SOUTHERN CALIFORNIA
EDISON
An EDISON INTERNATIONAL℠ Company

Dwight E. Nunn
Vice President

May 21, 2001

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

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

Gentlemen:

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

- 2001 Cash Reserve statement which is obtained from SCE's Form 10-Q Quarterly Report to the Securities and Exchange Commission (Form 10-Q) for the quarter ending March 31, 2001, as audited and certified by Arthur Anderson, LLP
- SCE's Form 10-Q Quarterly Report to the Securities and Exchange Commission (Form 10-Q) for the quarter ending March 31, 2001
- SCE's Annual Report to Shareholders for the fiscal year ending December 31, 2000
- SCE's Form 10K Annual Report to the Securities and Exchange Commission (Form 10K) for the fiscal year ending December 31,2000

Historically, SCE has reported the "Internal Cash Flow" as the method of meeting the reporting requirement of 10 CFR 140.21(e). However, due to the current California energy situation, SCE is now reporting the "Cash Reserve" to meet the reporting requirement of 10 CFR 140.21(e).

M004

P. O. Box 128
San Clemente, CA 92674-0128
949-368-1480
Fax 949-368-1490

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

Sincerely,

Enclosures

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

SOUTHERN CALIFORNIA EDISON COMPANY

2001 Cash Reserve
(Dollars in Thousands)

Cash Reserves as of March 31, 2001	$2,027,000
Percentage Ownership in All Nuclear Units:	
San Onofre Nuclear Generating Station Units 2 & 3	
o Southern California Edison Company	75.05%
o San Diego Gas & Electric Company	20.00%
o City of Anaheim	3.16%
o City of Riverside	1.79%
Palo Verde Nuclear Generating Station Units 1, 2 & 3	15.80%
Maximum Total Contingent Liability:	
San Onofre Nuclear Generating Station Unit 2	$10,000
San Onofre Nuclear Generating Station Unit 3	$10,000
Palo Verde Nuclear Generating Station Unit 1	$1,580
Palo Verde Nuclear Generating Station Unit 2	$1,580
Palo Verde Nuclear Generating Station Unit 3	$1,580
Total	$24,740

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

FORM 10-Q

(Mark One)

/X/ Quarterly report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the quarterly period ended March 31, 2001

OR

/ / Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the transition period from__________________ to __________________

Commission File Number 1-2313

SOUTHERN CALIFORNIA EDISON COMPANY

(Exact name of registrant as specified in its charter)

CALIFORNIA (State or other jurisdiction of incorporation or organization)	95-1240335 (I.R.S. Employer Identification No.)
2244 Walnut Grove Avenue (P. O. Box 800) Rosemead, California (Address of principal executive offices)	91770 (Zip Code)

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes X No ___

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date:

Class	Outstanding at May 10, 2001
Common Stock, no par value	434,888,104

SOUTHERN CALIFORNIA EDISON COMPANY

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PART I FINANCIAL INFORMATION

Item 1. Consolidated Financial Statements

Report of Independent Public Accountants

To Southern California Edison Company:

We have audited the accompanying consolidated balance sheets of Southern California Edison Company (SCE, a California corporation) and its subsidiaries as of March 31, 2001, December 31, 2000, and March 31, 2000, and the related consolidated statements of income (loss), comprehensive income (loss), cash flows and changes in common shareholder's equity for each of the three- and twelve-month periods ended March 31, 2001, and 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 March 31, 2001, December 31, 2000, and March 31, 2000, and the results of their operations and their cash flows for each of the three- and twelve-month periods ended March 31, 2001, and 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 for the three and twelve months ended March 31, 2001, 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
May 11, 2001

SOUTHERN CALIFORNIA EDISON COMPANY

CONSOLIDATED STATEMENTS OF INCOME (LOSS)
In millions

	3 Months Ended March 31,		12 Months Ended March 31,	
	2001	**2000**	**2001**	**2000**
Operating revenue	$ 1,512	$ 1,830	$ 7,552	$ 7,693
Fuel	47	55	187	221
Purchased power	1,724	504	5,907	2,956
Provisions for regulatory adjustment clauses – net	(29)	103	2,169	(380)
Other operation and maintenance	429	409	1,792	1,847
Depreciation, decommissioning and amortization	152	376	1,249	1,537
Income taxes	(419)	123	(1,549)	491
Property and other taxes	29	40	115	123
Net gain on sale of utility plant	(3)	(6)	(22)	(7)
Total operating expenses	1,930	1,604	9,848	6,788
Operating income (loss)	(418)	226	(2,296)	905
Interest and dividend income	25	20	178	75
Other nonoperating income	9	20	106	141
Interest expense – net of amounts capitalized	(207)	(127)	(652)	(489)
Other nonoperating deductions	8	(23)	(79)	(108)
Tax benefit (expense) on other income and deductions	(9)	3	3	21
Net income (loss)	(592)	119	(2,740)	545
Dividends on preferred stock	6	6	21	25
Net income (loss) available for common stock	$ (598)	$ 113	$ (2,761)	$ 520

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
In millions

	3 Months Ended March 31,		12 Months Ended March 31,	
	2001	**2000**	**2001**	**2000**
Net income (loss)	$ (592)	$ 119	$ (2,740)	$ 545
Other comprehensive income, net of tax:				
Unrealized gain on securities – net	—	3	—	37
Cumulative effect of change in accounting for derivatives	397	—	397	—
Unrealized loss on cash flow hedges	(422)	—	(422)	—
Reclassification adjustment for gains included in net income	—	—	(24)	(28)
Comprehensive income (loss)	$ (617)	$ 122	$ (2,789)	$ 554

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

SOUTHERN CALIFORNIA EDISON COMPANY

CONSOLIDATED BALANCE SHEETS
In millions

	March 31, 2001	December 31, 2000	March 31, 2000
ASSETS			
Utility plant, at original cost:			
Transmission and distribution	$ 13,247	$ 13,129	$ 12,558
Generation	1,749	1,745	1,736
Accumulated provision for depreciation and decommissioning	(7,794)	(7,834)	(7,705)
Construction work in progress	635	636	665
Nuclear fuel, at amortized cost	134	143	117
Total utility plant	7,971	7,819	7,371
Nonutility property – less accumulated provision for depreciation of $12, $11 and $8 at respective dates	107	102	100
Nuclear decommissioning trusts	2,372	2,505	2,581
Other investments	84	90	160
Total investments and other assets	2,563	2,697	2,841
Cash and equivalents	2,027	583	131
Receivables, less allowances of $23, $23 and $24 for uncollectible accounts at respective dates	891	919	613
Accrued unbilled revenue	393	377	378
Fuel inventory	14	12	40
Materials and supplies, at average cost	136	132	125
Accumulated deferred income taxes – net	525	545	125
Prepayments and other current assets	97	124	56
Total current assets	4,083	2,692	1,468
Regulatory assets – net	2,759	2,390	5,421
Other deferred charges	503	368	594
Total deferred charges	3,262	2,758	6,015
Total assets	$ 17,879	$ 15,966	$ 17,695

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

SOUTHERN CALIFORNIA EDISON COMPANY

CONSOLIDATED BALANCE SHEETS
In millions, except share amounts

	March 31, 2001	December 31, 2000	March 31, 2000
CAPITALIZATION AND LIABILITIES			
Common shareholder's equity:			
Common stock (434,888,104 shares outstanding at each date)	$ 2,168	$ 2,168	$ 2,168
Additional paid-in capital	334	334	335
Accumulated other comprehensive income (loss)	(25)	—	24
Retained earnings (deficit)	(2,320)	(1,722)	626
	157	780	3,153
Preferred stock:			
Not subject to mandatory redemption	129	129	129
Subject to mandatory redemption	256	256	256
Long-term debt	5,405	5,631	5,109
Total capitalization	5,947	6,796	8,647
Short-term debt	2,120	1,451	849
Current portion of long-term debt	646	646	448
Accounts payable	2,938	1,055	425
Accrued taxes	440	536	590
Accrued interest	163	96	83
Dividends payable	5	1	99
Regulatory liabilities – net	251	195	221
Deferred unbilled revenue	278	250	265
Other current liabilities	1,232	1,155	1,289
Total current liabilities	8,073	5,385	4,269
Accumulated deferred income taxes – net	1,960	2,009	2,880
Accumulated deferred investment tax credits	155	164	195
Customer advances and other deferred credits	834	755	816
Power-purchase contracts	439	467	539
Accumulated provision for pensions and benefits	378	296	246
Other long-term liabilities	93	94	103
Total deferred credits and other liabilities	3,859	3,785	4,779
Commitments and contingencies (Notes 2, 3, 11 and 12)			
Total capitalization and liabilities	$ 17,879	$ 15,966	$ 17,695

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

SOUTHERN CALIFORNIA EDISON COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
In millions

	3 Months Ended March 31, 2001	3 Months Ended March 31, 2000	12 Months Ended March 31, 2001	12 Months Ended March 31, 2000
Cash flows from operating activities:				
Net income (loss)	$ (592)	$ 119	$ (2,740)	$ 545
Adjustments to reconcile net income (loss) to net cash provided by operating activities:				
Depreciation, decommissioning and amortization	152	376	1,249	1,537
Other amortization	18	25	89	100
Deferred income taxes and investment tax credits	(303)	(39)	(1,182)	56
Regulatory balancing accounts – long-term	69	(92)	1,920	(1,116)
Net gain on sale of marketable securities	—	—	(41)	(48)
Other assets	(283)	(24)	(215)	(62)
Other liabilities	66	(6)	59	(40)
Changes in working capital:				
Receivables and accrued unbilled revenue	16	23	(289)	57
Regulatory balancing accounts – short-term	56	120	33	480
Fuel inventory, materials and supplies	(7)	8	15	7
Prepayments and other current assets	28	56	(41)	(1)
Accrued interest and taxes	(28)	90	(80)	(101)
Accounts payable and other current liabilities	1,987	(75)	2,650	271
Net cash provided by operating activities	1,179	581	1,427	1,685
Cash flows from financing activities:				
Long-term debt issued	—	248	1,511	739
Long-term debt repaid	—	(325)	(200)	(688)
Bonds repurchased and funds held in trust	(156)	—	(596)	—
Rate reduction notes repaid	(63)	(61)	(248)	(236)
Nuclear fuel financing – net	(9)	(14)	15	(43)
Short-term debt financing – net	669	53	1,271	220
Dividends paid	(1)	(100)	(296)	(614)
Net cash provided (used) by financing activities	440	(199)	1,457	(622)
Cash flows from investing activities:				
Additions to property and plant	(178)	(253)	(1,021)	(1,008)
Funding of nuclear decommissioning trusts	—	(23)	(46)	(102)
Proceeds from sales of marketable securities	—	—	41	50
Investments in other assets	3	(1)	38	6
Net cash used by investing activities	(175)	(277)	(988)	(1,054)
Net increase in cash and equivalents	1,444	105	1,896	9
Cash and equivalents, beginning of period	583	26	131	122
Cash and equivalents, end of period	$ 2,027	$ 131	$ 2,027	$ 131
Cash payments for interest and taxes:				
Interest – net of amounts capitalized	$ 69	$ 74	$ 298	$ 293
Taxes	—	—	306	433

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

SOUTHERN CALIFORNIA EDISON COMPANY

CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDER'S EQUITY
In millions

	Common Stock	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings (Deficit)	Total Common Shareholder's Equity
Balance at December 31, 1999	$ 2,168	$ 335	$ 22	$ 608	$ 3,133
Net income				119	119
Unrealized gain on securities			4		4
Tax effect			(2)		(2)
Dividends declared on common stock				(95)	(95)
Dividends declared on preferred stock				(5)	(5)
Stock option appreciation				(1)	(1)
Balance at March 31, 2000	$ 2,168	$ 335	$ 24	$ 626	$ 3,153
Balance at December 31, 2000	$ 2,168	$ 334	$ —	$ (1,722)	$ 780
Net income (loss)				(592)	(592)
Cumulative effect of change in accounting for derivatives			397		397
Unrealized loss on cash flow hedges			(422)		(422)
Dividends accrued on preferred stock				(6)	(6)
Balance at March 31, 2001	$ 2,168	$ 334	$ (25)	$ (2,320)	$ 157
Balance at March 31, 1999	$ 2,168	$ 334	$ 16	$ 700	$ 3,218
Net income				545	545
Unrealized gain on securities			59		59
Tax effect			(22)		(22)
Reclassified adjustment for gain included in net income			(48)		(48)
Tax effect			19		19
Dividends declared on common stock				(592)	(592)
Dividends declared on preferred stock				(25)	(25)
Stock option appreciation and other				(2)	(2)
Capital stock expense		1			1
Balance at March 31, 2000	$ 2,168	$ 335	$ 24	$ 626	$ 3,153
Net income (loss)				(2,740)	(2,740)
Cumulative effect of change in accounting for derivatives			397		397
Unrealized loss on cash flow hedges			(422)		(422)
Reclassified adjustment for gain included in net income			(41)		(41)
Tax effect			17		17
Dividends declared on common stock				(183)	(183)
Dividends accrued on preferred stock				(21)	(21)
Stock option appreciation and other				(2)	(2)
Capital stock expense		(1)			(1)
Balance at March 31, 2001	$ 2,168	$ 334	$ (25)	$ (2,320)	$ 157

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

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

SOUTHERN CALIFORNIA EDISON COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Summary of Significant Accounting Policies

Nature of Operations

Southern California Edison Company (SCE) is a rate-regulated electric utility that supplies electric energy 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 utility 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 utility 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 utility industry restructuring statute included provisions to finance a portion of the stranded costs that residential and small commercial customers would have paid between 1998 and 2001, which allowed SCE to reduce rates by at least 10% to these customers, effective January 1, 1998. These frozen rates (except for the surcharges effective first quarter 2001) 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 requirement for California utilities to buy and sell power exclusively through the ISO and PX was eliminated by the Federal Energy Regulatory Commission (FERC) in December 2000. On January 31, 2001, the PX stopped operation of its day-ahead and day-of markets and 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-period amounts were reclassified to conform to the March 31, 2001, 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.

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 transferred 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.

SOUTHERN CALIFORNIA EDISON COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 MOU 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.

SOUTHERN CALIFORNIA EDISON COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

In millions	March 31, 2001	December 31, 2000	March 31, 2000
Generation-related:			
Unamortized nuclear investment – net	$ —	$ —	$ 1,167
Flow-through taxes	—	—	245
Unamortized loss on sale of plant	—	—	107
Purchased-power settlements	—	—	507
Environmental remediation	—	—	16
Regulatory balancing accounts and other	—	—	1,013
Subtotal	—	—	3,055
Rate reduction notes – transition cost deferral	1,181	1,090	800
Other:			
Flow-through taxes	1,136	874	1,061
Unamortized loss on reacquired debt	267	273	289
Environmental remediation	57	52	106
Regulatory balancing accounts and other	(133)	(94)	(111)
Subtotal	1,327	1,105	1,345
Total	$ 2,508	$ 2,195	$ 5,200

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 had been recovering its investments in San Onofre Nuclear Generating Station Units 2 and 3 and Palo Verde Nuclear Generating Station on an accelerated basis, as authorized by the CPUC. The accelerated recovery was to continue through December 2001, earning a 7.35% fixed rate of return on investment. San Onofre's operating costs, including nuclear fuel and nuclear fuel financing costs, and incremental capital expenditures, 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 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 period.

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. 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.

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. Prior to adoption, hedges were not recorded on the balance sheet. Gains or losses from changes in the fair value of a recognized asset or liability or a firm commitment are reflected in earnings for the ineffective portion of the hedge. For a hedge of the cash flows of a forecasted transaction, the effective portion of the gain or loss is initially recorded as a separate component of shareholder's equity under the caption "accumulated other comprehensive income," and subsequently reclassified into earnings when the forecasted transaction affects earnings. The ineffective portion of the gain or loss is reflected in earnings immediately. Under the new standard, SCE's derivatives qualify for hedge accounting or for the normal purchase and sales exemption from derivatives accounting rules. See Note 4 for a further discussion.

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 $2 million and $10 million for the three and twelve months ended March 31, 2001, respectively, and $4 million and $14 million for the three and twelve months ended March 31, 2000, respectively. AFUDC – debt was $3 million and $9 million for the three and twelve months ended March 31, 2001, respectively, and $3 million and $12 million for the three and twelve months ended March 31, 2000, respectively.

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% and 3.5% for the three and twelve months ended March 31, 2001, respectively, and 3.7% for both the three and twelve months ended March 31, 2000.

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

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 $160 million and $471 million for the three and twelve months ended March 31, 2001, respectively, and $45 million and $240 million for the three and twelve months ended March 31, 2000, respectively. As a result of SCE's liquidity crisis, SCE has deferred payments for power purchases from some of these facilities.

Purchased Power

SCE purchased power through the PX from April 1998 through January 18, 2001. Ancillary and other services are purchased through the ISO. SCE also has bilateral forward contracts with other entities (as discussed in Note 4) and contracts with other utilities and qualifying facilities (QFs). Purchased power detail is provided below:

	3 Months Ended March 31,		12 Months Ended March 31,	
In millions	**2001**	**2000**	**2001**	**2000**
PX/ISO:				
Purchases	$ 1,081	$ 517	$ 9,014	$ 2,595
Generation sales	(705)	(441)	(6,385)	(1,876)
Purchased power – PX/ISO – net	376	76	2,629	719
Purchased power – bilateral contracts	52	—	52	—
Purchased power – interutility/QF contracts	1,296	428	3,226	2,237
Total	$ 1,724	$ 504	$ 5,907	$ 2,956

Other Nonoperating Income and Deductions

Other nonoperating income and deductions was comprised of:

	3 Months Ended March 31,		12 Months Ended March 31,	
In millions	**2001**	**2000**	**2001**	**2000**
Gain on sale of marketable securities	$ —	$ —	$ 41	$ 48
AFUDC	5	7	19	26
Key person life insurance income	4	5	4	16
Other	—	8	42	51
Total other nonoperating income	9	$ 20	$ 106	141
Provisions for regulatory issues and refunds	$ (16)	$ 19	$ 43	$ 82
Other	8	4	36	26
Total other nonoperating deductions	$ (8)	$ 23	$ 79	$ 108

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 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 temporarily suspended payments of certain obligations for principal and interest on outstanding debt and for purchased power. As of April 30, 2001, SCE had $3.1 billion in obligations that were unpaid and overdue including: (1) $882 million to the PX or the ISO; (2) $1.3 billion to QF power producers; (3) $230 million in PX energy credits for energy service providers; (4) $531 million of matured commercial paper; and (5) $200 million of principal on its 5-7/8% notes. If SCE is found responsible for the purchases of power by the California Department of Water Resources (CDWR) or the ISO for sale to SCE's customers on or after January 18, 2001, SCE's unpaid obligations as of April 30, 2001, could increase by as much as $800 million. See additional discussion in Note 3. As applicable, unpaid obligations will continue to accrue interest. At April 30, 2001, SCE had estimated cash reserves of approximately $1.9 billion, which is approximately $1.3 billion 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 $550 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 (as further discussed in Note 3), it is expected to allow SCE to recover its undercollected costs and to help 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 other investor-owned utilities 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 QFs' billing periods, 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 the 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 and the approval of a 3¢ per kWh rate increase (see Note 3). Based on these two decisions, SCE estimates that cash going forward may not be sufficient to cover 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 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 were $6 million as of April 30, 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 conditions under which dividends can be paid from sources other than retained earnings. As long as accumulated dividends in arrears on SCE's preferred stock remain unpaid, SCE cannot pay any dividends on its common stock.

In addition to the above, SCE has implemented 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.

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. SCE's independent public accountant's opinion on 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 other costs incurred to provide service to customers. Other costs include the recovery of income tax benefits previously flowed through to customers, postretirement benefit transition costs, and accelerated recovery of investment in San Onofre Units 2 and 3 and the Palo Verde units. Transition costs related to power-purchase QF 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 unable 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 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.

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. 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. 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 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 March 31, 2001. The cumulative TCBA undercollection (as recalculated) was $2.9 billion as of December 31, 2000, and $3.9 billion as of March 31, 2001. A summary of the components of this cumulative undercollection as of March 31, 2001, is as follows:

In millions	
Transition costs recorded in the TCBA:	
QF and interutility costs	$ 4,556
Amortization of nuclear-related regulatory assets	3,090
Depreciation of plant assets	613
Other transition costs	732
Total costs	8,991
Revenue available to recover transition costs	(5,117)
TCBA undercollections	$ 3,874

Unless the regulatory and legislative actions required to implement the MOU or other actions that make recovery probable are taken, SCE is unable 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, and an additional $996 million in TCBA undercollections was charged to earnings as of March 31, 2001. 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 CPUC 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 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 procurement 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 early June 2001. 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 Assembly Bill 1 (First Extraordinary Session, 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 (see CDWR Power Purchases). 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.

In December 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.

In December 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 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.

On April 25, 2001, the FERC issued an order providing for cost-based energy price controls during ISO Stage 1 or greater power emergencies (7% or less in reserve power). The order establishes an hourly clearing price based on the costs of the least efficient generating unit during the period. The new approach replaces the $150/MWh breakpoint discussed above. The order is in effect for one year.

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 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 the utility 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.

- Edison Mission Energy (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. Edison Mission Energy 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, 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 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 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. The CPUC has stated it will expeditiously review those provisions of the MOU that require resolution. SCE and the Governor have been working diligently to have the MOU supported by the legislature. However, no formal action has been taken by either the CPUC or the legislature.

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. AB 1X authorized the CDWR to enter into contracts to purchase electric power and sell power at cost directly to retail customers being served by SCE, and authorized the CDWR to issue revenue bonds to finance electricity purchases. On May 10, 2001, the Governor signed a bill authorizing the CDWR to issue up to $13.4 billion in bonds. The law will become effective in 90 days. AB 1X 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. AB 1X 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 or accrued $251 million for sales made by the CDWR and ISO during the period January 19 through April 30, 2001, and has forwarded $147 million to the CDWR on behalf of these customers as of April 30, 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. 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, and has billed SCE a total of $580 million for January and February 2001 purchases. If SCE is found responsible for purchases of power by the CDWR or the ISO for sale to SCE's customers on or after January 18, 2001, SCE's purchased-power costs (and pre-tax loss) for first quarter 2001 could increase by as much as $800 million. 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 its February 14, 2001, order that the ISO must have a creditworthy buyer for any transactions. SCE has not met the ISO's creditworthiness requirements since its credit ratings were downgraded in mid-January 2001. As a result, SCE has protested and returned the bills it has received from the ISO. 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). Under the MOU, 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 the PX could sell them. See further discussion below.

SCE also has bilateral forward contacts, which are considered normal purchases under accounting rules. 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. At March 31, 2001, these contracts had a nominal value of $435 million. 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 March 31, 2000, 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. See Note 1 for a further discussion. On the implementation date, SCE recorded its interest rate swap agreement (terminated January 5, 2001) and its block forward power-purchase contracts at fair value on its balance sheet. 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 seized the contracts, which at that time had an unrealized gain of approximately $500 million. If other elements of the MOU are implemented, SCE will relinquish all claims against the state for seizing these contracts. If the MOU is not implemented, SCE believes that it should be compensated for the reasonable value of these contracts under law, and would pursue the matter. SCE's March 31, 2001, balance sheet no longer includes these contracts. As of March 31, 2001, SCE did not have any derivatives as defined by the new accounting standard. SCE does not anticipate any earnings impact from any future derivatives, since it expects that any market price changes will be recovered in rates.

Fair values of financial instruments were:

In millions	March 31, 2001		December 31, 2000		March 31, 2000	
Instrument	Cost Basis	Fair Value	Cost Basis	Fair Value	Cost Basis	Fair Value
Financial assets:						
Decommissioning trusts	$1,720	$2,372	$ 1,720	$ 2,505	$ 1,673	$ 2,581
Equity investments	—	—	—	—	—	38
Gas call options	—	—	—	—	25	24
Financial liabilities:						
DOE decommissioning and decontamination fees	36	25	36	31	40	35
Interest rate swap	—	—	—	21	—	10
Short-term debt	2,120	1,985	1,451	1,339	849	849
Long-term debt	5,405	4,642	5,631	5,178	5,109	5,020
Preferred stock subject to mandatory redemption	256	89	256	157	256	258

Financial assets are carried at their fair value based on quoted market prices. Financial liabilities are recorded at cost. Financial liabilities' fair values are based on: quoted market prices for the interest rate swap; brokers' quotes for short-term debt, 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 approximated fair value at March 31, 2001, December 31, 2000, and March 31, 2000.

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Gross unrealized holding gains on debt and equity investments were:

In millions	March 31, 2001	December 31, 2000	March 31, 2000
Decommissioning trusts:			
Municipal bonds	$ 153	$ 193	$ 243
Stocks	322	384	474
U.S. government issues	113	136	148
Short-term and other	64	72	43
	652	785	908
Equity investments	—	—	38
Total	$ 652	$ 785	$ 946

There were no unrealized holding losses for the periods 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 $550 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	March 31, 2001	December 31, 2000	March 31, 2000
First and refunding mortgage bonds:			
2002 – 2026 (5.625% to 7.25%)	$ 1,175	$ 1,175	$ 1,175
Rate reduction notes:			
2002 – 2007 (6.22% to 6.42%)	1,662	1,724	1,909
Pollution control bonds:			
2008 – 2040 (5.125% to 7.2% and variable)	1,216	1,216	1,197
Bonds repurchased	(550)	(420)	—
Funds held by trustees	(47)	(20)	(2)
Debentures and notes:			
2001 – 2029 (5.875% to 7.625% and variable)	2,450	2,450	1,150
Subordinated debentures:			
2044 (8.375%)	100	100	100
Commercial paper for nuclear fuel	71	79	56
Long-term debt due within one year	(646)	(646)	(448)
Unamortized debt discount – net	(26)	(27)	(28)
Total	$ 5,405	$ 5,631	$ 5,109

Long-term debt maturities and sinking-fund requirements for the five twelve-month periods following March 31, 2001, are: 2002 – $646 million; 2003 – $746 million; 2004 – $1.4 billion; 2005 – $371 million; and 2006 – $446 million. These projections assume no acceleration of payments arising from default. See further discussion in Note 2.

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 April 30, 2001, SCE has failed to pay $200 million of maturing principal 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 or 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 $731 million in overdue principal 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.

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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	March 31, 2001	December 31, 2000	March 31, 2000
Commercial paper	$ 541	$ 700	$ 734
Bank loans	1,650	835	—
Floating rate notes	—	—	175
Amount reclassified as long-term debt	(71)	(79)	(56)
Unamortized discount	—	(5)	(4)
Total	$ 2,120	$ 1,451	$ 849
Weighted-average interest rate	6.4%	6.9%	6.0%

At March 31, 2001, SCE had lines of credit totaling $1.65 billion. As of January 2001, SCE had borrowed the entire $1.65 billion in funds available under its credit lines. The proceeds were used in part to repurchase $550 million of pollution control bonds; the balance was retained as a liquidity reserve. When available, the lines can be drawn at negotiated or bank index rates.

In SCE's efforts to conserve cash, SCE has deferred payment of approximately $531 million of maturing commercial paper as of April 30, 2001.

Note 7. Preferred Stock

Authorized shares of preferred and preference stock 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 five twelve-month periods following March 31, 2001, are: 2002 – zero; 2003 – $109 million; 2004 – $9 million; 2005 – $9 million; and 2006 – $9 million.

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Cumulative preferred stock consisted of:

Dollars in millions, except per share amounts	March 31, 2001 Shares Outstanding	March 31, 2001 Redemption Price	March 31, 2001	December 31, 2000	March 31, 2000
Not subject to mandatory redemption:					
$25 par value:					
4.08% Series	1,000,000	$ 25.50	$ 25	$ 25	$ 25
4.24	1,200,000	25.80	30	30	30
4.32	1,653,429	28.75	41	41	41
4.78	1,296,769	25.80	33	33	33
Total			$ 129	$ 129	$ 129
Subject to mandatory redemption:					
$100 par value:					
6.05% Series	750,000	$ 100.00	$ 75	$ 75	$ 75
6.45	1,000,000	100.00	100	100	100
7.23	807,000	100.00	81	81	81
Total			$ 256	$ 256	$ 256

There were no preferred stock issuances or redemptions for the periods presented.

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 April 30, 2001, SCE's preferred stock dividends in arrears were $6 million. 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.

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

In millions	March 31, 2001	December 31, 2000	March 31, 2000
Deferred tax assets:			
Property-related	$ 226	$ 277	$ 181
Unrealized gains or losses	420	420	453
Investment tax credits	73	81	105
Regulatory balancing accounts	2,123	1,763	77
Decommissioning	94	98	127
Accrued charges	387	379	254
Unbilled revenue	92	101	113
Other	173	56	77
Total	$ 3,588	$ 3,175	$ 1,387
Deferred tax liabilities:			
Property-related	$ 2,316	$ 2,184	$ 2,545
Capitalized software costs	214	264	231
Regulatory balancing accounts	1,819	1,632	476
Unrealized gains and losses	317	317	351
Other	357	242	539
Total	$ 5,023	$ 4,639	$ 4,142
Accumulated deferred income taxes – net	$ 1,435	$ 1,464	$ 2,755
Classification of accumulated deferred income taxes:			
Included in deferred credits	$ 1,960	$ 2,009	$ 2,880
Included in current assets	525	545	125

The current and deferred components of income tax expense were:

	3 Months Ended March 31,		12 Months Ended March 31,	
In millions	2001	2000	2001	2000
Current:				
Federal	$ (172)	$ 132	$ (409)	$ 437
State	—	30	(30)	112
	(172)	162	(439)	549
Deferred – federal and state:				
Accrued charges	(9)	(9)	(133)	(134)
Contributions in aid of construction	6	6	(10)	(9)
Property related	62	(48)	(192)	(196)
Investment and energy tax credits – net	(5)	(10)	(36)	(44)
Operating loss carryforwards	(51)	—	(66)	—
Regulatory assets	(53)	1	197	5
Regulatory balancing accounts	(193)	(9)	(923)	317
State tax privilege year	(10)	16	4	(11)
Unbilled revenue	(1)	9	11	(10)
Other	16	2	35	3
	(238)	(42)	(1,113)	(79)
Total	$ (410)	$ 120	$ (1,552)	$ 470
Classification of income taxes:				
Included in operating income	$ (419)	$ 123	$ (1,549)	$ 491
Included in other income	9	(3)	(3)	(21)

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

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

	3 Months Ended March 31,		12 Months Ended March 31,	
	2001	**2000**	**2001**	**2000**
Federal statutory rate	35.0%	35.0%	35.0%	35.0%
Capitalized software	0.2	(0.9)	0.3	(2.3)
Property-related and other	—	13.5	(4.2)	9.1
Investment and energy tax credits	0.5	(4.4)	0.8	(4.1)
State tax – net of federal deduction	5.3	6.8	4.2	8.4
Effective tax rate	41.0%	50.0%	36.1%	46.1%

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 $7 million and $29 million for the three- and twelve-months ended March 31, 2001, respectively, and $8 million and $28 million for the three- and twelve-months ended March 31, 2000, respectively.

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.

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Information on plan assets and benefit obligations is shown below:

In millions	3 Months Ended March 31, 2001	Year Ended December 31, 2000	3 Months Ended March 31, 2000
Change in benefit obligation			
Benefit obligation at beginning of period	$ 2,200	$ 2,075	$ 2,075
Service cost	17	63	16
Interest cost	38	155	39
Actuarial loss	—	90	—
Benefits paid	(61)	(183)	(52)
Benefit obligation at end of period	$ 2,194	$ 2,200	$ 2,078
Change in plan assets			
Fair value of plan assets at beginning of period	$ 3,067	$ 3,078	$3,078
Actual return on plan assets	(191)	143	177
Employer contributions	—	29	29
Benefits paid	(61)	(183)	(52)
Fair value of plan assets at end of period	$ 2,815	$ 3,067	$ 3,232
Funded status	$ 621	$ 867	$ 1,154
Unrecognized net loss (gain)	(483)	(745)	(1,125)
Unrecognized transition obligation	21	22	27
Unrecognized prior service cost	114	118	128
Recorded asset	$ 273	$ 262	$ 184
Discount rate	7.25%	7.25%	7.75%
Rate of compensation increase	5.0%	5.0%	5.0%
Expected return on plan assets	8.5%	8.5%	7.5%

The components of pension expense were:

In millions	3 Months Ended March 31,		12 Months Ended March 31,	
	2001	2000	2001	2000
Service cost	$ 17	$ 16	$ 64	$ 64
Interest cost	38	39	154	147
Expected return on plan assets	(63)	(57)	(272)	(197)
Net amortization and deferral	(3)	(8)	(35)	1
Pension expense (benefit) under accounting standards	(11)	(10)	(89)	15
Regulatory adjustment – deferred	11	10	89	22
Net pension expense recognized	$ —	$ —	$ —	$ 37

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	3 Months Ended March 31, 2001	Year Ended December 31, 2000	3 Months Ended March 31, 2000
Change in benefit obligation			
Benefit obligation at beginning of period	$ 1,762	$ 1,462	$ 1,462
Service cost	11	39	9
Interest cost	33	121	29
Actuarial loss	—	202	—
Benefits paid	(17)	(62)	(15)
Benefit obligation at end of period	$ 1,789	$ 1,762	$ 1,485
Change in plan assets			
Fair value of plan assets at beginning of period	$ 1,200	$ 1,283	$ 1,283
Actual return on plan assets	26	(40)	23
Employer contributions	5	19	21
Benefits paid	(17)	(62)	(15)
Fair value of plan assets at end of period	$ 1,214	$ 1,200	$ 1,312
Funded status	$ (575)	$ (562)	$ (173)
Unrecognized net loss (gain)	141	141	(206)
Unrecognized transition obligation	317	323	342
Recorded asset (liability)	$ (117)	$ (98)	$ (37)
Discount rate	7.5%	7.5%	8.0%
Expected return on plan assets	8.2%	8.2%	7.5%

Expense components were:

	3 Months Ended March 31,		12 Months Ended March 31,	
In millions	2001	2000	2001	2000
Service cost	$ 11	$ 9	$ 41	$ 44
Interest cost	33	29	125	112
Expected return on plan assets	(26)	(23)	(109)	(83)
Net amortization and deferral	6	6	27	26
Total	$ 24	$ 21	$ 84	$ 99

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 March 31, 2001, by $282 million and annual aggregate service and interest costs by $31 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated obligation as of March 31, 2001, by $242 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 1.4 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 8.4 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. No special stock options from the 2000 Equity Plan 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).

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. Additional performance shares were awarded in January 2001. The 2001 performance shares vest December 31, 2003, and payment will be made in January 2004, half in shares of Edison International common stock and half in cash. The cash amount is the product of the number of shares to be paid in cash, times the average of the high and low common stock price on the last market day of the year. Retention Incentive Deferred Stock Units were awarded on March 12, 2001. These vest no later than March 12, 2003, and are paid out on that date in shares of Edison International common stock, unless before that date the stock price averages at least $20 for 20 consecutive trading days. In that case the units will vest and pay out on the later of March 12, 2002, or the day following the period in which the $20 average price was achieved.

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

Options issued after 1997 generally vest in 25% annual installments over a four-year period, although vesting for the May 2000 grants does not begin until May 2002. 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; except that if the termination is covered by the Edison International Executive Severance Plan, the terminated executive must exercise vested options within 12 months. All unvested options are forfeited on the date of termination.

The performance share 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 $0 million and $3 million for the three and twelve months ended March 31, 2001, respectively, and $1 million and $5 million for the three and twelve months ended March 31, 2000, respectively.

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 $(600) million and $(2.767) billion for the three and twelve months ended March 31, 2001, respectively, and $118 million and $544 million for the three and twelve months ended March 31, 2000, respectively.

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:

	March 31, 2001	March 31, 2000
Expected life	7 years – 10 years	7 years – 10 years
Risk-free interest rate	4.7% – 6.0%	5.0% – 5.6%
Expected volatility	17% – 48%	17% – 24%

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.

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 March 31, 2001, 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	81	8	50%
Generating stations:				
Four Corners Units 4 and 5 (coal)	463	354	3	48%
Mohave (coal)	328	243	3	56%
Palo Verde (nuclear)(1)	1,626	1,461	16	16%
San Onofre (nuclear)(1)	4,270	3,893	22	75%
Total	$ 6,958	$ 6,043	$ 53	

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

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Note 11. Commitments

Leases

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

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

Year ended December 31,	In millions
2001	$ 11
2002	12
2003	11
2004	10
2005	6
Thereafter	15
Total	$ 65

Nuclear Decommissioning

Decommissioning is estimated to cost $2.2 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 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 licenses. 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 $11 million and $93 million for the three and twelve months ended March 31, 2001, respectively, and $23 million and $108 million for the three and twelve months ended March 31, 2000. The accumulated provision for decommissioning, excluding San Onofre Unit 1, was $1.4 billion at March 31, 2001, and at December 31, 2000, and $1.3 billion at March 31, 2000. The estimated costs to decommission San Onofre Unit 1 (approximately $344 million) are recorded as a liability.

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

Trust investments (cost basis) include:

In millions	Maturity Dates	March 31, 2001	December 31, 2000	March 31, 2000
Municipal bond	2001 – 2033	$ 491	$ 548	$ 661
Stocks	—	614	531	482
U.S. government issues	2001 – 2029	397	421	419
Short-term and other	2001	218	220	111
Total		$ 1,720	$ 1,720	$ 1,673

Trust fund earnings (based on specific identification) increase the trust fund balance and the accumulated provision for decommissioning. Net earnings (loss) were $(13) million and $16 million for the three and twelve months ended March 31, 2001, respectively, and $9 million and $53 million for the three and twelve months ended March 31, 2000, respectively. Proceeds from sales of securities (which are reinvested) were $765 million and $3.7 billion for the three and twelve months ended March 31, 2001, respectively, and $1.7 billion and $4.0 billion for the three and twelve months ended March 31, 2000, respectively. 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. In an effort to replace higher-cost contract payments with lower-cost replacement power, SCE has entered into agreements to end its contract obligations with certain qualifying facilities. The buyout agreements 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	$ 151	$ 108	$ 116	$ 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 October 2000, a class action securities lawsuit was filed in federal district court in Los Angeles against SCE and Edison International. As amended in December 2000 and March 2001, the lawsuit 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 by SCE. The response to the second amended complaint was deferred. This lawsuit has been consolidated with another similar 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 May 11, 2001, 25 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 $833 million for energy and capacity supplied to SCE under QF contracts, and in some cases for additional damages as well. Many of these QF lawsuits also seek an order allowing the suppliers to stop providing power to SCE so that they may sell the power to other purchasers. On April 5, 2001, SCE submitted a petition requesting the coordination before a single judge of those QF lawsuits then pending in California state court. A state court coordination judge has been assigned and SCE's motion to coordinate is pending. SCE is also taking steps to coordinate the QF cases on file in federal court. 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.

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SCE's recorded estimated minimum liability to remediate its 44 identified sites is $116 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 $46 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 $74 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 $10 million to $20 million. Recorded expenditures for the twelve months ended March 31, 2001, were $17 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.

Property damage insurance covers losses up to $500 million, including decontamination costs, at San Onofre and Palo Verde. Decontamination liability and property damage coverage exceeding the primary $500 million also has been purchased in amounts greater than federal requirements. Additional insurance covers part of replacement power expenses during an accident-related nuclear unit outage. These policies are issued primarily by 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.

Item 2. 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 except for the 1¢-per-kWh and 3¢-per-kWh surcharges effective first quarter 2001. See further discussion of the CPUC rate increases in Rate Stabilization Proceeding. 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 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 principles 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. When SCE determined that regulatory assets, such as the TRA and the transition cost balancing account (TCBA), were no longer probable of recovery through future rates, they were written off. The TCBA is a regulatory balancing account that tracks the recovery of generation-related transition costs, including stranded investments. SCE assessed the probability of recovery of the undercollected costs that were previously recorded in the TCBA in light of the CPUC's March 27, 2001, and April 3, 2001, decisions, including the retroactive transfer of balances from SCE's TRA to its TCBA and related changes that are discussed in more detail in Rate Stabilization 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 December 31, 2000, included 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. Transition costs in excess of transition revenue are charged against earnings in 2001 absent a regulatory or legislative solution, such as implementation of the actions called for in the MOU that make recovery of such costs probable. For first quarter 2001, $661 million (after tax) of unrecovered transition costs were charged to earnings. This resulted 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

SCE recorded a loss of $598 million and $2.8 billion, respectively, for the three and twelve months ended March 31, 2001. The quarterly and twelve-months-ended losses reflect $661 million (after tax) of transition costs in excess of transition revenue during the first quarter of 2001. For financial reporting purposes, these undercollected costs are no longer accumulated in the TCBA and instead are expensed as incurred. The twelve-months-ended loss also included a write-off of the TCBA and other generation-related 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. Based on the new rules arising from the CPUC's March 27, 2001, rate stabilization decision, the $4.5 billion TRA undercollection as of December 31, 2000, and the coal and hydroelectric balancing account overcollections were reclassified, and the TCBA balance was recalculated to be a $2.9 billion undercollection (see further discussion of the CPUC rate increase in the Rate Stabilization Proceeding section and the components of the TCBA undercollection in the Status of Transition and Power-Procurement Cost Recovery section of Regulatory Environment). The implementation of the MOU (see further discussion in Memorandum of Understanding with the CDWR) 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 was unable to conclude that, under applicable accounting principles, the $2.9 billion TCBA undercollection (as recalculated above) and $1.3 billion (book value) of other regulatory assets and liabilities, that were to be recovered through the TCBA mechanism by the end of the rate freeze, were probable of recovery through the rate-making process as of December 31, 2000. As a result, SCE's December 31, 2000, income statement included a $4.0 billion charge to provisions for regulatory adjustment clauses and a $1.5 billion net reduction in income tax expense, to reflect the $2.5 billion (after tax) write-off.

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 the regulatory assets that were written off probable. If and when those actions are taken, or others occur that make such recovery probable, and the necessary rate-making mechanism is adopted, the regulatory assets written off as of December 31, 2000, and the undercollected costs incurred in 2001, would be restored to the balance sheet, with a corresponding increase to earnings of approximately $3.2 billion (after tax).

As stated above, SCE recorded a loss of $598 million and $2.8 billion, respectively, for the three and twelve months ended March 31, 2001, compared with earnings of $113 million and $520 million, respectively, for the same periods in 2000. Excluding the $661 million (after tax) of undercollected transition costs that are no longer accumulated in balancing accounts and instead are expensed as incurred, SCE's first quarter 2001 earnings were $63 million, down $50 million from the prior-year period. The quarterly decrease was mainly due to higher interest expense resulting from the deteriorated financial condition of SCE and lower earnings resulting from the February 2001 fire and resulting outage at the San Onofre Nuclear Generating Station. See further discussion of the San Onofre fire in the San Onofre Nuclear Generating Station section. Excluding the $661 million (after tax) of undercollected transition costs and the $2.5 billion (after tax) December 31, 2000, write-off, SCE would have earned $421 million for the twelve months ended March 31, 2001. Excluding the $15 million one-time tax benefit SCE recorded in fourth quarter 1999 due to an Internal Revenue Service ruling, SCE's earnings for the twelve months ended March 31, 2000, were $505 million. The $84 million decrease for the twelve months ended March 31, 2001, from the prior-year period, was mainly the result of higher interest expense and adjustments to reflect potential regulatory refunds.

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. SCE anticipates that the losses resulting from these undercollections will continue unless a rate-making mechanism is established. In addition to the losses from the unrecovered transition costs, SCE expects its 2001 earnings to be negatively affected by the February 2001 fire and resulting outage at San Onofre Unit 3.

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 assessed to noncompliant customers after October 1, 2000, until a reevaluation of the operation of the interruptible programs can be completed.

Operating revenue decreased for the three and twelve months ended March 31, 2001, compared to the year-earlier periods. The quarterly decrease was primarily due to a 23% decrease in retail sales volume, as well as the credit given to customers who chose direct access. The volume decrease was primarily the result of SCE no longer supplying its customers with all of their electricity needs, beginning on January 18, 2001. See CDWR Power Purchases discussion. These decreases were partially offset by the effects of the 1¢-per-kWh surcharge originally granted on January 4, 2001, and affirmed by the CPUC on March 27, 2001. The twelve-months-ended decrease was primarily due to the credit given to customers who chose direct access. This decrease was partially offset by the effects of the 1¢-per-kWh surcharge and an increase in revenue related to penalties customers incurred for not adhering to their interruptible contracts.

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.

Operating Expenses

Fuel expense decreased for the twelve months ended March 31, 2001, compared with the same period in 2000, primarily due to fuel-related refunds resulting from a settlement with another utility that SCE recorded in the second and third quarters of 2000.

Purchased-power expense increased significantly for both the three and twelve months ended March 31, 2001, compared to the same periods in 2000. The increases were the result of: increased California Power Exchange (PX)/Independent System Operator (ISO) purchased-power expense through January 18, 2001, and increased purchased-power expense related to qualifying facilities (QFs) and interutility contracts. See Purchased Power table in Note 1 to the Consolidated Financial Statements. See further discussion in CDWR Power Purchases.

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. For the twelve months ended March 31, 2001, 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. For the twelve months ended March 31, 2001, compared to the same period in 2000, purchased-power expense was reduced by $104 million and $682 million, respectively, due to SCE's use of gas call options and PX block forward contracts. For a further discussion of SCE's hedging instruments and the significant increases in power prices, see Market Risk Exposures. In December 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.

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 QFs increased for both the three and twelve months ended March 31, 2001, compared to the year-earlier periods. The increases were primarily due to the short-run avoided cost factor (which is based on the price of natural gas) of the QF contracts causing a significant increase in the payments to QFs. The twelve-months-ended increase was partially offset by a fourth quarter 2000 contract adjustment with the CDWR, as well as the terms in some of the QF contracts reverting to lower prices.

Provisions for regulatory adjustment clauses decreased for the three months ended March 31, 2001, compared to the year-earlier period. The decrease primarily resulted from SCE no longer accumulating undercollected transition costs in the TCBA, as well as undercollections related to the administration of energy conservation programs and other public benefit programs. Provisions for regulatory adjustment clauses increased for the twelve months ended March 31, 2001, compared to the same period in 2000, mainly due to a $4 billion charge to the provisions related to the write-off of regulatory assets and liabilities as of December 31, 2000. See further discussion of the write-off in the Earnings section. In addition, the provisions also increased 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. SCE's use of gas call options decreased the provisions by $4 million for the quarter ended March 31, 2000. SCE's use of gas call options increased the provisions by $105 million and $2 million, respectively, for the twelve months ended March 31, 2001, and March 31, 2000.

Depreciation, decommissioning and amortization expense decreased for both the three and twelve months ended March 31, 2001, compared to the prior-year periods, primarily due to a decrease in SCE's amortization expense. Since SCE's December 31, 2000, write-off included the unamortized nuclear investment regulatory asset, SCE did not record any amortization expense related to this asset during first quarter 2001.

Income taxes decreased for both the three and twelve months ended March 31, 2001, compared to the year-earlier periods, primarily due to a $497 million income tax benefit arising from the transition costs in excess of transition revenue during first quarter 2001. The twelve-months-ended-decrease also reflects the $1.5 billion income tax benefit related to the $2.5 billion (after tax) write-off as of December 31, 2000, of regulatory assets and liabilities.

Other Income and Deductions

Interest and dividend income increased for both the three and twelve months ended March 31, 2001, compared to the year-earlier periods. The quarterly increase resulted primarily from higher cash balances as SCE conserves cash due to its liquidity crisis, as well as interest earned on undercollections in SCE's remaining balancing accounts. SCE wrote off its $2.9 billion (after tax) TCBA undercollection (as restated to reflect the CPUC's March 27, 2001, decisions) as of December 31, 2000. The twelve months ended increase is primarily due to interest earned, prior to the write-off, on higher balancing account undercollections.

Other nonoperating income decreased for both the three and twelve months ended March 31, 2001. The quarterly decrease was primarily due to CPUC-approved shareholder incentives related to QF contract restructurings in first quarter 2000. The twelve-months-ended decrease was mainly the result of lower earnings from energy conservation programs, lower earnings from life insurance investments for executives and less gains on the sales of equity investments.

Interest expense – net of amounts capitalized increased for both the three and twelve months ended March 31, 2001, compared to the year-earlier periods. The increases were primarily due to additional long-term debt and higher short-term debt balances. Higher interest expense resulting from balancing account overcollections at SCE also contributed to the twelve-months-ended increase.

Other nonoperating deductions decreased for both the three and twelve months ended March 31, 2001, compared to the same periods in 2000, due to lower accruals for regulatory matters.

The taxes on other income and deductions increased for the quarter ended March 31, 2001, compared to the year-earlier period, mostly due to higher pre-tax nonoperating income. Tax benefits on other income and deductions decreased for the twelve months ended March 31, 2001, compared to the same period in 2000, primarily the result of tax expense related to interest income and other nonoperating income exceeding the tax benefits related to interest expense and other nonoperating deductions, as well as a $15 million one-time tax benefit in 1999 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 $541 million of its short-term debt was approximately 75% of its carrying value.

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 temporarily suspended payments of certain obligations for principal and interest on outstanding debt and for purchased power. As of April 30, 2001, SCE had $3.1 billion in obligations that were unpaid and overdue including: (1) $882 million to the PX or ISO; (2) $1.3 billion to QFs; (3) $230 million in PX energy credits for energy service providers; (4) $531 million of matured commercial paper; and (5) $200 million of principal on its 5-7/8% notes. If SCE is found responsible for purchases of power by the CDWR or the ISO for sale to SCE's customers on or after January 18, 2001, SCE's unpaid obligations as of April 30, 2001, could increase by as much as $800 million. See additional discussion in CDWR Power Purchases. As applicable, unpaid obligations will continue to accrue interest. 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 $2.5 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 $731 million in overdue principal 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 forbearance agreement has been extended three times and currently expires on September 15, 2001. The $200 million short-term bank credit facility was scheduled to mature on May 14, 2001. The maturity date has been extended to September 15, 2001. At April 30, 2001, SCE had estimated cash reserves of approximately $1.9 billion, which was approximately $1.3 billion 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 help 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 periods, 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. See further discussion of QFs in Litigation.

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 cash going forward may not be sufficient to cover 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 April 30, 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 conditions 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 implemented 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 payments, 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 Cost 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. SCE's independent accountant's opinion on the accompanying financial statements includes an explanatory paragraph which states that the issues 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 $1.2 billion and $1.4 billion, respectively, for the three and twelve months ended March 31, 2001, compared with $581 million and $1.7 billion for the same periods in 2000. The quarterly increase in cash flows provided by operating activities was primarily due to SCE's conservation of cash. The decrease in cash flows provided by operating activities for the twelve months ended March 31, 2001, was due to the extremely high prices SCE paid for energy and ancillary services procured through the PX and ISO since May 2000. Cash flows provided by operations is expected to continue to increase in the first half of 2001 as SCE continues to defer payments on its obligations as a result of its liquidity crisis.

Beginning first quarter 2001, the cash flow coverage of dividends quarterly calculation is not being presented due to SCE's inability to pay dividends (discussed above in the Liquidity Crisis section). For the twelve months ended March 31, 2001, the cash flow coverage of dividends was 4.8 times compared to 2.7 times for the same period in 2000. The increase in 2001 reflects SCE's inability to pay dividends, as well as an increase in cash flows from operating activities which reflects SCE's conservation of cash.

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 March 31, 2001, SCE had drawn on its entire credit lines of $1.65 billion. These unsecured lines of credit have various expiration dates and, when available, can be drawn down at negotiated or bank index rates. SCE is currently negotiating with bank lenders to extend the $200 million 364-day credit facility maturing on May 14, 2001.

Short-term debt is used to finance balancing account undercollections, fuel inventories and general cash requirements, including purchased-power payments. Long-term debt is used mainly to finance capital expenditures. External financings are influenced by market conditions and other factors. Because of the $2.5 billion charge to earnings as of December 31, 2001. 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 $550 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 2002 and ending in 2007, with interest rates ranging from 6.22% to 6.42%. The notes are secured by the transition property and are not secured by, or payable from, assets of SCE or Edison International. SCE used the proceeds from the sale of the transition property to retire debt and equity securities. Although, as required by accounting principles generally accepted in the United States, SCE Funding LLC is consolidated with SCE and the rate reduction notes are shown as long-term debt in the consolidated financial statements, SCE Funding LLC is legally separate from SCE. The assets of SCE Funding LLC are not available to creditors of SCE or Edison International and the transition property is legally not an asset of SCE or Edison International. Due to its credit rating downgrade in late 2000, in January 2001, SCE began remitting its customer collections related to the rate-reduction notes on a daily basis.

Cash Flows from Investing Activities

Cash flows from investing activities are affected by additions to property and plant and funding of nuclear decommissioning trusts. Decommissioning costs are recovered in utility rates. These costs are expected to be funded from independent decommissioning trusts that receive SCE contributions of approximately $25 million per year. In 1995, the CPUC determined the restrictions related to the investments of these trusts. They are: not more than 50% of the fair market value of the qualified trusts may be invested in equity securities; not more than 20% of the fair market value of the trusts may be invested in international equity securities; up to 100% of the fair market values of the trusts may be invested in investment grade fixed-income securities including, but not limited to, government, agency, municipal, corporate, mortgage-backed, asset-backed, non-dollar, and cash equivalent securities; and derivatives of all descriptions are prohibited. Contributions to the decommissioning trusts are reviewed every three years by the CPUC. The contributions are determined from an analysis of estimated decommissioning costs, the current value of trust assets and long-term forecasts of cost escalation and after-tax return on trust investments. Favorable or unfavorable investment performance in a period will not change the amount of contributions for that period. However, trust performance for the three years leading up to a CPUC review proceeding will provide input into future contributions.

Projected Capital Requirements

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

Long-term debt maturities and sinking fund requirements for the five twelve month periods following March 31, 2001, are: 2002 – $646 million; 2003 – $746 million; 2004 – $1.4 billion; 2005 – $371 million; and 2006 – $446 million. These projections assume no acceleration of payments arising from default. See further discussion in Liquidity Crisis.

Preferred stock redemption requirements for the five twelve month periods following March 31, 2001, are: 2002– zero; 2003 – $109 million; 2004 – $9 million; 2005 – $9 million; and 2006 – $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.

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).

SCE does not believe that its short-term debt is subject to interest rate risk. However, SCE does believe that the fair market value of its fixed-rate long-term debt is subject to interest rate risk.

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 (see further discussion in Wholesale Electricity Markets). 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 November 2000, SCE began purchases of energy through bilateral forward contracts. At March 31, 2001, the nominal value of SCE's bilateral forward contracts was $435 million.

In accordance with a new accounting standard for derivatives, on January 1, 2001, SCE recorded its block forward contracts at fair value on the balance sheet. 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 seized the contracts, which at that time had an unrealized gain of approximately $500 million. If other elements of the MOU are implemented, SCE will relinquish all claims against the state for seizing these contracts. If the MOU is not implemented, SCE believes that it should be compensated for the reasonable value of these contracts under law, and would pursue the matter. SCE's March 31, 2001, balance sheet no longer includes 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, among other things, to 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 Cost 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 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 Cost 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 Cost 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. On May 10, 2001, the Governor signed a bill authorizing the CDWR to issue up to $13.4 billion in bonds. The law will be effective in 90 days. AB 1X 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. AB 1X 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 increased 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 or accrued $251 million for energy sales made by the CDWR and ISO during the period January 19 through April 30, 2001, and has forwarded $147 million to the CDWR on behalf of these customers as of April 30, 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. 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, and has billed SCE a total of $580 million for January and February 2001 purchases. If SCE is found responsible for purchases of power by the CDWR or ISO for sale to SCE's customers on or after January 18, 2001, SCE's purchased-power costs (and pre-tax loss) for first quarter 2001 could increase by as much as $800 million. 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 its February 14, 2001, order that the ISO must have a creditworthy buyer for any transactions. SCE has not met the ISO's creditworthiness requirements since its credit ratings were downgraded in mid-January 2001. As a result, SCE has protested and returned the bills it received from the ISO. 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). Under the MOU, 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 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 other costs incurred to provide service to customers. Other costs include the recovery of income tax benefits previously flowed through to customers, postretirement benefit transition costs and accelerated recovery of investment in San Onofre Units 2 and 3 and the Palo Verde units. Transition costs related to power-purchase QF 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 unable 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 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.

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. 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. 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 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, May 2000 was the first month in which SCE's costs exceeded revenue. 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 March 31, 2001. The cumulative TCBA undercollection (as recalculated) was $2.9 billion as of December 31, 2000, and $3.9 billion as of March 31, 2001. A summary of the components of this cumulative undercollection as of March 31, 2001, is as follows:

In millions	
Transition costs recorded in the TCBA:	
QF and interutility costs	$ 4,556
Amortization of nuclear-related regulatory assets	3,090
Depreciation of plant assets	613
Other transition costs	732
Total costs	8,991
Revenue available to recover transition costs	(5,117)
TCBA undercollections	$ 3,874

Unless the regulatory and legislative actions required to implement the MOU, or other actions that make such recovery probable are taken, SCE is unable 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), and an additional $996 million in TCBA undercollections was charged to earnings as of March 31, 2001. 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. Per mutual agreement of the parties, a stay has been issued while SCE is attempting to further the MOU implementation process with the CPUC. As discussed in the Memorandum of Understanding with the CDWR, if 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 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 October 2000, a class action securities lawsuit was filed in federal district court in Los Angeles against SCE and Edison International. As amended in December 2000 and March 2001, the lawsuit 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. As indicated below in the March 15, 2001, lawsuit discussion, the Court has agreed that the date for the response to the second amended complaint may be deferred. 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. In accordance with an agreement with Edison International and SCE, the court has allowed the consolidation of this lawsuit with the October 20, 2000, lawsuit discussed above. A consolidated complaint is expected to be filed by mid-May 2001. Edison International and SCE must respond within 30 days of receipt of the consolidated complaint.

In addition to the two lawsuits filed against SCE and discussed above, as of May 11, 2001, 25 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 $833 million for energy and capacity supplied to SCE under QF contracts, and in some cases additional damages as well. Many of these QF lawsuits also seek an order allowing the suppliers to stop providing power to SCE so that they may sell the power to other purchasers. On April 5, 2001, SCE submitted a petition requesting the coordination before a single judge of those QF lawsuits then pending in California state court. A state court coordination judge has been assigned and SCE's motion to coordinate is pending. SCE is also taking steps to coordinate the QF cases on file in federal court. 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. In December 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 procurement 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 early June 2001. 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 Cost 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 (see CDWR Power Purchases). 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 unable 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 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 the utility 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.

- Edison Mission Energy (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. Edison Mission Energy 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, 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 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. The CPUC has stated it will expeditiously review those provisions of the MOU that require resolution. SCE and the Governor have been working diligently to have the MOU supported by the legislature. However, no formal action has been taken by either the CPUC or the legislature.

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.

In December 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, 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.

In December 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.

On April 25, 2001, the FERC issued an order providing for cost-based energy price controls during ISO Stage 1 or greater power emergencies (7% or less in reserve power). The order establishes an hourly clearing price based on the costs of the least efficient generating unit during the period. The new approach replaces the $150/MWh breakpoint discussed above. The order is in effect for one year.

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 $116 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 $46 million of its recorded liability, through an incentive mechanism, which is discussed in Note 12. SCE has recorded a regulatory asset of $74 million for its estimated minimum environmental-cleanup costs expected to be recovered through customer rates.

SCE's identified sites include several sites for which there is a lack of currently available information. As a result, no reasonable estimate of cleanup costs can be made for these sites. SCE expects to clean up its identified sites over a period of up to 30 years. Remediation costs in each of the next several years are expected to range from $10 million to $20 million. Recorded costs for the twelve months ended March 31, 2001, were $17 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 at the end of 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 $110 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.

New Accounting Standard

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. Prior to adoption, hedges were not recorded on the balance sheet. Gains or losses from changes in the fair value of a recognized asset or liability or a firm commitment are reflected in earnings for the ineffective portion of the hedge. For a hedge of the cash flows of a forecasted transaction, the effective portion of the gain or loss is initially recorded as a separate component of shareholder's equity under the caption "accumulated other comprehensive income," and subsequently reclassified into earnings when the forecasted transaction affects earnings. The ineffective portion of the gain or loss is reflected in earnings immediately. Under the new standard, SCE's derivatives qualify for hedge accounting or for the normal purchase and sales exemption from derivatives accounting rules. 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. As of March 31, 2001, SCE did not have any derivatives as defined by the new accounting standard. SCE does not anticipate any earnings impact from any future 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 quarterly 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.

PART II OTHER INFORMATION

Item 1. Legal Proceedings

San Onofre Personal Injury Litigation

As previously reported in Part 1, Item 3 of SCE's Annual Report on Form 10-K for the fiscal year ended December 31, 2000 (2000 Form 10-K), SCE is actively involved in three lawsuits claiming personal injuries allegedly resulting from exposure to radiation at San Onofre. In addition, a fourth lawsuit claiming personal injuries from exposure to radiation at San Onofre has recently been filed and served on SCE.

On November 17, 1995, an SCE employee and his wife sued SCE in the U.S. District Court for the Southern District of California. Plaintiffs also named Combustion Engineering. The trial in this case resulted in a jury verdict for both defendants. The plaintiffs' motion for a new trial was denied. Plaintiffs filed an appeal of the trial court's judgment to the Ninth Circuit Court of Appeal. Briefing on the appeal was completed in January 1999, oral argument took place on February 10, 2000, and the matter was taken under submission. On July 20, 2000, the Ninth Circuit Court of Appeals issued an opinion reversing the District Court judgment and ordering a retrial as to both defendants. On August 10, 2000, SCE filed a petition for rehearing with the Ninth Circuit Court of Appeals. On January 2, 2001, the Court granted SCE's rehearing petition as to certain issues and ordered further briefing on those rehearing issues within 30 days. This further briefing was filed on February 1, 2001. On February 20, 2001, the Court issued an order setting oral argument on the rehearing issues which took place on April 26, 2001. The matter is now under submission and a decision on the rehearing is not expected for at least several weeks.

On May 9, 2001, SCE was served with a complaint filed on March 1, 2001, by a former contract worker at San Onofre and his wife in the U.S. District Court for the Southern District of California. In addition to SCE, Plaintiffs also named as defendants Combustion Engineering and Bechtel Construction Company, the employer of the former San Onofre worker. This is the fourth lawsuit claiming personal injuries from exposure to radiation at San Onofre that SCE is actively involved in.

Shareholder Litigation

As previously reported in Part 1, Item 3 of SCE's 2000 Form 10-K, these purported class actions both involve securities fraud claims arising from alleged improper accounting by Edison International and SCE of undercollections in SCE's TRA.

On October 30, 2000, a purported class action lawsuit (the "Stubblefield Action") was filed in federal district court in Los Angeles against SCE and Edison International. On December 28, 2000, plaintiffs, without requiring a response to the original complaint, filed a first amended complaint. In February 2001, the Court approved a stipulation of the parties providing that, in lieu of a motion to dismiss directed to the first amended complaint, plaintiffs would voluntarily file a second amended complaint. Pursuant to this stipulation, on March 5, 2001, plaintiffs filed a second amended complaint. The second amended complaint alleges that the companies are engaging in securities fraud by over-reporting income and improperly accounting for the TRA undercollections. The second amended complaint purports to be 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 statements. The second amended complaint seeks compensatory damages caused by the alleged fraud as well as punitive damages. The response to the second amended complaint was due April 2, 2001. As discussed below, plaintiff's counsel has agreed with counsel for Edison International and SCE that the date for Edison International and SCE to respond to the second amended complaint may be deferred.

On March 15, 2001, a purported class action lawsuit (the "King Action") was filed in federal district court in Los Angeles, California, 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 overreported income and improperly accounted for the TRA undercollections. The complaint purports to be 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. Plaintiffs seek damages, in an unstated amount, in connection with their purchase of securities during the class period.

The Court has granted a motion to consolidate this action with the Stubblefield Action, and has ordered plaintiffs to file a consolidated complaint by mid-May 2001. The Court has taken under consideration a motion to have the named plaintiffs in both cases be appointed "lead plaintiffs" in the consolidated matter. The Court has agreed that defendants need not respond to the separate Stubblefield and King Action complaints and, instead, must respond to the consolidated complaint within thirty days of the time that it is filed and served.

Qualifying Facilities Litigation

As previously reported in Part 1, Item 3 of SCE's 2000 Form 10-K, SCE is involved in a number of legal actions brought by various QFs alleging SCE's failure to timely pay for power deliveries made beginning in November 2000. The lawsuits, and the additional legal actions listed below, have been filed by various QF parties including gas-fired QFs, geothermal or wind energy QFs, and owners of cogeneration projects. The lawsuits, in aggregate, are seeking payments of more than $833,000,000 for energy and capacity supplied to SCE under QF contracts, and in some cases additional damages as well. Many of these QF lawsuits also seek an order allowing the suppliers to stop providing power to SCE so that they may 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 5, 2001, SCE submitted to the Chairperson of the California Judicial Counsel a petition requesting the coordination before a single judge of those QF lawsuits then-pending in California state court. A state court Coordination Judge has been assigned, and SCE's Motion to Coordinate is pending. In addition, SCE is taking steps to coordinate those QF cases on file in federal court.

Writs of attachment have been granted in four cases (Beowawa Power, L.L.C., Heber Geothermal Company, IMC Chemicals, Inc., and City of Long Beach) in the approximate amounts of $20,000,000, $28,000,000, $7,500,000, and $9,000,000 respectively, contingent on the posting of bonds. As of this date, SCE has not been notified that the bonds have been posted.

In addition to the cases previously referenced in SCE's 2000 Form 10-K, the following legal proceedings, identified by principal party, filing date, and court jurisdiction, have been brought against SCE:

Principal Party	Date Filed	Court Jurisdiction
Oak Creek Wind Power, Inc.	April 16, 2001	Kern County Superior Court, Central District
Willamette Industries, Inc.	April 17, 2001	Ventura County Superior Court
Berry Petroleum Company	May 2, 2001	Los Angeles County Superior Court, Central District

Ace Cogeneration Company	May 1, 2001	Los Angeles County Superior Court, Central District
Cabazon Power Partners LLC	May 2, 2001	Los Angeles County Superior Court, Central District
Black Hills Ontario, LLC	May 7, 2001	San Bernardino County Superior Court, Rancho Cucamonga District
U.S. Borax Inc. f/k/a United States Borax and Chemical Corporation	May 8, 2001	Kern County Superior Court
Luz Solar Partners LTD.	May 8, 2001	Sacramento County Superior Court

Item 6. Exhibits and Reports on Form 8-K

(a) Exhibits

3.1 Certificate of Amendment and Restated Articles of Incorporation of SCE effective June 1, 1993 (File No. 1-2313, Form 10-K for the year ended December 31, 1993)*

3.2 Certificate of Correction of Restated Articles of Incorporation of SCE dated June 23, 1997 (File No. 1-2313, Form 10-Q for the quarter ended September 30, 1997)*

3.3 Amended Bylaws of Southern California Edison Company as adopted by the Board of Directors on February 17, 2000 (File No. 1-2313, filed as Exhibit 3.3 to Form 10-K for the period ended December 31, 1999)*

10.1 Executive Retirement Plan Amendment 2001-1

10.2 Restatement of Terms of 2000 basic long-term incentive awards under the Equity Compensation Plan or the 2000 Equity Plan

10.3 Terms of 2001 basic long-term incentive awards under the Equity Compensation Plan or the 2000 Equity Plan

10.4 Terms of 2001 special long-term incentive awards under the Equity Compensation Plan or the 2000 Equity Plan

10.5 Terms of 2001 retention incentives under the Equity Compensation Plan

10.6 Terms of Executive Severance Plan as adopted effective January 1, 2001

23. Consent of Independent Public Accountants

(b) Reports on Form 8-K:

Date of Report	Date Filed	Item(s) Reported
January 15, 2001	January 16, 2001	5
January 18, 2001	January 18, 2001	5
February 1, 2001	February 5, 2001	5
February 12, 2001	February 16, 2001	5
March 20, 2001	March 22, 2001	5

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

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

SOUTHERN CALIFORNIA EDISON COMPANY
(Registrant)

By

THOMAS M. NOONAN
Vice President and Controller

By

KENNETH S. STEWART
Assistant General Counsel and
Assistant Secretary

May 14, 2001

EXHIBIT 23

CONSENT OF INDEPENDENT PUBLIC ACCOUNTANTS

As independent public accountants, we hereby consent to the incorporation by reference of our report included in this quarterly report on Form 10-Q for the quarter ended March 31, 2001, of Southern California Edison Company into the previously filed Registration Statements which follow:

Registration Form	File No.	Effective Date
Form S-3	33-50251	September 21, 1993
Form S-3	333-44778	September 7, 2000

ARTHUR ANDERSEN LLP

Los Angeles, California
May 11, 2001

Southern California Edison Company

Selected Financial and Operating Data: 1996-2000

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

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 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

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)

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,	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

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.

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.

Contents

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

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

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

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

Charles D. Miller
Retired Chairman of the Board,
Avery Dennison Corporation,
Pasadena, California

Luis G. Nogales
President,
Nogales Partners,
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Ronald L. Olson
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Pacific Life Insurance Company,
Newport Beach, California

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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
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Transmission and Distribution
Business Unit

Mahvash Yazdi
Senior Vice President and
Chief Information Officer

Emiko Banfield
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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

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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

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SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

/X/ Annual report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the fiscal year ended December 31, 2000

Commission File Number 1-2313

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

California (State or other jurisdiction of incorporation or organization)		95-1240335 (I.R.S. Employer Identification No.)
2244 Walnut Grove Avenue Rosemead, California (Address of principal executive offices)	91770 (Zip Code)	(626) 302-1212 (Registrant's telephone number, including area code)

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

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

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

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

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

As of April 16, 2001, there were 434,888,104 shares of Common Stock outstanding, all of which are held by the registrant's parent holding company. The aggregate market value of registrant's voting stock held by non-affiliates was approximately $197,534,061.75 on or about April 16, 2001, based upon prices reported by the American Stock Exchange. The market values of the various classes of voting stock held by non-affiliates, as of April 16, 2001, were as follows: CUMULATIVE PREFERRED STOCK $40,079,061.75; $100 CUMULATIVE PREFERRED STOCK $157,455,000.00.

DOCUMENTS INCORPORATED BY REFERENCE

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

(1) Designated portions of the Annual Report to Shareholders for the year ended December 31, 2000 .... Parts I, II and IV

(2) Designated portions of the Joint Proxy Statement relating to registrant's 2001 Annual Meeting of Shareholders .... Part III

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PART I

Item 1. Business

Southern California Edison Company (SCE) was incorporated in 1909 under the laws of the State of California. SCE is a public utility primarily engaged in the business of supplying electric energy to a 50,000 square-mile area of Central and Southern California, excluding the City of Los Angeles and certain other cities. The SCE service territory includes approximately 800 cities and communities and a population of more than 11 million people. Beginning in April 1998, pursuant to the restructuring of the California electric utility industry mandated by a 1996 state law, other entities have had the ability to sell electricity in SCE's service territory, utilizing SCE's transmission and distribution lines at tariffed rates. As a part of this utility industry restructuring, SCE sold some of its electric generating plants in 1998. SCE currently retains other electric generating plants, however, and it retains its transmission and distribution lines over which it transmits and distributes the electricity generated by SCE and other generators to the customers in SCE's service territory. The Memorandum of Understanding (MOU) that Edison International and SCE have entered into with the California Department of Water Resources (CDWR) with the endorsement of the Governor of California (described in Significant Developments in California Electric Utility Restructuring) calls for the sale of SCE's transmission assets to an agency of the State of California. As a further part of the industry restructuring, SCE had been required for an intended interim transitional period (ending no later than year-end 2001) to sell all SCE-generated electricity to the California Power Exchange (PX) at prices determined by periodic public auctions, and to buy any electricity needed to serve SCE's retail customers from the PX at similarly determined prices. As part of a December 15, 2000, order, the Federal Energy Regulatory Commission (FERC) eliminated the requirement that SCE buy and sell power exclusively through the PX and California Independent System Operator (ISO). In mid-January 2001, the PX suspended SCE's trading privileges for failure to post collateral due to SCE's rating agency downgrades. The PX suspended its day-ahead and day-of energy trading on January 30 and January 31, 2001, respectively. On March 9, 2001, the PX filed for Chapter 11 bankruptcy protection. As discussed in Significant Developments in California Electric Utility Restructuring below, the CDWR is providing power for sale to SCE's customers to the extent SCE cannot provide sufficient power from SCE's own generation and power contracts. SCE delivers such power and collects revenues for it on behalf of CDWR. In 2000, SCE's total operating revenue was derived from: 38.2% residential customers, 38.3% commercial customers, 8.4% industrial customers, 6.6% public authorities, 2.3% agricultural and other customers, and 6.2% other electric revenue. SCE had 12,593 full-time employees at year-end 2000. SCE comprises the largest portion of the assets and revenue of its parent holding company, Edison International.

Forward-Looking Statements

This annual report contains forward-looking statements that reflect SCE's current expectations and projections about future events based on SCE's knowledge of present facts and circumstances and assumptions about future events. Other information distributed by SCE that is incorporated herein or refers to or incorporates this annual report may also contain forward-looking statements. In this annual report and elsewhere, the words "expects," "believes," "anticipates," "estimates," "intends," "plans," "probable" and variations of such words and similar expressions are intended to identify forward-looking statements. Such statements necessarily involve risks and uncertainties that could cause actual results to differ materially from those anticipated. Some of the risks, uncertainties and other important factors that could cause results to differ are:

- Edison International's and SCE's financial condition, liquidity and credit ratings have been adversely affected by California's electricity crisis. Edison International and SCE have entered into a memorandum of understanding (MOU) with the endorsement of the Governor of California, which provides a plan for SCE's financial recovery by SCE selling its transmission assets to an agency of the State of California and issuing bonds to finance its undercollected power procurement costs, among other steps. However, the MOU cannot be implemented unless the California Legislature enacts necessary legislation, the California Public Utilities Commission (CPUC) and FERC adopt necessary orders, and various parties negotiate and execute definitive agreements. Edison International and SCE cannot be certain that all the required parties will take the necessary actions.

- Edison International and SCE are seeking to regain investment grade credit ratings so they can re-enter the credit markets on reasonable terms. The success of their efforts depends on the implementation of the MOU, which in turn depends on actions of legislators, regulatory bodies and others.

- SCE is seeking to avoid bankruptcy. To conserve cash, SCE suspended certain payments for debt service and purchased power. As a result numerous creditors are suing SCE, and some have threatened the possible filing of an involuntary bankruptcy petition against SCE. SCE's nonpayment of certain debt obligations also entitles debtholders to exercise remedies against Edison International, including possibly accelerating the repayment of principal.

- The CPUC recently adopted retroactive changes in regulatory accounting mechanisms and implemented other measures that impair SCE's ability to recover its costs and investments. As a result, SCE has taken a $2.5 billion ($4.2 billion on a pre-tax basis) fourth quarter write-off of regulatory assets. The write-off eliminates SCE's retained earnings and SCE's ability to pay dividends and issue additional first mortgage bonds. If the MOU described above 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. But to implement the MOU, SCE will need the cooperation of legislators, regulators and other parties.

- SCE may be affected by actions of regulatory bodies setting rates, adopting or modifying cost recovery, accounting or rate-setting mechanisms and implementing the restructuring of the electric utility industry. For example, regulatory actions in California affect SCE's ability to recover its past investments in utility plant and earn competitive returns.

- SCE may be affected by legislative and regulatory measures adopted and being contemplated by federal and state authorities to address the California electricity crisis or deregulation in other states, pending legislation that would repeal or amend key statutes governing the electric industry.

- SCE may be affected by increased competition in the electric utility business and other energy-related businesses, including among other things the ability of customers to purchase energy and metering and billing services from nonutility energy service providers.

- SCE owns and operates power generation facilities and, therefore, may be affected by changes in the supply, demand and price for electric capacity and energy in relevant markets and the cost and availability of fuel and fuel transportation.

- As an owner-operator of power generation facilities, SCE also may be affected by unpredictable weather conditions that may affect seasonal patterns of revenue collection, cause changes in demand (and prices) for electricity for heating and cooling purposes, and result in higher costs for repair or maintenance of assets.

- SCE may be affected by financial market conditions such as inflation and changes in interest rates, which could affect the availability and cost of external financing, as well as the actions of securities rating agencies.

- SCE is subject to power plant operation risks, including strikes, equipment failures and other issues.

- SCE may be affected by changes in tax laws or unfavorable interpretation and application of the laws by tax authorities.

- The operation of power generation, transmission or distribution facilities by SCE involves the potential for new or increased environmental liabilities associated with power plants and other facilities or operations, resulting from changes in laws, accidents or other events.

- SCE is seeking to create and expand new businesses, such as telecommunications and other energy-related consumer products and services. Those businesses are subject to various risks involved with start-up activities, such as developing products, gaining customers, establishing management processes, hiring qualified personnel, and so forth.

- SCE may be subject to legal proceedings arising out of financial reporting, commercial disputes, property rights, personal injuries, and other circumstances.

Additional information about the risk factors listed above is contained throughout this annual report. Readers are urged to read this entire report and carefully consider the risks, uncertainties and other factors that affect SCE's business. The information contained in this report is subject to change without notice. Readers should review future reports filed by SCE with the Securities and Exchange Commission (SEC).

Competitive 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 1994, state lawmakers and the CPUC initiated the electric industry restructuring process. In 1996, the California Legislature enacted comprehensive restructuring legislation. SCE was directed by the CPUC to divest the bulk of its gas-fired generation portfolio. Furthermore, under the legislation and CPUC decisions, prices for wholesale purchases of electricity from power suppliers are set by markets while the retail prices paid by utility customers for electricity delivered to them remained frozen at June 1996 levels. California's electric utilities, including SCE, are currently facing a financial and liquidity crisis as a result of the changes brought about by restructuring. (See Significant Developments in California Electric Utility Restructuring below for a description of the most recent developments.)

Significant Developments in California Electric Utility Restructuring

Beginning in May 2000, SCE began experiencing adverse impacts from unusually high prices for energy and ancillary services procured through the PX and the ISO. These high wholesale prices, coupled with the freeze on SCE's retail rates mandated by the 1996 restructuring legislation, resulted in substantial increases in the amount of undercollections in SCE's transition revenue account (TRA). SCE's TRA is a regulatory asset account in which SCE records the difference between revenues received from customers through the frozen rates and the costs of providing service to customers, (which includes purchased power procurement costs). As of December 31, 2000, the amount of undercollections recorded was \$4.5 billion. Based on a CPUC decision on March 27, 2001 (see further discussion below), this overcollection, and SCE's coal and hydroelectric balancing account undercollections (which amounted to \$1.5 billion as of December 31, 2000), were reclassified. In addition, SCE's transition cost balancing account (TCBA), representing recovery of stranded costs net of a previously recorded credit for market valuation of hydroelectric generation assets and the overcollections in the balancing accounts for the coal and hydroelectric generating assets, was recalculated to be a \$2.9 billion undercollection.

On April 9, 2001, Edison International, SCE and the 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, if implemented, 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. 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. 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 Edison International, SCE or the CDWR. Neither Edison International nor SCE can provide assurance that all the required legislation will be enacted, regulatory actions taken and definitive agreements executed before the applicable deadlines. Implementation of the MOU, which is discussed in more detail below, will require numerous actions by the parties and by other California state agencies and the FERC, and would require significant changes in the regulatory decisions and other actions discussed below.

The growing undercollections and the concerns of lenders and others that SCE might not obtain regulatory approval of rate increases sufficient to cover ongoing procurement costs and recover past costs materially and adversely affected the liquidity of Edison International and SCE, becoming particularly pronounced in January 2001. With its revenues providing substantially less cash flow than needed for power purchases and other ongoing costs, SCE and its parent company, Edison International, soon had no unused borrowing capacity under their existing credit facilities and were unable to arrange any additional facilities. Moreover, Edison International and SCE found themselves unable to issue commercial paper or otherwise access the capital markets on reasonable terms. To conserve cash and enable SCE to continue essential business operations, in mid-January 2001, SCE temporarily suspended the payment 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 obligations and preferred stock dividends in arrears. As of March 31, 2001, the total preferred stock dividends in arrears was $6 million. The amounts due to the ISO or PX in clause (1) above do not include $275 million that has been charged back to SCE as a result of defaults in payments by Pacific Gas and Electric Company (PG&E). SCE has disputed its obligation for such amount in proceedings before the FERC and on April 6, 2001, the FERC ordered that such charges be rescinded. As of March 31, 2001, SCE resumed payment of interest on its debt obligations. Edison International has paid and expects to continue to pay its obligations, as they are due, subject to obtaining financing. 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.

On March 27, 2001, SCE announced that it will commence payments on deferred indebtedness. These payments include (1) past due interest on first and refunding mortgage bonds, Series 93C Due 2026 and Series 93H Due 2004 (which was paid on March 30, 2001); (2) past due interest on senior unsecured notes, 5-7/8% Series Due 2001 (which will be paid on April 19, 2001, to holders of record as of April 9, 2001, in accordance with the applicable indenture); (3) interest on matured commercial paper; and (4) interest on extendible commercial notes. Payments on the commercial paper and extendible commercial notes were made on April 6, 2001, and all interest was brought current to March 31, 2001, for the commercial paper and March 28, 2001, for the extendible commercial notes. Payments will also include interest on past due interest. Regular payments will be resumed on all interest due going forward, including interest payments due under SCE's bank credit facilities. Interest on commercial paper will be paid monthly, and interest on the 5-7/8% Series notes will be paid semiannually. Notices will be provided to holders of the securities about the timing and amount of the interest payments they will receive. The aggregate amount required to bring interest payments on outstanding indebtedness current as of March 31, 2001, is approximately $26 million.

On December 14, 2000, following an announcement from the ISO that electricity generators were refusing to sell into the California market due to concerns about the financial stability of SCE and Pacific Gas and Electric Company, the U.S. Secretary of Energy issued an order requiring power generators to make arrangements to generate and deliver electricity as required by the ISO after the ISO certifies it has been unable to secure adequate electricity supplies 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 February 23, 2001, a federal court judge issued a stay of litigation in the case of four power suppliers who agreed to extend their power sales pending a hearing set for March 16, 2001. On March 16, 2001, a federal court judge put the case on hold until March 20, 2001. 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 had 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 Ninth Circuit Court of Appeals issued a stay order, suspending the lower court's March 21 order until a final appeals ruling can be issued.

On January 17, 2001, following rolling blackouts in the northern California service territory of Pacific Gas and Electric Company, California Governor Gray Davis signed an order declaring an emergency and authorizing the CDWR to purchase power in order to prevent further blackouts.

Subsequently, on February 1, 2001, Governor Davis signed into law Assembly Bill (AB) IX, which was passed by the California Legislature as an urgency measure during a special session and took effect immediately. 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 California Procurement Adjustment (CPA) to determine further the amount of the CPA 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 adopted an interim CPA-related order requiring SCE to pay the CDWR a per-kWh price equal to the applicable generation-related retail rate per kWh established in the order (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 component of retail rates should be equal to the total bundled electric rate (including the 1¢ per kWh surcharge adopted by the CPUC on January 4, 2001) less certain 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 cents per kWh. The CPUC determined that the company-wide generation-related rate component is 7.277 cents per kWh, (which will increase to 10.277 cents per kWh for electricity delivered after March 27, 2001, due to the 3 cent surcharge discussed below) 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 CDWR during the period January 19 through March 31, 2001, and has forwarded $52 million to CDWR on behalf of these customers as of March 31, 2001. In compliance with that same order, SCE is currently paying the CDWR amounts approximating $2.5 million to $4 million daily.

In addition, this interim order proposed a method the CPUC will use to calculate the CPA in accordance with AB 1X and applied the proposed method to propose a company-wide average CPA rate. Using this rate, the order determined a proposed CPA revenue amount, to be used by the CDWR to determine the amount of bonds it may issue. All or a portion of the CPA may be allocated by the CPUC to reimburse the CDWR for its power purchases on behalf of utility customers.

In an interim order on April 3, 2001, the CPUC adopted the method to calculate the CPA and then applied that method to calculate a company-wide CPA rate for each California utility. The CPUC used that rate to determine the CPA revenue amount which 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 cents per kWh, which generates annual revenues of $856.43 million. According to the CPUC's methodology, the aggregate annual revenues generated by the CPA rates determined for the three California investor-owned utilities would allow the CDWR to issue up to $13.4 billion of bonds to pay for power purchases by the CDWR under the provisions of AB 1X. In its calculation of the CPA, the CPUC disregarded all the adjustments requested by SCE in its comments filed on March 29, 2001 (discussed below). As to SCE's concerns that the CPA may be overstated and could cause deleterious financial effects on SCE, the CPUC stated that the interim order does not allocate the CPA, and SCE may comment on the allocation of the CPA at a later time.

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, scheduled or not. In any event, SCE takes the position that it is not responsible for purchases of power by the CDWR or the ISO from and after January 18, 2001, the day after the Governor signed the order authorizing the CDWR to begin purchasing power for utility customers. The MOU contemplates that the CDWR will assume the entire responsibility for procuring the electricity needs of SCE's customers through December 31, 2002, to the extent not met by SCE's retained generation and power contracts. SCE cannot predict the outcome of any of these proceedings or issues.

In addition to the CPA-related order discussed above, on March 27, 2001, the CPUC adopted several other significant decisions regarding California's current energy crisis. These March 27, 2001, decisions deal with complex matters and in many respects are unclear or ambiguous. Edison International and SCE believe that in some respects the CPUC's March 27, 2001, decisions are unlawful and unconstitutional. Many elements of the decisions will be developed further in ongoing proceedings, the timing of which is uncertain. Furthermore, key components of the decisions would have to be modified, or the decisions rescinded, to implement the MOU that Edison International and SCE signed on April 9, 2001, with the CDWR (discussed below).

In an interim order adopted on March 27, 2001, the CPUC granted SCE and other California utilities a rate increase in the form of a three-cents per kilowatt-hour (kWh) surcharge on electricity sold, effective immediately (rate stabilization decision). However, the three-cent surcharge will not be collected in rates until the CPUC establishes an appropriate rate design. The CPUC proposed a tiered rate design in an assigned commissioner's ruling and asked for comments. The assigned commissioner said the tiered rate design is intended to encourage conservation by requiring customers to pay more for electricity above a threshold usage level. The three-cent surcharge will not apply to residential electricity usage below 130% of baseline rates or to certain low-income customers. The CPUC will probably hold hearings on the rate design and may not issue a decision until some time in 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 stated in its interim order that SCE is to use revenue generated by the three-cent surcharge to pay power costs incurred after March 27, 2001. SCE must refund the surcharge to ratepayers if SCE does not properly use it to pay power costs. If any refunds of power costs are obtained from power generators and sellers, those refunds will be used to reduce customer rates or to pay power costs. SCE must also refund the three-cent surcharge to the extend that any court or administrative body denies refunds from power generators or sellers in a proceeding where recovery is hampered by lack of cooperation from SCE. The CPUC also affirmed that an earlier one-cent per kWh surcharge granted on January 4, 2001, is now permanent under California legislation adopted in February 2001, known as AB 1X. The CPUC stated that revenues from the one-cent surcharge must be used to pay for power purchases and not for any other costs. The CPUC ordered that the three-cent surcharge must be added to the rate paid to the CDWR to reimburse the CDWR for its costs of purchasing power for delivery to SCE's customers (see above).

On March 27, 2001, the CPUC also ordered SCE to begin making payments to 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. The CPUC provided two special payment options for the month of April only. 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 most QFs by substituting natural gas index prices based on deliveries at the Oregon border in the place of index prices at the Arizona border. The order further revises other aspects of the payment formula to take into account changes in intrastate gas transportation costs. SCE anticipates that the changes will probably result in lower QF energy prices. The changes apply where appropriate regardless of whether the QF uses natural gas or other resources such as solar or wind.

In its March 27 decisions, the CPUC granted a petition previously filed by The Utility Reform Network (TURN), a ratepayer advocacy group, that was opposed by SCE and Pacific Gas and Electric Company. The CPUC directed that the balance in SCE's TRA, whether positive or negative, be transferred on a monthly basis to SCE's transition cost balancing account (TCBA), effective retroactively to January 1, 1998. The TRA is a regulatory asset account in which SCE records the difference between revenues received from customers through currently frozen rates and the costs of providing service to customers, including power procurement costs. The TCBA is a regulatory balancing account that tracks the recovery of generation-related transition costs, including stranded investments. The CPUC also ordered SCE to retroactively restate and record balances in its generation memorandum accounts to the TRA on a monthly basis before any transfer of generation revenues to the TCBA. SCE believes that this decision by the CPUC is a fundamental departure from established regulatory accounting and ratemaking procedures and is unlawful and unconstitutional. SCE believes the CPUC's intent was to deny SCE lawful recovery of its costs and to artificially extend the end of the current rate freeze. The CPUC characterized the changes as merely reducing the prior revenues recorded in the TCBA, thereby affecting only the amount of transition cost recovery achieved to date. Based upon the transfer of balances into the TCBA, the CPUC stated that the current rate freeze has not ended and will not end until the earlier of recovery of all specified transition costs or March 31, 2002. The CPUC said that any undercollection in the TRA cannot be recovered after the rate freeze ends. But 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 CPUC decision through all appropriate avenues.

In response to the CPUC's request in the interim CPA-related order, SCE filed comments on the proposed CPA calculation method on March 29 and April 2, 2001. In the limited time available to consider the impact of the CPUC's March 27 decisions, SCE estimated that its future revenues will not be sufficient to cover its own costs of retained generation and power purchases. SCE provided a forecast showing that the net effect of the rate increases described above, the decision on QF payments described below, and the payments ordered to be made to CDWR could result in a shortfall in the CPA calculation of $1.743 billion for SCE during 2001. SCE further stated that the proposed calculation method does not properly reflect all relevant generation costs, and that adoption of the method and later allocation of a portion of the CPA to the CDWR would materially exacerbate SCE's revenue shortfall. SCE commented that other flaws in the calculation are that: (1) the proposed CPA is for an indefinite period with no mechanism for adjustments based on changes in actual costs; (2) it ignores the potential impact on SCE's costs if the CDWR is not responsible for the full net-short position; (3) it assumes too low a cost for QF payments (as discussed below); (4) it may improperly exclude authorized generation-related costs; (5) it improperly excludes revenues from nuclear incentive pricing; and (6) the methodology for calculating the CPA is flawed and based on unreasonable assumptions.

In its comments on the CPUC's methodology for calculating the CPA, SCE also discussed the QF pricing resulting from the CPUC's March 27 decision on QF payments. SCE stated that the CPA calculation proposed by the CPUC is based on an assumed QF price of $80 per MWh, which was a target price in earlier negotiations with QFs seeking a settlement on lower prices. However, those negotiations failed.

SCE provided to the CPUC a forecast showing that QF prices through the remainder of 2001, based on the revised formula adopted by the CPUC and independently forecasted gas prices, will be substantially higher than $80 per MWh.

On April 9, 2001, Edison International and SCE signed a MOU with the CDWR regarding the California energy crisis and its effects on SCE. California Governor Gray Davis and his representatives participated in the negotiation of the MOU, and Governor Davis 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, then if the State elects, SCE's hydroelectric assets, and potentially additional rights to output from other generating stations, 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 revenues 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, 2001. Through the same date, a ratemaking 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, Edison Mission Energy ("EME") 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. EME 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 on 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 parties agree in the MOU that each of its elements is part of an integrated package, and effectuation of each element will depend upon effectuation of the others. To implement the MOU, numerous actions must be taken by the parties and by other agencies of the State of California and the FERC. The California Legislature must enact legislation to authorize purchase of SCE's transmission system or other assets, establish the dedicated rate components, authorize and/or direct the CPUC to take certain actions, and authorize other agreements and actions. The CPUC must also adopt the dedicated rate components and financing orders, modify existing decisions, and take various ratemaking and other actions. The CDWR and other state agencies must enter into definitive agreements for the purchase of assets from SCE and to embody various other elements of the MOU. 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, and Governor Davis has endorsed the MOU and has agreed to work for its complete implementation. The California Legislature, the CPUC, the FERC, and other governmental entities on whose part action will be necessary to implement the MOU are not parties to the MOU.

The MOU may be terminated by either SCE or 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. Edison International and SCE cannot provide assurance that all the required legislation will be enacted, regulatory actions taken, and definitive agreements executed before the applicable deadlines.

Edison International and SCE believe that the MOU is an important step towards an acceptable resolution of the major issues affecting Edison International and SCE as a result of the California energy crisis, including restoring their creditworthiness and creating a positive framework for future financial stability, but achievement of those results is not assured. A California voter initiative or referendum previously has been threatened against any measures that would raise consumer rates or aid California's investor-owned utilities. In addition, execution of the MOU does not eliminate the possibility that any of SCE's creditors could take steps to force SCE into bankruptcy proceedings.

On April 6, 2001, Pacific Gas and Electric Company (PG&E) announced that it had filed for reorganization under Chapter 11 of the United States Bankruptcy Code. PG&E said that neither its parent holding company nor any of the parent's other subsidiaries are affected by PG&E's filing. PG&E cited as reasons for its bankruptcy filing the failure by the State of California to assume full procurement responsibility for PG&E's net short position, the CPUC's actions on March 27 and April 3, 2001, that created new payment obligations for PG&E, lack of progress in negotiations with the state to provide recovery of power purchase costs, the CPUC's adoption of an illegal and retroactive accounting change, and the slow progress of discussions with representatives of Governor Davis (the actions of the CPUC cited by PG&E are discussed above).

SCE is still working to avoid bankruptcy, despite PG&E's announcement that it is filing for bankruptcy court protection. Edison International and SCE continue to believe that a comprehensive solution to the current crisis through agreements, legislation and regulatory actions, as contemplated by the MOU, is a preferable course of action. Neither Edison International nor SCE can predict the impact of PG&E's bankruptcy on implementation of the MOU and on Edison International's and SCE's other efforts to resolve their current financial and liquidity problems.

Regulation

SCE's retail operations are, for the most part, subject to regulation by the CPUC. The CPUC has the authority to regulate, among other things, retail rates, issuance of securities, and accounting practices. SCE's wholesale operations are subject to regulation by the FERC. The FERC has the authority to regulate wholesale rates as well as other matters, including retail transmission service pricing, accounting practices, and licensing of hydroelectric projects.

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

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

The California Coastal Commission has continuing jurisdiction over the coastal permit for San Onofre Nuclear Generating Station Units 2 and 3. Although the units are operating, the permit's mitigation requirements have not yet been completed. California Coastal Commission jurisdiction may continue for several years due to implementation and oversight of permit mitigation conditions, including restoration of wetlands and construction of an artificial reef for kelp. Additionally, in the summer of 2000, SCE applied for a coastal permit to construct a dry cask spent fuel storage installation for Units 2 and 3. This permit application was approved, with certain conditions, by the California Coastal Commission at its meeting on March 13, 2001.

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

In 1997, the CPUC adopted a decision which established new rules governing the relationship between California's natural gas local distribution companies, electric utilities, and certain of their affiliates. While SCE and its affiliates have been subject to affiliate transaction rules since the establishment of its holding company structure in 1988, these new rules are more detailed and restrictive. As required by the new rules and an interim CPUC resolution, SCE has filed preliminary and revised compliance plans which set forth SCE's implementation of the new affiliate transaction rules. The CPUC has not yet ruled on the sufficiency of SCE's October 1998 revised compliance plan. In January 2001, the CPUC issued an Order Instituting Rulemaking to commence the review of the 1997 Affiliate Transaction Rules that the original decision itself requires. The CPUC proposes that some rules be considered for streamlining or other revision, while inviting interested parties to submit proposals of their own. No decision is expected before the end of the year 2001 at the earliest.

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 March 15, 2001, the CPUC released a draft of a proposed order instituting investigation.

At its March 27, 2000, meeting, the CPUC deferred action on a proposed order instituting an investigation whether California's investor-owned utilities, including SCE, have complied with past CPUC decisions authorizing the formation of their holding companies and governing affiliate transactions, as well as applicable statutes. On March 29, 2001, an assigned commissioner's ruling was issued that requires Edison International and SCE to respond within 10 days to document requests and questions that are identical to document requests and questions included in the proposed order instituting investigation. At its meeting on April 3, 2001, the CPUC adopted the proposed order. The order reopens past CPUC decisions authorizing the utilities to form holding companies and initiates an investigation into (1) whether the holding companies violated requirements to give priority to the capital needs of their respective utility subsidiaries; (2) 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; (3) 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; (4) any additional suspected violations of laws or CPUC rules and decisions; and (5) whether additional rules, conditions, or other changes to the holding company decisions are necessary. The MOU signed on April 9, 2001, with the CDWR 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. Neither Edison International nor SCE can provide assurance that the CPUC will adopt such a decision, or predict what effects the investigation or any subsequent actions by the CPUC may have on either of them.

Changing Regulatory Environment

SCE currently 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 1994, state lawmakers and the CPUC initiated the electric industry restructuring process. In 1996, the California Legislature enacted comprehensive restructuring legislation. 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 mandated 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.

As described above, skyrocketing wholesale energy pricing and resulting liquidity pressures placed upon SCE and other investor-owned utilities has caused the restructuring process to change significantly as California adopted short-term measures, and works to develop longer-term solutions, to address the energy crisis. SCE's remaining generation portfolio was impacted by California state legislation enacted in January 2001 barring the sale of utility generating facilities, including SCE's Mohave, Palo Verde and Four Corners generating facilities, until 2006. Under the MOU, SCE would continue to own its share of these generating assets, which would be subject to cost-based ratemaking, through 2010. SCE's efforts to recover its transition and power procurement costs associated with restructuring are described below under Recovery of Transition and Power Procurement Costs.

Recovery of Transition and Power Procurement Costs

SCE's transition costs included 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. The CPUC decisions provide that most of the remaining transition costs are subject to recovery only 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 retaining generation and existing power contracts, the implementation of the MOU requires the CPUC to modify various decisions. Because of the CPUC's decisions on and after March 27, 2001, including the retroactive transfer of balances from SCE's TRA to its TCBA and related changes and other regulatory and legislative actions (see discussion in the Significant Developments in California Electric Utility Restructuring above), 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. 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 amount that has been charged against earnings, a regulatory asset would be correspondingly reinstated with a corresponding increase in earnings.

During the rate freeze period, there are three sources of revenue available to SCE for transition cost recovery: competition transition charge (CTC) revenue, revenue from the sale or valuation of generation assets in excess of book values, and net market revenue from the sale of SCE-controlled generation into the ISO and PX markets. However, due to the events discussed above (see Significant Developments in California Electric Utility Restructuring), revenue from the sale of SCE generation into the ISO and PX markets and from the sale or valuation of generation assets in excess of book values (prohibited by state legislation enacted in January 2001) is no longer available to SCE. 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 were using or began using utility services on or after the CPUC's 1995 restructuring decision date. Residual CTC revenue is calculated through the TRA mechanism.

Beginning in May 2000, SCE experienced adverse impacts from high prices for energy and ancillary services procured through the PX and ISO. These high wholesale prices, coupled with the current freeze on SCE's rates, resulted in substantial increases in the amount of undercollections in SCE's TRA, reaching $4.5 billion as of December 31, 2000. Additional information about the financial impact of this undercollection and various ongoing and proposed legislative and regulatory efforts and judicial proceedings designed to address or otherwise relating to it, is provided in Management's Discussion and Analysis in SCE's Annual Report to Shareholders for the year ended December 31, 2000 (Annual Report), under Regulatory Environment – Status of Transition and Power Procurement Costs Recovery section incorporated herein by reference pursuant to General Instruction G(2).

Rate Reduction Notes

In December 1997, after receiving approval from the CPUC and the California Infrastructure and Economic Development Bank, a limited liability company created by SCE issued approximately $2.5 billion of rate reduction notes. Residential and small commercial customers, whose 10% rate reduction began January 1, 1998, are repaying the notes over the expected ten-year term through non-bypassable charges based on electricity consumption. There were originally seven classes of notes. The first class, in the amount of $246.3 million, matured in December 1998, and the second class in the amount of $307.3 million matured in March 2000. The remaining Notes consist of five classes with scheduled maturities beginning in 2001 and ending in 2007, with interest rates ranging from 6.17% to 6.42%.

Other Revenue and Cost-Recovery Mechanisms

Revenue is determined by various mechanisms depending on the utility operation: distribution, transmission and generation. Moreover, in response to the above-referenced skyrocketing wholesale energy pricing, SCE has initiated rate stabilization proceedings at the CPUC. In addition, SCE jointly petitioned the FERC to find that the California wholesale electricity market was not workably competitive, to immediately impose a price cap for energy and ancillary services, and to take other responsive measures.

Revenue related to distribution operations is being determined through a performance-based rate-making mechanism (PBR) and the distribution assets have the opportunity to earn a CPUC-authorized 9.49% return. 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 revenue is being determined through the FERC-authorized rates that are subject to refund. Since the initiation of the ISO in April 1998, transmission cost recovery has been under FERC authority. In July 2000, FERC issued a final decision in SCE's 1998 FERC transmission rate case in which it ordered a reduction of approximately $38 million to SCE's proposed annual base transmission revenue requirement of $213 million. Of the total reduction of $38 million, about $24 million is associated with the rejection by FERC of SCE's proposed method for allocating overhead costs to transmission operations. SCE filed a Conditional Petition for Rehearing of the decision in August 2000, asking that FERC reconsider the decision assuming that the CPUC does not allow SCE to recover the $24 million in CPUC jurisdictional rates. In February 2001, SCE filed with the CPUC a request to recover in CPUC-jurisdictional rates the overhead costs not permitted by FERC to be included in transmission rates. A CPUC decision is not expected until late in 2001. In the meantime, SCE continues to collect transmission revenues based on the originally proposed $213 million level, subject to refund pending final resolution of the 1998 rate case. SCE expects that any refund amounts ultimately ordered by FERC associated with transmission will not be refunded to retail customers but will be credited against the amount of accrued transition/procurement costs.

Effective with the commencement of the ISO and PX operations on March 31, 1998, generation costs were subject to recovery through the market and transition cost recovery mechanisms, which included the nuclear rate-making agreements. 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 were 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.

In 1999, SCE filed an application with the CPUC proposing for purposes of the application 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. Under the MOU, SCE would withdraw this application, and would continue to operate the hydroelectric assets under cost-based ratemaking, through 2010.

In April 2000, SCE agreed to sell its 15.8% interest in Palo Verde and its 48% interest in Four Corners Generating Station to Pinnacle West Energy (PWE) for $550 million, subject to certain adjustments. The transaction remained subject to the approval of the CPUC, the NRC, the FERC and other state and federal entities, and to the receipt of a favorable ruling from the Internal Revenue Service. In January 2001, California state legislation was enacted which bars the sale of utility generating facilities, including SCE's Palo Verde and Four Corners generating facilities, until 2006. Under the MOU, SCE would withdraw its application to sell these generation interests and would continue to own its generating assets, which would be subject to cost-based ratemaking, through 2010.

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. In light of its four-point market reform proposal of October 2000, on November 16, 2000, SCE filed a rate stabilization plan with the CPUC seeking, among other things, a 9.9% rate increase for all customers (excluding low-income customers whose increase would be 4.95%) for a two-year period beginning January 1, 2001. Hearings were held in late December 2000 and on January 4, 2001, and the CPUC issued an interim decision authorizing SCE to establish an interim surcharge of 1¢ per kilowatt-hour 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.

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. Also, in the interim order, the CPUC granted a petition previously filed by TURN and directed that the balance in SCE's TRA, over- or undercollected, be transferred on a monthly basis to the TCBA, retroactive to January 1, 1998, (see Significant Developments in California Electric Utility Restructuring).

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. 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 mechanisms. SCE's petition for rehearing remains pending.

In November 2000, SCE filed with the CPUC a request for approval to credit the TCBA (and debit the Generation Asset Balancing Account) as soon as possible with the aggregate net gain on the pending sales of the Mohave, Four Corners and Palo Verde generation plants, which would have the effect of substantially accelerating the end of SCE's statutory rate freeze. The CPUC dismissed the request without full proceedings on the grounds that it was premature. Due to events discussed above in Significant Developments in California Electric Utility Restructuring (State legislation enacted in

January 2001 bars the sale or valuation of SCE's remaining generation assets until 2006), revenue from the sale of generation assets in excess of book values is no longer available to SCE. Additionally, as indicated above, under the MOU SCE would continue to own its generating assets, which would be subject to cost-based ratemaking, through 2010.

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. On April 9, 2001, SCE filed opposing 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.

See Regulatory Environment – Generation and Power Procurement and Regulatory Environment – Rate Stabilization Proceeding sections of the Management's Discussion and Analysis in the Annual Report, incorporated herein by reference pursuant to General Instruction G(2), for more information about SCE's revenue from its generation-related operations, recovery of its investment in its nuclear facilities, market valuation of its hydroelectric generation-related assets, the proposed sales of its interests in the Palo Verde and Four Corners generating facilities, rate stabilization proceedings before the CPUC and its FERC petition seeking specific regulatory responses to the wholesale energy market dysfunction, and on accounting for generation-related assets and power procurement costs.

Restructuring Implementation Costs

In May 1998, SCE filed an application with the CPUC to identify the categories of restructuring implementation costs (including costs related to the start-up and development of both the PX and ISO, and related to the implementation of direct access) and to establish the reasonableness of those costs incurred in 1997. In September 1999, the CPUC approved a settlement agreement between SCE, the Office of Ratepayer Advocates (ORA) and several other parties allowing SCE to recover substantially all (approximately $300 million) of its restructuring implementation costs (incurred and estimated) for the period 1997–2001. In addition, the settlement provides that up to $210 million of generation-related costs (transition costs) that are displaced by recovery of the restructuring implementation costs during the rate freeze may be recovered after December 31, 2001; the date SCE would no longer be allowed to recover these transition costs under restructuring legislation.

Market Risk Exposures

In 1997, SCE bought gas call options to mitigate its transition cost recovery exposure to increases in energy costs. In October 2000, SCE sold its remaining options; the gains were credited to the TCBA. In July 1999, SCE began participating in forward purchases through a PX block forward market. Initially, the only product available in the PX block forward market provided a monthly block of energy delivered six days a week (excluding Sundays and holidays), 16 hours a day. The CPUC originally limited SCE's use of the PX block forward market to a maximum of approximately 2,000 MW in any month. The PX requested and was granted authority from the FERC to sell other forward products including a peak product that specified power delivery six days a week, eight hours a day (excluding holidays). In March 2000, the CPUC approved SCE's request for rate-making treatment for its use of these additional products and for an expansion of the limits from all forward PX products up to 5,200 MW in summer months. In April 2000, the CPUC approved SCE's request to begin a demand responsiveness program that would allow customers to be paid to curtail their load during times of very high PX energy prices. In August 2000, the CPUC approved SCE's request to enter into bilateral power contracts. The CPUC approval limited the quantity of power that could be contracted for, required pre-approval for contracts extending beyond 2002, and required that all contracts expire on or before December 31, 2005. SCE entered into bilateral power contracts in November 2000. On December 31, 2000, the "mark-to-market" value of SCE's block-forward and bilateral forward contracts (market value of the contracted power less the contract cost) was $424 million and $398 million, respectively. During the last eight months of 2000, SCE experienced significantly higher PX purchased-power expenses despite savings of $684 million realized from its power hedging contracts over that period.

On February 2, 2001, the State of California seized SCE's block forward contracts. Under law, 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 SCE owes to the PX from any proceeds from the contracts. On or about February 26, 2001, SCE filed a claim against the State Board of Control (now known as the California Victim Compensation and Government Claims Board) seeking recovery of damages incurred as a result of the State's seizure of the block forward contracts. SCE has also notified Governor Gray Davis of SCE's intention to pursue a claim for damages. The Board has yet to respond to SCE's claim. The MOU, if implemented, calls for settlement of SCE's claim relating to these block forward contracts.

Other Rate Matters

CPUC Retail Ratemaking

The CPUC regulates the charges for services provided by SCE to its retail customers. As discussed above in the section on Changing Regulatory Environment, the way in which the CPUC regulates SCE is changing. The CPUC has issued both final and interim decisions regarding direct access, transition cost recovery, and rate unbundling in the restructuring of the electric industry. While some of them (such as those regarding transition cost recovery) are being challenged by SCE both before the CPUC as well as in judicial proceedings, the above decisions have affected cost recovery and rate regulation, and authorized new ratemaking mechanisms which were implemented, replacing the Electric Revenue Adjustment Mechanism, Energy Cost Adjustment Clause (ECAC) and base rates mechanism (pre-restructuring ratemaking mechanisms) as of January 1, 1998.

Under the restructuring legislation, total rates for all customers were frozen at June 10, 1996, levels, although residential and small commercial customers received a 10% reduction from the June 10, 1996, rate levels beginning on January 1, 1998. These rate levels were to remain in effect for the remainder of the transition period; however, on January 4, 2001, the CPUC issued an interim decision authorizing SCE to establish an interim surcharge of 1¢ per kilowatt-hour for 90 days, subject to refund. This was followed by the CPUC's interim rate stabilization order adopted on March 27, 2001 (see Other Revenue and Cost Recovery Mechanisms). Under these frozen rates, individual rate components (distribution, transmission, nuclear decommissioning, and public purpose programs) are determined according to CPUC- or FERC-authorized mechanisms, with the generation rate determined residually by subtracting these other components from the total rate. Beginning for rates effective in 1999, the consolidation of the individual rate component changes and the calculation of the residual generation rate are set forth for CPUC approval as part of the Revenue Adjustment Proceeding (RAP). On June 1, 1998, SCE filed its first annual RAP Report in compliance with CPUC directives to: (1) consolidate authorized rates and revenue requirements associated with various proceedings and mechanisms; (2) verify the residual CTC revenue calculation in the TRA; (3) verify the regulatory account balances which were transferred to the TCBA on January 1, 1998 (see Annual Transition Cost Proceeding below for further discussion of the TCBA); (4) streamline certain balancing and memorandum accounts; and (5) review the PX charge/credit calculation. On June 6, 1999, the CPUC issued its final 1998 RAP decision. In compliance with that decision, SCE updated its nongeneration rate components in October 1999. To maintain overall frozen rate levels, to the extent nongeneration rate components are authorized to change, the generation rate component changes equal and opposite from the nongeneration rate component changes. The decision also instructed SCE to include in the 1999 RAP Report a PX credit calculation that reflects the long-run marginal costs of customer account managers, customer service representatives, self-provision of ancillary services, and financing costs for purchasing power from the PX.

In June 1999, the CPUC issued a decision regarding unbundling SCE's cost of capital based on major utility functions. The decision was in response to SCE's May 1998 application on this issue. The CPUC found no unbundling adjustment was required in setting 1999 cost of capital for the California electric utilities. Furthermore, the CPUC ruled that SCE's rate of return should continue to be governed by the cost of capital trigger mechanism authorized as part of SCE's performance-based ratemaking mechanism. (See discussion under Other Revenue and Cost-Recovery Mechanisms.) As a result, SCE's return on equity for 1999 was unchanged at 11.6%.

On August 9, 1999, SCE filed its 1999 RAP Report requesting CPUC approval of the following: (1) consolidation of the 2000 nongeneration revenue requirements; (2) rate levels for 2000, including the residually determined generation rates; (3) 2000 kWh sales forecast; (4) entries to the TRA for the period June 1, 1998, through May 31, 1999; (5) proposed retention, elimination, and modification of balancing and memorandum accounts; (6) implementation and costs of electric vehicle programs during the record period; (7) administration of SCE's self-generation deferral rate contracts during the record period; and (8) the proposed additional .007/kWh (7 cents/MWh) credit to direct access customers associated with SCE's procurement of PX energy for bundled service customers. The most hotly contested issue was the computation of the PX Credit Adder intended to reflect each utility's long-run marginal cost of power procurement. On August 2, 2000, two proposed decisions (PDs) were issued – a PD of ALJ Barnett and an Alternate PD of Commissioner Neeper. ALJ Barnett adopted for all three investor-owned utilities a PX Credit Adder of .007 cents per kWh (7 cents per MWh). This is the PX Credit Adder that SCE had proposed. ALJ Barnett adopted all of SCE's arguments on long-run marginal cost and used SCE's formulation of the PX credit as a model for the other utilities. Commissioner Neeper adopted, and later through a revised PD modified, a different PX Credit Adder. A revised Alternate PD by Commissioner Bilas proposing yet another PX Credit Adder was issued on November 6, 2000. Like other Alternates, it relied on the "average cost" methodology of the ORA. On January 4, 2001, the PD of ALJ Barnett was adopted by the CPUC. The decision put SCE on notice that it will no longer be able to prospectively recover 100% of its reliability must-run costs in the TRA. The decision adopted all other RAP issues SCE requested.

Nuclear Decommissioning and Public Purpose Program Rates

Recovery of SCE's nuclear decommissioning costs and legislatively mandated public purpose program funding is made through rates set to recover 100% of these costs. Public purpose programs include cost effective energy efficiency, research, renewable technology development, and low income programs.

Annual Transition Cost Proceedings (ATCP)

In 1997, the CPUC established the ATCP to determine whether SCE's TCBA entries are recorded pursuant to applicable CPUC decisions and the restructuring legislation, and whether certain expenses are justified. The purpose of the ATCP is to ensure the recovery of generation-related transition costs through the TCBA that complies with the guidelines established by the CPUC. The TCBA tracks the recovery of transition costs, including the accelerated recovery of plant balances, QF and purchased power costs, and regulatory assets and obligations.

1998 ATCP

On September 1, 1998, SCE filed its first ATCP Report with the CPUC and requested, among other things, that entries made to the TCBA and applicable generation-related memorandum accounts during the record period of January 1, 1998, through June 30, 1998, be found to be justified and in compliance with applicable CPUC decisions and the restructuring legislation. On March 31, 1999, the ORA submitted its report and made the following recommendations adverse to SCE: (1) $2.37 million in QF shareholder incentive amounts should be disallowed; (2) $3.2 million in employee-related transition costs should be disallowed; and (3) $9.67 million in post-retirement benefits other than pensions (PBOPs) and $5.76 million in long-term disability regulatory assets should be rejected. On June 14, 1999, the ALJ granted SCE's motion to strike the ORA's testimony and recommendations on the third item. Prior to hearings, the ORA and SCE recommended that the CPUC adopt a stipulation and joint recommendation whereby SCE would not recover $895,000 in retention bonuses, and $1.19 million of the total QF shareholder incentive amounts. On October 8, 1999, the matter was submitted to the CPUC.

On January 6, 2000, an ALJ issued a proposed decision adopting the stipulation and joint recommendation as specified above. In addition, the proposed decision provided clarification on the following four accounting issues impacting the operation of the TCBA: (1) It directs SCE and the other utilities to review their estimates of market value for each divested generating plant and recalculate the interest accrued on undercollections of the TCBA during the record period. SCE believes it used the market value accounting directed by the proposed decision; (2) It clarifies the accounting methodology used to estimate the market value of retained generating assets. At this time, SCE believes there will be no negative impact on earnings associated with this issue; (3) It directs SCE to apply the TCBA overcollection of $350.7 million as of June 30, 1998, to further accelerate the depreciation of those transition cost assets with the highest rate of return, and in a manner that provides the greater tax benefits (i.e., to accelerate the recovery of nuclear sunk costs). It also directs SCE to net a $238 million undercollection in the ISO/PX implementation delay memorandum account against the TCBA overcollection in the calculation. SCE estimates a $10 million impact over the entire transition period ending December 31, 2001, if this accounting change is adopted by the CPUC; and (4) It disallows the recovery through the TCBA for the record period of certain telecommunications, training, mechanical service shop and warehouse equipment that were related to SCE's divested generating plants but was not purchased by the new owners. The net book value of these retained assets is in the $8 million to $10 million range. Comments to the proposed decision were filed in January and a supplemental brief was filed on February 1, 2000.

On February 17, 2000, the ALJ prepared a revised proposed decision that addressed these four matters and left intact other provisions of the proposed decision. The revised proposed decision was approved by the CPUC on the same day. The decision found that SCE's calculation of the TCBA for the record period was correct and that SCE appropriately applied the overcollection as of June 30, 1998, to the subsequent undercollection. Therefore, the decision does not require SCE to accelerate recovery of its nuclear assets. The decision changes the accounting methodology used to estimate the market value of retained generating assets and requires that SCE credit the TCBA for the aggregate net book value of SCE's non-nuclear assets, including the land surrounding such assets. SCE's shares of the Mohave Station and Four Corners Generating Station (Four Corners) are excluded from this requirement. Ongoing depreciation, taxes, and return will be recovered through market revenue. The decision disallows the recovery through the TCBA for the record period of the retained assets but does not preclude SCE from seeking recovery in future record periods. The disallowance for the 1998 record period was $55,000.

On February 29, 2000, SCE made a request to the CPUC's Executive Director for an extension of time to file the compliance advice letter so that the CPUC could review SCE's soon-to-be filed petition for a stay of the decision, application for rehearing and/or petition for modification of the decision. In a letter dated March 3, 2000, the Executive Director granted SCE an extension of time until May 31, 2000, to file its advice letter compliance filing.

Once SCE had the opportunity to fully review the decision adopted by the CPUC, it discovered that the revisions by the CPUC in response to the parties' comments had inadvertently omitted establishing a new account to record the corresponding debit to the TCBA credit for the aggregate net book value of any remaining non-nuclear generation assets. SCE immediately informed the Assigned Commissioner of the omission, and the Assigned Commissioner issued on March 2, 2000, an Assigned Commissioner's Ruling (ACR) proposing the CPUC establish a generation asset memorandum account to record this debit. If no debit account was established by the CPUC, any offsetting debit would be considered as a $300 million charge to earnings on an after tax basis.

In its comments to the ACR, SCE proposed that this account be established as a balancing account, the Generation Asset Balancing Account, or GABA, in order to avoid problems associated with limits for short-term borrowing purposes. The CPUC agreed, and on June 8, 2000, established the GABA. SCE filed its compliance advice letter in June 2000. On April 13, 2000, SCE filed a petition for modification seeking modification of the decision to restore recovery of authorized return, taxes, and depreciation for its hydro assets through the TCBA. It is not known when the CPUC will act on SCE's petition for modification.

On November 9, 2000, SCE filed a petition for modification of D.00-02-048 requesting the CPUC to allow SCE to credit its TCBA (and debit its GABA) with the aggregate net above-book gain reflected in the pending sales of SCE's interest in Mohave, Four Corners and Palo Verde generating plants. Crediting these amounts to the TCBA would allow SCE to accelerate the end of its rate freeze as requested in SCE's Rate Stabilization Application, A.00-11-038 (as revised on December 20, 2000).

1999 ATCP

On September 1, 1999, SCE filed its 1999 ATCP setting forth entries made to the TCBA and other generation-related accounts for the months of July 1998 through June 1999. On February 23, 2000, the ORA issued its report and made the following disallowance recommendations adverse to SCE: (1) approximately $5.5 million in post-record period adjustments booked after the date of divestiture for capital additions made in 1996 to divested fossil generating plants that was transferred to the TCBA; (2) $17.2 million related to the termination contract with the Sacramento Municipal Utility District (SMUD); (3) $252,000 in employee-related transition costs; and (4) a $136,000 adjustment to the QF subaccount of the TCBA. SCE served its rebuttal testimony on March 29, 2000, and supplemental testimony on April 3, 2000. Prior to hearings, ORA and SCE executed a Settlement Agreement that resolved all issues associated with SCE's filing. The parties agreed that (1) SCE made the $5.5 million adjustment and a $136,000 adjustment to the TCBA as referred to above; (2) ORA no longer contests the reasonableness of SCE's termination contracts with SMUD; and (3) $192,000 in employee-related transition costs are to be disallowed. In the settlement, the parties agree that the Union Worker Protection Benefit (WPB) Agreements were reviewed for reasonableness by ORA in this proceeding and that the programs and benefits in each of the WPB Agreements are reasonable and qualify for recovery as transition costs through the TCBA. On October 19, 2000, the CPUC issued its decision that approved the Settlement Agreement, closing this proceeding.

2000 ATCP

On September 1, 2000, SCE filed its 2000 ATCP setting forth entries made to the TCBA and other generation-related accounts for the months of July 1999 through June 2000. ORA issued its report on February 27, 2001. In its report, ORA recommended, among other things, that the Commission: (1) defer review of SCE's natural gas procurement and management activities, including a $10 million post record period adjustment, until the 2001 ATCP; (2) disallow $882,000 of employee-related transition costs; and (3) adjust the TCBA undercollection downward $4.35 million to reflect the reasonableness of post record period adjustments. On March 15, 2001, in response to SCE's First Set of Data Requests based on ORA's Report, ORA withdrew its recommendation to defer its review of SCE's natural gas procurement and management activities, including a $10,000,000 gas options post-record period adjustment, until the 2001 ATCP. ORA found the $10,000,000 post-period adjustment to be reasonable as well as SCE's natural gas procurement and management activities during the record period with respect to the El Paso contract. Since ORA no longer objects to the $10,000,000 gas options post-record period adjustment, ORA no longer recommends that the TCBA needs to be further adjusted and now agrees with SCE's June 30, 2000, TCBA balance. The only contested issue that remains is the $882,000 in employee-related transition costs. SCE's rebuttal testimony was mailed on March 27, 2001, and hearings are scheduled for May 21 through May 25, 2001.

Annual Energy Cost Adjustment Clause (ECAC) Proceedings

Through 1998, SCE filed ECAC applications each year with the CPUC regarding its fuel and purchased power expenses, seeking the CPUC's determination that SCE's fuel and purchased power costs, including payments to QFs, were reasonable. The last ECAC application filed in 1998 was closed in 1999. The

ECAC reasonableness revision of certain costs, including QF payments, is now reviewed in the ATCP proceedings discussed above.

Palo Verde Nuclear Generating Station

In January 1997, the CPUC authorized a further acceleration of the recovery of SCE's remaining investment of $1.2 billion in Palo Verde Units 1, 2, and 3. The accelerated recovery will continue through December 2001, earning a 7.35% fixed rate of return. The future operating costs, including nuclear fuel and nuclear fuel financing costs, and incremental capital expenditures, are subject to balancing account treatment through 2001. Beginning January 1, 1998, the balancing account became part of the TCBA mechanism. The existing NUIP will continue only for purposes of calculating a reward for performance of any unit above an 80% capacity factor for a fuel cycle. These rate-making plans and the TCBA mechanism will continue for rate-making purposes through the end of the rate freeze period. However, due to the various unresolved regulatory and legislative issues (see discussion in the Significant Developments in California Electric Utility Restructuring above), SCE is not able to conclude that the unamortized nuclear investment regulatory 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. Beginning in 2002, SCE will be required to share the net benefits received from the operation of Palo Verde equally with ratepayers. 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 amount that has been charged against earnings, a regulatory asset would be correspondingly reinstated with a corresponding increase in earnings. In addition, if the MOU is implemented, the requirement that SCE share the net benefits received from the post-2001 operation of Palo Verde equally with ratepayers will be eliminated.

San Onofre Nuclear Generating Station Units 2 and 3

In April 1996, the CPUC authorized a further acceleration of the recovery of SCE's remaining investment of $2.6 billion in San Onofre Units 2 and 3. The accelerated recovery will continue through December 2001, earning a 7.35% fixed rate of return. San Onofre's operating costs, including nuclear fuel, nuclear fuel financing costs, and incremental capital expenditures, are recovered through an incentive pricing plan which allows SCE to receive about 4¢ per kWh through December 31, 2003. Beginning January 1, 1998, the accelerated plant recovery and incremental cost incentive pricing became part of the TCBA mechanism. These rate-making plans and the TCBA mechanism will continue for rate-making purposes through the end of the rate freeze period. However, due to the various unresolved regulatory and legislative issues (as discussed in Significant Developments in California Electric Utility Restructuring), SCE is not able to conclude that the unamortized nuclear investment regulatory 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. 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 amount that has been charged against earnings, a regulatory asset would be correspondingly reinstated with a corresponding increase in earnings. Beginning in 2004, SCE will be required to share the benefits received from operation of San Onofre Units 2 and 3 equally with ratepayers. In addition, if the MOU is implemented, the sharing of net benefits received from the post-2003 operation of San Onofre Units 2 and 3 equally between shareholders and ratepayers would be eliminated, but these units would continue to be subject to cost-based ratemaking through December 31, 2010.

New Accounting Rules

An accounting rule, which requires that costs related to start-up activities be expensed as incurred, became effective January 1, 1999. This new accounting rule did not materially affect SCE's results of operations or its financial position.

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.

Fuel Supply and Purchased Power Costs

Since April 1, 1998, SCE had been required to sell all of its generated and purchased power through the PX and ISO, schedule delivery of the power through the ISO, and acquire all of its power from the PX and ISO to distribute to its retail customers. These PX and ISO transactions were reported net. As of December 15, 2000, the FERC eliminated this buying and selling requirement. On January 30, 2001, the PX suspended its day-ahead and day-of energy trading, and it subsequently ceased operations and filed for bankruptcy. Furthermore, beginning in January 2001, the CDWR began purchasing power for SCE's customers. The MOU contemplates that the CDWR will assume the entire responsibility for procuring the electricity needs of SCE's customers through December 31, 2002, to the extent not met by SCE's retained generation and power contracts.

In 2000, PX/ISO purchased-power expense increased significantly due to electricity shortages and dramatic price increases for natural gas, a key input of electricity production. The increased volume of higher priced PX purchases was minimally offset by increases in PX sales revenue and ISO net revenue, as well as an increase in the market value of gas call options. Increases in the options' market value decreased purchased-power expense. These gas call options (which were sold in October 2000) mitigated SCE's transition cost recovery exposure to increases in energy prices.

SCE's sources of energy during 2000 were as follows: 58.6% purchased power; 22.3% nuclear; 13.7% coal; and 5.4% hydro.

Natural Gas Supply

As a result of the sale of all of its gas-fired generating stations, SCE has terminated four long-term natural gas supply and three long-term gas transportation contracts which had been used to import gas from Canada. In addition, SCE has exercised an option under its 15-year gas transportation commitment with El Paso Natural Gas Company to reduce its capacity obligation from 200 million to 130 million cubic feet per day. SCE permanently assigned its contract with El Paso in November 2000 paying $12.3 million in consideration to the assignee.

Nuclear Fuel Supply

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

Uranium concentrates(*)	2003
Conversion	2003
Enrichment	2003
Fabrication	2005

(*) Assumes the San Onofre participants meet their supply obligations in a timely manner.

Assuming normal operation and full utilization of existing on-site storage capacity, San Onofre Units 2 and 3 will maintain full-core offload reserve through 2005. The Nuclear Waste Policy Act of 1982 requires that the United States Department of Energy provide for the disposal of utility spent nuclear fuel beginning January 31, 1998. The Department of Energy has defaulted on its obligation to begin acceptance of spent nuclear fuel from the commercial nuclear industry by that date. Additional spent fuel storage either on-site or at another location will be required to permit continued operations beyond 2005.

Participants at Palo Verde have contractual agreements for uranium concentrates to meet projected requirements through 2002. Independent of arrangements made by other participants, SCE will furnish its share of uranium concentrates requirement through at least 2001 from existing contracts. Contracts covering 100% of requirements are in place for enrichment through 2003 and fabrication through 2015. Contracts covering 75% of conversion requirements in 2001 are in place with negotiations on-going for the remainder.

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

Environmental Matters

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

In California, pursuant to federal, state and regional Clean Air Act programs, SCE generating stations were required to reduce emissions of oxides of nitrogen and certain other pollutants. During 1998, SCE sold all of its oil- and gas-fueled generating stations within the Mohave Desert Air Quality Management District, Ventura County Air Pollution Control District, and in the Santa Barbara County Air Pollution Control District. SCE has sold all but one of its oil- and gas-fired generating stations within the South Coast Air Quality Management District. The remaining plant, the small diesel-fired Pebbly Beach Generating Station, supplies power to Santa Catalina Island.

SCE also owns a 56% undivided interest in the Mohave Generating Station (Mohave Station) located in Laughlin, Nevada, which is subject to certain air quality programs. 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. The decree was designed also to address concerns raised by two EPA programs regarding visibility and regional haze. The EPA issued its final rulemaking regarding regional haze regulations on July 1, 1999. The final rule is not expected to impose any additional emissions control requirements on the Mohave Station beyond meeting the provisions of the consent decree. The EPA and SCE also participated in a study to determine the specific impact of air contaminant emissions from the Mohave 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. Finally, in June, 1999, the 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 July 2000, EPA published a proposed rule and on August 21, 2000, SCE provided comments to the proposed rule. 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 Agency is considering incorporating the decree into the visibility provisions of its Federal Implementation Plan for Nevada.

The Clean Air Act also requires the EPA to carry out a three-year study of risk to public health from the emissions of toxic air contaminants from electric utility steam generating plants, and to regulate such emissions if the Administrator makes certain findings. The study's final report to Congress concluded that mercury from coal-fired utilities is the hazardous air pollutant of greatest potential concern and merits additional research and monitoring to better understand the risks of mercury exposure. Other pollutants that may potentially need further study are dioxins and arsenic from coal-fired plants, and nickel from oil-fired plants. The EPA concluded that the impacts from emissions from gas-fired utilities are negligible and that there is no need for further evaluation of the risks of hazardous air pollutants emitted from such plants.

On November 3, 1999, the United States Department of Justice filed suit against a number of electric utilities for alleged violations of the Clean Air Act's "new source review" requirements related to modifications of air emissions sources at electric generating stations located in the southern and midwestern regions of the United States. Several states have joined these lawsuits. In addition, the EPA has also issued administrative notices of violation alleging similar violations at additional power plants owned by some of the same utilities named as defendants in the Department of Justice lawsuit, as well as other utilities, and also issued an administrative order to the Tennessee Valley Authority for similar violations at certain of its power plants. The EPA has also issued requests for information pursuant to the Clean Air Act to numerous other electric utilities seeking to determine whether these utilities also engaged in activities that may have been in violation of the Clean Air Act's new source review requirements.

To date, one utility—the Tampa Electric Company—has reached a formal agreement with the United States (February 2000) to resolve alleged new source review violations. Two other utilities, the Virginia Electric Power Co. and Cinergy Corp., have reached agreements in principle with the EPA (November and December 2000, respectively). In each case, the settling party has agreed to incur over $1 billion in expenditures over several years for the installation of additional pollution control, the retirement or repowering of coal-fired generating units, supplemental environmental projects and civil penalties. These agreements provide for a phased approach to achieving required emission reductions over the next 10 to 15 years. The settling utilities have also agreed to pay civil penalties ranging from $3.5 million to $8.5 million.

On June 27, 2000, the EPA issued a Request For Information (RFI) for the Four Corners plant. SCE owns a 48% share of Four Corners' Units 4 and 5 and on September 1, 2000, replied to the RFI. To date, no further action has been taken with respect to Four Corners.

In December 2000, the EPA announced its intentions to regulate mercury emissions from coal-fired and oil-fired electric power plants under Section 112 of the Clean Air Act and indicated that it would propose a rule to regulate these emissions by no later than December 15, 2003. EPA expects to finalize this rule by December 15, 2004. Because SCE does not know what the EPA may require with respect to this issue, SCE is presently unable to evaluate the impact of potential mercury regulations on the operations of its facilities.

Regulations under the Clean Water Act require permits for the discharge of certain pollutants into U.S. waters. Under this act, the EPA issues effluent limitation guidelines, pretreatment standards, and new source performance standards for the control of certain pollutants. Individual states may impose more stringent limitations. SCE incurs additional expenses and capital expenditures in order to comply with guidelines and standards applicable to steam electric power plants. SCE presently has discharge permits for all applicable facilities.

The Safe Drinking Water and Toxic Enforcement Act prohibits the exposure to individuals of chemicals known to the State of California to cause cancer or reproductive harm and the discharge of such listed chemicals into potential sources of drinking water. Additional chemicals are continuously being put on the State's list, requiring constant monitoring.

The Resource Conservation and Recovery Act provides the statutory authority for the EPA to implement a regulatory program for the safe treatment, recycling, storage, and disposal of solid and hazardous waste. An unresolved issue remains regarding the degree to which coal waste should be regulated under the act. Currently, coal waste has been determined to be non-hazardous. Increased regulation may result in increased expenses relating to the operation of the Mohave Station.

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

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 discounted amounts).

SCE's recorded estimated minimum liability to remediate its 44 currently 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: (1) the extent and nature of contamination; (2) the scarcity of reliable data for identified sites; (3) the varying costs of alternative cleanup methods; (4) developments resulting from investigatory studies; (5) the possibility of identifying additional sites; and (6) 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- and oil-fueled generation plants (except the Pebbly Beach Generating Station) 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 (SCE may seek to include additional sites). Under this mechanism, SCE will recover 90% of cleanup costs through customer rates; shareholders fund the remaining 10%, with the opportunity to recover these costs from insurance carriers and other third parties. SCE has successfully settled insurance claims with all responsible carriers. Costs incurred at SCE's remaining sites are expected to be recovered through customer rates. SCE has recorded a regulatory asset of $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 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 that 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 its financial position. There is 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.

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

Item 2. Properties

Existing Generating Facilities

SCE owns and operates one diesel-fueled generating plant located on Santa Catalina Island, 37 hydroelectric plants, and an undivided 75.05% interest (1,614 MW net) in San Onofre Units 2 and 3. These plants are located in Central and Southern California.

SCE also owns a 15.8% (590 MW net) share of Palo Verde which is located near Phoenix, Arizona. SCE owns a 48% undivided interest (754 MW net) in Units 4 and 5 at the Four Corners, which is a coal-fueled steam electric generating plant located in New Mexico. Palo Verde and Four Corners are operated by other utilities. In April 2000, SCE agreed to sell its 15.8% interest in Palo Verde and its 48% interest in Four Corners Generation Station to Pinacle West Energy for $550 million, subject to certain adjustments. The transaction remained subject to the approval of the CPUC, the Nuclear Regulatory Commission, the FERC and other state and federal entities, and to the receipt of a favorable ruling from the Internal Revenue Service. Under the sales agreement, competing offers could be solicited by SCE, subject to certain conditions, and any superior offers received were subject to certain matching rights by PWE. In late 2000, SCE received a superior offer for its Four Corners Generating Station, which PWE elected not to match. In January 2001, California state legislation was enacted which bars the sale of utility generating facilities, including SCE's Palo Verde and Four Corners generating facilities, until 2006. Under the MOU, SCE would continue to own its share of these generating assets, which would be subject to cost-based ratemaking, through 2010.

SCE operates and owns a 56% undivided interest (885 MW) in the Mohave Station, which consists of two coal-fueled steam electric generating units in Clark County, Nevada. In April 2000, the CPUC approved SCE's proposed auction process to sell its 56% interest in Mohave Generating Station. In May 2000, SCE agreed to sell its interest in Mohave to AES Corporation for approximately $533 million. The transaction was subject to final approval by the CPUC and various federal regulatory agencies. In June 2000, SCE submitted a compliance filing with the CPUC seeking approval of the auction results and the sale to AES. In January 2001, California state legislation was enacted which bars the sale of utility generating facilities, including SCE's Mohave plant, until 2006. Under the MOU, SCE would continue to own its generating assets, which would be subject to cost-based ratemaking, through 2010.

At year-end 2000, the existing SCE-owned generating capacity (summer effective rating) was divided approximately as follows: 44.6% nuclear, 31.8% coal, 23.4% hydroelectric, and 0.2% diesel. San Onofre, Four Corners, certain of SCE's substations and portions of its transmission, distribution and communication systems are located on lands of the U. S. or others under (with minor exceptions) licenses, permits, easements or leases, or on public streets or highways pursuant to franchises. Certain of such documents obligate SCE, under specified circumstances and at its expense, to relocate transmission, distribution, and communication facilities located on lands owned or controlled by federal, state, or local governments.

The 37 hydroelectric plants (some with related reservoirs) have an effective operating capacity of 1,156 MW, and are, with five exceptions, located in whole or in part on lands of the U.S. pursuant to, 30- to 50-year governmental licenses that expire at various times between 2001 and 2029. Such licenses impose numerous restrictions and obligations on SCE, including the right of the United States to acquire projects upon payment of specified compensation. When existing licenses expire, the FERC has the authority to issue new licenses to third parties, but only if their license application is superior to SCE's and then only upon payment of specified compensation to SCE. Any new licenses issued to SCE are expected to be issued under terms and conditions less favorable than those of the expired licenses. SCE's applications for the relicensing of certain hydroelectric projects with an aggregate dependable operating capacity of about 112.67 MW are pending. Annual licenses have been issued to SCE hydroelectric projects that are undergoing relicensing and whose long-term licenses have expired. The annual licenses will be renewed until the long-term licenses are issued. SCE filed an application with the CPUC on December 15, 1999, seeking authorization to market value and retain the ownership and operation of the hydroelectric plants pursuant to the State's electric industry restructuring legislation. In 1999, SCE filed an application with the CPUC establishing for purposes of the application 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. The application has broad-based support from labor, ratepayer and environmental groups. 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. A final CPUC decision is expected in 2001. Under the MOU, SCE would withdraw this application, and would continue to own the hydroelectric assets, which would be subject to cost-based ratemaking, through 2010. In June 2000, SCE credited the TCBA with the proposed excess of market value over book value of its hydroelectric generation assets and simultaneously recorded the same amount in the 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 Significant Developments in California Electric Utility Restructuring), the GABA transaction was reclassified back to the TCBA, and the TCBA balance (as recalculated based on a March 27, 2001, CPUC interim decision) was written off as of December 31, 2000.

The capacity factors in 2000 for SCE's principal generation resources were: 45.1% for SCE's hydroelectric plants (lower than average due to below-normal water conditions); 96.4% for San Onofre; 77.9% for the Mohave Station; 79.2% for Four Corners Units 4 and 5; and 93% for Palo Verde.

Substantially all of SCE's properties are subject to the lien of a trust indenture securing First and Refunding Mortgage Bonds (Trust Indenture), of which approximately $2 billion in principal amount was outstanding on December 31, 2000. Such lien and SCE's title to its properties are subject to the terms of franchises, licenses, easements, leases, permits, contracts, and other instruments under which properties are held or operated, certain statutes and governmental regulations, liens for taxes and assessments, and liens of the trustees under the Trust Indenture. In addition, such lien and SCE's title to its properties are subject to certain other liens, prior rights and other encumbrances, none of which, with minor or insubstantial exceptions, affect SCE's right to use such properties in its business, unless the matters with respect to SCE's interest in Four Corners and the related easement and lease referred to below may be so considered.

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

Interior, and the possible invalidity of the Trust Indenture lien against SCE's interest in the easement, lease, and improvements on Four Corners.

As discussed above, the MOU between the CDWR and SCE calls for the State's purchase of SCE's transmission lines for an estimated price of $2.76 billion (2.3 times book value). The sale is subject to execution of a definitive sale agreement and other conditions. If a sale of the transmission assets is not completed under certain circumstances, the MOU calls for SCE's hydroelectric assets, and potentially additional rights to output from its other generating stations, to be sold to the State.

Construction Program and Capital Expenditures

Cash required by SCE for its capital expenditures totaled $1.6 billion in 2000, $984 million in 1999, and $861 million in 1998. Construction expenditures for the 2001–2005 period are forecasted at $4.5 billion, but may have to be scaled back unless regulatory or legislative changes make SCE creditworthy again.

In addition to cash required for construction expenditures for the next five years as discussed above, $3.4 billion is needed to meet requirements for long-term debt maturities and sinking fund redemption requirements.

SCE's estimates of cash available for operations for the five years through 2005 assume, among other things, satisfactory reimbursement of cost incurred during the California Energy Crisis, the receipt of adequate and timely rate relief and the realization of its assumptions regarding cost increases, including the cost of capital. SCE's estimates and underlying assumptions are subject to continuous review and periodic revision.

The timing, type, and amount of all additional long-term financing are also influenced by market conditions, rate relief, and other factors, including limitations imposed by SCE's Articles of Incorporation and Trust Indenture. Because of its current liquidity and credit problems, SCE is unable to obtain financing of any kind. Similarly, as a result of investor's concerns regarding the California energy crisis' effect on SCE's liquidity and overall financial condition, SCE has repurchased $849 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 January 2001, Fitch, Standard and 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.

Under the MOU among the CDWR, SCE and Edison International, Edison International and SCE would 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 would be funded from SCE's retained earnings or, if necessary, from equity investments by Edison International.

Nuclear Power Matters

SCE's nuclear facilities have been reliable sources of inexpensive, non-polluting power for SCE's customers for more than a decade. Throughout the operating life of these facilities, SCE's customers have supported the revenue requirements of SCE's capital investment in these facilities and for their incremental costs through traditional cost-of-service ratemaking.

In 1996, the CPUC adopted SCE's San Onofre Unit 2 and 3 proposal under which SCE would have recovered its remaining investment in the San Onofre Units at a reduced rate of return of 7.35%, but on an accelerated basis during the eight-year period from the effective date in 1996 through December 31, 2003. California's restructuring legislation, however, requires the recovery of the San Onofre investment to be completed by December 31, 2001. In addition, the traditional cost-of-service ratemaking for San Onofre Units 2 and 3 was superseded by an incentive pricing plan in which SCE's customers pay a preset price for each kWh of energy generated at San Onofre during the eight-year period. The restructuring legislation allows for the continuation of the incentive pricing plan through December 31, 2003. SCE is compensated for the incremental costs required for the continued operation of San Onofre Units 2 and 3 with revenue earned through the incentive pricing plan. SCE also retained the ability to request recovery of the cost of replacement energy for periods in which San Onofre will not generate power through ECAC filings and, beginning in 1998, as part of the TCBA mechanism. These rate-making plans and the TCBA mechanism will continue for rate-making purposes through the end of the rate freeze period. However, due to the various unresolved regulatory and legislative issues (see discussion in the Significant Developments in California Electric Utility Restructuring above), SCE is not able to conclude that the unamortized nuclear investment regulatory 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. The restructuring legislation also allows SCE to continue to collect funds for decommissioning expenses through traditional ratemaking treatment. 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 amount that has been charged against earnings, a regulatory asset would be correspondingly reinstated with a corresponding increase in earnings.

On July 16, 1997, the CPUC approved SCE's request to transfer the recorded net investment in San Onofre Units 2 and 3 step-up transformers to San Onofre Units 2 and 3 sunk costs for recovery by December 31, 2001, at a reduced rate of return of 7.35%.

On August 21, 1997, the CPUC approved San Diego Gas & Electric's (SDG&E) and SCE's Joint Petition to Modify, requesting continued recovery of certain corporate administrative and general costs allocable to San Onofre Units 2 and 3, at rates of 0.28¢ and 0.21¢ per kWh, respectively, for the period January 1, 1998, through December 31, 2003.

In 1996, SCE filed its Palo Verde Proposal Application requesting adoption of a new rate mechanism for Palo Verde consistent with that of San Onofre Units 2 and 3. On November 15, 1996, SCE, the ORA, and TURN entered into a settlement agreement, which was approved by the CPUC on December 20, 1996. The agreement allows SCE to recover its remaining investment in the Palo Verde units by December 31, 2001, at a reduced rate of return of 7.35% consistent with the restructuring legislation. The settling parties agreed that SCE would recover its share of Palo Verde incremental operating costs, except if those costs exceed 95% of the levels forecast by SCE in its application by more than 30% in any given year. In such cases, SCE must demonstrate that the aggregate amount of the costs exceeding the forecast in that year is reasonable. If the annual Palo Verde site gross capacity factor is less than 55% in a calendar year, SCE will bear the burden of proof to demonstrate that the site's operations causing the gross capacity factor to fall below 55% were reasonable in that year. If operations are determined to be unreasonable by the CPUC, SCE's replacement power purchases associated with that period of Palo Verde operations below 55% gross capacity factor may be disallowed.

Beginning in 2002, the net benefits of future operation of Palo Verde Units 1, 2, and 3 will be shared equally between shareholders and customers. Likewise, beginning in 2004, the benefits of future operation of San Onofre Units 2 and 3 will be shared equally between shareholders and customers. If the MOU is implemented, the sharing of net benefits received from the post-2001 operation of Palo Verde and post-2003 operation of San Onofre Units 2 and 3 equally between shareholders and ratepayers would be eliminated, but these units would continue to be subject to cost-based ratemaking through December 31, 2010.

San Onofre Nuclear Generating Station

In 1992, the CPUC approved a settlement agreement between SCE and the ORA to discontinue operation of Unit 1 at the end of its then-current fuel cycle. In November 1992, SCE discontinued operation of Unit 1. As part of the agreement, SCE recovered its remaining investment over a four-year period ending August 1996. On December 21, 1998, SCE filed an application with the CPUC requesting authorization to access its nuclear decommissioning trust funds for Unit 1 for the purpose of commencing decommissioning of Unit 1 in 2000. On March 8, 1999, SCE, SDG&E, the ORA and TURN entered into a settlement agreement that provided for SCE to access its nuclear decommissioning trust funds for Unit 1 decommissioning. On June 3, 1999, the CPUC adopted the settlement agreement. On December 6, 1999, SCE applied for a coastal permit to demolish and remove San Onofre Unit 1 buildings and other structures and to construct a temporary used fuel storage facility, also referred to as an independent spent fuel storage installation, as part of the San Onofre Unit 1 decommissioning project. On February 15, 2000, the California Coastal Commission approved SCE's application. Decommissioning of Unit 1 is now underway and it is anticipated that decommissioning will continue through 2008. At that time, San Onofre Unit 1 will be completely dismantled and only the spent nuclear fuel will remain on-site in an independent spent fuel storage installation. All of SCE's reasonable San Onofre Unit 1 decommissioning costs will be paid from its nuclear decommissioning trust funds.

San Onofre Unit 3 is in a forced outage because of the failure of an electrical component in the non-nuclear portion of the plant resulting in a fire on February 3, 2001. The electrical circuit breaker failure and resultant fire had significant consequences beyond just the damage to the electrical components and cabling. Loss of electrical power supply in the secondary side of the plant also resulted in loss of lubricating oil to the turbine generator system while it was still rotating. This caused severe and extensive damage to the turbine generator rotors, bearings and other components. SCE presently expects that repair costs will be covered by applicable insurance except for an approximate $1.9 million deductible. SCE loses about $800,000 per day of revenue for each day of the outage under the currently effective San Onofre Units 2 and 3 Incremental Cost Incentive Pricing plan. The unit is expected to return to service at the end of June. It is estimated that the lost revenue due to this repair outage will be approximately $100 million.

The San Onofre Units 2 and 3 steam generator 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.

Additionally, in the summer of 2000, SCE applied for a coastal permit to construct a dry cask spent fuel storage installation for Units 2 and 3. This permit application was approved, with certain conditions, by the California Coastal Commission at its meeting on March 13, 2001.

Palo Verde Nuclear Generating Station

In April 2000, SCE agreed to sell its 15.8% interest in Palo Verde and its 48% interest in Four Corners Generation Station to Pinacle West Energy (PWE) for $550 million, subject to certain adjustments. The transaction remained subject to the approval of the CPUC, the Nuclear Regulatory Commission, the FERC and other state and federal entities, and to the receipt of a favorable ruling from the Internal Revenue Service. Under the sales agreement, competing offers could be solicited by SCE, subject to certain conditions, and any superior offers received were subject to certain matching rights by PWE. In late 2000, SCE received a superior offer for its Four Corners Generating Station, which PWE elected not to match. In January 2001, California state legislation was enacted which bars the sale of utility generating facilities, including SCE's Palo Verde and Four Corners generating facilities, until 2006. Under the MOU, SCE would continue to own its generating assets, which would be subject to cost-based ratemaking, through 2010.

Nuclear Facility Decommissioning

Decommissioning of San Onofre Unit 1 (shutdown 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 funds. On March 9, 2000, the NRC amended the operating licenses for San Onofre Units 2 and 3 so that the operating licenses for both units expire in 2022. Prior to that amendment, the San Onofre Units 2 and 3 operating licenses expired in 2013. The Palo Verde operating licenses currently expire in 2026 and 2028, respectively. SCE plans to decommission San Onofre Units 2 and 3 as early as 2013 and Palo Verde at the end of each unit's operating license by a removal method authorized by the NRC.

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. This estimate considers the total cost of decommissioning and dismantling the plant, including labor, material, burial, and other costs. The site-specific studies are updated approximately every three years. Changes in the estimated costs, timing of decommissioning, or the assumptions underlying these estimates could cause material revisions to the estimated total cost to decommission in the near-term. SCE estimates that it will spend approximately $8.6 billion through 2060 to decommission its nuclear facilities.

Decommissioning expenses were $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, $1.3 billion at December 31, 1999, and $1.2 billion at December 31, 1998. 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 trust accounts which, together with accumulated earnings, will be utilized solely for decommissioning.

Nuclear Insurance

Federal law limits public liability claims from a nuclear incident to $9.5 billion. SCE and other owners of 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 NRC exempted San Onofre Unit 1 from this secondary level, effective June 1994. The maximum deferred premium for each nuclear incident is $88 million per reactor, but not more than $10 million per reactor may be charged in any one year for each incident. Based on its ownership interests, SCE could be required to pay a maximum of $175 million per nuclear incident. It would have to pay, however, no more than $20 million per incident in any one year. Such amounts include a 5% surcharge if additional funds are needed to satisfy public liability claims and are subject to adjustment for inflation. If the public liability limit above is insufficient, federal regulations may impose further revenue-raising measures to pay claims, including a possible additional assessment on all licensed reactor operators.

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

Item 3. Legal Proceedings

Geothermal Generators' Litigation

On June 9, 1997, SCE filed a complaint in Los Angeles County Superior Court against an independent power producer of geothermal generation and six of its affiliated entities (Coso parties). SCE alleges that in order to avoid power production plant shutdowns caused by excessive noncondensable gas in the geothermal field brine, the Coso parties routinely vented highly toxic hydrogen sulfide gas from unmonitored release points beginning in 1990 and continuing through at least 1994, in violation of applicable federal, state, and local environmental law. According to SCE, these violations constituted material breaches by the Coso parties of their obligations under their contracts with SCE and applicable law. SCE seeks damages for excess power purchase payments made to the Coso parties and other relief. The Coso parties' motion to transfer venue to Inyo County Superior Court was granted on August 31, 1997.

The Coso parties filed a cross-complaint against SCE, The Mission Group, and Mission Power Engineering Company (Mission parties), which contains claims for breach of contract, unfair competition, interference with contract, defamation, breach of an earlier settlement agreement between the Mission parties and the Coso parties, and other claims. As against SCE, the cross-complaint seeks restitution, compensatory damages in excess of $115 million, punitive damages in an amount not less than $400 million, interest, attorney's fees, declaratory relief, and injunctive relief. As against the Mission parties, the cross-complaint seeks damages for breach of warranty of authority with respect to the settlement agreement, and for equitable indemnity. Edison International was named as a cross-defendant, allegedly as an alter ego of SCE and the Mission parties. The Coso parties voluntarily dismissed the claims against Edison International.

Three of the Coso Parties also filed a separate action in the Inyo County Superior Court against SCE and Edison International, alleging claims for unfair competition, false advertising and for violations of Public Utilities Code § 2106, and seeking injunctive relief, restitution, and punitive damages. The Court ordered this action consolidated with the SCE action.

Effective February 8, 2000, the parties entered into confidential agreements resolving all claims in the consolidated action and calling for dismissals with prejudice and releases. The settlement is subject to the approval of the CPUC. On February 10, 2000, the Court approved a stipulation staying all proceedings during the period required to obtain CPUC approval. On April 26, 2000, SCE filed an application to obtain such approval. The Commission approved the settlement at its November 21, 2000 meeting, and issued its decision on November 22, 2000. That decision became final (no longer subject to appeal) on December 22, 2000. Performance of one of the Coso Parties' settlement obligations has not occurred, delaying the filing and entry of the dismissals. The case has not yet been dismissed pending completion of certain obligations under the settlement agreements.

San Onofre Personal Injury Litigation

SCE is actively involved in three lawsuits claiming personal injuries allegedly resulting from exposure to radiation at San Onofre. In addition, a fourth lawsuit claiming personal injuries from exposure to radiation at San Onofre has recently been filed but has not yet been served on SCE.

On August 31, 1995, the wife and daughter of a former San Onofre security supervisor sued SCE and SDG&E in the U.S. District Court for the Southern District of California. Plaintiffs also named Combustion Engineering and the Institute of Nuclear Power Operations as defendants. All trial court proceedings were stayed pending ruling of the Ninth Circuit Court of Appeal, on an appeal of a lower court's judgment in favor of SCE in two earlier cases raising similar allegations. On May 28, 1998, the Court of Appeal affirmed these judgments. Pursuant to an agreement of the parties as described below, all proceedings in this matter have been stayed.

On November 17, 1995, an SCE employee and his wife sued SCE in the U.S. District Court for the Southern District of California. Plaintiffs also named Combustion Engineering. The trial in this case resulted in a jury verdict for both defendants. The plaintiffs' motion for a new trial was denied. Plaintiffs filed an appeal of the trial court's judgment to the Ninth Circuit Court of Appeal. Briefing on the appeal was completed in January 1999, oral argument took place on February 10, 2000, and the matter was taken under submission. On July 20, 2000, the Ninth Circuit Court of Appeals issued an opinion reversing the District Court judgment and ordering a retrial as to both defendants. On August 10, 2000, SCE filed a petition for rehearing with the Ninth Circuit Court of Appeals. On January 2, 2001, the Court granted SCE's rehearing petition as to certain issues and ordered further briefing on those rehearing issues within 30 days. This further briefing was filed on February 1, 2001. On February 20, 2001, the Court issued an order setting oral argument on the rehearing issues for April 26, 2001. A decision on the rehearing is not expected for at least several weeks.

On November 28, 1995, a former contract worker at San Onofre, her husband, and her son, sued SCE in the U.S. District Court for the Southern District of California. Plaintiffs also named Combustion Engineering. On August 12, 1996, the Court dismissed the claims of the former worker and her husband with prejudice, leaving only the son as plaintiff. Pursuant to an agreement of the parties as described below, all proceedings in the matter have been stayed.

In March of 1999, SCE reached an agreement with the plaintiffs in both of the cases at the U.S. District Court level to stay all proceedings including trial, pending the results of the case currently before the Ninth Circuit Court of Appeal. The parties agreed that if the plaintiffs do not receive a favorable determination on appeal then the two cases at the District Court level will be dismissed. If, however, those plaintiffs receive a favorable determination on their appeal, then the two District Court cases will be set for trial. On March 23, 1999, the District Court approved the parties' stay agreement in both cases. The stay will remain in effect until the conclusion of the appellate process, including filing and disposition of any petitions for rehearing in the Ninth Circuit or petitions for certiorari in the United States Supreme Court.

On March 1, 2001, a former contract worker at San Onofre and his wife sued SCE in the U.S. District Court for the Southern District of California. Plaintiffs also named Combustion Engineering and Bechtel Construction Company, the employer of the former San Onofre worker. This lawsuit has not yet been served upon SCE or, to SCE's knowledge, upon the other defendants.

SCE was previously involved, along with other defendants, in two earlier cases raising allegations similar to those described above. Although SCE is no longer actively involved in these actions, the impact on SCE, if any, from further proceedings in those cases against the remaining defendants cannot be determined at this time.

Navajo Nation Litigation

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

The Navajo Nation had previously filed suit in the Court of Claims against the United States Department of Interior, alleging that the Government had breached its fiduciary duty concerning the above-referenced contract negotiations. On February 4, 2000 the Court of Claims issued a decision in the Government's favor, finding that while there had been a breach, there was no available redress from the Government. In its decision, the Court indicated that it was making no statements regarding, or findings in, the above federal civil court action. That decision is on appeal. On February 28, 2000, the Hopi Tribe filed a motion to intervene in the pending litigation, alleging that the royalty payments set for their interest in the coal leases with Peabody had been impacted by the events at issue in the Navajo case. The defendants filed an opposition to the motion, and the Court calendared all pending motions for hearing on March 15, 2001.

On March 15, 2001, the District Court heard arguments, granted the Hopi Tribe's motion to intervene and denied Peabody and SCE's motions to dismiss. The parties are preparing a discovery plan and the Court set a scheduling conference for June 15, 2001.

Shareholder Litigation

These purported class actions both involve securities fraud claims arising from alleged improper accounting by Edison International and SCE of undercollections in SCE's TRA.

On October 30, 2000, a purported class action lawsuit (the "Stubblefield Action") was filed in federal district court in Los Angeles against SCE and Edison International. On December 28, 2000, plaintiffs, without requiring a response to the original complaint, filed a first amended complaint. In February 2001, the Court approved a stipulation of the parties providing that, in lieu of a motion to dismiss directed to the first amended complaint, plaintiffs would voluntarily file a second amended complaint. Pursuant to this stipulation, on March 5, 2001, plaintiffs filed a second amended complaint. The second amended complaint alleges that the companies are engaging in securities fraud by over-reporting income and improperly accounting for the TRA undercollections. The second amended complaint purports to be 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 statements. The second amended complaint seeks compensatory damages caused by the alleged fraud as well as punitive damages. The response to the second amended complaint was due April 2, 2001. As discussed below, plaintiff's counsel has agreed with counsel for Edison International and SCE that the date for Edison International and SCE to respond to the second amended complaint may be deferred.

On March 15, 2001, a purported class action lawsuit (the "King Action") was filed in federal district court in Los Angeles, California, 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 overreported income and improperly accounted for the TRA undercollections. The complaint purports to be 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. Plaintiffs seek damages, in an unstated amount, in connection with their purchase of securities during the class period.

Plaintiffs in the King Action have filed motions to consolidate this action with the Stubblefield Action, to have the named plaintiffs in both cases be appointed "lead plaintiffs' in the consolidated matter and for leave to file a consolidated complaint. Plaintiffs' and defendants' counsel in the King and Stubblefield Actions have agreed, subject to the approval of the Court, that defendants' time for responding to the Stubblefield and King Action complaints may be deferred pending resolution of motions for consolidation and to appoint lead plaintiffs, and pending the filing of a consolidated complaint. The parties have filed stipulations with the Court memorializing this agreement and seeking the Court's approval.

Power Generator Litigation

SCE is involved in seventeen separate legal actions brought by various QFs alleging SCE's failure to timely pay for power deliveries made beginning in November 2000.

On February 9, 2001, SCE was served with a complaint that was filed against it, Edison International and unnamed parties in the South (Long Beach) district of the Los Angeles Superior Court. In this complaint, plaintiff City of Long Beach alleges that SCE failed to pay the City's biomass project for power deliveries made by the project in November and December 2000. The City states causes of action for breach of contract, account stated and unjust enrichment and claims damages in an amount not less than $4,933,489.78. The City also seeks an accounting from SCE of the amounts due for power deliveries for November and December 2000. On March 30, 2001, SCE responded to the complaint by asserting a general denial and a number of affirmative defenses.

On February 20, 2001, eight geothermal generators that purport to be QFs and which are each affiliated with CE Generation commenced an action against SCE and unnamed additional defendants in the Imperial County Superior Court. In their complaint, the generators allege that SCE has breached the power purchase agreements applicable to the eight projects by failing to pay the projects for energy and capacity delivered in November and December 2000. The generators contend that their collective compensatory damages for these two months are in the range of $45,000,000 and that they expect to be owed additional monies for deliveries made in months following December 2000 for which payment is not timely made by SCE. The generators also contend that SCE's alleged wrongful failures to pay monies owed to the generators constitutes a willful violation of one or more CPUC orders and/or other applicable laws, entitling them to exemplary damages. The complaint also seeks a declaration from the Court that SCE is obligated to make immediate payment for the November and December 2000 deliveries and that SCE is further obligated to reimburse the generators for all incidental and other damages resulting from the alleged breaches of contract. Finally, the generators seek declaratory and injunctive relief to restrain SCE from preventing the generators from selling their energy and capacity to third parties during such time as SCE remains noncurrent on its alleged payment obligations.

On March 9, 2001, SCE filed an answer denying the material allegations of the complaint and raising a number of affirmative defenses, including, among others, that the Court lacks subject matter jurisdiction over the lawsuit because the formula for determining the energy price to be paid to at least seven of the eight projects for the months in question is the subject of a proceeding before the CPUC, and, accordingly, SCE contends that the CPUC has exclusive jurisdiction over the lawsuit. In addition, SCE contends that the generators are barred from recovering the monies owed because of their own "unclean hands," arising from alleged unlawful price manipulation in the natural gas market by an affiliate of the generators, which manipulation allegedly caused the price of electricity to be improperly inflated. Furthermore, SCE filed a cross-complaint alleging that four of the affected projects have operated in a manner contrary to the terms of their contracts, by not having "stand alone" facilities for processing geothermal brine (the resource powering the projects' generators) and by wrongfully diverting electricity between the projects instead of delivering that electricity directly to SCE. SCE alleges that it has sustained damages as a result of these breaches of contract in an as-yet undetermined amount.

The generators obtained Court orders permitting them to file and to have heard on an expedited basis motions for summary adjudication with respect to several of the causes of action of their complaint. As a result of the first of such motions, which was heard on March 22, 2001, the generators obtained an order permitting them to sell energy and capacity to third parties during such time as SCE remains noncurrent on its alleged payment obligations, and providing that any such interim suspension of deliveries by the generators to SCE and resale to third parties will not result in the termination or modification of the generators' contracts with SCE. SCE has requested in a motion set for hearing on April 16, 2001, that the order be lifted in light of the CPUC's March 27, 2001, decision requiring SCE to resume payments to QFs. The second of the motions, which was scheduled for hearing on April 2, 2001, seeks summary adjudication of the generators' claims that SCE has breached each of the eight contracts by failing to make payment for deliveries over the period from November 1, 2000, to and including February 28, 2001, that SCE owes approximately $101 million for such deliveries, and that the generators are entitled to recover all incidental and other damages for the suspended deliveries and any future deliveries for which payment is not paid and that the generators have the right to file and prosecute additional breach of contract actions in response to any SCE nonpayment for future deliveries. SCE filed opposition to this motion on March 23, 2001, contending, among other things, that SCE has defenses and/or affirmative claims which constitute offsets to the generators' nonpayment claims, including the defenses and cross-claims noted above. The hearing has been continued to April 16, 2001, due to SCE's intention to seek coordination of this case with other actions that QFs have commenced in various California courts on the payment issue.

On March 2, 2001, SCE was served with a lawsuit filed against it in the United States District Court, District of Nevada, by two related plaintiffs (Beowawe Power, L.L.C. and Caithness Dixie Valley L.L.C.) that hold interests in two power purchase contracts with SCE. The plaintiffs, each of which purports to be a QF as defined under federal law, operate a geothermal generating facility in Nevada. The complaint seeks damages in excess of $20,000,000, based upon SCE's failure to make timely payment for energy deliveries made beginning in November 2000. Plaintiffs are also seeking a prejudgment attachment of SCE's undivided 56% interest in the Mohave generating facility, a coal-fired plant located in Nevada. A hearing on an order to show cause why the attachment should not issue took place on March 12, 2001. On March 14, 2001, the Court issued an order granting the requested attachment subject to the plaintiffs posting required security. On March 23, 2001, plaintiffs served an amended complaint which repeats the allegations of the original complaint and which adds three new claims for declaratory relief. Specifically, the amended complaint asks the Court to declare: (1) that SCE is obligated to make immediate payments to plaintiffs for deliveries in November and December 2000 and January 2001; (2) that plaintiffs may sell the output of their projects to third parties while SCE is not paying for deliveries; and (3) that plaintiffs are entitled to incidental damages, as well as compensatory damages, arising out of SCE's alleged breach. SCE has not yet responded to the amended complaint. Plaintiffs have also filed a summary judgment motion. On April 11, 2001, SCE filed its opposition to plaintiffs' motion. No hearing date has been set. SCE has requested oral argument, but the request has not been granted.

On March 5, 2001, SCE was served with a lawsuit filed against it in Los Angeles Superior Court by seven related plaintiffs that collectively hold interests in twelve power purchase contracts with SCE. The plaintiffs each purport to be a QF as defined under federal law. The complaint seeks "several million dollars" in damages for breach of each of the twelve contracts based on SCE's alleged failure to make timely payment for energy deliveries made beginning November 2000. It also seeks a declaration that SCE is obligated to pay for past and future power deliveries under these contracts, including payments of several million dollars for deliveries in November and December 2000 and January 2001. Concurrently with serving their complaint, the plaintiffs also served applications for writs of attachment against SCE's property within the State of California. On March 28, 2001, the Court denied the applications. On April 4, 2001, SCE responded to the complaint by asserting a general denial and a number of affirmative defenses.

On March 28, 2001, SCE was served with a complaint filed against it in the San Bernardino Superior Court (Barstow District) by IMC Chemicals Inc., a QF cogeneration project located in Trona, California. The complaint alleges that SCE failed to pay plaintiff for power deliveries under the contract from November 2000 through February 2001 and seeks damages of at least $2.8 million for such alleged failure under four different causes of action: breach of the power purchase contract between plaintiff and SCE, breach of the covenant of good faith and fair dealing and two common counts (quantum meruit and quantum valebant). The complaint also seeks declarations that (1) SCE is obligated to pay plaintiff all amounts owed for power deliveries under the contract and (2) plaintiff is entitled to suspend power deliveries and resell such power to third parties so long as SCE is unable or unwilling to pay for such deliveries and that such suspension does not terminate or modify the contract. Finally, the complaint requests an injunction that would restrain SCE from demanding further deliveries of energy from plaintiff and prohibiting plaintiff from selling power to third parties. SCE has not yet responded to this complaint.

On March 28, 2001, SCE was served with a complaint filed in the Los Angeles Superior Court by NP Cogen, a QF with which SCE has a power purchase contract. The complaint alleges that SCE has failed to pay NP Cogen for power deliveries made under the contract in November and December 2000 and January and February 2001 and, based on this alleged failure to pay, seeks damages for breach of contract, breach of the covenant of good faith and fair dealing; *quantum valebant*, open book account, under California Commercial Code section 2709, *indebitatus assumpsit* and unjust enrichment. Although the prayer does not specify the amount of damages sought, several of these causes of action allege that the amount presently owing is approximately $8,000,000. The complaint also seeks a declaration that SCE has effectively repudiated the contract and NP Cogen is therefore excused from further performance thereunder. SCE has not yet responded to this complaint.

On April 2, 2001, SCE was served with a complaint filed in Los Angeles County superior court by Watson Cogeneration Company, a QF. In its complaint, Watson alleges that SCE has failed to pay Watson for power deliveries between November 2000 and February 2001 under a power purchase contract between SCE and Watson. Watson seeks at least $150,000,000 for the alleged failure to pay pursuant to causes of action including breach of contract, breach of the implied covenant of good faith and fair dealing and common counts (quantum meruit and quantum valebant). In addition, Watson seeks declarations that (1) SCE must immediately pay Watson all amounts due for power deliveries under the contract for each month since November 2000; (2) Watson is entitled to suspend power deliveries and resell such power to third parties so long as SCE does not pay for such deliveries and that such suspension does not terminate or modify the contract; and (3) Watson is entitled to recover all commercially reasonable costs incurred in reselling power to third parties. Watson also seeks an injunction that prohibits SCE from requiring Watson to continue power deliveries under the contract; from interfering with Watson's right to suspend such deliveries and resell such power to third parties; and from hindering Watson's use of interconnection facilities and related services. Moreover, under Public Utilities Code section 2106 Watson seeks exemplary damages and an injunction that would restrain SCE and its parents and affiliates from converting to its own use, and failing to pay Watson for power delivered from, amounts collected from ratepayers. Finally, under California Business and Profession Code section 17200 et seq., Watson seeks an order that it is entitled to an injunction that would prohibit SCE from continuing the unfair business practices of unfairly interfering with the operating and continued success of Watson's generating facility. Watson also claims attorneys' fees and costs under this cause of action. SCE has not yet responded to this complaint.

On April 3, 2001, SCE was served with a lawsuit filed against it in the Los Angeles County Superior Court by four plaintiffs, O.L.S. Energy –Chino, O.L.S. Energy – Camarillo, Carson Cogeneration Company and Mojave Cogeneration Company, L.P. Each plaintiff is a QF that holds a power purchase contract with SCE. The complaint alleges that SCE has failed to pay for power deliveries under each of the four contracts in November and December 2000 and January and February 2001. The complaint seeks damages of at least $42,324,539.08 for breach of the four contracts ($8,863,888.52 for the Chino contract; $9,770,153.86 for the Camarillo contract; $12,465,578.58 for the Carson contract; and $11,216,918.12 for the Mojave contract) and under common counts for quantum meruit and quantum valebant. The complaint also seeks declarations that (1) SCE is obligated to pay each plaintiff for power delivered from November 2000 through February 2001; (2) plaintiffs are entitled to suspend power deliveries to SCE and sell to third parties so long as SCE is unable or unwilling to pay for such deliveries and this suspension shall not modify or terminate the contracts; (3) plaintiffs are entitled to terminate the contracts; (4) plaintiffs are entitled to all incidental and other damages incurred in suspending their power deliveries and sell to third parties; and (5) plaintiffs have independently negotiated contracts with SCE that are not subject to CPUC decision 01-03-067. Finally, plaintiffs seek an injunction that would restrain SCE from demanding further power deliveries and refusing to permit plaintiffs to sell to third parties.

On April 3, 2001, SCE was served with a complaint filed in the Ventura County Superior Court by E.F. Oxnard, a QF with which SCE has a power purchase contract. The complaint alleges that SCE has failed to pay Oxnard for deliveries under the contract in November and December 2000 and January and February 2001. It seeks unspecified damages for breach of contract, anticipatory breach of contract and breach of the implied covenant of good faith and fair dealing and damages of $13,561,773 for common counts (open book account, quantum meruit and quantum valebant), all arising from the alleged nonpayment. SCE has not yet responded to this complaint.

On April 5, 2001, Brea Power Partners, L.P. filed a complaint in the Los Angeles County Superior Court against SCE. Brea Power Partners L.P. is a QF that has a power purchase contract with SCE. The complaint alleges that SCE has made reduced payments for power delivered under the contract from June 2000 through October 2000 and has failed to make any payments for power delivered under the contract from November 2000 through March 2001. Based on these allegations, the complaint seeks damages under causes of action for breach of contract ($1.65 million), anticipatory breach of contract and breach of the covenant of good faith and fair dealing (each, $12 million). The complaint also seeks a declaration that SCE has breached the contract and is not entitled to demand further performance thereunder and that plaintiff may sell its power to third parties. Finally, the complaint seeks an injunction restraining SCE from unlawful and unfair conduct described in the complaint, which allegedly includes not paying plaintiff and refusing to permit sales to third parties. SCE has not yet been officially served with or responded to this complaint.

On April 5, 2001, SCE submitted to the Chairperson of the California Judicial Counsel a petition requesting the coordination before a single judge of each of the foregoing Power Generator cases except the Beowawe Power case (due to the fact it is in Nevada) and the Brea Power Partners case (due to the fact that SCE was at that time unaware of this case). The petition requests an immediate stay of the actions identified in the petition while the coordination issue is being decided. On April 9, 2001, SCE filed an amended petition for the purpose of adding the Brea Power Partners case to the petition. SCE is seeking coordination of all of the QF-related lawsuits that have commenced in various California courts. On April 13, 2001, the Chair of the Judicial Council of California issued an order assigning the Supervising Judge of the Los Angeles County Complex Civil Case Litigation Program to sit as coordination motion judge to determine whether the actions SCE sought to coordinate are complex, and if so, whether coordination of the included actions is appropriate. The hearing on the motion is set for May 30, 2001.

On April 9, 2001, Inland Paperboard and Packaging, Inc. (Inland), filed a lawsuit in the United States District Court, Central District of California, Los Angeles Division, against SCE and the California Independent System Operator. Plaintiff is a QF that sells power to SCE under a power purchase contract. In its complaint, plaintiff alleges that SCE materially breached the contract by failing to pay for power deliveries thereunder, beginning with deliveries made in November 2000. The complaint also seeks declarations that plaintiff has terminated the contract by reason of SCE's alleged material breach of same but that the interconnection agreement between SCE and plaintiff remains in full force and effect. The complaint also alleges the SCE and the ISO violated 16 U.S.C. §824d(b), and SCE violated California Business & Professions Code §16720 *et seq* and interfered with prospective economic advantage by refusing to deliver power from plaintiff's project to the California energy market. Finally, plaintiff also alleges a quantum meruit cause of action against SCE for power deliveries after plaintiff allegedly terminated the contract. (The complaint also seeks a declaration that the ISO is obligated to provide plaintiff with access to the California energy market.) In addition to the declarations described in this paragraph, plaintiff prays for actual damages not less than $5,300,000, restitution, lost profits and actual and treble damages under the California Business and Professions Code.

Also on April 9, 2001, Inland filed an application for a temporary restraining order and preliminary injunction that would prevent SCE and the ISO from refusing to deliver plaintiff's power for sale into the California energy market. SCE filed opposition to this application on April 10, 2001. The matter is under submission before Judge Stephen Wilson.

On April 10, 2001, Mammoth Pacific L.P. (Mammoth) filed a lawsuit against SCE in the Mono County Superior Court. Mammoth has an interest in three QF projects that sell power to SCE under three power purchase contracts. Mammoth seeks damages of at least $16,700,000 for SCE's alleged breach of the power purchase contracts by failing to pay for power deliveries beginning with deliveries made in November 2000, under causes of action for breach of contract, *quantum meruit* and *quantum valebant*.

The complaint also alleges causes of action for breach of the implied covenant of good faith and fair dealing and unfair competition under California Business & Professions Code §17203. Mammoth seeks a temporary restraining order and a preliminary and permanent injunction to prevent SCE from taking power from Mammoth's projects without paying for it and accepting payment from customers for sales of power generated by Mammoth's projects without using such funds for any purpose other than paying Mammoth. Finally, Mammoth seeks declarations that SCE is obligated to perform under Mammoth's contracts by paying Mammoth for power delivered since November 2000; that Mammoth is entitled to suspend deliveries until 90 days after SCE has paid all amounts due under the contracts and has also demonstrated its ability and willingness to continue to pay; and that this suspension does not modify or amend the contracts. Mammoth also seeks attorneys' fees. SCE has not yet responded to this complaint.

On April 10, 2001, Heber Geothermal Company (Heber) and Second Imperial Geothermal Company (Second Imperial) filed a lawsuit against SCE in the Imperial County Superior Court. Both Heber and Second Imperial are QFs that sell power to SCE under power purchase contracts. Plaintiffs seek damages of at least $35,600,000 for SCE's alleged breach of their power purchase contracts by failing to pay for power deliveries beginning with deliveries made in November 2000, under causes of action for breach of contract, *quantum meruit* and *quantum valebant*. The complaint also alleges causes of action for breach of the implied covenant of good faith and fair dealing and unfair competition under California Business & Professions Code §17203. Plaintiffs seeks a temporary restraining order and a preliminary and permanent injunction to prevent SCE from taking power from plaintiffs without paying for it and accepting payment from customers for sales of power generated by plaintiffs without using such funds for any purpose other than paying plaintiffs. Finally, plaintiffs seek declarations that SCE is obligated to perform under plaintiffs' contracts by paying plaintiffs for power delivered since November 2000; that plaintiffs are entitled to suspend deliveries until 90 days after SCE has paid all amounts due under the contracts and has also demonstrated its ability and willingness to continue to pay; and that this suspension does not modify or amend the contracts. Plaintiffs also seek attorneys' fees. SCE has not yet responded to this complaint.

On April 10, 2001, SCE was served with a complaint filed against it by Southern California Sunbelt Developers Inc. in the Riverside County Superior Court, Indio District. This complaint alleges three causes of action for breach of the power purchase agreement between Sunbelt and SCE. In the first cause of action, Sunbelt alleges that SCE breached the contract by failing to pay for power deliveries made in November 2000; in the second cause of action, Sunbelt alleges that SCE breached the contract by failing to pay for power deliveries made in December 2000; and in the third cause of action, Sunbelt alleges that SCE breached the contract by failing to pay for power deliveries made in January 2001. Sunbelt prays for damages of at least $158,781.51. SCE has not yet responded to this complaint.

On April 11, 2001, Corona Energy Partners, Ltd. served SCE with a complaint filed against SCE in Riverside County Superior Court. Corona is a QF that holds a power purchase contract with SCE. The complaint alleges that SCE breached the contract by failing to pay for power deliveries from November 2000 through February 2001. Based on this alleged failure, Corona states causes of action for breach of contract, breach of the implied covenant of good faith and fair dealing, quantum meruit, quantum valebant and action for the price, and seeks damages of at least $13,361,096 thereunder. Under the breach of contract cause of action, Corona also alleged entitlement to unspecified amounts allegedly recoverable under Uniform Commercial Code sections 2701, 2702, 2703, 2706, 2709 and 2710. Corona also seeks declarations that it need not resume deliveries to SCE until SCE pays all amounts due and "demonstrates an unequivocal commitment and ability to pay for deliveries going forward," that Corona is entitled to resell its energy to other purchasers during this time, and SCE cannot interfere with such sales; and the suspension and reselling shall not modify or amend the contract. Finally, Corona seeks an injunction that would restrain SCE from requiring Corona to deliver to SCE while SCE is still allegedly in default of the contract; from interfering with Corona's alleged right to resell its energy to third parties; and from refusing to pay Corona while allegedly collecting billions of dollars from ratepayers. SCE has not yet responded to this complaint.

On April 11, 2001, SCE was served with a complaint filed against it by Kern River Cogeneration Company ("KRCC") and Sycamore Cogeneration Company ("Sycamore") in the Kern County Superior Court. Each plaintiff is a QF that holds a power purchase contract with SCE. Each plaintiff is also an affiliate of SCE. In the complaint, each plaintiff alleges a cause of action against SCE for breach of contract, arising from SCE's alleged failure to pay for energy deliveries from November 2000 through March 2001 (the latter month is on information and belief, since the March payment is not yet due). KRCC seeks at least $112,033,000 in damages for the alleged breach, and Sycamore seeks at least $120,407,000. Plaintiffs jointly allege a cause of action for breach of the implied covenant of good faith and fair dealing, and seek compensatory and exemplary damages therefor. Plaintiffs additionally allege violations of CPUC Code section 2106 and unfair business practices for allegedly failing to pay plaintiffs for power deliveries when SCE allegedly received tens of millions of dollars from ratepayers and seek an injunction enjoining this alleged behavior under both causes of action and reasonably attorneys fees under the unfair business practices cause of action. Finally, plaintiffs seek a declaration that each of them is entitled to suspend power deliveries until SCE makes cash payments for all past due amounts and demonstrates that it is solvent, creditworthy and able to make payments when due on an ongoing basis; that each plaintiff is entitled to resell its power without hindrance from SCE; that SCE is required to provide each plaintiff with interconnection service without charge during the suspension; and that the suspension does not breach, modify or terminate the contracts. These plaintiffs have also brought a motion for summary adjudication of the cause of action for declaratory relief. It is scheduled for hearing on May 2, 2001. SCE's opposition papers are due on April 24, 2001.

On April 12, 2001, the Proctor & Gamble Paper Products Company filed a lawsuit against SCE in the Ventura County Superior Court. Plaintiff is a QF that holds a power purchase contract with SCE. In its complaint, plaintiff alleges causes of action for breach of contract, quantum meruit and quantum valebant, arising from SCE's alleged failure to pay for power deliveries made from November 2000 through February 2001. Plaintiff seeks at least $19,770,202.97 in damages under these causes of action. Plaintiff also seeks declarations that SCE must immediately pay all sums allegedly owed for power deliveries; that SCE has materially breached the contract; that plaintiff is entitled to suspend deliveries under the contract and may use its present interconnection to SCE's system, without charge, to sell power to solvent third parties; that plaintiff is entitled to terminate the contract upon giving notice of same; and that plaintiff is entitled to damages equal to the commercially reasonable amount of suspending deliveries and reselling its power and that such suspension and resale does not modify or terminate the contract. Finally, plaintiff seeks an injunction that would restrain SCE from demanding further deliveries of energy and capacity and preventing plaintiff from selling to third parties. SCE has not yet responded to this complaint.

PX Performance Bond Litigation

On January 19, 2001, American Home Assurance Company (American Home) notified SCE that due to SCE's failure to comply with its payment obligations to the PX, the PX issued a demand to American Home on a $20,000,000 pool performance bond. American Home demanded payment from SCE by January 29, 2001, of $20,000,000 under an indemnity agreement between SCE and American Home.

SCE has exercised its right under the indemnity agreement to assume the defense of American Home against claims arising from the pool performance bond. As required by the indemnity agreement, SCE has agreed to deposit $20,000,000, plus a reasonable amount for interest and expenses, in an account in trust to be available to satisfy any judgment, should there be one, against American Home under the pool performance bond.

SCE has further instituted the alternative dispute resolution provisions provided for in the applicable PX Tariff, which provide for negotiation followed by mediation and, if unsuccessful, arbitration.

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

Inapplicable

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

Executive Officers[1] of the Registrant

Executive Officer	Age at December 31, 2000	Company Position
Stephen E. Frank	59	Chairman of the Board, President, Chief Executive Officer and Director
Harold B. Ray	60	Executive Vice President, Generation Business Unit
Pamela A. Bass	53	Senior Vice President, Customer Service Business Unit
John R. Fielder	55	Senior Vice President, Regulatory Policy and Affairs
Robert G. Foster	53	Senior Vice President, Public Affairs
Richard M. Rosenblum	50	Senior Vice President, Transmission and Distribution Business Unit
Mahvash Yazdi	49	Senior Vice President and Chief Information Officer
Bruce C. Foster	48	Vice President, Regulatory Affairs
Thomas M. Noonan	49	Vice President and Controller
Stephen E. Pickett	50	Vice President and General Counsel
W. James Scilacci	45	Vice President and Chief Financial Officer

(1) Executive Officers are defined by Rule 3b-7 of the General Rules and Regulations under the Securities Exchange Act of 1934, as amended.

None of SCE's executive officers are related to each other by blood or marriage. As set forth in Article IV of SCE's Bylaws, the elected officers of SCE are chosen annually by and serve at the pleasure of SCE's Board of Directors and hold their respective offices until their resignation, removal, other disqualification from service, or until their respective successors are elected. All of the executive officers have been actively engaged in the business of SCE for more than five years except for Mahvash Yazdi. Those officers who have not held their present position for the past five years had the following business experience.

Executive Officer	Company Position	Effective Dates
Stephen E. Frank	Chairman of the Board, President, Chief Executive Officer and Director President, Chief Operating Officer and Director	January 2000 to present June 1995 to December 1999
Pamela A. Bass	Senior Vice President, Customer Service Business Unit Vice President, Customer Solutions Business Unit Vice President, Shared Services	March 1999 to present June 1996 to February 1999 January 1996 to May 1996
John R. Fielder	Senior Vice President, Regulatory Policy and Affairs Vice President, Regulatory Policy and Affairs	February 1998 to present February 1992 to February 1998
Robert G. Foster	Senior Vice President, Public Affairs Vice President, Public Affairs	November 1996 to present November 1993 to October 1996
Richard M. Rosenblum	Senior Vice President, Transmission and Distribution Business Unit Vice President, Distribution Business Unit Vice President, Nuclear Engineering and Technical Services	February 1998 to present January 1996 to February 1998 June 1993 to December 1995
Mahvash Yazdi	Senior Vice President and Chief Information Officer Vice President and Chief Information Officer Vice President of Information Technology and Chief Information Officer, Hughes Aircraft Company[1]	January 2000 to present May 1997 to December 1999 September 1995 to May 1997
Thomas M. Noonan	Vice President and Controller Assistant Controller	March 1999 to present September 1993 to February 1999
Stephen E. Pickett	Vice President and General Counsel Associate General Counsel	January 2000 to present November 1993 to December 1999
W. James Scilacci	Vice President and Chief Financial Officer Director, 2002 General Rate Case Director, Qualifying Facility Resources	January 2000 to present August 1999 to December 1999 January 1995 to August 1999

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

PART II

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

Certain information responding to Item 5 with respect to frequency and amount of cash dividends is included in SCE's Annual Report to Shareholders for the year ended December 31, 2000 (Annual Report), under Quarterly Financial Data on page 59 and is incorporated by reference pursuant to General Instruction G(2). As a result of the formation of a holding company described above in Item 1, all of the issued and outstanding common stock of SCE is owned by Edison International and there is no market for such stock.

Item 6. Selected Financial Data

Information responding to Item 6 is included in the Annual Report under Selected Financial and Operating Data: 1996 – 2000 on page 1 and is incorporated herein by reference pursuant to General Instruction G(2).

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

Information responding to Item 7 is included in the Annual Report under Management's Discussion and Analysis of Results of Operations and Financial Condition on pages 2 through 24 and is incorporated herein by reference pursuant to General Instruction G(2).

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Information responding to Item 7A is included in the Annual Report under Management's Discussion and Analysis of Results of Operations and Financial Condition on pages 11 through 12 incorporated herein by reference pursuant to General Instruction G(2), and in Part I, Item 1 of this report on page 15 under Market Risk Exposures.

Item 8. Financial Statements and Supplementary Data

Certain information responding to Item 8 is set forth after Item 14 in Part IV. Other information responding to Item 8 is included in the Annual Report on pages 25 through 59, and is incorporated herein by reference pursuant to General Instruction G(2).

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

None.

PART III

Item 10. Directors and Executive Officers of the Registrant

Information concerning executive officers of SCE is set forth in Part I in accordance with General Instruction G(3), pursuant to Instruction 3 to Item 401(b) of Regulation S-K. Other information responding to Item 10 will be incorporated by reference from SCE's definitive Joint Proxy Statement (Proxy Statement) filed with the SEC in connection with SCE's Annual Meeting to be held on May 14, 2001, under the heading, Election of Directors and Section 16(a) Beneficial Ownership Reporting Compliance, and is incorporated herein by reference pursuant to General Instruction G(3).

Item 11. Executive Compensation

Information responding to Item 11 will be incorporated by reference from SCE's definitive Proxy Statement under the headings Board Compensation, Executive Compensation, Summary Compensation Table, Option/SAR Grants in 2000, Aggregated Option/SAR Exercises in 2000 and FY-End Option/SAR Values, Long-Term Incentive Plan Awards in Last Fiscal Year, Pension Plan Table, Other Retirement Benefits, Employment Contracts and Termination of Employment Arrangements, and Compensation and Executive Personnel Committees' Interlocks and Insider Participation, and is incorporated herein by reference pursuant to General Instruction G(3).

Item 12. Security Ownership of Certain Beneficial Owners and Management

Information responding to Item 12 will be incorporated by reference from SCE's definitive Proxy Statement under the headings Stock Ownership of Directors and Executive Officers and Stock Ownership of Certain Shareholders, and is incorporated herein by reference pursuant to General Instruction G(3).

Item 13. Certain Relationships and Related Transactions

Information responding to Item 13 will be incorporated by reference from SCE's definitive Proxy Statement under the heading Certain Relationships and Transactions of Nominees and Executive Officers and Other Management Transactions, and is incorporated herein by reference pursuant to General Instruction G(3).

PART IV

Item 14. Exhibits, Financial Statement Schedules, and Reports on Form 8-K

(a)(1) Financial Statements

The following items contained in the Annual Report are found on pages 2 through 61, and incorporated by reference in this report.

Management's Discussion and Analysis of Results of Operations and Financial Condition
Consolidated Statements of Income – Years Ended December 31, 2000, 1999 and 1998
Consolidated Statements of Comprehensive Income – Years Ended
December 31, 2000, 1999, and 1998
Consolidated Balance Sheets – December 31, 2000, and 1999
Consolidated Statements of Cash Flows – Years Ended December 31, 2000, 1999, and 1998
Consolidated Statements of Changes in Common Shareholder's Equity – Years Ended
December 31, 2000, 1999, and 1998
Notes to Consolidated Financial Statements
Responsibility for Financial Reporting
Report of Independent Public Accountants

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

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

	Page
Report of Independent Public Accountants on Supplemental Schedules	45
Schedule II – Valuation and Qualifying Accounts for the Years Ended December 31, 2000, 1999, and 1998	46

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

(a)(3) Exhibits

See Exhibit Index beginning on page 50 of this report.

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

(b) Reports on Form 8-K

October 17, 2000	TRA Undercollections
November 3, 2000	$1.3B Notes
December 22, 2000	TRA Undercollections and Other Events

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS
ON SUPPLEMENTAL SCHEDULES

To Southern California Edison Company:

We have audited, in accordance with auditing standards generally accepted in the United States, the consolidated financial statements included in the 2000 Annual Report to Shareholders of Southern California Edison Company (SCE) incorporated by reference in this Form 10-K, and have issued our report thereon dated April 12, 2001. Our report on the financial statements includes an explanatory paragraph with respect to SCE's ability to continue as a going concern as discussed in Notes 2 and 3 to the financial statements. Our audits were made for the purpose of forming an opinion on those consolidated financial statements taken as a whole. The supplemental schedules listed in Part IV of this Form 10-K are the responsibility of SCE's management and are presented for purposes of complying with the Securities and Exchange Commission's rules and regulations, and are not part of the consolidated financial statements. These supplemental schedules have been subjected to the auditing procedures applied in the audits of the consolidated financial statements and, in our opinion, fairly state in all material respects the financial data required to be set forth therein in relation to the consolidated financial statements taken as a whole.

Arthur Andersen
ARTHUR ANDERSEN LLP

Los Angeles, California
April 12, 2001

Southern California Edison Company

SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS

For the Year Ended December 31, 2000

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

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

Southern California Edison Company

SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS

For the Year Ended December 31, 1999

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
		(In thousands)			
Group A:					
Uncollectible accounts					
Customers	$ 19,596	$ 21,968	$ —	$ 19,908	$ 21,656
All other	2,634	1,288	—	913	3,009
Total	$ 22,230	$ 23,256	$ —	$ 20,821(a)	$ 24,665
Group B:					
DOE Decontamination and Decommissioning	$ 39,419	$ —	$ (134)(b)	$ 4,695(c)	$ 34,590
Purchased-power settlements	129,697	466,043	—	32,281(d)	563,459
Pension and benefits	239,668	48,894	21,674(e)	77,335(f)	232,901
Insurance, casualty and other	73,249	37,674	—	42,043(g)	68,880
Total	$ 482,033	$ 552,611	$ 21,540	$ 156,354	$ 899,830

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

Southern California Edison Company

SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS

For the Year Ended December 31, 1998

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
		(In thousands)			
Group A:					
Uncollectible accounts					
Customers	$ 24,245	$ 19,808	$ —	$ 24,457	$ 19,596
All other	2,208	2,273	—	1,847	2,634
Total	$ 26,453	$ 22,081	$ —	$ 26,304(a)	$ 22,230
Group B:					
DOE Decontamination and Decommissioning	$ 44,336	$ —	$ (89)(b)	$ 4,828(c)	$ 39,419
Purchased-power settlements	145,640	—	—	15,943(d)	129,697
Pension and benefits	211,200	170,743	18,988(e)	161,263(f)	239,668
Insurance, casualty and other	78,461	69,275	—	74,487(g)	73,249
Total	$ 479,637	$ 240,018	$ 18,899	$ 256,521	$ 482,033

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

SIGNATURES

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

SOUTHERN CALIFORNIA EDISON COMPANY

By:

Kenneth S. Stewart
Assistant General Counsel

Date: April 17, 2001

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

Signature	Title	Date
Principal Executive Officer:		
Stephen E. Frank*	Chairman of the Board, President, Chief Executive Officer and Director	April 17, 2001
Principal Financial Officer:		
W. James Scilacci*	Vice President and Chief Financial Officer	April 17, 2001
Controller or Principal Accounting Officer:		
Thomas M. Noonan*	Vice President and Controller	April 17, 2001
Board of Directors:		
Warren Christopher*	Director	April 17, 2001
Stephen E. Frank*	Director	April 17, 2001
Joan C. Hanley*	Director	April 17, 2001
Carl F. Huntsinger*	Director	April 17, 2001
Charles D. Miller*	Director	April 17, 2001
Luis G. Nogales*	Director	April 17, 2001
Ronald L. Olson*	Director	April 17, 2001
James M. Rosser*	Director	April 17, 2001
Robert H. Smith*	Director	April 17, 2001
Thomas C. Sutton*	Director	April 17, 2001
Daniel M. Tellep*	Director	April 17, 2001
Edward Zapanta*	Director	April 17, 2001

*By:

Kenneth S. Stewart
Assistant General Counsel

EXHIBIT INDEX

Exhibit Number	Description
3.1	Certificate of Amendment and Restated Articles of Incorporation of SCE effective June 1, 1993 (File No. 1-2313, Form 10-K for the year ended December 31, 1993)*
3.2	Certificate of Correction of Restated Articles of Incorporation of SCE dated effective August 21, 1997 (File No. 1-2313, Form 10-Q for the quarter ended September 30, 1997)*
3.3	Amended Bylaws of Southern California Edison Company as adopted by the Board of Directors on February 15, 2001
4.1	SCE First Mortgage Bond Trust Indenture, dated as of October 1, 1923 (Registration No. 2-1369)*
4.2	Supplemental Indenture, dated as of March 1, 1927 (Registration No. 2-1369)*
4.3	Third Supplemental Indenture, dated as of June 24, 1935 (Registration No. 2-1602)*
4.4	Fourth Supplemental Indenture, dated as of September 1, 1935 (Registration No. 2-4522)*
4.5	Fifth Supplemental Indenture, dated as of August 15, 1939 (Registration No. 2-4522)*
4.6	Sixth Supplemental Indenture, dated as of September 1, 1940 (Registration No. 2-4522)*
4.7	Eighth Supplemental Indenture, dated as of August 15, 1948 (Registration No. 2-7610)*
4.8	Twenty-Fourth Supplemental Indenture, dated as of February 15, 1964 (Registration No. 2-22056)*
4.9	Eighty-Eighth Supplemental Indenture, dated as of July 15 1992 (File No. 1-2313, Form 8-K dated July 22, 1992)*
4.10	Indenture dated as of January 15, 1993 (File No. 1-2313, Form 8-K dated January 28, 1993)*
4.11	Indenture dated as of May 1, 1995 (File No. 1-2313, Form 8-K dated May 24, 1995)*
10.1	1981 Deferred Compensation Agreement (File No. 1-2313, filed as Exhibit 10.2 to Form 10-K for the year ended December 31, 1981)*
10.2	1985 Deferred Compensation Agreement for Executives (File No. 1-2313, filed as Exhibit 10.3 to Form 10-K for the year ended December 31, 1986)*
10.3	1985 Deferred Compensation Agreement for Directors (File No. 1-2313, filed as Exhibit 10.4 to Form 10-K for the year ended December 31, 1986)*
10.4	Director Deferred Compensation Plan (File No. 1-2313, filed as Exhibit 10.3 to Form 10-Q for the quarter ended June 30, 1998)*
10.5	Director Grantor Trust Agreement (File No. 1-2313, filed as Exhibit 10.10 to Form 10-K for the year ended December 31, 1995)*
10.6	Executive Deferred Compensation Plan (File No. 1-2313, filed as Exhibit 10.2 to Form 10-Q for the quarter ended March 31, 1998)*
10.7	Executive Grantor Trust Agreement (File No. 1-2313, filed as Exhibit 10.12 to Form 10-K for the year ended December 31, 1995)*
10.8	Executive Supplemental Benefit Program (File No. 1-2313, filed as Exhibit 10.2 to Form 10-Q for the quarter ended September 30, 1999)*
10.9	Dispute resolution amendment of 1981 Executive Deferred Compensation Plan, 1985 Executive and Director Deferred Compensation Plans and Executive Supplemental Benefit Program (File No. 1-2313, filed as Exhibit 10.21 to Form 10-K for the year ended December 31, 1998)*
10.10	Executive Retirement Plan (File No. 1-2313, filed as Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 1999)*
10.11	Executive Incentive Compensation Plan (File No. 1-2313, filed as Exhibit 10.12 to Form 10-K for the year ended December 31, 1997)*
10.12	Executive Disability and Survivor Benefit Program (File No. 1-2313, filed as Exhibit 10.22 to Form 10-K for the year ended December 31, 1994)*
10.13	Retirement Plan for Directors (File No. 1-2313, filed as Exhibit 10.2 to Form 10-Q for the quarter ended June 30, 1998)*

Exhibit Number	Description
10.14	Officer Long-Term Incentive Compensation Plan (File No. 1-2313, filed as Exhibit 10.3 to Form 10-Q for the quarter ended March 31, 1998)*
10.15	Equity Compensation Plan (File No. 1-2313, filed as Exhibit 10.1 to Form 10-Q for the quarter ended June 30, 1998)*
10.15.1	Amendment No. 1 to the Equity Compensation Plan (File No. 1-2313, filed as Exhibit 10.3 to Form 10-Q for the quarter ended June 30, 2000)*
10.16	2000 Equity Plan (File No. 1-2313, filed as Exhibit 10.1 to Form 10-Q for the quarter ended June 30, 2000)*
10.17	Forms of Agreement for long-term compensation awards under the Officer Long-Term Incentive Compensation Plan, the Equity Compensation Plan or the 2000 Equity Plan (File No. 1-2313, for 1991–1995 awards filed as Exhibit 10.21.1 to Form 10-K for the year ended December 31, 1995, for 1996 awards filed as Exhibit 10.16.2 to Form 10-K for the year ended December 31, 1996, for 1997 awards filed as Exhibit 10.16.3 to Form 10-K for the year ended December 31, 1997, for 1998 awards filed as Exhibit 10.4 to Form 10-Q for the quarter ended June 30, 1998, for 1999 awards filed as Exhibit 10.1 to Form 10-Q for the quarter ended March 31, 1999, for January 2000 awards filed as Exhibit 10.1 to Form 10-Q for the quarter ended March 31, 2000, and for May 2000 awards filed as Exhibit 10.2 to Form 10-Q for the quarter ended June 30, 2000)*
10.18	Form of Agreement for 2000 Director Awards under the Equity Compensation Plan (File No. 1-2313, filed as Exhibit 10.3 to Form 10-Q for the quarter ended June 30, 2000)*
10.19	Estate and Financial Planning Program as amended April 1, 1999 (File No. 1-2313, filed as Exhibit 10.2 to Form 10-Q for the quarter ended June 30, 1999)*
10.20	Option Gain Deferral Plan as restated September 15, 2000
10.21	Employment Letter Agreement with Bryant C. Danner (File No. 1-2313, filed as Exhibit 10.27 to Form 10-K for the year ended December 31, 1992)*
10.22	Employment Letter Agreement with Stephen E. Frank (File No. 1-2313, filed as Exhibit 10.25 to Form 10-K for the year ended December 31, 1995)*
10.23	Election Terms for Warren Christopher (File No. 1-2313, filed as Exhibit 10.21 to Form 10-K for the year ended December 31, 1997)*
10.24	Dispute resolution amendment of 1981 Executive Deferred Compensation Plan, 1985 Executive and Director Deferred Compensation Plans and Executive Supplemental Benefit Program (File No. 1-2313, filed as Exhibit 10.20 to Form 10-K for the year ended December 31, 1998)*
10.25	Memorandum of Understanding with Governor Davis's Transmittal Letter dated April 9, 2001
12.	Computation of Ratios of Earnings to Fixed Charges
13.	Annual Report to Shareholders for year ended December 31, 2000
23.	Consent of Independent Public Accountants – Arthur Andersen LLP
24.1	Power of Attorney
24.2	Certified copy of Resolution of Board of Directors Authorizing Signature

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

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