisms. Until legislative and regulatory actions contemplated by the MOU occur, or other actions are taken, SCE is unable to conclude that its undercollected costs that are recovered through the TCBA mechanism are probable of recovery in future rates. As a result, SCE's financial results for the year ended 2000 include an after-tax charge of approximately $2.5 billion ($4.2 billion on a pre-tax basis), reflecting a write-off of the TCBA (as restated to reflect the CPUC's March 27, 2001, decisions) and regulatory assets to be recovered through the TCBA mechanism, as of December 31, 2000. In addition, SCE currently does not have regulatory authority to recover any purchased-power costs it incurs during 2001 in excess of revenue from retail rates. Those amounts will be charged against earnings in 2001 absent a regulatory or legislative solution, such as implementation of the actions called for in the MOU that makes recovery of such costs probable. This will result in further material declines in reported common shareholder's equity, particularly in light of the CPUC's failure to provide SCE with sufficient rate revenue to cover its ongoing costs and obligations through the CPUC's March 27, 2001, decisions. The December 31, 2000, write-off also caused SCE to be unable to meet an earnings test that must be met before SCE can issue additional first mortgage bonds. If the MOU is implemented, or a rate mechanism provided by legislation or regulatory authority is established that makes recovery from regulated rates probable as to all or a portion of the amounts that were previously charged against earnings, current accounting standards provide that a regulatory asset would be reinstated with a corresponding increase in earnings.

The following pages include a discussion of the history of the TRA and TCBA and related circumstances, the devastating effect on the financial condition of SCE of undercollections recorded in the TRA and TCBA, the current status of the undercollections, the impact of the CPUC's March 27, 2001, decisions and related matters, and possible resolution of the current crisis through implementation of the MOU.

Results of Operations

Earnings

In 2000, SCE recorded a loss of $2.0 billion. The net loss in 2000 included a write-off of regulatory assets and liabilities in the amount of $2.5 billion (after tax) as of December 31, 2000. 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. On March 27, 2001, the CPUC issued a decision adopting a 3¢-per-kilowatt-hour (kWh) surcharge on rates effective immediately, with revenue generated by the surcharge to be applied to electric power costs incurred after the date of the order. This rate stabilization decision also stated 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 accounting overcollections (which amounted to $1.5 billion as of December 31, 2000) to be closed monthly to the TRA, rather than annually to the TCBA. In addition, it required the TRA to be transferred to the TCBA on a monthly basis. Previous rules had called for TRA 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. Based on the new rules, the $4.5 billion TRA undercollection as of December 31, 2000, and the coal and hydroelectric balancing account overcollections were reclassified, and the TCBA balance was recalculated to be a $2.9 billion undercollection (see further discussion of the CPUC rate increase in the Rate Stabilization Proceeding section and the components of the TCBA undercollection in the Status of Transition and Power Procurement Costs Recovery section of Regulatory Environment).

On April 9, 2001, SCE and the CDWR executed an MOU providing for the sale of SCE's transmission assets, or other assets under certain circumstances, recovery of SCE's net undercollected amount through the application of proceeds of the asset sale and one or more securitization financings, rate-making provisions for recovery of SCE's future power procurement costs, settlement of SCE's legal actions against the CPUC, and other elements of a comprehensive plan (see further discussion in Memorandum of Understanding with the CDWR). The implementation of the MOU requires various regulatory and legislative actions to be taken in the future. Until those actions or actions in other proceedings are taken, which would include modifying or reversing recent CPUC decisions that impair recovery of SCE's power procurement and transition costs, SCE is not able to conclude that, under applicable accounting principles, the $2.9 billion TCBA undercollection (as recalculated above) and $1.3 billion (book value) of other regulatory assets and liabilities, that were to be recovered through the TCBA mechanism by the end of the rate freeze, are probable of recovery through the rate-making process as of December 31, 2000.

As a result, accounting principles generally accepted in the United States require that the net balance of these accounts be written off as a charge to earnings as of December 31, 2000. This write-off consists of the following:

In millions	
TCBA (as recalculated)	$2,878
Unamortized nuclear investment — net	610
Purchased-power settlements	435
Unamortized loss on sale of plant	61
Other regulatory assets — net	39
Subtotal	4,023
Flow-through taxes	218
Total regulatory assets — net	4,241
Less income tax benefit	(1,720)
Net write-off	$2,521

This write-off is included in the income statement as a $4.0 billion charge to provisions for regulatory adjustment clauses, and a $1.5 billion net reduction in income tax expense.

As stated above, an MOU has been negotiated with representatives of the Governor (see Memorandum of Understanding with the CDWR) to resolve the energy crisis. The regulatory and legislative actions set forth in the MOU, if implemented, are expected to result in a rate-making mechanism that would make recovery of these regulatory assets probable. If and when those actions or other actions that make such recovery probable are taken, and the necessary rate-making mechanism is adopted, the regulatory assets would be restored to the balance sheet, with a corresponding increase to earnings.

Excluding the write-off, SCE's 2000 earnings were $471 million. SCE's earnings were $484 million in 1999 and $490 million in 1998. SCE's 1999 earnings include a $15 million one-time tax benefit due to an Internal Revenue Service ruling. The 2000 decrease was mainly due to adjustments to reflect potential regulatory refunds and lower gains from sales of equity investments, partially offset by superior operating performance at the San Onofre Nuclear Generating Station and higher kWh sales. Excluding the one-time tax benefit, SCE's 1999 earnings were $469 million, down $21 million from 1998. The 1999 decrease was primarily due to the accelerated depreciation of SCE's generation assets, partially offset by higher kWh sales in 1999.

Unless a rate-making mechanism is implemented in accordance with the MOU described above or other necessary rate-making action is taken, future net undercollections in the TCBA will be charged to earnings as the losses are incurred. The loss (before tax) incurred in this balancing account (as redefined) in January and February 2001 amounts to approximately $800 million. SCE anticipates that losses will continue unless a rate-making mechanism is established. In addition to the losses from the TCBA undercollections, SCE expects its 2001 earnings to be negatively affected by the recent fire and resulting damage at San Onofre Unit 3. See further discussion of the San Onofre fire in the San Onofre Nuclear Generating Station section.

Operating Revenue

SCE's customers are able to choose to purchase power directly from an energy service provider, thus becoming direct access customers, or continue to have SCE purchase power on their behalf. Most direct access customers are billed by SCE, but given a credit for the generation portion of their bills. Under Assembly Bill 1 (First Extraordinary Session) (AB 1X), enacted on February 1, 2001, the CPUC was directed (on a schedule it determines) to suspend the ability of retail customers to select alternative providers of electricity until the CDWR stops buying power for retail customers.

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

Operating revenue increased in 2000 (as shown in the table below), primarily due to: warmer weather in the second and third quarters of 2000 as compared to the same periods in 1999; increased resale sales; and an increase in revenue related to penalties customers incurred for not adhering to their interruptible contracts. The increase in resale sales resulted from other utilities and municipalities exercising their contractual option to buy more power from SCE as the price of power purchased through the California Power Exchange (PX) and Independent System Operator (ISO) increased significantly in 2000. These increases were partially offset by the credit given to customers who chose direct access. Operating revenue increased by less than 1% in 1999, as increased kWh sales and revenue resulting from maintenance work SCE was providing the new owners of generating plants previously sold by SCE was almost completely offset by the credit given to customers who chose direct access. On March 27, 2001, the CPUC affirmed that the interim surcharge of 1¢ per kWh granted on January 4, 2001, is now permanent. See further discussion in Rate Stabilization Proceeding.

In 2000, more than 92% 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 changes in operating revenue resulted from:

In millions Year ended December 31,	**2000**	1999	1998
Operating revenue —			
Rate changes (including refunds)	**$ 120**	$ (75)	$ (498)
Direct access credit	**(434)**	(213)	(29)
Interruptible noncompliance penalty	**102**	6	—
Sales volume changes	**520**	195	(44)
Other	**14**	136	117
Total	**$ 322**	$ 49	$ (454)

Operating Expenses

Fuel expense decreased in both 2000 and 1999. The decrease in 2000 was primarily due to fuel-related refunds resulting from a settlement with another utility that SCE recorded in the second and third quarters of 2000. The decrease in 1999 was due to the sale of 12 generating plants in 1998.

Prior to April 1998, SCE was required under federal law and CPUC orders to enter into contracts to purchase power from qualifying facilities (QFs) at CPUC-mandated prices even though energy and capacity prices under many of these contracts are generally higher than other sources. Purchased-power expense related to contracts decreased in both 2000 and 1999. The decrease in 2000 was primarily due to a contract adjustment with a state agency, as well as the terms in some of the remaining QF contracts reverting to lower prices. The decrease in 1999 was primarily due to the terms in some of the remaining QF contracts reverting to lower prices, as well as SCE's settlement agreements to terminate contracts with certain QFs. SCE's settlement agreements with certain QFs decreased purchased-power expense related to contracts by $47 million in 1999. SCE's purchased-power settlement obligations were recorded as a liability. Because the settlement payments were to be recovered through the TCBA mechanism as the payments were made, a regulatory asset was also recorded. As of December 31, 2000, the purchased-power settlement regulatory asset was written off as a charge to earnings. See further discussion of the write-off in Earnings.

In 2000, PX/ISO purchased-power expense increased significantly due to increased demand for electricity in California, dramatic price increases for natural gas (a key input of electricity production), and structural problems within the PX and ISO. The increased volume of higher priced PX purchases was minimally offset by increases in PX sales revenue and ISO net revenue, as well as the use of risk management instruments (gas call options and PX block forward contracts). The gas call options (which were sold in

October 2000) and the PX block forward contracts mitigated SCE's transition cost recovery exposure to increases in energy prices. SCE's use of gas call options reduced PX/ISO purchased-power expense by $200 million in 2000 compared to 1999. SCE's use of PX block forward contracts reduced PX/ISO purchased-power expense by $688 million in 2000 compared to 1999. In 1999, PX/ISO purchased-power expense increased compared to 1998, mainly due to three additional months of PX transactions in 1999. However, when 1999 PX purchased-power expense was compared on the same nine-month basis as 1998, the increase was less than 1%, despite the fact that SCE experienced a significant decrease in the volume of kWh sales through the PX. The lower volume of sales through the PX in 1999 was the result of less generation at SCE (due to San Onofre refueling outages in 1999, divestiture of 12 generating plants in 1998 and reduced hydroelectric generation) and fewer purchases from QFs. SCE's use of gas call options decreased PX/ISO purchased-power expense by $8 million in 1999 compared to 1998. SCE's use of PX block forward contracts increased PX/ISO purchased-power expense by $3 million in 1999 compared to 1998. For a further discussion of SCE's hedging instruments and the recent significant increases in power prices, see Market Risk Exposures. As of December 15, 2000, the FERC eliminated the requirement that SCE buy and sell its purchased and generated power through the PX and ISO. See further discussion in Wholesale Electricity Markets.

Due to SCE's noncompliance with the PX's tariff requirement for posting collateral for all transactions in the day-ahead and day-of markets as a result of the downgrade in its credit rating, the PX suspended SCE's market trading privileges for the day-of market effective January 18, 2001, and, for the day-ahead market effective January 19, 2001. See further discussion of SCE's liquidity crisis in Financial Condition.

Provisions for regulatory adjustment clauses increased in 2000 and decreased in 1999. The 2000 increase was mainly due to a write-off as of December 31, 2000, of $4.2 billion in regulatory assets and liabilities as a result of the California energy crisis. See further discussion of the write-off in the Earnings section. In addition, the provision also increased in 2000 due to adjustments to reflect potential regulatory refunds related to the outcome of the CPUC's reevaluation of the operation of the interruptible rate programs. The decrease in 1999 was mainly due to undercollections related to the TCBA and the rate-making treatment of the rate reduction notes. These undercollections were partially offset by overcollections related to the administration of public purpose funds. The rate-making treatment associated with rate reduction notes has allowed for the deferral of the recovery of a portion of the transition-related costs, from a four-year period to a 10-year period. SCE's use of gas call options increased the provisions by $200 million in 2000 compared to 1999, and decreased the provisions by $8 million in 1999 compared to 1998.

Other operation and maintenance expense decreased in 2000, primarily due to a $120 million decrease in mandated transmission service (known as must-run reliability services) expense and a $19 million decrease in operating expenses at San Onofre. The decrease at San Onofre in 2000 was primarily due to scheduled refueling outages for both units in the first half of 1999. San Onofre had only one refueling outage in 2000. Other operation and maintenance expense increased in 1999, mostly due to an increase in mandated transmission service expense and PX and ISO costs incurred by SCE. These increases were partially offset by lower expenses incurred for distribution facilities.

Income taxes decreased in 2000, primarily due to the $1.5 billion income tax benefit related to the write-off as of December 31, 2000, of regulatory assets and liabilities in the amount of $2.5 billion (after tax). Absent the write-off, SCE's income tax expense increased in 2000 due to higher pre-tax income.

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

Other Income and Deductions

Interest and dividend income increased in 2000, primarily due to increases in interest earned on higher balancing account undercollections.

Other nonoperating income decreased in 2000 but increased in 1999. Although SCE recorded gains on sales of equity investments in 2000, 1999 and 1998, the different amounts of the gains were the primary reason for other nonoperating income to decrease in 2000 when compared to 1999, and to increase in 1999 when compared to 1998.

Interest expense — net of amounts capitalized increased in 2000 and decreased slightly in 1999. The increase in 2000 was mostly due to higher overall short-term debt balances necessary to meet general cash requirements (especially PX and ISO payments) and higher interest expense related to balancing account overcollections. The decrease in 1999 was mainly due to a decrease in interest on long-term debt more than offsetting an increase resulting from higher overall short-term debt balances necessary to meet general cash requirements and higher interest expense related to balancing account overcollections. The 1999 decrease in interest on long-term debt was due to an adjustment of accrued interest in first quarter 1998 related to the rate reduction notes issued in December 1997.

Other nonoperating deductions decreased in 1999, as expenses related to a ballot initiative in 1998 more than offset additional accruals for regulatory matters in 1999.

The tax benefit on other income and deductions increased in both 2000 and 1999. The increase in 2000 was primarily the result of tax benefits related to interest expense and other nonoperating expenses exceeding the tax expense related to interest income and other nonoperating income. The increase in 1999 was primarily the result of a $15 million one-time tax benefit due to an Internal Revenue Service ruling.

Financial Condition

SCE's liquidity is primarily affected by power purchases, debt maturities, access to capital markets, dividend payments and capital expenditures. Capital resources include cash from operations and external financings. As a result of SCE's lack of creditworthiness (further discussed in Liquidity Crisis), at March 31, 2001, the fair market value of approximately $500 million of its short-term debt was approximately 75% of its carrying value (as compared to 100% at December 31, 2000) and the fair market value of its long-term debt was approximately 90% of its carrying value (as compared to 92% at December 31, 2000).

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

Liquidity Crisis

Sustained higher wholesale energy prices that began in May 2000 persisted through Spring 2001. This resulted in an increasing undercollection in the TRA. The increasing undercollection, coupled with SCE's anticipated near-term capital requirements (detailed in the Projected Capital Requirements section of Financial Condition) 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, have materially and adversely affected SCE's liquidity. As a result of its liquidity crisis, SCE has taken and is taking steps to conserve cash, so that it can continue to provide service to its customers. As a part of this process, SCE has temporarily suspended payments of certain obligations for principal and interest on outstanding debt and for purchased power. As of March 31, 2001, SCE had $2.7 billion in obligations that were unpaid and overdue including: (1) $626 million to the PX or ISO; (2) $1.1 billion to QFs; (3) $229 million in PX energy credits for energy service providers; (4) $506 million of matured commercial paper; (5) $206 million of principal and interest on its 5-7/8% notes; and (6) $7 million of other obligations. SCE's failure to pay when due the principal amount of the 5-7/8% series of notes constitutes a default on the series, entitling those noteholders to exercise their remedies. Such failure and the failure to pay commercial paper when due could also constitute an event of default on all the other series of notes (totaling $2.4 billion of outstanding principal) if the trustee or holders of 25% in principal amount of the notes give a notice demanding that the default be cured, and SCE does not cure the default within 30 days. Such failures are also an event of default under SCE's credit facilities, entitling those lenders to exercise their remedies including potential acceleration of the outstanding borrowings of $1.6 billion. If a notice of default is received, SCE could cure the default only by paying $700 million in overdue principal and interest to holders of commercial paper and the 5-7/8% notes. Making such payment would further impact SCE's liquidity. If a notice of default were received and not cured, and the trustee or noteholders were to declare an acceleration of the outstanding principal amount of the senior unsecured notes, SCE would not have the cash to pay the obligation and could be forced to declare bankruptcy.

Subject to certain conditions, the bank lenders under SCE's credit facilities agreed to forbear from exercising remedies, including acceleration of borrowed amounts, against SCE with respect to the event of default arising from the failure to pay the 5-7/8 notes and commercial paper when due. The initial forbearance agreement expired on February 13, 2001, but it has been extended twice and currently expires on April 28, 2001. At March 31, 2001, SCE had estimated cash reserves of approximately $2.0 billion, which is approximately $700 million less than its outstanding unpaid obligations (discussed above) and overdue amounts of preferred stock dividends (see below). As of March 31, 2001, SCE resumed payment of interest on its debt obligations. If the MOU is implemented, it is expected to allow SCE to recover its undercollected costs and to restore SCE's creditworthiness, which would allow SCE to pay all of its past due obligations.

On March 27, 2001, the CPUC ordered SCE and the other California investor-owned utilities to pay QFs for power deliveries on a going forward basis, commencing with April 2001 deliveries. SCE must pay the QFs within 15 days of the end of the QFs' billing period, and QFs are allowed to establish 15-day billing periods. Failure to make a required payment within 15 days of delivery would result in a fine equal to the amount owed to the QF. The CPUC decision also modified the formula used in calculating payments to QFs by substituting natural gas index prices based on deliveries at the Oregon border rather than index prices at the Arizona border. The changes apply to all QFs, where appropriate, regardless of whether they use natural gas or other resources such as solar or wind.

On March 27, 2001, the CPUC also issued decisions on the California Procurement Adjustment (CPA) calculation (see CDWR Power Purchases discussion) and the approval of a 3¢-per-kWh rate increase (see Rate Stabilization Proceeding discussion). Based on these two decisions, SCE estimates that revenue going forward will not be sufficient to recover retained generation, purchased-power and transition costs. In comments filed with the CPUC on March 29, 2001, and April 2, 2001, SCE provided a forecast showing that the net effects of the rate increase, the payment ordered to be made to the CDWR, and the QF decision discussed above could result in a shortfall to the CPA calculation of $1.7 billion for SCE during 2001. To implement the MOU, it will be necessary for the CPUC to modify or rescind these decisions.

In light of SCE's liquidity crisis, its Board of Directors did not declare quarterly common stock dividends to SCE's parent, Edison International, in either December 2000 or March 2001. Also, SCE's Board has not declared the regular quarterly dividends for SCE's cumulative preferred stock, 4.08% Series, 4.24% Series, 4.32% Series, 4.78% Series, 6.05% Series, 6.45% Series and 7.23% Series in 2001. As of March 31, 2001, SCE's preferred stock dividends in arrears were $6 million. As a result of SCE's $2.5 billion charge to earnings as of December 31, 2000, SCE's retained earnings are now in a deficit position and therefore under California law, SCE will be unable to pay dividends as long as a deficit remains. SCE does not meet other tests under which dividends can be paid from sources other than retained earnings. As long as accumulated dividends on SCE's preferred stock remain unpaid, SCE cannot pay any dividends on its common stock.

SCE has begun immediate cost-cutting measures which, together with previously announced actions, such as freezing new hires, postponing certain capital expenditures and ceasing new charitable contributions, are aimed at reducing general operating costs. These actions were expected to impact about 1,450 to 1,850 jobs, affect service levels for customers, and reduce near-term capital expenditures to levels that will not sustain operations in the long term. However, on March 15, 2001, the CPUC issued an order rescinding SCE's layoffs of employees involved with service and reliability. SCE was also ordered to restore specified service levels, make regular reports to the CPUC concerning its cost-cutting measures, and track its cost savings pending future adjustments to rates. The amount of the cost savings affected by the order is not material. SCE's current actions, including the suspension of debt and purchased-power obligations, are intended to allow it to continue to operate while efforts to reach a regulatory solution, involving both state and federal authorities, are underway. Additional actions by SCE may be necessary if the energy and liquidity crisis is not resolved in the near future. See further discussion in Status of Transition and Power Procurement Costs Recovery.

For additional discussion on the impact of California's energy crisis on SCE's liquidity, see Cash Flows from Financing Activities. For a discussion on an agreement to resolve SCE's crisis, see Memorandum of Understanding with the CDWR.

SCE's future liquidity depends, in large part, on whether the MOU is implemented, or other action by the California Legislature and the CPUC is taken in a manner sufficient to resolve the energy crisis and the cash flow deficit created by the current rate structure and the excessively high price of energy. Without a change in circumstances, such as that contemplated by the MOU, resolution of SCE's liquidity crisis and its ability to continue to operate outside of bankruptcy is uncertain. In addition, SCE's independent accountant's opinion in the accompanying financial statements includes an explanatory paragraph which states that the issues resulting from the California energy crisis raise substantial doubt about SCE's ability to continue as a going concern.

Cash Flows from Operating Activities

Net cash provided by operating activities totaled $829 million in 2000, $1.5 billion in 1999 and $978 million in 1998. The decrease in cash flows provided by operating activities in 2000 was primarily due to the extremely high prices SCE paid for energy and ancillary services procured through the PX and ISO. Cash flows provided by operations is expected to increase in the first half of 2001 as SCE conserves cash as result of the liquidity crisis (see Liquidity Crisis discussion).

SCE's cash flow coverage of dividends was 2.1 times for both 2000 and 1999, and 0.9 times for 1998. The 1999 increase primarily reflects the rate-making treatment of the gains on sales of the generating plants, as well as the special dividend ($680 million) SCE paid to Edison International in 1998. Beginning in first quarter 2001, the cash flow coverage of dividends calculation will reflect SCE's inability to pay dividends (discussed above in the Liquidity Crisis section).

SCE's estimates of cash available for operations in 2001 assume, among other things, satisfactory reimbursement of costs incurred during California's energy crisis, the receipt of adequate and timely rate relief, and the realization of its assumptions regarding cost increases, including the cost of capital.

Cash Flows from Financing Activities

At December 31, 2000, SCE had total credit lines of $1.65 billion, with $125 million available for the refinancing of its variable-rate pollution-control bonds. These unsecured lines of credit have various expiration dates and can be drawn down at negotiated or bank index rates. However, as of January 2, 2001, SCE had drawn on its entire credit lines of $1.65 billion.

Short-term debt is used to finance balancing account undercollections, fuel inventories and general cash requirements, including purchased-power payments. Long-term debt is used mainly to finance capital expenditures. External financings are influenced by market conditions and other factors. Because of the $2.5 billion charge to earnings, SCE does not currently meet the interest coverage ratios that are required for SCE to issue additional first mortgage bonds or preferred stock. In addition, because of its current liquidity and credit problems, SCE is unable to obtain financing of any kind.

As a result of investors' concerns regarding the California energy crisis and its impact on SCE's liquidity and overall financial condition, SCE has repurchased $549 million of pollution-control bonds that could not be remarketed in accordance with their terms. These bonds may be remarketed in the future if SCE's credit status improves sufficiently. In addition, SCE has been unable to sell its commercial paper and other short-term financial instruments.

In January 2001, Fitch IBCA, Standard & Poor's and Moody's Investors Service lowered their credit ratings of SCE to substantially below investment grade. In mid-April, Moody's removed SCE's credit ratings from review for possible downgrade. The ratings remain under review for possible downgrade by the other agencies.

Subject to the outcome of regulatory, legislative and judicial proceedings, including steps to implement the MOU, SCE intends to pay all of its obligations.

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

In December 1997, $2.5 billion of rate reduction notes were issued on behalf of SCE by SCE Funding LLC, a special purpose entity. These notes were issued to finance the 10% rate reduction mandated by state law. The proceeds of the rate reduction notes were used by SCE Funding LLC to purchase from SCE an enforceable right known as transition property. Transition property is a current property right created by the restructuring legislation and a financing order of the CPUC and consists generally of the right to be paid a specified amount from 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 beginning in 2001 and ending in 2007, with interest rates ranging from 6.17% to 6.42%. The notes are secured by the transition property and are not secured by, or payable from, assets of SCE or Edison International. SCE used the proceeds from the sale of the transition property to retire debt and equity securities. Although, as required by accounting principles generally accepted in the United States, SCE Funding LLC is consolidated with SCE and the rate reduction notes are shown as long-term debt in the consolidated financial statements, SCE Funding LLC is legally separate from SCE. The assets of SCE Funding LLC are not available to creditors of SCE or Edison International and the transition property is legally not an asset of SCE or Edison International. Due to its recent credit rating downgrade, in January 2001, SCE began remitting its customer collections related to the rate-reduction notes on a daily basis.

Cash Flows from Investing Activities

Cash flows from investing activities are affected by additions to property and plant and funding of nuclear decommissioning trusts. Decommissioning costs are recovered in 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 review proceeding will provide input into the contribution analysis for that proceeding's contribution determination.

Projected Capital Requirements

SCE's projected construction expenditures for 2001 are $602 million. This projection reflects SCE's recently announced cost-cutting measures discussed above in the Liquidity Crisis section.

Long-term debt maturities and sinking fund requirements for the next five years are: 2001 – $646 million; 2002 – $746 million; 2003 – $1.4 billion; 2004 – $371 million; and 2005 – $246 million.

Preferred stock redemption requirements for the next five years are: 2001– zero; 2002 – $105 million; 2003 – $9 million; 2004 – $9 million; and 2005 – $9 million.

Market Risk Exposures

SCE's primary market risk exposures arise from fluctuations in both energy prices and interest rates. SCE's risk management policy allows the use of derivative financial instruments to manage its financial exposures, but prohibits the use of these instruments for speculative or trading purposes. At December 31, 2000, a 10% change in market rates would have had an immaterial effect on SCE's financial instruments not specifically discussed below.

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

At December 31, 2000, SCE did not believe that its short-term debt was subject to interest rate risk, due to the fair market value being approximately equal to the carrying value. SCE did believe that the fair market value of its fixed-rate long-term debt was subject to interest rate risk. At December 31, 2000, a 10% increase in market interest rates would have resulted in a $222 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 $244 million increase in the fair market value of SCE's long-term debt. See further discussion in Financial Condition of the impact of SCE's lack of creditworthiness on its short-term and long-term debt.

SCE used an interest rate swap to reduce the potential impact of interest rate fluctuations on floating-rate long-term debt. At December 31, 2000, a 10% increase in market interest rates would have resulted in a $5 million increase in the fair value of SCE's interest rate swap. A 10% decrease in market interest rates would have resulted in an $8 million decrease in the fair value of SCE's interest rate swap. As a result of the downgrade in SCE's credit rating below the level allowed under the interest rate hedge agreement, on January 5, 2001, the counterparty on this interest rate swap terminated the agreement. As a result of the termination of the swap, SCE is paying a floating rate on $196 million of its debt due 2008.

Since April 1998, the price SCE paid to acquire power on behalf of customers was allowed to float, in accordance with the 1996 electric utility restructuring law. Until May 2000, retail rates were sufficient to cover the cost of power and other SCE costs. However, since May 2000, market power prices have skyrocketed, creating a substantial gap between costs and retail rates. In response to the dramatically higher prices, the ISO and the FERC have placed certain caps on the price of power, but these caps are set at high levels and are not entirely effective. For example, SCE paid an average of $248 per megawatt in December 2000, versus an average of $32 per megawatt in December 1999.

SCE attempted to hedge a portion of its exposure to increases in power prices. However, the CPUC has approved a very limited amount of hedging. In 1997, SCE bought gas call options as a hedge against electricity price increases, since gas is a primary component for much of SCE's power supply. These gas call options were sold in October 2000, resulting in a $190 million gain (lowering purchased-power expense) for 2000. In July 1999, SCE began forward purchases of electricity through the PX block forward market. In November 2000, SCE began purchases of energy through bilateral forward contracts. At December 31, 2000, the nominal value of SCE's block and bilateral forward contracts was $234 million and $798 million, respectively. The block forward contracts reduced purchased-power costs by $684 million in 2000.

At December 31, 2000, a 10% fluctuation in electricity prices would have changed the fair market value of SCE's forward contracts by $187 million.

Because SCE has temporarily suspended payments for purchased power since January 16, 2001, the PX sought to liquidate SCE's remaining block forward contracts. Before the PX could do so, on February 2, 2001, the State of California seized the contracts, but must pay SCE the reasonable value of the contracts under the law. A valuation of the contracts is expected in mid-2001. After other elements of the MOU are implemented, SCE would relinquish all claims against the State for seizing these contracts.

Due to its speculative grade credit ratings, SCE has been unable to purchase additional bilateral forward contracts, and some of the existing contracts were terminated by the counterparties.

In January 2001, the CDWR began purchasing power for delivery to utility customers. On March 27, 2001, the CPUC issued a decision directing SCE to, among other things, immediately pay amounts owed to the CDWR for certain past purchases of power for SCE's customers. See additional discussion of regulatory proceedings related to CDWR activities in the Generation and Power Procurement section of Regulatory Environment.

Regulatory Environment

SCE operates in a highly regulated environment in which it has an obligation to deliver electric service to customers in return for an exclusive franchise within its service territory and certain obligations of the regulatory authorities to provide just and reasonable rates. In 1996, state lawmakers and the CPUC initiated the electric industry restructuring process. SCE was directed by the CPUC to divest the bulk of its gas-fired generation portfolio. Today, independent power companies own those generating plants. Along with electric industry restructuring, a multi-year freeze on the rates that SCE could charge its customers was mandated and transition cost recovery mechanisms (as described in Status of Transition and Power Procurement Costs Recovery) allowing SCE to recover its stranded costs associated with generation-related assets were implemented. California's electric industry restructuring statute included provisions to finance a portion of the stranded costs that residential and small commercial customers would have paid between 1998 and 2001, which allowed SCE to reduce rates by at least 10% to these customers, effective January 1, 1998. These frozen rates 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. However, since May 2000, the prices charged by sellers of power have escalated far beyond what SCE can currently charge its customers. See further discussion in Wholesale Electricity Markets.

Generation and Power Procurement

During the rate freeze, revenue from generation-related operations has been determined through the market and transition cost recovery mechanisms, which included the nuclear rate-making agreements. The portion of revenue related to coal generation plant costs (Mohave Generating Station and Four Corners Generating Station) that was made uneconomic by electric industry restructuring has been recovered through the transition cost recovery mechanisms. After April 1, 1998, coal generation operating costs have been recovered through the market. The excess of power sales revenue from the coal generating plants over the plants' operating costs has been accumulated in a coal generation balancing account. SCE's costs associated with its hydroelectric plants have been recovered through a performance-based mechanism. The mechanism set the hydroelectric revenue requirement and established a formula for extending it through the duration of the electric industry restructuring transition period, or until market valuation of the hydroelectric facilities, whichever occurred first. The mechanism provided that power sales revenue from hydroelectric facilities in excess of the hydroelectric revenue requirement is accumulated in a hydroelectric balancing account. In accordance with a CPUC decision issued in 1997, the credit balances in the coal and hydroelectric balancing accounts were transferred to the TCBA at the end of 1998 and 1999. However, due to the CPUC's March 27, 2001, rate stabilization decision, the credit balances in these balancing accounts have now been transferred to the TRA on a monthly basis, retroactive to January 1, 1998. In addition, the TRA balance, whether over- or undercollected, has now been transferred to the TCBA on a monthly basis, retroactive to January 1, 1998. Due to a December 15, 2000, FERC order, SCE is no longer required to buy and sell power exclusively through the ISO and PX. In mid-January 2001, the PX suspended SCE's trading privileges for failure to post collateral due to SCE's rating agency downgrades. As a result, power from SCE's coal and hydroelectric plants is no longer being sold through the market and these two balancing accounts have become inactive. As a key element of the MOU, SCE would continue to own its generation assets, which would be subject to cost-based ratemaking, through 2010. The MOU calls for the CPUC to adopt cost recovery mechanisms consistent with SCE obtaining and maintaining an investment grade credit rating.

SCE has been recovering its investment in its nuclear facilities on an accelerated basis in exchange for a lower authorized rate of return on investment. SCE's nuclear assets are earning an annual rate of return on investment of 7.35%. In addition, the San Onofre incentive pricing plan authorizes a fixed rate of approximately 4¢ per kWh generated for operating costs including incremental capital costs, nuclear fuel and nuclear fuel financing costs. The San Onofre plan commenced in April 1996, and ends at the earlier of December 2001 or the date when the statutory rate freeze ends for the accelerated recovery portion, and in December 2003 for the incentive-pricing portion. The Palo Verde Nuclear Generating Station's operating costs, including incremental capital costs, and nuclear fuel and nuclear fuel financing costs, are subject to balancing account treatment. The Palo Verde plan commenced in January 1997 and ends in December 2001. The benefits of operation of the San Onofre units and the Palo Verde units are required to be shared equally with ratepayers beginning in 2004 and 2002, respectively. Beginning January 1, 1998, both the San Onofre and Palo Verde rate-making plans became part of the TCBA mechanism. These rate-making plans and the TCBA mechanism will continue for rate-making purposes at least through the end of the rate freeze period. Under the MOU, both nuclear facilities would be subject to cost-based ratemaking upon completion of their respective rate-making plans and the sharing mechanisms that were to begin in 2004 and 2002 would be eliminated. However, due to the various unresolved regulatory and legislative issues (as discussed in Status of Transition and Power Procurement Costs Recovery), SCE is no longer able to conclude that the unamortized nuclear investment regulatory assets (as discussed in Accounting for Generation-Related Assets and Power Procurement Costs) are probable of recovery through the rate-making process. As a result, these balances were written off as a charge to earnings as of December 31, 2000 (see further discussion in Earnings).

In 1999, SCE filed an application with the CPUC establishing a market value for its hydroelectric generation-related assets at approximately $1.0 billion (almost twice the assets' book value) and proposing to retain and operate the hydroelectric assets under a performance-based, revenue-sharing mechanism. If approved by the CPUC, SCE would be allowed to recover an authorized, inflation-indexed operations and maintenance allowance, as well as a reasonable return on capital investment. A revenue-sharing arrangement would be activated if revenue from the sale of hydroelectricity exceeds or falls short of the authorized revenue requirement. SCE would then refund 90% of the excess revenue to ratepayers or recover 90% of any shortfalls from ratepayers. If the MOU is implemented, SCE's hydroelectric assets will be retained through 2010 under cost-based rates, or they may be sold to the State if a sale of SCE's transmission assets is not completed under certain circumstances. In June 2000, SCE credited the TCBA with the estimated excess of market value over book value of its hydroelectric generation assets and simultaneously recorded the same amount in the generation asset balancing account (GABA), pursuant to a CPUC decision. This balance was to remain in GABA until final market valuation of the hydroelectric assets. If there were a difference in the final market value, it would have been credited to or recovered from customers through the TCBA. Due to the various unresolved regulatory and legislative issues (as discussed in Status of Transition and Power Procurement Costs Recovery), the GABA transaction was reclassified back to the TCBA, and as discussed in the Earnings section, the TCBA balance (as recalculated based on a March 27, 2001, CPUC interim decision discussed in Rate Stabilization

Proceeding) was written off as of December 31, 2000.

During 2000, SCE entered into agreements to sell the Mohave, Palo Verde and Four Corners generation stations. The sales were pending various regulatory approvals. Due to the shortage of electricity in California and the increasing wholesale costs, state legislation was enacted in January 2001 barring the sale of utility generation stations until 2006. Under the MOU, SCE would continue to retain its generation assets through 2010.

CDWR Power Purchases

Pursuant to an emergency order signed by the Governor, the CDWR began making emergency power purchases for SCE's customers on January 18, 2001. On February 1, 2001, AB 1X was enacted into law. The new law authorized the CDWR to enter into contracts to purchase electric power and sell power at cost directly to retail customers being served by SCE, and authorized the CDWR to issue revenue bonds to finance electricity purchases. The new law directed the CPUC to determine the amount of a CPA as a residual amount of SCE's generation-related revenue, after deducting the cost of SCE-owned generation, QF contracts, existing bilateral contracts and ancillary services. The new law also directed the CPUC to determine the amount of the CPA that is allocable to the power sold by the CDWR which will be payable to the CDWR when received by SCE. On March 7, 2001, the CPUC issued an interim order in which it held that the CDWR's purchases are not subject to prudency review by the CPUC, and that the CPUC must approve and impose, either as a part of existing rates or as additional rates, rates sufficient to enable the CDWR to recover its revenue requirements.

On March 27, 2001, the CPUC issued an interim CDWR-related order requiring SCE to pay the CDWR a per-kWh price equal to the applicable generation-related retail rate per kWh for electricity (based on rates in effect on January 5, 2001), for each kWh the CDWR sells to SCE's customers. The CPUC determined that the generation-related retail rate should be equal to the total bundled electric rate (including the 1¢-per-kWh temporary surcharge adopted by the CPUC on January 4, 2001) less certain non-generation related rates or charges. For the period January 19 through January 31, 2001, the CPUC ordered SCE to pay the CDWR at a rate of 6.277¢ per kWh. The CPUC determined that the company-wide generation-related rate component is 7.277¢ per kWh (which will increase to 10.277¢ per kWh for electricity delivered after March 27, 2001, due to the 3¢-surcharge discussed in Rate Stabilization Proceeding), for each kWh delivered to customers beginning February 1, 2001, until more specific rates are calculated. The CPUC ordered SCE to pay the CDWR within 45 days after the CDWR supplies power to retail customers. Using these rates, SCE has billed customers $196 million for energy sales made by the CDWR during the period January 19 through March 31, 2001, and has forwarded $52 million to the CDWR on behalf of these customers as of March 31, 2001.

On April 3, 2001, the CPUC adopted the method (originally proposed in the March 27 CDWR-related order discussed above) it will use to calculate the CPA (which was established by AB 1X) and then applied the method to calculate a company-wide CPA rate for SCE. The CPUC used that rate to determine the CPA revenue amount that can be used by the CDWR for issuing bonds. The CPUC stated that its decision is narrowly focused to calculate the maximum amount of bonds that the CDWR may issue and does not dedicate any particular revenue stream to the CDWR. The CPUC determined that SCE's CPA rate is 1.120¢ per kWh, which generates annual revenue of $856 million. In its calculation of the CPA, the CPUC disregarded all of the adjustments requested by SCE in its comments filed on March 29 and April 2, 2001. SCE's comments included, among other things, a forecast showing that the net effect of the rate increases (discussed in Rate Stabilization Proceeding), as well as the March 27 QF payment decision (discussed in Liquidity Crisis) and the payments ordered to be made to CDWR (discussed above), could result in a shortfall in the CPA calculation of $1.7 billion for SCE during 2001. SCE estimates that its future revenue will not be sufficient to cover its retained generation, purchased-power and transition costs. To implement the MOU described in Memorandum of Understanding with CDWR, the CPUC will need to modify the calculation methods and provide reasonable assurance that SCE will be able to recover its ongoing costs.

SCE believes that the intent of AB 1X was for the CDWR to assume full responsibility for purchasing all power needed to serve the retail customers of electric utilities, in excess of the output of generating plants owned by the electric utilities and power delivered to the utilities under existing contracts. However, the CDWR has stated that it is only purchasing power that it considers to be reasonably priced, leaving the ISO to purchase in the short-term market the additional power necessary to meet system requirements. The ISO, in turn, takes the position that it will charge SCE for the costs of power it purchases in this manner. If SCE is found responsible for any portion of the ISO's purchases of power for resale to SCE's customers, SCE will continue to incur purchased-power costs in addition to the unpaid costs described above. In its March 27, 2001, interim order, the CPUC stated that it can not assume that the CDWR will pay for the ISO purchases and that it does not have the authority to order the CDWR to do so. Litigation among certain power generators, the ISO and the CDWR (to which SCE is not a party), and proceedings before the FERC (to which SCE is a party), may result in rulings clarifying the CDWR's financial responsibility for purchases of power. On April 6, 2001, the FERC issued an order confirming that the ISO must have a creditworthy buyer for any transactions. In any event, SCE takes the position that it is not responsible for purchases of power by the CDWR or the ISO on or after January 18, 2001, the day after the Governor signed the order authorizing the CDWR to begin purchasing power for utility customers. SCE cannot predict the outcome of any of these proceedings or issues. The recently executed MOU states that the CDWR will assume the entire responsibility for procuring the electricity needs of retail customers within SCE's service territory through December 31, 2002, to the extent those needs are not met by generation sources owned by or under contract to SCE (SCE's net short position). SCE will resume buying power for its net short position after 2002. The MOU calls for the CPUC to adopt cost recovery mechanisms to make it financially practicable for SCE to reassume this responsibility.

Status of Transition and Power Procurement Costs Recovery

SCE's transition costs include power purchases from QF contracts (which are the direct result of prior legislative and regulatory mandates), recovery of certain generating assets and regulatory commitments consisting of recovery of costs incurred to provide service to customers. Such commitments include the recovery of income tax benefits previously flowed through to customers, postretirement benefit transition costs, accelerated recovery of investment in San Onofre Units 2 and 3 and the Palo Verde units, and certain other costs. Transition costs related to power-purchase contracts are being recovered through the terms of each contract. Most of the remaining transition costs may be recovered through the end of the transition period (not later than March 31, 2002). Although the MOU provides for, among other things, SCE to be entitled to sufficient revenue to cover its costs from January 2001 associated with retained generation and existing power contracts, the implementation of the MOU requires the CPUC to modify various decisions (discussed in Rate Stabilization Proceeding). Until the various regulatory and legislative actions necessary to implement the MOU, or other actions that make such recovery probable are taken, SCE is not able to conclude that the regulatory assets and liabilities related to purchased-power settlements, the unamortized loss on SCE's generating plant sales in 1998, and various other regulatory assets and liabilities (including income taxes previously flowed through to customers) related to certain generating assets are probable of recovery through the rate-making process. As a result, these balances were written off as a charge to earnings as of December 31, 2000 (see further discussion in Earnings).

During the rate freeze period, there are three sources of revenue available to SCE for transition cost recovery: revenue from the sale or valuation of generation assets in excess of book values, net market revenue from the sale of SCE-controlled generation into the ISO and PX markets, and competition transition charge (CTC) revenue. However, due to events discussed elsewhere in this report, revenue from the sale or valuation of generation assets in excess of book values (state legislation enacted in January 2001 bars the sale of SCE's remaining generation assets until 2006) and from the sale of SCE-controlled generation into the ISO and PX markets (see discussion in Generation and Power Procurement) are no longer available to SCE. During 1998, SCE sold all of its gas-fueled generation plants for $1.2 billion, over $500 million more than the combined book value. Net proceeds of the sales were used to reduce transition costs, which otherwise were expected to be collected through the TCBA mechanism.

Net market revenue from sales of power and capacity from SCE-controlled generation sources was also applied to transition cost recovery. Increases in market prices for electricity affected SCE in two fundamental ways prior to the CPUC's March 27, 2001, rate stabilization decision. First, CTC revenue decreased because there was less or no residual revenue from frozen rates due to higher cost PX and ISO power purchases. Second, transition costs decreased because there was increased net market revenue due to sales from SCE-controlled generation sources to the PX at higher prices (accumulated as an overcollection in the coal and hydroelectric balancing accounts). Although the second effect mitigated the first to some extent, the overall impact on transition cost recovery was negative because SCE purchased more power than it sold to the PX. In addition, higher market prices for electricity adversely affected SCE's ability to recover non-transition costs during the rate freeze period. Since May 2000, market prices for electricity were extremely high and there was insufficient revenue from customers under the frozen rates to cover all costs of providing service during that period, and therefore there was no positive residual CTC revenue transferred into the TCBA.

CTC revenue is determined residually (i.e., CTC revenue is the residual amount remaining from monthly gross customer revenue under the rate freeze after subtracting the revenue requirements for transmission, distribution, nuclear decommissioning and public benefit programs, and ISO payments and power purchases from the PX and ISO). The CTC applies to all customers who are using or begin using utility services on or after the CPUC's 1995 restructuring decision date. Residual CTC revenue is calculated through the TRA mechanism. Under CPUC decisions in existence prior to March 27, 2001, positive residual CTC revenue (TRA overcollections) was transferred to the TCBA monthly; TRA undercollections were to remain in the TRA until they were offset by overcollections, or the rate freeze ended, whichever came first. Pursuant to the March 27, 2001, rate stabilization decision, both positive and negative residual CTC revenue is transferred to the TCBA on a monthly basis, retroactive to January 1, 1998 (see further discussion in Rate Stabilization Proceeding).

Upon recalculating the TCBA balance based on the new decision, SCE has received positive residual CTC revenue (TRA overcollections) of $4.7 billion to recover its transition costs from the beginning of the rate freeze (January 1, 1998) through April 2000. As a result of sustained higher market prices, SCE experienced the first month in which costs exceeded revenue in May 2000. Since then, SCE's costs to provide power have continued to exceed revenue from frozen rates and as a result, the cumulative positive residual CTC revenue flowing into the TCBA mechanism has been reduced from $4.7 billion to $1.4 billion as of December 31, 2000. The cumulative TCBA undercollection (as recalculated) is $2.9

billion as of December 31, 2000. A summary of the components of this cumulative undercollection is as follows:

In millions	
Transition costs recorded in the TCBA:	
QF and interutility costs	$3,561
Amortization of nuclear-related regulatory assets	3,090
Depreciation of plant assets	577
Other transition costs	634
Total transition costs	7,862
Revenue available to recover transition costs	(4,984)
Unrecovered transition costs	$2,878

Unless the regulatory and legislative actions required to implement the MOU, or other actions that make such recovery probable are taken, SCE is not able to conclude that the recalculated TCBA net undercollection is probable of recovery through the rate-making process. As a result, the $2.9 billion TCBA net undercollection was written off as a charge to earnings as of December 31, 2000 (see further discussion in Earnings). In its interim rate stabilization decision of March 27, 2001, the CPUC denied a December motion by SCE to end the rate freeze, and stated that it will not end until recovery of all specified transition costs (including TCBA undercollections as recalculated) or March 31, 2002. For more details on the matters discussed above, see Rate Stabilization Proceeding.

Litigation

In November 2000, SCE filed a lawsuit against the CPUC in federal court in California, seeking a ruling that SCE is entitled to full recovery of its past electricity procurement costs in accordance with the tariffs filed with the FERC. The effect of such a ruling would be to overturn the prior decisions of the CPUC restricting recovery of TRA undercollections. In January 2001, the court denied the CPUC's motion to dismiss the action and also denied SCE's motion for summary judgment without prejudice. In February 2001, the court denied SCE's motion for a preliminary injunction ordering the CPUC to institute rates sufficient to enable SCE to recover its past procurement costs, subject to refund. The court granted, in part, SCE's additional motion to specify certain material facts without substantial controversy, but denied the remainder of the motion and declined to declare at that time that SCE is entitled to recover the amount of its undercollected procurement costs. In March 2001, the court directed the parties to be prepared for trial on July 31, 2001. As discussed in the Memorandum of Understanding with the CDWR, after the other elements of the MOU are implemented, SCE will enter into a settlement of or dismiss its lawsuit against the CPUC seeking recovery of past undercollected costs. The settlement or dismissal will include related claims against the State of California or any of its agencies, or against the federal government. SCE cannot predict whether or when a favorable final judgment or other resolution would be obtained in this legal action, if it were to proceed to trial.

In December 2000, a first amended complaint to a class action securities lawsuit (originally filed in October 2000) was filed in federal district court in Los Angeles against SCE and Edison International. On March 5, 2001, a second amended complaint was filed that alleges that SCE and Edison International are engaging in fraud by over-reporting and improperly accounting for the TRA undercollections. The second amended complaint is supposedly filed on behalf of a class of persons who purchased Edison International common stock beginning June 1, 2000, and continuing until such time as TRA-related undercollections are recorded as a loss on SCE's income statement. The response to the second amended complaint was due April 2, 2001. The response has been deferred pending resolution of motions to consolidate this lawsuit with the March 15, 2001, lawsuit discussed below. SCE believes that its current and past accounting for the TRA undercollections and related items, as described above, is appropriate and in accordance with accounting principles generally accepted in the United States.

On March 15, 2001, a purported class action lawsuit was filed in federal district court in Los Angeles against Edison International and SCE and certain of their officers. The complaint alleges that the defendants engaged in securities fraud by misrepresenting and/or failing to disclose material facts concerning the financial condition of Edison International and SCE, including that the defendants allegedly over-reported income and improperly accounted for the TRA undercollections. The complaint is supposedly filed on behalf of a class of persons who purchased all publicly traded securities of Edison International between May 12, 2000, and December 22, 2000. Pursuant to an agreement with Edison International and SCE, this lawsuit is expected to be consolidated with the October 20, 2000, lawsuit discussed above, pending the court's approval.

In addition to the two lawsuits filed against SCE and discussed above, as of April 13, 2001, 17 additional lawsuits have been filed against SCE by QFs. The lawsuits have been filed by various parties, including geothermal or wind energy suppliers or owners of cogeneration projects. The lawsuits are seeking payments of at least $420 million for energy and capacity supplied to SCE under QF contracts, and in some cases for damages as well. Many of these QF lawsuits also seek an order allowing the suppliers to stop providing power to SCE and sell the power to other purchasers. SCE is seeking coordination of all of the QF-related lawsuits that have commenced in various California courts. On April 13, 2001, an order was issued assigning all pending cases to a coordination motion judge and setting a hearing on SCE's coordination petition by May 30, 2001. SCE cannot predict the outcome of any of these matters.

Rate Stabilization Proceeding

In January 2000, SCE filed an application with the CPUC proposing rates that would go into effect when the current rate freeze ends on March 31, 2002, or earlier, depending on the pace of transition cost recovery. On December 20, 2000, SCE filed an amended rate stabilization plan application, stating that the CPUC must recognize that the statutory rate freeze is now over in accordance with California law, and requesting the CPUC to approve an immediate 30% increase to be effective, subject to refund, January 4, 2001. SCE's plan included a trigger mechanism allowing for rate increases of 5% every six months if SCE's TRA undercollection balance exceeds $1 billion. Hearings were held in late December 2000.

On January 4, 2001, the CPUC issued an interim decision that authorized SCE to establish an interim surcharge of 1¢ per kWh for 90 days, subject to refund (see additional discussion below). The revenue from the surcharge is being tracked through a balancing account and applied to ongoing power procurement costs. The surcharge resulted in rate increases, on average, of approximately 7% to 25%, depending on the class of customer. As noted in the decision, the 90-day period allowed independent auditors engaged by the CPUC to perform a comprehensive review of SCE's financial position, as well as that of Edison International and other affiliates.

On January 29, 2001, independent auditors hired by the CPUC issued a report on the financial condition and solvency of SCE and its affiliates. The report confirmed what SCE had previously disclosed to the CPUC in public filings about SCE's financial condition. The audit report covers, among other things, cash needs, credit relationships, accounting mechanisms to track stranded cost recovery, the flow of funds between SCE and Edison International, and earnings of SCE's California affiliates. On April 3, 2001, the CPUC adopted an order instituting investigation (originally proposed on March 15, 2001). The order reopens past CPUC decisions authorizing the utilities to form holding companies and initiates an investigation into: whether the holding companies violated requirements to give priority to the capital needs of their respective utility subsidiaries; whether ring-fencing actions by Edison International and PG&E Corporation and their respective nonutility affiliates also violated the requirements to give priority to the capital needs of their utility subsidiaries; whether the payment of dividends by the utilities violated requirements that the utilities maintain dividend policies as though they were comparable stand-alone utility companies; any additional suspected violations of laws or CPUC rules and decisions; and whether additional rules, conditions, or other changes to the holding company decisions are necessary. An assigned commissioner's ruling on March 29, 2001, required SCE to respond within 10 days to document requests and questions that are substantially identical to those included in the March 15 proposed order instituting investigation. The MOU calls for the CPUC to adopt a decision clarifying that the first priority condition in SCE's holding company decision refers to equity investment, not working capital for operating costs. SCE cannot provide assurance that the CPUC will adopt such a decision, or predict what effects any investigation or any subsequent actions by the CPUC may have on SCE.

In its interim rate stabilization order adopted on March 27, 2001, the CPUC granted SCE a rate increase in the form of a 3¢-per-kWh surcharge applied only to electric power costs, effective immediately, and affirmed that the 1¢ interim surcharge granted on January 4, 2001, is now permanent. Although the 3¢-increase was authorized immediately, the surcharge will not be collected in rates until the CPUC establishes an appropriate rate design, which is not expected to occur until May 2001. SCE has asked the CPUC to immediately adopt an interim rate increase that would allow the rate change to go into effect sooner. The CPUC also ordered that the 3¢-surcharge be added to the rate paid to the CDWR pursuant to the interim CDWR-related decision (see CDWR Power Purchases).

Also, in the interim order, the CPUC granted a petition previously filed by The Utility Reform Network and directed that the balance in SCE's TRA, whether over- or undercollected, be transferred on a monthly basis to the TCBA, retroactive to January 1, 1998. Previous rules called only for TRA overcollections (residual CTC revenue) to be transferred to the TCBA. The CPUC also ordered SCE to transfer the coal and hydroelectric balancing account overcollections to the TRA on a monthly basis before any transfer of residual CTC revenue to the TCBA, retroactive to January 1, 1998. Previous rules called for overcollections in these two balancing accounts to be transferred directly to the TCBA on an annual basis (see further discussion of the recalculation of the TCBA in Status of Transition and Power Procurement Costs Recovery). SCE believes this interim order attempts to retroactively transform power purchase costs in the TRA into transition costs in the TCBA. However, the CPUC characterized the accounting changes as merely reducing the prior residual CTC revenue recorded in the TCBA, thus only affecting the amount of transition cost recovery achieved to date. Based upon the transfer of balances into the TCBA, the CPUC denied SCE's December 2000 filing to have the current rate freeze end, and stated that it will not end until recovery of all specified transition costs or March 31, 2002; and that balances in the TRA cannot be recovered after the end of the rate freeze. The CPUC also said that it would monitor the balances remaining in the TCBA and consider how to address remaining balances in the ongoing proceeding. If the CPUC does not modify this decision in a manner consistent with the MOU, SCE intends to challenge this decision through all appropriate means.

Although the CPUC has authorized a substantial rate increase in its March 27, 2001, order, it has allocated the revenue from the increase entirely to future purchased-power costs without addressing SCE's past undercollections for the costs of purchased power. The CPUC's decisions do not assure that SCE will be able to meet its ongoing obligations or repay past due obligations. By ordering immediate payments to the CDWR and QFs, the CPUC aggravated SCE's cash flow and liquidity problems. Additionally, the CPUC expressed the view that AB 1X continues the utilities' obligations to serve their customers, and stated that it cannot assume that the CDWR will purchase all the electricity needed above what the utilities either generate or have under contract (the net short position) and cannot order the CDWR to do so. This could result in additional purchased power costs with no allowed means of recovery. To implement the MOU, it will be necessary for the CPUC to modify or rescind these decisions. SCE cannot provide any assurance that the CPUC will do so.

Accounting for Generation-Related Assets and Power Procurement Costs

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

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

The implementation of the MOU requires various regulatory and legislative actions to be taken in the future. Unless those actions or other actions that make such recovery probable are taken, which would include modifying or reversing recent CPUC decisions that impair recovery of SCE's power procurement and transition costs, SCE is not able to conclude that its $2.9 billion TCBA undercollection (as redefined in the March 27 decisions) and $1.3 billion (book value) of its generation-related regulatory assets and liabilities to be amortized into the TCBA, are probable of recovery through the rate-making process. As a result, accounting principles generally accepted in the United States require that the balances in the accounts be written off as a charge to earnings as of December 31, 2000 (see Earnings).

As discussed below, an MOU has been negotiated with representatives of the Governor as a step to resolving the energy crisis. The regulatory and legislative actions set forth in the MOU, if implemented, are expected to result in a rate-making mechanism that would make recovery of these regulatory assets probable. If and when those actions, or other actions that make such recovery probable are taken, and the necessary rate-making mechanism is adopted, the regulatory assets would be restored to the balance sheet, with a corresponding increase to earnings.

Memorandum of Understanding with the CDWR

On April 9, 2001, SCE signed an MOU with the CDWR regarding the California energy crisis and its effects on SCE. The Governor of California and his representatives participated in the negotiation of the MOU, and the Governor endorsed implementation of all the elements of the MOU. The MOU sets forth a comprehensive plan calling for legislation, regulatory action and definitive agreements to resolve important aspects of the energy crisis, and which, if implemented, is expected to help restore SCE's creditworthiness and liquidity. Key elements of the MOU include:

- SCE will sell its transmission assets to the CDWR, or another authorized California state agency, at a price equal to 2.3 times their aggregate book value, or approximately $2.76 billion. If a sale of the transmission assets is not completed under certain circumstances, SCE's hydroelectric assets and other rights may be sold to the state in their place. SCE will use the proceeds of the sale in excess of book value to reduce its undercollected costs and retire outstanding debt incurred in financing those costs. SCE will agree to operate and maintain the transmission assets for at least three years, for a fee to be negotiated.

- Two dedicated rate components will be established to assist SCE in recovering the net undercollected amount of its power procurement costs through January 31, 2001, estimated to be approximately $3.5 billion. The first dedicated rate component will be used to securitize the excess of the undercollected amount over the expected gain on sale of SCE's transmission assets, as well as certain other costs. Such securitization will occur as soon as reasonably practicable after passage of the necessary legislation and satisfaction of other conditions of the MOU. The second dedicated rate component would not be securitized and would not appear in rates unless the transmission sale failed to close within a two-year period. The second component is designed to allow SCE to obtain bridge financing of the portion of the undercollection intended to be recovered through the gain on the transmission sale.

- SCE will continue to own its generation assets, which will be subject to cost-based ratemaking, through 2010. SCE will be entitled to collect revenue sufficient to cover its costs from January 1, 2001, associated with the retained generation assets and existing power contracts. The MOU calls for the CPUC to adopt cost recovery mechanisms consistent with SCE obtaining and maintaining an investment grade credit rating.

- The CDWR will assume the entire responsibility for procuring the electricity needs of retail customers within SCE's service territory through December 31, 2002, to the extent that those needs are not met by generation sources owned by or under contract to SCE. (The unmet needs are referred to as SCE's net short position.) SCE will resume procurement of its net short position after 2002. The MOU calls for the CPUC to adopt cost recovery mechanisms to make it financially practicable for SCE to reassume this responsibility.

- SCE's authorized return on equity will not be reduced below its current level of 11.6% before December 31, 2010. Through the same date, a rate-making capital structure for SCE will not be established with different proportions of common equity or preferred equity to debt than set forth in current authorizations. These measures are intended to enable SCE to achieve and maintain an investment grade credit rating.

- Edison International and SCE will commit to make capital investments in SCE's regulated businesses of at least $3 billion through 2006, or a lesser amount approved by the CPUC. The equity component of the investments will be funded from SCE's retained earnings or, if necessary, from equity investments by Edison International.

- An affiliate of Edison International will execute a contract with the CDWR or another state agency for the provision of power to the state at cost-based rates for 10 years from a power project currently under development. The Edison International affiliate will use all commercially reasonable efforts to place the first phase of the project into service before the end of summer 2001.

- SCE will grant perpetual conservation easements over approximately 21,000 acres of lands associated with SCE's Big Creek and Eastern Sierra hydroelectric facilities. The easements initially will be held by a trust for the benefit of the State of California, but ultimately may be assigned to nonprofit entities or certain governmental agencies. SCE will be permitted to continue utility uses of the subject lands.

- After the other elements of the MOU are implemented, SCE will enter into a settlement of or dismiss its federal district court lawsuit against the CPUC seeking recovery of past undercollected costs. The settlement or dismissal will include related claims against the State of California or any of its agencies, or against the federal government.

The sale of SCE's transmission system and other elements of the MOU must be approved by the FERC. SCE and the CDWR committed in the MOU to proceed in good faith to sponsor and support the required legislation and to negotiate in good faith the necessary definitive agreements. The MOU may be terminated by either SCE or the CDWR if required legislation is not adopted and definitive agreements executed by August 15, 2001, or if the CPUC does not adopt required implementing decisions within 60 days after the MOU was signed, or if certain other adverse changes occur. SCE cannot provide assurance that all the required legislation will be enacted, regulatory actions taken, and definitive agreements executed before the applicable deadlines.

Distribution

Revenue related to distribution operations is determined through a performance-based rate-making (PBR) mechanism and the distribution assets have the opportunity to earn a CPUC-authorized 9.49% return on investment. The distribution PBR will extend through December 2001. Key elements of the distribution PBR include: distribution rates indexed for inflation based on the Consumer Price Index less a productivity factor; adjustments for cost changes that are not within SCE's control; a cost-of-capital trigger mechanism based on changes in a utility bond index; standards for customer satisfaction; service reliability and safety; and a net revenue-sharing mechanism that determines how customers and shareholders will share gains and losses from distribution operations.

Transmission

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

Wholesale Electricity Markets

In October 2000, SCE filed a joint petition urging the FERC to immediately find the California wholesale electricity market to be not workably competitive; immediately impose a cap on the price for energy and ancillary services; and institute further expedited proceedings regarding the market failure, mitigation of market power, structural solutions and responsibility for refunds. On December 15, 2000, the FERC released a final order containing remedies and other actions in response to the problems in the California electricity market. The order, among other things, eliminated the requirement for California utilities to buy and sell power exclusively through the ISO and PX; created a benchmark price for wholesale bilateral power contracts; created penalties for under-scheduling power loads; provided for an independent governing board for the ISO; and established a breakpoint of $150/MWh so that bids below $150 may clear at a single market-clearing price at or below $150/MWh and bids above $150 will be paid as bid. On December 18, 2000, SCE filed with the FERC an emergency request for rehearing and expedited action seeking reconsideration of the December 15 order. On January 12, 2001, the FERC issued an order granting rehearing for the purpose of further consideration. The PX did not immediately implement the $150/MWh breakpoint and on February 26, 2001, made a compliance filing with the FERC, which requested the FERC's guidance on an acceptable recalculation methodology. On April 6, 2001, the FERC issued an order providing guidance to the PX, which should reduce SCE's energy costs owed to the PX for the month of January 2001.

On December 13, 2000, the ISO announced that generators of electricity were refusing to sell into the California market due to concerns about the financial stability of SCE and Pacific Gas and Electric Company. In response to this announcement, on December 14, 2000, the United States Secretary of Energy issued an order requiring power companies to make arrangements to generate and deliver electricity as requested by the ISO after the ISO certifies that it has been unable to acquire adequate supplies of electricity in the market. After being renewed multiple times, the order expired on February 6, 2001. However, on February 7, 2001, a federal court judge issued a temporary restraining order requiring power suppliers to sell to the California grid. On March 21, 2001, a federal court judge ordered one of the power suppliers to continue to sell power to the California grid. Three other power suppliers have signed an agreement with the judge voluntarily agreeing to continue to sell power to the grid while awaiting a review of the issue by the FERC. On April 6, 2001, the United States Court of Appeals issued a stay order, suspending the lower court's March 21 order until a final appeals ruling can be issued.

On December 26, 2000, SCE filed an emergency petition in the federal Court of Appeals challenging the FERC order and seeking a writ of mandamus requiring the FERC to immediately establish cost-based wholesale rates. On January 5, 2001, the court denied SCE's petition. The effect of the denial is to leave in place the FERC's market controls that have allowed wholesale prices to climb to current levels. SCE's petition for rehearing remains pending. SCE cannot predict what action the FERC may take. SCE is considering the possibility of judicial appeals and other actions.

On March 9, 2001, the FERC directed 13 wholesale sellers of energy to refund $69 million or submit cost-of-service information to the FERC to justify their prices above $273/MWh during ISO Stage 3 emergencies in January 2001. SCE will oppose the order as inadequate, particularly because the FERC is unwilling to exercise any control over the sellers' exercise of market power during periods other than Stage 3 emergencies. On March 16, 2001, the FERC ordered six wholesale sellers of energy to refund an additional $55 million or submit cost-of-service information to the FERC to justify their prices above $430/MWh during ISO Stage 3 emergencies in February 2001. A Stage 3 emergency refers to 1.5% or less in reserve power, which could trigger rotating blackouts in some neighborhoods.

Environmental Protection

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

As further discussed in Note 12 to the Consolidated Financial Statements, SCE records its environmental liabilities when site assessments and/or remedial actions are probable and a range of reasonably likely cleanup costs can be estimated. SCE's recorded estimated minimum liability to remediate its 44 identified sites is $114 million. SCE believes that, due to uncertainties inherent in the estimation process, it is reasonably possible that cleanup costs could exceed its recorded liability by up to $272 million. In 1998, SCE sold all of its gas-fueled power plants but has retained some liability associated with the divested properties.

The CPUC allows SCE to recover environmental-cleanup costs at certain sites, representing $45 million of its recorded liability, through an incentive mechanism, which is discussed in Note 12. SCE has recorded a regulatory asset of $75 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 $5 million to $15 million. Recorded costs for 2000 were $13 million.

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

The Clean Air Act requires power producers to have emissions allowances to emit sulfur dioxide. Power companies receive emissions allowances from the federal government and may bank or sell excess allowances. SCE expects to have excess allowances under Phase II of the Clean Air Act (2000 and later). A study was undertaken to determine the specific impact of air contaminant emissions from the Mohave Generating Station on visibility in Grand Canyon National Park. The final report on this study, which was issued in March 1999, found negligible correlation between measured Mohave station tracer concentrations and visibility impairment. The absence of any obvious relationship cannot rule out Mohave station contributions to haze in Grand Canyon National Park, but strongly suggests that other sources were primarily responsible for the haze. In June 1999, the Environmental Protection Agency (EPA) issued an advanced notice of proposed rulemaking regarding assessment of visibility impairment at the Grand Canyon. SCE filed comments on the proposed rulemaking in November 1999. In 1998, several environmental groups filed suit against the co-owners of the Mohave station regarding alleged violations of emissions limits. In order to accelerate resolution of key environmental issues regarding the plant, the parties filed, in concurrence with SCE and the other station owners, a consent decree, which was approved by the court in December 1999. In a letter to SCE, the EPA has expressed its belief that the controls provided in the consent decree will likely resolve the potential Clean Air Act visibility concerns. The EPA is considering incorporating the decree into the visibility provisions of its Federal Implementation Plan for Nevada.

SCE's projected environmental capital expenditures are $1.2 billion for the 2001-2005 period, mainly for undergrounding certain transmission and distribution lines.

San Onofre Nuclear Generating Station

On February 3, 2001, SCE's San Onofre Unit 3 experienced a fire due to an electrical fault in the non-nuclear portion of the plant. The turbine rotors, bearings and other components of the turbine generator system were damaged extensively. SCE expects that Unit 3 will return to service sometime in mid-June 2001. SCE anticipates that its lost revenue under the currently effective San Onofre rate-recovery plan (discussed in the Generation and Power Procurement section of Regulatory Environment) will be approximately $100 million.

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

Accounting Changes

On January 1, 2001, SCE adopted a new accounting standard for derivative instruments and hedging activities. The new standard requires all derivatives be recognized on the balance sheet at fair value. Gains or losses from changes in fair value would be recognized in earnings in the period of change unless the derivative is designated as a hedging instrument. Gains or losses from hedges of a forecasted transaction or foreign currency exposure would be recorded as a separate component of shareholders' equity under the caption "Accumulated other comprehensive income." Gains or losses from hedges of a recognized asset or liability or a firm commitment would be reflected in earnings for the ineffective portion of the hedge. SCE's derivatives qualify for hedge accounting under the new standard. On the implementation date, SCE recorded its interest rate swap agreement (terminated January 5, 2001), and its block forward power purchase contracts (seized by the State of California on February 2, 2001) at fair value on its balance sheet. SCE does not anticipate any earnings impact from its derivatives, since it expects that any market price changes will be recovered in rates.

Forward-looking Information

In the preceding Management's Discussion and Analysis of Results of Operations and Financial Condition and elsewhere in this annual report, the words estimates, expects, anticipates, believes, and other similar expressions are intended to identify forward-looking information that involves risks and uncertainties. Actual results or outcomes could differ materially as a result of such important factors as implementation (or non-implementation) of the MOU as described above; the outcome of negotiations for solutions to SCE's liquidity problems; further actions by state and federal regulatory bodies setting rates, adopting or modifying cost recovery, accounting or rate-setting mechanisms and implementing the restructuring of the electric utility industry; actions by lenders, investors and creditors in response to SCE's suspension of payments for debt service and purchased power, including the possible filing of an involuntary bankruptcy petition against SCE; the effects, unfavorable interpretations and applications of new or existing laws and regulations relating to restructuring, taxes and other matters; the effects of increased competition in energy-related businesses; changes in prices of electricity and fuel costs; the actions of securities rating agencies; the availability of credit, including SCE's ability to regain an investment grade credit rating and re-enter the credit markets; changes in financial market conditions; the amount of revenue available to both transition and non-transition costs; new or increased environmental liabilities; the financial viability of new businesses, such as telecommunications; weather conditions; and other unforeseen events.

Consolidated Statements of Income (Loss)

Southern California Edison Company

In thousands Year ended December 31,	**2000**	1999	1998
Operating revenue	**$ 7,869,950**	$ 7,547,834	$ 7,499,519
Fuel	**194,961**	214,972	323,716
Purchased power — contracts	**2,357,336**	2,419,147	2,625,900
Purchased power — PX/ISO — net	**2,329,276**	770,574	636,343
Provisions for regulatory adjustment clauses — net	**2,301,268**	(762,653)	(472,519)
Other operation and maintenance	**1,771,792**	1,933,217	1,891,210
Depreciation, decommissioning and amortization	**1,472,872**	1,547,738	1,545,735
Income taxes	**(1,006,825)**	451,247	445,642
Property and other taxes	**125,720**	121,628	128,402
Net gain on sale of utility plant	**(24,602)**	(3,035)	(542,608)
Total operating expenses	**9,521,798**	6,692,835	6,581,821
Operating income (loss)	**(1,651,848)**	854,999	917,698
Interest and dividend income	**172,736**	69,389	66,725
Other nonoperating income	**118,064**	162,317	129,046
Interest expense — net of amounts capitalized	**(571,760)**	(483,241)	(484,788)
Other nonoperating deductions	**(110,163)**	(107,285)	(116,845)
Taxes on other income and deductions	**14,627**	13,242	3,286
Net income (loss)	**(2,028,344)**	509,421	515,122
Dividends on preferred stock	**21,443**	25,889	24,632
Net income (loss) available for common stock	**$ (2,049,787)**	**$** 483,532	$ 490,490

Consolidated Statements of Comprehensive Income (Loss)

In thousands Year ended December 31,	**2000**	1999	1998
Net income (loss)	**$ (2,028,344)**	$ 509,421	$ 515,122
Unrealized gain on securities – net	**2,919**	28,009	9,275
Reclassification adjustment for gains included in net income	**(24,470)**	(45,920)	(17,836)
Comprehensive income (loss)	**$ (2,049,895)**	$ 491,510	$ 506,561

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

Consolidated Balance Sheets

In thousands	December 31,	**2000**	1999
ASSETS			
Utility plant, at original cost:			
Transmission and distribution		**$13,128,755**	$12,439,059
Generation		**1,745,505**	1,717,676
Accumulated provision for depreciation and decommissioning		**(7,834,201)**	(7,520,036)
Construction work in progress		**635,572**	562,651
Nuclear fuel, at amortized cost		**143,082**	132,197
Total utility plant		**7,818,713**	7,331,547
Nonutility property — less accumulated provision for depreciation of $11,008 and $6,797 at respective dates		**102,223**	103,644
Nuclear decommissioning trusts		**2,504,990**	2,508,904
Other investments		**89,570**	160,241
Total investments and other assets		**2,696,783**	2,772,789
Cash and equivalents		**583,159**	26,046
Receivables, less allowances of $23,220 and $24,665 for uncollectible accounts at respective dates		**919,045**	579,859
Accrued unbilled revenue		**376,873**	433,802
Fuel inventory		**11,720**	49,989
Materials and supplies, at average cost		**131,651**	122,866
Accumulated deferred income taxes — net		**544,561**	188,143
Prepayments and other current assets		**124,736**	111,151
Total current assets		**2,691,745**	1,511,856
Regulatory assets — net		**2,390,124**	5,555,216
Other deferred charges		**368,731**	485,898
Total deferred charges		**2,758,855**	6,041,114
Total assets		**$15,966,096**	$17,657,306

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

In thousands, except share amounts December 31,	Southern California Edison Company 2000	1999
CAPITALIZATION AND LIABILITIES		
Common shareholder's equity:		
Common stock (434,888,104 shares outstanding at each date)	**$2,168,054**	$ 2,168,054
Additional paid-in capital	**334,030**	335,038
Accumulated other comprehensive income	**—**	21,551
Retained earnings (deficit)	**(1,721,599)**	608,453
	780,485	3,133,096
Preferred stock:		
Not subject to mandatory redemption	**128,755**	128,755
Subject to mandatory redemption	**255,700**	255,700
Long-term debt	**5,631,308**	5,136,681
Total capitalization	**6,796,248**	8,654,232
Short-term debt	**1,451,071**	795,988
Current portion of long-term debt	**646,300**	571,300
Accounts payable	**1,055,483**	573,919
Accrued taxes	**535,517**	500,709
Accrued interest	**96,053**	82,554
Dividends payable	**662**	94,407
Regulatory liabilities — net	**195,047**	100,907
Deferred unbilled revenue	**249,949**	300,339
Other current liabilities	**1,154,834**	1,114,834
Total current liabilities	**5,384,916**	4,134,957
Accumulated deferred income taxes — net	**2,009,290**	2,938,661
Accumulated deferred investment tax credits	**163,952**	205,197
Customer advances and other deferred credits	**754,741**	823,992
Power purchase contracts	**466,231**	563,459
Accumulated provision for pensions and benefits	**296,380**	233,003
Other long-term liabilities	**93,978**	103,470
Total deferred credits and other liabilities	**3,784,572**	4,867,782
Minority interest	**360**	335
Commitments and contingencies (Notes 2, 3, 11 and 12)		
Total capitalization and liabilities	**$15,966,096**	$17,657,306

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

Consolidated Statements of Cash Flows

In thousands	Year ended December 31,	**2000**	1999	1998
Cash flows from operating activities:				
Net income (loss)		**$(2,028,344)**	$ 509,421	$ 515,122
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, decommissioning and amortization		**1,472,872**	1,547,738	1,545,735
Other amortization		**96,958**	95,060	89,323
Deferred income taxes and investment tax credits		**(927,607)**	177,599	(94,504)
Regulatory balancing accounts — long-term		**1,758,594**	(1,353,570)	(361,403)
Regulatory asset related to the sale of generating plants		**48**	179	(220,232)
Net gain on sale of generating plants		**(14,287)**	(938)	(564,623)
Net gain on sale of marketable securities		**(41,161)**	(77,241)	(30,002)
Other assets		**44,369**	(62,328)	(45,191)
Other liabilities		**850**	17,315	40,263
Changes in working capital:				
Receivables		**(282,257)**	98,969	(206,242)
Regulatory balancing accounts — short-term		**96,882**	363,071	(94,067)
Fuel inventory, materials and supplies		**29,484**	(5,297)	23,481
Prepayments and other current assets		**(13,585)**	(19,159)	1,106
Accrued interest and taxes		**48,307**	(185,520)	174,107
Accounts payable and other current liabilities		**588,154**	352,489	205,256
Net cash provided by operating activities		**829,277**	1,457,788	978,129
Cash flows from financing activities:				
Long-term debt issued		**1,759,708**	490,840	—
Long-term debt repaid		**(524,700)**	(362,872)	(776,030)
Bonds repurchased and funds held in trust		**(439,855)**	—	—
Preferred stocks redeemed		—	—	(74,300)
Rate reduction notes repaid		**(246,300)**	(246,300)	(251,591)
Nuclear fuel financing — net		**8,651**	(37,287)	16,244
Short-term debt financing — net		**655,033**	326,423	147,537
Dividends paid		**(394,718)**	(685,731)	(1,129,812)
Net cash provided (used) by financing activities		**817,819**	(514,927)	(2,067,952)
Cash flows from investing activities:				
Additions to property and plant		**(1,095,633)**	(985,623)	(860,837)
Proceeds from sale of generating plants		**18,880**	—	1,203,039
Funding of nuclear decommissioning trusts		**(69,428)**	(115,937)	(162,925)
Proceeds from sales of marketable securities		**41,161**	84,306	32,127
Investments in other assets		**11,607**	15,870	(3,952)
Other		**3,430**	3,069	1,599
Net cash provided (used) by investing activities		**(1,089,983)**	(998,315)	209,051
Net increase (decrease) in cash and equivalents		**557,113**	(55,454)	(880,772)
Cash and equivalents, beginning of year		**26,046**	81,500	962,272
Cash and equivalents, end of year		**$ 583,159**	**$** 26,046	$ 81,500
Cash payments for interest and taxes (in millions):				
Interest — net of amounts capitalized		**$ 303**	$ 287	$ 264
Taxes		**306**	433	405

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

Consolidated Statement of Changes in Common Shareholder's Equity

Southern California Edison Company

In thousands	Common Stock	Additional Paid-in Capital	Accumulated Other Comprehensive Income	Retained Earnings (deficit)	Total Common Shareholder's Equity
Balance at December 31, 1997	$2,168,054	$ 334,031	$ 48,023	$ 1,407,834	$3,957,942
Net income				515,122	515,122
Unrealized gain on securities			13,784		13,784
Tax effect			(4,509)		(4,509)
Reclassified adjustment for gain included in net income			(30,002)		(30,002)
Tax effect			12,166		12,166
Dividends declared on common stock				(1,100,777)	(1,100,777)
Dividends declared on preferred stock				(24,632)	(24,632)
Stock option appreciation				(3,922)	(3,922)
Balance at December 31, 1998	$2,168,054	$ 334,031	$ 39,462	$ 793,625	$3,335,172
Net income				509,421	509,421
Unrealized gain on securities			45,813		45,813
Tax effect			(17,804)		(17,804)
Reclassified adjustment for gain included in net income			(77,241)		(77,241)
Tax effect			31,321		31,321
Dividends declared on common stock				(665,884)	(665,884)
Dividends declared on preferred stock				(25,889)	(25,889)
Stock option appreciation				(2,820)	(2,820)
Capital stock expense		1,007			1,007
Balance at December 31, 1999	$2,168,054	$ 335,038	$ 21,551	$ 608,453	$3,133,096
Net income (loss)				(2,028,344)	(2,028,344)
Unrealized gain on securities			8,027		8,027
Tax effect			(5,108)		(5,108)
Reclassified adjustment for gain included in net income			(41,161)		(41,161)
Tax effect			16,691		16,691
Dividends declared on common stock				(278,522)	(278,522)
Dividends declared on preferred stock				(21,443)	(21,443)
Stock option appreciation				(1,743)	(1,743)
Capital stock expense and other		(1,008)			(1,008)
Balance at December 31, 2000	**$2,168,054**	**$ 334,030**	**$ —**	**$ (1,721,599)**	**$ 780,485**

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

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

Note 1. Summary of Significant Accounting Policies

Nature of Operations

Southern California Edison Company (SCE) is a rate-regulated electric utility which supplies electric energy for its 4.3 million customers in central, coastal and Southern California. SCE operates in a highly regulated environment in which it has an obligation to deliver electric service to customers in return for an exclusive franchise within its service territory. In 1996, state lawmakers and the California Public Utilities Commission (CPUC) initiated the electric industry restructuring process. SCE was directed by the CPUC to divest the bulk of its generation portfolio. Today, those generating plants are owned by independent power companies. Along with electric industry restructuring, a multi-year freeze on the rates that SCE could charge its customers was mandated and transition cost recovery mechanisms allowing SCE to recover its stranded costs associated with generation-related assets were implemented. California's electric industry restructuring statute included provisions to finance a portion of the stranded costs that residential and small commercial customers would have paid between 1998 and 2001, which allowed SCE to reduce rates by at least 10% to these customers, effective January 1, 1998. These frozen rates are to remain in effect until the earlier of March 31, 2002, or the date when the CPUC-authorized costs for utility-owned generation assets and obligations are recovered. However, since the summer of 2000, the prices charged by generators and other sellers have escalated far beyond what SCE can currently charge its customers. See Note 3 for a further discussion.

SCE also produces electricity. On April 1, 1998, SCE began selling all of its electric generation through the California Power Exchange (PX) and Independent System Operator (ISO) and scheduling delivery through the ISO, as mandated by the CPUC's 1995 restructuring decision. By purchasing wholesale electricity through the PX and ISO, SCE satisfied the electric energy needs for customers who did not choose an alternative energy provider. The Federal Energy Regulatory Commission (FERC) issued an order on December 15, 2000, which, among other things, eliminated the requirement for California utilities to buy and sell power exclusively through the ISO and PX. On January 19, 2001, the PX announced that it will permanently cease operations by April 2001; on March 9, 2001, the PX filed for Chapter 11 bankruptcy protection.

The CPUC regulates SCE's capital structure, limiting the dividends it may pay Edison International. In light of SCE's liquidity crisis, its Board of Directors did not declare quarterly common stock dividends to its parent, Edison International, in either December 2000 or March 2001. See Note 2 for a further discussion.

Basis of Presentation

The consolidated financial statements include SCE and its subsidiaries. Intercompany transactions have been eliminated. Certain prior-year amounts were reclassified to conform to the December 31, 2000, financial statement presentation.

SCE's accounting policies conform with accounting principles generally accepted in the United States, including the accounting principles for rate-regulated enterprises, which reflect the rate-making policies of the CPUC and the FERC. Since 1997, SCE has used accounting principles applicable to enterprises in general for its investment in generation facilities, as a result of industry restructuring legislation enacted by the State of California and related changes in the rate-recovery of generation-related assets. Application of such accounting principles to SCE's generation assets did not result in any adjustment of their carrying value.

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

Estimates

Financial statements prepared in compliance with accounting principles generally accepted in the United States require management to make estimates and assumptions that affect the amounts reported in the financial statements and disclosure of contingencies. Actual results could differ from those estimates. Certain significant estimates related to liquidity, regulatory matters, decommissioning and contingencies are further discussed in Notes 2, 3, 11 and 12 to the Consolidated Financial Statements, respectively.

Regulatory Balancing Accounts

During the rate freeze period, the difference between certain generation-related revenue and generation-related costs are being accumulated in the transition cost balancing account (TCBA). The gains resulting from the sale of 12 of SCE's generating plants during 1998 have been credited to the TCBA; the losses are being amortized over the remaining transition period and accumulated in the TCBA.

In June 2000, SCE credited the TCBA for the estimated excess of the market value over book value of its hydroelectric generation assets and simultaneously recorded the same amount in the generation asset balancing account (GABA), pursuant to a CPUC decision. This balance was to remain in GABA until final market valuation of the hydroelectric generation assets. If there was a difference in the final market valuation, it would have been credited to or recovered from customers through the TCBA mechanism. Due to the various unresolved regulatory and legislative issues (as discussed in Note 3), the GABA transaction was reclassified back into the TCBA as of December 31, 2000.

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. Overcollections were credited to the TCBA in 1998 and 1999, pursuant to a 1997 CPUC decision. Due to a January 4, 2001, interim CPUC decision, the balance at year-end 2000 was not credited to the TCBA, pending further testimony and evidence on the implications of crediting the overcollections to the transition revenue account (TRA) rather than the TCBA. The TRA is a CPUC-authorized regulatory asset in which SCE recorded the difference between revenue received from customers through currently frozen rates and the costs of providing service to customers, including power procurement costs.

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 accounting overcollections (which amounted to $1.5 billion as of December 31, 2000) to be closed monthly to the TRA, rather than annually to the TCBA. 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. Based on the new rules, the $4.5 billion TRA undercollection as of December 31, 2000, and the coal and hydroelectric balancing account overcollections, were reclassified to the TCBA, and the TCBA balance was recalculated to be a $2.9 billion undercollection.

Due to the various unresolved regulatory and legislative issues (as discussed in Note 3), the TCBA undercollection was charged to earnings as of December 31, 2000.

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

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. SCE's discontinuance of the application of accounting principles for rate-regulated enterprises to its generation assets in 1997 did not result in a write-off of its generation-related regulatory assets at that time since the CPUC had approved recovery of these assets through the TCBA mechanism.

There are many factors that affect SCE's ability to recover its regulatory assets. SCE must assess the probability of recovery of its generation-related regulatory assets in light of the CPUC's March 27, 2001, and April 3, 2001, decisions (discussed in Note 3), including the retroactive transfer of balances from SCE's TRA to its 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. Until legislative and regulatory actions contemplated by the memorandum of understanding (MOU, as discussed in Note 3) occur, or other actions are taken, SCE is unable to conclude that its generation-related regulatory assets are probable of recovery through the rate-making process. Therefore, in accordance with accounting rules, SCE recorded a $2.5 billion after-tax charge to earnings as of December 31, 2000, to write off the TCBA and other regulatory assets (see below).

In addition to the TCBA, generation-related regulatory assets totaling $1.3 billion (including 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. Unless the memorandum of understanding (MOU, as discussed in Note 3) is implemented or a rate-making mechanism is in place that would make recovery of SCE's TCBA-related regulatory assets probable, future net undercollections in the TCBA will be charged to earnings as losses are incurred. The regulatory and legislative actions set forth in the MOU are expected to result in a rate-making mechanism that would make recovery of these regulatory assets probable. If and when those actions are taken, or other actions occur that make such recovery probable, and the rate-making mechanism is adopted, the regulatory assets would be restored to the balance sheet, with a corresponding increase to earnings.

Regulatory assets and liabilities included in the consolidated balance sheets are:

In millions	December 31,	**2000**	1999
Generation-related:			
Unamortized nuclear investment – net		**$ —**	$ 1,366
Flow-through taxes		—	414
Unamortized loss on sale of plant		—	122
Purchased-power settlements		—	531
TCBA		—	1,044
Other – net		—	47
Subtotal		—	3,524
Rate reduction notes – transition cost deferral		**1,090**	707
Other:			
Flow-through taxes		**874**	859
Unamortized loss on reacquired debt		**273**	295
Environmental remediation		**52**	111
Regulatory balancing accounts and other		**(94)**	(42)
Subtotal		**1,105**	1,223
Total		**$2,195**	$ 5,454

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

The unamortized nuclear investment regulatory asset was created during the second quarter of 1998. SCE reduced its remaining nuclear plant investment by $2.6 billion (as of June 30, 1998) and recorded a regulatory asset on its balance sheet for the same amount 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. This reclassification had no effect on SCE's results of operations.

Nuclear

SCE has been recovering its investments in San Onofre Nuclear Generating Station Units 2 and 3 and Palo Verde Nuclear Generating Station on an accelerated basis, as authorized by the CPUC. The accelerated recovery was to continue through December 2001, earning a 7.35% fixed rate of return on investment. San Onofre's operating costs, including nuclear fuel and nuclear fuel financing costs, and incremental capital expenditures, are recovered through an incentive pricing plan which allows SCE to receive about 4¢ per kilowatt-hour through 2003. Any differences between these costs and the incentive price will flow through to the shareholders. Palo Verde's accelerated plant recovery, as well as operating costs, including nuclear fuel and nuclear fuel financing costs, and incremental capital expenditures, are subject to balancing account treatment through December 31, 2001. The San Onofre and Palo Verde rate recovery plans and the Palo Verde balancing account are part of the TCBA.

The nuclear rate-making plans and the TCBA mechanism will continue for rate-making purposes at least through the end of the rate freeze period and through 2001 for Palo Verde operating costs and through 2003 for the San Onofre incentive pricing plan. However, due to the various unresolved regulatory and legislative issues (as discussed in Note 3), SCE is no longer able to conclude that the unamortized nuclear investment is probable of recovery through the rate-making process. As a result, the balance was written off as a charge to earnings as of December 31, 2000.

The benefits of operation of the San Onofre units and the Palo Verde units are required to be shared equally with ratepayers beginning in 2004 and 2002, respectively. Palo Verde's existing nuclear unit incentive procedure will continue through 2001 only for purposes of calculating a reward for performance of any unit above an 80% capacity factor for a fuel cycle.

Under the MOU (discussed in Note 3), both nuclear facilities would be subject to cost-based ratemaking upon completion of their respective rate-making plans and the sharing mechanisms that were to begin in 2004 and 2002 would be eliminated.

Cash Equivalents

Cash equivalents include tax-exempt investments, time deposits and other investments with original maturities of three months or less.

Planned Major Maintenance

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

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.

Revenue

Operating revenue includes amounts for services rendered but unbilled at the end of each year.

Investments

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

All investments are classified as available-for-sale.

Derivative Financial Instruments

SCE uses the hedge accounting method to record its derivative financial instruments. Hedge accounting requires an assessment that the transaction reduces risk, that the derivative be designated as a hedge at the inception of the derivative contract, and that the changes in the market value of a hedge move in an inverse direction to the item being hedged. Under hedge accounting, the derivative itself is not recorded on SCE's balance sheet. Mark-to-market accounting would be used if the hedge accounting criteria were not met. Interest rate differentials and amortization of premiums for interest rate caps are recorded as adjustments to interest expense. If the derivatives were terminated before the maturity of the corresponding debt issuance, the realized gain or loss on the transaction would be amortized over the remaining term of the debt.

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 2000, $13 million in 1999 and $12 million in 1998. AFUDC – debt was $10 million in 2000, $11 million in 1999 and $8 million in 1998.

Replaced or retired property and removal costs less salvage are charged to the accumulated provision for depreciation. Depreciation expense stated as a percent of average original cost of depreciable utility plant was 3.6% for both 2000 and 1999, and 4.2% for 1998.

SCE's net investment in generation-related utility plant was $1.0 billion at both December 31, 2000, and December 31, 1999.

Related Party Transactions

Certain Edison Mission Energy (a wholly owned subsidiary of Edison International) subsidiaries have ownership in partnerships that sell electricity generated by their project facilities to SCE under long-term power purchase agreements. Such sales to SCE were $716 million in 2000, $513 million in 1999 and $535 million in 1998. As a result of SCE's liquidity crisis, SCE has deferred payments for power purchases from some of these facilities.

Purchased Power — PX/ISO

Transactions through the PX and ISO (reported net) were:

In millions Year ended December 31,	**2000**	1999	1998
Purchases	**$8,449**	$2,490	$1,984
Generation sales	**6,120**	1,719	1,348
Purchased power — PX/ISO — net	**$2,329**	$ 771	$ 636

Other Nonoperating Income and Deductions

Other nonoperating income and deductions was comprised of:

In millions Year ended December 31,	**2000**	1999	1998
Gain on sale of marketable securities	**$ 41**	$ 77	$ 30
AFUDC	**21**	24	20
Other	**56**	61	79
Total other nonoperating income	**$ 118**	$ 162	$ 129
Provisions for regulatory issues and refunds	**$ 78**	$ 79	$ 66
Other	**32**	28	51
Total other nonoperating deductions	**$ 110**	$ 107	$ 117

Note 2. Liquidity Crisis

SCE's liquidity is primarily affected by debt maturities, dividend payments, capital expenditures and power purchases. Capital resources include cash from operations and external financings.

The increasing undercollection in the TRA, 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, have materially and adversely affected SCE's liquidity. As a result of the liquidity crisis, SCE has taken and is taking steps to conserve cash, so that it can continue to provide service to its customers. As a part of this process, SCE has temporarily suspended payments of certain obligations for principal and interest on outstanding debt and for purchased power. As of March 31, 2001, SCE had $2.7 billion in obligations that were unpaid and overdue including: (1) $626 million to the PX or the ISO; (2) $1.1 billion to power producers that are qualifying facilities (QFs); (3) $229 million in PX energy credits for energy service providers; (4) $506 million of matured commercial paper; (5) $206 million of principal and interest on its 5-7/8% notes; and (6) $7 million of other obligations. Unpaid obligations will continue to accrue interest, as applicable. At March 31, 2001, SCE had estimated cash reserves of approximately $2.0 billion, which is approximately $700 million less than its outstanding unpaid obligations and preferred stock dividends in arrears (see below).

SCE is unable to obtain financing of any kind. As a result of investors' concerns regarding the California energy crisis and its impact on SCE's liquidity and overall financial condition, SCE has repurchased $549 million of pollution-control bonds that could not be remarketed in accordance with their terms. These bonds may be remarketed in the future if SCE's credit status improves sufficiently. In addition, SCE has been unable to market its commercial paper and other short-term financial instruments. As of March 31, 2001, SCE resumed payment of interest on its debt obligations. If the MOU is implemented, it is expected to allow SCE to recover its undercollected costs and to restore SCE's creditworthiness, which would allow SCE to pay all of its past due obligations.

On March 27, 2001, the CPUC ordered SCE to pay QFs for power deliveries on a going forward basis, commencing with April 2001 deliveries. SCE must pay QFs within 15 days of the end of the QF's billing period, and QFs are allowed to establish 15-day billing periods. Failure to make a payment when due will result in a fine equal to the amount owed. The CPUC also modified the formula used in calculating payments to QFs by substituting natural gas index prices based on deliveries at the Oregon border rather than the Arizona border. The CPUC stated that the changes will probably result in lower QF power prices. The changes apply to all QFs, where appropriate, regardless of whether they use natural gas or other resources such as solar or wind.

On March 27, 2001, the CPUC also issued decisions on the California Procurement Adjustment (CPA) calculation and the approval of a 3¢ per kWh rate increase (see Note 3). Based on these two decisions, SCE estimates that revenue going forward will not be sufficient to recover retained generation, purchased-power and transition costs. In comments filed with the CPUC on March 29, 2001, and April 2, 2001, SCE provided a forecast showing that the net effects of the rate increase, the payment ordered to be made to the California Department of Water Resources (CDWR), and the QF decision discussed above could result in a shortfall to the CPA calculation of $1.7 billion for SCE during 2001. To implement the MOU, it will be necessary for the CPUC to modify or rescind these decisions.

In light of SCE's liquidity crisis, its Board of Directors did not declare quarterly common stock dividends to its parent, Edison International, in either December 2000 or March 2001. Also, SCE's Board has not declared the regular quarterly dividends for SCE's cumulative preferred stock, 4.08% Series, 4.24% Series, 4.32% Series, 4.78% Series, 6.05% Series, 6.45% Series and 7.23% Series in 2001. The total preferred stock dividends in arrears is $6 million as of March 31, 2001. As a result of the $2.5 billion charge to earnings as of December 31, 2000, SCE's retained earnings are now in a deficit position and therefore, under California law, SCE will be unable to pay dividends as long as a deficit remains. SCE does not meet other tests under which dividends can be paid from sources other than retained earnings. As long as dividends in arrears on SCE's cumulative preferred stock remain unpaid, SCE cannot pay any dividends on its common stock.

In addition to the above, SCE has begun immediate cost-cutting measures which, together with previously announced actions, such as freezing new hires, postponing certain capital expenditures and ceasing new charitable contributions, are aimed at reducing general operating costs. SCE's current cost-cutting measures are intended to allow it to continue to operate while efforts to reach a regulatory solution, involving both state and federal authorities, are underway. Additional actions by SCE may be necessary if the energy and liquidity crisis is not resolved in the near future.

On April 9, 2001, SCE and the CDWR signed an MOU that, if approved by the legislature, would allow SCE to restore its financial health.

For a more detailed discussion on the matters discussed above, see Notes 3 through 7.

SCE's future liquidity depends, in large part, on whether the MOU is implemented, or other action by the California Legislature and the CPUC is taken in a manner sufficient to resolve the energy crisis and the cash flow deficit created by the current rate structure and the excessively high price of energy. Without a change in circumstances, such as that contemplated by the MOU, resolution of SCE's liquidity crisis and its ability to continue to operate outside of bankruptcy is uncertain. In addition, SCE's independent public accountant's opinion in the accompanying financial statements includes an explanatory paragraph which states that the issues resulting from the California energy crisis raise substantial doubt about SCE's ability to continue as a going concern.

Note 3. Regulatory Matters

Status of Transition and Power-Procurement Cost Recovery

SCE's transition costs include power purchases from QF contracts (which are the direct result of prior legislative and regulatory mandates), recovery of certain generating assets and regulatory commitments consisting of recovery of costs incurred to provide service to customers. Such commitments include the recovery of income tax benefits previously flowed through to customers, postretirement benefit transition costs, accelerated recovery of investment in San Onofre Units 2 and 3 and the Palo Verde units, and certain other costs. Transition costs related to power-purchase contracts are being recovered through the terms of each contract. Most of the remaining transition costs may be recovered through the end of the transition period (not later than March 31, 2002). Although the MOU provides for, among other things, SCE to be entitled to sufficient revenue to cover its costs from January 2001 associated with retained generation and existing power contracts, the implementation of the MOU requires the CPUC to modify various decisions. Until the various regulatory and legislative actions to implement the MOU are taken, or other actions occur that make such recovery probable, SCE is not able to conclude that the regulatory assets and liabilities related to purchased-power settlements, the unamortized loss on SCE's generating plant sales in 1998, and various other regulatory assets and liabilities (including income taxes previously flowed through to customers) related to certain generating assets are probable of recovery through the rate-making process. As a result, these balances were written off as a charge to earnings as of December 31, 2000.

During the rate freeze period, there are three sources of revenue available to SCE for transition cost recovery: revenue from the sale or valuation of generation assets in excess of book values, net market revenue from the sale of SCE-controlled generation into the ISO and PX markets and competition transition charge (CTC) revenue. However, due to events discussed elsewhere in this report, revenue from the sale or valuation of generation assets in excess of book values (state legislation enacted in January 2001 prohibits the sale of SCE's remaining generation assets until 2006) and from the sale of SCE-controlled generation into the ISO and PX markets is no longer available to SCE. During 1998, SCE sold all of its gas-fueled generation plants for $1.2 billion, over $500 million more than the combined book value. Net proceeds of the sales were used to reduce transition costs, which otherwise were expected to be collected through the TCBA mechanism.

Net market revenue from sales of power and capacity from SCE-controlled generation sources was also applied to transition cost recovery. Increases in market prices for electricity affected SCE in two fundamental ways prior to the CPUC's March 27, 2001, rate stabilization decision. First, CTC revenue decreased because there was less or no residual revenue from frozen rates due to higher cost PX and ISO power purchases. Second, transition costs decreased because there was increased net market revenue due to sales from SCE-controlled generation sources to the PX at higher prices (accumulated as an overcollection in the coal and hydroelectric balancing accounts). Although the second effect mitigated the first to some extent, the overall impact on transition cost recovery was negative because SCE purchased more power than it sold to the PX. In addition, higher market prices for electricity adversely affected SCE's ability to recover non-transition costs during the rate freeze period. Since May 2000, market prices for electricity were extremely high and there was insufficient revenue from customers under the frozen rates to cover all costs of providing service during that period, and therefore there was no positive residual CTC revenue transferred into the TCBA.

CTC revenue is determined residually (i.e., CTC revenue is the residual amount remaining from monthly gross customer revenue under the rate freeze after subtracting the revenue requirements for transmission, distribution, nuclear decommissioning and public benefit programs, and ISO payments and power purchases from the PX and ISO). The CTC applies to all customers who are using or begin using utility services on or after the CPUC's 1995 restructuring decision date. Residual CTC revenue is calculated through the TRA mechanism. Under CPUC decisions in existence prior to March 27, 2001, positive residual CTC revenue (TRA overcollections) was transferred to the TCBA monthly; TRA undercollections were to remain in the TRA until they were offset by overcollections, or the rate freeze ended, whichever came first. Pursuant to the March 27, 2001, rate stabilization decision, both positive and negative residual CTC revenue is transferred to the TCBA on a monthly basis, retroactive to January 1, 1998.

Upon recalculating the TCBA balance based on the new decision, SCE has received positive residual CTC revenue (TRA overcollections) of $4.7 billion to recover its transition costs from the beginning of the rate freeze (January 1, 1998) through April 2000. As a result of sustained higher market prices, SCE experienced the first month in which costs exceeded revenue in May 2000. Since then, SCE's costs to provide power have continued to exceed revenue from frozen rates and as a result, the cumulative positive residual CTC revenue flowing into the TCBA mechanism has been reduced from $4.7 billion to $1.4 billion as of December 31, 2000. The cumulative TCBA undercollection (as recalculated) is $2.9 billion as of December 31, 2000. A summary of the components of this cumulative undercollection is as follows:

In millions	
Transition costs recorded in the TCBA:	
QF and interutility costs	$3,561
Amortization of nuclear-related regulatory assets	3,090
Depreciation of plant assets	577
Other transition costs	634
Total transition costs	7,862
Revenue available to recover transition costs	(4,984)
Unrecovered transition costs	$2,878

Unless the regulatory and legislative actions required to implement the MOU or other actions that make recovery probable are taken, SCE is not able to conclude that the recalculated TCBA net undercollection is probable of recovery through the rate-making process. As a result, the $2.9 billion TCBA net undercollection was written off as a charge to earnings as of December 31, 2000. In its interim rate stabilization decision of March 27, 2001, the CPUC denied a December motion by SCE to end the rate freeze, and stated that it will not end until recovery of all specified transition costs (including TCBA undercollections as recalculated) or March 31, 2002.

Rate Stabilization Proceeding

In January 2000, SCE filed an application with the CPUC proposing rates that would go into effect when the current rate freeze ends on March 31, 2002, or earlier, depending on the pace of transition cost recovery. On December 20, 2000, SCE filed an amended rate stabilization plan application, stating that the CPUC must recognize that the statutory rate freeze is now over in accordance with California law, and requesting the CPUC to approve an immediate 30% increase to be effective, subject to refund, January 4, 2001. SCE's plan included a trigger mechanism allowing for rate increases of 5% every six months if SCE's TRA undercollection balance exceeds $1 billion. Hearings were held in late December 2000.

On January 4, 2001, the CPUC issued an interim decision that authorized SCE to establish an interim surcharge of 1¢ per kWh for 90 days, subject to refund. The revenue from the surcharge is being tracked through a balancing account and applied to ongoing power procurement costs. The surcharge resulted in rate increases, on average, of approximately 7% to 25%, depending on the class of customer. As noted in the decision, the 90-day period allowed independent auditors engaged by the CPUC to perform a comprehensive review of SCE's financial position, as well as that of Edison International and other affiliates.

On January 29, 2001, independent auditors hired by the CPUC issued a report on the financial condition and solvency of SCE and its affiliates. The report confirmed what SCE had previously disclosed to the CPUC in public filings about SCE's financial condition. The audit report covers, among other things, cash needs, credit relationships, accounting mechanisms to track stranded cost recovery, the flow of funds between SCE and Edison International, and earnings of SCE's California affiliates. On April 3, 2001, the CPUC adopted an order instituting investigation (originally proposed on March 15, 2001). The order reopens the past CPUC decision authorizing the utilities to form holding companies and initiates an investigation into: whether the holding companies violated company requirements to give priority to the capital needs of their respective utility subsidiaries; whether ring-fencing actions by Edison International and PG&E Corporation and their respective nonutility affiliates also violated the requirements to give priority to the capital needs of their utility subsidiaries; whether the payment of dividends by the utilities violated requirements that the utilities maintain dividend policies as though they were comparable stand-alone utility companies; any additional suspected violations of laws or CPUC rules and decisions; and whether additional rules, conditions, or other changes to the holding company decisions are necessary. An assigned commissioner's ruling on March 29, 2001, required SCE to respond within 10 days to document requests and questions that are substantially identical to those included in the March 15 proposed order instituting investigation. The MOU calls for the CPUC to adopt a decision clarifying that the first priority condition in SCE's holding company decision refers to equity investment, not working capital for operating costs. SCE cannot provide assurance that the CPUC will adopt such a decision, or predict what effects this investigation or any subsequent actions by the CPUC may have on SCE.

In its interim order adopted on March 27, 2001, the CPUC granted SCE a rate increase in the form of a 3¢ per kWh surcharge applied only to electric power costs, effective immediately, and affirmed that the 1¢ interim surcharge granted on January 4, 2001, is now permanent. Although the 3¢ increase was authorized immediately, the surcharge will not be collected in rates until the CPUC establishes an appropriate rate design, which is not expected to occur until May 2001. SCE has asked the CPUC to immediately adopt an interim rate increase that would allow the rate change to go into effect sooner. The CPUC also ordered that the 3¢ surcharge be added to the rate paid to the CDWR pursuant to the interim CDWR-related decision.

Also, in the interim order, the CPUC granted a petition previously filed by The Utility Reform Network and directed that the balance in SCE's TRA account, whether over- or undercollected, be transferred on a monthly basis to the TCBA account, retroactive to January 1, 1998. Previous rules called only for TRA overcollections (residual CTC revenue) to be transferred to the TCBA. The CPUC also ordered SCE to transfer the coal and hydroelectric balancing account overcollections to the TRA on a monthly basis before any transfer of residual CTC revenue to the TCBA, retroactive to January 1, 1998. Previous rules called for overcollections in these two balancing accounts to be transferred directly to the TCBA on an annual basis. SCE believes this interim order attempts to retroactively transform power purchase costs in the TRA into transition costs in the TCBA. However, the CPUC characterized the accounting changes as merely reducing the prior residual CTC revenue recorded in the TCBA, thereby only affecting the amount of transition cost recovery achieved to date. Based upon the transfer of balances into the TCBA, the CPUC denied SCE's December 2000 filing to have the current rate freeze end, and stated that it will not end until recovery of all specified transition costs or March 31, 2002; and that balances in the TRA cannot be recovered after the end of the rate freeze. The CPUC also said that it will monitor the balances remaining in the TCBA and consider how to address remaining balances in the ongoing proceedings. If the CPUC does not modify this decision in a manner consistent with the MOU, SCE intends to challenge this decision through all appropriate means.

Although the CPUC has authorized a substantial rate increase in its March 27, 2001, order, it has allocated the revenue from the increase entirely to future purchased-power costs without addressing SCE's past undercollections for the costs of purchased power. The CPUC's decisions do not assure that SCE will be able to meet its ongoing obligations or repay past due obligations. By ordering immediate payments to the CDWR and QFs, the CPUC aggravated SCE's cash flow and liquidity problems. Additionally, the CPUC expressed the view that AB 1X (see CDWR Power Purchases) continues the utilities' obligations to serve their customers, and stated that it cannot assume that the CDWR will purchase all the electricity needed above what the utilities either generate or have under contract (the net short position) and cannot order the CDWR to do so. This could result in additional purchased power costs with no allowed means of recovery. To implement the MOU, it will be necessary for the CPUC to modify or rescind these decisions. SCE cannot provide any assurance that the CPUC will do so.

Wholesale Electricity Markets

In October 2000, SCE filed a joint petition urging the FERC to immediately find the California wholesale electricity market to be not workably competitive, immediately impose a cap on the price for energy and ancillary services, and institute further expedited proceedings regarding the market failure, mitigation of market power, structural solutions and responsibility for refunds. On December 15, 2000, the FERC released a final order containing remedies and other actions in response to the problems in the California electricity market. The order, among other things, eliminated the requirement for California utilities to buy and sell power exclusively through the ISO and PX; created a benchmark price for wholesale bilateral power contracts; created penalties for under-scheduling power loads; provided for an independent governing board for the ISO; and established a breakpoint of $150/MWh so that bids below $150 may clear at a single market-clearing price at or below $150/MWh and bids above $150 will be paid as bid. On December 18, 2000, SCE filed with the FERC an emergency request for rehearing and expedited action seeking reconsideration of the December 15 order. On January 12, 2001, the FERC issued an order granting rehearing for the purpose of further consideration. The PX did not immediately implement the $150/MWh breakpoint and on February 26, 2001, made a compliance filing with the FERC, which requested the FERC's guidance on an acceptable recalculation methodology. On April 6, 2001, the FERC issued an order providing guidance to the PX, which should reduce SCE's energy costs owed to the PX for the month of January 2001.

On December 13, 2000, the ISO announced that generators of electricity were refusing to sell into the California market due to concerns about the financial stability of SCE and Pacific Gas and Electric Company. In response to this announcement, on December 14, 2000, the United States Secretary of Energy issued an order requiring power companies to make arrangements to generate and deliver electricity as requested by the ISO after the ISO certifies that it has been unable to acquire adequate supplies of electricity in the market. After being renewed multiple times, the order expired on February 6, 2001. However, on February 7, 2001, a federal court judge issued a temporary restraining order requiring power suppliers to sell to the California grid. On March 21, 2001, a federal court judge ordered one of the power suppliers to continue to sell power to the California grid. The three other power suppliers have signed an agreement with the judge voluntarily agreeing to continue to sell power to the grid while awaiting a review of the issue by the FERC. On April 6, 2001, the United States Court of Appeals issued a stay order, suspending the lower court's March 21 order until a final appeals ruling can be issued.

On December 26, 2000, SCE filed an emergency petition in the federal Court of Appeals challenging the FERC order and seeking a writ of mandamus requiring the FERC to immediately establish cost-based wholesale rates. On January 5, 2001, the court denied SCE's petition. The effect of the denial is to leave in place the FERC's market controls that have allowed wholesale prices to climb to current levels. SCE's petition for rehearing remains pending. SCE cannot predict what action the FERC may take. SCE is considering the possibility of judicial appeals and other actions.

On March 9, 2001, FERC directed 13 wholesale sellers of energy to refund $69 million or submit cost-of-service information to FERC to justify their prices above $273/MWh during ISO Stage 3 emergencies in January 2001. SCE will oppose the order as inadequate, particularly because the FERC is unwilling to exercise any control over sellers exercise of market power during periods other than Stage 3 emergencies. On March 16, 2001, the FERC ordered six wholesale sellers of energy to refund an additional $55 million or submit cost-of-service information to the FERC to justify their prices above $430/MWh during ISO Stage 3 emergencies in February 2001. A Stage 3 emergency refers to 1.5% or less in reserve power, which could trigger rotating blackouts in some neighborhoods.

Memorandum of Understanding with the CDWR

On April 9, 2001, Edison International and SCE signed an MOU with the CDWR regarding the California energy crisis and its effects on SCE. The Governor of California and his representatives participated in the negotiation of the MOU, and the Governor endorsed implementation of all the elements of the MOU. The MOU sets forth a comprehensive plan calling for legislation, regulatory action and definitive agreements to resolve important aspects of the energy crisis, and which, if implemented, is expected to help restore SCE's creditworthiness and liquidity. Key elements of the MOU include:

- SCE will sell its transmission assets to the CDWR, or another authorized California state agency, at a price equal to 2.3 times their aggregate book value, or approximately $2.76 billion. If a sale of the transmission assets is not completed under certain circumstances, SCE's hydroelectric assets and other rights may be sold to the state in their place. SCE will use the proceeds of the sale in excess of book value to reduce its undercollected costs and retire outstanding debt incurred in financing those costs. SCE will agree to operate and maintain the transmission assets for at least three years, for a fee to be negotiated.

- Two dedicated rate components will be established to assist SCE in recovering the net undercollected amount of its power procurement costs through January 31, 2001, estimated to be approximately $3.5 billion. The first dedicated rate component will be used to securitize the excess of the undercollected amount over the expected gain on sale of SCE's transmission assets, as well as certain other costs. Such securitization will occur as soon as reasonably practicable after passage of the necessary legislation and satisfaction of other conditions of the MOU. The second dedicated rate component would not be securitized and would not appear in rates unless the transmission sale failed to close within a two-year period. The second component is designed to allow SCE to obtain bridge financing of the portion of the undercollection intended to be recovered through the gain on the transmission sale.

- SCE will continue to own its generation assets, which will be subject to cost-based ratemaking, through 2010. SCE will be entitled to collect revenue sufficient to cover its costs from January 1, 2001, associated with the retained generation assets and existing power contracts. The MOU calls for the CPUC to adopt cost recovery mechanisms consistent with SCE obtaining and maintaining an investment-grade credit rating.

- The CDWR will assume the entire responsibility for procuring the electricity needs of retail customers within SCE's service territory through December 31, 2002, to the extent that those needs are not met by generation sources owned by or under contract to SCE. (The unmet needs are referred to as SCE's net short position.) SCE will resume procurement of its net short position after 2002. The MOU calls for the CPUC to adopt cost recovery mechanisms to make it financially practicable for SCE to reassume this responsibility.

- SCE's authorized return on equity will not be reduced below its current level of 11.6% before December 31, 2010. Through the same date, a rate-making capital structure for SCE will not be established with different proportions of common equity or preferred equity to debt than set forth in current authorizations. These measures are intended to enable SCE to achieve and maintain an investment-grade credit rating.

- Edison International and SCE will commit to make capital investments in SCE's regulated businesses of at least $3 billion through 2006, or a lesser amount approved by the CPUC. The equity component of the investments will be funded from SCE's retained earnings or, if necessary, from equity investments by Edison International.

- An affiliate of Edison International will execute a contract with the CDWR or another state agency for the provision of power to the state at cost-based rates for ten years from a power project currently under development. The Edison International affiliate will use all commercially reasonable efforts to place the first phase of the project into service before the end of summer 2001.

- SCE will grant perpetual conservation easements over approximately 21,000 acres of lands associated with SCE's Big Creek and Eastern Sierra hydroelectric facilities. The easements initially will be held by a trust for the benefit of the State of California, but ultimately may be assigned to nonprofit entities or certain governmental agencies. SCE will be permitted to continue utility uses of the subject lands.

- After the other elements of the MOU are implemented, SCE will enter into a settlement of or dismiss its federal district court lawsuit against the CPUC seeking recovery of past undercollected costs. The settlement or dismissal will include related claims against the State of California or any of its agencies, or against the federal government.

The sale of SCE's transmission system and other elements of the MOU must be approved by the FERC. Edison International, SCE and the CDWR committed in the MOU to proceed in good faith to sponsor and support the required legislation and to negotiate in good faith the necessary definitive agreements. The MOU may be terminated by either SCE or the CDWR if required legislation is not adopted and definitive agreements executed by August 15, 2001, or if the CPUC does not adopt required implementing decisions within 60 days after the MOU was signed, or if certain other adverse changes occur. SCE cannot provide assurance that all the required legislation will be enacted, regulatory actions taken, and definitive agreements executed before the applicable deadlines.

CDWR Power Purchases

Pursuant to an emergency order signed by the Governor, the CDWR began making emergency power purchases for SCE's customers on January 18, 2001. On February 1, 2001, Assembly Bill 1 (First Extraordinary Session) (AB 1X) was enacted into law. The new law authorized the CDWR to enter into contracts to purchase electric power and sell power at cost directly to retail customers being served by SCE, and authorized the CDWR to issue revenue bonds to finance electricity purchases. The new law directed the CPUC to determine the amount of the CPA as a residual amount of SCE's generation-related revenue, after deducting the cost of SCE-owned generation, QF contracts, existing bilateral contracts and ancillary services. The new law also directed the CPUC to determine the amount of the CPA that is allocable to the power sold by the CDWR, which will be payable to the CDWR when received by SCE. On March 7, 2001, the CPUC issued an interim order in which it held that the CDWR's purchases are not subject to prudency review by the CPUC, and that the CPUC must approve and impose, either as a part of existing rates or as additional rates, rates sufficient to enable the CDWR to recover its revenue requirements.

On March 27, 2001, the CPUC issued an interim CDWR-related order requiring SCE to pay the CDWR a per-kWh price equal to the applicable generation-related retail rate per kWh for electricity (based on rates in effect on January 5, 2001), for each kWh the CDWR sells to SCE's customers. The CPUC determined that the generation-related retail rate should be equal to the total bundled electric rate (including the 1¢ per kWh temporary surcharge adopted by the CPUC on January 4, 2001) less certain nongeneration-related rates or charges. For the period January 19 through January 31, 2001, the CPUC ordered SCE to pay the CDWR at a rate of 6.277¢ per kWh for power delivered on an interim basis to SCE's customers. The CPUC determined that the applicable rate component is 7.277¢ per kWh (which will increase to 10.277¢ per kWh for electricity delivered after March 27, 2001, due to the 3¢ surcharge discussed in Rate Stabilization Proceeding), for electricity delivered by the CDWR to SCE's retail customers after February 1, 2001, until more specific rates are calculated. The CPUC ordered SCE to pay the CDWR within 45 days after the CDWR supplies power to retail customers, subject to penalties for each day the payment is late. Using these rates, SCE has billed customers $196 million for sales made by the CDWR during the period January 19 through March 31, 2001, and has forwarded $52 million to the CDWR on behalf of these customers as of March 31, 2001.

On April 3, 2001, the CPUC adopted the method (originally proposed in the March 27 CDWR-related order discussed above) it will use to calculate the CPA (which was established by AB 1X) and then applied the method to calculate a company-wide CPA rate for SCE. The CPUC used that rate to determine the CPA revenue amount that can be used by the CDWR for issuing bonds. The CPUC stated that its decision is narrowly focused to calculate the maximum amount of bonds that the CDWR may issue and does not dedicate any particular revenue stream to the CDWR. The CPUC determined that SCE's CPA rate is 1.120¢ per kWh, which generates annual revenue of $856 million. In its calculation of the CPA, the CPUC disregarded all of the adjustments requested by SCE in its comments filed on March 29 and April 2, 2001. SCE's comments included, among other things, a forecast showing that the net effect of the rate increases (discussed in Rate Stabilization Proceeding), as well as the March 27 QF payment decision (discussed in Note 2) and the payments ordered to be made to CDWR, could result in a shortfall in the CPA calculation of $1.7 billion for SCE during 2001. SCE estimates that its future revenue will not be sufficient to cover its retained generation, purchased-power and transition costs. To implement the MOU, the CPUC will need to modify the calculation methods and provide reasonable assurance that SCE will be able to recover its ongoing costs.

SCE believes that the intent of AB 1X was for the CDWR to assume full responsibility for purchasing all power needed to serve the retail customers of electric utilities, in excess of the output of generating plants owned by the electric utilities and power delivered to the utilities under existing contracts. However, the CDWR has stated that it is only purchasing power that it considers to be reasonably priced, leaving the ISO to purchase in the short-term market the additional power necessary to meet system requirements. The ISO, in turn, takes the position that it will charge SCE for the costs of power it purchases in this manner. If SCE is found responsible for any portion of the ISO's purchases of power for resale to SCE's customers, SCE will continue to incur purchased-power costs in addition to the unpaid costs described above. In its March 27, 2001, interim order, the CPUC stated that it cannot assume that the CDWR will pay for the ISO purchases and that it does not have the authority to order the CDWR to do so. Litigation among certain power generators, the ISO and the CDWR (to which SCE is not a party), and proceedings before the FERC (to which SCE is a party), may result in rulings clarifying the CDWR's financial responsibility for purchases of power. On April 6, 2001, the FERC issued an order confirming that the ISO must have a creditworthy buyer for any transactions. In any event, SCE takes the position that it is not responsible for purchases of power by the CDWR or the ISO on or after January 18, 2001, the day after the Governor signed the order authorizing the CDWR to begin purchasing power for utility customers. SCE cannot predict the outcome of any of these proceedings or issues. The recently executed MOU states that the CDWR will assume the entire responsibility for procuring the electricity needs of retail customers within SCE's service territory through December 31, 2002, to the extent those needs are not met by generation sources owned by or under contract to SCE (SCE's net short position). SCE will resume buying power for its net short position after 2002. The MOU calls for the CPUC to adopt cost-recovery mechanisms to make it financially practicable for SCE to reassume this responsibility.

Hydroelectric Market Value Filing

In 1999, SCE filed an application with the CPUC establishing a market value for its hydroelectric generation-related assets at approximately $1.0 billion (almost twice the assets' book value) and proposing to retain and operate the hydroelectric assets under a performance-based, revenue-sharing mechanism. If approved by the CPUC, SCE would be allowed to recover an authorized, inflation-indexed operations and maintenance allowance, as well as a reasonable return on capital investment. A revenue-sharing arrangement would be activated if revenue from the sale of hydroelectricity exceeds or falls short of the authorized revenue requirement. SCE would then refund 90% of the excess revenue to ratepayers or recover 90% of any shortfall from ratepayers. If the MOU is implemented, SCE's hydroelectric assets will be retained through 2010 under cost-based rates, or they may be sold to the state if a sale of SCE's transmission assets is not completed under certain circumstances.

Note 4. Financial Instruments

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.

SCE used the mark-to-market accounting method for its gas call options, which were used to mitigate SCE's transition cost recovery exposure to increases in energy prices. Gains and losses from monthly changes in market prices were recorded as income or expense. In addition, the options' costs and market price changes were included in the TCBA. As a result, the mark-to-market gains or losses had no effect on earnings. In October 2000, SCE sold its gas call options resulting in a $190 million gain. The options covered various periods through 2001. The gains were credited to the TCBA.

The PX block forward market allowed SCE to purchase monthly blocks of energy and ancillary services for six days a week (excluding Sundays and holidays) for 8 to 16 hours a day, up to 12 months in advance of the delivery date.

SCE purchased block forward energy contracts through the PX, with various terms and prices, to hedge its exposure to fluctuations in energy prices. Due to the 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 block forward contracts. On February 2, 2001, SCE's motion for a preliminary injunction was denied, freeing the PX to liquidate the contracts and apply the proceeds to amounts owed by SCE to the PX. On the same day, the State seized the contracts for the benefit of the State before they could be sold by the PX. The State must compensate SCE for the reasonable value of the contracts. The PX has indicated that it will also seek to recover the monies that SCE owes to the PX from any proceeds realized from those contracts. After other elements of the MOU are implemented, SCE would relinquish all claims against the State for seizing these contracts. At December 31, 2000, these contracts had a nominal value of $234 million.

SCE also has bilateral forward contacts, which are considered normal purchases under accounting rules. At December 31, 2000, these contracts had a nominal value of $798 million. Due to its deteriorating credit ratings, SCE has been unable to purchase additional bilateral forward contracts, and $379 million (nominal value) of its existing contracts were terminated by the counterparties in early 2001. 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. SCE is exposed to market risk resulting from changes in the spot market price for power. Changes in the value of bilateral forward contracts affects purchased power expense in the period when the power is delivered.

SCE used an interest rate swap to reduce the potential impact of interest rate fluctuations on floating-rate long-term debt. At December 31, 2000, and December 31, 1999, SCE had an interest rate swap agreement which fixed the interest rate at 5.585% for $196 million of debt due 2008; the receive rate on the swap averaged 3.839% in 2000. As a result of the downgrade in SCE's credit rating below the level allowed under the interest rate hedge agreement, on January 5, 2001, the counterparty on this interest rate swap terminated the agreement. As a result of the termination of the swap, SCE is paying a floating rate on $196 million of its debt due 2008. The realized loss of $26 million will be amortized over a period ending in 2008.

On January 1, 2001, SCE adopted a new accounting standard for derivative instruments and hedging activities. The new standard requires all derivatives to be recognized on the balance sheet at fair value. Gains or losses from changes in fair value will be recognized in earnings in the period of change unless the derivative is designated as a hedging instrument. Gains or losses from hedges of a forecasted transaction or foreign currency exposure will be recorded as a separate component of shareholder's equity under the caption "Accumulated other comprehensive income." Gains or losses from hedges of a recognized asset or liability or a firm commitment would be reflected in earnings for the ineffective portion of the hedge. SCE's derivatives qualify for hedge accounting under the new standard. On the implementation date, SCE recorded its interest rate swap agreement (terminated January 5, 2001) and its block forward power purchase contracts (seized by the State on February 2, 2001) at fair value on its balance sheet. SCE does not anticipate any earnings impact from its derivatives, since it expects that any market price changes will be recovered in rates.

Fair values of financial instruments were:

In millions December 31,	2000		1999	
	Cost Basis	**Fair Value**	Cost Basis	Fair Value
Financial assets:				
Decommissioning trusts	**$1,720**	**$2,505**	$1,650	$2,509
Equity investments	—	**—**	—	33
Gas call options	—	**—**	28	20
Financial liabilities:				
DOE decommissioning and decontamination fees	**36**	**31**	40	35
Interest rate swap	—	**21**	—	13
Long-term debt	**5,631**	**5,178**	5,137	5,044
Preferred stock subject to mandatory redemption	**256**	**157**	256	259

Financial assets are carried at their fair value based on quoted market prices for decommissioning trusts, equity investments and gas call options. Financial liabilities are recorded at cost. Financial liabilities' fair values are based on: quoted market prices for the interest rate swap; brokers' quotes for long-term debt and preferred stock; and discounted future cash flows for U.S. Department of Energy (DOE) decommissioning and decontamination fees. Due to their short maturities, amounts reported for cash equivalents and short-term debt approximated fair value at December 31, 2000, and 1999.

As a result of investors' concerns regarding SCE's liquidity difficulties, its short-term debt and long-term debt fair values have decreased approximately $150 million and $500 million, respectively, from amounts reported at year-end.

Gross unrealized holding gains on debt and equity securities were:

In millions December 31,	2000	1999
Decommissioning trusts:		
Municipal bonds	**$193**	$239
Stocks	**384**	454
U.S. government issues	**136**	119
Short-term and other	**72**	47
	785	859
Equity investments	—	33
Total	$**785**	$892

There were no unrealized holding losses on debt and equity securities for the years presented.

Note 5. Long-Term Debt

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

Almost all SCE properties are subject to a trust indenture lien. SCE has pledged first and refunding mortgage bonds as security for borrowed funds obtained from pollution control bonds issued by government agencies. SCE uses these proceeds to finance construction of pollution control facilities. Bondholders have limited discretion in redeeming certain pollution-control bonds, and SCE has arrangements with securities dealers to remarket or purchase them if necessary. As a result of investors' concerns regarding SCE's liquidity difficulties and overall financial condition, SCE has had to repurchase

$549 million of pollution control bonds in December 2000 and early 2001 that could not be remarketed in accordance with their terms.

Debt premium, discount and issuance expenses are amortized over the life of each issue. Under CPUC rate-making procedures, debt reacquisition expenses are amortized over the remaining life of the reacquired debt or, if refinanced, the life of the new debt.

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

In December 1997, $2.5 billion of rate reduction notes were issued on behalf of SCE by SCE Funding LLC, a special purpose entity. These notes were issued to finance the 10% rate reduction mandated by state law. The proceeds of the rate reduction notes were used by SCE Funding LLC to purchase from SCE an enforceable right known as transition property. Transition property is a current property right created by the restructuring legislation and a financing order of the CPUC and consists generally of the right to be paid a specified amount from 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 secured by the transition property and are not secured by, or payable from, assets of SCE or Edison International. SCE used the proceeds from the sale of the transition property to retire debt and equity securities. Although, as required by accounting principles generally accepted in the United States, SCE Funding LLC is consolidated with SCE and the rate reduction notes are shown as long-term debt in the consolidated financial statements, SCE Funding LLC is legally separate from SCE. The assets of SCE Funding LLC are not available to creditors of SCE or Edison International and the transition property is legally not an asset of SCE or Edison International. Due to SCE’s recent credit downgrade, in January 2001, SCE began remitting its customer collections related to the rate-reduction notes on a daily basis.

Long-term debt consisted of:

In millions December 31,	2000	1999
First and refunding mortgage bonds:		
2002-2026 (5.625% to 7.25%)	**$1,175**	$1,400
Rate reduction notes:		
2001-2007 (6.17% to 6.42%)	**1,724**	1,970
Pollution-control bonds:		
2008-2040 (5.125% to 7.2% and variable)	**1,216**	1,196
Bonds repurchased	**(420)**	—
Funds held by trustees	**(20)**	(2)
Debentures and notes:		
2001-2029 (5.875% to 7.625% and variable)	**2,450**	1,000
Subordinated debentures:		
2044 (8.375%)	**100**	100
Commercial paper for nuclear fuel	**79**	71
Long-term debt due within one year	**(646)**	(571)
Unamortized debt discount — net	**(27)**	(27)
Total	**$5,631**	$5,137

Long-term debt maturities and sinking-fund requirements for the next five years are: 2001 — $646 million; 2002 — $746 million; 2003 — $1.4 billion; 2004 — $371 million; and 2005 — $246 million.

As a result of its liquidity crisis, SCE has taken steps to conserve cash, and has been forced to consider further alternatives for conserving cash, so that it can continue to provide service to its customers. As a part of this process, SCE has temporarily suspended payments of certain obligations. As of March 31, 2001, SCE has failed to pay $206 million of maturing principal and accrued interest on its 5-7/8% notes. Under the indenture for SCE's senior unsecured notes, the failure to pay principal was an immediate event of default as to the one series of notes on which the principal was due. If an event of default occurs as to any series of senior unsecured notes, the trustee or the holders of 25% in principal amount of the notes of such series may declare the principal of the notes of that series to be immediately due and payable. In addition, SCE's failure to pay any obligation for borrowed money in an aggregate amount in excess of $10 million would constitute an event of default with respect to all of the senior unsecured notes and SCE's outstanding quarterly income preferred securities if not cured within 30 days after notice from the trustee of holders of the securities. No such notice has been received by SCE.

If a notice of default is received, SCE could cure the default only by paying $700 million in overdue principal and interest to holders of commercial paper and the 5-7/8% notes. (SCE has also deferred payment of maturing commercial paper. See Note 6 for a further discussion.) Making such payment would further impact SCE's liquidity. If a notice of default were received and not cured, and the trustee or noteholders declare an acceleration of the outstanding principal amount of the senior unsecured notes, SCE would not have the cash to pay the obligation and could be forced to declare bankruptcy.

In January 2001, three rating agencies lowered their credit ratings of SCE to substantially below investment grade. In mid-April, one agency removed SCE's credit ratings from review for possible downgrade. The ratings remain under review for possible downgrade by the other two agencies.

Note 6. Short-Term Debt

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

Short-term debt consisted of:

In millions December 31,	2000	1999
Commercial paper	**$ 700**	$ 696
Bank loans	**835**	—
Floating rate notes	—	175
Amount reclassified as long-term debt	**(79)**	(71)
Unamortized discount	**(5)**	(4)
Total	**$1,451**	$ 796
Weighted average interest rates	**6.9%**	6.1%

At December 31, 2000, SCE had lines of credit totaling $1.65 billion, with $125 million available for the refinancing of certain variable-rate pollution control debt. The lines can be drawn at negotiated or bank index rates.

As of January 2001, SCE had borrowed the entire $1.65 billion in funds available under its credit line. The proceeds were used in part to repurchase $420 million of pollution control bonds; the balance was retained as a liquidity reserve.

In late 2000, SCE was unable to complete the syndication of a $1 billion revolving credit agreement that was intended to finance current and expected balancing account undercollections and other operating requirements. In addition, SCE has been unable to market its commercial paper and other short-term financial instruments. And, in SCE's efforts to conserve cash, SCE has deferred payment of approximately $506 million of maturing commercial paper as of March 31, 2001.

Note 7. Preferred Stock

Authorized shares of preferred and preference stocks are: $25 cumulative preferred — 24 million; $100 cumulative preferred — 12 million; and preference — 50 million. All cumulative preferred stocks are redeemable.

Mandatorily redeemable preferred stocks are subject to sinking-fund provisions. When preferred shares are redeemed, the premiums paid are charged to common equity.

Preferred stock redemption requirements for the next five years are: 2001 — zero; 2002 —$105 million; 2003 — $9 million; 2004 — $9 million; and 2005 — $9 million.

Cumulative preferred stocks consisted of:

Dollars in millions, except per share amounts	December 31, 2000 Shares Outstanding	December 31, 2000 Redemption Price	**2000**	1999
Not subject to mandatory redemption:				
$25 par value:				
4.08% Series	1,000,000	$25.50	**$ 25**	$ 25
4.24	1,200,000	25.80	**30**	30
4.32	1,653,429	28.75	**41**	41
4.78	1,296,769	25.80	**33**	33
Total			**$ 129**	$ 129
Subject to mandatory redemption:				
$100 par value:				
6.05% Series	750,000	$100.00	**$ 75**	$ 75
6.45	1,000,000	100.00	**100**	100
7.23	807,000	100.00	**81**	81
Total			**$ 256**	$ 256

In 1998, SCE redeemed 2.2 million shares of Series 5.8% and 193,000 shares of Series 7.23% preferred stock. SCE did not issue any preferred stock in the last three years.

SCE's Board of Directors did not declare the regular quarterly dividend for its cumulative preferred stock in 2001. As long as these dividends remain unpaid, SCE cannot declare or pay future cash dividends on any series of preferred stock or on its common stock, and SCE cannot repurchase any shares of its common stock. As a result of the $2.5 billion charge to earnings during fourth quarter 2000, SCE's retained earnings are now in a deficit position and therefore under California law, SCE will be unable to pay dividends as long as a deficit remains.

Note 8. Income Taxes

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

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

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

In millions December 31,	**2000**	1999
Deferred tax assets:		
Decommissioning	**$ 98**	$ 127
Accrued charges	**379**	247
Investment tax credits	**81**	113
Property-related	**277**	184
Regulatory balancing accounts	**1,763**	67
Unbilled revenue	**101**	122
Unrealized gains or losses	**420**	453
Other	**56**	92
Total	**$3,175**	$1,405
Deferred tax liabilities:		
Property-related	**$2,184**	$2,629
Capitalized software costs	**264**	225
Regulatory balancing accounts	**1,632**	448
Unrealized gains and losses	**317**	351
Other	**242**	502
Total	**$4,639**	$4,155
Accumulated deferred income taxes — net	**$1,464**	$2,750
Classification of accumulated deferred income taxes:		
Included in deferred credits	**$2,009**	$2,938
Included in current assets	**545**	188

The current and deferred components of income tax expense were:

In millions Year ended December 31,	**2000**	1999	1998
Current:			
Federal	**$ (104)**	$299	$450
State	**—**	79	101
	(104)	378	551
Deferred—federal and state:			
Accrued charges	**(133)**	(76)	(43)
Investment and energy tax credits — net	**(41)**	(45)	(74)
Property related	**(302)**	(194)	(169)
Regulatory asset amortization	**251**	7	63
Regulatory balancing accounts	**(740)**	371	177
State tax—privilege year	**31**	7	—
Unbilled revenue	**20**	(5)	(67)
Other	**(4)**	(5)	4
	(918)	60	(109)
Total	**$(1,022)**	$438	$442
Classification of income taxes:			
Included in operating income	**$(1,007)**	$451	$445
Included in other income	**(15)**	(13)	(3)

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

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

Year ended December 31,	**2000**	1999	1998
Federal statutory rate	**35.0%**	35.0%	35.0%
Capitalized software	**—**	(2.4)	(0.7)
Investment and energy tax credits	**1.4**	(4.4)	(6.8)
Property-related and other	**(6.6)**	9.3	11.4
State tax — net of federal deduction	**3.7**	8.5	6.9
Effective tax rate	**33.5%**	46.0%	45.8%

Note 9. Employee Compensation and Benefit Plans

Employee Savings Plan

SCE has a 401(k) defined-contribution savings plan designed to supplement employees' retirement income. The plan received employer contributions of $29 million in 2000, $25 million in 1999 and $17 million in 1998.

Pension Plan

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

Information on plan assets and benefit obligations is shown below:

In millions Year ended December 31,	**2000**	1999
Change in benefit obligation		
Benefit obligation at beginning of year	**$2,075**	$2,251
Service cost	**63**	66
Interest cost	**155**	146
Plan amendment	—	(22)
Actuarial loss (gain)	**90**	(224)
Benefits paid	**(183)**	(142)
Benefit obligation at end of year	**$2,200**	$2,075
Change in plan assets		
Fair value of plan assets at beginning of year	**$3,078**	$2,552
Actual return on plan assets	**143**	620
Employer contributions	**29**	48
Benefits paid	**(183)**	(142)
Fair value of plan assets at end of year	**$3,067**	$3,078
Funded status	**$867**	$1,003
Unrecognized net loss (gain)	**(745)**	(1,018)
Unrecognized transition obligation	**22**	28
Unrecognized prior service cost	**118**	132
Recorded asset	**$262**	$ 145
Discount rate	**7.25%**	7.75%
Rate of compensation increase	**5.0%**	5.0%
Expected return on plan assets	**8.5%**	7.5%

Expense components were:

In millions Year ended December 31,	**2000**	1999	1998
Service cost	**$ 63**	$ 66	$ 59
Interest cost	**155**	146	141
Expected return on plan assets	**(266)**	(188)	(170)
Net amortization and deferral	**(40)**	12	14
Expense under accounting standards	**(88)**	36	44
Regulatory adjustment — deferred	**88**	14	11
Total expense recognized	**$ —**	$ 50	$ 55

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,	**2000**	1999
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 1,462**	$ 1,545
Service cost	**39**	46
Interest cost	**121**	109
Actuarial loss (gain)	**202**	(185)
Benefits paid	**(62)**	(53)
Benefit obligation at end of year	**$ 1,762**	$ 1,462
Change in plan assets		
Fair value of plan assets at beginning of year	**$ 1,283**	$ 1,029
Actual return on plan assets	**(40)**	185
Employer contributions	**19**	122
Benefits paid	**(62)**	(53)
Fair value of plan assets at end of year	**$ 1,200**	$ 1,283
Funded status	**$ (562)**	$ (179)
Unrecognized net loss (gain)	**141**	(207)
Unrecognized transition obligation	**323**	349
Recorded asset (liability)	**$ (98)**	$ (37)
Discount rate	**7.5%**	8.0%
Expected return on plan assets	**8.2%**	7.5%

Expense components were:

In millions Year ended December 31,	**2000**	1999	1998
Service cost	**$ 39**	$ 46	$ 41
Interest cost	**121**	109	99
Expected return on plan assets	**(106)**	(79)	(62)
Net amortization and deferral	**27**	27	28
Total expense	**$ 81**	$ 103	$ 106

The assumed rate of future increases in the per-capita cost of health care benefits is 11.0% for 2001, 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, 2000, by $277 million and annual aggregate service and interest costs by $30 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated obligation as of December 31, 2000, by

$239 million and annual aggregate service and interest costs by $25 million.

Stock Option Plans

In 1998, Edison International shareholders approved the Edison International Equity Compensation Plan, replacing the Long-Term Incentive Compensation Program (prior program), which had been adopted by shareholders in 1992. Under the prior program, options on 1.5 million shares of Edison International common stock remain outstanding to officers and senior managers of SCE. The 1998 plan authorizes a limited annual award of Edison International common shares and options on shares. The annual authorization is cumulative, allowing subsequent issuance of previously unutilized awards. In May 2000, Edison International adopted an additional plan, the 2000 Equity Plan, which did not require shareholder approval.

Under the 1998 and 2000 plans, options on 8.6 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 expire 10 years after the date of grant, and vest over a period of up to five years. A portion of the executive long-term incentive program was awarded in the form of performance shares. The performance shares were restructured as retention incentives in December 2000, which will pay as a combination of Edison International common stock and cash if the executive remains employed at the end of the performance period. Performance shares may still be awarded in 2001 and 2002. No special stock options may be exercised before five years have passed unless the stock appreciates to $25 (based on the average of 20 consecutive trading day closing prices). Edison International stock options awarded between 1994 and 1999 included a dividend equivalent feature. Dividend equivalents are accrued to the extend 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 included a dividend equivalent feature. The 2000 stock option awards did not include dividend equivalents. Future stock option awards are not expected to include dividend equivalents.

All stock options have 10-year terms. Options issued after 1997 generally vest in 25% annual installments over a four-year period, although the vesting period for the May 2000 grants does not begin until May 2001. Stock options issued prior to 1998 had a three-year vesting period with one-third of the total award vesting after each of the first three years of the award term. If an option holder retires, dies or is 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 exercised 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. 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 performance shares values are accrued ratably over a three-year performance period. SCE measures compensation expense related to stock-based compensation by the intrinsic value method. Compensation expense recorded under the stock-compensation programs was $4 million in 2000, $5 million in 1999 and $8 million in 1998.

Stock-based compensation expense under the fair value method of accounting would have resulted in pro forma net income (loss) available for common stock of $(2.054) billion in 2000, $484 million in 1999 and $491 million in 1998.

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

December 31,	**2000**	**1999**
Expected life	7 years—10 years	7 years
Risk-free interest rate	4.7%—6.0%	5.0% – 5.5%
Expected volatility	17%—46%	18%

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

The weighted-average fair value of options granted during 2000 and 1999 was $5.50 per share option and $4.37 per share option, respectively. The weighted-average remaining life of options outstanding as of December 31, 2000, and December 31, 1999, was 7 years.

Note 10. Jointly Owned Utility Projects

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

The investment in each project as of December 31, 2000, was:

In millions	Original Cost of Facility	Accumulated Depreciation and Amortization	Under Construction	Ownership Interest
Transmission systems:				
Eldorado	$ 41	$ 11	$ 1	60%
Pacific Intertie	230	80	6	50
Generating stations:				
Four Corners Units 4 and 5 (coal)	463	351	3	48
Mohave (coal)	327	240	3	56
Palo Verde (nuclear)[1]	1,624	1,399	15	16
San Onofre (nuclear)[1]	4,268	3,874	22	75
Total	$6,953	$5,955	$50	

(1) Regulatory assets, which were written off as a charge to earnings as of December 31, 2000, as discussed in Notes 1 and 3.

Note 11. Commitments

Leases

SCE has operating leases, primarily for vehicles, with varying terms, provisions and expiration dates.

Estimated remaining commitments for noncancellable leases at December 31, 2000, were:

Year ended December 31,	In millions
2001	$ 15
2002	12
2003	10
2004	9
2005	6
Thereafter	14
Total	$ 66

Nuclear Decommissioning

Decommissioning is estimated to cost $2.1 billion in current-year dollars, based on site-specific studies performed in 1998 for San Onofre and Palo Verde. Changes in the estimated costs, timing of decommissioning, or the assumptions underlying these estimates could cause material revisions to the estimated total cost to decommission in the near term. SCE estimates that it will spend approximately $8.6 billion through 2060 to decommission its nuclear facilities. This estimate is based on SCE's current dollar decommissioning costs, escalated at rates ranging from 0.3% to 10.0% (depending on the cost element) annually. These costs are expected to be funded from independent decommissioning trusts, which, effective June 1999, receive contributions of approximately $25 million per year. SCE estimates annual after-tax earnings on the decommissioning funds of 3.9% to 4.9%.

SCE plans to decommission its nuclear generating facilities by a prompt removal method authorized by the Nuclear Regulatory Commission. The operating licenses expire in 2022 for San Onofre Units 2 and 3, and in 2026 and 2028 for the Palo Verde units. SCE could decommission San Onofre Units 2 and 3 as early as 2013. Palo Verde is planned to be decommissioned at the end of its operating license. Decommissioning costs, which are recovered through nonbypassable customer rates over the term of each nuclear facility's operating license, are recorded as a component of depreciation expense.

Decommissioning of San Onofre Unit 1 (shut down in 1992 per CPUC agreement) started in 1999 and will continue through 2008. All of SCE's San Onofre Unit 1 decommissioning costs will be paid from its nuclear decommissioning trust funds.

Decommissioning expense was $106 million in 2000, $124 million in 1999 and $164 million in 1998. The accumulated provision for decommissioning, excluding San Onofre Unit 1 and unrealized holding gains, was $1.4 billion at December 31, 2000, and $1.3 billion at December 31, 1999. The estimated costs (recorded as a liability) to decommission San Onofre Unit 1 is approximately $342 million as of December 31, 2000.

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,	**2000**	1999
Municipal bonds	2001—2034		**$ 548**	$ 684
Stocks	—		**531**	482
U.S. government issues	2001—2029		**421**	351
Short-term and other	2001		**220**	133
Total			**$1,720**	$1,650

Trust fund earnings (based on specific identification) increase the trust fund balance and the accumulated provision for decommissioning. Net earnings were $38 million in 2000, $58 million in 1999 and $63 million in 1998. Proceeds from sales of securities (which are reinvested) were $4.7 billion in 2000, $2.6 billion in 1999 and $1.2 billion in 1998. Approximately 90% of the trust fund contributions were tax-deductible.

Other Commitments

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

SCE has power-purchase contracts with certain qualifying facilities (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. As a result of the utility industry restructuring, SCE has entered into purchased-power settlements to end its contract obligations with certain qualifying facilities. 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 $159 million through 2017. The purchased-power contract is expected to provide approximately 5% of current or estimated future operating capacity, and is reported as power purchase contracts (approximately $31 million). The transmission service contract requires a minimum payment of approximately $6 million a year.

Certain commitments for the years 2001 through 2005 are estimated below:

In millions	2001	2002	2003	2004	2005
Fuel supply contracts	$150	$107	$115	$ 97	$ 97
Purchased-power capacity payments	647	644	637	635	632

SCE's projected construction expenditures for 2001 total approximately $602 million. The construction program is subject to periodic review and revision, and actual construction costs may vary from estimates because of numerous factors.

Note 12. Contingencies

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

Energy Crisis Issues

In December 2000, a first amended complaint to a class action securities lawsuit (originally filed in October 2000) was filed in federal district court in Los Angeles against SCE and Edison International. On March 5, 2001, a second amended complaint was filed that alleges that SCE and Edison International are engaging in fraud by over-reporting and improperly accounting for the TRA undercollections. The second amended complaint is supposedly filed on behalf of a class of persons who purchased Edison International common stock beginning June 1, 2000, and continuing until such time as TRA-related undercollections are recorded as a loss on SCE's income statement. The response to the second amended complaint was due April 2, 2001. The response has been deferred pending resolution of motions to consolidate this lawsuit with another lawsuit filed on March 15, 2001. SCE believes that its current and past accounting for the TRA undercollections and related items is appropriate and in accordance with accounting principles generally accepted in the United States.

As of April 13, 2001, 17 additional lawsuits have been filed against SCE by QFs. The lawsuits have been filed by various parties, including geothermal or wind energy suppliers or owners of cogeneration projects. The lawsuits are seeking payments of at least $420 million for energy and capacity supplied to SCE under QF contracts, and in some cases for damages as well. Many of these QF lawsuits also seek an order allowing the suppliers to stop providing power to SCE and sell the power to other purchasers. SCE is seeking coordination of all of the QF-related lawsuits that have commenced in various California courts. On April 13, 2001, an order was issued assigning all pending cases to a coordination motion judge and setting a hearing on SCE's coordination petition by May 30, 2001. SCE cannot predict the outcome of any of these matters.

Environmental Protection

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

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

SCE's recorded estimated minimum liability to remediate its 44 identified sites is $114 million. The ultimate costs to clean up SCE's identified sites may vary from its recorded liability due to numerous uncertainties inherent in the estimation process, such as: the extent and nature of contamination; the scarcity of reliable data for identified sites; the varying costs of alternative cleanup methods; developments resulting from investigatory studies; the possibility of identifying additional sites; and the time periods over which site remediation is expected to occur. SCE believes that, due to these uncertainties, it is reasonably possible that cleanup costs could exceed its recorded liability by up to $272 million. The upper limit of this range of costs was estimated using assumptions least favorable to SCE among a range of reasonably possible outcomes. SCE has sold all of its gas-fueled generation plants and has retained some liability associated with the divested properties.

The CPUC allows SCE to recover environmental-cleanup costs at certain sites, representing $45 million of its recorded liability, through an incentive mechanism. Under this mechanism, SCE will recover 90% of cleanup costs through customer rates; shareholders fund the remaining 10%, with the opportunity to recover these costs from insurance carriers and other third parties. SCE has successfully settled insurance claims with all responsible carriers. Costs incurred at SCE's remaining sites are expected to be recovered through customer rates. SCE has recorded a regulatory asset of $75 million for its estimated minimum environmental-cleanup costs expected to be recovered through customer rates.

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

SCE expects to clean up its identified sites over a period of up to 30 years. Remediation expenditures in each of the next several years are expected to range from $5 million to $15 million. Recorded expenditures for 2000 were $13 million.

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

Nuclear Insurance

Federal law limits public liability claims from a nuclear incident to $9.5 billion. SCE and other owners of San Onofre and Palo Verde have purchased the maximum private primary insurance available ($200 million). The balance is covered by the industry's retrospective rating plan that uses deferred premium charges to every reactor licensee if a nuclear incident at any licensed reactor in the U.S. results in claims and/or costs which exceed the primary insurance at that plant site. Federal regulations require this secondary level of financial protection. The Nuclear Regulatory Commission exempted San Onofre Unit 1 from this secondary level, effective June 1994. The maximum deferred premium for each nuclear incident is $88 million per reactor, but not more than $10 million per reactor may be charged in any one year for each incident. Based on its ownership interests, SCE could be required to pay a maximum of $175 million per nuclear incident. However, it would have to pay no more than $20 million per incident in any one year. Such amounts include a 5% surcharge if additional funds are needed to satisfy public liability claims and are subject to adjustment for inflation. If the public liability limit above is insufficient, federal regulations may impose further revenue-raising measures to pay claims, including a possible additional assessment on all licensed reactor operators.

Property damage insurance covers losses up to $500 million, including decontamination costs, at San Onofre and Palo Verde. Decontamination liability and property damage coverage exceeding the primary $500 million also has been purchased in amounts greater than federal requirements. Additional insurance covers part of replacement power expenses during an accident-related nuclear unit outage. These policies are issued by a mutual insurance company owned by utilities with nuclear facilities. If losses at any nuclear facility covered by the arrangement were to exceed the accumulated funds for these insurance programs, SCE could be assessed retrospective premium adjustments of up to $19 million per year. Insurance premiums are charged to operating expense.

Spent Nuclear Fuel

Under federal law, the DOE is responsible for the selection and development of a facility for disposal of spent nuclear fuel and high-level radioactive waste. Such a facility was to be in operation by January 1998. However, the DOE did not meet its obligation. It is not certain when the DOE will begin accepting spent nuclear fuel from San Onofre or from other nuclear power plants.

SCE, as operating agent, has primary responsibility for the interim storage of its spent nuclear fuel at San Onofre. Current capability to store spent fuel is estimated to be adequate through 2005. SCE has not determined the costs for spent-fuel storage beyond that period, which would require new and separate interim storage facilities. Extended delays by the DOE could lead to consideration of costly alternatives involving siting and environmental issues. SCE has paid the DOE the required one-time fee applicable to nuclear generation at San Onofre through April 6, 1983 (approximately $24 million, plus interest). SCE is also paying the required quarterly fee equal to one mill per kilowatt-hour of nuclear-generated electricity sold after April 6, 1983.

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

Quarterly Financial Data

	2000					1999				
In millions	Total	Fourth	Third	Second	First	Total	Fourth	Third	Second	First
Operating revenue	$ 7,870	$ 1,755	$2,432	$1,853	$1,830	$7,548	$1,827	$2,310	$1,726	$1,685
Operating income (loss)	(1,652)	(2,402)	273	250	227	855	224	257	198	176
Net income (loss)	(2,028)	(2,485)	177	161	119	509	146	168	112	83
Net income (loss) available for common stock	(2,050)	(2,491)	172	156	113	484	141	160	106	77
Common dividends declared	279	—	92	91	96	666	117	269	111	169

Responsibility for Financial Reporting

The management of Southern California Edison Company (SCE) is responsible for the integrity and objectivity of the accompanying financial statements. The statements have been prepared in accordance with accounting principles generally accepted in the United States and are based, in part, on management estimates and judgment.

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

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

As a further measure to assure the ongoing objectivity of financial information, the audit committee of the Board of Directors, which is composed of outside directors, meets periodically, both jointly and separately, with management, the independent public accountants and internal auditors, who have unrestricted access to the committee. The committee recommends annually to the Board of Directors the appointment of a firm of independent public accountants to conduct audits of its 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

Stephen E. Frank
Chairman of the Board, President
and Chief Executive Officer

April 12, 2001

To the Shareholders and the Board of Directors,
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, 2000, and 1999, 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, 2000. 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, 2000, and 1999, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2000, in conformity with accounting principles generally accepted in the United States.

The accompanying financial statements have been prepared assuming that SCE will continue as a going concern. As discussed in Notes 2 and 3 to the consolidated financial statements, the current energy crisis in California has resulted in SCE incurring a loss from operations in the current year due to the uncertainty associated with its ability to collect certain costs through the regulatory process and has resulted in legal, regulatory and legislative uncertainties which have adversely impacted SCE's liquidity. These issues raise substantial doubt about SCE's ability to continue as a going concern. Management's plans in regard to these matters are also described in Notes 2 and 3. The financial statements do not include any adjustments relating to the recoverability and classification of asset carrying amounts or the amount and classification of liabilities that might result should SCE be unable to continue as a going concern.

ARTHUR ANDERSEN LLP

Los Angeles, California
April 12, 2001

Board of Directors

Warren Christopher
Senior Partner,
O'Melveny & Myers,
Los Angeles, California

Stephen E. Frank
Chairman of the Board, President and
Chief Executive Officer,
Southern California Edison Company

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The Former General Partner and Manager,
Miramonte Vineyards,
Rancho Palos Verdes, California

Carl F. Huntsinger
General Partner,
DAE Limited Partnership Ltd.,
Ojai, California

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Retired Chairman of the Board,
Avery Dennison Corporation,
Pasadena, California

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Senior Partner,
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Los Angeles, California

James M. Rosser
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California State University, Los Angeles,
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Managing Director,
Smith and Crowley Incorporated,
Pasadena, California

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Chief Executive Officer
Pacific Life Insurance Company,
Newport Beach, California

Daniel M. Tellep
Retired Chairman of the Board,
Lockheed Martin Corporation,
Bethesda, Maryland

Edward Zapanta, M.D.
Physician and Neurosurgeon,
Torrance, California

Management Team

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Chairman of the Board, President and
Chief Executive Officer

Harold B. Ray
Executive Vice President,
Generation Business Unit

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

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

Robert G. Foster
Senior Vice President,
External Affairs

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

Mahvash Yazdi
Senior Vice President and
Chief Information Officer

Emiko Banfield
Vice President,
Shared Services

Robert C. Boada
Vice President and Treasurer

Clarence Brown
Vice President,
Corporate Communications

Bruce C. Foster
Vice President,
San Francisco Regulatory Operations

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

Lawrence D. Hamlin
Vice President, Power Production

Harry B. Hutchison
Vice President,
Mass Customers

James A. Kelly
Vice President,
Regulatory Compliance

Russell W. Krieger
Vice President,
Nuclear Generation

J. Michael Mendez
Vice President, Labor Relations

Thomas M. Noonan
Vice President and Controller

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

Stephen E. Pickett
Vice President and General Counsel

Frank J. Quevedo
Vice President,
Equal Opportunity

Joseph P. Ruiz
Vice President and General Auditor

W. James Scilacci
Vice President and
Chief Financial Officer

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

Anthony L. Smith
Vice President, Tax

David Ned Smith
Vice President, Major Customers

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

Beverly P. Ryder
Secretary

Shareholder Information

Annual Meeting of Shareholders

Monday, May 14, 2001
1:30 p.m.
DoubleTree Hotel Ontario
222 N. Vineyard Avenue
Ontario, California 91764

Stock Listing and Trading Information

SCE Preferred Stock

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

Where to Buy and Sell Stock

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

Transfer Agent and Registrar

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

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

The address of Wells Fargo Shareowner Services is:

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

SCE Web Address:
www.edisoninvestor.com

Southern California Edison Company
2244 Walnut Grove Avenue
Rosemead, California 91770
(626) 302-1212